CITY OF CAPE TOWN | ISIDEKO SASEMAPA | STAD KAAPSTAD

City of Cape Town Mini Hydro Prefeasibility Study

An assessment of the potential for the development of hydroelectric plants at eight sites in the CCT Bulk Water System

5th August 2011

Authors:	Luel Culwick
	Christiaan Bode

sidala
energy solutions

Executive Summary

This study was undertaken to determine the initial feasibility of Mini Hydro Electric generation in the City of Cape Town's Bulk Water Infrastructure system. The study commenced on the 1st June 2011 and was finalized on the 5th August 2011 over a period of 10 weeks.

Prefeasibility Design

The analysis yielded positive results and it is recommended that a full feasibility study is to commence.

A total of eight sites were assessed at four of the major water treatment works. These being:

1. **Steenbras Water Treatment Plant**
   o Rockview Dam to Steenbras Upper Dam
   o Steenbras Lower Dam to the Steenbras Water Treatment Plant
   o Steenbras Water Treatment Plant to the 840 & 810 Break Pressure Tanks
2. **Wemmershoek Water Treatment Plant**
   o Wemmershoek Dam to Wemmershoek Water Treatment Plant
3. **Blackheath Water Treatment Plant**
   o Blackheath Water Treatment Plant raw water supply pipeline
   o Blackheath Water Treatment Plant to the Upper Blackheath Reservoir
   o Blackheath Lower Reservoir Inlet
4. **Faure Water Treatment Plant**
   o Faure Water Treatment Plant Inlet

A full technical and financial assessment was performed on each of the sites, identifying various potentials for each site. The following is a list of feasible options identified. Table 1 is a summary of all the sites that should be investigated further in the feasibility study following the outcomes of this prefeasibility. Table 2 and Table 3 summarise the design and financial results for these sites.

Table 1: Feasible Sites

	List of Feasible Sites
1	Steenbras Water treatment works to break pressure tanks 810, 840
2	Steenbras Lower Dam to Steenbras Water treatment works 2
3	Wemmershoek water treatment works
4	Blackheath Raw Water Inlet
5	Blackheath Water Treatment Works to Upper Service Reservoir
6	Blackheath Upper reservoir to Lower Reservoir 1
7	Faure water treatment works 2

When performing the site investigation at Steenbras, another potential site was identified and included in this investigation. The plant is to be situated at the 760 break pressure tank at Steenbras but did not yield positive investment results. It was concluded that it would still worth investigating further in the feasibility study.

Figure 1 to Figure 4 show a summary of the Capex, Cost of Electricity, NPV and Equity IRR for the sites to be further assessed.

Table 2: Summary of design results for sites to be further investigated

		SB Lower Dam to SBWTW C	SB Lower Dam to SBWTW 2	SBWTW to 760	SBWTW to 810, 840	BH Raw Water	BHWTW to Upper	BHUpper to Lower C	BHUpper to Lower 2	Wemmers-hoek C	Wemmers-hoek 1	Faure C	Faure 2
Static Head	m	*	55	172	74	77	8	64	64	*	35	*	*
Hydraulic losses	%	*	15%	10%	10%	45%	5%	5%	7%	*	10%	*	5%
Rated Head	m	34	48	155	66	42	7.6	60	60	28	31	130	124
Design Flow	m3/s	0.66	1.60	0.18	1.50	3.40	3.40	1.16	2.00	0.46	2.50	1.16	2.50
Design Flow	Ml/day	58	138	16	130	294	294	100	173	40	216	100	216
Turbine type		2 xTurgo	Francis	Pelton	Pelton	Francis	Kaplan	Turgo	Francis	Francis	Francis	Turgo	Francis
Runner Diameter	m	0.53	0.57	0.22	0.58	0.82	0.82				0.71	0.79	0.71
Turbine Design Efficiency	%	*	87%	91%	87%	86%	91%	*	88%	*	85%	*	90%
Turbine Capacity	kW	179	605	228	784	1 096	184	537	932	207	576	1 174	2 441
Annual Plant Downtime Losses	%	*	*	5%	5%	5%	5%	5%	5%	5%	5%	*	5%
Theoretical Energy Delivered	kWh	2 508 864	5 035 791	1 896 047	6 521 722	9 119 251	1 530 190	6 219 600	7 759 567	1 544 356	4 795 447	12 921 000	20 316 175
Actual Energy Delivered	kWh	788 196	2 532 311	767 260	4 266 995	6 138 489	1 041 251	3 294 928	4 473 515	*	3 596 066	7 772 310	13 445 706
Capacity Factor	%	31%	50%	40%	65%	67%	68%	53%	58%		75%	60%	66%
Actual Increase from Current Generation	kWh	-	1 744 116	-	-	-	-	-	1 178 587	-	2 051 711	-	5 673 396
% Increase	%	-	221%	-	-	-	-	-	36%	-	133%	-	73%

Table 3: Summary of financial results for sites to be further investigated

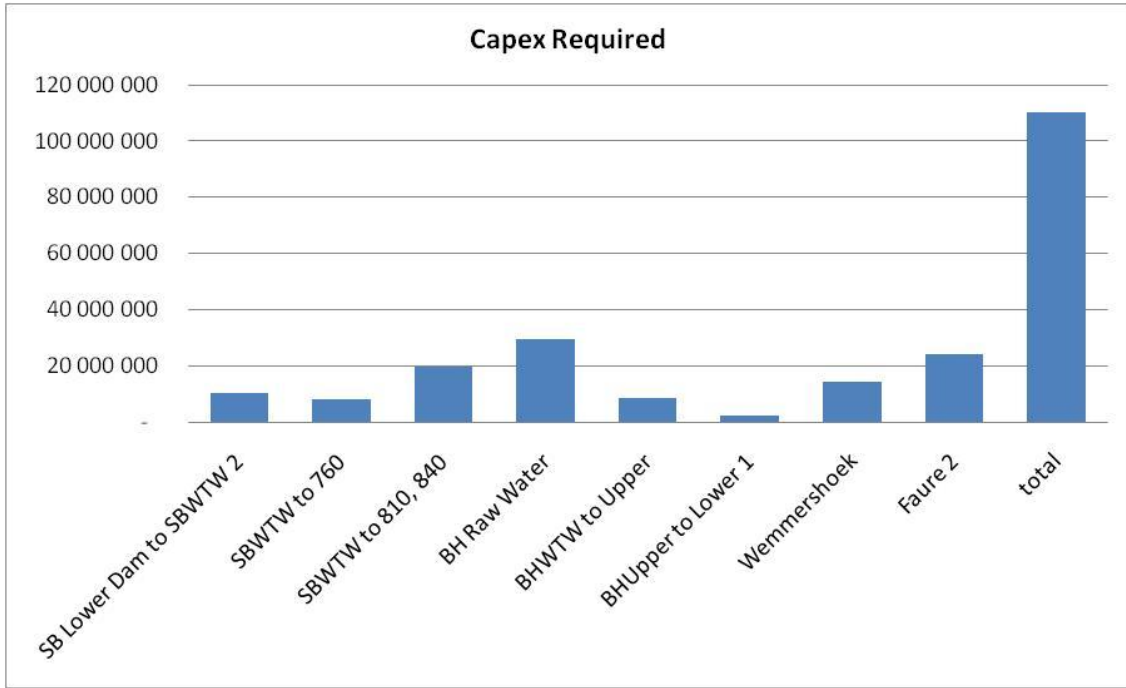| Key Outputs	SB Lower Dam to SBWTW 2	SBWTW to 760	SBWTW to 810, 840	BH Raw Water	BHWTW to Upper	BHUpper to Lower 1	Wemmershoek	Faure 2	total
Capex Required	10 497 625	8 395 250	19 858 625	29 442 375	8 818 750	2 590 000	14 284 375	24 005 625	110 122 827
Equity Required at Fin Close	3 149 288	2 518 575	5 957 588	8 832 713	2 645 625	777 000	4 285 313	7 201 688	33 036 848
PPA Revenue	60 951 029	26 813 190	149 117 267	214 519 745	36 388 266	37 001 251	71 700 451	198 266 275	603 042 102
Operating Costs	10 004 401	3 766 800	12 956 439	18 116 844	3 039 966	3 303 029	9 526 918	40 361 314	93 339 250
EBITDA	50 946 628	23 046 390	136 160 828	196 402 901	33 348 300	33 698 222	62 173 533	157 904 961	544 281 910
Net Cashflow	34 791 947	10 127 031	105 600 606	151 094 350	19 777 221	29 712 499	40 191 463	120 962 965	255 770 682
NPV	2 171 023	-1 437 295	11 471 378	16 023 515	175 233	4 279 048	1 707 157	12 276 372	7 130 424
Equity IRR	19%	8%	29%	28%	14%	54%	17%	27%	27%
Incremental Levelised Cost of Energy (ZAR/kWh)	R 0.71	R 1.05	R 0.49	R 0.49	R 0.78	R 0.66	R 0.73	R 0.63	R 0.62
Real Levelised Cost of Energy (ZAR/kWh)	R 0.49	R 1.05	R 0.49	R 0.49	R 0.78	R 0.16	R 0.42	R 0.27	R 0.38

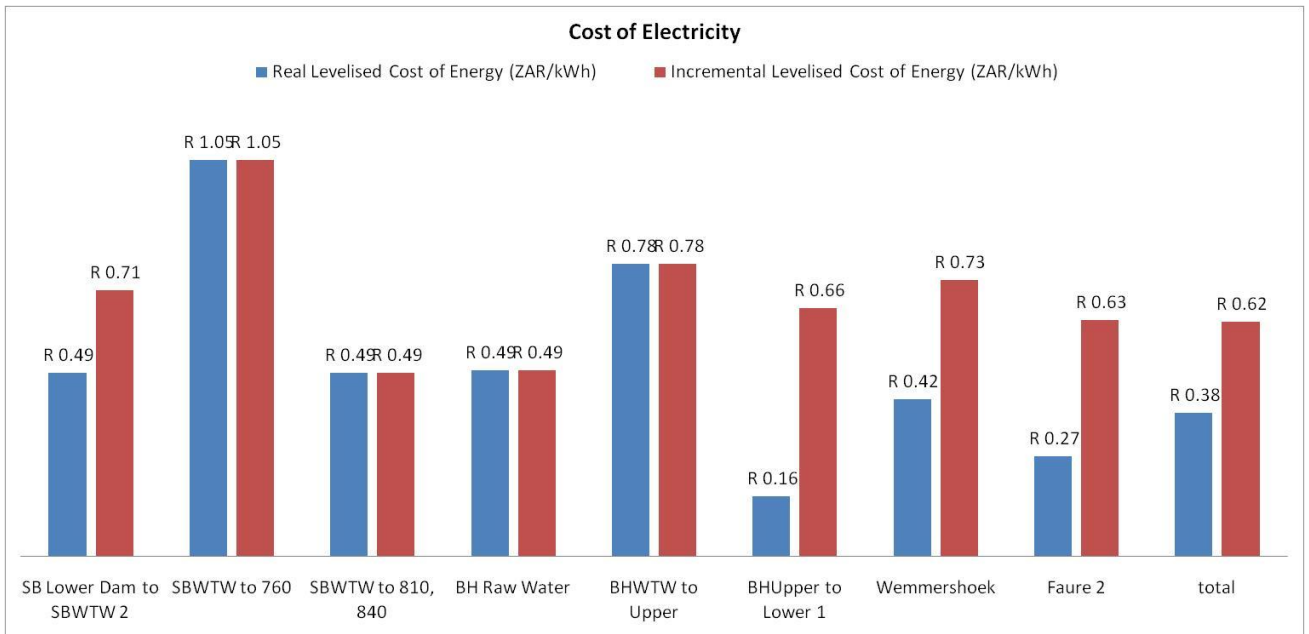**Figure 1: Capex Summary**

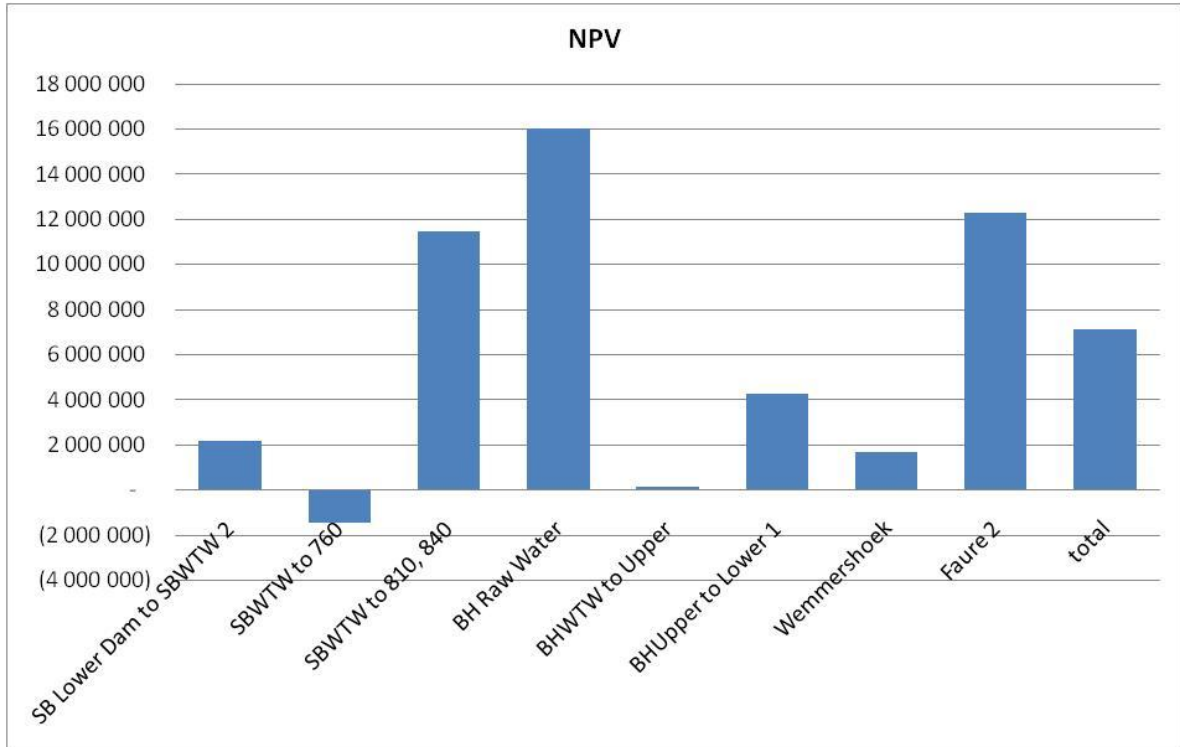**Figure 2: Cost of Electricity Summary**
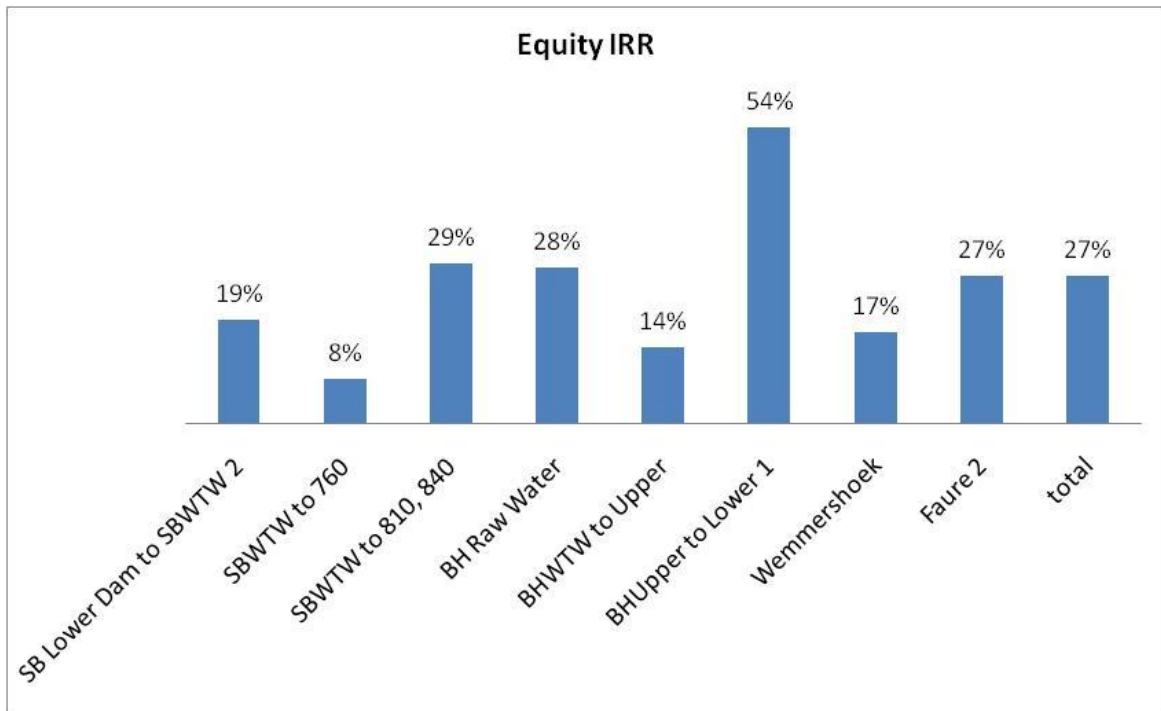
Figure 3: NPV Summary

Figure 4: IRR Summary

Project Plan

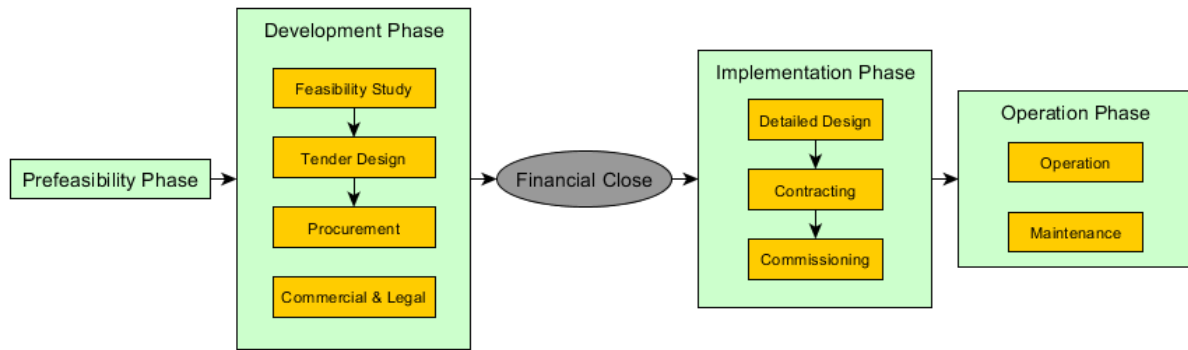The project cycle through all phases was considered with a likely phasing shown in Figure 5.

Figure 5: Project Cycle

Optimization of the project cycle is largely driven by the technical elements. Each technical item will occur within a phase of the project cycle. Each project phase has a different intention, and it is important that the technical items are scoped in such a way that the right level of detail is achieved according to spending levels appropriate to the phase of development.

A conservative program was constructed to illustrate the path ahead for the Project starting from the beginning of 2012 shown in Figure 6.
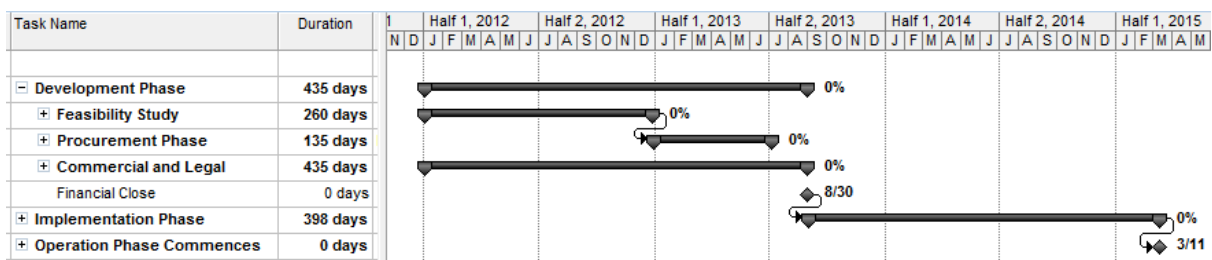

Figure 6: Project Program

The Development and Implementation Phases are estimated to take a little over one and a half years each, and the Operation Phase to commence in the first half of 2015, a little over three years after the start of the Feasibility Study.

Project Structure

The CCT must determine its risk appetite and availability of finance to determine the desirable procurement mechanism for the Project. Risks associated with the Project include:

- Resource
  - Flow reductions/non supply
  - Flow fluctuation
  - Sub-optimal flow regime
  - Head Losses
- Capex
  - Low or negative Equity returns
  - Inability to repay Lenders
- Opex
  - Cashflow shortages

- o Unexpected or "lumpy" maintenance costs
- Energy Offtake
  - o Non-payment
  - o Insufficient term
  - o Insufficient balance sheet of buyer
  - o Insufficient security, inability to attach public assets
- CER Offtake
  - o Non-payment
  - o Insufficient term
  - o Insufficient balance sheet of counterparty
- Implementation
  - o Cost overrun
  - o Delay
- Operational
  - o Suboptimal operation
  - o Unplanned, unpredictable unavailability
- Production
  - o Underperforming energy production and therefore CER production
- Grid Connection
  - o Inability to connect
  - o Connection delay
  - o Connection unavailability
- Compliance
  - o Environmental non-authorisation
  - o Water use non-authorisation
  - o Other non-compliance
- Terminal Project Hazards
  - o Earthquake
  - o Flood
  - o etc

A potential PPP Agreement is proposed, the structure of which is shown in Figure 7.
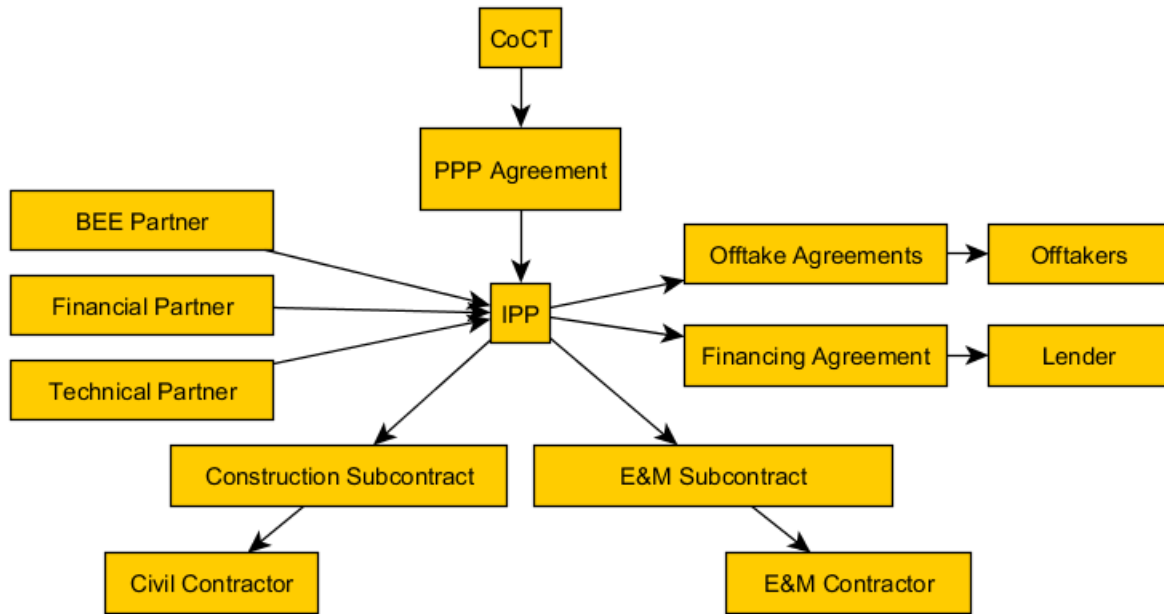
Figure 7: PPP Structure

The PPP agreement provides for the commercial use of Public Property (CCT Bulk Water Infrastructure) by the Private Party (IPP). The basis of the agreement is to provide tenure to the IPP over CCT assets required for hydroelectric generation, which the IPP will develop and operate for a profit. In return, the IPP will pay CCT for this tenure. The terms of the agreement will include the following:

- It is suggested that the IPP receive tenure over infrastructure via a lease in order to generate power. *Note, the IPP does not acquire assets, the CCT will continue to own the power generation assets throughout and following the term of the PPP.*

- Infrastructure required includes:

  o Land on which the plant will be located

  o Existing buildings within which plant will be located

  o Water conveyance infrastructure

  o Existing power generation assets

- The lease term will need to be sufficient to allow the IPP to project finance itself. This would need to be a minimum of 20 years.

- The IPP is required to develop and operate the leased assets to produce and sell energy profitably.

- The IPP makes concessionary payments to CCT. *Note these payments should be linked to the profitability of the IPP. In this way a partnership is forged through alignment. The more*

profitable the IPP is the more direct financial benefits CCT will receive.

- CCT is required to supply water according to agreed flow regimes. *Note the flow regime received by the IPP of course impacts directly on the profitability of the IPP. Through the alignment created by the structure of concessionary payments, the CCT and the IPP will strive to provide optimal flows for power generation while maintaining water supply objectives.*

- Output Specification placed on IPP:

    o Based on flow received, energy production levels and corresponding profit must be generated by the IPP according to agreed levels. If the production levels are not attained, the IPP will pay penalties to the CCT.

Through this structure the CCT receives guaranteed income through the PPP agreement via either concessionary payments or penalties. Financial, technical and operational risk is assumed by the IPP. The IPP and CCT are aligned, promoting cooperation between the two parties.

Determination of Project Structure

Consideration of internal and external procurement mechanisms allows CCT to assume or transfer virtually all of the risks associated with power generation. The proposed PPP transfers all but Resource risk to the IPP. In addition, the proposed PPP provides relief from capital shortage to CCT by leveraging Private Sector finance. The PPP will provide long term, guaranteed income and will enable efficient use of CCT Assets. On the other end of the scale, using an internal mechanism with a traditional contracting structure, CCT assumes all the risk and capital requirements. Internal Procurement using an EPC Wrap contracting structure is a hybrid between the two.

Clear consideration of structural options will allow the CCT to ensure that risks assumed are manageable and that the activities taking place in-house are determined to be core, as well providing options suited to the capital constrains of the Institution.

Environmental Authorisation

The expected Project activities were analyses and compared to activities listed in the NEMA. The analysis indicated that a full EIA is not necessary and no activities triggering a BA are definitely present. The assessment could change once more detailed information become available. Following the completion of the Feasibility Design, a general assessment of activities and potential triggers of environmental authorisations by an EAP is recommended.

Clean Development Mechanism

The scale of the individual sites considered in the Project means that it is not viable to develop a single CDM project for each site. Hence it is necessary to develop the CDM potential through within a Program of Activities, or some other structure bundles of the sites to share the costs of CDM component development. A Carbon Consultant must advise on this in the Feasibility Study.

The production and resulting income from CDM are shown in Table 4. It is recommended that a Carbon Consultant be employed in the Feasibility Study to fully investigate the CDM aspect of the Project.

Table 4: CER production and income

Total Energy	kWh/annum	35 100 549
Total CERs	#/annum	33 633
Total CER Revenue	ZAR	70 337 219
Total CER Costs	ZAR	7 569 182
Total CER Net Income	ZAR	62 768 038

Local Socio-Economic Benefits

Job creation created by the Project is somewhat limited. Temporary jobs will be created during the Development and Implementation phases. In hydropower projects, the biggest job creation element is found in the procurement of the Civil Contractor, due to civil construction and earthworks. Based on previous experience in South African hydropower projects, the temporary jobs created could potentially be 96 employees. Because the majority of the sites in this study do not require significant civil works, this number is most likely to be lower.

Further local benefits can be created by the project through the creation of a Community Trust, which is a powerful way to create local and targeted broad-based socio-economic benefits. A Needs Analysis will identify areas to be targeted including, but are not limited to:

- involvement of, and direct benefits to, non-governmental organisations, religious institutions, civics, clinics, child-care centres, and the like
- employment preference for youth in a targeted geographic area
- employment targets for disabled people
- employment preferences for women
- preference for contracting with SMMEs as suppliers of materials and/or services in a targeted geographic area
- initiatives that will support HIV and Aids education
- other local socio-economic impacts appropriate to the project and its location

Table of Contents

List of Figures

List of Tables

List of Acronyms

Acronym	Expanded Form
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CCT	City of Cape Town
CPI	Consumer Price Inflation
DWA	Department of Water Affairs
EIA	Environmental Impact Assessment
EPC	Engineering Procurement Contracting
ESD	Electricity Services Department
GHG	Green House Gas
IPP	Independent Power Producer
IRR	Internal Rate of Return
ISMO	Independent System Market Operator
O&M	Operation and Maintenance
NERSA	National Energy Regulator of South Africa
NPV	Net Present Value
PDD	Project Design Document
PIN	Project Idea Note
PPA	Power Purchase Agreement
PPP	Public-Private Partnership
REFIT	Renewable Energy Feed-In Tariff
ROR	Run of River
SHP	Small Hydro Plant
TOR	Terms of Reference
TOU	Time of Use
WACC	Weighted Average Cost of Capital
WTW	Water Treatment Works

1   Introduction

1.1   Background

The South African Local Government Association (SALGA) and the South African Cities Network (SACN) sourced funding for this study from the Public-Private Infrastructure Advisory Facility (PPIAF) to undertake a REEE programme to support improved municipal infrastructure development through private investment.

Sidala Energy Solutions was contracted by SACN to conduct a Prefeasibility Study on the Mini Hydro Electric generation in the City of Cape Town's Bulk Water Infrastructure system. The study commenced on the 1st June 2011 and was finalized on the 5th August 2011 over a period of ten weeks.

1.2   Context

The development of the Project occurs within the parameters defined by the Bulk Water supply system. As such hydroelectric power generation is a secondary activity. At present, power generation occurs purely as a support activity to water distribution. It is only considered in terms of its benefit to water supply activities. This is illustrated by the fact that existing generation plant are used to offset electricity bills and power water supply related infrastructure exclusively.

However, changes in the South African and world energy environment and the climate change phenomenon warrant specific focus on the hydroelectric generation potential. Electricity tariffs in South Africa are set to rise far quicker than inflation, and a premium will be paid for green power. This makes the generation of green power an economic opportunity which it will not have been a decade ago. In addition, the potential should be optimized for ethical reasons, and the exposure of the projects maximized to demonstrate what local, provincial and national government achievements.

Both water supply and renewable power generation objectives are present and will remain inextricably linked. While renewable power generation will never compromise or supplant water supply, it can provide significant economic and social benefits. As such it has a valid position and within a fully functional and balanced Municipality renewable power generation should receive just recognition. It is possible to integrate both objectives in such a way that water supply is not compromised and power generation is maximized.

1.3   Scope

1.3.1   Feasibility Design

A total of eight sites were assessed at four of the major water treatment works. These being:

- **Steenbras Water Treatment Plant**
    1. Rockview Dam to Steenbras Upper Dam
    2. Steenbras Lower Dam to the Steenbras Water Treatment Plant
    3. Steenbras Water Treatment Plant to the 840 & 810 Break Pressure Tanks
- **Wemmershoek Water Treatment Plant**

4. Wemmershoek Dam to Wemmershoek Water Treatment Plant

- **Blackheath Water Treatment Plant**
    5. Blackheath Water Treatment Plant raw water supply pipeline
    6. Blackheath Water Treatment Plant to the Upper Blackheath Reservoir
    7. Blackheath Lower Reservoir Inlet
- **Faure Water Treatment Plant**
    8. Faure Water Treatment Plant Inlet

The viability of these sites was assessed by estimating potential power output using the latest hydropower conversion technologies. The financial business cases for these sites were then analysed.

The methodology used is described in detail below.

1.3.1.1 Technical Assessment

This commenced with a literature review to identify available hydropower conversion technologies.

Site visits were conducted to properly evaluate each site. Various layout options, surrounding infrastructure, grid connection options and general technical feasibility were be assessed first hand. Any recommendations for further specialist studies were recorded.

Layout options were assessed and described. A preliminary flow analysis of the various resources using historical flow data was conducted. The hydrology data was compiled into Flow Duration Curves (FDCs).

Technical models were constructed to evaluate each site according to its head and flow parameters, which drive the electromechanical specification. Technical modelling was performed using RETScreen methodology and included consideration of the following:

- Gross and Net Head
- Flow Duration Curves
- Turbine Design
    o Preliminary Type Selection
    o Design Flow
- Model Construction
    o Efficiency Curves
    o Electricity Production
    o Capacity Factor

1.3.1.2 Financial Assessment

*Financial model*s were constructed to analyse the sites financial viability. The results from the technical feasibility were used as the input data for the financial modelling. Market based assumptions were made, outlining the various interest rates and cost of capital. Various structuring options were assessed taking into account different sources of finance from commercial and development banks as well as equity financing from the private and the public sector.

A basic costing analysis was performed which analysed the cost of infrastructure required. This costing analysis was based on RETScreen Methodology for costing mini hydro plants. The results of

the costing analysis and the technical viability resulted in the preferred options that will be taken to the final feasibility design.

Financial modelling of each site included the consideration of:

- Sale of Electricity and operation costs
- Finance Assumptions
- Cashflow Analysis
- Investment Analysis

1.3.2 Project Plan
The project cycle through all phases was considered and the optimisation in terms of appropriate spending levels for each stage of development. A conservative program was constructed to illustrate the path ahead for the Project starting from the beginning of 2012.

1.3.3 Project Structure
A risk assessment of the Project was conducted to assist CCT to determine procurement mechanism for the Project.

A stated objective of the study is to develop "an implementation plan for the establishment of the micro hydro project as PPPs between the selected municipalities and private sector partners". In line with this, a potential PPP Agreement was proposed through which CCT can procure the Project shifting financial burden and risk to the Private Sector.

1.3.4 Environmental Authorisation
The expected Project activities were analysed and compared to activities listed in the NEMA. This gave an indication of the likely environmental authorisation requirements. The process of meeting these requirements were then investigated and described.

1.3.5 Clean Development Mechanism
Development of CDM potential was investigated for the Project. The production and resulting income from CDM were calculated based on the energy production results from the Prefeasibility Design.

1.3.6 Local Socio-Economic Benefits
Temporary and Permanent job creation is assessed according to South African hydropower experience. The likely direct job creation stemming from the CCT project is quantified. Further to this, other methods of creating local socio-economic benefits are assessed.

2   Background

2.1   Prefeasibility 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 financiers 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 8 shows this progression.
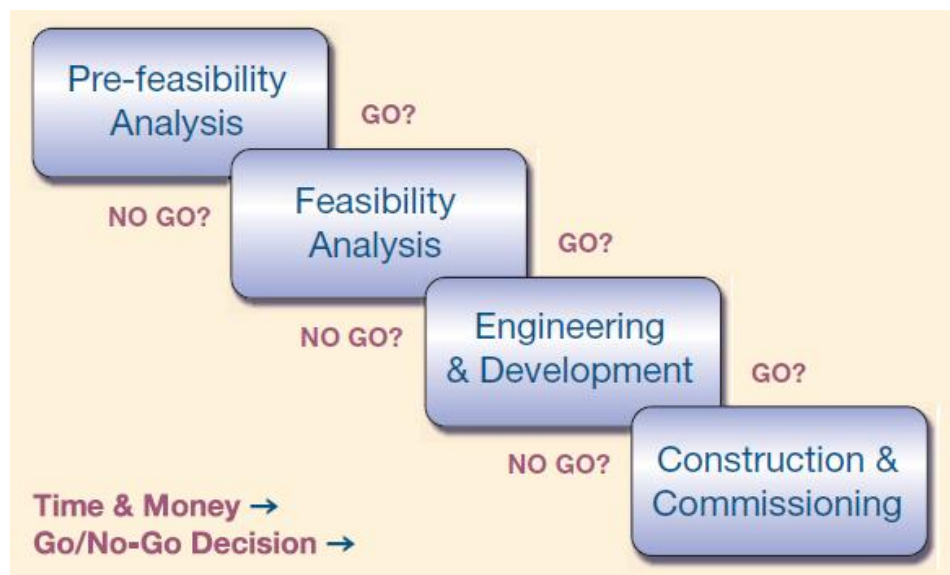
Figure 8: Project development phases

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 9. A similar curve would be applicable to small hydro projects.
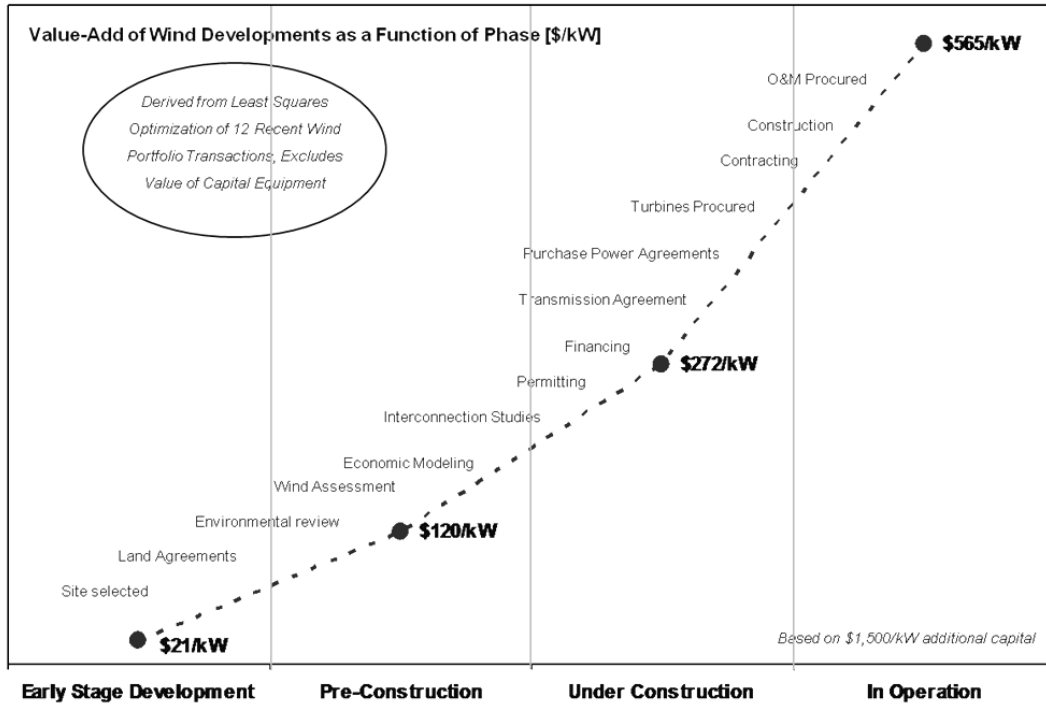
Figure 9: Thorndike curve for wind projects

2.2 Small Hydro

2.2.1 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. 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 at 10MW.

2.2.2 Operational Distinctions

Small Hydro can be either Run of River, located at the base of a dam or integrated in a canal or pipeline. 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. This is largely applicable in the CCT sites as well.

2.2.3 Head Distinction

Schemes are generally classified according to head as this has large bearing on the layout type. Three head classifications are recognised:

- 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.

2.2.4 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.

2.2.4.1 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 10.

Figure 10: Pelton Wheel

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 11.

Figure 11: Turgo Turbine

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 12.
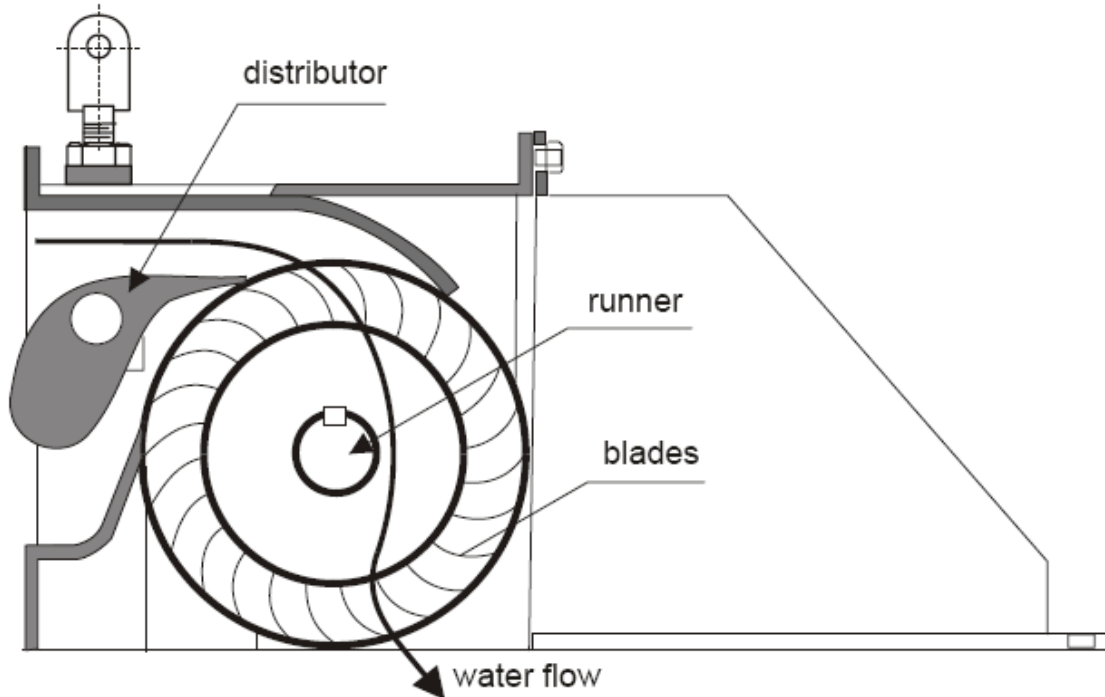
Figure 12: Cross-Flow Turbine

2.2.4.2   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. A Francis turbine is shown in Figure 13.
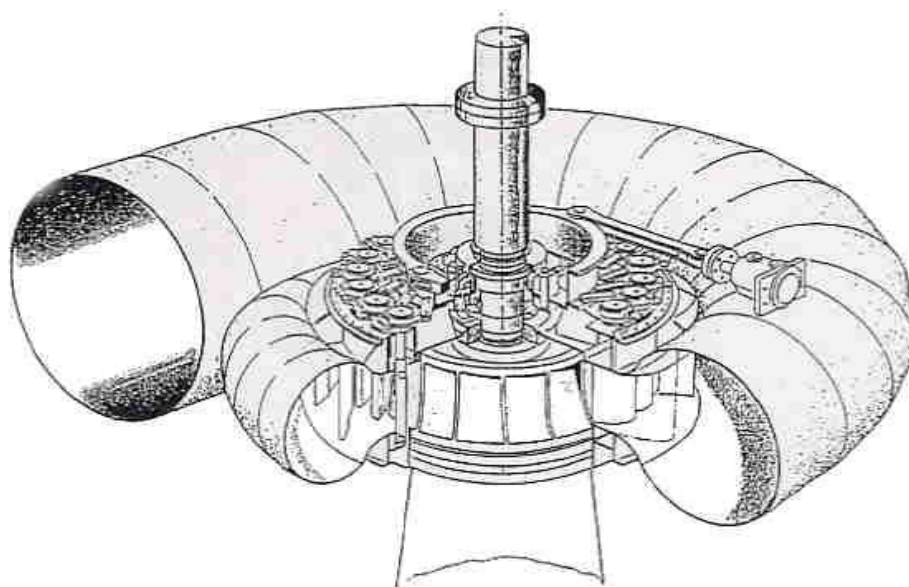
Figure 13: Francis Turbine

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 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 design flow. A Kaplan runner is shown in Figure 14.

Figure 14: Kaplan Turbine.

2.2.5   Turbine Selection

A very basic method of turbine selection is through the use of charts such as that shown in Figure 15. 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.
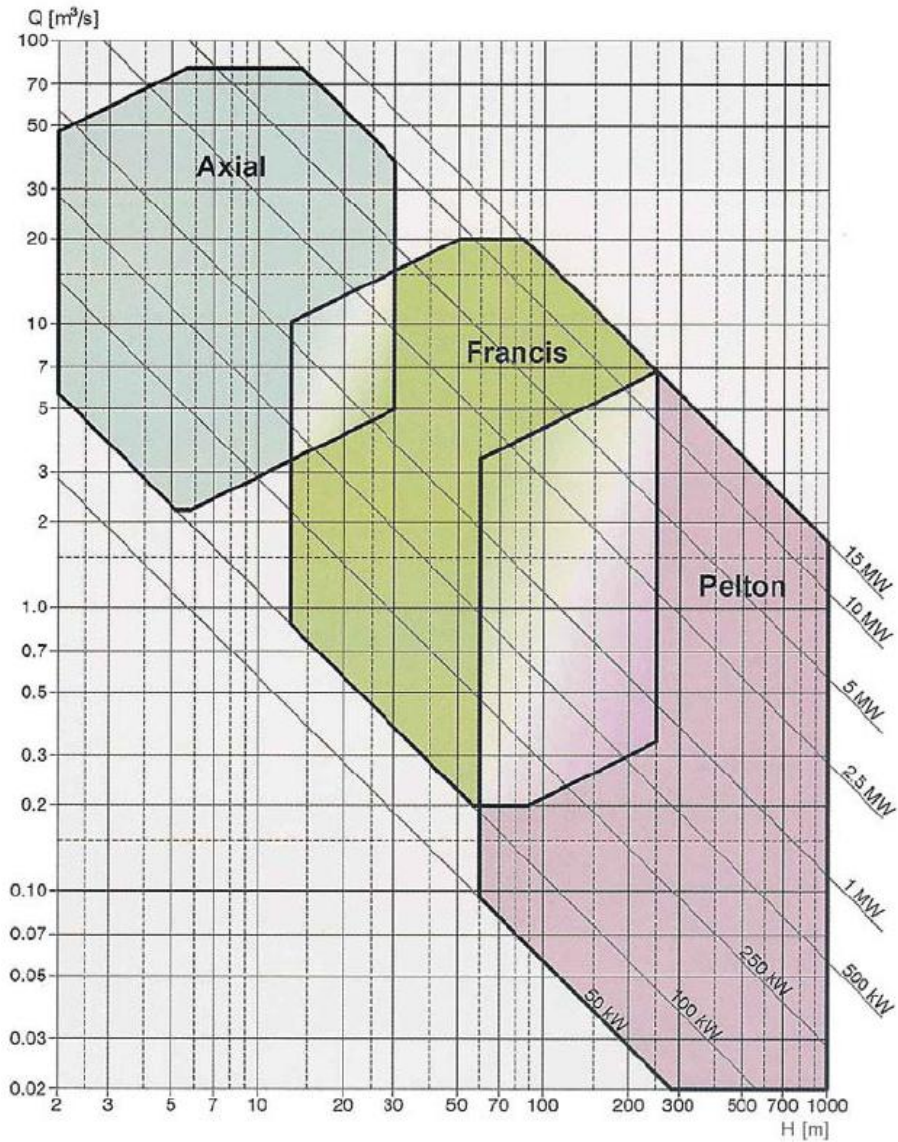
Figure 15: Turbine Selection Chart

More advanced methods of turbine selection involve the use of the quantity specific speed.

2.3 Risks to Water Supply Objective

Both water supply and hydroelectric power generation objectives are present and will remain inextricably linked.

Hydroelectric power generation is emerging as a focus in its own right when in the past is has only been a support to water supply activities. It may therefore present increased risks to water supply objective such as:

- Disruption of systems during execution of the works
- Disruption of operations
- Water contamination

Further to these risks, there also remains the risk that some of remote CCT Water Treatment Works which have power supply that rely on current hydro electric generation would be compromised. It would be very important to consider this element in the full feasibility of the plants. A possible solution to this is to ensure that the grid connection for the plants would also act as a backup for the Water Treatment Works. This risk should be properly addressed in the Electrical Feasibility.

Below are some technical recommendations for the plants considering their integration into the water supply of CCT.

2.3.1 Technical recommendations for hydroelectric plants set in existing infrastructures

Infrastructure requirements	Recommended technique
Water quality	The generation plant must not impact on the water quality, unless it leads to its improvement, while optimising the equipment efficiencies and lifetime.
Discharges at the turbine outlet	The turbine is designed from the flow duration curve of the scheme so as to optimise the production. A bypass is set to reach the infrastructure discharge requirement at any times. Storage is avoided, apart when required for the existing infrastructures.
Pressure at the turbine outlet	For heads > 60 meters, if the needed turbine outlet pressure has to be higher than the atmospheric one, the Pelton turbine is at a higher elevation, or a counter pressure turbine set.
Flexibility	The turbine has high efficiencies for the optimal range of pressure and discharges, defined by the existing system
Flow Integration	Optimisation between dual objectives of Water Supply and Power Generation is to some extent explored.
System Availability	Water Supply is a critical service and systems are conceived with availability must >99,9%

2.3.1.1 Water quality

A SHP plant must not impact on the water quality, unless it leads to its improvement, while optimising the equipment efficiencies and lifetime. Especially while defining the penstock and turbine, attention will be paid on the mechanical resistance and manufacturing easiness of the selected materials but also on their corrosion and abrasiveness behaviour.

Water Quality	Recommended technique
Gravels and stones	• Setting of a grid at the forebay
Sand particles	• Setting of a de-silted set before the forebay • Pelton runner built with mounted bucket to unset and replace the buckets
Drinking water	• All parts in contact with water in stainless steel • Electrical actuators to replace all oil ones

2.3.1.2 Discharges, flexibility and performances

The SHP plant operation must not impact on the primary function of the existing infrastructure. Thus, the turbine has to be as much flexible as possible regarding the available pressures and discharges, while guaranteeing high performance on the largest operation ranges. The turbine design is based on the site flow duration curve, a crucial tool to optimize the production and the viability of the project. Indeed, the discharges can evolve with the spring hydrology and/or with human activities.

2.3.1.3 Drinking water quality and turbines

To demonstrate that turbines can respect water quality, or in other words that drinking water can pass through the turbine before being consumed, a comparison with pumps can be achieved, as shown in Figure 16.

	Pump station	Turbine station
Inlet valve	yes	yes
Discharge regulation device	**no**	**yes**
Runner linked to a rotating shaft	yes	yes
Shaft gaskets	yes	yes
Casing and runner in contact with water	yes	yes
Greased-for-life roller bearings	yes	yes
Electrical machine	**yes (engine)**	**yes (generator)**
Electrical panels	yes	yes
Medium voltage/high voltage transformer	Yes, if needed	Yes, if needed
Usual building materials of the hydraulic machine	Cast, black steel, stainless steel, bronze	Cast, black steel, stainless steel, bronze
Automatic by pass	**no**	**yes**
Water access	Disassembly necessary	Disassembly necessary

Figure 16: Pump and Turbine Comparison

2.3.1.4 Regulation

Generally, the turbine is regulated on the upstream water level in the forebay, so that it remains steady. The process can be defined by the following steps: When the upstream level tends to rise, the turbine opens up to increase its discharge up to the nominal one. If the upstream level keeps on rising, the surplus can pass through the bypass. When the upstream level tends to go down, the turbine closes itself to take less discharge. If the upstream level keeps on going down, the turbine is shut down. By controlling the needle stroke for Pelton turbines, the vanes or blades opening for Francis, and Kaplan turbines, the turbine can turn to be an efficient and convenient device to regulate discharges.

