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CHABROUH PUMPED-STORAGE PLANT DESIGN

by
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AN ABSTRACT OF THE THESIS OF

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Pumped hydro storage (PHS) systems are used for both energy storage and generation. Although there are appropriate sites, there is not any PHS project that is implemented in Lebanon. A study is performed on the possibility of a PHS power plant at Chabrouh Dam in Faraya, and the cost analysis for the project was implemented using a Matlab program. It was concluded that such a power plant would be feasible for its owner because of the lower levelized cost and its high efficiency, if used under the right conditions.

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CHAPTER I

INTRODUCTION

Global warming and its impact on humans and their environment has been a major concern for many countries for the past years. Thus policies and actions have been developed by the international community to promote and encourage investments in renewable energies and in energy efficiency. Some policies are becoming more evolved and differentiated by technology (REN21, 2014) which serves as an incentive for countries to get involved in the global change towards cleaner and renewable energies. The persistent drop in levelized cost and increasing technological advancement for various renewable energies serve also as a major incentive for wide scale adaptation.

Renewable energy sources are categorized into major four sources, each of which has its different forms (biomass...) and effects (evaporation...):

- Tidal energy
- Solar energy
- Geothermal energy
- Hydropower energy (Kaltschmitt, Streicher, & Wiese, 2007a)

A. Hydro power energy

Hydropower energy harnesses potential energy from falling water and transforms it, by the use of mechanics, into electrical energy (Kaltschmitt, Streicher, &

Wiese, 2007b). By the end of 2013, hydropower accounted for around 1000 GW in the power sector globally which was a 4% increase from 2012. The share of renewable electricity from the global electricity production in 2013 was 22%, and hydropower generated around 16.14% of that share, as shown in Figure **1** (REN21, 2014).

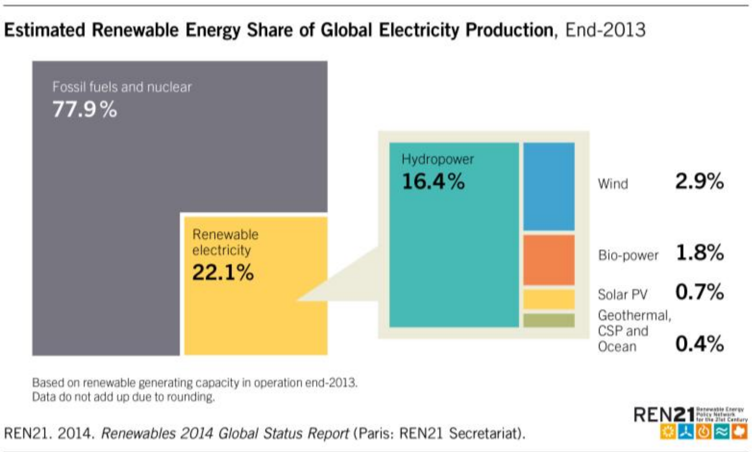

Figure 1: Estimated Renewable Energy Share of Global Electricity Production at the end of 2013

B. Electrical energy storage

Electrical energy storage has been a major concern globally. In the beginning of the twentieth century, electrochemical batteries were used to power mobile phones and telegraphs. Electric cars were more common back then from gasoline-powered cars and thus batteries were essential for such technology. Even at older times, water dams were used to store potential energy.(Farret & Simões, 2006)

C. Pumped hydroelectric storage

Pumped hydroelectric storage (PHS), as its name reveals, is a combination of the two technologies, hydropower energy generation and battery storage. Nonetheless, PHS is mainly categorized as a battery storage system for electricity. It consists of two reservoirs at a head difference, and connected by a penstock and a power plant. The power plant includes the essential pumps, turbines, generators, motors and regulatory equipment. During off-peak time and when the demand is low and the electricity tariff is low, water is pumped from the lower reservoir to the upper one. On the other hand, during peak times and when the demand is high and the electricity tariff is high, water naturally flow through the turbines to generate electricity. Thus by this scenario, generation peaks are shaved as shown in Figure **2** (*Poullikkas*, 2013).

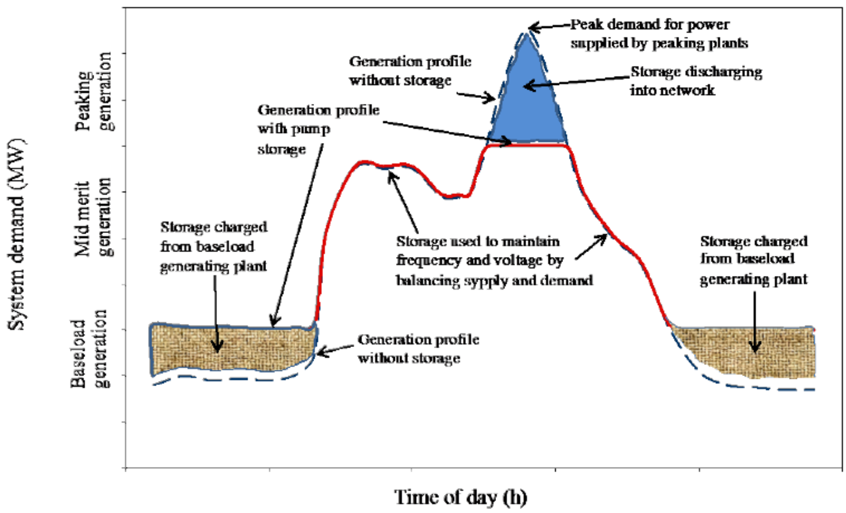

Figure 2: Load demand and generation for one day

D. Hydroelectricity in Lebanon

Lebanon is located on the eastern Mediterranean Sea shore and is bounded by Syrian land from the north to the south-east and by Palestine from the south. It occupies an area of 10,452 km^2.

After the war in neighboring countries and the cease of electricity import from Syria and Egypt, electricity in Lebanon has been mainly provided from two sources in 2013 as shown in Table 1:

- Hydropower: 918 GWh that constitutes around 8.7% of the total energy production
- Thermal power plants: 9625 GWh that constitutes around 91.3% of the total energy production (Osseiran, Alaya, & Kabakian, 2013).

According to the policy paper in 2009, there was a deficit of 23% between the energy supplied and the energy demanded. Thus, the energy market depends on private generation (PG) which costs around 30 USC/KWh. It should also be noted that in the absence of any fuel imports restriction, emissions of effluents, or fuel quality requirements, the use of thermal power plants and diesel PGs is harmful both economically and environmentally. In 2009, the CO_2 emissions from thermal power plants with the inclusion of RE were around 7,319,424 tons, and they were 2,164,523 tons from PGs (Chedid & Ghajar, 2013).

Table 1: Thermal and Hydro production in Lebanon

Plant	**Net Installed Capacity**	**Current Yearly Production**	**Rehabilitated Plant Yearly Production**
	MW	**GWh**	**GWh**
Zouk	607	1897	3164
Jieh	327	1218	1704
Deir Ammar	450	2977	3275
Zahrani	450	2984	3283
Baalbek	64	166	186
Tyr	72	187	209
Hrayche	70	200	364
Total Thermal	2040	9629	12185
Kadisha Hydro	21	72	82
Litani	199	680	775
Nahr Ibrahim	32	92	105
Bared	17	54	62
Richmaya	13	20	23
Total Hydro	282	918	1047
Total Thermal & Hydro	2322	10547	13232
% of Hydro Energy		8.70%	7.91%

Nonetheless, there is a government commitment to reach 12% RE integration into the total energy production capacity by 2020 with the help of both the private and public sectors (Chedid & Ghajar, 2013). Such integration would be helpful not only economically, but also environmentally and thus socially. With the increase in the share of RE in the generation sector, the dependence on PGs would decrease. Thus the multiple high electricity bills (for EDL and PG) and the significant CO_2 emissions from the PGs would both decrease.

E. Chabrouh Dam project

Chabrouh Dam is located in Chabrouh valley in Kesserwan at a distance of 40 km north-east of Beirut and 5 km from east of Faraya. It consists of the dam with its peak at 1618 m from sea level, a lake with a volume of 8,000,000 m^3, inlet from Nabaa El Laban with a flow of 1.5 m^3/s, and a water refining station with a capacity of 60,000 m^3/day. The height of the dam is 63 m and its length is 470 m. Its maximum width at the base is 200 m and the width at the top is 10 m.

F. Motivation behind the project

According to sources from the Ministry of Energy and Water, Chabrouh Dam was built for the sole purpose of distribution of utility water to the surrounding area. Thus it was interesting to study the energy generation and storage capacity of the Dam taking into consideration its main purpose of water distribution.

The potential of the construction of a pumped storage power plant was studied and a cost analysis was prepared for Chabrouh Dam. The advantage that was mostly appealing for this study is the upper reservoir that was already constructed and operating, and thus its cost is reduced from the initial cost of the project.

Such a project would be important for Lebanon in several economical, environmental and social aspects. A pumped storage power plant would help shave the peaks in the daily generation curve, has lower levelized cost than thermal plants and PG, aid in lowering the CO_2 emissions, and, on the country scale, help raise the social awareness and standards.

CHAPTER II

PUMPED HYDROELECTRIC STORAGE

The first pumped hydroelectric storage (PHS) plants were introduced in Switzerland, Austria and Italy in the 1890s with separate pumps-motors and turbines-generators. In the 1950s, the reversible turbine-pump was introduced into the industry. With the realization of the importance of nuclear power in the 1990s, PHS development boomed as a compliment to the nuclear plants. (Yang, 2011)

PHS is a combination of hydroelectric energy production and energy storage system. In addition to the conventional hydroelectric production system that functions by releasing water from an upper reservoir to a lower one through a turbine, PHS also pumps the water back from a lower reservoir to store it as potential energy.

A. Description of the system

PHS generally consists of two reservoirs at a certain height difference, an intake for water at the upper reservoir, a penstock between the reservoirs, and a power plant containing the electrical equipment (turbines, pumps, generators, motors...) at a lower altitude, closer to the lower reservoir as shown in Figure **3**.

In a conventional hydroelectric system, water is released by gravity from the upper reservoir through the intake where potential energy is converted to kinetic energy. Water then flows in the penstock to the turbine. In the penstock, potential energy is further converted to pressure energy and losses occur due to friction in the pipes. In the turbine, kinetic energy is converted to mechanical energy. Losses in the turbine which are characterized by the turbine's efficiency (η_t) are mainly losses due to the type of material, blades, design... In reaction turbines, the use of a draft tube behind the turbine is useful for decreasing losses due to turbulence. Since the diameter of the draft tube is smaller at the exit of the turbine than at the inlet of the lower reservoir, kinetic energy is decreased at the inlet and thus pressure is increased. This system of energy losses and gains is described in (Kaltschmitt, et al., 2007b).

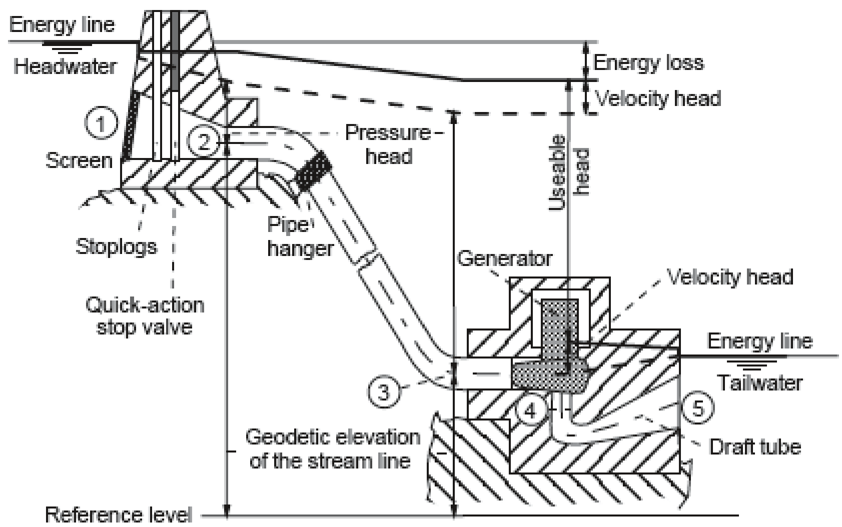

Figure 3: Hydroelectric System

In a PHS, the above scheme of electric generation is carried out during peak times when both the demand and electricity tariff are high. An additional pumping scheme is added to the conventional hydroelectric generation system during off-peak hours when the demand and the electricity tariff are low.

Water is pumped back from the lower reservoir to the upper one through the penstock. The losses in the pump which are characterized by the pump's efficiency (η_p)

are also losses due to the design of the pump, its material, shape of blades, copper and core losses, etc... In addition, the friction losses of the pipe are also accounted for.

As shown in Figure 2, PHS helps shave the peaks in the daily generation curve.

