final report

Environment

Project code: **A.ENV.0095**

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Date published: **May 2010**

ISBN: **9781741914122**

PUBLISHED BY
Meat & Livestock Australia Limited
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NORTH SYDNEY NSW 2059

Renewable energy and energy efficiency options for the Australian meat processing industry

Meat & Livestock Australia acknowledges the matching funds provided by the Australian Government to support the research and development detailed in this publication.

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1 About IT Power

The IT Power Group, formed in 1983, is a specialist renewable energy, energy efficiency and carbon markets consulting company. The group has offices and projects throughout the world. IT Power (Australia) was established in 2003, and has undertaken a wide diversity of projects, including providing advice for government policy, feasibility studies for large hybrid systems, developing micro-finance models for small-scale community-owned systems in developing countries and modelling large-scale systems for industrial use.

The staff at IT Power (Australia) have backgrounds in renewable energy and energy efficiency research, development and implementation, managing and reviewing government incentive programs, high level policy analysis and research, including carbon markets, engineering (system) design and project management.

About this report

This report builds on previous projects for the MLA that have separately assessed the renewable energy and energy efficiency potential in the industry, focusing on particular waste streams or generation technologies. Here we take a case study approach, focussing on four particular facilities, that focuses on the opportunities for renewable energy within the context of the Renewable Energy Target (RET), the National Greenhouse and Energy Reporting System (NGERS) and potential carbon markets.

This report is produced in conjunction with a supplementary report, *Carbon Markets and their Relevance to the Meat Processing Industry*. It firstly provides an overview of the Kyoto Protocol, the proposed Carbon Pollution Reduction Scheme (CPRS) and the NGERS. It then explains in some detail what these mean for the Australian meat processing industry, in terms of both direct and indirect impacts, including what emissions are covered under NGERS and the CPRS, how the liable entity is defined, their obligations and possible cost impacts. It then outlines the various options meat processors have to reduce their liabilities and costs under both NGERS and the CPRS, focussing on energy efficiency, renewable energy, and purchase of Australian permits, international certificates and derivatives.

2 Background

With ever increasing energy costs and the introduction of both the Carbon Pollution Reduction Scheme (CPRS) and the Renewable Energy Target (RET), the agricultural processing industry in Australia is well placed to benefit from a close inspection of energy usage and energy sources.

Renewable Energy sources offer a number of clear benefits, including lowering emissions, increasing energy security, reducing or removing liability under the CPRS and providing industries with legitimate and real branding opportunities. More importantly, in many cases the use of renewable energy sources to complement existing energy sources provides a strong economic positive.

A recent project undertaken by IT Power demonstrated that renewable energy can be highly cost effective, saving nearly $2 million per year for an outlay of less than $12 million.

Through discussions with staff from the MLA and individuals from the meat processing industry, it is clear this sector has the potential to realise significant gains from undertaking a study into the feasibility of incorporating renewables into the energy mix. Opportunities will be available at various sites to incorporate technologies such as wind, solar (both thermal and photovoltaic), methane capture and reuse and other. As well as the renewable sources, there will be opportunities to better use the current energy sources, through such technologies as low level heat capture.

The idea for this project grew out of a conversation between staff from the MLA and IT Power, who met at a renewable energy conference. From here the concept was refined and progressed through emails and meetings, and informed through a basic desktop investigation of the industry.

Processors currently fall into two categories for the purpose of this proposal: those relying entirely on grid electricity for their energy needs, and those who generate some or all of their energy needs autonomously. Both categories will have obligations under the CPRS, although for many of the smaller organisations these obligations will be minimal. The most effected group will be the larger entities that are generating energy on site, and are consequently paying the full cost of generation.

With coal sourced electricity being relatively inexpensive, and the externalised costs such as carbon emissions not being accounted for, the best business case for any industry is to negotiate the cheapest tariff and use as much electricity as required. As the cost of electricity increases, a number of organisations implement energy efficiency measures to reduce the electricity liability. However, the moment the externalised costs are included into the equation, a radically different approach may be required.

An example of this is a processor who wants to reduce their emissions to below the reporting thresh hold, and consequently offset significant expenses. Modifications of practices and energy efficiency could get them very close to the thresh hold, at which point self-generation of energy through a clean and sustainable resources may be enough to drop their emissions below the thresh hold. The combination of savings from the reporting requirements, savings from energy purchases and income from the RET scheme has the potential for a strong cost benefit argument.

A number of other industries are already investigating this approach, and in Europe the meat processing industry is already implementing offsetting actions. This project proposes there is opportunity for the Australian industry to learn from these experiences, and adapt the outcomes to the industry here.

At the conclusion of the project the opportunity will be available for any individual plant to proceed to the next level of a full feasibility study or even system design.

3 Objectives

The key outcome of this project will be a thorough understanding of the potential costs and benefits to the industry, as a whole and for particular plants / sites, of implementing renewable energy projects. This will be achieved through consultation with industry throughout the project life, culminating with a report aimed at industry, and through optional presentations at industry forums or similar.

4 Introduction

With ever increasing energy costs and the introduction of the Renewable Energy Target (RET), the National Greenhouse and Energy Reporting System (NGERS) and possibly the Carbon Pollution Reduction Scheme (CPRS), the meat processing industry in Australia is well placed to benefit from a close inspection of its sources of energy as well as how that energy is used.

This report builds on previous projects for the MLA that have separately assessed the renewable energy and energy efficiency potential in the industry, focusing on particular waste streams or generation technologies. In particular, it builds on:

- *Red Meat Processing Industry Energy Efficiency Manual*, by Hydro Tasmania for the MLA (Hydro Tas, 2008)
- *Review of Waste Solids Processing and Energy Capture Technologies*, by GHD (GHD, 2005)

Here we take a case study approach that focuses on the opportunities for renewable energy within the context of the RET, NGERS and potential carbon markets. A key outcome of this project is an understanding of the potential costs and benefits of implementing renewable energy projects. The information in this report can be used by meat processors to assess whether they wish to proceed to the next level of a full feasibility study or even system design.

An accompanying report “Carbon Markets and their Relevance to the Meat Processing Industry”, discusses in detail the CPRS and NGERS, focusing on what these mean for the Australian meat processing industry in terms of both direct and indirect impacts. It then outlines how various options can reduce meat processors’ liabilities and costs under both NGERS and the CPRS, focussing on energy efficiency, renewable energy, and purchase of Australian permits, international certificates and derivatives.

4.1 Renewable energy and energy efficiency

With conventional electricity and gas being relatively inexpensive, and externalised costs such as carbon emissions not currently accounted for, the best business case for any industry has been to negotiate the cheapest tariffs and use as much energy as required. However, as the cost of energy increases, more and more organisations are finding it worthwhile to implement energy efficiency measures to reduce energy use, and often to use renewable energy to meet their own electricity, heat and sometimes cooling loads on-site. The NGERS and CPRS add an additional level of complexity beyond simple increased energy costs.

As detailed in the report “Carbon Markets and their Relevance to the Meat Processing Industry”, energy efficiency can help an entity to drop below the NGERS energy threshold as well as the NGERS greenhouse gas threshold, but cannot reduce CPRS liabilities for onsite emissions because liabilities for energy-related emissions are not applied to the meat processing facility. Instead, liabilities are applied to upstream suppliers and so electricity and such fuels will simply be more expensive, and energy efficiency can help reduce the use of these fuels and hence costs.

Renewable energy cannot be used to avoid energy-related NGERS obligations because they are based on energy use, no matter how or where that energy is produced. If the facility is below the NGERS energy threshold, renewable energy may be able to avoid greenhouse gas-based NGERS obligations if it reduces onsite emissions. Renewable energy can be used to reduce CPRS liabilities for onsite non-energy-related emissions, and can reduce the use of external sources of energy, and hence costs.

Renewable energy and energy efficiency offer additional benefits such as increased energy security and legitimate and real branding opportunities. Renewable energy technologies can also be used to generate income through the RET.

As discussed below, opportunities are available at various sites to incorporate renewable energy technologies such as wind, solar (both thermal and photovoltaic), methane capture and reuse and others – although at this time, bioenergy is clearly the most financially viable option. As well as the renewable sources, there are opportunities to better use the current energy sources through reduced energy use and technologies such as low level heat capture.

4.2 Structure of this report

Section **Error! Reference source not found.** describes the methodology used to assess the financial viability of a range of different renewable energy options, including any assumptions that were made.
Section 6 summarises the typical energy use and greenhouse emissions of the different types of meat processor, with the main differences dependent on whether the facility renders and/or freezes meat on-site.

Section **Error! Reference source not found.** discusses the findings at each of the case studies, including the electricity and heat that could be produced, any reduction in emissions, the capital costs, cost savings and resultant simple payback and net present values of the different options.

Finally, Section **Error! Reference source not found.** summarises the outcomes most relevant to the Australian meat processing industry, and it is clear that bioenergy is currently the most viable renewable energy technology.
Appendix A provides a technical description of some of the technologies that can be used for on-site generation of renewable energy.

Appendix B provides an overview of the various Commonwealth and state government incentives for the use of renewable energy most relevant to the meat processing industry.

5 Methodology

The methodology used to undertake this study was as follows.

Desktop reviews were undertaken of reports that focussed on the use of renewable energy and energy efficiency in the Australian meat processing industry. In particular, Hydro Tas (2008), GHD (2005) and UNEP(2002).

Site visits to four meat processing facilities were undertaken. Every effort was made to cover facilities that represented different locations, species and size of plant, however the number of plant that wished to volunteer was limited. A brief summary of the sites visited is shown in Table 5-1.

Table 5-1 Overview of sites visited

Site	State	Species processed	NGERS Reporting
A	NSW	Cattle	Yes
B	QLD	Cattle	No
C	QLD	Cattle	Yes
D	NSW	Sheep	No

During the site visits the plants were examined for areas where fossil fuel energy could be displaced with renewable energy sources. In particular the areas investigated were:

- The potential for energy generation from waste streams including yard and paunch manure and effluent ponds,
- The potential for co-generation (heat and electricity from the same source),
- The resources and potential for solar generation including both PV and solar thermal technologies,
- The potential for wind energy generation, and
- The potential for energy generation from tallow including direct combustion as well as production of biodiesel.

Data collected during the site visits included:

- Breakdown of energy use and costs including time of use and peak demand tariffs for electricity.
- Production yields for the facility, including quantity of livestock processed, quantity of meat produced and quantity of by-products produced.
- Quantity of solid and liquid wastes generated.
- Current energy saving and renewable energy initiatives being undertaken.

Following the site visits, the team developed a number of real world options for these sites, to be used as case studies and examples for the industry as a whole. These case studies included a basic feasibility study of resources, modelling of initial capital and life cycle costs, and the likely payback periods and net present value (NPV) for individual sites. The assumptions used during financial modelling are shown in Table 5-2.

Table 5-2 Assumptions used in financial modelling

Discount Rate	7.5%
REC Price	$40 per MWh
Operational life	
- Pond Cover	20 yr
- Cogeneration unit (overhaul after 2,500 hr)	15 yr
- LGP burner modifications	20 yr
- Fuel Cell (overhaul after 5 to 10 years)	20 yr
- PV	20 yr
- Wind turbine	20 yr

6 Typical Energy Use and Emissions of Meat Processors

The amount of energy used by a meat processing plant, as well as the related greenhouse gas emissions, are largely dependent on whether the plant has onsite rendering and/or onsite freezing of meat. The rendering process can typically account for over 70% of the heat energy requirements of a plant. Similarly, refrigeration can account for over 50% of electricity use in plants incorporating onsite/longer term freezing (Hydro Tas, 2008). These figures closely match those obtained from the site visits. Table 6-1 summarises the characteristics of the meat processing plants visited in this study, including energy use.

Table 6-1 General characteristics of meat processing facility case studies

Plant	Species	Head per Day	Onsite Rendering	Onsite Freezing	Electricty Usage (kWh/tHSCW)	Heat Energy Usage (MJ/tHSCW)	NGERS Reporting
A	Cattle	1250	Y	Y	959	2,350	Yes
B	Cattle	500	Y	Y	655	2,645	No
C	Cattle	1600	Y	Y	1,070	2,751	Yes
D	Sheep	2000	N	N	1,049	701	No

Of the four sites visited, two are currently required to report under the NGERS. Another of the plants is very close to reaching the reporting threshold and may even exceed it for this reporting period. The fourth plant is well below the reporting threshold.

Typically heat energy accounted for 70% of the total energy used at the sites visited but only accounted for 30% of the total cost of energy. A breakdown of energy costs for the sites visited is shown in Table 6-2. Facilities in Queensland typically used coal as the main heat source while those in New South Wales used gas

Table 6-2 Energy costs of meat processing facility case studies

Plant	Natural Gas ($/GJ)	Coal ($/GJ)	LPG ($/GJ)	Peak Electricity[1] (c/kWh)	Off-peak Electricity (c/kWh)
A	4.00	-	-	10.56	5.7
B	-	1.95	24.33	9.07	3.94
C	18.43	4.06	-	7.39	3.38
D	11.52	-	-	10.88	5.49

[1] Note: Electricity the prices above do not include demand charges

7 Case studies

7.1 Plant A

Plant A is an integrated cattle processing facility that kills and processes approximately 1,250 head per day. The average processed weight per head is 240kg and total yield per year is approximately 75,000 tHSCW. The facility includes kill floor, boning room, freezing (with capacity for a number of days storage) and rendering. Gas is the main heat source used and the plant pays comparatively high electricity use and demand tariffs. However, the average electricity price is low indicating that a large proportion of electricity use is during off-peak times.

Summary of findings
There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant A. The most economic of these are summarised below.

- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 3,640,000 kWh of electricity and 13,000 GJ of gas per year. It could also reduce direct emissions from effluent ponds by approximately 6,756 tCO_2-e/yr and indirect emissions (from electricity and gas use by approximately 4,560 tCO_2-e/yr). The cost of such an installation would be in the order of $3,405,000 and the project would have a simple payback period of about 5.5 years. This option would remove the vast majority of any direct liability the plant may have under the introduction of the currently proposed CPRS. It would not, however, remove the plants requirement to report under NGERS.
- Capture of biogas from paunch and yard manure through the use of a plug and flow anaerobic digester. This option has the potential to offset approximately 836,000kWh of electricity and 3,000 GJ of gas per year. The project would reduce indirect emissions by approximately 1,050 tCO_2-e/yr. Further investigation is required into the feasibility of this option.

Technologies that are currently feasible but not economic (although they may be in the not too distant future) for use at Plant A include:

- The use of fuel cells in place of reciprocal gas generators
- Solar PV technologies to generate electricity
- Solar thermal technologies to preheat boiler water
- Wind turbines to generate electricity
- Geothermal heating and cooling
- Combustion of tallow

7.1.1 Energy and waste characteristics

Figure 7.1, Figure 7.2 and Table 7-1 show a breakdown of the energy used and associated costs for Plant A. While heat energy accounts for over 70% of energy used, it accounts for less than 30% of the total energy costs. Plant A currently exceeds both its emissions and energy reporting threshold under the NGERS. In order to no longer be liable under NGERS the plant would need to reduce its energy use by over 70% and emissions by over 40%.

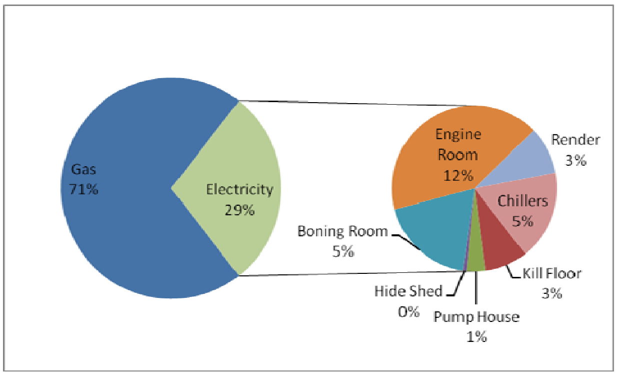


Figure 7.1: Energy use: Plant A

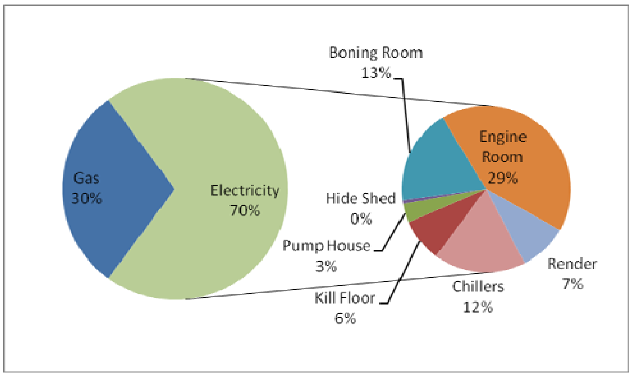


Figure 7.2: Energy costs: Plant A

Table 7-1: Energy use and cost breakdown: Plant A

Enegy Source	Average Usage (MJ/tHSCW)	% of Total	Cost (c/MJ)	% of Total
Electricity	959	29.0%	2.3	70.1%
Gas	2,350	71.0%	0.4	29.9%
Total	3,309	100%	0.9	100%

It is estimated that about 60% of electricity consumed by the plant is used for refrigeration. The refrigeration system includes 9 compressors varying in size from 75kW to 465kW. All compressors used by the plant are screw driven. The majority of the heat energy required by the plant is generated by a 10MW water-tube boiler and a 7MW fire-tube boiler. Both boilers operate on natural gas. Approximately 97% of the gas used by the plant goes to the boilers, with the remainder used for drying blood. The 10MW boiler has economisers fitted and condensate is captured from the cooker to preheat boiler water. The plant also has a flash steam recovery system.

The plant produces approximately 11ML per week or 577 ML of waste water per year, which is treated in two ponds. The ponds each have a capacity of 28ML. The treated waste water is used to irrigate adjacent paddocks. The waste water has an average chemical oxygen demand (COD) of 6,100 kg/ML. The plant is currently investigating options for the capture of methane from waste water ponds. The options considered include the construction and cover of a 65ML pond. The ponds are approximately 600 metres from the plant which should allow transport of the captured biogas back to the plant for use. While the transport of the gas is feasible, it will be expensive given the distance to the ponds.

7.1.2 Options to reduce emissions and costs using EE and RE

7.1.2.1 Biogas capture for flaring

Plant A has reported a wastewater flow rate of 577 ML/yr with an average COD of 6.1 kg/kL. This equates to an annual COD input of 3,522 tonnes to wastewater treatment ponds. Under NGERS reporting methods, which assume a COD removal effectiveness of 40% for wastewater treatment systems at meat and poultry plants, and a methane yield of $0.35m^3CH_4/kgCOD_{removed}$, this facility emits around 7,467 tCO_2-e.

The site currently has 3 ponds in place with capacities of 56 ML, 28ML, and 28ML. Covering of the existing ponds is not feasible as the total capacity exceeds that required for optimal COD removal. Based on the wastewater flowrate, and the optimal retention time for an anaerobic digester (40 days), a new pond of 65 ML capacity may be feasible.

Based on a cover cost of $80/m^2$ (AMPC 2008), excavation costs of $10/m^3$ (NIWA 2008) and installation costs of $40/m^2$ installed, the new pond could be excavated and covered for a capital outlay of $2,210,000.

Based on cost estimates from UNEP (2002), flaring systems require capital outlay for the following components:

Technology	Cost
Flare – combustion mechanism for methane destruction	$60,000
Gas Pipe – piping from ponds to flare at a cost of $100/m. Flare site is undetermined	$10,000
Gas blower and regulator – gas pressure must be raised for pumping from ponds to boiler and generator	$15,000
Condensate trap – to remove water content of biogas and ensure high-temperature, and thus efficient, combustion	$5,000
Gas storage system – to allow for fluctuations in yield	$10,000

Including these capital requirements with those for pond covering, as well as design costs of $25,000, a total capital requirement of $2,335,000 is estimated.

Flaring of captured biogas would reduce annual emissions from wastewater ponds to 711 tCO_2-e and should reduce odour. A cost benefit analysis was carried out assuming the proposed CPRS was legislated. Further assumptions included a system lifetime of 20 years, a discount rate of 7.5%, and annual operating and maintenance (O&M) costs of 2.5% of the capital cost of the cover and flare system.

The findings are summarised in Table 7-2 below, alongside potential carbon permit prices (see accompanying report - *Carbon Markets and their Relevance to the Meat Processing Industry*).

Table 7-2: Cost Benefit Analyses for Gas Capture & Flaring

Permit Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV
10	2,335,000	72,900	41,500	74.4	-$2,014,900
15	2,335,000	109,300	41,500	34.4	-$1,643,800
20	2,335,000	145,700	41,500	22.4	-$1,272,700
25	2,335,000	182,200	41,500	16.6	-$900,600
30	2,335,000	218,600	41,500	13.2	-$529,600
35	2,335,000	255,000	41,500	10.9	-$158,500
40	2,335,000	291,500	41,500	9.3	$213,600

Revenue refers to savings in penalties for carbon emissions under the ETS, SPP refers to Simple Payback Period, and NPV refers to Net Present Value

7.1.2.2 Biogas capture for heat and electricity generation

An alternative to flaring captured gas is to use it to replace fuels from external sources for heat and electricity generation. This allows for additional savings through the offset of fuel costs. An analysis of this strategy is discussed in the forthcoming sections.

Biogas Capture for Heat Generation

Though NGERS accounting methods assume a digester effectiveness of 40%, actual effectiveness of 80% COD removal can be expected (DCC, 2009). Thus, from the expected biogas yield, actual methane yield is expected to be 991,800 m^3CH_4/yr. With an energy content of 37.7 MJ/m^3CH_4, (DCC, 2009) around 37,400 GJ/yr of heat energy is available to this facility.

Heat demand at this site is serviced via boilers running on natural gas. A gas price of ~0.61c/MJ has been reported. Due to the low price of gas at this facility, use of biogas to generate electricity and heat through a cogeneration system is more beneficial than simply using it for boilers alone.

Biogas Capture for Combined Heat and Power Generation

Captured biogas may be used to fuel a gas generator to service the electricity demand of the facility. Electrical energy yield accounts for around 35-45% of energy input, with the remainder typically being waste heat. Capturing and using this waste heat allows for overall efficiency to improve to upwards of 70%.

For a gas generator efficiency of 35%, from the expected biogas yield, around 13,100 GJ/yr or 3,635,300 kWh/yr of electrical energy could be produced. This accounts for ~13% of total electricity demand.

If a further 35% of energy is captured as heat through a cogeneration system, 13,100 GJ/yr is available as low-grade heat energy, suitable for boiler feed pre-heating or production of hot (82˚C) and warm water (43˚C). At a gas price of 0.61c/MJ, captured heat energy is worth around $79,800/yr to this facility. Cogeneration capacity is expected to add $200/kW installed to the cost of a generator, giving a total cost estimate of $1200/kW installed.

Generation Scheme Analysis

An onsite generator may be operated during high tariff periods only, or continuously across all tariff periods. Assuming that in New South Wales, the high tariff extends for 15 hrs/day on weekdays, and assuming 15min start-up and shut-down, a continuous generation scheme (24hrs/day, 365days/yr) would require a 415 kW gas generator, while for on-peak-only generation (15hrs/day, 365 days/yr) an 888 kW generator would be required.

A cost benefit analysis was carried out to determine the comparative value of each generation scheme. The following were considered in the analysis:

- Capital requirements for the purchase and installation of a combined heat and power generator were estimated at $1,200/kW installed.

- Savings from generation through offset of grid-connect electricity were determined using generator output and a breakdown of the sites tariff structure, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.

- Maintenance costs were estimated with consideration of the need for a complete generator overhaul after 25,000 hrs of operation. An overhaul was estimated to cost half the initial capital costs of the generator.

- Generator lifetime of 15 years was used for continuous generation, and 25 years for on-peak only generation.

As this analysis does not consider the cost of gas capture, the figures reported below do not reflect the full project cost. As can be seen from Table 7-3, continuous operation has a shorter payback time. However, because of the longer assumed operational life under 'high tariff' operation, this option has a greater NPV.

Table 7-3: Cost Benefit Analysis of continuous and high tariff generation

	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
High tariff only (888kW)	1,065,100	745,200	83,400	1.6	6,312,200
Continuous (415kW)	498,000	595,300	87,300	1.0	3,986,400

Note: Revenue refers to savings in grid-connect electricity consumption.

Cost Benefit Analysis of Combined Heat and Power Generation Scheme

From values determined previously, the installation of a combined heat and power generator requires capital of $1,065,100. The cost of biogas capture and treatment can be estimated from flaring costs (excluding the cost of the flare which is no longer required) with the following additional components being necessary:

Technology	Cost
Storage system upgrade – in the absence of a flare to control gas stock, storage system will likely require capacity increase	$5,000
Gas Piping – site is around 600m from digestion ponds (100m already accounted for), with a gas piping cost of $100/m (UNEP 2002)	$50,000
Gas pre-treatment system (scrubber) - required to remove hydrogen sulphide content to ensure the lifetime of the generator is not reduced through corrosion	$10,000

From these figures, total capital requirements for the design and installation of a combined heat and power generation system from captured biogas at this site are $3,405,100. The project is expected to return annual revenues of $745,200 through offset of grid-connect electricity, gas use, and RECs sales. Operating and maintenance (O&M) costs are expected to increase by $123,400 annually.

Based on these figures, a system lifetime of 15 years, and a discount rate of 7.5%, a cost benefit analysis against varying ETS prices returned the results in Table 7-4.

Table 7-4: Cost Benefit Analyses of Gas Capture for Heat & Electricity Generation

ETS Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	ETS Savings ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	3,405,100	745,200	0	123,400	5.5	$2,083,600
10	3,405,100	745,200	72,900	123,400	4.9	$2,727,100
15	3,405,100	745,200	109,300	123,400	4.7	$3,048,400
20	3,405,100	745,200	145,700	123,400	4.4	$3,369,700
25	3,405,100	745,200	182,200	123,400	4.2	$3,691,900
30	3,405,100	745,200	218,600	123,400	4.1	$4,013,200
35	3,405,100	745,200	255,000	123,400	3.9	$4,334,500
40	3,405,100	745,200	291,500	123,400	3.7	$4,656,700

Sensitivity analysis

The following graphs present the results of a sensitivity analysis undertaken on the capture of biogas for use in a combined heat and power generator. The sensitivity analysis includes three scenarios, the assumptions used for each scenario are:

- Scenario 1: The starting price of electricity and heat energy are fixed to their current rates and the price of price of carbon under an ETS is varied between $0 to $40/tCO2-e.
- Scenario 2: The starting price of heat energy is fixed to its current rate, the price of carbon is assumed to be $0 and the price of electricity varies from its current rate of 14c/kWh to 28c/kWh.
- Scenario 3: The starting price of electricity is fixed to its current rate, the price of carbon is assumed to be $0 and the price of heat energy varies from its current rate of $6/GJ to 9/GJ.
- For each scenario the price of electricity and heat energy has been modelled at three different escalation rates (2%, 5% and 7% per year).

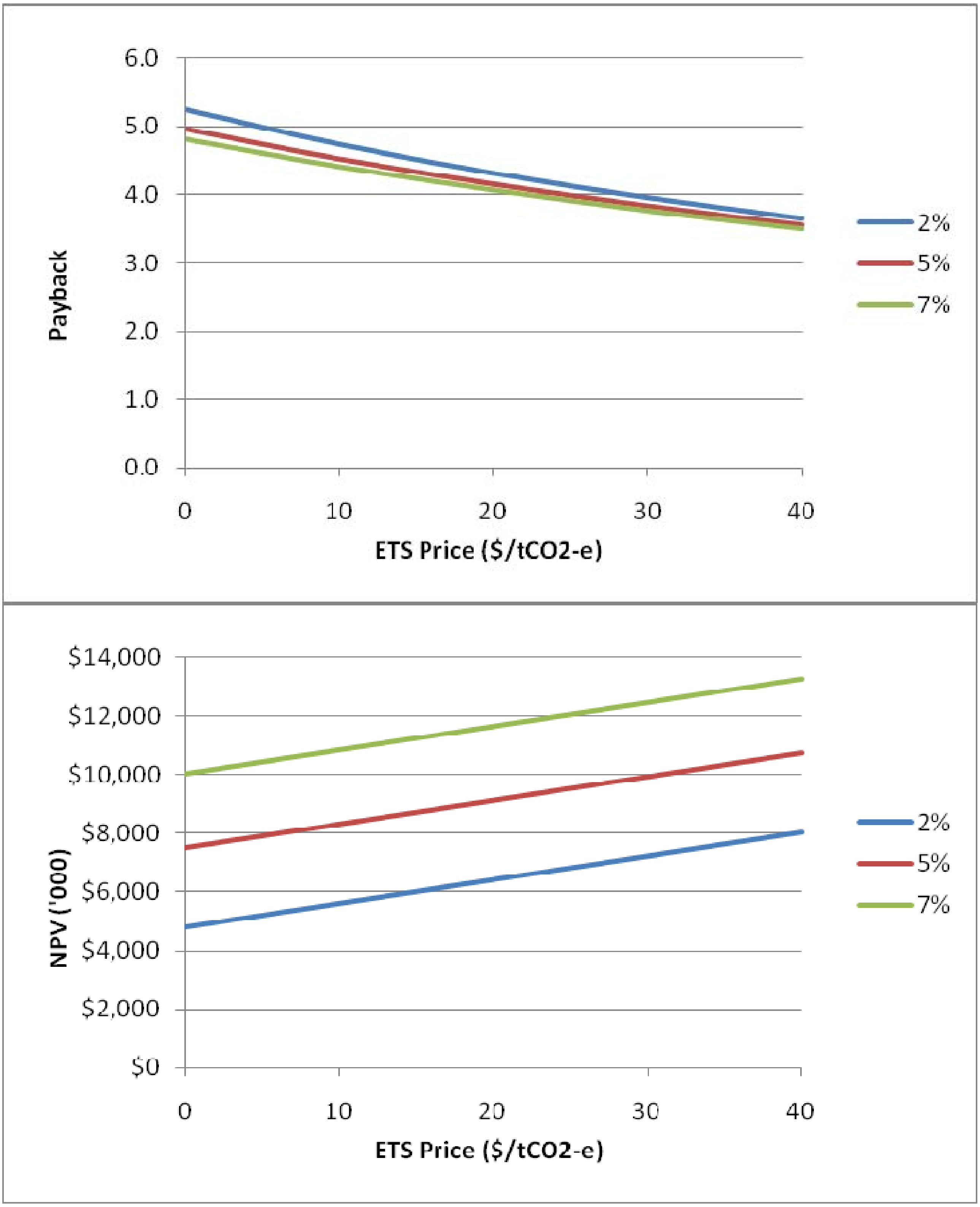


Figure 7.3: Cogeneration sensitivity analysis: Scenario 1

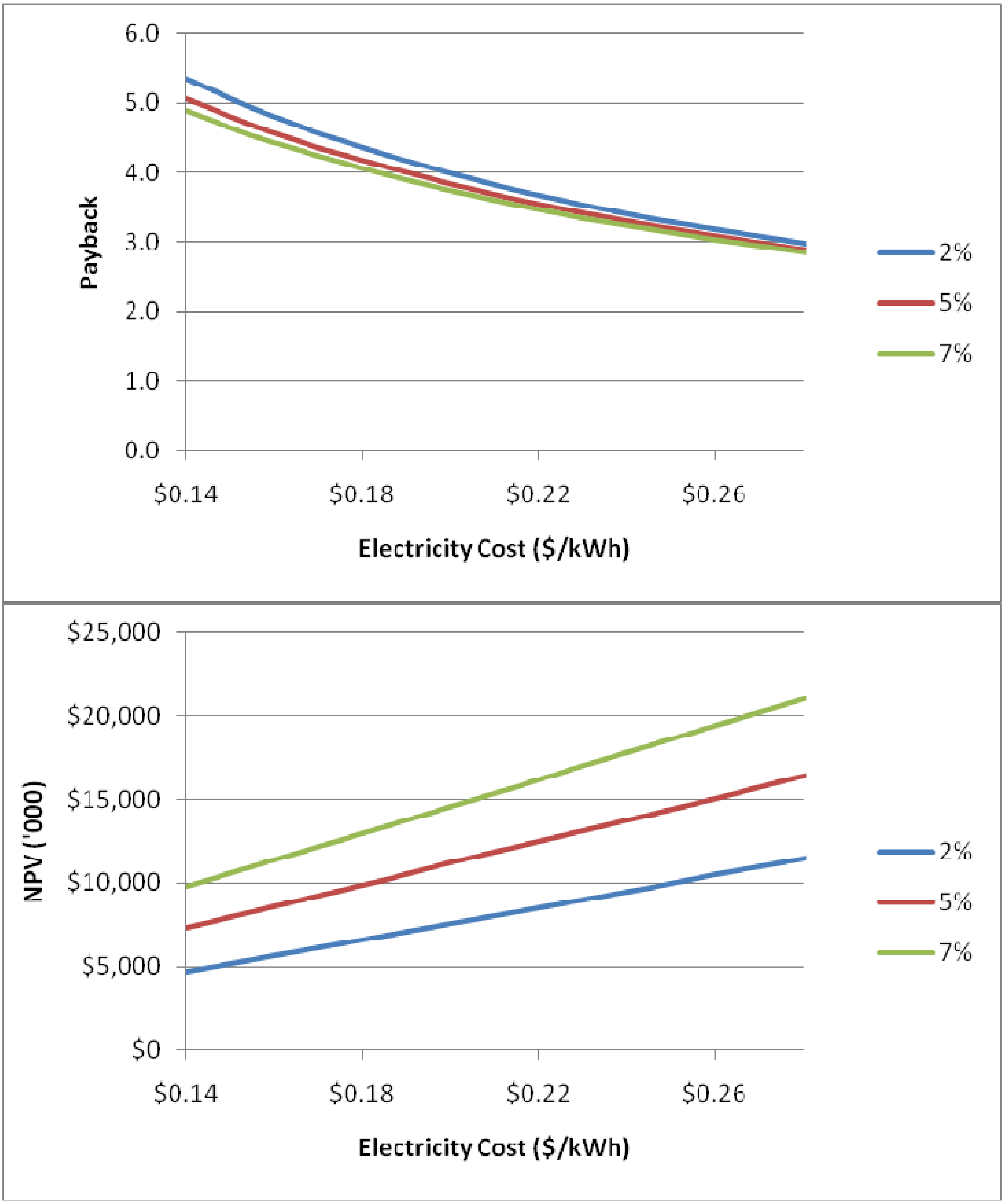


Figure 7.4: Cogeneration sensitivity analysis: Scenario 2

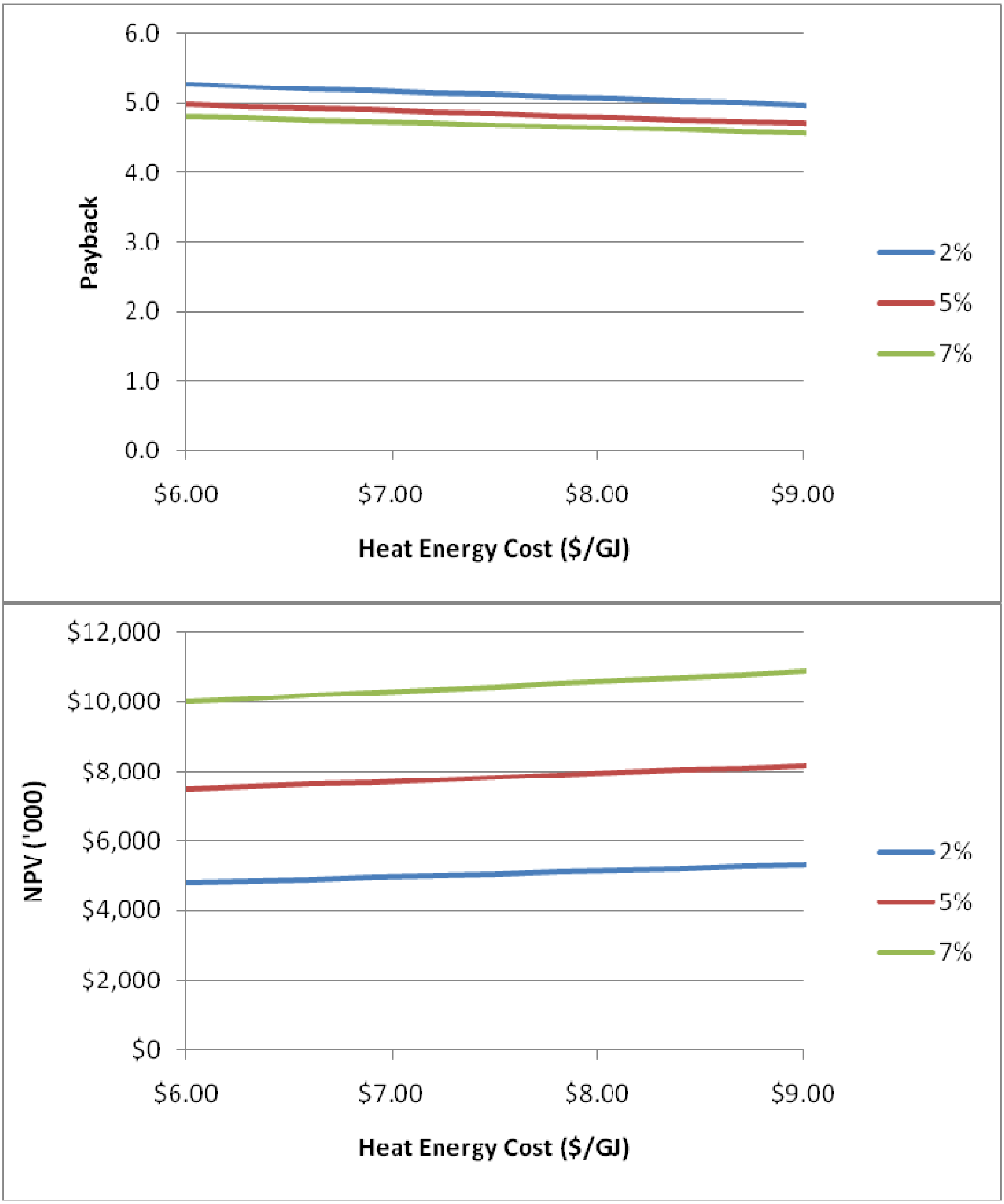


Figure 7.5: Cogeneration sensitivity analysis: Scenario 3

The results of the sensitivity analysis suggest that at Plant A the price of electricity has the greatest impact on the economics of the capture of biogas for use in a cogeneration plant.

Summary of the use of methane for heat and combined heat and power generation

The economic benefit available to this facility through installation of a biogas capture and flaring system is dependent entirely on the introduction of the CPRS or similar scheme that places a price on greenhouse emissions. Capital requirements for capture and flaring are lower than for capture, heat and electricity generation.

Installation of biogas capture for heat and electricity generation returns a positive NPV without the introduction of the CPRS. If the prices of gas and electricity rise, the value of onsite heat and electricity generation is expected to increase accordingly.

Biogas use in Fuel Cells

As stated above, the potential methane yield from the covering of the effluent ponds is 991,800 m^3CH_4/yr. This biogas could be used by a fuel cell to produce between 4,300,000 kWh and 4,900,000 kWh of electricity, about 17% of the plants total electricity use. This system could also generate approximately 13,500 GJ/yr of useful heat energy. As this heat is low-grade it is unlikely to be useful for producing steam. However, it may be used to produce warm (43˚C) and hot (82˚C) water and preheat boiler feed water.

At a gas price of $6.10/GJ, captured heat energy is worth around $80,000/yr to the facility. A basic cost benefit analysis for the use of biogas in fuel cells at Plant A was performed using the following assumptions:

- Savings from generation through offset of grid-connect electricity are determined using generator output and a breakdown of New South Wales tariff structures, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.
- Savings from reduced gas use are based on a gas price of $6.10 per GJ.
- Maintenance costs were estimated assuming the need for a complete generator overhaul after 5 or 10 of operation (depending on the type of fuel cell used). An overhaul was estimated to cost half the initial capital costs of the generator.
- Generator lifetime of 20 years
- Discount rate of 7.5%
- Future costs are those promised by the manufacture once economies of scale are reached, manufactures have estimated this timeframe to be between 5 and 10 years.

