final report

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Development of a clean, viable, and sustainable energy strategy for red meat processing

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Executive summary

This is the final report for project P.PIP.0739 – Development of a clean, viable, and sustainable energy strategy for red meat processing, which considered the technical and financial feasibility analysis of biogas cogeneration and a renewable solid fuel boiler at a Queensland abattoir (**Test Site**). These clean energy options were evaluated against the base case scenario of continued use of coal for thermal energy and electrical power from the grid.

As heat and power prices rapidly increase, Australia's red meat industry is under increasing pressure to find innovative ways to reduce energy costs whilst maintaining business continuity and profitability. A key opportunity to act on these pressures is when major plant is at the "end of life" (e.g. boiler replacement). Rather than a like-for-like replacement, there are technically and financially sound opportunities to install clean tech to shield against rising energy costs and to protect businesses against future emissions regulations. In addition to the thermal aspect of energy, lagoon biogas that is currently being flared is an immense opportunity for power and revenue generation.

To improve the economic viability of installing sustainable energy technology at the Test Site, including a biogas cogeneration engine and biomass boiler, financing plans were developed by Northquest based on initial vendor budget pricing. The summary of the key parameters with and without financing is summarized in the table below according to an EBITDA (i.e. earnings where no interest/cost of capital/discounting, taxation, depreciation or amortization has been applied) Cost-Benefit analysis:

	Without Financing		With Financing (3 years)	
	Cumulative cash flow	IRR	Cumulative cash flow	IRR
Biogas Cogeneration – 15-year life of plant; $2.497 mil cap ex.	$19.04 mil	44%	$18.98 mil	137%
Biomass Boiler – 25-year life of plant; $6.358 mil cap ex.	$3.58 mil	3.3%	$3.41 mil	3.7%
Integrated renewable Facility (cogen + biomass boiler); $8.855 mil cap ex)	Not analysed		$22.39 mil	24%

The value proposition to industry of this project is technological and financial information on how a site may reduce the impact of rising fuel and power prices via the use of fuels generated on-site from organic by-products or from locally sourced biomass. These results show a pathway for significant operating cost reduction, revenue via credits under the Federal Government's Renewable Energy Target (RET) scheme and an economically viable way for making deep in-roads to running a facility on renewable energy. The integrated bioenergy facility presented in this report would enable a transition from "black" energy (grid power and coal) towards an estimated 86% "green" energy on a gross energy delivered to site basis. This project shows a practical way in which the red meat industry can further enhance its "clean and green" image.

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1 Background

1.1 The Test Site Energy Loads

1.1.1 Thermal Loads

Average daily coal consumption was reported as 22 tpd and 24 tpd in summer and winter, respectively. Averaging at 23 tpd with an assumed bituminous coal LHV of 25.9 GJ/t, approximately 596 GJ/day of fuel energy is consumed, or 193,603 GJ pa. A 25% allowance was added to allow for increased production in the short term, hence fuel usage estimates were based on an estimated annual consumption of 242,003 GJ pa.

Detailed SCADA information was not available, however the image below summarizes the main steam uses at the Test Site. The existing boiler has a reported rating of 8 MWt. On available information the estimated boiler average efficiency was calculated at 78%, which considering the age of the boiler (30 years) appears reasonable.

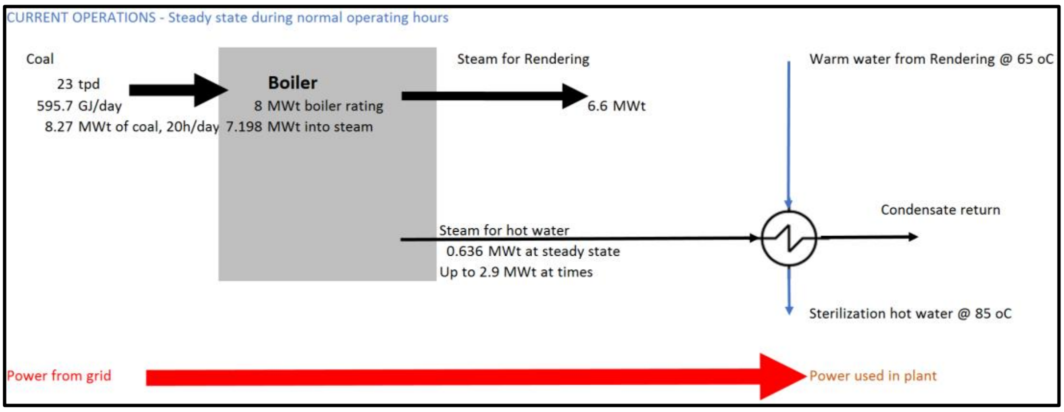

Figure 1: Estimated steady state thermal loads at the Test Site.

