Renewable Energy 38 (2012) 195–205

Contents lists available at ScienceDirect

Renewable Energy

journal homepage: www.elsevier.com/locate/renene

Small-scale (≤6 kW_e) stand-alone and grid-connected photovoltaic, wind, hydroelectric, biodiesel, and wood gasification system's simulated technical, economic, and mitigation analyses for rural regions in Western Australia

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A R T I C L E I N F O

Article history:
Received 24 May 2011
Accepted 20 July 2011
Available online 16 August 2011

Keywords:
Renewable energy
Small-scale
Photovoltaic
Wind
Bioenergy
Hydroelectric

A B S T R A C T

This research develops models and simulations of technical performance, net emission reductions, and discounted market values of thirteen small-scale (≤6 kW_e) renewable energy projects. The research uses a simple methodology suitable for small private entities and governments to compare alternative investment options for both climate change mitigation and adaptation in the southwest of Western Australia. The system simulation and modelling results indicate that privately-owned, small-scale, grid-connected renewable energy systems were not competitive options for private entities relative to sourcing electricity from electricity networks, despite subsidies. The total discounted capital and operating costs, combined with the minimal mitigation potentials of the small-scale renewable energy systems resulted in unnecessarily high electricity costs and equivalent carbon prices, relative to grid-connection and large-scale clean energy systems. In contrast, this research suggests that small-scale renewable energy systems are cost-effective for both private entities and governments and exhibit good mitigation potentials when installed in remote locations far from the electricity network, mostly displacing diesel capacity.

1. Introduction

This research analyses a small range of small-scale renewable energy system technical outputs and overlays current market cost frameworks to explore their cost-effectiveness for the provision of electricity and carbon emission mitigation. The research aims to answer the question "What small-scale renewable energy technologies are currently available for implementation, and are they profitable now in agricultural regions in the southwest (SW) of Western Australia (WA)?" Thus, the research estimates values and uncertainties of both the market adaptation and the market mitigation potential of specific small-scale renewable energy projects relative to current stand-alone and grid-connected options for a representative rural homestead.

Policymakers are increasingly calling upon the research community to provide: effective approaches for identifying and evaluating both existing and prospective adaptation measures and strategies; methods of costing different outcomes and response measures, and; a basis to compare and prioritise alternative response measures, including both adaptation and mitigation [1]. As a response to these calls, this research provides a regionally-specific approach to identify and evaluate existing adaptation measures and outcomes using a quantitative comparative analysis. As there are inadequacies for many analytical frameworks for evaluating the links between adaptation and mitigation [2], the research attempts to provide a limited, albeit precise analytical and institutional framework for an assessment within the context of rural stakeholders making decisions concerning both adaptation and mitigation, and a relatively simple and quantifiable methodology of integrating energy project market prices. In terms of mitigation, policies that provide a real or implicit price for carbon could create incentives for producers and consumers to significantly invest in low-greenhouse gas (GHG) products, technologies and processes [3]. However, various published estimates of carbon prices required to stabilise atmospheric GHG concentrations at around 550 ppm CO_2-e by 2100 are dependent on technological development scenarios up to 2030, and range from around zero to more than 100 USD per tCO_2-e [3–5]. Such a range of potential carbon prices are of little use for current conventional strategic agricultural investments. Therefore, the economic modelling in this research assumes a carbon price of zero in most project scenarios to reflect a current lack of policy to give a real financial value to mitigation in Australia.

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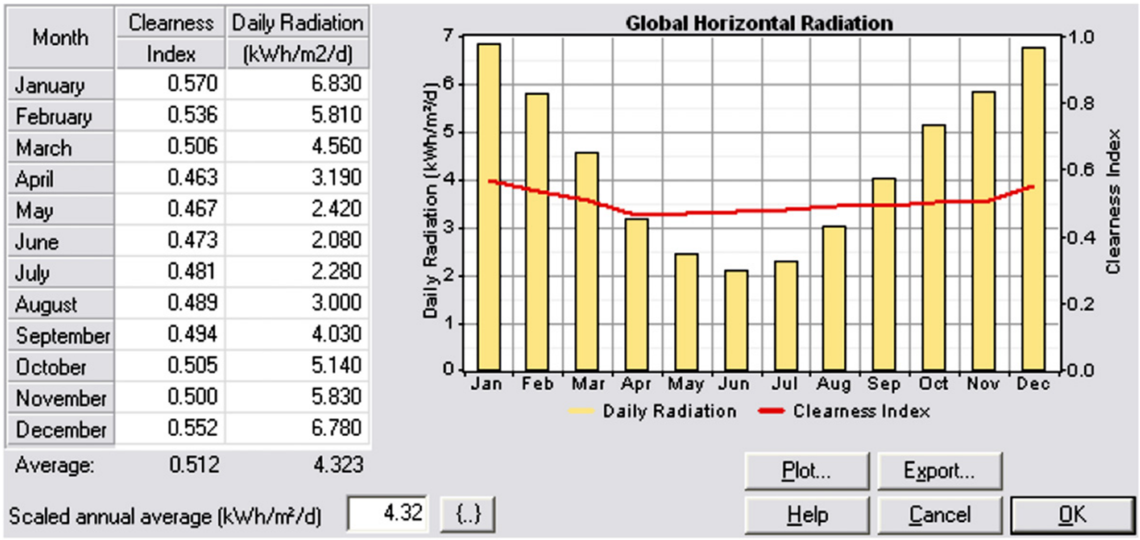
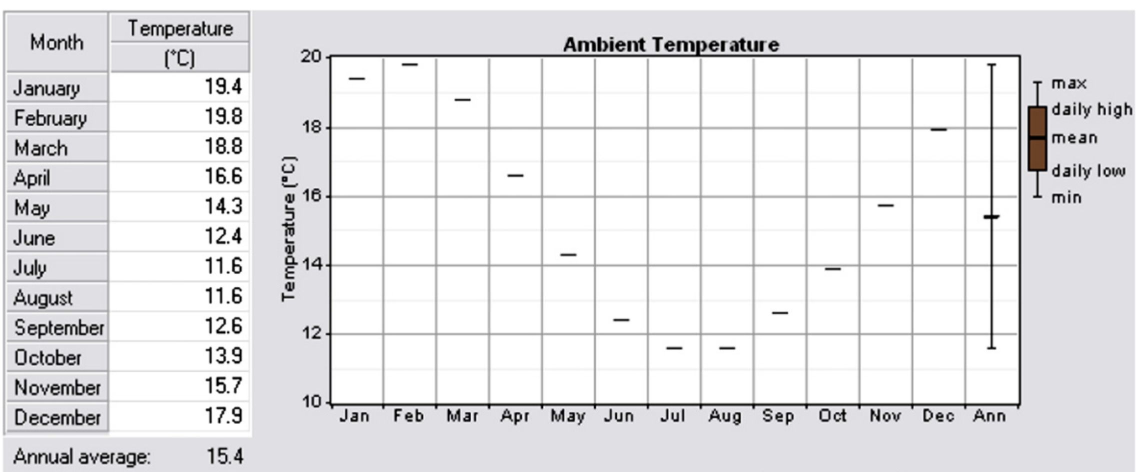
doi:10.1016/j.renene.2011.07.032



Month	Clearness Index	Daily Radiation (kWh/m2/d)
January	0.570	6.830
February	0.536	5.810
March	0.506	4.560
April	0.463	3.190
May	0.467	2.420
June	0.473	2.080
July	0.481	2.280
August	0.489	3.000
September	0.494	4.030
October	0.505	5.140
November	0.500	5.830
December	0.552	6.780
Average:	0.512	4.323

Fig. 1. Annual solar radiation data for Albany airport. Source: [15].



