final report

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Oakey Abattoir methane capture, storage & re-use

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Executive summary

This report summarizes the findings of a concept level feasibility study and associated cost-benefit analysis of an onsite waste to energy (W2E) facility where biogas is used in boilers or in a reciprocating biogas engine. W2E via anaerobic digestion is one of the very limited options for a red meat processor (RMP) to invest in waste management that will deliver a positive rate of return.

The cost-benefit analysis presented within this report is a high-level, concept feasibility study and is not a detailed design or detailed cost estimate.

At the design COD loading and design biomethane production potential where all biogas is used to off-set natural gas at $12/GJ, the COHRAL could deliver an IRR of 8.3%.

A biogas fired reciprocating cogeneration engine in conjunction with the COHRAL (466 kWe power output with associated renewable energy credits) could deliver an IRR of 11.7% when operating at design capacity. Considering a biogas engine in isolation and accounting for the opportunity cost of not using current rates of biogas production in a boiler, an engine could deliver an IRR of 69% (~3-year payback). However, via the use of equipment financing it is possible for the monthly net cash flow to be positive thereby improving the IRR even further, hence trending towards an “instantaneous” payback.

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1 Abbreviations and Definitions

AD Anaerobic Digestion

AEPL All Energy Pty Ltd

AMPC Australian Meat Processor Corporation

ARENA Australian Renewable Energy Agency

BMP Biomethane potential (m^3 methane / tonne volatile solids)

BOD Biological oxygen demand

COD Chemical oxygen demand

Cogen Cogeneration – a facility for the combined generation of power and heat

DAF Dissolved Air Flotation

EoI Expression of Interest

HAZOP Hazard and Operability Study

hr hour

JHA Job Hazard Analysis

kg kilogram

kPa Kilopascals as unit of pressure (gauge)

kVA Kilo Volt Amperes

kVAr Kilo Volt Amperes reactive

kW Kilowatts

kWe Kilowatts of electrical load / generation

kWh Kilowatt hour

kWt Kilowatts of thermal load / generation

MJ Megajoule

MLA Meat and Livestock Australia Ltd

MW Megawatt

MWe Megawatt electric – electrical power production.

MWh Megawatt hour

MWt Megawatt thermal – thermal power production.

NRV No Return Valve

P&ID Piping and Instrumentation Diagram

PRV Pressure Release Valve

s seconds (time)

SMP Safety Management Plan

SOP Standard Operating Procedures

t Metric tonne (1,000 kg)

tpa Metric tonnes per annum

tpd Metric tonnes per day

tph Metric tonnes per day

tpw Metric tonne per week

W Watts

WAS Waste Activated Sludge

WWTP Waste Water Treatment Plant

yr year

2 Background

Oakey Abattoir has installed a biogas generation, capture, storage & re-use project which included the detailed design and installation of a high rate covered anaerobic lagoon (COHRAL) system. The primary aim of the project was to offset the site's dependence on natural gas for boiler use by substituting biogas as a boiler fuel. This rise in energy costs means that sustainable alternative energy sources need to be introduced to remain competitive not only on a domestic but also international level. Further, GHG emissions arising from the wastewater treatment system will be reduced. The follow on primary benefits would be a significant reduction in odour and a waste water treatment system with a significantly smaller foot print than a traditional pond construction. Additionally, Oakey suffers urban encroachment and odour could become a significant issue. The installation of the COHRAL system will minimize issues of odour, ensuring this does not become an issue affecting the plant's long-term viability. The proposed biogas capture system is an alternative to the more commonly adopted Covered Anaerobic Lagoon (CAL) system and Oakey Beef believe this will be the first installation of this type in the Australian Red Meat Processing Industry. Oakey Beef is interested in the COHRAL system rather than a CAL as the European design shows a higher level of safety in construction and design along with a much smaller footprint, lower retention times and a sludge re-use component as part of the design. Therefore, the project will provide valuable information to industry in relation to an alternative methane capture system to a conventional CAL. The lower operational pressures used by COHRAL relative to CALs also means that this technology should have a lower risk of gas escape.

