# FEASIBILITY STUDY OF A HYDROPOWER FACILITY IN EASTERN ANGOLA

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## ABSTRACT

The increasing demand in the energy sector and global energy needs, determined by the growth of the world's population and socio economic development, is considered by many experts as an opportunity for the definition and implementation of a sustainable energy model, which enables energy access to all potential users in a perspective of rational and efficient use of the available energy resources. Among the renewable energy technologies used worldwide, hydropower plays a major role being the most used renewable energy source at the moment.

In Angola there is a great abundance of this natural resource and a great potential in the hydropower sector, which is not yet developed. In the country there is also a great deficit in what concerns the available energy per capita. In this master thesis, it is presented a feasibility study of a hydropower facility in the Eastern Angola, one of the most deprived areas in terms of access to energy. The hydropower facility is supposed to supply the city of Saurimo, the capital of the Lunda Sul province, that has an estimated population of about 200 000 inhabitants.

The present study includes an analysis of the Chiumbe River, in all its extents inside the Angolan boarders, in order to determine the best possible location to build a hydropower facility. After the selection of the best location, an optimization of some of the parameters of the facility is made, as well as a pre-study and primarily analysis on floods, hydraulic structures, equipment's and construction materials. Also a preliminary estimative of the quantities and works associated with the construction of the facility is elaborated, as well as an economic analysis, for the best location in the Chiumbe River to construct a hydropower facility, and also for the more adequate configuration.

**Keywords**: Angola, Saurimo, Chiumbe River, hydropower facility, feasibility study.

## INTRODUCTION

The future projections for the growth of the world's population and the expected socio-economic development determine, among other aspects, an increase in global energy needs. This increasing demand in the energy sector is considered by many experts as an opportunity for the definition and implementation of a sustainable energy model, which enables energy access to all potential users in a perspective of rational and efficient use of the available energy resources. The predictions of several analysts suggest that the fossil fuels will continue, in the medium term, to be the predominant source of energy. However, the global paradigm of energy dependence on fossil fuels and the associated global problems determine considerable challenges to sustainability, in terms of investment in alternative technologies (GEA 2012). Among the renewable energy technologies used worldwide, hydropower plays a major role being the most used renewable energy source at the moment.

In Angola there is a great abundance of water resources and a great potential in the hydropower sector, which is not yet developed. In the country there is also a great deficit in what concerns the available energy per capita. A widespread access to energy is a fundamental condition for economic growth and development of the country, being that in the next years the actions performed by the Angolan Government in the energy sector will be directed to an expansion of the electricity network to the entire territory, with the purpose of using, in a sustainable and integrated manner, the unique natural features available in Angola, resulting in a suitable combination of different energy sources supported in new technologies. These actions are expected to improve the efficiency of the energy sector and the quality of living of the populations.

Considering the importance of the energy sector to Angola, it was launched the challenge towards the development of a feasibility study for the implementation of a hydroelectric facility in Angola, more precisely in the Chiumbe River basin. The Chiumbe River is located along the provinces of Lunda Norte and Lunda Sul, in northeast of Angola, one of the most deprived areas in terms of access to energy, within the Angolan territory. Therefore, the aim of this study is to define, along the Chiumbe River, the best location and optimal configuration, from a technical and economic point of view, to build a hydropower facility with an installed capacity of 100 MW, which should be able to supply the city of Saurimo, the capital of Lunda Sul that has an estimated population of 200 000 inhabitants.

The present study includes: an analysis of the Chiumbe River, in all its extents inside the Angolan boarders as well as comparative analysis between possible locations, in order to determine the most adequate to build a hydropower facility; an analysis of the reservoir and available water resources, with the objective of optimizing some of the parameters of the facility; a pre-study and primarily analysis on floods, hydraulic structures, equipment's and construction materials; development of a preliminary bill of quantities associated with the construction of the facility; the definition of a timetable for the construction works and finally an economic analysis, for the best location and optimal configuration, with the objective of determining if the facility in study will be profitable.

## ROLE OF HYDROPOWER IN RENEWABLE ENERGY SOURCES

To evaluate the importance and the role of renewable energy sources in the global energy market, as well as the percentage for the main technologies in this sector, the latest REMIPEG (Renewable Energy Market, Installed Power and Annual Electricity Generation) report from 2014, was taken into consideration (Renewable Energy Focus 2014).

This report presents an overview on the status of the renewable energy market through the end of 2013. According to the report, the total energy consumption worldwide in 2013 was about 170 PWh (Petawatts hour 1PWh = $10^{15}$ Wh). In the same year, the total electricity generation worldwide was about 23 PWh, which represents almost 14 % of the total annual energy generation. From this 23 PWh, 22 %, so more a less 5 PWh, are produced using renewable energy sources with a total installed capacity of 1 658 GW. The 5 PWh of electricity generated annually using renewable energy sources, represent 3 % of the total energy consumption worldwide, in that same year (Kleineidam et al. 2014). The values observed follow the trends verified in the last decade. As said before, in this period the demand for renewable energy sources has been increasing as a result of environmental policies and economic related factors.

| Renewable Energy Type | Cumulated Installed Capacity in 2013 [GW] | % of the Market Worldwide [%] | New Installed Capacity in 2013 [GW] | Growth of Cumulated Installed Capacity [%] | Estimated Electricity Generation in 2013 [TWh/year] |
|---|---|---|---|---|---|
| Hydropower | 1103.8 | 66.6% | 39.9 | 5% | 3704.9 |
| Windpower | 315.7 | 19.0% | 35.5 | 13% | 683.0 |
| Solar PV | 134.7 | 8.1% | 36.3 | 41% | 140.6 |
| Solar CSP | 3.8 | 0.2% | 1.2 | 56% | 6.8 |
| Biomass | 88.0 | 5.3% | 4.3 | 5% | 308 - 616 |
| Geothermal | 12.0 | 0.7% | 0.5 | 4% | 73.0 |
| World Total | 1658.0 | 100% | 117.7 | 21% | 4916.4 - 5224.4 |

**Table 1** – Worldwide installed capacity of renewable energy sources and estimated annual energy generation in 2013, as well as the percentage of each energy technology in the Global energy market

| Region | Cumulated Installed Capacity 2013 [GW] | Installed Capacity 2013 [GW] | Estimated Electricity Generation 2013 [TWh/year] |
|---|---|---|---|
| North America | 194.1 | 2.2 | 728.4 |
| South America | 142.7 | 2.4 | 643.9 |
| Europe | 240.7 | 2.9 | 657.7 |
| Asia | 484.6 | 32.4 | 1512.8 |
| Oceania | 14.2 | 0.0 | 41.4 |
| Africa | 27.6 | 1.0 | 120.7 |
| World Total | 1103.9 | 40.9 | 3704.9 |

**Table 2** – Summary of the Global Hydropower Market in 2013 and installed capacity in 2013 in each continent

In what concerns the renewable energy technologies, hydropower leads the pack representing more than three times the cumulated capacity of the second largest contributor, the wind power, as it is presented in Table 1. Also, the major projects created in 2013 (installed capacity in 2013) were in the hydropower sector. In Table 2 it is possible to observe the importance of hydropower in each continent, which is larger in Asia than in the remaining ones. Despite the fact that in Africa and Oceania, hydropower is almost the only renewable energy source used at the moment, these continents present the lowest values of installed capacity and energy generation from hydropower, as it possible to observe in Table 2.

## CONTEXT IN ANGOLA

### Geography

Angola is an African country with an estimated population of 24.14 million inhabitants, according to the World Bank in 2014. Angola is located in the western Atlantic coast of southern Africa. The total area is estimated at 1 246 000 km2, 7 680 of which form the northern coastal province of Cabinda, isolated from mainland Angola. To the north, Cabinda is bordered by the Republic of Congo and to the east and the south by the Democratic Republic of Congo. The mainland Angola is bordered to the north and northeast by the Democratic Republic of Congo, to the east by Zambia, and to the south by Namibia, while the western border is formed by the Atlantic Ocean, as it is presented in the Figure 1.

The Angolan territory is characterized by the extensive plateau areas of the interior and by the intense reliefs in the central area near the city of Huambo that descends to the Atlantic Ocean. A noticeable characteristic in the Angolan territory is the almost complete absence of natural lakes in its river system, mainly because it's a phenomenon that frequently occurs in Southern Africa. The river system of Angola is divided into five main drainage basins: the river basins of Western Angola composed by the Kwanza and Cunene river basins; Cuvelai; Congo; Okavango and finally the Zambezi River Basin.

**Figure 1** – Angola's boundaries and some of its main cities

### Climate

The climate in Angola is generally tropical, tempered by the sea, but it varies considerably with the altitude. Its geographical location, morphology and the cold Benguela current are the three main factors that determine the climate characteristics in the country. The climate is more humid in the north region and drier in the south as well as near the coast. Like the rest of tropical Africa, Angola experiences distinct, alternating rainy and dry seasons with precipitation close to zero in the summer.

The highest values of mean annual rainfall occur in the north and northeast regions of the country, although at any latitude they tend to increase from the cost to the interior and in altitude. In these regions the annual precipitation varies between 1 400 mm and 1 700 mm. In what concerns the temperature, along the country, it tends to fall with distance to the equator and with altitude. On the other hand, it rises with the proximity to the Atlantic Ocean. The lowest values of mean annual temperature are verified in higher altitudes of the interior. Near Luanda, the average annual temperature is close to 26°C, but it is under 16°C near Huambo on the temperate central plateau.

## Economy

Angola's economy is replete with contrasts and contradictions. On the one hand, with its abundance of natural resources, the country has been registering record levels of growth; on the other hand it remains one of the poorest countries in Africa. On paper Angola's potential is noticeable. In 2008, the country surprised many when it temporarily overtook Nigeria as Africa's biggest oil producer. Its GDP has been in double figures for the several years over the last decade. The countries oil sector is booming and interest in its diamond-mining potential is reported to have reached record-breaking levels. Infrastructure development projects have also been thriving, with roads, bridges and railways being restored at an incredible speed. Unsurprisingly, foreign interest in Angola with respect to all these sectors is intensifying and the outlook seems very bright for Angola (African Business 2012).Yet Angola's economic progress is precarious and it remains one of the poorest countries in the world. The richest fifth of the population holds almost two thirds of the country's total wealth. This whole scenario raises suspicions of corruption levelled at the country's government.

Angola is also a recovering economy, its infrastructure, production and labor pool were left almost annihilated after the long period of civil war that lasted for 27 years, causing more than 1.5 million deaths and internally displacing more than four million citizens (which represent one third of Angola's total population at the time). In some ways, the determination with which Angola has bounced back since the conflict has been remarkable. In other ways, there have been some serious rehabilitation failures. All of this makes it tricky to elaborate the economic analysis of the country. Both delusive optimism, infused with utopian visions of Angola standing alongside South Africa and Nigeria as an African superpower, and gloomy despair that Angola is yet another African country doomed to be defined by poverty and corruption are depending on what figures are invoked (African Business 2012).

