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# The Economics of Integrating Alternative Energy: A Farm Case Study at Emerald, Queensland[1]

Janine W. Powell and Jon M. Welsh

AgEcon, 535 Tareela Lane, Burren Junction 2390 New South Wales. Email: janine@agecon.com.au

## Abstract

National environmental objectives have led to the development of government policies that create incentives for businesses to invest in renewable energy. These policies, increasingly affordable renewable energy and storage technology have aligned to deliver both economic benefits to farmers and co-benefits to the environment in on- and off-grid scenarios. This analysis aims to determine the economic feasibility of renewable and innovative energy systems to assist in reducing grid electricity cost for irrigation pumps and small industrial applications. Using a case study approach, optimal engineering and economic assessment are applied on a farm characterised by energy consumption in three different scales and usage patterns; sporadic large seasonal use, uniform industrial use and small-scale industrial use.

The case study farm's electricity demand and pricing agreements were assessed and entered into the Hybrid Optimisation of Multiple Energy Resources design software to analyse a range of hypothetical microgrid installations. A major aspect of the study is the connectivity between Government incentives, tariff uncertainty and the electricity retailers' rules regarding feed-in-tariffs and network connection criteria. While the challenge of aligning seasonal demand with renewable energy supply remains, the cost competitiveness of solar energy proves a realistic supplementary source for grid-connected agricultural loads where year-round utilisation rates are high. Of each of the case study sites evaluated in this paper, the highest returning economic and environmental business case occurred where the modelled micro-grid included photovoltaic (PV) and remained eligible for a Feed-in-tariff – enabling revenue creation out-of-season. Those larger PV systems exceeding the export limit of 30kW still showed a lower cost of energy than the grid, however, where a diesel genset was included to avoid peak tariffs, carbon emission abatement was negligible. Designing optimal engineering solutions to reduce on-farm energy costs is heavily dependent on awareness of current carbon and energy policy incentives, as well as the changing landscape of connection rules and feed-in-tariffs.

***Key words:*** renewable energy, solar, irrigation, pumping costs, emissions, feed-in-tariff

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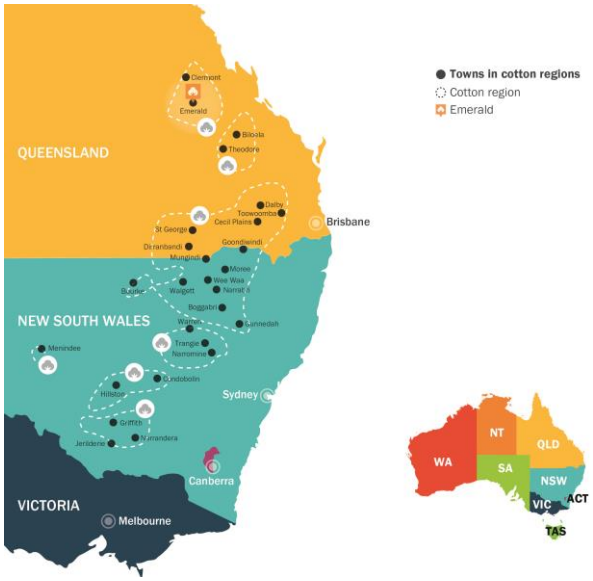
## Introduction

National environmental objectives have led to the development of government policies that create incentives for businesses to invest in renewable energy. The case study was undertaken to consider the economic and environmental impact of installing microgrids to offset the energy use across surface water irrigation pumps and a small grain drying facility in the Fitzroy Valley of Queensland. The study aimed to find solutions ultimately leading to lower energy costs and greater sustainability through carbon emissions abatement.

### Irrigation energy demand – cotton industry overview

Water is critical to the cotton industry to maximise crop yields and fibre quality. In most cotton growing regions, during the production cycle, crop water demand exceeds rainfall supply. Although rain-fed cotton crops are successfully grown in some areas, irrigation enables high quality, high yielding cotton to be grown in a wider range of regions. Data collected by the Australian Bureau of Statistics (2017) found in 2015-16, of the 280,422 ha of cotton harvested, 211,298 ha (75 per cent) was irrigated. The average volume of water applied across the irrigated area was 6.8 ML/ha. Figure 1 shows the cotton growing regions of Australia, which includes a placemark for Emerald, Queensland – the nearby location of the case study.

**Figure 1. Cotton growing regions of Australia. The case study location: Emerald, Queensland**




Methods of transferring irrigation water to fields vary between gravity, scheme water, pumped ground water, to deep wells pumping into storage. The further water is pumped, the more energy is required to move it. For simplicity, assuming an average 30 m total pumping head and an efficient pump consumption of 4.55 kilowatt hour (kWh)/ML/m of electricity (Foley, 2015), the industry would use around 195,481 megawatts (MW) of power per annum – if all irrigation pumps were grid-connected. If the water is moved once at a cost of $0.27/kWh the annual total energy spend is just over $52.8 million. Further, applying an emissions factor of 0.94 kg of $CO_2$e/kWh (Department of the Environment and Energy, 2016), an estimated 183,752 tonnes of $CO_2$e would be generated from this practice annually. Therefore, adoption of industry-wide energy efficiency measures or capital installations aimed at improving water productivity has potential to make both economic and environmental gains.

