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CERTS Customer Adoption Model

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1. Introduction

1.1 CERTS Context

This effort represents a contribution to the wider distributed energy resources (DER) research of the Consortium for Electric Reliability Technology Solutions (CERTS, http://certs.lbl.gov) that 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. The longer term goal of the Berkeley Lab effort is to guide the wider technical research towards the key technical problems by forecasting some likely patterns of DER adoption. In sharp contrast to traditional electricity utility planning, this work takes a customer-centric approach and focuses on DER adoption decision making at, what we currently think of as, the customer level. This study reports on Berkeley Lab's second year effort (completed in Federal fiscal year 2000, FY00) of a project aimed to anticipate patterns of *customer* adoption of distributed energy resources (DER). Marnay, *et al.*, 2000 describes the earlier FY99 Berkeley Lab work. The results presented herein are not intended to represent definitive economic analyses of possible DER projects by any means. The paucity of data available and the importance of excluded factors, such as environmental implications, are simply too important to make such an analysis possible at this time. Rather, the work presented represents a demonstration of the current model and an indicator of the potential to conduct more relevant studies in the future.

1.2 Microgrid Concept

CERTS is building its DER research effort upon an innovative fundamental concept known as the *microgrid*. A microgrid is a semi-autonomous grouping of loads and generation under some form of coordinated control, active or passive. It is connected to the power grid, as we currently know it, by some form of interface that allows the microgrid 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 a generator. The CERTS expectation is that improved small-scale generating technology, limits on the continued expansion of the current power system, the potential for application of combined heat and power (CHP) technologies, and improved customer control over service quality and reliability will together make generation of electricity close to end uses competitive with central station generation.

A typical microgrid may be a cluster of generators and loads capable of operating in a coordinated fashion autonomously or semi-autonomously from the wider power grid. The cluster would most likely exist on a small dense group of contiguous geographic sites, but could be more dispersed and transfer electrical energy through a distribution network and/or heat energy through other media. The generators and loads within the cluster are placed and coordinated to minimize the 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.

The heart of the microgrid concept is the notion of a controllable interface between the microgrid and the wider power system. This interface can separate the two sides electrically, but connects them economically. On the inside, the conditions and quality of service are determined by the microgrid, while flows across the dividing line are motivated by the prevailing valuation of energy and other services on either side of the interface at any instant. From the customer side of the interface, the microgrid should appear as an autonomous power system functioning optimally to meet the requirements of the customer. Operating schedules and reliability performance should be those that support the customers' objectives. From the wider power system side, however, the microgrid should appear as a good citizen of the grid, whether it be a net source, sink, or both at various times. In its simplest form, the interface could be a simple barrier that allows the microgrid to island itself and resynchronize as desired. While operating in island mode, the microgrid need serve only its own requirements, although the control capability to facilitate this may be complex. While operating in normal connected mode, the microgrid must be a good citizen.

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 centralized authority. The ongoing deregulation of generation represents the first step towards abandoning the centralized 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 coordinated global ones.

The emergence of the microgrid stratifies the current strictly hierarchical centralized control of the power system into at least two layers. The upper layer is the one with which current power engineers are familiar; that is, the high voltage meshed power grid. A centralized control center 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. Control of the generating assets is governed by extremely precise technical standards 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 recognized that these standards are not economically optimal in the sense that the benefits of improving reliability are weighed against its costs, and vice-versa. Rather, reliability is based on arbitrary targets and are translated into engineering specifications that are believed will meet the targets.

The loads and generators within the microgrid not only appear as components of the microgrid's overall buying and selling pattern, but also may form complex economic relationships among themselves; e.g., through bilateral or multilateral contracts for electricity, fuels, ancillary services, and heat for CHP applications. The microgrid forms a low voltage neighborhood of the power system that obeys the upper layer central command center only to the extent that its behavior at the node is in keeping with the rigorous requirements of the grid, i.e., it is a good citizen. Locally within the microgrid, standards of operation, and methods of control could diverge significantly from the norms of the upper layer, and between microgrids, given its own requirements.

1.3 Approach of Current Work

The approach taken in this work, since the outset, has been customer oriented. The starting point is established methods of minimizing the cost of meeting a known electrical load, 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, in essence, 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 economic perspective.

2. Mathematical Model

2.1 Introduction

In this section the FY00 version of the CERTS Customer Adoption Model (C-CAM) is presented. This version of the model has been programmed in GAMS (General Algebraic Modeling System).[1] This section contains a brief description of this software and the reasons behind its selection for this task and concludes with a description of the present version of the model, as well as its 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 C-CAM. For example, only equipment first cost as claimed by the manufacturer is used; 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, possibly reliability benefits and CHP application is 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 minimize the cost of supplying electricity to a specific customer by optimizing the installation of distributed generation and the self-generation of part or all of its electricity." In other words, the focus of this work continues to be strictly economic. In order to attain this objective, the following issues must be addressed:

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

For this study, it is assumed that the customer wants to install distributed generation to minimize the cost of electricity consumed on site. Consequently, it should be 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.

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

Key inputs into the model are:

- the customer's load profile,
- the customer's default tariff Southern California Edison (SCE) tariffs that apply to the customer,
- the capital, operating and maintenance (O&M), and fuel costs of the various available technologies, together with the interest rate on customer investment,
- the basic physical characteristics of alternative generating technologies, and
- the California Power Exchange (CalPX) price at all hours of the year.

Outputs to be determined by the optimization 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, and
- if the customer should, from an economic point of view, remain connected to the grid.

Some of the assumptions that were established from the previous study (Marnay, *et al.*, 2000) have been maintained, but some others have changed. The key maintained assumptions are:

- 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 Additions to the Model

The main advantage of C-CAM is its flexibility. The use of GAMS enables the model to be complex without hindering the ability of researchers to make adjustments in the details. Consequently, run time is dramatically improved, and ultimately this code could be embedded in a broader customer adoption decision tool.

The new features added to the customer adoption model are a good example of the flexibility that has been previously mentioned. The new features are as follows:

- More DER options are evaluated. Currently, thirty different types of distributed energy generation options are considered simultaneously.
- More detailed hourly simulation of equipment operations of the adopted generation is endogenously determined by the solution.
- The optimal investment combination and associated hourly operation is almost always a feasible and quickly identified solution.
- C-CAM provides easier access to some important information, such as the effective marginal price of electricity to the customer, which could be either the net effect of the customer’s monthly bill of an incremental kW in a certain hour or the marginal operating cost of an adopted technology.
- Implementation of new tariffs is now easier.
- The solution is obtained much faster than before, typically in seconds rather than days.
- More options are implemented: three different ways to handle sales, three different ways to purchase electricity, and application of a stand-by charge at will. These options will be explained later.

2.4 Justification for Using GAMS

Electricity utility expansion planning and operations simulation has a long history, and many methods have been developed for solving a problem that is very similar to the one addressed in this work. Some of the established approaches are based on rule-of-thumb chronological simulation of system operation, some are based on mathematical approximations to actual system operation, and yet others apply optimization techniques (Marnay and Strauss, 1989). The reason the economics of customer adoption can be readily modeled by a mathematical optimization problem rests on the assumption that the customer always tries to minimize internal cost. Moreover, the use of optimization techniques has the added advantage of offering robust and powerful tools that can almost guarantee finding an optimal solution.

Obviously, the use of classic optimization techniques has some significant limitations; notably, some customer decisions (adoptions) are likely to be more qualitative than quantitative. For example, some “benefits,” such as great perceived control over electricity supply, cannot be easily translated to economic values. However, in the context of the present work these limitations are not expected to be important, although efforts will certainly be made in subsequent years to address them. There are additional purely mathematical limitations that will eventually arise. For example, the costs of small scale generators are not fixed, as is required in C-CAM’s current formulation, but will tend to fall as a customer's experience with a certain technology accumulates. In other words, while the first unit of a certain generating technology may not be the most attractive to a customer, given that it has experience with the technology, subsequent units may be attractive.

In other work at Berkeley Lab, some less mature simulation tools, such as autonomous agents models were also reviewed. These are being applied to DER operational problems in some cases (see Gibson and Ishii, 1999).

Ultimately, the GAMS software was selected because it:

- provides a high-level language for the compact representation of large and complex models;
- allows changes to be made in model specifications simply and safely;
- allows unambiguous statements of algebraic relationships; and
- permits model descriptions that are independent of solution algorithms.

While there are some other optimization software packages that have these same qualities, GAMS is widely used and well known to the research team.

2.5 Mathematical Formulation

This section describes in detail the core mathematical problem solved by C-CAM. It is structured into three main parts. First, the names of all input parameters are listed. Second, the decision variables are defined. And third, the mathematical formulation is presented for two possible tariff options.

2.5.1 Variables and Parameters Definition

2.5.1.1 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***
$DERmaxp_i$	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] 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.
[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.

2.5.1.2 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.

2.5.2 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. buying that power from the distribution company at the regulated tariff; or
2. 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.

2.5.2.1 Option 1: Buying at the Default Regulated Tariff

The mathematical formulation of the problem follows:

$$\min_{InvGen, GenL, GenX} \quad \sum_m RTFCharge \cdot max(DRLoad_{m,t,h}) + \sum_m RTCCharge$$

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

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

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

$$+\sum_{i} InvGen_i \cdot \left(DERcapcost_i + DEROMfix_i\right) \cdot AnnuityF$$

$$+\sum_{m}\sum_{i} InvGen_i \cdot DERmaxp_i \cdot StandbyC$$

$$-\sum_{i}\sum_{m}\sum_{t}\sum_{h} \left(GenX_{i,m,t,h} \cdot PX_{m,t,h}\right) \qquad (1)$$

Subject to:

$$Cload_{m,t,h} = \sum_{i} GenL_{i,m,t,h} + DRLoad_{m,t,h} \quad \forall_{m,t,h} \qquad (2)$$

$$GenL_{i,m,t,h} + GenX_{i,m,t,h} \le InvGen_i \cdot DERmaxp_i \quad \forall_{m,t,h} \qquad (3)$$

$$GenX_{i,m,t,h} = 0 \text{ } if \sum_{i} GenL_{i,m,t,h} < Cload_{m,t,h} \quad \forall_{i,m,t,h} \qquad (4)$$

$$AnnuityF = \frac{IntRate}{\left(1 - \frac{1}{\left(1 + IntRate\right)^{DERlifetime_i}}\right)} \qquad (5)$$

Equation (1) is the objective function which says that the customer will try to minimize 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 annualizes the capital cost of owning on-site generating equipment.

2.5.2.2 Option 2: Buying from Alternative Energy Providers

The problem mathematical formulation follows:

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

$$+\sum_{i}\sum_{m}\sum_{t}\sum_{h} \left(GenL_{i,m,t,h} + GenX_{i,m,t,h}\right) \cdot DERCostkWh_i$$

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

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

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

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

(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

Here, we describe the load consumption patterns of five typical southern California commercial electricity customers (restaurant, grocery store, shopping mall, office complex, and a microgrid, i.e., an entity that is composed of the four main customers acting as one). The load profiles were extracted from Maisy[7] from the year 1998 data for the state of California, and considering only those customers which are located in Southern California Edison (SCE) territory (since these are the utility rates used for the analysis).

The selected commercial customers have a larger weight in the total number of commercial customers than probably any other. The description of every type of customer according to Maisy is:

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

The data are organized into day-types. Every load detail includes 24 hourly electricity loads (measured in kW) for each of three day-types in each of the twelve months. Day-types are:

- peak day
- average weekday
- weekend

In order to match the 365 days in a year, the following number of type-days has been considered:

- 20 weekdays per month for those months with 31 days, 19 weekdays for those months with 30 days and 17 weekdays for February;
- 3 peak days per month for all of them; and
- 8 weekend days per month for all of them (weekend includes Saturdays and Sundays).

Having three different day-types yields a more accurate analysis of the real load profile of these customers because average CalPX prices for those day-types can be calculated and assigned to them.

[7] Maisy (Market Analysis and Information System) is an energy industry source 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.

3.1 Grocery

Before implementing the customer adoption model it is useful to have a look at the load profile of the grocery and discuss some of its main characteristics. The peak load profiles of January and August are chosen as representative ones.

The January load profile (see Figure 1) is very flat compared to that for August (see Figure 2), with a ratio of minimum load to maximum load of 274 kW / 334 kW = 0.82. On the other hand, August has a noticeable peak in the central hours of the day (around 13:00) and the ratio of minimum load to maximum is 0.65. These trends can also be noticed in the other months, e.g., from April until October, the load profiles have a clear peak, not as high as in August, but still quite noticeable. On the other hand, months from November to March pose a much flatter load profile, like the one for January.

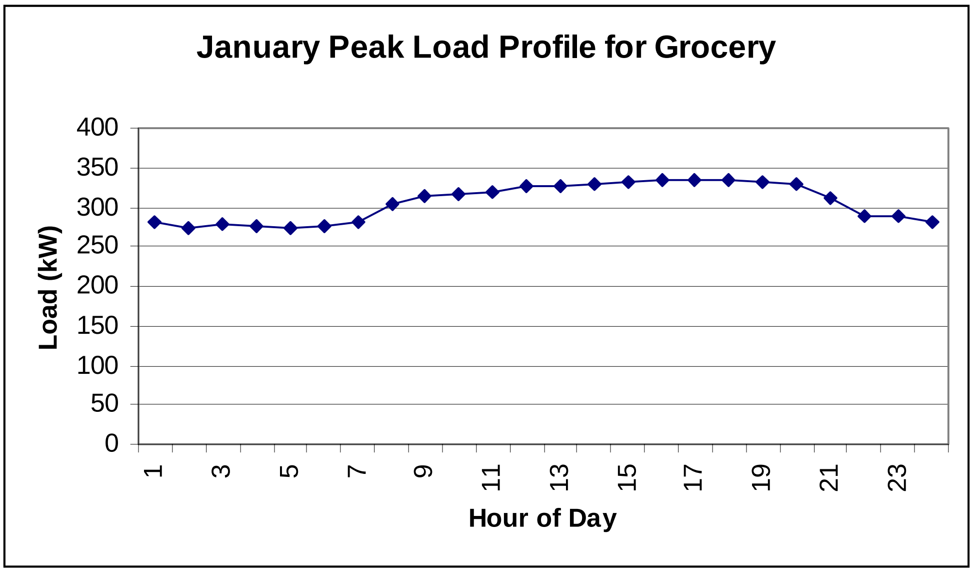

Figure 1. January Peak Load Profile for Grocery

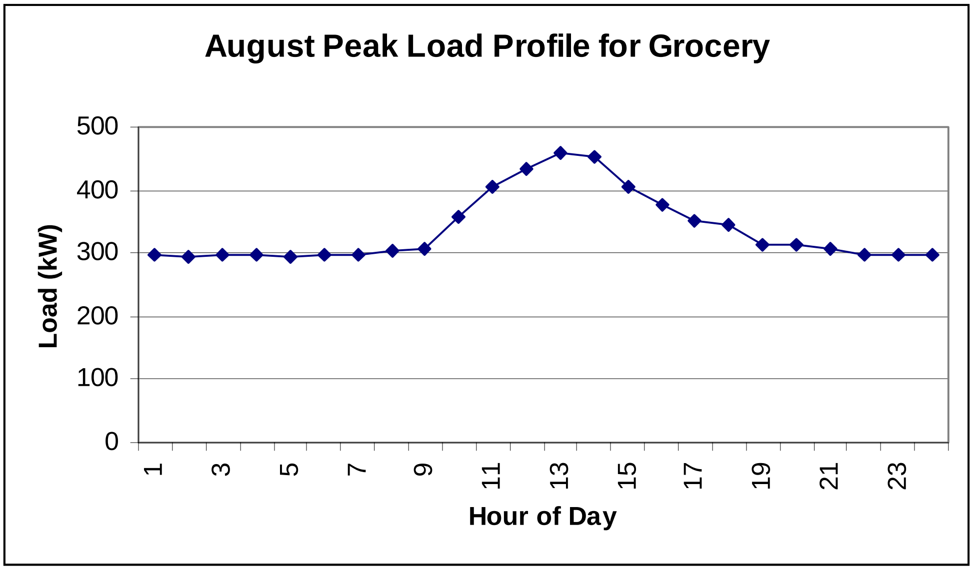

Figure 2. August Peak Load Profile for Grocery

Another important characteristic of the load profile is the load factor. The load factor is the ratio of the average to the maximum or peak demand during the entire year and gives a sense of the load profile (i.e., flatter load profiles will have a larger load factor, whereas load profiles with peaks have a smaller load factors). A high load factor means the load is at or near the peak a good portion of the time. In the case of the grocery, the load factor is 0.62, which indicates that the maximum demand is significantly larger than the average one (the annual average demand is 283 kW, the maximum is 457 kW, and the minimum one is 167 kW).[8]

3.2 Restaurant

The load profile of the restaurant, for both January and August (see and Figure 4, respectively), remains quite flat and without noticeable changes (except for the maximum and minimum loads that are, of course, higher in August). The ratio of minimum load to maximum load is 0.62 for January and 0.68 for August, and both load profiles present a high level of sustained demand from around 12 noon to 22:00. During the remaining hours, the load is stable at a low level. This load profile responds, probably, to the type of activity taking place in restaurants that has a higher demand between the mentioned hours.

[8] All the data and results for the different cases and load profiles are presented at the end in the Appendix.

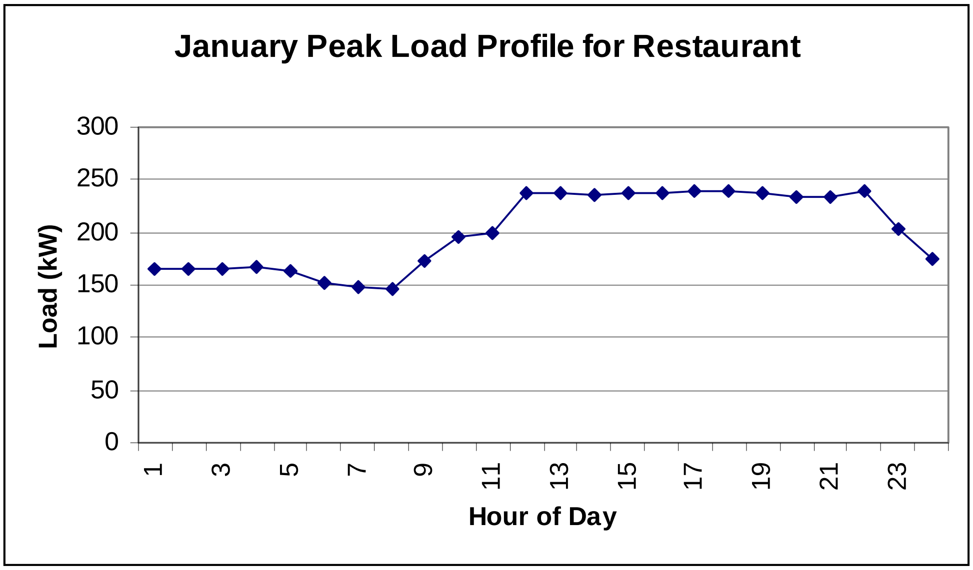

Figure 3. January Peak Load Profile for Restaurant

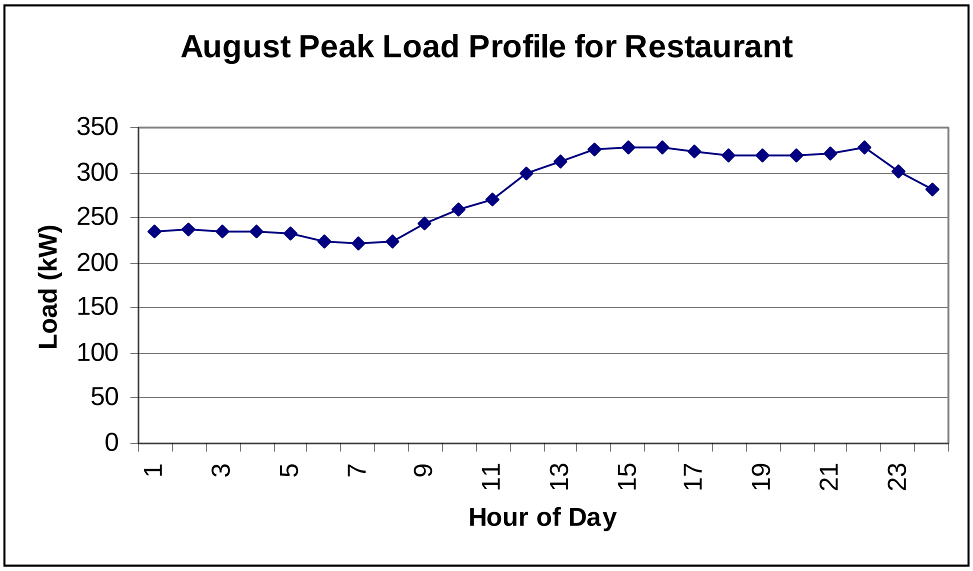

Figure 4. August Peak Load Profile for Restaurant

The load factor for the restaurant is 0.60, indicating that the maximum demand (328 kW) is well above the average one (197 kW).

3.3 Office

The peak load profiles during January and August (see Figure 5 and Figure 6, respectively) are quite different for the office complex. In both cases, the ratio of minimum load to maximum load is quite low (0.41 in January and 0.45 in August).

However, the shape of the profile is different. Whereas in August the peak takes place at around 15:00 (the hottest part of the day, so probably the result of air conditioning working at full power), in January, the peak occurs at the beginning of the day, between hours 6:00 and 7:00.

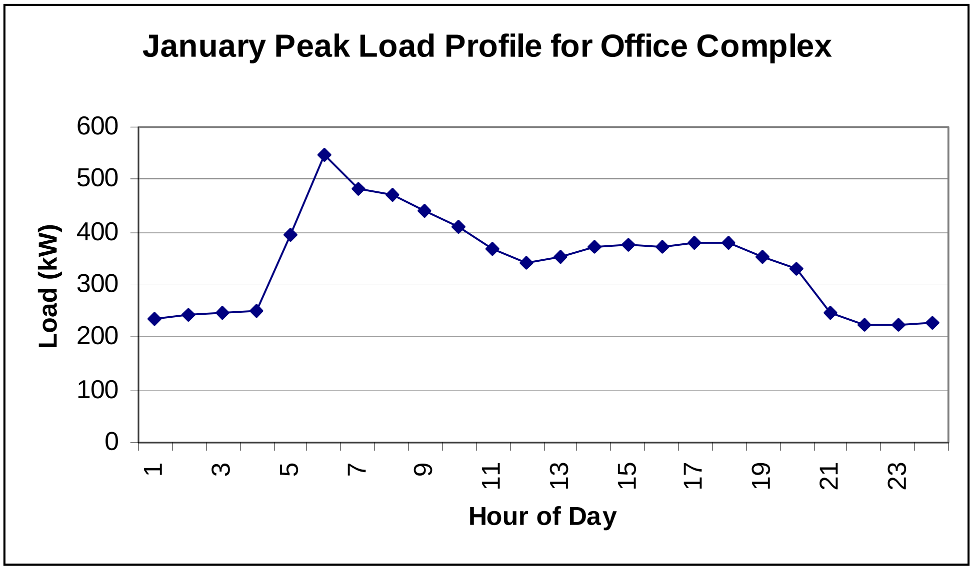

Figure 5. January Peak Load Profile for Office Complex

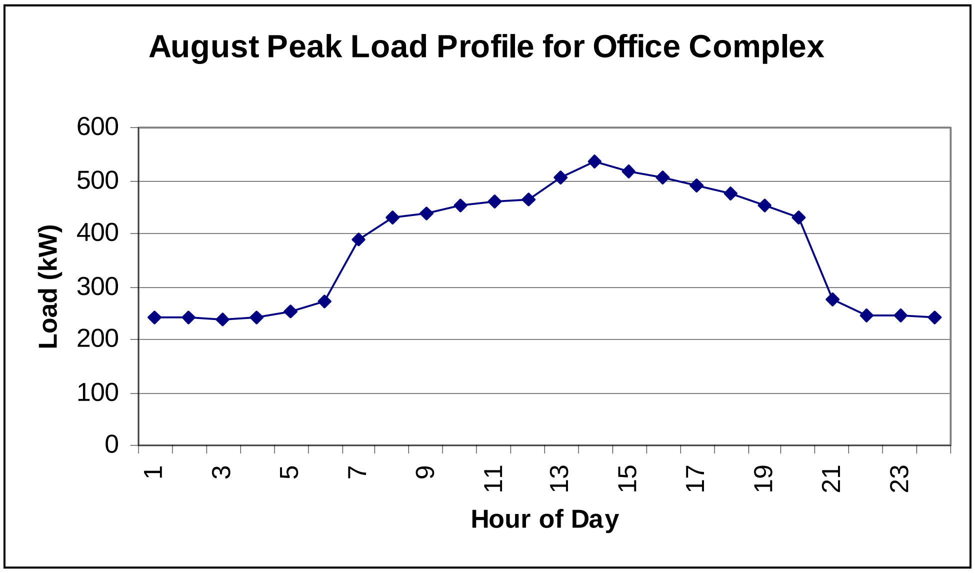

Figure 6. August Peak Load Profile for Office Complex

The load factor for this customer is 0.42, quite low, which means that there is a big difference between the maximum load demanded (peak at 545 kW) and the average power (229 kW).

3.4 Mall

The load profile for the mall is quite interesting because it is possible to find big differences during the year. In this case, the ratio of minimum to maximum load is smaller in January than it is in August (0.31 in January and 0.53 in August). This implies that the difference between minimum load and the peak is more evident in January than in August (for the other customer types, so far, the opposite was true). Moreover, differences in the shape of the profiles for those months are worth mentioning.

January (see Figure 7) presents a sustained high level of load demand from approximately 10:00 to 22:00, and then the demand drops dramatically to the low level. The load coincides with the hours of operation of a commercial mall.

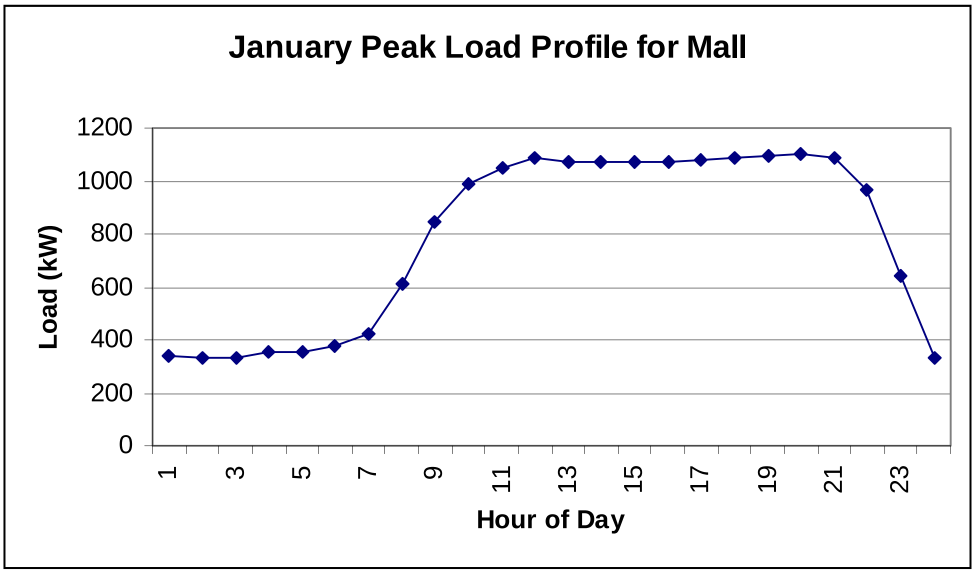

Figure 7. January Peak Load Profile for Mall

On the other hand, August (see Figure 8), with higher load levels, has a clear peak in the profile at around 15:00 (again, as in the case of the office, during the hottest part of the day). In all other hours, the load declines to or rises from the level that is maintained from around 22:00 to 10:00.

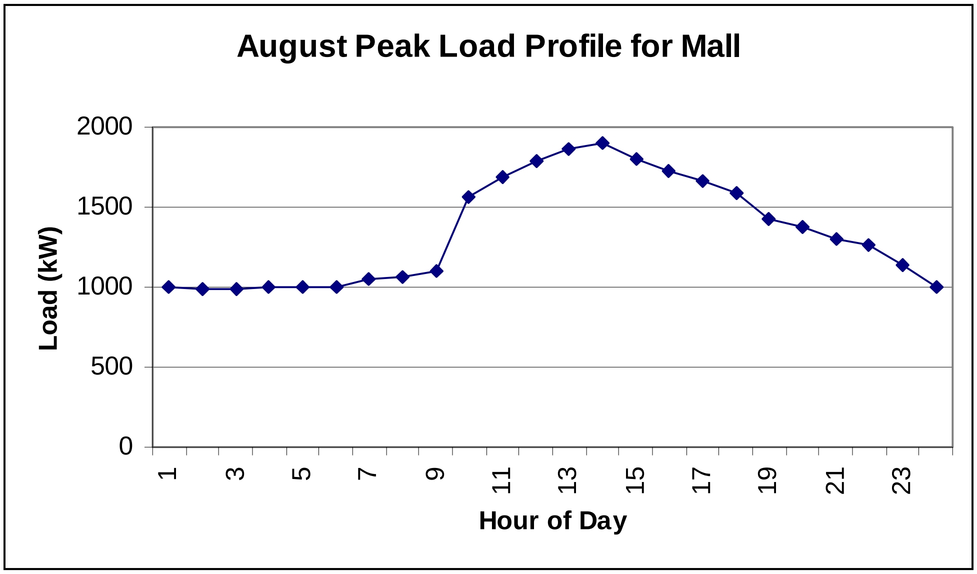

Figure 8. August Peak Load Profile for Mall

The load factor for this customer is 0.36, pretty low, showing that the peaks are well above the average load demanded (686 kW).

3.5 Microgrid

When the four representative consumers combine their load profiles in order to act as a microgrid, the monthly load variation is dampened, but the differences between minimum and peak loads within a month are more prominent. For example, during January (see Figure 9), the ratio of minimum to maximum load is 0.50. This is slightly flatter than the January load profiles for the office and the mall, but significantly more variable than those for the grocery and restaurant.

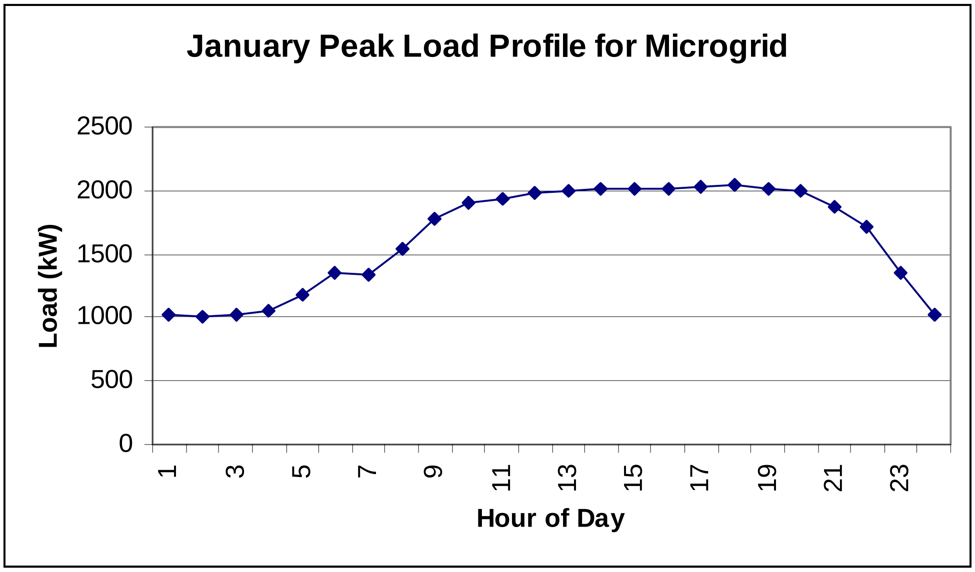

Figure 9. January Peak Load Profile for Microgrid

The August load profile (see Figure 10) has a minimum to peak load ratio of 0.55, which is again flatter than the August profiles for the office and the mall, but not quite as flat as those for the grocery and restaurant. On the other hand, while the grocery and mall experienced significant month to month variation in the shape of the load profile, the microgrid enables customers to eliminate much of this variability. This resulting month to month load profile stability will have consequences for how DER technologies are selected.

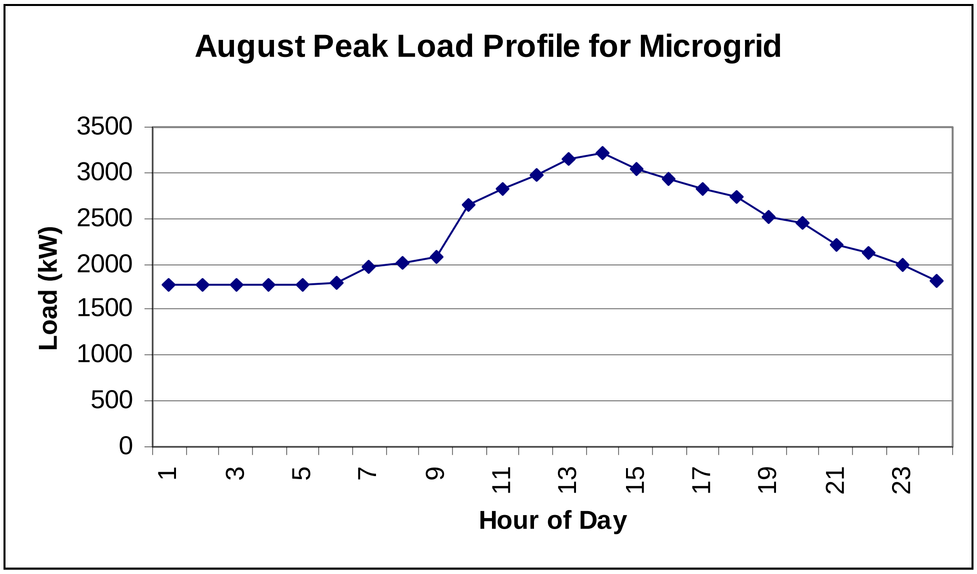

Figure 10. August Peak Load Profile for Microgrid

The load factor for the microgrid is 0.46, still relatively small. Again, this indicates that while combining the loads of the customers eliminates the month to month load variability, it doesn't affect the variation of load *within* a month.

4. Inputs

The other key inputs to C-CAM, as listed in section 2.2, are:

1. energy pricing data, namely, the SCE tariff details and CalPX hourly day prices for 1999; and
2. the characteristics of the on-site generating technologies available for customer adoption.

4.1 SCE Tariff and CalPX Prices

Customers purchasing electricity from the utility are assumed to do so at established tariffs. In this study, publicly available tariff rates for various customers are used (see Table 1). For each tariff type, season (where summer months are June through September, inclusive), and load period (on-peak, mid-peak, and off-peak), the power and energy charge is given as per the SCE rates in 1999. In addition, a fixed charge per customer per month and a power charge are included (see Table 2).

Table 1. SCE Tariff Information

Tariff Type	Season	Load Period	Power Charge ($/kW)	Energy Charge ($/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 ($/month)	Facility Charge ($/kW)
TOU2A	79.95	5.40
TOU2B	79.95	5.40
TOU8	298.65	6.40

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 California is essentially divided into two zones, north of Path 15 (NP15) and south of Path 15 (SP15), there is one market-clearing price for each zone. Since the customers in this study are located in southern California, they receive the appropriate SP15 CalPX DA constrained price for any sales to the grid. From the price duration curve for this market (see Figure 11), we see a rather well-functioning market in 1999, with the *effective* price cap of $250/MWh never reached.[9] If price data from 2000 had been used instead, there would have been greater instances of higher prices. For future research, it would be interesting to see what kinds of results are obtained if customers are faced with the option of selling into such a volatile market.

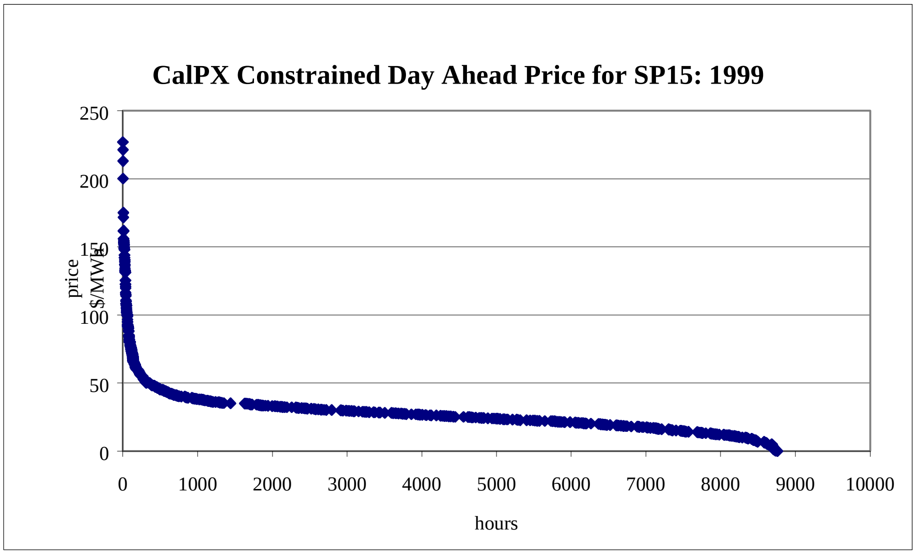

Figure 11. CalPX Day-Ahead Constrained Market Price Duration Curve for 1999 (Source: CalPX)

[9] While the CalPX did not have an explicit price cap in 1999, the California ISO's imbalance energy market did have one of $250/MWh. Due to the sequential nature of the California markets, the ISO imbalance energy market clears after the CalPX DA constrained market does. Consequently, the ISO's price cap becomes effective for the CalPX markets as well. Indeed, no seller would attempt to submit offers in excess of $250/MWh to the CalPX markets because buyers would simply shift their bids to the ISO's capped imbalance energy market.

4.2 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 labeled "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.

