Balancing distributor and customer benefits of battery storage co-located with solar PV

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Bachelor of Electrical Engineering

A thesis submitted in fulfilment of the requirements for the degree of Doctor of Philosophy

October, 2015
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I hereby certify that this thesis is in the form of a series of published papers. I have included as part of the thesis a written statement from each co-author, endorsed in writing by the Faculty Assistant Dean (Research Training), attesting to my contribution to the jointly authored papers.

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________________________________________
Elizabeth L. Ratnam
October, 2015
To Marcel, Mum and Dad.
First and foremost, I would like to thank my husband, Marcel, and our respective families. Thank you for all your love, guidance, encouragement and all-round support in all of my career choices including this PhD.

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Chapter 1 consists of Sections 5.1 and 5.2.2 of a technical report published by the Australian Energy Market Commission (AEMC) titled *Future Energy Storage Trends: An Assessment of the Economic Viability, Potential Uptake and Impacts of Electrical Energy Storage on the NEM 2015-2035*. This published report is outside the scope of Rule 39.2 i that governs research higher degrees, therefore we have sought the approval of the Dean of Graduate Studies to include this work in accordance with Rule 39.2 v. A Statement of Contribution from each co-author of this technical report is included in the thesis.

Chapters 2–6 consist of five co-authored papers that are published, in press or have been submitted for publication in scholarly journals. Specifically, three papers have been published (or accepted for publication) in refereed journals, and two papers have been submitted to journals for publication at the time of submission. For each of these five co-authored papers a written statement of contribution from each co-author follows.
Statement of Contribution 1

Technical report in Chapter 2


Authors

By signing below I confirm that Elizabeth Louise Ratnam contributed to report writing and techno-economic modelling for the Australian Energy Market Commission (AEMC) Integration of Storage Study. For the purpose of this thesis, permission to reproduce Sections 5.1 and 5.2.2 of the report titled Future Energy Storage Trends: An Assessment of the Economic Viability, Potential Uptake and Impacts of Electrical Energy Storage on the NEM 2015-2035 prepared for the AEMC is granted. The contribution of Elizabeth L. Ratnam specific to this report was to prepare, draft and edit Sections 5.1 and 5.2.2. Both the AEMC and CSIRO have reviewed these sections in the report prior to publication.

I hereby certify that this statement of contribution is accurate

Dr. Thomas Brinsmead Signed: ... Date: 21/9/15

Mr. Paul Graham Signed: ... Date: 21/9/15

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Statement of Contribution 2

Technical paper in Chapter 3


Authors

By signing below I confirm that Elizabeth Louise Ratnam contributed to developing the high-level framework, prepared the data, and took primary responsibility for preparing, drafting and editing the journal publication listed above.

I hereby certify that this statement of contribution is accurate

Associate Professor Steven Weller Signed: ........................................ Date: 16/10/2015

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Statement of Contribution 3

Technical papers in Chapters 4-6


Authors

By signing below I confirm that Elizabeth Louise Ratnam contributed to developing the high-level framework, algorithms, simulations and took primary responsibility for preparing, drafting and editing the journal publications listed above.

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Statement of Contribution 4

Technical paper in Chapter 7

E. L. Ratnam, S. R. Weller, Receding horizon optimization-based approaches to manage supply voltages and power flows in a distribution grid with battery storage, Submitted to journal for publication 2015.

Authors

By signing below I confirm that Elizabeth Louise Ratnam contributed to developing the high-level framework, algorithms, simulations and took primary responsibility for preparing, drafting and editing the journal publication listed above.

I hereby certify that this statement of contribution is accurate

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22/10/2016
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In recent years, a rapid and dramatic increase in electrical power generation from renewable energy sources has been observed in many countries. Rapid increases in grid-connected small-scale solar photovoltaics (PV) have been driven by government incentives and renewable energy rebates, including residential feed-in tariffs and the financial policy of net metering. However, new challenges arise in balancing the generation of electricity with variable demand at all times as traditional fossil fuel-fired generators are retired and replaced with intermittent renewable electricity sources.