2.3.1.5 Bypass

A bypass of the turbine may be required to guarantee the primary function of the existing infrastructure at any time. For water networks for example, it has to be systematically set. It can be used when the turbine is not operating due, for example, to a too low discharge or to maintenance needs. It can also be used when the discharge needed for the existing scheme is higher than the turbine nominal one. In such situation, the turbine uses its maximal discharge, whereas the surplus flows through the bypass (if the head losses are still acceptable for the turbine). As it replaces the turbine, the bypass has different functions: to regulate the discharges and/or the water levels, and to reduce the pressure.

2.3.1.6 Penstock and head losses

At the start of a SHP project in existing infrastructure, a first issue is to define if the existing penstocks and channels are suitable for electricity production, which implies mainly to check their mechanical resistance (nominal pressure for a penstock) and head losses. In general, head losses are acceptable if at nominal discharge they are lower than 10% of the difference in levels, or in other

words if the penstock efficiency is higher than 90%. Indeed, this corresponds to the present state of the art for equipment that uses optimally the water resource.

To sum up, head losses in a penstock depend on:

- Its shape: singularities as elbows, forks tend to increase head losses
- Its internal diameter
- Its wall roughness and its evolution due to its degradation or/and to wall deposits.

3 Prefeasibility Technical Modelling

3.1 Methodology Followed

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. RETScreen tool is particularly appropriate as it has been shown to dramatically reduce the time and cost associated with preparing pre-feasibility studies.

The RETScreen tool is built on the experience of over 210 experts from industry, government and academia 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 are provided.

The technical model developed for this study was performed in Microsoft Excel and is based on the method proposed by RETScreen. It has been developed primarily to determine the small hydro project possibilities and to evaluate a number of alternatives identified. The method has been verified against certain turbine manufacturers showing a very close correlation to the results predicted. Some of the model definitions are described below.

3.2 Head

The static head experienced at the plant and is merely a difference in height levels. After the penstock and hydraulic losses the net rated head is the pressure seen on the turbine at the design flow rate.

3.3 Design Flow Rate

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. 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.

For the various sites the choice of design flow was optimised to give the maximum amount of energy over a given year in kWh. It was assumed that the cost of production for the incremental amount of power output was less than the purchase price of that energy. Therefore the turbines are sized to maximise the energy output.

3.4 Turbine selection and Sizing

The purpose of a hydraulic turbine is to transform the water's potential energy to mechanical rotational energy. It is necessary to emphasize that no advice is comparable to that provided by the

manufacturer, and every developer should refer to manufacturer from the beginning of the development project. It is however appropriate at this stage to provide a few criteria to guide the choice of the right turbine for a particular application and even to provide appropriate formulae to determine its main dimensions.

Note: Only Francis, Kaplan, and Pelton Wheel turbines were considered in the Prefeasibility Design. There were a number of sites where a Turgo turbine would also be suitable but these turbines are no longer prevalent in the industry and Pelton's have similar characteristics and higher efficiency.

3.5 Turbine Efficiency

The type of turbine is selected based on its suitability to the available head and flow conditions. The calculated turbine efficiency curves take into account a number of factors including rated head (static head less maximum hydraulic and penstock losses), runner diameter (calculated), turbine specific speed (calculated for reaction turbines) and the turbine manufacture/design coefficient. Turbine efficiency was calculated using the RETScreen approach. In this, the efficiency equations were derived from a large number of manufacturer's efficiency curves for different turbine types and head and flow conditions.

3.6 Losses

Maximum Hydraulic Losses In a small hydro system, energy is lost as water flows through the water passages. A value of 5% has been selected for the scenarios identified. Hydraulic losses are adjusted over the range of available flows based on the method.

Maximum tailwater effect At most sites, during high flows, the tailwater level rises more than the level upstream of the intake and causes a reduction in the gross head. Consequently, during these periods, less power and energy are available.

The maximum tailwater head loss for the plants has been taken as 1m the 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.

Other Losses Other losses assumed were generator losses (3%), transformer losses (3%) and parasitic losses (2%).

3.7 Energy Delivered

This represents the total amount of electricity produced at a certain flow rate. Actual energy delivered from the small hydro plant at any given flow value *Q* is calculated for every historical daily flowrate and summed over a year to give the total energy production over the historical period (Flow data from CCT is available from 1997-2011). Most of the plants have a varying head for the range of different flows due to friction losses in pipes and varying head conditions from dams. This variance in head was not considered in the calculations and should be done in the feasibility study.

3.8 Capacity factor

The annual capacity factor of the small hydro power plant is a measure of the available flow at the site and how efficiently it is used. It is defined as the average output of the plant compared to its rated capacity.

4   Financial Modelling

4.1   Methodology

In order to evaluate the financial feasibility of the separate schemes a full financial model has been produced. This model evaluates Before Tax Cash Flows for each individual site as well as Discounted Cash Flows which result in investment results such as NPVs as well as IRRs for the sites. This section describes the assumptions used in the financial modelling.

4.1.1   Incremental Energy Costs

Where there are existing turbines at the Water Treatment Works analysed, a real cost of electricity (R/KWh) as well as the incremental cost or marginal cost of electricity (R/kWh).

The real cost of electricity is calculated by dividing the full capital cost and lifetime costs for a site by the total lifetime energy produced by the site.

The incremental cost of electricity produced is calculated by dividing the full capital cost and lifetime costs for a site by the incremental lifetime energy produced by the site. That is the energy over and above what is currently being produced to run the plant.

The cash flows and IRRs are based on the incremental costs of the plant and therefore are the 'worst case' option which doesn't truly represent the actual cost of electricity produced. This is a conservative approach and the true cost of electricity will sit in between the real costs and the incremental costs of energy.

4.2   Project Development Costs

The project development costs have been estimated based on current industry experience. This pricing is indicative and will vary from firm to firm. A good project manager who is knowledgeable in this area will be able to negotiate a reasonable proposal from the various firms.

It is important to note that the costs indicated here were selected conservatively and a 25% contingency was added to the total costs. The total costs of R16.65M were equally divided over the feasible sites in the investigation.

Table 5: Project Feasibility Costs

Project Feasibility Costs	Total	SB Lower Dam to SBWTW 2	SBWTW to 760	SBWTW to 810, 840	BH Raw Water	BHWTW to Upper	BHUpper to Lower 1	Wemmers hoek	Faure 2
Technical									
Feasibility Design	1 300 000	170 000	170 000	200 000	200 000	120 000	120 000	200 000	120 000
Hydrology	400 000	50 000	50 000	50 000	50 000	50 000	50 000	50 000	50 000
Head Assessment	350 000	50 000	50 000	50 000	100 000	-	-	-	100 000
Bulk Water Integration	240 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000	30 000
Geological assessment of site	90 000	30 000	15 000	15 000	10 000	10 000	-	10 000	-
		0	0	0	0	0	0	0	0
Environmental	-								
Assessment	150 000								
Basic Assessment	210 000	70 000	70 000	70 000	-	-	-	-	-
Full EIA	-	-	-	-	-	-	-	-	-
Water Use License	-	-	-	-	-	-	-	-	-
Specialist Studies	180 000	60 000	60 000	60 000	-	-	-	-	-
CDM	-								
Project Development and Documentation	500 000								
Registration	500 000								
Legal	-								
Project Documentation	2 500 000								
Project Finance	3 000 000								
Ancillary	1 000 000								
	-								
Finance	-								
Financial Modeling	400 000								
Lender Due Diligence	2 500 000								
Sub Total	13 320 000								
Contingency	3 330 000								
Total	**16 650 000**								

4.3   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.

For the costing of each of the sites analysed for CCT Hydro, the major works were separated into major cost components. These being:

- **Civil**- These costs mainly comprise of major civil works such as power house construction, penstocks, earthworks, water conveyance infrastructure etc
- **Mechanical & Electrical –** these costs include the turbine and generator costs and all associated ancillaries
- **Electrical –** these costs mainly comprise of the grid connection costs and grid infrastructure needed to support the feed in of electricity.

The construction arrangement would generally comprise of three contracts for each of the above with the balance of plant contract held with the civil contractor.

In order to estimate the costs for the individual systems for CCT, the major electrical and M&E costs were estimated using the hydro costing model in RETScreen. The accuracy of this methodology is assumed to be within 50% of the actual costs. Only through the feasibility design phase where a Bill of Quantities is drawn up, will one be able to estimate more accurate values. Figure 17 below shows how the accuracy of the estimate will increase over time.
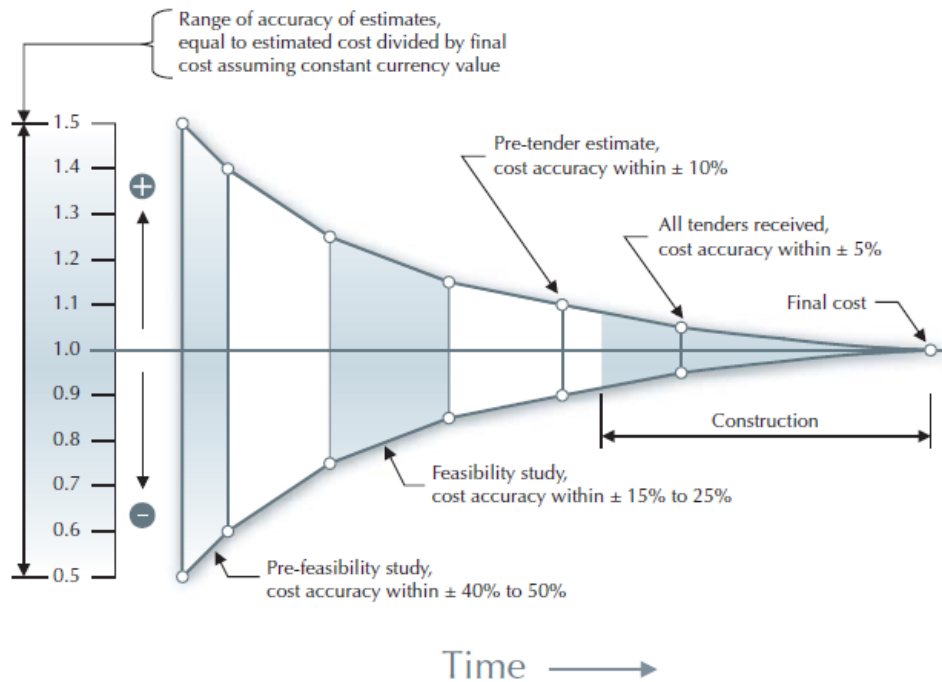
Figure 17: Capital cost estimate accuracy

4.4 Income Streams

4.4.1 Sale of Electricity – Power Purchase Agreement (PPA)

The electricity produced by the hydro developments will need to be purchased by an authority. For the financial modelling, only two tariff structures were considered:

1. *The base case used in the financial modelling is the sale of green power to the local municipality at the same price they are currently purchasing power at from Eskom. I.e. MegaFlex tariffs*
2. *Some of the plants analysed have the option of configuring the operation to be peak power producers and in this case the MegaFlex peak and standard weighted tariff was assumed.*

However there are several ways to structure these projects and, depending on this, other tariffs may be considered. These are highlighted below and further elaborated on. This decision will only be able to be made during the feasibility stage of the projects. These options were not considered in the modelling process.

- The second option is to sell the power at a premium to a private buyer of electricity such as a large corporate or a mine.
- The third option available is the Renewable Energy Feed-In Tariff (REFIT) programme which is currently being promulgated by the government. The REFIT for small hydro is 94c/kWh, and it increases with inflation according to the CPI. The term of the PPA is 20 years. This would only be possible n the event of an Independent Power Producer being established.

4.4.1.1 Eskom MegaFlex

It is assumed that the power plants will be able to sell the power to the City's Electricity Services Department (ESD) at the same rate (or at a higher negotiated rate) that ESD is purchasing power at from Eskom. It is assumed that the city is purchasing power at the Megaflex Tariff.

A power tariff forecast has been compiled that takes into account the average Eskom tariff increase based on NERSA current approvals as well as a predicted 10% real increase for 5 years and then a 2% increase after that. This is illustrated in Table 6. This forecast is shown in comparison to the REFIT tariff for small hydro power in Figure 19.

4.4.1.2 Eskom MegaFlex Peak weighted

The MegaFlex tariff is structured as a time of use which is the same way ESD bills its large industrial users. Figure 18 shows these times where the red represents peak times, the yellow standard times and the green off-peak times. There are also seasonal energy rates for winter (June – August) and summer (September – May).
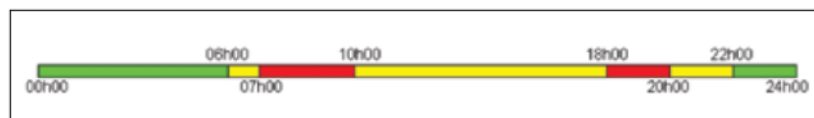
<div align="center">Figure 18: Time of Use structure</div>

4.4.1.3 ESD

A CCT normal and peak weighted tariff has been included in the comparison for illustrative purposes but has not been used in the analysis.

4.4.1.4 Renewable Energy Feed-In Tariff (REFIT)

In 2009 the National Energy Regulator of South Africa (NERSA) announced a 20-year Feed-In Tariff for various renewable energy technologies. The Power Purchase Agreements (PPA) that will be signed under the REFIT programme will be issued by the newly established Independent System Market Operator (ISMO) which now stands outside of Eskom. These PPA's will be 20 year PPA's that will be backed by National Treasury. The tariff has been set at ZAR 0.94/kWh for small hydro plants. For small hydro, the minimum project size qualifying for the REFIT is 1MW and maximum 10MW. REFIT has not been considered in the analysis.

4.4.1.5 Summary of Tariffs

Table 6 shows the assumptions used in the tariff forecast and Table 7 are the results. Figure 19 below shows these results tabulated. It will be up to the established IPP to negotiate a PPA agreement with the relevant authority.

<div align="center">Table 6: Power Price assumptions</div>

SA Power Price Forecast	Megaflex	
10% real for 5 years then 2% real		
2009/10 price	30.74	c/kWh

Nersa approved average prices		
2010/11	41.57	c/kWh
2011/12	52.3	c/kWh
2012/13	65.85	c/kWh
Inflation	5%	

Table 7: Price Forecast

Year	Megaflex Average	Increase	REFIT	MegaFlex peak weighted average	CCT Peak weighted average	CCT weighted average
2009/10	30.7		101.7		67.4	51.7
2010/11	41.6	35%	111.6	55.4	67.4	51.7
2011/12	52.3	26%	118.4	69.7	84.8	65.1
2012/13	65.9	26%	125.6	87.8	106.7	82.0
2013/14	75.7	15%	133.3	100.9	122.7	94.3
2014/15	87.1	15%	141.4	116.1	141.2	108.4
2015/16	100.1	15%	150.0	133.5	162.3	124.6
2016/17	115.2	15%	159.2	153.5	186.7	143.3
2017/18	132.4	15%	168.9	176.5	214.7	164.8
2018/19	141.7	7%	179.2	188.9	229.7	176.4
2019/20	151.6	7%	190.1	202.1	245.8	188.7
2020/21	162.3	7%	201.7	216.3	263.0	201.9
2021/22	173.6	7%	214.0	231.4	281.4	216.1
2022/23	185.8	7%	227.1	247.6	301.1	231.2
2023/24	198.8	7%	240.9	264.9	322.2	247.4
2024/25	212.7	7%	255.6	283.5	344.7	264.7
2025/26	227.6	7%	271.2	303.3	368.8	283.2

2026/27	232.1	2%	287.8	309.4	376.2	288.9
2028/29	236.8	2%	305.3	315.6	383.7	294.7
2029/30	241.5	2%	323.9	321.9	391.4	300.6
2030/31	246.3	2%	343.7	328.3	399.3	306.6
2032/33	251.3	2%	364.7	334.9	407.2	312.7
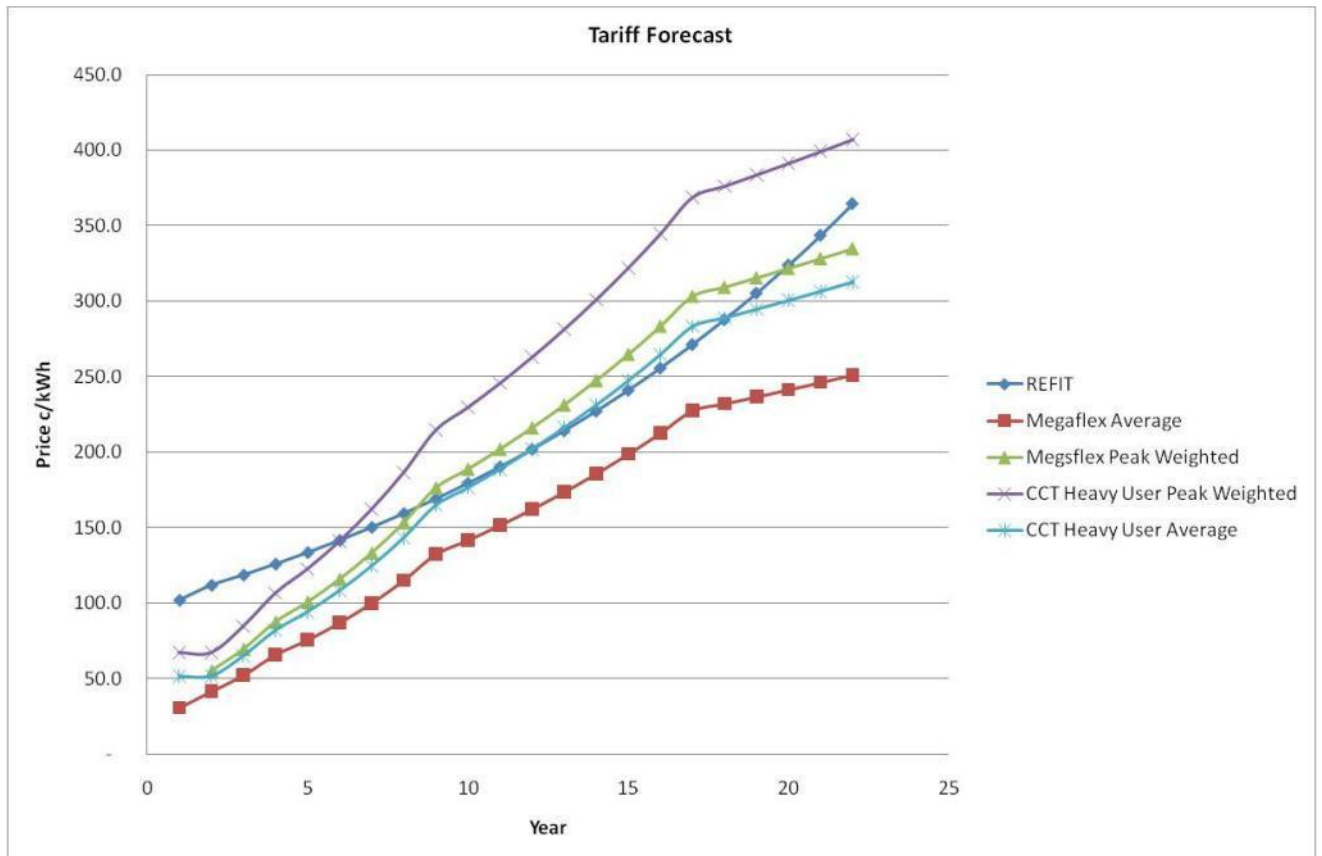
Figure 19: Tariff Comparison

4.4.2   Clean Development Mechanism (CDM)

Sidala are confident that the CCT mini hydro projects would qualify as a project, or programme of activities under CDM, however, for the purposes of this study, ***the income derived selling the carbon credits has not been applied to the individual sites and neither as a group or a programme.*** The costs associated with CDM feasibility and registration have been included in the project development costs. This is in line with the conservative approach taken in the development cost estimation. Results of potential CERs and income are given in the Results section.

4.5   Operation and Maintenance (O&M) Costs

The O&M costs of the existing turbines at the plants are difficult to ring fence out of the normal operation of the treatment works and if therefore difficult to obtain historic O&M costs. This exercise would encompass a considerable accounting investigation and is beyond the scope of work for this report.

For the purposes of analysis a fixed O&M cost/kW installed is used and aims to encompass the following hydro operation costs, outlined in Table 8. This fixed cost is assumed to be R500/kW/annum. Considerable cost savings will be found at sites where more than one hydro plant is planned.

Table 8: O&M costs

Direct Expenses
Power plant
Operational hours Staff Expenses Salaries & Wages Operational Expenses Water price Operation and Maintenance Professional services Insurance Rental Environmental Wheeling and Grid Costs
Overheads
Admin & General
Staff Expenses Salaries & Wages Other staff Operational Expenses Auditors Remuneration + Audit Fees Computer Charges Legal Fees Rates and Taxes Water & electricity Repairs and Maintenance - Building Telephone + Cellular+internet Training Travelling
Marketing
Information Technology
Operational Expenses Outside contract Webhosting

Telephone
Maintenance
Operational Expenses
Consumables
Licence & Registration
Outside contracts
Repairs & Maintenance - Refurbishments
Surveillance & Security
Major Maintenance
Machinery and Equipment

4.6   Project Finance

The financial modelling of the CCT Hydro projects was done with the assumption that the projects will be Project Financed. Financing can be a major challenge to IPPs where the owner does not have sufficient funds for balance sheet or Corporate 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.

4.7 Other Financial Assumptions (Inputs)

The following key assumptions were made in the modelling process, the actual values can be found in Table 9:

Project Development Costs: These are the costs associated with getting the project to financial closure. This requires work on resource measurement, grid connection studies, EPC structuring, plant design, licensing and permitting and fund-raising.

Capex contingency: This has been included to reflect any unforeseen capital expenditure required for a project of this nature.

Project Lifespan: The generally accepted investment lifespan for a renewable energy project of this nature is 20 years.

Debt Equity Ratio, Interest Rate, Length of Debt Financing and number of instalments: If funded by the private sector, the current accepted debt to equity ratio for a project of this nature is 70% Debt and 30% equity. Our research has indicated that this portion of debt would be serviced with an interest rate of 12%. As these projects are very capex intensive, the levels of this ratio and rate of interest are crucial to viability of these projects. Furthermore the length of debt financing and the number of instalments per annum contribute to this viability.

Discount Rate: This is the rate used to discount future cashflows in the business model back to the start of the project. It is proxy for the weighted average cost of capital (WACC).

Inflation: Inflation has a direct impact on the REFIT tariff, the operating and maintenance costs of the plant and an indirect effect on the prevailing interest rates of debt. Inflation is taken from StatSA's calculation of the Consumer Price Index (CPI).

Depreciation: Although a non-cash flow item, depreciation affects the accounting profitability of the project and hence the amount of tax paid to SARS. This tax amount is a cashflow item and hence affects the NPV and IRR of the projects.

Table 9: Financial Assumptions

Renewable Energy Technology	Small Hydro	Run of River
Project Development Costs	ZAR	R 2 081 644
PPA	R/kWh	R 0.3
Operation & Maintenance Cost	ZAR installed Watt p.a.	R 0.50
CapEx Contingency	%	25%
Exchange Rate	ZAR/$	$ 6.70
Exchange Rate	ZAR/€	€ 9.70
Plant Lifespan (years)	years	20
Interest Rate	%	12.0%
Length of Debt Financing	number of years	10
Number of Instalments	per annum	1
RSA - CPI	%	6.0%
WACC - Discount Rate	%	12%
Debt Equity Ratio	%	70%
Corporate Tax Rate	%	28%
Plant Depreciation	number of years	7

5   Steenbras Water Treatment Works (SWTW)

Steenbras WTW (Figure 20) treats a maximum of 150 Ml/day receiving water from the Lower Steenbras Dam. There are a number of sites that have been identified at the works and are further described.

1.   Steenbras Water Treatment Plant to the Break pressure tanks 840 and 810 (SBWTW to 810, 840)
2.   Steenbras Lower Dam to Steenbras Water Treatment Works (SB Lower to SBWTW)
3.   Steenbras Water Treatment Plant to the Break pressure tank 760 (SBWTW to 760)

Also described in this section, although it does not form part of the treatment works, it is very close in vicinity. That is

4.   Rockview Dam to Steenbras Upper Dam

Figure 20: View of Lower Steenbras and the SWTW

5.1 Steenbras Water Treatment Plant to the Break pressure tanks 840 and 810 (SBWTW to 810, 840)

5.1.1 Description

The clearest potential for power generation where there is no existing turbine is at the Break pressure tanks 810 and 840 after clean water has left the water treatment works. Hence, this site potential is described first.

Once the water leaves the Steenbras WTW it flows into a small clearwell reservoir where it is then distributed into two separate pipelines. One of those pipelines is a 610mm pipe that takes water and splits it into two break pressure tanks 810 and 840, further down the mountain. Figure 21 shows these two tanks.

Figure 21: Break Pressure tanks 810 & 840

5.1.2 Data Used

5.1.2.1 Levels

Two main data sources were used in calculating levels. The second column in Table 10 describes the data given in the Terms of Reference (TOR) whist the third column is the data taken from the drawing W3-013-103 of treatment works provided by head office.

Table 10: Levels at 810 & 840 [m]

Level	TOR	Drawing	Calculated
Clearwell	282.03-276		280
810 TWL		208.46	
840 TWL	206.45	207.26	

5.1.2.2 Flowrates

The flow regime experienced here is very similar to the raw water coming into the plant and can be seen in the flow duration curve (Figure 22). A summary of the flows show that the average flow is slightly less than the raw water flow. It was noted in the terms of reference that the plant production could change to 180Ml/day in the future. This has not been planned for here and the details of this should be clarified in the feasibility study.

Table 11: Flow Rates SBWTW to 810, 840

Min Flow	m3/s	0.52	0.52
Min Flow	Ml/day	45	45
Max Flow	m3/s	1.74	1.74
Max Flow	Ml/day	150	150
Average Flow	m3/s	1.05	1.02
Average Flow	Ml/day	90	87.71
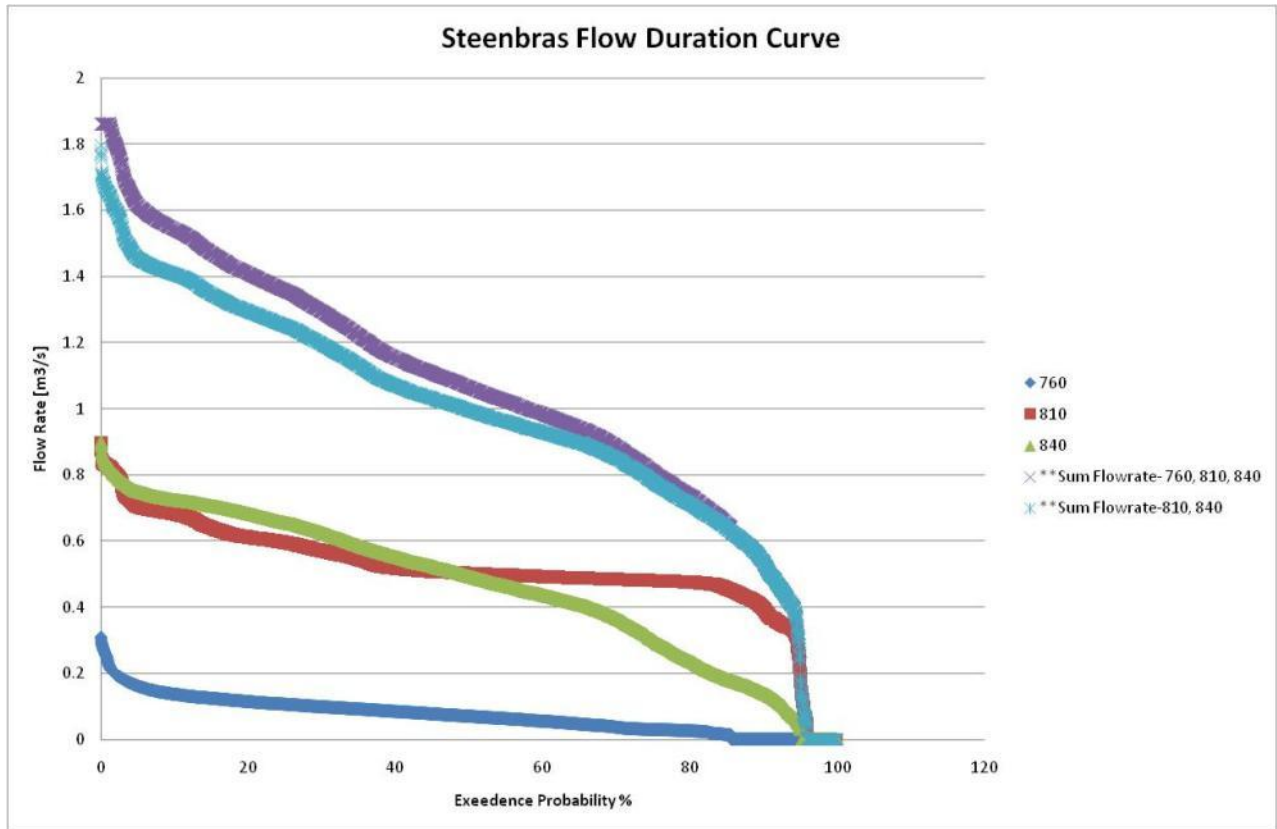
Figure 22: Flow Duration curve Steenbras

5.1.3   Design concept

This design will take all the flows leaving the Clearwell reservoir (average level 280m) through the existing 610mm pipe onto a single pelton wheel turbine at the level of the existing 840 break pressure tank (206.45m MSL). Flows of up to 150Ml/day would be realised here.

This design would utilise all the pressure that the tanks are designed to remove from the system. Minimal civil works here would include the construction of a power house for the wheel at either of the break pressure tanks. The existing 810mm and 840mm pipes that deliver clean water to Cape Town would be connected to outlet works of the pelton wheel.

A similar situation here exists as with the raw water inlet to the WTW. The pipes leading to the break-pressure tanks were most likely not optimised for electricity production and large penstock losses would most likely be found. For conceptual design purposes, a 10% penstock loss is assumed and it is also assumed that a new penstock will need to be installed.

It is further noted that there remains the option of installing an "in-line" type reaction turbine in a sealed system where the water leaving the turbine remains pressured. An example of this would be a Francis turbine. This should be considered because there is a significant drop in static head from the break-pressure tanks to the bottom of the mountain. However, it is suggested that no further head would be gained because it was discovered that, through consultation with operators of the plant, the remaining head is needed to ensure delivery at the Newlands reservoir. The pressure is not further broken and at times the water is even re-pressurised using booster pumps.

5.1.4 Design Results

The actual energy delivered of 4.2 GWh is the average yearly output of the new plant operating at a design capacity of 784 kW. This output was determined using the historical flow rate data since 1997 and can be seen in Table 13. The historical capacity factor is also shown.

Table 12: Design inputs and assumptions

Static Head	m	74
Penstock losses	%	10%
Rated Head	m	66
Design Flow	m3/s	1.50
Design Flow	Ml/day	130
Turbine type		Pelton
Runner Diameter	m	0.58
Turbine Design Efficiency	%	87%
Turbine Capacity	kW	784
Annual Plant Downtime Losses	%	5%
Theoretical Energy Delivered	kWh	6 521 722
Actual Energy Delivered	kWh	4 266 995
Capacity Factor	%	65%

Table 13: Design Results SBWTW to 810, 840

Design Results		
Plant Design Capacity	kW	784
Annual downtime losses	%	5%
Theoretical Energy Delivered	kWh	6 521 722
Edelivered 1998	kWh	4 616 640
Edelivered 2000	kWh	4 617 008
Edelivered 2002	kWh	4 106 253
Edelivered 2004	kWh	4 249 142
Edelivered 2006	kWh	4 233 032
Edelivered 2008	kWh	3 791 301
Edelivered 2010	kWh	4 255 592
Average	kWh	4 266 995
Capacity Factor Theoretical	%	100%
Capacity Factor 1998	%	71%
Capacity Factor 2000	%	71%
Capacity Factor 2002	%	63%
Capacity Factor 2004	%	65%
Capacity Factor 2006	%	65%
Capacity Factor 2008	%	58%
Capacity Factor 2010	%	65%
Average	%	65%

5.1.5   Grid Connection

Current Steenbras is not connected to any Municipal or Eskom grid and uses a diesel generator as its only back-up. The assumption used here is that the line plant will need to be connected to the closest Eskom Sub-station which is located in Gordon's bay. A summary of the connection details is given in Table 14. The line length was measured off Google Earth and a screen shot of the line is shown in Figure 23.

There may be a closer Municipal Substation or a loop-in grid connect option into a municipal line but this would need to be further investigated in the Feasibility study. A 22kV line is assumed for financial modelling purposes but this can only be determined after a full investigation.

Table 14: Steenbras Grid Connection

	Steenbras
Generation Capacity	1.4-1.8MW
Feed-in Voltage	22kV
Current back up supply	Diesel Generator
Eskom Substation Connection	
Closest Eskom Substation	Gordon's Bay Substation
Coordinates	18.87980209580 E 34.15303044270 S
Substation Voltage	66 kV
Distance to Substation (length of line)	4468 m (Figure 23)

Figure 23: Steenbras Grid Connect Eskom Sub-station

5.1.6   Works

The estimation of the infrastructure costs are given in Table 15. These prices are only indicative and have been estimated using the RETScreen methodology.

Table 15: SBWTW to 810, 840 works

SBWTW to 810, 840	Item	Specific Costs		Item Cost	
Civils			**R**	**4 660 000**	
Power House and Balance of Plant			R	3 500 000	
New Penstock designed for max power generation			R	560 000	
Access Road/upgrade rail access			R	500 000	
Other Civils			R	100 000	
Hydro Mechanical Electrical			**R**	**7 000 000**	
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a Single 784 kW Pelton)	784	R	8 932	R	7 000 000
Electricals and Grid Connection			**R**	**1 269 000**	
Transmission line 22kV	5	R	230 000	R	1 150 000
Substation/Other Electricals			R	119 000	
Total			**R**	**12 929 000**	

A new penstock is assumed to be installed here delivering only 10% losses. The existing pipe needs to be assessed to see if it is adequate. This work would merely include a short penstock from the existing 525 valve and could lead to potential savings.

Bypass systems need to be considered for safe shut down and to ensure continuous water supply to Cape Town.

5.1.7   Financial Modelling results

The financial modelling of this site assumes that the energy produced will be fed into the grid and sold to the municipality. Therefore all energy produced is considered here, sold at the MegaFlex average Tariff. Table 16 shows the total estimated costs for this site. Table 17 shows the key financial outputs.

Table 16: Total Project Costs SBWTW to 810, 840

		SBWTW to 810, 840
Project Development Costs	ZAR	2 081 250
Installation Cost	ZAR/kW	18 147.76
	ZAR	14 221 900
Contingency	%	25%
	ZAR	3 555 475
Total Capital Cost	ZAR	19 858 625
Funding		
Funding Horizon	years	10
Interest Rate	%	12.00%
Debt:Equity Ratio	%	70%
Debt amount	ZAR	13 901 038
Equity amount	ZAR	5 957 588
Total Capex		**19 858 625**
Number of debt instalments per annum		1
Total Number of instalments		10
Total Interest Paid	ZAR	10 701 598
Total Operation and Maintenance Costs	ZAR	11 023 288
Total Lifetime Costs	ZAR	41 583 510
Incremental Energy Production	kWh	85 339 909
Actual Energy Production	kWh	85 339 909
Incremental Levelised Electricity Cost	0.9	0.49
Real Levelised Electricity Cost	0.8	0.49
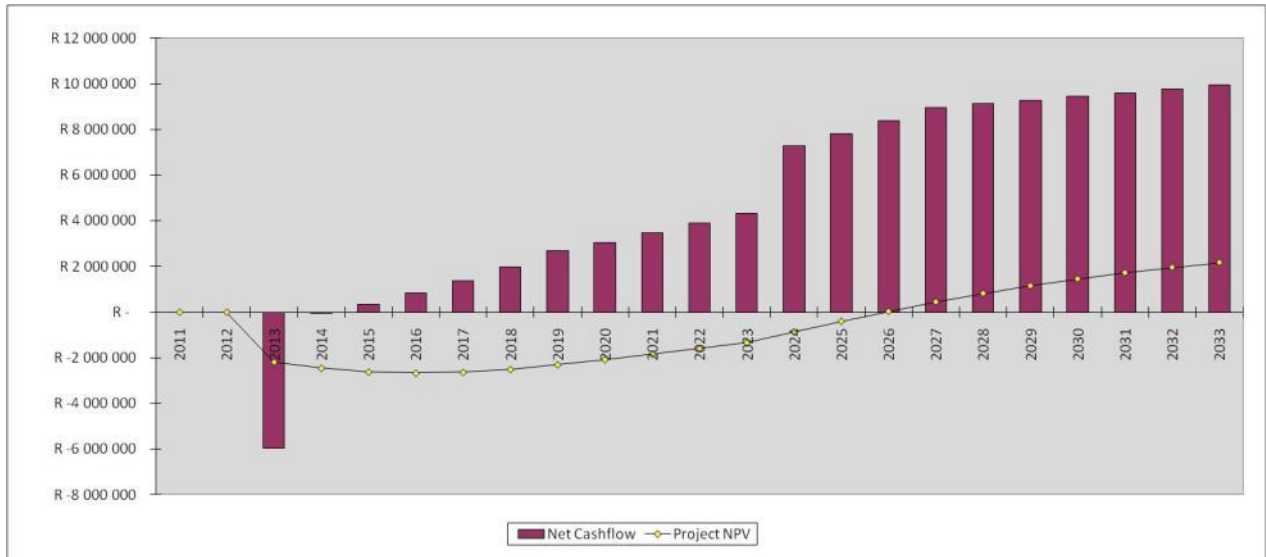
Figure 24: Cash Flow and NPV for SBWTW to 810, 840

Table 17: Financial Modelling results SBWTW to 810, 840

Key Outputs	SBWTW to 810, 840	
Capex Required	19 858 625	
Equity Required at Fin Close	5 957 588	
PPA Revenue	149 117 267	
Operating Costs	12 956 439	
EBITDA	136 160 828	
Net Cashflow	105 600 606	
NPV	11 471 378	
Equity IRR		29%
Incremental Levelised Cost of Energy (ZAR/kWh)	R	0.49
Real Levelised Cost of Energy (ZAR/kWh)	R	0.49

5.1.8   Conclusions and Recommendations

Access for this site is a problem with a very steep slope and no access road. Access is by foot path only. There is a rail access with max capacity assumed at 5 tonnes. This rail would need to be upgraded or a new road installed from the bottom of the mountain. The environmental aspects of this installation would also need to be considered in the Environmental report.

The feasibility design should also include the following investigation:

- Whether the existing pipeline is feasible as a penstock for the new system or whether this should be replaced
- Further studies on how to bypass and break pressure in case of plant shut down
- Investigation as to whether a Francis turbine based on the pressure requirements of the distribution system
- Do proper flow measuring to find out the daily cycle values and how the cycling would affect the turbine design and the power output.

5.2 Steenbras Lower Dam to Steenbras Water Treatment Works (SB Lower to SBWTW)

5.2.1 Description (SB Lower Dam to SBWTW C)

The Lower Steenbras Dam supplies the Water Treatment Works (WTW) through an 810mm steel pipe transferring a maximum of 150Ml/day. Before the water enters the works it enters the New Screening chamber where the water is split and 115 Ml/day is fed to two existing Turgo turbines of capacity 179 kW. Only one turbine functions at a time taking a flow of 57.5 Ml/day and the rest is bypassed. The remaining 35 Ml/day is bypassed through the old screening chamber where it then enters the works. Figure 25 show views of Lower Steenbras and the WTW.
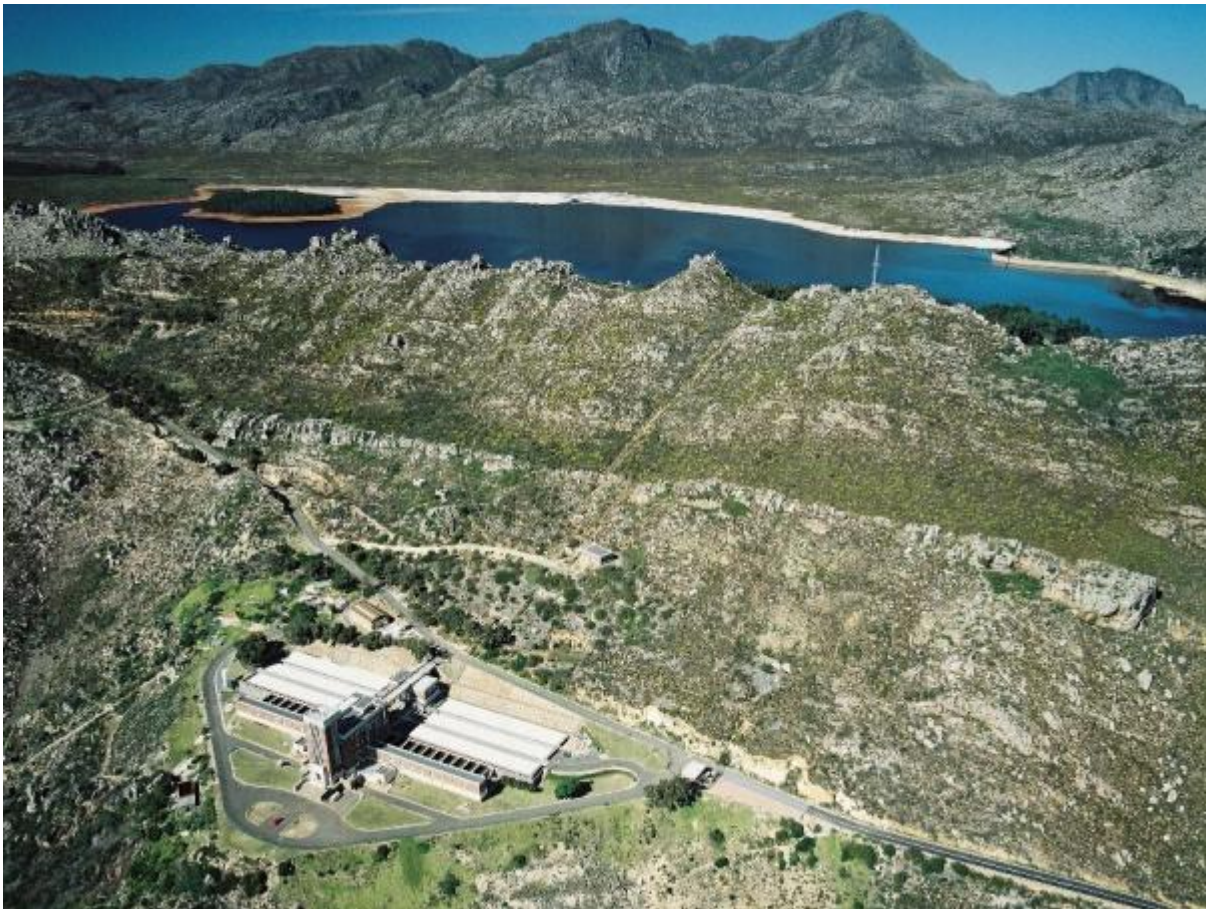
Figure 25: View of Lower Steenbras and the WTW

5.2.2 Data used

5.2.2.1 Levels

The following levels were considered in the design. Again the drawing levels were taken from drawing W3-013-103.

The turbine data sheet (Appendix A Turbine Spec Sheets) shows that the existing turbine rated head is 34.4m which is the net head after losses between the New Service Reservoir and the Turbine. This

leads to the calculated value of 291.06m as the level of the turbine (note that this calculation does not take into account losses and is therefore only and indicative value of the turbine level).

Table 18: Steenbras Lower Dam to WTW

	TOR	Drawing	Turbine Data Sheet	Calculated
Steenbras Lower FSL	345.8	345.8	-	-
Steenbras Lower Limit	330	-	-	-
New screening chamber	325.46	325.46	-	-
Old screening chamber	298.56	298.56	-	-
turbine house	295.5	-	-	291.06
Water Treatment Plant	-	282.06	-	-
clearwell	282.03-276	-	-	-
Rated Turbine Head (existing)	-	-	34.4	-

5.2.2.2 Flow Rates

The flow rate data was taken from the data provided by Bulk Water Head office and dates back to 1997. The flow data seems quite accurate with few discrepancies. A summary of the flowrates out of the dam are shown in Table 19 and correlate with the plant conditions given in the TOR. A flow duration curve has been compiled for all the flows at Steenbras and is shown in Figure 22.

Table 19: Flow rate data for SB Lower Dam to SBWTW C

Min Flow	m3/s	0.52
Min Flow	Ml/day	45
Max Flow	m3/s	1.74
Max Flow	Ml/day	150
Average Flow	m3/s	1.05
Average Flow	Ml/day	90

5.2.3 Current Turbine Operation

The base case used here is the existing installed turbines that are generating for own use on the plant. They are two 21" Turgo Impulse Turbines that are arranged in Tandem and have a design capacity of 179 kW each. The current design of the existing turbines makes use of the head drop from the new screening chamber to the turbine floor (34.4m net head, 0.66m3/s each). An image of this turbine is shown in Figure 26.

Figure 26: Steenbras Turgo Turbine

Because these two turbines are not synchronised properly and the technology is so old (1940's), only one plant is operated at a time with water flowing through the other turbine but not taking the load and generating. Therefore at any one time, the maximum generation capacity of the plants is 179kW.

Without having details about the current plant electrical demand and electric usage, certain assumptions have been made. It is assumed that the current plant consumes all electricity that is generated by the existing turbine. This operational assumption has is shown in Table 20.

Table 20: Current Steenbras Turbine Operation Assumptions

Average Flow	94	Ml/day
Turbine Power Output	179	kW
Turbine Efficiency	80%	
Capacity Factor	63%	
Theoretical Energy Delivered Current (One turbine)	2 508 864	kWh
Energy Delivered Current	788 196	kWh

Therefore the assumed base power generation for the site is 0.78GWh/annum. If a new design is to be incorporated it, only the incremental energy delivered will be considered in the financial modelling, that is only the power generated above 0.78GWh.

There are two identified options for this site. These are:

- Turbine Re-furb and synchronisation (SB Lower Dam to SBWTW 1)
- Turbine replacement (SB Lower Dam to SBWTW 2)

5.2.4   Design Concept - SB Lower Dam to SBWTW 1

Because these turbines are so old and inefficient (installed 1940's), the option here would be to replace the current generating equipment with newer technology as well as re-synchronising the two turbines so that they can operate at the simultaneously. On the site visit, it was noted the turbine runners have been recently replaced.

The turbines will most likely then generate more than what is required on site. In order to evaluate what the feasibility is of putting this power into the grid a study and energy audit will need to be performed to determine what the amount is in excess of the current usage. If the income generated from this sale of electricity is greater than the costs of grid connection then it will be viable to connect it.

5.2.4.1   Works

The estimation of the infrastructure costs are given in Table 21. These prices are only indicative and have been estimated using the RETScreen methodology.

Table 21: Works SB Lower Dam to SBWTW 1

SB Lower Dam to SBWTW 1	Item	Specific Costs		Item Cost	
Civils				**R**	**-**
N/A				-	
Hydro Mechanical Electrical				**R**	**1 960 000**
New works include replacement of generating equipment and synchronisation of the two 179 kW Turgo turbines	358	R	5 475	R	1 960 000
Electricals and Grid Connection				**R**	**280 000**
Transmission line 22kV	1	R	230 000	R	230 000
Substation/Other Electricals				**R**	**50 000**
Total		R	6 883	**R**	**2 464 000**

Grid connection here is assumed to be shared by the discussed site at the break pressure tanks 810 and 840. Grid Connection is further discussed.

5.2.5   Design Concept - SB Lower Dam to SBWTW 2

The new design will incorporate the construction of a single turbine (Francis/Turgo). This design would also make use of the head drop from Lower Steenbras Dam to the new screening chamber by bypassing it completely (this would gain approximately 12.5m static head). This design would mean a full bypass of the two screening chambers currently existing on the site. The screening chambers were originally installed to clean the water initially before they entered the plant. They however are not used for this function anymore and the only use is to ensure a constant head to the existing turbine (new screening chamber). By bypassing the two chambers, full water flow to the turbines can be utilised (gain in 35Ml/day flowrate).

Lower Steenbras Dam is usually full because it is controlled by the inlet from the Upper Steenbras Dam. Therefore, for the design calculations, the static head of the plant is taken at FSL less the existing turbine level. The existing 810mm steel pipe is was not optimised for electricity production when it was originally built and it is therefore highly recommended that further investigation of the penstock is undertaken. This would involve pressure testing at the new screening chamber and at the existing turbine inlet.

In order to estimate the size of the turbine required it has been assumed that maximum penstock losses are estimated at 10%. It is also assumed that a new penstock will need to be installed at the site. For this initial design has been done for a Francis turbine but because the water entering the Water Treatment works only needs to be at atmospheric pressure, an impulse turbine such as a Turgo could also be used.

According to the evaluation of the flow rates experienced by the plant, the chosen design flow rate for this design is 1.6m3/s (138Ml/day). Choosing the design flow-rate higher than this would result in a drop in efficiency a resulting drop in energy production over the range of raw water flowrates.

5.2.5.1   Works

The estimation of the infrastructure costs and their description is given bellow in Table 22.

Table 22: Works SB Lower Dam to SBWTW 2

SB Lower Dam to SBWTW 2	Item	Specific Costs		Item Cost	
Civils				**R**	**900 000**
Install 810mm pipe connecting the existing steel pipe (entering the New screening chamber) to the new turbine at the turbine house floor (length?). This penstock pipe bypasses all screening chambers and connect directly to the turbine inlet				R	350 000
Power House (non required)				R	-
Balance of Plant				R	350 000
Other Civils				R	200 000
Hydro Mechanical Electrical				**R**	**4 900 000**
M&E – Turbine full turnkey installation. Works here is typical Water-to Wire. (Design Concept for a Single 605 kW Francis but also investigate a Turgo)	605	R	8 098	R	4 900 000
Electricals and Grid Connection				**R**	**321 000**
Transmission line 22kV	1	R	230 000	R	230 000
Substation/Other Electricals				R	91 000
Total				**R**	**6 121 000**

By using the existing power house, civil costs are reduced. The turbine costs have been estimated for a Francis turbine but a Turgo should also be investigated however indicative costs show this option to be +-R1.5mil more expensive.

The replacement of the existing pipeline from the LSD was also investigated but these costs have come out +- R5mil for a 900mm pipe at 700m (excavation costs ignored) and therefore may be too costly.

5.2.6 Design Results

The rated head for the refurbishment option (Lower Dam to SBWTW 1) was taken as 34.4m. Because of the dam level fluctuation a variable head should be taken into account when doing the energy calculations for the replacement option (Lower Dam to SBWTW 2). The gross static head for this design was taken as the dam preferred SL less the New Screening chamber level add the existing rated head 34.4m (=345.8-325.46+34.4=54.74m). Penstock losses were estimated at 15% resulting in a rated turbine head of 48.m. This with the design flow resulted in a turbine capacity of 649 kW.

When calculating the energy output during for the period 1997-2011 an average dam level of 342 m was used resulting in a net head of 43.3m. This head is viewed as a conservative estimate because the dam is most often full.

The resulting energy output for all three cases is shown below in Table 23. By synchronising and refurbishing the generator equipment it would be possible to double the electric output of the plant and by re-sizing and replacing the turbine, a further 1.7 GWh can be generated. It is this value that was used to determine the financial viability.

