PREFEASIBILITY STUDY FOR BIOMASS POWER PLANT, NAMIBIA

COMMERCIAL ASSESSMENT

2013/07/29

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Signature				
Checked by	Helen Hulett			
Signature				
Authorised by	Elan Theeboom			
Signature				
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Client

Mrs L Amaambo
Nampower Centre
15 Luther Street
Windohoek, Namibia

PO Box 2864
Windhoek, Namibia
(Tel) + 264 612052385

Consultant

WSP Environmental (Pty) Ltd.
3rd Floor, 35 Wale Street,
Cape Town
8001
South Africa
Tel: +27 21 481 8646
Fax: +27 21 481 8799

www.wspenvironmental.co.za

Registered Address

WSP Environment & Energy South Africa
1995/008790/07
WSP House, Bryanston Place, 199 Bryanston Drive,
Bryanston, 2191, South Africa

WSP Contacts

Elan Theeboom: Resource Assessment Director
(Tel) + 27 21- 4818646

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List of Acronyms

BFB – Bubbling Fluidised Bed

BOOT – Build/Own/Operate/Transfer

CAPEX – Capital Expenditure

CBEND – Combating Bush Encroachment for Namibia's Development

CCF – Cheetah Conservation Fund

DBSA – Development Bank of South Africa

DSCR – Debt Service Coverage Ratio

DRFN – Desert Research Foundation Namibia

EBITDA – Earnings before Interests, Taxes, Depreciation and Amortisation

EBtP – Encroacher Bush to Power

ECA – Export Credit Agency

ECB – Electricity Control Board (Namibia)

EFF – Energy For Future

EIA – Environmental Impact Assessment

GB – Grate Boiler

IFC – International Finance Corporation

IPP – Independent Power Producer

IRR – Internal Rate of Return

JIBAR – Johannesburg Interbank Agreed Rate

KfW – KfW Entwicklungsbank

LLCR – Loan Life Coverage Ratio

LUC – Levelised Unit Cost (also "Levelised Cost of Electricity" or LCOE)

MW_{el} – Megawatt electrical

MW_{th} – Megawatt thermal

O&M – Operation & Maintenance

OPEX – Operational Expenditure

PPA – Power Purchase Agreement

PV – Photovoltaic

SC – Supply Chain

SPC – Special Purpose Corporation

SVA – Shared Value Africa

T&D – Transmission & Distribution

WACC – Weighted Average Cost of Capital

1 Background

In the following document, the procedures and results of the economic and financial analysis of the different encroacher bush to power plant (EBtP) concepts at sites in Otjiwarongo, Ohorongo and Otjikoto are described. As defined in the accompanying "Technical Report" and "Biomass Supply Chain Report", the following power plant and supply chain process options were chosen:

1. Otjiwarongo: For this site (option 1) a 5 MW_{el} powerplant with a grate boiler (GB) system (24 MW_{th}) and steam turbine is foreseen. For the supply chain a harvesting process with semi-mechanized harvesting method was chosen. This includes using a skid steer for harvesting, several mobile chippers and tractors to transport the wood chips to the field storage site as well as trucks to transport the material to the power plant. The field storage is designed as a material handling site. A day's storage is planned at the power plant. Reference should be made to the "Harvesting, Handling, Storage and Transport" companion report for further details of the supply chain.
2. Ohorongo Cement: For the Ohorongo Cement plant site two different 20 MW_{el} powerplant configurations (power generation by two 10 MW_{el} turbines) were calculated. Option 2a is equipped with a bubbling fluidized bed (BFB) boiler (78 MW_{th}) and option 2b with a GB (75 MW_{th}). Harvesting will be fully mechanized, using a cutter chipper with tractor and trailer between harvesting and field storage as well as trucks for road transport.
3. Otjikoto Substation: For this site again two 20 MW_{el} powerplant configurations (2 x 10 MW_{el}) with BFB (option 2c) as well as with GB (Option 2d) were analyzed. The harvesting method is fully mechanized as at the Ohorongo Cement site.

For options 2 and 3, it has been assumed that substantial biomass storage is kept at the powerplant as well as temporary storage in the field (1-3 months' combined supply).

An initial financial and economic model was developed for the project by the IER University of Stuttgart (IER). The analysis considered a single quote (Supplier A) for the 5 $MW_{e}l$ powerplant and four quotes for the 20 MWel options (three grate based technologies – Suppliers B – D – and one bubbling fluid bed technology option – Supplier E). The results of the model suggested a viable commercial sale price as follows:

Table 1: Electricity Sale Price – Results of IER Financial Modelling (N$/kWh)

Location	NamPower	Independent Power Producer (IPP)
Otjiwarongo	2.67	3.12
Ohorongo	1.04 – 1.57	1.2 – 1.85
Otjikoto	1.13 – 1.68	1.31 – 1.98

Reference should be made to the "Preliminary Commercial Assessment Report" developed by WSP Environmental (Pty) Ltd. (WSP) and IER for further details. Following on from this analysis, it was decided to develop a more sophisticated financial model for further project feasibility analysis. For this purpose the Corality Financial Group was subcontracted to WSP to develop a comprehensive financial model, in cooperation with NamPower and the financial lending institutions (DBSA and KfW).

This report briefly describes the financial model characteristics and results.

2 Model Overview

2.1 Structure

The model comprises two separate but commercially interdependent entities: a Supply Chain (SC) commercial operation and a Power Plant (PP) commercial operation. The SC entity is responsible for harvesting the biomass resource and delivering it to the power plant. Revenue is generated primarily from the sale of biomass to the power plant (price “at the gate” of the power plant). From that point on, the power plant is responsible for the storage and handling of the biomass resource. The power plant entity receives the biomass resource as a fuel (and OPEX) input, and generates its revenue from the resultant sale of electricity.

The model provides the following **output** for each commercial entity:

- Annual Financial Statements (cashflows, profit & loss statement, balance sheet and various chart data);
- Integrated Financial Statements (cashflows, profit & loss statement and balance sheet); and
- Summary sheet for the selected scenario, indicating:
  - Project characteristics;
  - Nominal returns;
  - Debt ratios;
  - Rolling Equity IRR graph;
  - Table summary of financial characteristics for first 15 sub-scenarios (see Section 3.3);
  - Production characteristics;
  - Cashflows (SC and PP);
  - Annual debt service (SC and PP);
  - Annual cost breakdown (SC and PP);
  - Annual actual debt service coverage ratio (DSCR) and hurdle DSCR (SC and PP).

For the purposes of sensitivity analysis, the model provides a Scenario Manager worksheet that allows for multiple scenarios to be analysed simultaneously and the results shown on a single table. For the purposes of this analysis, a base case scenario was identified for each location (i.e. three base cases). Subsequently, a number of variation scenarios have been run in order to assess overall project sensitivity and robustness of the financial business case.

2.2 Model Inputs

2.2.1 Overview

Base case model inputs have been provided in the financial model. The base case inputs are based on the best available information at the time of the study (with the bulk of research being undertaken during the course of 2012), and should be subjected to review and refinement as better information comes to light. A description of the source of each input parameter (base case) is provided in **Appendix A**.

2.2.2 Model Set-up

The model set-up assumes the **start of construction** in January of 2015. The Power Plant is assumed to require 18 months for completion for the larger plants (Ohorongo and Otjikoto). A shorter construction time of 12 months is assumed for the 5 MW option at Otjiwarongo.

For the Supply Chain, a 24 month construction period has been assumed. This is based upon feedback from DBSA which indicated that significant delays had been experienced with the Energy For Future (EFF) operation in receiving cutter chipper harvesters from Europe in addition to time needed for subsequent optimization modifications for local Namibian conditions. Hence the 24 month period assumes that the Supply Chain is fully operational by that stage. In reality, the Supply Chain will be partially operational at a much earlier stage, with a gradual ramping up of operations taking place over an extended period of time. The assumption is that the Supply Chain will utlise this period as an opportunity to build up the power plant's **initial contingency biomass stockpile** (assumed to be approximately 3 months' worth of biomass fuel) to be stored either in the field or on-site at the Power Plant.

The **operational lifespan** is taken to be 25 years.

2.2.3 Construction - SC

CAPEX for the supply chain will vary depending on the scenario. For Otjiwarongo, the CAPEX comprises skid steers, mobile chippers, tractors, trailers, skid loaders and lorries for final transportation to the Power Plant. For Ohorongo and Otjikoto, the plant comprises advanced (integrated) cutter chippers in place of the skid steer and mobile chipper, similar to the system currently utilised by EFF.

CAPEX values for the base case are in Euros (other currencies can be selected for updating of costs) and are based on estimate from the literature as well as from feedback from interviews conducted as part of the study (i.e. with Development Bank of South Africa (DBSA), EFF, Cheetah Conservation Fund (CCF), Green Coal etc.).

The **number of plant** required is calculated based on biomass fuel requirement at the Power Plant. The fuel requirement is based on:

- Technology and location-specific **biomass fuel input requirements** for the Power Plant (Thermoflex modelling);
- **Handling and storage losses** experienced on the Supply Chain side of the operation (10% base case assumption);
- **Handling and storage losses** experienced on the Power Plant side of the operation (10% base case assumption); and
- **Contingency for back-up machinery** (20% base case assumption);

The number of lorries also takes into account the distance from the harvesting operation to the Power Plant. As a result of the existing (and competing) EFF harvesting operations, the Ohorongo scenario requires a greater harvesting radius of operation and hence more lorries are needed. However Ohorongo also benefits from a lower fuel input requirement associated with the utilization of thermal waste heat from the cement production facility, which does manifest in lower harvesting plant requirements under some circumstances (but not under the base case conditions).

Table 2: Start-up CAPEX requirements for the Supply Chain

Machinery	Unit	Cost per item	No. of Machinery Required (base cases) incl. contingency		
			Otjiwarongo	Ohorongo	Otjikoto
Cutter chipper	EUR '000	400.00	-	11	11
Skid steer	EUR '000	28.15	5	-	-
Mobile chipper	EUR '000	75.00	7	-	-
Tractor	EUR '000	91.30	5	11	11
Trailer	EUR '000	21.45	5	11	11
Skid loader	EUR '000	140.80	3	9	9

Lorry- towing	EUR '000	92.00	4	28	24
Lorry- trailer	EUR '000	52.00	4	28	24

SC plant is refinanced based on the useful life estimates for each type of machine (see the "Depreciation" section of the Inputs worksheet of the financial model for useful lifespan assumptions).

It is noted that the number of machinery estimated is lower than that indicated in the Biomass Supply Chain Assessment Report for this study, due to the less conservative base case assumption for the contingency (20% used in this financial model versus 50% contingency in the Biomass Supply Chain Report). In addition to the 20% contingency in machine numbers, a further **financial contingency** input parameter is available in terms of total CAPEX spend (with regards to the supply chain). This is set at 10% for the base case.

2.2.4 Construction - PP

CAPEX for the Power Plant is based on the information provided in the "Technical Report" for the study (which details the Power Plant engineering design). These are summarized in **Table 3**. The CAPEX includes certain Transmission and Distribution (T&D) infrastructure investment but also excludes a significant portion which will be borne by NamPower rather than the Power Plant commercial entity (refer to the "Transmission & Distribution Assessment" report for the study). However, these excluded T&D investment costs are recovered by NamPower form the Power Plant via an OPEX maintenance fee.

The CAPEX estimates are based on quotes received from five technology vendors (one for the 5 MW option and four for the 20 MW_{el} options) as well as general estimates (e.g. for civils) and some conservative allowances, where required. Costs at Ohorongo are generally lower than at Otjikoto due to the existing infrastructure.

Table 3: CAPEX estimates for power plant

Location		Lowest Quote	2^{nd} Lowest	2^{nd} Highest	Highest Quote
Otjiwarongo	EUR '000	21,081			-
Ohorongo	EUR '000	32,787	34,808	50,120	59,998
Otjikoto	EUR '000	36,661	39,561	55,376	64,494

For the base case scenario, the **second lowest CAPEX estimate** has been adopted for Ohorongo and Otjikoto. In addition, a **contingency allowance** can be included as an input parameter, with a 10% contingency being adopted for the base case models.

It is worth noting that only one quote was sourced for the 5 MW_{el} option (primarily because this scenario was only identified at a relatively late stage of the project). Furthermore, this quote is suspected to be relatively expensive and WSP considers it to be not unlikely that a significantly lower CAPEX quote could be achieved under more extensive (or competitive) bidding process. This is underscored by the fact that the most expensive quote received for the 20 MW_{el} option is almost double the cost of the cheapest (also received from a reputable supplier). This variation underscores the uncertainty associated with obtaining informal quotes outside of a formal tendering process.

For this reason, a variant scenario of the 5 MW_{el} Otjiwarango scenario has also been modeled with an assumption of 30% lower CAPEX requirement.

2.2.5 Operations - SC

Technical and associated financial operational inputs for the base case Supply Chain scenarios are taken from the "Biomass Supply Chain" report for this study, for the most part. The key inputs are described below:

The **harvestable land area required** (for the lifetime of the Power Plant) is automatically calculated based upon:

- Annual required biomass fuel supply;
- Mass yield (per ha) (site dependent, described in the Biomass Supply Chain report).

The resultant **radius of harvesting area** assumes a circular area of operation around the Power Plant. In reality this will not be the case, however, as a conservative assumption, the maximum journey length (in terms of this idealised circle of operation) has been used as the "average" trip length for lorries transporting the biomass (and consequent calculation of diesel costs etc.).

The radius of operation also takes into account a "**harvestable land availability factor**", assumed to be 50% of surrounding land under the base case scenarios. In the case of Otjikoto and Ohorongo, a further 50% correction factor is applied (i.e. overall 25% land availability) due to likely Environmental Impact Assessment (EIA) conditions whereby only half of each farm is allowed to be cleared via the fully mechanised cutter chipper method. For the Otjiwarongo scenario, due to the more sensitive (semi-mechanised) method and the fact that CCF is confident of access to around 90,000 ha of surrounding bush-encroached land, this EIA condition has not been applied.

For the Ohorongo scenario, the projected EFF target harvest rate of 90,000 t/yr has also been taken into account (at the time of the site visit, EFF was only harvesting around 40,000 t/yr).

