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Prefeasibility Study for a Small Hydro Project

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Declaration

I, Luel Culwick, know the meaning of plagiarism and declare that all the work in the document, save for that which is properly acknowledged, is my own.

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Abstract

A prefeasibility study for the production of hydroelectricity on the Kruisvallei 190 farm was conducted. The work progression included a site assessment, preliminary layout design, a basic technical specification, and production and financial analyses.

Site Assessment

The flow through the system measured in 2007 was processed and captured in a Flow Duration Curve. Projected increased average flow in the future was researched and to account for this, linear FDCs were constructed, tested and shown to be valid for use over the period of project analysis.

The total head on the Kruisvallei is 33m, and the majority of this drop is concentrated over three sections of river.

Preliminary Layout Design

An iterative process of layout design was conducted which included consideration of eight potential layouts, five of which have been discarded. Three layouts are proposed to make use of the head on Kruisvallei, referred to as Upper Kruisvallei (UK), Middle Kruisvallei (MK) and Lower Kruisvallei (LK). The results of the layout design are summarised in the table below.

Layout	upper level	lower level	Total Head	Canal Length	Gross Head
UK	1715m	1699m	16m	320m	15.68m
MK	1695m	1688m	7m	270m	6.73m
LK	1682.5m	1676m	6.5m	0m	6.5m

Technical Specification and Production Analysis

Each of the three layouts was analyzed using a technical model based on the RETScreen methodology. Literature was consulted to decide on turbine type and design flow was determined by maximizing the NPV of the investment. Selected technical results are shown in the table below.

	Site			
Turbine Design	**UK**	**MK**	**LK**	**Units**
Turbine Type	Double Regulated Kaplan			
Design Flow (Q_{des})	34	34	34	m^3/s
Runner Size (d)	2.17	2.17	2.17	m
Specific Speed (n_q)	207.28	316.39	321.94	dimensionless
Design Results	**UK**	**MK**	**LK**	**Units**
Plant Design Capacity	4221	1758	1693	kW
Capacity Factor (K) (2014)	71%	71%	70%	%
Capacity Factor (K) (2033)	95%	95%	93%	%
Production Results	**UK**	**MK**	**LK**	**Units**
Energy Produced (E_{dlvd}) (2014)	26,089,353	10,862,713	10,345,298	kWh
Energy Produced (E_{dlvd}) (2033)	35,220,116	14,634,475	13,806,462	kWh
CERs produced (CER_{issued}) (2014)	28,177	11,732	11,173	Tons of CO_2 eq.
CERs produced(CER_{issued}) (2033)	38,038	15,805	14,911	Tons of CO_2 eq.

Financial Results

Capital costs were quantified and compared with expert estimates and historical small hydro figures. Periodic costs were quantified, taking into account O&M, water and land lease costs.

The financial model translates production outputs from the technical model into income through the sale of electricity (at upper and lower expected levels) and CERS. A cash flow is constructed for each layout at both upper and lower off-take levels to give assumed base and best case results. The cash flows are analysed, yielding the NPV and IRR results shown in the table below.

	IRR [%]	
	Base Case	**Best Case**
UK	23%	32%
MK	22%	30%
LK	17%	25%
	NPV [R]	
	Base Case	**Best Case**
UK	R76,571,724	R155,252,095
MK	R29,120,709	R61,867,884
LK	R14,878,483	R48,654,648

The following investment recommendations are made following the study:

- The analysis strongly suggests investment in UK and MK, and this is recommended. LK shows marginally less attractive results, but investment here is also recommended.
- An iterative development process is advisable to mitigate risk. Nevertheless, the results are sufficiently emphatic to recommend the next study to be at full bankable feasibility level.

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List of Abbreviations

BTCF	Before Tax Cash Flow
CDM	Clean Development Mechanism
CER	Certified Emissions Reduction
CPI	Consumer Price Index
DL	Discarded Layout
DWAF	Department of Water Affairs
DWEA	Department of Water and Environmental Affairs
EIA	Environmental Impact Assessment
EU	European Union
FDC	Flow Duration Curve
FIT	Feed-In Tariff
GHG	Green House Gas
IPP	Independent Power Producer
IRR	Internal Rate of Return
LHWP	Lesotho Highlands Water Project
LK	Lower Kruisvallei
MK	Middle Kruisvallei
NOI	Net Operating Income
NPV	Net Present Value
PI	Profitability Index
PPA	Power Purchase Agreement
REFIT	Renewable Energy Feed-In Tariff
REPA	Renewable Energy Purchasing Authority
ROR	Run-Of-River
SBO	Single Buyer Office
TCTA	Trans Caledon Tunnel Authority
TOU	Time Of Use
UK	Upper Kruisvallei
UNFCCC	United Nations Framework Convention for Climate Change
WACC	Weighted Average Cost of Capital

1 Introduction

1.1 Research Description

This study is an investigation into the hydroelectric potential on the farm Kruisvallei 190 in the Bethlehem district, Free State, South Africa. It is the first piece of work of this nature conducted for this site, and prior knowledge of the extent of the hydroelectric potential is limited to uneducated estimation. The study falls within the prefeasibility phase of the project's development, and hence investment into the study is limited and it is based purely on freely available information.

1.2 Kruisvallei 190

In 2007 Mayborn Investments (Pty) Ltd (Mayborn) purchased the farm Kruisvallei 190 (Kruisvallei), in the Bethlehem district and in extent 649.66 hectares. The farm lies two kilometres west of the tarred road linking Bethlehem and Clarence. The Ash River takes the outfall from the Lesotho Highlands water scheme and flows through the property from its Southern end to the North West corner of the farm over a distance in excess of six kilometres. The farm was bought in 2007 primarily for its anticipated potential for hydroelectric generation. A map of the farm is shown in Figure 1. It is the hourglass shaped region.

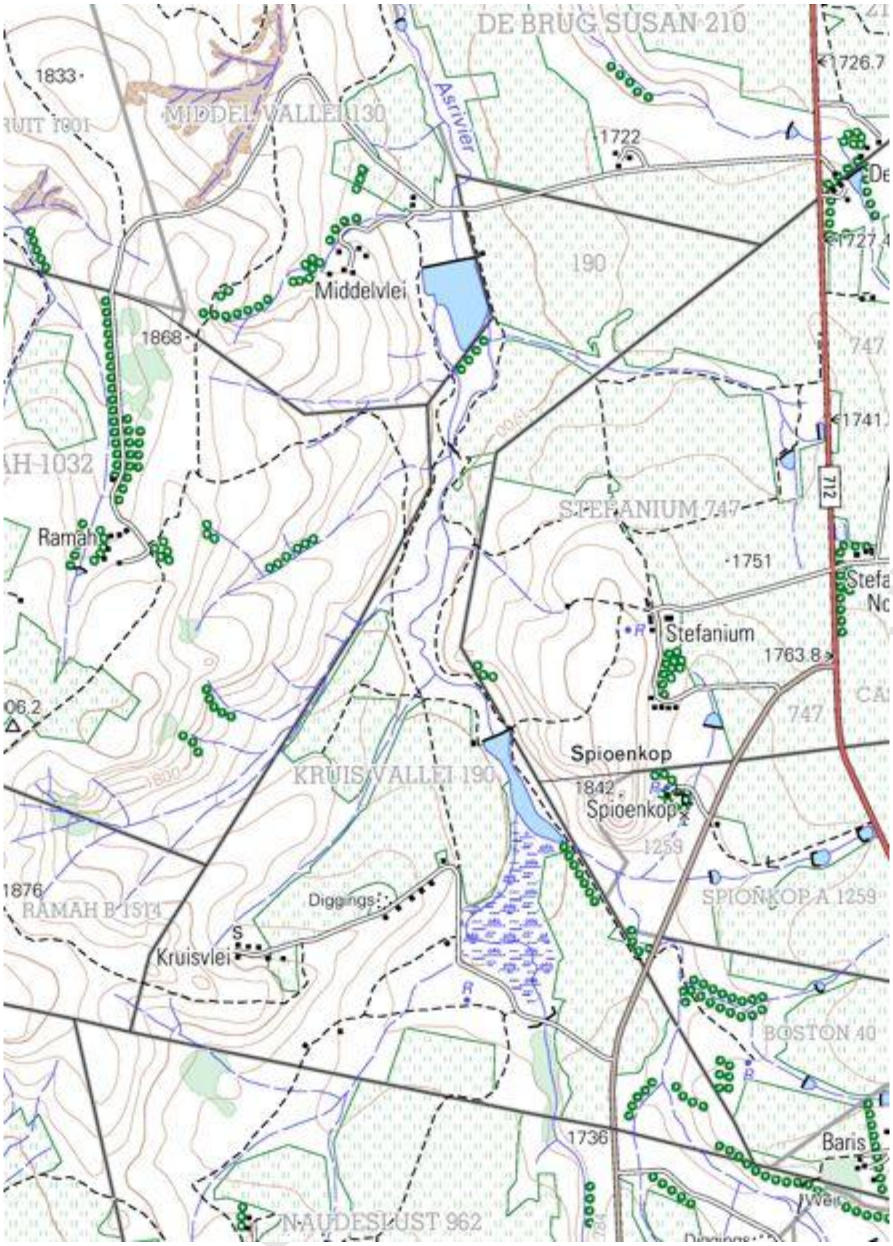

Figure 1. 1:50 000 map of Kruisvallei 190

1.3 Objectives

The aim of the study is to educate Mayborn's decision making for investment into the development of the hydroelectric potential on Kruisvallei. The study objectives are therefore to:

- Quantify the resource potential on Kruisvallei
- Determine and design a likely technical specification for exploitation of the resource

- Analyze the resulting production
- Quantify capital and periodic costs
- Analyze the business case to estimate the feasibility of further development of the site
- Make recommendations for this development

1.4 Report Structure

The flow of this report on the study includes the following chapters:

- Literature Survey.

Here the context of the study is described with respect to the development of a project and the international Small Hydro environment. Literature supporting the technical and financial analyses is briefly presented.

- Site Survey

Here the resource is quantified including consideration of flow and head. Pertinent existing structures on the farm are also described.

- Preliminary Plant Layout Design

Here concept layouts are designed to make use of the available head on the farm.

- Technical Analysis

Here the resource and layout results are processed and the technical specification is extended through turbine design. The operation of the plant is considered and production is determined. Further technical aspects, including grid connection and further site potential, are discussed.

- Financial Analysis

Here costs (capital and periodic) and income (base and best cases) are quantified. Financial parameters are assumed and cash flows are constructed and analyzed using certain investment criteria.

- Results

Key outcomes of the technical and financial analyses are presented here.

- Discussion and Recommendations

Finally, the results are interpreted and discussed, allowing recommendations to be made.

2 Literature Survey

2.1 Preliminary Analysis of Small Hydro Projects

Costs incurred before a project is operational have risk attached to them, and costs incurred before feasibility is proven are high risk investments. The Clean Energy Support Centre (2004:30) states that "project proponents, investors, and financers continually grapple with questions like "how accurate are the estimates of costs and energy savings or production and what are the possibilities for cost over-runs and how does the project compare financially with other competitive options?" These are very difficult to answer with any degree of confidence, since whoever prepared the estimate would have been faced with two conflicting requirements:

- Keep the project development costs low in case funding cannot be secured, or in case the project proves to be uneconomic when compared with other energy options.
- Spend additional money and time on engineering to more clearly delineate potential project costs and to more precisely estimate the amount of energy produced or energy saved.

This dilemma is tackled through the use of a phased approach to development where the level of study detail is gradually built up. Figure 2 shows this progression.

Figure 2. Project development phases. Source: (Clean Energy Support Centre, 2004:31)

Hence levels of study detail are increased according to investor confidence and reducing possibilities of "no-go" decisions or business uncertainty. This risk reduction is reflected in the increasing value of a project as development progresses. This value gain is represented in a Thorndike curve for wind projects shown in Figure 3. A similar curve would be applicable to small hydro projects.

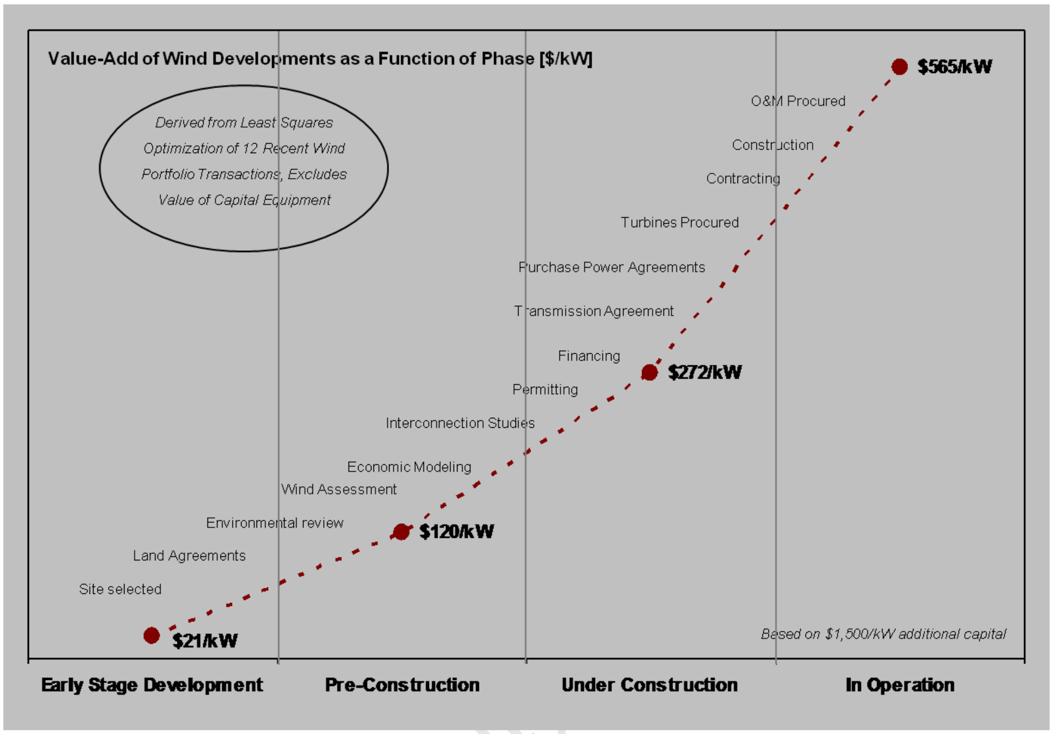

Figure 3. Thorndike curve for wind projects. Source: (Levington, 2010)

2.2 Prefeasibility Study Scope

This study is the first piece of work of its kind conducted for this site. Hence the scope is determined by the study descriptions for prefeasibility or preliminary studies in literature. According to Gordon (1989), there are normally four phases for engineering work required to develop a hydro project. A number of points can and should be interchanged between phases, depending on site and country specifics. A lot of the first stage outlined here does not apply in the Kruisvallei case because this study does not involve site selection.

Reconnaissance surveys and hydraulic studies

This first phase of work frequently covers numerous sites and includes:

- map studies;
- delineation of the drainage basins;
- preliminary estimates of flow and floods;
- and a one day site visit to each site (by a design engineer and geologist or geotechnical engineer);
- preliminary layout;
- cost estimates (based on formulae or computer data);
- a final ranking of sites based on power potential;
- and an index of cost.

Pre-feasibility study

Work on the selected site or sites would include:

- site mapping and geological investigations (with drilling confined to areas where foundation uncertainty would have a major effect on costs);
- a reconnaissance for suitable borrow areas (e.g. for sand and gravel);
- a preliminary layout based on materials known to be available;
- preliminary selection of the main project characteristics (installed capacity, type of development, etc.);
- a cost estimate based on major quantities;
- the identification of possible environmental impacts;
- and production of a single volume report on each site.

Feasibility study

- Work would continue on the selected site with a major foundation investigation programme;
- delineation and testing of all borrow areas;

- estimation of diversion,
- design and probable maximum floods;
- determination of power potential for a range of dam heights and installed capacities for project optimisation;
- determination of the project design earthquake and the maximum credible earthquake;
- design of all structures in sufficient detail to obtain quantities for all items contributing more than about 10% to the cost of individual structures;
- determination of the dewatering sequence and project schedule;
- optimisation of the project layout, water levels and components;
- production of a detailed cost estimate;
- and finally, an economic and financial evaluation of the project including an assessment of the impact on the existing electrical grid along with a multi-volume comprehensive feasibility report.

System planning and project engineering

- This work would include studies and final design of the transmission system;
- Integration of the transmission system;
- integration of the project into the power network to determine precise operating mode;
- production of tender drawings and specifications;
- analysis of bids and detailed design of the project;
- production of detailed construction drawings and review of manufacturer's equipment drawings.
- However, the scope of this phase would not include site supervision nor project management, since this work would form part of the project execution costs.

Aurecon (2009) proposes that the work for such a development be split into 3 phases.

Phase 1 – Preliminary assessment

- This study comprises of a report of the potential of the site and an overview of the geology of the site which is the result of a surface assessment.
- The report will comment on the sites potential and generation capacity.
- Brief turbine selection and electrical requirements will be included.
- A preliminary flow analysis will be performed.
- The report will judge the feasibility of the sites.
- A cost estimate will also be provided with a 25% accuracy.

Phase 2 - Full Bankable Feasibility

This study will cover the following items:

- **Survey**: detailed topography
- **Electromechanical:** Refined turbine selection based on quotations from turbine manufacturers.
- **Electrical:** Detailed connection assessment outlining possible losses.
- **Hydrological:** Detailed analysis of the flow and rainfall data, flood estimate and tail water analysis is performed.
- **Geotechnical:** Detailed site investigation which will include test pitting and core drilling at the intake and power station foundation. Surface geological mapping and profiling of the site, identification of potential construction material (rock for aggregates and sand filters)
- **Civil:** the conceptual aspect of the project (sized according to the selected turbine, power station, design at feasibility level, water conveyance system (penstock/canal etc), intake structure and possible sedimentation problem, hoisting facility and access roads.
- **Construction Management:** Construction Program
- **Cost Estimates and Financial Analysis**

- **Viability analysis:** This will provide the minimum selling rate of the power for the repayment of the power station within 12 years.

Phase 3: Detailed Design and Construction Supervision

This phase will commence once the funding for the development has been secured and environmental approval obtained. This will cover the following processes:

- Preparation of the tender documentation for the mechanical, civil and electrical contracts.
- Tender Process
- Tender evaluation and report
- Contract award and contract administration
- Project management
- Detailed design of the civil, electrical and mechanical components
- Construction monitoring and quality control
- Commissioning
- Completion and site closure

2.3 Small Hydro

2.3.1 Definition of Small Hydro

Small Hydro typically receives a higher tariff than Large Hydro because it is considered to be a renewable energy source. This is not the case for Large Hydro because of the adverse environmental effects caused by the storage of water and flow alteration. (ESHA, 2004) 10MW is the generally accepted threshold between small and large hydro, although in China this is agreed to be 50MW, in France 12MW, and in the UK 20MW. (ESHA, 2004) The threshold for small hydro tariff eligibility in South Africa is set by the Renewable Energy Feed-In Tariff (REFIT) at 10MW. ($Nersa_a$:2009)

2.3.2 Operational Distinctions

Small Hydro can be either Run of River (ROR), located at the base of a dam or integrated in a canal or pipeline. (ESHA, 2004) The vast majority of small hydro is of the ROR type, and this is applicable to the current study. A schematic of ROR operation is shown in Figure 4.

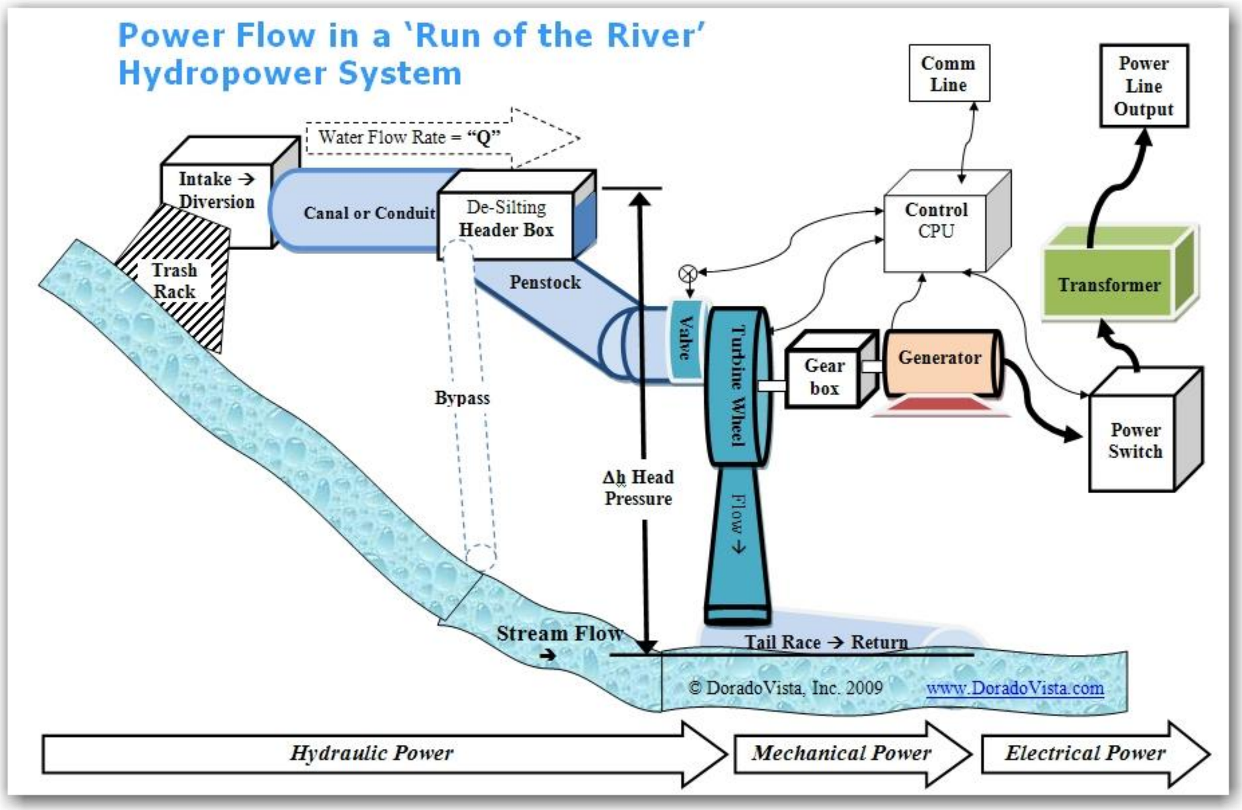

Figure 4. ROR schematic. Source (ESHA, 2004)

In a ROR scheme the system only generates power according to the flow it receives. It does not have the capability of altering the flow for the purposes of generating power optimally.

2.3.3 Head Distinction

Schemes are generally classified according to head as this has large bearing on the layout type. ESHA (2004) defines three head classifications:

- High head: 100-m and above
- Medium head: 30 - 100 m

- Low head: 2 - 30 m

In higher head schemes, the cost of the penstock becomes a dominant cost component because of the length required. In lower head schemes, turbine and turbine casing costs are a dominant cost component because they must accommodate large volumes of water at elevated pressures.

2.3.4 Hydro Power Conversion

Strongly connected to the head classification is the type of energy conversion technology required. Hydro power conversion occurs through the use of either impulse or reaction turbines. Impulse turbines convert the kinetic energy into mechanical energy while reaction turbines convert the pressure energy. (ESHA, 2004)

Impulse Turbines

The most common impulse turbine is the Pelton Wheel. Here water jets impinge perpendicular to buckets, transferring linear kinetic energy of the water into rotation of the runner. A Pelton wheel is shown in Figure 5.

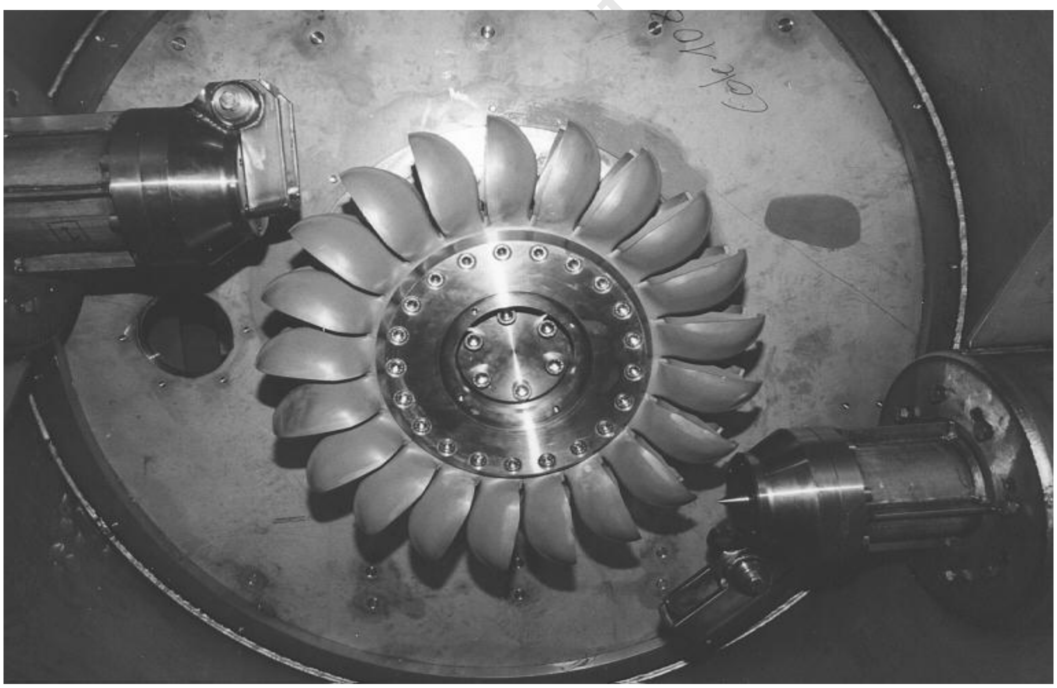

Figure 5. Pelton Wheel. Source (ESHA, 2004)

A variation to the Pelton Wheel is the Turgo turbine. The function of a Turgo runner is similar to a Pelton wheel except that the jet impinges at an angle of (usually) 20° and exits on the other face. The 20° angle at which the jets impinge is to avoid interference between consecutive buckets, which can occur in Pelton wheels. Efficiency is sacrificed however according to the cosine of the angle of incidence. A Turgo turbine is shown in Figure 6.

Figure 6. Turgo Turbine. Source: (Google Images$_a$, 2009)

Cross-flow turbines are a low cost, highly flexible (to head variation) and low efficiency impulse turbine. It is easy to manufacture and repair, and can be useful for well defined energy requirements where there is a sufficient water resource and small investment availability. A Cross-flow turbine is shown in Figure 7.

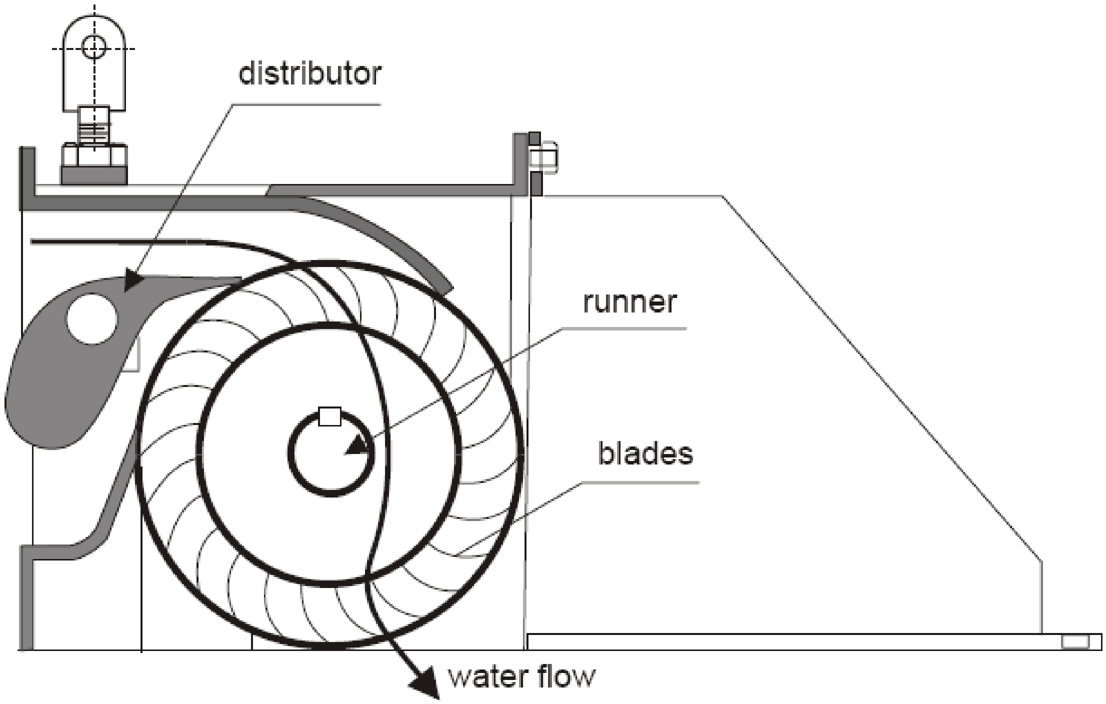

Figure 7. Cross-Flow Turbine. Source (ESHA, 2004).

Reaction Turbines

Francis Turbines have fixed runner blades and adjustable guide vanes. Water enters the runner radially and exits axially. The spiral casing is designed to keep the water's "tangential velocity constant along the consecutive sections and to distribute it peripherally to the distributor." (ESHA, 2004: 161) A Francis turbine is shown in Figure 8.

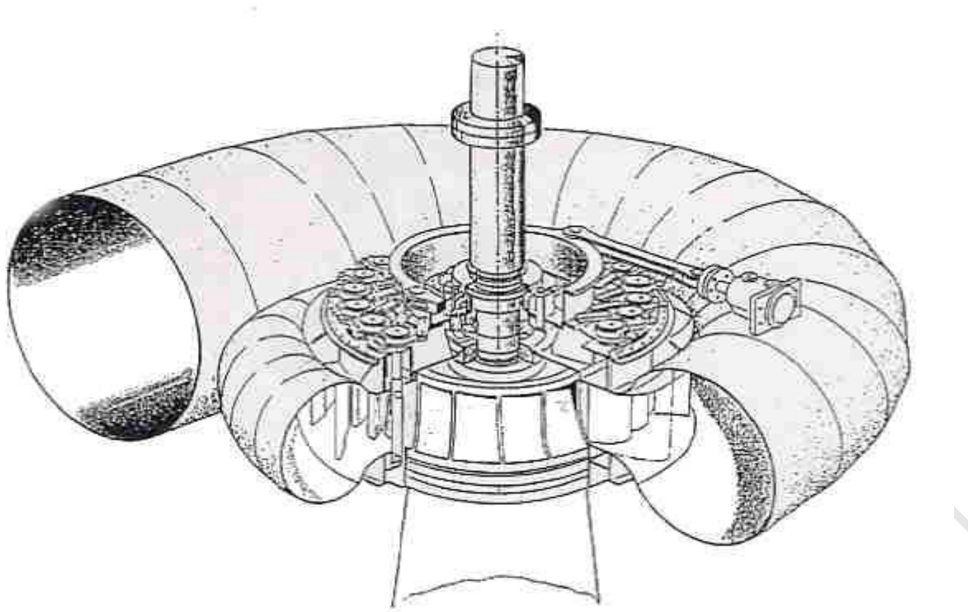

Figure 8. Francis Turbine. Source (ESHA, 2004)

Axial flow turbines include both propeller and Kaplan turbines. Propeller turbines are axial flow turbines and are similar to marine propellers in appearance. A Kaplan turbine is a flexible propeller turbine. The flexibility is provided by either "single-" or "double-regulation", with either adjustable guide vanes or runner blades or both. "The double regulation allows, at any time, for the adaptation of the runner and guide vanes coupling to any head or discharge variation. It is the most flexible Kaplan turbine that can work between 15% and 100% of the maximum design discharge. Single regulated Kaplan allows a good adaptation to varying available flow but is less flexible in the case of important head variation. They can work between 30% and 100% of the maximum design discharge." (ESHA, 2004: 164) A Kaplan runner is shown in Figure 9.

Figure 9. Kaplan Turbine. Source (ESHA, 2004).

2.3.5 Turbine Selection

A very basic method of turbine selection is through the use of charts such as that shown in Figure 10. Because of the overlap in the regions and the flexibility provided by the technologies, this method is not definitive. It can provide a reasonable initial suggestion of turbine type, but it gives no indication of the dimensions of the turbine.