The equipment includes a new pond-cover and liner, gas collection transportation and drying equipment, gas storage facility, SUPERSEP sludge recycling system, and boiler conversion. The MLA project number P.PIP.0336, (Oakey Biogas Recovery & Feasibility Study for Co-generation or Tri-generation) included a feasibility study which unearthed this new design and providers that are more closely aligned with the needs of Nippon. Primarily, the COHRAL design offers the most efficient option for biogas production enabling maximal returns by turning waste into a valuable resource (biogas) that can be utilised within the facility. The greater efficiency has other advantages such as lowering emissions (GHGs, BOD, COD and nutrients), largely eliminates odour issues, ultimately reducing environmental impacts from the operation of the plant. Oakey also chose this design due to its relatively small footprint; like many other abattoirs in Australia, Oakey has limited space for expansion of current waste water treatment. Furthermore, the SUPERSEP sludge recycling system addresses a major issue that the site experiences with the follow on serpentine aerobic system becoming inefficient with undigested sludge matter from the anaerobic pond. Nippon pride themselves with a high level of Work Health & Safety and the European Designed COHRAL demonstrates a higher level of safety for the Oakey site.

The outcome for industry of this project is to evaluate the successfulness of the smaller footprint, high rate anaerobic process along with the best utilisation of biogas in the process. Nippon believes this will be the first installation of this type in the Australian Red Meat Processing Industry and as such the project will provide valuable information to industry in relation to an alternative methane capture system to a conventional CAL. The Oakey facility is implementing novel technologies compared to other Australian red meat processing waste treatment facilities:

- Hydraulic mixing in the inlet.
- Buffering pond.

• Lower residence time.
• Different anchoring system.
• Biogas handling / drying.
• Separate gas storage system.
• Sludge reuse system.

Viable technical solutions exist for converting organic waste into energy; the challenge is to optimize the system to meet the environmental requirements (e.g. emissions to air; waste streams) whilst meeting the economic drivers (e.g. maximize profitability; acceptable capital cost; minimize the payback period; maximize rate of return).

Anaerobic digestion provides one of the few options for Australian food companies to simultaneously create renewable energy on-site, improve waste management practices, and increase energy productivity via a net positive return technology. Uptake is limited due to the modest rates of return for waste to energy compared to other "core business" activities and, particularly in Queensland, low waste disposal costs. A simplified block schematic of an anaerobic digestion waste to energy (W2E) facility is shown in Figure 1 below.