Table 3. Candidate DER Technologies

Technology	Plate kW	lifetime	$/kW cost	OMFix	OMVar	Heat Rate	Fuel
		(years)	Turn-key cost	$/kW/year	$/kWh	kJ/kWh	
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

5. Results

This section discusses the various operating scenarios for distributed generation technologies, results from the analysis based on the customer adoption model described in section 2, and the sensitivity of certain variables to changes in parameters. First, the run cases will be described and then, the results and sensitivity analysis will be presented.

5.1 Scenarios and Sensitivities

A total of four scenarios describe the conditions under which the customer purchases electricity. One of the scenarios is selected as base case and five sensitivities are computed based on this scenario. Table 4 lists the scenarios and their descriptions.

Table 4. Scenarios for Purchasing Electricity

Scenarios	Description
PXRN (PX + revenue neutrality)	In this scenario the customer can buy all of its electricity at the PX price, but it also has to pay an extra fee (named "DiscoER" in the mathematical model) in order to achieve the revenue neutrality for the distribution company (compared with the tariff scenario, later described). With the extra fee, the customer's purchase costs are the same as in the "tariff" scenario (see below). This scenario is selected as the base case because it is the most representative.
Tariff	In this scenario, the customer buys all of its electricity from the distribution company at the established tariff.
Fixed Rate	The customer buys all of its electricity at a fixed tariff. It pays the same during all hours and all months.

Once the scenarios have been described, it is necessary to outline the sensitivities (see Table 5). The sensitivities are performed on the base case only.

Table 5. Description of Sensitivity Analysis

Sensitivities	Description
10Turn.	10% increase in turn-key costs of DER technologies.
50Turn.	50% increase in turn-key costs of DER technologies.
HNGP	High natural gas prices.

LNGP	Low natural gas prices.
PXRN-Sales	This is the similar to the first scenario, but now, the customer can sell its electricity at the PX price without fully meeting its own load.[10]
STDBY	Stand-by[11] charges are applied to all customers.

5.2 Outline of Results

For each scenario and sensitivity, the following annual results are obtained:

- Total customer electricity supply cost ($).
- Energy payments to the distribution company during peak hours ($).
- Energy payments to the distribution company during mid-peak hours ($).
- Energy payments to the distribution company during off-peak hours ($).
- PX Purchases ($).
- Power payments to the distribution company ($).
- Self-generation investment costs ($).
- Self-generation variable costs ($).
- Energy sales to the PX ($).
- Consumed energy (kWh).
- Average paid price (c/kWh).
- Installed capacity (kW) and number of units installed.
- Hourly marginal cost of electricity supply ($/kWh).
- Hourly electricity production of every DER technology.

5.3 Results

In this subsection, we present the full set of results for the grocery. The results for the remaining customers can be found in the Appendix. We conclude this subsection by providing a summary of results that gives an overview of all customers' decisions.

[10] In all cases except "PXRN-Sales," the customer must fully meet its own load before it can sell power into the CalPX market. This case relaxes that constraint and allows the customer to sell power while simultaneously purchasing it.

[11] According to Californian tariffs, all customers with autonomous generation must pay a monthly stand-by charge of $6.40/kW.

5.3.1 Grocery "Do-Nothing" Scenario

It is important to review the characteristics of this customer prior to reviewing the autonomous generation adoption of the grocery under different scenarios and sensitivities.

In Table 6, the total cost of purchasing from the distribution company is presented, along with the breakdown of energy and power payments.

Table 6. Breakdown of Electricity Purchase Costs for Grocery ("Do-Nothing" Scenario)

Total Supply Cost ($)	217359
Dist. Energy Purchases (peak) ($)	44320
Dist. Energy Purchases (Mid) ($)	73556
Dist. Energy Purchases (Off) ($)	55912
Dist. Power Purchases ($)	43569
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	8.76

The grocery's load shapes for the three different types of day and all months are presented below:

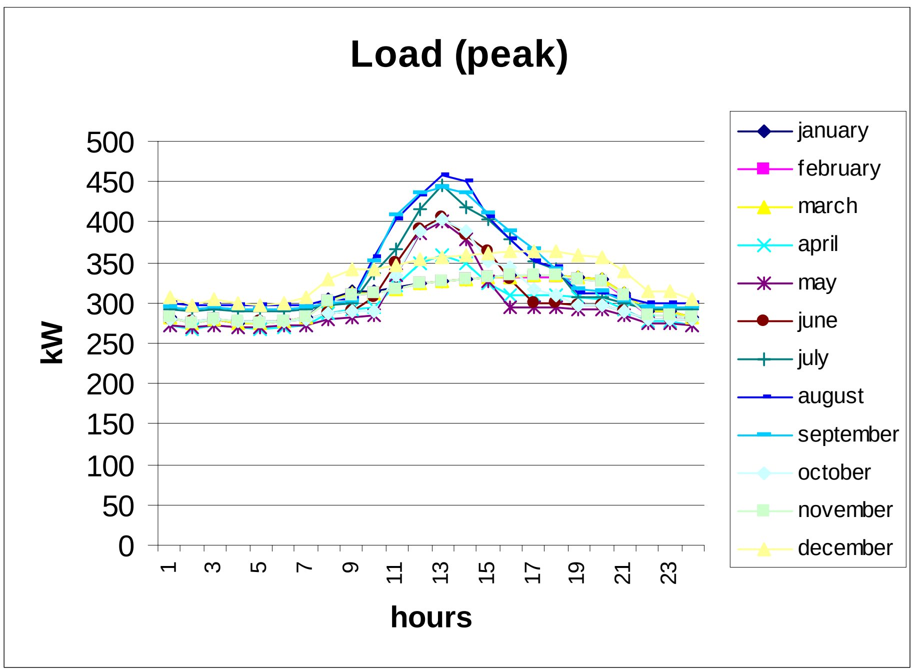

Figure 12. Grocery Peak Load Shape

As is easily seen, the load factor (0.62) indicates that the maximum demand is much larger than the average one (the annual average demand is 283 kW, the maximum demand is 457 kW, and the baseload is 167 kW).

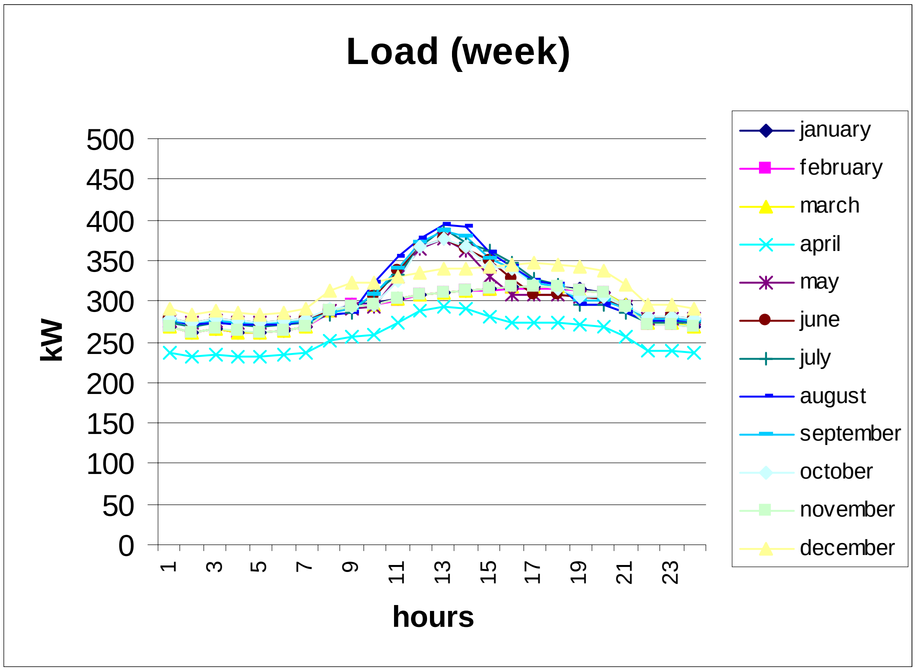

Figure 13. Grocery Week Load Shape

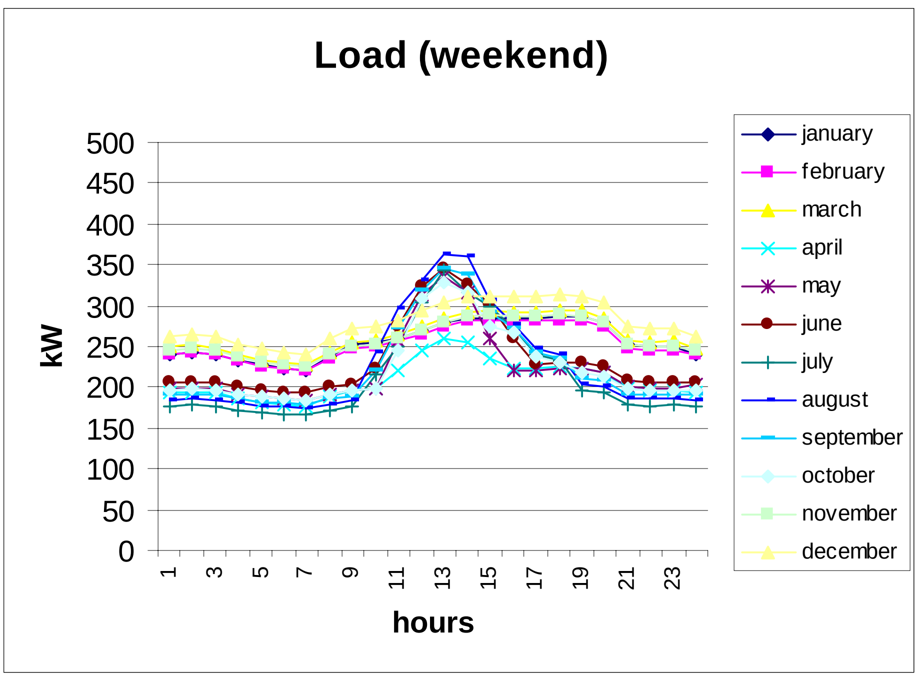

Figure 14. Grocery Weekend Load Shape

Other illuminating data include the hourly marginal cost of the electricity the customer is consuming. It is interesting to know this in the "do-nothing" scenario in order to compare it with the marginal cost once the onsite generation is installed. The marginal cost patterns for the three types of days are presented in the next three figures.

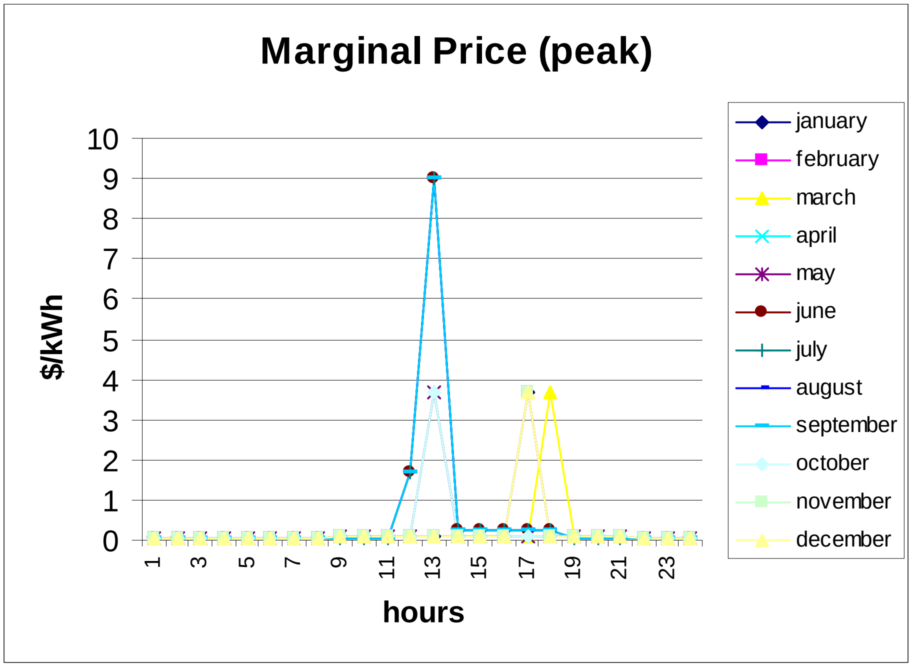

Figure 15. Marginal Supply Cost (peak hours)

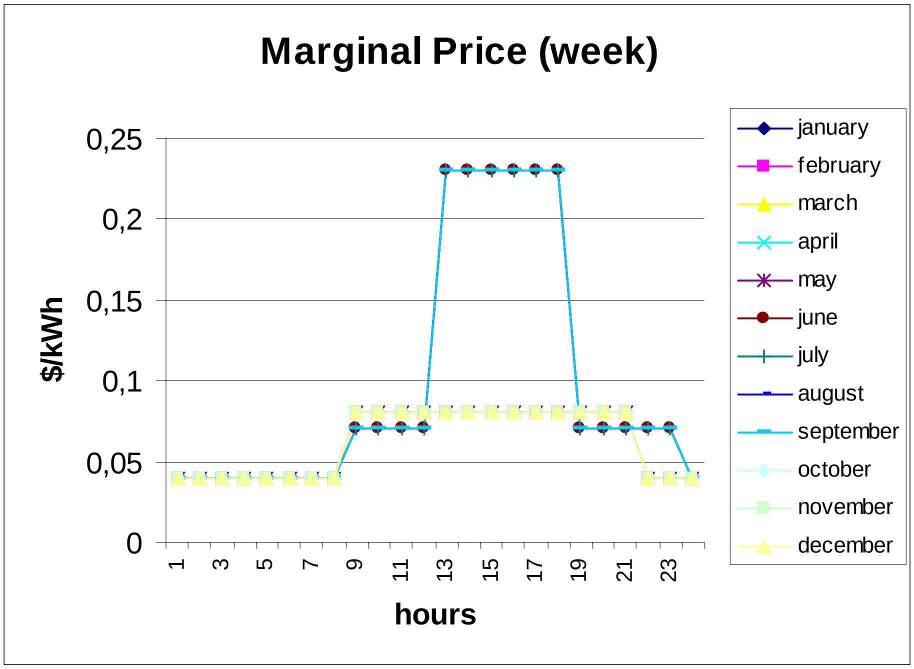

Figure 16. Marginal Supply Cost (week)

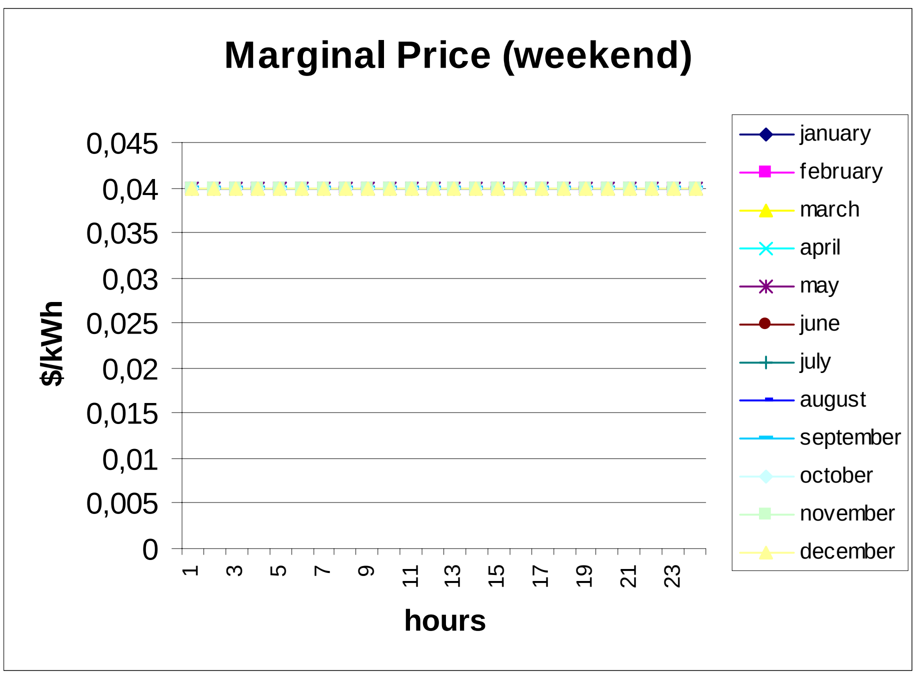

Figure 17. Marginal Supply Cost (weekend)

It is interesting to note the different shapes of the marginal costs. In Figure 15, there is a very high marginal cost (almost 9 $/kWh) in June, July, August, and September (all curves are superimposed) due to the power charge. That is, in these months and in these hours consuming 1 kW more implies paying a higher power charge for the whole month. On the other hand, in Figure 16 and Figure 17, the marginal cost simply equals the energy cost in each period (peak, mid-peak, and off-peak) defined by the applicable tariff.

5.3.2 Scenarios

5.3.2.1 Base Scenario

As indicated in Section 1.1, the base case is PXRN. That is, the customer can buy its electricity from the PX, but is subject to an adder to the PX price in order compensate the distribution company for local services. This additive term makes the customer pay exactly the same amount for energy as he pays under the normal tariff.

Table 7. Breakdown of Electricity Purchase Costs for the Grocery Base Case (PXRN)

Total Supply Cost ($)	170428
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	6185
Self Generation Investment Costs ($)	43197
Self Generation Variable Costs ($)	121045
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	6.87
Installed Capacity (kW)	312
Technologies	9 - SOFCo1 4 - SOFCo2 1 - mT_P

As shown in Table 7, the installation of DER technologies reduces the average price of electricity from 8.76 cents/kWh to 6.87 cents/kWh. It is interesting here to check the residual demand (the demand that the distribution company observes and is calculated by subtracting the self-generation from the original demand).

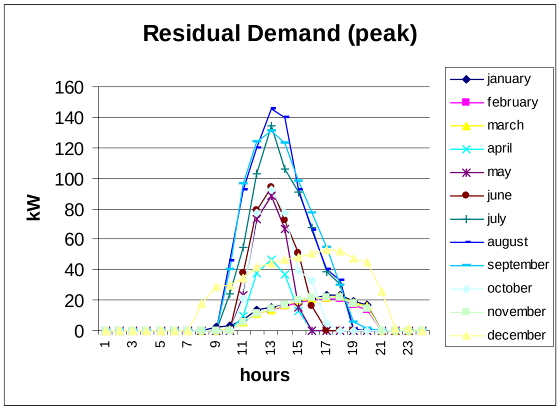

Figure 18. Grocery PXRN Residual Demand (peak)

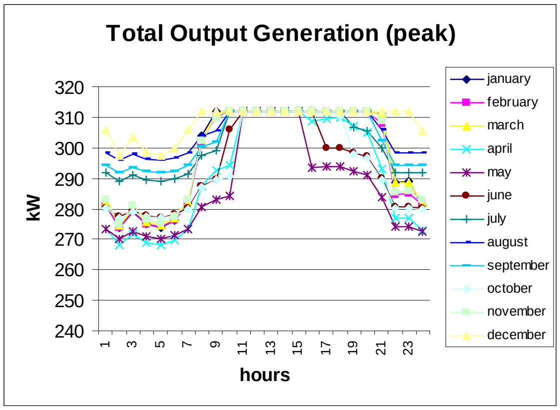

Figure 19. Grocery PXRN Total Output Generation (peak)

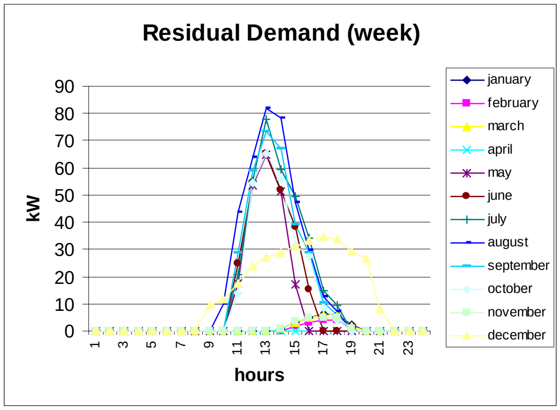

Figure 20. Grocery PXRN Residual Demand (week)

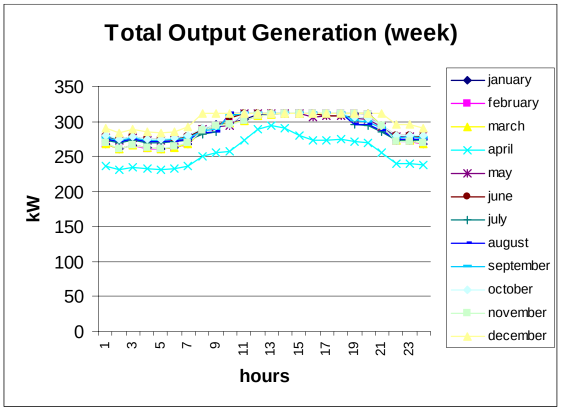

Figure 21. Grocery PXRN Total Output Generation (week)

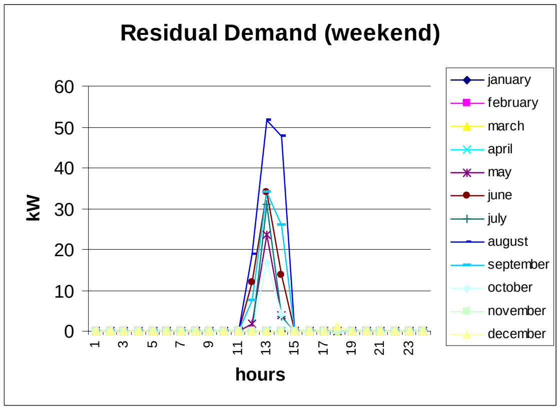

Figure 22. Grocery PXRN Residual Demand (weekend)

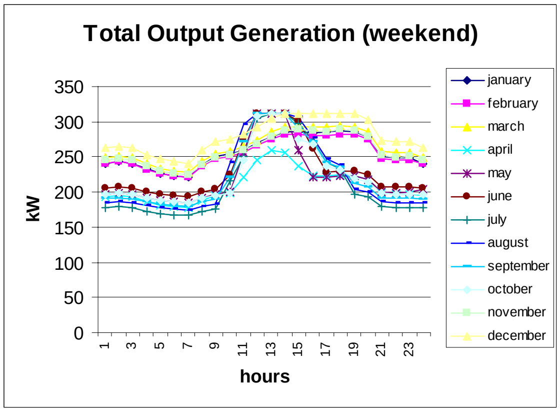

Figure 23. Grocery PXRN Total Output Generation (weekend)

Figure 18 through Figure 23 indicate that the customer's generators produce enough electricity to cover the demand *most* of the time. Since it is not economic is to cover the peak demand through self-generation, the distribution company supplies the remaining energy during these hours.

Regarding the operation of the three different types of DER that have been installed, it is only necessary to comment that the fuel cells generate at full capacity almost all of the time. Conversely, it is the micro-turbine that follows the load shape.

The last piece of relevant information about the base case results is the marginal cost. The calculation of these marginal costs indicates that the installation of DER results in an equilibration and reduction of their values.

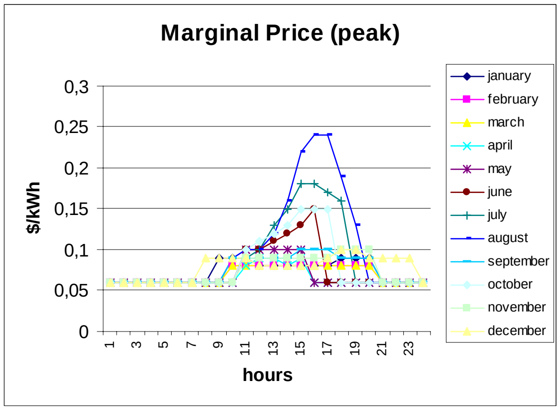

Figure 24. Grocery PXRN Marginal Supply Cost (peak)

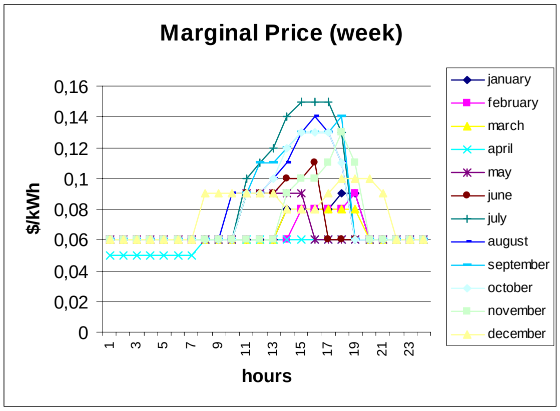

Figure 25. Grocery PXRN Marginal Supply Cost (week)

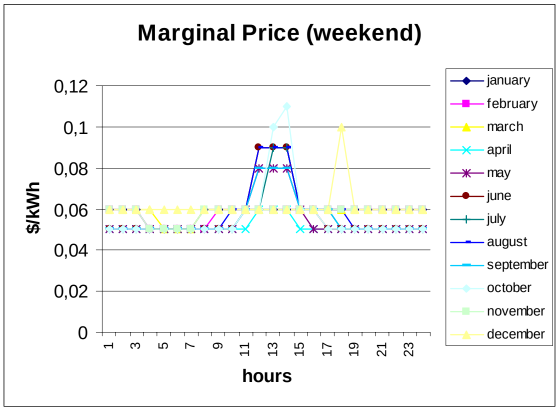

Figure 26. Grocery PXRN Marginal Supply Cost (weekend)

The new marginal cost curves have the characteristic that they are almost always constant, except during the peak hours, when the autonomous generation is not able to cover the whole demand. The different marginal costs during the peak are due to the volatile PX prices in these hours.

5.3.2.2 Tariff Scenario

In this scenario, the customer is still subject to its tariff (TOU-2), but also has the option to install autonomous generation. This scenario approximates the case of DER inside a tariff environment. It is an approximation because it may not be plausible to use the same tariff with or without self-generation.

Table 8. Breakdown of Electricity Purchase Costs for the Grocery Tariff Scenario

Total Supply Cost ($)	127030
Dist. Energy Purchases (peak) ($)	191
Dist. Energy Purchases (Mid) ($)	36,
Dist. Energy Purchases (Off) ($)	832
Dist. Power Purchases ($)	1710
PX Energy Purchases ($)	0
Self Generation Investment Costs ($)	37988
Self Generation Variable Costs ($)	86271
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	5.12
Installed Capacity (kW)	307.5
Technologies	3 - SOFCo2 2 - mT_P

In this new scenario, the total supply cost is reduced relative to the "do-nothing" case (see Table 8). However, this time the savings are greater than under the PXRN scenario. Here, the customer achieves a 41% reduction in its electricity bill, whereas under the PXRN scenario, the savings were 22%. This is because there is an important reduction in the demand charge expenses. The DER are going to be used in a way that causes that reduction. As it will be shown shortly, the DER are operated differently than before. The residual demand and total generation output are presented below (see Figure 27 through Figure 32).

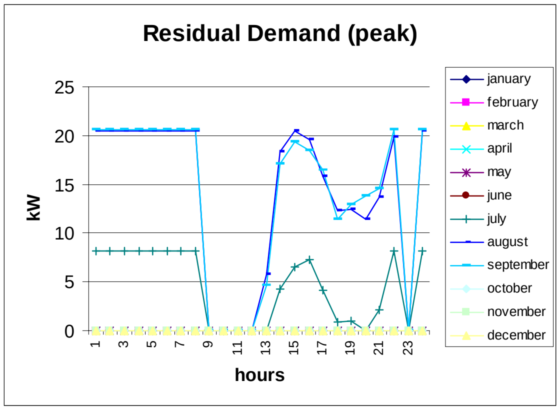

Figure 27. Grocery Tariff Residual Demand (peak)

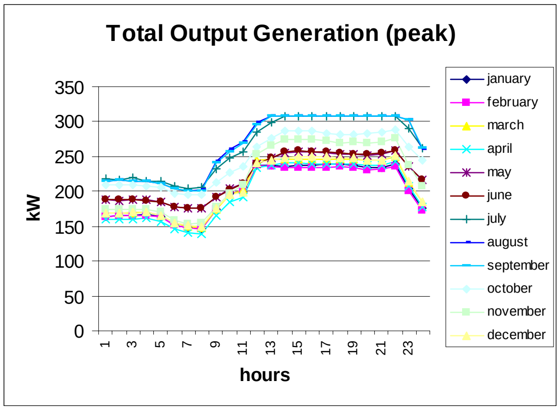

Figure 28. Grocery Tariff Total Output Generation (peak)

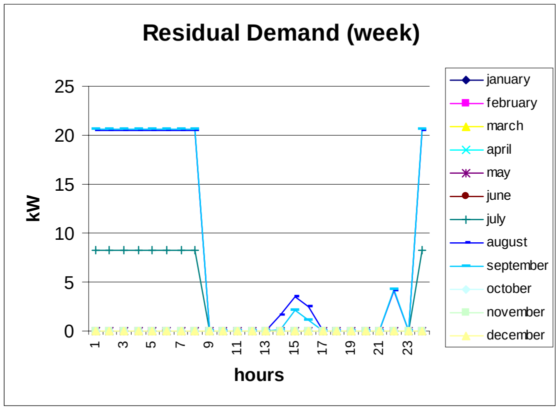

Figure 29. Grocery Tariff Residual Demand (week)

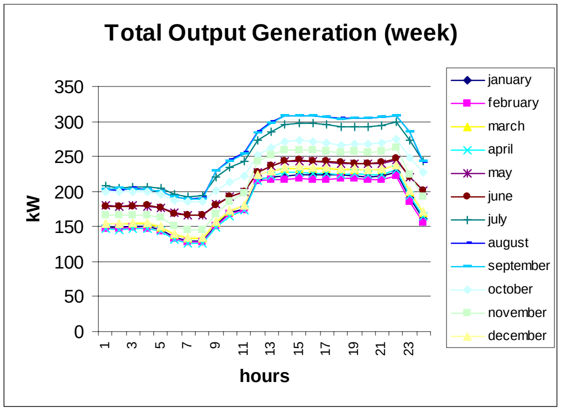

Figure 30. Grocery Tariff Total Output Generation (week)

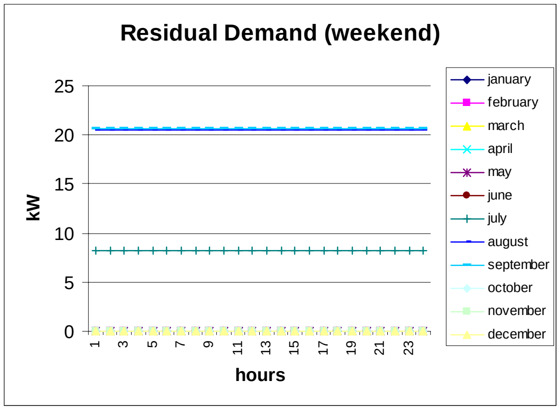

Figure 31. Grocery Tariff Residual Demand (weekend)

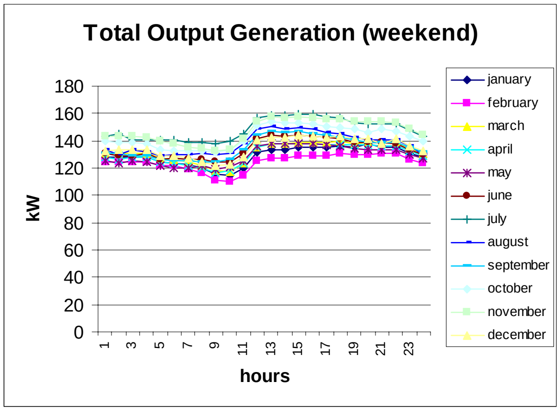

Figure 32. Grocery Tariff Total Output Generation (weekend)

From the above figures, it is easy to see that now the installed generation is used in a starkly different way than under the PXRN scenario. The very visible residual demand peak that was seen before does not exist now. Moreover, the installed generation is not operating at maximum capacity during the peak hours of all months. The explanation is twofold: first, the demand charge (as defined by the distribution company) distorts the generators' output since they try to reduce that demand charge by trying to cover peaking demand through self-generation. Second, the constant energy price offered by the company in different periods is frequently lower that the generator's variable cost, thereby allowing smoother consumption of electricity.

In Figure 33 through Figure 35, the marginal cost is plotted. In this case, there is a reduction in the peak period marginal prices (with the exception of the two price spikes). Also, they are higher during the weekends because some generation is needed to prevent the demand charge from being applied during these hours.

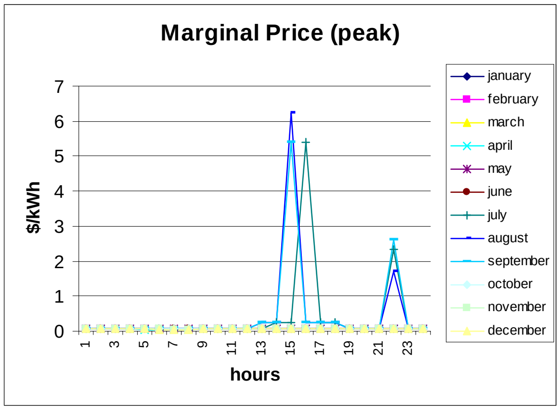

Figure 33. Grocery Tariff Marginal Supply Cost (peak)

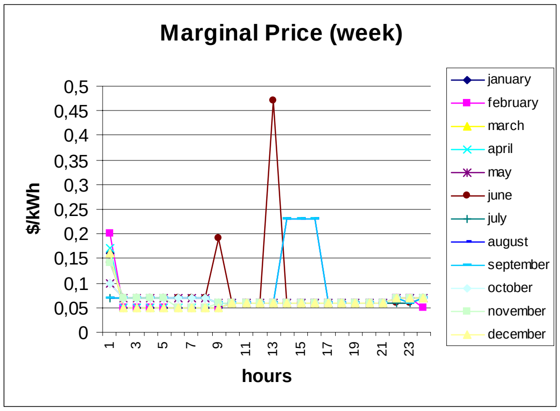

Figure 34. Grocery Tariff Marginal Supply Cost (week)

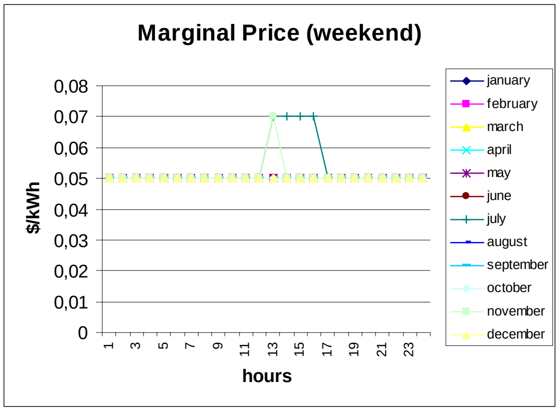

Figure 35. Grocery Tariff Marginal Supply Cost (weekend)

5.3.2.3 Fixed Rate Scenario

In this scenario the customer buys its electricity at a fixed rate during the whole year. The fixed rate (8.76 cents/kWh) is equal to the average price paid by the customer in the "do-nothing" scenario.

Table 9. Breakdown of Electricity Purchase Costs for the Grocery Fixed Rate Scenario

Total Supply Cost ($)	169097
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	8512
Self Generation Investment Costs ($)	40762
Self Generation Variable Costs ($)	119821
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	6.82
Installed Capacity (kW)	297
Technologies	4 – SOFCo1 4 - SOFCo2 1 - mT_P

This scenario is similar to the PXRN one with both the savings relative to the "do-nothing" case (22.2%), and the residual demand and the output generation being nearly identical. The only difference is in the marginal costs. The residual demand and total generation output are presented in Figure 36 through Figure 41.