The application of renewable energy in Australian irrigated agriculture at an industrial scale is relatively under examined. A feasibility study into alternative energy sources for irrigated cotton production by Chen et al. (2013) found solar resources to be unsuitable for irrigation, but useful in offsetting domestic electricity consumption. The study found wind resources were regarded as unreliable and expensive. Eyre et al. (2014) concluded that renewable energy infrastructure is not cost effective and unable to meet peak irrigation demands. Similar studies undertaken abroad concur with these findings e.g. Irrigated rice in Qinghai Province in China by Campana et al. (2013); irrigated cotton, corn and wheat in the United States by Vick and Clark (2009), Vick and Almas (2011), Vick and Neal (2012); and vineyard drip-irrigation in the Mediterranean area (Carroquino et al. 2015).

More recent studies related to irrigated cotton (Powell and Welsh, 2016a, 2016b) found that unless renewable energy generation closely matches the timings of irrigation energy demand, or the water can be pumped and stored in reservoirs, the economics become marginal at best. Utilisation of surplus renewable energy generation was identified as a potential area to improving project economics when incorporating renewable sources into existing loads. However, recent advances in PV and pumping technology has reduced the capital cost of installation. These advances in conjunction with substantial increases in power prices, Feed-in-tariff (FiT) mandates and storage capabilities becoming more affordable, have changed the economic feasibility considerably. As the cost of PV components has decreased over time, islanded micro-grids incorporating PV and diesel gensets have become a feasible alternative for irrigators in Bangladesh. Md Asaduzzaman and Shafiullah (2018) found load-shifting irrigation to daylight hours was an economic and environmental imperative. Battery storage was a high-cost option, so diesel gensets were called upon on cloudy days to meet peak demand. Hybrid power systems with renewable energy can be reliable, economic, effective and more sustainable compared to either grid-connected or standalone diesel generators (DG) utilising a single fossil fuel-based power source. While other studies have reviewed the cost of energy to the Australian agricultural sector (Davis, 2018; Heath et al., 2018) this analysis focuses on a broadacre irrigator using the highly regulated electricity grid of Queensland. This research aims to quantify investment feasibility using HOMER optimisation software within the policy framework and connection rules identified in the next section.

## Method

The study uses the HOMER optimisation software to design microgrid systems with the view to reducing energy costs and emissions (Hybrid Optimisation of Multiple Energy Resources, 2018). Prior to undertaking the HOMER analysis, a detailed assessment of each load, site layout, constraints, component pricing and available resources on the case study farm is conducted. Once data has been collected and technical details have been verified by engineers and Transmission Service Providers (TSP), the information is entered into the software. The HOMER analysis combines engineering design with economic assessment by comparing a wide range of equipment, each with different initial and ongoing cost structures and constraints to determine the most optimal system design. Other factors influencing system design include investigation of all interacting physical (plant and soil type, irrigation system specifications, renewable plant and battery sizing, site attributes), meteorological (solar radiation, air temperature, relative humidity, wind speed, precipitation) and managerial (irrigation scheduling) variables within the system (Maurya et al., 2015). Sensitivity analyses on component pricing and other key variables were completed using HOMER. Three individual loads have been analysed in this study with their own unique seasonal energy demand attributes.

### Site characteristics

The case study farm is a 2600 hectare (ha) broadacre irrigated and grazing farm in the Fitzroy catchment of Central Queensland, Australia. The nearest town is Comet, which is approximately 50 km to the east of Emerald. Flat, low lying areas have been developed for irrigation. Water is harvested from the Comet River and overland flow during storm events on hilly terrain to the south-east of the farm. Site details are summarised in Table 1.

**Table 1. Details of the case study farm**

| **Particulars** | **Details** |
|---|---|
| Nearest township | Comet |
| Catchment | Fitzroy Valley |
| State | Queensland |
| Latitude | 23°36'97" |
| Longitude | 148°32'39" |
| Elevation | 161 m |
| Irrigable Land | 618 ha |
| Farm size | 2600 ha |
| Annual average rainfall | 592 mm |

Cotton is the primary source of income for the farming business. However, climate and agronomic conditions also favour cereal and peanut production. Farm grain infrastructure has been developed to enable peanuts to be stored, dried to marketing specifications and sold. Drying peanuts for sale uses considerable energy for two months of the year. The cropping rotation consists of cotton (summer), wheat (winter), peanuts (summer) before being returned to cotton over a four year period. A schematic of the cotton-wheat-peanut crop rotation is shown in Figure 2.

