Demand Charge and Response with Energy Storage

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***Abstract*—Commercial and industry (C&I) customers incur two types of electricity charges on their bills: one for the amount of energy usage and another one for the maximum demand during certain billing periods. The second charge type is known as Demand Charge (DC), which could account for over half of a customers' electricity bill. Those C&I customers often sign up for Demand Response (DR) programs to contribute to peak demand reduction as well as to receive incentives and rewards from participating in the programs. The critical factor of achieving both DR and DC reduction is to recognize the nature of these two types of problems and create an effective strategy that can handle them at the same time by which the benefits from DR incentives and DC reduction are maximized. This paper discusses the possible DR scenarios with DC reduction framework for C&I customers who use a Behind-the-Meter (BTM) energy storage and proposes a consistent real-time procedure of deciding battery's charging and discharging setpoints to solve the problem of maximizing the rewards by conducting DRs as well as the savings by reducing DC costs.**

***Index Terms*—Demand Charge, Demand Response, Energy Storage, Behind-The-Meter (BTM) Application**

I. Introduction

Distributed energy storages have become critical resources to commercial and industrial (C&I) customers not only for making the most use of renewable energies such as a Photovoltaic (PV) to get eligible for Investment Tax Credit (ITC), but also for curtailing peak demands to reduce Demand Charge (DC) costs that depend on the maximum consumption of electricity of a month. A Behind-the-Meter (BTM) energy storage has been utilized as a core function of demand charge management since the storage could absorb energy when no peak demands are expected and discharge power during the peak demand periods to lower and flatten those peaks.

The energy storages are also getting important to achieve Demand Response (DR) to integrate renewable energies and respond to critical peak pricing and slow/fast load reduction requests sent from a utility or Independent System Operator (ISO). Motivation of the customers could be to receive incentives and rewards by participating in one of DR programs or more. In addition, many vendors and laboratories have spent lots of efforts in creating Open Automated Demand Response (OpenADR) as a key technological open standard to make DR automated, which defines the communications protocol and procedures on how to handle important DR events that need to be conducted promptly with the instructional signals sent from a dispatcher. Together with the development of OpenADR protocols and its platform, more and more C&I customers are adopting the DR programs that could be achieved by using their own energy storage in addition to reducing the usage of load consumption. OpenADR specification [1] also lists up essential templates of DR programs for C&I customers so that they can integrate their own DR strategy into Energy Management System (EMS) for the immediate business use with utilities and ISOs.

The competence of the proposed DC and DR management framework especially lies in a unique real-time battery control strategy that is designed to solve both DC reduction and DR programs at the same time by taking the full advantage of an energy storage. Essential DR programs including peak-pricing and load-reduction types are handled by not violating Demand Charge Thresholds (DCTs) that are used to reduce the demand peaks under certain limits to minimize DC costs. In this way, it is guaranteed to earn as much savings and incentives as possible with precise calculation of energy balance of a battery installed at the BTM premise of a C&I customer.

II. Related Work

Demand charge reduction using energy storage has recently been researched, which motivates customers to purchase batteries for reducing their electricity cost. The paper [2] is a relatively early work on demand charge, which discusses a dispatch strategy of a PV battery storage conducting solar forecasting. A linear programming (LP) is used to establish a demand charge threshold (DCT) that is the optimal level to which the day-ahead load forecast can be reduced. Hence the perfect battery dispatch profile is calculated based on day-ahead load and PV forecasts. The article [3] gives us a picture of how to deploy the energy storage for the BTM premises where rate structure, facility load and PV generation, and battery modeling and control are discussed. The work [4] focuses on the stochastic nature of demand charge reduction by forecasting load especially for C&I customers and data-driven and machine learning approaches have been explored in [5], [6] to sophisticate the short-term load forecasting. Electricity cost reduction considering both Time of Use (ToU) and real time pricing policies based on demand charge has also been explored in [7].

