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Mobilising Renewable Energy Investments

Burundi: Small Hydropower and Rural Development

Model Business Case: 150 kW Commercial and Industrial (C&I) Hydropower Project

INTRODUCTION

With its vast network of rivers, Burundi is endowed with abundant hydropower resources. Small hydropower can benefit commercial and industrial (C&I) enterprises, especially in rural settings. It can also benefit rural development more broadly, including supporting a wide range of community uses of electricity.

This Model Business Case (MBC) analyses the financial feasibility of a hypothetical 150 kW hydropower project serving a **grid-connected** tea processing facility in Burundi ("the Project"). The output of the hydropower plant will completely replace grid electricity and backup diesel power normally consumed by the facility, while the excess power generated will be fed into the main grid operated by the national utility, the Water and Electricity Production and Distribution Company (Régie de Production et de Distribution de l'Eau et de l'Electricité, REGIDESO).

TARGET AUDIENCE

A detailed financial analysis of the Project was conducted to determine its viability and its cost savings potential. The target audience of this MBC includes (but is not limited to):

— Owners or lessors of commercial, agricultural or industrial property who might consider small hydro for power generation to reduce electricity costs;

— Project developers (and their investors) who may be interested in pursuing opportunities for development of C&I hydropower projects in Burundi; and

— Policymakers, donor agencies, development partners and DFIs.

GET.invest Burundi

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KEY ASSUMPTIONS

This MBC is based on the assumptions described below. The assumptions presented are mainly based on publicly available information gathered through desk research and local stakeholder interviews.[1] A detailed feasibility study would be required to determine the availability of adequate hydroelectric resources and the actual applicable costs and parameters for specific sites/projects.

Technical assumptions

Table 1 presents the assumptions related to the C&I customer load characteristics, based on data obtained from a large-scale tea processing facility in Burundi.

TABLE 1. Customer load characteristics

CUSTOMER LOAD CHARACTERISTICS	UNIT	VALUE
REGIDESO customer category	–	Medium voltage[2]
Facility power demand	kW	150[3]
Annual grid electricity consumption	kWh	321,600[4]
Portion of annual load supplied by diesel generator	%	10%[5]

1) The assumptions are not based on field studies detailing the baseline hydrological conditions and spatial land use trends of the project site. Also, future changes in hydrology due to land degradation, changes in water use, and climate change were not considered.
2) Based on the tea processing facility's electricity bill.
3) Based on the tea processing facility's electricity bill.
4) Based on the tea processing facility's electricity bill.
5) Stakeholder interviews, 2022.

Table 2 presents the assumptions related to the diesel generator capacity and costs.

TABLE 2. Diesel generator characteristics

PARAMETERS	UNIT	VALUE
Diesel gen capacity	kW	400[6]
Diesel gen CAPEX	EUR/kW	€225[7]
Diesel gen lifetime	years	7[8]
Annualised capital cost	**EUR/year**	**€12,885**[9]
Annual diesel consumption	Litres/year	4,800[10]
Diesel price per litre	EUR/litre	€1.25[11]
Annual diesel cost	**EUR**	**€5,998**[12]
Annual O&M costs	**EUR**	**€988**[13]
Total diesel power annual cost	**EUR/year**	**€19,871**[14]

Table 3 presents the assumptions related to the technical parameters of the C&I hydropower system.

TABLE 3. Hydropower system technical assumptions

HYDROPOWER SYSTEM PARAMETERS	UNIT	VALUE
Installed capacity	kW	150[15]
Average annual energy production	MWh	654[16]
Project lifetime	Years	20[17]
Interconnection line	km	0.5[18]

6) Stakeholder interviews, 2022.
7) Based on data obtained from desk research. This translates to a total diesel generator CAPEX of EUR 90,198 (i.e., EUR 225.5 multiplied by 400kW).
8) Stakeholder interviews, 2022.
9) Derived by dividing the diesel generator CAPEX by its lifetime.
10) Stakeholder interviews, 2022.
11) Based on a price of BIF 3,795: https://www.globalpetrolprices.com/Burundi/diesel_prices/; Accessed on September 2, 2023.
12) Derived by multiplying the annual diesel consumption by the cost of diesel per litre.
13) Stakeholder interviews, 2022.
14) Derived by adding the annual diesel cost, the annualised capital cost and the annual O&M cost.
15) Based on the power demand of the tea factory interviewed.
16) "Zambia: Solar PV and Hydro Mini-Grids: Case Study: Hydropower Mini-Grid at Lwakela Falls," GET.invest Market Insights, (2020): https://www.get-invest.eu/wp-content/uploads/2020/10/GETinvest-Market-Insights_ZMB_Mini-grid_-CS-Hydro_2019.pdf
17) Ibid.
18) Assuming a distance of 500m between the tea factory and the hydro resource.

