

A cost-benefit analysis of options for the retrofit of Kiri dam to generate hydroelectric energy

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Abstract

A largely overlooked approach to expanding electricity access in rural regions while minimizing environmental harm involves retrofitting existing dams. Although upgrading these structures presents a promising alternative for power generation with reduced ecological consequences, the economic viability of various financing models for such hydropower retrofits remains poorly understood. This study addresses that gap by modifying the Hydropower Environmental Costs Analysis Model (HECAM) to evaluate the long-term economic feasibility of dam retrofits, considering the interplay between environmental, economic, and social factors. A cost-benefit analysis of upgrading Kiri Dam for hydroelectric power generation evaluated three potential financing and ownership models: a 20 MW public-private partnership (PPP) over 20 years, a 30 MW PPP over 20 years, and a 30 MW PPP over 30 years. Among these, the 30 MW 20-year PPP option yielded the highest annual revenue from electricity sales when compared to the 20 MW 20-year and 30 MW 30-year alternatives. However, the 30 MW 30-year PPP model generated greater total annual revenue from additional reservoir services than the other two options. Sensitivity analysis suggests that, at this early phase of project development, it is advisable to explore multiple equity tranches with different payment structures. The results highlight that factors such as contract duration, water flow, capacity factor, capital expenses, debt term, interest rates, and other variables should all be considered when evaluating the costs and benefits of retrofitting existing dams. Given that hydropower projects can have long operational lifespans under favorable conditions, project developers and equity investors should prioritize longer-term contracts.

Keywords: *Retrofitting Dams, Hydroelectric Project, Financial Analysis, Socio-Economic Impacts, Water-Energy Nexus, Retrofit*

1. Introduction

Retrofitting non-powered dams has always entailed benefits and drawbacks, much like other structures of such magnitude [1]. The physical, biological, and socioeconomic repercussions of improper planning and poor management of dams typically have detrimental effects, including loss of life and property, employment, food and natural resources, environmental degradation, and a decline in local security and safety [2,3]. Hence, the assessment of hydroelectric dams and projects has become crucial to international decision-making due to these externalities.

Multi-aspect models have been employed by numerous researchers to study hydro projects [2].

Considering the Asian Development Bank's model, Sospiro et al. [4] examined the advantages, drawbacks, suggested countermeasures, and oversight procedures associated with the development and management of Pumped Hydroelectricity Storage, taking into account both direct and indirect costs and benefits. An ex-post economic analysis of the NCH1HP using cost-benefit analysis by Nhiakao et al. [5] revealed that, although the NCH1HP might be advantageous based solely on financial analysis, it could have unfavorable side effects when considering the environmental impact after dam completion. Nonetheless, a comprehensive prospective

financial assessment that accounted for the project's spillover effects showed that it was beneficial.

The benefit-cost analysis and the discount rate, determined by contrasting with alternative options, indicate that the third scenario is more significant than the others. This led to the conclusion that if the monetary aspects of such systems are overlooked, compensation for implementation and operating costs will ultimately fail [6]. When a profit-sharing scheme for hydropower development was designed using game theory and a cost-benefit model that incorporated displaced populations as an investment in the project, it was found that adjusting income distribution based on the results validated the logic of the adjustment plan [7]. However, a dam minimally benefits the economy, as evidenced by the fact that it provides less than 5% of the country's electricity needs, followed by numerous foreign and complex expenditures [8]. The outcomes of balancing the costs and benefits of the environmental economy influence the NPV and decision factors, such as the usual water level and installed capacity. However, the NPV and energy production of the HPP project decreased by a specific proportion because the negative environmental effects held greater economic value than the positive ones [9]. Nonetheless, enhanced benefit assessment methods enable a more trustworthy and comprehensive evaluation of the costs and benefits of flood risk management interventions. This evaluation assists experts and policymakers working on related projects in making better decisions and allocating resources more effectively in flood risk mitigation [10]. Arango-Gil et al. [11] suggest that, to more accurately determine the true value of implementing such innovative energy-production approaches at the national level, cost-benefit assessments for adopting renewable energies should include new methods.

Since the primary challenge of dam impact assessments in developing nations is the time lag between the design and evaluation stages, none of the methods used to identify dams and predict consequences are generally sufficiently flexible to allow for frequent updates and the addition of unpredictable variables [1]. Certain indicators are often overlooked in research, such as sedimentation and land use/landcover changes in conjunction with agriculture and fisheries [12]. For instance, in Nigeria, a country with a distinct political and economic landscape, environmental and social impact studies are typically released after the assignment of hydro project sites [13].

Despite advances in comprehensive approaches, this tendency can lead to significant socio-environmental issues in some cases, and few economic models incorporate these elements when assessing hydroelectric dam viability.

Numerous studies have primarily highlighted the negative consequences of hydroelectric projects despite their strategic importance in food supply, flood control, and power generation. However, due to the complex, multifaceted, and dynamic nature of dam construction, the effects of large dams have not been sufficiently explored [14,15]. Since natural resources are neither monetary nor inherently observable, market-driven cost-benefit evaluations remain in their formative stages. Although extensive scientific research exists on the costs and benefits of dam construction from a specialized professional perspective, very little research has concurrently examined the biophysical, social, and geopolitical consequences, as noted by [16,17].