Month	Temperature (°C)
January	19.4
February	19.8
March	18.8
April	16.6
May	14.3
June	12.4
July	11.6
August	11.6
September	12.6
October	13.9
November	15.7
December	17.9
Annual average:	15.4

Fig. 2. Annual and monthly mean ambient temperature data for Albany airport. Source: [15].

Nonetheless, the projects do include CO_2-e accounting for mitigation purposes to inform investors of the technical mitigation benefits or costs and the vagaries of current-day climate policy-making and markets. Enabling an annualised quantification of tCO_2-e emissions for the mitigation potential allows a simple multiplication of tCO_2-e with any future carbon price an investor may be able to secure or project into the future [6]. This method refines the research method to reduce the scenarios required for modelling, and also decreases the uncertainties of final outputs.

2. Data and methodology

This research uses a bottom-up market mitigation methodological approach to obtain the market mitigation potential of selected market adaptation activities using existing technologies [6]. The units chosen to represent the market adaptation potential for each feasibility study were Australian dollars (AUD) to quantify the market adaptation potential, and tonnes of carbon dioxide equivalent (tCO_2-e^{-1}) to quantify the market mitigation potential. Each project's market adaptation and market mitigation potential was described in terms of an "equivalent carbon price" which combined the adaptation potential and mitigation potential of each system[1]. The calculation of both the market mitigation and market adaptation potentials for each year of the project enables the calculation of both marginal market mitigation and adaptation potentials on an annual basis.

2.1. Meteorological data

A 15 year project investment cycle was selected for rural investments to avoid issues of intergenerational discounting, technical lifecycles, to reduce the uncertainty of the economic modelling, and circumvent the use of regional climate projections. The daily solar radiation on a horizontal plane, air temperature, and the wind speed input data were derived from the Bureau of Meteorology (BOM) station at Albany Airport (Station 009741, Lat.(S): −34.9414, Long.(E): 117.8022, 69 m above sea level). The transformed data were sourced from RETScreen's (version 4)

[1] The units of the equivalent carbon price were dollars per tonne of carbon dioxide equivalent emissions (AUD tCO_2-e^{-1}).

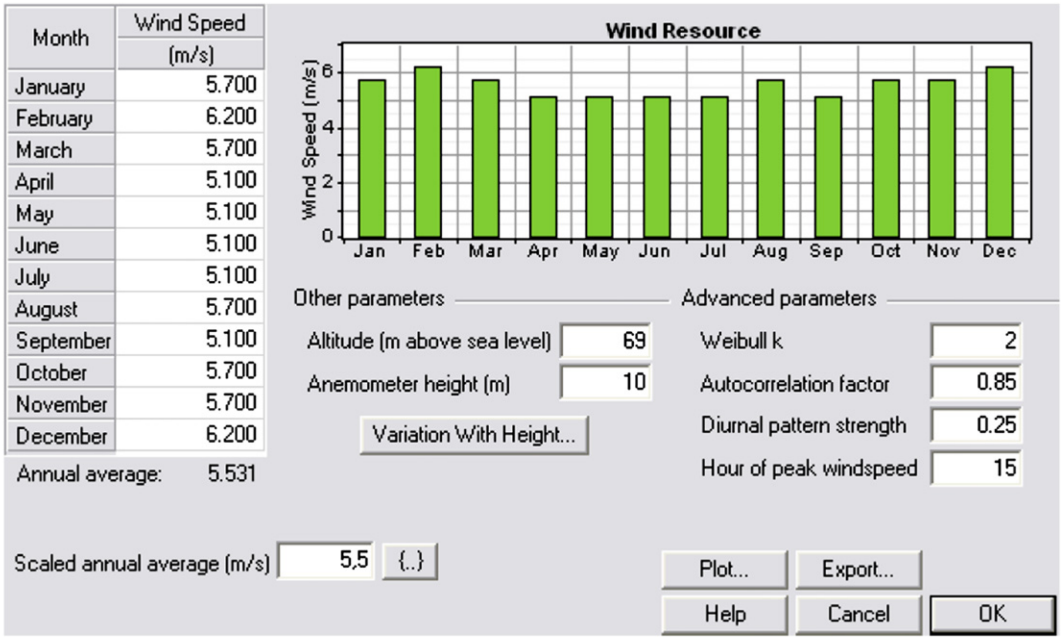


Fig. 3. Annual and monthly mean wind speed data for Albany airport. Source: [15].

climate database which incorporates the improved NASA Surface Meteorology and Solar Energy Dataset. The Albany airport was selected as representative of the focus region as it exhibits many similar meteorological characteristics to most of the population living rural and agricultural regions in WA[2].

The simulated site's annual average clearness index is 0.512, the annual average horizontal plane solar irradiance is 4.323 kWh m^{-2} day^{-1} (Fig. 1), and the annual average temperature is 15.4 °C (Fig. 2). The wind data was recorded from an anemometer at 10 m height aboveground, and generic advanced parameters were used to characterise the wind resource to the height of the turbine (Fig. 3). The hydrological resource was generated by the author and was developed by iteratively combining intermittent seasonal river flow monitoring and regional rainfall data with local farm gully dams characteristic of the SW of WA. The annual average available water flow rate was scaled to 10 L s^{-1}. The river flow data in Fig. 4 shows the flow component available to the modelled pico-hydroelectric units rather than the total resource at the sites. The simulations used both annual and monthly averaged input data with random variability to determine system technical performance.

2.2. Technical and economic data and modelling methods

The technical simulations were performed using HOMER version 2.68 beta, a distributed power and micro-power optimisation software tool that simulates the operation of renewable energy-based systems by making energy balance calculations for each simulation interval throughout an entire year [7]. A 15 min simulation interval was chosen to provide enough resolution to model the intermittent nature of the simulated rural homestead loads and renewable energy resources. The simulation tool compares the electricity demand to the energy production, and calculated the flow of electricity to and from each component of the system during each interval to determine whether the system design can meet the electricity demand under the specified conditions[3]. All systems were designed to meet relevant Australian Standards and economic modelling assumed installation by suitably accredited persons/entities.

While both HOMER and RETScreen can perform economic analyses, an explicitly clear economic model was developed in a simple spreadsheet to enable detailed third-person analysis of the unique attributes of the various renewable energy technology, policy, and emission assumptions[4]. The spreadsheet, referred to as "the model", incorporated the technical performance output and incorporated capital expenditure cost calculations including (but were not limited to) site preparation, equipment modification, operating costs, maintenance, replacements, fuel/electricity costs (etc.). The model incorporated 2010 market prices of energy and labour projected over the 15 year project lifetime. Each feasibility study contained a considerable number of assumptions and also incorporated an annual discount rate of 11% and an inflation rate of 3% (8% real discount rate). Whilst rural infrastructure investments generally use a slightly lower real discount rate, commercial investments often use much higher real discount rates. Therefore, a flat real discount rate of 8% over the 15 year investment reflected a compromise.

The model was designed around the well established economic methods of net present value (NPV) discounted cash flow (DCF) methods [8]. However, such methods are not without limitations, as even the most probable NPV for a project (with or without a sensitivity analysis) does not recognise the asymmetric probabilities associated with each variable [9]. However, this research uses a simulation and scenario approach to explicitly recognise some asymmetries and their effect on the NPV calculation, despite modelling a very limited number of possible system simulations and scenarios.