Considering the traumas that the country's economy has been exposed to in the recent past, its current growth level is all the more impressive. In 2005, Angola has experienced an economic "boom". It has moved from the disarray caused by a quarter of century of war to being the second fastest growing economy in Africa and one of the fastest in the world. Its GDP growth rate was 18 % in 2005 and it would rise above 20 % in the following years, 2006 and 2007. Such growth has been overwhelming due to Angola's exports of its most lucrative natural resource: oil. The government has invested heavily in oil exploitation and infrastructure in order to boost production and capacity. In the last years the foreign interest in Angola has been increasing. China, in particular, has been pumping millions into the country in form of loans and credit lines in an attempt to gain favored access to Angola's oil reserves. Such financial assistance has mainly focused on public investment projects in infrastructures, agriculture and telecommunications.

Yet, the drawbacks of Angola's reliance on revenues from oil exports became clear during the global crisis of 2008-2009, when slowing demand from oil-consuming countries caused a huge reduction of the average price per barrel. This being said, any projections when it comes to Angola's GDP growth prospects for the years to come are inevitably volatile, being ultimately connected to the variations of the oil prices

In many ways Angola has a long way to go. Take the country's agricultural sector. Before the war Angola was self-sufficient in almost all food crops and exported various products, including banana, tobacco, sisal and maize. It was also the fourth largest coffee producer in the world. At the moment, a large proportion of food is imported and only 10 % of the country's cultivable land is being used for agriculture. Probably the most challenging task that Angola faces over the next years is creating a skilled labor pool. The overall proportion of skilled workers is very low, according to the OECD and the implications that this has in terms of boosting non-oil aspects of the economy and encouraging foreign firms to invest in both industry and agriculture is massive.

## Energy Matrix and Objectives for the Near Future

Angola does not present a well-developed energy panorama. This comes as an impeditive factor for the economic development in the country and improvement of the populations living conditions. Inefficient organization, insufficient infrastructures and distribution systems make it almost impossible to satisfy the population's energy needs.

In 2011, according to the US Energy Information Administration (eia), the main primary energy sources in Angola were solid biomass & waste (55 %), petroleum (33 %), hydropower (7 %) and natural gas (5 %).

The fact that the Angolan economy is overly dependent on oil caused the emersion of an action plan with medium and long term results (NEW ANGOLA'S ENERGY STRATEGY). The main goal of this plan is to quadruple the existing energy supply, by making the best possible use of the endogenous resources and allocating the most efficient technologies.

For this reason, it is expected that the Angolan energy matrix suffers severe changes, including a strong growth in production and consumption of renewable energy through hydropower, wind and geothermal plants. Thus, the energy matrix will tend to be increasingly more balanced and sustainable, regarding the energy sources used in the country. Concerning the hydropower sector, for 2017 the objective is to increase the annual average energy consumption per capita in Angola in order to match the African consumption in 2007 (640 kWh/inhabitant/year). For 2025, the goal is to catch up with the emerging countries annual average consumption of 2 000 kWh per inhabitant, which represents an increase of 8 500 MW in the country's installed capacity since 2010, as it is presented in Figure 2.

As already explained, in recent years the economic development of Angola has been pronounced. Major investments in infra-structuring the country were made, particularly in buildings, hospitals and roads but as well as in the water and energy sectors, namely in terms of production, transport and distribution. In large cities the energy demand has increased significantly and is considerably higher than energy supply. The country's electrification rate is currently about 30 %, and is expected to reach 60 % in 2025, supported on heavy investments in building new power plants and distribution networks and also in the rehabilitation of infrastructure and equipment already existing (Stauber 2014).

### Hydroelectric Potential

Angola has an estimated hydropower potential of 150 000 GWh/year, of which 80 000 GWh/year is the average energy and 65 000 GWh/year is considered to be firm and feasible potential, in Kwanza, Catumbela and Cunene river basins. This hydropower potential represents 18 000 MW of potential installed capacity (Hydropower and Dams 2013).

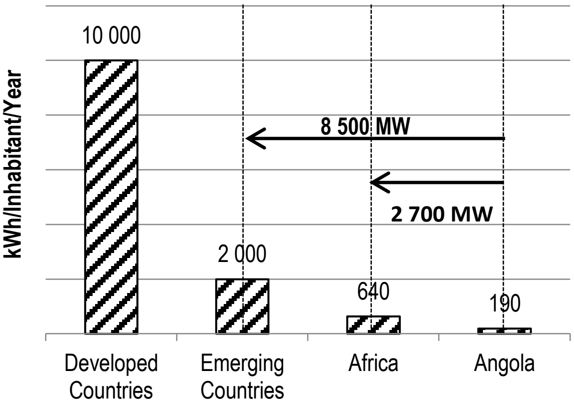


**Figure 2** – Objectives regarding the energy consumption per capita in Angola for the next years

In 2011, Angola generated about 5.5 million kWh with an estimated installed capacity of 1 700 MW, of which, around 60 % was contributed by hydropower facilities. So, until now, Angola has only exploited about 4 % of its hydropower potential. From the 5.5 million kWh of energy generated, coming from hydro and fossil fuel sources, more than 70 % (almost 71 %) was generated at the country's hydroelectric facilities, primarily from hydroelectric dams on the Kwanza , Catumbela, and Cunene Rivers (Hydropower and Dams 2013).

### Electric System and Current Installed Capacity

The Angolan national electric system is divided into five independent groups (Figure 3): Cabinda (A); Northern System (B); Central System (C); Southern System (D) and finally the Eastern System (E), which includes the provinces of Lunda Norte and Lunda Sul, where the Chiumbe River develops. In 2013 there was a pattern of low installed capacity available per capita, in all the five groups. Southern and Eastern systems presented the lowest installed capacity available per capita, in all five groups (0-10 W/capita) and the Northern System presented the highest (95 W/capita). In 2013 the national average available power was about 40 W per inhabitant.

In 2015 a small increase was verified in each group, but the most market increases were in groups (A) and (B), as it is represented in Figure 3.8. In this year the average available power per inhabitant was 101 W, being that groups (C), (D) and (E) are far below the average in that year. For 2017 it is expected an increase of the available power per capita in all groups that will raise the national average to 192 W per inhabitant, although the increase will be smaller in Group E and significantly higher in the Northwest Angola (groups (B), (C) and (D)), as presented in Figure 3.9. For group (A) it is not predicted any increase between 2015 and 2017. Finally in the years after 2017 it is predicted a major increase in the available power per capita, raising the total available power to 786 W per inhabitant. The increments per sector are presented in Figure 3.10. There will also be made improvements in the national electric grid in order to allow energy transfers from the center region to the south and eastern regions. This being said, the systems will be independent but connected between themselves.

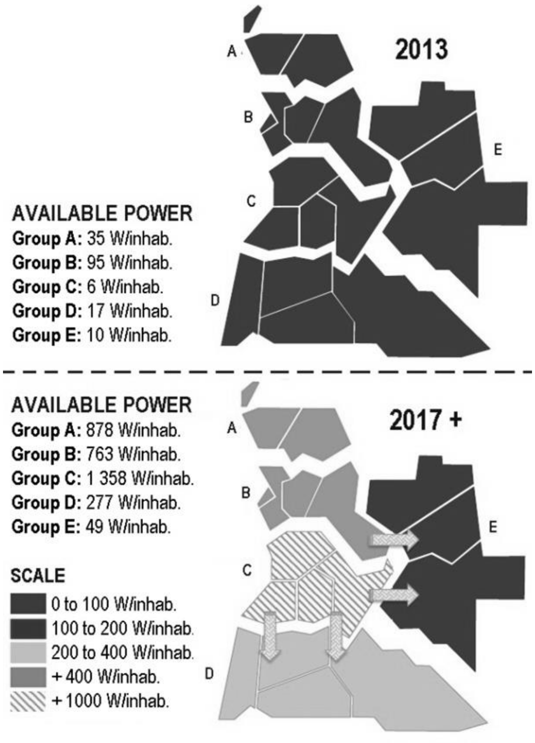


**Figure 3** – Objectives regarding the energy consumption per capita in Angola for the next years (Steiger-Garção and Reis 2013)

At the moment, the major hydropower facilities existing in Angola are:

- Cambambe: an arch concrete dam located in the Kwanza River, with an installed capacity of 780 MW;
- Capanda: a concrete gravity dam located in the Kwanza River, with an installed capacity of 520 MW;
- Lomaum: located in the province of Benguela, in the Catumbela River and with an installed capacity of 37 MW;
- Gove: an embankment dam in the Cunene River, in the province of Huambo and with an installed capacity of 60 MW;
- Matala: located in the Cunene River, in the province of Huila with an installed capacity of 40 MW
- Luachimo: located in the Luachimo River, in the province of Lunda Norte with an installed capacity of 36 MW;
- Chicapa: located in the Chicapa River, in the Lunda Norte province with an installed capacity of 18 MW;
- Chiumbe-Dala: a run-off-river type facility located in the province of Lunda Sul, in the Chiumbe River, with an installed capacity of 12 MW;

It is desirable to increase the use of other energy resources to produce electricity, although the contribution of hydropower production tends to be higher in the coming years. The major contributions will be from Cambambe II, which will have an increase of the total installed of 700 MW. Also from the construction of three major hydropower facilities, which are Laúca, a RCC dam already under construction in the Kwanza River that will have a total installed capacity of 2070 MW; Caculo Cabaça also in the Kwanza River, which is predicted to have an installed capacity of 2047 MW and finally Catumbela that will provide a major increase after the predicted construction works.

**Base Data**

The input data that was needed for this study was, in a first stage, topography information and hydrology data. For the topography information, besides Google Earth (that was considered in parallel with the other topography information) a numerous of elevation datasets are available online and for this study two of those datasets were used:

- Raster elevation data from the project Advanced Spaceborn Thermal Emission and Reflection Radiometer (ASTER), Global Digital Elevation Model Version 2 (GDEM V2). (https://reverb .echo .nasa.gov Date: 4/10/2014);
- SRTM version 2 (Shuttle Radar Topography Mission V2) elevation data, (http://earthexplorer.usgs.gov / Date: 4/10/2014);

The lack of information was heavily noted when searching for hydrological data. Nevertheless some information was obtained:

- Satellite precipitation: a 0.25 per 0.25 degree squares with precipitation series from the first of January 1998 to the 31 of December of 2013 that covered the whole region of the case study. The series of precipitation is composed by daily values and was provided by José Pedro Matos in the product TRMM 3B42 v7a (Matos 2014), which aggregated the data to daily values.
- Specific discharge data found in a document by the Norwegian Water Resources and Energy Directorate, in three hydrometric stations close to the Chiumbe River basin (Bjoru 2004).
- Runoff data from a hydrometric station in the Kasai River basin, obtained from the GRDC (Global Runoff Data Center) website (GRDC n.d.).

In a more advanced phase of the study, more topographic information was obtained from Google Earth and using the PlexEarth software, as well as discharge measurements in the Chiumbe River, which was a series of mean monthly discharge values in the station of Dala.