**Figure 2: Schematic of the first four years of a 20 year continuous cropping rotation**


Irrigation infrastructure on the case study farm is made up of the following sites:

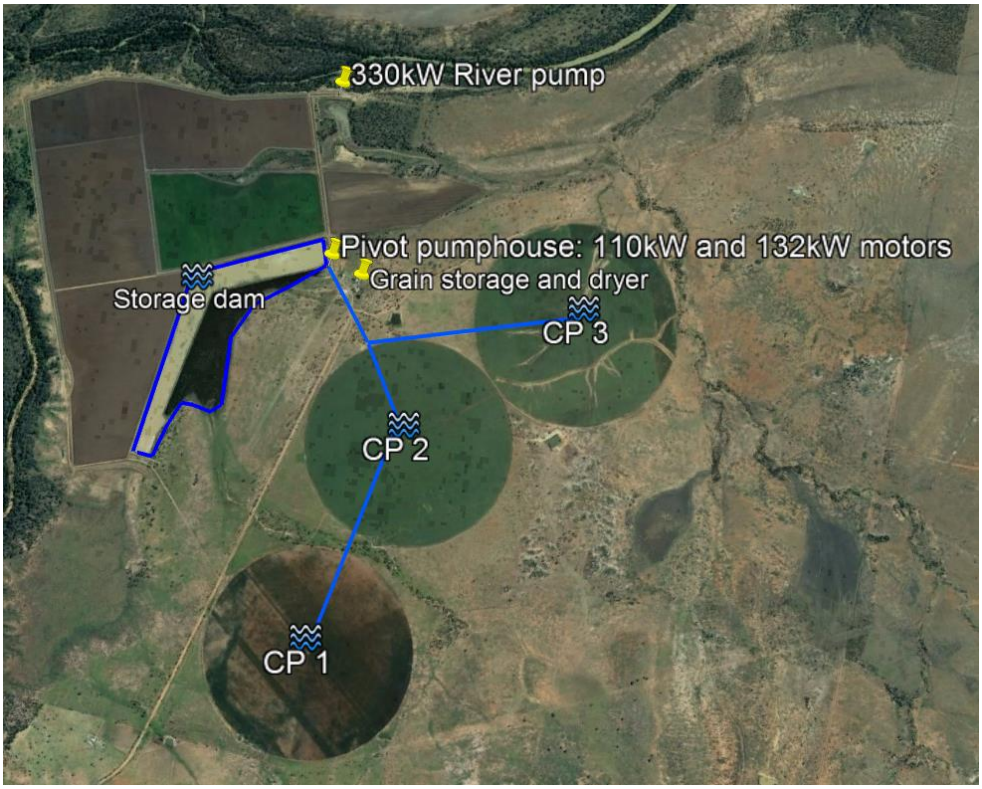
A. A grid-connected 415 volt, 3-phase 330 kW river pump used for transferring surface water into on-farm storage;

B. A grid-connected 415 volt, 3-phase pump house containing 110 kW and 132 kW independent pump motors supplying three centre pivots. These pumps may be run at the same time;

C. A grid-connected grain storage and drying facility is situated near the pivot pump house. This is a 415 volt, 3-phase connected grain facility with a combined nameplate capacity of 40 kW - made up of small grain auger motors and a 37 kW electric fan used for drying peanuts.

The farm map (Figure 3) shows the location of the three sites within the case study. Site A is the river pump, Site B is the pivot pump house, Site C is the grain storage and drying facility. Figure 3 also illustrates the farm layout, showing the flood irrigated farm land in the north-west corner and three centre pivots in the centre of the property.

**Figure 3: Case study farm map showing the irrigation layout and grid-connected loads (yellow placemarks)**




*Source*: Map image courtesy Google Earth

**Load assessment and electricity pricing**

An electric load is the power consumption of one or more components, for a specific time frame, usually measured by a meter. The load profile considers the variation of usage over time. The case study farm has three electricity connection points with differing seasonal load profiles and random variability. This section looks at the characteristics of each connection in more detail.

***Site A: River Pump***

The 330 kW river pump is the only load for this connection. The pump is off for long periods and then operational at a constant level for 24 hrs a day often for several days when conditions permit. This usage pattern is a result of the availability of allocated water in the river that needs to be pumped to the farm within a designated time frame. If there is no water to be pumped, then there is zero electricity usage. A 12-month load profile of half-hourly interval data was sourced from the TSP and analysed. The usage showed a large day to day variance in the electricity load, with the one component off (0 kW) or on (max. 336 kW), however as the pump is off for weeks at a time and on for days at a time, the hour to hour variance is low creating a block like profile. The peak demand exceeds the capacity due to soft start componentry for the motor. October has the highest monthly usage in the dataset. The random day-to-day and time step variability of the river pump is summarised in Table 2.

***Site B: Pivot pumphouse***

The pivot pumphouse contains two electric motors that supply energy to the centre pivot irrigators in three different fields (see Figure 3). These motors are sized 132 kW and 110 kW and can be used together or independently i.e. one motor at a time. The pivot irrigators are used for both summer and winter cropping, however increased crop evapotranspiration in summer results in more water needing to be applied to the summer crops, particularly early in the season prior to the onset of the monsoon. A 12-month load profile of half-hourly interval data was sourced from the TSP to better understand energy demand. October to March had the highest electricity use, however month-by-month demand is heavily influenced by crop evapotranspiration which can change each year. For example, 70 mm of rainfall was recorded at Comet during October 2017, twice the mean of 36 mm (Bureau of Meteorology, 2018). The energy demand from pivot irrigating for that month was negligible due to abundant soil moisture. During April to September the pumping load is reduced, as wheat crop demand for water is less due to cooler season growing conditions. The day-to-day variability shown in Table 2 is less than that of the river pump, with more consistent use.

