Università degli Studi di Padova

Department of Industrial Engineering - DII

Master's degree course in Energy Engineering

PUMPED HYDRO STORAGE: TECHNOLOGY OVERVIEW AND METHODS FOR THE EVALUATION OF NEW PUMPING PLANTS APPLIED TO THE CASE STUDY OF TIRSO 1 AND TIRSO 2 IN SARDINIA

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ABSTRACT

Nowadays, with the climate change challenge and the goals to decarbonize our industries, starting from the energy sector, the subject of energy storage is more important than ever. The electrification of the final uses will mean an increase in the request of electric energy, but a more intermittent power supply, mainly from solar (scale utility and solar rooftop) and wind (onshore and offshore), will create a more challenging environment for the grid managing, stability and for the predictability of the production.

Pumped hydro can offer a serious and competitive option when considering utility scale storage.

The objectives of this thesis are to give an overview of the state of the art for the hydroelectric storage, talking about its strengths and weaknesses, always having in mind economic and environmental considerations, and its future, particularly in Italy. And thinking about how to correctly use the limited water resource so that all the stakeholders can be considered when making decisions, so all the services shall be considered.

After an overview of the technology, the thesis will focus on a real case study of Tirso 1 and Tirso 2 in Sardinia, where there is an opportunity to evaluate the feasibility of a pumped storage plant. The PHS would work in parallel to Tirso 1. The goal here is to study the case and understand its critical aspects.

One of the aspects presented in this thesis, is the importance of revamping or repowering older hydropower power plants, older dams, so to reduce the civil works and costs behind these capital-intensive projects, since it is difficult to find suitable sites and that, at least in Europe, there is not a lot of appetite for large new hydropower power plant.

Clearly pumped hydro storage is not the one solution but, it is part of a wide range of technologies, necessary to achieve the stated long-term climate goals.

GLOSSARY

RES	Renewable energy source
VRE	Variable renewable energy
HP	Hydropower
IRENA	International Renewable Energy Agency
PHS	Pumped Hydro Storage
DOE	Department of Energy (United States of America)
CCS	Carbon capture and storage
IRA	Inflation reduction act
PV	Photovoltaic
GT	Gas turbine
TSO	Transmission system operator
HV	High voltage
MV	Medium voltage
CAES	Compressed air energy storage
LCOS	Levelized cost of storage
CAGR	Compounded annual growth rate
ARERA	Autorità di Regolazione per Energia, Reti e Ambiente
TSO	Transmission System Operator
PaT	Pump As Turbine
PT	Pump Turbine
GIS	Geographical Information System
NREL	National Renewable Energy Laboratory
US	United States
GWP	Global Warming Potential
MCA	Multi Criteria Analysis
LCA	Life Cycle Assessment
DMV	Minimum vital flow (or Deflusso Minimo Vitale)
ISTAT	Italian National Institute of Statistics
DCF	Discounted Cash Flow
PBT	Pay Back Time
ROI	Return On the Investment
NPV	Net Present Value
IP	Profitability Index
IRR	Internal Rate of Return
WACC	Weighted Average Cost of Capital
CAPEX	Capital or Investment cost
OPEX	Operation and maintenance cost
VIA	Environmental impact assessment (or Valutazione Impatto Ambientale)
M	Million
MAX	Maximum
MIN	Minimum
T1	Tirso 1
T2	Tirso 2

NOTATION

P	Power	$[W]$
R	Electrical resistance	$[\Omega]$
I	Current	$[A]$
n	Rotational speed	$[rpm]$
f'	Frequency	$[Hz]$
s	Slip factor	$[-]$
p	Number of polar couples	$[-]$
E	Energy	$[Wh]$
p	Electricity price	$[€]$
c	Electricity cost	$[€]$
ρ	Density	$[kg/m^3]$
g	Gravitational acceleration	$[m/s^2]$
Q	Flow rate	$[m^3/s]$
A	Area	$[m^2]$
DMV	Minimum vital flow	$[m^3/s]$
H	Head	$[m]$
V	Volume	$[m^3]$
$\dot{V}$	Volumetric flow rate	$[m^3/s]$
η	Efficiency	$[-]$
	Markup	$[-]$
f	Utilization factor	$[-]$
h_{eq}	Equivalent hour	$[h]$
	Total cost	$[€]$
	Total revenues	$[€]$
NPV	Net present value	$[€]$
LCOS	Levelized cost of storage	$[€/MWh]$

1. Introduction

Hydropower is a renewable energy source based on the natural water cycle. It is one of the oldest renewable, used by mankind since ancient times.

Hydropower is the most proven technology inside the world of the RES, and it has provided clean, affordable, and reliable electric energy for more than a century.

Due to its long history, its role inside the electricity mix has change during this time. First it was used as the main electricity source, but with the increase in the installation of thermal plants, first coal and then moving to natural gas, and then finally with nuclear, its application on the grid was to produce electricity during peaks of the demand.

Nowadays, with the grid becoming “greener”, the hydro sector has taken a different role on the grid. The one of storage the excess power, help the grid stability thanks to the inertia of its large rotating machine and its ability to give an important power reserve since, only a few minutes are needed to turn on the plant.

Nowadays the hydroelectricity is the main renewable on the electric grid.

Pumped hydro storage is going to be ever more essential to correctly manage the challenges that the electrical sector will face in the future, in a grid with a high penetration of RES, to keep it balanced and adequate.

RES, particularly solar and wind, are known for their variable nature (also known as VRE). This is an issue for those who must manage the balance between generation and consumption.

From the report “2016 DOE Hydropower Vision” [1] it is estimated that, with the increase of VRE on the grid, it is expected an increase of the installed PSH capacity (Figure 1.1).

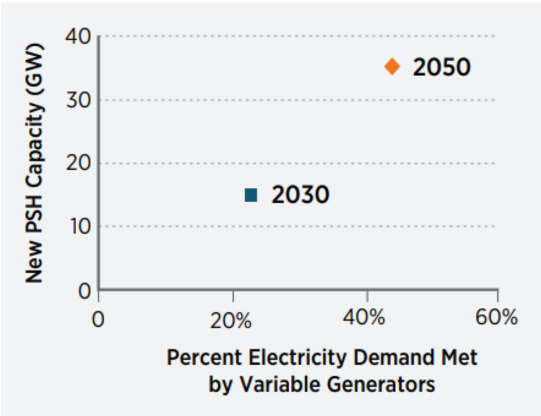


Figure 1.1 VRE penetration vs new PHS capacity [1]

Of course, this is not a direct correlation, since it depends on the characteristics of the generation and of the transmission, but it can give an idea of the importance of developing the pumped storage capacity needed.

Also, in all the scenarios considered by the Hydropower vision [1], an increase in the installed capacity of hydro plant, both conventional and pumped, is considered necessary to achieve the decarbonization goals (Figure 1.2).

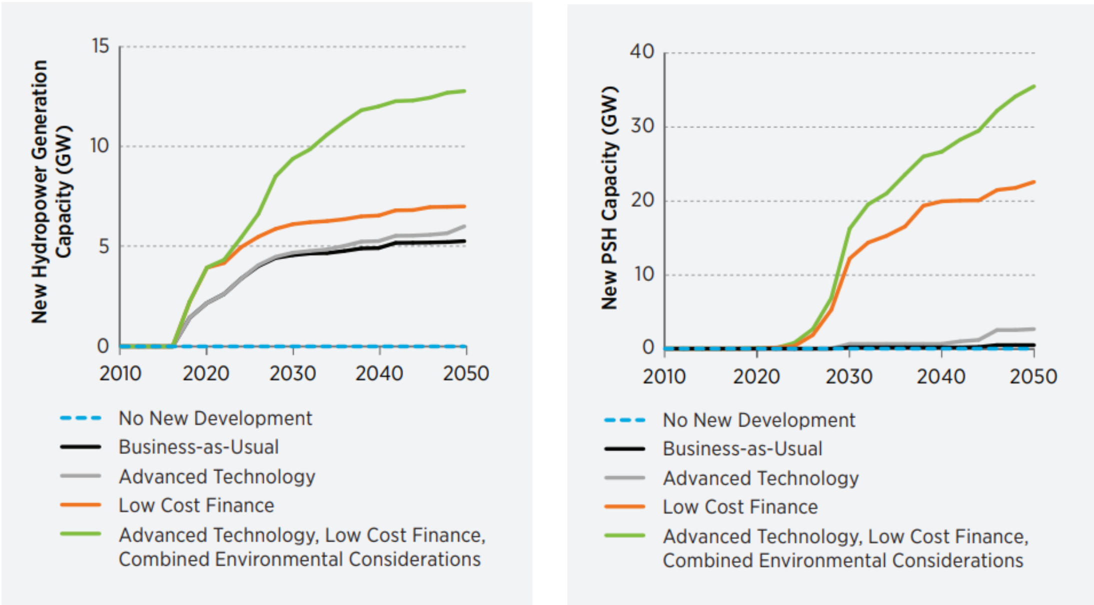


Figure 1.2 Conventional hydropower and PHS future scenarios [1]

So, pumped storage is complementary to the variable generation VRE.

Understand the role of PHS plants means, in more general terms, understand the role of storage systems in the grid of the future.

To understand better the role of storage the "2022 Standard Scenarios Report: A U.S. Electricity Sector Outlook" [2] will be investigated. It is particularly interesting to look at the mid scenario for the US made by the DOE.

This scenario is chosen because it assumes that:

1. Wind and solar capacity will grow very rapidly, making a large portion of the new installed capacity.
2. Fossil fuel power plant with CCS can still play a role.
3. US electricity sector emissions will decrease significantly in the 2030s.
4. Considers IRAs tax credit that are going to expire.

In this instance the scenarios taken into consideration are the one for Mid case with 95% decarbonization by 2050 and Mid case with 100% decarbonization by 2035, since the Mid case is considered as the policy as usual.

The objectives of these scenarios are to explore a range of possible power generation mix following economic, technological and policy considerations. The technologies are classified as seen in Appendix 1.

The generation and the installed capacity for the three scenarios is as reported:

- Mid case (Figure 1.3)

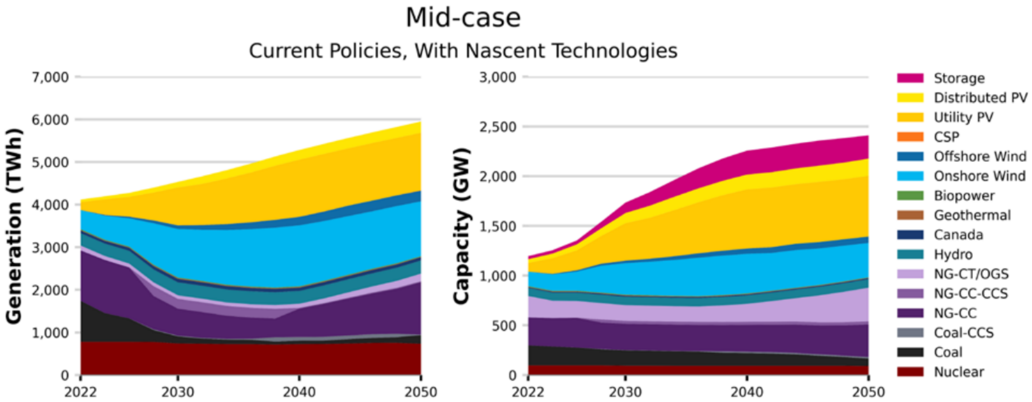


Figure 1.3 U.S. electricity sector generation (left) and capacity (right) over time for the current policies scenario [2]

In this scenario it can be seen the importance of fossil fuel even in 2050.