B. System parameters

In a PHS, Bernouli's equation is applied for both pumping and generation operations. The energy supplied by the generation process in a PHS is given by Eq. (1), and that consumed by the PHS for the pumping process by Eq. (2).

$$\boldsymbol{P_g = \eta_{gm} \rho_w g H Q_t} \quad \textbf{(1)}$$

$$\boldsymbol{P_p = \frac{\rho_w g H Q_p}{\eta_{pm}}} \quad \textbf{(2)}$$

where

- P_g and P_p are the amount of power generated and used for pumping in (W), respectively
- η_{gm} and η_{pm} are the generation and pumping modes efficiencies, respectively
- ρ_w is the density of water in (Kg/m^3)
- g is the gravitation acceleration in (m/s^2)
- H is the total head after losses in (m)
- Q_t and Q_p are the design flow discharge of water in (m^3/s) for the turbine and pump, respectively.

Thus it can be deduced that to increase electric generation, sufficient head and flow discharge of the water are needed. This is based on a proper choice of location for the reservoirs and the proper design of both the turbine and pump.

In addition, the head losses due to friction in the penstock should be reduced by the proper choice of penstock material. The loss is estimated first by using the dimensionless Reynold's number of Eq. (3) and according to its range in Eq. (4), (5), or (6), the flow is categorized as laminar, transitional, or turbulent, respectively.

$$\boldsymbol{Re = \frac{\rho_w D V_s}{v_w}} \quad \textbf{(3)}$$

$$\boldsymbol{Re < 2100} \quad \textbf{(4)}$$

$$\boldsymbol{2100 \leq Re \leq 4000} \quad \textbf{(5)}$$

$$\boldsymbol{Re > 4000} \quad \textbf{(6)}$$

where D is the diameter of the penstock in (m), V_s is the flow speed of water in the penstock in (m/s), and v_w is the viscosity of water in (Ns/m^2).

If the flow is laminar, friction factor is calculated using Eq. (7). Otherwise, if it is turbulent, friction factor is calculated using the Swamee-Jain equation represented by Eq. (8).

$$\mathbf{f = \frac{64}{Re}} \quad \textbf{(7)}$$

$$\mathbf{f = \frac{0.25}{\left[\log\left(\frac{1}{3.7\left(\frac{D}{\varepsilon}\right)}\right)+\frac{5.74}{Re^{0.9}}\right]^2}} \quad \textbf{(8)}$$

where $\left(\frac{\mathbf{D}}{\boldsymbol{\varepsilon}}\right)$ is the dimensionless relative roughness of the material.

The head loss due to friction in (m) is calculated using Darcy-Weisbach equation represented by Eq. (9).

$$\boldsymbol{h_L = f \times \frac{L}{D} \times \frac{{V_s}^2}{2g}} \quad \textbf{(9)}$$

C. PHS in Lebanon - Chabrouh

There are no PHS projects in Lebanon. Nonetheless, there are several locations with the potential of introducing PHS plants that are studied in (Geadah, 2009) as shown in Table 2. The significant variation in the payback periods of these plants can be explained by the variation in the capital (initial) cost of each project.

In Chabrouh, the upper reservoir is already constructed with the dam. Nonetheless, if we want to produce enough electricity from this existing project, we need to provide sufficient head and discharge flow between this existing upper reservoir and a lower one. Based on (Abboud, Zghaib, & Chader, 2015), a proper position for the lower reservoir was located on Google maps, at 1900 m distance and 177 m head and from the upper one. The details of the position are shown in Figure **4**.

Table 2: Data of identified typical potential PHS projects

Category	Project	Generating Capacity (MW)	Expected Annual Peak Generation (GWh)	Base Investment Cost (Million USD)	Estimated Pay Back Period (Year)
I-Inland/ Qaraoun Lake/ Litani River	**Qaraoun Lake- Marj Et Taouil**	388	713	565	20
II- Inland/ River Basin Dam	**Hasbani River- Ibl Es Saqi Dam**	21	37	34	31
III- Inland/ Perennial Spring-Hill Lake	**Hammana-El Mghiti**	12	9	31	35
IV- Sea Shore/ Coastal Cliffs	**Ras Ech Chaqaa**	30	54	50	37
	Ouajh El Hajar	33	60	52	16
	Ej Jiye	225	405	344	16
	Ras Nabi Younes – Alt. 1	234	421	348	18
	Ras Nabi Younes – Alt. 2	221	398	351	23
	Ras El Bayada	90	163	135	18
	Ras Ed Draijat	140	252	219	20
Total		1173	2114	1778	16-37

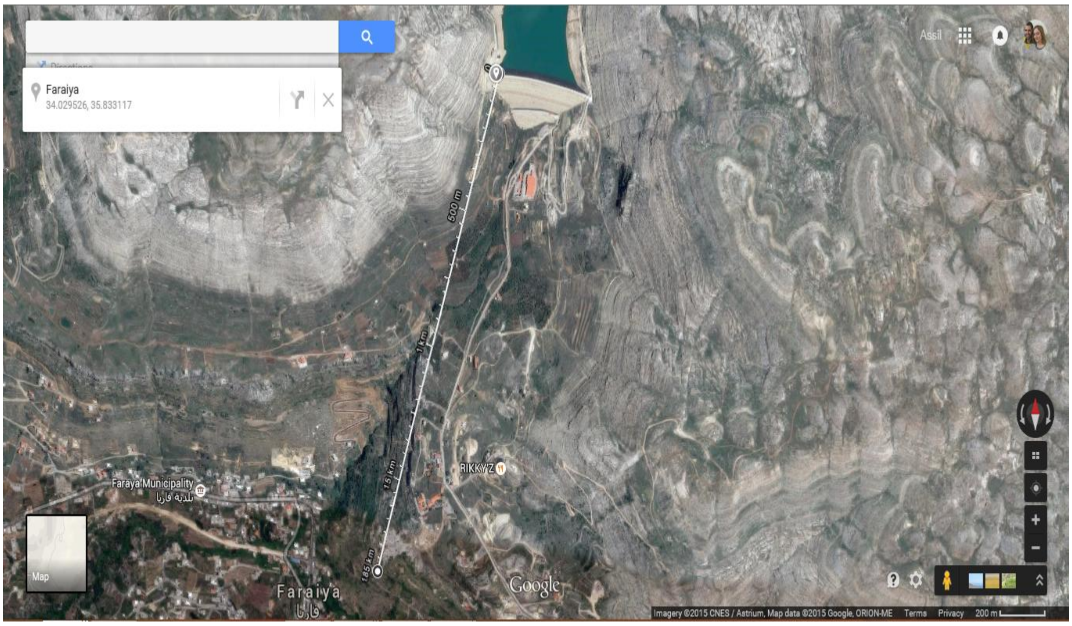

Figure 4: Satellite image of the location of the upper and suggested lower reservoirs in Chabrouh

For an appropriate penstock material, high density polyethylene (HDPE) was chosen for its small roughness and long lifetime.

D. Advantages and disadvantages of PHS

As any other system, PHS has its advantages and disadvantages.

1. Advantages

- Functions as an energy source and a large energy storage system: by storing energy, PHS can protect the electric system from outages, thus increasing the stability of the system.
- Generates energy at lower cost: the levelized cost of PHS is lower than other thermal energy sources because it takes advantage of the difference in tariff

between peak and off-peak hours. Electric generation using the turbine is operated at peak hours to increase the revenues, and water pumping to the upper reservoir for energy storage purposes is operated during off-peak times to decrease the expenses.

- Low operation and maintenance (O & M) costs
- Has less environmental impact: due to the use of hydropower to generate electricity, and if the energy used for pumping is provided by a renewable source (PV panels, wind...), PHS can be subcategorized as a renewable source of energy. Moreover, in Chabrouh's case, the energy used for pumping is from an already operating thermal plant, and thus no extra emissions are released into the atmosphere.
- Has fast response to changes in demand: when demand is high, PHS generates electricity, but if the demand suddenly drops, PHS has the fast time response to accommodate with this change. The same can be said for a change in demand during pumping.

2. Disadvantages

- Includes high initial cost: mainly due to the cost of construction of the reservoirs
- Has negative environmental effects: dams that are built on rivers can sometimes disrupt the aquatic ecosystem. Dams can also have the danger of flooding which may destroy the habitats of neighboring wildlife. In case the electricity for pumping is provided by a thermal plant that is constructed specifically for the project, CO2 emissions are accounted for.

CHAPTER III

LITERATURE REVIEW

The use of PHS as an energy storage system and for energy generation was addressed by many authors around the world since a long time. The Bath County PHS in Northwestern Virginia was designed to produce an output of 2100 MW in 1986. Significant features of the project were the two reservoirs and dams, the water conduits and the powerhouse (Fostiak & Thompson, 1982). The Ohkawachi adjustable speed PHS was commissioned in Dec 3, 1993 in Japan. It has the capacity of 400 MW. The design considerations and some sample performance results for this PHS were addressed in (Kuwabara, Shibuya, Furuta, Kita, & Mitsuhashi, 1996). "The Central and the Saratov administration of the scientific and technical association of power engineering and electro technical industry, together with the Ministry of Power Engineering and Electrification of the USSR, organized a scientific and technical conference on the subject "The Prospects of Planning and Building Hydroelectric Storage Power Plants" from May 14 to 16, 1969, at Balakov" (Goncharov, 1969). In the conference, they studied the potential and financing of PHS in several areas in order to cover peak loads. In his paper, Geadah emphasized the importance of introducing PHS in the Lebanese energy production. He introduced the potential PHS projects' locations in several areas in Lebanon (Geadah, 2009).

Several techniques were used by authors to study PHS. Two energy storage technologies, batteries and PHS were studied for a micro grid power supply system in

Hong Kong (Ma, Yang, & Lu, 2014). A feasibility study comparing several costs of the different options was proposed and a conclusion that PHS is more cost effective if the energy storage capacity and the days of autonomy are both increased. Moreover, WASP IV software was used to perform a technical and economical analysis on the integration of PHS in the Cyprus power system (*Poullikkas*, 2013). On the other hand, linear programming optimization was used to study whether or how much PHS can be included in a small island system in order to optimize the unit capacity in MW and the reservoir capacity in MWh (Brown, Peas Lopes, & Matos, 2008). It was shown that such inclusion can improve both dynamic security and economic operation of the system. Stochastic programming was also applied to size a PHS in Azoras (Correia, Ferreira de Jesus, & Lemos, 2014). The ability of PHS to cope with the change in Wind power and provide energy storage was concluded. A model was developed in (Crampes & Moreaux, 2010) to find out when is the use of PHS considered efficient and when it should be dispatched. An optimization problem for the use of PHS with a Wind park was suggested for Spain in (Bayón, Grau, Ruiz, & Suárez, 2013). Moreover, in (Khandualo, Barisal, & Hota, October 2013), evolutionary programming (EP) techniques were used to solve the generation/pumping scheduling of PHS. Dimensionless quantities were developed in (Leon & Zhu, 2014) to determine the optimal flow discharge and penstock diameter for both reaction and impulse turbines in a PHS.

In addition, many authors investigated the financial aspect of hydroelectric power stations, PHS, and the combination of PHS with other renewable sources. The energy return on investment (EROI) for Fljotsdalsstod hydroelectric plant in Iceland was studied in (Atlason & Unnthorsson, 2014) using a standardized methodology. It was concluded that the EROI for hydroelectric generation is higher than any other renewable source so far. The feed-in-tariff (FIT) for a potential PHS project in Croatia was found to be in the range of 42-265 €/MWh for a load factor of around 20% (Krajačić et al., 2013). In Russia, when using the combination of NPP-PHS, the effect due to fuel saving can amount to around 956 USD/yr, and the effect of the increase in efficiency was estimated by the increase in operating cost of NPP by 0.039–0.052 USC/kWh (Malinina, Shulginov, & Yushkov, 2013). In (Fertig, Heggedal, Doorman, & Apt, 2014), due to wind fluctuations, energy prices are estimated to rise. Thus a study was performed on how a PHS system, modeled after the proposed upgrade to the Tonstad hydropower plant in southern Norway, can operate in the German market in order to maximize profit and cope with the rise in spot prices. Tilahun performed a feasibility study for a proposed PHS in Amhara region in Ethiopia (Tilahun, 2009). Another feasibility study was performed in (D. Sagale, 2013) for a PHS in MIDC Dhule, Maharashtra. Considering Lebanon, a paper was published to examine the possibility of introducing renewable energies (RE) in the electricity production sector. It was concluded, among other matters, that a comparison between the cost of the private generation (≈30 USC/KWh) and the cost of RE would be an incentive for end users to switch to RE (Chedid & Ghajar, 2013).

Authors have also addressed some disadvantages of hydroelectric and PHS. The generation losses in hydroelectric plants due to corrosion in pipes were tackled in

(Kharlamov, Édel, & Ivanchenko, 1980). Authors emphasized the increase in head loss due to increased roughness of the pressure pipes. The environmental and socioeconomic impacts of PHS were studied in (Prasad, Jain, & Gairola, November 2013) using Geomatics techniques. Some solutions for avoiding such impacts were also suggested. In (Bou Jaoude, Karanouh, Momjian, Chehadeh, & Cheikh Hussein, 2010), the leaks in Chabrouh dam basin into Qana plateau were estimated to around 200 L/s.

CHAPTER IV

CHABROUH PHS PROJECT

Chabrouh dam project is used to distribute utility water, after refining, to the neighboring areas. It includes the dam and an 8 million m^3 reservoir with a water refinery unit. Such a huge reservoir can have measurable energy storage potential if used in a PHS system.