As can be seen from Table 7-5, the United Technology Corporation Phosphoric Acid Fuel Cell (PAFC) provides the shortest payback time and greatest NPV based on current cost estimates.

Table 7-5: Cost benefit analysis of the use of biogas in fuel cells for Plant A

	Capital[2] $/kW	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
Now						
UTC PAFC	$4,500	$4,590,000	$650,080	$152,540	9.2	$482,100
FCE MCFC	$4,300	$4,748,000	$706,140	$280,840	11.2	-$412,300
Future						
UTC PAFC	$1,500	$3,090,000	$650,080	$77,540	5.4	$2,746,700
FCE MCFC	$2,500	$3,740,000	$706,140	$180,040	7.1	$1,623,300

The following table shows the economic performance of the United Technology Corporation Phosphoric Acid Fuel Cell (PAFC) under different ETS situations.

Table 7-6: Cost benefit analysis of the use of biogas in fuel cells for Plant A under an ETS

ETS Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	ETS Savings ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	4,590,000	650,080	0	152,540	9.2	$482,200
10	4,590,000	650,080	72,900	152,540	8.0	$1,225,300
15	4,590,000	650,080	109,350	152,540	7.6	$1,596,900
20	4,590,000	650,080	145,800	152,540	7.1	$1,968,500
25	4,590,000	650,080	182,250	152,540	6.8	$2,340,100
30	4,590,000	650,080	218,700	152,540	6.4	$2,711,700
35	4,590,000	650,080	255,150	152,540	6.1	$3,083,300
40	4,590,000	650,080	291,600	152,540	5.8	$3,454,900

Sensitivity analysis

The following charts present the results of a sensitivity analysis undertaken on the capture of biogas for use in a fuel cell.

[2] (NREL 2009)

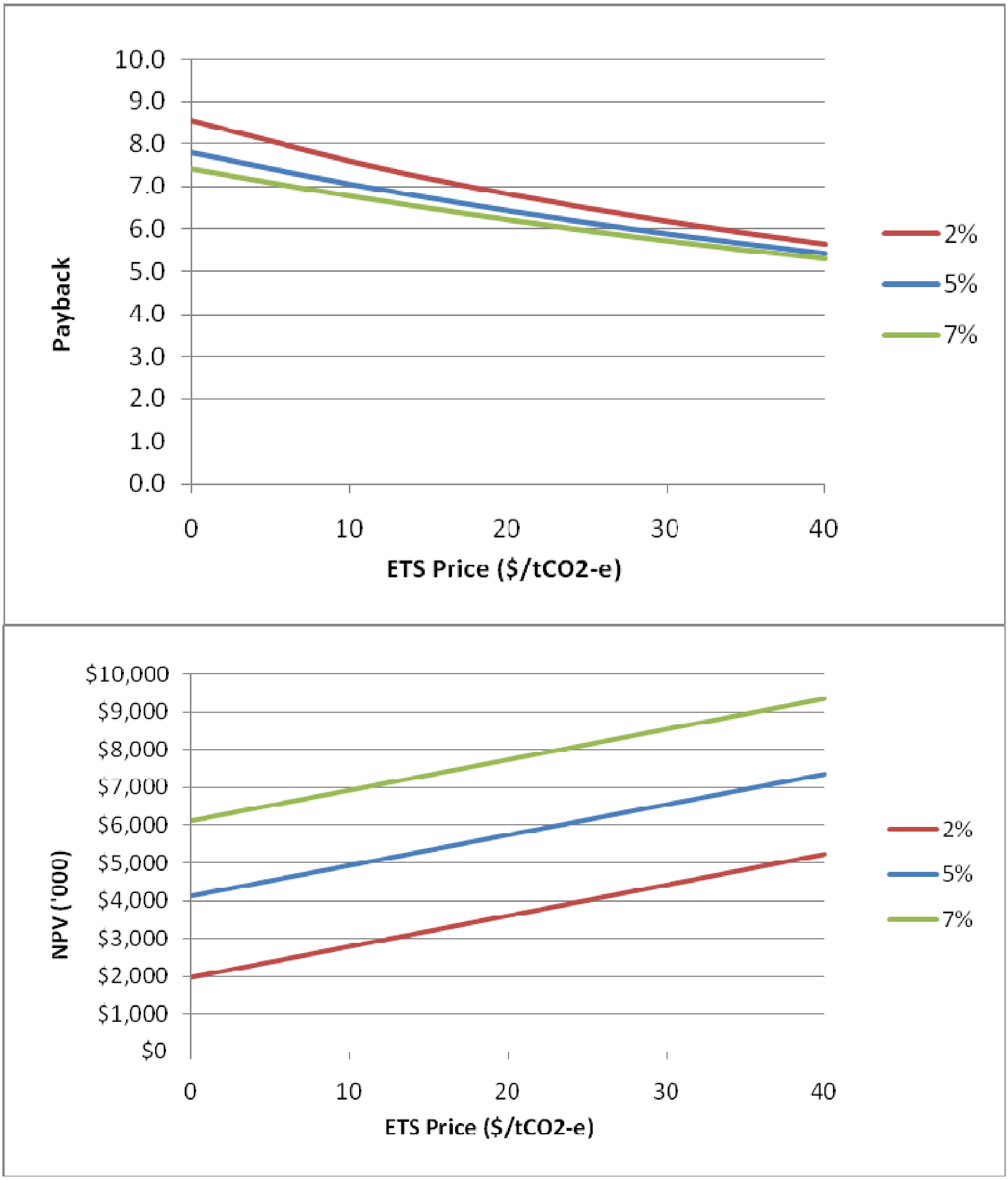


Figure 7.6: Fuel Cells sensitivity analysis: Scenario 1

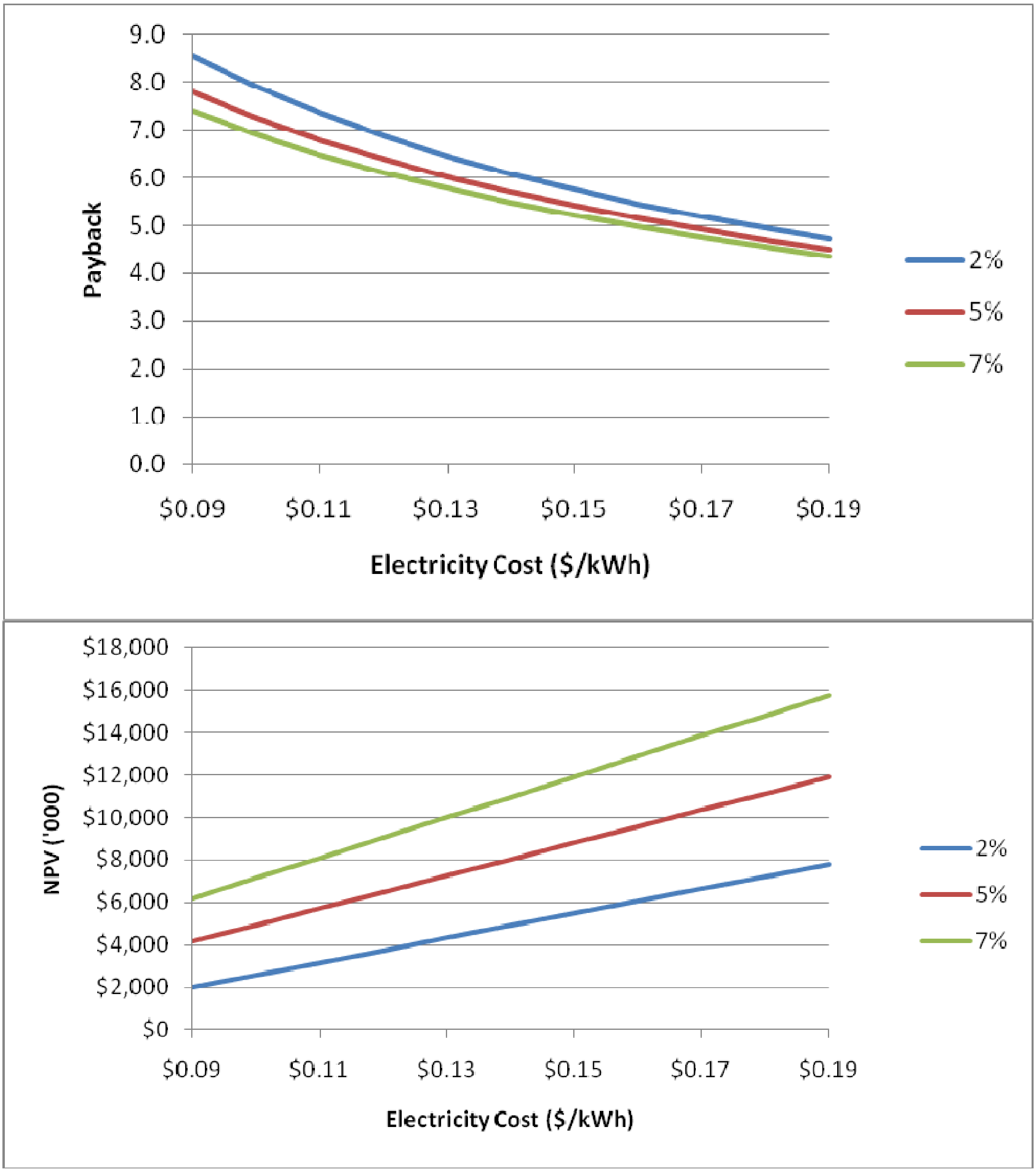


Figure 7.7: Fuel Cells sensitivity analysis: Scenario 2

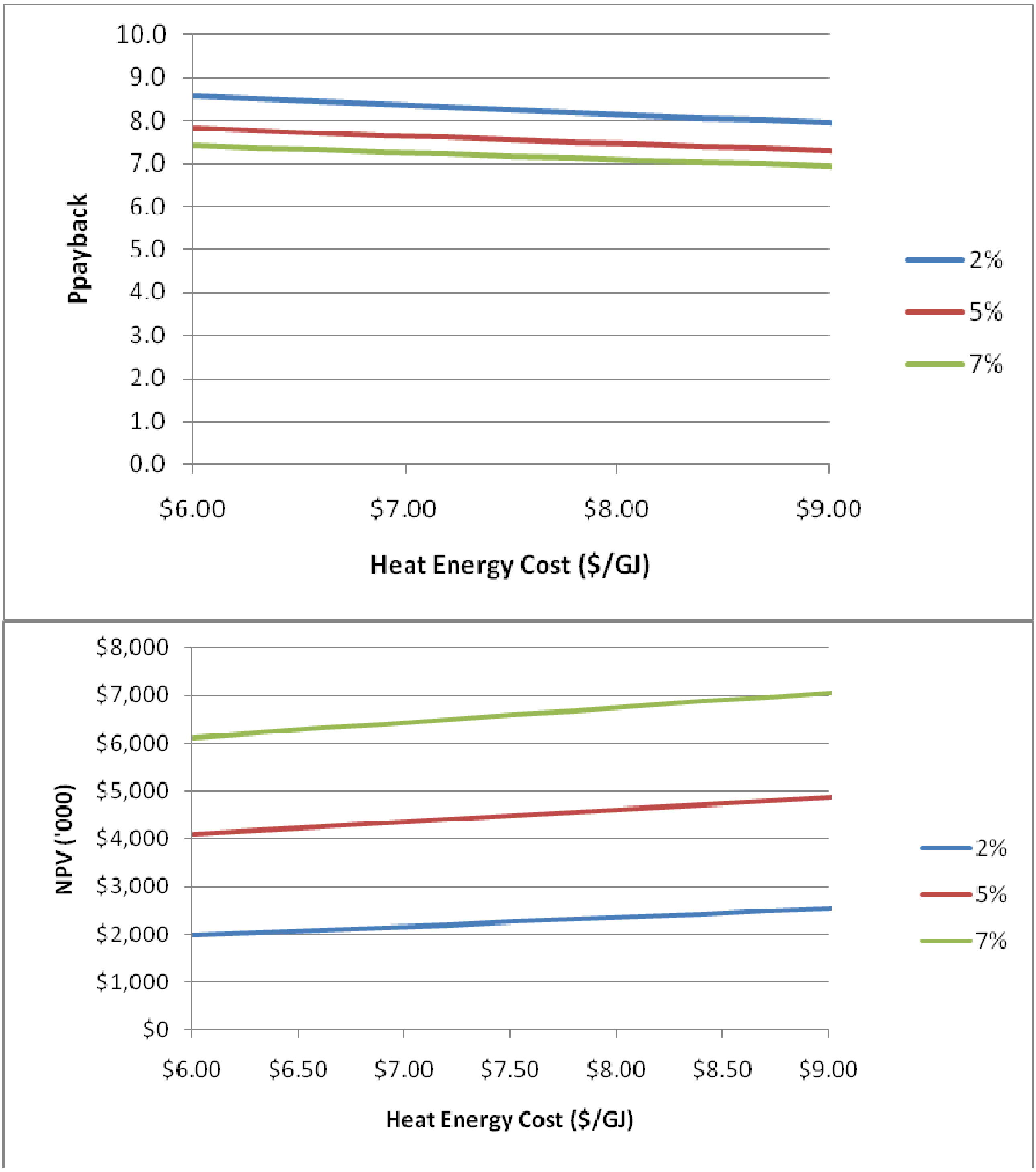


Figure 7.8: Fuel Cells sensitivity analysis: Scenario 3

7.1.2.3 Use of yard and paunch manure

The plant produces approximately 180m^3 per week or 9,000 m^3 per year of paunch and yard manure. The manure is removed by a local composting company in 12m^3 bins at a cost of $266 per bin or approximately $200,000 per year. As the plant use natural gas as their main heat energy fuel source it is not feasible to incorporate co-firing of dried manure. It may however be feasible to build an anaerobic digester to produce biogas from the manure. This would involve construction of a purpose-built digester whose temperature could be controlled. Such a digester would be capable of converting as much as 25-35% of the organic material into biogas (Alvarez, et al). The remaining material could be removed and used as a high quality fertiliser (GHD, 2005). Assuming the remaining material is still removed by the local composting company at the same cost per bin, this would correspond to a saving in manure disposal fees of $40,000 to $60,000 per year.

The total solids contained in the paunch manure is in the order of 14.3%, with volatile solids making up about 88.5% of this (UASV, 1998). Given the high moisture content the density approaches that of water (MSU 1995). Therefore the plant produces approximately 180 tonnes of wet manure per week. Table 7-7 below summarises the approximate methane yields available from the anaerobic digestion of this manure.

Table 7-7: Potential methane production from anaerobic digestion of yard and paunch manure

	Per Week	Per Year
Material available for digestion (kg paunch manure)	180,000	9,000,000
Organic load available for digestion (kg VS)[3]	22,800	1,140,000
Methane conversion rate (m3/kg VS added)[4]	0.2	0.2
Methane yield (m3 CH4)	4,560	228,000
Energy yield (MJ)	171,900	8,595,000

Based on the above figures, the captured methane could provide over 5% of the heat energy requirements of the site. As the main heat energy used is currently natural gas, the captured biogas could be either co-fired in the boilers or used for drying blood. As there would be a larger amount of biogas available than is needed for blood drying, the most feasible solution would be to use it in the boilers. It is recommended that the biogas be used in the water-tube boiler as the chamber volume of the fire-tube boiler many be insufficient.

Alternatively the biogas could be used in a cogeneration unit to generate electricity and heat. For further information on the use of co-generation units refer to the discussion regarding capture of methane from effluent ponds. Assuming a generator electrical efficiency of 35% the cogeneration unit could produce up to 836,000 kWh of electricity or almost 4% of the plant's requirements. The unit would also produce about 3,000GJ of heat energy that could be used to produce hot water or preheat boiler feed water. In order to ensure all gas is consumed, a generator of about 125kW would be required. The savings from offset electricity and gas use for such a system would be approximately $130,000.

[3] UNEP working group (2002)

[4] UNEP working group (2002), UASV1998

Currently there are not any commercially available digesters for use with paunch manure. A number of laboratory scale demonstrations have been carried out and these indicate that the digestion of paunch manure is feasible. It is recommended that further analysis into the potential options for digestion of paunch manure be carried out.

7.1.2.4 Use of tallow

Tallow yields from this facility have been reported at 75 tonnes/day. With an energy content of 40 MJ/kg, annual available heat energy through combustion of tallow is 750,000 GJ. At a reported price of $750/tonne, the shadow cost per unit energy is 1.875 c/MJ.

Natural gas costs of 0.61c/MJ have been reported at this site. Even considering the expected increase in gas price with the introduction of an ETS, the use of tallow to replace natural gas for heat generation is not feasible at this site.

7.1.2.5 Photovoltaics

The plant has a large amount of well orientated roof space that could be used for both solar PV and solar thermal technologies. Given the relatively low price of electricity paid by Plant A (average less than 10c/kWh) is unlikely that PV will be economically viable at this stage. However, PV system prices have reduced significantly in previous years and with the ever increasing cost of electricity (particularly at times of peak demand) it is likely that PV will be viable in the not too distant future.

Information obtained during the site visit suggests that Plant A could have up to 7,000m^2 of roof space suitable for the installation of PV. Depending on the spacing of PV arrays, this could accommodate between 350 – 700kW of PV. In addition, the facility is surrounded by a significant area of flat land that would be suitable for the installation of PV. The site has good solar resources with little or no horizon shading and a well installed system could generate over 1600 kWh/kWp/yr. This would correspond to a reduction in carbon emissions of approximately 1.7 tCO_2e/kWp/yr.

The demand profile of the plant indicates that peak electricity demand usually occurs in the early afternoon (around 2pm to 3pm). An analysis of the plant's current electricity tariff structure against peak usage times and PV output characteristics indicated that the potential value of PV in offsetting electricity use world be in the order of 14.5 c/kWh. For details on the methodology used to determine the economic value of PV see section 0. A summary of the economic performance of PV systems of varying size is shown in Table 7-8 below.

Table 7-8: Economic performance of different sized PV systems installed at Plant A

System size	10kW	50kW	100kW	500kW
Energy Produced (kWh)	16,300	81,500	163,000	815,000
GHG offset (tCO_2-e)	17	87	174	872
Cost $/W	$4.75	$4.50	$4.25	$4.00
Total Cost	$47,500	$225,000	$425,000	$2,000,000
REC Rebate (@ $40 per REC)	$13,000	$46,000	$87,000	$0
Net Cost	$34,500	$179,000	$338,000	$2,000,000
O&M Costs	$238	$1,125	$2,125	$10,000
Income (@ 14.5c/kWh)[5]	$2,400	$11,800	$23,600	$150,800
Payback (years)	16	17	16	14
NPV (7.5%)	-$12,000	-$70,000	-$119,000	-$565,000

The above table demonstrates that the installation of PV is currently not economic at Plant A. However, independent modelling (PJPL, 2009) suggests that if an emissions trading scheme were introduced, and in conjunction with future load growth in the area, retail electricity prices could double in the next five years. In addition, PV prices have been falling steadily over the past decades and even conservative estimates would see the price continue to fall at 5% per year. If this were the case, the economics of PV would change dramatically, see Table 7-9 below.

Table 7-9: Possible future economic performance of different sized PV systems installed at Plant A

System size	10kW	50kW	100kW	500kW
Cost $/W	$3.70	$3.50	$3.30	$3.10
Total Cost	$37,000	$175,000	$330,000	$1,550,000
REC Rebate (@ $40 per REC)	$8,000	$41,000	$82,000	$0
Net Cost	$29,000	$134,000	$248,000	$1,550,000
O&M Costs	$185	$875	$1,650	$7,750
Income (@ 29c/kWh)	$4,700	$23,600	$47,300	$269,000
Payback (years)	6	6	5	6
NPV (7.5%)	$17,000	$98,000	$217,000	$1,113,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of photovoltaics to generate electricity.

[5] For installation greater than 100kW the income includes an addition 4c/kWh from RECs

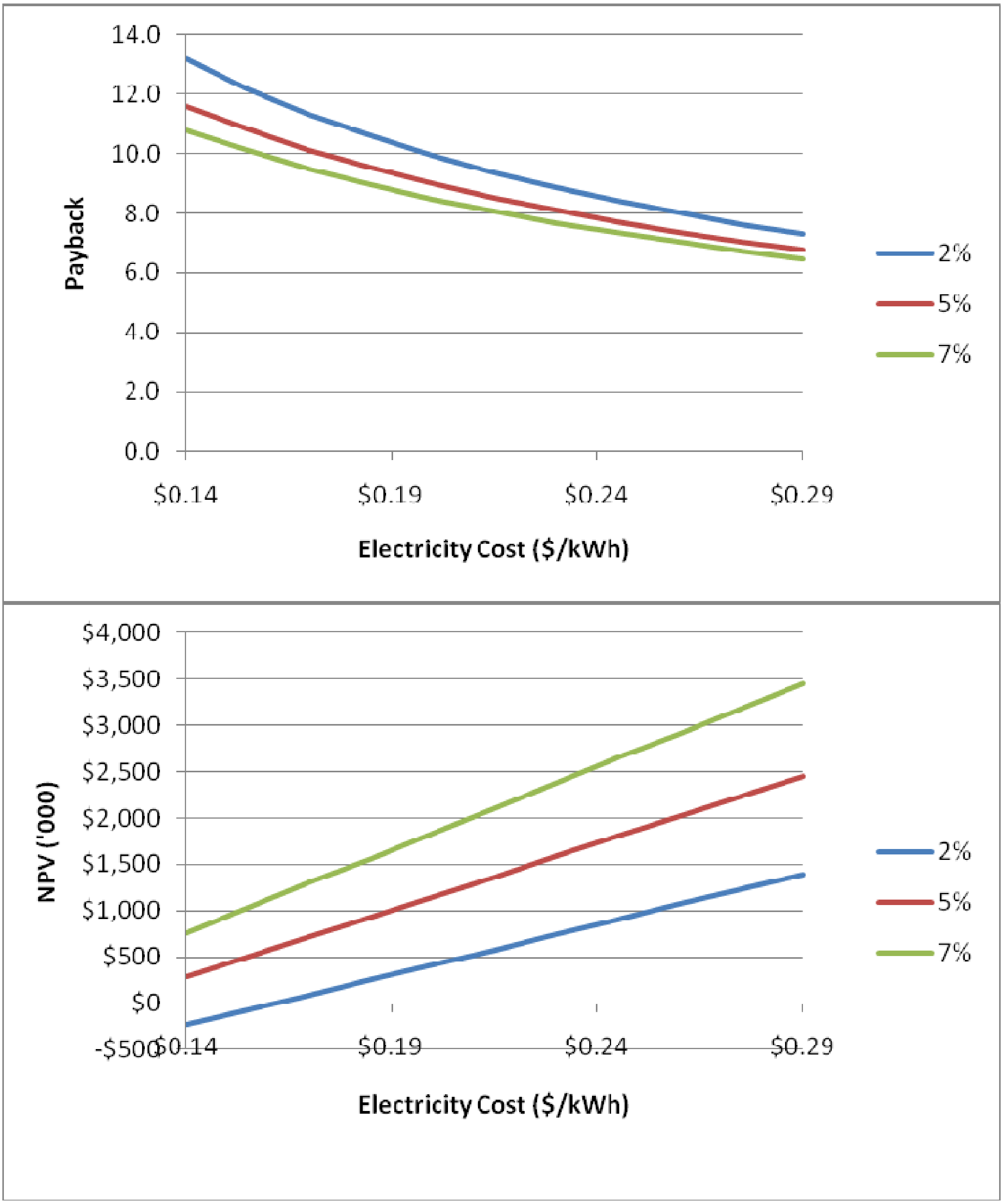


Figure 7.9: PV sensitivity analysis

7.1.2.6 Solar thermal for process heat

The use of solar thermal technologies for electricity generation is currently only economically viable on a large scale (10MW+) and as such is not suitable for use at Plant A. At the scale required for a meat processing facility, solar thermal technologies are more likely to be economically viable for heat generation.

Simple flat plate collectors are the most cost-effective method of small scale solar thermal. Flat-plate collectors could be used to preheat boiler feed water. The plant currently has a feed water rate of 41 kL/day at an average temperature of 20°C. In order to heat this water to 80°C approximately 750m^2 of collectors would be needed and would cost in the order of $340,000 (including extra plumbing and installation). These collectors could be mounted on the roof of the facility, to minimise land use.

The assumptions and results of a preliminary economic analysis of solar thermal preheating of boiler water at Plant A are given in Table 7-10 and Table 7-11 respectively.

Table 7-10 Assumptions used for preliminary economic analysis of preheating boiler feed water using solar flat-plate collectors.

Feed water rate	41,000 L/day
Water inlet temperature	20°C
Water outlet temperature	80°C
Average efficiency of solar collector	50%
Maximum solar radiation (summer)	7.64 kWh/m^2/day
Average solar radiation (yearly)	4.89 kWh/m^2/day
Cost of gas	$4/GJ
Cost of solar collectors (installed)	$450/m^2
Operating days per year	250 days

Table 7-11 Preliminary economic analysis of using solar flat-plate collectors for preheating boiler feed water.

Energy savings per year	1,648 GJ
Collector area	748 m^2
Collector cost	$337,000
Cost savings per year	$6,592/year
Simple payback	51 years

As Table 7-11 shows, flat-plate collectors for preheating boiler feed water are not cost-effective given the current low price of gas. Other solar thermal technologies (parabolic troughs, heliostats, parabolic dishes) are much less economical, due to the relatively small thermal load of Plant A.

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of solar thermal technologies to preheat boiler feed water.

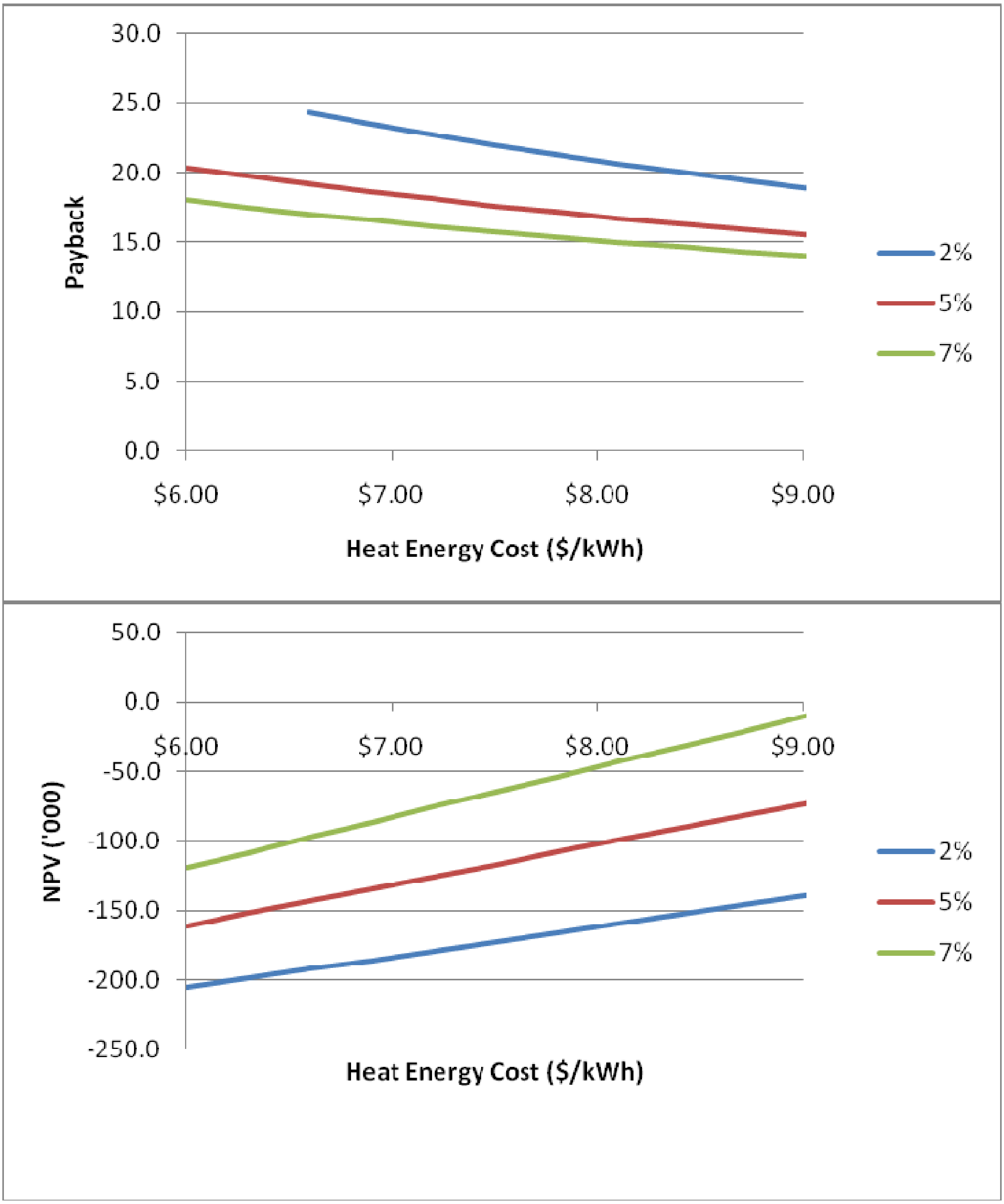


Figure 7.10: Solar thermal sensitivity analysis

7.1.2.7 Wind turbines

Another form of renewable energy that could be used to provide some of the plant's electricity is wind power. The output of wind turbines is very much related to the available wind resources and these resources vary considerably between sites. In order to fully assess the appropriateness of wind power options, detailed wind monitoring must be undertaken.

The site has large amounts of cleared land adjacent to the facility which would be suitable for the installation of wind turbines. If the site had adequate wind resources it is feasible that up to 1 MW of wind generation could be installed. Although this could be via a single 1 MW turbine, it is likely that the most appropriate solution would be to install several smaller turbines. The cost of such an installation would be between $3 and $8 per watt installed. Depending on the local planning requirements it may not be possible to install large quantities of wind power at the site. The assumptions used when assessing the economics of wind power options are given in Table 7-12.

Table 7-12: Assumptions for cost benefit analysis of wind power options

System size	500kW
Capital cost	$4/W or $2,000,000
Project lifetime	20yrs
Discount rate	7.5%
Average electricity price	11c/kWh
REC Price	$40/MWh or 4c/kWh

Table 7-13 shows the economics of installing wind turbines at Plant A for a number of different capacity factors. A capacity factor of 25%, which would be achieved at a reasonable wind site, means that the turbines produce 25% of the electricity they would if they were operating at full capacity all the time. It can be seen that wind turbines are currently not economic at Plant A.

Table 7-13: Cost benefit analysis of wind power installed at Plant A

Capacity Factor	10%	15%	20%	25%	30%
Energy Produced (kWh)	438,000	657,000	876,000	1,095,000	1,314,000
GHG offset (tCO_2-e)	469	703	937	1,172	1,406
O&M Costs	$40,000.00	$40,000.00	$40,000.00	$40,000.00	$40,000.00
Income (@ 11c/kWh)	$66,000	$99,000	$131,000	$164,000	$197,000
Payback	77	34	22	16	13
NPV (7.5%)	-$1,735,000	-$1,399,000	-$1,072,000	-$736,000	-$399,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of wind turbines to generate electricity.

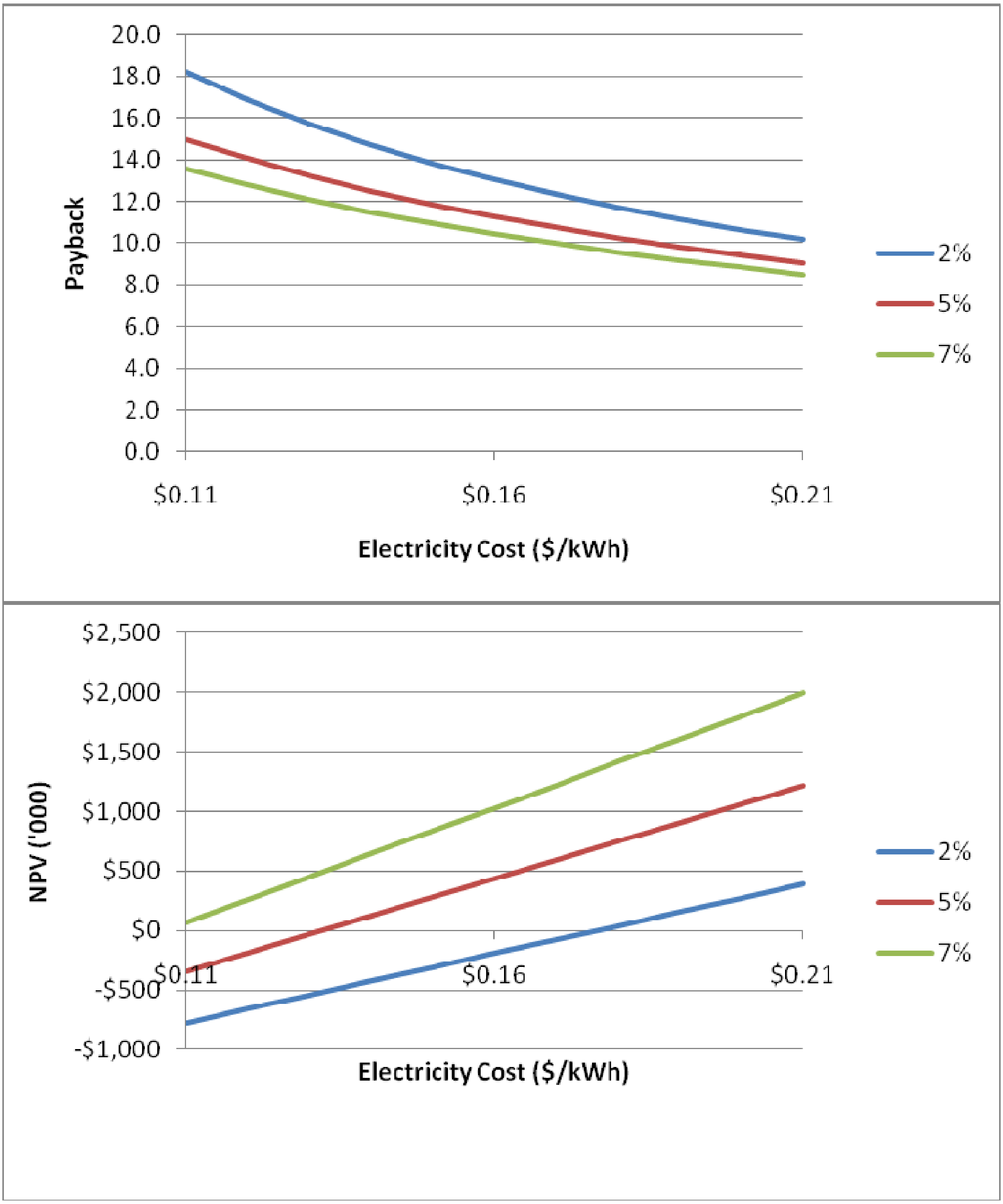


Figure 7.11: Wind power sensitivity analysis

7.1.3 Summary table for Plant A

Table 7-14 summarises the technologies assessed in this report and their potential effectiveness for use at Plant A.

Table 7-14 Summary of renewable energy technologies assessed: Plant A

Technology	Electricity Offset (kWh/yr)	Thermal Offset (GJ/yr)	Emissions Reduction (tCO_2-e/yr)	Cost Saving ($/yr)	Capital Cost ($)	Payback (yrs)
Capture of Methane from Ponds						
- Flaring	NA	NA	7,290	#[6]	2,335,000	#
- Cogeneration	3,635,000	13,100	4,560	622,000	3,405,000	5.5
- Fuel Cell	4,362,000	14,200	5,400	498,000	4,590,000	9.2
Yard and Paunch Manure	836,000	3,000	1,050	NA	NA	NA
PV	815,00	NA	872	140,800	2,000,000	14
Wind	876,000	NA	937	91,000	2,000,000	22
Solar thermal	NA	1,650	84	6,600	340,000	51

7.2 Plant B

Plant B is an integrated cattle processing facility that kills and processes approximately 520 head per day. The average processed weight per head is 240kg and total yield per year is approximately 31,500 tHSCW. The facility includes kill floor, freezing (with capacity for a number of days storage) and rendering. There is a boning room on site but this is leased and operated by a separate company. Coal is the main heat source used and the plant pays comparatively low coal and electricity use and demand tariffs.

Summary of findings

There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant B. The most economic of these are summarised below:

- Combustion of tallow in place of LPG. This option has potential to offset 1,490 GJ of LPG and save to plant approximately $36,300. Taking into account the lost income from tallow this would have a simple payback period of 6.0 years.
- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 1,260,000 kWh of electricity and 6,000 GJ of coal and LPG per year. It could also reduce direct emissions from effluent ponds by approximately 2,810 tCO_2-e/yr and indirect emissions (from electricity, coal and LPG use by approximately 1,750 tCO_2-e/yr). The cost of such an installation would be in the order of $793,900 and the project would have a simple

[6] Dependant on carbon price

payback period of about 4.4 years. This option would remove the vast majority of any direct liability the plant may have under the introduction of the currently proposed CPRS. It would not, however, remove the plants requirement to report under NGERS.

- Co-firing of dried yard and paunch manure could also be cost effective and could offset over 10% of coal used per year. This would reduce emissions by 790 tCO_2-e per year. Further analysis of the feasibility of such a project would need undertaken.

Technologies that are currently feasible but not economic (although they may be in the not too distant future) for use at Plant B include:

- The use of fuel cells in place of reciprocal gas generators
- Anaerobic digestion of yard and paunch manure
- Solar PV technologies to generate electricity
- Solar thermal technologies to preheat boiler water
- Wind turbines to generate electricity
- Geothermal heating and cooling

7.2.1 Energy and waste characteristics

Figure 7.12, Figure 7.13 and Table 7-15 show a breakdown of the energy used and associated costs for Plant B. While heat energy accounts for over 80% of energy used it accounts for less than 30% of the total energy costs. Plant B is currently very close to exceeding its energy reporting threshold under the NGERS scheme and on current usage patterns may exceed the threshold by up to 5% in the coming reporting period. It should be possible to maintain the plant below the reporting threshold through the use of renewable energy and energy efficiency.

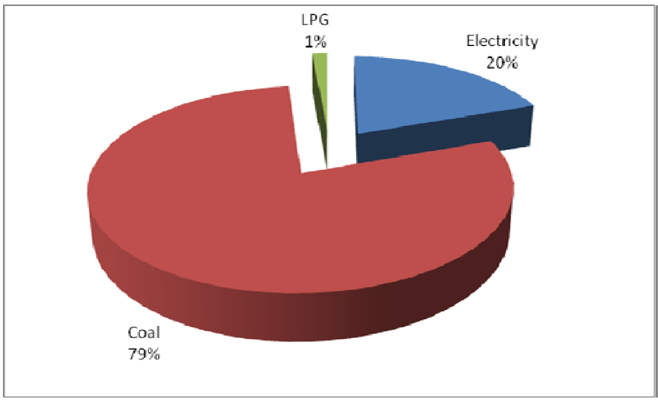


Figure 7.12: Energy use: Plant B

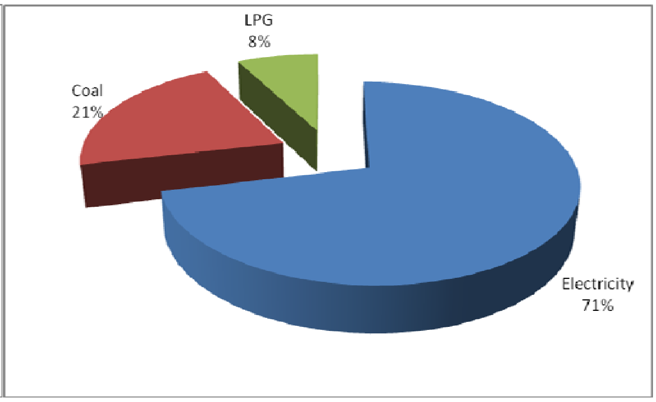


Figure 7.13: Energy costs: Plant B

Table 7-15: Energy use and cost breakdown: Plant B

Enegy Source	Average Usage (MJ/tHSCW)	% of Total	Cost (c/MJ)	% of Total
Electricity	655	19.6%	2.7	71.3%
Coal	2,645	79.0%	0.2	21.0%
LPG	48	1.4%	3.9	7.7%
Total	3,348	100%	0.7	100%

The plant uses 12 chillers of different sizes to meet its refrigeration requirements. While the other operators occupying the site have separate electricity metering for their own equipment, Plant B meets some of the chilling demand of these tenants. The plant uses 5 screw compressors and 5 tower condensers. The majority of the heat energy required by the plant is generated via a single 8MW boiler. The boiler has economisers fitted and condensate is captured from the cooker and other smaller processes and returned as feed water to the boiler.

