**POLYTECHNIQUE MONTRÉAL**
affiliée à l'Université de Montréal

# Intégration au marché du stockage énergétique résidentiel après le compteur

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Mémoire présenté en vue de l'obtention du diplôme de *Maîtrise ès sciences appliquées*
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Ce mémoire intitulé :

**Intégration au marché du stockage énergétique résidentiel après le compteur**

présenté par **Valérie PROVOST**
en vue de l'obtention du diplôme de *Maîtrise ès sciences appliquées*
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# DÉDICACE

*À mes proches, collègues et enseignants,*
*merci pour votre soutien*

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## RÉSUMÉ

Une nouvelle opportunité d'affaires fait présentement son apparition grâce à trois tendances clés sur le marché : (1) la croissance accélérée du nombre d'installation de panneaux solaires dans le marché résidentiel ; (2) la baisse rapide du coût des batteries ; et (3) l'émergence des prosommateurs. Ce mémoire propose un modèle d'affaires innovant pour exploiter le potentiel d'agrégation du stockage d'énergie résidentiel derrière le compteur. À haut niveau, l'agrégateur offre une compensation financière aux propriétaires de systèmes de stockage résidentiels afin d'utiliser leurs batteries pour fournir des services au réseau d'électricité. Un modèle d'optimisation a été élaboré pour évaluer le potentiel de ce modèle d'affaires et déterminer les modalités de compensation optimales pour les participants. Cette étude confirme qu'un tel modèle d'affaires pourrait s'avérer lucratif pour les distributeurs d'électricité agissant à titre d'agrégateur. Le principal facteur influençant le choix des modalités de compensation pour les participants est l'incitatif offert pour l'utilisation de la batterie en fonction des besoins de l'agrégateur. Cet incitatif est quantifié selon un pourcentage du prix de revente de l'électricité utilisée pour l'arbitrage. Selon les données pour le Rhode Island, les participants pourraient économiser en moyenne 100 $ par an sur leurs factures d'électricité. Réciproquement, les distributeurs d'énergie pourraient réaliser des profits d'environ 100 $ par participant. Étant donné le nombre croissant de clients possédant des systèmes de stockage, ces gains pourraient représenter dans le futur une source de revenus importante pour l'entreprise. Nos résultats confirment également la rentabilité du modèle tout au long de l'année, permettant ainsi de rapporter des revenus constants dans le temps. De plus, ces profits pourraient être accrus par l'offre de services additionnels, tels que pour des services auxiliaires, qui ne sont pas actuellement comptabilisés dans l'étude réalisée. Des bénéfices supplémentaires pourraient également provenir de la flexibilité offerte par la distribution de la capacité de stockage sur le réseau, notamment par la réduction de la congestion et le report d'investissements dans les actifs de transport et distribution d'électricité. Le tout serait possible sans investissements en capitaux dans des solutions de stockage d'énergie à l'échelle du réseau.

## 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 thesis 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.

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| | |
|---|---|
| CII | Commercial, Institutional and Industrial |
| GES | Gaz à effet de serre |
| ISO | Independent System Operator |
| PV | Photovoltaic |
| RTO | Regional Transmission Organization |

# CHAPITRE 1 INTRODUCTION

Ces dernières années, la capacité de stockage d'énergie installée (en excluant l'hydroélectricité) a augmenté de 50 % par an [1]. Entre 2013 et 2018, 12 GW d'énergie solaire photovoltaïque distribuée ont été ajoutés au réseau aux États-Unis [2]. Avec la récente baisse du coût des batteries [3] et le nombre croissant de propriétaires de systèmes solaires résidentiels [4], de plus en plus de clients envisagent de combiner les deux technologies pour réduire leur facture d'électricité. Aux États-Unis, le marché du stockage de l'énergie a augmenté de 60 % entre 2017 et 2018, principalement en raison d'une forte augmentation des déploiements dans le secteur résidentiel [5]. Tout cela a conduit à une importante capacité de stockage inexploitée au sein des ménages.

Ce mémoire étudie l'opportunité d'agréger la capacité de stockage disponible dans le secteur résidentiel afin d'offrir des services au réseau d'électricité. Nous examinons la possibilité d'offrir une compensation aux propriétaires des systèmes de stockage en échange de leur autorisation d'utiliser leur capacité en fonction des besoins. Par conséquent, un agrégateur pourrait proposer aux ménages éligibles de participer à un programme qui leur permettrait de réduire leur facture d'électricité en échange de services fournis sur le réseau.

L'objectif de cette étude est d'abord d'évaluer si ce modèle d'affaires serait financièrement viable et, dans l'affirmative, d'identifier un mécanisme de compensation qui offrirait un équilibre entre la maximisation des profits de l'agrégateur et la minimisation des coûts d'électricité des participants. Ce dernier serait bénéfique à la fois pour l'agrégateur et pour les participants, tout en apportant au réseau une flexibilité tant recherchée. Ce document propose une structure pour encadrer ce modèle d'affaires et un modèle d'optimisation pour évaluer la rentabilité d'une combinaison de modalité de compensation dans une juridiction donnée.

# CHAPITRE 2 REVUE DE LITTÉRATURE

## 2.1 Contexte

Depuis la fin du 19e siècle, suite à la guerre des courants entre Thomas Edison et Nikola Tesla [6], les réseaux de transport et de distribution d'électricité ont pris énormément d'ampleur en Amérique du Nord. Jusqu'à tout récemment, les réseaux d'électricité étaient construits dans l'optique de déplacer l'électricité des centrales de génération vers les consommateurs. Puisqu'historiquement seules les centrales pouvaient produire de l'électricité et ces dernières nécessitaient des investissements capitaux de plusieurs millions, ou même milliards, il était logique de croire que le courant se déplacerait toujours dans une seule direction. Ainsi des investissements majeurs ont été faits durant le 20e siècle pour développer des réseaux interconnectés à travers le continent. Ces actifs arrivent maintenant à la fin de leur durée de vie utile et devront être remplacés au cours des prochaines années [6]. Toutefois, la question se pose maintenant à savoir si le réseau devrait continuer à être unidirectionnel.

En parallèle, la demande en électricité n'a cessé d'augmenter dans les dernières années. Le Canada et les États-Unis sont parmi les plus grands consommateurs d'électricité [7] et les prévisions indiquent que la consommation continuera à augmenter [8]. De plus, la communauté internationale est de plus en plus sensibilisée à l'urgence des enjeux climatiques mondiaux, incluant les émissions de gaz à effet de serre (GES).

Une des principales sources d'émissions de GES est la production d'électricité à l'aide de combustibles fossiles. Ainsi, pour adresser le réchauffement climatique, les centrales et génératrices fonctionnant à base de combustibles fossiles devront rapidement être remplacées au cours de prochaines années. Les dernières avancées dans le domaine des énergies renouvelables offrent une multitude d'options et les coûts de ces solutions ne cessent de baisser. En 2018, les coûts de l'énergie solaire concentrée, de la bioénergie, de l'énergie photovoltaïque, de l'énergie éolienne terrestre et de l'hydroélectricité ont diminué respectivement de 26 %, 14 %, 13 %, 13 % et 12 % [9]. La production d'électricité à base d'énergie renouvelable triplera entre 2018 et 2040 selon les projections de l'Agence internationale de l'énergie dans un scénario de développement durable [8]. Ainsi, une augmentation significative de la production d'énergie renouvelable est à prévoir à moyen terme.

