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# LCOE-Based Optimization for the Design of Small Run-of-River Hydropower Plants

**Claude Boris Amougou [1,2], David Tsuanyo [1,*], Davide Fioriti [3], Joseph Kenfack [2], Abdoul Aziz [1] and Patrice Elé Abiama [1]**

[1] National Centre for Development of Technologies, Ministry of Scientific Research and Innovation, Yaoundé P.O. Box 1457, Cameroon
[2] Laboratory of Small Hydropower and Hybrids Systems, National Advanced School of Engineering, University of Yaoundé I, Yaoundé P.O. Box 8390, Cameroon
[3] Department of Energy, Systems, Territory and Construction Engineering, University of Pisa, Largo Lucio Lazzarino 1, 56122 Pisa, Italy
* Correspondence: david.tsuanyo@gmail.com

**Abstract:** Run-of-river hydropower plants are a cost-efficient technology that produce a power output proportional to the instantaneous flow of water diverted from the exploited stream by exploiting several mechanical, hydraulic, and electric devices. However, as no storage is available, its design and operation is tailored according to the unpredictability of its power generation. Hence, the modelling of this type of power plants is a necessity for the promotion of its development. Accordingly, based on models from the literature, this study proposes a comprehensive methodology for optimally designed small run-of-river hydropower plants based on a levelized cost of energy (LCOE). The proposed methodology aims at facilitating a faster design for more cost-effective and energy-efficient small hydropower plants. Depending on the average daily flow rates and the gross head of a given site, the model proposed in this study calculates the diameter, thickness, and length of a penstock; it also suggests the optimal selection of a turbine, determines the admissible suction head of a turbine for its optimal implementation, and determines the optimal number of turbines, all in order to minimize the LCOE of the proposed project. The model is tested to design a small run-of-river hydropower plant with a capacity of 6.32 MW exploiting the river Nyong in Mbalmayo. The results confirm the profitability of the investment with an LCOE of around 0.05 USD/kWh, which is the lowest limit value of the LCOE range for small hydropower plants, as presented in the IPCC (Intergovernmental Panel on Climate Change) report, assuming a project lifespan of 50 years and a discount rate of 12.5%. These results also show that it may be worth to provide the energy sector with a small hydropower design tool with a graphical interface. In addition, it would be appropriate to use a similar method in an off-grid context where a hydropower plant, with or without storage, is combined with another source to meet the electrical needs of a given population.

**Keywords:** run-of-river; hydropower; optimal design; levelized cost of energy (LCOE); genetic algorithm; energy systems; sizing

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## 1. Introduction

As of today, around 81.4% of the primary energy exploited in the world is of fossil origin, mainly in the form of coal, oil, and natural gas [1]. This shows that fossil fuels still continue to play a dominant role in the energy sector, despite the drawbacks on the environment and ecosystems that accompany their exploitation.

Thus, this challenge of reducing the consumption of fossil fuels, combined with the need for increasing energy production capacity to meet the expected increase in the global energy demand, forces the international community to increase the contribution of renewable energies to world energy production.

Of all the renewable energy sources, hydropower is thus far among the most efficient and reliable resources because it has a simple but very mature technology [2,3].

However, when it comes to hydropower, small run-of-river hydropower plants—which is a type of hydropower plant that does not need a reservoir and that, therefore, has its power production instantaneously proportional to the exploited water course—seem more attractive [4].

Indeed, small run-of-river hydropower plants have lower investment costs, less of a harmful impact on the environment, and a shorter construction time when compared to hydroelectric power plant projects with storage [5]. More concretely, they pose fewer problems of inundation and sedimentation, they have less of a harmful impact on fish migration, and they decrease issues regarding navigation on the rivers—which occur in large-scale hydropower projects [6]. Another advantage of run-of-river hydropower projects is the fact that they drive generators with small turbines that can be manufactured locally, thus promoting job creation and economic development through local industry [7]. Due to these advantages, it is also easier to gain public and government acceptance for run-of-river hydropower projects compared to hydropower projects with storage that require large areas of submersion [6].

In the work of Alexandros et al. [8], it was found that the potential of small hydropower (1–10 MW in this context) in Sub-Saharan Africa is estimated at 21,800 MW and run-of-river hydropower plants are generally categorized as small hydropower plants [9–13]. Additionally, more particularly in Cameroon, the small hydropower capacity is estimated at 970 MW, according to the UNIDO small hydropower development report [14]. Small hydropower and hence run-of-river systems can be an appropriate option for rural electrification in Africa.

Despite the fact that run-of-river hydroelectric plants represent a better alternative to installations with dams [15], their unforeseeable power production can make their design and exploitation very complex, especially when they have no pondage, without an accurate estimation of their energy production over the lifetime of the project.

This study aims to develop a model for the sizing and techno-economical optimization of small run-of-river hydropower plants, which could help designers, hydropower engineers, and even decision makers to deal with run-of-river hydropower plants prefeasibility studies in a more efficient, easier, and faster way. Unlike most of the existing models (such as HOMER, Retscreen), which are unusable without a minimum of data, the model presented in this article relies on a minimum of data (daily average flows and gross head) in order to provide a maximum of results. Existing models sometimes require special knowledge in the field of energy, pre-sizing in the first step or a good knowledge of the market for hydroelectric equipment (e.g., the price of the equipment, cost of maintenance and exploitation, etc.).

The study presented in this paper begins by identifying and analyzing existing models used in the literature for hydropower plant projects (such as models for the sizing of plant components and for estimating energy production—as well as for estimating investment, operation, and maintenance costs). Then, the models that fit the context of our study are selected or adapted and finally, a program is realized using the equations of the selected models and relying on a genetic algorithm for the optimization process. In fact, once the technical model has been developed, it is integrated into an economical model with LCOE as the objective function. The function obtained being a non-differential function because of the discontinuous equations, which are integrated therein, therefore the optimization was made from a genetic algorithm, since today it has been already proven for similar optimization cases [16–18].

There are several works relating to the optimal design of hydropower plants, and particularly, small run-of-river hydropower plants, in order to reduce the costs, to maximize energy production, or to maximize profitability of the project [9,15,19–39].

Some researchers have focused on the optimal design of the penstock in order to reduce operation and the initial purchase cost since the penstock has a high share in the total small hydropower plant budget [23,24].

Other researchers worked on the choice of the optimal turbine in order to maximize the energy production or the economic benefits of the investment [25–29]. Most of these studies focused on the choice for the optimum nominal flow of a turbine [25–27]. Indeed, the nominal flow must be chosen carefully in order to create a hydro project that is profitable and efficient enough.

Many other authors also worked on the development of correlations to estimate the cost of small hydropower plant projects and, therefore, providing tools for the development of models, thereby allowing the techno-economic design optimization of small hydropower plants [30–37].

There are also more complete methods that have been developed that take into consideration several parameters at the same time [9,13,15,19–22,38,39].

Najmaii and Movaghar [38] worked on a mathematical model that enables the overall design optimization of run-of-river hydropower plants, and which takes into consideration the discharge design, the penstock diameter, the turbine capacity, the number of units, and the type of turbines for the maximization of the yearly energy and yearly benefits.

Athanassassios et al. [13] developed a program for the preliminary evaluation of the potential of small hydropower plant installations, and they took into account economic life, discount rate, Net Present Value, benefit–cost ratio, Internal Rate of Return, payback period, and generation cost, but without information on the design of the components of the plant.

Anagnostopoulos and Papantonis [19,20] presented a numerical model for the maximization of the Net Present Value using a stochastic evolutionary algorithm for the optimization process and used variables such as the type and size of the two turbines considered as well as the penstock diameter.

Santolin et al. [39] developed a techno-economical method for the capacity sizing of a small hydropower plant, which takes into consideration the turbine type, the turbine dimensions, the annual energy production, the maximum installation height (in order to avoid cavitation inception), the machine cost, the Net Present Value, and the Internal Rate of Return in its analyses; however, this was without an optimization process.

Haddad et al. [9] worked on the optimal design, control, and operation of small run-of-river hydropower plants with the honey bee mating optimization algorithm; this was conducted for the determination of the optimal diameter of the penstock, the optimal number of turbines, the type of turbines, and the optimal scheduling of the operation of the plant for maximization of the annual benefit.

Getachew [21] developed a mathematical model for the determination of the design discharge, the installed capacity, and the number of turbines for the optimal configuration of small run-of-river hydropower plants.

Yildiz [15] produced a numerical model that uses a built-in evolutionary algorithm for the maximization of the Net Present Value by optimizing the penstock diameter (while considering the thickness); the type; design flow and configuration of the two turbines considered; and the specific and rotational speed of the two turbines considered (while considering the suction head to avoid cavitation).

More recently, Mohamed et al. [22] developed an optimal planning and preliminary-design model for the maximization of the annual net benefit of run-of-river hydropower projects. Their model uses a genetic algorithm and allows one to determine intake location; the diameter and the length of the penstock and the type; number; and discharge of the turbines.

However, in most run-of-river hydropower plant optimization studies conducted thus far, no more than two turbines were considered in order to avoid making the project too expensive [15,19,20].

In this study, we review and develop a comprehensive design methodology for multi-turbines that combines mechanical, hydraulic, and electric limitations. The model proposed enables the use of more than two turbines. In fact, although a larger number of turbines can increase the total cost of the plant, they can also allow a better harness of the hydraulic energy available, thus increasing the quantity of energy produced and sold.

The model proposed allows for a detailed calculation of the investment, replacement, operating, and maintenance costs of the project over its lifetime to be made, in a context where replacement, operating, and maintenance costs are generally ignored despite their significant contribution to the total expenditures of the project over its lifetime [40]. It takes into consideration the choice of the generator according to the market constraints; the use of a speed increaser; the diameter of the air vent pipe (to protect the penstock against water hammering); the main dimensions of the turbine wheel; the specific speed and rated speed of the turbine; and the maximum suction head (to avoid the excavation cost). The model developed can perform the simulation of the operating mode of the sized run-of-river plant equipment (penstocks, turbines, and generators). Thus, making it possible to estimate the average daily flow rates driving each turbine; the number of turbines used each day of the year; the average daily speeds of water in the penstock; friction; singular and total average daily head losses in the penstock; the average daily net heads; and average daily energies produced.

Another novelty is that our model also considers the maximum length of the penstock for its analysis, which should not be exceeded in order to allow for a maximum total head loss of 4% of the gross head, as recommended by ESHA [41]. This is unlike most of the other models, where the length of the penstock is not optimized. Furthermore, it is also necessary to underline the fact that the optimal configuration of the system here makes it possible to minimize the LCOE rather than to maximize the profitability as it is conducted in most studies [9,15,19–22].

This paper is organized as follows: in Section 2, the developed model is presented, including its assumptions, its different equations (for the calculation of the characteristic parameters of the optimal turbine, the characteristic parameters of the appropriate generator, the characteristic parameters of the penstock, the energetic criteria, the costs, and the economic criteria of the project) and the optimizing process. In Section 3, a case study with data from the river Nyong in Mbalmayo is presented with the economic and technical parameters chosen for the simulation. In Section 4, the results of the case study are analyzed and discussed. Finally, the concluding remarks and suggestions of future works are summarized in Section 5.

## 2. Materials and Methods: Description of the Developed Model

### *2.1. The Design Procedure*

In general, the design of a small run-of-river hydropower plant relies on the technical knowledge and experience of hydropower engineers, supported by mathematical tools to support the analysis that may approximate the large number of possibilities depending onsite-specific conditions [41]. Based on a number of hypotheses, this study proposes a numerical model for the LCOE-based optimization of the design of a small run-of-river hydroelectric power plant with the aim of simplifying the pre-feasibility studies for this type of project. This numerical model aims at providing approximate general results to support a preliminary feasibility study for a site using a limited number of information, up to only the average daily flows and the gross head.

The assumptions on which the numerical model is based are as follows:

- Penstocks are buried only if a minimum of rock excavation is required [41]. However, since excavation leads to additional costs, this study assumes that penstocks are installed over the ground, hence leading to a positive suction head;
- The plant is connected to an existing electrical network and, hence, all the electricity produced is actually sold;
- The power plant is always in operation: no fault occurs, and as multiple turbines are installed, it is assumed that the maintenance plan can be performed without interruptions;

- Line losses are neglected;
- In order to generalize the model, the penstock configuration and its singularities are understood as sufficiently close to those of the 21 power plants that allowed Singhal MK and Arun Kumar [23] to develop a relationship between total head losses and friction losses: this formula allows one to calculate total head losses from friction losses, penstock length, and gross head and was found to be usable for hydropower projects due to the correlation coefficient of the relation obtained being 0.837, which is within the authorized limit;
- The deviation of the watercourse is made from a weir that does not allow considerable storage, as the role of the retaining structure is only to keep the level constant so as to ensure that the water intake and penstock are always supplied [41]. Additionally, that it is set up with what is necessary for the normal operation of the power plant, for example, it should be able to prevent the entry of suspended sediments;
- The topography of the site is appropriate for the production of hydroelectricity;
- The gross head is constant and that when dealing with low head schemes (2–30 m), since this assumption is no longer verified, an average value of the gross head measured is used;
- The numerical model focuses on small run-of-river hydropower plants with a capacity between 500 kW and 10 MW, therefore having low- and high-head projects (3–20 m and above 100 m) and for a configuration where the intake is directly linked to the penstock, as shown in Figure 1.