The plant produces approximately 170 ML of waste water per year, which is treated in three ponds. Two of the ponds have a capacity of 10ML while the third has a capacity of 16ML. The treated waste water is used to irrigate adjacent paddocks. The waste water has an average chemical oxygen demand (COD) of 8,000 kg/ML and 95% of this is removed during the treatment process. The plant is currently investigating options for the capture of methane from waste water ponds. With this in mind they have excavated 5 new 2ML ponds near to the original ponds. The ponds are approximately 300 metres from the plant which should allow transport of the captured biogas back to the plant for use.

7.2.2 Options to reduce emissions and costs using EE and RE

7.2.2.1 Biogas capture for flaring

The Plant has reported a wastewater flow rate of 170 ML/yr with an average COD of 8.0 kg/kL. This equates to an annual COD input of 1,360 tonnes to wastewater treatment ponds. Under NGERS reporting methods, with a methane yield of $0.35m^3CH_4/kgCOD_{removed}$, this facility is liable for emissions of around $2{,}880tCO_2$-e.

The site currently has 5 ponds in place with dimensions of 40m x 12.5m x 4m (length x width x depth). Based on a cover cost of $\$80/m^2$**,** and engineering and works costs of $\$40/m^2$ installed, ponds could be covered for a capital outlay of approximately $300,000.
Based on cost estimates from UNEP (2002), flaring systems require capital outlay for the following components:

Technology	Cost
Flare – combustion mechanism for methane destruction	$60,000
Gas Pipe – piping from ponds to flare at a cost of $100/m. Flare site is undetermined	$10,000
Gas blower and regulator – gas pressure must be raised for pumping from ponds to boiler and generator	$15,000
Condensate trap – to remove water content of biogas and ensure high-temperature and thus efficient combustion	$5,000
Gas storage system – to allow for fluctuations in yield	$10,000

Including these capital requirements with those for pond covering, and design costs of $25,000, results in an estimated capital requirement of $425,000.

Flaring of captured biogas would reduce annual emissions from wastewater ponds to 70 tCO_2-e, and should reduce odour. A cost benefit analysis of flaring was performed assuming the proposed CPRS was legislated. Further assumptions included a system lifetime of 20 years, a discount rate of 7.5%, and annual operating and maintenance (O&M) costs of 2.5% of capital cost. The findings are summarised in Table 7-16 for possible carbon emission permit prices.

Table 7-16: Cost Benefit Analyses for Gas Capture & Flaring

Permit Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
10	425,000	28,100	10,000	23.5	-$240,500
15	425,000	42,200	10,000	13.2	-$96,700
20	425,000	56,300	10,000	9.2	$47,000
25	425,000	70,300	10,000	7.0	$189,700
30	425,000	84,400	10,000	5.7	$333,500
35	425,000	98,500	10,000	4.8	$477,200
40	425,000	112,500	10,000	4.1	$619,900

Revenue refers to savings in penalties for carbon emissions under the ETS, SPP refers to Simple Payback Period, and NPV refers to Net Present Value

7.2.2.2 Biogas capture for heat and electricity generation

An alternative to flaring captured gas is to use it to replace fuels from external sources for heat and electricity generation. This allows for additional savings through the offset of fuel costs. This is discussed in the forthcoming sections.

Biogas Capture for Heat Generation

From the expected biogas yield, methane yield is estimated to be 383,000 m^3/yr. With an energy content of 37.7 MJ/m^3CH_4 (DCC 2009), about 14,400 GJ/yr of heat energy is available to this facility.

Currently, the site uses LPG for drying blood. A larger, 8MW coal boiler provides steam. The modifications required to convert the coal-fired boiler to biogas are more extensive than those required to convert the LPG-fired boiler, and captured biogas would provide only approximately 18% of the heat of the coal-fired boiler. Therefore, conversion of the coil-fired boiler is neither economically beneficial, nor practical.

However, the biogas is sufficient to service the heat energy demand placed on the LPG-fired boiler. Given that the site uses only 58 kL of LPG annually (1,490 GJ/yr), only 10% of the biogas would be required to replace LPG use at the facility. At this site, due to the high cost per unit of energy of LPG compared to electricity, the maximum benefit comes from replacing LPG and using the remainder of the biogas for electricity generation. Electricity generation is discussed in the following section.

Components of the flaring system, excluding the flare itself, are required when using captured gas for heat generation in existing boilers. As such, the costings from the flaring system, excluding the cost of the flare, can be used with the following modifications:

Technology	Cost
Storage system upgrade – in the absence of a flare to control gas stock, storage system will likely require capacity increase	$5,000
Gas Piping - the existing LPG boiler is around 200m from digestion ponds, with a gas piping cost of $100/m (MLA EEMMP)	$10,000
Gas pre-treatment system (scrubber) - required to remove hydrogen sulphide to ensure the lifetime of the boiler and generator are not reduced through corrosion	$10,000
Boiler feed modifications – piping modifications to allow for biogas to be fed from storage system	$10,000

With these modifications, including the cost of covering ponds and design costs of $25,000, a capital outlay of $400,000 is required. The site has reported an LPG price of $0.63/L. For an energy content of 25.7 GJ/kL (DCC, 2009), this equates to 2.4 c/MJ. In order to calculate the levelised energy cost of heat derived from biogas capture and combustion, the following assumptions were made:

- a discount rate of 7.5%
- O&M costs equal to 2.5% of capital outlay
- a system lifetime of 15 years

Table 7-17 shows the levelised energy costs (LECs) of heat generated through biogas capture and combustion. These values can be seen to be considerably cheaper than the cost of LPG per unit energy.

Table 7-17: LEC of heat through biogas capture and combustion

Carbon price ($/tCO2-e)	0	10	15	20	25	30	35	40
LEC (c/MJ)	0.38	0.33	0.30	0.27	0.25	0.22	0.19	0.16

Biogas Capture for Combined Heat and Power Generation

Captured biogas may be used to fuel a gas generator to service the electricity demand of the facility.

With approximately 10% of the biogas yield to be used for heat generation to replace LPG, a gas generator efficiency of 35% will allow 4,500 GJ/yr or 1,260,000 kWh of electrical energy generation from the remaining biogas. If it is assumed that 35% of energy input in the form of biogas is available as heat energy, from the expected energy input in the form of biogas, 4,500 GJ/yr or 1,260,000 kWh/yr of waste heat may be captured. As this heat is low-grade it is unlikely to be useful for steam generation. However, it may be used to produce warm (43˚C) and hot (82˚C) water.

At a coal price of $52/tonne, captured heat energy is worth around $8,800/yr to this facility. If the installation of cogeneration capacity adds $200/kW installed, the generator cost increases to $1200/kW installed.

Generation Scheme Analysis

The generator may be operated during high tariff periods only, or continuously across all tariff periods. Assuming that in Queensland, the high tariff period extends for 14 hrs/day on weekdays, and assuming 15min start-up and shut-down, continuous generation (24hrs/day, 365days/yr) would require a 144 kW gas generator, while high tariff generation (14hrs/day, 365 days/yr) would require a 328 kW generator.

A cost benefit analysis was carried out to compare these two options. The following were considered in the analysis:

- Capital requirements for the purchase and installation of a combined heat and power generator were estimated at $1,200/kW.

- Savings from generation through offset of grid-connect electricity were determined using generator output and a breakdown of Queensland tariff structures, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.

- Maintenance costs were estimated assuming the need for a complete generator overhaul after 25,000 hrs of operation. An overhaul was estimated to cost half the initial capital costs of the generator.

- Generator lifetime of 15 years was used for continuous generation, and 25 years for on-peak only generation.

As this analysis does not consider the cost of gas capture, the figures reported below do not reflect the full project cost. As can be seen from Table 7-18, continuous operation has a shorter payback time. However, because of the longer assumed operational life under 'high tariff' operation, this option has a greater NPV.

Table 7-18: Cost Benefit Analysis of continuous and high tariff generation

	Capital ($)	Revenue ($/yr)	O&M ($/yr)	SPP (yr)	NPV ($)
High tariff only (328kW)	393,900	182,000	28,800	3.0	1,313,600
Continuous (144kW)	172,400	145,800	30,200	1.8	847,500

Note: Revenue refers to savings in grid-connect electricity consumption.

Cost Benefit Analysis of Combined Heat and Power Generation Scheme

From values determined above, the installation of a heat generation system and a combined heat and power generation system requires a capital outlay of $793,900. The project is expected to return annual revenues of $36,300 for offset of LPG use, and $218,200 for offset of grid-connect electricity, coal use, and REC sales. O&M costs are expected to increase by $37,300 annually. Based on these figures, a system lifetime of 15 years and a discount rate of 7.5%, a cost benefit analysis returned the results in Table 7-19.

Table 7-19: Cost Benefit Analyses of Gas Capture for Heat & Electricity Generation

ETS Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	ETS Savings ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	793,900	218,200	0	37,300	4.4	$802,900
10	793,900	218,200	28,100	37,300	3.8	$1,051,000
15	793,900	218,200	42,200	37,300	3.6	$1,175,400
20	793,900	218,200	56,300	37,300	3.3	$1,299,900
25	793,900	218,200	70,300	37,300	3.2	$1,423,500
30	793,900	218,200	84,400	37,300	3.0	$1,547,900
35	793,900	218,200	98,500	37,300	2.8	$1,672,400
40	793,900	218,200	112,500	37,300	2.7	$1,796,000

Sensitivity analysis

The following graphs present the results of a sensitivity analysis undertaken on the capture of biogas for use in heat generation and in a combined heat and power generator. The sensitivity analysis includes three scenarios, the assumptions used for each scenario are:

- Scenario 1: The starting price of electricity and heat energy are fixed to their current rates and the price of price of carbon under an ETS is varied between $0 to $40/tCO2-e.
- Scenario 2: The starting price of coal is fixed to its current rate, the starting price of LPG is fixed to its current rate, the price of carbon is assumed to be $0 and the price of electricity varies from its current rate of 10c/kWh to 20c/kWh.

- Scenario 3: The starting price of electricity is fixed to its current rate, the starting price of LPG is fixed to its current rate, the price of carbon is assumed to be $0 and the price of coal varies from its current rate of $1.95/GJ to 2.95/GJ.
- For each scenario the price of electricity and heat energy has been modelled at three different escalation rates (2%, 5% and 7% per year).

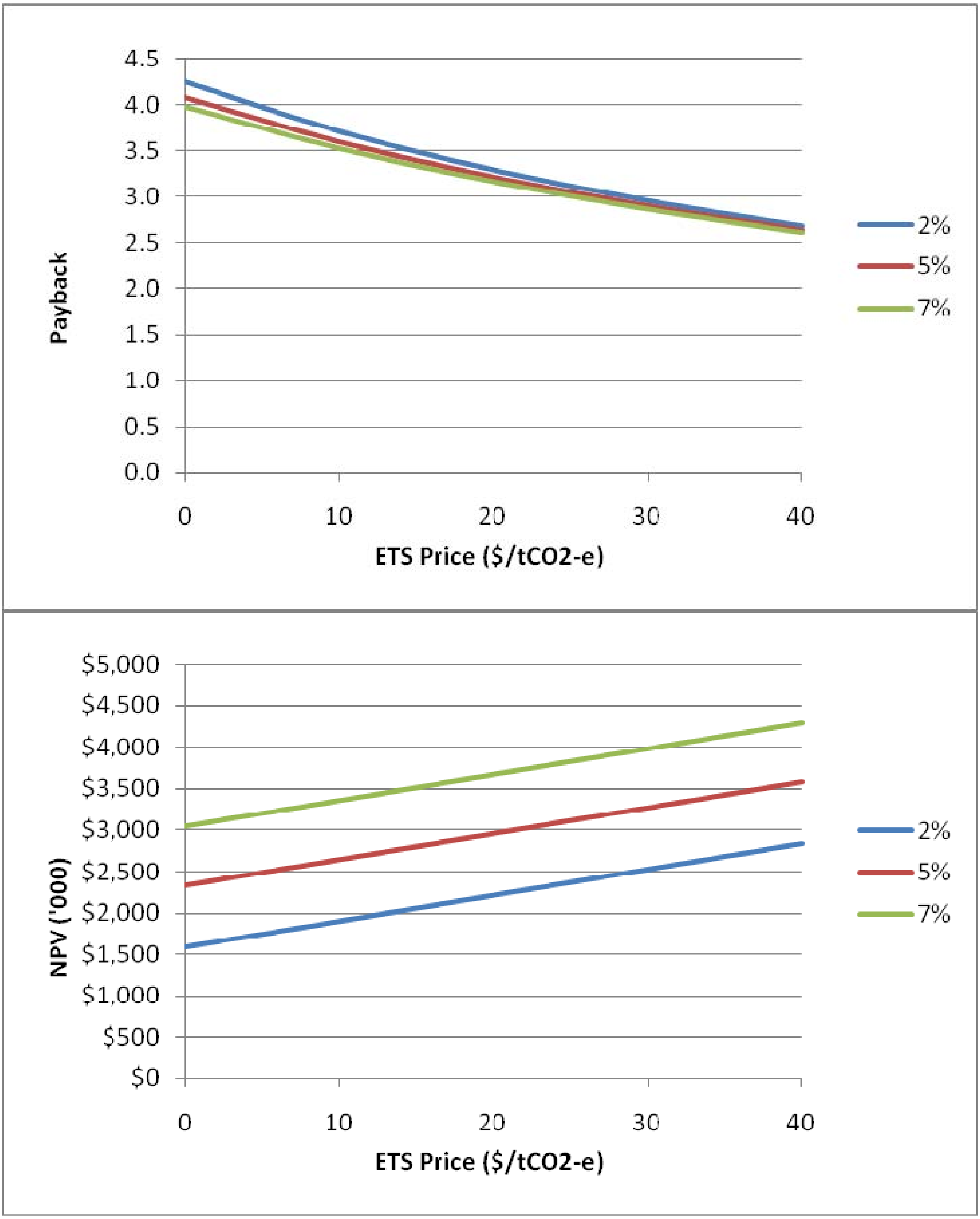


Figure 7.14: Sensitivity analysis: Scenario 1

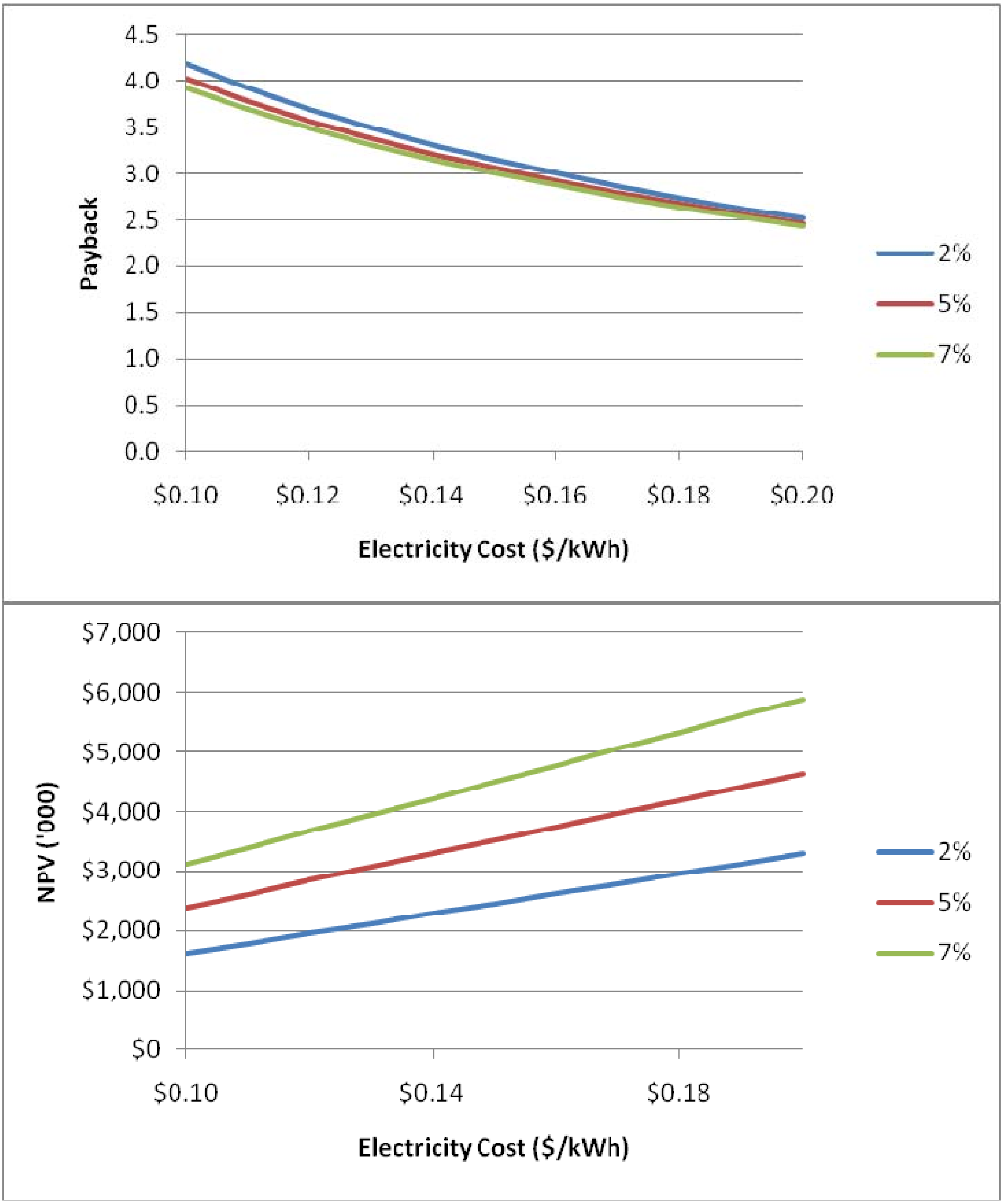


Figure 7.15: Sensitivity analysis: Scenario 2

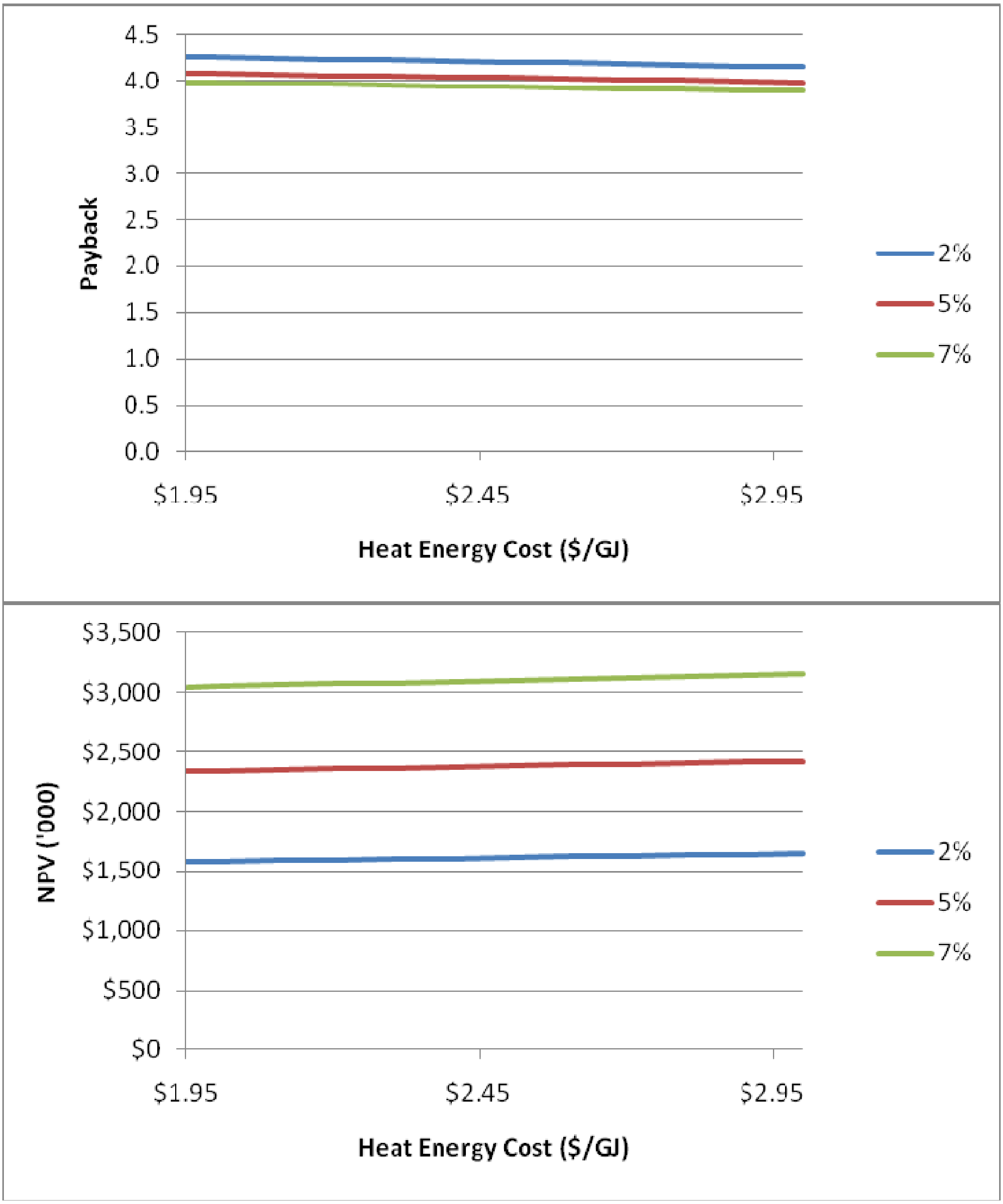


Figure 7.16: Sensitivity analysis: Scenario 3

The results of the sensitivity analysis suggest that at Plant B the price of electricity has the greatest impact on the economics of the capture of biogas for use in heat generation and a cogeneration plant.

Summary of the use of methane for heat and combined heat and power generation

The economic benefit available to this facility through installation of a biogas capture and flaring system is dependent entirely on the introduction of the CPRS, or similar scheme that places a price on greenhouse emissions. Capital requirements for capture and flaring are slightly lower than for capture, heat and electricity generation.

Installation of biogas capture for heat and electricity generation returns a positive NPV without the introduction of the CPRS. If the prices of gas and electricity rise, the value of onsite heat and electricity generation is expected to increase accordingly.

Biogas use in Fuel Cells

If it is again assumed that 10% of the captured biogas is used to replace LPG then the remaining biogas could be used by a fuel cell to produce between 1,500,000 kWh and 1,700,000 kWh of electricity. This system could also generate approximately 4,500 GJ/yr of useful heat energy. As this heat is low-grade it is unlikely to be useful for producing steam. However, it may be used to produce warm (43˚C) and hot (82˚C) water and preheat boiler feed water.

At a coal price of $52/tonne, captured heat energy is worth around $8,800/yr to the facility. A basic cost benefit analysis for the use of biogas in fuel cells at Plant B was performed using the following assumptions:

- Savings from generation through offset of grid-connect electricity are determined using generator output and a breakdown of Queensland tariff structures, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.
- Savings from reduced coal use are based on a coal price of $52 per tonne.
- Maintenance costs were estimated assuming the need for a complete generator overhaul after 5 or 10 of operation (depending on the type of fuel cell used). An overhaul was estimated to cost half the initial capital costs of the generator.
- Generator lifetime of 20 years
- Discount rate of 7.5%
- Future costs are those promised by the manufacture once economies of scale are reached, manufactures have estimated this timeframe to be between 5 and 10 years.

As can be seen from Table 7-20, the UTC PAFC provides the shortest payback time and greatest NPV based on current cost estimates.

Table 7-20: Cost benefit analysis of the use of biogas in fuel cells for Plant B

	Capital[7] $/kW	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
Now						
UTC PAFC	$4,500	$1,210,032	$182,500	$49,028	9.1	$150,600
FCE MCFC	$4,300	$1,260,032	$201,700	$94,528	11.8	-$167,500
Future						
UTC PAFC	$1,500	$670,032	$182,500	$22,028	4.2	$965,900
FCE MCFC	$2,500	$900,032	$201,700	$58,528	6.3	$559,500

The following table shows the economic performance of the United Technology Corporation Phosphoric Acid Fuel Cell (PAFC) under different ETS situations.

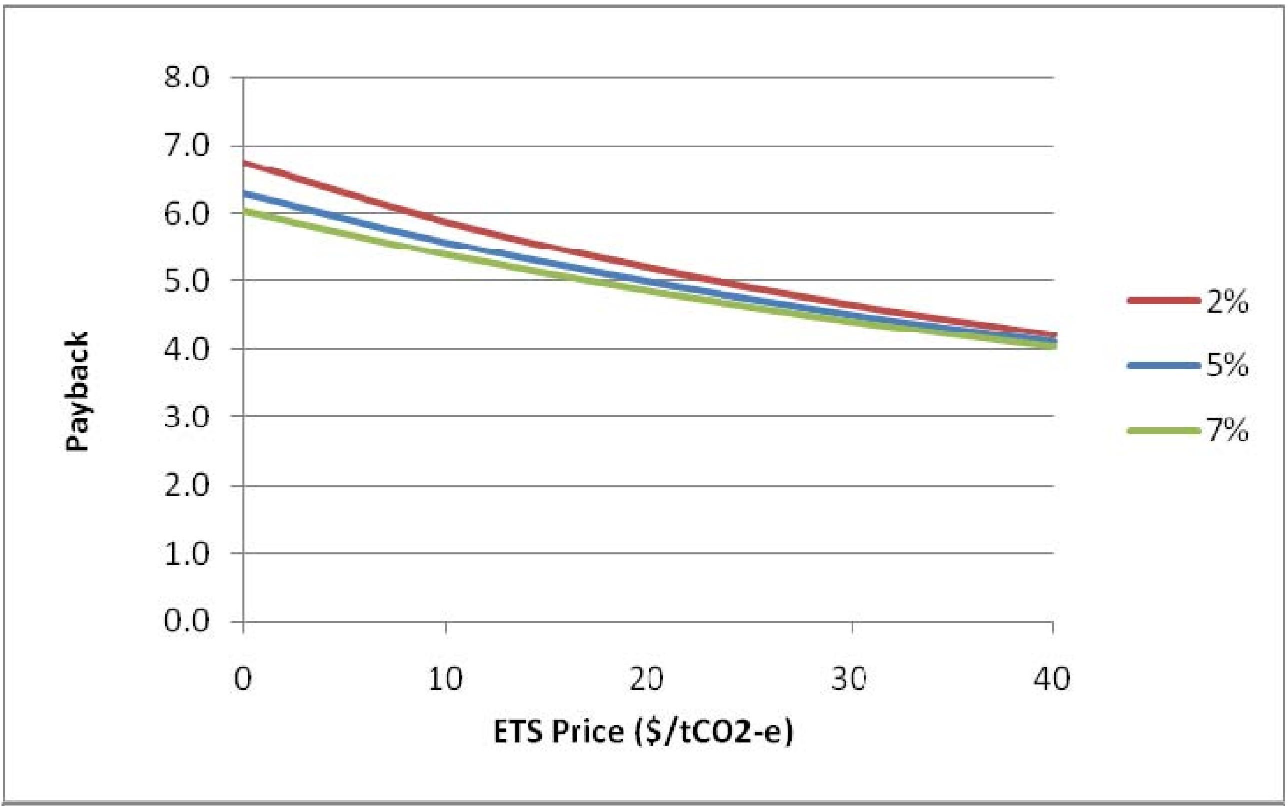
Table 7-21: Cost benefit analysis of the use of biogas in fuel cells for Plant B under an ETS

ETS Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	ETS Savings ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	1,210,032	182,500	0	49,028	9.1	$150,600
10	1,210,032	182,500	28,100	49,028	7.5	$437,100
15	1,210,032	182,500	42,150	49,028	6.9	$580,300
20	1,210,032	182,500	56,200	49,028	6.4	$723,600
25	1,210,032	182,500	70,250	49,028	5.9	$866,800
30	1,210,032	182,500	84,300	49,028	5.6	$1,010,000
35	1,210,032	182,500	98,350	49,028	5.2	$1,153,300
40	1,210,032	182,500	112,400	49,028	4.9	$1,296,500

Sensitivity analysis

The following charts present the results of a sensitivity analysis undertaken on the capture of biogas for use in a fuel cell.

[7] (NREL 2009)



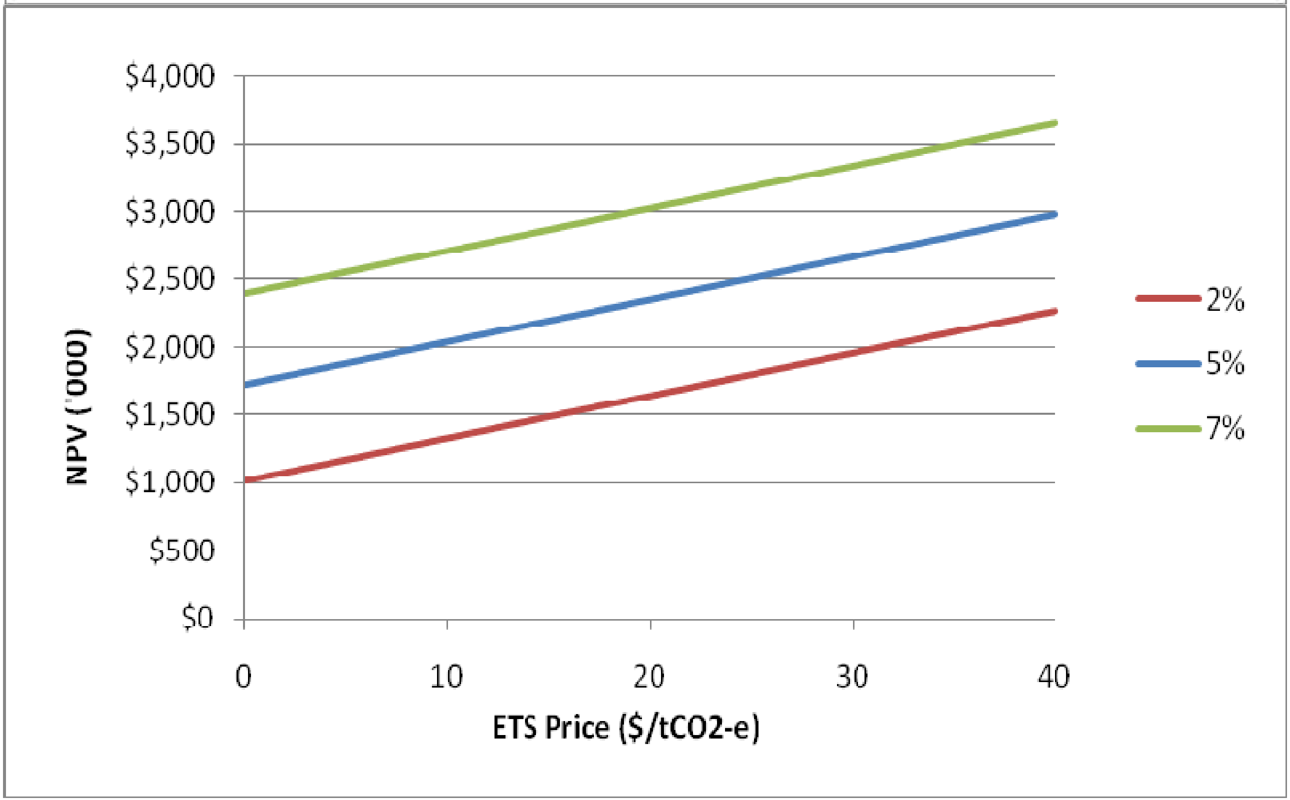


Figure 7.17: Fuel Cells sensitivity analysis: Scenario 1

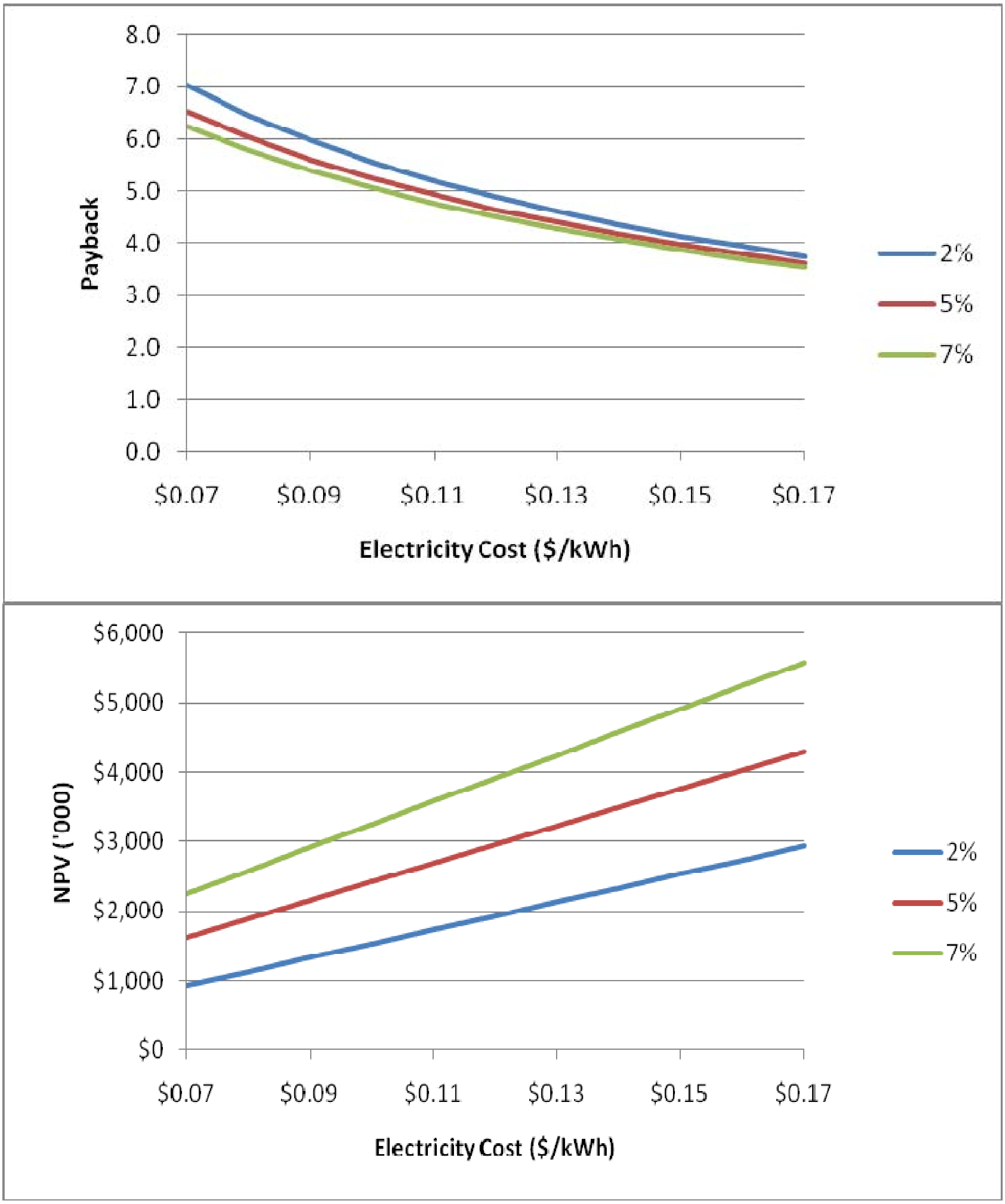


Figure 7.18: Fuel Cells sensitivity analysis: Scenario 2

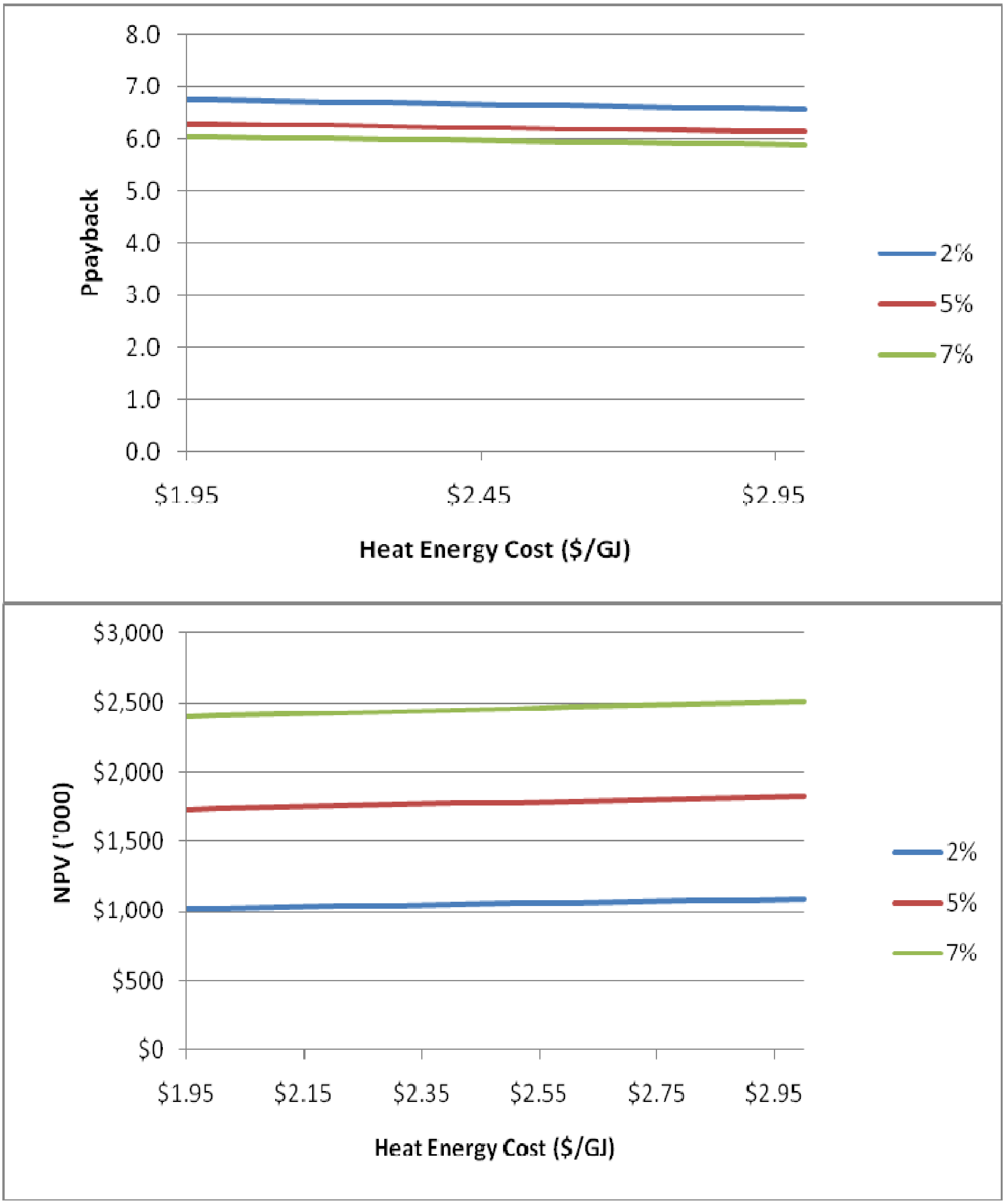


Figure 7.19: Fuel Cells sensitivity analysis: Scenario 2

7.2.2.3 Use of yard and paunch manure

The plant removes approximately 60 tonnes of paunch manure per week from the waste water stream. In addition, approximately 30 tonnes of yard manure is produced per week. The manure is currently removed by a local composting company at no cost to the plant. There are two potential options for Plant B to use the paunch manure as a source of energy. The first would be to construct an anaerobic digester to produce biogas. The second would be to dry the manure and directly combust it in the boiler to offset coal use. Option one would involve construction of a purpose-built digester whose temperature could be controlled. Such a digester would be capable of converting as much as 25-35% of the organic material into biogas (Alvarez, et al). The remaining material could be removed and used as a high quality fertiliser (GHD, 2005).