1.1.1 Electrical Load

The 30-minute NMI meter data was provided by the Test Site for the year of 2016. Collating the kW load and kWh consumed data for each meter is summarised in table 1.

Table 1: Summarised Meter Data - Site-Wide

NMI	Serial	Max kW	Average kW	MWh annual
A	-	49	29	258
B	-	95	36	320
C	E...4	1218	602	5287
	E...6	1279	539	4738
	E…1	809	304	2674
D	-	73	34	301
E	E...8	569	381	3347
	E...6	783	510	4483
	E...7	545	360	3160
TOTAL		**5,420**	**2,437**	**24,567**

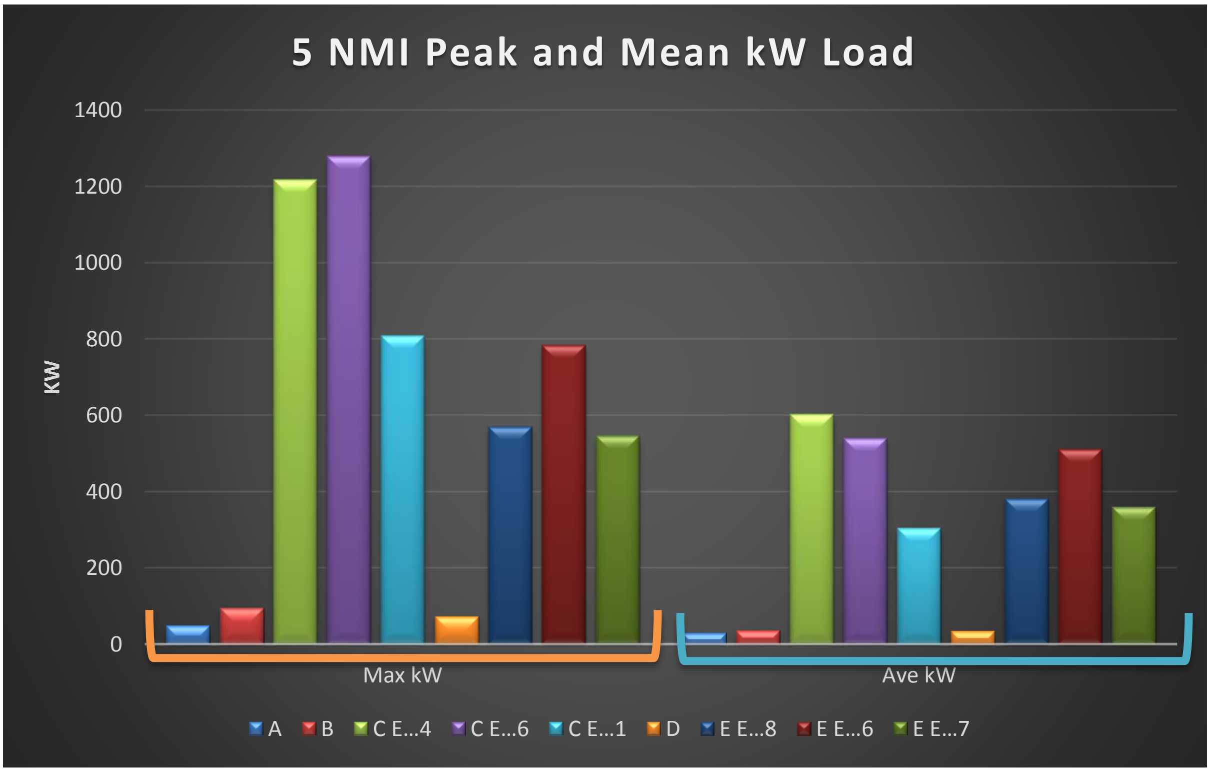

Figure 2: Peak and Mean Loads - Site-Wide

It can be seen from the figure above that there are 2 meters that contribute the great majority of total site power consumed. These were reported as the meters servicing the kill floor, boiler, and rendering, and refrigeration plant.

To estimate the peak and average power loads of the eventual expansion capacity of the site, production data was supplied by the Test Site of head and tonnes throughput per week of 2016. Referencing this with the weekly MWh consumed calculated from the 30-minute data produced figure 3 below.

