14.3.8 SENSITIVITY ANALYSIS

In order to check the robustness of the results obtained in the base case scenario for the financial analysis, as just described in the previous section, and to gain an insight into some of the possible risks involved with the project, in particular its viability, a sensitivity analysis with regard to changes in major variables was carried out. This analysis uses the following three variables, which are considered to be the main parameters which determine the success or failure of the Project.

- Capital costs.
- SAPP price.
- Power generation.

14.3.8.1 Capital Costs Sensitivity Analysis

The capital costs estimate is based on a careful analysis of all major cost items. However, the entire procedure leaves a small degree of uncertainty concerning capital cost estimates. Unforeseen increases in capital costs cannot be excluded, despite the fact that 5% physical contingencies have already been included in the capital cost estimate. For the purpose of this sensitivity analysis, it has therefore been assumed that the capital costs would be 10% higher than in the base case scenario.

An increase of the capital costs has no influence on the ranking of the hydro power plant options as was to be expected. The performance indicators of Option 8 resulting from this analysis are as follows:

- FLUC: 34.65 US$/MWh
- FIRR: 9.33%
- FNPV: 9,640
- Benefit/cost ratio: 1.25

The FIRR is well above the WACC and hence the FNPV is positive. Therefore the project is still a financially viable undertaking even if the capital cost increases by 10%.

14.3.8.2 SAPP Price Sensitivity Analysis

The benefits of the project arise mainly from the revenues based on the NamPower SAPP price projection, but the actual values may differ from this. Consequently, a sensitivity calculation with prices 10% below the SAPP price projection for the respective years of the entire investigation period has been carried out. This calculation can generally be considered as a sensitivity test for lower benefits of the Project in general.

Here also, a decrease of the SAPP prices by 10% for particular years of operation, has no influence on the ranking of the hydro power plant options as this is based on the LUC. The performance indicators for Option 8 resulting from this analysis, are as follows:

- FLUC: 31.51
- FIRR: 9.37%
- FNPV 8,954 TUS$
- Benefit/cost ratio: 1.26

Here again, the FIRR is well above the WACC and hence the FNPV is positive. The project is therefore still a financially viable undertaking, even if the SAPP prices amount only to 90% of the base case SAPP price projection.

14.3.8.3 Power Generation Sensitivity Analysis

The calculation of the power output of the Popa Falls Hydro Power Plant is based on the available hydrological data. However, future changes in the flow and hence water level cannot be entirely excluded. Although one would expect this to last only for a limited period, during dry or drought conditions, the sensitivity analysis assumes a power output that is 10% below the level in the base case scenario as a further test for lower benefits and revenues from the Project.

A decrease of the power output also has no influence on the ranking of the hydro power plant options. The performance indicators of Option 8, resulting from this analysis, are as follows:

- FLUC 34.97 US$/MWh
- FIRR: 8.63%
- FNPV: 5,280
- Benefit/cost ratio: 1.15

Even if power generation is 10% below the base case assumptions, the FIRR is well above the WACC and hence the FNPV is positive. The project is therefore still a financially viable undertaking if the power generation decreases by 10%.

14.4 CASH FLOW ANALYSIS

14.4.1 CAPACITY, POWER GENERATION AND BENEFITS

The figures regarding capacity, power generation and SAPP price projection applied in the financial analysis, also apply to the cash flow analysis. Hence the benefit is the same as those determined for the financial analysis. The same applies to O&M costs. The financial analysis was carried out exclusively for hydro power plant Option 8.

14.4.2 CAPITAL AND FINANCING COSTS

In the cash flow analysis, interest during the construction phase as well as principal and interest payments, are considered. Assumptions for the financing conditions of the debt portion are as follows:

- Equity/debt ratio: 50%:50%
- Loan amount 20,223 TUS$
- Interest rate: 7%
- Loan term : 12 years

Such financing conditions will lead to interest payments during construction amounting to 1,061 TUS$ and, in the case of the total project budget, to 40.446 TUS$. Repayment of the principal is assumed to be in equal annual instalments.