Because dam construction impacts many socioeconomic and environmental domains, basic evaluation approaches are inadequate for calculating the costs associated with human-made, biological, and traditional systems. Techniques such as extended CBA, HECAM (Hydropower Environmental Costs Analysis Model), and SimPacts combine financial costs (construction, O&M) with significant environmental and social implications. The calculations of the SimPacts software are insufficiently detailed, despite its sound logic and substantial evaluations. This model entirely overlooks benefits and considers only costs. Moreover, most of the particularly significant environmental effects of hydroelectric dams—such as expenses related to agriculture, energy production, fisheries system maintenance, and municipal water supply facilities—are neglected by the model. The IAEA's SimPacts model was further modified into the HECAM model to thoroughly evaluate the external costs and benefits of hydropower projects. It extends beyond simple energy generation to include socioeconomic and ecological impacts such as energy revenues, irrigation, pollution, land use, sedimentation, and evaporation effects, enabling a comprehensive assessment of the project's sustainability [1].

Although Yuguda et al. [18] compared three possible options for retrofitting dams to generate hydroelectric energy using LCA, no study to date has attempted to compare the potential financing options for dam retrofitting in terms of cost-benefit analysis. The objective of this study is therefore to compare three possible funding and ownership alternatives for the Kiri dam

hydropower development, utilizing and modifying the more comprehensive version of the Hydropower Environmental Costs Analysis Model (HECAM II). While the actual costs and benefits of hydroelectric power generation are considered to determine the project's viability, this socio-environmentally critical case study and its financing options are used to validate the HECAM II model, in light of SDGs.

2. Hydropower retrofit and Sustainable Development

The scientific community has proposed sustainable development as a consequence of accelerated growth strategies that have exacerbated induced climate change and disparities across many regions. Hydroelectric dams have been used as case studies in numerous recent publications on the (nexus) linkages. Compared to counties with proposed but unbuilt hydropower projects, those that constructed hydropower plants had higher GDP and tax revenues in the early stages of development. However, these economic benefits were fleeting, according to [12]. The Three Gorges Dam illustrates that such massive public works initiatives have significant social ramifications, as noted in [19]. Further findings suggest that SHP-based REPs have considerable potential to achieve their stated objectives of improving socioeconomic indicators in remote and rural areas. Nonetheless, programs often fall short of expectations or further alienate local populations due to various factors, as demonstrated in [20]. Regression analyses and comparable geographical assessments provide preliminary statistical evidence that hydropower economies tend to perform poorly on several stability, financial growth, and administrative criteria [21]. A comparison of the standardized cost of electricity for each retrofitting scheme with the LCOE estimates for other renewable energy sources indicates that retrofitting NPDs could be an underexplored option to support the global transition to renewable energies by offering a more affordable and environmentally friendly approach to rural electrification [22]. Essentially, a framework was developed that considers social, environmental, and economic variables and provides metrics suitable as a preliminary step in deciding whether to proceed with a retrofitted hydropower project [23]. Moreover, potential hazards associated with dam retrofitting should not be overlooked, even though cost remains a critical factor in assessing the feasibility of hydropower projects [18]. Synergies can be leveraged to optimize resource use and enhance system resilience by integrating hydropower generation

into existing reservoir functions. Countries can significantly improve their energy security and reduce their carbon footprint by utilizing current infrastructure and exploring innovative approaches [24]. Future research should incorporate emerging technologies, examine collaboration strategies, and consider socioeconomic benefits and limitations to foster development at retrofittable dams [25].

To provide valuable insights for sustainable decision-making in developing nations, this study first examines a major hydro project that has received limited attention. Second, the assessment is conducted under pre-construction conditions to prevent any catastrophic decisions. Third, the model has been adapted to be comprehensive in terms of reliability and simplicity for retrofitting dams. Fourth, the project's social, environmental, economic, and ecological components are considered to encompass most elements of sustainable development within the integrated model.

3. Case study

The Upper Benue River Basin Development Authority (UBRBDA), the project owner and operator, supplied a briefing document containing this summary of the Kiri Dam Project [18]. The authority completed construction of the project in 1982. The dam's primary function is irrigation, which sustains sugar production and commercialization. Other uses of the dam include minor agricultural operations from upstream to downstream of the construction site, beyond the irrigation networks of the reservoir, access across the river connecting adjacent communities, fishing in the reservoir, and various recreational activities. The project is situated on the Gongola River near Kiri Village in the northeastern Nigerian state of Adamawa. The dam is located approximately 25 kilometers upstream of the confluence of the Gongola and Benue rivers. The Benue River is part of the Niger River Basin.

The project features a large earthen embankment and sizable tainter-type gates for releasing high flows. The irrigation infrastructure includes intake facilities at the dam's right abutment, which supply project-related distribution channels for water used in irrigation. To release low-level water and prevent sediment buildup around the irrigation facilities, there are also small gates called scouring sluices. "Figure 1" is a photograph of the facilities taken by the author during postgraduate research investigations, while "Figure 2" is a map of the study area.



Figure 1. Photograph of Kiri dam spillway and sluices taken by the author during investigation.