A program was developed using MatLab to perform the necessary calculations for the anticipated hydro-power plant. It first prompts the user to enter needed parameters/variables for the system. Then it calculates the energy generated and used for pumping for the first daily cycle of operation in order to calculate the volume of the needed lower reservoir. After that, the daily degradation of energy can be calculated in order to calculate the number of days of operation of the plant per year, given the constant volume of water and the daily distribution amount of utility water. Using these parameters, the first year's energy quantities are calculated, and assuming a 1% degradation of energy production per year, the yearly energy quantities are calculated over the lifetime of the project (50 years). In the end, a cash flow analysis is done to calculate the present value of the project, the levelized cost of energy, the internal rate of return, and the payback period.

A. Input parameters

The parameters were grouped into two categories, existing parameters and parameters defined by the user.

1. Existing

The already existing reservoir with 8 million m^3 volume and its dam can be considered as the upper reservoir in the potential PHS project at Chabrouh. Moreover, it should be taken into consideration that the dam project has an original usage of distributing around 60,000 m^3 of water, daily, after refining.

To calculate the energy storage potential of the upper reservoir, we can use Eq. (1) and substitute Q by its equivalent in Eq. (10) to get Eq. (11).

$$\mathbf{Q} = \frac{\mathbf{V}}{\mathbf{t}} \tag{10}$$

$$\boldsymbol{E_{upp}} = \frac{\boldsymbol{\rho_w g H V}}{\mathbf{60 \times 60}} \tag{11}$$

where V in this case is the volume of the upper reservoir in m^3, t is the duration of flow of water in sec, and E_{upp} is the energy storage potential of the upper reservoir in Wh.

Taking the head from the location specified in Figure **4**, and that are specific to the design of the system, $H = 177\ m$. Thus, $E_{upp} = 3.9$ GWh, taking into consideration a 100% availability factor, or 643 MWh taking into account a 25% availability factor ($\frac{6 hours/day of\ operation}{24 hours/day} = 25\%$).

2. User-defined

The user shall input the roughness of the pipe chosen, total head, penstock length and diameter, and flow velocity in the penstock. The user shall also input the different efficiencies of generator, motor, turbine, and pump chosen for the system. It was also assumed that the generation process was distributed among 1 stage during the peak period and the pumping process occurs in 1 stage during night time (off-peak). Thus the user shall input the times of the start and end of each of these stages. Regarding the cost analysis, the user shall input the interest rate and equity for the system.

For analysis purposes, quantities for the above mentioned parameters were assumed and summarized in Table 3.

Table 3: Input parameters by user

Parameter	Symbol	Quantity	Unit
Penstock Parameters			
Roughness of the pipe	ε	$3x10^{-6}$	m
Total head	H_g	177	m
Penstock length	L	1900	m
Penstock diameter	D	3	m
Flow velocity	V	4.57	m/s
Volume of Upper Reservoir	V_1	8,000,000	m^3
Power Plant Parameters			
Lifetime of plant	l	50	years
Rating of pump-turbine (generator-motor)	R_{p-t}	20	MW
Efficiency of generator	η_{gen}	93	%
Efficiency of motor	η_{mot}	90	%
Efficiency of turbine	η_t	88	%
Efficiency of pump	η_p	88	%
Time of start of generation process	T_{gs}	7: 00	
Time of end of generation process	T_{ge}	13: 00	
Time of start of pumping process	T_{ps}	00: 00	
Time of end of pumping process	T_{ps}	4: 00	
Financial Parameters			
Equity	Eq	50	%
Interest Rate	ir	10	%

3. Constants, tariffs, costs, and conversion rates

An important factor that influences the feasibility of the PHS system is the difference between peak and off-peak tariffs. PHS takes advantage of such difference to generate during peak hours when the tariff is high, and pump water back during off-peak hours when the tariff is low. This scenario is a main reason behind the profit of PHS systems. Because there is no difference in the peak and off-peak tariffs in Lebanon, the tariffs of the industrial system provided by EDL were considered.

EDL categorizes the tariff according to the summer and winter seasons. During the summer season, the day times are 07:00-18:30 and 21:30-23:00, the peak time is between 18:30-21:30, and the night time (off-peak) is 23:00-24:00 and 00:00-07:00. On the other hand, during the winter season, the day times are 07:00-16:30 and 20:30-23:00, the peak time is between 16:30-20:30, and the night time is between 23:00-24:00 and 00:00-07:00. In our study, the day time is considered as part of the peak times for both seasons. Thus the peak duration is 16 hours and the off-peak duration is 8 hours for both seasons.

Costs for the system infrastructure include the civil costs involved in the construction of the lower reservoir (excavation, piling...), the civil costs for the excavation of the penstock, the cost of the pipes and their installation, the cost of the land needed to construct the lower reservoir, the costs for the pump-turbine and generator-motor, the operations and maintenance costs which are 1% of the total initial cost of the project, and an additional cost accounting for any extra works that might come up.

The constants, costs, and tariffs that are needed for the calculations are summarized in Tables 4, 5, and 6, respectively.

Table 4: Constants used in infrastructure calculations

Parameter	**Symbol**	**Quantity**	**Unit**
Gravitational acceleration	g	9.81	m/s^2
Density of water at 10°C	ρ_w	999.7	Kg/m^3
Viscosity of water	v_w	$1.308*10^{-3}$	Ns/m^2
Rate of CO_2 emissions (MEW)		778	Kg/MWh

Table 5: Relevant infrastructure costs

Cost of	Symbol	Quantity	Unit
CO_2 emissions (El-Fadel et al., 2010)	C_{CO2}	65	\$/ton
Civil works on lower reservoir	C_{lower}	200	\$/m^3
Civil works on penstock	C_{pens}	50	\$/m^3
Pipes	C_{pipe}	500	\$/m
Land for lower reservoir	C_{land}	250	\$/m^2
Pump-turbine	C_{t-p}	10,000	\$
Generator-motor	C_{g-m}	50,000	\$
O&M	C_{om}	1% of the initial cost	%
Additional	C_{add}	500,000	\$

Table 6: Assumed tariffs for PHS

Tariff	Symbol	Quantity	Unit
Peak	t_{peak}	320	LBP/KWh
Off-peak	$t_{off-peak}$	80	LBP/KWh

B. Operation of the PHS

In order to calculate the daily operation parameters of the plant, first, the flow type in the penstock should be figured out using Reynolds's number, in order to calculate the friction factor. Using the friction factor, the head loss after each operation can be calculated. Then the power generated and the power used for pumping can be calculated for each hour of operation or no-operation modes. Moreover, the volume of the lower reservoir can also be calculated on hourly basis so that we can find the maximum volume of water needed.

Given the above, and taking into consideration the losses in the system, the yearly operation parameters can be calculated as inputs to the cash flow analysis.

1. Flow type and head loss

As explained in Chapter II, Section B, and by using Eq. (3), Reynold's number should be calculated to figure out the type of flow (laminar, turbulent, or transient) in the penstock by using the conditions presented in Eq. (4), (5), and (6). Thus the friction factor can be calculated accordingly by Eq. (7) and (8).

After the calculation of the friction factor, the head loss due to friction can be calculated by using Eq. (9).

2. Flow discharge in generation mode

By using the area of the penstock and the flow velocity, the flow discharge of the water in generation mode is calculated in order to start the first operation with generation mode.

3. Volume and area of the lower reservoir

Using the flow discharge in generation mode, and since the duration of generation is known, the volume of the lower reservoir at the end of the generation period can be calculated using Eq. (10). Moreover, the area of the lower reservoir can be calculated assuming a 40 m depth for the excavation.

4. Flow discharge in pumping mode

During the pumping mode, the water in the lower reservoir should be returned to the upper reservoir for energy storage purposes. Thus the flow discharge in pumping mode (Q_p) is calculated using Eq. (10) as well, but by using the total volume in the lower reservoir and the duration of the pumping.

5. Daily power in generation and pumping modes

For each hour in generation or pumping modes, the power generated or the power used for pumping can be calculated using Eq. (1) and (2). The Efficiencies in both modes can be calculated using Eq. (12) and (13).

$$\boldsymbol{\eta_{gm} = \eta_g \times \eta_t} \quad \textbf{(12)}$$

$$\boldsymbol{\eta_{pm} = \eta_m \times \eta_p} \quad \textbf{(13)}$$

where η_g, η_m, η_t and η_p are the efficiencies of the generator, motor, turbine and pump, respectively, assumed in Table 3.

Moreover, the head loss should be taken into account during generation as a loss subtracted from the maximum head of the plant, and during pumping as a head gain added to that maximum head.

At the end of the hourly loop for the first operation, the total power for both generation and pumping during the first 24 hours as:

$$\boldsymbol{P_{g-d} = \sum_{h=Tgs}^{Tgs+24} P_g(h)} \quad \textbf{(14)}$$

$$\boldsymbol{P_{p-d} = \sum_{h=Tgs}^{Tgs+24} P_p(h)} \quad \textbf{(15)}$$

where P_{g-d} and P_{p-d} are the daily power generated and used for pumping, respectively, in W, and the 24-hour cycle starts from the time of generation T_{gs}, assumed in Table **3.**

6. Daily losses in power

At the end of every cycle (24 hours), the water that was used for generation is pumped back into the upper reservoir at an hourly rate of 'Q_p'. Taking into consideration the 60,000 m3 distributed as utility water on a daily basis, the total amount of loss of water per day can be calculated as in Eq. (16).

$$\boldsymbol{V_{loss} = V_{w-utility} = 60{,}000\ m^3} \quad \textbf{(16)}$$

When the PHS plant is operating, the water level (h) in the upper reservoir decreases because of the losses. To calculate the daily total head taking into consideration the head loss h_{loss} due to V_{loss}, Eq. (17) is used.

$$\boldsymbol{H_d = H_g - (\mathrm{d} - 1) \times h_{loss}} \quad \textbf{(17)}$$

where

- H_d is the total head at day d of operation in m
- H_g is the initial total head at day 1 of operation in m, given in Table 3
- h_{loss} is the head loss in m/day
- d is the day of operation of the plant in days

7. Number of days and months of operation per year

To calculate the number of days '$n_{days\text{-}op}$' of operation of the plant, we simply divide the initial volume of the upper reservoir, given in Table **3**, by the volume loss calculated by Eq. (16), as in Eq. (18).

$$\boldsymbol{n_{days-op} = \frac{V_1}{V_{loss}}} \quad \textbf{(18)}$$

The number of months of operation per year is given in Eq. (19).

$$\boldsymbol{n_{month-op}} = \frac{n_{days-op}}{30} \qquad \textbf{(19)}$$

8. Energy over year 1

After calculating the number of days of operation per year, the power and thus energy for generation and pumping modes can be calculated for each day over a 1-year period.

9. Yearly energy over lifetime

After the total energy generated and used for pumping over the first year is calculated, the total energy for both modes $E_m(y)$, over the lifetime of operation, should be calculated in MWh by assuming a yearly energy loss of 1%.

The number of pump-turbines and generator-motors is calculated by Eq. (20).

$$\boldsymbol{n_{p-t} = n_{g-m}} = \frac{\max(P_m(h))}{R_{p-t}} \qquad \textbf{(20)}$$

where R_{p-t} is given in Table **3** and $P_m(h)$ is the energy in generation or pumping mode 'm' in hour 'h' in MW.

10. Overall system efficiency

Finally, the efficiency of the overall system is calculated using Eq. (21).

$$\boldsymbol{\eta_{system}} = \frac{\sum_{y=1}^{lifetime} E_g(y)}{\sum_{y=1}^{lifetime} E_p(y)} \qquad \textbf{(21)}$$

C. Yearly CO_2 emissions

The yearly amount of PHS-related CO_2 emissions can be calculated by Eq. (22) in order to calculate the cost of these emissions in the cash flow. According to MEW (MEW), the rate of CO_2 emissions in Lebanon is 778 Kg/KWh, given in Table 4.

$$\boldsymbol{CO_2(y)} = \mathbf{emm_p(y)} + \mathbf{emm_g(y)} \quad \textbf{(22)}$$

$$\mathbf{emm_p(y)} = \boldsymbol{rate_{CO2}} \times \boldsymbol{E_p(y)} \quad \textbf{(23)}$$

$$\mathbf{emm_g(y)} = -\boldsymbol{rate_{CO2}} \times \boldsymbol{E_g(y)} \quad \textbf{(24)}$$

where

- rate of CO_2 is given in Table 4 in Kg/MWh
- $E_g(y)$ and $E_p(y)$ are the energy of generation and pumping,

respectively, in year y in MWh

In Chabrouh's case, when the mode is generation, the CO_2 emissions are subtracted from the total yearly amount of CO_2 emissions because no thermal plant is used for the generation. Instead hydro energy is used for the generation mode with almost no emissions. On the other hand, the CO_2 emissions in the pumping mode are added to the total yearly amount of emissions because a thermal plant from EDL is used for providing energy for pumping the water back to the upper reservoir. It should be noted that the increase in efficiency due to the extra load on the thermal plant for pumping is not taken into consideration.

D. Cash flow analysis

A cash flow calculation phase is performed after the energy calculation phase. Several parameters are calculated and assumed for the cash flow including initial cost, salvage value, and amount of money borrowed at year 0.