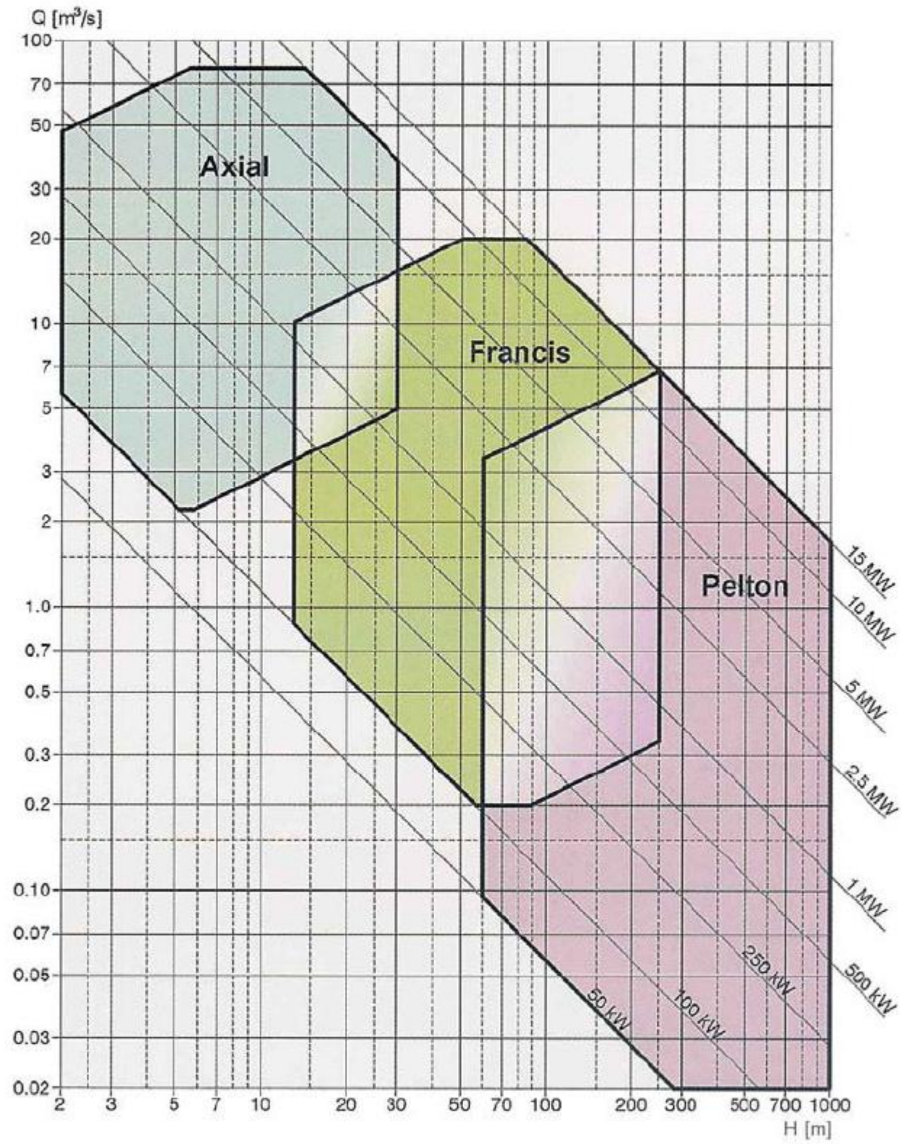

Figure 10. Turbine Selection Chart. Source (ESHA, 2004)

One can see that for a site such as Kruisvallei (an average flow rate of around 24m^3/s and a drop of around 10m, an axial turbine (Kaplan or propeller) is the obvious choice. More advanced methods of turbine selection involve the use of the quantity specific speed which are conducted in the model and explained below.

2.3.6 Draft Tube and Tailrace

"The draft tube of a reaction turbine aims to recover the kinetic energy still remaining in the water leaving the runner. As this energy is proportional to the square of the velocity one of the draft tube objectives is to reduce the turbine outlet velocity. An efficient draft tube would have a conical section but the angle cannot be too large, otherwise flow separation will occur. The optimum angle is 7^{o} but to reduce the draft tube length, and therefore its cost, sometimes angles are increased up to 15^{o}." (ESHA, 2004: 163)

2.4 Technical Modelling

To progress with the project it is necessary to make decisions educated using a sound techno-economic model. The technical component of this deals with the manner in which hydraulic energy is converted to electrical power. It is possible to simplify this model vastly through various assumptions. However, a more detailed approach was possible in this study through the use of the RETScreen publication. This increases accuracy of results enables a more holistic understanding of the system under consideration.

"The RETScreen International Clean Energy Project Analysis Software is the leading tool specifically aimed at facilitating pre-feasibility and feasibility analysis of clean energy technologies." (Clean Energy Support Centre 2004:5) In light of the discussion on project development and risk reduction in section 2.1, the RETScreen tool is particularly appropriate as it has been shown to "dramatically reduce the time and cost associated with preparing pre-feasibility studies" and can produce "accurate analyses that cost roughly one-tenth the amount of pre-feasibility studies with custom-developed methodologies." (Clean Energy Support Centre 2004:5)

The RETScreen tool is built on the "experience of over 210 experts[3] from industry, government and academia" (Clean Energy Support Centre 2004:7) and has vast meteorological and product data support. Of these, technology performance is particularly important in this study. For this purpose "over 6,000 pertinent product performance and specification data needed to describe the performance of the proposed clean energy system" (Clean Energy Support Centre 2004:47) are provided.

Apart from reducing costs, the RETScreen tool is educational. "Someone with no prior knowledge in wind energy, for example, could gain a good understanding of the capabilities of the technology."

(Clean Energy Support Centre 2004:6) For this purpose, an electronic textbook and online manual for software support are provided.

2.5 Financial Modelling

2.5.1 Costs

Costs of a small hydro powerplant arise at different stages of project development and from a number of different components. The following is a breakdown of cost items typically incurred during the phases of development of a small hydro project (RETScreen, 2009):

Feasibility Phase

- Site investigation
- Resource assessment
- Environmental assessment
- Preliminary design
- Detailed cost estimate
- GHG baseline study & MP
- Report preparation
- Project management
- Travel & accommodation

Implementation Phase

- Development
    - Contract negotiations
    - Permits & approvals
    - Site survey & land rights
    - GHG validation & registration
    - Project financing
    - Legal & accounting
    - Project management

  - Travel & accommodation
- Engineering
  - Site & building design
  - Mechanical design
  - Electrical design
  - Civil design
  - Tenders & contracting
  - Construction supervision
- Power System
  - Hydro turbine
  - Road construction
  - Transmission line
  - Energy efficiency measures
  - Substation
- Balance of Plant
  - Specific project costs
  - Preparation equipment Delivery equipment
  - Storage equipment
  - Distribution equipment
  - Building & yard construction
  - Spare parts
  - Transportation
  - Training & commissioning
  - Contingencies
  - Interest during construction

Operation and Maintenance Phase

- Periodic Costs
  - Land lease & resource rental
  - Property taxes

- Insurance premium
- Parts & labour
- GHG monitoring & verification
- Community benefits
- General & administrative

2.5.2 Capital Costs

The most significant cost component in this study is the capital cost incurred during the implementation phase. The capital required for small hydro plant depends on a number of determining factors including the effective head, flow rate, geological and geographical features, the equipment (turbines, generators etc.), civil engineering works, and water flow variation throughout the year. Making use of existing weirs, dams, storage reservoirs and ponds can significantly reduce both environmental impact and costs. Sites with low heads and high flows require a greater capital outlay as larger civil engineering works and turbine machinery will be needed to handle the larger flow of water. Each site is unique, since about 75% of the development cost is determined by the location and site conditions. Only about 25% of the cost is relatively fixed, being the cost of manufacturing the electromechanical equipment. (Clean Energy Support Centre, 2004)

Specific capital costs are investigated through historic small hydro projects and expert estimates. The first provided by Olivier (2009) shows the costs involved in the development of the Bethlehem hydro. This source is particularly relevant as the scheme uses the same resource. Secondly, an EU study outlines the specific costs involved in the installation of a small scale hydro plant ($ESHA_a$:9). Thirdly, a value has been suggested by Viljoen (2009) of VelaVKE. Lastly, a value has been suggested by Collet (2009) of Aurecon. All estimates are brought to 2012 value (the year when capital costs are assumed to be incurred in this study) for comparative purposes and shown in Table 1.

Table 1. Historic and estimated specific capital costs

Source	Year	Specific Capital Cost (R/MW)	2012 Specific Capital Cost (R/MW)
Olivier	2005	R14,285,714	R22,493,286
EU	2003	R13,440,000	R24,092,343
Viljoen	2009	R18,000,000	R21,865,820
Collet	2009	R20,000,000	R24,295,355

Capital cost estimates increase in accuracy depending on the level of development of the project. Typical ranges of accuracy by development phase are given in Figure 11.

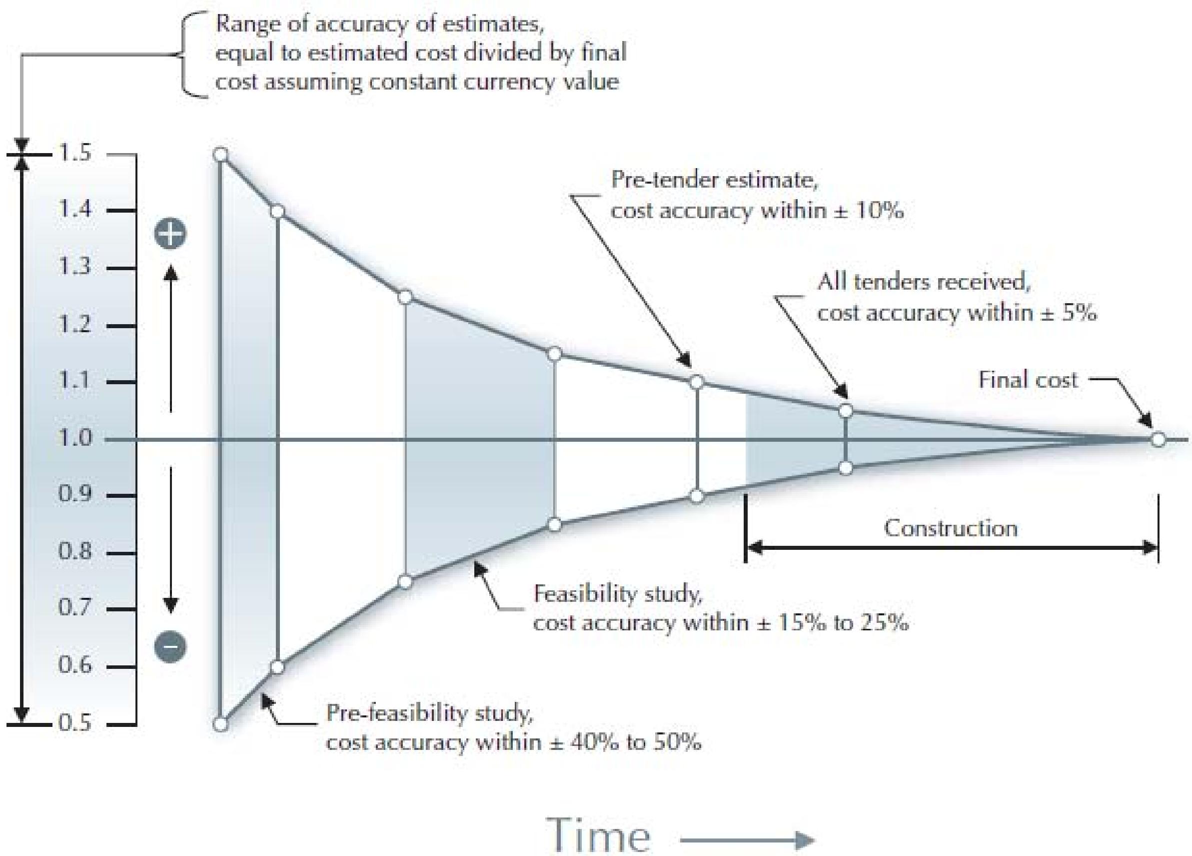

Figure 11. Capital cost estimate accuracy. Source (Clean Energy Support Centre, 2004)

It is therefore reasonable to expect capital cost estimates at the current level of study to be in the range 40% to 50% accuracy.

2.5.3 Periodic Costs

Specific periodic costs are investigated through historic small hydro projects and expert estimates. Olivier estimates O&M costs to be R1 200 000/MW for the 7MW Bethlehem Hydro layout which equates to R171 428/MW. Viljoen (2009) estimates O&M costs to be R500 000/MW. EU estimates are given as a function of energy generated and not installed capacity. These values are shown in Table 2.

Table 2. EU O&M cost estimates. Source ($ESHA_a$:9).

Country	€ cents/kWh		
Spain	0.9		
Austria	0.4		
Sweden	1.4	**ZAR cents/kWh**	**ZAR/kWh**
average	0.9	10.08	0.1008

These values are converted to R/MW value of R626 935/MW through the use of a hypothetical 1MW plant operating at an appropriate capacity factor of 71% (see section 5.3.2). All estimates are brought forward to 2014 values (the year when periodic costs are assumed to first be incurred) and shown in Table 3.

Table 3. Historic and estimated specific O&M costs

Source	Year	Specific O&M Cost (R/MW)	Specific O&M Cost (R/MW) 2014
Olivier	2005	R171,429	R307,300
EU	2003	R626,936	R1,279,474
Viljoen	2009	R500,000	R691,500

2.5.4 Income – Sale of Electricity

The buyer of electricity from an electricity generator is usually referred to in industry as an off-taker. The agreement between the Independent Power Producer (IPP) and the off-taker is spelled out in detail in the Power Purchase Agreement (PPA). It describes the power capacity and quantity of energy to be supplied by the IPP, prices and the price regulation agreement, and penalty clauses that come into effect if the conditions are not fulfilled. The PPA is extremely important for bankability because it is the lenders' primary security that the IPP will be able to pay its debt. Potential off-takers identified include:

- **REPA**. The power purchaser in South Africa is the Renewable Energy Purchasing Agency (REPA), also referred to as the Single Buyer Office (SBO), housed within Eskom. It is possible to negotiate a PPA with the SBO, and it is be possible to sell to the SBO at wholesale tariffs. Wholesale tariffs are sub-economic and it is not expected that a higher tariff will be achieved. (Gcabashe 2010) However, recent announcement of the Renewable Energy Feed-In Tariff (REFIT) has caused great excitement in industry. Feed-In Tariffs (FITs) have been shown internationally to be the most effective policy mechanism for the rapid and widespread implementation of renewable energy technologies. "The basic economic principle underpinning the FITs is the establishment of a tariff (price) that covers the cost of generation plus a "reasonable profit" to induce developers to invest." ($Nersa_a$, 2009:1) One of the objectives is to provide IPP investors with a body which has an obligation to purchase power generated, and guaranteed access to the central grid. ($Nersa_a$, 2009) From an analysis of the official documentation presenting the REFIT, positive conclusions can be drawn. Renewable Energy IPPs have a guaranteed buyer of their power, the tariff is fixed over a period long enough for debt repayments to be completed, and the tariff is not reduced over time as may have been the case. However, doubts remain about the process and timelines for acquiring a REFIT PPA with REPA. The competitive IPP tendering (DME_a, 2009:7) (whereby all private generators, including fossil fuel-based plants have to compete for PPAs on an equal footing) process draft released in January 2009 by the DME, for example, does not complement the REFIT legislation. Some uncertainty therefore remains around securing a PPA under REFIT. See Appendix A: REFIT for more information on the REFIT.
- **Private Buyer**. Flexibility is provided by the REFIT legislation in that renewable energy IPPs can sell to willing buyers outside of the REFIT mechanism. It will be necessary to negotiate a wheeling agreement with Eskom to "transport" the power from generator to end-user.
- **Local Municipality**. It is possible to sell electricity sold directly to an end user. In this case the power sold will be used directly by the end-user and not put back into the transmission grid. Bethlehem Hydro has a PPA with the Dihlabeng Municipality. This demonstrates the viability of pursuit of such an off-take agreement. However, risks are associated with a municipality's balance sheet and reliability, and it is highly doubtful whether financiers would view an

agreement with a municipality as sufficient for bankability, especially in the light of recent news of the failure of municipalities to pay Eskom for electricity for lack of funds (Engineering News, 2010), including the Dihlabeng Municipality.

- **Amatola Green Power**. Amatola is a broker of green power, and sources parties interested in purchasing green power originating from renewable sources. The power broker will sign a PPA with the IPP and sell on the electricity to the end user. Amatola has expressed interest in the Kruisvallei projects (Van Wyk, 2009). It is attractive to sell through a private broker because it eliminates the need to deal with REPA (a subsidiary of Eskom) which may bring delays as well as being a cumbersome bureaucracy. However, Amatola does not have a sufficient balance sheet to ensure bankability.

2.5.5 Income - Sale of Certified Emission Reductions (CERs)

The Kyoto protocol placed requirements on annex 1 (developed) countries to reduce emissions of Green House Gases (GHGs). It is often more cost effective for reductions to be made in developing countries than in already industrialised countries. Hence global emissions reductions are reduced at a lower cost. This system is known as the Clean Development Mechanism (CDM). The owner of a project which reduces emissions can develop a CDM project and sell the Certified Emissions Reductions (CERs). The CDM has been operational since 2006 and has registered more than 1000 projects equivalent to more than 2,7 billion tonnes of $C0_2$ reduction. ($UNFCCC_a$, 2009)

2.5.6 Project Finance

Bode (2009) indicates that financing can be a major challenge to IPPs where the owner does not have sufficient funds for balance sheet or self financing nor sufficient assets to provide security for a bank loan. In addition, the developer may not wish to bear all the project risk involved in the development. In this situation, the owner can try to finance the project by securing loans against the anticipated cash flow of the project, requiring a series of complex contractual arrangements that are expensive to set up. This is referred to as limited recourse financing. The principal difference between balance sheet financing and limited-recourse financing is the way in which the bank loans are secured. In limited-recourse project financing the future cash flows from the project are the lenders' main security.

As the lenders cannot rely on the liquidation value of the project as a means of securing repayment, they will "take security". This involves exercising tight control over most aspects of the project development and may be subject to the following:

- Charge over the physical assets
- Assignment of the project contracts
- Contract undertakings
- Shareholder undertakings
- Insurance
- Bonding

All aspects of the project will be arranged to control the risk for the lenders, who will insist on seeing evidence of the project's economic viability and mitigation of all risks. They will require an independent technical report by a credible consultant and will scrutinize important agreements such as the power purchase agreement, the operating agreement, shareholders' agreement, etc.

The lenders will wish contractors, suppliers and operators that have a strong record of accomplishment in their field, and wherever possible the risk is transferred to third parties. A contractor working on a turnkey fixed-price basis can be used to minimize the implementation risk. A long-term Power Purchase Agreement with a secure off-taker mitigates the market risk. The lenders may also reserve the right to step in and operate the project in the case that it is not paying its debt.

2.5.7 Investment Criteria

Simple Payback

The simple payback is an easily understood metric where an investment is made if the sum of the undiscounted cash flows becomes positive before a selected cut off point. The simple payback is flawed in that it "ignores risk, the time value of money and cash flows beyond the cut off point." (Firer et al 2008: 292)

Yield

Yield is a financial term with various meanings and in this study refers to a criterion used to evaluate an investment after its first year of operation. In this way it mitigates against market uncertainty associated with longer term income projections. ($McIntosh_a$ 2009) Investment is made if the yield is greater than a required first year return.

NPV

The NPV of a potential investment is usually found by subtracting the capital cost from the discounted future cash flows. It "has no serious flaws" and is the "preferred decision rule" (Firer et al 2008: 292)

IRR

The IRR is "the discount rate that makes the estimated NPV of an investment equal to zero" (Firer et al 2008: 292) Investment decisions can be made "when the IRR exceeds the required rate of return" (Firer et al 2008: 292)

Profitability Index

The PI is a cost-benefit ratio evaluation where discounted future cash flows are divided by capital investment. The PI "is sometimes used to rank projects when a firm has more positive NPV investments than it can currently finance." (Firer et al 2008: 292)

3 Site Survey

The key resource inputs from which production can be evaluated are flow and head. These are discussed with respect to Kruisvallei. The section of the Ash River which flows through Kruisvallei is illustrated in blue.

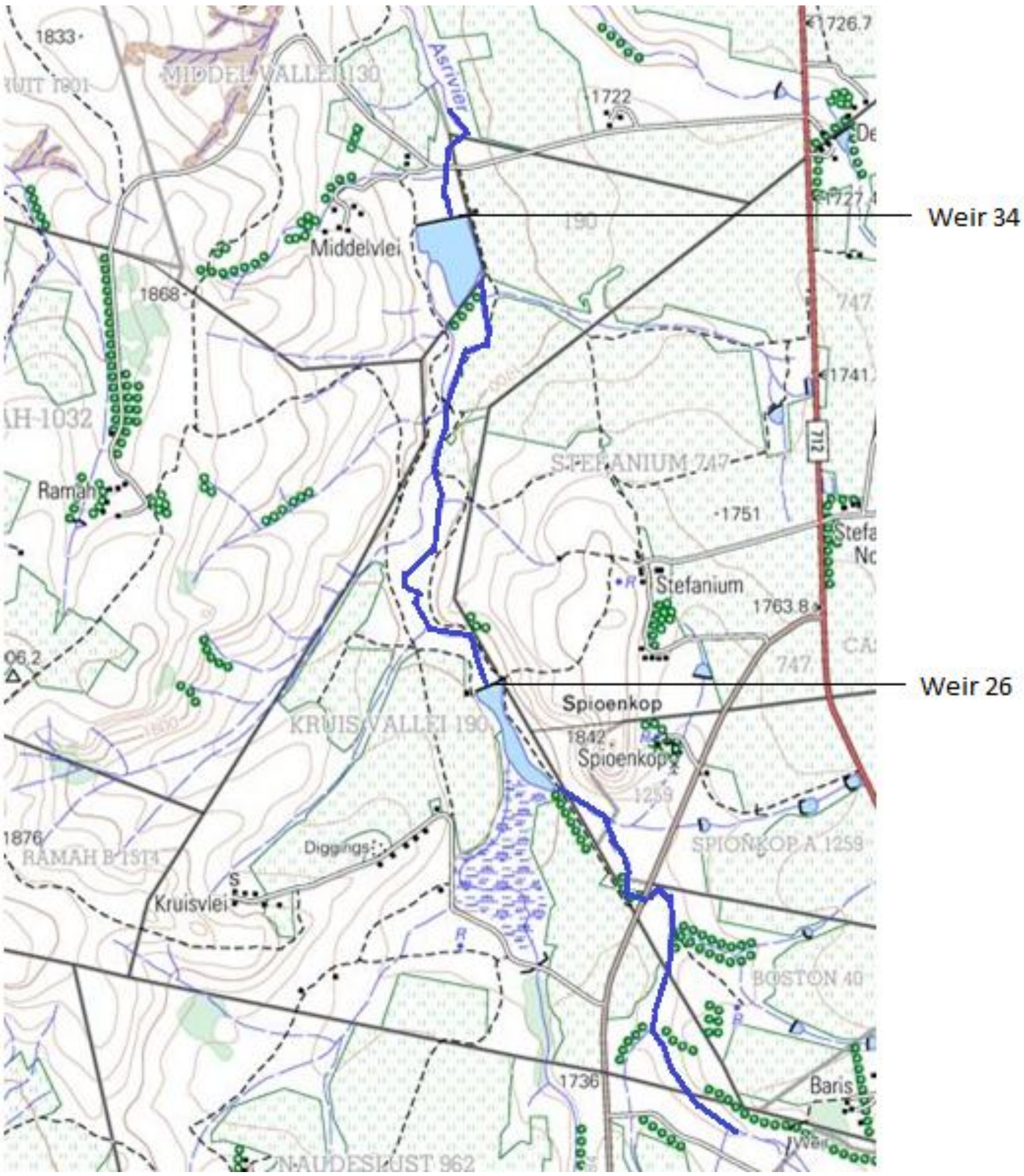

Figure 12. Kruisvallei 190 and Ash River

It is noted that the river leaves the boundaries of Kruisvallei onto the Farms Boston 40, Spionkop and Middel Vallei 130. There are two weirs on the property known as Weir 26 and Weir 34. Weir 26 in particular is significant in this study and is shown in Figure 13.

Figure 13. Weir 26

Weir 34 is shown in Figure 14.

Figure 14. Weir 34

3.1 Head

Levels in this study are taken from data provided by TCTA which is in the form of CAD drawings with topographical detail which were made in 2003. These levels give detail of the elevation of the land as well as structures such as roads and weirs. The varying level of the water is not given, and the satellite photographs were taken when the flow was zero. Although imperfect, this information is the best available. The level of a pertinent region of the river has been surveyed to be at a level of 1699m. (Olivier, 2009) Using the topographic maps used in this study this same level for this region is arrived at, providing evidence of the validity of the methodology. It is expected that levels accurate to within ±2m (Mr Viljoen has recorded erosion changes to this maximum extent in isolated regions) but in order to reach full feasibility a surveyor will need to be engaged to take accurate levels. In general, a 2m error is expected to be an outlier, and all estimates are verified using visual inspection at site including the use of a GPS device, and consultation with Mr Viljoen.

The drop in elevation of the river is shown in Figure 15.

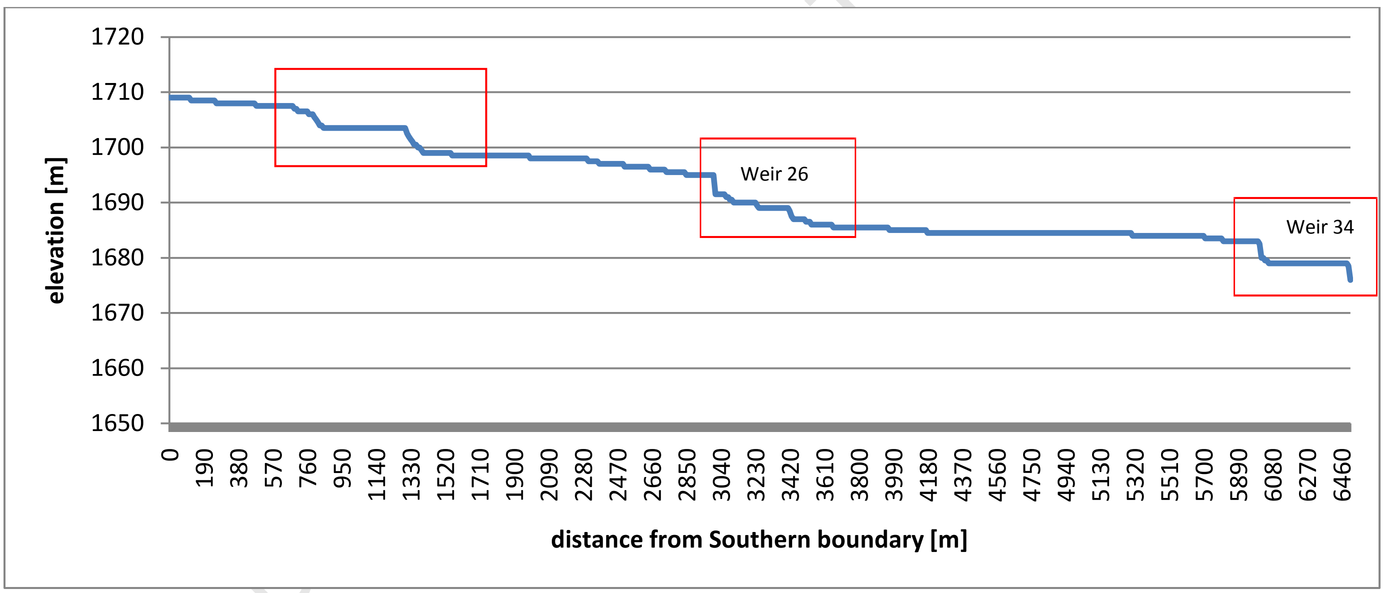

Figure 15. River elevation

The river enters the farm at a level of 1709m and exits at 1676m, giving a total of 33m drop. There are three sections on the property where the river drops significantly. Firstly, in the upper region there are two significant rapids, secondly in the middle of the farm directly below Weir 26, and lastly, directly below Weir 34.

3.2 Flow

The flow data used in the assessment has been taken from the data provided by Mr Chris Viljoen of VelaVKE, who are contracted by TCTA to oversee a portion of the river including that which traverses Kruisvallei 190. Flow information has been provided by VelaVKE and is based on flow measurements taken on 0.1 hour intervals averaged to an hourly value for the full year of 2007. Flow data for 2008 is also available but is not considered reliable.

Using data acquired over a period of a single year may be less accurate than desired and data averaged over a number years would yield more accurate results. However, because the flow is a water transfer scheme and is regulated this is not necessary. A useful check on the flow values is provided by the fact that a total of 785 million m^3 is purchased from Lesotho by DWAF every year (Viljoen, 2009), resulting in an average flow of 24,89m^3/s.

3.2.1 Flow Duration curve

For run of river (ROR) plants, a flow duration curve (FDC) specifies all the necessary flow information to calculate annual energy generation potential. An FDC shows graphically the proportion of time a flow is exceeded. The flow-duration curve is specified by twenty-one values *Q*0, *Q*5, … *Q*100 representing the flow on the flow-duration curve in 5% increments. In other words, *Qn* represents the flow that is equalled or exceeded *n*% of the time.

Figure 16 shows the monthly FDC for the ash river on Kruisvallei measured a small distance upstream of Kruisvallei 190, at the Botterkloof wall. (Viljoen, 2009)

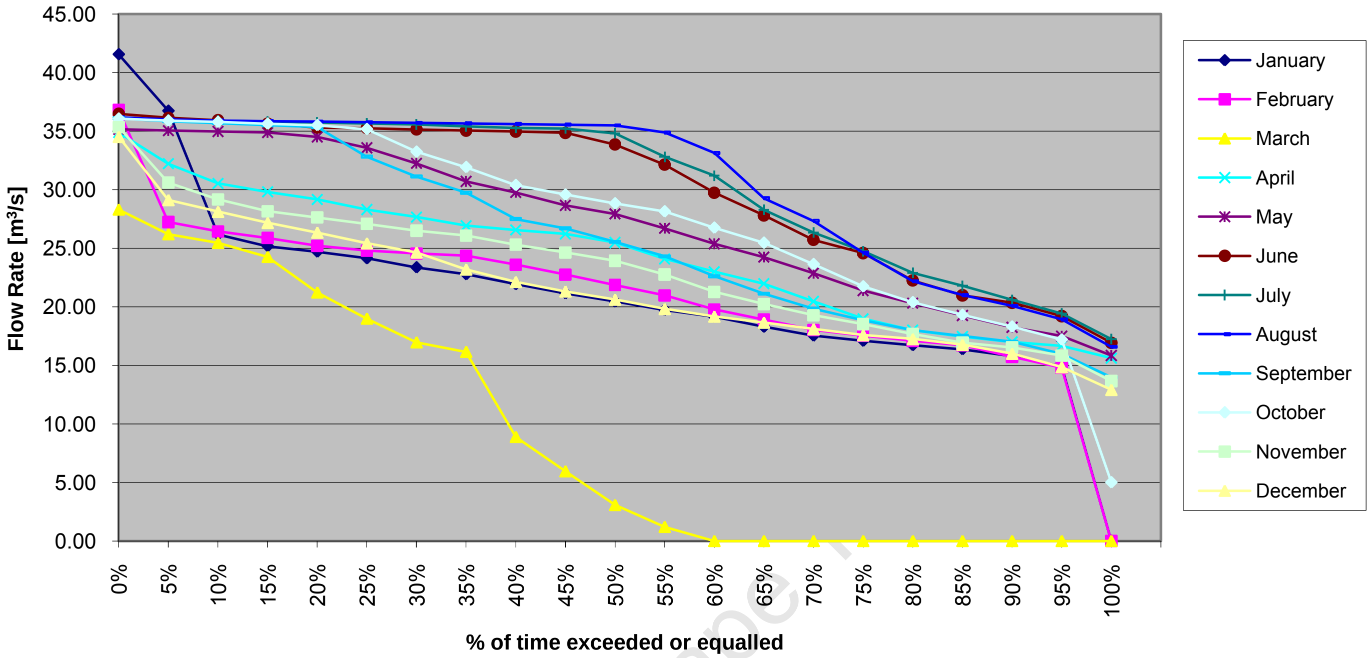

Figure 16. Monthly FDC

The monthly FDCs can be averaged to yield an annual FDC. Often, a certain flow must be left in the river throughout the year for environmental reasons. This *residual flow* must be subtracted from all values of the flow-duration curve for the calculation. The residual flow for the Ash river is conservatively assumed to be $0.25 m^3/s$. (McIntosh$_b$, 2009)

Subtracting the residual flow yields the annual FDC shown in Figure 17.