[2] Whilst many areas exhibit highly localised variations when compared to the Albany airport data, the impracticalities of simulating for a range of locations was the deciding factor in the selection of one representative meteorological location.

[3] The energy simulation results are particularly sensitive to load estimations and renewable resource assessment data. The high precision of the modelling outputs should not be misinterpreted as a high level of certainty, as many assumptions underpin its appropriateness and accuracy.

[4] For copies of the each economic model used in the analyses, please contact the author.

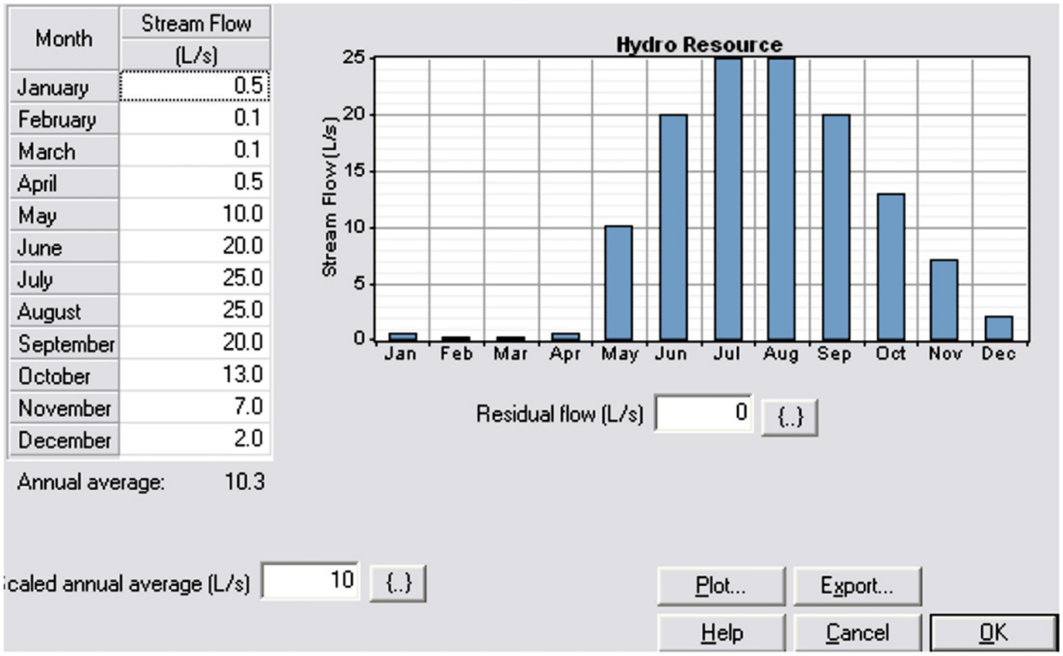


Fig. 4. Generated annual and monthly mean available river flow for hydroelectric simulations.

2.3. Electricity supply and load profile simulations

The simulated rural homestead incorporated a connection to the local regional electricity network known as the Southwest Interconnected System (SWIS) with a standard "rural supply system" of 240 V, 32 A two phase distribution line. The analyses solely focussed on simulating the electricity consumption of the homestead and two primary sheds which are best described as a medium-to-large house, general workshop, and a shearing shed, respectively. For simplicity, this research refers only to the "homestead" when describing the aggregate load of the homestead and sheds. Simulated load profiles for the homestead were developed from the three years of billing data, the on-site monitoring, and on-site energy audit. The simulated intra-day electricity demand reflected the significant variation and reflects the normal daily routine of the homestead and the farm operations. As the complete time series of the farm's load profile was not available, the model's random variability of "day-to-day" and "time-step-to-time-step" was allocated 50% and 250%, respectively to reflect an intermittent demand profile. These random time-step variations produced a maximum peak load on a 15 min basis of around 10.1 kW, selected for consistency with parallel operational demands from the energy audit appliance data. The high day-to-day energy demand variability reflects the high irregularity of rural tasks that persist through weekends, and associated seasonal variability (Figs. 5 and 6).

2.4. Uncertainties and assumptions

The simulation results were highly dependent on the input load data and assumptions[5]. Similarly, the net renewable electricity production results are sensitive to renewable energy resource inputs and how they relate to real-time load simulations. In turn, the simulated technical and economic model results are dependent on the load and renewable energy generation component(s), in addition to cost estimations projected over time. The technical simulation uncertainties are much smaller than economic modelling uncertainties of future electricity prices, policy changes (such as increased network charge components for bi-directional electricity support infrastructure), new subsidy policies (etc.), and the eligibility rules for such changes.

Notably, the projection of both capital and ongoing maintenance cost estimations for small-scale renewable energy systems are problematical as there are commonly choices between "high-end" and "low-end" technologies in terms of quality and cost, which can result in markedly different capital and operational cash flows. Furthermore, the modelled cost analyses were based on a whole system lifetime of 15 years. This simplification creates a situation where a PV module with an assumed lifetime of 15 years is likely to be an underestimate. Yet the lifetime of inverters and battery banks were also modelled as 15 years, which is likely an overestimate based on recent research under Australian conditions [10]. Despite these limitations, an iteratively balanced approach was chosen for each system simulation and scenario based on the author's knowledge and previous research of small-scale renewable energy systems in WA.

Further economic modelling uncertainties are derived from fluctuations in electricity tariffs. Rural areas in the SW of WA are generally connected to the SWIS and choose the government-owned retailer's (Synergy) Home Business Plan (K1) tariff. The daily supply charge and the cost of the first 20 kWh are identical to Synergy's Home Plan (A1) tariff, tailored for urban domestic users. However, electricity consumption above 20 kWh per day is supplied at Synergy's Business Plan (L1) tariff rate, which is tailored for non-agricultural small businesses [11]. Each of these tariffs has markedly increased in recent years (Table 1), and is likely to continue to increase in real terms, albeit at a reduced rate.

The WA Renewable Energy Buyback Scheme (REBS) is a net-metring mechanism available for renewable energy grid-

[5] An independent assessment of the uncertainty of the input data (primarily meteorological data) and simulated results have not been undertaken by the for each feasibility study. However, much model verification has been undertaken for both the HOMER and RETScreen software packages and both NASA and BOM have data quality assurance procedures. Nonetheless, the research results should be used only as a guide, and actual system performance will vary depending on a number of on-site variables.