Macroeconomic assumptions

For this analysis, the Burundian Franc (BIF) to EUR exchange rate is assumed to be 3,037.1, while the annual BIF to EUR depreciation is assumed to be 5.1%.[19] In addition, annual inflation is assumed to be 10.7% over the life of the Project, based on projections for the country.[20]

Capital and operating costs

Table 4 presents the capital and operating cost assumptions for the Project.[21] It is assumed that the system will be depreciated via straight line depreciation over its 20-year lifetime at a rate of 5% per year. Annual operations and maintenance (O&M) costs for the hydropower plant and connection line are assumed to be 4% of the total capital cost of the Project.[22] O&M costs are assumed to increase by 10.7% annually in line with inflation.

TABLE 4. Capital and operating cost assumptions

CAPITAL COSTS	UNIT	UNIT COST	TOTAL COST
Hydropower plant cost	EUR/kW	€3,500[23]	€525,000
Interconnection line cost	EUR/km	€12,000[24]	€6,000
Development and other costs	EUR/kW	€500[25]	€75,000
		Total CAPEX	**€606,000**
		Annual O&M cost – year 1[26]	**€24,240**

Taxes

A corporate income tax rate of 30% was applied to the Project, in line with the applicable tax rate in Burundi, with no tax holiday. In addition, a Value Added Tax (VAT) rate of 18% was applied to the equipment and services used for the Project, as well as the C&I facility's grid electricity costs. It is assumed that the EPC costs stated above already incorporate VAT.[27]

19) Calculated based on BIF/EUR exchange rate data.
20) Burundi: Inflation forecast: https://www.theglobaleconomy.com/Burundi/inflation_outlook_imf/
21) Capital costs include the cost of civilworks, the penstock, turbine, generator, powerhouse, substation, interconnection cost, installation cost, cost of freight, taxes (onshore and offshore), applicable duties, and development and other costs including costs for studies and design, supervision and contingency.
22) Stakeholder interviews, 2022.
23) Stakeholder interviews, 2022.
24) Stakeholder interviews, 2022.
25) Stakeholder interviews, 2022.
26) Derived by multiplying the total CAPEX by 4%.
27) The corporate tax rate in Burundi is fixed at 30%, subject to a minimum of 1% of the turnover if the company makes a loss or if the taxable profit is below 1/30th of the turnover.

Grid electricity costs

Electricity tariffs for C&I customers in Burundi are comprised of active power charges and fixed charges.[28] These grid power charges are eliminated with the installation of the hydropower plant. **Table 5** presents the grid electricity cost assumptions used in the model, which are based on the tea processing facility's electricity bill for May 2022 and are in line with REGIDESO charges for medium-voltage customers with subscribed power and without peak consumption. A feed-in-tariff (FiT) of BIF 337/kWh is assumed for the excess power injected into the grid.[29] It is also assumed that the grid electricity costs, and feed-in-tariff will increase by 10.7% annually in line with inflation.

TABLE 5. Grid electricity cost assumptions

TARIFF	UNIT	UNITS/MONTH	COST/UNIT (BIF)	COST/UNIT + VAT (BIF)	TOTAL COST (INCLUDING VAT) (BIF MILLION)	TOTAL COST (INCLUDING VAT) (EUR)
Active power charge	kWh	26,800	218	257	6.89	2,270
Fixed charges	kW	150	16,283	19,214	2.88	949
				Total monthly cost	**9.78**	**3,219**

Financing structure and debt assumptions

It is assumed that the Project will be financed by the tea processing company via a Special Purpose Vehicle (SPV) with 30% equity and 70% commercial debt. Two debt financing scenarios were considered: (i) EUR-denominated debt; and (ii) BIF-denominated debt. **Table 6** presents the Project debt assumptions for both scenarios. The debt tenor is assumed to be 10 years under both scenarios.[30] It is also assumed that the required rate of return for the company to consider the Project attractive is 15%.[31]

TABLE 6. Project debt assumptions

PROJECT DEBT	UNIT	EUR DEBT	BIF DEBT
Debt amount	EUR/BIF	€424,200	BIF 1.29B
Debt interest rate	%	8.5%[32]	16%[33]