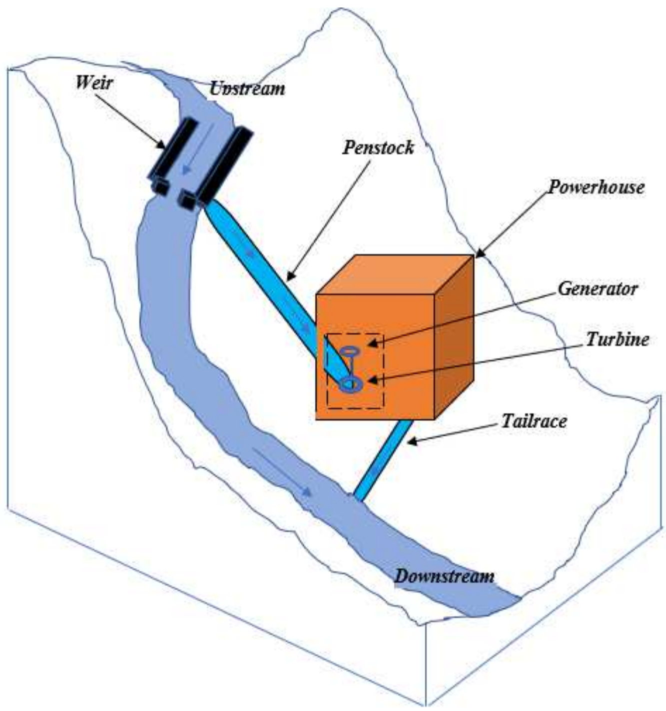



**Figure 1.** Site configuration of the model.

Thus, the procedure used to design the run-of-river project is as follows:

1. Design of the penstock: calculation of its diameter, its thickness, and its aeration pipe diameter;
2. Determination of the optimal number of turbines;
3. Optimal selection of turbine: turbine type, admissible suction head, design flow rate, rated head, rated power, rotational speed, specific speed, and main dimensions of the turbine wheels;
4. Choice of generator: type of generator, frequency, number of pairs of poles, rated power, and rotation speed;

5. Choice of whether or not to use a speed increaser between the turbine and the generator;
6. Estimate of the annual energy produced;
7. Estimation of the investment, operating, and maintenance costs of the project over its lifetime;
8. Calculation of economic criteria: LCC, LCOE, Net Present Value, and return on investment time;
9. Choice of the technical solution with the best LCOE;
10. Simulation of the operating mode of the sized run-of-river plant equipment (penstocks, turbines, and generators), thus making it possible to estimate the average daily flow rates driving each turbine; the number of turbines used each day of the year; the average daily speeds of water in the penstock; friction; singular and total average daily head losses in the penstock; the average daily net heads; and average daily energies produced.

### 2.2. Definition of the Flow Rate of the Equipment

The flow of equipment is the maximum flow that can be carried by the installation without causing unacceptable losses; further, the flow rate of equipment is set from the flow duration curve [42–44].

According to several authors [43,44], the choice of the flow rate of equipment also depends on the type of application, be it a standalone system or connected to the grid. This is the reason why the flow rate of equipment here will be a flow between the 25th (Q_25) and 15th (Q_15) quartiles of the flow, as recommended by Hanggi and Weingartner [44].

The flow duration curve will be obtained by ranking the daily flow rates from largest to smallest, and by calculating the probability of exceeding each flow rate with the formula below [45]:

$$P = \frac{m}{N+1} \times 100\% \tag{1}$$

where $m$ is the rank of the flow in the classification made above, and $N$ the total number of recorded flows (which in our case is 365 because this study is dealing with average daily flows).

### 2.3. Selection of Turbine and Generator Technology

#### 2.3.1. Turbine Case

The type of the turbine can be preliminarily chosen based on the chart in Figure 2, provided the design flow rate, which is calculated before, and the rated head of the study site.

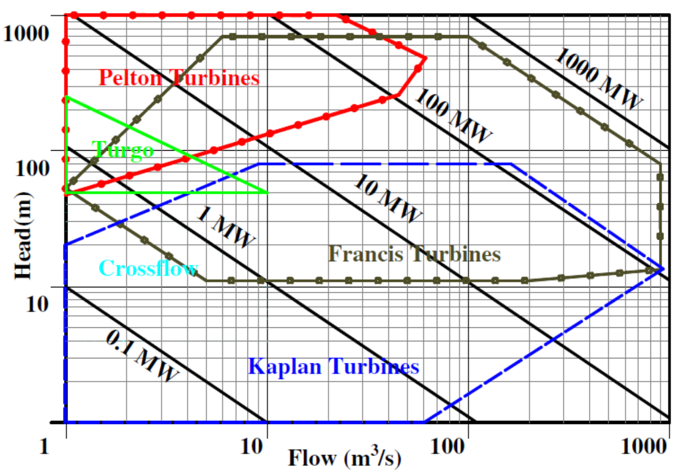



**Figure 2.** Turbine application chart [46].

As can be seen on the chart above, there are situations in which the values of the design flow rate and the rated head of the study site could refer to several types of turbine. Kaplan, Francis, and Pelton are the only types of turbine considered here because they are the turbine technologies with the best efficiencies; thus, often a choice has to be made between them. Since according to Table 1, Pelton and Kaplan turbines better handle fluctuations in the flow and head; as such, they may often be preferred.

**Table 1.** Flow and head variation acceptance [41].

| Turbine Type | Acceptance of Flow Variation | Acceptance of Head Variation |
|---|---|---|
| Pelton | High | Low |
| Francis | Medium | Low |
| Kaplan double regulated | High | High |
| Kaplan single regulated | High | Medium |
| Propeller | Low | Low |

Once the type of turbine is chosen, the minimum and maximum rotation speeds of the turbine can be calculated using Table 2 and Formula (2):

$$n = \frac{n_{QE} \cdot (gH_{rated})^{3/4}}{\sqrt{Q_{design}}} \tag{2}$$

where $n$ is the speed of rotation of the turbine in rpm, $n_{QE}$ the specific speed of the turbine, $g$ the acceleration of gravity in m/s$^2$, $H_{rated}$ the rated head in m, and $Q_{design}$ the design flow rate of the turbine in m$^3$/s.

**Table 2.** Ranges of the specific speed of each type of turbine [41].

| Type of Turbine | Range |
|---|---|
| Pelton one nozzle | $0.005 \leq n_{QE} \leq 0.025$ |
| Pelton n nozzles | $0.005\ n^{0.5} \leq n_{QE} \leq 0.025\ n^{0.5}$ |
| Francis | $0.05 \leq n_{QE} \leq 0.33$ |
| Kaplan, propellers, bulbs | $0.19 \leq n_{QE} \leq 1.55$ |

Then, this study initially takes, as the speed of rotation of the turbine, the standard speed of Table 3 as directly lower than the maximum speed calculated above.

**Table 3.** Generator synchronization speed.

| Number of Poles | Speed for a Frequency of 50 Hz (rpm) |
|---|---|
| 2 | 3000 |
| 4 | 1500 |
| 6 | 1000 |
| 8 | 750 |
| 10 | 600 |
| 12 | 500 |
| 14 | 428 |
| 16 | 375 |
| 18 | 333 |
| 20 | 300 |
| 22 | 272 |
| 24 | 250 |
| 26 | 231 |
| 28 | 214 |

Finally, the specific speed $n_{QE}$ and the maximum admissible suction head $H_s$, in the case of reaction turbines, can be calculated using Equations (2) and (3) [41]:

$$H_S = H_a - H_v + \frac{V^2}{2g} - \sigma_{turbine\ type}\, H_{rated} \tag{3}$$

In Equation (3), $\sigma$ will be calculated from Equations (4) and (5) where $V$ = 2 m/s, as is recommended by ESHA [41].

$$\sigma_{Kaplan} = 1.5241 {n_{QE}}^{1.46} + \frac{V^2}{2gH} \tag{4}$$

$$\sigma_{Francis} = 1.2715 {n_{QE}}^{1.41} + \frac{V^2}{2gH} \tag{5}$$

If the maximum admissible suction head is negative, an excavation is necessary (additional civil works), which would increase the costs of the project. To avoid this, there is the need to change the speed of rotation for the turbine to obtain a non-negative value of the maximum admissible suction head. If no standard rotation speed in the table allows a positive maximum admissible suction head to be obtained, the problem can still be resolved in the optimization process, through the selection of a flow rate of equipment allowing one to respect this constraint (through the design flow rate).

The main dimensions of the turbine wheels are also estimated in order to further guide the choice.

- **Pelton turbines**

With the rotational speed of the runner of a Pelton turbine, the diameter can be calculated by the following equations [41]:

$$D_1 = 0.68 \frac{\sqrt{H_{rated}}}{n} \tag{6}$$

$$B_2 = 1.68 \sqrt{\frac{Q_{design}}{n_{jet}} \cdot \frac{1}{\sqrt{H_{rated}}}} \tag{7}$$

$$D_e = 1.178 \sqrt{\frac{Q_{design}}{n_{jet}} \cdot \frac{1}{\sqrt{H_{rated}}}} \tag{8}$$

where $n$ is the rotational speed in rpm, $n_{jet}$ the number of nozzles, $H_{rated}$ the rated head in m, and $g$ the gravity constant in m/s$^2$.

$D_1$ is defined as the diameter of the circle describing the bucket's center line in m. $B_2$ is the bucket width in m, which is mainly dependent on the flow rate and the number of nozzles. $D_e$ is the nozzle diameter in m.

Generally, the inequality of $D_1/B_2$ >2.7 should always hold; otherwise, a new calculation with a lower rotational speed or a higher number of nozzles will have to be carried out [41].

- **Francis turbines**

The reference diameters of a Francis runner can be estimated using Equations (9)–(11), where their nomenclature is highlighted in Figure 3 [41]:

$$D_3 = 84.5(0.31 + 2.488 n_{QE}) \frac{\sqrt{H_{rated}}}{60n} \tag{9}$$

$$D_1 = \left(0.4 + \frac{0.095}{n_{QE}}\right) D_3 \tag{10}$$

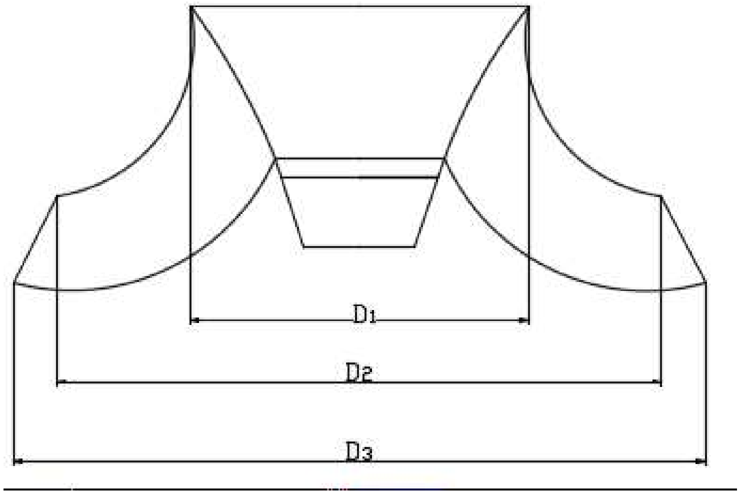



**Figure 3.** Cross section of a Francis runner.

The inlet diameter is given by the equation below for $n_{QE} > 0.164$ [41]:

$$D_2 = \frac{D_3}{0.96 + 0.3781 n_{QE}} \tag{11}$$

For $0.164 > n_{QE}$: $D_1 = D_2$.

- **Kaplan turbines**

The reference diameters of a Kaplan runner are reported in the Equations (12) and (13), then highlighted in Figure 4 [41]:

$$D_e = 84.5\left(0.79 + 1.602 n_{QE}\right)\frac{\sqrt{H_{rated}}}{60n} \tag{12}$$

$$D_i = \left(0.25 + \frac{0.0951}{n_{QE}}\right).D_e \tag{13}$$

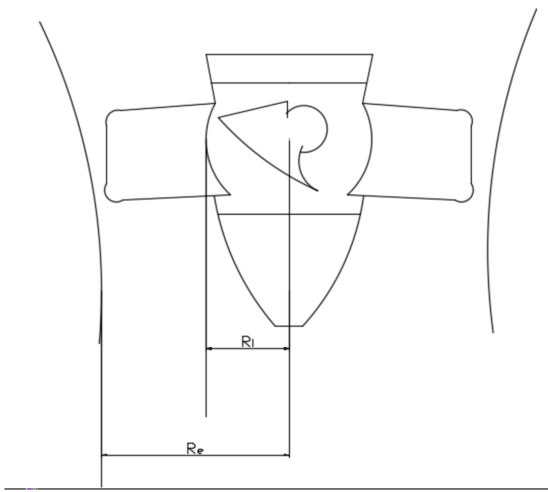



**Figure 4.** Cross section of a Kaplan turbine.

At this level, based on the speed of rotation of the turbine, it is also possible to estimate whether a speed increaser is necessary. According to ESHA [41], a speed increaser will be used only to interface turbines with a rotational speed of less than 428.57 rpm and standard alternators with nominal rotating speeds between 750 and 1500 rpm.

The remaining characteristics of the turbine can be calculated using the formulas below:

$$H_{rated} = H_{min} = 0.96H_{gross} \tag{14}$$

$$P_{turbine} = \eta_{turbine} g Q_{design} H_{rated} \tag{15}$$

with:

$P_{turbine}$: Rated power of the turbine (kW);
$\eta_{turbine}$: Rated efficiency of the turbine (-);
$H_{rated}$: Rated head of the turbine (m);
$H_{min}$: Minimal net head of the turbine (m);
$H_{gross}$: Gross head of the turbine, which is the difference between the upstream and the downstream level for reaction turbines and also the difference between the upstream and the downstream level minus the height of the nozzle jet above the tail race, which is fixed at 1 m here for impulse turbines [15] (m);
$Q_{design}$: Design flow rate of the turbine ($m^3/s$);
$Q_{equipement}$: Flow rate of equipment of the plant ($m^3/s$);
$n_t$: Number of turbines (-).

The expected rated efficiency of the turbine can be estimated using Table 4.