## CASE STUDY AND RESULTS

### Stage 1: Screening of Possible Locations

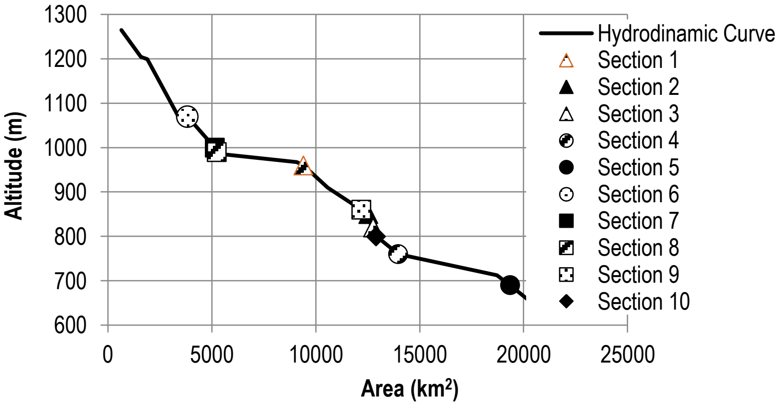
1st Loop: Definition of Possible Locations

The site location for a hydropower facility is mainly conditioned by head and flow requirements, since these are the parameters that mostly influence the power potential and consequently the energy output. In a preliminary stage, the hydroelectric potential of the river is taken into account as well as the quantity of works and cost estimation associated with each possibility, more specifically each of the locations considered.

In a first stage it was made the definition of the Chiumbe River Basin as well as the definition of main water courses using the Quantum GIS software and freeware elevation data from ASTER and SRTM. Then it was made an analysis of the topography, namely the river's longitudinal profile. Also a characterization of the basin was made and the topics covered were the hydrographic network, the geomorphological characteristics, the soil coverage and vegetation, the soil typology and finally the climate. The Chiumbe River Basin has a total area of 2 0649.7 km$^2$. The length of the main water course from the source till it reaches the border between Angola and the Democratic Republic of the Congo is 682.6 km, with a maximum altitude of 1 370 m and a minimum altitude of 640 m. The main soil types in the basin are Arenosols (63 %) and Ferralsols (35 %), with some traces of Gleysols. The soil coverage is mainly characterized by grassland savanna and deciduous forest (woodland savanna). Regarding the climate, the mean annual precipitation is very similar in the entire basin, although it slightly increases from the south to the north. The mean annual values of precipitation vary between 1 300 mm and 1 400 mm. The mean annual temperature increases with proximity to the equator. The yearly variations are more marked in the south than they are in the north of the basin, where temperatures are very similar the entire year. The coolest months are June and July and lower values of temperature occur during the dry season, a typical behaviour of tropical hot humid climate.

Finally it was made the definition of the alternatives, which was made in two stages: in a first screening the sections with higher natural topographic difference in the less possible length were searched for. This parameter is very important since it will increase the net head for the same dam height, which means more power generation. In the second screening, the goal was to find locations with more attractive cross sections, which means higher bank slopes and less volume for the dam, as well as a smaller length of the dam's crest. The result is a group of 10 sections, placed in very distinct locations and with very different drainage areas associated. A representation of these sections in a hydrodynamic curve (Figure 4) was elaborated, allowing a different perspective when comparing the sections and an idea of the increasing hydropower potential from each section to the other. In Figure 5 is made their representation in the basin.

**Figure 4** – Representation of the 10 sections in the hydrodynamic curve



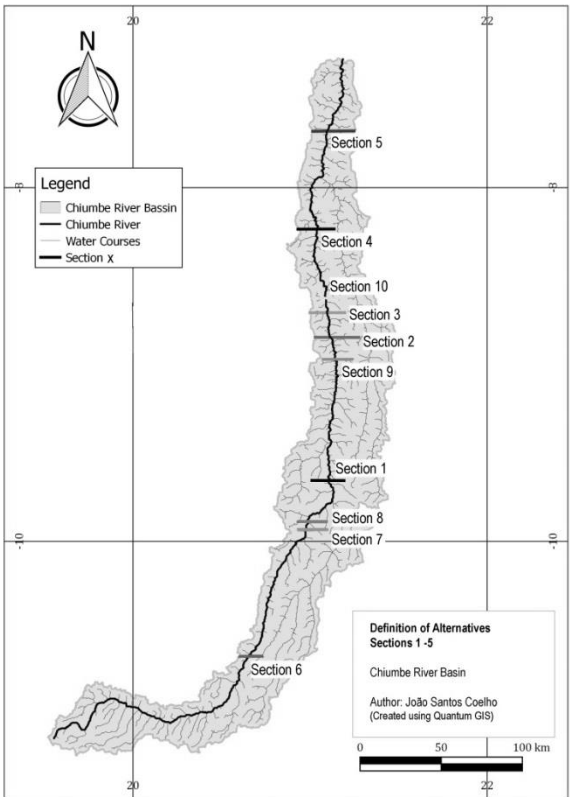


**Figure 5** –Possible sections in the Chiumbe River Basin

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2nd Loop: Comparison of Alternatives

First it was made the characterization of the different alternatives, namely: the physiographic characteristics of each catchment area controlled by each section; the possible location for the power plant and the topographic difference in relation to the dam; the distance to Saurimo and the accesses needed to create (Table 3)

Then, the transversal profiles in each section were determined as well as the dam volumes and lengths of the dam's crest associated with different dam heights. To calculate the dam volumes a typical concrete cross section was considered and a model in excel was defined. The depth *vs.* volume and depth *vs.* area curves were also defined for each section, using the Quantum GIS software.

Once the characterization of alternatives was finished, it was made an analysis of the available water resources for energy production.

First the rainfall values were obtained for each catchment area. The values obtained were the mean monthly values and the mean daily values, for each of the 13 years of the series. To convert these values into runoff, a runoff coefficient was calibrated. This was made using the discharge measurements from the hydrometric station described in the base data and the specific discharge values from the other three hydrometric stations. The runoff coefficient was compared with typical values for the same soil groups and similar characteristics of the watershed, namely the slope and soil coverage. The value was fixed in 0.21. Based on the runoff coefficient and the precipitation data, the flow duration curves were obtained for each section, as well as the mean annual affluent volumes. These are presented in Table 4.

| **Section ID** | | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Coordinates | Longitude | 21° 06' 36.00'' E | 21° 06' 53.10'' E | 21° 05' 42.00'' E | 21° 02' 09.98'' E | 21° 07' 13.03'' E | 20° 39' 00.00'' E | 20° 58' 40.80'' E | 20° 59' 09.60'' E | 21° 08' 29.40'' E | 21° 05' 24.00'' E |
| | Latitude | 09° 39' 24.37'' S | 08° 50' 48.30'' S | 08ª 42' 32.40'' S | 08° 14' 09.23'' S | 07° 38' 37.37'' S | 10° 39' 21.60'' S | 09° 55' 48.00'' S | 09° 52' 58.80'' S | 08° 57' 30.24'' S | 08° 38' 48.84'' S |
| Physiographic characteristics | Basin area (km$^2$) | 9412 | 12536 | 12767 | 13974 | 19351 | 3820 | 5149 | 5249 | 12192 | 12907 |
| | Main water course (km) | 332.4 | 444.3 | 463.2 | 528.3 | 615.6 | 182.7 | 286.9 | 292.5 | 428.9 | 471.3 |
| | Altitude (m) | 960 | 850 | 820 | 770 | 690 | 1070 | 1010 | 1000 | 860 | 807 |
| | Mean slope (%) | 0.12 | 0.12 | 0.12 | 0.11 | 0.11 | 0.16 | 0.13 | 0.13 | 0.12 | 0.12 |
| Power Plant location | Altitude (m) | 940 | 830 | 800 | 760 | 680 | 1070 | 1000 | 990 | 860 | 800 |
| | Lenght from the source (km) | 334.7 | 449.3 | 465.7 | 530.6 | 615.8 | 183.0 | 288.1 | 292.9 | 429.0 | 471.6 |
| | Topographic difference (m) | 20 | 20 | 20 | 10 | 10 | 0 | 10 | 10 | 0 | 7 |
| Conveyance system | Lenght (m) | 3.06 | 6.49 | 3.27 | 3.06 | 0.29 | 0.37 | 1.60 | 0.52 | 0.08 | 0.48 |
| | Head losses (m) | 6.13 | 12.98 | 6.53 | 6.12 | 0.58 | 0.75 | 3.19 | 1.04 | 0.17 | 0.97 |
| Connections | Distance to Saurimo (km) | 78 | 119 | 129 | 173 | 236 | 114 | 71 | 70 | 111 | 135 |
| | Total of accesses (km) | 22.1 | 63.7 | 54.6 | 5.2 | 19.5 | 62.4 | 16.9 | 11.7 | 71.5 | 54.6 |

**Table 3** – Characterization of sections

| **Section ID** | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** |
|---|---|---|---|---|---|---|---|---|---|---|
| Mean annual precipitacion (mm) | 1328 | 1328 | 1327 | 1331 | 1339 | 1320 | 1321 | 1321 | 1328 | 1328 |
| Mean Annual Discharge 90 % (m$^3$/s) | 46.6 | 64.6 | 66.0 | 73.9 | 104.5 | 17.1 | 24.7 | 25.3 | 62.5 | 66.9 |
| Mean Annual Discharge - $Q_{mod}$ (m$^3$/s) | 83.2 | 110.8 | 112.8 | 123.9 | 172.6 | 33.6 | 45.3 | 46.2 | 107.8 | 114.1 |
| Discharge 90 days (m$^3$/s) | 115.8 | 158.8 | 161.9 | 181.9 | 255.7 | 43.6 | 61.9 | 63.2 | 153.9 | 164.2 |
| Discharge 140 days (m$^3$/s) | 48.9 | 74.0 | 75.8 | 85.0 | 125.9 | 14.7 | 25.2 | 26.0 | 71.4 | 76.6 |
| Discharge 180 days (m$^3$/s) | 16.4 | 27.2 | 28.2 | 35.4 | 55.2 | 3.5 | 7.5 | 7.9 | 25.7 | 29.1 |
| Mean annual affluent volume (hm$^3$) | 2625.1 | 3495.0 | 3558.8 | 3906.3 | 5442.5 | 1058.8 | 1428.5 | 1456.1 | 3400.9 | 3598.4 |

**Table 4** – Available water resources for energy production in each section

After this analysis, the reservoir volumes necessary to turbinate a certain equipped discharge were determined. To do so, the mean affluent volume curves in each section, as well as the accumulated turbinated volumes curve, had to be calculated.

Depending on the value of the equipped discharge, the turbines can work more or less days per year, so that in the end of the year the accumulated turbinated volume is equal to the accumulated affluent volume, which means that the balance in the reservoir is equal to zero. The turbinated volumes are calculated considering different values of equipped discharge in order to have a wide range of comparative values, for the same section and between different sections. The values of equipped discharge considered were the discharge exceeded 180 ($Q_{180}$), 140 ($Q_{140}$) and 90 ($Q_{90}$) days per year, as well as the mean annual discharge ($Q_{mod}$).

Finally, based on the estimated reservoir volumes and on the depth *versus* volume curves, the dam heights necessary to integrate those volumes were determined in a way that the dam's height generates a reservoir volume bigger than the one estimated before, in an iterative calculation process. In Table 5 it is presented necessary reservoir volume, the associated dam height and the number of days a year the turbines are working, for each section and for each value of equipped discharge considered.