- Mid case with 95% decarbonization by 2050 (Figure 1.4)

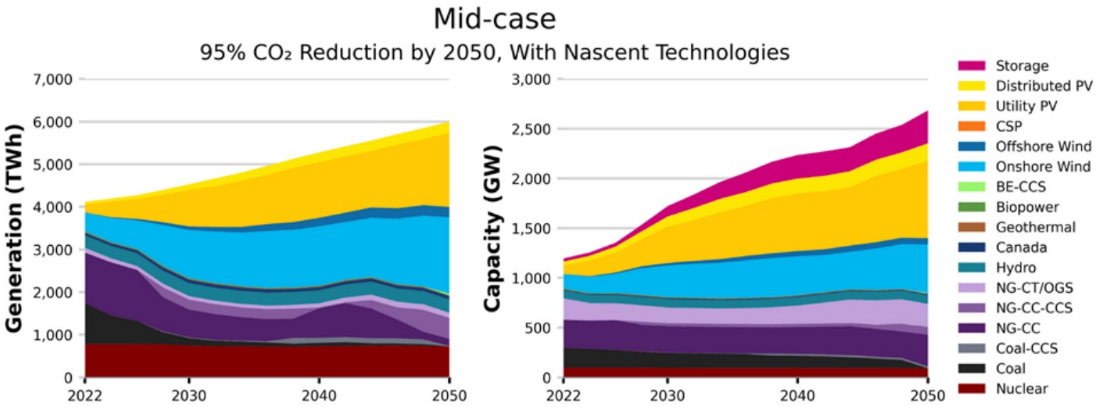


Figure 1.4 U.S. electricity sector generation (left) and capacity (right) over time for the 95% CO2 reduction by 2050 [2]

- Mid case with 100% decarbonization by 2035 (Figure 1.5)

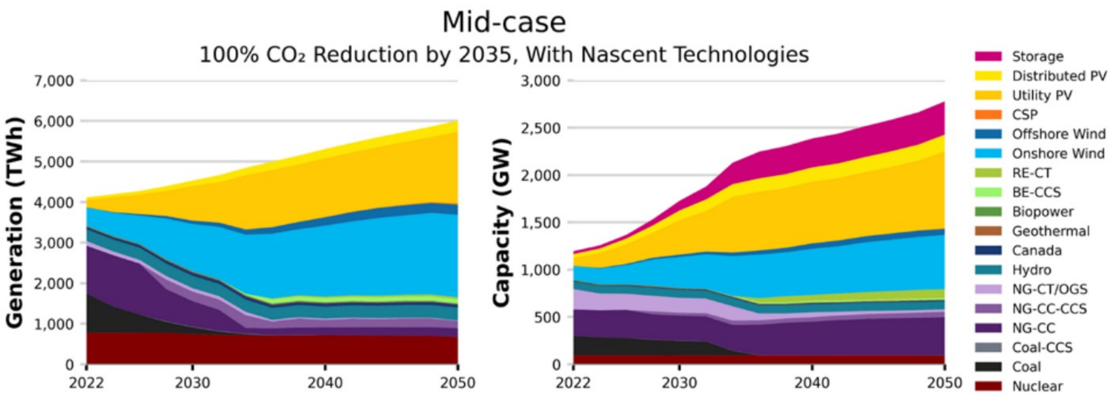


Figure 1.5 U.S. electricity sector generation (left) and capacity (right) over time for the 100% CO2 reduction by 2035 [2]

In all the scenarios the storage has a fundamental part to play in the energy transition.

A more detailed view of the mix of the energy generating sources considered in these scenarios can be seen in the graphs in Figure 1.6.

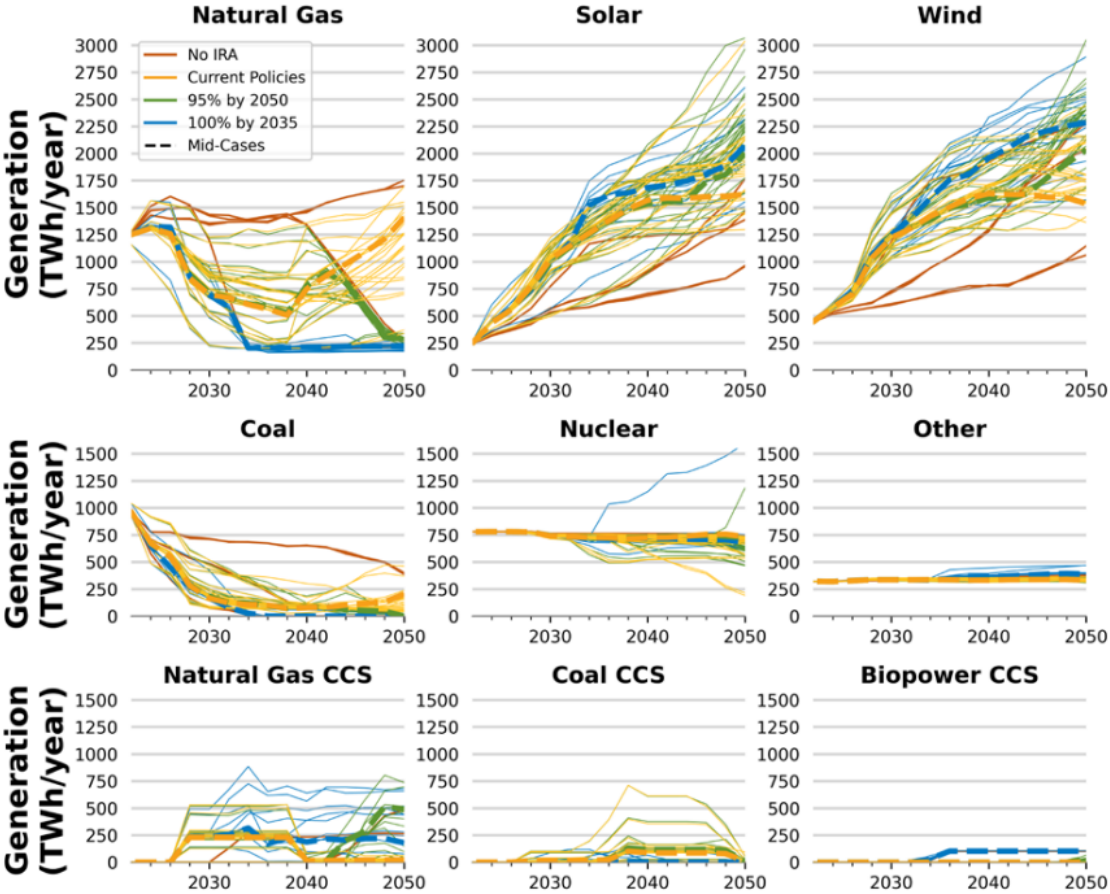


Figure 1.6 Generation across the suite of Standard Scenarios by fuel type [2]

As it can be seen the yearly generation is on the ordinate. One of the things that it can be noticed is how much VRE such PV and wind will grow, as stated in the initial hypothesis and what is it expected for the future. Since CCS is a still developing technology, there is still a lot of uncertainty surrounding it, so it is better to be careful when considering it.

It can be noted that nuclear energy remains flat in almost all scenarios, except for the Mid case with 100% decarbonization by 2035.

It can be also interesting to see the trends of the installed capacity for the different sources in the Figure 1.7, particularly for solar and wind.

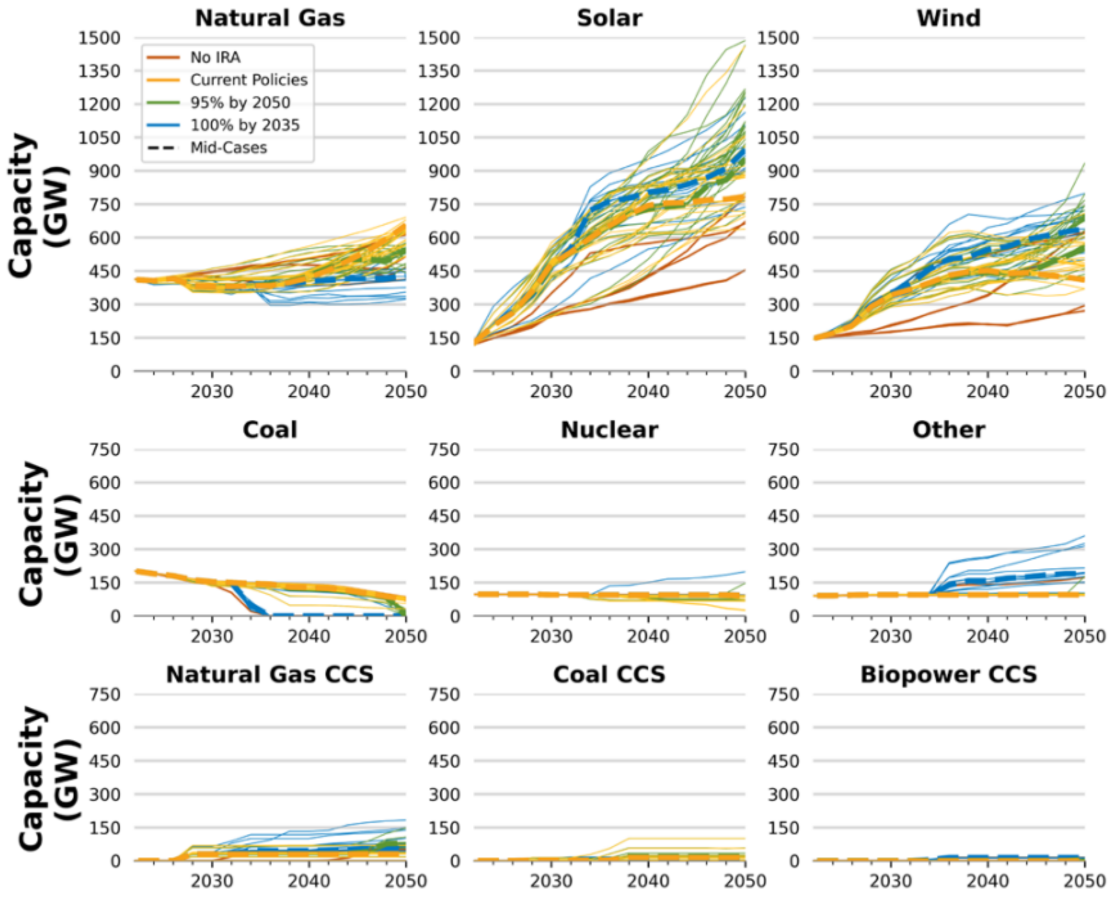


Figure 1.7 Capacity by fuel type across the Standard Scenarios [2]

This shows an even more rapid increase for PV solar and wind energy capacities installed. The only fossil fuel that increases is natural gas with CCS which will be present due to its low carbon footprint.

At last, it is interesting to see the emission trends for the different scenarios from the electricity generation mix reported in the Figure 1.8.

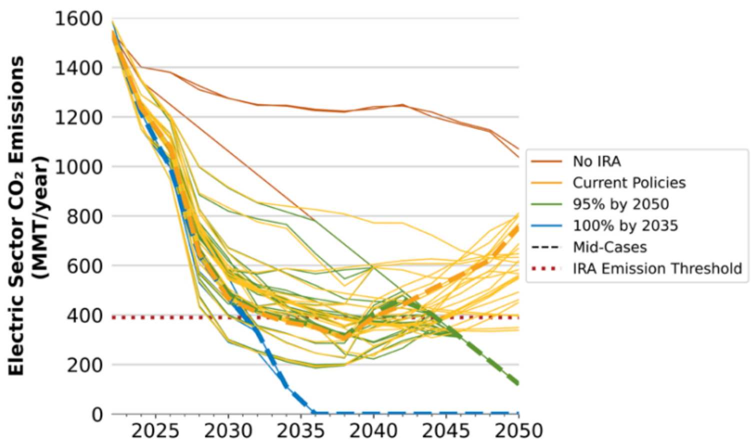


Figure 1.8 Electricity sector CO2 emissions for the range of Standard Scenarios [2]

These scenarios give us the scale of the transformation that the grid will be going through in the next thirty years.

