ON EQUITY IN A DISTRIBUTED ELECTRICITY SYSTEM: VOLTAGE MANAGEMENT IN SOUTH AUSTRALIA

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Overview

Distribution network operators, regulators and policy makers worldwide continue to grapple with the challenge of increasingly distributed electricity systems with growing penetrations of distributed energy resources (DER). As one example, globally, near 40GW of distributed 'rooftop' PV alone installed in 2017, almost 40% of total installations. Despite its growing role, there remains a stark lack of visibility over distributed energy resources (DERs) such as rooftop solar PV and residential Battery Energy Storage Systems (BESS) in many jurisdictions, and thus, a distinctly absent evidence base to guide decision making – private, industry, regulatory and policy making. Australia has one of the highest penetrations (proportion of residential dwellings with PV installed) of distributed solar PV in the world, indeed in the state of South Australia PV penetration is 32% with periods already recorded in which 40% of total state demand is being met by distributed PV alone. South Australia therefore provides a useful case study for examining challenges associated with such PV, the trade-offs which will invariably arise between small and utility-scale resources, and between energy users now facing new distributed energy options, and policy implications.

Managing voltage in the low voltage networks with high penetrations of distributed PV is widely cited as the leading challenge for DER integration. Traditionally, network operators have primarily had to contend with peak demand days, designing the network and setting distribution transformer taps so as to ensure adequate voltage at the furthest customers when losses, and hence voltage drop, are highest during these peak demands. Such network settings mean that voltage often sits near its upper allowed range. However distributed PV injects power, thus raising the voltage, and as PV uptake has escalated, this has led the already high voltages to sometimes exceed allowable limits. Whilst this may lead to power quality issues for neighbouring consumers, it most negatively affects consumers who have installed PV as the inverter connecting it to the grid will typically shut down once voltage increases above a set, geneally regulated, threshold. As a result, PV customers might be argued to be being penalised; losing both PV generation and the expected income. Such arrangements are, by comparison, benefiting energy users who unduly contribute to peak demand, for example through the use of large air-conditioners.

A number of solutions exist to manage this challenge: on both the consumer and network side of th meter. Some network interventions could be argued to represent good practice, and all consumers can benefit. However some of these solutions also involve a significant cost, and as network capital and operational expenditure is typically recovered from all consumers under sector based network tariffs, such solutions may primarily benefit PV customers, whilst imposing a cost to all consumers. This study evaluates operational data from distributed PV systems in South Australia to estimate the volume of PV generation currently curtailed due to overvoltage, and the resultant financial impact on its owners. The total and distribution of this financial impacts is compared against the cost of some of the network solutions to voltage management. Implications are considered for consumers, policy makers and regulators where the critical concept of consumer choice is explored in the context of a high penetration DER system.

Methods

The analysis utilizes a novel operational data set, kindly provided by Solar Analytics, for 170 households distributed solar PV generation data, local voltage and frequency measurements and household load over March 2017. Data is reported in 30sec increments with all sites located in Adelaide, the capital city of South Australia. Analysis consists of three key steps; first the cost imposed on households with PV due overvoltage curtailment is estimated using operational data and custom algorithms implemented in Python. Secondly, the annualised per customer cost of implementing network solutions for voltage management is calculated, where network solution costs are based upon distribution regulatory proposals and considers expenses directly attributed to voltage management with high PV penetration. The capex is annualized using an assumed weighted average cost of capital (WACC) of 6% and an asset lifetime of 25 years, whilst opex is passed through directly. In the final method step, the cost burden imposed under each model (curtailment or management through network solutions) is compared at a system level and individual level with particular attention to the distribution of impacts.