As observed in the table, the smaller the equipped discharge, the lower will be the turbinated volume and consequently the necessary reservoir volume. Lower reservoir volumes implicate smaller dam heights. For these cases, and when turbining with the same equipped discharge the whole year, there is not being taken advantage of all the affluences. As a consequence the spillage volume is bigger and volume that could be turbinated might be wasted.

| Parameter | | **Section ID** | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** |
| Necessary Reservoir Volume (hm$^3$) | $Q_{180}$ | 128 | 216 | 224 | 286 | 434 | 22 | 56 | 60 | 203 | 232 |
| | $Q_{140}$ | 518 | 779 | 798 | 885 | 1286 | 147 | 266 | 274 | 752 | 804 |
| | $Q_{mod}$ | 1034 | 1324 | 1344 | 1447 | 1922 | 425 | 567 | 577 | 1294 | 1355 |
| | $Q_{90}$ | 1411 | 1797 | 1825 | 2011 | 2769 | 573 | 783 | 796 | 1758 | 1839 |
| Minimum dam height (m) | $Q_{180}$ | 16 | 13 | 20 | 14 | 26 | 5 | 3 | 11 | 8 | 23 |
| | $Q_{140}$ | 31 | 24 | 34 | 27 | 39 | 14 | 12 | 19 | 21 | 37 |
| | $Q_{mod}$ | 42 | 29 | 42 | 34 | 45 | 22 | 19 | 26 | 29 | 44 |
| | $Q_{90}$ | 48 | 33 | 47 | 39 | 51 | 25 | 24 | 31 | 33 | 50 |
| Number of days working (days/year) | $Q_{100}$ | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| | $Q_{60}$ | 262 | 255 | 254 | 249 | 246 | 281 | 267 | 266 | 256 | 254 |
| | $Q_{mod}$ | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |
| | $Q_{91}$ | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 | 365 |

**Table 5** – Reservoir characterization for each section and different values of equipped discharge

Finally the cost estimation was elaborated for the implementation of the hydropower facility in each section. The parameters considered in this analysis were: the accesses, the connection to Saurimo (medium tension lines), the construction materials, the conveyance system, the deforestation and the cost of equipment's. To calculate the costs, the quantities calculated were majored in 30 %, to account for possible errors and uncertainties in the base data, and a list of unitary prices was defined, which is presented in Table 6. The quantities described are presented for each section in Table 7 and the cost estimation for each of the quantities as well as the total cost of the facility for each alternative are presented in Table 8 and Table 9, respectively.

| Parameter | Unit rate |
|---|---|
| Transmission lines (USD/m) | 100 |
| Accesses (USD/m) | 400 |
| Concrete (USD/m$^3$) | 60 |
| Steel (USD/kg) | 6 |
| Escavations (USD/m$^3$) | 25 |
| Deforestation (USD/km$^2$) | 250 |
| Engeneering (%) | 10 |

**Table 6** – Comparative costs

As it is noticeable in Table 8, there is a big disparity between the different alternatives and also between the different sections considered. This is mainly due to the topography in the regions of each cross section, which influences the dam volumes, the distance to Saurimo and to the nearest accesses, the possible locations for the power plant that are directly connected to the conveyance system length and finally the cost of the equipment's, which is related to the installed capacity that is dependent of the discharge and net head.

The parameters taken into consideration when comparing the different alternatives were the total cost estimated for the facility, the length of the dams crest as well as its volume and finally some indicators, which were obtained for the 10 sections and different values of equipped discharge that allowed a more visual and detailed comparison between the sections. To obtain these indicators, the net head, the installed capacity and the energy generated per year were calculated for each alternative and are presented in Table 10.

| **Section ID** | | **1** | **2** | **3** | **4** | **5** | **6** | **7** | **8** | **9** | **10** |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Dist. Saurimo (km) | | 101.4 | 154.7 | 167.7 | 224.9 | 306.8 | 148.2 | 92.3 | 91 | 144.3 | 175.5 |
| Total accesses (km) | | 22.1 | 63.7 | 54.6 | 5.2 | 19.5 | 62.4 | 16.9 | 11.7 | 71.5 | 54.6 |
| Dam volume (×10$^3$ m$^3$) | $Q_{180}$ | 71 | 137 | 301 | 178 | 1379 | 8 | 4 | 13 | 15 | 94 |
| | $Q_{140}$ | 278 | 484 | 1207 | 583 | 3161 | 39 | 24 | 42 | 86 | 384 |
| | $Q_{mod}$ | 543 | 714 | 2025 | 910 | 4313 | 93 | 57 | 94 | 164 | 711 |
| | $Q_{90}$ | 728 | 985 | 2722 | 1179 | 5565 | 124 | 97 | 140 | 219 | 1069 |
| Lenght of the dam's crest (m) | $Q_{180}$ | 1020 | 2531 | 4307 | 2295 | 8993 | 252 | 125 | 363 | 391 | 753 |
| | $Q_{140}$ | 1453 | 4065 | 6660 | 3038 | 10420 | 613 | 463 | 608 | 726 | 1190 |
| | $Q_{mod}$ | 1725 | 4738 | 9205 | 3380 | 10826 | 825 | 629 | 821 | 900 | 2947 |
| | $Q_{90}$ | 1871 | 5416 | 10141 | 3587 | 11267 | 898 | 747 | 979 | 986 | 5429 |
| Reservoir area (km$^2$) | $Q_{180}$ | 13 | 23 | 22 | 29 | 41 | 3 | 8 | 8 | 22 | 25 |
| | $Q_{140}$ | 35 | 59 | 55 | 62 | 87 | 12 | 30 | 29 | 58 | 55 |
| | $Q_{mod}$ | 54 | 95 | 85 | 92 | 116 | 30 | 44 | 45 | 88 | 83 |
| | $Q_{90}$ | 68 | 119 | 101 | 117 | 146 | 40 | 53 | 56 | 109 | 113 |
| Reservoir Volume (hm$^3$) | $Q_{180}$ | 130 | 224 | 230 | 298 | 467 | 23 | 66 | 76 | 203 | 257 |
| | $Q_{140}$ | 530 | 839 | 800 | 920 | 1305 | 153 | 299 | 287 | 756 | 829 |
| | $Q_{mod}$ | 1066 | 1384 | 1378 | 1536 | 1992 | 440 | 573 | 590 | 1360 | 1360 |
| | $Q_{90}$ | 1478 | 1893 | 1864 | 2083 | 2776 | 632 | 839 | 841 | 1807 | 1926 |

**Table 7** – Reservoir characterization for each section and different values of equipped discharge

| Section ID | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Con. to Saurimo (USD*$10^6$) | | 10.1 | 15.5 | 16.8 | 22.5 | 30.7 | 14.8 | 9.2 | 9.1 | 14.4 | 17.6 |
| Accesses (USD*$10^6$) | | 8.8 | 25.5 | 21.8 | 2.1 | 7.8 | 25.0 | 6.8 | 4.7 | 28.6 | 21.8 |
| Dam cost (USD*$10^6$) | $Q_{180}$ | 4.3 | 8.2 | 18.1 | 10.7 | 82.8 | 0.5 | 0.3 | 0.8 | 0.9 | 5.6 |
| | $Q_{140}$ | 16.7 | 29.1 | 72.4 | 35.0 | 189.6 | 2.3 | 1.5 | 2.5 | 5.2 | 23.0 |
| | $Q_{mod}$ | 32.6 | 42.9 | 121.5 | 54.6 | 258.8 | 5.6 | 3.4 | 5.7 | 9.9 | 42.6 |
| | $Q_{90}$ | 43.7 | 59.1 | 163.3 | 70.7 | 333.9 | 7.4 | 5.8 | 8.4 | 13.1 | 64.1 |
| Deflorestation cost (USD*$10^6$) | $Q_{180}$ | 0.003 | 0.006 | 0.005 | 0.007 | 0.010 | 0.001 | 0.002 | 0.002 | 0.006 | 0.006 |
| | $Q_{140}$ | 0.009 | 0.015 | 0.014 | 0.016 | 0.022 | 0.003 | 0.007 | 0.007 | 0.014 | 0.014 |
| | $Q_{mod}$ | 0.013 | 0.024 | 0.021 | 0.023 | 0.029 | 0.007 | 0.011 | 0.011 | 0.022 | 0.021 |
| | $Q_{90}$ | 0.017 | 0.030 | 0.025 | 0.029 | 0.036 | 0.010 | 0.013 | 0.014 | 0.027 | 0.028 |
| Total cost of the equipment (USD*$10^6$) | $Q_{180}$ | 5.0 | 6.5 | 7.5 | 7.5 | 12.0 | 0.1 | 1.0 | 1.7 | 3.0 | 7.0 |
| | $Q_{140}$ | 12.5 | 15.0 | 22.5 | 17.5 | 35.0 | 3.5 | 6.0 | 6.5 | 12.0 | 19.0 |
| | $Q_{mod}$ | 24.0 | 27.0 | 33.0 | 33.0 | 45.0 | 7.5 | 9.5 | 10.5 | 24.0 | 34.0 |
| | $Q_{90}$ | 38.0 | 39.0 | 47.0 | 45.0 | 57.0 | 9.0 | 13.5 | 14.5 | 37.0 | 47.0 |

**Table 8** – Cost estimation for each section and different values of equipped discharge

| Section ID | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Total cost (USD*$10^6$) | $Q_{180}$ | 31.1 | 61.2 | 70.6 | 47.0 | 146.6 | 44.4 | 19.0 | 17.9 | 51.7 | 57.2 |
| | $Q_{140}$ | 53.0 | 93.5 | 146.9 | 84.7 | 289.4 | 50.2 | 25.8 | 25.1 | 66.2 | 89.6 |
| | $Q_{mod}$ | 83.1 | 121.9 | 212.5 | 123.4 | 376.5 | 58.1 | 31.8 | 32.9 | 84.6 | 127.6 |
| | $Q_{90}$ | 110.7 | 153.0 | 273.9 | 154.4 | 472.4 | 61.8 | 38.9 | 40.4 | 102.5 | 165.6 |

