Les Cahiers du GERAD ISSN: 0711–2440

Market integration of behind-the-meter residential energy storage

V. Provost,
M. F. Anjos

G–2020–32

June 2020

Citation suggérée : V. Provost, M. F. Anjos (Juin 2020). Market integration of behind-the-meter residential energy storage, Rapport technique, Les Cahiers du GERAD G–2020–32, GERAD, HEC Montréal, Canada.

Suggested citation: V. Provost, M. F. Anjos (June 2020). Market integration of behind-the-meter residential energy storage, Technical report, Les Cahiers du GERAD G–2020–32, GERAD, HEC Montréal, Canada.

Avant de citer ce rapport technique, veuillez visiter notre site Web (https://www.gerad.ca/fr/papers/G-2020-32) afin de mettre à jour vos données de référence, s'il a été publié dans une revue scientifique.

Before citing this technical report, please visit our website (https://www.gerad.ca/en/papers/G-2020-32) to update your reference data, if it has been published in a scientific journal.

La publication de ces rapports de recherche est rendue possible grâce au soutien de HEC Montréal, Polytechnique Montréal, Université McGill, Université du Québec à Montréal, ainsi que du Fonds de recherche du Québec – Nature et technologies.

The publication of these research reports is made possible thanks to the support of HEC Montréal, Polytechnique Montréal, McGill University, Université du Québec à Montréal, as well as the Fonds de recherche du Québec – Nature et technologies.

Dépôt légal – Bibliothèque et Archives nationales du Québec, 2020
– Bibliothèque et Archives Canada, 2020

Legal deposit – Bibliothèque et Archives nationales du Québec, 2020
– Library and Archives Canada, 2020

GERAD HEC Montréal
3000, chemin de la Côte-Sainte-Catherine
Montréal (Québec) Canada H3T 2A7

Tél. : 514 340-6053
Téléc. : 514 340-5665
info@gerad.ca
www.gerad.ca

Market integration of behind-the-meter residential energy storage

Valérie Provost [a,b]
Miguel F. Anjos [a,c]

[a] *GERAD, Montréal (Québec), Canada, H3T 2A7*

[b] *Department of Mathematics and Industrial Engineering, Polytechnique Montréal (Québec) Canada, H3C 3A7*

[c] *School of Mathematics, University of Edinburgh, Edinburgh, United Kingdom, EH9 3FD*

valerie.provost@polymtl.ca
miguel.f.anjos@ed.ac.uk

June 2020
Les Cahiers du GERAD
G–2020–32

Abstract: A new business opportunity is emerging with the combination of three key market trends: (1) Increased penetration of residential solar PV; (2) Rapid reduction of battery costs; and (3) Emergence of prosumers. This article proposes an innovative business model to harness the potential of aggregating behind-the-meter residential storage. In its simplest form, the aggregator compensates residential storage system owners for using their battery on an on-demand basis. An optimization model was developed to evaluate the potential of this proposed business model and determine the ideal compensation scheme for the participants. This study confirms there is a business case for utilities to implement such a business model. The main driver for the definition of the appropriate incentive is the compensation for usage which is based on a percentage of the resell price of the electricity used for arbitrage. Based on the Rhode Island data, participants could save on average \$100 per year on their energy bills. Reciprocally, the utility (acting as an aggregator) could make profits of approximately \$100 per participant. Given the growing number of customers with storage systems, these earnings could represent an important source of revenue for the utility. Our results also confirm the year-round profitability of the model, that could bring regular income for the utility. Moreover, additional profits could come from providing ancillary services, although these have not been quantified in this study. The utilities would also benefit from the flexibility provided by these distributed storage units, to address congestion problems and defer upgrades. All this would be possible without capital investment in grid-scale storage.

Keywords: Electricity market, residential energy storage, distributed behind-the-meter storage, aggregator, business model, prosumer, flexibility, optimization

1 Introduction

In recent years, the installed energy storage capacity (excluding pumped hydro) has grown by 50% annually [10]. Between 2013 and 2018, 12 GW of distributed solar PV has been added to the grid in the United States [12]. With the recent drop in battery costs [11] and the growing number of residential solar system owners [21], more and more customers are considering combining both technologies to lower their electricity bills. In the U.S., the energy storage market grew by 60% between 2017 and 2018, mostly due to a strong increase of deployments in the residential sector [30]. All this has led to a large untapped storage capacity residing within the households.

This paper focuses on the opportunity to integrate aggregated behind-the-meter residential storage in the electricity grid's operations. We consider the potential to offer compensation to storage system's owners in exchange for being allowed to use their capacity. The concept is of an aggregator proposing to eligible households to participate in a program for which they would be financially compensated for their services to the grid through a reduction of their electricity bills for providing services to the grid.

The goal of this study is to first assess if this business model would be financially viable, and, in the affirmative, to identify a compensation scheme that would provide an acceptable trade-off between maximizing the profits for the aggregator, and minimizing the cost of electricity for the participants. A successful business model would be beneficial for both the aggregator and the participants, while also providing highly needed flexibility to the grid. This paper proposes a mechanism to operate this business model, and an optimization model to evaluate the profitability of a combination of compensation schemes in a given jurisdiction.

2 Literature review

Given the recent penetration of residential storage systems in the market, there is a limited number of studies that have specifically looked at the potential for residential storage aggregation and the associated business model and compensation schemes required.

Some studies assessed opportunities for utility-scale battery storage. These tend to look at the benefits for offering a specific service, for example arbitrage. They concluded in general that it was not financially interesting to invest in energy storage in the current context [25, 5, 2]. As a consequence of focusing on a single service, the battery is idle most of the day [5]. Thus, the battery usage is simply not maximized making it difficult to recover the investment. In a few other cases, the stacking of services was also assessed [14]. A common example is the stacking of arbitrage and ancillary services. Although more advantageous than the previous case presented, profitability is still very limited [5].

Considering energy storage at the distribution level, as proposed in this paper, opens the door to a multitude of new opportunities to maximize the value of the investment in battery storage [5]. However, there are still major barriers to entry for investors and customers to fully maximize their return on investment, which in turns limits the benefits of storage on the grid [22, 7]. The main challenge faced by most approaches and business models is the current electricity market structure. Markets in most regions do not accurately compensate flexible resources for the benefits they provide [9].

Given the limitations induced by this economical and regulatory context, most studies conducted on the topic of grid flexibility and energy storage focus solely on the complex challenges of planning, scheduling and dispatch. Only a few studies have investigated the potential of behind-the-meter energy storage and the associated business opportunities. Therefore, a limited number of economic models have assessed its value.

Within the commercial, institutional and industrial (CII) sector, some business models have been developed. These models often involve an aggregator that manages the scheduling of operations and leverages the potential of large storage systems owned or rented by CII customers. Although innovative by the usage of battery energy storage, these models typically leverage pricing schemes of previously existing demand response programs. Hence, they are not impacted by the regulatory context of the energy markets; they are mainly operated at the distribution level with local utilities. Specifically in relation with the topic of this paper, one study has assessed the benefits of an incentive-based model to aggregate CII battery storage and participate in the electricity market which concluded the participants could make on average 12% of extra revenues [20].

For the residential sector, some have analyzed the profitability of solar PV and battery storage with or without market subsidies (e.g. feed-in tariffs) [4, 29, 8]. For example, one German study concluded that the profitability of residential storage increased significantly if households were given access to the wholesale market and became net producers [8].

On the compensation side, a multi-agent model was developed to define remuneration and tariff schemes for a virtual power plant including all potential players [24]. This model, however, did not specifically focus on the potential of aggregating residential storage.

Other work has been done on peer-to-peer trade using residential battery storage [31, 16], without considering further integration in the wholesale market. Studies show this is indeed a promising avenue. However, it ignores the larger potential of a region-wide aggregation.

