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# The Marginal Economic Benefits of Centrally Controlled and Maintained Virtual Power Plants

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## Abstract

Virtual power plants are expected to be integral components of nascent intelligent large-scale electricity systems, as they enable the integration of distributed energy resources (DERs) to form a coalition to trade in wholesale markets in a profit-maximising, system-stabilising and sustainable way. This investigation develops a new internationally replicable model to estimate the economic outcome when a central body, such as an electricity retailer, community organisation or utility, owns, deploys, co-ordinates and maintains many DERs in a specific market. Australia's National Electricity Market is used as a case study to analyse the marginal economic benefit a retailer receives when DER systems – including a solar array, battery, smart inverter and smart meter – are deployed across each of the six wholesale markets within the National Electricity Market. From the analysis, eight out of the ten locations have long-term commercial potential, as the estimated internal rate of return (IRR) significantly exceeds the benchmark industry return on investment. The system's ability to conduct daily arbitrages in the wholesale market by centrally charging DERs during price troughs and discharging DERs during price peaks accounts for most of the estimated economic benefit. Wholesale price profiles, wholesale price projections, capital expenditure projections and solar data sets are the inputs with greatest impact on the expected IRR. The maximum IRR that can be attributed to renewable support schemes was very small, indicating that virtual power plant returns are likely to surpass industry benchmarks even in the absence of direct legislative support in this case.

**Keywords:** *Virtual power plant; Renewable energy; Scenario analysis; Distributed energy resource; Demand response.*

## Abbreviations

| | |
|---|---|
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| BOM | Bureau of Meteorology |
| CSIRO | Commonwealth Scientific and Industrial Research Organisation |
| DER | Distributed Energy Resource |
| DG | Distributed Generation |
| DOGMMA | Distributed On-site Generation Market Model Australia |
| DNSP | Distribution Network Service Provider |
| ES | Energy Storage |
| GALLM | Global and Local Learning Model |
| IRR | Internal Rate of Return |
| LGC | Large-scale Generation Certificate |

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| | | | |
|---|---|---|---|
| NEM | National Electricity Market | PV | Photovoltaic |
| NPV | Net Present Value | VPP | Virtual Power Plant |

## 1. Introduction

Virtual power plants (VPPs) are recent innovations that are rapidly attracting global interest due to their ability to trade in wholesale markets by integrating renewable distributed energy resources (DERs) to form a coalition to trade in wholesale markets in a profit-maximising, system-stabilising and sustainable way [1, 2]. These outcomes far surpass the outcomes of passive, independent and non-market orientated renewable DER operation modes. Therefore, VPPs have the capacity to significantly impact the generation mix, contribute to building the nascent intelligent energy infrastructure and supply systems globally and to progress the international renewable generation agenda [1-3].

VPPs have many definitions, though most tend to agree that VPPs are an aggregation of small generating units of different electricity generation technologies connected to the distribution network, which operate as a single power plant via central control of the aggregated units [3-5]. VPPs are modular, with each incremental deployment consisting of three main components: distributed generation (DG) units, energy storage (ES) units, information and communication systems. This study defines one module to be a DER system, as illustrated in Figure 1.

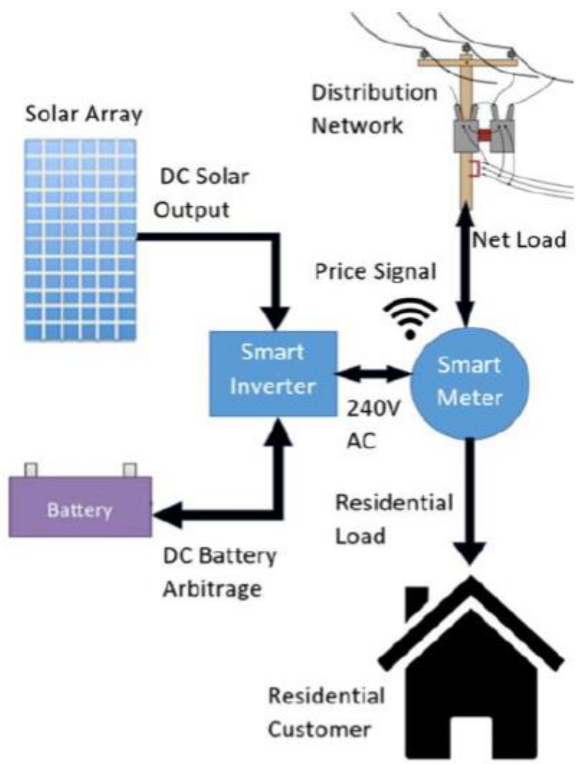


Figure 1: DER system representing one module of a VPP.

VPPs present an opportunity for central bodies such as companies, community organisations and governments to progress the international renewable generation agenda in a potentially lucrative way. There is significant existing literature focusing on the technical optimisation of DG systems to determine the optimal schedules, sites and sizes to reduce power loss, improve voltage profiles and optimise the generation of DG units [6-13]. Recent literature reviews highlight the extent the numerous scheduling problems have been investigated and the associated frameworks developed to solve them, including multi-objective optimisation methods [14, 15]. The most common commercial objectives are maximisation of self-supply and maximisation of market revenue [16]. VPPs are not confined to scholarly literature, they are operational globally [2]. In Australia alone at least four VPPs are already operational [17] and continued pressure from community organisations and the burgeoning renewable energy industry is encouraging the transition to a more renewable generation mix [18, 19]. There is substantial research into the technical implementation and optimisation of VPPs, however, there are few commercial economic optimisations and no commercial economic implementation models to the authors' knowledge.