On the other hand, various DR problems using energy storage have been discussed and resolved as seen in [8], [9], [10], which define the problem with energy storage using dynamic programming and threshold-based control policies. [11] considers the problem of demand response with energy storage in a finite horizon, and formulates it as a convex optimization program. Furthermore, the problem of optimal demand response is considered in [12] with energy storage management for a power consuming entity based on the Lyapunov optimization technique.

However, there has been no mechanism or framework that handles demand charge and response at the same time using a BTM energy storage for C&I customers, although solving demand charge reduction with DCTs and demand response together by battery management is an important problem to explore. The role of this paper is to discuss essential DR scenarios for C&I customers with energy storage to be integrated into DC management mechanisms, and to propose a solution to maximize the savings from DC reduction and rewards from conducting DR.

III. Problem Analysis and Formulation

The concepts of demand charge and response are similar to each other as they are related to curtailing the peak loads for grid operators to make the grid stable as well as for the customers to receive incentives or savings with load shedding and reduction. A BTM battery primarily serves as minimizing the DC cost for C&I customers as well as integrating PV effectively. Some of the C&I customers have also joined DR programs provided by their utility, some of which are specific to the customers whose average monthly or annual demand is large enough to be eligible for participation. However, the way the customers receive savings and incentives is different in demand charge and response and there would be conflicts in realizing DR and DC reduction at the same time. Although DC reduction is critical and sensitive, if customers fail to follow the rule of DR event, they may lose all the rewards for that entire DR period or have to pay penalty for violation and will not be allowed to participate in the DR program again in the following year. Therefore, we need to explore the best way of realizing both DR and DC by leveraging a battery and consider the possible scenarios based on the types of DR programs available to C&I customers.

Let SAV_{DC} and REW_{DR} be the monthly savings from demand charge reduction and the monthly rewards from conducting demand response, respectively. The objective function of the problem of demand charge and response management is maximizing $SAV_{DC} + REW_{DR}$ as in (12). The reward of individual DR differs based on the types of DR program including Peak Pricing and Load Reduction. We discuss these two types that could become the basis of other extended versions of the DR programs.

The notations and definitions used in problem formulation are found in Table I.

TABLE I
Notations and Definitions

$D(t)$	Demand at a customer at time t
$P_{PV}(t)$	Photovoltaic (PV) generation at a customer at t
$N(t)$	Net demand defined as $N(t) := D(t) - P_{PV}$
$P_G(t)$	Power from the grid at time t
$P_B(t)$	Power from a battery at time t
η	Round-trip efficiency where $\eta = [0, 1]$ when a battery is charging $P_B(t) < 0$, otherwise $\eta = 1$
$S(t)$	Amount of stored energy in a battery
T_1	Anytime or off-peak demand charge period
T_2	Partial-peak demand charge period
T_3	Peak demand charge period
$\mathbf{T}_{dr}$	Set of Demand Response event periods in a month $\mathbf{T}_{dr} = \{T_i^{dr}\}$
$DCT(t)$	Demand Charge Threshold (DCT) at certain time t
DCT_1	DCT during anytime or off-peak time
DCT_2	DCT during partial peak time
DCT_3	DCT during peak time
$FSL(t)$	Firm Service Level (FSL) at time t
$\overline{D}(t)$	Demand Reduction Threshold (DRT), which is either DCT or FSL at time t, whichever is smaller.
$D_B(t)$	Baseline of demand calculated with its average of historical data at time t

A. Demand Charge Saving

DC calculation in electricity bill is based on the peak grid power measured by the utility meter, averaged over 15-minute or 30-minute period, during a monthly bill cycle. This implies that at the beginning of each month, the BTM Energy Management System must calculate the target peak grid power, and then tries to keep the grid power below the target peak grid power during the entire monthly cycle. Target peak grid powers are called Demand Charge Threshold (DCT). In most utilities, the actual DC is calculated based on maximum grid power over a month at different times of a day. Specifically, the DC structure that has been used for problem formulation in this paper consists of three main components:

1) Anytime DC: Defined as the maximum grid power over the entire time horizon.
2) Partial DC: Defined as the maximum grid power only during the partial peak time periods of a day.
3) Peak DC: Defined as the maximum grid power only during the peak time periods of a day.