A **seasonality factor** is applied on a monthly basis i.e. the % of annual harvesting that takes place in a given month. The base case assumption is that no harvesting is undertaken in the rainy season of Jan – Mar, with an in-built logic test to ensure that fuel stockpiles never drop below zero even over the course of this period.

An **initial stockpile volume** is also provided as an input. This is the stockpile built up by the Supply Chain during its "construction period", prior to the Power Plant becoming operational. This stockpile provides for an initial fuel resource buffer i.e. for the rainy season or any supply disruptions. The base case assumes a three month supply stockpile charged out (to the Power Plant) at a margin of around 43% (reflected as a once off expense/revenue item of each entity's accounts at the start of the project.

A **farmer payment** input is provided to account for revenue or expenses incurred in accessing the farmers'' land. Farmers are currently reporting to be paying as much as N$ 400 per ha to EFF for clearing land, and even more than that for alternative crop spraying with arboricides. While unlikely, it is also theoretically possible that farmers may be in a position, at some stage of the project's lifecycle, to demand payment for access to the biomass resource. The base case scenarios conservatively assume zero payment by the farmers.

A **supply chain availability factor** is provided to allow for modelling of supply chain interruptions. However the base case scenarios assume 100% availability, taking into account that a 20% contingency (rounded up) is in place in terms of the number of machines purchased.

Reference should be made to the Biomass Supply Chain report for details on labour costs, machinery running costs etc.

2.2.6 Operations - PP

As discussed earlier, the **biomass fuel input** (tonnes per hr), which also drives many of the Supply Chain operational costs, is based on technology and location-specific input requirements as modelled by WSP engineers using the Thermoflex modelling package. Allowance is also made for **handling and storage losses** at various stages of the process (10% loss on the Supply Chain side and a further 10% at the Power Plant side of fuel handling and storage). The **biomass fuel cost** (N$ per ton woodchip) is the key user input that interlinks the Supply Chain and Power Plant entities, and which drives the commercial feasibility for the Supply Chain entity as well as the final electricity sale price.

A conservative assumption of 7,500 **operating hours per annum** has been assumed, based on discussions between WSP and KfW engineers. By comparison, operating hours of 8,000 plus per annum is considered typical for similar European power plants.

The model makes some allowance for including thermal energy generation for commercial purposes; however this is considered unlikely in the Namibian context and has been assumed to be non-commercial under all scenarios assessed.

Power Plant **availability** has also been assumed at 100%, keeping in mind the already conservative assumption in terms of annual operating hours (allowing for plenty of time for maintenance downtime). It is further noted that the 20 MW_{el} options comprise two lines of 10 MW, thus further minimising any downtime potential.

Other key OPEX costs include:

- Standard plant **servicing and maintenance costs** (WSP engineer estimates as in N$ per MWh);
- **Labour costs** (estimated by IER, based on staff numbers provided by WSP engineers, and following engagement with NamPower to confirm);
- **T&D maintenance charge**, estimated as the NamPower-borne CAPEX spend (as opposed to the T&D CAPEX spend on the Power Plant balance sheet) discounted at 6.5% over the plant lifetime (see the T&D specialist report for details);
- **Maintenance CAPEX** spend (for periodic plant replacement), assumed to be 1.25% of initial CAPEX per annum; and
- **Insurance costs**, estimated at 0.65% of initial Power Plant CAPEX per annum for the base case scenario.

For the purposes of this exercise, all costs excepting fuel purchases are taken to be fixed.

2.2.7 Funding

Funding requirements are calculated from the various CAPEX and other relevant inputs. For the base case, gearing is set at 80% (based on discussions with KfW), although 70% gearing is also modelled as an alternative scenario. The other key assumptions (for the base case) are:

- Grace period of 6 months;
- Equity first drawdown;
- 60% payout ratio (i.e. dividends);
- Project nominal discount rates of 8.17% for NamPower (based on NamPower WACC) and 11.41% for an IPP investor;
- Equity nominal discount rates of 11.51% for NamPower and 20% for an IPP investor; and
- 12 year tenor for the Power Plant and 25 year tenor for the Supply Chain (5 year tenor for non-machine Supply Chain CAPEX);

A somewhat different funding structure has been applied to the Supply Chain to allow for the refinancing of harvesting and transport machinery at the end of the (differing) useful asset lifespans. For the Power Plant, a number of repayment calculation methods can be selected i.e. annuity, linear or DSCR sculpting (with annuity method being the default assumption).

The above input values are the outcome of discussions between KfW and Corality on the most appropriate parameter values (based on their experience). DBSA provided guidance with respect to interest rate margin (3.5% for a NamPower funded project and 5% margin for an IPP funded project, over and above the 6 month JIBAR rate (taken as 5.5% for the base case scenario). Input parameters were communicated to NamPower for comment during the model build process.

2.2.8 Tax and Depreciation

Tax and depreciation assumptions are based on typical international practice; no assessment of Namibian specific tax regime and requirements has been undertaken. Supply Chain machinery is depreciated via straight line calculation based on estimated useful operational asset life. For the Power Plant, depreciation is calculated over the full 25 year operational lifespan (also straight line calculation).

2.2.9 Macroeconomics

The base case interest rate is set at the 6 month JIBAR (taken at the time of the development of the IER financial model in late 2012), based on feedback from DBSA. Base case inflation has been assumed at 8%.

Exchange rate assumptions have been made based on recent (June 2013) rates and have been held constant over the project lifespan. While allowance has been made for modelling of currency hedging, the base case assumes that no such hedging is being undertaken.

2.3 Commercial Feasibility Criteria

The model is designed to test various Power Plant and Supply Chain scenarios against a screen of financial feasibility criteria comprising Project and Equity Internal Rate of Return (IRR), minimum DSCR, the Maximum Debt to Earnings before Interests, Taxes, Depreciation and Amortisation (EBITDA) and the Minimum Loan Life Coverage Ratio (LLCR). The key financial hurdle rates are as follows:

Table 4: Funders' and investors' hurdle rates for project feasibility assessment.

Hurdle rates	Project IRR	Equity IRR	Min DSCR	Max Debt/EBITDA	Min LLCR
Supply chain	8.17%	20.00%	1.30x	4.00x	
Power plant	8.17%	20.00%	1.30x		1.50x

The criteria and relevant hurdle rates have been developed jointly by KfW and Corality, with the exception of Project IRR which is based upon NamPower's WACC.

In addition to the hurdle rates, the model has a number of in-built logic tests, both commercial and technical (from a model perspective i.e. ensuring that certain values add up to no more than 100% etc.). The in-built commercial logic tests comprise the following:

Table 5: Commercial logic tests for the revised model scenarios.

Commercial Entity	Commercial Logic Tests
Power Plant	Cash balance >0 (Integrated Financial Statement)
Power Plant	Cash balance >0 (Annual Financial Statement)
Power Plant	Debt repaid within tenor
Power Plant	Sufficient biomass fuel available (on a monthly basis)
Supply Chain	Cash balance >0 (Integrated Financial Statement)
Supply Chain	Cash balance >0 (Annual Financial Statement)
Supply Chain	Initial machinery inputs = optimal (calculated) plus contingency

3 Results

3.1 Base Case Scenarios

Three base cases were established, one for each location (Otjikoto, Ohorongo and Otjiwarango). All three base cases utlise a set of (mostly) conservative assumptions, as described in Section 2. The base cases assume that both the Power Plant and Supply Chain operations are owned and run by NamPower. Among these base cases, the Otjikoto option is considered the primary base case scenario, for the reason that it is the only scenario that does not directly rely on any third party for its development potential (i.e. no reliance on Schenk Cement or CCF for the Ohorongo and Otjiwarongo scenarios respectively).

The results Summary sheet outputs for each of the three base case scenarios are included in **Appendix B**.

Table 6: Base case summary of financial model results.

Case	Prices			Supply Chain Finances (2)				Power Plant Finances (2)			
	Biofuel price (N$/ tonne)	Elec-tricity price (N$/ MWh)	LUC (1) (N$/ MWh)	Project IRR	Equity IRR	Min DSCR	Max Debt/ EBITDA	Project IRR	Equity IRR	Min DSCR	Min LLCR
Otjiko-to	**395**	**1,240**	**1,773**	**22%**	**32%**	**1.41x**	**3.91x**	**19%**	**29%**	**1.43x**	**1.50x**
Oho-rongo	**430**	**1,215**	**1,742**	**21%**	**31%**	**1.37x**	**3.97x**	**19%**	**31%**	**1.50x**	**1.51x**
Otjiwa-rongo	**345**	**2,185**	**2,948**	**15%**	**30%**	**1.30x**	**3.93x**	**18%**	**28%**	**1.30x**	**1.56x**

(1) LUC – Levelised Unit Cost. Also known as Levelised Cost of Electricity (LCOE).
(2) The constraining hurdle criteria are indicated in grey shading.

The "Electricity Price" as indicated above refers to the electricity sale price in year 1 of the model (i.e. in current terms, more or less). This price is then adjusted for inflation etc. during future years. By comparison, the LUC remains constant over the lifespan of the Power Plant.

The following observations can be made in terms of the relative financial performance:

- The cost advantage (both in terms of electricity sale price and LUC) offered by Ohorongo is quite modest as compared to Otjikoto. This is mainly ascribed to the additional costs imposed on the biomass supply chain by having to compete with the existing EFF operations.
- Despite the above, there clearly is a cost advantage at Ohorongo, and this needs to be considered in addition to the other commercial benefits offered by the Ohorongo scenario, namely access to EFF's practical experience with biomass harvesting in Namibia, a clearly identified investment partner (Schwenk) and a power offtaker (Ohorongo Cement).
- While the cost of biomass is substantially lower for Otjiwarongo, the cost of electricity is substantially higher for this scenario – around double the cost (or 66% more in terms of LUC) as compared to the 20MW power plant options.
- For both the Supply Chain and Power Plant, it is not the project (and equity) returns that constrain the electricity sale price and LUC from dropping even lower; rather it is the lenders criteria (i.e. DSCR and LLCR hurdle rates) on the project finances to ensure adequate solvency in the business. The Project and Equity IRR's are actually highly attractive for all scenarios.
- The model outputs are in broad agreement with the results produced by the original IER model, with the exception of Ojtiwarongo where the electricity sale price has dropped by around 20% from N$2,67 per kWh (IER). This is a result of both model optimisation as well as an input error identified in the Otjiwarongo model (for T&D costs). It is noted that the IER model utilised less stringent hurdle rate criteria (as instructed by KfW at the time), namely a DSCR of 1.2x and Equity IRR of 20% (and no hurdle rates for LLCR, Debt/EBITDA ratio etc.). It is likely that if the Corality model were run with only the Equity IRR and DSCR hurdle rate criteria, the electricity sale price and LUC would drop significantly[1].

While it is ultimately up to NamPower to indicate whether the electricity sale price and LUC outputs for each scenario are considered acceptable (in terms of financial impacts on the overall electricity supply regime), a brief benchmarking exercise is presented in Section 3.2.

[1] A model run indicates that using only an Equity IRR of 20% and DSCR of 1.2x, the Otjikoto base case electricity sale price drops to N$ 1.10 per kWh and a LUC of N$ 1,712 per MWh.

3.2 Benchmarking

Discussions with NamPower and the Electricity Control Board Namibia (ECB) has indicated the following comparative prices for other renewable energy opportunities in Namibia:

Table 7: Selected Namibian renewable energy investment options

Project	Status	Estimated costs
Tsumkwe Energy Project: **Solar PV (200kWp)/Diesel (2x140KVA)/Batteries (700kWh)** **System overall capability: 410kWp**	Off-grid Project commissioned in August 2011; project subsidized	Price per Watt - N$56.10 (source: NamPower)
CBEND (Combating Bush Encroachment for Namibia's Development) Project **250 kW wood gasifier plant**	Plant installed in 2010; PPA negotiation finalised; due to some technical problems not yet operational; problems are being attended to	Unit price Less than N$2.00/kWh (source: NamPower)
CSP 50MW at either Kokerboom or Ausnek with 6-8 hrs of storage	Pre- feasibility studies completed in July 2012 by a consortium led by GESTO Energy Consulting; the study was arranged by Renewable Energy & Energy Efficiency Institute (REEEI) and the Ministry of Mines and Energy with the support of UNDP – GEF and the Ministry of Foreign Affairs of Finland through the Energy and Environment Partnership with Southern and Eastern Africa. Pending is a Full feasibility study and decision on investment	The LUC per kWh for dry cooling technology / trough or tower technology will range between: 0.144 - 0.239 US$/kWh if DFIs financed and implemented by a utility. This converts to 1.42 – 2.36 N$/kWh using the Corality model assumed exchange rate. (source: NamPower)
Solar PV plants by IPPs, country -wide	IPPs are responsible for all the studies. So far 6 companies have been issued with conditional generation licences. One project for 10 MW reported to be proceeding on the basis of a tendered price.	Prices to be negotiated. For the 10 MW tender, the ECB indicates a price expected to be around N$ 2.00 per kWh. (source: ECB)
Wind power projects by IPPs, Luderitz and Walvisbay	So far 2 companies have been issued with conditional licences. However, the ECB has indicated that at least one of the projects is unlikely to proceed and has some doubts regarding the second project as well.	Prices to be negotiated (source: NamPower and ECB)

In the case of CBEND and the IPP solar PV plants, it is not known whether the figures provided are the LUC or the proposed electricity purchase price (sale price). However, the LUC's for Otjikoto and Ohorongo scenarios (circa 1.75 N$/kWh) are clearly comparable to the LUC for the 50 MW CSP project (1.42 – 2.36 N$/kWh). The LUC for Otjiwarongo is significantly higher (2.95 N$/kWh), which is not surprising for a 5 MW system.

International benchmarking of the LUC compared to biomass power plant projects for the UK and USA is shown below:

Table 8: International benchmarking of levelised costs.