One other interesting chart (Figure 1.9) is the one representing the share of renewable generation, also known as renewable penetration, that increases in all the scenarios (from 55 to 80% in 2050). But it also shows the importance of policy to drive renewable growth objectives.

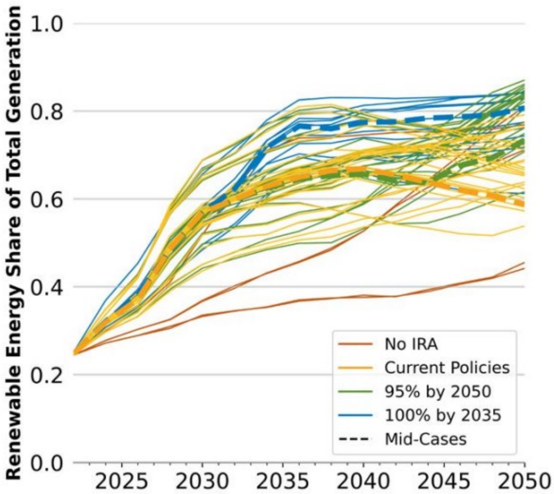


Figure 1.9 Renewable energy share over time across the Standard Scenarios [2]

To the ends of having a larger penetration of VRE, an expansion of the transmission network must be considered. It is most fundamental in the Mid case 100% decarbonization by 2030, but its role is fundamental in all the scenarios as it can be seen in the Figure 1.10.

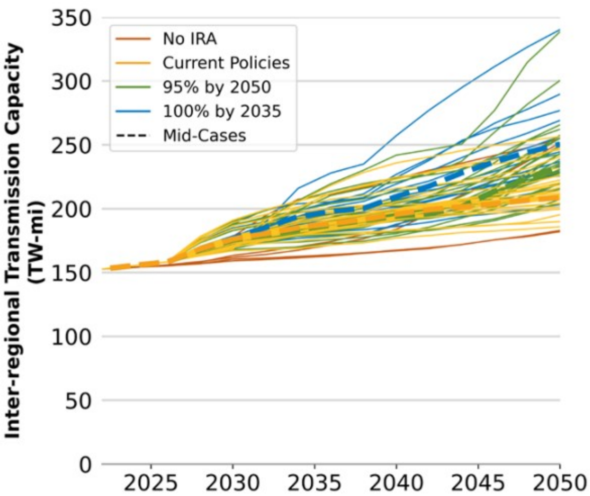


Figure 1.10 Interregional transmission capacity over the Standard Scenarios [2]

The expansion of transmission capacity is correlated to the expansion of VRE capacity, which is more distributed across land and sea, and higher natural gas prices. This allows the expansion of renewable VRE and its connection the consumption nodes.

At last, some observation must be made on the marginal energy cost and on the curtailment of VRE. These two factors are a fundamental when storage systems are involved.

Marginal energy cost will decrease in time, particularly in the scenario with high penetration of renewable energy as it can be seen on the left of Figure 1.11. This, as it will be shown later, is a challenge if the goal is implementing storage systems with the current market conditions.

On the right of Figure 1.11, it can be understood that marginal planning reserve costs will grow exponentially as planning reserve capacity decreases. So, it is fundamental, for the future, to plan ahead and to consider this factor when choosing the energy storage system, since that is one of the benefits that can be provided.

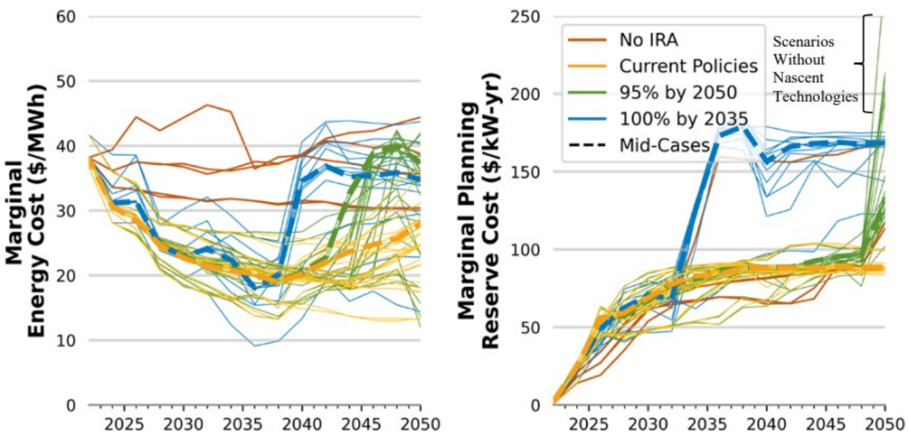


Figure 1.11 National annual average marginal costs for energy and capacity services (cost are in 2021 dollars) [2]

At last, the curtailment of the VRE must be considered, because it can be reduced thanks to the presence of storage system and a smarter use of the grid. In the Figure 1.12, the trends for different scenarios are shown.

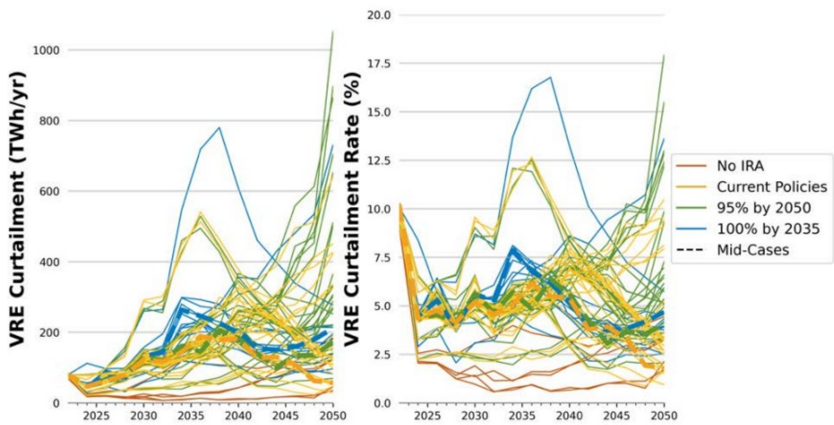


Figure 1.12 Wind and solar curtailment in future scenarios [2]

In fact, one of the reasons to build storage system is to avoid the curtailment of VRE sources and to use that energy later when it is needed, maybe at higher prices. All these factors will be view in the following chapters in more detail.

In this master's thesis the role of pumped hydro storage is going to be discussed, analyzing the state of the art, future development in technology and market deployment.

2. Hydroelectricity

Hydropower is the most flexible power generation available, and it is very suitable as a complement to VRE.

The modern era of HP, as it is known, has started around 1870, as reported in the document by IRENA “Renewable energy technologies: cost analysis series - hydropower” [3].

Conflicts and geopolitical tensions can produce spikes in the price of fossil fuels commodities as it has been shown in the crisis in Ukraine and during the oil embargo in the 70’. Meanwhile HP is less affected by this since it is a more local source.

At the same time this statement is not completely true, since particularly the filling of very large reservoir can cause tensions with downstream neighbors. Two prime examples of this are the filling of the Grand Renaissance Dam in Ethiopia on the Blue Nile, which is increasing tensions with Sudan and Egypt, and the other is the decrease in water level of the Mekong River in Southeast Asia, due to the construction of dams in its northern part in China.

The HP plants are known to have a very large range of installed capacity, from some kW to thousands of MW and they are also known for their very high-capacity factor coefficient.

Conventional hydropower has a very long-life span, ranging from 30 to 80 years.

Hydropower plants can be grid connected or off grid (or connected to a small grid). This is ideal for isolated areas and can play a fundamental role in the electrification of rural areas particularly in poor countries with an absence of large national power grid.

The main components of a conventional HP plant are:

- Dam with the intake, penstock, and surge chamber.
- Powerhouse with turbine and generator.
- Transformer and transmission lines.
- Outflow.

These components are also shared with the PHS plant.

Large-scale hydropower plants with storage can largely de-couple the timing of hydropower generation from variable river flows [4]. Large storage reservoirs may be sufficient to buffer seasonal or multi-seasonal changes in river flows, whereas smaller reservoirs may be able to buffer river flows on a daily or weekly basis.

With a very large reservoir relative to the size of the hydropower plant, or very consistent river flows, hydropower plants can generate power at a near constant level throughout the year, operating as a base-load plant or it could work as a peaking plant, and in this case, it will be designed to generate large quantities of electricity to meet peak electricity system demand.

2.1 Hydropower worldwide

From the “2022 Hydropower Status Report” [4], about 16% of the world's electricity production has been generated by hydropower, that makes it the main renewable energy source.

The installed capacity worldwide is 1360 GW, with China, Brazil, and the United States on the top spot (Figure 2.1). Meanwhile at the bottom of the figure are reported the data for new installed capacity in 2021.

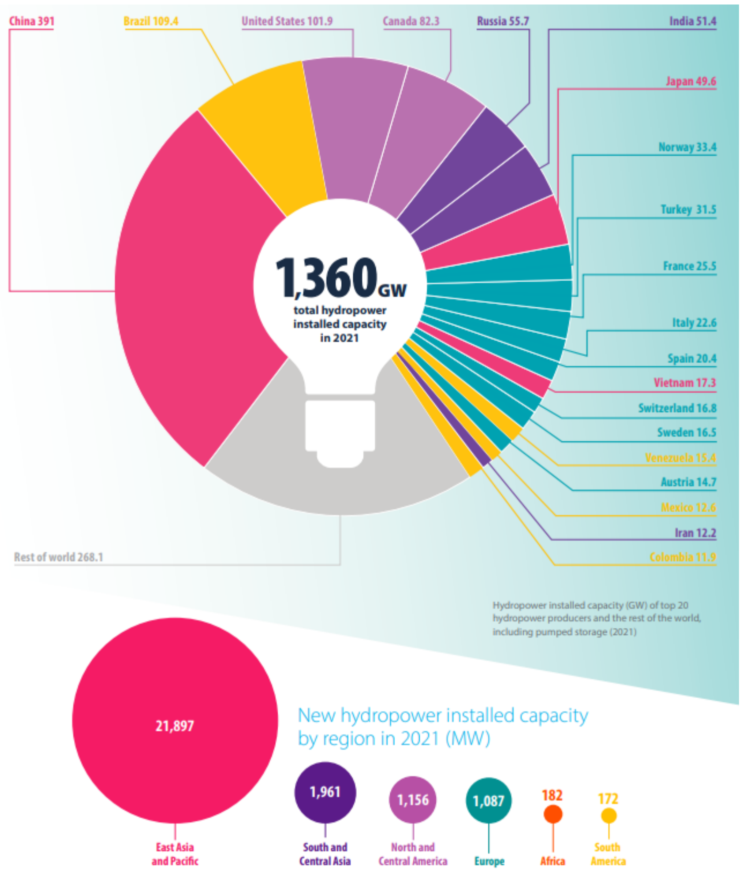


Figure 2.1 Total hydropower installed capacity and new HP installed in 2021 [4]

This gives an indication for the future of hydropower as it is expected that a large part of the new installed capacity will be in the Asia and Pacific regions, where there are suitable sites and a lot of emerging economies like China, India, and Vietnam.

One other important consideration regarding hydropower must be done for the potential capacity. In Europe, for example, the potential has been in large part utilized, meanwhile in all other regions there are areas with an abundance of residual potential.

2.2 Hydropower plant classification

There are several types of ways in which a HP plant can be classified.

HYDROPOWER CLASSIFICATION BY TYPE

The main types of hydropower schemes are:

- Run-of-river.
  These schemes have very little to no storage capacity. The electricity generation is driven by the natural flow of the river and by the head. The main advantage is a reduction in the civil costs.
- With reservoir for storage.
  The reservoir behind a dam is used for storing the water, allowing for its release when favorable prices are present on the market.
  The amount of electricity generated depends on the flow rate and the head.
  The main advantage is that the power generation is not coupled with river flow, rainfalls, or snow melting.
  However, the requirement of the dam increases the cost dramatically.
- Pumped storage.
  It allows off peak electricity to be used for pumping and during on peak electricity the possibility of turbining and then selling that electricity. They are generally more expensive than conventional hydro schemes and the suitable location are harder to find.