This investigation is the first study into the marginal economic benefit that a central body – such as an electricity retailer, community organisation or distribution network service provider (DNSP) – could expect to gain if they were to own, deploy, co-ordinate and maintain DER systems in a VPP structure. Specifically, this structure incorporates daily energy arbitrages by charging DERs during price troughs and discharging DERs during price peaks and the purchase of electricity from the wholesale grid and assumed sale to residential consumers.

This investigation uses Australia's National Electricity Market (NEM) as a test market and analyses the marginal economic benefit attained when additional DER systems are deployed across each of the six wholesale markets within the NEM. Public institution source data was used for all stages of the analysis and MATLAB was used to conduct the analysis.

The paper is organised as follows: Section 2 outlines the data sources used; Section 3 describes the investigation method: Section 4 provides the results; Section 5 discusses the results; and Section 6 concludes the paper and outlines potential future work.

## 2. Data Sources

Location-specific time-varying data sourced from public institution reports was used for this analysis and was applied to seasonal profiles over 30-minute intervals for each component of the analysis. Specifically, distribution network load profiles, zoned solar irradiance profiles and regional wholesale price profiles were each converted to seasonal 30-minute intervals. The data sources are tabulated in Table 1.

Table 1. Data sources.

| Dataset | Source | Reference |
|---|---|---|
| Projected capital costs | CSIRO Future Energy Storage Trends | [20] |
| Projected ongoing maintenance | CSIRO Future Energy Storage Trends | [20] |
| Installation costs | CSIRO Future Energy Storage Trends | [20] |
| Distribution network load profiles | AEMO Type 6 Meter Load Profile Data | [21] |
| Zoned solar irradiance profiles | BOM 1-Minute Mean Solar Irradiance Data | [22] |
| Regional wholesale price profiles | AEMO Regional Demand Data Dashboard | [23] |
| Regional wholesale price projections | AEMC Residential Electricity Price Trends | [24] |
| Transmission network tariffs | AEMC Residential Electricity Price Trends | [24] |
| Distribution network tariffs | AEMC Residential Electricity Price Trends | [24] |
| Network tariff projections | Deemed futile (regulatory issues - AER) | [25] |
| Daily annual average residential load | AEMC Residential Electricity Price Trends | [24] |
| Annual average load projections | AEMO National Electricity Forecasting | [26] |

The analysis was conducted across ten locations which spanned the six wholesale markets within the NEM. The analysis used location-specific datasets, as shown in Table 2.

Table 2. Data sets for each location considered.

| Location | Latitude | Solar Datasets | Wholesale Market[a] | Load Datasets | Price & Network Charge Data sets[a] |
|---|---|---|---|---|---|
| Canberra | 35.28° S | Adelaide | ACT | ActewAGL | NSW |
| Sydney | 33.87° S | Adelaide | NSW | Ausgrid | NSW |
| Wagga Wagga | 35.11° S | Wagga Wagga | NSW | Essential Energy | NSW |
| Bourke | 30.09° S | Rockhampton | NSW | Essential Energy | NSW |
| Brisbane | 27.47° S | Rockhampton | QLD | Energex | QLD |
| Longreach | 23.44° S | Longreach | QLD | Ergon | QLD |
| Townsville | 19.26° S | Townsville | QLD | Ergon | QLD |
| Adelaide | 34.93° S | Adelaide | SA | SA Power | SA |
| Hobart | 42.88° S | Cape Grim | TAS | Aurora | TAS |
| Melbourne | 37.81° S | Melbourne | VIC | Powercor | VIC |

[a]*: These regions are Australian states and territories within the NEM.*

## 3. Method

### 3.1 Assumptions

This analysis evaluated DER systems of the following ten solar photovoltaic (PV) arrays: 2.5kW, 3kW, 3.5kW, 4kW, 4.5kW, 5kW, 7.5kW, 10kW, 15kW and 20kW at each location. The analysis made the assumptions shown in Table 3.

Table 3. System assumptions.

| System Factor | Assumption |
|---|---|
| Solar array size (kW) | Specified by the investigation (1.5kW to 20kW) |
| Inverter size (kW) | Nameplate solar array size (1.5kW to 20kW) |
| Battery size (kWh) | Net energy surplus storage requirement |
| Battery charge and discharge time (min) | 30 minutes (one interval) |
| Solar derating factor | 0.85 [27, 28] |
| Li-ion battery round-trip efficiency | 0.90 [20] |
| Li-ion depth of discharge | 0.90 [20] |
| DER system warranty | 10 years [20] |
| DER system life | 10 years (warranted-life) |
| Large-scale generation certificate (LGC) price | $82.30 (September 2017 spot price) |
| Yearly maintenance | $60 per year [20] |
| Installation cost | $400 for <7kWh; function of kWh for >7kWh |
| Daily annual average residential load (kW) | Regional: 0.460kW to 0.976kW [29] |

Array size determines how much energy is produced and therefore how much and at what rate energy can be transmitted and consumed/stored. For calculation simplicity, this analysis has assumed battery sizes and smart inverter limits for each system are also determined by array size. This assumption is reasonable because the charge and discharge capabilities of the battery must at least accommodate power generated from the array [20]. Furthermore, as lithium-ion (Li-ion) is the prevalent energy storage technology used to couple with rooftop solar [20], only Li-ion technology batteries were considered in this analysis. Note also, in practice, inverters sized larger than the array may be optimal as they enable faster charging and discharging at optimal times.