Plant Type	Levelised Costs (N$/MWh)		
	Min	Avg	Max
Otjikoto (base case)		1,773	
Ohorongo (base case)		1,742	
Otjiwarongo (base case)		2,948	
Biomass (USA) (1)	969	1,098	1,296
Biomass (UK) (2)	1,745	1,967	2,100

(1) For plants entering service in 2018 (in 2011 dollars). http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm. 9.89 N$/US$.
(2) 5-50 MW plants, 25yr lifespan, financial close 2030. 14.79 N$/GBP.
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/147863/3237-cons-ro-banding-arup-report.pdf.

The results indicate that while all base case scenarios are relatively expensive in comparison to the USA, the Otjikoto and Ohorongo scenarios are actually very cost competitive (in terms of LUC) compared to UK biomass power plants. It is likely that European costs are similar to the UK numbers. Otjiwarongo remains an expensive option in comparison to both the UK and USA benchmark costs.

3.3 Sensitivity Analysis

Twenty three variant scenarios have been run within the WSP-Corality developed model in order to assess how the financial performance of the project may be affected by deviations in the base case assumptions. Of the 23 sub-scenarios, 13 are variants of the Otjikoto base case, 3 are variants of the Ohorongo base case, and 7 are variants of the Otjiwarongo base case. The variable parameters for each sub-scenario and the resultant (revised) electricity sale price and LUC are indicated in the tables below (Tables 9, 10 and 11).

The results indicate the following:

Otjikoto:

The electricity sale price and LUC are fairly resilient to changes in base case assumptions. Variations in key parameters such as labour inflation, diesel costs, additional farmer payments for resource access, higher fuel (biomass) input requirements, higher CAPEX requirements etc. all result in shifts of less than 10% in both electricity sale price and LUC. The only exception is the inflation assumption where a 10% annual inflation assumption (compared to 8% for base case scenario) results in an LUC 21% higher. However this risk will be shared by any power generation investment in the country.

It is further noted that the IPP sub-scenario results in an electricity sale price 5% higher than the base case but only negligible difference to the LUC (<1% shift).

Ohorongo:

Only a small number of variant sub-scenarios have been run for Ohorongo, as the sensitivities are expected to be broadly in line with the Otjikoto sub-scenarios. A sub-scenario for higher fuel (biomass) input requirements was run in view of the higher biomass fuel costs as compared to Otjikoto, however the result was a similarly modest impact on electricity prices in line with that observed for Otjikoto. The IPP sub-scenario results in a 6% increase in electricity sale price and 1% increase in LUC.

Otjiwarongo:

Otjiwarongo generally demonstrated higher sensitivity to key parameters, notably the labour inflation rate where a 2% increase on the base case assumption results in an increase in the LUC of +10%, and a 10% reduction in operating hours at the Power Plant also having a noticeable effect. The “high inflation” sub-scenario results in a 3% drop in the initial electricity sale price but a 24% increase in the LUC. The IPP sub-scenario results in an 11% and 6% increase in electricity sale price and LUC respectively. Higher farmer costs were not modelled as a sub-scenario for Otjiwarongo due to the fact that CCF has practically guaranteed access to around 90,000 ha of land.

3.4 Exclusions

The study has not included certain costs that are likely to be borne by external parties (besides NamPower and/or the IPP), for example, by local municipalities or government i.e. for road and infrastructure upgrade to support the increased truck freight traffic required to deliver the biomass to the power plant.

Table 9: Otjikoto sub-scenarios for sensitivity analysis purposes.

Parameter Alteration	Base Case	Variant Scenario	Electricity Price (N$/MWh)	LUC (N$/MWh)	Electricity Price Shift (cmp. Base Case)	LUC Shift (cmp. Base Case)
			Base Case = 1,240	***Base Case = 1,773***		
High base interest rate	5%	7.5%	1,295	1,786	+4%	+1%
Higher farmer costs for biomass access	N$ 0 per ha	N$200 per ha (SC OPEX)	1,275	1,822	+3%	+3%
Lower farmer costs for biomass access	N$ 0 per ha	N$ 200 per ha (SC revenue)	1,205	1,724	-3%	-3%
Higher labour inflation rate	8% base case	10% labour escalation rate	1,260	1,817	+2%	+2%
Higher PP operating hours	7,500 hrs per annum	+10%	1,215	1,734	-2%	-2%
Lower PP operating hours	7,500 hrs per annum	-10%	1,300	1,851	+5%	+4%
Higher diesel and oil costs	Euro 1 per litre	+15%	1,275	1,822	+3%	+3%
Higher CAPEX required (PP and SC)	10% CAPEX contingency	20% CAPEX contingency	1,305	1,858	+5%	+5%
Lower PP CAPEX	2nd Lowest PP CAPEX quote	Lowest PP CAPEX quote	1,200	1,719	-3%	-3%
Lower gearing ratio (PP and SC)	80% gearing	70% gearing	1,130	1,699	-9%	-4%
High inflation	8%	10%	1,170	2,140	-6%	+21%
Higher woodchip requirement (per kWh) for PP	19.06 t per hr	+10%	1,330	1,896	+7%	+7%
IPP investor (SC and PP)	3.5% margin (above base interest rate) Project discount rate (for NPV and IRR hurdle rate): 8.17% Equity discount rate (for NPV calculation): 11.51% (1)	5.5% margin above base interest rate Project discount rate (for NPV and IRR hurdle rate): 11.41% Equity discount rate (for NPV): 20.05% (1)	1,300	1,778	+5%	0%

Table 10: Ohorongo sub-scenarios for sensitivity analysis purposes.

Parameter Alteration	Base Case	Variant Scenario	Electricity Price (N$/MWh)	LUC (N$/MWh)	Electricity Price Shift (cmp. Base Case)	LUC Shift (cmp. Base Case)
			Base Case = 1,215	***Base Case = 1,742***		
Higher woodchip requirement (per kWh) for PP	18.18 t per hr	+10%	1,285	1,842	+6%	+6%
IPP investor (SC and PP)	3.5% margin (above base interest rate) Project discount rate (for NPV and IRR hurdle rate): 8.17%. Equity discount rate (for NPV calculation): 11.51% (1)	5.5% margin above base interest rate Project discount rate (for NPV and IRR hurdle rate): 11.41%. Equity discount rate (for NPV): 20.05% (1)	1,285	1,757	+6%	+1%
IPP investor (SC and PP) and lower PP CAPEX	As above and use of 2nd lowest CAPEX quote for PP	As above and use of lowest available CAPEX quote for PP	1,220	1,671	0%	-4%

Table 11: Otjiwarongo sub-scenarios for sensitivity analysis purposes.

Parameter Alteration	Base Case	Variant Scenario	Electricity Price (N$/MWh)	LUC (N$/MWh)	Electricity Price Shift (cmp. Base Case)	LUC Shift (cmp. Base Case)
			Base Case = 2,185	***Base Case = 2,948***		
Higher labour inflation rate(2)	8% base case	10% labour escalation rate	2,185	3,252	0%	+10%
Higher PP operating hours	7,500 hrs per annum	+10%	2,005	2,848	-8%	-3%
Lower PP operating hours	7,500 hrs per annum	-10%	2,345	3,265	+7%	+11%
Lower gearing ratio (PP and SC)	80% gearing	70% gearing	1,980	3,016	-9%	+2%
High inflation	8%	10%	2,125	3,664	-3%	+24%
Lower PP CAPEX costs	10% contingency	-20% contingency	1,815	2,754	-17%	-7%
IPP investor (SC and PP)	3.5% margin (above base interest rate) Project discount rate (for NPV and IRR hurdle rate): 8.17%. Equity discount rate (for NPV calculation): 11.51% (1)	5.5% margin above base interest rate Project discount rate (for NPV and IRR hurdle rate): 11.41%. Equity discount rate (for NPV): 20.05% (1)	2,435	3,116	+11%	+6%

(1). An Equity IRR hurdle rate of 20.05% is used for both IPP and NamPower.
(2). Supply Chain Equity Payout Ratio drops from 60% to 40% to maintain adequate cashflow balances for this sub-scenario.

4 Further Commercial Considerations

4.1 Security of Biomass Supply and Harvesting Revenue

A key consideration in this project is assessing the commercial security of supply. This represents, arguably, the biggest commercial risk to the project.

There are three fundamental questions that need to be answered with respect to the biomass supply chain:

- Is there enough biomass?
- Is the project's financial attractiveness resilient to increases in the biomass supply chain cost?
- Is the biomass supply chain commercially secure, preferably via long term contracts?

4.1.1 Physical Availability of Biomass

It has already been discussed elsewhere in this study that the physical quantities of encroacher bush are more than sufficient to sustain a significant number of 20 MW power plants. Hence, physical constraints are unlikely to be a significant issue at a national scale.

Local scarcity can be an issue as debushing activities roll out over time, however this will manifest itself primarily as a cost increase in the biomass supply chain as harvesters and trucks need to travel further to obtain the necessary fuel stock.

4.1.2 Resilience to Biomass Supply Chain Cost Increases

The sensitivity analysis in the preceding section also attempts to account for uncertainty in the supply chain costs. The revised financial model indicates that even if the Supply Chain was required to pay N$ 200 per ha for access to the resource (given that currently, one would expect the farmers to pay the Supply Chain entity a fee for debushing), the impact on the LUC and electricity sale price is limited to a 3% increase. It is further noted that the base case already incorporates the conservative assumption that no revenue will be generated from the farmers for debushing.

4.1.3 Commercial Security of Biomass Supply

The first aspect to consider is the ability for the powerplant to secure short term harvesting contracts. The current modus operandi for EFF, for example, is to charge farmers for the "service" of debushing and harvesting. The price that EFF charges is broadly competitive with the alternative cost of arboricide application by the farmer[2]. It has already been concluded in this study that a significant number of farmers accept and are willing to spend money on debushing their farms, seeing it as a necessary and long term business investment. One study reports that commercial farmers spend in the region of N$ 170 million per annum on managing bush encroachment[3].

Clearly, the alternative debushing methods such as arboricide application cannot compete with a zero-cost price point to farmers, while the alternative debushing option of the farmer manually or mechanically clearing himself followed by charcoal-making also has substantial negatives compared to the proposed EBtP harvesting option (high risk of fires, slower and less efficient operation).

Considering that the commercial farmer benefits substantially from the debushing, it is difficult to imagine a scenario whereby farmers would not want harvesting to take place (on heavily encroached land) at no cost to

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[2] EFF reportedly charges between N$ 300 – N$ 700 per ha while arboricide costs around N$ 500 – N$ 700 per ha.

[3] Chiriboga *et al*. See the Socio-Economic report for more details.

themselves. This adds substantial robustness to the commercial long term security of biomass supply, even in the absence of long term contracts with the farmers i.e. harvesting for energy generation appears to be able to commercially outcompete all other debushing alternatives currently available, either on price (arboricide) or on efficiency and risk (manual/mechanical clearing followed by charcoal making), by fully subsidizing the cost with electricity sales.

Based on feedback from farmers as well as EFF, it appears unlikely that commercial farmers will commit to long term harvesting contracts. Due to the direct dependence on the climatic conditions and rainfall, farmers are very hesitant to commit themselves for long term contracts which are going to cost them a specific amount each year. They would assess their position after the rainy season each year and base their needs for debushing on that assessment.

However, considering the ability of the EBtP project to undertake harvesting at zero (or low) charge to farmers, the possibility of establishing long term contracts under terms which are sufficiently attractive to commercial farmers may still be a possibility. At least initially, however, there appears to be an adequate market for charging farmers on the basis of short term contracts.

Finally it is noted that in the case of the Otjiwarongo plant, CCF is confident of having around 90,000 ha available for debushing (CCF land and a neighbour's land) to start off with, which should be sufficient to sustain the powerplant for the first few years at least.

4.2 Identification of Potential Investors

4.2.1 Overview of Energy Investment Framework in Namibia

Discussions with the ECB indicated the following energy framework in Namibia:

- At present, Namibia operates on a Single Buyer model, where the buyer is NamPower. An IPP would typically be required to enter into a Power Purchase Agreement (PPA) with NamPower.
- There is no intention at present or in the foreseeable future to implement a feed in tariff. The preferred approach is to engage in a tendering process for renewable energy generation. The winner would then enter into a PPA with NamPower who would pass on the price increase. A cautious approach is being adopted in order to avoid price shocks to the end customer.
- Although this has not been done to date, the ECB can, on an ad hoc basis, elect to allow an IPP to sell directly to a customer. A wheeling charge would need to be determined for NamPower.
- The ECB would like to promote IPP entry into Namibia. The ECB is open to NamPower and other investors forming a partnership for investment in power generation.
- The transmission infrastructure operates on the basis of a natural monopoly (NamPower), however the ECB has the authority to license a new transmission entity i.e. a single line company from an IPP directly to a customer.

4.2.2 Generic Investor Options

WSP has reviewed various available funding sources and possible financial structures for the Project in order to develop financing options that will maximize returns on investment to the Project's sponsor(s). Such sponsors potentially include international development banks, specialized investment funds, commercial banks, and independent power producers.

Potential participants in project financing and ownership structures include (Figure 1):

- Donors and Regional Development Banks - Multilateral development banks such as the World Bank Group/ International Finance Corporation (IFC), the African Development Bank, and other donor agencies/institutions such as Global Environmental Facility (GEF) and UNIDO, are possible funding sources for infrastructure projects in Namibia.

- Bilateral and Export Credit Agencies ("ECAs") - ECAs typically offer loans or guarantees tied to goods and services exported from the country of origin, although covered amounts include a significant percentage of local content. ECA loans or guarantee programs could provide support for this Project, depending on the Project's final structure. ECAs include the US Ex-Im Bank, OPIC, ECGD, Coface, KfW, JICA/JBIC, SACE, etc.
- Local and International Commercial Banks and Institutional lenders - Local and International Commercial bank involvement will depend on the strength (and breadth) of the risk coverage available, given the project's risk profile, and the re-opening of the credit markets globally. International commercial banks are typically cautious in providing long-term financing without political and commercial risk guarantees from governmental/multilateral institutions. Local financiers might be more willing to support domestic projects in Namibia.
- Investment Funds - There are several investment funds that provide funding for energy and infrastructure projects in Namibia, such as the Inspired Evolution Fund, Reliance Diversified Power Sector Fund, OPIC's Global Environment Emerging Markets Funds, and other private equity funds.
- Carbon Finance Institutions - Various carbon finance institutions are active globally and may be willing to offer attractive terms for participation in the Project.
- Independent Power Producers – Several renewable power project development companies currently operate in Southern Africa. Among these are Exxaro, Cennergi, Veolia, BioTherm, Globeleq, and GDF SUEZ.