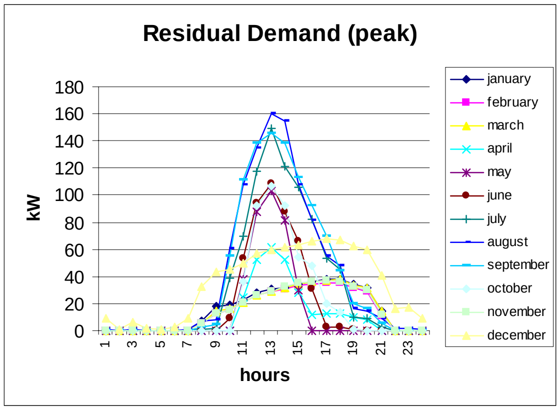

Figure 36. Grocery Fixed Rate Residual Demand (peak)

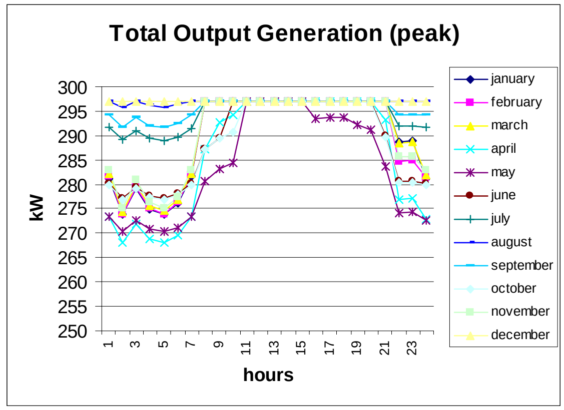

Figure 37. Grocery Fixed Rate Total Output Generation (peak)

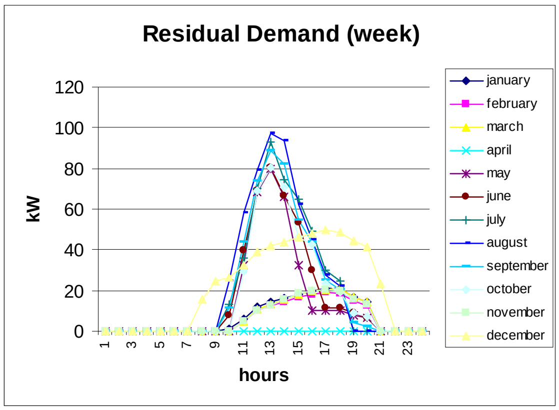

Figure 38. Grocery Fixed Rate Residual Demand (week)

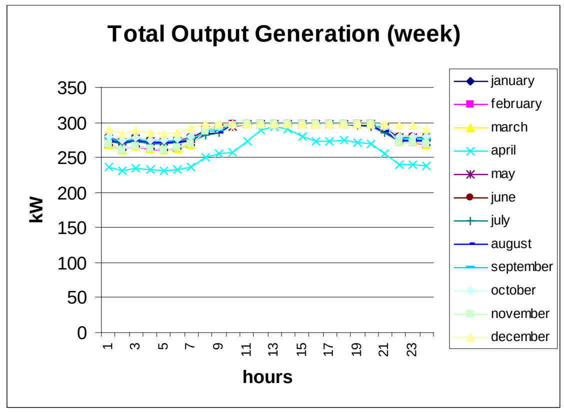

Figure 39. Grocery Fixed Rate Total Output Generation (week)

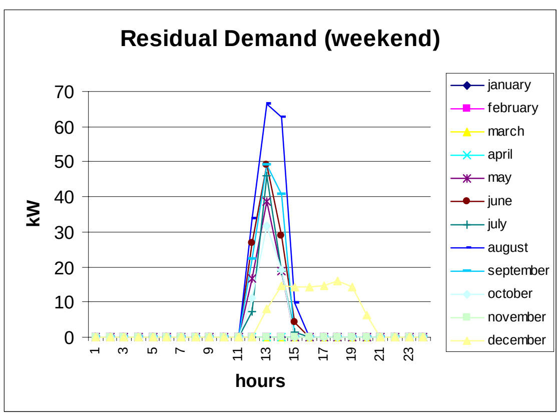

Figure 40. Grocery Fixed Rate Residual Demand (weekend)

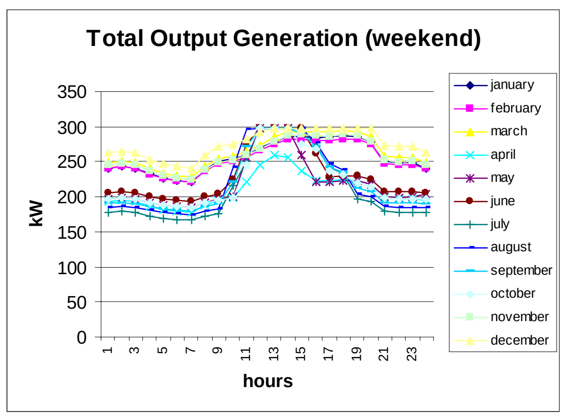

Figure 41. Grocery Fixed Rate Total Output Generation (weekend)

The marginal costs (see Figure 42 through Figure 44) are less volatile when compared to those for the PXRN scenario. This is because the marginal costs for the PXRN scenario were dependent upon the PX prices. In the fixed rate scenario, the customer doesn't see the volatility of market price, hence its marginal costs simply fluctuate between the fixed rate and the variable cost of the self-generation.

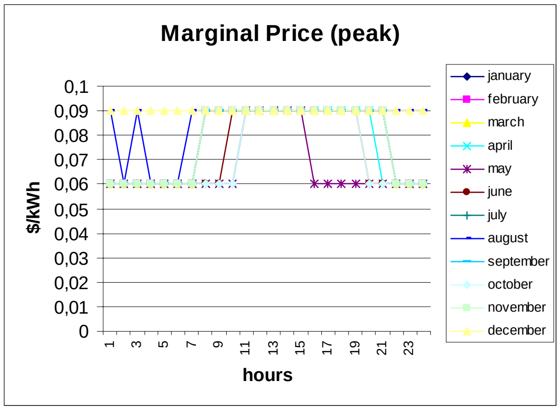

Figure 42. Grocery Fixed Rate Marginal Supply Cost (peak)

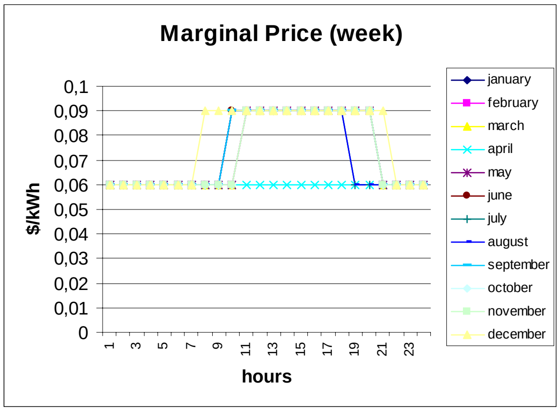

Figure 43. Grocery Fixed Rate Marginal Supply Cost (week)

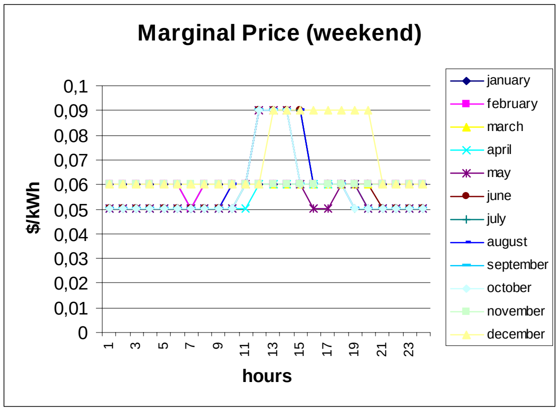

Figure 44. Grocery Fixed Rate Marginal Supply Cost (weekend)

5.3.2.4 PXRN Scenario With Sales

The only difference between this scenario and the base one is that the customer can sell its electricity into the wholesale market at the PX price. The summary of this scenario is presented in Table 10.

Table 10. Breakdown of Electricity Purchase Costs for the Grocery PXRN With Sales Scenario

Total Supply Cost ($)	170407
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	6847
Self Generation Investment Costs ($)	42710
Self Generation Variable Costs ($)	121103
Sales at the PX Price ($)	254
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	6.87
Installed Capacity (kW)	309
Technologies	8 – SOFCo1 4 - SOFCo2 1 - mT_P

It is immediate that the differences are minimal. The total sales of $254 merely enable a slight reduction in fuel cell investment. Besides this difference, the graphs of residual demand, generation, and marginal costs are otherwise similar to those presented in the PXRN scenario.

5.3.3 Sensitivities

In this section, sensitivities to the base scenario (PXRN) are analyzed.

5.3.3.1 Stand-By Charge

In this sensitivity, an extra fee (the *stand-by charge*) is added to the price of electricity. The value that has been used is $6.40/kW per month. This charge is applied either to the self-generation installed or the peak demand, whichever is smaller. In this example, in order to simplify the model, it is assumed that the installed capacity is always smaller.

Table 11. Breakdown of Electricity Purchase Costs for the Stand-By Charge Sensitivity

Total Supply Cost ($)	192663.5
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0

PX Energy Purchases ($)	18720
Self Generation Investment Costs ($)	62670
Self Generation Variable Costs ($)	111272
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	7.77
Installed Capacity (kW)	274.5
Technologies	4 – SOFCo1 5 - SOFCo2

Inclusion of the stand-by charge limits DER. For the Grocery, the 274.5 kW is the lowest obtained value from among all cases. However, the adoption of DER technology still entails savings for the customer over the "do-nothing" case, as this result indicates. The residual demand and total output generation patterns are in Figure 45 through Figure 50.

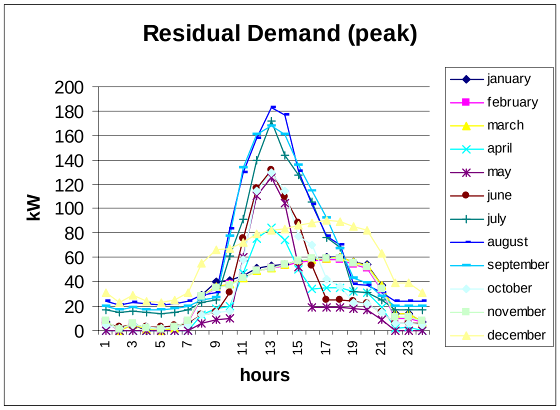

Figure 45. Grocery Stand-By Charge Residual Demand (peak)

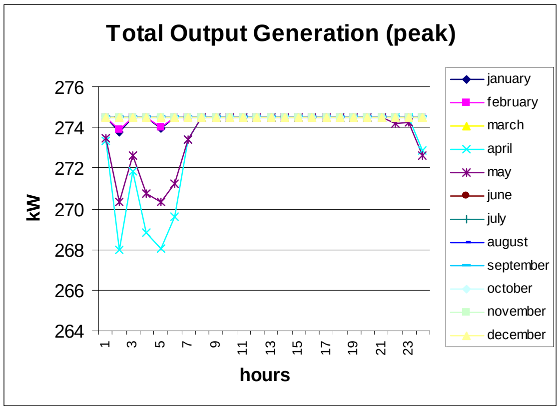

Figure 46. Grocery Stand-By Charge Total Output Generation (peak)

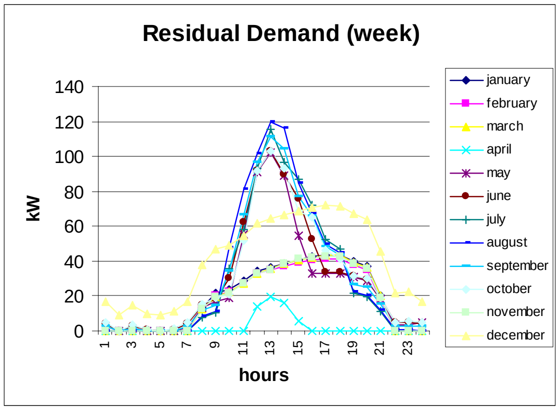

Figure 47. Grocery Stand-By Charge Residual Demand (week)

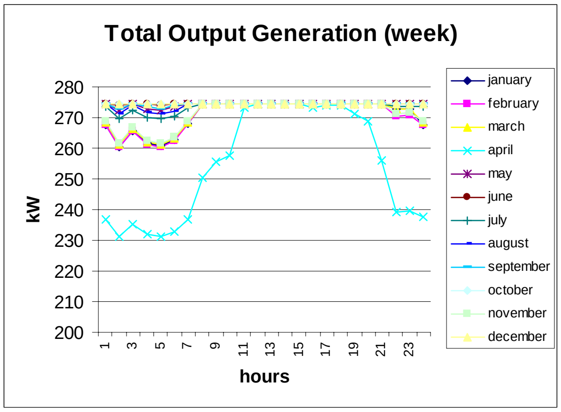

Figure 48. Grocery Stand-By Charge Total Output Generation (week)

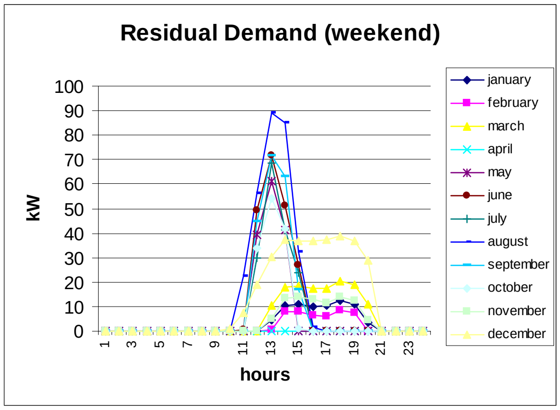

Figure 49. Grocery Stand-By Charge Residual Demand (weekend)

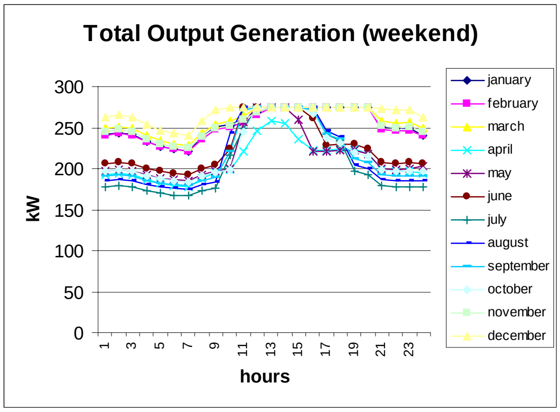

Figure 50. Grocery Stand-By Charge Total Output Generation (weekend)

The residual demand pattern is similar to that seen in previous scenarios. The generation output is smoother than before because only fuel cells are installed. These fuel cells work at maximum capacity, more or less, almost all the time. An interesting result is that the investment inflection point (the point at which there is no investment) is reached with a stand-by charge of about $15/MW.

5.3.3.2 10% Increase in Fuel Cell Turn-Key Costs

In this sensitivity, investment costs for fuel cells are increased by 10%. The summary of the results is presented below.

Table 12. Breakdown of Electricity Purchase Costs for the 10% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	173740
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	7575,241
Self Generation Investment Costs ($)	45518
Self Generation Variable Costs ($)	120646
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	7.01
Installed Capacity (kW)	306
Technologies	7 – SOFCo1 4 - SOFCo2 1 - mT_P

The only significant change is that the installed capacity is reduced. The residual demand, generation output, and marginal costs are almost identical to those in the base scenario.

5.3.3.3 50% Increase in Fuel Cell Turn-Key Costs

Here, investment costs for fuel cells are increased by 50%. The summary of the results is presented below.

Table 13. Breakdown of Electricity Purchase Costs for the 50% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	174882
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0

Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	9188
Self Generation Investment Costs ($)	28408
Self Generation Variable Costs ($)	137285
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	7.05
Installed Capacity (kW)	300
Technologies	4 - mT_P

In this sensitivity, fuel cells are no longer installed due to the high cost. However, it is still profitable to invest in four micro-turbines. The savings are slightly smaller than in the base scenario. This result indicates that micro-turbines and fuel cells are very comparable technologies from the economic point of view, and thus, are substitute products.

5.3.3.4 Low Natural Gas Price Sensitivity

In this sensitivity, the natural gas price is decreased to $2.53/GJ from $4.2/GJ.

Table 14. Breakdown of Electricity Purchase Costs for the Low Natural Gas Price Sensitivity

Total Supply Cost ($)	126807
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	6185
Self Generation Investment Costs ($)	30356
Self Generation Variable Costs ($)	90264
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	5.11
Installed Capacity (kW)	312
Technologies	4 – SOFCo1 4 - mT_P

As expected, more micro-turbines installed and the savings over the “do-nothing” case are higher (41%) than in the base case (22%). It is worth commenting that this sensitivity applies low natural gas prices only to the DER without assuming reduction of PX prices. The same caveat applies to the next sensitivity.

5.3.3.5 High Natural Gas Price Sensitivity

In this sensitivity, the natural gas price is increased to $5.88/GJ.

Table 15. Breakdown of Electricity Purchase Costs for the High Natural Gas Price Sensitivity

Total Supply Cost ($)	202342
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	18720
Self Generation Investment Costs ($)	41588
Self Generation Variable Costs ($)	142033
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	8.16
Installed Capacity (kW)	274.5
Technologies	4 – SOFCo1 5 – SOFCo2

No micro-turbines are installed since the fuel cells are more efficient now. The savings over the "do-nothing" case are now reduced by only 7%.

5.3.3.6 High Interest Rate Sensitivity

In this sensitivity, the interest rate is increased to 9.5% from 7.5%.

Table 16. Breakdown of Electricity Purchase Costs for the High Interest Rate Sensitivity

Total Supply Cost ($)	175573
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	8360
Self Generation Investment Costs ($)	46818
Self Generation Variable Costs ($)	120394
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2480166
Average Price (c/kWh)	7.08

Installed Capacity (kW)	303
Technologies	6 – SOFCo1 4 – SOFCo2 1 - mT_P

The solution of the base scenario remains relatively stable with a few minor changes. The higher interest rate has the effect of reducing savings slightly and making fuel cells less attractive due their high capital costs. To compensate for the three fewer fuel cells, PX energy purchases are increased.

5.3.4 Summary Of Results

In this section a brief summary of all results is presented. For each customer (grocery, restaurant, office, mall, and the microgrid) and for every scenario and sensitivity, the adopted technologies, the total savings, and the power and energy coverage of DER are presented.

5.3.4.1 Adopted Technologies

The following tables summarize the capacity installed in all cases. While the technologies adopted vary across customers and their circumstances, we find that if customers bind together to form a microgrid, then the pattern of adopted technologies is more stable than if customers act separately. For example, the microgrid usually selects between 18 and 25 SOFCo2 type fuel cells, which are supplemented by some micro-turbines. In contrast, customers acting on their own select a whole medley of technologies. This seems to imply that customers acting as a microgrid would be better suited to functioning in various market environments than individual customers. Intuitively, this seems plausible because a larger customer is able to pool its resources in order to capitalize upon the economies of scale inherent in many DER technologies.

Table 17. Adopted Technologies (Grocery and Restaurant)

Case / Customer	Grocery	Restaurant
PXRN	9 SOFCo1 / 4 SOFCo2 / 1 mT_P	1 SOFCo1 / 3 SOFCo2 / 1 mT_P
Frate	4 SOFCo1 / 4 SOFCo2 / 1 mT_P	3 SOFCo2 / 1 mT_P /
Tariff	3 SOFCo2 / 2 mT_P /	3 SOFCo2 / 2 mT_P /
HighNatG	4 SOFCo1 / 5 SOFCo2 /	4 SOFCo2 / /
LowNatG	4 SOFCo1 / 4 mT_P /	4 mT_P / /
IntRate	6 SOFCo1 / 4 SOFCo2 / 1 mT_P	3 SOFCo2 / 1 mT_P /
10Turnkey	7 SOFCo1 / 4 SOFCo2 / 1 mT_P	2 SOFCo2 / 2 mT_P /
50Turnkey	4 mT_P / /	3 mT_P / /
Standby Charge	4 SOFCo1 / 5 SOFCo2 /	3 SOFCo1 / 3 SOFCo2 /
Free Sales	8 SOFCo1 / 4 SOFCo2 / 1 mT_P	1 SOFCo1 / 3 SOFCo2 / 1 mT_P

Table 18. Adopted Technologies (Office and Mall)

Case / Customer	Office	Mall
PXRN	4 SOFCo2 / 1 mT_P /	8 SOFCo2 / 7 mT_P /
Frate	4 SOFCo2 / 1 mT_P /	8 SOFCo2 / 6 mT_P /
Tariff	1 230ROZD / 2 SOFCo1 / 4 mT_P	2 350ROZD / 2 SOFCo2 / 11 mT_P
HighNatG	5 SOFCo2 / /	14 SOFCo2 / 1 mT_P /
LowNatG	4 mT_P / /	13 mT_P / /
IntRate	8 SOFCo1 / 2 SOFCo2 / 2 mT_P	7 SOFCo2 / 7 mT_P /
10Turnkey	9 SOFCo1 / 2 SOFCo2 / 2 mT_P	6 SOFCo2 / 8 mT_P /
50Turnkey	4 mT_P / /	12 mT_P / /
Standby Charge	1 SOFCo1 / 3 SOFCo2 / 1 mT_P	9 SOFCo2 / 4 mT_P /
Free Sales	4 SOFCo2 / 1 mT_P /	8 SOFCo2 / 7 mT_P /

Table 19. Adopted Technologies (Microgrid)

Case / Customer	Microgrid
PXRN	21 SOFCo2 / 8 mT_P /
Frate	21 SOFCo2 / 6 mT_P /
Tariff	3 350ROZD / 19 SOFCo2 / 13 mT_P
HighNatG	25 SOFCo2 / /
LowNatG	24 mT_P / /
IntRate	19 SOFCo2 / 9 mT_P /
10Turnkey	18 SOFCo2 / 11 mT_P /
50Turnkey	23 mT_P / /
Standby Charge	21 SOFCo2 / 3 mT_P /
Free Sales	21 SOFCo2 / 8 mT_P /

5.3.4.2 Savings

We see from Figure 51 that installation of DER generation capacity results in significant savings over the “do-nothing” scenario. As discussed previously, customers acting together as a microgrid are able to realize greater savings due to their ability to take advantage of economies of scale.

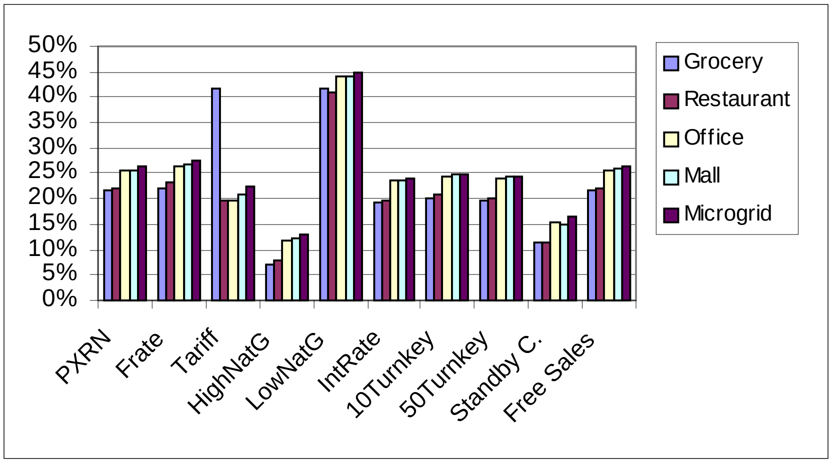

Figure 51. Savings Per Scenario/Activity Over "Do-Nothing" Case

5.3.4.3 Power and Energy Coverage

From Figure 52 and Figure 53, we see that customers cover most of their peak demand and consumed energy through installed capacity. Again, the microgrid stands out as it covers less of its peak demand and energy needs via installed capacity. This is due to its ability to be more flexible than individual customers.

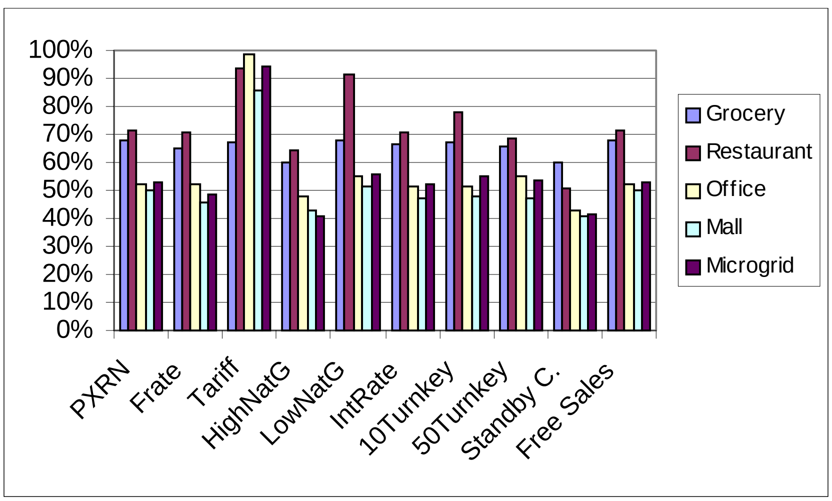

Figure 52. Percent Coverage of Peak Demand through Installed Capacity

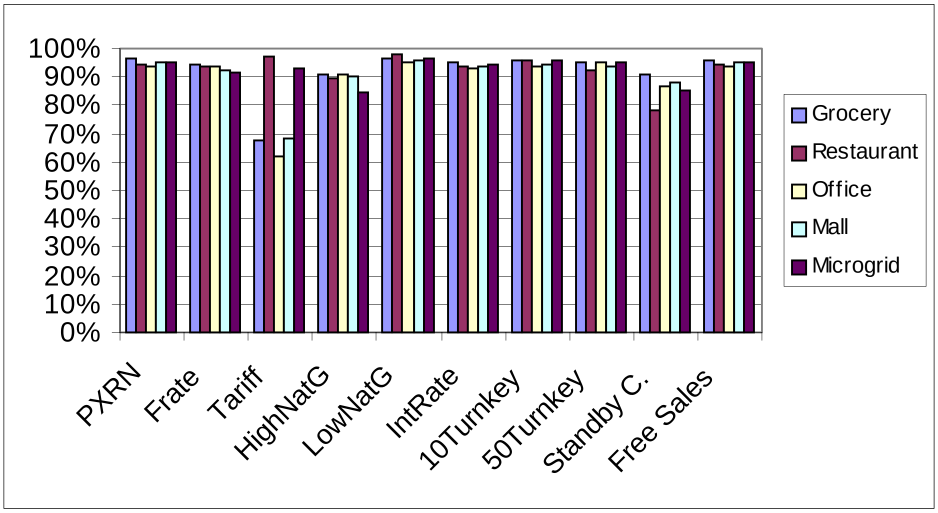

Figure 53. Percent Coverage of Consumed Energy through Installed Capacity

5.4 Conclusions

In this section, we described the various environments under which the customer can be hypothesized to operate. Then, we chose one customer (the grocery) and presented key operating characteristics for each scenario and sensitivity. Specifically, we described how changes in costs and tariff structures force the customer to alter its array of installed generation capacity. These changes then have consequences for how the installed capacity is generated to meet the customer's energy needs and the marginal price that the customer effectively pays for its energy consumption.

In general, we find that installation of generation capacity is attractive to the customer under a variety of circumstances. Indeed, even in situations where a standby charge is levied, the customer is still better off installing some generation capacity rather than doing nothing (see Figure 51). And while this installed capacity is used to generate a significant proportion of the customer's energy (over 90% in most cases), we don't find any scenario given the set of PX prices used in which the customer opts to disconnect fully from the grid (see Figure 53).

6. Conclusions

The work described in this document covers the FY00 DOE funded CERTS work completed at Berkeley Lab. The main objective of this year's activity was to develop a more sophisticated customer adoption model that could produce results more rapidly and deliver optimal solutions. This has been achieved by means of developing a GAMS model that accepts a typical customer electrical load, data on available DER options, and various economic inputs and produces an optimal DER adoption pattern for the customer and a rudimentary operating schedule for each adopted resource.

Typical load curves for the following four customer types were analyzed: a grocery, a restaurant, an office, and a mall. In addition, these customers were simulated together, as if they were functioning as a microgrid.

Very simple assumptions about DER costs were used. Manufacturer claims for equipment prices were accepted as the full installed cost, while no allowance was made for the potential benefits of improved reliability and power quality, or for the possibility of CHP applications. Customers were able to buy and sell power under several different scenarios.

Under these assumptions, the typical customers adopted some on-site generation under all scenarios. Typical annual electricity cost savings for the customers is about 20-25%. Fuel cells are attractive under the assumptions used, but manufacturer 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 distribution company, 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.

The base scenario study assumes that the customer buys and sells electricity at the CalPX 1999 hourly price, but has to pay a price adder on purchases. This adder covers other non-energy costs of electricity delivery and was assumed to be a levelized per kWh charge. Since non-energy costs represent close to two thirds of retail electricity price, this assumption results in considerably damped prices. In other words, to the customer, buying from the CalPX results in fairly stable prices, and, in fact, results for this arrangement, PXRN, tend not to vary significantly from a flat tariff assumption. Furthermore, other than variations that one would expect, for example higher natural gas prices that discourage self-generation, results tend to be fairly robust across scenario assumptions. Fuel cells tend to dominate the base load role, while microturbines meet peaking requirements, and diesels rarely appear in results.

However, when the customer faces the default SCE tariff, which includes a stiff demand charge, results are dramatically different. Suddenly, fuel cells lose their competitive edge, and diesels become highly desirable technologies. This result derives from the importance of the demand charge in the overall bill. To drive down the cost of the demand charge, customers, especially those with peakier loads, install cheap diesel capacity to drive down peak demand. The net consequence of this strategy is that, under the tariff scenario, installed capacities are higher but self-provision is lower. Clearly, the structure of tariffs faced by the customer can have a significant effect on technology choice.

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.

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7. Appendix 1: Customer Results

Here, we present the results from the analysis based on the customer adoption model described in section 2 for the other customers (mall, office, restaurant, and microgrid).

7.1 Mall

7.1.1 "Do-Nothing" Scenario

Table 20. Breakdown of Electricity Purchase Costs for Mall ("Do-Nothing" Scenario)

Total Supply Cost ($)	593383
Dist. Energy Purchases (peak) ($)	55567
Dist. Energy Purchases (Mid) ($)	184844
Dist. Energy Purchases (Off) ($)	107605
Dist. Power Purchases ($)	245367
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	9.87

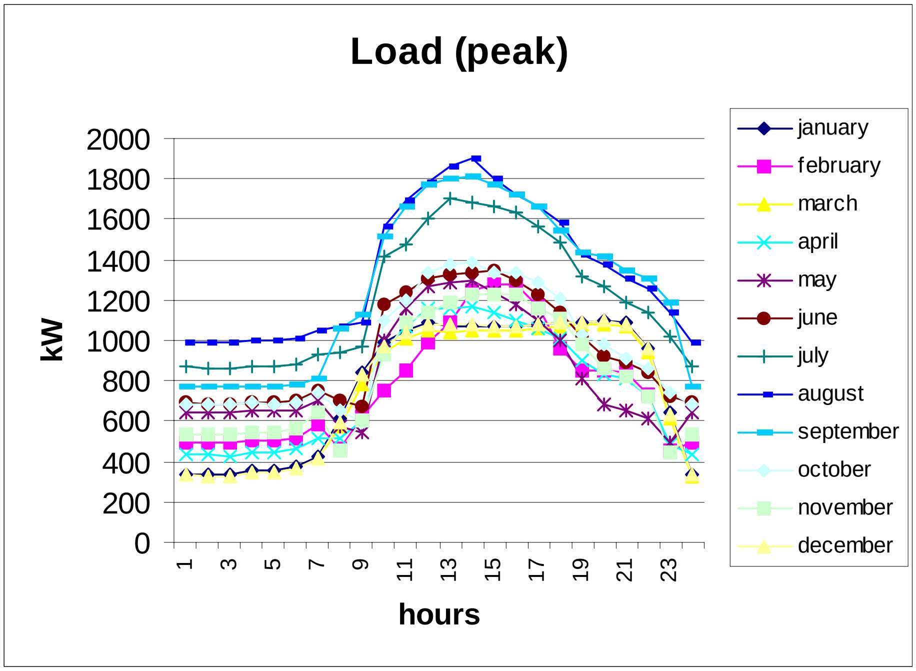

Figure 54. Mall Peak Load Shape

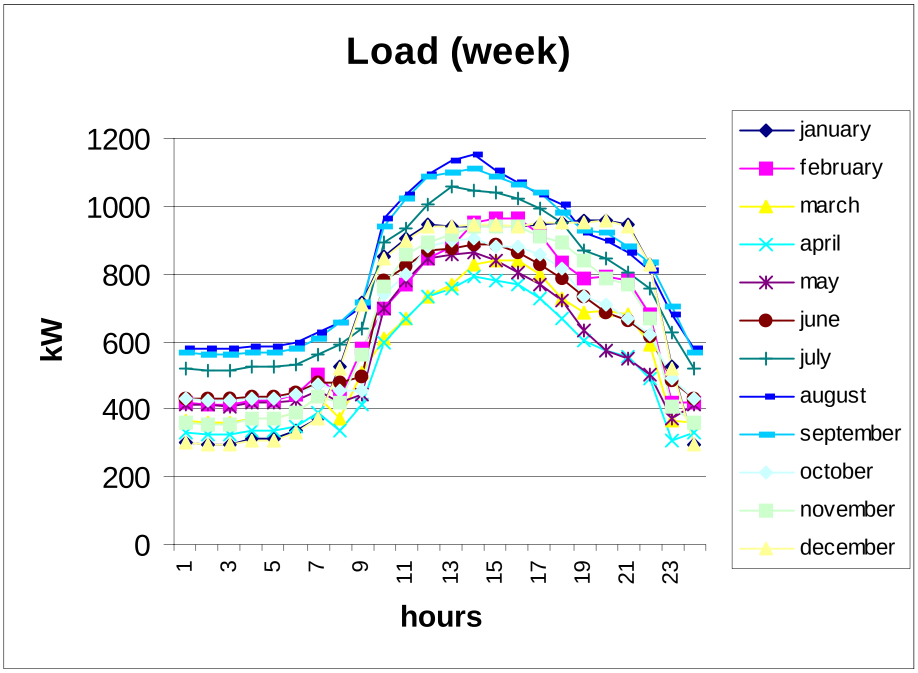

Figure 55. Mall Week Load Shape

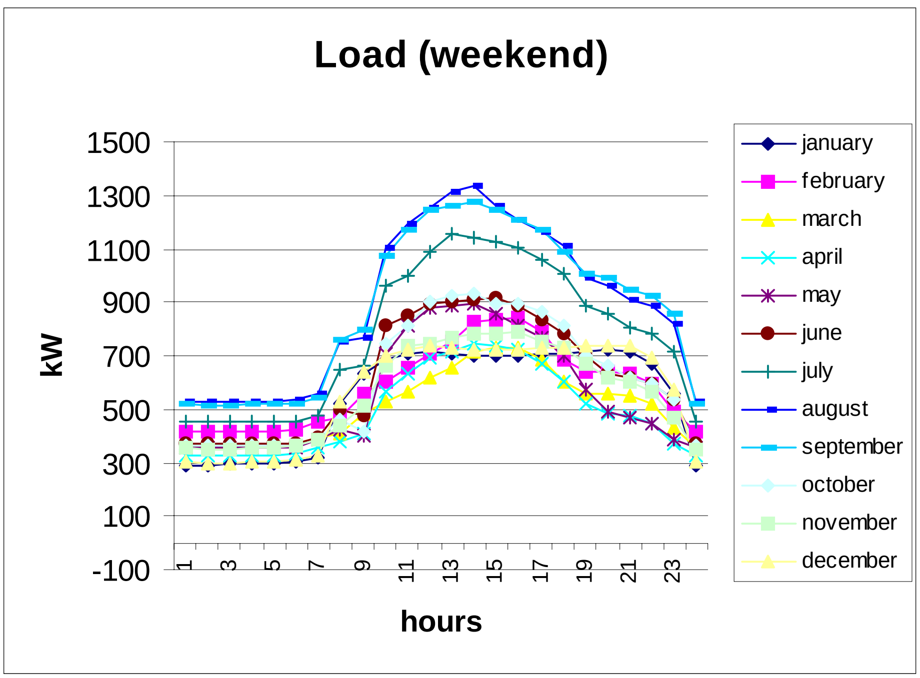

Figure 56. Mall Weekend Load Shape

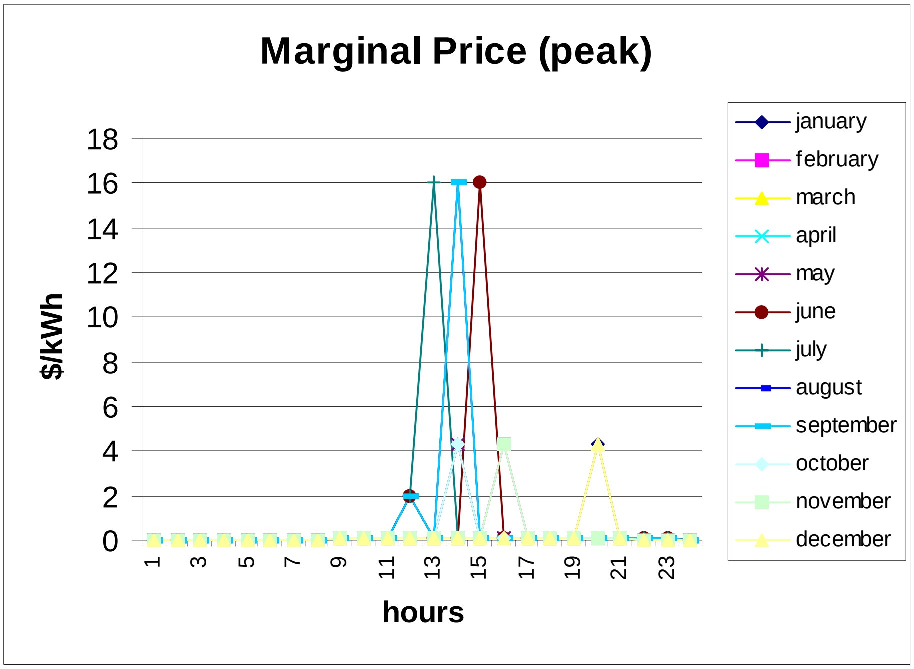

Figure 57. Mall "Do-Nothing" Marginal Supply Cost (peak hours)

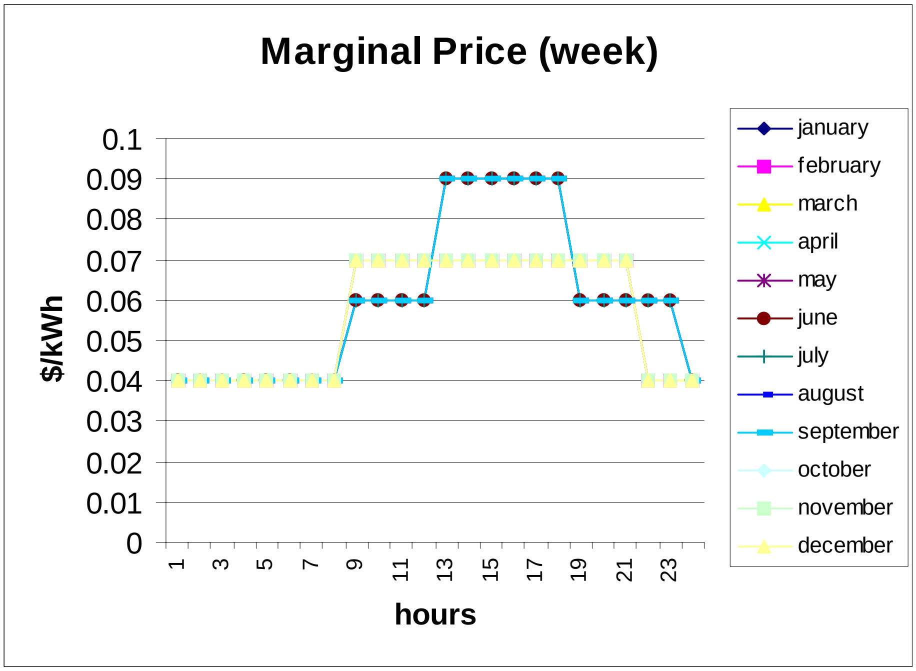

Figure 58. Mall "Do-Nothing" Marginal Supply Cost (week)