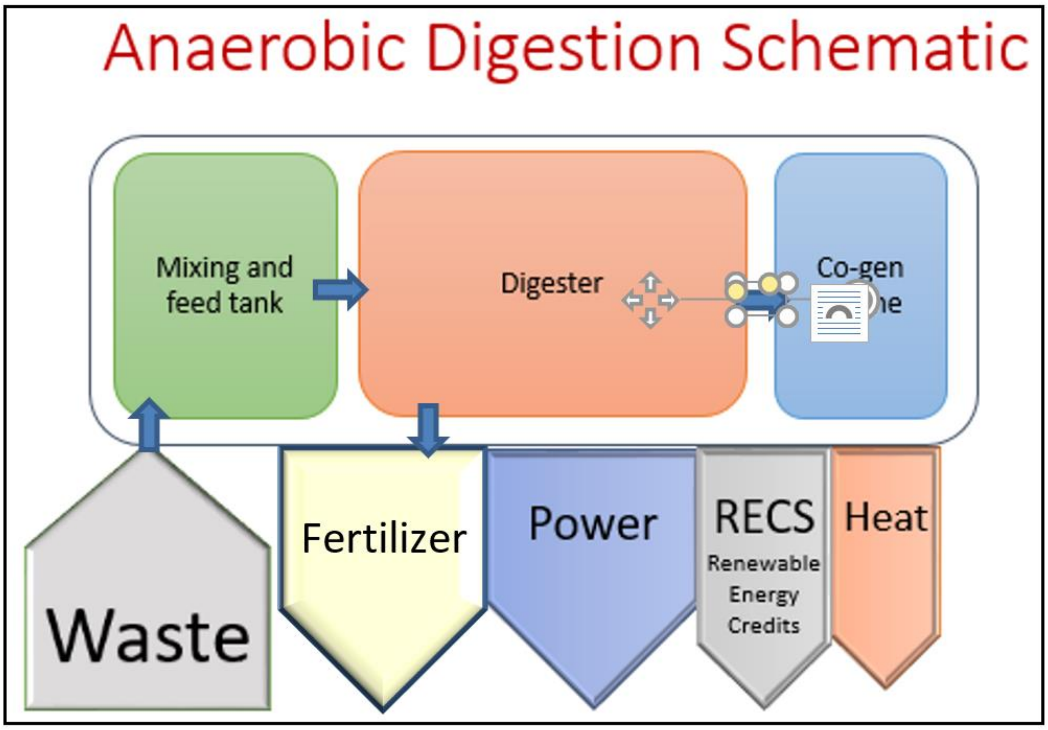

Figure 1: Anaerobic Digestion Waste to Energy Schematic.

3 Project objectives

All Energy Pty Ltd was engaged directly by Oakey Beef to complete the following scope of works:

[1] Site visit to document the COHRAL system and data hand over.
[2] Data aggregation and analysis of ex-post COHRAL.
[3] Completion of an ex-post Cost Benefit Analysis (CBA) to the MLA method comparing a "business as usual" base case (pre-) with the post-installation results.

In addition to this scope, a large number of biogas cogeneration engine scenarios and associated funding options were modelled as discussed in this report.

4 Methodology and Results

4.1 Assumptions and Schematic Diagram

The key assumptions are summarized as per below and in the Mass and Energy Balance:

Biogas engine operational hours	8000	hours pa
Digester operational hours	8424	hours pa
Digester operational days	351	days per annum
Biogas composition	78%	methane
Plant production	4750	head per week
Plant production	51	weeks per annum
Plant production	255	days pa
Plant operating hours per operational day	12	hrs per day
Plant operating hours pa	3060	hours pa
81%	consumption of COD Sept 2017	
70%	COD-removal design capacity	
73.8	% consumption of VS	
98.5%	biogas collection efficiency	

Electricity price increases at	5.6% in 10 years 2002 to 2012	Source: aph.gov.au.
CPI all other items	1.80% in year to sept 2017	Source: http://www.abs.gov.au/ausstats/
Cost of capital not considered		

Costs		#	Rate	Value $ pa
Maintenance and Repair - COHRAL.				None
Chemicals				26,760
Consumables				8,600
Environmental Fees				16,700
Water				33
Additional FTE (Includes 40% oncosts)		1.00	91,000	91,000
TOTAL ESTIMATED ANNUAL OPERATING EXPENSES Per $ pa				143,093

Revenue	$/t	$/GJ	$/kWh	
Fuel Saving				
Coal (offset value)	150	5.8		
Natural Gas (offset value)		12		
Power				
Peak $/kWh			0.084	
Off Peak $/kWh			0.056	
$/kVA/monthdemand charge. Assume Tariff 52B—over 4 GWh high voltage (CAC STOUD 22/11kV Bus)			11	Source: http://www.qca.org.au/

For the cogeneration engine, it was assumed that the existing COHRAL biogas treatment (filtering, packed bed scrubbing and storage) system treats the biogas to a suitable level for a biogas cogeneration reciprocating engine. The engine capital cost allowed for supply, delivery, and installation of the engine and all associated equipment. Overnight capital was assumed (i.e. all costs incurred at time = 0) and the results as presented as Earnings Before Interest, Tax, Depreciation and Amortisation (EBITDA).

Figure 2: Assumed engine location (blue rectangle) and thermal fluid reticulation (yellow line) for heating liquid existing feed pond (upper left) and entering the main COHRAL system (at bottom of image).

4.2 Mass and Energy Balance

A definitive / exhaustive mass and energy was not completed, but rather a high-level review of Biomethane Potential in order to understand where the COHRAL system is currently performing in relation to the design capacity. The final column shows a design capacity based on a biomethane potential of 0.245 Nm^3/kg COD, with this amount of biogas production used. This analysis is summarized in the table below.