28) World Trade Organisation (WTO): Burundi: https://docs.wto.org/dol2fe/Pages/SS/directdoc.aspx?filename=q:/WT/TPR/S384R1-02.pdf&Open=True
29) Assumption based on $0.09 FIT for the Mwenga Hydro Project in Tanzania: https://www.usaid.gov/energy/mini-grids/case-studies/tanzania-hydropower. It is worth noting that there is no feed-in-tariff regime in place yet in Burundi, although it is being considered by the government.
30) "Zambia: Solar PV and Hydro Mini-Grids: Model Business Case: Hydro Mini-Grid for Rural Electrification," GET.invest Market Insights, (2020): https://www.get-invest.eu/wp-content/uploads/2020/10/GETinvest-Market-Insights_ZMB_Mini-grid_-MBC-Hydro_2019.pdf
31) "CrossBoundary Energy fully exits first fund at 15% net internal rate of return (IRR), raises $40M to continue to scale financed solar for businesses in Africa," CrossBoundary Energy, (17 November 2020): https://www.sun-connect-news.org/news/details/press-release-crossboundary-energy-fully-exits-first-fund-at-15-net-internal-rate-of-return-irr/
32) Daglish, J., 2019. "A Prefeasibility Analysis of a PV Mini Grid with Ice Plant on Buvu Island in Lake Victoria," KTH School of Industrial Engineering and Management, Stockholm, Sweden, https://upcommons.upc.edu/bitstream/handle/2117/333364/jonathan-daglish-thesis.pdf?sequence=1&isAllowed=y
33) Banque de la République du Burundi: https://www.brb.bi/sites/default/files/BM_June_2022_4.pdf

RESULTS

Based on the assumptions described above, the financial analysis yielded the following conclusions:

— Under the EUR-denominated debt scenario, the Project is attractive with an after-tax equity IRR (EIRR) of 16.5%, equity NPV of EUR 31,392 and total cost savings of EUR 451,010.

— Under the BIF-denominated debt scenario, the Project is also attractive, but to a less extent with an after-tax EIRR of 15.7%, equity NPV of EUR 16,244 and total cost savings of EUR 446,368 due to the high cost of local debt.

— However, the minimum Debt Service Coverage Ratio (DSCR) is below the threshold of 1.2 typically required by lenders to finance a project under both scenarios due to lower revenues in the first few years (before the grid and diesel costs escalate to higher levels), indicating the need for concessional debt terms and/or a debt service reserve account (DSRA).

The results of the financial analysis are summarised in **Table 7**.

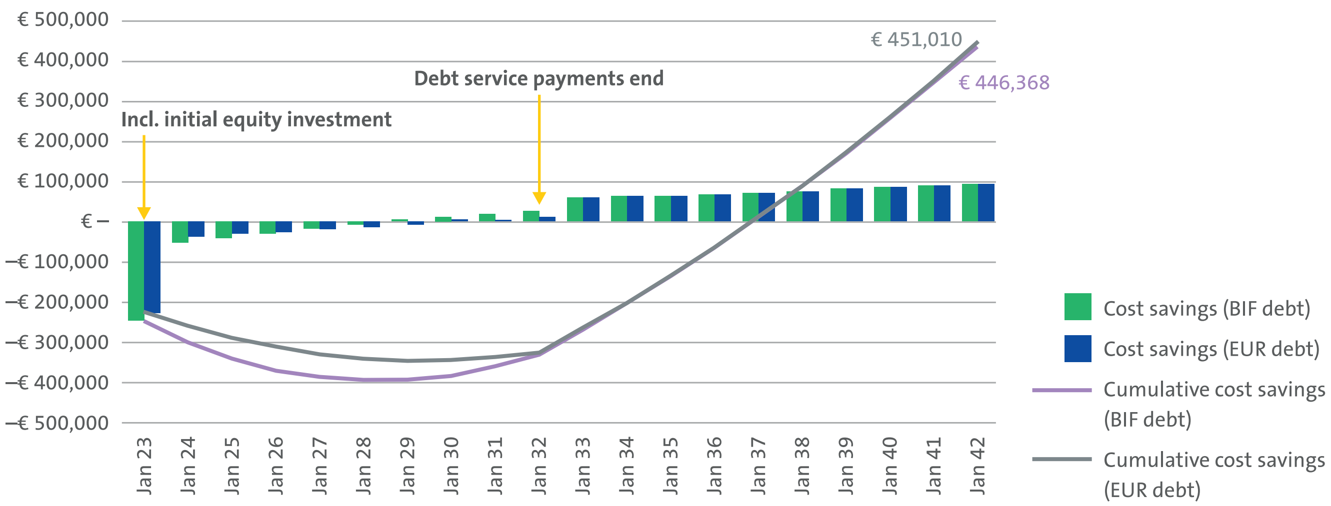
TABLE 7. Financial analysis results

C&I HYDROPOWER PROJECT RESULTS SUMMARY

INDICATOR	EUR-DENOMINATED DEBT	BIF-DENOMINATED DEBT
Avg. annual grid electricity and diesel power cost avoided	€105,639	
Avg. annual cost savings	€22,551	€22,318
Avg. annual cost savings (%)	21.3%	21.1%
Total cumulative cost savings	€451,010	€446,368
Avg. annual FIT revenue	€65,963	
Avg. net income	€61,960	€57,963
LCOE	€0.14	€0.16
Total CF to equity	€1.42M	€1.44M
Net CF to equity	€1.24M	€1.26M
After tax equity IRR	16.5%	15.7%
After tax project IRR	12.3%	
Equity NPV	€31,392	€16,244
Project payback period (yrs.)	9	
Avg. DSCR	1.41	1.66
Min. DSCR	0.93	0.72

Figure 1 illustrates the estimated annual electricity cost savings and cumulative electricity cost savings that can be realised by the C&I facility over the lifetime of the hydropower system. As shown, the hydropower project costs are initially higher than the C&I facility's avoided grid power and diesel generator costs. After 10 years, when debt service payments end, the C&I facility begins to accumulate savings. After 20 years, the C&I facility's cumulative cost savings are similar under both scenarios, but higher under the EUR debt scenario due to the lower cost of debt.