Investigations have shown that solar output can be approximated by including a derating factor that reduces the generation output to account for effects of soiling, wiring losses and nameplate inaccuracies, as well as sub-optimal tilt and azimuth angles if they are not separately accounted for [27, 28]. As this investigation applies a standard system to a variety of locations, optimal tilt and azimuth angles vary and therefore a simplified derating factor is suitable. When tilt and azimuth were accounted for, the derating factor in Australia was calculated to be 0.92 [28]. When all factors were accounted for in the Carolinas, USA, a derating factor of 0.85 was calculated [27, 28], thus an all-encompassing derating factor of 0.85 is deemed a reasonable assumption for this investigation.

The Australian Commonwealth Scientific and Industrial Research Organisation's (CSIRO) Future Energy Storage Trends Report [20] reviewed the datasheets of a cross-section of available battery systems in 2015. A Li-Ion battery round-trip efficiency of 90% and a depth of discharge of 90% was determined.

This investigation has been conservative in assuming that the DER system lifetime matches the expected warranty of the subcomponents. Therefore, a constant 10-year lifetime for each iteration of DER system analysis is assumed.

The $82.30/LGC September 2017 spot price was used as the flat rate renewable scheme support, extending for the lifetime of this analysis. LGCs are Large-scale Generation Certificates, Australia's commercial renewable rebate. This assumption is equivalent to assuming that legislative support of $82.30/MWh will remain for the proposed system, regardless of the scheme name or jurisdiction.

DER systems used the same components in each location except for the battery sizes, which varied according to the cumulative net surplus solar output. This was determined by the amount of solar energy generated from the time the battery was discharged one morning, until it was discharged again in the late afternoon, minus the energy consumed by the household during summer. This cumulative amount was then rounded up to the nearest kWh to 'size' the battery, at a specific location for a specific size system.

Table 4. Battery sizes chosen for Canberra location.

| Array Size (kW) | Inverter Size (kW) | Storage Requirement (kWh) | Battery Size (kWh) |
|---|---|---|---|
| 2.5 | 2.5 | 7.7 | 8 |
| 3 | 3 | 10.5 | 11 |
| 3.5 | 3.5 | 13.5 | 14 |
| 4 | 4 | 16.5 | 17 |
| 4.5 | 4.5 | 19.5 | 20 |
| 5 | 5 | 22.5 | 23 |
| 7.5 | 7.5 | 37.0 | 38 |
| 10 | 10 | 53.5 | 54 |
| 15 | 15 | 84.9 | 85 |
| 20 | 20 | 116.2 | 117 |

For example, for the Canberra analysis the storage requirement and corresponding battery sizes selected for each system are shown in Table 4.

For the economic sensitivity analysis, the complete DER system, as well as the component standalone ES and standalone PV systems were evaluated for each location. The cashflow assumptions made for each of these systems are highlighted in Table 5.

Table 5. Capital expenditure & cashflow assumptions for each system type.

| System Type | Capital Expenditures | Cashflows |
|---|---|---|
| **DER System** | Array capital expenditure; battery capital expenditure; inverter capital expenditure; installation cost | Wholesale value of solar energy produced; transmission network charge reduction; distribution network charge reduction; battery arbitrage (with added solar value); 'Green Credits' (LGC value); ongoing maintenance cost |
| **PV System** | Array capital expenditure; inverter capital expenditure; installation cost | Wholesale value of solar energy produced; transmission network charge reduction; distribution network charge reduction; 'Green Credits' (LGC value); ongoing maintenance cost |
| **ES System** | Battery capital expenditure; inverter capital expenditure; installation cost | Battery arbitrage (without added solar value); ongoing maintenance cost |

### 3.2 Procedure

The global and local learning (GALLM) model produced by CSIRO was used as the basis for capital expenditure projections extending from 2017 to 2035. The GALLM model is an endogenous technological learning model that accounts for complex changes in the global and local environments. This model uses a consistent, robust and transparent methodology. The GALLM model projects that PV prices, Li-ion prices and smart inverter prices will continue to fall due to technological maturity and scale benefits, with the greatest drop coming from the least mature technology – Li-ion batteries [20]. Projections made by alternative investigations in other jurisdictions, whilst lacking the same robust methodology and proximity to the Australian market, are within the maximum and minimum bounds of the GALLM projections [30]. The GALLM model also projects no material change in price of installation costs or on-going maintenance costs, as they are largely manual tasks with established processes [20]. This analysis has chosen to use the projected minimum, base and maximum case prices produced by the GALLM model as its capital expenditure projections.

