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Energetic and economic optimisation of islanded household-scale photovoltaic-plus-battery systems

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ABSTRACT

This paper examines combinations of photovoltaic (PV) generation plus battery energy storage for islanded electricity systems from energetic and economic perspectives, using hourly solar resource data, and 17 household-scale demand profiles, for Christchurch, New Zealand. Optima for normalised storage, expressed as a proportion of annual demand, and for energy returned on energy invested (EROEI), occurred at energy penetrations ranging from 2.50 to 4.00. The ratio of maximum to minimum daily demand predicted optimal storage capacity and EREOI. Improved optimal EROEI values occurred following reductions in embodied energy and at lowered penetrations with longer battery lifetimes. Energy spillage at the optimal penetrations was spread relatively evenly over the year, with the exception of several weeks during winter, and final discharge depths averaged 3.1%. Economic optima, expressed as net present cost, occurred at energy penetrations ranging from 3.00 to 5.00. Reductions in PV panel and battery capital costs, and a longer battery lifetime, reduced the penetrations at which economic optima occurred, and in some cases these coincided with energetic optima. It is suggested that both energetic and economic optima need to be evaluated in the planning process, and that the role of secondary loads be investigated in future research programmes.

1. Introduction

Energy storage requirements for islanded electricity systems utilising variable generation have been shown to be substantial when these systems have been sized to provide the annual demand, including storage charging and discharging losses, exactly. For example, normalised storage capacities, expressed as a fraction of annual demand, ranged from 0.062 to 0.345 for modelled wind-storage and photovoltaic (PV)-storage systems when these were designed to meet community-scale domestic load profiles [1]. Systems with reduced storage capacities have been identified by previous researchers seeking economic cost minima as summarised in Ref. [2] and reported more recently [3,4]. Such solutions have been obtained by specifying generation over-capacity, i.e. installed capacity in excess of that needed to provide the annual demand plus storage-related losses, with consequent energy spillage (in practice curtailment or diversion to dump loads), or alternatively the utilisation of secondary loads. In a simulation study involving a large electricity network in the USA and conducted at hourly resolution over 4 years, Budischak et al. [3] used variable renewables to supply 30%, 90% and 99.9% of electricity demand. Surplus electricity was directed in the first instance to one of three storage options, then any remaining electricity was used to meet heating loads, replacing fossil-gas, and finally, any residual electricity was spilled. For the 90% and 99.9% cases (the 30% case produced very little surplus), an optimal economic solution was found when renewables generated 180% and 290% of the initial total demand, respectively. Similar results may be derived from an economic optimization study of stand-alone household and commercial PV-plus-battery systems at 5 different locations in the USA [4]. These authors explored optimal combinations of PV installed capacity and battery storage capacity from a net present cost (NPC) point of view, using hourly load profiles for a typical meteorological year in conjunction with modelled hourly PV generation. Examination of the results for the year 2014 (Table 1) illustrated that the economic cost optima were obtained when electricity production was between approximately 2.0 and 2.2 times the annual demand (Table 2).

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Table 1
Residential PV-plus-battery system characteristics for 2014 (from Ref. [4]).

Location	PV[a] kWp	Battery[a] kWh	Demand kWh/y	Energy generated kWh/y
Honolulu, Hawaii	20	95	14,481	31,952
Los Angeles, California	10	65	7914	16,057
San Antonio, Texas	20	220	15,247	31,030
Louisville, Kentucky	20	220	12,837	27,180
Westchester, New York	20	240	11,927	25,959

Note: [a] installed capacity for the economically optimal combination.