HYDROPOWER CLASSIFICATION BY HEAD

In the following Table 1 the classification of the head is reported.

Table 1 Hydropower classification based on the head

	Head [m]
High head	> 100
Medium head	From 30 to 100
Low head	< 30

HYDROPOWER CLASSIFICATION BY INSTALLED CAPACITY

Even though the classification can vary from country to country, in this master's thesis the classification from IRENA [5] will be used and it is reported in Table 2.

Table 2 Hydropower classification based on installed capacity

	Installed power capacity
Large hydro	> 100 MW
Medium hydro	From 20 to 100 MW
Small hydro	From 1 MW to 20 MW
Mini hydro	From 100 kW to 1 MW
Micro hydro	From 5 kW to 100 kW
Pico hydro	< 5 kW

2.3 Hydraulic turbine

The turbines are the devices that convert kinetic and pressure energy of the flowing water into mechanical energy available at a shaft connected to the generator.

There are two kinds of turbine that can be identified in [5]:

- Reactionary.
- Impulse, in which the hydraulic wheel extracts the energy from the exchange of momentum, like the Pelton turbine.

The most suitable turbine for a hydropower scheme depends mainly on the flow rate and on the head. The graph reported in Figure 2.2. shows the working areas for different types of turbines.

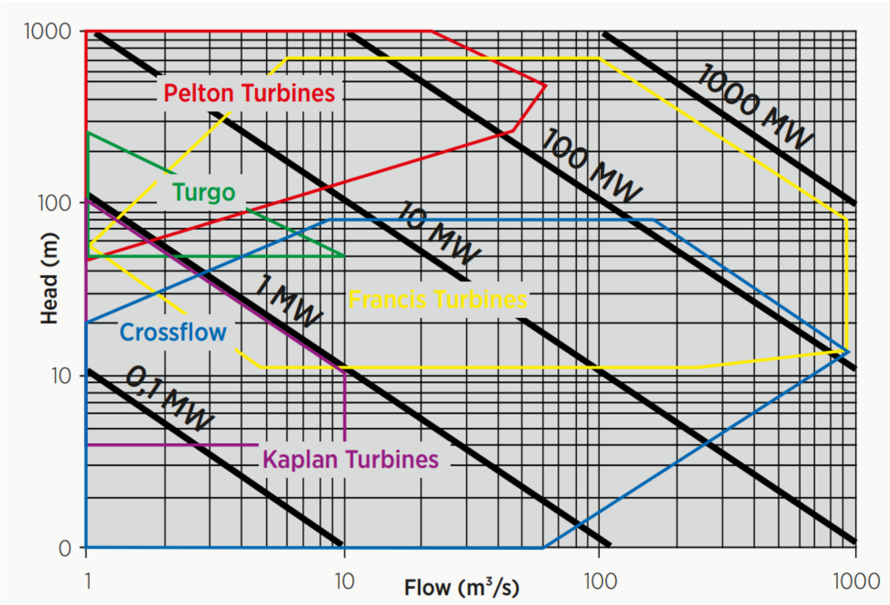


Figure 2.2 Working areas of different turbine types [4]

Pelton turbines for example, can be used for high head and low flow rate; meanwhile the Francis turbine, a reactionary turbine, can be used for intermediate flow rates and heads with a high efficiency and they are diffuse in the PHS field thanks to its reversible option.

3. Storage systems overview

3.1 Types of different energy storage technologies

Energy storage systems are structured to better integrate the renewable energy sources on the grid [6]. The energy storage systems can be classified into six types: mechanical, thermochemical, electrochemical, chemical, electrical, and thermal, as reported in Figure 3.1.

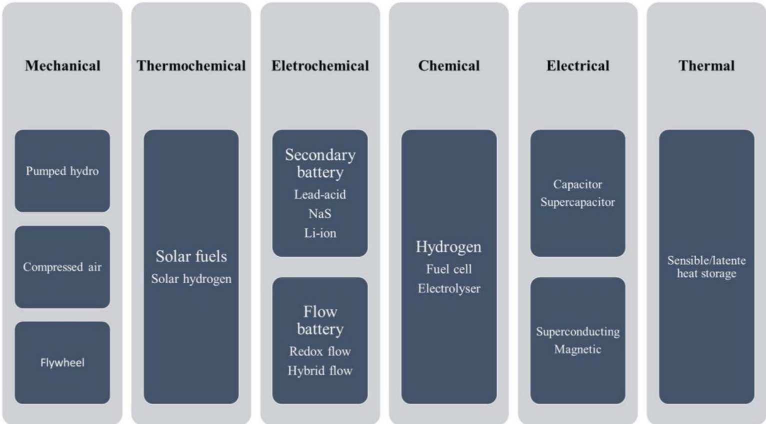


Figure 3.1 Electricity storage systems classification

It is also interesting to know the definition of grid scale storage as given by the IEA: "Grid-scale storage refers to technologies connected to the power grid that can store energy and then supply it back to the grid at a more advantageous time – for example, at night, when no solar power is available, or during a weather event that disrupts electricity generation. The most widely used technology is pumped-storage hydropower, where water is pumped into a reservoir and then released to generate electricity at a different time, but this can only be done in certain locations. Batteries are now playing a growing role as they can be installed anywhere in a wide range of capacities."[1] Because this is where most of the new investment will be.

In this master's thesis, the PHS, which is a mechanical storage system, will be analyzed in detail, particularly through a the "Case study of Tirso 1 and Tirso 2 power plants".

The main competitor of the PHS, also considering the maturity of the technology, is the Li-ion battery systems, but in the future more technologies will become of age, for the example hydrogen for the very long storage solution. Some of the technologies reported in Figure 3.1 are still subject of research and are not deployed nowadays. But, depending on their future development, they may have a role in the storage mix.

[1] https://www.iea.org/energy-system/electricity/grid-scale-storage#tracking

3.2 Levelized cost of storage (LCOS)

A lot of studies have been done evaluating the levelized cost of storage, which is one of the most important parameters when considering the feasibility of the investment. One of the most useful considerations is that for all storage technologies it is expected a decrease in their lifetime cost.

An adequate cost assessment for electricity storage can be challenging due to the large range of cost and storage performance characteristics.

The LCOS gives us the discounted cost of the technology considering all the costs that it will encounter during its lifetime. So, comparing the LCOS of different technologies is an appropriate tool.

The levelized cost of storage can also be described as the total lifetime cost divided by its cumulative delivered electricity [7].

It reflects the average electricity price at which it must be sold to achieve the point of parity with the investment, or in other word, the point at which the NPV is equal to zero. It is also analogous to the LCOE, for the power generation.

The LCOS can be defined as:

Equation 1 LCOS formula

$$LCOS\left[\frac{\$}{MWh}\right] = \frac{investment\ cost + \sum_n^N \frac{O\&M\ cost}{(1+r)^n} + \sum_n^N \frac{Charging\ cost}{(1+r)^n} + \frac{end\ of\ life\ cost}{(1+r)^{N+1}}}{\sum_n^N \frac{electricity\ discharged}{(1+r)^n}}$$

The elements of the Equation 1 are the investment cost, the operation and maintenance cost (O&M), the charging cost, the end-of-life cost and the electricity discharged during its lifetime period (defined as N).

When comparing different technologies, the different characteristics and scale must be considered. For example, PHS has relative long response time, in fact it is not considered useful if the goal is to optimize the power purchase to maximize the PV production. Other than that, it is important to say that PHS are generally large to very large plant, at least more than 5 MW.

3.3 Storage needs

The "working paper on sustainability of pumped storage hydropower" [8] states that the main attributes to describe a modern power system are the stability, the reliability, the cleanliness (in terms of emission and social impacts), the affordability, the flexibility, the resilience, and the expandability. The storage systems play a key role in all the cited attributes.

The first thing a TSO (grid manager) does, it to evaluate the "demonstration of need" of the storage, and then it follows an analysis of which mix of technologies is better considering the economic, technical, and environmental terms.

The Figure 3.2 shows, for example, how the PHS can be integrated into the Austrian grid, a mountainous country with high potential for pumped storage, to couple the VRE.

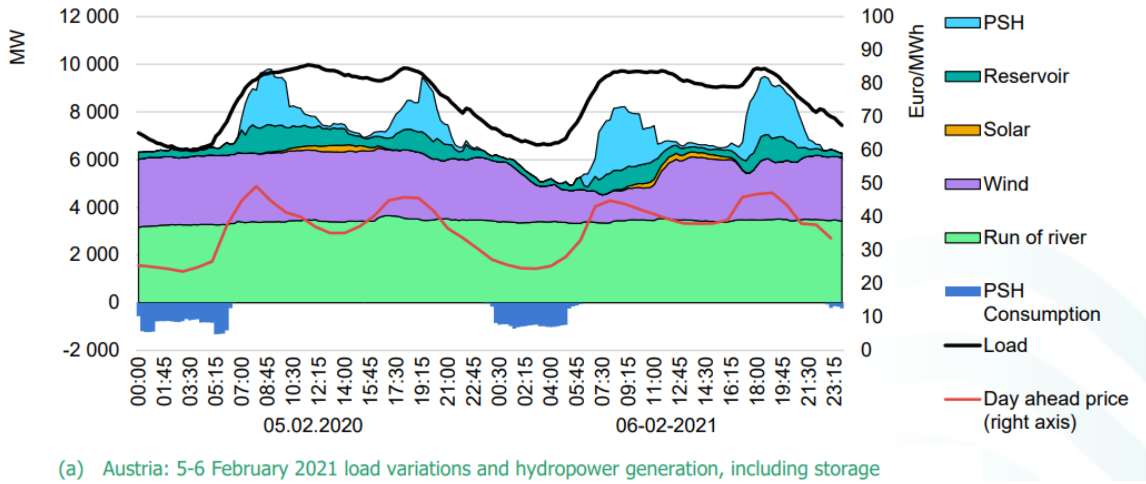


Figure 3.2 Austrian grid generation 5 - 6 February 2021 [8]

It can be seen how the pump or turbine mode follows the prices of electricity (the red line in Figure 3.2). The pump mode is operational when the price of electricity is low, meanwhile the water rushes through the turbine when the prices are high, during the morning and evening peaks.

To choose if the PHS or one other technology is a good option for the grid, three steps must be followed.

The first one is doing a strategic assessment at a system wide level, to understand the need and use of energy storage, flexibility, and ancillary services. Then a technology or mix of technologies must be consider starting from the stated needs. Third, good industry practices must be followed in the design phase to reduce cost and impact of the project.

The system-level strategic assessment consists of the identification of the needs:

- The needs of the electric system with the goals of reducing the greenhouse gas emissions of the electricity production sector must be considered.

- Knowing that the grid has a high penetration of VRE, high flexibility must be provided. Flexibility and ancillary services must be considered, and their need evaluated.
- When planning in the long term the economic performance and lifetime duration expectation must be considered.
- When choosing a site, there are aspects different from the technical ones that must also be considered, such as environmental function and sensitivity, safety issue and social issue. That covers the socio-environmental integration of the project. All this is done so that it is possible to act to reduce the impact of the project.

At the end of these considerations the goal is to obtain the "demonstrated need".

The options assessment consists into making a correct assessment of the most suitable technology. All different parameters, essential when considering energy storage, must be taken into account (Figure 3.3). These parameters differ between technical capabilities and performance metrics.