**Table 4.** Typical efficiencies of small turbines [41].

| Turbine Type | Best Efficiency |
|---|---|
| Kaplan single regulated | 0.91 |
| Kaplan double regulated | 0.93 |
| Francis | 0.94 |
| Pelton n nozzles | 0.9 |
| Pelton 1 nozzle | 0.89 |
| Turgo | 0.85 |

### 2.3.2. Generator Case

First, since this study deals with the design of a run-of-river hydroelectric power plant, the type of generator used will always be asynchronous with a frequency of 50 Hz, as is the case in Cameroon.

As for the generator rotational speed, if no speed increaser is used, the generator will have the same speed as the turbine. Otherwise, a speed of 750 rpm will always be considered. The number of pole pairs can be deduced from Table 3, presented above.

The rated power of the generator is calculated with Formula (16) below:

$$P_{generator} = \eta_{generator} \eta_{increaser} \eta_{turbine} g Q_{design} H_{rated} \tag{16}$$

where $\eta_{generator}$ is the rated efficiency of the generator depending on its rated power, as can be seen in Table 5, and $\eta_{increaser}$ is the efficiency of the speed increaser set at 0.97 (as according to ESHA [41], its efficiency varies from 0.96 to 0.98) and $\eta_{turbine}$ is the rated efficiency of the turbine.

**Table 5.** Typical efficiencies of small generators [41].

| Rated Power | Best Efficiency |
|---|---|
| 10 | 0.91 |
| 50 | 0.94 |
| 100 | 0.95 |
| 250 | 0.955 |
| 500 | 0.96 |
| 1000 | 0.97 |

### 2.4. Design of the Penstock

#### 2.4.1. Calculation of the Penstock Diameter

To calculate the optimal diameter, first, the maximum speed interval needs to be quantified in relationship with the head for the case study, which is given in Table 6.

**Table 6.** Maximum speed in penstock according to the head [47].

| Head (m) | Maximum Speed (m/s) |
|---|---|
| Low head (50 < H) | 2–3 |
| Medium head (50 ≤ H ≤ 250) | 3–4 |
| High head (H > 250) | 4–5 |

Then, provided the maximum and minimum speeds apply as shown in Table 6, the maximum and minimum diameter of the penstock can be determined with Equations (17) and (18):

$$D_{min} = \sqrt{\frac{4Q_{design}}{V_{max}\pi}} \tag{17}$$

$$D_{max} = \sqrt{\frac{4Q_{design}}{V_{min}\pi}} \tag{18}$$

Once these bounds are calculated, the diameter of the interval that allows having the best value of the objective function shall be calculated by using an optimization algorithm, which will be presented in the next few subsections.

#### 2.4.2. Calculation of the Penstock Thickness

To determine the thickness of the penstock, the three methods presented below can be used. Further, it is the maximum value, among the three values obtained from the three methods, that should be taken.

The first method uses the iterative procedure presented below [48]:

1. Proposal of a first estimate of $e$
2. Calculate $c$, $h_{max}$, and $e_{min}$
3. Compare $e$ and $e_{min}$: if $e < e_{min}$, then start again with a larger value of e and $e > e_{min}$. Attempt to make $e$ equal to the available wall thickness that is closest to $e_{min}$, above or below, and repeat the calculation.
4. Repeat the two previous steps until the minimum available wall thickness is made to be greater than $e_{min}$
5. $e$ should be increased by 1.5 mm while dealing with mild steel pipes in order to take into consideration corrosion effects.

The parameters mentioned above are calculated with the equations below:

$$h_{surge} = \frac{CV}{g} \tag{19}$$

$$C = \frac{1}{\sqrt{\rho\left(\frac{1}{k} + \frac{D}{Ee}\right)}} \tag{20}$$

$$e_{min} = \frac{\rho g h_{max} D F}{2\sigma} \tag{21}$$

$$H_{max} = H_{gross} + H_{surge} \tag{22}$$

where

$H_{surge}$: Surge pressure head (m);

$H_{max}$: Maximum possible pressure head experienced by the pipe (m);

$H_{gross}$: Gross head (m);
$C$: Velocity of the pressure wave through the water (m/s);
$V$: Flow velocity with valve fully open (m/s);
$\rho$: Density of water ($m^3$/s);
$k$: Bulk Modulus of water (N/$mm^2$);
$E$: Young's Modulus of Elasticity for pipe material (N/$m^2$);
$D$: Pipe diameter (mm);
$e$: Pipe wall thickness (mm);
$e_{min}$: Minimal pipe wall thickness (mm);
$g$ : Gravitational acceleration (m/$s^2$);
$F$: Safety factor, typically 3;
$\sigma$: Ultimate tensile strength of pipe material (N/$mm^2$);

The two other methods rely, respectively, on the two equations given below and are used to estimate the minimum wall thickness that will make the penstock rigid enough to be handled without danger of deformation in the field [41]:

$$e_{\min} = 2.5D + 1.2 \tag{23}$$

where $D$ is the diameter in m.

$$e_{\min} = \frac{D + 508}{400} \tag{24}$$

where $D$ is the diameter in mm.

2.4.3. Calculation of the Air Vent Pipe Diameter

According to ESHA [41], a penstock can collapse due to high depression. The maximum negative depression the material can withstand is given by the formula below (in kN/$mm^2$):

$$P_C = 882500\left(\frac{e}{D}\right)^3 \tag{25}$$

When an aeration pipe is installed, the diameter can be reduced as described in (26) [42]:

$$d = 7.47\sqrt{\frac{Q_{design}}{\sqrt{P_C}}} \tag{26}$$

for $P_C \leq 0.49\ \text{kgN/mm}^2$.

Otherwise, the minimum recommended diameter shall be computed using (27)

$$d = 8.94\sqrt{Q_{design}} \tag{27}$$

*2.5. Turbine Operation Model*

For the simulation of the turbine operation, not only are the minimum and the maximum flow rates of the turbine, respectively $Q_{min}$ and $Q_{max}$, considered, but also the safety flow rate $Q_{safety}$ , which is the maximum operational flow of the hydroelectric power plant. The safety flow rate is an important parameter because, according to Hanggi and Weingartner [44], if the flow exploited by the power plant is greater than $Q_{safety}$, then the plant may suffer from damage.

This flow will be the one with an exceedance probability of 2%, as proposed by Hanggi and Weingartner [44]. Since this study proposes a model of a power plant with several identical turbines ($n_t$), for a more efficient use of the hydraulic resource, based on the constraints presented above, this study uses the following operating algorithm:

$$Q_{\text{exploited}}(j) = \begin{cases} 0 \quad if \quad Q_{exploitable}(j) < Q_{min} \ (1) \\ Q_{exploitable}(j) \quad if \quad Q_{min} \le Q_{exploitable}(j) \le Q_{max} \ (2) \\ Q \quad if \quad Q_{max} < Q_{exploitable}(j) \le n_t Q_{max} \ (3) \\ n_t Q_{max} \quad if \quad n_t Q_{max} < Q_{exploitable}(j) < Q_{safety} \ (4) \\ 0 \quad if \quad Q_{exploitable}(j) \ge Q_{safety} \ (5) \end{cases} \tag{28}$$

- In the first case (1), no turbine is in operation;
- In case (2), a turbine is in operation, and this is all the exploitable flow that is used;
- In case (3), ($x$ + 1) turbines operate such that $Q = y.(x+1).Q_{max}$ with $0 \le y \le 1$ and ($x$ + 1), which is the natural number directly greater than $Q/Q_{max}$ ($x \le Q/Q_{max} \le x+1$), if $Q_{min}/Q_{max} \le y$ or $x$ turbines operate such that $Q = x.Q_{max}$ if $y < Q_{min}/Q_{max}$;
- In case (4), all the turbines are in rated operation, each of them exploiting the maximum flow that it can turbinate and the rest of the water flow $Q_{turbinable} - n_t Q_{max}$ being lost;
- In case (5), no turbine is operating.

The minimum flow $Q_{residual}$ , which cannot be used for environmental reasons, is here assumed to be 10% of the interannual flow of the watercourse in order to produce a project that is more respectful of the environment [41].

This leads to:

$$Q_{exploitable}(j) = Q_{available}(j) - Q_{residual} = Q_{available}(j) - 0.1Q_{interannual} \tag{29}$$

where $Q_{exploitable}$ is the exploitable flow rate in m$^3$/s, $Q_{exploited}$ is the exploited flow rate in m$^3$/s, $Q_{available}$ is the available flow rate in m$^3$/s, and $Q_{interannual}$ is the average daily flow rate available over the year in m$^3$/s.

The formulas for the calculation of the daily average values of the head losses, and the net head, for each day $j$ of the year are presented below [23]:

$$V(j) = \frac{4Q_{exploited}(j)}{D^2\pi} \tag{30}$$

$$\Delta H_{friction}(j) = \frac{\lambda V(j)^2 L}{2Dg} \tag{31}$$

$$\text{with } \frac{1}{\sqrt{\lambda(j)}} = -2log_{10}\left(\frac{\varepsilon}{3.7D} + \frac{2.51}{R_e(j)\sqrt{\lambda(j)}}\right) \tag{32}$$

$$\text{and } R_e(j) = \frac{V(j)\text{D}}{\nu} \tag{33}$$

$$\Delta H_{\ total} = 2.644\left(\frac{L}{H_{gross}}\right)^{-0.19} \Delta H_{friction}(j) \tag{34}$$

$$\Delta H_{singular}(j) = \Delta H_{total}(j) - \Delta H_{friction}(j) \tag{35}$$

$$H_{net}(j) = H_{gross} - \Delta H_{total}(j) \tag{36}$$

$H_{gross}$ : Gross head (m);
$H_{net}(j)$ : Net head of the day j (m);
$\Delta H_{friction}(j)$: Friction loss of the day j (m);
$\Delta H_{singular}(j)$: Singular losses of the day j (m);
$\Delta H_{total}(j)$ : Total head loss of the day j (m);
$\lambda(j)$ : Friction factor of the day j (-);
$V(j)$ : Flow velocity the day j (m/s);
$L$ : Length of the penstock (m);
$D$ : Diameter of the penstock (m);

$g$ : Gravitational acceleration (m/s$^2$);
$\varepsilon$ : Roughness heigh for welded steel (mm);
$\nu$ : Kinematic viscosity of water (m$^2$/s);
$R_e\ (j)$ : Reynolds number of the day j (-);
$Q_{exploited}(j)$: Exploited flow rate of the day j (m$^3$/s).

In the same way, the average daily powers and energies can also be estimated with the following formulas:

$$P_{hyd}(j) = gQ_{exploited}(j)\ H_{net}(j) \tag{37}$$

$$P_{meca}(j) = \eta_{turbine}(j)P_{hyd}(j) \tag{38}$$

$$P_{elec}(j) = \eta_{transformer}\hat{\eta}_{generator}P_{meca}(j) \tag{39}$$

$$E_{elec}(j) = 24P_{elec}(j) \tag{40}$$

$P_{hyd}(j)$ : Hydraulic power of the day $j$ (kW);
$P_{mec}(j)$ : Mechanical power of the day $j$ (kW);
$P_{elec}(j)$ : Electrical power of the day $j$ (kW);
$E_{elec}(j)$ : Electrical energy of the day $j$ (kWh);
$\eta_{turbine}(j)$ : Efficiency of the turbine the day $j$ (-);
$\hat{\eta}_{generator}$ : Average efficiency of the generator set to 0.9 (-);
$\eta_{transformer}$: Average efficiency of the transformer set to 0.98 (-) [49].

The hydro turbines efficiencies for each day $j$ are calculated through the equations below depending on parameters such as the rated head, the runner diameter, the turbine specific speed, and the turbine manufacturer/design coefficient [50]:

$$\hat{\eta}_{Kaplan/peak} = \left(0.905 - \hat{\eta}_{kaplan/nq} + \hat{\eta}_{d}\right) - 0.0305 + 0.005R_m \tag{41}$$

$$\hat{\eta}_{kaplan/nq} = \left((\eta_q - 170)/700\right)^2 \tag{42}$$

$$\hat{\eta}_{kaplan\ /d} = \left(0.095 + \hat{\eta}_{kaplan/nq}\right)\left(1 - 0.789\ d^{-0.2}\right) \tag{43}$$

$$\hat{\eta}_{Kaplan}(j) = \left[1 - 3.5\left(\frac{Q_{P/kaplan} - Q(j)}{Q_{P/kaplan}}\right)^6\right]\hat{\eta}_{Kaplan/peak} \tag{44}$$

$$d = KQ_{design}{}^{0.473} \tag{45}$$

$$n_q = kH_{rated}{}^{-0.5} \tag{46}$$

$$\hat{\eta}_{francis/peak} = \left(0.919 - \hat{\eta}_{francis/nq} + \hat{\eta}_{francis/d}\right) - 0.0305 + 0.005R_m \tag{47}$$

$$\hat{\eta}_{francis/nq} = \left((\eta_q - 56)/256\right)^2 \tag{48}$$

$$\hat{\eta}_{francis\ /d} = \left(0.081 + \hat{\eta}_{francis/nq}\right)\left(1 - 0.789\ d^{-0.2}\right) \tag{49}$$

$$\hat{\eta}_{francis/below}(j) = \left[1 - \left[1.25\left(\frac{Q_{P/francis} - Q(j)}{Q_{P/francis}}\right)^{(3.94 - 0.0195n_q)}\right]\right]\hat{\eta}_{francis/peak} \tag{50}$$

$$\hat{\eta}_{francis/above}(j) = \hat{\eta}_{francis/peak} - \left[\left(\frac{Q(j) - Q_{P/francis}}{Q_{design} - Q_{P/francis}}\right)^2\left(\hat{\eta}_{francis/peak} - \hat{\eta}_{francis/r}\right)\right] \tag{51}$$

$$\hat{\eta}_{francis/p} = 0.0072n_q{}^{0.4} \tag{52}$$

$$\hat{\eta}_{francis/r} = \left(1 - \hat{\eta}_{francis/p}\right)\hat{\eta}_{francis/peak} \tag{53}$$

$$n = 31\left(H_{rated}\frac{Q_{design}}{j}\right)^{0.5} \tag{54}$$

$$d_{out} = \frac{49.4 H_{rated}{}^{0.5} j^{0.02}}{n}, \tag{55}$$

$$\hat{\eta}_{pelton/peak} = 0.864\, d_{out}{}^{0.04}, \tag{56}$$

$$\hat{\eta}_{pelton}(j) = \left[1 - \left[(1.31 + 0.025j)\left|\left(\frac{Q_{P/pelton} - Q(j)}{Q_{P/pelton}}\right)\right|^{(5.6+0.4J)}\right]\right]\hat{\eta}_{pelton/peak}, \tag{57}$$

where:

$\hat{\eta}_{Kaplan}(j)$ is the efficiency of Kaplan turbines at a flow above or below peak efficiency and

$\hat{\eta}_{turbine\ type/peak}$ is the turbine peak efficiency of the turbine type considered.