The Australian Energy Market Operator (AEMO) is responsible for conducting the market activities within the NEM. AEMO reports 30-minute interval wholesale price data by state and 30-minute interval load data by DNSP [23]. AEMO predicts annual average loads and consumption profiles to remain steady over the long term. They were assumed constant from 2016 onwards in this analysis.

The Bureau of Meteorology (BOM) provides national 1-minute interval mean global irradiance levels at key regional centres [22]. For each location, annual data sets were processed and averaged across seasonal 30-minute intervals (2014, 2015 and 2016 data sets when available). For locations where no specific data stations were present, stations in the same solar exposure zone were used. This study considered solar irradiance forecasting as outside its scope. Seasonal mean global irradiance profiles sourced from the BOM were converted into seasonal mean solar output profiles using Eq. 1 [27].

$$PV_{output} = 0.85 \times pv_c \left(\frac{I_m}{1000\, W/m^2}\right) \times [1 - 0.005(T_c - 25^oC)]\ (kW) \quad (1)$$

where

0.85 is the total system derating factor (including wire, azimuth angle, tilt and other losses);

$pv_c$ is the nameplate capacity of the system;

$Im$ is the incident solar radiation; and

$T_c$ is the module's temperature – assumed to be 25°C to simplify analysis.

Thus, the final equation used to calculate solar output from mean global irradiance becomes

$$PV_{output} = 0.85 \times pv_c \left(\frac{I_m}{1000\, W/m^2}\right)\ (kW) \quad (2)$$

The value of solar output was calculated by converting 30-minute interval solar output data to MWh and then multiplying by the corresponding wholesale price interval (same 30-minute interval, same season). This data was used to calculate the annual solar output profiles.

The value of LGCs generated were then calculated. VPPs qualify for provisional accreditation as a decentralised power station under the Australian Renewable Energy Regulations Act [31], as they meet the requirements specified in Part 2.

An LGC is created each time eligible generation systems produce 1MWh of electricity. After adjustments are made to account for the nature of VPPs, the final equation used to calculate LGCs generated is

$$Eligible\ MWh = TLEG \quad (3)$$

where

$TLEG$ is the total amount of electricity, in MWh, generated by the power station in the year. This is equal to the cumulative solar output (in MWh) and is calculated by averaging the seasonal cumulative daily solar output and multiplying by 365/1000.

Historical average 30-minute spot pricing for each jurisdiction in the NEM is published online by AEMO [23] and FY2016-17 data was used to aggregate a seasonal mean daily wholesale price profile across each region. Wholesale pricing profiles use only FY2016-17 data for two reasons: 1) Material changes in volume-weighted average wholesale price have occurred over the past 3 years; 2) the volatility of the profile would be substantially reduced by averaging data sets. This volatility is critical to approximating the value of the battery arbitrage opportunity. Calculating seasonal mean daily prices by seasonally averaging a year's data still materially reduces the day-to-day volatility of the pricing profile and masks the revenue opportunities presented by extreme movements. The prevalence of these extreme wholesale price peaks has been rising steadily over the past five years in the NEM [32]. Therefore, the economic analysis conducted by this investigation understates the financial potential of the battery arbitrage. Regional indexed pricing projections from 2017 to 2037 [24] were used as a proxy for forecasted changes in baseline wholesale electricity prices, as well as volatility. Cash flows from each of the system component elements were adjusted yearly to reflect these projected changes in wholesale prices. A minimum, base and maximum case were analysed.

As Australia's generation mix progressively contains more wind and solar PV, Australia's electricity supply becomes increasingly variable and so the rising prevalence of extreme price peaks is expected to continue in coming the decade [24]. While increasing volatility was not directly accounted for, regional indexed pricing projections developed by a government-commissioned study [24] were used as a proxy for forecasted changes in baseline electricity prices and volatility. Minimum, maximum and base case price projections by distribution network region for 2015 to 2037 were made. Cashflows from 2037 onwards were assumed constant for the remaining system lifetime. These projections use the DOGMMA (Distributed On-site Generation Market Model Australia) which is robust, reliable and forms the basis of electricity demand forecasting reports by AEMO and retail competition reports by the Australian Energy Market Commission (AEMC) [24, 29].

Transmission and distribution network charges are determined by the Australian Energy Regulator (AER). Firstly, the DNSP submits a Tariff Structure Statement proposal and the AER makes a decision on recoverable costs, using the proposal as one of the many inputs the decision-making process [25]. These decisions are typically reviewed every five years. The AER's latest decisions have been strongly contested by DNSPs and there is significant legislative uncertainty surrounding transmission and distribution network charges in both the short and long-term [24, 25]. This investigation has therefore used FY2016-17 regional transmission and distribution network charges [24] and has projected these as constant rates throughout the analysis. The value of network charge reductions was calculated. This is dependent on the residential load that is displaced by the solar output, as network charges are made in cents per kWh. Since solar output and residential load are assumed to be constant over the analysis lifetime for each array size, displaced load and reductions in transmission and distribution network charges are also constant.