A group of researchers in Australia have conducted an analysis for a similar business model to the one presented in this paper and assessed the joint benefits for the battery owner and the retailer [6]. Although the study concluded that such a business model in the context of the Australian electricity market was beneficial to both the battery owner and the retailer, it did not assess the optimal apportionment of the benefits between the parties. Nonetheless, as mentioned in [31], very little has been done to develop a business model that leverage the potential of residential distributed generation and storage to provide services to the grid, and the market is now ripe for disruption. The financial case for a residential storage system remains largely unproven in most jurisdictions in North America [1]. Still, a large number of households are procuring them for the peace of mind they provide in case of a power outage. Our main hypothesis for this paper is that households would be open to participate in a program that would allow them to profit from their investment in energy storage by offering services to the grid. This would contribute to lowering their utility bills without inconveniencing them and would be at no additional cost to them.

This paper proposes an innovative approach to increase the storage capacity available on the grid by aggregating end-user energy storage to offer grid services. Given that prosumers, defined as someone who both produces and consumes energy [27], seem willing to participate in providing flexibility [15], we believe there is a business opportunity for aggregators to provide an advantageous service to energy consumers, utilities and Independent System Operators (ISO)/Regional Transmission Organizations (RTO). This study aims at assessing the optimal compensation for the participants to ensure the business model is simultaneously profitable for the aggregator and advantageous for the solar PV and battery storage system owners.

3 Proposed business model

The proposed business model rests on the ability and willingness of residential PV-solar and battery storage system owners to participate in an incentive-based program that would reward them for providing flexibility to the grid. We consider an aggregator enrolling participants who agree to give access to and control of their energy storage systems. This aggregator can be an independent entity or a utility, depending on the regulatory context. It wishes to maximize its profits by offering grid services, including energy arbitrage, ancillary services, congestion relief and transmission/distribution system upgrade deferral. In exchange, participants receive compensation for the access, availability and usage of their storage system. This compensation reduces their overall cost of electricity. Participants can also request that only a portion of their storage capacity be used by the aggregator, thus always keeping a backup for themselves. The stored electricity must also be available for the participant in case of outages to ensure the battery still provides the main service for which it was purchased by the participant: power backup.

The viability of this business model comes from the savings made by the aggregator through having access to energy storage without having to invest and bear the financial risk of purchasing a grid-scale storage system. Based on the cost projections for utility-scale battery storage developed by NREL, we estimate the aggregator can save approximately US$0.24/kW/day [3]. This is equivalent to US$6.51/day/participant assuming participants have on average a storage system with capacity equivalent to two Tesla Powerwalls [26].

4 Initial optimization model

The initial model proposed is based on a bilevel formulation. The question the model aims to answer is: What is the optimal compensation an aggregator should offer to a participant to maximize its profits while still ensuring it sufficiently reduces the energy costs to be attractive for the participants?

Indices

t Index of energy market time periods
i Index of participants

Parameters

Π_t^{DA} Price of day-ahead energy market at time t [\$/MWh]
Π_t^{B} Price paid for electricity stored in the battery at time t (for market participation only) [\$/MWh]
Π_t^{R} Retail price of electricity at time t [\$/MWh]

$D_{i,t}$ Electricity consumption of participant i at time t [MWh]
$G_{i,t}$ Electricity generated by participant i at time t [MWh]

S_i^{max} Maximum storage capacity of participant i [MWh]
S_i^{min} Minimum stored electricity in the battery per participant i request [MWh]
η Round-trip battery efficiency

N Total number of participants
T^{max} Total number of time periods

B_t Savings from not purchasing a utility-scale storage system [\$/MWh]

Variables

$x_{i,t}^{DA}$ Electricity sold on the day-ahead market by participant i at time t [MWh]
$y_{i,t}^{P}$ Electricity bought by participant i at time t specifically for his own needs [MWh]
$y_{i,t}^{DA}$ Electricity bought by participant i at time t specifically to participate in the market [MWh]

$s_{i,t}$ State of charge of the battery of participant i at time t [MWh]
$s_{i,t}^{c}$ Charged capacity by participant i at time t (minus the charged capacity bought specifically to participate on the market) [MWh]
$s_{i,t}^{d}$ Discharged capacity by participant i at time t [MWh]

$\pi_{t,i}^{CA}$ Compensation offered to participant i for the availability of their battery at time t [\$/MWh]
$\pi_{i,t}^{CU}$ Compensation offered to participant i for using their battery at time t [\$/MWh]

Model

Level 1: Maximize the aggregator's profits

$$\underset{x_{i,t}^{DA},y_{i,t}^{DA},\pi^{CA},\pi^{CU},s_{i,t},s_{i,t}^{c}}{\text{maximize}} \quad \sum_{t\in T}\sum_{i\in I} B_t * S_i^{max} \tag{1}$$

$$+\sum_{t\in T}\sum_{i\in I}(\Pi_t^{DA} * x_{i,t}^{DA} - \Pi_t^{B} * y_{i,t}^{DA}) \tag{2}$$

$$- \sum_{t \in T} \sum_{i \in I} (\pi^{CA} * (s_{i,t} - S_i^{min} - s_{i,t}^c)) \quad (3)$$

$$- \sum_{t \in T} \sum_{i \in I} (\pi^{CU} * \Pi_t^{DA} * x_{i,t}^{DA}) \quad (4)$$

subject to

$$x_{i,t}^{DA} * y_{i,t}^{DA} = 0 \quad \forall i, t \quad (5)$$

$$\sum_{t \in T} x_{i,t}^{DA} = \sum_{t \in T} y_{i,t}^{DA} \quad \forall i \quad (6)$$

$$x_{i,t}^{DA}, y_{i,t}^{DA}, \pi^{CA}, \pi^{CU}, s_{i,t}, s_{i,t}^c \geq 0 \quad \forall i, t \quad (7)$$

$$(x_{i,t}^{DA}, y_{i,t}^{DA}, s_{i,t}, s_{i,t}^c) \in \arg\min f(\tilde{x}_{i,t}^{DA}, \tilde{y}_{i,t}^{DA}, y_{i,t}^P, \tilde{s}_{i,t}, \tilde{s}_{i,t}^c, s_{i,t}^d) \quad (8)$$

Level 2: Minimize the cost of electricity for the participants

$$f(\tilde{x}_{i,t}^{DA}, \tilde{y}_{i,t}^{DA}, y_{i,t}^P, \tilde{s}_{i,t}, \tilde{s}_{i,t}^c, s_{i,t}^d) = \quad (9)$$

$$\underset{\tilde{x}_{i,t}^{DA}, \tilde{y}_{i,t}^{DA}, y_{i,t}^P, \tilde{s}_{i,t}, \tilde{s}_{i,t}^c, s_{i,t}^d}{\text{minimize}} \quad \sum_{t \in T} \sum_{i \in I} \Pi_{i,t}^P * y_{i,t}^P \quad (10)$$

$$- \sum_{t \in T} \sum_{i \in I} (\pi^{CA} * (\tilde{s}_i - S_i^{min} - \tilde{s}_{i,t}^c)) \quad (11)$$

$$- \sum_{t \in T} \sum_{i \in I} (\pi^{CU} * \Pi_t^{DA} * \tilde{x}_{i,t}^{DA}) \quad (12)$$

subject to

$$y_{i,t}^P + G_{i,t} + s_{i,t}^d - \tilde{s}_{i,t}^c = D_{i,t} + \tilde{x}_{i,t}^{DA} \quad \forall i, t \quad (13)$$

$$\sum_{t \in T} y_{i,t}^P = \sum_{t \in T} (D_{i,t} - G_{i,t}) \quad \forall i \quad (14)$$

$$\tilde{s}_{i,t+1} = \tilde{s}_{i,t} + \eta * (\tilde{s}_{i,t}^c + \tilde{y}_{i,t}^{DA} - s_{i,t}^d) \quad \forall i, t > 0 \quad (15)$$

$$\tilde{s}_{i,t} = S_i^{min} \quad \forall i, t = 0 \quad (16)$$

$$S_i^{min} \leq \tilde{s}_{i,t} \leq S_i^{max} \quad \forall i, t \quad (17)$$

$$\tilde{x}_{i,t}^{DA}, \tilde{y}_{i,t}^{DA}, y_{i,t}^P, \tilde{s}_{i,t}, \tilde{s}_{i,t}^c, s_{i,t}^d \geq 0 \quad \forall i, t \quad (18)$$

The first level of the problem maximizes the profits for the aggregator and the second level minimizes the cost of electricity for the participant.