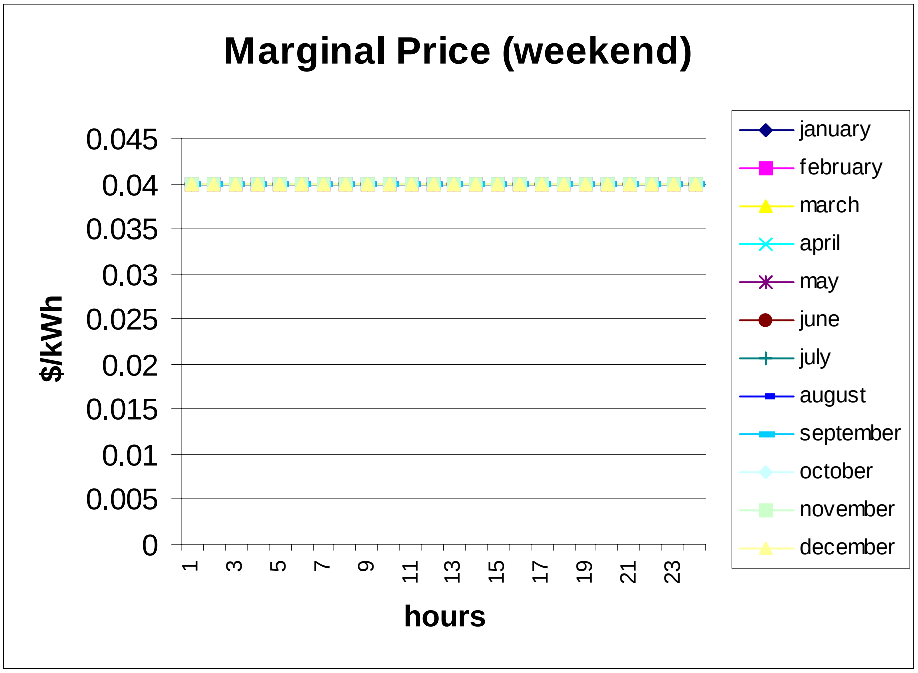

Figure 59. Mall "Do-Nothing" Marginal Supply Cost (weekend)

7.1.2 Scenarios

7.1.2.1 Base Scenario

Table 21. Breakdown of Electricity Purchase Costs for the Mall Base Case (PXRN)

Total Supply Cost ($)	440486
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	26945
Self Generation Investment Costs ($)	113140
Self Generation Variable Costs ($)	300401
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	7.33
Installed Capacity (kW)	945
Technologies	8 - SOFCo2 7 - mT_P

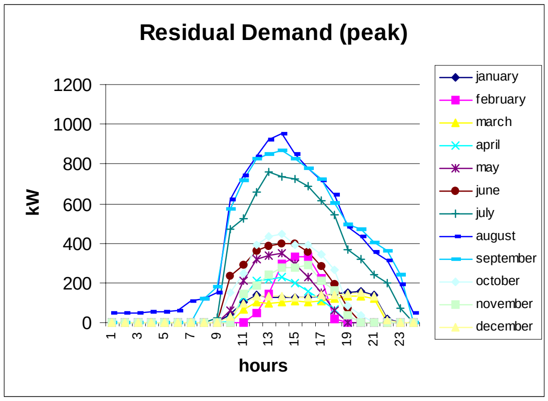

Figure 60. Mall PXRN Residual Demand (peak)

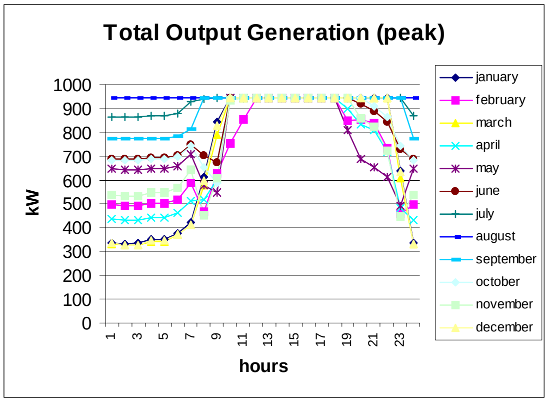

Figure 61. Mall PXRN Total Output Generation (peak)

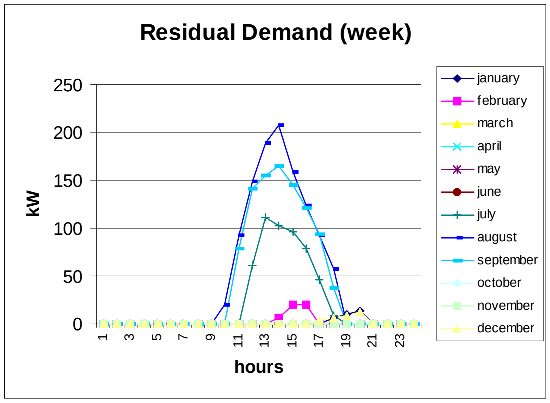

Figure 62. Mall PXRN Residual Demand (week)

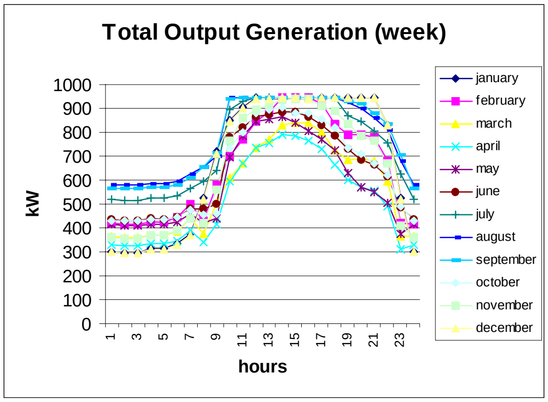

Figure 63. Mall PXRN Total Output Generation (week)

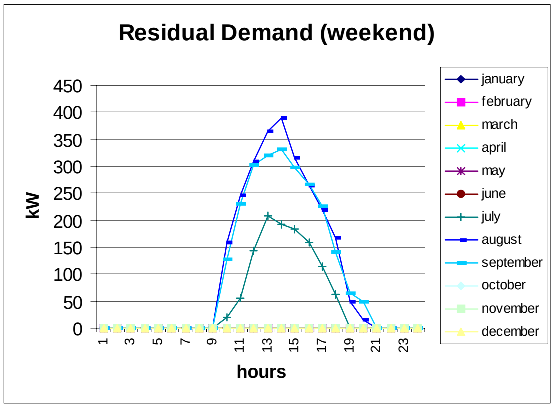

Figure 64. Mall PXRN Residual Demand (weekend)

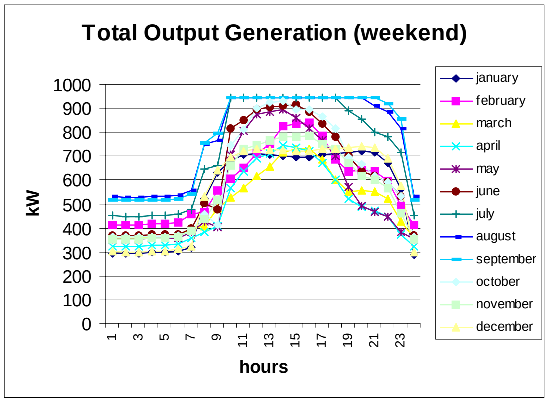

Figure 65. Mall PXRN Total Output Generation (weekend)

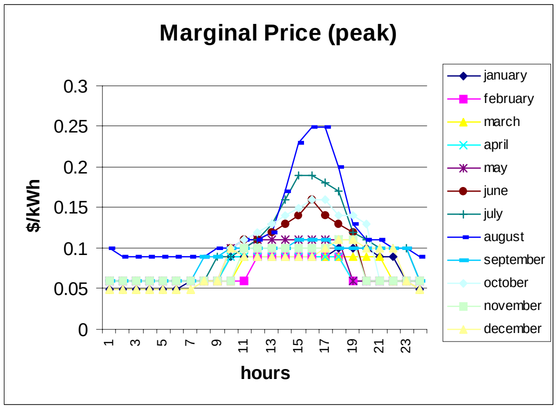

Figure 66. Mall PXRN Marginal Supply Cost (peak)

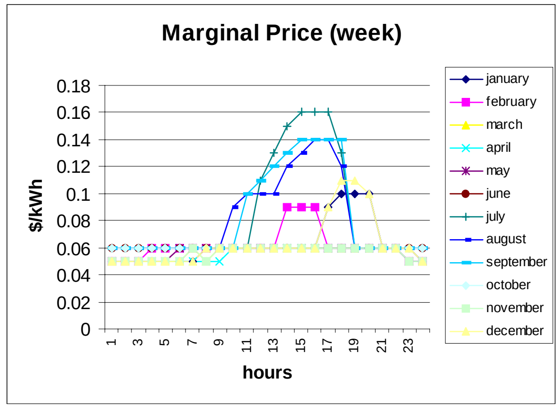

Figure 67. Mall PXRN Marginal Supply Cost (week)

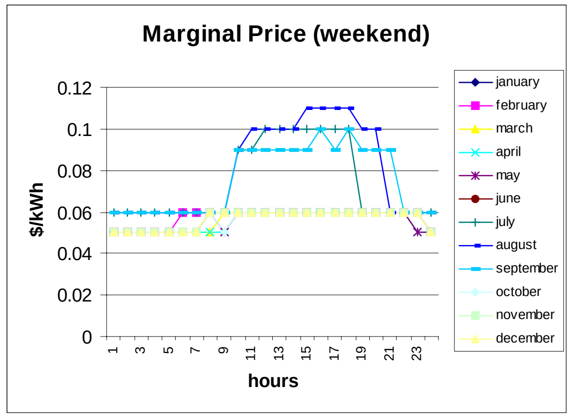

Figure 68. Mall PXRN Marginal Supply Cost (weekend)

7.1.2.2 Tariff Scenario

Table 22. Breakdown of Electricity Purchase Costs for the Mall Tariff Scenario

Total Supply Cost ($)	468417
Dist. Energy Purchases (peak) ($)	4814
Dist. Energy Purchases (Mid) ($)	6159
Dist. Energy Purchases (Off) ($)	65997
Dist. Power Purchases ($)	41727
PX Energy Purchases ($)	0
Self Generation Investment Costs ($)	108847
Self Generation Variable Costs ($)	240872
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	7.79
Installed Capacity (kW)	1630
Technologies	2 - 350ROZD 2 - SOFCo2 11 - mT_P

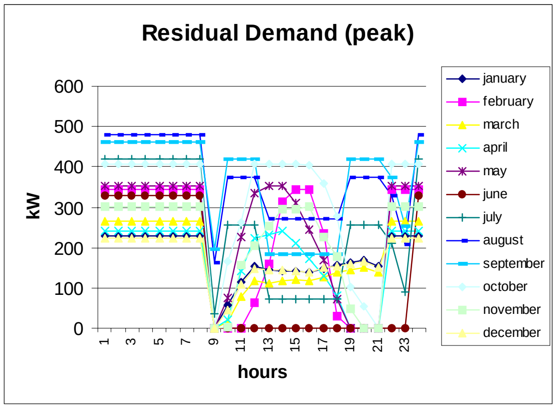

Figure 69. Mall Tariff Residual Demand (peak)

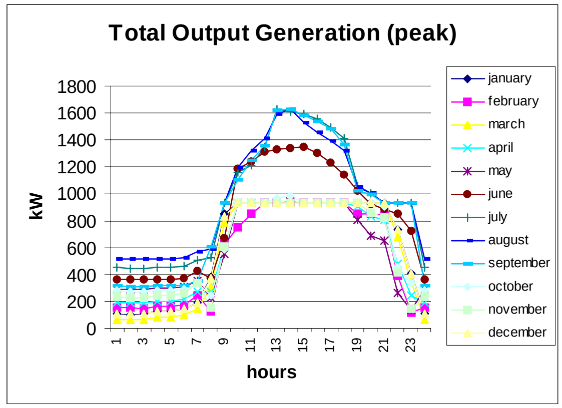

Figure 70. Mall Tariff Total Output Generation (peak)

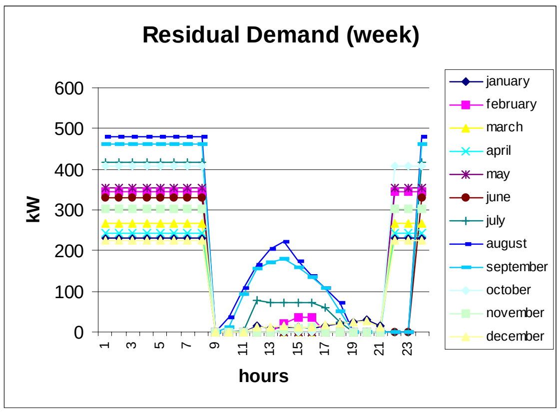

Figure 71. Mall Tariff Residual Demand (week)

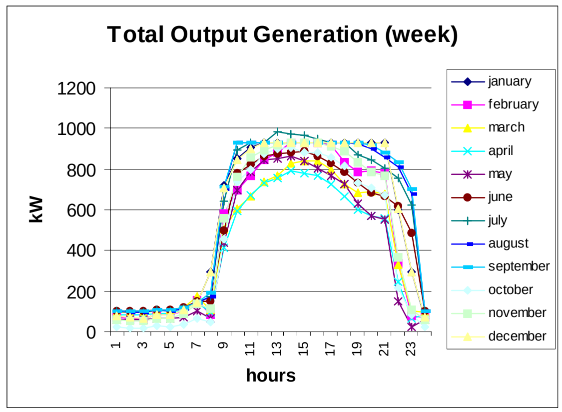

Figure 72. Mall Tariff Total Output Generation (week)

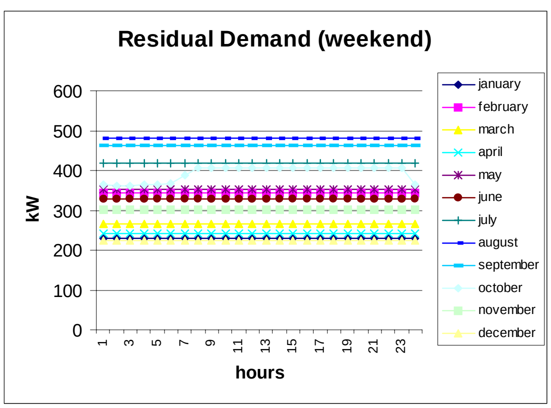

Figure 73. Mall Tariff Residual Demand (weekend)

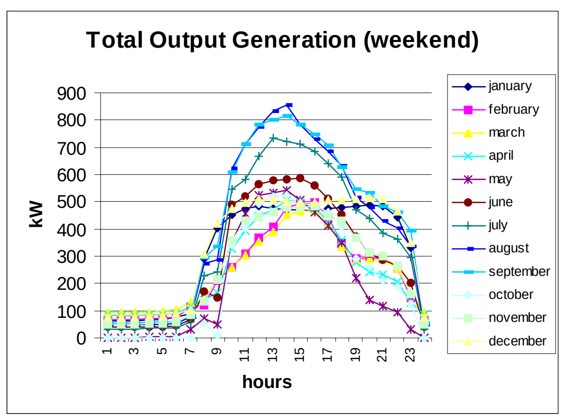

Figure 74. Mall Tariff Total Output Generation (weekend)

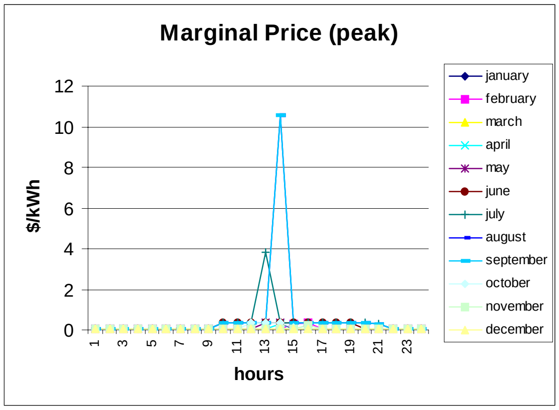

Figure 75. Mall Tariff Marginal Supply Cost (peak)

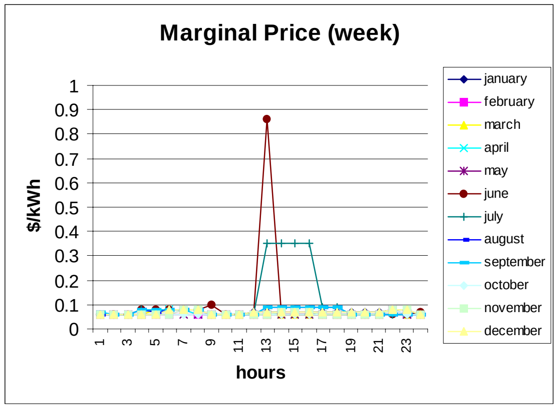

Figure 76. Mall Tariff Marginal Supply Cost (week)

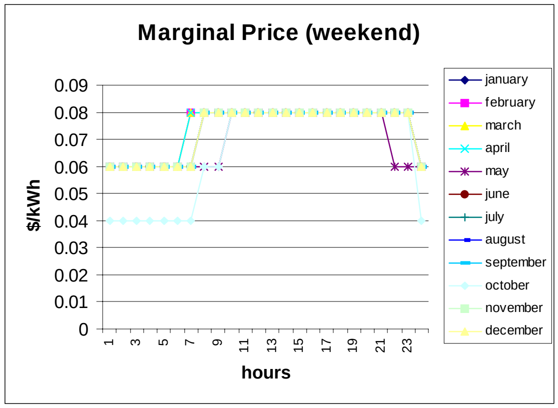

Figure 77. Mall Tariff Marginal Supply Cost (weekend)

7.1.2.3 Fixed Rate Scenario

Table 23. Breakdown of Electricity Purchase Costs for the Mall Fixed Rate Scenario

Total Supply Cost ($)	434853
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	36732
Self Generation Investment Costs ($)	106038
Self Generation Variable Costs ($)	292083
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	7.24
Installed Capacity (kW)	870
Technologies	8 - SOFCo2 6 - mT_P

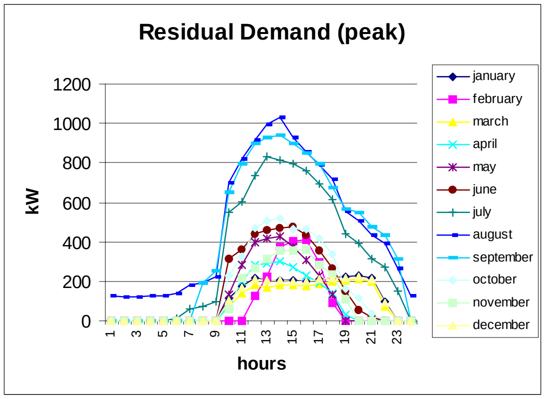

Figure 78. Mall Fixed Rate Residual Demand (peak)

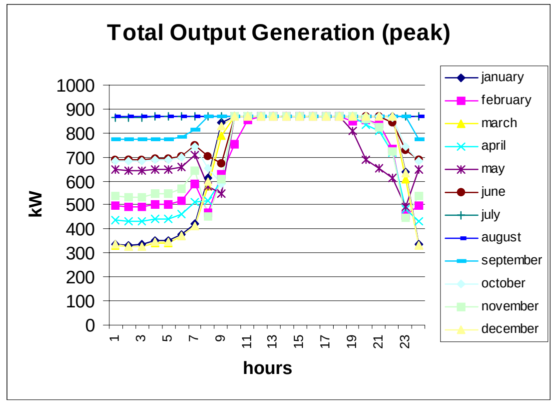

Figure 79. Mall Fixed Rate Total Output Generation (peak)

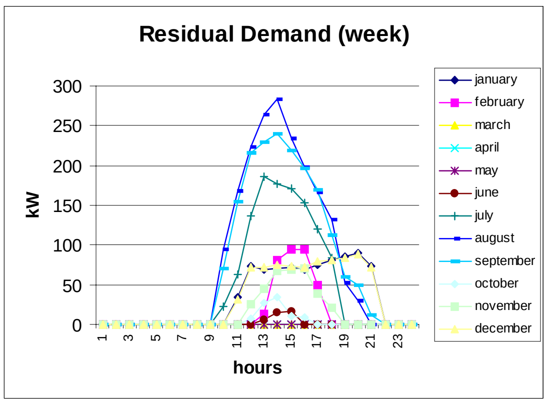

Figure 80. Mall Fixed Rate Residual Demand (week)

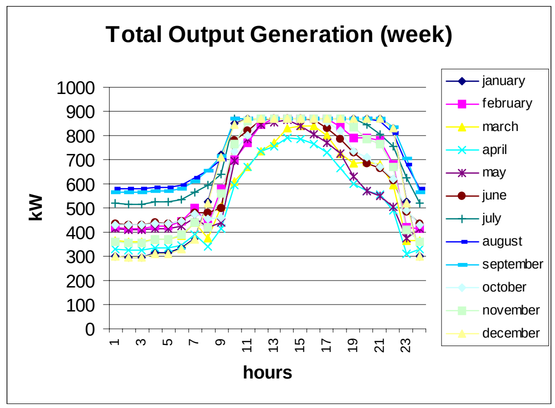

Figure 81. Mall Fixed Rate Total Output Generation (week)

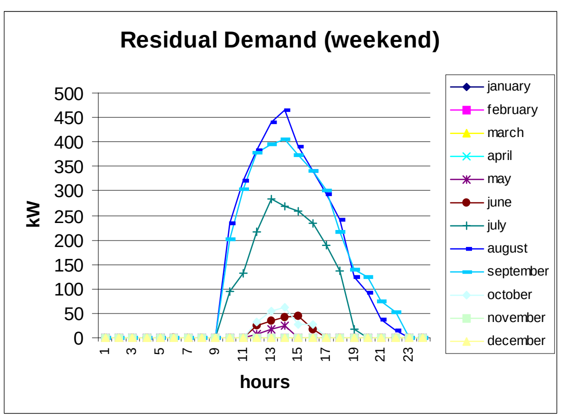

Figure 82. Mall Fixed Rate Residual Demand (weekend)

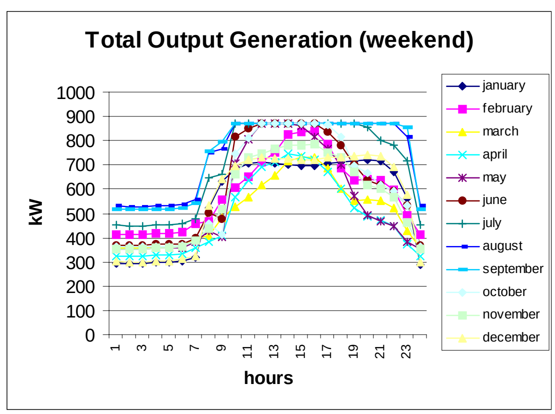

Figure 83. Mall Fixed Rate Total Output Generation (weekend)

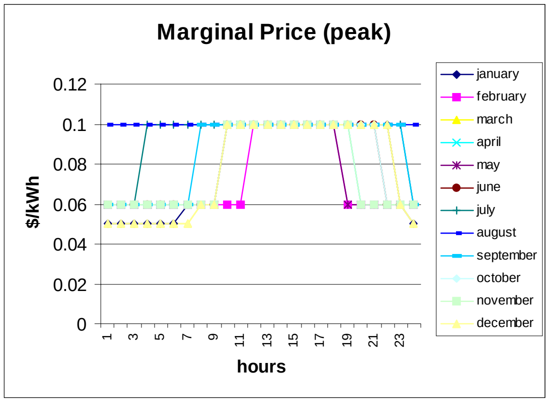

Figure 84. Mall Fixed Rate Marginal Supply Cost (peak)

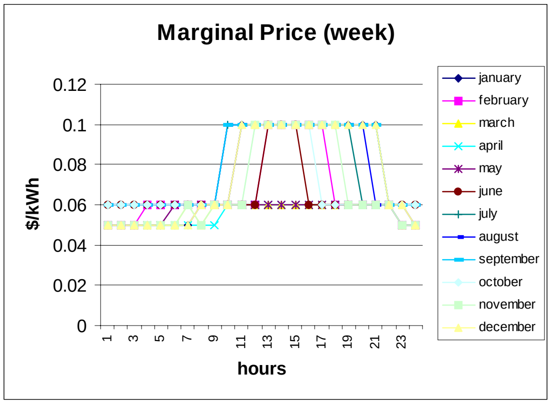

Figure 85. Mall Fixed Rate Marginal Supply Cost (week)

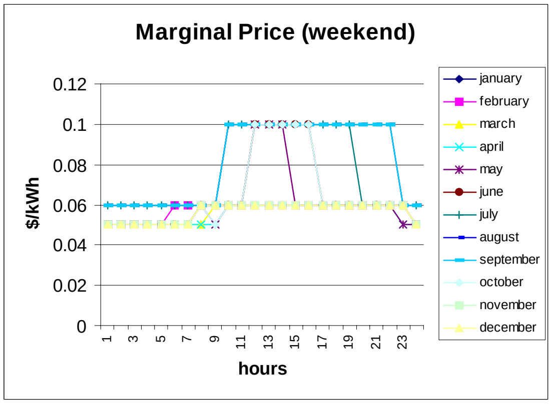

Figure 86. Mall Fixed Rate Marginal Supply Cost (weekend)

7.1.2.4 PXRN Scenario With Sales

Table 24. Breakdown of Electricity Purchase Costs for the Mall PXRN With Sales Scenario

Total Supply Cost ($)	440303
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	26945
Self Generation Investment Costs ($)	113140
Self Generation Variable Costs ($)	301820
Sales at the PX Price ($)	1602

Consumed Energy (kWh)	6009629
Average Price (c/kWh)	7.33
Installed Capacity (kW)	945
Technologies	8 - SOFCo2 7 - mT_P

Not surprisingly, the patterns of residual demand, total output generation, and marginal supply cost are similar to those under the base case (see section 7.1.2.1).

7.1.3 Sensitivities

7.1.3.1 Stand-By Charge

Table 25. Breakdown of Electricity Purchase Costs for the Mall Stand-By Charge Sensitivity

Total Supply Cost ($)	504707
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	72523
Self Generation Investment Costs ($)	159090
Self Generation Variable Costs ($)	273094
Sales at the PX Price ($)	0
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	8.40
Installed Capacity (kW)	772.5
Technologies	9 - SOFCo2 4 – mT_P

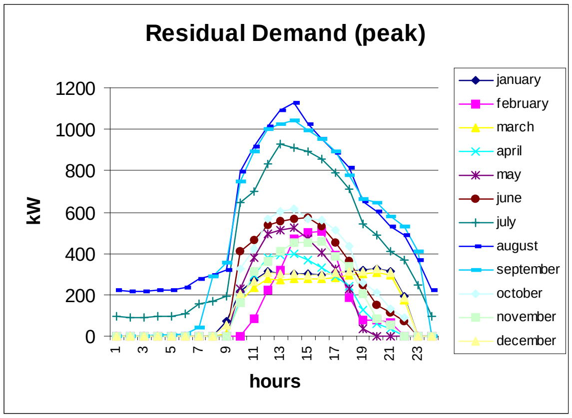

Figure 87. Mall Stand-By Charge Residual Demand (peak)

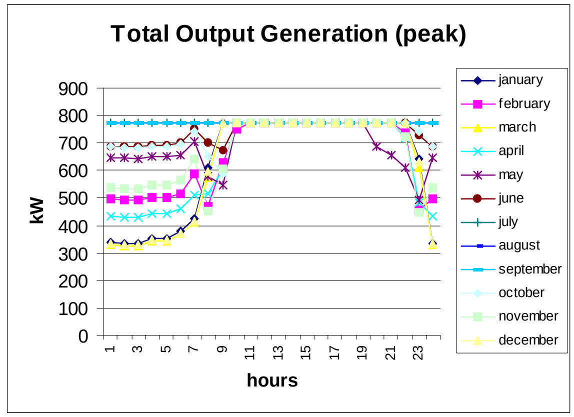

Figure 88. Mall Stand-By Charge Total Output Generation (peak)

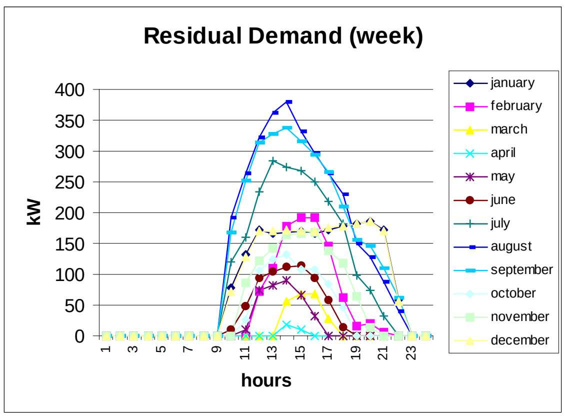

Figure 89. Mall Stand-By Charge Residual Demand (week)

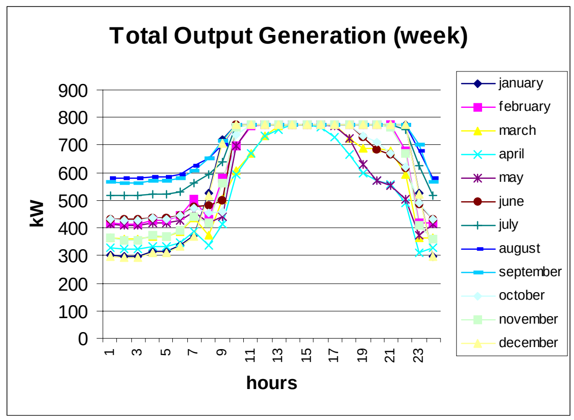

Figure 90. Mall Stand-By Charge Total Output Generation (week)

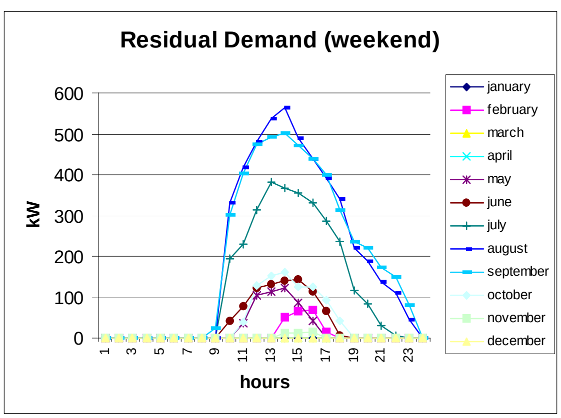

Figure 91. Mall Stand-By Charge Residual Demand (weekend)

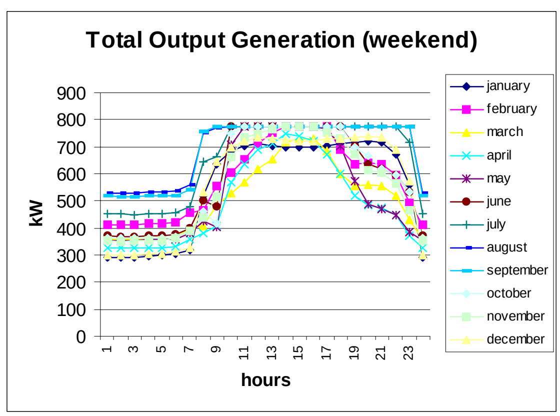

Figure 92. Mall Stand-By Charge Total Output Generation (weekend)

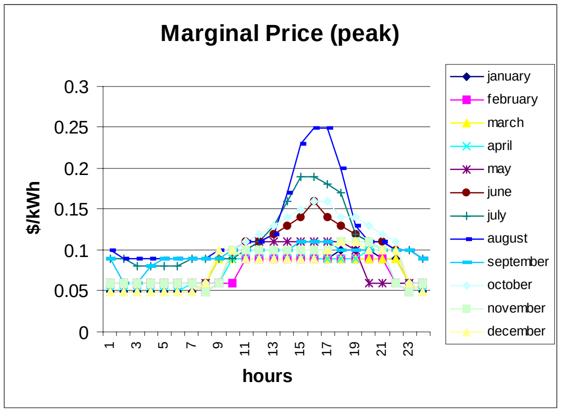

Figure 93. Mall Stand-By Charge Marginal Supply Cost (peak)

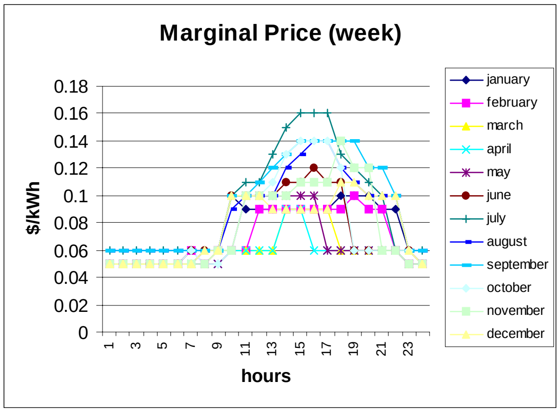

Figure 94. Mall Stand-By Charge Marginal Supply Cost (week)

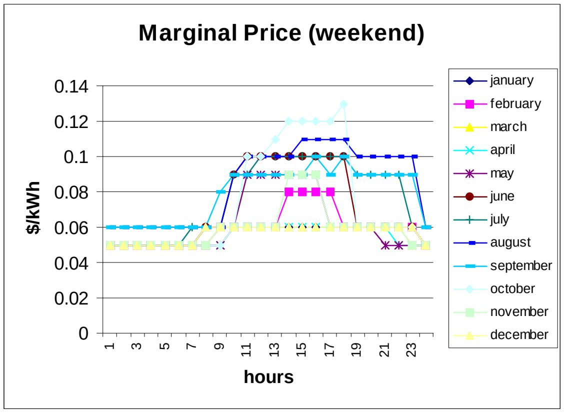

Figure 95. Mall Stand-By Charge Marginal Supply Cost (weekend)

7.1.3.2 10% Increase in Fuel Cell Turn-Key Costs

Table 26. Breakdown of Electricity Purchase Costs for the Mall 10% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	882562
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	38888
Self Generation Investment Costs ($)	234212
Self Generation Variable Costs ($)	609462
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	7.22

Installed Capacity (kW)	1770
Technologies	18 - SOFCo2 11 - mT_P

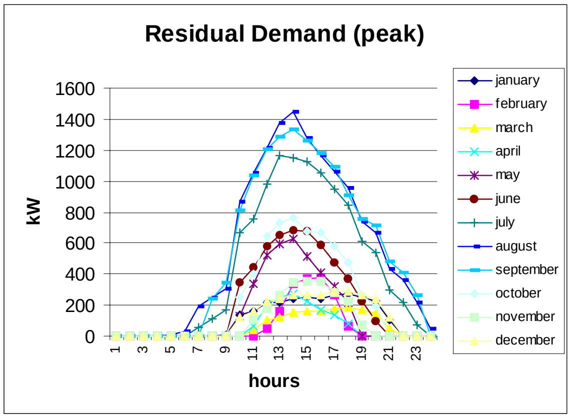

Figure 96. Mall 10% Increase in Fuel Cell Cost Residual Demand (peak)

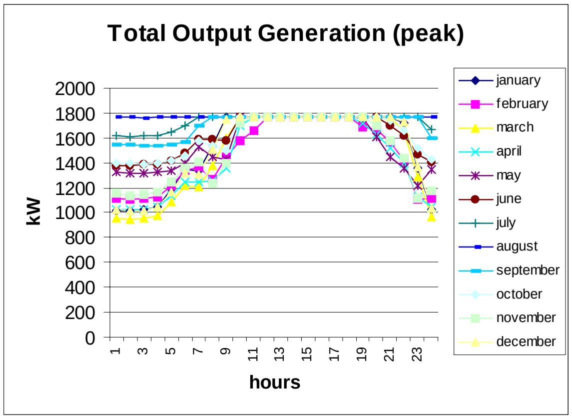

Figure 97. Mall 10% Increase in Fuel Cell Cost Total Output Generation (peak)

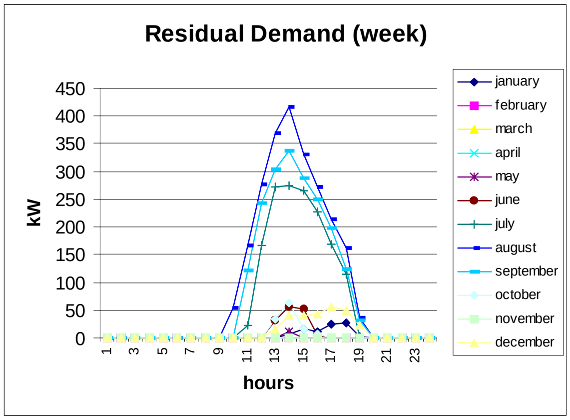

Figure 98. Mall 10% Increase in Fuel Cell Cost Residual Demand (week)

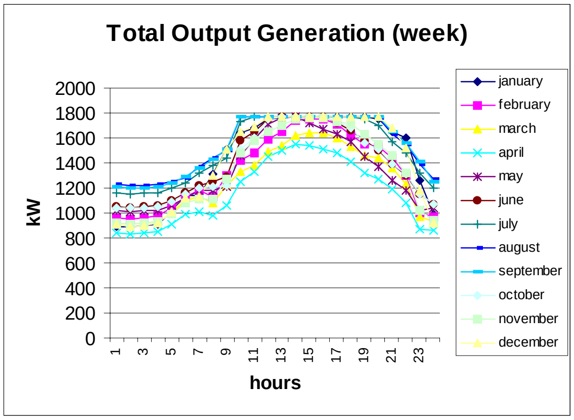

Figure 99. Mall 10% Increase in Fuel Cell Cost Total Output Generation (week)

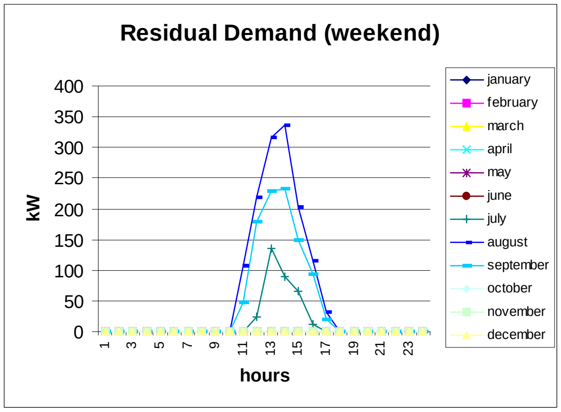

Figure 100. Mall 10% Increase in Fuel Cell Cost Residual Demand (weekend)

