Demand Response through a Temperature Setpoint Market in Ontario

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***Abstract*—The electrical grid is designed to meet peak loads, which may occur for only a few hours each year. Consequently, there are significant economic gains from a reduction in the peak load. Air conditioner (AC) load from residential buildings forms a significant portion of peak summer loads. The existing 'peaksaver' program in Ontario attempts to reduce AC loads by setting thermostats a few degrees higher in volunteer households on hot summer days. This has had only a limited success. To address this issue, we propose a scheme that provides monetary incentive for participation. We describe the operation of this 'temperature market' and demonstrate its effectiveness with a heterogeneous population of potential participants. We find that even a payment of $2 per hour of setback can reduce grid operating costs by $688 million over a period of 20 years.**

I. Introduction

The many gains from a reduction in peak loads are well known [1]–[3]. For example, in Ontario, Canada, the highest 3% load occurs for less than 15 hours during a year [20], but it costs more than $130 million every year to maintain this peaking generation capacity! Ontario therefore plans to spend $12 billion by 2030 to reduce its peak load [4].

The peak load in Ontario, which occurs in the late afternoon on a hot summer working day [6], has a significant contribution from AC, which accounts for more than 50% of a typical home's load. Thus, peak load can be reduced by increasing thermostat temperature setpoint during summer peak hours [5], [6]. Importantly, empirical studies have shown that a two degree Celsius increase in home temperature can reduce AC load by up to 37% [16].

Ontario already has a program called *peaksaver*® [15] which allows utilities to remotely control thermostat settings at volunteering homes. Homeowners do not have any monetary incentive for participation in the program, however, and perhaps the fear of losing thermostat control during the warmest days of the summer has resulted in an adoption rate of only 4% [17]. To address the problem of low penetration rate of this program, we propose to give homeowners a monetary incentive for participation. Moreover they do not need to give up control of their home thermostat setting. We call our scheme *smartset*.

The main contributions of our work are:

1) We present *smartset*, a market model for demand response where participants are given monetary incentives for AC setback
2) We describe and analyze an adoption model that takes population heterogeneity into account
3) Using optimization and real aggregate load data for Ontario, we determine that, despite paying out monetary incentives, a grid operator can still reduce its operating costs using our approach

Although our analysis is specific to Ontario, our approach can be adopted in other parts of the world that also have summer peaking loads.

II. Related Work

Demand Response is an active area of research. Reduction in demand is akin to virtual power generation, measured in negawatts (from negative watts). A widely studied approach for peak load reduction [7]–[10] is for the grid to conduct multiple bidding rounds. In each round, the utility tentatively offers home owners a monetary incentive per unit reduction in power. Bidding concludes and the offered price is finalized when a 'sufficient number'of people agree to reduce their load. These papers do not answer the question that how a home owner actually reduces home load by, say, 500W, given that most home owners have only a vague idea of the demand of a given appliance [19]. For this reason, we believe that such schemes are rather impractical. It would be far better for homeowners to be paid for adjusting a temperature setpoint, which is easy for any home owner to understand. This is the motivation for our work.

We note that there are already some direct load control programs like peaksaver® (Section III-C) and Cool Credits Direct Load Control Program [18], where the grid operator uses thermostat setback to reduce the peak load. Based on voluntary participation, they have had limited success. To the best of our knowledge, our work in this paper is the first step towards combining demand response market models with direct thermostat control.

III. Motivation

Our work focuses on Ontario. Peak load in Ontario is in the late afternoon of a working day in summer with extreme weather conditions. Also, as central air conditioning (CAC) load in summers is far higher than that of electricity-based heating in winters, we restrict our attention to only reducing summer peak loads.

A. Residential load significance

All buildings with a CAC consume electricity in summers. As much as 60% of home's yearly electricity costs can go towards heating or cooling of a home [23]. Faruqui et al. [11] say that in the US, residential loads "account for a third of over-all energy consumption and for a larger share of peak demand". The rate of increase of aggregate residential load is also greater than the rate of increase of industrial load [22]. Thus reducing residential peak load can have a significant impact in reducing Ontario peak load.