Une autre source importante d'émissions de GES est la combustion de pétrole pour le transport. Avec l'apparition dans les dernières années des véhicules électriques et les projections agressives de baisse de coût, ces véhicules occuperont une place de plus en plus importante, d'abord pour le transport des passagers, mais aussi pour le transport des marchandises. De plus, la réglementation des émissions des véhicules deviendra de plus en plus présente, encourageant l'acquisition de véhicule électrique. Il est donc à prévoir que le rechargement de ces véhicules aura un impact croissant sur le réseau électrique.

### 2.2 Enjeux

Cette augmentation de la demande, combinée au vieillissement de l'infrastructure de génération, transmission et distribution de l'électricité, cause des enjeux importants pour le futur du réseau électrique. Il sera primordial à l'avenir d'avoir des réseaux plus flexibles. Selon l'Agence international de l'énergie, les besoins de flexibilité du réseau américain augmenteront de 156 % entre 2018 et 2040 dans le cadre d'un scénario de développement durable [8].

Cette flexibilité est critique pour permettre l'intégration efficace de la production d'énergie renouvelable sur le réseau. Étant donné que la production d'énergie solaire et éolienne est fortement dépendante de la météo, le réseau doit pouvoir s'ajuster en temps quasi réel pour répondre aux fluctuations de la production, tout en garantissant de pouvoir répondre à la demande des consommateurs à l'instant où celle-ci apparait. Cela peut être complexe à gérer, par exemple lorsque le réseau est saturé et qu'il fait également face à des enjeux de congestion sur les lignes de transmission et distribution. Dans ces cas, la solution actuelle principale est de restreindre la production, soit ne pas faire usage de la capacité produite. Ce problème est particulièrement présent en Allemagne depuis la forte expansion de leur capacité de production d'énergie éolienne. Étant donné que la production est principalement située dans une région isolée et que le réseau n'a pas encore été amélioré pour fournir la capacité de transport requise et réagir rapidement à ces fluctuations de génération et demande, des quantités importantes d'électricité sont perdues. [10].

L'émergence de prosommateurs, soit de consommateurs ayant également une capacité de production locale pour leurs besoins [11], a également complexifié la situation. De plus en plus de clients des distributeurs d'électricité, autant dans le secteur résidentiel que commercial et industriel, décident de réduire leur dépendance envers le réseau, que ce soit pour faire des économies financières ou pour avoir une option alternative dans le cadre d'une panne. Toutes ces nouvelles variables ajoutent un niveau d'incertitude supplémentaire qui rend plus difficile la gestion du réseau.

Finalement, la modernisation requise du réseau afin de permettre une génération distribuée, notamment d'être capable d'avoir des flux d'énergie bidirectionnels, pose des défis technologiques importants. Cette modernisation vient également à un coût élevé. Des investissements majeurs seront requis pour permettre cette intégration des ressources de l'autre côté des compteurs [12]. Cela devra être fait en parallèle d'autres investissements visant à maintenir le réseau dû à l'âge d'une grande partie des équipements actuellement en service. Les distributeurs d'électricité devront être prêts à naviguer à travers le contexte réglementaire de leur juridiction pour obtenir les capitaux requis pour cette transformation du réseau.

## 2.3 Opportunités

### 2.3.1 Solutions actuelles et limitations

Avec les années, plusieurs solutions ont été développées afin de prendre en considération les besoins de flexibilité sur le réseau. Les méthodes les plus répandues comprennent la promotion des solutions d'efficacité énergétique, le développement de technologies informatiques permettant la gestion de réseaux intelligents et la mise en œuvre de stratégies de gestion de la demande.

Plus récemment, les solutions de stockage d'électricité ont gagné en popularité. En effet, les différentes technologies de stockages ont grandement évolué pour offrir des solutions adaptées à divers contextes. Outre l'utilisation de barrages hydroélectriques pour le stockage d'énergie, les batteries semblent une des avenues les plus prometteuses [13], notamment à cause de la forte baisse des prix qui est observée grâce aux investissements qui ont été faits dans le secteur automobile.

Les opérateurs de réseau d'électricité à travers le monde étudient les options pour intégrer une plus grande capacité de stockage d'énergie à leur réseau [14]. En parallèle, les clients du secteur commercial et industriel évaluent les opportunités pour réduire leurs factures d'électricité et leur perte de productivité en cas de panne. Les clients résidentiels, quant à eux, sont de plus en plus intéressés par les opportunités que présente la combinaison d'une batterie avec leur système de panneaux solaires. Ainsi le marché du stockage d'énergie est en pleine expansion et apporte une multitude d'opportunités pour contribuer à améliorer le service sur le réseau d'électricité. Toutefois, il reste à déterminer la meilleure approche pour intégrer cette capacité de stockage dans le marché.

### 2.3.2 Opportunité pour l'intégration au marché du stockage énergétique résidentiel après le compteur

Compte tenu de la récente pénétration des systèmes de stockage résidentiels sur le marché, il existe un nombre limité d'études qui ont spécifiquement examiné le potentiel d'agrégation du stockage résidentiel ainsi que les modèles d'affaires et les modalités de compensation requis qui y sont associés.

Certaines études ont évalué les possibilités de stockage de batteries à l'échelle du réseau. Elles examinent typiquement le potentiel pour un service spécifique, par exemple l'arbitrage. Elles concluent en général qu'il n'était pas financièrement intéressant d'investir dans le stockage d'énergie dans le contexte actuel [15–17]. Puisque le système de stockage se concentre sur l'offre d'un seul service, la batterie est inutilisée la plupart du temps [16]. Ainsi, l'utilisation de la batterie n'est tout simplement pas maximisée, ce qui rend difficile le recouvrement de l'investissement. Dans quelques autres cas, des combinaisons de services ont également été évaluées [18]. Un exemple courant est la combinaison de services d'arbitrage et de services auxiliaires. Bien que plus avantageux que le cas précédent, la rentabilité est encore très limitée [16].

Considérer le stockage de l'énergie au niveau du réseau de distribution, tel que proposé dans ce mémoire, ouvre la porte à une multitude de nouvelles possibilités pour maximiser la valeur de l'investissement dans des batteries [16]. Toutefois, il existe encore des barrières de marché majeures limitant le retour sur investissement, ce qui empêche un déploiement plus important sur le réseau [19, 20]. La réglementation des marchés de l'électricité reste le principal défi auquel sont confrontés la plupart des approches et des modèles d'affaires. Dans la plupart des régions, les marchés ne compensent pas adéquatement les ressources fournissant de la flexibilité par rapport à la valeur des avantages qu'elles procurent [13].

Compte tenu des contraintes induites par ce contexte économique et réglementaire, la plupart des études menées sur le thème de la flexibilité du réseau et du stockage de l'énergie se concentrent uniquement sur les défis complexes de la planification et de la distribution des ressources de stockage. Seules quelques études ont examiné le potentiel du stockage d'énergie derrière le compteur et les opportunités d'affaires qui en découlent. Par conséquent, un nombre limité de modèles économiques ont évalué la valeur de ces modèles d'affaires.

Dans le secteur commercial, institutionnel et industriel (CII), certains modèles économiques ont été développés. Ces modèles impliquent souvent un agrégateur qui gère la planification des opérations et exploite le potentiel des grands systèmes de stockage appartenant ou loués par les clients du secteur CII. Bien qu'ils soient innovants par l'utilisation de batteries, ces modèles s'appuient généralement sur des mécanismes de tarification de programmes de gestion de la demande qui existent depuis longtemps. Par conséquent, ils ne sont pas affectés par le contexte réglementaire des marchés de l'énergie, car les opérations sont réalisées uniquement au niveau de la distribution. Plus proprement liée à notre sujet, une étude a évalué les avantages d'un modèle basé sur des incitatifs pour agréger le stockage des batteries dans le secteur CII et participer au marché de l'électricité. Elle conclut que les participants peuvent réaliser en moyenne 12 % de revenus supplémentaires [21].