***Site C: Grain Dryer***

A 37 kW capacity electric fan is used to reduce the moisture content of freshly harvested peanuts in the months of April and May. Two augers totalling 3 kW transfer the grain in and out of the grain drying facility. A synthetic electric load has been created from information provided by the landholder. The 36 kW operating load has been calculated at 90 per cent power factor of the 40 kW electric motors. The dryers typically run for 8 hours a day on fine days between 10am and 6pm when the air temperature is warm, and humidity is low. Consumption and day-to-day variability assumptions are shown in Table 2.

**Table 2. A summary of load details of each site for the HOMER analyses**

| Site | Description | Capacity (kW) | Peak (kW) | Average kWh/day | Day-to-day variability (%) |
|---|---|---|---|---|---|
| A | River pump | 330 | 336 | 858 | 295 |
| B | Pivot pump house | 242 | 234.8 | 1085 | 186 |
| C | Grain dryer | 40 | 36 | 35 | 6 |

An illustration of monthly grid-consumption from each site, drawn from two years of consumption data, is shown in Figure 4. The seasonal usage of each site combined with TSP rules provides a unique set of challenges when modelling technology options for each connection.

As the case study farm is in regional QLD, the consumer has only one available retailer, however there are several tariff options for each connection to best fit energy consumption. The retailer is also undergoing tariff reform post-2020, making assumptions over the 25-year investment challenging (Ergon Energy, 2016). Speculation on future tariff structures and charges is outside the scope of this study, so modelling has been conducted on existing tariffs. Any future increase in electricity prices would further improve the feasibility results reported in this analysis.

A summary of the tariffs used is provided in Table 3. Ergon Time-of-use (TOU) Tariff 62 has been used for case study sites A and B. As annual energy demand exceeds 100 MWh, it is assumed no FiT is available due to failing the eligibility criteria set out in Section 2.2 on ‘connecting embedded generation’. Tariff 20, a flat-rate ‘Business General Supply’ is the current supply structure for site C with a TOU FiT added.

**Figure 4. Monthly average energy demand for each site: River pump (A), Pivot pumphouse (B) and Grain dryer (C)**

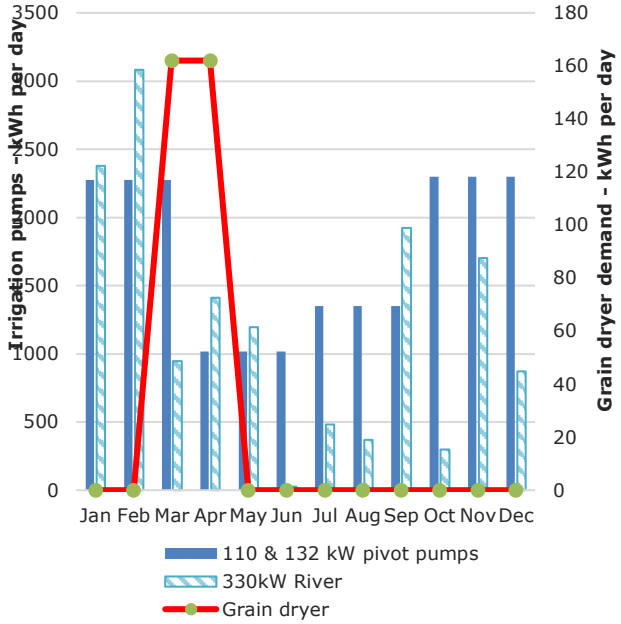



**Table 3. Tariff assumption for each site**

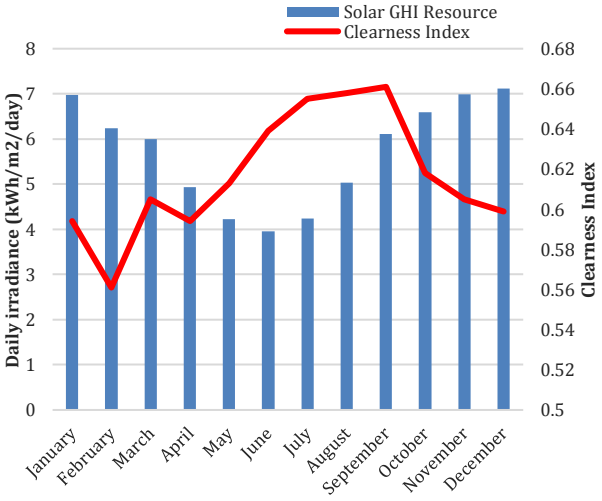
| Site | Tariff Name | Supply charge | Peak tariff | Off-peak tariff | FiT all hours | FiT (3-7pm) |
|---|---|---|---|---|---|---|
| A | Tariff 62 | $286 | $0.410 | $0.165 | N/A | N/A |
| B | Tariff 62 | $286 | $0.410 | $0.165 | N/A | N/A |
| C | Tariff 20 | $440 | $0.2772 | $0.265 | $0.07358 | $0.13606 |

**Resource assessment**

The analysis considers solar and wind resources for the case study farm. Solar exposure or Global Horizontal Irradiance (GHI) and wind resource data were both downloaded from NASA (2018) Surface Meteorology and Solar Energy website for the case study location (23°36.3 S latitude and 145°32.7E longitude). Annual average solar radiation was 5.7 kWh/m$^2$/day with a clearness index of 0.6168 as shown in Figure 5. The location can provide consistent solar production throughout the year, although cloudiness impacts on the clearness index during the wet season and improves considerably during the drier winter months. Peak months for energy production are November, December and January when day lengths increase and are aligned with usage of the pivot pump house.