The final DC cost in an electricity bill is calculated by summing up all three components of the DC together. Thus, the BTM energy management system needs to calculate three optimal DCTs for anytime DCT_1, partial DCT_2, and peak DCT_3 times of the days, accordingly.

Let C_1, C_2, and C_3 be Demand Charge costs associated with anytime/off-peak time, partial peak time, and peak time, respectively. The monthly savings from demand charge reduction is defined as

$$\begin{aligned} SAV_{DC} = C_1\big(\max_{t \in T_1} N(t) - \max_{t \in T_1} P_G(t)\big) \\ + C_2\big(\max_{t \in T_2} N(t) - \max_{t \in T_2} P_G(t)\big) \\ + C_3\big(\max_{t \in T_3} N(t) - \max_{t \in T_3} P_G(t)\big). \end{aligned} \quad (1)$$

B. Demand Response Rewards

The typical types of DR programs that are mainly applicable to BTM energy storage applications are Critical Peak Pricing (CPP) Program, Ancillary Services Program, Distributed

Energy Resources (DER) Program, and Capacity Bidding Program (CBP). The DER DR program is intrinsically the same as pricing events where customers can plan well for maximizing the use of DERs when the electricity price is high. The CBP program is applicable to an aggregated model of BTM storages. Therefore, we discuss the peak pricing type DR and load reduction type DR by ancillary service program as they are the basis of various extended DR programs used for BTM applications.

1) Peak Pricing DR Rewards: Peak Pricing DR requires customers to pay for higher prices during Peak Pricing DR events that happen several times per year, typically occurring on the hottest days of the summer. By reducing electricity usage during Peak Pricing events, customers help utilities and ISOs to keep energy supply reliable for everyone as well as save business money.

The incentive of joining Peak Pricing DR program is that customers are sometimes offered with an optional rate discounted on regular summer electricity rates in exchange for higher prices during DR events. The discount could be either on demand charge per kW or energy usage per kWh. Let C_1^{dis}, C_2^{dis}, and C_3^{dis} be discounts on demand charge costs associated with anytime/off-peak time T_1, partial peak time T_2, and peak time T_3, respectively. Then, the following rewards rew_1 could be added to monthly DC savings with Peak Pricing DR.

$$\begin{aligned} rew_1 = C_1^{dis}\big(\max_{t\in T_1} N(t) - \max_{t\in T_1} P_G(t)\big) \\ + C_2^{dis}\big(\max_{t\in T_2} N(t) - \max_{t\in T_2} P_G(t)\big) \\ + C_3^{dis}\big(\max_{t\in T_3} N(t) - \max_{t\in T_3} P_G(t)\big). \end{aligned} \tag{2}$$

Let r_1^{dis}, r_2^{dis}, and r_2^{dis} be discounts on energy prices during off-peak period T_1, partial-peak period T_2, and peak period T_3, respectively. Also, C_{sur} is electricity peak surcharge price sent to customers with DR event signal. The benefit from discounts on energy usages during non-event periods as well as penalty from peak price surcharge during event period is calculated as

$$\begin{aligned} rew_2 = \sum_{t\in T_1} c_1^{tou}\big(N(t) - P_G(t)\big)\Delta t + \sum_{t\in T_1} r_1^{dis} P_G(t)\Delta t \\ + \sum_{t\in T_2} c_2^{tou}\big(N(t) - P_G(t)\big)\Delta t + \sum_{t\in T_2} r_2^{dis} P_G(t)\Delta t \\ + \sum_{t\in T_3} c_3^{tou}\big(N(t) - P_G(t)\big)\Delta t + \sum_{t\in T_3} r_3^{dis} P_G(t)\Delta t \\ - \sum_{T_i^{dr}\in \mathbf{T}_{dr}} \sum_{t\in T_i^{dr}} C_{sur} P_G(t)\Delta t. \end{aligned} \tag{3}$$

where Δt (hour) is a metering interval of measuring demands. Hence the monthly rewards from Peak Pricing DR types is