The total solids contained in the paunch manure is in the order of 14.3%, with volatile solids making up about 88.5% of this (UASV, 1998). Table 7-22 below summarises the approximate methane yields available from the anaerobic digestion of this manure.

Table 7-22: Potential methane production from anaerobic digestion of yard and paunch manure

	Per Week	Per Year
Material available for digestion (kg manure (dry))	90,000	4,500,000
Organic load available for digestion (kg VS)[8]	11,400	569,500
Methane conversion rate (m3/kg VS added)[9]	0.2	0.2
Methane yield (m3 CH4)	2,280	113,900
Energy yield (MJ)	86,000	4,294,000

Based on the above figures, the captured methane could provide over 5% of the heat energy requirements of the site. However, as the facility currently uses coal as its main heat source it may prove too costly to integrate the captured methane into the boilers. The most economic use of the captured methane would most likely be to replace the LPG currently used for blood drying. This would reduce the cost of LPG by about $36,000 and only require about 35% of the captured methane.

The remaining methane could ether be flared or used within a cogeneration unit. For further information on the use of co-generation units refer to the discussion regarding capture of methane from effluent ponds. Assuming a generator electrical efficiency of 35% the cogeneration unit could produce up to 272,000 kWh of electricity or almost 5% of the plant's requirements. The unit would also produce about 980 GJ of heat energy that could be used to produce hot water or preheat boiler feed water. In order to ensure all gas is consumed, a generator of between 40kW to 60kW would be required, depending on the whether a storage system is employed or not. The economic benefit of such an installation would be approximately $40,000.

Currently there are not any commercially available digesters for use with paunch manure. A number of laboratory scale demonstrations have been carried out and these indicate that the digestion of paunch manure is feasible. It is recommended that further analysis into the potential options for digestion of paunch manure be carried out.

[8] UNEP working group (2002), UASV1998

[9] UNEP working group (2002), UASV1998

If the manure is to be co-fired in the boiler to offset coal use it must first be dried to reduce the moisture content. One method of drying the manure would be through the use of solar thermal technologies (see solar thermal section for further details). Another would be to use any waste heat available at the plant. The dried manure would have an energy content of approximately 19.8 GJ per tonne. Based on the manure yield discussed above this would provide Plant B with up to 180 GJ of energy per week or 9,000 GJ per year. This could offset approximately 10% of the coal used per year and save $18,000 per year.

7.2.2.4 Use of tallow

The rendering process at the plant currently yields approximately 150kg of tallow and 125kg of meat meal per tHSCW. The tallow produced is of a high quality and contains less than 1% free fatty acids. The tallow is sold as stock feed and is priced between $600 and $1,000 per tonne.
At the current price of $750/tonne, which equates to 1.875 c/MJ, heat generation through tallow combustion is not a feasible alternative to coal. However, LPG is reported to cost 2.4 c/MJ at this facility for use in blood drying. At the current tallow price, energy derived from tallow is significantly cheaper per unit of energy than LPG.

At room temperature, tallow is solid. Consequently, a fuel pre-heating system will be required to avoid solidification within pipes. A conservative estimate of the cost of implementing this system would be $50,000. O&M costs are not expected to increase from those currently in place for LPG use. Revenue is determined through savings achieved via reduced energy costs, it is assumed the impact of a carbon price will be passed on to the Plant in the form of higher LPG prices. For the energy costs given above, a boiler lifetime of 15 years, and a discount rate of 7.5%, a cost benefit analysis is shown in Table 7-23.

Table 7-23: Cost benefit analyses of tallow to substitute LPG

Permit Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	50000	8300	0	6.02	23,300
10	50000	9200	0	5.43	31,200
15	50000	10500	0	4.76	42,700
20	50000	12300	0	4.07	58,600
25	50000	14500	0	3.45	78,000
30	50000	17200	0	2.91	101,800
35	50000	20300	0	2.46	129,200
40	50000	23900	0	2.09	161,000

The long-term value of this approach is seen to be less than that for replacing LPG use with captured biogas from wastewater ponds. However, capital requirements are far smaller. As a result, this may be an attractive strategy for this facility in the event that capital is restricted.

7.2.2.5 Photovoltaics

The plant has a large amount of well orientated roof space that could be used for both solar PV and solar thermal technologies. Given the relatively low price of electricity paid by Plant B (average less than 10c/kWh) is unlikely that PV will be economically viable at this stage. However, PV system prices have reduced significantly in previous years and with the ever increasing cost of electricity (particularly at times of peak demand) it is likely that PV will be viable in the not too distant future.

Information obtained during the site visit suggests that Plant B could have up to 5,000m^2 of roof space suitable for the installation of PV. Depending on the spacing of PV arrays, this could accommodate between 250 – 500kW of PV. In addition, the facility is surrounded by a significant area of flat land that would be suitable for the installation of PV. The site has good solar resources and a quality system could generate up to 1600 kWh/kWp/yr. This would correspond to a reduction in carbon emissions of approximately 1.6 tCO_2e/kWp/yr.
An analysis of the plant's current electricity tariff structure indicated that the potential value of PV in offsetting electricity use world be in the order of 10 c/kWh. For details on the methodology used to determine the economic value of PV see section 0. A summary of the economic performance of PV systems of varying size is shown in Table 7-24 below.

Table 7-24: Economic performance of different sized PV systems installed at Plant B

System size	10kW	50kW	100kW	500kW
Energy Produced (kWh)	16,000	80,000	160,000	800,000
GHG offset (tCO_2-e)	16	81	162	808
Cost $/W	$4.75	$4.50	$4.25	$4.00
Total Cost	$47,500	$225,000	$425,000	$2,000,000
REC Rebate (@ $40 per REC)	$13,000	$46,000	$87,000	$0
Net Cost	$34,500	$179,000	$338,000	$2,000,000
O&M Costs	$238	$1,125	$2,125	$10,000
Income (@ 10c/kWh)	$1,600	$8,000	$16,000	$112,000
Payback (years)	25	26	24	20
NPV (7.5%)	-$21,000	-$109,000	-$197,000	-$960,000

The above table demonstrates that the installation of PV is currently not economic at Plant B. However, independent modelling (PJPL, 2009) suggests that if an emissions trading scheme were introduced, and in conjunction with future load growth in the area, retail electricity prices could double in the next five years. In addition, PV prices have been falling steadily over the past decades and even conservative estimates would see the price continue to fall at 5% per year. If this were the case, the economics of PV would change dramatically, see Table 7-25 below.

Table 7-25: Possible future economic performance of different sized PV systems installed at Plant B

System size	10kW	50kW	100kW	500kW
Energy Produced (kWh)	16,000	80,000	160,000	800,000
GHG offset (tCO_2-e)	16	81	162	808
Cost $/W	$3.70	$3.50	$3.30	$3.10
Total Cost	$37,000	$175,000	$330,000	$1,550,000
REC Rebate (@ $40 per REC)	$8,000	$41,000	$82,000	$0
Net Cost	$29,000	$134,000	$248,000	$1,550,000
O&M Costs	$185	$875	$1,650	$7,750
Income (@ 10c/kWh)	$3,200	$16,000	$32,000	$192,000
Payback (years)	10	9	8	8
NPV (7.5%)	$2,000	$20,000	$61,000	$328,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of photovoltaics to generate electricity.

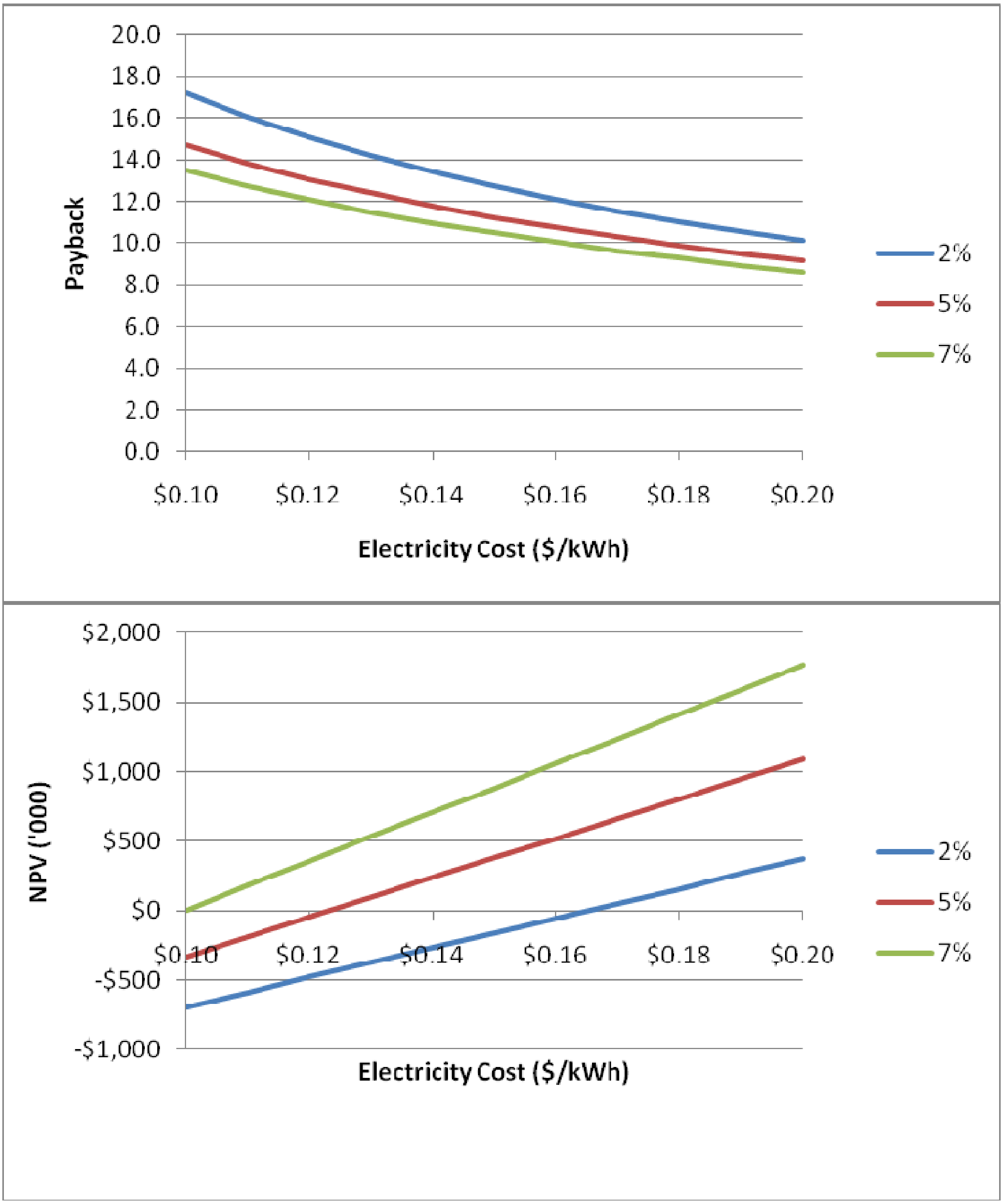


Figure 7.20: PV sensitivity analysis

7.2.2.6 Solar thermal for process heat

The use of solar thermal technologies for electricity generation is currently only economically viable on a large scale (10MW+) and as such is not suitable for use at Plant B. At the scale required for a meat processing facility, solar thermal technologies are more likely to be economically viable for heat generation.

Simple flat plate collectors are the most cost-effective method of small scale solar thermal. Flat-plate collectors could be used to preheat boiler feed water. The plant currently has a feed water rate of 13 kL/day at an average temperature of 20°C. In order to heat this water to 80°C approximately 270 m^2 of collectors would be needed and would cost in the order of $120,000 (including extra plumbing and installation). These collectors could be mounted on the roof of the facility, to minimise land use.

The assumptions and results of a preliminary economic analysis of solar thermal preheating of boiler water at Plant B are given in Table 7-26 and Table 7-27 respectively.

Table 7-26 Assumptions used for preliminary economic analysis of preheating boiler feed water using solar flat-plate collectors.

Feed water rate	13,000 L/day
Water inlet temperature	20°C
Water outlet temperature	80°C
Average efficiency of solar collector	50%
Maximum solar radiation (summer)	6.67 kWh/m^2/day
Average solar radiation (yearly)	5.00 kWh/m^2/day
Cost of coal	$2/GJ
Cost of solar collectors (installed)	$450/$m^2$
Operating days per year	250 days

Table 7-27 Preliminary economic analysis of using solar flat-plate collectors for preheating boiler feed water.

Energy savings per year	612 GJ
Collector area	272 m^2
Collector cost	$122,000
Cost savings per year	$1,224/year
Simple payback	100 years[10]

As Table 7-27 shows, flat-plate collectors for preheating boiler feed water are not cost-effective given the current low price of coal. Other solar thermal technologies (parabolic troughs, heliostats, parabolic dishes) are much less economical, due to the relatively small thermal load of Plant B.

[10] Hydro Tas (2008) shows that under very similar conditions to that of Plant B the payback period for displacing coal using flat plate collectors is 12 years. However, it appears there was a calculation mistake which underestimated the number of collectors required by a factor of 10. The calculations should have shown a payback period of 120 years for coal, and 20 years for gas.

A sensitivity analysis has not been performed for solar thermal technologies at Plant B as option will clearly not be economic at this facility.

7.2.2.6 Wind turbines

Another form of renewable energy that could be used to provide some of the plant's electricity is wind power. The output of wind turbines is very much related to the available wind resources and these resources vary considerably between sites. In order to fully assess the appropriateness of wind power options, detailed wind monitoring must be undertaken.

The site has large amounts of cleared land adjacent to the facility which would be suitable for the installation of wind turbines. If the site had adequate wind resources it is feasible that up to 1 MW of wind generation could be installed. Although this could be via a single 1 MW turbine, it is likely that the most appropriate solution would be to install several smaller turbines. The cost of such an installation would be between $3 and $8 per watt installed. Depending on the local planning requirements it may not be possible to install large quantities of wind power at the site. The assumptions used when assessing the economics of wind power options are given in Table 7-28.

Table 7-28: Assumptions for cost benefit analysis of wind power options

System size	500kW
Capital cost	$4/W or $2,000,000
Project lifetime	20yrs
Discount rate	7.5%
Average electricity price	10c/kWh
REC Price	$40/MWh or 4c/kWh

Table 7-29 shows the economics of installing wind turbines at Plant B for a number of different capacity factors. A capacity factor of 25%, which would be achieved at a reasonable wind site, means that the turbines produce 25% of the electricity they would if they were operating at full capacity all the time. It can be seen that wind turbines are currently not economic at Plant B.

Table 7-29: Cost benefit analysis of wind power installed at Plant B

Capacity Factor	10%	15%	20%	25%	30%
Energy Produced (kWh)	438,000	657,000	876,000	1,095,000	1,314,000
GHG offset (tCO_2-e)	442	664	885	1,106	1,327
O&M Costs	$40,000	$40,000	$40,000	$40,000	$40,000
Income (@ 10c/kWh)	$61,000	$92,000	$123,000	$153,000	$184,000
Payback	95	38	24	18	14
NPV (7.5%)	-$1,786,000	-$1,470,000	-$1,154,000	-$848,000	-$532,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of wind turbines to generate electricity.

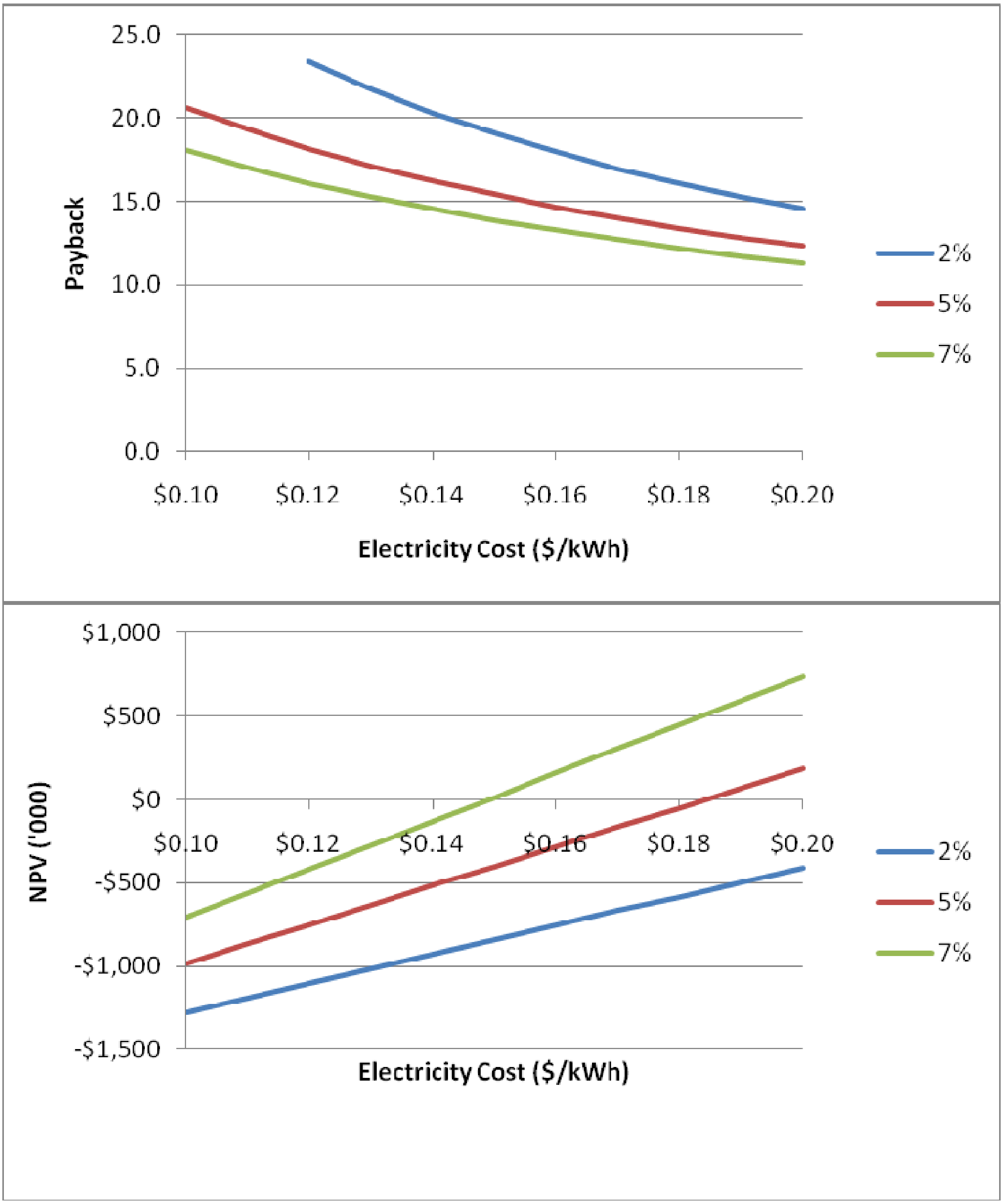


Figure 7.21: Wind power sensitivity analysis

7.2.3 Summary table for Plant B

Table 7-30 summarises the technologies assessed in this report and their potential effectiveness for use at Plant B.

Table 7-30 Summary of renewable energy technologies assessed: Plant B

Technology	Electricity Offset (kWh/yr)	Thermal Offset (GJ/yr)	Emissions Reduction (tCO_2-e/yr)	Cost Saving ($/yr)	Capital Cost ($)	Payback (yrs)
Capture of Methane from Ponds						
- Flaring	NA	NA	2,880	#[11]	425,000	#
- Cogeneration	1,260,000	6,000	1,750	180,900	793,900	4.4
- Fuel Cell	1,510,000	4,900	1,780	133,500	1,210,000	9.1
Yard and Paunch Manure						
- Methane	292,000	2,470	495	NA	NA	NA
- Direct Combustion	NA	9,000	770	NA	NA	NA
Tallow						
- Combustion	NA	1,490	88	8,300	50,000	6.0
PV	800,000	NA	808	102,00	2,000,000	20
Wind	657,000	NA	664	52,000[12]	2,000,000	38
Solar thermal	NA	610	790	1,200	122,000	100

7.3 Plant C

Plant C is an integrated cattle processing facility that kills and processes approximately 1,600 head per day and operates about 240 days per year. The average processed weight per head is 255kg and total yield per year is approximately 98,000 tHSCW. The facility includes kill floor, boning room, freezing (with capacity for a number of days storage) and rendering. Coal is the main heat source used and the plant pays comparatively low electricity use and demand tariffs.

[11] Dependant on carbon price

[12] Assume capacity factor of 15%

Summary of findings

There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant C. The most economic of these are summarised below.

- Installation of PV at sites adjacent to main facility, as these sites are separate to the main facility they may be eligible for the Queensland net Feed-in-Tariff of 44 c/kWh. There are four potentially suitable sites owned by the plant. This option has the potential to offset approximately 198,000 kWh of electricity and reduce emissions from electricity use by approximately 200 tCO_2-e per year. The cost of the installations would be in the order of $450,000 and the project would have a simple payback period of 5.7 years.
- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 8,120,000 kWh of electricity and 29,000 GJ of gas per year. It could also reduce direct emissions from effluent ponds by approximately 16,300 tCO_2-e/yr and indirect emissions (from electricity and gas use by approximately 9,700 tCO_2-e/yr). The cost of such an installation would be in the order of $6,680,000 and the project would have a simple payback period of about 7.4 years. This option would remove the vast majority of any liability the plant may have under the introduction of the currently proposed CPRS.

Technologies that are currently feasible but not economic (although they may be in the not too distant future) for use at Plant A include:

- The use of fuel cells in place of reciprocal gas generators
- Capture of biogas from yard and paunch manure
- Solar thermal technologies to preheat boiler water
- Wind turbines to generate electricity
- Geothermal heating and cooling
- Combustion of tallow

7.3.1 Energy and waste characteristics

Error! Reference source not found., **Error! Reference source not found.** and Table 7-31 show a breakdown of the energy used and associated costs for Plant C. While heat energy accounts for over 70% of energy used, it accounts for just over 30% of the total energy costs. Plant C currently exceeds both its emissions and energy reporting threshold under the NGERS. In order to no longer be liable under NGERS the plant would need to reduce its energy use by over 70% and its emissions by over 40%.

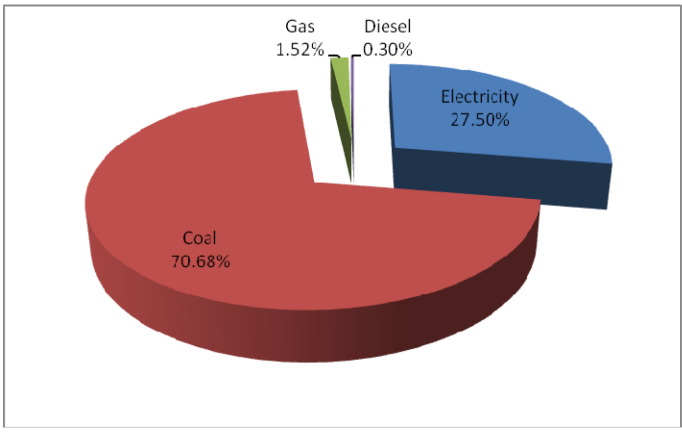
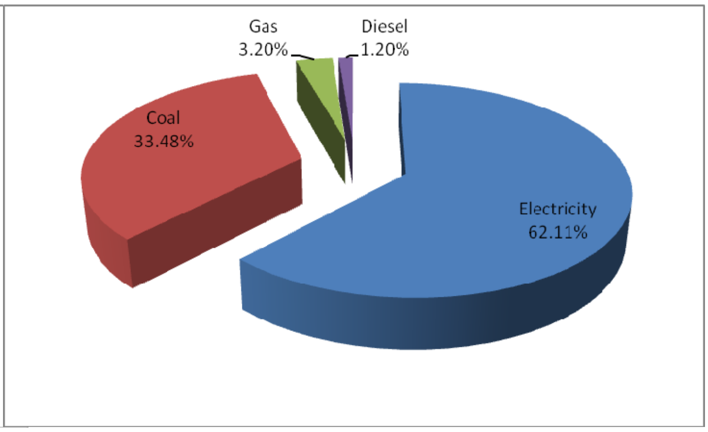


Figure 7.22: Energy use: Plant C



Fibgure 4.23: Energy costs: Plant C

Table 7-31: Energy use and cost breakdown: Plant C

Energy Source	Average Usage (MJ/tHSCW)	% of Total	Cost (c/MJ)	% of Total
Electricity	1,070	27.5%	1.94	62.1%
Coal	2,751	70.7%	0.41	33.5%
Gas	59	1.5%	1.81	3.2%
Diesel	12	0.3%	3.43	1.2%
Total	3,892	100%	0.86	100%

It is estimated that almost 70% of electricity consumed by the plant is used for refrigeration. The refrigeration system includes 11 compressors of various sizes. The refrigeration plant is designed such that if must be run at least once per day even in times of total shut down. The majority of the heat energy required by the plant is generated by two 11MW coal-fired boilers, which use about 40 tonnes of coal per day. Approximately 80% of the steam generated is used in rendering, with the majority of the remaining steam used for hot water generation. Neither of the boilers have economisers fitted and there is no heat recovery from the boiler stack gases. Heat is however recovered from the cooker to generate hot water. Natural gas is used by the plant for drying blood.

Waste water production by the plant varies between 3 to 4 ML per day or 720 to 960 ML per year. The waste water is treated in two anaerobic ponds, then fed into a facultative pond and finally gravity fed into a finishing pond. The majority of discharge from the finishing pond is to the tidal flat area adjacent to the nearby River, with some used for irrigation. The waste water has an average chemical oxygen demand (COD) of 8,200 kg/ML. The ponds are located a considerable distance from the plant and as such transportation of capture biogas back to the plant is expected to be very expensive.

7.3.2 Options to reduce emissions and costs using EE and RE

7.3.2.1 Biogas capture for flaring

Plant C has reported a wastewater flow rate of 960 ML/yr with an average COD of 8.2 kg/kL. This equates to an annual COD input of 7,900 tonnes to wastewater treatment ponds. Under NGERS reporting methods, which assume a COD removal effectiveness of 40% for wastewater treatment systems at meat and poultry plants, and a methane yield of $0.35m^3CH_4/kgCOD_{removed}$, this facility emits around 16,700 tCO_2-e.

The site currently has a complex multi-pond wastewater treatment system making covering of existing ponds unfeasible. The feasibility of excavation and covering of a new pond is analysed in this section.

Based on the wastewater flow rate and the optimal retention time for an anaerobic digester (40 days), a new pond of 105 ML capacity may be feasible.

Based on a cover cost of $\$80/m^2$ (AMPC 2008), excavation costs of $\$10/m^3$ (NIWA 2008) and installation costs of $\$40/m^2$ installed, the new pond could be excavated and covered for a capital outlay of $2,392,000.

Based on cost estimates from UNEP (2002), flaring systems require capital outlay for the following components:

Technology	Cost
Flare – combustion mechanism for methane destruction	$60,000
Gas Pipe – piping from ponds to flare at a cost of $100/m. Flare site is undetermined	$10,000
Gas blower and regulator – gas pressure must be raised for pumping from ponds to boiler and generator	$15,000
Condensate trap – to remove water content of biogas and ensure high-temperature, and thus efficient, combustion	$5,000
Gas storage system – to allow for fluctuations in yield	$10,000

Including these capital requirements with those for pond covering, as well as design costs of $25,000, a total capital requirement of $3,695,000 is estimated.

Flaring of captured biogas would reduce annual emissions from wastewater ponds to 795 tCO_2-e and should reduce odour. A cost benefit analysis was carried out assuming the proposed CPRS was legislated. Further assumptions included a system lifetime of 20 years, a discount rate of 7.5%, and annual operating and maintenance (O&M) costs of 2.5% of the capital cost of the cover and flare system.

The findings are summarised in Table 7-32 alongside potential carbon permit prices (see accompanying report - *Carbon Markets and their Relevance to the Meat Processing Industry*).

Table 7-32 Cost Benefit Analyses for Gas Capture & Flaring

Permit Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV
10	3,695,000	162,800	65,500	38.0	-$2,703,100
15	3,695,000	244,300	65,500	20.7	-$1,872,200
20	3,695,000	325,700	65,500	14.2	-$1,042,400
25	3,695,000	407,100	65,500	10.8	-$212,600
30	3,695,000	488,500	65,500	8.7	$617,300
35	3,695,000	570,000	65,500	7.3	$1,448,100
40	3,695,000	651,400	65,500	6.3	$2,278,000

Revenue refers to savings in penalties for carbon emissions under the ETS, SPP refers to Simple Payback Period, and NPV refers to Net Present Value

7.3.2.2 Biogas capture for heat and electricity generation

An alternative to flaring captured gas is to use it to replace fuels from external sources for heat and electricity generation. This allows for additional savings through the offset of fuel costs. An analysis of this strategy is discussed in the forthcoming sections.

Biogas Capture for Heat Generation

Though NGERS accounting methods assume a digester effectiveness of 40%, actual effectiveness of 80% COD removal can be expected. Thus, from the expected biogas yield, actual methane yield is expected to be 2,216,700 m^3CH_4/yr. With an energy content of 37.7 MJ/m^3CH_4, (DCC, 2009) around 83,600 GJ/yr of heat energy is available to this facility.

Heat demand at this site is serviced via coal-fired boilers. A coal price of ~$109/tonne has been reported, giving a heat energy cost of $4.06/GJ. From the average electricity price reported for this site, electrical energy has a cost of $20.9/GJ. From these energy costs, offsetting grid-connect electricity demand can be seen to offer greater economic benefit than offsetting coal use at this site. Feasibility analysis of electricity generation from captured biogas is discussed in subsequent sections.

Biogas Capture for Combined Heat and Power Generation

Captured biogas may be used to fuel a gas generator to service the electricity demand of the facility. For a gas generator efficiency of 35%, from the expected biogas yield, around 29,300 GJ/yr or 8,124,900 kWh/yr of electrical energy could be produced. This accounts for 28% of total electricity demand at this site.

If a further 35% of energy is captured as heat through a cogeneration system, 29,300 GJ/yr is available as low-grade heat energy, suitable for boiler feed pre-heating or production of hot (82˚C) and warm water (43˚C). At a coal price of $4.06/GJ, captured heat energy is worth around $118,800/yr to this facility. Cogeneration capacity is expected to add $200/kW installed to the cost of a generator, giving a total cost estimate of $1200/kW.

Generation Scheme Analysis

The generator may be operated during high tariff periods only, or continuously across all tariff periods. Assuming that in Queensland, the high tariff period extends for 14 hrs/day on weekdays, and assuming 15min start-up and shut-down, a continuous generation scheme (24hrs/day, 365days/yr) would require a 928 kW gas generator, while for on-peak only generation (15hrs/day, 365 days/yr) a 2119 kW generator would be required.

A cost benefit analysis was carried out to determine the comparative value of each generation scheme. The following were considered in the analysis:

- Capital requirements for the purchase and installation of a combined heat and power generator were estimated at $1,200/kW installed.
- Savings from generation through offset of grid-connect electricity were determined using generator output and a breakdown of the sites tariff structure, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.
- Maintenance costs were estimated with consideration of the need for a complete generator overhaul after 25,000 hrs of operation. An overhaul was estimated to cost half the initial capital costs of the generator.
- Generator lifetime of 15 years was used for continuous generation, and 25 years for on-peak only generation.

As this analysis does not consider the cost of gas capture, the figures reported below do not reflect the full project cost. As can be seen from Table 7-33, continuous operation has a shorter payback time. However, because of the longer assumed operational life under ‘high tariff’ operation, this option has a greater NPV.

Table 7-33: Cost Benefit Analysis of continuous and high tariff generation

	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
High tariff only (2119 kW)	2,542,300	1,162,300	185,700	2.6	8,343,700
Continuous (928 kW)	1,113,000	983,100	195,100	1.4	5,842,600

Note: Revenue refers to savings in grid-connect electricity consumption.

Cost Benefit Analysis of Combined Heat and Power Generation Scheme

From values determined in the sections above, the installation of a 2119 kW combined heat and power generator requires capital of $2,542,300. The cost of biogas capture and treatment can be estimated from flaring costs (excluding the cost of the flare which is no longer required) with the following additional components being necessary:

Technology	Cost
Storage system upgrade – in the absence of a flare to control gas stock, storage system will likely require capacity increase	$5,000
Gas Piping – site is around 5000m from digestion ponds (100m already accounted for), with a gas piping cost of $100/m (UNEP 2002)	$490,000
Gas pre-treatment system (scrubber) - required to remove hydrogen sulphide content to ensure the lifetime of the generator is not reduced through corrosion	$10,000

From these figures, total capital requirements for the design and installation of a combined heat and power generation system from captured biogas at this site are $6,682,300. The project is expected to return annual revenues of $1,162,300 through offset of grid-connect electricity, gas use, and RECs sales. Operating and maintenance (O&M) costs are expected to increase by $262,300 annually.

Based on these figures, a system lifetime of 15 years and a discount rate of 7.5%, a cost benefit analysis returned the results in Table 7-34.

Table 7-34: Cost Benefit Analyses of Gas Capture for Heat & Electricity Generation

ETS Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	ETS Savings ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	6,682,300	1,162,300	0	262,300	7.4	$1,262,100
10	6,682,300	1,162,300	162,800	262,300	6.3	$2,699,200
15	6,682,300	1,162,300	244,300	262,300	5.8	$3,418,600
20	6,682,300	1,162,300	325,700	262,300	5.5	$4,137,100
25	6,682,300	1,162,300	407,100	262,300	5.1	$4,855,600
30	6,682,300	1,162,300	488,500	262,300	4.8	$5,574,200
35	6,682,300	1,162,300	570,000	262,300	4.5	$6,293,600
40	6,682,300	1,162,300	651,400	262,300	4.3	$7,012,100

Sensitivity analysis

The following graphs present the results of a sensitivity analysis undertaken on the capture of biogas for use in a combined heat and power generator. The sensitivity analysis includes three scenarios, the assumptions used for each scenario are:

- Scenario 1: The starting price of electricity and heat energy are fixed to their current rates and the price of price of carbon under an ETS is varied between \$0 to \$40/tCO2-e.
- Scenario 2: The starting price of heat energy is fixed to its current rate, the price of carbon is assumed to be \$0 and the price of electricity varies from its current rate of 7c/kWh to 17c/kWh.
- Scenario 3: The starting price of electricity is fixed to its current rate, the price of carbon is assumed to be \$0 and the price of heat energy varies from its current rate of \$4/GJ to 6GJ.
- For each scenario the price of electricity and heat energy has been modelled at three different escalation rates (2%, 5% and 7% per year).