For the first level, the profits are calculated by estimating the economies made by not purchasing a utility-scale storage system (1), maximizing the profits made on the day ahead market by doing arbitrage (2), and minimizing the compensation paid to the participant for the availability (3) and the usage (4) of their residential storage system. Constraint (5) prevents the aggregator from selling and buying electricity during the same time period. Constraint (6) ensures that all electricity used for arbitrage by the aggregator has been purchased for this purpose, and that the participant's electricity for own consumption was not used.

For the second level, the objective function minimizes the cost of the electricity bought on the retail market (10) and maximizes the savings made by participating in the program (11 and 12). Constraint (13) ensures supply and demand are balanced, while constraint (14) ensures the electricity purchased at the retail rate is only used for the participant's own demand. Constraint (15) calculates the state of charge of the storage system of each participant based on the round-trip efficiency of the battery. The added capacity by the participants ($s_{i,t}^c$) and the added capacity for arbitrage purposes ($y_{i,t}^{DA}$) are represented by different variables to allow the possibility of purchasing the electricity at different rates (Π_t^B) depending on the regulatory context. Constraint (17) ensures the stored capacity respects the battery specifications and the participant's requirement of maintaining a minimum amount of energy in the battery at any given time period. Constraint (16) sets the initial state of charge of the battery.

Finally, for both levels, the variables cannot be negative (7 and 18).

This type of optimization problem is in general NP-Hard to solve because it is bilevel and non-linear. A few methods were tested to solve this initial model, however the preliminary results were unsatisfactory. Because the focus of this work is not to develop a methodology for solving these complex optimization problems, but to obtain results on the application to the proposed business model and to develop an accessible methodology to quickly and easily assess the business opportunity in different jurisdictions, we developed a simplified version of the problem as presented in the next section.

5 Simplified optimization model

In order to have a model that could be solved within reasonable time, we simplified the previous model. The main advantage of this simplified model is that it can be solved using standard solvers for mixed-integer linear optimization.

The following modifications were made to obtain the simplified model:

1. Linearizing the model:
   (a) The two variables for the price of compensation for batteries' availability and usage were replaced by two parameters. Thus, the variables for the energy sold ($x_{i,t}^{DA}$), bought ($y_{i,t}^{DA}$) and stored ($s_{i,t},\ s_{i,t}^{c}$) are not multiplied by another variable, but by the new parameters that represent the value of the compensation.
   (b) The constraint (5) was replaced by three constraints using the big-M method with M set to the maximum aggregated storage capacity. Two new binary variables ($z_{i,t}^{x}$ and $z_{i,t}^{y}$) are used to capture if electricity is sold or bought.
2. Removing the second level of optimization: The simplified model uses parameters to define the compensation for the availability of the battery (C^A) and the compensation for using it (C^U). To minimize the cost of energy for the participant, we manually vary the values of C^A and C^U. The optimal compensation for the participant is thus calculated outside of the optimization model.

For this simplified model, all indices remain the same. Two additional parameters and three new variables are added, and the variables $\pi_{t,i}^{CA}$ and $\pi_{t,i}^{CU}$ are removed.

Indices

t Index of energy market time periods
i Index of participants

Parameters

C^A Compensation offered for availability of the battery [$/MWh]
C^U Compensation offered for using the battery as a percentage of the selling price [%]

Π_t^{DA} Price of day-ahead energy market at time t [$/MWh]
Π_t^{B} Price paid for electricity stored in the battery at time t (for market participation only) [$/MWh]
Π_t^{R} Retail price of electricity at time t [$/MWh]
Π^{R} Retail price of electricity (constant in time) [$/MWh]

$D_{i,t}$ Electricity consumption of participant i at time t [MWh]
$G_{i,t}$ Electricity generated by participant i at time t [MWh]

S_i^{max} Maximum storage capacity of participant i [MWh]
S_i^{min} Minimum stored electricity in the battery per participant i request [MWh]
η Round-trip battery efficiency
M Maximum aggregated storage capacity [MWh]

N	Total number of participants
T^{max}	Total number of time periods
B_t	Savings from not purchasing a utility-scale storage system [$/MWh]

Variables

$x_{i,t}^{DA}$	Electricity sold on the day-ahead market by participant i at time t [MWh]
$y_{i,t}^{P}$	Electricity bought by participant i at time t specifically for his own needs [MWh]
$y_{i,t}^{DA}$	Electricity bought by participant i at time t specifically to participate in the market [MWh]
$s_{i,t}$	State of charge of the battery of participant i at time t [MWh]
$s_{i,t}^{c}$	Charged capacity by participant i at time t (minus the charged capacity bought specifically to participate on the market) [MWh]
$s_{i,t}^{d}$	Discharged capacity by participant i at time t [MWh]
$c_{i,t}^{A}$	Compensation offered to participant i for battery availability at time t [$]
$c_{i,t}^{U}$	Compensation offered to participant i for battery usage at time t [$]
$c_{i,t}$	Total compensation offered to participant i for contributions at time t [$]
$z_{i,t}^{x}$	$\begin{cases} 1 & \text{if electricity is sold on the day-ahead market by participant } i \text{ at time } t \\ 0 & \text{otherwise} \end{cases}$
$z_{i,t}^{y}$	$\begin{cases} 1 & \text{if electricity is bought on the day-ahead market by participant } i \text{ at time } t \\ 0 & \text{otherwise} \end{cases}$

Model

$$\text{maximize} \quad \sum_{t \in T} \sum_{i \in I} (B_t * S_i^{max} + \Pi_t^{DA} * x_{i,t}^{DA} - \Pi_t^{B} * y_{i,t}^{DA} - c_{i,t}) \tag{19}$$

$$\text{subject to} \quad y_{i,t}^{P} + G_{i,t} + s_{i,t}^{d} - s_{i,t}^{c} = D_{i,t} + x_{i,t}^{DA} \quad \forall i, t \tag{20}$$

$$\sum_{t \in T} y_{i,t}^{P} = \sum_{t \in T} (D_{i,t} - G_{i,t}) \quad \forall i \tag{21}$$

$$y_{i,t}^{P} \leq D_{i,t} \quad \forall i, t \tag{22}$$

$$\sum_{t \in T} y_{i,t}^{P} * \Pi^{R} = \sum_{t \in T} (D_{i,t} - G_{i,t}) * \Pi^{R} \quad \forall i \tag{23}$$

$$s_{i,t+1} = s_{i,t} + \eta * (s_{i,t}^{c} + y_{i,t}^{DA} - s_{i,t}^{d}) \quad \forall i, t > 0 \tag{24}$$

$$s_{i,t} = S_i^{min} \quad \forall i, t = 0 \tag{25}$$

$$S_i^{min} \leq s_{i,t} \leq S_i^{max} \quad \forall i, t \tag{26}$$

$$z_{i,t}^{x} + z_{i,t}^{y} \leq 1 \quad \forall i, t \tag{27}$$

$$x_{i,t}^{DA} \leq M * z_{i,t}^{x} \quad \forall i, t \tag{28}$$

$$y_{i,t}^{DA} \leq M * z_{i,t}^{y} \quad \forall i, t \tag{29}$$

$$\sum_{t \in T} x_{i,t}^{DA} = \sum_{t \in T} y_{i,t}^{DA} \quad \forall i \tag{30}$$

$$x_{i,t}^{DA} \leq s_{i,t}^{d} \quad \forall i, t \tag{31}$$

$$c_{i,t}^{A} = C^{A} * (s_i - S_i^{min} - s_{i,t}^{c}) \quad \forall i, t \tag{32}$$

$$c_{i,t}^{U} = C^{U} * \Pi_t^{DA} * x_{i,t}^{DA} \quad \forall i, t \tag{33}$$

$$c_{i,t} = c_{i,t}^{A} + c_{i,t}^{U} \quad \forall i, t \tag{34}$$

$$x_{i,t}^{DA}, y_{i,t}^{P}, y_{i,t}^{DA}, s_{i,t}, s_{i,t}^{c}, s_{i,t}^{d}, c_{i,t}^{A}, c_{i,t}^{U}, c_{i,t} \geq 0 \quad \forall i, t \tag{35}$$

$$z_{i,t}^{x}, z_{i,t}^{y} \in \{0, 1\} \tag{36}$$

This simplified model solely maximizes the profits of the aggregator using an objective function similar to that used in the initial model. The main difference is that the two compensation equations have been replaced by a single variable $c_{i,t}$. Three constraints were added in relation to this variable that define the compensation for the availability of the battery (32) and the compensation for the use of the battery (33). The last constraint (34) is simply the sum of the two amounts to obtain the total compensation offered to the participant.