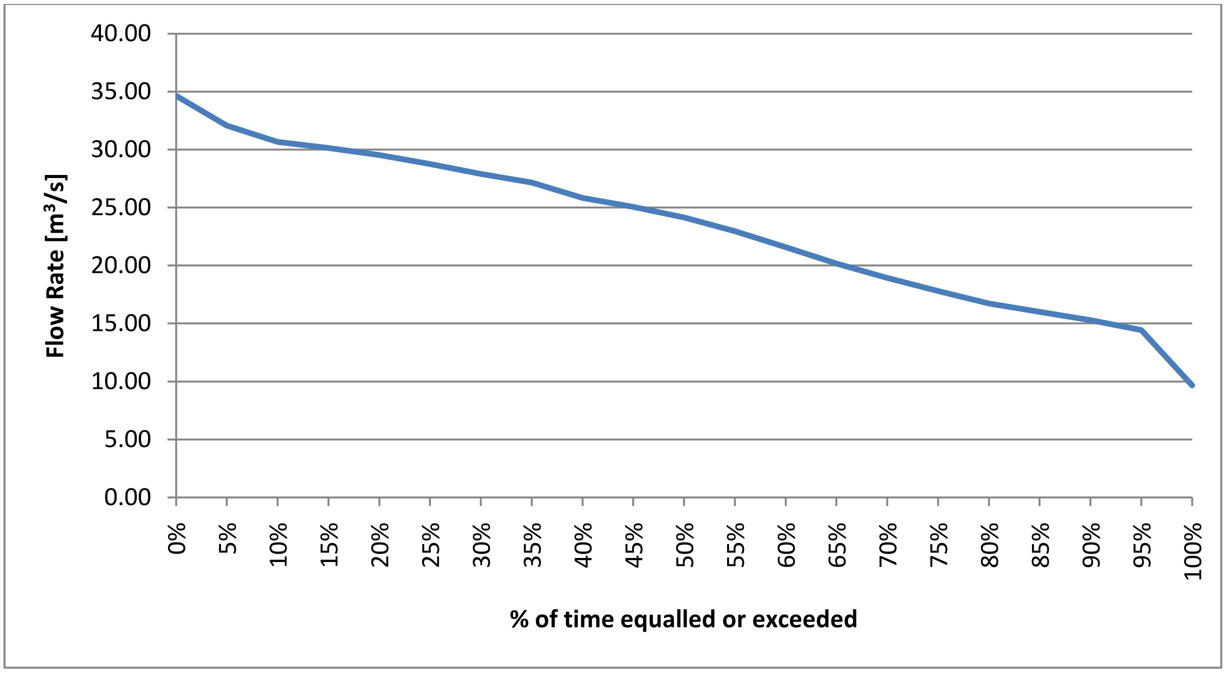

Figure 17. Annual FDC

3.2.2 Increasing Flow

Flow is due to increase over the period 2018 to 2048. According to Mr Viljoen, "the present flow is the maximum assured flow in the system – short term peaks are possible, i.e. the flow will vary between 12 m^3/s and 37m^3/s with 25 m^3/s being the average until 2018/2019. Then additional flow will be available that will slowly grow by 16m^3/s to a total of 42 m^3/s by 2048." (Viljoen, 2009) After the completion of Phase 2 of the Lesotho Highlands Water Project (LHWP) is complete in 2018, the average flow is expected to increase linearly until 2048, when a constant flow of 42m^3/s will be transferred. (Viljoen, 2009) This projection is shown in Figure 18.

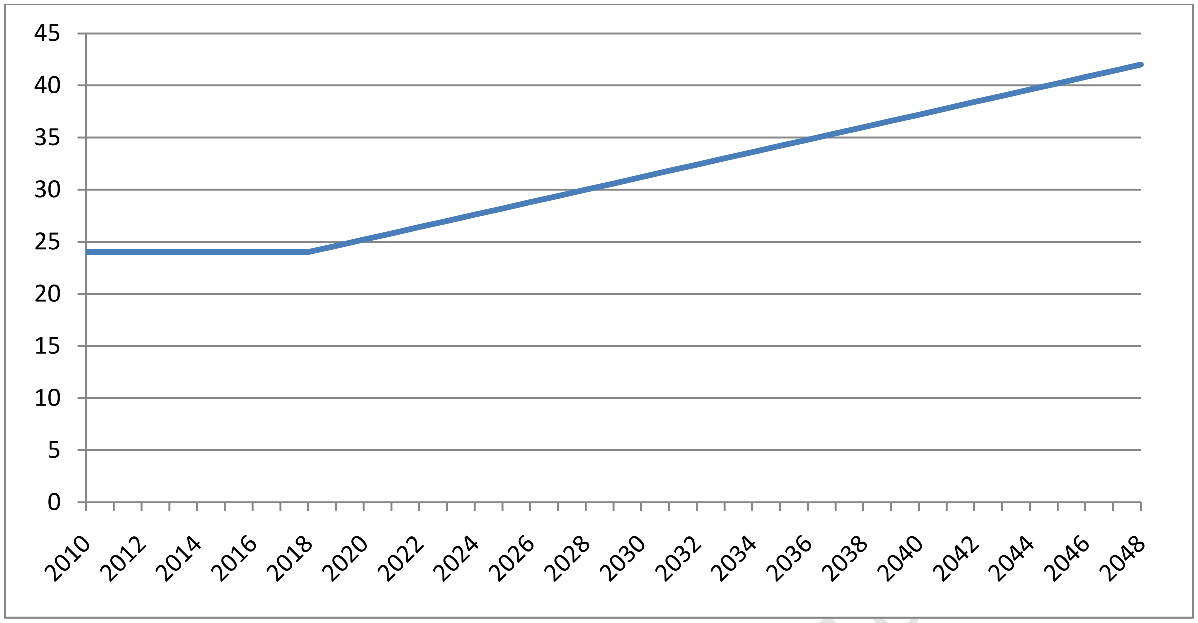

Figure 18. Projected average flow Increase

The FDC from 2007 in Figure 17 is clearly not applicable to the future years of increased flow. It is essential that the increase be taken into account as it has powerful consequences for the evaluation of hydroelectric power generation potential at the Kruisvallei sites. Therefore it is necessary to approximate FDCs for each year considered in this study to account for the increasing flow. To do this, it is convenient to use a linear curve. Figure 19 shows a linear approximation overlaid onto the actual FDC for 2007.

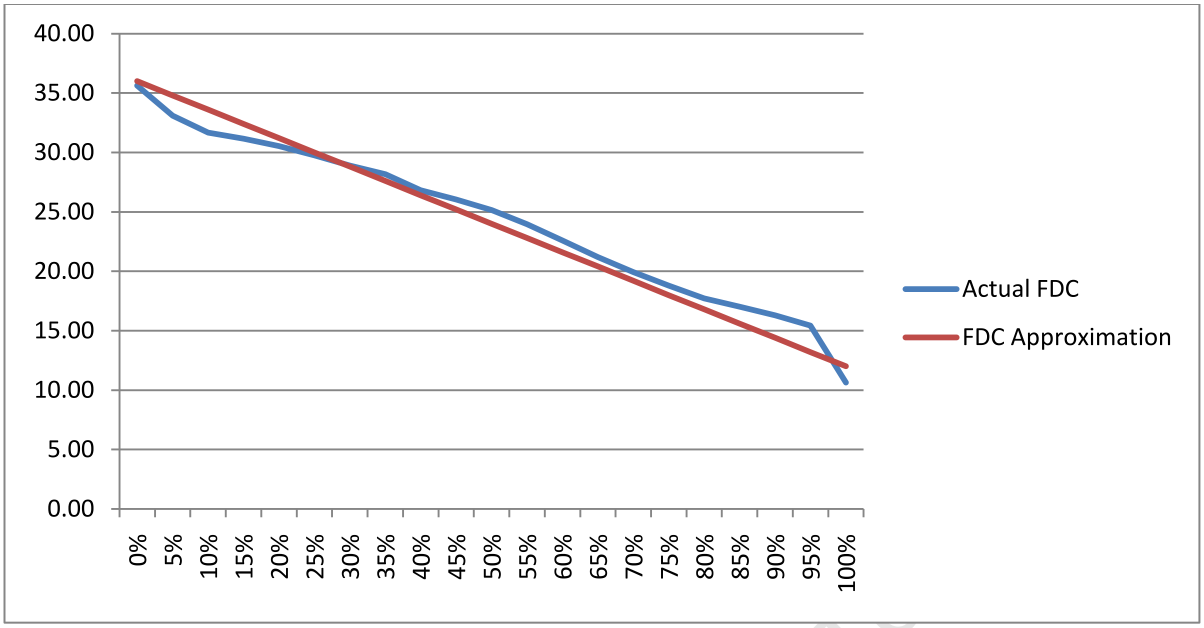

Figure 19. FDC approximation

An exercise was carried out to compare the generation of electricity using the actual flow of 2007 with the linear approximation, and the resulting electricity generation differed by a fraction of a percentage, evidencing the validity of the linear FDC approximations. This is because of the flat efficiency curves of the turbines considered in this study.

In later years the minimum flows will increase significantly, resulting in flatter FDCs of more consistent flow. This is illustrated in Figure 20, where selected FDC approximations for future years are shown.

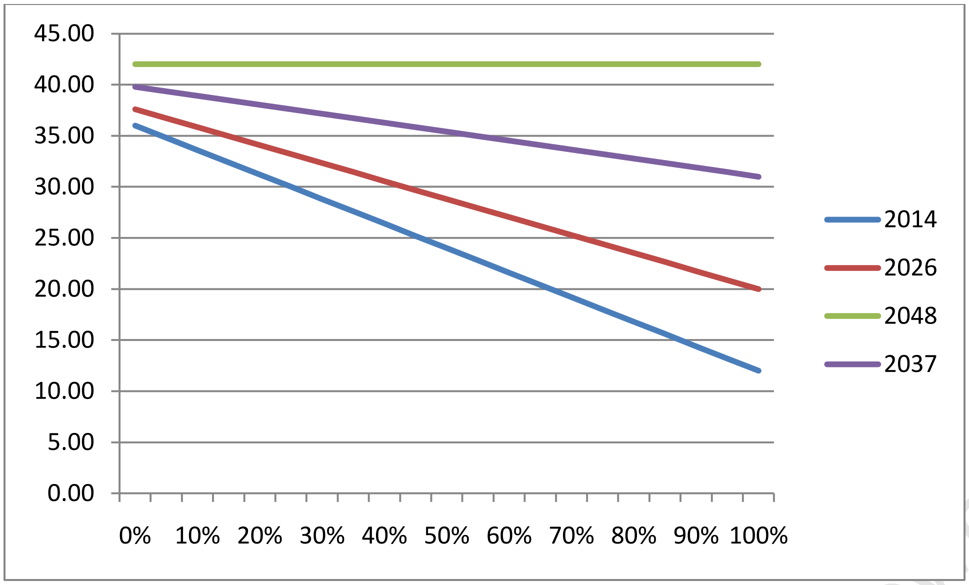

Figure 20. Selected FDCs

Although the actual FDCs in future years will probably differ in form from the approximations used in this study, the water volume passing through the system annually is accurate. Hence the linear FDCs are valid approximations for flows during the period over which the project is analyzed.

4 Preliminary Plant Layout Design

4.1 Introduction

The flow of water through the plants is a given, but the head is determined by the design of layouts. The primary purpose of the layout design is to determine the head so that power production can be estimated, and secondly to provide a basis for cost estimates.

In a ROR system, water is diverted from a section of river through the use of a weir and transported (near) horizontally by canal (or other conduit) in parallel with a dropping section of river. Water is dropped onto a turbine which converts the hydraulic energy to mechanical energy. Water is returned to the river via a tailrace. Head can be increased through the construction of a weir or dam wall onto which the powerhouse can be directly placed, precluding the need for a conduit. Most of the layouts considered in this study are weir-canal-powerhouse systems, although one is a weir-powerhouse system. A generic layout is shown in Figure 21.

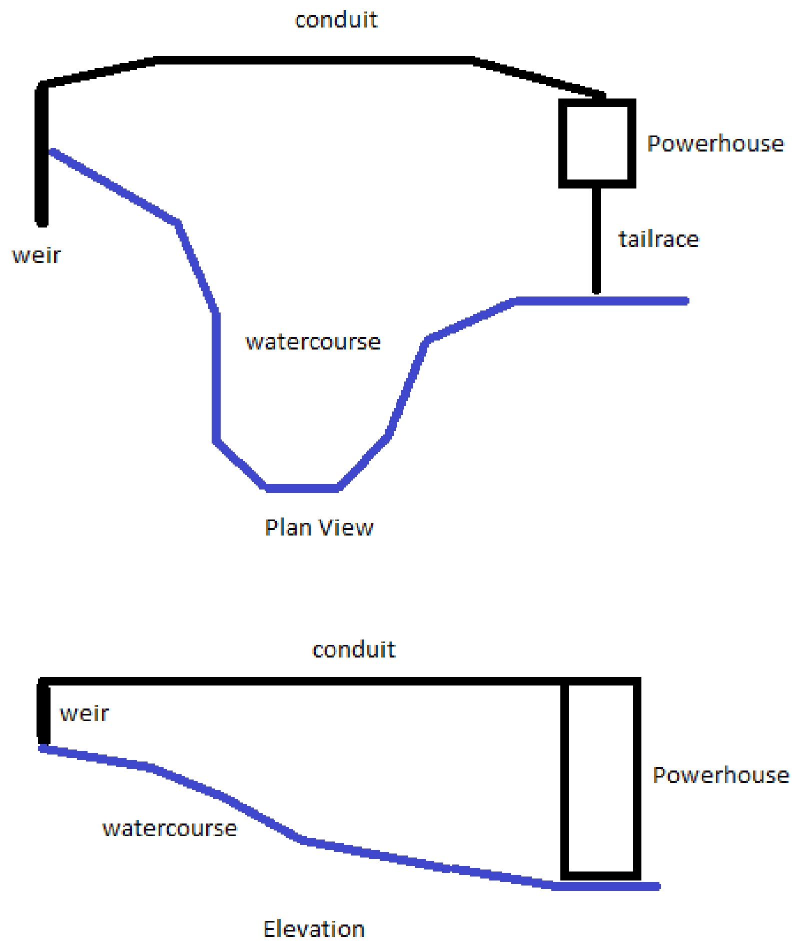

Figure 21. Generic Plant Layout

The layouts considered here are simplistic in some respects, but greater level of detail is not possible without significant civil engineering expertise. The methodology is however supported by the Clean Energy Support Centre (2004): "the main civil works of a small hydro development are the diversion dam or weir, the water passages and the powerhouse." In conjunction with flow information, it is possible to estimate power production reasonably accurately, and in consultation with Mr Viljoen, layout capital costs can be quantified.

4.1.1 Methodology

The key aspects of the layouts considered are the off-take and the re-entry point. Intuitively, one would locate the off-take point shortly before a region of steep gradient and the re-entry point after it.

The off-take system has the potential to increase the head if the upper level can be increased by building a weir higher than the water level or raising an existing weir.

Each layout is described in terms of the section of river which it spans, and the nature of the off-take system. The re-entry system for all scenarios is assumed to be a straightforward rejoining of the river at the altitude of the river at re-entry point. There is a possibility of increasing head further by lowering the level of the re-entry point. This is not taken into account at this stage as it is not likely that it will be possible nor permissible to do this. Canals linking off-take and power plants are drawn following the contour of the altitude of the off-take. Canal lengths are determined by inspection of the topographic maps.

The layouts described below are those considered to be most likely candidates for construction as of September 2009. The process of selecting these scenarios was iterative, however. Descriptions of other layouts which have been evaluated and discarded are included in Appendix C: Discarded Layouts.

4.2 Upper Kruisvallei (UK)

4.2.1 Description

A layout for the upper (southern-most) drop on Kruisvallei is considered. The layout proposed here involves the construction of a weir, a canal on the western bank and a powerplant. The river level profile from the southern boundary of Kruisvallei is shown in Figure 22, with the red line being the region where the river is on the farm Boston.

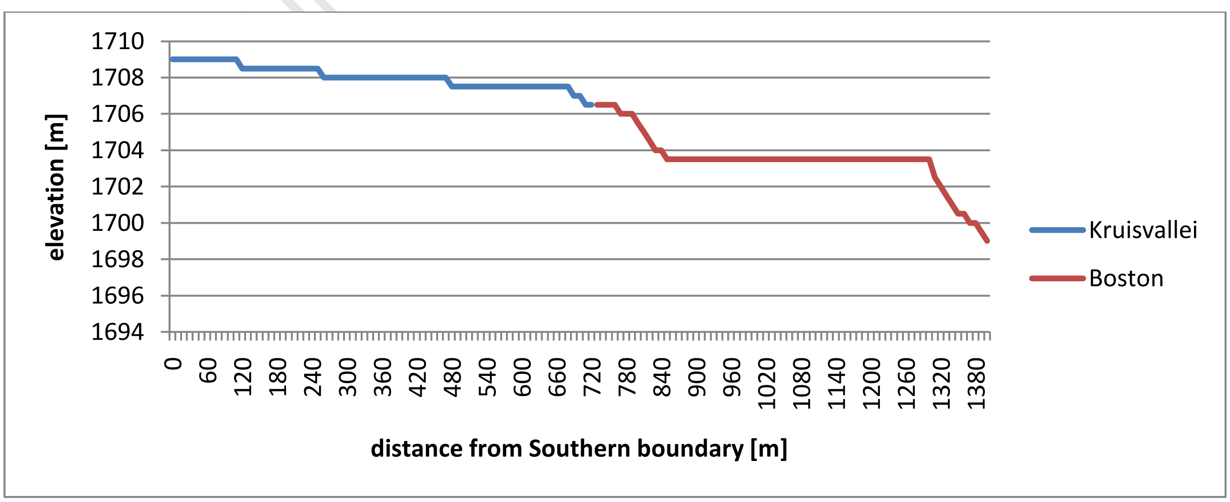

Figure 22. Scenario Upper Kruisvallei Head Profile

The proposed layout is shown in Figure 23.

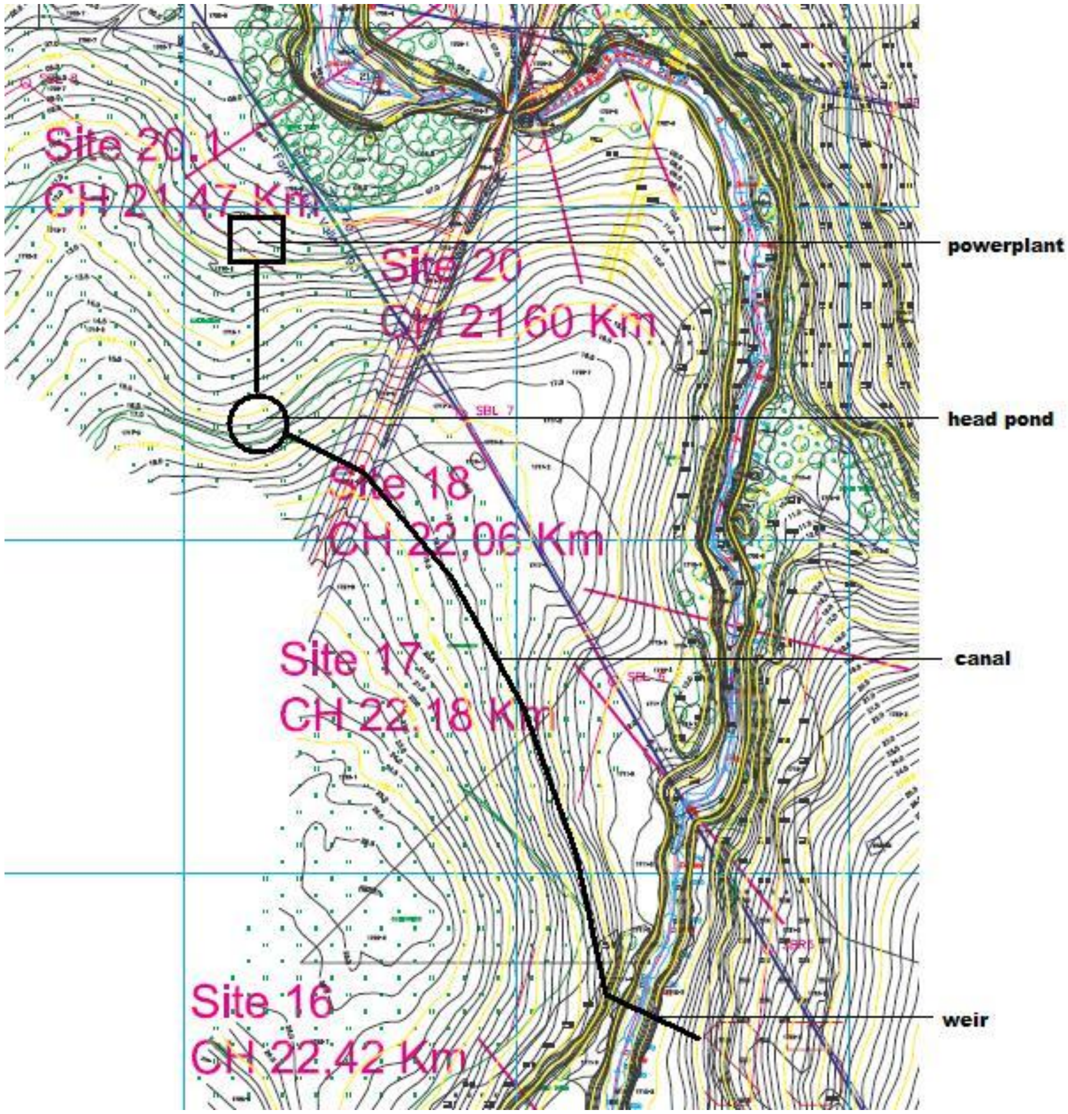

Figure 23. Upper Kruisvallei Schematic

4.2.2 Discussion

Off-take

- The main decision point for this layout is the location and height of the weir. A weir is a necessity, and it would therefore make sense to construct it reasonably far downstream to reduce canal length, and build it high to increase head. A weir height of 7,5m is chosen because of the convenient placement of the canal at that contour and the satisfactory flooded region.

- All construction is on Kruisvallei. The weir drawn has a height of 7,5m above water level. It may be feasible to build a higher weir/damn wall, up to a level of perhaps even 1725m, increasing head further.
- The location of the weir is chosen because of the narrow neck in the valley at that particular point which may be a least cost location because of a material requirements reduction.
- The potential of the dam created by the weir in this layout is discussed separately below.

Canal

- The canal is on the left hand bank and is just 320 metres long, and it passes through (from a visual inspection and analysis of topographic map) straightforward terrain.
- The canal will need to pass the road. This will probably mean the construction of a bridge over it, and some arrangement for vehicles to pass during construction.

Re-entry

- The powerplant and re-entry point are set back from the river. This means that the powerplant will be on Kruisvallei. Secondly it ensures that the construction site will be protected from the river by a wide section of flood plain.
- The tailrace will involve construction on Spionkop.

Environment

- The main environmental concern is the region flooded by the high weir. This is shown in Figure 24. If this results in EIA failure, the weir can be lowered. This will of course reduce head and therefore generating capacity.

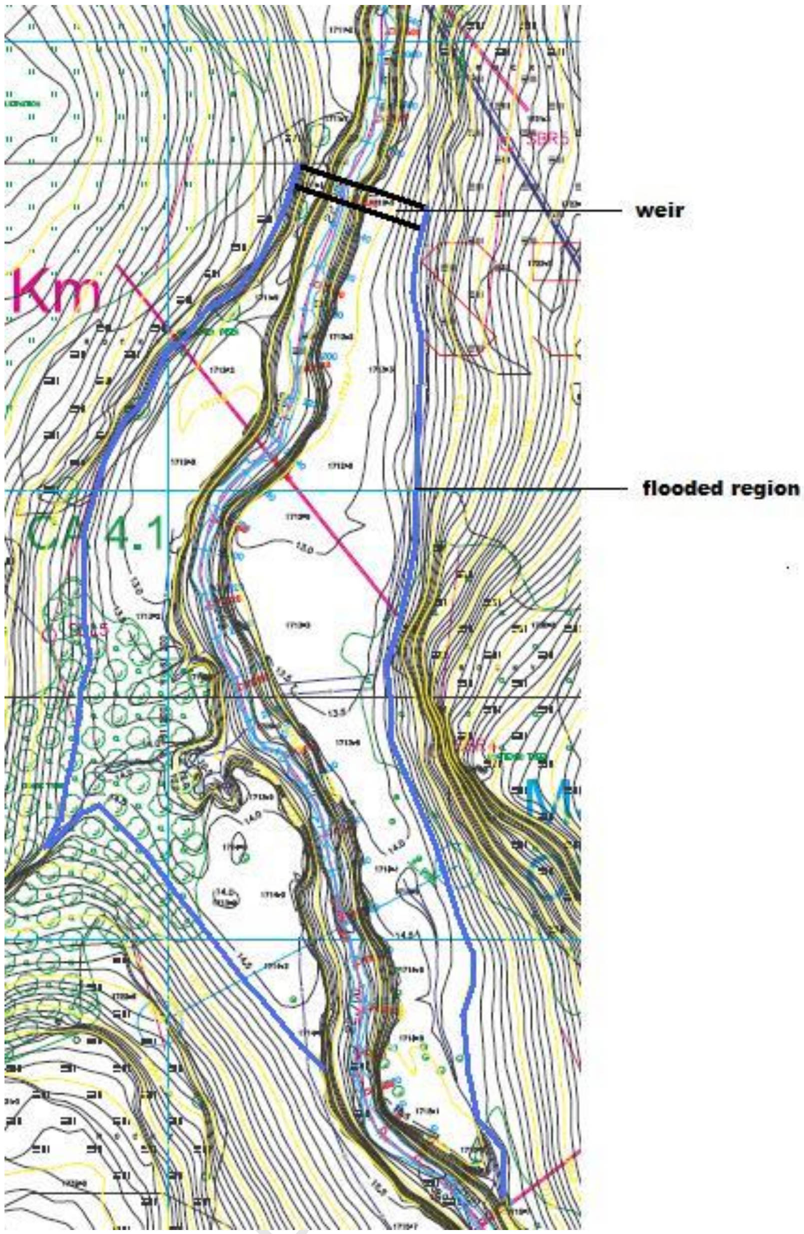

Figure 24. Upper Kruisvallei Flooded region

4.3 Middle Kruisvallei (MK)

4.3.1 Description

The natural starting point for designing layouts for the central region is weir 26 as it precedes the region of greatest drop, and costs are significantly reduced because of the existing weir structure. The MK layout makes use of the drop immediately below weir 26. Figure 25 shows the head profile of the river in the region spanned by this layout which has an average gradient of 1,54%.

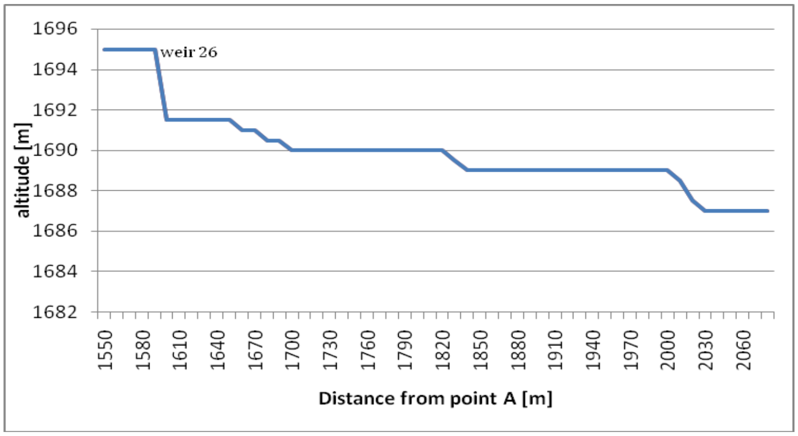

Figure 25. MK Head Profile

Figure 26 shows a schematic of MK.

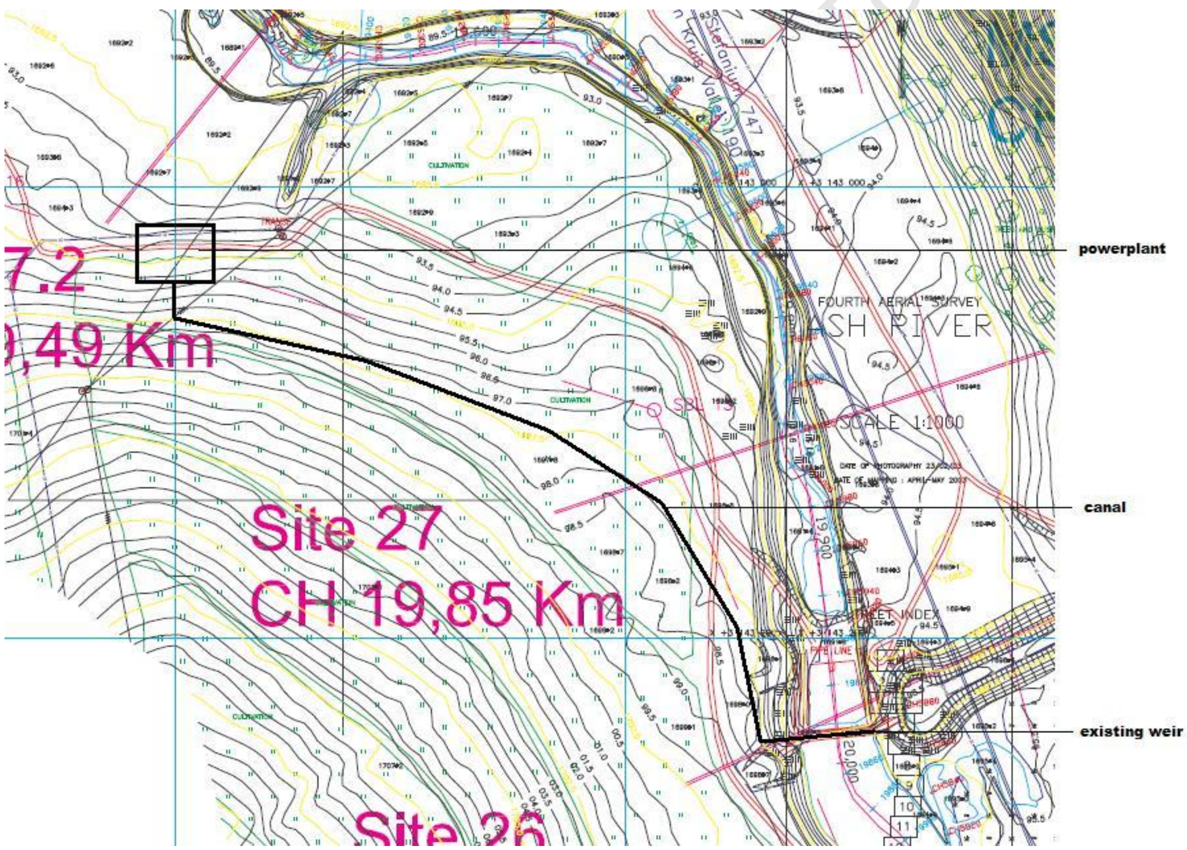

Figure 26. MK Schematic

4.3.2 Raising weir 26

The possibility of raising the height weir 26 holds potential to increase capacity significantly. Mr Viljoen mentioned that weir 26 is designed to be raised by one metre. The possibility of raising it two to three metres needs further study as this will involve added complexity and cost. The first criterion for this possibility is passing an EIA. If a weir is raised, it floods a greater area upstream. The regions flooded by raising weir 26 by one, two and three metres are shown in Figure 27.

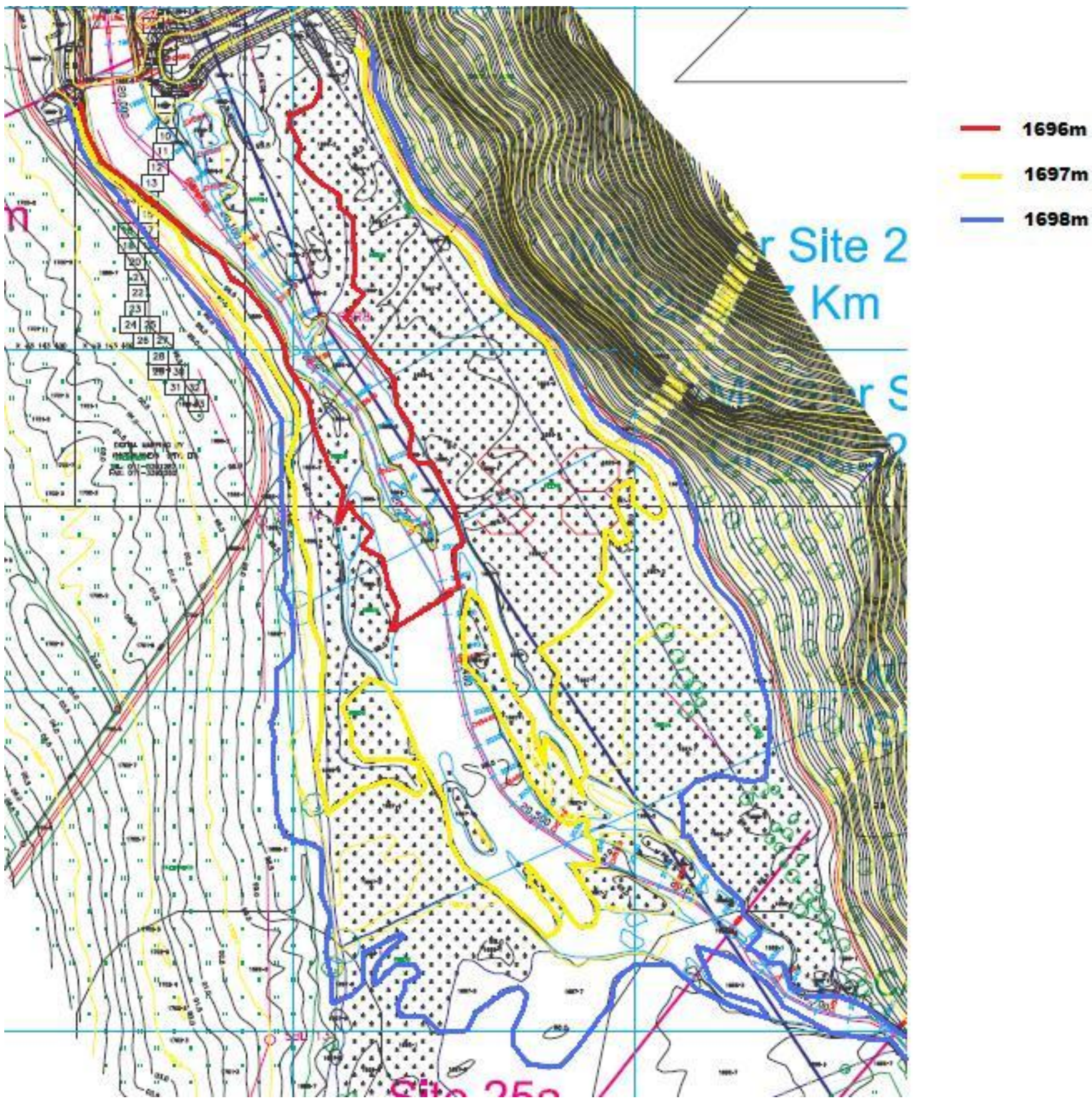

Figure 27. Raising weir 26

4.3.3 Discussion

Off-take

- The off-take is on the western bank adjacent to weir 26. Minimal new construction will be required.