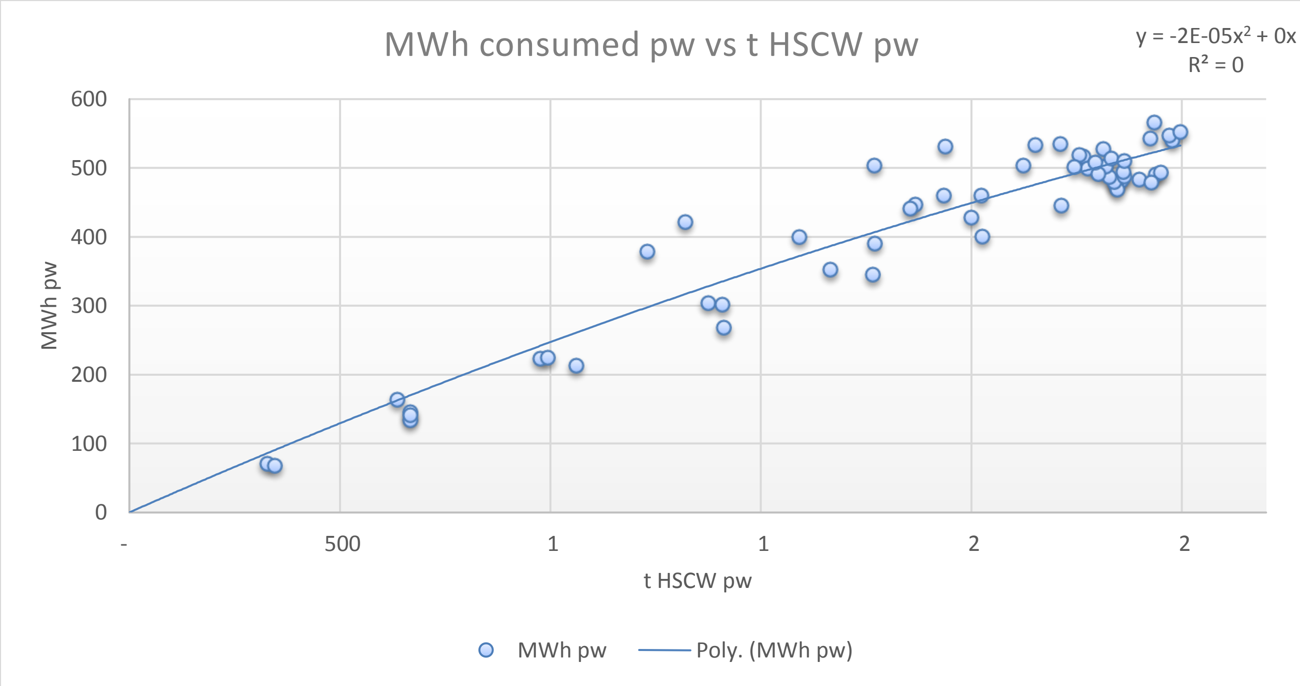

Figure 3: Weekly Power Volume Consumed vs Tonnes Throughput

The high R^2 of the derived polynomial gives good confidence in extrapolating out power loads. Noting the previously mentioned schedule of running equipment longer but not harder, at an eventual capacity of 2000 hpd, or approx. 4987 t HSCW per week, the weekly power consumption is estimated as 848 MWh, translating to a peak load of 6.8 MW, and an average load of 3.1 MW.

