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Receding horizon optimization-based approaches to managing supply voltages and power flows in a distribution grid with battery storage co-located with solar PV☆

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HIGHLIGHTS

- Two receding horizon optimization-based algorithms proposed for coordinating residential battery storage.
- Addresses the problem of managing bi-directional power flows in a distribution grid.
- Improves supply voltages in a low voltage network.
- Proposed A-RHO approach is preferable when voltages at a residential PCC fall outside set tolerances.

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ABSTRACT

In this paper we propose two optimization-based algorithms for coordinating residential battery storage to balance increases in daily operational savings that accrue to residential customers with the management of bi-directional power flows in the distribution grid. Bi-directional power flows are managed to improve the supply voltage for residential customers with rooftop solar PV, in addition to alleviating (potentially infrequent) congestion that occurs in the evening when PV production is unavailable. Our objectives are threefold: (1) to reduce reverse power flow leading to significant voltage rise; (2) to reduce peak loads creating sustained under-voltages and/or approaching a network thermal capacity; and (3) to increase operational savings for the residential customer. To achieve our objectives we present a Distributed-Receding Horizon Optimization (D-RHO) algorithm, wherein charge and discharge rates of residential battery storage are coordinated so as to directly influence power flows along a distribution feeder. We also present an Adaptive-Receding Horizon Optimization (A-RHO) algorithm, in which charge and discharge rates of residential battery storage are coordinated to more directly manage supply voltages. To assess the distributor benefit, both RHO-based algorithms are applied to a publicly available model of an Australian distribution region located in Elermore Vale. The results of this case study confirm that the A-RHO algorithm improves supply voltages in a low voltage network, and that the D-RHO algorithm offers a peak load reduction of 32% along the Elermore Vale medium voltage feeder.

1. Introduction

The recent rapid uptake of grid-connected solar photovoltaics (PV) in many countries has led to concerns regarding the management of bi-directional power flows in distribution networks previously designed for one-way power flow [1,2]. Distributors are typically concerned with power flows approaching a network capacity, and reverse power flows inducing voltage rise, especially when either situation leads to substantial network investment [3–6].

Demand-side approaches to managing distribution power flows potentially defer (or possibly avoid) significant costs associated with distribution reinforcement [7–22]. The demand-side approach in [7] curbs PV generation in response to significant voltage rise in the distribution grid. The demand-side approaches in [8,9] control a PV inverter that adjusts the real and reactive power supplied to, or absorbed by, the distribution grid. Other demand-side approaches include direct

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load control [10–15] and price-responsive load control, e.g. time-of-use pricing [16–18,23,24]. Several authors have also investigated co-ordinated approaches to charge and discharge battery storage with the objective of managing bi-directional power flows in a distribution network [19–22].

Approaches that coordinate battery storage in order to directly control supply voltages in the distribution network, while critical in facilitating continual increases in grid-connected solar PV generation, are less prevalent in the literature. Approaches to controlling battery storage with the aim of improving supply voltages have recently been considered in [25–28], and include charging of a residential battery co-located with solar PV when a predetermined threshold for PV generation is exceeded [25]. In [26,27] the main control center coordinates battery charge/discharge rates, where the main control center in Lee et al. [26] collects supply voltages, supply frequencies, and the state of charge of each battery. With the exception of [27], none of these approaches factors in increases in operational savings that accrue to customers with battery storage. Furthermore, studies [25–28] lack validation against distribution models which incorporate not only the low voltage (LV) network but also the medium voltage (MV) feeder, with realistic customer-specific PV generation and load profiles included as inputs, a crucial step in assessing and potentially mitigating detrimental impacts on distribution voltage associated with solar PV [29].

In this paper, we present two demand-side approaches to managing bi-directional power flows and supply voltages within a distribution network, where the coordination of numerous customer-sited batteries is assessed by means of a realistic network model that includes the MV feeder and associated LV network. In the first approach, referred to as Distributed-Receding Horizon Optimization (D-RHO), charge and discharge rates of residential battery storage are coordinated to reduce peak loads and reverse power flow in the upstream distribution grid. Here, the strategy is to improve supply voltages by way of flattening the feeder-level load curve. In the second approach, referred to as Adaptive-Receding Horizon Optimization (A-RHO), charge and discharge rates of residential battery storage are coordinated to more directly manage supply voltages while influencing (to a lesser extent) power flows in the upstream distribution grid. In each approach a customer solves an optimization problem subject to current and future constraints, with each problem formulated as a quadratic program (QP). Incorporating operational savings into the objective function of each proposed algorithm fills a gap in the existing literature. Further, the extensive distribution model used in assessing the algorithms includes realistic residential load and PV generation profiles at numerous customer sites in the respective LV network.