To replace the second level and ensure the proposed business model does not increase the cost of electricity for the participant, constraints (22) and (23) are added. These constraints ensure that the solar energy produced by the participants is used by them to keep their electricity costs as low as possible. If the PV production of the participant is used to participate in the market, constraint (23) ensures this is financially advantageous for the participant. In the previous model, these constraints were implicit in the objective function of the lower level that minimizes the cost for the participants. However, after removing this objective, they now need to be specifically enforced in the new model.

Similarly, constraint (31) is added to ensure the electricity purchased on the retail market is not used to participate in the day-ahead market.

Finally, constraint (5) is linearized using the big-M method and replaced by constraints (27), (28) and (29). The new binary variables $z^x_{i,t}$ and $z^y_{i,t}$ are used to denote if electricity is being sold on or purchased from the day-ahead market at a given time. Constraint (27) ensures electricity cannot be sold or bought at the same time, and constraints (28) and (29) ensure the amounts sold and bought are in accordance with the value of the corresponding binary variables. The value of the Big M parameter used is equal to the maximum aggregated storage capacity ($\sum_{i\in I} S_i^{max}$), thus the largest value $x^{DA}_{i,t}$ and $y^{DA}_{i,t}$ could possibly take.

The other aspects of the initial model remained unchanged in the simplified model.

6 Results & analysis

6.1 Data

This analysis looks at the deterministic scenario where the aggregator would have perfectly forecasted the day-ahead market price.

For this experiment, we used a combination of two typical participants ($N = 2$). Participant 1 lives in a fully electrified dwelling and Participant 2 lives in a dwelling using natural gas for heating and domestic hot water. The hourly demand is estimated based on a single-family dwelling in Rhode Island. The demand estimates are based on residential prototype building models developed by the Pacific Northwest National Laboratory (PNNL) [28] using climate data sets for the city of Providence, RI developed by NREL [19]. The solar generation (G) is assumed to be on average 15 kWh/day (i.e. the solar generation covers 25% of the demand for a fully electrified home) distributed evenly between 8 am and 4 pm. To reduce the computing time, we solved the optimization problem for one winter day and one summer day. These days are assumed to be representative of their respective half of the year. The prices of energy used are the prices on 8 February 2019 and 22 July 2019 for the Rhode Island load zone operated by the New England ISO [13]. National Grid, a large utility in the northeast of the U.S., has 500,000 electricity customers in Rhode Island [17] and 3.5M in the country [18]. The residential retail price of electricity of National Grid in Rhode Island was 10.99 cents/kWh in the winter and 9.24 cents/kWh in the summer [23]. Both participants own a storage unit with maximum capacity (S_i^{max}) of 27 kWh which is equivalent to owning two Tesla Powerwall batteries. Each has a round-trip efficiency (η) of 90% [26].

The model was solved using the CPLEX solver in Julia with the JuMP module.

6.2 Scenarios

6.2.1 Scenario 0: Battery is charged at the retail price

For the reference scenario, we tested the profitability of a business model where the battery was charged at the distributor's retail price ($\Pi_t^B = \Pi_t^R$). Given the model primarily optimizes the profits from arbitrage, our hypothesis was that this scenario could not be profitable. This hypothesis was confirmed by the results obtained. Even with no compensation offered to the participant ($CA = 0$ and $CU = 0$), the optimal solution was to abstain from participating in the market.

6.2.2 Scenario 1 & 2: Battery is charged at the day-ahead market price

For the other two scenarios, we tested the profitability of a business model where the battery was charged directly at the rate of the day-ahead market price ($\Pi_t^B = \Pi_t^D A$). In the current regulatory environment, this would mean the aggregator is the utility. The utility could purchase on the day-ahead market a high quantity of electricity which would be used to recharge the participants' battery solely for offering grid services. Although there would be a risk of doing so, we believe the unquantified benefits from congestion relief and investment deferral could make the model attractive for the utility.

The model was built specifically to use two different rates for the purchase of electricity. The retail rate (Π^R) is applied to the electricity purchased for the sole purpose of meeting the participant's own personal demand. A different rate is used specifically for the electricity bought for energy arbitrage purposes (Π_t^B). This distinction is important because nowadays all electricity distribution costs are blended together in a retail rate. There is no distinction between the fixed cost to be connected to the grid and the variable cost per kWh used. Therefore, if the model were to assume the participant would pay the day-ahead market price for all the electricity purchased (i.e. for personal use and for grid services), they would never pay for the distribution services they use. This would not be a viable situation for the distributors who still need to pay for these operational costs. Obviously, this pricing scheme could change in the future if a more holistic market integration of prosumers becomes a reality. In that case, the optimization model could quickly be adapted to use a different approach, for example using the day-ahead market price for all energy purchases and paying a separate fee for distribution services. We set up our proposed model to capture the likeliest scenario in the current context.

In this context, we evaluated two scenarios:

- Scenario 1: Profitability of the business model during a typical winter day
- Scenario 2: Profitability of the business model during a typical summer day

The objective is to determine if the profitability of the business model is constant throughout the year by comparing the winter results with the summer results. Given the variation in the demand throughout the seasons, our hypothesis is that the winter period will be significantly more profitable than the summer period because of the stress caused on the network by heating needs. We also consider two types of customer in each scenario to evaluate the impact of the consumption profile of a household with gas heating versus electric heating.

For each scenario, we ran three experiments:

- Experiment A: Optimal solution without compensation for the participant
- Experiment B: Estimating the optimal compensation for the participant
- Experiment C: Optimal solution with compensation for the participant

The results for scenarios 1 and 2 are presented and compared for each experiment. A summary of the results comparing both scenarios concludes this section.

6.3 Experiment A: Optimal solution without compensation for the participant

We first set the compensation parameters to zero ($C^A = 0$ and $C^U = 0$) to assess the maximal benefits for the aggregator per type of customer and per day.

6.3.1 Scenario 1A: Winter results

Unlike in the reference scenario, daily profits from price arbitrage could be achieved. Based on the results obtained, an average of \$0.63 per winter day can be achieved for electricity-only customers, and of \$0.59 for natural gas and electricity customers.

6.3.2 Scenario 2A: Summer results

In the summer, the profits are higher than in the winter. They are respectively \$0.65 and \$0.63 for the electricity-only customer (participant 1) and the electricity and natural gas customer (participant 2).

6.4 Experiment B: Estimating the optimal compensation for the participant

Having confirmed this approach was lucrative with Experiment A, we ran a series of sub-scenarios to estimate the optimal compensation to offer the participants. The values tested ranged from \$0 to \$0.10 by increments of \$0.01/kW for the compensation for availability (C^A), and from 1% to 50% of the resell price for the compensation for usage (C^U) by increments of 1%. The value for C^A was capped at \$0.10/kW to align with the electricity retail price. A higher compensation would have been disproportionate in this context. All compensation combinations were solved to optimality.

For the compensation for access, a fixed monthly or daily amount could be offered to the participant based on the capacity offered. This additional compensation would directly be drawn from the fixed benefits of \$6.51/day/participant which are generated by having access to an energy storage system without requiring an initial investment. This would be assessed outside of the optimization model, and thus is not presented in the results below for scenarios 1 and 2.