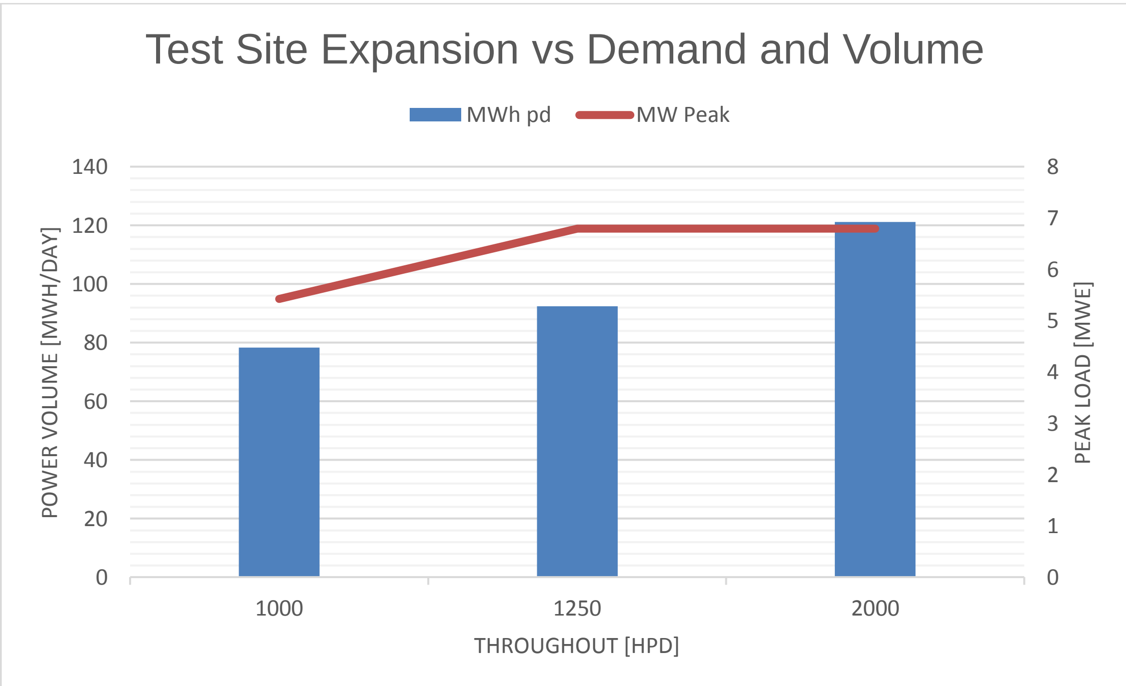

Figure 4: Test Site Expansion Capacities vs Power Peak Load and Volume Consumed

1.2 Fuel Long List

Table 2 below shows the long list of available fuels, energy content, quoted supply costs, and calculated supply only $/GJ cost.

Table 2: Long List of Available Fuels

Fuel	Units	Notes	LHV MJ/kg	LHV MJ/L	Fuel Supply $/GJ LHV
Hardwood chip, ex-mill, air dried	Per tonne	Delivered to Site	15.1		3.44
Hardwood chip, ex-mill, air dried	Per tonne	Delivered to Site	13.9		7.91
Coal	Per tonne	Delivered to Site	25.9		4.37
Fuel Oil	Per Litre	Delivered to Site	37.28	34.67	13.96
Processed fuel oil	Per Litre	Delivered to Site	41.51	38.19	15.99
Diesel	Per Litre	Delivered to Site	42.61	35.58	20.26
LNG	Per tonne	Delivered to Site + 10% allowance for storage costs	48.63	20.72	20.36
LPG	Per Litre	Delivered to Site +5% allowance for storage costs	46.61	23.07	27.31
CAL Biogas	Trenched 150mmND poly-pipe (Biogas free issue).	$255,000 cap ex & $4520 p.a. op ex + power costs for 3.05 kWe fan blower.		0.0251	0.188

The alternative uses / opportunity cost for hardwood chip is low, due to pine, cypress, cedar and bark products being preferred for poultry and landscaping applications. Hence, the main cost associated with hardwood chip procurement is haulage costs. A key variable between the hardwood chip submissions is the delivery method, with the lower cost option being 120 m3 B doubles, in comparison to a 90 m^3 walking floor option. Haulage is effectively charged per m3, hence options for consideration when procuring woodchip include:

- Payments being based on GJ delivered and/or dry weight of fuel delivered, to incentivise the suppler to provide a dryer product with less contamination / soil, etc.
- Ensuring that each load meet a minimum density / tonnage requirement.
- Considering screening, hammer milling and/or compaction of fuel at the point of truck loading.
- Using the woodchip twice e.g. for pens to improve animal welfare before use in the boiler. It is anticipated that up to 5% by mass of boiler fuel could be manure with no long term detrimental impact on the boiler.

For biogas, costs were assumed to be a trenched 150mmND poly pipe; 5.0 kW biogas blower; 25-year life of plant (biogas free issue). A 460 m trenched/pipe run was assumed, excavated to 0.2 m wide trench to depth of 0.6m in non-rocky soil, at $25,000 per 100m of trenching; $200/m for materials (PE Gas Pipe Y/S SDR21 PE100; 150 mm ND), fittings, supply, trench, laid in trench, install, electrofusion joints, commission. Power was assumed at $0.19/kWh for a hazardous area rated biogas fan blower drawing 3.05 kWe. A pipeline optimizer was utilized as per below, allowing for a potential doubling in available biogas rates to 900 m^3/h.

