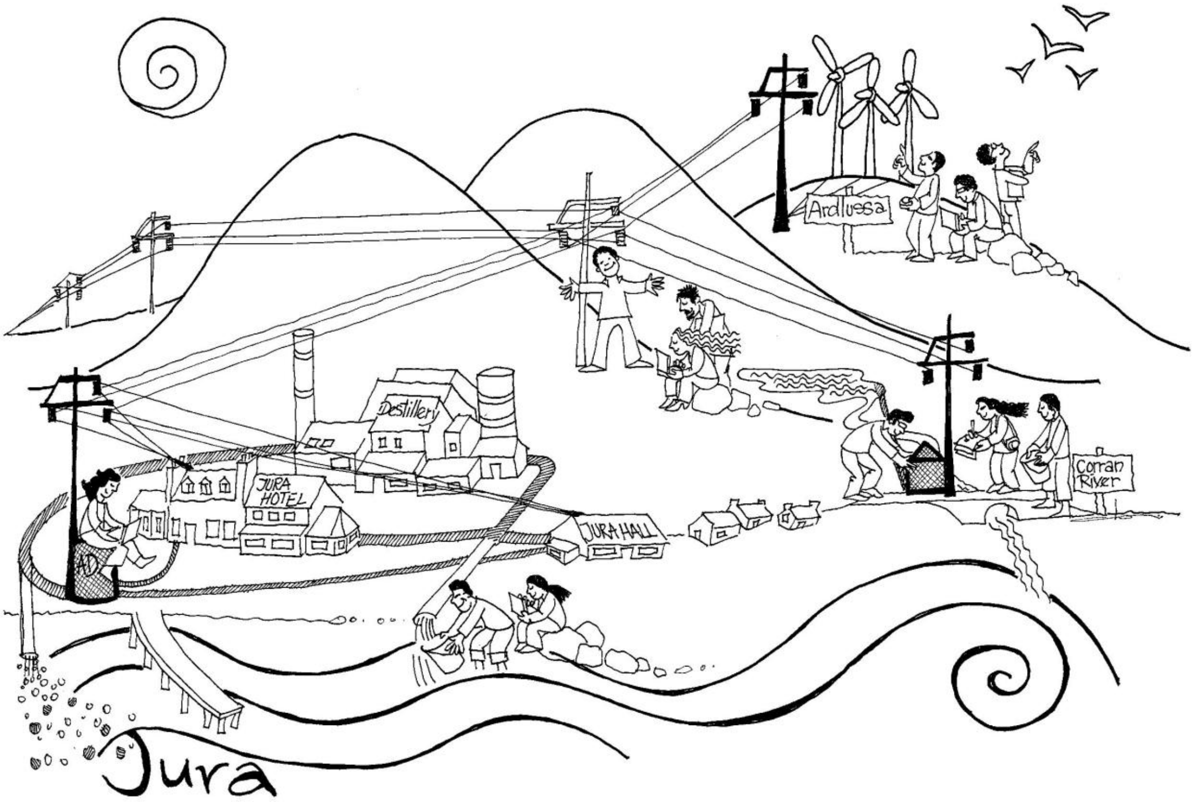
ASSESSMENT OF RENEWABLE ENERGY TECHNOLOGIES
FOR THE
SUSTAINABLE DEVELOPMENT OF THE ISLE OF JURA



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COVER PHOTO: CRAIGHOUSE ON JURA AND STONE PIER

scotlandinfo.eu/isle-of-jura.htm

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Our special thanks go to these individual personalities for their relentless contribution towards this work; Mr. John Potts and Rob Tiger from the Jura Development Trust (JDT) for continuously supporting us during the research and Mr. Felix Wight of Community Energy Scotland (CES) for providing the vital pieces of information needed for this study. Our appreciation also goes to Mr. Andrew Fletcher (Ardlussa), Mr. Ally Miller (Forest Estates) and Willy Cochrane (Manager-Jura Distillery) for sharing their experience and information on hydro projects and distillery processes.

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EXECUTIVE SUMMARY

This report has been prepared for the Jura Development Trust (JDT) to provide a credible basis for making informed decisions on the development of community-owned energy projects on the Isle of Jura. The report presents the findings and results of a five-week assessment study conducted on the island in February/March, 2012 by a team of 12 students of the Energy and Environmental Management Master's program at the University of Flensburg, Germany and could be used as input for further detailed technical and economic analyses. The projects identified by the Trust for evaluation are:

- 50-500kW wind energy at Ardlussa;
- Corran river hydropower;
- Anaerobic digestion and combined heat and power generation options at the Jura Distillery.

The project also evaluates grid feed-in options to optimise income generation for the community.

For the past ten years, the University of Flensburg has been working in close collaboration with Community Energy Scotland (CES) on various energy and environmental studies on island communities in Scotland.

With increasing fossil fuel prices and occasional disruptions to power supply, embedded generation from locally available renewable resources is an attractive alternative. Sizable community-owned renewable projects can reduce that community's dependence on fossil fuels and lead to more self-sufficiency whilst significantly reducing grant dependency.

However, most of parts of Jura are designated National Scenic Areas. This places legal constraints and introduces additional requirements for consideration when planning power projects on the island. There are a large number of distributed/embedded generators on the grid in Argyll. There are thus significant upgrades required before any other connections are possible. Access to the grid is therefore very competitive and a date when connection is possible could be a "significant number of years in the future". Unofficial discussions with Scottish and Southern Energy, the Distribution Network Operator in Jura indicate a 50kW limitation connection capacity. In the light of these threats and opportunities, this study assessed the resource availability, energy production potential, environmental and regulatory constraints as well as the grid connection and export alternatives for the community-owned projects identified by the Trust.

Overall, the key objective of this assessment study was to analyse the technical, economical, social and environmental feasibility of developing community-owned energy projects on Jura. Thus the undertaken activities focused on assessing the energy resources and analyzing legal frameworks to support the development of renewable energy projects. As such, this report should be viewed as the start of an ongoing set of activities and discussions about renewable energy developments rather than being seen as an end in itself. The study does, however, confirm that there are renewable energy resources that could be profitably exploited and that the future power production potential for the Island of Jura is significant. It is also clear that there are a number of planning and legal issues that would need to be carefully assessed if these developments are to proceed in a sustainable and acceptable manner.

A key finding that has appeared at all levels of the study areas is the present regulatory framework on grid feed-in. This restriction makes it extremely difficult for the community of Jura Island to supply power to the community using the public grid even though it seems to be more profitable than exporting electricity only. Therefore until the modifications proposed by the OfGEM are effected, it is not recommended for the community of Jura to attempt community supply through the public network.

Finally a summary of the technical and economical findings of the various energy components have showed that community-owned projects can be developed for wind, hydro, biogas and waste-heat recovery power plants.

Wind energy potential

The favourable wind condition at the project site at Ardlussa allow for wind energy exploitation with optimally three feasible scenarios. The scenario found fitting to the present situation is the installation of one 50kW wind turbine at the proposed site. This option yields an annual energy output of approximately 239,201 kWh/year with a payback period of 10.4 years. A larger capacity turbine however would generate more energy and provide more attractive economics if constraints of grid is solved. The 50 kW wind turbine can be installed nearly on the top of Ardlussa hill with a tip height of about 40.1 meters.

Hydro power potential

The results of the hydrology study conducted on the Corran river shows that it is both economically and technically feasible to develop a small hydropower scheme on the river. A 330 kW capacity hydropower plant is found to be the most beneficial in terms of energy produced per year (1344 MWh /year), however it would operate at full capacity for less hours of the year. The capacity factor of 330 kW would be 46.5%. A 100 kW and 50 kW would operate at full capacity for more hours per year and would produce 596 and 334.5 MWh/year respectively. The capacity factor would be 68% and 76.4% respectively.

Heat Recovery and Biogas potential

The energy retained by the waste water, pot ale and spent lee from the Jura distillery is high. This can effectively be used to produce heat energy and electricity. Installing a CHP system fed from biogas produced by the fermentation of pot ale and spent lee with a 50 kWe or with 155 kWe CHP plant is financially feasible. Nonetheless, for the implementation of the CHP project the distillery support is vital. If the distillery shows no interest in the CHP project, the waste heat recovery project would be the second alternative. A detailed study by a specialised HVAC engineer is recommended for the implementation of this project.

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1 INTRODUCTION

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For the past ten years, the University of Flensburg has been working in close collaboration with Community Energy Scotland (CES) on various energy and environmental studies on island communities in Scotland.

1.1 Background

The Isle of Jura, like most of Scotland is endowed with an abundance of renewable energy resources including wind, biomass and small hydro. Situated in the path of the west flowing winds of the North Atlantic, there is a constant flow of warm, moist air which accounts for the good wind speeds and high rain levels (Feolin Study Centre 2005, 13). In the face of increasing fossil fuel prices and occasional disruptions to power supply, embedded generation from locally available renewable resources is an attractive alternative. Indeed, small hydro power plants, one of which is still running with an output of 29 kW, have been used for decades on the island. Biomass in the form of wood and peat are also widely used for heating by the households. There is also a 6 kW off-grid wind turbine installed on north of the island. Results of a survey conducted by the team on the island showed that most members of the community support renewable energy projects in general and a community owned project in particular as indicated in Figure 1-1.

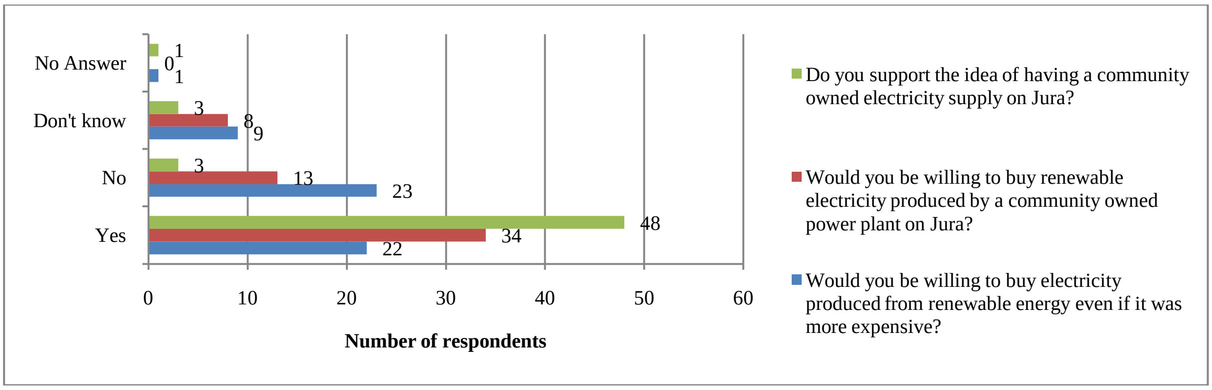


Figure 1-1: Results of door-to-door survey on community support for renewable energy projects

Members of the community are also generally aware of ongoing energy projects being evaluated by the Trust as is illustrated in Figure 1-2. Details are included in Annex 1.

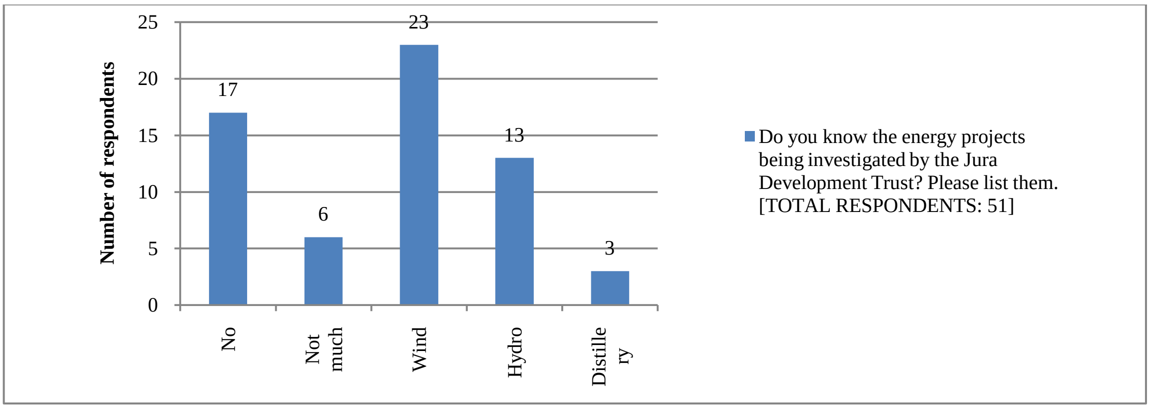


Figure 1-2 Survey results showing awareness of energy projects under investigation

However, most of Jura are designated National Scenic Areas. This places legal constraints and introduces additional requirements for consideration when planning power projects on the island. Despite these constraints, the installed capacity of embedded generation sources is increasing due to various financial incentives provided by the Scottish and UK governments to increase the share of renewable energy in the generation mix. The Inver Estate of Jura is scheduled to commission a 1 MW (expandable to 2 MW) hydro plant in April 2012. The Ardlussa and Forest Estates on the island are also planning two hydro schemes with outputs of 150 kW and 100 kW respectively. All three projects are privately owned and their benefits to the community pale in comparison with a community-owned project.

Sizable community-owned renewable projects can reduce the community’s dependence on fossil fuels, increase awareness of energy issues, increase energy efficiency across the community and subsequently reduce energy costs and carbon emissions. Income generated from such projects can also lead to more self-sufficiency and significantly reduces grant dependency. (Community Energy Scotland n.d., 56)

The Jura Development Trust (JDT), with the support of Community Energy Scotland (CES) has already taken the initiative to investigate the framework and procedures for development according to the National Scottish Policy. The findings of that study identified the Corran River and Ardlussa as suitable areas for a small-hydro plant and wind turbines respectively that are most likely to comply with regulations of the Scottish Natural Heritage.

Small-scaled community-owned projects such as those under consideration by the JDT are particularly susceptible to the risks of planning permission and limited grid access which may reduce the potential output of the project or may take a long time to obtain. There are a large number of distributed/embedded generators on the grid in Argyll. There are thus significant upgrades required before any other connections are possible. Therefore access to the grid is very competitive and a date when connection is possible could be a “significant number of years in the future” Unofficial discussions with Scottish and Southern Energy (SSE), the Distribution Network Operator (DNO) in Jura indicate a 50kW limitation connection capacity. (Community Energy Scotland n.d., Annex, p. 22)

In the light of these threats and opportunities, this study assesses the resource availability, energy production potential, environmental and regulatory constraints as well as the grid connection and export alternatives for the community-owned projects identified by the Trust.

1.2 Objectives

The overall objective of the assessment study was to analyse the technical, economical, social and environmental feasibility of developing community-owned renewable energy plants on Jura. The specific objectives were to assess:

- the feasibility of installing small or medium sized wind generators at Ardlussa, north of Jura;
- the feasibility of developing a small hydro power plant on the Corran river;
- the feasibility of recovering heat from the cooling water of the Jura Whisky Distillery and combined heat and power generation with an anaerobic digester using waste from the Distillery; and
- grid feed-in options to optimise income generation for the community.

Given that the primary aim of the assessment is to provide a credible estimate of acceptable energy production on the island, the factors chosen for investigation cover the major contributory factors, but are not necessarily exhaustive.

1.3 General methodology

The methodology employed to meet the objectives was to continue with desk studies which were started in Flensburg, to gain insight into the existing situation. This involved a review of previous work done, the relevant regulations and available appropriate technology. During the first week, the team visited several installations and projects on the island that are of particular interest to the reference study. The project sites were also visited several times to collect or ascertain data and interview relevant stakeholders. Various computer programmes were used for analyses. This included the development of models for simulations. Community consultations and acceptance are key to the success of a community owned project. A door-to-door survey was thus conducted with a structured questionnaire during which households were interviewed to assess their perception towards renewable energy in general, a community-owned project in particular and awareness of ongoing work by the Trust.

The project was divided into specific components which are classified under four categories according to the various components of the project. These are options for the direct sale of power to the community, hydropower and wind energy potentials as well as energy from heat recovery and anaerobic digestion. The specific methodologies and tools used to accomplish the various objectives are discussed under the respective sections in this report.

2 REGULATORY OPTIONS AND INCENTIVES FOR DISTRIBUTED GENERATION

The Scottish government is currently promoting the generation of renewable energy capacity and it is important to understand how these promotional schemes work and their implications in order to maximize benefits for the community.

2.1 Regulatory options for interconnection distributed generation

Under the current regulations, distributed generators with net outputs under 5MW do not require licenses to operate. As outlined in a connection guide developed by the Energy Networks Association (2011,p. 22), the installation of these plants is governed by standards outlined in the following Engineering Recommendation (ER) documents:

- ER G83/1-1: Recommendations for the installation of Small-Scale Embedded Generators – up to 16A per phase – in parallel with low-voltage distribution networks. This corresponds to around 3.68kW on a single phase and 11.04 kW on a three-phase supply.
    - ER G83/1-1 Stage 1 outlines the standards for the connection of a single G83/1-1 unit.
    - ER G83/1-1 Stage 2 outlines the standards for the connection of multiple G83/1-1 units within different customer sites and in close geographic proximity.
- ER G59/2: Recommendations for the connection of units larger than the threshold for G83/1-1. This document also allows for a simplified connection process for generating units with capacities up to 50kW. The process is more rigorous for plants above 50kW. Consent is required from the DNO before connecting any unit classified under G59/2.

These standards reduce the regulatory burden otherwise associated with connecting generators to the public grid. It is currently not possible for a small scale generator to sell electricity to customers through the local public grid. This transaction can only be accomplished through licensed suppliers who buy and sell electricity. The alternative is to construct a privately owned line or network to the premises of the customers – a concept known as “Private wire”. Electricity demand cannot be predicted with full accuracy to the minute and it is necessary to plan for balancing power which is the difference between predicted and actual demand. A project developer supplying through a private network may therefore size the plant to cover these differences but this increases the investment cost. Another option is to install an additional system to provide balancing power at an additional cost. A third option is for the private wire to be connected to the public network for the provision of balancing power. A meter is then installed to record power import from and export to the public network. The cost of balancing power is higher than the cost of normal consumption per customer class. (Energy Networks Association 2011) (OfGEM 2009)

The community of Jura can apply for licensing to supply power from its plants to members of the community. However, this imposes significant regulatory, financial and administrative burdens on the community. The Electricity Act (1989, Clause 11) stipulates that licensed suppliers must be party to

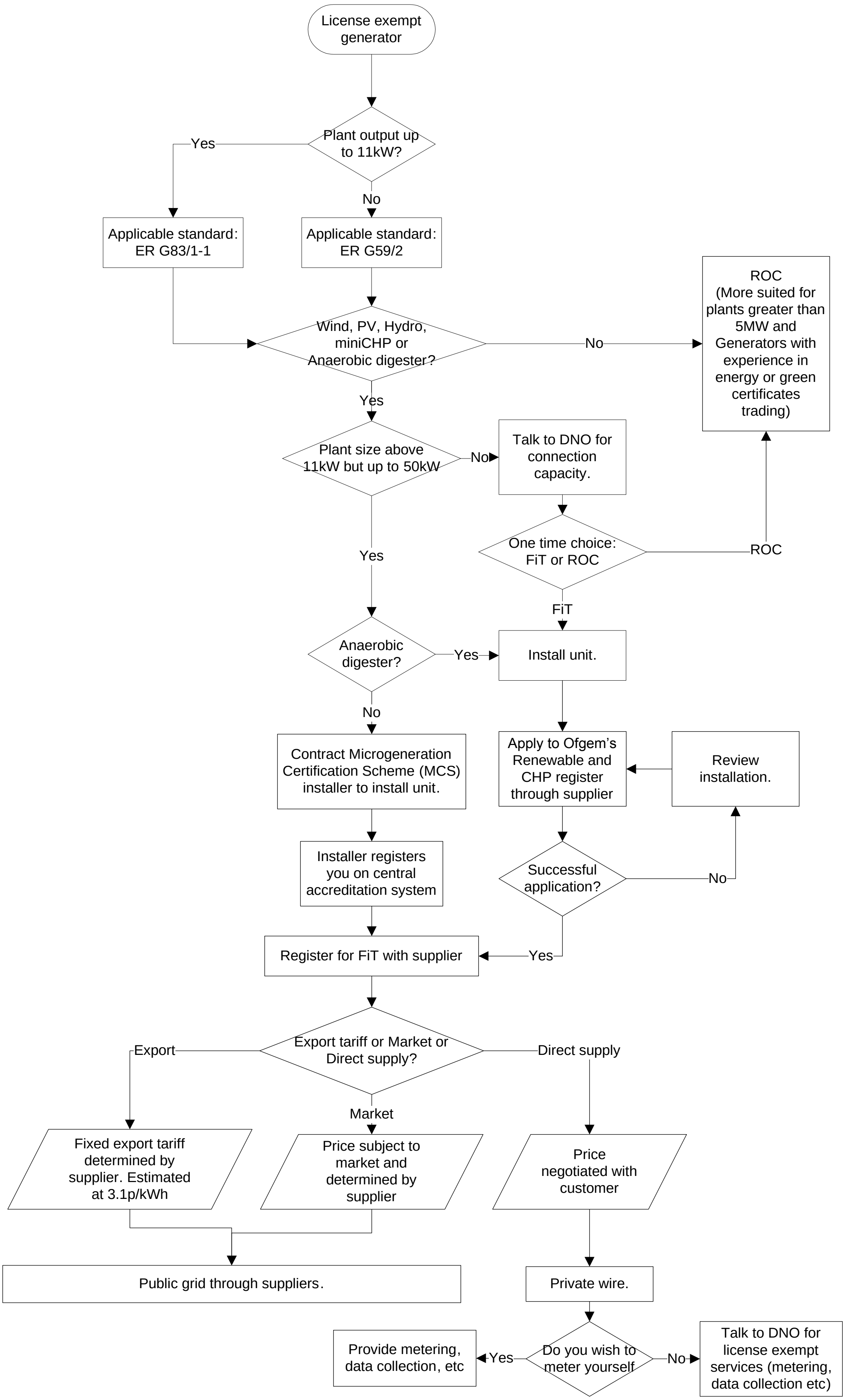


Figure 2-1 Summary of options required for the connection of distributed generation (Produced with data from the connection guide by the ENA)

the Distribution Connection and Use of System Agreement, the Connection and Use of System Code as well as the Balancing and Settlement Code.

The Office of Gas and Electricity Markets (OfGEM) has proposed modifications to make it easier for small suppliers to operate as licensed suppliers on the public network. This modification will provide an option for derogation from the requirement to be a direct party to the industry codes in the electricity supply licence condition. This modification will reduce the costs, complexities and risks associated with small-scale licensed supply.

Until the modifications proposed by the OfGEM are effected, it is not recommended for the community of Jura to attempt community supply through the public network.

2.2 Financial incentives for distributed generation

There are currently two different incentives to promote the generation of electricity coming from renewables in Scotland; the Renewable Obligation Certificates (ROCs) and the Feed in Tariffs (FiTs).

2.2.1 ROCs and FIT

The ROC system provides certificates for each MWh of electricity generated from a renewable source. The amount of certificates received by each supplier depends on the technology used. Electricity suppliers are expected to comply with a minimum amount of renewable certificates which means that for each MWh of electricity produced, there should be a percentage of electricity generated from a renewable source. If the supplier is not able to comply with the amount of certificates required it is fined for the amount of certificates missing.

According to the Scottish government, the amount of ROCs required between 2011 and 2013 are:

- From 1st April 2011 to 31st March 2012 the ROCs should be of 0.124 ROCs per MWh. (The Scottish Government 2011e)
- From 1st April 2012 to 31st March 2013 the ROCs should be of 0.158 ROCs per MWh. (The Scottish Government 2011d)

The disadvantage of this mechanism is that it requires licensed suppliers. These licensed suppliers combine their pool of renewable energies in order to satisfy the amount of ROCs that they should emit. This method does not guarantee the price of the ROCs and causes uncertainty especially in small producers that do not have enough knowledge of the energy business.

This regulation discourages small producers due to the complexity and uncertainty of the mechanism to trade certificates.

The second mechanism, which is more suited to small-scale generation, is the Feed-in-tariff (FiT) scheme. The FIT applies under two schemes, the microgeneration scheme and the small generation facilities scheme. The micro-electricity technologies that are supported are solar PV, micro-wind turbines, micro-hydro and micro-CHP.

FITs are paid per unit output once the plant complies with the standards of the Office of Gas and Electricity Markets (OfGem). This is irrespective of whether generated energy is consumed on site or exported. Refurbished and second hand installations are not eligible for FiTs because such units may have already benefited from some sort of incentives. (Office of the Gas and Electricity Markets 2011b) .

Systems above 50 kW and up to 5 MW are eligible for FiTs but would need to be accredited by the OFGEM through a relatively rigorous process compared with plants under 50kW. The amount of money that can be received under the FIT varies according to the technology and size of the installation. The capacity limit for CHP plants that run on fossil fuels is 2 kW. The FiT table is included in ANNEX 2. (The Scottish Government 2011f) (Energy saving trust 2011b)

In conclusion, the FIT scheme is more suited to generate income from renewable energy sources with community owned generation facilities on the island of Jura. FITs, once approved, assure a steady stream of income for a period of 20 years. In contrast, the future value of ROCs is not certain which risks the economically viability of the project.

2.2.2 Power purchase agreements (PPA)

In addition to the benefits of FiTs and ROCs, distributed generators receive income for power sold to direct customers or exported to the public grid through electricity suppliers. The terms and conditions for these tariffs are agreed on in Power Purchase Agreements (PPAs). The export tariff is currently set at 3.2p/kWh[1] for 2012/2013. If a generator can control its output (e.g. biogas) and guarantee to supply electricity at peak times, then they can receive a higher PPA through a non-fixed price contract.

[1] price for 2012/2013

3 ASSESSMENT OF WIND ENERGY RESOURCES AND TECHNOLOGIES AT ARDLUSSA

3.1 Introduction

This part of the report describes the findings of the assessment study conducted for a proposed community-owned wind energy project at Ardlussa. The JDT initially identified a site at Cnoc an Lomair, Ardlussa (56^{0}01’51.66”N, 05^{0}46’27.70”W) for the project and a wind mast was installed at this location to record wind speeds. However, Jura is one of the 40 National Scenic Areas (NSAs) of Scotland and the Scottish National Heritage (SNH) is generally opposed to the erection of any tall structure(s) on the Island. A ‘Landscape design strategy[2]’ study by Green Cat Renewables Ltd therefore identified an alternative site which could also be used for the project. The alternative site is in the western escarpment of Cnoc na Glaic Moire (56^{0}02’22.74”N, 05^{0}45’55.99”) and approximately 1.2km north of the proposed site. The wind turbines are less visible from this site.

The study focuses on these two locations. In the report, the locations are referred to as the proposed site and the alternative site.

3.2 Scope

The scope of this part of the study included an assessment of wind resources, the selection of an appropriate turbine and an estimation of feasible annual energy production at Ardlussa. An economic analysis of the project was also carried out on the basis of 100% grid feed-in for all turbine sizes considered. Additionally, the study discusses possible environmental impacts as well as the social acceptance of wind turbines in the community based on results of the survey conducted in the community.

3.3 Methodology

The methodology applied to this study was based on observations and information from the site. It included a review and analysis of the collected data and the development of computer models. The computer programmes - WindPRO and WAsP - were the key software employed to model and simulate calculations of wind resources and energy yields at the Ardlussa sites. In addition, a qualitative household survey was conducted at the start of the study to determine the community’s acceptance of the proposed wind project.

The study considered the following four scenarios based on the Scottish National Heritage (SNH) regulations and grid connection limitations:

- *Scenario 1: 50kW Endurance E-3120 wind turbine installed at the proposed site,* hub height 30.5 m, overall height 40.1 m. This scenario was considered against the backdrop of the grid feed-in limitation on the 33kV transmission line.

[2] Document available at JDT

- *Scenario 2: Three 50kW Endurance E-3120 wind turbines installed at the proposed site.* There is a 50m turbine height restriction at the proposed site and this scenario attempts to maximize energy output whilst complying with this restriction.
- *Scenario 3: 225kW ACSA A27 turbine wind turbine installed at the proposed site,* hub height 31m, overall height 44.5m. This scenario was considered because it meets the height restriction at the proposed site.
- *Scenario 4: 330kW Enercon E33 wind turbine installed at the alternative site, hub height 44 m, overall height 61.7 m.* This scenario was considered because of the 50m turbine height limitation at the proposed site

All costs used in the economics calculation of the study were derived from other completed projects in Scotland. These values and figures were provided by Community Energy Scotland and in some cases directly from the turbine manufactures.

3.4 Analysis of wind energy potential

3.4.1 Wind resource

There is no long-term on-site wind data for the identified sites and the Measure-Correlate-Predict (MCP) toolbox in WindPRO was used to generate a long term corrected wind data for the study. Thus the wind resource analysis is based on data from three sources:

- On-site wind measured at 10 meters height at Ardlussa (4months data).
- On-site wind data measured at 10 meters height at Kilchoan (1year data).
- Long term (2003 to 2012) METAR wind data for the nearest measuring station at Campbell Town ($55^0$43'N, $05^0$68W) provided online by EMD for use in the MCP toolbox of WindPRO.

The measured data from Kilchoan was used to correlate and predict one year data for Ardlussa. Due to the variability of wind conditions over a longer period of time, a one year data cannot be taken as a representative wind data for the site. It was thus necessary to generate long term data for Ardlussa using the nine year wind data from 2003 to 2012. Site specific wind distribution was then produced using roughness classifications, obstacles and wind statistics generated by WAsP. The surrounding terrain is largely open moorland occasionally broken by small hills. The roughness classification – a measure of the obstacles on the terrain – that was used is included in Annex 3: Table 1. The proposed site and alternative site are 110 m and 95 m above sea level respectively. Hills and Paps with higher altitudes within a 20km radius were considered during the development of the model of the surrounding terrain. The most noticeable obstacles are the Paps of Jura which are located in the West South West (WSW) sector at a distance of 18.8 km from the proposed site

A summary of the mean wind speeds at 10m used for MCP is given in Table 3-1. It can be seen from the table that the four month measured data at Ardlussa was during a high wind period. The MCP long term mean wind speed for Ardlussa was found to be 8.62 m/s at 10 m.

Table 3-1 Mean wind speeds at 10 meter of the MCP analysis

Four months mean wind speed at Ardlussa	9.11 m/s
One year mean wind speed at Ardlussa (MCP result using four months Ardlussa and one year Kilchoan data	7.9 m/s
Mean wind speed of four months of the MCP result using Kilchoan data which coincides with the measurement period at Ardlussa (Four months concurrent mean wind speeds MCP result)	8.3 m/s
Nine years long term reference data from EMD mean wind speed	6.22 m/s
Long term corrected mean wind speed for Ardlussa (MCP result with long term EMD data)	8.62 m/s

Figure 3-1 shows that the model adjusted the wind speed values based on the long term data obtained from EMD. The blue colored rose shows the predicted wind speed and frequency for the period time which coincides with the short term measurement period at Ardlussa. The green rose shows the long term one year MCP result for Ardlussa based on the long term data.

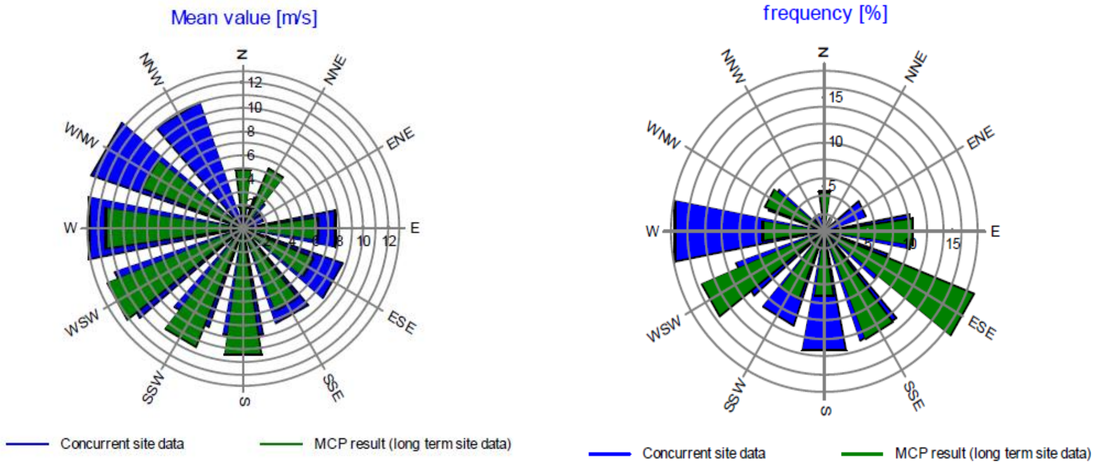


Figure 3-1 Concurrent site measurement data and MCP result at Ardlussa

A regression best fit diagram of the MCP long term data and short term wind data at Ardlussa for sectors 120 degrees and 240 degrees is shown in Figure 3-2 to compare wind speeds between the two sectors. These sectors were chosen because sector 120 degrees contains the most frequent wind speeds and sector 240 degrees covers high wind speeds.

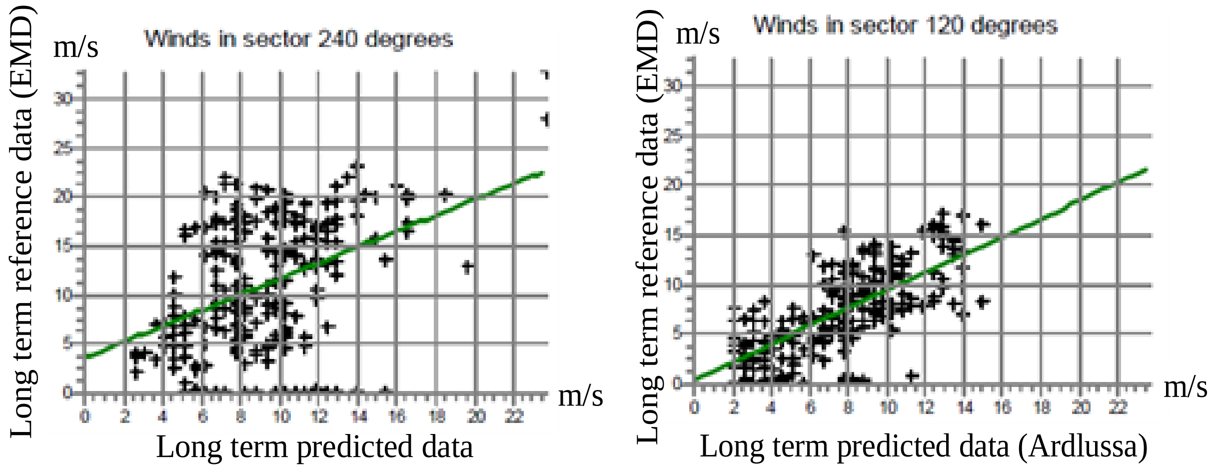


Figure 3-2 Regression best fit

The Paps in the southwest reduce wind speeds and this can be observed in Figure 3-3 which shows a comparison between the sector-wise distribution of wind speeds on a flat terrain without obstacles and the wind distribution of the local site considering obstacles and hills. It shows that higher wind speeds blow from the southwest. However, the most frequent low speed wind blows from the Southeast. This sector-wise frequency of wind speeds is shown in **Figure 3-3**. The green color represents the wind speed and frequency on a flat terrain and the wind speed and frequency given in blue stand for the terrain and obstacle corrected data. The Weibull distribution of the wind data is included in the appendix (Annex 3: Figure 1).

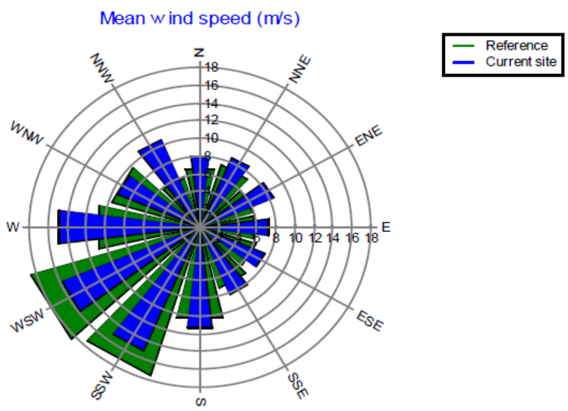


Figure 3-3 Mean wind speed distribution by sector

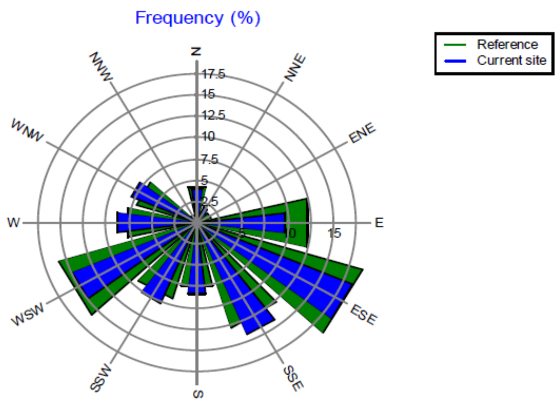


Figure 3-4 Frequency of wind speeds by sector

3.4.2 Selection of wind turbine and other technical components

The sites in reference are suitably located in a high wind speed area. Thus, the wind turbine(s) considered should be capable of overcoming strong turbulence and gusty winds. Fortunately, the UK market provides a preponderant list of wind generators that are designed to operate under these conditions. This therefore narrowed the turbine selection task to the existing regulations for wind project development in Jura.