1. Initial cost

The initial cost of the project in year 0 of study is the sum of the costs used to build the project as estimated using Eq. (31). These costs are:

- Civil costs involved in the construction of the lower reservoir (excavation, piling...) given by Eq. (25)
- Civil costs for the excavation of the penstock given by Eq. (26)
- Cost of the pipes and their installation given by Eq. (27)
- Cost of the land needed to construct the lower reservoir given by Eq. (28)
- Costs for the pump-turbine and generator-motor given by Eq. (29)
- Additional cost accounting for any extra works that might come up given by Eq. (30)

$$C_1 = C_{lower} \times V_{lower} \quad \textbf{(25)}$$

$$C_2 = C_{penstock} \times (2 \times (D + 0.5) \times L) \quad \textbf{(26)}$$

$$C_3 = C_{pipe} \times L \quad \textbf{(27)}$$

$$C_4 = C_{land} \times (A_{lower} + 20\%A_{lower}) \quad \textbf{(28)}$$

$$C_5 = C_{t-p} \times n_{t-p} + C_{g-m} \times n_{g-m} \quad \textbf{(29)}$$

$$C_6 = C_{add} \quad \textbf{(30)}$$

$$C_{initial}(y = 0) = C_1 + C_2 + C_3 + C_4 + C_5 + C_6 \quad \textbf{(31)}$$

where

- C_{lower} is the cost of excavation and insulation in $/m^3$ given in Table 5 and V_{lower} is the volume of the lower reservoir calculated in Subsection 3 (Chapter IV, Section B).
- $C_{penstock}$ is the cost of excavating for the penstock in $/m^3$ given in Table 5 and $(2 \times (D + 0.5) \times L)$ is the volume of the penstock excavation in m^3 where D is the penstock diameter with a 0.5 m addition on all sides so that the excavation is wider than the pipe size, and L is the penstock length. D and L are given in Table 3.
- C_{pipe} is the cost of purchasing the pipes in $/m given in Table 5.
- C_{land} is the cost of the land to be purchased as a location for building the lower reservoir, and is given in Table 5 in $/m^2$, and $(A_{lower} + 20\%A_{lower})$ is the area of the lower reservoir (A_{lower}), calculated in Subsection 3 (Chapter IV, Section B), in m^2 with an addition of 20% so that the area purchased is bigger than the exact area of the reservoir.
- $C_{t\text{-}p}$ and $C_{g\text{-}m}$ are the costs of the turbine-pump and the generator-motor of rating 20MW in $, given in Table 5. $n_{t\text{-}p}$ and $n_{g\text{-}m}$ are the number of turbine-pumps and generator-motors, respectively, needed in the design and calculated in Subsection 9 (Chapter IV, Section B).
- C_{add} is an additional cost, given in Table 5 in $.

2. Salvage value

The salvage value is assumed to be 10% from the initial cost at the final year of study:

$$\boldsymbol{Salvage(y = lifetime) = C_{initial} \times 10\%} \quad \textbf{(32)}$$

3. Borrowed amount

The borrowed amount for the financing of the project is calculated by Eq. (33) where equity is the percentage that the owner of the plant is willing to pay to finance the project, and it is given in Table 3.

$$\boldsymbol{Borrowed\ (y = 0) = C_{initial} \times (1 - equity)} \quad \textbf{(33)}$$

4. Yearly depreciation

Yearly depreciation is calculated for $1 \leq y \leq$ lifetime by the Straight-Line (SL) Method by using the following Eq. (34). This method distributes the initial cost of the project into yearly costs over the lifetime of the project. (Jun, 2011)

$$\boldsymbol{dep(y) = (C_{initial} - Salvage) \times \left(\frac{1}{l}\right) \times \left(\frac{n_{months-op}}{12}\right)} \quad \textbf{(34)}$$

5. Profit from energy generated and cost of energy for pumping

By using the tariffs of energy that correspond to peak and off-peak hours from Table 6, the profit from energy generated and cost of energy used for pumping can be calculated by Eq. (35) and (36), respectively.

$$\boldsymbol{P_g(y) = E_g(y) \times t_{peak}} \quad \textbf{(35)}$$

$$C_p(y) = E_p(y) \times t_{off-peak} \quad (36)$$

where

- $1 \leq y \leq$ lifetime
- $P_g(y)$ is the profit from energy generated in year y in US$
- $C_p(y)$ is the cost of energy used for pumping in year y in US$.
- $E_g(y)$ and $E_p(y)$ are the energy generated and the energy used for pumping, respectively, calculated in Subsection 9 (Chapter IV, Section B) in MWh.

6. Cost of CO_2 emissions

The cost of CO_2 emissions, which can be referred to by the social cost of carbon, is the net present value of the climate change impacts of one additional ton of carbon emission, over the next 100 years (Watkiss, 2003). A price on CO_2 emissions gives incentive to both producers and consumers to reduce emissions (Litterman, Summer 2013). The cost of CO_2 emissions in Lebanon is taken from (El-Fadel, et al., 2010), as given in Table 5.

The cost of CO_2 emissions per year can be calculated by using the cost of CO_2 emissions per ton from Table 5 by Eq. (37), it can also be considered as profit as in Eq. (38)

$$C_{CO2}(y) = \begin{cases} C_{CO2} \times CO_2(y), & CO_2(y) \geq 0 \\ 0, & CO_2(y) < 0 \end{cases} \quad (37)$$

$$P_{CO2}(y) = \begin{cases} -C_{CO2} \times CO_2(y), & CO_2(y) < 0 \\ 0, & CO_2(y) \geq 0 \end{cases} \quad (38)$$

where $C_{CO2}(y)$ is the cost of emissions in year y in US$, given in Table 5, and $CO_2(y)$ is calculated by Eq. (22).

The cost of emissions per year from the pumping energy should be added to the total costs. However, for the generated energy, the cost of emissions from equivalent thermal plant should be deducted from the costs of the PHS plant. They are considered as savings or profit on the total cost.

7. Operations and maintenance (O&M) cost

From Table 5, it is assumed that the O&M cost is 1% from the initial cost of the project.

8. Principle annual payments

When a loan is borrowed with an interest rate over a certain period, there are two payments that are to be paid to the bank, a principal repayment and an interest repayment.

The annual payment is calculated for $\mathbf{1 \leq y \leq lifetime}$, using Eq. (39), using parameters from Table 4 (Beggs, 2009). It represents the borrowed money distributed on annual payments with a given interest rate.

$$\boldsymbol{AP(y) = -\frac{Borrowed}{\frac{(1+i)^{l}-1}{i(1+i)^{l}}}} \qquad \textbf{(39)}$$

The annual interest repayment is the annual amount of interest money owed to the bank. It can be calculated by using Eq. (40) where the unpaid balance is introduced in Eq. (42) (Beggs, 2009)

$$\boldsymbol{Int\_pay(y)} = \begin{cases} \mathbf{0}, \ \boldsymbol{for\ y = 0} \\ \boldsymbol{Unpaid\_balance(y-1) \times i}, \ \boldsymbol{for\ 1 \le y \le l} \end{cases} \quad \textbf{(40)}$$

Finally, the yearly principle repayment is the amount of money owed to the bank towards the original loan, not taking into consideration the interest repayments. For example, if the owner takes a 1,000$ loan from the bank at an interest rate of 10% for a 5 year period. After year 1, the interest repayment to be paid to the bank is 100$, from Eq. (40). Thus the owner now owes 1100$ to the bank (1000$ loan plus 100$ interest). The annual payment to be paid at this interest rate is 263.8$ over 5 years, from Eq. (39). Thus, after year 1, the owner owes the bank 836.2$ as unpaid balance (1100-263.8). The principal payment is 163.8$ not including the 100$ as interest.

An annual principal repayment is calculated by Eq. (41) by taking into consideration the annual payments and the interest payments.

$$\boldsymbol{Pay(y) = AP(y) + Int\_pay(y)} \quad \textbf{(41)}$$

To verify that the calculations are true, we can calculate the yearly unpaid balance that should be zero at the end of the lifetime. Eq. (42) is used

$$\boldsymbol{Unpaid\_balance(y)} = \begin{cases} \boldsymbol{borrowed, for\ y = 0} \\ \boldsymbol{Unpaid\_balance(y-1) + Pay(y)}, \ \boldsymbol{for 1 \le y \le l} \end{cases}$$

(42)

9. Net income

The yearly total cost of the project is the sum of the cost of energy used for pumping, the social cost of CO2 emissions, the O&M cost, the depreciation cost, and the interest payments. They are summarized in Eq. (43). The yearly profit is in Eq. (44). Yearly net income can thus be calculated by Eq. (45).

$$\boldsymbol{C_{total}(y) = C_p(y) + C_{CO2}(y) + C_{O\&M}(y) + dep(y) + Int\_pay(y)} \quad \textbf{(43)}$$

$$\textbf{Profit}(\mathbf{y}) = \boldsymbol{P_g(y)} + \mathbf{P_{CO2}(y)} \quad \textbf{(44)}$$

$$\boldsymbol{net\_income(y) = f(x) = \begin{cases} 0, & y = 0 \\ P_g(y) - C_{total}(y), & 1 \le y \le lifetime \end{cases}} \quad \textbf{(45)}$$

where $P_g(y)$ is the profit from the energy generated in year y in \$.

10. Project investment appraisal

Several financial techniques can be used to justify a project's capital. The payback period, discounted cash flow techniques of the net present value and internal rate of return are discussed and studied for this project.

First, the net cash flow of savings and the net cash flow of costs of the project are calculated by using Eq. (46) and (47). These are the net savings and the net costs per year, respectively. Then the cumulative cash flow, given by Eq. (48), can be calculated by using the net cash flow. It reflects the profit per year taking into consideration the initial cost (capital) and the borrowed money at year 0. The discounted cumulative cash flow, given by Eq. (49), also represents the profit per year, but taking into consideration the discount rate (interest rate). (Beggs, 2009)

$$\boldsymbol{net\_cash\_flow(y) = -C_{initial}(y) + Borrowed(y) + net\_income(y) + Salvage(y) + dep(y) + Pay(y)} \quad \textbf{(46)}$$

$$\boldsymbol{cash\_flow\_costs(y) = P_g(y) - net\_cash\_flow(y)} \quad \textbf{(47)}$$

$$\boldsymbol{cum\_cash\_flow(y)} =$$

$$\begin{cases} (-\boldsymbol{C_{initial}} + \boldsymbol{Borrowed}), & \boldsymbol{for\ y = 0} \\ \boldsymbol{cum\_cash\_flow(y-1)} + \boldsymbol{net\_cash\_flow(y)}, & \boldsymbol{for\ 1 \le y \le l} \end{cases}$$

(48)

$$\boldsymbol{dis\_cash\_flow(y)} =$$

$$\begin{cases} (-\boldsymbol{C_{initial}} + \boldsymbol{Borrowed}) & ,\boldsymbol{for\ y = 0} \\ \boldsymbol{dis\_cash\_flow(y-1)} \times \left(\boldsymbol{1} + \frac{\boldsymbol{ir}}{\boldsymbol{100}}\right) + \boldsymbol{net\_cash\_flow(y)}, & \boldsymbol{for\ 1 \le y \le l} \end{cases}$$

(49)

The net present value (NPV) method given by Eq. (53) quantifies the impact of time on a future cash flow. This is done by determining the PV of any future cash flow or, in other words, equating each future cash flow to its PV today (Beggs, 2009). The PVs for the net profit, net costs, and energy generated are calculated by Eq. (50), (51), and (52). A positive NPV implies that the investment will exceed the project requirements; a zero NPV implies that the investment will exactly meet the project requirements; and a negative NPV implies that the investment will not meet the project requirements.

$$\boldsymbol{PV_{netcashflow}(y)} = \frac{\boldsymbol{net\_cash\_flow(y)}}{(\boldsymbol{1}+\boldsymbol{interest})^{y}} \quad \textbf{(50)}$$

$$\boldsymbol{PV_{cashflowcosts}(y)} = \frac{\boldsymbol{cash\_flow\_costs(y)}}{(\boldsymbol{1}+\boldsymbol{interest})^{y}} \quad \textbf{(51)}$$

$$\boldsymbol{PV_{energy}(y)} = \frac{\boldsymbol{E_g(y)}}{(\boldsymbol{1}+\boldsymbol{interest})^{y}} \quad \textbf{(52)}$$

$$\boldsymbol{NPV} = \sum_{y=0}^{l} \boldsymbol{PV_{netcashflow}(y)} \quad \textbf{(53)}$$

The payback period (PBP) is defined as 'the length of time required for the running total of net savings before depreciation to equal the capital cost of the project'

(Beggs, 2009). In other words, after the PBP has passed, any savings from the project is considered pure profit. Thus the shorter the PBP, the more attractive the project is. The discounted PBP is more realistic than the simple PBP in that it takes into consideration that 'time value' of the money invested. Thus the discounted PBP includes the interest rate over the period of study (lifetime of the project). Both PBPs are calculated using Eq. (54) and (55).