$$REW_{DR} = rew_1 + rew_2. \tag{4}$$

In *Load Reduction DR* Dispatch events with DC reduction during DR periods, a customer has a strict rule to follow that the curtailed demand needs to be below or equal to Firm Service Level (FSL) $FSL(t)$, which is decided by a DR provider and usually must be no more than 85% of each customer's highest monthly maximum demand during the summer on-peak and winter partial-peak periods over the past 12 months. Instead, customers receive an incentive R_{inc} for curtailing demand per kW or kWh. Most of the DR programs of this category use a baseline specific to the facility, denoted as $D_B(t)$, in order to measure reductions relative to the baseline. An example of calculating the baseline uses the demand data of previous 10 weekdays excluding weekends, holidays, and days to reduce load.

2) Scheduled Load Reduction Program (SLRP): The Scheduled Load Reduction Program (SLRP) pays the customers to reduce electric load during pre-selected time periods that they have specified in advance. They can select the time period, the weekdays, and the load reduction. To receive the incentive, reducing load by this committed load reduction during the selected time period on the selected weekdays is required. Thereby, the monthly rewords by SLRP type of DR is

$$REW_{DR} = \begin{cases} 0 & \text{if violated} \\ \sum_{T_i^{dr}\in \mathbf{T}_{dr}} \sum_{t\in T_i^{dr}} R_{inc}\delta_{slrp}(t)\Delta t & \text{otherwise} \end{cases} \tag{5}$$

where

$$\delta_{slrp}(t) = \begin{cases} D_B(t) - P_G(t) & \text{if } D_B(t) > P_G(t) \\ 0 & \text{otherwise.} \end{cases} \tag{6}$$

When violated, there usually will not be any incentive payment for any load reductions made during a DR event period. Violation happens if the grid power exceeds the FSL where $P_G(t) > FSL(t)$ at anytime of DR event period.

3) Base Interruptible Program (BIP): The Base Interruptible Program (BIP) is generally intended to provide load reduction on a day-of basis when ISO issues a curtailment notice. Customers enrolled in the program will be required to reduce their load down to or below its FSL. However, the customers need to pay for penalty if they fail to reduce their load to or below the FSL. Let C_{pen} be a penalty per kW for not following DR instructions, and then monthly rewards from DR in this case is

$$REW_{DR} = \sum_{T_i^{dr}\in \mathbf{T}_{dr}} \sum_{t\in T_i^{dr}} \{R_{inc}\delta_{inc}(t) - C_{pen}\delta_{pen}(t)\}, \tag{7}$$

where

$$\delta_{inc}(t) = \begin{cases} D_B(t) - P_G(t) & \text{if } P_G(t) \le FSL(t) \\ 0 & \text{otherwise} \end{cases} \tag{8}$$

$$\delta_{pen}(t) = \begin{cases} P_G(t) - FSL(t) & \text{if } P_G(t) > FSL(t) \\ 0 & \text{otherwise.} \end{cases} \tag{9}$$

4) Peak Time Rebate (PTR): There are several DR programs that do not have any violation rule or penalty, which are typically categorized into Peak Time Rebate (PTR) DR programs. Thus, the monthly rebate amount is as follows:

$$REW_{DR} = \sum_{T_i^{dr}\in \mathbf{T}_{dr}} \sum_{t\in T_i^{dr}} R_{inc}\delta_{ptr}(t)\Delta t, \tag{10}$$

where

$$\delta_{ptr}(t) = \begin{cases} D_B(t) - P_G(t) & \text{if } P_G(t) < D_B(t) \\ 0 & \text{otherwise.} \end{cases} \quad (11)$$