Suitable Hub height

To meet the 50m height restriction, the wind turbines have been chosen on the basis of finding a good combination of energy yield and suitable tower height.

Figure 3-5 shows five selected turbines of varying hub heights and rated power. The 50m height restriction is indicated by the horizontal red line.

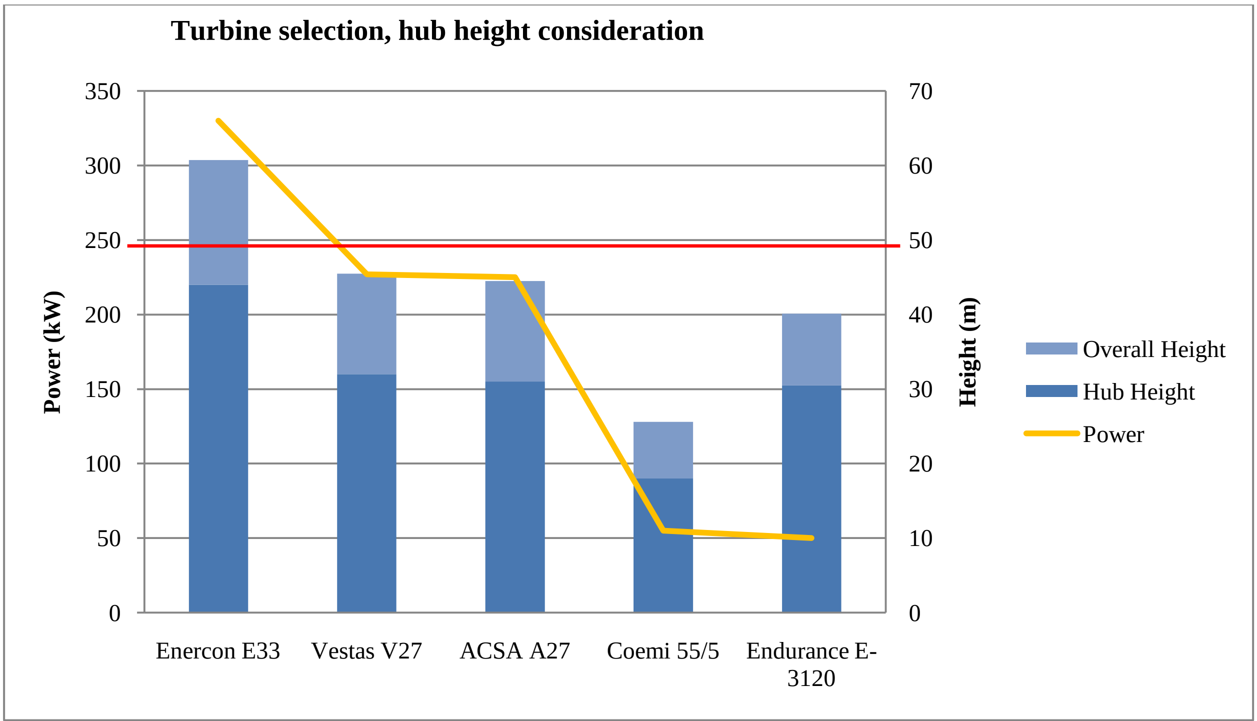


Figure 3-5 Height Consideration

Four of the turbines shortlisted meet the height restriction and one lies completely outside the limit. Based on the wind statistics, the wind predictions for the site and concerns over the landscape, it is recommended to select a turbine(s) with hub height in the range 18-35m for the proposed sites. Qualifying this recommendation to the shortlisted turbines means that the E-3120, Vestas V27, ACSA A27 and Coemi 55/5 turbines are suitable generations for the proposed site. The Coemi 55/5 is however disqualified by virtue of its design characteristics. It functions better at higher mean wind speeds. Vestas V27 has the same rated power capacity as ACSA A27 turbine and furthermore the ACSA turbine is more popular in Scotland. Thus ACSA has been chosen for further analysis along with Endurance at the proposed site. The alternative site on the other hand has no height limitation. The Enercon E33 turbine therefore can only be installed at this location. This turbine is chosen because it is capable of delivering high energy outputs. Finally the Endurance E-3120, the ACSA A27 and the Enercon E33 are the three main turbines chosen for this study.

Suitable Turbine Size

The wind turbines suitable for energy production at Ardlussa have been selected based on the criteria below:

- Energy yield,
- Transportation and access to the project site,
- Availability of operation and maintenance teams,

- Warranty and service contracts,
- Popularity of turbine in Scotland or those on the UK market.

The data on wind turbine manufacturers and suppliers in the UK showed that most of them offered a standard 2-year parts and labor warranty; which includes a power curve and availability warranty for generators under 500kW. It is also common for turbine manufacturers to extend the warranty to 5 years at an additional cost. These warranties address design and manufacturing flaws and provide replacement parts and labor. A turbine supplier from within the Argyll and Bute region is therefore preferred. Another advantage of this choice is that transportation costs will be significantly reduced.

Access to the site is a point of concern. Jura has one main road (A846) running from Feolin in the South to Lussagiven in the North. From Lussagiven it is only possible to access the sites through private roads on the Fletcher estate. These roads are narrow and in poor conditions. They will require improvement and upgrade before considering them as transportation routes for the bulky turbine parts and installation equipments, especially the crane.

Consequently, the only option of transporting them would be by ferry-shipment to the closest Pier at Ardlussa. These transportation options certainly increase costs and overheads of the project. A market survey that has been conducted to identify airlifting services in Scotland showed a number of companies are involved in the reference business with reckoned experience in maneuvering the Scottish climatic conditions.

3.4.3 Annual energy production

The amount of electricity production for the evaluated scenarios has been mentioned in Table 3-2:

Table 3-2: Annual energy production from wind

Scenario	Site	Generator	Rated Power, (kW)	Hub Height, (m)	Capacity Factor, %	Net Annual Energy Production (MWh)
1	Proposed site	Endurance E-3120-50	50	30.5	60.6	239
2	Proposed site	Endurance E-3120-50	3 x 50	30.5	59.0	698
3	Proposed site	ACSA-A27-225	225	31	43.3	768
4	Alternative site	Enercon E-33-330	330	44	49.7	1295

The net annual energy production is calculated by deducting the losses due to wind turbulence, connection losses and uncertainties of wind power from the gross energy production. Based on the surrounding terrain description (e.g. roughness, hills and other obstacles) the gross energy productions from 12 directions for the three scenarios are discussed.

Scenario 1 (1x50 kW)

The maximum amount of gross energy obtainable from the West South-West direction (WSW) is 48.6 MWh as shown in Figure 3-6. Thus, one fifth of the total energy is derived from WSW direction.

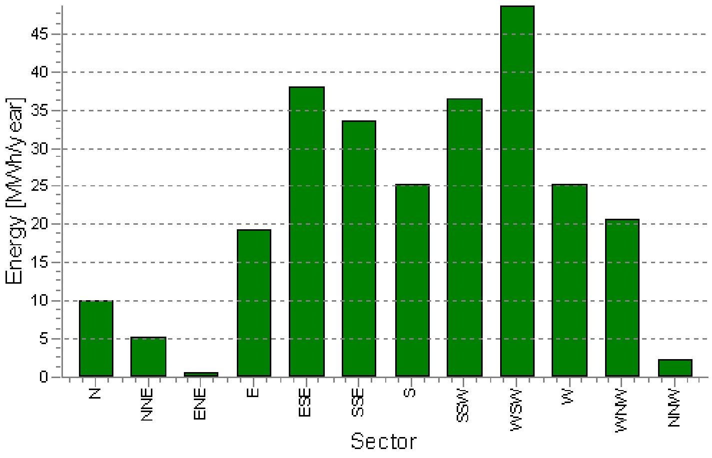


Figure 3-6 Sector wise Energy for scenario 1 (1 X 50 kW)

Scenario 2 (3x50 kW)

The annual gross energy production varies in the second scenario according to the array of the three turbines. Due to array losses when the turbines are in a linear position the annual gross energy production is 8.7 MWh (775.8-761.1 MWh) less than the annual gross energy production when the turbines are installed in a triangular position (refer to Figure 3-7).

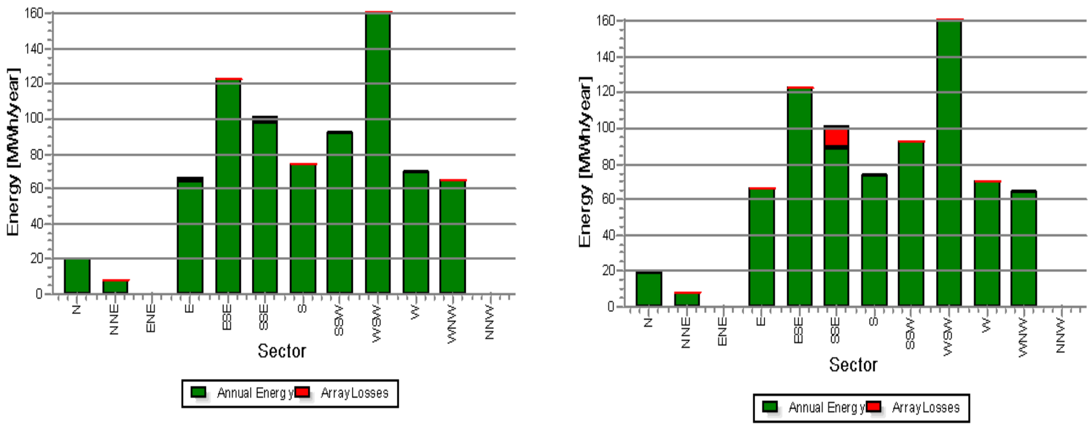


Figure 3-7 Sector wise energy production for Triangular and linear position

The energy produced from the WNW direction wind for scenarios 1 & 2 is 1.4% less than energy produced from the WSW direction due to the Paps of Jura which are located 18.8 km away from the site as shown in Figure 3-8.

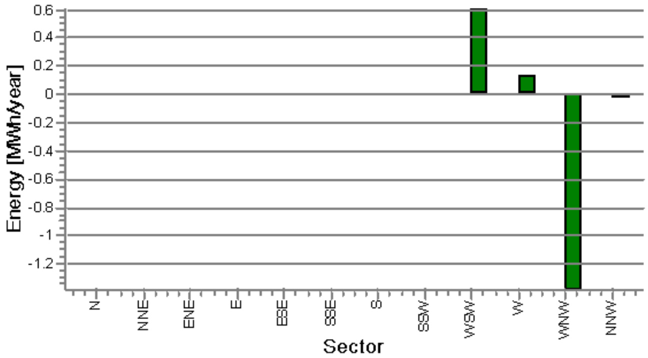


Figure 3-8 Impact of hills and obstacles on scenario 1 & 2

<u>**Scenario 3 (1x330 kW)**</u>

The maximum contributing sector in total gross energy production in this scenario is again from the WSW direction accounting for 18.59% (267.4 out of 1438.7 MWh) of the total energy. The reduction in gross energy due to the Paps is around 13% which is much higher than that of scenarios 1 & 2 (Figure 3-10).

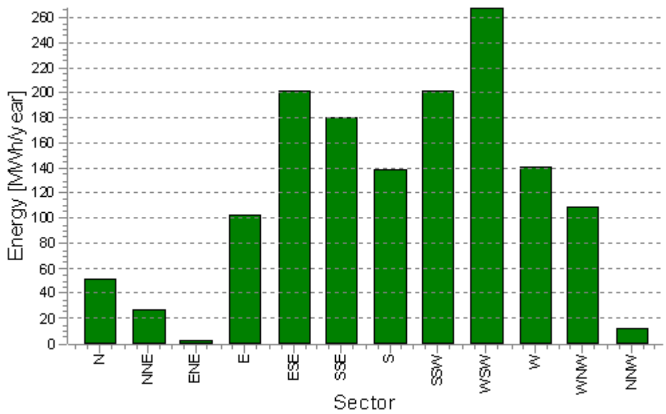


Figure 3-9 Sector wise energy for scenario 3

Figure 3-10 Scenario 3 - Impact of hills and obstacles

3.4.4 Grid connection

In order to meet technical and economic requirements, the wind turbines are connected to the nearest point of the existing grid. This not only reduces the connection cost, but also the power losses and voltage drop on the connection lines. The proposed connecting points are shown in the Figure 3-11 and the Figure 3-12.

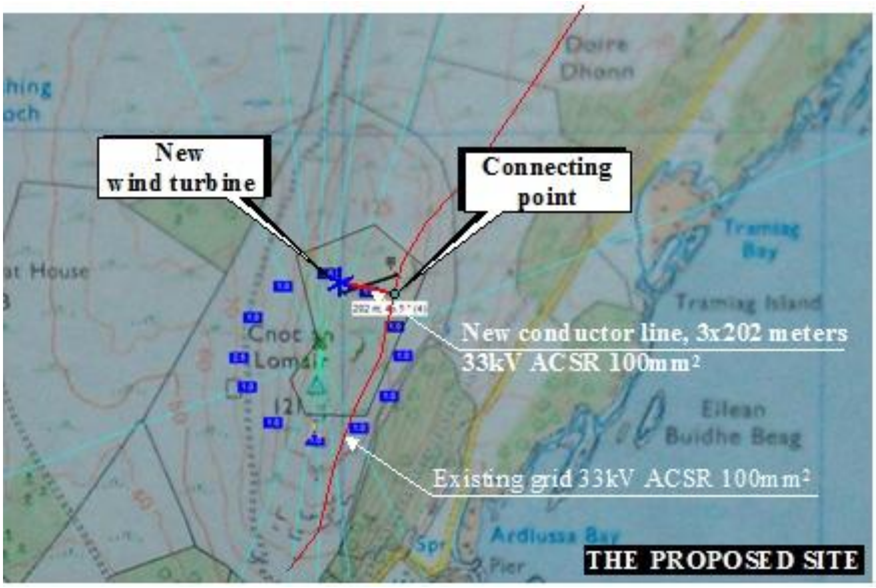


Figure 3-11 Proposed connecting point of the wind turbine (the proposed site)

For the proposed site (scenario 1x50kW and scenario 3x50kW), the distance from the wind turbine(s) to the connecting point is 202 meters.

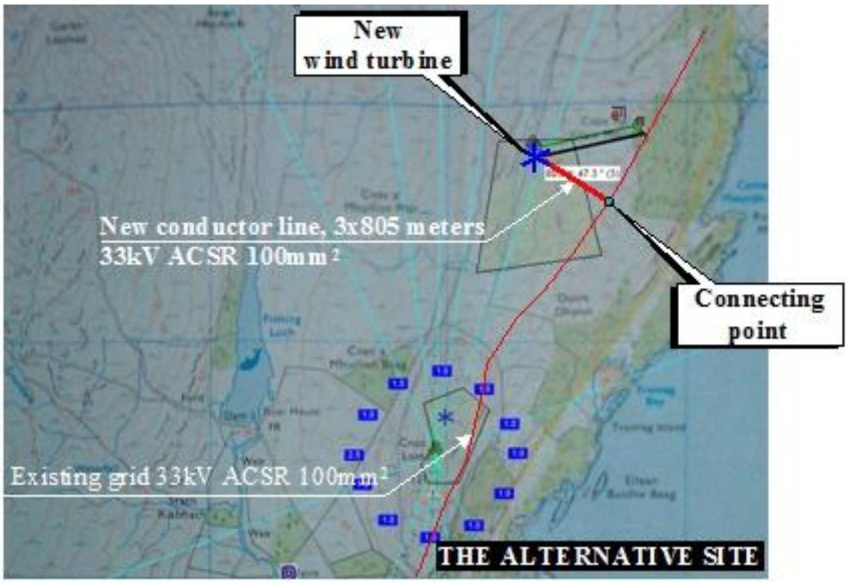


Figure 3-12 Proposed connecting point of the wind turbine (the alternative site)

For the alternative site (scenario 1x330kW), the distance from the wind turbine to the connecting point is 805 meters.

Conductor type

There will be two options of conductor type for grid connection in both proposed sites: The first option is to install a new overhead line with the same voltage level and cross sectional area with the existing grid to connect the new wind turbine to the existing gird. The second option is to install an underground cable to connect the new wind turbine to the existing grid. However, this option is, on average, three times more expensive and is not considered further.

Grid connection structure

The grid connection structure is described in the Figure 3-13. A small substation is needed to transform the electricity from 480VAC of the wind turbine to 33 kV of the existing grid. A standard 3-wire overhead line system mounted on wooden poles would then link this substation to the nearest suitable point of the grid through switchgears.

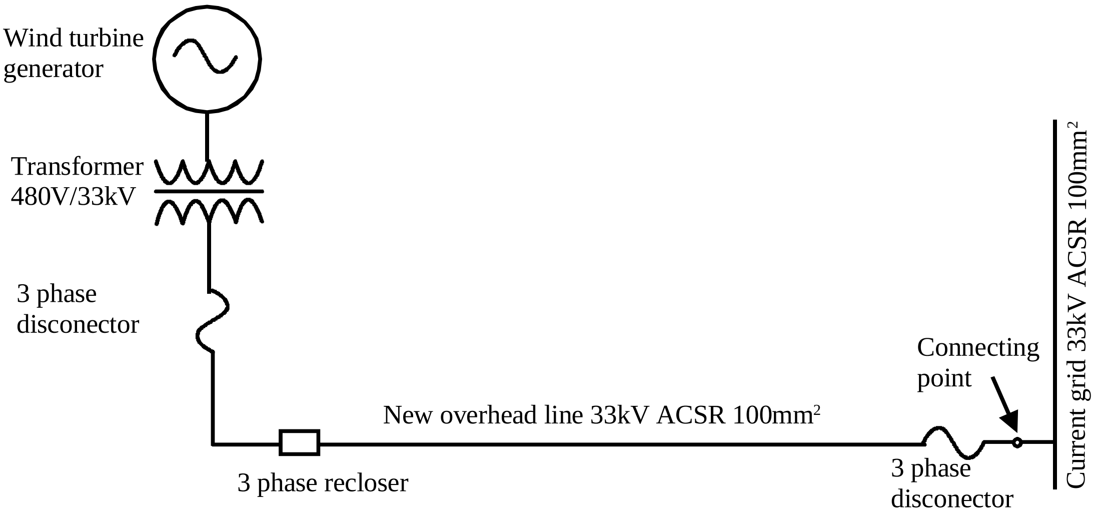


Figure 3-13 Grid connection structure

When implementing the detailed design of the grid connection, some typical technical requirements such as operating voltage levels and voltage flicker need to be carefully considered to ensure the power quality on the grid.

3.5 Economic analysis

In the economic analysis, the identified parameters applied for calculations include:

- investment cost of the wind turbine(s)
- operating & maintenance cost
- electricity prices (FIT and export tariff)

The relevant costs and parameters used in the economic analysis are listed in Table 3-3. The Capital Investment, operating and maintenance cost for Endurance, Enercon and ACSA turbines were obtained from Manufacturers' catalogues. Feed in tariff, export tariff, and grid connection costs have been adapted from OFGEM. Road construction and upgrade cost were obtained from the Forestry Commission, Scotland (2005). Terminal equipment cost (Aquatera Ltd 2005)

Table 3-3 Cost and parameters for economic analysis.

Economic cost		**Endurance E3120-50kW**	**ACSA A27 225kW**	**Enercon E-33 330kW**
Investment cost of wind turbine		£259,000 (including 5 year service & maintenance plan)	£500,000	£700,000
Annual O&M cost[3]		£1,250	£12,600	£20,000
Road construction and upgrade cost		Existing: 0.2kmx55,147£/km New: 0.5kmx110,294£/km Total = £66,176	Existing: 0.2kmx55,147£/km New: 0.5kmx110,294£/km Total= £66,176	Existing: 0.7kmx55,147£/km New: 1kmx110,294£/km Total= £148,897
Transportation cost[4]		£3,000	£3,000	£3,000
Investment cost of 3phases 33kV distribution line (conductors, poles, etc.)		79,159£/km x 0.202km = 15,990£	79,159£/km x 0.202km = 15,990£	79,159£/km x 0.805km = 63,723£
Investment cost of terminal equipment (switchgears, transformers, etc.) and labour	Construction and craneage	60,000 £	60,000 £	60,000 £
	Transformer	9,000 £	9,000 £	0.00
	Other equipment (on-site electrical)	25,000 £	25,000 £	25,000 £
	Labour	10,000 £	10,000 £	10,000 £
	Decommissioning (bond or amount invested)	15,000 £	15,000 £	15,000 £
Feed-in tariff		£0.254	£0.206	£0.206
Duration of FIT		20 years	20 years	20 years
Export tariff		£0.032	£0.032	£0.032
Annual interest rate		6.5%	6.5%	6.5%
Lifetime		20 years	20 years	20 years

The results produced in the economic analysis show that all the four scenarios are economically feasible as tabulated below.

[3] Data obtained from the manufacturers
[4] This cost considers only a single trip for the vessel. Transportation cost from manufacturer's warehouse to the harbour is included in the turbine cost.

Table 3-4 Results of profitability criteria

	Scenario 1 (1x50kW)	**Scenario 2 (3x50kW)**	**Scenario 3 (1x225kW)**	**Scenario 4 (1x330kW)**
Total investment (£)	£463,166	£981,166	£704,166	£1,025,620
FIT income (£/year)	£60,757	£143,830	£158,224	£261,169
Export income (£/year)	£7,654	£22,343	£24,578	£40,570
O &M cost (£/year)	£1,250	£ 3x1,250	£12,600	£20,000
Loan and interest payments (year 1-15) (£/year)	£49,259	£104,350	£74,890	£109,077
Net profit before tax (year 1-15) (£/year)	£19,153	£61,823	£95,312	£172,661
Net profit before tax (year 16-20) (£/year)	£67,162	£162,423	£170,202	£281,739
IRR (%)	13.4	15.9	23.7	27.1
NPV (£)	263,710	770,404	1,086,817	1,931,363
PbP (years)	10.4	8.7	5.5	4.7

Details of calculation results (cash flow, income, expenditures) are shown Annex 3: Table 2 to Annex 3: Table 5.

From the economic point of view, scenario 4 (Enercon E33 330kW) yields the highest profit. The main reason is that the specific investment cost in £/kW is much lower than in scenario 1 and 2 and the net energy production of the 330kW wind turbine in the scenario 4 is 1,295 MWh/year, much higher than those in other scenarios (5.42, 1.67 and 1.69 times higher than scenario 1, 2 and 3), whereas, the FIT and export tariff are not much different among 3 scenarios.

3.6 Environmental impacts and social acceptance

Environmental Impact

The probable impacts of small scale wind energy projects are minimal. However, environmental issues like noise, visual effect and shadows have been considered during the environmental assessment of the wind project.

Noise

The calculation for noise propagation of the proposed turbines Endurance and Enercon has been done in accordance with ISO 9613-2 United Kingdom standard. The noise level propagation in the ambient area after ground attenuation and air absorption is shown in Figure 3-14, Figure 3-15 and Figure 3-16.

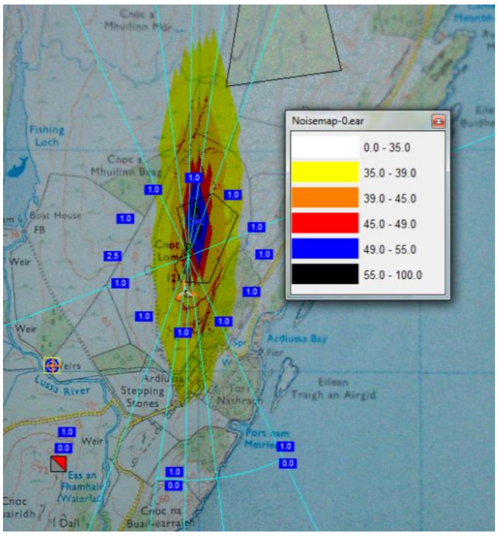


Figure 3-14 Noise propagation- Scenario 1 (50kW)

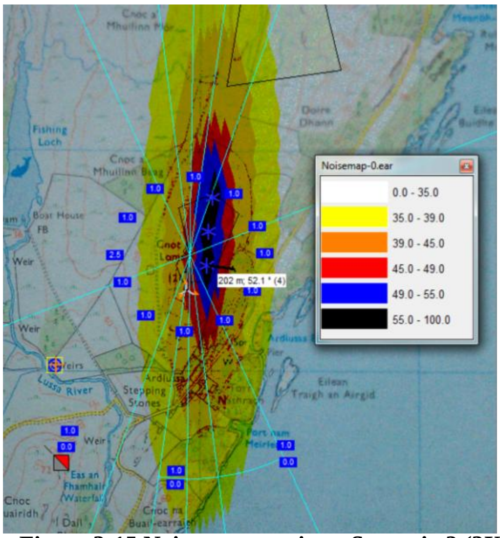


Figure 3-15 Noise propagation - Scenario 2 (3X50kW)

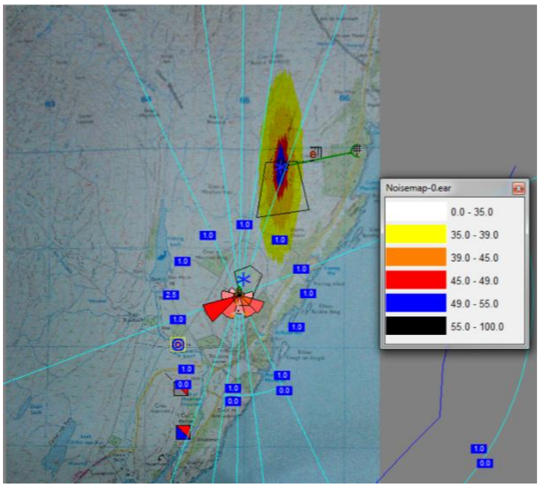


Figure 3-16 Noise propagation – (1X330kW)

According to the settlement types (mixed area with farm, individual houses) of the surrounding area, a threshold value of noise emission in decibel of 60 dB(A) and 45 dB(A) by day and at night respectively has been assumed[5]. Here, to be mentioned that sound is measured on a logarithmic scale called 'Decibel' and expressed as 'dB(A)'. Figure 3-17 shows the noise level typically produced by different sources in the community which would be helpful to realize the magnitude of different decibel level. Thus, it can be seen in all the scenarios that noise propagations from the turbines at the nearby settlements are less than the permissible threshold value.

[5] As the British standards were not available the authors assumed threshold values aaccording to TA Lärm (German Law, Federal Emission Control Act)

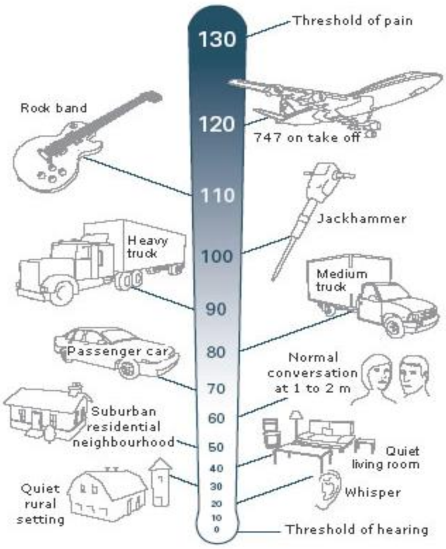


Figure 3-17 Typical sound level from different sources
(Sound Smart Engineering Services 2005)

Visual impact

Figure 3-18**Error! Reference source not found.** to Figure 3-21 show some photomontages developed with WindPRO to help envisage the visual impact of the turbines at Ardlussa. The proposed, efficient turbines with low heights reduce the visual impact. The turbines at the alternative site cannot be seen from the Ardlussa pier side.

Figure 3-19 1x50kW Endurance at proposed site as viewed from Steppingstone (Lussa River Bridge)

Figure 3-18 3x50 kW Endurance at proposed site as viewed from Steppingstone (Lussa River Bridge)

Figure 3-20 1x50kW Endurance at proposed site as viewed from Ardlussa pier

Figure 3-21 1x225 kW ACSA at proposed site as viewed from Steppingstone (Lussa River Bridge)

Birds

In good weather during daytime, the chance of birds flying into the turbine is negligible. Thousands of local birds fly around turbines without any mishap. Accidents occur mainly with the nocturnal migrants flying in large number at low heights. The risk is much higher when the turbines are constructed in the confined flight path of migratory birds. (Dillon Consulting Ltd. 2000, 29) It should therefore be confirmed before project implementation that the proposed site is not within the regular flying zone of migratory birds.

Shadow

The proposed sites have no settlement nearby; therefore shadow and flickering are not issues of concern.

Social Acceptance

The social acceptance of the wind energy project has been analysed through the review of the responses of the survey done amongst the residents of Jura. It was observed that 61.8% of the sample population perceive small to medium scale wind energy project will have no negative environmental impact (Figure 3-22). 5.5% of the respondents are not aware of the potential environmental issues. The remaining 32.7% are concerned about the negative impact of wind projects. Concerns raised by this 32.7% mainly included damage of natural scenic beauty. 5 out of 55 respondents also indicated bird casualties as an issue of concern. Thus, the overall social acceptance of wind turbines in the society is positive.

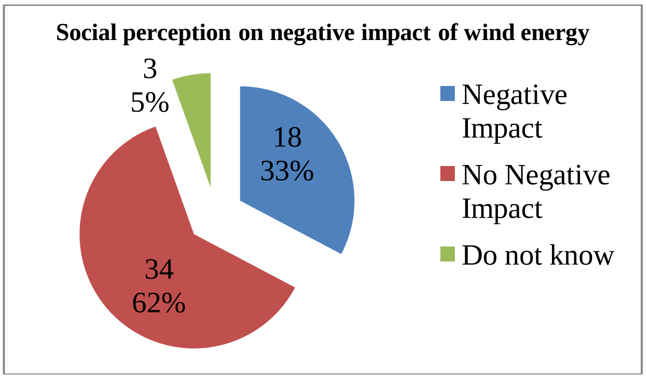


Figure 3-22 Perception on environmental impact of wind energy

3.7 Legal & Authorization Process

A national policy document, “Designing Places: A Policy Statement for Scotland”, stipulates that a design framework must be developed prior to the commencement of the project and identifies a set of principles to which the proposed project must adhere to. In the case of Jura, the design framework and principles were completed in February, 2012 and the findings are presented in the “Landscape Design Strategy” report. The key design principles identified by that study are summarized as:

- Overall turbine to hill height ratio should be 1:3.
- The project site should not lie within the Golden Eagle protection areas.

Another issue that should be considered in this section is the development land allocated to the project. The consent or buy-in of the estate owners is important if the project is to be successful. Fortunately, this is the case for the Ardlussa land.

3.8 Conclusion & suggestions

Due to the favourable wind condition at the project site at Ardlussa, all scenarios of the project in general are feasible. In the context of the present situation, the economic analysis and the evaluation of the legal and authorization processes, the option of 1x50kW wind turbine is proposed for installation at Ardlussa. This option yields an annual energy output of approximately 239,201 kWh/year. The annual net profit before tax for one 50 kW turbine would be 19,153 £/year during the first 15 years of operation when the loan still has to be paid back, and 67,162 £/year for year 16-20, and the total annual revenue is 68,412 £/year. The payback period is 10.4 years. An Enercon E-33 would generate approximately 1,295,000 kWh/year. The annual net profit before tax for this turbine would be 172,661 £/year during the first 15 years of operation when the loan still has to be paid back, and 281,739 £/year for year 16-20. Enercon would be the best option, but due to the grid constraints, currently only a 50 kW turbine is possible.

The 50 kW wind turbine can be installed nearly on the top of Ardlussa hill with the tip height of about 40.1 meters. The dimensions and location of the wind turbine do not appear to have a significant impact on surrounding environment and wildlife on Jura Island. Furthermore, the overall social acceptance of wind turbines in the society is positive.

4 ASSESSMENT OF HYDRO POWER RESOURCES AND TECHNOLOGIES AT CORRAN RIVER

4.1 Introduction

Jura Island has significant potential for small scale hydropower plants. At present three hydropower schemes are at different stages of development namely in the Inver, Forest and Ardlussa Estates. This section of the report presents the analysis and findings of the study conducted to assess the hydropower potential for a small run of river hydropower plant at Corran River which will be owned by the Jura community itself.

4.2 Scope

The study covers the initial technical and economical assessment including an estimate of energy outputs and monetary benefits from feasible plant capacities. It discusses technical design details only to the extent that is required for a realistic cost estimation. The study also discusses the social acceptance of the proposed hydropower plant by members of the Jura community and highlights possible environmental impact assessment requirements as well as legal / authorization aspects.

4.3 Methodologies

The study was performed in the order shown in Figure 4-1.

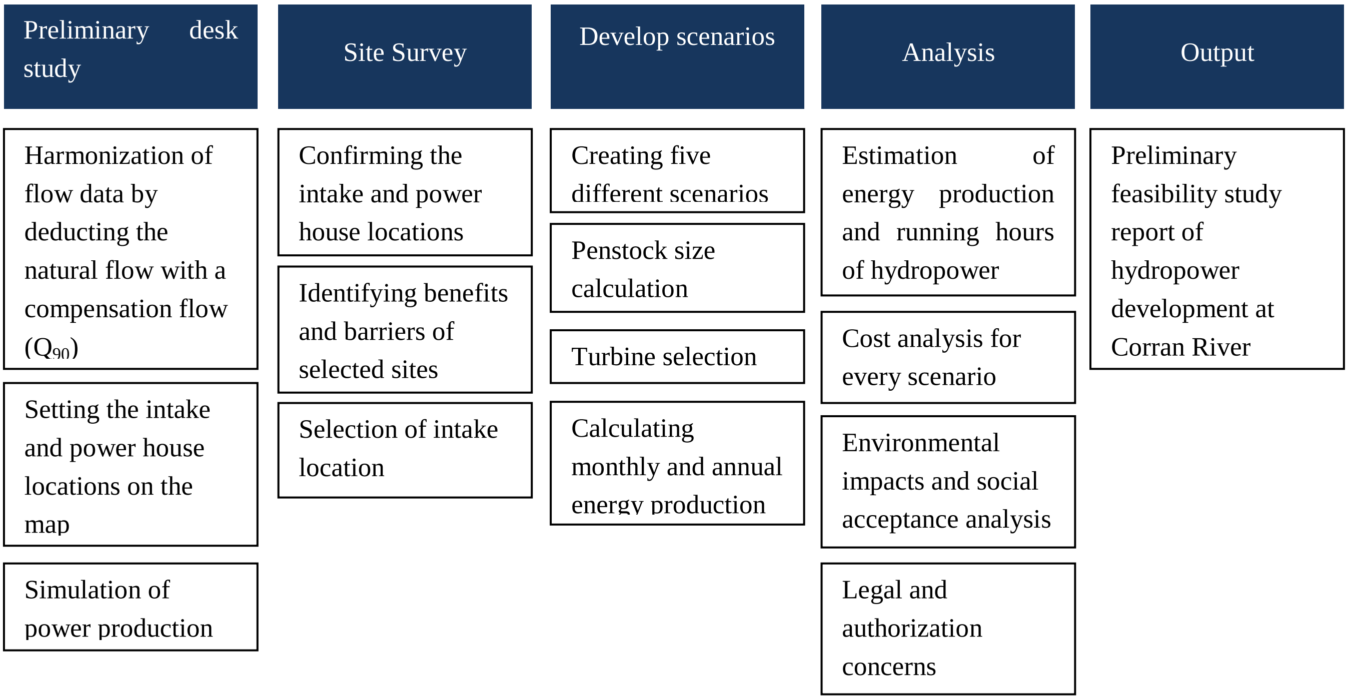


Figure 4-1: Research flowchart

4.4 Analysis of hydro power potential

4.4.1 Hydro resource and comparison of different intake options

Corran River originates at the outlet of Loch an t-Siob at an elevation of 170 meters above sea level. Three intake options at coordinates 5225/7350 (Intake 1), 5270/7360 (Intake 2) and 5292/7345 (Intake3) have been considered as shown in Figure 4-3. Intake 1 is located immediately downstream the outlet of the Loch with highest elevation (170 m) followed by Intake 2 and 3 further downstream at elevations of 160 and 140 meters respectively.

The catchment area for Intake 1 is 6.614 km^2 as shown in Figure 4-2. Around 75% of the catchment is covered by peat soils and around 22% is covered by mineral soils overlying impermeable bedrock (HydroSolutions 2011). The catchment areas for Intake 2 and Intake 3 are estimated as 7.177 km^2 & 8.494 km^2 respectively.