$$\boldsymbol{PBP = f(x) =}$$

$$\begin{cases} \mathbf{0}, & \boldsymbol{for\ comm\_cash\_flow(y = 0) > 0} \\ (\boldsymbol{y} - \mathbf{1}) + \left| \frac{\boldsymbol{comm\_cash\_flow(y-1)}}{\boldsymbol{comm\_cash\_flow(y) - comm\_cash\_flow(y-1)}} \right|, & \boldsymbol{for\ comm\_cash\_flow(1 \leq y < l\,) > 0} \\ > \boldsymbol{lifetime}, & \boldsymbol{for\ comm\_cash\_flow(y = l\,) < 0} \end{cases} \quad \textbf{(54)}$$

$$\boldsymbol{dis\_PBP =}$$

$$\begin{cases} \mathbf{0}, & \boldsymbol{for\ dis\_cash\_flow(y = 0) > 0} \\ (\boldsymbol{y} - \mathbf{1}) + \left| \frac{\boldsymbol{dis\_cash\_flow(y-1)}}{\boldsymbol{dis\_cash\_flow(y) - dis\_cash\_flow(y-1)}} \right|, & \boldsymbol{for\ dis\_cash\_flow(1 \leq y < l) > 0} \\ > \boldsymbol{lifetime}, & \boldsymbol{for\ dis\_cash\_flow(y = l\,) < 0} \end{cases} \quad \textbf{(55)}$$

If the interest (discount) rate is reduced, there will be a point where the NPV becomes zero. The discount rate at this point is the internal rate of return (IRR). Obviously, for a higher IRR than the interest rate, the project is more appealing. IRR is calculated using Eq. (56) (Beggs, 2009).

$$\boldsymbol{irr = interest\ rate(for\ NPV = 0)} \quad \textbf{(56)}$$

To study the project's financial viability, the profitability index (PI) can as well be calculated using Eq. (57) (Beggs, 2009). Also, the higher the PI, the more attractive the project is:

$$\boldsymbol{PI = \frac{Sum\ of\ discounted\ net\ savings}{Capital\ Cost}} \quad \textbf{(57)}$$

In energy projects for particular, the levelized cost (LC) for the project should be calculated in order to compare it with other projects of the same or different nature. The LC is the per KWh cost of building and operating a power plant in (USD/KWh) over the lifetime of that plant as shown in Eq. (58).

$$\boldsymbol{levelized\ cost = \frac{NPV\ costs}{NPV\ energy}} \quad \textbf{(58)}$$

11. Results

For the assumed and given input parameters, the results obtained by the MatLab program are summarized in Table 9. It is worth mentioning that for the power plant design, the head loss due to friction was 5.53 m, the generation flow discharge is 32.3 m^3/s, and the pumping flow discharge is 48.5 m^3/s in this case.

Table 7: MatLab cost analysis output for 3 m diameter

Parameter	**Symbol**	**Unit**	**Quantity**
Head Loss due to Friction	h_L	meters	5.53
Net Present Value	NPV	Millions of USD	-9.55
Payback Period	PBP	Years	10.38
Discounted Payback Period	dis_PBP	Years	50
Internal Rate of Return	IRR	%	8.38
Levelized Cost	c_lev	USC	21.27
Profitability Index	PI		0.44
Overall System Efficiency	η_{system}	%	63.56

The estimated levelized cost compares favorably with those of conventional thermal power plants and even renewable plants in Lebanon where levelized costs vary typically between 22.8 and 37.032 USC/KWh, as shown in Figure 5. The estimated efficiency of a pumped-storage system is between 70-85% (*Electrical Energy Storage*, 2011). Most of the output parameters for the assumed conditions reflect a non-profitable project for the assumed conditions. The NPV is negative, the discounted PBP is very high, the overall system efficiency is 64% and the profitability index is less than 1. Thus the overall system design is not acceptable or feasible for the assumed parameters.

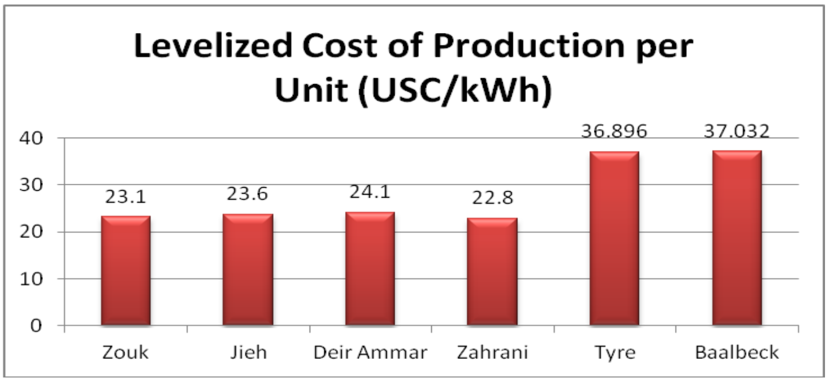

Figure 5: Levelized Cost of production per unit (USC/KWh) for power plants in Lebanon (MoE/URC/GEF, December, 2012)

In case we change the diameter of the penstock in the system parameters from 3 m to 2 m, and for the same other parameters, the head loss due to friction increases to 8.8 m which is still very acceptable taking a maximum of 10% head loss to be the accepted loss. The generation and pumping flow discharges become 14.36 and 21.55

m^3/s, respectively. All feasibility parameters reflect a non-feasible project for this case as shown in Table 8. The parameters when the diameter of the penstock is 2 m are worse -taking feasibility ranges- from those when the diameter is 3 m. The reason is that with the increase in diameter, the flow discharges increase and thus the power increases. The increase in the diameter of the penstock is used to compensate the low head between the reservoirs.

Table 8: MatLab cost analysis output for 2 m diameter

Parameter	Symbol	Unit	Quantity
Head loss due to Friction	h_L	meters	8.8
Net Present Value	NPV	Millions of USD	-33.58
Payback Period	PBP	Years	50
Discounted Payback Period	dis_PBP	Years	50
Internal Rate of Return	IRR	%	-15.22
Levelized Cost	c_lev	USC	26.38
Profitability Index	PI		-0.00631
Overall System Efficiency	η_{system}	%	51

CHAPTER V

COST ANALYSIS

After obtaining the results of the cost parameters, a cost analysis will be conducted in order to assess those parameters and get the ultimate solution(s). Sensitivity analysis will be conducted where some input parameters that are of interest were varied and the cost parameters for each case were calculated for comparison purposes. Those input parameters were the interest rate (discount rate), lifetime (study period), duration of generation, and duration of pumping.

A. Interest rate

When a project is financed partially or totally through bank loans, an interest rate or discount rate is applied on the amount of money, thus adding to the overall cost of the project.

The interest rate (ir) is varied from 1% to 10%, the interest rate of return (IRR), net present value (NPV), payback period (PBP), discounted PBP, levelized cost (LC), the profitability index (PI), and the overall system efficiency were calculated for each value of ir. The solutions are plotted in Figures 6, 7, 8, 9, 10, and 11. According to the World Bank Indicators (Economics, 2014), the interest rate on loans varied up to 10% in the past couple of years in Lebanon, thus the 10% rate will be our margin.

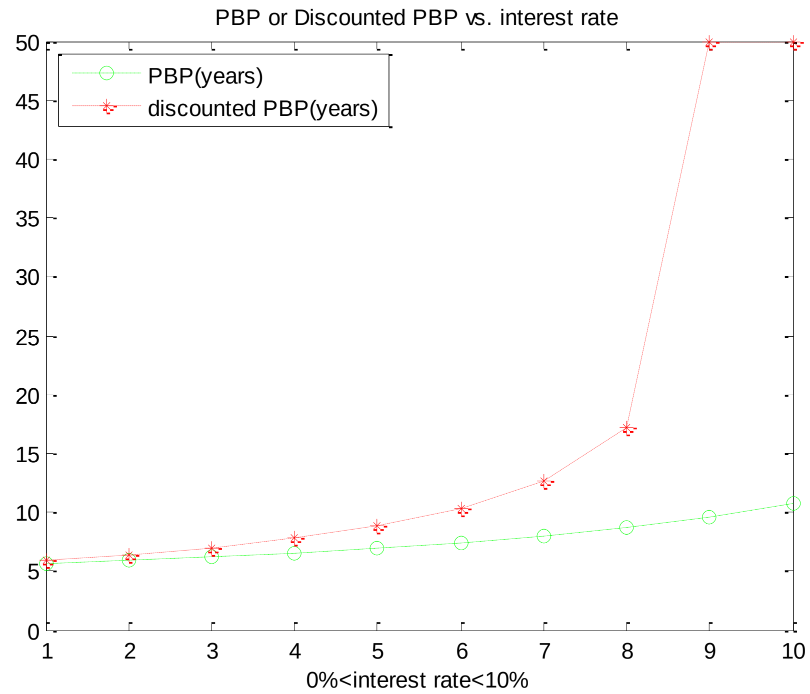

Figure 6: PBP and Discounted PBP for Different Interest Rates

As mentioned earlier, the PBP is the time after which the income can be considered pure profit to the owner. Obviously, the smaller the PBP or the discounted PBP, the more attractive the project is. As shown in Figure 6, the discounted PBP is reasonable for all the values of interest rate less than 8%. Thus, interest rate should not exceed 8% (ir $\leq$ 8%).

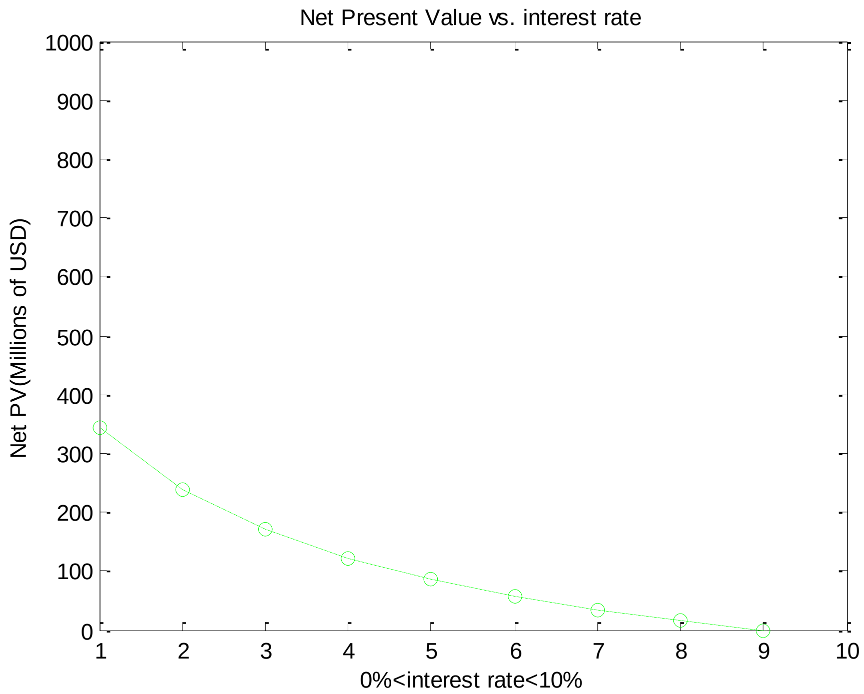

Figure 7: NPV for Different Interest Rates

Since the NPV represents the present value of the cash flow, the higher the NPV is, the more attractive is the investment. NPV should be positive. Thus, from Figure 7, the interest rate should not exceed 9% ($ir < 9\%$).

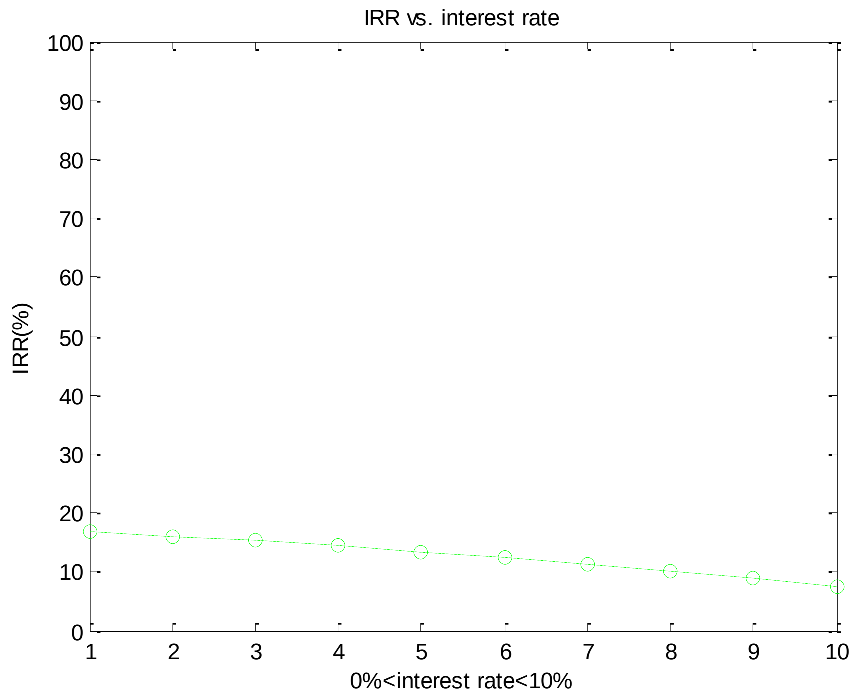

Figure 8: IRR for Different Interest Rates

IRR is the interest rate where NPV becomes zero. Thus when IRR is higher than the interest rate, the investment is the more appealing. The interest rate should not exceed 8% as shown in Figure 8 ($ir < 8\%$).