Pour le secteur résidentiel, certains ont analysé la rentabilité de systèmes d'énergie solaire photovoltaïque et de stockage avec ou sans subventions (p. ex. : tarifs de rachat) [22–24]. Par exemple, une étude allemande a conclu que la rentabilité du stockage résidentiel augmentait significativement si les ménages avaient accès au marché de gros et devenaient des producteurs nets [24].

En ce qui concerne le volet de compensation, un modèle multi-agents a été élaboré pour définir les systèmes de rémunération et de tarification d'une centrale électrique virtuelle incluant tous les acteurs potentiels [25]. Ce modèle n'a toutefois pas mis l'accent sur le potentiel d'agrégation du stockage résidentiel.

D'autres travaux ont été réalisés sur les échanges entre pairs utilisant le stockage résidentiel [26, 27], sans envisager une intégration plus complète avec le marché de l'électricité. Ces études montrent qu'il s'agit d'une voie prometteuse. Toutefois, elles ignorent le potentiel plus important d'une agrégation à l'échelle régionale.

Un groupe de chercheurs australiens a effectué une analyse pour un modèle d'affaires similaire à celui présenté dans ce mémoire et a évalué les avantages conjoints pour le propriétaire de la batterie et le distributeur d'électricité [28]. Bien que l'étude ait conclu qu'un tel modèle d'affaires dans le contexte du marché australien de l'électricité était bénéfique à la fois pour le propriétaire de la batterie et le distributeur d'électricité, elle n'a pas évalué la répartition optimale des bénéfices entre les parties. Néanmoins, comme mentionné dans [26], très peu a été fait pour développer un modèle d'affaires qui exploite le potentiel de la production et du stockage résidentiel distribué pour fournir des services au réseau, et le marché est maintenant prêt pour une révolution. L'argument financier en faveur d'un système de stockage résidentiel reste largement à démontrer dans la plupart des juridictions d'Amérique du Nord [29]. Pourtant, un grand nombre de ménages les achètent pour la tranquillité d'esprit qu'ils procurent en cas de panne de courant. Notre principale hypothèse pour ce mémoire est que les ménages seraient ouverts à participer à un programme qui leur permettrait de tirer profit de leur investissement dans un système de stockage d'énergie résidentiel en offrant des services au réseau. Cela contribuerait à réduire leur facture d'électricité sous condition de ne pas être impacté et sans coût additionnel.

Ce mémoire propose une approche innovante pour augmenter la capacité de stockage disponible sur le réseau en regroupant le stockage d'énergie des utilisateurs finaux pour offrir des services au réseau. Étant donné que les prosommateurs semblent ouverts à offrir leur aide pour améliorer la flexibilité du réseau, nous pensons qu'il existe une opportunité d'affaires pour les agrégateurs souhaitant fournir un service avantageux aux consommateurs d'énergie, aux distributeurs d'électricité et aux opérateurs de réseau indépendants (ISO). Cette étude vise à évaluer la compensation optimale pour les participants afin de s'assurer que le modèle d'affaires est à la fois rentable pour l'agrégateur et avantageux pour les propriétaires de systèmes de stockage d'énergie.

# CHAPITRE 3 ARTICLE 1 : MARKET INTEGRATION OF BEHIND-THE-METER RESIDENTIAL ENERGY STORAGE

Article soumis à la revue scientifique Energy le 30 mars 2020. Quelques modifications ont été apportées suite aux recommandations faites par le jury.

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## 3.1 Abstract

A new business opportunity beckons with the emergence of prosumers. This article proposes an innovative business model to harness the potential of aggregating behind-the-meter residential storage in which the aggregator compensates residential storage system owners for using it 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. A realistic example shows that participants could save on average $100 per year on their energy bills, and the utility (acting as an aggregator) could make similar profits. 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. The utilities would also benefit from the flexibility provided by these distributed storage units, to address congestion problems and defer upgrades without capital investment in grid-scale storage.

## 3.2 Introduction

In recent years, the installed energy storage capacity (excluding pumped hydro) has grown by 50% annually [1]. Between 2013 and 2018, 12 GW of distributed solar PV has been added to the grid in the United States [2]. With the recent drop in battery costs [3] and the growing number of residential solar system owners [4], 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 [5]. 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.

### 3.3 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 [15–17]. As a consequence of focusing on a single service, the battery is idle most of the day [16]. 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 [18]. A common example is the stacking of arbitrage and ancillary services. Although more advantageous than the previous case presented, profitability is still very limited [16].

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 [16]. 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 [19, 20]. 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 [13].

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 [21].

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) [22–24]. 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 [24].

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 [25]. 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 [26, 27], 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 [28]. 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 [26], 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 [29]. 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 [11], seem willing to participate in providing flexibility [30], 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.

### 3.4 Proposed Business Model

The proposed business model rests on the ability and willingness of residential solar PV 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 [31]. This is equivalent to US$6.51/day/participant assuming participants have on average a storage system with capacity equivalent to two Tesla Powerwalls [32].

### 3.5 Initial Optimization Model

The initial model proposed is based on a bilevel formulation [33,34]. 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**

| | |
|---|---|
| $\Pi_t^{DA}$ | Price of day-ahead energy market at time $t$ [$/MWh] |
| $\Pi_t^{B}$ | Price paid for electricity stored in the battery at time $t$ (for market participation only) [$/MWh] |
| $\Pi_t^{R}$ | 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] |
| $\eta$ | 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] |
| | |
| $\pi_{i,t}^{CA}$ | 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*

$$\underset{x_{i,t}^{DA},y_{i,t}^{DA},\pi_{i,t}^{CA},\pi_{i,t}^{CU},s_{i,t},s_{i,t}^{c}}{\text{maximize}} \quad \sum_{t\in T}\sum_{i\in I} B_t \times S_i^{max} \tag{3.1}$$

$$+\sum_{t\in T}\sum_{i\in I}(\Pi_t^{DA} \times x_{i,t}^{DA} - \Pi_t^{B} \times y_{i,t}^{DA}) \tag{3.2}$$

$$-\sum_{t\in T}\sum_{i\in I}(\pi_{i,t}^{CA} \times (s_{i,t} - S_i^{min} - s_{i,t}^{c})) \tag{3.3}$$

$$-\sum_{t\in T}\sum_{i\in I}(\pi_{i,t}^{CU} \times \Pi_t^{DA} \times x_{i,t}^{DA}) \tag{3.4}$$

subject to

$$x_{i,t}^{DA} \times y_{i,t}^{DA} = 0 \quad \forall i,t \tag{3.5}$$

$$\sum_{t\in T} x_{i,t}^{DA} = \sum_{t\in T} y_{i,t}^{DA} \quad \forall i \tag{3.6}$$

$$x_{i,t}^{DA}, y_{i,t}^{DA}, \pi_{i,t}^{CA}, \pi_{i,t}^{CU}, s_{i,t}, s_{i,t}^{c} \geq 0 \quad \forall i,t \tag{3.7}$$

$$(x_{i,t}^{DA}, y_{i,t}^{DA}, s_{i,t}, s_{i,t}^{c}) \in \arg\min f(\tilde{x}_{i,t}^{DA}, \tilde{y}_{i,t}^{DA}, y_{i,t}^{P}, \tilde{s}_{i,t}, \tilde{s}_{i,t}^{c}, s_{i,t}^{d}) \tag{3.8}$$