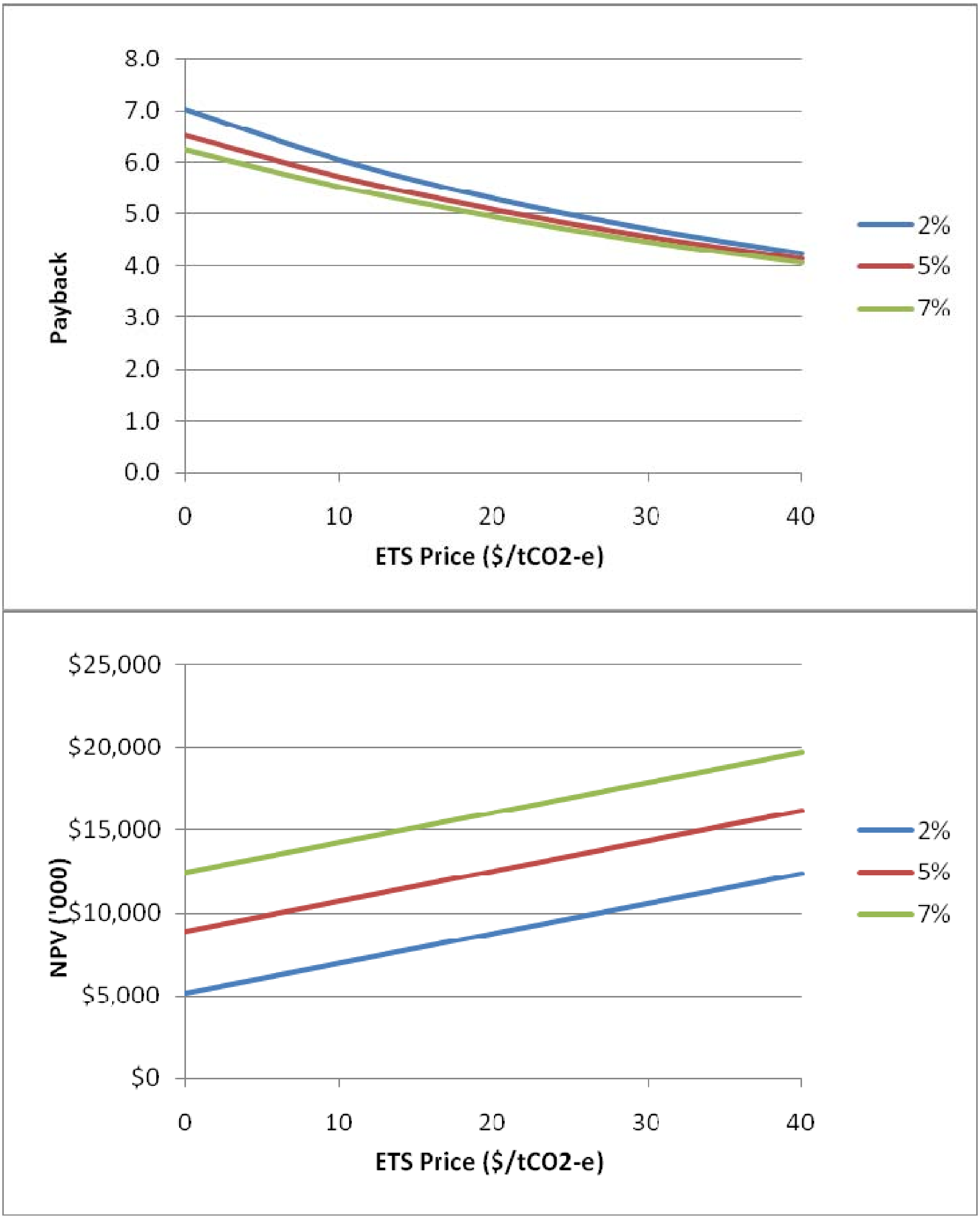


Figure 7.23: Cogeneration sensitivity analysis: Scenario 1

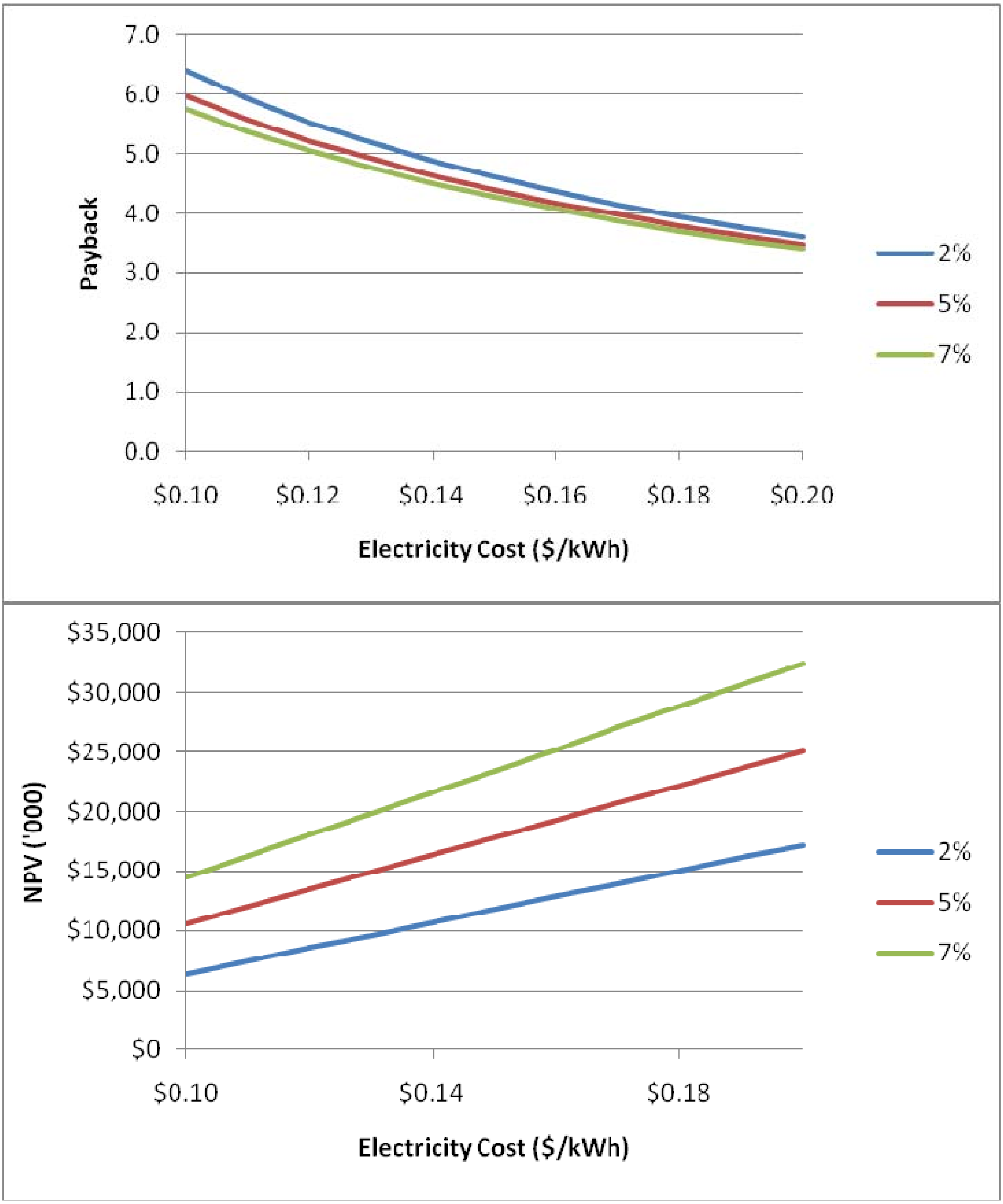


Figure 7.24: Cogeneration sensitivity analysis: Scenario 2

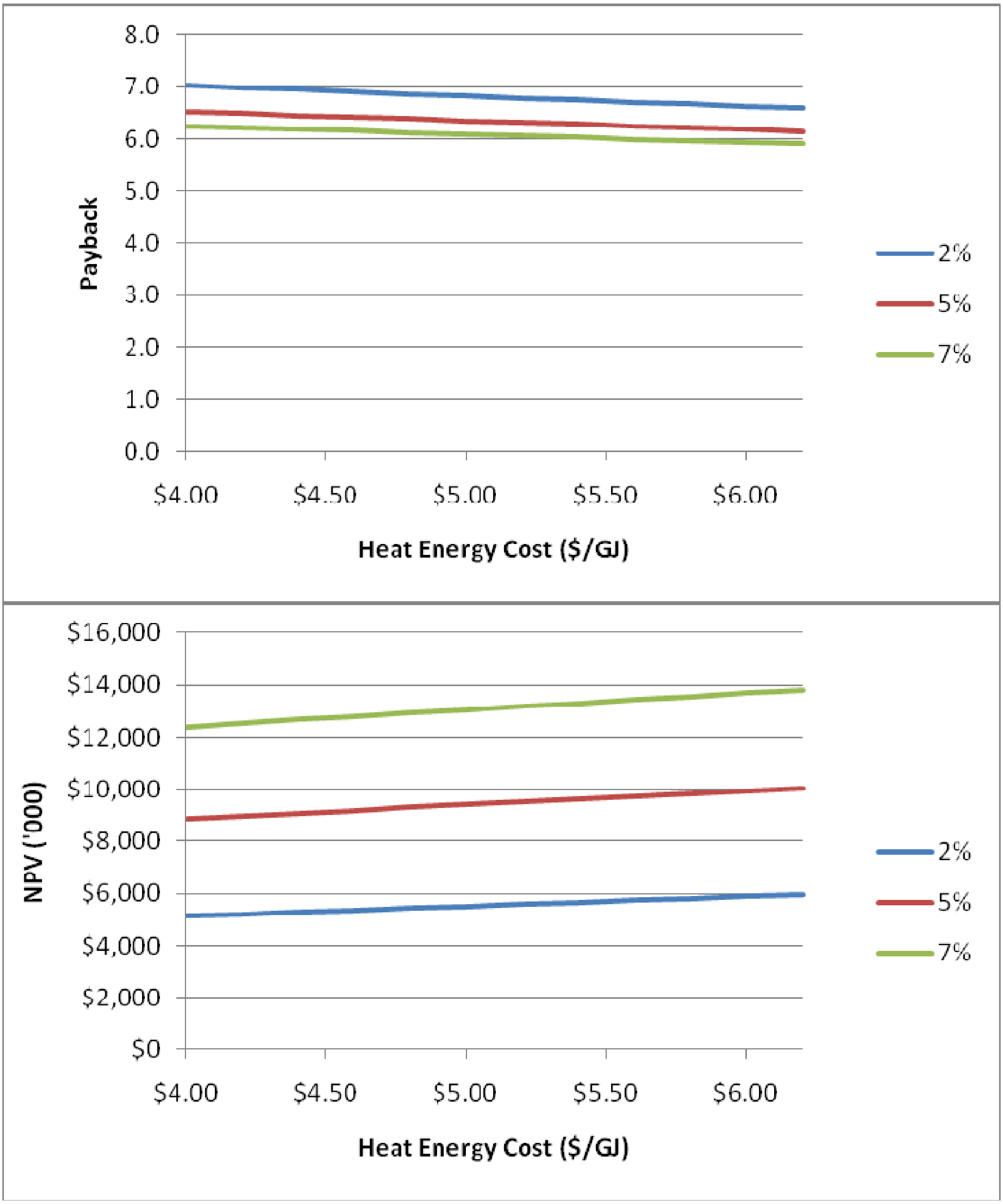


Figure 7.25: Cogeneration sensitivity analysis: Scenario 3

The results of the sensitivity analysis suggest that at Plant C the price of electricity has the greatest impact on the economics of the capture of biogas for use in a cogeneration plant

Summary of the use of methane for heat and combined heat and power generation

The economic benefit available to this facility through installation of a biogas capture and flaring system is dependent entirely on the introduction of the CPRS or similar scheme that places a price on greenhouse emissions. Capital requirements for capture and flaring are lower than for capture, heat and electricity generation.

Installation of biogas capture for heat and electricity generation returns a positive NPV without the introduction of the CPRS. While the distance between wastewater treatment ponds and the site limits the effectiveness of this strategy due to the high cost of gas piping, if the prices of gas and electricity rise, the value of onsite heat and electricity generation is expected to increase accordingly.

Biogas use in Fuel Cells

As stated above the potential methane yield from the covering of the effluent ponds is 2,216,700 m^3CH_4/yr. This biogas could be used by a fuel cell to produce between 9,750,000 kWh and 10,910,000 kWh of electricity, about 35% of the plants total electricity use. This system could also generate approximately 29,700 GJ/yr of useful heat energy. As this heat is low-grade it is unlikely to be useful for producing steam. However, it may be used to produce warm (43˚C) and hot (82˚C) water and preheat boiler feed water.

At a coal price of $4.1/GJ, captured heat energy is worth around $120,000/yr to the facility. A basic cost benefit analysis for the use of biogas in fuel cells at Plant C was performed using the following assumptions:

- Savings from generation through offset of grid-connect electricity are determined using generator output and a breakdown of New South Wales tariff structures, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.
- Savings from reduced gas use are based on a coal price of $4.10 per GJ.
- Maintenance costs were estimated assuming the need for a complete generator overhaul after 5 or 10 of operation (depending on the type of fuel cell used). An overhaul was estimated to cost half the initial capital costs of the generator.
- Generator lifetime of 20 years
- Discount rate of 7.5%
- Future costs are those promised by the manufacture once economies of scale are reached, manufactures have estimated this timeframe to be between 5 and 10 years.

As can be seen from Table 7-35, the UTC PAFC provides the shortest payback time and greatest NPV based on current cost estimates.

Table 7-35: Cost benefit analysis of the use of biogas in fuel cells for Plant C

	Capital[13] $/kW	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
Now						
UTC PAFC	$4,500	$9,180,000	$1,154,160	$328,600	11.1	-$763,800
FCE MCFC	$4,300	$9,515,000	$1,259,000	$614,100	14.8	-$2,940,600
Future						
UTC PAFC	$1,500	$5,820,000	$1,154,160	$160,600	5.9	$4,308,800
FCE MCFC	$2,500	$7,265,000	$1,259,000	$389,100	8.4	$1,603,200

The following table shows the economic performance of the United Technology Corporation Phosphoric Acid Fuel Cell (PAFC) under different ETS situations.

Table 7-36: Cost benefit analysis of the use of biogas in fuel cells for Plant C under an ETS

ETS Price ($/tCO2-e)	Capital ($)	Revenue ($/yr)	ETS Savings ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
0	9,180,000	1,154,160	0	328,600	11.1	-$763,800
10	9,180,000	1,154,160	162,800	328,600	9.3	$895,800
15	9,180,000	1,154,160	244,200	328,600	8.6	$1,725,700
20	9,180,000	1,154,160	325,600	328,600	8.0	$2,555,500
25	9,180,000	1,154,160	407,000	328,600	7.4	$3,385,300
30	9,180,000	1,154,160	488,400	328,600	7.0	$4,215,200
35	9,180,000	1,154,160	569,800	328,600	6.6	$5,045,000
40	9,180,000	1,154,160	651,200	328,600	6.2	$5,874,800

Sensitivity analysis

The following charts present the results of a sensitivity analysis undertaken on the capture of biogas for use in a fuel cell.

[13] (NREL 2009)

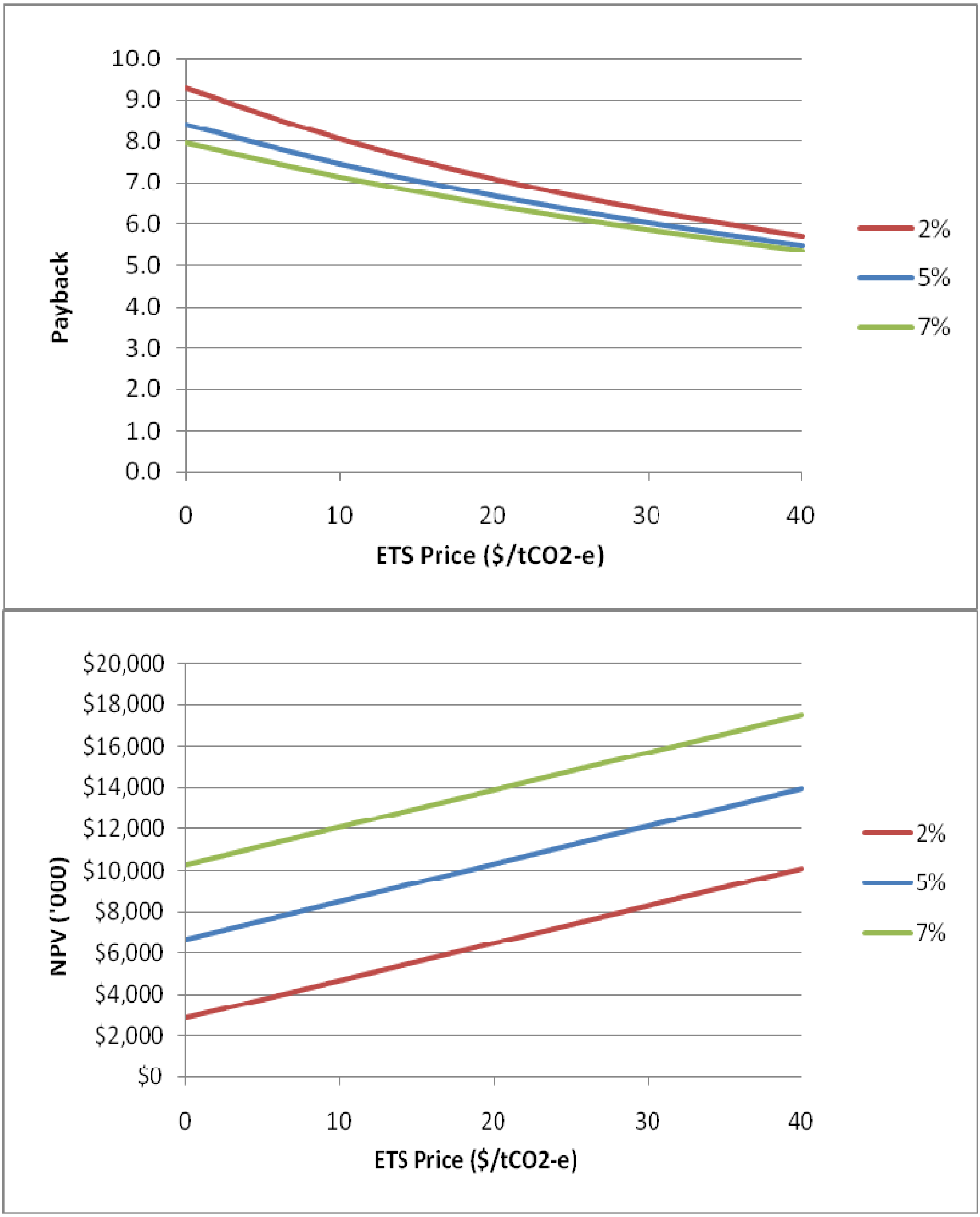


Figure 7.26: Fuel Cells sensitivity analysis: Scenario 1

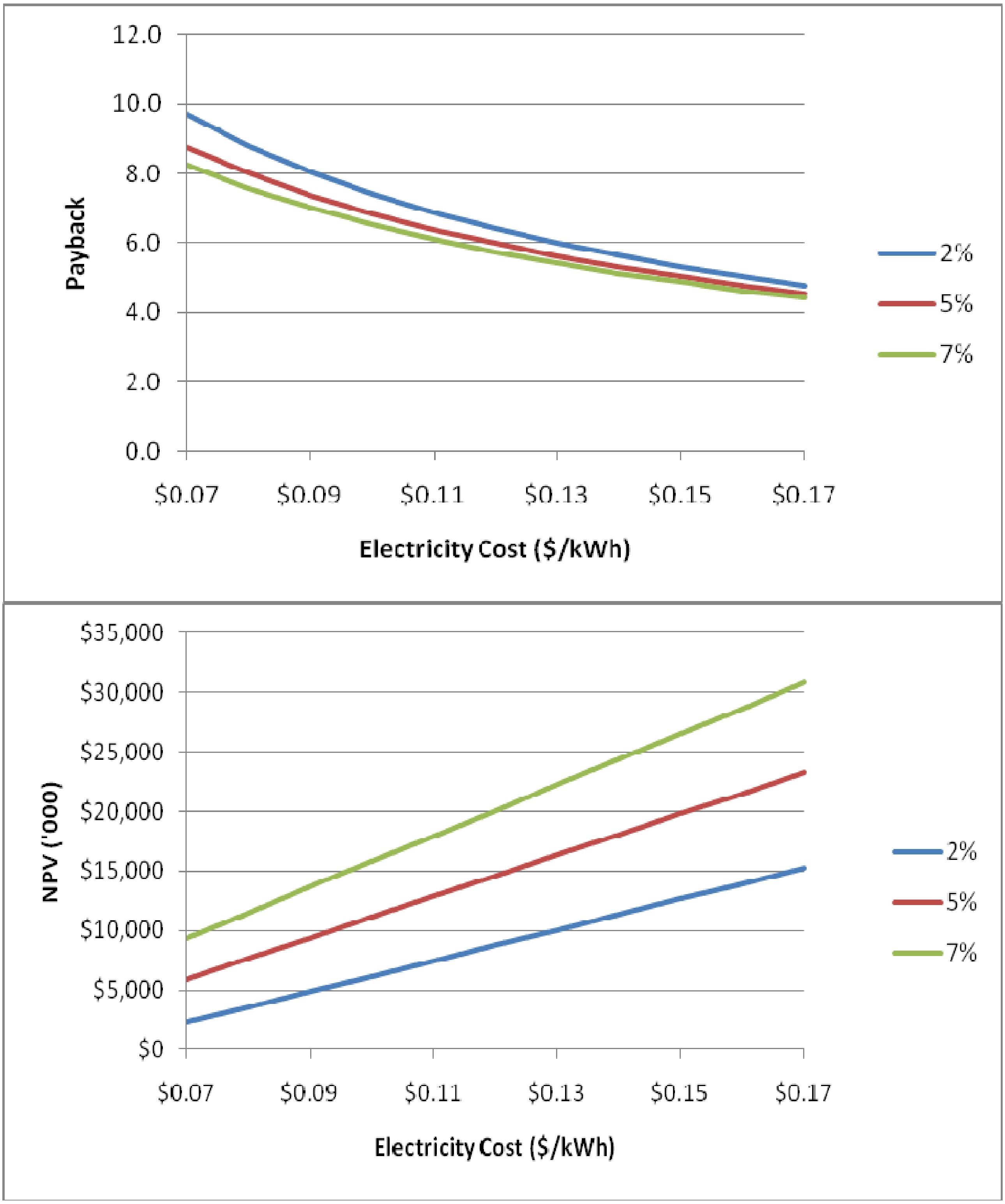


Figure 7.27: Fuel Cells sensitivity analysis: Scenario 2

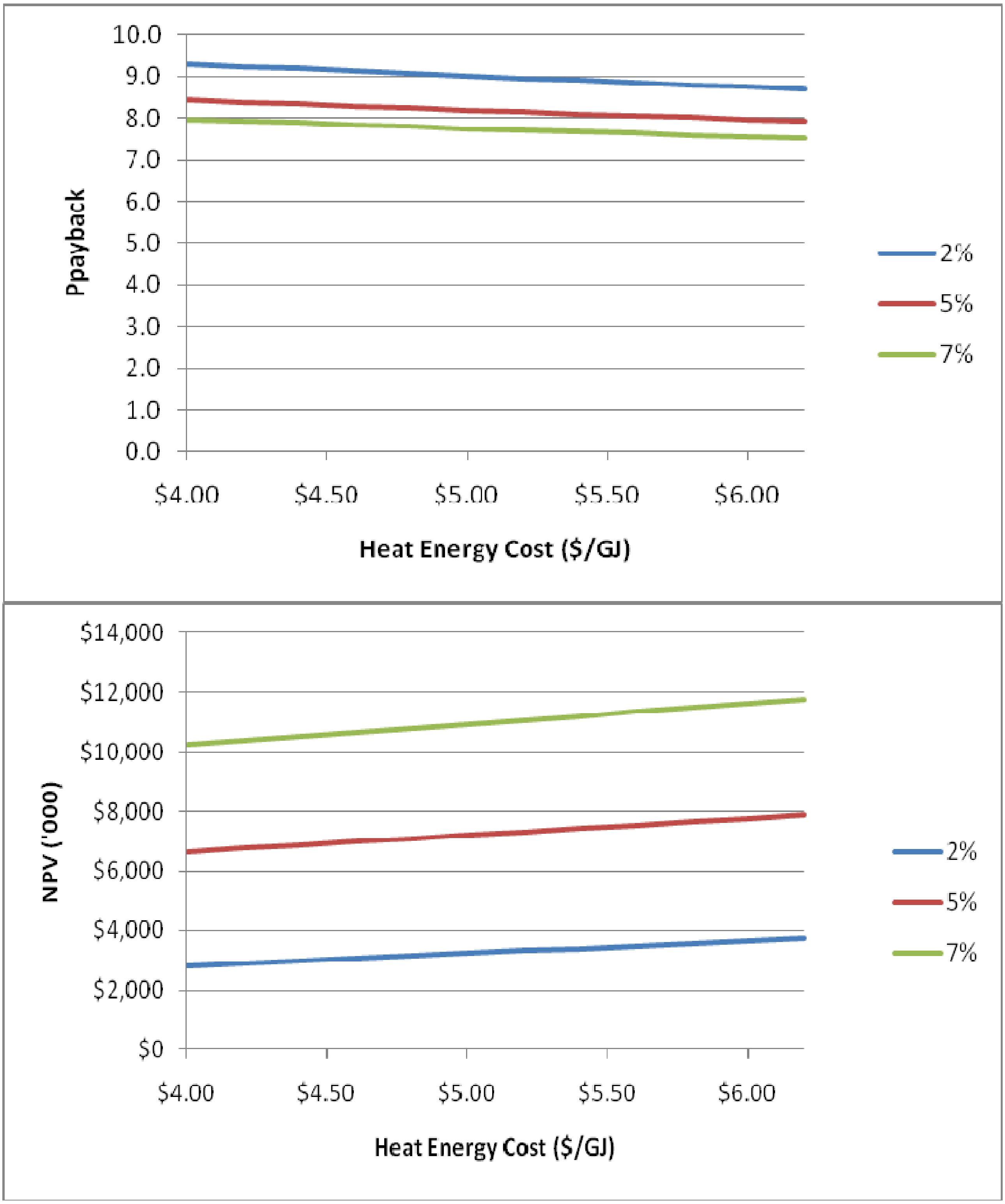


Figure 7.28: Fuel Cells sensitivity analysis: Scenario 3

7.3.2.3 Use of yard and paunch manure

The plant produces approximately 60m^3 per day or 14,400 m^3 per year of paunch and yard manure. The manure is removed by a local composting company in at a cost of approximately $200,000 to $250,000 per year. There are two potential options for Plant C to use the paunch manure as a source of energy. The first would be to construct an anaerobic digester to produce biogas. The second would be to dry the manure and directly combust it in the boiler to offset coal use. Option one would involve construction of a purpose-built digester whose temperature could be controlled. Such a digester would be capable of converting as much as 25-35% of the organic material into biogas (Alvarez, et al). The remaining material could be removed and used as a high quality fertiliser (GHD, 2005). Assuming the remaining material is still removed by the local composting company at the same cost per m^3, this would correspond to a saving in manure disposal fees of $50,000 to $75,000 per year.

The total solids contained in the paunch manure is in the order of 14.3%, with volatile solids making up about 88.5% of this (UASV, 1998). Given the high moisture content the density approaches that of water (MSU 1995). Therefore the plant produces approximately 300 tonnes of wet manure per week. Table 7-37 below summarises the approximate methane yields available from the anaerobic digestion of this manure.

Table 7-37: Potential methane production from anaerobic digestion of yard and paunch manure

	Per Week	Per Year
Material available for digestion (kg manure (dry))	300,000	14,400,000
Organic load available for digestion (kg VS)[14]	38,000	1,822,400
Methane conversion rate (m3/kg VS added)[15]	0.2	0.2
Methane yield (m3 CH4)	7,600	364,480
Energy yield (MJ)	286,500	13,740,900

Based on the above figures, the captured methane could provide over 5% of the heat energy requirements of the site. However, as the facility currently uses coal as its main heat source it may prove too costly to integrate the captured methane into the boilers. The most economic use of the captured methane would most likely be to replace the natural gas currently used for blood drying. This would reduce the cost of natural gas by about $105,000 and only require about 40% of the captured methane.

Alternatively the biogas could be used in a cogeneration unit to generate electricity and heat. For further information on the use of co-generation units refer to the discussion regarding capture of methane from effluent ponds. Assuming a generator electrical efficiency of 35% the cogeneration unit could produce up to 800,000 kWh of electricity or almost 4% of the plant's requirements. The unit would also produce about 2,880 GJ of heat energy that could be used to produce hot water or preheat boiler feed water. In order to ensure all gas is consumed, a generator of about 130kW would be required. The savings from offset electricity and gas use for such a system would be approximately $115,000.

[14] UNEP working group (2002)

[15] UNEP working group (2002), UASV1998

Currently there are not any commercially available digesters for use with paunch manure. A number of laboratory scale demonstrations have been carried out and these indicate that the digestion of paunch manure is feasible. It is recommended that further analysis into the potential options for digestion of paunch manure be carried out.

If the manure is to be co-fired in the boiler to offset coal use, it must first be dried to reduce the moisture content. One method of drying the manure would be through the use of solar thermal technologies (see solar thermal section for further details). Another would be to use any waste heat available at the plant. The dried manure would have an energy content of approximately 19.8 GJ per tonne. Based on the manure yield discussed above this would provide Plant C with up to 600 GJ of energy per week or 28,500 GJ per year. This could offset approximately 10% of the coal used per year and save $110,000 per year

7.3.2.4 Use of tallow

Tallow yields from this facility have been reported at 70 tonnes/day. With an energy content of 40 MJ/kg, annual available heat energy through combustion of tallow is 700,000 GJ. At a reported price of $750/tonne, apparent cost per unit energy is 1.875 c/MJ.

Natural gas costs of approximately 1.84 c/MJ have been reported at this site. In the event of gas price increase and/or tallow price decrease, offsetting natural gas demand through tallow combustion may become feasible (for further information refer Appendix A). At this point, however, owing to the capital costs required for boiler modification, the strategy is not financially viable at Plant C.

7.3.2.5 Photovoltaics

The plant has a large amount of well orientated roof space that could be used for both solar PV and solar thermal technologies. Given the relatively low price of electricity paid by Plant C (average less than 7c/kWh) is unlikely that it would be economically viable to install PV at the main plant at this stage. However, PV system prices have reduced significantly in previous years and with the ever increasing cost of electricity (particularly at times of peak demand) it is likely that PV will be viable in the not too distant future.

Information obtained during the site visit suggests that Plant C could have up to 8,000m^2 of roof space suitable for the installation of PV at the primary plant. Depending on the spacing of PV arrays, this could accommodate between 400 – 800kW of PV. In addition, the facility is surrounded by a significant area of flat land that would be suitable for the installation of PV. The site has good solar resources with little or no horizon shading and a well installed system could generate over 1650 kWh/kWp/yr. This would correspond to a reduction in carbon emissions of approximately 1.7 tCO_2e/kWp/yr.

In addition to the main plant, the facility has a number of other buildings for operations located away from the main plant. For example there are separate buildings for effluent ponds, pumping station, cattle yard and off site cold store. Under the Queensland Feed-in-Tariff each of these sites may be eligible to install up to 30kW (assuming 3 phase supply) of PV and receive the net tariff of 44 c/kWh. The following table summarises the economics of such an option.

Table 7-38: Economic performance of 30kW PV systems installed at locations other than Plant C

Site Number	1	2	3	4	All Sites
Current use	4,438	7,434	16,262	2,403	30,537
Current tariff (c/kWh)	16.7	16.6	12.5	25.3	17.8
Proportion of energy exported	96%	92%	84%	98%	92%
Estimated average tariff[16]	42.8	41.9	38.8	43.5	41.8
Energy Produced (kWh)	49,500	49,500	49,500	49,500	198,000
GHG offset (tCO_2-e)	50	50	50	50	200
Cost $/W	$4.75	$4.75	$4.75	$4.75	$4.75
Total Cost	$142,500	$142,500	$142,500	$142,500	$570,000
REC Rebate (@ $40 per REC)	$29,000	$29,000	$29,000	$29,000	$116,000
Net Cost	$113,500	$113,500	$113,500	$113,500	$454,000
O&M Costs	$713	$713	$713	$713	$2,850
Income (@ Net FiT 44c/kWh)	$21,200	$20,800	$19,200	$21,600	$82,800
Payback (years)	5.5	5.7	6.1	5.4	5.7
NPV (7.5%)	$95,000	$91,000	$75,000	$99,000	$361,000

The demand profile of the main plant indicates that peak electricity demand usually occurs in the early afternoon (around 2pm to 4pm). An analysis of the plant's current electricity tariff structure against peak usage times and PV output characteristics indicated that the potential value of PV in offsetting electricity use world be in the order of 8.5 c/kWh. For details on the methodology used to determine the economic value of PV see section 0. A summary of the economic performance of PV systems of varying size is shown in Table 7-39 below.

16 Estimated average tariff based on the estimated amount of electricity exported to the grid and the current tariff

Table 7-39: Economic performance of different sized PV systems installed at Plant C

System size	10kW	50kW	100kW	500kW
Energy Produced (kWh)	16,500	82,500	165,000	825,000
GHG offset (tCO_2-e)	17	83	167	833
Cost $/W	$4.75	$4.50	$4.25	$4.00
Total Cost	$47,500	$225,000	$425,000	$2,000,000
REC Rebate (@ $40 per REC)	$13,000	$46,000	$87,000	$0
Net Cost	$34,500	$179,000	$338,000	$2,000,000
O&M Costs	$238	$1,125	$2,125	$10,000
Income (@ 8.5c/kWh)[17]	$1,400	$7,000	$14,000	$103,100
Payback (years)	30	30	28	21
NPV (7.5%)	-$23,000	-$119,000	-$217,000	-$1,051,000

The above table demonstrates that the installation of PV is currently not economic at Plant C. However, independent modelling (PJPL 2009) suggests that if an emissions trading scheme were introduced, and in conjunction with future load growth in the area, retail electricity prices could double in the next five years. In addition, PV prices have been falling steadily over the past decades and even conservative estimates would see the price continue to fall at 5% per year. If this were the case, the economics of PV would change dramatically, see Table 7-40 below.

Table 7-40: Possible future economic performance of different sized PV systems installed at Plant C

System size	10kW	50kW	100kW	500kW
Cost $/W	$3.70	$3.50	$3.30	$3.10
Total Cost	$37,000	$175,000	$330,000	$1,550,000
REC Rebate (@ $40 per REC)	$8,000	$41,000	$82,000	$0
Net Cost	$29,000	$134,000	$248,000	$1,550,000
O&M Costs	$185	$875	$1,650	$7,750
Income (@ 17c/kWh)	$2,800	$14,000	$28,100	$173,300
Payback (years)	11	10	9	9
NPV (7.5%)	-$2,000	$0	$22,000	$138,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of photovoltaics to generate electricity.

[17] For installation greater than 100kW the income includes an addition 3c/kWh from RECs

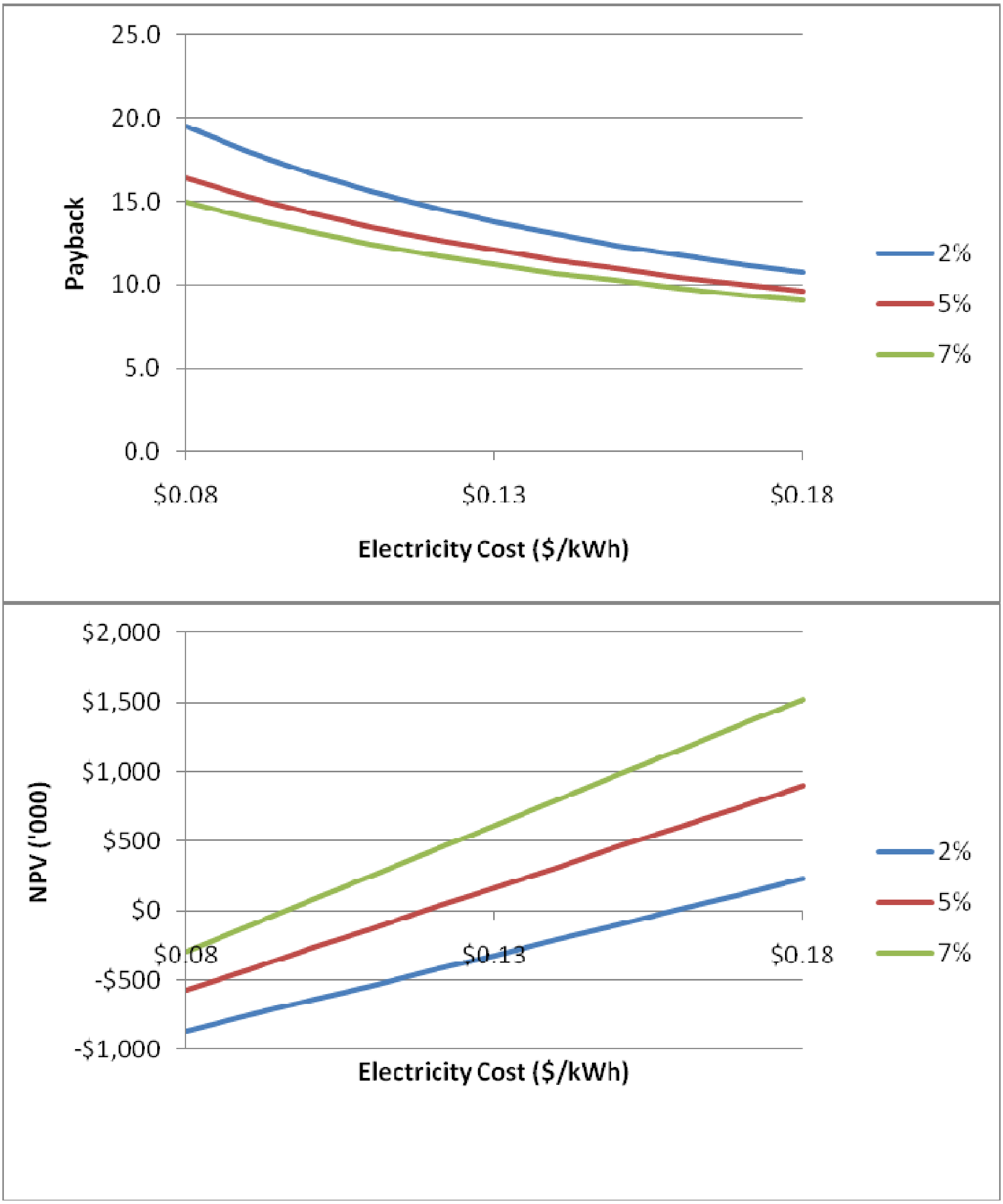


Figure 7.29: PV sensitivity analysis

7.3.2.6 Solar thermal for process heat

The use of solar thermal technologies for electricity generation is currently only economically viable on a large scale (10MW+) and as such is not suitable for use at Plant C. At the scale required for a meat processing facility, solar thermal technologies are more likely to be economically viable for heat generation.

Simple flat plate collectors are the most cost-effective method of small scale solar thermal. Flat-plate collectors could be used to preheat boiler feed water. The plant currently has a feed water rate of 39 kL/day at an average temperature of 20°C. In order to heat this water to 80°C approximately 800 m^2 of collectors would be needed and would cost in the order of \$360,000 (including extra plumbing and installation). These collectors could be mounted on the roof of the facility, to minimise land use.

The assumptions and results of a preliminary economic analysis of solar thermal preheating of boiler water at Plant C are given in Table 7-41 and Table 7-42 respectively.

Table 7-41 Assumptions used for preliminary economic analysis of preheating boiler feed water using solar flat-plate collectors.

Feed water rate	39,000 L/day
Water inlet temperature	20°C
Water outlet temperature	80°C
Average efficiency of solar collector	50%
Maximum solar radiation (summer)	6.75 $kWh/m^2/day$
Average solar radiation (yearly)	5.31 $kWh/m^2/day$
Cost of coal	\$4/GJ
Cost of solar collectors (installed)	\$450/m^2
Operating days per year	250 days

Table 7-42 Preliminary economic analysis of using solar flat-plate collectors for preheating boiler feed water.

Energy savings per year	1,924 GJ
Collector area	806 m^2
Collector cost	\$363,000
Cost savings per year	\$7,696/year
Simple payback	47 years

As Table 7-42 shows, flat-plate collectors for preheating boiler feed water are not cost-effective given the current low price of coal. Other solar thermal technologies (parabolic troughs, heliostats, parabolic dishes) are much less economical, due to the relatively small thermal load of Plant C.

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of solar thermal technologies to preheat boiler feed water.

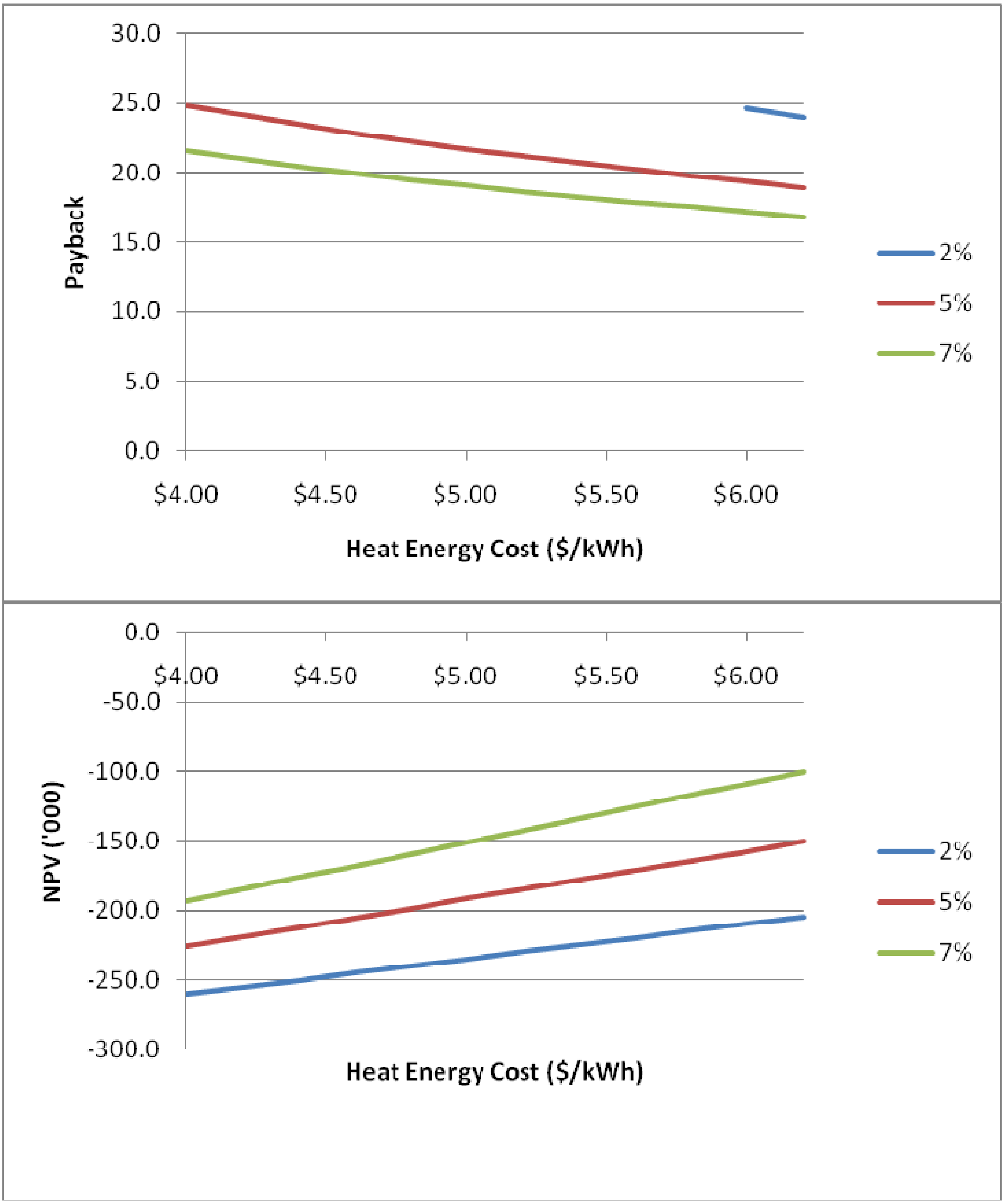


Figure 7.30: Solar thermal sensitivity analysis

7.3.2.6 Wind turbines

Another form of renewable energy that could be used to provide some of the plant's electricity is wind power. The output of wind turbines is very much related to the available wind resources and these resources vary considerably between sites. In order to fully assess the appropriateness of wind power options, detailed wind monitoring must be undertaken.