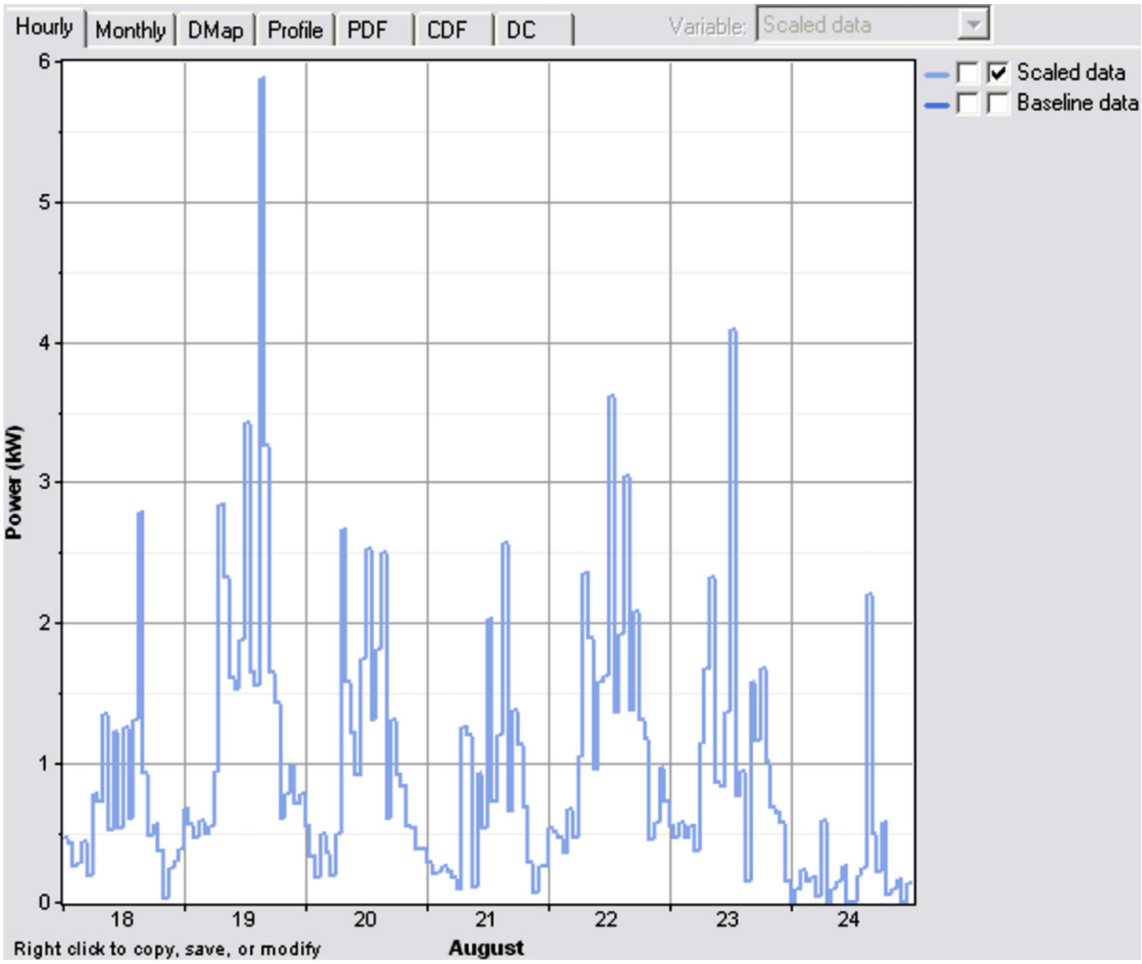


Fig. 5. Simulated 15 min interval homestead electrical load profile.

connected systems on the SWIS of capacity between 500 W and 5 kW_e. REBS was calculated on the net import total over the billing period, at a tariff equal to the purchase rate minus GST. This was amended in 2010 to AUD0.07 per kWh on the SWIS, while the other major government-owned retailer in WA, Horizon Power (which operate off the SWIS on several isolated much smaller networks) remain at the equal rate minus GST. Therefore, on the SWIS, the Synergy REBS renders the value of electricity exported into the network from residential homes at around one-third of the value of electricity sales to homes. Furthermore, to be eligible for REBS, the client must be on the A1 or Smart Power (a time of use variable) tariff, and residences on the K1 tariff are ineligible. Similarly, K1 clients are ineligible to receive the WA feed-in tariff (FiT)[6], and no system models include the WA FiT.

In the model, electricity exports to the SWIS received a zero economic return due to the K1 tariff REBS ineligibility. Each system performance simulation was designed to supply the homestead in real-time (15 min simulated intervals), only displacing electricity imports. The simulation calculates electricity exports from the small-scale homestead generation system to the network, although it was given a zero economic value in the standard models. Therefore, any economic costs resulting from small distributed generators providing capacity or voltage and frequency control ancillary services are modelled as captured by the SWIS network operator (Western Power) or various other generators under the auspice of the SWIS System Management. Thus, the model essentially represents the exported generation (etc.) as an opportunity cost at the expense of K1 customers. This particular model assumption is relevant to around 13,000 customers on the K1 tariff, consuming an estimated 130,000 MWh each year on average and growing [12].

2.5. Renewable energy certificates (RECs) and mitigation calculations

One REC is equivalent to 1 MWh of renewable energy produced by an accredited (by an independent regulator) renewable energy generator. Rebate structures available for small-scale renewable energy systems have undergone recent changes, based on the earning of RECs. Previously, under the Australian Government's Solar Homes and Communities Program, a 1 kW_e PV grid-connected system was previously eligible for an AUD-8,000 capital cost subsidy. The deemed RECs generated by the system were often sold to the installers to further minimise the owner's capital expenditures. Currently (2011), the only available national rebate for this system is the Solar Credit Scheme. Under the Solar Credit Scheme, specified sizes and outputs of small PV, wind, or hydroelectric

[6] As the K1 tariff supply structure (under 20 kWh) reflects the A1 tariff, it may be perceived as inconsistent that K1 tariff customers are ineligible for REBS. Therefore, K1 customers, most of which are located in rural areas are unable to receive equivalency for electricity that is exported and imported from any on-site generation system to the SWIS network akin to A1 or Smart Power customers.

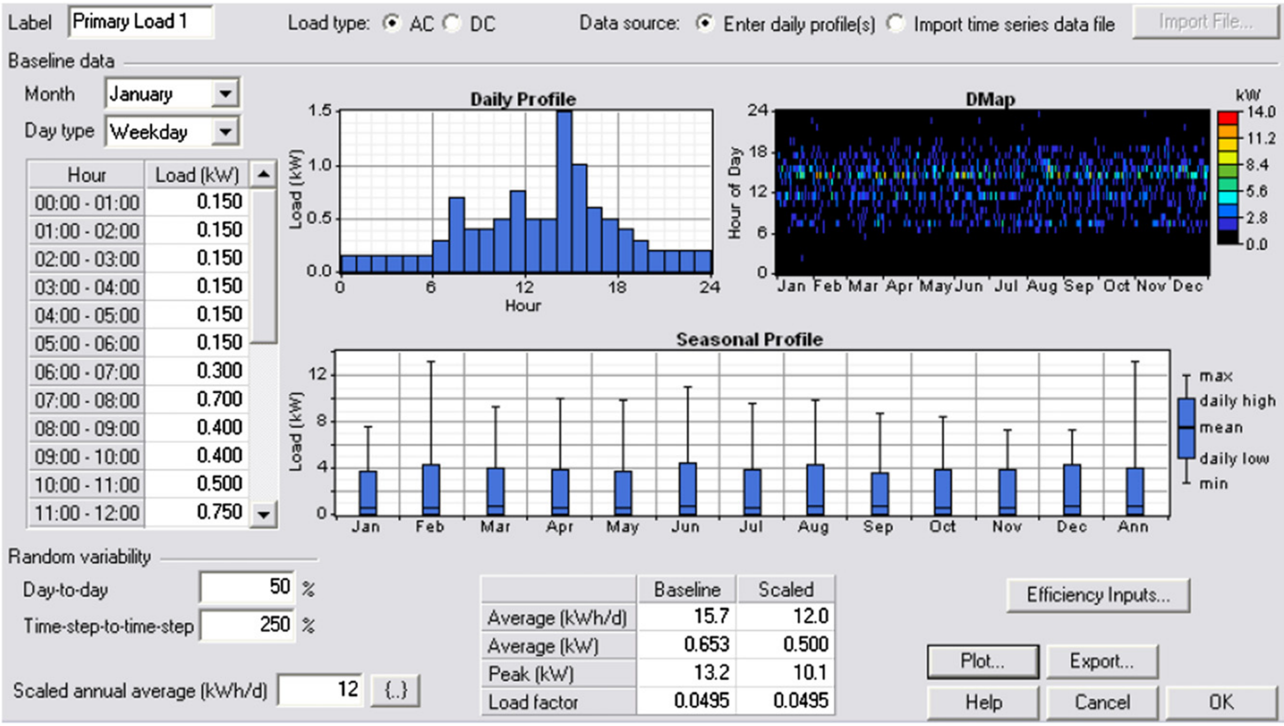


Fig. 6. Simulated intra-hourly, hourly, daily, and monthly electrical load profiles for the homestead.