Table 23: SB Lower Dam to SBWTW Design Summary

		SB Lower Dam to SBWTW C	SB Lower Dam to SBWTW 1	SB Lower Dam to SBWTW 2
Static Head	m	*	*	55
Hydraulic losses	%	*	*	15%
Rated Head	m	34	34	48
Design Flow	m3/s	0.66	1.32	1.60
Design Flow	Ml/day	58	115	138
Turbine type		2 xTurgo	Turgo	Francis
Runner Diameter	m	0.53	1.07	0.57
Turbine Design Efficiency	%	*	*	87%
Turbine Capacity	kW	179	358	605
Annual Plant Downtime Losses	%	*	*	
Theoretical Energy Delivered	kWh	2 508 864	2 508 864	5 035 791
Actual Energy Delivered	kWh	788 196	1 576 392	2 539 701
Capacity Factor	%	31%	63%	50%
Actual Increase from Current Generation	kWh	-	788 195.81	1 751 506
% Increase	%	-	100%	222%

Table 24: Design Results SB Lower Dam to SBWTW 2

Design Results		Raw Water
Plant Design Capacity	kW	605
Annual downtime losses	%	5%
Theoretical Energy Delivered	kWh	5 035 791
Edelivered 1998	kWh	2 656 366.51
Edelivered 2000	kWh	2 657 206
Edelivered 2002	kWh	2 469 176
Edelivered 2004	kWh	2 553 944
Edelivered 2006	kWh	2 552 815
Edelivered 2008	kWh	2 184 815
Edelivered 2010	kWh	2 703 587
Average	kWh	2 539 701
Capacity Factor Theoretical	%	100%
Capacity Factor 1998	%	53%
Capacity Factor 2000	%	53%
Capacity Factor 2002	%	49%
Capacity Factor 2004	%	51%
Capacity Factor 2006	%	51%
Capacity Factor 2008	%	43%
Capacity Factor 2010	%	54%
Average	%	50%

5.2.7 Grid Connection

The grid connection assumption made here is that the plant will feed excess electricity into the grid via the transformer and grid connection at the Break pressure tank 810 and 840. It is assumed that the distance is 1km and costs for a 22kV line were used, which is a conservative cost.

5.2.8 Financial Modelling and Results

The required electricity needed to run the treatment works is assumed to be 788 196 kWh which was estimated from the current plant operating conditions. This would need to be confirmed with a full energy audit of the site. The modelling here is based on the incremental energy value over and above this.

Based on this assumption, the amount of kWh used in the financial analysis is the total energy output less the required energy on site. The newly established plant would have to ensure sufficient electricity available to continue operation of the works. The financial viability of SB LD to SBWTW 1 & 2 is compared using the financial analysis procedure described in Section 4.

Table 25 shows a summary of the inputs used in the financial modelling of the plant for the two scenarios. To test the financial viability of the plant the energy used analysed is the incremental energy produced of each option compared to the current production. This financial modelling did not take into account the current diesel generator costs, merely the current turbine production compared to the new scenarios.

Table 25: SB LD to SBWTW Financial Summary

		SB Lower Dam to SBWTW 1	SB Lower Dam to SBWTW 2
Project Development Costs	ZAR	2 081 250	2 081 250
Installation Cost	ZAR/kW	6 882.68	18 807.54
	ZAR	2 464 000	6 733 100
Contingency	%	25%	25%
	ZAR	616 000	1 683 275
Total Capital Cost	ZAR	5 161 250	10 497 625
Funding			
Funding Horizon	years	10	10
Interest Rate	%	12.00%	12.00%
Debt:Equity Ratio	%	70%	70%
Debt amount	ZAR	3 612 875	7 348 338
Equity amount	ZAR	1 548 375	3 149 288
Total Capex	ZAR	**5 161 250**	**10 497 625**
Number of debt instalments per annum		1	1
Total Number of instalments		10	10
Total Interest Paid	ZAR	2 781 342	5 657 056
Total Operation and Maintenance Costs	ZAR	5 035 697	8 511 705
Total Lifetime Costs	ZAR	12 978 288	24 666 386
Incremental Energy Production	kWh	15 763 916	34 882 313
Actual Energy Production	kWh	31 527 833	50 646 230
Incremental Levelised Electricity Cost	R/kWh	0.82	0.71
Real Levelised Electricity Cost	R/kWh	0.41	0.49
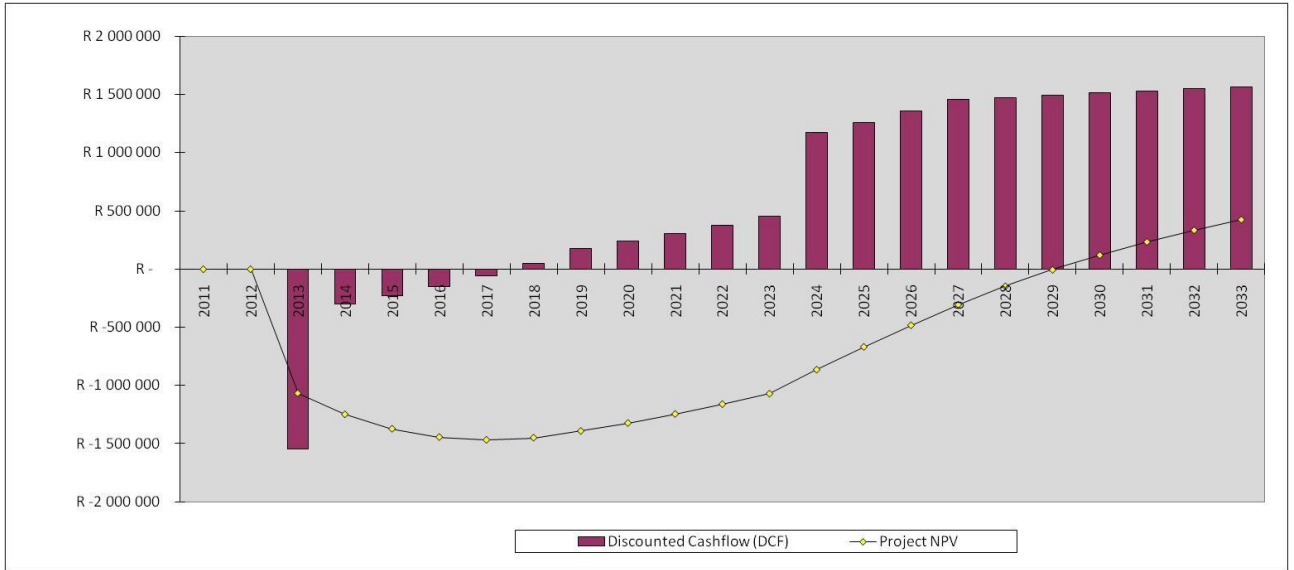
Figure 27: SB LD to SBWTW 1
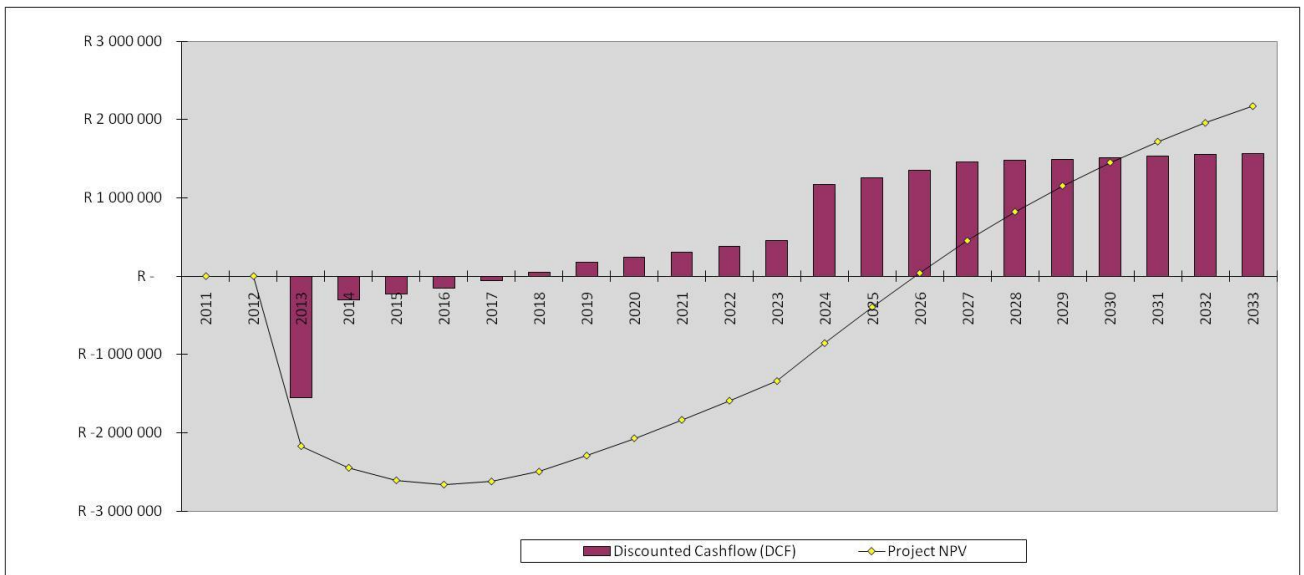
Figure 28: SB LD to SBWTW 2

Figure 27 and Figure 28 show the net cash flow and the NPV for the replacement options. Table 26 below summarises the financial outputs from the modelling process.

Table 26: SBLD to SBWTW Key Financial Outputs

Key Outputs	SB Lower Dam to SBWTW 1	SB Lower Dam to SBWTW 2
Capex Required	5 161 250	10 497 625
Equity Required at Fin Close	1 548 375	3 149 288
PPA Revenue	27 544 816	60 951 029
Operating Costs	5 918 806	10 004 401
EBITDA	21 626 011	50 946 628
Net Cashflow	13 683 419	34 791 947
NPV	426 658	2 171 023

Equity IRR		15%		19%
Incremental Levelised Cost of Energy (ZAR/kWh)	R	0.82	R	0.71
Real Levelised Cost of Energy (ZAR/kWh)	R	0.41	R	0.49

5.2.9   Conclusions and recommendations

Clearly the most feasible option of the replacement option SB LD to SBWTW 2.

For the feasibility Study, the following is recommended

- Full energy audit will need to take place to calculate the current energy produced.
- Energy Modelling for SB LD to SBWTW 2 needs to take into account:
- Variance in head because of varied flow rates in new penstock must be taken into account
- Variance in head because of changing level of SB Lower Dam should be considered
- Optimal penstock design to be compared to current design to find savings or replacement

5.3   Steenbras Water Treatment Plant to the Break pressure tank 760 (SBWTW to 760)

5.3.1   Description

This site was not included in the scope of work outlined. The site visit resulted in the discovery of a small potential at the 760 lower break pressure tank. There is a second 610mm pipe leaving the clearwell reservoir at the WTW and the pressure is broken twice, at two separate tanks 710 Upper and 710 lower. On the drawing W3-013-103, there appears to have been a pelton wheel at the lower tank but it has been de-commissioned and no design details were sourced. A view of this tank is seen in Figure 29 and Figure 30.

Figure 29: Water Treatment works to upper 760 break pressure tank
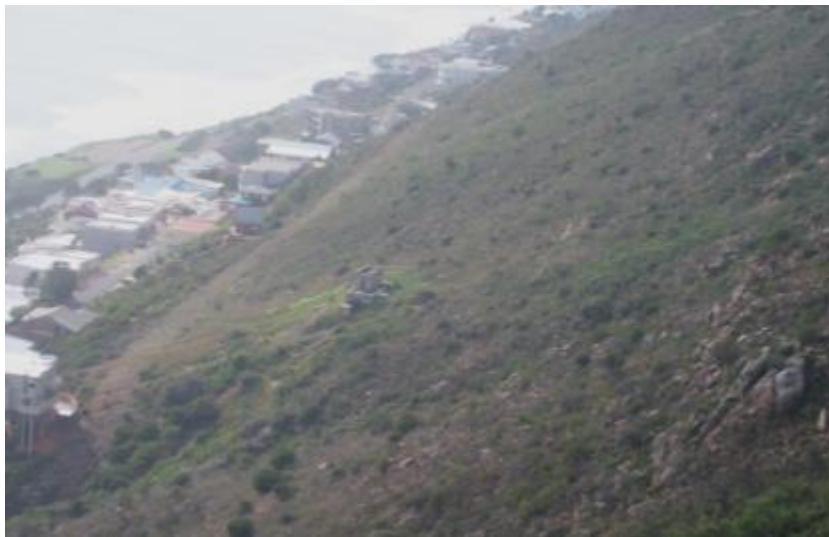
Figure 30: Lower Break pressure tank 760

5.3.2   Data Used

5.3.2.1   Levels

The following levels were considered in the design. Again the drawing levels were taken from drawing W3-013-103.

Level	TOR	Drawing	Calculated
clearwell	282.03-276		280
710 Upper TWL	-	213.36	-
710 Lower TWL	-	108.12	-

5.3.2.2 Flowrates

The flow duration curve for the 760 pipe can be seen in Figure 22. A summary of the historical flows is also given in Table 27.

Table 27: Flow rates SBWTW to 760

Min Flow	m3/s	0.012
Min Flow	Ml/day	1.0
Max Flow	m3/s	0.28
Max Flow	Ml/day	24.2
Average Flow	m3/s	0.08
Average Flow	Ml/day	7.28

5.3.3 Design concept

A 610mm pipe leaves the clearwell reservoir at (average level 280m) and realises a gross static head drop of 171m to a level of 108m at the lower break pressure tank. The water would then leave the installed pelton wheel through the existing 760mm pipe line to Cape Town. This site, as with the 810 and 840 pipe has a near constant static head.

5.3.4 Works

A summary of the works required is shown in Table 28

Table 28: Works SBWTW to 760

SBWTW to 760	Item	Specific Costs	Item Cost
Civils			**R 2 032 000**
Power House and Balance of Plant			R 1 000 000
New Penstock designed for max power generation			R 532 000
Access Road			R 500 000
Hydro Mechanical Electrical			**R 2 100 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a Single 265 kW Pelton)	228	R 8 920	R 2 100 000
Electricals and Grid Connection			**R 460 000**
Transmission line 22kV	2	R 230 000	R 460 000
Substation/Other Electricals			R -
Total		**R 20 155**	**R 4 592 000**

A possible cost saving could be found if the existing pipeline can act as an efficient penstock to the plant. If so, works would include upgrading pipe connections and re-routing the pipe to the pelton wheel from the existing 460 valve. Savings could be in the region of R0.5mil.

It is assumed that minimal turbine house upgrades will need to be done as there was an existing pelton wheel at this location.

Access needs to be considered as the plant currently has no road access.

5.3.5   Grid Connection

The grid connection assumption made here is that the plant will feed electricity into the grid via the transformer and grid connection at the Break pressure tank 810 and 840. The distance is 1 km and costs for a 22kV line were used which is a conservative cost.

5.3.6   Design Summary

A design flow rate of 0.18m3/s was used to maximise energy output. 10% average penstock loss was assumed. It is noted that these losses can be significant at varying flow rates and would need to be investigated further. Table 29 shows the design summary and results.

Table 29: Design Summary SBWTW to 760

		SBWTW to 760
Static Head	m	172
Hydraulic losses	%	10%
Rated Head	m	155
Design Flow	m3/s	0.18
Design Flow	Ml/day	16
Turbine type		Pelton
Runner Diameter	m	0.22
Turbine Design Efficiency	%	91%
Turbine Capacity	kW	228
Annual Plant Downtime Losses	%	5%
Theoretical Energy Delivered	kWh	1 896 047
Actual Energy Delivered	kWh	767 260
Capacity Factor	%	40%

Energy output has been estimated for the period 1997-2011 for the design capacity of 228kW. Average yearly output is 0.8 GWh giving an average capacity factor of 40%. Table 30 shows this historical estimate.

Table 30: Design Results SBWTW to 760

Design Results		
Plant Design Capacity	kW	228
Annual downtime losses	%	5%
Theoretical Energy Delivered	kWh	1 896 047
Edelivered 1998	kWh	251 101
Edelivered 2000	kWh	252 699
Edelivered 2002	kWh	981 527
Edelivered 2004	kWh	914 025
Edelivered 2006	kWh	692 315
Edelivered 2008	kWh	920 108
Edelivered 2010	kWh	1 359 048
Average	kWh	767 260

Capacity Factor Theoretical	%		100%
Capacity Factor 1998	%		13%
Capacity Factor 2000	%		13%
Capacity Factor 2002	%		52%
Capacity Factor 2004	%		48%
Capacity Factor 2006	%		37%
Capacity Factor 2008	%		49%
Capacity Factor 2010	%		72%
Average	%		40%

5.3.7   Financial Modelling Results

This plant was modelled in a similar way to the other plant described above. Table 31 shows the expected project costs and Figure 31 is the NPV and IRR for the site.

Table 31: SBWTW to 760 Project Costs

		SBWTW to 760
Project Development Costs	ZAR	2 081 250
Installation Cost	ZAR/kW	22 170.38
	ZAR	5 051 200
Contingency	%	25%
	ZAR	1 262 800
Total Capital Cost	ZAR	8 395 250
Funding		
Funding Horizon	years	10
Interest Rate	%	12.00%
Debt:Equity Ratio	%	70%
Debt amount	ZAR	5 876 675
Equity amount	ZAR	2 518 575
Total Capex	ZAR	**8 395 250**
Number of debt instalments per annum		1
Total Number of instalments		10
Total Interest Paid	ZAR	4 524 109
Total Operation and Maintenance Costs	ZAR	3 204 778
Total Lifetime Costs	ZAR	16 124 138
Incremental Energy Production	kWh	15 345 206
Actual Energy Production	kWh	15 345 206

Incremental Levelised Electricity Cost	R/kWh	1.05
Real Levelised Electricity Cost	R/kWh	1.05
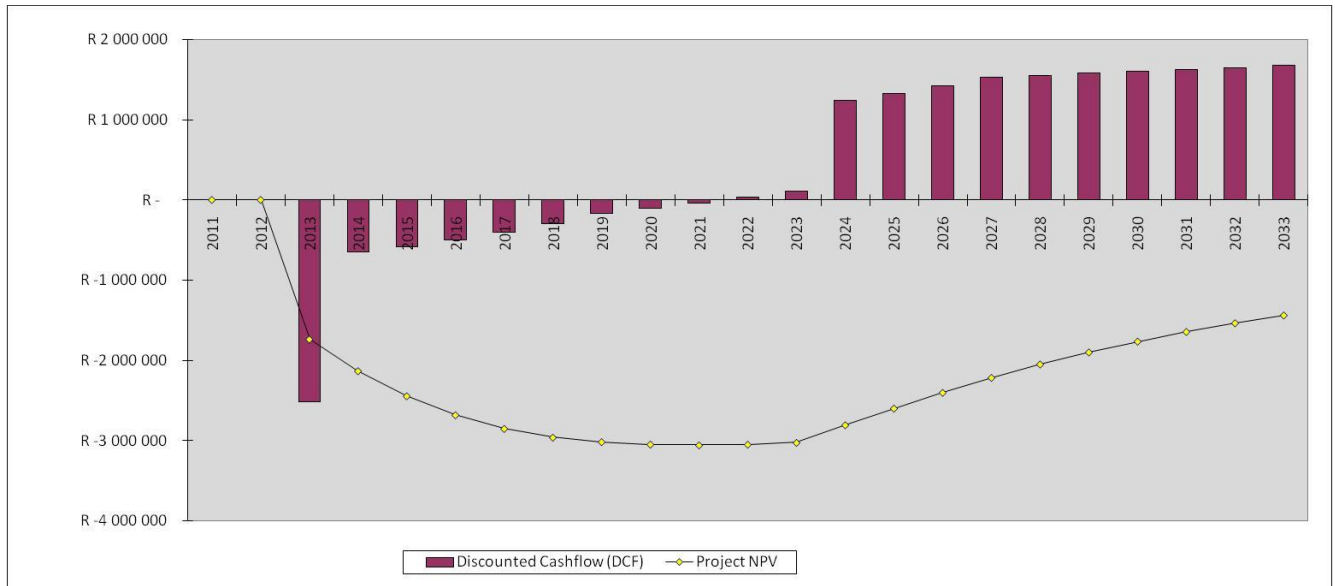
Figure 31: SBWTW to 760 NPV and IRR

Table 32 below shows the key financial outputs.

Table 32: SBWTW to 760 Key Financial Outputs

Key Outputs	SBWTW to 760
Capex Required	8 395 250
Equity Required at Fin Close	2 518 575
PPA Revenue	26 813 190
Operating Costs	3 766 800
EBITDA	23 046 390
Net Cashflow	10 127 031
NPV	(1 437 295)
Equity IRR	8%
Incremental Levelised Cost of Energy (ZAR/kWh)	R 1.05
Real Levelised Cost of Energy (ZAR/kWh)	R 1.05

5.3.8   Conclusions and Recommendations

- According to the financial analysis, this site does not yield positive results. The NPV is however close to zero and with some savings in the Feasibility and perhaps some Capex savings, this site may well yield positive results.

- It is recommended that this site be investigated in the Feasibility Study
- The feasibility design should also include the following investigation:
  - Whether the existing pipeline is feasible as a penstock for the new system or whether this should be replaced

  o Further studies on how to bypass and break pressure in case of plant shut down

  o Do proper flow measuring to find out the daily cycle values and how the cycling would affect the turbine design and the power output.

  o Access is an issue at this site and should be investigated further

5.4 Rockview Dam to Upper Steenbras Dam (Rockview to USD)

5.4.1 Description

Eskom currently operates a pumped storage hydro power scheme by pumping water from the Kogelberg Dam to the Rockview Dam during times of low demand and weekends. It then uses that water to generate electricity needed to meet peak electric demands.

Occasionally CCT buys water from the Eskom Scheme taking water out of the Rockview Dam into the Upper Steenbras Dam located on the other side of the mountain. Water is only fed through this pipe when there is enough water on the Kogelberg Dam side which is controlled by DWA. The water flows out of the Rockview Dam into an 875m canal before entering a pipe. A 1691mm ID pipeline starting at T.O.P. (Top of Pipe) sees a static head drop of 125m over a length of 2051m. Figure 32 below shows the Rockview Dam with the canal outlet and the intake to the pipe. Figure 33 depicts the inlet to the Upper Steenbras Dam.

Figure 32: Rockview Dam with canal outlet

Figure 33: Rockiew dam inlet to Upper Steenbras

5.4.2 Data Used

5.4.2.1 Levels

The only reference for the operating levels of this scheme were given in the Terms of Reference and shown below.

Level	TOR
Rockview Top of Dam	509- unconfirmed
Rockview Base of Dam	499.56
Rockview Dam Top of Pipe (TOP)	497.41
Steenbras Upper Dam	372

5.4.2.2 Flow Rates

The flow rate data used is summarised in Table 33 below and shown graphically in Figure 34. The data was manipulated to give more favourable conditions for power generation. This is explained in Section 5.4.4.

Table 33: Flow Rate Summary Rockview to USD

Min Flow	m3/s	0.1	0.1
Min Flow	Ml/day	10.8	10.8
Max Flow	m3/s	12.0	3.0
Max Flow	Ml/day	1036.8	259.2
Average Flow	m3/s	5.6	1.5
Average Flow	Ml/day	484.0	130.4
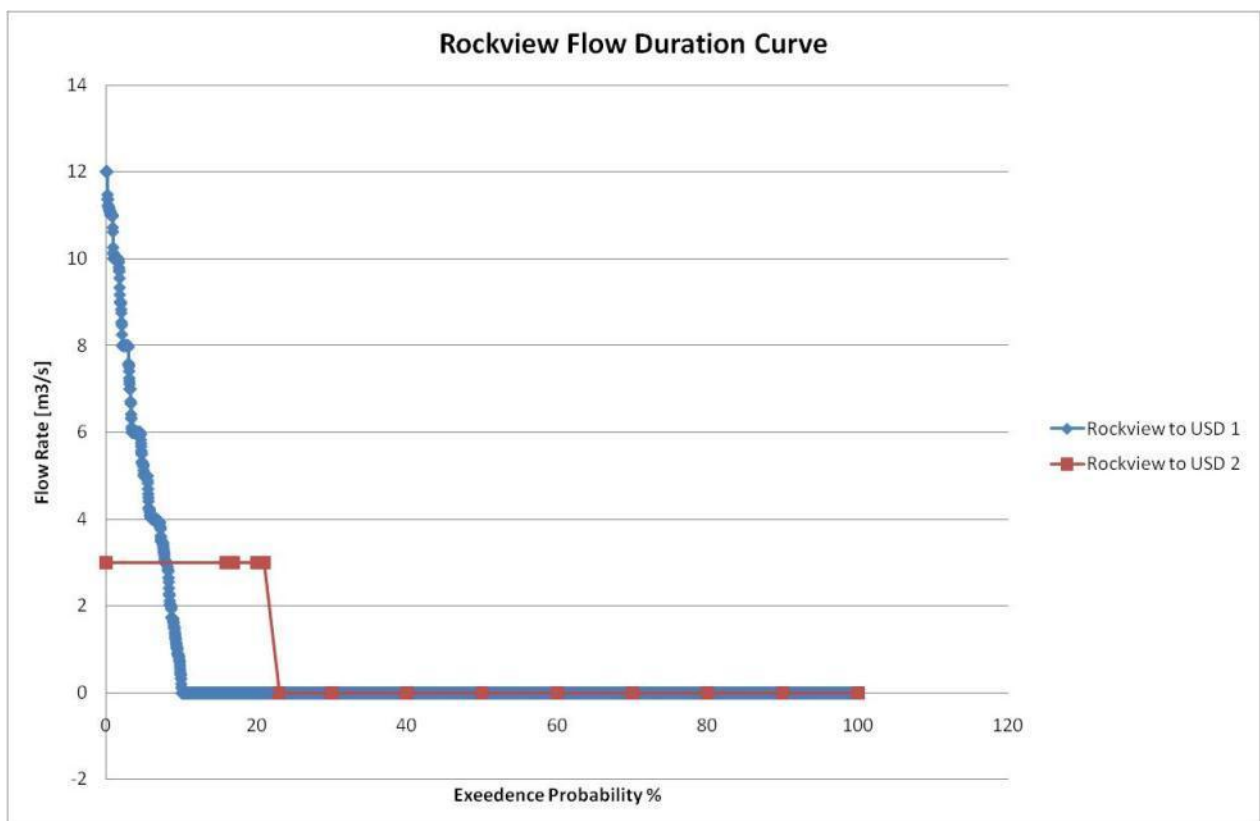
Figure 34: Flow Duration Curve for Water entering Upper Steenbras Dam

5.4.3 Design concept (Rockview to USD 1)

The Hydro Power Plant that would make use of this energy will be placed at the bottom of the pipe where the water enters the Upper Steenbras Dam.

The first design scenario analysed makes use of the historical flow data and sized a turbine to fit this flow. The chosen design flow is 5m3/s. Flows of up to 12m3/s are realised although very seldom. Flows above 5m3/s were 'bypassed' in this analysis.

The gross static head of this scheme was taken as 125m and total pipe losses were estimated at 25% leaving a rated turbine head of 94m. The analysis was performed for a Francis turbine.

5.4.3.1 Works

Table 34 shows the assumed costs for the works.

Table 34: Works Rockview to USD 1

Rockview to USD 1	Item	Specific Costs		Item Cost	
Civils				**R**	**19 800 000**
Power House and Balance of Plant				R	19 800 000
New Penstock designed for max power generation				R	-
Other Civils				R	10 000 000
Hydro Mechanical Electrical				**R**	**18 200 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a Single 265 kW Pelton)	3832	R	4 750	R	18 200 000
Electricals and Grid Connection				**R**	**1 946 000**
Transmission line 66kV	2	R	518 000	R	1 036 000
Substation/Other Electricals				R	910 000
Total				**R**	**39 946 000**

5.4.4 Design (Rockview to USD 2)

The flow rate data was manipulated in order to produce more favourable design conditions for electricity production. With a site that has the option of flow control it would be a wise decision to design the plant as a peaking plant to provide electric energy during peak and standard demand schedules. The Time of Use (ToU) tariff that Eskom charges heavy users is shown in Figure 19. CCT charges its users a premium on that with peak and standard rates being significantly higher than the average rate.

The assumption here is that a specified amount of water is allowed to be extracted at any given time and that the water released should not ever exceed the design flow rate this here was taken as 3m3/s. The sample year used was 2002, which is closest to its long term average option conditions. The daily average operating hours for Rockview is shown in Table 33. Figure 35 shows this graphically.

The assumption for the manipulation is that the total amount of water released in a month has to remain constant but can be averaged into a constant flow rate over the month. These values, as well as the historical flows are also shown in a flow duration curve (Figure 34). If this is a viable way to bring in water from Rockview then a more detailed flow analysis and manipulation will need to be performed for in the full feasibility study to follow, using all historical flow data.

Table 35: Average daily Hours at design flow 2002- Rockview to USD 2

Month	Hours	Capacity Factor
Jan	5	21%
Feb	0	0%
Mar	0	0%
Apr	12	48%

May	5	21%
Jun	18	74%
Jul	7	28%
Aug	0	0%
Sep	0	0%
Oct	0	0%
Nov	0	0%
Dec	0	0%
Average	4	16%
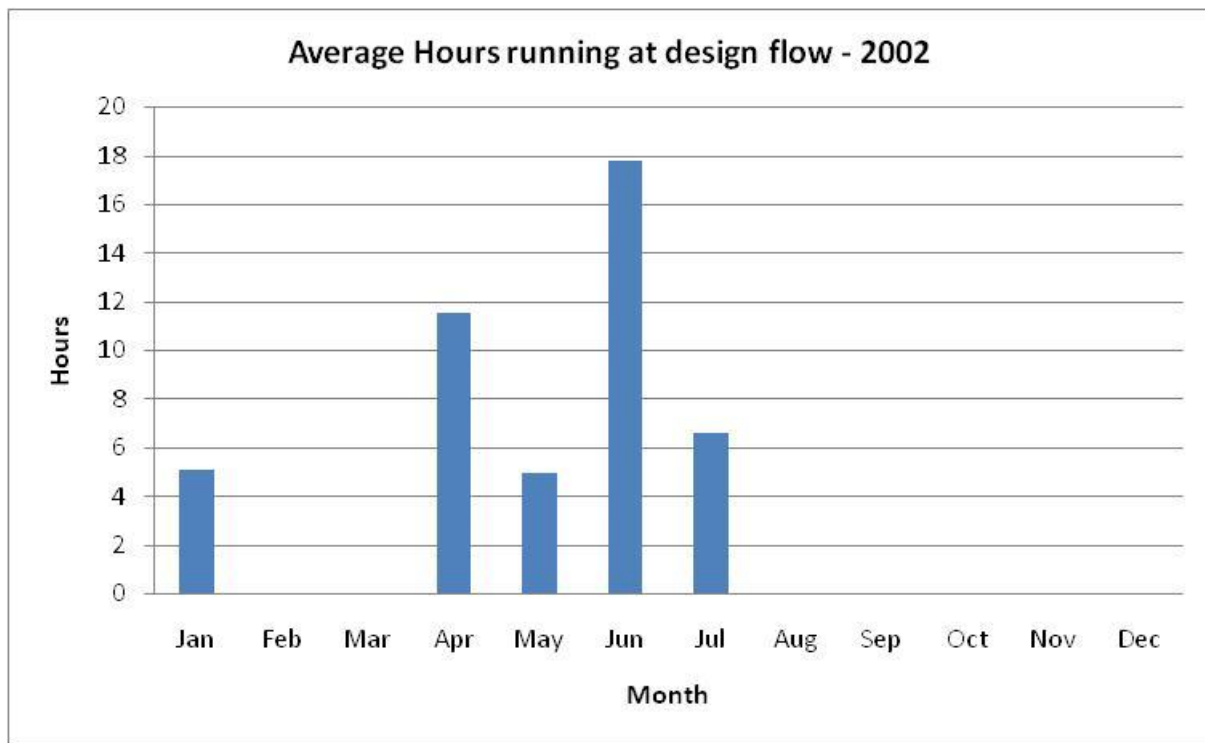
Figure 35: Average daily hours operating at design flow

Because the design flow is lower, the water velocity will also be slow resulting n fewer losses. A value of 15% loss has been selected for the analysis but this should be re-looked in the feasibility study. The resulting net head is 107m.

5.4.4.1 Works

Because the manipulated flows in this concept are significantly lower and as a result fewer friction losses are expected, it opens the possibility of extending the pipe to the base of the dam to make

use of the further 10m (unconfirmed) head drop at the dam wall. These costs have however, not been considered.

Rockview to USD 2	Item	Specific Costs		Item Cost	
Civils					
Power House and Balance of Plant				R	6 300 000
New Penstock designed for max power generation				R	-
Other Civils				R	10 000 000
Hydro Mechanical Electrical				**R**	**11 200 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a Single 265 kW Pelton)	2166	R	5 172	R	11 200 000
Electricals and Grid Connection				**R**	**1 596 000**
Transmission line 66kV	2	R	518 000	R	1 036 000
Substation/Other Electricals				R	560 000
Total				**R**	**29 096 000**

5.4.5 Grid Connection

Figure 50below shows the proximity of the Rockview scheme to the Eskom grid. The line distance is less than 2kms and the connection would be a loop in system that connects at 66kV.
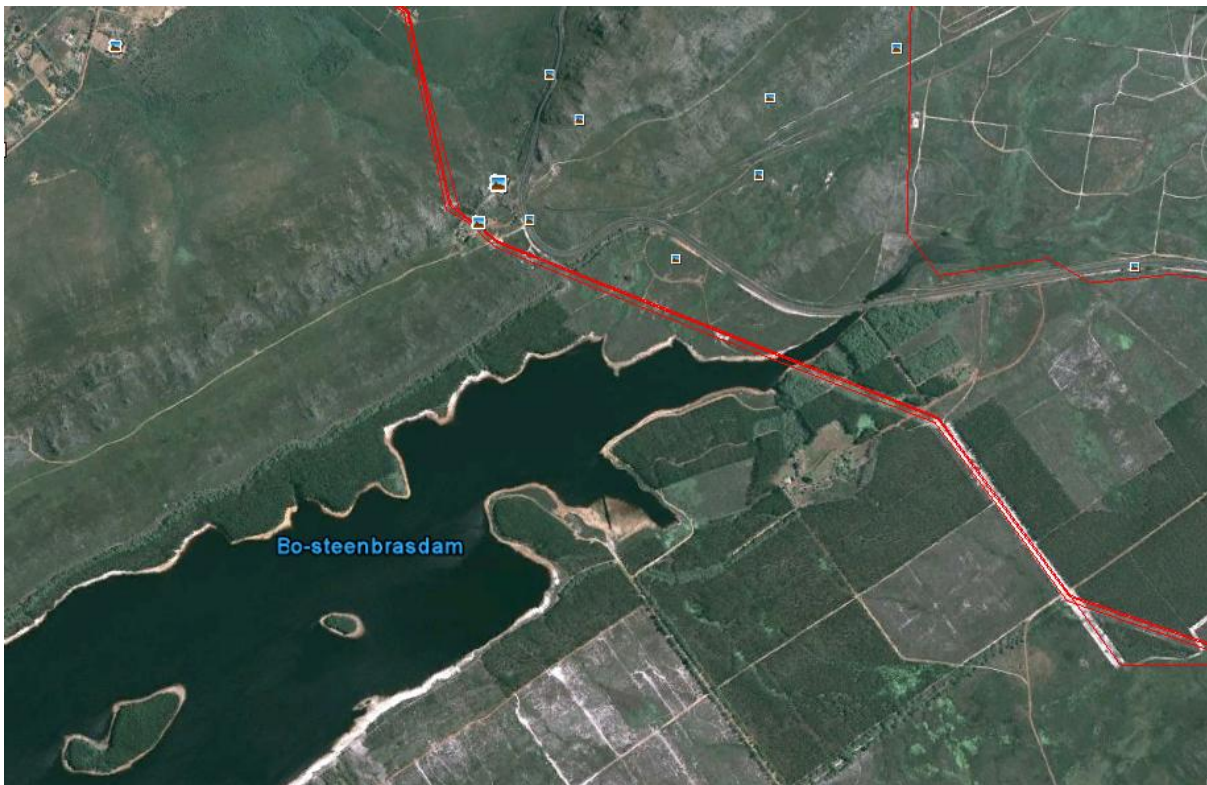
Figure 36: Rockview Grid Connection

5.4.6 Design Summary

Using 5m3/s as the design flow resulted in a turbine sizing of 3832kW. The resulting annual average energy generated over the period 1997-2011 is only 2.3GWh, capacity factor 7%. The resulting

turbine size for the second concept is smaller at 2166kW but produced just under double the amount of electricity.

Table 37 shows the design summary for the Steenbras system.

Table 37: Design Summary Rockview to USD

		Rockview to USD1	Rockview to USD 2
Static Head	m	125	125
Hydraulic losses	%	25%	15%
Rated Head	m	94	107
Design Flow	m3/s	5.00	2.50
Design Flow	Ml/day	432	216
Turbine type		Francis	Francis
Runner Diameter	m	0.98	0.71
Turbine Design Efficiency	%	90%	90%
Turbine Capacity	kW	3 832	2 166
Annual Plant Downtime Losses	%	5%	5%
Theoretical Energy Delivered	kWh	31 889 249	18 022 741
Actual Energy Delivered	kWh	2 323 708	3 528 640
Capacity Factor	%	7%	20%

Table 38: Design Results Rockview to USD 1

Design Results		Rockview to USD 1	Rockview to USD 2
Plant Design Capacity	kW	3 832	2 166
Annual downtime losses	%	5%	5%
Theoretical Energy Delivered	kWh	31 889 249	18 022 741
Edelivered 1998	kWh	656 707.63	864 104.03
Edelivered 2000	kWh	631 990	828 009
Edelivered 2002	kWh	1 828 946	3 024 484
Edelivered 2004	kWh	4 474 203	7 897 685
Edelivered 2006	kWh	5 725 106	8 061 506
Edelivered 2008	kWh	1 179 958	1 325 393
Edelivered 2010	kWh	1 769 044	2 699 296
Average	kWh	2 323 708	3 528 640
Capacity Factor Theoretical	%	100%	100%
Capacity Factor 1998	%	2%	5%
Capacity Factor 2000	%	2%	5%
Capacity Factor 2002	%	6%	17%
Capacity Factor 2004	%	14%	44%
Capacity Factor 2006	%	18%	45%
Capacity Factor 2008	%	4%	7%
Capacity Factor 2010	%	6%	15%
Average	%	7%	20%

As can be seen, with some simple manipulation of the flows, greater energy can be extracted out of the water at a smaller design capacity, leading to a higher capacity factor. A full investigation will need to be undertaken in order to find what level of manipulation can be accommodated.

5.4.7 Financial Modelling and Results

Table 39 below shows the Total costs for the Rockview schemes compared.

Table 39: Rockview Total Costs

		Rockview to LSD1	Rockview to LSD 2
Project Development Costs	ZAR	2 081 250	2 081 250
Installation Cost	ZAR/kW	11 466.99	14 778.58
	ZAR	43 940 600	32 005 600
Contingency	%	25%	25%
	ZAR	10 985 150	8 001 400
Total Capital Cost	ZAR	57 007 000	42 088 250
Funding			
Funding Horizon	years	10	10
Interest Rate	%	12.00%	12.00%
Debt:Equity Ratio	%	70%	70%
Debt amount	ZAR	39 904 900	29 461 775
Equity amount	ZAR	17 102 100	12 626 475
Total Capex	ZAR	**57 007 000**	**42 088 250**
Number of debt instalments per annum		1	1
Total Number of instalments		10	10
Total Interest Paid	ZAR	30 720 454	22 680 901
Total Operation and Maintenance Costs	ZAR	53 900 542	30 462 791
Total Lifetime Costs	ZAR	141 627 996	95 231 942
Incremental Energy Production	kWh	35 380 883	70 572 793
Actual Energy Production	kWh	35 380 883	70 572 793
Incremental Levelised Electricity Cost	R/kWh	4.00	1.35
Real Levelised Electricity Cost	R/kWh	4.00	1.35
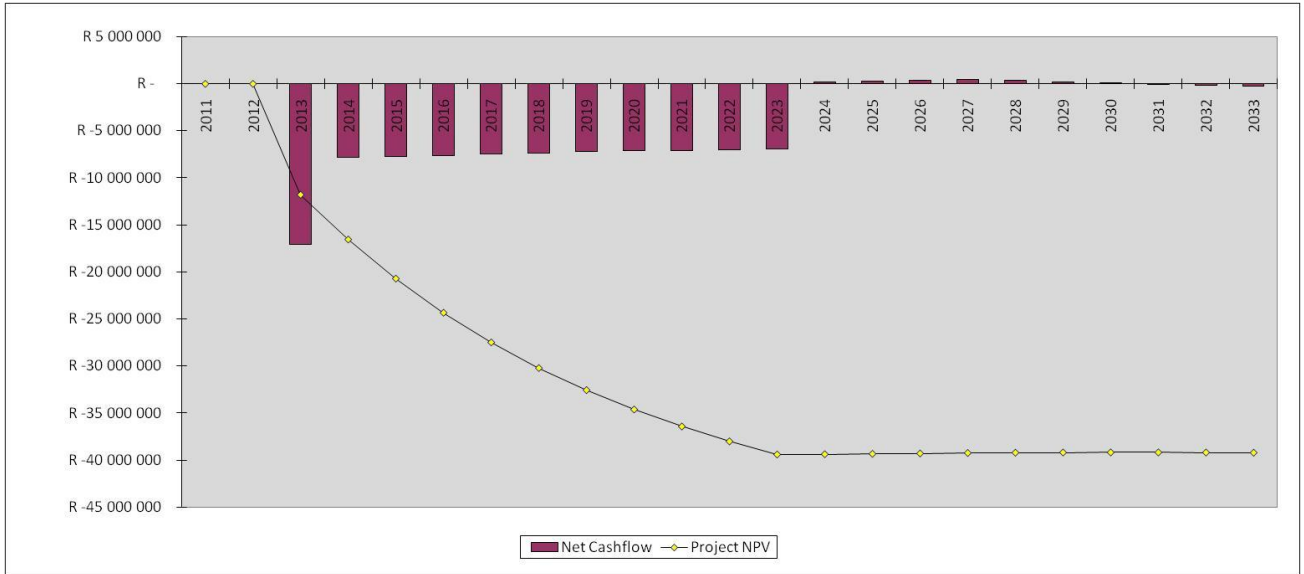
Figure 37: Rockview to USD 1 NPV and Cash Flows
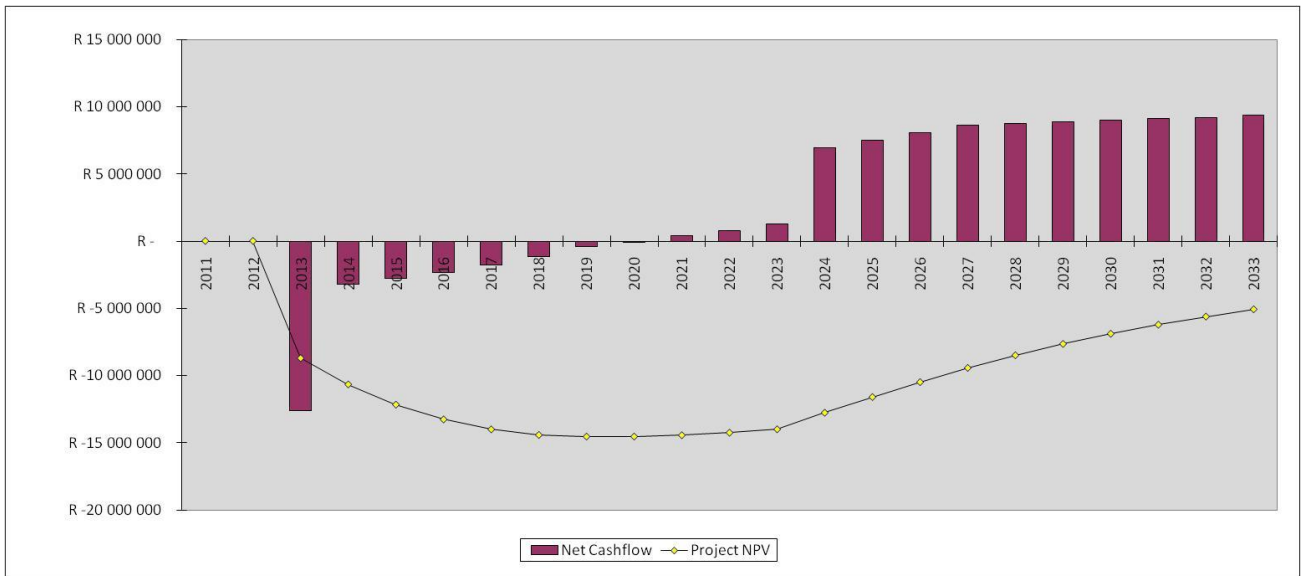
Figure 38: Rockview to USD 2 NPV and Cash Flows

Table 40: Rockview to USD 1 Key Financial outputs

Key Outputs	Rockview to USD 1		Rockview to USD 2	
Capex Required	57 007 000		42 088 250	
Equity Required at Fin Close	17 102 100		12 626 475	
PPA Revenue	61 822 195		164 404 350	
Operating Costs	63 353 067		35 805 043	
EBITDA	-1 530 872		128 599 307	
Net Cashflow	-89 258 325		63 830 156	
NPV	-39 220 881		-5 075 320	
Equity IRR	-		10%	
Incremental Levelised Cost of Energy (ZAR/kWh)	R	4.00	R	1.35
Real Levelised Cost of Energy (ZAR/kWh)	R	4.00	R	1.35

5.4.8   Conclusions and Recommendations

As can be seen in the comparison between cashflows, there is a strong motivation to manipulate the flows in order to generate on peak. However, whether these flows can be manipulated needs to be better understood.

This site is not considered to be feasible in the short term unless better flow manipulation can be produced. This seems unlikely because there are multiple parties interested, CCT, DWA and Eskom who would pump the water to Rockview.

6 Wemmershoek

6.1 Description

The treatment plant receives raw water from two sources, namely the Wemmershoek Dam and the Theewaterskloof Dam, also referred to as the RSE. A cement lined 1200mm raw water pipeline runs from the dam to the water treatment works supplying between 60-250Ml/day. Before the raw water enters the WTW it passes through an existing Turbine House. The flow entering the inlet works is controlled by two high pressure 21'' Glen field valves, one per turbine and two high pressure bypass valves. A portion of the raw water then passes through two Francis spiral type turbines which generate 130 KVA each, operating at a peak with 28m head. The plant was built in 1958, with the turbines coming online at the same time. There is the potential to upgrade this facility making use of all the potential. Wemmershoek WTW is shown below.

.

Figure 39: Wemmershoek Water Treatment Works

6.2 Current Turbine Operation

There are currently two Francis turbines at Wemmershoek which have a 130kVA rating each. It is assumed that the energy produced in a full year of operation is 1.5 GWh. This is calculated assuming that the turbine runs at full capacity over a full year. This electricity is used on site which an Eskom connection in place for the shortfall of needed electricity.

Table 41: Current Plant Operation

Type	Francis	
Flow	40	Ml/day
Rated Head	28	m
Turbine Power Output	208	kW
Theoretical Energy Output	1544346	kWh

The plant is currently running sub-optimally and does not make use of the potential energy on site mainly because it was originally designed to a capacity needed to run the plant and its surroundings. In recent years, through upgrading the processes and by the growth in civilian population, an Eskom supply has been connected to meet the higher demands. One of the existing turbines is shown below in Figure 40. There currently remains no existing data for the Wemmershoek Turbines.

Figure 40: Wemmershoek Turbine

6.3   Data Used

6.3.1   Levels

The head data used for the turbine sizing was taken from the Terms of Reference document as well as from consultation with Water and Sanitation who collected data from old drawings at the Bulk Water office. A summary is shown below in Table 42. The average dam level was calculated from records dating back from 2000.

Table 42: Level data Wemmershoek

Levels	Supplied Data	TOR
Average Dam level 2000-2010	288.11	?
Level at the base of the dam	242.32	?
Full supply level	297.18	296.7
Level at the works intake	-	?
Francis Turbines		
Level at the existing turbines	253.59	256.4
Current turbine maximum tail water level	252.07	?
Current turbine minimum tail water level	249.94	?
Peak Head	-	28
20 year low head	-	17.9

A diagram of the dam wall is shown in Figure 41
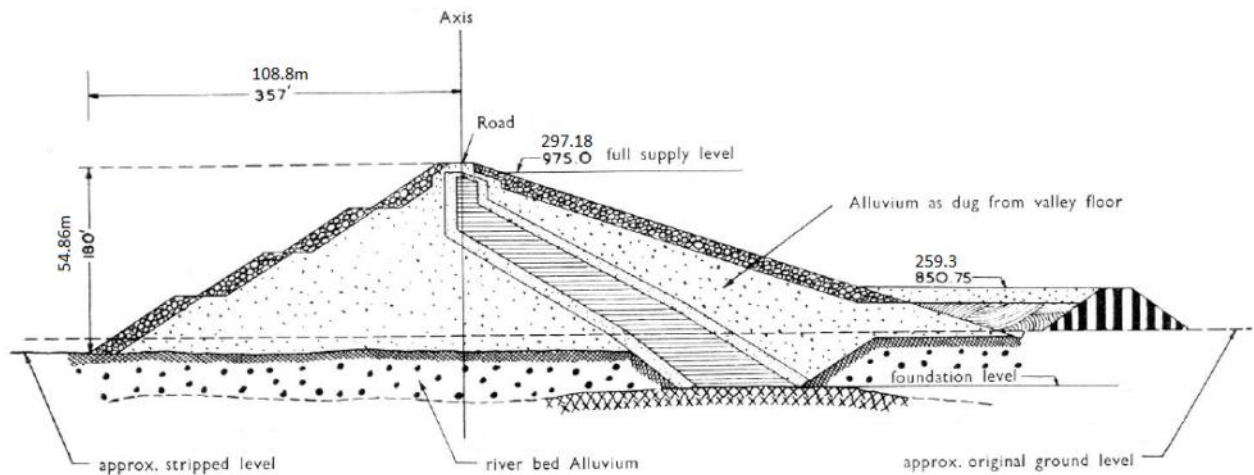
Figure 41: Wemmershoek Schematic

6.3.2   Flow Rates

The flow rate data was taken from the data provided by Bulk Water Head office and dates back to 1997. The flow data seems quite accurate with few discrepancies. A summary of the flowrates out of the dam are shown in Table 43. A flow duration curve has been compiled and is shown in Figure 42.