B. Effectiveness of thermostat setback

Reports of peaksaver program [16] [17] show up to 37% reduction in AC load during peak hours by using a 50% cycling strategy. According to reports by National Research Council Canada (NRCAN) [13] [14], AC-setback of 2°C results in 23% savings over a complete day. As savings increase with outside temperature, savings are far higher than 23% during the summer peak load hour.

C. peaksaver®

peaksaver is a voluntary demand response program for small commercial and residential consumers [16] [17]. It involves installation of a programmable communicating thermostats (PCTs) and/or direct load control switches. The control is enforced in two ways– a) increasing thermostat set point, or b) limiting cycling run time– by using a wireless pager system that reduces CAC load during the peak hours. According to the 2011 annual program evaluation report [17], the program already has more than 150,000 participating houses. Some of the highlights of the program are:-

1) A $225 PCT device is installed for free at each participating home.
2) There are a maximum of 10 activations in a year (average ≤ 4 though), and a maximum of 2°C or 50% cycling ease on CAC.
3) In 2009, the maximum reduction in load due to peaksaver activation was 60 MW, and the maximum increase in load due to a snapback[1] in the hours following the event was 40 MW.

D. Ontario's Long Term Energy Plan

Ontario's electricity sector is a $15 billion annual industry with overall demand varying from 11 GW to 25 GW. According to the province's long term energy plan [12], Ontario needs to rebuild or create another 15 GW of generation capacity by 2030. The total capital cost in 2010 dollars is estimated to be $87 billion over the next 20 years. Thus a 3% decrease in the peak load can save $130 million every year till 2030. This accounts for new and refurbished energy supply, transmission and distribution infrastructure, and conservation investments. The plan is to make 7.1 GW of conservation to reduce demand by 2030 with residential sector contributing 30% of this conservation.

[1]This is the increase in load after a DR event to make up for the loss of cooling during the DR event

E. Goals

Given that the grid benefits from reducing the peak load, we have the following two goals:

1) To design a temperature market where the grid operator provides monetary incentive to homeowners to encourage their participation in thermostat setback.
2) To study effectiveness of thermostat setback in reducing Ontario peak load, and verify the feasibility of the above market by ensuring every participant gains from participation.

IV. Modeling

A. Overview

The goal of the electrical grid is to match electricity supply and demand. As most other jurisdictions, aggregate power demand of Ontario is highly volatile. Although predictions are quite accurate on short time scales (such as a few days), prediction of the peak load in the next five years is error-prone. Similarly, prediction of future generation capacity is also error-prone, mainly due to maintenance and failures of power generation plants. It is to prepare for an event that might occur only once in five to ten years that the grid always maintains a contingency plan. In this paper we are trying to address the problem of peak demand and will therefore restrict our attention to the contingency of excess demand.

The contingency corresponding to excess demand is met in three ways – *a) Purchasing electricity from a neighboring jurisdiction, b) building 'extra' generation capacity, and c) Demand-Response programs*. Usually purchasing electricity from a neighboring jurisdiction is the cheapest option. Nevertheless, during long term planning, a jurisdiction tries to avoid relying on other jurisdictions and become energy independent. One of the reasons for this is apparent from the California energy crisis of 2000-2001 where California had to suffer from multiple large scale blackouts due to market manipulation and illegal shutdowns of pipelines by power generators in Texas. Another reason for not relying on a neighboring jurisdiction is that it may shut down its generators for maintenance or may itself face a power shortage. As the above factors are not within its control, a jurisdiction tries to meet the excess demand contingency by building out extra generation capacity or putting demand response programs into place.

B. Modeling Assumptions

Our modeling assumptions are as follows:

1) Generation capacity planning is done for a predefined time (such as 5 years) during which the generation capacity does not change.
2) In the event of a thermostat setback, all participating homeowners are paid the same amount for participation.
3) Although homeowners fall into different classes with respect to participation (details in Section IV-D), home loads in different classes have the same distribution.
4) The snapback load[1] following a DR event extends for only one hour.