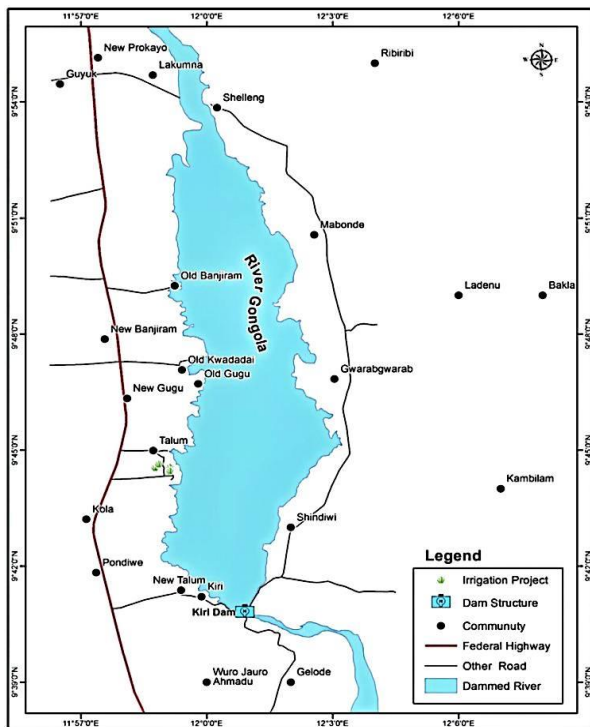


Figure 2. Existing Kiri dam, reservoir, and environs

4. Method

The SimPacts and HECAM models are adjusted to reflect the beneficial aspects and cost implications of constructing hydroelectric dams. The straight-line depreciation method is used to calculate the necessary investment for the hydroelectric dam over its lifetime, assuming that the power plant will depreciate over 50 years. Three ownership/financing structure scenarios were considered for hydropower retrofit installation, as the sensitivity analysis assessed contract life, water flow, capacity factor, capital cost, debt term, and debt interest rate. The three project structures are:

- i. Scenario 1: 20 MW, 20-year Public-Private Partnership.

- ii. Scenario 2: 30 MW, 20-year Public-Private Partnership.
- iii. Scenario 3: 30 MW, 30-year Public-Private Partnership.

While some operating expenses are constant, the power plant's nominal capacity must account for costs such as employee wages, fees, and habitat irrigation that are unrelated to generation. Since these costs are linked to the actual capacity (MW), fixed costs are unaffected by output, whereas variable costs depend on energy production. Fixed Operation and Maintenance costs do not depend on the amount of energy produced; instead, they are based on the installed or available capacity, measured in kilowatts or megawatts per year. In contrast, Variable O&M costs are directly tied to overall electricity output, typically expressed in kilowatt-hours or megawatt-hours. Assuming installments occur in the latter half of each year, the actual interest during the development phase was calculated using the plant's yearly income at the annual interest rate. The contractual investment costs for the dam and generation plant were then determined, and the debt servicing cost per unit of energy for the 30 MW power plant was computed at 10.6 to 13.1 US cents per kWh. Additionally, the retrofit cost was calculated starting in the 20th–30th year of its contract life, depending on the option, and the present value was computed using an 8.0%–9.50% annual interest rate. Equation (1) was used to determine the total capitalized monetary cost (Interest During Construction) IDCF.

$$IDCF = [y_1 \times (1 + i)^{(CS-1)+0.5} + y_2 \times (1 + i)^{(CS-2)+0.5} + \dots + y_n \times (1 + i)^{0.5}] - 1 \quad (1)$$

Where y_1 and y_2 denote the yearly payment coefficients for the power plant construction period; CS denotes the construction period; and i denotes the construction interest rate. For initial evaluation, the nominal financing rate during construction is assumed to be the same as the reference discount rate (r). However, in typical commercial project finance setups, these rates often differ due to factors such as the project's debt-to-equity ratio, credit spreads, and specific lending conditions. The sensitivity analysis examines how this difference affects outcomes.

For both the evaluation period and the reconstruction period, a $(25 + n)$ year reinvestment period was considered (n = the age of the existing dam). The useful life of the generation plant is assumed to be half of the existing dam, while the hydrological analysis duration was approximately 50 years. About 25% of the total investment was considered for the energy plant reinvestment in the $(25 + n)$ th year of the dam's existence. Equation (2)

was used to determine the present reinvestment value (PRV), taking into account the original investment.

$$PRV = \frac{PVA}{(1+i)^{15}} \quad (2)$$

where the PVA is the dam annuity's present value over the 50 years of the dam's existence, calculated using the following formulas:

$$PVA = A(50) \times B(100) \quad (3)$$

$$A(50) = \frac{i \times (1+i)^{25+n}}{(1+i)^{25+n} - 1} \quad (4)$$

$$A(100) = \frac{(1+i)^{25+n} - 1}{i \times (1+i)^{25+n}} \quad (5)$$

where $A(50)$ denotes the annuity's present value over 50 years, and $B(100)$ denotes the annuity factor over 100 years. Consequently, the power plant's investment cost is calculated as follows:

$$FICH = PGH \times FUCP \times \left[FUCP \times \frac{RF}{i+1^{RY}} \right] \times (1 + IDCF) \times A(50) \quad (6)$$

where $FICH$ denotes the investment cost of the energy plant (US\$), PGH denotes the installed capacity of the energy plant (KW), $FUCP$ is the construction expense for the energy plant (US\$/kW), RY is the retrofitting cost, RF is the retrofitting factor, and $IDCF$ is the interest rate during the construction of the energy facility. Equations (7) and (8) are used to calculate repair and maintenance costs.

$$DFOM = PGH \times DFOMUC \quad (7)$$

$$FVOM = TEG \times FVOMUC \times 0.01 \quad (8)$$

where $FVOM$ is the cost of repairing the power plant that varies over time (US\$/kWh), and $DFOM$ is the cost of fixing the power plant that does not change over time (US\$/kWh). $FVOMUC$ is the repair cost per kilowatt-hour of energy produced, while $DFOMUC$ is the repair cost per kilowatt of the plant's total capacity. Equation (9) is used to determine the total cost of power generation (TCP).

$$TCP(USD) = FICH + DFOM + FVOM \quad (9)$$

The total revenue of the 30 MW Kiri Dam is derived from energy sales and greenhouse gas emission mitigation. Revenue from exporting the power generated by the hydroelectric plant will be a primary benefit of retrofitting the Kiri Dam. Therefore, the HECAM II model incorporated calculations for this revenue source. According to estimates by delegated energy experts in conjunction with GOBEDEC for the administration of Kiri Dam Hydroelectric Power, the unit price of electricity sales was determined to be 10 to 12 cents per kWh [18].