Preliminary Results

Preliminary results indicate that overall the level of PV curtailment remains relatively small, with an estimated 0.6% of total power being curtailed in the operational data set (noting that the current estimation methodology is highly conservative, as shown in Fig. 1, while the set of household PV systems being analysed are all being provided with on-line PV system diagnostics including potential output losses so might be expected to exhibit lower curtailment than non-monitored systesms). Whilst the PV curtailment is limited, it must be noted that the data set provides insight into March 2017 conditions with further curtailment expected as PV penetrations grow. Critically, the impact disproportionally affects some customers, with the worst affected losing an estimated 26% of generation due to curtailment (Fig. 2). Fig. 2 compares the approximate annualized cost of curtailment for the 40 most affected consumers studied with the annualized network solution cost per consumer. The lower estimate of curtailment cost assumes lost Feed in Tariff revenue (6c/kWh) and the upper estimate assumes that PV is curtailed when there is behind the meter load (as observed in some cases), therefore imposing a penalty equal to the retail rate (25c/kWh). It also indicates an approximate annual 3kWh BESS cost, noting that these systems are similarly inverter connected and it have been reported as unable to operate (even to act as a load) when voltage is high. It is clear that a residential battery system is not the preferable option for the majority of consumers (ignoring other benefits), and that the network solution is preferable only for the most affect 4%-17% of PV customers studied.

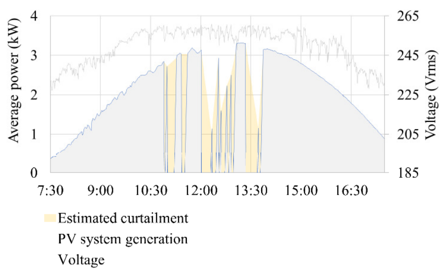

Fig. 1 – Estimated PV curtailment

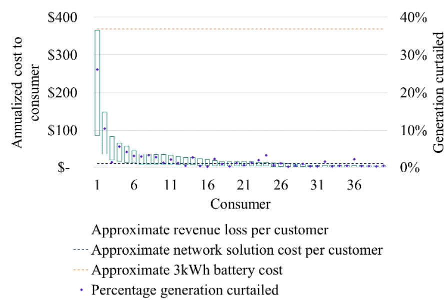

Fig. 2 – Annualized cost comparison

Upscaling across the fleet of installed PV in South Australia, the value of this lost energy is $0.6m - $1.8m p.a. In comparison, initial network solutions are estimated to have a total annualized cost of $9.7m ($8.7 capex and $1m opex), suggesting that it may currently be preferable to curtail PV, although it is of note that such a comparison should take into account forecast PV growth and projected future curtailment, as well as other values of distributed PV such as avoided losses and reduced carbon emissions, while there may often be network solutions that involve very little expenditure and, indeed, represent good practice.

Conclusions

Preliminary results suggest that whilst PV loss due to steady state voltage constraints affects a limited proportion of households even in a State with likely the highest residential PV system contribution in the world, the financial penalty for these unlucky households can be significant, and is largely beyond the individual's control. Comparatively, the works proposed by network operators would be preferable for roughly 4%-17% of households, *if* these successfully rectified voltage constraints at these properties (not a given outcome). The issue remains however, that whilst 4%-17% of PV households would logically support network spend, the cost would be imposed across the entire electricity consuming population of South Australia and that as the costs increase with PV penetration, footing the bill for a neighbour's PV system may no longer be considered socially acceptable.

Two critical policy challenges emerge from this analysis: firstly, what should be the extent of individual choice the electricity system? Specifically, is it acceptable that PV systems are prevented from generating electricity during high voltage *not only when exporting*, but also during periods when the household in question is consuming power, thereby robbing the individual of their ability to change their load profile behind the meter. Secondly, what is an acceptable level of cross subsidisation between households given the extent to which their behind the meter decisions (regarding both generation and load) can impact network costs? As just one example, households with ducted air-conditioning effectively receive very significant cross-subsidies from other consumers under current tariffs, as do consumers in remote areas. Set against the backdrop of a changing climate, strong legacy social objectives and the shift to cost reflective network tariffs, this question is non trivial. However we argue that a useful and necessary step is to quantify current financial impacts arising from distributed PV and the distribution of these impacts. The key point is that what we expect as a society from a high penetration DER electricity system is unresolved. In Australia and perhaps other jurisdictions worldwide, ambiguities in social expectation and rapidly changing electricity systems make it imperative that we reconsider what is meant by the long-term interests of consumers in a rapidly warming world, and one that appears increasingly beset by inequality.