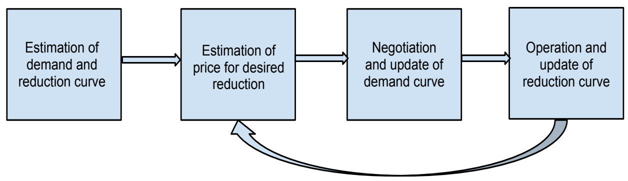

Fig. 1. Market Model

Name	*Description*
L	Aggregate residential AC load
$\mathcal{L}(p)$	Aggregate residential AC load when offered price is p
$\mathcal{A}$	Set of altruistic homes
$\mathcal{M}$	Set of medium homes
$\mathcal{S}$	Set of selfish homes
x, y, z	Fraction of altruistic, medium, & selfish homes respectively
τ	Fraction of aggregate load that forms residential load
λ	Fraction of residential load that forms CAC load
H	Number of houses in Ontario

TABLE I
NOTATION

C. *smartset* Design

smartset assumes the existence of : a) a *demand curve* that indicates the fraction of homes that accept a given price to participate in thermostat setback, and b) a *reduction curve* that indicates the expected reduction in aggregate load given the fraction of participating homes. We believe that these curves can be estimated using historical data, or as discussed is Section IV-D.

smartset operates in four phases (see Figure 1):

(a) The grid estimates the demand and reduction curves.

(b) To reduce aggregate load by r, the grid computes fraction f using the reduction curve, and price c_1 corresponding to f using the demand curve.

(c) In the negotiation phase, there are multiple iterations of bidding. Starting with price c_1, in iteration i the grid announces price c_i – amount received by a home for letting the grid control its thermostat for an hour. All homes respond whether they accept or reject the bid. Depending on whether the fraction of homes accepting to participate is more or less than f, it offers a new price c_{i+1}. Finally when fraction f of homes are ready to participate in setback, the offered price is finalized[2]. The grid also uses the information of negotiation phase to update the demand curve.

(d) The grid controls thermostat of the accepting fraction f of homes to reduce aggregate load by r. In case the estimated fraction f is not sufficient to reduce load by r, the grid updates the reduction curve and returns to phase (b).

We now analyze the effectiveness of *smartset*.

D. The Effectiveness of smartset

We first discuss how to estimate the demand and reduction curves. Let h_i represent the AC load of home i. Thus aggregate residential AC load before activation of *smartset* is $L = \sum_i h_i$. Suppose the grid offers a price p (in \$/hr) to home owners for participation in thermostat setback. As a first-order approximation, we model the reduction curve linearly: if home i accepts the offer, its load reduces from h_i to αh_i where $0 < \alpha < 1$ is a constant depending on the conditions of the day[3]. To estimate the demand curve while modeling the heterogeneous behaviour of homes, we divide the homes into three classes: selfish, medium, and altruistic. We assume the following intuitively reasonable probability distribution, $P_i(p)$, for different classes of homes to accept the offer price p,

$$\textbf{Altruistic } (\mathcal{A})\textbf{:} \qquad P_i(p) = 1 \qquad 0 \le p \tag{1}$$

$$\textbf{Medium } (\mathcal{M})\textbf{:} \qquad P_i(p) = \begin{cases} \frac{p}{c} & 0 \le p < c \\ 1 & c \le p \end{cases} \tag{2}$$

$$\textbf{Selfish } (\mathcal{S})\textbf{:} \qquad P_i(p) = \begin{cases} 0 & p \le a \\ \frac{p-a}{b-a} & a < p < b \\ 1 & b \le p \end{cases} \tag{3}$$

This classification is justified as the set of homes already participating in peaksaver represent the altruistic homes. Assuming a price-proportional distribution for medium class homes seems reasonable. As shown later, we will never try to activate *smartset* in selfish homes, and hence their probability distribution does not affect our results.