6.4.1 Scenario 1B: Winter results

The winter results obtained are shown on Figure 1. The value of C^U is presented on the x-axis and the value of C^A is given by each curve. The variation in the profitability of the model was minimally impacted by the variation of the compensation for availability. Most curves for the different C^A values overlap. Where there is a small distinction, the lowest curve represents a compensation of \$0.1/kW and the highest one a compensation of \$0/kW. The main driver for reaching an equilibrium between the aggregator's profits and the participants' savings is clearly the compensation for usage (C^U) modelled as a percentage of the resell price and allocated to the participants from the profits made on the energy market.

In this specific case, the compensation for usage should not exceed 24% of the resale price. As observed, the profits of the aggregator constantly diminish when C^U increases, while the savings per day for a participant are approximately the same as if a higher percentage of the resale price was used. Therefore, a compensation for usage of 24% is the upper bound for the solution range. This compensation would be more advantageous for the participants than the aggregator, while also optimal for the grid since we are selling a higher volume of electricity.

Figure 2 shows the point of equilibrium to have evenly shared profits and savings between the aggregator and the participants for the winter day. The compensation for usage at equilibrium equals 18.5%. Surprisingly, profits and savings are higher when the compensation for availability is at its lowest.

Also, there is no significant difference between the results obtained for each type of customer, thus we conclude the quantity of electricity consumed by the participants does not significantly impact the profitability.

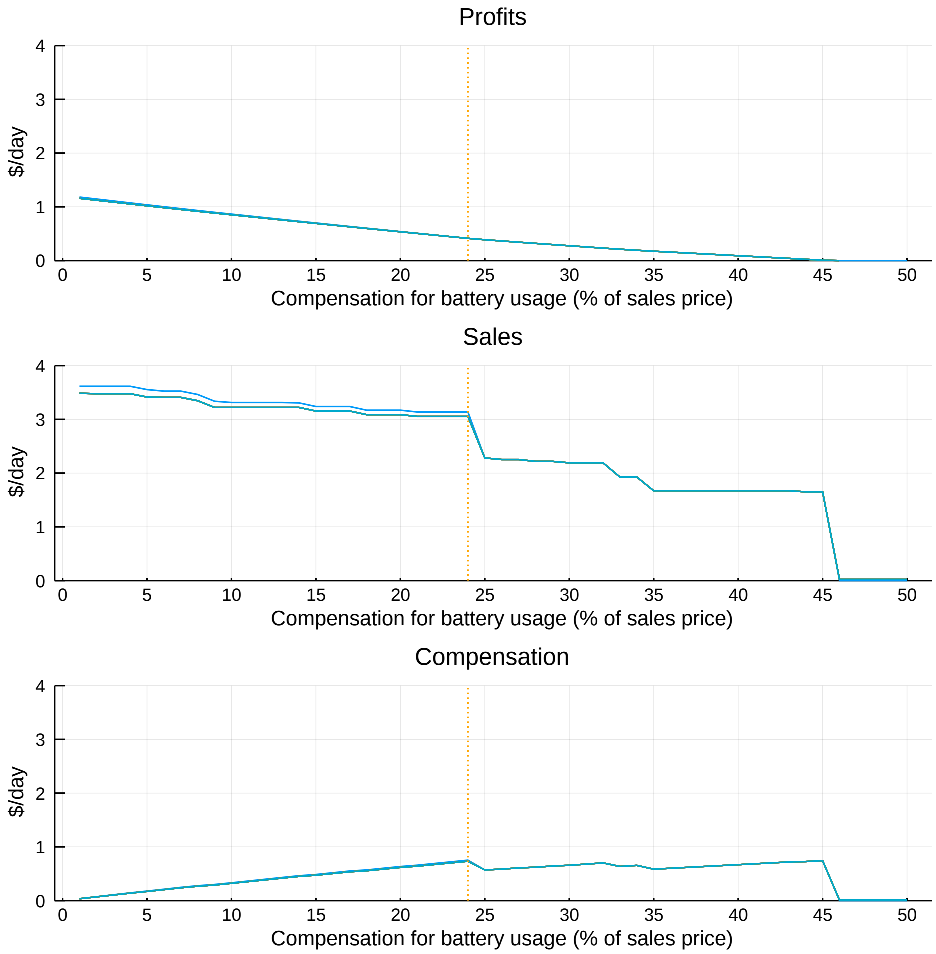

Figure 1: Impact of the compensation scheme on the business model profitability in the winter (Scenario 1B)

6.4.2 Scenario 2B: Summer results

In the summer, the lower and upper bound of the range of optimal profitability for both the aggregator and the participants are respectively $C^U = 3\%$ and $C^U = 45\%$. Figure 3 shows the summer results for the profits, sales and savings; and Figure 4 shows the point of equilibrium to have evenly shared profits and savings between the aggregator and the participants for a typical summer day.

During the summer period, a higher compensation is more advantageous. In this scenario, a compensation for usage of 21.15% procures the higher combination of profits and savings. As observed in the winter scenario, the profits and savings are still higher when the compensation for availability is at its lowest.

6.5 Experiment C: Optimal solution with compensation for the participant

Based on the results obtained in the previous section, we chose to use a compensation for usage of 20% which is more advantageous for the participant in the winter, and less so in the summer, and vice versa for the aggregator. Having a constant compensation scheme throughout the year was preferred to simplify the message to potential participants. The compensation for availability was set to 0 since previous results showed it was preferable for both the aggregator and the participants in all scenarios.

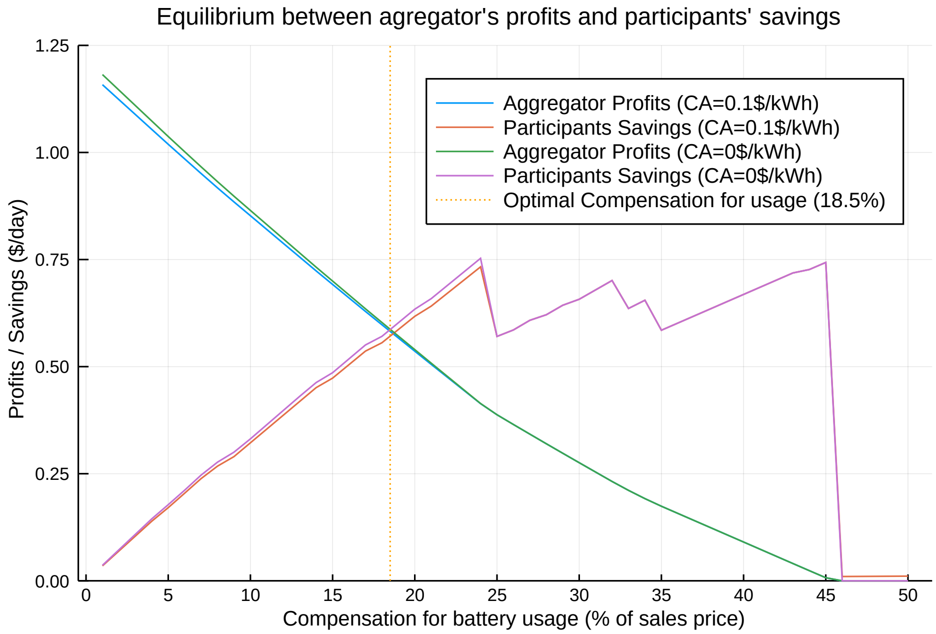

Figure 2: Equilibrium between aggregator's profits and participants' savings (Scenario 1B)

6.5.1 Scenario 1C: Winter results

Figure 5 offers a deeper look into the dynamic between the energy market and the residential storage system. On this figure, we observe differences in the pattern for both electricity-only customers, and natural gas and electricity customers.