FIGURE 1. Tea factory annual electricity cost savings



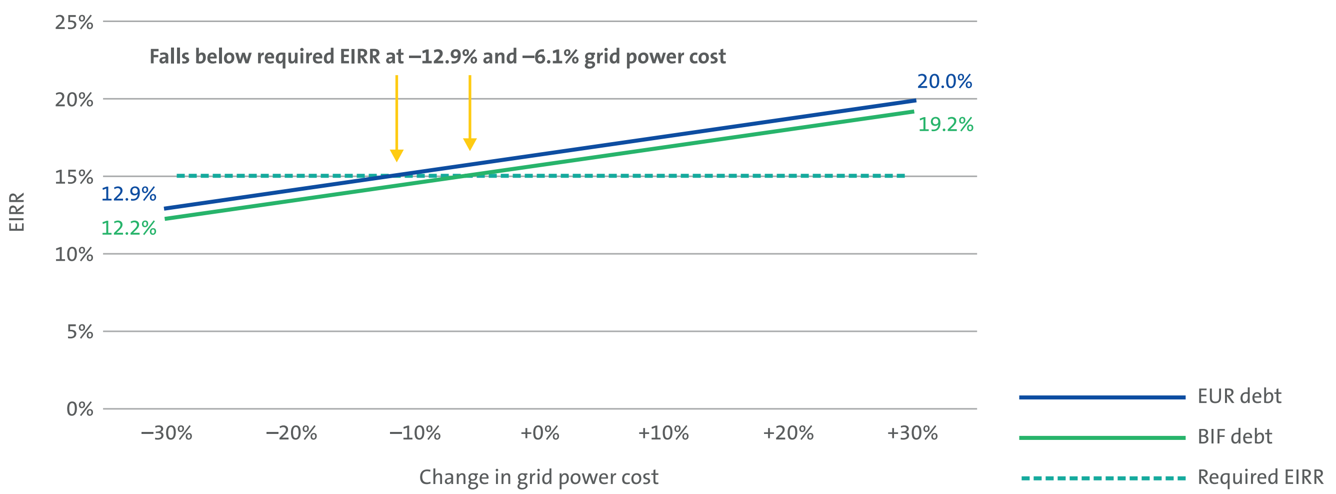
SENSITIVITY ANALYSIS

A sensitivity analysis was conducted to assess the impact of changes in key assumptions on the EIRR and minimum DSCR as measures of the Project's viability. The figures below present the results under various scenarios.

Grid power cost scenarios

Figure 2 shows the impact on EIRR of increases in the grid power costs avoided by the tea factory. The analysis found that the required EIRR will not be achieved unless the cost of grid power decreases by 12.9% under the EUR debt scenario and 6.1% under the BIF debt scenario. This indicates that the Project is sensitive to minor changes in the grid tariff under both scenarios, particularly if financed with BIF debt.

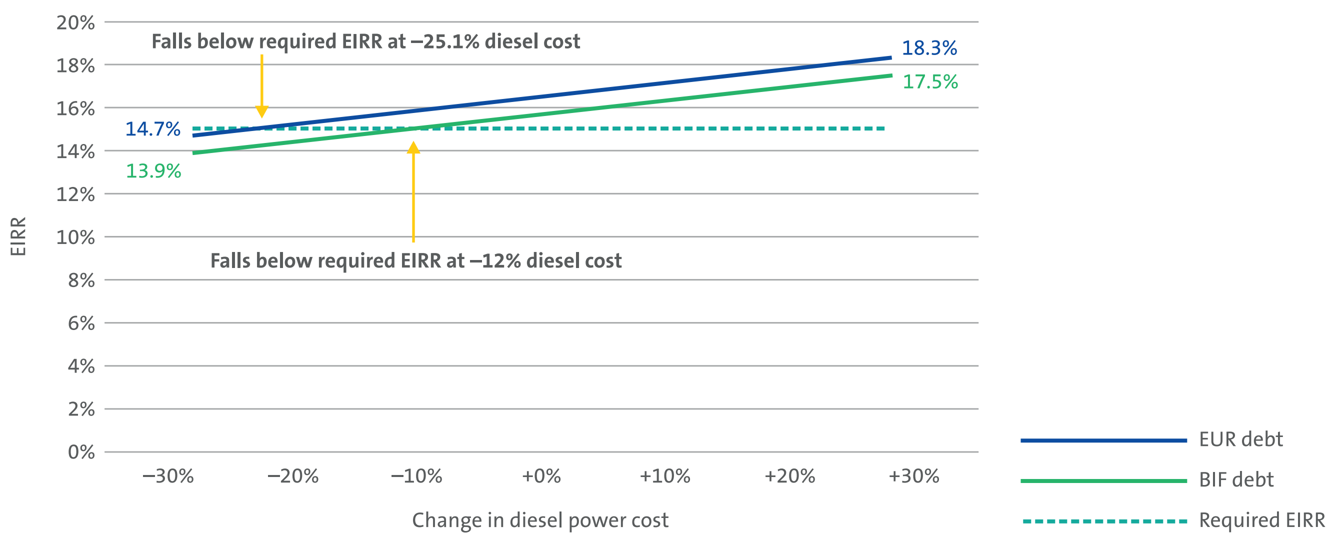
FIGURE 2. Equity IRR at various grid electricity cost levels