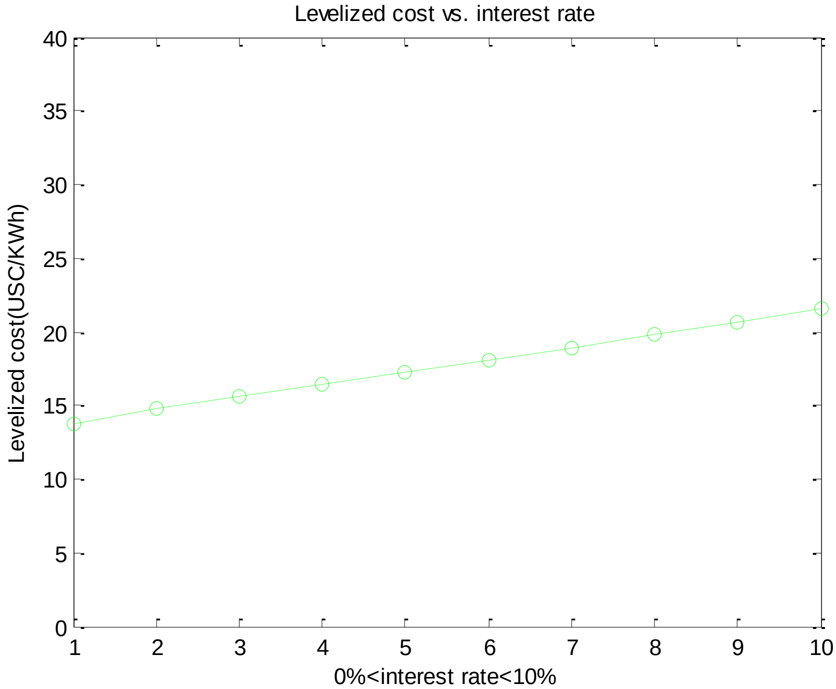

Figure 9: Levelized Cost for Different Interest Rates

Levelized cost (LC) is the cost of the project in US$/ KWh. In renewable energy systems, the less the LC is, the better it is compared to other systems. In order to analyze Figure 9, a comparison should be made with other systems given in Figure 5. LC for the different thermal power plants in Lebanon is between 22.8 USC/KWh and 37.032 USC/KWh. From Figure 9, the highest levelized cost reached was less than 25 USC/KWh for interest rate of 10%. ($ir < 10\%$).

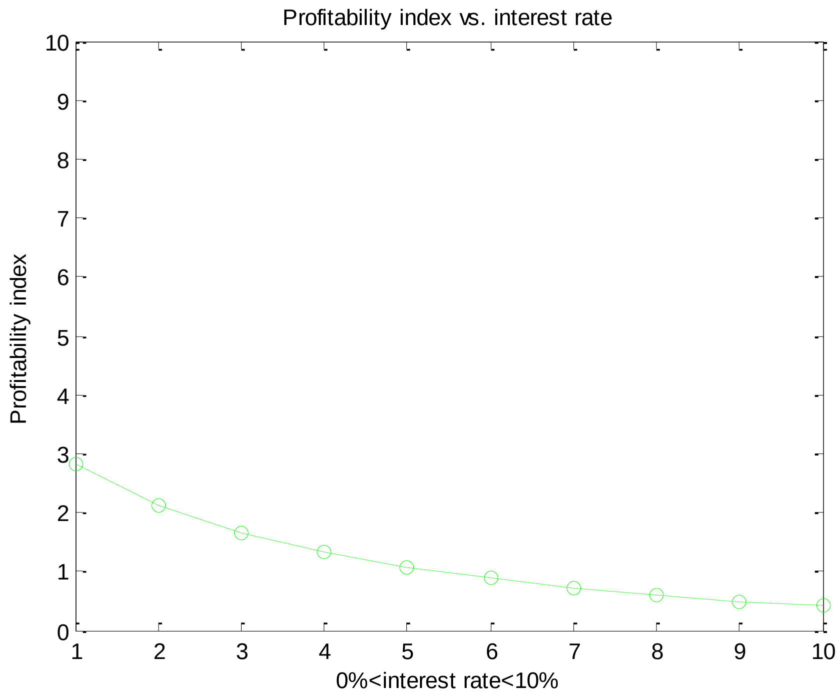

Figure 10: PI for Different Interest Rates

As mentioned earlier, the higher the profitability index (PI) is, the more attractive is the investment. Moreover, since PI is the sum of the discounted net savings over the capital cost as given in Eq. (53), PI should be greater than 1 for a more profitable project. Thus from Figure 10, the interest rate should not exceed 5% ($ir < 5\%$).

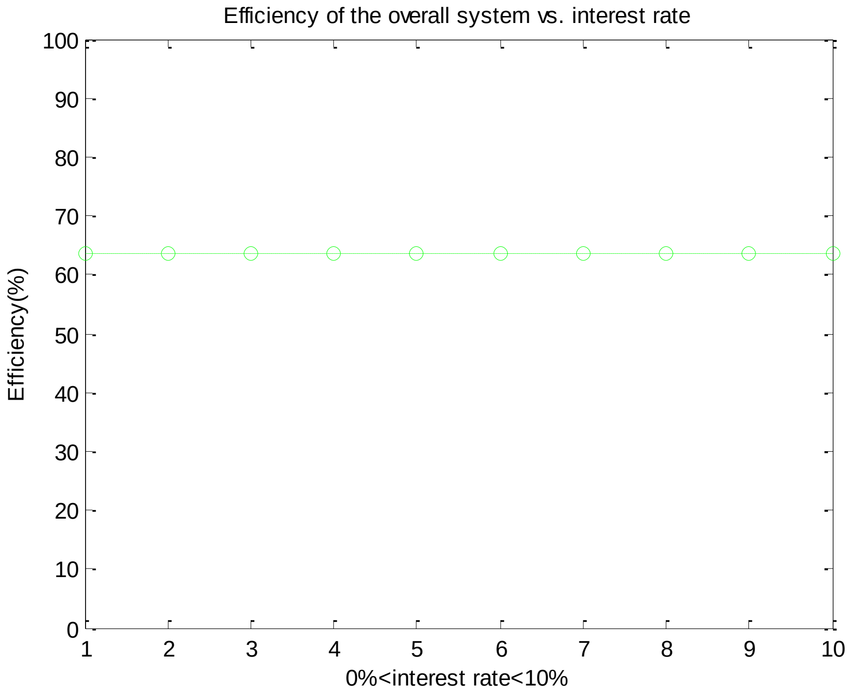

Figure 11: Overall System Efficiency for Different Interest Rates

Since both, the energy generated and the energy used for pumping, do not depend on the interest rate, the efficiency is not affected by the variation of the interest rate.

In conclusion, taking all the above conditions, for a more profitable investment, interest rate should not exceed 5% ($ir \leq 5\%$).

B. Equity

Equity is the percentage from the capital cost that the owner of the investment is willing to pay from his own balance.

First, for this part, the interest rate is assumed 5% referring to the previous conclusions. Equity is varied from 0% and 100%, where zero equity implies that the bank will fully finance the project, and 100% equity implies that the owner of the project will fully finance it. IRR, NPV, PBP, discounted PBP, levelized cost, the overall system efficiency, and the PI were calculated again for each value of equity. The solutions are plotted in Figures 21-25.

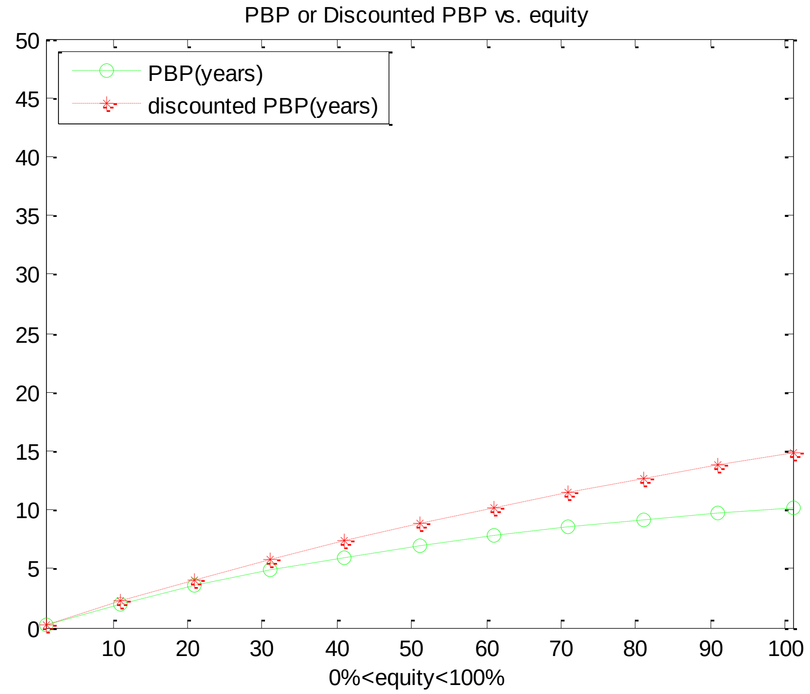

Figure 12: PBP and Discounted PBP for Different Equity Values

The PBP and discounted PBP increase with the increase in equity. The reason for this gradual increase is that the PBPs are dependent on the cumulative cash flow and the discounted cash flow which, in turn, are dependent on equity as explained by Eq. (31), (44), (45), (50), and (51). Both PBPs are still less than 15 years which is reasonable.

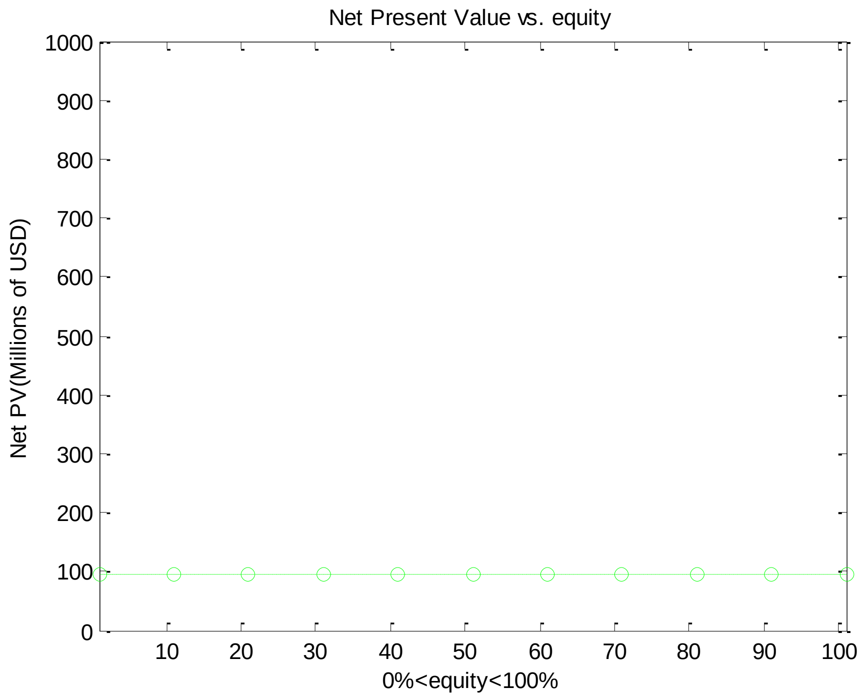

Figure 13: NPV for Different Equity Values

NPV doesn't vary with the variation in equity. The reason is that with the increase in equity, the present value of the cash flow increases with the same amount of decrease in borrowed funds.

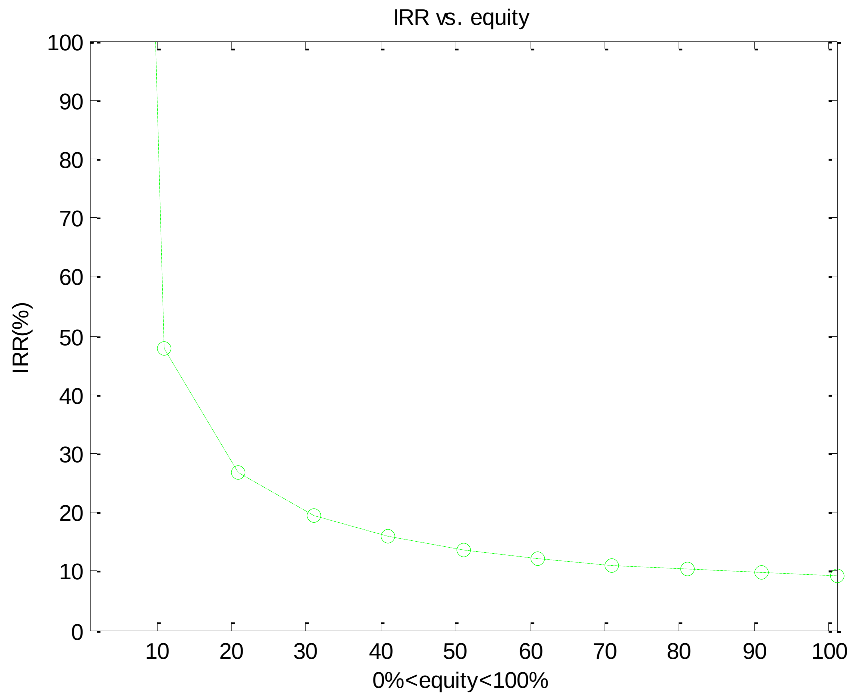

Figure 14: IRR for Different Equity Values

IRR decreases with the increase in equity because with the increase in equity value, a zero NPV is attained for a lower interest rate. Any case with an equity value that exceeds 10% gives a feasible solution, according to Figure 14 ($equity \geq 10\%$).