**Table 9** – Total cost of the facility for each alternative

| Section ID | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Conduit lenght (km) | | 3.1 | 6.5 | 3.3 | 3.1 | 0.3 | 0.4 | 1.6 | 0.5 | 0.1 | 0.5 |
| Energy losses (m) | | 6.1 | 13.0 | 6.5 | 6.1 | 0.6 | 0.7 | 3.2 | 1.0 | 0.2 | 1.0 |
| Net head (m | $Q_{180}$ | 29.9 | 20.0 | 33.5 | 17.9 | 35.4 | 4.3 | 9.8 | 20.0 | 7.8 | 28.6 |
| | $Q_{140}$ | 44.9 | 31.0 | 47.5 | 30.9 | 48.4 | 13.3 | 18.8 | 28.0 | 20.8 | 42.6 |
| | $Q_{mod}$ | 55.9 | 36.0 | 55.5 | 37.9 | 54.4 | 21.3 | 25.8 | 35.0 | 28.8 | 49.6 |
| | $Q_{90}$ | 61.9 | 40.0 | 60.5 | 42.9 | 60.4 | 24.3 | 30.8 | 40.0 | 32.8 | 55.6 |
| Installed capacity (MW) | $Q_{180}$ | 3.9 | 4.4 | 7.6 | 5.1 | 15.7 | 0.1 | 0.6 | 1.3 | 1.6 | 6.7 |
| | $Q_{140}$ | 17.6 | 18.4 | 28.9 | 21.1 | 49.0 | 1.6 | 3.8 | 5.8 | 12.0 | 26.2 |
| | $Q_{mod}$ | 37.4 | 32.1 | 50.3 | 37.7 | 75.5 | 5.7 | 9.4 | 13.0 | 25.0 | 45.5 |
| | $Q_{90}$ | 57.6 | 51.1 | 78.7 | 62.7 | 124.2 | 8.5 | 15.3 | 20.3 | 40.6 | 73.4 |
| Energy generation (GWh/year) | $Q_{180}$ | 34.4 | 38.4 | 66.5 | 44.5 | 137.7 | 1.1 | 5.2 | 11.1 | 14.1 | 58.6 |
| | $Q_{140}$ | 154.6 | 161.5 | 253.4 | 184.8 | 429.2 | 13.7 | 33.3 | 51.1 | 104.7 | 229.8 |
| | $Q_{mod}$ | 327.4 | 281.0 | 440.7 | 330.3 | 661.1 | 50.2 | 82.3 | 113.6 | 218.9 | 398.5 |
| | $Q_{90}$ | 362.6 | 312.2 | 480.4 | 373.9 | 734.0 | 57.3 | 98.2 | 129.9 | 249.2 | 446.7 |

**Table 10** – Calculation of the net head, installed capacity and energy generation per year

For the comparison of the different alternatives, the cost per installed capacity, the cost per energy generated per year and the MW of installed capacity per km$^2$ of reservoir area were calculated. The referred comparative indicators are presented in the graphics of Figure 6. The objective in this phase is to differentiate the best sections from the total of sections considered, in a first screening. In a second screening the same type of comparison is made with more values of equipped discharge for the sections still remaining after the first screening.

By evaluating the values obtained, there is a big difference between the cost indicators for the alternatives with $Q_{180}$ and $Q_{140}$ to the other two. This happens in every section and more evidently in sections 6 and 7.

Faced with this situation, these two alternatives were rejected because the equipped discharge would be to low and the power generated would not compensate, when compared with alternatives associated with higher equipped discharges.

By analyzing the graphs in figure 6 and the quantities in Table 7, it's easily noted that section 6 stands out as being the worst of the considered sections in terms cost per benefits. The alternatives for sections 2, 3, 4 and 5, in addition to having associated very large crest lengths, which probably would not be feasible, present very high costs per installed capacity and GWh per year, which are not competitive with the remaining sections (not including section 6). In section 5 it would be possible to achieve the objective of 100 MW of installed capacity, although this solution does not seem to be possible due to the dimension of the construction works. At the same time the equipped discharge is very high and thus the HPP could only work for a limited number of days per year. By analyzing the remaining sections, the two best sections are sections 1 and section 8, since they present the less cost per GWh of energy generated per year and the less cost per MW of installed capacity.

By analyzing the indicators presented, it is easily noted that the cost per installed capacity decreases as the equipped discharge increases, which makes sense since the installed capacity is higher and the cost of having a bigger dam and more expensive equipment's does not increase in proportion. On the other hand the cost per GWh generated per year increases with the increase of the equipped discharge from $Q_{mod}$ to $Q_{90}$, since the number of days that the turbines work is lower and consequently the energy generated per year decreases, despite the increasing in the installed capacity.

Also, regarding the MW per km$^2$ of reservoir, section 1 reveals itself to be one of the best, along with section 5. On the other hand, section 8 presents' lower values than the ones described. Of course that the higher this indicator is the better, since lower reservoir areas represent less cost and less potential problems, for example with expropriations and occupancy of territory or reallocations for the affected population.

Another important aspect to take into consideration regarding sections 1 and 8 is the difference between their installed capacity, energy generation per year and estimated total cost of the facility. It is evident that section 1 generates more or less the triple of the energy than section

8, but costs almost three times more. This is why the indicators are similar. Nevertheless, in terms of power, energy and investment the order of magnitude of the values is much different from one section to another. Given this situation it was decided to continue the study for both of these sections, removing the rest of the sections from the picture, and considering more values of equipped discharge. After this second screening, section 1 was considered to be the best location in the Chiumbe River for the construction of a hydropower facility.

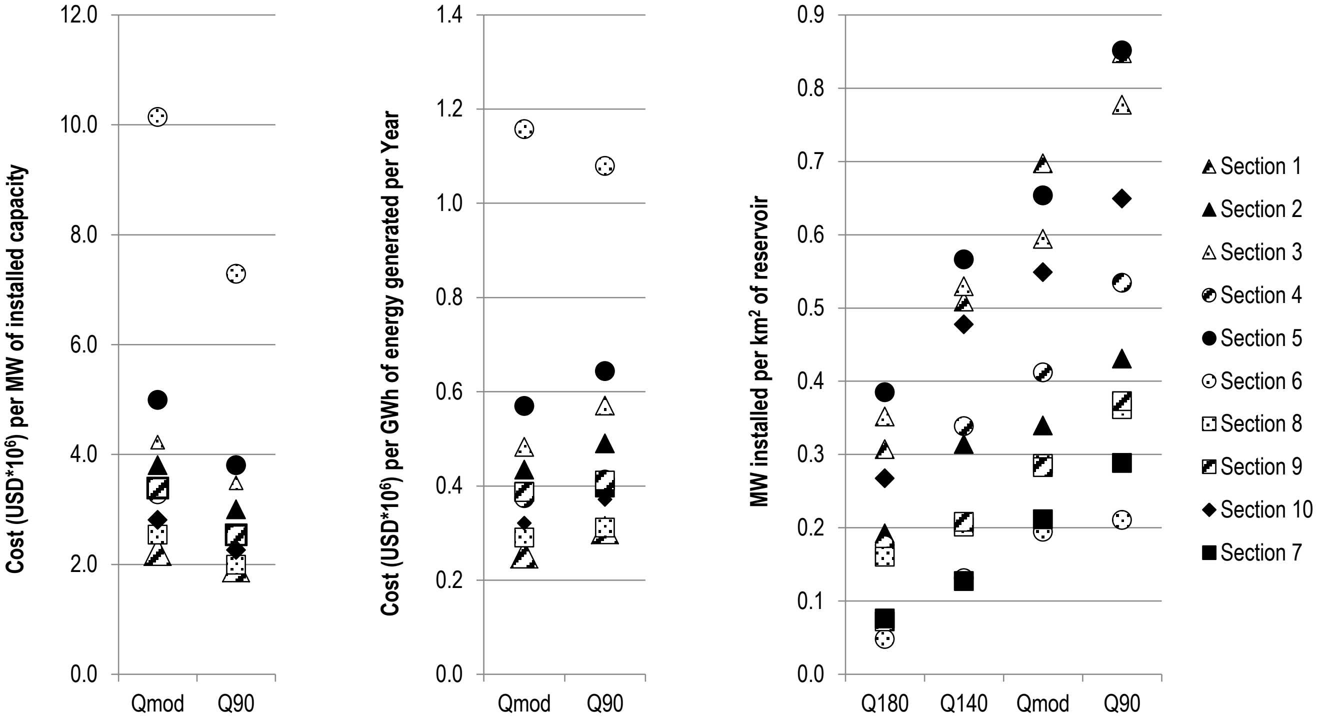

**Figure 6** - Cost per installed capacity, the cost per energy generated per year and the MW of installed capacity per km$^2$ of reservoir area for each alternative

### Stage 2: Feasibility Study of the Selected Option

Reservoir Analysis

At this phase of the study more information on runoff for the Chiumbe River basin was obtained, as explained in the topic of the base data. This information regarding the water resources was used from this point on in all the studies. The flow duration curve was extrapolated from the Dala station to section 1, using a relation between the drainage areas and the mean monthly discharge values, as well as the mean affluent volumes were obtained in section 1. The mean affluent volumes per month were the ones used in the reservoir analysis.

To analyze the reservoir, a model was created to make a balance in the reservoir considering the inputs and outputs in each month. The parameters considered in the balance for this model were: the inflows, the evaporation in the reservoir, the ecologic discharge and the turbinated volume. The model was defined in a way that the inputs are the inflows, which are constant in each month, and the evaporation, which is a constant value per area (mm/km$^2$) in each month. The parameters that are optimized are the equipped discharge, the dam height and the number of machines (turbines), being the model fully automatized for the remaining parameters (The depth volume curve and the depth area curve were adjusted to polynomial functions in order to optimize the process of obtaining the reservoir area and volume at different levels).

For the reservoir analysis, different scenarios were considered, which are presented in the following topics:

- Scenario 1 (C1): One turbine working 365 days per year;
- Scenario 2 (C2): Don’t turbinate in June, July, August and September with only one machine;
- Scenario 3 (C3): Don’t turbinate in two of the dryer months of the year. This scenario considers three hypothesis: don´t turbinate in July and September (C3.1), don´t turbinate in June and August (C3.2) and don’t turbinate in August and September (C3.3);
- Scenario 4 (C4): Don’t turbinate in August;
- Scenario 5 (C5): Equip a discharge that allows a reaching the installed capacity of 100 MW. The number of days that the turbines are working will be fixed in a way that the turbinated volume does not surpass the inflows;
- Scenario 6 (C6) and 7 (C7): In August and September, turbinate only part of the discharge;
- Scenario 8 (C8): Considering a dam height of 80 meters allowing a higher installed capacity. One turbines working the entire year and the equipped discharge is fixed in a way that the reservoir level is the same in the beginning and in the end of the year;
- Scenario 9 (C9): Use two turbines the entire year and two times a year, for small periods of time, only one of the turbines is working in order to allow reparations if needed. The months when the turbines will be stopped were optimized in order to maximize the energy gains;

- Scenario 10 (C10): The same as scenario 9 but with three turbines;
- Scenario 11 (C11): Use two turbines with one of them working with Q/Qmáx = 20 %. Two hypotheses were considered: one where one of the turbines only works with Q/Qmáx = 20 % from May to September (C11.1) and one where it happens during the whole year (C11.2);
- Scenario 12 (C12): Use two turbines with one of them working with Q/Qmáx = 40 %. Two hypotheses were considered: one where one of the turbines only works with Q/Qmáx = 40 % from May to September (C12.1) and one where it happens during the whole year (C12.2);
- Scenario 13 (C13): Use two turbines with one of them working with Q/Qmáx = 60 %. Two hypotheses were considered: one where one of the turbines only works with Q/Qmáx = 60 % from May to September (C13.1) and one where it happens during the whole year (C13.2);

The objective when modelling the reservoir was to maximize the energy gains by turbining the maximum volume without exceeding the inflows. So the main goal was to guarantee the initial live storage in the first month of the next year after the "simulated year" and at the same time not to use the spillway in order to avoid wasting water that could be used to generate energy.

Turbining with lower values of Q/Qmáx, as it happens with C11, it is possible to equip higher discharge values (since one of the turbines uses less amount of water, hence there is more water available), on the other hand the energy generated will be lower.