The annual average wind speed for the location is 5.04 m/s at the height of 10m. The resource data from NASA Surface Meteorology and Solar Energy database is based on the closest weather station. It should be noted that significant variance exists in wind resources between locations due to existing vegetation, topography and proximity to buildings. Simulated wind speed data for a given location should not be relied upon. Instead, on-site data collected at hub height is the more accurate resource assessment for wind generation.

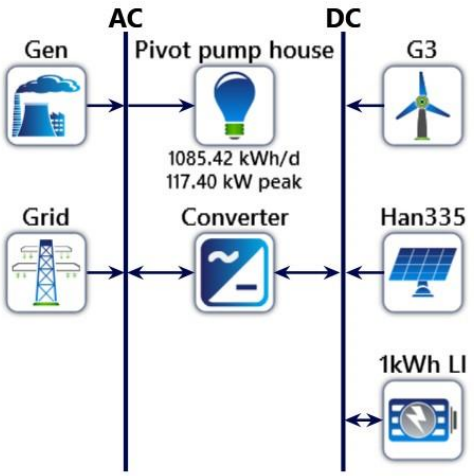
**Figure 5. Monthly average solar GHI for the case study location**




**Component assessment**

The components within a microgrid system either generate, store, control or use energy. Within this analysis the generating resources considered were solar PV, wind turbines, diesel generators and the existing grid and tariff structure. Lithium-ion batteries were considered for storage and converters for the control of the energy. Figure 6 is an example of the schematic system configuration for site B, pivot pump house.

**Figure 6. HOMER component schematic (Site B)**




Component pricing considers all applicable costs and are an 'installed and commissioned' price. All pricing and monetary terms are in AUD. The solar PV capital costs are $1,500 for 1 kW ground mounted at site A, $1,400 for site B and $900 for 1 kW on the aluminium roof in site C. The pricing differences account for the mount and racking requirements of each site. Site A mounts are quoted to be high enough to keep the panels out of flood water, Site B mounts are slightly lower, and Site C is basic roof racking. These prices are net of the applicable government rebates SREC (site C) and LGC (site A and B). The Solar PV has a 25-year lifetime so does not replace within the 25-year analysis. Annual operating and maintenance are $4 for 1 kW. To account for the effects of temperature, dust and time, a derating factor of 85% has been used. The panels are modelled on a fixed tilt facing North with a slope of 26.3$^{o}$, tracking systems are not considered. Panels on the aluminium roof are modelled with a 40% ground reflectance, 10% when on ground mounts.

A generic 3 kW wind turbine is considered in the modelling. A capital cost of $14,000 for 1kW, a life time of 20 years and a replacement cost of $12,000. The annual operating and maintenance is $180 for 1 kW.

Site A modelling considered a 500kVA (400kW) generator sized to account for soft start capability. This has an installed capital cost of $102,712, lifetime of 90,000 hours, and a replacement cost of $80,000. Costs to connect embedded generation to the network have been estimated at $20,000 (Ergon Energy, 2017). These costs have been independently verified by local engineers who size, supply and install gensets. Telemetry for remote monitoring, start/stop as well as commissioning has been included in genset capital costs. Site B and C modelling considered the Homer Auto-size diesel generator with a capital cost of $240 per kW, a lifetime of 15,000 hours and replacement cost of $240/kW. All generators had an annual operating and maintenance cost of $0.03/hr. The diesel price was modelled at $1 per litre (net of taxes), with a real indexation of 5 per cent per annum and sensitivity tested for Site A.

The storage option in the modelling was an auto size generic lithium-ion Battery, with a capital cost of $800 for 1 kW, a lifetime of 3000 hours and a replacement cost of $500/kW. The annual operating and maintenance costs are $10/kW/yr.

The capital costs for a generic system converter are $300 for 1 kW, a lifetime of 15 years and a replacement cost of $300. The annual operating and maintenance is $0. The inverter and rectifier efficiencies are 95%.

**Economic inputs**

Parameters uniform to each site include the project lifetime of 25 years, an annual discount rate of 7 per cent, inflation rate of 2 per cent and an install date of 2018.

***The grid***

Each site has an existing grid connection, so the grid scenario is used as the base case in HOMER to compare all other scenarios. The grid is modelled using the existing regulatory environment and existing policy frameworks for the TSP and retailer. The tariffs outlined above are used for each site. Indexation within the model has also been incorporated to account for price movements that in recent times have exceeded inflation. Queensland's electricity prices doubled between 2007–2008 and 2013–2014, predominantly driven by increases in network charges which increased sixfold from 2004–2005 to 2014– 2015, accounting for over 95 per cent of the total electricity price increases during the period. The proportion of network charges relative to the wholesale price of power has also changed over time. Network charges now account for over half of Queensland's retail electricity prices, whereas in 2004–2005, they only accounted for around 20 per cent (Davis, 2018). Graham et al. (2015) researched the issue of Australian electricity prices in detail to 2040 and considered different jurisdictions and bill components. Although outcomes are sensitive to carbon policy outcomes, a value of 5 per cent has been used as a price index over the investment period. Key grid restrictions were: no net metering on all sites, no export of energy on Sites A and B and export capacity limited to 30 kW for Site C.