C. Problem Formulation

Given the battery capacity S_{max}, minimum level of storage S_{min}, battery maximum power output $\overline{P}_B$, initial amount of energy $S(0)$, round-trip efficiency η, demand metering interval Δt (hour), monthly time frame T, off-time peak period T_1, partial peak period T_2, peak period T_1, Demand Charge Thresholds (DCT_1, DCT_2, and DCT_3), Firm Service Level $FSL(t)$ at time t, demand $D(t)$ at t, PV generation $P_{PV}(t)$ at t, and PV Capacity $\overline{P}_B$, the problem of demand charge and response management is formulated as follows:

$$\max_{P_B, \Delta D} \quad SAV_{DC} + REW_{DR}, \quad (12)$$

$$\text{s.t} \quad N(t) = D(t) - P_{PV}(t), \ t \in T, \quad (13)$$

$$P_G(t) + P_B(t) + \Delta D(t) = N(t), \ t \in T, \quad (14)$$

$$DCT(t) = \begin{cases} DCT_1 & \text{if } t \in T_1 \\ DCT_2 & \text{if } t \in T_2 \\ DCT_2 & \text{if } t \in T_3, \end{cases} \quad (15)$$

$$\overline{D}(t) = \begin{cases} DCT(t) & \text{if } \ FSL(t) > DCT(t) \\ FSL(t) & \text{otherwise,} \end{cases} \quad (16)$$

$$P_G(t) \leq \overline{D}(t), \quad t \in T, \quad (17)$$

$$0 \leq P_{PV}(t) \leq \overline{P}_{PV}(t), \quad t \in T, \quad (18)$$

$$|P_B(t)| \leq \overline{P}_B, \quad t \in T, \quad (19)$$

$$S(t) = S(t-1) - \eta P_B(t)\Delta t, \quad t \in T - \{0\}, \quad (20)$$

$$S_{min} \leq S(t) \leq S_{max}, \quad t \in T. \quad (21)$$

Although the rewards by conducting DR differ depending on the types of DR programs, the benefit can be maximized by solving the problem defined through (12) - (21). At time t, DCT and FSL are checked to see which is smaller to decide Demand Reduction Threshold (DRT) $\overline{D}(t)$ according to (16) that needs to be followed when curtailing the demand to satisfy (17). If there is no FSL to follow as in Peak Pricing and PTR DR programs, we assume that $FSL(t) = +\infty$. DCTs could still be updated with DCT violation, whereas FSL usually is not negotiable. Therefore, we need to decide whether we should keep the DCT as it is even if DR is not achieved. Otherwise, we should either update DCT or curtail the demand $\Delta D(t)$ to satisfy (14) by reducing electricity usage to make DR feasible considering the amount of DR rewards and DC savings carefully.

IV. Energy Storage Solution for Demand Charge and Response

First, DCTs are calculated in a monthly-layer demand charge management mechanism as in [5], [4], [6], which NEC Labs have been working on with optimal DCT calculation methods to minimize the DC costs for C&I customers.

Let T_{dr} be a DR event period where $T_{dr} \in \mathbf{T}_{dr}$. Algorithm 1 is a battery control strategy at time $t \in T_{dr}$ during a DR period. If T_1, T_2, or $T_3 \not\supseteq T_{dr}$, DC and DR management is independent of each other so that there is no conflict in solving the problems for DC reduction and DR individually. However, it is highly possible that DC reduction and DR happen at the same time as both of them target curtailing peak demands. In addition, many DC tariff structures have anytime DC rate by which we have to take care of DC reduction at any time of operation.

DC reduction saving is usually much higher than Time of Use (TOU), which is true even for a peak pricing DR event. In addition, there would also be discounts on DC in peak pricing DR programs. Hence even with a peak pricing event, the better solution would be to keep the DCTs and reduce the energy usage as much as possible with the remaining energy in the battery, or charge the battery when the net demand is negative with excess generation of PV. Therefore, the algorithm is to decide on battery power profile of charges and discharges based on the DCTs according to Algorithm 1. As mentioned, $FSL(t) = +\infty$ in peak pricing DR events.