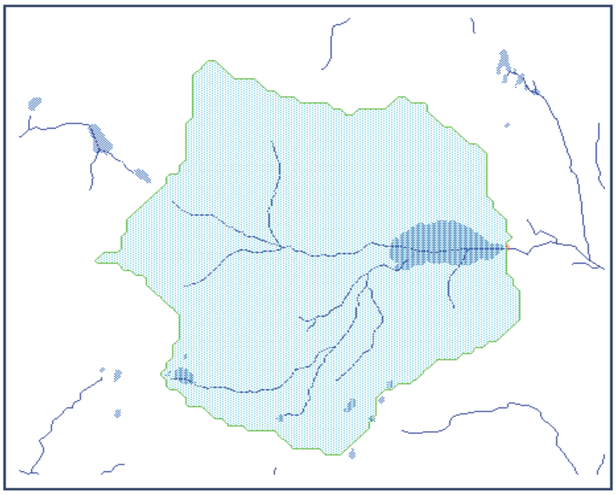


Figure 4-2: Catchment area of Corran river
Source: LowFlows Report 103/11, 2011

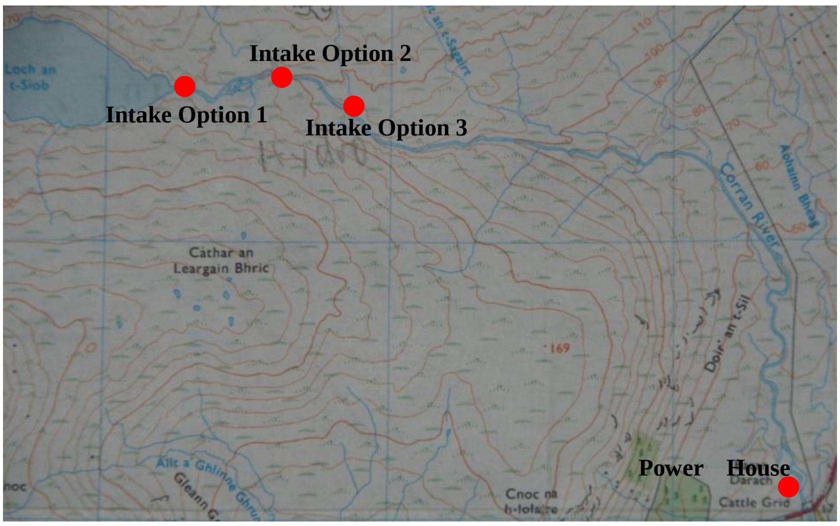
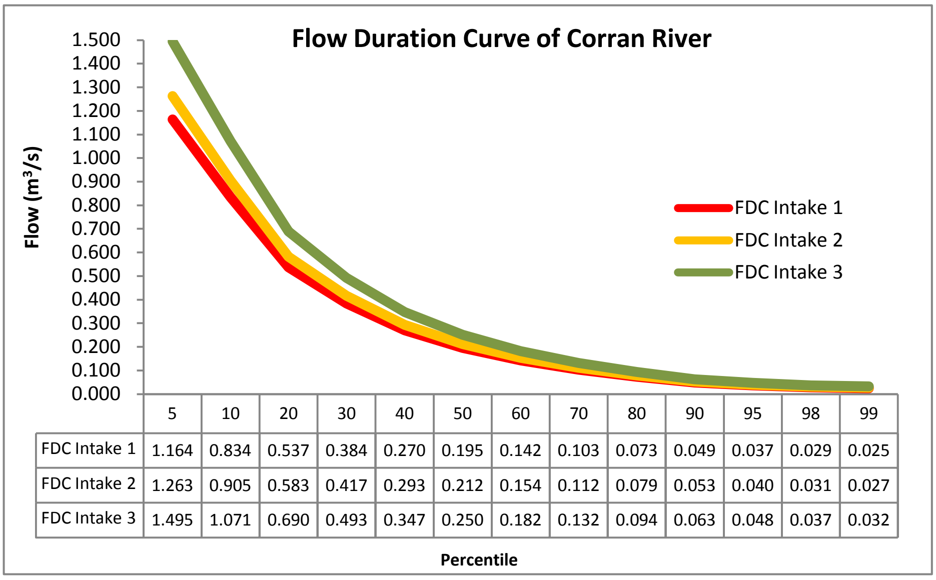


Figure 4-3: Different Intake Options (Source: Author and Ordnance Survey 2006)

Annual and Monthly mean flows & Flow Duration Curve (FDC) statistics for Intake 1 are estimated through LowFlows 2 software. Flow data for Intake 2 and Intake 3 is generated by rescaling the estimates for Intake 1 by the ratio of catchment areas under the assumption that hydrology is consistent across the area. The detailed flow data is attached in Annex.2. Figure 4-4 shows the summary of the annual FDC for Intake 1, Intake 2 and Intake 3.



	5	10	20	30	40	50	60	70	80	90	95	98	99
FDC Intake 1	1.164	0.834	0.537	0.384	0.270	0.195	0.142	0.103	0.073	0.049	0.037	0.029	0.025
FDC Intake 2	1.263	0.905	0.583	0.417	0.293	0.212	0.154	0.112	0.079	0.053	0.040	0.031	0.027
FDC Intake 3	1.495	1.071	0.690	0.493	0.347	0.250	0.182	0.132	0.094	0.063	0.048	0.037	0.032

Figure 4-4: Summary of Annual Flow Duration Curve (FDC) For Intake 1, Intake 2 and Intake 3 (Source: Author and HydroSolutions 2011)

The power house is suggested to be located at coordinates 5450/7210 as shown in Figure 4-3. This location offers the advantages of proximity to the grid and access road as well as a low elevation (20 meters above sea level) which increases the available head.

Three intake options were analysed for a power capacity of 100 kW as shown in Table 4-1. The penstock sized for 330 kW to allow for future expansion and 5% head loss in penstock is assumed.

Table 4-1: Comparison of Intake Options, based on preliminary calculation of penstock diameter(Source: Author)

Characteristics	**Intake 1**	**Intake 2**	**Intake 3**
Head (m)	150	140	120
Catchment area (km^2)	6.614	7.177	8.494
Penstock Length (m)	3,600	3,200	2,700
Mean Flow (m^3/s)	0.335	0.363	0.430
Diameter (m) - for design	0.5	0.5	0.55
Energy produced (MWh/year) with 100 kW capacity	595.93	593.16	594.81
Penstock Cost	**264,849.75**	**235,422.00**	**233,091.84**

Intake 1 has a higher head with smaller catchment area and less mean flow as compared to the other intake options. On the other hand, Intake 3 delivers comparable energy output (0.16% less energy than Intake 1) with the least cost for the Penstock (which is one of major contributors to overall project cost). The Penstock cost for intake 1 is found to be 13% more than the Penstock cost for Intake 3.Therefore Intake option 3 seemed to be more attractive in terms of cost.

However it was found during site surveys that the Intake 2 & Intake 3 are located at difficult terrain. The construction of intake weir would be more costly with higher environmental impacts. Relatively flat ground is available for construction of intake near the outlet of the Loch defined as Intake 1 in this report. The gorges immediately downstream intakes 2 and 3 are shown in Figure 4-5.

Figure 4-5: Gorge structure along penstock intake 2 and 3 (Source: Author)

Therefore Intake 1 is suggested as more suitable and further calculations & analysis are conducted with Intake option 1.

The calculations showed that the Corran River's head and flow rate is feasible for the construction of a 330 kW capacity hydropower plant in terms of cost & benefit.

In addition to this, 50 kW and 100 kW hydropower plants were also evaluated technically and economically for two reasons. Firstly, under the present situation, the grid allows only 50 kW to be fed in and secondly the generation tariffs are higher for equal and less than 100 kW capacity plants, which could make smaller plants more feasible economically in some cases. The penstock's material and installation is a major contributor to overall project cost. Therefore calculations have been done for 50 kW, 100 kW and 330 kW with their optimum penstock size and also with a larger penstock compatible with 330 kW capacity to allow for easy and less costly plant capacity extension of 50 kW or 100 kW hydropower plant to 330 kW in future.

Therefore five scenarios have been analysed, namely:

- 50 kW hydropower plant with optimum penstock size
- 50 kW hydropower plant with larger penstock size (plant extendable to 330 kW in future)
- 100 kW hydropower plant with optimum penstock size
- 100 kW hydropower plant with larger penstock size (plant extendable to 330 kW in future)
- 330 kW hydropower plant with optimum penstock size

4.4.2 Selection of penstock size and layout

The optimum Penstock sizes for 50 kW, 100 kW and 330 kW capacities are calculated as 250 mm, 350 mm and 500 mm respectively. High Density Polyethylene (HDPE) pipe material is suggested as it is durable, does not become brittle at 0°C and does not corrode (ISCO INDUSTRIES n.d.). It can also be easily handled and laid in rough terrain. HDPE pipe is illustrated in Figure 4-6 below.

**Figure 4-6: HDPE pipe,
source: (ISCO INDUSTRIES n.d.)**

The layout of the penstock is determined on the basis of site survey and contour maps. From Intake 1 (point 1) (Coordinates 5225/7350) the pipe will go down to the elevation 150 m (point 2) along the river. It then continues down to the elevation 130 m (point 3) and descends along the slope to the elevation 70 m (point 4). At point 4 (coordinates 5413/7327) the penstock will cross the river and continues to the power house location (point 5) (coordinates 5450/7210). There is a 50 m gain of head between point 4 and point 5. The layout of penstock is illustrated in Figure 4-7. (See Annex.2 for the site pictures of point 1, point 4 and point 5).

A straight pipe from point 1 to point 5 is not suitable because the terrain is found extensively uneven. Moreover the land at the south side of the river is much steeper as compared to north side, therefore it is proposed to lay the penstock on the north side along the river up to point 4. At point 4 the penstock can cross the river to point 5 as the descending is gradual and land is relatively even.

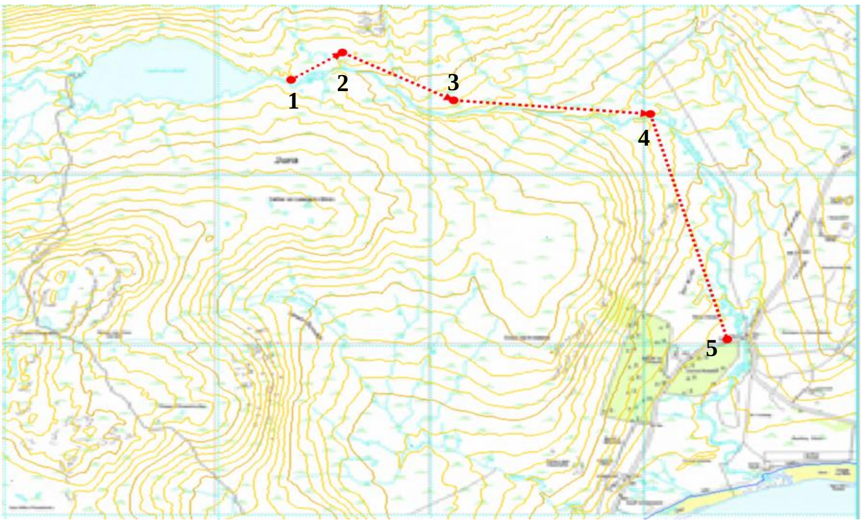


Figure 4-7: Penstock layout (Source: Author)

4.4.3 Selection of hydraulic turbine

A Pelton turbine is suggested to be used because of the medium head (150 m) and small water flow rate (Annual mean 0.374 m^3/s) available at the Corran River Intake 1. Additionally, as the proposed hydropower plant is a run-off river scheme and the monthly flow rate variation is quite considerable, the Part Flow Efficiency analysis also suggests the Pelton turbine as the most feasible choice. The efficiency of Pelton turbines is not affected significantly by variations in flow rate over the year. (See Annex 4 for Part Flow Efficiency of Pelton Turbine).

4.4.4 Annual energy production

Energy production was estimated for 50 kW, 100 kW and 330 kW capacities based on monthly flow duration curve statistics for Intake 1 with a compensation flow of Q_{90} which is 0.049 m^3.

An overall efficiency of 67% was assumed for the calculations. This comprises the following efficiencies: efficiency of penstock: 95%; maximum efficiency of Pelton turbine: 85%; efficiency of generator: 90% and efficiency of transformer: 98%.

Annual power duration curves are shown in figures Figure 4-8.

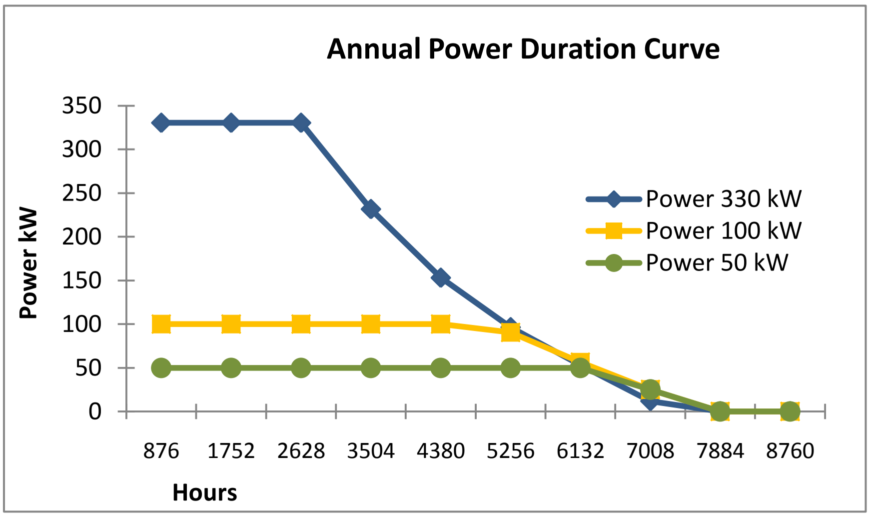


Figure 4-8: Annual Power Duration Curve for 50 kW, 100 kW and 330 kW (Source: Author)

With a 50 kW capacity hydropower plant, the energy produced is expected to be up to 334.5 MWh per year and will run at least 40% of the full capacity through the year. On average, the system will run at full capacity for 67% (equal to 5869 hours) of the year. The annual capacity factor is 76.4 %. The energy production and full capacity operation hours for 50 kW are shown in Figure 4-9 and Figure 4-10.

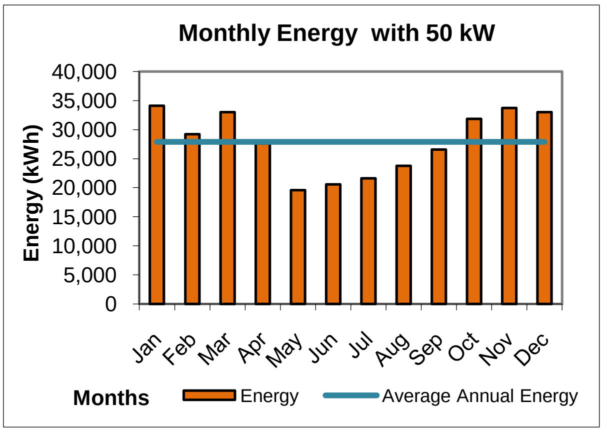


Figure 4-9: Energy Production from 50 kW
(Source: Author)

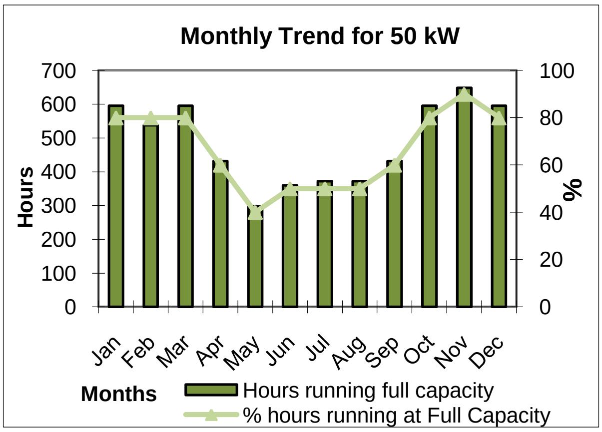


Figure 4-10: Running Capacity for 50 kW
(Source: Author)

With 100 kW hydropower capacity, 596 MWh of energy per year can be produced. However, the system will run 30% of full capacity during May to July. On average, it will run 54% of full capacity throughout the year (equal to 4,745 hours). The annual capacity factor is 68%. The energy production and full capacity operation hours for 100 kW are shown in Figure 4-11 and Figure 4-12.

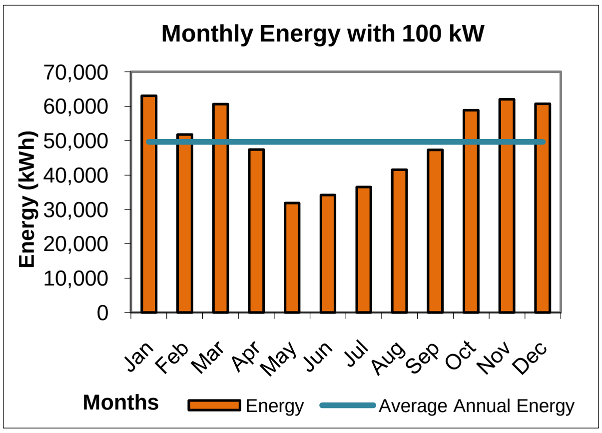


Figure 4-11: Energy Production from 100 kW
(Source: Author)

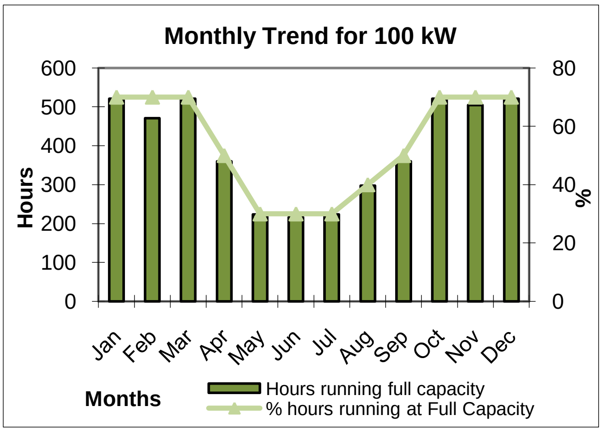


Figure 4-12: Running Capacity for 100 kW
(Source: Author)

The installed capacity of a 330 kW hydropower plant is able to produce around 1,344 MWh per year. It is estimated to run for 27% at full capacity on average per year (equal to 2,336 hours). From May – July it will run for only 10% of full capacity. The annual capacity factor is 46.5%. The energy production and full capacity operation hours for 330 kW systems is shown in Figure 4-13 and Figure 4-14.

The monthly power and energy output for 50 kW, 100 kW & 330 kW are attached in Annex 2.

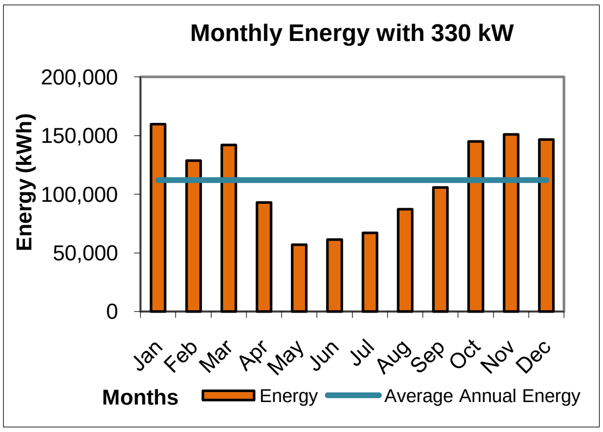


Figure 4-13: Energy Production from 330 kW (Source: Author)

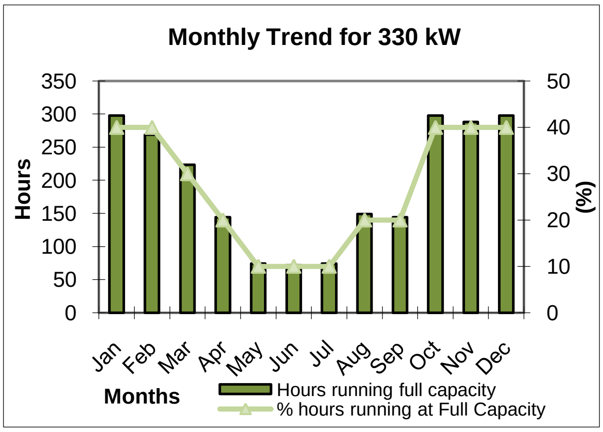


Figure 4-14: Running Capacity for 330 kW (Source: Author)

4.4.5 Grid connection

Scottish and Southern Energy (SSE) currently allows 50 kW as the maximum limit to export to the grid. The assessment of 100 kW and 330 kW hydropower plants has been carried out under the assumption that a higher capacity can be connected to the grid or electricity can be consumed locally.

The proposed location of the Power House is approximately 200 m from the grid and this significantly reduces the cost of grid connection. The total cost of grid connection is estimated about £ 22,500.

4.5 Economic analysis

For the economic analysis of the five scenarios discussed in section 3.4.1, it is assumed that all electricity produced will be exported to the grid. The price of electricity comprises the feed-in tariff and export tariff. For hydropower with a total installed capacity greater than 15 kW but not exceeding 100 kW, the feed-in tariff is 19.6 pence/kWh and the export tariff is 3.2 pence/kWh. So, the total price for electricity is 22.8 pence/kWh. For hydropower with a total installed capacity greater than 100 kW but not exceeding 2 MW, the feed-in tariff is 12.1 pence/kWh and the export tariff is 3.2 pence/kWh that gives a total price for electricity of 15.3 pence/kWh (ofgem 2007). The Feed-in-Tariff (FIT) payment rates apply in respect of electricity generated or exported on or after 1 April 2012. According to current policy the eligibility period of getting paid the feed-in tariff is twenty years starting from the eligibility date (which in most cases is the commissioning date of the installation) (ofgem 2007). To assess the economic feasibility, the following assumptions have been used:

- Lifetime of project as 50 years
- Discount rate of 6.5%
- Loan return period is 15 years for 100 kW and 330 kW schemes
- Loan return period is 20 years for 50 kW scheme. A loan with return period of 15 years with interest rate of 6.5% is found to give negative cash flows in case of 50 kW. Therefore, to get net income from the project from the first year a loan return period of 20 years is considered.
- Cost estimation is established from the cost data available for comparable hydropower schemes in Forest Estate and Ardlussa Estate on Jura Island. Wherever data was missing for specific sizes, the estimation is made through interpolation or extrapolation.

- Cost for engineering design and engineering supervision is assumed to be 7.5% and 8% of construction cost respectively. In addition, a contingency cost equal to 8% of sum of costs is assumed.

The detailed economic analysis for every scenario is tabulated in Table 4-2 and Table 4-3. Cash flows are shown in Table 4-4 to Table 4-5.

Table 4-2: Summary of penstock cost
(Source: Author)

<table>
<tr><th rowspan="2"></th><th rowspan="2">Penstock Length (m)</th><th colspan="2">Helicopter Lift Cost for Penstock</th><th rowspan="2">Excavation Cost for Penstock (per meter)</th><th rowspan="2">Installation Cost for Penstock (per meter)</th><th rowspan="2">Penstock material (per meter)</th><th rowspan="2">Pipe Fittings (per meter)</th></tr>
<tr><th>Heli Cost</th><th>Heli cost / meter</th></tr>
<tr><td>Forest Estate d=400mm</td><td>1,280</td><td>16,250</td><td>12.70</td><td>31.25</td><td>30.4</td><td>48.04</td><td>7.8</td></tr>
<tr><td>Ardlussa</td><td>1,540</td><td>11,250</td><td>7.31</td><td></td><td>31</td><td></td><td></td></tr>
<tr><td>Assumed Corran river cost d=250mm</td><td rowspan="3">3,600</td><td rowspan="3">45,703.13</td><td rowspan="3">12.7</td><td rowspan="3">31.25</td><td rowspan="3">30.4</td><td>14.04</td><td rowspan="3">7.8</td></tr>
<tr><td>Assumed Corran river cost d=350mm</td><td>35.29</td></tr>
<tr><td>Assumed Corran river cost d=500mm</td><td>73.57</td></tr>
</table>

Table 4-3: Economic Analysis
(Source: Author)

	Costs																	Revenues				
Power Capacity Options / Scenarios	**Environmental Surveys**	**Intake**	**Helicopter Lifts for Intake**	**Excavation**	**Helicopter Lifts for Penstock**	**Penstock**	**Penstock Fittings**	**Installation**	**Power House**	**Turbine & Generator**	**Grid Connection**	**Secondary Electrical & Controls**	**Engineering Design & Planning**	**Engineering Supervision**	**Sum of Costs**	**Contigency Costs 8%**	**Total Cost**	**Annual Maintenance Cost**	**Energy Generated kWh / Year**	**Income £/year**	**Payback Period (Years)**	**IRR**	**NPV**
50 kW with Optimum Penstock	5,000	50,000	3,750	112,500	45,703	50,544	28,125	109,446	50,000	47,500	22,500	40,000	42,005	44,805	651,878	52,150	704,029	2,500	334,531	76,273	9.54	8.71%	£130,750
50 kW with Larger Penstock (extendable to 330 kW)	5,000	50,000	3,750	112,500	45,703	264,850	28,125	109,446	50,000	47,500	22,500	40,000	58,078	61,950	899,401	71,952	971,354	2,500	334,531	76,273	13.17	4.95%	-£120,260
100 kW with Optimum Penstock	5,000	50,000	3,750	112,500	45,703	127,032	28,125	109,446	50,000	94,800	22,500	40,000	51,289	54,708	794,853	63,588	858,441	5,000	595,939	135,874	6.56	14.30%	£596,938
100 kW with Larger Penstock (extendable to 330 kW)	5,000	50,000	3,750	112,500	45,703	264,850	28,125	109,446	50,000	94,800	22,500	40,000	61,626	65,734	954,033	76,323	1,030,356	5,000	595,939	135,874	7.87	11.38%	£435,516
330 kW with Optimum Penstock	5,000	50,000	3,750	112,500	45,703	264,850	28,125	109,446	50,000	300,000	22,500	40,000	77,016	82,150	1,191,039	95,283	1,286,322	20,000	1,344,542	205,715	6.93	13.41%	£793,719

Table 4-4: Summary of cash flow for 50 kW capacity with optimum penstock size (Source: Author)

Years	Investment £	Income from energy sales (£/year)	Maintenance Cost (£/year)	Loan and interest payment (£/year)	Net income (£/year)
1 – 20	704,029	76,273	2,500	63,895	9,878
21 – 50	---	10,705	2,500	---	8,205

Table 4-5: Summary of cash flow for 50 kW capacity with larger penstock size (Extendable to 330 kW) (Source: Author)

Years	Investment £	Income from energy sales (£/year)	Maintenance Cost (£/year)	Loan and interest payment (£/year)	Net income (£/year)
1 – 20	971,354	76,273	2,500	-88,156	-14,383
21 – 50	---	10,705	2,500	---	8,205

Table 4-6: Summary of cash flow for 100 kW capacity with optimum penstock size (Source: Author)

Years	Investment £	Income from energy sales (£/year)	Maintenance Cost (£/year)	Loan and interest payment (£/year)	Net income (£/year)
1 – 15	858,441	135,874	5,000	-91,298	39,576
16 – 20	---	135,874	5,000	---	130,874
21 – 50	---	19,070	5,000	---	14,070

Table 4-7: Summary of cash flow for 100 kW capacity with optimum penstock size (Source: Author)

Years	Investment £	Income from energy sales (£/year)	Maintenance Cost (£/year)	Loan and interest payment (£/year)	Net income (£/year)
1 – 15	1,030,355.5	135,874	5,000	-109,581	21,293
16 – 20	---	135,874	5,000	---	130,874
21 – 50	---	19,070	5,000	---	14,070

Table 4-8: Summary of cash flow for 330 kW capacity with larger penstock size (Extendable to 330 kW) (Source: Author)

Years	Investment £	Income from energy sales (£/year)	Maintenance Cost (£/year)	Loan and interest payment (£/year)	Net income (£/year)
1 – 15	1,286,322	205,715	20,000	-136,804	48,911
16 – 20	---	135,874	5,000	---	185,715
21 – 50	---	19,070	5,000	---	23,025

50 kW with larger penstock (extendable to 330 kW) is economically not feasible as it gives a negative Net Present Value (NPV) and negative net income for the first 20 years.

The most suitable capacity is 100 kW with optimum penstock size with a positive Net Present Value (NPV), highest Internal Rate of Return 14.3% and the least Payback Period of 6.56 years. It would generate a net income of 39,576 £/year for the first 15 years, which would then increase to 130,874 £/year for the next 5 years as the loan would be already paid off. But from 21st year the net income would reduce to 14, 070 £/year for the rest of life of the project as the feed-in tariff guaranteed for the first 20 years of project would no longer be available.

The second most feasible capacity is 330 kW with optimum penstock size. Its Internal Rate of Return is 13.41% and the Payback Period is 6.93 years. It would even generate more net income than 100 kW with optimum penstock size scheme. For the first 15 years it would earn net 48,911 £/year. After the payment of loan from the 16th year to the 20th year, the net income would be 185,715 £/year. From the 21st year to the 50th year the net income would reduce to 23,025 £/year as only the export tariff would be applied under the current policy.

4.6 Environmental impacts and social acceptance

Electricity production in small hydro plants does not produce carbon dioxide or liquid pollutants, but sometimes, because of their location in sensitive areas, the local impacts could be significant. Impacts of hydropower schemes are location and technology specific. It is strongly recommended by the concerned environmental authorities to establish a permanent dialogue with them as a very first step in the project phase.

The location of hydropower scheme at Corran River comes under Designated Area for Natural Heritage Value as a Natural Scenic Area. Considering this fact a run-off-river scheme is suggested without storage/dam. Intake 1 is selected as it would need less manipulation and would cause less scenic distortion as compared to constructing intakes at location 2 & 3. A buried penstock is also suggested to keep the landscape clean. (See Annex 2. for National Scenic Areas in Scotland)

During discussions with managers and owners of other hydropower schemes on Jura, it was found that there will be the need for the following surveys as the minimum requirement before applying for planning permission:

- Salmon and sea trout survey

- Moss survey
- Mammals survey

In a survey to identify the perception and acceptance of the environmental impacts of a small hydro scheme, members of the community were asked the following question:

"Do you think a small to medium size hydro project will have negative environmental impacts? If yes, what kind of impacts?"

Out of 55 respondents, 8 answered 'yes', 41 answered 'no', and 6 respondents answered 'do not know'. From 8 respondents who answered 'yes': 2 respondents said that hydropower project will affect the wildlife such as: birds, fishes and plants; 2 respondents answered that a hydropower project will spoil the scenery; and 1 respondent answered it will affect both of wildlife and spoil scenery. However, 3 respondents answered 'yes' but were not sure of the specific impacts stating that it will depend on the location. Generally, it can be concluded that most of the respondents (75%) perceive that a small to medium size hydro project will not have negative environmental impacts. This is better as compared to the perception for wind energy project where 61.8% of the respondents say that small to medium scale wind energy project will have no negative environmental impacts.

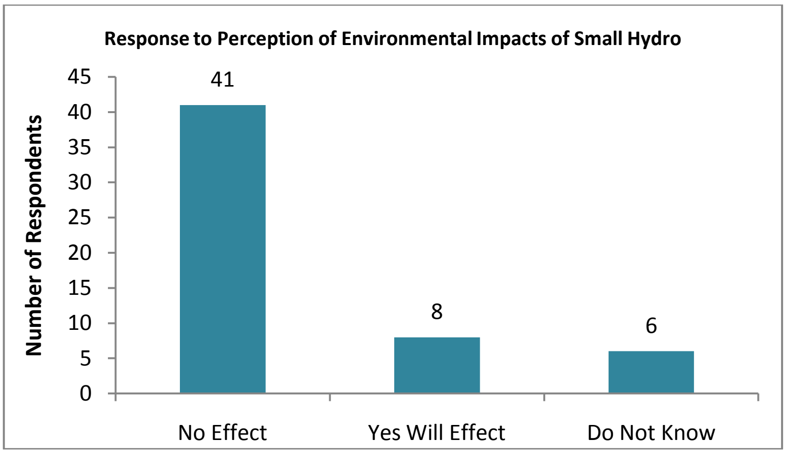


Figure 4-15: Perception of Environmental Impact of Small to Medium Size Hydropower Plant in Jura Community

4.7 Legal & Authorization Process

The Scottish Government recognizes the need of development of community owned small hydropower projects and is very supportive by establishing targets for renewable energies.

Developing a hydropower project needs a planning permission and abstraction licence. It is advised to contact the Argyll and Bute Council at the early stage. The planning office will guide through the process and provide the further contacts as many organizations could be involved in giving the consent for permission.

The Scottish Environmental Protection Agency (SEPA) is Scotland's environmental regulator. By the rules of Scottish government, hydropower developers need to get a water use license from SEPA. SEPA also issues regulations concerning salmon and sea trout, moss, mammals and archaeological sites. SEPA has developed Guidance for Developers of Run-off River Hydropower Schemes (Scottish

Environmental Protection Agency 2010). It provides checklists for the evaluation of a scheme. If the community decides to build a hydropower plant at Corran River that document will be useful at the early stage.

In the general legislative framework of Scotland, Scottish Natural Heritage SNH is a statutory consulting body and natural heritage adviser, SNH deals with renewable energy proposals, applications and enquiries. Under the Environmental Assessment (Scotland) Regulations 1999, a developer will be required to undertake an Environmental Impact Assessment (EIA) and produce an Environmental Statement if the proposal is likely to have significant effects on the environment (SNH 2010). As the proposed hydropower plant area comes under designated areas of natural heritage defined by SNH, it is suggested to contact SNH at the early phase of a hydropower scheme development for detailed guidance.

4.8 Conclusions & suggestions

A majority of the community has no objections against a hydropower plant at the Corran river. Survey results exhibits that 41 out of 55 respondents of Jura community perceive that small to medium size hydropower project will not have any negative environmental effects. This is better as compared to the community's perception of small to medium sized wind energy project. In conclusion:

1. A 330 kW capacity hydropower plant would be the most beneficial in terms of energy produced in MWh per year that is 1344 MWh /year. But it will be running on full capacity for less number of hours per year. Especially in summer it would be running only 10% of hours at full capacity. The capacity factor of 330 kW would be 46.5%. 100 kW and 50 kW will be running at full capacity for more hours per year and would produce 596 and 334.5 MWh/year respectively. The capacity factor would be 68% and 76.4% respectively.
2. The economic analysis shows that with grid feed-in, 100 kW & 330 kW with optimum penstock sizes are most viable. The 100 kW capacity scheme is estimated to have a payback period of 6.56 years and an IRR of 14.3%. It would generate net positive income. The next closest feasible capacity is 330 kW, with a payback period of 6.93 years and an IRR of 13.41%. It would even generate more net income than 100 kW. 50 kW capacity with a larger penstock is economically not feasible. 50 kW capacity with the optimum penstock size shows positive figures. The Payback Period is 9.54 years and the Internal Rate of Return is 8.71%, but the net income would be quite low, that is 9878 £/year. Intake 2 & 3 downstream the river could save considerable costs in penstock. However, the difficult terrain around these two intakes might significantly increase the costs of installation. Intake 1 close to the Loch is therefore proposed.
3. An oversized penstock (optimum for 330 kW) for 100 kW capacities could be installed at this stage to allow for cheaper expansion to 330 kW in future. However the net income would be low (21,293 £/year) and payback period (7.87 years) would be longer as compared to a 100 kW scheme with optimum penstock size.
4. It is proposed to construct the power house close to the road for easy access and cheaper connection to the grid.

5 ASSESSMENT OF HEAT RECOVERY AND BIOGAS POTENTIALS AT THE JURA DISTILLERY

5.1 Introduction

The Jura whisky distillery produces around 2,200,000[6] litres of spirit in a year. By-products of the distillery's process include draff[7], spent lees[8] and pot ale[9]. The distillery currently sells draff to another company that uses it as a forerunner of animal food and discharges the spent lees and pot ale into the sea through a 1.7 km long pipeline. Water used for cooling from the distillation process is also discharged to the sea through a second pipe. This discharge from the distillery could be harnessed for energy generation and this section of the report explores the energy potential of the discharged wastes.

This section is divided into three parts. In the first part, the Scottish and EU regulations on discharging waste water from distilleries, heat recovery and anaerobic digestion are described. The second part presents an analysis of heat recovery potential from the distillery cooling water to heat the Jura Hall and the Jura Hotel. The third part then presents an analysis of the biogas potential for combined heat and power generation from the distillery's waste water.

5.2 Scope

The study covers the initial technical and economical assessment including an estimate of energy outputs. This involves:

a. a review of the relevant regulations governing heat recovery, discharges of waste water from distilleries and anaerobic digestion in Scotland.
b. an analyses of the potential and financial feasibility of recovering heat from the distillery's cooling water to provide space heating to Jura Hall and to provide space heating and hot water to Jura Hotel.
c. an analyses of the potential and financial feasibility of combined heat and power generation from pot ale and spent lee.

5.3 Methodology

The study started with a desk study about the processes involved in whisky production. The task was divided into two parts; heat recovery from cooling water and combined heat and power generation from biogas produced from pot ale and spent lee.