Canal

- MK has a canal of 270m over (from a visual inspection) very simple terrain.
- All construction and will take place on the Kruisvallei farm eliminating the need to include other farms in negotiations.

Re-entry

- The powerhouse will best be located before the flood plain on the slope of the hill as founding rock is more readily available here (Viljoen, 2009), and this leaves a significant region of flood plain which can be used to protect the construction of the powerplant. However, this would include deep-shaft excavation directly down into the hill where the water will flow onto a turbine with a long shaft reaching the generator above (Viljoen, 2009). The tailrace can be piped or preferably canalled, allowing the water to enter the river again. During floods the tailrace can be overtopped.
- There is a stream that will collect water during the rainy season and the civil works should avoid this.

Environment

- No significant EIA problems anticipated.
- Because the system is compact, it naturally has a small visual impact, and because it's on the western bank, it will be obscured from the view from the Kruisvallei farmhouse.

4.4 Lower Kruisvallei (LK)

4.4.1 Description

The LK layout involves the construction of a wall just above the "pot" on the Northern-most corner of Kruisvallei. A powerplant is constructed on the wall, and no canal is required. A schematic of the LK layout is shown in Figure 28.

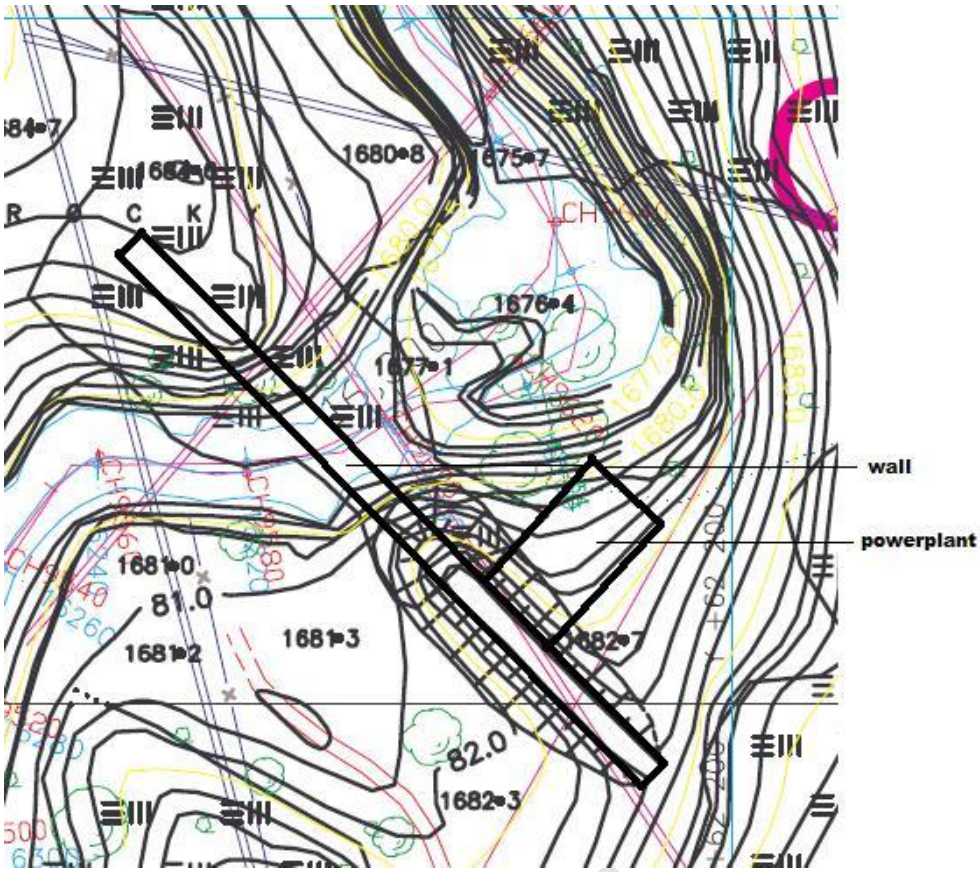

Figure 28. Lower Kruisvallei schematic

4.4.2 Discussion

Height of the Wall

The limiting factors affecting the height of the wall are:

- Region flooded. The owner of the farm Middel Vallei 130 (on the western bank) will need to be consulted as a portion of their land will be flooded which is currently used for grazing.
- Altitude of the road over the river (approximately 1682.5m). This means at a water level of 1682 there may be difficulty concerning the road.
- Increasing the water level above that caused by weir 34 (1682m)

The level chosen for the analysis is 1682m, which yields the flooded regions shown in Figure 29.

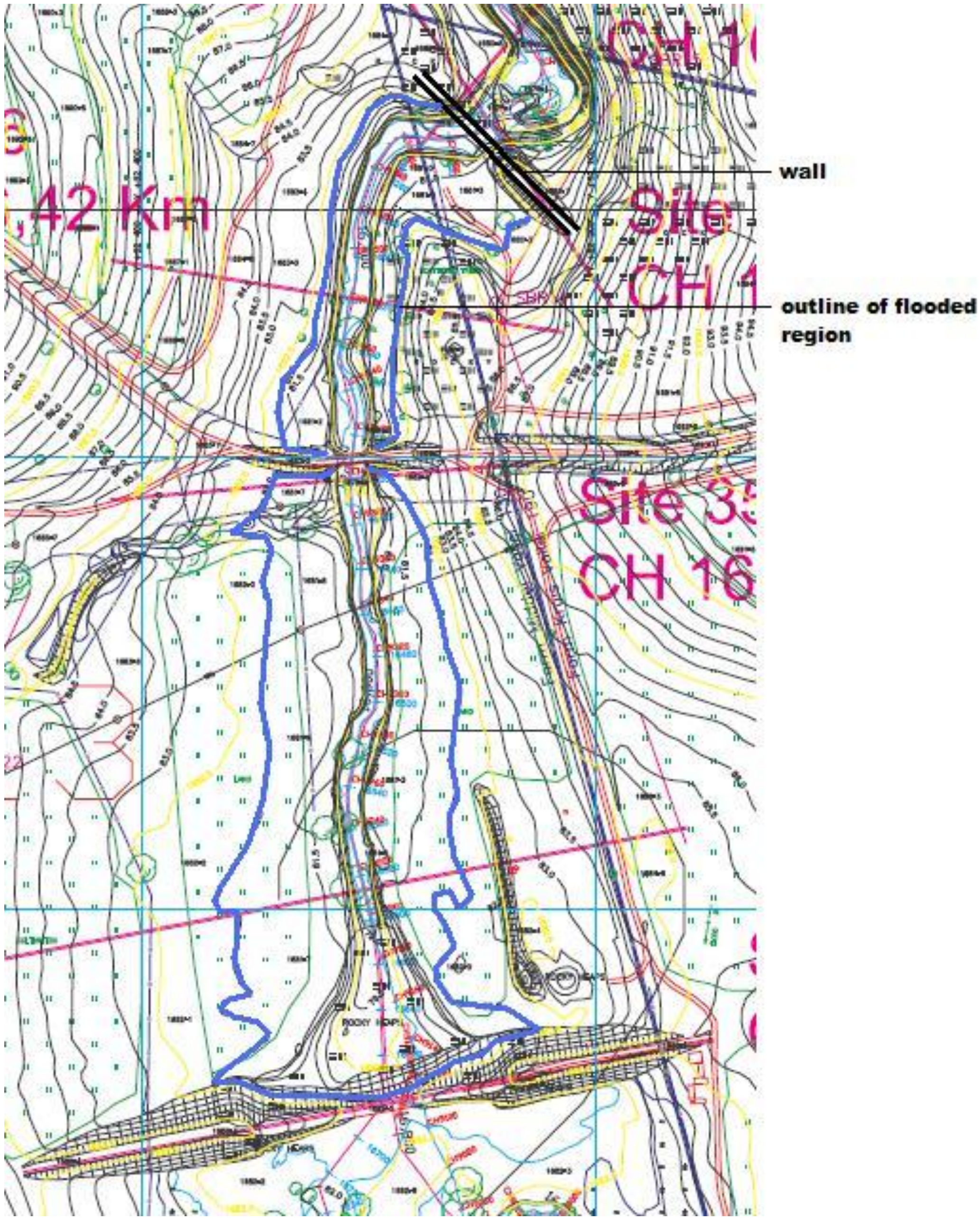

Figure 29. Lower Kruisvallei flooded region

Environment

The main environmental concern of this scheme is the region flooded through the construction of the wall. This is limited by the existence of weir 34, making the environmental impact very small.

4.5 Gross head

For layouts that incorporate a canal, the gross head is the drop in elevation as measured from the lower end of the canal to the tailrace. Hence the gross head does not include any drop in elevation along the length of the canal. The drop in elevation over the length of the canal can be approximated assuming that the canal drops approximately 1 m every 1,000 m (i.e. has a 0.001 slope). This is based on canal calculations performed based on ($ESHA_a$, 2004).

Key head statistics for the proposed layouts are given in Table 4.

Table 4. Layout Summary

Scenario	upper level [m]	lower level [m]	Total Head [m]	Canal Length [m]	Gross Head [m]
UK	1715	1699	16	320	15.68
MK	1695	1688	7	270	6.73
LK	1682.5	1676	6.5	0	6.5

5 Technical Analysis

A technical model is used to translate resource and layout outputs into production. The RETScreen software can be used to analyze the Kruisvallei sites. However, it was decided that a custom model would be constructed so that the financial analysis could be customized and to gain a greater understanding of the system under consideration. The RETScreen technical methodology was used as the basis for the technical model constructed for the analysis. The information flow of the model is shown in Figure 30.

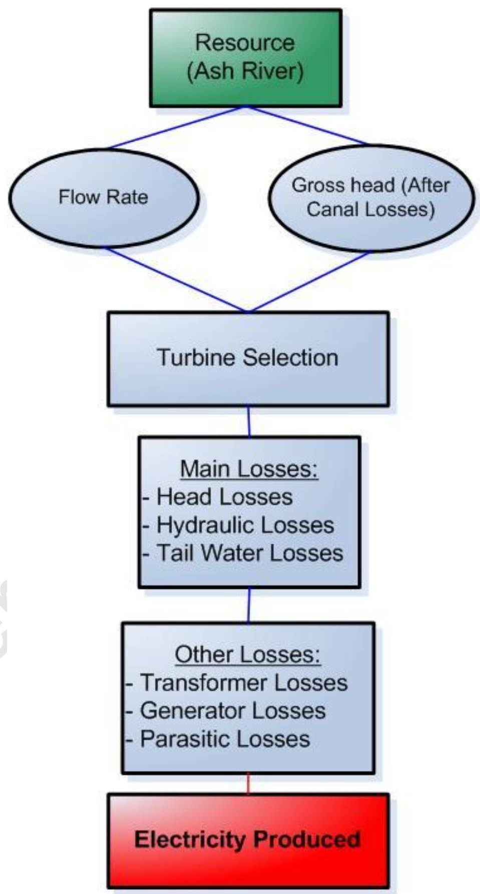

Figure 30. Technical Model Flow

Each component of the technical model is described below. All calculations are provided in the RETScreen electronic textbook.

5.1 Rated and Net Head

5.1.1 Rated Head

Rated head is the gross head less the hydraulic losses. In a small hydro system, energy is lost as water flows through the water passages. A maximum value of 5% is appropriate for most small hydro plants. For plants with very short water passages, a value of 2% is appropriate. For low-head small hydro plants with long water passages, the factor can be increased to 7%. Maximum hydraulic losses are assumed to be 5% of the gross head. These values are shown in Table 5.

Table 5. Gross and rated head

	UK	MK	LK
Gross head [m]	15.68	6.73	6.50
Max Hydraulic losses [%]	5%	5%	5%
Max Hydraulic losses [m]	0.78	0.34	0.33
Rated head [m]	14.90	6.39	6.18

5.1.2 Tailwater Effects

At most sites, during high flows, the tailwater level rises more than the headwater level, causing a reduction in the gross head. Consequently, despite the increased flow during these periods, less power and energy are available. Tailwater effect can be significant, especially for low-head sites. This value is only applied to river flows that are greater than the plant design flow. To calculate this value the following formula is used:

$$h_{tail} = h_{tail,\max} \frac{(Q - Q_{des})^2}{(Q_{\max} - Q_{des})^2}$$

where

h_{tail} = tailwater head loss

$h_{tail,max}$ = the maximum tailwater effect, conservatively assumed to be 0,5m (Viljoen 2009).

Q_{max} = the maximum river flow

Q = current river flow

Q_{des} = Turbine Design Flow

5.1.3 Net Head

The net head is the head available less the hydraulic losses and tailwater effects. The net head is therefore a function of flow.

5.2 Turbine Design

The purpose of a hydraulic turbine is to transform the water's potential energy to mechanical rotational energy. It is commonly reiterated in the literature that no advice is comparable to that provided by the manufacturer and that every developer should refer to the manufacturer as early as possible in the development of a hydroelectric project. It is, however, appropriate at this level of study to determine the main dimensions of the selected turbine.

5.2.1 Turbine Type

The Kruisvallei sites are clearly of the low-head, high-flow variety, hence a reaction turbine is appropriate, as opposed to an impulse turbine. From Figure 10 it can clearly be seen that axial turbines are appropriate for the head and flow conditions present on MK and LK. Additional head at UK indicates it may be possible to use a Francis turbine. However, an axial turbine is the more likely candidate here as well. Hence axial turbines are selected for all three sites.

There are two types of axial turbine: propeller and Kaplan, which can be either single or double regulated to increase flexibility and generate across a wider range of head and flow conditions. The flow variation present warrants at least a single regulated Kaplan. The Bethlehem Hydro turbines are both double regulated Kaplans (Olivier, 2009), and hence this selection is made here as well.

5.2.2 Design Flow

It is necessary to select a turbine design flow as flows in excess of the turbine design flow are discarded through the overflow system (ie wasted). For sites on the LHWP system, this decision is more complex than is probably usually the case because of the projected increasing flow due to the completion of phase two of the LHWP in 2018. A large turbine would be capable of capturing the energy available in the future but would operate sub-optimally during the early stages prior to increased flow and would of course require greater capital. A turbine sized for current flow would yield quicker returns as flow increases more water would be wasted or alternatively, additional works would need to be carried out to capture additional flow. The selection is dependent on the off-take agreement eventually signed because a higher tariff would warrant a higher cost turbine which captures more available energy even at extreme high and low flows. A final decision on design flow would occur later on in the project development cycle.

The selection of the design flow depends, primarily, on the available flow (hydrology) at the site. For grid-connected run-of-river projects the optimum design flow is usually close to the flow that is equalled or exceeded about 30% of the time. (ESHA, 2004) In this case, this would result in a design flow selection of 29m^3/s. For isolated-grid and off-grid applications, the flow required to meet the peak load may be the deciding factor for selecting the design flow, provided that this flow is available.

It is currently desired that a REFIT tariff be signed, although there is no guarantee of this. At REFIT tariff, design flow is plotted against NPV in Figure 31.

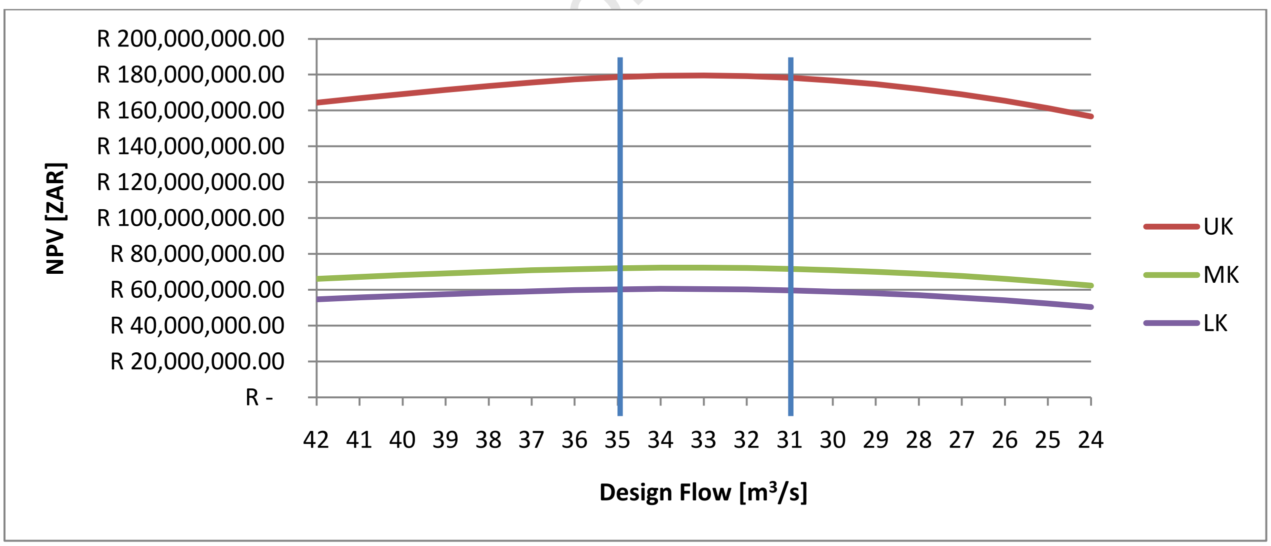

Figure 31. Design Flow - NPV relationship

From this it can be seen that the NPV maximizes at a design flow between 31 m^3/s and 35m^3/s. It can also be see that the NPV drops off more sharply if the selected design flow is smaller than the optimal level than if it is larger. Hence a design flow of $34m^3/s$ is selected for all three turbines for the present analysis.

5.2.3 Turbine Diameter

Turbine manufacturers require certain constants in order to correctly size the runner or diameter of the turbine. The Kaplan turbine runner diameter is a function of the chosen design flow so for each of the layouts considered in this study yielding differing heads the turbine dimensions will be the same because the flow is the same.

Axial turbine diameter is calculated using the formula:

$$d = kQ_{des}^{0.473}$$

Where

d = runner throat diameter in m

k = 0.46 for d<1.8

k = 0.41 for d>1.8

The k value is not immediately apparent but after a few iterations it is clear that a value of 0.41 is to be used.

$Q_{des} = 34m^3/s$

This results in a turbine runner diameter of 2.17m.

5.2.4 Specific Speed

Specific speed is calculated using the formula:

$$n_q = kh^{-0.5}$$

Where

n_q = specific speed based on flow

k = 800 for propeller and Kaplan turbines

k = 600 for Francis turbines

Hence a k value of 800 is used.

h = rated head on turbine in m (gross head less max hydraulic losses)

This results in the dimensionless specific speeds shown in Table 6.

Table 6. Specific speeds

	UK	MK	LK
Specific Speed [nq]	207.28	316.39	321.94

5.2.5 Turbine Peak Efficiency

Efficiency of the turbine is a function of a peak efficiency value for the turbine. The peak efficiency is assumed to occur at a flow according to:

$$Q_p = 0.75 \times Q_d$$

This peak efficiency is adjusted according to two values, e_{nq} (specific speed adjustment to peak efficiency) and e_d (runner size adjustment to specific speed).

e_{nq} is calculated using:

$$e_{nq} = \{(n_q - 170)/700\}^2$$

where

n_q = specific speed

e_d is calculated using:

$$e_d = (0.095 + e_{nq})(1 - 0.789d^{-0.2})$$

where

d = turbine diameter

e_{nq} = specific speed adjustment to peak efficiency

This results in the adjustments shown in Table 7.

Table 7. Adjustments to peak efficiency

Adjustment	UK	MK	LK
Specific speed adjust [^enq]	0.00	0.04	0.05
Runner size adjust [^ed]	0.03	0.05	0.05

Turbine peak efficiency e_p is calculated using:

$$e_p = (0.905 - e_{nq} + e_d) - 0.0305 + 0.005R_m$$

Where

R_m = Turbine Design coefficient, between 2.8 and 6.1, default assumption 4.5

e_{nq} = specific speed adjustment to peak efficiency

e_d = runner size adjustment to specific speed

This results in the peak efficiencies shown in Table 8.

Table 8. Peak efficiencies

	UK	MK	LK
Turbine peak Efficiency	0.93	0.90	0.90

5.2.6 Turbine Efficiency

The turbine efficiencies for the turbines will eventually be provided by the manufacturer after procurement but for this study generic calculations are applied. The calculated turbine efficiency curves take into account a number of factors including rated head (gross head less maximum hydraulic losses), runner diameter (calculated), turbine specific speed (calculated for reaction turbines) and the turbine manufacture/design coefficient. For the RETScreen model, efficiency equations were derived from a large number of manufacturer efficiency curves for different turbine types and head and flow conditions. ” (Clean Energy Support Centre, 2004)

Turbine efficiency e_q for flow Q is calculated using:

$$e_q = \left[1 - 3.5\left(\frac{Q_p - Q}{Q_p}\right)^6\right] e_p$$

Where

Q_p = peak efficiency flow

Q = flow through turbine

e_p = peak efficiency

This results in the efficiencies shown in Figure 32.

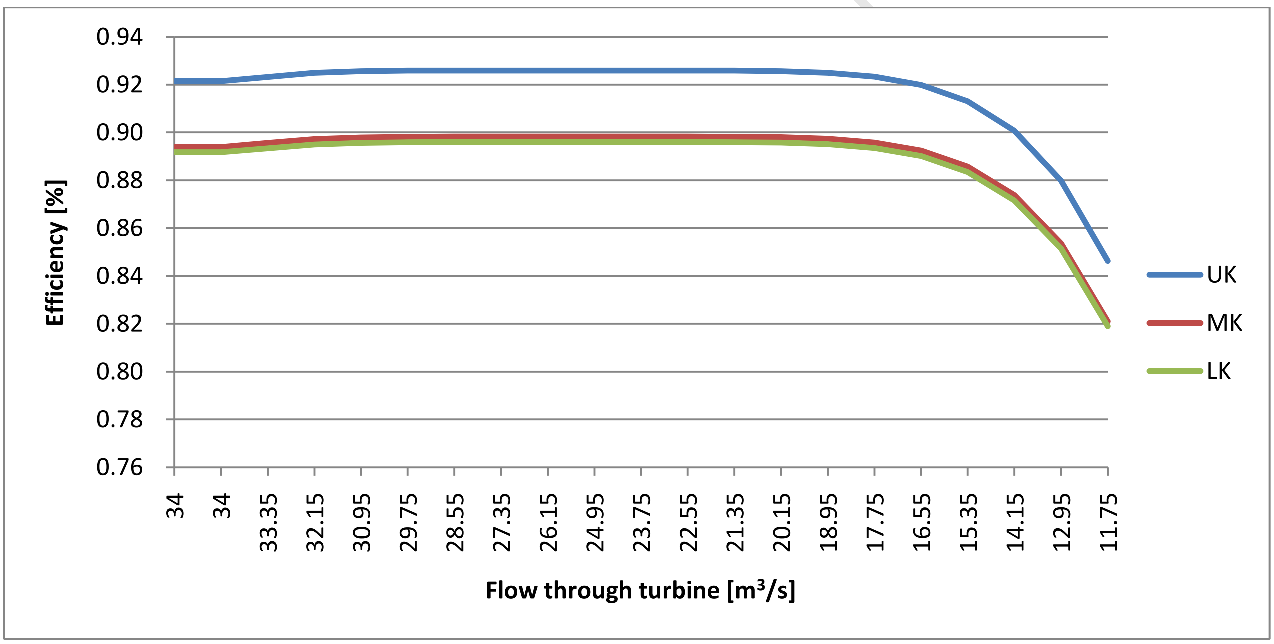

Figure 32. Turbine efficiencies

5.2.7 Hydraulic Losses

Hydraulic losses are adjusted over the range of available flows based on the following relationship:

$$h_{hydr} = H_g l_{hydr,\max} \frac{Q^2}{{Q_{des}}^2}$$

Where

H_{hydr} = hydraulic losses

H_g = Gross head

$l_{hydr,max}$ = the maximum hydraulic losses

Q = flow through turbine

Q_{des}= turbine design flow

This results in the hydraulic losses shown in Figure 33.

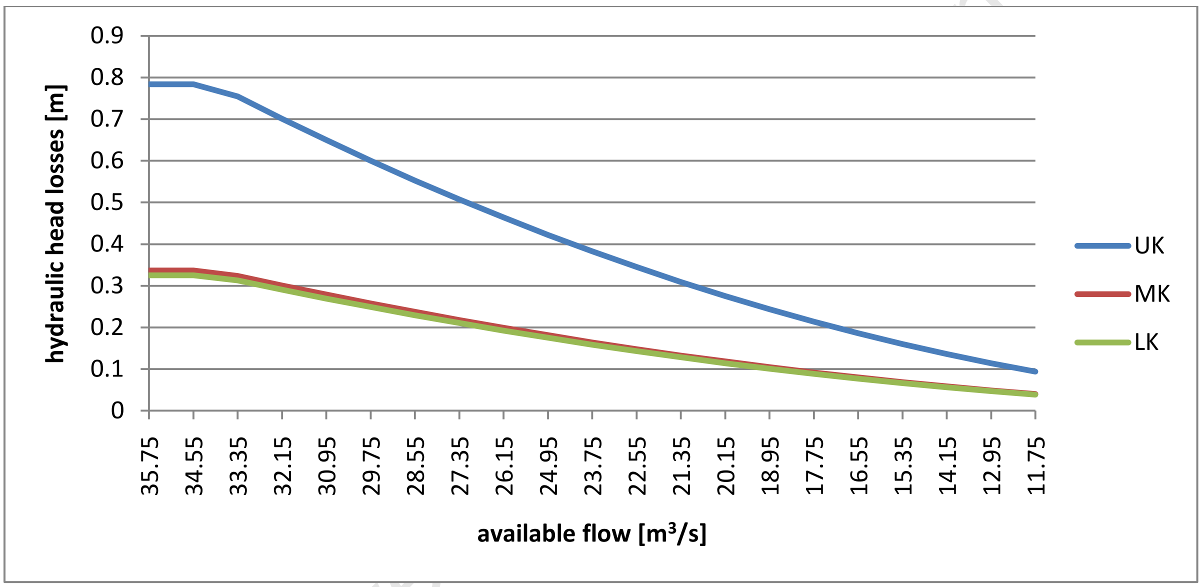

Figure 33. Hydraulic losses

5.2.8 Generation Capacity

The generation power at flow Q is calculated using the formula:

$$P = \rho g Q \left[H_g - \left(h_{hydr} + h_{tail} \right) \right] e_t e_g \left(1 - l_{trans}\right)\left(1 - l_{para}\right)$$

where

ρ = the density of water (1000 kg/m^3)

g = the acceleration of gravity (9.81 m/s^2)

Q = flow through turbine

H_g = gross head

h_{hydr} = hydraulic losses

h_{tail} = head losses resulting from tailwater effect

e_t = turbine efficiency

e_g = the generator efficiency, assumed to be 97% ()

l_{trans} = the transformer losses, assumed to be 3% ()

l_{para} = the parasitic electricity losses, assumed to be 2% ()

5.2.9 Power-duration curve

Power available as a function of flow is calculated for all 21 values of the available flow used to define the flow-duration curve, leading to 21 values of available power defining a power-duration curve. Since the design flow is defined as the maximum flow that can be used by the turbine, the flow values used in the equations to calculate the hydraulic and tailwater losses are Q_n, Q_{used} defined as:

$$Q_{used} = min(Q_n, Q_{des})$$

It is useful to plot the available flow against the generation capacity as shown in Figure 34.

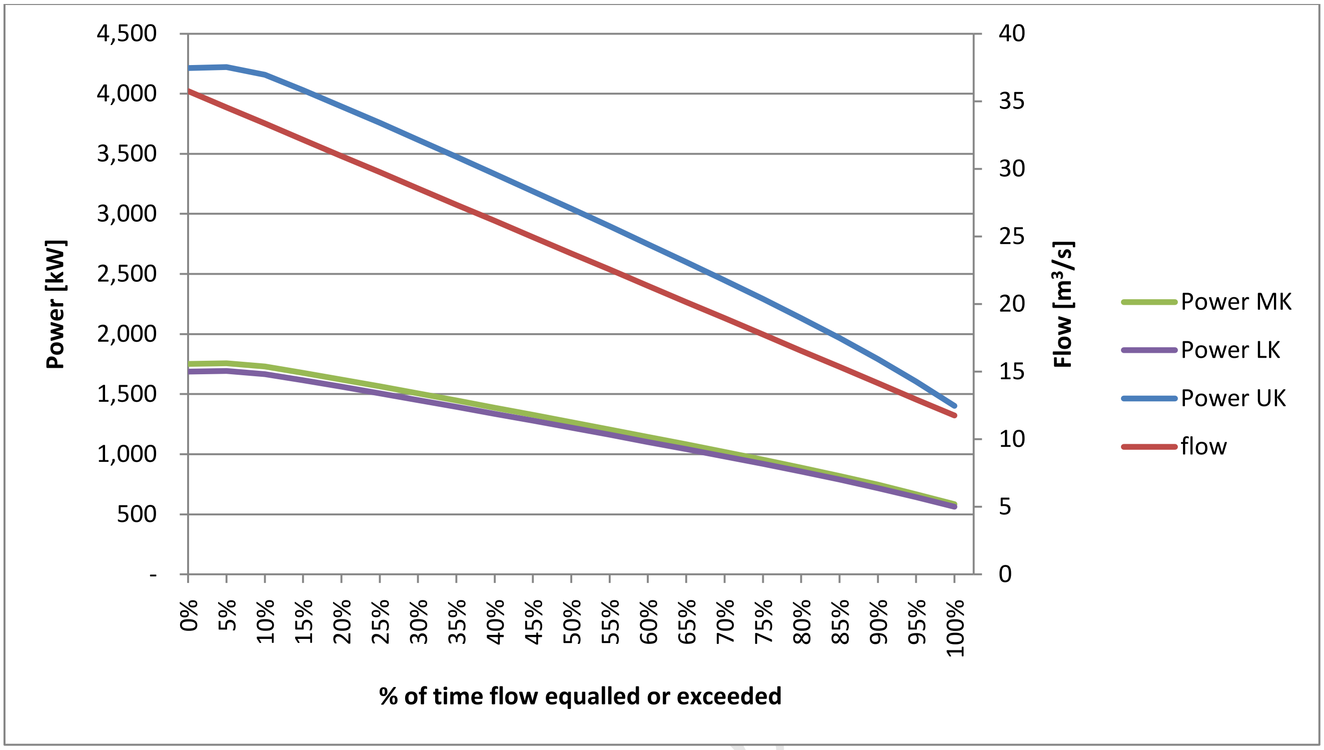

Figure 34. Power duration curve

5.3 Production

5.3.1 Electricity Production

Energy available is determined by calculating the area under the power duration curve assuming a straight-line between adjacent calculated power output values. Given that the flow-duration curve represents an annual cycle, each 5% interval on the curve is equivalent to 5% of 8,760 hours (number of hours per year). The annual available energy E_{avail} (in kWh/yr) is therefore calculated from the values P (in kW) by:

$$E_{avail} = \sum_{k=1}^{20} \left(\frac{P_{5(k-1)} + P_{5k}}{2} \right) \frac{5}{100} 8760 \left(1 - l_{dt}\right)$$

Where

l_{dt} = the annual downtime losses, assumed to be 3%

This equation provides the amount of renewable energy produced. The amount actually delivered to the grid depends on the type of grid and connection variables. In this study energy produced is assumed to equal energy delivered. This is shown in Figure 35.