On the upper graph, describing the loads for the electricity-only customer, an interesting observation is made during the 3rd and 4th hour of the day: no energy is purchased from the retail market and the stored capacity is not used to meet the demand. Instead, electricity is directly purchased from the day ahead market and used to meet the participants' demand. This interesting behaviour of the model is a result of constraining the model to ensure the participant will not pay more for electricity than he would have outside of the program. However, it does not directly constrain how this is done. In this case, the participant is generating energy at a time of interest for the aggregator. Instead of storing energy in the morning to use later in the day, and compensating the participant for the hourly energy stored in their battery, it is more profitable for the aggregator to directly use that energy to meet the participant's demand, and later store the PV capacity in the battery for a shorter period of time. This is possible because the retail prices are not time-of-use. Similar assessment of jurisdictions with variable retail pricing scheme would result in different load profiles.

A similar pattern is observed for a natural gas and electricity customer, albeit at a smaller scale. In this case, the electricity generated on site is greater than the demand during the day. The additional production is therefore stored in the battery to resell on the day-ahead market, and it is replaced in the early hours of the day by electricity purchased on the day-ahead market. If the model had assessed a multi-day period, this pattern could represent the result of storing additional capacity at night and using it in the early hours of the next day.

In terms of arbitrage, the timing to purchase and sell large energy quantities is the same for both customers. This is simply based on the electricity prices of the day-ahead market. The batteries are always fully charged right before the market prices are high in order to maximize profits.

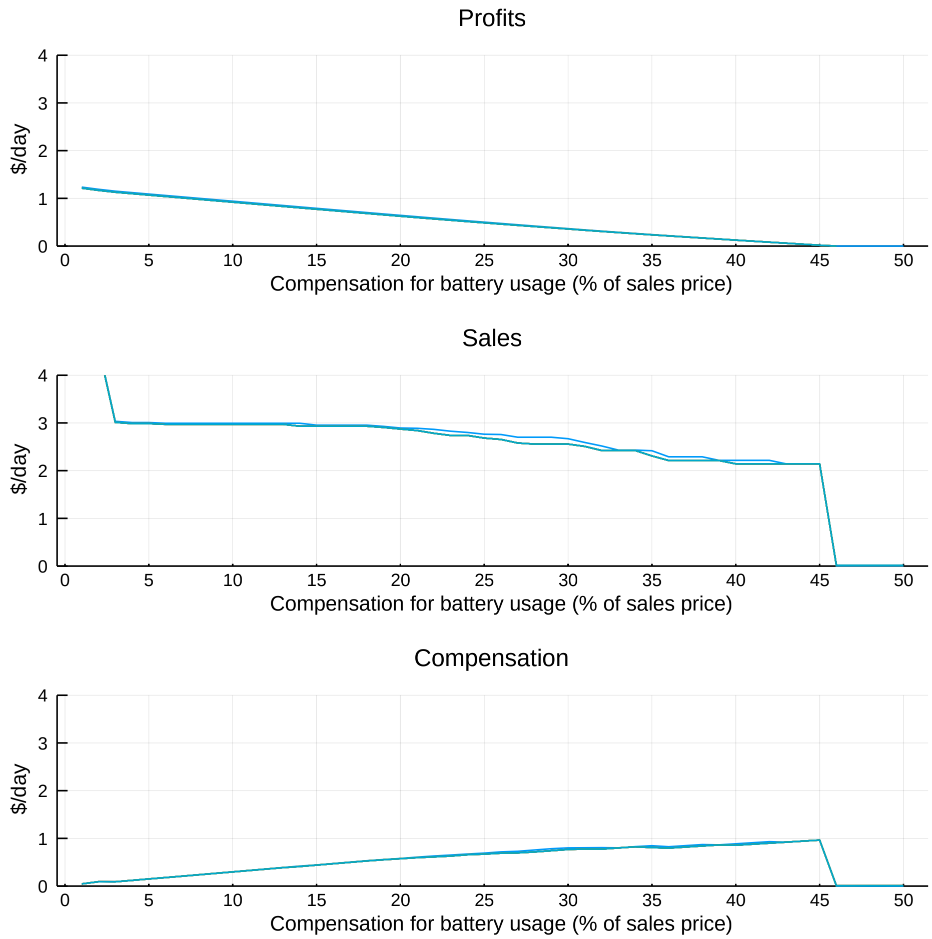

Figure 3: Impact of the compensation scheme on the business model profitability in the summer (Scenario 2B)

6.5.2 Scenario 2C: Summer results

In the summer, significant quantities of electricity are purchased and sold on the day-ahead market only once. This can be observed on Figure 6. This difference in energy trading is due to the fluctuation of prices on the day-ahead market for the two typical days evaluated resulting from the deterministic approach used.

6.6 Summary of results

Based on the optimal compensation scenario presented above, the profitability of the business model for both the aggregator and the participant are detailed in Figure 7.

For the two types of participants, daily savings are identical in the winter day and very similar in the summer day. The small difference in the summer is caused by a difference in sales between 9 a.m. and 11 a.m. In the winter, the timing and volume of the sales are identical for both participants which explains the identical savings.

For the aggregator, the cost to purchase the electricity has a greater impact on the profitability. In the winter, the volume purchased is distributed differently at two moments in time (4 a.m. and 3 p.m.). This explains the small variation in profitability given that the sales were identical. In the summer, the difference observed is due to the same factor as mentioned above for the participants.

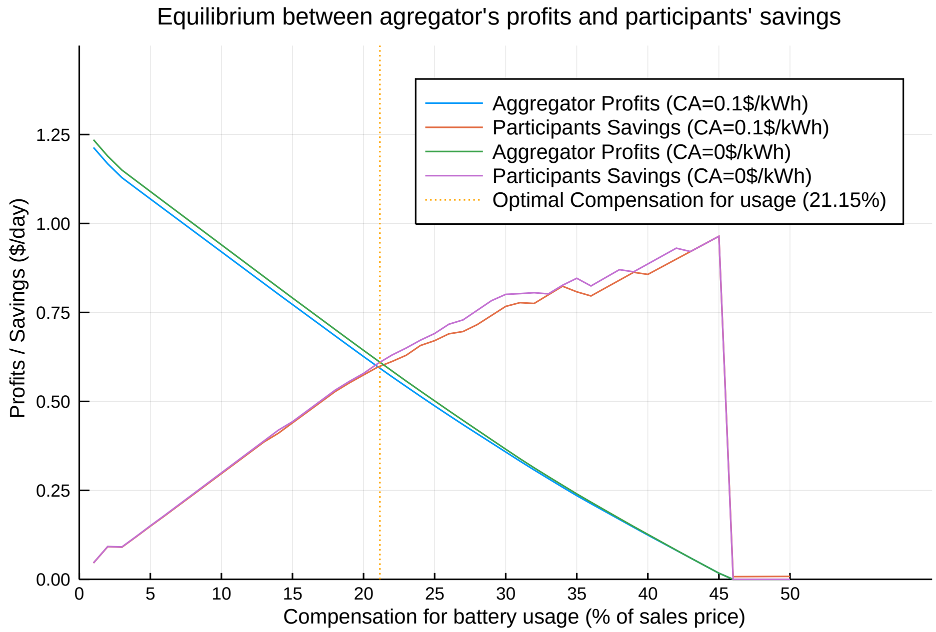

Figure 4: Equilibrium between aggregator's profits and participants' savings (Scenario 2B)