$Q_{P/turbine\ type}$ is the peak efficiency flow of the turbine type considered (= $0.75Q_{design}$ $for\ Kaplan, = 0.65Q_{design}n_q{}^{0.05} for\ Francis\ turbine\ and = (0.662 + 0.001j)Q_{design}\ for\ pelton)$.

$\hat{\eta}_{turbine\ type/d}$ is the runner size adjustment to peak efficiency of the turbine type considered.

$\hat{\eta}_{turbine\ type/nq}$ is the specific speed adjustment to peak efficiency of the turbine type considered.

$Q_{design}$ is the design flow rate;

$n_q$ is the specific speed based on flow;

$k$ = 800 for Kaplan turbines and 600 for Francis turbines;

$H_{rated}$ is the rated head on turbine in m;

$d$ is the runner throat diameter in m;

$K$ = 0.46 for $d$ <1.8 and $K$ = 0.41 for $d \geq 1.8$;

$R_m$ is the turbine manufacturer/design coefficient (2.8 to 6.1; default = 4.5);

$j$ is the number of jets while dealing with Pelton turbines;

$n$ is the rotational speed of Pelton turbines;

$d_{out}$ is the outside diameter of runner of Pelton turbines.

The Figure 5 below shows the general configuration of the small run-of-river hydropower plant proposed by our methodology with all the parameters characterizing each of the component taken into account in our case and whose models are presented above.

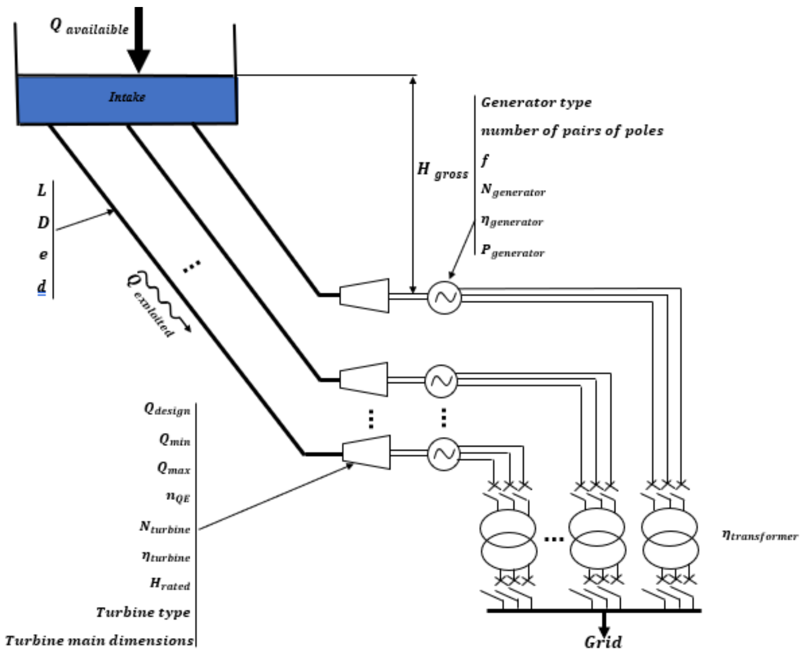



**Figure 5.** Schematic plant layout and parameters for optimization.

### 2.6. Annual Energy Production Estimation

Since, in this study, several turbines are considered, including their alternators and their penstock, it must be stressed that they will not always be working all at the same time. The operating forecasts of these turbines can therefore make it possible to set up a maintenance schedule for electromechanical equipment, which would prevent downtime for maintenance.

Thus, this study first assumes that the power plant is always in operation (it never experiences any downtime).

$$E_{elec\ annual} = \sum_{j=1}^{365} 24P_{elec}(j) \quad (58)$$

$E_{elec\ annual}$: Productible annual electrical energy (kWh);
$P_{elec}(j)$: Electrical power of the day $j$ (kW).

### 2.7. Economic Analysis

Economic analysis is the phase following the design of the plant and thus allowing the assessment of the profitability of the project. Costs of small hydropower projects include fixed and variable cost. Fixed costs include expenditures due to civil works and electromechanical equipment, while the variable costs take into consideration replacement, operation, and maintenance costs [33,50].

#### 2.7.1. Cost Estimate Model

The equations of the model used for the estimation of the investment cost of the project are presented below:

- For a low-head project (3–20 m) [33]

$$Cost\ of\ power\ house\ building:\ C_1 = 92615P^{-0.2351}H^{-0.0585}, \quad (59)$$

$$Cost\ of\ diversion\ weir\ \&\ intake:\ C_2 = 12415P^{-0.2368}H^{-0.0597}, \quad (60)$$

$$Cost\ of\ penstock:\ C_3 = \pi(D+2e)e\rho L prix_{penstock}/\left(P.\check{E}\right), \quad (61)$$

$$Cost\ of\ tail\ race\ channel:\ C_7 = 28164P^{-0.376}H^{-0.624} \quad (62)$$

Finally, the cost in Indian rupees per kilowatt of civil works is $C_C = C_1 + C_2 + C_3 + C_7$

$$Cost\ of\ turbines\ with\ governing\ system:\ C_8 = 63346P^{-0.1913}H^{-0.2171} \quad (63)$$

$$Cost\ of\ generator\ with\ excitation\ system:\ C_9 = 78661P^{-0.1855}H^{-0.2083} \quad (64)$$

$$Cost\ of\ electrical\ \&\ mechanical\ auxiliaries\ :C_{10} = 40860P^{-0.1892}H^{-0.2118} \quad (65)$$

$$Cost\ of\ transformer\ \&\ switchyard\ equipment:\ C_{11} = 18739P^{-0.1803}H^{-0.2075} \quad (66)$$

Finally, the cost in Indian rupees per kilowatt of electromechanical equipment is

$$C_{e\&m} = C_8 + C_9 + C_{10} + C_{11} \quad (67)$$

where $P$ is the rated power capacity in kW, $H$ is the rated head in m, $D$ is the penstock diameter in m, $e$ is the thickness of the penstock in m, $\rho$ is the density of welded steel in m$^3$/s, $L$ is the length of the penstock in m, $\check{E}$ is Indian rupee/USD rate exchange and $Prix_{penstock}$ is the cost of the penstock in USD/ton.

- For a high-head project (more than 100 m) [32]

For civil works components, the equations below are used:

$$C_x = 1.06 \times \left(\frac{E}{W} \times cost\ of\ earth\ work\ in\ excavation\right) + (Conc. \times cost\ of\ Concreting) + (RS \times cost\ of\ Reinforced\ steel) + (SS \times cost\ of\ Structural\ Steel/Material) \tag{68}$$

$$C_C = C_W + C_{IC} + C_{DT} + C_{HRC} + C_{FS} + C_P + C_{PH} + C_{TRC} \tag{69}$$

The equations for the calculation of costs of civil works components presented above are used with Table 7 and considering the prices as per schedule of rates prevailing for the year 2012 in India [32].

**Table 7.** Correlations of civil works for run-of-river small hydropower plant scheme [51].

| No. | Civil Works Components | | Items | | | |
|---|---|---|---|---|---|---|
| | | | **Earth Work in Excavation ($m^3$), E/W** | **Concreting ($m^3$), Conc.** | **Reinforcement Steel (MT), RS** | **Structural Steel/Material (MT), SS** |
| 1 | Diversion weir | | $47.00P^{1.10} H^{-0.99}$ | $38.55P^{1.17} H^{-1.16}$ | $2.59P^{1.18} H^{-1.15}$ | $1.51P^{0.71} H^{-0.67}$ |
| 2 | Penstock (per meter) | PVC pipe | $0.42P^{0.83} H^{-0.98}$ | $0.31P^{0.84} H^{-0.98}$ | $0.03P^{0.83} H^{-0.97}$ | $0.04P^{1.5} H^{-0.81}$ |
| | | GRP pipe | | | | $0.01P^{1.5} H^{-0.85}$ |
| | | HDPE pipe | | | | $0.08P^{1.5} H^{-0.80}$ |
| | | Steel pipe | | | | $0.05P^{0.83} H^{-0.95}$ |
| 3 | Tail race channel (per meter) | | $0.91P^{0.83} H^{-0.90}$ | $1.82P^{0.87} H^{-0.91}$ | $0.01P^{0.80} H^{-0.79}$ | - |
| 4 | Powerhouse building | Pelton/Turgo impulse | $16.09P^{2.46} H^{-1.75}$ | $0.00052P^{2.54} H^{-0.42}$ | $0.00022P^{4.02} H^{-2.83}$ | $0.09P^{4.55} H^{-3.50}$ |
| | | Francis | $0.08P^{2.33} H^{-1.33}$ | $0.03P^{2.29} H^{-1.32}$ | $0.05P^{2.36} H^{-1.34}$ | $0.02P^{2.19} H^{-1.26}$ |

Thus, the prices used are as follows:

- The price for structural steel (including fabrication, transportation to site, and erection) is 75,000 Indian Rupee/MT;
- The price for M20 grade concrete work in plain cement concrete as well as in reinforced cement concrete, including shuttering, mixing, placing in position, compacting, and curing is 3640 Indian Rupee/$m^3$;
- The price for reinforcement steel bars of iron 500 grade, including cutting, bending, binding, and placing in position is 55,000 Indian Rupee/MT;
- The price for earthwork in excavation with all leads and lifts in ordinary soil is 265 Indian Rupee/$m^3$;
- The price for earthwork in excavation with all leads and lifts in soft rock, where blasting is not required is 330 Indian Rupee/$m^3$;
- The price for earthwork in excavation with all leads and lifts in hard rock, including blasting is 550 Indian Rupee/$m^3$.

For electromechanical equipment, the equations below are used:

$$C_y = a_1 P^{x_1} H^{x_2} \tag{70}$$

$$C_{e\&m} = C_{TG} + C_{GE} + C_{Aux} + C_{T/F} + C_{SY} \tag{71}$$

The electromechanical equipment considered and the value of the constants $a_1$, $x_1$, and $x_2$ are presented in Table 8.

**Table 8.** Coefficients in cost correlation for electromechanical equipment with different types [51].

| No. | Type of Equipment | | Coefficients in Cost Correlation | | |
|---|---|---|---|---|---|
| | | | $a_1$ | $x_1$ | $x_2$ |
| 1 | Turbine with governing system (TG) | Pelton | 117,313 | −0.03 | −0.39 |
| | | Turgo impulse | 145,121 | −0.12 | −0.24 |
| | | Francis | 125,354 | −0.01 | −0.38 |
| 2 | Generator with excitation system or capacitor bank (GE). | Induction | 130,262 | −0.19 | −0.22 |
| | | Synchronous | 143,660 | −0.18 | −0.21 |
| 3 | Auxiliaries | | 21,846 | −0.19 | −0.22 |
| 4 | Transformer | | 221 | 0.11 | 0.01 |
| 5 | Switchyard | | 1.82 | 0.17 | 0.93 |

The total project cost includes the cost of civil works, the cost of electromechanical equipment, the cost of various items, and other indirect costs. These miscellaneous and indirect costs—which include the costs of design; indirect costs; models; plants; communication; preliminary charge of preparing the report; survey and investigation; environmental impact assessment; and cost of land—represent 13% of the sum cost of civil works and electromechanical equipment. Thus, the total cost of the project in this case can be calculated through the equation below:

$$C_{total} = 1.13P.\check{E}(C_{civilwork} + 2.C_{em}) \tag{72}$$

While considering a lifetime of 50 years for the project (50 years for the civil works components and 25 years for electromechanical equipment).

2.7.2. Economic Criteria Calculation

The main economic criteria are presented as follows, based on [52].

- Life Cycle Cost (*LCC*)

The *LCC* represents the total amount of costs that are involved during the life of a project. The discounted salvage value is taken into account in the LCC calculation.

*LCC* is calculated using the formula below:

$$LCC = C_{total} + \sum_{j=1}^{T} \frac{C_{OM}(j)}{(1+i)^j} \tag{73}$$

with $i$ being the discount rate, $C_{OM}(j)$ the operating cost of year $j$, and $T$ the life of the project in years. This study assumes that $C_{OM}(j) = C_{OM} = 0.025C_{total}$ [53].

As can be seen, the *LCC* criterion does not take into account the income generated by the project. Therefore, this criterion cannot help in making an investment decision on a project, but, however, could help in obtaining an optimal design of a project.

- Levelized Cost of Energy (*LCOE*)

*LCOE* is the annualized cost of a unit of energy (kWh). This criterion is, by definition, only useful for energy projects and is part of the most popular economic measures in this area. It is the ratio of the project's *LCC* to the total amount of discounted energy produced over the life of the project. It is calculated using Equation (74):

$$LCOE = \frac{LCC}{\sum_{j=1}^{T} \frac{E_{elec\ annuelle}(j)}{(1+i)^j}} \tag{74}$$

Similar to the *LCC*, the *LCOE* does not take into account the income generated by the project and is therefore not suitable for making an investment decision on a project, but instead used to help achieve an optimal design of a project.