Comparison metrics	Type of energy storage	Pumped Storage Hydro	Li-Ion Battery Storage (LFP)	Lead Acid Battery Storage	Vanadium RF Battery Storage	CAES compressed air	Hydrogen bidirect. with fuel cells
		1000 MW / 10hr	100 MW / 10hr	100 MW / 10hr	100 MW / 10hr	1000 MW / 10hr	100 MW / 10hr
Technical Capabilities	Technical readiness level (TRL)	9	9	9	7	7	6
	Inertia for grid resilience	Mechanical	Synthetic	Synthetic	Synthetic	Mechanical	no reference
	Reactive power control	Yes	Yes	Yes	Yes	Yes	Yes
	Black start capability	Yes	Yes	Yes	Yes	Yes	Yes
Performance Metrics	Round trip efficiency (%*)	80%	86%	79%	68%	52%	35%
	Response time from standstill to full generation / load (s*)	65...120 / 80...360	1...4	1...4	1...4	600 / 240	< 1
	Number of storage cycles (#*)	13,870	2,000	739	5,201	10,403	10.403
	Calendar lifetime (yrs*)	40	10	12	15	30	30

Figure 3.3 Table to compare different technic and performance metrics (The positive (green) or negative (red) parameters can be seen from the color) [8]

In some situations, PHS may not be the most suitable technology. Clearly the issue, from the management point of view of the grid is the fact that PHS has a relatively long response time from stand still to full generation or to load, depending on the PHS technology used. But a very interesting characteristic is the fact that there is a higher installed power of 1000 MW and a higher storage discharge time of 10 hours, compared with the electrochemical storage systems.

Here some tools, which will be explored in later chapters, like MCA and LCA, combining technical and non-technical factors, can be used to evaluate the most suitable technology for the grid. An interesting parameter that can be used to evaluate the suitability of a storage system is the energy payback. The concept quantifies how much a system can deliver over its lifetime. Hydropower usually exhibits energy paybacks far higher than other technologies, between the values of 150 to 200.

The project optimization, as the name suggests, has the goal to find the most sustainable storage system, that for PHS project entails the evaluation of technical, environmental, social, and economic factors, such as:

- The position of the penstock and power station (underground or superficial).
- Proximity of the grid.
- Conservation of the ecological function.
- Closed or open loop scheme.

- Multipurpose scheme, which is usually a way of showing more benefit of having a dam like increase economic activity due to recreational activity, agricultural usages, drinkable water, protection from floods, etc.
- Use of surface water or ground water to fill the reservoir.
- Assessing geological risks with the project, which range from seismic activity to landslides.
- An interesting option may be the installation of PV panels on the lake surface, combining the two renewable resources.

Worldwide there is a huge interest in utility scale storage, particularly in places like the US, China, and Europe. This can be shown in the Figure 3.4, and it can be noticed the rapid paste of addition in the last six years.

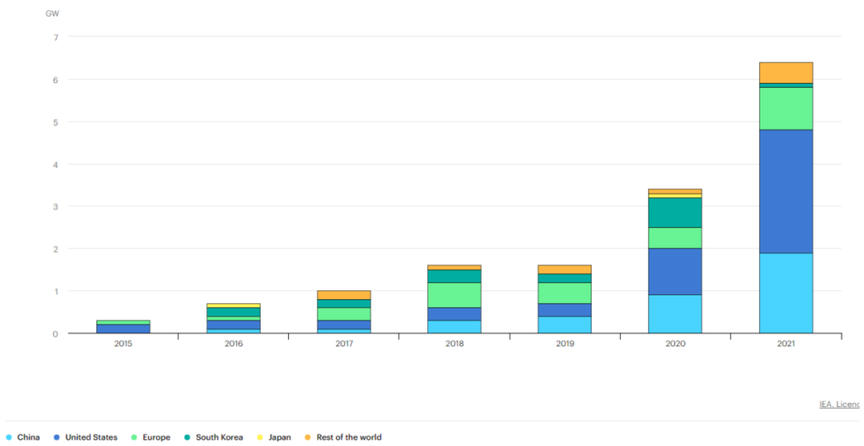


Figure 3.4 Annual grid scale battery storage additions, 2016-2021 IEA

3.4 Storge benefit

To analyze the benefits of the storage, the "SANDIA REPORT – Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide" [9] individuates 26 benefits (Figure 3.5), which can be categorized in 6 groups as follows:

1) Electric supply.
2) Ancillary service (like area regulation, electric supply reserve capacity and voltage support which includes storages whose capabilities include absorbing and injecting reactive power). It is also important to consider the benefit of providing short circuit power.
3) Grid system.
4) End user/Utility customer.
5) Renewables integration.
6) Incidental.

	Application-specific Benefits
1.	Electric Energy Time-shift
2.	Electric Supply Capacity
3.	Load Following
4.	Area Regulation
5.	Electric Supply Reserve Capacity
6.	Voltage Support
7.	Transmission Support
8.	Transmission Congestion Relief
9.	Transmission and Distribution (T&D) Upgrade Deferral
10.	Substation On-site Power
11.	Time-of-use (TOU) Energy Cost Management
12.	Demand Charge Management
13.	Electric Service Reliability
14.	Electric Service Power Quality
15.	Renewables Energy Time-shift
16.	Renewables Capacity Firming
17.	Wind Generation Grid Integration
	Incidental Benefits
18.	Increased Asset Utilization
19.	Avoided Transmission and Distribution Energy Losses
20.	Avoided Transmission Access Charges
21.	Reduced Transmission and Distribution Investment Risk
22.	Dynamic Operating Benefits
23.	Power Factor Correction
24.	Reduced Generation Fossil Fuel Use
25.	Reduced Air Emissions from Generation
26.	Flexibility

Figure 3.5 Application-specific and incidental benefits of using energy storage

These benefits can take two forms. In the first one is additional revenues for the operator, meanwhile in the second one they are the costs that are avoided thanks to the storage. Examples of additional revenues may be energy sale, capacity, and ancillary services.

3.4.1 Electric supply

3.4.1.1 Electric energy time shift

Electric energy time shift involves the purchase of inexpensive electric energy when prices are low, to charge the storage plant.

For example, this is the projected price of electricity in California for 2009 (Figure 3.6).

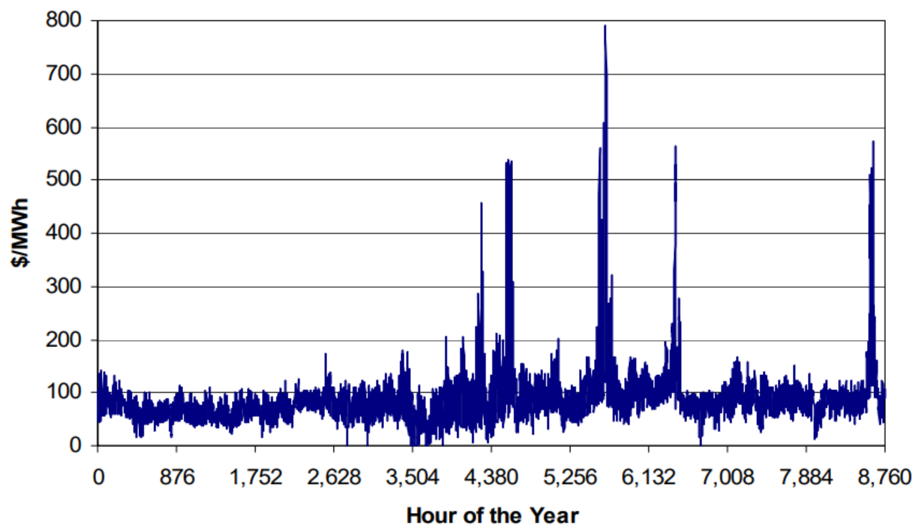


Figure 3.6 Chronological projected electricity prices for California in 2009

That stored energy can be sold later when the prices are high.

This can be done by a large spectrum of entities, from utilities to smaller application.

The standard assumption value for storage minimum discharge duration for this kind of application is two hours. Meanwhile the upper boundary for the discharge duration is given by CAES or pumped hydroelectric facilities.

When considering time shift, the variable operating cost and the storage efficiency are especially important because time shifting requires many transactions which are linked to the cost of charging and the sell price when discharging the storage.

The performance characteristics have a significant impact on the transaction that decide the economic sustainability of the storage.

The discharge duration for the electric energy time shift is between 2 and 8 hours and depends on the energy price differential, storage efficiency, and storage variable operating cost.

In this thesis, the electric energy time shift will be explored in detail in the case study.

3.4.1.2 Electric supply capacity

The goal here is to have some plant that only work in some circumstances. For example, in this category, there are the peaking power plants. And this can be useful in areas with low generating capacity.

The resulting avoided cost (benefit) is associated with the storage used for the electricity supply capacity application.

3.4.1.3 Avoid the curtailment of VRE

Decreasing the VRE curtailment is one of the goals of the storage, since sun radiation and wind are free, but they cannot be stored easily or cheaply. So, if too much energy is produced, it cannot be moved to a later date when it would be needed. The storage allows us to do that, not to waste the energy produced by these sources. This allows also to reduce the thermal power plants working in the reserve of the grid.

It is interesting to see, in the graph below (Figure 3.7), the energy mix projected in 2030 in Morocco during a 6-day span with VRE penetration at 30%, to see how fundamental the PHS can become in reducing the curtailment of VRE, reducing the need for thermal peaking generation.

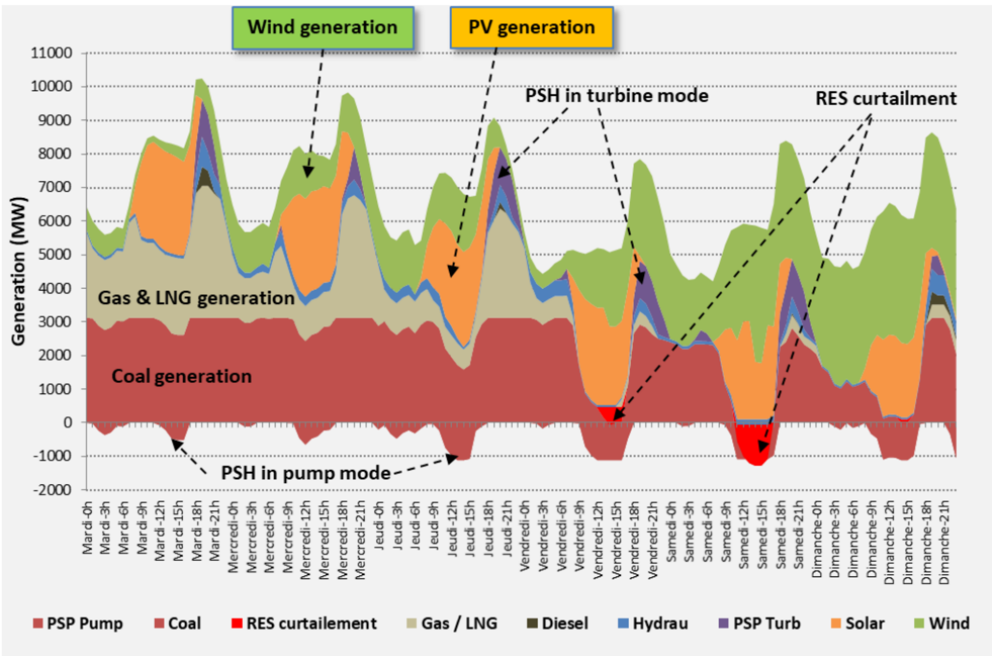


Figure 3.7 Projected grid mix in Marocco - 2030

3.4.2 Ancillary services

3.4.2.1 Load following

It is necessary to operate the grid properly. On the grid production and consumption must be balanced. So, the production must follow the demand keeping the voltage and the frequency constant. In the figure below it is reported where the load following acts (Figure 3.8).