*Level 2 : Minimize the cost of electricity for the participants*

$$f(\tilde{x}^{DA}_{i,t}, \tilde{y}^{DA}_{i,t}, y^{P}_{i,t}, \tilde{s}_{i,t}, \tilde{s}^{c}_{i,t}, s^{d}_{i,t}) = \tag{3.9}$$

$$\underset{\tilde{x}^{DA}_{i,t}, \tilde{y}^{DA}_{i,t}, y^{P}_{i,t}, \tilde{s}_{i,t}, \tilde{s}^{c}_{i,t}, s^{d}_{i,t}}{\text{minimize}} \quad \sum_{t\in T}\sum_{i\in I} \Pi^{P}_{i,t} \times y^{P}_{i,t} \tag{3.10}$$

$$- \sum_{t\in T}\sum_{i\in I} (\pi^{CA}_{i,t} \times (\tilde{s}_i - S^{min}_i - \tilde{s}^{c}_{i,t})) \tag{3.11}$$

$$- \sum_{t\in T}\sum_{i\in I} (\pi^{CU}_{i,t} \times \Pi^{DA}_{t} \times \tilde{x}^{DA}_{i,t}) \tag{3.12}$$

$$\text{subject to} \quad y^{P}_{i,t} + G_{i,t} + s^{d}_{i,t} - \tilde{s}^{c}_{i,t} = D_{i,t} + \tilde{x}^{DA}_{i,t} \quad \forall i, t \tag{3.13}$$

$$\sum_{t\in T} y^{P}_{i,t} = \sum_{t\in T} (D_{i,t} - G_{i,t}) \quad \forall i \tag{3.14}$$

$$\tilde{s}_{i,t+1} = \tilde{s}_{i,t} + \eta \times (\tilde{s}^{c}_{i,t} + \tilde{y}^{DA}_{i,t} - s^{d}_{i,t}) \quad \forall i, t > 0 \tag{3.15}$$

$$\tilde{s}_{i,t} = S^{min}_i \quad \forall i, t = 0 \tag{3.16}$$

$$S^{min}_i \leq \tilde{s}_{i,t} \leq S^{max}_i \quad \forall i, t \tag{3.17}$$

$$\tilde{x}^{DA}_{i,t}, \tilde{y}^{DA}_{i,t}, y^{P}_{i,t}, \tilde{s}_{i,t}, \tilde{s}^{c}_{i,t}, s^{d}_{i,t} \geq 0 \quad \forall i, t \tag{3.18}$$

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 (3.1), maximizing the profits made on the day ahead market by doing arbitrage (3.2), and minimizing the compensation paid to the participant for the availability (3.3) and the usage (3.4) of their residential storage system. Constraint (3.5) prevents the aggregator from selling and buying electricity during the same time period. Constraint (3.6) 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 (3.10) and maximizes the savings made by participating in the program (3.11 and 3.12). Constraint (3.13) ensures supply and demand are balanced, while constraint (3.14) ensures the electricity purchased at the retail rate is only used for the participant's own demand. Constraint (3.15) 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 ($s^{c}_{i,t}$) and the added capacity for arbitrage purposes ($y^{DA}_{i,t}$) are represented by different variables to allow the possibility of purchasing the electricity at different rates ($\Pi^{B}_{t}$) depending on the regulatory context. Constraint (3.17) 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 (3.16) sets the initial state of charge of the battery.

Finally, for both levels, the variables cannot be negative (3.7 and 3.18).

In this optimistic bilevel formulation of the model, the leader can choose the optimal solution of the second level that best suits its own interest [33]. The tildes over the variables of the second level represent the variables that are shared with the first level of the model.

This type of optimization problem is in general NP-Hard to solve because it is bilevel and non-linear. Even linear bilevel problems are proven to be strongly NP-Hard [35]. A few methods were tested to solve this initial model, however the preliminary results were unsatisfactory. When using the KKT conditions, the algorithms converge to the origin, which we know is a saddle point due to the nature of the problem. 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.

### 3.6 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 (3.5) 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 $\pi^{CA}_{t,i}$ and $\pi^{CU}_{t,i}$ 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 [%] |
| | |
| $\Pi^{DA}_t$ | Price of day-ahead energy market at time $t$ [$/MWh] |
| $\Pi^B_t$ | Price paid for electricity stored in the battery at time $t$ (for market participation only) [$/MWh] |
| $\Pi^R_t$ | Retail price of electricity at time $t$ [$/MWh] |
| $\Pi^R$ | 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] |
| | |
| $S^{max}_i$ | Maximum storage capacity of participant $i$ [MWh] |
| $S^{min}_i$ | Minimum stored electricity in the battery per participant $i$ request [MWh] |
| $\eta$ | 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 $t$ [$] |

$$z_{i,t}^{x} \quad \text{is equal to} \begin{cases} 1 \text{ if electricity is sold on the day-ahead market} \\ \quad \text{by participant } i \text{ at time } t \\ 0 \text{ otherwise} \end{cases}$$

$$z_{i,t}^{y} \quad \text{is equal to} \begin{cases} 1 \text{ if electricity is bought on the day-ahead market} \\ \quad \text{by participant } i \text{ at time } t \\ 0 \text{ otherwise} \end{cases}$$

**Model**

$$\text{maximize} \quad \sum_{t\in T}\sum_{i\in I}(B_t \times S_i^{max} + \Pi_t^{DA} \times x_{i,t}^{DA} - \Pi_t^{B} \times y_{i,t}^{DA} - c_{i,t}) \tag{3.19}$$

$$\text{subject to} \quad y_{i,t}^{P} + G_{i,t} + s_{i,t}^{d} - s_{i,t}^{c} = D_{i,t} + x_{i,t}^{DA} \quad \forall i,t \tag{3.20}$$

$$\sum_{t\in T} y_{i,t}^{P} = \sum_{t\in T}(D_{i,t} - G_{i,t}) \quad \forall i \tag{3.21}$$

$$y_{i,t}^{P} \leq D_{i,t} \quad \forall i,t \tag{3.22}$$

$$\sum_{t\in T} y_{i,t}^{P} \times \Pi^{R} = \sum_{t\in T}(D_{i,t} - G_{i,t}) \times \Pi^{R} \quad \forall i \tag{3.23}$$

$$s_{i,t+1} = s_{i,t} + \eta \times (s_{i,t}^{c} + y_{i,t}^{DA} - s_{i,t}^{d}) \quad \forall i, t > 0 \tag{3.24}$$

$$s_{i,t} = S_i^{min} \quad \forall i, t = 0 \tag{3.25}$$

$$S_i^{min} \leq s_{i,t} \leq S_i^{max} \quad \forall i,t \tag{3.26}$$

$$z_{i,t}^{x} + z_{i,t}^{y} \leq 1 \quad \forall i,t \tag{3.27}$$

$$x_{i,t}^{DA} \leq M \times z_{i,t}^{x} \quad \forall i,t \tag{3.28}$$

$$y_{i,t}^{DA} \leq M \times z_{i,t}^{y} \quad \forall i,t \tag{3.29}$$

$$\sum_{t\in T} x_{i,t}^{DA} = \sum_{t\in T} y_{i,t}^{DA} \quad \forall i \tag{3.30}$$

$$x_{i,t}^{DA} \leq s_{i,t}^{d} \quad \forall i,t \tag{3.31}$$

$$c_{i,t}^{A} = C^{A} \times (s_i - S_i^{min} - s_{i,t}^{c}) \quad \forall i,t \tag{3.32}$$

$$c_{i,t}^{U} = C^{U} \times \Pi_t^{DA} \times x_{i,t}^{DA} \quad \forall i,t \tag{3.33}$$

$$c_{i,t} = c_{i,t}^{A} + c_{i,t}^{U} \quad \forall i,t \tag{3.34}$$

$$x_{i,t}^{DA}, y_{i,t}^{P}, y_{i,t}^{DA}, s_{i,t}, s_{i,t}^{c}, s_{i,t}^{d}, c_{i,t}^{A}, c_{i,t}^{U}, c_{i,t} \geq 0 \quad \forall i,t \tag{3.35}$$

$$z_{i,t}^{x}, z_{i,t}^{y} \in \{0,1\} \tag{3.36}$$

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 (3.32) and the compensation for the use of the battery (3.33). The last constraint (3.34) 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 (3.22) and (3.23) 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 (3.23) 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 (3.31) is added to ensure the electricity purchased on the retail market is not used to participate in the day-ahead market.