Table 43: Flow rates Wemmershoek

Flow Rates		
Min Flow	m3/s	0.5
Min Flow	Ml/day	40
Max Flow	m3/s	2.9

Max Flow	Ml/day	250
Average Flow	m3/s	1.9
Average Flow	Ml/day	166.4
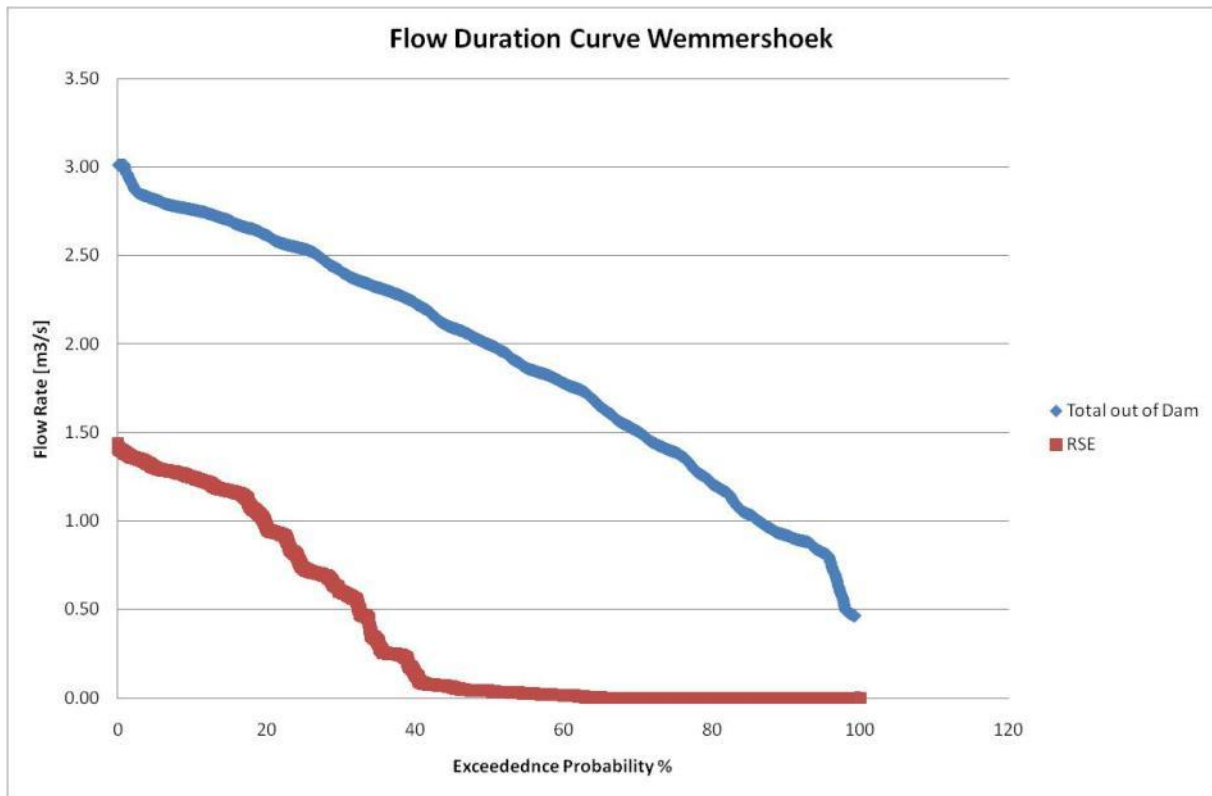
Figure 42: Flow Duration Curve Wemmershoek

6.4   Design concept

The ideal location for the plant would most likely be at the base of the dam. At this point there will be minimal head loss due to friction and other hydraulic losses. The existing turbines are at a level about 6m higher than the base of the dam and therefore would require a remaining pressure head to ensure successful delivery of water to the plant. A Francis turbine would be ideal in this situation as it utilises the pressure of the water and will operate in an in-line mode.

The benefits of locating the plant at the base of the dam for a few meters of extra head may not out way the capital costs involved in the construction of a new power house and an extension of the power line to take the power out of the new plant.

The turbines are currently only using a fraction of the existing water coming into the plant and by channelling all the water flow available through a replacement turbine, the design flow will be increased and the power plant will be able to maximise power output.

The design of the replacement turbine has been done using a design flow of 2.5 m3/s (216 Ml/day), chosen in order to maximise energy production. The static head of 34.5m (=Average Dam Level 2010

– level of existing turbines) was used. Hydraulic and friction losses were estimated at 10% resulting in a Rated Head of 31.1m.

An estimation of historical energy production (kWh) using the daily flow rates from 1997 has been produced, however a discrepancy must be noted here. Because the static head is dependent on the dam level, it is constantly varying. To calculate energy output more accurately this variation in head needs to be taken into account.

6.5 Grid Connection

Grid connection for the Wemmershoek plant would either be at the local Municipal grid or to the closest Eskom connection. The table below describes the details about the considered connection for Wemmershoek. The 66kV grid connect option adds significant project costs to the project and during the feasibility this should be thoroughly investigated. It is assumed that this is most conservative grid connection option for the site.

Table 44: Grid Connection Wemmershoek

	Wemmershoek
Generation Capacity	500kW-1MW
Feed-in Voltage*	66kV
Current back up supply	Eskom
Eskom Substation Connection	
Closest Eskom Substation	Wemmershoek Substation
Coordinates	19.04408335270E 33.87482423610 S
Substation Voltage	66 kV
Distance to Substation (length of line)	7183 m (Figure 43)
Transformer Capacity	?
Eskom Loop In Connection	
Conductor Description	Wemmershoek / Tee 66kV OHL
Potential Loop In Line	33°51'23.59"S 19° 2'23.11" E
Distance to Loop-in Connection	4388 m (Figure 44)
Line Capacity	?
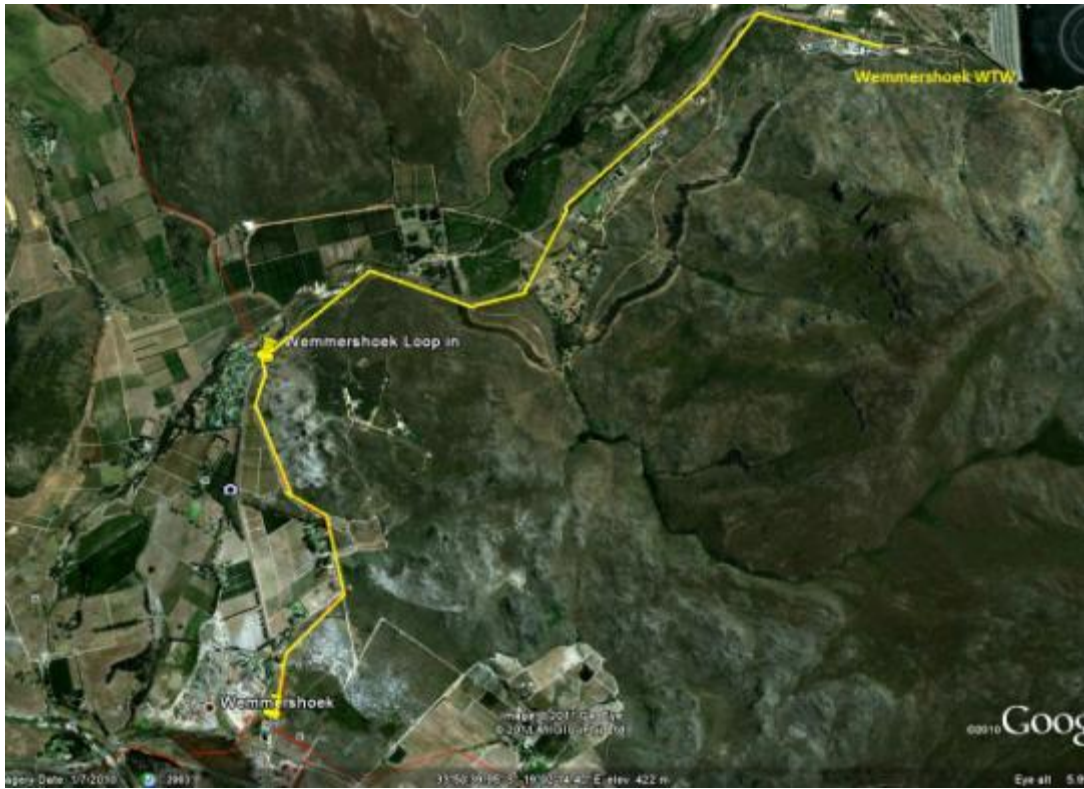
Figure 43: Wemmershoek Grid Connect Eskom Sub-station
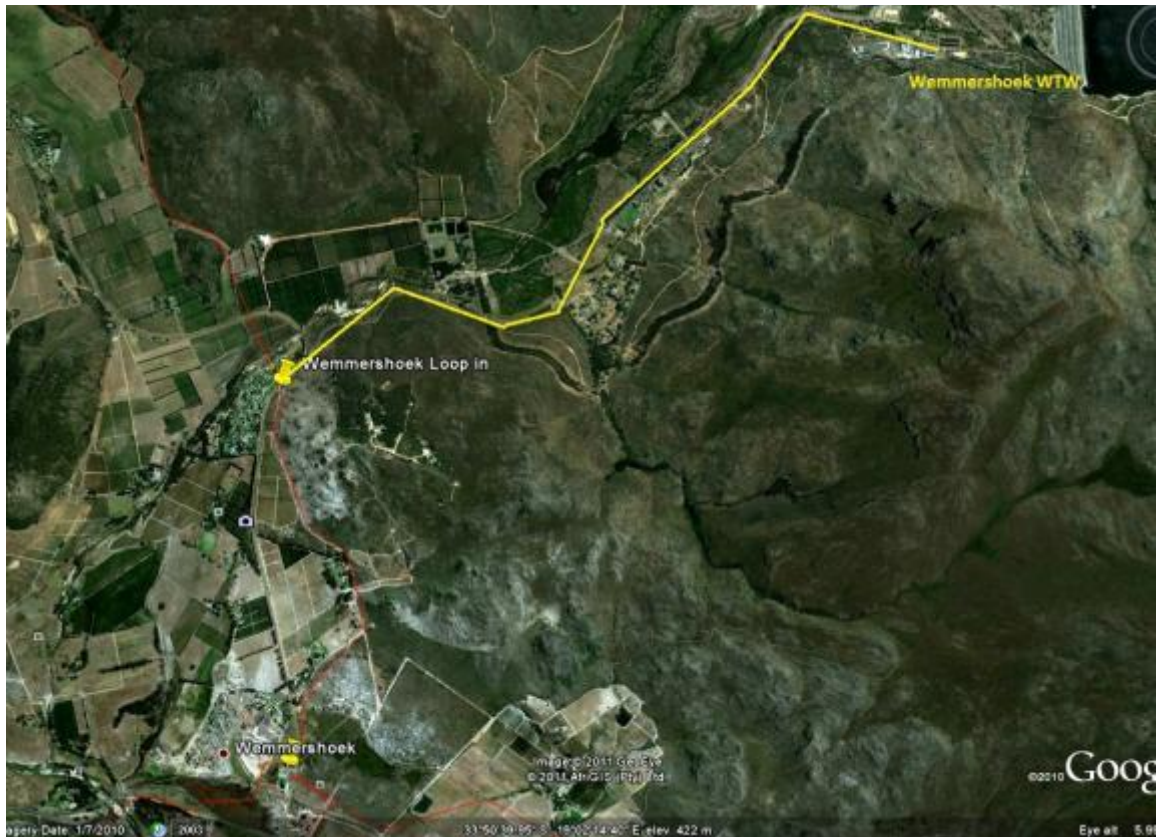
Figure 44: Wemmershoek grid connect Eskom Loop in

6.6   Works

An estimate of the costs involved in the works is given below in Table 45. It was assumed that the transmission line would be the loop in option described with a 4.5kM 66kV line.

Table 45: Works Wemmershoek

Wemmershoek	Item	Specific Costs		Item Cost	
Civils				**R**	**2 800 000**
Civil works required to accommodate the replacement turbine.				R	1 000 000
Balance of Plant				R	1 800 000
Hydro Mechanical Electrical				**R**	**4 900 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a 564kW Francis turbine)	**564**	**R**	**8 682**	R	4 900 000
Electricals and Grid Connection				**R**	**1 175 000**
Transmission line 66kV	4.5	R	518 000	R	1 035 000
Substation/Other Electricals				R	140 000
Total		**R**	**15 726**	**R**	**8 875 000**

6.7   Design Results

The operation was modelled for the years 1997-2010 with Figure 45 depicting the theoretical power output for the year 2010.
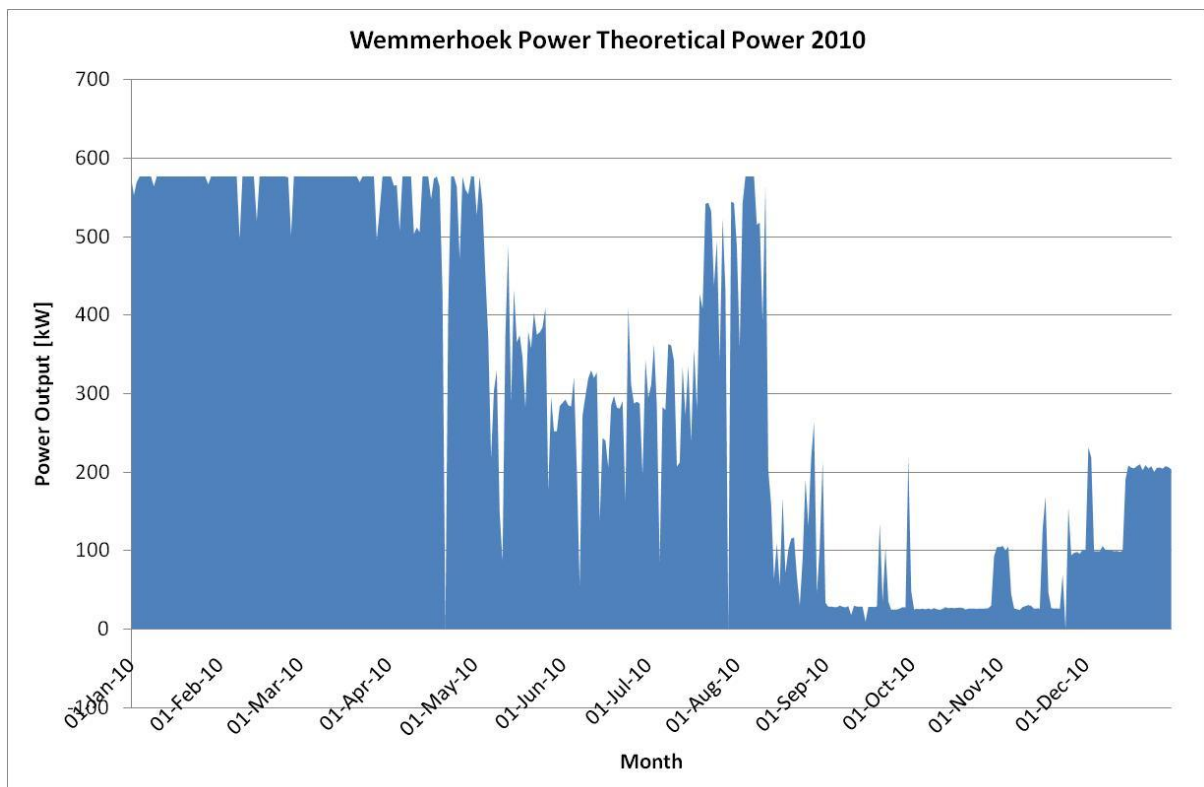
Figure 45: Wemmershoek Theoretical Power Output 2010

The actual energy delivered of 3.6 GWh is the average yearly output of the new plant operating at a design capacity of 576kW. This output was determined using the historical flow rate data since 1997 and can be seen in Table 46. The historical capacity factor is also shown.

Table 46: Wemmershoek Design Results

Design Results		
Plant Design Capacity	kW	576
Downtime Losses	%	5%
Theoretical Energy Delivered	kWh	4 795 447
Edelivered 1998	kWh	4 568 365
Edelivered 2000	kWh	3 147 276
Edelivered 2002	kWh	4 329 708
Edelivered 2004	kWh	2 670 067
Edelivered 2006	kWh	3 976 373
Edelivered 2008	kWh	3 725 017
Edelivered 2010	kWh	2 755 658
Average	kWh	3 596 066
Capacity Factor Theoretical	%	100%
Capacity Factor 1998	%	95%
Capacity Factor 2000	%	66%
Capacity Factor 2002	%	90%
Capacity Factor 2004	%	56%
Capacity Factor 2006	%	83%
Capacity Factor 2008	%	78%
Capacity Factor 2010	%	57%
Average	%	75%

Table 47 below illustrates the design data used and compares it to the existing turbines on site. By replacing the existing turbines a new turbine could theoretically generate 75% more power than the estimated theoretical maximum of the existing turbines.

Table 47: Design Summary Wemmershoek

		Wemmershoek C	Wemmershoek 1
Static Head	m	*	35
Hydraulic losses	%	*	10%
Rated Head	m	28	31
Design Flow	m3/s	0.46	2.50
Design Flow	Ml/day	40	216
Turbine type		Francis	Francis
Runner Diameter	m		0.71
Turbine Design Efficiency	%	*	85%
Turbine Capacity	kW	207	576
Annual Plant Downtime Losses	%	5%	5%
Theoretical Energy Delivered	kWh	1 544 356	4 795 447
Actual Energy Delivered	kWh	*	3 596 066
Capacity Factor	%		75%

Actual Increase from Current Generation	kWh	-	2 051 711
% Increase	%	-	133%

6.8   Financial Modelling and Results

Because a certain amount of power is currently being produced and utilised on site, the financial modelling has been set to analyse the incremental energy output that would be produced in the event of a turbine replacement. This value is 1.3GWh as seen in Table 47. A cash flow was produced for this value and the results are shown below.

Table 48: Total Project Costs Wemmershoek

		Wemmershoek
Project Development Costs	ZAR	2 081 250
Installation Cost	ZAR/kW	16 941.80
	ZAR	9 762 500
Contingency	%	25%
	ZAR	2 440 625
Total Capital Cost	ZAR	14 284 375
Funding		
Funding Horizon	years	10
Interest Rate	%	12.00%
Debt:Equity Ratio	%	70%
Debt amount	ZAR	9 999 063
Equity amount	ZAR	4 285 313
Total Capex	ZAR	**14 284 375**
Number of debt instalments per annum		1
Total Number of instalments		10
Total Interest Paid	ZAR	7 697 695
Total Operation and Maintenance Costs	ZAR	8 105 465
Total Lifetime Costs	ZAR	30 087 535
Incremental Energy Production	kWh	33 202 126
Actual Energy Production	kWh	71 921 326
Incremental Levelised Electricity Cost	R/kWh	0.91
Real Levelised Electricity Cost	R/kWh	0.42
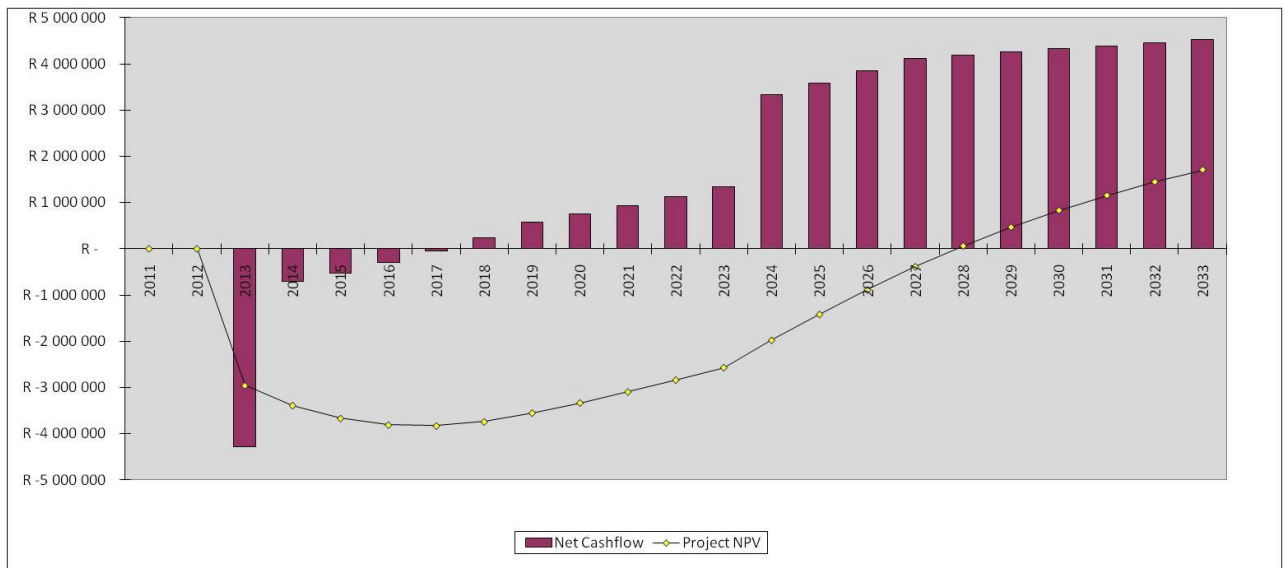
Figure 46: Wemmershoek Cash flow and NPV

As can be seen in Figure 46, the plant gets paid off in the analysed 20 year life span. This analysis is inherently inaccurate because the analysis was done for the incremental energy produced with the replacement turbine and the current generation is unknown and can only be estimated. Furthermore, what has not been factored into this is the fact that the current generating equipment would most likely have to be replaced in the near future and making the investment yield more positive results.

As can be seen in Table 48, the real levelised cost of energy is a low 42c/kWh. Key financial outputs are summarised in Table 49.

Table 49: Wemmershoek Key Financial Outputs

Key Outputs	Wemmershoek
Capex Required	14 284 375
Equity Required at Fin Close	4 285 313
PPA Revenue	71 700 451
Operating Costs	9 526 918
EBITDA	62 173 533
Net Cashflow	40 191 463
NPV	1 707 157
Equity IRR	17%
Incremental Levelised Cost of Energy (ZAR/kWh)	R 0.73
Real Levelised Cost of Energy (ZAR/kWh)	R 0.42

6.9   Conclusions and Recommendations

- To understand the true lifetime replacement costs of the turbine a full energy audit of the site must be performed. The incremental value of energy produced can then be better estimated and the true investment costs compared.
- The feasibility study should also take note of the following:

- o Investigate the possibility of installing a turbine at the base of the dam to make use of potentially higher head.
- o According to Figure 45, the most energy produced is during the summer months which almost doubles the theoretical power output of the turbine during winter. Perhaps a more efficient operation would include installing two turbines and operationally only run one of them during the winter months.
- o Investigate the installation of a turbine on the RSE water inlet.
- This site should be considered for the full feasibility design.

7   Faure Water Treatment Works

7.1   Description

There is an existing turbine installed on the Raw Water Pipeline entering the plant from the DWA water supply from the Theewaterskloof Dam. The 1675mm pipeline has a static head of 142m and sees draws of up to 620Ml/day max. Typical flows are between 100 and 500 Ml/day. An aerial view of the treatment works is shown in Figure 47.

Figure 47: Faure Water Treatment works

7.2   Current Turbine Operation

The existing turbine is rated at 1475 kW and produces enough electricity for the running of the plant. The remaining raw water is bypassed into the WTW. The existing Turgo Turbine is shown in Figure 48.

Figure 48: Existing Faure Turgo Turbine

The existing Turgo turbine data sheet can be found in Appendix A Turbine Spec Sheets. The turbine is currently operated sub optimally running at a constant 100Ml/day, with excess flow being bypassed to the works. The table below is the assumed turbine operating conditions.

Table 50: Existing Faure operation

Manufacturer	Gilbert Gilkes & Gordon	
Type	Turgo Impulse Twin Jet	
Runner Size	31	in
Flow	1.16	m3/s
Rated Head	130	m
Turbine Power Output	1174	kW
Capacity Factor	60%	
Theoretical Energy Output	12921000	kWh
Current Energy Production	7772310	kWh

The current energy production was calculated using the historical flow rates and assuming that the max operation of the turbine is at 100Ml/day. This gives a capacity factor of 60%. It is very important that this value is confirmed in an energy audit because the following analysis and financial viability is based on the financial benefits of the energy production over and above that required for current plant production.

7.3   Data Used

7.3.1   Levels
The only level made available in the terms of reference is the static head between Kleinplaas Dam and the plant of 142m. The rated turbine head is 130m as taken from the Turbine data sheet. This rated head was for a design flow rate of 1.45m3/s. The actual head measurements for different flow

rates have only been estimated in this prefeasibility. Pressure measurements should be taken for the full flow regime in the feasibility study.

7.3.2 Flow Rates

Flow rates were processed from the daily data received at the Bulk Water Head Office. The flow rates very seldom fluctuate within a day because of the storage in the large storage reservoir (640Ml). This minimal fluctuation allows for daily flows to be averaged into hourly and per second flow data with reasonable accuracy.

Table 51 below shows the flow summary of the Raw Water entering the plant. In consultation with Eric Bezuidenhout, the Faure plant manager, it was discovered that the minimum flow needed for the turbine to power the works is 100Ml/day. If water is only being brought in via the Firlands pump station then the turbine is put offline and only Eskom power is used. Although the plant is able to process 620Ml/day the max flow brought in through the raw water pipe was 370Ml/day. There should theoretically be no hydro potential on the Firlands inlet because the water is being pumped and arrives with no excess energy.

Figure 49 illustrates the typical variance in the flows over a typical year (2009) and Figure 50 is the flow duration curve over the entire period 1997-2011. Figure 50 also depicts the modified flow rate that is further explained.

Table 51: Faure Flow Summary

Min Flow	m3/s	1.2
Min Flow	Ml/day	100.0
Max Flow	m3/s	4.3
Max Flow	Ml/day	372.2
Average Flow	m3/s	1.9
Average Flow	Ml/day	162.1
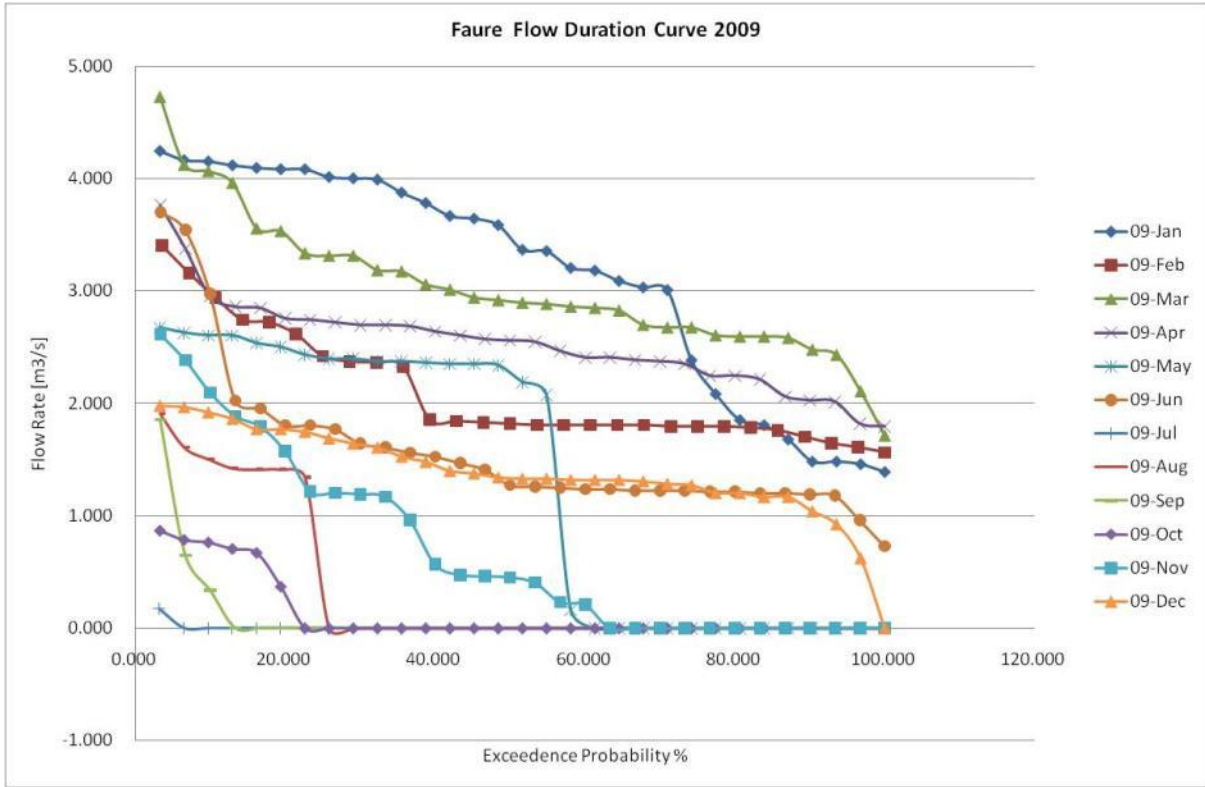
Figure 49: Faure Flow Duration Curve Monthly 2009
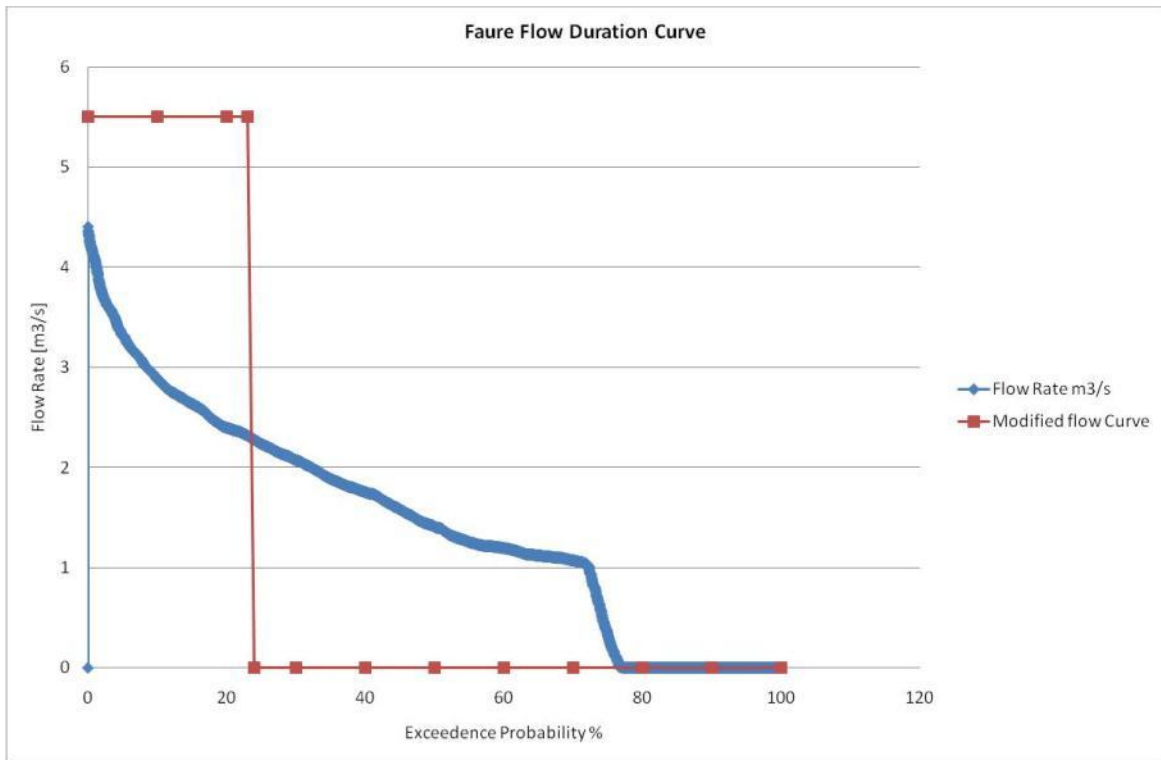
Figure 50: Faure Flow Duration Curve 1997-2011

7.4 Design Concept - Increase production to Design Capacity (Faure 1)

It is possible to make use of all the flow coming into the plant and to keep the existing turbine in place. This would result in the turbine operation capacity increase from 1173 kW currently (average flow rate of 1.16m3/s, 100Ml/day) to the design capacity of 1475 kW (design flow rate of 1.458m3/s, 126Ml/day). Because of the close proximity of the Eskom Grid Connection, it would be possible to feed this power back into the grid at very little expense.

7.4.1 Works

The works involved here only entail connecting the existing infrastructure to the Eskom grid. It is assumed that the plant will be connected to the Firgrove substation and the costs indicated below only serve as an estimate.

Table 52: Works Faure 1

Faure 1	Item	Specific Costs		Item Cost	
Civils				**R**	**-**
None			R		-
Hydro Mechanical Electrical				**R**	**-**
None			R		-
Electricals and Grid Connection				**R**	**1 595 000**
Transmission line 66kV	2.5	R	518 000	R	1 295 000
Substation/Other Electricals				R	300 000
Total		**R**	**1 189**	**R**	**1 595 000**

7.5 Design Concept - Replace Existing Turbine (Faure 2)

Because the turbine is only designed to a flow rate of 1.458 m3/s, there is a significant amount of water that is being bypassed during times of higher flow. A turbine replacement option would entail the installation of a larger capacity turbine and generator that will be able to handle higher flow rates. By doing this the capacity factor of the plant will decrease but there will be an increase in the total energy delivered.

The turbine was sized at the design flow of 2.5m3/s, chosen to coincide with the existing historical flow values. The rated head of this concept takes into account the rated head of 130m less a further 5% (124m). This results in a rated capacity of 2441 kW. The energy and turbine efficiency analysis was done for a standard Francis Turbine but it will be determined in the feasibility study which turbine is the optimal solution. The power output for the plant based on 2009 values is given in Figure 51.
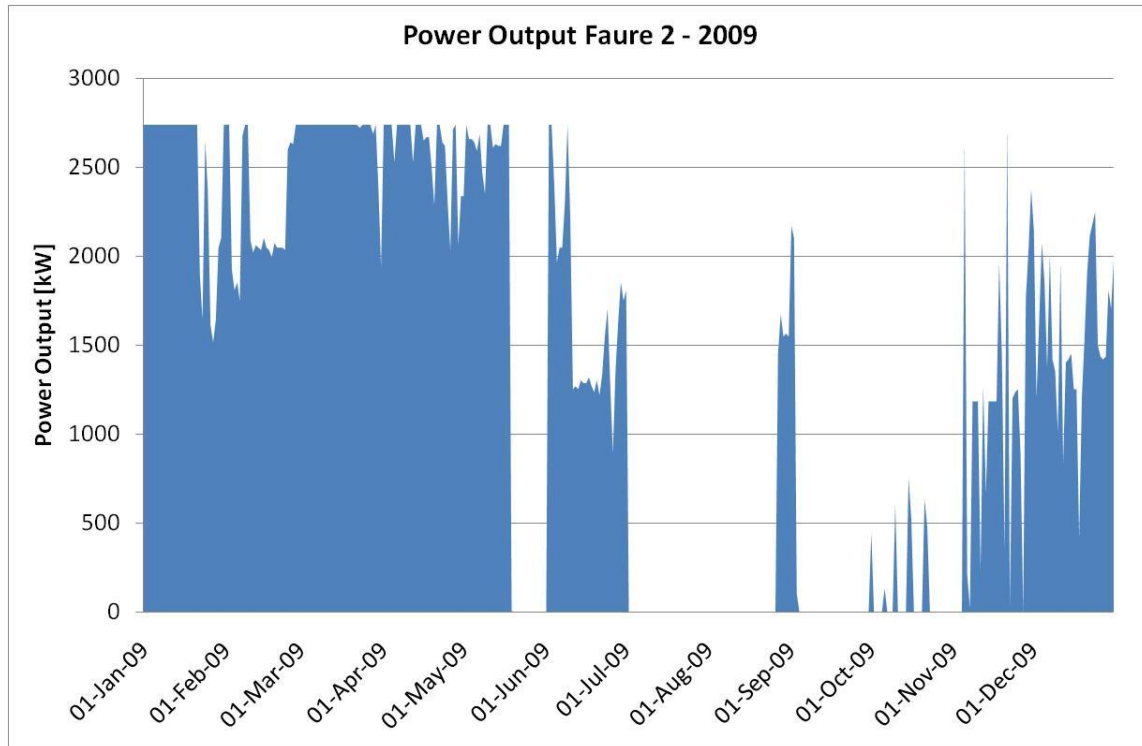
Figure 51: Faure 2 Power Output 2009

7.5.1 Works

The estimation of costs for this design concept is given below in Table 53.

Table 53: Works Faure 2

Faure 2	Item	Specific Costs		Item Cost	
Civils				**R**	**3 100 000**
Civil works required to accommodate the replacement turbine.				R	1 000 000.00
Balance of Plant				R	2 100 000.00
Hydro Mechanical Electrical				**R**	**11 200 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a 2441 Francis turbine but design should consider replacing with a Turgo)	**2441**	**R**	**4 588**	R	11 200 000
Electricals and Grid Connection				**R**	**1 645 000**
Transmission line 66kV	2.5	R	518 000	R	1 295 000
Substation/Other Electricals				R	350 000
Total				**R**	**15 945 000**

7.6 Design Concept - Replace Existing Turbine (Faure 3)

The terms of reference mentioned that using Faure as a peaking plant should also be considered, this concept aims to analyse its viability. This concept considers the fact that the plant is running at a very low capacity and there is a reservoir on site that can store 620Ml. The pipe line was also designed to handle higher flows. This leaves room for the sizing of a turbine that could handle very high flow rates. However, Table 51 shows that the average flow rate (daily demand) is not sufficient to run a larger turbine at a continuous operation.

This design concept considers the possibility of operating a larger turbine (and hence the water treatment works) as a peaking plant whereby the plant will operate during times of peak and standard energy demand. The large reservoir will continue being operated at a 24 hour/day level as it will be determined by the water demand.

The Time of Use (ToU) tariff that Eskom charges heavy users is shown in Figure 19. CCT charges its users a premium on that with peak and standard rates being significantly higher than the average rate. The modelling of this system takes into account the Megaflex peak and standard weighted tariff because it is these costs that the plant is offsetting.

Figure 52 shows the number of average hours Faure would operate *daily* during 2009. This manipulated graph takes the total daily water demand and calculates how many hours the plant could run at 6m3/s (518Ml), constant flow rate. Figure 53 show the average plant capacity factor over the year to be 23%. The flow duration curve is shown in Figure 50.
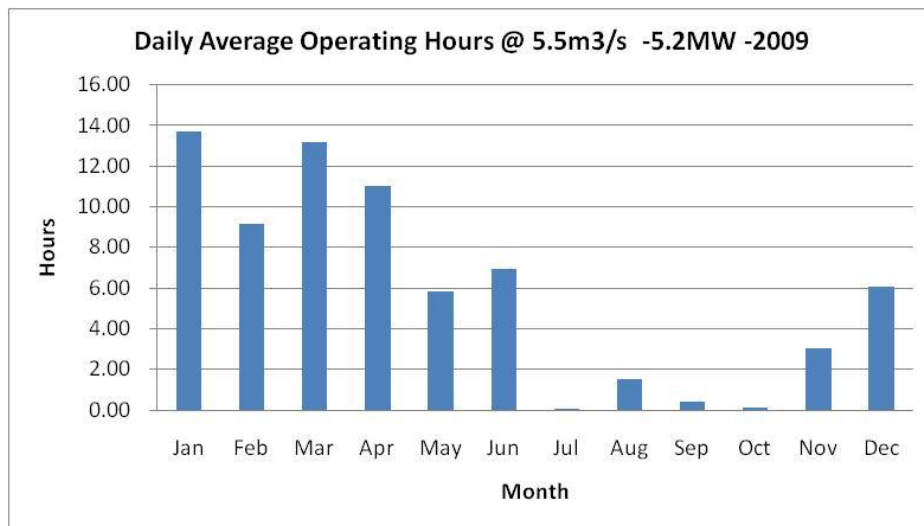
Figure 52: Daily average operating hours at Faure
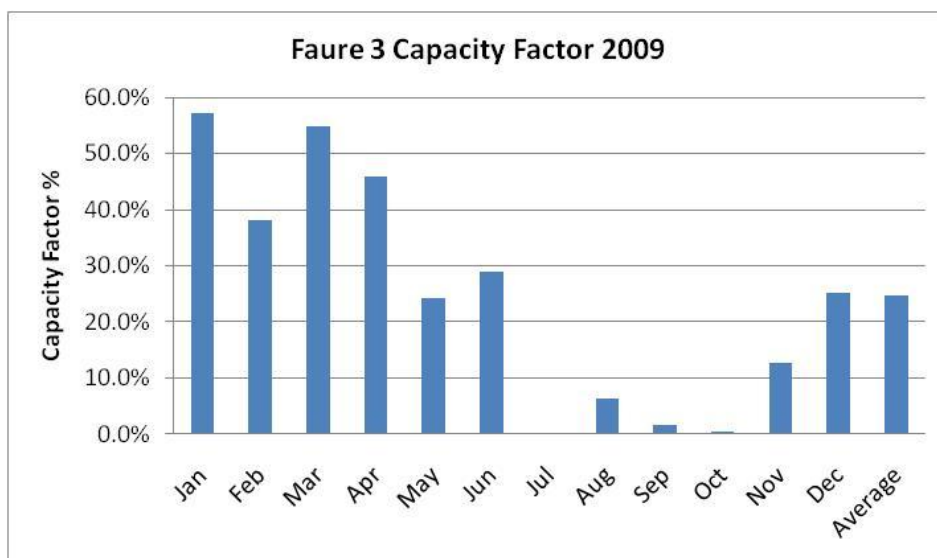
Figure 53: Faure 3 Capacity factor

7.6.1   Works

The works for the resulting concept are described in Table 54.

Table 54: Works Faure 3

Faure 3	Item	Specific Costs		Item Cost	
Civils				**R**	**5 700 000**
Civil works required to accommodate the replacement turbine.				R	1 500 000
Balance of Plant				R	4 200 000
Hydro Mechanical Electrical				**R**	**17 500 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a 5230 Francis turbine but design should consider replacing with a Turgo)	**5230**	**R**	**3 346**	R	17 500 000
Electricals and Grid Connection				**R**	**3 290 000**
Transmission line 66kV	2.5	R	518 000	R	1 295 000
Substation/Other Electricals				R	595 000
Total				**R**	**26 490 000**

7.7   Grid Connection

There is a large Eskom Substation situated about 2.5 km away from the Faure WTW. It has been assumed for this study that this will be the connection point for the extra generated capacity. Table 55 shows the details of this substation and the line route is depicted in Figure 54. There remains the possibility of connecting the generator to through a loop in connection to the 66kV line that runs past the treatment works.

Table 55: Faure Grid Connection

	Faure
Generation Capacity	1.475 MW – 5.230MW
Feed-in Voltage	66kV
Current back up supply	Eskom
Eskom Substation Connection	
Closest Eskom Substation	Firgrove Substation
Coordinates	18.78245770740 E 34.04864783400 S
Substation Voltage	132 kV
Distance to Substation (length of line)	2498m (Figure 54)
Transformer Capacity	?

Figure 54: Faure Grid Connect Eskom Sub-station

7.8 Design Summary

Faure 2, because of the lower head losses associated with the lower flow rate will produce more energy than the concept described in Faure 3 which runs at a higher capacity flow. Here the average difference for the two plants using the historical flow rates is just under 1 GWh. These outputs are compared below in Table 56. The historical capacity factor is also shown.

Table 56: Faure Design Results for Replacement Turbine

Design Results		Faure 2	Faure 3
Plant Design Capacity	kW	2441	5230
Annual downtime losses	%	5%	5%
Theoretical Energy Delivered	kWh	20 316 175	43 525 141
Edelivered 1998	kWh	14 399 110	12 749 238
Edelivered 2000	kWh	13 946 906	13 362 586
Edelivered 2002	kWh	12 553 111	11 292 511
Edelivered 2004	kWh	11 297 711	10 335 288
Edelivered 2006	kWh	10 859 261	9 806 652
Edelivered 2008	kWh	16 445 847	15 850 421

Edelivered 2010	kWh	14 617 996	14 715 420
Average	kWh	13 445 706	12 587 445
Capacity Factor Theoretical	%	100%	100%
Capacity Factor 1998	%	71%	29%
Capacity Factor 2000	%	69%	31%
Capacity Factor 2002	%	62%	26%
Capacity Factor 2004	%	56%	24%
Capacity Factor 2006	%	53%	23%
Capacity Factor 2008	%	81%	36%
Capacity Factor 2010	%	72%	34%
Average	%	66.2%	28.9%

Table 57 below illustrates the difference in production from the existing operation to the current design capacity. This increase is 2 GWh/annum or a 26% increase. Although the current turbine should theoretically generate 12.9 GWh/annum it could only produce 9.7GWh due to the calculated 76% capacity factor of the plant.

By replacing the turbine (Faure 2) the plant could theoretically could theoretically generate 13.4 GWh (73% more power than the current operation).

The modified plant operation and turbine replacement (Faure 3) results in less energy output per year, but because it is designed to run during peak electric demands, it may be a wiser investment option, capturing higher tariffs. This is summarised in Table 57. The choice between the three options will be determined in the Financial Analysis (Section 7.9).

Table 57: Faure Design Summary

		Faure C	Faure 1	Faure 2	Faure 3
Static Head	m	*	*	*	*
Hydraulic losses	%	*	5%	5%	10%
Rated Head	m	130	124	124	117
Design Flow	m3/s	1.16	1.46	2.50	5.50
Design Flow	Ml/day	100	126	216	475
Turbine type		Turgo	Turgo	Francis	Francis
Runner Diameter	m	0.79	0.79	0.71	*
Turbine Design Efficiency	%	*	*	90%	90%
Turbine Capacity	kW	1 174	1 475	2 441	5 230
Annual Plant Downtime Losses	%	*	5%	5%	5%
Theoretical Energy Delivered	kWh	12 921 000	12 921 000	20 316 175	43 525 141
Actual Energy Delivered	kWh	7 772 310	9 768 276	13 445 706	12 587 445
Capacity Factor	%	60%	76%	66%	29%
Actual Increase from Current Generation	kWh	-	1 995 966	5 673 396	4 815 135
% Increase	%	-	26%	73%	62%

7.9 Financial Modelling and Results

The table below shows the results from the costing analysis and the inputs into the cashflow analysis.

Table 58: Faure Total Costs

		Faure 1	Faure 2	Faure 3
Project Development Costs	ZAR	2 081 250	2 081 250	2 081 250
Installation Cost	ZAR/kW	1 189.49	7 184.61	5 571.37
	ZAR	1 754 500	17 539 500	29 139 000
Contingency	%	25%	25%	25%
	ZAR	438 625	4 384 875	7 284 750
Total Capital Cost	ZAR	4 274 375	24 005 625	38 505 000
Funding				
Funding Horizon	years	10	10	10
Interest Rate	%	12.00%	12.00%	12.00%
Debt:Equity Ratio	%	70%	70%	70%
Debt amount	ZAR	2 992 063	16 803 938	26 953 500
Equity amount	ZAR	1 282 313	7 201 688	11 551 500
Total Capex		**4 274 375**	**24 005 625**	**38 505 000**
Number of debt instalments per annum		1	1	1
Total Number of instalments		10	10	10
Total Interest Paid	ZAR	2 303 414	12 936 371	20 749 927
Total Operation and Maintenance Costs	ZAR	20 747 634	34 339 249	73 568 013
Total Lifetime Costs	ZAR	27 325 423	71 281 245	132 822 940
Incremental Energy Production	kWh	39 919 320	113 467 918	96 302 702
Actual Energy Production	kWh	195 365 520	268 914 118	251 748 902
Incremental Levelised Electricity Cost	R/kWh	0.68	0.63	1.38
Real Levelised Electricity Cost	R/kWh	0.14	0.27	0.53

The three scenarios were modelled using two different tariff structures. Faure 2 and Faure 3 were analysed according to the standard average MegaFlex rates and Faure 3 analysed according to the standard and peak weighted time of use tariff TOU structure. The results are depicted below.
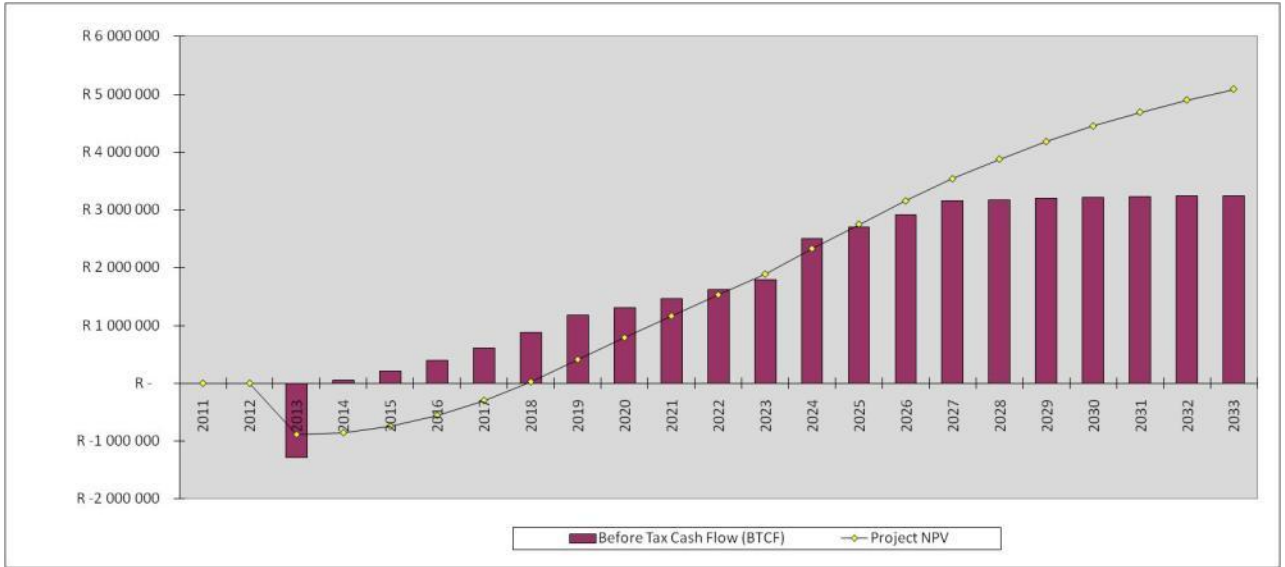
Figure 55: Faure 1 Cash Flow and NPV
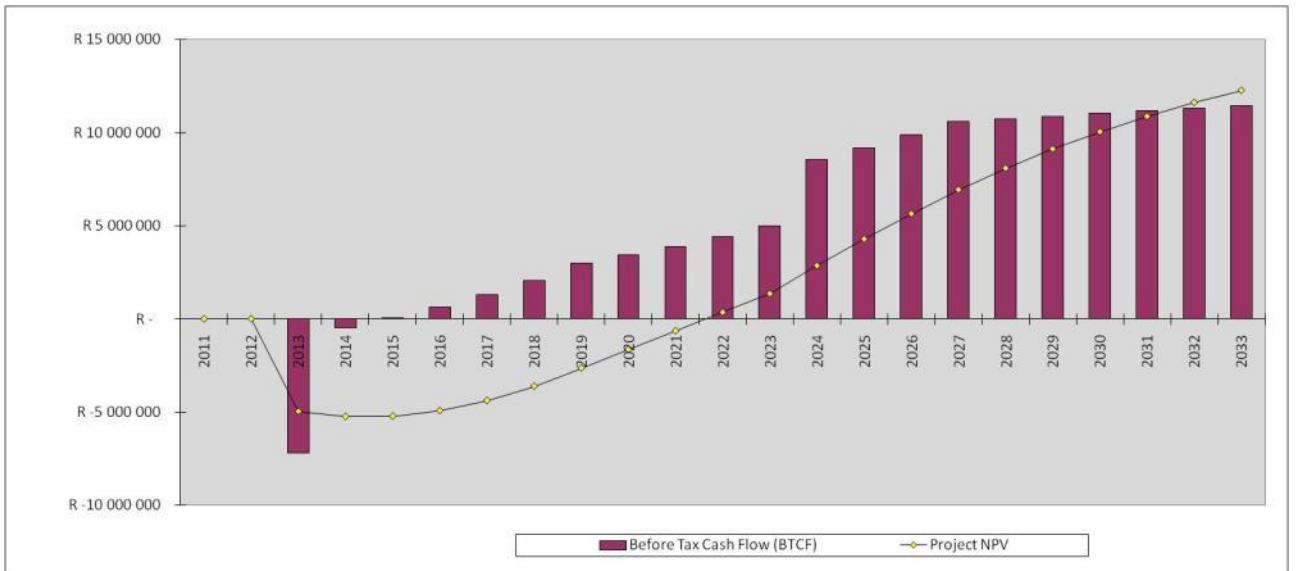
Figure 56: Faure 2 Cash Flow and NPV
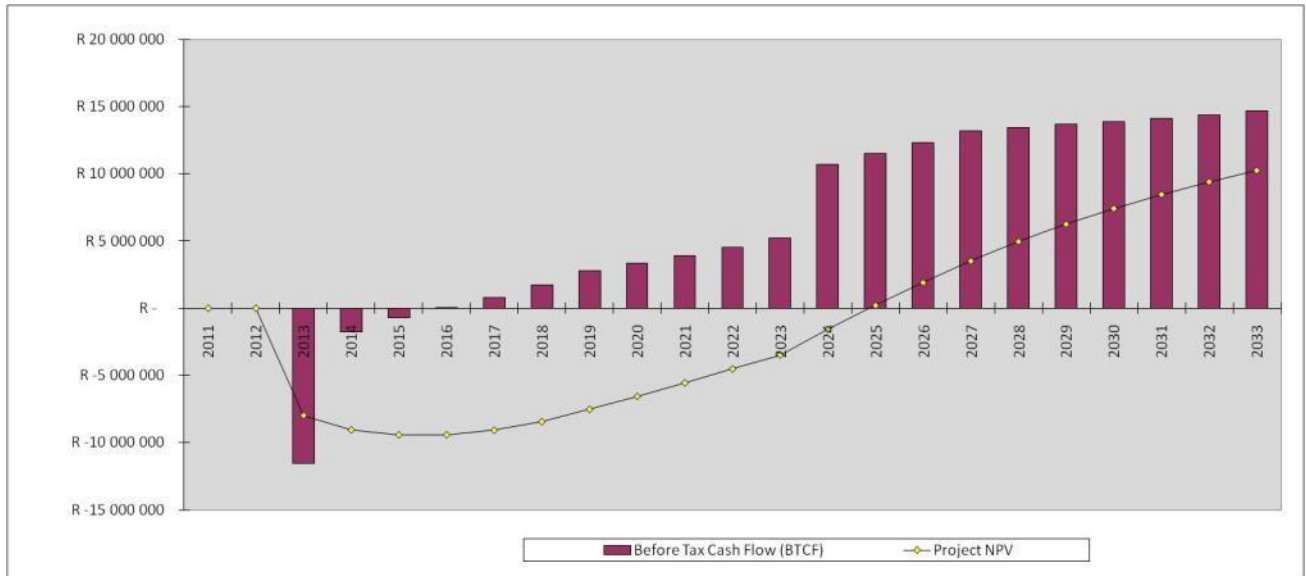
Figure 57: Faure 3 Cash Flow and NPV

Table 59 below shows the key financial outputs of the three analysed options. The IRR of the first option is clearly the highest because the capital costs of installation are so low. The other two options also yield positive results and it is worth investigating these further.