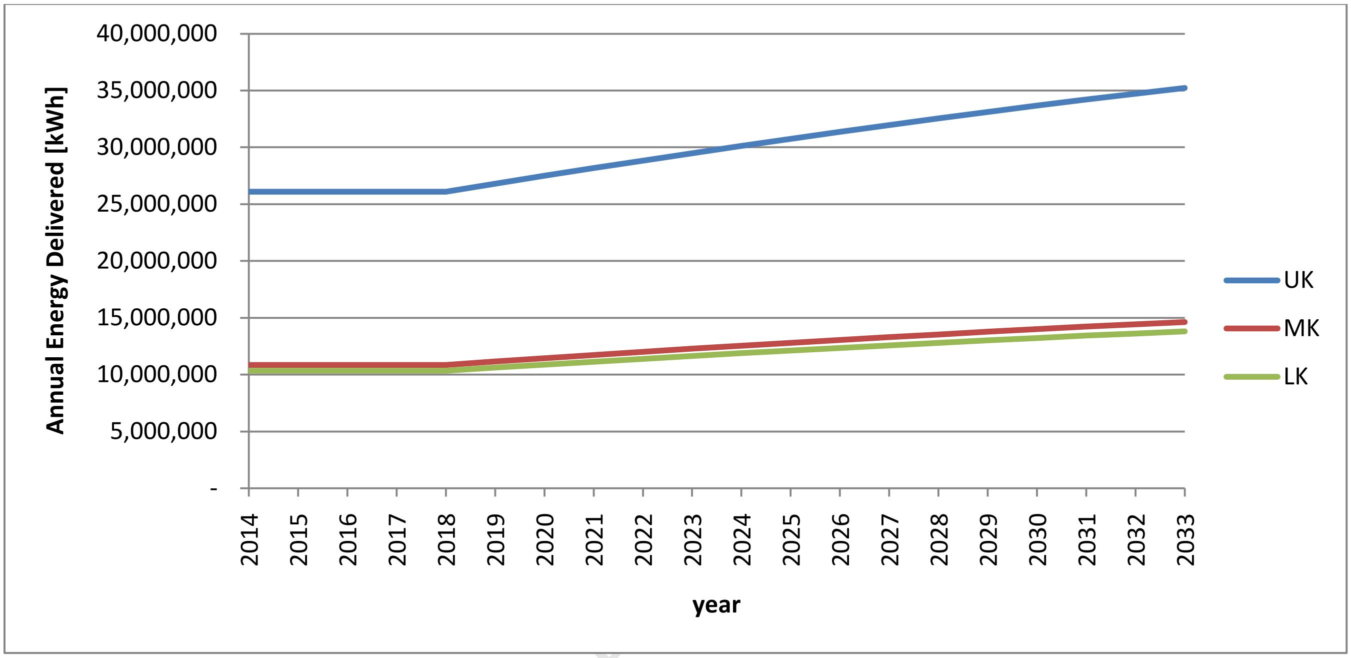

Figure 35. Annual energy delivered

5.3.2 Capacity Factor

The annual capacity factor *K* of each plant is a measure of the consistency of the resource (flow) at the site and how efficiently it is used. To design for a high capacity factor "sweats" the assets. It is defined as the average output of the plant compared to its rated capacity:

$$K = \frac{E_{dlvd}}{8760 P_{des}}$$

where

E_{dlvd} = the annual renewable energy delivered in kWh

P_{des} = plant capacity calculated through is expressed in kW

The capacity factor in each year is shown in Figure 36. Note the correlation between capacity factor and increased flow.

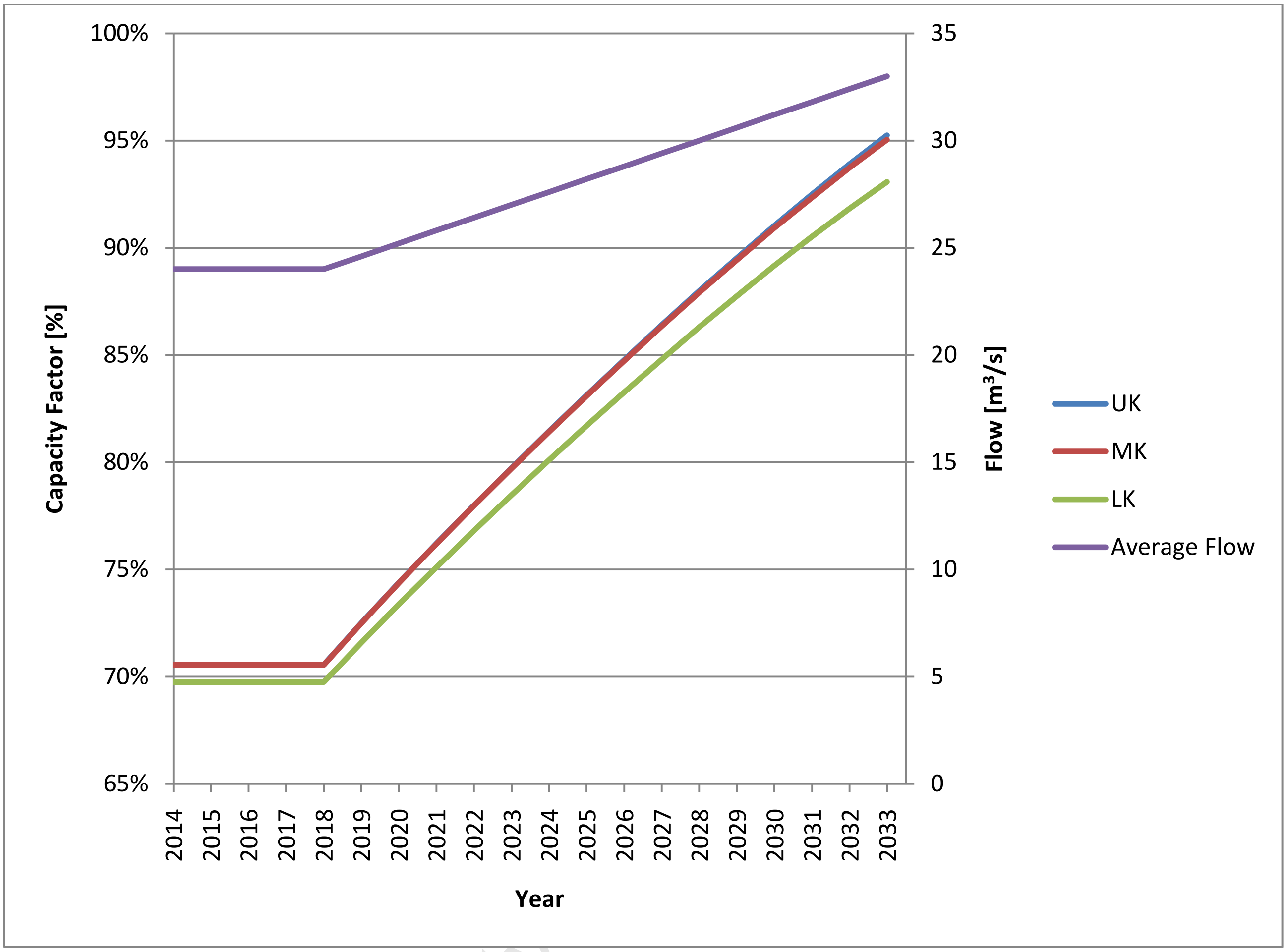

Figure 36. Capacity factors

5.3.3 CER Production

A GHG baseline study identifies and justifies a credible project baseline based on the review of relevant information such as grid expansion plans, dispatch models, fuel use on the margin, current fuel consumption patterns and emissions factors. ($UNFCCC_a$, 2010) The GHG baseline study sets a project boundary and identifies all sources of GHG emissions that would have occurred under the baseline scenario, i.e. the scenario most likely to have occurred if the project were not implemented.

The Kruisvallei projects will sell electricity into the national grid; displacing grid electricity; which is primarily coal-based, hence reducing emissions. For generation supplying the national grid in South Africa, the baseline analysis is straightforward through the publication by Eskom of a CO_2 yield rate per kWh of electricity delivered to the grid using existing power generation infrastructure. The number of CERs generated per year (CER_{issued}) is calculated using the formula:

$$CER_{issued} = y(E_{dlvd} - E_{dlvd}T_l)$$

Where

y = CER yield rate, equal to 1.2 tons/MWh (Eskom, 2008)

E_{dlvd} = kWh delivered to the grid per annum

T_l = Transmission and distribution losses, assumed to be 10% (Eskom 2008)

The number of CERs issue per annum is shown in Figure 37.

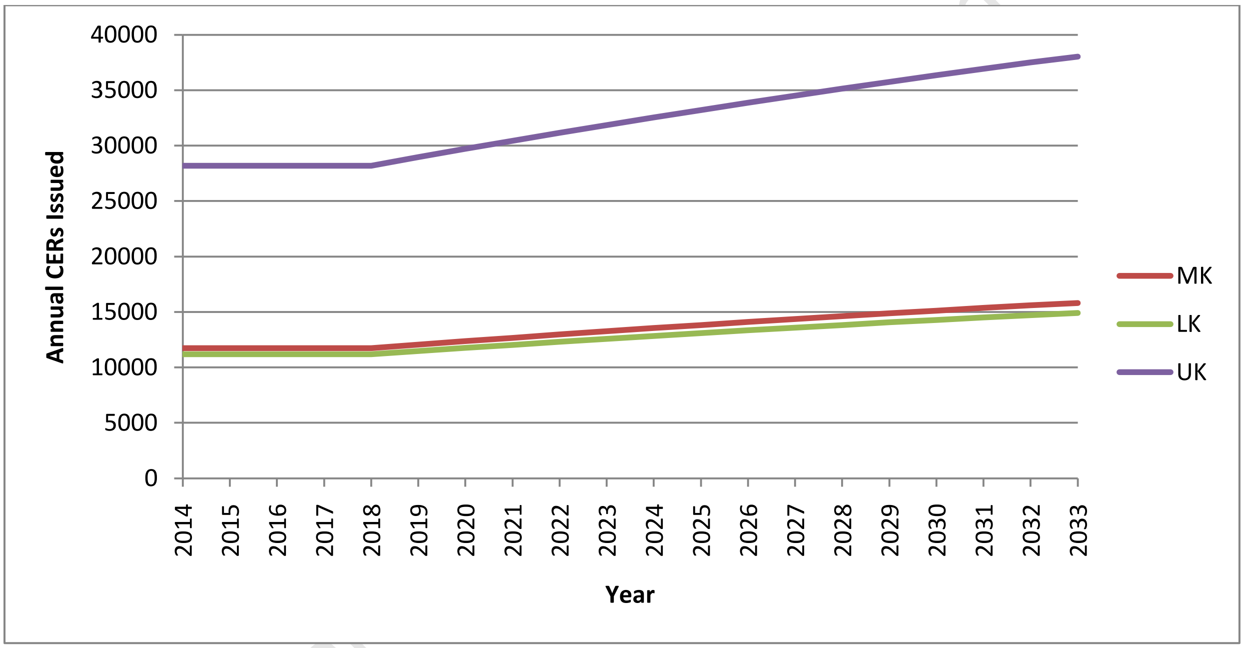

Figure 37. CERs issued

5.4 Grid Connection

A number of factors provide opportunity for Kruisvallei's connection to the grid. Electricity will be generated at 6kV and need to be stepped up to the voltage of the connection. Lines may be either 22kV or 88kV. Integration of the hydro plants along the Ash River is likely to be the most cost-effective way to approach grid connection. The plants on the Ash River are shown in Figure 38, with Merino 2 being the Northern-most installation. Only Merino 1 currently exists, and the others are all planned by Nuplanet, the developer of Bethlehem Hydro.

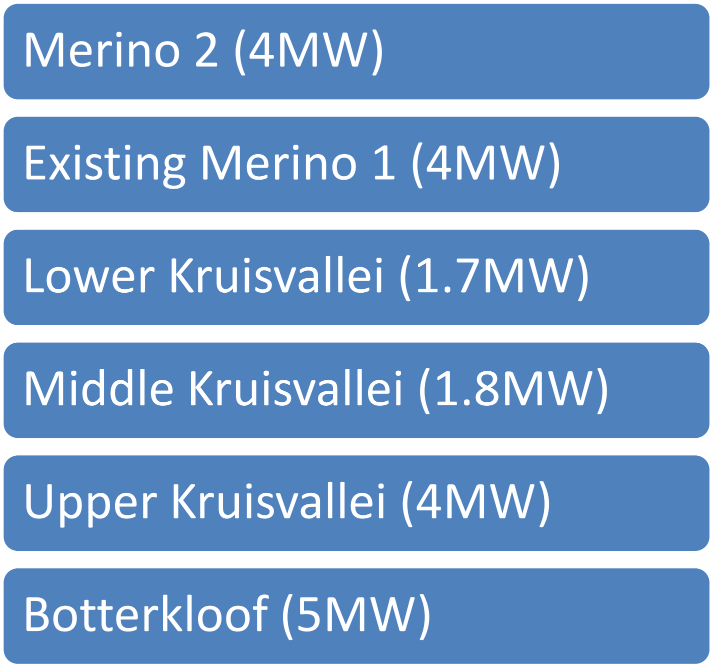

Figure 38. Small hydro plants on the Ash river system

On the north side of the Kruisvallei farm is Merino 1, and Merino 2 is planned. Merino 1 is connected to the Node substation via a 22kV line shown as a dotted orange line in Figure 39.

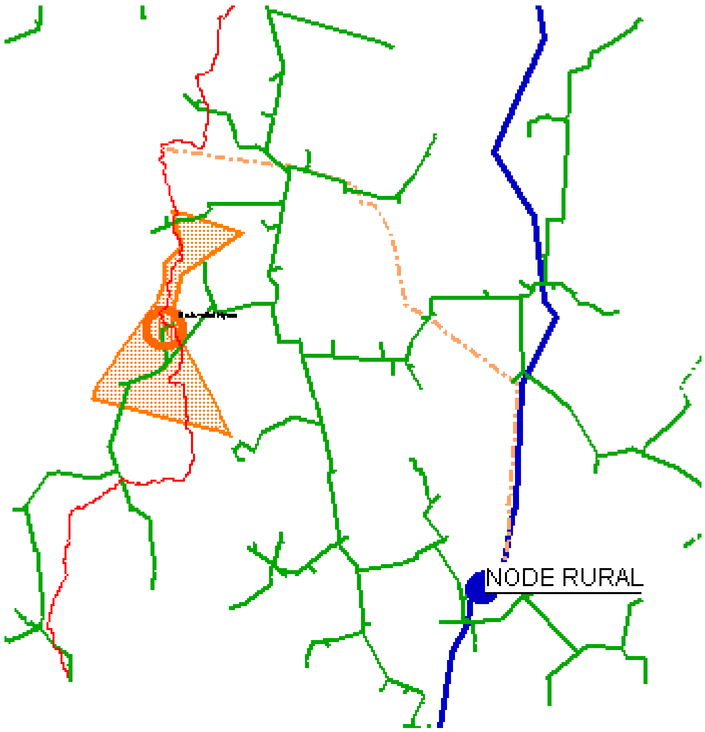

Figure 39. Grid connection map

Merino 2 will connect to this same line, and the line capacity is expected to have been reached. In addition, Nuplanet have negotiated an exclusive use arrangement of this line (Kirsten 2010), the details of which are not known. Hence integration with these plants or the existing 22kV line is not an option.

It is expected that there is opportunity for integration with The Botterkloof Hydro development on the south side of the Kruisvallei farm. A single line could be shared between the four plants. This line could be either 22kV or 88kV. A 22kV is far cheaper than an 88kV line (van Wyk 2010) and does not require an EIA, while an 88kV does. (Fouche 2010) A 22kV line is viable because there is an existing 22/88 transformer at Node. (Kirsten 2010) However, losses are reduced if a higher voltage is used, and an 88kV may be more resistant to lightning strike. (van Rensburg 2010) Further costs could be saved by sharing a single transformer between the Botterkloof and Kruisvallei plants, which would be located at either Botterkloof or Kruisvallei which would then connect to the Node substation via a single line.

There are a three alignment/operation options available (Kirsten 2010):

- The line can be self-aligned to own specifications, and owned and operated entirely without Eskom approval

- The line can be self-aligned to ESKOM specifications and then passed on to Eskom to operate.
- The line can be aligned, owned and operated by Eskom.

5.5 Raising Weir 26

The benefits of raising weir 26 have been analyzed by adding extra head to MK. The additional generation capacities achieved are shown in Figure 40

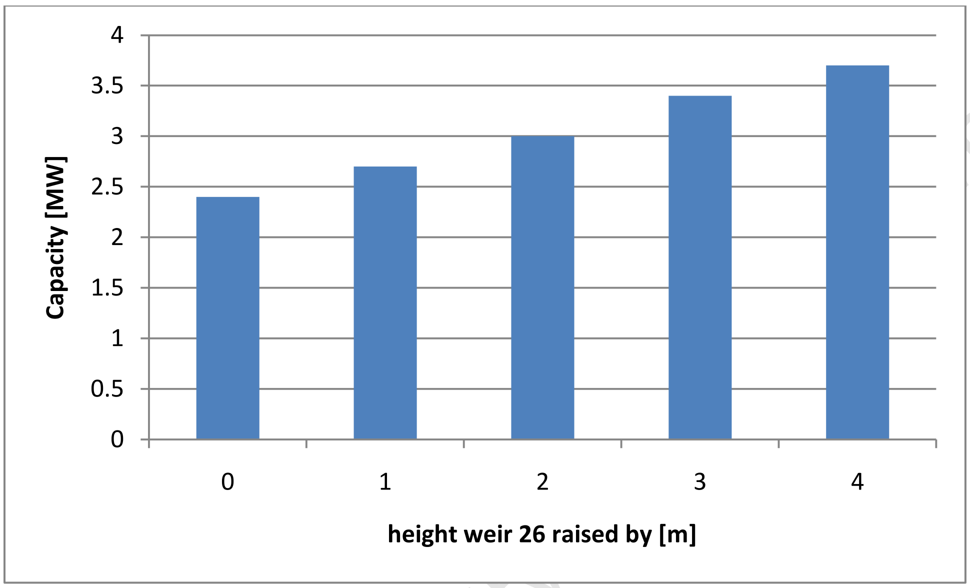

Figure 40. Effect on Capacity with raising weir 26

The additional annual earnings are shown in Figure 41 (electricity sale of 94c/kWh).

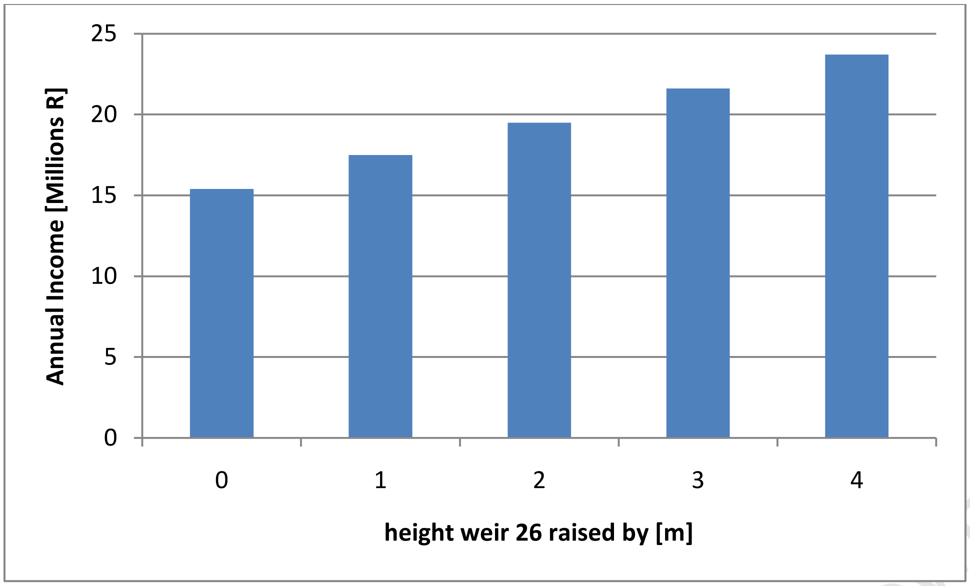

Figure 41. Effect on income of raising weir 26

It is clear that each additional metre of head results in a capacity increase of between 300kW - 400 kW which in turn results in increased income of approximately R2M – R2,1M annually.

5.6 Storage at UK

Storing water in the dam at UK provides the opportunity to control flow. The type of storage envisioned allows timing of power generation on a daily basis (as opposed to larger storage required for seasonal flow control). Depending on the flow velocity (for which further research is required), powerplants downstream can also receive increased flow during peak periods. The electricity demand curve is shown in Figure 42.

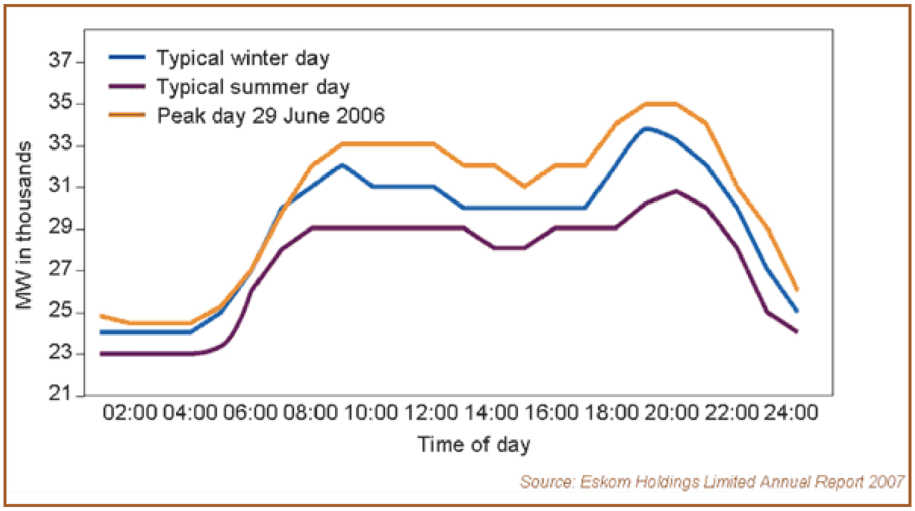

Figure 42. National electricity demand curve (DPE, 2008)

Flow velocity will affect the time it takes for water move from UK wall to the power plants at MK and LK, or even Merino 1 and 2, further plants down stream on the same system. This will mean that power can be generated during peak demand periods, making Kruisvallei's production more attractive to Eskom.

At present there is no legislation providing separate (higher) time of use (TOU) tarrifs. It is expected that within the next few years these may emerge. There has been discussion around this issue. The value to Eskom is undeniable, as at present they frequently use OCGT plant for peaking power at a cost in excess of R2/kWh. (Olivier$_a$, 2008)

Calculations of dam volume required for different periods of peak flow are conducted. It is assumed that the peak flow used is 40m^3/s. It may be possible to increase this to enable higher generation capacity during peak periods. The minimum flow in to the storage is approximately 13m^3/s. During peak periods the net outflow is therefore assumed to be 27m^3/s (40 – 13 m^3/s). It will not be any higher than this, meaning that the storage volumes calculated will certainly be sufficient in all circumstances apart from periods of maintenance when the flow is switched off altogether. The storage volumes required are shown for dispatchable periods of 2, 3, 4 and 5 hours in Figure 43.

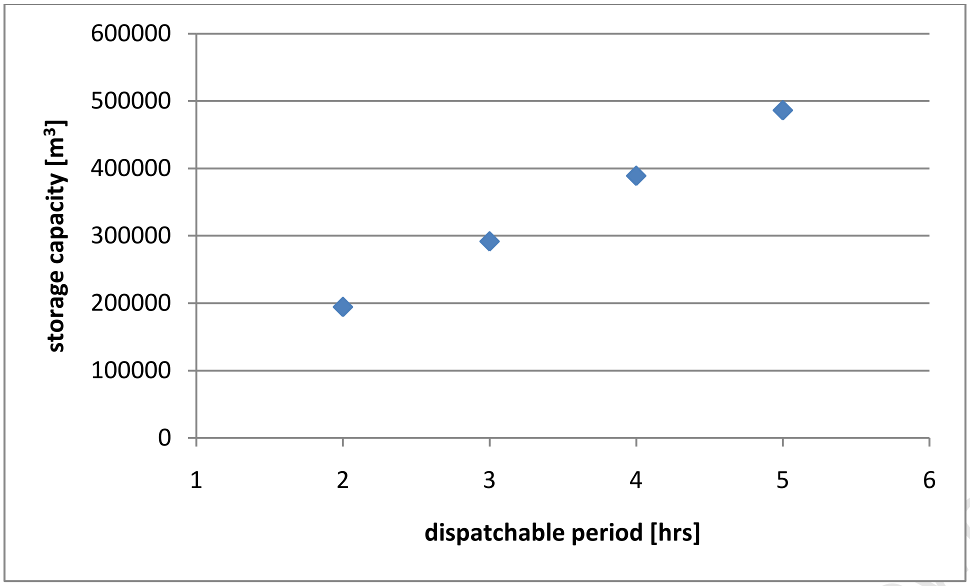

Figure 43. Dam capacities required

6 Financial Analysis

6.1 Capital Cost

The scope of this study does not include a full costing analysis covering each item mentioned in section 2.5.2. In order to examine the investment potential of the scenarios identified, a basic costing analysis was performed. The main cost items of the works were considered, including:

- Electromechanical. R17M/MW (Boving Fouress, 2009) (Mecamidi, 2010)
- Civils. Mr Viljoen was personally consulted with regards each layout considered in this study, and additional construction expertise was sought from Mr Willie Van der Merwe of Raubex Construction and Mr Jan Oberholzer of Stefanutti Stocks. The items considered include:
    - Weir. A value of R20m is used (Viljoen, 2009) (Van de Merwe, 2009) (Oberholzer, 2009)
    - Off-take. R5m for new weirs, R10m for existing weirs (Viljoen, 2009)
    - Canal. R20m per kilometer (Viljoen, 2009) (Van de Merwe, 2009) (Oberholzer, 2009)

This results in the works costs shown in Table 9.

Table 9. Works costs

	Units	**Specific Cost**	**UK**	**MK**	**LK**
M&E	R/kW	R 17,000	R 71,765,265	R 29,883,225	R 28,788,629
Civils					
Canal Length	km		0.32	0.27	0
Canal cost	R/km	R 20,000,000	R 6,400,000	R 5,400,000	R 0
offtake cost	R		R 5,000,000	R 10,000,000	R 5,000,000
Weir cost	R	R 20,000,000	R 20,000,000	R 0	R 20,000,000
Works Total			R 103,165,265	R 45,283,225	R 53,788,629

Professional fees are added at 19% of the cost of the works (Viljoen, 2009) to yield capital cost subtotals. A contingency of 10% is then added to this. These values are brought forward to 2012 value as this is the year in which these costs are incurred and shown in Table 10.

Table 10. Capital costs

	UK	MK	LK
Capital Costs Subtotal (2012)	R 152,366,946	R 66,879,746	R 79,441,555
Calculated final Specific Costs [R/MW]	R 36,093	R 38,047	R 46,911

These values are compared to historic and expert estimates in Figure 44.

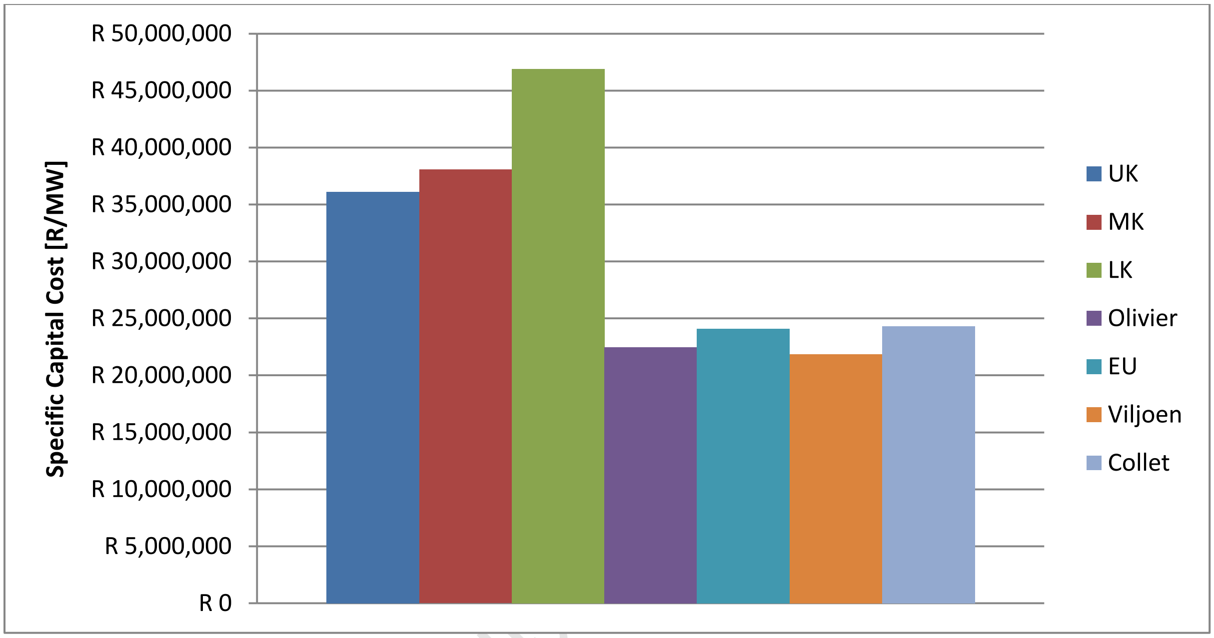

Figure 44. Specific capital costs

It is noted that the capital costing conducted here is conservative relative to the literature.

6.2 Periodic Cost

Periodic costs in hydropower are a small component relative to upfront because the primary energy (water) is typically free and the simple, low temperature energy conversion equipment and high degree of automation. Periodic costs taken into account include:

- O&M. 75% of the average of the O&M costs in section 2.5.3 is taken as the specific O&M cost per annum. The reduction is used because it is expected that the EU values are higher than expected local values.

- Water Cost. DWEA charge for the use of water for hydroelectric power generation at R5/kW/annum of installed capacity and at R0.01/kWh produced.
- Land Lease. The land owners have indicated that they will charge 0.25% of the annual income for the use of their land. (McIntosh$_a$, 2009)

The annual periodic costs are shown in Figure 45.

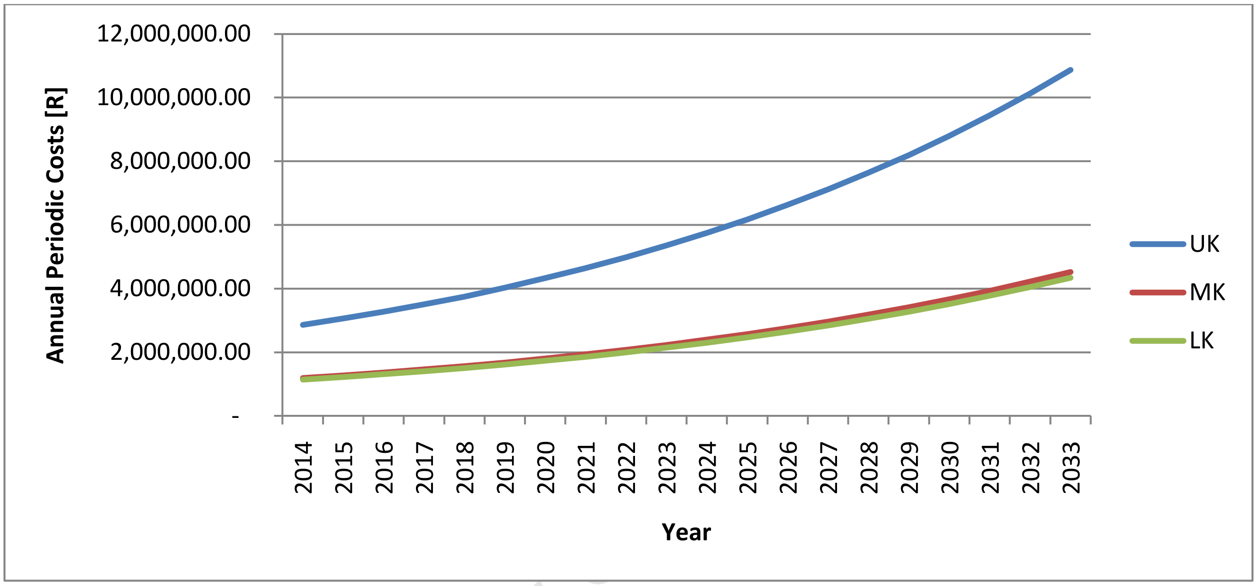

Figure 45. Annual periodic costs

6.3 Sale of Electricity

The off-take agreement is an element of the business which needs to be optimized as far as possible, and this may involve negotiation with a number of potential off-takers to secure the best off-take agreement possible. The tariff level is a key component. The REFIT is seen as the highest level tariff likely to be signed. A low er level is expected to be 33c/kWh (2009) which is the avoided cost the Dihlabeng municipality would be prepared to sign a PPA tariff at. (Olivier$_a$, 2009) This avoided cost is assumed to track the average electricity price increases. Three increases of 25% are assumed. Following this, electricity tariffs are not yet expected to have reached cost-reflectivity and therefore a further three increases of 15% are assumed. This results in the two off-take tariffs shown in Figure 46.