The site has small amount of cleared land adjacent to the facility which would be suitable for the installation of wind turbines. If the site had adequate wind resources it is feasible that up to 100 kW of wind generation could be installed. The cost of such an installation would be between $6 and $8 per watt installed. Depending on the local planning requirements it may not be possible to install large quantities of wind power at the site. The assumptions used when assessing the economics of wind power options are given in Table 7-43.

Table 7-43: Assumptions for cost benefit analysis of wind power options

System size	100kW
Capital cost	$7/W or $700,000
Project lifetime	20yrs
Discount rate	7.5%
Average electricity price	7c/kWh
REC Price	$40/MWh or 4c/kWh

Table 7-44 shows the economics of installing wind turbines at Plant C for a number of different capacity factors. A capacity factor of 25%, which would be achieved at a reasonable wind site, means that the turbines produce 25% of the electricity they would if they were operating at full capacity all the time. It can be seen that wind turbines are currently not economic at Plant C.

Table 7-44: Cost benefit analysis of wind power installed at Plant C

Capacity Factor	10%	15%	20%	25%	30%
Energy Produced (kWh)	88,000	131,000	175,000	219,000	263,000
GHG offset (tCO_2-e)	89	132	177	221	266
O&M Costs	14,000	14,000	14,000	14,000	14,000
Income (@ 7c/kWh)	$10,000	$14,000	$19,000	$24,000	$29,000
Payback	N/A	N/A	140	70	47
NPV (7.5%)	-$741,000	-$700,000	-$649,000	-$598,000	-$547,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of wind turbines to generate electricity.

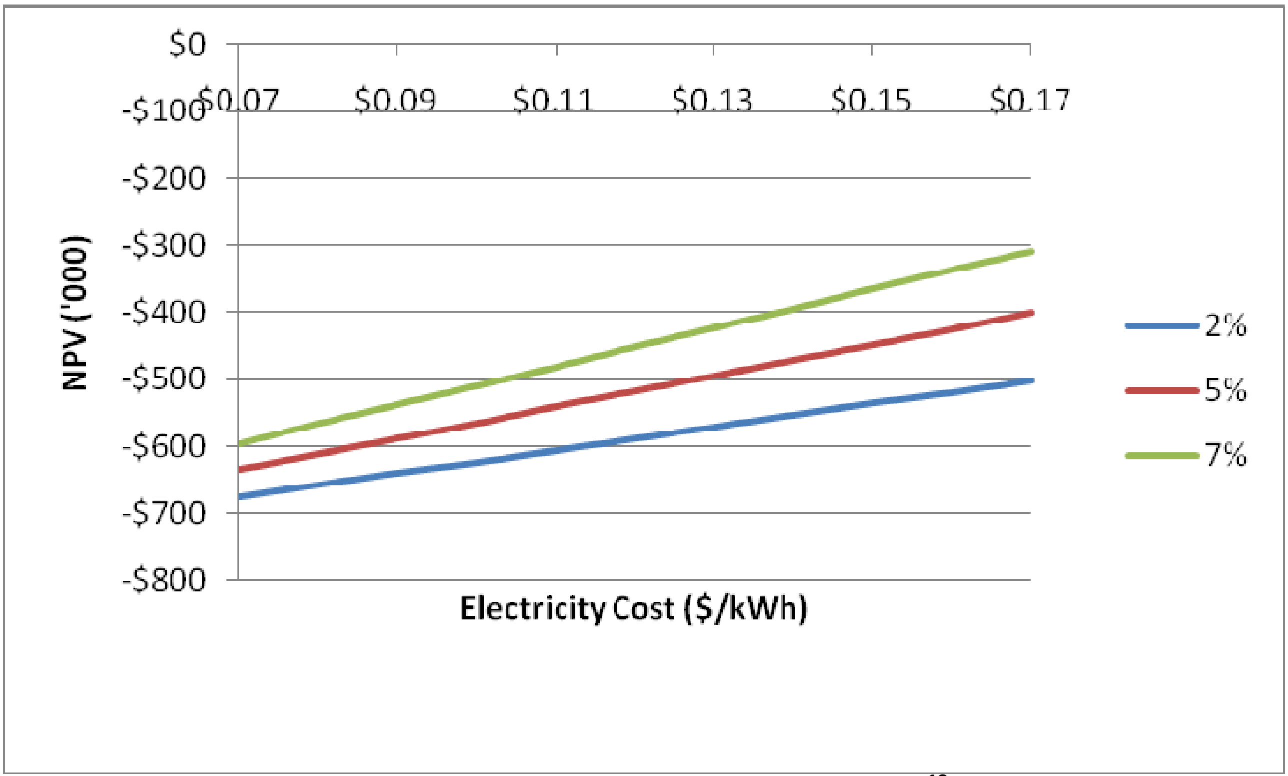


Figure 7.31: Wind power sensitivity analysis[18]

[18] Payback times for wind power installed at Plant C exceed the modelled project life of 25 years

7.3.2 Summary table for Plant C

Table 7-45 summarises the technologies assessed in this report and their potential effectiveness for use at Plant C.

Table 7-45 Summary of renewable energy technologies assessed: Plant C

Technology	Electricity Offset (kWh/yr)	Thermal Offset (GJ/yr)	Emissions Reduction (tCO_2-e/yr)	Cost Saving ($/yr)	Capital Cost ($)	Payback (yrs)
Capture of Methane from Ponds						
- Flaring	NA	NA	16,300	#[19]	3,695,000	#
- Cogeneration	8,125,000	29,300	9,700	900,000	6,682,000	7.4
- Fuel Cell	9,750,000	35,100	11,640	826,000	9,180,000	11.1
Yard and Paunch Manure						
- Methane	800,000	6,300	1,660	NA	NA	NA
- Direct Combustion	NA	28,500	2,450	NA	NA	NA
Tallow						
- Combustion	NA	NA	NA	NA	NA	NA
PV	198,000	NA	200	80,000	454,000	5.7
Wind[20]	131,000	NA	132	0	700,000	N/A
Solar thermal	NA	1,920	170	7,700	360,000	47

[19] Dependant on carbon price

[20] Assume capacity factor of 15%

7.4 Plant D

Plant D is an integrated sheep processing facility that kills and bones approximately 2,000 head per day. The average processed weight per head is approximately 20kg and total yield per year is approximately 10,000 tHSCW. The facility includes kill floor, boning room, freezing (with capacity for a small amount of storage) but does not include rendering. The plant recently completed a twelve month study into incorporating rendering into the facility but is yet to make a final decision as to whether to proceed. Gas is the main heat source used and the plant pays comparatively high electricity use and demand tariffs. However, the facility is considering upgrading its electricity feed and becoming a high voltage customer, which may reduce it tariffs slightly.

Summary of findings
There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant D. However, at this stage none of them are economically viable. The options that are closest to being economic are:

- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 65,300 kWh of electricity and approximately 235 GJ of gas per year. It could also reduce direct emissions from effluent ponds by approximately 128 tCO_2-e and indirect emissions (from electricity and gas use by approximately 80 tCO_2-e). The cost of such an installation would be in the order of $201,000 and the project would have a simple payback period of about 19.9 years.
- The use of wind turbines to generate electricity for use within the plant. This option has the potential to offset approximately 986,000 kWh of electricity use and reduce emissions by approximately 1,055 tCO_2-e. The cost of such an installation would be in the order of $2,000,000 and the project would have a simple payback period of about 17 years.

Technologies that are currently feasible but not economic (although they may be in the not too distant future) for use at Plant D include:

- The use of fuel cells in place of reciprocal gas generators
- Solar PV technologies to generate electricity
- Solar thermal technologies to preheat boiler water
- Wind turbines to generate electricity
- Geothermal heating and cooling
- Combustion of tallow

7.4.1 Energy and waste characteristics

Error! Reference source not found., **Error! Reference source not found.** and Table 7-46 show a breakdown of the energy used and associated costs for Plant D. While heat energy accounts for over 40% of energy used, it accounts for only about 16% of the total energy costs. Plant D is not currently required to report under the NGERS and it is unlikely to in the future even if rendering is incorporated into the site.

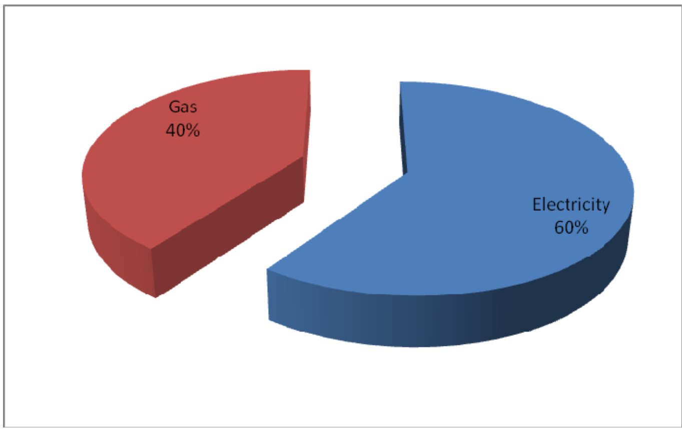


Figure 7.32: Energy use: Plant D

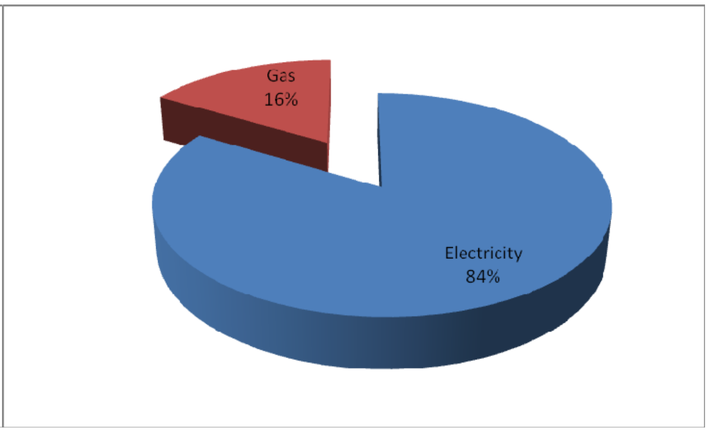


Figure 4.34: Energy costs: Plant

Table 7-46: Energy use and cost breakdown: Plant D

Energy Source	Average Usage (MJ/tHSCW)	% of Total	Cost (c/MJ)	% of Total
Electricity	1,049	59.9%	3.93	83.6%
Gas	701	40.1%	1.15	16.4%
Total	1,750	100%	2.81	100%

It is estimated that almost 70% of electricity consumed by the plant is used for refrigeration. The refrigeration system includes 4 compressors of 200kW, 250kW, 35kW and 90kW. The 200kW and 250kW are screw driven. The majority of the heat energy required by the plant is generated by a 2MW gas-fired boiler. The boiler does not produce any steam but rather produces hot water at 90°C. The average inlet flow rate for the boiler is 0.37 L/s.

The plant produces approximately 100kL of waste water per day or 25ML per year. The waste water is treated in two anaerobic ponds before being used for irrigation. The ponds are almost completely full and the plant is investigating its options for new ponds. The plant has expressed some interest in covering these new ponds to capture methane. The waste water has an average chemical oxygen demand (COD) of 8,000 kg/ML. The ponds are approximately 100 metres from the plant which should allow transport of the captured biogas back to the plant for use.

7.4.2 Options to reduce emissions and costs using EE and RE

7.4.2.1 Biogas capture for flaring

Plant D has reported a wastewater flow rate of 25 ML/yr with an average COD of 2.5 kg/kL. This equates to an annual COD input of 63 tonnes to wastewater treatment ponds. Under NGERS reporting methods, which assume a COD removal effectiveness of 40% for wastewater treatment systems at meat and poultry plants, and a methane yield of $0.35m^3CH_4/kgCOD_{removed}$, this facility emits around 134 tCO_2-e.

Due to the small size of the facility, it will not be subject to accounting requirements under the proposed CPRS. As a result, no economic benefit is available to this facility through biogas capture and flaring.

7.4.2.2 Biogas capture heat and electricity generation

The site requires the excavation of a new wastewater treatment pond. This allows for a pond to be designed such that biogas yield is optimised. Based on the wastewater flow rate given, and the optimal retention time for an anaerobic digester (40 days), a new pond of 3 ML capacity will maximise biogas yield.

Based on a cover cost of $\$80/m^2$ (AMPC 2008), excavation costs of $\$10/m^3$ (NIWA, 2008) and installation costs of $\$40/m^2$ installed, the new pond could be excavated and covered for a capital outlay of $102,000.

Based on cost estimates from UNEP (2002), biogas capture systems require capital outlay for the following components:

Technology	Cost
Gas Pipe – piping from ponds to flare at a cost of $100/m. Ponds are ~100m from site.	$10,000
Gas blower and regulator – gas pressure must be raised for pumping from ponds to boiler and generator	$15,000
Gas pre-treatment system (scrubber) - required to remove hydrogen sulphide content	$10,000
Condensate trap – to remove water content of biogas and ensure high-temperature, and thus efficient, combustion	$5,000
Gas storage system – to allow for fluctuations in yield	$15,000

Including these capital requirements with design costs of $25,000, a total capital requirement of $167,000 is estimated.

Captured gas may be used to replace fuels from external sources for heat and electricity generation. This allows for savings through the offset of fuel costs. An analysis of this strategy is discussed in the forthcoming sections.

Biogas Capture for Heat Generation

Though NGERS accounting methods assume a digester effectiveness of 40%, actual effectiveness of 80% COD removal can be expected. Thus, from the expected biogas yield, actual methane yield is expected to be 17,817 m^3CH_4/yr. With an energy content of 37.7 MJ/m^3CH_4, (DCC, 2009) around 672 GJ/yr of heat energy is available to this facility.
Heat demand at this site is serviced via boilers run on natural gas. The gas price reported at this site equates to an energy cost of $18.43/GJ. A cost benefit analysis of the installation of a heat generation through captured biogas system returned results depicted in Table 7-47. The analysis considered the following:

- Capital requirements: pond cover and gas pre-treatment (determined above)
- Revenues through natural gas offset
- O&M costs of 2.5% of capital requirements (excluding costs for pond excavation and design)

- System lifetime of 15 years
- Discount rate of 7.5%

Table 7-47: Cost Benefit Analysis of Heat Generation from Captured Biogas

Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
182,000	7,738	3,175	39.9	-$141,700

Owing to the small biogas yield, the capital costs associated with installation of this system outweigh the benefits through natural gas offset over the system lifetime.

Biogas Capture for Combined Heat and Power Generation

Captured biogas may be used to fuel a gas generator to service the electricity demand of the facility. For a gas generator efficiency of 35%, from the expected biogas yield, around 235 GJ/yr or 65,300 kWh/yr of electrical energy could be produced.

If a further 35% of energy is captured as heat through a cogeneration system, 235 GJ/yr is available as low-grade heat energy, suitable for hot (82˚C) and warm water (43˚C) raising. At a gas price of $18.43/GJ, captured heat energy is worth around $4,300/yr to this facility. Cogeneration capacity is expected to add $200/kW installed to the cost of a generator, giving a total cost estimate of $1200/kW.

Generation Scheme Analysis

An onsite generator may be operated during high tariff periods only, or continuously across all tariff periods. Assuming that in New South Wales, the high tariff period extends for 15 hrs/day on weekdays, and assuming 15min start-up and shut-down, a continuous generation scheme (24hrs/day, 365days/yr) would require a 16 kW gas generator, while for on-peak only generation (15hrs/day, 365 days/yr) a 7 kW generator would be required.

A cost benefit analysis was carried out to determine the comparative value of each generation scheme with the following considerations:

- Capital requirements for the purchase and installation of a combined heat and power generator were estimated at $1,200/kW installed.
- Capital requirements for pond cover and gas treatment/piping were determined above.
- Savings from generation through offset of grid-connect electricity were determined using generator output and a breakdown of the sites tariff structure, as well as a RECs price of $40/MWh. Tariffs were assumed to remain constant over the system lifetime.

- Maintenance costs were estimated with consideration of the need for a complete generator overhaul after 25,000 hrs of operation. An overhaul was estimated to cost half the initial capital costs of the generator.

- Generator lifetime of 15 years was used for continuous generation, and 25 years for on-peak only generation.

As this analysis does not consider the cost of gas capture, the figures reported below do not reflect the full actual project cost. As can be seen from Table 7-48, neither continuous operation or 'high tariff' operation are financially viable.

Table 7-48: Cost Benefit Analysis of continuous and high tariff generation

	Capital ($)	Revenue ($/yr)	O&M Costs ($/yr)	SPP (yr)	NPV ($)
High tariff only (16kW)	201,100	14,800	4,700	19.9	-$111,900
Continuous (7kW)	190,900	13,600	4,743	21.6	-$112,700

Note: Revenue refers to savings in grid-connect electricity consumption.

Sensitivity analysis

The following graphs present the results of a sensitivity analysis undertaken on the capture of biogas for use in a combined heat and power generator. The sensitivity analysis includes three scenarios, the assumptions used for each scenario are:

- Scenario 1: The starting price of heat energy is fixed to its current rate, the price of carbon is assumed to be $0 and the price of electricity varies from its current rate of 14c/kWh to 27c/kWh.
- Scenario 2: The starting price of electricity is fixed to its current rate, the price of carbon is assumed to be $0 and the price of heat energy varies from its current rate of $11/GJ to 16GJ.
- For each scenario the price of electricity and heat energy has been modelled at three different escalation rates (2%, 5% and 7% per year).

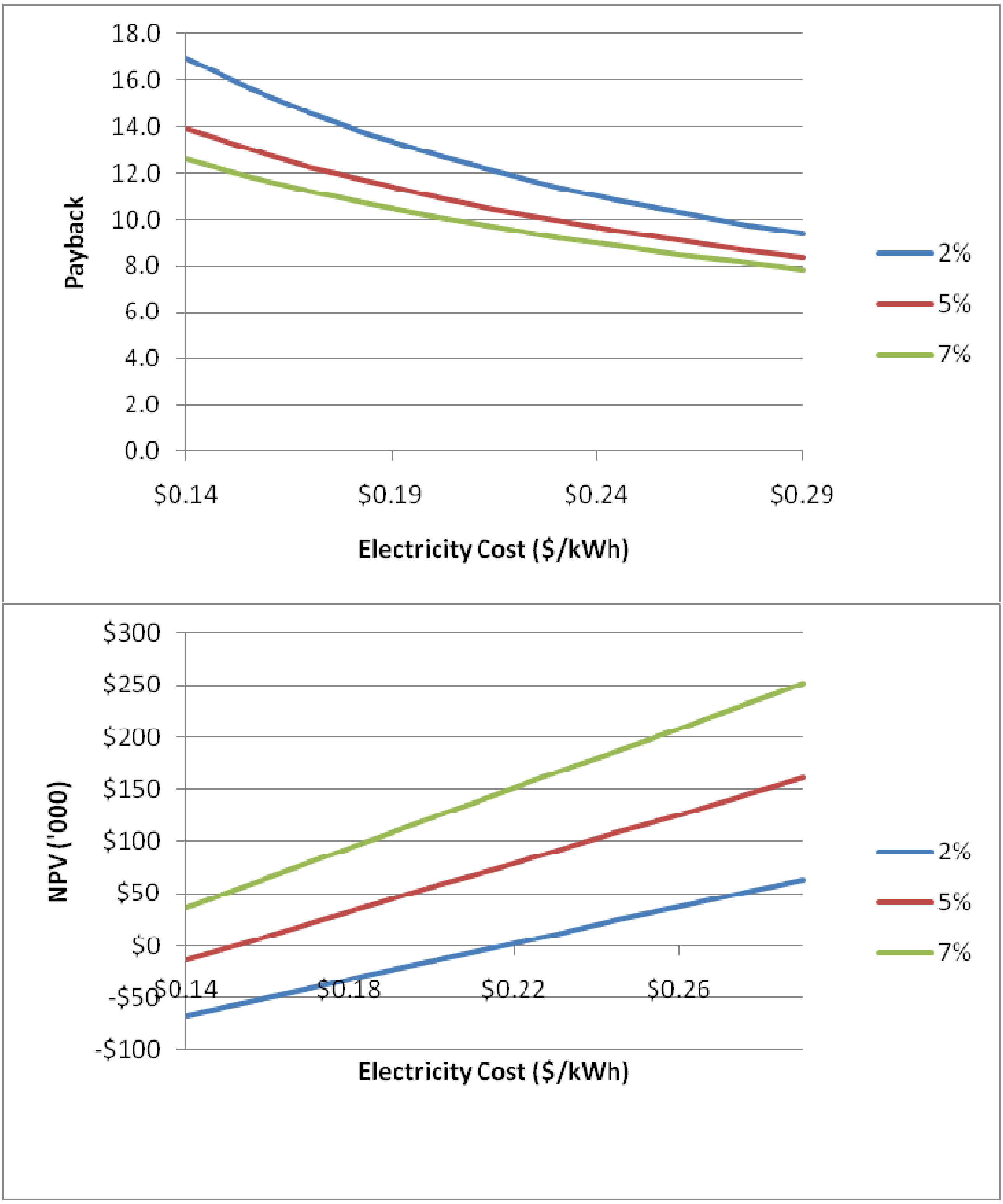


Figure 7.33: Cogeneration sensitivity analysis: Scenario 1

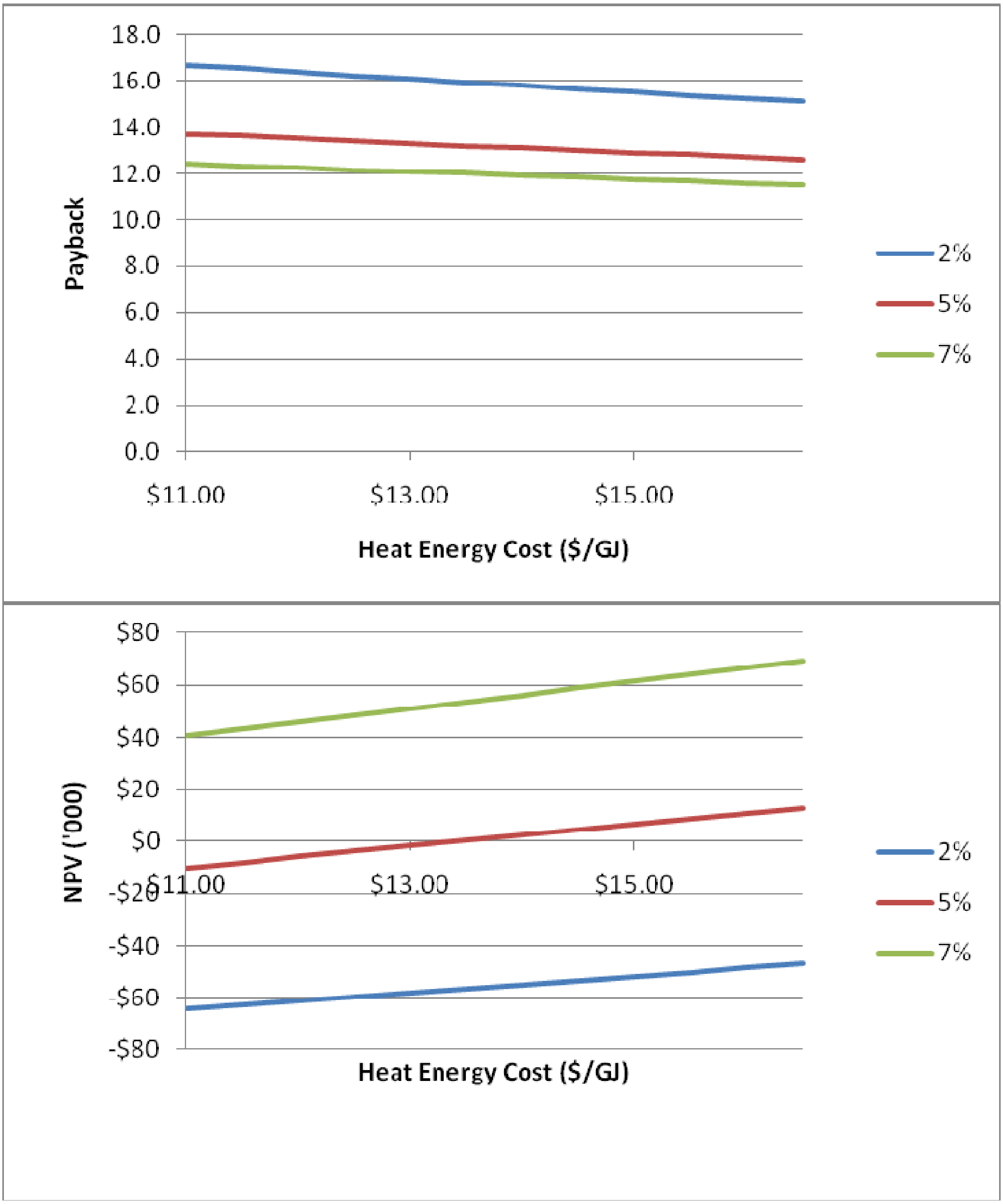


Figure 7.34: Cogeneration sensitivity analysis: Scenario 2

The results of the sensitivity analysis suggest that at Plant D the price of electricity has the greatest impact on the economics of the capture of biogas for use in a cogeneration plant.

Summary of the use of methane for heat and combined heat and power generation

From Table 7-48, it can be seen that the installation of a cogeneration unit at Plant D is not economically viable under either generation scheme. Capital and O&M costs outweigh the benefit of expected revenues through RECs sales and electricity demand offset. Additionally, no savings under the proposed CPRS are available as the emissions and energy use of the facility is well below reporting thresholds.

Biogas use in Fuel Cells

As it is not currently economically viable to capture methane from the ponds at Plant D for use in a cogeneration gas engine, it will also not be economic to incorporate fuel cells into the plant. As such the use of fuel cells at Plant D has not been investigated further at this stage. Further information of the use of fuel cells can be found in Appendix A.

7.4.2.3 Use of yard and paunch manure

Due to the small volumes involved the use of yard and paunch manure to produce energy will not be feasible at plant D. As such a detailed analysis has not been undertaken.

7.4.2.4 Use of tallow

The facility does not have onsite rendering and as such has no tallow to use for energy generation. If the plant were in incorporate rendering, further information on the use of tallow can be found in Appendix A.

7.4.2.5 Use of photovoltaics

The plant has a reasonable amount of well orientated roof space that could be used for both solar PV and solar thermal technologies. While the average electricity price paid by Plant D is the highest of all the sites visited at about 14 c/kWh, it is still unlikely that PV will be economically viable at this stage. However, PV system prices have reduced significantly in previous years and with the ever increasing cost of electricity (particularly at times of peak demand) it is likely that PV will be viable in the not too distant future.

Information obtained during the site visit suggests that Plant D could have up to 1,500m^2 of roof space suitable for the installation of PV. Depending on the spacing of PV arrays, this could accommodate between 75 – 150kW of PV. In addition, the facility is surrounded by a significant area of flat land that would be suitable for the installation of PV. The site has reasonable solar resources but is located at the foot of a nearby ridge which would provide some level of horizon shading. It is expected that this ridge would reduce the available solar resource by as much as 10%, and so it is recommended that detailed shade analysis be undertaken to quantify this before any system is installed. Taking this into consideration, a well installed system could generate approximately 1460 kWh/kWp/yr. This would correspond to a reduction in carbon emissions of approximately 1.6 tCO_2e/kWp/yr.

The demand profile of the plant indicates that peak electricity demand usually occurs in the early afternoon (around 2pm to 3pm). An analysis of the plant's current electricity tariff structure against peak usage times and PV output characteristics indicated that the potential value of PV in offsetting electricity use world be in the order of 14.5 c/kWh. For details on the methodology used to determine the economic value of PV see section 0. A summary of the economic performance of PV systems of varying size is shown in Table 7-49 below.

Table 7-49: Economic performance of different sized PV systems installed at Plant D

System size	10kW	50kW	100kW
Energy Produced (kWh)	14,580	72,900	145,800
GHG offset (tCO_2-e)	16	78	156
Cost $/W	$4.75	$4.50	$4.25
Total Cost	$47,500	$225,000	$425,000
REC Rebate (@ $40 per REC)	$13,000	$46,000	$87,000
Net Cost	$34,500	$179,000	$338,000
O&M Costs	$238	$1,125	$2,125
Income (@ 14.5c/kWh)	$2,100	$10,600	$21,100
Payback (years)	19	19	18
NPV (7.5%)	-$16,000	-$82,000	-$145,000

The above table demonstrates that the installation of PV is currently not economic at Plant D. However, independent modelling (PJPL, 2009) suggests that if an emissions trading scheme were introduced, and in conjunction with future load growth in the area, retail electricity prices could double in the next five years. In addition, PV prices have been falling steadily over the past decades and even conservative estimates would see the price continue to fall at 5% per year. If this were the case, the economics of PV would change dramatically, see Table 7-50 below.

Table 7-50: Possible future economic performance of different sized PV systems installed at Plant D

System size	10kW	50kW	100kW
Cost $/W	$3.70	$3.50	$3.30
Total Cost	$37,000	$175,000	$330,000
REC Rebate (@ $40 per REC)	$8,000	$41,000	$82,000
Net Cost	$29,000	$134,000	$248,000
O&M Costs	$185	$875	$1,650
Income (@ 29c/kWh)	$4,200	$21,100	$42,300
Payback (years)	7	7	6
NPV (7.5%)	$12,000	$72,000	$166,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of photovoltaics to generate electricity.

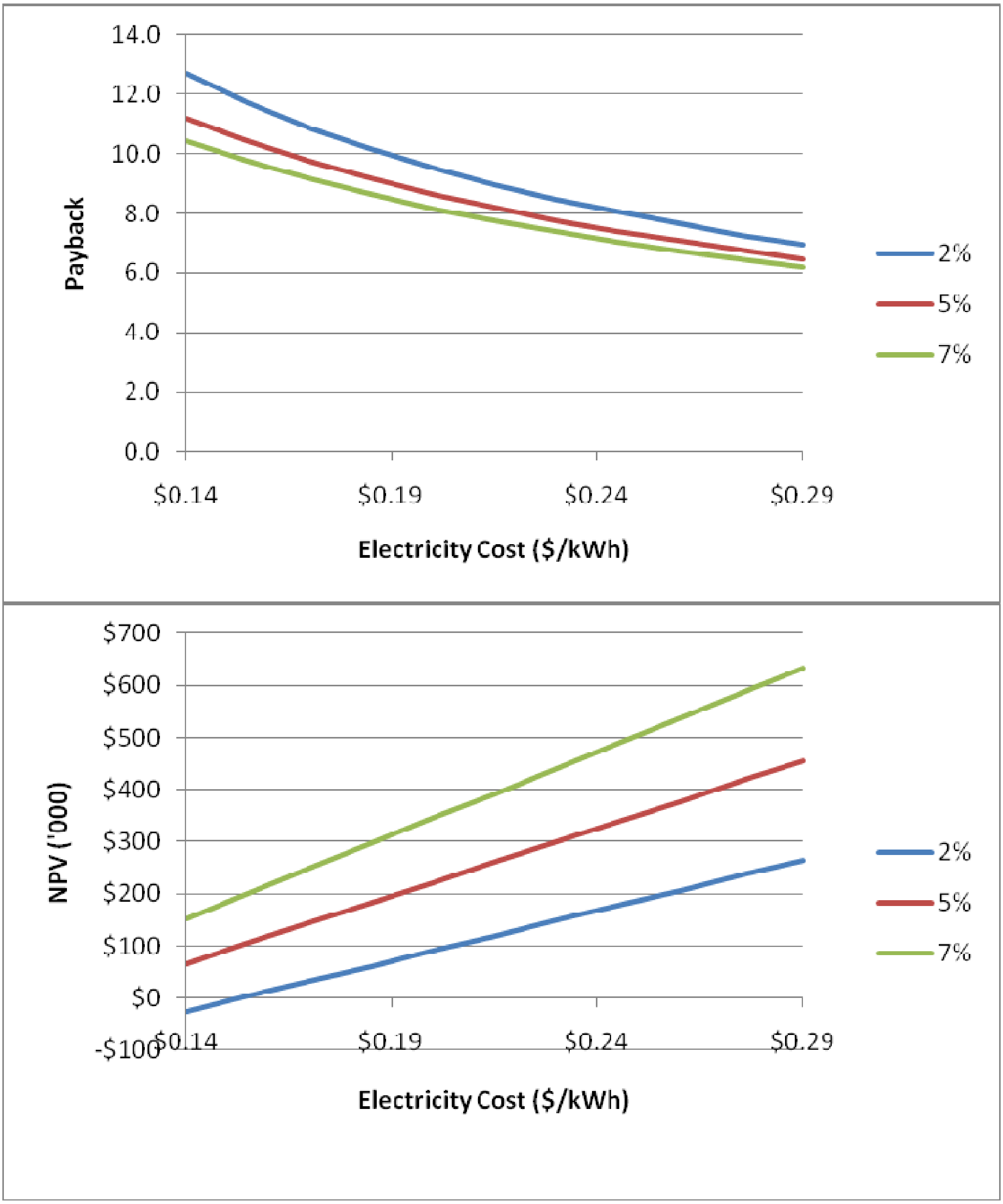


Figure 7.35: PV sensitivity analysis

7.4.2.6 Solar thermal for process heat

The use of solar thermal technologies for electricity generation is currently only economically viable on a large scale (10MW+) and as such is not suitable for use at Plant D. At the scale required for a meat processing facility, solar thermal technologies are more likely to be economically viable for heat generation.

Simple flat plate collectors are the most cost-effective method of small scale solar thermal. Flat-plate collectors could be used to preheat boiler feed water. The plant currently has a feed water rate of 32 kL/day at an average temperature of 20°C. In order to heat this water to 80°C approximately 650 m^2 of collectors would be needed and would cost in the order of $290,000 (including extra plumbing and installation). These collectors could be mounted on the roof of the facility, to minimise land use.

The assumptions and results of a preliminary economic analysis of solar thermal preheating of boiler water at Plant C are given in
Table **7-51** and Table 7-52 respectively.

Table 7-51 Assumptions used for preliminary economic analysis of preheating boiler feed water using solar flat-plate collectors.

Feed water rate	32,000 L/day
Water inlet temperature	20°C
Water outlet temperature	80°C
Average efficiency of solar collector	50%
Maximum solar radiation (summer)	6.88 kWh/m^2/day
Average solar radiation (yearly)[21]	4.40 kWh/m^2/day
Cost of gas	$11/GJ
Cost of solar collectors (installed)	$450/$m^2$
Operating days per year	250 days

Table 7-52 Preliminary economic analysis of using solar flat-plate collectors for preheating boiler feed water.

Energy savings per year	1,285 GJ
Collector area	649 m^2
Collector cost	$292,000
Cost savings per year	$14,140/year
Simple payback	21 years

As Table 7-52 shows, flat-plate collectors for preheating boiler feed water are not cost-effective given the current low price of gas. Other solar thermal technologies (parabolic troughs, heliostats, parabolic dishes) are much less economical, due to the relatively small thermal load of Plant D.

[21] The values for yearly and average solar radiation have been reduced by 10% of their nominal value to take into account the early morning horizon shading from a nearby hill.

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of solar thermal technologies to preheat boiler feed water.

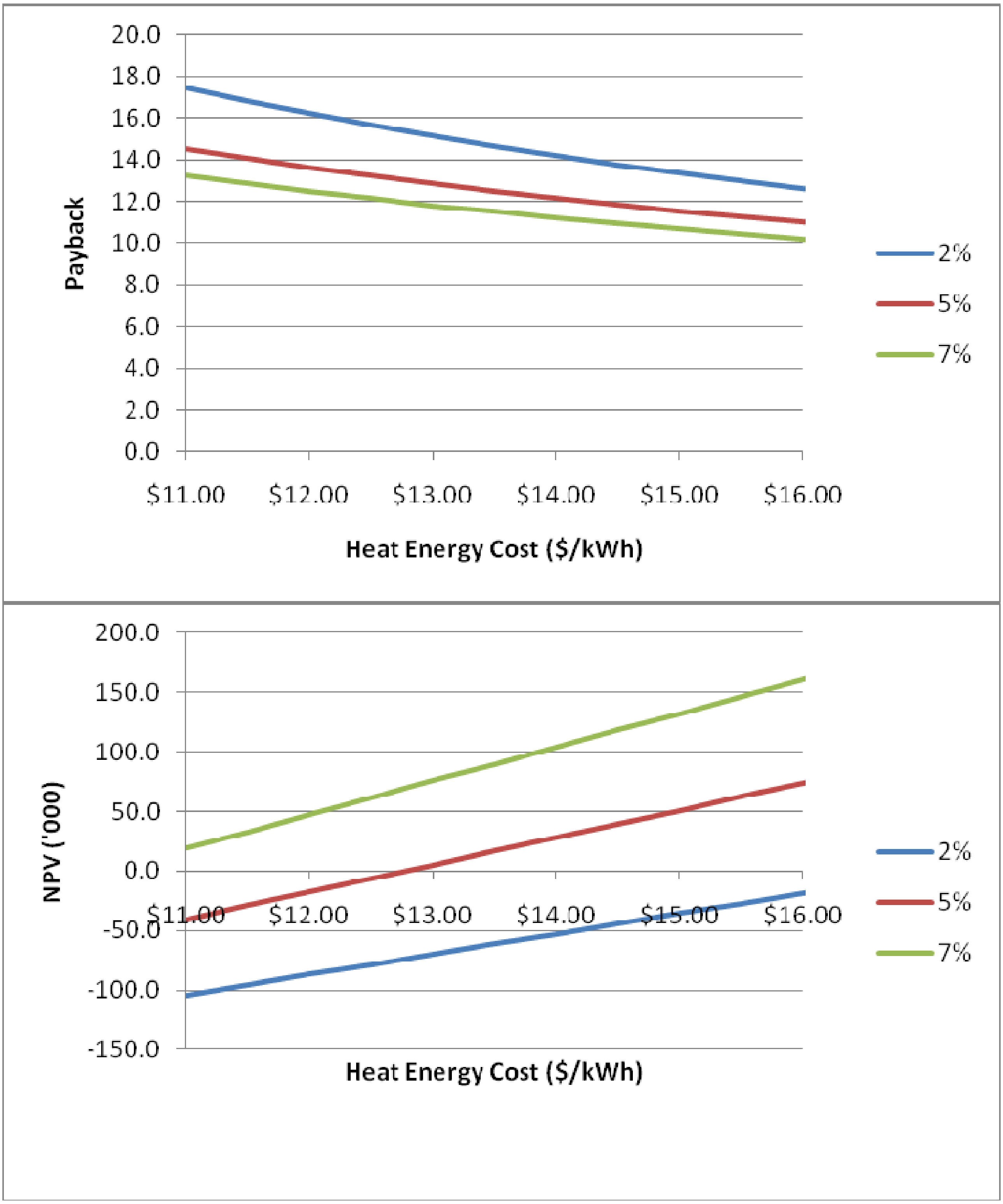


Figure 7.36: Solar thermal sensitivity analysis

7.4.2.7 Wind turbines

Another form of renewable energy that could be used to provide some of the plant's electricity is wind power. The output of wind turbines is very much related to the available wind resources and these resources vary considerably between sites. In order to fully assess the appropriateness of wind power options, detailed wind monitoring must be undertaken.