- Net Present Value (*NPV*)

The Net Present Value (*NPV*) is the sum of the annual cash flows returned to its equivalent value on the project start date. Therefore, for the Net Present Value, the annual costs return to the start date of the project using the discount factor as below:

$$NPV = -C_{total} + \sum_{j=1}^{T} \frac{IF(j) - C_{OM}(j)}{(1+i)^j} \tag{75}$$

where $IF(j)$ is the net revenue from the sale of electricity in year $j$ and is assumed to be constant and equal to *price*. $E_{elec\ annuelle}(j)$ (price is the cost of kWh).

The project is accepted if $NPV \geq 0$ and the higher the *NPV*, the more attractive the project.

- Return on investment time

This criterion allows an investor to assess the minimum time necessary to recover their initial investment. To determine this time, it will be a question of determining the *PBP* duration such as in

$$\sum_{j=1}^{PBP} \frac{IF(j) - C_{OM}(j)}{(1+i)^j} = C_{total} \tag{76}$$

*2.8. Optimization Method*

The models for sizing the power plant, i.e., estimating the costs and calculating the economic criteria presented above, are here combined into the proposed optimization problem. The main economic criterion to be optimized here is the *LCOE*, whereas the other economic criteria are calculated for informational purposes in order to better inform the user on the various economic constraints that go with the proposed solution of the model.

The main optimization variables are the equipment flow $Q_{equipment}$, the diameter $D$, and the number of identical turbines $n_t$. The algorithm has been written in the python language for the purposes of simulations.

$$\left\{ \begin{array}{c} Min\left(LCOE\left(Q_{equipment},\ D, n_t\right)\right) \\ 1 \leq n_t \leq 100 \\ D_{min} \leq D \leq D_{max} \\ Q_{25} \leq Q_{equipement} \leq Q_{15} \\ Q_{equipement} = n_t Q_{design} \\ \left(\frac{H_a - H_v}{1.5241 H_n}\right)^{\frac{1}{1.46}} \frac{60(gH_{rated})^{\frac{3}{4}}}{N_{nominal}} \geq Q_{design}\ for\ KAPLAN\ (to\ have\ H_S \geq 0) \\ \left(\frac{H_a - H_v}{1.2715 H_{rated}}\right)^{\frac{1}{1.41}} \frac{60(gH_{rated})^{\frac{3}{4}}}{N_{nominal}} \geq Q_{design}\ for\ FRANCIS (to\ have\ H_S \geq 0) \\ \frac{(60)^2 (0.68)^2 H_{rated} n \sqrt{gH_{rated}}}{(N_{nominal})^2 (2.7)^2 (1.178)^2} \geq Q_{design}\ for\ PELTON \left(to\ have\ \frac{D_1}{B_2} > 2.7\right) \\ L < 2.644^{\frac{1}{0.19}} H_{gross}\ (the\ condition\ for\ the\ use\ of\ the\ head\ losses\ calculation\ model) \end{array} \right.$$

Figure 6 below summarizes the methodology used:

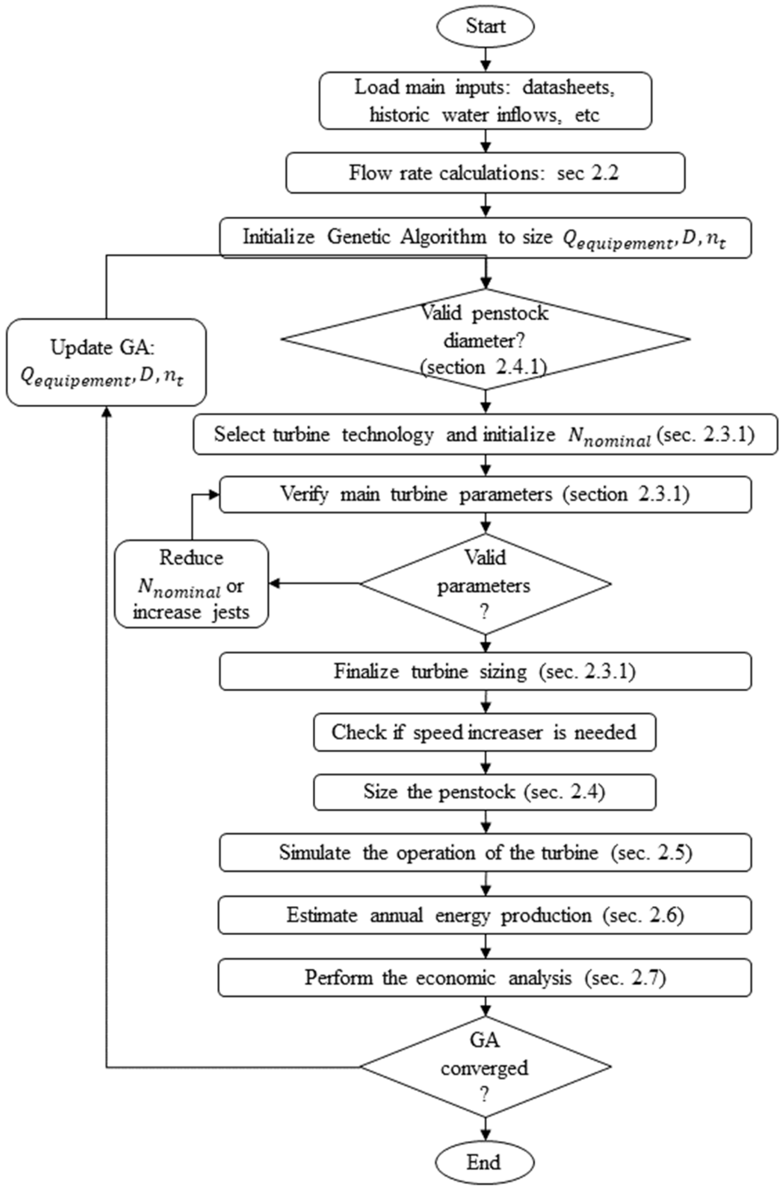



**Figure 6.** Optimization process minimizing LCOE.

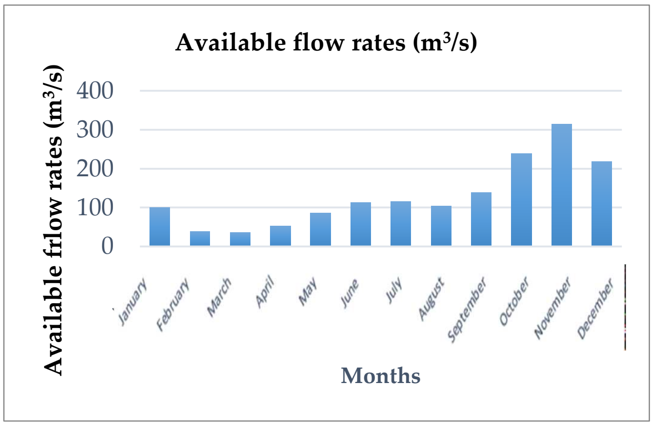
To produce this methodology, several existing models used in the literature for the calculation of the parameters mentioned above (diameter; thickness and aeration pipe diameter of a penstock; main dimensions of a turbine; energy production; and expected cost of the small hydropower plant) were analyzed one by one according to their specificities. Then, the most appropriate models, according to our context of study, were chosen and combined together. This was done in order to use the models more efficiently, and even adapted, depending on the circumstances for the techno-economic design of small run-of-river hydropower plants. A new algorithm for the turbine operation of more than two turbines was also developed for this methodology. All this made it possible to have, in the end, an optimal design model for small run-of-river hydropower plants. Of which, not only can the model consider more than two turbines, but it also can calculate the maximum length of the penstock (in order to allow for a maximum total head loss at 4% of the gross head); the main dimensions of the turbine wheel; the specific speed and rated speed of the turbine; the maximum suction head (to avoid the excavation cost); and the rated speed of the generator, to which the turbine is coupled before determining if a speed increaser is necessary.

## 3. Case Study

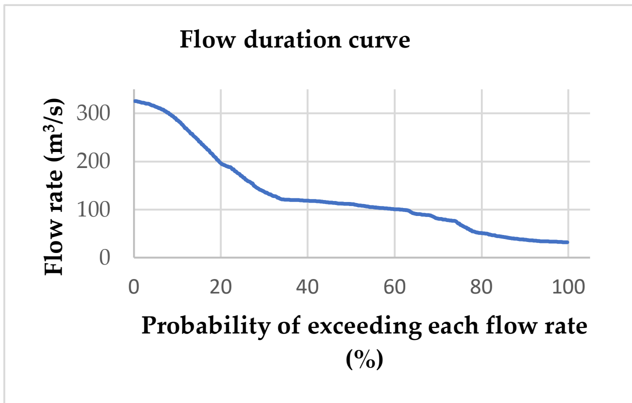
The LCOE-based optimization methodology for small run-of-river hydroelectric power plants was developed to calculate the number and characteristics of the turbines, the penstocks, and the generators that could be used to harness the hydraulic potential of the river Nyong in Mbalmayo, in an energy efficient and financially sustainable way.

For our case study, the flow measurements that were carried out, regularly for 15 successive years every day (from 1998 to 2013), were used as to provide a realistic test case and also produce useful results that can be used as a reference for other studies. These hydrological data are products of the CZO M-TROPICS [54].

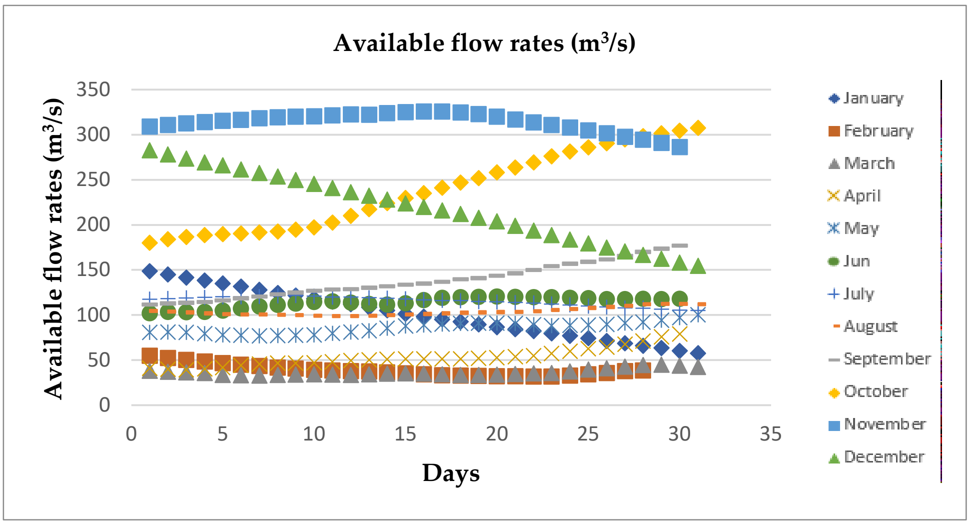
Figure 7 highlights the hydraulic potential of the river Nyong that can be exploited for the production of electricity through the proposed small run-of-river hydroelectric power plant. It can be noticed that the months of October, November, and December are those where we have the most important flows of the year (especially in November where the flows revolve around 300 $m^3/s$ continuously, every day of the month). On the other hand, during the months of February, March, and April we have the lowest flows of the year, especially during March when the flows always remain continuously below 45 $m^3/s$, every day of the month.




(**a**)




(**c**)




(**b**)

**Figure 7.** (**a**) Average monthly available flow rates histogram, (**b**) average daily available flow rates curve, and (**c**) flow duration curve of the river Nyong (1998–2013).

The economic and technical parameters used for this simulation are presented in Table 9.

**Table 9.** Economic and technical parameters of simulation.

| Economic and Technical Parameters | Symbol | Value |
|---|---|---|
| Roughness height for welded steel | $\varepsilon$ | 0.6 mm [41] |
| Density of welded steel | $\rho_a$ | 7.9 ton/m$^3$ (7.7–8 ton/m$^3$) [55] |
| Kinematic viscosity of water (at 26 °C, average temperature of Mbalmayo over the year) | $\nu$ | $0.878 \times 10^{-6}$ m$^2$/s [56] |
| Density of water | $\rho$ | 1000 kg/m$^3$ |
| Gravitational acceleration | $g$ | 9.81 m/s$^2$ |
| Flow velocity of water at the outlet of the turbine | $V$ | 2 m/s [41] |
| Bulk modulus of water | $k$ | $2.1 \times 10^9$ N/mm$^2$ [41] |
| Young's Modulus of Elasticity for welded steel | $E$ | $2.06 \times 10^{11}$ N/m$^2$ [41] |
| Ultimate tensile strength of welded steel | $\sigma$ | $400 \times 10^6$ N/mm$^2$ [41] |
| Energy price | $price_{energy}$ | 0.1 USD/kWh |
| Operation and Maintenance cost coefficient | $Coef_{O\&M}$ | 2.5 % [53] |
| Indian rupee/ USD exchange rate | Ě | 0.0136333 [57] |
| Percentage of non-operated interannual flow | $Q_{residual}$ | $10\%Q_{interannual}$ [41] |
| Project lifespan | $T$ | 50 years |
| Lifespan of civil works components | $T_{civil}$ | 50 years |
| Lifespan of electromechanical equipment | $T_{electromca}$ | 25 years |
| Generator efficiency | $\eta_{generator}$ | Table 5 [41] |
| Average efficiency of the generator | $\hat{\eta}_{generator}$ | 0.9 |
| Turbine efficiency | $\eta_{turbine}$ | Table 4 [41] |
| Speed increaser efficiency | $\eta_{increaser}$ | 0.97 [41] |
| Transformer efficiency | $\eta_{transformer}$ | 0.98 [49] |
| Discount rate | $i$ | 12.5 % [58] |
| Atmospheric pressure | $H_a$ | 10.3 mCE (101 000 Pa) [41] |
| Vapor pressure of water (at 26 °C, average temperature of Mbalmayo over the year) | $H_v$ | 0.34 mCE (3 360 Pa) [59] |

## 4. Results

This section describes the results of the proposed optimization procedure when applied to the case study introduced in the previous section.