Load Reduction DR cases are considered to be extended problems of peak pricing type of DR. This type requires a customer to respond to DR Load Reduction Dispatch to curtail the expected peak demands to stabilize the grid. The incentive is only paid to customers if they completely conduct the required amount of load reduction at any time of the DR event period unless DR is a PTR type or peak pricing type. Therefore, demand reduction DR capability constantly needs to be checked by comparing the amount of stored energy at the previous time step and the amount of energy required to fulfill both DR and DC reduction, which is defined as Demand Reduction Capacity (DRC) $Cap_{dr}(t)$ during a DR period defined as

$$Cap_{dr}(t) = \sum_{t \in T_{dr} - \{0,\ldots,t-1\}} \delta_{cap}(t)\Delta t, \quad (22)$$

where

$$\delta_{cap}(t) = \begin{cases} N(t) - \overline{D}(t) & \text{if } \ N(t) > \overline{D}(t), \\ 0 & \text{otherwise.} \end{cases} \quad (23)$$

Based on the DRC $Cap_{dr}(t)$, we calculate the battery power $P_B(t)$ at each time during DR period $t \in T_{dr}$. Algorithm 1 describes the procedure that calculates battery profile using DRC to complete both DC reduction and the DR event.

$\gamma = [0, 1]$ in Algorithm 1 is used when controlling the amount of discharge from a battery when there is uncertainties in prediction of demands and PVs so that the storage does not run out of energy during important peak curtailment periods.

Note that once the value of $P_B(t)$ is decided as $P_B^*(t)$, the actual value is always bounded by the maximum power of the battery according to (19) and/or its capacity and remaining energy. Let S_{rem} and S_{vac} be the remaining energy and the vacancy in a battery, respectively, defined as

$$S_{rem} := S(t-1) - S_{min}, \quad (24)$$

$$S_{vac} := S_{max} - S(t-1). \quad (25)$$

When the battery is discharging where $P_B^*(t) \geq 0$,

$$P_B(t) = \begin{cases} P_B^*(t) & \text{if } P_B^*(t)\Delta t < S_{rem}, \\ \frac{S_{rem}}{\Delta t} & \text{if } P_B^*(t)\Delta t \geq S_{rem}. \end{cases} \tag{26}$$

If the energy storage is charging where $P_B^*(t) < 0$,

$$P_B(t) = \begin{cases} P_B^*(t) & \text{if } \eta |P_B^*(t)|\Delta t < S_{vac}, \\ -\frac{S_{vac}}{\Delta t} & \text{if } \eta |P_B^*(t)|\Delta t \geq S_{vac}. \end{cases} \tag{27}$$

In case $P_B(t) \neq P_B^*(t)$ in (26) and $N(t) > \overline{D}(t)$, $DCT(t)$ is updated and/or the customer violates the DR rule unless $\Delta D(t)$ has been curtailed by direct load control such as changing setpoints of their facility's devices. Therefore, if $N(t) - P_B(t) \leq \overline{D}(t)$ is not satisfied, a customer needs to curtail $\Delta D(t) = N(t) - P_B(t) - \overline{D}(t)$, otherwise there would be no incentive for any other curtailments or be penalized over violation unless the DR type is peak pricing or PTR.

Algorithm 1 Battery control strategy with Demand Reduction Threshold (DRT) and Demand Reduction Capacity (DRC) during a DR event period