The site has a large ridge located just behind the facility, which could have significant wind resources. It is assumed that the site would have wind resources equivalent to a capacity factor of 20% to 25%[22]. If this is the case it is feasible that up to 1 MW of wind generation could be installed. Although this could be via a single 1 MW turbine, it is likely that the most appropriate solution would be to install several smaller turbines. The cost of such an installation would be between $3 and $8 per watt installed. Depending on the local planning requirements it may not be possible to install large quantities of wind power at the site. The assumptions used when assessing the economics of wind power options are given in Table 7-53.

Table 7-53: Assumptions for cost benefit analysis of wind power options

System size	500kW
Capital cost	$4/W or $2,000,000
Project lifetime	20yrs
Discount rate	7.5%
Average electricity price	12c/kWh
REC Price	$40/MWh or 4c/kWh

Table 7-54 shows the economics of installing wind turbines at Plant D for a number of different capacity factors. A capacity factor of 25%, which would be achieved at a reasonable wind site, means that the turbines produce 25% of the electricity they would if they were operating at full capacity all the time. It can be seen that wind turbines are currently not economic at Plant D.

Table 7-54: Cost benefit analysis of wind power installed at Plant D

Capacity Factor	10%	15%	20%	25%	30%
Energy Produced (kWh)	438,000	657,000	876,000	1,095,000	1,314,000
GHG offset (tCO_2-e)	469	703	937	1,172	1,406
O&M Costs	40,000	40,000	40,000	40,000	40,000
Income (@ 10c/kWh)	$70,000	$105,000	$140,000	$175,000	$210,000
Payback	67	31	20	15	12
NPV (7.5%)	-$1,694,000	-$1,337,000	-$981,000	-$624,000	-$267,000

Sensitivity analysis

The following chart presents the results of a sensitivity analysis undertaken on the use of wind turbines to generate electricity.

[22] This is an assumption only and detailed wind monitoring would need to be undertaken before any the feasibility of any wind project could be accurately assessed

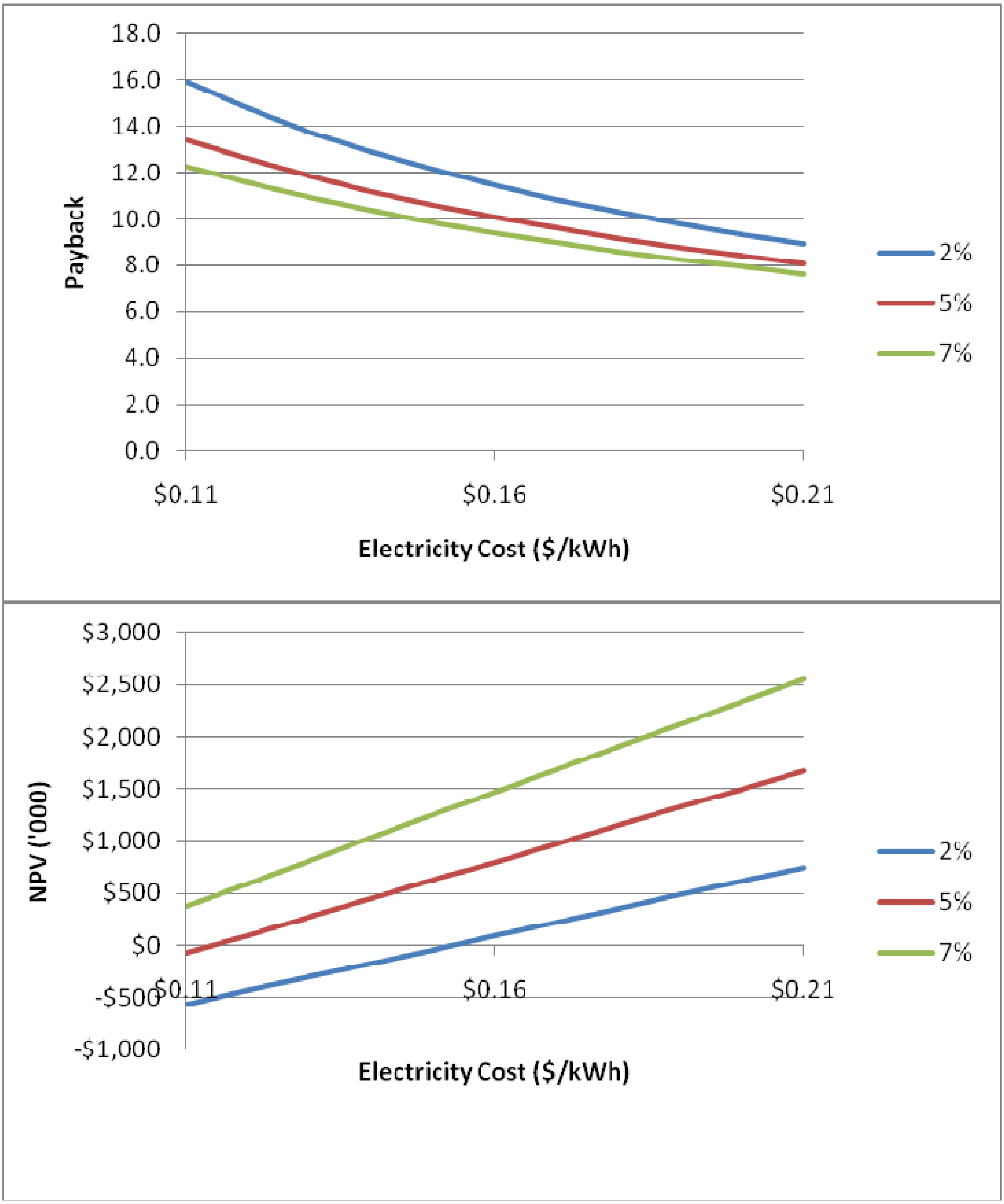


Figure 7.37: Wind power sensitivity analysis

7.4.2 Summary table for Plant D

Table 7-55 summarises the technologies assessed in this report and their potential effectiveness for use at Plant D.

Table 7-55 Summary of renewable energy technologies assessed: Plant D

Technology	Electricity Offset (kWh/yr)	Thermal Offset (GJ/yr)	Emissions Reduction (tCO_2-e/yr)	Cost Saving ($/yr)	Capital Cost ($)	Payback (yrs)
Capture of Methane from Ponds						
- Flaring	NA	NA	128	NA	NA	NA
- Heat Generation	NA	670	31	7,700	158,000	39.9
- Cogeneration	65,300	235	80	11,100	201,100	19.9
- Fuel Cell	NA	NA	NA	NA	NA	NA
Tallow	NA	NA	NA	NA	NA	NA
PV	145,800	NA	156	19,000	338,000	18
Wind	986,000	NA	1,055	118,000	2,000,000	17
Solar thermal	NA	1,285	66	14,100	292,000	21

8 Summary of findings

The study found that for plants with onsite rendering, the most economic renewable energy technology is the capture and use of biogas from effluent ponds. The most effective use of this captured biogas is in a cogeneration plant. For plants with very high gas or LPG costs it may also be viable to replace these directly with biogas. For the three sites visited that incorporated rendering, payback periods of between 3.8 years and 10.1 years were found for the use of biogas.

For facilities that use coal as their main fuel source, it may be feasible to co-fire dried yard and paunch manure with coal in the boiler. This could reduce coal use by as much as 10% but further analysis into the costs and technical issues associated with this option would be required. Generation of biogas from an anaerobic digester fuel by the manure may also be feasible but further investigation would be necessary.

The use of other renewable energy technologies is not economically feasible at this stage but with rising electricity prices it is likely that the use of PV will be feasible in the not too distant future. A summary of the individual findings for each plant are shown below.

8.1 Plant A

There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant A. The most economic of these are summarised below.

- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 3,640,000 kWh of electricity and 13,000 GJ of gas per year. It could also reduce direct emissions from effluent ponds by approximately 6,756 tCO_2-e/yr and indirect emissions (from electricity and gas use by approximately 4,560 tCO_2-e/yr). The cost of such an installation would be in the order of $3,405,000 and the project would have a simple payback period of about 5.5 years. This option would remove the vast majority of any direct liability the plant may have under the introduction of the currently proposed CPRS. It would not, however, remove the plants requirement to report under NGERS.
- Capture of biogas from paunch and yard manure through the use of a plug and flow anaerobic digester. This option has the potential to offset approximately 836,000kWh of electricity and 3,000 GJ of gas per year. The project would reduce indirect emissions by approximately 1,050 tCO_2-e/yr. Further investigation is required into the feasibility of this option.

8.2 Plant B

There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant B. The most economic of these are summarised below.

- Combustion of tallow in place of LPG. This option has potential to offset 1,490 GJ of LPG and save to plant approximately $36,300. Taking into account the lost income from tallow this would have a simple payback period of 6.0 years.
- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 1,260,000 kWh of electricity and 6,000 GJ of coal and LPG per year. It could also reduce direct emissions from effluent ponds by approximately 2,810 tCO_2-e/yr and indirect emissions (from electricity, coal and LPG use by approximately 1,750 tCO_2-e/yr). The cost of such an installation would be in the order of $793,900 and the project would have a simple payback period of about 4.4 years. This option would remove the vast majority of any direct liability the plant may have under the introduction of the currently proposed CPRS. It would not, however, remove the plants requirement to report under NGERS.
- Co-firing of dried yard and paunch manure could also be cost effective and could offset over 10% of coal used per year. This would reduce emissions by 790 tCO_2-e per year. Further analysis of the feasibility of such a project would need undertaken.

8.3 Plant C

There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant A. The most economic of these are summarised below.

- Installation of PV at sites adjacent to main facility, as these sites are separate to the main facility they may be eligible for the Queensland net Feed-in-Tariff of 44 c/kWh. There are four potentially suitable sites owned by the plant. This option has the potential to offset approximately 198,000 kWh of electricity and reduce emissions from electricity use by approximately 200 tCO_2-e per year. The cost of the installations would be in the order of $450,000 and the project would have a simple payback period of 5.7 years.
- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 8,120,000 kWh of electricity and 29,000 GJ of gas per year. It could also reduce direct emissions from effluent ponds by approximately 16,300 tCO_2-e/yr and indirect emissions (from electricity and gas use by approximately 9,700 tCO_2-e/yr). The cost of such an installation would be in the order of $6,680,000 and the project would have a simple payback period of about 7.4 years. This option would remove the vast majority of any liability the plant may have under the introduction of the currently proposed CPRS.

8.4 Plant D

There are a number of renewable energy technologies that could be used to reduce the energy use and emission at Plant D. However, at this stage none of them are economically viable. The options that are closes to being economic are:

- Covering of effluent ponds to capture methane for use in a combined heat and power generator. This option has the potential to offset approximately 65,300 kWh of electricity and approximately 235 GJ of gas per year. It could also reduce direct emissions from effluent ponds by approximately 128 tCO_2-e and indirect emissions (from electricity and gas use by approximately 80 tCO_2-e). The cost of such an installation would be in the order of $201,000 and the project would have a simple payback period of about 19.9 years.
- The use of wind turbines to generate electricity for use within the plant. This option has the potential to offset approximately 986,000 kWh of electricity use and reduce emissions by approximately 1,055 tCO_2-e. The cost of such an installation would be in the order of $2,000,000 and the project would have a simple payback period of about 17 years.

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10 Appendices

10.1 Appendix 1 - Acronyms

AC	Alternating Current
CH_4	Methane
CO_2	Carbon dioxide
COD	Chemical Oxygen Demand
CPRS	Carbon Pollution Reduction Scheme
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CSP	Concentrated Solar Power
DC	Direct Current
EE	Energy Efficiency
ESAS	Environmental Sustainability Action Statement
ETS	Emissions Trading Scheme
FCE	Fuel Cell Energy
FiT	Feed-in Tariff
GHG	Greenhouse Gas
GJ	Gigajoule
HSCW	Hot Standard Carcase Weight
kJ	Kilojoule
kW	Kilowatt
LPG	Liquefied Petroleum Gas
MCFC	Molten Carbonate Fuel Cell
MJ	Megajoule
MMA	McLennan Magasanik Associates
MW	Megawatt
NGAF	Nation Greenhouse Accounts Factors
NGERS	National Greenhouse and Energy Reporting Scheme
NPV	Net Present Value
O&M	Operation and Maintenance
ORER	Office of the Renewable Energy Regulator
PAFC	Phosphoric Acid Fuel Cell
PV	Photovoltaic
QREP	Queensland Renewable Energy Plan
RE	Renewable Energy
REC	Renewable Energy Certificate
RET	Renewable Energy Target
SGU	Small Generation Unit
SOFC	Solid Oxide Fuel Cell
SPP	Simple Payback Period
UTC	United Technologies Corporation

VS	Volatile Solids

10.2 Appendix 2 - Renewable energy technologies relevant to the meat processing industry

A number of well proven and cost-effective renewable energy technologies can be used at meat processing facilities to provide electricity and possibly direct heat, and often are. The most prospective are currently bioenergy, solar thermal, photovoltaics and wind energy.

The MLA report *Review of Waste Solids Processing and Energy Capture Technologies* (GHD, 2005) discussed in great detail the various sources of organic waste as well as the technologies and processes that can be used to convert them into useful forms of energy, including biodiesel. Similarly, the report *Red Meat Processing Industry Energy Efficiency Manual* (Hydro Tas, 2008) covered suitable energy efficiency technologies and processes in great detail.

Thus, the following firstly summarises then provides more detail on solar thermal, photovoltaics and wind energy.

- Solar thermal can be used either as a source of hot water or to generate electricity. The use of solar hot water systems is one of the most cost-effective renewable technologies currently available. Solar thermal electric technology (using concentrated sunlight to super heat water which is in turn used to run a steam turbine) may also have some potential, however, it is not currently widely used in Australia.
- Photovoltaic modules can be used to produce electricity directly from the sun. While these systems only produce power during sunlight hours their output profile often closely matches that of a meat processing facility. In addition, they reduce the electricity purchased at peak tariffs, further adding to the system's cost-effectiveness.
- Wind turbines are a well proven technology and can be a cost-effective renewable energy option. However, the effectiveness of wind power systems is very much site specific and as such detailed wind monitoring is needed before the suitability of a site can be determined.

Renewable energy options currently of less relevance to the meat processing industry include:

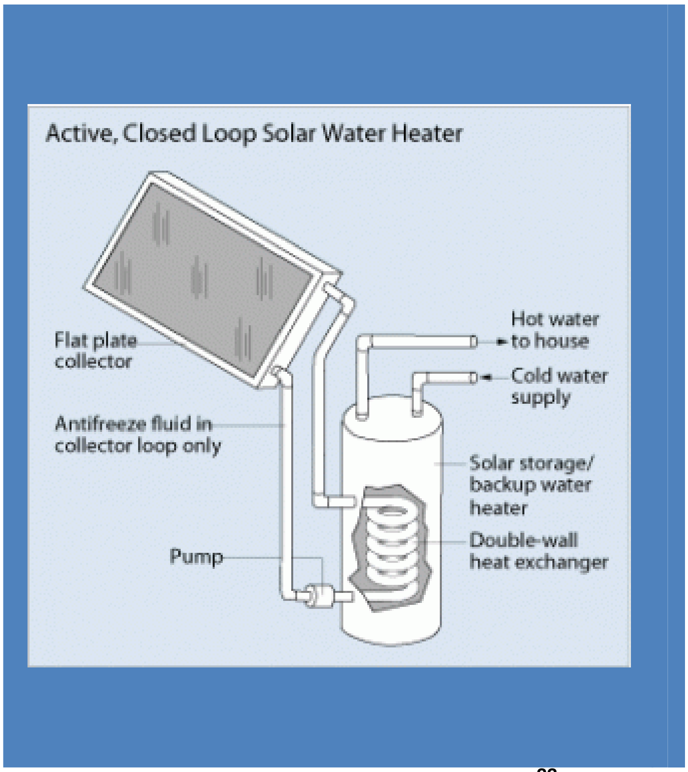
- Geothermal power: this is only feasible at certain locations with access to sources of relatively deep high temperature rock and is only cost-effective at large scale (i.e. tens of MW)
- Hydro power: this is only feasible where there is access to either a fast flowing river or a significant drop of water.
- Marine power: is an emerging area with technologies still in the demonstration phase and is only feasible where there is access to the ocean.

The report *Review of Waste Solids Processing and Energy Capture Technologies* (GHD, 2005) discussed the various sources of organic waste as well as the technologies and processes that can be used to convert them into useful forms of energy.

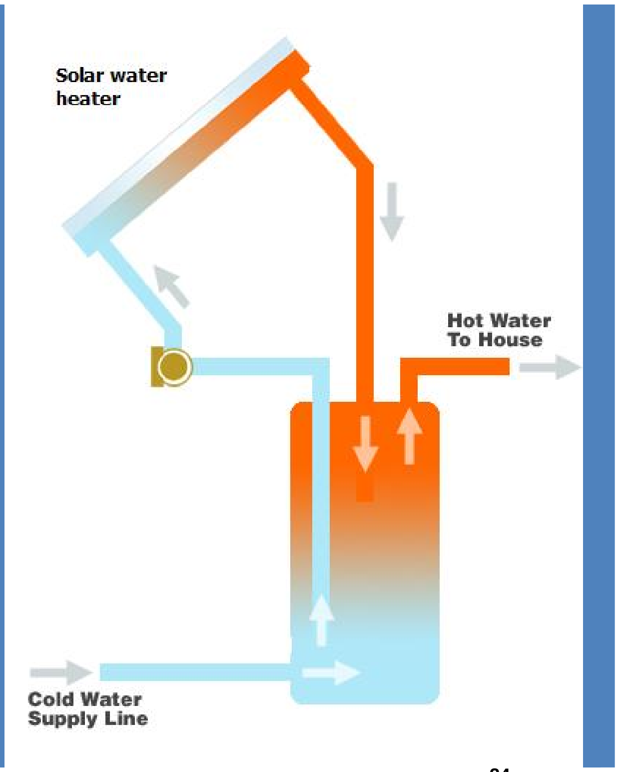
Solar Thermal
Solar thermal technologies use heat from the sun to directly heat a fluid, which is then used to create steam (for power generation), to create hot water (domestic hot water, preheating boiler feed water, space heating), or for underground thermal storage (to preheat feed water or ventilation air in the winter). There are two broad categories of solar thermal technologies: low temperature (below 150°C) and high temperature (over 500°C).

Low-temperature solar thermal technologies

The most common examples of this type of technology can be seen on the roofs and pools of homes in Australia. Solar water collectors are used to heat water for domestic use, either for drinking or for space heating in the winter. They can either be closed loop (for use in climates when freezing is a concern – the thermal fluid is typically glycol) or open loop (in warmer climates, where the water can be directly heated by the solar collector). Examples of each type are shown below.



Closed loop solar water heater [23]



Open loop solar water heater [24]

There are two main types of solar collector: flat plate collectors, which consist of a flat black plate painted black with a copper pipe welded behind it, and vacuum tube collectors, which consist of a series of double-walled glass vacuum tubes, with the inside tube painted black to better absorb solar radiation. Flat plate collectors tend to be cheaper but slightly less efficient than vacuum tube collectors. However, vacuum tube collectors have the advantage of being able to replace individual tubes should one break, whereas flat-plate collectors need to be replaced in their entirety should they break. Collectors generally require pumps and a backup source of heat for cloudy days.

[23] http://www.energysavers.gov/your_home/water_heating/index.cfm/mytopic=12850

[24] http://www.atlassolarinnovations.com/solar-water-heating-choices/

Flat plate collectors (with hot water tanks on top) [25]

Vacuum tube collector (with hot water tank on top) [26]

These collectors are not designed to create steam, and therefore do not operate past 120°C (water boils at a higher temperature under pressure). If a higher temperature is needed, or if steam is required (for power generation, for example), a high-temperature solar thermal technology is required.

High-temperature solar thermal technologies

These technologies are typically used for power generation by boiling water or a thermal fluid (such as liquid sodium, as the temperatures obtained in these systems can reach up to 3,800°C) which in turns boils water via a heat exchanger. The steam that is created is then fed into a turbine that drives a generator. High temperature solar technologies are only possible if the sun's energy is concentrated onto a very small area; therefore these technologies are also known as Concentrated Solar Power, or CSP.

An advantage that CSP technologies have over photovoltaic power generation is that they can store heat during the day and use it at night to create electricity. They therefore create a smoother power output (passing clouds will drastically affect the power output of a photovoltaic plant, but not a CSP plant) and can generate power 24 hours a day. Overall efficiency is usually better, with values of around 30% achievable.

These systems are only economical on a large scale (over 50 MW) as they require dedicated maintenance staff and the cost of mirrors is high. Furthermore, these technologies require direct solar radiation (they do not work in cloudy conditions, although they can tolerate short moments of passing cloudiness), and must therefore be placed in sites with low cloud cover, such as the desert. It is for these reasons that CSP technologies are not appropriate for meat processing facilities, which typically require much less power and heat than such power stations would provide.

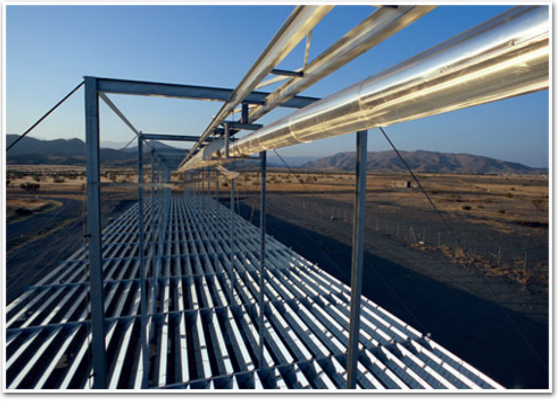
[25] http://www.solar-best.com/References.html

[26] http://www.sz-wholesale.com/shenzhen_China_products/Solar-Water-Heater_1.htm

Different types of CSP technologies are shown below:

Parabolic trough collectors. The sun's rays are concentrated on a pipe containing the thermal fluid [27]

Solar tower, or heliostat, which uses an array of mirrors to concentrate solar energy on top of a tower [28]



A Fresnel mirror. Solar energy is concentrated on the pipe running along the array (at top of picture) [29]

The Suncatcher, which uses a Stirling engine at the focal point of the parabolic mirror. It is an efficient way of generating electricity, although it can only work during the day [30]

[27] http://www.renewablepowernews.com/archives/422

[28] http://heatusa.com/blog/us-economics/google-major-renewable-energy-sources-corner/

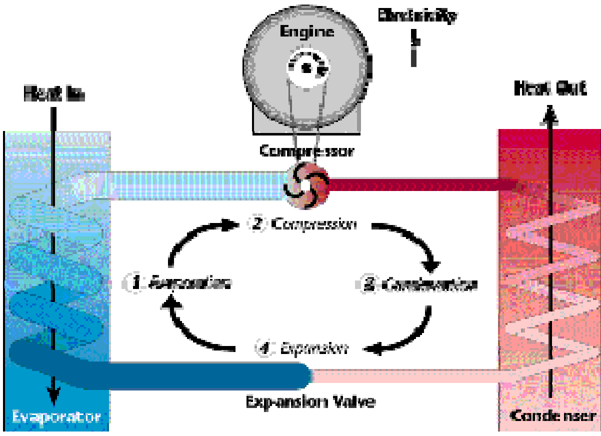
[29] http://www.rtcc.org/2010/html/solar-power-group.html

[30] http://www.sandia.gov/news/resources/news_releases/new-suncatcher-power-system-unveiled-at-national-solar-thermal-test-facility-july-7-2009/

Ground Source Heating/Cooling

Ground source heat pumps are an efficient method of providing space heating and cooling using relatively stable underground soil temperatures to heat or cool air to a comfortable temperature.

At depths greater than a few metres, the temperature of the ground remains relatively stable throughout the year. In southern Australia, this temperature is consistently in the range of 18-20°C. A ground source heat pump operates by extracting this heat through a series of pipes or coils, buried at a depth of approximately 100m.

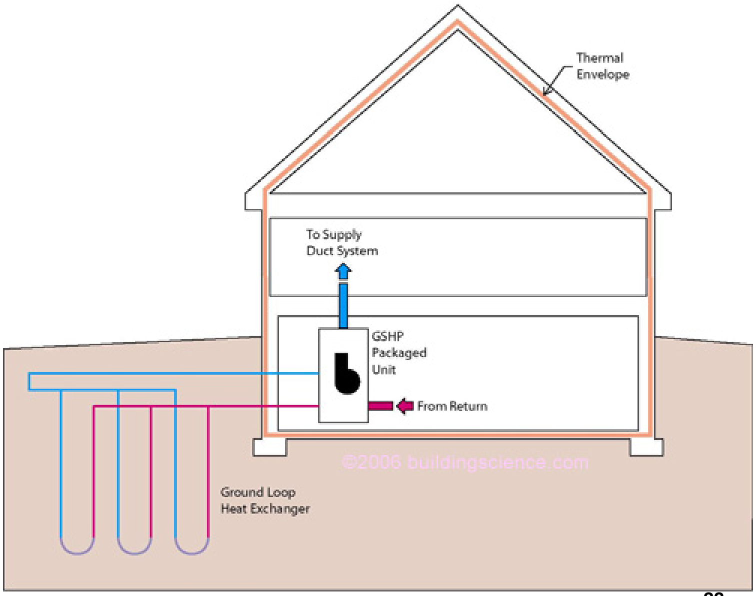


Basic Heat Pump [31]

Heat pumps use a compression and expansion cycle to transfer low temperature heat from one source to useful heat where it is required. The figure below shows a standard vapour compression cycle. A working fluid with a low evaporation temperature is used in the compression cycle. The working fluid passes through the evaporator coil at a lower temperature than the surroundings (in this case, the ground). Heat is transferred from the ground to the fluid, causing the fluid to evaporate and become vapour. The vapour passes through an electric-powered compressor which compresses the vapour and increases its temperature. The compressed vapour then passes through the condenser coil and condenses to fluid form, releasing heat to the surroundings in the process. Finally, the compressed fluid passes through an expansion valve. Now cold and uncompressed, it returns to the evaporator coil to begin another cycle.

When a ground source heat pump is in heating mode, the piping located in the ground act as the evaporator and the condenser piping is exposed to air in the location that is to be heated. When it is in cooling mode, the cycle is run in the reverse direction with the above ground coil acting as the evaporator and the in-ground piping acting as the condenser. In this case, cold fluid passes through the warm room, extracting heat and evaporating in the process. The vapour is compressed, then passes through the cooler ground and condenses, releasing its heat.

[31] From www.heatpumpcentre.org



Heat pump: standard vapour compression cycle[32]

The compressor capacity and fluid flow rate affect the performance of the heat pump as a system. The steady-state performance of an electric compression heat pump at a given set of temperature conditions is referred to as the coefficient of performance (COP). It is defined as the ratio of heat energy delivered by the heat pump compared to the electrical energy used to power the compressor. Standard heat pumps typically have COPs in the range of 2.5-5, meaning that for every MJ of electrical energy consumed, the heat pump produces 2.5-5MJ of heat energy. The operating COP of the system should be optimised for the climactic conditions; in the case of MLA's plants, heat pumps would be used primarily for space cooling.

Due to the increased efficiency obtained from using ground temperature for heat transfer, ground source heat pumps used for cooling typically consume approximately half the power of conventional reverse cycle air conditioners.

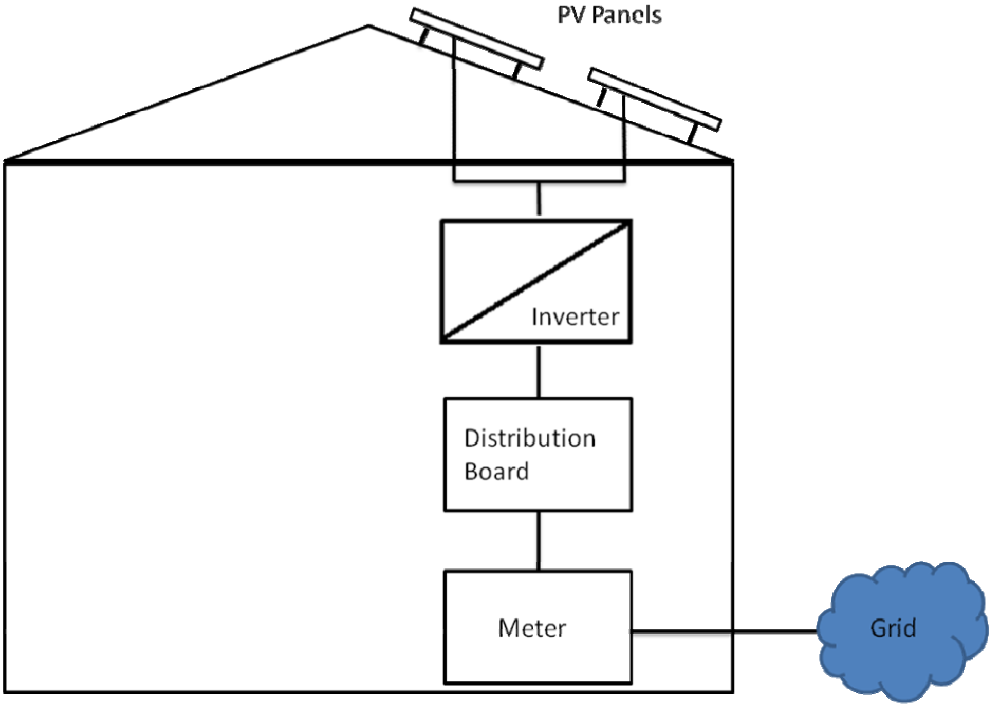
Photovoltaics

Photovoltaic (PV) modules or solar cells produce electricity directly from the sun through a process called the photovoltaic effect. The standard components of a PV system are:

- Solar modules
- Mounting frame
- Inverter (used to convert the DC electricity produced by the solar modules in AC electricity)
- Cabling and miscellaneous components

The figure below shows the basic configuration of a grid-connected PV system.

[32] BuildingScience (2006)



Traditionally solar cells have been made using either mono-crystalline or poly-crystalline silicon. However, more recently second and third generation technologies incorporating more novel technologies are also becoming more widely used. Second generation technologies include amorphous silicon Cadmium Telluride and Copper Indium (Gallium) Diselenide. Third generation technologies include dye sensitised solar cells, organic cells and nano-technology.

PV modules can either be installed on a building or ground mounted on a frame. The installation of the modules on the roof of a building can reduce mounting costs and increase the overall cost effectiveness of the system. The modules are ether mounted on a fixed frame or on a tracking system. The figure below shows examples of both fixed installations and tracking systems.

a) Fixed roof-top PV installation (Powersmart Solar); b) Ground mounted PV installation with duel-axis tracking (IT Power)

The amount of space required for the installation of a PV system depends on the angle at which the panels are tilted. For a flush mounted system (no additional tilting above that of the roof) the space required is approximately 8 – 15 m^2 per kW. From the sites visited the available roof area for insallation of PV varied from 1,500 to 10,000 m^2, this would correspond to between 150 to 1,000 kW of PV. In addition all sites visited had substantial land surrounding the facilities that could be used for ground mounded PV arrays. It is estimated that this adjacent land could hold between 200 and 10,000 kW of PV, depending on the facility.

Solar PV array orientation has the largest effect of energy yield. Typically, fixed PV arrays are oriented for maximum annual yield, with the array inclination favouring the summer period where radiation levels are higher. The inclination at which maximum yearly yield is achieved is approximately equal to the latitude of the site. The table below shows the percentage of maximum yield that can be achieved for various fixed arrays relative to an optimal inclination and azimuth of 30° facing north. A fixed PV array may also be oriented to maximum yield at one point during the day when electricity demand is highest (eg during peak production time) or electricity tariffs are at a peak.

Effect of Azimuth (orientation) and Inclination on the annual yield of a fixed grid tie array

Inclination \ Azimuth	-90°	-60°	-30°	0°	30°	60°	90°
0°	90%	90%	90%	90%	90%	90%	90%
15°	88%	93%	96%	98%	96%	93%	88%
30°	83%	92%	98%	100%	98%	92%	83%
45°	77%	88%	95%	97%	95%	88%	77%
60°	69%	80%	87%	90%	87%	80%	69%
75°	60%	70%	77%	78%	77%	70%	60%
90°	51%	59%	63%	63%	63%	59%	51%

Tracking systems can increase the yield of the system by up to 35% over a fixed installation but also introduce a greater cost and more complexity into the system.

The output from a PV system is directly related to the prevailing weather conditions and will vary throughout the day and over the course of the year. As such the output of a system will vary considerably between locations across Australia. Indicative outputs for PV systems installed a different locations are shown in the table below.

Specific output of PV systems for different locations

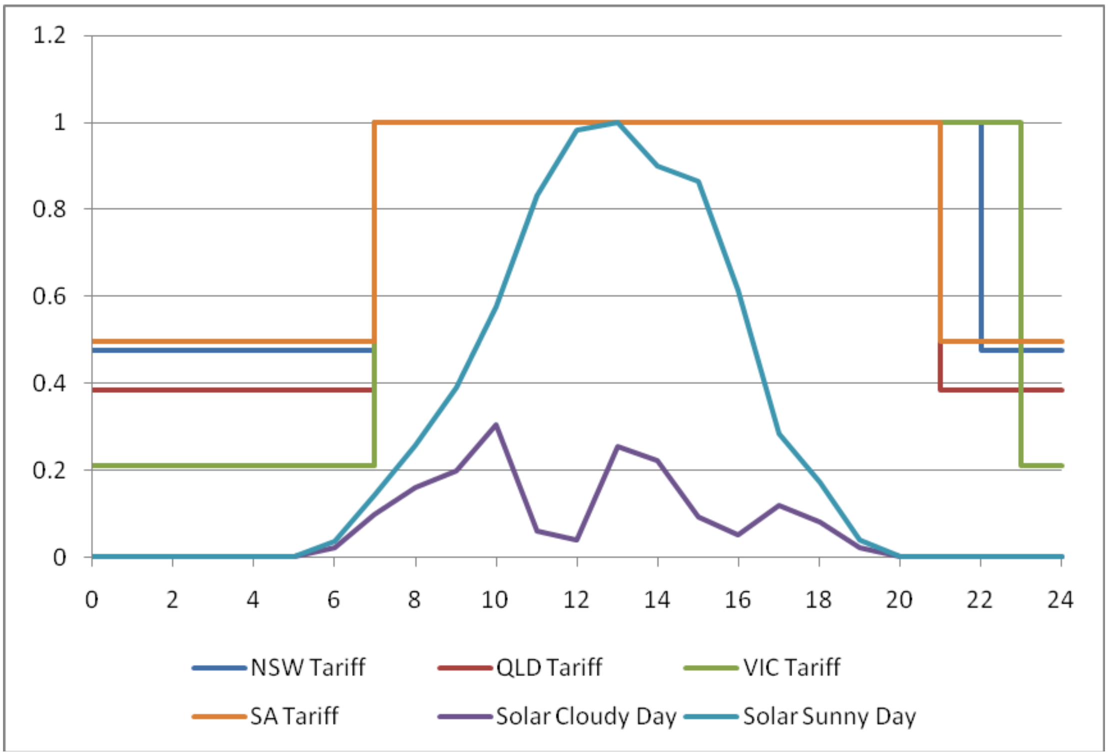
Location	Output (Clean Energy Council)[33] kWh/kWp/yr	Output (RETScreen)[34] kWh/kWp/yr
Adelaide	1470	1550
Alice Springs	1660	1940
Brisbane	1410	1600
Cairns	1350	1640

[33] Output figures taken from, *Electricity from the Sun – Solar PV systems explained*, 3rd Edition, June 2008, Clean Energy Council

[34] Output figures based on modelling undertaken using RETSceen and based on an inclination for all sites of 22°

Canberra	1450	1620
Darwin	1570	1720
Geraldton	1690	1850
Hobart	1180	1350
Melbourne	1230	1380
Perth	1350	1620
Sydney	1460	1500
Wagga Wagga	1480	1620

One of the advantages of PV systems is that the output typically aligns well with peak electricity tariffs and this increases the value of the electricity generated. Typical daily output profiles for a system are shown against time of use tariffs for selected states in the figure below. It demonstrates that almost all output from a PV system would go towards offsetting electricity purchased at the peak tariffs, which are between 2 to 5 times higher than the off-peak tariffs. In addition, PV systems can also effectively reduce the maximum daily electricity demand of the facility, which further adds to the value of the generated electricity.



Normalised electricity tariffs versus solar output for a typical sunny cloudy day.

Assumptions of cost benefit analysis of PV

The following assumptions were used in assessing the cost benefit analysis of PV for all sites considered.

System size	10 to 500kW
Capital cost	$4.75 to $4.00/W
Project lifetime	20yrs
Discount rate	7.5%
Average electricity price	As per plants tariff structure
REC Price	$40/MWh or 4c/kWh

Wind

Introduction

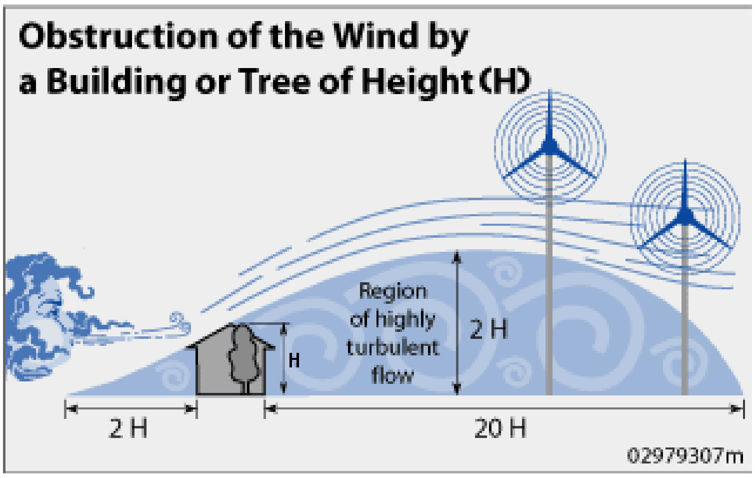
For centuries, the power of the wind has been harnessed for milling grain, pumping water and other applications through windmills. In recent years, wind has become one of the world's leading renewable sources of electricity. Wind turbines use large blades to turn a turbine, similar to that used in a hydro-electric or gas generator, to create electricity. The reliability of wind turbines as a source of energy depends heavily on location.

The wind resource

Australia has significant wind resources, which have been the subject of several detailed studies. The CSIRO's Wind Resource Document identifies approximately 50% of Australia's wind generating capacity to be in South Australia, with the Victorian and NSW coastlines also providing good wind resources.

Wind resources are dependent upon geography, air density and temperature. While wind speed typically varies throughout the day and year, over the long term wind speeds and availability are regular and predictable. In coastal areas, regular sea breezes are generated by the difference in temperature between the land and the sea.

Wind maps for each state are available from state governments and are useful in selecting an appropriate site. Local (site specific) features must also be taken into account to ensure that wind flows are not obstructed. An obstruction to wind flow creates a turbulent region twice as high as the obstruction as illustrated in the figure below.