This thesis looks at ways to balance distributor and customer benefits of battery storage co-located with solar PV, with a view to facilitating continual increases in grid-connected solar PV. Two issues that arise when accommodating significant residential-scale PV generation are addressed: the first is reverse power flow that leads to considerable voltage rise; the second corresponds to peak loads that occur infrequently, but potentially lead to the need for costly network augmentation when PV generation is unavailable. The benefits associated with addressing these two distributor issues are balanced with the benefit of scheduling battery storage to improve operational savings that accrue to customers.

Conventional approaches to managing peak loads and reverse power flows in distribution networks vary from country-to-country, since they are often driven by government policies and regulation. In the Australian context, the first part of the thesis introduces typical costs associated with the design and operation of electrical networks to assess the economic viability of large-scale energy storage. We also introduce a publicly available dataset consisting of load and rooftop PV generation for 300 de-identified Australian residential customers in a distribution network. All simulation-based results in the thesis incorporate data from this publicly available dataset.

The second part of the thesis considers potential savings that accrue to residential customers that co-locate battery storage with solar PV. We address reverse power flow and peak-loads coincident with peak pricing periods where the residential customer designs battery charge and discharge schedules. This leads us to a constrained optimization-based problem that we formulate as a quadratic program.

The third part of the thesis focuses on coordinated approaches to charge and discharge residential battery storage. Emphasis is given to the management of bi-directional power flows in a distribution grid, and the maintenance of supply voltages within prescribed limits. This has motivated a novel approach to Adaptive-Receding Horizon Optimization (A-RHO). We implement our A-RHO approach in a GridLAB-D model of an Australian distribution network to assess the distributor benefits.
Climate change, national energy security, and the declining economic availability of fossil fuel resources are key drivers for the integration of renewable energy sources such as solar into the modern power grid [1–4]. These drivers, in conjunction with renewable energy incentives such as feed-in tariffs [4–7] and the financial policy of net metering [8–11], have lead to a rapid and dramatic uptake of residential-scale solar photovoltaics (PV) in some countries [12,13]. As the capital cost of small-scale PV continues to drop [14], and electricity prices continue to increase [12], it is expected that this trend in significant PV uptake will continue into the next decade [13,15].

However, there are significant challenges in converting the abundant solar resource into reliable, high-quality electricity [16–19]. Challenges include the variability of solar irradiance on both daily and seasonal timescales in addition to intermittency arising from moving cloud cover on much shorter timescales [17,18]. Further, new challenges in balancing the generation of electricity with variable demand at all times arise as traditional fossil fuel-fired generators are retired and replaced with these intermittent renewable sources [19–21]. Despite the challenges, there was a 480% increase in Australian solar PV installations in a single year from 2009 to 2010, of which 99% was grid-connected [22, 23]. Further, there is more than 3.8 GW of installed rooftop PV in Australia [24], up from 1 GW in 2012 [23]. In the United States, there is more than 16 GW of installed solar PV [25], up from 0.8 GW in 2010 [26]. PV plant installations in Germany exceed 1.2 million, and as of September 2012, peak PV capacity reached 31 GW with about 70% of this capacity being connected to the low voltage grid [27].

Literature Overview

As residential PV penetration continues to increase, the management of supply voltages within operational limits becomes increasingly challenging for distribution operators [27–44]. For example, if PV generation exceeds the demand of a residential customer in addition to demand in the downstream distribution feeder, the excess PV generation is pushed upstream creating voltage rise [29–32]. Voltage rise that exceeds an upper tolerance with respect to the nominal supply voltage, potentially occurs when a large number of rooftop PV generators are connected in close proximity to each other [33–39]. Voltage dips are another concern when grid-connecting a large
number of rooftop PV generators in close proximity to each other [28]. For example, a voltage dip potentially occurs when passing cloud cover results in a significant drop in rooftop PV generation that would otherwise be servicing residential load [35–37,40]. If these voltage deviations fall outside power quality standards, either the utility covers the direct cost of mitigation or the burden of voltage regulation falls to the PV producer [18,27,29,33,38].