4.1. Irrigation and Drainage

The income from the expansion of cultivated sugarcane lands and the cost of water transfer are calculated in this section. It was assumed that,

during the early phases of dam construction, the cost of water transfer—including pumping and excavating diversion tunnels—should have been included as a single lump sum. Therefore, by applying Equation (10), the present value of the annuity was determined based on the monthly costs of irrigation and drainage for agricultural expansion.

$$TCID = WCT \times A(50) \quad (10)$$

where $TCID$ denotes the prevailing allocation valuation of irrigation and drainage costs (US\$), and WCT represents the cost of water transfer. The model accounts for the profits generated from constructing drainage and water transfer systems to irrigate thousands of hectares of sugarcane fields. TBID (irrigation and drainage income) can be calculated using Equation (11).

$$TBID = \sum A_i \times P_i \times Pr_i \quad (11)$$

where A_i denotes the total area designated for the cultivation of the i th crop (km²), P_i signifies the total yield of the i th crop (tons/km²), and Pr_i indicates the unit market price of the i th crop (US\$/tons).

As shown in Equation (12), floodwater management is a significant application of dam construction that indirectly reduces expenditures by preventing flood-related damages.

$$TFCD = FCD \times \left[1 + \frac{1}{(1+i)^{30}} \times \frac{A(30)}{A(20)} \right] \quad (12)$$

where $TFDC$ represents the annual present value of flood-related damages (US\$), and FDC denotes the total damage caused by floods over a 30-year period. Given that flood events are assumed to occur over a span of 30 years, and considering a study duration of 50 years, it follows that floods may occur approximately 1.05 times within the lifespan of the project [26,27].

4.2. Water transfer

The total cost of water distribution, as well as the annual maintenance and replacement expenses for water distribution infrastructure, are calculated using the present value of the water transfer cost dividend in the HECAM II model.

$$TCSF = TISF + A(50) + FOMSF + VOMSF \quad (13)$$

The annual expense of water conveyance is represented by $TCSF$ (US\$), the expense of water conveyance facilities is represented by $TISF$, the repair and upkeep cost of water conveyance facilities is represented by $FOMSF$ (US\$); the annual cost of essential components is represented by $VOMSF$ (US\$); and the income index over the course of this investigation is represented by $A(50)$.

4.3. Domestic water supply

In addition to supplying the Dangote Sugar Company with irrigation water, Kiri Dam sustains household water supplies for neighboring towns, which are used as drinking water. To determine the annual revenue from potable water transmission, Equation (14) was used.

$$T_{rev} = Inc_w + W_s \quad (14)$$

T_{rev} is the sum of the annual income from consumable water (US\$), Inc_w is the growth in commercially supplied water (m^3), W_s is the water sale pricing (US\$/ m^3).

The HECAM II model uses Equation (15) to determine the value of each additional volume of water based on the water requirements of downstream areas, in order to calculate the overall income related to the increase in water supply.

$$W_{val} = \frac{AgW_{vol} \times AgW_{val} + IndW_{vol} \times IndW_{val}}{AgW_{vol} + IndW_{vol}} \quad (15)$$

W_{val} represents the aggregate economic value of water in downstream regions (US\$), whereas AgW_{vol} denotes the cumulative volume of water designated for agricultural applications in downstream areas ($\times 10^6 m^3$). AgW_{val} signifies the monetary value of water within the agricultural domain (US\$/ m^3), while $IndW_{val}$ reflects the economic valuation of water in the agricultural sector (US\$/ m^3). $IndW_{vol}$ corresponds to the total volume of water allocated for industrial and potable purposes, with the unit ($\times 10^6 m^3$) representing the cost in US\$ for drinking and industrial water.

Equation (16) is used to assess the financial gains resulting from increased reservoir discharge attributable to dam retrofitting and energy production.

$$Rev.IPG = IPG \times P \quad (16)$$

$Rev.IPG$ represents the revenue generated from higher electricity output at downstream sites (US\$), where P stands for the energy price per unit (US\$/kWh), and IPG denotes the additional amount of electricity produced annually (MWh/yr).

4.4. Evaporation

The amount of water that evaporates from the surface of a dam lake is greatly influenced by its area, pressure, temperature, and humidity. This viewpoint considers evaporation as a loss because it results in the forfeiture of an opportunity. Based on this, evaporation is a cost since it leads to the loss of potential benefits. With an approximate volume of 107,000,000 m^3 , the Kiri Dam reservoir has an average evaporation volume of 9.16 m^3/s from the reservoir surface [28].

Equations (17) and (18) are used by the HECAM II model to calculate the evaporation cost.

$$EVP_{vol} = AER \times Total_{vol} \quad (17)$$

$$EVP_{cost} = EVP_{vol} \times W_{vol} \times 10^6 \quad (18)$$

EVP_{vol} represents the annual evaporation volume ($\times 10^6 m^3/yr$), AER is the yearly evaporation rate expressed as a percentage of the reservoir's total water volume (%), $Total_{vol}$ denotes the total reservoir capacity ($\times 10^6 m^3$), EVP_{cost} refers to the associated evaporation cost (in US\$), and W_{vol} indicates the volume of water released downstream ($\times 10^6 m^3$).