Note that the supply cost of prospective fuels was the metric of interest here since over the lifetime of a boiler plant, fuel costs constitute the greatest percentage of life cycle costs. At current fuel, boiler cap ex and boiler op ex prices, over the life of plant for a solid fuel boiler, fuel costs are estimated at up to 89% of combined cap ex and op ex costs. Hence, the logic behind selecting the fuel first. It can be seen in the above table that both hardwood chip and CAL biogas make for attractive thermal fuel substitutes. To distinguish further between these, certain considerations must be addressed during Milestone 2 including

- Operational costs of each option
- Skills and FTE requirements of operating staff
- Highest value application of biogas

Due to the different conditions of a solid fuel or a gas boiler, solid fuel boilers generally being more operationally complex, the full impact of operational requirements are to be considered to guide decisions. Since a solid fuel boiler is currently installed, there is anticipated to be no additional staffing requirements for a new solid fuel boiler compared to a "business as usual", that is, additional resources are not expected to be required other than initial training of operators.

The highest value application of the biogas is cogeneration over boiler fuel, factoring the capital cost and producing an estimated savings versus the base case of coal and grid power. To optimise the total site-wide savings in the highest value energy strategy, biogas will be used for cogeneration and woodchip for substitute boiler fuel. The figure below outlines the opportunity to reduce solid fuel consumption by the creation of hot sterilization water using thermal energy from a cogen engine rather than using steam.

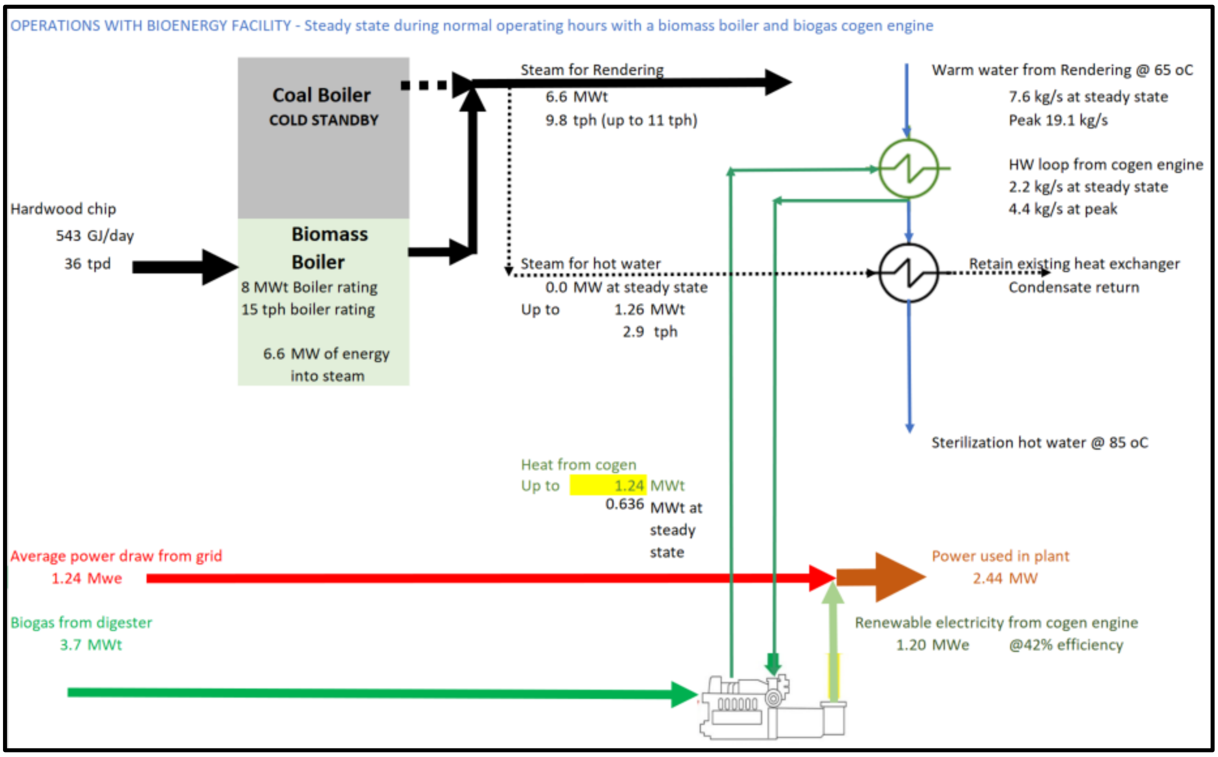

Figure 6: Preliminary concept for utilization of cogeneration thermal energy at the Test Site and integration with a new biomass boiler.