Table 59: Faure Financial Modelling Key Results

Key Outputs	Faure 1	Faure 2	Faure 3
Capex Required	4 274 375	24 005 625	38 505 000
Equity Required at Fin Close	1 282 313	7 201 688	31 015 598
PPA Revenue	69 752 358	198 266 275	224 344 005
Operating Costs	24 386 141	40 361 314	24 869 272
EBITDA	45 366 217	157 904 961	199 474 734
Net Cashflow	38 788 428	120 962 965	140 219 807
NPV	5 084 975	12 276 372	10 236 358
Equity IRR	41%	27%	20%
Incremental Levelised Cost of Energy (ZAR/kWh)	R 0.68	R 0.63	R 1.38
Real Levelised Cost of Energy (ZAR/kWh)	R 0.14	R 0.27	R 0.53

7.10 Conclusions and Recommendations

- The scenario that produces the highest IRR is Faure 1 which would involve running the plant at its installed capacity and feeding the excess power into the grid. The only infrastructure requirements here are the grid connection costs. This is a project that could be performed relatively quickly and will involve minimal investment.

- However, with the resizing of the plant (Faure 2 & 3) a further 4GWh can be produced per annum. An optimisation process needs to be undertaken in the Feasibility stage whereby the optimum size turbine and plant operation is determined. What also needs to be taken into account is the future water demand of Cape Town and how this affects Faure which is currently running under capacity.

- What also needs to be taken into account is the varying head with the associated flow. The actual head measurements for different flow rates have only been estimated in this

prefeasibility. Pressure measurements should be taken for the full flow regime in the feasibility study.

- The concept of Faure 3 was not received well in consultation with Bulk Water. The reasons being that a Water Treatment works needs to run on a 24 hour basis and the idea of intermittency is not favourable. Design concept Faure 3 is therefore not recommended for future consideration.

8 Blackheath Water Treatment Works

Blackheath WTW (Figure 58) treats between 120 and 420 Ml/day receiving water from the Theewaterskloof Dam through a 21km pipeline. There are a number of sites that have been identified at the works and are further described.

1. Blackheath Raw Water Inlet (BH Raw Water)
2. Blackheath Water Treatment Plant to the Upper Blackheath Reservoir (BHWTW to Upper)
3. Blackheath Lower Reservoir Inlet (BH Upper to Lower)

Figure 58: Blackheath Water Treatment Works

8.1 Blackheath Raw Water Inlet (BH Raw Water)

8.1.1 Description

The Treatment Plant is supplied by a 1500mm pipeline that is 21600m long which brings in flows that vary between 120 to 420 Ml/d. This pipeline has a 77m static head from the Kleinplaas Dam.

There are existing needle valves on the 1500mm pipe before it enters the treatment works on site (located underground - Figure 59). It is assumed that these valves are breaking the pressure. There is also an 1100mm bypass valve also located underground (Figure 60).

Figure 59: 1500mm needle valve

Figure 60: 1100 mm bypass needle valve

8.1.2   Data Used

8.1.2.1   Levels

The only level data obtained is from the Terms of Reference which states that static head from Kleinplaas Dam is 77m. The pipe is 21km long and would endure significant friction losses.

8.1.2.2   Flow Rates

Table 60 shows a summary of the Raw Water inlet flows. These flow rates represent the plant operating flows and correlate with the flows from the data provided from Bulk Water Head Office. The daily flows have been measured and recorded from 1997-2011 and are represented in the flow duration curve as Stellenbosch Inlet - Figure 61.

Comparing the integrator readings on the site visit to those submitted to Head Office, there is a slight discrepancy. After consultation with Mr Winston Stanley at the Blackheath reservoir, it was confirmed that the readings submitted to Head Office were accurate, even though some of the gauges on site weren't functional. This flow analysis will need to be confirmed in the feasibility study.

Table 60: Blackheath Raw Water Flow Rate Summary

Min Flow	m3/s	1.4
Min Flow	Ml/day	120
Max Flow	m3/s	4.9
Max Flow	Ml/day	420
Average Flow	m3/s	2.6
Average Flow	Ml/day	223.8
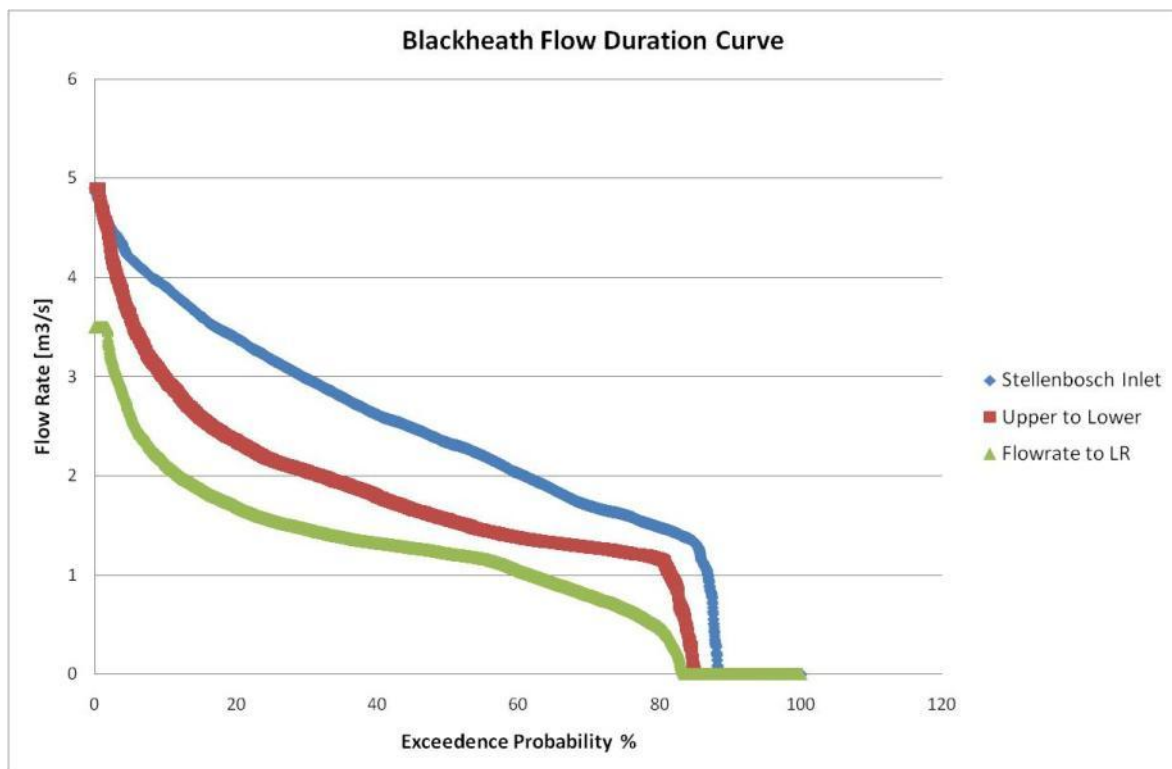
Figure 61: Flow Duration Curve Blackheath

8.1.3   Design concept

The valves described in Section 8.1.1 could be the location of the installed hydro turbine. Locating them here would require minimum construction and earthworks. Water passes through the turbine and carries on its way through the pipe. This setting means that a pressure defined by the network requirements has to be maintained at the turbine outlet. There is a pressure that needs to be

maintained in order for the water to reach the treatment plant. A reaction turbine such as the Francis would be the ideal fit in this case.

8.1.4   Grid Connection

The assumption used here is that the in line plant will need to be connected to the closest Eskom line. A summary of the connection details is given in Table 61. The line length was measured off Google Earth and a screen shot of the line is shown in Figure 62.

There may be a closer Municipal Substation or a loop-in grid connect option into a municipal line but this would need to be further investigated in the Feasibility study. A 66kV line is assumed for financial modelling purposes but this can only be determined after a full investigation.

Table 61: Blackheath Grid Connection

	Blackheath
Generation Capacity	1-3 MW
Feed-in Voltage*	66kV
Current back up supply	Municipality
Eskom Substation Connection	
Closest Eskom Substation	Kuilsrivier/Langverwagt substation
Coordinates	18.70001613850 E 33.93502028300 S
Substation Voltage	66 kV
Distance to Substation (length of line)	4652m
Eskom Loop In Connection	
Conductor Description	Blackheath / Kuilsrivier 66kV OHL
Potential Loop In Line	33°56'59.36"S 18°42'19.35"E
Distance to Loop-in Connection	2464m

Figure 62: Blackheath Grid Connect Eskom Sub-station

8.1.5 Works

The works described in Table 62 below indicate the extent of the construction needed to fit a turbine in line with the raw water pipe. A power house will need to be sunk in order to accommodate the turbine and generating equipment and a 2.5 km 22kV line is assumed for transmission.

Table 62: Works BH Raw Water

BH Raw Water	Item	Specific Costs		Item Cost	
Civils				**R**	**10 000 000**
Power House and Balance of Plant				R	8 000 000
Other Civil Works				R	2 000 000
Hydro Mechanical Electrical				**R**	**9 100 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a 1096kW Francis Turbine)	**1096**	**R**	**8 304**	R	9 100 000
Electricals and Grid Connection				**R**	**799 000**
Transmission line 22kV	2.5	R	518 000	R	575 000
Substation/Other Electricals				R	224 000
Total		**R**	**18 159**	**R**	**19 899 000**

8.1.6 Design Summary

The sizing of this plant was performed with the assumption that the pipe losses due to friction etc were 45%. In real operation this value will be constantly changing making the variable head a major design consideration. Because this was not modelled in this study the energy output of this particular design concept will be inaccurate and should only be considered indicative. Special attention should be paid to this when performing the feasibility design. It is recommended that pressure transducers should be used to measure the pressure situation at different flow regimes.

A summary of the modelling process is given in Table 63 and the results of the energy modelling on the historical flow data is given in Table 64.

Table 63: Design Summary BH Raw Water

		BH Raw Water
Static Head	m	77
Hydraulic/pipe losses	%	45%*estimate
Rated Head	m	42
Design Flow	m3/s	3.40
Design Flow	Ml/day	294
Turbine type		Francis
Runner Diameter	m	0.82
Turbine Design Efficiency	%	86%
Turbine Capacity	kW	1 096
Annual Plant Downtime Losses	%	5%
Theoretical Energy Delivered	kWh	9 119 251
Actual Energy Delivered	kWh	6 138 489
Capacity Factor	%	67%

Table 64: Design Results BH Raw Water

Design Results		
Plant Design Capacity	kW	1096
Annual downtime losses	%	5%
Theoretical Energy Delivered	kWh	9 119 251
Edelivered 1998	kWh	6 145 201
Edelivered 2000	kWh	5 939 949
Edelivered 2002	kWh	4 958 076
Edelivered 2004	kWh	5 689 475
Edelivered 2006	kWh	6 595 763
Edelivered 2008	kWh	7 544 820
Edelivered 2010	kWh	6 096 143
Average	kWh	6 138 489
Capacity Factor Theoretical	%	100%
Capacity Factor 1998	%	67%
Capacity Factor 2000	%	65%

Capacity Factor 2002	%	54%
Capacity Factor 2004	%	62%
Capacity Factor 2006	%	72%
Capacity Factor 2008	%	83%
Capacity Factor 2010	%	67%
Average	%	67%

8.1.7 Financial Modelling and Results

A full costing estimate is shown below in Table 65.

Table 65: BH Raw water total costs

		BH Raw Water
Project Development Costs	ZAR	2 081 250
Installation Cost	ZAR/kW	19 975.26
	ZAR	21 888 900
Contingency	%	25%
	ZAR	5 472 225
Total Capital Cost	ZAR	29 442 375
Funding		
Funding Horizon	years	10
Interest Rate	%	12.00%
Debt:Equity Ratio	%	70%
Debt amount	ZAR	20 609 663
Equity amount	ZAR	8 832 713
Total Capex	ZAR	**29 442 375**
Number of debt instalments per annum		1
Total Number of instalments		10
Total Interest Paid	ZAR	15 866 176
Total Operation and Maintenance Costs	ZAR	15 413 740
Total Lifetime Costs	ZAR	60 722 291
Incremental Energy Production	kWh	122 769 789
Actual Energy Production	kWh	122 769 789
Incremental Levelised Electricity Cost	R/kWh	0.49
Real Levelised Electricity Cost	R/kWh	0.49
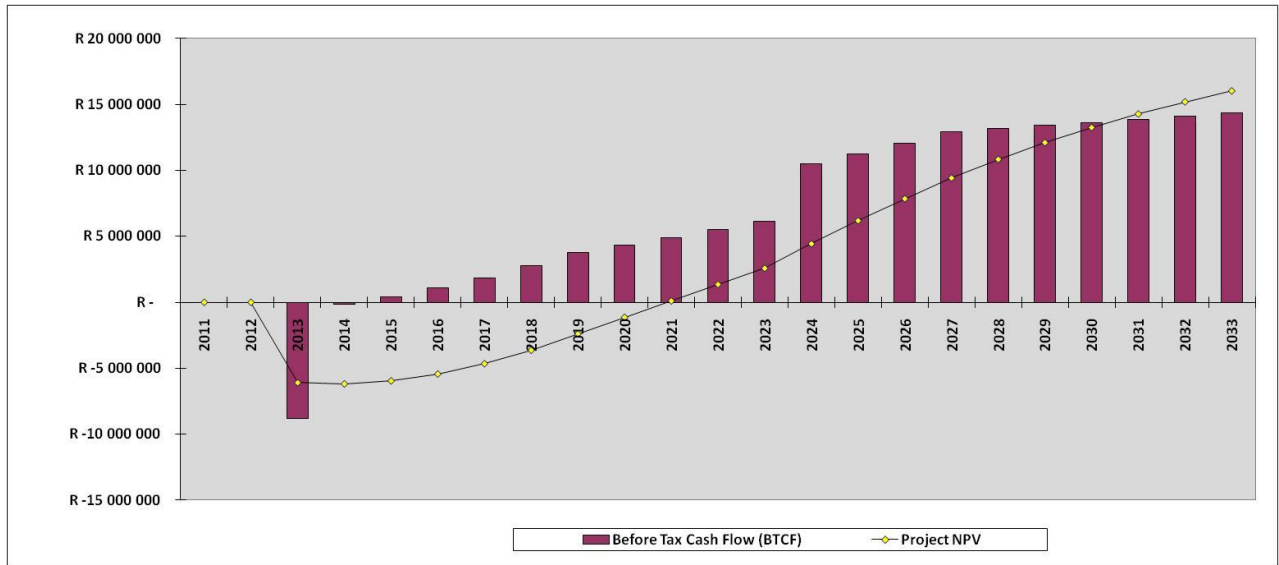
Figure 63: BH Raw Water Cash Flow and NPV

The cash flow analysis above yields positive results and a summary of key financial outputs is given in Table 66. Because of the discrepancies in the energy modelling process it is important to note here that these outputs are at best indicative and can only be confirmed in the feasibility study.

Table 66: BH Raw Water Key Financial Outputs

Key Outputs	BH Raw Water	
Capex Required		29 442 375
Equity Required at Fin Close		8 832 713
PPA Revenue		214 519 745
Operating Costs		18 116 844
EBITDA		196 402 901
Net Cashflow		151 094 350
NPV		16 023 515
Equity IRR		28%
Incremental Levelised Cost of Energy (ZAR/kWh)	R	0.49
Real Levelised Cost of Energy (ZAR/kWh)	R	0.49

8.1.8 Conclusions and recommendations

- The head measurement was estimated by the assumption that the average loss in the pipe was 45%. This value will in actual fact vary dramatically throughout the flow regime rendering the energy output results largely inaccurate. For the feasibility design it will be important to perform pressure tests over the full flow regime in order to accurately size the plant and estimate its output.
- According to the financial results, this scenario is showing positive results and should be pursued in the feasibility report.
- Grid connection with the local municipal grid should also be investigated.

8.2 Blackheath Water Treatment Plant to the Upper Service Reservoir (BHWTW to Upper)

8.2.1 Description

As the water exits the treatment works there is a small 8m drop before it enters the Upper Service Reservoir. Figure 64 shows the aerial view of this drop.

Figure 64: Drop between the works and the Upper Service Reservoir

8.2.2 Data Used

8.2.2.1 Levels

The only reference to the head at this site is in the Terms of Reference which refers to an 8m drop between the outlet of the treatment works and the upper reservoir. This drop has been used in the design. A full investigation of the relative drop will need to be investigated here because of varying level of the service reservoir.

8.2.2.2 Flow Rates

The flow into the upper service reservoir is the water coming in less the waste water from the works. This waste water is very minimal and for the purposes of this investigation the same flow data for the inlet is used. See Section 8.1.2.2.

8.2.3 Design Concept

"Low head" hydro is the term often used for a hydro scheme with a head between 5 and 20 m. A low head hydro scheme requires a large passage/opening to accommodate a high volume of flow, making low head turbines inevitably large in size and expensive consequently creating a number of engineering challenges. In addition, low head schemes suffer from a high head fluctuation due to the variation in headwater and tail water levels. This variation can mean that a head of 3 m is reduced to 1 m, thus reducing the system reliability and power output.

For this scheme at Blackheath, minimal infrastructure is needed. A power house will need to be built to house the M&E Equipment as well as an intake structure and draft tube. Because of the low head at this site a Kaplan Turbine would probably be most suited. The Kaplan is also suited for a large variance in flow rate.

8.2.4 Grid Connection

The grid connection assumption made here is that the plant will feed excess electricity into the grid via the transformer and grid connection at the BH Raw Water Power House. It is assumed that the distance is 0km with minimal connection infrastructure.

8.2.5 Works

This small turbine will require some hydraulic infrastructure as well as a small power house to house the turbine and generator. For the financial modelling it has been assumed that the grid connection costs will be covered by the Raw Water plant where the power generated at this Kaplan will be stepped up and fed into the grid. A full electrical study will be able to determine this viability.

Table 67: Works BHWTW to Upper

BHWTW to Upper	Item	Specific Costs		Item Cost	
Civils				**R**	**2 000 000**
Power House and Balance of Plant				R	2 000 000
Other Civil Works				R	-
Hydro Mechanical Electrical				**R**	**2 800 000**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a 184kW Kaplan turbine)	**184**	**R**	**15 228**	R	2 800 000
Electricals and Grid Connection				**R**	**100 000**
Transmission line 66kV	0				
Substation/Other Electricals				R	100 000
Total		**R26 649**		**R**	**4 900 000**

8.2.6 Design Summary

The actual energy delivered of 1 GWh is the average yearly output of the new plant operating at a design capacity of 184 kW. This output was determined using the historical flow rate data since 1997 and can be seen in Table 69. The historical capacity factor is also shown. Table 68 is the design summary.

Table 68: Design Summary (BHWTW to Upper)

		BHWTW to Upper
Static Head	m	8
Hydraulic losses	%	5%
Rated Head	m	7.6
Design Flow	m3/s	3.40
Design Flow	Ml/day	294
Turbine type		Kaplan
Runner Diameter	m	0.82
Turbine Design Efficiency	%	91%
Turbine Capacity	kW	184
Annual Plant Downtime Losses	%	5%
Theoretical Energy Delivered	kWh	1 530 190
Actual Energy Delivered	kWh	1 041 251
Capacity Factor	%	68%

Table 69: Design Results BHWTW to Upper

Design Results		
Plant Design Capacity	kW	184
Annual downtime losses	%	5%
Theoretical Energy Delivered	kWh	1 530 190
Edelivered 1998	kWh	1 038 823
Edelivered 2000	kWh	999 902
Edelivered 2002	kWh	880 464
Edelivered 2004	kWh	965 396
Edelivered 2006	kWh	1 115 073
Edelivered 2008	kWh	1 254 375
Edelivered 2010	kWh	1 034 727
Average	kWh	1 041 251
Capacity Factor Theoretical	%	100%
Capacity Factor 1998	%	68%
Capacity Factor 2000	%	65%
Capacity Factor 2002	%	58%
Capacity Factor 2004	%	63%
Capacity Factor 2006	%	73%
Capacity Factor 2008	%	82%
Capacity Factor 2010	%	68%
Average	%	68%

8.2.7 Financial Modelling and Results

A full costing estimate is shown below in Table 70.

Table 70: BH Upper Total Costs

		BHWTW to Upper
Project Development Costs	ZAR	2 081 250
Installation Cost	ZAR/kW	29 313.74
	ZAR	5 390 000
Contingency	%	25%
	ZAR	1 347 500
Total Capital Cost	ZAR	8 818 750
Funding		
Funding Horizon	years	10
Interest Rate	%	12.00%
Debt:Equity Ratio	%	70%
Debt amount	ZAR	6 173 125

Equity amount	ZAR	2 645 625
Total Capex		**8 818 750**
Number of debt instalments per annum		1
Total Number of instalments		10
Total Interest Paid	ZAR	4 752 329
Total Operation and Maintenance Costs	ZAR	2 586 391
Total Lifetime Costs	ZAR	16 157 470
Incremental Energy Production	kWh	20 825 028
Actual Energy Production	kWh	20 825 028
Incremental Levelised Electricity Cost	R/kWh	0.78
Real Levelised Electricity Cost	R/kWh	0.78
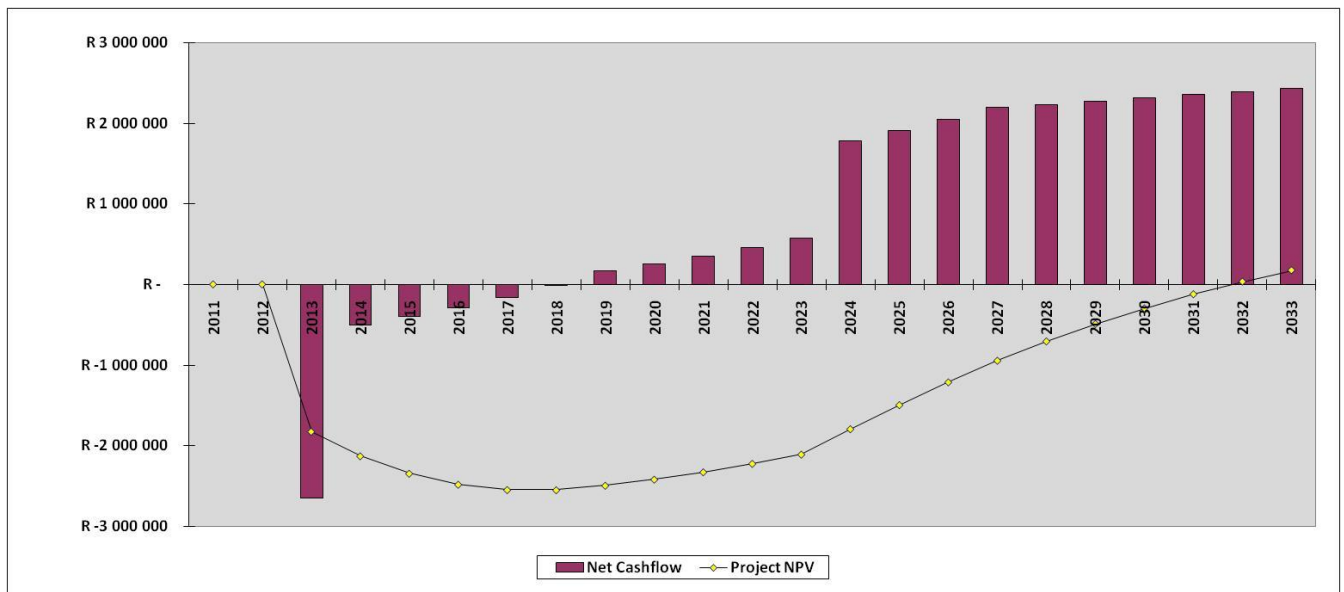
Figure 65: BHWTW to Upper NPV and Cash Flows

Figure 65 above shows that the investment yields positive results after about 19 years. The financial results could definitely be improved if for example, the operating costs from the plant were borne by the BH Raw Water inlet turbine.

Table 71: BH Upper Key Financial Outputs

Key Outputs	BHWTW to Upper
Capex Required	8 818 750
Equity Required at Fin Close	2 645 625
PPA Revenue	36 388 266
Operating Costs	3 039 966
EBITDA	33 348 300
Net Cashflow	19 777 221
NPV	175 233
Equity IRR	14%
Incremental Levelised Cost of Energy (ZAR/kWh)	R 0.78
Real Levelised Cost of Energy (ZAR/kWh)	R 0.78

8.2.8   Conclusions and recommendations

- It is recommended that this plant is developed further and taken to the feasibility study.
- Cost savings in the Capex can be found as well as in the development costs and operating costs that would make the investment more attractive.

8.3   Blackheath Lower Reservoir Inlet (BH Upper to Lower)

8.3.1   Description

From the Upper Service Reservoir there is a 1500mm pipeline dropping from 174.5 to 110.58m MSL. This pipeline sees a flow of between 100 and 300 Ml/day and the draw closely follows the residential water demand.

8.3.2   Current Turbine Operation

There is an existing turbine at this inlet that was designed to meet the requirements of the plant. This turbine is designed to a capacity of 712kW (unconfirmed - gearbox input rating) and is not operating to its full potential. It is shown in Figure 66.

Figure 66: Blackheath Lower Reservoir inlet Turgo Turbine

No information about the current turbine or its operation could be found. According to the staff at Blackheath, the current turbine operates at 100Ml/day minimum and usually stays quite constant. Using this assumption of 100Ml/day operation and using historical flow data, the following are the calculated turbine outputs and are used as the base case for the design concept. The incremental energy generated will be used to calculate the financial viability. It is advised that, for the feasibility study, a full energy audit of the plant is performed in order to find the true incremental/excess production from the proposed design concepts.

Table 72: Blackheath Lower Res Inlet Turbine Data

Manufacturer	Gilbert Gilkes & Gordon	
Type	Turgo	
Average Flow	1.16	m3/s
Average Flow	100	Ml/day
Rated Head	59	m
Average Turbine Power Output	537	kW
Theoretical Energy Output	6 219 600	kWh
Current Energy Production	3 294 928	kWh
Capacity Factor	53%	

8.3.3   Data Used

8.3.3.1   Levels
The levels used here are the same levels given in the Terms of Reference.

Table 73: Head Levels

Upper Reservoir	174.5	m
Lower Reservoir Inlet	110.58	m
Static Head	63.92	m

8.3.3.2 Flow Rates

Table 74: Flow Summary BH Upper to Lower

Min Flow	m3/s	1.2
Min Flow	Ml/day	100
Max Flow	m3/s	3.5
Max Flow	Ml/day	300
Average Flow	m3/s	1.9
Average Flow	Ml/day	167.0

Figure 61 shows the flow duration curve at three gauges over the period 1997-2011. The water that flows into the Lower Reservoir is the water that is measured flowing from the Upper to the Lower Reservoir less the water flowing out the High Pressure Outlet that supplies Newlands Reservoir with water. There is no measuring gauge at the turbine inlet.

8.3.4 Design Concept - Increase Production (BH Upper to Lower 1)

There is a lot of water at this existing turbine that is currently being diverted away from the turbine to the lower reservoir. This could be fed through the existing turbine and used to generate extra capacity that could be fed into the grid.

8.3.4.1 Works

The only works that would be required here is a simple grid connection, this has been assumed to be a 1km line that would connect to other Blackheath turbine transformer where it will be stepped up and fed into the existing grid. For financial modelling purposes the cost of a 22kV line has been assumed. It may be found during the feasibility study a turbine refurbishment would be required. These costs have not been taken into account.

Table 75: Works BH Upper to Lower 1

BH Upper to Lower 1	Item	Specific Costs	Item Cost	
Civils				
None			R	-
Hydro Mechanical Electrical				
None			R	-
Electricals and Grid Connection			**R**	**370 000**
Transmission line 66kV	1	R 230 000	R	230 000
Substation/Other Electricals			R	140 000
Total			**R**	**370 000**

8.3.5   Design Concept – Turbine Replacement (BH Upper to Lower 2)

Because the turbine is only designed at a flow rate of 1.5 m3/s (unconfirmed – no data sheet available), there is a significant amount of water that is being bypassed, especially during times of high flow. This option would entail a complete replacement of the turbine and generating equipment that will be able to handle higher flow rates.

The capacity of the plant would only nominally increase to 932kW (from 710 kW).

8.3.5.1   Works

Table 76 shows the assumed item costs for this design concept.

Table 76: Works BH Upper to Lower 2

BHUpper to Lower 2	Item	Specific Costs	Item Cost	
Civils			**R**	**3 500 000**
Civil works required to accommodate the replacement turbine.			R	1 000 000
Balance of Plant			R	2 500 000
Hydro Mechanical Electrical			**R**	**7 550 329**
M&E – Turbine full turnkey installation. Work here is typical Water-to Wire. (Design Concept for a 932kW Francis turbine but design should consider replacing with a Turgo)	932	R 8 098	R	7 550 329
Electricals and Grid Connection			**R**	**370 000**
Transmission line 66kV	1	R 230 000	R	230 000
Substation/Other Electricals			R	140 000
Total		**R 12 248**	**R**	**11 420 329**

8.3.6   Grid Connection

It is assumed that this plant will be connected to in a similar way to the BH Raw Water to Upper concept, i.e. stepped up at the Raw Water Power Plant and fed into the grid there. This can only be confirmed during the feasibility study. For modelling purposes a 1km, 22kV line cost was assumed.

8.3.7   Design Summary

The actual energy delivered of 4.4 GWh is the average yearly output of the new plant operating at a design capacity of 932 kW. This output was determined using the historical flow rate data since 1997 and can be seen in Table 77. The historical capacity factor is also shown.

Table 77: BH Upper to Lower 2 Energy Results

Design Results		
Plant Design Capacity	kW	932
Annual downtime losses	%	5%
Theoretical Energy Delivered	kWh	7 759 567
Edelivered 1998	kWh	4 056 807
Edelivered 2000	kWh	4 566 470
Edelivered 2002	kWh	4 331 297
Edelivered 2004	kWh	4 418 684
Edelivered 2006	kWh	4 525 005
Edelivered 2008	kWh	5 853 234
Edelivered 2010	kWh	3 563 107
Average	kWh	4 473 515
Capacity Factor Theoretical	%	100%
Capacity Factor 1998	%	52%
Capacity Factor 2000	%	59%
Capacity Factor 2002	%	56%
Capacity Factor 2004	%	57%
Capacity Factor 2006	%	58%
Capacity Factor 2008	%	75%
Capacity Factor 2010	%	46%
Average	%	58%

Table 78 below illustrates the difference in production from the existing operation to the existing turbine design capacity. This increase is 1 GWh/annum or a 32% increase. Although the turbine should theoretically generate 6.2 GWh/annum it could only produce 4.3 GWh due to the calculated 70% capacity factor.

By replacing the turbine (BH Upper to Lower 2) the plant would generate a slight incremental to its current design operation (BH Upper to Lower 1) and is likely to be financially unfeasible.

Table 78: Blackheath Upper to Lower Design Summary

		BH Upper to Lower C	BH Upper to Lower 1	BH Upper to Lower 2
Static Head	m	64	64	64
Hydraulic losses	%	5%	7%	7%
Rated Head	m	60	60	60
Design Flow	m3/s	1.16	1.53	2.00
Design Flow	Ml/day	100	132	173
Turbine type		Turgo	Turgo	Francis
Runner Diameter	m	*	*	0.64
Turbine Design Efficiency	%	*	*	88%

Turbine Capacity	kW	537	710	932
Annual Plant Downtime Losses	%	5%	0%	5%
Theoretical Energy Delivered	kWh	6 219 600	6 219 600	7 759 567
Actual Energy Delivered	kWh	3 294 928	4 353 720	4 473 515
Capacity Factor	%	53%	70%	58%
Actual Increase from Current Generation	kWh	-	1 058 792	1 178 587
% Increase	%	-	32%	36%

Figure 67 below shows the power output for the 3 Blackheath sites. The third site considered in the comparison is BH Upper to Lower 2. Although this is the least feasible, it is shown for illustration purposes. BH Upper to Lower 1 should yield very similar results.
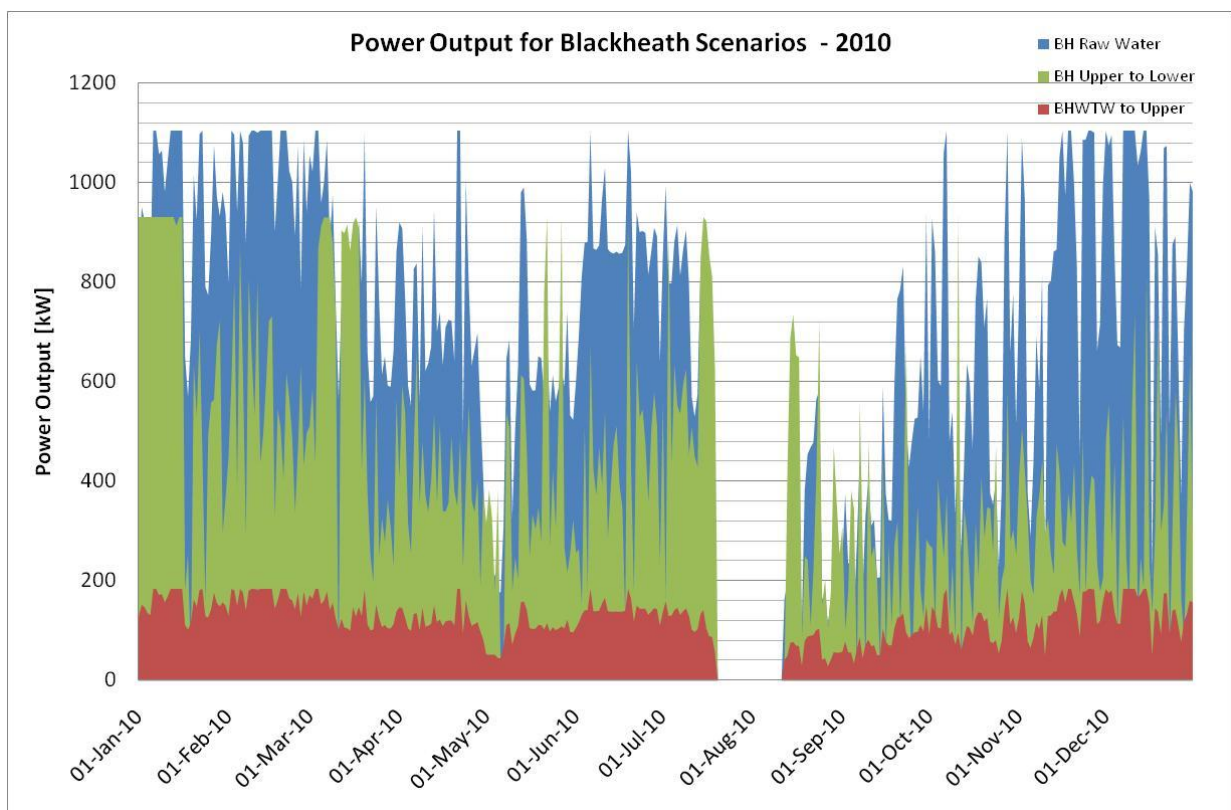
Figure 67: Blackheath Power output 3 sites

8.3.8   Financial Modelling and Results

Table 79 below compares the total costs for the two schemes.

Table 79: Total Costs BH Lower Res Inlet

		BH Upper to Lower 1	BH Upper to Lower 2
Project Development Costs	ZAR	2 081 250	2 081 250
Installation Cost	ZAR/kW	573.24	13 472.91
	ZAR	407 000	12 562 362
Contingency	%	25%	25%
	ZAR	101 750	3 140 590
Total Capital Cost	ZAR	2 590 000	17 784 202
Funding			
Funding Horizon	years	10	10
Interest Rate	%	12.00%	12.00%
Debt:Equity Ratio	%	70%	70%
Debt amount	ZAR	1 813 000	12 448 941
Equity amount	ZAR	777 000	5 335 261
Total Capex	ZAR	**2 590 000**	**17 784 202**
Number of debt instalments per annum		1	1
Total Number of instalments		10	10
Total Interest Paid	ZAR	1 395 723	9 583 714
Total Operation and Maintenance Costs	ZAR	9 986 997	13 115 545
Total Lifetime Costs	ZAR	13 972 719	40 483 461
Incremental Energy Production	kWh	21 175 840	23 571 737
Actual Energy Production	kWh	87 074 400	89 470 297
Incremental Levelised Electricity Cost	R/kWh	0.66	1.72
Real Levelised Electricity Cost	R/kWh	0.16	0.45
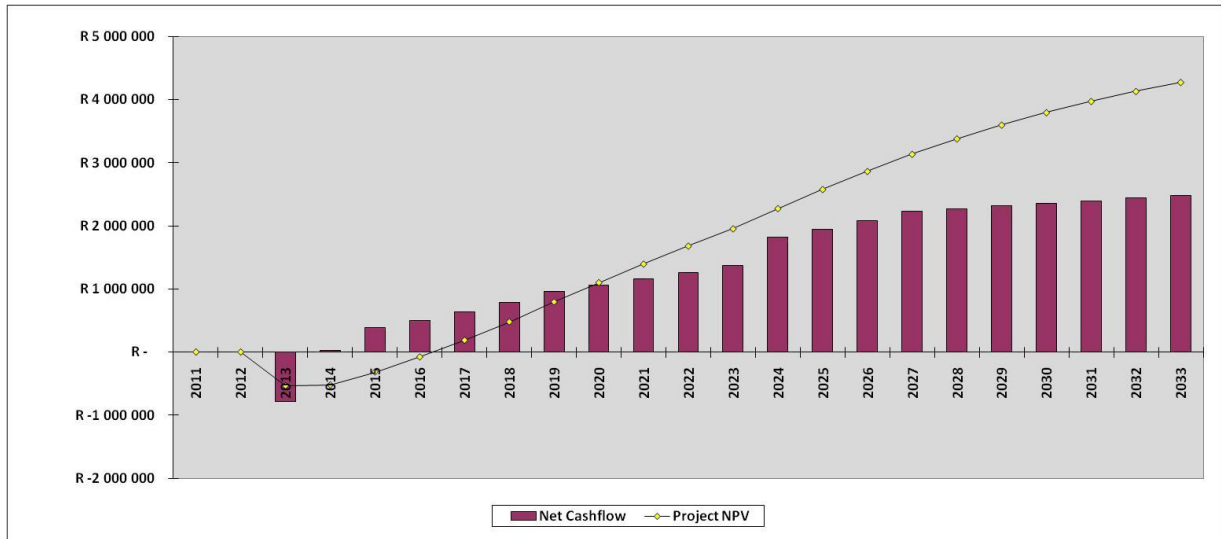
Figure 68: BH Upper to Lower 2 NPV and Cash Flow

Table 80 and Figure 68 show the positive results of the investment. Noted here is the particularly high IRR of 54% being due to the low estimated infrastructure costs.

Table 80: BH Upper to Lower 2 Key financial results

Key Outputs		BH Upper to Lower 1
Capex Required		2 590 000
Equity Required at Fin Close		777 000
PPA Revenue		37 001 251
Operating Costs		3 303 029
EBITDA		33 698 222
Net Cashflow		29 712 499
NPV		4 279 048
Equity IRR		54%
Incremental Levelised Cost of Energy (ZAR/kWh)	R	0.66
Real Levelised Cost of Energy (ZAR/kWh)	R	0.16

8.3.9 Conclusions and recommendations

- There is a certain amount of energy that can be fed into the grid. To estimate this potential accurately, a full energy audit of the treatment works is recommended.
- Concept BH Upper to Lower 1 is recommended for further investigation in the Feasibility study.

9 Summary of Results

The following is a list of feasible sites.

Table 81: Feasible Sites

	List of Feasible Sites
1	Steenbras Water treatment works to break pressure tanks 810, 840
2	Steenbras Lower Dam to Steenbras Water treatment works 2
3	Wemmershoek water treatment works
4	Blackheath Raw Water Inlet
5	Blackheath Water Treatment Works to Upper Service Reservoir
6	Blackheath Upper reservoir to Lower Reservoir 1
7	Faure water treatment works 2

- The plant to be situated at the 760 break pressure tank at Steenbras did not yield positive investment results but it is still worth investigating further in the feasibility study.
- Neither of the Rockview concepts seem feasible at this stage and should not be investigated at this point in time.
- Table 82 is a summary of all the sites that should be investigated further in the feasibility study following the outcomes of this prefeasibility. Table 83 summarises the financial results for these sites.
- Figure 69 to Figure 72 shows a summary of the Capex, Cost of Electricity, NPV and Equity IRR for the sites to be further assessed.