5. Results

In assessing the expenditure and incomes of energy generation at Kiri Dam, the total dam lifespan considered was (n+50) years. Annual energy output from the hydropower facility varied between 142,700 MWh for the 20 MW scenario and 175,085 MWh for the 30 MW option. Correspondingly, revenue from electricity sales was estimated to range from US\$ 18,736,690 to US\$ 22,537,471. For the three options, the power plant's annuity present value of investment was calculated to be US\$ 15,750,000, US\$ 23,625,000, and US\$ 27,562,500, respectively. The proposed Kiri Dam's hydropower generation costs and revenues are broken down in detail in "Table 1," "Table 2," and "Table 3." According to the data in the tables, the projected cost and income for power generation at the Kiri power plant are as follows: for the 20 MW over 20 years scenario, costs are estimated at US\$ 51,309,500 with income at US\$ 95,300,369; for the 30 MW over 20 years, costs rise to US\$ 76,964,250 and income drops to US\$ 42,950,553; and for the 30 MW over 30 years, costs reach US\$ 89,791,625 while income increases significantly to US\$ 166,775,645. While both cost and revenue figures can be adjusted to better reflect real-world conditions, the overall trend suggests that, on average, energy generation revenue is approximately 1.9 times the total cost.

Kiri Dam's catchment area, or drainage basin, is 56,200 km^2 . Commercial sugar production is maintained using the irrigation waters supplied by the Kiri Project. The fairly massive Dadin Kowa Multipurpose Dam, located about 110 km upstream of Kiri Dam on the Gongola River, significantly impacts the hydrology of Kiri Dam. For a 100-year return period, the peak flood of the ungauged river was found to be 54.88 m^3/s , compared to 20 m^3/s predicted conventionally, whereas approximately one flood occurrence is anticipated to occur in downstream communities over the dam's 50-year life cycle.

Table 1 Cash flow of payments during the construction period based on the S-curve

Financing Structure	20 MW 20-year PPP			30 MW 20-year PPP			30 MW 30-year PPP		
Construction Period (Yr.)	1	2	3	1	2	3	1	2	3
Adjustment factor of construction & operation	1.00	1.118	0.129	1.00	0.106	0.123	1.00	0.102	0.109

Table 2 The HECAM II Model's estimation of Kiri Dam's power generation costs

Financing Structure	20 MW 20-year PPP		30 MW 20-year PPP		30 MW 30-year PPP	
	Quantity		Quantity		Quantity	
Cost variable						
Annuity factor	8.5594		8.3042		9.0968	
Escalation factor	0.5		0.75		0.75	
Present value of annuity for investment in power plant	15,750,000 USD		23,625,000 USD		27,562,500 USD	
Present value of annuity for investment in dam retrofit	34,360,000 USD		51,540,000 USD		60,130,000 USD	
Fixed monetary present value of repairs and maintenance costs for the duration of operation	137,000	USD	205,500		239,750	
Present value of repairs and maintenance costs for the duration of operation	1,062,500	USD	1,593,750		1,859,375	
Total annual cost	51,309,500		76,964,250		89,791,625	

Table 3 Power generating revenue as calculated by the HECAM II Model.

Financing Structure	20 MW 20-year PPP	30 MW 20-year PPP	30 MW 30-year PPP
	Profit	Profit	Profit
Revenue Potential			
Annual power generation	142,700.2 MWh	175,085 MWh	175,085 MWh
Annual revenue from sales of electricity	18,736,690 USD	25,643,324 USD	22,537,471 USD
Total annual revenue	95,300,369 USD	142,950,553 USD	166,775,645 USD

According to the Upper Benue River Basin Development Authority (UBRBDA), the Kiri reservoir storage accounts for the difference between the project's 4,250 m³/s inflow and 4,000 m³/s outflow. Based on local datum, the operating project's normal top water surface elevation is 170.5 meters; the minimum drawdown level is 167.2 meters; and the reservoir flood elevation is 171.5 meters. In warmer seasons, flows increase from 5.7 m³/sec to 21 m³/sec, but flood peaks decline from 1,420 m³/sec to 1,256 m³/sec [13].

For scenarios 1, 2, and 3, the anticipated costs of conveying irrigation water from Kiri Dam to Dangote sugarcane plantations were US\$ 17,508,609, US\$ 29,002,899, and US\$ 26,333,485, respectively. It is predicted that 180 × 10⁶ m³ per month, along with increased irrigation from the Kiri facilities, would be used to supply 77 × 10⁶ m³ per month of drinking water, out of the 615 × 10⁶ m³ of water monitored and controlled in the Kiri Dam at the time of development. The predicted total revenue from water transfer across all three scenarios ranged from US\$ 35,000,000 to US\$ 48,000,000, assuming a water retail price in Adamawa State of

roughly US\$ 0.90/m³ to US\$ 1.20/m³. The HECAM II model additionally incorporated the unit monetary value of this type of water consumption. Consequently, total revenue from flood prevention ranged from US\$ 1,355,364 for scenario 1 to US\$ 1,506,497 for scenarios 2 and 3. The irrigation releases from Kiri Dam may also significantly boost hydroelectricity generation because stored water and hydro energy have a positive correlation, according to [18]. Since heavy sediments and debris prevent flushing releases from being used for generation, it is generally understood that only flows released by the project's tainter gates would be suitable for generation.

The annual revenue from the enhanced hydroelectric energy generation for the three scenarios is projected to be US\$ 1,561,390/yr, US\$ 2,136,945/yr, and US\$ 1,878,122/yr, respectively, based on the price per kilowatt-hour of power. Additionally, Yuguda et al. [28] reported that the average evaporation rate from the dam reservoir is around 9.16 m³/sec, with the total annual evaporation from the Kiri reservoir being 2,700 mm/yr and its highest monthly value being 250 mm in July. According to estimates, the

evaporation rate is 29% of the reservoir's total yearly volume, thereby diminishing the benefits downstream in several agricultural, consumer, and industrial sectors. "Figure 3" shows the cost of retrofitting Kiri Dam.