Diesel power cost scenarios

Figure 3 illustrates the impact of changes in the tea factory's diesel power costs on EIRR. The analysis found that the required EIRR will not be achieved if the cost of diesel power decreases by 25% under the EUR debt scenario and 12% under the BIF debt scenario. This indicates that the Project is sensitive to minor changes in diesel prices if financed with BIF debt. It also shows that the viability of the Project is more sensitive to grid power charges than diesel power cost.

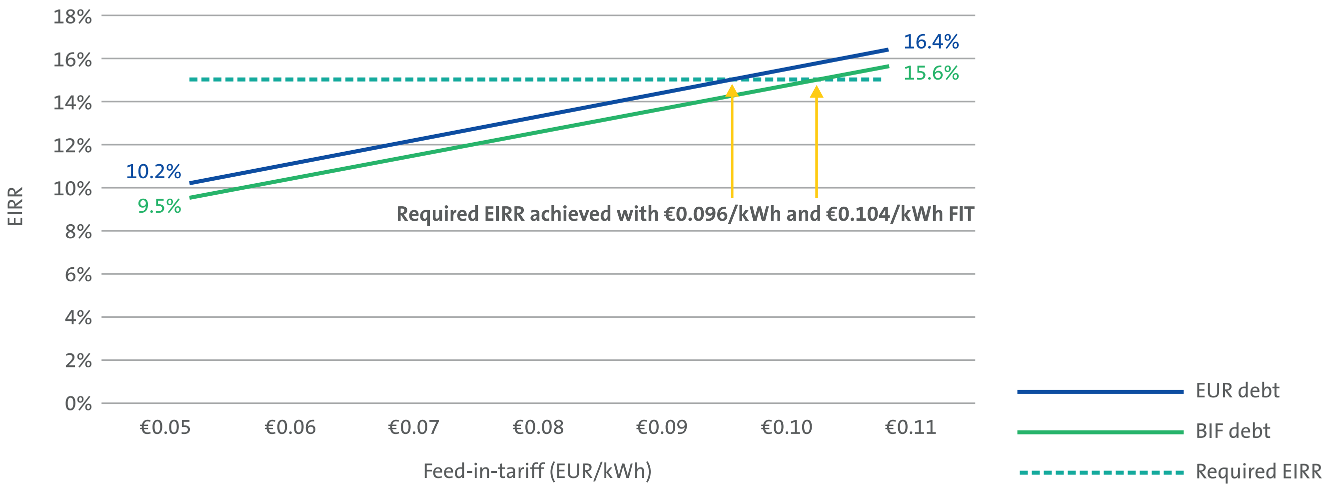
FIGURE 3. Equity IRR at various diesel power cost levels



Feed-in-tariff scenarios

Figure 4 shows the impact of increases in the feed-in-tariff on EIRR. The analysis found that the required EIRR can only be achieved if the feed-in-tariff is at least EUR 0.096/kWh and EUR 0.104/kWh (which is below the assumed EUR 0.11/kWh FIT) under the EUR debt and BIF debt scenarios, respectively. The results also indicate that the Project will not be attractive without a feed-in-tariff (i.e., if the excess power produced is not sold to the grid).

FIGURE 4. Equity IRR at various feed-in-tariffs



Debt interest rate scenarios

Figure 5 and **Figure 6** illustrate the impact of increases in both the EUR-denominated and BIF-denominated debt interest rates on EIRR and minimum DSCR, respectively. The results show that the required EIRR will be achieved if interest rates do not exceed 11.8% and 17.7% (above the assumed rates of 8.5% and 16%) under the EUR-denominated and BIF-denominated debt scenarios, respectively. More importantly, it also reveals that the minimum DSCR threshold will not be achieved at the interest rates considered under both scenarios. This indicates that the Project will require concessional debt terms (e.g., grace period) and/or a DSRA.