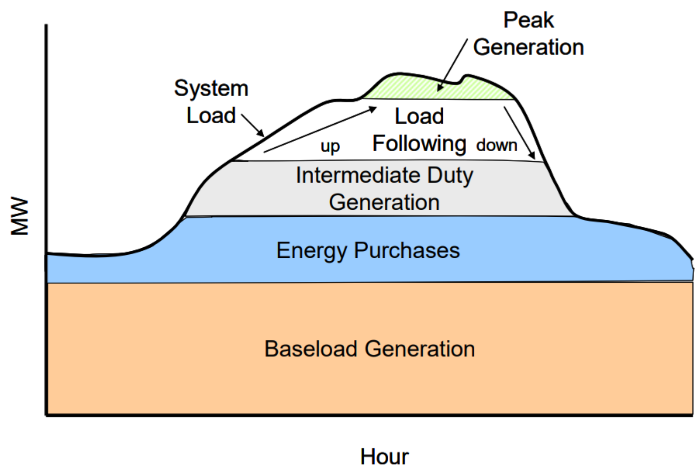


Figure 3.8 Electric supply source stack

Generation is usually used for load following. For load following up the generation is operated at lower power output than the nominal one, and then the power is increased following the load. Meanwhile for the load following down, the generation initially is at a high power and then it is reduced following the decrease in the load.

All this working at partial load may not be the most sustainable option, for example with fossil fuel power plant, which will require more fuel and emit more GHG as well as an increase in the maintenance of the generator.

Storage is well suited for load following application, since they are quick to respond and can operate at partial load without a lot of penalties.

The generation cost has two elements:

1) The marginal cost: it consists mainly of fuel and maintenance. These can be eliminated if storage is used or reduce if the plants are working at partial load, but that is not a great option.
2) The capacity cost: these involve the cost incurred in adding new generation capacity. The type of new generation capacity depends, of course, on the region. It can go from hydropower plant to GT open cycle.

The problem of this fast ramping, with the increase of VRE, can be seen in the case of the Indian grid and its comparison between the generation profile in 2019 and expected in 2030 (Figure 3.9).

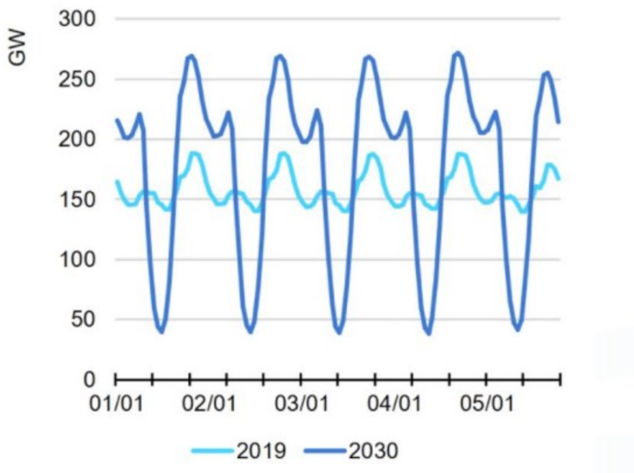


Figure 3.9 Indian daily on peak and off-peak load swings

It can be seen how this can be an issue for the future since, in the ramping up, it could even reach 70 GW/h, storage will be fundamental to avoid the curtailment of the VRE. Ramping reserve will be necessary in the future.

3.4.2.2 Area regulation

It may be the ancillary service for which the storage is most suited for. Regulation means closely watching all the interconnection and the demand in an area to make sure that the grid is stable moment by moment.

In more basic terms, regulation is used to reconcile momentaneous differences between production and demand. So, it dampens the differences, resulting into a more smother curve as it can be seen in the Figure 3.10 below.

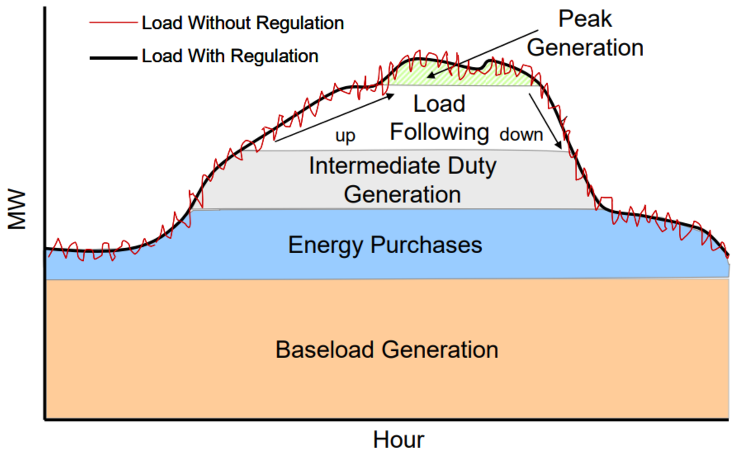


Figure 3.10 System load without and with area regulation

Regulation is typically provided by generation that is online and that can rapidly reduce or increase its power production as needed.

Also here, plants like the thermoelectric power plants are not suited to work at partial or with rapidly changing load. So here there is a large possibility for the implementation of high efficiency and fast responding storage solutions.

In this application, frequency stability is the ability of the grid of maintaining a constant frequency after system interruption or disruption, which leads to imbalances between supply and demand. Typically, when demand increases above the generation, the frequency will decline.

In the following Figure 3.11 it is reported the regulation effect to balance the grid demand and generation.

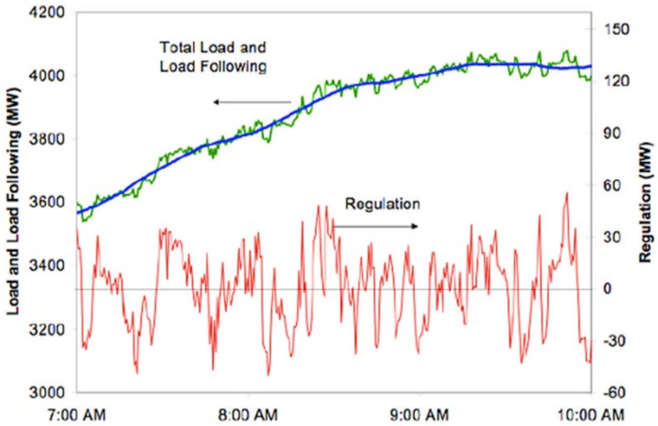


Figure 3.11 System load following and frequency regulation. Frequency regulation is the fast-fluctuating component that balances total load, while load following is the slower trend

In this application, the use of flywheels, capacitors, and many types of batteries, which have a fast response time, can be implemented. But also, PHS and CAES can respond quickly than baseload power plant.

3.4.2.3 Electric supply reserve capacity

This is needed to have a prudent operation of the grid.

The grid operator leaves a generation reserve in case the other supply sources becomes unavailable unexpectedly. Generally, the reserve is about 15% to 20% of the normal electric supply capacity.

There are three types of electric supply reserve capacity, they are:

- Spinning reserve: it is the generation capacity that is online but unloaded, so not connected to the grid. It can come in operation in about 10 minutes to compensate for generation or transmission outage. Meanwhile the ones that also are there to control the frequency respond in 10 seconds.
- Supplemental reserve: this generation is offline, but it can be activated very rapidly within 10 minutes. This supplemental capacity is not synchronized with the grid frequency.
- Back up reserve: meanwhile this is the generation capacity that can be online within 1 hour.

When a storage is designated for electric supply reserve capacity application it must be operated differently, because it cannot discharge the part of the storage allocated to the reserve since it must be there in the moment of need.

Of course, the storage to be consider useful must have a discharge time of at least 1 hour.

It takes at least two hours for thermal power plants to be ready, without considering the cost of the fuel associated with keeping the power plant “hot”. Clearly there is an associated cost also for the hydro storage since water is still moving from the upper to the lower reservoir, and this water, of course, will not be available later, but it is lower if compared to thermal power plants.

3.4.2.4 Voltage support

The other challenge when operating a grid is to maintain stable voltage levels. The goal is to manage the reactance.

New challenges have risen due to the distributed generation. Distributed storage offers an economically viable option since reactive power cannot be transmitted over long distances.

One of the characteristics of the storage system that have voltage support application is that it must be fast, within a few seconds.

3.4.2.5 Black start

Black start is the ability of a generation unit to start without power from the network in a situation where there is a major system collapse or a system wide blackout.

Only a small power is needed at a HP plant, since there is no need for cooling or for fuel preparation.

Some PHS are so large that they excite the transmission grid, pick up load and supply other power station to restart their operation.

3.4.3 Grid system

3.4.3.1 Transmission support

It can compensate for electrical anomalies and disturbances. The storage used for transmission support must be very reliable.

3.4.3.2 Transmission congestion relief

Adding transmission capacity is not an easy task and, considering the long-term goal of electrification, new lines capacity construction still lags behind the target. During peak periods the lines are already congested. This may lead to the introduction of congestion charges on the network. The goal of the storage would be to avoid these extra costs.

Discharge duration may vary from case to case. The storage, when it is not used for transmission congestion relief, can be used for other purposes.

There are alternatives to the storage, which are dumping energy upstream from the congestion, providing load management downstream to clear the congestion, paying congestion charges and adding transmission capacity.

3.4.3.3 Transmission and distribution upgrade deferral

The enhancement of the grid is an expensive and a lengthy process. An alternative to that is the increase in the local storage capacity, in order to store the electricity that will be released to a later date.

It consists of delaying or avoiding the cost related to transmission and/or distribution, using relatively small storage. Since it is known that in some node there are only few days a year when the maximum power capacity is reached. This can work very well coupled with other storages and peaking plants.

3.4.3.4 Substation on site power

Using the batteries present at the substation, for its need like switching components, substation communication and control equipment when the grid is not energized, as a storage. But the batteries should satisfy primarily the substation need.

3.4.4 End users/utility customer

3.4.4.1 Time of use energy cost management

The end users store the electric energy to reduce their overall costs. So, the batteries are charged during off peak and discharge during peak time. It is similar to time-shifting. This sound good, but the investment cost behind a system like this is still too high for most customers.

3.4.4.2 Demand change management

Energy storage system could be used to reduce the demand of the user from the grid.

The goal is to reduce or avoid the demand charges. So, the storage can be charged when no demand charges are applied, so when prices are low. And discharged when prices are high and demand charges apply.

3.4.4.3 Electric service reliability

This is done to reduce the power outage to some seconds, to increase the reliability of the electric service.

3.4.4.4 Electric service power quality

The electric service power quality benefits are highly user specific since the customer that are most affected are commercial and industrial ones, for which a power outage may cause significant losses.

So, to protect downstream load from low power quality the voltage, the frequency, the harmonic content, and the interruptions in service must be considered.

The financial reasoning behind the storage application is to reduce the losses related to the low power quality and power anomalies.

3.4.5 Renewable integration

3.4.5.1 Renewable energy time shift

For VRE it is not possible to control when they produce energy. In other words, they may produce energy in times when prices are low, at night, during holidays or on weekends.

What it can be done is to store this energy for a later date when the prices are higher and then discharge the storage. When the demand is high, on peak, this energy must be moved to the area where it is needed.

Generally, the discharge time is between 4 to 6 hours.

This can be done for VRE but also for baseload renewables (biomass, geothermal and hydroelectric) to optimize their power production coupling it with the market.

An example can be shown, for the wind generation, in the Figure 3.12.