Stream Description	COHRAL INLET		COHRAL EFFLUENT		BIOGAS - Document "CBA Summary", 25th Oct 2017.		BIOGAS - Winter [Site visit data]		BIOGAS - Summer [Site visit data]		COHRAL - At Design Biogas Production [Document: 251425 Rev C]		COHRAL INLET - At Design Biomethane Potential [251425 Rev C]	
Stream #	1		2		3		3		3		Theoretical Biogas		Theoretical Biogas	
Temperature (°C)	24		24		24		24		45		24		24	
Pressure (Bara)	1		1		1		1		1		1		1	
Phase	Liquid		Liquid		Gas		Gas		Gas		Gas		Gas	
Volume Flow m3/pa	614250		613585		471644	Nm3	589680	Nm3	912500		1,898,910		1,330,022	
Volume Flow m3/ COHRAL operational day	1750		1681		1344		1680		2500		5,410		3,789	
Volume Flow m3/hr	73		72.8		56.0		70		108		225		158	
Density (kg/m^3)	1020		1020		1.15		1.15		1.15					
Biomethane potential (BMP, L biogas / kg VS dw @ 60% CH4	TBA													
pH	TBA								6.7					
Component Flows														
TOTAL tonnes per annum (tpa)	626535		625857		542		678		1049					
SOLIDS - tpa	tpa	%												
Total Solids	1813	0.3%	609	0.1%										
Volatile solids [% VS/TS]	1306	72.0%	330	54%										
Fat	313	0.1%	78	0.01%										
Nitrogen	13	0.002%	0											
Sulphur	6	0.001%	0											
COD (mg/L)	3227	0.5%	626	0.1%										

For the scenario "COHRAL INLET - At Design Biomethane Potential [251425 Rev C]" the biogas LHV was assumed to be 0.02883 GJ/m^3 which yields 38,347 GJ pa at the design biomethane potential.

Calculated from "251425 Rev 3c" 6.4.3	0.3498	Nm^3 methane/kg COD
Theoretical Biomethane potential - Lit.	0.35	Nm^3 methane/kg COD
Measured - Max	0.27	Nm^3 methane/kg COD
Design - "251425 Rev 3c" 6.4.3	0.245	Nm^3 methane/kg COD
Measured - COD received - Summer	0.221	Nm^3 methane/kg COD
Measured - COD received - Winter	0.143	Nm^3 methane/kg COD
Measured - Ave	0.18	Nm^3 methane/kg COD
Common CAL Literature Data	0.1 - 0.15	Nm^3 methane/kg COD

4.3 Cost Benefit Analysis

The following cost-benefit analyses were created for scenarios where biogas is used within the onsite boiler to offset natural gas usage. The “Design Capacity” is assumed to be the amount of biogas created according to the vendor’s assumed Biomethane Potential (0.245 Nm3 methane/kg COD) noting that under summer conditions the COHRAL is currently generating approximately 68% of the vendor’s design production rate.

CURRENT OPERATION									
Biogas unit value as heating fuel		12	$/GJ						
Biogas production pa (averaged over a year)		10607	GJ pa	471644 m3 pa biogas specified by site					
Life of plant		25.00	years	To:	2042				
Head per annum		242,250	hpa						
Total Capital Investment	4,300,000	$							
Cost increase indexation	1.80%	pa							
Year	2,016	2,017	2,018	2,019	2,020	2,021	2,022	2,023	2,024
Op Ex	-143093	-145,669	-148,291	-150,960	-153,677	-156,443	-159,259	-162,126	-165,044
Cost saving	127,279	129,570	131,903	134,277	136,694	139,154	141,659	144,209	146,805
Net Cash Flow (NCF)	-4,315,814	-16,098	-16,388	-16,683	-16,983	-17,289	-17,600	-17,917	-18,239
Cumulative NCF	-4,315,814	-4,331,912	-4,348,300	-4,364,983	-4,381,966	-4,399,255	-4,416,855	-4,434,772	-4,453,012
NPV	-4,843,625	$							
NPV per head	-0.80	$ NPV/head							
IRR	#NUM!	%							
Simple payback period	No payback in life of plant	years							