Finally, constraint (3.5) is linearized using the Big M method and replaced by constraints (3.27), (3.28) and (3.29). 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 (3.27) ensures electricity cannot be sold or bought at the same time, and constraints (3.28) and (3.29) 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 ($\sum_{i \in I} S^{max}_i$), 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.

## 3.7 Results & Analysis

### 3.7.1 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) [36] using climate data sets for the city of Providence, RI developed by NREL [37]. 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 [38]. National Grid, a large utility in the northeast of the

U.S., has 500,000 electricity customers in Rhode Island [39] and 3.5M in the country [40]. 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 [41]. 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 ($\eta$) of 90% [32].

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

### 3.7.2 Scenarios

#### 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 ($C^A = 0$ and $C^U = 0$), the optimal solution was to abstain from participating in the market.

#### 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 ($\Pi_t^B = \Pi_t^{DA}$). 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 ($\Pi^R$) 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 ($\Pi_t^B$). 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.

### 3.7.3 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.

#### 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.

### 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).

### 3.7.4 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.

### Scenario 1B : Winter Results

The winter results obtained are shown on Figure 3.1. 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

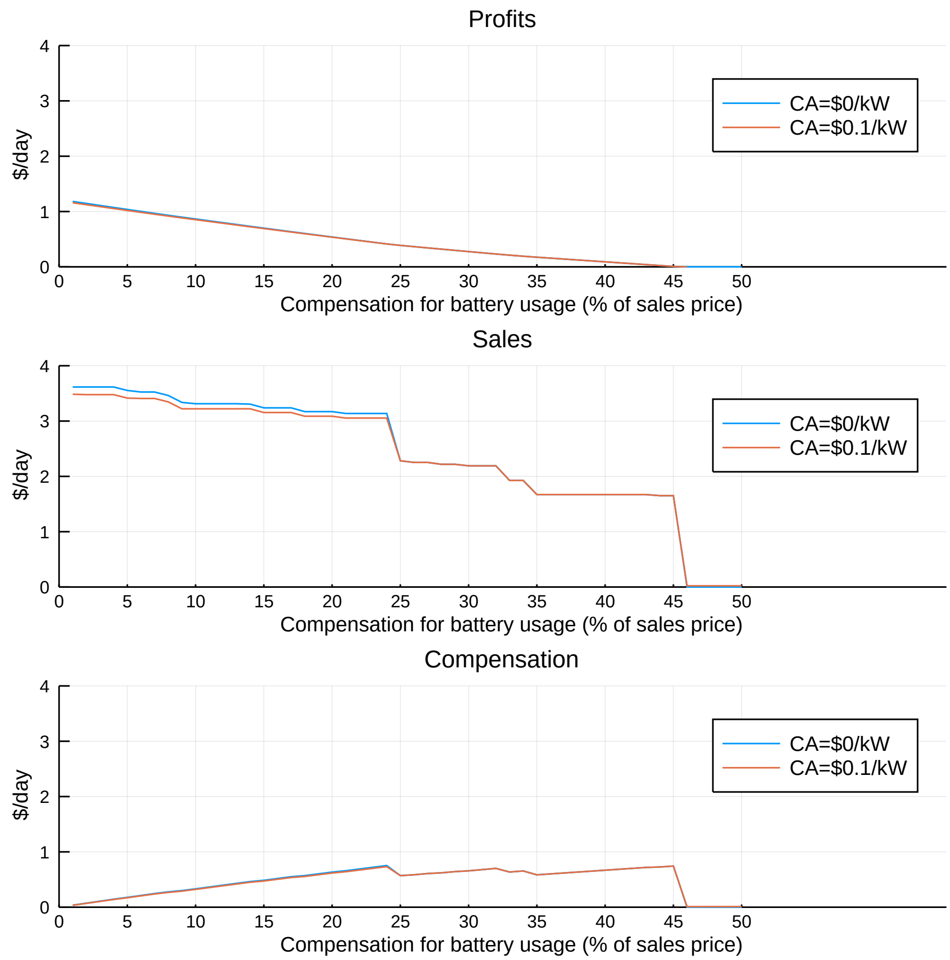


Figure 3.1 Impact of the compensation scheme on the business model profitability in the winter (Scenario 1B)

aggregator, while also optimal for the grid since we are selling a higher volume of electricity.

Figure 3.2 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.

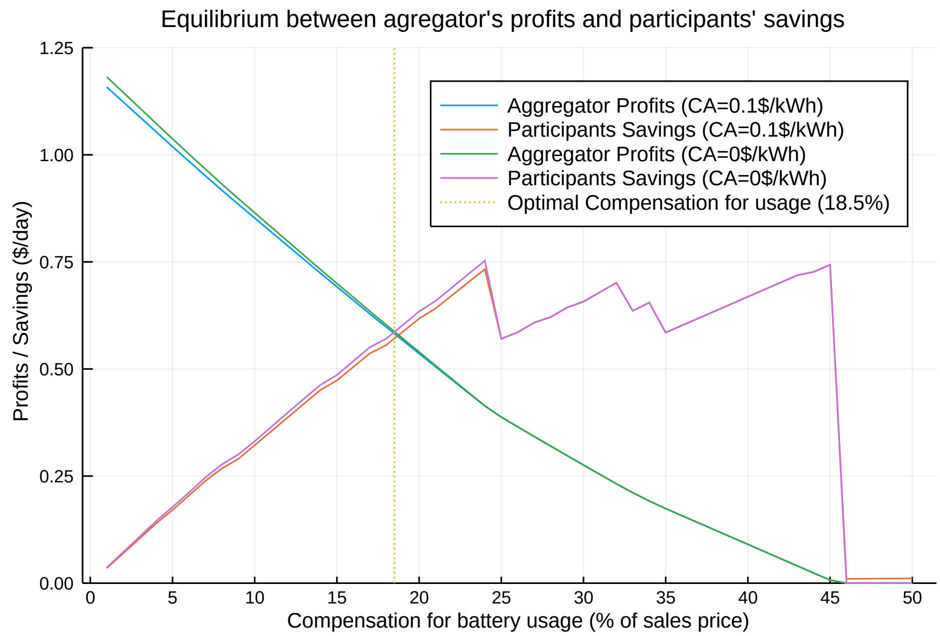


Figure 3.2 Equilibrium between aggregator's profits and participants' savings (Scenario 1B)

**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 3.3 shows the summer results for the profits, sales and savings ; and Figure 3.4 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.