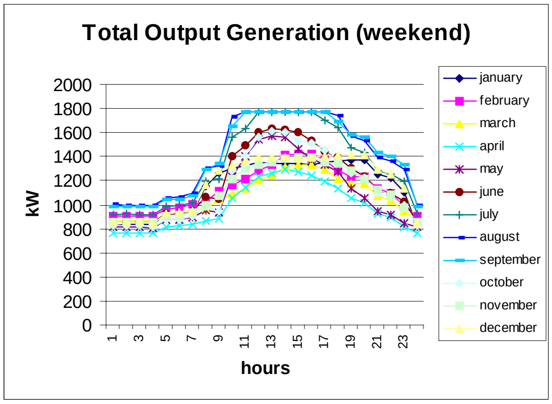

Figure 101. Mall 10% Increase in Fuel Cell Cost Total Output Generation (weekend)

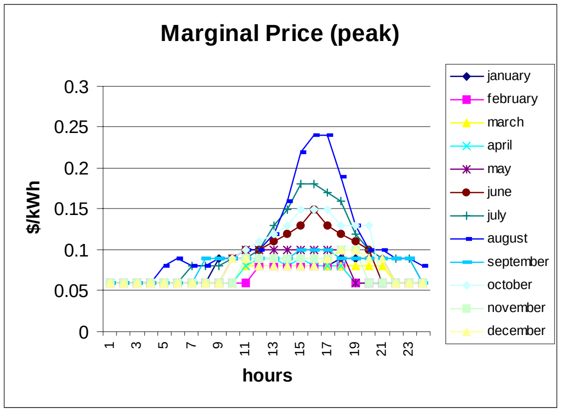

Figure 102. Mall 10% Increase in Fuel Cell Cost Marginal Supply Cost (peak)

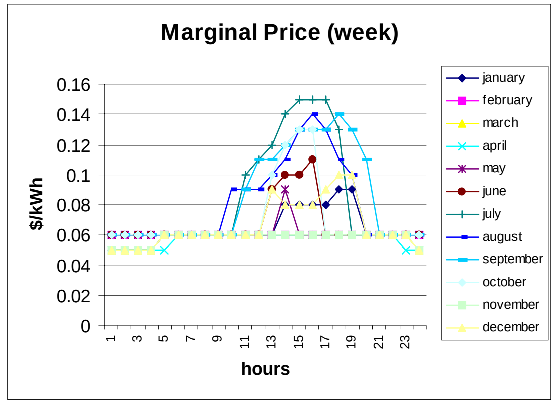

Figure 103. Mall 10% Increase in Fuel Cell Cost Marginal Supply Cost (week)

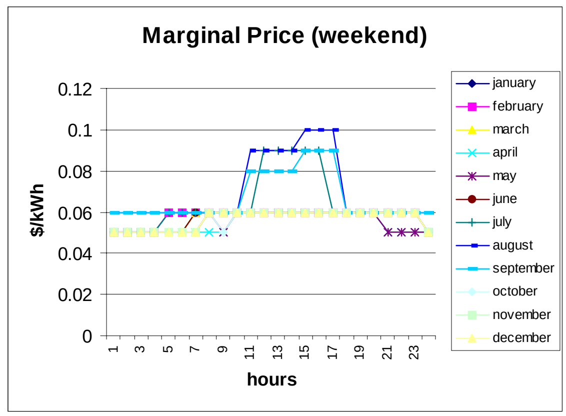

Figure 104. Mall 10% Increase in Fuel Cell Cost Marginal Supply Cost (weekend)

7.1.3.3 50% Increase in Fuel Cell Turn-Key Costs

Table 27. Breakdown of Electricity Purchase Costs for the Mall 50% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	448211
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	35654
Self Generation Investment Costs ($)	85226

Self Generation Variable Costs ($)	327330
Sales at the PX Price ($)	0
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	7.46
Installed Capacity (kW)	900
Technologies	12 - mT_P

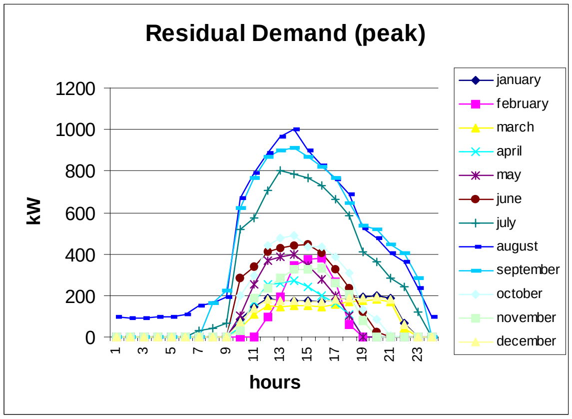

Figure 105. Mall 50% Increase in Fuel Cell Cost Residual Demand (peak)

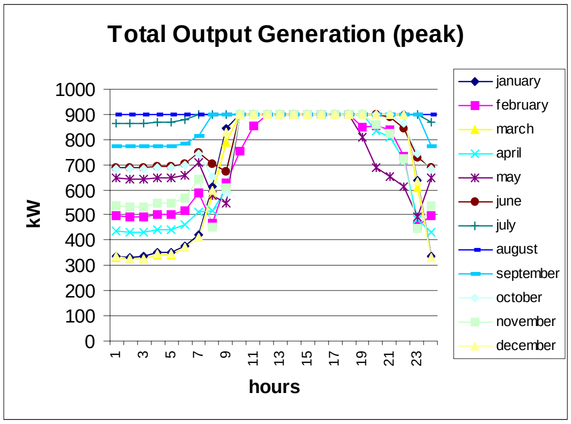

Figure 106. Mall 50% Increase in Fuel Cell Cost Total Output Generation (peak)

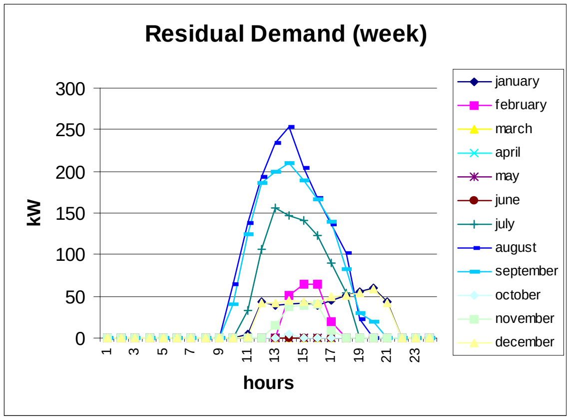

Figure 107. Mall 50% Increase in Fuel Cell Cost Residual Demand (week)

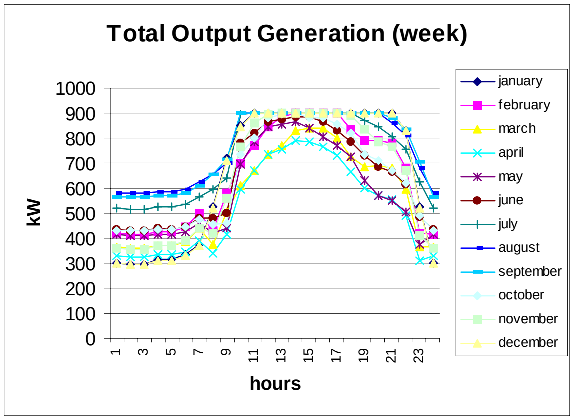

Figure 108. Mall 50% Increase in Fuel Cell Cost Total Output Generation (week)

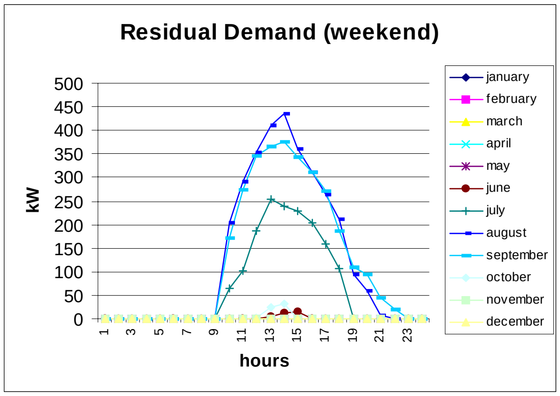

Figure 109. Mall 50% Increase in Fuel Cell Cost Residual Demand (weekend)

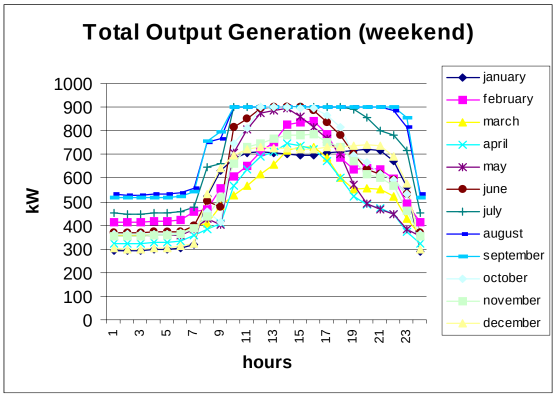

Figure 110. Mall 50% Increase in Fuel Cell Cost Total Output Generation (weekend)

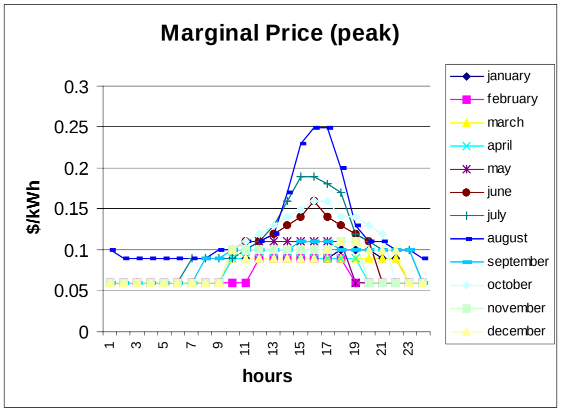

Figure 111. Mall 50% Increase in Fuel Cell Cost Marginal Supply Cost (peak)

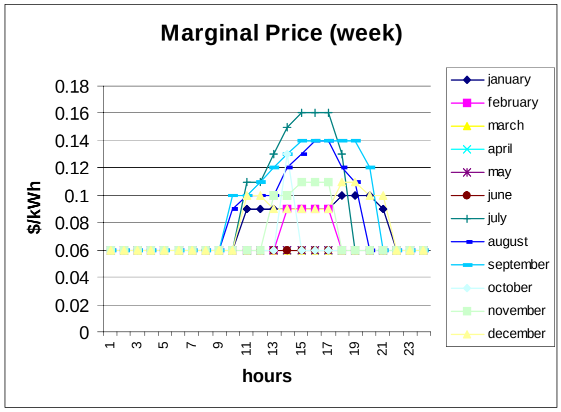

Figure 112. Mall 50% Increase in Fuel Cell Cost Marginal Supply Cost (week)

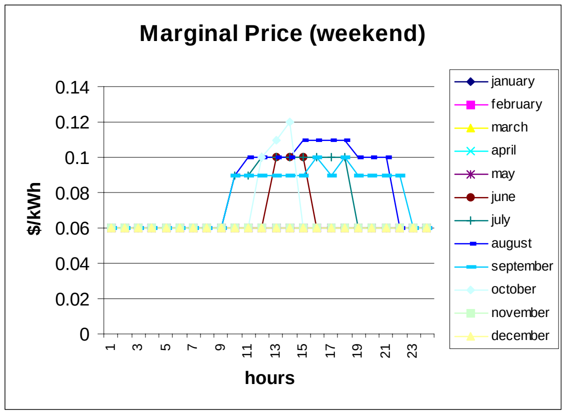

Figure 113. Mall 50% Increase in Fuel Cell Cost Marginal Supply Cost (weekend)

7.1.3.4 Low Natural Gas Price Sensitivity

Table 28. Breakdown of Electricity Purchase Costs for the Mall Low Natural Gas Price Sensitivity

Total Supply Cost ($)	332575
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0

PX Energy Purchases ($)	22875
Self Generation Investment Costs ($)	92328
Self Generation Variable Costs ($)	217372
Sales at the PX Price ($)	0
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	5.53
Installed Capacity (kW)	975
Technologies	13 - mT_P

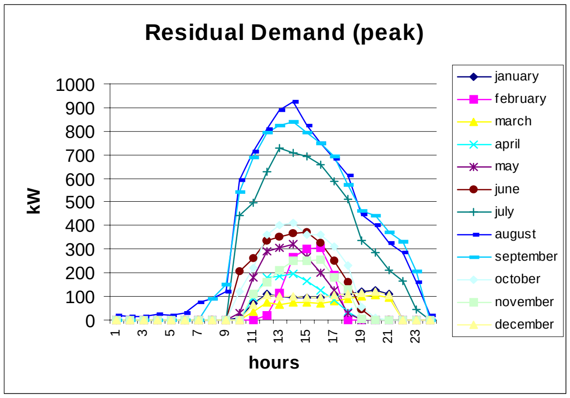

Figure 114. Mall Low Natural Gas Price Residual Demand (peak)

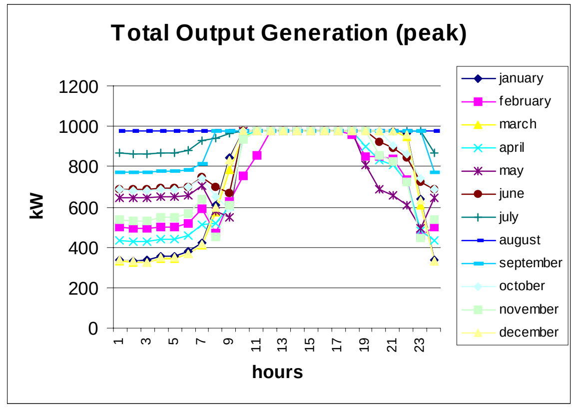

Figure 115. Mall Low Natural Gas Price Total Output Generation (peak)

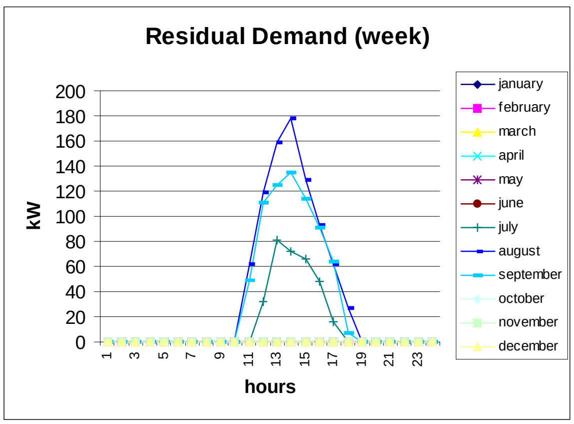

Figure 116. Mall Low Natural Gas Price Residual Demand (week)

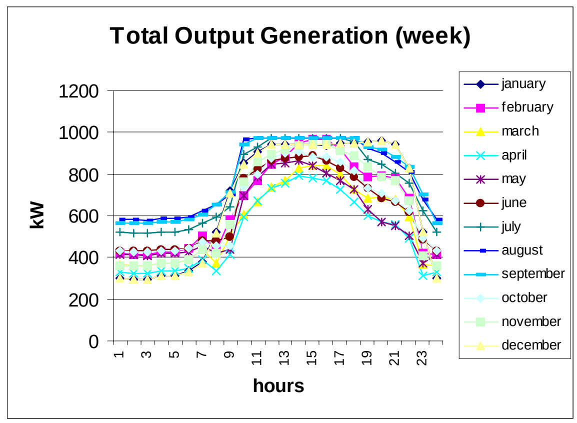

Figure 117. Mall Low Natural Gas Price Total Output Generation (week)

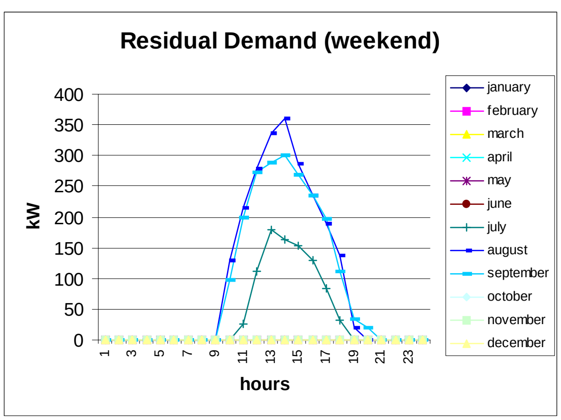

Figure 118. Mall Low Natural Gas Price Residual Demand (weekend)

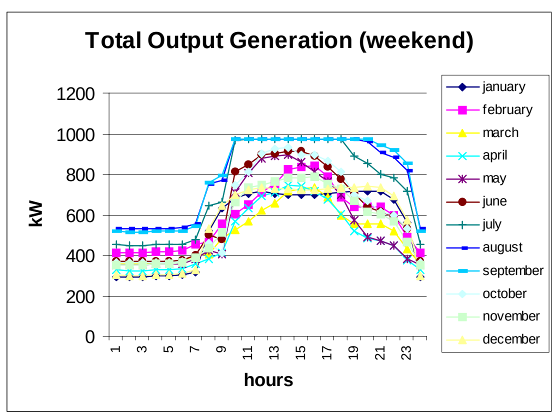

Figure 119. Mall Low Natural Gas Price Total Output Generation (weekend)

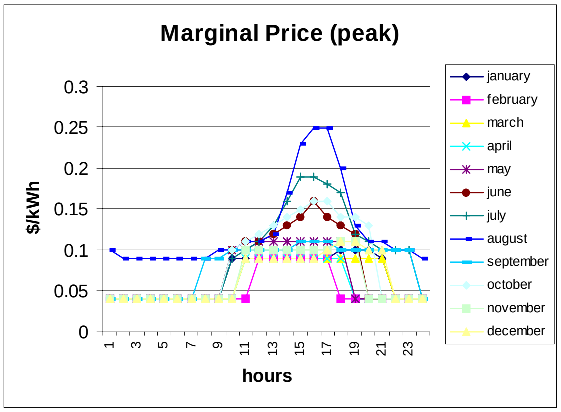

Figure 120. Mall Low Natural Gas Price Marginal Supply Cost (peak)

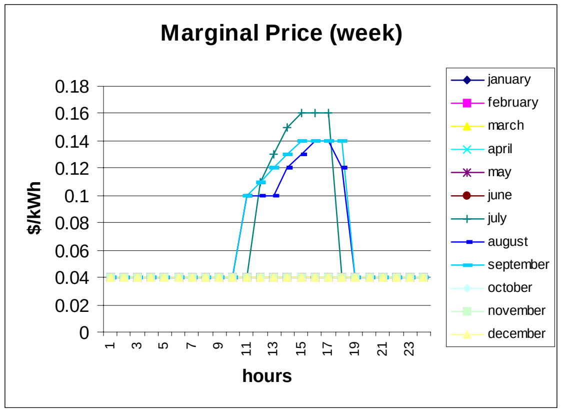

Figure 121. Mall Low Natural Gas Price Marginal Supply Cost (week)

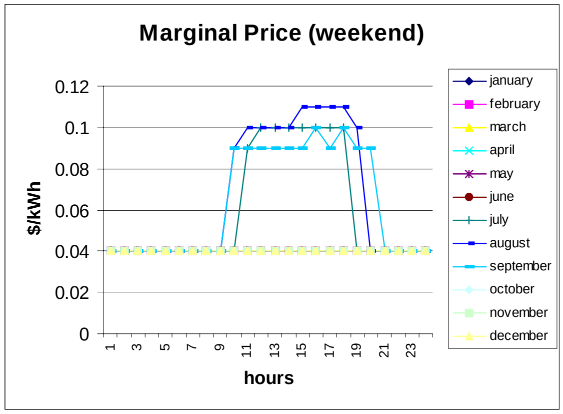

Figure 122. Mall Low Natural Gas Price Marginal Supply Cost (weekend)

7.1.3.5 High Natural Gas Price Sensitivity

Table 29. Breakdown of Electricity Purchase Costs for the Mall High Natural Gas Price Sensitivity

Total Supply Cost ($)	521495
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	59991
Self Generation Investment Costs ($)	118096
Self Generation Variable Costs ($)	343408
Sales at the PX Price ($)	0

Consumed Energy (kWh)	6009629
Average Price (c/kWh)	8.68
Installed Capacity (kW)	810
Technologies	14 - SOFCo2 1 - mT_P

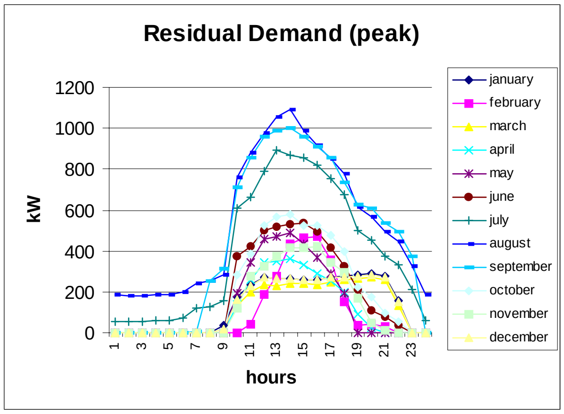

Figure 123. Mall High Natural Gas Price Residual Demand (peak)

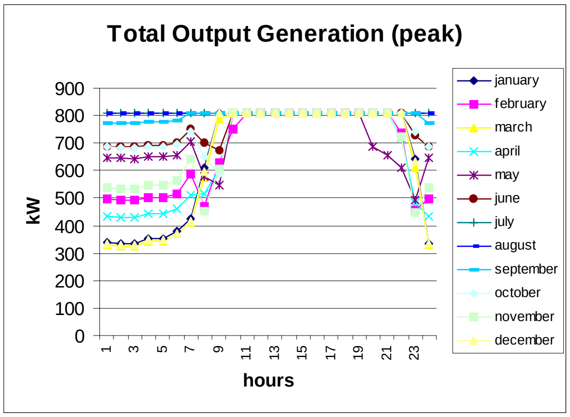

Figure 124. Mall High Natural Gas Price Total Output Generation (peak)

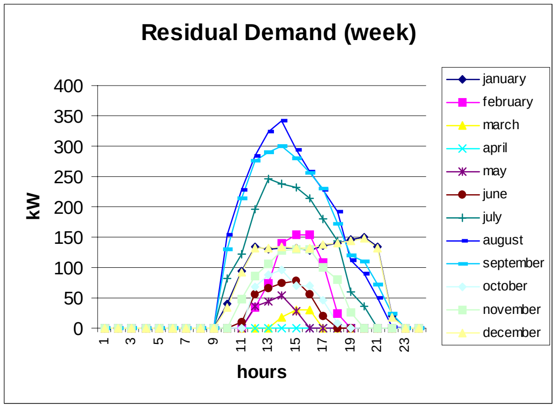

Figure 125. Mall High Natural Gas Price Residual Demand (week)

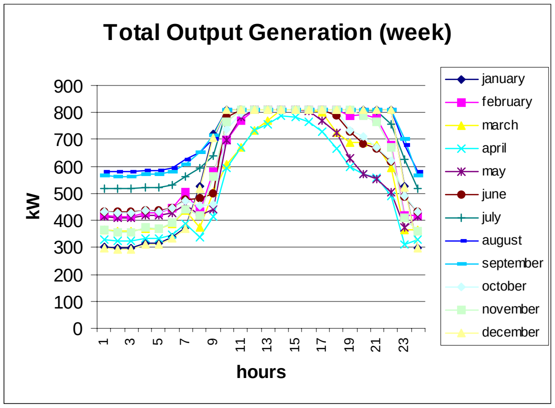

Figure 126. Mall High Natural Gas Price Total Output Generation (week)

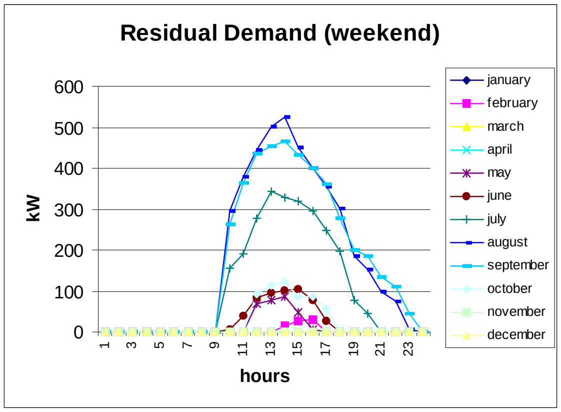

Figure 127. Mall High Natural Gas Price Residual Demand (weekend)

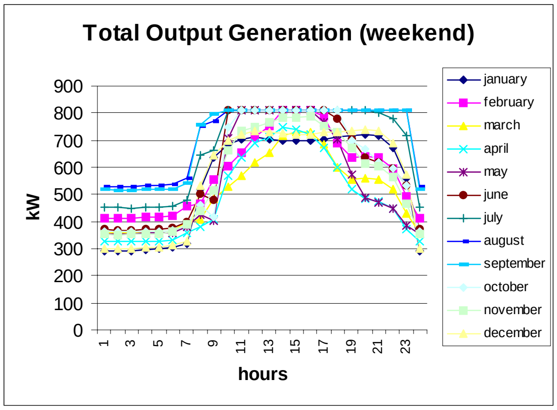

Figure 128. Mall High Natural Gas Price Total Output Generation (weekend)

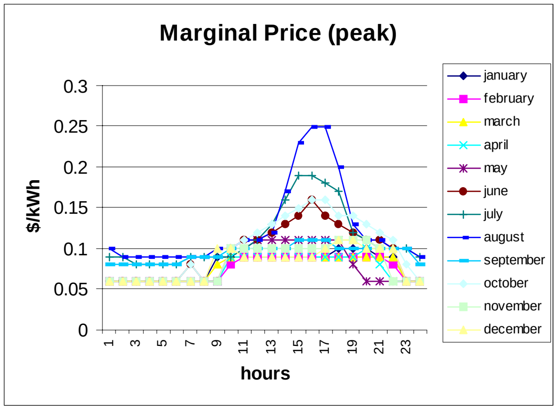

Figure 129. Mall High Natural Gas Price Marginal Supply Cost (peak)

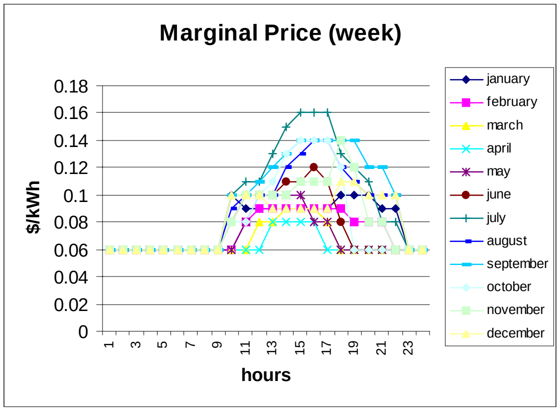

Figure 130. Mall High Natural Gas Price Marginal Supply Cost (week)

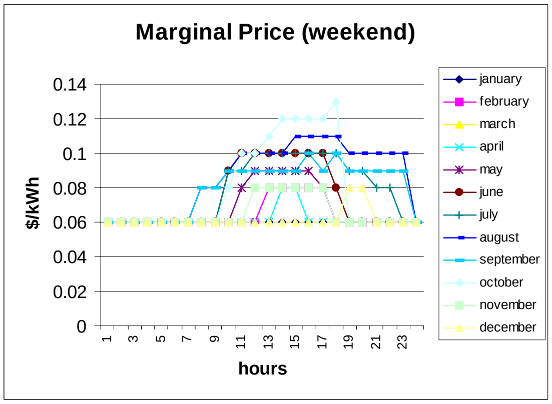

Figure 131. Mall High Natural Gas Price Marginal Supply Cost (weekend)

7.1.3.6 High Interest Rate Sensitivity

Table 30. Breakdown of Electricity Purchase Costs for the Mall High Interest Rate Sensitivity

Total Supply Cost ($)	452586
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	37310
Self Generation Investment Costs ($)	116928
Self Generation Variable Costs ($)	298347
Sales at the PX Price ($)	0
Consumed Energy (kWh)	6009629
Average Price (c/kWh)	7.53
Installed Capacity (kW)	892.5
Technologies	7 - SOFCo2 7 - mT_P

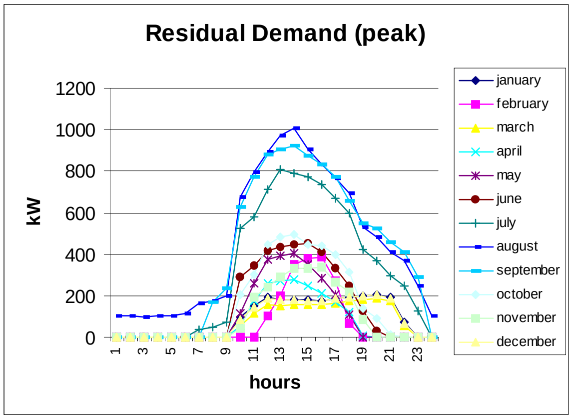

Figure 132. Mall High Interest Rate Residual Demand (peak)

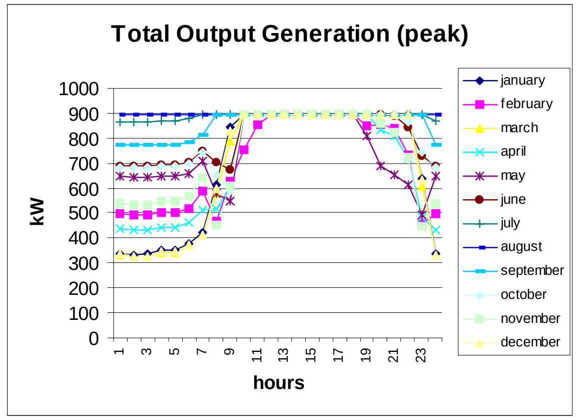

Figure 133. Mall High Interest Rate Total Output Generation (peak)

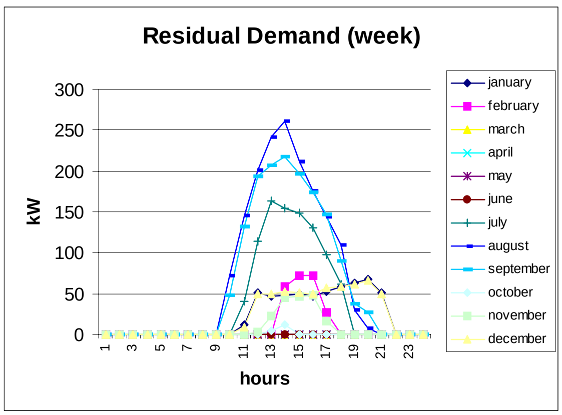

Figure 134. Mall High Interest Rate Residual Demand (week)

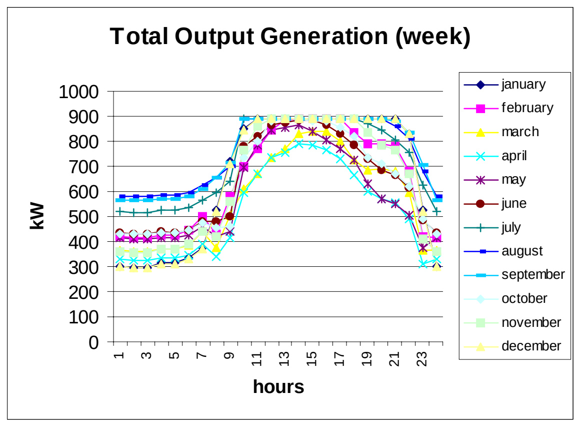

Figure 135. Mall High Interest Rate Total Output Generation (week)

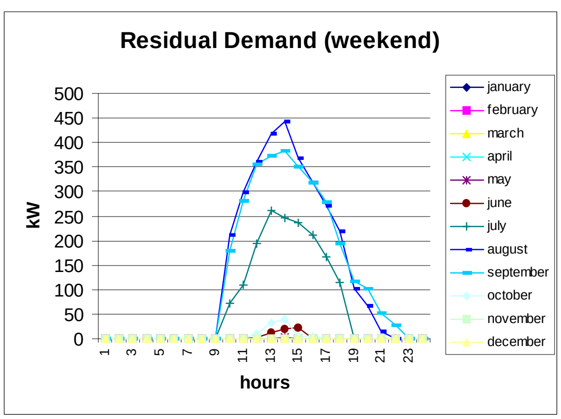

Figure 136. Mall High Interest Rate Residual Demand (weekend)

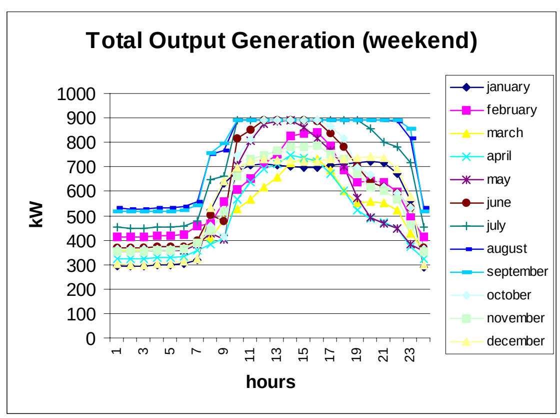

Figure 137. Mall High Interest Rate Total Output Generation (weekend)

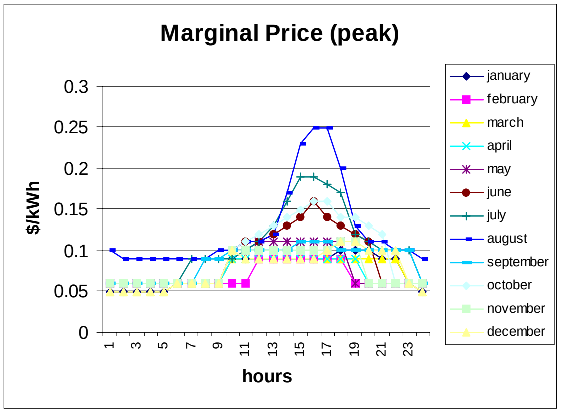

Figure 138. Mall High Interest Rate Marginal Supply Cost (peak)

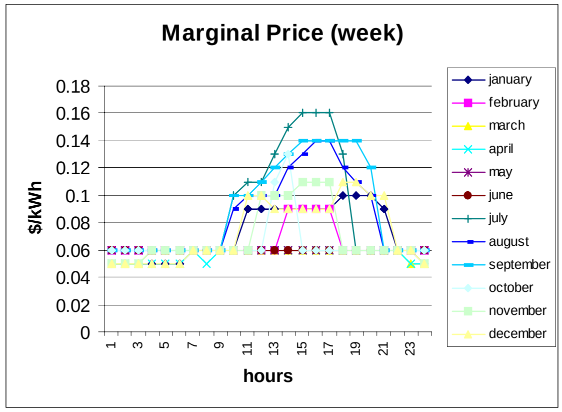

Figure 139. Mall High Interest Rate Marginal Supply Cost (week)

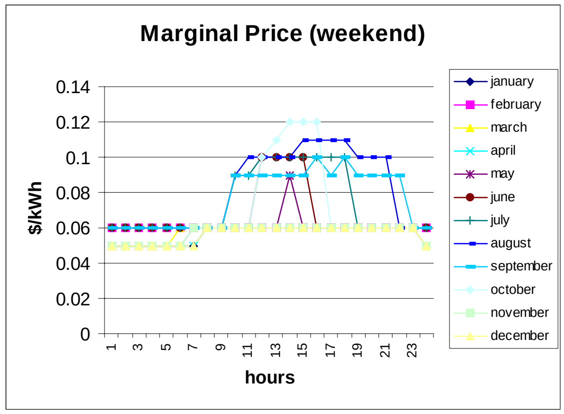

Figure 140. Mall High Interest Rate Marginal Supply Cost (weekend)

7.2 Office

7.2.1 "Do-Nothing" Scenario

Table 31. Breakdown of Electricity Purchase Costs for Office ("Do-Nothing" Scenario)

Total Supply Cost ($)	194215
Dist. Energy Purchases (peak) ($)	17531
Dist. Energy Purchases (Mid) ($)	57898
Dist. Energy Purchases (Off) ($)	38492
Dist. Power Purchases ($)	80294
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	9.70