A number of site visits were made to the Jura distillery to understand the operations of the plant. These visits also included structured interviews with the manager and personnel at the plant to obtain relevant information such as the volumes of alcohol, pot ale and spent lee produced and the volume of

[6] Information from the Jura distillery manager
[7] Spent grain from the mash tuns; moisture content 70-80%. Source: (Bob Pass & Lambert, 2003)
[8] Liquid residue from the spirit stills. Source: (Bob Pass & Lambert, 2003)
[9] Liquid residue from the wash stills. Source: (Bob Pass & Lambert, 2003)

water used. Some technical measurements were also done to get data on temperature and flow of cooling water.

The Bruichladdich and Bowmore distilleries on the Isle of Islay were also visited. These two distilleries are of interest because the Bruichladdich distillery has installed a biogas digester for power generation and cooling water from the Bowmore distillery is used for space heating and heating the swimming pool at the Mactaggart Leisure Center on Islay.

Jura Hotel and Jura Hall were selected for the application of recovered heat from the distillery. Field visits and interviews were carried out with the hotel manager and the personnel from the Jura Development Trust to get information about occupancy rates, existing heating systems, and energy required for heating.

The required data and information collected during interviews and field visits were then analysed to determine the feasibility of using heat recovery in Jura Hall and the Jura Hotel and the feasibility of combined heat and power in different scenarios.

5.4 Regulations for heat recovery project

In an interview with the general manager of the Mactaggart Leisure Center, it was learnt that there is no regulation from the Scottish Government to control the use of excess heat from whisky distillation processes. It depends on a private agreement between the distillery and heat users. This would also be the case should the Jura Hotel and Jura Hall be interested in using excess heat from Jura distillery. The Scottish government has no temperature regulations to control discharges from cooling water systems into the sea. Temperature regulations only apply to discharging cooling water into the rivers. (The Scottish gorvernment 2008).

5.5 Regulations for discharges of waste water from distillery

5.5.1 Scottish regulations

The Water Environment (Control Activities) (Scotland) Regulation 2011 (CAR) is one of main regulations to control impacts on the water environment. It means that both direct and indirect activities which can cause ter pollution fall under this regulation. The regulation covers rivers, lochs, canal, reservoir and coastal water, ground water and wetland. There are three types of CAR authorization which are as follows:

- General Binding Rules (GBRs) - GBRs set up the rules which cover low risk activities. If an activity complies with these rules, there is no need to apply for permission from the Scottish Environment Protection Agency (SEPA).
- Registration - This covers small-scale low risk activities which can accumulate environmental risks and result in greater impacts on the water environment. Project developers must apply to SEPA to register such activities.
- License - Licensing is required for high risk activities which can seriously harm the water environment.

According to the compliance report of waste water analysis of Jura distillery, the distillery has a CAR License. The controlled parameters are Nitrogen, Biological Oxygen Demand (BOD)[10], Copper, Suspended Solid and pH[11] (SEPA 2011).

5.5.2 *EU legislation on water quality*

In 1991, the EU Environmental Ministers adopted the Urban Waste Water Treatment Directive (UWWTD). After 3 years, this directive was transcribed into UK legislation in England, Wales and Scotland. The main purpose of the directive is to ensure that all significant discharges of sewage are treated before dumping into the water environment. However according to the current UK legislation, SEPA will consider each application for discharge of industrial waste water on a case by case basis and set conditions according to the nature of the effluent and the nature of the water environment (The Scottish Office for Agriculture 1998).

5.6 Regulations for anaerobic digestion

For this study, anaerobic digestion (AD) plants are considered as the secondary treatment process of waste water from the distillery. Waste water will be fed into the AD plants before being discharged into the sea. The digestate (excess sludge from AD plants) could be used as fertilizer (Figure 5-1). An AD plant could be an isolated plant that provides waste delivery services to the distillery.

In Scotland, all AD projects must comply with regulations concerning Waste Management License (WML) or Pollution Prevention and Control (PPC) permits. Additionally, there still are Standard permits of AD, Classification of Output from AD processes, Zero Waste (Scotland) Regulations, Duty of Care, Health, Safety and Planning permissions. These permits are discussed in the subsequent sections.

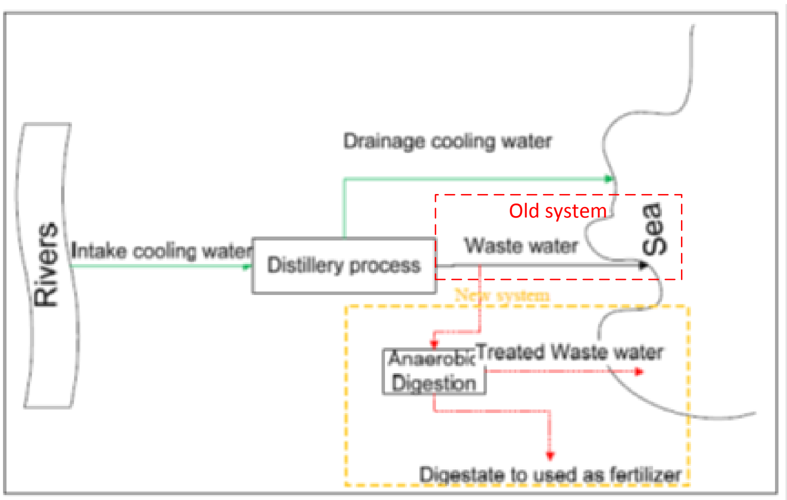


Figure 5-1 Existing system and new system of waste water treatment (Source: Author)

[10]BOD is a measure of the quantity of oxygen consumed by microorganisms during the decomposition of organic matter.
[11] pH is a measure of the acidity or Alkalinity of an aqueous solution

5.6.1 Waste management license or Pollution Prevention and Control permit

For anaerobic digestion (AD) projects in Scotland, a Waste Management License (WML) or Pollution Prevention and Control (PPC) permit is required. The type of permit depends on the size and nature of the facility. WMLs regulate the input and output materials into and out of the digester - waste water which is produced from the distillery and waste disposal. PPCs regulate treated waste water from AD plants. Therefore, developers must apply for a WML license and a PPC permit from SEPA (UK's national centre for renewable fuels 2012).

5.6.2 Standard permits of AD

The Environmental Agency has established rules which allow an operator to operate an AD plant and use biogas in a gas engine with an aggregate rated input of up to 3 megawatts (The Environmental Agency 2011). Therefore, AD operators must ensure that their AD systems and operations comply with this rule (The Environment Agency 2012).

5.6.3 Classification of Output from AD processes

The digestate from AD is considered as waste and use of it is controlled under the waste management legislation. SEPA has produced a guide on the Classification of Outputs from AD Processes. This regulation mainly focuses on the use and handling of digestate outputs from the AD processes. (SEPA, Classification of Outputs from Anaerobic Digestion Processes 2012)

5.6.4 Proposed Zero Waste (Scotland) Regulation 2011

In Scotland, the new version of this regulation is now under consideration by the Scottish Government. The use of a Carbon Metric included in the proposed regulation may affect AD facilities processing waste materials because the recycling performance is identified by a carbon factor of waste or raw material which is fed into AD plant. In other words, the Scottish government will quantify the amount of carbon that could be saved from feeding waste into an AD plant instead of sending it to a landfill (UK's national centre for renewable fuels 2012).

5.6.5 Duty of Care

This law considers how to manage waste from generation processes, waste transportation, waste storage and final waste disposal without harming the environment. Operators of AD plants must have the correct permit, license and exemption from SEPA. (UK's national centre for renewable fuels 2012).

5.6.6 Health and Safety

AD plants are considered high risk plants in terms of health and safety because of the presence of toxic gases such as hydrogen sulphide, flammable gases such as methane, confined space gases such as carbon dioxide and pressurised systems. Therefore, hazard and risk assessments must be carried out at each stage of a project during design, installation, commissioning, implementation and operation (SEPA 2011).

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5.6.7 Planning permission

Developers of AD must apply for planning permission from Argyll and Bute Planning Authority, the local planning authority. (Argyll and Bute Council 2012).

5.7 Analysis of the biogas potential from Jura Distillery

Pot ale and spent lee can be used to produce biogas to generate heat and/or electricity. A combined heat and power (CHP) plant can produce heat and electricity. The following plant sizes of CHP plants were analysed:

- a 50kW CHP unit due to power grid restrictions and
- a 155kW CHP unit based on maximum constant production of biogas

The plant could be used to deliver the following services:

- Provision of Heat for Jura Hotel and Jura Hall
- Provision of electricity to the Jura Hotel or other customers close to the plant using through a private wire and export of electricity to the grid
- Export of electricity to the grid.

It is assumed that the Jura Community would own the power plant and the Distillery would deliver the pot ale and spent lees at no cost. The amount of biogas that can be produced varies according to the different energy production purposes. The distillery currently dilutes the pot ale and spent lee before discharging it to the sea and the study assumes that the pot ale and the spent lees are taken from the distillery in the undiluted state. The proposed scenarios are displayed in the following figures:

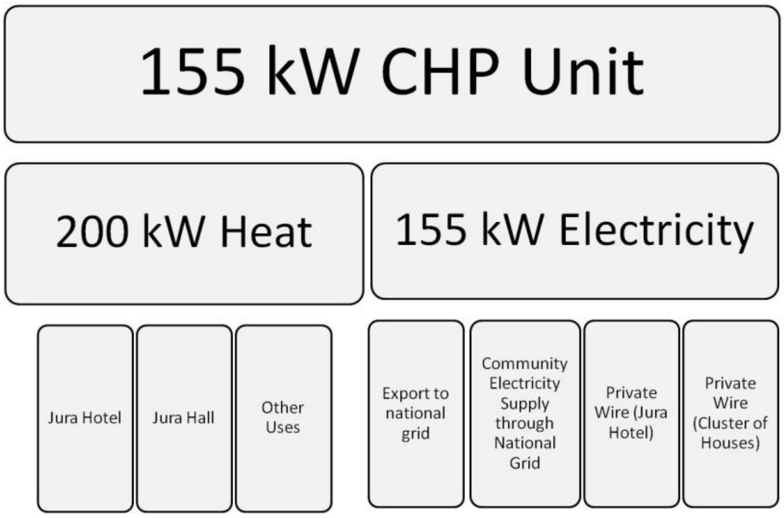

Figure 5-2: 155 kWe CHP Unit

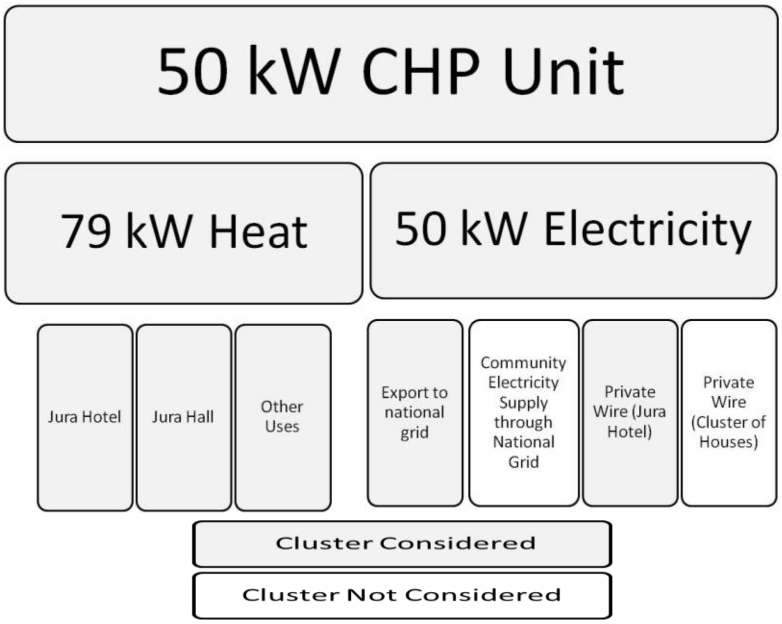

Figure 5-3: 50 kW CHP Unit

The parameters considered for the biogas calculation are shown in Annex 5: Table 1 to Annex 5: Table 3. It is proposed to install the biogas plant approximately 280 meters from the Distillery to reduce the costs associated with pumping the discharge over long distances. Additionally, it reduces the impact on the landscape and heat and electricity could be provided to Jura Hotel, Jura Hall and a cluster of selected houses all of which are close to the distillery.

Figure 4- 1: Possible Installation place of Jura CHP Plant

5.7.1 Biogas Production and comparison of different wastewater concentrations

Biogas monitoring is extremely important to produce the necessary quantity and quality of biogas. To avoid imbalance, the most important wastewater features to consider in biogas production are the acidity (measured by the pH), temperature and wastewater concentration. One of the most important factors which indicate the organic load of wastewater is the chemical oxygen demand (COD)[12]. Waste from whisky distilleries is high in COD and can therefore produce a lot of biogas. The annual

[12] Indication of the oxidizable materials in the water during the process of methane formation used as an indicator of the amount of biogas production

production of pot ale is 25,497,872 litres with a COD of 45,000 mg/litre and the annual spent lee production is approximately 10,199,148 litres with a COD of 2,000 mg/litre. The COD of the combination of these two is 32,714 mg/litre. (Pass and Lambert 2003) (Goodwin, Finlayson and Low 2008) (Rajeshwari, et al. 2000).

The amount of biogas required to operate a 50 kW CHP unit is 190,368 m^3/ year and the biggest biogas generation potential that can be generated from the Jura Distillery is about 613,000 m^3/ year. Nevertheless, to get the biggest economical incentives from Scottish Government, the recommended system design is the one that produces 597,000 m^3 of biogas as a higher volume of biogas puts the plant in a lower category of incentives. This would mean the usage of 28,800 litres of pot ale and 11,528 litres of spent lee per year, or the amount of wastewater to produce 2,140,000 litres of spirit.

5.7.2 Anaerobic Digester and Engine Selection

An Up-flow Anaerobic Sludge Blanket (UASB) reactor is the best technology for biogas formation because it is suitable for high levels of organic rates. This increases the resistance towards inhibiting chemicals in the case of higher amounts of copper in the liquid wastewater from the distillery. Additionally this technology reduces space requirements and increases the efficiency of the anaerobic digestion plant. Nevertheless, the UASB reactor would need frequent maintenance and higher levels of monitoring during operation. The dimensions of the UASB reactor chosen can be seen in Annex 5: Table 4 to Annex 5: Table 6. The designed system consists of three UASB bio-digesters of 60 m^3 each with 155 kWe or one reactor of 70 m3 with 50 kWe. (Rajeshwari, et al. 2000)

5.7.3 Electricity Production

The plant was sized for continuous operation between 8,350 and 8,400 hours per year with biogas from the digesters to avoid operating a powerful machine and engine for short periods per day.

The amount of electricity that can be generated with a capacity of 155 kW_e would be around 1,305,000 kWh which is approximately equal to the electrical consumption of 200 houses per year.

Jura Hotel has an annual electricity consumption of 92,000 kWh per year. With a capacity of 155 kW_e, 7.07% of the electricity generated would be allocated to it. The amount of electricity that can be generated with a capacity of 50 kW_e would be around 420,000 kWh. In this scenario, the percentage of electricity provided to Jura Hotel would be 22%. The rest can be assigned to other clusters or exported to the national grid. Table 5-1compares the electricity generation from the two plant sizes.

Table 5-1: Electricity Generation with two proposed scenarios

Engine capacity [kWe]	50	155
Efficiency [%]	31.6	36.6
Electricity generated [kWh]	420,000	1,305,000
Electricity assigned to the Hotel [kWh]	92, 297	
Electricity available for other uses [kWh]	327,703	1,212,776

5.7.4 Combined Heat and Power Production

The amount of heat that can be generated with a capacity of 155 kW_e and 200 kW_{th} is 1,667,000 kWh. Less than 1% of the heat produced would be required to heat the digester, as the temperature of the effluent is 74º C and the minimum temperature required to maintain the digester heated is 38º C.

The space heating and domestic hot water demand of the Jura Hotel and the space heating of Jura Hall is 329,500 kWh and 27,700 kWh respectively. They represent 19% and 2% respectively of the heat produced[13]. The peak heat demand of the hotel is 70 kW. This implies that the capacity is sufficient to meet the demand of further 10-15 buildings of residential size. The rest of the heat generated, in particular in summer, could be used to dry the draff that is sold to the animal food company. The draff has a moisture content of 78% and drying the draff with the excess heat from the CHP unit could increase the selling price of the draff from 5 pound per ton to 18 pounds per ton (Pass and Lambert 2003)**.** The Table 5-2 shows the energy outputs of the two plant sizes;

Table 5-2: CHP Generation with two proposed scenarios

Engine capacity	50 kWe, 79 kW_{th}	155 kW_e, 200 kW_{th}
Heat generated[kWh/year]	660,492	1,667,761
Heat demand of Jura Hotel [kWh/year]	329, 500	
Heat demand of Jura Hall [kWh/year]	27 700	
Heat available for other uses, for example draff drying [kWh/year]	73,200	1,317,531

5.7.5 Economic analysis

In addition to the feed-in tariffs considered in the economic analysis, the renewable heat incentive for space heating from biogas combustion to Jura Hotel and Jura Hall represents an additional incentive of around 7.9 pence per kW_{th} for a plant of up to 200 kW_{th} installed capacity (Biomas Energy Centre 2012).

The following assumptions have been made for the financial calculations:

- Two loans from the Carbon Trust and from the Anaerobic Digestion Loan Fund (ADLF) were considered as sources of 100% funding. (Anaerobic Digestion Loan Fund 2012). With these funds, the principals and interests are negotiated with the individual organizations.
- It was assumed that both loans are paid in yearly installments with interest rates based on the reference rate[14] of 6.5%.
- No risk factor was considered.
- Life time is considered for 20 years.
- Loan payment period of 15 years.

The detailed calculation of the financial analysis is given in Annex 5: Table 7 and Annex 5: Table 8. A brief summary of the results is presented below:

[13] When producing 1, 600,00 kWh (maximum availability)
[14] http://ec.europa.eu/competition/state_aid/legislation/reference_rates.html

Table 5-3: Summary of the CHP financial analysis

	50 kWe	**155 kWe**
Investment Cost [£]	357,087	608,034
Annual Cost [£/year]	11,295	28,918
First Fifteen Years Income [£/year]	69,061	154,855
Last Five Years Income [£/year]	107,038	219,521
Payback Period [year]	3.34	2.7
Internal Rate on Return	29.81%	36.03%
Net Present Value [£]	772,124	1,700,243

5.8 Analysis of heat recovery potential from cooling water from Jura Distillery

Personnel at the Jura distillery indicated that the distillery uses around 4,800,000 litres of water per day for process and cooling purposes. According to the Scottish Whisky Association (Scotch Whisky Industry 2010) 50 to 75 percent of water is used for cooling purposes and returned to the environment. Based on this ratio and the theoretical calculation of the cooling water demand for the condensation process , the minimum amount of cooling water required is estimated at 185,000 litres per day. The temperature of cooling water is between 40°C and 45°C. The distillery is reusing around 1.5 percent of this water to feed into the mash tun and discharging the rest into the sea.

The power potential of discharged cooling water is estimated at slightly below 3000 kWth and its energy content is approximately 25,000 MWh/y. The detailed calculation of this is shown in Annex 5: Table 9 to Annex 5: Table 11.

5.8.1 Possibility of using recovered heat in Jura Hotel

The hotel requires 48,773 kWh of energy per year for supplying domestic hot water and 163,742 kWh of energy per year for space heating. Presently, this required energy is supplied by a 50/70 kW Worcester Bosch green star oil boiler. This boiler is connected to two hot water storage tanks of 300 litres each. The hotel installed this boiler a few months ago based on the recommendations of an audit report by the Energy Saving Trust. The hotel also adopted other energy saving measures such as fitting thermostats to public rooms, adding insulation in walls etc. (McCallum 2010)

The monthly energy required for hot water and space heating in the hotel is included as Annex 5: Table 12 and Annex 5: Table 13.

5.8.1.1 Selection of technology

The hot water and space heating systems for the hotel is designed for 70kW. Two types of technical options are analysed to recover heat from the distillery.

Option 1: Heating with heat recovered using a heat pump and existing radiators

A 23kW heat pump such as the one from Nyle Systems is used for the study. This heat pump delivers 75kW using only 23kW electricity. The output temperature of the heat pump is around 70°C which satisfies the hotel requirement. This heat pump has to be installed as close to the distillery as possible to reduce installation costs and heat losses. Other components selected are a light commercial circulator pump (such as the Grundfos UPS 25-100) and valves. This system is connected in parallel to the existing oil boiler. The schematic diagram for this option is shown in Figure 5-4.

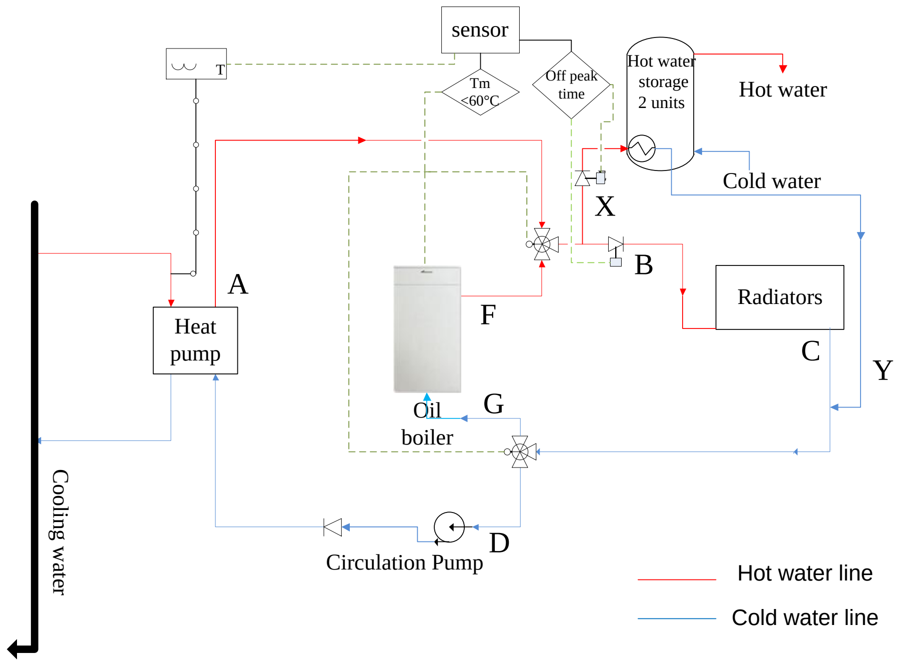

Figure 5-4: Using a heat pump for providing hot water and space heating in the Jura Hotel

The temperature sensor at the distillery cooling water pipe senses the hot water temperature and activates the loops.

- *When the distillery is in operation*: The sensor senses hot water coming from the distillery and then the loop ABCD is activated for space heating and loop AXYD is activated for hot water heating. Loops FBCG and FXYG are deactivated. In this situation the oil boiler is turned off.
- *When the distillery is closed*: There is no heat from the distillery, therefore the sensor deactivates loop ABCD and loop AXYD and actives the loop FBCG for space heating and FXYG for hot water heating. In this situation, the oil boiler starts working.

This uses 69,840 kWh of electricity and 900 litres of oil per year and saves 21,350 litres of oil per year.

Option 2: Heating with recovered heat using heat exchangers and new radiators

The cooling water of the distillery is discharged to the sea at a temperature of 40-45°C. Space heating is possible even at lower input temperatures of 40°C to 50°C if the exchange of heat to the room can be ensured. In low temperature heating systems this is usually guaranteed by large heat exchange areas, e.g with underfloor heating systems. As the installation of underfloor heating in an existing building is very expensive the industry has developed highly efficient radiators (E.g. PURMO Compact type 22) which have better performances at low temperatures. The size and number of radiators is selected based on the area and type of room.

The required temperature for hot water in the hotel is at least 60°C. Therefore this system cannot satisfy the hot water needs. The oil boiler thus operates continuously in this system to heat water to the required temperature. However, energy requirement from the oil boiler can be reduced by pre-heating cold water going to the hot water storage tank. If water is pre-heated, this can save around 13,902 kWh in a year which is 28% of the total energy consumed by the boiler to heat domestic water.

Other selected components for this option are two plate heat exchangers, a light commercial circulator pump and insulated district heating pipes. One 70 kW heat exchanger has to be installed close to the distillery to reduce installation cost and heat losses. The schematic diagram for this option is shown in Figure 5-5.

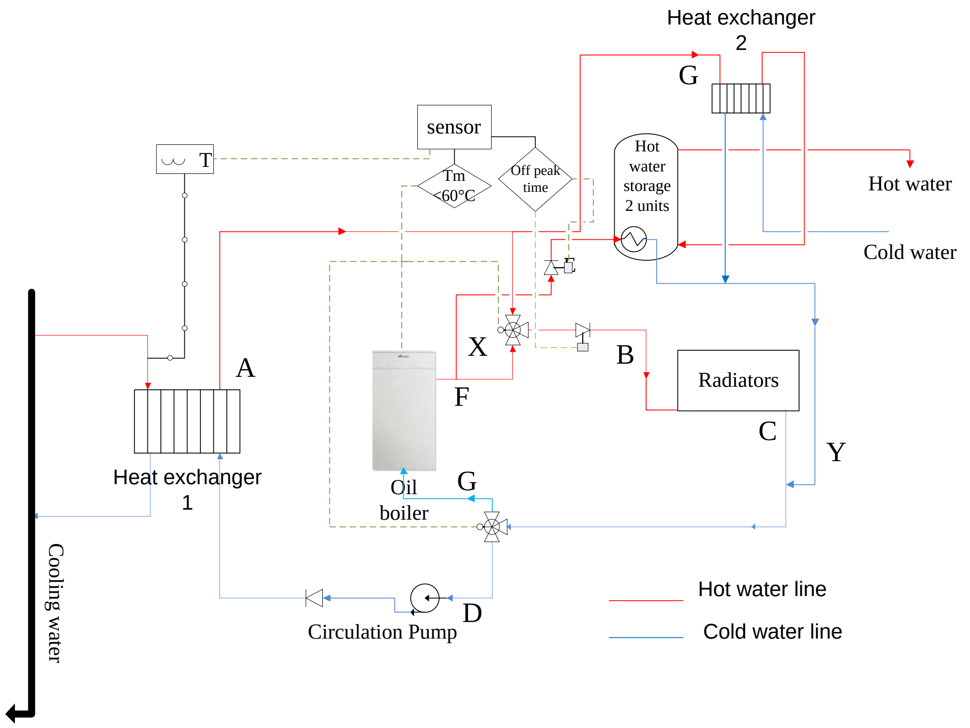

Figure 5-5: Using a heat exchanger for providing hot water and space heating in the Jura Hotel

This system also operates in a similar way to the above system. The difference is in the domestic water heating loop.

- *When the distillery is in operation*: The sensor senses hot water coming from the distillery and then the loop ABCD is activated for space heating and loop FBCD is deactivated. The input water temperature in the hot water storage tank will be increased due to exchange in heat between cooling water from the distillery and tap water in heat exchanger 2 as shown in Figure 5-5. In this situation, the oil boiler increases the temperature of water in the hot water storage tank. Loops AGYD and loop XYD heat water in the storage tank.
- *When the distillery is closed:* The boiler provides the energy required for both space heating and domestic water heating. The sensor deactivates loop ABCE and activates loop FBCD for

space heating. The loop XYD is working to heat water in the storage tank. But in this case input water temperature to the storage is at ambient temperature.

To operate this system 408 kWh of electricity and 4,284 litres of oil per year is required. However, it saves 17,948 litres of oil per year.

5.8.1.2 Economic Analysis of use of recovered heat in Jura Hotel

The economic analysis compares the three alternatives below:

Option 1: heating with recovered heat using heat pump and existing radiators

Option 2: heating with recovered heat using heat exchanger and new radiators

Option 3: heating with the existing oil boiler

The following assumptions were made for the financial calculations:

- Interest rate used for calculation is 6.5%.
- Life time is 20 years for all alternatives.
- For all options investment cost of the oil boiler and storage tanks is not considered because it is already installed in the hotel. Similarly, the cost of other equipment like radiators, pipe lines currently in use at the hotel are not considered in options 1 and 3.
- Electricity consumption of the pump in the radiator loop is not considered.
- Prices of components used are obtained from the internet.
- Installation and transportation costs for option 1 and option 2 are assumed to be the same and considered £3000.
- Domestic hot water is required throughout the year but space heating is required for only 8 months.
- Energy cost for electricity and oil is taken as 0.12 £/kWh and 0.065 £/kWh respectively.
- The Distillery closes for 14 days in a year.

Table 5-4: Economic analysis of different options for heating in the Jura Hotel

Description	Alternatives		
	Option 1: Heating with heat recovered using heat pump and existing radiators	**Option 2: Heating with heat recovered using heat exchanger and new radiators**	**Option 3: Heating with the existing oil boiler**
Investment Cost, Io [£]	29,433.3	23,028.2	
Total energy required for heating [kWh/y]	212,464.7	212,464.7	212,464.7
Electricity energy cost for operating heat pump, circulation pump and sensors [£/year]	8,380.9	48.9	
Energy cost for operation oil boiler [£/year]	572.0	2,784.4	14,450.4
Total energy cost [£/year]	8,952.8	2,833.3	14,450.4
Saving in energy cost [£/year]	5,497.5	11,617.0	
Net Present Value [£]	31,141.1	104,974.3	
Payback period [years]	5.4	2.0	
Internal Rate of Return	18.00%	50.40%	

The analysis shows that option 2: heating with heat recovered using heat exchanger and new radiators is the most financially viable option. The saving in energy cost using this system is £11,617 per year comparing with the option 3: heating with the existing oil boiler. The payback period of this option is only 2 years.

The 2nd best financially viable option is option 1 and its payback period is 5.4 years compared to the option 3. Option 3 is the most expensive heating option. The detailed analyses are included in Annex 5: Table 15.

5.8.2 Possibility of using recovered heat in Jura Hall

After an analysis of the actual situation, three different options are technically described and financially compared:

Option 1: heat exchanger for distillery cooling water and new radiators,

Option 2: log boiler

Option 3: electrical thermal storage heaters

Jura Hall was recently refurbished as per the recommendations of AECOM except its floor insulation following a review of energy efficiency measures of the hall in June 2009. The total energy demand of the hall is estimated at 27,793 kWh per year when a room temperature of 20C° is maintained throughout the year.

The capacity of the heating equipment required is 11.86 kW. Presently Jura Hall is heated by seven electrical convector heaters rated at 2 kW each. But 5 electric heaters are not working properly. The Jura Development Trust is considering installing a 25 kW log fired warm air boiler for space heating. However, calculations showed that this is over-sized and a14 kW boiler is adequate for space heating.

The detailed calculation of energy requirements of the Hall is included as inAnnex 5: Table 16 to Annex 5: Table 19.

5.8.2.1 Selection of technology

The space heating system capacity is designed at 14 kW. The heat energy obtained from the distillery is at lower temperature between 40°C and 50°C. High efficiency radiators (such as the PURMO Compact type 22 which have dimensions of 3000mm x 600mm) are used for the study. Other major components selected are a 14kW Plate heat Exchanger, a Domestic Circulating Pump (Grundfos 15-60), temperature sensors, an immersion water heater with storage and 3-way valves. The immersion water heater will be used as backup when the distillery is closed. The heat exchanger has to be installed as close to the distillery as possible to reduce piping costs and heat losses. The schematic diagram of the space heating system for the Jura Hall is shown in Figure 5-6: Space heating with cooling water of the distillery at the Jura HallFigure 5-6.

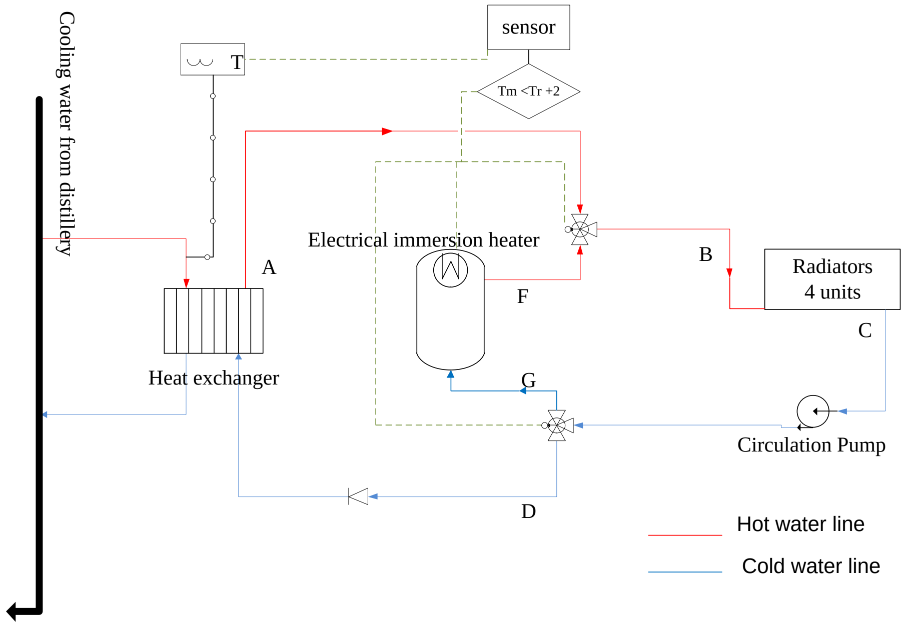

Figure 5-6: Space heating with cooling water of the distillery at the Jura Hall

The temperature sensor at the distillery cooling water pipe senses the hot water temperature and activates the loops.

- *When the distillery is in operation*: The sensor senses hot water coming from distillery and then the loop ABCD is activated. The hot water from heat exchanger goes to the radiators. In this situation the immersion water heater is off.
- *When distillery is closed*: The sensor deactivates loop ABCD and actives the loop FBCG. At this situation, the hot water from electrical hot water generator goes to the radiators.

The detailed specifications of components are presented in Annex 5: Table 21to Annex 5: Table 24.

5.8.2.2 Economic Analysis of use of recovered heat in Jura Hall

The economic analysis for the project was done by comparing the project with its alternatives: a Vigas 16s log boiler of 16kW and electrical thermal storage heaters for different scenarios. The following assumptions have been made for the financial calculations:

- Interest rate used for calculation is 6.5%.
- Life time is 20 years for all alternatives
- Prices of components used in alternative heating systems are obtained from the internet and the Jura Development Trust
- Installation and transportation cost is also taken same for all alternatives and is considered to be £3000.
- Underground piping works from the distillery to Jura Hall are considered to be done by the community voluntarily; otherwise approx. £4200 would have to be added to the investment cost with £30 per meter.
- The operation of the log boiler is done voluntarily by the community members.

- No investment cost for the space required for the wood boiler (Option 2) or immersion water heater (option 1) is considered. But the cost of a shed for log storage is considered to be £1000.
- Renewable Heat Incentive (RHI) tariff is considered as 7.9 pence per kW_{th}. (Ofgem 2011)
- Energy cost for electricity is taken as 0.12 £/kWh for a peak load and 0.103 £/kWh for off peak load. Wood cost is considered as 0.02 £/kWh (£50 /m^3).
- The Distillery closes for 14 days in a year.

The investment cost of the distillery heat recovery project is around £13,398, which is the highest among the alternatives.

Figure 5-7: Economic analysis of different options for heating in the Jura Hall at different occupancy

Description	Existing Occupancy			50% increase in Occupancy		
	Distillery heat Recovery	Log boiler	Electrical thermal storage (base case)	Distillery heat Recovery	Log boiler	Electrical thermal storage (base case)
Investment Cost, Io [£]	13,398	10,504	5,633	13,398	10,504	5,633
Energy required [kWh/y]	5,692	5,692	5,692	8,538	8,538	8,538
Total electrical energy cost [£/year]	62.26	48.85	586.26	93.39	73.28	879.39
Wood energy cost [£/year]	-	130.33	-	-	195.50	-
Energy cost before RHI [£/year]	62.26	179.18	586.26	93.39	268.78	879.39
Renewable Heat Incentive [£/year]		450			674	
Yearly running cost including RHI [£/year]	62	(270)	586	93	(406)	879
Net present value compared with base case [£]	(1,991)	1,124		896	9,289	
Payback period compared with base case [Year]	beyond project period	7.3		16.3	4.5	
Internal Rate of Return compared with base case	-3.25%	16.80%		7.90%	26.10%	

The existing occupancy of the Jura hall is only 20% that is 1794 hours per year. With this occupancy rate the most financially feasible alternative is the log boiler and then the electrical thermal storage. The wood boiler is still the most financially feasible option even when the occupancy rate is increased by 50%. But in this case the distillery heat project is more financially feasible than the electrical thermal storage.

The main reason of the log boiler being more financial feasible option is due to the renewable heat incentive (RHI). The RHI that the hall will receive is greater than the energy cost per kWh. The heat recovery from the cooling water from distillery will not get RHI because the heat is generated as a by-product of fossil fuelled process. (Ofgem 2011)

5.9 Conclusions and suggestions

There is a high energy potential in the waste that Jura distillery is currently discharging to the sea. The heat power potential of discharged cooling water is around 2968kWth and the electrical power potential of the mixture of pot ale and spent lee is 155 kWe.