Table 82: Summary of design results for sites to be further investigated

		SB Lower Dam to SBWTW C	SB Lower Dam to SBWTW 2	SBWTW to 760	SBWTW to 810, 840	BH Raw Water	BHWTW to Upper	BHUpper to Lower C	BHUpper to Lower 2	Wemmers-hoek C	Wemmers-hoek 1	Faure C	Faure 2
Static Head	m	*	55	172	74	77	8	64	64	*	35	*	*
Hydraulic losses	%	*	15%	10%	10%	45%	5%	5%	7%	*	10%	*	5%
Rated Head	m	34	48	155	66	42	7.6	60	60	28	31	130	124
Design Flow	m3/s	0.66	1.60	0.18	1.50	3.40	3.40	1.16	2.00	0.46	2.50	1.16	2.50
Design Flow	Ml/day	58	138	16	130	294	294	100	173	40	216	100	216
Turbine type		2 xTurgo	Francis	Pelton	Pelton	Francis	Kaplan	Turgo	Francis	Francis	Francis	Turgo	Francis
Runner Diameter	m	0.53	0.57	0.22	0.58	0.82	0.82				0.71	0.79	0.71
Turbine Design Efficiency	%	*	87%	91%	87%	86%	91%	*	88%	*	85%	*	90%
Turbine Capacity	kW	179	605	228	784	1 096	184	537	932	207	576	1 174	2 441
Annual Plant Downtime Losses	%	*	*	5%	5%	5%	5%	5%	5%	5%	5%	*	5%
Theoretical Energy Delivered	kWh	2 508 864	5 035 791	1 896 047	6 521 722	9 119 251	1 530 190	6 219 600	7 759 567	1 544 356	4 795 447	12 921 000	20 316 175
Actual Energy Delivered	kWh	788 196	2 532 311	767 260	4 266 995	6 138 489	1 041 251	3 294 928	4 473 515	*	3 596 066	7 772 310	13 445 706
Capacity Factor	%	31%	50%	40%	65%	67%	68%	53%	58%		75%	60%	66%
Actual Increase from Current Generation	kWh	-	1 744 116	-	-	-	-	-	1 178 587	-	2 051 711	-	5 673 396
% Increase	%	-	221%	-	-	-	-	-	36%	-	133%	-	73%

Table 83: Summary of financial results for sites to be further investigated

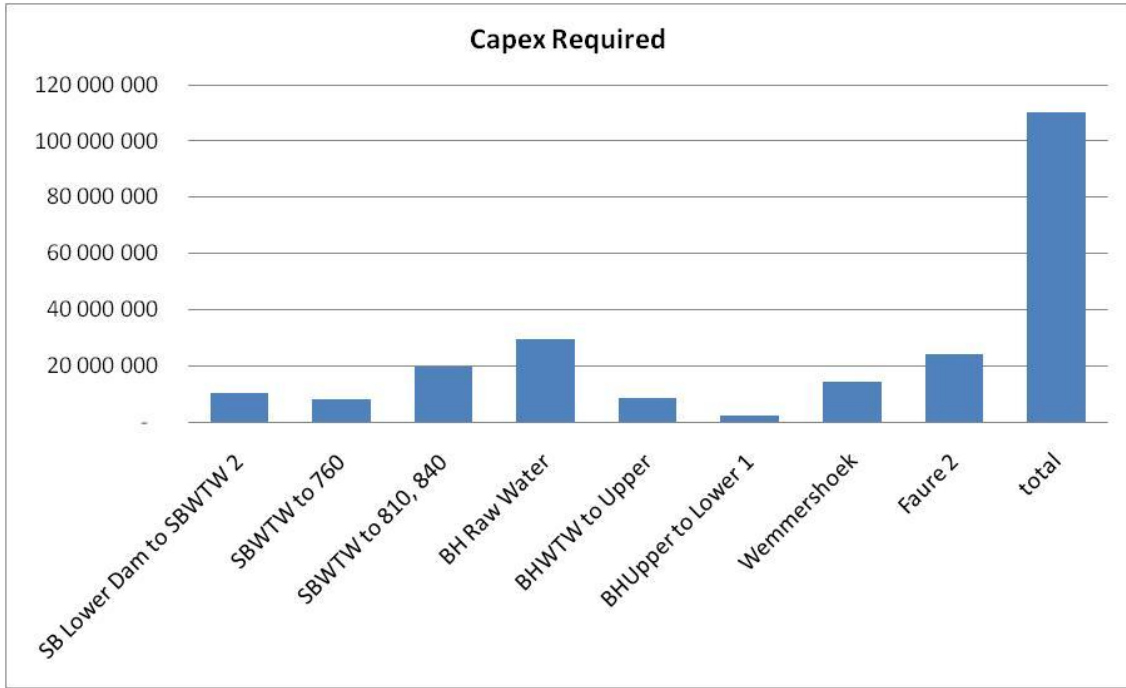| Key Outputs	SB Lower Dam to SBWTW 2	SBWTW to 760	SBWTW to 810, 840	BH Raw Water	BHWTW to Upper	BHUpper to Lower 1	Wemmershoek	Faure 2	total
Capex Required	10 497 625	8 395 250	19 858 625	29 442 375	8 818 750	2 590 000	14 284 375	24 005 625	110 122 827
Equity Required at Fin Close	3 149 288	2 518 575	5 957 588	8 832 713	2 645 625	777 000	4 285 313	7 201 688	33 036 848
PPA Revenue	60 951 029	26 813 190	149 117 267	214 519 745	36 388 266	37 001 251	71 700 451	198 266 275	603 042 102
Operating Costs	10 004 401	3 766 800	12 956 439	18 116 844	3 039 966	3 303 029	9 526 918	40 361 314	93 339 250
EBITDA	50 946 628	23 046 390	136 160 828	196 402 901	33 348 300	33 698 222	62 173 533	157 904 961	544 281 910
Net Cashflow	34 791 947	10 127 031	105 600 606	151 094 350	19 777 221	29 712 499	40 191 463	120 962 965	255 770 682
NPV	2 171 023	-1 437 295	11 471 378	16 023 515	175 233	4 279 048	1 707 157	12 276 372	7 130 424
Equity IRR	19%	8%	29%	28%	14%	54%	17%	27%	27%
Incremental Levelised Cost of Energy (ZAR/kWh)	R 0.71	R 1.05	R 0.49	R 0.49	R 0.78	R 0.66	R 0.73	R 0.63	R 0.62
Real Levelised Cost of Energy (ZAR/kWh)	R 0.49	R 1.05	R 0.49	R 0.49	R 0.78	R 0.16	R 0.42	R 0.27	R 0.38

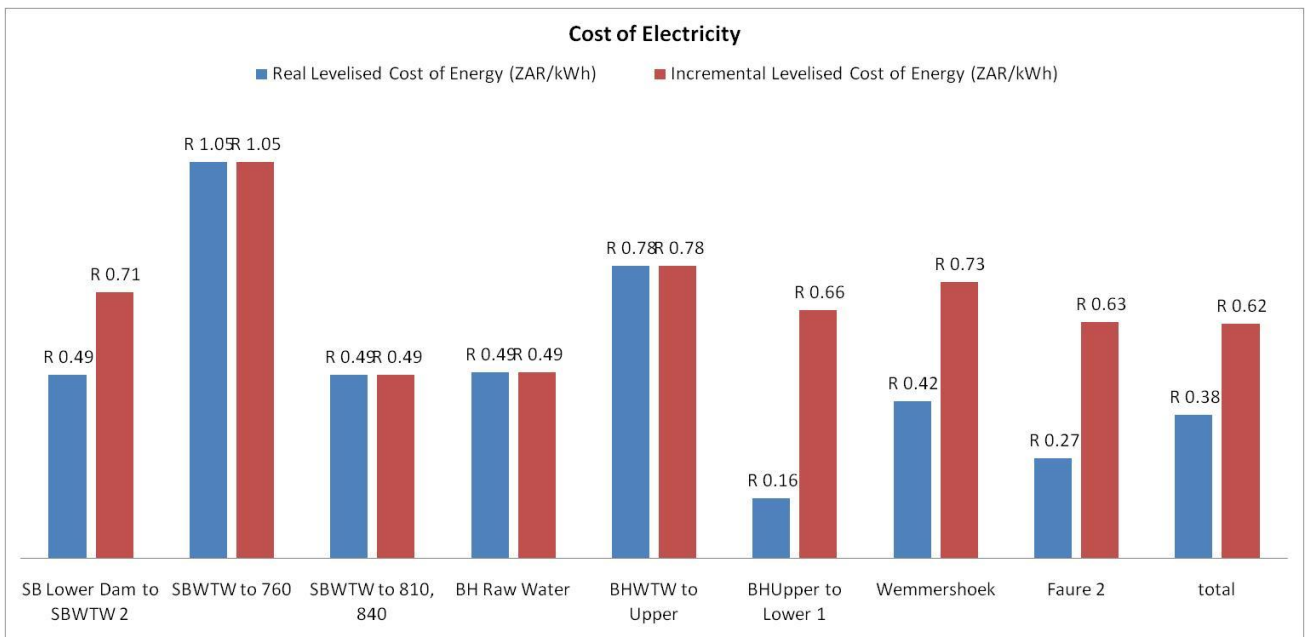**Figure 69: Capex Summary**

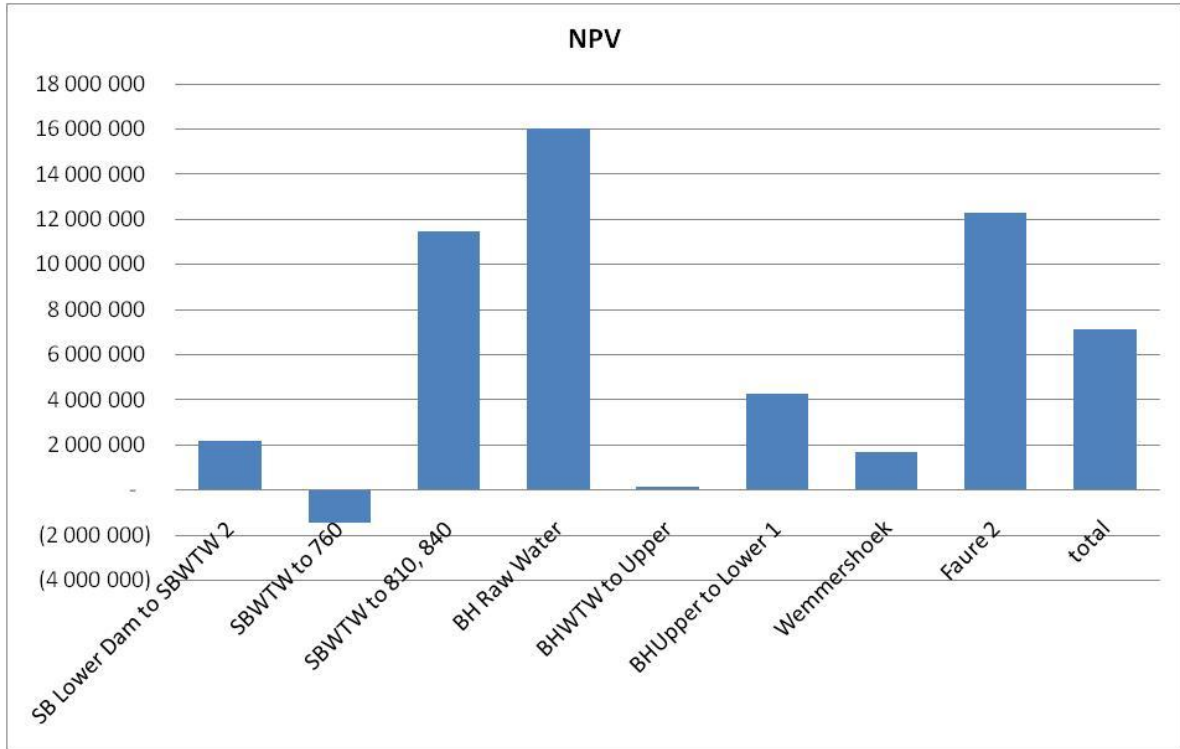**Figure 70: Cost of Electricity Summary**
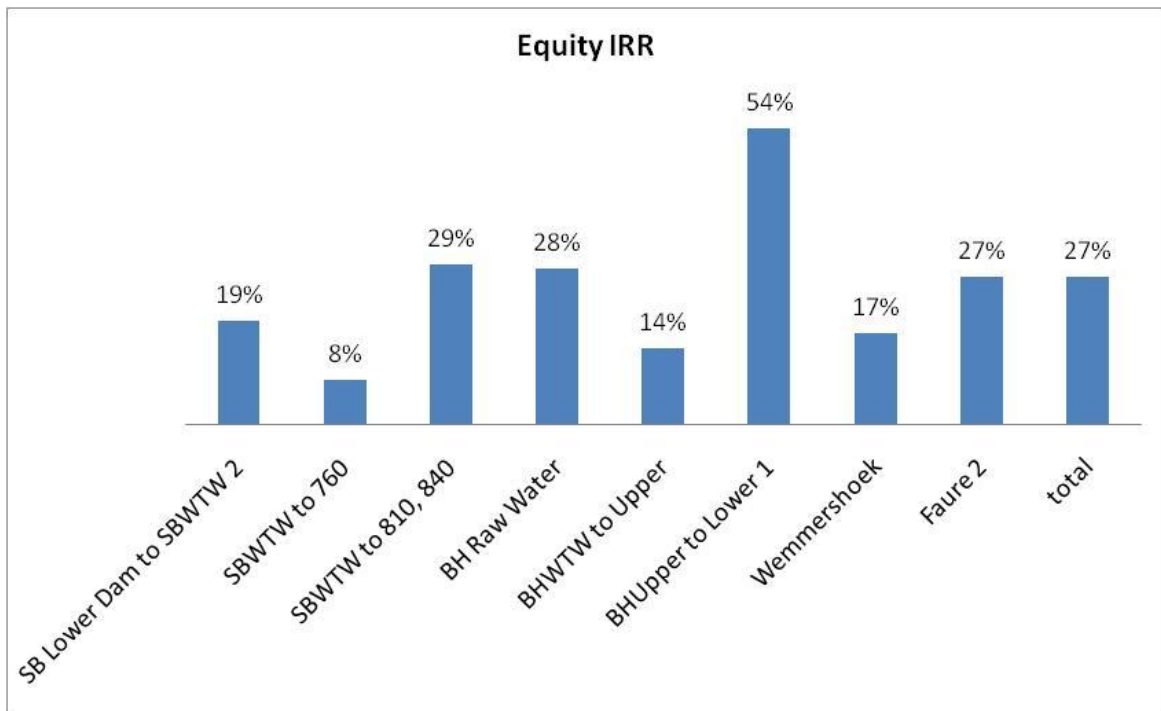
Figure 71: NPV Summary

Figure 72: IRR Summary

10 Project Plan

The Project Plan concerns the cycle of the Project, and highlights elements to be considered for phasing the optimal cycle. A typical project financed greenfields hydropower project is phased as shown Figure 73:
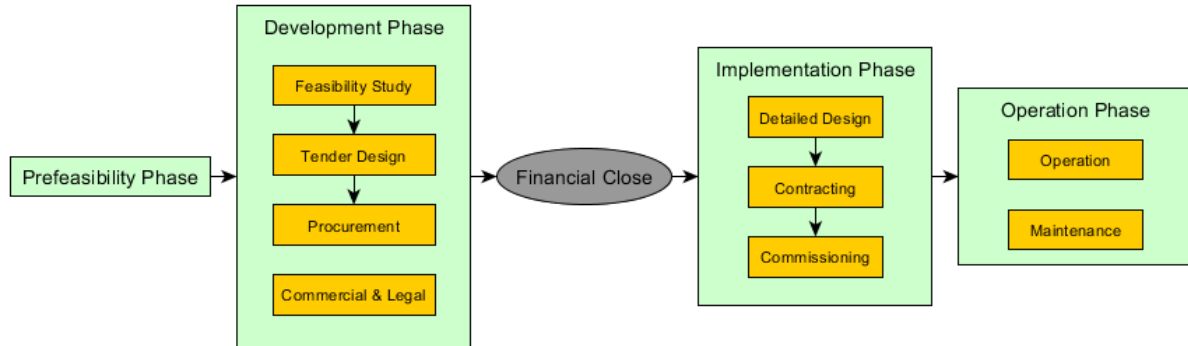
Figure 73: Project Cycle

Optimization is largely driven by the technical elements, which, during the total cycle of the Project, include:

- Prefeasibility Design
- Feasibility Design
- Tender Design
- Detailed Design (sometimes tender and detailed design are merged into a single item)
- Procurement
- Contract Management (Project Management, Monitoring, Quality Control)
- Contracting
- Operation and Maintenance

Each technical item will occur within a phase of the project cycle. Each project phase has a different intention, and it is important that the technical items are scoped in such a way that the right level of detail is achieved according to spending levels appropriate to the phase of development.

An alternative is to combine the Tender and Detailed Design components into a single design phase post financial close. This is shown in Figure 74.

Figure 74: Alternate Project Cycle

This has the following advantages:

- Development costs are reduced because the scope and level of detail of the technical work in the Development Phase is reduced. The more complex design work is then budgeted for within the Implementation Capex which has a lower risk associated with it, reducing the financial burden on the project as a whole.
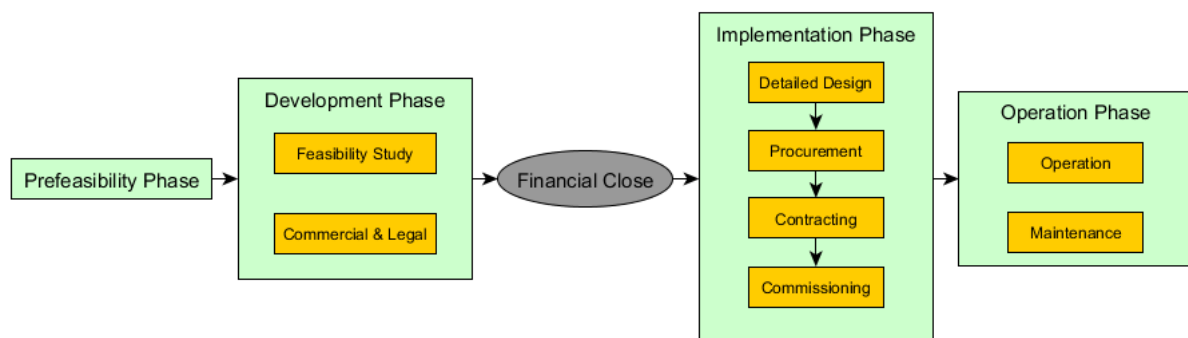- It will allow the Tender and Detail design phases to merge into a single item, also reducing cost and time.
- It leaves flexibility in the final designs so that if an IPP becomes the proponent (in the event that a PPP is the selected procurement mechanism), the IPP will have the chance to input into the design process.

However, this approach has challenges in a Project Finance context. Lenders are less likely to be satisfied with future cashflows based on Capex and production estimates resulting from feasibility level design. However, in a Corporate Finance structure this approach is acceptable because the Lender's security is based on the Proponent's balance sheet. Hence the phasing of technical elements is based on the Project structure see section 12.

Given the focus on PPPs in this report, a Project Finance structure is more appropriate. This decision must however be made by the Proponent after consideration of project structural and finance.

11 Project Leadership and Management

Leadership and Management are performed by the Proponent (or Sponsors/Owners/Shareholder). This is because the work is core to project ownership and leadership from the head of the project is therefore critical to ensuring that the final product is in the desired form. In the Private Sector this role is performed by the Developer.

This role is particularly significant in the Development Phase because this is the most formative stage in the project cycle. Alignment of low level details during the development of the project with high level strategic objectives is essential to ensure that the final product is in the desired form.

11.1 Scope

The scope of work of the Proponent is varied and the requirement is for a multi-skilled team with understanding of financial, technical, commercial, legal, and statutory elements. Management and communication skills are essential as the Proponent must interact with a large number of individuals and teams conducting the various components of the Development Phase.

11.1.1.1 Strategic Guidance

The Proponent must provide the high level and long term strategic guidance necessary for the Project's success. This includes:

- Monitoring Project landscape and ongoing risk assessment and opportunity identification
- Managing strengths and weaknesses of the Project
- Decision making
- Sourcing and entering beneficial alignments with partners and subcontractors

11.1.1.2 Project Management

- Management of all Project phases to ensure:
  - The high level outputs of each phase occur on time and on budget
  - Lower level tasks are feeding into the high level program
  - All interdependencies between components are managed
  - Sufficient flow of information horizontally and vertically in the Project structure
- In the Development Phase this includes, but is not limited to the components:
  - Environmental
  - Technical
  - Carbon
  - Legal
  - Commercial and Financial
- Financial management of the Development budget, payment authorisations etc
- Secretarial, ensuring all communications, proofs, are documented etc

11.1.1.3 Financial Modelling

A bankable financial model must be constructed, providing accurate insight into financial characteristics of the Project. Skilful financial engineering can create significant value for the Proponent, enabling:

- Early recognition of threats to financial viability
- Optimal presentation of the Project to financiers
- Evaluation of complex agreements with subcontractors and financiers

It is possible to source financial modelling skills externally, but the work is core to the role of the Proponent and ideally is sourced internally.

11.1.1.4 Commercial Arrangement

The success of the Project hinges on the Proponent's ability to execute key Project Agreements. Although assisted by the Project's Legal Counsel, the Proponent is ultimately responsible for the sourcing and execution of the requisite commercial arrangements. These include but are not limited to the Project Documentation and Project Finance Agreements described in Legal TOR. The Proponent is also responsible for packaging of the Project for financiers and the preparation of Bids necessary to secure offtake agreements.

11.2 Project Program

A program was constructed to illustrate the path ahead for the Project. It is assumed for illustrative purposes that the Development Phase begins at the start of 2012. The project cycle from this point onwards has been estimated as shown in Figure 75.
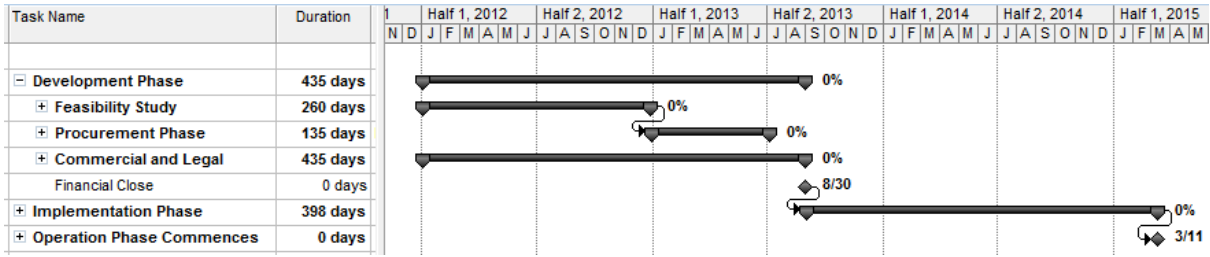
Figure 75: Project Program

This estimation shows the duration of the individual phases and the project as a whole. Note that both the Development and Implementation Phases are estimated to take a little over one and a half years each, and the Operation Phase to commence in the first half of 2015, a little over three years after the start of the Feasibility Study.

Note also that this is a somewhat simplistic program which considers all the sites under consideration as a single project. In reality, some of the smaller and less complex sites will progress more quickly through all phases. This estimation is therefore conservative and is representative of the most complex site under consideration. All the sites can be expected to be operational within the timeframe indicated here.

11.3 Development Phase

The Development Phase typically begins following a Prefeasibility Study indicating good potential for further development. The completion of the Development Phase is marked by the financial close of the project. At this point the complete detail of the proceeding Implementation Phase is ready for immediate execution; and the required Capex is committed and available to be drawn down.

Figure 76: Development Phase

The Development Phase typically include the sequenced components:

1. Feasibility Study

2. Tender Design
3. Procurement

The Commercial and Legal component is not in sequence with the other components, but instead largely tracks the other components.
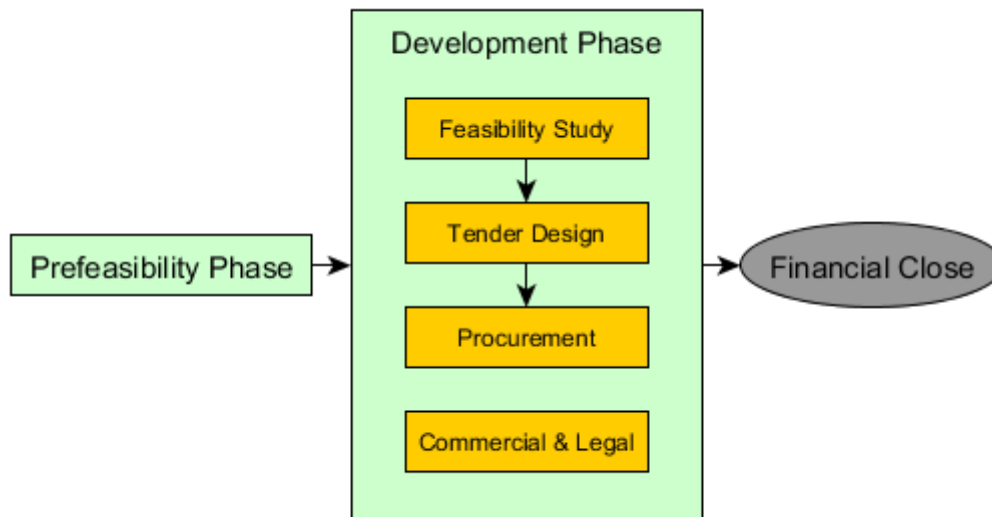
11.3.1 Feasibility Study

The feasibility study produces certainty on all relevant project components and reduces risk sufficiently for expenditure on greater levels of design (either Tender or Detailed design). It involves all work necessary to bring the level of knowledge to the point at which future phases of the Project can commence and compliance requirements are filled. The work has requirements for technical, carbon (technical and industry), environmental and legal skills. All statutory requirements are investigated and applications made to ensure compliance, and outcomes are contained within legal documentation.

11.3.1.1 Feasibility Design

The Feasibility Design enables the Project to determine the scope of its activities and apply for environmental authorisation, as well as provide more solid cost and revenue information. The Feasibility Design expands on the Prefeasibility Design. The typical scope includes:

- Assess Head to bankable confidence levels
- Assess Flow to bankable confidence levels
- Selection of a preferred option from the options identified in the Prefeasibility Design.
- Optimisation of the preferred layout and design to feasibility level, including:
    - Electromechanical
    - Electrical
    - Civil
    - Hydrological
    - Geotechnical
- Perform hydraulic modelling of the preferred option
- Project production based on preferred option
- Compile Bill of Quantities (BOQ) and provide cost estimate to +-10%
- Identify major technical risks at each site
- Compile program for the implementation of the preferred option

11.3.1.2 Environmental Authorization

The Environmental Authorization work ensures that the Project is environmentally compliant. The Environmental component is carried out by an EAP and the scope includes:

- Notify Authorities of Project
- Conduct Public Participation process according to regulations
- Draft Basic Assessment Report (BAR)
- Submit Basic Assessment Report and manage interaction with the relevant Authority until ROD

11.3.1.3 Feasibility Design and Environmental Authorization Program

The Feasibility Design and Environmental Authorization determine the duration of the Feasibility Study. The estimated program for these two components is shown Figure 77.
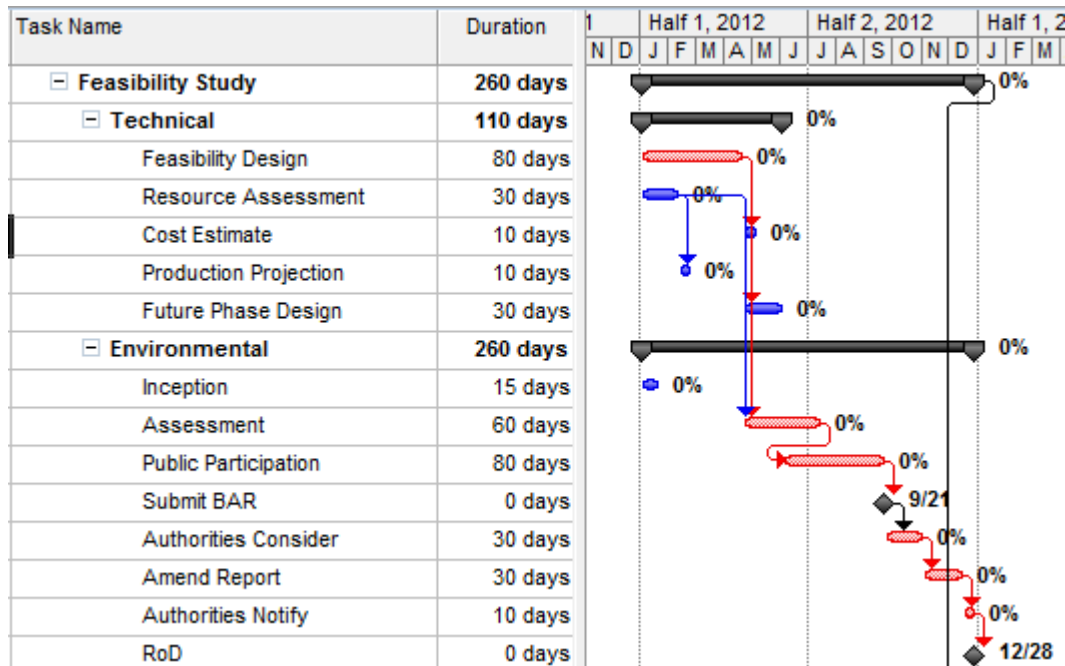
Task Name	Duration	Gantt
⊟ Feasibility Study	260 days	0%
⊟ Technical	110 days	0%
Feasibility Design	80 days	0%
Resource Assessment	30 days	0%
Cost Estimate	10 days	0%
Production Projection	10 days	0%
Future Phase Design	30 days	0%
⊟ Environmental	260 days	0%
Inception	15 days	0%
Assessment	60 days	0%
Public Participation	80 days	0%
Submit BAR	0 days	9/21
Authorities Consider	30 days	0%
Amend Report	30 days	0%
Authorities Notify	10 days	0%
RoD	0 days	12/28

Figure 77: Feasibility Study Program

11.3.2 CDM

Although not listed nor necessarily a part of the project cycle, the CDM component is considered here because it is initiated and managed concurrently with technical and environmental components in the feasibility study. The CDM project can be thought of as a parallel yet separate activity to the Project. This is in line with the exclusion of CDM income from the financial models when assessing the viability of the Project. If successful, the CDM revenue is "cream on top" of an already viable project. The CDM component is usually carried out by a Carbon Consultant and the scope includes:

- Confirm Project eligibility under CDM
- Select optimal CDM project structure
- Prepare Preliminary Estimates of GHG Reductions and Determine Their Market Value
- Draft PIN and obtain DNA letter of no objection
- Conduct CDM Public Participation according to relevant regulations
- Develop Project Design Document (PDD)
- Assist with engaging a DOE and facilitate Validation process and Registration

The CDM Project program has been estimated as shown in the figure below. The CDM component is also not on the critical path for the project and hence does not drive the duration of the Development or any other phase. The estimated CDM program is shown in Figure 78 alongside the Project Program.
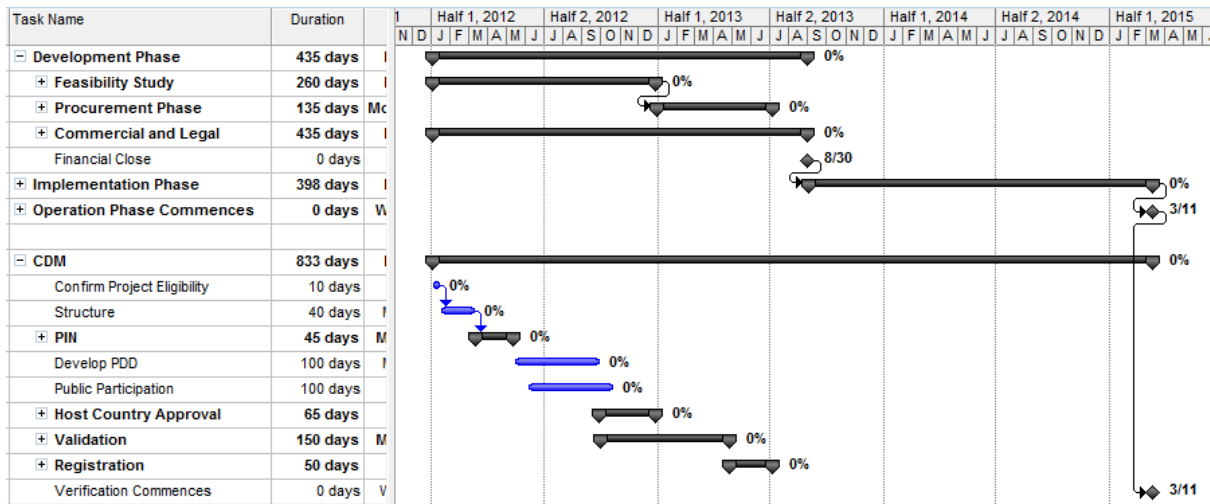
Figure 78: CDM Program

11.3.3 Tender Design

The purpose of Tender Design is to progress the design to a point at which Implementation contracts can be procured. This involves production of tender drawings and associated documentation.

11.3.4 Procurement

Electromechanical and Civil implementation contracts must be procured. The tender process includes:

- Publish Tender Documentation
- Evaluate bids
- Select Preferred Bidder
- Negotiate Contract
- Draft Contract
- Award and execute contract

11.3.5 Commercial and Legal

As mentioned, the Commercial and Legal component largely tracks the phased activities. Throughout the Development Phase the Project's Legal Counsel supports the phased activities.

The work of the Legal Counsel consists of drafting, reviewing, negotiating and commenting on:

- Project Documentation, such as PPA, Implementation Agreements, Shareholder's Agreement etc
- Project Finance, which puts in place all the commercial agreements necessary to reach financial close.

The Project Legal Counsel works in close proximity to the Proponent on the necessary agreements. The Proponent must ensure all agreements are executed in line with the Project Program.

11.3.6 Development Phase Program

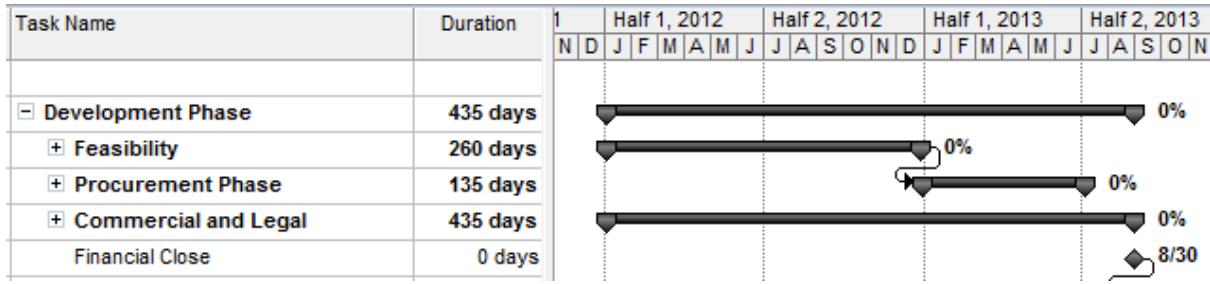The Development Phase Program is shown in Figure 79.

Figure 79: Development Phase Program

The execution of agreements and first draw down of Capex is possible on the back of successful completion of all Development Phase work. Financiers will not commit unless it is shown in the due diligence process that the project is compliant in all respects. If non-compliance is discovered later in the project cycle the costs are far higher hence Project Finance places high requirements on the ground work being exhaustively completed during the Development Phase.

11.4 Implementation Phase

The Implementation Phase is concerned with the execution of the Works. It is complete when the plant reaches full operation.

11.4.1 Detailed Design

Detailed Design involves production of detailed construction drawings and review of manufacturer's equipment drawings in order for the contractors to execute the works.

11.4.2 Contracting

Contracting involves the physical execution of the works, including:

- Civil Construction

- Electromechanical supply and installation

- Balance of Plant

There is also a requirement for professional services including Project Management, Construction Monitoring, quality control and site closure. This is typically performed by the Engineering Consultancy.

11.4.3 Commissioning

The Implementation Phase is complete after commissioning when the plant will be delivering energy to the grid. Commissioning involves grid synchronisation of the plant, handover to Operators.

12 Project Structure

Correct structuring, or commercial arrangement, is central to establishing a successful project. The structure will determine:

- Who the "Proponents" (or Sponsors/Owners/Shareholders) are
- The entity which will be the contracting party for all project work, usually a "Project SPV" or "Project Company"
- Risk allocation between Proponents, Subcontractors to the Project Company, and counterparties to the Project Company
- The source, routes and destination of Development Finance, Capex, Opex and income associated with the project.

It is important that structuring occurs upfront as it can be costly to alter it at a later stage, but most significantly, momentum of the project can be severely damaged without clear buy in and role definition among the Proponents. The structure may take a different form in Development, Implementation and Operation phases. These differences need to be identified as early as possible. The Legal counsel must document the structure and commercial arrangements as early as possible to govern all activity going forward.

CCT is currently the Proponent of the Project, and must decide on the mechanism for procurement of the Project going forward. This may be through either an internal or external mechanism. Key factors to consider in making this decision are:

- Affordability of the mechanism
- Value-for-money achieved through the mechanism
- Risk assumed by CCT through the mechanism

The scope of this study included consideration of "the optimal manner in which to structure and manage the project, in order to shift risk and financing from the municipality onto the private sector providers" with specific focus on a PPP as the mechanism of procurement. As such, PPPs are a prominent focus in this study.

Firstly, PPPs are briefly introduced in terms of fundamental objectives, legal grounding, proces and typical characteristics. Secondly, building on this, a specific PPP model has been identified as a possible structure through which the hydropower potential in the Bulk Water system may be exploited.

12.1 Introduction to PPPs

Luel Culwick and Christiaan Bode from Sidala attended the PPP Foundation Training Course run by National Treasury's PPP Unit in Midrand on the 23rd and 24th June 2011. The PPP Unit has produced a number of useful publications on PPPs, most particularly the PPP Manual and the Municipal Service Delivery and PPP Guidelines which are used extensively in this report.

PPPs are structures which provide integration between Public and Private sectors for a collective good. The public receives higher quality, more cost-effective services from their governing institution while the private party receives a business opportunity.

A PPP is legally defined as:

- A contract between a Public Institution and Private Party
- The Private Party performs an institutional function and/or uses state property in terms of output specifications
- Substantial project risk (financial, technical, operational) transferred to the Private Party
- The Private Party benefits through: unitary payments from government budget and/or user fees

A PPP is somewhere between simple outsourcing and full privatisation in terms of the degree of risk transferred to the Private Party. In outsourcing, the Institution retains purchases goods or services but retains financial, technical and operational risk. In privatisation, state assets and liabilities are sold, leaving only the regulatory function to the Institution. In between these two models, a PPP allows financial, technical and operational risk to be transferred to the private party which has responsibility for outputs while the Institution retains ownership of assets.

The typical structure of a PPP is shown in Figure 80:
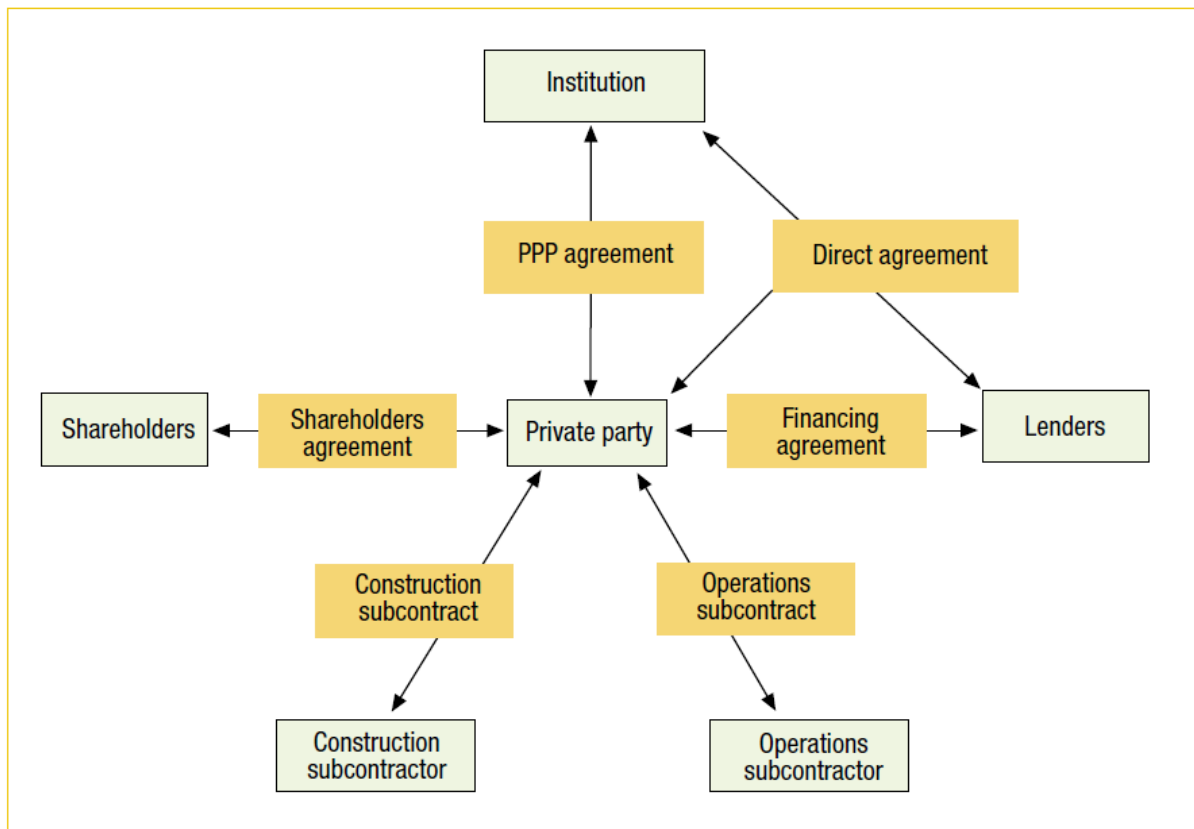
Figure 80: PPP structure

Whatever the PPP type, structure, payment mechanism, or sources of funding, all South African PPPs are subjected to three tests:

1. Can the Institution afford the deal?
2. Is it a value-for-money solution?

3. Is substantial technical, operational and financial risk transferred to the Private Party?

The PPP process is highly regulated and prescribed as indicated in Figure 81.
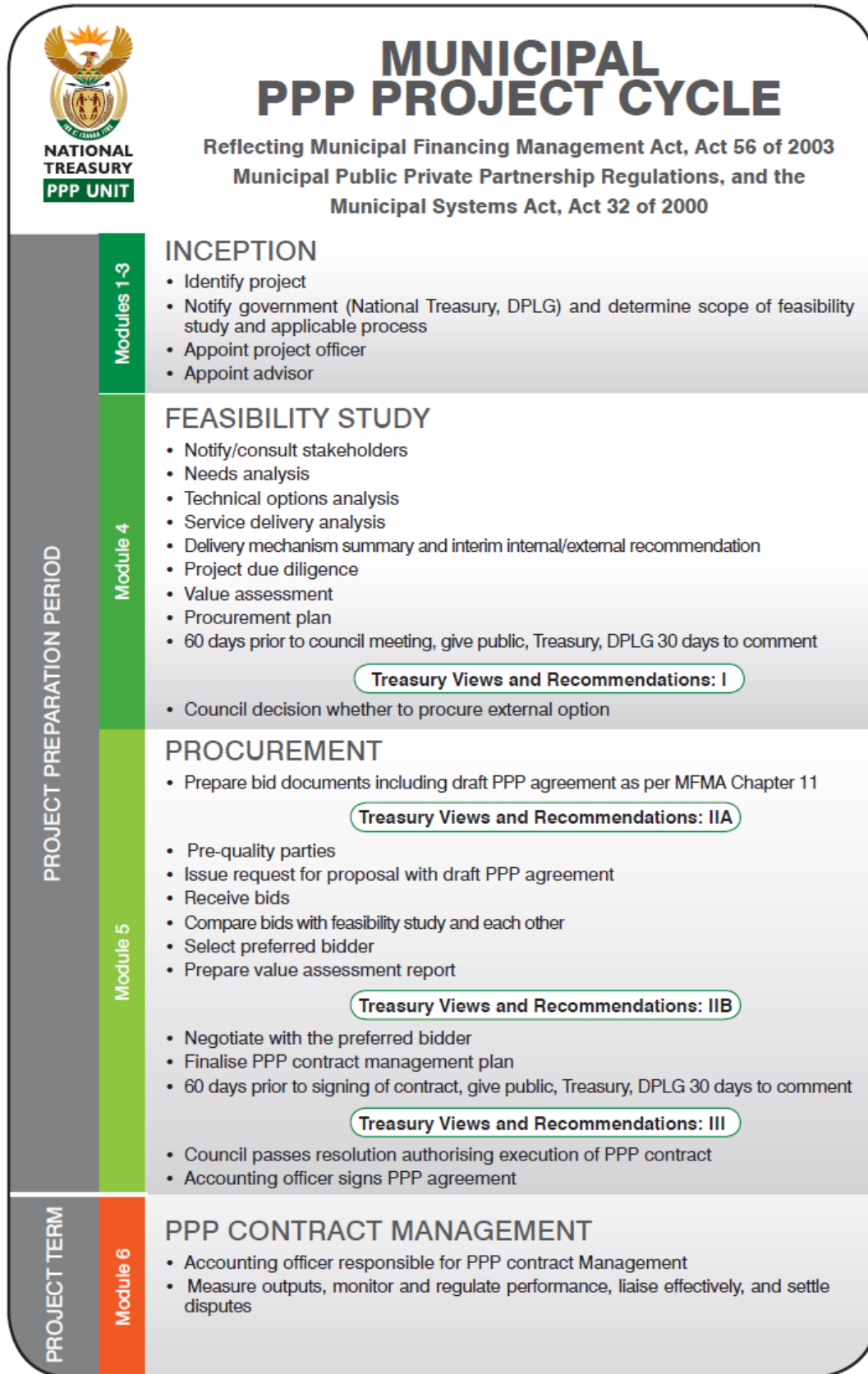
Figure 81: PPP Process

This brief introduction is expanded on in greater detail in Appendix C PPPs in South Africa.

12.2 PPP for CCT Small Hydro

A PPP is an external mechanism which CCT can use to procure the hydropower projects. The likely characteristics of a PPP tailored specifically for the Project are discussed here.

12.2.1 Proposed PPP Structure

Figure 82 shows the proposed PPP structure. It closely resembles the standard form of PPP agreements.
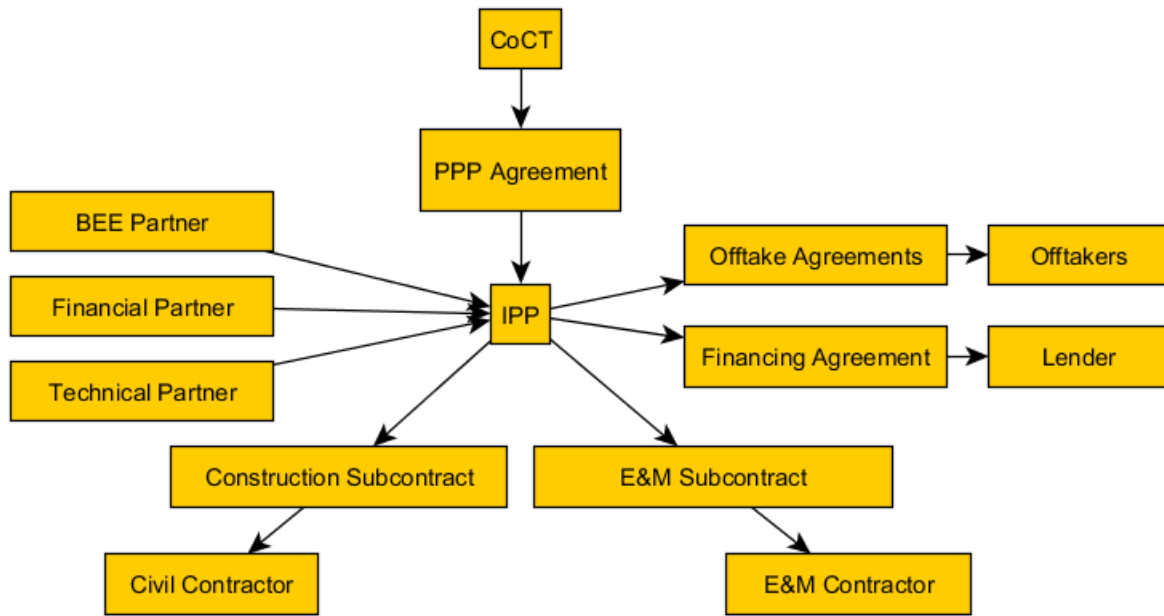
Figure 82: CoCT PPP Structure

The PPP agreement provides for the commercial use of Public Property (CCT Bulk Water Infrastructure) by the Private Party (IPP). The terms of the agreement will include the following:

- The basis of the agreement is to provide tenure to the IPP over CCT assets required for hydroelectric generation, which the IPP will develop and operate for a profit. In return, the IPP will pay CCT for this tenure

- It is suggested that the IPP receive tenure over via a lease infrastructure in order to generate power.

- Infrastructure required includes:

  o Land on which the plant will be located

  o Existing buildings within which plant will be located

  o Water conveyance infrastructure

  o Existing power generation assets

- The lease term will need to be sufficient to allow the IPP to project finance itself. This would need to be a minimum of 20 years.

- Note, the IPP does not acquire assets, the CCT will continue to own the power generation assets.

- The IPP is required to develop and operate the leased assets to produce and sell energy profitably.

- The IPP makes concessionary payments to CCT. *Note these payments should be linked to the profitability of the IPP. In this way a partnership is forged through alignment. The more profitable the IPP is the more direct financial benefits CCT will receive*.

- CCT is required to supply water according to agreed flow regimes. *Note the flow regime received by the IPP of course impacts directly on the profitability of the IPP. Through the alignment created by the structure of concessionary payments, the CCT and the IPP will strive to provide optimal flows for power generation while maintaining water supply objectives.*

- Output Specification placed on IPP:

  o Based on flow received, energy production levels and corresponding profit must be generated by the IPP according to agreed levels. If the production levels are not attained, the IPP will pay penalties to the CCT.

In this way the CCT receives guaranteed income via the PPP agreement via either concessionary payments or penalties. Financial, technical and operational risk is assumed by the IPP. The IPP and CCT are aligned, promoting cooperation between the two parties.

12.2.2 Risk Allocation

Risks to the power generation objective include:

- Resource
  o Flow reductions/non supply
  o Flow fluctuation
  o Sub-optimal flow regime
  o Head Losses
- Capex
  o Low or negative Equity returns
  o Inability to repay Lenders
- Opex
  o Cashflow shortages
  o Unexpected or "lumpy" maintenance costs
- Energy Offtake
  o Non-payment
  o Insufficient term

- o Insufficient balance sheet of buyer
  - o Insufficient security, inability to attach public assets
- CER Offtake
  - o Non-payment
  - o Insufficient term
  - o Insufficient balance sheet of counterparty
- Implementation
  - o Cost overrun
  - o Delay
- Operational
  - o Suboptimal operation
  - o Unplanned, unpredictable unavailability
- Production
  - o Underperforming energy production and therefore CER production
- Grid Connection
  - o Inability to connect
  - o Connection delay
  - o Connection unavailability
- Compliance
  - o Environmental non-authorisation
  - o Water use non-authorisation
  - o Other non-compliance
- Terminal Project Hazards
  - o Earthquake
  - o Flood
  - o etc

In the proposed PPP, the allocation of risks is as shown in Table 84:

Table 84: Risk Allocation

Risk	IPP	CCT	Other
Resource		y	
Capex	y		
Opex	y		
Energy Offtake	y		
CER Offtake	Y		
Implementation	Y		
Operational	Y		
Production	Y		
Grid Connection	y		Grid Operator
Compliance	y		
Terminal Project Hazards	y		

12.2.3   PPP Inception

The PPP regulations are legally binding and are prescriptive. The project could be brought all the way to inception if the process is not followed from the start. Therefore it is prudent to begin the Inception stage of the PPP process if it is only a possibility that the Project may be procured using a PPP mechanism. This does not mean that the Project will be procured using a PPP mechanism but that if it is desired, the process followed is compliant.

For this reason some of the activities within the Inception Stage were identified.   These are described below.

12.2.3.1   Project Conception

The first step of the Inception Phase is to categorise the hydropower generation as one of:

- Municipal Service
- Municipal Support Activity
- Commercial use of Municipal Property

The activity of generating power is excluded from the list of activities determined to be Municipal services. Hence the MSA is not applicable in the procurement of this PPP. This leaves the second two options. Hydroelectric power generation could be considered as a municipal support activity in that it is incidental to the municipal service of water and sanitation. Equally, the activity could be considered to be private sector use of municipal property in the land and relevant water conveyance and power generation fixed property can be leased to a private party. In either case, MFMA regulations apply and MSA regulations do not apply.

Under the definition, and as discussed above, the Project as a PPP will include all key exclusions and inclusions in the PPP definition:

- The structure involves a contract between a government institution (CCT) and a private party (IPP).
- CCT grants concession to the IPP to use its assets in return for concession payments by the IPP to CCT.
- The IPP performs construction, management and operation of hydroelectric generation activities which are either municipal support activities or commercial use of municipal property.
- Substantial risk is transferred to the IPP which finances, manages and operates the hydroelectric generation activities.
- The IPP benefits through sale of electricity and pays concession fees to CCT for use of fixed property.
- The IPP does not receive ownership of public property, but only leases it. Hence the structure is not privatisation.
- The IPP assumes significant risk. Hence the structure is not simple outsourcing.
- The IPP conducts its work for a profit. Hence the structure is not a donation or charity.

The proposed structure is therefore a PPP. If it is possible that the Project be procured according to this structure then the PPP Unit must be notified. The Municipal Desk at the unit will assist CCT in complying with the appropriate regulations. If the process followed is not compliant significant risk is introduced to the project because non-compliance may mean that the process will need to be restarted. Such delays can be extremely costly.

12.2.3.2 Treasury Notification

Luel Culwick and Christiaan Bode from Sidala met with Strover Maganedisa from the Municipal Desk at National Treasury's PPP Unit on Thursday 14th July 2011. The meeting involved discussion of the following points:

- Sidala gave a basic description of the project (activities involved, potential generation potential, Capex estimation)
- PPPs in general and a potential PPP structure specifically for the CCT project were conceptualised with Mr Maganedisa's assistance.

The Accounting Officer of CCT should meet with the Municipal Desk to discuss the potential PPP. Prior to the meeting, CCT must provide information to the PPP Unit including:

- Prefeasibility study of the Project
- Authorisation for commencement of Feasibility Study
- Description of CCT's capacity (within or procured by CCT) to adhere to MFMA regulations

After sufficient time for the PPP Unit to understand the information on the PPP, a meeting between the Accounting Officer of CCT and the PPP Unit must take place. Discussion points should include:

- Definition of the hydroelectric generation as either a municipal support activity or commercial use of municipal property should be investigated further.
- The potential risks associated with the potential PPP both from the perspective of power generation and water supply.
- CCT must also disclose budgetary commitments to the project for development of the project and internal costs.
- The potential for support of the project from the PDF if the appointment of a Transactional Advisor is necessary.

The PPP Unit will determine how significant the impact on municipal finances, risks and organised labour resulting from the activity of the IPP are likely to be. Based on this assessment, it may be possible to gain exemption from:

- Procurement of a Transactional Advisor
- Full feasibility (PSC) in favour of a simplified feasibility
- Simplified procurement (combining RFQ and RFP)

It is important that CCT define its needs and assess internal and external options to justify the use of a PPP. This may include:

- Financial limitations such as challenges in raising the required capex

- A desire to focus on core activities such as water supply and in so doing to remove risk resulting from having to divide focus between core and secondary activities such as power generation
- Disqualification on the basis that CCT is a public entity and it will not be possible to acquire an offtake agreement with the Single Buyer (ISMO)

The PPP unit will enter the project on the official database, assign an internal project advisor, and make the following determinations:

- Activity type
- Feasibility study provisions
- Whether the services of a transactional advisor are necessary

The project advisor from the PPP Unit will assist the CCT Accounting Officer to fulfill his/her duties with respect to establishing a Project Team and Project Officer to drive the project from CCT's side, and to budget and apply for funding for a transactional advisor if necessary.

12.2.3.3 Project Team

CCT will need to assemble a team to drive the PPP. This begins with the Project Officer who is responsible for the management of the Project. Key questions:

- Who has the skill set to drive the Project? Is there someone available internally?
- How can the Project Officer get decisions from necessary Departments including Water, ECC, Electricity, other?
- What management level will the Project Officer be on to have the necessary authority to drive the Project?
- How can the Project Officer be contracted such that he/she is tied in at least until the project is in Operation Phase?

The Project Officer will need significant secretarial support in order to meet all requirements.

12.2.3.4 Due Diligence

Before an IPP enters into a PPP agreement with CCT, it will conduct a due diligence. Therefore it is necessary for obstacles to the proposed PPP be identified as early as possible. Regarding the assets to be leased, potential obstacles may include:

- Land claims
- Servitudes
- Long Leases and constraints
- Environmental and heritage status of the land

Because existing municipal assets are to be incorporated into the PPP, the condition and maintenance records must be fully understood. Existing municipal assets present uncertainty, and the IPP will be reluctant to accept performance and availability risk if it does not have access to detailed information on which to base its due diligence.

This will enable the IPP to set out clear schedules for asset replacement and disposal. The IPP will decide for itself on the management of assets to maximise the use of assets. This has particular relevance for the sites with existing hydropower installations.