The table below summarizes information on the fuel long list. A “Goal Seek” analysis determined that the “breakeven” point for woodchip is a LHV of 13.27 MJ/kg, if woodchip can be procured at $58 / tonne. That is, the heating value that the woodchip requires to be at the same $ per annum cost as coal.

A key limitation of the biogas is that it is estimated to be able to provide 27% of the site thermal energy requirement, hence if a biogas boiler were employed, a second boiler would still need be operated to deliver the site steam requirements.

Table 3: Fuel long list cost impact estimation.

Fuel	LHV MJ/kg	tpa of fuel required	Fuel Cost pa	Savings pa vs Base; Fuel Only
Hardwood chip, ex-mill, air dried	17.5	13,829	$802,068	$255,925
Hardwood chip, ex-mill, air dried	15.1	16,027	$1,762,937	-$704,944
Coal	25.9	9,344	$1,057,993	$-
Solvent extracted fuel oil	37.3	6,491	$3,378,164	-$2,320,171
Fuel oil	41.5	5,830	$3,868,684	-$2,810,691
Diesel	42.6	5,679	$4,822,240	-$3,764,247
LNG	48.6	4,976	$4,926,450	-$3,868,457
LPG	46.6	5,192	$6,608,535	-$5,550,542
CAL Biogas	21.5	4,107	$13,800	$307,168

1.3 Boiler and Cogeneration Submissions

Vendors were selected due to their experience in delivering projects within Australia and overseas.

2 Project objectives

The overall project objectives are as follows:

- Conduct a general feasibility review for on-site steam and power generation with the potential option of utilising renewable energy (i.e. biogas) from the waste water treatment plant at a beef processing operation.
- Develop concept design(s) for creation of energy at a red meat processing facility
- Present a business case for investment
- Evaluate the impacts of the Renewable Energy Target and the Emissions Reduction Fund to improve the overall economic viability of on-site steam and power generation with and without hot water

3 Methodology

The following methodology was formulated and applied in this milestone.

In the first two milestones, heat and power loads at the current capacity were extrapolated out to the planned expansion capacities of the Test Site to size appropriate biogas cogeneration and biomass boiler plant. Requests for budget pricing were sent out to vendors to estimate both fully costed $/GJ thermal and $/kWe, and total installed capital $TIC for each piece of plant. Against the base case of coal and grid power, the feasibility of each was investigated by the standard metrics of simple payback, internal rate of return (IRR), net present value (NPV), annual net benefit (ANB), and discounted payback period.

After new information became available and cost benefit analyses were refined, submissions were made to a third-party funding group, Northquest, to assist in managing the financial risk to the Test Site. These financing models were built into the CBA for a final presentation to the Test Site.

The key assumptions made were as follows:

- Grid power purchased at $0.068 / kWh peak, $0.042 / kWh off peak and $0.00092 / kWh for “other” charges (e.g. SREC, LREC, AEMO)
- Electricity demand charge $13.659 / kVa / month
- Coal purchased at $4.37 / GJ lower heating value (LHV)
- Air dried hardwood chip purchased at $3.44 / GJ lower heating value (LHV)
- Emissions Reduction Fund (ERF) credits net revenue to the Test Site at $8 / t CO_2-e ($136,606 through to 2022 for complete replacement of coal with bioenergy).
- 5.09% pa indexation on all cost and revenue items.
- Facility commences full operation 1 Jan 2019 with deposits paid in 2018.
- 25-year boiler plant life
- 15-year cogen plant life
- No discount rate applied.
- Operational model has been semi-optimized at 100% throttle during peak periods (16 hours during weekdays), with 85% throttle for 8 hours per day in off-peak period (the off-peak operation effectively serves as a kVA load reduction and gas consumption strategy).
- For financing, GST is payable up-front.

At 450 m3/h of biogas at 70% methane (LHV approx. 25.15 MJ/m3), the available biogas contains 11,317 MJ per hour. The 2G engine calls upon 580 m3/h of biogas at 50% methane (LHV approx. 17.96 MJ/m3), which is 10,417 MJ per hour. Hence, there should be sufficient biogas to run the engines at full load (estimated 7.9% oversupply). However, a conservative scenario was modelled allowing for 32 hours per week of engine unavailability for scheduled and unscheduled down time. The service contract guarantees 8234 hours per annum of availability, whilst the CBA assumed 7072 hours per annum utilization (80.7%).

4 Results and Discussion

4.1 Biogas Cogeneration with Financing CBA

Northquest submitted financing contracts for the ex GST installed capital of $2,270,000 for a duration of three, four, and five years summarised as follows.