14.4.3 BASE CASE RESULTS:

Under the base case scenario, the Project reveals the following financial performance:

- IRR Pre Tax Cash Flow (return on equity): 13.27%
- Net Present Value: 20,207 TUS$
- Payback periods: 8 years of operation

The debt service coverage ratio (DSCR) for the first 5 years of operation will be as follows:

Year	DSCR
2008:	0.65
2009:	0.86
2010:	0.99
2011:	1.13
2012:	1.30

Since the SAPP price during the early years of operation is projected to be low compared to the years after 2018, the project cash flow is not capable of bearing principal and interest payments associated with loans on a 50:50 debt-equity ratio. This is clearly expressed by the low DSCR in the years 2008-2010. Financial institutions usually seek to achieve a minimum DSCR of between 1.2 and 1.3 for the entire loan term. However, the IRR indicates that the project is quite viable from the NamPower perspective. A debt portion exceeding 50% of the project's budget would increase the FIRR further. Projects of this nature are usually able to obtain a 70:30 debt-equity ratio. Therefore NamPower should seek to mitigate the effects of the low cash flow of the first years with regard to DSCR by a combination of the following measures:

- Obtain a mortgage style loan or,
- obtain a sculpted principal payment arrangement, which considers the increase of the SAPP prices,
- obtain a grace period,
- obtain a loan term exceeding 12 years,
- obtain a loan at soft loan conditions, e.g. 2% interest rate.

14.4.4 SENSITIVITY ANALYSIS

Since a sensitivity analysis with regard to capital costs, SAPP prices, and power generation, produces results similar to the financial analysis, only the results of varying the financing conditions are presented.

14.4.4.1 Tighter Financing Conditions Scenario

Assuming loans for the project are available only for an interest rate of 8% and no bank will accept a DSCR of less than 1.0, then the debt/equity ratio must be reduced to a ratio of 69:31. Such financing conditions would lead to a financial performance as follows:

- IRR Pre Tax Cash Flow (return on equity): 12.22%
- Net Present Value: 15,505 TUS$
- Payback period: 8 years of operation

The DSCR for the first 5 years of operation is as follows:

Year	DSCR
2008:	1.00
2009:	1.33
2010:	1.54
2011:	1.77
2012:	2.04

The increase of the interest rate and the reduction of the debt portion would lead to a reduction of the return on equity to 12.22%, which is still a financially very sound scenario.

14.4.4.2 Soft Loan Scenario

Given the economic conditions of Namibia and the environmentally sound characteristics of the Project in terms of greenhouse gas emissions, the Popa Falls Hydro Power Project could obtain a soft loan from development banks. Such a soft loan could be structured as follows:

- Interest rate: 2%
- Term: 12 years
- Amount (25% of project budget): 10,036 TUS$

In the event that 50% of the Project's base case loan be substituted with a soft loan of the above mentioned structure, then the financial performance would improve as follows:

- IRR Pre Tax Cash Flow (return on equity): 13.88%
- Net Present Value: 31,090 TUS$

- Payback period: 7 years of operation

The DSCR for the first 5 years of operation is as follows:

Year	DSCR
2008:	0.79
2009:	1.00
2010:	1.14
2011:	1.28
2012:	1.44

A soft loan has the potential to increase the Project's return on equity to 13.88%. It would also eliminate the constraints with regard to DSCR in year 2009 and 2010. The still negative DSCR in year 2008 could be mitigated by a grace period of one year.

14.5 ECONOMIC ANALYSIS

14.5.1 APPROACH AND ASSUMPTIONS

As mentioned above, the economic analysis has been carried out in a two-step approach:

(a) Comparison of the Project with other options for the supply of power to the Rundu and Otjikoto load centres, based on the determination of economic levelised unit costs. This least cost analysis seeks to verify that the Project is the least cost option in the context of north-east Namibia.

(b) Determination of the economic performance indicators in a cost-benefit analysis.

Small and medium sized hydro power projects are typically evaluated by the application of the Thermal Alternative Approach (**TAA**). In case of significant power imports – as is the case for Namibia – prospective import options have to be considered as well. According to the TAA, the benefits of the hydropower project equal the avoided cost of an alternative thermal power plant producing an equivalent amount of firm capacity and energy. The Popa Falls Hydro Power Project will supply energy mainly to load centres at Rundu and Otjikoto, and later on probably also to the Caprivi Region and consumers situated along the Okavango River. The options for serving incremental power demand in Namibia are as follows:

- 400-800 MW CCGT plant based on Kudu Gas
- Imports via the SAPP from South Africa
- Imports via the SAPP from Zambia

The economic analysis has been carried out in real 2003 US$ terms. The discount rate applied in the economic analysis is 10% p.a., as this is considered to be the opportunity cost of capital in Namibia. This assumption is based on standard practice by international financial institutions such as the World Bank and African Development Bank for countries with similar economic characteristics as Namibia, and can be considered as conservative.