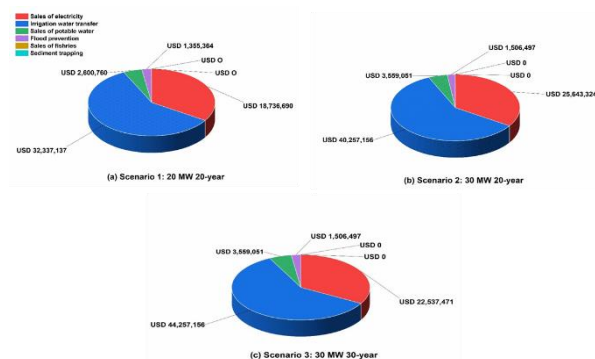


Figure 3 Total costs of retrofitting Kiri Dam to generate hydropower.

The primary expense for all three scenarios is power generation, followed by evaporation and irrigation water transport. Potable water sales constitute the smallest portion of the overall expenses. Due to insufficient data and the unique topography of Kiri Dam, no costs were calculated for fisheries sales and sediment trapping. The increased revenue from upgrading Kiri Dam is depicted in "Figure 4."

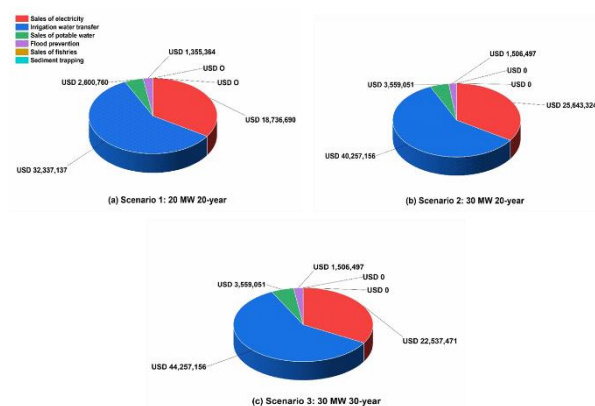


Figure 4 Net revenue from retrofitting Kiri Dam

Sales of hydroelectricity and agricultural water transfer are the primary sources of income, with sales of potable water and flood protection ranking third and fourth, respectively.

According to HECAM II's results, the overall cost of upgrading Kiri Dam to produce clean energy would range from US\$ 51,309,500 to US\$ 89,791,625, depending on the options. However, based on the same options, the predicted

total revenue from the dam retrofit was between US\$ 95,300,369 and US\$ 166,775,645. This indicates that, considering the technical, environmental, and social aspects of the project collectively, retrofitting Kiri Dam could generate total net benefits ranging from US\$ 45 million to US\$ 77 million, with a benefit-cost ratio of approximately 1.85. While the HECAM II model allows for expansion through the addition of further parameters or components, it is important to note that, given data limitations and the dam's operational history of over 40 years, the analysis focused only on the main costs and benefits associated with its construction.

6. Discussion

The projected costs and benefits of dam retrofitting were assessed alongside outcomes from alternative modeling approaches. Although there is limited research on the cost-effectiveness of such upgrades, adapting the HECAM model into its improved version, HECAM II, and applying it in a case study demonstrated that overall expenses, revenues, and the benefit-to-cost ratio could effectively address socio-environmental issues when implemented through a broader strategic approach, regardless of location. Hydroelectricity production, agricultural irrigation, fisheries, drinkable water, sediment retention, and evaporation are the primary drivers of this cost underestimation, even though it has been hinted that there is a fairly significant difference between the estimates of the HECAM II and SimPacts models according to [1]. Estimating greenhouse gas emissions from the reservoir surface during dam operation relies heavily on the HECAM II model, particularly its ability to use real land use data and associated values to determine the extent of flooded wetlands, agricultural land, and residential areas. In this study, however, external impacts are limited to those directly tied to construction activities, as the project will utilize areas already affected by prior development, minimizing effects on local plant and animal life. Aside from its proximity to the river, these potential impacts are not specific to the Kiri Hydroelectric Project and could apply to similar developments elsewhere.

Even though this study is the first to assess the cost-benefit of retrofitting dams by including three distinct financing/ownership options, none of the previous research has covered all known modeling components. The lack of validation data is the primary reason for this. Sediment trapping and sales of fisheries benefits, for example, were overlooked in the HECAM II model, underscoring

the fact that feasibility methodologies should often be sufficiently straightforward for use in industry. Initially, the project's capacity installation appraisal was based on the interest of the authority to supply a capacity of roughly 20 MW. The restricted regulation and grid utilization of increased output were one of the driving forces. Second, there is power in the area during the wet season, but it is quite scarce during the dry season. According to reports, the available electricity retail pricing is US\$0.032/kWh. It is very hard to justify adding hydropower at this low cost of electricity. Even during the rainy months, there is interest in attempting to fulfill some of the unmet load. As a result, a different option on the chosen plan was examined. To increase the output, that option adds another unit. The plant size is essentially increased by one unit, or from 20 MW (scenario 1) to 30 MW (scenarios 2&3), with this option for larger capacity. Since it doesn't alter the site's hydrology, the additional energy is only supplied during the rainy season.

