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Technical, mitigation, and financial comparisons of 6 kW_e grid-connected and stand-alone wood gasifiers, versus mineral diesel and biodiesel generation for rural distributed generation

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ABSTRACT

This research presents a technical simulation and economic model of three small-scale technical alternatives supplying a typical rural homestead electricity load: a 15 kVA wood gasification unit coupled to a 6 kW_e modified grid-connected petrol generator; the same system operating as a stand-alone system, and; a 6 kW_e diesel generator, all modelled against the electricity network in the southwest (SW) of Western Australia (WA). The three technical alternatives are supplemented by a further four comparative scenarios, including zero woodgas fuel and labour costs, generous capital and feed-in-tariff subsidies, and also the displacement of mineral diesel with biodiesel. The results quantify technical outputs of the systems and also the associated financial and greenhouse gas emissions of each system and scenario. The results indicate that significant mitigation is possible from each regional household using woodgas technologies or biodiesel fuels, yet the associated costs of this mitigation is extremely high when compared to the electricity network. In light of the extremely high cost of electricity and mitigation using small-scale bioenergy systems, governments may consider re-allocation of small-scale grid-connected distributed energy support mechanisms towards larger regional bioenergy projects, or risk increasing the electricity prices for private entities and governments.

1. Introduction

Policymakers are increasingly calling upon the research community to analyse approaches for identifying and evaluating climate change adaptation measures and strategies, and methods of costing different outcomes and response measures [1]. The inadequacy of many available analytical frameworks that evaluate links between climate change adaptation and mitigation [2] are of little use for conventional tactical investment decision-making. In theory, policies that provide a real or implicit price for mitigation could stimulate investment in clean energy products, technologies and processes [3], although various published estimates of carbon prices required to stabilise atmospheric GHG concentrations at around 550 ppm CO_2-e by 2100 range from around zero to more than 100 USD per tCO_2-e [3–5]. Given the increasing investment by governments in renewable energy systems, a number of regionally specific analyses are required to assess the most cost-effective range of mitigation and energy services for a region. The high capital cost of small-scale renewable energy systems in rural areas remains a stubborn barrier to market expansion, despite regional development benefits [6–11]. The expansion of support mechanisms (capital subsidies, tradable certificates, feed-in tariffs, etc.) is injecting new public expenditure into both small and large-scale renewable energy systems [10–12], and due diligence is required to quantify the value of technical alternative investments in terms of financial and greenhouse gas mitigation. This research uses a similar approach and software as Rehman and Al-Hadhrami [13] for analysing the technical, emissions, and financial cost of small-scale renewable energy generation components. However, this research compares three exclusive technical investment choices in the rural region of the southwest (SW) of Western Australia (WA) against the baseline of grid-connection for a basic rural homestead and overlays simulated outputs with actual market cost/price data and available support subsidies. The research aim was to determine the technical performance and net present value (NPV) of each technology choice to inform both potential investors and policymakers on the unique differences and sensitivities of each option, and a subset of comparative scenarios for the provision of electricity services and greenhouse gas emissions mitigation in the SW of WA.

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2. The electricity load profile data, technical simulation, and economic model

The simulated grid-connected rural homestead was connected to a standard WA rural supply of 230–240 V, 32A two phase distribution line. The analyses solely focussed on modelling only the electricity consumption of the homestead which includes a medium sized house and two primary sheds best described as a general workshop and a sheep shearing shed. As the complete load profile was unavailable, an energy audit was undertaken with real-time electricity consumption monitoring for two weeks, appliance data gathering, and three years of historical electricity retailer billing data were used to characterise the load, including average and peak electricity demand. The generated simulation electricity load profiles for the homestead are presented in Fig. 1 The model's random variability of "day-to-day" and "time-step-to-time-step" were allocated 50% and 250%, respectively to reflect the significant variation of load in the normal daily and seasonal routines of the homestead and the farm operations. Random time-step variations produced a maximum peak load on a 15 min basis of around 10.1 kW, which was consistent with energy audit and appliance data.