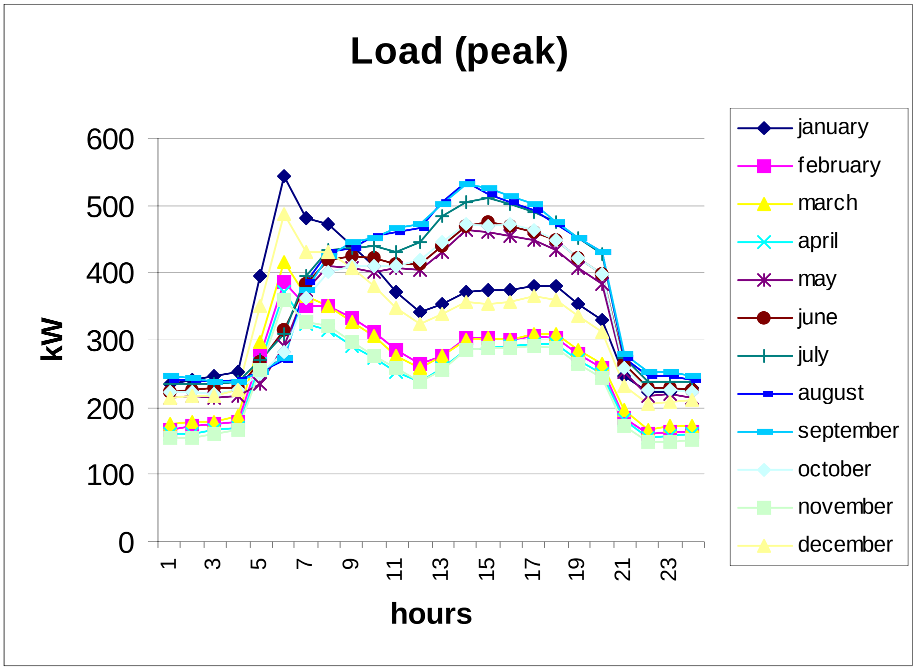

Figure 141. Office Peak Load Shape

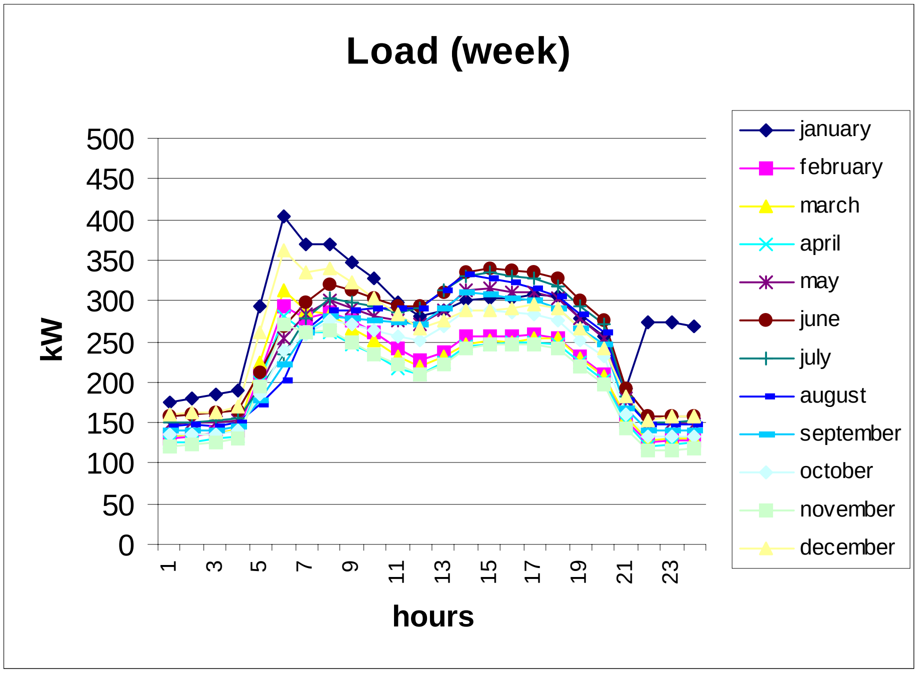

Figure 142. Office Week Load Shape

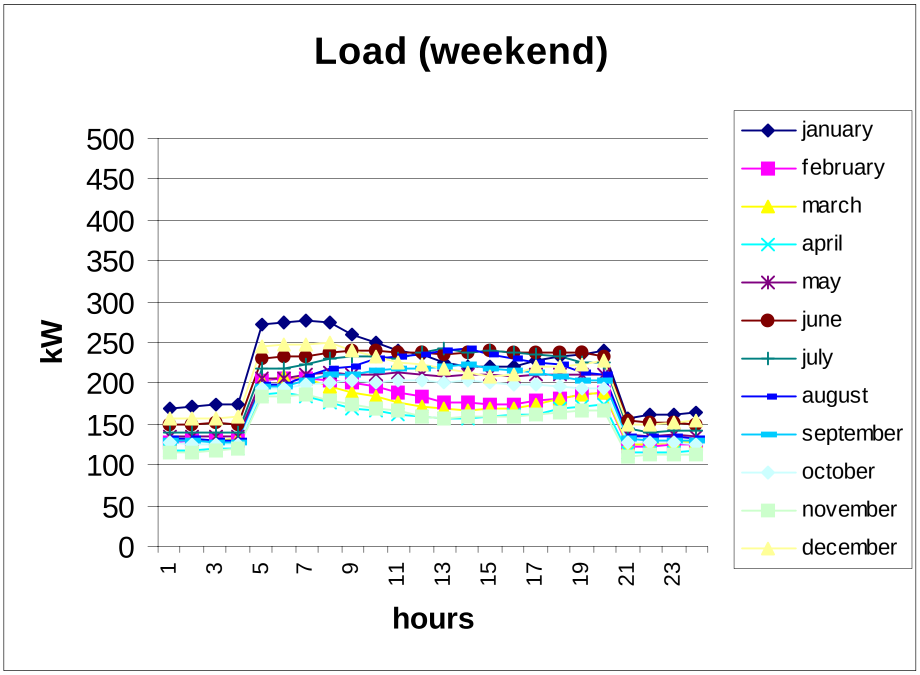

Figure 143. Office Weekend Load Shape

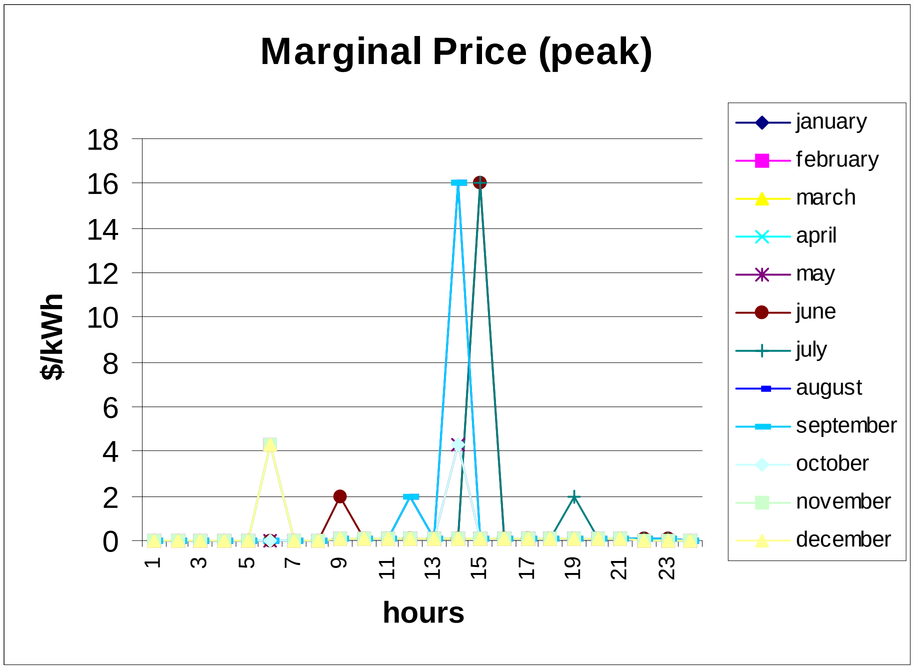

Figure 144. Office "Do-Nothing" Marginal Supply Cost (peak hours)

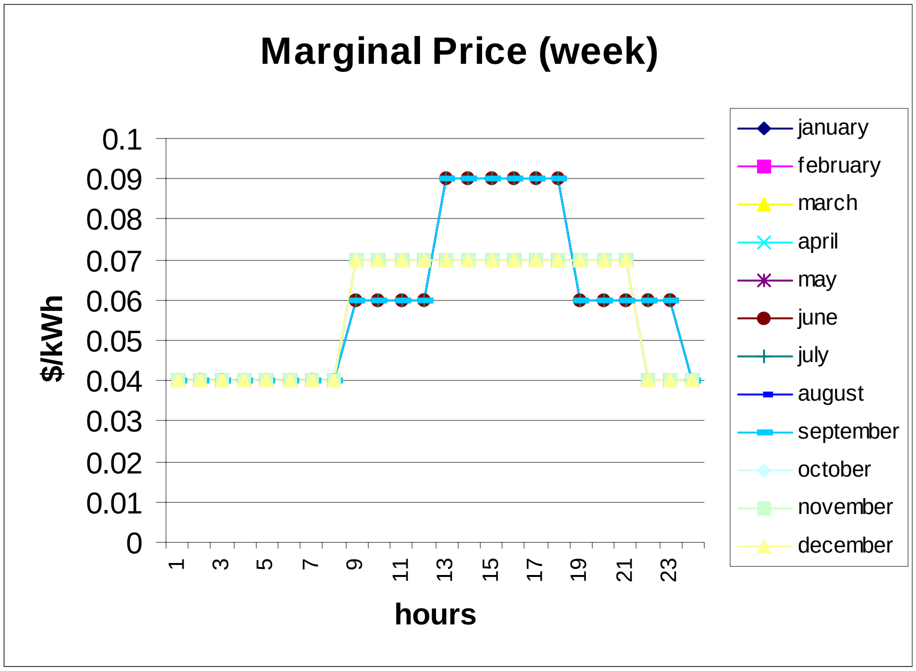

Figure 145. Office "Do-Nothing" Marginal Supply Cost (week)

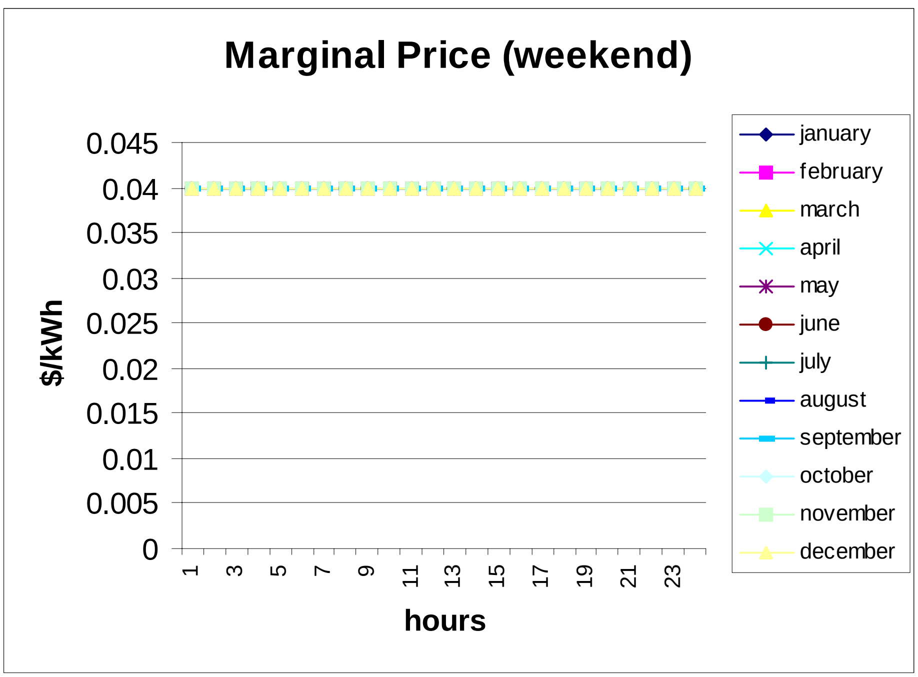

Figure 146. Office "Do-Nothing" Marginal Supply Cost (weekend)

7.2.2 Scenarios

7.2.2.1 Base Scenario

Table 32. Breakdown of Electricity Purchase Costs for the Office Base Case (PXRN)

Total Supply Cost ($)	144468
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	10569
Self Generation Investment Costs ($)	38815
Self Generation Variable Costs ($)	95084
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	7.21
Installed Capacity (kW)	945
Technologies	8 - SOFCo2 7 - mT_P

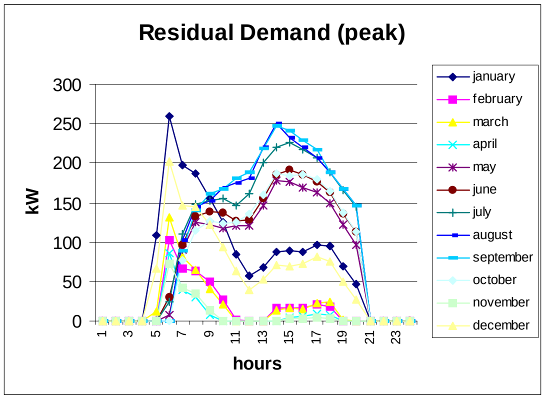

Figure 147. Office PXRN Residual Demand (peak)

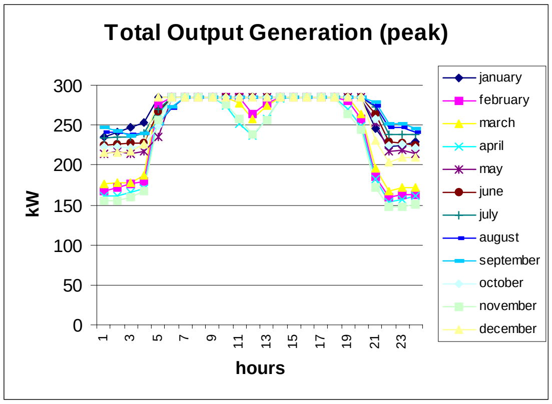

Figure 148. Office PXRN Total Output Generation (peak)

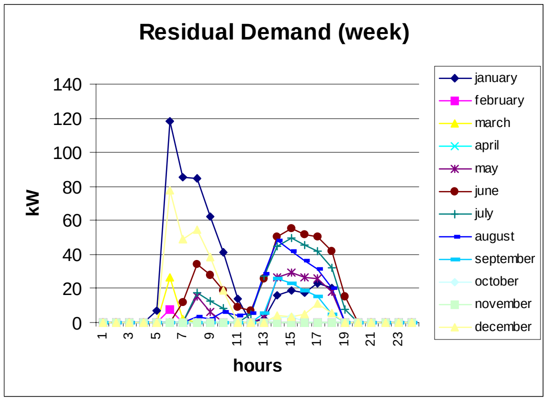

Figure 149. Office PXRN Residual Demand (week)

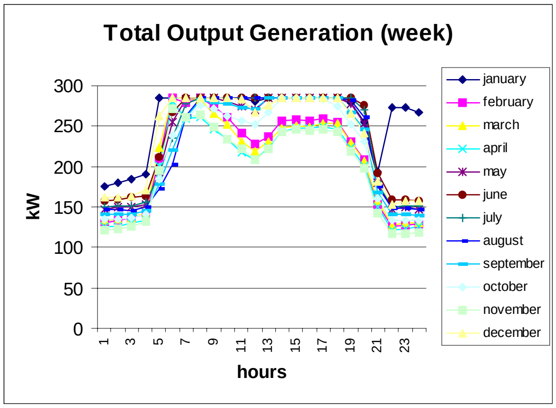

Figure 150. Office PXRN Total Output Generation (week)

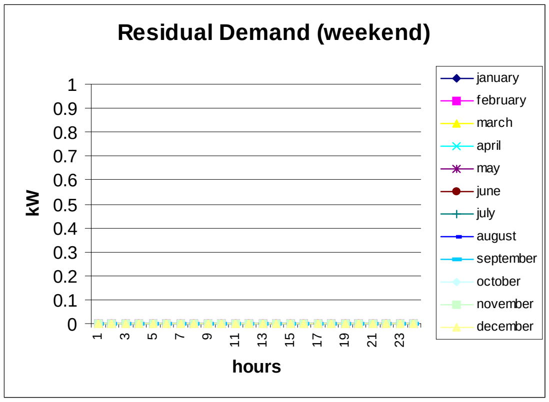

Figure 151. Office PXRN Residual Demand (weekend)

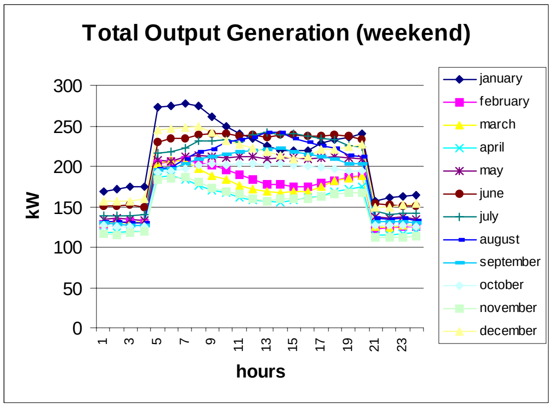

Figure 152. Office PXRN Total Output Generation (weekend)

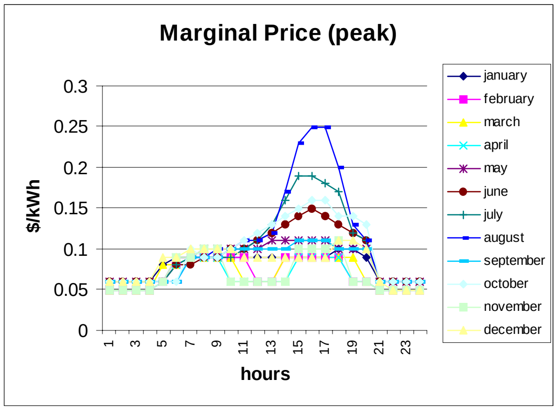

Figure 153. Office PXRN Marginal Supply Cost (peak)

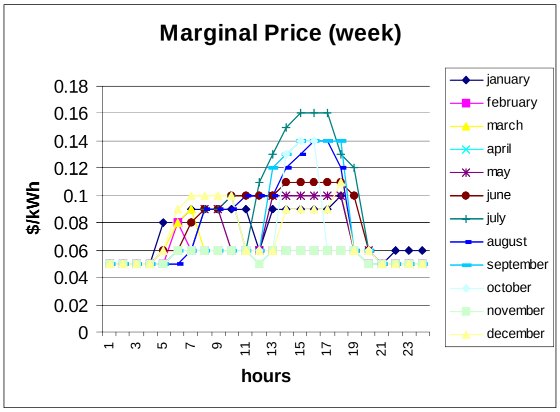

Figure 154. Office PXRN Marginal Supply Cost (week)

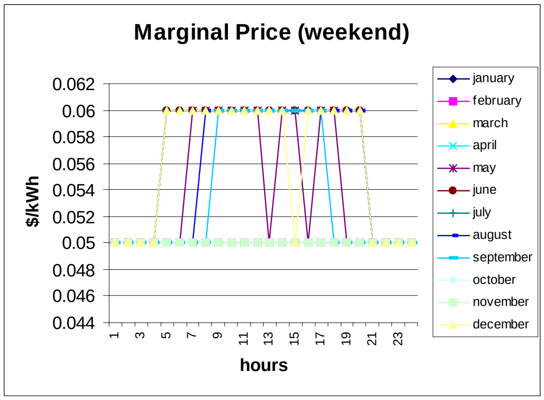

Figure 155. Office PXRN Marginal Supply Cost (weekend)

7.2.2.2 Tariff Scenario

Table 33. Breakdown of Electricity Purchase Costs for the Office Tariff Scenario

Total Supply Cost ($)	155678
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	1620
Dist. Energy Purchases (Off) ($)	27600
Dist. Power Purchases ($)	15687
PX Energy Purchases ($)	0
Self Generation Investment Costs ($)	34694
Self Generation Variable Costs ($)	76076
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	7.77

Installed Capacity (kW)	536
Technologies	1 - 230ROZD 2 - SOFCo1 4 - mT_P

7.2.2.3 Fixed Rate Scenario

Table 34. Breakdown of Electricity Purchase Costs for the Office Fixed Rate Scenario

Total Supply Cost ($)	142948
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	9049
Self Generation Investment Costs ($)	38815
Self Generation Variable Costs ($)	95084
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	7.14
Installed Capacity (kW)	285
Technologies	4 - SOFCo2 1 - mT_P

7.2.2.4 PXRN Scenario With Sales

Table 35. Breakdown of Electricity Purchase Costs for the Office PXRN With Sales Scenario

Total Supply Cost ($)	144412
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	10569
Self Generation Investment Costs ($)	38815
Self Generation Variable Costs ($)	95739
Sales at the PX Price ($)	712
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	7.21
Installed Capacity (kW)	285

Technologies	4 - SOFCo2 1 - mT_P

7.2.3 Sensitivities

7.2.3.1 Stand-By Charge

Table 36. Breakdown of Electricity Purchase Costs for the Office Stand-By Charge Sensitivity

Total Supply Cost ($)	164487
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	26026
Self Generation Investment Costs ($)	49460
Self Generation Variable Costs ($)	89001
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	8.21
Installed Capacity (kW)	235.5
Technologies	1 - SOFCo1 3 - SOFCo2 1 - mT_P

7.2.3.2 10% Increase in Fuel Cell Turn-Key Costs

Table 37. Breakdown of Electricity Purchase Costs for the Office 10% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	146658
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	11237
Self Generation Investment Costs ($)	36344
Self Generation Variable Costs ($)	99077
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2002813

Average Price (c/kWh)	7.32
Installed Capacity (kW)	282
Technologies	9 - SOFCo1 2 - SOFCo2 2 - mT_P

7.2.3.3 50% Increase in Fuel Cell Turn-Key Costs

Table 38. Breakdown of Electricity Purchase Costs for the Office 50% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	147345
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	7919
Self Generation Investment Costs ($)	28409
Self Generation Variable Costs ($)	111017
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	7.36
Installed Capacity (kW)	300
Technologies	4 - mT_P

7.2.3.4 Low Natural Gas Price Sensitivity

Table 39. Breakdown of Electricity Purchase Costs for the Office Low Natural Gas Price Sensitivity

Total Supply Cost ($)	108585
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	7919
Self Generation Investment Costs ($)	28409
Self Generation Variable Costs ($)	72258
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	5.42

Installed Capacity (kW)	300
Technologies	4 - mT_P

7.2.3.5 High Natural Gas Price Sensitivity

Table 40. Breakdown of Electricity Purchase Costs for the Office High Natural Gas Price Sensitivity

Total Supply Cost ($)	170978
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	16447
Self Generation Investment Costs ($)	39641
Self Generation Variable Costs ($)	114890
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	8.54
Installed Capacity (kW)	262.5
Technologies	5 - SOFCo2

7.2.3.6 High Interest Rate Sensitivity

Table 41. Breakdown of Electricity Purchase Costs for the Office High Interest Rate Sensitivity

Total Supply Cost ($)	148654
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	11943
Self Generation Investment Costs ($)	37801
Self Generation Variable Costs ($)	98910
Sales at the PX Price ($)	0
Consumed Energy (kWh)	2002813
Average Price (c/kWh)	7.42
Installed Capacity (kW)	279
Technologies	8 - SOFCo1

	2 - SOFCo2 2 - mT_P

7.3 Restaurant

7.3.1 "Do-Nothing" Scenario

Table 42. Breakdown of Electricity Purchase Costs for Restaurant ("Do-Nothing" Scenario)

Total Supply Cost ($)	158045
Dist. Energy Purchases (peak) ($)	36249
Dist. Energy Purchases (Mid) ($)	55067
Dist. Energy Purchases (Off) ($)	35551
Dist. Power Purchases ($)	31178
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	9.15

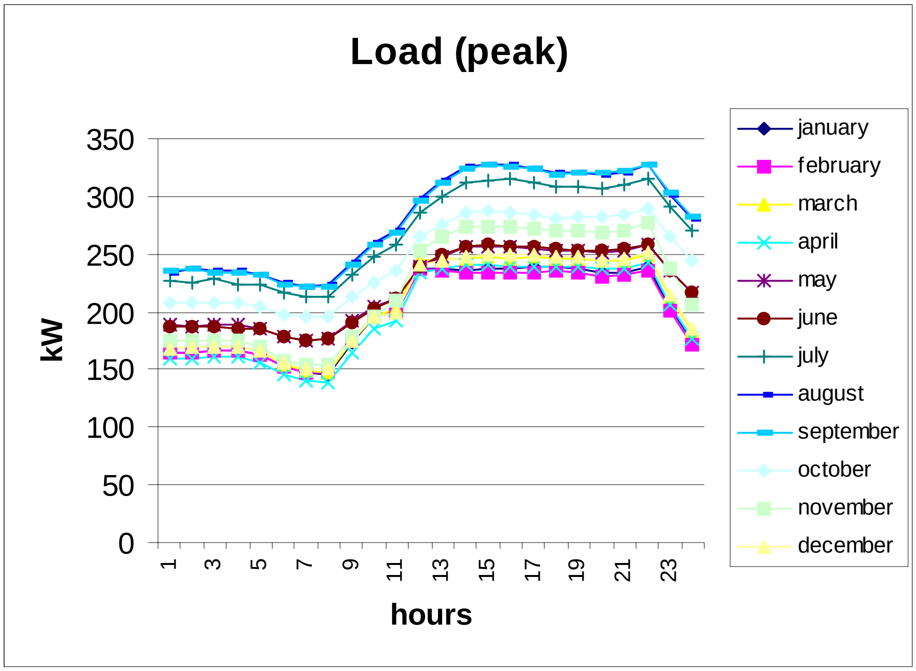

Figure 156. Restaurant Peak Load Shape

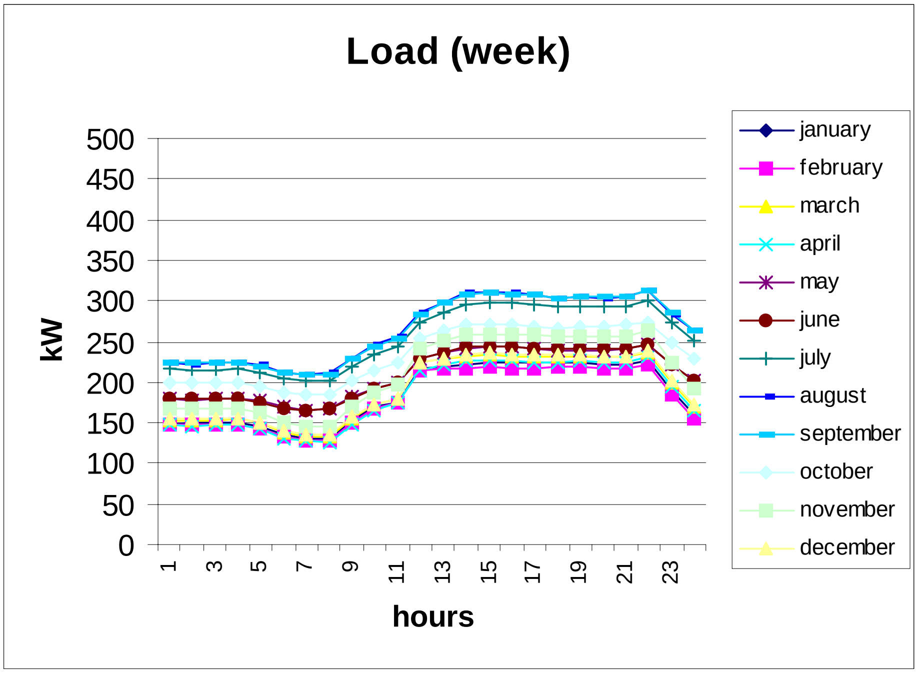

Figure 157. Restaurant Week Load Shape

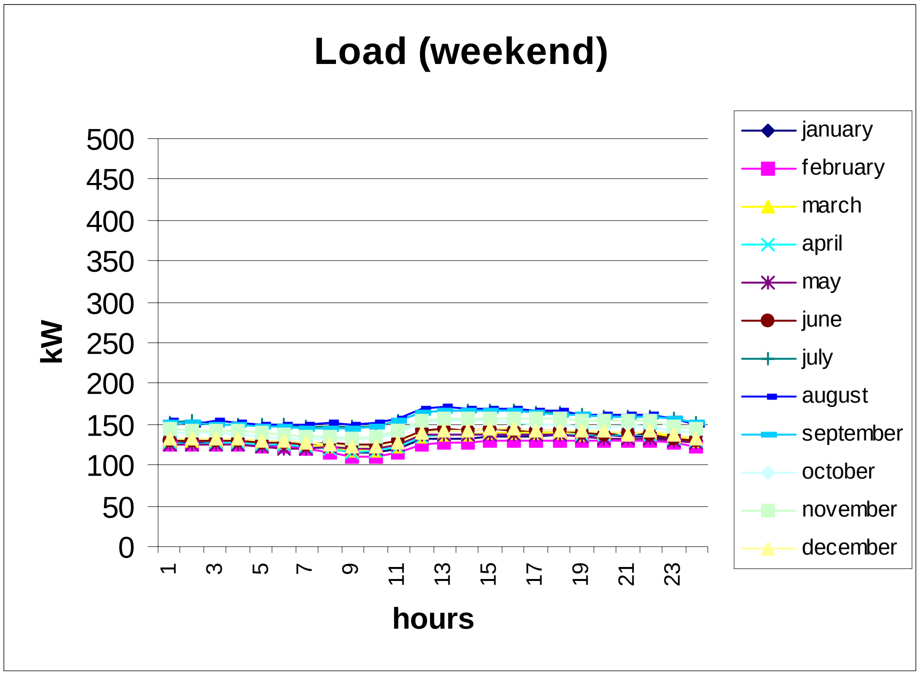

Figure 158. Restaurant Weekend Load Shape

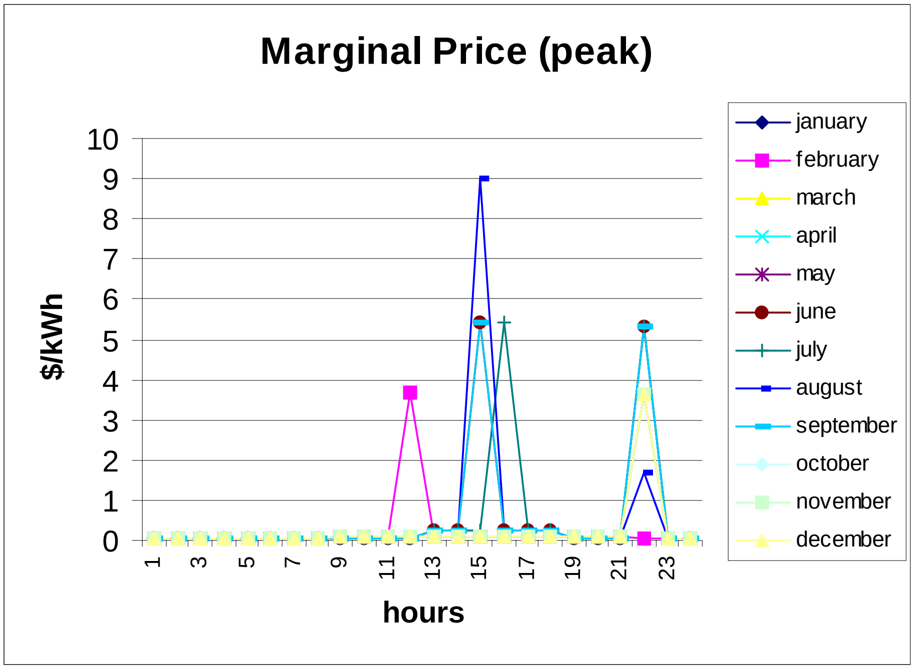

Figure 159. Restaurant "Do-Nothing" Marginal Supply Cost (peak hours)

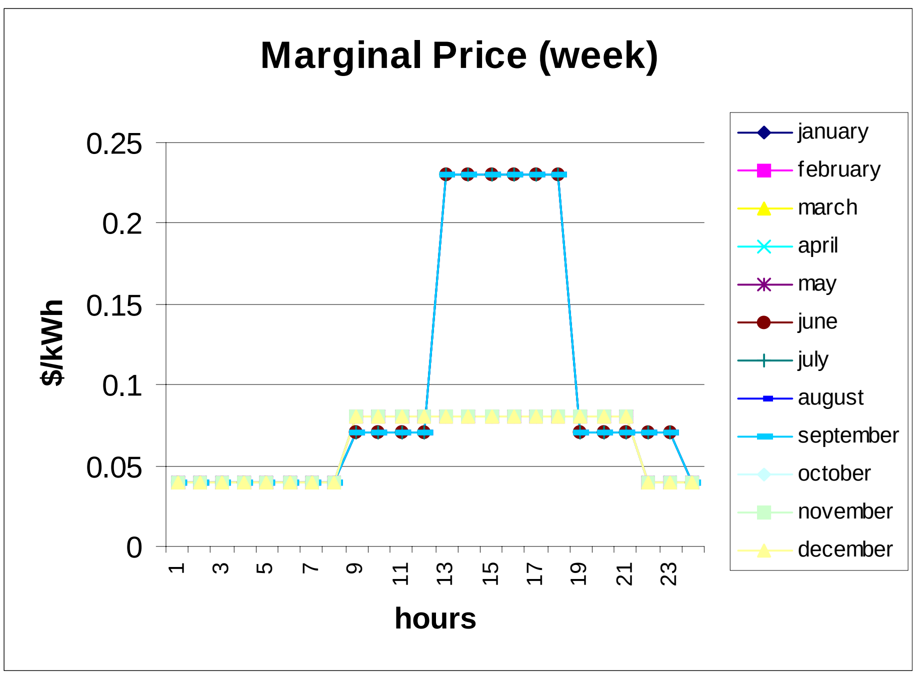

Figure 160. Restaurant "Do-Nothing" Marginal Supply Cost (week)

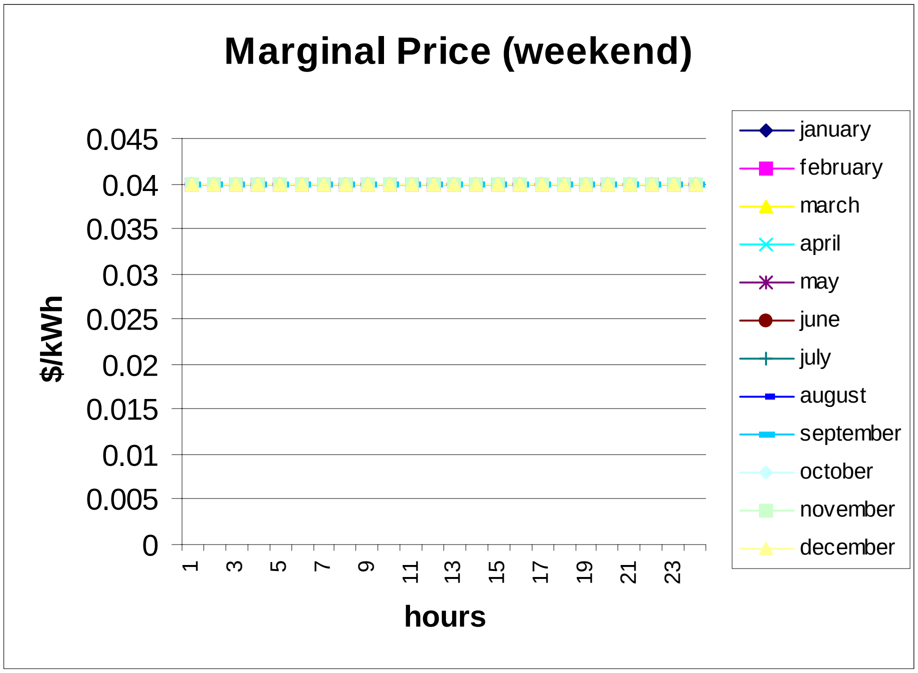

Figure 161. Restaurant "Do-Nothing" Marginal Supply Cost (weekend)

7.3.2 Scenarios

7.3.2.1 Base Scenario

Table 43. Breakdown of Electricity Purchase Costs for the Restaurant Base Case (PXRN)

Total Supply Cost ($)	122982
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	8709
Self Generation Investment Costs ($)	31374
Self Generation Variable Costs ($)	82899
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.12
Installed Capacity (kW)	235.5
Technologies	1 - SOFCo1 3 - SOFCo2 1 - mT_P

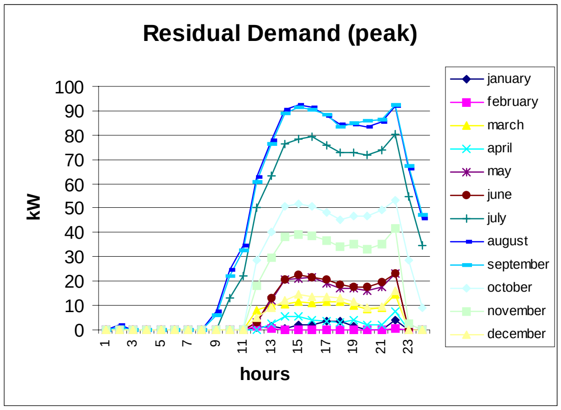

Figure 162. Restaurant PXRN Residual Demand (peak)

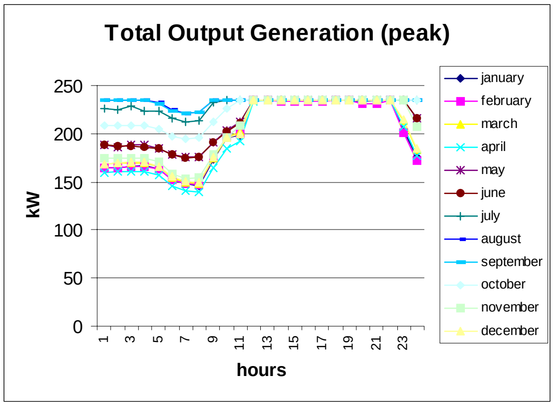

Figure 163. Restaurant PXRN Total Output Generation (peak)

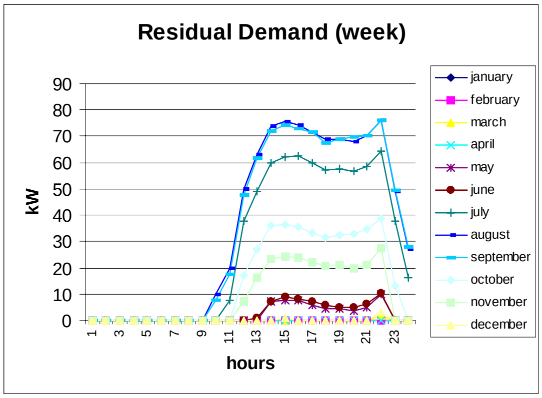

Figure 164. Restaurant PXRN Residual Demand (week)

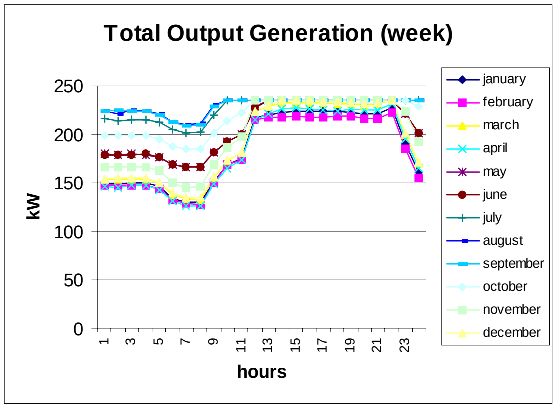

Figure 165. Restaurant PXRN Total Output Generation (week)