There are two common approaches to managing voltage rise in the low voltage grid. The first is to augment the distribution grid by increasing conductor size and/or upgrading transformers to lower network impedances [27,34,41,45]. The second is to constrain PV generation at times of low electricity consumption in order to preserve compliance of allowable voltage deviations [29,42,46]. Neither approach is optimal for significant PV penetration, as network augmentation adds to the overall PV grid integration costs [34, 45] whereas spilling PV generation leads to lost revenue for the producer [31,32].

There are a number of emerging approaches to overcome non-compliant voltage deviations arising from the intermittency and variability of solar PV, with applicable incentives, mandates and regulation driving the solutions. Some of these approaches include energy storage [47–50], direct load control [51,52], price-responsive load control [53–56], active PV generation curtailment [57], and enhanced PV inverter control to manage real and reactive power output [58,59]. Different incentives driving these approaches include dynamic day-ahead electricity tariffs [53,60], reductions in appliance-specific electricity billing [51, 61], standards curbing PV production [42], and energy storage mandates such as those in California [62]. Depending on the incentives and regulatory environment, one or more of these approaches may serve as a demand management option for a distribution operator faced with significant PV penetration [63, 64]. More specifically, enhanced PV inverter control alone does not always maintain distribution voltages within set tolerances [64]. Consequently, coordinated control of PVs and battery energy storage has been proposed in [65–68].

Without careful coordination, however, the potential benefits of demand-side approaches to managing bi-directional power flows in a distribution network might not be realized [14,51,69,70]. For example, a second load peak in the distribution grid may occur when autonomous, time-based battery charging schedules are implemented [14,51], potentially leading to a need for costly distribution reinforcement [14]. Furthermore, increases in reverse power flows (or peak loads) potentially occur when battery storage units connected to a distribution grid are discharged (or charged) in response to time-varying electricity prices [71], which may also necessitate network investment. In recent work [11] we illustrate a second ‘rebound’ load peak in addition to an increase in reverse power flow occurs across a day, when customers schedule battery storage co-located with solar PV
with the aim of minimizing their electricity bill (or maximizing their operational savings).

Several authors have considered approaches that co-locate battery storage with solar PV with a focus on reducing network peak demand [72–78], potentially leading to battery schedules that either mitigate or exacerbate voltage rise associated with reverse power flow when inverters operate at unity power factor [58,77]. The reduction of network peak demand is incorporated into a linear program in [72], where the energy flowing from the point of common coupling (PCC) to the customer is minimized when residential load exceeds residential PV production. Otherwise the battery is scheduled in [72] to charge during the off-peak pricing period, and discharge during the peak pricing period, with no limit on reverse power flow (i.e., the power delivered to the grid). Consequently, battery scheduling in [72] potentially induces voltage rise at the PCC. The reduction of network peak demand is also incorporated into an optimization problem in [73], where the objective function includes financial incentives for residents to deliver energy to the grid when the purchase cost of electricity is high. Hence, when interconnected customers in close proximity minimize the objective function in [73], large voltage swings associated with reverse power flow potentially arise due to the battery scheduling.

In contrast, peak demand and reverse power flow is reduced by solving the optimization problems in [74,79], where the objective functions eliminate residential subsidies for electricity delivered to the grid and include payments for electricity received from the grid. Thus, the optimization problems in [74,79] potentially reduce voltage rise associated with reverse power flow. The optimization problem in [75] also removes incentives for reverse power flow associated with battery scheduling, while permitting incentives encouraging solar PV uptake. In addition, the optimization problem in [75] includes residential payments for electricity received from the grid. Consequently, the optimization problem in [75] leads to reductions in both peak demand and reverse power flow, potentially mitigating voltage rise. Another method for reducing both peak demand and reverse power flow is incorporated into the optimization problem in [76], where a sophisticated dynamic pricing environment provides additional incentives for customers to smooth their day-ahead energy consumption. Hence, the optimization problem in [76] potentially abates voltage rise associated with reverse power flow.