In the event that NamPower wishes to not have the encroacher bush-to-power project on its own balance sheet, the likely alternative project financing structure would use the Build/Own/Operate/Transfer (BOOT) or IPP model. In the BOOT structure, NamPower delegates to a 3rd-party entity the concession to design and build the power plant and to then operate and maintain the plant for a certain period. During this period, the 3rd-party entity (special-purpose corporation – SPC) owns the plant, has the responsibility to arrange the financing for the project, and retains all revenues generated by the project. At the end of the concession period, ownership of the plant transfers to NamPower. BOOT has advantage over NamPower owning the plant from the outset by transferring technical and financial risk away from NamPower and by taking the plant off of NamPower's balance sheet, while providing NamPower the opportunity to be an SPC shareholder. Plant operations would typically be outsourced by the SPC to a specialized O&M company (which could be NamPower itself).

Several entities may play key roles in a financing structure for the Project. Generic representations of such players are presented below. This generic roster of players is equally applicable to a BOOT project structure centering on an SPC or an IPP structure centering on an IPP (independent power producer).

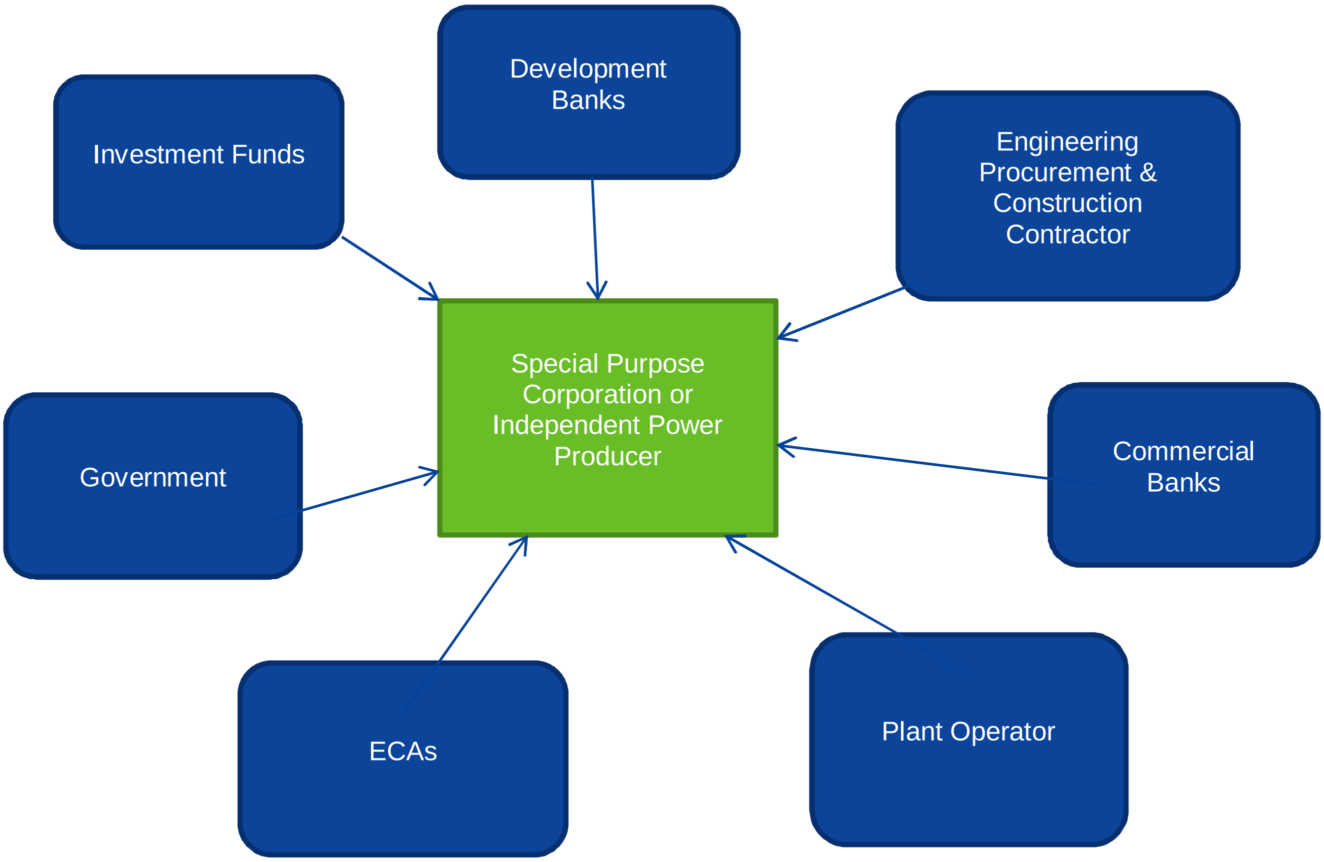


Figure 1: Roleplayers in setting up an IPP or SPC.

An IPP structure differs from BOOT in that the plant owner/operator is a specialized company that itself performs plant O&M and retains ownership of the plant. Like BOOT, the IPP structure has advantage over NamPower owning the plant from the outset by transferring technical and financial risk away from NamPower and by taking the plant off of NamPower's balance sheet. Similar to BOOT, in which NamPower has the opportunity to be an equity player (in that case a shareholder in the SPC), NamPower would have the possibility of being an equity partner to the IPP under the IPP project structure alternative.

It is worth noting at this stage that ownership and management of the harvesting part if the operation can also be separated out from the SPC or IPP entity. Either this can be wholly outsourced (via supply contracts) or it can be a separate commercial entity but with common ownership structure. An example is Ohorongo Cement and EFF, where Schwenk are majority owners of Ohorongo Cement (around 60% plus) while EFF is also a 100% owned subsidiary of Scwenk.

A list of generic potential investors is included in **Appendix C**.

4.2.3 Scenario-Specific Investment Partners

Some scenario-specific investment options available are:

<u>Otjiwarongo:</u>

CCF: The Otjiwarongo option provides the opportunity to partner with the CCF as co-investor. On the face of it, CCF would make an unlikely partner, being a conservation focused non-profit organization. However CCF is already giving consideration to investing in an EBtP as an IPP (in order to supply the nearby gold mine currently under construction – requiring 12.5 MWe – although they are also considering a smaller unit of 2 MWe and/or perhaps trying to acquire the smaller DRFN unit). This presumably would be with the support of CCF's investment contacts in the USA, which is likely to comprise both private equity as well as US donor financing.

Additionally, CCF is highly interested in acting as a harvesting subcontractor or contract biomass fuel supplier, regardless of any opportunities to participate in the powerplant component of the project.

Key Persons: Dr Bruce Brewer (General Manager) or Mr Dan Beringer (Biomass Project Manager)

Shared Value Africa (Private Equity-linked consultants): Shared Value Africa (SVA) is a management and consulting firm focusing on commercially driven projects that address socio-environmental risks in the Sub-Saharan Africa region. They have links to several private equity investors active the Sub-Saharan African energy market. SVA specializes in designing and implementing market-driven approaches that meet the need for energy, access to finance, nutrition, health and communications in low-income communities throughout Africa. WSP came across SVA through SVA's interest in CCF. SVA's interest is focused on the potential for expanding CCF's Bushblok product both from Namibian encroacher bush as well as elsewhere in Africa. While the interest of SVA and its network of private equity investors in an EBtP is difficult to gauge at this stage, it is something worth considering, seeing as SVA is already expressing interest in a encroacher bush-related energy opportunities.

Key Persons: Mr John Fay (Director)

Ohorongo:

Schwenk Zement KG:

Schwenk is a major cement manufacturing company headquartered in Germany. They are the majority owners of Ohorongo Cement and 100% owners of EFF. Schwenk has expressed a strong interest in collaborating on an EBtP facility at Ohorongo. The sentiment expressed by Schwenk is that they are not interested in supporting any other EBtP venture or location other than at Ohorongo Cement. The role of Scwenk would be subject to negotiation but is likely to include:

- Equity investor in the SPC;
- Technical partner (engineering design, experience in negotiating international finance arrangements etc.);
- Technical support for and equity ownership in an "EFF-2" entity set up to supply the power station;
- Customer to purchase the electricity (i.e. Ohorongo Cement).

In addition, Schwenk would provide other support in the form of existing infrastructure as well as waste heat load from the cement kiln at Ohorongo Cement.

Key Person: Mr Klaus Bauer (Technical Director)

Otjikoto:

While it is not impossible that Schwenk could be convinced to support an EBtP facility at Otjikoto instead of Ohorongo, the basis for the Otjikoto scenario is if NamPower did not have Schwenk as a partner and wished to develop the EBtP in any event. Under this scenario, there are no immediately obvious partner institutions and NamPower / KfW would need to solicit investment partners from the "generic" pool of potential partners (see **Appendix C** as well as Agro-Sector Investors section below).

Torrefaction:

UFF Agri Asset Management:

UFF is a Dutch-South African agro-sector focused private equity firm linked to Old Mutual's FutureGrowth fund. UFF are partially owned by the Dutch Development Bank. As described in companion reports to this document, UFF are interested in establishing a torrefaction plant based entirely on UFF-sourced finance (i.e. no equity required from NamPower, KfW or DBSA). NamPower's involvement would be entirely as a customer for the torrefied product.

Key Person: Mr Theo van der Veen (European office), Mr Paul Paree (Cape Town office)

Green Coal:

Similar to UFF, Green Coal offers the opportunity for a commercial scale torrefaction unit independent of any equity input from NamPower, KfW or DBSA. Green Coal is an entrepreneurial enterprise owned by South African-based businessman, Mr Gershon Ben Tovim. Green Coal reportedly has adequate finance in place to establish a commercial scale facility, should NamPower agree to enter into a supply contract. It is understood that the Israel Electric Corporation (IEC) may also participate as an equity partner in any Green Coal torrefaction facility.

Key Person: Mr Gershon Ben Tovim (CEO)

4.2.4 Agro-Sector Investors and Government Agro-Sector Subsidies

The impact of encroacher bush on the commercial agro-sector in Namibia is such that agro-sector focused financial institutions may also be interested in participating as investment partners. **UFF** is an obvious candidate with whom to engage in discussions regarding an EBtP plant. UFF has already indicated a strong interest in investing in an encroacher bush-related energy development (torrefaction) and has a strong interest in helping to develop the Namibian agro-sector. While UFF has to date only indicated an interest in investing in a torrefaction facility, there does not appear to be any obvious reason why UFF would not also be interested in an EBtP facility as well.

An additional option may be the **Agricultural Bank of Namibia** (Agribank), a Namibian State owned institution with a mandate to support and promote development of the agricultural sector in Namibia. In part, involvement of the Agribank would be linked to possible Ministry of Agriculture support (and subsidy) for the proposed project. The political reality in Namibia is such that meaningful subsidy or support for the project may be difficult to obtain so long as the focus is on debushing and harvesting from commercial (predominantly white-owned) farmland. If and when the project seeks to focus on debushing of communal farm land, some type of financial involvement on the part of the Agribank and/or Ministry of Agriculture (in terms of subsidy support) will certainly be worth exploring.

Appendix A: Selected Model Input Parameters

		Otjikoto	Ohorongo	Otjiwarongo
Technology				
Location selection		Otjikoto	Ohorongo	Otjiwarongo
Technology selection		BI	BI	KIV
Funding				
Supply chain investor		NamPower	NamPower	NamPower
Power plant investor		NamPower	NamPower	NamPower
Supply chain gearing		80.00%	80.00%	80.00%
Power plant gearing		80.00%	80.00%	80.00%
Supply chain- equity payout ratio		60.00%	60.00%	60.00%
Power plant- equity payout ratio		60.00%	60.00%	60.00%
<u>Debt funding of replacement machinery</u>				
Harvesting and transport machinery		80.00%	80.00%	80.00%
Supply chain				
Construction period	Months	24	24	18
Machinery contingency		20.00%	20.00%	20.00%
Global capex contingency		10.00%	10.00%	10.00%
Biofuel price	NAD/tonne	395	430	345
Initial stockpile (at power plant)	t mass	50,000	50,000	15,500
Farmer payments	NAD/ha	0	0	0
Power plant				
Construction period	Months	18	18	12
Capex contingency		10.00%	10.00%	10.00%
Electricity price	NAD/MWh	1,240	1,215	2,250

Appendix B: Summary Financial Model Outputs for Base Case Scenarios

Note: The “Scenarios” table info for sub-scenarios “Otjikoto high operating hours”, “Otjikoto low operating hours”, “Otjikoto lowest power plant quote” and “Otjikoto – More Woodchips” are not correct. This relates to the structure of the model whereby these sub-scenarios require changes within the model “Inputs” worksheet (as opposed to altering parameters form the “Scenarios” worksheet) and hence must be run as a completely separate scenario. The required changes within the “Inputs” worksheet (for the three aforementioned sub-scenarios) relate to the SC number of plant required and hence the varying levels of SC CAPEX requirement.

coraality

Base case: Otjikoto
NamPower
Encroacher bush to power | Advanced draft

NamPower
Powering the Nation and beyond

Project characteristics

Location	Otjikoto
Technology	BI
Biofuel price (NAD/t)	395
Electricity price (NAD/MWh)	1,240
Payment to farmers (NAD/ha)	-
Radius of harvesting area (km)	70.75
Lorries required	24
Supply chain investor	NamPower
Supply chain gearing	80.00%
Power plant investor	NamPower
Power plant gearing	80.00%

Timing

	Supply	Plant
Construction start	01-Jan-15	01-Jul-16
Construction end	31-Dec-16	31-Dec-17
Operations start	01-Jan-17	01-Jan-18
Operations end	31-Dec-41	31-Dec-42