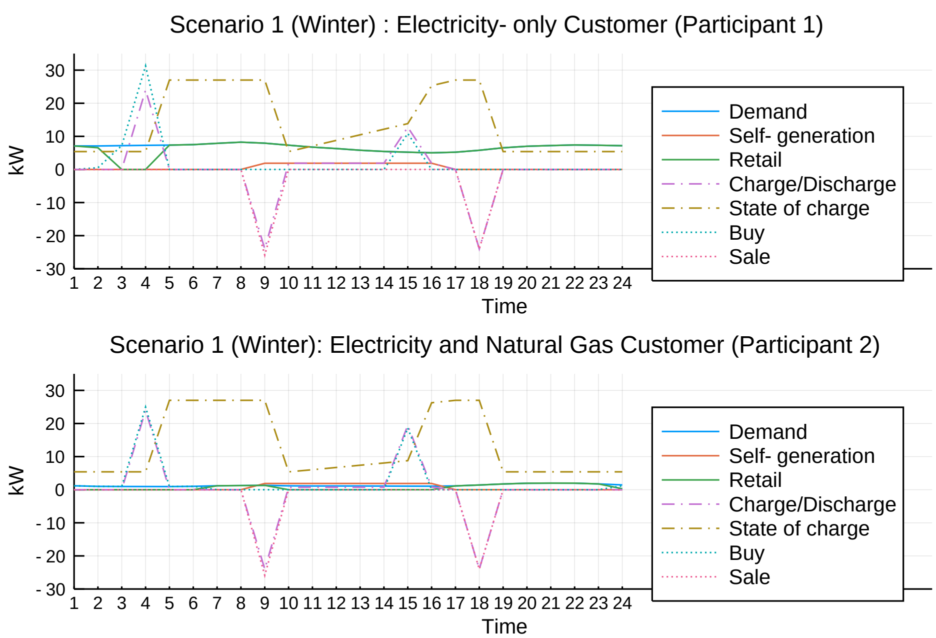

Figure 5: Load profiles in the winter for the optimal compensation (Scenario 1C)

The overall financial benefits are very similar for the aggregator and the group of participants. Figure 8 shows the results for the winter and summer days. Although the profits are higher for the participants in the winter, the total profits for the aggregator when combining the two days is only slightly less than the savings made by the participants.

This confirms that a compensation for usage of 20% in Rhode Island, based on the typical parameters assumed, creates a business opportunity for a potential aggregator, while also reducing participants' electricity bills. Over a year, a participant matching the simulated conditions could save approximately \$110, all the while contributing flexibility of the grid and the utility could generate

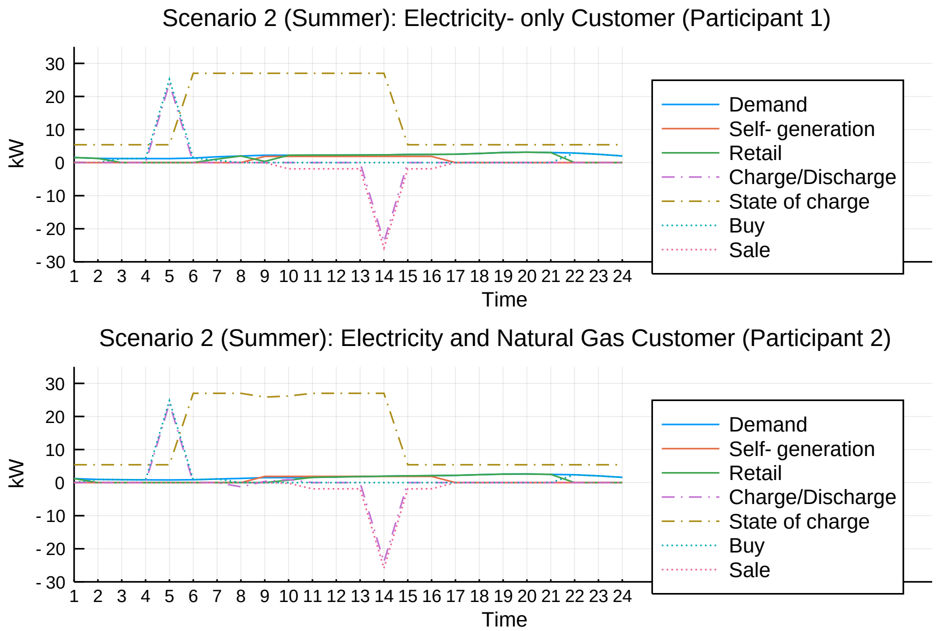

Figure 6: Load profiles in the summer for the optimal compensation (Scenario 2C)

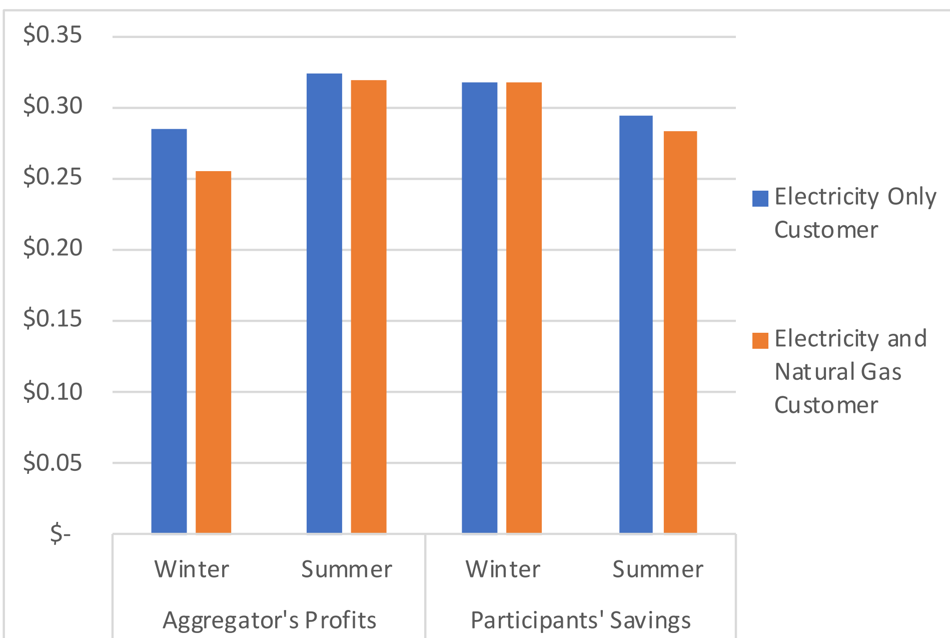

Figure 7: Daily aggregator's profits and participants' savings

similar profits per participant. Even with a low participation rate, the utility's profits could quickly add-up to an interesting amount of money. For example, with only 100 participants this business model could lead to profits of approximately $10,800.

6.7 Key messages

There are three key messages from the results obtained.

1) The compensation for usage is the main driver for the determination of the optimal compensation scheme

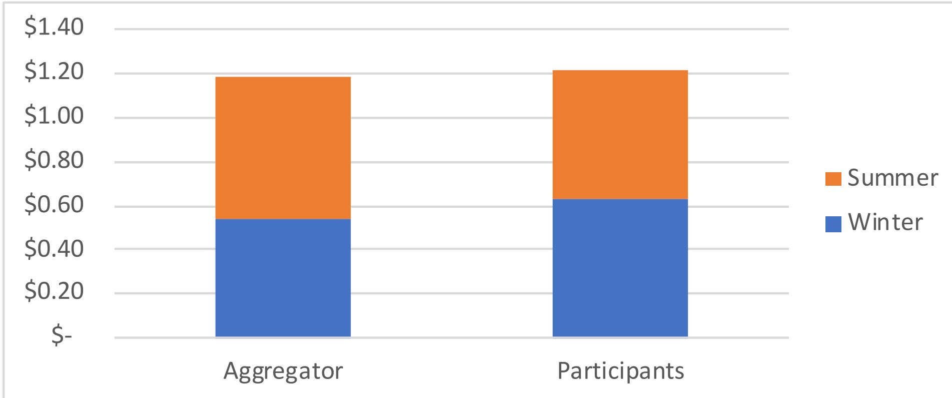

Figure 8: Combined savings/profits for a typical winter and summer day

We considered a combination of three types of compensation: access, availability and usage. The compensation for usage is the determining factor for the profitability of the model. The compensation for availability had a negligible impact on the results, and contributed to reducing the financial benefits for both the aggregator and the participants. Thus it was removed from the final compensation scheme selected.

A compensation for access could also be considered separately as a fixed compensation per participant based on the storage system capacity. Since the aggregator saves in theory $7.35/kWh per month by not investing in a grid-scale storage system, a small portion of this amount could be offered to the participants for agreeing to enter the program and renewing their commitment monthly.