After inspection of the mean wholesale price profiles of each region, it became clear that there tended to be a morning peak and trough, as well as an afternoon peak and trough. Thus, it was determined that two battery arbitrage cycles (morning and afternoon), where the battery is fully charged at the trough and fully discharged at the peak, was an appropriate assumption to make. For each season at each location, both arbitrage cycles were first tested for viability. The morning and/or afternoon price differential had to overcome battery efficiency limits, as well as the distribution network charge that would be incurred, as shown by the following

$$\frac{Price\ Differential}{Round\ Trip\ Efficiency\ \times\ Depth\ of\ Discharge} > Distribution\ Network\ charge \tag{4}$$

After calculating the threshold limits of the energy arbitrage differential, arbitrage profit was calculated for a stand-alone ES system and for complete DER system (batteries and solar combined). The DER system unlocked greater value as the solar energy supplied did not have to be purchased at the morning minimum and was not subject to the distribution network charge hurdle. Note that any local price minimum followed by local price maximum that creates a price differential larger than the distribution network charge threshold is a potential arbitrage opportunity. Thus, the potential number of arbitrages is restricted only by the number of times the pricing differential crosses the threshold in a day. The mean calculation of the wholesale price profile and consequent 'double peak' arbitrage method understates the daily volatility of the wholesale price curve. In practice, the arbitrage value realised would likely be larger.

Economic analyses require financial calculations to compare the value of projects over time. These valuation methods can typically be categorised into net present value (NPV) methods, rate of return methods, ratio methods, payback methods and accounting methods [33]. Two valuation methods are usually desirable for analysing a project [33, 34]. NPV and internal rate of return (IRR) have been shown to yield independent results that do not need to be used in conjunction with other methods, however, each has its disadvantages. NPV ignores the size of the project and requires a discount rate to be specified, where IRR implicitly assumes reinvesting cashflows at the IRR [33]. Since the IRR calculation allows a company with a set capital budgeting hurdle rate to accept or reject a project, or compare projects competing for the same financial resources, it was used in this research as a comparison tool. The cashflow re-investment assumption is considered reasonable over the projection timeline as it is unlikely market saturation would be reached. In this case, IRR can be and was, used to explicitly benchmark DER system returns against industry return on capital invested for DNSPs (6.2% [25]) and electricity retailers (12% [29]) to determine the commercial viability of the proposed VPP.

Payback period was chosen as the second valuation method as it offers valuable insight into the cashflow profile and liquidity requirements of projects and can be easily understood by people unfamiliar with engineering economics [33]. The disadvantage of the payback period is that it does not account for the time value of money and ignores cash flows after the payback period [33, 34]. In this paper, figures displaying payback period illustrate the payback period for a specific module commissioned in that year.

A MATLAB script was developed to execute each of these calculations and applied iteratively for each location. Once the cashflows were calculated, the IRR and payback periods for commissioned systems in years 2017 to 2035 were calculated for maximum, minimum and base cases. Finally, the analysis assumptions were tested by an iterative process of input assumption variation and result comparison. The understanding developed from this process was comprehensive, providing insight into how system scale, location and the passage of time are expected to impact expected returns on investment.

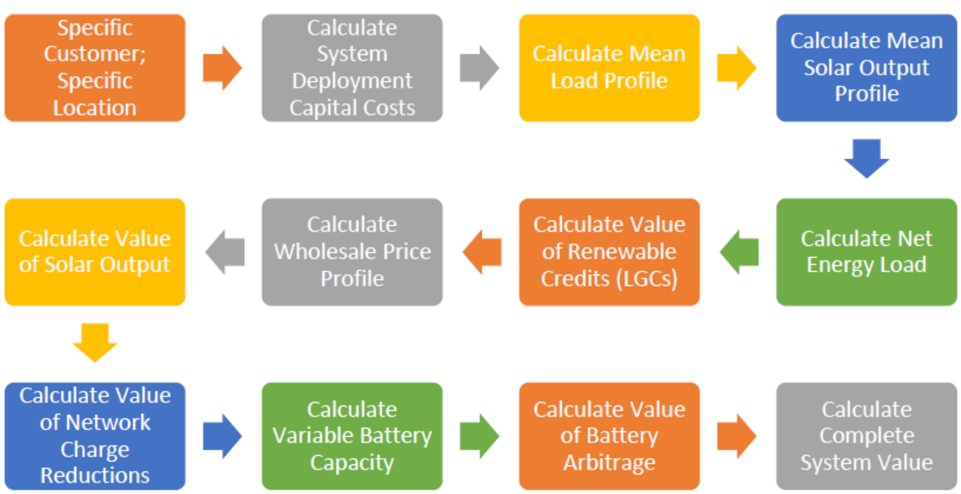

Figure 2. Generalised investigation methodology.

In summary, a specific customer type (residential) at a specific location was selected. Their mean load profile over 30-minute intervals was calculated, followed by solar output and then net load.

Next, renewable energy (LGC) value was calculated from the solar output. Then, 30-minute wholesale price was calculated and consequently, the value of solar output, network charge reduction, battery arbitrage and complete system value. This process isolates stand-alone component values as well as the complete system value where stand-alone component values have been determined, simplifying assumptions such as constant installation costs, constant maintenance costs and constant inverter costs are assumed. This process is outlined in Figure 2.