### 3.7.5 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.

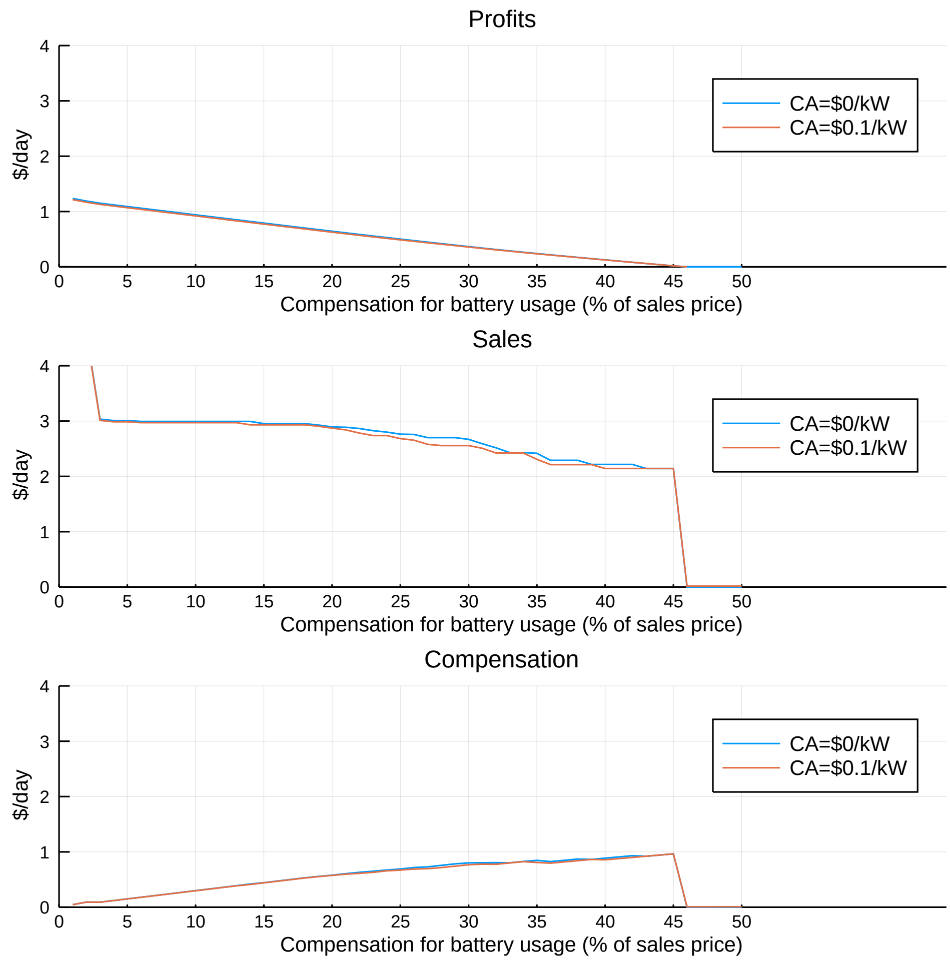


Figure 3.3 Impact of the compensation scheme on the business model profitability in the summer (Scenario 2B)

Each of the following scenarios has 528 variables and 582 constraints to assess a situation with 2 participants over a 24-hour period. The resolution time is 0.02 seconds.

### Scenario 1C : Winter Results

Figure 3.5 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.

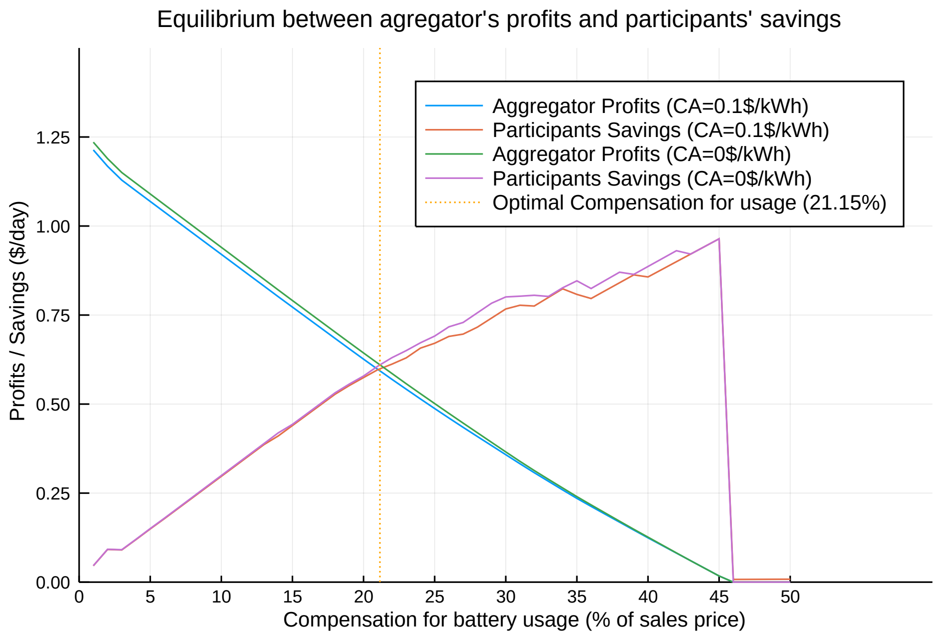


Figure 3.4 Equilibrium between aggregator's profits and participants' savings (Scenario 2B)

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.

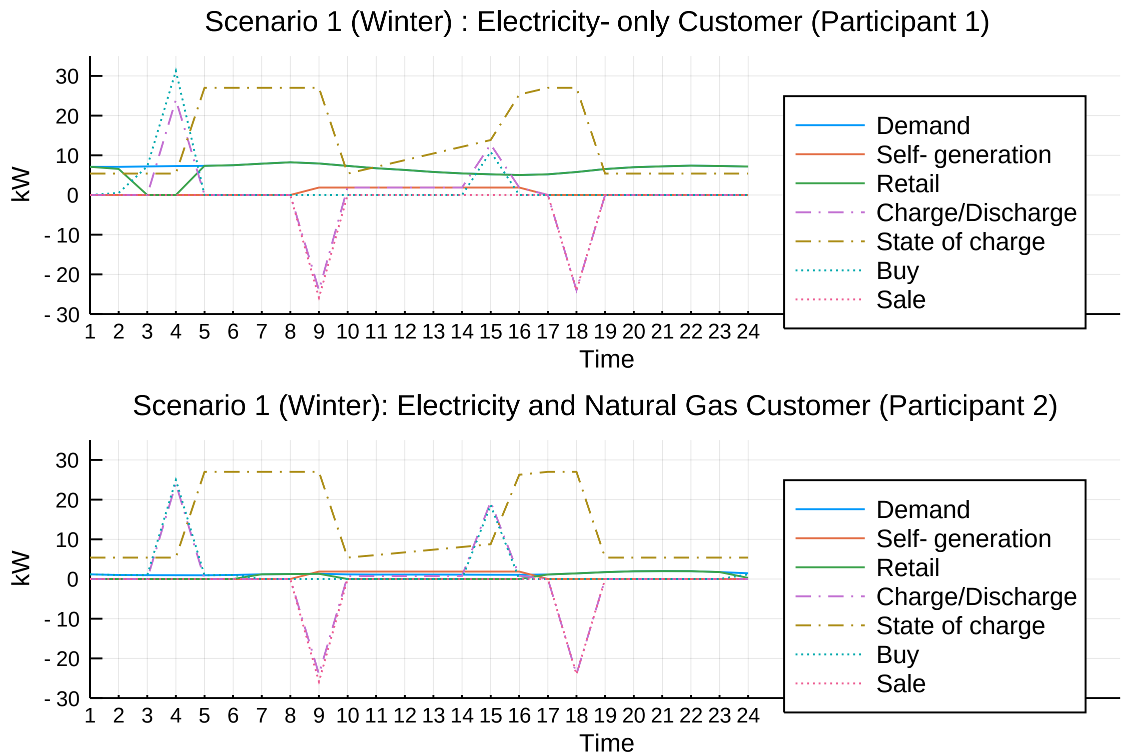


Figure 3.5 Load profiles in the winter for the optimal compensation (Scenario 1C)