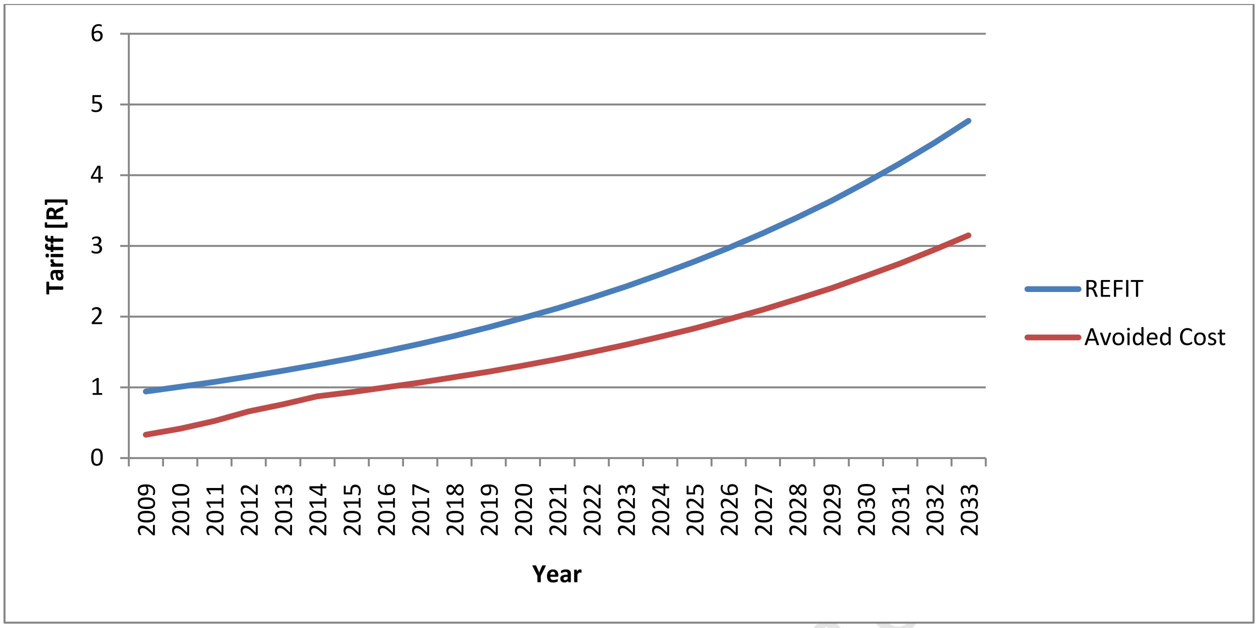

Figure 46. Off-take tariffs

6.4 Sale of CERs

It is assumed that the development of the CDM project will be financed by the project owners, ie CERs will not be forward sold. Hence the full market value of the CERs is used in the financial analysis. The CER price is difficult to predict because of market uncertainty post 2012, and uncertain outcomes from the upcoming talks in Copenhagen. The current CER price is €11 (as at 4th August 2009). The exchange rate is R11.20/€ (as at 4th August 2009) which results in a current CER price of R123.20. This value is escalated at 5% per annum.

6.5 Project Finance

6.5.1 Assumptions

Inflation

Statistics South Africa (2009) released the CPI data shown in Table 11.

Table 11. CPI data

Year	Index	% Change
1981	7.8	
1982	8.9	14.1%
1983	10.0	12.4%
1984	11.2	12.0%
1985	13.0	16.1%
1986	15.5	19.2%
1987	17.9	15.5%
1988	20.2	12.8%
1989	23.2	14.9%
1990	26.5	14.2%
1991	30.6	15.5%
1992	34.8	13.7%
1993	38.2	9.8%
1994	41.7	9.2%
1995	45.3	8.6%
1996	48.6	7.3%
1997	52.8	8.6%
1998	56.4	6.8%
1999	59.3	5.1%
2000	62.5	5.4%
2001	66.1	5.8%
2002	72.1	9.1%
2003	76.3	5.8%
2004	77.4	1.4%
2005	80.0	3.4%
2006	83.7	4.6%
2007	89.7	7.2%
2008	100.0	11.5%
Average		**6.7%**

Hence an inflation value of 6.7% is used to evaluate annual changes in the time value of money.

Cost of equity

The cost of equity is set at 17%. (Sotobe, 2010) Because of the nature of the business and level of risk involved, medium returns will be expected.

Debt interest rate

The debt interest rate is set at 12% but would be subject to the financing agreements with various lenders.

Debt parameters

Debt term is 10 years and is based on a fixed price payback.

Leverage

The equity portion of project finance is assumed to be 30%, and the remaining 70% is debt. This results in a WACC of 13.5%.

Project life

The project is modeled over the construction period and a further 20 years of production.

The financial assumptions are summarized in Table 12.

Table 12. Financial assumptions

Financial Assumptions	Units	Value
Inflation rate	%	6.7%
Project life	years	23
Equity Portion	%	30%
Debt Portion	%	70%
Cost of Equity	%	17%
Debt Interest Rate	%	12%
WACC	%	13.5%
Debt term	years	10
CER Price (4/8/2009)	€	11.00
Exchange Rate (4/8/2009)	R/€	11.20
CER Spot Price Rand (2009)	R/€	123.20
CER Price Annual Escalation	%	5%

6.5.2 Interest During Construction

A development cash flow showing the monthly usage of equity during the construction period is recommended when more accurate costs estimates are taken into account. For the purposes of this study, the equity will be drawn on first and the debt second during the two year implementation phase. It is assumed that expenditure during implementation phase is consistent. Hence, of the two years of implementation, the first 0.6 years is funded by equity, and the following 1,4 years is funded by debt. During this 1.4 year period interest on the debt is accrued. It is calculated using the formula:

$$I_c = C(1+i)^T$$

Where

I_c = Interest during construction

C = total capital cost

I = debt interest rate, 12%

T = period over which interest is accrued, 1.4 years

6.5.3 Summary

Table 13. Financial parameters

	UK	MK	LK
Total Capital Cost	R 152,366,946	R 66,879,746	R 79,441,555
Equity	R 45,710,084	R 20,063,924	R 23,832,467
Debt	R 106,656,862	R 46,815,822	R 55,609,089
Interest during construction	R 18,338,539	R 8,049,494	R 9,561,405
Debt + Interest during construction	R 124,995,401	R 54,865,316	R 65,170,494
Annual Debt Payments	-R 22,122,207	-R 9,710,292	-R 11,534,145

6.6 Cash Flows

A Cash-Flow has been assembled to analyze the economic viability of each site. The cash flow takes into account the following parameters:

- Income from sale of electricity and CERs.
- Capital and periodic costs.
- NOI- the net operating income which is the difference between the income and costs.
- BTCF is the before tax cash flow which is the NOI less debt servicing payments.

Following this study, should it be decided that the project will progress, a full bankable feasibility study will be conducted with which it will be possible to raise finance. The duration of the feasibility phase is expected to be 18 to 24 months, depending on the satisfaction of certain compliance components (see Appendix D: Compliance Requirements). This would mean that financial closure would be reached midway through 2011, the end point of the feasibility phase. The duration of the implementation phase is expected to be a further 18 to 24 months starting in 2012. The equity invested in the project is injected at the end of 2011. Operation and maintenance phase begins at the start of 2014 with first periodic costs and income at the end of 2014.

The cash flows for avoided cost and REFIT are shown in Figure 47 and Figure 48 respectively.

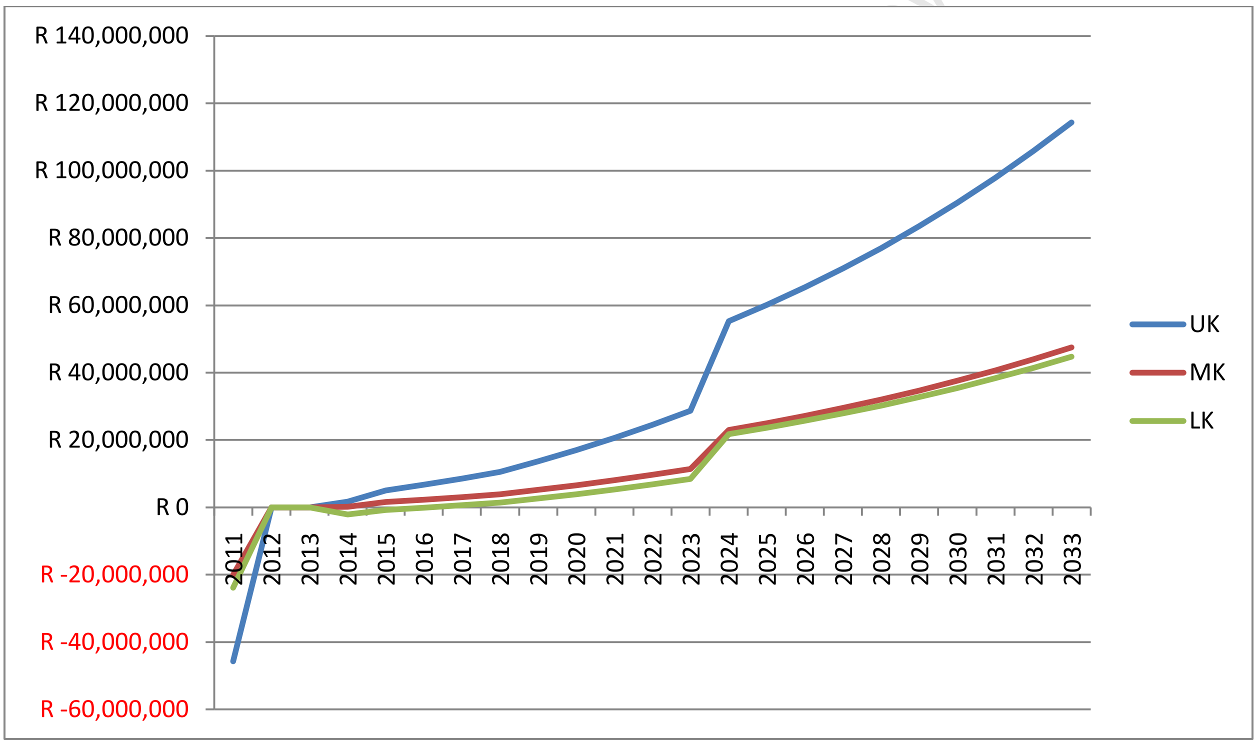

Figure 47. Cash flows avoided cost

The avoided cost cash flow is considered to be a base case scenario.

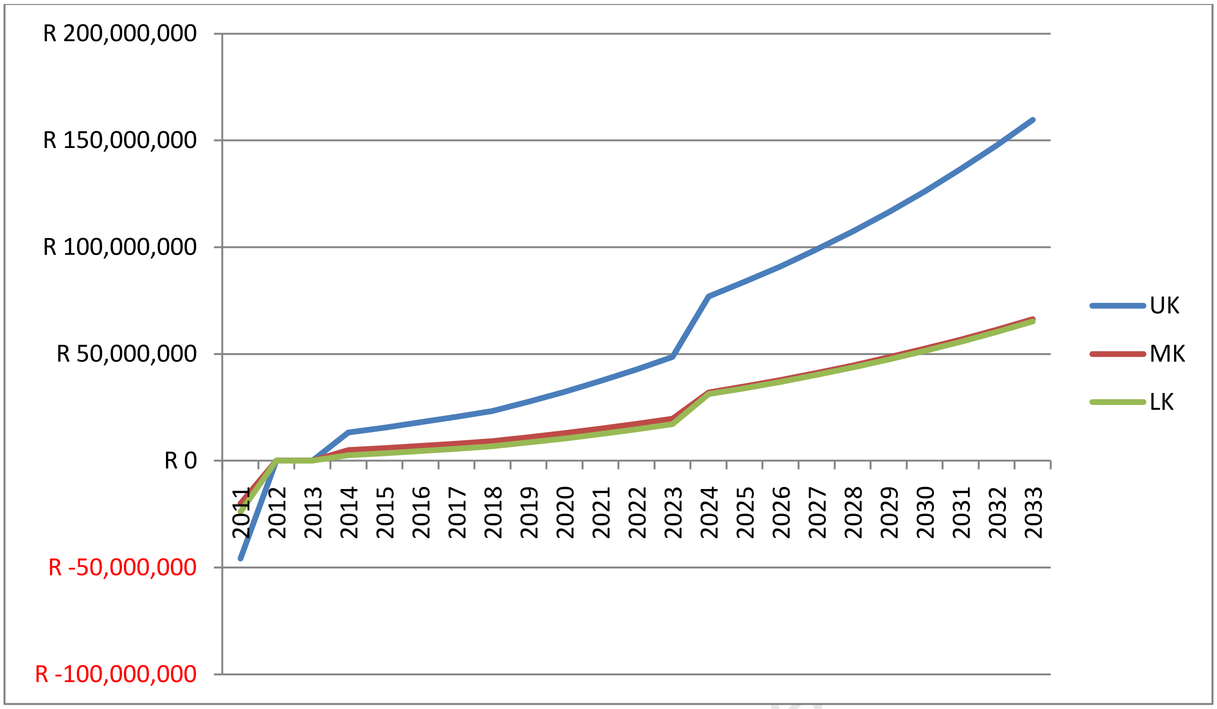

Figure 48. Cash flows REFIT

The REFIT cash flow is considered to be a best case scenario.

6.7 Investment Criteria

6.7.1 Simple Payback

The simple payback is the point at which the cumulative cash flow becomes positive. The pertinent portion of the cumulative cash flows for the base case is shown in Figure 49.

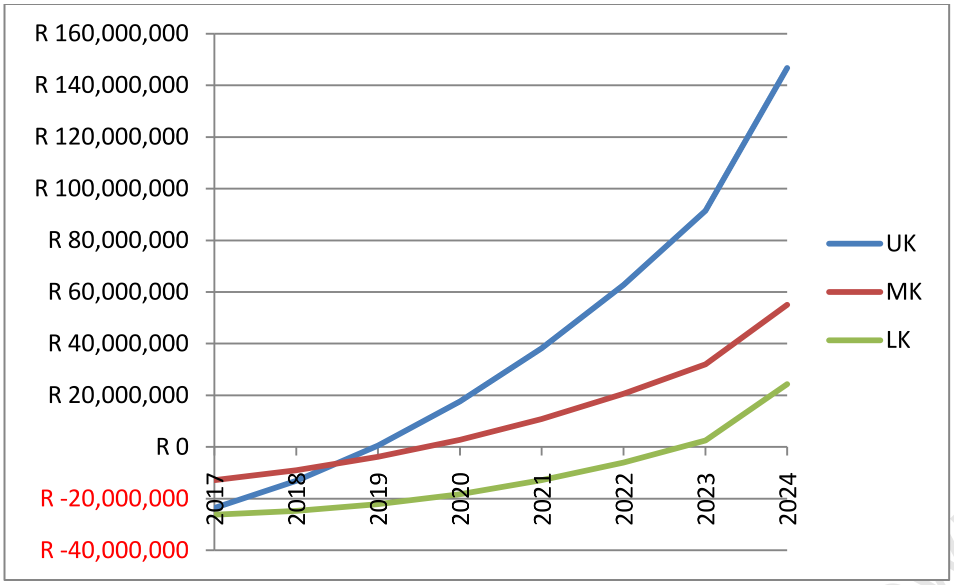

Figure 49. Base case cumulative cash flow

It can be seen that the base case simple payback is in 2018 for UK (7 years), 2019 for MK (8 years) and in 2022 for LK (11 years). The pertinent portion of the cumulative cash flows for the best case is shown in Figure 50.

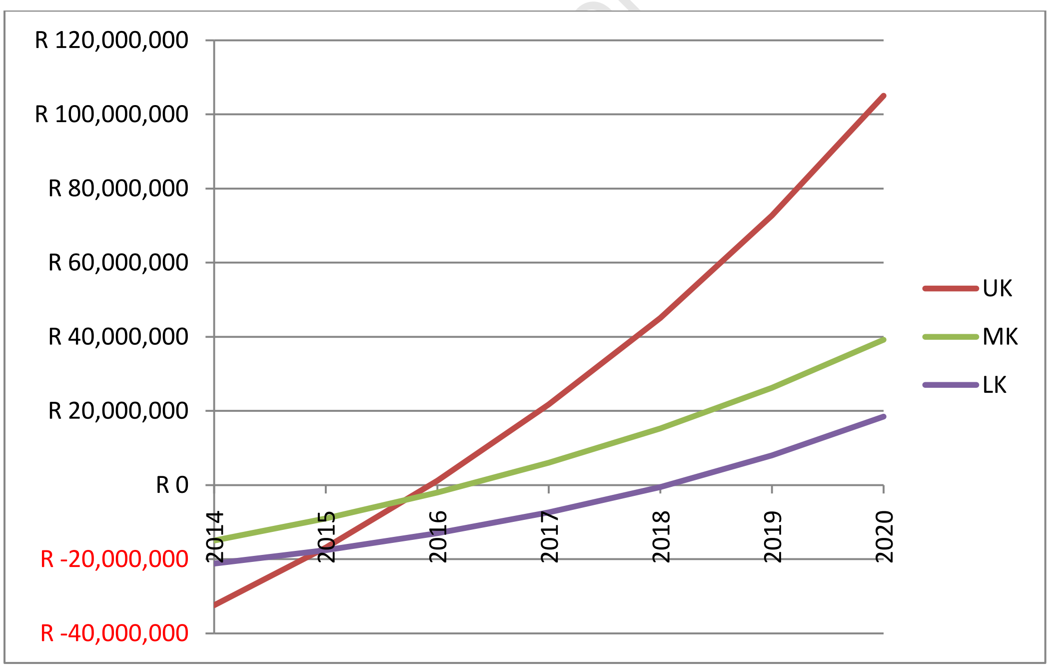

Figure 50. Best case cumulative cash flow

It can be seen that the best case simple payback is in 2015 for UK (4 years), 2016 for MK (5 years) and in 2018 for LK (7 years).

6.7.2 Yield

The yield is the first year of production's NOI divided by the total capital outlay.

6.7.3 NPV and IRR

The NPV and IRR have been taken from the Before Tax Cash Flows. The discount rate applied is the WACC at 13.5% (Sibiya, 2010).

6.7.4 Profitability Index

The profitability index is the NPV divided by the equity portion.

7 Results

7.1 Site Survey

The flow through the system in 2007 was processed and captured in a FDC. Projected increased average flow in the future was researched. To account for this, linear FDCs were constructed, tested and shown to be valid for use over the period of project analysis. The 2007 actual FDC and selected linear approximations used in the technical model are shown in Figure 51.

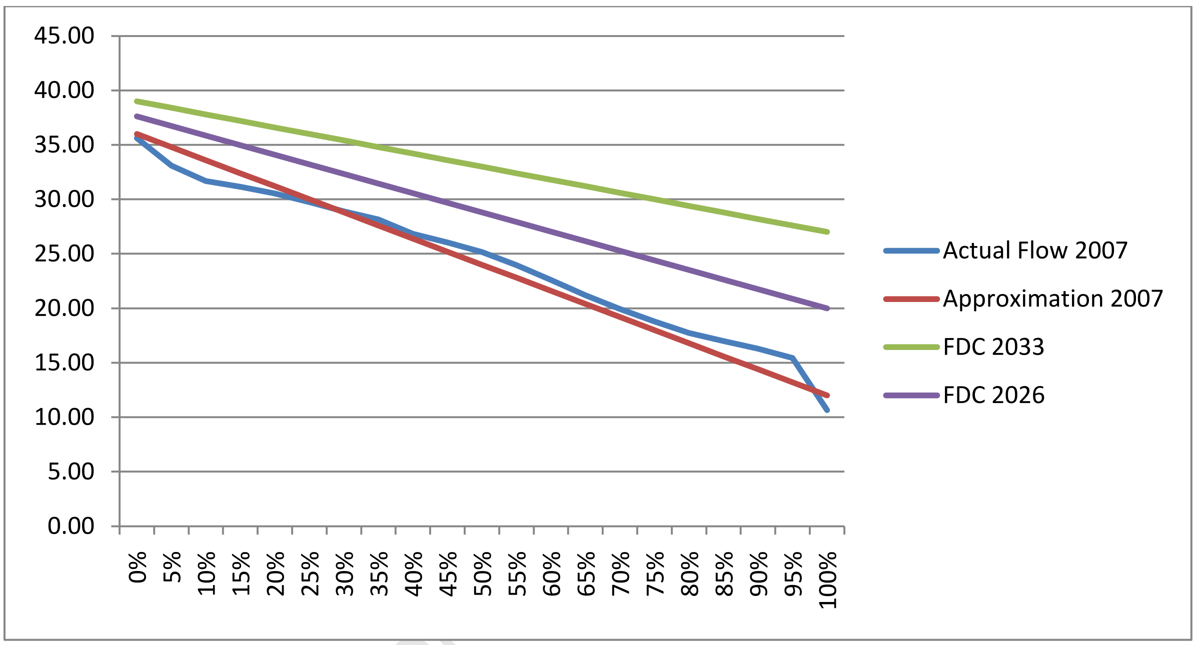

Figure 51. 2007 FDC and selected linear approximations

The total head on Kruisvallei 190 is 33m, and the majority of this drop occurs in three sections of river, shown in Figure 52.

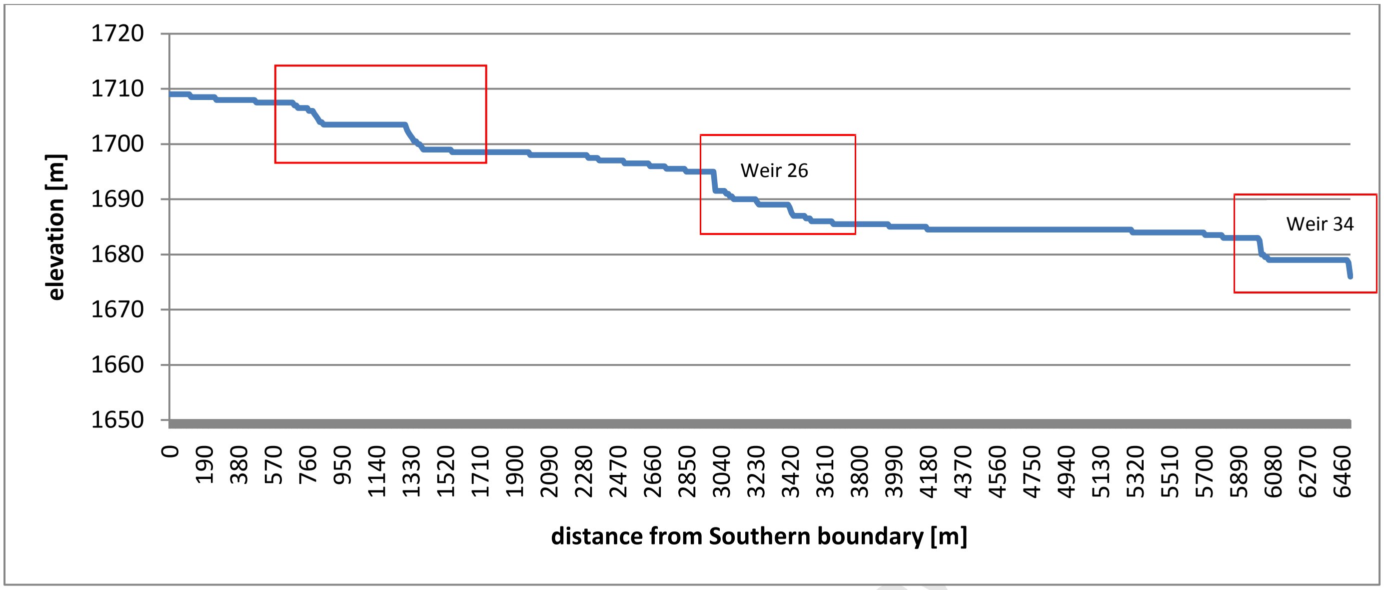

Figure 52. River elevation

7.2 Preliminary Layout Design

An iterative process of layout design was conducted which included consideration of eight potential layouts, five of which have been discarded. Three layouts are recommended to make use of the head on Kruisvallei, referred to as Upper Kruisvallei (UK), Middle Kruisvallei (MK) and Lower Kruisvallei (LK). The results of the layout design are summarised in Table 14.

Table 14. Layout design results

	upper level [m]	lower level [m]	Total Head [m]	Canal Length [m]	Gross Head [m]
UK	1715	1699	16	320	15.68
MK	1695	1688	7	270	6.73
LK	1682.5	1676	6.5	0	6.5

7.3 Technical Results

Each of the three layouts was modeled technically. Literature was consulted to decide on turbine type and design flow was determined by maximizing the NPV of the investment. Key results of the technical analysis are summarized in Table 15.

Table 15. Technical results summary

	Site			
Turbine Design	**UK**	**MK**	**LK**	**Units**
Turbine Type	Double Regulated Kaplan			
Design Flow (Q_{des})	34	34	34	m^3/s
Runner Size (d)	2.17	2.17	2.17	m
Max Flow (Q_{max})	42	42	42	m^3/s
Specific Speed (n_q)	207.28	316.39	321.94	dimensionless
Head and Losses	**UK**	**MK**	**LK**	
Gross head (H_g)	15.68	6.73	6.5	m
Max Hydraulic losses (h_{hydr})	0.784	0.3365	0.325	m
Rated head (H_r)	14.90	6.39	6.18	m
Max Tailwater head loss ($h_{tailmax}$)	0.5	0.5	0.5	m
Max Hydraulic losses	5%	5%	5%	%
Turbine Efficiency	**UK**	**MK**	**LK**	
Peak Efficiency Flow (Q_p)	25.5	25.5	25.5	m^3/s
Turbine peak Efficiency (e_p)	92.59%	89.83%	89.60%	%
Specific speed adjust (e_{nq})	0.28%	4.37%	4.71%	%
Runner size adjust (e_d)	3.17%	4.50%	4.61%	%
Turbine design coefficient (R_m)	4.5	4.5	4.5	dimensionless
Design turbine efficiency	92.15%	89.40%	89.17%	%
Power Variables	**UK**	**MK**	**LK**	
Density of Water (ρ)	1000	1000	1000	kg/m^3
Gravitational Acceleration (g)	9.81	9.81	9.81	m/s^2
Generator efficiency (e_g)	97%	97%	97%	%
Transformer losses (l_{trans})	3%	3%	3%	%
Parasitic losses (l_{para})	2%	2%	2%	%
Annual downtime losses (l_{dt})	3%	3%	3%	%
Design Results	**UK**	**MK**	**LK**	
Plant Design Capacity	4221	1758	1693	kW
Energy Produced (E_{dlvd}) (2014)	26,089,353	10,862,713	10,345,298	kWh
Energy Produced (E_{dlvd}) (2033)	35,220,116	14,634,475	13,806,462	kWh
Capacity Factor (K) (2014)	71%	71%	70%	%
Capacity Factor (K) (2033)	95%	95%	93%	%
CERs produced (CER_{issued}) (2014)	28,177	11,732	11,173	dimensionless
CERs produced(CER_{issued}) (2033)	38,038	15,805	14,911	dimensionless

The electricity and CER production are shown in Figure 53 and Figure 54 respectively.

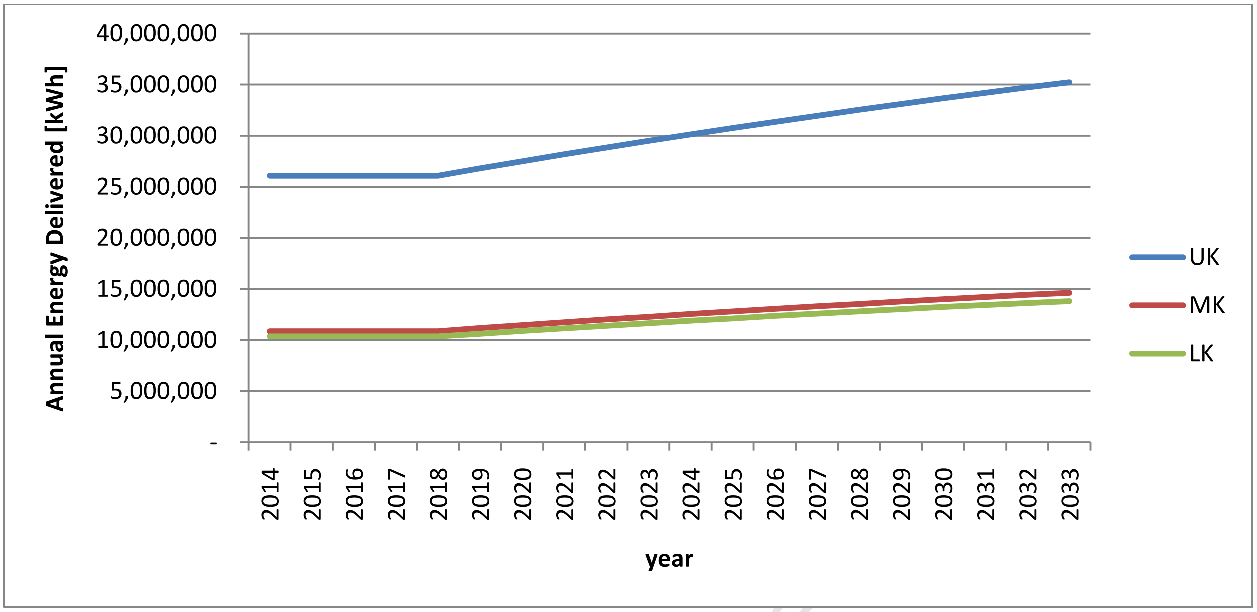

Figure 53. Electricity production

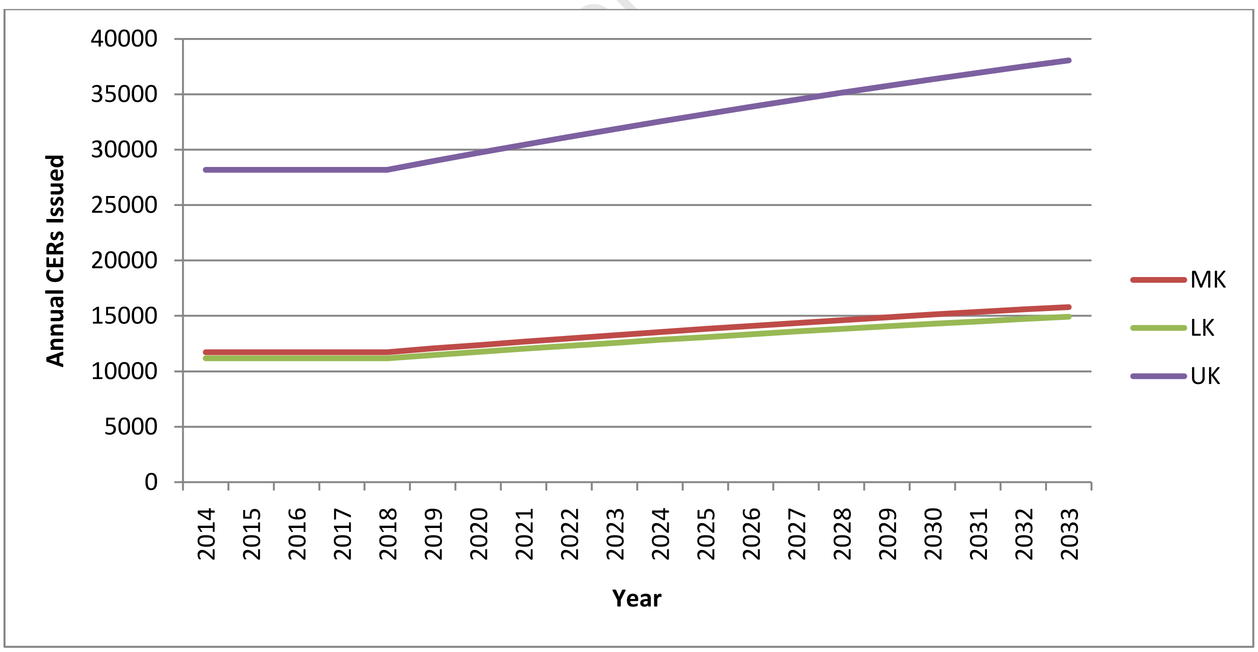

Figure 54. CER production

7.4 Financial Results

The capital cost of each layout was estimated as shown in Figure 55. These values were translated into specific costs per MW and demonstrated to be higher than historically found and estimated by experts. Periodic costs were estimated, taking into account O&M, water and land lease costs.