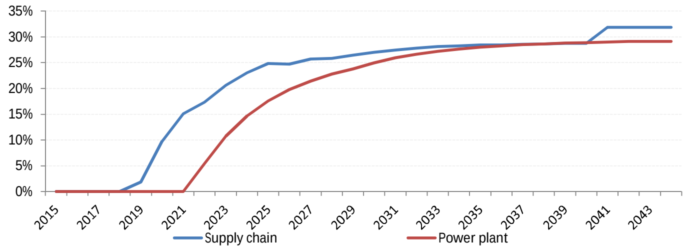
Returns (nom)

	Supply	Plant
Project IRR	22.04%	18.54%
Equity IRR	31.88%	29.12%
LUC @ 8.17% (NAD/MWh)		1,773

Debt ratios

	Supply	Plant
Min DSCR	1.41x	1.43x
Avg DSCR	1.99x	1.74x
Min LLCR		1.50x
LLCR @ ops start	4.21x	1.67x
PLCR @ ops start	4.21x	3.07x

Rolling equity IRR (%)

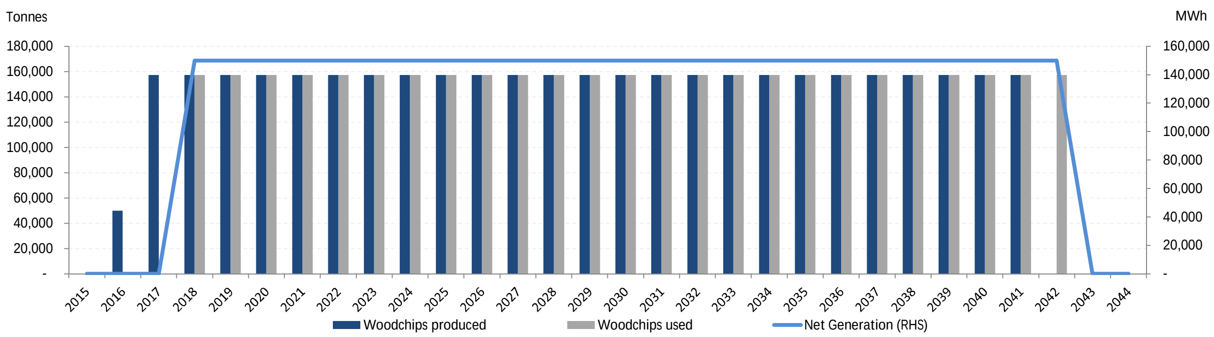


Scenarios

Case	All hurdles met?	Biofuel price (NAD/tonne)	Electricity price (NAD/MWh)	LUC (NAD/MWh)	Supply chain: Project IRR	Supply chain: Equity IRR	Supply chain: Min DSCR	Supply chain: Max Debt/EBITDA	Power plant: Project IRR	Power plant: Equity IRR	Power plant: Min DSCR	Power plant: Min LLCR
Base case: Otjikoto	**Yes**	**395**	**1,240**	**1,773**	**22.04%**	**31.88%**	**1.41x**	**3.91x**	**18.54%**	**29.12%**	**1.43x**	**1.50x**
Base case: Ohorongo	**Yes**	**430**	**1,215**	**1,742**	**21.23%**	**30.94%**	**1.37x**	**3.97x**	**19.32%**	**30.98%**	**1.50x**	**1.51x**
Base case: Otjiwarongo	**Yes**	**345**	**2,250**	**2,948**	**14.53%**	**29.86%**	**1.30x**	**3.93x**	**18.27%**	**29.31%**	**1.37x**	**1.63x**
Otjikoto high base interest rate	**Yes**	**400**	**1,295**	**1,786**	**22.64%**	**31.47%**	**1.32x**	**3.85x**	**19.51%**	**29.69%**	**1.37x**	**1.51x**
Otjikoto high farmer costs	**Yes**	**415**	**1,275**	**1,822**	**22.01%**	**31.85%**	**1.41x**	**3.91x**	**18.76%**	**29.65%**	**1.45x**	**1.50x**
Otjikoto low farmer costs	**Yes**	**375**	**1,205**	**1,724**	**22.06%**	**31.91%**	**1.41x**	**3.91x**	**18.31%**	**28.58%**	**1.40x**	**1.50x**
Otjikoto 10% labour escalation	**Yes**	**395**	**1,260**	**1,817**	**20.59%**	**30.78%**	**1.41x**	**3.91x**	**18.70%**	**29.73%**	**1.46x**	**1.51x**
~~**Otjikoto high operating hours**~~	~~**Yes**~~	~~**405**~~	~~**1,215**~~	~~**1,734**~~	~~**24.18%**~~	~~**36.18%**~~	~~**1.62x**~~	~~**3.33x**~~	~~**19.19%**~~	~~**30.70%**~~	~~**1.49x**~~	~~**1.52x**~~
~~Otjikoto low operating hours~~	~~No~~	~~395~~	~~1,300~~	~~1,851~~	~~20.19%~~	~~28.60%~~	~~1.24x~~	~~4.44x~~	~~18.14%~~	~~28.17%~~	~~1.39x~~	~~1.51x~~
Otjikoto high diesel cost	**Yes**	**415**	**1,275**	**1,822**	**22.07%**	**31.95%**	**1.41x**	**3.90x**	**18.76%**	**29.65%**	**1.45x**	**1.50x**
Otjikoto high investment cost	**Yes**	**410**	**1,305**	**1,858**	**22.88%**	**32.29%**	**1.39x**	**3.96x**	**18.32%**	**28.59%**	**1.40x**	**1.50x**
~~**Otjikoto lowest power plant quote**~~	~~**Yes**~~	~~**395**~~	~~**1,200**~~	~~**1,719**~~	~~**21.47%**~~	~~**31.09%**~~	~~**1.37x**~~	~~**4.00x**~~	~~**18.87%**~~	~~**29.91%**~~	~~**1.46x**~~	~~**1.51x**~~
Otjikoto 70% gearing	**Yes**	**365**	**1,130**	**1,699**	**16.38%**	**22.30%**	**1.39x**	**3.99x**	**17.00%**	**22.56%**	**1.46x**	**1.51x**
Otjikoto high inflation	**Yes**	**395**	**1,170**	**2,140**	**23.64%**	**34.00%**	**1.41x**	**3.91x**	**19.16%**	**28.96%**	**1.31x**	**1.55x**
~~**Otjikoto - More Woodchips**~~	~~**Yes**~~	~~**405**~~	~~**1,330**~~	~~**1,896**~~	~~**24.18%**~~	~~**36.18%**~~	~~**1.62x**~~	~~**3.33x**~~	~~**19.16%**~~	~~**30.63%**~~	~~**1.49x**~~	~~**1.51x**~~

Production

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Woodchips produced	3,981,125	1,307,960	-	50,000	157,245	157,245	157,245	157,245	157,245	157,245	157,245	157,245
Woodchips used	3,931,125	1,100,715	-	-	-	157,245	157,245	157,245	157,245	157,245	157,245	157,245
Net generation (MWh)	3,750,000	1,050,000	-	-	-	150,000	150,000	150,000	150,000	150,000	150,000	150,000



Supply chain

Cashflows

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue	4,560,490	680,410	-	19,750	62,112	67,081	72,447	78,243	84,502	91,263	98,564	106,449
Opex	(2,318,431)	(346,875)	-	(11,179)	(31,560)	(34,085)	(36,812)	(39,757)	(42,938)	(46,373)	(50,082)	(54,089)
Working capital adjustments	-	(6,344)	-	(1,398)	(2,304)	(296)	(320)	(345)	(373)	(403)	(435)	(470)
Operating cashflows	2,242,059	327,192	-	7,174	28,247	32,699	35,315	38,141	41,192	44,487	48,046	51,890
Capex	(1,238,647)	(197,528)	(76,293)	(79,676)	-	-	-	-	-	(41,559)	-	-
Funding	1,238,647	197,528	76,293	79,676	-	-	-	-	-	41,559	-	-
Taxes and other	(380,057)	(33,754)	-	-	(2,914)	-	-	(3,404)	(4,828)	(6,492)	(7,711)	(8,405)
CFADS	1,862,002	293,438	-	7,174	25,333	32,699	35,315	34,736	36,364	37,995	40,336	43,485
Interest	(339,683)	(65,419)	-	-	(11,230)	(10,486)	(9,418)	(8,252)	(6,979)	(5,638)	(7,352)	(6,064)
Principal	(590,256)	(102,200)	-	-	(5,429)	(11,602)	(12,669)	(13,835)	(15,108)	(14,262)	(14,003)	(15,292)
Cash available for equity	932,064	125,818	-	7,174	8,675	10,612	13,228	12,649	14,276	18,095	18,980	22,129
Dividends	(932,064)	(115,066)	-	-	-	(19,615)	(13,829)	(12,385)	(13,480)	(16,608)	(18,158)	(20,990)
Net cashflow	(0)	10,752	-	7,174	8,675	(9,003)	(601)	264	796	1,487	822	1,140
Cash balance B/f			-	-	7,174	15,849	6,845	6,244	6,508	7,304	8,791	9,613
Cash balance C/f			-	7,174	15,849	6,845	6,244	6,508	7,304	8,791	9,613	10,752

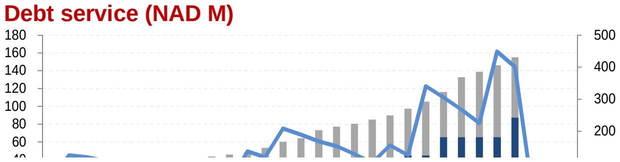
Cashflows (NAD '000)

Uses

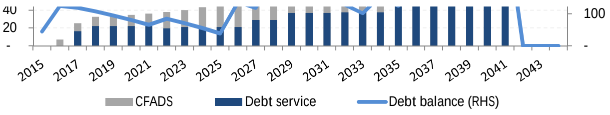
	NAD '000	%
Machinery	1,228,710	99.20%
Other capex	-	-
IDC & Fees	9,937	0.80%
Total	1,238,647	100.00%

Sources

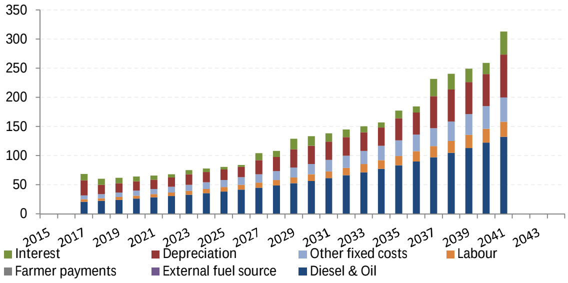
Debt service (NAD M)



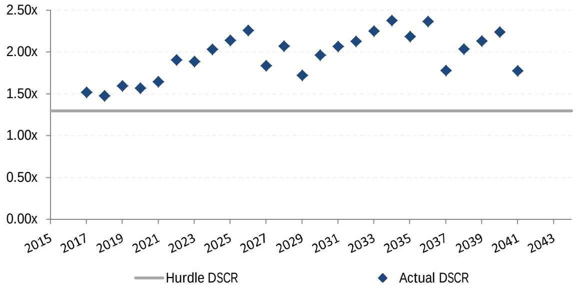
Initial equity	31,194	2.52%
Debt	990,917	80.00%
Additional equity	216,536	17.48%
Total	1,238,647	100.00%



Cost breakdown (NAD M)



Actual DSCR and hurdle DSCR



Power plant

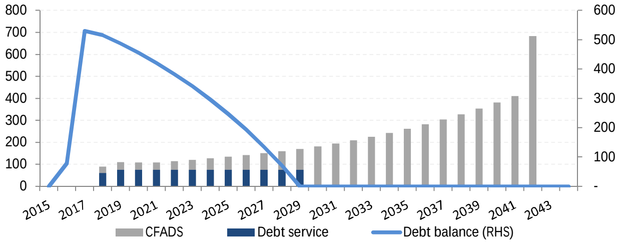
Cashflows (NAD '000)

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue	14,685,521	1,792,413	-	-	-	200,880	216,950	234,306	253,051	273,295	295,159	318,771
Opex	(6,799,047)	(956,045)	-	(19,750)	(62,112)	(98,103)	(105,903)	(114,326)	(123,423)	(133,248)	(143,859)	(155,319)
Working capital adjustments	-	(10,201)	-	3,220	3,666	(13,296)	(517)	(558)	(603)	(651)	(703)	(759)
Operating cashflows	7,886,474	826,167	-	(16,530)	(58,446)	89,480	110,531	119,422	129,025	139,396	150,596	162,693
Capex	(587,947)	(587,947)	-	(194,833)	(393,115)	-	-	-	-	-	-	-
Funding	662,923	662,923	-	211,363	451,560	-	-	-	-	-	-	-
Taxes and other	(2,360,562)	(121,676)	-	-	-	-	-	(10,779)	(20,624)	(25,105)	(29,957)	(35,211)
CFADS	5,600,887	779,467	-	-	-	89,480	110,531	108,643	108,401	114,291	120,639	127,482
Interest	(355,696)	(277,453)	-	-	-	(47,730)	(45,864)	(43,186)	(40,260)	(37,066)	(33,578)	(29,769)
Principal	(530,338)	(233,725)	-	-	-	(13,620)	(29,107)	(31,786)	(34,711)	(37,905)	(41,393)	(45,203)
Cash available for equity	4,714,853	268,288	-	-	-	28,130	35,559	33,671	33,430	39,320	45,668	52,510
Dividends	(4,714,853)	(256,792)	-	-	-	(22,204)	(32,583)	(35,194)	(34,026)	(38,067)	(44,015)	(50,703)
Net cashflow	-	11,496	-	-	-	5,926	2,976	(1,522)	(596)	1,253	1,653	1,807
Cash balance B/f			-	-	-	-	5,926	8,902	7,380	6,783	8,036	9,689
Cash balance C/f			-	-	-	5,926	8,902	7,380	6,783	8,036	9,689	11,496

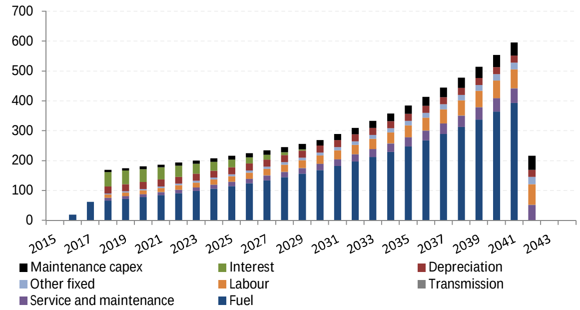
Sources & Uses (NAD '000)