Case 1: All homes are homogeneous and of type $\mathcal{S}$

Let $\mathcal{L}_i(p)$ be the expected load of user i at price p. Then for $a < p < b$, we have

$$\mathcal{L}_i(p) = \alpha h_i \left(\frac{p-a}{b-a}\right) + \left(1 - \frac{p-a}{b-a}\right) h_i \tag{4}$$

$$= h_i \left(\frac{\alpha p - \alpha a + b - p}{b-a}\right) \tag{5}$$

As expectation can be distributed over summation, expected aggregate load is given by

$$\mathcal{L}(p) = L\left(\frac{\alpha p - \alpha a + b - p}{b-a}\right)$$

As probability of acceptance of two users is independent, we can calculate the variance as

$$\text{Variance of aggregate load} = \sum_i (\text{Var. of load } h_i)$$

$$= \sum_i (E[\text{square of load of user i}] - (E[\text{load of user i}])^2)$$

$$= g(\alpha, a, b, p)(\sum_i h_i^2)$$

Here $g(\alpha, a, b, p) = [(q\alpha^2 + (1-q)) - (q\alpha + (1-q))^2]$, where $q = \frac{p-a}{b-a}$

Note that the function g does not depend on i and hence can be factored out.

[2]The reduction of the number of iterations in the negotiation phase has been studied in prior work [7] [8] [10]

[3]As the electrical grid is dealing with millions of homes, it can make a good estimate of the parameter

Case 2: Homes are heterogeneous and of all three types

Let fraction of homes in $\mathcal{A}$ be x, in $\mathcal{M}$ be y, and in $\mathcal{S}$ be z, such that

$$x + y + z = 1$$

We assume that the homeowners in different classes have the same distribution i.e. if L is the aggregate load then aggregate load of homes in $\mathcal{A}$ is xL, in $\mathcal{M}$ is yL, and in $\mathcal{S}$ is zL. For simplicity, we assume $c = a$ and study the load by considering the following cases:

Case 2a) $p \leq a$
Here only homes in $\mathcal{A}$ and $\mathcal{M}$ can accept the bid. The expected load at price p is given as

$$\mathcal{L}(p) = \left(x\alpha + y\alpha\frac{p}{a} + y(1 - \frac{p}{a}) + z\right)L$$

The variance of aggregate load is the sum of individual variances of homes in the three classes. As homes in $\mathcal{A}$ and $\mathcal{S}$ have a deterministic load (homes in $\mathcal{A}$ always participates and in $\mathcal{S}$ never participates), their variance is 0. Thus variance of aggregate load is equal to the variance of the load of homes in $\mathcal{M}$

$$g(\alpha, 0, a, p)(\sum_{i \in \mathcal{M}} h_i^2)$$

where g is the same function as defined in Case 1.

Case 2b) $a < p \leq b$
Here homes in all the three classes participate in the bidding. The expected aggregate load is given by

$$\mathcal{L}(p) = \left(x\alpha + y\alpha + z\alpha\frac{p-a}{b-a} + z(1 - \frac{p-a}{b-a})\right)L$$

As homes in $\mathcal{A}$ and $\mathcal{M}$ have a deterministic load (they always participate), their variance is 0. Thus variance of aggregate load is equal to the variance of the load of homes in $\mathcal{S}$

$$g(\alpha, a, b, p)(\sum_{i \in \mathcal{S}} h_i^2)$$

A simple way of approximating $(\sum_{i\in\mathcal{M}} h_i^2)$ and $(\sum_{i\in\mathcal{S}} h_i^2)$ in the above equations is $y^2(\sum_i h_i^2)$ and $x^2(\sum_i h_i^2)$ respectively.

E. Numerical Examples

For a better intuition on the impact of *smartset*, we give numerical examples using reasonable values of the system parameters. Let

$$a = 1, b = 3, x = 0.1, y = 0.45, z = 0.45, \alpha = 65\%$$

Also, assume aggregate Ontario load during a peak hour to be 25 GW, and aggregate AC load to be 5 GW. Now consider the expected aggregate load $\mathcal{L}$ as a function of bidding price p. Substituting the values in case 2 above, we have