12.3 PPP and Project Cycles

The PPP cycle is intended to investigate, evaluate, source and manage the execution of a PPP agreement. It consists of the phases below:

Figure 83: PPP Cycle

The project cycle consists of the development, implementation and operation of the hydropower projects. It is separate from the PPP cycle, and consists of the phases below:

Figure 84: Project Cycle

The two processes of course relate to each other, as shown in the figure:
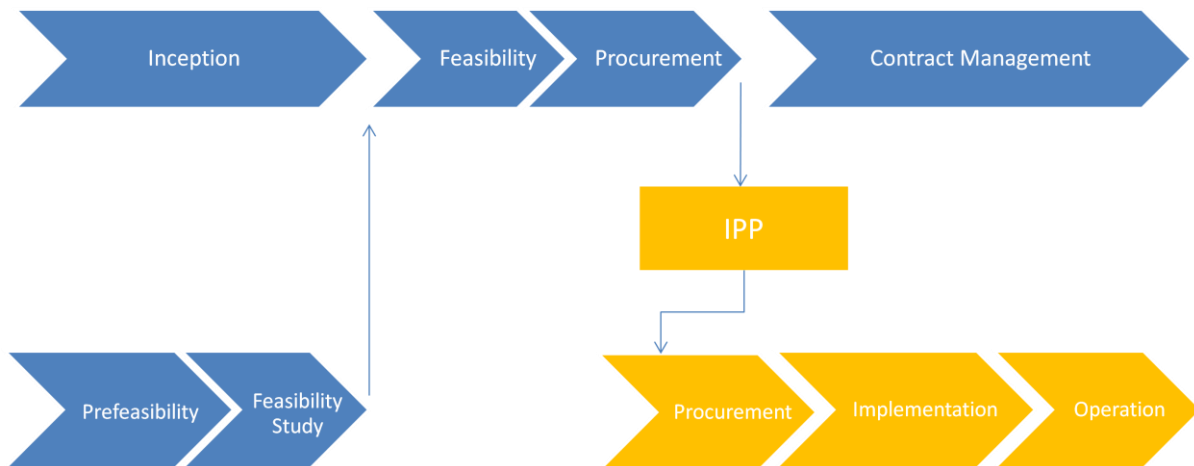
Figure 85: PPP and Project Cycle

The blue areas are driven by CCT, while the yellow areas are driven by the IPP. At present, the PPP process is at inception phase and the project is at the end of the prefeasibility phase. The Project feasibility phase will commence next. Following this work, sufficient information for the PPP feasibility phase to begin will be available. After completion of the PPP feasibility, the PPP procurement will commence, the output of which is a signed PPP agreement between CCT and the selected IPP. The IPP will then assume the project work, procuring, implementing and operating the

project. The CCT role during these Project phases will be to manage the PPP contract to ensure delivery and to optimise the partnership.

12.4 Contracting structure and risk management

Although the IPP will assume significant risk, it will in turn transfer portions of this on to subcontractors. Implementation risk can be transferred away from the IPP through an EPC Wrap or Turnkey agreement. The EPC Contractor will add a premium for assuming the risk, but from the proponent's perspective, the price and delivery date are fixed. An EPC Wrap structure is shown in Figure 86.
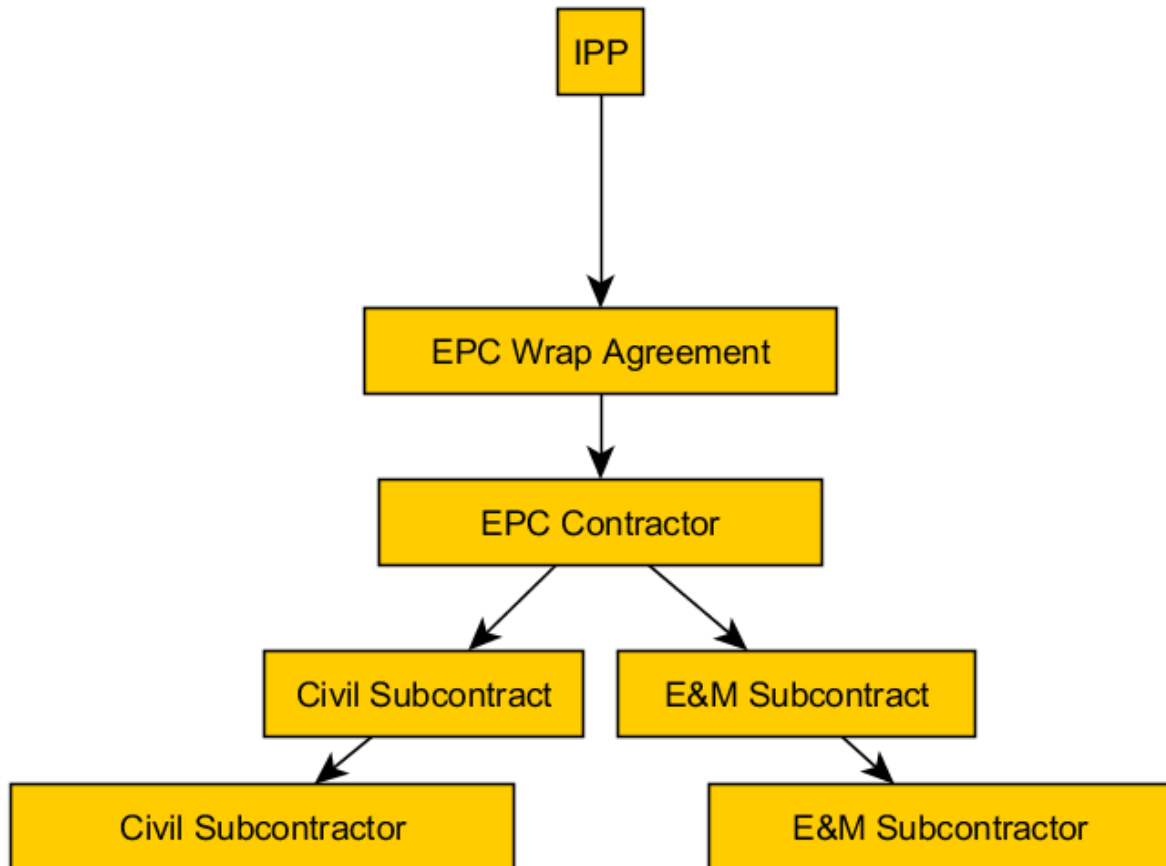
Figure 86: EPC Wrap Structure

CCT can procure the projects internally, but transfer significant risk using the same contracting technique. This is shown in Figure 87:
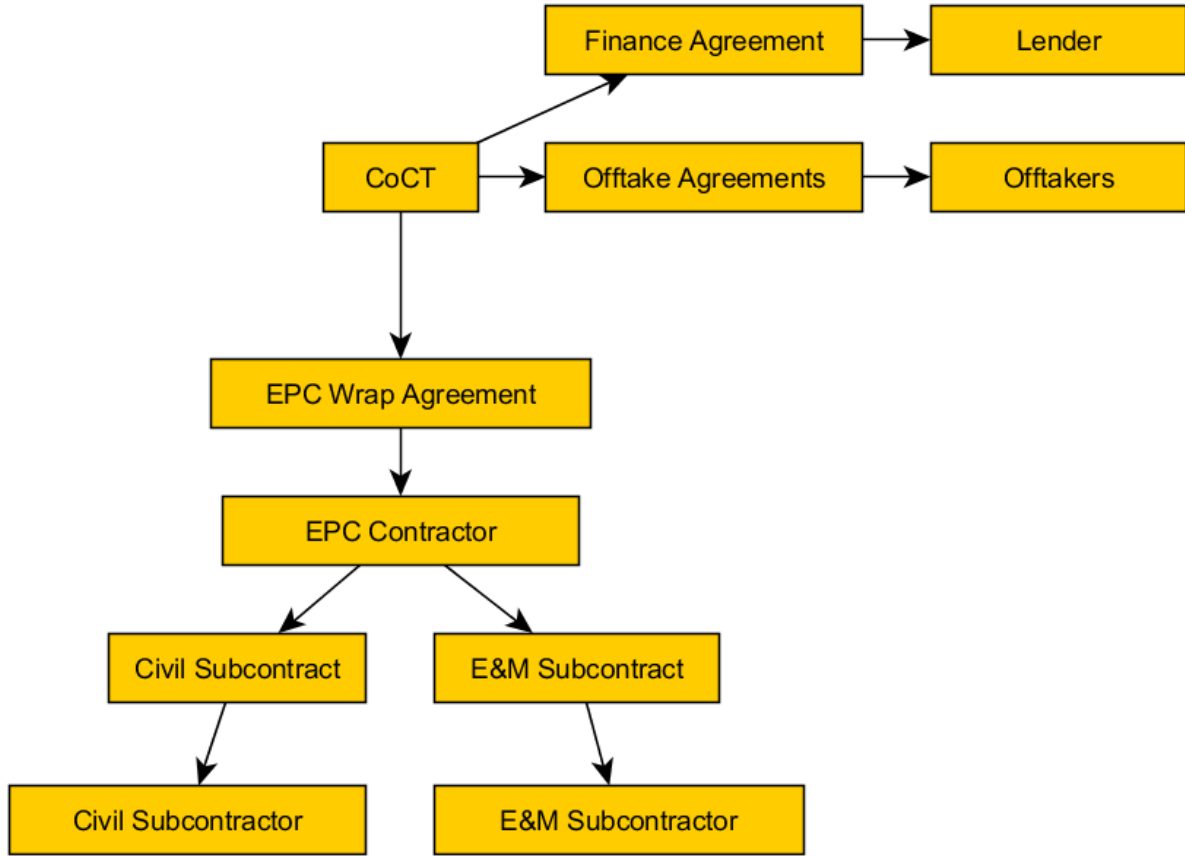
Figure 87: Internal Procurement with EPC Wrap contracting structure

This will result in the risk apportioning shown in Table 85:

Table 85: Risk Allocation

Risk	CCT	Other
Resource	y	
Capex	Y	
Opex	Y	
Energy Offtake	Y	
CER Offtake	Y	
Implementation		EPC Contractor
Operational	Negotiable	
Production		EPC Contractor
Grid Connection	Shared with Grid Operator	
Compliance	Y	
Terminal Project Hazards	Y	

This is contrasted with a traditional contracting structure, shown in Figure 88:
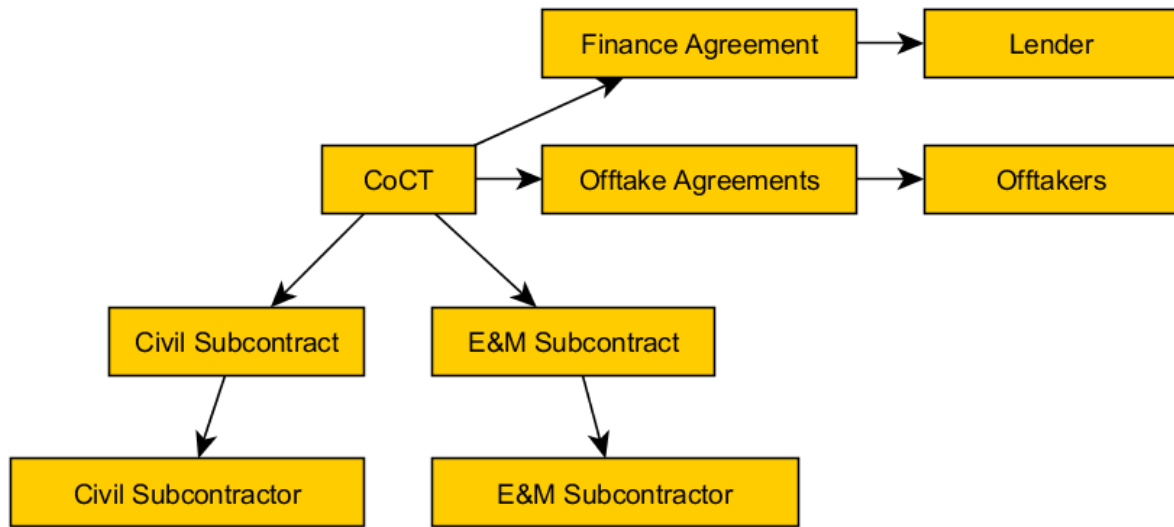
Figure 88: Internal procurement with traditional contracting structure

This results in the risk apportioning shown in Table 86:

Table 86: Risk Allocation

Risk	CCT	Other
Resource	y	
Capex	Y	
Opex	Y	
Energy Offtake	Y	
CER Offtake	Y	
Implementation	Y	
Operational	Y	
Production	Y	
Grid Connection	Shared with Grid Operator	
Compliance	Y	
Terminal Project Hazards	Y	

12.5 Conclusions

- The CCT must determine its risk appetite and availability of finance to determine which procurement mechanism to adopt for the Project.
- Consideration of internal and external procurement mechanisms allows CCT to assume or transfer virtually all of the risks associated with power generation. The proposed PPP transfers all but Resource risk with the IPP. In addition, the proposed PPP provides relief from capital shortage to CCT by leveraging Private Sector finance. The PPP will provide long term, guaranteed income and will enable efficient use of CCT Assets.
- On the other end of the scale, using an internal mechanism with a traditional contracting structure, CCT assumes all the risk and capital requirements.
- Internal Procurement using an EPC Wrap contracting structure is a hybrid between the two.

- This analysis indicates that the procurement mechanism and contracting structure allows CCT to select the level of risk assumed. Clear consideration of options will allow the City to ensure that risks assumed are manageable and that the activities taking place in-house are determined to be core. The selected procurement mechanism and contracting structure also can allow the City to develop the projects within available budget.

13 Environmental Authorisation

Basic Assessments and Environmental Impact Assessments must be carried out by an independent Environmental Assessment Practitioner (EAP). The Proponent will need to contract an EAP to develop the environmental applications.

13.1 Legislation

Although the proposed activities are located within infrastructure which is already disturbed, a small aspect may trigger an EIA by being an associated aspect.

Generally, the construction of hydroelectric plant and associated listed activities may require an application under Regulation 386 and/or 387 of the National Environmental Management Act (NEMA). Schedule R386 defines activities which will trigger the need for a Basic Assessment and R 387 defines activities which trigger a full EIA process. If activities from both schedules are triggered, then a full EIA process will be required.

In terms of R386, the following activities are potentially associated with the proposed project:

Item 1(a): The construction of facilities or infrastructure, including associated structures or infrastructure, for the generation of electricity where the electricity output is more than 10 megawatts but less than 20 megawatts.

Item 1(k): The construction of facilities or infrastructure, including associated structures or infrastructure, for the bulk transportation of sewage and water, including storm water, in pipelines with -

(i) an internal diameter of 0,36 metres or more; or

(ii) a peak throughput of 120 litres per second or more.

More specifically, if any of the activities listed below are triggered – the project will require a Basic Assessment process to be done, and no construction may commence before the Environmental Authorisation has been received.

On sites requiring excavation, it may trigger **Activity 29** of the act:

The expansion of facilities for the generation of electricity where:

- *The electricity output will be increased by 10 megawatts or more, excluding where such expansion takes place on the original development footprint, or*
- *Regardless the increased output of the facility, the development footprint will be expanded by 1 hectare or more.*

Specifically with respect to the mountainous Steenbras sites where it may be necessary to remove the old underground pipes and make adjustments to them, **Activity 29** may be triggered, but also potentially **Activity 37**:

The expansion of facilities or infrastructure for the bulk transportation of water, sewage or storm water where:

- *The facility or infrastructure is expanded by more than 1000meteres in length, or*
- *Where the throughput capacity of the facility or infrastructure will be increased by 10% or more.*

Excluding where such expansion:

- *Relates to transportation of water, sewage or storm water within a road reserve, or*
- *Where such expansion will occur within urban areas but further than 32 metres from a watercourse, measured from the edge of the watercourse.*

Regarding Grid connection, the following Activities may be triggered:

Activity 10

The construction of facilities or infrastructure for the transmission and distribution of electricity –

- *Outside urban areas or industrial complexes with a capacity of more than 33 but less than 275 kilovolts, or*
- *Inside urban areas or industrial complexes with a capacity of 275 kilovolts or more.*

Therefore the power line may trigger this activity if it falls into these thresholds. Another activity that may be triggered is **Activity 39:**

The expansion of facilities for the transmission and distribution of electricity where the expanded capacity will exceed 275 kilovolts and the development footprint will increase.

In addition, **Activity 11** may be pertinent:

The construction of:

- *Canals*
- *Channels*
- *Bridges*
- *Dams*
- *Weirs*
- *Bulk storm water outlet structures*
- *Marinas*
- *Jetties >50 square metres in size*
- *Slipways >50 square metres in size*
- *Buildings >50 square metres in size*
- *Infrastructure or structures covering 50 square meters or more*

Where such construction occurs within a watercourse or within 32 metres of a watercourse, measured from the edge of a watercourse, excluding where such construction will occur behind the development setback line.

According to the NEMA a full EIA process is required in terms of the following activities listed in Regulation 387:

1 The construction of facilities or infrastructure, including associated structures or infrastructure, for (a) the generation of electricity where (ii) the elements of the facility cover a combined area in excess of 1 hectare.

This activity is not present on any site considered here and it therefore appears highly unlikely that a full EIA will be required.

Table 87 contains an analysis of the potential requirement for a BA:

Table 87: Activities which trigger BA

	Activity 29	Activity 37	Activity 10	Activity 39	Activity 11
SB Lower Dam to SBWTW 2	no	no	no	possible	possible
SBWTW to 760	possible	no	no	possible	possible
SBWTW to 810, 840	possible	no	possible	possible	possible
BH Raw Water	no	no	no	no	no
BHWTW to Upper	no	no	no	no	no
BHUpper to Lower 1	no	no	possible	no	no
Wemmershoek	no	no	no	no	possible
Faure 1	no	no	no	possible	possible

The above analysis indicates that no activities triggering a BA are definitely present. It is possible that one or more triggering activities may occur, although this is considered unlikely. It is therefore possible that no environmental authorisations will be necessary for the development of all the sites under consideration. The above is, however, a preliminary assessment of potential activities against specific listed activities which may trigger the need for environmental authorisation. The assessment could change once more detailed information become available. Following the completion of the technical feasibility design, a general assessment of activities and potential triggers of environmental authorisations by an EAP is recommended. This is budgeted for in the feasibility study.

In addition, the proximity of the Steenbras sites with Gordon's Bay is a concern because it is a particularly sensitive area. Therefore Basic Assessments with respect to the Steenbras sites are provisionally budgeted for in the feasibility study.

13.2 Specialist Studies

The need for Specialist Studies is very limited because the activities will occur within already disturbed locations, removing the need for Heritage and Visual Impact Studies. Because the activities occur within man-made conduits, this removes the need for Aquatic and Terrestrial Ecological Studies.

Necessary studies may include:

- Socio-economical Study

- Geotechnical Study

At Inception, the required Specialist Studies should be identified and finalised.

EAPs usually quote upfront for Specialist Studies. It is better if these costs are kept out of the initial proposal, and Specialist Study costs added on separately with full transparency.

14 Clean Development Mechanism

14.1 Context

The Kyoto protocol placed requirements on annex 1 (developed) countries to reduce emissions of Green House Gasses (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. It has been operational since 2006 and had registered more than 1000 projects equivalent to more than 2,7 billion tonnes of CO_2 reduction.

Certified Emission Reductions (CERs) or 'carbon credits' 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 (i.e. sold at any point prior 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.

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."

The Project will sell electricity into the national grid; displacing grid electricity; which is primarily coal-based. Hence carbon emissions are reduced as a result of the operation of the Project. It is possible to quantify and securitize the emissions reductions which can then be traded as Certified Emissions Reductions (CERs) under the CDM.

14.2 CDM Project Cycle

The sequence of activity for developing and implementing a CDM project is shown in Table 88

Table 88: CDM Project Cycle

Project Development Phase	
	Project Idea Note
	Project Design Document
	Validation
	Registration

Project Implementation Phase	
	Monitoring
	Verification
	Certification
	Issuance of CERs

Each stage of the process is described below.

14.2.1 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.

14.2.2 Project Design Document

Development of a Project Design Document (PDD) includes a baseline estimate and an analysis of the net carbon emissions reductions against this business as usual scenario. In the case of hydro generation plant in South Africa, the baseline is a predominantly coal-fired electricity generation system. The proposed project will produce annual emissions reductions approximately equal to the amount of CO_2 emitted through the coal-fired production of the same quantity of electricity as the project produces annually.

14.2.3 Host country approval

This is carried out by the Designated National Authority. 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. To receive host country approval, sustainable development must be demonstrated. There are three main criteria 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?

14.2.4 Validation

Third-party validation of the Project Design Document This step is carried out by a Designated Operational Entity.

14.2.5 Registration

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

14.2.6 Monitoring

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

14.2.7 Third-party verification of project performance

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

14.2.8 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.

14.3 Structure

The scale of the individual sites considered in the Project means that it is not viable to develop a single CDM project for each site. Hence it is necessary to develop the CDM potential through within a Program of Activities, or some other structure bundles of the sites to share the costs of CDM component development. A Carbon Consultant must advise on this.

14.4 PIN

It is not possible at this stage to compile a PIN. The Project and CDM component structure must be decided before this is possible.

14.5 CER Production and Income

Sidala are confident that the CCT mini hydro projects would qualify as a project, or programme of activities under CDM, however, for the purposes of this study, *the income derived selling the carbon credits has not been applied to the individual sites and neither as a group or a programme.* The costs associated with CDM feasibility and registration have been included in the project development costs. This is in line with the conservative approach taken in the development cost estimation. Results of potential CERs and income are given in the Results section.

These projects would need a carbon consultant familiar with the processes to apply on behalf of the project. Proponents and stakeholders in the project need to be finalised and the structure of the project would have to be clear before registering the PIN and moving forward with the CDM aspects of the project. The assumptions used in the financial modelling of the CDM component are given in Appendix B.

The total estimated kWh for the sites listed in Table 2 is **35 100 549kWh/annum.**

According to the assumptions used in Appendix B, the CDM results shown in Table 89 are applicable. These results have not been included in the financial modelling. The results are extremely positive and it is therefore strongly recommended that the CDM aspect of the project be fully investigated.

Table 89: CER Results

Total Energy	kWh/annum	35 100 549
Total CERs	#/annum	33 633
Total CER Revenue	ZAR	70 337 219
Total CER Costs	ZAR	7 569 182
Total CER Net Income	ZAR	62 768 038

15 Local Socio - Economic Benefits

15.1 Job Creation

15.1.1 Temporary Jobs

Temporary jobs will be created during the Development and Implementation phases. Although, technical, environmental, carbon and legal work is created in the Development Phase, the Implementation Phase creates the vast majority of temporary jobs.

The following are certain aspects of the Implementation Phase that would require staffing.

- Technical. Local Engineering consultancies do not typically have significant experience in Small Hydro. This is a result of the fact that the small hydro potential in South Africa is limited and the industry is still in its infancy. However, this has begun to change as local consultancies have partnered with international consultancies in order to access the required expertise.
- Construction. This contract presents the largest opportunity for local content in the Implementation phase. There are a multitude of civil construction firms which are capable of delivering the civil works. It is possible to procure Civil Contractors with Level 3 or even Level 2 BEE scores.
- Electromechanical. The suppliers of Small Hydro Turbines and ancillary equipment are not found in South Africa as a rule. Therefore foreign content is necessary for this contract.

Figure 89 shows the benefits derived from the Sol Plaatje site of Bethlehem Hydro, the most recent private Hydro development in South Africa. The size of the plant was a 4MW plant that involved heavy civil works.

Figure 89: Bethlehem Hydro socio-economic benefits

To estimate how many temporary jobs will be created in the CCT development depends on which sites are feasible and the works involved.

Assuming 6.4MW are built in the CCT infrastructure, the jobs created could potentially be 96 employees (assuming 15 jobs/MW). Because these sites could all be built simultaneously, economies of scale cannot be assumed.

In hydropower projects, the biggest job creation element is found in the procurement of the Civil Contractor, due to civil construction and earthworks. Because the majority of the sites in this study do not require significant civil works, this number is most likely to be lower.

15.1.2 Permanent Jobs

Permanent jobs during the Operation Phase for the direct O&M will depend on the structuring of the project, if this project is to be owned through a PPP structure then the IPP will most likely appoint permanent staff to run the plant but it the plant is owned by the CCT, the personnel appointed to run the current turbines would most likely be used to continue operations on the new plants.

15.2 PPP projects

PPP projects must be seen, and tangibly experienced, as directly beneficial to the people in whose neighbourhoods they operate. Every PPP must therefore be designed, and proactively seek, to produce a positive local socio-economic impact in any way that is appropriate to the project and its location. This must be done taking cognisance of relevant Integrated Development Plans. The targets that may be set in this element need not be limited only to Black People or Black Enterprises, but in targeting local communities must directly benefit the poor and the marginalised, and must effect local socio-economic upliftment. This final set of PPP BEE elements must be:

- determined by the Institution on a project-by-project basis during the Feasibility Study phase;
- communicated with bidders during procurement;
- proposed by bidders in their plans, with costs reflected in their financial models;
- negotiated with the preferred bidder;
- and committed in the PPP Agreement.

Such elements may be itemised individually or, on larger projects, incorporated under a requirement that the Private Party devise and implement an innovative and effective social responsibility programme as part of its operations.

15.3 Community Trust

Further local benefits can be created by the project through the creation of a Community Trust. This trust will own 100% of the shares in an SPV which will own a share of the Project Company. This share can be any portion but is not likely to be a majority, and is usually between 5% and 25% of the Project Company. A community SPV is financed by local DFIs such as IDC or DBSA. The proceeds over and above the financing costs then pass through to the SPV.

A Needs Analysis is conducted by a community intervention consultant to assess the specific challenges faced by the community. Trustees are selected to determine who/what the Beneficiaries of the Community Trust will be. Potential areas to be targeted include, but are not limited to:

- involvement of, and direct benefits to, non-governmental organisations, religious institutions, civics, clinics, child-care centres, and the like

- employment preference for youth in a targeted geographic area
- employment targets for disabled people
- employment preferences for women
- preference for contracting with SMMEs as suppliers of materials and/or services in a targeted geographic area
- initiatives that will support HIV and Aids education
- other local socio-economic impacts appropriate to the project and its location

The establishment of a Community Trust is a powerful way to create local and targeted broad-based socio-economic benefits.

Appendix A Turbine Spec Sheets

Refurbishment, Operation and Maintenance Manual	The City of Cape Town Steenbras Water Treatment Plant	GILKES

SITE INFORMATION

- Project: Steenbras Water Treatment Plant
- Location: The City of Cape Town, Republic of South Africa
- Customer: The City of Cape Town Bulk Water Department

TURBINE COMPONENT DATA

Turbine

- Manufacturer: Gilbert Gilkes & Gordon Ltd.
- Serial No: 4549 and 4550
- Size and type: 2 × 21" Turgo Impulse, Single Jet arranged in tandem
- Speed:
  - Normal: 428 rpm
  - Runaway: 775 rpm
- Net head: 34.44 m
- Flow rate at full load: 0.66 m³/s
- Turbine power output: 179 kW
- Bearings: 3 × Michell Horizontal Journal Bearing, 5" 1 × Michell Horizontal Thrust and Journal Bearing, 5"
- Weight of Runner: 285 kg (627 lb)

Document No: OM805554, Revision: 2   Section 6, Page 2

Figure 90: Steenbras Turbine Spec Sheet

SECTION 7: DATA

7.1   SITE INFORMATION

Project	:	FAURE HYDRO PROJECT
Location	:	FAURE – CITY OF CAPETOWN, R.S.A.
Customer	:	BIWATER (PROPRIETARY) LTD.
Auxiliary Power Supply	:	AC – 380 V, 3 ph, 50 Hz. DC – 24 V.

7.2   TURBINE

Manufacturer	:	GILBERT GILKES & GORDON LTD.
Serial No.	:	56386
Size	:	31 inch
Type	:	High Capacity Turgo Impulse Twin Jet
Normal Speed	:	500 RPM
Runaway Speed	:	1105 RPM
Net Head (Design)	:	130 metres
Flow (Design)	:	1.458 m^3/sec
Turbine Output (Design)	:	1475 kW
Branchpipe Test Pressure	:	360 PSI
Rotation	:	Anti-clockwise viewed from generator
Nozzle Dia.	:	269.7 mm
Deflector Setting	:	236.2 mm

7.3   SPEAR/NEEDLE VALVE ACTUATOR

Manufacturer	:	AUMA
Type	:	SAR 14.1 B22
Gearbox Type	:	GK 25.2 A6
Closing Time	:	442 Seconds (approx.)

Replaced with Rotork actuator (handwritten annotation)

Figure 91: Faure Turbine Spec Sheet

Appendix B CDM Assumptions

Table 90: CDM Assumptions

Carbon Credit Revenue			
Assumptions			
Diesel Emissions	kg C02 per litre	2.63000	Source: Guidelines to Defra's GHG conversion factors for company reporting
	t C02 per litre	0.00263	
	kg CO2 per kWh	0.26300	Source: Guidelines to Defra's GHG conversion factors for company reporting
	t C02 per kWh	0.00026	
Total Emission per annum	t C02 per annum	209 000 000	Source: Eskom Abridged Financial Report, 2007
Total Power Generated	kWh	218 120 000 000	
	t C02 per kWh	0.00096	
	kg C02 per kWh	0.95819	
Certified Emissions Reductions			
Sales Price	€/TCO2e	10	2010 Price
	R/TCO2e	97.00	

Exchange Rates	ZAR/€	9.70	
	ZAR/$	6.70	
Validation Costs	€	70 000	A UN accredited auditor will have to validate the project
Verification Costs	€/year	15 000	A UN accredited auditor will have to verify that emission reductions have taken place
Registration costs	US $/CER	$ 0.10	For the first 15,000 CER's issued per year. (Capped at $350,000). To calculate the number of CER's issued you can take the average over the 1st 7 years of operation.
Registration costs	US $/CER	$ .20	For every issued CER over 15,000 per year
Adaption Fund		2%	The EB registry will take 2% of the CER's from the project before they are issued.
Issuance Fee	US $/CER	$ 10	For the first 15,000 CER's issued per year. (This does not get charged for the 1st issuance)
Issuance Fee	US $/CER	$ .20	For every issued CER over 15,000 per year
		7	year cycle

Appendix C PPPs in South Africa

The PPP Unit has produced a number of useful publications on PPPs, most particularly the PPP Manual and the Municipal Service Delivery and PPP Guidelines which are used extensively in this report.

Legal Grounding for PPPs

PPPs are structures which provide integration between Public and Private sectors for a collective good. The public receives higher quality, more cost-effective services from their governing institution while the private party receives a business opportunity. A PPP is the mechanism which is intended to release these benefits.

The characteristics of the PPP regulations are founded in the constitution. "When an organ of state ... contracts for goods or services, it must do so in accordance with a system which is fair, equitable, transparent, competitive and cost-effective." The identity of the public institution determines the legal framework which governs the PPP Development and Implementation. The central legislation governing PPPs for national and provincial government is Treasury Regulation 16 issued to the Public Finance Management Act, 1999 (PFMA). PPPs for municipal government are governed by the Municipal Systems Act, 2000, and the Municipal Finance Management Act, 2003 (MFMA). Municipalities are not subject to the PFMA or to Treasury Regulation 16. (PPP Manual, 2003)

National Treasury has issued various manuals and toolkits to assist public institutions and private parties in developing and establishing PPP agreements in accordance with the appropriate regulations. CCT is identified as a municipal institution and hence the MFMA and MSA form the legal basis for any PPP into which the municipality may choose to enter. The Municipal Service Delivery and PPP Guidelines is a useful document developed by National Treasury to assist CCT in Developing the hydropower potential as a PPP. Numerous elements in this study were taken from this and other National Treasury publications.

PPP Definition

A PPP is legally defined as:

- A contract between government institution and private party
- Private party performs an institutional function and/or uses state property in terms of output specifications
- Substantial project risk (financial, technical, operational) transferred to the private party
- Private party benefits through: unitary payments from government budget and/or user fees

Two types of PPPs are specifically defined:

1. Where the private party performs a municipal function
2. Where the private party acquires the use of municipal property for its own commercial purposes

Further to this, a PPP is a commercial transaction between a municipality and a private party in terms of which the private party:

a) Performs a municipal function for or on behalf of a municipality, or acquires the management or use of municipal property for its own commercial purpose; or both performs a municipal function for or on behalf of a municipality and acquires the management or use of municipal property for its own commercial purposes.

b) Assumes substantial financial, technical and operational risks in connection with:
   i) The performance of the municipal function
   ii) The management or use of the municipal property; or
   iii) Both

c) Receives a benefit from performing the municipal function, or from using the municipal property or both, by:
   i) Consideration to be paid or given by the municipality or a municipal entity under the sole or shared control of the municipality
   ii) Charges or fees to be collected by the private party from users or customers of a service provided to them
   iii) A combination of the benefits referred to in subparagraphs (i) and (ii).

The way that a PPP is defined in the regulations makes it clear that:

- a PPP is not a simple outsourcing of functions where substantial financial, technical and operational risk is retained by the institution
- a PPP is not a donation by a private party for a public good
- a PPP is not the privatisation or divesture of state assets and/or liabilities
- a PPP is not the 'commercialisation' of a public function by the creation of a stateowned enterprise
- a PPP does not constitute borrowing by the state.

Therefore, a PPP sits somewhere between simple outsourcing and full privatisation in terms of the degree of risk transferred to the private party. In outsourcing, capitalisation remains with the institution, purchases goods or services but retains the risk of service delivery itself. In privatisation, state assets and liabilities are sold, leaving only the regulatory function to government. In between these two models, a PPP allows financial, technical and operational risk to be transferred to the private party which has responsibility for outputs but retains ownership of fixed assets.

The typical structure of a PPP is shown below:
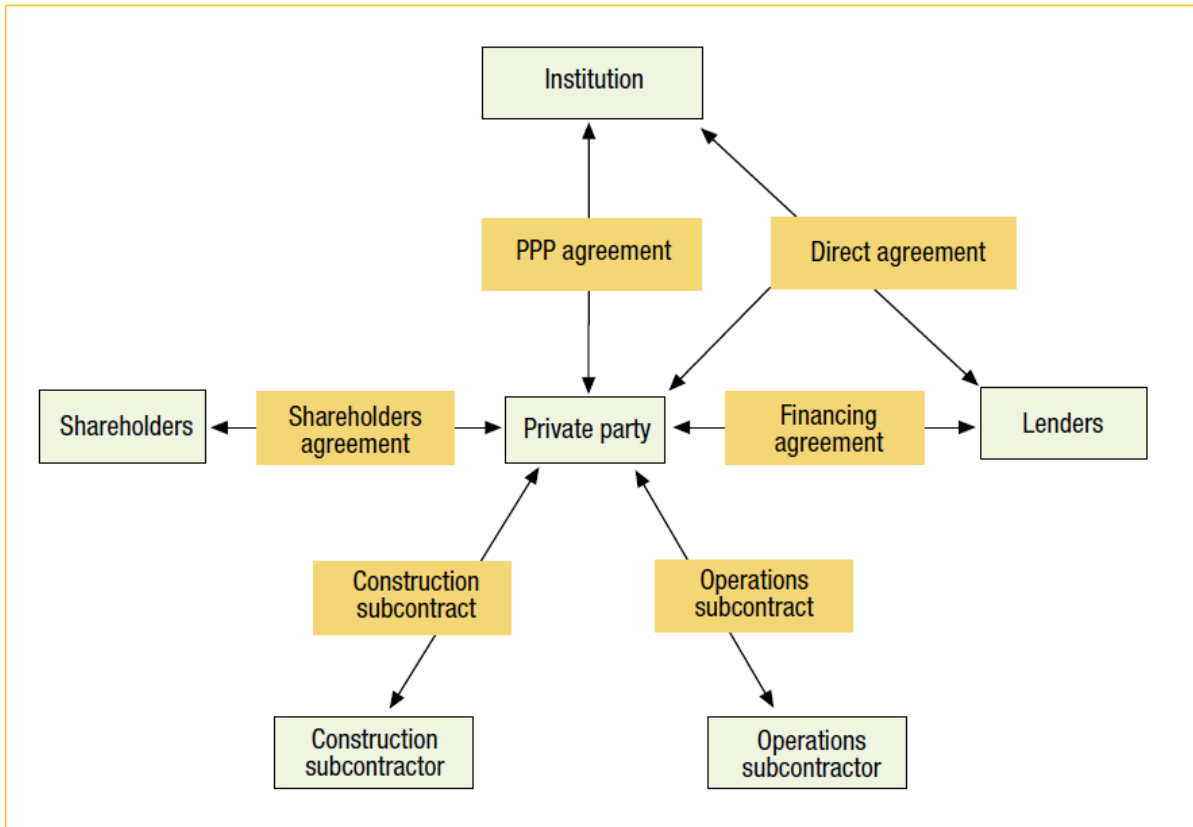
Whatever the PPP type, structure, payment mechanism, or sources of funding, all South African PPPs governed by Treasury Regulation 16 are subjected to three strict tests:

4. Can the institution afford the deal?
5. Is it a value-for-money solution?
6. Is substantial technical, operational and financial risk transferred to the private party?

Exemption from Regulations

PPP Exemption

The application must demonstrate the institution's capacity to manage the PPP through the phases and to the standards set by Treasury Regulation 16 without the oversight and approvals of the relevant treasury.

The following must be addressed:

1. Give a short description of the project.
2. What institutional function and/or use of state property is envisaged?
3. What is the envisaged extent of public funding and/or revenue from users?
4. What is the proposed extent of private sector capital/skill/infrastructure?
5. What risks are to be transferred to a private party?
6. What is the anticipated duration of the PPP agreement?
7. How does the institution propose to determine affordability, value for money and appropriate risk allocation for the project?

8. Give a short history of similar projects undertaken by the institution.

9. Outline the policy and actual procedures followed to date by the institution in three similar projects, specifically in relation to approving project feasibility studies, compiling and approving bid documents, managing the competitive bidding process, evaluating bids, determining value for money, establishing contract management systems and negotiating and managing contracts.

10. Outline the institution's management system for the project, attaching relevant resumés of key personnel.

11. Submit the curriculum vitae of the appointed project officer, together with his or her job description.

Institutional Exemption

National Treasury views the past experience of the institution in successfully planning for, procuring and implementing PPP projects as the key factor in granting an institutional exemption. The application must therefore demonstrate the capacity of the institution established for procuring and managing all its possible PPPs through the phases and to the standards set in Treasury Regulation 16 without the oversight and approvals of the relevant treasury. The exemption may be granted for a specific period, and re-applied for after that. The application must state the extent to which such institutional capacity relies on the experience of specific individuals.

The following must be addressed:

1. Give a short description of the institution.
2. Motivate the period of time for which an exemption is sought.
3. What institutional function and/or use of state property is envisaged for PPPs?
4. What is the extent of public funding and/or revenues from users, for projects envisaged?
5. What is the extent of private sector capital/skill/infrastructure envisaged?
6. What risks are likely to be transferred to the private sector?
7. Provide a summary of the PPP projects undertaken by the institution to date.
8. Outline the institution's policy for determining project affordability, value for money and appropriate risk allocation.
9. Outline the actual procedures established in the institution for approving project feasibility studies, approving bid documents, managing the competitive bidding process, evaluating bids, determining value for money, establishing contract management systems, and negotiating and managing PPP agreements.
10. Outline the institution's capacity to manage and administer PPPs, attaching relevant resumés of key personnel.
11. Submit the curriculum vitae of people who will be assigned as project officers for the institution's envisaged PPP projects, together with their job descriptions.

PPP Finance

The Municipal Public-Private Partnership Regulations are not prescriptive about the financing structure of a PPP. It is assumed that these will vary widely from project to project and sector to

sector, and will be closely linked to the funding sources that can be secured for each deal. However, in most PPPs the private party raises both debt and equity to capitalise the project. This is called "project financing". In smaller municipal PPPs, the private sector often obtains any required funding on the strength of its balance sheet, which is called "corporate financing."

BEE in PPPs

PPPs are specific targets for the development of BEE practice and the regulations are designed accordingly. "Code of Good Practice for BEE in Public Private Partnerships" is National Treasury's official framework for black economic empowerment in PPPs.

The stated Policy Objectives of the regulations are to:

- to achieve meaningful and beneficial direct ownership of substantial equity interests in the Private Party to a PPP Agreement by Black People, Black Women and Black Enterprises;
- to achieve effective participation in the management control of the Private Party and its subcontractors by Black People and Black Women;
- to ensure that a substantive proportion of the Private Party's subcontracting and procurement is to Black People, Black Women and Black Enterprises;
- to ensure effective employment equity and skills development in the Private Party and its Subcontractors throughout the PPP project;
- to promote positive local socio-economic impact from the project to the benefit of SMMEs, the disabled, the youth, and non-government organisations within a targeted area of project operations;
- to create jobs; and
- for Institutions to be supported in all PPP projects by financial, legal and technical Transaction Advisors who generally reflect South Africa's diverse population, and to build the professional skills and number of Black People and Black Enterprises in these fields.

The diagram below shows the different BEE elements targeted by the regulations in a typical PPP structure. It is important that all these elements are incorporated into a prospective PPP.
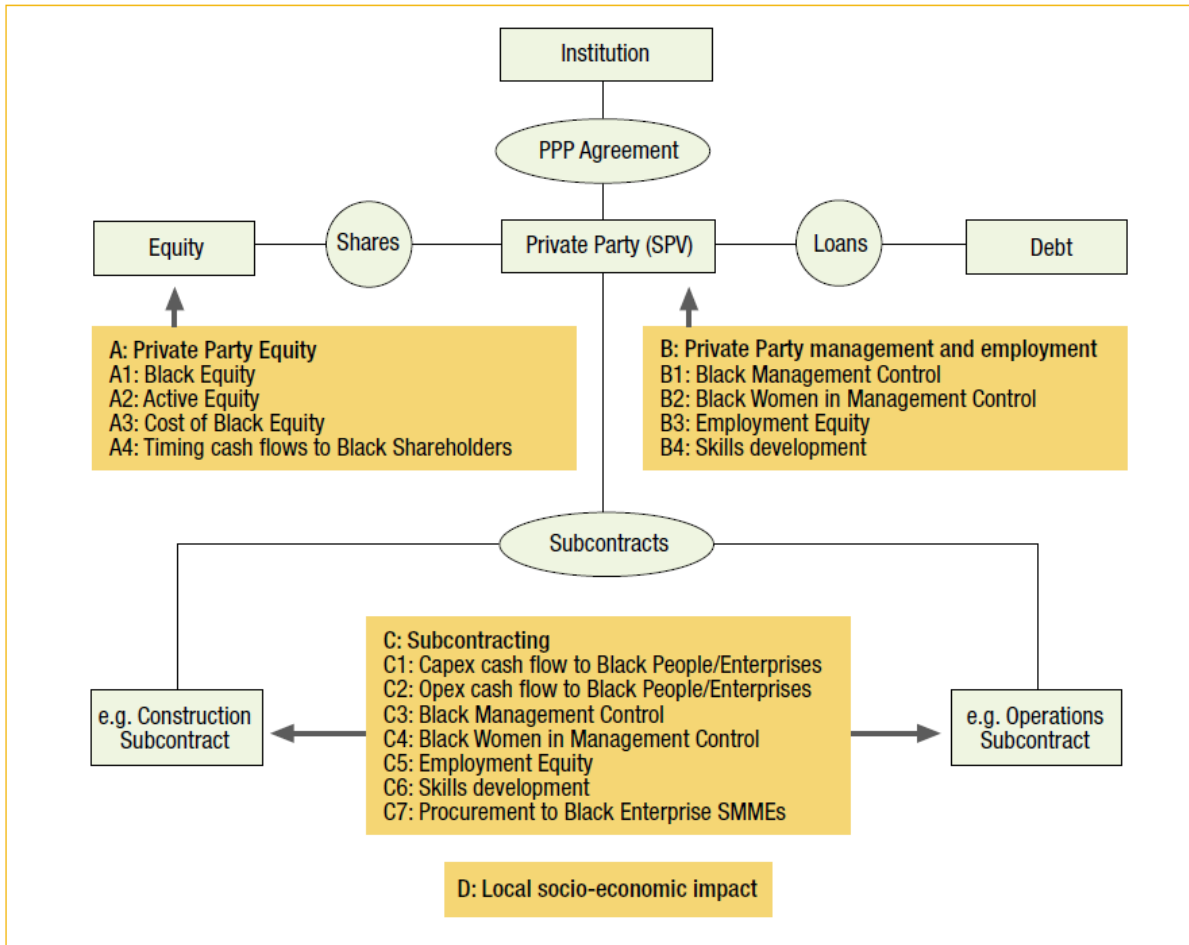
The table below summarizes the requirements and expectations which the relevant treasury will have with respect to BEE in a PPP.

Code	Criteria	Indicative Requirement/Comment
A	**Private Party Equity**	
A1	Black Equity	40%
A2	Active Equity	55% of A1
A3	Cost of Black Equity	Evaluated in Feasibility Study, total cost of equity to be minimized, cost of BEE equity shown as a separate component
A4	Timing of project cash flows to Black Shareholders	Evaluated in Feasibility Study, and reflected in Shareholder's Agreement, bids should show how their funding structures effectively unlock value for Black Shareholders early and throughout the project

		term
B	**Private Party management and employment**	
B1	Black Management Control in the Private Party	Commensurate with A1 and A2
B2	Black Women in Management Control in the Private Party	15% of B1
B3	Employment Equity in the Private Party	in compliance with the Employment Equity Act, 1998
B4	Skills development in the Private Party	1% in addition to the skills development levy prescribed by the Skills Development Levies Act, 1999
C	**Subcontracting**	
C1	Percentage participation by Black People and/or Black Enterprises in the capital expenditure forecast to be incurred by the Private Party under the Subcontracts	30%
C2	Percentage participation by Black People and/or Black Enterprises in the operating expenditure forecast to be incurred by the Private Party under the Subcontracts	30%
C3	Percentage of Black Management Control in the Subcontractors	25%
C4	Percentage of Black Women in Management Control in the Subcontractors	15% of C3
C5	Employment equity plans of the Subcontractor	Compliance with law
C6	Percentage of Subcontractors' payrolls to be spent on skills development per annum	1%
C7	Percentage of procurement budget committed by the Subcontractors to Black Enterprise SMMEs	30%
D	**Local socio-economic impact**	Determined by the Institution on a project-by-project basis during the

		Feasibility Study phase

BEE is enforced in procurement processes according to the following weightings:

- Transaction Advisor Procurement (10% weighting, minimum 60% on balanced scorecard)
- Procurement (10% weighting, minimum 50% on balanced scorecard)

BEE is applied in the PPP Project Cycle according to the following program:

- Treasury Approval I (containing a clear and appropriate set of BEE elements, targets, minimum thresholds, and weightings, duly approved as part of the Feasibility Study)
- Treasury Approval IIA (the quality of the BEE component of the preferred bid forms part of the value-for-money report to be submitted by the Institution, prior to negotiations)
- Treasury Approval IIB (Negotiations that follow must seek to maximise BEE benefits in the final terms of the deal, and to tie up provisions for managing the PPP Agreement post signature)
- Treasury Approval III (PPP Agreement binds the parties to their BEE commitments for the duration of the PPP, stipulating the consequences of default)

The PPP Process

The PPP process differs slightly between National and Provincial government institutions and Municipal institutions. The process discussed here is for Municipal institutions according to the Municipal Service Delivery and PPP Guidelines. The process is described briefly with the intention of giving an indication of what the development of a PPP will entail. It is recommended that the Guidelines are consulted in the event that the CCT would like to actively pursue a PPP or a potential PPP.

Inception Phase

The starting point in any Municipal PPP is determining the nature of the activity to be conducted by the private party according to legislation. It may be a "municipal service", a "municipal support activity"; or "private-sector use of municipal property for commercial purposes". If it is a municipal service, then the MSA and MFMA apply; if it is a municipal support activity or private sector use of municipal property for commercial purposes, then only the Municipal Finance Management Act (MFMA) applies.

A municipal service is any service that a municipality provides or may provide to or for the benefit of a community. The following services are listed in the guidelines as municipal services and require a feasibility study under the MSA:

- Ambulance services
- Beaches and amusement facilities
- Cemeteries
- Child care facilities

- Cleansing
- Electricity and gas reticulation
- Housing
- Local sports facilities
- Local tourism
- Markets
- Municipal abattoirs
- Municipal airports
- Municipal health services
- Municipal parks and recreation
- Municipal public transport
- Municipal public works
- Municipal roads
- Nature conservation
- Pollution control
- Pontoons, ferries, jetties, piers and harbours
- Public transport
- Refuse removal, refuse dumps and solid waste disposal
- Storm water management systems in built-up areas
- Street lighting
- Traffic and parking
- Water and sanitation services

Municipal Support Activities are reasonably necessary for, or incidental to, the effective performance of a Municipality's functions and the exercise of its powers" that do not constitute a "municipal service". A non-exhaustive list of examples includes:

- Municipal composting activities
- Municipal fleet services
- Municipal ITC services
- Municipal office accommodation
- Industrial water supply and industrial wastewater treatment
- Meter reading, billing, and revenue management.

The third activity considered is the "use of municipal property for its own [the private party's] commercial purposes". This most frequently involves the lease of land to a private party which then develops and manages the land commercially. However, the term property refers generally to "fixed property" which can include a broader range of commercial enterprises.

The MSA defines how a Municipality may provide a service through either an internal or external mechanism review of its delivery mechanisms. A Municipality must first assess the provision of that activity through an internal mechanism, after which it may decide to explore the delivery of that activity by an external mechanism. A PPP is one such external option.

The inception Phase lays the foundation for all following phases in the PPP. The regulations are exacting and potentially cumbersome, but are intended to ensure that the public institution and private party can integrate roles in such a way that the PPP objectives are met which is beneficial for all parties and the nation at large. If projects are determined to be small or low risk, National Treasury can exempt the institution from certain or all regulatory requirements. It is very important that all the procedure is followed correctly or else it will be necessary to repeat the process to satisfy the prescribed process and legal requirements.

Following identification of a potential PPP, National Treasury must be notified. This will include a discussion of the activity and potential team within the institution which is to execute the project. The Municipal representative at National Treasury will make determinations in consultation with the Accounting Officer of the institution, on whom significant responsibility for strategic guidance and compliance sits. The PPP unit will assign an internal project advisor to assist the municipality, who will convey Treasury Views and Recommendations in line with project timelines. A Project Officer and supporting Project Secretariat must be assigned from within the municipality or from external sources. The Project Officer has the responsibility of ensuring the project is delivered on time and on budget, and that compliance with regulations in all phases is achieved. Support and empowerment of the Project Officer is also critical and access to key decision makers is central to this.

Treasury will determine whether a Transactional Advisor must be procured. The role of the Transactional Advisor is to advise the Municipality on achieving informed decisions concerning the effective delivery of the service. The process of procuring a Transactional Advisor is clearly defined in the guidelines, which should be consulted should such services be required. The PPP Unit project advisor will assist in compiling the TOR for the Transactional Advisor. The scorecard for procurement of the Transactional Advisor is prescribed using a two envelope method, giving weighting primarily to technical and price elements (90%), and also to BEE (10%) but with a gatekeeper requirement of 60%.

It is possible to raise funding for the services of a Transactional Advisor. The PDF has been established as a vehicle for municipalities to source funding for a portion of the adviser costs, reducing the impact of service-delivery assessment and procurement costs on municipal budgets. National Treasury's Project Development Facility (PDF) may fund a significant portion of a project's adviser costs for MSA and MFMA feasibility studies, and/or PPP procurement.

Feasibility

A feasibility study is used to decide on the appropriate delivery option for the proposed project. A Public Sector Comparator (PSC) is a model which compares internal and external mechanisms for delivery. "Municipal Services" require the use of a PSC, "Municipal Support Services" may require the use of a PSC while "use of state property" feasibility studies do not require the use of a PSC. All PPPs require a feasibility study for which the process is prescribed in the regulations, although adaptations can be agreed with National Treasury.