FIGURE 5. Equity IRR at various debt interest rates

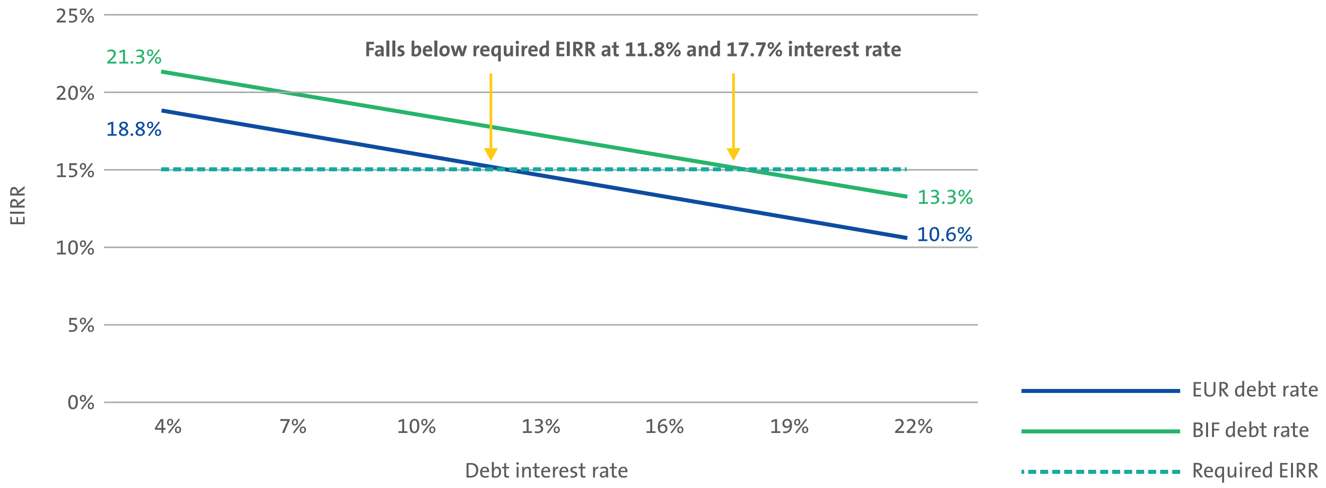
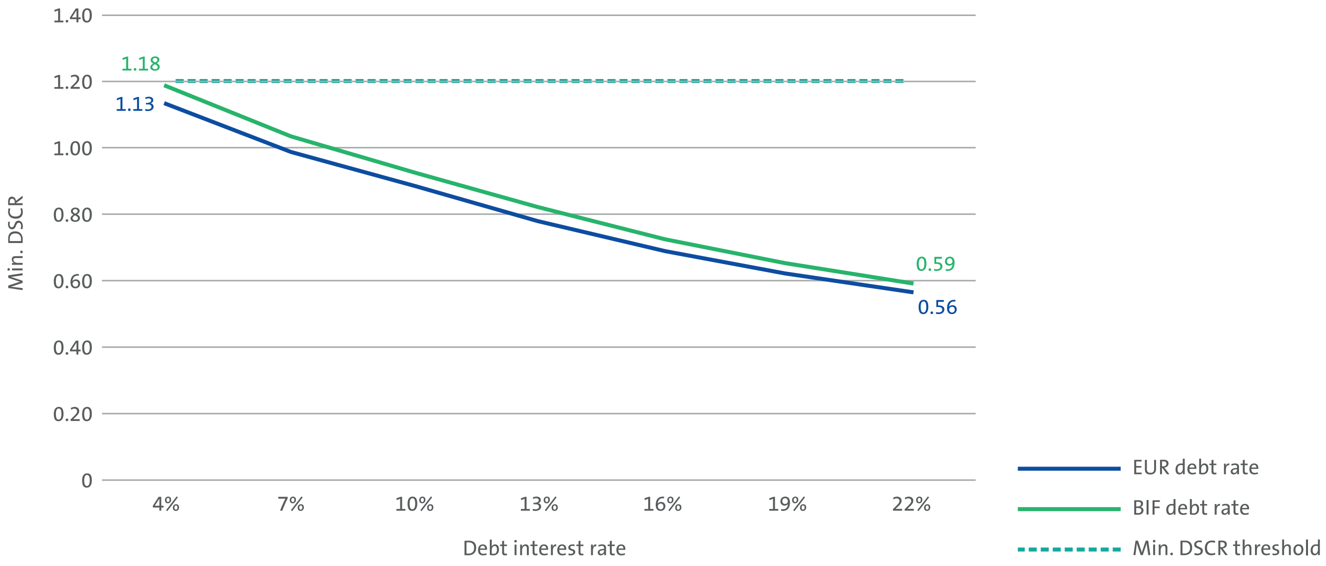