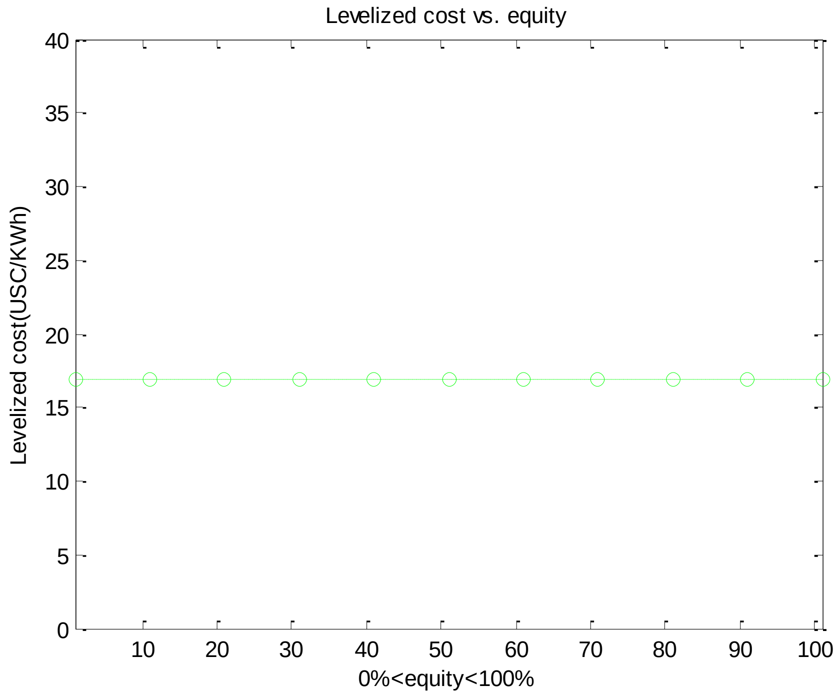

Figure 15: Levelized cost for different equity values

The levelized cost doesn't vary with the increase in equity because the increase in costs is neutralized with the cash flow.

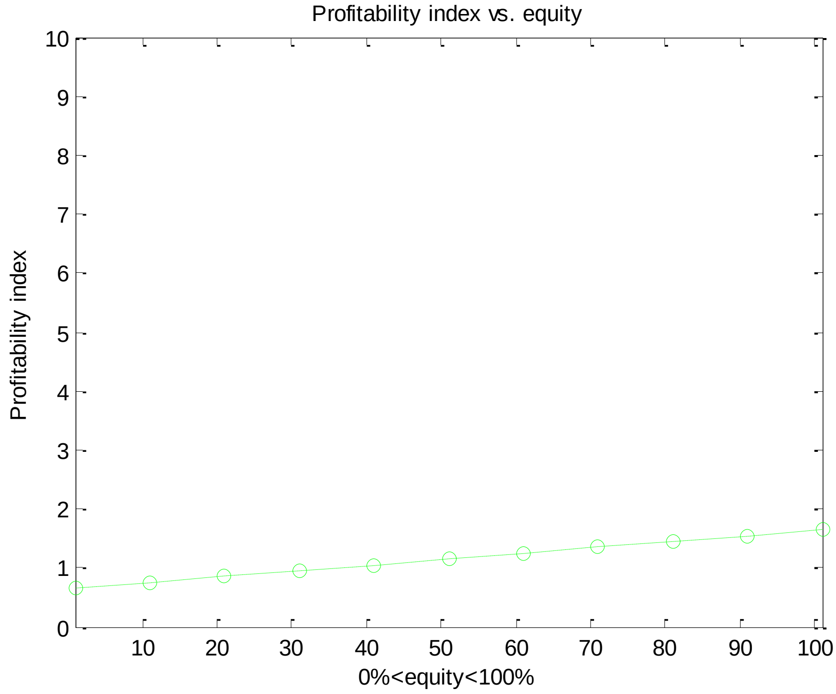

Figure 16: PI for different equity values

The profitability index increases with the increase in equity because of the increase in the present value of the cash flow. PI is greater than 1 for all values of equity that exceed 40% ($40 \leq equity \leq 100\%$).

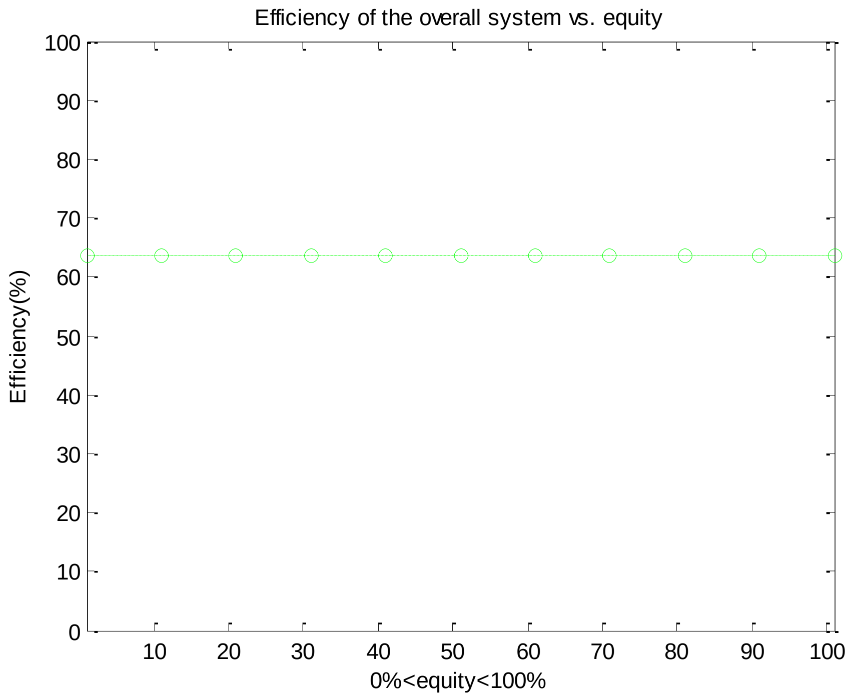

Figure 17: Overall System Efficiency for Different Equity Values

The overall system efficiency does not depend on equity, thus it doesn't vary with the variation of equity.

In conclusion, any equity value greater than 40% is a feasible solution ($40 \leq equity \leq 100\%$).

C. Generation and pumping durations

The profitability of the project is also affected by the generation and pumping durations of the PHS power plant. The generation duration is the duration of generating hydro-energy per day during the peak hours. The pumping duration is the duration of pumping water from the lower back to the upper reservoir during off-peak hours.

For this part of the analysis, equity is changed to 40%. The generation duration is varied from 1 hour to 16 hours (peak duration), and the duration of pumping is varied from 1 hour to 8 hours (off-peak duration). IRR, NPV, PBP, discounted PBP, levelized cost, the overall system efficiency, and the PI were calculated again for each combination of the generation and pumping durations.

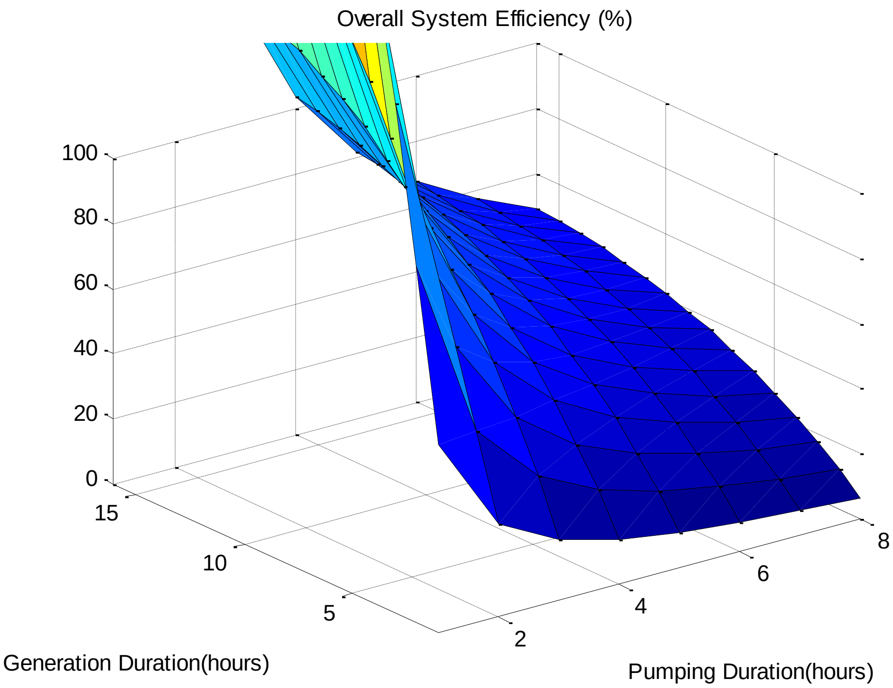

Figure 18: Overall System Efficiency for Different Generation and Pumping Durations

The overall system efficiency increases with the increase in generation duration because the energy generated increases, simultaneously. Yet it decreases with the increase of pumping duration because it is inversely proportional to the energy used for pumping.

As mentioned earlier, the standard efficiency of such a system is 70-85%. By using Matlab code, a combination of 11 optimal solutions is deduced, in Table 9, meeting the above requirement. To compare the other scenarios, the IRR, PI, levelized cost, initial cost and NPV were computed. A compromise needs to be achieved between different factors affecting the profitability of the project.

Table 9: Combination of Generation and Pumping Durations for optimal efficiency

Scenario Number	Generation Duration (hours)	Pumping Duration (hours)	Efficiency (%)	Discounted PBP (years)	IRR (%)	PI (%)	Levelized Cost (USC/KWh)	NPV (Millions USD)
1	**3**	**2**	76.9	16.42	-14.43*	-0.14**	18.96	-40.55*
2	**5**	**3**	75.9	49.11	-2.36*	0.11**	14.86	-35.20*
3	**7**	**4**	71	114.6	0.057	0.19**	13.97	-36.41*
4	**8**	**4**	77.3	22.4	7.36	0.52**	12.31	24.44
5	**9**	**4**	82.7	10.6	12.52	0.84**	11.04	96.93
6	**11**	**5**	72	18.42	8.46	0.59**	12.22	49.81
7	**12**	**5**	75.2	10.66	12.73	0.84**	11.42	127.3
8	**13**	**5**	**77.6**	**7.88**	**16.17**	**1.04**	**10.84**	**203.92**
9	**14**	**5**	**79.2**	**6.52**	**18.9**	**1.21**	**10.43**	**276.62**
10	**15**	**5**	**81.2**	**5.48**	**21.86**	**1.39**	**10.00**	**363.19**
11	**16**	**5**	**82**	**4.95**	**23.84**	**1.52**	**9.77**	**435.24**

*less than zero
**less than one

Parameters for scenarios 1-7 are not in the accepted ranges. Thus EDL would have to compromise between the different parameters for scenarios 8-11 according to its priorities. It was noticed that the project is feasible mostly in the cases where the hours of generation exceed the hours of pumping. Such cases give a higher efficiency than when pumping hours are higher than generation hours.

Graphs for discounted PBP, IRR, PI, levelized cost, and NPV are shown in Figure 19, Figure 20, Figure 21, Figure 22, and Figure 23, respectively. The different colors in the same graph reflect the change in the curve shape.

The discounted PBP is affected negatively by the increase in the cost of generation, and positively by the increase in the cost of pumping, as shown in Figure 19.