OPERATION AT DESIGN CAPACITY									
Biogas unit value as heating fuel		12	$/GJ						
Biogas production pa AT DESIGN CAPACITY		38347	GJ pa	Based on increased COD loading and Design nominate biomethane potential					
Life of plant		25.00	years	To:	2042.00				
Head per annum		242,250	hpa						
Total Capital Investment	4,300,000	$							
Cost increase indexation	1.80%	pa							
Year	2,016	2,017	2,018	2,019	2,020	2,021	2,022	2,023	2,024
Op Ex	-143,093	-145,669	-148,291	-150,960	-153,677	-156,443	-159,259	-162,126	-165,044
Cost saving	460,159	468,442	476,874	485,458	494,196	503,091	512,147	521,366	530,750
Net Cash Flow (NCF)	-3,982,934	322,773	328,583	334,498	340,519	346,648	352,888	359,240	365,706
Cumulative NCF	-3,982,934	-3,660,161	-3,331,578	-2,997,080	-2,656,561	-2,309,913	-1,957,026	-1,597,786	-1,232,080
NPV	6,599,816	$							
NPV per head	1.09	$ NPV/head							
IRR	8.3%								
Simple payback period	13	years							

The following cost-benefit analyses were created for scenarios where biogas is used within a cogeneration engine, where the engine heat is utilized to heat feed as it is pumped from the holding pond to the COHRAL digester. The schematic below shows a simple overview of the cogen engine arrangement. Assuming 21.3 kg/s of feed and where 533 kWt of engine block and flue gas heat is transferred into the feed (assumes 40% heat recovery efficiency), then the water temperature can be raised by approximately 5.9 ^{o}C. Further heat could be maintained within the system by heat exchanging liquid exiting the digester with feed from the pond then boosting the temperature of the feed further with the engine heat, with the aim being to maintain a target digester temperature of 38 – 40 ^{o}C.

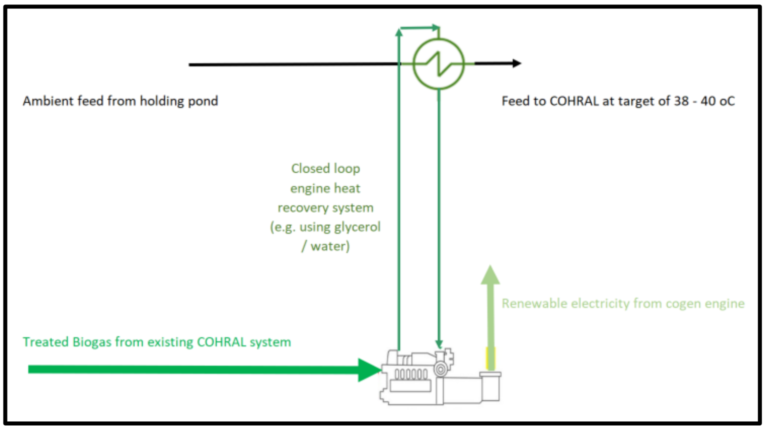

Figure 3: Flow schematic of potential cogeneration arrangement.

An electricity price indexation of 5.6% pa was used based on data from 2002 to 2012[1]. This time period was selected, as the more recent price volatility is considered exceptional. For example, from Jan 2007 to Jan 2017 the industrial power price index for medium to large users increased by 7.57% compound year on year[2]. From Dec 2010 to Dec 2017 the industrial power price index for medium to large users increased by 11.09% compound year on year. All other items have had a standard Australian CPI applied of 1.80% pa[3].

A budget was allowed for the procurement of an engine rated to approximately 500 kWe, thereby being run at approximately 90 to 95% load to generate 466 kWe output for 8000 hours per annum, assuming that the COHRAL system is generating the equivalent of 38,347 GJ pa LHV of biogas and that the engine has a 35% electrical efficiency. An additional cogen engine operating cost was allowed for of $0.019 / kWh generated. It is unclear what renewable energy / carbon pricing policy will be in place over a 25-year life of plant, however the conservative scenario that was modelled was that Large-scale Renewable Energy Credits (LGCs) will not continue after 2030 and that no other renewable energy support / carbon cost reduction policy is implemented.