$$\mathcal{L}(0) = \alpha x L + (y + z)L = 4.85 \text{ GW}$$

$$\mathcal{L}(a) = \alpha(x + y)L + zL = 4.0375 \text{ GW}$$

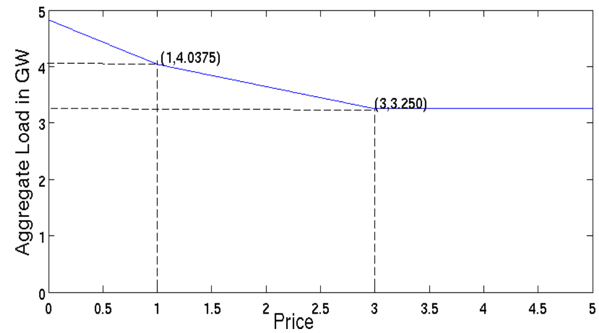

Fig. 2. Expected Load

$$\mathcal{L}(b) = \alpha(x + y + z)L = \alpha L = 3.25 \text{ GW}$$

We can see from Figure 2 that even when the price is a, i.e. when selfish people are not participating in the bidding, the reduction in load is 0.965 GW or 3.85% of the aggregate Ontario load.

3.85% of aggregate load corresponds to \$3.35 billion as per Ontario's long term energy plan. Currently there are around 5 million homes [21] in Ontario and installation cost of \$225 device per home is an expenditure of \$1.125 billion. If the devices last untill 2030, the remaining \$2.225 billion can be used in incentivizing 2.75 million homes in $\mathcal{A}$ or $\mathcal{M}$, or \$809 per home, for the next 20 years.

From the last 10 years of Ontario aggregate load data, one can observe that the top 3.85% load in an year occurs for around 15 hours. Thus, even if we assume homogeneous homes and pay every home \$2 per hour for reducing the load by causing thermostat setback during the peak hours, the grid still saves around \$575 million in the next 20 years.

V. Optimization problem

We now consider the optimal operation of *smartset* from the perspective of the grid operator. Consider an interval of k successive hours on a day with *smartset* activation (practically $k < 10$). *smartset* decreases aggregate load during the activation (event) hours but is followed by an increase due to a snapback load in the post event hours. The grid therefore needs to solve an optimization problem to ensure that the aggregate load never crosses the available power supply d. We model the snapback load by assuming that it lasts for one hour and that increases a home's load from h_i to $h_i + \beta h_i$, where $\beta \geq 0$ is a constant[3]. Let l_i, $1 \leq i \leq k$, represent aggregate AC load during i th hour of the event before the activation of *smartset*. In practice the optimization problem will use a predicted value for l_i, but we assume that the exact values are known for simplification. Let l_i' represent the aggregate AC load after the activation of *smartset* in f_i fraction of total homes. To ensure that there is no effect of the event beyond the k hours, we set $f_1 = 0 = f_k$.

Let $p(f_i)$ be a non-negative convex function denoting the amount to be paid to each home for participation in thermostat setback[4]. The grid's objective is to minimize its expenditure in providing monetary incentive while ensuring that the aggregate load remains less than d. Note that the grid does not pay homes during the snapback period. We can now formulate the problem as an optimization problem with linear constraints.

Objective:

$$\min \left(\sum_{i=1}^{k} f_i * p(f_i) * H \right) \tag{6}$$

Subject To:

$$l'_i = \left[\tau\lambda + (1-\tau\lambda)(f_i\alpha + (1-f_i) + d_i\beta) \right] l_i \tag{7}$$

$$f_1 = f_k = 0 \tag{8}$$

$$l'_i \leq d \ , \forall i \tag{9}$$

$$0 \leq f_i \leq 1 \tag{10}$$

$$0 \leq d_i \tag{11}$$

$$f_{i-1} - f_i \leq d_i \tag{12}$$

Fortunately, the above optimization problem can be converted to a linear optimization problem. We prove by contradiction in the following paragraph that replacing the objective function in equation 6 with $\min\left(\sum_{i=1}^{k} f_i\right)$ will not change the optimal solution, f^*.