Alternatively, coordinated approaches to managing bi-directional power flows in a distribution network have been proposed in the recent literature [71,80,81]. For example, a linear program (LP) is employed in [71] to reduce peak power flows (potentially in the reverse direction) through a distribution substation. Furthermore, [71] proposes direct control of a customer’s battery schedule by the distributor when the LP-based power flow reductions are required. The optimization problem
in [80] includes penalties for large power fluctuations to and from an interconnection point that connects a smart grid to an upstream electricity network. To reduce power fluctuations within a distribution grid, [80] proposes direct control of demand-side battery schedules by a distributor. In contrast, a central energy management system (EMS) in [81] coordinates supply and demand within a microgrid in a number of ways. For example, a central EMS in [81] either dispatches power flow references to customers connected to a microgrid, or directly controls battery charge and discharge schedules of each microgrid customer. That is, each microgrid customer in [81] has a local EMS that manages residential battery schedules subject to central EMS references or directives.

Other coordinated approaches to improving supply voltages in a distribution network are considered in [65, 82–85], and include charging a residential battery co-located with solar PV when a predetermined threshold for PV generation is exceeded [82]. In [83–85] a main control center coordinates battery charge/discharge rates, where the main control center in [83] collects supply voltages, supply frequencies, and the state of charge of each battery. With the exception of our recent work [84, 85], none of these approaches incorporate and balance increases in operational energy savings that accrue to customers with battery storage as defined in Chapter 3.

In this thesis we consider a balance in benefits to a utility and customer, in the context of grid-connected residential-scale battery storage co-located with solar PV. We propose optimization-based approaches to schedule residential battery storage, with a direct focus on balancing financial benefits for a customer with utility benefits in managing bi-directional distribution power flows, and an indirect focus on incorporating low requirements for sensing and communications infrastructure. In our assessment of the financial benefits that accrue to a customer with battery storage, we consider operational savings or reductions in energy bills for a cross-sectional sample of customers located in Sydney and regional New South Wales (NSW), Australia. In our assessment of the utility benefits we present aggregate power flows to or from residential customers, and consider supply voltages within an Australian distribution network with significant residential PV penetration. Our overarching objective is to balance distributor and customer benefits of battery storage co-located with solar PV, with a view to facilitate continued increases in distributed, small-scale PV generation.
Key Contributions of this Thesis

The key contributions of this thesis are:

- a report extract that informed Australian policy makers on the economic viability and impacts of electrical energy storage on the National Electricity Market (NEM) 2015–2035,

- a detailed description of a publicly available dataset comprised of interval readings of load and PV generation for each of 300 residential customer, that forms the basis of each case study presented in the thesis,

- a linear program (LP)-based scheduling algorithm that maximizes operational savings that accrue to customers with grid-connected battery storage,

- a case study demonstrating the LP-based approach potentially leads to undesirable consequences for a distributor, that is, when all customers discharge battery storage during the peak pricing period, reverse power flow creating significant voltage rise potentially occurs,

- a quadratic program (QP)-based scheduling algorithm that minimizes of the energy supplied by, or to, the grid in a residential PV system with co-located battery storage,

- a greedy-search heuristic that selects the key design parameters in the QP-based scheduling algorithm to improve operational savings that accrue to customers,

- a case study demonstrating a balance in the customer and utility benefits of the QP-based scheduling algorithm,

- two coordinated QP-based approaches to adjust and improve the balance in managing bi-directional distribution power flows with increases in operational savings that accrue to customers,

- a case study confirming a centralized approach to coordinating residential battery storage is preferable in that no customer is disproportionately penalized for reducing peak load and/or reverse power flow in a distribution network,

- a case study confirming the customer payback period for a 10 kWh battery is in the vicinity of 6 years when a centralized approach to coordinating residential battery storage is implemented,

- two receding horizon optimization (RHO)-based algorithms for coordinating residential battery storage to further improve the balance in managing (1) bi-directional distribution power
flows and associated supply voltages, with (2) increases in operational savings that accrue to customers,

- a case study confirming an adaptive (A)-RHO algorithm more directly improves supply voltages in a low voltage network,

- a case study with a realistic distribution-level electricity network model, showing a peak load reduction of 32% along a medium voltage feeder when approximately 50% of residential customers implemented a distributed (D)-RHO algorithm.