2) The proposed business model is profitable all year around
The results for the typical winter and summer days considered suggest that this business model is profitable throughout the year. Therefore, even if the daily profits and savings are small, this can result in interesting sums of money on a yearly basis. Adding services that have not been considered in this first study would likely reinforce the business case.

3) The participant's electricity consumption does not influence the profitability of the business model
Finally, given that the level of consumption of the customers does not influence the profitability of the model, any customer with a storage system is a potential participant. Assuming the aggregator would be a utility, this represents a large pool of potential participants that is growing over time, further contributing to the attractiveness of this business model.

7 Conclusion

We considered a business model to leverage the existing storage capacity behind-the-meter in the residential sector. An aggregator would compensate participants in exchange for being allowed to use their storage systems to provide services to the grid. The optimization model proposed in this paper provides the ability to identify the optimal compensation to participants while maximizing profitability for the aggregator. In addition, it allows aggregators to quickly evaluate different scenarios specific to their jurisdictional context.

Our results confirm that the proposed business model has good economic potential. Aggregating residential behind-the-meter storage provides value to both the utilities (acting as aggregators) and their participating customers, given the right regulatory context. Based on Rhode Island historical data, participants would save approximately $100 per year on their electricity bill. This is non-negligible, and it allows the storage-system owners to maximize the value of their investment in the technology. For utilities, the business case is even better. By looking only at the financial benefits of energy arbitrage, the utility can generate profits of approximately $100/participant annually. Given that all households with a storage system are potential participants, even if the profit per participant is low, at the scale of a utility, this represents a great business opportunity. Additionally, many utilities can have a competitive advantage in the current regulatory context and should consider taking advantage of it to establish their position in the market early on.

There are other unquantified benefits for the utilities in addition to the profits generated by energy arbitrage. First, additional participation in the energy market by offering ancillary services would increase the profitability of the business model. These services typically require small volumes of electricity at specific moments in time and for short periods. Batteries are perfectly adapted to those needs and could easily provide this important flexibility at a low cost. Secondly, although hard to estimate, there are important benefits to be made on the operations side through congestion relief and upgrade deferral for both transmission and distribution systems. All this is possible with no large upfront investments in grid-scale storage. Furthermore, those aggregated resources provide additional flexibility to the grid that will increase in importance as the penetration rate of renewable energy generation increases.

Further improvements could be made to the model by adding ancillary services profits in the objective function and incorporating the notion of time-of-use and other retail pricing schemes adapted to the different jurisdictions. Finally, a variant of the model could consider always fully recharging the battery when prices are low to increase the probability of the participant having a fully charged battery when needed.

References

[1] Edward Barbour and Marta C. González. Projecting battery adoption in the prosumer era. Applied Energy, 215:356–370, April 2018.

[2] Adrien Barbry, Miguel F. Anjos, Erick Delage, and Kristen R. Schell. Robust self-scheduling of a price-maker energy storage facility in the New York electricity market. Energy Economics, 78:629–646, February 2019.

[3] Wesley Cole and A. Will Frazier. Cost Projections for Utility-Scale Battery Storage. Technical Report NREL/TP–6A20–73222, National Renewable Energy Laboratory, 2019.

[4] Federica Cucchiella, Idiano D'Adamo, and Massimo Gastaldi. Photovoltaic energy systems with battery storage for residential areas: an economic analysis. Journal of Cleaner Production journal, 131:460–474, September 2016.

[5] Garrett Fitzgerald, James Mandel, Jesse Morris, and Hervé Touati. The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid. Technical report, Rocky Mountain Institute, 2015.

[6] Evan Franklin, Daniel Lowe, and Matthew Stocks. Assessment of Market Participation Opportunities for Behind-the-meter PV/Battery Systems in the Australian Electricity Market. Energy Procedia, 110:420–427, March 2017.

[7] Justin Gundlach and Romany Webb. Distributed Energy Resource Participation in Wholesale Markets : Lessons from the California ISO. Energy Law Journal, 39(1):47–77, May 2018.

[8] Joern Hoppmann, Jonas Volland, Tobias S Schmidt, and Volker H Hoffmann. The economic viability of battery storage for residential solar photovoltaic systems–A review and a simulation model. Renewable and Sustainable Energy, 39:1101–1118, November 2014.

[9] Eric Hsieh and Robert Anderson. Grid flexibility: The quiet revolution. The Electricity Journal, 30(2):1–8, March 2017.

[10] IEA. Tracking Clean Energy Progress 2017. Technical report, International Energy Agency, 2017.

[11] IEA. Global EV Outlook 2019. Technical report, International Energy Agency, 2019.

[12] IEA. Renewables 2019. Technical report, International Energy Agency, 2019.

[13] ISO New England. Pricing Reports, 2020.

[14] Mostafa Kazemi, Hamidreza Zareipour, Nima Amjady, William D Rosehart, and Mehdi Ehsan. Operation scheduling of battery storage systems in joint energy and ancillary services markets. IEEE Transactions on Sustainable Energy, 8(4):1726–1735, May 2017.

[15] Merla Kubli, Moritz Loock, and Rolf Wüstenhagen. The flexible prosumer: Measuring the willingness to co-create distributed flexibility. Energy Policy, 114:540–548, March 2018.

[16] Alexandra Lüth, Jan Martin Zepter, Pedro Crespo del Granado, and Ruud Egging. Local electricity market designs for peer-to-peer trading: The role of battery flexibility. Applied energy, 229:1233–1243, November 2018.

[17] National Grid. Rhode Island: Narragansett Electric and Gas, 2018.

[18] National Grid. National Grid Investors, 2020.

[19] National Renewable Energy Laboratory. National Solar Radiation Data Base, 2015.

[20] M. Parandehgheibi, S. A. Pourmousavi, K. Nakayama, and R. K. Sharma. A two-layer incentive-based controller for aggregating BTM storage devices based on transactive energy framework. In 2017 IEEE Power Energy Society General Meeting, pages 1–5, Chicago, IL, USA, July 2017.

[21] Austin Perea, Colin Smith, Michelle Davis, Xiaojing Sun, Bryan White, Molly Cox, Gregson Curtin, Shawn Rumery, Aaron Holm, Rachel Goldstein, and Justin Baca. Solar Market Insight Report 2019 Q4. Technical report, SEIA, 2019.

[22] Ignacio Pérez-Arriaga and Christopher Knittel. Utility of the Future. An MIT Energy Initiative response to an industry in transition. Technical report, MIT, 2016.

[23] Rhode Island Public Utility Commission. National Grid Standard Offer, 2019.

[24] Catarina Ribeiro, Tiago Pinto, Hugo Morais, Zita Vale, and Gabriel Santos. Intelligent remuneration and tariffs for virtual power players. In 2013 IEEE Grenoble Conference, pages 1–6, Grenoble, France, 16-20 June 2013.

[25] Ramteen Sioshansi, Paul Denholm, Thomas Jenkin, and Jurgen Weiss. Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects. Energy Economics, 31(2):269–277, March 2009.

[26] Tesla. Powerwall Technical Specs, 2020.

[27] U.S. Department of Energy. Consumer vs Prosumer: What's the Difference?, 2017.

[28] U.S. Department of Energy. Residential Prototype Building Models, 2019.

[29] Johannes Weniger, Joseph Bergner, Tjarko Tjaden, and Volker Quaschning. Economics of residential PV battery systems in the self-consumption age. In 29th European Photovoltaic Solar Energy Conference and Exhibition, pages 2936–2938, 2014.

[30] Wood Mackenzie Power & Renewables, U.S. Energy Storage Association. U.S. Energy Storage Monitor : Q2 2018, Executive Summary. Technical report, Wood Mackenzie, 2018.

[31] Jan Martin Zepter, Alexandra Lüth, Pedro Crespo del Granado, and Ruud Egging. Prosumer integration in wholesale electricity markets: Synergies of peer-to-peer trade and residential storage. Energy and Buildings, 184:163–176, February 2019.