Decide $\overline{D}(t)$ at time t based on the following:
if $FSL(t) > DCT(t)$ **then**
  $\overline{D}(t) \leftarrow DCT(t)$.
else
  $\overline{D}(t) \leftarrow FSL(t)$.
end if
Let $\delta_{cap}(t)$ be $\delta_{cap}(t) = \begin{cases} N(t) - \overline{D}(t) & \text{if } N(t) > \overline{D}(t), \\ 0 & \text{otherwise.} \end{cases}$
Calculate $Cap_{dr}(t) = \sum_{t \in T_{dr} - \{0,\ldots,t-1\}} \delta_{cap}(t)\Delta t$.
if $N(t) > \overline{D}(t)$ **then**
  if $Cap_{dr}(t) > S(t-1)$ **then**
    $P_B^*(t) = N(t) - \overline{D}(t)$.
  else
    if $S(t-1) - Cap_{dr}(t) > (N(t) - \overline{D}(t))\Delta t$ **then**
      $P_B^*(t) = (S(t-1) - Cap_{dr}(t))/\Delta t$.
      $\Delta D(t) = N(t) - P_B^*(t) - \overline{D}(t)$.
    else
      $P_B^*(t) = N(t) - \overline{D}(t)$.
    end if
  end if
else if $0 \leq N(t) \leq \overline{D}(t)$ **then**
  if $Cap_{dr}(t) > S(t-1)$ **then**
    if $Cap_{dr}(t) - S(t-1) > (\overline{D}(t) - N(t))\Delta t$ **then**
      $P_B^*(t) = N(t) - \overline{D}(t)$.
    else
      $P_B^*(t) = (S(t-1) - Cap_{dr}(t))/\Delta t$.
    end if
  else
    if $S(t-1) - Cap_{dr}(t) > N(t)\Delta t$ **then**
      $P_B^*(t) = \gamma N(t)$.
    else
      $P_B^*(t) = \gamma(S(t-1) - Cap_{dr}(t))/\Delta t$.
    end if
  end if
else
  $P_B^*(t) = N(t)$.
end if

V. Simulation Studies and Analysis

The simulation is conducted to testify our proposed approach shown in Algorithm 1 for a certain day with a DR event.

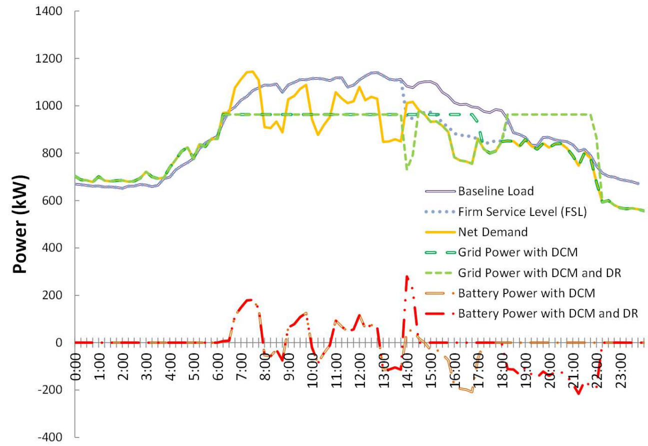

Fig. 1. Baseline load and firm service level (FSL) as well as net demand, grid power, and battery profile with only Demand Charge Management (DCM) and both DCM and DR of an event day June 22 in 2012 with a DR period from 14:00 to 18:00.

A. Demand Charge with Peak Pricing DR

We have used a battery with its capacity $S_{max} = 580$ kWh and max power $\overline{P}_B = 280$ kW. The round-trip efficiency is 85% ($\eta = 0.85$). We assume the prediction is perfect at any time t so that minimum energy level is $S_{min} = 0$ and battery discharge control factor is $\gamma = 1$. The load is from a certain site in Vermont. PV is also a real profile with 500 kW generation capacity. DCTs given by the monthly layer DC management mechanims are 963.5 kW for peak time and 1043.37 kW for other time frames.

Figure 1 shows the difference between only Demand Charge Management (DCM) and both DCM and DR at the same time. In demand charge reduction, the battery profile is just calculated based on the DCTs. Therefore, the battery charges up to 100% just after discharging power for satisfying the DCTs. On the other hand, the strategy with both DCM and DR does not charge the battery but discharge it during the event period, and starts charging up just after the event.

Tariff structure of DC rates used in this case is that Any (Off-Peak) Time DC Rate is \$5.15 from 0:00 to 6:00 and 23:00 to 24:00, Partial Peak Time DC Rate is \$0.0, and Peak Time DC Rate is \$17.32 from 6:00 to 23:00 for an entire year. Thus, the total saving of the DC reduction in this month is \$3,817.83 with peak demand reduction of 101.32 kW, which is 8.9% less from the net load peak.