One characteristic of the existing grid is the random and common supply interruptions known as 'black outs'. These periods may range anywhere from less than a minute to several days and occur more regularly in the summer season when water application can be critical to crops. New technology currently under development aims to allow an appropriately sized, grid connected microgrid to operate a load/s independently during times of grid failure. The improvement of energy

reliability reduces production risk through better agronomic management and would be a welcome benefit of a microgrid, however the benefit has not been valued in this analysis.

***Indexation of diesel fuel***

Amid rapid recent changes in energy markets, the predicted penetration of electric passenger vehicles is almost certain to displace a portion of traditional hydrocarbon-based fuels in the future. The outlook and indexation assumptions for future diesel fuel cost have used the global oil price outlooks as a proxy to the year 2040. Although forecasts do not account for domestic exchange rate variation, Australia remains highly dependent on imported petroleum products. All reporting agencies surveyed suggest four factors underpin the future price of oil: global economic growth and consumer demand; the rate of urbanisation in non-OECD countries (particularly China and India) affecting energy demand; energy innovation (nuclear and renewables); and government carbon policies/adoption of innovative technologies. Analysis by Powell et al. (2019) found the average real indexation across various agencies to be 2.79 per cent and this value is used in the analysis.

**Sensitivity of inputs**

Utilisation rates of solar power (to offset grid electricity costs), the amount received for a FiT and falling technology costs are key variables which have been discussed previously (Powell and Welsh, 2016b). Within this analysis four other key inputs are sensitivity tested. Site A considers a varied diesel price, $1, $1.20 and $1.40 per litre net of excise and goods and services tax. Site B compares the results when the PV is limited to 100kW to be eligible for up-front STCs. Site C compares the results on the flat FiT v the TOU FiTs and a net metering scenario.

**Economic modelling and optimisation**

The HOMER model optimises system componentry to minimise total net present cost (NPC) using simulation. In this case, Site A has been optimised using HOMER across all inputs except the genset component – due to technical limitations. Scenarios for Site C have been altered slightly upon consideration of TSP connection limitations and access criteria for renewable energy subsidies. The rationale behind limiting the size of some components are summarised in Table 4.

**Table 4. Economic model parameters for HOMER and rationale for each site**

| Site | PV | Wind | Genset | Battery | Inverter | Rationale |
|---|---|---|---|---|---|---|
| A | Optimise | Optimise | 400kW | Optimise | Optimise | Genset fixed due to motor soft-start |
| B | Optimise | Optimise | Optimise | Optimise | Optimise | |
| C | 38kW | Optimise | Optimise | Optimise | 30kW | PV/inverter sized for FiT eligibility |

**Avoided emissions**

The installation of solar technology on farm is an environmental consideration. By substituting traditional grid-supplied energy with renewable energy, emissions are avoided. This can be substantial and is a clear environmental benefit. The avoided emissions were calculated using the total electricity offset due to the use of solar energy over the 25-year life of the project. Emissions from combusted diesel fuel generation have also been considered. The emissions factor of 2.697 kg $CO_2e$ per litre is underpinned by the Intergovernmental Panel on Climate Change (United States Environmental Protection Agency, 2016) assumptions to include all nitrous oxide and methane

emissions. Electricity generation and environmental impacts varies depending on types of generation in that state. Emissions factors have been calculated using data obtained from the Department of the Environment and Energy (2017) for Queensland electricity. This value is the scope 2 emission factor, for the State, Territory or electricity grid in which the consumption occurs (kg $CO_2e$ per kilowatt hour).

## Results and Discussion

This section shows the results of the analysis. First, the optimisation results are presented, which is followed by the outcomes of the sensitivity analysis and environmental outcomes.

### Optimisation results

The optimal combinations based on lowest net present cost for the three sites are summarised in Table 5. These sites have been compared with the grid-connect business-as-usual (BAU) scenario. Due to the sporadic energy use of the river pump at Site A, incorporating solar PV at a size to match the electric pump load was found to be uneconomical. The DG was found to be optimal, being incorporated as a substitute during peak tariff periods. The optimal combination on Site B found load sharing between solar PV, DG and grid. The final site C was chosen as the optimal size to FiT current TSP connection requirements where 38 kW of PV is the upper limit for FiT eligibility. Other input combinations such as DG and batteries did not feature as low-cost alternatives.

**Table 5. Optimal component combination for each site**

| Site | PV | Wind | Genset | Battery | Inverter | Rationale |
|---|---|---|---|---|---|---|
| A | 0 | 0 | 400kW | 0 | 0 | Load shared DG/grid (44%/56%) |
| B | 225kW | 0 | 130kW | 0 | 115kW | Load shared PV/DG/grid (60%/6%/34%) |
| C | 38kW | 0 | 0 | 0 | 30kW | PV/inverter sized for FiT eligibility |

The optimal combination of componentry on Site A included remaining connected to the grid resulting in the generator replacing 44 per cent of the pumps annual electricity. This combination had the lowest NPC of $1.5M, 28 per cent lower than BAU. The payback period of five years and a 24 per cent internal rate of return (IRR) showed a good investment at the current diesel fuel price[2]. The avoided $CO_2e$ from change in fuel source to include diesel generation is a meagre 294 t of $CO_2e$ over 25 years. This scenario requires $122,712 of initial capital and $99,075 operating each year, 32 per cent lower than the BAU operating cost of $145,204 a year. The resulting levelised cost of energy is $0.338 kWh, 27 per cent lower than the BAU levelised cost of $0.464 kWh. PV did not feature in the economically optimal scenario as the sporadic load profile combined with no FiT and underutilisation of a solar resource. The use of a DG reduces the cost of electricity, however it does little to avoid emissions.