## 3. Results

Using the assumptions specified above (Tables 3 - 5), analyses were conducted for each location. The Canberra IRR analysis results for the complete DER system under base case assumptions are shown in Figure 3 and the corresponding payback period results are shown in Figure 4.

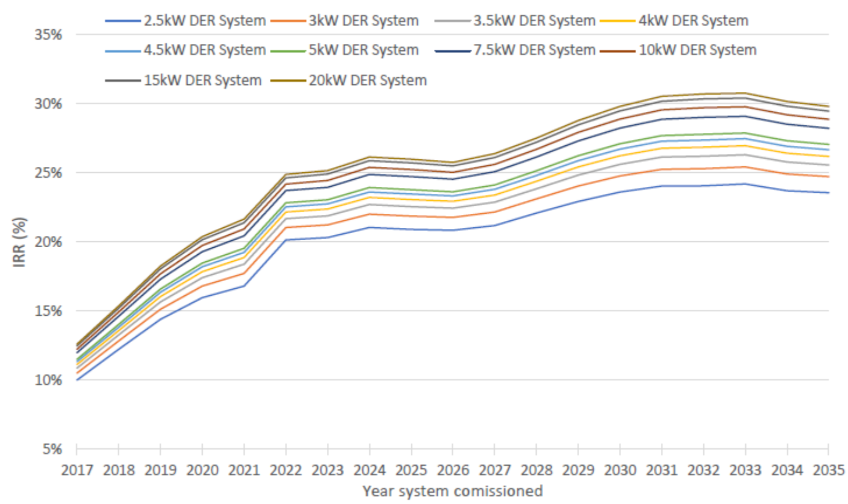


Figure 3. Canberra IRR analysis (complete DER system, base case).

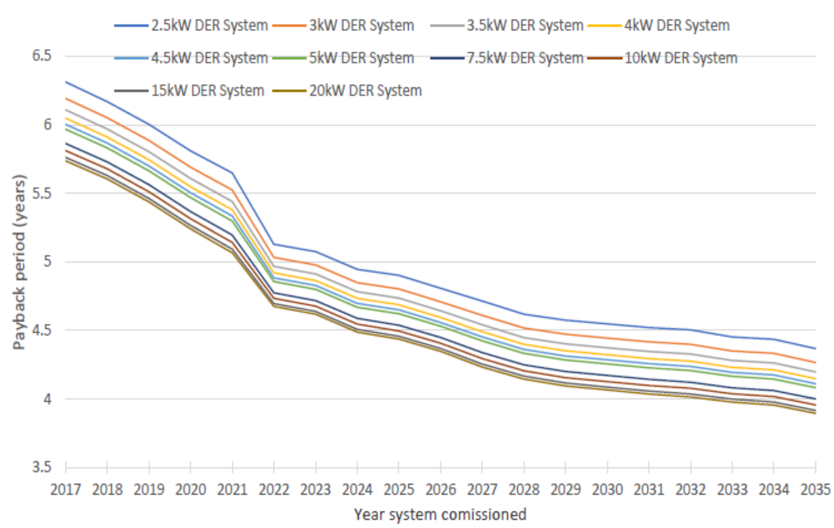


Figure 4. Canberra payback period analysis (complete DER system, base case).

For each location, IRR and payback period follow consistent trends, specifically IRR increases with system size up to a limit and IRR tends to increase with year commissioned, as illustrated in Figures 3 & 4. Thus, representative systems were compared from each location in results tables. Specifically, four comparative analyses were conducted:

1. IRR and payback period results between locations for 5kW systems were compared. This ranked locations on a yearly basis and highlighted component system values (Table 6).
2. IRR spread for each location was compared. This enabled each location's relationship between system value and system size to be quantitatively evaluated (Table 7).
3. Differences between the minimum, base and maximum case IRR differentials were compared. This enabled each location's and each system's sensitivity to be calculated (Table 7).
4. Differences in expected cashflow compositions between locations were compared. This highlighted the added value the combination system creates, or 'the system synergy' (Table 9).

Table 6. IRR results for a representative 5kW array system, base case.

| Location | 2017 IRR (base case, %) | 2035 IRR (base case, %) | Avg. IRR (base case, %) | IRR rank |
|---|---|---|---|---|
| Longreach | 16.7 | 33.9 | 28.9 | 1 |
| Townsville | 15.7 | 32.3 | 27.5 | 2 |
| Brisbane | 13.9 | 28.7 | 26.1 | 3 |
| Adelaide | 17.4 | 28.7 | 25.5 | 4 |
| Bourke | 12.5 | 28.2 | 24.1 | 5 |
| Canberra | 11.5 | 27.1 | 23.1 | 6 |
| Wagga | 11.0 | 25.8 | 21.9 | 7 |
| Sydney | 11.0 | 25.6 | 21.8 | 8 |
| Melbourne | 3.3 | 13.1 | 8.9 | 9 |
| Hobart | -2.3 | 5.1 | 2.2 | 10 |

Table 7. Scale sensitivity analysis between 2.5kW & 20kW array systems summary.