[1] **aph.gov.au**
[2] http://www.energyaction.com.au/energy-procurement/aex-reverse-auction/energy-action-price-index
[3] http://www.abs.gov.au/, CPI for year to Sept 2017, accessed 9 Nov 2017.

OPERATION AT DESIGN CAPACITY WITH BIOGAS COGENERATION						
Biogas unit value as power	0.0538	$/kWhe		Gen set efficie	35%	0 kWe cogen engine assuming 8000 hours per annum operation
RECs @ $70/MWh (less than 2017 spot price)	0.0700	$/kWhe	Source: http://greenmarkets.com.au/res	Engine rating @	0	kWe 512 kVA @ 0.9 PF
Demand charge savings	67584	$ pa				kVA
Biogas production pa AT DESIGN CAPACITY; engine heat to COHRAL	12	GJ pa	Assumes steady biogas production	Power output:	3,728,140	kWhe pa generated @ 8000 hours per annum
Life of plant	25.00	years	To: 2042	Cogen and he	683,972	Factorial interpolation on a large cogen reciprocating biogas engine data set, as per method of Sinnott
Head per annum	25	hpa		Reticulation ar	64800	Costs were assumed to be a trenched 150mmND poly pipe; 25-year life of plant. A 80 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;
Investment	5,048,772	$		TCI	748,772	Allied Heat Transfer plate and frame HX, T8-BFG 870kWt plate $7000 EX Bris. 3.4 total capital investment multipler
Power cost increase	5.57%	pa				
All other costs indexation	1.80%	pa				

																Cessation of LGC revenue
Year	2,016	2,017	2,018	2,019	2,020	2,021	2,022	2,023	2,024	2,025	2,026	2,027	2,028	2,029	2,030	2,031
Op Ex	-143,093	-145,669	-148,291	-150,960	-153,677	-156,443	-159,259	-162,126	-165,044	-168,015	-171,039	-174,118	-177,252	-180,443	-183,691	-186,997
Cost saving	529,128	558,616	589,748	622,614	657,313	693,945	732,618	773,447	816,551	862,057	910,100	960,820	1,014,366	1,070,897	1,130,578	604,900
Cost saving	-4,662,737	412,947	441,457	471,654	503,635	537,501	573,359	611,321	651,507	694,042	739,060	786,701	837,114	890,454	946,887	417,902
Net Cash Flow (NCF)	-4,662,737	-4,249,790	-3,808,333	-3,336,678	-2,833,043	-2,295,542	-1,722,183	-1,110,862	-459,356	234,687	973,747	1,760,448	2,597,562	3,488,016	4,434,903	4,852,805
Cumulative NCF	11,908,704	$														
NPV per head	19,053.93	$														
IRR	11.7%															
Simple payback period	10.0	years														

The above analysis shows the viability of utilizing biogas within an engine (11.7% IRR for the entire project). When considering the engine and heat recovery in isolation ($0.75 million) and allowing for the value of the biogas that would otherwise have been sent to the boiler (at $12/GJ), an IRR of 69% is achieved (3-year payback).

It is stressed that the cost-benefit analysis presented within this report is a high-level, concept feasibility study and is not a detailed design or detailed cost estimate, hence a sensitivity analysis was run just for the biogas engine varying the Total Capital Investment from -50% up to 50% and the aggregated cost savings for power and revenue from Largescale Renewable Energy Credits (LGCs) were also varied from -50% up to 50% in comparison to the Base Case.