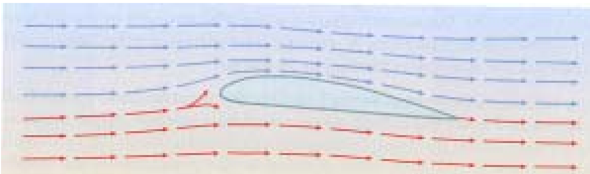
Effect of obstructions to the flow of wind (CWS, 2009)

The theoretical energy available from wind is expressed as a quantity of air passing through a cylindrical area at a certain speed. The power available is expressed by the equation

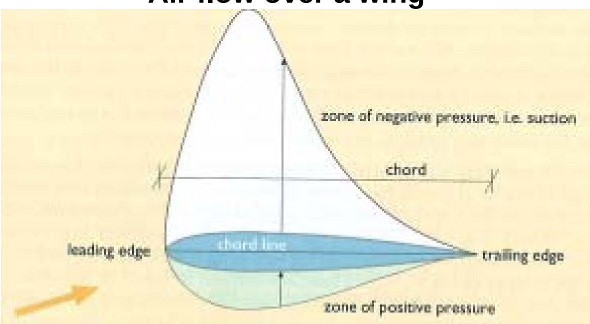
$P = 0.5\rho AV^2$ where
P = Power in Watts;
p = air density in kg/m^3
A = Area in m^2
V = Velocity in m/s

Turbine technology

Wind turbines transform the kinetic energy of the wind into electrical energy via a turbine. The actual energy produced from a wind turbine depends on the aerodynamics of the blade and the efficiency of the rotor. Modern blade design draws on the principles employed in aircraft wing design, using changes in pressure caused by air flow over an airfoil to create lift – see figures below.



Air flow over a wing[35]



Positive and negative pressure zones created by air flow over a wing[35]

[35] Boyle (2004)

Many wind turbine designs have been proposed, and several types are in common use. The most widely used wind turbine design is the triple-blade horizontal axis turbine. These turbines consist of a three blades turning a turbine at the top of a pole. Industrial scale turbines are typically mounted on an 80m pole with blades and are rated at 1-3MW production.

Typical three blade industrial scale wind turbines[36]

Fuel Cells

An alternative to using a engine to generate electricity from captured biogas would be to use fuel cells. The use of biogas in fuel cells is an emerging market and there a few plants currently in operation. A number of waste water treatment plants in the US currently use fuel cells powered by biogas. US manufacturers that supply fuel cell power plants for use with anaerobic gas digesters include:

- FuelCell Energy, Inc. (Molten Carbonate Technology)
    - Danbury, Connecticut
    - Power Plants Sizes: 300 kW, 1.4 MW, and 2.8 MW
- UTC Power, Inc. (Phosphoric Acid Technology)
    - South Windsor, Connecticut
    - Power Plant Size: 400 kW
- ONSI Corporation (Phosphoric Acid Technology)
    - Portland, Oregon
    - Power Plant Size: 170 kW

[36] Cogan (2008)

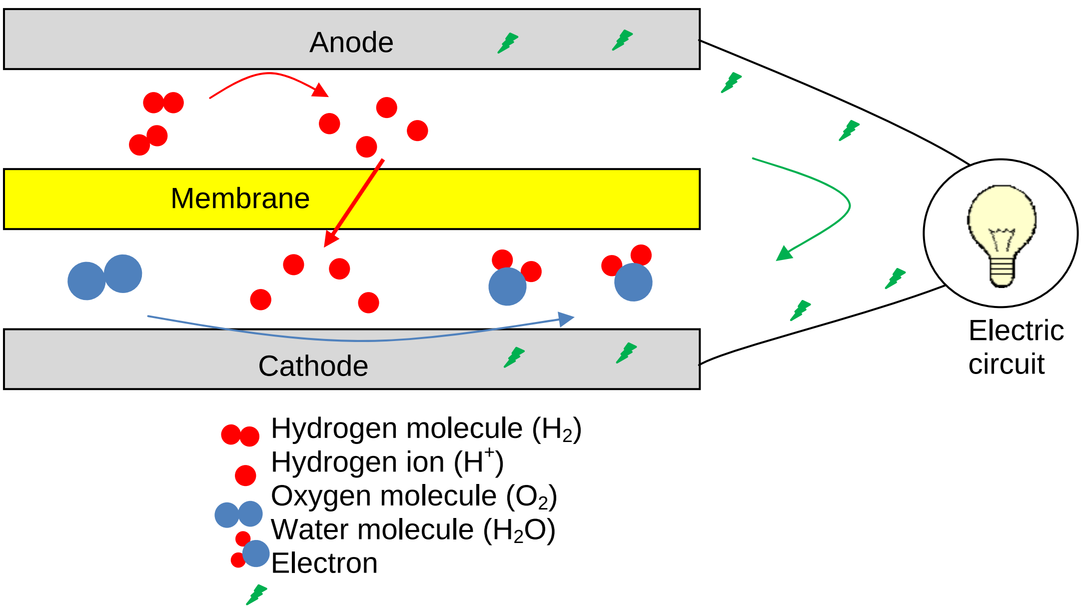
One of the advantages that fuel cells have over gas engines is greater electrical conversion efficiency. Fuel cells operate with electrical conversion efficiencies of up to 42 to 47% and with combined heat and electrical efficiencies of approximately 80% (NREL 2009).

Technology

Fuel cells work on the principle of electrochemically breaking down a source fuel into its component ions on a catalyst on one side of an electrolyte or membrane. The electrons that result from this breakdown are then fed through a circuit and recombine on a catalyst on the other side of the electrolyte. Several types of fuel cells exist, but can be broken down into two categories: proton-exchange membrane fuel cells (PEM fuel cells), which are more suited for transportation applications due to their small size and low operating temperatures, and high-temperature fuel cells, which are suited for stationary power generation due to their size (up to 100 MW for some technologies) and high operating temperatures.

PEM fuel cells

This type of fuel cell uses hydrogen as a fuel. The hydrogen gas enters the fuel cell and gets broken down into hydrogen ions and electrons by a catalyst at the anode. The hydrogen ions can pass through the membrane, but the electrons cannot as the membrane is electrically insulating. To recombine with the hydrogen ions, the electrons pass through an electric circuit (thereby powering electrical appliances) to reach the cathode. There, the electrons and the ions combine with oxygen molecules on a catalyst to create water.



PEM fuel cells are the type that is being used on automobile manufacturers' concept cars. However, the technology still has some major hurdles before it becomes mainstream, including the high cost of the membrane, the short lifespan of the fuel cell, the sensitivity to contaminants such as carbon monoxide, and the relatively slow startup. There is also debate as to the overall efficiency of the system, as hydrogen is not naturally occurring and needs to be created, thus consuming energy.

Other types of proton exchange fuel cells exist, such as direct-methanol fuel cells. These generally use liquid hydrocarbons as a fuel and emit water and carbon dioxide. They have the advantage of having a more energy-dense and easily transportable fuel than hydrogen fuel cells. However, they emit carbon dioxide, which may be problematic in enclosed spaces, and are less efficient than hydrogen PEM cells.

High-temperature fuel cells

Solid oxide fuel cells (SOFC)
Solid oxide fuel cells use a ceramic electrolyte to drive the reaction. They can handle a wide range of hydrocarbon fuels, and are not susceptible to carbon monoxide poisoning and are resistant to sulphur. They operate at very high temperatures (around 1000 °C), meaning that the hydrocarbon fuel can be directly fed into the fuel cell and easily be dissociated to produce hydrogen gas. The efficiency of these systems is higher than that of a PEM fuel cell, but the high operating temperatures mean that start up time is long; furthermore, few materials can operate for extended periods of time at these temperatures, so need to be frequently replaced. SOFCs have an electrical efficiency of 50-60%, and a cogeneration efficiency of 80-85%

Molten carbonate fuel cells (MCFC)
This type of fuel cell uses a molten carbonate salt as an electrolyte. They operate at temperatures of around 600 °C, and like SOFCs, their high operating temperature can internally reform hydrocarbon fuels to create hydrogen gas. MCFCs are not prone to carbon monoxide poisoning, but cannot handle sulphur very well. Consequently, they may not be suitable for using coal-derived gas as a feedstock. Their high temperatures and corrosive electrolyte shorten the lifespan of the cells, so maintenance requirements are higher than lower temperature fuel cells. Their electrical efficiency can reach 60%, and when combined with cogeneration can be of 85%.

Phosphoric acid fuel cells (PAFC)
This type of fuel cell works the same way as a PEM fuel cell. Hydrogen gas is broken down into hydrogen ions, pass through the electrolyte, and combine with oxygen molecules to create water at the cathode. They operate at higher temperatures than PEM fuel cells (around 200 °C), but not so high that they can reform hydrocarbon gases to create hydrogen; consequently they need a reformer to create hydrogen gas from hydrocarbons. This is the most mature fuel cell technology for stationary applications (they are large and heavy, making them impractical for transportation applications), and is being developed commercially. Their electrical efficiency is comparable to that of a standard power plant, at around 40%.

Tallow
The high energy content of tallow makes it an attractive option as an energy source, particularly for meat processing and/or rendering facilities located in remote regions. Energy stored within tallow may be burnt directly for heat generation, or converted to biodiesel. At present, within Australia, waste-to-energy technologies are rarely used by meat processors. However, with rising electricity costs and obligations under NGERS, strategies which can offset energy use and emissions must be investigated.

Tallow for Heat Generation

Typical properties of tallow against conventional fuels for heat generation are given in the table below.

	Diesel	Light Fuel Oil	Heavy Fuel Oil	Tallow
Ultimate composition (%)				
Carbon	86.3	86.2	86.1	70
Hydrogen	12.8	12.4	11.8	11
Sulphur	0.9	1.4	2.1	0
Oxygen	0	0	0	19
Specific gravity at 15.5°C	0.830	0.895	0.949	0.920
Calorific value (kJ/kg)	45,700	44,200	43,100	40,000
(kJ/L)	39,700	39,500	40,400	36,800
Combustion air requirements:				
kg dry air/kg fuel	14.40	14.20	14.00	15.60
m^3 air/kg fuel (0°C, 760 mm Hg)	11.09	10.99	10.85	12.04
Composition of wet flue gas (%)				
Carbon dioxide (CO_2)	13.4	13.6	13.8	13.9
Water (H_2O)	12.0	11.7	11.3	13.1
Sulphur dioxide (SO_2)	0.1	0.1	0.1	0
Nitrogen (N_2)	74.5	74.6	74.8	73.0
Flash point (°C)	75.5	79.4	110.0	288 - 316

Physical and combustion properties of tallow and three grades of fuel oil[37]

Tallow can be seen to have greater air requirements for efficient combustion than conventional liquid fuels. The high flash point also requires that furnace temperatures are maintained upwards of 300˚C to ensure efficient combustion.

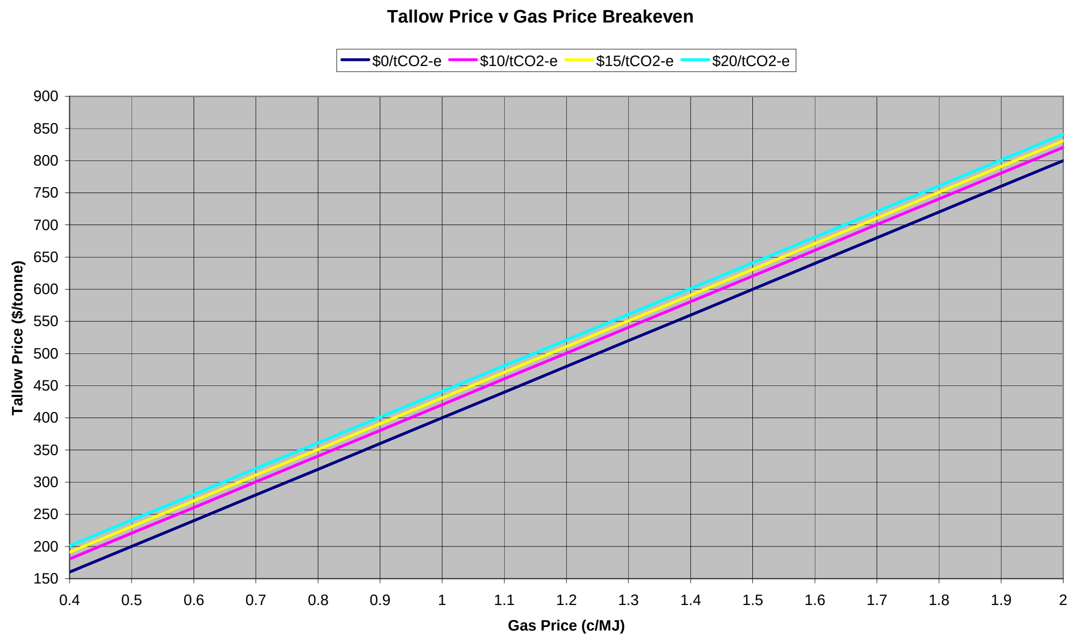
Upgrading existing boilers for tallow combustion is fairly simple. Oil boilers will require either the addition of a fuel pre-heat system and a pipe post-flush system to avoid solidification of tallow within feed pipes. This may be avoided by using an alternative fuel at boiler start-up and shut-down, provided that this heats pipes sufficiently to melt tallow. Gas boilers will also require the addition of a spray injection system which will allow for the tallow to be combusted efficiently.

According to the Eco-Efficiency Manual for Meat Processing published by the MLA in 2002, a typical meat processor will require 236,667 MJ of potential heat energy per day. As a typical plant processes 625 head per day, this equates to a heat energy demand of 379 MJ per head. As the energy content of tallow is 40 MJ/kg, a tallow yield of 9.5 kg/head will be sufficient to provide all potential heat energy required. The average tallow yield per head processed is significantly higher than this, indicating the potential for tallow to service a plant's heat energy demand completely.

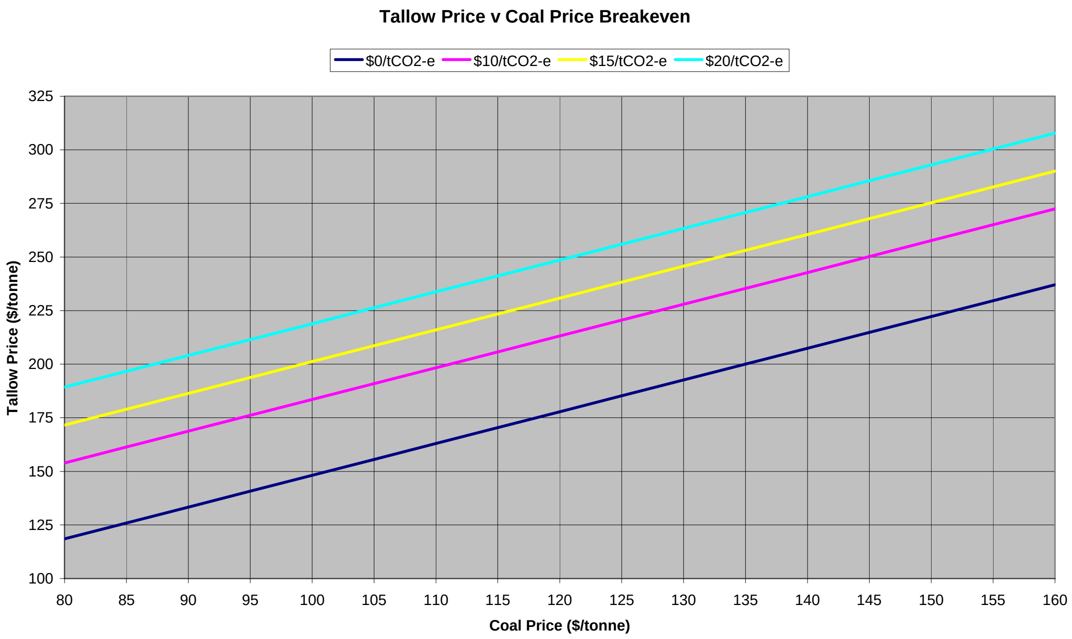
[37] FSA (2002)

Currently, it is unlikely that this is a cost-effective strategy for many meat processors in Australia owing to low gas prices (~0.9 c/MJ) and high tallow prices (~$750/tonne = 1.875 c/MJ). The strategy would likely be cost effective for lower grades of tallow, but their suitability as a substitute fuel in boilers has not been studied in great depth. Though the energy content of low grade tallow is expected to be comparable, the effect of fatty free acids and other impurities would require further investigation.

With the proposed introduction of an ETS, natural gas prices would be expected to increase. The chart below depicts the breakeven point, for various permit prices, when the running cost of heat generation through tallow combustion equals the running cost through networked natural gas combustion. Below each line indicates when tallow combustion is more cost effective than natural gas combustion.



Replacing coal with tallow as a heat energy source is extremely unlikely to be cost effective given current coal prices (~$110/t = 0.41 c/MJ) Additionally, the necessary boiler modifications to convert to tallow combustion would also be extensive. Though the proposed ETS is expected to impact coal price more significantly than other, cleaner fuels, considering the current tallow price, the impact can be seen to be unlikely to make this a cost effective strategy.



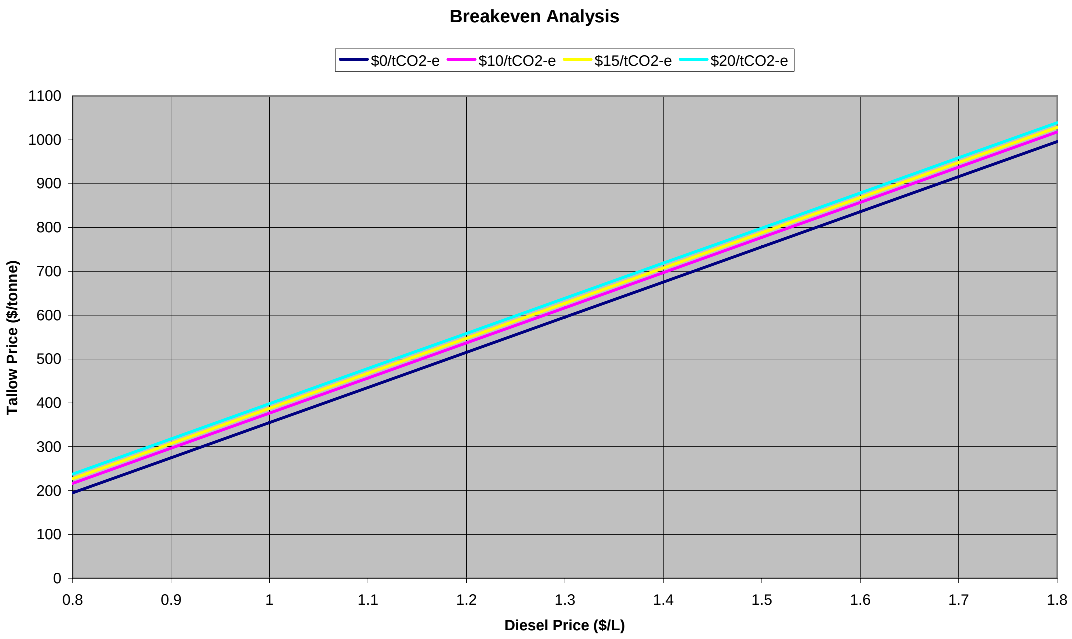
Purely in terms of emission reduction, however, using tallow to substitute traditional fuels is a very effective strategy. At present, the National Greenhouse Accounts Factors (NGAF) do not provide an emissions factor for tallow combustion, as it is rarely used for heat generation in Australia. However, the factor can be estimated by using that given for biodiesel produced from tallow – 0.4 kgCO_2-e/GJ. Compare this with emissions factors for natural gas combustion, 51.33 kgCO_2-e/GJ, for fuel oil combustion, 73.13 kgCO_2-e/GJ, or for black coal combustion, 88.43 kgCO_2-e/GJ.

Tallow for Biodiesel

Tallow can be converted to biodiesel via a simple chemical reaction involving methanol and a catalyst (usually sodium hydroxide or potassium hydroxide). The process is referred to as transesterification and is simple enough to be operated on any scale. However, tallow used in production is required to be of a high grade as fatty free acids inhibit the necessary reaction.

Using a tallow price of $750/tonne, the apparent cost of producing tallow is estimated to be $1.34/L. If this figure is adjusted to account for the lower energy content of biodiesel (34.6 MJ/L) than conventional diesel (38.6 MJ/L), this apparent cost becomes $1.49/L. If consumed on site, biodiesel producers can avoid the fuel excise of $0.38/L. However, current fuel rebates also allow for this excise to be avoided if traditional diesel is consumed onsite, negating the value of onsite production. Accordingly, with the current fuel rebate scheme, and at current tallow prices, biodiesel production from tallow is not a cost effective strategy.

The introduction of an ETS is not expected to significantly affect the viability of this strategy. Diesel price would be expected to raise 2.7c/L at a carbon emission permit price of $10/t$CO_2$-e and 5.4c/L at $20/tCO2-e. The chart below depicts the breakeven point between the cost of buying diesel and the cost of producing biodiesel from tallow, depending on the carbon emission permit price.


Breakeven Analysis
$0/tCO2-e
$10/tCO2-e
$15/tCO2-e
$20/tCO2-e
Tallow Price ($/tonne)
0
100
200
300
400
500
600
700
800
900
1000
1100
0.8
0.9
1
1.1
1.2
1.3
1.4
1.5
1.6
1.7
1.8
Diesel Price ($/L)

10.3 Appendix 3- Government policies that support renewable energy

The only Commonwealth government policy that provides financial value to the renewable energy systems most likely to be used by meat processing facilities is the Renewable Energy Target. As discussed below, although most states offer Feed-in Tariffs, these are unlikely to be available to meat processing facilities. Queensland, NSW and Victoria offer some targeted support to renewable energy projects, and some meat processing facilities have already taken advantage of them.

Renewable Energy Target (RET)

The Australian Government has expanded the Renewable Energy Target (RET) to 45,000 GWh by 2020. This is intended to increase the amount of renewable generation from current levels of around 8% of total generation to 20% by 2020. The RET will continue to use the Renewable Energy Certificate (REC) mechanism, with each MWh of renewable energy generation eligible to create one REC.

REC multipliers (also known as Solar Credits), are available to PV systems, wind turbines and micro-hydro systems for the first 1.5 kW of capacity, as shown in Table 0-1. Output from capacity above 1.5kW is eligible for 1 REC per MWh. Although it is likely that most renewable energy systems installed at meat processing facilities would be significantly greater than 1.5kW, Solar Credits still provide some additional revenue from the first 1.5kW. Homeowners, schools, community groups, businesses and developers are all eligible for Solar Credits.

Table 0-1 Solar Credits Available from 2009/10 to 2014/15

Year	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	From 2015-16 onwards
Multiplier	5	5	5	4	3	2	No multiplier

Creating and selling REC's

Under the RET, renewable energy power stations are divided into Small Generation Units (SGUs) and power stations – see Table 0-2.

Table 0-2 Criteria for Classification as a Small Generation Unit

System type	System capacity and annual electricity output	Installation periods
Small wind turbines	No more than 10 kW and a total annual electricity output less than 25 MWh	On or after 1 April 2001
Solar (photovoltaic) systems	No more than 100 kW and a total annual electricity output less than 250 MWh	On or after 14 November 2005
Solar (photovoltaic)systems	No more than 10 kW and a total annual electricity output less than 25 MWh	Between 1 April 2001 and 13 November 2005
Hydroelectric systems	No more than 6.4 kW and a total annual electricity output less than 25 MWh	On or after 1 April 2001

If you have an SGU, there are two ways to create and sell RECs – 'agent assisted' or 'individual trading'. Using the agent assisted method, you would find an agent and assign your RECs to the agent in exchange for a financial benefit which could be in the form of a delayed cash payment or upfront discount on your SGU. With individual trading, you would create the RECs yourself, find a buyer then sell and transfer them in the REC Registry. These options are summarised in Figure 0.1 and described in detail at the 'SGU Owner's Guide' section of the Office of the Renewable Energy Regulator (ORER) website.[38]

If your system is classified as a power station, it must become accredited according to criteria set by ORER. RECs can then be created using the internet-based registry system, know as the REC-registry.[39] You would then sell them as described above for 'individual trading'. An Annual Electricity Generation Return must be lodged with ORER by 14 February each year. More information on this process can be found at the 'Power stations' section of the ORER website.[40]

[38] http://www.orer.gov.au/sgu/index.html

[39] https://www.rec-registry.gov.au/

[40] http://www.orer.gov.au/generators/index.html

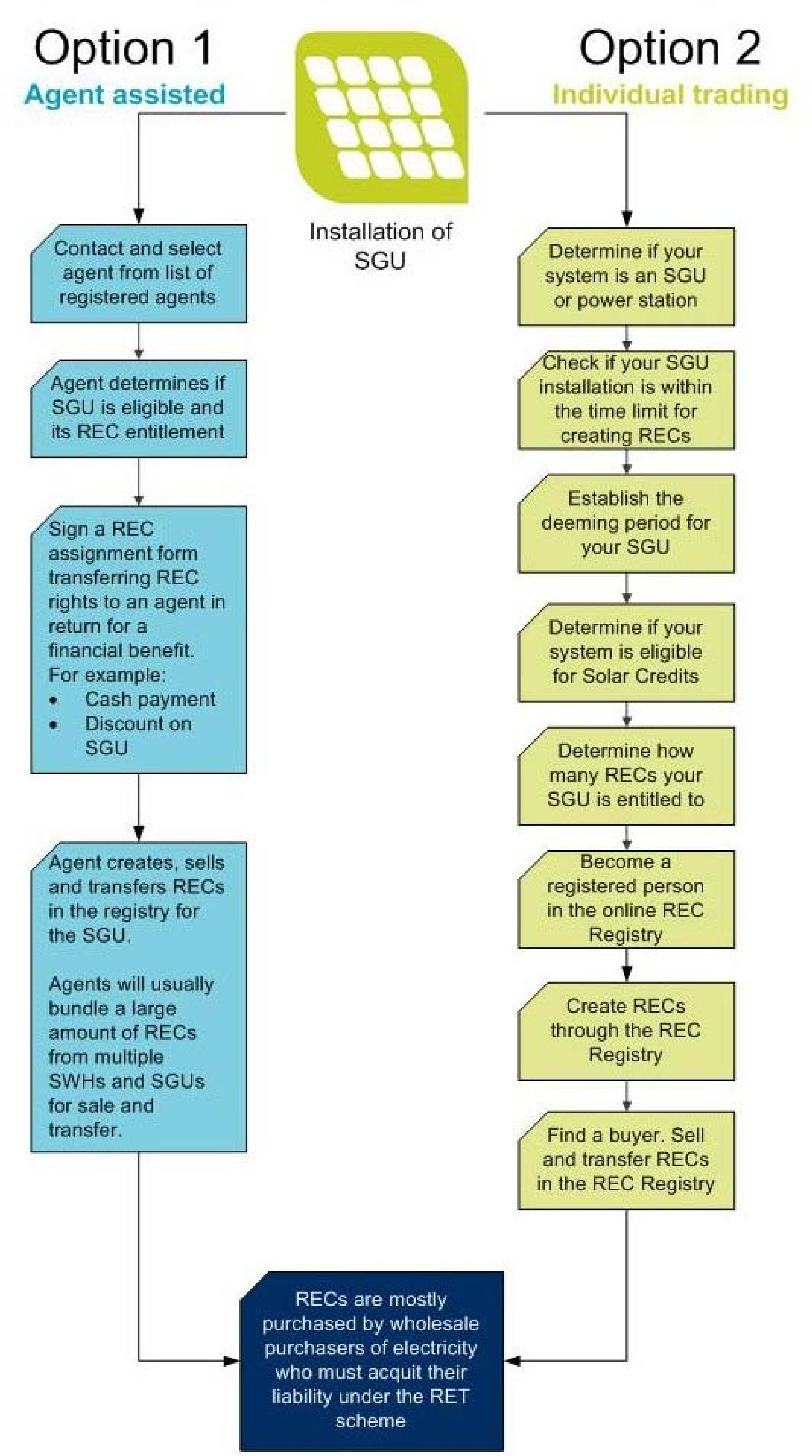


Figure 0.1 SGU Process: Options for gaining financial benefits from RECs

REC Revenue

The revenue you would receive from RECs is simply the amount of renewable energy generation (in MWh) multiplied by the price you receive per REC (plus any additional revenue fro Solar Credits). The amount you receive per REC will depend on negotiations with an agent and/or a buyer, but the spot price can be used as a guide. The spot price has historically been very volatile, being influenced by changes to the scheme as well as the perception that enough RECs have been created to meet the target – see Figure 0.2. The spot price is currently around $35. Figure 0.3 shows some REC price forecasts by MMA (2009), EDL (2009) and internal estimates by IT Power (2010).

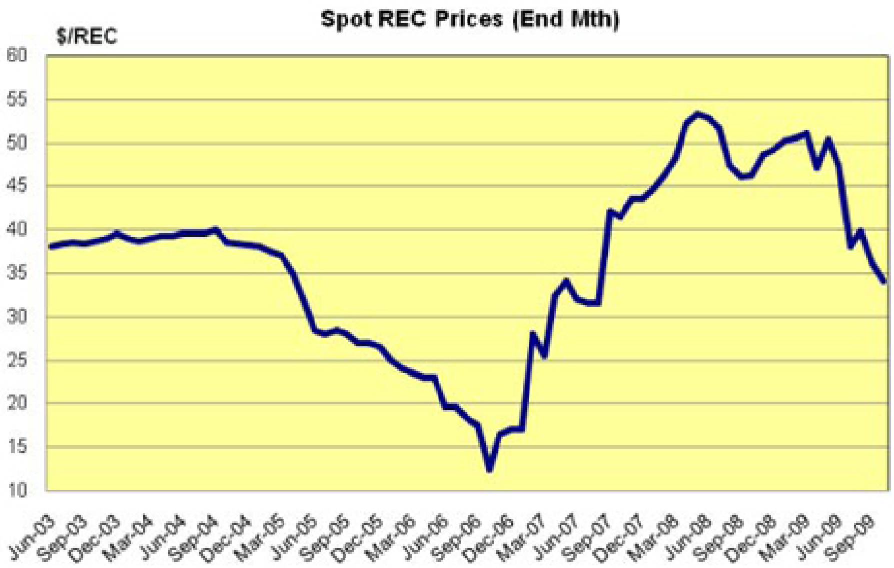


Figure 0.2 Historical REC Spot Prices[41]

[41] From http://www.greenenergytrading.com.au/

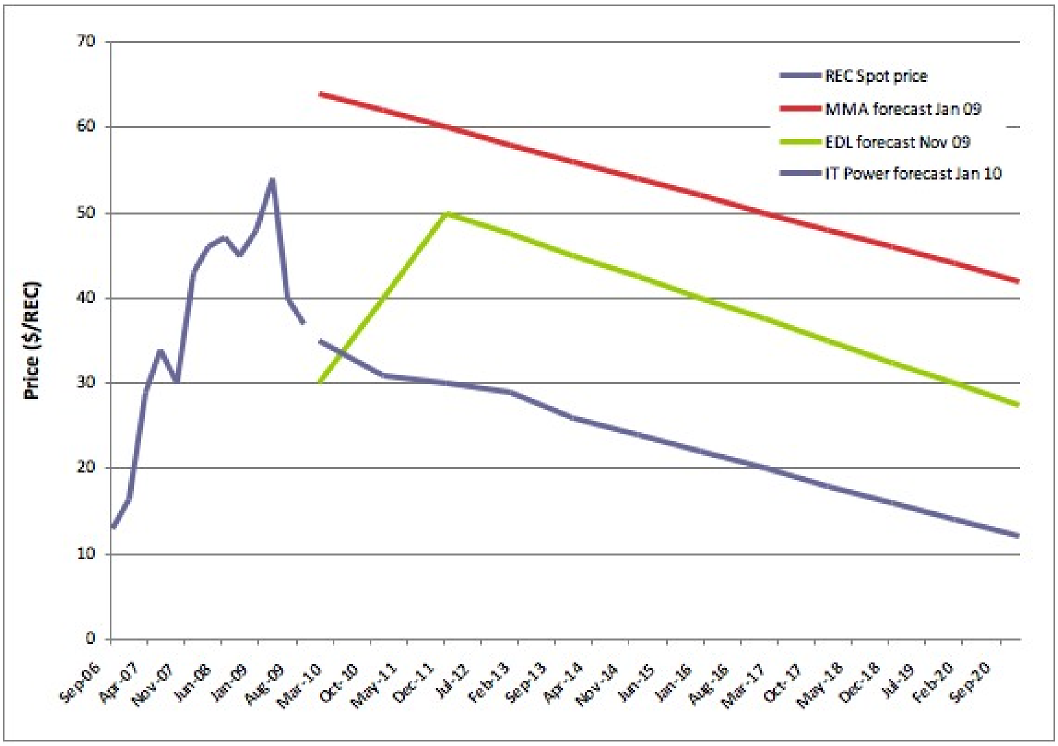


Figure 0.3 Historical REC and various REC price forecasts

The MMA forecast (January 2009) is high as it was before the May 2009 Budget which included generous rebates for solar hot water and heat pumps and the Solar Credits. Solar hot water systems plus heat pumps create a significant proportion of RECs and the number of Solar Credits is also growing exponentially. The solar hot water/heat pump rebate is due to end on 30 June 2012 while the Solar Credit multiplier is reduced gradually from July 2012 to June 2015.

The EDL forecast (November 2009) is more recent but does not document why they expect REC prices to rise over the next two years. They may be factoring in optimistic assumptions about removing solar hot water and heat pumps from eligibility. Their assumptions about the CPRS start date would also effect forecast REC prices.

IT Power does not share this optimistic view and expects REC prices to continue to decline as solar hot water, heat pumps and small-scale renewable generation continue to create a significant proportion of the required RECs. Wind developments will also play a key role in the supply of RECs. While the price path is likely to be more volatile than the IT Power forecast and the start of the CPRS has not specifically been included, these are the values used in our calculations for the case studies.

Feed in Tariffs

A Feed-in Tariff (FiT) is a mechanism by which renewable energy generators are paid a premium rate for either all the electricity they produce (a gross FiT) or only the electricity they feed into the electricity grid (a net FiT - electricity generated minus electricity used). FiTs are currently in operation in over 40 countries around the world.

There is currently no national FiT in Australia but each state and territory has introduced their own scheme. Table 0-3 outlines the current FiTs operating in the Australia.

Apart from the ACT, all jurisdictions either limit the FiT to residential systems or to facilities that use less electricity than most meat processing facilities in Australia. One possible exception to this is WA which is still designing its FiTs. As a result, FiTs are unlikely to be available to meat processors. In addition, most FiTs only apply to excess electricity exported to the grid, and limit the size of the system such that they are unlikely to generate more than would be used on site. Again, the WA commercial FiT may be an exception to this.

Table 0-3 Feed-in-Tariffs in Australia

State	Start date	Max Size	Rate Paid	Duration	Eligibility	Model
ACT	March 2009	30kW	50.05c/kWh up to 10kW and 40.04c/kWh up to 30kW [a]	20 years	All	Gross
NSW	Jan 2010 [b]	10 kW	60c	7 years [c]	Up to 160MWh use/yr	Gross
NT (Alice Springs)	July 2009	tbc	49.92 c/kWh. Capped at $5 per day	tbc	Residential [d]	Net
QLD	July 2008	10 kW (single phase), 30kW (three phase)	44c (some retailers may pay slightly more)	20 years	Up to 100MWh use/yr	Net
SA	July 2008	10 kW (single phase), 30kW (three phase)	44c (some retailers may pay slightly more) [e]	20 years	Up to 160MWh use/yr	Net
TAS		tbc	Same as retail rate	tbc	tbc	Net
VIC	Nov 2009	5 kW	60c	15 years	Up to 100MWh use/yr	Net
WA	July 2010	tbc	Expected to be 60c/kWh	Likely 2 - 9 years	tbc [f]	Net

a: The ACT Independent Competition and Regulatory Commission (ICRC) recently recommended that the 50.05c/kWh rate be dropped to 37c/kWh. At the time of writing the government had not indicated whether it would follow this advice.

b: Limited availability of appropriate meters mean that systems will only be paid on a net basis until more meters become available.

c: Payments end in year 7, meaning that systems installed in year 5 for example will only receive 2 years of payments.

d: Commercial customers will most likely just be offered a net FiT at the standard retail usage rate.

e: The scheme is currently being reviewed and the results were meant to be released by the end of 2009.

f: The WA government is currently designing both a residential and commercial FiT, and while the residential is expected to be net, they are considering a gross design for the commercial FiT.

State-based support for particular projects

These programs are focussed more on support for particular projects on a case by case basis rather than across the board support as occurs for the RET.

Queensland

The Queensland Renewable Energy Plan (QREP)
The QREP is an industry development strategy aiming to support projects built to meet the Commonwealth target of 20% renewable energy by 2020. The components of the QREP most likely to be of interest to meat processors are: 2. Solar thermal options for regional Qld, 4. RE options for Qlds isolated networks, 5. Government Owned Generators partnering with industry to identify renewable energy solutions, and 10c. Renewable Energy Incentives Package.
The Office of Energy should be contacted for more detail on individual programs. For more information see http://www.cleanenergy.qld.gov.au/queensland_renewable_energy_plan.cfm,

The Queensland Renewable Energy Fund (QREF)
This is a $50 million funding program that supports the development and deployment of renewable energy generation technologies in Queensland. Round One is now closed and it supported Ergon Energy's new Birdsville Geothermal Power Station and Mackay Sugar's Cogeneration Project. Further funding rounds are yet to be determined.
For more information see http://www.cleanenergy.qld.gov.au/queensland_renewable.cfm.

New South Wales

Renewable Energy Development Program
The Renewable Energy Development Program under the NSW Climate Change Fund provides $40 million over five years to support projects which are expected to lead to large scale greenhouse gas emission savings in NSW by demonstrating renewable energy technologies in NSW, and by supporting the early commercialisation of renewable energy technologies in NSW. Round 1 of the Renewable Energy Development Program allocated $27 million to seven renewable energy projects.

These projects include $2.9m allocated to Cargill meat processors in Wagga Wagga to generate energy from animal waste methane. The project will use a 75 million litre covered anaerobic pond and a 1,400 kW co-generation set that will generate 1,200 kW electricity (3 phase, 415 V) and 500 kW equivalent steam.

For more information see http://www.environment.nsw.gov.au/grants/ccfred.htm.

Alternative Energy Generation Projects
Alternative Energy Generation Projects are funded under the NSW Climate Change Fund (was originally under the Water and Energy Savings Funds). Funded projects include:
Burrangong Meat Processors receiving $700,000 for methane recovery from effluent ponds to generate electricity to meet 65% of its energy needs. The project involves installing ultrasound equipment in the effluent pond to maximise methane production and capture the gas. It will then be sent via a pipeline to a gas engine to generate electricity to power the plant. The project is expected to save 3,600 MWh of electricity each year and 3,546 tonnes of greenhouse gases a year.

Rockdale Beef receiving $2.1 million for collecting methane from waste water and manure to generate enough energy to run the facility. Excess electricity generated from the new biogas plant will be fed back into the grid and the upgrades to equipment and existing wastewater treatment plant will save both water and money by avoiding manure disposal costs. The project will use 120,000 tonnes of manure produced each year and save 15,500 megawatt-hours of electricity each year.

For more information see http://www.environment.nsw.gov.au/grants/altpowgenprojects.htm

Victoria

Sustainability Fund
The Sustainability Fund has supported three rounds of open grants and also supports sustainability projects in Neighbourhood Renewal Areas, projects outlined in the Environmental Sustainability Action Statement (ESAS) and projects in partnership with local councils through the Victorian Local Sustainability Accord. Since 2004, the Fund has provided $61.3 million in funding to support 166 diverse projects in schools, businesses, local government and community groups, including two cogeneration projects in the most recent round.

For more information see http://www.sustainability.vic.gov.au/www/html/2418-about-the-sustainability-fund.asp?intSiteID=4