Installing a CHP system fed from biogas produced by the fermentation of pot ale and spent lee with a 50 kWe or with 155 kWe is financially feasible. In both cases, there would be enough heat or electricity to provide the demand of the Jura Hall and the Jura Hotel and the rest can be exported to the grid or used for local demand. Besides, the 50 kWe and the 155 kWe projects reduce 348 and 830 tons of CO_2 per year respectively alleviating climate change.

The analyses also show that using distillery cooling water to provide hot water and space heating to the Jura Hotel is financially viable compared to the oil boiler that they are using. But in the case of the Jura hall the wood boiler is the most financially feasible option because of the high Renewable Heat Incentive and low heating demand.

The CHP project and the distillery heat recovery project exclude each other. If a CHP system is to be installed, the use of the distillery cooling water for heating purposes would not be useful due to the lower temperature level of the distillery cooling water compared to the heat generated by the CHP. Besides, a community owned CHP project would be more beneficial to the community because it could generate more income by selling heat and electricity.

Nonetheless, for the implementation of the CHP project the distillery support is vital. If the distillery shows no interest in the CHP project, the waste heat recovery project would be the second best alternative. A detailed study by a specialised HVAC engineer is recommended for the implementation of the project.

6 GRID CONNECTION OPTIONS AND OPPORTUNITIES

6.1 Introduction

The objective of this section of the report is to analyze the different generation capacities and sources available to satisfy the electricity demand of the island considering the technical and regulatory constraints of grid interconnection.

There is a 50 kW grid interconnection capacity restriction and this is the main constraint when considering the possibility of producing electricity on the island. This scenario is more complex if we consider the fact that power flow between the mainland and Islay/Colonsay goes through Jura. Each one of these islands has a demand for electricity and electricity generation facilities.

Different scenarios were analyzed. Some of them are feasible with the current regulatory framework and grid constraints whilst others assume proposals that are currently being considered have been implemented. Some scenarios consider that JDT forms a subsidiary as an electricity supplier and includes recommended tariffs for electricity supplied to customers on the island. These tariffs are competitive in the market and will bring additional benefits to members of the Jura community. Additionally a simulation of the current situation of the grid in peak moments will be provided in this study to estimate available capacity on the grid under present conditions. The acceptance of the society towards a community-owned energy supply is also discussed.

6.2 Detailed scope and assumptions for grid connection options

Three scenarios were developed based on available resources to maximize the benefits to the community. There is currently no reliable data available on the load profile in Jura. Different load profiles were analyzed and used as input to model a probable load profile of the island. These are:

- The comprehensive load profile of the three islands Islay, Jura and Colonsay, provided by Scottish Hydro
- The load profile of South Uist, provided by Scottish Hydro
- The load profile of the Knoydart peninsula, which is supplied by a stand-alone hydropower plant
- The standard UK load profile for residential and commercial customers (Ilex Energy Consulting report, year)
- Results of a door-to-door survey on Jura carried out by the team

For this study the standard UK load profiles were modified with the information obtained from the above mentioned island profiles. Monthly seasonality was considered through the UK profile. It was assumed that 10% of the households on Jura use electricity for heating. This figure was derived from the respondents interviewed during the survey carried out by the team and extrapolated to the rest of the community. The electricity required to heat domestic hot water tanks and electrical storage heaters is considered to be a deferrable load, which means that it is supplied within predefined time limits only when there is an excess of electricity generation.

The distillery is excluded from demand calculations in all the scenarios due to the high electricity demand, the unavailability of a load profile and the unpredictability of its peak loads.

In developing the scenarios, the security of supply, lower tariffs for customers and the economic feasibility of the project were the main parameters considered. A day to day load variation of 5 % and a 5% hourly variation were also set within the simulation parameters to secure the supply. Different customer tariffs were considered in the scenarios. These tariffs are compared within the scenarios with commercial rates to establish additional economic benefits to the community. The scenarios also consider two different tariffs, one tariff for heating purposes and another tariff for appliance use.

6.3 Methodology

The first step was to determine the demand of electricity of the island. This will be explained in detail in its corresponding section.

Once the demand was calculated, the existing and proposed (but likely) regulations were analyzed to determine options available to satisfy the demand. The grid capacity restriction was as well considered in designing the scenarios. In some scenarios the grid constraint is considered to be 50 kW, but in other scenarios the grid constraint is not taken into account to show the possibilities that Jura would have if the capacity would increase. Grid analyses were carried out with Power factory, a software from Digsilent, to estimate losses and voltage drops.

The tariffs of a community owned electricity supply were fixed comparing the tariffs of other electricity suppliers to provide better prices if possible. These tariffs provide extra-income for the production of electricity in addition to the FITs.

Once the tariffs were set the most appropriate technologies to satisfy the demand were chosen. To do this, the technologies were considered within their maximum output constraints and grid feed in constraints. The simulations for the optimum power dispatch of the technologies and the demand calculations were done with HOMER, a power optimization model. Two scenarios were evaluated. These are:

1. Scenario 1: Private wire supply

    a. Private supply to a cluster of houses with an estimated load of 20kW around Ardfernal/Knockrome
    b. Private supply to a cluster of houses with an estimated load of 90kW around Craighouse

2. Community supply through public grid, considering a limit of 50kW for each of the embedded generators

An economic evaluation was also carried out to find out the payback periods (PBP), internal rates of return (IRR) and net present values (NPV). Finally an analysis of the acceptance of the community of Jura towards owning an electricity supply company was evaluated.

6.4 Electricity demand analysis

The estimation of the electricity demand of the island plays a very important role in the evaluation of the scenarios. During the door-to-door survey, respondents were requested to estimate their annual consumption of electricity in either pounds or units of electricity and the average energy consumption was calculated to be 6,345 kWh/year/household. Households with white meters were not considered in the calculations.

The heating demand for households considered is 12,386 kWh/year based on research carried out by students of the University of Flensburg on the isles of Barra and Vatersay; islands that have many similarities with the island of Jura (2009, 9). According to the door-to-door survey, 10% of the respondents on the island of Jura have electrical space heating with storage heaters. This percentage is extrapolated to the population to estimate the amount of electricity required for heating purposes on the island.

The load profile for Jura households was modeled, using data from the UK, the islands of South Uist, Knoydart Peninsula and the three islands Islay, Jura and Colonsay together with the calculated energy demands for electrical appliances and heating from the survey.

The annual household consumption for appliances (6,345 kWh) was distributed for the whole year. For simplicity and to account for inaccuracies in the monthly peak estimations the year was divided into 5 seasons: winter, spring summer, high summer, autumn and the peak demand of the respective season was assumed for all months of the seasons.

To calculate the heat requirements, the assumed annual consumption of 12,386 kWh per household was included in the profile according to the annual temperature distribution. The following graph shows the average heat demand distribution for a single house during the year:

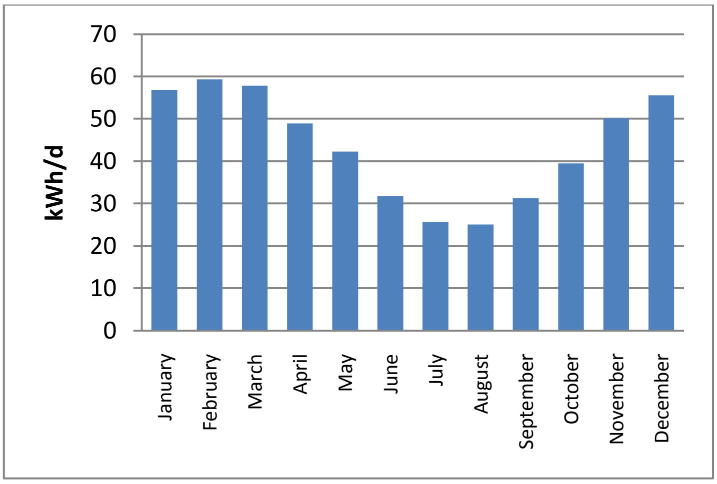

Figure 6-1 Monthly heat demand for a hoursehold of Jura in kWh/day, based on Islay heating degree days

The demand profiles for the service point, the surgery, the school, the hotel, holiday flats, the distillery, the store and the restaurant were also estimated.

The load profile of the hotel was based on the quarterly electricity consumption of the hotel. This data was obtained through an oral interview with the manager of the hotel. The daily consumption pattern for the hotel is very similar to the household profile and the distribution for unrestricted customers was therefore used. The demand profile of the store was also estimated based on an oral interview with the storekeeper.

The daily demand profile of holiday flats was assumed to be similar to the one of a household on a weekend. Through information collected with interviews and documents provided by the JDT, 25 holiday flats were identified. The occupancy rates were assumed to be similar to that of the hotel and this was used for the calculations.

Pupils of the school record readings of their standard and white meters intermittently under staff supervision. This information was used to estimate the energy consumption for the school. A visual audit of appliances and times of use of the service center was used to estimate the energy consumption of the service center. In an interview with staff of the surgery, it was indicated that the surgery pays approximately GBP500 per quarter. This was used to estimate the annual consumption of the surgery.

6.5 Grid analysis

The grid analysis was carried out with Power factory, a power system analyses tool, to estimate the state of the network and evaluate the impact of the proposed plants on Jura on system conditions. The model used for the analysis is approximate and only gives an indication of the state of the grid. It was developed with a geographic map of the power line route which was obtained through Community Energy Scotland (CES). Per information received from CES, a 100mm^2 Aluminium Conductor with Steel Reinforcement (ACSR) was used for the overhead lines and a 70mm^2 copper cable with polyethylene sheathing used for the sub-sea cable. The model did not include the Islay and Colonsay networks. These two networks were modeled as a load at the end of the overhead line close to the Islay/Jura Ferry line. Due to node limitations with the license version of the software, transformers on Jura were not included in the model. No reactive power compensation devices were included in the model and all loads were assumed to have a power factor of 0.98. Other impacts of embedded generation such as voltage fluctuations, reverse capabilities of transformers and harmonics are not considered in the analysis because this will require a more accurate and detailed model of the grid.

Based on the assumptions, peak load (11.15MW) losses between Lilt Bay on the mainland and the Ferry point on Jura was 1.4MW. The sub-sea cable from the main-land was 78% loaded. The scenarios evaluated were:

- Case 1: Lowest load with maximum embedded generation
- Case 2: Peak load conditions with maximum embedded generation
- Case 3: Peak load conditions with maximum embedded generation without distillery
- Case 4: Private supply to a cluster of houses with estimated load of 20kW around Ardfernal/Knockrome
- Case 5: Private supply to a cluster of houses with estimated load of 90kW around Craighouse

The conditions and results of Cases 1 to 3 are tabulated below:

Table 6-1 Conditions and results of load flow simulations

	Case 1	Case 2	Case 3
Generation at Islay (MW)	1	1	1
Total Generation on Jura (MW)	1.735	1.735	1.735
Tidal energy (MW)	9	9	9
Inver Hydro (MW)	1	1	1
Ardlussa Hydro (MW)	0.15	0.15	0.15
Ardlussa Wind (MW)	0.33	0.33	0.33
Corran River (MW)	0.1	0.1	0.1
Biogas Plant (MW)	0.155	0.155	0.155
Load in Jura (MW)	0.200	0.25	0.25
System load (MW)	5.600	11.150	11.05
Losses (MW)	0.87	0.15	0.15
Load on subsea cable (%)	63.42	27.08	27.43

The introduction of embedded generation under peak load conditions in Case 2 significantly reduces losses and the loading on the sub-sea cable. This is expected because the load is satisfied by generation closest to its maximum. Reverse power flow (from Jura towards the mainland instead of flowing from the Mainland towards Jura) occurs when all embedded generators are running at full load and demand is at the minimum. This condition is simulated in Case 1 and it was observed that loading on the sub-sea cable was lower than the loading under present peak load conditions.

The difference between Case 3 and Case 2 is that the Jura distillery is not included in Case 3. This represents peak load conditions for Scenario 2 in which the community supplies power to its members. The results are similar to that of Case 2 in which losses and loading on the sub-sea cable are reduced.

Case 4 simulates conditions with private wire supply to a load of 20kW to a cluster of houses up to Ardfernel and an additional 50kW exported to the grid. The supply uses the existing 33kV tee-off to supply the load. There is a voltage drop of 8% at the furthest point on the line.

Case 5 simulates conditions with private wire supply to a load of approximately 90kW from the biogas plant to the hotel, the store and a cluster of houses close to the proposed plant site at Craighouse. The load was supplied with a 415V line to minimise the cost of installation. The voltage drop at the furthest point is approximately 5% at 394V. This option allows the capacity of the CHP biogas plant to be utilised because the spare capacity of 50kW can be exported to the grid under the present limitations.

Embedded generation reduces losses in the Jura network and loading on the sub-sea cable. However, this scenario could change entirely with increased embedded generation on Jura, Islay and Colonsay; hence the 50kW limit imposed on new embedded generators. Active network management systems could be employed to share spare capacity on the network amongst embedded generators. These possibilities could be discussed with Scottish and Sothern Energy (SSE).

It is technically feasible to supply up to 20kW and 90kW to loads close to the hydro and CHP biogas plants respectively. If feasible, the community could purchase the radial tee-off to Ardfernal to supply the 20kW. The 90kW supply from the CHP biogas plant could be supplied at 415V to reduce the cost of investment. The community will be responsible for metering, customer service, data and revenue collection and settlement of the net power consumed from the public grid which could incur large costs.

6.6 Analysis of scenarios

6.6.1 Scenario 1: Private wire supply

Scenario 1 proposes the sale of electricity to customers that are located near the generation points through the installation of a private wire. To maximize profits of this scheme it is necessary that the clusters are as close as possible to the generation point to reduce the cost of connection. Two clusters are proposed with a 50 kW restriction to export electricity to the grid considered.

6.6.1.1 Ardfernal/Knockrome HydroCluster

This cluster of consumers is situated near the proposed site for the powerhouse of the Corran River hydropower plant and comprises 14 households.

It is assumed that none of the 14 households is using electricity for heating purposes, and all the houses pay standard tariffs. The simulation of the demand profile in HOMER showed that the lowest demand within the cluster is 3.79 kW and reaches a peak of 25.02 kW. A hydropower plant with a capacity of 50 kW will allow both, the supply of peak electricity to the cluster and the export of up to 48.7 kW to the grid at times of low demand in the cluster. The figure below shows the electricity balance of the Hydro cluster over a year:

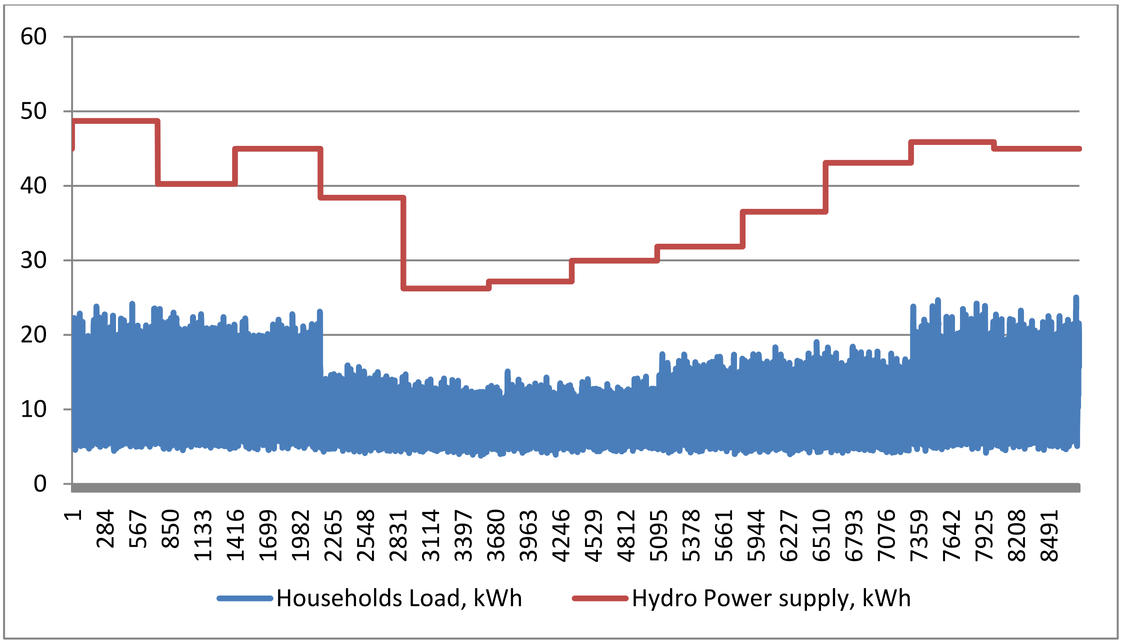

Figure 6-2 Electricity balance of the Ardfernal/Knockrome HydroCluster

The gap between demand load and supply shows the amount of electricity, which is going to be exported to the grid.

A private wire of 33 kV from the power house was used to supply power to Ardfernal and the Old School House Knockrome. The length of the line is 2.17 km. Grid analysis determined that voltages are with acceptable limits in this scenario.

The total investment cost of the project is 904,806.2 pounds, where investment cost for the grid is 171,777.2 pounds (Öko-Institut 2011) and cost of connections to public grid is 29,000pounds[15]. Annual operation and maintenance costs were estimated at 19,678 pounds per year (Öko-Institut 2011). In addition, costs for administration and management of the private wire were estimated on the level of 1,000 pounds per month. The project is considered to have a lifetime of 50 years, with an annual discount rate of 6.5% and annuity loan return period of 20 years.

The annual electricity production of the hydropower plant is of 334.23 MWh. However, for 1752 hours per year the hydropower generation will be below 25 kW. This means that a community owned energy supplier can only sell 75.92 MWh hydroelectricity of the total demand of 94.9 MWh to the households. 18.98 MWh would have to be purchased from the DNO. The cost of this electricity depends on the electricity market but it can be assumed that the cost will be higher than the cost for a regular consumer. For our calculations we have assumed a low electricity price of 14 p/kWh for the electricity supplied by the DNO. The earnings of the cluster has three components; the FiT received by generating electricity from renewable energy, an export tariff for every unit exported to the grid and another income for every unit of electricity sold to the customers. The FiT for the hydropower plant is 19.6 p/kWh for 2012/2013 (Ofgem 2012). The export tariff defined by Ofgem is 3.2 p/kWh (Ofgem 2012). These two values are stable and can be considered as the basis for project earnings. The tariff for consumers is considered at a level of 10 p/kWh which is 2p cheaper than the rates from

[15] The costs were considered according to information got from the Ardlussa Hydro Project.

SSE of 12.7 p/kWh (SHEPD 2012). In total, the project generates 7,658 pounds per year by exporting electricity to the grid, 9,490 pounds per year by the customer's consumption and 65,509 pound from the feed-in tariff. 2,557 pound have to be paid to the DNO for import of electricity.

The economic analysis for the construction of a hydro power plant with private wire supply interconnected with the public grid showed that the NPV is -198,187 pounds and the IRR is 4.68%, with a payback period of more than 50 years. The results show inexpediency of Ardfernal/Knockrome Hydro Cluster supply through the private wire. The negative result is the cause of high costs of private wire construction and maintenance. This was also seen in Chapter 4.

In conclusion, the option of supplying the Ardfernal/Knockrome Hydro Cluster with private wire is not economically feasible. It is more profitable and less complicated to export electricity directly to the grid.

6.6.1.2 Woodside, Craighouse, Keils biogas cluster

The second cluster of load has a peak demand of 90kW and covers the area of Woodside, Craighouse and up to Keils and could be connected to the biogas fired CHP plant.

The area of the cluster was selected according to considerations of the population and proximity to the biogas plant. The circuit length distance of the cluster is nearly 2 km.

Based on the survey results, four households within the cluster of 40 houses are assumed to use electricity for space heating with white meters and 36 houses use standard meters. The demand of the cluster also includes the hotel, the restaurant and the store. The total consumption of the cluster in one year is estimated at 395.3 MWh, where the peak demand is 93 kW and the lowest demand is 16.5 kW.

The simulations in HOMER showed that a 100 kW Biogas CHP plant is the most feasible plant size within the cluster, in order to satisfy the cluster's demand and export electricity to the grid with a 50 kW connection constraint. However, due to the grid restriction the CHP plant cannot run at full capacity throughout the day, which reduces its capacity factor by 9 %. The figure below shows electricity balance for the cluster.

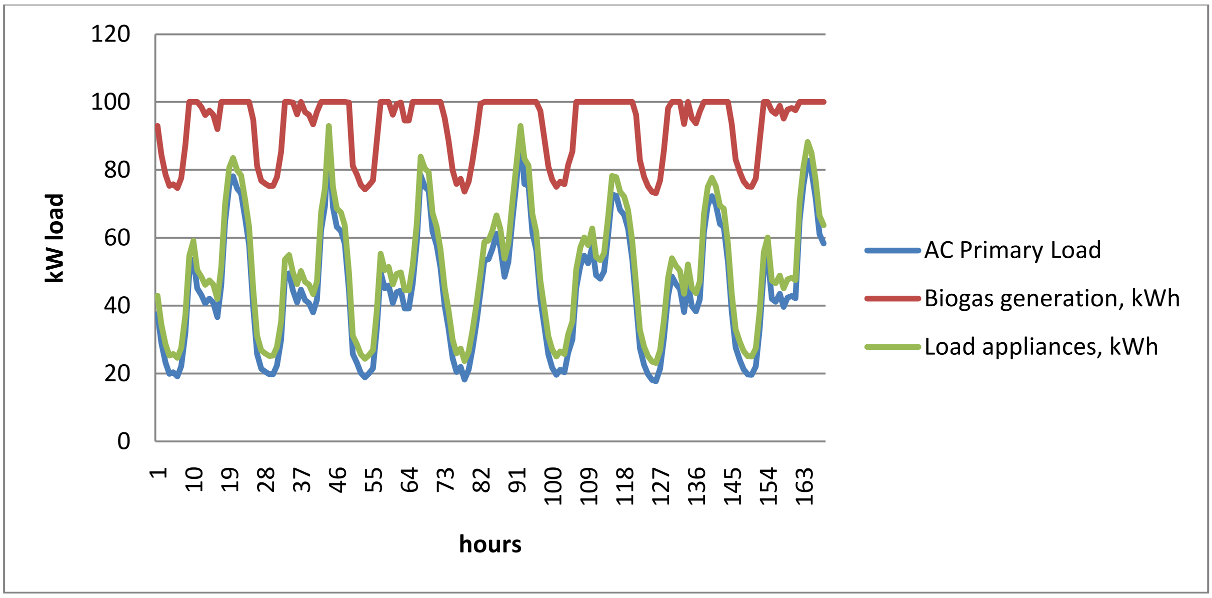

Figure 6-3. Electricity balance of the Biogas cluster during a typical week of November in kW

From the figure, it can be seen that a 100 kW biogas plant satisfies the demand of the cluster in a typical week of the peak month November. with the possibility of exporting electricity to the grid. The electrical heat consumption of the cluster in one year is 30.9 MWh and electricity consumption of other appliances in the households is 395.3 MWh per year.

The FiT for biogas plants is 14.7 p/kWh and an export tariff of 3.2 p/kWh was used (Ofgem 2012). The tariffs for the customers were determined according to the present tariff for electricity used for heating (8.1p/kWh) (SHEPD 2012) and the tariff for electrical appliances was 9.75[16] to simplify the analyses. It was proposed to reduce the value of the tariffs to 6 p/kWh and 8.5 p/kWh respectively, in order to attract customers. Electricity prices for commercial customers is approximately 20% lower than for households. The lowest tariff regime was used for the project to show the worst case scenario. The total income of the project considering all tariffs is 158,238.70 pounds per year. Since this is a community project, appropriate schemes should be implemented to fairly distribute the benefits across the community.

A 415V private wire was considered to supply the cluster with an approximate length of 2 km. The private wire will cost 79,160 pounds (Öko-Institut 2011) per 2 km including the wire to the houses, with annual operation and maintenance costs of 7,916 pounds (Öko-Institut 2011). From Chapter 5, the capital cost for 100 kW the Biogas plant is 493,318 pounds with an annual operation and maintenance costs of 19,444 pounds per year. Additionally, administration and management costs are estimated at 1,000 pounds per month.

With the construction of a private wire, and reduced tariffs for the customers, the project has attractive returns. The IRR is 20.45% and the NPV, with the consideration of 20 years lifetime period, is 739,331 pounds, with a PBP of 4.77 years. When the project is financed with a 15 year annuity loan and a 6.5% annual discount rate, the project generates an annual cash flow in the first 15 years of 62,080 pounds. The annual loan repayment is 63,968 pounds. When the loan is repaid, the project will

[16] Tariff price for the Hotel of Jura. Investigated through the Survey.

earn approx. 126,049 pounds per year for the next five years. The price of the waste water coming out from the distillery is considered to be zero. This scenario is compared with 50kW export to the grid in the table below

Table 6-2 Comparison of 50kW export and private wire with export

	50 kW export to the grid	**Private wire supply with export of excess electricity**
Total investment (£)	357,087	601,478
Total annual profit (£/year)	25,326	62,080
IRR (%)	16. 37	20.45
NPV (£)	324,321	739.331
PbP (years)	5.82	4.77

6.6.2 Scenario 2: Community supply through public grid (50kW limit)

This scenario attempts to satisfy the entire domestic demand without heating with rescources from community-owned plants using the public grid.

It is assumed that the grid restrictions allow the installation of a50 KW Wind power plant in Ardlussa, a 50 KW Hydro power plant on Coran River and a 50 KW biogas CHP plant near the Distillery. Due to the distances involved, it is assumed that the plants will be considered individually by SHEPD and not as a cluster of plants.

The limit capacity of 150 KW is not enough to satisfy the peak demand of the Island of 320 KW.To find an optimum solution to supply the community through the public grid, different scenarios were simulated in HOMER. The simulations showed that the above mentioned power plant composition allows the supply of 50 Households of the island and export excess electricity to the grid. Again, 5 out of 50 households are assumed to use electricity for heating.

The supply and demand of Scenario 2 is shown in the following graph:

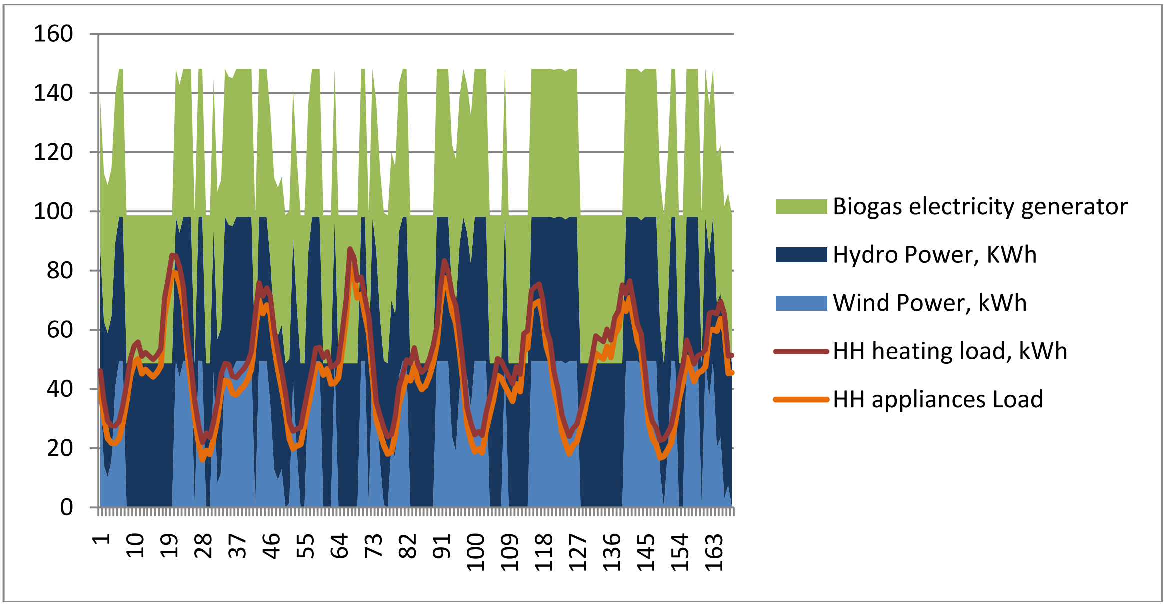

Figure 6-4. Electricity balance of Community supply by 3 PP (150KW) during 1 week of January

The economic calculations were based on the respective FiTs for each technology, 3.2 p/kWh export tariff and the necessary charges were applied. The tariffs for the customers considered are 6 p/kWh for heating and 8.5 p/kWh for other appliances.

The PBP period of this community electricity supply scenario is 6.56 years with an IRR of 14.17% and an NPV of 899,023.67 pounds over a 20 year lifetime period. A 15 year annuity loan with 6.5% annual discount rate returns 149,650.70 pounds per annum during the loan term.

Since the tariffs used are higher than the export tariff, the scenario has higher economic benefits than 100% export to the grid. The NPV and IRR for direct export are 704,538.43 and 12.62% respectively with a payback period of 7.19 years.

However, administrative cost of a community owned electricity supply can presently only be based on rough estimations and from the authors' point of view the relatively small added benefit of this option does not justify the increased risk and management efforts that are required. Under the present regulatory framework, it will be extremely difficult for the community to consider the option to supply power to the community through the public grid. The regulatory burdens will be reduced if proposals by the OfGEM to modify the supplier licensing requirements are accepted. Whilst these proposals will make it easier for the community to supply power to itself using the public grid, the responsibilities, expertise and experience required are significant. We suggest that the community starts with 100% export to the grid.

6.7 Options for demand side management

By reducing peak loads, power plants can be sized and utilized more efficiently because they usually do not last for long periods. For example, if the average demand is 50kW and the peak which lasts for 2 hours a day is 100kW, an additional investment in a capacity of 50kW will be required only to run for 2 hours a day. The options that can be considered case of Jura are electricity storage and demand side response. This is because there are two options involved in the case of Jura. Storage of excess electricity becomes important in minimizing the import of electricity from the public grid during peak times.

Power storage can also be used to shift the time of electricity production by renewable sources to synchronize it with time of consumption. Thus it would be appropriate to consider storage and demand side response as options to the possibility of setting up a community managed electricity supply system. By using smart meters, consumers will be able to monitor their energy consumption and decide to alter consumption based on the dynamic real time tariffs (avoiding peak hour tariff). Through demand side response, more power can be exported to the grid during peak times which could earn more money for the community.

However, the installation of new infrastructure for smart meters such as communication and control systems (wireless or optical system) could be very expensive.

6.8 Social acceptance

Out of 55 respondents interviewed during the survey, most of the respondents supported the idea of a community-owned project for the following reasons:

1. Creation of new jobs in the Island
2. Source of additional earnings to the Community resulting in economic growth.
3. Cheap and reliable electricity.

Four respondents are prepared to pay a premium for energy from renewable sources in general but are are not sure of paying a premium for energy from a community owned project. Three respondents are against a community owned project. Results are indicated in the graphs below:

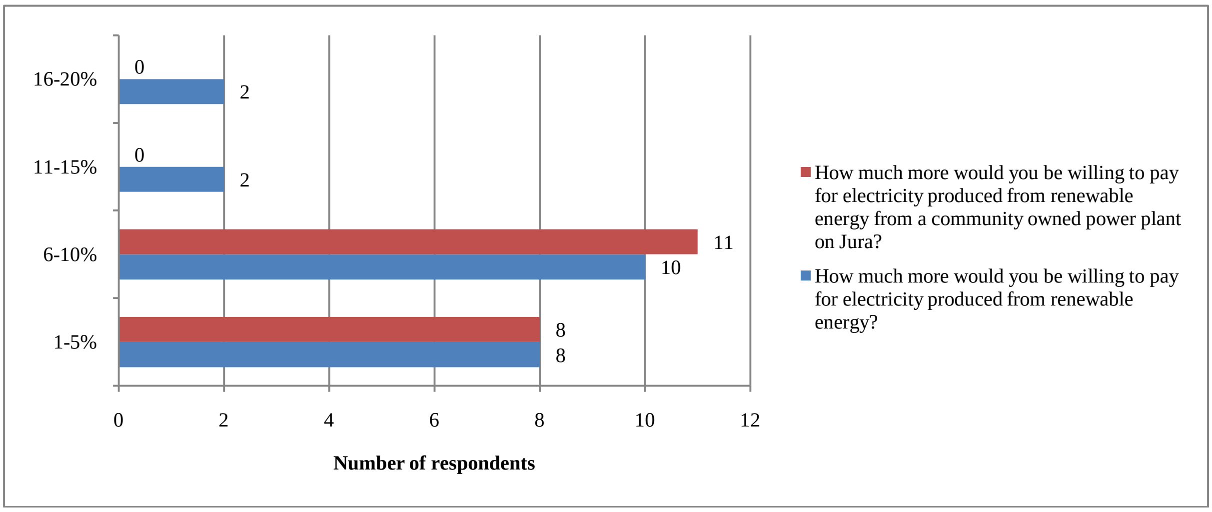

Figure 6-5 Results of survey showing willingness to pay for renewable energy

6.9 Conclusions and suggestions for grid connection options

Most of the respondents interviewed during the survey supported the idea of a community-owned project. The 50kW restriction is the main bottleneck for the development of renewable energies on the island. Using a private wire to supply demand close to a 100kW biogas plant whilst exporting excess electricity to the grid is more profitable than simply exporting power from a 50kW plant but this option presents considerable responsibilities which require considerable expertise and experience.

Under the present regulatory framework, it will be extremely difficult for the community to consider the option to supply power to the community through the public grid even though it seems to be slightly more profitable than exporting electricity only to the grid and supports social growth. The regulatory burdens will be reduced if proposals by the OfGEM to modify the supplier licensing requirements are accepted. Whilst these proposals will make it easier for the community to supply power to itself using the public grid, the responsibilities, expertise and experience required are still significant.

We suggest that the community starts with 100% export to the grid.

7 CONCLUSIONS AND RECOMMENDATIONS

Overall, the key objective of this assessment study was to analyse the technical, economical, social and environmental feasibility of developing community-owned energy projects on Jura. Thus the undertaken activities focused on assessing the energy resources and analyzing legal frameworks to support the development of renewable energy projects. As such, this report should be viewed as the start of an ongoing set of activities and discussions about renewable energy developments rather than being seen as an end in itself. The study does, however, confirm that there are renewable energy resources that could be profitably exploited and that the future power production potential for the Island of Jura is significant. It is also clear that there are a number of planning and legal issues that would need to be carefully assessed if these developments are to proceed in a sustainable and acceptable manner.

The key recommendation that has appeared at all levels of the study areas is the present regulatory framework on grid feed-in. This restriction makes it extremely difficult for the community of Jura Island to supply power to the community using the public grid even though it seems to be more profitable than exporting electricity only. Therefore until the modifications proposed by the OfGEM are effected, it is not recommended for the community of Jura to attempt community supply through the public network.

Finally a summary of the technical and economical findings of the various energy components have showed that community-owned projects can be developed for wind, hydro and waste-heat recovery power plants.

Wind

The favourable wind condition at the project site at Ardlussa allow for wind energy exploitation with optimally three feasible scenarios. The scenario found fitting to the present situation at installation of one 50kW wind turbine at proposed for installation. This option yields an annual energy output of approximately 239,201 kWh/year with a payback period of 10.4 years. A larger capacity turbine however would generate more energy and provide more attractive economics if constraints of grid is solved. The 50 kW wind turbine can be installed nearly on the top of Ardlussa hill with the tip height of about 40.1 meters.

Hydro

The result of the hydrology study conducted on the Corran river shows that it is both economically and technically feasible to develop a small hydropower scheme on the river. A 330 kW capacity hydropower plant is found to be the most beneficial in terms of energy produced in energy per year (1344 MWh /year), however it would operate at full capacity for less hours of the year. The capacity factor of 330 kW would be 46.5%. A 100 kW and 50 kW would operate at full capacity for more hours per year and would produce 596 and 334.5 MWh/year respectively. The capacity factor would be 68% and 76.4% respectively. The 50 kW plant only yields an income for the community during the first 15 years of operation if the loan period can be negotiated to be 20 years.

Heat Recovery and Biogas potential

The energy retained by the waste water, pot ale and spent lee from the Jura distillery is high. This can effectively be used to produce heat energy. Installing a CHP system fed from biogas produced by the fermentation of pot ale and spent lee with a 50 kWe or with 155 kWe is financially feasible. Nonetheless, for the implementation of the CHP project the distillery support is vital. If the distillery shows no interest in the CHP project, the waste heat recovery project would be the second alternative. A detailed study by a specialised HVAC engineer is recommended for the implementation of the project.