Table 1
Summary of K1 tariff charges (GST inclusive).

Charges per day	Pre 1/07/'09	Post 1/07/'09	Post 1/4/'10	Post 1/7/'10
Supply	25.57 ¢ day^{-1}	32.33 ¢ day^{-1}	34.75 ¢ day^{-1}	38.23 ¢ day^{-1}
<20 kWh	13.94 ¢ kWh^{-1}	17.61 ¢ kWh^{-1}	18.93 ¢ kWh^{-1}	20.83 ¢ kWh^{-1}
>20 - <1650 kWh	17.47 ¢ kWh^{-1}	22.08 ¢ kWh^{-1}	23.73 ¢ kWh^{-1}	26.11 ¢ kWh^{-1}

Source: [11,16].

systems are allocated RECs as a small generating unit (SGU). Assuming the simulated system is designed and installed by a Clean Energy Council accredited installer (for both stand-alone and grid-connected power systems), the system is eligible to create RECs as an SGU, valued at a fixed AUD40 each [13]. Table 2 shows the REC entitlement for all simulation designs used in the model.

The total lifecycle market mitigation potential calculation for each system was based on a simplified assumption of displacing the equivalent 2009 “scope 2” SWIS emissions factor of 0.84 $kgCO_2$-e kWh^{-1}, remaining stable over the 15 year interval[7]. Additionally, the mitigation potential results were also based on the assumption that the electricity exported onto the network does not displace conventional supply, while the inverter output supplied directly to the homestead does reduce conventional electricity consumption and associated emissions. This generous assumption was chosen because an enormous number of systems will be required on the SWIS to reduce the scheduled output of generators in the hundreds of MW range, controlled by System Management[8]. Regardless of whether the reader perceives this assumption as too generous or not sufficiently generous, the market mitigation potential calculations are a useful indicator of the overall level of penetration aggregated systems may eventually make into network generator scheduling.

3. System designs, simulations, and model summary

For the sake of brevity, this section summarises the main characteristics and assumptions of each system (Note that all system components in the technical simulations incorporated numerous generic manufacturer specifications and conversion efficiencies, some of which are discussed). All system capital and operating costs were customised for each system based on each technology requirement and were incorporated into the economic model.

3.1. A 1 and 3 kW_e grid-connect and a 6 kW_e stand-alone PV array system

A 1 kW_e solar PV array and a 1.1 kW_e grid-connected inverter and a 3 kW_e solar PV array and a 3.5 kW_e grid-connected inverter were separately simulated supplying the homestead electricity load in parallel with the SWIS electricity network. All PV technology

Table 2
REC entitlement for each simulated system as derived from the Office of the Renewable Energy Regulator's Small Generation Unit REC Calculator.

System	Deeming period	REC Entitlement
1 kW_e PV grid-connected	15 years	88
3 kW_e PV grid-connected	15 years	159
6 kW_e PV stand-alone	15 years	213
1 kW_e wind grid-connected	5 years	47
3 kW_e wind grid-connected	5 years	85
0.4 kW_e hydroelectric grid-connected	5 years	38
1 kW_e hydroelectric grid-connected	5 years	95

[7] This was likely to be an overestimate as the SWIS emission factor has slowly reduced over time, decreasing the per unit mitigation potential of cleaner electricity options relative to the network.

[8] It should be noted that even the assumption that the electricity consumed in the homestead produced from the PV system results in any emission reduction from a large fossil-fuel generator is unrealistic.

Table 3
The total market adaptation potential (AUD), market mitigation potential (tCO_2-e), and the market equivalent carbon price (AUD tCO_2-e^{-1}) for each system, all relative to electricity network connection.

Primary system scenario	NPV (AUD)	Mitigation (tCO_2-e)	AUD tCO_2-e^{-1}
1 kW_e PV grid-connect	−6436	9.513	667
3 kW_e PV grid-connect	−15,015	20.954	716
6 kW_e PV stand-alone	−79,981	55.188	1451
120 W_e PV water pumping	−1100	0.520	2115
1 kW_e wind grid-connect	−5416	8.467	640
3 kW_e wind grid-connect	−8849	17.728	755
400 W_e hydro grid-connect	−6290	8.266	761
1 kW_e hydro grid-connect	−3316	16.708	198
6 kW_e gasifier grid-connect	−116,486	18.850	6180
6 kW_e gasifier stand-alone	−140,710	55.188	2553
6 kW_e diesel stand-alone	−78,164	−34.347	**−2276**
6 kW_e diesel stand-alone[a]	−79,693	−58.693	**−1358**
6 kW_e biodiesel stand-alone	−86,924	55.188	1577

[a] The second 6 kWe diesel stand-alone system was derived from the comparison with the 6 kWe PV stand-alone system, whereas the first was from the 6 kWe woodgas system comparison (as was the biodiesel system). The system design and associated enabling equipment losses resulted in a marked increase in diesel fuel consumption and associated emissions for the second diesel.

simulations assumed a temperature coefficient of power of $-0.5\%\,°C^{-1}$, a nominal operating temperature of 47 °C, an efficiency at standard test conditions of 13%, a derating factor of 85%, a ground reflectance of 20%, non-tracking systems orientated with an azimuth of 180 (degrees West of South), and a slope of 35°, (measured from the horizontal plane). Whilst the 1 and 3 kW_e grid-connected PV systems were modelled against the baseline of grid-only connection, the 6 kW_e solar PV array was simulated with a battery bank supplying the total homestead load in parallel through an 11 kW_e stand-alone inverter, located off-grid to the SWIS. The battery bank had a nominal capacity of 139 kWh, 83 kWh of useable nominal capacity (with a 60% minimum state of charge) on a 120 V DC bus. The simulations required that 100% of the electricity load must be supplied.

3.2. A 1 and 3 kW_e wind, and a 400 W_e and 1 kW_e hydroelectric grid-connected systems

A 1 and 3 kW_e grid-connected wind turbines mounted on 15 m towers (with enabling components identical to the 1 and 3 kW_e PV systems) were also simulated to supply the homestead load in parallel with the SWIS. The power curves of the DC turbines (derived from the HOMER database) were selected to represent average wind conversion efficiencies at a range of wind speeds. The simulated efficient pico-hydroelectric reaction turbine (average turbine efficiency of 65%) was installed on a low gross head (2.5 m), with a inlet pipe loss of 12% to operate at a maximum 400 W DC. In addition, a nominal 1 kW_e DC high-efficiency impulse pico-hydroelectric turbine installed on a medium gross head (6.5 m), was simulated with identical pipe losses. Both pico-hydroelectric systems were simulated to operate with the same 1.1 kW_e grid-connected inverter as the 1 kW_e PV and wind systems. All systems supplied the homestead load in parallel with the SWIS electricity network.