Scenarios C11.1, C12.1 and C13.1 consider that one of the turbines works with Q/Qmáx lower than 1 from May to September wherein scenarios C11.2, C12.2 and C13.2 consider that only one of the turbines is working at its full capacity during the entire year. The difference relies on the fact that with the first three scenarios (C11.1, C12.1 and C13.1) the energy generation is higher and with the last three scenarios (C11.2, C12.2 and C13.2) the installed capacity is higher because the turbines consume less water at the end of the year and it is possible to equip higher discharge values. Of course that, regardless of the chosen scenario, the facility can be operated in different ways depending upon the situation and more importantly the energy needs. Q/Qmáx can increase or decrease and the percentage of time during the year that both the turbines work at full capacity can also change, in order for the facility to adapt to the city's needs.

Finally it was studied the possibility of a runoff river facility, in order to compare the indicators and to see if there is the need to have a reservoir associated with this facility. Even before this analysis, the indicators will probably be more attractive with the reservoir since the discharge values in the Chiumbe River vary a lot through the year and the reservoir allows an annual regulation: storing water in the rainy season and then discharge it in the dry season, allowing to turbinate with a fixed discharge and a constant energy supply throughout the entire year. The reservoir reduces the dependence on the variability of the inflow, being that the facility is not totally dependent on the affluences.

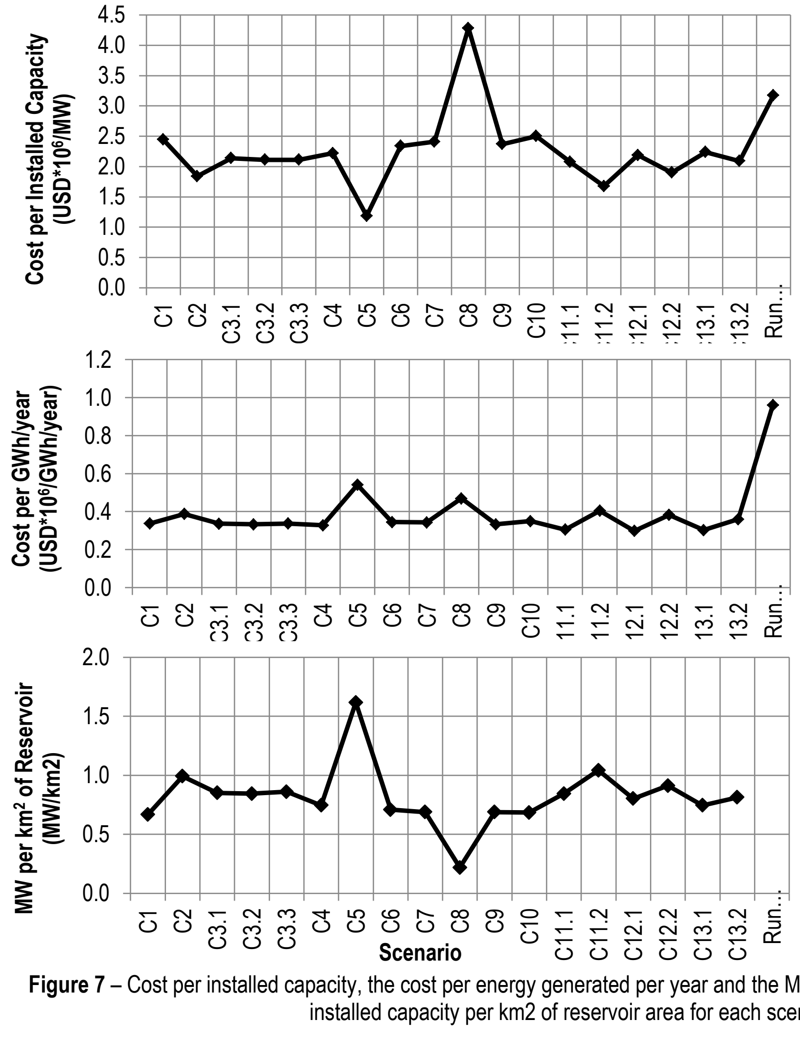

**Figure 7** – Cost per installed capacity, the cost per energy generated per year and the MW of installed capacity per km2 of reservoir area for each scenario

After the reservoir analysis, the indicators already used in the previous analysis were once again calculated for each scenario. These indicators and the power and energy generated per year are presented in Figure 7 and Figure 8. By analyzing these figures main conclusions were:

- Scenario C8 is the one that allows more energy gains. On the other hand has an associated dam height of 80 m that results in a very big length for the dam's crest and enormous dam volume when compared with other solutions;
- The run of river possibility reveals very low values of energy production when compared to the other solutions. Also in terms of installed capacity it's not a very interesting solution;
- Despite the fact that scenario C5 presents the second bigger dam height of all the scenarios, it is still the one that presents the lower cost per installed capacity. The major problem with this scenario is that it can only work for a limited number of days per year and in specific months, so it is not a very good solution when the objective is to supply a city;
- The remaining scenarios show similar values for the considered indicators. Although, based on the elements analyzed so far and on the analysis made individually, scenarios C11, C12 and C13 are the best solutions since they present the best values for the indicators and with these scenarios there is always one turbine working, assuring the supply to the city. C12.1, which corresponds to having one of the two turbines working at 40 % of its full capacity during five months, has associated the lowest cost

per GWh generated per year and C11.2, that is the same as C12.1 but during the whole year and with the turbines working at 20 % of their capacity, corresponds to the lowest cost per MW of installed capacity;

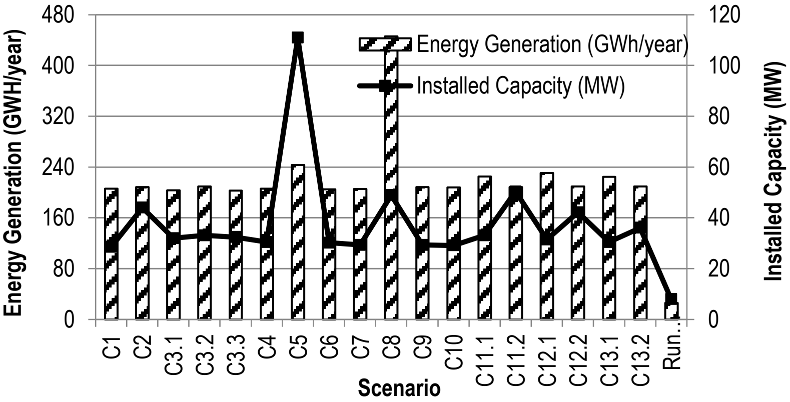

**Figure 8** – Energy generation and Installed capacity for each scenario

Also, it is not possible to create a HPP in the Chiumbe River with an installed capacity of 100 MW that consists in a feasible project. As shown in this analysis, in order to achieve such a value one of two consequences are going to occur: either the cost of the facility is so big, with enormous and unfeasible construction works associated that it does not compensate the investment when compared to other solutions; or the facility would have to be equipped with very high values of discharge, meaning it could only work a few months per year. Since the objective is to constantly supply the city of Saurimo along the year and not to fulfil peak demands in some periods, this is not a feasible solution. The only way to achieve the 100 MW would be by studying the possibility of constructing several small hydropower facilities in the Chiumbe River basin that, all together, could reach this value.

Faced with these conclusions, it was decided to select scenario C12.1, which means equipping two turbines with a discharge of 38 m$^3$/s, a net head of 46.9 m, with one of them working from May to September at 40 % of its capacity, and the other one working at its full capacity the entire year. As already referred, regardless of the chosen scenario the facility can be operated in different ways depending upon the situation. The relation between the discharge that the turbine is working with and the equipped discharge (Q/Qmáx) can increase or decrease and the percentage of time during the year that both the turbines work at fully capacity can also change, in order for the facility to adapt to different situations.

Scenario C12.1 presents an installed capacity of 31.4 MW. Considering this value and assuming that the objective of the facility would be only to supply the city of Saurimo, there would be "31.4×1 000 000/200 000=157 W/inhabitant", which is higher than the national average predicted for 2015 and equal to about 100 W/inhabitant, which means that about 11.4 MW could be used to supply the Catoca mining society, located near Saurimo. It should also be noted that the objective for after 2017 is to have an available power per capita equal to 49 W/inhabitant in group E (where Lunda Norte and Lunda Sul are included) so the facility in study with scenario C12.1 allows to achieve this value with a big margin.

After deciding the best scenario and configuration for the facility, it was analyzed the concept of firm energy. Firm energy is the amount of energy guaranteed to be available at a given time. The definition of firm energy of a hydro plant is often dictated by the system requirement for such guaranteed energy. Typically, firm energy from a hydro power plant may be defined as the energy that could be generated by the plant during low flow sequences. Mean energy is an estimate of average annual energy production of a hydro power plant if historical river flows were repeated. The estimate is derived by simulating proposed plant operation using historical flows.

To calculate the firm energy, it was made a reservoir analysis with the scenario C12.1 for each of the nine years of data (instead of using the average values as it was made before when comparing the different scenarios) and the total annual energy generation was calculated. The value considered for the firm energy was the minimum annual energy generation from nine year long series of data, which corresponds to the driest year of the series. The value corresponds to 188.8 GWh and it is safe to assume that it as a probability of occurrence of about 89 % (1-1/9). The mean energy corresponds to the energy generation calculated with the series of mean affluent volumes, which is 230.6 GWh. This is illustrated in Figure 9.

The difference between mean energy and firm energy is called secondary energy, or non-firm energy, and is particularly important in the design and negotiation of power contracts. Non-firm energy refers to all available energy above and beyond firm energy. Energy benefits of both firm and non-firm energy are measured in terms of the fuel and other variable operating costs that would otherwise be required to produce that amount of energy by the least expensive technically feasible alternative.

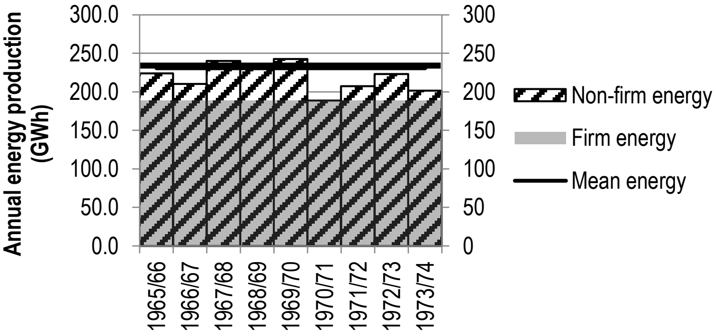

**Figure 9** – Firm energy

Construction Materials

The selection of the dam type is highly dependent on the geology and topography of the location, on the type and location of the hydraulic structures and on the cost of construction. In this chapter the geology of the location was first analyzed in order to determine whether or not it is possible to build a concrete dam since the foundation conditions can difficult this process, and also if there are available resources near the construction site that can be used as construction materials. To analyze the construction materials, the geology and the soil types were taken into consideration.