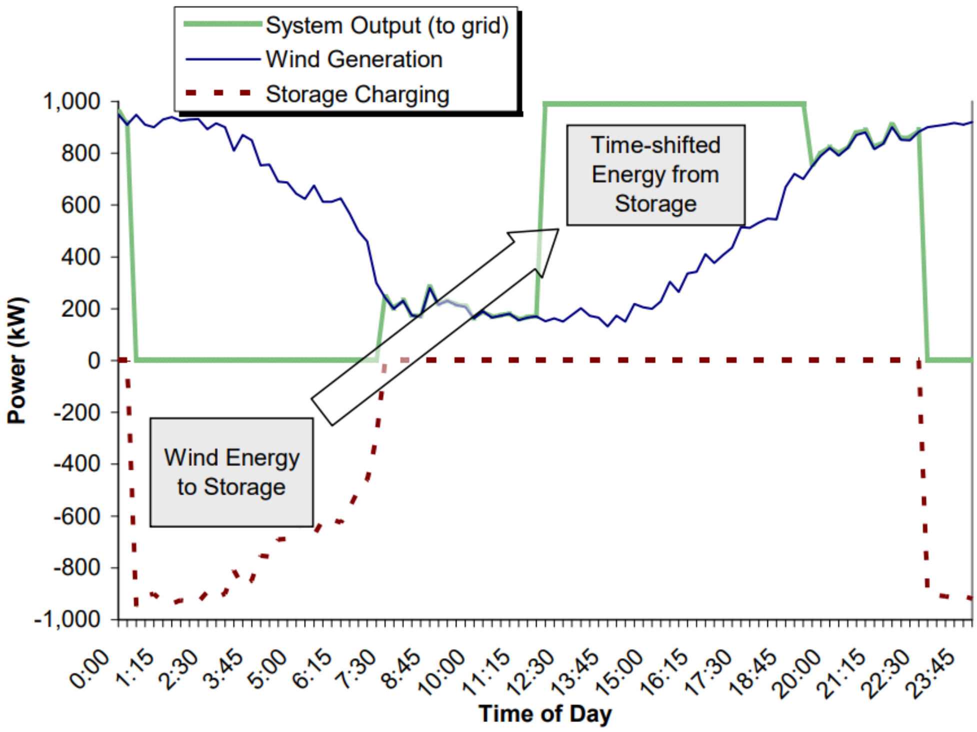


Figure 3.12 Wind generation energy time-shift

The energy is "moved" to times where the prices are higher.

This can also help reducing the intermittency of the VRE, working in couple to reduce the variability and the ramping up of fossil fuels peaking plant which are the most expensive and polluting to operate.

Meanwhile, for renewable baseload power plant, as said before, the goal is the same: storing the energy which is not used to cover the demand to charge a storage system. This can be seen in the Figure 3.13.

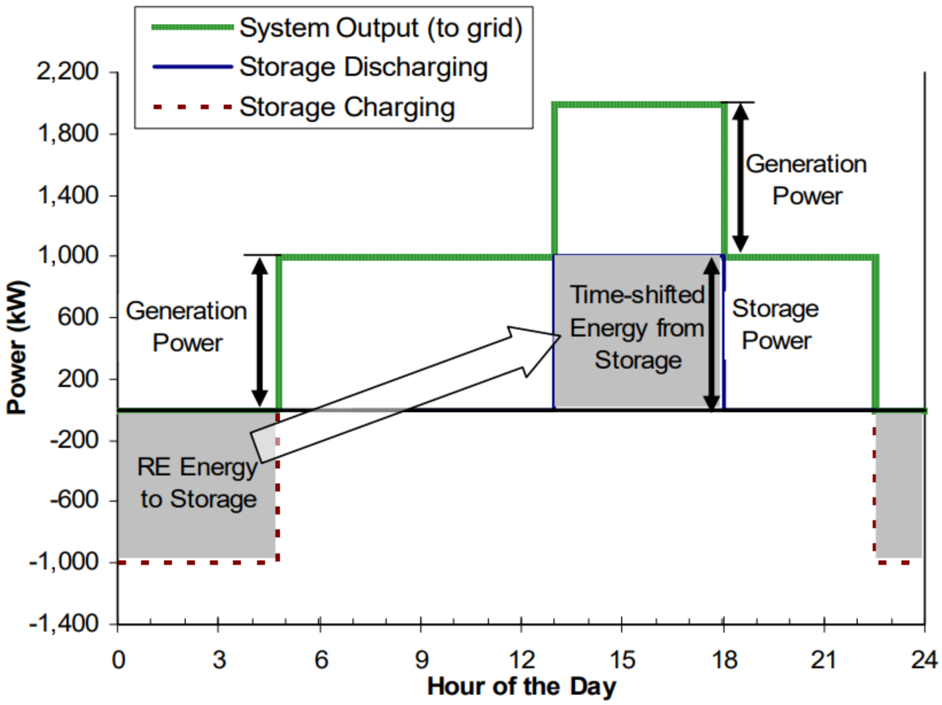


Figure 3.13 Baseload renewables energy time-shift

This is also done so these power plants do not have to work at partial load.

The discharge duration for this kind of storage is circumstances specific, and it depends mainly on the expected energy prices. For intermittent renewable it must be known when the maximum energy production is reached, and that is site related.

3.4.5.2 Renewable capacity firming

Capacity firming can be defined as making a VRE a nearly constant supply source. So, it is not the same as time shifting.

The goal here is to cover the moments where the demand is greater than the power generated. Of course, the main issue here is the fact that the changes may be very rapidly. And these rapid changes lead to an output which is not constant. Non-renewable power plant generally works better with a constant output.

This is especially valuable when the grid is at peak demand.

It can be said that there is a good opportunity for capacity firming when the renewable VRE source has the peak in production when there is the peak in demand. In this way the storage discharge time is greatly reduced.

The benefit of firming the capacity is that the cost for additional power capacity is reduced.

3.4.5.3 Wind generation grid integration

Even for a relatively small penetration of wind energy in the energy mix, there can be some issue which must be addressed since wind energy will be of great relevance to the grid of the future (Figure 1.6 and Figure 1.7).

These effects are unique to the wind generation, and they can be categorized as follows in Table 3.

Table 3 Benefit and application of storage for wind integration.

Short duration application (few seconds to minutes)	
Reduce voltage output	These are caused by short term variation in the wind generation output. Geographical diversity of the wind turbine can help reduce it. This requires a storage since it is needed more area regulation.
Improve power quality	Are related to performance standard and interconnection requirements. The main challenges are reactive power, harmonic content, voltage flicker, transmission line protection, transient stability, dynamic stability, and system voltage stability. A solution may be using conventional technology to avoid power quality and stability issue.
Long duration application (for many minutes to hours)	
Reduce output variability	The goal here is to reduce the variability due to the nature of the wind source itself. Increase in wind penetration means an increased need for load following.
Transmission congestion relief	There may be a time when the transmission lines are congested. The solution is upstream and/or downstream storage system.
Backup for unexpected wind generation shortfall	These happen when in a region the velocity is a lot lower than expected. This is rare. The two options are to reduce the demand and activate the reserve.
Reduce minimum load violation	It happens when wind generation and other baseline or must run plant are operating. Here storage is fundamental to avoid curtailment.

In an energy sector with more distributed energy sources than ever, these challenges become sort of more local or distributed.

The issue of grid congestion is directly linked to the reduction in productivity of wind farms, as reported in [10]. This reduction is clear since it can be seen that the missed production of wind farms in Italy has grown from 156 GWh (2012) to 822 GWh (2020), as shown in Figure 3.14.

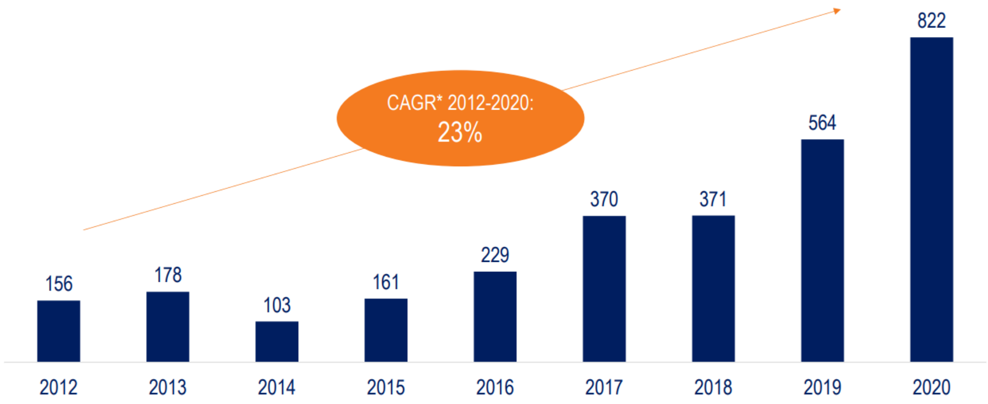


Figure 3.14 Missed wind energy production in Italy (GWh)

3.4.5.4 Provides inertia to the grid

Increasing the share of the VRE in the energy mix will mean a decrease in the inertia of the system due to the lack of large spinning rotating machines. For example, in the graph (Figure 3.15) it can be shown how, the increase of VRE is reducing the inertia of the grid.

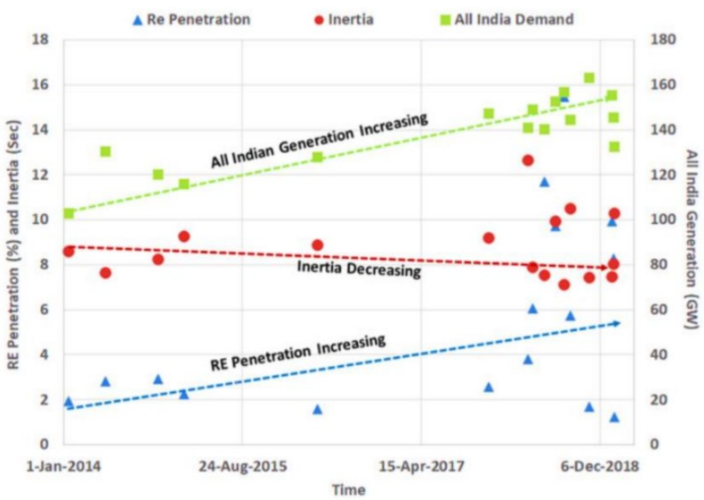


Figure 3.15 Effect of VRE penetration on grid's inertia

The mechanical inertia, nowadays provided by large hydroelectric, thermal, and nuclear power plant, is fundamental in the stabilization of the grid. Large generators spinning resists the frequency drop when a power plan or a transmission line fails.

So, in the future the TSOs will make not only prevision of the power production but also the prevision on the inertia available on the grid.

3.4.6 Incidental benefits

The incidental benefits are benefit that are not specific to one application. For example, dynamic operating benefit occurs because storage is used and that makes the electric supply system work in a more optimal fashion. One other kind may be avoided charges associated with the access on the transmission network.

3.4.6.1 Increase in asset utilization

Using storage can increase the amount of electricity generated, transmitted, and distributed using existing assets.

There are two consequences of this. The cost of owning the existing asset is amortized across more energy, which reduces the unitary price of that energy. Second, the payback time of the investment is reduced, which reduces the risk behind the investment.

3.4.6.2 Avoided transmission and distribution losses

It is known that electrical losses are proportional to the resistance of the medium and to the squared of the current.

Equation 2 Joule losses

$$P_{losses} = RI^2 = \frac{V^2}{R}$$

They are high during the day, especially in hot days when the temperature is high.

Here the goal is to charge the storage off peak, even better if locally generated electricity so to avoid going through the grid. And not on peak, so in this way the transmission cost is reduced.

3.4.6.3 Avoided transmission charges

When the transmission grid is used, a cost is associated with that service. Considering for example a locally own grid where there is some generation and storage, where they generally do not own the transmission lines.

Nowadays there is a new market emerging which is the one for the transmission capacity, local markets will allow for precise cost of transmission.

3.4.6.4 Reduce transmission and distribution investments risk

As for any investment, there is a risk even for the construction of transmission and distribution lines. For example, it may be that a company is upgrading some lines to find that a large customer will no longer be present. This is a huge issue since that would mean that the project is no longer financially viable.

Even though it is hard to consider it, it is generally a cost directly pass through the users.

Storage can be placed downstream to reduce the risk associated with the transmission and/or distribution grid expansion.

3.4.6.5 Dynamic operating benefits

It is a cost, that can be reduced or avoided with the presence of storage.