However, since the figure is not determined by thorough macroeconomic analyses and the projects viability being sensitive to variations of the discount rate, greater attention has to be given to the outcomes of the sensitivity analysis with regard to the discount rate.

The standard conversion factor applied for locally sourced goods and services is 0.9. This standard conversion factor has been applied to Popa Falls and Kudu CCGT capital costs as well as all fixed O&M costs, including incremental fixed O&M costs for transmission investments. The proportion of local costs of the total fixed O&M costs is estimated to be 50%.

External economic costs relate to unmitigated impacts of greenhouse gas emissions of particular options. For the economic evaluation of the Popa Falls Hydro Power Project, only CO_2 has been quantified. The associated environmental costs of carbon emissions have been charged to the particular options at a cost of 7.00 US$ per tonne of CO_2 emitted. This figure is based on available international data on abatement and damage costs of CO_2 emissions as well as price forecasts for CO_2 trade auctions beyond 2007.

14.5.2 POPA FALLS HYDRO POWER PLANT

The capacity and energy data of the site options are described in detail in **Section 7**. The considerations under **Section 14.3.1** are also applicable to the economic analysis.

All capital cost items are given in **Section 13**. Since plant equipment for the power projects is not subject to import duties or other non-reimbursable taxes, no adjustment for import duties and taxes is necessary. However, the Consultant applied a standard conversion factor for all locally sourced inputs of 0.9. This leads to a difference of 3,654 TUS$ in the cost estimate applied in the financial analysis.

The annual operation and maintenance (O&M) costs have been estimated at 0.75% of capital expenditures, excluding social and environmental mitigation costs. The O&M costs are made up of personnel costs associated with the staff permanently employed by the Scheme, plus routine expenditures for operating and maintenance material. Since the economic analysis has been carried out in real terms, no inflation escalation rate was applied. 50% of the fixed O&M costs are estimated to be local costs. The standard conversion factor applied on local cost components is 0.9.

The transmission costs of the project consist of the interconnection costs to the Rundu load centre and the transmission losses to Rundu and Otjikoto. The O&M costs of the transmission line are 1% of the interconnection capital costs.

The Popa Falls Hydro Power Plant supply option has not been charged with costs for CO_2 emissions since it does not burn any fossil fuel and the incremental emissions from the reservoir are negligible.

14.5.3 400-800 MW CCGT PLANT BASED ON KUDU GAS NEAR ORANJEMUND

The Kudu CCGT is the only thoroughly investigated thermal generation option for the near future in Namibia. At the fully planned capacity of 800 MW, the plant will generate

approximately 260% of the current Namibian power supply. Thus it could export a large proportion of its generated electricity to South Africa.

The basic data for the calculation of the levelised unit costs of the Kudu CCGT plant are given in **Table 14-2** below:

Table 14-2 : Basic Data for the Calculation of Levelised Unit Costs for the Kudu CCGT Plant

Capacity costs	US$/MW	650.00
Interconnection costs	US$/MW	90.00
Fixed O&M	US$/MW	10.00
Variable O&M	US$/MWh	2.00
Fuel costs	US$/GJ	2.50
Fuel costs	US$/MWh	9.00
Net efficiency @ busbar	%	52%
Transmission losses to load centres	%	6%
Firm capacity provided by PFHP	MWh	9.47
Firm capacity required @ Kudu CCGT	MWh	10.08

The proportion of locally sourced capital goods is 15%. It has been assumed that the cost of the Kudu gas will increase by 0.5% p.a. in real terms. An increase of 0.5% in real terms for crude oil and natural gas is in line with the price projections of the International Energy Agency and the US Department of Energy.

When analysing the levelised unit costs of the Kudu CCGT plant shown above, it must be borne in mind that the capital cost component applies only to the firm capacity equivalent of Popa Falls, which amounts to 10.08 MW. The secondary energy generated by the Popa Falls has no capacity equivalent. However, a 10.08 MW CCGT is not capable of generating 131.8 MW p.a. Therefore the figure above should not be considered as the generation cost of the Kudu CCGT project in total, since a CCGT would reveal higher specific capital and fixed O&M costs.