**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 3.6. 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.

### 3.7.6 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 3.7.

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

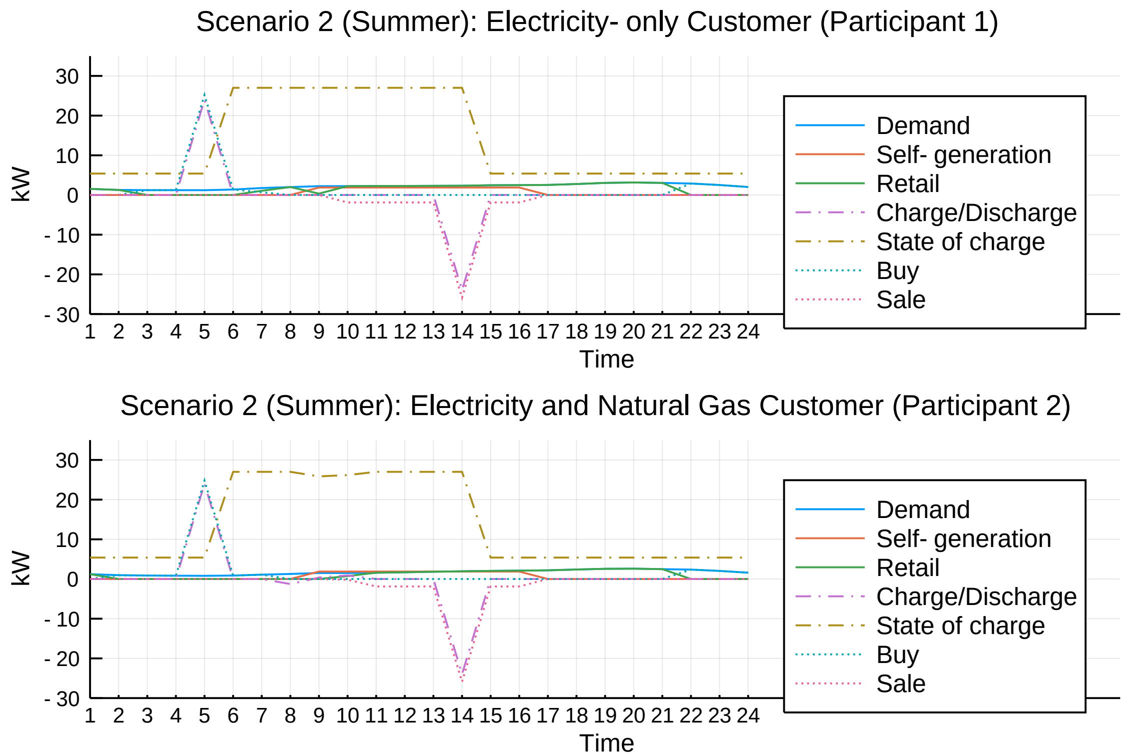


Figure 3.6 Load profiles in the summer for the optimal compensation (Scenario 2C)

(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.

The overall financial benefits are very similar for the aggregator and the group of participants. Figure 3.8 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 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.

In terms of performance, the model can easily accommodate an analysis of 1,000 profiles of participants for a typical period of 24 hours. The numbers of variables and constraints grow

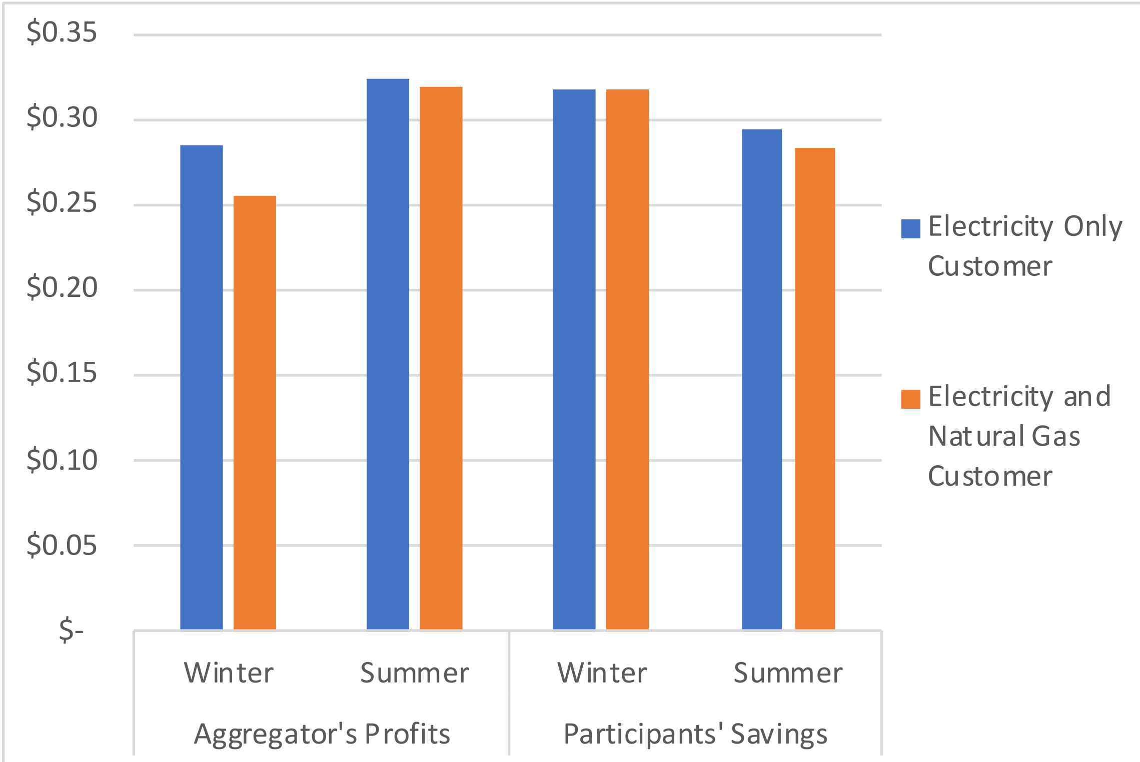


Figure 3.7 Daily Aggregator's Profits and Participants' Savings

proportionally with the number of participants. The time of resolution also appears to follow a similar trend. Memory capacity limitations become an issue at around 5,000 participants. Table 3.1 shows the results for an increasing number of identical electricity-only customers in the winter.

Tableau 3.1 Results for a variable number of participants

| Number of participants | 2 | 20 | 50 | 100 | 500 | 1,000 | 5,000 |
|---|---|---|---|---|---|---|---|
| Number of periods | 24 | 24 | 24 | 24 | 24 | 24 | 24 |
| Number of variables | 528 | 5,280 | 13,200 | 26,400 | 132,000 | 264,000 | 1,320,000 |
| Number of constraints | 582 | 5,820 | 14,550 | 29,100 | 145,500 | 291,000 | 1,455,000 |
| Resolution time (sec) | 0.01 | 0.09 | 0.25 | 0.46 | 1.67 | 3.55 | 25.9 |
| Aggregator's Profits | $0.57 | $5.70 | $14.25 | $28.50 | $142.48 | $284.96 | $1,424.80 |
| Savings per participant | $0.32 | $0.32 | $0.32 | $0.32 | $0.32 | $0.32 | $0.32 |

### 3.7.7 Key messages

There are three key messages from the results obtained.