Let $f'(\neq f^*)$ be the optimal solution with the new objective function. Consider the minimum j, $1 < j < k$, for which $f'_j \neq f^*_j$. Now f^*_j less than f'_j would make the constraint 9 infeasible for $i = j$. On the other hand, f^*_j cannot be more than f'_j as otherwise we can reduce f^*_j in f^* without losing feasibility of our solution, and hence further decrease the optimal value. As we obtain a contradiction in both the cases, $f'_j = f^*_j$

VI. Evaluation

A. Simulation Strategy

We simulate our model that takes heterogeneity of homes into account (Section IV-D) using the optimization problem from Section V. We compare it with a model that assumes homogeneous behaviour of homes. For homogeneous behaviour, we define $p(f)$ to be identically \$1, and for heterogeneous behaviour we define

$$p(f) = \begin{cases} 0 & f \leq x \\ \frac{c(f-x)}{y} & x < f < x + y \end{cases} \tag{13}$$

As c is a multiplicative term, we take $c =$\$1 for the simulation. The grid benefits from *smartset* if the money saved due to peak load reduction is more than the expenditure in providing monetary incentives. We therefore vary different parameters of our model to show their effect on the expenditure.

[4] $p(f)$ is convex because with increasing f, the rate of increase in money being paid to each home also increases.

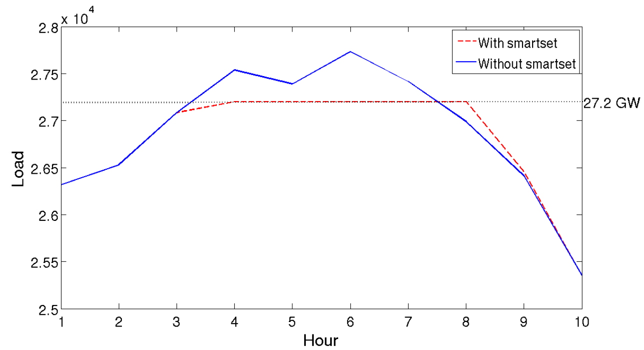

Fig. 3. Impact of *smartset* on Ontario aggregate load with a cap of 27.2GW on 7^{th} July 2010 between 11am-9pm. The simulation assumes $x = 0.1$; $y = 0.45$; $z = 0.45$; $c \leq a$; $\alpha = 0.65$; $\beta = 0.3$

B. Results

The impact of *smartset* on the load profile for the peak load day in 2010 is shown in Figure 3. For simulation purpose we assume that the homes behave exactly according to our model and the aggregate AC load predictions are accurate. Hence, aggregate load after *smartset* activation is always close to the cap. Figures 4–6 show sensitivity of expenditure to various model parameters. In each figure we show the expenditure for both homogeneous and heterogeneous behaviour of homes.

For heterogenous behaviour, Figure 4 illustrates a large decrease in expenditure with a slight increase in the fraction of altruistic homes or the cap on the aggregate load. Expenditure for homogeneous behaviour is also very sensitive to the cap but is independent of x. Figures 5 and 6 show more than 50% decrease in expenditure as the fraction of aggregate load formed by CAC increases from 10% to 20% or as α decreases from 0.75 to 0.5. From a graph between expenditure and β (not shown here), we found expenditure to be robust to small variations in β.

By comparing Figures 4 and 7, we observe that the expenditure between 2006 to 2010 for heterogeneous behaviour of homes is dominated by the 2010 expenditure. We do not observe a similar pattern for homogeneous behaviour. The reason for this difference is the activation of *smartset* in only a fraction of altruistic homes that incur no cost for the heterogeneous model.

The peak load in Ontario between 2006 to 2010 was 27.8 GW. With a cap of 27.2 GW on the aggregate load, the grid saves 2.1% of contingency corresponding to excess demand. For the homogeneous model of \$1 per hour payment to each home, Figure 7 shows an expenditure of less than \$8 million due to *smartset* activation over the five years. Hence, calculations similar to Section IV-E show that even with a payment of \$2 per hour of setback to each home, *smartset* can reduce the grid operating costs by \$688 million in the next 20 years.