| Location | IRR differential (%, absolute) | IRR differential (%, relative) | Differential rank |
|---|---|---|---|
| Canberra | 5.2 | 25.8 | 1 |
| Sydney | 3.9 | 19.5 | 2 |
| Wagga | 3.8 | 18.8 | 3 |
| Bourke | 3.4 | 15.4 | 4 |
| Adelaide | 3.4 | 14.3 | 5 |
| Brisbane | 3.1 | 12.7 | 6 |
| Townsville | 3.3 | 12.6 | 7 |
| Longreach | 3.4 | 12.3 | 8 |
| Melbourne | 0.2 | 1.8 | 9 |
| Hobart | -0.8 | -24.8 | 10 |

Table 8. Maximum & minimum case sensitivity analyses for a representative 5kW array system.

| Location | Average % DER min deviation | Average % DER max deviation | Average % PV min deviation | Average % PV max deviation | Average % ES min deviation | Average % ES max deviation |
|---|---|---|---|---|---|---|
| Longreach | -44.7 | 41.1 | -64.0 | 54.2 | -67.0 | 66.6 |
| Townsville | -45.8 | 41.9 | -70.9 | 60.2 | -68.0 | 67.5 |
| Brisbane | -47.0 | 42.8 | -80.9 | 69.0 | -69.2 | 68.5 |
| Bourke | -59.4 | 49.7 | -79.2 | 61.5 | -150.7 | 128.9 |
| Wagga | -63.1 | 52.7 | -91.4 | 71.0 | -150.7 | 128.9 |
| Sydney | -63.3 | 52.9 | -90.1 | 70.0 | -150.7 | 128.9 |
| Canberra | -64.1 | 51.1 | -96.9 | 75.0 | -106.6 | 88.5 |
| Adelaide | -65.4 | 69.5 | -96.8 | 91.5 | -112.2 | 127.5 |
| Melbourne | -128.1 | 154.8 | -25.3 | 21.1 | 30.9 | -83.6 |
| Hobart | - | - | -66.8 | 74.7 | - | - |

Table 9. Cumulative system revenues for a representative 5kW array system.

| Location | Average system revenues ($) | Avg. PV (% total) | Avg. battery (% total) | Avg. added value (% total) | Ranking by added value |
|---|---|---|---|---|---|
| Melbourne | 32,664 | 60.0 | 3.3 | 36.7 | 1 |
| Bourke | 54,427 | 47.4 | 31.0 | 21.7 | 2 |
| Hobart | 21,507 | 75.9 | 2.9 | 21.3 | 3 |
| Wagga Wagga | 50,892 | 47.1 | 33.1 | 19.8 | 4 |
| Adelaide | 58,735 | 39.8 | 41.0 | 19.3 | 5 |
| Sydney | 50,707 | 47.6 | 33.2 | 19.2 | 6 |
| Brisbane | 58,808 | 39.6 | 42.5 | 18.0 | 7 |
| Longreach | 65,435 | 40.5 | 41.6 | 18.0 | 8 |
| Townsville | 62,007 | 40.1 | 42.1 | 17.9 | 9 |
| Canberra | 53,450 | 44.0 | 41.0 | 15.1 | 10 |

The comparative expected return on capital invested for the DER system and its component systems is highlighted in Figure 5.

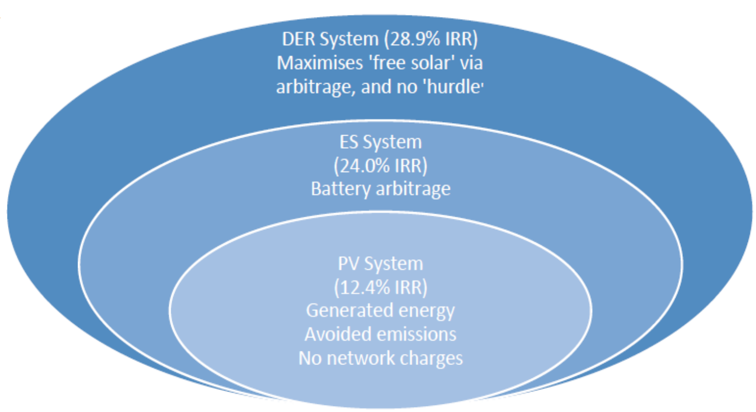


Figure 5. IRR comparison of the DER system and its component systems for Longreach.

## 5. Discussion

The results reveal that eight out of the ten locations analysed have commercial potential, as the estimated IRR significantly exceeds the benchmark industry returns over the warranted-life of the system, i.e. 6% for DNSPs [25] and 12% for electricity retailers [29]. For each of these locations, the average estimated payback period is also below five years. The subsequent comparison and extrapolation of the results regionally, suggests system potential is greatest in South Australia in the short-term and in northern Queensland in the medium to long-term, as shown in Table 6.