3.3. A 15 kVA wood gasification unit coupled to a 6 kW_e modified generator (electricity only)

A spark-ignition engine coupled with a 6 kW_e generator (3 L engine operating at 1500/1800 rpm, single phase 240 V generator) powered by a wood gasifer was simulated to supply the homestead as a stand-alone system in batch mode. The gasifier input fuel was

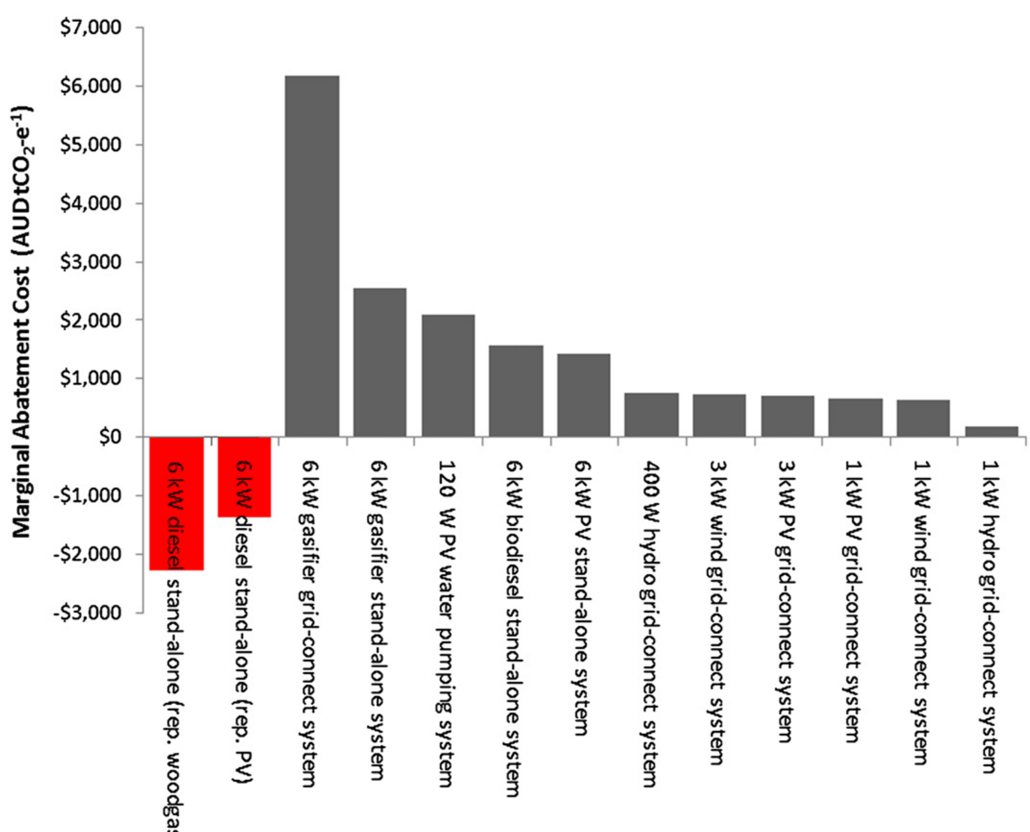


Fig. 7. The total market adaptation potential (AUD) and market mitigation potential (tCO_2-e), for each system represented as a MAC.

small air dry wood pieces and fed to the throated downdraft unit. The maximum hourly wood consumption of 20 kg delivered a simulated wood gas output of 45 Nm^3 (an approximate output gas calorific value of 5 MJ m^{-3}), and was simulated at half maximum output to enable a comparison with the other 6 kW_e systems. The net system emissions were assumed to carbon neutral. The scheduling times were forced on between the hours of 1pm and 5pm. The simulated average daily consumption for this configuration was approximately 40 kg of dry wood. The system supplied the homestead in parallel through an 11 kW_e stand-alone inverter/rectifier, located off-grid to the SWIS electricity network. The battery bank was identical to all the other battery banks. An identical spark-ignition engine generator and gasifier system was simulated as a grid-connected system without the battery bank.

3.4. The 6 kW_e stand-alone diesel and biodiesel systems

For comparison, the both the 6 kW_e PV and wood gas stand-alone systems were compared against a 6 kW_e diesel generator component with identical enabling stand-alone system design, all against the electricity network. A 6 kW_e diesel generator comparison with the 6 kW_e PV stand-alone system components was simulated at a 70% minimum load ratio AC diesel generator with an average specific fuel consumption of 0.397 L kWh^{-1}. The unit supplied the annual homestead load, restricted to operate only between the hours of 1pm and 5pm, and forced to operate once a day at 1pm–3pm and satisfied system load and battery state of charge control requirements. This scheduling did not have a significant negative impact on performance or efficiency. The diesel price was AUDD1.20 L^{-1} gross delivered, with the Fuel Tax Credit of AUD0.38143 L^{-1}, resulting in a net cost of AUD0.82 L^{-1} (rounded). The equivalent electricity price per kWh was simulated as AUD0.3255 kWh^{-1}, with annual emissions of 7.592 tCO_2-e (2830 L $\times$ 38.6 MJ L^{-1} $\times$ 0.0695 $kgCO_2$-e MJ^{-1}) from the 2830 L consumed. The capital costs, the minor servicing, and major reconditioning requirements for the diesel generator were estimated and included in the economic model, yet non-operational periods were omitted in the simulation due to the flexibility allowed by the scheduling. When operating in a manner comparable to the 6 kW_e PV system, the annual average diesel fuel consumption was 2225 L due to operating optimisation fuel savings.

The diesel system was also simulated using biodiesel as a carbon neutral fuel in a similar manner to the wood fuel used in the woodgas system. The biodiesel cost was assumed to be AUD0.08 L^{-1} more expensive than mineral diesel, for a total price of AUD1.28 L^{-1}, as the Fuel Tax Credit was simulated as unavailable. The biodiesel system exhibited a specific fuel consumption of