The estimated incremental interconnection cost of the Kudu CCGT option is 907 TUS$ based on a firm capacity of 10.08 MW. The interconnection costs are based on a 250 km long, 400 kV transmission line, costing 200 TUS$/km. The power supply to the north-eastern load centre by the Kudu CCGT plant would require an upgrade of the Otjikoto-Rundu transmission line in the year 2015 as well as incremental upgrades of the 400 kV transmission system. The present Otjikoto-Rundu transmission line is capable of transporting 15 MW. An upgrade to 30 MW would cost approximately 12,100 TUS$ in 2003 US$ terms. The cost of an incremental upgrade of the 400 kV transmission network over a distance of 600 km from Kokerboom to the northern load centres – capable of transporting 20.85 MW non-firm

capacity – is estimated at 4,754 TUS$. The Consultant assumed that such an upgrade would be required in year 2010.
The Kudu CCGT option has been charged at 329 US$ p.a. for CO_2 emissions, which translates to environmental costs of 2.61 US$/MWh. These figures are based on a specific emission rate of 0.35 t CO_2/MWh.

14.5.4 IMPORTS VIA THE SAPP FROM SOUTH AFRICA

Namibia is currently importing a large proportion of its power supply from South Africa. In general it is technically feasible to increase the imports from South Africa in order to cover future increases of the power demand. The disadvantage of imports from South Africa with regard to power supply to the northern regions of Namibia is, however, the extremely long transmission distances. Given the strong increase of Namibian power demand, the dependency on South Africa would require significant additional capacity investments in the Namibian high voltage transmission system in the mid term.

The total economic cost of supplies to the northern load centres due to imports from South Africa is made up of the power purchase costs at SAPP prices, incremental capital investments and O&M costs in the 400 kV transmission system as well as significant charges for CO_2 emissions.

The cost for power purchases from the SAPP is expected to rise from 16.91 US$/MWh in 2008 to 32.22 US$/MWh in year 2019. The transmission losses attributable to imports from SA are 6%. A detailed feasibility study should consider that transmission losses increase over the investigation period, since the proportion of power generated by the Ruacana Hydro Power Plant, which physically flows via Omburu to the central load centres, will be increasingly consumed in the north of Namibia and in Angola.

The transmission costs attributable to supplies from South Africa include an incremental investment in the 400 kV transmission system required in year 2010, costing 6,339 TUS$, as well as a 15 MW upgrade of the Otjikoto – Rundu 132 kV line required in year 2015, costing 12,100 TUS$. The associated incremental O&M costs are 1% of the transmission investment.

The SA import option is charged at 655 TUS$ p.a. for CO_2 emissions, which translates to environmental costs of 5.18 US$/MWh. This figure is based on a 90% proportion of steam-coal generation and 3% losses in the SA transmission system, as well as a specific emission of 0.75 t/MWh for steam-coal generation.

14.5.5 IMPORTS VIA THE SAPP FROM ZAMBIA

Namibia is currently importing power from Zambia to supply the demand at the isolated Katima-Mulilo load centre. The supply of power from Zambia to the northern Namibian regions is technically feasible and constitutes a real option to supply firm capacity and energy to Rundu and the Caprivi Region. Zambia has significant under-utilised hydro power resources and is supplying power to Katima Mulilo at very competitive terms. However, hydro power resources in southern Africa are prone to drought effects, therefore thermal power stations must be installed to a certain extent to cover seasonal hydro power variations in Zambia. This means that incremental capacity costs rise disproportionately with excessive peak prices during droughts once the SAPP power market becomes completely operational.

The disadvantage of supplies from Zambia in the near future is the currently low load density in the Caprivi Region and Rundu combined with the need for construction of a 600 km 220 kV transmission line.

The total economic costs of supplying the northern load centres by imports from Zambia in 2008 are made up of the power purchase costs at SAPP prices, capital and O&M costs of a 600 km 220 kV transmission line, as well as charges for CO_2 emissions.

The economic costs for power purchases are assumed to be equal to those of imports from SA, since the price projection for imports from Zambia is also derived from SAPP prices. The transmission losses attributable to imports from Zambia are 6%.

The economic transmission costs attributable to a supply from Zambia include capital costs for the Katima-Mulilo to Rundu 220 kV transmission line, costing 19,000 TUS$, and O&M costs for this transmission line of 1% of the investment.

The Zambia import option is charged at 67 TUS$ p.a. for CO_2 emissions, which translates to an environmental LUC of 0.53 US$/MWh. This figure is based on an 80% proportion of hydro power, 20% proportion of CCGT generation and 2% losses in the Zambian transmission system, as well as specific emissions of 0.35 t CO_2/MWh for CCGT generation.