The sensitivity of each location relative to system size (Table 7) illustrates that returns tend to correlate positively with system size and that changes are logarithmic in nature and therefore, that returns have a natural limit according to the model. The location with the largest proportionate IRR differential and therefore most sensitivity to system size, is Canberra. This is attributed to Canberra’s relatively high average annual demand (0.835 kW, second only to Hobart), as high average load consumes proportionately more solar output which would have otherwise been used in the arbitrage process for smaller array sizes. This effect is compounded by the low DNSP tariff these outflows are subjected to in Canberra (5.68c/kWh, the lowest). System sensitivities to maximum and minimum case assumptions (Table 7) tend to be heavily region-dependent, with locations in each state ranked one after the other without exception. DER system deviations are also consistently significantly below those of the component system deviations in each location. These observations imply that regional wholesale price projections are the most influential factor affecting the sensitivities of each component system and that complete DER system returns are more stable and reliable than the returns of their respective component systems. Locations in Queensland, the region with the least volatility in its wholesale pricing projections, have the least deviation in the analysis.

The expected cumulative revenues to the central body generated by a representative 5kW system during its 10-year lifetime for each location range from $21,500 (Hobart) to $65,400 (Longreach), as illustrated in Table 9. The locations that benefit the greatest proportionately from the complete DER system coincide with when threshold arbitrage price limits restrict battery arbitrages. These threshold arbitrage limits are a direct combination of the DNSP charges and daily wholesale price differentials, thus in areas with low differentials and high DNSP charges, threshold arbitrage price limits are high and the synergies created increase as a proportion of total system revenues. When the converse conditions apply, threshold values are low and the synergies created decrease as a proportion of total system revenues.

As Table 9 demonstrates, the benefit of the DER system is superior to the sum of its parts. There is significant value created by having the opportunity to store surplus solar energy, and then sell it in the wholesale market at the price peak. This is despite the opportunity cost of the battery arbitrage forgone by storing the solar energy. A stand-alone battery system simply creates value by load-shifting, i.e. charging during price troughs and discharging during price peaks. A stand-alone PV system creates value through the energy it generates, the emissions it avoids (LGCs) and the network charges it avoids. While stand-alone PV systems generate significantly more revenue than stand-alone ES systems, their IRR is substantially inferior due to the greater investment. Overall, the DER system is the configuration that maximises the return on investment, as highlighted in Figure 5.

Further comparative analyses were used to evaluate the investigation’s sensitivity to input datasets. Wholesale price profiles, wholesale price projections, capital expenditure projections and solar data sets are the inputs with greatest impact on the expected IRR (more than 10%). Distribution network tariffs, and average annual load estimates have minor impacts on expected IRR (1% - 2%), while load profiles are immaterial. The maximum IRR contribution of renewable support schemes was estimated to be 3.64%, as this is the average additional IRR for Longreach, the location with the greatest solar irradiance exposure. This indicates that DER system returns are likely to continue to surpass industry benchmarks in the absence of direct legislative support in Australia.

## 6. Conclusions

This paper provides a novel, globally replicable framework to estimate the expected economic benefit of centrally controlled and maintained VPPs for a specific geography or customer type in a very accessible way. VPP business models are already technically feasible, regulatory compliant, and commencing implementation in some markets, however a readily accessible investment evaluation framework did not exist previously. This valuation is critical for early decision-making in the capital budgeting process, and so by providing this simple and practical framework this paper lowers a significant barrier to VPP adoption. It is the authors' hope that by making it easier for decision-makers to develop economic appraisals of VPPs, this paper contributes to progressing our world towards their adoption, and the more rapid realisation of a renewable energy future.

This investigation conservatively calculates that a central body in the Australian NEM (e.g. retailer, community organisation, DNSP) coordinating a VPP could expect to receive a sustained marginal economic benefit of greater than 20% return on investment for eight of the ten locations analysed, well above industry benchmarks for DNSPs and electricity retailers. These results support the commercial viability of a centrally controlled and maintained VPPs. The elevated return on investment advantage would allow, say, an electricity retailer to either reduce their prices and increase market share, maintain prices and increase profits, or take a midpoint approach (reduce prices, increase market share, and increase profitability). Of course, this also relies on price elasticity, marketing and a host of other commercial factors. Furthermore, since the limit of IRR contribution from renewable support schemes was calculated to be 3.64%, DER system returns on investment continue to surpass industry benchmarks in the absence of direct legislative support. These eight locations were representative of Queensland, New South Wales, South Australia and the Australian Capital Territory, which account for 60% of Australia's population. Therefore, the commercial potential of a VPP to facilitate the growth of decentralised renewable energy generation in Australia is independent of public policy support.

Where future economic appraisals are required to be more precise, decision-makers can consider:

- Grouping datasets by week or month (as opposed to season).
- Using smaller time intervals (than 30 minutes).
- Adjusting for the battery charge and discharge time requirement based on inverter size.
- Accounting for all arbitrage opportunities that cross the 'arbitrage threshold' (more than two).
- Accounting for component purchase scale discounts within capital expenditure projections.

There are also four key areas where the research scope of this study could be expanded, specifically:

- The imminent arrival of electric vehicles is an opportunity to conduct an electricity price arbitrage without additional capital outlay for batteries after the vehicle itself is purchased.
- The development of a decentralised VPP gentailer business model to evaluate the potential impact on customer bills, and the market opportunity for new entrants and existing players.
- Quantification of costs for business operational overheads, information and communication systems. The deployment scale needs to overcome fixed costs and reach profitability.
- A comparison of the potential economic benefits to individual members (i.e. households, small businesses) of the VPP with the benefits to the central body.

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