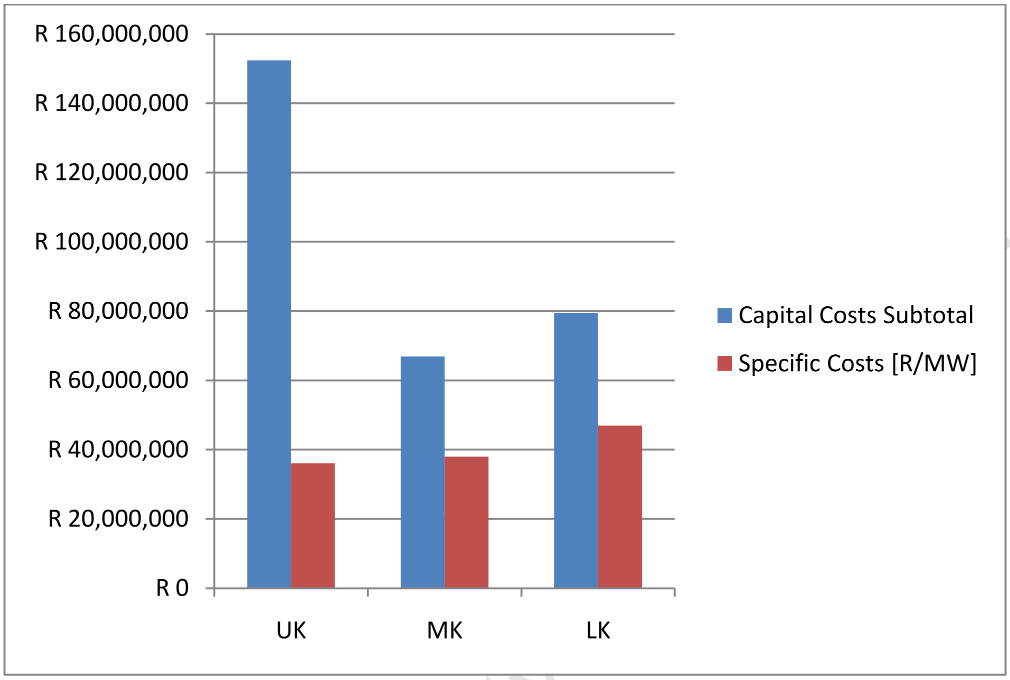

Figure 55. Capital costs

The financial model translates production outputs from the technical model into income through the sale of electricity and CERS. A REFIT PPA is considered to be a maximum off-take level, and a minimum off-take level is assumed based on the avoided cost to the local municipality. The CER price is estimated using 2009 figures and projected to escalate at 5% per annum.

Finance of the project is makes use of both debt and equity. The financial assumptions are shown in Table 16.

Table 16. Financial assumptions

Financial Assumptions	Units	Value
Inflation rate	%	6.7%
Project life	years	23
Equity Portion	%	30%
Debt Portion	%	70%
Cost of Equity	%	17%
Debt Interest Rate	%	12%
WACC	%	13.5%
Debt term	years	10
CER Price (4/8/2009)	€	11.00
Exchange Rate (4/8/2009)	R/€	11.20
CER Spot Price Rand (2009)	R/€	123.20
CER Price Annual Escalation	%	5%

This results in the financial apportioning shown in Table 17.

Table 17. Financial parameters

	UK	MK	LK
Total Capital Cost	R 152,366,946	R 66,879,746	R 79,441,555
Equity	R 45,710,084	R 20,063,924	R 23,832,467
Debt	R 106,656,862	R 46,815,822	R 55,609,089
Interest during construction	R 18,338,539	R 8,049,494	R 9,561,405
Debt + Interest during construction	R 124,995,401	R 54,865,316	R 65,170,494
Annual Debt Payments	-R 22,122,207	-R 9,710,292	-R 11,534,145

A cash flow is constructed for each layout at both upper and lower PPA levels for base and best case scenarios. The cash flows for each layout are shown in Figure 56, Figure 57 and Figure 58.

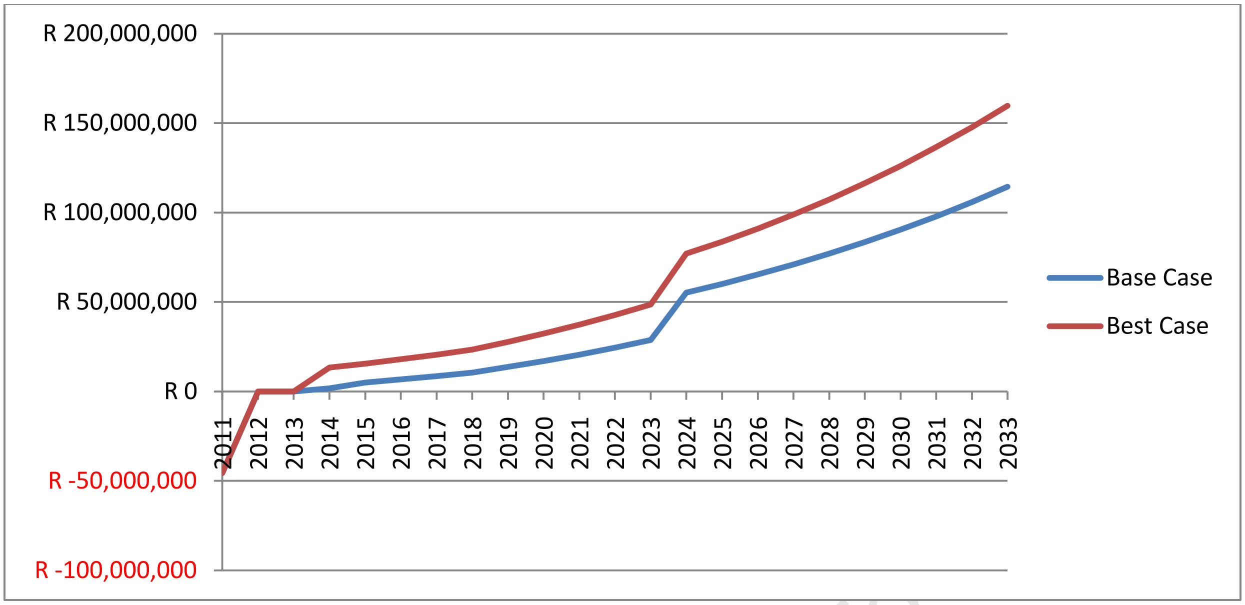

Figure 56. UK cash flow

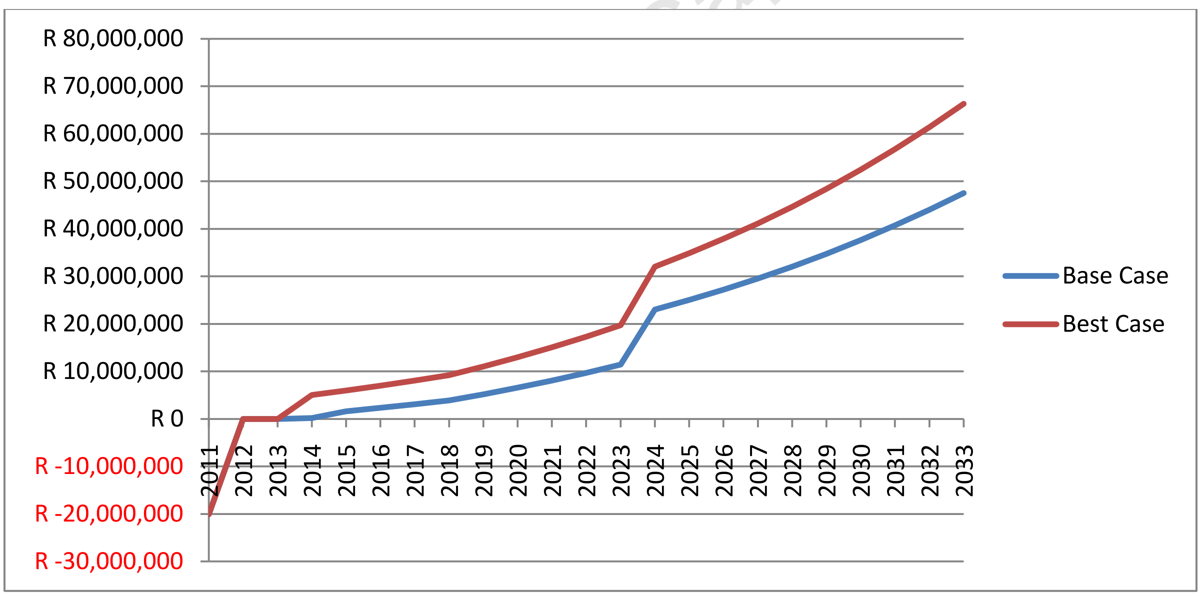

Figure 57. MK cash flow

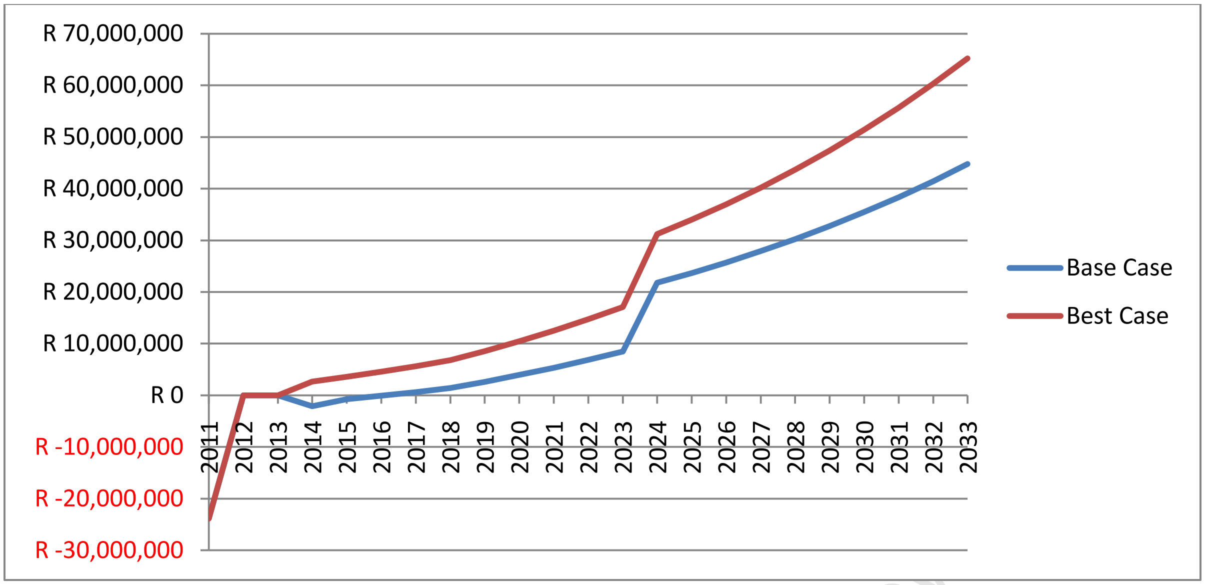

Figure 58. LK cash flow

It is noted that the LK base case shows negative cash flows in the first three years of production.

The investment criteria results are summarized in Table 18.

Table 18. Investment criteria

	Simple Payback [years]	
	Base Case	Best Case
UK	7	4
MK	8	5
LK	11	7
	Yield [%]	
	Base Case	Best Case
UK	16%	23%
MK	15%	22%
LK	12%	18%
	IRR [%]	
	Base Case	Best Case
UK	23%	32%
MK	22%	30%
LK	17%	25%
	NPV [R]	
	Base Case	Best Case
UK	R76,571,724	R155,252,095
MK	R29,120,709	R61,867,884
LK	R14,878,483	R48,654,648
	Profitability Index	
	Base Case	Best Case
UK	2.68	4.40
MK	2.45	4.08
LK	1.62	3.04

These figures are compared graphically. The simple payback figures for base and best cases are shown graphically in Figure 59.

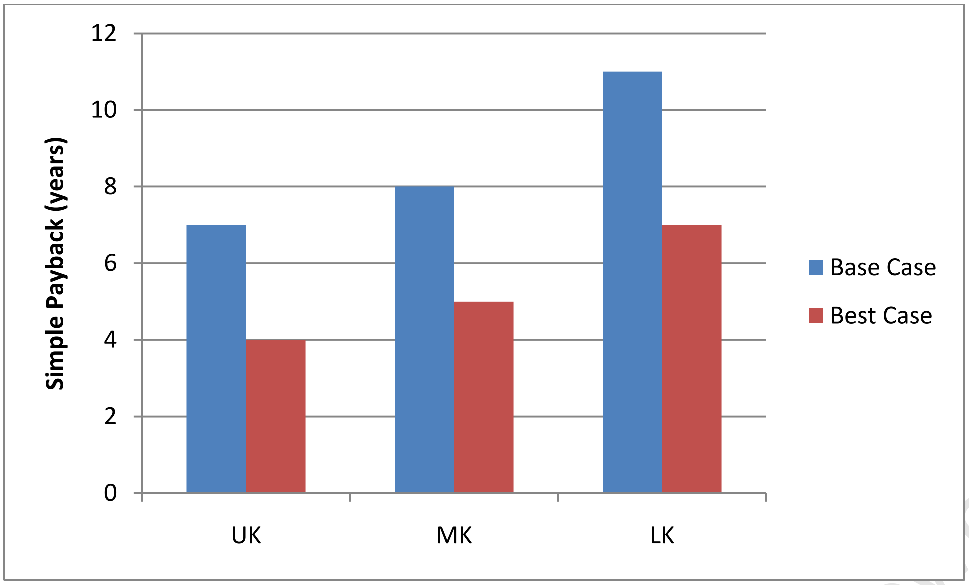

Figure 59. Simple payback

The yield for base and best cases are shown graphically in Figure 60.

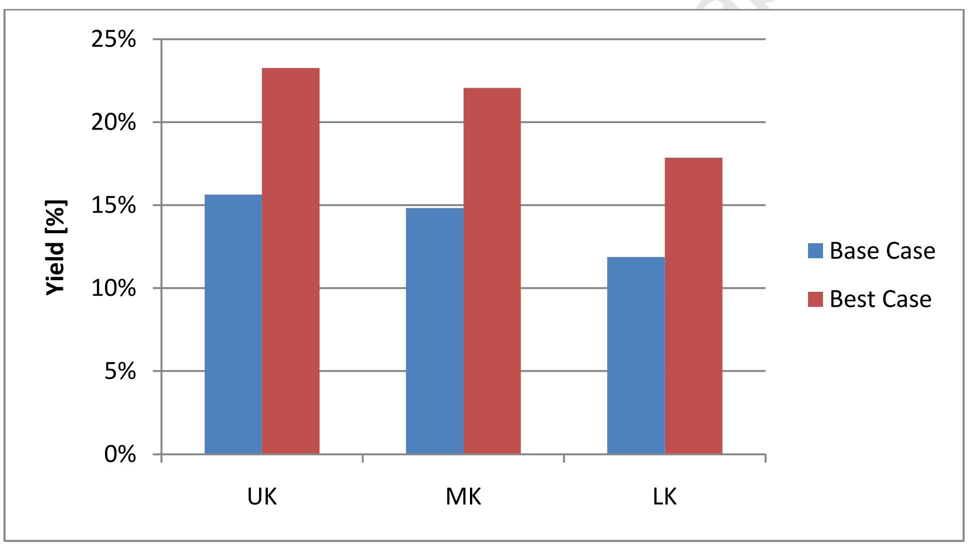

Figure 60. Yield

The IRR for base and best case are shown graphically in Figure 61.

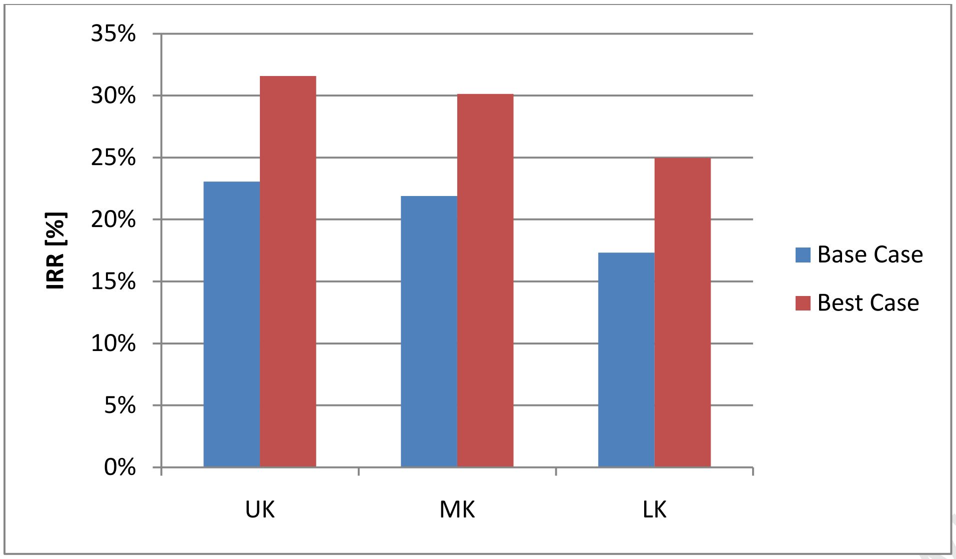

Figure 61. IRR

The NPV for base and best case are shown graphically in Figure 62.

Figure 62. NPV

The profitability indices for base and best cases are shown graphically in Figure 63.

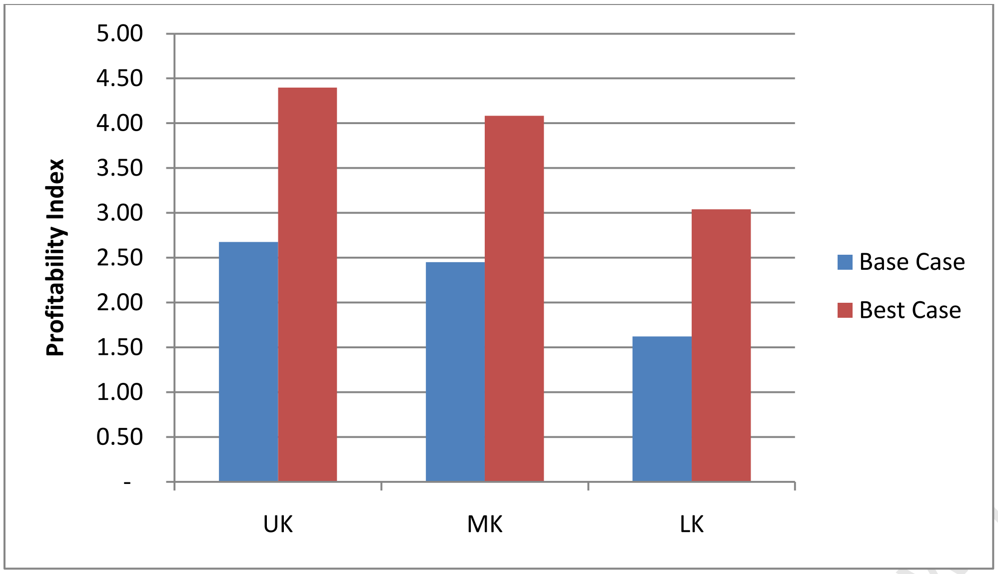

Figure 63. Profitability indices

8 Discussion and Recommendations

8.1 Layout Design

Eight layouts were analyzed, and three are proposed as making the best use of available head. Each layout is discussed separately below.

8.1.1 UK

The level of the weir crest constructed at UK is an important parameter as it determines the head at this layout. The level of 1715 is a maximum level because if it is built any higher it will impact on Botterkloof weir and the proposed Botterkloof Hydro plant will lose head. If for any reason it is necessary to reduce the level of the weir crest then the income will drop significantly.

It is necessary to co-operate with the owner of farm Spionkop for the construction of the tailrace, and in all likelihood also with the owner of farm Boston as the canal and weir are just a few metres away from the boundary with this farm, and a portion of this farm will be flooded, depending on the height of the weir constructed.

Because of the benefit created for downstream powerplants by storing water and timing generation for peak periods, it may be possible to distribute the costs of the storage system between all beneficial plants. This may be significant for the viability of UK, especially if a high (costly) wall (and large storage) is chosen.

If it is not permissible to create variation in the flow (which may be the case as it exacerbates erosion, and has other negative effects), then the storage dam can be used to attenuate the flow which has a lesser but not insignificant advantage. This will allow the selection of turbines with lower degrees of flexibility (such as a single-regulated Kaplan or even propeller rather than a double-regulated Kaplan), lowering the cost of the systems.

8.1.2 MK

The existence of Weir 26 is extremely valuable as its construction would cost in the region of R20M. However, its existence means that the head at this layout is set, and the gross head of the system is on the low side at below 7m. Hence raising Weir 26 could yield significant benefits. The cost of this exercise is not currently known, although it is not expected to be significant. The region flooded will determine whether or not the EIA will be granted. Once it is known what level of flooding is likely to be allowed from an environmental perspective, the upper limit of the weir is known. It may be feasible to raise the weir by as much as four metres, which would result in the use of all the head available below UK. Following the environmental analysis, the technical feasibility of raising the weir to different levels is to be investigated. The costs of stopping or diverting the water during construction also need to be taken into account when considering this.

8.1.3 LK

The height to which the weir to be constructed at LK is raised is the most significant factor determining the viability of this site. Its construction will inundate a portion of Middelvallei 130, and cooperation with the owner of this property is essential for the success of the layout. In addition, the bridge over the road just upstream of the weir will need to be altered. This is not a complex or expensive process technically (Viljoen 2009), but may involve contact with the authority in charge of such infrastructure. This may introduce delays and is considered a risk.

8.2 Technical

8.2.1 Turbine type

The selection of double regulated Kaplan turbines is considered the likely final selection. However, it may be cost-effective to select a single regulated turbine. Further work on the variability of head is required as a single regulated Kaplan does not adapt well to variation in head. Its high efficiency between 30% and 100% of design flow would enable it to adapt sufficiently to the flow variation present at Kruisvallei. If the head variation is not significant, it may perform virtually as well as double regulated Kaplan, and will cost less.

8.2.2 Turbine Design Flow

The selection of a design flow of $34m^3/s$ by maximizing NPV is valid and is therefore expected to be near the final decision. In light of discussion point 8.5 it may be advisable to increase the design flow further. However, until the PPA level is known, it is not possible to optimize this design decision. If the PPA is higher than expected, then it will pay to "spread the net wider" with a larger design flow and "gather" more energy during extreme high flow periods. If the PPA is lower than expected, then "gathering" energy at high flows will not be cost effective.

8.2.3 Grid Connection

Integration with the Botterkloof plant south of Kruisvallei appears to provide a number of opportunities for cost-effective grid connection. This is not possible with the Merino plants on the Northern side of Kruisvallei. Selection of a 22kV line will be cheaper and more straightforward to align than an 88kV line. Which of the three alignment options is best is not yet clear. Uncertainty remains around which party will be required to pay for what, but it may be possible to save money by allowing Eskom to align the connection. However, risks are associated with releasing control over such an integral element of the development to a third party.

8.2.4 Compliance

Although not central to the analysis conducted in this study, compliance requirements are central to the development of the Kruisvallei sites and the scope of the study as defined in section 2.2 requires their consideration. The compliance requirements identified include:

- Water Use License
- Environmental Impact Assessment
- Generation License

Appendix D: Compliance Requirements discusses these in more detail. The main concern is delays resulting from the Water Use License.

8.2.5 Building for the Customer

The primary product produced by IPPs is electricity. Despite the fact that electricity is a commodity, (one electron being just like any other) the developer of Kruisvallei has the ability to make the electricity more or less marketable. The likely customer is Eskom, and the best case scenario is based on the REFIT tariff which is offered by REPA. On top of a number of base requirements (including phase and voltage), the following aspects can make Kruisvallei's power attractive:

- Reliability

It is possible to construct the hydraulic structures so that they will be able to withstand various flood levels, say 2-, 50- or 100-year floods. The more robust the system, the more reliable the power generated will be.

- Predictability

It is possible to predict with high levels of accuracy the energy quantities which Kruisvallei will produce, because of the controlled flow. This is in contrast to other renewable energy technologies, where wind or solar energy intensities can be very unpredictable.

- Dispatchability

Generation during peak periods is very costly to Eskom. If Kruisvallei has the capability to dispatch power during peak periods this will make the power extremely attractive. This further illustrates the benefit of storage at UK.

8.3 Financial Analysis

8.3.1 Capital Cost

The extent to which capital costs are higher than historical and expert estimates is a contentious issue. It could mean one of two things, or a combination of both. Firstly, that the costing methodology is very conservative and both civil and electromechanical works will actually cost significantly less. Alternatively it could mean that the viability of the sites is fundamentally limited. It is plain to see from the consideration of raising Weir 26 that additional head results in great increases in income. Hence if the sites had greater head for the same civil works costs, the specific capital costs could approach best historical and expert estimates, illustrating the potential for the second possible cause.

UK has the lowest specific cost, followed closely by MK with LK being third. UK has the highest capital cost resulting from the need to construct three significant civil structures. However, its low capital cost can be attributed to the high head achieved. In the case of MK, the existence of weir 26 is extremely valuable. LK has a similar cost profile to MK, although slightly lower head, increasing its specific capital cost. The potential for raising weir 26 and increasing the level of the weir to be constructed at LK has excellent potential to reduce the specific capital costs of these two layouts. This potential is highly significant because the total cost of a small hydro investment is dominated so much by capital costs, as against periodic costs.

8.3.2 Project Life

It is typical to analyze a project of this nature over a period of twenty years. However, the actual life time of a hydroelectric plant is likely to be in excess of fifty years and ignoring cash flows beyond this period may hide additional benefits of a long term investment. In light of the use of the WACC to discount cash flows a twenty year analysis is justified. In the light of the discussion in section 8.3.3 a longer analysis period may result in different financial results.

8.3.3 Risk

In addition to the discussion on project life, the discount rate can skew investment decisions. The evaluation of the WACC, at which the investment is discounted, includes an allocation for implementation risk. Once the project is in the O&M phase, this risk is removed. Hence the entire income earning period is perceived at a far higher risk level than it would be after the project has reached this phase. It may therefore be appropriate to analyze the Implementation and O&M phases separately to account for the respective risk levels of each phase.

8.4 Investment

Simple payback and yield are somewhat superficial investment analysis tools, although they do give a useful synopsis of the total investment under consideration. The first conclusion that is drawn from these results is that the ranking of the investments is clearly UK first, MK a close second and LK third. Best case simple paybacks of 4-7 years are very encouraging. The base case figure of 11 year simple payback for LK is concerning. The use of yield gives an idea of the performance of the business in the early stages of production. Income over the following years of production is relatively constant with inflationary or little more than inflationary increases, indicating low market risk. The yield results are close to the inverse of the simple payback results. Therefore, the simple payback and yield results indicate encouraging fundamentals underpinning the investments considered.

The NPV, IRR and PI analyses focus on the equity investment. This is significant because it focuses on the owner's investment (the equity portion of project finance), as opposed to analyzing the total investment. Positive base case NPV results indicate that investment in all three layouts should be made. The minimum IRR value is 17% for the LK base case. This is equal to the assumed cost of equity, indicating this is probably near the minimum adequate return level. It would be necessary to consult the owners for their required rate of return, but the IRR base case results indicate more than adequate returns. Best case returns are extremely high. The PI results (maximum of 4.4 for UK best case) indicate exceptional cost-effectiveness in the investments considered.

The sole concerning outcome of the investment analysis is the existence of negative cash flows in the first three years of production for the LK base case. Additional cash injection post implementation is likely to be highly undesirable.

8.5 Consideration of Life Time Benefits

A decision type which will repeat itself is the opportunity to spend more initially to gain increased life-time earnings and a higher overall investment value. This is illustrated by a hypothetical comparison between LK and DL 5 (see section 11.3). If one assumes that (at some complication and cost) weir 34 can be raised by 3m and that the LK wall cannot be raised beyond its current level. The cost of LK will increase significantly, reducing IRR. However, it will mean a head of 9m for DL 5 and just 6m for LK. LK is most likely a "better business" over the analysis period, but additional earnings beyond this period are not reflected in the analysis. If they were, it may be possible that DL 5 is in fact a more valuable investment. A similar decision will face the developer for the final choice of turbine design flow where a larger turbine enables the use of higher future flows, but will have a higher initial cost.

The decision is between smaller and larger investments, the smaller one showing a higher rate of return. The analysis conducted in this study is geared towards bankability and risk mitigation. Lenders are most concerned about ensuring that there money will be repaid, and hence the study focuses on the term over which repayments will be made. However, if two competing ideas are both bankable, the developer has the decision to pursue either. If the nearer-term cash flows are an investor priority, it may be a better decision to pursue the smaller, higher rate of return option. On the other hand, if the developer has the means to pursue the larger investment, it may have a higher net value. A larger system will generate larger income for the entire period after debt payback, creating benefits in excess of those from a smaller one for long periods of time. The magnitude of earnings over the lifetime of the plant will be greater for the larger plant.

8.6 Next Steps

Although the Kruisvallei projects have been analyzed from their implementation phase onwards, the next step in the development is to conduct a full bankable feasibility study. Typically the cost of this phase is in the region of 2,5% of the total capital expenditure (Porter 2009). This would result in a feasibility expenditure of approximately R3M for UK and R1.5M for both MK and LK. It will be possible to achieve some savings through the bundling of the three. Although small in comparison to the implementation costs, the feasibility costs are spent when the project has a much higher risk associated with it, making such investment very substantial. The work conducted in this study will have increased understanding and reduced the project risk to some extent, but the results presented here are by no means concrete.

8.7 Recommendations

8.7.1 Investment

- The analysis strongly suggests investment in UK and MK, and this is recommended. LK shows marginally less attractive results, but investment here is also recommended.
- An iterative development process is advisable to mitigate risk. Nevertheless, the results are sufficiently emphatic to recommend the next study to be at full bankable feasibility level.

8.7.2 Layouts

UK

- It is recommended that the owners of the farms Spionkop and Boston be consulted as soon as possible to assess the sentiment with regards to the proposed layout.
- The potential and benefits of UK storage should be investigated fully. This includes the available storage potential, maximum peak discharge allowable from an environmental perspective.

MK

- Further investigation into the possibility of raising Weir 26 is recommended. This firstly into the environmental feasibility to establish a maximum crest height, and then into the technical feasibility to gain cost figures for raising the weir to different heights after which point a cost-benefit analysis can be more accurately performed.

LK

- It is recommended that the owner of the farm Middelvallei be consulted regarding the area flooded by the LK system. If an arrangement can be made, and it does not cause difficulties with the road over the river, it may be possible to increase the head to 7 – 8m, improving this layout significantly.

8.7.3 Technical

- All three layouts are very sensitive to head, and it is recommended that a surveyor be engaged to increase confidence in the gross head values.
- It is recommended that further work be conducted on final head variation with flow so as to educate the decision between single-and double-regulated Kaplan turbines.
- It is recommended that the design flow of $34m^3/s$ be used until such time as the off-take level is known.
- As long as the projects remain bankable, it is recommended that the capacity of the installation be maximized to benefit from income over the life of the system

8.7.4 Financial

- Accuracy of capital cost estimates can quickly be improved through engagement of civil engineering expertise and this is recommended.
- It is recommended that actual realizable off-take agreements be pursued to gain a firmer picture of the income level. TOU tariff development must be watched closely.
- A financial analysis taking into account the risk reduction resulting from development progression is recommended.

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11 Appendices

11.1 Appendix A: REFIT

The Renewable Energy White Paper 2003 set as its target 10000GWh of “renewable energy contribution to final energy consumption by 2013.” (DME_c ,2003) This has given a high-level drive to the implementation of renewable energy technologies. Since 2003, however, the use of renewable energy sources has not seen much increase, and the publishing of the REFIT is a final effort to achieve or at least show progress towards the 10 000 GWh target outlined in the White Paper.

Feed-in tariffs have been shown internationally to be the most effective policy mechanism for the rapid and widespread implementation of renewable energy technologies. “The basic economic principle underpinning the FITs is the establishment of a tariff (price) that covers the cost of generation plus a "reasonable profit" to induce developers to invest.” ($Nersa_a$, 2009) A further objective is to provide IPP investors with a body which has “an obligation to purchase power generated” ($Nersa_a$, 2009)

Tariff Detail

The South African REFIT is not reduced over time, as was originally planned ($Nersa_a$, 2009) in line with the view that renewable energy technologies should reach market competitiveness over time). The REFIT for small hydro is 94 2009 cents, and it increases with inflation according to the CPI. The term of the PPA is 20 years. The PPA draft is based on the MTPPP (Medium Term Power Purchase Plan), and can be viewed on the Renewable Energy Feed-In Tariff Phase 2 consultation paper. ($Nersa_b$, 2009)

Legislation Environment

The buyer of power under the REFIT is named the Renewable Energy Purchasing Agent (REPA) and is the Eskom Single Buyer Office. This appointment is also “in line with the ‘Statement on Cabinet Meeting of 05 September 2007 whereby Eskom is designated as the single buyer of power from Independent Power Producers (IPPs) in South Africa.” ($Nersa_b$, 2009)

Nersa has “the mandate to determine the prices at and conditions under which electricity may be supplied by licence.” ($Nersa_b$, 2009) License applications are therefore made with Nersa. Eskom is obligated to comply by awarding REFIT PPAs to renewable energy generators who have satisfied the necessary conditions. "For projects awarded licences by the Regulator under REFIT, REPA is obliged to purchase the power, subject to fulfilment of all necessary licence conditions." ($Nersa_b$, 2009)

Qualification for REFIT

The following are mentioned as the criteria for REFIT qualification ($Nersa_c$, 2009) :

- The energy source must be renewable, and accommodated by the REFIT guidelines. Small hydro power plant (less than 10MW) was outlined in REFIT phase 1 guidelines.
- The generator must have acquired a generation license.
- Reporting on the quantity of renewable energy generated.
- Monitoring and verification of renewable energy generated. This is the responsibility of REPA.
- Termination conditions for non-compliance on renewable generation.
- Generators under REFIT must be connected to the transmission and/or distribution system.