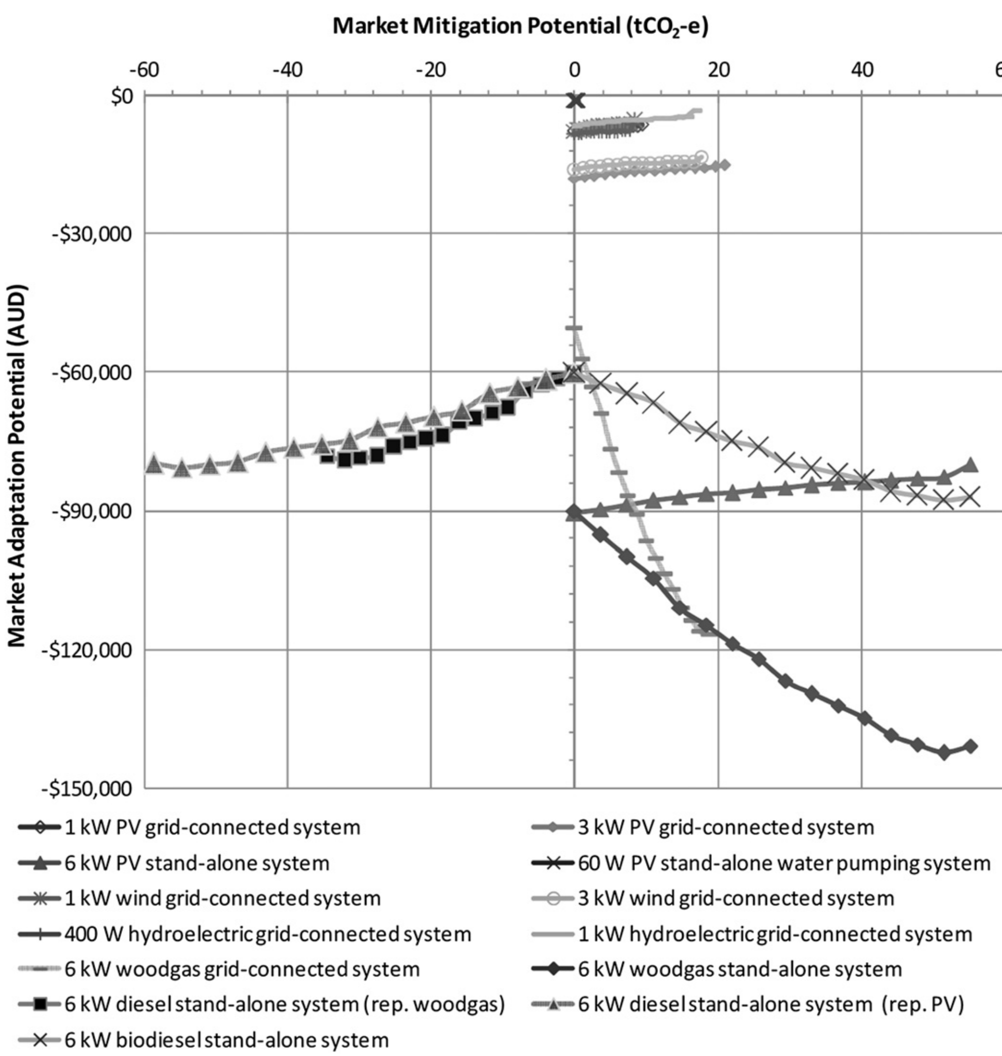


Fig. 8. The total market adaptation potential (AUD) and market mitigation potential (tCO_2-e), for each primary system model.

0.383 L kWh^{-1}, with an equivalent electricity price of AUD0.49 kWh^{-1}.

3.5. A 120 W PV stand-alone 60 W water pumping system

This simulation compared the economics between a small stand-alone (60 W) water pump for stock-watering powered by a 120 W PV array, relative to a small SWIS network grid-connected pump of identical capacity. The model assumed the same performance and costs of the pumping component, the piping system and associated components, including filters, tank, etc. The small 60 W pump was designed to provide 1000 L day^{-1} in winter and also 1500 L day^{-1} for stock-watering in summer at a total dynamic head of 16 m. This analysis assumed an average annual working time per day over a year of 2 h and 10 min for a 120 W PV array supplying the 60 W DC water pump.

4. Results

The summary results of the technical simulations and associated modelled market adaptation and market mitigation potentials for each system are shown in Table 3. The analyses show that, relative to the existing option of connecting to the electricity network, all of the renewable energy small-scale system technical simulations and market potential modelling generated negative NPVs. However, the range of market mitigation potentials for each system type demonstrates that, in theory, significant mitigation is possible from each regional homestead/household. Unfortunately the costs of this mitigation, as shown in Table 3, were very high in terms of an equivalent carbon price. In contrast, the mineral diesel systems exhibited both a negative NPV and generated negative mitigation, resulting in a perverse carbon value (in bold).

These results are represented graphically as a "marginal abatement cost" (MAC) curve in Fig. 7. While the MAC curve is becoming a useful method of presenting comparisons of investment choices, they are limited for detailed analyses and for private investments when compared to some other methods of presentation. For instance, Fig. 7 indicates that most suitable option (or least mitigation cost) is to install small hydroelectric systems in the SW of WA. However, the MAC does not show that the 1 kW_e hydrological system looks promising primarily due to the relatively high decommissioning value from remaining system infrastructure. This additional value only exists in a real sense if a second hydrological system is installed after the first system useful life expires, or the infrastructure is able to be removed and sold, which is often unrealistic (particularly with dams). MACs can also become confusing when options are presented that generate higher emissions relative to a baseline scenario, such as the two diesel systems indicated in red. (These two systems should not be interpreted as a negative cost, as the negative values are derived from a negative mitigation potential.) Furthermore, MACs presentations may lack clearly defined terminology that prevents misinterpretation of whether the calculates represent the total market cost useful private entities, or the total economic/socio-economic costs which are generally only suitable for governments when calculating externalities, and correspondingly the direct emissions, or the full

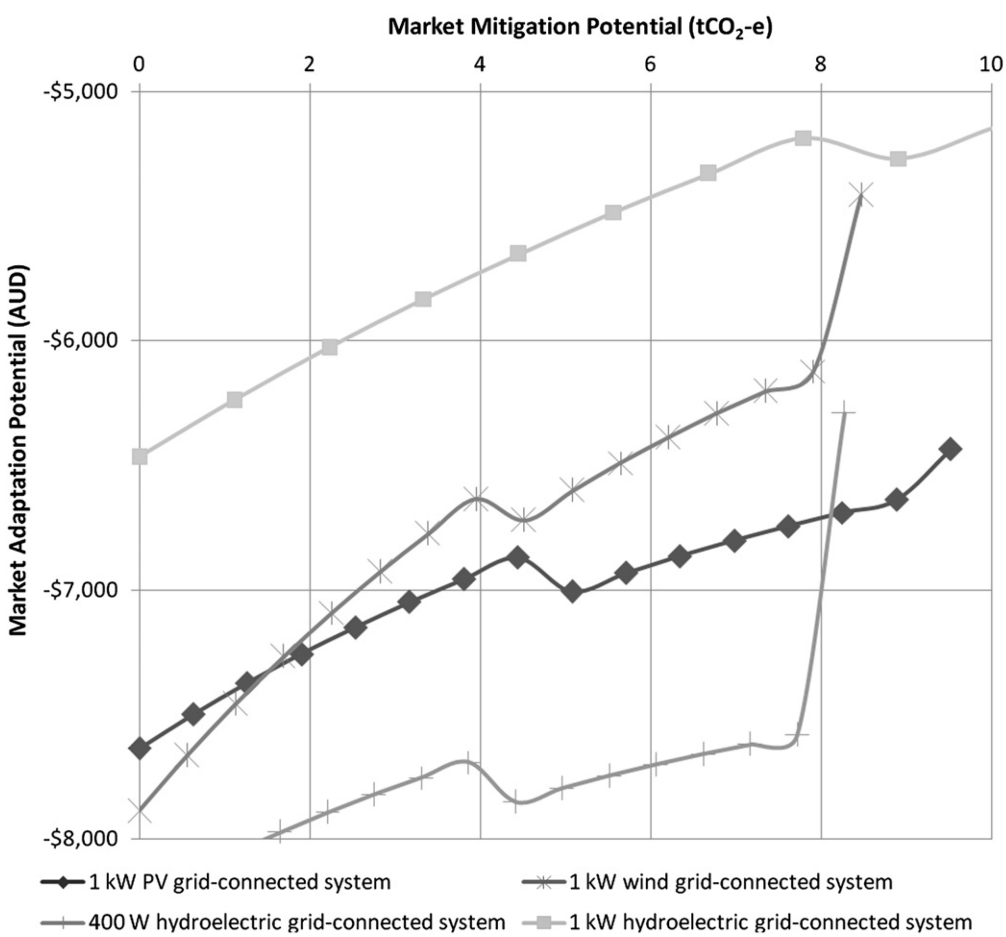


Fig. 9. The total market adaptation potential (AUD) and market mitigation potential (tCO_2-e), for selected small-scale (≤1 kW) system models at coordinates between zero and ten tCO_2-e, and AUD-5000 and AUD-8.000.