Table 7: Northquest Biogas Cogeneration Financing Plans

Term	Payment pa	Total	Additional Paid	Additional pa	% of Principal
3 years	$778,390	$2,335,170	$65,170	$21,723	2.9%
4 years	$602,512	$2,410,049	$140,049	$46,683	6.2%
5 years	$503,543	$2,517,716	$247,716	$82,572	10.9%

To compare each financing model, an Earnings Before Income Tax, Depreciation, and Amortisation (EBITDA) analysis showed the feasibility outputs of each option over a 15-year life of plant as

Table 8: Biogas Cogeneration CBA - With Financing

Term	Cumulative cash flow over life of plant	Internal rate of return (IRR)
3 years	$18.98 mil	137%
4 years	$18.90 mil	187%
5 years	$18.79 mil	226%

The similarity between the "Cumulative cash flow over life of plant" gives the freedom to choose a shorter or longer-term contract to manage cash flow.

The reason for the high internal rates of return compared to the "no financing" option is that for the financing options the cash flow is positive by the second year.

Table 9: Cash flow and cumulative cash flow for first 5 years of facility operation (assumed deposits paid in 2018, facility commences full operation 1 Jan 2019).

No financing cash flow and cumulative cash flow.

Year	2018	2019	2020	2021	2022	2028
Cash Flow	-2,497,000	991,420	1,041,883	1,094,915	1,150,646	1,209,214
Cumulative Cash Flow	-2,497,000	-1,505,580	-463,698	631,217	1,781,863	2,991,077

3-year financing cash flow and cumulative cash flow.

Year	2018	2019	2020	2021	2022	2028
Cash Flow	- 227,000	213,030	263,493	316,525	1,150,646	1,549,923
Cumulative Cash Flow	- 227,000	- 13,970	249,522	566,047	1,716,693	9,960,307

4.2 Biomass Boiler with Financing CBA

Northquest submitted financing contracts for the ex GST installed capital of $5,780,000 for a duration three, four, and five years summarised as

Table 11: Northquest Biomass Boiler Financing Plans

Term	Payment pa	Total	Additional Paid	Additional pa	% of Principal
3 years	$1,982,078	$5,946,233	$76,233	$25,411	1.3%
4 years	$1,534,243	$6,136,973	$266,973	$66,743	4.5%
5 years	$1,282,235	$6,411,176	$541,176	$108,235	9.2%

To compare each financing model, an Earnings Before Income Tax, Depreciation, and Amortisation (EBITDA) analysis showed the feasibility outputs of each over a 25-year life of plant as

Table 12: Biomass Boiler CBA - With Financing

Term	Cumulative cash flow life of plant (25 years)	IRR
3 years	$ 3.41 mil	3.7%
4 years	$ 3.12 mil	3.4%
5 years	$ 2.79 mil	3.1%

4.3 Integrated Renewables Facility - Biomass Boiler and Biogas Cogeneration with Integrated Financing Model CBA

Northquest submitted financing contracts for the ex GST installed capital of $8,050,000 for financing options of three, four, and five years summarised as per below.

Table 13: Northquest Combined Plant Financing Plans

Term	Payment pa	Total	Additional Paid	Additional pa	% of Principal
3 years	$2,760,506	$8,281,518	$231,518	$77,173	2.9%
4 years	$2,136,792	$8,547,168	$497,168	$124,292	6.2%
5 years	$1,785,812	$8,929,060	$879,060	$175,812	10.9%

To compare each financing model, an Earnings Before Income Tax, Depreciation, and Amortisation (EBITDA) analysis showed the feasibility outputs of each over a 15-year (engine) and 25-year (boiler) life of plant as follows.

Table 14: Integrated Renewables Facility CBA - With Financing

Term	Cumulative cash flow life of plant (25 years)	IRR
3 years	$ 22.39 mil	24%
4 years	$ 22.12 mil	26%
5 years	$ 21.74 mil	28%

4.4 Integrated Renewables Facility – Sensitivity Analysis

It is anticipated that a carbon pricing regime will be introduced within the life of plant of any major equipment installed today. It is very difficult to predict exactly when this will happen, since it is a strongly partisan issue, with additional intra-party conflicts. The Australian Government's Productivity Commission in its 24 Oct 2017 report called for Australian governments to "work cooperatively to resolve the issues currently confronting Australian energy markets. They must: stop the piecemeal and stop-start approach to emission reduction, and ***adopt a proper vehicle for reducing carbon emissions that puts a single effective price on carbon***"[1].