VII. Conclusion

We design a temperature market for the electrical grid and the homeowners. We describe and analyze an adoption model

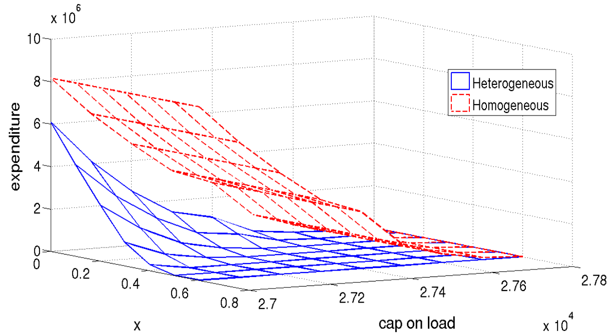

Fig. 4. Expenditure in dollars vs x vs cap on aggregate load in MW on 7^{th} July 2010. The simulation assumes $y = 0.45; c = 1 \leq a; \tau = 1/3; \lambda = 0.5; \alpha = 0.65; \beta = 0.3$

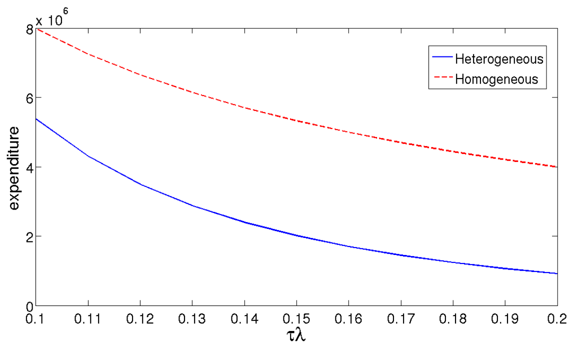

Fig. 5. Expenditure in dollars vs $\tau\lambda$ on 7^{th} July 2010. If $\tau = 1/3$, λ goes from 30% to 60%. The simulation assumes $x = 0.1; y = 0.45; c = 1 \leq a$; cap on generation capacity= $27.2GW$

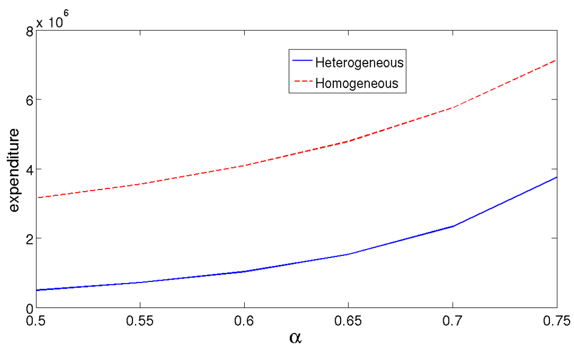

Fig. 6. Expenditure in dollars vs α on 7^{th} July 2010. The simulation assumes $x = 0.1; y = 0.45; c = 1 \leq a; \tau = 1/3; \lambda = 1/2; \beta = 0.3$; cap on generation capacity= $27.2GW$

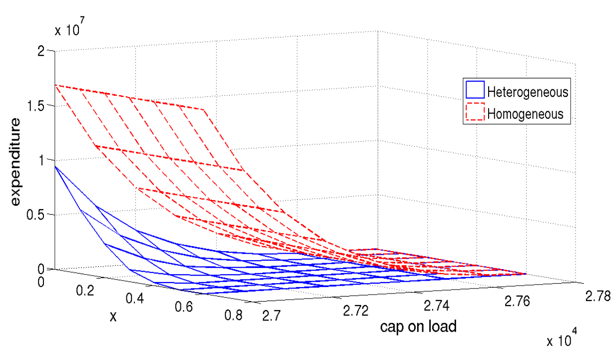

Fig. 7. Expenditure in dollars vs x vs cap on aggregate load in MW from 2006 to 2010. The simulation assumes $y = 0.45; c = 1 \leq a; \tau = 1/3; \lambda = 0.5; \alpha = 0.65; \beta = 0.3$

that takes heterogeneous behaviour of homes into account. By simulating our models on real Ontario aggregate load data, we show the sensitivity of grid expenditure in providing monetary incentives to different model parameters. We conclude from numerical examples that the above temperature market is feasible on a large scale. For future work, we would like to improve the accuracy of our results by finding a better estimate of our model parameters. Studying other temperature market schemes, like every degree payment and iterative bidding, is also an important extension.

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