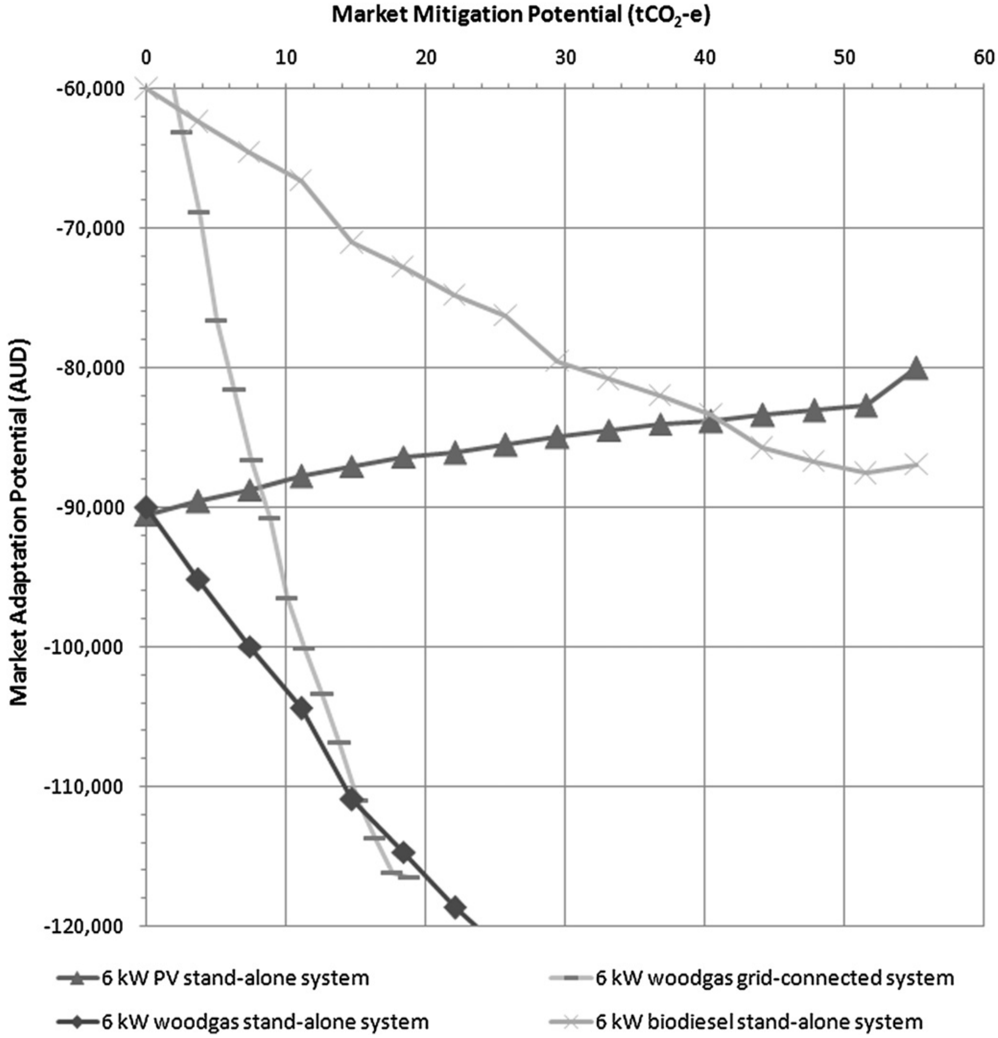


Fig. 10. The total market adaptation potential (AUD) and market mitigation potential (tCO_2-e), for the four 6 kW_e system and scenario models at coordinates between zero and sixty tCO_2-e, and AUD-60,000 and AUD-120,000.

lifecycle emissions for an option. Finally, Fig. 7 does not indicate useful information regarding the capital cost component, subsequent cash flows, a visual indication of the discount rate influence. Therefore, the research results are again presented as an integrated market mitigation and adaptation potential curve in Fig. 8.

Fig. 8 shows the total market adaptation potential (AUD) and market mitigation potential (tCO_2-e), for each primary system model. Whilst Fig. 8's presentation for the range of 13 modelled systems and selected scenarios seems unnecessarily complicated at first, it represents a large amount of useful information, including capital costs, relative operational costs, cash flows and annual mitigation of selected intervals, in addition to the final equivalent carbon price[9]. The line marker located at the zero coordinate on the market adaptation potential axis (y) represents the total upfront capital cost of the system in "year zero". The line markers also indicate the annual mitigation on the market mitigation potential axis(x) for each system. The final year (15) is indicated by the marker furthest away from the market adaptation (y) axis. This Cartesian coordinate form of presentation enables refinement of the axes scales to explore differences between close technical substitutes. Figs. 9 and 10 show selected coordinates refining the resolution of Fig. 8.

[9] This research uses an annual basis for the economic model interval.

Fig. 9 shows the nuances of cash flows and final value at decommissioning for each of the smallest renewable energy system technology types, and how the cash flows influence total equivalent carbon prices. Likewise, Fig. 10 shows how seemingly very similar technology choices (all 6 kW_e systems) can reflect very different cash flows and emission profiles. Even though these models only represent annual averages of market mitigation and cash flows, the nuances of when they occur in the investment lifecycle will certainly influence decisions made by private entities, and are an important aspect to explicitly recognise. Therefore, the Cartesian coordinate form enables simple visual calculations of annual market mitigation, market adaptation, and the subsequent annual equivalent carbon price simply from the subtracting values from the previous year, and also simple polynomial approximation to enable a greater understanding of the relationships between system mitigation and adaptation potentials for particular technology types and scenarios [6].

5. Conclusion

Based on the simulated systems and model assumptions, the results indicate that both small-scale renewable and small-scale non-renewable home energy systems in grid-connected rural areas in the SW of WA are unsuitable for displacing centralised electricity generation from a simple private financial perspective. In light of the extremely high market mitigation (AUD tCO_2-e^{-1}) costs in the several hundred to thousands of Australian dollars per tonne for the range of grid-connected small-scale renewable energy systems over the 15 year scenarios, the current government subsidies for small-scale grid-connected renewable energy systems may be more efficiently re-allocated to medium-to-large-scale systems (>1 MW_e). The results also indicate a higher capital and operating cost for small-scale woody biomass-to-electricity only systems, primarily due to higher fuel and pre and post processing requirements. These results cast doubt over the commonly discussed option of cost-effectively recycling agricultural by-products for the production of electricity only (without heat capture technologies), in order to generate mitigation opportunities in rural regions using small-scale systems. Similarly, the assertion that grid-connected decentralised energy systems were already commercial in mini-grids in markets with high grid-connection costs and abundant renewable energy resources [14], does not appear appropriate for the modelled scenarios in SW of WA.

Conversely, the research results suggest that small-scale home renewable energy systems are cost competitive off-grid in stand-alone systems primarily due to the prohibitive cost of electricity network extension, rather than the avoidance of network electricity service costs. However, from the limited number of system designs in this work, there seems to be a lack of a significant advantage of using PV versus diesel generation components in NPV terms. This is despite each technology choice committing the owner to markedly different operational characteristics and maintenance regimes, with the PV component exhibiting relatively higher capital costs, yet, much less operational and maintenance requirements [10]. The research findings support the continuation of existing capital subsidies for off-grid small-scale renewable electricity components, and suggest that a nominal increase will generate a sufficient incentive. In additional to social equity reasons, and in contrast to grid-connected systems, such off-grid subsidies will decrease the costs of electricity to off-grid rural people and also deliver verifiable mitigation by displacing non-renewable generation in stand-alone systems.

Further research is recommended for assessing a diverse range of medium-to-large renewable energy systems (in the multi MW range) which can supply energy demands in parallel with existing fossil-fuel systems. Such systems are likely to effectively and measurably reduce greenhouse gas emissions, reduce total energy costs, and defer augmentation or extension of distribution or transmission networks.

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