The Economic Cost-Benefit Analysis (CBA) of Project Environmental Impacts for three possibilities, taking into account various hydropower assessment scenarios, revealed that the differences between the three scenarios' CBAs are noticeable but not significant. This is illustrated by the unique conditions of the Hydroelectric Project, which include the potential to prevent the loss of a significant ecological zone, minimal to no lasting effect on an already significantly altered river network, and no relocation. The findings could have varied significantly if these circumstances were reversed [29]. From an economic perspective, the proportion of power compared to requirements in 2050 for five alternative scenarios produced highly beneficial outcomes from environmental, social, and territorial perspectives, taking into account direct and indirect costs and benefits [4]. Therefore, modeling methods and decision layouts are inferior to cost-benefit processes. Lastly, whether or not suitable scenarios are selected affects the ultimate test of the techniques and the reliability of the data collected. It is clear that validated methods in actual situations have greater validity than hypothetical ones. The cost-benefit assessment could be carried out on complex systems as well, given the present practice of using different energy resources to produce electricity. It is expected that hybrid systems will deliver significant benefits in terms of reducing greenhouse gas emissions and protecting the environment, though this requires justification.

Every hydropower initiative must contend with common challenges related to technology,

environmental and social impacts, and access to funding. In Nigeria, improving key dam facilities like Kainji, Jebba, and Shiroro hinges on tackling technical viability, reservoir sediment buildup, and the socio-political aspects of Public-Private Partnerships (PPPs). Modernizing current hydropower systems through upgrades such as electromechanical refurbishments, dynamic line rating, or expanding turbine capacity presents substantial technical hurdles. These include integrating new technology with aging civil structures, as well as ensuring grid stability and seamless interconnection. So far, the Nigerian energy sector has remained overshadowed by policy changes, financial uncertainties, and scandals, especially evident within the China–Nigeria partnership. Moreover, the difficulties encountered in public-private partnerships for hydropower dams stem largely from weak and uncoordinated management by the Nigerian government. Consequently, numerous large-scale dams have been constructed over the years with financial and technical assistance from foreign governments and their agencies [30]. In 2019, Nigeria's energy sector experienced a total revenue loss of USD 2.6 billion. Nearly one-third of this loss stemmed from funds that were either not billed or not paid, while the remainder was largely due to constraints in power generation—issues the dam is intended to resolve. Efforts to deliver generated electricity through the existing grid are hindered by insufficient transmission and distribution capabilities, compounded by the network's unreliable performance [30]. Moreover, transferring hydropower technology from China to Nigeria faces significant challenges. Despite Nigeria's advancements driven by greater technical knowledge through such transfers, private foreign investment from developed countries into Nigeria has shown little change over the last ten years.

Sedimentation, involving the slow buildup of soil, silt, and organic material behind dam walls, significantly reduces the lifespan and storage effectiveness of hydroelectric infrastructure in Nigeria. Upstream catchment areas experiencing deforestation for agriculture contribute to heightened soil erosion, leading to large amounts of sediment entering major river systems like the Niger and Benue basins. Over time, this accumulation diminishes the available water storage, limiting electricity production, particularly during dry periods [31]. Public-private partnership frameworks such as concession agreements or Build-Operate-Transfer models are designed to help bridge financing and operational shortfalls in Nigeria. However, they encounter significant

socio-political challenges, including inconsistent policies and political instability, underdeveloped legal and institutional systems, public opposition related to pricing and service tariffs, as well as issues surrounding community displacement and inadequate compensation [32].

“Table 4” compares the current model with earlier analyses, summarizing key features of both the present and previous models. It also lists the case studies used to validate each model.

Table 4 A comparison between similar studies that employed the HECAM model

Case Study	Model	Method	Contribution	Shortcomings
This study (Kiri dam Nigeria)	HECAM II	A cost-benefit analysis (CBA)	Application of the HECAM Model to 3 scenarios of dam retrofit	Overlooked sediment trapping and sales of fisheries benefits
Bakhtiari Hydropower Dam	HECAM II	A cost-benefit analysis (CBA)	Adding evaporation and sedimentation costs to the HECAM model	Ignoring the advantages of tourism and hybrid systems
Alborz Dam in Northern Iran	HECAM	A cost-benefit analysis (CBA)	Adding different cost and benefit parameters to the SIMPACT model	Ignoring certain expenses like sedimentation and evaporation
Siah Bishe- Dam in Northern Iran	SimPacts	A cost-benefit analysis (CBA)	Dams and power plants' combined effects on the economy, environment, and water supply	Concentrating only on the price of dams

As shown in the table, the algebraic feasibility assessments differ based on three primary factors. The depth of analysis varies across models. While basic assessments focus primarily on economic profitability, more sophisticated ones also incorporate environmental and social factors. This study stands out by adopting one of the most comprehensive frameworks to date, integrating detailed elements like sedimentation and evaporation into its cost-benefit evaluation. Yet, none of the existing studies incorporate every known modeling component, primarily because of insufficient data available for validation. For example, the HECAM II model does not account for tourism benefits. Additionally, the level of simplicity in feasibility studies varies across cases. Typically, these approaches should be straightforward enough to support practical, commercial use. As a result, cost-benefit analyses tend to be more effective than model-based techniques and structured decision-making frameworks. Ultimately, the reliability of the data used and the practical evaluation of these methods depend on whether suitable case studies are applied. It is clear that approaches validated through real-world applications hold greater credibility than theoretical ones. Given the current trend of using diverse energy sources for electricity generation, cost-benefit analyses can also be applied to hybrid systems. While this would require a dedicated assessment, hybrid systems are expected to offer significant benefits in reducing greenhouse gas emissions and enhancing environmental protection.