According to the geology map, the superficial formation lays on a siliceous sandstone layer, although in the region of section 1, it lies directly on the formations of the substrate. These formations are from the archaic period and include gneisses, granites, migmatites, gabbros, quartzites, schists and some granite-migmatite complexes. The granites, gabbros and gneisses are plutonic rocks that evolve, normally from schists, during a slow metamorphic process at a considerable depth. These rocks form crystals during a chemical process and present a very high mechanical resistance. Migmatites are similar to granites but are characterized by higher foliation. The schists have an accentuated foliation, which considerably reduces their resistance in the weaker direction of the rock. Finally the quartzites, which evolve initially from sands, are characterized for being very resistant and abrasive. They also present considerably good mechanic performance.

If the conditions described before, are verified and if after a more detailed analysis the costs do not increase considerably, a concrete gravity dam seems to be a good solution. The volume of materials associated with an embankment dam is normally higher than it is in a concrete dam, on the other hand the cost of concrete per cubic meter is higher than the cost of the materials used in the an embankment dam, which are available in the case study region, so the second solution is normally cheaper. Nevertheless in a concrete dam it is easier to allocate the hydraulic structures.

Flood Analysis

First it was made a physiographic analysis and calculation of the concentration time for the catchment area in study. For the flood analysis the satellite precipitation values were used, since the series is longer and the maximum values are higher. First the maximum precipitation in 24 hours (P24) was determined for each year of the 16 years-long series of data. Then a statistical Gumbel law was adjusted to this series. The χ2 adjustment test was used and the values revealed an acceptable approximation.

After the adjustment, the values of maximum daily precipitation were determined for different return periods, based on the Gumbel law. The return periods considered were 20, 50, 100 and 1000 years. Then the udometric curves were calibrated, for the return periods described, which is presented in Figure 10.

Once the udometric curves were obtained, the precipitation hyetographs were calculated for each of the return periods. These hyetographs were defined for durations equal to the concentration time (tc) and double the concentration time (2tc) of the hydrographic basin defined by section 1. The blocks were defined with a duration D of two and four hours for the tc and 2tc, respectively so, for each hyetograph there are 35 blocks.

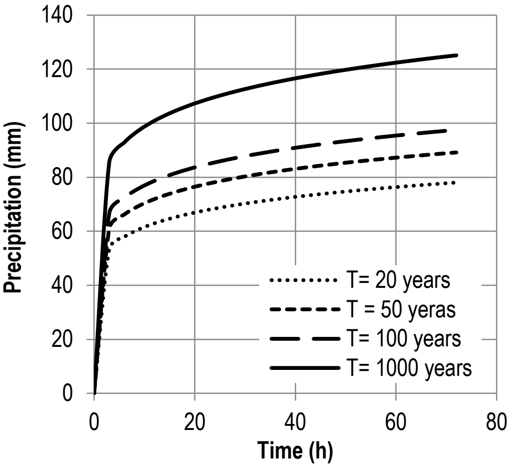

**Figure 10 –** Udometric curves for section 1 and different return periods

Regarding the precipitation hyetographs, the higher the number of blocks for the same duration of the rainfall considered, the higher will be peak discharge, since the maximum intensity of precipitation (mm/h) is also higher. The consideration of an alternate distribution for the precipitation blocks, results in higher values of peak discharge. Considering the same amount of blocks for hyetographs with the durations of tc and 2 tc, the first one is associated with more severe values of peak discharge and the second one in higher volumes of flood. So in order to calculate the spillway, the hyetograph with the duration of tc should be used.

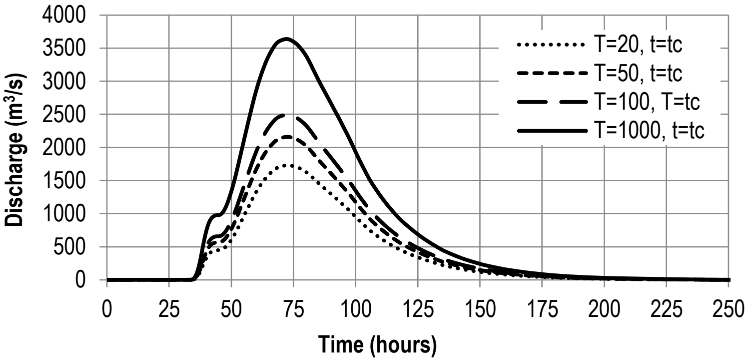

**Figure 11 –** Flood hydrographs for section 1 and different return periods

With the hyetographs concluded, the flood analysis was made using the HEC-HMS software. For the catchment area in study, three sub-basins were defined and the respective concentration times were calculated. It is important to separate the sub basins since they have considerably different concentration times and areas, being that this will influence the peak discharge values. The flood hydrographs are presented in figure 11.

Hydraulic Structures

The decisions regarding the displacement of the main hydraulic structures and the type of the dam are presented in the following topics. A schematic representation is also made in Figure 12:

- Dam type: It was considered a mixed dam, which is composed by rockfill embankment dam on the sides of the valley and a central part composed by concrete. This allows a simple allocation of the hydraulic structures in the center of the dam, and at the same time the costs of construction are expected to be lower since the embankment materials are less expensive than the concrete. The central part of the dam was considered to be a typical gravity dam;
- Spillway: It was considered over the dam with guided fall and an energy dissipation structure. The length of the spillway will be the same as the length of the concrete part of the dam;
- Water intake and Bottom outlet: Were considered to be located in the dam's body on the left side of the spillway;
- Conveyance system: It's composed by a steel conduit, a tunnel in concrete and a penstock, with the layout made in a straight line. The adduction system was considered to have always the same slope and at this stage the water hammer was not considered;
- Powerhouse: Located at an altitude of 940 m;

In order to calculate the spillway it was first considered the flood weakening in the reservoir. This was made using HEC_HMS, for a return period of 1000 years. For the spillway, different lengths were tested as it is presented in Table 11.

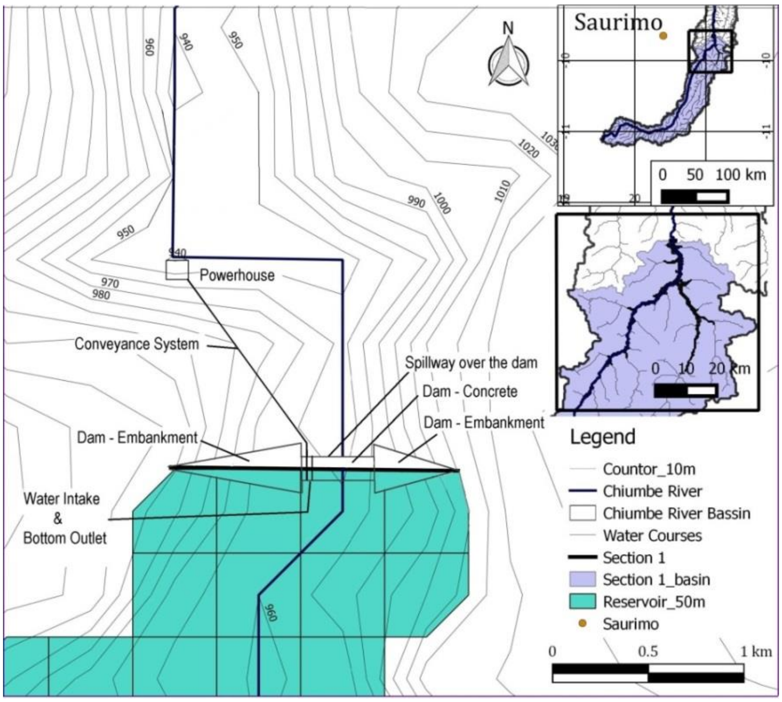

**Figure 12 –** Location of the main hydraulic structures and dam type

| L (m) | Storage (hm3) | Outflow (m3/s) | H (m) | FRL (m) | MWL (m) |
|---|---|---|---|---|---|
| 250.0 | 926.2 | 2291.4 | 2.6 | 993.0 | 995.6 |
| 260.0 | 921.2 | 2324.9 | 2.5 | | 995.5 |
| 270.0 | 916.3 | 2356.4 | 2.5 | | 995.5 |
| 300.0 | 903.0 | 2444.4 | 2.4 | | 995.4 |
| 500.0 | 842.1 | 2838.1 | 1.9 | | 994.9 |
| 1000.0 | 772.7 | 3249.7 | 1.3 | | 994.3 |

**Table 11 –** Weakening of the floods in the reservoir

The decision regarding the length of the spillway is made considering a trade-off between the length of the spillway and the total dam height. For smaller lengths, the dam height will be bigger since the maximum water level is higher and for bigger lengths the opposite happens. In the end, it was considered a length of the spillway of 250 m, which corresponds to a maximum water level of 995.6 m.

Some considerations on the remaining hydraulic structure were made, namely the water intake, the bottom outlet and the adduction system. These considerations, as well as the pre dimensioning of the spillway, were very important when elaborating the pre study drawings.

- Water intake: The water intake structure is considered as part of the dam; there were considered two vertical gates; the entrance of the water intake has a rectangular shape and then it is made a transition to a circular shape. It is located at an elevation of 975 m and the connection to the adduction circuit is made at an elevation of 960 m, which means that the adduction system is buried at the beginning. The shape of the water intake needs to be dimensioned in a way that local pressures do not reach the vapour pressure of the water in order not to occur cavitation. It should be avoided the formation of vortices, the separation of the flow from the walls of the water intake and the entrance of sediments in the water circuit. This being said, the minimum submersion has to be verified in order to avoid cavitation, and a grid needs to be dimensioned for the entrance of the water intake to keep the sediments from entering the circuit, which might damage the remaining hydraulic organs (e.g. valves , turbines, filters) or that might be undesirable in terms of maintenance; to dimension the diameter of the water intake it was considered a maximum velocity of 4 m/s and considering the total discharge, the diameter should be fixed at 5 m;

- Adduction: The adduction system was considered to be composed by a conduit, a tunnel and a penstock that connects the tunnel to the powerhouse (e.g. the turbines); to dimension the adduction system it was defined the longitudinal profile of the terrain and then designed the longitudinal profile of the circuit. The first part of the circuit is composed by a steel conduit with 10 cm of thickness. When the depth, relative to the surface of the terrain, reaches the double of the conduits diameter (approximately 10 m) the circuit continues in a tunnel of concrete with a thickness of 20 cm. Finally when the depth becomes lower than 10 m the tunnel is divided in two penstocks with 3.5 m of diameter, in order not to have velocities higher than 4 m/s. The two penstocks are connected with the two turbines in the power house; for the tunnel it was considered a maximum velocity of 2.5 m/s and it was considered 80 cm extra to the diameter of the tunnel in order to account with the excavations. The cost was defined per meter of tunnel;

- Bottom outlet: The bottom outlet is located near the water intake at an elevation of 967 m in the concrete part of the dam; it is installed one vertical gate upstream of the transition from a rectangular section to a circular section; It was assumed a diameter of 2 m and the in the end of the structure there is a Howell-Bunger valve installed and the jet lands in the energy dissipation structure;

Pre Study Drawings and Preliminary Bill of Quantities

To elaborate the bill of quantities, first a set of pre study drawings were elaborated, which include a general layout of the facility, a plan and profile of the dam, a transversal profile trough the concrete and embankment area, a profile of the water intake and bottom outlet, a longitudinal profile of the adduction circuit and a plan and profile of the power house. In order to obtain the referred drawings, it was used the software REVIT and AutoCAD. The referred drawings were elaborated in a preliminary stage since a lot of hypotheses were assumed and they were based on typical and already tested solutions for other similar hydropower facilities. The objective with this drawings is to allow a more visual understanding of the facility as well as its implementation in the case study region, namely in section 1. Also these elements allow a more reliable and better founded estimation of the quantities associated with the construction of this hydropower facility.