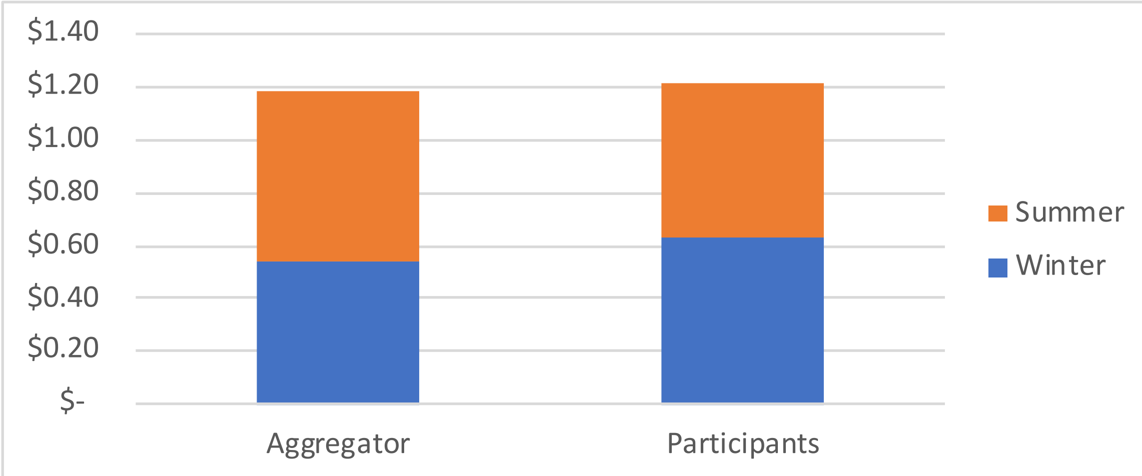


Figure 3.8 Combined Savings/Profits for a Typical Winter and Summer Day

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

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.

### 3.8 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. The useful life of the battery and the operating costs for the participant could also be taken in consideration to refine the estimation of fair compensation. 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.

# CHAPITRE 4 CONCLUSION ET RECOMMANDATIONS

## 4.1 Synthèse des travaux

Dans le cadre des travaux réalisés, nous avons étudié le potentiel d'un modèle d'affaires permettant l'agrégation du stockage d'énergie disponible dans le secteur résidentiel. Nous avons également développé un modèle d'optimisation permettant à l'agrégateur d'estimer la profitabilité d'un tel modèle d'affaires dans leur juridiction et de définir le niveau de compensation requis pour créer un contexte mutuellement bénéfique pour les participants et l'agrégateur.

Les résultats obtenus démontrent qu'un tel modèle d'affaires est profitable et avantageux pour les distributeurs d'électricité (agissant à titre d'agrégateur) et pour les participants, en plus d'apporter des bénéfices importants pour l'opération du réseau. Selon les données historiques du Rhode Island utilisées pour l'analyse, les participants peuvent économiser environ 100 $ par année sur leur facture d'électricité. Ce montant est non négligeable. Réciproquement, les distributeurs d'électricité peuvent faire des profits de 100 $ par participant annuellement. Les profits étant constants sur l'année, cela représente une opportunité de revenu stable pour l'agrégateur. De plus, le nombre de clients faisant l'acquisition de système de stockage résidentiel étant croissant, ce modèle d'affaires représente une opportunité grandissante à long terme. Les résultats montrent que les profits ne varient pas en fonction du profil de consommation des participants, et donc tous les clients des distributeurs possédant une batterie sont des participants potentiels. Cela représente un grand marché à capturer avant que d'autres compétiteurs ne saisissent l'opportunité.

Finalement, nos résultats montrent que le principal facteur influençant les profits et économies réalisés par l'agrégateur et les participants respectivement est la compensation sur l'utilisation de la batterie. Cette composante de la compensation devrait être choisie avec soin pour assurer la viabilité du modèle d'affaires.

## 4.2 Limitations de la solution proposée

La solution proposée est conservatrice, car elle n'inclut pas les profits additionnels qui pourraient provenir de la participation au marché pour des services auxiliaires. Fournir ces services au réseau, en plus des services d'arbitrage, contribuerait à faire augmenter les profits. De plus, le modèle proposé ne tient pas compte des bénéfices difficilement quantifiables de réduction de la congestion et du report de la réalisation de travaux de maintenance sur le réseau de transmission et distribution. Ainsi, le potentiel est encore plus grand que démontré dans cette étude.

Du côté des participants, la dépréciation du système de stockage, de même que la durée de vie utile et les coûts d'opération ne sont pas actuellement inclus le modèle. Bien que l'acquisition se fait à l'extérieur du modèle d'affaires décrit, les impacts sur l'utilisation du système pourraient être pris en compte dans l'analyse.

Additionnellement, l'étude réalisée se concentre sur une seule juridiction, le Rhode Island, pour une journée typique d'été et une journée typique d'hiver. L'étude du potentiel dans d'autres juridictions pour une plus grande variété de jours dans l'année pourrait être réalisé afin de quantifier de façon plus systématique le potentiel de ce modèle d'affaires à différents endroits du monde.

## 4.3 Améliorations futures

Les contributions de cet article offrent un point départ pour faire évoluer le modèle d'affaires proposé.

Premièrement, le modèle d'affaires pourrait être amené à évoluer afin de garantir l'accès à une batterie entièrement rechargée en tout temps à l'extérieur des périodes de participation au marché de l'électricité. Ainsi, jusqu'à une certaine mesure, la batterie pourrait être entièrement rechargée pour minimiser le risque que le participant se retrouve en situation de panne d'électricité avec une batterie qui n'est pas entièrement rechargée.

De plus, des améliorations au modèle d'optimisation simplifié pour ajouter les services auxiliaires, incorporer différentes modalités de tarification dynamique et quantifier les bénéfices liés à la réduction de la congestion et au report d'investissements de maintenance permettraient de capturer de nouvelles opportunités pour rendre le modèle plus profitable pour tous.

Complémentairement, une étude pourrait être réalisée pour évaluer la question d'équité afin d'assurer une répartition juste des récompenses entre les participants en fonction de l'effort réalisé pour contribuer aux bénéfices pour le réseau.

Finalement, de futures recherches pourront être réalisées pour développer une méthodologie pour rendre la résolution du modèle bi-niveau plus accessible. Le modèle initial, à l'aide d'une méthodologie de résolution fiable, permettrait l'obtention de résultats plus précis. Préalablement, une évaluation approfondie des impacts de la simplification pourrait aussi être réalisée. Par exemple, il serait intéressant d'évaluer si la solution optimale du problème simplifié donne nécessairement une borne supérieure sur la valeur optimale du problème bi-niveau initial.

Ultimement, une grande variété de travaux futurs pourraient être réalisés autour de l'implémentation du modèle d'affaires, notamment l'intégration d'un modèle stochastique pour prendre en compte l'incertitude des prix sur le marché de l'électricité, l'analyse de considérations techniques au niveau de la connexion des systèmes résidentiels sur le réseau de distribution, ainsi que les enjeux de performances et de contrôle optimal pour traiter en temps réel les données.

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