6.1. Sensitivity analysis

Sensitivity analysis requires the selection of a base case for comparison and contrast [33–35]. This study’s sensitivity analysis focused on several key variables: (1) Total Initial Capital Expenditure (CAPEX), (2) Base Capacity Factor (Hydrology), (3) Annual Operating Expenditure (OPEX), (4) Base Electricity Price, (5) Discount Rate / WACC. For the base cases—scenarios #1, #2, and #3—selection was made from among seven potential ownership and financing models outlined in the Economic Analysis. Results from all three cases are shown in “Table 5” below. Case #1 is the 20 MW Public-Private Partnership for a 20-year contract term. Case #6 is the 30 MW Public-Private Partnership for a 20-year contract term. Results are presented by three measures of project feasibility: Cost of Energy for customers, debt coverage for debt investors, and internal rate of return for the project owners/equity investors. The latter two variables must meet certain standards, and then COE rises or falls with the independent variable that is changed. For example, if the plant’s budgeted capital cost increases, plant owners will charge a higher tariff, so COE will increase, but the extent of this change must be measured.

The main factors affecting revenue—Electricity Price, Annual Energy Yield, and Water Availability—have the greatest impact on the project’s financial success. CAPEX and Discount Rates influence outcomes to a lesser extent, while Annual OPEX has only a small effect. Among these, Electricity Price is the most pivotal factor. A

20% decrease causes NPV to become negative across all three project configurations, resulting in losses between \$1.01 million and \$1.41 million, and reduces the IRR for the 20 MW scenario to

7.30%. Conversely, a 20% increase in price leads to substantial gains, with NPV rising as much as \$35.49 million in the 30 MW, 30-year PPP model.

Table 5 Sensitivity analysis of results for the three possible options

Input	Variation (%)	20 MW 20-year PPP		30 MW 20-year PPP		30 MW 30-year PPP		Sensitivity Rank
		IRR (%)	NPV (\$)	IRR (%)	NPV (\$)	IRR (%)	NPV (\$)	
Electricity Price	-20%	7.30%	-\$1,012,000	9.10%	-\$1,203,000	12.50%	-\$1,410,000	High
	+20%	12.30%	+\$21,345,000	13.70%	+\$29,377,000	14.88%	+\$35,490,000	
Annual Energy Yield	-20%	14.98%	-\$1,110,000	15.78%	-\$1,211,000	16.98%	-\$1,410,000	Medium
	+20%	12.44%	+\$20,836,000	13.10%	+\$30,366,000	14.67%	+\$35,490,000	
CAPEX Cost Overrun	-20%	13.60%	+\$19,243,000	14.01%	+\$21,974,000	16.33%	+\$26,040,000	Medium
	+20%	8.70%	+\$5,419,000	9.23%	+\$6,333,000	11.46%	+\$8,040,000	
Discount Rate	-20%	10.80%	+\$29,180,000 (-2% rate)	11.27%	+\$29,180,000 (-2% rate)	12.88%	+\$29,180,000 (-2% rate)	Medium
	+20%	10.80%	+\$4,765,000 (+2% rate)	12.21%	+\$5,345,000 (+2% rate)	13.00%	+\$7,120,000 (+2% rate)	
Annual OPEX	-20%	10.30%	+\$14,221,000	11.12%	+\$16,986,000	13.43%	+\$19,740,000	Low
	+20%	11.20%	+\$10,734,000	12.49%	+\$12,734,000	13.89%	+\$14,340,000	
Water availability	-20%	13.70%	\$958,000	14.22%	\$1,156,000	16.02%	\$1,750,000	High
	+20%	7.30%	\$16,989,000	8.46%	\$19,564,000	10.06%	\$22,950,000	

Energy Yield and Water Availability are key operational variables that directly affect total power generation. A 20% reduction in either water flow or energy output poses significant downside risks, underscoring their importance to project performance. A cost overrun exceeding 20% results in a significant decline in NPV, ranging from 60% to 70% across all project setups. For instance, the NPV for a 30 MW system over 30 years drops from +\$26.04 million under a 20% CAPEX reduction to just +\$8.04 million when CAPEX increases by 20%, highlighting the strong influence of initial investment on present value. Adjusting the discount rate also has a pronounced effect: reducing it by 20% raises NPV to +\$29.18 million across configurations, while a 20% increase reduces it to between +\$4.77 million and +\$7.12 million. In contrast, operational expenses have a limited impact on financial returns. A $\pm 20\%$ variation in OPEX results in only a modest change in NPV, approximately a \$3.5 million to \$5.4 million range, indicating that the project's economics are primarily driven by capital costs rather than ongoing operating expenses.

7. Conclusion

The HECAM II model developed in this study incorporated both the costs and benefits associated with dam retrofitting, such as income from electricity sales, irrigation water delivery, water supply sales, flood protection, and

evaporation losses, alongside expenses related to power generation, irrigation water transfer, domestic water supply, and evaporation. The analysis evaluated three possible ownership and financing arrangements for the Kiri Dam hydroelectric initiative. Of these three scenarios, the 30 MW, 20-year PPP option yielded more annual revenue from electricity sales compared to the 20 MW, 20-year PPP and 30 MW, 30-year PPP options. However, the 30 MW, 30-year PPP option generated higher total annual revenue from other reservoir functions compared to the other two options. These findings highlight the importance of considering contract duration, water flow and capacity factor, capital costs, debt term, interest rate, and other factors when assessing the cost-benefit analysis of dam retrofitting. Because hydroelectric projects can operate over a long lifespan, all other factors being equal, it is advisable for the project developer and equity investors to pursue a longer-term contract. Additionally, all other things being equal, a shorter-term debt of around 15 years is preferable to a 22-year term. If the public partner opts to structure its investment as partly subordinated debt, this approach is less risky than pure equity investment and can reduce the cost of equity while maximizing profit.

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