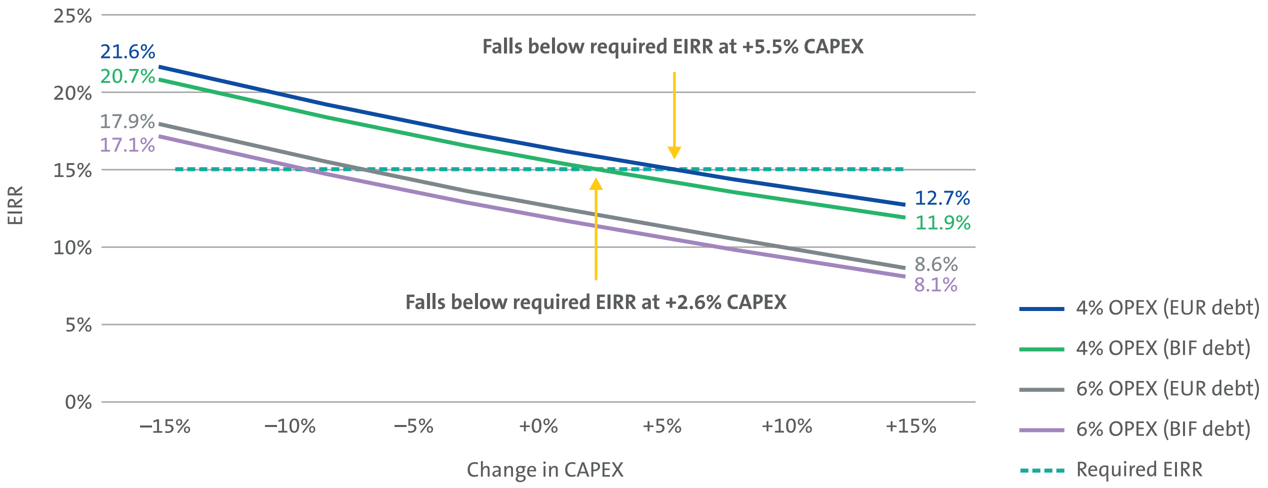
FIGURE 6. Minimum debt service coverage ratio at various debt interest rates



CAPEX and OPEX scenarios

Figure 7 shows the impact of changes in CAPEX and OPEX on EIRR. The analysis found that the required EIRR can only be achieved at the base OPEX level if increase in CAPEX does not exceed 5.5% under the EUR debt scenario and 2.6% under the BIF debt scenario. This suggests that the viability of the Project is sensitive to minor increases in CAPEX; hence, the developer must pay close attention to capital cost overruns.

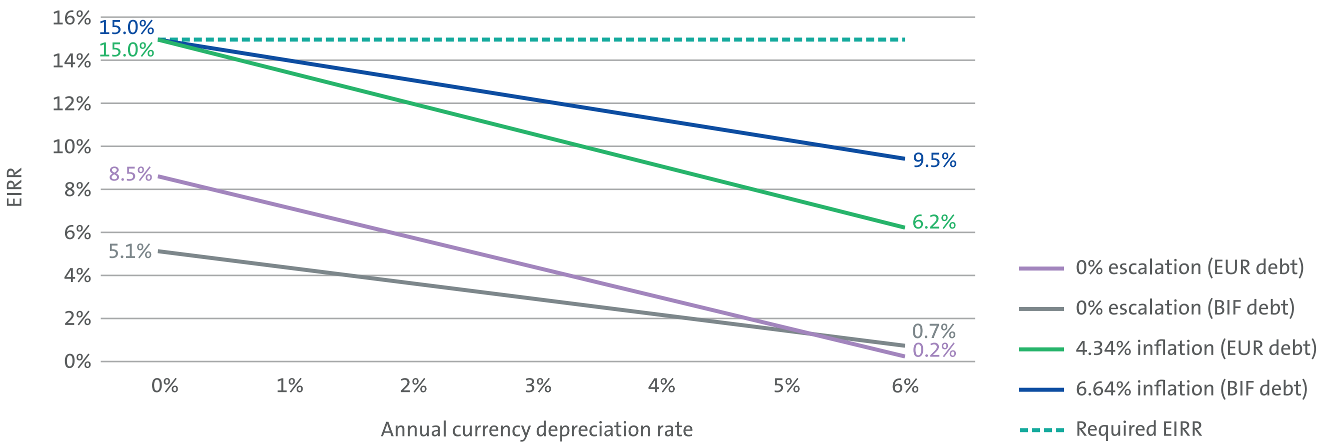
FIGURE 7. Equity IRR at various CAPEX and OPEX levels



Local currency depreciation and inflation scenarios

Figure 8 illustrates the impact of increases in the annual local currency depreciation rate and inflation rate on EIRR. The analysis found that even if the local currency does not depreciate, the required EIRR will only be achieved if the grid electricity and diesel power costs and the feed-in-tariff escalate annually by at least 4.3% and 6.6% under the EUR debt and BIF debt scenarios, respectively. This shows that the viability of the Project will depend on annual diesel price, grid tariff and FIT increases and the stability of the BIF.