14.5.6 DETERMINATION OF LEVELISED UNIT COST

The main results of the economic evaluation are summarised in **Table 14-3 below**. The economic least cost test reveals that Popa Falls is the least cost option for the supply of power to the north-eastern regions of Namibia. The Project generates power at a level of 30.89 US$/MWh. For the transfer to the load centres, transmission costs of 4.14 US$/MWh are incurred, leading to total LUC of 35.04 US$/MWh. Therefore, even if external environmental costs are not considered, Popa Falls is the least cost option. The difference between the project's LUC and the second best option – the Kudu CCGT plant – amounts to 1.38 US$/MWh. Since the external costs in terms of CO_2 emissions are nil, the resulting total economic cost of the project is 33.59 US$/MWh. This analysis does not take into consideration other environmental costs as these have not been quantified during the pre-feasibility study.

Table 14-3 : Results of the Economic Analysis

Prospective substitutions of small isolated diesel stations in the close vicinity of the Popa Falls Project and the effects of a possible rural electrification program in the vicinity of the Project are not considered, since the extent of such prospective projects is unknown. However, if such local projects exceed the demand of 1 MW, then their consideration would effectively reduce the transmission costs of the project, since less energy has to be transmitted to Otjikoto. Furthermore, consideration of such projects would increase the levelised unit cost of the alternative thermal and import options. Thus consideration of rural electrification projects would increase the benefits of the Popa Falls Project.

The large difference between imports from Zambia and imports from SA in transmission costs can be explained by the fact that importing from Zambia would require a heavy investment in transmission capacity in 2007, while imports from South Africa could continue until 2015 without major additional investments in transmission capacity. The transmission investments required in 2010 and 2015 for the SA import option will be significantly discounted, and therefore give the SA import option an advantage in NPV terms over the Zambia import option.

		Supply Options for Rundu & Otjikoto			
		Popa Falls HP	**Import SA**	**Import Zambia**	**Kudu CCGT**
Present Value of Total Costs	**TUS$**	**27,975**	**33,949**	**36,890**	**31,804**
PV of plant capital costs	TUS$	23,357	0	0	4,377
PV of power purchase costs	TUS$	0	22,317	22,317	0
PV of fuel costs	TUS$	0	0	0	16,037
PV of plant O&M costs	TUS$	1,820	0	0	2,350
PV of transmission costs	TUS$	3,377	7,408	14,139	6,916
PV of environmental costs	TUS$	0	4,223	434	2,124
Levelised Unit Costs	**US$/MWh**	**35.04**	**36.47**	**44.73**	**36.42**
Capital costs plant	US$/MWh	28.66	0.00	0.00	5.37
Power purchase costs	US$/MWh	0.00	27.38	27.38	0.00
Fuel costs	US$/MWh	0.00	0.00	0.00	19.68
O&M costs	US$/MWh	2.23	0.00	0.00	2.88
Transmission costs	US$/MWh	4.14	9.09	17.35	8.49
Levelised Unit Costs incl. Environmental	**US$/MWh**	**35.04**	**41.66**	**45.26**	**39.02**
Environmental Costs	US$/MWh	0.00	5.18	0.53	2.61
Rank		**1**	**3**	**4**	**2**

14.5.7 ECONOMIC BENEFITS OF THE POPA FALLS PROJECT

The benefits in the economic analysis equal the avoided cost of the best alternative supply option. Thus the benefits of the Popa Falls Hydro Power Project equals the cost of power supply by the Kudu CCGT plant. The benefits are therefore determined by the avoided incremental capital, fuel and O&M costs at the Kudu CCGT plant, the avoided transmission losses attributable to power evacuation from Oranjemund, as well as the avoided incremental capital and O&M costs of the transmission system starting in Kokerboom.

14.5.8 BASE CASE RESULTS

Under the base case assumptions applied, the project yields an Economic Internal Rate of Return of 11.92%, which is well above the opportunity cost of capital – the discount rate of 10%. Thus the Popa Falls Hydro Power Project is a viable project and desirable in economic terms. The investigated economic performance indicators are as follows:

- Economic IRR: 11.92%
- Economic NPV: 3,829 TUS$
- Economic Benefit/Cost Ratio: 1.14

14.5.9 SENSITIVITY ANALYSIS

A sensitivity analysis, similar to that carried out for the financial analysis, was carried out for the economic analysis. The reader is therefore referred to **Section 14.3.8** of this report for background on this type of analysis.