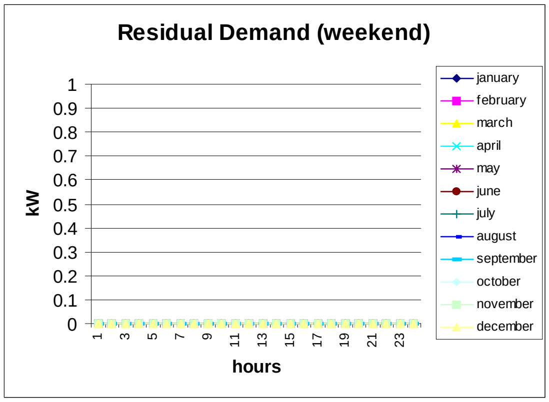

Figure 166. Restaurant PXRN Residual Demand (weekend)

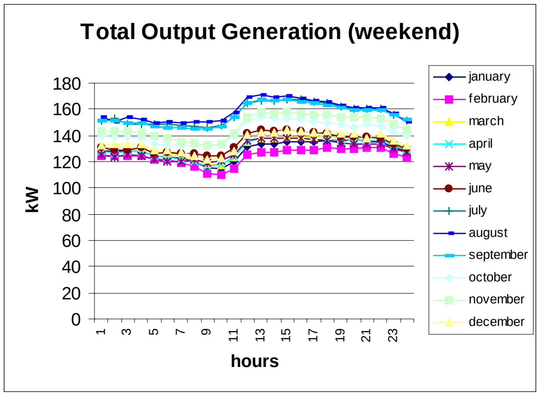

Figure 167. Restaurant PXRN Total Output Generation (weekend)

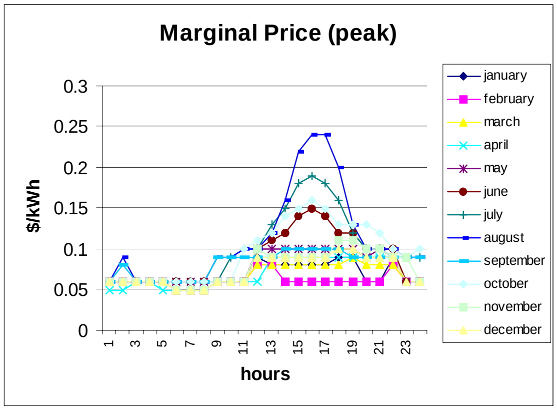

Figure 168. Restaurant PXRN Marginal Supply Cost (peak)

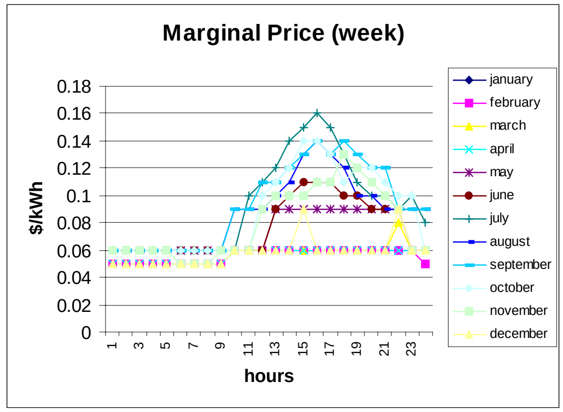

Figure 169. Restaurant PXRN Marginal Supply Cost (week)

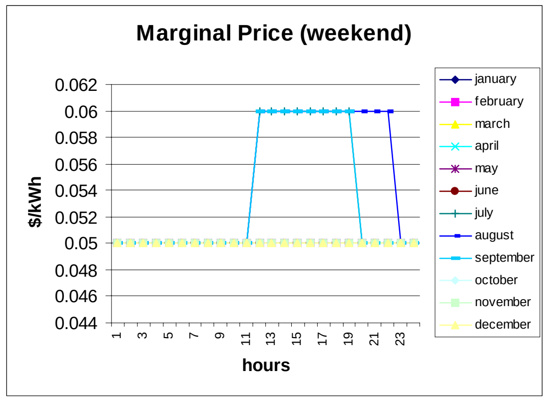

Figure 170. Restaurant PXRN Marginal Supply Cost (weekend)

7.3.2.2 Tariff Scenario

Table 44. Breakdown of Electricity Purchase Costs for the Restaurant Tariff Scenario

Total Supply Cost ($)	127030
Dist. Energy Purchases (peak) ($)	192
Dist. Energy Purchases (Mid) ($)	37
Dist. Energy Purchases (Off) ($)	832
Dist. Power Purchases ($)	1710
PX Energy Purchases ($)	0
Self Generation Investment Costs ($)	37989
Self Generation Variable Costs ($)	86271
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.36

Installed Capacity (kW)	307.5
Technologies	3 - SOFCo2 2 - mT_P

7.3.2.3 Fixed Rate Scenario

Table 45. Breakdown of Electricity Purchase Costs for the Restaurant Fixed Rate Scenario

Total Supply Cost ($)	121109
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	7565
Self Generation Investment Costs ($)	30887
Self Generation Variable Costs ($)	82657
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.01
Installed Capacity (kW)	232.5
Technologies	3 - SOFCo2 1 - mT_P

7.3.2.4 PXRN Scenario With Sales

Table 46. Breakdown of Electricity Purchase Costs for the Restaurant PXRN With Sales Scenario

Total Supply Cost ($)	122967
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	8709
Self Generation Investment Costs ($)	31374
Self Generation Variable Costs ($)	83138
Sales at the PX Price ($)	254
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.12

Installed Capacity (kW)	235.5
Technologies	1 - SOFCo1 3 - SOFCo2 1 - mT_P

7.3.3 Sensitivities

7.3.3.1 Stand-By Charge

Table 47. Breakdown of Electricity Purchase Costs for the Restaurant Stand-By Charge Sensitivity

Total Supply Cost ($)	140136
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	35358
Self Generation Investment Costs ($)	38033
Self Generation Variable Costs ($)	66746
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	8.12
Installed Capacity (kW)	166.5
Technologies	3 - SOFCo1 3 - SOFCo2

7.3.3.2 10% Increase in Fuel Cell Turn-Key Costs

Table 48. Breakdown of Electricity Purchase Costs for the Restaurant 10% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	125131
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	5070
Self Generation Investment Costs ($)	31548
Self Generation Variable Costs ($)	88513

Sales at the PX Price ($)	0
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.25
Installed Capacity (kW)	255
Technologies	2 - SOFCo2 2 - mT_P

7.3.3.3 50% Increase in Fuel Cell Turn-Key Costs

Table 49. Breakdown of Electricity Purchase Costs for the Restaurant 50% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	126009
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	11488
Self Generation Investment Costs ($)	21307
Self Generation Variable Costs ($)	93214
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.30
Installed Capacity (kW)	225
Technologies	3 - mT_P

7.3.3.4 Low Natural Gas Price Sensitivity

Table 50. Breakdown of Electricity Purchase Costs for the Restaurant Low Natural Gas Price Sensitivity

Total Supply Cost ($)	93274
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	519
Self Generation Investment Costs ($)	28409
Self Generation Variable Costs ($)	64346
Sales at the PX Price ($)	0

Consumed Energy (kWh)	1726515
Average Price (c/kWh)	5.40
Installed Capacity (kW)	300
Technologies	4 - mT_P

7.3.3.5 High Natural Gas Price Sensitivity

Table 51. Breakdown of Electricity Purchase Costs for the Restaurant High Natural Gas Price Sensitivity

Total Supply Cost ($)	145791
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	16715
Self Generation Investment Costs ($)	31713
Self Generation Variable Costs ($)	97364
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	8.44
Installed Capacity (kW)	210
Technologies	4 - SOFCo2

7.3.3.6 High Interest Rate Sensitivity

Table 52. Breakdown of Electricity Purchase Costs for the Restaurant High Interest Rate Sensitivity

Total Supply Cost ($)	126675
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	9434
Self Generation Investment Costs ($)	34584
Self Generation Variable Costs ($)	82657
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1726515
Average Price (c/kWh)	7.34

Installed Capacity (kW)	232.5
Technologies	3 - SOFCo2 1- mT_P

7.4 Microgrid

7.4.1 "Do-Nothing" Scenario

Table 53. Breakdown of Electricity Purchase Costs for Microgrid ("Do-Nothing" Scenario)

Total Supply Cost ($)	1176284
Dist. Energy Purchases (peak) ($)	259371
Dist. Energy Purchases (Mid) ($)	389267
Dist. Energy Purchases (Off) ($)	252187
Dist. Power Purchases ($)	275459
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	9.63

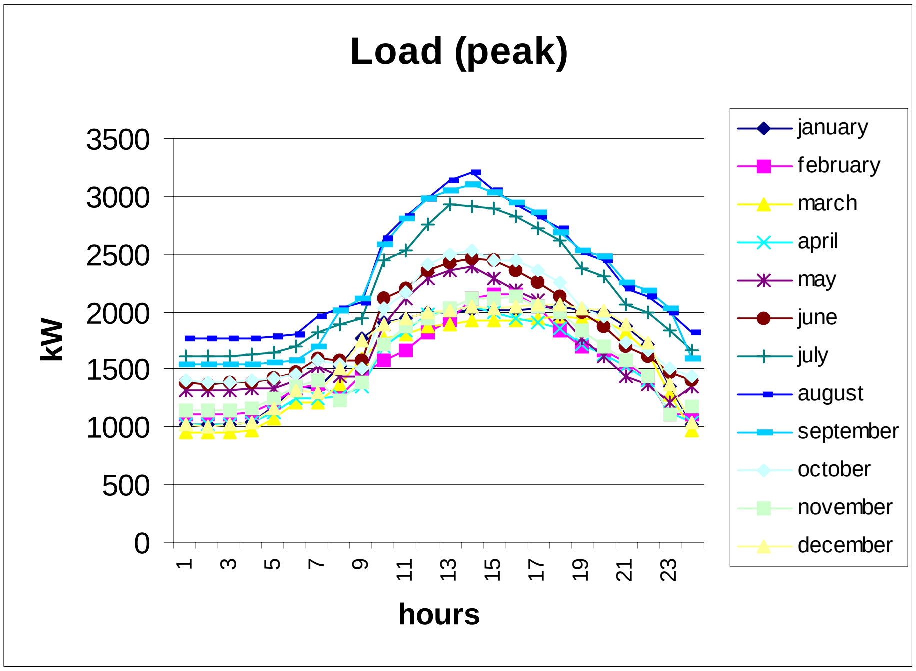

Figure 171. Microgrid Peak Load Shape

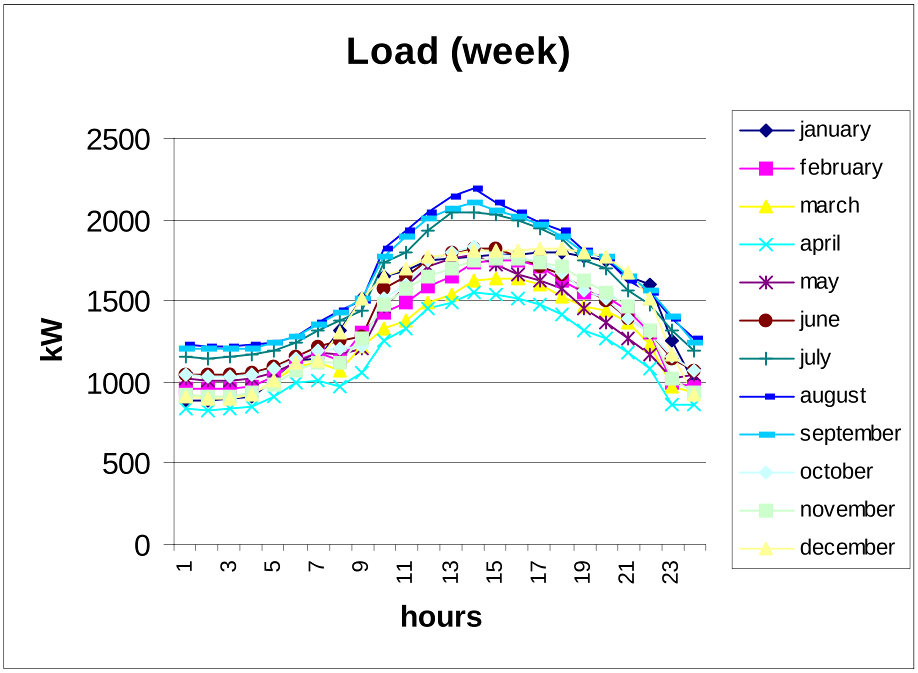

Figure 172. Microgrid Week Load Shape

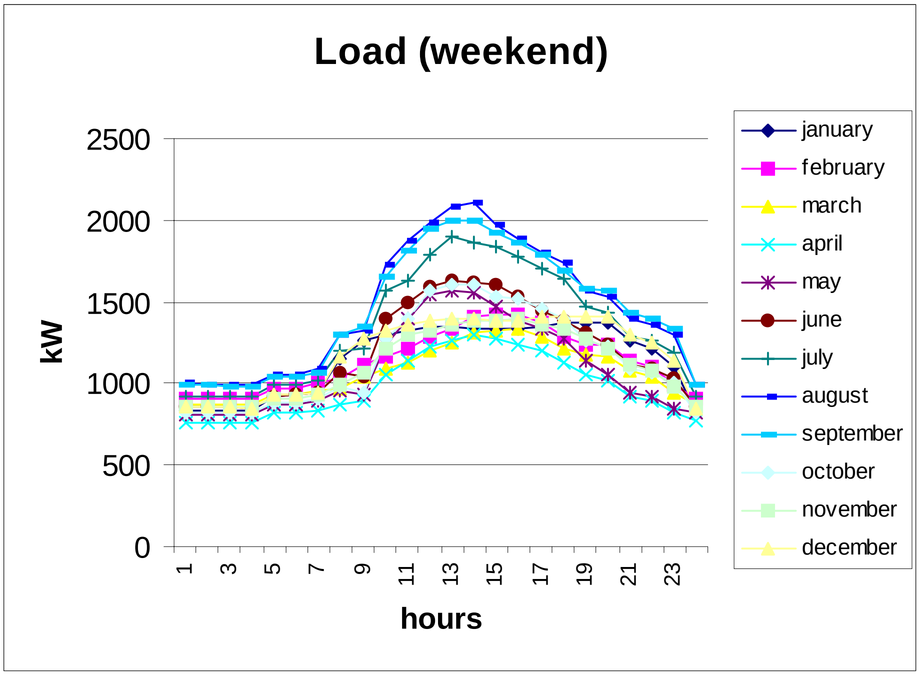

Figure 173. Microgrid Weekend Load Shape

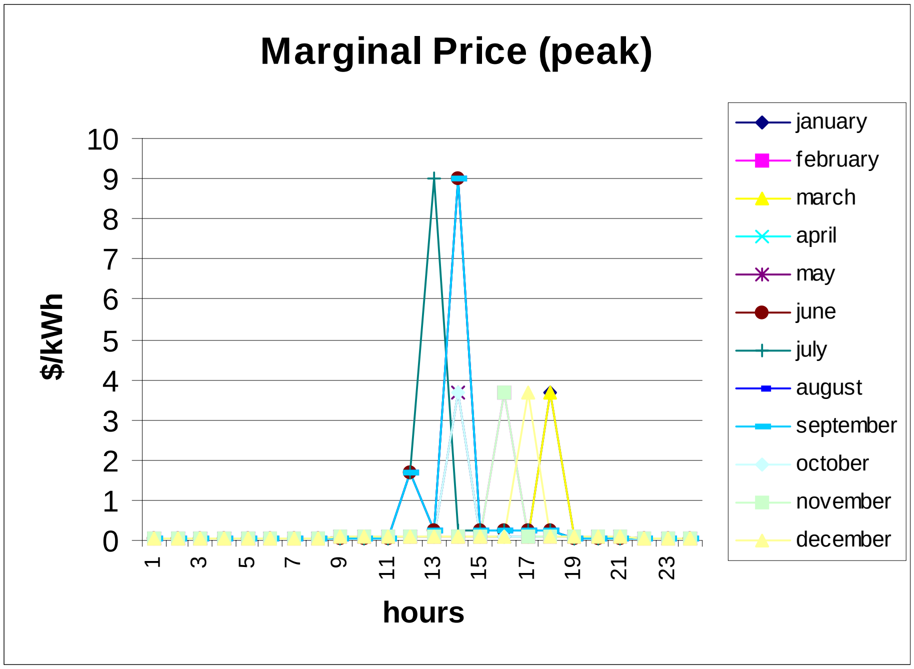

Figure 174. Microgrid "Do-Nothing" Marginal Supply Cost (peak hours)

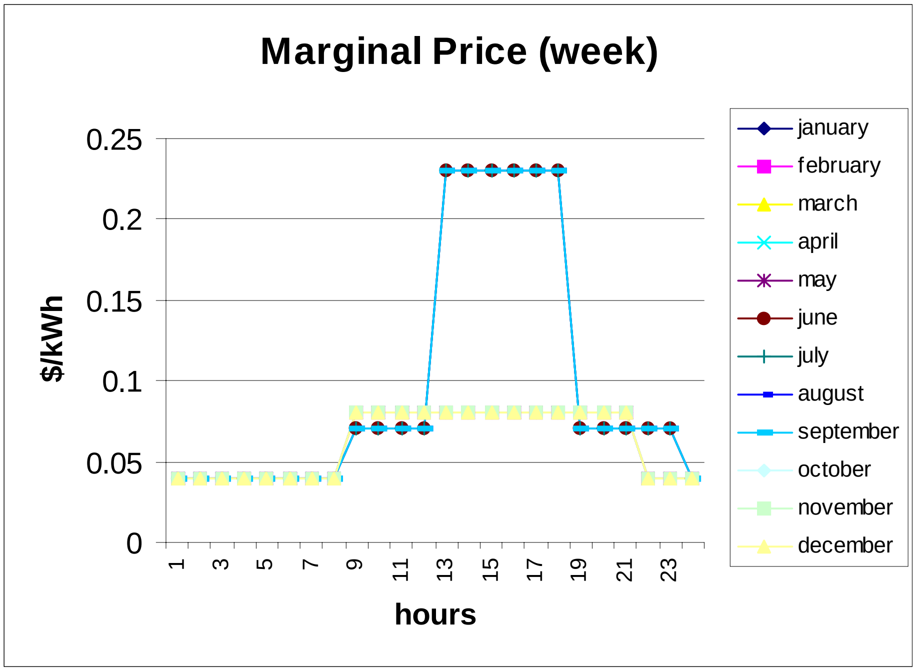

Figure 175. Microgrid "Do-Nothing" Marginal Supply Cost (week)

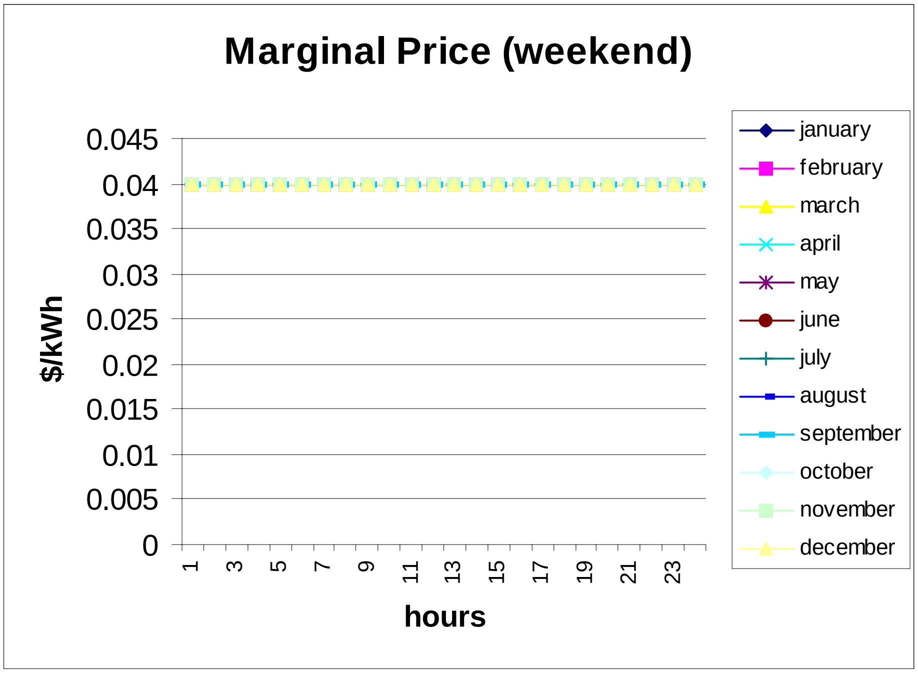

Figure 176. Microgrid "Do-Nothing" Marginal Supply Cost (weekend)

7.4.2 Scenarios

7.4.2.1 Base Scenario

Table 54. Breakdown of Electricity Purchase Costs for the Microgrid Base Case (PXRN)

Total Supply Cost ($)	867735
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	52048
Self Generation Investment Costs ($)	223308
Self Generation Variable Costs ($)	592379
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	7.10
Installed Capacity (kW)	1702.5
Technologies	21 - SOFCo2 8 - mT_P

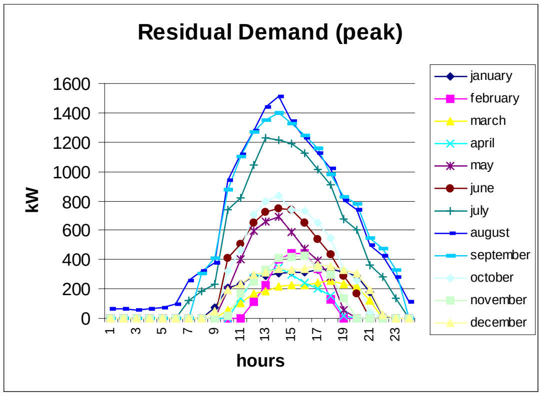

Figure 177. Microgrid PXRN Residual Demand (peak)

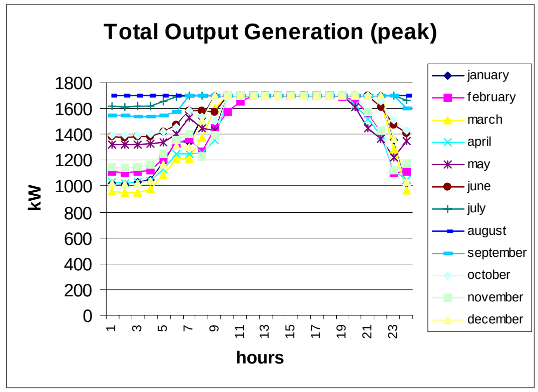

Figure 178. Microgrid PXRN Total Output Generation (peak)

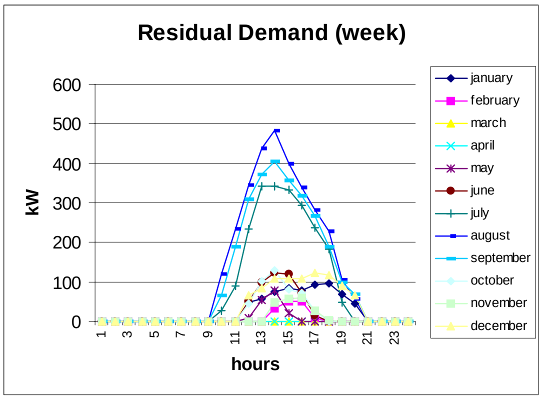

Figure 179. Microgrid PXRN Residual Demand (week)

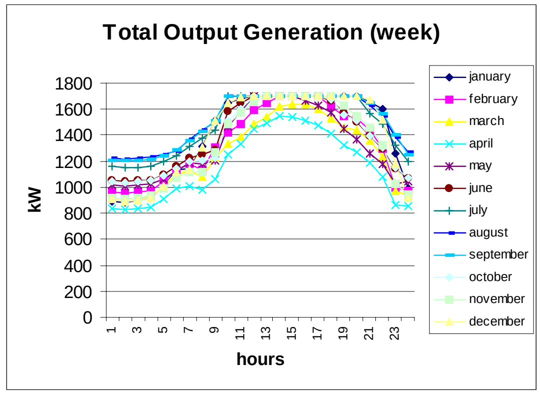

Figure 180. Microgrid PXRN Total Output Generation (week)

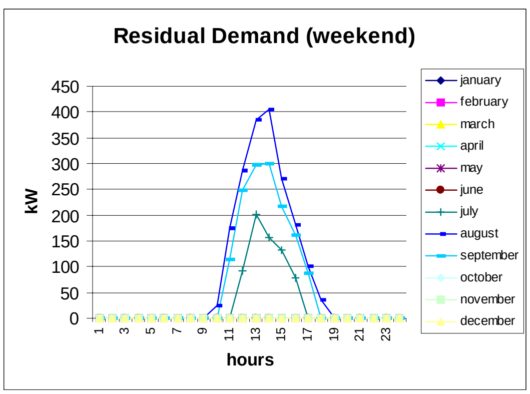

Figure 181. Microgrid PXRN Residual Demand (weekend)

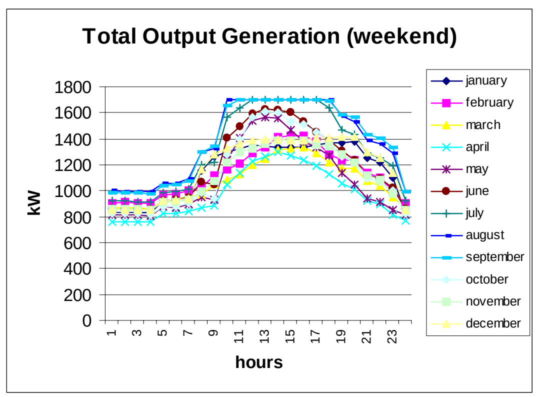

Figure 182. Microgrid PXRN Total Output Generation (weekend)

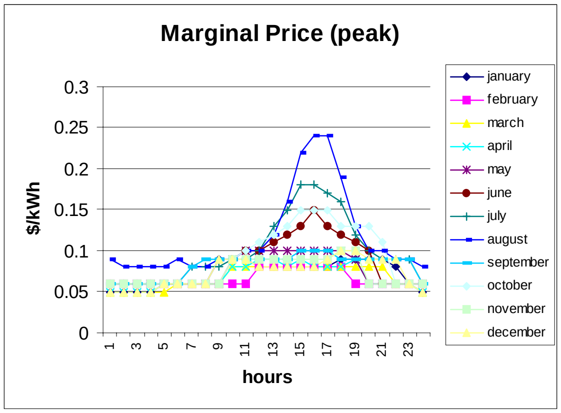

Figure 183. Microgrid PXRN Marginal Supply Cost (peak)

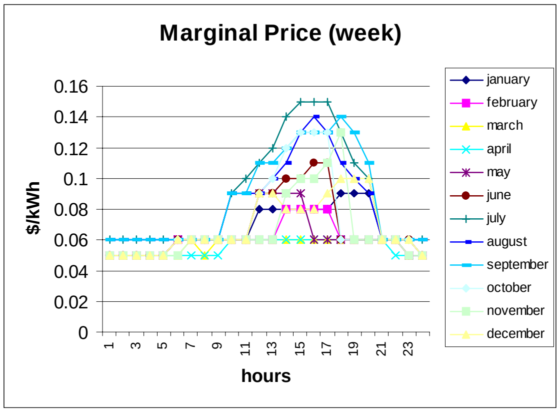

Figure 184. Microgrid PXRN Marginal Supply Cost (week)

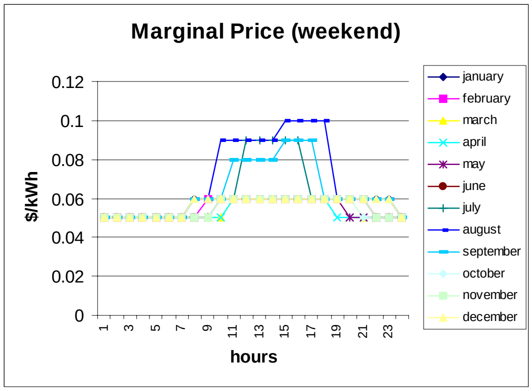

Figure 185. Microgrid PXRN Marginal Supply Cost (weekend)

7.4.2.2 Tariff Scenario

Table 55. Breakdown of Electricity Purchase Costs for the Microgrid Tariff Scenario

Total Supply Cost ($)	914396
Dist. Energy Purchases (peak) ($)	320
Dist. Energy Purchases (Mid) ($)	2340
Dist. Energy Purchases (Off) ($)	27515
Dist. Power Purchases ($)	12564
PX Energy Purchases ($)	0
Self Generation Investment Costs ($)	265263
Self Generation Variable Costs ($)	606393
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	7.48

Installed Capacity (kW)	3022.5
Technologies	3 – 350ROZD 19 - SOFCo2 13 - mT_P

7.4.2.3 Fixed Rate Scenario

Table 56. Breakdown of Electricity Purchase Costs for the Microgrid Fixed Rate Scenario

Total Supply Cost ($)	853849
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	74247
Self Generation Investment Costs ($)	209104
Self Generation Variable Costs ($)	570499
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	6.99
Installed Capacity (kW)	1552.5
Technologies	21 - SOFCo2 6 - mT_P

7.4.2.4 PXRN Scenario With Sales

Table 57. Breakdown of Electricity Purchase Costs for the Microgrid PXRN With Sales Scenario

Total Supply Cost ($)	867658
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	52048
Self Generation Investment Costs ($)	223308
Self Generation Variable Costs ($)	593697
Sales at the PX Price ($)	1395
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	7.10

Installed Capacity (kW)	1702.5
Technologies	21 - SOFCo2 8 - mT_P

7.4.3 Sensitivities

7.4.3.1 Stand-By Charge

Table 58. Breakdown of Electricity Purchase Costs for the Microgrid Stand-By Charge Sensitivity

Total Supply Cost ($)	982936
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	170913
Self Generation Investment Costs ($)	289749
Self Generation Variable Costs ($)	522274
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	8.04
Installed Capacity (kW)	1327.5
Technologies	21 - SOFCo2 3 - mT_P

7.4.3.2 10% Increase in Fuel Cell Turn-Key Costs

Table 59. Breakdown of Electricity Purchase Costs for the Microgrid 10% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	882562
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	38888
Self Generation Investment Costs ($)	234212
Self Generation Variable Costs ($)	609462

Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	7.22
Installed Capacity (kW)	1770
Technologies	18 - SOFCo2 11 - mT_P

7.4.3.3 50% Increase in Fuel Cell Turn-Key Costs

Table 60. Breakdown of Electricity Purchase Costs for the Microgrid 50% Increase in Fuel Cell Cost Sensitivity

Total Supply Cost ($)	887944
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	47336
Self Generation Investment Costs ($)	163350
Self Generation Variable Costs ($)	677258
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	7.27
Installed Capacity (kW)	1725
Technologies	23 - mT_P

7.4.3.4 Low Natural Gas Price Sensitivity

Table 61. Breakdown of Electricity Purchase Costs for the Microgrid Low Natural Gas Price Sensitivity

Total Supply Cost ($)	650352
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	34453
Self Generation Investment Costs ($)	170453
Self Generation Variable Costs ($)	445446

Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	5.32
Installed Capacity (kW)	1800
Technologies	24 - mT_P

7.4.3.5 High Natural Gas Price Sensitivity

Table 62. Breakdown of Electricity Purchase Costs for the Microgrid High Natural Gas Price Sensitivity

Total Supply Cost ($)	1024112
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	177351
Self Generation Investment costs ($)	198203
Self Generation Variable Costs ($)	648558
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07
Average Price (c/kWh)	8.38
Installed Capacity (kW)	1312.5
Technologies	25 - SOFCo2

7.4.3.6 High Interest Rate Sensitivity

Table 63. Breakdown of Electricity Purchase Costs for the Microgrid High Interest Rate Sensitivity

Total Supply Cost ($)	893335
Dist. Energy Purchases (peak) ($)	0
Dist. Energy Purchases (Mid) ($)	0
Dist. Energy Purchases (Off) ($)	0
Dist. Power Purchases ($)	0
PX Energy Purchases ($)	58733
Self Generation Investment costs ($)	239735
Self Generation Variable Costs ($)	594867
Sales at the PX Price ($)	0
Consumed Energy (kWh)	1.22E+07

Average Price (c/kWh)	7.31
Installed Capacity (kW)	1672.5
Technologies	19 - SOFCo2 9 - mT_P