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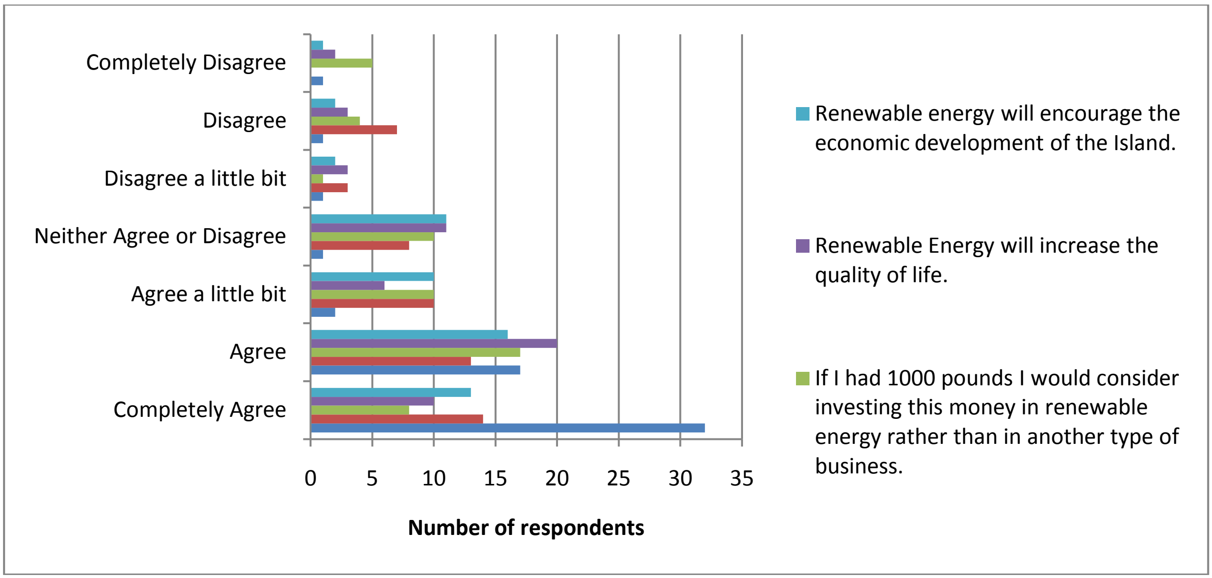
GLOSSARY

AC	Alternating Current
AD	Anaerobic Digestion
ADLF	Anaerobic Digestion Loan Fund
BOD	Biological Oxygen Demand
CES	Community Energy Scotland
CHP	Combined Heat and Power
COD	Chemical Oxygen Demand
DNO	Distribution Network Operator
EIA	Environmental Impact Assessment
ENA	Energy Networks Association
ER	Engineering Recommendation
EU	European Union
FDC	Flow Duration Curve
FIT	Feed in Tariff
GBP	Great Britain Pounds
GBRs	General Binding Rules
HDPE	High density Polyethylene
HVAC	Heat Ventilation and Air Conditioning
IRR	Internal Rate of Return
ISO	International Standards Organization
JDU	Jura Development Trust
MCP	Measure Predict Correlate
MCS	Micro generation Certification Scheme
NPV	Net Present Value
NSAs	National Scenic Areas
O & M	Operation and Maintenance
Ofgem	Office of Gas and Electricity Markets
PbP	Pay back period
PPA	Power Purchase Agreement
PPC	Pollution Prevention and Control
PV	Photovoltaic
RHI	Renewable Heat Incentive
RoC	Renewable Obligation Certificate
SEPA	Scottish Environmental Protection Agency
SNH	Scottish National Heritage
SSE	Scottish and Southern Energy
UASB	Up-flow Anaerobic Sludge Blanket
UK	United Kingdom
UWWTD	Urban Waste Water Treatment Directive
WML	Waste Management Licence

ANNEX 1 SOCIAL ACCEPTANCE

90 households were visited in the door-to-door survey conducted by the team during the period March 6-10, 2012. Out of the houses contacted, 55 interviews were conducted whilst 14 declined the interviews and occupants of 21 houses were not available for the interviews. This represents a positive response rate of 61%. Some results of the questionnaire are graphed below. A copy of the questionnaire together with detailed results of the survey is included on the attached CD.



Annex 1: Figure 1 Perception on renewable energy

Most of respondents were in support of a community owned project because they hoped this could bring income to the community. Three respondents who opposed the idea cited the following reasons:

- Members of the community lack the skills required to operate these plants.
- Community projects do not work because of self interests.
- Community systems do not work.

ANNEX 2 FEED IN TARIFFS

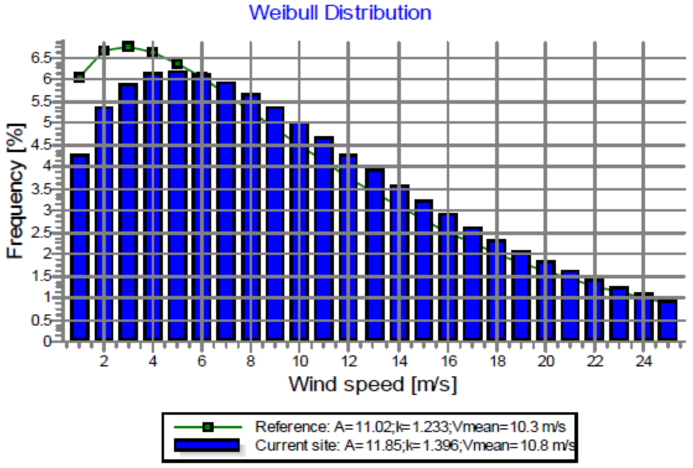
Table Annex 2-1 Feed in Tariff from 1st April 2012

Description	FIT Year in which the Eligibility Date of an Eligible Installation falls		
	FIT Year 1 2010/11	FIT Year 2 2011/12	FIT Year 3 2012/13
Anaerobic digestion with total installed capacity of 250kW or less	12.7	*If Eligibility Date is before 30th September 2011* 12.7 *If Eligibility Date is on or after 30th September 2011* 14.7	14.7
Anaerobic digestion with total installed capacity greater than 250kW but not exceeding 500kW	12.7	*If Eligibility Date is before 30th September 2011* 12.7 *If Eligibility Date is on or after 30th September 2011* 13.6	13.6
Anaerobic digestion with total installed capacity greater than 500kW	9.9	9.9	9.9
Hydro generating station with total installed capacity of 15kW or less	21.9	21.9	21.9
Hydro generating station with total installed capacity greater than 15kW but not exceeding 100kW	19.6	19.6	19.6
Hydro generating station with total installed capacity greater than 2MW	4.9	4.9	4.9
Combined Heat and Power with total installed electrical capacity of 2kW or less (Tariff available only for 30,000 units)	11.0	11.0	11.0
Solar photovoltaic with total installed capacity of 4kW or less, where attached to or wired to provide electricity to a new building before first occupation	39.6	*If Eligibility Date is before 3rd March 2012* 39.6 *If Eligibility Date is on or after 3rd March 2012* 21.0	Higher rate 21.0* Middle rate 16.8* Lower rate 9.0*
Solar photovoltaic with total installed capacity of 4kW or less, where attached to or wired to provide electricity to a building which is already occupied	45.4	*If Eligibility Date is before 3rd March 2012* 45.4 *If Eligibility Date is on or after 3rd March 2012* 21.0	Higher rate 21.0* Middle rate 16.8* Lower rate 9.0*
Solar photovoltaic (other than stand-alone) with total installed capacity greater than 4kW but not exceeding 10kW	39.6	*If Eligibility Date is before 3rd March 2012* 39.6 *If Eligibility Date is on or after 3rd March 2012* 16.8	Higher rate 16.8* Middle rate 13.4* Lower rate 9.0*
Solar photovoltaic (other than stand-alone) with total installed capacity greater than 10kW but not exceeding 50kW	34.5	*If Eligibility Date is before 3rd March 2012* 34.5 *If Eligibility Date is on or after 3rd March 2012* 15.2	Higher rate 15.2* Middle rate 12.2* Lower rate 9.0*
Solar photovoltaic (other than stand-alone) with total installed capacity greater than 50kW but not exceeding 100kW	34.5	*If Eligibility Date is before 1st August 2011* 34.5 *If Eligibility Date is on or after 1st August 2011 and before 3rd March 2012* 19.9 *If Eligibility Date is on or after 3rd March 2012* 12.9	Higher rate 12.9* Middle rate 10.3* Lower rate 9.0*
Solar photovoltaic (other than stand-alone) with total installed capacity greater than 100kW but not exceeding 150kW	32.2	*If Eligibility Date is before 1st August 2011* 32.2 *If Eligibility Date is on or after 1st August 2011 and before 3rd March 2012* 19.9 *If Eligibility Date is on or after 3rd March 2012* 12.9	Higher rate 12.9* Middle rate 10.3* Lower rate 9.0*

Description	FIT Year in which the Eligibility Date of an Eligible Installation falls		
	FIT Year 1 2010/11	FIT Year 2 2011/12	FIT Year 3 2012/13
Solar photovoltaic (other than stand-alone) with total installed capacity greater than 150kW but not exceeding 250kW	32.2	*If Eligibility Date is before 1st August 2011* 32.2 *If Eligibility Date is on or after 1st August 2011 and before 3rd March 2012* 15.7 *If Eligibility Date is on or after 3rd March 2012* 12.9	Higher rate 12.9* Middle rate 10.3* Lower rate 9.0*
Solar photovoltaic (other than stand-alone) with total installed capacity greater than 250kW	32.2	*If Eligibility Date is before 1st August 2011* 32.2 *If Eligibility Date is on or after 1st August 2011* 8.9	8.9
Stand-alone (autonomous) solar photovoltaic (not attached to a building and not wired to provide electricity to an occupied building)	32.2	*If Eligibility Date is before 1st August 2011* 32.2 *If Eligibility Date is on or after 1st August 2011* 8.9	8.9
Wind with total installed capacity of 1.5kW or less	37.9	37.9	35.8
Wind with total installed capacity greater than 1.5kW but not exceeding 15 kW	29.3	29.3	28.0
Wind with total installed capacity greater than 15kW but not exceeding 100kW	26.5	26.5	25.4
Wind with total installed capacity greater than 100kW but not exceeding 500kW	20.6	20.6	20.6
Wind with total installed capacity greater than 500kW but not exceeding 1.5MW	10.4	10.4	10.4
Wind with total installed capacity greater than 1.5MW	4.9	4.9	4.9
Eligible Installations with a declared net capacity of 50kW or less Commissioned on or before 14th July 2009 and accredited under the ROO on or before 31st March 2010	9.9	9.9	9.9
EXPORT TARIFF	3.2	3.2	3.2

ANNEX 3 WIND ENERGY POTENTIAL (DETAILED CALCULATIONS)

Annex 3: Figure 1Weibull distribution of the wind data at Ardlussa

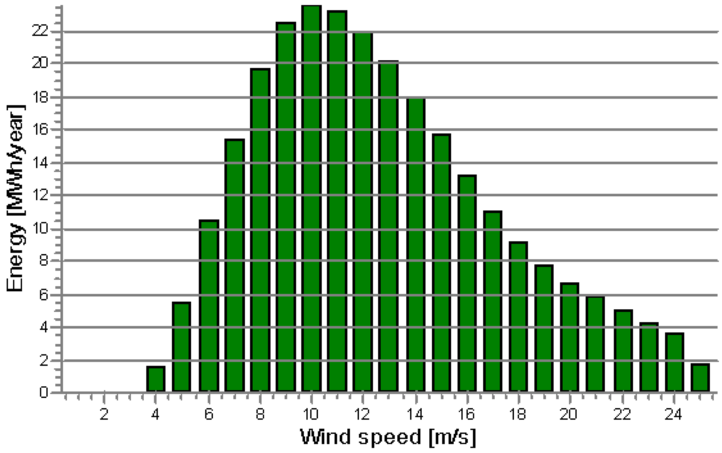


Annex 3: Table 1 Roughness class used to model the terrain at Ardlussa at a 20 km radius

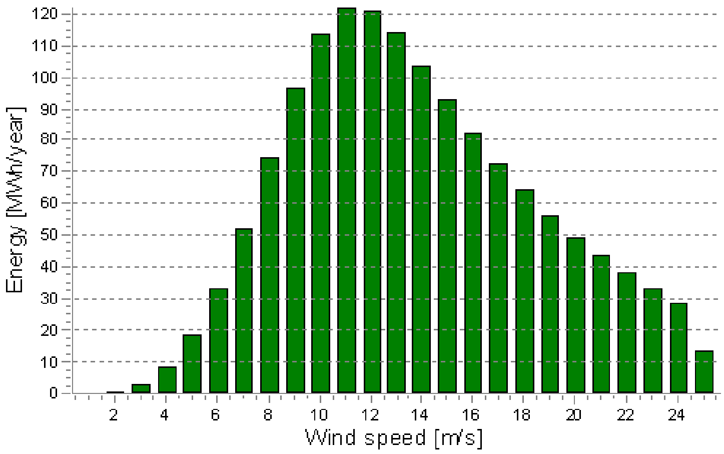
Sector	Roughness class	Distance to first change in roughness (m)	Roughness after first change	Distance to second change in roughness (m)	Roughness after second change
N	1	11900	0		
NNE	1	11200	0		
ENE	1	1600	0		
E	1	550	0		
ESE	1	550	0		
SSE	1	550	0		
S	1	2000	0		
SSW	2.5	0			
WSW	1	12300	0	14000	2
W	1	14700	0		
WNW	1	8700	0		
NNW	1	7300	0		

Wind Energy

The annual energy corresponding to wind speed has been shown for 50 kW Endurance E 3120 turbine and Enercon E-33-330 turbine have been shown in the figures below:



Annex 3: Figure 2 Energy vs Wind speed for Endurance E 3120 turbine



Annex 3: Figure 3 Energy vs Wind for Enercon E-33-330 turbine

Annex 3: Table 2 Main result and cash flow of economic analysis for scenario 1 (1x50kW)

TURN-KEY BUDGET

(Amount in Pounds excl. VAT)

1 units : Endurance E-3120 50 19.0 !O!

		Fixed assets	Operating Costs
Turbine Investment Cost	:	259,000	-
Grid Connection and Terminal Equipment	:	134,990	-
Road Construction Cost	:	66,176	-
Transport Cost	:	3,000	-
Total	:	**463,166**	**0**

Total Turn-Key Price:	**463,166**	**Cost per 1,000 kWh**	**1,936 Pounds**

Profit and loss account (before financing)

(Amount in Pounds excl. VAT)

Income (electricity)			Years: 1		Years: 6		Mean of 20 years Deflated	
Description	Adjustment	kWh/Years	/kWh	total	/kWh	total	/kWh	total
FIT	No inflation	239,201	25.40	60,757	25.40	60,757	25.40	60,757
Export Tarrif	No inflation	239,201	3.20	7,654	3.20	7,654	3.20	7,654
Total, electricity			28.60	68,412	28.60	68,412	28.60	68,412
-O&M and transferences:			0.00	0	0.52	1,250	0.39	938
Annual profit before tax and financing			28.60	68,412	28.08	67,162	28.21	67,474
Profit in % of investment				15 %		15 %		15 %

Return on investment: 131.8 %

Internal rate of return: 13.5% *)

*)In Windbank all Interest rates are nominal, which approximately are the real interest rate + Inflation. The NPV and IRR are based on nominal interest rates as well.

Amount in Pounds (excl. VAT) when nothing is specified. All expenditures are marked with (-).

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Operation											
INCOME											
Sale of electricity, 239,201 KWh/Year (Note 1)	0	68,412	68,412	68,412	68,412	68,412	68,412	68,412	68,412	68,412	68,412
EXPENDITURES	**-463,166**	**0**	**0**	**0**	**0**	**0**	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**
Operation and maintenance (Note 2)	0	0	0	0	0	0	-1,250	-1,250	-1,250	-1,250	-1,250
Depreciation (Straight-line over 0 years)	-463,166	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	**-463,166**	**68,412**	**68,412**	**68,412**	**68,412**	**68,412**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**
FINANCING	**0**	**-30,106**	**-28,861**	**-27,535**	**-26,123**	**-24,619**	**-23,017**	**-21,312**	**-19,495**	**-17,561**	**-15,500**
Interests, loans (Note 3)	0	-30,106	-28,861	-27,535	-26,123	-24,619	-23,017	-21,312	-19,495	-17,561	-15,500
Working profits	**-463,166**	**38,306**	**39,551**	**40,877**	**42,289**	**43,792**	**44,144**	**45,850**	**47,668**	**49,601**	**51,661**
BALANCE											
ASSETS	**0**	**19,153**	**38,305**	**57,458**	**76,610**	**95,763**	**113,665**	**131,568**	**149,470**	**167,373**	**185,275**
Cash balance	0	19,153	38,305	57,458	76,610	95,763	113,665	131,568	149,470	167,373	185,275
LIABILITIES	**0**	**19,153**	**38,305**	**57,458**	**76,610**	**95,763**	**113,665**	**131,568**	**149,470**	**167,373**	**185,275**
Net worth	-463,166	-424,860	-385,310	-344,433	-302,144	-258,352	-214,208	-168,358	-120,692	-71,091	-19,429
Debt (Note 3)	463,166	444,013	423,615	401,891	378,755	354,115	327,873	299,926	270,162	238,464	204,705
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	0	19,153	19,153	19,153	19,153	19,153	17,903	17,903	17,903	17,903	17,903

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operation										
INCOME										
Sale of electricity, 239,201 KWh/Year (Note 1)	68,412	68,412	68,412	68,412	68,412	68,412	68,412	68,412	68,412	68,412
EXPENDITURES	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**	**-1,250**
Operation and maintenance (Note 2)	-1,250	-1,250	-1,250	-1,250	-1,250	-1,250	-1,250	-1,250	-1,250	-1,250
Depreciation (Straight-line over 0 years)	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**
FINANCING	**-13,306**	**-10,969**	**-8,480**	**-5,829**	**-3,006**	**0**	**0**	**0**	**0**	**0**
Interests, loans (Note 3)	-13,306	-10,969	-8,480	-5,829	-3,006	0	0	0	0	0
Working profits	**53,858**	**56,193**	**58,682**	**61,332**	**64,156**	**67,162**	**67,162**	**67,162**	**67,162**	**67,162**
BALANCE										
ASSETS	**203,178**	**221,080**	**238,983**	**256,885**	**274,788**	**341,949**	**409,111**	**476,272**	**543,434**	**610,595**
Cash balance	203,178	221,080	238,983	256,885	274,788	341,949	409,111	476,272	543,434	610,595
LIABILITIES	**203,178**	**221,080**	**238,983**	**256,885**	**274,788**	**341,949**	**409,111**	**476,272**	**543,434**	**610,595**
Net worth	34,426	90,619	149,300	210,633	274,788	341,949	409,111	476,272	543,434	610,595
Debt (Note 3)	168,751	130,461	89,682	46,253	0	0	0	0	0	0
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	17,903	17,903	17,903	17,903	17,903	67,162	67,162	67,162	67,162	67,162

Annex 3: Table 3 Main results and cash flow of economic analysis for scenario 2 (3x50kW)

TURN-KEY BUDGET			**(Amount in Pounds excl. VAT)**
		Fixed assets	**Operating Costs**
Turbine Investment Cost	:	777,000	-
Grid Connection and Terminal Equipment	:	134,990	-
Road Construction Cost	:	66,176	-
Transport Cost	:	3,000	-
Total	**:**	**981,166**	**0**
Total Turn-Key Price:	**981,166**	**Cost per 1,000 kWh**	**1,405 Pounds**

Profit and loss account (before financing) **(Amount in Pounds excl. VAT)**

Income (electricity)			Years: 1		Years: 6		Mean of 20 years Deflated	
Description / Adjustment	kWh/Years	/kWh	total	/kWh	total	/kWh	total	
FIT — No inflation	698,204	20.60	143,830	20.60	143,830	20.60	143,830	
Export Tarrif — No inflation	698,204	3.20	22,343	3.20	22,343	3.20	22,343	
Total, electricity		23.80	166,173	23.80	166,173	23.80	166,173	
-O&M and transferences:		0.00	0	0.54	3,750	0.40	2,813	
Annual profit before tax and financing		23.80	166,173	23.26	162,423	23.40	163,360	
Profit in % of investment			17 %		17 %		17 %	

Return on investment: 173.5 %
Internal rate of return: 15.9% *)
*)In Windbank all Interest rates are nominal, which approximately are the real interest rate + Inflation. The NPV and IRR are based on nominal interest rates as well.

Amount in Pounds (excl. VAT) when nothing is specified. All expenditures are marked with (-).

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Operation										
INCOME										
Sale of electricity, 698,204 kWh/Year (Note 1)	0	166,173	166,173	166,173	166,173	166,173	166,173	166,173	166,173	166,173
EXPENDITURES	**-981,166**	**0**	**0**	**0**	**0**	**0**	**-3,750**	**-3,750**	**-3,750**	**-3,750**
Operation and maintenance (Note 2)	0	0	0	0	0	0	-3,750	-3,750	-3,750	-3,750
Depreciation (Straight-line over 0 years)	-981,166	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	**-981,166**	**166,173**	**166,173**	**166,173**	**166,173**	**166,173**	**162,423**	**162,423**	**162,423**	**162,423**
FINANCING	**0**	**-63,776**	**-61,138**	**-58,330**	**-55,338**	**-52,153**	**-48,760**	**-45,147**	**-41,298**	**-37,200**
Interests, loans (Note 3)	0	-63,776	-61,138	-58,330	-55,338	-52,153	-48,760	-45,147	-41,298	-37,200
Working profits	**-981,166**	**102,397**	**105,034**	**107,843**	**110,834**	**114,020**	**113,663**	**117,276**	**121,124**	**125,222**
BALANCE										
ASSETS	**0**	**61,823**	**123,646**	**185,468**	**247,291**	**309,114**	**367,187**	**425,259**	**483,332**	**541,405**
Cash balance	0	61,823	123,646	185,468	247,291	309,114	367,187	425,259	483,332	541,405
LIABILITIES	**0**	**61,823**	**123,646**	**185,468**	**247,291**	**309,114**	**367,187**	**425,259**	**483,332**	**541,405**
Net worth	-981,166	-878,769	-773,735	-665,892	-555,058	-441,039	-327,376	-210,100	-88,976	36,247
Debt (Note 3)	981,166	940,592	897,381	851,361	802,350	750,153	694,563	635,360	572,308	505,158
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	0	61,823	61,823	61,823	61,823	61,823	58,073	58,073	58,073	58,073

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operation											
INCOME											
Sale of electricity, 698,204 kWh/Year (Note 1)	166,173	166,173	166,173	166,173	166,173	166,173	166,173	166,173	166,173	166,173	166,173
EXPENDITURES	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**	**-3,750**
Operation and maintenance (Note 2)	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750	-3,750
Depreciation (Straight-line over 0 years)	0	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**
FINANCING	**-32,835**	**-28,187**	**-23,236**	**-17,964**	**-12,349**	**-6,369**	**0**	**0**	**0**	**0**	**0**
Interests, loans (Note 3)	-32,835	-28,187	-23,236	-17,964	-12,349	-6,369	0	0	0	0	0
Working profits	**129,587**	**134,236**	**139,186**	**144,459**	**150,074**	**156,054**	**162,423**	**162,423**	**162,423**	**162,423**	**162,423**
BALANCE											
ASSETS	**599,478**	**657,551**	**715,623**	**773,696**	**831,769**	**889,842**	**1,052,264**	**1,214,687**	**1,377,109**	**1,539,532**	**1,701,954**
Cash balance	599,478	657,551	715,623	773,696	831,769	889,842	1,052,264	1,214,687	1,377,109	1,539,532	1,701,954
LIABILITIES	**599,478**	**657,551**	**715,623**	**773,696**	**831,769**	**889,842**	**1,052,264**	**1,214,687**	**1,377,109**	**1,539,532**	**1,701,954**
Net worth	165,834	300,069	439,256	583,714	733,788	889,842	1,052,264	1,214,687	1,377,109	1,539,532	1,701,954
Debt (Note 3)	433,644	357,481	276,368	189,982	97,981	0	0	0	0	0	0
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	58,073	58,073	58,073	58,073	58,073	58,073	162,423	162,423	162,423	162,423	162,423

Annex 3: Table 4 Main results and cash flow of economic analysis for scenario 3 (1x225kW)

TURN-KEY BUDGET (Amount in excl. VAT)

1 units : ACSA 225-50 27.0 !O!

		Fixed assets	Operating Costs
Turbine investment cost	:	500,000	-
Grid Connection and Terminal Equipment	:	134,990	-
Road construction and Upgrade	:	66,176	-
Transport	:	3,000	-
Total	:	**704,166**	**0**

Total Turn-Key Price:	**704,166**	**Cost per 1,000 kWh**	**917**

Profit and loss account (before financing) (Amount in excl. VAT)

Income (electricity)			Years: 1		Years: 6		Mean of 20 years Deflated	
Description	Adjustment	kWh/Years	/kWh	total	/kWh	total	/kWh	total
FIT	No inflation	768,075	20.60	158,224	20.60	158,224	20.60	158,224
Export Tariff	No inflation	768,075	3.20	24,578	3.20	24,578	3.20	24,578
Total, electricity			23.80	182,802	23.80	182,802	23.80	182,802
-O&M and transferences:			1.64	12,600	1.64	12,600	1.64	12,600
Annual profit before tax and financing			22.16	170,202	22.16	170,202	22.16	170,202
Profit in % of investment				24 %		24 %		24 %

Return on investment: 323.9 %

Internal rate of return: 23.8% *)

**)In Windbank all Interest rates are nominal, which approximately are the real interest rate + Inflation. The NPV and IRR are based on nominal interest rates as well.*

Amount in (excl. VAT) when nothing is specified. All expenditures are marked with (-).

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Operation											
INCOME											
Sale of electricity, 768,075 kWh/Year (Note 1)	0	182,802	182,802	182,802	182,802	182,802	182,802	182,802	182,802	182,802	182,802
EXPENDITURES	-704,166	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600
Operation and maintenance (Note 2)	0	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600
Depreciation (Straight-line over 0 years)	-704,166	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	-704,166	170,202	170,202	170,202	170,202	170,202	170,202	170,202	170,202	170,202	170,202
FINANCING	0	-45,771	-43,878	-41,862	-39,715	-37,429	-34,994	-32,401	-29,639	-26,698	-23,565
Interests, loans (Note 3)	0	-45,771	-43,878	-41,862	-39,715	-37,429	-34,994	-32,401	-29,639	-26,698	-23,565
Working profits	-704,166	124,431	126,324	128,340	130,486	132,773	135,208	137,801	140,563	143,504	146,637
BALANCE											
ASSETS	0	95,312	190,624	285,936	381,248	476,560	571,871	667,183	762,495	857,807	953,119
Cash balance	0	95,312	190,624	285,936	381,248	476,560	571,871	667,183	762,495	857,807	953,119
LIABILITIES	0	95,312	190,624	285,936	381,248	476,560	571,871	667,183	762,495	857,807	953,119
Net worth	-704,166	-579,735	-453,411	-325,071	-194,585	-61,812	73,396	211,197	351,760	495,264	641,900
Debt (Note 3)	704,166	675,047	644,035	611,007	575,832	538,372	498,476	455,987	410,736	362,543	311,219
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	0	95,312	95,312	95,312	95,312	95,312	95,312	95,312	95,312	95,312	95,312

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operation										
INCOME										
Sale of electricity, 768,075 kWh/Year (Note 1)	182,802	182,802	182,802	182,802	182,802	182,802	182,802	182,802	182,802	182,802
EXPENDITURES	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600
Operation and maintenance (Note 2)	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600	-12,600
Depreciation (Straight-line over 0 years)	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	170,202	170,202	170,202	170,202	170,202	170,202	170,202	170,202	170,202	170,202
FINANCING	-20,229	-16,676	-12,892	-8,863	-4,571	0	0	0	0	0
Interests, loans (Note 3)	-20,229	-16,676	-12,892	-8,863	-4,571	0	0	0	0	0
Working profits	149,973	153,526	157,310	161,339	165,631	170,202	170,202	170,202	170,202	170,202
BALANCE										
ASSETS	1,048,431	1,143,743	1,239,055	1,334,367	1,429,679	1,599,881	1,770,083	1,940,285	2,110,487	2,280,689
Cash balance	1,048,431	1,143,743	1,239,055	1,334,367	1,429,679	1,599,881	1,770,083	1,940,285	2,110,487	2,280,689
LIABILITIES	1,048,431	1,143,743	1,239,055	1,334,367	1,429,679	1,599,881	1,770,083	1,940,285	2,110,487	2,280,689
Net worth	791,873	945,399	1,102,708	1,264,048	1,429,679	1,599,881	1,770,083	1,940,285	2,110,487	2,280,689
Debt (Note 3)	256,558	198,344	136,347	70,319	0	0	0	0	0	0
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	95,312	95,312	95,312	95,312	95,312	170,202	170,202	170,202	170,202	170,202

Annex 3: Table 5 Main results and cash flow of economic analysis for scenario 4 (1x330kW)

TURN-KEY BUDGET **(Amount in Pounds excl. VAT)**

1 units : ENERCON E-33 330 33.4 !-!

		Fixed assets	Operating Costs
Turbine Investment Cost	:	700,000	-
Grid Connection and Terminal Equipment	:	173,723	-
Road Construction and Upgrade	:	148,897	-
Transport	:	3,000	-
Total	:	**1,025,620**	**0**

Total Turn-Key Price:	**1,025,620**	**Cost per 1,000 kWh**	**809 Pounds**

Profit and loss account (before financing) **(Amount in Pounds excl. VAT)**

Income (electricity)			Years: 1		Years: 6		Mean of 20 years Deflated	
Description	Adjustment	kWh/Years	/kWh	total	/kWh	total	/kWh	total
FIT	No inflation	1,267,809	20.60	261,169	20.60	261,169	16.84	213,524
Export Tarrif	No inflation	1,267,809	3.20	40,570	3.20	40,570	2.62	33,169
Total, electricity			23.80	301,739	23.80	301,739	19.46	246,693
-O&M and transferences:			1.58	20,000	1.58	20,000	1.58	20,000
Annual profit before tax and financing			22.22	281,739	22.22	281,739	17.88	226,693
Profit in % of investment				27 %		27 %		22 %

Return on investment: 262.4 %

Internal rate of return: 27.1% *)

*)In Windbank all Interest rates are nominal, which approximately are the real interest rate + Inflation. The NPV and IRR are based on nominal interest rates as well.

Amount in Pounds (excl. VAT) when nothing is specified. All expenditures are marked with (-).

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Operation											
INCOME											
Sale of electricity, 1,267,809 kWh/Year (Note 1)	0	301,739	301,739	301,739	301,739	301,739	301,739	301,739	301,739	301,739	301,739
EXPENDITURES	**-1,025,620**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**
Operation and maintenance (Note 2)	0	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000
Depreciation (Straight-line over 0 years)	-1,025,620	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	**-1,025,620**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**
FINANCING	**0**	**-66,665**	**-63,909**	**-60,973**	**-57,848**	**-54,516**	**-50,969**	**-47,192**	**-43,169**	**-38,885**	**-34,323**
Interests, loans (Note 3)	0	-66,665	-63,909	-60,973	-57,848	-54,516	-50,969	-47,192	-43,169	-38,885	-34,323
Working profits	**-1,025,620**	**215,073**	**217,830**	**220,766**	**223,893**	**227,223**	**230,770**	**234,547**	**238,569**	**242,853**	**247,416**
BALANCE											
ASSETS	**0**	**172,661**	**345,322**	**517,983**	**690,644**	**863,305**	**1,035,966**	**1,208,627**	**1,381,289**	**1,553,950**	**1,726,611**
Cash balance	0	172,661	345,322	517,983	690,644	863,305	1,035,966	1,208,627	1,381,289	1,553,950	1,726,611
LIABILITIES	**0**	**172,661**	**345,322**	**517,983**	**690,644**	**863,305**	**1,035,966**	**1,208,627**	**1,381,289**	**1,553,950**	**1,726,611**
Net worth	-1,025,620	-810,547	-592,717	-371,950	-148,058	79,165	309,935	544,482	783,051	1,025,904	1,273,319
Debt (Note 3)	1,025,620	983,208	938,039	889,934	838,702	784,140	726,031	664,145	598,238	528,046	453,291
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	0	172,661	172,661	172,661	172,661	172,661	172,661	172,661	172,661	172,661	172,661

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Operation										
INCOME										
Sale of electricity, 1,267,809 kWh/Year (Note 1)	301,739	301,739	301,739	301,739	301,739	301,739	301,739	301,739	301,739	301,739
EXPENDITURES	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**	**-20,000**
Operation and maintenance (Note 2)	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000	-20,000
Depreciation (Straight-line over 0 years)	0	0	0	0	0	0	0	0	0	0
WORKING PROFITS, ORDINARY	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**
FINANCING	**-29,464**	**-24,289**	**-18,778**	**-12,908**	**-6,657**	**0**	**0**	**0**	**0**	**0**
Interests, loans (Note 3)	-29,464	-24,289	-18,778	-12,908	-6,657	0	0	0	0	0
Working profits	**252,275**	**257,450**	**262,961**	**268,830**	**275,081**	**281,739**	**281,739**	**281,739**	**281,739**	**281,739**
BALANCE										
ASSETS	**1,899,272**	**2,071,933**	**2,244,594**	**2,417,255**	**2,589,916**	**2,871,655**	**3,153,393**	**3,435,132**	**3,716,871**	**3,998,609**
Cash balance	1,899,272	2,071,933	2,244,594	2,417,255	2,589,916	2,871,655	3,153,393	3,435,132	3,716,871	3,998,609
LIABILITIES	**1,899,272**	**2,071,933**	**2,244,594**	**2,417,255**	**2,589,916**	**2,871,655**	**3,153,393**	**3,435,132**	**3,716,871**	**3,998,609**
Net worth	1,525,594	1,783,044	2,046,005	2,314,835	2,589,916	2,871,655	3,153,393	3,435,132	3,716,871	3,998,609
Debt (Note 3)	373,678	288,889	198,569	102,420	0	0	0	0	0	0
Liquidity of the year (This year's cash balance growth minus transferences) (after tax)	172,661	172,661	172,661	172,661	172,661	281,739	281,739	281,739	281,739	281,739

ANNEX 4 HYDRO POWER POTENTIAL (DETAILED CALCULATIONS)

Annex 4: Figure 1 Intake Option 1 (Point 1)

Annex 4: Figure 2 Altitude 70 m (Point 4, point where the penstock crosses the river)

Annex 4: Figure 3 Power house location (point 5)

Annex 4: Table 1 Annual Flow Data of Corran River

Month	Natural Flow area 1 (m^3/s)	Flow with Compensation Q_{90} (m^3/s) - Intake 1	Flow with Compensation Q_{90} (m^3/s) - Intake 2	Flow with Compensation Q_{90} (m^3/s) - Intake 3
Jan	0.560	0.511	0.554	0.656
Feb	0.481	0.432	0.469	0.555
Mar	0.448	0.399	0.433	0.512
Apr	0.272	0.223	0.242	0.286
May	0.181	0.132	0.143	0.170
Jun	0.187	0.138	0.150	0.177
Jul	0.204	0.155	0.168	0.199
Aug	0.273	0.224	0.243	0.288
Sep	0.354	0.305	0.331	0.392
Oct	0.496	0.447	0.485	0.574
Nov	0.503	0.454	0.493	0.583
Dec	0.536	0.487	0.528	0.625

Source: Author and Wallingford HydroSolutions, 2011

Annex 4: Table 2 Annual Flow Duration Curve of Corran river

Percentile	Natural Flow Intake 1 (m^3/s)	Natural Flow Intake 2 (m^3/s)	Natural Flow Intake 3 (m^3/s)	Flow with Compensation Q_{90} (m^3/s) - Intake 1	Flow with Compensation Q_{90} (m^3/s) - Intake 2	Flow with Compensation Q_{90} (m^3/s) - Intake 3
5	1.164	1.263	1.495	1.115	1.210	1.432
10	0.834	0.905	1.071	0.785	0.852	1.008
20	0.537	0.583	0.690	0.488	0.530	0.627
30	0.384	0.417	0.493	0.335	0.363	0.430
40	0.270	0.293	0.347	0.221	0.240	0.284
50	0.195	0.212	0.250	0.146	0.158	0.187
60	0.142	0.154	0.182	0.093	0.101	0.119
70	0.103	0.112	0.132	0.054	0.059	0.069
80	0.073	0.079	0.094	0.024	0.026	0.031
90	0.049	0.053	0.063	0.000	0.000	0.000
95	0.037	0.040	0.048	0.000	0.000	0.000
98	0.029	0.031	0.037	0.000	0.000	0.000
99	0.025	0.027	0.032	0.000	0.000	0.000

Source: Author and Wallingford HydroSolutions, 2011

Annex 4: Table 3 Monthly Flow Duration Curve (FDC)