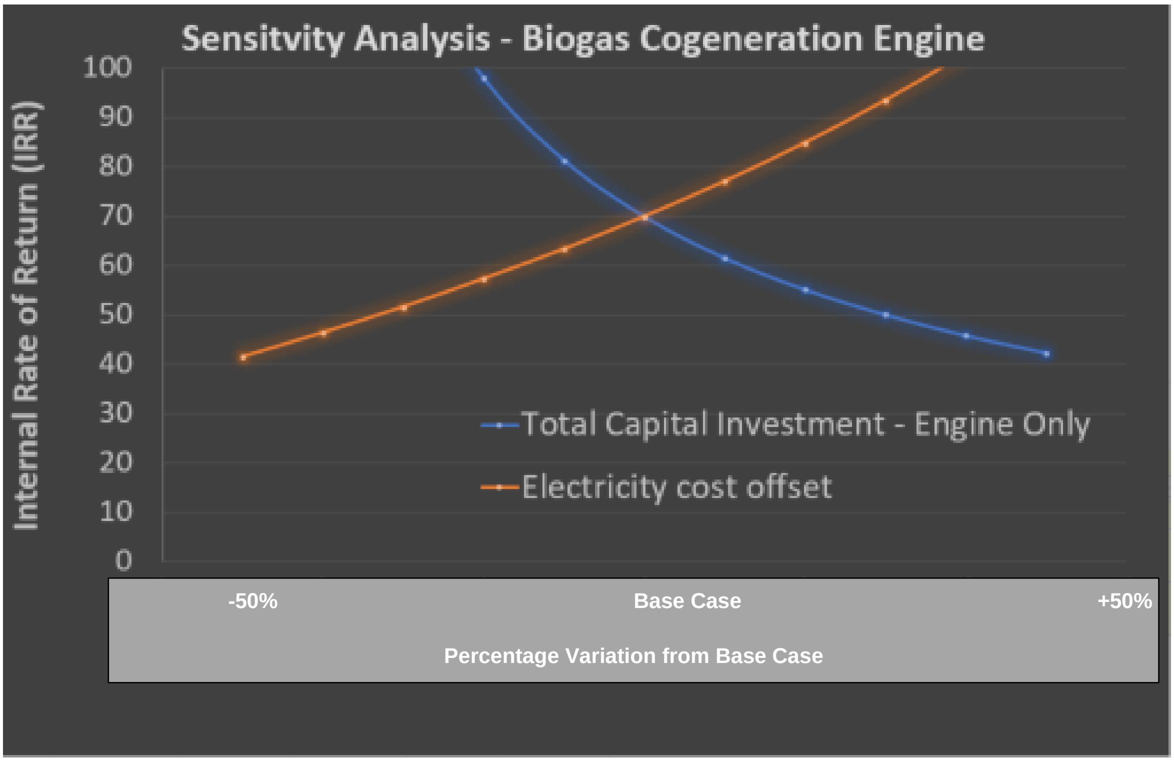

Figure 4: Sensitivity analysis for a biogas engine only.

4.4 Additional Scenario Modelling for Future Consideration

Equipment leasing / financing offers an opportunity for the project to deliver an improved internal rate of return. An indicative 3-year financing period increases the IRR to 12.6% (COHRAL and engine together). For a financing period of 12 years or longer, the entire project has the potential to deliver a positive cash flow once the engine is running at steady state, that is, power savings plus RECs revenue being higher than op ex plus equipment leasing / financing costs (assuming biogas is produced at the above-mentioned design capacity). Unless significant budget for capital works exists, financing or leasing is generally a vital consideration for project delivery.

For the engine only, a leasing period of 4 years or longer could deliver an "instantaneous" payback where the engine is delivering an immediate positive cash flow.

A further option is to install a smaller engine now that can run at full capacity throughout the year on currently available biogas (i.e. engine sized to approximately 210 kWe output for the minimum gas flor rate in winter), then install a second engine when biogas availability closer to the design capacity is available. Procuring two (2) engines is considered best practice to maximise power generation from biogas as it enables power to be generated whilst one engine is undergoing scheduled / unscheduled maintenance.

With regards to controlling the temperature within the digester, the open feed holding pond is major point of heat loss within the system. Value engineering analyses from previous works have shown the advantages of a pond covering or floating covering system. Figure 5 below shows a maintenance free floating pond covering to reduce heat loss, evaporation, algae growth and odours. High surface area coverage is achieved by placing a sufficient amount of balls on the surface of the liquid; the balls arrange themselves to provide coverage of up to 91%. The result is a thermal insulation barrier which combines the insulation factor of the air held in each ball with the poor heat conductivity of plastic. Rhombus shaped floating units are claimed to have the highest insulation thereby minimizing heat loss[4]. The capital for pond covering was not considered as part of the cost-benefit analysis.