### 4.1. Optimal Design of the System

The tables below show the optimal configuration of the small run-of-river hydroelectric power plant when connected to an electric network as proposed in our model. This configuration has four identical Kaplan turbines (double regulated) with a design flow rate of 38.35 m$^3$/s, a rated head of 4.8 m, a rated power of 1.68 MW, and a rated rotational speed of 210 rpm, each coupled to a 8 poles asynchronous generator with a rated power of 1.58 MW. Hence, leading to a total installed capacity of 6.32 MW. Since the speed of rotation of the turbine is different from that of the generator (which is 750 rpm), a speed increaser must be coupled between the turbine and the generator (Tables 10 and 11).

**Table 10.** Characteristics of the turbine selected.

| Characteristics of the Turbine | |
|---|---|
| Turbine type | KAPLAN double regulated |
| Design flow rate ($m^3/s$) | 38.35 |
| Specific speed (-) | 1.21 |
| Rotational speed (rpm) | 210 |
| Rated head (m) | 4.8 |
| Maximal suction head (m) | 0.34 |
| The runner outer diameter$_t$ (m) | 2.4 |
| The runner hub diameter$_t$ (m) | 0.79 |
| Best efficiency (-) | 0.93 |
| Rated power (MW) | 1.68 |
| Number of turbines (-) | 4 |
| Minimal flow rate ($m^3/s$) | 5.75 |
| Maximal flow rate ($m^3/s$) | 38.35 |

**Table 11.** Characteristics of the generator selected.

| Characteristics of the Generator | |
|---|---|
| Generator type | Asynchronous |
| Number of poles | 8 |
| Frequency (Hz) | 50 |
| Rotational speed (rpm) | 750 |
| Best efficiency (-) | 0.97 |
| Rated power (MW) | 1.58 |

In this configuration, in order to limit the total head losses to 4% of the gross head, and to have a penstock rigid enough to withstand the effects of instantaneous overpressures and depressions, the penstock must have a maximum length of 97.61 m, a diameter of 4.1 m, a minimum thickness of 19 mm, and an air vent pipe diameter of 55.36 cm (Table 12).

**Table 12.** Characteristics of the designed penstock.

| Characteristics of the Penstock | |
|---|---|
| Optimal diameter of the penstock (m) | 4.1 |
| Minimal thickness of the penstock (mm) | 19.04 |
| Length of the penstock (m) | 97.62 |
| Air vent pipe diameter of the penstock (cm) | 55.36 |
| Maximal total head losses in the penstock (m) | 0.2 |
| Maximal friction losses in the penstock (m) | 0.133 |
| Maximal singular losses in the penstock (m) | 0.067 |
| Maximal speed of water in the penstock (m/s) | 2.9 |
| Average speed of water in the penstock (m/s) | 2.4 |
| Surge head in the penstock (m) | 353.88 |
| Total head in the penstock (m) | 358.88 |
| Wave speed (m/s) | 1447.46 |

The equipment and safety flow rates obtained with this configuration are, respectively, 153.41 $m^3/s$ and 309.17 $m^3/s$ (Table 13).

**Table 13.** Other characteristics of the project.

| Other Characteristics of the Project | |
|---|---|
| Flow rate of equipment ($m^3/s$) | 153.41 |
| Gross head (m) | 5 |
| Average available flow rate over the year ($m^3/s$) | 130.13 |
| Residual flow rate ($m^3/s$) | 13.01 |
| Average exploitable flow rate over the year ($m^3/s$) | 117.11 |
| Safety flow rate ($m^3/s$) | 309.17 |

*4.2. Optimal System Operation over the Year*

Figure 8a,b show the flow rates that can be directly used by the power plant. That is to say, the flow rates remaining after subtracting from the available flow rates and the residual flow rate, which is the flow rate reserved for environmental reasons. As partially introduced, the exploitable flow rates during February to April are very low and almost always below 50 $m^3/s$, thus making the exploitation of this watercourse particularly difficult during these months.

Figure 9 shows the exploited flow rates in the plant, which is to say the flows actually used. It can be seen in Figure 9b that only during the periods of November 13 and November 14 to 19 (only 7 days a year) the plant is shut down. The shutdown of the plant during these 7 days is due to the fact that the plant cannot exploit all the large flow rates in the month of November as, during these days, the daily exploitable flow rates, which are all greater than the safety flow rate (309.17 $m^3/s$), is beyond which the safety of the plant is no longer guaranteed.

As for the other days of the year, the plant remains in operation by efficiently using the exploitable flow rates.

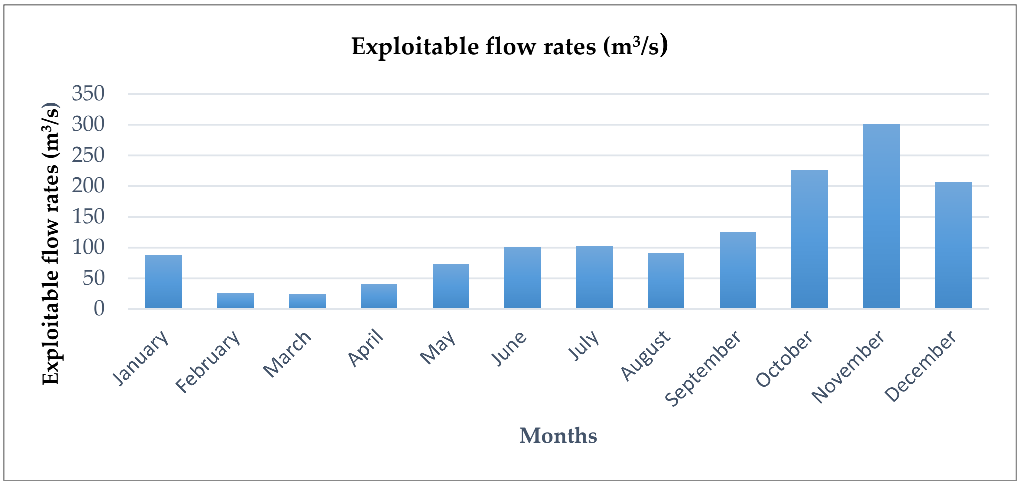
Therefore, the configuration proposed by the model makes it possible to not only to use large flow rates, of the order of the equipment flow rate when flow rates are strictly lower than the safety flow rate, but also to exploit very low flow rates such as those of the months of February, March, and April when the lowest exploitable flow rates of the year occur. With this configuration, the minimum and maximum flow rates that can be exploited by the power plant are 5.75 $m^3/s$ and 153.41 $m^3/s$, respectively.

Figure 10 illustrates the optimal management of the system by showing the number of turbines that will operate each day of the year. Through this curve, it is noted that a maintenance schedule could be set up, thus reducing plant downtime, ensuring a more continuous production of electrical energy. In fact, according to the curve in Figure 10, for about 70% of the year, there are less than four turbines in operation in the plant.

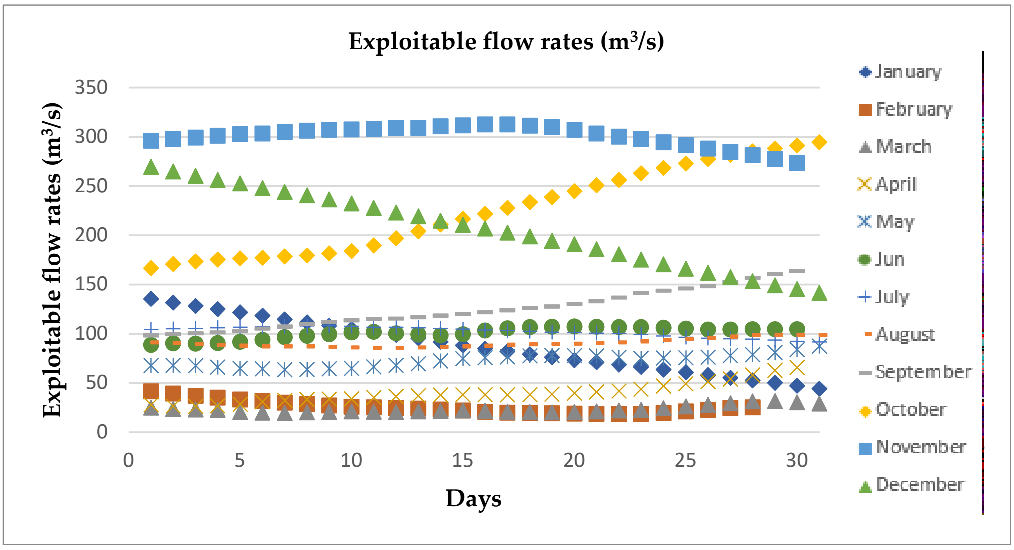
Thus, as can be seen in Figures 11 and 12, apart from the 7 days listed above, the plant is always in operation during the year, thus providing the grid with a large amount of electrical energy.

*4.3. Analysis of the Energy Efficiency of the Optimal System*

As shown again by the histogram and the curve in Figure 13, the exploitation of the hydraulic energy of the river Nyong, in Mbalmayo, is limited not only by the minimum and maximum operating flow rates of the turbines, but also by the safety flow rate beyond which the plant infrastructure could be damaged. November has the largest amount of flow rates that cannot be managed due to the danger they could represent for the plant. From 28 September to 27 December, for example, flow rates—hence hydraulic energy—decrease every day continuously either due to flow rates being higher than the maximum flow rates of the turbines, or due to the flow rates being greater than the safety flow rate. This is the case during the periods of the 13th and from 14 to 19 November, thus forcing the power plant to be shut down (here, all exploitable flow rates are lost). All the constraints presented above, therefore, prevents the exploitation of a total flow rate of 9386.41 $m^3/s$ per year (or hydraulic energy of about 11.05 GWh per year).




(**a**)

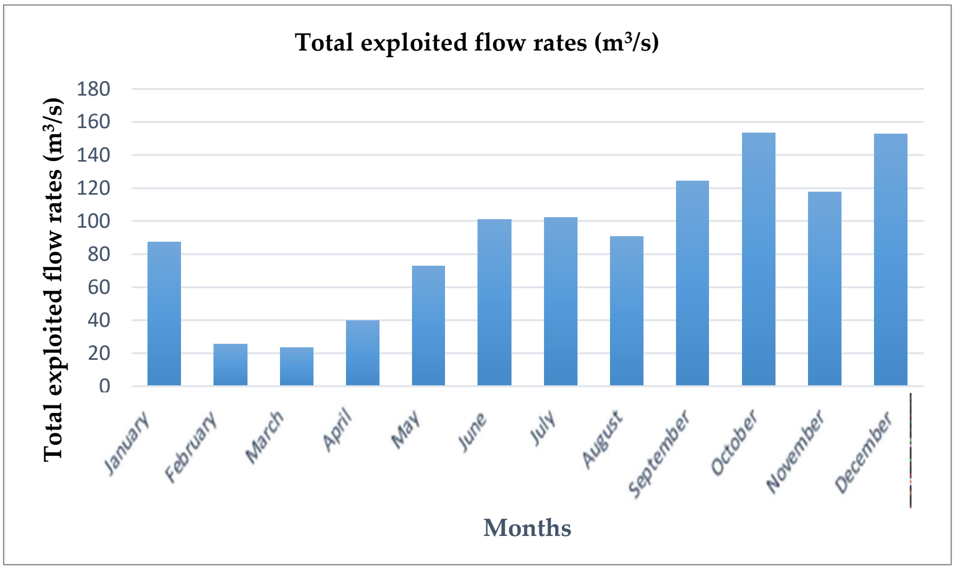



(**b**)

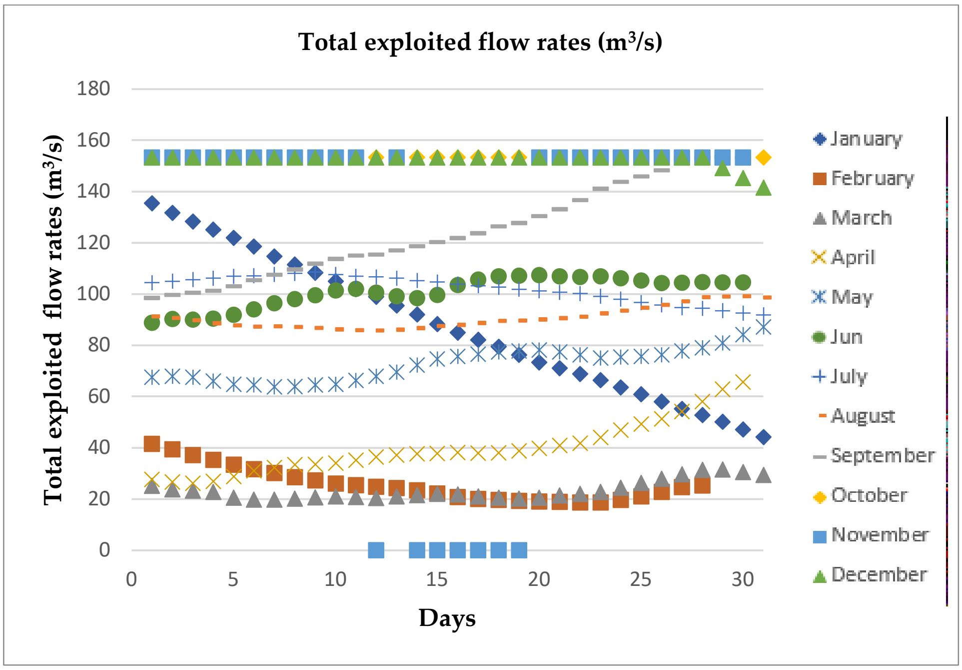
**Figure 8.** (**a**) Average monthly exploitable flow rates histogram and (**b**) average daily exploitable flow rates curve.