Uses	NAD '000	%
Construction costs	557,451	84.09%
Negative pre-operating cashflows	74,975	11.31%
IDC & Fees	30,496	4.60%
Total	662,923	100.00%
Sources		
Initial equity	132,585	20.00%
Debt	530,338	80.00%
Additional equity	0	0.00%
Total	662,923	100.00%

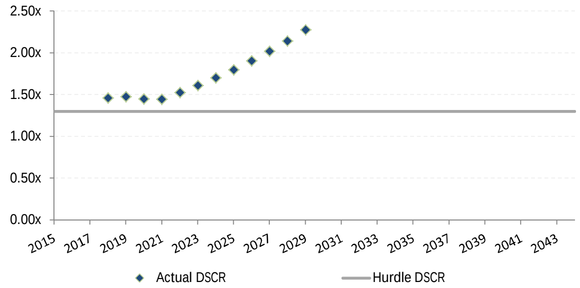
Debt service (NAD M)



Cost breakdown (NAD M)



Actual DSCR and hurdle DSCR



Base case: Ohorongo
NamPower
Encroacher bush to power | Advanced draft

Project characteristics

Location	Ohorongo
Technology	BI
Biofuel price (NAD/t)	430
Electricity price (NAD/MWh)	1,215
Payment to farmers (NAD/ha)	-
Radius of harvesting area (km)	87.40
Lorries required	28
Supply chain investor	NamPower
Supply chain gearing	80.00%
Power plant investor	NamPower
Power plant gearing	80.00%

Timing

	Supply	Plant
Construction start	01-Jan-15	01-Jul-16
Construction end	31-Dec-16	31-Dec-17
Operations start	01-Jan-17	01-Jan-18
Operations end	31-Dec-41	31-Dec-42

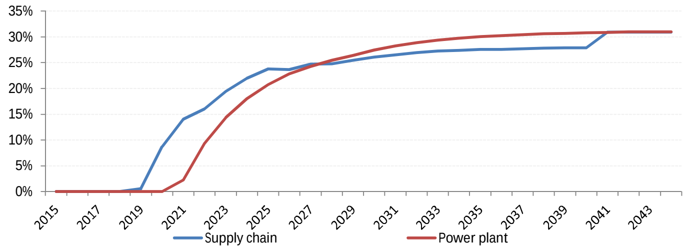
Returns (nom)

	Supply	Plant
Project IRR	21.23%	19.32%
Equity IRR	30.94%	30.98%
LUC @ 8.17% (NAD/MWh)		1,742

Debt ratios

	Supply	Plant
Min DSCR	1.37x	1.50x
Avg DSCR	1.95x	1.82x
Min LLCR		1.51x
LLCR @ ops start	4.16x	1.75x
PLCR @ ops start	4.16x	3.24x

Rolling equity IRR (%)

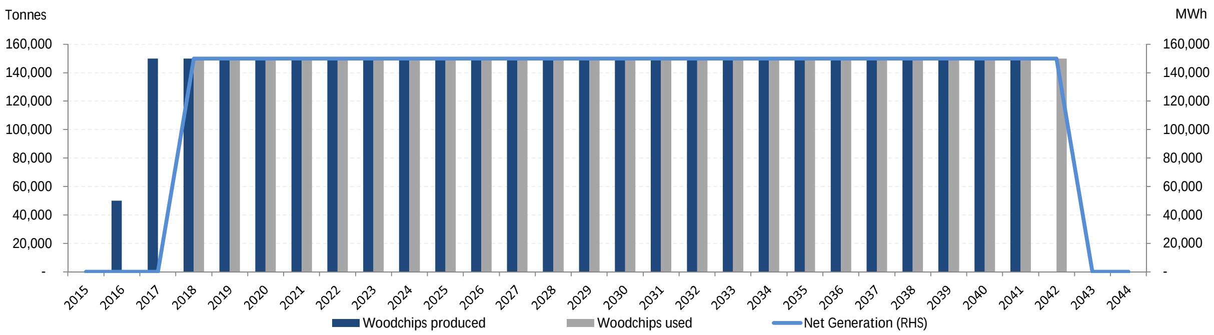


Scenarios

Case	All hurdles met?	Biofuel price (NAD/tonne)	Electricity price (NAD/MWh)	LUC (NAD/MWh)	Supply chain: Project IRR	Supply chain: Equity IRR	Supply chain: Min DSCR	Supply chain: Max Debt/EBITDA	Power plant: Project IRR	Power plant: Equity IRR	Power plant: Min DSCR	Power plant: Min LLCR
Base case: Otjikoto	**Yes**	**395**	**1,240**	**1,773**	**22.04%**	**31.88%**	**1.41x**	**3.91x**	**18.54%**	**29.12%**	**1.43x**	**1.50x**
Base case: Ohorongo	**Yes**	**430**	**1,215**	**1,742**	**21.23%**	**30.94%**	**1.37x**	**3.97x**	**19.32%**	**30.98%**	**1.50x**	**1.51x**
Base case: Otjiwarongo	**Yes**	**345**	**2,250**	**2,948**	**14.53%**	**29.86%**	**1.30x**	**3.93x**	**18.27%**	**29.31%**	**1.37x**	**1.63x**
Otjikoto high base interest rate	**Yes**	**400**	**1,295**	**1,786**	**22.64%**	**31.47%**	**1.32x**	**3.85x**	**19.51%**	**29.69%**	**1.37x**	**1.51x**
Otjikoto high farmer costs	**Yes**	**415**	**1,275**	**1,822**	**22.01%**	**31.85%**	**1.41x**	**3.91x**	**18.76%**	**29.65%**	**1.45x**	**1.50x**
Otjikoto low farmer costs	**Yes**	**375**	**1,205**	**1,724**	**22.06%**	**31.91%**	**1.41x**	**3.91x**	**18.31%**	**28.58%**	**1.40x**	**1.50x**
Otjikoto 10% labour escalation	**Yes**	**395**	**1,260**	**1,817**	**20.59%**	**30.78%**	**1.41x**	**3.91x**	**18.70%**	**29.73%**	**1.46x**	**1.51x**
~~**Otjikoto high operating hours**~~	~~**Yes**~~	~~**405**~~	~~**1,215**~~	~~**1,734**~~	~~**24.18%**~~	~~**36.18%**~~	~~**1.62x**~~	~~**3.33x**~~	~~**19.19%**~~	~~**30.70%**~~	~~**1.49x**~~	~~**1.52x**~~
~~Otjikoto low operating hours~~	~~No~~	~~395~~	~~1,300~~	~~1,851~~	~~20.19%~~	~~28.60%~~	~~1.24x~~	~~4.44x~~	~~18.14%~~	~~28.17%~~	~~1.39x~~	~~1.51x~~
Otjikoto high diesel cost	**Yes**	**415**	**1,275**	**1,822**	**22.07%**	**31.95%**	**1.41x**	**3.90x**	**18.76%**	**29.65%**	**1.45x**	**1.50x**
Otjikoto high investment cost	**Yes**	**410**	**1,305**	**1,858**	**22.88%**	**32.29%**	**1.39x**	**3.96x**	**18.32%**	**28.59%**	**1.40x**	**1.50x**
~~**Otjikoto lowest power plant quote**~~	~~**Yes**~~	~~**395**~~	~~**1,200**~~	~~**1,719**~~	~~**21.47%**~~	~~**31.09%**~~	~~**1.37x**~~	~~**4.00x**~~	~~**18.87%**~~	~~**29.91%**~~	~~**1.46x**~~	~~**1.51x**~~
Otjikoto 70% gearing	**Yes**	**365**	**1,130**	**1,699**	**16.38%**	**22.30%**	**1.39x**	**3.99x**	**17.00%**	**22.56%**	**1.46x**	**1.51x**
Otjikoto high inflation	**Yes**	**395**	**1,170**	**2,140**	**23.64%**	**34.00%**	**1.41x**	**3.91x**	**19.16%**	**28.96%**	**1.31x**	**1.55x**
~~**Otjikoto - More Woodchips**~~	~~**Yes**~~	~~**405**~~	~~**1,330**~~	~~**1,896**~~	~~**24.18%**~~	~~**36.18%**~~	~~**1.62x**~~	~~**3.33x**~~	~~**19.16%**~~	~~**30.63%**~~	~~**1.49x**~~	~~**1.51x**~~

Production

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Woodchips produced	3,798,800	1,249,616	-	50,000	149,952	149,952	149,952	149,952	149,952	149,952	149,952	149,952
Woodchips used	3,748,800	1,049,664	-	-	-	149,952	149,952	149,952	149,952	149,952	149,952	149,952
Net generation (MWh)	3,750,000	1,050,000	-	-	-	150,000	150,000	150,000	150,000	150,000	150,000	150,000



Supply chain

Cashflows

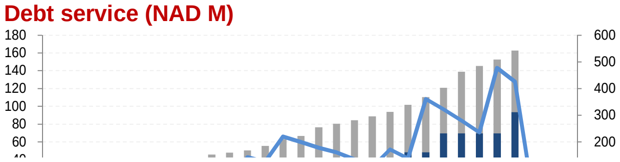
	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue	4,735,324	707,343	-	21,500	64,479	69,638	75,209	81,225	87,723	94,741	102,321	110,506
Opex	(2,405,704)	(360,419)	-	(12,169)	(32,741)	(35,360)	(38,189)	(41,244)	(44,543)	(48,107)	(51,955)	(56,112)
Working capital adjustments	-	(6,593)	-	(1,521)	(2,325)	(308)	(332)	(359)	(388)	(419)	(452)	(488)
Operating cashflows	2,329,620	340,331	-	7,810	29,413	33,970	36,688	39,623	42,793	46,216	49,913	53,906
Capex	(1,327,180)	(213,123)	(80,533)	(84,104)	-	-	-	-	-	(48,486)	-	-
Funding	1,327,180	213,123	80,533	84,104	-	-	-	-	-	48,486	-	-
Taxes and other	(382,915)	(33,345)	-	-	(3,173)	-	-	(2,777)	(4,810)	(6,462)	(7,931)	(8,192)
CFADS	1,946,706	306,987	-	7,810	26,241	33,970	36,688	36,846	37,983	39,754	41,982	45,714
Interest	(359,121)	(69,052)	-	-	(11,854)	(11,052)	(9,902)	(8,645)	(7,273)	(5,827)	(7,940)	(6,559)
Principal	(636,271)	(110,000)	-	-	(5,850)	(12,502)	(13,652)	(14,909)	(16,281)	(15,418)	(15,004)	(16,384)
Cash available for equity	951,313	127,934	-	7,810	8,537	10,416	13,134	13,291	14,429	18,508	19,039	22,771
Dividends	(951,313)	(116,879)	-	-	-	(19,839)	(13,769)	(12,898)	(13,671)	(16,930)	(18,286)	(21,486)
Net cashflow	-	11,055	-	7,810	8,537	(9,423)	(635)	394	757	1,578	752	1,285
Cash balance B/f			-	-	7,810	16,346	6,924	6,288	6,682	7,440	9,018	9,770
Cash balance C/f			-	7,810	16,346	6,924	6,288	6,682	7,440	9,018	9,770	11,055

Cashflows (NAD '000)

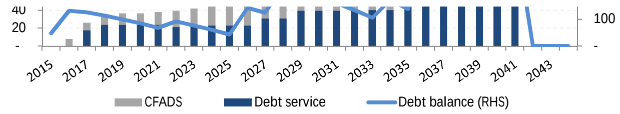
Uses	NAD '000	%
Machinery	1,316,690	99.21%
Other capex	-	-
IDC & Fees	10,489	0.79%
Total	1,327,180	100.00%

Sources

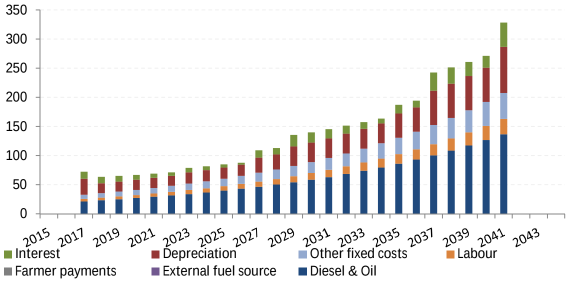
Debt service (NAD M)



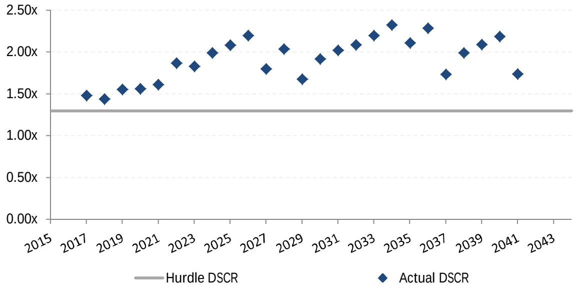
Initial equity	32,927	2.48%
Debt	1,061,744	80.00%
Additional equity	232,508	17.52%
Total	1,327,180	100.00%



Cost breakdown (NAD M)



Actual DSCR and hurdle DSCR



Power plant

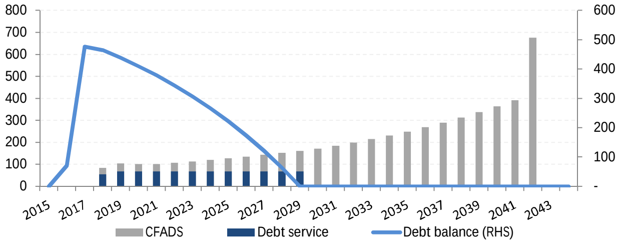
Cashflows (NAD '000)