A sensitivity analysis was run on the main revenue streams for this project to determine how changes in the assumed/calculated values affect the non-discounted IRR of the project. Values were varied within realistic ranges, showing that the greatest sensitivity is to coal and power prices, meaning as these prices trend upwards, the viability of the project greatly improves. A value was applied to CO_2-e emissions from \$0 to the EU level of CO_2-e currently trading at 7.70 Euros (\$AUS 12.08) but has historically been as high as EU21.03 (\$AUS 36.13)[2].

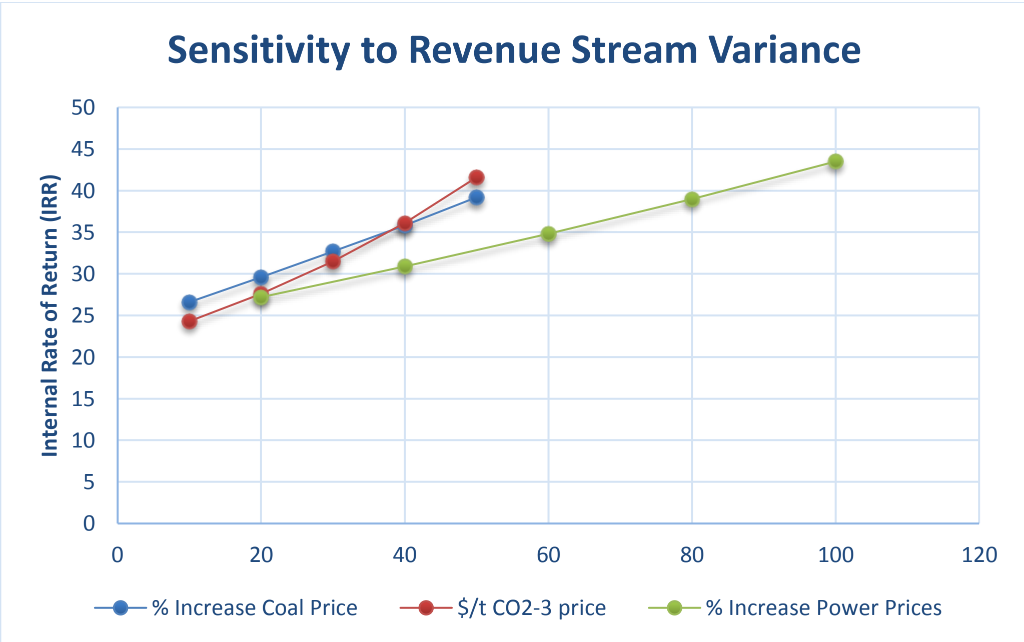

Figure 10: Sensitivity to Revenue Stream Variance

[1] https://www.pc.gov.au/inquiries/completed/productivity-review/report/5-improving-markets, accessed 29 Nov 2017.
[2] https://www.investing.com/commodities/carbon-emissions-historical-data, accessed 27 Nov 2017.

5 Conclusions/recommendations

This milestone showed that there is very good justification in utilising currently flared biogas for cogeneration to create power and heat for sterilization water. Switching to woodchip for process steam generation does not have rates of return as high as that of a biogas cogen engine, however when considering both pieces of plant as an integrated renewable energy plant with appropriate financing models, an internal rate of return of 24% could be realised.

The next stages of work include detailed design, refined cost benefit analyses, installation, and commissioning.

5.1 R&D, Innovation and Future Opportunities

The innovative aspects of an integrated renewable energy solution could form the basis of an MLA R&D project, including:

- Engine heat recovery using a high-pressure glycerol/water heat transfer fluid to offset towards 100% of the steady state steam demand for sterilization hot water.
- Industry first multi-fuel biomass boiler that could test a range of feedstocks to raise steam including clean woodchip, post-holding pen woodchip, cotton gin waste, lower quality wood industry fuels (bark and forestry mulch), dried paunch (would only be a fraction of fuel consumed).
- Export of power to adjacent power loads, businesses and/or the grid, especially during times when “new engine room” load is below 1.0 MWe.
- Site-wide energy management system to manage cogen engine and kVA loads throughout the plant.
- An option to increase the production of biogas by dosing the CAL with additional organic waste stream, especially during non-production times to maintain biogas production rates.

The installation of a biogas engine and biomass boiler provides the opportunity for the Test Site to move from approximately 100% “black” energy (grid power and coal) to approximately 85.2% green energy on a gross energy delivered to site basis.