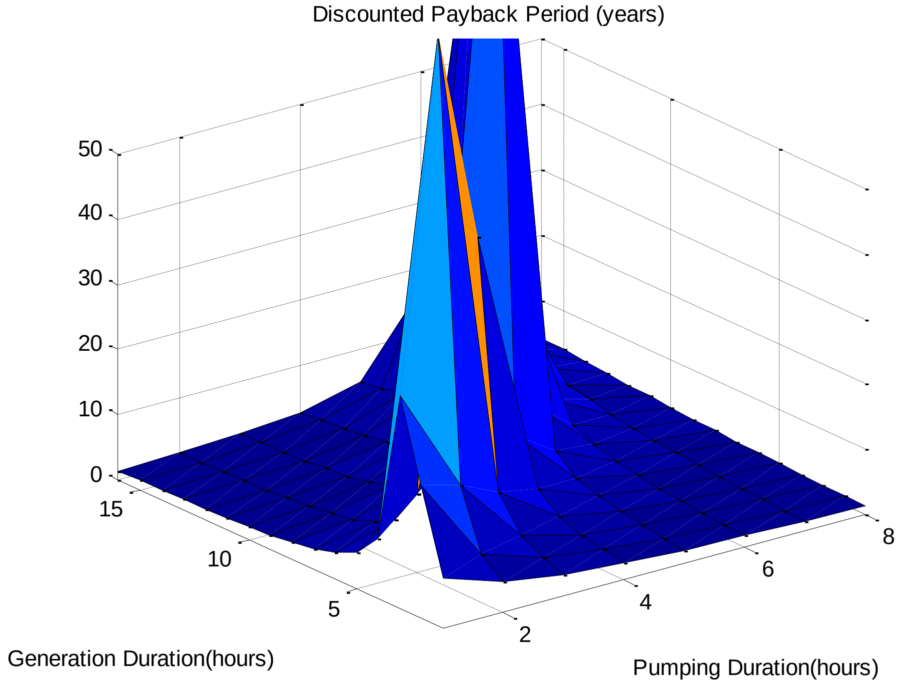

Figure 19: Discounted PBP for Different Generation and Pumping Durations

IRR is dependent on the cost of generation and the cost of pumping. Thus it depends on both the generation and pumping durations. Thus IRR increases with the increase in generation duration and decreases with the increase in pumping duration as shown in Figure 20.

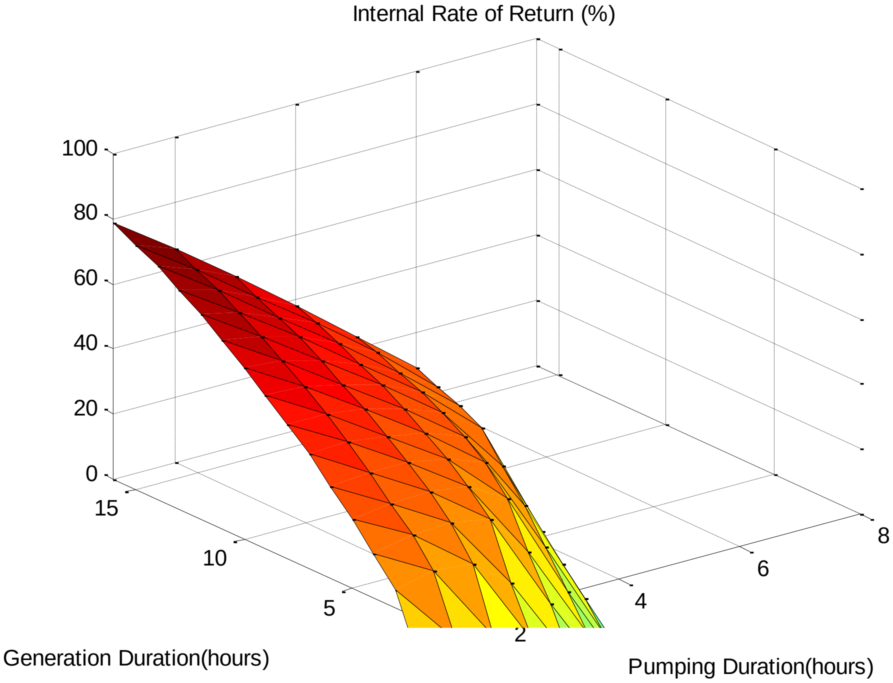

Figure 20: IRR for Different Generation and Pumping Durations

PI depends on the sum of discounted net savings which is in fact the net present value (NPV) from year 1 till lifetime. NPV is dependent on the cost of generation and the cost of pumping. Thus PI depends on both the generation and pumping durations. Thus PI increases with the increase in generation duration and decreases with the increase in pumping duration as shown in Figure 21.

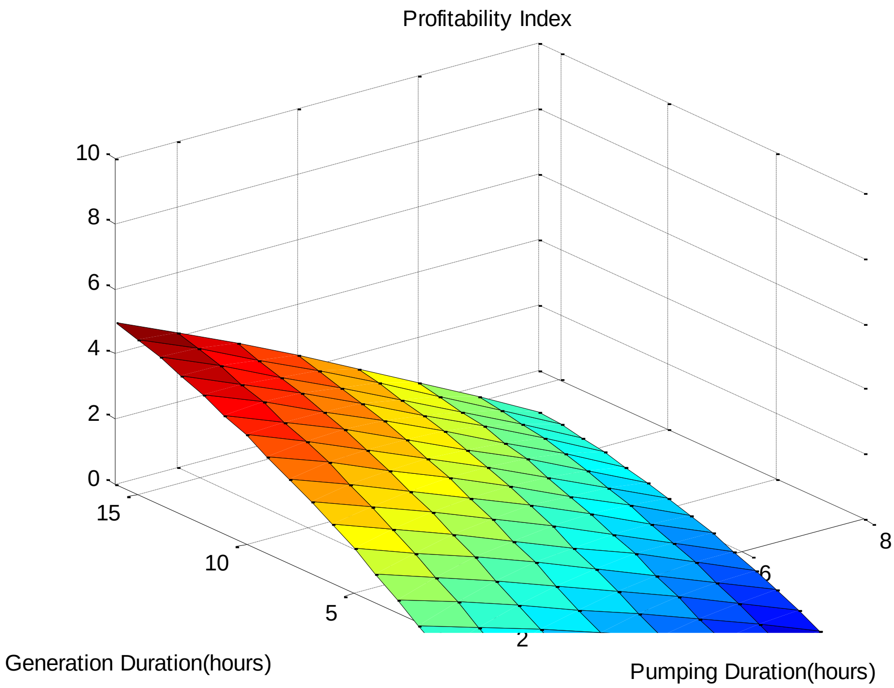

Figure 21: PI for Different Generation and Pumping Durations

Levelized cost is inversely proportional to the energy generated and thus the duration of energy. Therefore, levelized cost decrease with the increase in generation duration as shown in Figure 22.

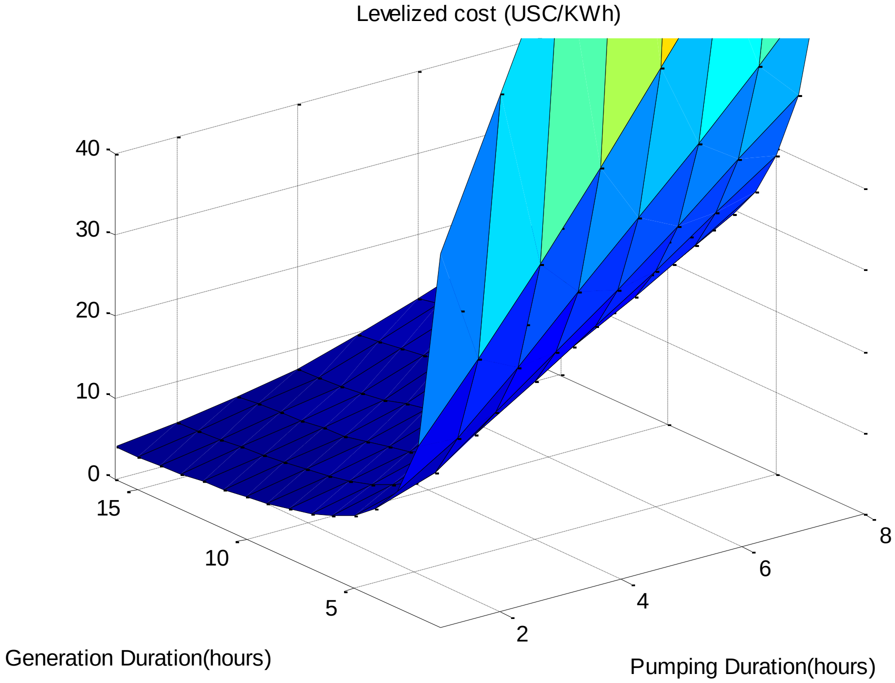

Figure 22: Levelized Cost for Different Generation and Pumping Durations

NPV is dependent positively on the cost of generation and negatively on the cost of pumping, as shown in Figure 23.

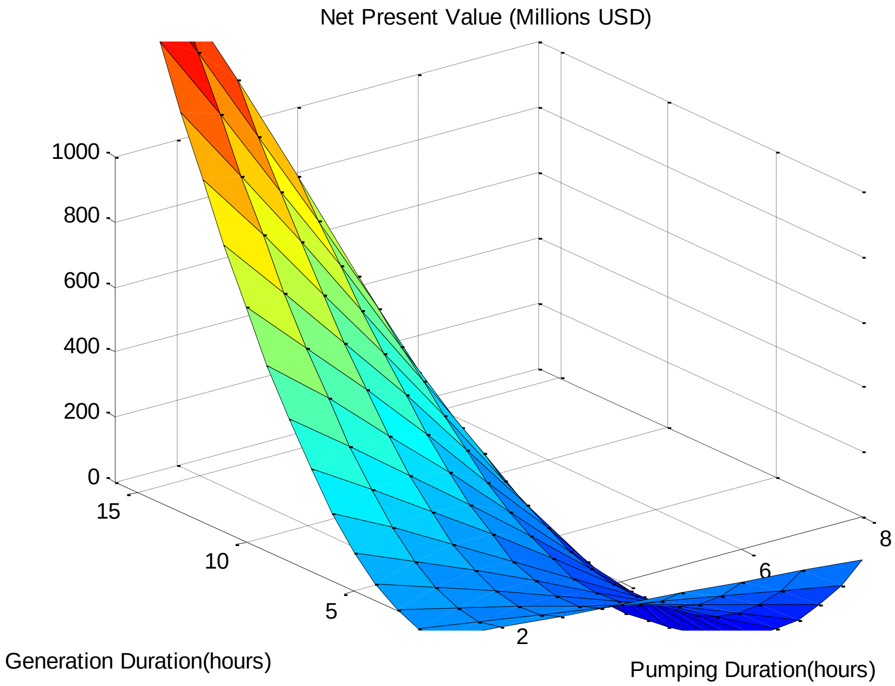

Figure 23: NPV for Different Generation and Pumping Durations

CHAPTER VI

CONCLUSIONS

A design for a pumped hydro storage (PHS) power plant at Chabrouh is performed. A proper location for the lower reservoir is chosen so that the system head is 177 m head and the penstock is 1.9 km linking the lower reservoir to the upper- already existing- reservoir. Then, the type of flow is determined by calculating Reynold's number. The type of flow determines the friction factor that is used to calculate the head loss due to friction. In addition, the head loss due to the daily distribution of water is calculated. To conclude the hourly generation and pumping power, and thus energy, the generation and pumping flow discharges were calculated. Eventually, the daily and yearly generation and pumping energy values were concluded.

A cost analysis for the project is studied taken into consideration the cost parameters given in Table 5.

Initial cost of the project is a combination of civil and electrical costs. A borrowed amount is considered when the owner doesn't finance 100% of the project's initial cost.

CO_2 emmissions from generation are taken as a negative value because the generation is from a hydroenergy source with little emmissions to be considered. On the other hand, CO_2 emmissions from pumping are taken as positive because a thermal plant is used in the pumping process. We have to note that due to this pumping energy that is taken from the thermal plant, there should be an increase in efficiency that is not taken into consideration in the study.

Yearly depreciation, cost of energy for pumping, CO_2 emmissions cost, opeations and maintainance (O&M) cost, and interest annual payments, all constitute the costs of the project. Profit from energy generation and profit from CO_2 emmissions constitute the the profit of the project. The net income is therefore deduced.

In order to study the system's feasibility, the net present value (NPV), internal rate of return (IRR), profitability index (PI), the discounted payback period (PBP), levelized cost (LC), and the overall system efficiency are calculated. Thus, the net cash flow, net cash flow for costs only, commulative cash flow, and discounted commulative cash flow are calculated.

It is obvious from the analysis that the project can be feasible for certain conditions, and that it can be beneficial both financially and environmentally.

The following conditions for a feasible PHS power plant at Chabrouh are concluded:

- The recommended interest rate for the PHS power plant is less than or equal to 5%.
- The recommended equity or percentage invested by the owner in the initial cost of the PHS power plant is greater than or equal to 40%.
- Taking an interest rate of 10% and an equity of 40%, 4 scenarios were obtained in Table **9** and can be chosen from. The cost of CO_2 emissions, the initial cost, and the mean annual generation were calculated, in Table **10**, for each of the scenarios in order to compare them with those in Table **2**.

Table 10: Comparison between efficient scenarios

Scenario Number	**Generation Duration (hours)**	**Pumping Duration (hours)**	**Cost of CO_2 emmissions (million USD)**	**Initial Cost (million USD)**	**Mean Annual Generation Capacity (GWh)**	**Discounted PBP (years)**
8	**13**	**5**	**364.92**	**316.65**	**499.9**	**7.88**
9	**14**	**5**	**375.01**	**340.9**	**564.9**	**6.52**
10	**15**	**5**	**370.61**	**365.09**	**631.6**	**5.48**
11	**16**	**5**	**386.96**	**389.35**	**699.3**	**4.95**

- By comparing the parameters for the PHS projects given in Table 2 to those in Table **9**, scenarios with similar annual generation capacity have lower initial costs. The reason is that the upper reservoir is already constructed and thus its cost is deducted from the intial cost. Moreover, the PBP in our design is much less than those in Table **2**.

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