14.5.9.1 Capital Cost Sensitivity Analysis

The capital cost estimate is based on a careful investigation of all major cost items. However, the entire procedure leaves a small degree of uncertainty concerning capital cost estimates. Therefore, unforeseen increases in capital costs cannot be excluded, despite the fact that 5% physical contingencies are already included in the capital cost estimate. For the purpose of this sensitivity analysis it has therefore been assumed that the capital costs would be 10% higher than in the base case scenario. The economic performance indicators of Popa Falls Hydro Power Project in the case of a 10% capital cost increase are as follows:

- ELUC generation: 34.17 US$/MWh
- ELUC total incl. transmission: 38.32 US$/MWh
- EIRR: 10.53%
- ENPV: 1,156 TUS$
- Economic benefit/cost ratio: 1.04

The ranking of the options in terms of total economic LUC does not change if capital costs rise by 10%. The EIRR remains above the discount rate of 10% – hence the ENPV is positive and the benefit/cost ratio is above 1.0. The Project is therefore still viable in economic terms if capital costs rise by 10%. The critical value for capital cost increase, as the EIRR falls below 10%, and ENPV falls below zero, is 15%. This means the Project could bear capital cost increases of up to 14%.

14.5.9.2 Discount Rate Sensitivity Analysis

Hydro power projects are generally capital intensive projects. Hence their financial and economic viability is very sensitive to variations of the applied discount rate. As noted above, the applied discount rate of 10% is not determined by thorough macro-economic investigations and can be considered as conservative. Therefore the Consultant investigated

the impact of variations of the discount rate applying discount rates of 8% and 12% in a sensitivity test.

(a) Discount Rate of 8%

The analysis has shown that the application of a discount rate of 8% does not change the ranking of the options, but increases the advantage of the Popa Falls Project significantly. Also the difference between the Kudu CCGT option and the SA import option widens, since Kudu involves significantly more up-front capital costs compared to the import options. The performance indicators of Popa Falls Project under an 8% discount rate are as follows:

- ELUC generation only: 25.70 US$/MWh
- ELUC generation and transmission: 29.15 US$/MWh
- EIRR: 11.92%
- ENPV: 9,767
- Economic benefit/cost ratio: 1.33

(b) Discount Rate of 12%:

The results of the sensitivity analysis for discount rate of 12% shows that the ranking has changed. It was found that this changes at a discount rate of 10.6%, if environmental costs are not considered. Above a discount rate of 10.5%, imports from SA would constitute the least cost option. If environmental costs from CO_2 emissions are considered, the critical value for the discount rate is 11.92% - which equals the EIRR of the base case. Above a discount rate of 11.92%, the Kudu CCGT plant is the least cost option in terms of total ELUC. The performance indicators of the Popa Falls Hydro Power Project under a 12% discount rate are as follows:

- ELUC generation only: 36.31 US$/MWh
- ELUC generation and transmission: 41.18 US$/MWh
- EIRR: 11.92%
- ENPV: -125 TUS$
- Economic benefit/cost ratio: 0.995

The EIRR is slightly below the discount rate of 12% – hence the FNPV is negative and the benefit/cost ratio is slightly below 1.0. Therefore the Project's viability is at risk if a discount rate of 12% is applied.

14.5.9.3 Power Generation Sensitivity Analysis

The calculation of the power output of the Popa Falls Hydro Power Plant is based on the available hydrological data. However, changes in the water flow level cannot be entirely excluded. Although one would expect this to last only for a limited period, during dry or drought conditions, the sensitivity analysis assumes an output that is 10% below the level in the base case scenario. So this can be considered as a test for lower benefits from the Project.

The results of the power generation sensitivity analysis shows that a decrease of power generation by 10% does not change the ranking of the power supply options. The economic

performance indicators of the Project in the case of a power generation reduction in the order of 10% are as follows:

- ELUC generation: 34.28 US$/MWh
- ELUC generation and transmission: 38.88 US$/MWh
- EIRR: 10.65%
- ENPV: 1,296
- Economic benefit/cost ratio: 1.05

If the power generation is 10% below the base case assumptions, the EIRR remains above the discount rate – hence the ENPV is positive and the benefit/cost ratio is above 1. Therefore the project remains economically viable if the power generation is reduced by 10% over the period of analysis. The critical value with regard to reduced power output is 13%. This means that if power output reduces more than 12%, the EIRR falls below 10% and ENPV falls below zero.