Application and Administrative Process

The process of acquiring a PPA with REPA is not fully emerged, and as yet no IPP has achieved this. However, the following guidelines are however published ($Nersa_b$, 2009) :

- "Applications to qualify as an RE Generator shall be made to the Regulator in conjunction with the application for a licence to generate electricity in terms of Section 11 of the Electricity Regulation Act, No. 4 of 2006.
- The agreed tariff will be set according to the base year in which the Generation License for the RE Generator is issued by the Regulator.
- Approval of qualification for the REFIT shall be defined in the Generation License. This will specify the technology, the tariff approved, duration of the REFIT and other specific licensing conditions."

From an analysis of the official documentation presenting the REFIT, positive conclusions can be drawn. Renewable Energy IPPs have a guaranteed buyer of their power, the tariff is fixed over a period long enough for debt repayments to be completely made, and the tariff is not reduced over time as may have been the case. However, doubts remain about the practical processes of acquiring a REFIT PPA. The competitive IPP tendering (whereby all private generators, including fossil fuel-based plants have to compete for PPAs on an equal footing) process draft released in January 2009 by the DME, for example, clearly does not complement the REFIT legislation. [14] Some uncertainty therefore remains around securing a PPA under REFIT.

11.2 Appendix B: CDM

Introduction

The Kyoto protocol placed requirements on annex 1 (developed) countries to reduce emissions of Green House Gases (GHGs) ($UNFCCC_b$, 1998). It is often more cost effective for reductions to be made in developing countries than in already industrialized countries. These emissions reducing projects developed in developing countries are funded by buyers of CERs in Annex 1 countries. Hence global emissions reductions are reduced at a lower cost. This system is known as the Clean Development Mechanism (CDM). The owner of a project which reduces emissions can develop a CDM project and sell the Certified Emissions Reductions (CERs). The CDM has been operational since 2006 and had registered more than 1000 projects equivalent to more than 2,7 billion tonnes of $C0_2$ reduction. ($UNFCCC_a$ 2010) A key concept concerning CDM is additionality. The Kyoto protocol defines "additional" reductions as "Reductions in emissions that are additional to any that would occur in the absence of the certified project activity." ($UNFCCC_a$, 2010)

Finance from the CDM

CERs can be sold at any stage of the development or implementation of a CDM project. CERs are traded on an internationally regulated market. If the CER's are forward sold (ie sold at any point before the issuance of CERs) then the risk of the CERs not being issued increases for the buyer, and hence a lower price is paid. Payment for CERs will not occur before issuance of the CERs. However it is possible to acquire funding for development costs (such as EIA, CDM registration or PDD validation costs) from CER buyers.

Key bodies involved with CDM projects

Designated National Authority (DNA)

The main task of the DNA is to assess potential CDM projects to determine whether they will assist South Africa in achieving its sustainable development goals and to issue formal host country approval where this is the case. (DME_e, 2009) The DNA in South Africa sits in the DME.

Executive Board (EB)

The EB is the supervisor of all CDM activity, and receives its authority from the Conference of Parties, the supreme body of the CDM. The EB "is responsible for accrediting operational entities, defining modalities and procedures for the CDM, approving new methodologies and guidelines related to baselines, monitoring plans and project boundaries. It also maintains the CDM registry and database." (DME_e, 2009)

Designated Operational Entities (DOEs)

Independent bodies accredited by the EB to perform validation, monitoring and certification. The DOEs function is the practical application of CDM principles. Accredited DOEs include:

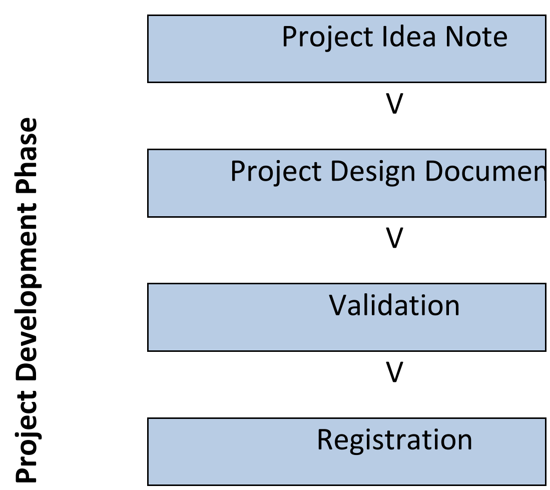
- Bureau Veritas
- Environmental Resource Management

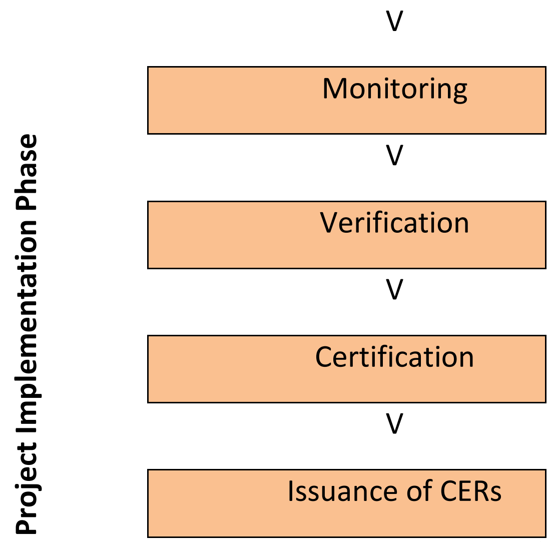
Carbon Consultants

Carbon Consultants are firms with intimate knowledge of the climate change and emissions environment as well as CDM project activity. Carbon Consultants primary roles are formulation of the Project Design Document and oversight of the development of the CDM project.

The CDM Project Cycle

The sequence of activity for developing and implementing a CDM project is shown below (Scharling, 2009).





Each stage of the process is described below. (DME_e, 2009)

Project Idea Note

This is an optional registration of the project with the DNA, who may or may not issue a "letter of no objection." Information requirements for the preparation of the PIN are contained in this report.

Project Identification and Design

The project owner identifies an opportunity for a CDM project and develops a Project Design Document (PDD) that includes a baseline estimate and an analysis of the net carbon emissions reductions.

Host Country Approval

This is carried out by the Designated National Authority. Note: The process for host country approval can happen "in parallel" with the validation process but it is required before a project can be submitted for registration to the Executive Board. There are three guiding criteria for this which are evaluated by the DNA.

- **Economic**. Does the project contribute to national economic development?
- **Social**. Does the project contribute to social development in South Africa?

- **Environmental**. Does the project conform to the National Environmental Management Act principles of sustainable development?

Third-party validation of the Project Design Document

This step is carried out by a Designated Operational Entity.

Registration

Once a project is validated and approved by the host country, it is registered by the CDM Executive Board.

Monitoring

Project performance, including baseline conditions, is measured by the project developer in the commissioning process and during on-going project operation.

Third-party verification of project performance

An independent third party (a Designated Operational Entity or DOE) verifies project performance against the validated design and baseline in order to approve certification.

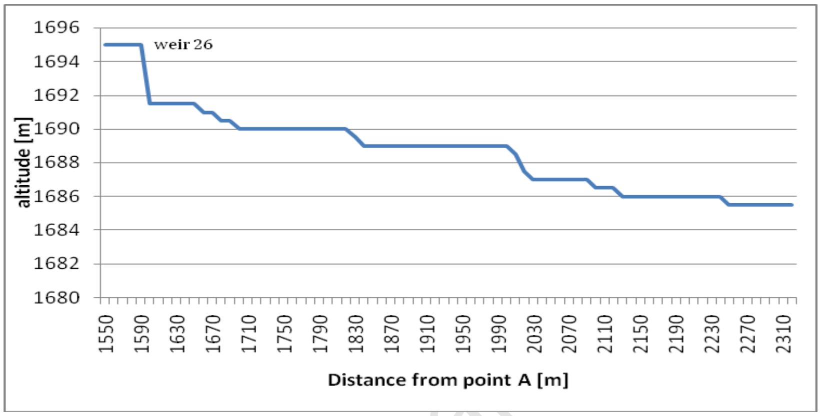
Certification and issuance of CERs

Based on the host-country approval, the validated project design and baseline, and the verified project performance, CERs are certified by a DOE and issued by the CDM Executive Board.

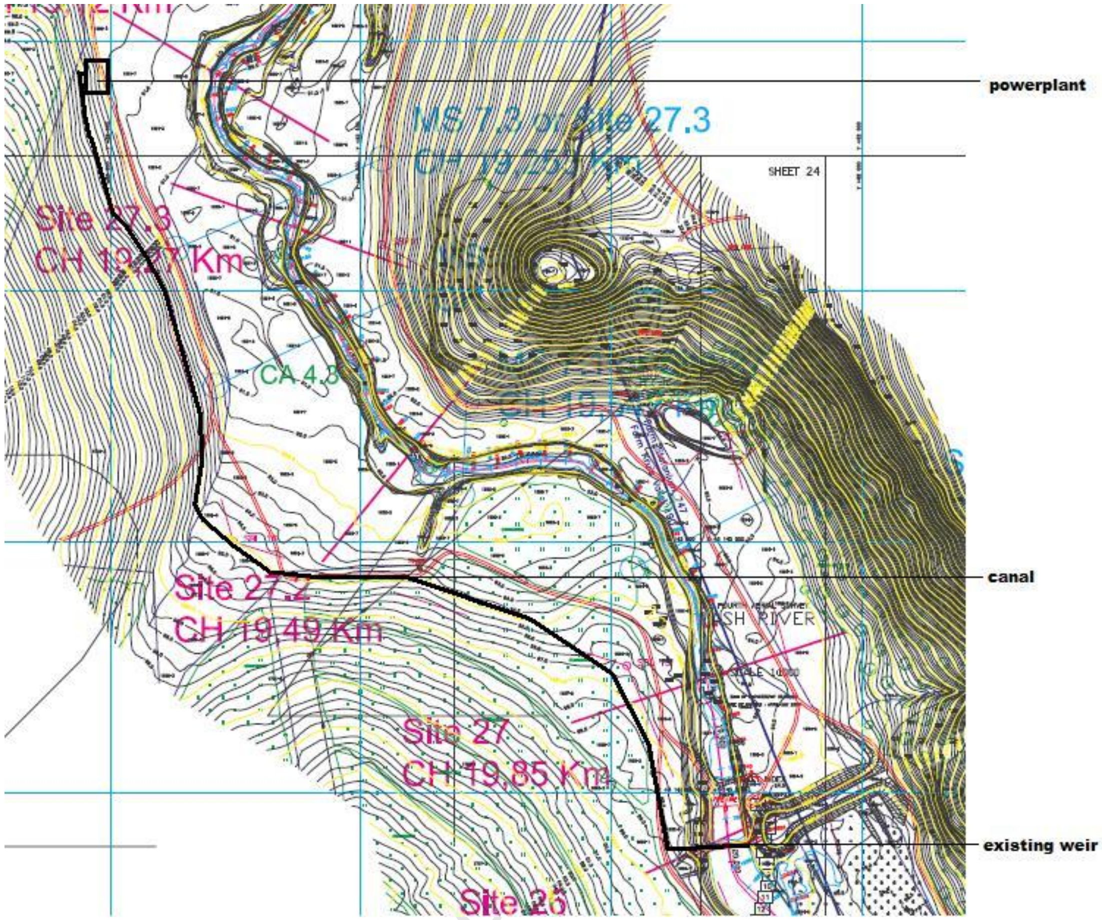
11.3 Appendix C: Discarded Layouts

Discarded Layout 1

DL 1 makes use of the drop immediately below weir 26 (as does MK), and extends a small distance further than MK downstream, gaining an additional 1,5m of gross head. The head profile of the river in the region spanned by this layout which has an average gradient of 1,25% is shown below.



A schematic of DL 1 is shown below.

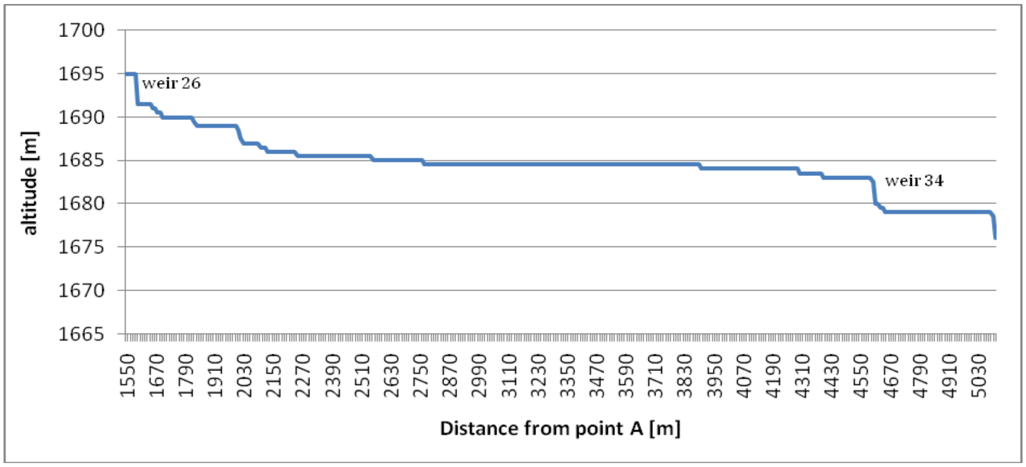


Rationale and Reason for Discard

This layout was considered as a potential add-on to the MK which makes use of the additional head just below the proposed re-entry point of MK. This makes use of an additional 1,5m head through the construction of an additional 400m of canal. The layout was discarded because from a visual inspection it is suspected that there is not an additional 1,5m of head available. This is a region of high erosion and the levels make have changed since 2003 when the maps were constructed. In short, this layout is less favourable than MK economically.

Discarded Layout 2

DL 2 makes use of the total head below weir 26 using a single system. The head profile of the river in the region spanned by this layout which has an average gradient of 0,54% and is shown below.



A schematic of DL 2 is shown below:

Rationale and Reason for Discard

The rationale of this layout is to use all the head below weir 26 in the simplest possible way: in a single system. The problems with this scenario are:

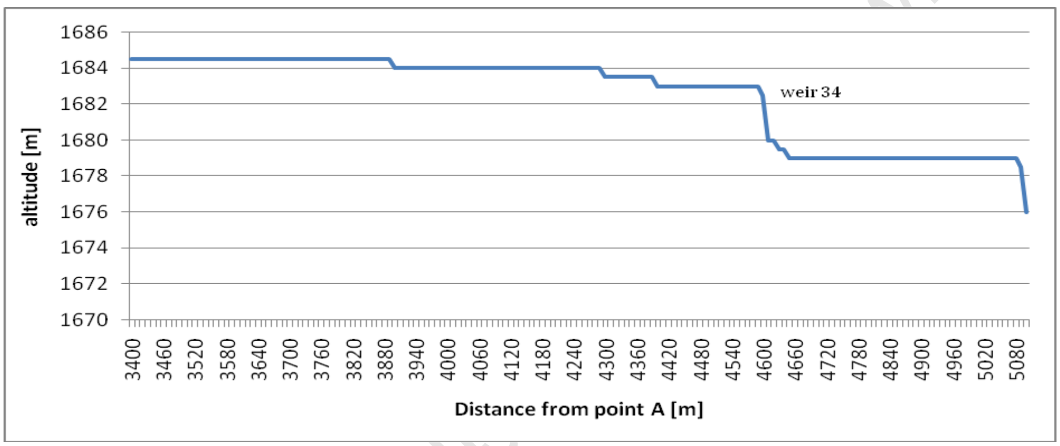
- A portion of the canal and the off-take are not on Kruisvallei.
- The terrain through which the canal must pass is not straightforward; rocky outcrops, a marsh and steep side slopes must be negotiated.

- The 3,5km canal is prohibitively expensive

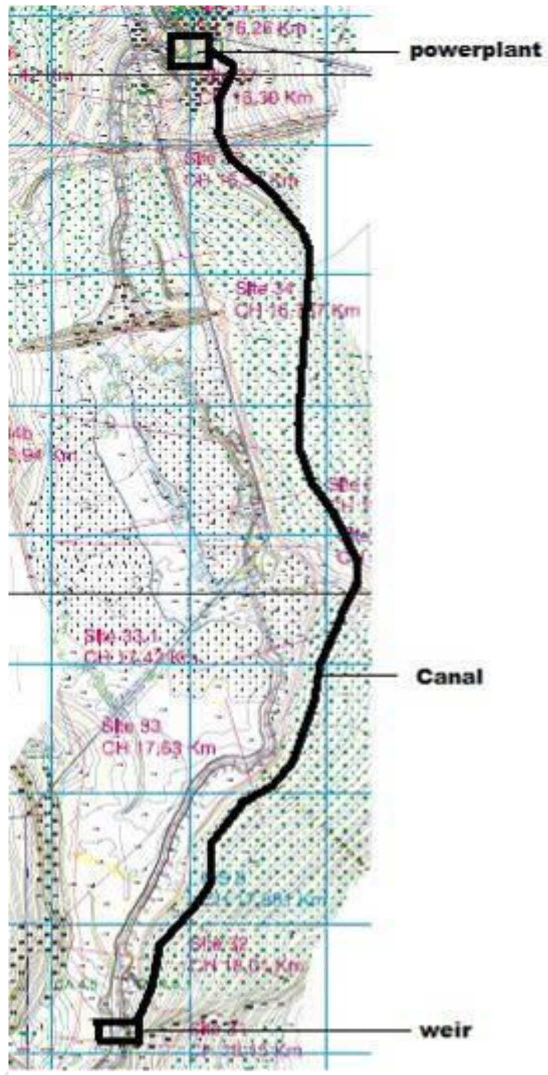
DL 2 was discarded because of the problems listed as well as the fact that it is not the best economic layout. This is partially due to the fact that over 3m of head is lost in the canal, defeating the object of the layout.

Discarded Layout 3

DL 3 makes use of the total head available below MK through the construction of a new weir 2,5m above the current level of the river. The head profile of the river in the region spanned by this layout which has a gradient of 0,65% is shown below.



A schematic of DL 3 is shown below.

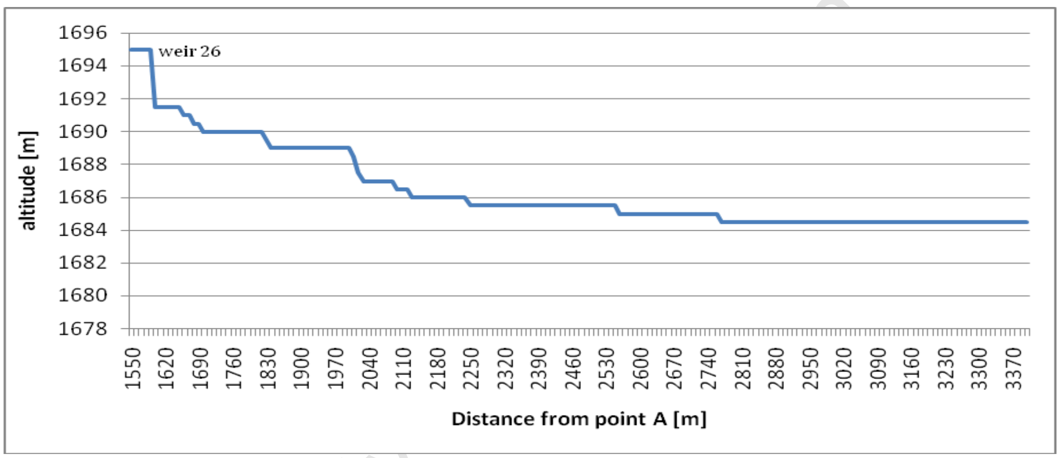


Rationale and Reason for Discard

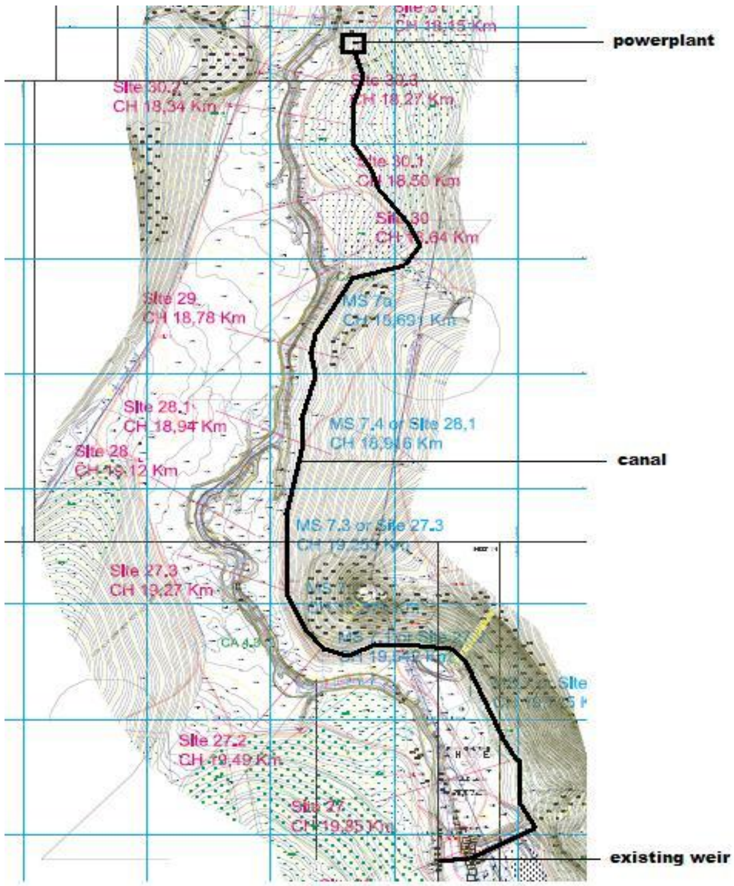
The rationale behind this scenario was the desire to make use of all the available head below MK. It is possible to build a weir to the height of the tailrace of MK, thereby using all the head available below. The main problem with this layout is the construction of the weir which will require extensive piling because of the depth of the bed rock, probably making the layout uneconomic. In addition, significant head is lost in any event because of the length of the canal, to a certain extent defeating the object of the layout.

Discarded Layout 4

DL 4 is the layout proposed by Nuplanet, analysed in the same way as all layouts in this study. It makes use of the drop below weir 26 and returns the water back to the existing river course shortly before the lower marsh begins. Figure shows the head profile of the river in the region spanned by this layout which has a gradient of 0,59%.



A schematic of DL 4 is shown below



Rationale and Reason for Discard

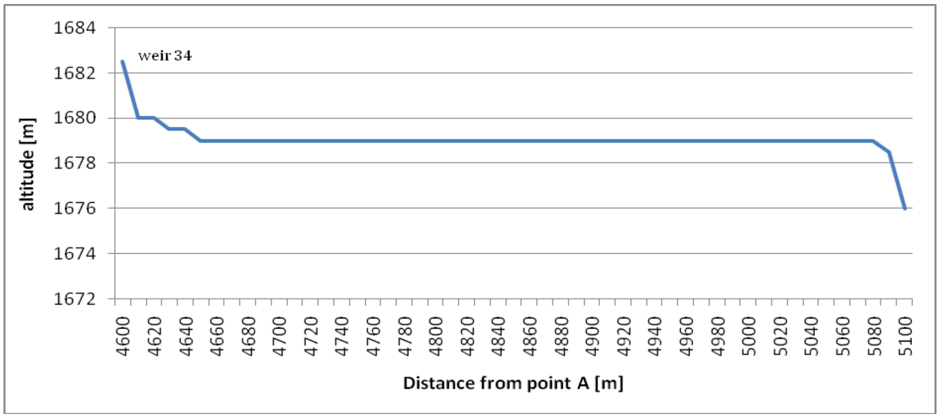
This layout was analysed purely because it was proposed by Nuplanet, not because the author saw potential in it. It has the following problems:

- It has the same problems as DL 2 in the early portion of the canal.

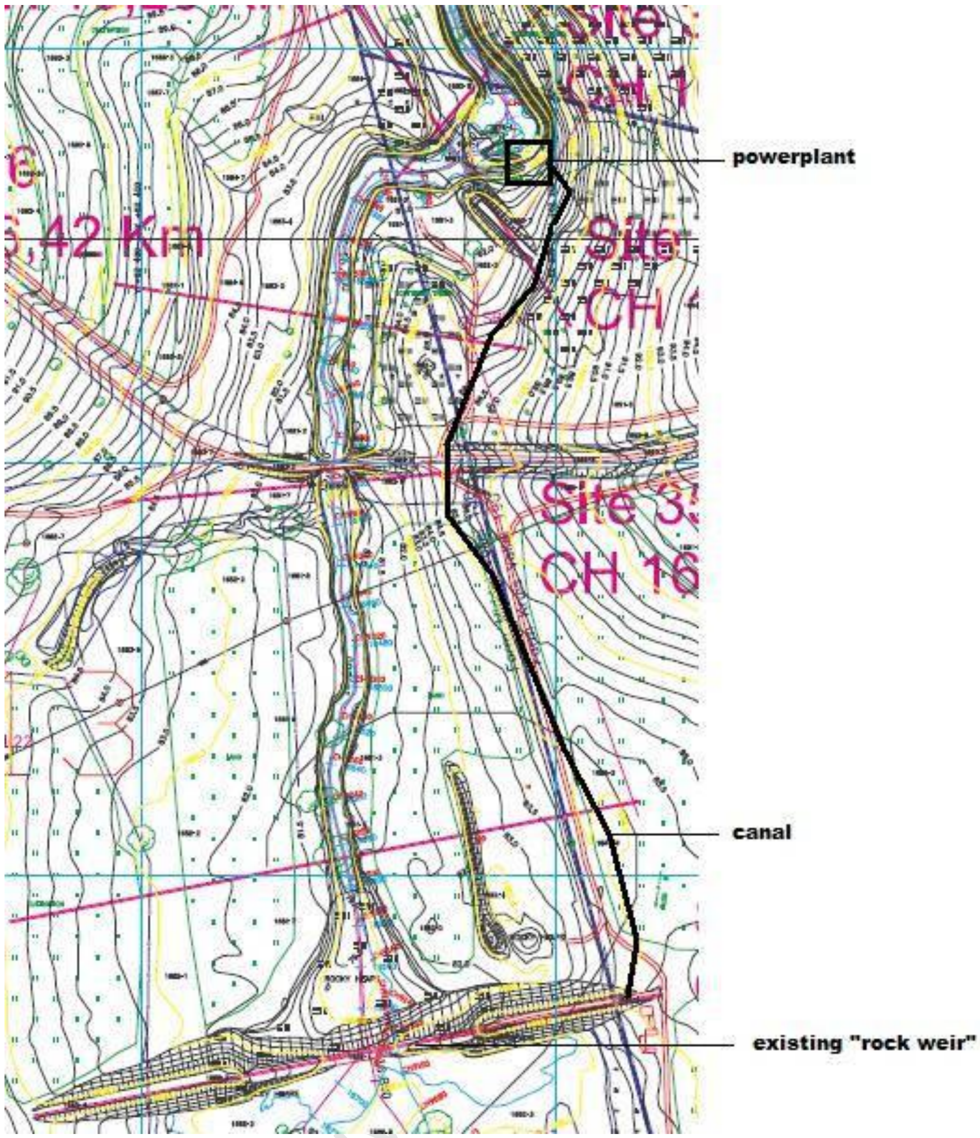
It was discarded because it is not likely to be cost-effective because it involves the construction of a lengthy canal to make use of a very small head in the lower regions (as can be seen in the head profile diagram). It is discarded because it is not the highest performing layout economically.

Discarded Layout 5

DL 5 makes use of the drop immediately below weir 34. The head profile of the river in the region spanned by this layout which has a gradient of 1,40% which is shown below.



A schematic of DL 5 is shown below:



Rationale and Reason for Discard

DL 5 suggests itself as the natural layout to make use of the drop below weir 34. It was initially thought that cost savings would be made because the weir already exists. The layout has the following problems:

- Construction of the off-take is extremely difficult because the bedrock is approximately 14m below the surface, making foundations very expensive.
- LK had better financial results
- The head is relatively low (5,6m gross head) making cost effectiveness unlikely.

DL 5 was discarded because it is thought that LK is a simpler and cheaper layout which will provide a greater generation capacity.

11.4 Appendix D: Compliance Requirements

Bode (2009) describes the compliance requirements for the Kruisvallei projects.

Water Use License

Custodian: Department of Water Affairs and forestry (DWAF)

Application Process

Applications are obtained and submitted in the DWAF regional office

- The regional office will assess the applications and advise on the requirements. The Regional office will further make a recommendation to the delegated official
- The regional office will then submit the application to the Head Office Chief Directorate Water Use for further handling
- The Chief Directorate Water Use reviews license application submission for compliance with the policy
- The Chief Director Water Use makes a recommendation for the Minister to take a decision.
- Applicants may appeal decisions to the Water Tribunal.
- Should the installation be installed in DWAF infrastructure, e.g. replace the Vaal Dam river outlet with a mini Hydro power unit, an application for a water use license from DWAF is required and authorisation/permission from the infrastructure owner will be required.

Environmental Impact Assessment

Custodian: Department of Environmental Affairs and Tourism (DEAT)

Application Process

Environmental Authorizations are regulated by the National Environmental Management Act, Act 107 of 1998 (NEMA), as stipulated under chapter 5 of the Act. Section 24 (i) of NEMA provides, "in order to give effect to the general objectives of integrated environmental management laid down in chapter 5, the potential impact on the environment of listed activities must be considered, investigated, assessed and reported on to the competent authority charged by this Act with granting the relevant environmental authorization. Section 24 (2) (a) further state that the minister and MEC's with the concurrence of the Minister, may identify activities which may not commence without environmental authorization from the competent authority. These activities were published in the government gazette and came into force on 21 April 2006 as GN No. R386 and GN No. R387 together with the EIA regulations GN No. R 385.

Since then, the construction of facilities or infrastructure, including associated structures or infrastructure for the generation of electricity are listed activities and as such requires an environmental authorization from the competent authority. Some applications are subject to a basic assessment while others are subject to scoping and environmental impact assessment depending on the nature and scale of the activity. In order to comply with the EIA regulations in this regard, before applying for environmental authorization of an activity, an applicant must appoint an Environmental Assessment practitioner (EAP) at own cost to manage the application. As indicated earlier, Basic Assessment must be applied to an application if the authorization applied for is in respect of an activity listed in government notice number R 386. Scoping must be applied to an application if the authorization applied for is in respect of an activity listed in Government Notice No. R387.

The Minister and provincial MECs entered into an agreement in terms of section 24 C (3) and according to that agreement, the department becomes the competent authority to process all applications related to electricity generation, distribution and transmission. This agreement is valid until 2013. Applications are lodged in a prescribed application form, must comply with the requirements for Basic Assessment process, scoping and EIA as prescribed in the regulations. The applicant or EAP must meet all the requirements in the regulations including Chapter 6. Failure to meet the requirements may result in reports being rejected or requiring amendments in the reports. The competent authority takes a decision on an application once all the information and requirements in terms of the regulations have been met, in which case the competent authority may decide to grant or refuse to grant an environmental authorization. The competent authority is required to take decisions within prescribed time frames in the regulations. The applicant / EAP can appeal against every decision taken by the authority.

Generation License

Custodian: National Energy Regulation of South Africa (NERSA)

Application Process

The Generation licence application process is initiated at the concept stage of a project with phased interim or provisional acceptance during the course of project development. The license application process particularly for generating plant should be phased with the development stages of such a plant. NERSA need to be provided with information concerning the project at the earliest stage of its development, and should confirm if the project warrants further development. An application for a license must be made in writing. Application form can also be obtained at NERSA website (http://www.nersa.org.za/). The application form should be accompanied by all documents indicated in the application form. Application for a license will be provided with a receipt from the energy Regulator recordings. Date, name of person who received the application and reference number will be recorded to track the progress of the application. It is the responsibility of the applicant to make sure that their application complies with all the requirements. The processes of license application are as follows:

- Prior to submitting a formal license application to the Regulator, it is recommended that potential applicants contact the Regulator's Head of Department: Licensing and compliance Electricity to determine the level of information required in the application. It is advised that the applicant receives expert advice, and should indicate the type of license being applied and nature of business activities undertaken or to be undertaken by the applicant.
- NERSA will then undertake the public hearing process. Public notice is published in national/provincial/local newspaper. The aim of public hearing is to receive public comments about license application and to use those comments as part of decision making processes.

- NERSA is required by the National Energy Regulator Act, 2004 (ACT No. 40 of 2004) to consult the public, especially the affected parties before making any decisions.
- An applicant is required to publish a notice of a license application in at least two newspapers on at least three different days in each newspaper, circulating in the area of the proposed activity in any official languages. Where application is made for a generation license in excess of 100 MVA installed capacity, or an import or export license, newspapers with national coverage should be used.