The optimisation of Site B resulted in a payback period of 6.8 years, a 17 per cent IRR and a NPC of $1.62m. The scenario requires initial capital of $383,900, to reduced power prices by 35 per cent resulting in a levelised cost of energy of $0.287 kWh. These results are achieved without a FiT as current TSP rules negate a FiT for current high levels of grid consumption. The avoided $CO_2e$ from production of 'green' energy is 2,711 t of $CO_2e$ over 25 years. Batteries did not feature in the

[2] Decision support software support (HOMER) was used to calculate IRR, hence the Modified Internal Rate of Return (MIRR) was unable to be calculated. The MIRR allows for a market rate of reinvestment of benefits applied through the analysis period (rather than the 24% IRR) and would be substantially lower than IRR.

economically optimal scenario, however as energy storage technologies improve and prices fall, a storage component could potentially be added into the PV array at a later date, further improving the investment feasibility. New technology to enable supply continuity from PV may also assist irrigation during power outages in Site B (GEM Energy, 2018). Energy reliability is a major issue in the region and loss of yield occurs when plant demand for water is unable to be optimised through irrigation.

The base analysis results for Site C found a payback period of 4.3 years, a 24 per cent IRR and a NPC of -$8,673 over the period showing a net profit from the installation. The initial capital requirement of $35,000 provides a microgrid that can generate enough energy to power the site and export via FiT to result in 100 per cent offset of the variable cost of energy. The avoided $CO_2e$ from production of 'green' energy is 150 t of $CO_2e$ over 25 years. Results of the three sites are summarised in Table 6.

**Table 6. Results of the HOMER optimisation of three case study sites**

| Site | Optimal hybrid configuration | Cost of energy $/kW | NPC | Payback | IRR | Change in emissions from base (25 years) |
|---|---|---|---|---|---|---|
| A | Grid/Genset | $0.338 | $1.50m | 5.2 years | 24% | 294 t CO2 |
| B | Grid/Genset/ PV | $0.287 | $1.62m | 6.8 years | 17% | 2,712 t CO2 |
| C | Grid/PV | -$0.008 | -$8,673 | 4.3 years | 24% | 150 t CO2 |

The results consider only the variable costs of energy. Fixed costs such as line rental and demand charges are still payable. As renewable investments increase, they affect the demand and supply profiles of grid energy and TSP's are likely to restructure their charges to reflect the changing nature of grid energy supply. Any increases in electricity costs to the customer will only enhance the feasibility of microgrid installations, particularly those that allow the customer to go off grid.

**Sensitivity results**

An analysis using static values and assumptions is subject to change or error (Pannell, 1997). Additional investigation was conducted where there was uncertainty with baseline assumptions to enable consideration of other feasible component combinations. Parameters tested for each optimal combination were dependent on the primary input for each site. Diesel price was chosen for site A, where the addition of a DG was recommended. A reduced PV array was tested for Site B to ensure qualification for the 'small' STC rebate. Site C compared the results of the flat and TOU FiT. The sensitivity parameters are summarised in Table 7.

**Table 7. Sensitivity parameters for sites A, B and C**

| Site | Parameters | Detail |
|---|---|---|
| A | Diesel price | $1.00, 1.25 & $1.40 Diesel indexed @ 2.79% |
| B | Set PV size | 99.5kW to keep within the small-scale scheme |
| C | FiT | Flat 10c FiT vs TOU FiT |

Sensitivity analysis on the results for Site A, indicate that an investment in a generator shows project returns are sensitive to diesel price increases. A 40 per cent increase in diesel price slows the payback period from 5 years in the base case scenario to 10 years. This 40 per cent price increase added 6.2c/kWh to the cost of energy, however at $0.40 it is still 13 per cent below the BAU cost of $0.46. Results are summarised in Table 8.

Reducing the size of the PV array for Site B resulted in a higher IRR and quicker payback period due to the reduced capital outlay. The cost of energy in this scenario was slightly higher due to the PV offsetting a smaller proportion of the 242 kW maximum load with the more costly DG making up the balance. The small scale solar installation (<100 kW PV), achieved a levelised cost of energy 29 per cent lower than the grid only scenario, but nine per cent higher than the optimal microgrid solution. Offset emissions for the small-scale scenario were 40 per cent lower than the optimal microgrid solution. Results of these scenarios are presented in Table 9.