Our previous work [30,27] is extended in this paper in a number of different ways. We implement receding horizon optimization to incorporate updates in day-ahead load and PV generation forecasts, and to reduce the magnitude of the 'rebound peak' during the off-peak pricing period as observed in prior work [30,27]. We apply the D-RHO and A-RHO algorithms to a GridLAB-D model of an Australian distribution network, and consider the case where approximately 50% of customers have solar PV systems. Further, we more directly improve the daily voltage profile of each residential customer by incorporating feedback of residential voltage measurements in the formulation of the A-RHO algorithm.

To implement D-RHO, an electrical distributor is required to broadcast to Advanced Metering Infrastructure (AMI) day-ahead demand forecasts, day-ahead electricity prices, and a design parameter in the form of a scalar weight. Furthermore, each customer requires an energy management system with an AMI interface that is capable of executing optimization-based algorithms, applying battery charge/discharge rates, and updating the battery state of charge. The A-RHO approach extends the system architecture required for D-RHO, wherein the energy management system of each customer requires additional functionality. Specifically, to implement A-RHO the energy management system of each customer must also: (1) forecast day-ahead residential load and PV generation; (2) retrieve weights from a look-up table; and (3) select an optimization-based algorithm to run.

This paper is organized as follows. In Section 2 we define a single residential system that we incorporate into a publicly available model of an Australian distribution region. In Section 3 we propose two optimization-based approaches to manage power and voltage profiles in a distribution network. In Section 4 we present simulation results that are based on a GridLAB-D model of an Australian distribution feeder located in Elermore Vale, NSW.

1.1. Notation

Let $\mathbb{R}^s$ denote s-dimensional vectors of real numbers and $\mathbb{R}^s_{\geqslant 0}$ s-dimensional vectors with all non-negative components where, as usual, $\mathbb{R}^1 = \mathbb{R}$. $\mathbf{I}$ denotes the s-by-s identity matrix and $\mathbb{1} \in \mathbb{R}^s_{\geqslant 0}$ denotes the all-1s column vector of length s. $\mathbf{0}$ denotes an all-zero matrix, or an all-zero column vector, where the context will make clear the dimension intended, and $\mathbf{T} = [t_{ij}]$ denotes the s-by-s matrix satisfying $t_{ij} = 1$ for $i \geqslant j$ and $t_{ij} = 0$ elsewhere.

2. Preliminaries

In Section 2.1 we define a single residential system with solar PV co-located with battery storage as depicted in Fig. 1. We incorporate this residential system into a larger distribution model which we introduce in Section 2.2. In particular, our residential system replaces the assumed topology behind the Point of Common Coupling (PCC) for approximately 50% of customers in the distribution model. Our forecasting methodology for residential load and PV generation is presented in Section 2.3.

2.1. Residential system

Before introducing a publicly available distribution model we start with defining a single residential system. Our simple definition of a residential system is consistent with previous work [30], and is included in this paper to improve clarity of the forecasting methodology presented in Section 2.3, and the problem formulation presented in Section 3.

Fig. 1 illustrates the assumed topology of the residential system under consideration. We denote by $x_2(k)$ the measured power flow (in kW) over the k^{th} interval of length Δ. By convention measured power flows from (to) the grid to (from) the residential system over the period $((k-1)\Delta, k\Delta)$ are represented by $x_2(k) > 0$ ($x_2(k) < 0$) for all $k \in \{1,\ldots,s\}$. To represent all measured power flows over a time window $[0,T]$, where s is the number of time intervals of length Δ, and $T = s\Delta$ (in hours) is the time window of interest, we define the *grid profile* by

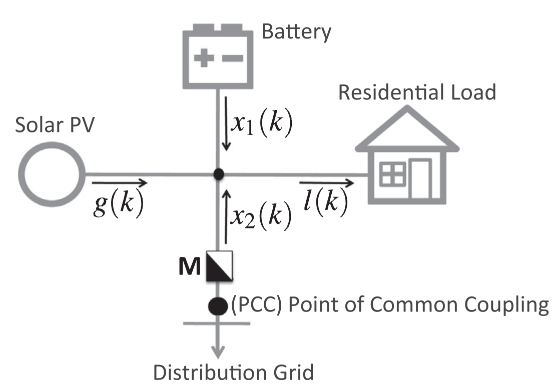

Fig. 1. Residential system illustrating the direction of positive power flows and the bi-directional meter **M**. Arrows associated with $g(k)$, $l(k)$, $x_1(k)$ and $x_2(k)$ illustrate the direction of positive power flow. Meter **M** measures and records (in kW) power flow $x_2(k)$, where k is a time index.