Percentile	January, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	February, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	March, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	April, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	May, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	June, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1
5	1.403	1.354	1.346	1.297	1.179	1.130	0.842	0.793	0.624	0.575	0.620	0.571
10	1.077	1.028	0.978	0.929	0.885	0.836	0.580	0.531	0.429	0.380	0.435	0.386
20	0.769	0.720	0.662	0.613	0.598	0.549	0.375	0.326	0.256	0.207	0.264	0.215
30	0.592	0.543	0.494	0.445	0.447	0.398	0.262	0.213	0.162	0.113	0.181	0.132
40	0.454	0.405	0.382	0.333	0.353	0.304	0.196	0.147	0.115	0.066	0.134	0.085
50	0.351	0.302	0.282	0.233	0.270	0.221	0.152	0.103	0.085	0.036	0.099	0.050
60	0.271	0.222	0.207	0.158	0.211	0.162	0.121	0.072	0.067	0.018	0.075	0.026
70	0.198	0.149	0.152	0.103	0.161	0.112	0.098	0.049	0.056	0.007	0.058	0.009
80	0.137	0.088	0.107	0.058	0.117	0.068	0.076	0.027	0.045	0.000	0.046	0.000
90	0.093	0.044	0.076	0.027	0.082	0.033	0.056	0.007	0.036	0.000	0.034	0.000
95	0.073	0.024	0.064	0.015	0.066	0.017	0.045	0.000	0.030	0.000	0.028	0.000
99	0.053	0.004	0.050	0.001	0.047	0.000	0.032	0.000	0.025	0.000	0.024	0.000

Percentile	July, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	August, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	Sept, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	Oct, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	Nov, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1	Dec, Flow (m^3/s)	with Compensation Flow Q_{90} (m^3/s) - Intake 1
5	0.651	0.602	0.898	0.849	1.091	1.042	1.333	1.284	1.285	1.236	1.466	1.417
10	0.463	0.414	0.628	0.579	0.772	0.723	0.973	0.924	0.983	0.934	1.106	1.057
20	0.286	0.237	0.398	0.349	0.510	0.461	0.678	0.629	0.681	0.632	0.743	0.694
30	0.194	0.145	0.264	0.215	0.362	0.313	0.516	0.467	0.525	0.476	0.540	0.491
40	0.139	0.090	0.187	0.138	0.249	0.200	0.402	0.353	0.407	0.358	0.408	0.359
50	0.105	0.056	0.133	0.084	0.180	0.131	0.297	0.248	0.312	0.263	0.293	0.244
60	0.078	0.029	0.096	0.047	0.133	0.084	0.215	0.166	0.241	0.192	0.215	0.166
70	0.059	0.010	0.069	0.020	0.096	0.047	0.158	0.109	0.186	0.137	0.162	0.113
80	0.046	0.000	0.051	0.002	0.069	0.020	0.110	0.061	0.138	0.089	0.119	0.070
90	0.036	0.000	0.037	0.000	0.045	0.000	0.072	0.023	0.100	0.051	0.083	0.034
95	0.030	0.000	0.030	0.000	0.034	0.000	0.057	0.008	0.080	0.031	0.064	0.015
99	0.025	0.000	0.024	0.000	0.025	0.000	0.037	0.000	0.054	0.005	0.044	0.000

Source: Author and Wallingford HydroSolutions, 2011

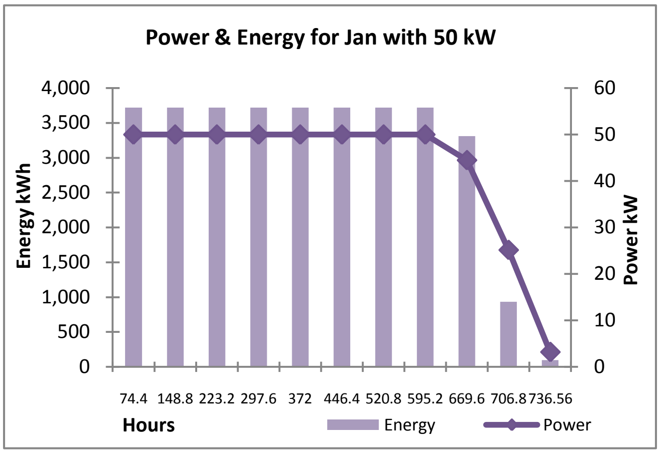
Annex 4: Table 4 Part Flow Efficiency of Pelton Turbine with Different Flow

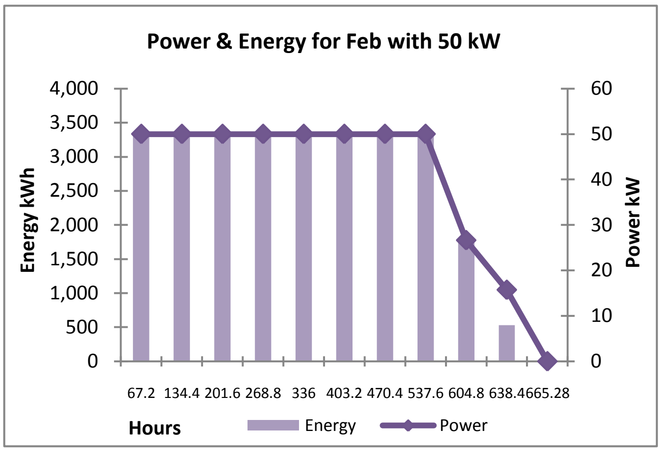
Flow with compensation Q_{90}, (m^3/s)	Design Flow for 330 kW	Flow / Design Flow for 330 kW	Part Flow Efficiency for Pelton 330 kW	Design Flow for 100 kW	Flow / Design Flow For 100 kW	Part Flow Efficiency for Pelton 100 kW	Design Flow for 50 kW	Flow / Design Flow for 50 kW	Part Flow Efficiency for Pelton 50 kW
1.115	0.335	1.00	0.80	0.101	1.00	0.80	0.051	1.00	0.80
0.785	0.335	1.00	0.80	0.101	1.00	0.80	0.051	1.00	0.80
0.488	0.335	1.00	0.80	0.101	1.00	0.80	0.051	1.00	0.80
0.335	0.335	1.00	0.80	0.101	1.00	0.80	0.051	1.00	0.80
0.221	0.335	0.66	0.85	0.101	1.00	0.80	0.051	1.00	0.80
0.146	0.335	0.44	0.85	0.101	1.00	0.80	0.051	1.00	0.80
0.093	0.335	0.28	0.84	0.101	0.92	0.79	0.051	1.00	0.80
0.054	0.335	0.16	0.80	0.101	0.53	0.85	0.051	1.00	0.82
0.024	0.335	0.07	0.40	0.101	0.24	0.85	0.051	0.47	0.85
0.000	0.335	0.00	0.00	0.101	0.00	0.00	0.051	0.00	0.00
0.000	0.335	0.00	0.00	0.101	0.00	0.00	0.051	0.00	0.00
0.000	0.335	0.00	0.00	0.101	0.00	0.00	0.051	0.00	0.00
0.000	0.335	0.00	0.00	0.101	0.00	0.00	0.051	0.00	0.00

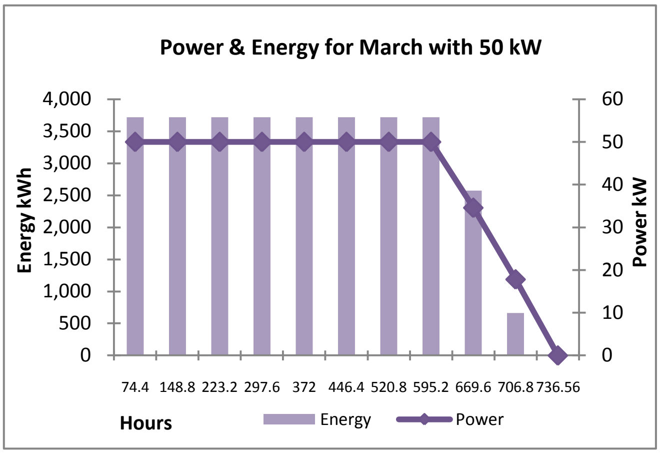
Source: Author and Wallingford HydroSolutions, 2011

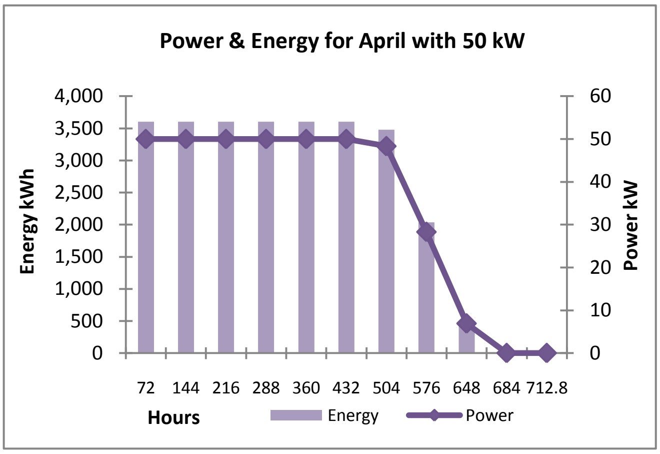
Annex 4: Figure 4Monthly Power and Energy for 50 kW (Jan – June)

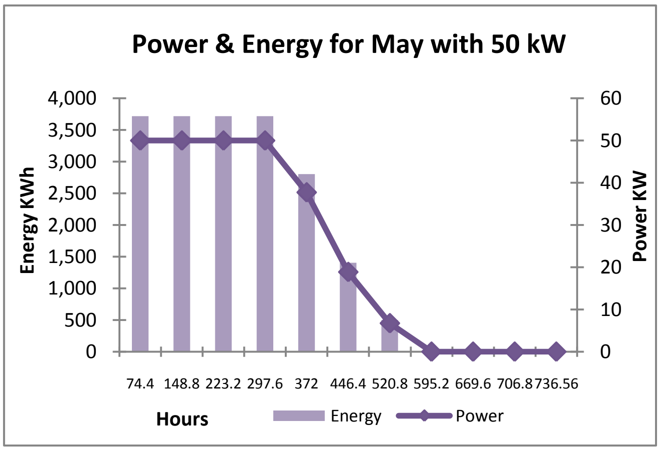
Source: Authors

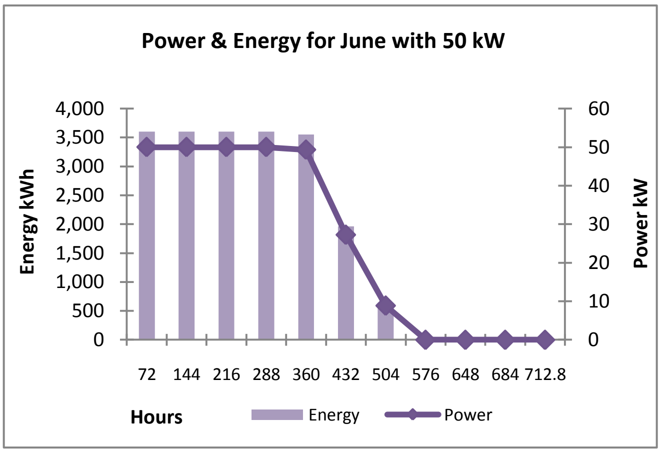




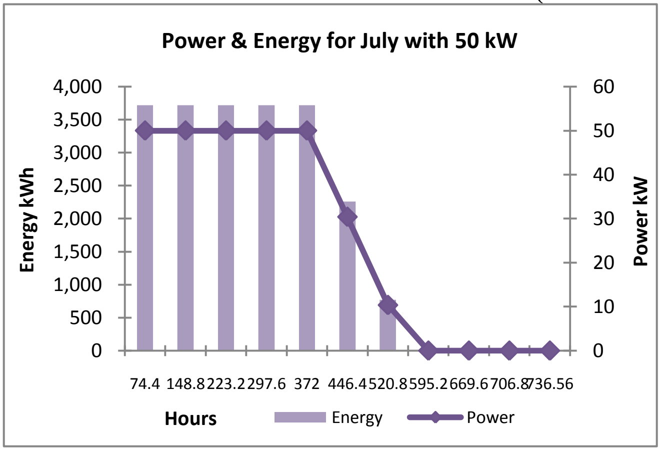


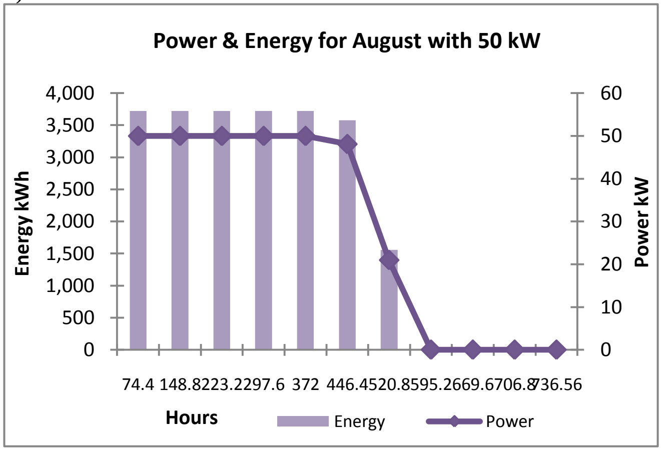


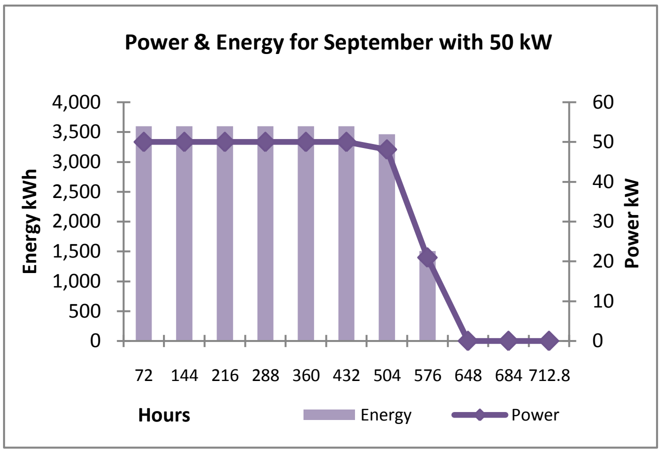


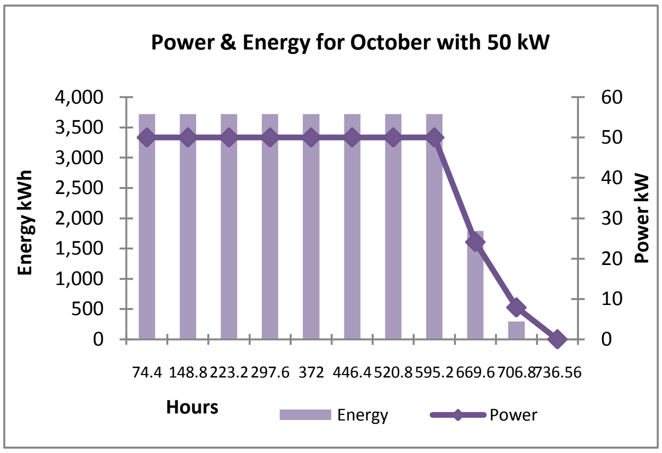


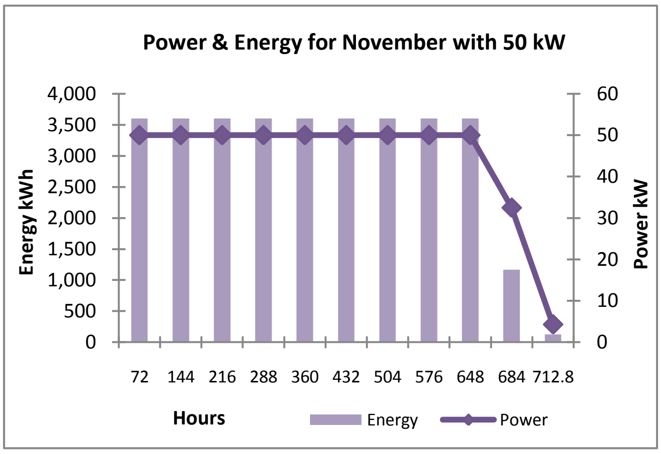
Annex 4: Figure 5 Monthly Power and Energy for 50 kW (July – Dec)
(Source: Author)

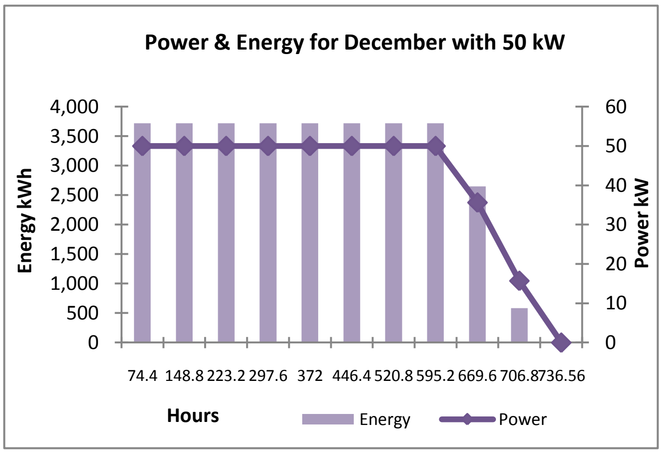




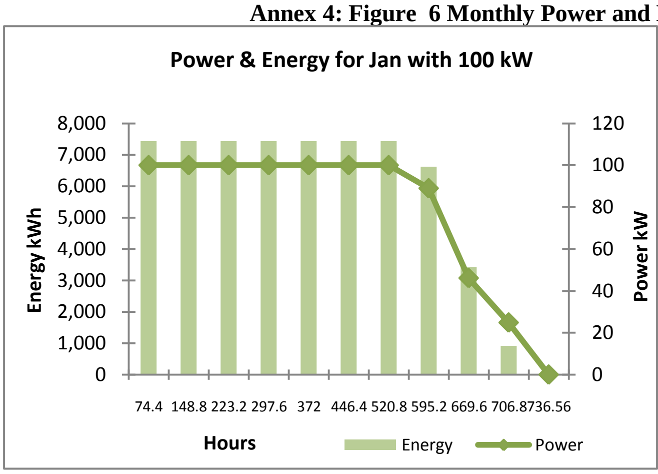


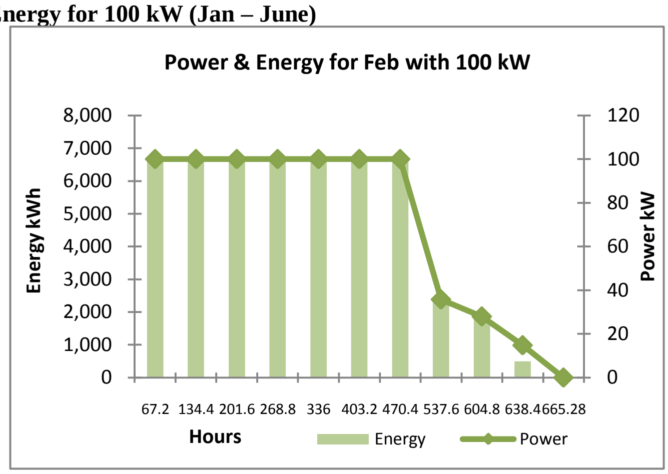


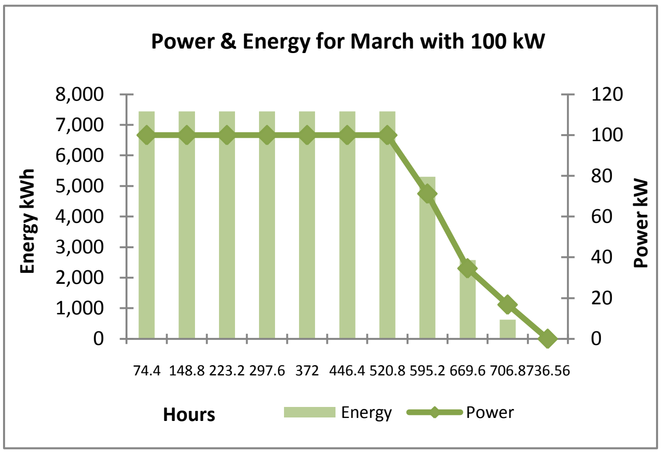


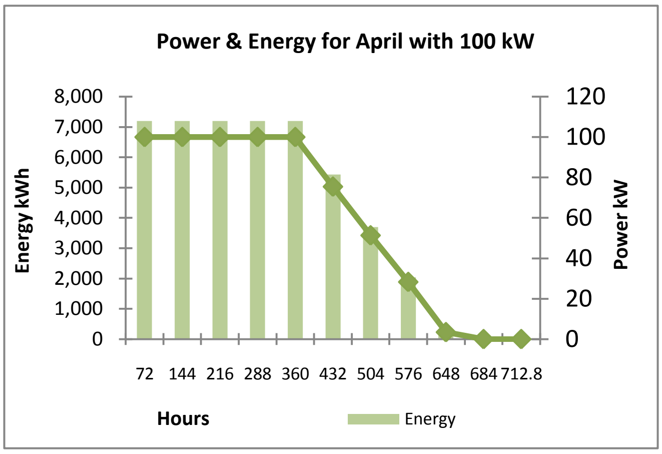


Annex 4: Figure 6 Monthly Power and Energy for 100 kW (Jan – June)









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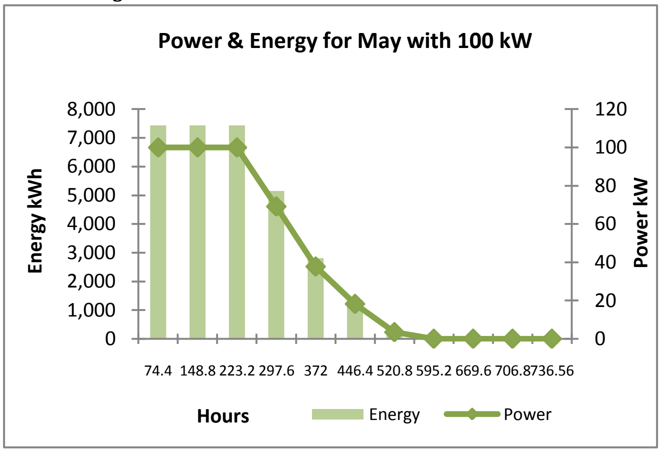
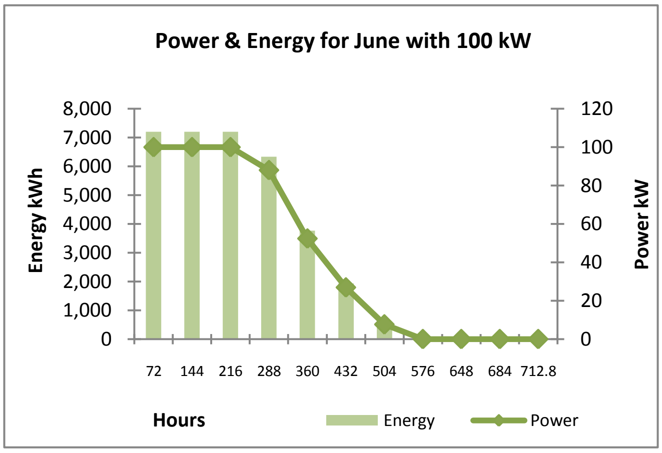
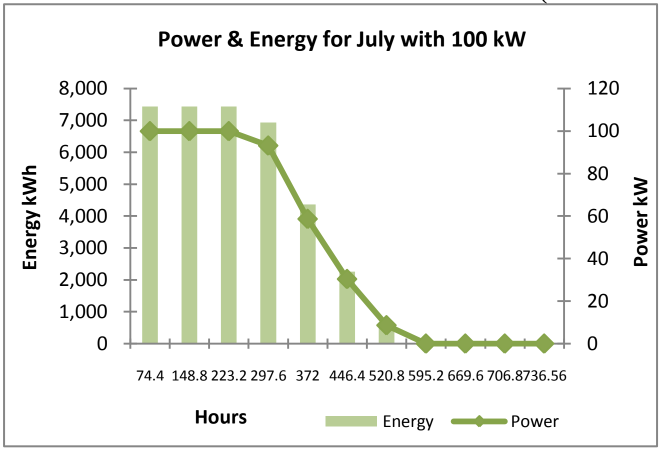
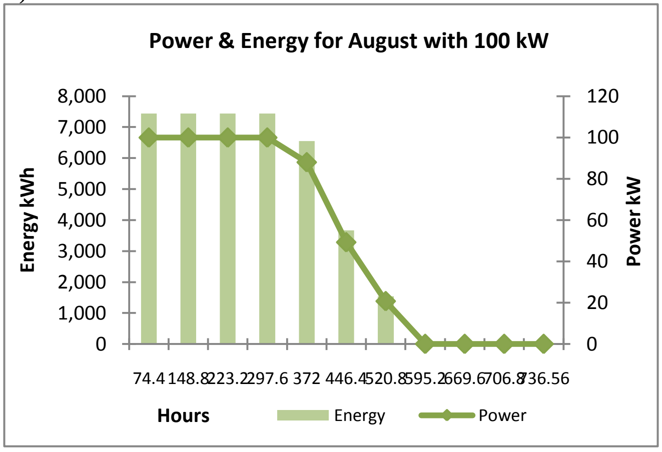
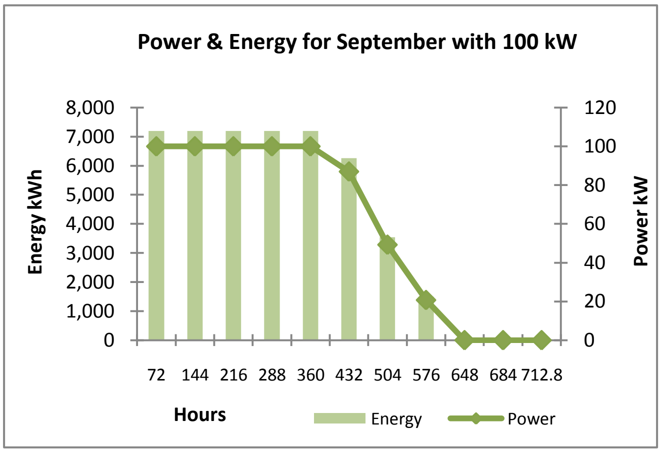


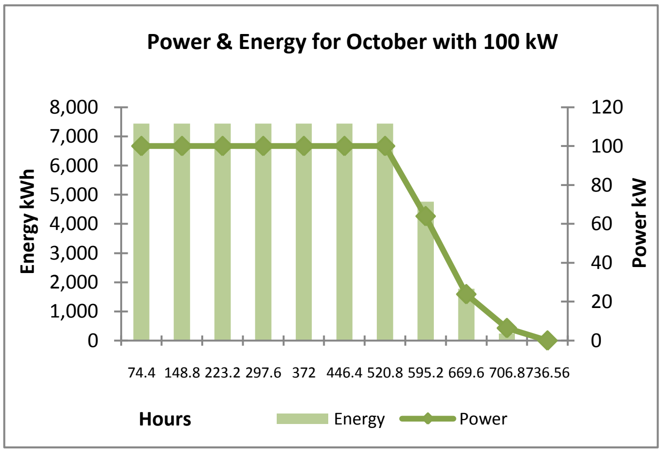


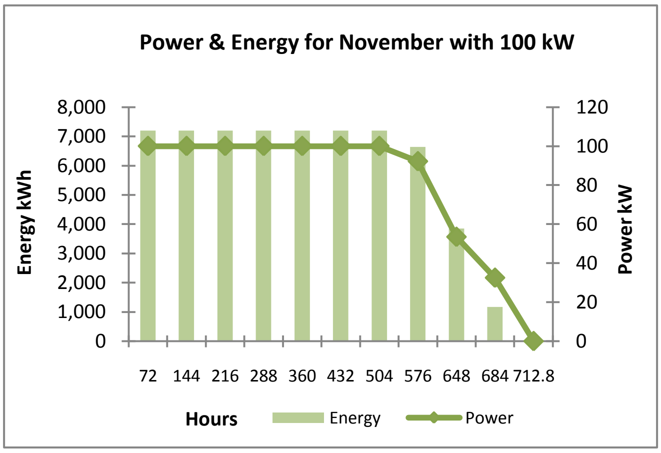
Annex 4: Figure 7 Monthly Power and Energy for 100 kW (Jul – Dec)
(Source: Author)

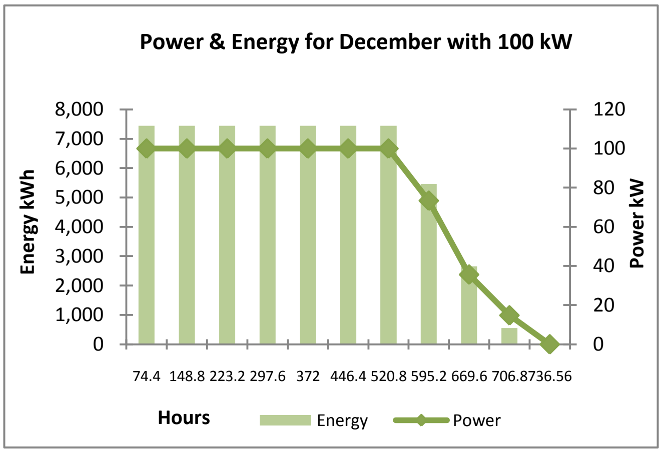




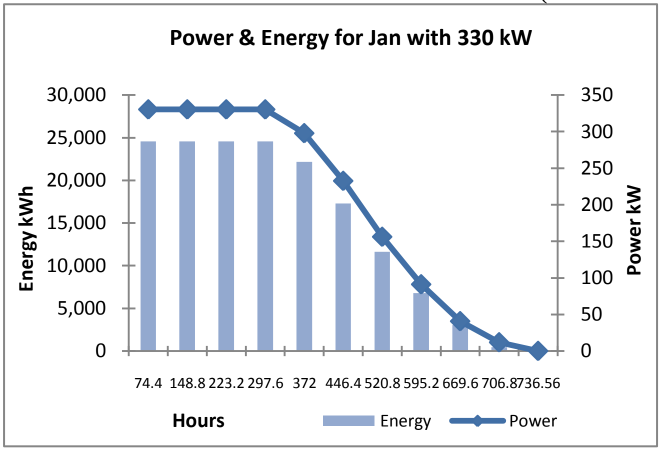


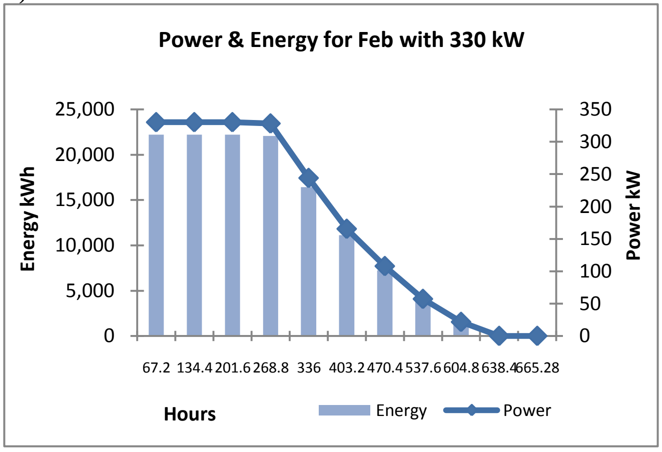


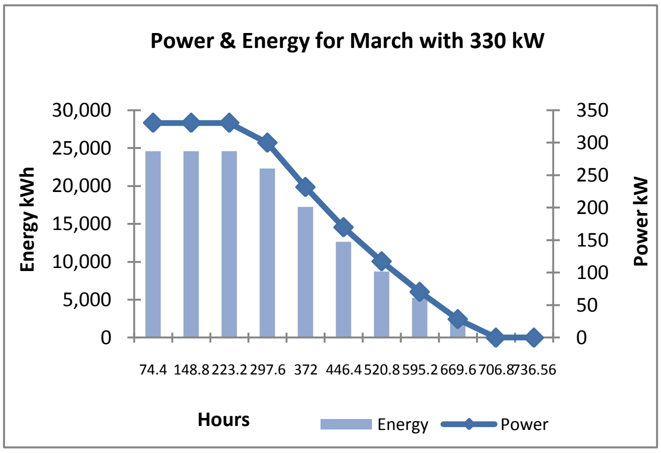


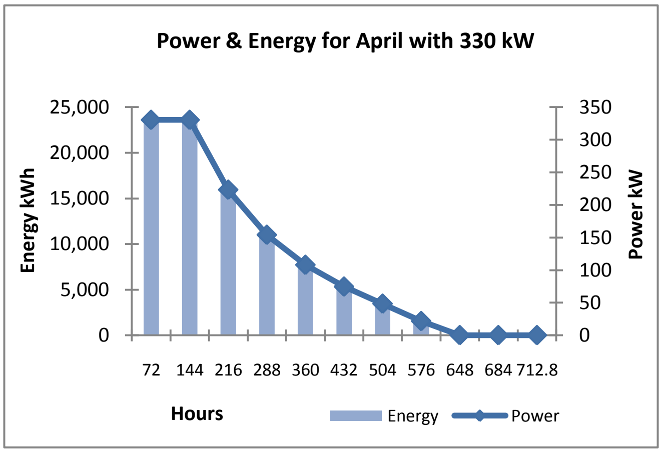


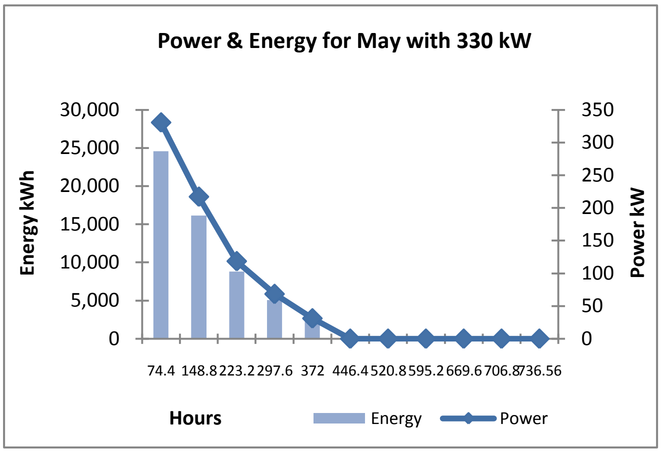
Annex 4: Figure 8 Monthly Power and Energy for 330 kW (Jan – June)
(Source: Author)