**List of Publications**

A complete list of publications related to this thesis is provided below.

**Refereed Journal Articles**


**Technical Reports**


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\(^1\)This paper was titled “An optimization-based approach to power management in distribution networks with residential battery storage,” prior to publication.
Overview of Thesis Content

The remainder of this thesis is organized into three thematic parts, and we include an additional chapter for conclusions. The first part includes background material, provides context, includes a detailed description of the dataset used throughout the thesis, and serves as a high-level overview. Part 2 introduces a single residential system, and Part 3 incorporates the residential system into a larger distribution network. The introduction of each chapter in Part 2 and Part 3 incorporates a focused literature review, that places the work in an established body of knowledge and links papers (from prior chapters) included in the thesis. At the beginning of each chapter of the thesis, an explanatory overview is provided to link the separate papers included in the thesis.

References at the end of the thesis refer to the introductory and concluding chapters of the thesis, and main body chapters contain a literature review and a list of references. An outline of the remaining chapters of the thesis follows.

Part 1 Overview and context

- Chapter 1 investigates the economic viability of large-scale battery storage. We propose two case studies to investigate factors influencing the economic viability of energy storage for (1) power system operators and (2) large industrial-sized customers, respectively. Background material is included to provide context for the underlying
assumptions considered in this chapter and the remainder of the thesis.

• Chapter 2 reports a publicly available dataset considered in the remaining chapters of the thesis. The dataset consists of load and rooftop PV generation for 300 de-identified residential customers in an Australian distribution network. Following a detailed description of the dataset, we identify several means by which anomalous records (e.g. due to inverter failure) are identified and excised. All papers in this thesis incorporate data from this publicly available dataset.

Part 2 Battery scheduling: A single residential system

• Chapter 3 proposes an optimization-based algorithm for the scheduling of residential battery storage co-located with solar PV, in the context of PV incentives such as feed-in tariffs. We present a quadratic program (QP)-based algorithm that is applied to measured load and generation data from 145 residential customers located in an Australian distribution network. The results of the case study confirm the QP-based scheduling algorithm significantly penalizes reverse power flow and peak loads corresponding to peak time-of-use billing.

• Chapter 4 presents a linear programming (LP)-based approach to designing day-ahead battery charge and discharge schedules when any generation in excess of residential load is compensated by the electricity retailer via net metering. We further show that when net metering is used, that it is possible to balance the objective of the utility in limiting reverse power flow, with the customer objective of increasing operational savings, with the QP-based approach first presented in Chapter 3.

Part 3 Battery scheduling: Coordinated residential systems

• Chapter 5 addresses the problem of managing reverse power flow and peak loads within a distribution network. We propose a two optimization-based algorithms for coordinating residential battery storage when solar photovoltaic (PV) generation in excess of load is compensated via net metering, extending the framework presented in Chapter 4. A case study confirms a centralized approach to coordinating residential battery storage is preferable to a more localized approach, in that no customer is disproportionately penalized for reducing peak load and/or reverse power flow in a distribution network.

• Chapter 6 considers three key problems that may occur infrequently in Australian distribution networks, but could potentially lead to costly remediation for distributors:
  1. significant reverse power flows along a medium voltage feeder that may render existing voltage control and/or protection schemes (designed for uni-directional power
flow) inadequate,

2. peak electricity demand non-coincident with PV generation approaching a medium voltage network capacity, and

3. supply voltages in a low voltage network that are above or below allowable thresholds.

To address these three key problems we propose two receding horizon optimization-based algorithms that incorporate updates in forecast information at each time step. Both algorithms include one or more of the objective functions presented in Chapter 5, and are applied to a GridLAB-D model of an Australian distribution region located in the suburb of Elermore Vale, NSW to assess the distributor benefits.

- The final chapter draws conclusions and describes possible future research directions.