The DR event period is on June 22 in 2012 from 14:00 to 18:00. Peak pricing credits are \$0.18576 and \$0.03515 for peak-time period and other time period, respectively. A surcharge during the DR period is added to the bill with \$0.60 per kWh of energy usage. The reward of the DR event in this case is \$786.2.

B. Demand Charge with Load Reduction DR

Additional case studies are discussed for DC management with Load Reduction DR types using Figure 1. The settings of demand charge and response are the same as the previous ones including the battery size and properties, load and PV profiles, DC tariff structure and DCTs, and DR event period.

1) Scheduled Load Reduction Program (SLRP): The committed load reduction in this case is 10 percent of the maximum demand of the month, which is 129.87 kW here. Load reductions are measured relative to the baseline load shown in Figure 1 that is specific to the load site. This baseline is the average load during the selected time periods on the previous 10 normal weekdays. A finding in this case study is that if the Firm Service Level (FSL) in Figure 1 is compared with the net load and grid power with DCM, a first violation against FSL happened around 14:00, and thus there is no reward from DR. However, the grid power with DCM and DR shows that there is no violation against FSL during DR event period so that the customers are eligible for the DR reward. If the DR program pays $0.20/kWh for the actual energy reductions, $161.31 will be saved in addition to the DC reduction of the month.

2) Base Interruptible Program (BIP): In BIP, even if there are violations during the DR period, customers just have to pay the penalty for the deviation from the FSL. Therefore, both DCM only and DCM with DR could obtain some benefits unless the penalty is bigger. Both monthly incentive for potential load reduction and penalty for violations here are set to be $2 per kW. As this event is called as an emergency by ISO usually, the saving is large as seen in $1613.15 for hourly power reduction with both DCM and DR control. Only DCM still saves $168.3, but it pays $268.6 as penalty out of $436.9 of rewards. Therefore, the penalty could also be large if they violate the FSL often during the DR period.

3) Peak Time Rebate (PTR): PTR does not depend on FSL so that customers can get rewords as long as the load or grid power is lower than the baseline to which the load reductions are measured as well. If the incentive is $R_{inc} =$ \$0.60 per kWh, \$271.36 and \$483.94 can be rewarded by DCM only and both DCM and DR, respectively.

VI. Conclusions and Future Work

We have provided a framework to maximize the benefits of various types of Demand Response (DR) programs with Demand Charge (DC) reduction using a BTM energy storage installed at a C&I customer's premise. The main feature of our demand charge and response management with an energy storage proposed in this paper is to consider the demand charge thresholds (DCTs) for DC management, firm service levels required by load reduction types of DR, and electricity prices and rebates all at the same time by which the benefits from both DC reduction and DR participation are maximized when optimizing energy storage utilization in real time.

In particular, our battery control strategy with demand reduction capacity (DRC) ensures effective use of energy storage for peak-pricing types of DR given the DCTs and FSLs to further gain incentives by curtailing more demands during DR event periods. It also ensures that the battery avoids charging up to the capacity when the electricity price is high unless the DRC is less than the stored energy in the battery to be used for upcoming DC reduction or DR events. In addition, the battery control framework for load reduction DR enables to respond ancillary service programs with DC minimization by which C&I customers can avoid losing the whole incentive for the DR event period, violating DCTs, and getting penalized by violating the rule of the program. If there is not enough storage space in the battery during load reduction DR period, customers could get instructed to further curtail the demand by adjusting their facility devices' setpoint.

Although we have seen that energy storages save a significant portion of electricity bills of our various customers, an energy storage is still capital-intensive and the promised net savings depend on pricing regimes, demand profiles, and battery costs. The problem that has not been addressed here is on how we select the best battery capacity and its output power with a variety of demand profiles and pricing structures. As the saving from DC reduction and the reward by DR are influenced by the sizes, loads, and tariff profiles, it is critical to explore the suitable battery specifications considering payback periods as well. Also, the initial battery energy assumed to be given in this paper, which needs to be addressed with PV integration. Management of a number of batteries for C&I customers also needs to be explored, potentially using emerging Blockchain technologies, for Distributed Storage Solution (DSS) vendors to be able to maximize their benefit.

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