However, the histogram and the turbine efficiency curves in Figure 14 show that every time the plant is in operation, each turbine has an efficiency greater than or equal to 0.87.

We can also see through these results the interest of using several turbines in parallel to increase the energy efficiency of the plant. For example, let us pay attention to the period from 3 February to 18 April in which only one turbine is in operation. As such, if that plant were a single large turbine, the plant would have been shut down several times during these periods because, in some cases, exploitable flow rates would have been below the minimum starting flow rate of the large turbine. Another matter to emphasize is that even in cases where the flow rates would have been greater than the minimum starting flow rate of the large turbine, the large difference between these flow rates and the design flow rate of the large turbine (here equal to the equipment flow rate) would have brought the system to operate with very a poor performance or with low efficiency.




(**a**)




(**b**)

**Figure 9.** (**a**) Average monthly exploited flow rates histogram and (**b**) average daily exploited flow rates curve.

Anagnostopoulos and Papantonis [20] also suggested the use of three indices in order to assess the energy efficiency of a hydroelectric plant: the energy production index, obtained by dividing the total annual energy production by the total annual exploitable hydraulic energy; the water exploitation index, which is the fraction of the exploitable flow rates used; and the load index, which is the ratio of the average daily power produced over the year to the rated power of the plant. The values for the proposed case study are reported in Table 14.

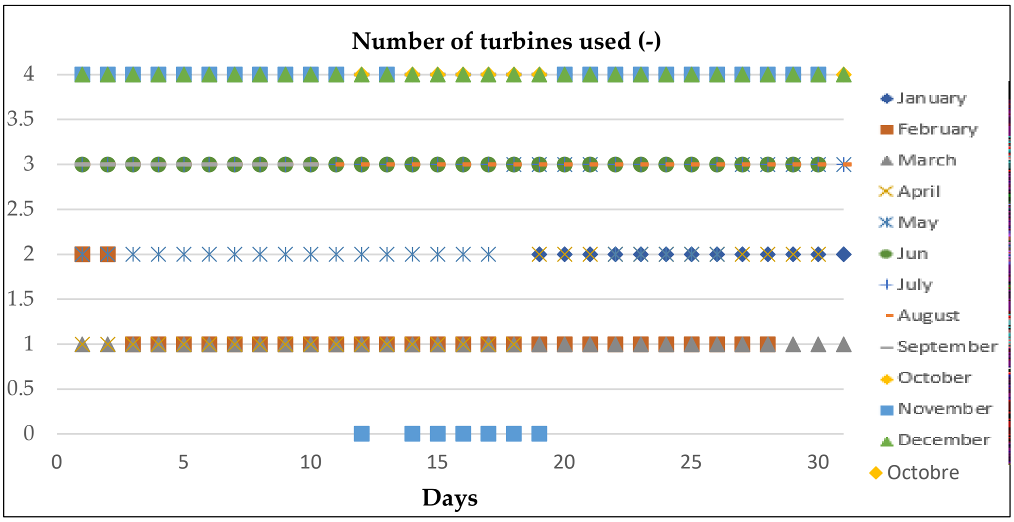
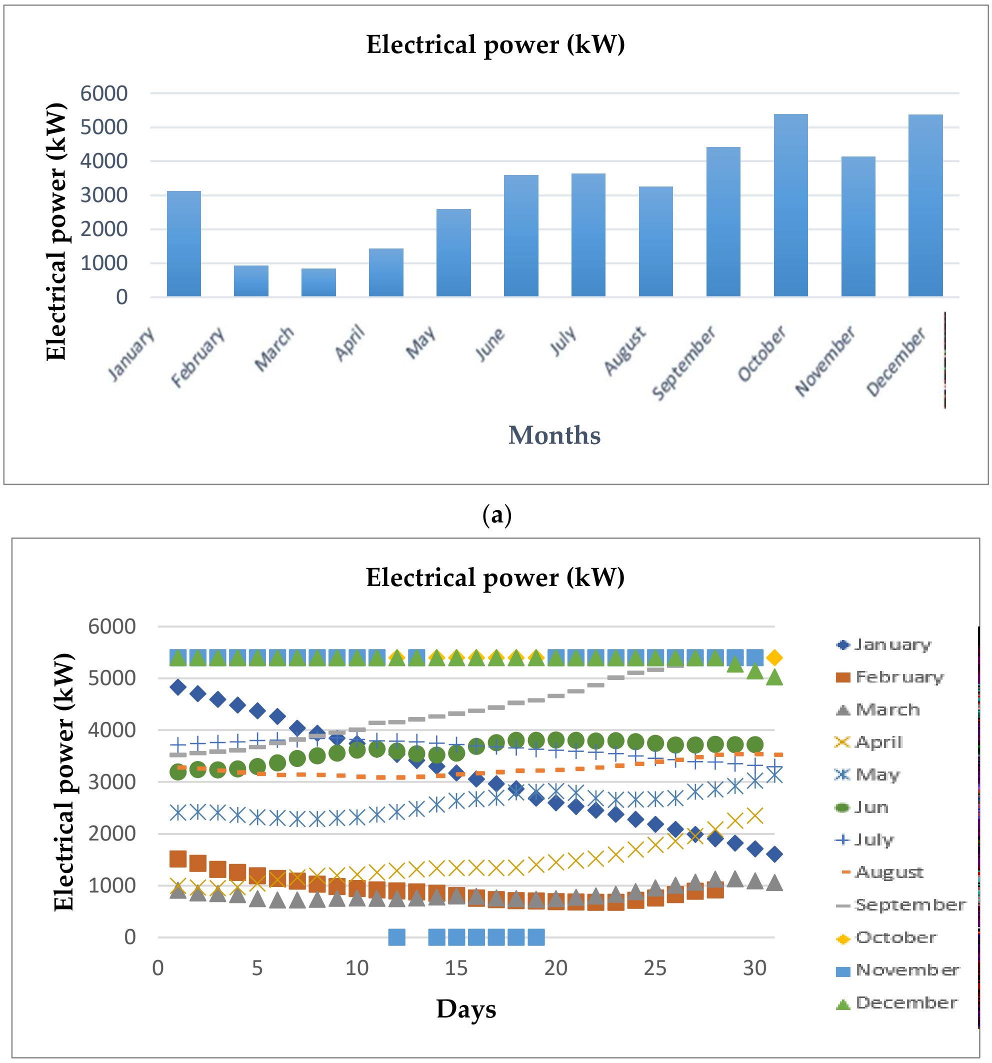


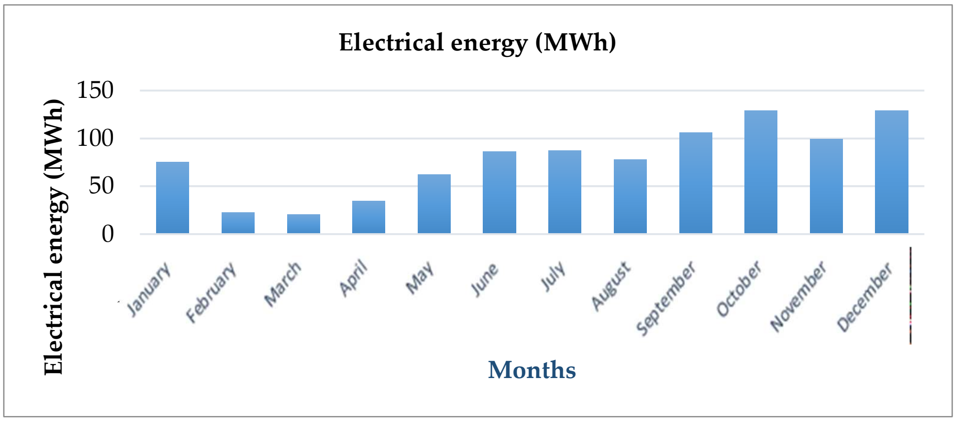

**Figure 10.** Curve of the number of turbines used.



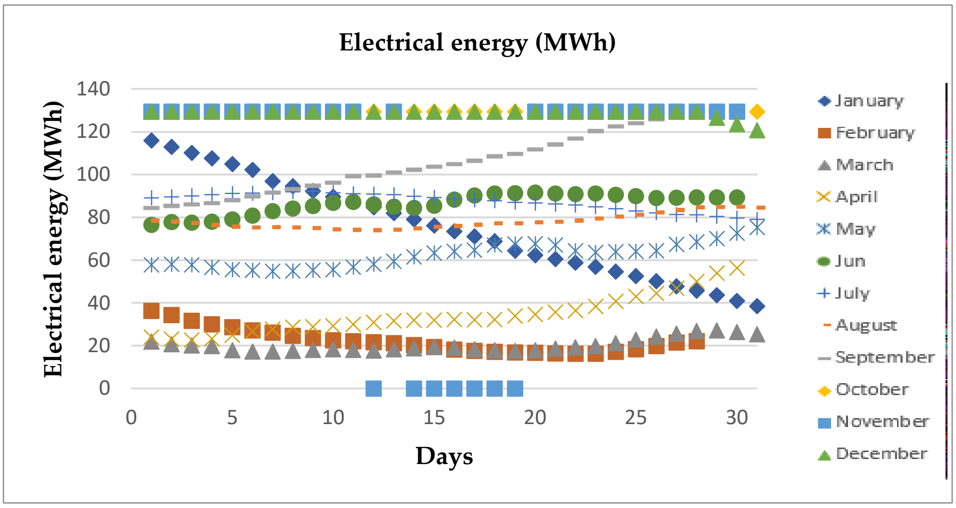

(**a**)

(**b**)

**Figure 11.** (**a**) Average monthly electrical power histogram and (**b**) average daily electrical power curve.

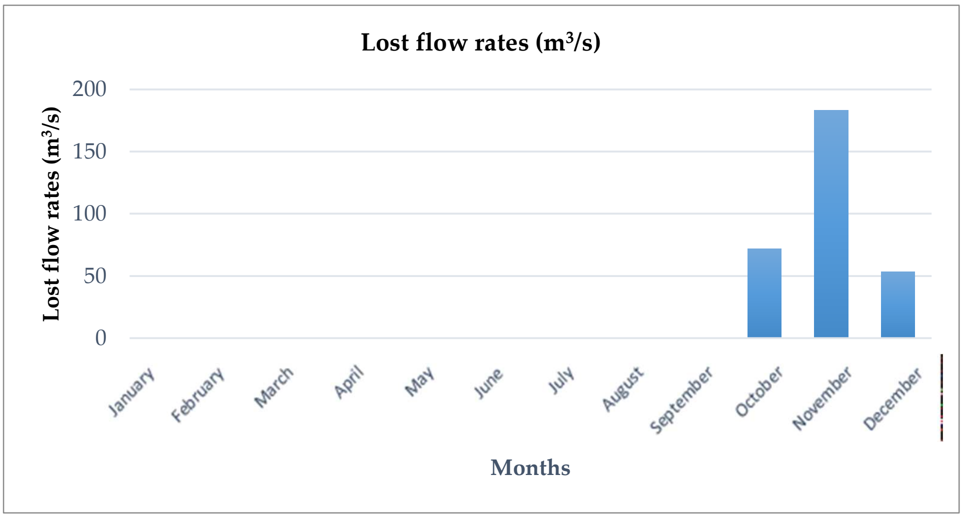



(**a**)



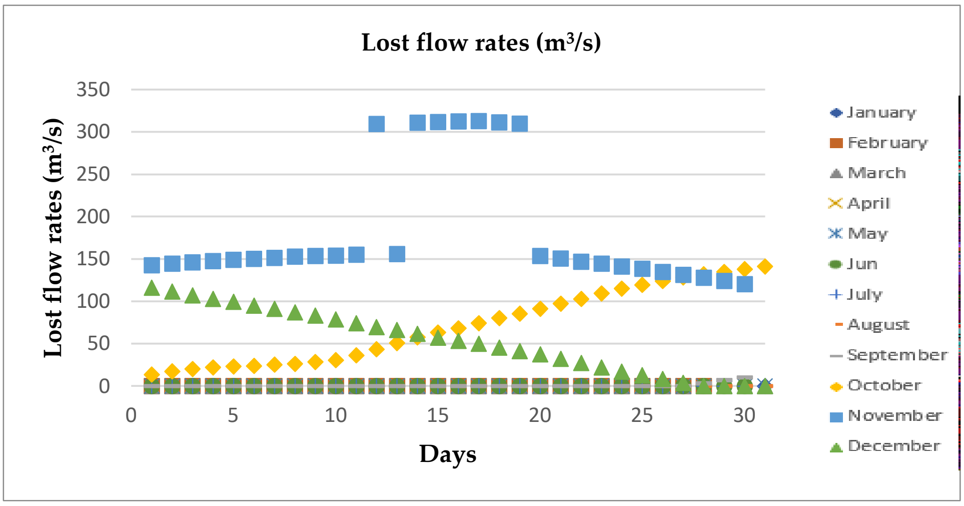

(**b**)

**Figure 12.** (**a**) Average monthly electrical energy histogram and (**b**) average daily electrical energy curve.




(**a**)

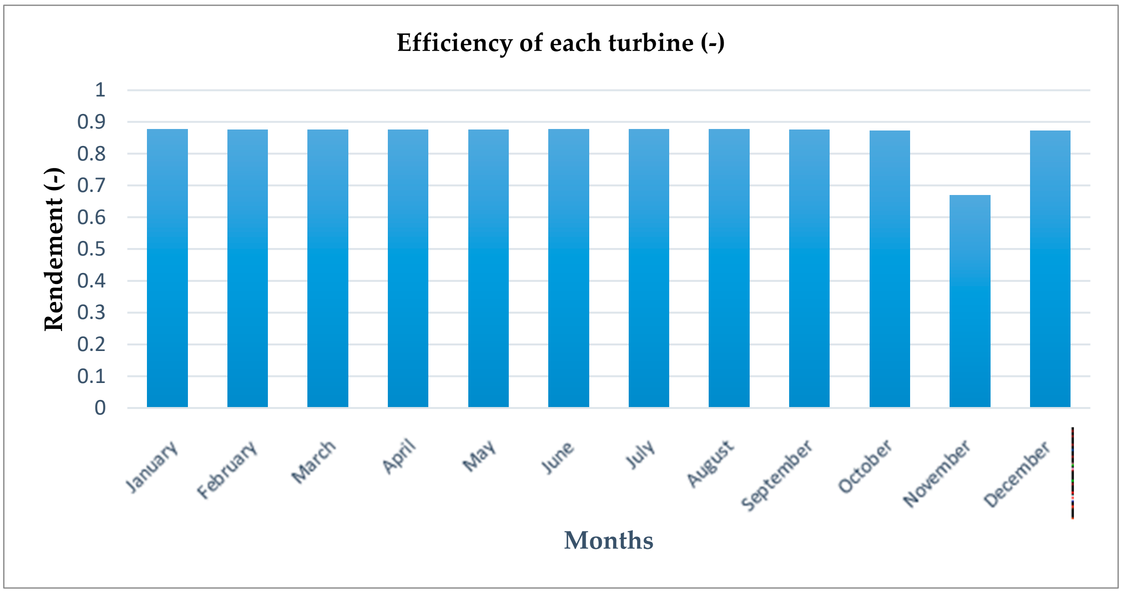
**Figure 13.** *Cont*.