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue	14,389,442	1,756,275	-	-	-	196,830	212,576	229,583	247,949	267,785	289,208	312,344
Opex	(6,835,245)	(970,560)	-	(21,500)	(64,479)	(99,515)	(107,336)	(115,782)	(124,905)	(134,757)	(145,398)	(156,889)
Working capital adjustments	-	(9,430)	-	3,505	3,643	(13,038)	(483)	(521)	(563)	(608)	(657)	(709)
Operating cashflows	7,554,197	776,285	-	(17,995)	(60,836)	84,277	104,758	113,279	122,481	132,420	143,154	154,746
Capex	(517,843)	(517,843)	-	(171,607)	(346,236)	-	-	-	-	-	-	-
Funding	596,674	596,674	-	189,602	407,072	-	-	-	-	-	-	-
Taxes and other	(2,283,509)	(121,197)	-	-	-	-	-	(10,990)	(20,841)	(25,077)	(29,663)	(34,628)
CFADS	5,349,518	733,918	-	-	-	84,277	104,758	102,289	101,641	107,344	113,491	120,118
Interest	(320,150)	(249,726)	-	-	-	(42,961)	(41,281)	(38,870)	(36,237)	(33,362)	(30,222)	(26,794)
Principal	(477,339)	(210,368)	-	-	-	(12,259)	(26,198)	(28,609)	(31,242)	(34,117)	(37,257)	(40,685)
Cash available for equity	4,552,029	273,824	-	-	-	29,057	37,279	34,810	34,162	39,864	46,012	52,639
Dividends	(4,552,029)	(262,470)	-	-	-	(22,815)	(34,173)	(36,506)	(34,917)	(38,700)	(44,441)	(50,917)
Net cashflow	-	11,355	-	-	-	6,242	3,106	(1,696)	(755)	1,164	1,571	1,722
Cash balance B/f			-	-	-	-	6,242	9,348	7,652	6,897	8,062	9,633
Cash balance C/f			-	-	-	6,242	9,348	7,652	6,897	8,062	9,633	11,355

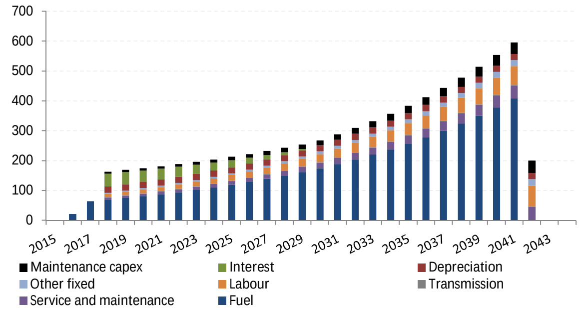
Sources & Uses (NAD '000)

Uses	NAD '000	%
Construction costs	490,477	82.20%
Negative pre-operating cashflows	78,831	13.21%
IDC & Fees	27,366	4.59%
Total	596,674	100.00%
Sources		
Initial equity	119,335	20.00%
Debt	477,339	80.00%
Additional equity	-	-
Total	596,674	100.00%

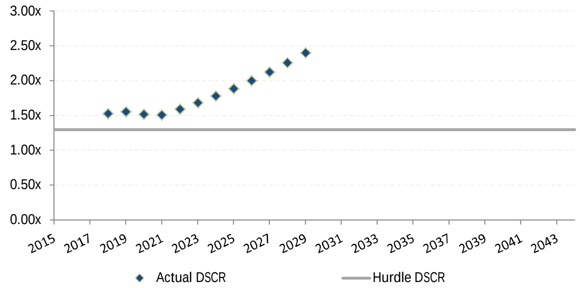
Debt service (NAD M)



Cost breakdown (NAD M)



Actual DSCR and hurdle DSCR



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Base case: Otjiwarongo
NamPower
Encroacher bush to power | Advanced draft

NamPower
Powering the Nation and beyond

Project characteristics

Location	Otjiwarongo
Technology	BI
Biofuel price (NAD/t)	345
Electricity price (NAD/MWh)	2,185
Payment to farmers (NAD/ha)	-
Radius of harvesting area (km)	31.27
Lorries required	4
Supply chain investor	NamPower
Supply chain gearing	80.00%
Power plant investor	NamPower
Power plant gearing	80.00%

Timing

	Supply	Plant
Construction start	01-Jan-15	01-Jul-16
Construction end	30-Jun-16	30-Jun-17
Operations start	01-Jul-16	01-Jul-17
Operations end	30-Jun-41	30-Jun-42

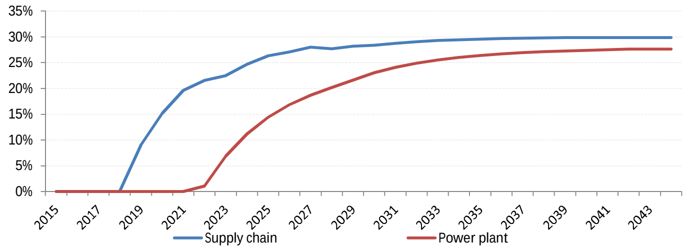
Returns (nom)

	Supply	Plant
Project IRR	14.53%	17.60%
Equity IRR	29.86%	27.62%
LUC @ 8.17% (NAD/MWh)		2,948

Debt ratios

	Supply	Plant
Min DSCR	1.30x	1.30x
Avg DSCR	1.83x	1.64x
Min LLCR		1.56x
LLCR @ ops start	4.08x	1.56x
PLCR @ ops start	4.08x	2.82x

Rolling equity IRR (%)

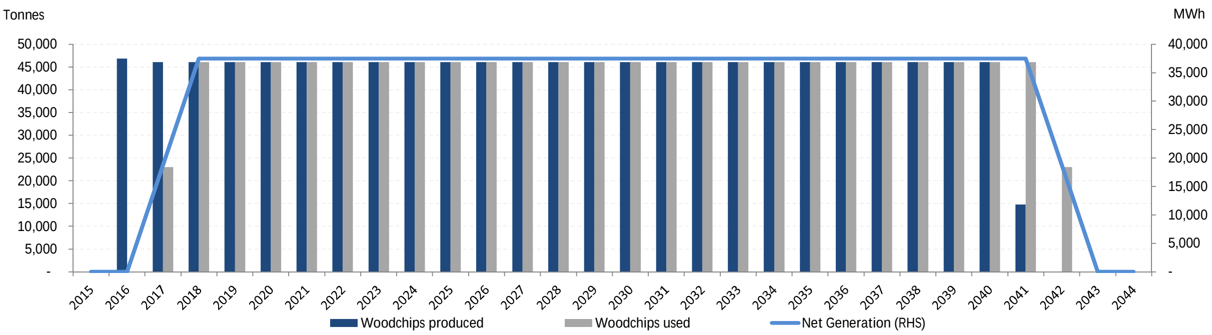


Scenarios

Case	All hurdles met?	Biofuel price (NAD/tonne)	Electricity price (NAD/MWh)	LUC (NAD/MWh)	Supply chain: Project IRR	Supply chain: Equity IRR	Supply chain: Min DSCR	Supply chain: Max Debt/EBITDA	Power plant: Project IRR	Power plant: Equity IRR	Power plant: Min DSCR	Power plant: Min LLCR
Base case: Otjikoto	**Yes**	**395**	**1,240**	**1,773**	**22.04%**	**31.88%**	**1.41x**	**3.91x**	**18.54%**	**29.12%**	**1.43x**	**1.50x**
Base case: Ohorongo	**Yes**	**430**	**1,215**	**1,742**	**21.23%**	**30.94%**	**1.37x**	**3.97x**	**19.32%**	**30.98%**	**1.50x**	**1.51x**
Base case: Otjiwarongo	**Yes**	**345**	**2,250**	**2,948**	**14.53%**	**29.86%**	**1.30x**	**3.93x**	**18.27%**	**29.31%**	**1.37x**	**1.63x**
Otjikoto high base interest rate	**Yes**	**400**	**1,295**	**1,786**	**22.64%**	**31.47%**	**1.32x**	**3.85x**	**19.51%**	**29.69%**	**1.37x**	**1.51x**
Otjikoto high farmer costs	**Yes**	**415**	**1,275**	**1,822**	**22.01%**	**31.85%**	**1.41x**	**3.91x**	**18.76%**	**29.65%**	**1.45x**	**1.50x**
Otjikoto low farmer costs	**Yes**	**375**	**1,205**	**1,724**	**22.06%**	**31.91%**	**1.41x**	**3.91x**	**18.31%**	**28.58%**	**1.40x**	**1.50x**
Otjikoto 10% labour escalation	**Yes**	**395**	**1,260**	**1,817**	**20.59%**	**30.78%**	**1.41x**	**3.91x**	**18.70%**	**29.73%**	**1.46x**	**1.51x**
~~**Otjikoto high operating hours**~~	~~**Yes**~~	~~**405**~~	~~**1,215**~~	~~**1,734**~~	~~**24.18%**~~	~~**36.18%**~~	~~**1.62x**~~	~~**3.33x**~~	~~**19.19%**~~	~~**30.70%**~~	~~**1.49x**~~	~~**1.52x**~~
~~Otjikoto low operating hours~~	~~No~~	~~395~~	~~1,300~~	~~1,851~~	~~20.19%~~	~~28.60%~~	~~1.24x~~	~~4.44x~~	~~18.14%~~	~~28.17%~~	~~1.39x~~	~~1.51x~~
Otjikoto high diesel cost	**Yes**	**415**	**1,275**	**1,822**	**22.07%**	**31.95%**	**1.41x**	**3.90x**	**18.76%**	**29.65%**	**1.45x**	**1.50x**
Otjikoto high investment cost	**Yes**	**410**	**1,305**	**1,858**	**22.88%**	**32.29%**	**1.39x**	**3.96x**	**18.32%**	**28.59%**	**1.40x**	**1.50x**
~~**Otjikoto lowest power plant quote**~~	~~**Yes**~~	~~**395**~~	~~**1,200**~~	~~**1,719**~~	~~**21.47%**~~	~~**31.09%**~~	~~**1.37x**~~	~~**4.00x**~~	~~**18.87%**~~	~~**29.91%**~~	~~**1.46x**~~	~~**1.51x**~~
Otjikoto 70% gearing	**Yes**	**365**	**1,130**	**1,699**	**16.38%**	**22.30%**	**1.39x**	**3.99x**	**17.00%**	**22.56%**	**1.46x**	**1.51x**
Otjikoto high inflation	**Yes**	**395**	**1,170**	**2,140**	**23.64%**	**34.00%**	**1.41x**	**3.91x**	**19.16%**	**28.96%**	**1.31x**	**1.55x**
~~**Otjikoto - More Woodchips**~~	~~**Yes**~~	~~**405**~~	~~**1,330**~~	~~**1,896**~~	~~**24.18%**~~	~~**36.18%**~~	~~**1.62x**~~	~~**3.33x**~~	~~**19.16%**~~	~~**30.63%**~~	~~**1.49x**~~	~~**1.51x**~~

Production

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Woodchips produced	1,167,613	415,513	-	46,837	46,085	46,085	46,085	46,085	46,085	46,085	46,085	46,085
Woodchips used	1,152,113	345,634	-	-	23,042	46,085	46,085	46,085	46,085	46,085	46,085	46,085
Net generation (MWh)	937,500	281,250	-	-	18,750	37,500	37,500	37,500	37,500	37,500	37,500	37,500



Supply chain

Cashflows

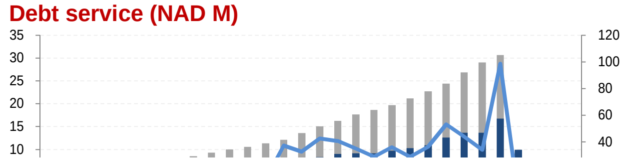
	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue	1,109,924	185,272	-	16,159	15,899	17,171	18,545	20,028	21,631	23,361	25,230	27,248
Opex	(667,778)	(109,578)	-	(8,559)	(9,497)	(10,257)	(11,078)	(11,964)	(12,921)	(13,955)	(15,071)	(16,277)
Working capital adjustments	-	(1,475)	-	(861)	(0)	(69)	(74)	(80)	(87)	(94)	(101)	(109)
Operating cashflows	442,146	74,220	-	6,739	6,402	6,845	7,393	7,984	8,623	9,313	10,058	10,863
Capex	(280,900)	(50,549)	(21,726)	(11,224)	-	-	-	-	-	(6,927)	(10,672)	-
Funding	280,900	50,549	21,726	11,224	-	-	-	-	-	6,927	10,672	-
Taxes and other	(69,390)	(7,704)	-	(789)	(260)	(183)	(432)	(701)	(994)	(1,311)	(1,512)	(1,523)
CFADS	372,756	66,516	(0)	5,950	6,142	6,663	6,961	7,283	7,629	8,002	8,546	9,340
Interest	(70,951)	(14,956)	-	(1,186)	(2,320)	(2,099)	(1,859)	(1,596)	(1,309)	(1,269)	(1,611)	(1,706)
Principal	(131,612)	(24,019)	-	-	(2,394)	(2,614)	(2,855)	(3,118)	(3,233)	(3,224)	(3,226)	(3,356)
Cash available for equity	170,193	27,541	(0)	4,764	1,429	1,949	2,248	2,569	3,087	3,510	3,708	4,278
Dividends	(170,193)	(25,243)	-	-	-	(6,211)	(2,786)	(2,501)	(2,840)	(3,311)	(3,569)	(4,025)
Net cashflow	-	2,298	(0)	4,764	1,429	(4,262)	(539)	68	246	198	140	253
Cash balance B/f			-	(0)	4,764	6,192	1,930	1,392	1,460	1,706	1,905	2,044
Cash balance C/f			(0)	4,764	6,192	1,930	1,392	1,460	1,706	1,905	2,044	2,298

Cashflows (NAD '000)

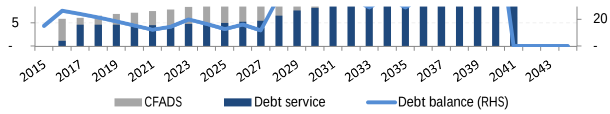
Uses	NAD '000	%
Machinery	279,343	99.45%
Other capex	-	-
IDC & Fees	1,557	0.55%
Total	280,900	100.00%