8. Appendix 2: Sample GAMS Code

Here we present some of the GAMS code used in the C-CAM study. The following code is for the microgrid PXRN with sales case.

```
* DER Customer Adoption Model
* Version 1.2
*
* Author: Fco. Javier Rubio
* Lawrence Berkeley National Laboratory

*output restrictions
$OFFSYMXREF OFFSYMLIST OFFUELLIST OFFUELXREF

*OPTIONS subsystems
OPTION LIMROW=0, LIMCOL=0;
OPTION SYSOUT=OFF, SOLPRINT=OFF;

Option optcr = 0.001;


OPTIONS DECIMALS=8;


* Options and scalar definitions

SCALARS

    opt1      '0-Do nothing 1-Invest                '  / 1 /
*    opt2       0-Continous  1-Integer                 / 0 /
    opt3      '0-No sales   1-Free    2-Cover & Sell'  / 1 /
    opt4      '0-Tariff     1-PX1     2-Fixed       '  / 1 /
    opt5      '0-No STB     1-Stand by charge       '  / 0 /
    opt6      '0-Nothing    x-var. turnk. tech x    '  / 1 /

    IntRate    'Interest rate p.u.              '       / 0.075 /
    DiscoER    'Disco extra Revenue (c/kWh)     '       / 0.05577 /
    FRate      'Fixed rate (c/kWh)              '       / 0.0876 /
    Standby    'Stand-by charge ($/kW/month)    '       / 6.40 /
    turnvar    'turnkey cost variation (pu)     '       / 0.50 /
    ;

* Explanation of options
*
* PX1: Customer purchase energy at PX price + a fixed DiscoER rate
*
* PX2: Customer purchase at a fixed rate
*


* This is the place for the SETS

SETS

    MONTHS          months       / january, february, march, april, may,
                                   june, july, august,
                                   september, october, november, december /
    LTYPES          load type    / week, peak, weekend /
    WEPE(LTYPES)    week-peak    / week, peak /
    HOURS           24 hours     / 1 * 24 /
    SUMMERM(MONTHS) s. months    / june, july, august, september /
    WINTERM(MONTHS) w. months    / january, february, march, april, may,
                                   october, november, december /

    NTARIFF   tariffs            / TOU2A, TOU2B, TOU8 /
    SEASONS   two seasons        / summer, winter /
    LPERIOD   load periods       / on, mid, off /
    TCONCEPT  energy or power    / energy, power /
    TCHARG    tariff charges     / custoc, facilitc /
```

```
    DERTECH   der technologies   / 20ROZJ,30ROZJ,40ROZJ,50ROZJ,60ROZJ,80ROZJ
                                  ,100ROZJ,135ROZJ,150ROZJ,180ROZJ,200ROZD
                                  ,230ROZD,250ROZD,275ROZD,300ROZD,350ROZD
                                  ,400ROZD,450ROZD,500ROZD,600ROZD,DAIS,FCEnergy
                                  ,H-Power,ONSI-P, SOFCo1, SOFCo2, MCPower, TMI
                                  ,mT_P, mT_Cap
                                 /
    DERTCHAR  der charact        / maxp, lifetime, capcost, OMFix,
                                   OMVar, HeatR, Fuel, Type /

    FUELS     fuel types         / NatG, Diesel /
    FUELCH    fuel charact.      / num, price /

    ONHOURSS(HOURS)  on-peak h.(summer) / 13 * 18 /
    MIDHOURSS(HOURS) mid h. (summer)    / 9 * 12, 19 * 23 /
    OFFHOURSS(HOURS) off h. (summer)    / 1 * 8, 24 /
    MIDHOURSW(HOURS) mid h. (winter)    / 9 * 21 /
    OFFHOURSW(HOURS) off h. (winter)    / 1 * 8, 22 * 24/

    APPLT(NTARIFF)   applicable tariff  / TOU2A /
    ;


* Parameter definitions

PARAMETERS

    TCENERGY                          'consumed energy         (kWh)'
    AVPRICE                           'Average Price           (c/kWh)'
    InsCap                            'installed capacity      (kW)'
    MAXL(months, lperiod)             'Max consumed power      (kW)'
    lperind(months, ltypes, hours)  load period index
    MCEnergy(months, lperiod)         'Monthly consumed energy (kWh)'
    RMPower(months, lperiod)          'Residual Max. Power     (kW)'
    RDemand(months, ltypes, hours)  'Residual Energy         (kWh)'
    InvAnnuity(dertech)               'Investment Annuity      ($)'
    KWHCost(dertech)                  'Energy cost             ($/kWh)'

    NDLTYPES (months,ltypes)      days of each type
              / january  . week        20
                january  . peak         3
                january  . weekend      8
                february . week        17
                february . peak         3
                february . weekend      8
                march    . week        20
                march    . peak         3
                march    . weekend      8
                april    . week        19
                april    . peak         3
                april    . weekend      8
                may      . week        20
                may      . peak         3
                may      . weekend      8
                june     . week        19
                june     . peak         3
                june     . weekend      8
                july     . week        20
                july     . peak         3
                july     . weekend      8
                august   . week        20
                august   . peak         3
                august   . weekend      8
                september. week        19
                september. peak         3
                september. weekend      8
                october  . week        20
                october  . peak         3
                october  . weekend      8
                november . week        19
```

```
                november . peak         3
                november . weekend      8
                december . week        20
                december . peak         3
                december . weekend      8 /
    ;


* Classification of hours in the different periods: on-peak, etc.

 lperind(summerm,wepe,onhourss)  = 1 ;
 lperind(summerm,wepe,midhourss) = 2 ;
 lperind(summerm,wepe,offhourss) = 3 ;
 lperind(winterm,wepe,midhoursw) = 2 ;
 lperind(winterm,wepe,offhoursw) = 3 ;
 lperind(months,'weekend',hours) = 3 ;


* Data input: Fuel Prices

TABLE FLData (fuels,fuelch) Fuel Information

         num     price
*               ($/kJ)
NatG      1     4.20e-6
Diesel    2     7.36e-6
;


* Data input: DER Technologies information

TABLE DEROPT (dertech, dertchar) DER technologies information

          maxp  lifetime capcost  OMFix   OMVar   HeatR   Fuel   Type
*         (kW)  (years)  ($/kW)($/kW/year)($/kWh)(kJ/kWh)

 20ROZJ    25      10    486.84    0       0    42709.61   2       3
 30ROZJ    33      10   398.4848   0       0    43414.06   2       3
 40ROZJ    40      10    373.45    0       0    38181.85   2       3
 50ROZJ    55      10   309.3090   0       0    40055.62   2       3
 60ROZJ    62      10     299      0       0    37931.15   2       3
 80ROZJ    80      10    257.6     0       0    41560.77   2       3
100ROZJ   100      10    231.89    0       0    37843.96   2       3
135ROZJ   135      10   206.1481   0       0    40146.63   2       3
150ROZJ   153      10   194.6732   0       0    35776.85   2       3
180ROZJ   185      10   174.1027   0       0    37917.01   2       3
200ROZD   200      10   174.875    0       0    39127.95   2       3
230ROZD   230      10   158.5130   0       0     30000     2       3
250ROZD   250      10   159.292    0       0     30000     2       3
275ROZD   275      10   158.9018   0       0     30000     2       3
300ROZD   300      10    152.54    0       0     30000     2       3
350ROZD   350      10   145.7828   0       0     30000     2       3
400ROZD   400      10   161.475    0       0     30000     2       3
450ROZD   450      10   162.0666   0       0    37183.19   2       3
500ROZD   500      10   159.956    0       0    38546.77   2       3
600ROZD   600      10   165.3533   0       0    38181.85   2       3
  DAIS     3       15     1667    311    0.015   10000     1       1
FCEnergy  250      15     1200    280    0.015    8000     1       1
H-Power    3       15     2000    333    0.015   10550     1       1
 ONSI-P   200      15     3310    421    0.015   10002     1       1
 SOFCo1    3       15     1350     83    0.015    7991     1       1
 SOFCo2   52.5     15     1250     83    0.015    7991     1       1
MCPower   250      15     1350     90    0.015    8000     1       1
  TMI     100      15     1194    180    0.015    7994     1       1
  mT_P     75      10     650      0     0.007   12000     1       2
 mT_Cap    28      10     1240     0      0.01   14400     1       2
 ;


 DEROPT(dertech, 'capcost')$(opt6 eq DEROPT(dertech,'type'))
                          =  DEROPT(dertech, 'capcost')
```

```
                             *
                             (1 + turnvar);

 KWHCost(dertech) =

       DEROPT(dertech, 'HeatR')
      *
       SUM( fuels$(FLData(fuels,'num') eq DEROPT(dertech, 'Fuel')),
           FLData(fuels,'price')
          );

 InvAnnuity(dertech)
           = ( DEROPT(dertech, 'capcost') + DEROPT(dertech, 'OMFix') ) * IntRate
             / ( 1 - 1 / ( 1 + IntRate ) ** DEROPT(dertech,'lifetime') ) ;


* Data input: Tariffs information

TABLE TARPE (ntariff, seasons, lperiod, tconcept) Power and Energy charges

                        power       energy
*                       ($/kW)      ($/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 TARFIX (ntariff, tcharg) Other charges

           custoc    facilitc
*        ($/month)    ($/kW)

 TOU2A     79.95       5.40
 TOU2B     79.95       5.40
 TOU8     298.65       6.40
 ;


* Data input: Load Data

TABLE LOAD (months, ltypes, hours) MICROGRID load in kW

                        1       2       3       4       5       6       7       8       9
10       11       12       13       14       15       16       17       18       19       20
21      22      23      24
January   . week       892.69   885.75   897.02    914.5  1011.84  1136.21  1143.83  1311.77
1513.69 1644.73 1681.67  1750.9 1758.11 1777.54 1785.03 1781.56 1795.41 1797.69 1771.49
1747.13 1653.35 1603.47 1261.05  994.46
February . week        963.42   954.77   963.24   975.65  1039.81  1132.58  1177.48  1129.66
1300.53 1423.42 1484.82 1594.46  1646.8 1736.42 1754.26  1753.7 1711.79 1622.67 1550.26
1527.36 1441.12 1299.96 1003.14  967.63
March      . week       919.68   909.66   915.58   929.77 1004.66   1100.7 1126.39 1077.14
1220.56 1328.76  1382.7 1486.67 1538.54 1620.31 1638.46 1638.38 1604.07 1528.75 1461.06
1438.18  1361.9 1231.45  968.37  931.66
```

```
April     . week      838.12  828.94  837.88  847.42  908.88  992.84 1012.33  976.89
1064.13 1251.15 1333.69 1447.69 1495.44 1549.97 1537.09 1513.34 1475.88 1412.17 1320.18
1267.39 1187.8 1081.78 867.43 857.31
May       . week      1016.99 1012.42 1015.44 1022.97 1059.3 1123.25 1183.96 1175.58
1205.02 1463.42 1588.36 1710.39 1755.14 1780.94 1724.13 1666.91 1628.26 1573.84 1452.42
1367.47 1264.49 1175.31 1023.66 1042.37
June      . week      1049.26 1043.32 1049.52 1057.03 1098.68 1158.57 1219.89 1254.48
1285.69 1582.04 1651.32 1752.73 1800.42 1826.29 1821.93 1773.4 1716.12 1663.14 1576.99
1502.57 1391.46 1300.28 1146.02 1071.82
July      . week      1158.23 1150.68 1155.43 1164.76 1196.21 1242.6 1316.2 1379.9
1443.15 1730.9 1792.97 1937.13 2043.14 2043.98 2035.21 1997.98 1939.74 1885.21 1751.76
1702.99 1566.03 1480.68 1323.81 1196.19
August    . week      1226.98 1219.2 1223.94 1230.64 1249.12 1282.4 1372.27 1436.42
1503.79 1823.35 1937.39 2046.08 2140.08 2185.98 2101.84 2041.73 1984.75 1931.32 1806.21
1759.88 1628.18 1547.36 1388.8 1265.75
September. week      1208.45 1203.08 1203.91 1212.1 1241.06 1286.1 1355.25 1431.78
1513.58 1769.31 1891.55 2011.98 2073.23 2107.19 2058.36 2019.18 1969.07 1892.81 1802.37
1770.03 1646.1 1563.78 1406.39 1247.09
October   . week      1044.42 1037.01 1040.42 1048.86 1088.22 1145.48 1197.34 1205.52
1223.49 1509.08 1604.71 1748.76 1804 1832.11 1784.79 1775.97 1730.56 1676.17 1559.31
1513.12 1393.86 1308.97 1154.43 1071.57
November . week      919.55 907.43 916.11 932.1 989.51 1075.08 1114.85 1114.74
1272.82 1481.74 1578.72 1653.86 1698.85 1751.08 1760.42 1762.02 1730.76 1706.02 1625.97
1550.48 1460.07 1321.85 1021.78 940.88
December . week      905.59 893.81 900.11 919.99 1005.55 1119.28 1130.82 1304.68
1509.88 1645.31 1694.27 1768.83 1786.34 1809.57 1811.07 1811.81 1825.43 1820.45 1793.41
1769.67 1677.61 1517.32 1175.26 917.94
January   . peak      1018.96 1013.89 1028.29 1047.43 1185.08 1350.87 1334.7 1533.16
1774.22 1908.54 1933.66 1988.96 1990.44 2009.34 2015.28 2012.45 2033.88 2041.5 2016.63
1993.56 1875.46 1715.14 1357.28 1020.46
February . peak      1112.02 1104.91 1114.66 1123.57 1215.99 1333.25 1369.45 1266.53
1447.03 1575.59 1657.76 1818.28 1928.64 2106.36 2141.3 2145.81 2038.72 1832.11 1691.73
1667.56 1562.86 1415.6 1106.15 1115.11
March     . peak      959.36 947.26 953.01 976.05 1081.12 1216.58 1209.56 1376.86
1598.09 1758.83 1806.95 1873.74 1888.14 1922.09 1930.93 1927.1 1944.7 1958.71 1937.16
1916.45 1820.8 1650.78 1283.66 968.06
April     . peak      1029.12 1020.93 1028.94 1042.66 1131.04 1246.46 1247.59 1259.02
1354.66 1702.75 1835.36 1973.9 2015.7 2046.66 1996.44 1940.42 1902.9 1852.45 1718.42
1624.79 1520.98 1395 1124.78 1045.59
May       . peak      1321.92 1318.46 1318.07 1325.57 1341.04 1399.14 1531.43 1446.33
1430.3 1894.76 2106.98 2294.3 2362.8 2394.02 2286.53 2180.28 2094.87 1983.85 1761.29
1611.92 1446.13 1361.48 1220.28 1350.01
June      . peak      1381.57 1377.28 1382.24 1383.62 1421.12 1472.39 1587.38 1582.96
1575.67 2113.46 2208.47 2351.85 2422.47 2452.06 2442.57 2356.92 2244.67 2138.15 1992.89
1869.09 1698.26 1613.92 1470.03 1410.17
July      . peak      1618.1 1612.56 1618.62 1622.66 1653.11 1694.36 1826.38 1883.79
1936.44 2441.08 2526.15 2748.72 2934.41 2917.07 2894.68 2826.95 2716.25 2611.89 2378.97
2305.44 2066.64 1986.63 1840.77 1668
August    . peak      1768.66 1767.63 1761.92 1768.91 1776.94 1798.48 1960.2 2021.03
2079.14 2639.2 2823.61 2980.82 3141.91 3213.4 3048.08 2934.78 2828.1 2727.15 2508.94
2439.29 2204.38 2131.78 1985.03 1816.41
September. peak      1549.94 1542.97 1535.98 1541.41 1550.89 1571.18 1702.63 2011.47
2115.29 2580.64 2805.83 2975.88 3055.56 3105.04 3031.35 2951.91 2859.49 2682 2528.42
2483.66 2251.47 2177.87 2032.86 1597.53
October   . peak      1396.63 1392.27 1391.14 1398.77 1419.49 1455.24 1579.53 1536.23
1502.25 2022.18 2172.54 2411.46 2501.66 2537.72 2445.67 2437.95 2352.31 2247.66 2034.72
1961.16 1739.21 1656.93 1514.39 1431.49
November . peak      1151.42 1137.99 1147.81 1165.01 1247.78 1360.03 1405.1 1231.28
1392.11 1717.67 1871.26 1948.92 2031.67 2112.07 2120.44 2127.77 2052.02 1998.21 1842.59
1696.39 1575.87 1432.43 1117.48 1178.29
December . peak      1024.12 1012.39 1019.22 1041.89 1162.59 1312.99 1302.54 1508.59
1752.38 1891.45 1933.72 1997.37 2013.85 2038.01 2035.54 2038.64 2060.74 2057.14 2031.45
2009.2 1893.29 1727.37 1369.03 1033.44
January   . weekend  829.55 834.13 836 833.21 922.5 927.31 939.42 1153.56
1261.07 1301.78 1323.76 1348.74 1342.1 1338.75 1338.79 1337.5 1352.95 1366.96 1372.09
1374.99 1257.98 1219.21 1103.97 824.89
February . weekend  906.33 909.15 908.72 902.85 968.14 972.36 1003.24 1023.69
1115.08 1161.81 1213.35 1285.16 1331.26 1411.8 1423.81 1424.96 1376.44 1284.42 1235.03
1234.47 1136.92 1097.26 989.67 902.05
```

```
March      . weekend   868.97   870.22   867.64   864.02   926.48   932.65   956.24   969.06
1044.21 1086.74 1132.37 1201.19 1245.33 1315.83 1329.28 1330.81 1290.99 1216.31 1171.16
1169.97 1075.79 1039.38  945.63  865.64
April      . weekend   764.43   763.24   765.45   761.42   820.59   823.39   838.85   864.59
890.46 1050.94 1139.95 1230.66 1265.48 1297.75 1270.11 1239.88 1195.24 1131.33 1053.24
1015.35  924.65  895.28   818.7  766.73
May         . weekend   812.33   813.22   811.08   806.49   873.92   872.87   898.96   952.94
932.02 1237.83 1402.37 1539.34 1569.15 1560.39 1466.31 1383.44 1331.86 1271.22 1137.82
1050.75  941.14  915.28  850.69  819.38
June        . weekend   855.89   855.56   855.72   851.53   924.03   929.81   949.58 1064.65
1045.72 1403.17 1492.01 1598.16 1630.78 1620.42 1600.02 1528.51 1446.62 1389.18 1306.81
1232.35 1116.83 1089.73 1023.51  856.03
July        . weekend   918.49   921.05   915.07   913.14    987.3    990.1 1014.75   1196.5
1215.38 1562.94 1635.09 1794.64 1905.06 1858.85 1834.77   1781.5   1699.9 1637.83 1472.15
1432.08 1285.94 1258.16 1190.31  921.49
August     . weekend   1000.9   997.85    997.4   993.17 1055.59 1059.89 1091.22 1302.09
1323.08 1727.44 1877.35  1989.6 2086.62 2106.89 1973.14 1884.96 1802.48   1739.2 1574.46
1533.59 1391.48 1365.51 1293.67  998.23
September. weekend   988.63   988.86   982.96   980.44 1042.21 1044.88 1070.65 1297.24
1342.55 1655.74 1817.66 1950.01 1999.72 2002.49 1920.04 1863.11 1789.97 1693.86 1585.52
1563.94 1428.45 1402.52 1331.62  989.62
October   . weekend   826.92   824.71   821.89   818.31   877.91   879.96   902.02   984.54
944.74 1279.74 1399.21 1563.69 1608.09 1605.33 1527.97 1516.26 1452.31 1391.51 1259.65
1220.67 1089.81 1064.92  999.88  825.25
November . weekend   858.27    857.7   857.33   853.86   909.22   911.15   933.57   991.49
1071.15 1216.55 1300.42 1329.32 1357.74 1387.26 1389.44 1391.65 1356.52 1340.36 1278.69
1215.55 1119.57 1080.79     975  854.79
December . weekend   852.99      855   851.82   850.42   926.12   930.35   941.34 1163.83
1279.13  1327.4 1359.42 1389.76 1393.05 1393.08  1384.8 1388.47 1404.24 1409.75 1411.96
1411.06 1294.36 1254.18  1135.7   849.1
;


* Data input: PX prices

TABLE PX (months, ltypes, hours) "PX prices in $/MWh"

                                1        2        3        4        5        6        7        8
9       10       11       12       13       14       15       16       17       18       19       20
21      22       23       24
January       .        Peak       18.107   15.730   14.987   14.963   17.137   23.707   28.427
29.557   29.543   29.863   29.583   28.113   26.663   26.317   25.777   25.283   26.260   32.263
31.790   30.633   29.830   27.160   25.670   22.007
February      .        Peak       13.856   13.163   13.161   13.161   14.285   18.647   22.592
23.375   23.053   22.917   22.780   22.773   22.740   22.467   21.877   21.330   21.643   23.220
23.977   23.061   22.550   22.247   20.021   15.943
March         .        Peak       13.630   12.113   10.573   10.187   14.427   17.887   21.927
22.800   23.007   23.450   23.803   23.643   23.580   23.387   22.547   22.263   22.260   21.750
28.353   26.370   23.617   21.397   20.883   17.003
April         .        Peak       18.249   17.406   16.494   16.249   17.251   20.106   25.076
26.970   27.079   27.771   28.343   29.602   29.264   28.586   30.233   28.499   27.613   27.446
29.858   31.592   30.961   27.505   25.935   20.885
May           .        Peak       21.085   18.187   16.135   12.910   15.477   21.130   28.390
31.333   37.644   34.083   40.073   40.697   42.293   45.623   46.460   46.727   43.331   40.589
36.998   34.966   38.995   33.895   25.777   23.662
June          .        Peak       18.500   13.158   11.163    9.497    9.430   13.166   20.236
25.408   28.915   33.360   40.970   44.558   54.688   65.562   78.897   90.623   78.335   65.992
56.882   43.873   45.237   37.659   31.103   23.529
July          .        Peak       27.340   21.483   18.293   16.313   15.293   18.391   21.552
24.618   28.170   30.497   37.309   44.965   69.460   96.367 124.743 128.113 117.903 102.420
60.003   41.270   38.416   32.167   32.297   27.617
August        .        Peak       31.757   27.810   25.543   24.377   24.823   29.763   25.247
27.587   31.730   34.817   42.749   44.587   60.185 105.071 165.747 186.701 183.003 138.914
70.337   43.723   45.083   37.540   35.193   27.063
September     .        Peak       25.960   21.897   17.957   15.163   21.717   26.527   27.160
30.233   30.383   34.120   35.580   36.263   36.010   39.207   42.097   43.513   42.077   37.584
36.524   36.214   36.413   33.940   32.263   29.217
October       .        Peak       38.033   34.663   30.970   27.577   31.997   38.610   32.497
29.917   28.850   35.640   44.333   51.673   63.003   77.797   90.467   98.550   92.713   71.897
73.088   69.362   59.217   41.733   35.467   37.968
```

November	.	Peak		24.320	19.260	17.673	17.427	23.417	30.013	26.337
35.077	31.540	35.263	37.820	37.933	32.257	32.980	32.897	32.193	34.807	47.190
47.237	43.123	37.147	31.203	32.513	28.593					
December	.	Peak		25.340	22.713	21.837	22.133	24.020	28.170	32.193
31.993	32.707	31.237	30.210	28.690	28.193	27.913	27.760	27.753	30.668	44.500
43.470	35.900	33.750	31.677	30.327	27.327					
January	.	Week		15.993	15.493	15.327	15.327	16.077	20.160	28.793
30.317	30.557	30.863	29.383	28.283	27.530	27.530	26.480	26.137	27.820	38.540
35.727	31.253	29.057	25.177	25.160	20.660					
February	.	Week		13.996	13.995	13.991	13.992	14.853	19.278	25.433
26.813	26.102	25.046	23.803	22.610	22.917	22.640	22.453	22.357	22.813	27.539
30.863	28.927	24.171	22.000	20.423	17.123					
March	.	Week		14.547	13.450	12.687	13.093	14.757	17.443	21.780
24.130	23.117	23.197	23.503	23.230	24.040	23.810	23.607	23.370	22.427	21.475
27.377	26.023	23.023	21.497	19.383	16.733					
April	.	Week		18.280	17.713	16.903	17.213	18.370	21.057	26.274
28.786	29.175	28.336	28.627	28.117	27.980	27.197	25.843	23.693	22.892	22.755
24.772	27.167	29.489	25.350	25.013	20.950					
May	.	Week		17.148	15.521	12.455	12.119	13.712	19.477	23.994
29.614	29.798	30.775	33.171	33.541	33.605	36.660	36.294	35.791	33.619	32.001
31.687	31.429	35.850	31.486	27.060	21.899					
June	.	Week		15.178	10.990	9.924	9.387	9.333	9.908	17.477
24.285	28.726	32.980	34.788	34.719	35.893	42.829	48.265	50.584	49.300	45.836
38.516	34.059	36.545	34.727	25.443	22.522					
July	.	Week		23.571	17.147	13.410	12.747	12.577	16.646	16.733
25.791	28.578	33.873	41.145	49.692	65.840	84.316	92.599	97.408	95.681	69.569
52.732	40.831	40.230	31.737	37.364	24.181					
August	.	Week		26.557	23.370	21.000	20.927	20.929	23.540	23.081
25.503	28.953	30.393	33.417	36.133	39.337	51.615	69.608	79.481	73.539	57.506
41.897	37.578	35.113	31.945	30.762	27.560					
September	.	Week		21.130	16.750	12.557	9.283	9.570	17.993	19.003
24.737	24.463	31.417	35.697	49.437	55.277	61.770	73.733	78.013	74.227	80.447
72.600	57.697	57.057	33.267	33.683	27.963					
October	.	Week		30.413	26.667	27.587	25.453	28.537	33.443	36.657
33.327	32.997	34.330	36.583	38.667	48.617	66.053	77.899	77.900	76.327	54.307
62.003	64.317	50.057	42.497	37.203	35.327					
November	.	Week		26.667	28.187	25.330	25.347	27.737	31.110	26.217
33.323	28.660	32.647	36.327	36.660	37.977	38.643	43.327	47.777	49.690	72.723
58.443	50.663	42.543	35.510	33.810	24.023					
December	.	Week		25.267	22.780	22.040	22.083	23.803	29.663	33.230
36.950	35.643	33.870	32.213	30.650	29.513	29.067	28.287	27.817	30.351	45.810
45.510	40.428	37.423	33.077	32.200	29.010					
January	.	Weekend		17.661	14.796	13.883	13.660	14.603	17.587	17.016
20.321	22.533	22.470	22.443	22.649	22.411	22.208	21.690	21.938	22.251	26.780
26.887	26.342	24.699	23.962	20.592	17.909					
February	.	Weekend		14.067	13.861	13.827	13.143	13.661	12.659	12.846
17.070	18.665	19.817	19.965	19.460	18.616	18.495	17.928	17.688	18.071	21.264
22.129	21.771	20.546	19.464	17.138	13.497					
March	.	Weekend		17.244	15.147	14.317	13.967	14.681	14.847	14.927
17.412	19.423	20.197	20.903	21.210	20.973	20.893	20.163	19.590	19.770	21.333
25.883	25.657	22.940	20.287	18.120	15.597					
April	.	Weekend		22.144	20.391	18.435	18.178	18.399	19.105	20.261
22.668	25.328	26.053	25.885	25.997	24.829	24.663	24.029	23.392	23.103	23.206
24.743	26.482	27.034	25.745	24.069	21.281					
May	.	Weekend		18.237	13.660	10.509	9.659	9.563	7.669	7.997
15.330	22.007	25.694	26.977	27.174	27.443	27.504	27.408	27.401	27.763	27.836
26.759	26.592	31.571	26.890	21.775	15.730					
June	.	Weekend		15.799	12.505	11.996	11.158	11.378	8.394	6.915
12.282	19.667	26.009	32.915	33.028	33.831	35.029	36.338	36.708	38.667	36.350
34.958	32.684	36.596	34.941	24.819	17.664					
July	.	Weekend		24.493	22.023	16.887	16.880	14.450	15.593	13.350
21.389	24.532	27.478	28.830	31.432	37.148	35.389	34.621	33.052	32.139	31.563
30.506	28.295	28.091	27.007	26.626	22.321					
August	.	Weekend		29.087	24.390	23.207	19.853	19.600	22.397	18.089
24.056	27.533	29.326	31.447	31.973	35.587	38.540	47.352	48.500	48.503	46.940
36.297	33.380	33.680	31.059	30.743	25.653					
September	.	Weekend		25.947	19.740	16.363	12.620	13.447	11.627	14.023
15.403	17.157	22.817	24.900	25.524	29.190	28.259	30.499	30.648	30.037	30.995
27.981	26.736	27.433	24.927	23.650	21.080					

```
October      .        Weekend    35.233   32.414   32.279   30.197   31.911   33.067   30.013
31.887   27.333   31.337   37.840   38.913   45.330   54.603   58.090   60.090   60.333   64.020
58.050  58.920  51.520  42.680  36.080  34.457
November     .        Weekend    26.673   18.997   14.273   12.657   16.633   20.467   15.583
18.092   19.183   22.266   25.395   24.505   22.869   21.796   21.958   22.262   23.685   33.847
35.006  35.696  32.494  27.958  28.647  22.653
December     .        Weekend    26.757   25.473   22.960   21.343   19.170   23.100   27.950
28.763   29.127   29.873   29.263   28.650   28.180   27.227   27.030   27.107   29.776   39.387
39.473  37.067  36.500  32.733  29.850  26.517
;


* Computation of maximum power

 maxl (months, lperiod)
      =
      smax ( (hours, ltypes)$(lperind(months, ltypes, hours) eq ord(lperiod)),
              load(months, ltypes, hours) );
 maxl (winterm, 'on') = 0;

* Computation of consumed energy per month and period

 MCEnergy (months, lperiod)
      =
      sum ( (hours, ltypes)$(lperind(months, ltypes, hours) eq ord(lperiod)),
            load(months, ltypes, hours) * ndltypes (months, ltypes) );


* Computation of the total consumed energy

 TCENERGY = sum ( (months, ltypes, hours), load (months, ltypes, hours)
                                           * ndltypes (months, ltypes) );



* Variables definition

VARIABLES

    GenL   (dertech, months, ltypes, hours) DER generation up to the load (kW)
    GenX   (dertech, months, ltypes, hours) DER generation to sell        (kW)
    GenInv (dertech)                        DER investment             (units)
    TotCost                                 Goal Function Cost
    DEPP                                    Dist. Energy Purchases (peak)  ($)
    DEPM                                    Dist. Energy Purchases (Mid)   ($)
    DEPO                                    Dist. Energy Purchases (Off)   ($)
    DPP                                     Dist. Power Purchases          ($)
    PPXP                                    Power PX Purchases             ($)
    SGIC                                    Self Gen. Investment costs     ($)
    SGVC                                    Self Gen. Variable costs       ($)
    EnSales                                 Energy Sales                   ($)
    BillingPP(months, lperiod)              Billing Power per Period      (kW)
    BillingP (months)                       Billing Power                 (kW)
    DEPur  (months, ltypes, hours)          Dist. Energy Purchases       (kWh)
    w1     (months, ltypes, hours)          Auxiliar integer variable
    ;

* Variables characteristics

POSITIVE VARIABLES GenL, GenX, DEPur;
BINARY VARIABLE w1;

INTEGER VARIABLE GenInv;

*GenInv.fx('SOFCo1') = 9;
*GenInv.fx('SOFCo2') = 4;
*GenInv.fx('mT_P') = 1;

GenInv.up(dertech)$(opt1 eq 0) = 0 ;
GenX.up(dertech, months, ltypes, hours)$(opt3 eq 0) = 0;
```

```
* Equations definition

EQUATIONS

    GoalF                                   Goal Function
    GoalFX                                  Goal Funcion (PX case)
    Gen    (dertech, months, ltypes, hours) Max machine generation
    Supply (months, ltypes, hours)          Balance equation
    DEPPe                                   Dist. Energy Purchases (peak)
    DEPMe                                   Dist. Energy Purchases (Mid)
    DEPOe                                   Dist. Energy Purchases (Off)
    DPPe                                    Dist. Power Purchases
    PPXPe                                   Power PX Purchases
    SGICe                                   Self Gen. Investment costs
    SGVCe                                   Self Gen. Variable costs
    EnSalese                                Energy Sales
    BillingPPe(months, ltypes, hours)       Billing Power per period
    BillingPe (months, ltypes, hours)       Billing Power
    FillX1 (months, ltypes, hours)          Proper GenX filling
    FillX2 (months, ltypes, hours)          Proper GenX filling
    ;

    GoalF  ..   TotCost

                =E=

                DEPP + DEPM + DEPO + DPP + SGIC + SGVC - EnSales
                ;

    GoalFX ..   TotCost

                =E=

                PPXP + SGIC + SGVC - EnSales
                ;


*           Purchases of Electricity (energy peak hours)

    DEPPe  ..  DEPP

               =E=

               sum ( (summerm, wepe, onhourss),
                     ( DEPur (summerm, wepe, onhourss)
                     ) * ndltypes (summerm,wepe)
                   )
                   * sum (applt, tarpe (applt, 'summer', 'on', 'energy') )
               ;

*           Purchases of Electricity (energy mid hours)

    DEPMe  ..  DEPM

               =E=

               sum ( (summerm, wepe, midhourss),
                     ( DEPur (summerm, wepe, midhourss)
                     ) * ndltypes (summerm,wepe)
                   )
                   * sum (applt, tarpe (applt, 'summer', 'mid', 'energy') )
               +
               sum ( (winterm, wepe, midhoursw),
                     ( DEPur (winterm, wepe, midhoursw)
                     ) * ndltypes (winterm,wepe)
                   )
                   * sum (applt, tarpe (applt, 'winter', 'mid', 'energy') )
               ;
```

```
*           Purchases of Electricity (energy off hours)

    DEPOe  ..  DEPO

               =E=

               sum ( (summerm, wepe, offhourss),
                     ( DEPur (summerm, wepe, offhourss)
                     ) * ndltypes (summerm, wepe)
                   )
                   * sum (applt, tarpe (applt, 'summer', 'off', 'energy') )
               +
               sum ( (winterm, wepe, offhoursw),
                     ( DEPur (winterm, wepe, offhoursw)
                     ) * ndltypes (winterm, wepe)
                   )
                   * sum (applt, tarpe (applt, 'winter', 'off', 'energy') )

               +
               sum ( (summerm, hours),
                     ( DEPur (summerm, 'weekend', hours)
                     ) * ndltypes (summerm, 'weekend')
                   )
                   * sum (applt, tarpe (applt, 'summer', 'off', 'energy') )
               +
               sum ( (winterm, hours),
                     ( DEPur (winterm, 'weekend', hours)
                     ) * ndltypes (winterm, 'weekend')
                   )
                   * sum (applt, tarpe (applt, 'winter', 'off', 'energy') )
               ;

*           Purchases of Electricity at PX price

    PPXPe  ..  PPXP

               =E=

               sum ( (months, ltypes, hours),
                     ( DEPur (months, ltypes, hours)
                       * (PX (months, ltypes, hours) / 1000. + DiscoER)
                     ) * ndltypes (months, ltypes)
                   )$(opt4 eq 1)

               +

               sum ( (months, ltypes, hours),
                     ( DEPur (months, ltypes, hours)
                       * FRate
                     ) * ndltypes (months, ltypes)
                   )$(opt4 eq 2)

               ;

*           Purchases of Electricity (power)


    DPPe   ..  DPP

               =E=

               sum ( (summerm, lperiod, applt),
                      BillingPP (summerm, lperiod)
                      * tarpe(applt, 'summer', lperiod, 'power')
                   )
               +
               sum ( (winterm, lperiod, applt),
                      BillingPP (winterm, lperiod)
                      * tarpe(applt, 'winter', lperiod, 'power')
                   )
```

```
*           Purchases of electricity (fixed costs)

                +
                12 * sum ( applt, tarfix (applt, 'custoc') )

                +
                sum ( months, BillingP (months)
                    ) * sum ( applt, tarfix (applt, 'facilitc') )
                ;


*           Self generation costs (investment). The standby charge is added to the
*                                               generation because it is assumed
*                                               that is always lower than the
*                                               demand


    SGICe ..  SGIC

               =E=

               sum ( dertech, GenInv (dertech) * deropt (dertech, 'maxp')
                              * ( InvAnnuity (dertech) )
                   )

               +

               sum ( dertech, GenInv (dertech) * deropt (dertech, 'maxp')
                              * ( 12 * Standby )
                   )$(opt5 eq 1)
               ;

*           Self generation costs (variable costs)


    SGVCe  ..  SGVC

               =E=

               sum ( (dertech, months, ltypes, hours),
                      (GenL (dertech, months, ltypes, hours)
                       + GenX (dertech, months, ltypes, hours)
                      ) * ( KWHCost (dertech) + deropt (dertech, 'OMVar') )
                        * ndltypes (months, ltypes)
                   )
               ;

*           Energy sales

   EnSalese ..  EnSales

                =E=

                sum ( (dertech, months, ltypes, hours),
                         GenX (dertech, months, ltypes, hours)
                         * PX (months, ltypes, hours) / 1000.
                         * ndltypes (months, ltypes)
                    )
                ;


* Power Purchase decision (Billing power per period and month)

   BillingPPe(months, ltypes, hours)

            ..  sum ( lperiod $(ord(lperiod) eq lperind(months, ltypes, hours)),
                      BillingPP (months, lperiod )
                    )

                =G=
```

```
                DEPur (months, ltypes, hours)
                ;

* Power Purchase decision (Billing power per month)

   BillingPe (months, ltypes, hours)

            ..  BillingP (months)

                =G=

                DEPur (months, ltypes, hours)
                ;




* Constraints

    Gen  (dertech, months, ltypes, hours)  ..

                GenL (dertech, months, ltypes, hours)
                +
                GenX (dertech, months, ltypes, hours)

                =L=

                GenInv (dertech) * deropt (dertech, 'maxp')
                ;

    Supply (months, ltypes, hours) ..

                sum (dertech, GenL(dertech, months, ltypes, hours) )
                +
                DEPur (months, ltypes, hours)

                =E=

                load (months, ltypes, hours)
                ;

* Auxiliar constraints


    FillX1 (months, ltypes, hours) ..

                sum (dertech, GenL (dertech, months, ltypes, hours) )

                =G=

                w1 (months, ltypes, hours) * load (months, ltypes, hours)
                ;

    FillX2 (months, ltypes, hours)$(opt3 eq 2) ..

                sum (dertech, GenX (dertech, months, ltypes, hours) )

                =L=

                1000. * w1 (months, ltypes, hours)
                ;


* Solver Statement
```

```
MODEL CUSTADOP  / GoalF, Gen, Supply, DEPPe, DEPMe,
                  DEPOe, DPPe, SGICe, SGVCe, EnSalese,
                  BillingPPe, BillingPe, FillX1, FillX2
                /;

MODEL CUSTADOPX / GoalFX, Gen, Supply,
                  PPXPe, SGICe, SGVCe, EnSalese,
                  FillX1, FillX2
                /;


if ( (opt4 eq 0),
     SOLVE CUSTADOP USING MIP MINIMIZING TOTCOST;
   );
if ( (opt4 eq 1),
     SOLVE CUSTADOPX USING MIP MINIMIZING TOTCOST;
   );
if ( (opt4 eq 2),
     SOLVE CUSTADOPX USING MIP MINIMIZING TOTCOST;
   );

* Different outputs

avprice = totcost.l / tcenergy ;

* DISPLAY genL.l, genX.l, w1.l;

InsCap = sum (dertech, GenInv.l(dertech) * deropt (dertech, 'maxp'));

* DISPLAY genInv.l, InsCap;

* DISPLAY totcost.l , DEPP.l, DEPM.l, DEPO.l, DPP.l, SGIC.l, SGVC.l, EnSales.l ;
* DISPLAY tcenergy , avprice ;
* DISPLAY mcenergy ;

* Residual Max. Power

RMPower (months, lperiod)
      =
      smax ( (hours, ltypes)$(lperind(months, ltypes, hours) eq ord(lperiod)),
              load(months, ltypes, hours)
              -
              sum (dertech, GenL.l(dertech, months, ltypes, hours) )
            );

* DISPLAY RMPower ;

* Residual Demand

 RDemand (months, ltypes, hours)
        =
        load (months, ltypes, hours)
        - sum (dertech, GenL.l(dertech, months, ltypes, hours)
              ) ;


file results /results.txt/ ;
results.pc = 5 ;
results.pw = 255;
results.nd = 4;

put results ;

put$(opt4 eq 0) totcost.ts, totcost.l
   /depp.ts, depp.l
   /depm.ts, depm.l
   /depo.ts, depo.l
   /ppxp.ts         ;

put$(opt4 ne 0) totcost.ts, totcost.l
```

```
   /depp.ts
   /depm.ts
   /depo.ts
   /ppxp.ts, ppxp.l ;

put /dpp.ts, dpp.l
    /sgic.ts, sgic.l
    /sgvc.ts, sgvc.l
    /ensales.ts, ensales.l
    //tcenergy.ts, tcenergy
    /avprice.ts, avprice
   //inscap.ts, inscap ;

loop (dertech $( GenInv.l(dertech) gt 0.), put dertech.tl, Geninv.l(dertech);
     );

put // 'Model options and parameters'
    /opt1.ts, opt1
    /opt3.ts, opt3
    /opt4.ts, opt4;

loop(applt$(opt4 eq 0), put applt.tl;);

put /opt5.ts, opt5
    /opt6.ts, opt6
    /intrate.ts, intrate
    /discoer.ts, discoer
    /frate.ts, frate
    /standby.ts, standby
    /turnvar.ts, turnvar
    // 'Fuel Prices ($/GJ)' /;

loop (Fuels , put Fuels.tl, (FLData(Fuels,'price')*1e6) ;
     );

results.nd = 2;

put // 'Residual demand' //

loop (ltypes, put ltypes.tl /;
      loop (months, put months.tl ;
            loop (hours, put RDemand (months, ltypes, hours);
                  ) ;
            put /;
            );
     );


put / 'Power Sells' //

loop (ltypes, put ltypes.tl /;
      loop (months, put months.tl ;
            loop (hours, put sum(dertech, GenX.l(dertech, months, ltypes, hours) );
                 ) ;
            put /;
            );
     );


put // 'Marginal purchase price' //

loop (ltypes, put ltypes.tl /;
      loop (months, put months.tl ;
            loop (hours, put ( (Supply.m(months, ltypes, hours)
                               +BillingPPe.m(months, ltypes, hours)
                               +BillingPe.m(months, ltypes, hours) )
                                      /ndltypes(months, ltypes) );
                 ) ;
            put /;
            );
     );
```

```
put // 'Load' //

loop (ltypes, put ltypes.tl /;
      loop (months, put months.tl ;
            loop (hours, put load (months, ltypes, hours)
                 ) ;
            put /;
            );
     );


put // 'Generation Output' //
put 'Total' /
loop (ltypes, put ltypes.tl /;
      loop (months, put months.tl ;
            loop (hours, put (sum(dertech,genL.l(dertech, months, ltypes, hours)));
                 ) ;
            put /;
           );
      );

loop (dertech $( GenInv.l(dertech) gt 0.), put dertech.tl /;
      loop (ltypes, put ltypes.tl /;
            loop (months, put months.tl ;
                 loop (hours, put genL.l(dertech, months, ltypes, hours);
                      ) ;
                 put /;
                 );
            );
      );


* DISPLAY supply.m, supply.l ;
* DISPLAY BillingPe.m, BillingPPe.m ;
* DISPLAY genL.l, w1.l;
* DISPLAY KWHcost;
```