(b)

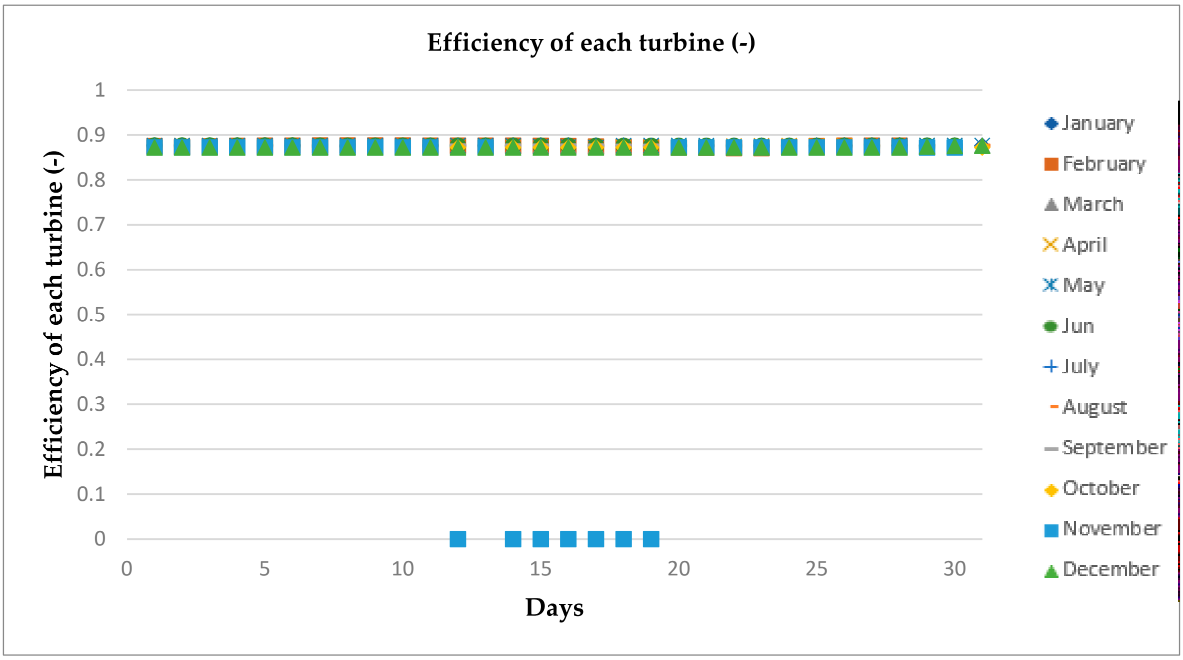
**Figure 13.** (**a**) Average monthly lost flow rates histogram and (**b**) average daily lost flow rates curve.

In general, the energy efficiency of the system is quite good, even if the values of certain energy criteria do not emphasize it sufficiently. The water exploitation index shows, for example, that the configuration proposed by our model exploits approximately 78.04% the available flow rates; the rest is lost due to the constraints linked due to not only to the maximum turbine operating flow rate, but also to the safety flow rate. The value of the energy production index is only 56.47% due to the large quantity of lost flow rates presented above and the head losses. The value of the load index is only 51.32% not only because there are periods during which the plant is shut down, but also because the plant uses its four turbines simultaneously only 111 days per year. During this period the plant operates at full capacity 85 days per year, due to the fact that on the rest of the days of the year either the exploitable flow rates are not high enough to trigger the startup of the four turbines, or they are greater than the safety flow rate.

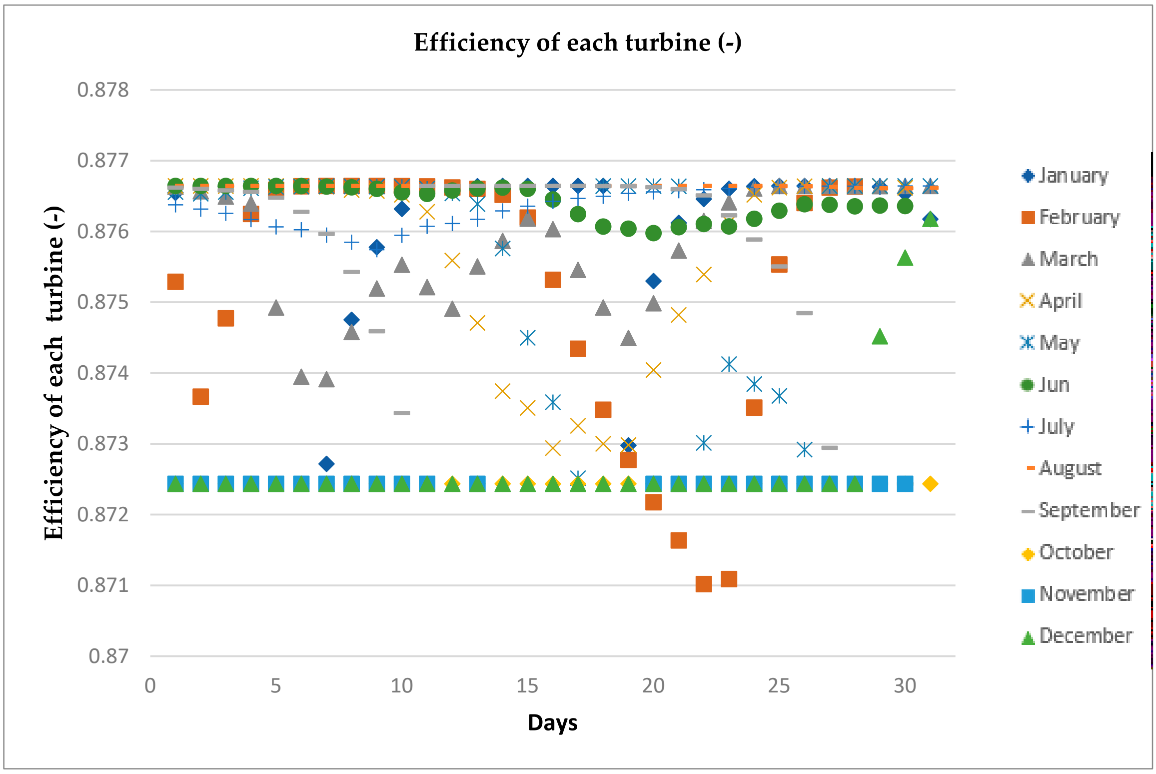



(a)

**Figure 14.** *Cont.*




(**b**)




(**c**)

**Figure 14.** (**a**) Average monthly turbine efficiency histogram and (**b**,**c**) average daily turbine efficiency curve.

**Table 14.** Energy criteria.

| Energy Criteria | |
| --- | --- |
| Total installed capacity (MW) | 6.32 |
| Productible (GWh) | 28.42 |
| Water exploitation Index (%) | 78.04 |
| Energy production Index (%) | 56.47 |
| Average efficiency of the turbines over the year (-) | 0.88 |
| Load Index (%) | 51.32 |

### 4.4. Economic Analysis of the Optimal System

Table 15 details the different costs of the optimal run-of-river hydroelectric system proposed in this study. The minimum LCOE (0.05 USD/kWh) obtained here remains in the range (0.05–0.12 USD/kWh) as per Table 16 of the LCOE for hydroelectric projects with a power of less than 10 MW as presented in the special report of the IPCC (Intergovernmental Panel on Climate Change) [60]. In the same way, according to IRENA [53], the small hydropower projects have an average LCOE of 0.05 USD/kWh. Therefore, the proposed configuration allows one to have robust LCOE estimations in alignment with other studies in the literature.

**Table 15.** Economic criteria.

| Economic Criteria | |
| --- | --- |
| LCC (MUSD) | 11.37 |
| LCOE (USD/kWh) | 0.0502 |
| Net Present Value (MUSD) | 11.30 |
| Payback period (years) | 5 years 2 months |
| Cost of civil works (MUSD) | 2.13 |
| Cost of electromechanical equipment (MUSD) | 3.13 |
| Miscellaneous and indirect cost (MUSD) | 1.09 |
| Initial investment cost (MUSD) | 5.94 |
| Replacement cost over the lifetime project (MUSD) | 3.54 |
| Total investment cost over the lifetime project (MUSD) | 9.48 |
| Operation and Maintenance cost per year (MUSD) | 0.237 |

In addition, by taking an energy price of 0.1 USD/kWh (or about 55 F CFA/kWh), the payback period is about 5 years and 2 months for the project (assuming a lifetime of 50 years) with a Net Present Value of 11.3 MUSD (approximately 6.1 billion CFA Francs). As according to ESHA [42], a small hydro project should have a payback period of less than 7 years to be considered profitable; therefore, the proposed configuration makes the project sufficiently profitable.

**Table 16.** General values of LCOE for hydropower projects [60].

| No. | Investment Cost (IC) ($USD_{2005}$/kW) | O&M Cost (% of IC) | Capacity Factor (%) | Lifetime (Years) | Discount Rate (%) | LCOE (cents/kWh) | Comments |
|---|---|---|---|---|---|---|---|
| 1 | <500–6200<br>Median 1650<br>90% below 3250 | | 41–61 | | | | 2155 Projects in USA<br>43,000 MW in total<br>Annual Capacity factor (except Rhode Island) |
| 2 | <500–4500<br>Median 1000<br>90% below 1700 | | 55–60 | | | | 250 Projects for commissioning 2002–2020<br>Total Capacity 202,000 MW<br>Worldwide but mostly Asia and Europe |
| 3 | 1000–3500<br>700–8000 | | 35–60<br>20–90 | | | 2–10<br>2–12 | Large Hydro<br>Small Hydro (<10 MW)<br>(Not explicitly stated as levelized cost in report) |
| 4 | 2184 | 2.5 | 45 | 40 | 10 | 7.1 | |
| 5 | 1000–5500<br>2500–7000 | 2.2–3 | | | 10<br>10 | 3–12<br>5.6–14 | Large Hydro<br>Small Hydro |
| 6 | 2880 in 2010 | 4 | 45 | 40 | 10 | 10.4 | |
| 7 | 2440 | | | | 6 | 7.3 | Study applies to Germany only |
| 8 | 1000–5500 | 4 | 33 | 30 | | 9.8 | Indicative average LCOE year 2000 |
| 9 | 750–19,000 in 2010 (1278 average) | | 51 | 80<br>80 | | 2.3–45.9<br>4.8 | Range for 13 projects from 0.3 to 18,000 MW<br>Weighted average for all projects |
| 10 | | | | | | 5–12<br>3–5<br>5–40 | Small Hydro (<10 MW)<br>Large Hydro (>10 MW)<br>Off-Grid (<1 MW) |

## 5. Conclusions and Future Scope

The objective of this study is to provide a model for the optimal sizing and techno-economic optimization of a small run-of-river hydroelectric power plant connected to an existing electricity network. This work focuses on the optimal design of the diameter and thickness of the penstock; the selection and optimal location of a turbine; the estimation of the production of electrical energy; and the estimation of the costs of a small run-of-river hydroelectric power plant, without pondage, when connected to an existing electricity network.

The study applies the model on a case study of the river Nyong in Mbalmayo. The results show that the optimal system is energy efficient, with efficiency beyond 87%, and successfully converts about 78% of the exploitable flow rates of the stream into electricity; however, the flow rates fluctuate significantly, between 31.71 $m^3$/s and 325.75 $m^3$/s. Moreover, these results show that the proposed configuration is also very cost effective as its LCOE is around 0.05 USD/kWh (which is the lowest limit for the interval of LCOE for small hydropower plants as presented in the report of the IPCC). Its Net Present Value is USD 11.3 billion, or about 6.1 billion CFA Francs, assuming an energy price of 0.1 USD/kWh (or about 55 F CFA/ kWh), and its payback time is about 5 years 2 months—when it must be less than 7 years to be considered profitable according to ESHA— assuming a lifespan of 50 years.

This study is expected to provide a solid base for scholars and developers who are interested in developing preliminary feasibility studies for run-of-river hydropower plants in Sub-Saharan Africa, which are expected to be an important source of energy (especially for rural areas) with limited drawbacks. As for future works, it would be interesting to extend the analysis to estimate the hydropotential in the Central African context in order to propose a more reliable cost estimate model for small run-of-river hydroelectric plants. A second possible consideration for this work is to extend the analysis beyond a single hydropower plant, therefore combining multiple energy sources (e.g., a photovoltaic system) and/or a storage system, to meet the electrical energy needs of a population in isolated areas. In the end, the methodology developed in this study could lead to an optimal design tool for small hydro systems with a graphical user interface to ease its use by developers.

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