Figure 5: Image of a wind resistant floating pond covering[4].

[4] https://www.coastalnetting.com/floating-pond-covers.html, accessed 19 Dec 2017.

4.5 Embedded Generation

Appropriate permission will be required for installing embedded generation such as a biogas engine and may require installation of appropriate switching gear.

With respect to grid connections, a more consumer-friendly approach to connect renewables to the grid is the ambition of a new suite of guidelines being developed by Energy Networks Australia. Standardising and streamlining the connection of next generation technology has been identified as a key priority by networks, customers and industry stakeholders. The Distributed Energy Resources National Connection Guidelines will provide a consistent set of protocols to connect and integrate a range of Distributed Energy Resources (DER) with Australia's electricity networks. The Electricity Network Transformation Roadmap found that almost two-thirds of customers will have distributed energy resources by 2050 and network service providers could buy grid support in a network optimisation market worth $2.5 billion per year. Energy Networks Australia will work with the Clean Energy Council and other key stakeholders to develop the Guidelines, enabling customers to connect to electricity networks and markets in a consistent way that improves grid efficiency and security.

Peer-to-peer power trading (e.g. as proposed by PowerLedger and GreenSync) provide an opportunity to generate higher revenues again from power (e.g. by selling green power at a $/kWh higher than Oakey Beef's current power costs, more revenue can be generated from the power). This scenario has not been modelled as it is unknown when peer-to-peer trading will be possible via the existing power grid to sell power to other NMI meters within Oakey Beef's operations and/or other businesses and households.

5 Conclusions/recommendations

There is sufficiently strong technical and economic viability to consider completing the front-end engineering design and associated capital cost estimation for a cogeneration engine.

Equipment financing / leasing implications have been modelled and shown to provide an opportunity to increase the overall internal rate of return and reduce the payback period as via selection of a suitable contract period, the equipment monthly repayments can be less than the revenue from power usage charges, power capacity charges and renewable energy credits.

In terms of biogas production rates, one of the process guarantees given was: "COD removal rate is 70 % minimum...326 Nm3 biogas/day (245 Nm3 CH4/day) per 1,000 kg COD/day for lower than nominal plant load". COD removal under spring conditions was 81%. In summer, the methane production rate is 221 Nm3 CH4/day per 1,000 kg COD/day and in winter is 143 Nm3 CH4/day per 1,000 kg COD/day. The theoretical maximum conversion is 315 Nm3/day per 1,000 kg COD/day however due to cell maintenance and bacterial competition (e.g. sulphate reducing), actual methane production is less than the theoretical amount. The normal range reported for waste water plants is 100 to 170 CH4 Nm3/day per 1,000 kg COD/day (slightly different material to your system). It would appear that the Nm3 CH4/day per 1,000 kg COD/day, even in summer, is lower than the process guarantee, possibly due to the basis of design assuming a high Nm3 CH4/day per 1,000 kg COD/day (i.e. a theoretical maximum rather than operational average). A further issue is that the "in vessel" operating temperature was not considered as part of the biogas production rate, that it, it was expected that the system was to operate at 35 to 40 ^{o}C / 30 to 40 ^{o}C (rather than at lower temperatures as occurs during periods of low ambient temperature conditions). Hence, a key R&D opportunity is to analyse then implement energy recovery options including covering the holding pond, lagging pipework that is above ambient temperature, recovering heat from digestate exiting the COHRAL (by heat exchanging with the incoming feed), then boosting the feed just before it enters the COHRAL with heat from the engine. For example, previous works have shown that increasing from 35 to 39 ^{o}C has been found to increase the methane yield (ml CH4 g VS^{-1}) by between 10 to 30%[5].

[5] Nielsen, M. et al. Biotechnol Lett (2017) 39:1689–1698.