RETScreen (version 4) meteorological data were used for the technical simulations which were derived from the Australian Bureau of Meteorology (BOM) station at Albany Airport (Station 009741, Lat.(S): −34.9414, Long.(E): 117.8022) [14]. The technical simulations were performed using HOMER (version 2.68 beta), a distributed power and micro-power optimisation model [15]. A 15 min simulation interval was chosen to provide sufficient resolution to model the intermittent nature of the electricity load. HOMER was used to perform energy balance calculations between an identical load and the simulated technical alternative systems. While both HOMER and RETScreen can perform economic analyses, an explicitly clear economic model was developed using a simple spreadsheet to ensure all unique attributes of the various technologies, policies, and emission calculations were able to be remodelled by third parties. The spreadsheet is referred to as "the model", and incorporated the technical performance output data from RETScreen, HOMER, and peer reviewed literature. The model incorporated capital expenditure cost calculations (including, but not limited to) site preparation and equipment modification etc.), and operating cost components (including, but not limited to maintenance, replacements, fuel/electricity costs etc.). 2010 real market prices were used to project and NPV (or net present cost, NPC) over the modelled 15 year project lifetime. The models contained a number of assumptions, including a real discount rate (8%), and an inflation rate of 3%. While these economic tools are well established [16], they are not without limitations, as even the most probable NPV for a project does not recognise asymmetric probabilities associated with each variable [17,18]. However, a simulation and scenario approach can recognise at least some asymmetries and their effect on the NPV calculation [17], although this research only models a small number of systems and scenarios. Whilst the model includes general maintenance scheduling and servicing costs (etc.), for simplicity the model does not include asymmetric assumptions of quality and reliability of respective technologies. For example, the lifetime of the inverters and battery banks have been modelled as 15 years, which is likely an overestimate, based on recent research under Australian conditions [8]. Despite such uncertainties, an iteratively balanced approach of selected "mid-range equivalent" performance and cost for each technology was selected for simulations and scenarios. Similarly, an independent assessment of the uncertainty of the input data (primarily meteorological data) and simulated results have not been undertaken for this research as HOMER and RETScreen models have been extensively validated, and BOM has excellent data quality assurance procedures. As such, the research results should be used as a guide, premised upon the understanding that actual technical performance results will vary depending on the installation site. Furthermore, the economic analyses contain more obvious input uncertainties, including future electricity prices, tariff eligibility changes, and the eligibility rules for such changes (etc.). Such financial uncertainties in the economic model are outside the scope of this analysis.

The electricity tariff used in the model was the government-owned retailer's (Synergy) Home Business Plan (K1) tariff, commonly used in regional areas with a homestead and workshop/sheds are use the same electricity meter. The daily supply charge and the cost of the first 20 kWh in 2010 was US\$0.3823 day^{-1} and the consumption charges were US\$0.2083 kWh^{-1} (for less than

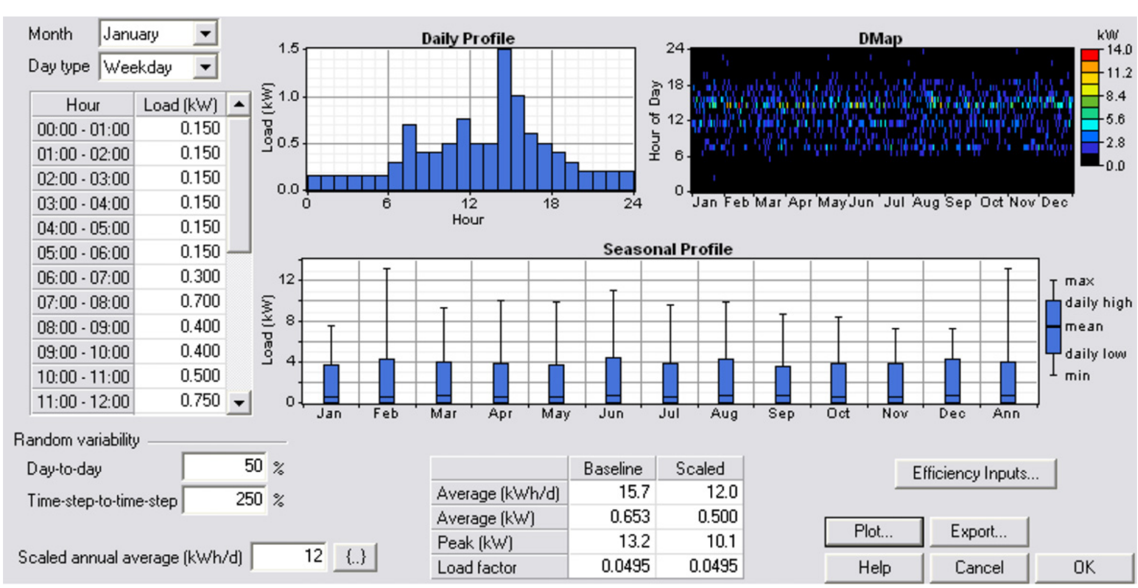

Fig. 1. Simulated homestead intra-hourly, hourly, daily, and monthly electrical load profile.