FIGURE 8. Equity IRR at various inflation and currency depreciation levels



CONCLUSIONS AND KEY TAKEAWAYS

In conclusion, based on the assumptions in this Model Business Case, the Project is estimated to be attractive with an after-tax EIRR of 16.5% and 15.7% when financed with EUR debt and BIF debt, respectively, with total cost savings above EUR 0.4M. However, due to the high cost of developing and operating a hydroelectric power system, the viability of the Project depends on the costs of the C&I facility's grid electricity and diesel power consumption displaced by the hydro system, the feed-in-tariff level, and the annual increase of these project revenue components. Without a feed-in-tariff (for the sale of excess power to the grid), the Project will require an alternative off-taker to purchase the excess power generated in order to be attractive. The viability of the Project will also depend on the ability of the Project proponent to identify a site with sufficient hydroelectric resources and on the changes in its hydrological conditions over time.

In addition, the Project will require concessional debt terms (e.g., grace period, longer tenor, low interest rate) and/or a Debt Service Reserve Account in order to adequately meet lenders' minimum DSCR requirements. The viability of the Project is also sensitive to minor increases in CAPEX; hence, the developer must pay close attention to capital cost overruns.

KEY DEFINITIONS

Avg. annual grid electricity and diesel power cost avoided is the average annual grid electricity cost and back-up diesel power cost that the C&I facility would have incurred without the Project over the life of the Project.

Avg. annual cost savings is the average annual cost savings realised by the C&I facility over the life of the Project after accounting for operating expenses and debt service.

Avg. annual cost savings (%) is the average annual cost savings expressed as a percentage of the C&I facility's average annual electricity cost without the mini hydro plant.

Total cumulative cost savings is the total cumulative cost savings realised by the C&I facility over the life of the Project.

Avg. annual FIT revenue is the average annual revenue generated from the sale of excess power into the grid over the life of the Project. Feed-in tariffs are fixed electricity prices that are paid to renewable energy producers for each unit of energy produced and injected into the electricity grid.

Avg. net income is the average net income generated over the life of the Project.

LCOE (levelised cost of energy) is the net present value of the total costs incurred by the Project over its lifetime divided by the net present value of the total power generated over its lifetime.

Total cashflow to equity refers to the total cash flow distributed to the equity investor over the life of the Project.

Net cashflow to equity refers to the Total Cashflow to Equity less the equity investment in the Project.

After tax equity IRR is the post-tax internal rate of return on equity investment after taking account of debt service.

After tax project IRR is the post-tax internal rate of return on the Project. It is the discount rate at which the net present value (NPV) of the Project is equal to zero.

Equity NPV is the net present value of the free cash flows to the equity investor using the required equity rate of return as the discount rate.

Project payback period (yrs.) refers to the number of years it takes to recover the initial capital cost of the Project.

Avg. DSCR is the average debt service coverage ratio over the life of the Project.

Min. DSCR is the minimum debt service coverage ratio over the life of the Project.

ABOUT GET.INVEST MARKET INSIGHTS

The first series of GET.invest Market Insights was published in early 2019 covering four renewable energy market segments in three countries, namely: renewable energy applications in the agricultural value-chain (Senegal), captive power (behind the meter) generation (Uganda), mini-grids (Zambia) and stand-alone solar systems (Zambia).

A **Developer Guide** aims at informing project developers, private sector technology suppliers, innovators and entrepreneurs about opportunities for small hydropower (SHP) development in Burundi. The Guide is organised into four main sections: **1)** introduction; **2)** context for SHP development in sub-Saharan Africa; **3)** role of small hydropower in supporting local communities or industries in rural areas of Burundi; and **4)** "Route-to-market" – i.e., how to leverage the market research presented in the Guide to contribute to SHP development in Burundi.

Accompanying the Guide are two corresponding Model Business Cases, which provide financial analyses for concrete business examples. The two **Model Business Cases** included in this package analyse: **1)** a tea factory that develops a SHP project to power its operations; and **2)** a hybrid solar PV-small hydropower mini-grid that provides electricity to an off-grid community in rural Burundi.

The GET.invest Market Insights summarise a considerable amount of data that may inform early market exploration and pre-feasibility studies. It is therefore recommended to cross-read this Developer Guide and the Model Business Cases for a comprehensive overview. The products are accessible at www.get-invest.eu.

ABOUT GET.INVEST BURUNDI

GET.invest is a European programme that mobilises investment in renewable energy, supported by the European Union, Germany, Sweden, the Netherlands, and Austria.

Since October 2021, the programme has been operating a country window in Burundi funded by the European Union and implemented by the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ). Find out more at GET.invest Burundi.

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We welcome your feedback on the Market Insights by sharing any questions or comments via email at info@get-invest.eu.

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