At this stage it was also retrieved more information regarding the unitary costs of construction. The unit rates were obtained based on contacts from GIBB Portugal and GIBB Angola and by analyzing the market prospections in Angola, also some values retrieved from database of the LCH laboratory in EPFL and by analyzing similar projects in similar locations. A resumed preliminary bill of quantities is presented in Table 12, being that the cost of the facility was estimated at 194.2 MUSD.

**Table 12 –** Resume of the preliminary bill of quantities

| ID | DESCRIPTION | Units | Qtt. | U.R. | Amount (USD) |
|---|---|---|---|---|---|
| | | | | | |
| 0.1 | INVESTIGATION WORK | | | | 19 048 168 |
| | | | | | |
| 0.2 | CONSTRUCTION SITE | | | | 12 239 267 |
| | | | | | |
| 1 | CONSTRUCTION WORK | | | | 140 088 769 |
| 1.1 | Preparation | | | | 902 000 |
| 1 | Water Intake and Bottom Outlet | | | | 19 666 133 |
| 1 | Penstock and Tunnel | | | | 2 538 373 |
| 1 | Dam Construction | | | | 115 955 400 |
| 2 | Powerhouse | | | | 1 026 864 |
| 2 | ELECTRO & HYDRO MECHANIC EQUIPMENT | | | | 22 800 000 |
| 2 | Generation Equipment | | | | 9 000 000 |
| 2 | Equipment for the Powerhouse | | | | 13 800 000 |
| | | | | TOTAL COST | 194 176 204 |

**Stage 3: Economic Analysis**

The initial values considered for the economic analysis were the ones presented in Table 13. The capital expenditure is the result of the preliminary bill of quantities, the operational expenditure was assumed to be 0.2 MUSD per year and the annual gross income is calculated based on the energy generated per year (230.6 GWh) and the sale price of energy, estimated at 0.0075 USD/kWh. In this economic analysis it was not included the cost for replacement of electro mechanic equipment or heavy maintenance.

| | |
|---|---|
| CAPEX (MUSD) | 194.2 |
| OPEX (MUSD/year) | 0.2 |
| Annual gross income (MUSD/year) | 17.3 |
| Net annual income (MUSD/year) | 17.1 |

**Table 13 –** Values for the economic analysis

It was elaborated a sensitivity analysis and there were considered several values for the interest rate and discount rate, being defined six different scenarios. For the construction of the facility it was assumed a construction time of four years, being the capital cost distributed in those four years according to the work planning. The timetable regarding the work planning was developed using the software MSProject and the distribution of the CAPEX and OPEX was made in the four years of. For each scenario the capital costs, the interests, the operation costs and the revenues were calculated in the present year. Also the economic indicators were determined, which are presented in 14.

| Scenario | A-1.1 | A-1.2 | A-1.3 | A-2.1 | A-2.2 | A-2.3 |
|---|---|---|---|---|---|---|
| Discount rate (%) | 5 | 5 | 5 | 10 | 10 | 10 |
| Interests rate (%) | 0 | 2.5 | 5 | 0 | 2.5 | 5 |
| Net Present Value | 64.45 | 24.97 | -14.51 | -53.97 | -76.90 | -99.82 |
| Benefits/Costs Ratio | 1.37 | 1.14 | 0.92 | 0.66 | 0.52 | 0.37 |
| Internal Rate of Return | 6.94 | 5.75 | 4.64 | 6.94 | 5.75 | 4.64 |
| Payback Period | 26 | 37 | >50 | >50 | >50 | >50 |

**Table 14 –** Different scenarios and economic indicators

Since that the studies conducted so far are characterized by a lack of certainty about the capital costs, future annual costs (operational costs and reparations) and future value of the energy, another sensitivity analysis was conducted, now considering variations in the costs and revenues, and assuming an interest rate of 2.5 % and a discount rate of 5 %.

The economic indicators were calculated for the various alternatives and are presented in Table 15. For some combinations of variations of the costs and benefits, the facility will not be profitable. These values are highlighted with a light grey in the table. This means that this facility does not have a great margin, regarding its economic feasibility, being that for some variations of the costs or the benefits the economic indicators show that it might not be profitable. To be more specific, for fixed benefits it is necessary an increase of 20 % in the costs or, for fixed costs the benefits need to decrease 20 %, for the rejection of this project, in what concerns its economic feasibility.

| NPV | | Variation of the Benefits | | | | |
|---|---|---|---|---|---|---|
| | | -20% | -10% | 0% | 10% | 20% |
| Variation of the Costs | -20% | 20.0 | 44.3 | 68.5 | 92.7 | 117.0 |
| | -10% | -1.7 | 22.6 | 46.8 | 71.0 | 95.3 |
| | 0% | -23.5 | 0.8 | 25.0 | 49.2 | 73.5 |
| | 10% | -45.2 | -20.9 | 3.3 | 27.5 | 51.8 |
| | 20% | -66.9 | -42.6 | -18.4 | 5.8 | 30.1 |

| IRR | | Variation of the Benefits | | | | |
|---|---|---|---|---|---|---|
| | | -20% | -10% | 0% | 10% | 20% |
| Variation of the Costs | -20% | 5.72 | 6.54 | 7.32 | 8.06 | 8.78 |
| | -10% | 4.94 | 5.72 | 6.45 | 7.15 | 7.82 |
| | 0% | 4.29 | 5.02 | 5.72 | 6.38 | 7.01 |
| | 10% | 3.72 | 4.42 | 5.09 | 5.72 | 6.32 |
| | 20% | 3.23 | 3.90 | 4.54 | 5.14 | 5.72 |

| B/C | | Variation of the Benefits | | | | |
|---|---|---|---|---|---|---|
| | | -20% | -10% | 0% | 10% | 20% |
| Variation of the Costs | -20% | 1.14 | 1.32 | 1.49 | 1.66 | 1.84 |
| | -10% | 0.99 | 1.14 | 1.30 | 1.45 | 1.60 |
| | 0% | 0.87 | 1.00 | 1.14 | 1.28 | 1.42 |
| | 10% | 0.77 | 0.89 | 1.02 | 1.14 | 1.27 |
| | 20% | 0.68 | 0.80 | 0.91 | 1.03 | 1.14 |

| Payback Period | | Variation of the Benefits | | | | |
|---|---|---|---|---|---|---|
| | | -20% | -10% | 0% | 10% | 20% |
| Variation of the Costs | -20% | 36 | 30 | 24 | 22 | 20 |
| | -10% | >50 | 37 | 30 | 26 | 23 |
| | 0% | >50 | 49 | 37 | 31 | 27 |
| | 10% | >50 | >50 | 48 | 37 | 31 |
| | 20% | >50 | >50 | >50 | 47 | 37 |

**Table 15 –** Calculation of economic indicators for different variations of the costs and benefits

## CONCLUSIONS

Despite the difficulties associated to the lack of information available for this case study, it has been very challenging and at the same time formative in terms of acquired competences, in the way that it allowed to perceive what can be developed only with freeware information available online and by taking advantage of new technologies that have been in development in the last years, mainly satellite information and some of its derivative products. Nowadays this information is a very powerful tool for hydrology work and it's essential for studies in developing countries that have deficient measurement stations, don´t have sufficient on-site measurements and lack on a lot of needed information.

Based on the studies within the framework of this study for the Chiumbe River basin, the best location to build a hydropower facility is section 1. This section is located 78 km from the city of Saurimo at the coordinates 21.1 East and 9.7 South, in the km 332.4 of the Chiumbe River (from the source). The catchment area dominated by this section is 9 412 km$^2$, the mean slope of the river is 0.12 % and section 1 is located at an altitude of 960 m.

At this stage, the best configuration for the facility is considered to be a mixed dam composed by a concrete gravity dam and an embankment dam. The concrete part of the dam will be in the center of the valley, with 38 m of height and a crest length of 250 m, with a spillway over the dam. The hydraulic structures, namely the bottom outlet and the water intake, will be located in the concrete part of the dam next to the spillway, as it is presented in the drawings in the Appendices. The embankment dam fills the remaining parts of the valley. The total crest length is estimated to have 1 111 m, based on the drawings elaborated and for the final location considered for secion1. The reservoir created will have a total area of 39.2 km2 and a maximum volume of 591.3 hm$^3$.

The total energy generated by the HPP should be around 230.6 GWh per year, with a total installed capacity of 31.4 MW, with two groups of turbines (of 15.7 MW each) and an equipped discharge of 38 m3/s per group. The turbines should have a vertical axis. One of the turbines will be working at 40 % of its full capacity from May to September and the other one will be working at its full capacity the entire year.

Based on the studies elaborated so far, it is not possible to create a HPP in the Chiumbe River with an installed capacity of 100 MW that consists in a feasible project. As shown in the performed study, in order to achieve such a value one of two consequences are going to occur: Either the cost of the facility is so big, with enormous and unfeasible construction works associated (for example dams with a crest length higher than 10 km, which happens for section 5 with the equipped discharge of Q90) that it does not compensate the investment when compared to other solutions; or the facility would have to be equipped with very high values of discharge, meaning it could only work a few months per year. Since the objective is to constantly supply the city of Saurimo along the year and not to fulfil peak demands in some periods, this is not a feasible solution.

At this stage, the estimated cost of the facility, based on the preliminary bill of quantities elaborated, was estimated on about 194.2 million USD.

As a result from the economic analysis elaborated, this hydropower scheme associated with the considerations described above, reveals itself to be profitable with an associated payback period of approximately 37 years after the facility starts operating, for a considered discount rate of 5 %, an interest rate of 2.5 % and the sale price of the energy fixed in 0.075 USD/kwh.

## FUTURE WORK

The definition of the runoff coefficient that relates the total precipitation with the precipitation that effectively generates runoff should be calibrated using other data sources, preferably runoff or discharge measurements made in the catchment area of the case study. A model should be defined that takes into account the fact the coefficient varies along the year, and the runoff values obtained should be revised and founded in more reliable information.

With more reliable information, the topics considered in the feasibility study should also be revised and the pre dimensioning made for the hydraulic structures and equipment's can be elaborated with more detail. The pre study drawings might need to be adjusted, which will influence the bill of quantities and probably the costs. Also a more founded work planning and execution scheme could be developed after the revision of the bill of quantities. This is important since it influences (and is at the same time influenced by) the location of some of the hydraulic structures, the construction materials and the time for construction of the HPP, which will influence the economic analysis indicators, mainly the payback period.

With a more detailed bill of quantities and the construction stages defined, there is more information that can be added to economic analysis, which will lead to more founded conclusions about the feasibility of this facility and about the benefits that can be expected from its implementation in the Chiumbe River.

It should also be considered an environmental impact assessment (EIA). This was not considered in this thesis since it was not the purpose of the study, but being a feasibility study it makes sense to consider the environmental impacts that are inherent to the construction of a hydropower facility. The pre-design of a hydrometric station would be desirable.

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