The energetics of household-level systems with generation over-capacity, reduced storage capacity and energy spillage have been examined for simulated stand-alone wind-battery and PV-battery systems on three Greek Islands [2]. Based on modelling at hourly resolution over a 1-year period these authors demonstrated: a) that energy storage requirements fell sharply as generation over-capacity increased, and b) the existence of minima for system embodied energy and for energy payback period (EPBP). For wind-battery and PV-battery systems, using lead-acid batteries, EPBP values for the optimal configurations where the systems met demand only and excess electricity was spilled were approximately 8.2–19.1 years for the wind-battery systems and 10–12 years for the PV-battery systems. On assuming that all surplus electricity was utilised i.e. that secondary loads were available, the EPBP values decreased to less than 2 years and 4.5 years respectively. Similar findings regarding the rapid decline in storage capacity and the existence of cost minima were reported in an economic optimisation study on three different Greek islands [5].

Decreases in the economic costs of both PV systems and battery storage, particularly at the household level, plus recently emerging evidence of householder aversion to rising electricity prices and a desire for self-sufficiency, have been identified as potential drivers of grid defection e.g. Refs. [6–8]. Bronski et al. [4] concluded that: a) grid parity for PV-plus-battery systems, or a “utility in a box”, had already arrived for some parts of the USA; b) that utilities would begin to see revenue decay from such systems, even before grid defection becomes more widely economic; and c) grid defection would result in the demise of traditional utility business models. However, other researchers have suggested that grid defection may not be beneficial at the individual household level. Using a decision support model, at 30-min resolution over 1 year for PV-battery systems in selected Australian households, Khalilpour and Vassallo [9] found that grid defection was, for most cases modelled, not the best economic option for householders. It was concluded that 100% independence would require “… a very large PV-battery system which is subject to significant capital costs”, and a degree of load defection was suggested instead. Whilst concerned only with grid-tied systems, an economic modelling study of household electricity production in Germany concluded that “while the consumption of self-produced electricity is beneficial from the single household's perspective, it is inefficient from the total system perspective” [10].

Given this background, it is of interest to investigate whether or not energetic optima for PV-battery systems are coincident with economically optimal solutions. In addition, similar studies to that reported in Ref. [2] for temperate climate countries, and using Li-ion battery technology, would be of value. Apart from a study on hybrid systems by Malheiro et al. [11], the literature appears to contain little detailed information on the time series behaviour of energy storage systems relevant to cases where energy spillage is incorporated as a design principle, and a need for further investigation is indicated. The latter point has implications for understanding the timing of spill events, and the state of charge of the storage technology over time. The objectives of this research were therefore to: a) determine and compare energetically and economically optimal PV-battery combinations for a range of household-scale demand profiles in a temperate climate country; and b) to understand the temporal behaviour of the storage system with respect to energy spillage and state of charge.

2. Methods

2.1. Data sources

Global solar radiation and temperature data measured at a climate station located in Christchurch (43.5° S, 172.6° E) were sourced from a national database [12]. All data were hourly totals, or hourly averages, and were reported at New Zealand Standard Time (NZST). Any gaps found in the climate station data sets were filled, either by interpolation, or by inserting data from adjacent, or similar, time periods.

Demand data originated from electricity load measurements covering 30-min intervals between 1 January 2012 and 31 December 2012, for 2200 individual households in Christchurch, New Zealand [13]. The households were classified in Ref. [13] according to annual electricity use, the presence or absence of electrical space heating and electrical water heating, daytime occupancy, and the type of night rate water heating tariff, resulting in 32 categories, of which 17 were populated. Median values for all half-hourly periods within each populated category were then used to create the 17 profiles, key characteristics of which are shown, in descending order of annual demand, in Table 3. The use of median values arose from a requirement from the data supplier to preserve individual household anonymity. For

Table 2
Residential system performance parameters for 2014 (after Ref. [4]).

Location	Normalised storage	Penetration (energy)[a]	Capacity factor (energy generated)	Capacity factor (energy used)
Honolulu, Hawaii	0.007	2.21	0.182	0.083
Los Angeles, California	0.008	2.03	0.183	0.090
San Antonio, Texas	0.014	2.04	0.177	0.087
Louisville, Kentucky	0.017	2.12	0.155	0.073
Westchester, New York	0.020	2.18	0.148	0.068

Note: [a] energy generated/energy demand.