The figure below shows the cycle of the feasibility study.

Note:
* For municipal services only
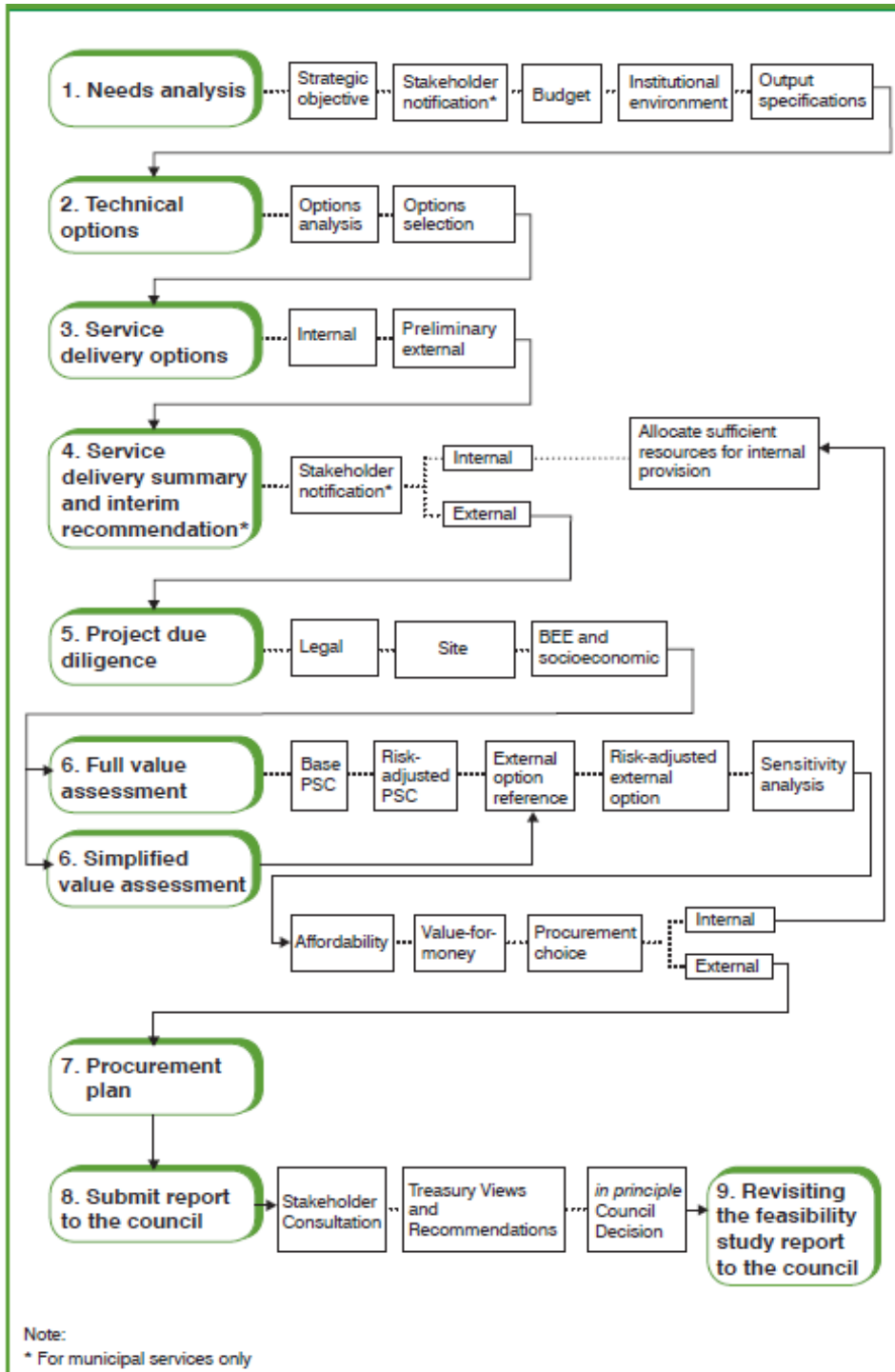
The needs analysis determines whether and to what extent the proposed project is in alignment with the strategic objectives of the municipality as well as broader government policy. Budgetary considerations and potential cost savings and revenues from the project are to be identified and quantified. The Municipality's commitment and capacity to deliver the project needs to be demonstrated including an analysis of both the internal project team and transactional advisor and the combined team's abilities in terms of the project scope. Public participation during the course of the Feasibility Phase is prescribed in the regulations to ensure all stakeholders have input. During the needs analysis each stakeholder's relationship to the project and anticipated impacts must be identified.

In conventional procurement the Municipality employs consultants to prepare specifications describing the infrastructure required to deliver desired outputs. This infrastructure, or input, is then put out to tender leaving the municipality responsible for the design of the project, all statutory requirements, and unforeseen costs. The Private Party, however, is only responsible for items specified within its scope. A key distinction of PPPs as against conventional procurement is that with a PPP risk is transferred to the Private Party through the specification of outputs as opposed to inputs. This leaves room for the Private Party to come up with innovative solutions to deliver the outputs, and requires that the Private Party assume the risk of output delivery.

The Technical Options stage evaluates the various technical options which could meet the required outputs. This is very project specific and the analysis does not include procurement options, of which a PPP may be one. Instead, technical options are appraised in terms of a wide range of criteria including financial, risk, technical, HR capacity and other factors. This appraisal should allow the best technical solution to be selected.

Following the Technical Options stage, the Service Delivery stage focuses on the method of procurement. Internal and External options are identified and evaluated. The table below indicates the elements to be evaluated for different Service Delivery Options.

Option	Advantages	Disadvantages	Risk transfer
A department or administrative unit (internal mechanism)	• If can restructure, then in-house capacity strengthened	• Lack of capacity • Lack of fundraising ability	• No risk transfer
Business unit (internal mechanism)	• Can provide a one-point service • Can align the income and expenditure nature of the trading service • Can allow for a more devolved decision making process	• Could lead to a duplication of certain functions and the reduction of responsibilities of other departments in the municipality • Limited capacity • Lack of fundraising ability	• No risk transfer
Municipal entity (MSP)	• Ring-fenced entity with total responsibility for service delivery	• Limited ability to raise on funding • Possible issues on staff and asset transfer	• Ultimate risk stays with the municipality
Another municipality (MSP)	• Established service delivery organisation	• Lack of capacity, lack of fundraising ability	• Some risks can be transferred. Financial risk cannot
Organ of state – licensed service provider (MSP)	• Technical and managerial skills	• Lack of fundraising ability	• Some risk can be transferred. Financial risk cannot
Organ of state – traditional authority (MSP)	• Local community knowledge	• Lack of fundraising ability	• Little risk transfer
CBO or NGO (PPP)	• Local community knowledge	• Lack of fundraising ability	• Little risk transfer
Other institution, entity or person legally competent (PPP)	• Private sector expertise • Fund raising ability	• Requires robust contract management by the municipality • Politically more difficult	• Significant technical, operational and financial risks can be transferred

Following the evaluation of service delivery options, it is necessary to acquire interim recommendations if the mechanisms under consideration include one or more external options. This entails creating a summary of the feasibility study to date, attaining municipal manager approval and notification of local community and labour.

The due diligence stage aims to uncover any issues in the preferred technical solution and service delivery option that may significantly affect the proposed project. This assessment considers Legal issues, site enablement issues and BEE and other socioeconomic issues. Legal issues are far more easily dealt with in the feasibility phase than during procurement. Potential legal issues are associated with the rights for a Private Party to use public property and ensuring that through the

elected service delivery mechanism, the municipality does not abdicate its constitutional responsibilities. Site enablement includes all tenure and zoning considerations, as well as potential title deed registrations such as land claims. Within a PPP structure, BEE requirements are clearly stated and these must be investigated in depth.

Following the due diligence, a value assessment is conducted which is the analysis which allows the municipality to make a decision between internal and external mechanisms for service delivery. The key criteria are:

- Is it affordable?
- Does it appropriately transfer risk from the municipality to the private party?
- Does it provide value for money?

Key terminology is defined in the figure below:

Value assessment terminology

Value for money means that the provision of a municipal service or function by a private party results in a net benefit to the municipality, defined in terms of cost, price, quality, quantity, or risk transfer, or a combination of these.

Full value assessment involves a value-for-money comparative assessment between a conventional public sector procurement and a PPP delivering the same output specifications. A risk-adjusted PSC model and external reference model must therefore be constructed for the chosen solution option. These provide costings of each procurement option in the form of a discounted cash-flow model adjusted for risk. In addition to costs, qualitative considerations may also be taken into account. This assessment also includes a determination of affordability.

A cost-benefit analysis is essentially the same as a value-for-money analysis whereby benefits are reflected in the output specifications and both quantitative and qualitative considerations are captured in the PSC and external reference models.

A PSC model is a costing of a project with specified outputs with the public sector as the supplier. Costs are based on recent, actual costs of a similar project, or best estimates.

An external reference model is a costing of a project with the identical specified outputs but with the private sector as supplier.

Comparing the two models enables a municipality to assess whether service delivery by government or by a private party yields the best value for the municipality. The three criteria are affordability, risk transfer and value for money.

A simplified value-for-money analysis is determined by assessing whether value-for-money drivers are demonstrated in the external reference model. Qualitative considerations under this analysis often take increased importance as cost differences between options may be difficult to quantify.

Risk

Risk is inherent in every project. Conventional public sector procurement has tended not to take risk into account adequately, often resulting in unbudgeted cost overruns. In a PPP, the private party manages and costs the risks inherent in the project differently. The treatment of risk in the project is a key aspect of the value assessment.

Affordability is whether the cost of the project over the whole project term can be accommodated in the municipality's budget, given its existing commitments.

Value for money is a necessary condition for PPP procurement, but not a sufficient one. Affordability is the driving constraint in PPP projects.

Demonstrating affordability

As a preliminary analysis of affordability, the risk-adjusted PSC model is compared with the municipality's budget. Then the risk-adjusted external reference model is compared with the municipality's budget. If the project is not affordable, the municipality may modify the output specifications or may have to abandon the project.

Either a full value assessment or a simplified value assessment will be undertaken depending on the determination at inception. A simplified value assessment is conducted when an internal mechanism is not a realistic option for the municipality. This is done in terms of value for money drivers including the following for a PPP option:

- Project objectives expressed as measurable outputs
- Incentive for demonstrable innovation by the private party

- Transfer of substantial financial, technical and operational risks to the private party
- Competitive procurement as to which there are a sufficient number of qualified private sector firms that may bid
- Contract design reflecting good PPP contracting practices to provide for efficient monitoring and regulation.

In the case of a PPP involving the use of municipal property for commercial purposes by a private party, value for money is demonstrated through the following drivers:

- Increased direct revenue to the municipality
- Increased socioeconomic activities within the community
- Optimal use of under-performing assets
- Job creation
- BEE

A full value assessment entails the construction of a PSC. This is encapsulated in the schematic shown in the figure below:
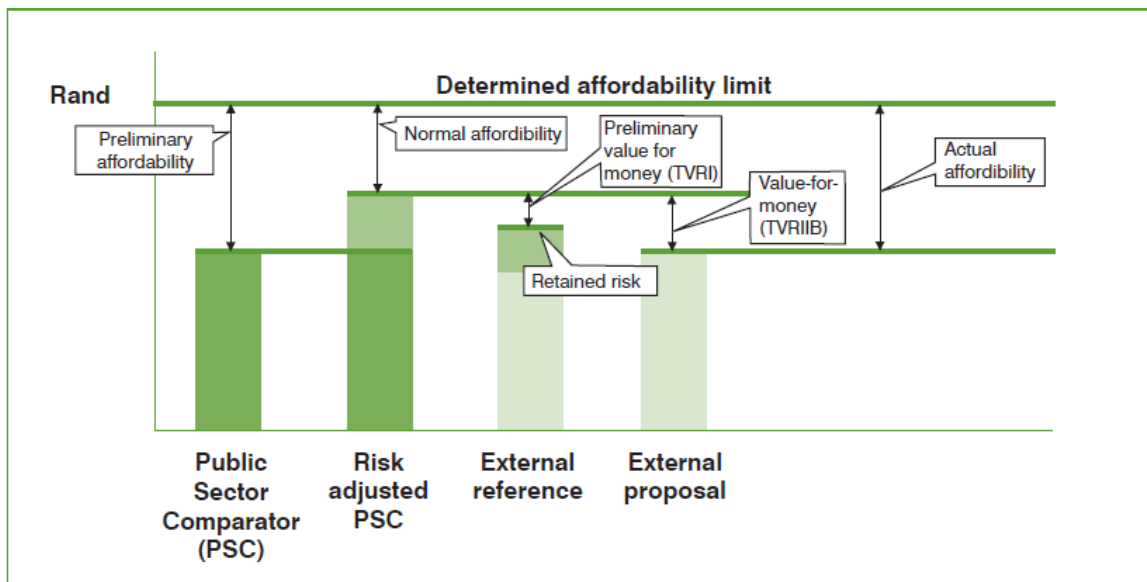
The process and detail of constructing a PSC are elaborated in detail in the Municipal guidelines, enabling a thorough comparison of options. This includes thorough project definition, analysis and quantification of all costs, revenues, assumptions and risk identification and quantification. For the construction of the external reference model, private sector financing must be modelled to quantify the cost of capital. An independent assessment of risk perception from the Private Party's perspective must be conducted. It is expected that greater value can be liberated through the private sector's greater capacity to deal with risks. This may be a corporate finance structure, or a project finance structure shown below:
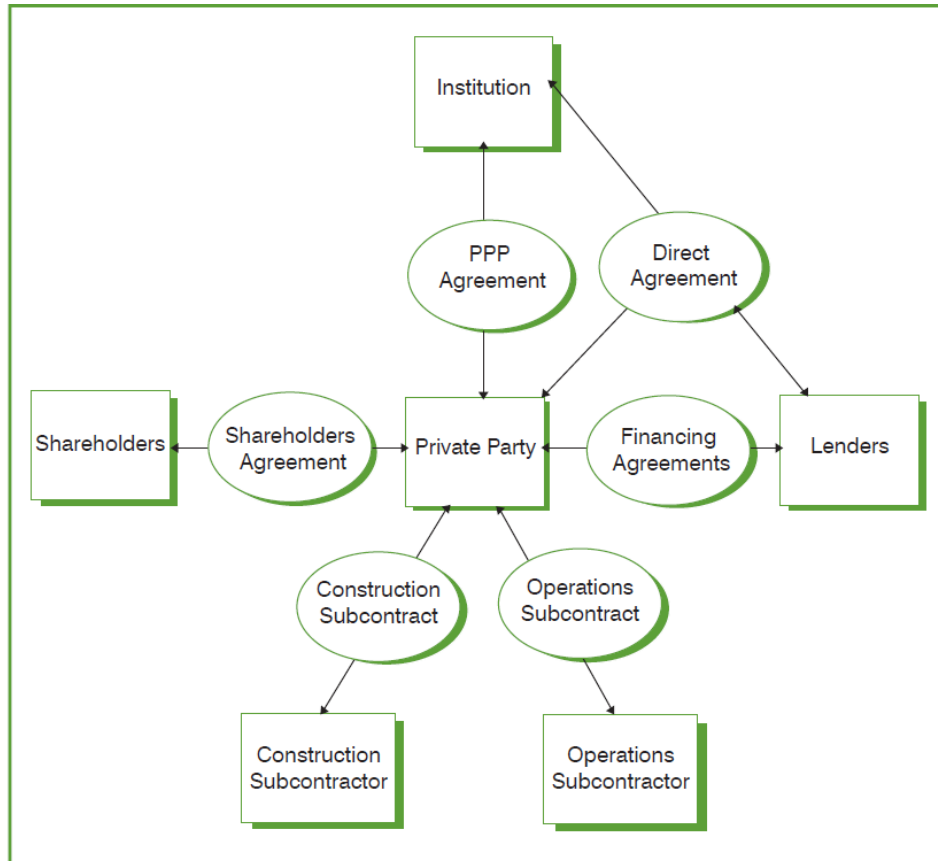
The models must be stress-tested through sensitivity analysis. The value assessment provides a quantitative answer on the expected value for the delivery mechanisms under consideration. However, qualitative elements such as impacts revealed in stakeholder consultation, allowing the municipality to focus on core functions and wider benefits must also be considered. If, on the three key criteria, an external mechanism is preferable, it must be selected and the procurement plan begun. It is highly recommended that the guidelines are consulted at the point when full value assessment detail is required.

The procurement plan demonstrates that the municipality has the necessary capacity and budget to undertake the procurement of the external option. This plan will include:

- A project timetable for the key milestones and all approvals which will be required to take the project from TVR I to TVR III
- Confirmation that sufficient funds in the municipality's budget are available to take the project to TVR III and into contract implementation
- A list of any potential challenges to the project and a discussion on how these will be addressed by the project team and adviser
- The best procurement practice and procedures suited to the project type and structure
- The governance processes to be used by the municipality in its management of the procurement, especially regarding decision-making
- The project stakeholders and the extent of their involvement in the external option
- The project team with assigned functions
- Categories of information to be made available to bidders and how such information will be

developed
- A list of required approvals from within and outside the municipality
- A Gantt chart of the procurement process, including all approvals and work items necessary for obtaining these approvals (for procurement documentation as well as, for example, the land acquisitions and environmental studies to be procured by the municipality)
- Contingency plans for dealing with deviations from the timetable and budgets
- The bid evaluation process and teams
- An appropriate quality assurance process for procurement documentation
- The means of establishing and maintaining an appropriate audit trail for the procurement
- Appropriate security and confidentiality systems, including confidentiality agreements, anti-corruption mechanisms, and conflict of interest forms to be signed by all project team members.

The report must then be compiled with all relevant details and submitted to the municipal council and to the PPP Unit, which will grant TVRI at this point.

Procurement

All PPPs must be procured in accordance with the requirements of the MSA, MFMA and the National Treasury regulations and guidelines. However, the regulations are not prescriptive in terms of procurement processes. It is the responsibility of the accounting officer to design and manage the procurement process in a way that meets the requirements of the regulations. In addition, with appropriate motivation, the PPP unit project adviser will approve a simplified procurement process. Usually, a municipal PPP not requiring the preparation of a PSC should also be a candidate for a simplified procurement process. However, best practices have been established through experience of Municipal PPPs.

It is important that the outcomes of the feasibility study are clearly communicated in all procurement documentation. This includes guiding objectives and outputs expected from the Private Party. It is crucial that the affordability limits determined in the feasibility study are not compromised during the procurement phase.

The typical PPP procurement process with indicative timelines is shown in the figure below:
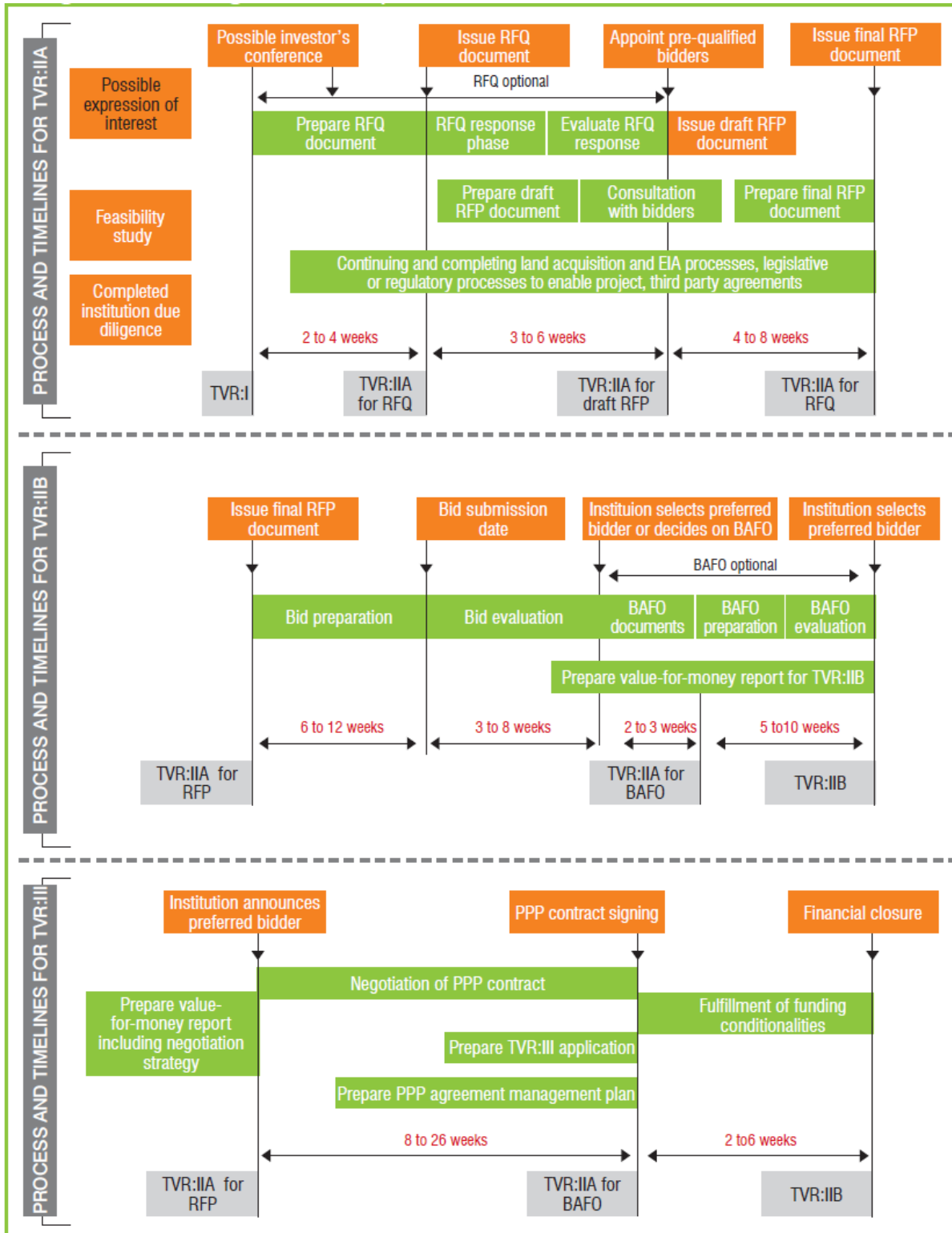
An Expression of Interest can determine the level of interest in the market, and can allow the Municipality to determine at an early stage the likely success of the Procurement. Private parties will be able to provide more useful information if the EoI contains greater information on the project including:

- Project Definition
- Project Objectives

- Value drivers from the municipality's perspective
- Available affordability
- Timelines for future phases and communications
- Information requirements from private parties such as legal status, relevant track record, BEE status.

The EOI should be issued early on, probably during the feasibility phase of a PPP.

The Request For Qualification (RFQ) is a likely but not mandatory stage in procurement. The objectives of an RFQ are to:

- Select a limited number of the bidders that are qualified technically, financially and in terms of BEE.
- Set out the rules of participation in the procurement process clearly
- Give guidance on the expected kinds of participants in bidding consortiums

It allows the RFP to be issued to a sufficient number of bidders to ensure a healthy level of competition whilst ensuring that the number of bidders is not so high that proposals are not of sufficient quality. This number is typically either three or four. In this way commitment and capacity from bidders during the RFP stage can be assured.

If the RFQ is under-subscribed it may be necessary to restructure the project and issue a new RFQ. It is undesirable if there are only one or two pre-qualified bidders following an RFQ. If a satisfactory number of bidders pre-qualify, there is a risk that they will drop out of the procurement before the RFP. This can be mitigated through the use of a bid-bond.

Potential qualification criteria for the RFQ in the case of a PPP are shown in the figure below:

Category and subcategories	Good, adequate or poor
Respondent capability and strength	
• Proposed respondent composition and structure • Skill and experience of relevant organisations and key subcontractors • Construction • Operations • Advisers • Suppliers • Strength of covenant between relevant organisations and key subcontractors and respondent • Financial and market standing • Ability to raise debt and equity and to provide security	
BEE qualifications	
• Written confirmation that each proposed consortium member and first-tier subcontractor, is compliant with the BEE charter applicable to its particular sector or applicable generic code • Where no consortium is to be formed, written confirmation that the bidder is in compliance with its applicable sector BEE charter or generic code	
Deliverability	
• Commitment and capacity to meet project timetable • Project management capability • Current workload of consortium members • Quality assurance systems • Risk management capability	
Project awareness	
• Demonstration of understanding key project demands and complexities	

Before the RFQ document can be distributed, the municipal desk at the National Treasury PPP Unit must be consulted. Distribution method must be according to the Municipality's supply chain management policy. Evaluation of responses must be based on the criteria published in the RFQ document, and the communication to both qualifying and non-qualifying bidders must be clear and sufficiently detailed so as to justify the decision to bidders.

In the Request for Proposal (RFP) stage, it is desirable that all pre-qualified bidders participate. Further value can be yielded if bidders participate in the preparation of the final RFP document, leading to shorter bidding times and increased bidder confidence. The document must be drafted by the municipality with the transaction advisor with assistance from the PPP Unit Project Officer. The draft RFP must be submitted to National Treasury PPP Unit for TVRIIA along with a draft PPP agreement. The document includes a description of the project and its current status including statutory aspects such as EIA; instructions to bidders with procurement timelines; minimum bidder requirements (financial, technical, legal, BEE); specification of outputs; anticipated payment mechanisms (with underperformance penalties); draft PPP agreement; commitments required from

bidders (project structure, financial including financial models, legal, technical, BEE); evaluation criteria and scoring formula (it is important that these elements are set because they cannot be changed at the evaluation and adjudication stages).

Following the bid preparation period, the bids received must be evaluated in a transparent and structured manner, helped through management of the bid by experienced officials.

There are three levels of evaluation:

- Technical evaluation teams (TETs), evaluate technical, price, and BEE elements
- The bid evaluation committee (EC), evaluate the overall integrated solution
- The bid adjudication committee (AC), scores the bids, selects the preferred bidder or implements a best and final offer (BAFO)

Following selection of preferred bidder TVRIIB must be requested. A BAFO is usually requested if:

- The bids are identical or too similar to choose a clear preferred bidder
- No single bid meets the municipality's defined project objectives

It should be avoided if possible because the RFBAFO document needs to be submitted and TVR IIA requested for a second time, a further process of evaluation and adjudication completed (similar to RFP), as well as placing additional cost burden on bidders. Finally, a value assessment report must be compiled and submitted to council.

Moving from preferred bidder to a signed PPP agreement requires a negotiation to bridge any gaps, provide clarification where necessary and to ensure the agreement is fair and functional. The negotiations are best conducted in an atmosphere of trust and cooperation. After resolution, TVR III must be requested with a report which is a continuation of the value assessment report including contingent liabilities incurred by the municipality and a PPP management plan. After receiving TVR III, an MFMA section 33 report must be compiled reflecting the views and recommendations of National Treasury. After financial close of the project, the transactional advisor will produce a close out report for the municipality and a case study for the public.

Contract Management

Contract management is the process that enables both parties to a contract to meet their obligations to deliver the objectives of the agreement. It involves building a good working relationship between the two parties, and continues throughout the life of a contract. Naturally, a significant emphasis is placed on soft skills to ensure this.

From the perspective of the Municipality, the main aim of contract management is to obtain the services specified in the output specification and ensure affordability, value for money and appropriate risk transfer. Alignment between municipality and private party is achieved because both parties desire achievement of outputs, resulting in an increasingly constructive partnership. The more severe the effects of a failure to deliver outputs, the more stringent the monitoring plan needs to be.

According to the MFMA, the responsibility for effective contract management ultimately sits with the accounting officer. Delegation is made by the Accounting Officer to the Project Officer who needs to be appointed early in the inception phase and who ideally will continue to manage the project through future phases. In this was continuity is achieved through all phases of the PPP project. Succession planning for critical skills is essential as PPP projects will usually outlive employment periods.

It is the Project Officer's responsibility to assemble the team to manage the PPP contract. Skill requirements include:

- Expert subject matter knowledge
- Design and construction
- Business and product assurance
- Facilities and services management
- Information technology
- Statutory safety and regulatory responsibilities
- Regulation and law
- Human resources
- Customer service
- Public relations
- Finance
- Black economic empowerment.

The three main functions of PPP contract management are:

- Partnership management, concerning how the municipality and the private party relate to each other
- Service delivery management, the systems and procedures designed to manage risk and performance
- Contract administration, ensuring that all the procedures in the contract and accompanying documentation are effectively managed

These elements are described in the figure below:
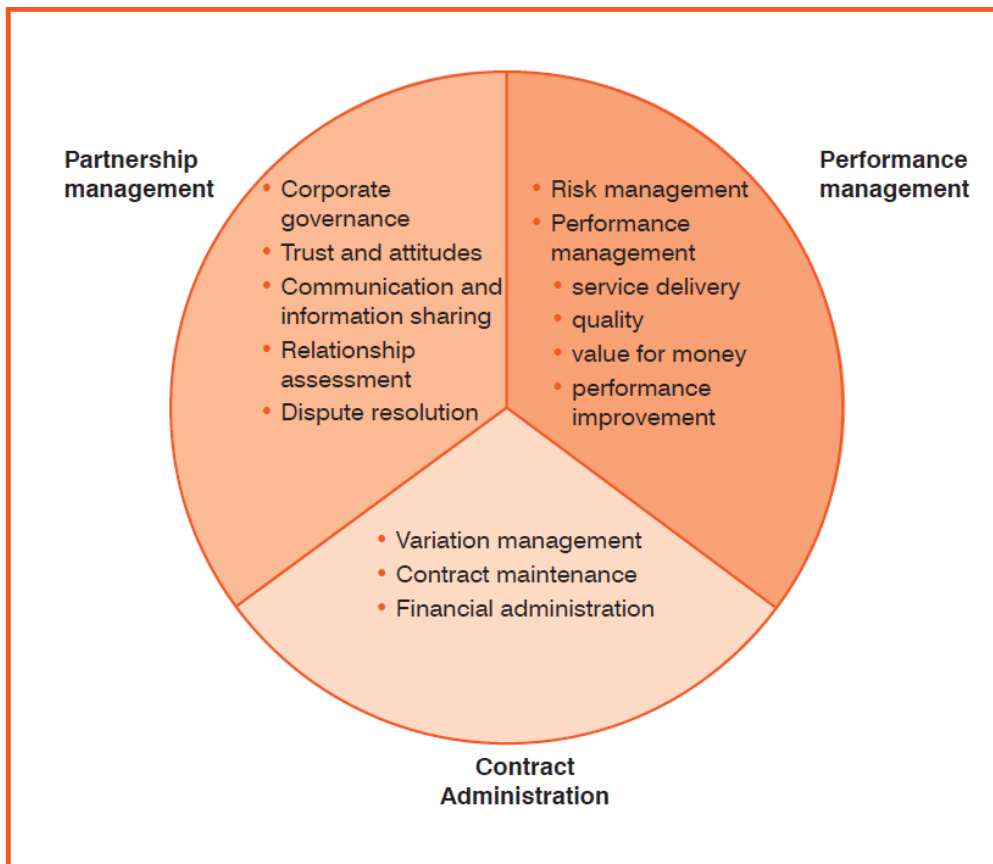
Each element of contract management has application in each phase of a PPP project. The stages of PPP contract management are:

- The procurement stage – from the start of a PPP project until the signing of the contract
- The development stage – from the signing of the contract until the commencement of service delivery
- The delivery stage – the period when services are provided and used
- The exit stage – the phase towards the end of the life of the project (whether the project ends through expiry or termination) during which activities are wound up and the municipality makes new financial and contractual arrangements for continued service delivery.

A PPP contract will contain written agreement on service, pricing mechanisms, private-party incentives, contract timetable, means to measure performance, communication routes, referral procedures, variation management procedures, agreed exit strategy and agreed termination options. These elements are all established prior to signing of the agreement, meaning that the foundations for management of the contract are also established prior to signature. The three elements are further divided in terms of the phases of a PPP project in the figure below:

Critical stages of PPP contract management	Key functions of contract management			Change management
	Partnership management	Service delivery management	Contract administration	
Procurement	• Develop the partnership management plan • Establish the contract management team • Prepare the contract management plan	• Develop the performance management plan • Develop the risk management plan	• Develop the contract administration plan	
Development	• Ensure a seamless transition to the new arrangements • Establish sound partnership management systems	• Establish risk control procedures • Establish performance management systems • Monitor the development of the service towards the commencement date	• Develop financial administration, contract maintenance and variation management procedures • Develop the contract management manual	
Delivery	• Review and revise the partnership as necessary • Review and revise the contract management plan • Commission independent reviews	• Ensure contracted services are provided in accordance with the output specification • Manage risks • Manage performance • Manage variations	• Review and revise financial administration, contract maintenance and variation management procedures • Update the contract management manual	
Exit	• Organise closure event • Integrate lessons of the partnership into the work of the municipality	• Assess deliverables, value for money, quality and innovation achieved by the project • Organise post implementation review	• Implement hand back procedures • Make arrangements for the delivery of the service by the municipality or re-tendering	

Partnership management involves the development of processes to ensure accountability and manage the relationship. Accountability is established through the implementation of corporate

governance frameworks, outlined in the King Code. Trust and communication must be encouraged in strategic, business and operational levels off the PPP activities, and an appropriate system for dispute resolution between the parties is established and understood.

Service delivery management is divided into two principal categories: risk management, concerning project exposure to threats; and performance management, concerning delivery and optimization of outputs. Risk management is established prior to signature of the PPP agreement, and the risk matrix apportioning established at this stage needs to be upheld following procurement of the agreement. The Project Officer must ensure that each risk is assigned a responsible party, and that the party is able to mitigate the risk sufficiently.

Performance management consists of three key elements:

- The level of performance in output delivery, must be reasonable and measurable
- The method of monitoring performance, this will include monitoring methodology specified in the performance management plan including user feedback and corrective actions for deviation
- The consequences for the private party of failure to meet the required level of performance, including both penalties and incentives for exceeding the required level of performance

Both risk and performance management are conducted in a cyclic manner, allowing continual improvement of the operation and increase of value provided by the PPP to both parties.

Contract administration activities can be broadly grouped into three main categories:

- Variation management, enables accommodation of changes to the PPP, can be initiated by either party and the intention is to distribute costs or benefits fairly
- Contract maintenance, ensures that the PPP agreement is kept up to date with changes as the project progresses
- Financial administration, procedures to make and receive financial payments, and keep records of financial transactions

Appendix D Development Phase TOR

Technical TOR

Background

The sites are within a bulk water supply system, which is a critical municipal service. Thus the operation of hydroelectric plant within the system must not impact on the availability of the relevant system components.

Scope

The scope of work is to enhance, refine the Prefeasibility Design through:

1. Head Assessment
2. Hydrology Assessment
3. Feasibility Design (including all required components such as geotech studies and grid studies)
4. Cost Estimation
5. Production projection
6. Implementation and Operation Phase Design

Head Assessment

- Confirm Gross Head at each site either by survey or from existing drawings
- Evaluate head losses to quantify Net Head to 95% confidence at required turbine locations at all relevant flow rates through:
  - Long-section analysis of pipelines including consideration of upstream agricultural supply and leakage.
  - Pressure measurements at the required location

Hydrology Assessment

- Confirm feasibility findings and conduct detailed analysis of the flow to produce yearly, flow duration curves. Monthly, daily and hourly flow distributions must also be produced for each site.
- Flood estimate
- Investigate integration with Bulk Water system operation for alteration and optimisation of flows for power generation without any compromise of water supply operations

Feasibility Design

Feasibility Design must be conducted, considering the following general requirements:

1. The consultant must at all junctures be aware that the hydroelectric plant will exist within, and as a result of the operation of the Bulk Water supply system. Water supply objectives must remain paramount and ongoing consultation with Bulk Water stakeholders is essential.

2. Availability of the water supply infrastructure must be at levels >99.9% continuously. In the event of the hydroelectric plant not being able to operate for whatever reason, it shall be bypassed to allow the water supply operations to continue irrespective.
3. Minimum maintenance and remote operation and monitoring is required

Determine, design and conduct the following:

- Selection of a preferred option for each site from, but not limited to, the options identified in the prefeasibility design taking into account power potential and energy production. The selection must be made in conjunction with the proponent to optimise:
    o Specific cost (R/MW) minimisation and levelised cost of electricity (R/kWh)
    o Energy generation maximisation (MWh/annum)
    o Project IRR maximisation (Project and Equity IRR)

- Optimisation of the preferred layout, including design to feasibility level of the following:
    o **Electromechanical:** Refined turbine selection based on quotations from turbine manufacturers.
    o **Electrical:** Detailed connection assessment outlining possible losses, single-line diagram, precise operating mode and integration with the power network. Facilitate and communicate with Eskom and ESD regarding the grid study initiated by the client.
    o **Civil:** size according to the selected turbine water conveyance system (penstock/canal etc), intake structure and possible sedimentation problems, hoisting facility and access roads/route plan if required. All water conveyance structures must be designed to minimise losses and where existing infrastructure is in place, a cost benefit analysis to be performed analysing a replacement option.
    o **Hydrological:** flow modelling, tailwater analysis where necessary, flood potential and appropriate protection for maximum floods where necessary
    o **Geotechnical:** detailed foundation investigation including, as necessary, test pitting, core drilling, machine excavations at key foundation points. Surface geological mapping and profiling of the site, identification of potential construction material (rock for aggregates and sand filters)Foundation investigation programme for all necessary sites with particular emphasis on sites with significant civil works requirements

- Design of all components in sufficient detail to obtain quantities for all items contributing more than 10% to the cost of the works
- Perform hydraulic modelling of the preferred option at each site
- Identify major risks at each site facing hydroelectric generation objectives, and select mitigation measures
- In conjunction with relevant Bulk Water stakeholders, identify any and all risks facing Bulk Water objectives as a result of the presence of the hydroelectric plant, and select mitigation measures

Cost Estimation

Based on the bill of quantities for the preferred option, estimate the cost of all professional services and works for Implementation to +-10% confidence.

Production Projection

Production estimates resultant from the above must be projected taking into account:

- Determine annual energy production
- Determine monthly energy production
- Determine daily energy production giving distribution for time of generation and potential to optimise peak, standard and off-peak generation. The consultant is to communicate with the client regarding the benefits provided in this regard in the expected offtake agreement.

Design of future phases

Design and consider the following for the progression of the project:

- Determine Detailed Design requirements
- Determine requirements for safeguarding live pipes during execution of works
- Determine requirements for civil and electromechanical works including construction site maintenance in an orderly state during execution of the works and condition following completion of works with surplus material/debris removal from site etc
- Compile Tender Documentation and Tender program
- Compile Construction Program
- Determine Project Management and construction monitoring requirements during implementation
- Investigate and describe impacts during implementation, operation and decommissioning phases for environmental applications

Deliverables

All work must be documented in a multi-volume, comprehensive feasibility report. Specific deliverables include:

- Full resource assessment including:
  - Quantification of generating head to 95% confidence at all relevant flows for each site
  - Flow Duration curves and monthly, daily and hourly flow distributions for each site to 95% confidence. 1/50 year flood potential. Potential for optimisation of flow regimes for power generation and water supply objectives.
- Feasibility Design:
  - Layout option selection according to specific cost, energy generation, and investment optimization criteria
  - Engineering drawings to feasibility level design according to CoCT Bulk Water standards considering an expected 30 year project life for: electromechanical, electrical (including single line diagram), civil, hydrological, geotechnical.

- o Bill of Quantities
- o Risk and mitigation matrix for each site for risks facing hydroelectric generation objectives
- o Risk and mitigation matrix for each site for risks facing water supply objectives as a result of the presence of the hydroelectric plant
- Cost estimate of all professional services and works for Implementation to +-10%
- Energy production projections to 95% confidence, providing annual figures with monthly variations. Daily variations are to be presented with sufficient detail to determine the validity and facilitate execution of potential Time of Generation offtake agreement.
- Future Phase Design
  - o Tender Program
  - o Integration plan safeguarding Bulk Water objectives during Implementation Phase
  - o Integration plan safeguarding Bulk Water objectives during Operation Phase
  - o Construction program and professional services required for implementation
  - o Description of environmental impacts sufficient for environmental impacts

All data must be provided to the client for input into financial models at all times for the continual assessment of the Project's viability.

Counterpart Provisions

The following will be provided to the consultant by the client:

- Prefeasibility Flow Data in spreadsheet form
- Raw Data from central and sites
- Infrastructure Drawings and specifications
- Pipeline long sections
- Contact details and facilitation of meetings with site managers
- Water quality standards and minimum requirements

Information Required for Selection Process:

- Experience and track record (including intended partners providing specific expertise)
- Composition of team and names of individuals that would handle the assignment including CV's
- Immediate availability
- Fee charges including total financial proposal, hourly rate applicable to each individual and alternative pricing structures
- Other charges
- Conflicts of interest
- PI cover

Legal TOR

Background

The Proponent is developing the hydroelectric potential in the CoCT Bulk Water system and requires the services of a Project Legal Advisor. The Project's Legal Advisor is required to advise and assist the Client generally on all legal aspects of the Project.

Scope

Project Documentation

Review, comment on, advise and draft if necessary:

- Power Purchase agreement
- Eskom Inter-Connection Agreement
- Electricity generation licence
- Implementation Agreement/s:
    - EPC Wrap (Turnkey) Agreement or;
    - Tender and Detailed Design Agreements
    - Construction Monitoring Agreement
    - Civil Construction Agreement
    - Electromechanical Supply and Installation Agreement
- Operation and Maintenance Agreement
- Warranty Agreement/s
- Shareholders Agreement or equivalent as necessary
- Fixed and movable property Lease Agreement/s as necessary

Project Finance

Review, comment on, advise, and draft as necessary:

- Financing term-sheet prepared by the Project's financing institution/s
- Assist the Proponent in negotiation of comments and heads of terms raised by the Lenders' Legal Advisor (LLA)
- Common terms agreement relating to common covenants and other terms which apply to senior and any mezzanine facilities, if applicable
- Senior Facilities Agreement, if applicable
- Mezzanine Facilities Agreement, if applicable
- Intercreditor Agreement governing relations amongst senior and mezzanine lenders. It is unusual for the Project to be a party to the intercreditor agreement, but counsel must ensure that there are no unusual or prejudicial intercreditor terms
- Account Bank Agreement regulating the role of the Account Bank in relation to project cashflows
- Subordination Agreement in terms of which any financial contributions made by the Proponent to the Project are subordinated to the claims of the senior and mezzanine lenders against the Project Company

- Various Security Documents whereby the Project provides necessary guarantee to the Lenders. The structure for provision of the necessary security through guarantees of Project obligations must be investigated and selected. The Security provided by the Project may include, but is not limited to:
    - o Cession of claim on shares and loan claims held in the Project by the Proponent
    - o Cession of rights to income streams under the PPA and Emissions Reduction Purchase Agreement (if applicable) held by the Proponent
    - o As applicable under relevant legislation, Direct Agreement between Lenders and property owner, CoCT, such as claim on registered long term lease in respect of the sites. Counsel must bear in mind limitations for attachment of the property of a Public Institution
    - o Provision of necessary claim on tangible assets of high value including turbines and related such equipment

Ancillary

Provide ancillary services required by the Project arising from the Project Documentation and Project Finance work. Review, comment on, advise and draft as necessary all constitutional aspects and other documentation in relation to the Project excluded from the specified documentation above. Services may include, but are not limited to:

- Advise on specific BBBEE issues, setting up of BEE shareholding trusts and so forth
- Review the Project's risk matrix providing an assessment and proposed mitigation of all major risks and issues which may affect the Project
- Advise the Proponent on all relevant approvals, permits and regulatory matters which may have an impact on the Project

Deliverables

- All documentation executed

Information Required for Selection Process:

- Experience and track record (including intended partners providing specific expertise)
- Composition of team and names of individuals that would handle the assignment, CV's
- Immediate availability
- Fee charges including total financial proposal, hourly rate applicable to each individual and alternative pricing structures
- Other charges
- Conflicts of interest
- PI cover

Environmental TOR

Scope

Notify Authorities

Notify the relevant Local, Provincial and National Authorities in accordance with relevant regulations. The next phase (Public participation) can only take place after the relevant authority has issued a reference number, hence this process must be conducted timeously.

Public Participation

Below is an overview of the public participation process to be undertaken on behalf of the client by the EAP. In accordance with the EIA Regulations (2006) and the guideline on Public Participation in support of the EIA Regulations (developed by DEAT, 2005), the EAP must ensure that the following is undertaken:

- Place site notices
- Provide written notices to:
  - Adjacent land owners and occupiers
  - Owners and occupiers within 100m of boundary of site
  - Ward Councilor
  - Municipality
  - Organisations such as rate payers associations, farmer unions, NGO's, etc
  - Provincial Departments having jurisdiction
- Place newspaper adverts (local and/or provincial)
- Prepare Interested and Affected Parties (I&APs) Database
- Convene a public meeting
- Provide I&Aps opportunity to comment on reports

In addition, an authorities meeting must be facilitated by the EAP. The invitation must be extended to relevant institutions including but not limited to Department of Environmental Affairs and Tourism (DEAT), South African Heritage Resources Agency (SAHRA), Department of Water Affairs (DWA), CoCT, National Energy Regulation of South Africa (NERSA) and Department of Energy (DoE). Provide the attendees with the relevant information and determine the requirements of the various authorities.

Application Form

Prepare the relevant Application Form and facilitate the signing thereof by CoCT, for submission with the Basic Assessment Report (BAR) to DEAT.

Basic Assessment Report

Prepare a compliant Basic Assessment Report, containing all relevant information including the following:

- A description of the proposed activity and of any feasible and reasonable alternatives that have been identified
- An identification of all legislation and guidelines that have been considered in the

preparation of the report

- Physical size of the activity
- Site Access
- Site or route plan
- Site Photographs
- Facility Illustration
- Description of the receiving environment
- Property Description
- Activity Positions
- Details regarding the site including – gradient, location in landscape, groundwater, soil and geological stability, groundcover and cultural /historical features
- Land-use character of the surrounding area
- Socio Economic Context
- Resource use and process details including waste, effluent, emission management, water use, power supply and energy efficiency
- Impact assessment during the construction, operation, decommissioning and closure phases
- Assessment of cumulative impacts
- EAP Details
- Any specific information that may be required by the competent authority
- An environmental impact statement which contains:
  o A summary of the key findings of the environmental impact assessment
  o A comparative assessment of the positive and negative implications of the proposed activity and identified alternatives
- EAP recommendations
- Environmental Management Plan (EMP), which complies with regulation 34 of R385
- A summary of the findings and recommendations of any specialist report or report on authorization process

Submit Basic Assessment Report
Submit Basic Assessment Report to the relevant authority.

Deliverables

- Compliant public participation process with proof of all activity, representations, comments and objections complete
- Application form for signoff by CoCT prepared
- Application form submitted
- Basic Assessment Report complete
- Basic Assessment Report submitted
- ROD received

Counterpart Provisions

- Site information necessary for the compilation of the Basic Assessment Report
- Technical information necessary for the compilation of the Basic Assessment Report, including activity during implementation, commissioning, operation, and decommissioning.
- Necessary engineering sketches and drawings
- Necessary legal documentation associated with pertinent property
- Information on existing operations on the sites

Information Required for Selection Process:

- Experience and track record (including intended partners providing specific expertise)
- Composition of team and names of individuals that would handle the assignment including CV's
- Immediate availability
- Fee charges including total financial proposal, hourly rate applicable to each individual and alternative pricing structures
- Other charges
- Conflicts of interest
- PI cover

Clean Development Mechanism TOR

Scope

Confirm Project eligibility under CDM

An assessment must be conducted to confirm that the project is eligible to be developed as a CDM under the guidelines established by multi-lateral and host country institutions for climate change projects under the Kyoto Protocol. Particular attention must be paid to key issues that are central to determining a project's eligibility, the fulfilment of host country sustainable development criteria and, most importantly, the additionality of the project. (The reduction must be additional to any "business-as-usual" emission reductions). Consultation with DNA and UNFCCC personnel must be conducted to discuss the eligibility of the projects.

Select optimal CDM project structure

Investigate and select the most cost-effective structure in which to develop the carbon reduction value produced by the Project. Individual project development, "Bundling" and "Programme of Activities" are potential options identified.

Prepare Preliminary Estimates of GHG Reductions and Determine Their Market Value

To assist the client in understanding and quantifying the financial benefits of developing the project under the CDM, an evaluation must be conducted with and without project (i.e., baseline) scenarios. This evaluation must provide a preliminary estimate of the amount of carbon credits that would be generated by the project, and their potential value on the market at current and expected prices.

Obtain DNA letter of no objection

The consultant must, on behalf of the Client, complete the required documentation (e.g. a Project Idea Note (PIN)) and provide ongoing advice to the Client with respect to obtaining a Letter of No Objection from the Designated National Authority (DNA).

Public Participation

Conduct Public Participation in accordance with relevant national and UNFCCC regulations.

Develop Project Design Document (PDD)

The consultant must prepare a Project Design Document (PDD) for the project, the formal document that must be submitted with the methodology submission for independent third-party validation by a DOE and ultimately submitted to the CDM Executive Board for registration of the project as a CDM activity. The consultant must ensure that all of the relevant information is presented appropriately. The Measurement and Verification plan must be assessed and system design supported to ensure standards acceptable to UNFCCC are incorporated in the technical specification of the project.

Validation and Registration

The consultant must facilitate the engagement of a DOE and the validation process including:

- Assist with the contracting of a suitable DOE
- Select appropriate team/ review of CVs
- Coordinate and attend site-visit
- Manage project validation and answer requests for clarification / corrective actions as

applicable

The consultant must facilitate engagement with UNFCCC executive board and the registration process.

Deliverables

The specific deliverables that will be prepared for this project are:

- Confirmation that the project is eligible under CDM
- Optimal CDM project/program structure to incorporate the multiple sites identified and associated development and implementation planned
- Projected CER production complete and CDM income quantified
- PIN complete
- PIN submitted to DNA
- Receive Letter of No Objection from the DNA
- Assess Measurement and Verification plan
- PDD complete
- Public Participation complete
- PDD submitted to DNA
- Receive Host Country Approval from the DNA
- Source, engage and contract DOE on behalf of client
- Validation of Project
- PDD submitted to UNFCCC
- Registration of Project

Counterpart Provisions

The following inputs will be provided to the consultant by the client:

- Technical inputs regarding the specification of the project, enabling development of the PDD.
- Financial inputs regarding the specification of the project, enabling development of the PDD.
- Information on barriers that may be overcome by the registration of the project as a CDM project, to assist with additionality argument.
- Information about the Project Proponent's sustainable development initiatives, enabling DNA acceptance for Host Country Approval.
- Information and progress reporting on environmental applications and approvals and process followed. The public participation for Environmental and CDM purposes must occur simultaneously to save costs and it is the responsibility of the consultant to ensure that the CDM public consultation occurs alongside the Environmental public consultation.

Information Required for Selection Process:

- Number of CDM projects registered by the Consultancy
- Experience and track record (including intended partners providing specific expertise)

- Composition of team and names of individuals that would handle the assignment including CV's
- Immediate availability
- Fee charges including total financial proposal, hourly rate applicable to each individual and alternative pricing structures
- Other charges
- Conflicts of interest
- PI cover