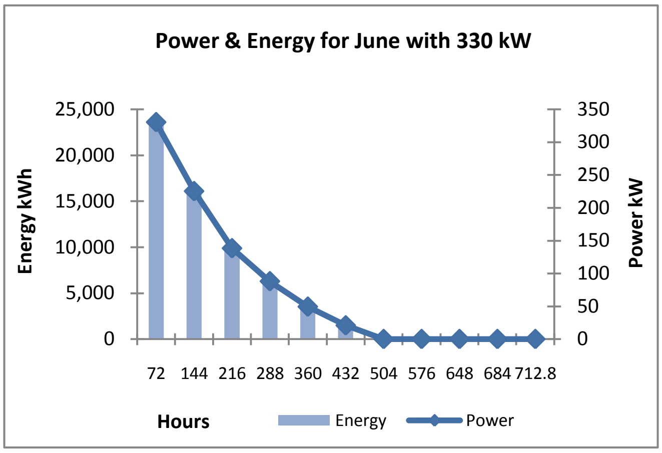




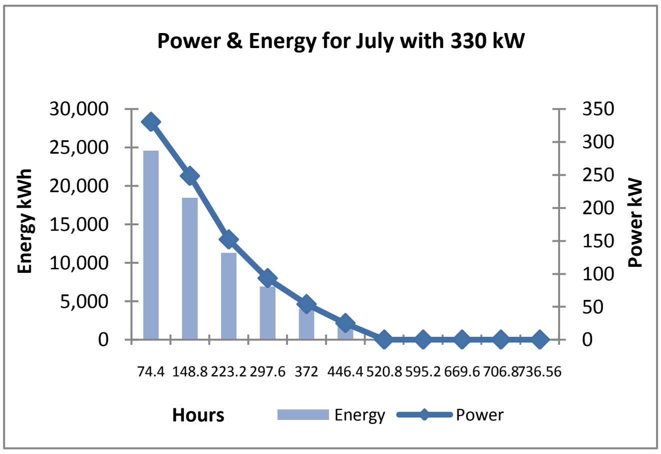


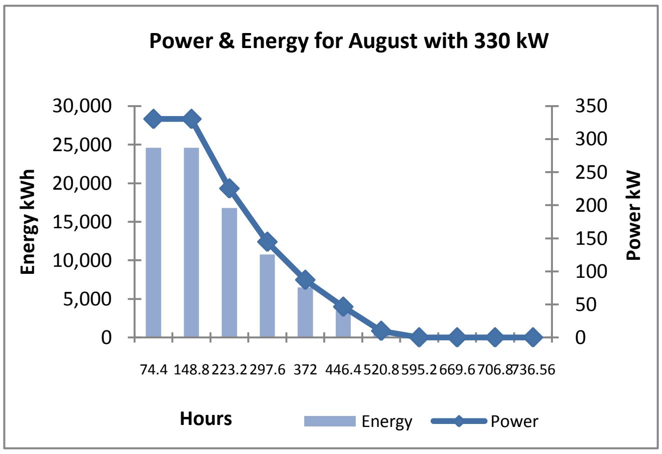


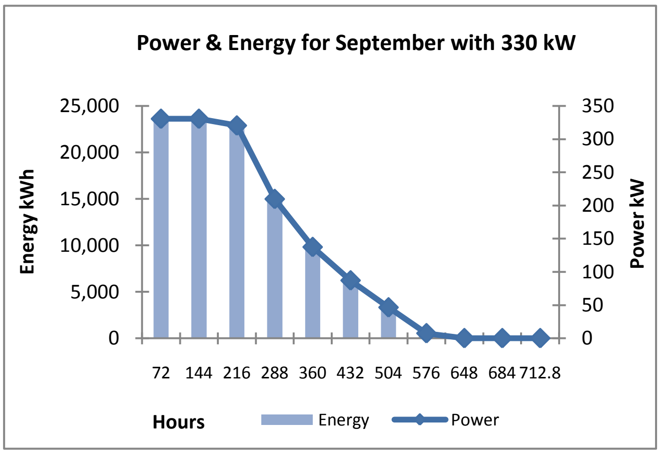


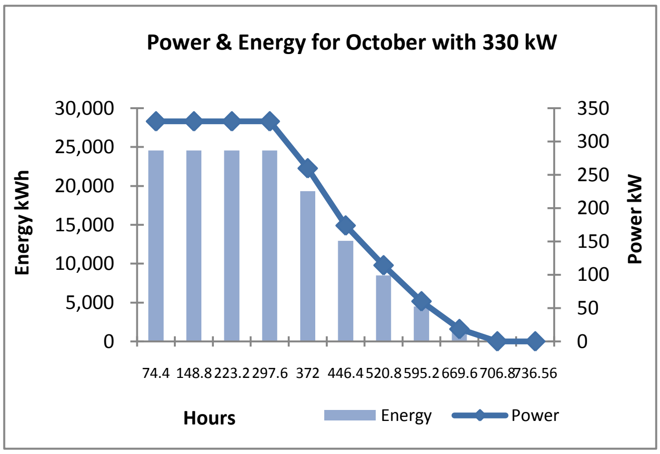


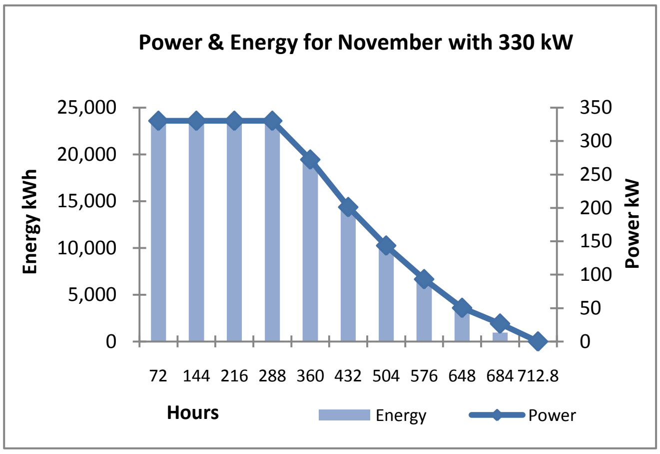
Annex 4: Figure 9 Monthly Power and Energy for 330 kW (Jul – Dec)
(Source: Author)

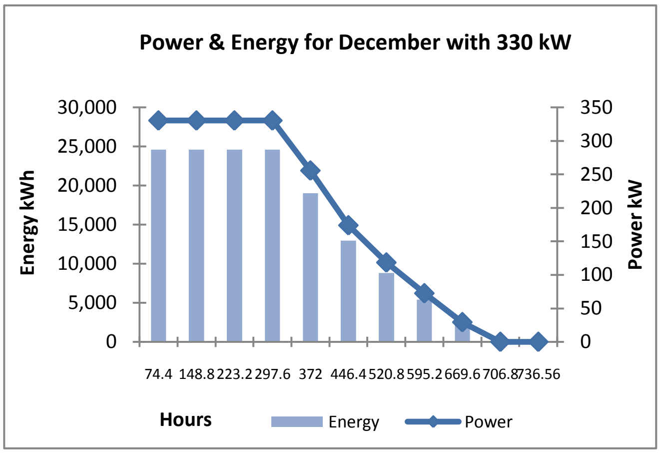


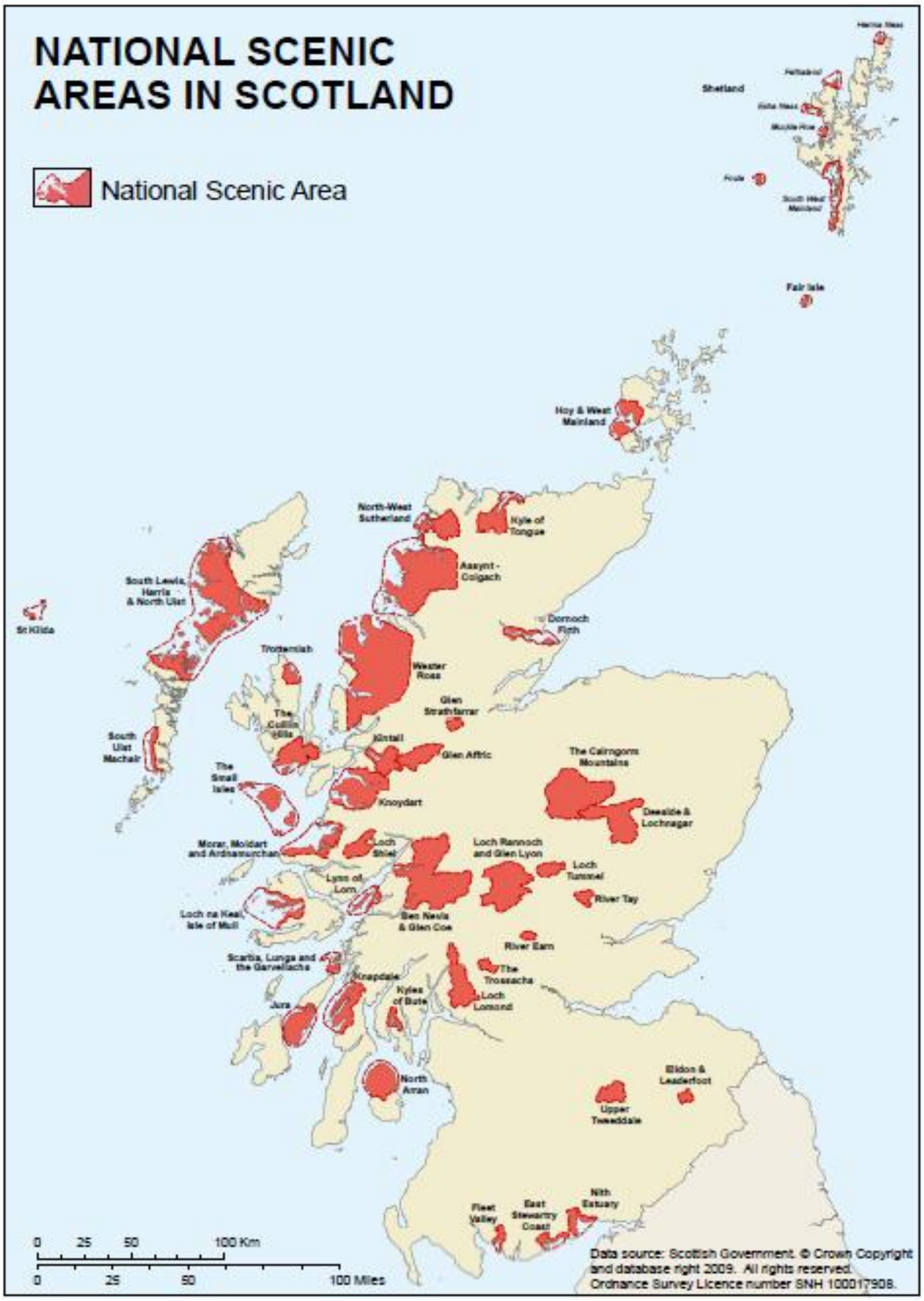












Annex 4: Figure 10 National Scenic Area in Scotland

ANNEX 5 HEAT RECOVERY AND BIOGAS POTENTIAL

Annex 5: Table 1: Renewable Heat Incentive, Feed in Tariff, and Electricity Price

Energy data		
Renewable Heat Incentive	0.079	£/kWh
Electricity cost	0.105	£/kWh
Electricity CO2 emissions	0.000545	t/kWh
Feed In Tariff	0.115	£/kWh
Electricity export price	0.032	£/kWh

Annex 5: Table 2 Process data considerations for 50 kWe and 155 kWe

Process data		
Average Alc content (% by volume):		
Wash	8	%
low wines	30	%
spirit	65	%
Pot ale	1	%
Spent Lees	1	%
Co-product produced per litre spirit:		
Pot ale	10.15	litres
Spent lees	1.69	litres

Annex 5: Table 3 Production and process data for 155 kWe and 50 kWe

	Production data	
	155 kW_e	**50 kW_e**
Annual spent wash+ lees [tonnes]	31,348	11,690
Annual alcohol production [litre]	2,140,000	798,047
Annual volume of Biogas [m^3]	597,119.26	222,677.20
Distillery shutdown in a year [weeks]	2	2

Annex 5: Table 4 Anaerobic Digester considerations for 50 kWe and 155 kWe

Methane Production Rate		
Influent COD	32.71	g/l
Expected COD conversion	29.44	g/l
Expected SMP	14.13	m3/t
Effluent COD	3.27	g/l
Methane produced per tonne of liquid co-product	14.13	m^3/t
Biogas Data:		
Biogas Methane Content	60%	
Net CV of methane	35850	kJ/m^3
Net CV of biogas	21510	kJ/m^3

Annex 5: Table 5: Anaerobic Digester Plant

AD Plant: size			
	50 kWe	**155 kWe**	
Retention time	2.10	2.10	days
Daily feed rate	33.40	89.57	t/day
Specific Volume of co-product	1.00	1.00	m3/t
Digester Volume	70.14	188.09	m3

Annex 5: Table 6: Anaerobic Digester Heating Demand

AD plant: heating demand			
	50 kWe	**155 kWe**	
Digester Operating Temperature	38	38	C
Digester Surface Area	23	62	m^2
Insulation thickness	0.05	0.05	m
Insulation thermal conductivity	0.03	0.03	W/m C
Annual Digester Heat Loss	3.5	9.4	MWh
Co-product specific heat Cp	4.18	4.18	kJ/kg C
Co-product Temperature	74	74	C
Annual Feed	11,690.38	31,348.31	t/yr

Annex 5: Table 7: Financial Analysis of 155 kWe

155 kWe production									
Years	Investment Cost	Annual Cost	Annual Income	Net Income	IRR	NPV	PBP	Loan Payment	Net Cash Flow
0	608,035			-608,034.70	36.03%	£1,700,243.22	2.77		
1		28,918	248,439	219,521				-£64,666.00	154,855
2		28,918	248,439	219,521				-£64,666.00	154,855
3		28,918	248,439	219,521				-£64,666.00	154,855
4		28,918	248,439	219,521				-£64,666.00	154,855
5		28,918	248,439	219,521				-£64,666.00	154,855
6		28,918	248,439	219,521				-£64,666.00	154,855
7		28,918	248,439	219,521				-£64,666.00	154,855
8		28,918	248,439	219,521				-£64,666.00	154,855
9		28,918	248,439	219,521				-£64,666.00	154,855
10		28,918	248,439	219,521				-£64,666.00	154,855
11		28,918	248,439	219,521				-£64,666.00	154,855
12		28,918	248,439	219,521				-£64,666.00	154,855
13		28,918	248,439	219,521				-£64,666.00	154,855
14		28,918	248,439	219,521				-£64,666.00	154,855
15		28,918	248,439	219,521				-£64,666.00	154,855
16		28,918	248,439	219,521					219,521
17		28,918	248,439	219,521					219,521
18		28,918	248,439	219,521					219,521
19		28,918	248,439	219,521					219,521
20		28,918	248,439	219,521					219,521

(MGM International 2006)

Installation cost includes: Anaerobic digester investment: £376,180, Jura Hotel and Jura Hall heat supply: £59,182, Jura hotel electricity supply: 23,800, CHP investment: £148,873

Annual cost includes: operational and maintenance cost of CHP: £10,109, anaerobic digester unit: £18,809

Annual income includes: export to the grid: £38,809, feed in tarrif: £150,083, heat provided to Jura hotel and hall: £21622, Renewable Heat Incentive: £28,234, Electricity to Jura Hotel: £9,691

Annex 5: Table 8-: Financial Analysis of 50 kWe

50 kWe production									
Years	Investment Cost	Annual Cost	Annual Income	Net Income	IRR	NPV	PBP	Loan Payment	Net Cash Flow
0	357,087			-357,087.00	29.81%	£772,123.92	3.34		
1		11,295	118,333	107,038				-£37,977.00	69,061
2		11,295	118,333	107,038				-£37,977.00	69,061
3		11,295	118,333	107,038				-£37,977.00	69,061
4		11,295	118,333	107,038				-£37,977.00	69,061
5		11,295	118,333	107,038				-£37,977.00	69,061
6		11,295	118,333	107,038				-£37,977.00	69,061
7		11,295	118,333	107,038				-£37,977.00	69,061
8		11,295	118,333	107,038				-£37,977.00	69,061
9		11,295	118,333	107,038				-£37,977.00	69,061
10		11,295	118,333	107,038				-£37,977.00	69,061
11		11,295	118,333	107,038				-£37,977.00	69,061
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14		11,295	118,333	107,038				-£37,977.00	69,061
15		11,295	118,333	107,038				-£37,977.00	69,061
16		11,295	118,333	107,038					107,038
17		11,295	118,333	107,038					107,038
18		11,295	118,333	107,038					107,038
19		11,295	118,333	107,038					107,038
20		11,295	118,333	107,038					107,038

(MGM International 2006)

Installation cost includes: Anaerobic digester investment: £175,356, Jura Hotel and Jura Hall heat supply: £59,182, Jura hotel electricity supply: 23,800, CHP investment: £98,749

Annual cost includes: operational and maintenance cost of CHP: £2,527, anaerobic digester unit: £8,768

Annual income includes: export to the grid: £10,486, feed in tarrif: £48,300, heat provided to Jura hotel and hall: £21622, Renewable Heat Incentive: £28,234, Electricity to Jura Hotel: £9,691

Annex 5: Table 9: Mass flow in whiskey making process at the Jura distillery

Alcohol production	2,200,000	liters of spirit per year
composition of pure alcohol	70% alcohol and 30% water by concentration	
mass of water in one liter alcohol	0.30	kg/ liter of spirit
1 liter alcohol =	0.789	kg
mass of alcohol in one liter of spirit	0.5523	kg/ liter of spirit
Second distillation		
2200000 liter of spirit (70%) contains		
	660,000	kg of water/year
	1,215,060	kg of alcohol/year
First distillation		
2,200,000	liter spirit (70%) per year	
600,000	liter spent lee per year	
2,800,000	liter low wine from first distillation	
	this low wine contains 21% alcohol and 79% water concentration	
mass of water in one liter of low wine	0.79	kg/liter of low wine
mass of alcohol in one liter of low wine	0.16569	kg/liter of low wine
2800000 liter of low wine contains		
	2212000	liter of water/year
	463932	liter of alcohol/year
cooling of wort		
wort contain water and grist		
grist per batch	4750	kg of grist
water per batch	20000	liter per batch
batches in a week	28	batches/ week
wort (considering grist property as water) per hr passing through heat exchanger	34650000.00	liter per hour

Annex 5: Table 10: Energy Balance distillery cooling water

Distillery side

Process	Components	m	h_{fg}	C_P	T_i	T_o	Δt	heat loss
		kg/hr	kJ/kg	kJ/kg ^{o}C	°C	°C	°C	Q kJ/hr
Second distillation	alcohol	144	855	2.84	78.6	10	-68.6	-151424
	water	78	2257	4.18	78.6	10	-68.6	-199296
First distillation	alcohol	55	855	2.84	78.6	10	-68.6	-57817
	water	263	2257	4.18	78.6	10	-68.6	-667945
Wort cooling	water	4113	2257	4.18	64.3	10	-54.3	-10217201
							Total heat loss:	-10217201

Cooling water Side

	m_W	C_{pW}	T_{iW}	T_{oW}	Δt
Process	kg/hr	kJ/kg °C	°C	°C	°C
Second distillation	2393.26	4.187	10	45	35
First distillation	4952.48				
Wort cooling	69720.57				
Water going back to mash tun	-4166.67				
Cooling water going to sea	72899.65	kg/hr			
Cooling water going to sea	20.25	kg /sec			
Power contain in water	2967.52	kJ/sec			
	2967.52	**kW**			
Energy contain in water	**24,998.41**	**MWh/year**			

Annex 5: Table 11: Monthly energy demand for the Jura hotel for domestic hot water and space heating

Month	Hot water (kWh)	Space heating (kWh)	Total
January	2979	23288	26267
February	3015	21958	24973
March	2396	22914	25310
April	5109	20029	25138
May	6727	16754	23481
June	6010	0	6010
July	4694	0	4694
August	5853	0	5853
September	4859	0	4859
October	3497	16179	19677
November	1940	19870	21810
December	1691	22750	24441
Year	48771	163742	212513

Author based on (McCallum 2010)

Assumption for above calculation

Total beds	34
Required room temperature	20 °C
Heating Degree Days taken is for Islay as it is near to Jura	
Hot Water requirement for one time Shower	60 liters (Solahart 2011)
Hot Water requirement for one time bath	18 liters
Hot Water requirement for wash basin	2 liters
Dish Washing Sinks	10 liters

Occupants in bar and lounge includes person staying in hotel and camps

Guest staying in hotel 50% take bath once a day and 50% take bath twice a day

Guest staying in camps shower once a day

8 regular staff stay in hotel throughout year and in summer 7 part time staffs are added

Annex 5: Table 12: Components and cost for heating with heat recovered using heat pump and existing radiators

S.No.	Components	Components Description	Quantity	unit	unit price (£)	Amount (£)
1	Heat pump	Nyle system heat pump 70kW thermal, 23kW electrical	1.00	nos	21,250.00	21,250.00
2	insulated copper pipes	insulated copper pipes	30.00	meter	80.00	2,400.00
3	Pump	Grundfos UPS 25-100 (180mm) Light Commercial Circulator 240V	1.00	nos	380.27	380.27
					subtotal	24,030.27
6	other accessories	valves, control units, connections	0.10			2,403.03
7					Installation and transportation	3,000.00
					Total cost	29,433.30

Annex 5: Table 13: Components and cost for heating with heat recovered using heat exchanger and new radiators

S.No.	Components	Components Description	Quantity	unit	unit price (£)	Amount (£)
1	Radiators					
		Compact type 22 (1000mm X 450 mm)	8		199.40	1,595.20
		Compact type 22 (1000mm X 600 mm)	4		247.98	991.92
		Compact type 22 (1100mm X 600 mm)	11		272.75	3,000.25
		Compact type 22 (1200mm X 600 mm)	8		297.55	2,380.40
		Compact type 22 (1300mm X 600 mm)	5		322.35	1,611.75
		Compact type 22 (500mm X 450 mm)	1		99.51	99.51
		Compact type 22 (900mm X 450 mm)	24		179.13	4,299.12
2	Heat exchanger	250,000 BTU/hr: 20-Plate Heat Exchanger, 1" MNPT ports, 4-1/4" x 12"	1		115.00	115.00
		LA14-10 Brazed Plate Exchanger 48,000 Btu/hr	1	nos	84.00	84.00
3	insulated copper pipes	2 inch insulated copper pipes	30	meter	80.00	2,400.00
4	Pump	Grundfos UPS 25-100 (180mm) Light Commercial Circulator 240V	1	nos	380.27	380.27
5	Pipes		250	nos	5.00	1,250.00
					subtotal	18,207.42
6	other accessories	valves, control units, connections	10%			1,820.74
7					Installation and transportation	3,000.00
					Total cost	23,028.16

Annex 5: Table 14 : Total yearly energy cost of different options for heating in the Jura Hall

Description	Alternatives		
	Option 3: Heating with the existing oil boiler	Option 1: Heating with heat recovered using heat pump and existing radiators	Option 2: Heating with heat recovered using heat exchanger and new radiators
Investment Cost, Io [£]		29,433.3	23,028.2
Lifetime [years]	20	20	20
Depreciation, D [£/year]		1471.66	1151.41
Interest rate, i [%]		0.065	0.065
Interest, i [£/year]		956.58	748.42
operating hours for space heating [h/year]	5808	5808	5808
Percent of space heating demand covered by system	100%	96%	96%
energy output for space heating [kWh/y]	163741.8	163741.8	163741.8
operating hours for hot water heating [h/year]	8760	8760	8760
Percent of hot water demand covered by system	100%	96%	96%
energy output for hotwater heating [kWh/y]	48722.9	48722.93	48722.93
Total energy output for heating [kWh/y]	212,464.7	212464.7	212464.7
Energy saving by increasing inlet water temperature to hot water storage [KWh/y]			13902.1
Efficiency of System	95%	96%	96%
Electricity energy cost [£/kWh]	0.12	0.12	0.12
Electricity energy cost for operating heat pump [£/year]		8,331.95	
Electricity energy cost for operating pumps and sensors [£/year]		48.90	48.90
Oil energy cost [£/liter]	0.65	0.65	0.65
Oil heating value [kWh/liter]	10.06	10.06	10.06
Oil energy cost [£/kWh]	0.065	0.065	0.065
Energy cost for operation oil boiler [£/year]	14,450.36	571.99	2,784.42
Total energy cost [£/year]	14,450.36	8,952.85	2,833.32
total Cost [£/year]	14,450.36	11,381.09	4,733.14
savings [£/year]		3,069.27	9,717.21
Oil required (liter/year)	22,231.32	879.99	4,283.72
Oil saving (liter/year)		21,351.33	17,947.60

Annex 5: Table 15: NPV, Payback and IRR calculation for option 1 and option 2 compared to option 3

Discount rate	6.5%																				
life time	20	years																			
Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Project life (t)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20

Option1: heating with heat recovered using heat exchanger and new radiators

Investment (£)	-29433																				
Annual Savings (£/year)		5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51
Annual Cashflow (C_t)	-29433	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51	5497.51
Discount factor $[(1/(1+r)^t]$	1.00	0.94	0.88	0.83	0.78	0.73	0.69	0.64	0.60	0.57	0.53	0.50	0.47	0.44	0.41	0.39	0.37	0.34	0.32	0.30	0.28
Present value, PV $[(C_t/(1+r)^t]$	-29433.30	5161.98	4846.93	4551.11	4273.34	4012.53	3767.63	3537.68	3321.77	3119.03	2928.67	2749.92	2582.09	2424.50	2276.52	2137.58	2007.12	1884.62	1769.59	1661.59	1560.18
Cumulative PV	-29433.30	-24271.31	-19424.38	-14873.27	-10599.93	-6587.40	-2819.76	717.92	4039.69	7158.72	10087.39	12837.31	15419.40	17843.89	20120.42	22257.99	24265.11	26149.73	27919.32	29580.91	31141.09
Net Present Value (NPV)	31141.09																				
Payback period	5.4																				
Internal Rate of Return (IRR)	18.0%																				

Option 2: heating with heat recovered using heat exchanger and new radiators

Investment (£)	-23028																				
Annual Savings (£/year)		11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04
Annual Cashflow (C_t)	-23028	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04	11617.04
Discount factor $[(1/(1+r)^t]$	1.00	0.94	0.88	0.83	0.78	0.73	0.69	0.64	0.60	0.57	0.53	0.50	0.47	0.44	0.41	0.39	0.37	0.34	0.32	0.30	0.28
Present value, PV $[(C_t/(1+r)^t]$	-23028.16	10908.02	10242.27	9617.15	9030.19	8479.05	7961.55	7475.64	7019.38	6590.96	6188.70	5810.98	5456.32	5123.31	4810.62	4517.01	4241.33	3982.47	3739.40	3511.18	3296.88
Cumulative PV	-23028.16	-12120.14	-1877.88	7739.28	16769.47	25248.53	33210.08	40685.71	47705.09	54296.06	60484.75	66295.74	71752.06	76875.37	81685.99	86203.00	90444.33	94426.80	98166.20	101677.38	104974.26
Net Present Value (NPV)	104974.26																				
Payback period	1.98																				
Internal Rate of Return (IRR)	50.4%																				

Annex 5: Table 16: Specific transmission heat losses

Component	Area (m^2)	U-value [W/m^2K]	F	ΔU_{TB}	Specific transmission heat losses [W/K]
Window	36.37	1.8	1	0.05	67
Door	14.59	1.8	1	0.05	27
Floor	225.55	0.500	1	0.05	124
Wall	157.44	0.16	1	0.05	33
Roof	270.7	0.160	1	0.05	57
Specific transmission heat losses [W/K]					308

U value is taken from (Martin C Stewart Ltd 2010), (Community Energy Scotland 2009), (Kingspan n.d.)

Annex 5: Table 17: Solar heat gain through walls (opaque elements)

Wall	Outer Heat Transfer Resistance 1/ha [m^2K/W]	Absorption coefficient α	Solar Irradiation I (Wh/ sq-m) average during heating period	Form Factor between element and sky F_f	Emission Coefficient ε	Temperature difference between sky and ambient air ΔT (K)	Heating period t (hours)	Heat Gains kWh / year
West	0.04	0.4	571000	0.5	0.4	10	6600	53
South	0.04	0.4	718000	0.5	0.4	10	6600	42
North	0.04	0.4	324000	0.5	0.4	10	6600	10
East	0.04	0.4	559000	0.5	0.4	10	6600	52
								157

Annex 5: Table 18: Solar heat gain through roof

Roof	Outer Heat Transfer Resistance 1/ha [m^2K/W]	Absorption coefficient α	Solar Irradiation I (Wh/ sq-m) average during heating period	Form Factor between element and sky Ff	Emission Coefficient ε	Temperature difference between sky and ambient air DT (K)	Heating period t (hours)	Heat Gains kWh / year
North East	0.04	0.60	703000	1	0.4	10	6600	211
South West (big)	0.04	0.60	867000	1	0.4	10	6600	248
South West (small)	0.04	0.60	872000	1	0.4	10	6600	107
South East	0.04	0.60	905000	1	0.4	10	6600	38
								604

Annex 5: Table 19: Solar heat gain through windows

Windows	Area (m^2)	Insolation KWh/m^2 year	Reduction frame factor F_f	Reduction Soiling Factor F_V	Reduction Factor g	Solar Heat Gain kWh / year
West	13.4	571	0.8	0.9	0.7	3856
South	1.65	718	0.8	0.9	0.7	597
East	12.6	559	0.8	0.9	0.7	3550
North	8.72	324	0.8	0.9	0.7	1424
						9427

Annex 5: Table 20: Monthly irradiation in kWh/m²

Monthly irradiation in kWh/m²									
Month	Sunshine hour	I_{east} (kWh/m²)	I_{north} (kWh/m²)	I_{west} (kWh/m²)	I_{south} (kWh/m²)	$I_{northeast\ 42°}$ (kWh/m²)	$I_{southwest\ 42°}$ (kWh/m²)	$I_{southwest\ 12°}$ (kWh/m²)	$I_{southeast\ 10°}$ (kWh/m²)
January	36.9	8	5	10	25	9	16	14	15
February	63.3	18	11	21	43	20	33	29	32
March	103.2	40	21	39	67	46	62	60	64
April	164.4	74	35	66	91	89	104	107	114
May	226	98	52	87	90	126	133	142	148
June	179.1	93	60	94	82	125	137	146	148
July	161.5	83	53	81	78	112	122	130	133
August	160	66	40	71	71	86	105	107	109
September	124.2	42	23	51	67	49	74	69	71
October	83.7	21	14	28	44	25	43	38	39
November	47.7	10	6	15	35	10	24	19	20
December	31	6	4	8	25	6	14	11	12
Total	1399	559	324	571	718	703	867	872	905

H_T Total Transmission heat loss [W/K], H_T	**308.24**	
Specific ventilation heat losses [W/K], Hv	**230.82**	[W/K]
$H_v = \beta \times V \times 0.34\ Wh/(m^3K)$		
$\beta = 0.7/h$ and $V = 969.85\ m^3$	0.7	/h
Total specific heat losses [W/K], $H_L = H_T + H_V$	**539.06**	[W/K]
hdd=	**3090.25**	Kd
Total heat loss [kWh]	**37,981.00**	**kWh/year**
$Q_L = H_L x\ hdd \times 24\ h/d \times 0.95$		
Total heat Gain [kWh]	**10188**	**kWh/y**
Space Heating Demand (kWh)	**27,792.94**	**kWh**

Calculation of Required Capacity of heating equipment

Room temperature, T_R	20	°C	293	K	
Lowest ambient temperature:T_a	-2	°C	271	K	
Capacity of heating equipment (**H_L*(T_R –T_a-2)**)	11.86	kW			
Capacity of log fired warm Air boiler	14	kW	@85% efficiency (Dunster Heat Limited n.d.)		

Annex 5: Table 21: Selection of components for Jura hall

Radiator		
Brand	PURMO Compact, Compact type 22	
dimension	3000mm X 600mm	
Output	5028.0	watt @ ΔT50
correction factor for 40°C	0.75	
Output at 40°C	3771	watt
Required capacity of radiators	14	kW
Number of radiators required	3.71	numbers
Number of radiators required	4	numbers
Pump		
	Grundfos 15-60 Domestic Circulating Pump	
Brand		
Operating temperature	+15°C to +110°C Max Temp. Range	
Flow Volume Q Maximum	3m³/h	
correction factor for 40°C	0.75	
Can be Used for Max 35kW Application		
Voltage	230V 50hz	
Electrical immersion heater		
	MegaLife HE 100	
Brand		
Coil loading	15.4 kW	
Recovery minutes	14 minutes	
Storage tank capacity	100 liters	
Voltage	230V 50hz	

Annex 5: Table 22: Components and cost for distillery heat recovery

S.No.	Components	Components Description	Quantity	unit	unit price (£)	Amount (£)
1	Radiators	PURMO Compact, 3000mm X 600mm	4	nos	400.96	1603.8
2	Heat exchanger	LA14-10 Brazed Plate Exchanger 48,000 Btu/hr	1	nos	84	84.0
3	Pump	Grundfos 15-60 Domestic Circulating Pump	1	nos	95	95.0
4	insulated copper pipes	2 inch insulated copper pipes	140	meter	50	7000.0
5	copper pipes		40		5	200.0
6	immersion water heater with storage	MegaLife HE 100 (15.4 kW)	1	nos	469.75	469.8
					subtotal	9452.6
6	other accessories	valves, control units, connections	10%			945.3
7					Installation and transportation	3000.0
					Total cost	13,397.85

(Hydronic Heating Suppliers 2012), (ScrewFix 2011), (Panels - PURMO Compact 2010), (UK plumbing 2010)

Annex 5: Table 23 : Components and cost for log boiler

S.No.	Components	Components Description	Quantity	unit	unit price (£)	Amount (£)
1	Wood boiler	Vigas 16s with 1000 Lt Thermal Store and accessories	1	nos	5727	5727
2	Radiators	Kudox Premium Type 22 Double Panel Double Convector Radiator White 500x1000	10	nos	79.99	799.9
3	insulated copper pipes	2 inch insulated copper pipes	40	meter	5	200
4	Pump	Grundfos 15-60 Domestic Circulating Pump	1	nos	95	95.0
5	Space for log storage		1	nos	1000	1000.0
					sub total	6821.9
6	other accessories	connectors, valves	10%			682.2
7	Installation and transporatation					3000.0
	Total cost					10,504.09

(Dunster wood boiler n.d.), (ScrewFix 2011)

Annex 5: Table 24: Components and cost for the electrical thermal storage

S.No.	Components	Components Description	Quantity	unit	unit price (£)	Amount (£)
1	Combination Storage Heaters	XLS18 "Medium" 2.5 kw + 1.45 kw	6	nos	399	2394
2	other accessories	connectors, valves	10%			239.4
3	installation and transporatation					3000.0
	Total cost					5,633.40

(HW electric and supplies 2012)

Annex 5: Table 25 : Financial analysis of Jura hall at different occupancy rate

Description	Existing Occupancy			50% increase in Occupancy			100% increase in Occupancy		
	Distillery heat Recovery	Log boiler	Electrical thermal storage	Distillery heat Recovery	Log boiler	Electrical thermal storage	Distillery heat Recovery	Log boiler	Electrical thermal storage
Investment Cost, Io [£]	13,397.85	10,504.09	5,633.40	13,397.85	10,504.09	5,633.40	13,397.85	10,504.09	5,633.40
Lifetime [years]	20	20	20	20	20	20	20	20	20
Depreciation, D [£/year]	669.89	525.20	281.67	669.89	525.20	281.67	669.89	525.20	281.67
Interest rate, i [%]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Interest, i [£/year]	334.95	262.60	140.84	334.95	262.60	140.84	334.95	262.60	140.84
Labour cost [£/year]									
operating hours [h/year]	1794	1794	1794	2691	2691	2691	3588	3588	3588
Percent of demand covered by system	96%	100%	100%	96%	100%	100%	96%	100%	100%
energy output [kWh/y]	5,691.84	5,691.84	5,691.84	8,537.76	8,537.76	8,537.76	11,383.68	11,383.68	11,383.68
Electricity energy cost[£/kWh]	0.1205	0.1205	0.1030	0.1205	0.1205	0.1030	0.1205	0.1205	0.1030
Electricity energy cost for operating fans [£/year]	-	12.97	-	-	19.46	-	-	25.94	-
Electricity energy cost electrical heating [£/year]	26.38	-	586.26	39.57	-	879.39	52.76	-	1,172.52
Electricity energy cost for operating pumps [£]	35.88	35.88		53.82	53.82		71.76	71.76	
Total electrical energy cost [£/year]	62.26	48.85	586.26	93.39	73.28	879.39	124.52	97.70	1,172.52
Wood energy consumption [kWh/year]	-	6,696.28	-	-	10,044.43	-	-	13,392.57	-
Wood energy cost [£/kWh]	-	0.02	-	-	0.02		-	0.02	
Wood energy cost [£/year]	-	130.33	-	-	195.50	-	-	267.85	-
Energy cost before RHI [£/year]	62.26	179.18	586.26	93.39	268.78	879.39	124.52	365.55	1,172.52
Renewable Heat Incentive [£/kWh]		0.079			0.079			0.079	
Renewable Heat Incentive [£/year]		450			674			899	
Yearly running cost [£/year]	62	(270)	586	93	(406)	879	125	(534)	1,173
Total Cost [£/year]	1,067.10	517.34	1,008.76	1,098.23	382.10	1,301.89	1,129.36	254.05	1,595.02

Annex 5: Table 26: NPV and Payback period for different options of heating for the Jura hall

50% increase in Occupancy

Discount rate	6.5%	
life time	20	years

Years	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Project life (t)	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Distillery heat recovery																					
Investment (£)	-7764																				
Annual Savings (£/year)		786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00
Annual Cashflow (C_t)	-7764	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00	786.00
Discount factor $[(1/(1+r)^t]$	1.00	0.94	0.88	0.83	0.78	0.73	0.69	0.64	0.60	0.57	0.53	0.50	0.47	0.44	0.41	0.39	0.37	0.34	0.32	0.30	0.28
Present value, PV $[(C_t/(1+r)^t]$	-7764.45	738.03	692.98	650.69	610.98	573.69	538.67	505.80	474.93	445.94	418.72	393.17	369.17	346.64	325.48	305.62	286.97	269.45	253.01	237.56	223.06
Cumulative PV	-7764.45	-7026.42	-6333.44	-5682.75	-5071.77	-4498.08	-3959.41	-3453.61	-2978.69	-2532.75	-2114.03	-1720.86	-1351.69	-1005.05	-679.57	-373.95	-86.98	182.47	435.47	673.04	896.10
Net Present Value (NPV)	896.10																				
Payback period	16.3																				
Internal Rate of Return (IRR)	7.9%																				
Wood boiler																					
Investment (£)	-4871																				
Annual Savings (£/year)		1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10
Annual Cashflow (C_t)	-4871	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10	1285.10
Discount factor $[(1/(1+r)^t]$	1.00	0.94	0.88	0.83	0.78	0.73	0.69	0.64	0.60	0.57	0.53	0.50	0.47	0.44	0.41	0.39	0.37	0.34	0.32	0.30	0.28
Present value, PV $[(C_t/(1+r)^t]$	-4870.69	1206.66	1133.02	1063.87	998.93	937.97	880.72	826.97	776.49	729.10	684.60	642.82	603.59	566.75	532.16	499.68	469.18	440.55	413.66	388.41	364.71
Cumulative PV	-4870.69	-3664.03	-2531.01	-1467.15	-468.21	469.75	1350.47	2177.44	2953.94	3683.04	4367.64	5010.46	5614.05	6180.80	6712.96	7212.64	7681.82	8122.37	8536.03	8924.44	9289.14
Net Present Value (NPV)	9289.14																				
Payback period	4.5																				
Internal Rate of Return (IRR)	26.1%																				