**Table 8. Site A diesel price sensitivity results**

| Diesel Price | Optimal hybrid configuration | Initial capital | Cost of energy $/kW | NPC | Payback | IRR | Change in emissions from base (25 years) |
|---|---|---|---|---|---|---|---|
| BASE | Grid only | | $0.46 | $2.07m | | | Base Case |
| 1 | Grid/Genset | $122,712 | $0.338 | $1.50m | 5.2 yrs | 24% | 294t CO2 |
| 1.2 | Grid/Genset | $122,712 | $0.369 | $1.64m | 7.0 yrs | 19% | 294t CO2 |
| 1.4 | Grid/Genset | $122,712 | $0.400 | $1.78m | 10.0 yrs | 14% | 294t CO2 |

**Table 9. Site B PV size and optimal microgrid configurations**

| PV | Optimal hybrid configuration | Initial capital | Cost of energy $/kW | NPC | Payback | IRR | Change in emissions from base (25 years) |
|---|---|---|---|---|---|---|---|
| BASE | Grid Only | | $0.440 | $2.48m | | | |
| 225 | Grid/Genset/PV | $383,900 | $0.287 | $1.62m | 6.8 years | 17 % | 2,711t CO2 |
| 99.5 | Grid/Genset/PV | $201,200 | $0.313 | $1.76m | 5.5 years | 22% | 1,632t CO2 |

Site C sensitivity testing considered the two FiT options available to the site. The NPC of the flat FiT resulted in an $8,673 benefit as opposed to a $7,054 cost for the TOU FiT. The flat FiT option is superior in this scenario, however TOU FiT still results in a 98 per cent reduction in the levelised cost of energy and had a payback period of under ten years. The comparison results are shown in Table 10. The energy consumption breakdown was; solar power used 12,672kWh (71 per cent of load requirements), grid purchases of 5,087kWh and grid sales of 65,120kWh. In this scenario, grid sales exceed grid purchases, and with a flat FiT this results in an overall profit from installing the solar PV. Current PV pricing results in solar energy being produced for a lower cost than existing FiTs, so where eligible it pays to install the maximum PV allowed for a FiT. Ergon does not allow net metering, however if this scenario were net metered, the profit would be even greater.

**Table 10. Site C flat v time-of-use FiT**

| PV | Optimal hybrid configuration | Initial capital | Cost of energy $/kW | NPC | Payback | IRR | Change in emissions from base (25 years) |
|---|---|---|---|---|---|---|---|
| BASE | Grid Only | | $0.469 | $84,659 | | | |
| Flat FiT | Grid/PV | $35,600 | -$0.008 | -$8,673 | 4.3 years | 23.7% | 149.8t CO2 |
| TOU FiT | Grid/PV | $35,600 | $0.006 | $7,054 | 4.9 years | 20.7% | 149.8t CO2 |

## Conclusion

Current government renewable energy policy, increased energy costs, advances in solar technology and falling cost of solar installations have all aligned to create a good opportunity for cotton growers to employ renewable energy pumping systems that will reduce both on-farm costs and carbon emissions. Our search for a technically feasible and economically viable solution to supply alternative energy to an irrigation farm in central Queensland found several factors influenced the project returns and environmental benefits. Firstly, Site A, characterised by sporadic seasonal use with high day-to-day variability was best suited to a mix of grid and on-site diesel-powered electricity generation. However, returns were found to be very sensitive to the current diesel price, whereby a 40 per cent increase doubled the payback period from five to ten years. Under the DG and grid scenarios the level of carbon abatement achieved was negligible. Noting the Queensland tariff structure post-2020 is currently under review the analyses also assumed ongoing eligibility to a TOU Tariff (62) for the duration of the 25-year investment period. A fixed demand tariff would change results a great deal and require a new study.

The pivot pump shed, Site B was found to have the most well-rounded energy demand profile throughout the year owing to the continuous cropping rotation on the farm. Optimisation results included a combination of 225kW of PV, DG and remaining connected to the grid. Although sensitivity testing identified a configuration with higher returns, the larger PV system would enable continued irrigating during periods of grid supply interruptions during daylight hours. Benefits from energy security resulting in optimal crop irrigation have not been considered in this study and may be a future area of research. The larger system offsets the highest amount of grid electricity and provides an alternative fuel source and buffer against any further grid price increases. This system also has the highest abatement of any site analysed at 2,711t $CO_2e$.

Site C, a grain drying facility has a short two-month window of operation after harvest in March and April. This was the only site on the case study farm to comply with the FiT requirement of energy consumption under 100 MW annually, so the economic parameters were set to the maximum limits of PV (that comply with FiT eligibility). Even with a small amount of annual self-consumption, the analysis found the project returns to be highly profitable with a payback period of between four and five years for both combinations of FiT rates. This payback is benefited from the high grid sales of unutilised PV. If network regulations change to include net metering, the profit would be even higher.

This study has found that the feasibility outcomes of installing innovative energy solutions to seasonal energy loads is highly dependent on the rate of self-consumption and policy settings such as available tariff, retailer competition and access to Feed-in-tariffs. The economic and environmental benefits offered by low-cost PV are inextricably linked to these key parameters. The TOU tariffs in the study ascertained a viable inclusion of a diesel generator showing a competitive levelised cost of energy during peak periods. Battery storage costs did not feature in optimisation results across the

three case study sites. Although the majority of irrigators in the Australian cotton industry are not connected to the Ergon network, those that are do have options to reduce per kWh energy costs. With some international energy agencies forecasting energy storage prices to fall in the coming years, there is an avenue for future research. In the absence of a FiT for solar PV above 38kW, economic and environmental benefits were achieved only where energy demand was closely matched with renewable energy supply throughout the year.

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