Sources

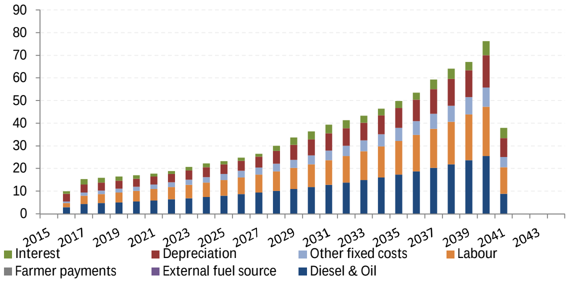
Debt service (NAD M)



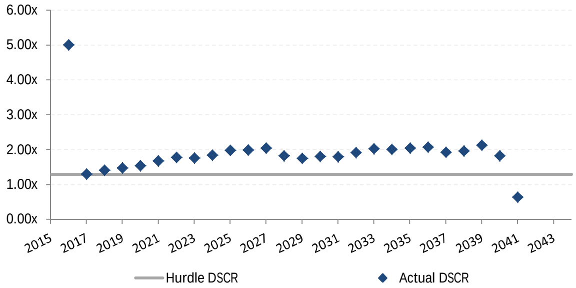
Initial equity	6,590	2.35%
Debt	224,720	80.00%
Additional equity	49,590	17.65%
Total	280,900	100.00%



Cost breakdown (NAD M)



Actual DSCR and hurdle DSCR



Power plant

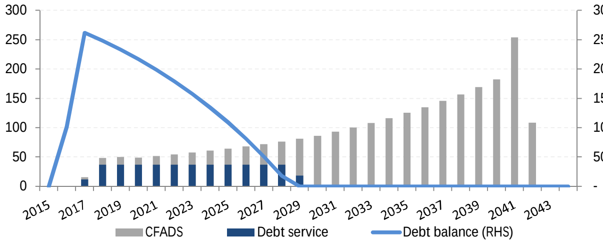
Cashflows (NAD '000)

	Total	Partial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Revenue	6,229,723	830,570	-	-	40,969	88,493	95,572	103,218	111,475	120,393	130,025	140,426
Opex	(2,671,828)	(397,381)	-	(16,159)	(26,482)	(39,957)	(43,079)	(46,451)	(50,093)	(54,026)	(58,274)	(62,861)
Working capital adjustments	-	(5,524)	-	1,763	(4,954)	(261)	(282)	(305)	(329)	(356)	(384)	(415)
Operating cashflows	3,557,895	427,666	-	(14,396)	9,532	48,275	52,211	56,462	61,053	66,012	71,367	77,151
Capex	(307,212)	(307,212)	-	(152,981)	(154,231)	-	-	-	-	-	-	-
Funding	327,616	327,616	-	167,378	160,238	-	-	-	-	-	-	-
Taxes and other	(1,045,465)	(59,899)	-	-	-	-	(1,910)	(7,231)	(9,240)	(11,417)	(13,774)	(16,327)
CFADS	2,532,833	388,170	-	-	15,539	48,275	50,301	49,231	51,813	54,595	57,593	60,823
Interest	(175,785)	(143,713)	-	-	(11,794)	(23,285)	(22,019)	(20,635)	(19,125)	(17,475)	(15,674)	(13,706)
Principal	(262,092)	(127,436)	-	-	-	(13,765)	(15,032)	(16,415)	(17,926)	(19,576)	(21,377)	(23,344)
Cash available for equity	2,094,956	117,021	-	-	3,745	11,224	13,250	12,181	14,762	17,544	20,542	23,773
Dividends	(2,094,956)	(110,763)	-	-	-	(11,678)	(13,021)	(12,645)	(14,179)	(16,751)	(19,661)	(22,829)
Net cashflow	-	6,258	-	-	3,745	(454)	230	(464)	583	793	881	944
Cash balance B/f			-	-	-	3,745	3,291	3,521	3,057	3,639	4,432	5,314
Cash balance C/f			-	-	3,745	3,291	3,521	3,057	3,639	4,432	5,314	6,258

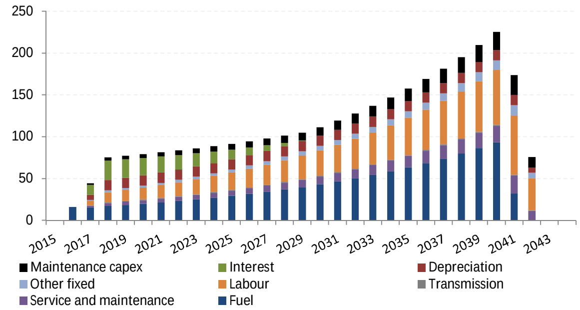
Sources & Uses (NAD '000)

Uses	NAD '000	%
Construction costs	297,052	90.67%
Negative pre-operating cashflows	20,403	6.23%
IDC & Fees	10,161	3.10%
Total	327,616	100.00%
Sources		
Initial equity	65,523	20.00%
Debt	262,092	80.00%
Additional equity	-	-
Total	327,616	100.00%

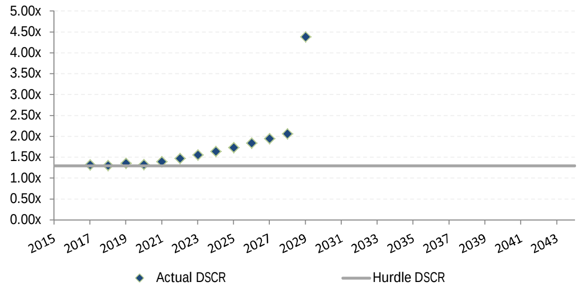
Debt service (NAD M)



Cost breakdown (NAD M)



Actual DSCR and hurdle DSCR



Appendix C: Generic Investors and Selected Contact Details

Examples of prospective players in the project financing/ownership/operations structure include:

Export Credit Agencies

- OPIC, http://www.opic.gov/financing, https://financere.nrel.gov/finance/content/opic-can-help-pick-check-renewables
- US EX-IM, http://www.exim.gov/products/guarantee/proj_finance.cfm

  Example of Debt Finance: Direct Loans are made by the Ex-Im Bank to foreign buyers of U.S. equipment or services covering 85% of the purchase price. The remaining 15% is expected in cash. These loans usually carry fixed interest rates based on a 1% spread over 3-, 5-, and 7-year U.S. Treasury notes. A negotiated credit agreement is required for all direct loans from the Ex-Im Bank. Also possibly available would be a commercial loan guaranteed by the Ex-Im Bank.
- KfW IPEX-Bank, http://www.kfw-ipex-bank.de/ipex/en/index.jsp
- China EXIM Bank, http://english.eximbank.gov.cn/index.shtml
- EXIM Bank of India, http://www.eximbankindia.com/oif.asp
- UK Export Finance, http://www.ukexportfinance.gov.uk/
- Coface, http://www.coface.com/CofacePortal/COM_en_EN/pages/home
- JICA, http://www.jica.go.jp/english/index.html
- JBIC, http://www.jbic.go.jp/en/
- SACE, http://www.sace.it/GruppoSACE/content/en/

Development Banks and Funds

- KfW/German Finance Corporation, http://www.kfw-entwicklungsbank.de/ebank/EN_Home/About_Us/Our_promotional_instruments/index.jsp
- Caisse des Depots, http://www.caissedesdepots.fr/en/activity/fighting-against-climate-change.html
- GEF Africa Growth Fund
- EU-Africa Infrastructure Trust Fund, http://www.eu-africa-infrastructure-tf.net/
- Equipment Vendors
- GE Energy Financial Services, http://www.geenergyfinancialservices.com/products/projectequity.asp
- Siemens Financial Services, http://finance.siemens.com/financialservices/global/en/products_solutions/Project_Equity_Participations/Pages/Project_Equity_Participations.aspx
- Other development banks that may be of interest include Southern African based entities such as the Industrial Development Corporation (IDC) of South Africa, the Development Bank of Namibia and Development Bank of South Africa.

Private Investment Banks

- Taylor-DeJongh, http://www.taylor-dejongh.com/sectors/renewable-energy/
- Goldman Sachs, http://www.goldmansachs.com/what-we-do/investing-and-lending/direct-private-investing/equity-folder/gs-infrastructure-partners.html

- HSBC, http://www.hsbc.com

Independent Power Producers

- GDF SUEZ, http://www.gdfsuez.com/en/businesses/electricity/biomass/
- BioTherm Energy, http://www.biothermenergy.com/
- Globeleq, http://www.globeleq.com
- Cennergi, http://www.cennergi.com/about-cennergi/our-history/
- Veolia, http://www.veoliaenergyna.com/solutions/renewable-energy/

Equity Investment Funds

- Denham Capital, http://www.denhamcapital.com/
- **Inspired Evolution Fund**, http://inspiredevolution.co.za/funds/evolution-one-fund/

  Example of Equity Finance: This fund specializes in clean energy projects and clean technology companies in southern Africa. The Fund would take an ownership share in the project; likely a minority position. Therefore other (potentially local) sources of capital would be needed to provide the required balance of equity.

The profiles of a few selected potential investors are presented below:

Macquarie Funds Group

In 2000 Macquarie Africa (a wholly owned subsidiary of the Macquarie Group of Australia) and Old Mutual Investment Group (South Africa) established the African Infrastructure Investment Managers (Pty) Ltd ("AIIM") joint venture. This joint venture successfully combines the experience of one South Africa's largest financial institutions, Old Mutual with that of the world's leading infrastructure investment manager, Macquarie Capital. The Old Mutual Investment Group (South Africa) is recognised as a leading investor in infrastructure assets in Southern Africa, while Macquarie has established a global presence in the infrastructure sector with in excess of 110 assets on a globally dispersed platform.

Funds under Management:

AIIM was originally established to take over management of the then existing South Africa Infrastructure Fund (SAIF), a R806 million fund established in 1996. Following the full commitment of SAIF and successful management of this fund, AIIM established AIIF in 2004, which at R1,320 million was the largest single private equity capital raising of that year in South Africa. AIIM is also a shareholder in the Infrastructure Empowerment Fund Managers ("IEFM"), a joint venture with Kagiso Trust Investments. IEFM is the manager of the Kagiso Infrastructure Empowerment Fund which is a fund established to promote empowerment objectives and investments in infrastructure projects.

AIIF2, a successor fund to AIIF, reached first close in early 2010, and together SAIF, AIIF, KIEF and AIIF 2 have combined equity capital commitments of approximately R5.1 billion. The AIIM funds primarily target equity investments in such assets as roads, airports, power, telecommunications, rail, port, water and social infrastructure across Africa.

Investor Base:

The investors in the AIIM managed funds comprise the major institutional investors from the pension fund, banking and non-banking sectors, as well as international development finance institutions.

Contact Details:

Andrew Johnstone
African Infrastructure Investment Managers (Pty) Limited
Colinton House
The Oval
1 Oakdale Road Newlands 7700
Cape Town

P O Box 23777
Claremont
7735 Cape Town
South Africa

Office : +27 21 670 1234
Direct : +27 21 670 1214
Fax : +27 21 670 1220
email : andrew.johnstone@macquarie.com

Inspired Evolution Investment Management

As the first dedicated, specialised cleantech fund manager in Africa, Inspired Evolution offers investee companies and projects a compelling value proposition:

- leading global investor with specialised knowledge in cleantech
- global portal for cutting-edge clean technologies and R&D expertise for deployment into projects and companies located in the SADC region
- global footprint to enhance export of local and regional technologies, goods and services to worldwide markets
- active management and post-investment value addition
- highly skilled team with relevant local and global track record
- deep commercial, financial and sustainability credentials
- strong black empowerment credentials and BBBEE deal structuring experience
- flexible, rapid decision-making
- tailor-made, packaged financial solutions based on:
    - proprietary relationships with select local and international co-investors, equity and debt providers for turnkey financing and for larger investment amounts
    - ability to structure CDM and other appropriate finance mechanisms
    - ability to fund at an earlier stage in the process (pre-bankable stage) where warranted through access to complimentary seed capital facilities
- enhanced sustainability performance

Inspired Evolution seeks to lead transactions, participates on the board of directors of investee companies and supports best practice governance. We bring a global network of leading venture capital and private equity firms, universities and businesses that provide us with valuable market insights, relationships and channels to market.

Contact Details:

Mr Christopher Clarke

Tel: +27 21 702 1290
Fax: +27 21 702 1483
Mobile: +27 82 496 0522
E-mail: chris@inspiredevolution.co.za

1st Floor, Amdec House,
Silverwood Close,
Steenberg Office Park,
Tokai 7945,
Cape Town,
South Africa

PostNet Suite 136,
Private Bag X26,
Tokai 7966,
Cape Town,
South Africa.
Johannesburg

Contact: Mr Campbell Barnes
Tel: +27 11 883 8036
Mobile: +27 83 276 9616
E-mail: campbell@inspiredevolution.co.za

2nd Floor, Summit Square,
15 School Road,
Cnr Rivonia & Summit Rd,
Morningside,
Sandton

Globeleq

Globeleq is an experienced operating power company, actively developing energy solutions for the emerging markets of Africa and the Americas. We develop economically sustainable businesses that support the continued development of the electric power sector in these regions and actively participate in the communities in which we operate.

The company was launched in 2002 when the UK's CDC Group contributed both equity capital and portfolio of power assets to the new enterprise. Over the next 5 years, Globeleq became a power industry leader in the emerging markets by operating or acquiring interest in multiple power facilities totalling nearly 4,000 MW of generation capacity in more than 20 countries.

In 2007, Globeleq divested its holdings in a number of power companies in its portfolio. Legal ownership of Globeleq was transferred in 2009 from CDC to the Actis Infrastructure Fund, a fund managed by Actis, the leading equity investor in emerging markets. CDC continues to be a key stakeholder in Globeleq’s business as a material investor in the Actis Infrastructure Fund.

The company continues to safely operate electricity generation facilities and with a committed shareholder providing access to funds for new investments, Globeleq is uniquely positioned for further investment in the power industries of its target regions in Africa and the Americas.

Contact Details:

Paul Kunert
Head of Business Development, Africa & Asia
2 More London Riverside
LONDON
SE1 2JT
PH: +44 (0)207 234 5400

WSP Environment & Energy South Africa
Block A, 1 on Langford
Langford Road, Westville
Durban
3629
South Africa
Tel: +27 21 481 8646
Fax: +27 21 481 8799
www.wspenvironmental.co.za

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