This cost can be reduced if:

- Generation equipment is less frequently used (lower number of startups).
- The generation plant works at a more constant output (so the use at partial loads is avoided).
- It operates at its rated output for most of the time, since it is the region with the highest efficiency and, for fossil fuel power plant, the lower emissions.

As said before, this reduces the wear (and that can increase the lifespan of the component), the operational and maintenance costs, the fuel cost, and the emissions.

3.4.6.6 Power factor correction

Utilities must compensate the reactance that causes low power factor. The two typical responses to this are:

- Charge the end user customer with low power factor (below 0.85).
- Use capacitor to offset the effect of reactive loads.

There are also other more expensive options than capacitor like static VAR compensator and conventional motor-generator system.

3.4.6.7 Reduce fossil fuel use

There are three ways in which the fossil fuel use is reduced:

- The energy stored from efficient thermal plant and/or renewable can reduce the use of plant working at partial load or peaking generation. This is known as energy time-shift.
- The fuel consumption is reduced due to dynamic operating benefits.
- The efficiency of the thermal power plant tends to be higher when temperatures are low. Coincidentally during the night is when the loads are low and when the prices are low. So, this is when it is more convenient to charge the storage system. Then, it can also be said that transmission losses are lower during the night since the temperature is lower.

Of course, the degree of the reduction of fossil fuel use depends on the characteristics of the fossil fuel power plant.

3.4.6.8 Reduced air emission from generation

This is directly linked to the lower use of peaking fossil fuel power plant and to the reduction in use of fossil fuel.

This depends on the storage characteristics, the fossil fuel power plant characteristics, and the storage efficiency.

Case by case, this could bring to a reduction in different polluting compounds like nitrogen oxide NOx, sulphur oxide SOx, carbon monoxide CO, soot and particles, volatile organic compounds, and emission of carbon dioxide CO_2.

3.4.6.9 Flexibility

The flexibility can be defined as the rate at which the storage system can adapt to changing circumstances. It may allow the choice of an optimal solution to business related needs, challenges, and opportunities.

In the current grid environment, the fossil fuels power plant and the hydropower are the main provides of flexibility (Figure 3.16).

Hydropower contributes to the grid services since they can ramp up or down quick and smoothly. This flexibility gives hydropower and pumped storage an extremely high value when considering energy and electricity security.

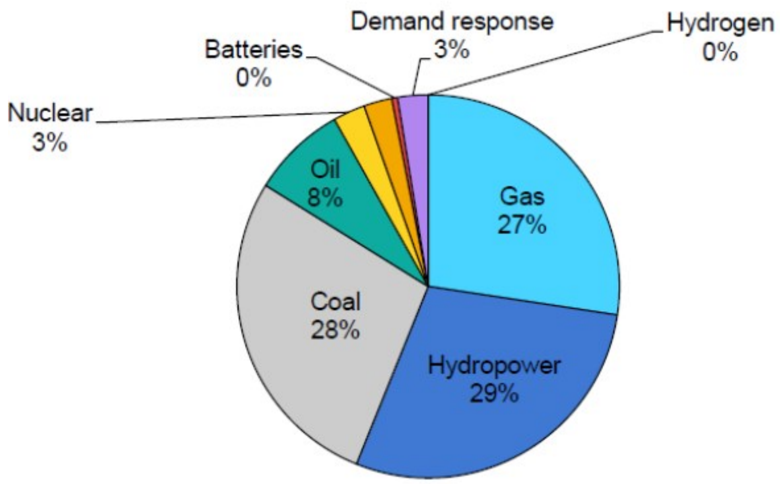


Figure 3.16 Global electricity system flexibility by source (IEA,2021)

3.5 Storage value proposition

The main value propositions that can be followed when considering the various storage systems are:

1. Electric energy time shift plus transmission and distribution upgrade deferral
2. Time of use energy cost management plus demand charge management.
3. Renewable energy time shift plus electric energy time shift.
4. Renewable energy time shift plus electric energy plus electric supply reserve capacity.
5. Transportable storage for transmission and distribution upgrade deferral and electric service power quality/reliability at multiple locations.
6. Storage to serve small air conditioning loads.
7. Distributed storage in lieu of new transmission capacity.
8. Distributed storage for bilateral contracts with VRE generators.

It is now interesting, considering the Figure 3.17 from the SANDIA report [9], to evaluate how these different applications can work together. In fact, a value proposition consists in having more than one application in the designed storage system to make it more financially attractive. But, of course, applications must be compatible if they are combined.

● Excellent ◉ Good ◎ Fair ○ Poor ⊗ Incompatible

Application	Electric Energy Time-shift	Electric Supply Capacity	Load Following	Area Regulation	Electric Supply Reserve Capacity	Voltage Support[1]	Transmission Congestion Relief[1]	T&D Upgrade Deferral[1]	Time-of-Use Energy Cost Management[1]	Demand Charge Management[1]	Electric Service Reliability[1]	Electric Service Power Quality[1]	Renewables Energy Time-shift	Renewables Capacity Firming	Wind Generation Grid Integration
Electric Energy Time-shift		●	◉	◎*	◉	●	●†	●†	⊗	⊗	⊗	⊗	◉	◉	◉
Electric Supply Capacity	●		◎*	◎*	◎*	●	◎†	●†	⊗	⊗	⊗	⊗	◎X*	◎X*	⊗
Load Following	◉	◎*		◎*	◎*	◉	◎X	◎X*	◎*‡	◎*‡	⊗	⊗	◉	⊗	⊗
Area Regulation	◎*	◎*	◎*		◎*	⊗	◎X*	⊗	⊗	⊗	⊗	⊗	○	○	⊗
Electric Supply Reserve Capacity	◉	◎*	◎*	◎*		●	◎*	◎*	◎*‡	◎*‡	⊗	⊗	◎*	◎*	○*
Voltage Support[1]	●	●	◉	⊗	●		◉	●	◎‡	◎‡	◎‡	◎‡	◎#‡	◎#‡	⊗
Transmission Congestion Relief[1]	●†	◎†	◎X	◎X*	◎*	◉		◎X†	◎†	◎†	○	⊗	◎#	◎†	⊗
T&D Upgrade Deferral[1]	●†	●†	◎X*	⊗	◎*	●	◎X†		◎†	◎†	○	⊗	◎#	◎†	⊗
Time-of-Use Energy Cost Management[1]	⊗	⊗	◎*‡	⊗	◎*‡	◎‡	◎†	◎†		●†	●	●	◎#	◎†#	⊗
Demand Charge Management[1]	⊗	⊗	◎*‡	⊗	◎*‡	◎‡	◎†	◎†	●†		●	●	◎#	●†#	⊗
Electric Service Reliability[1]	⊗	⊗	⊗	⊗	⊗	◎‡	○	○	●	●		●	◎#	◎#	⊗
Electric Service Power Quality[1]	⊗	⊗	⊗	⊗	⊗	◎‡	⊗	⊗	●	●	●		⊗	⊗	⊗
Renewables Energy Time-shift	◉	◎X*	◉	○	◎*	◎#‡	◎#	◎#	◎#	◎#	◎#	⊗		●	◎X
Renewables Capacity Firming	◉	◎X*	⊗	○	◎*	◎#‡	◎†	◎†	◎†#	●†#	◎#	⊗	●		◎X
Wind Generation Grid Integration	◉	⊗	⊗	⊗	○*	⊗	⊗	⊗	⊗	⊗	⊗	⊗	◎X	◎X	

Figure 3.17 Application synergies matrix [9]

3.6 Societal value, challenges, and opportunities of storage systems

The societal value is fundamental because it is the most interesting feature for the public, to make them understand the benefit, direct and indirect, that they are going to see from the investment into storage systems, which can go from lithium ions batteries to large pumped hydro storage plant.

These societal benefits can be:

- Reduce need of peaking plant.
- Increase asset utilization.
- Enabling better utilization of existing power generation fleet.
- Reduce fossil fuel consumption and increase energy security.
- Reduction in air emissions and energy losses.
- Better integration of renewables.
- Smart grids.
- More reliable grid causes an increase in business productivity.
- Reduced use of raw materials like steal, concrete, etc.

When storge systems are evaluated, the societal benefit must be considered, leading to an increase of its value.

Meanwhile the main challenges, identified in the SANDIA report, for the storage are:

- Storage is still relatively high cost per installed kWh and that there is a lot of competition among a wide range of technologies.
- Lack of storage regulation and permitting rule. Application may not be remunerated correctly.
- A lot of storage technology are still research topics.
- Difficulties in financing new technologies.
- Inadequate infrastructure to optimize the storage.
- Opposition from local communities' interest, particularly for large storage systems.

Meanwhile some of the opportunities present when storage systems are implemented are:

- Modular storage technology development in response to the growing demand.
- Increasing interest in managing peak demand due to peaking generation and transmission constraints (transmission capacity constraints).
- Expected increase in the penetration of VRE.
- Decrease in the consumption of fossil fuels and emissions.
- Financial risk behind the investment in new transmission capacity coupled with increasing congestion.
- The increase in generation on the medium voltage lines and Smart grids (increase in distributed power generation).
- Accelerating the decrease in the LCOS.

4. Energy transition and the need for storage in Italy

As reported in [11], PHS usually has a very large scale, in the MWs, and it is positioned to work with the high voltage transmission grid. The high voltage transmission grid is managed by the TSO, which is Terna in Italy.

Terna is the responsible of planning, upgrading, and maintaining the grid and of managing the power flows. It works in a monopoly regime according to Italian legislation and regulation.

When looking at the Italian electric system, the record demand was recorded in 2007 at 340 TWh. This number is expected to increase due to the electrification of the final users. To cover it, it is expected a large increase in the VRE like solar and wind. But, as it is shown in the graphs on the bottom left of Figure 4.1, there was a slowdown in annual new installed capacity after 2010-2011, due to tax incentives expiration, which is only now starting to increase again.

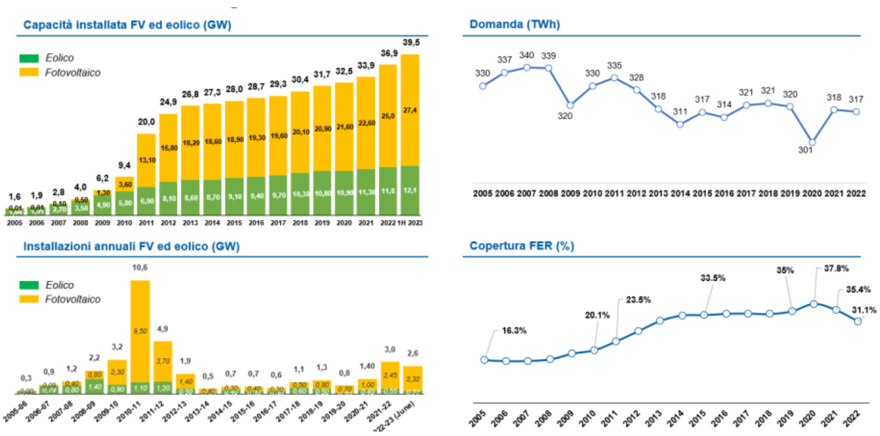


Figure 4.1 Moving clockwise from the upper left: the installed capacity for solar PV and wind. The yearly electricity demand in Italy. VRE penetration in the Italian grid. Annual installation of PV solar and wind.

As said before, the issue with all renewables is that they are dependent on the weather, and so it is hydroelectricity, which is the main renewable energy source in the Italian grid. In Italy there are around 5000 HP plants, mainly in the northern mountainous regions as it can be seen in the Figure 4.2, with a total installed power capacity of around 23 GW.

Figure 4.2 Distribution of hydropower plants in Italy

For example, 2022 was a very dry year. In fact, considering the hydrologic basin of the longest river in Italy, the Po River, it was reported from measurement in Figure 4.3, how the lack of rain falls, and snowfall had reduced the stored volume behind the hydropower dams.

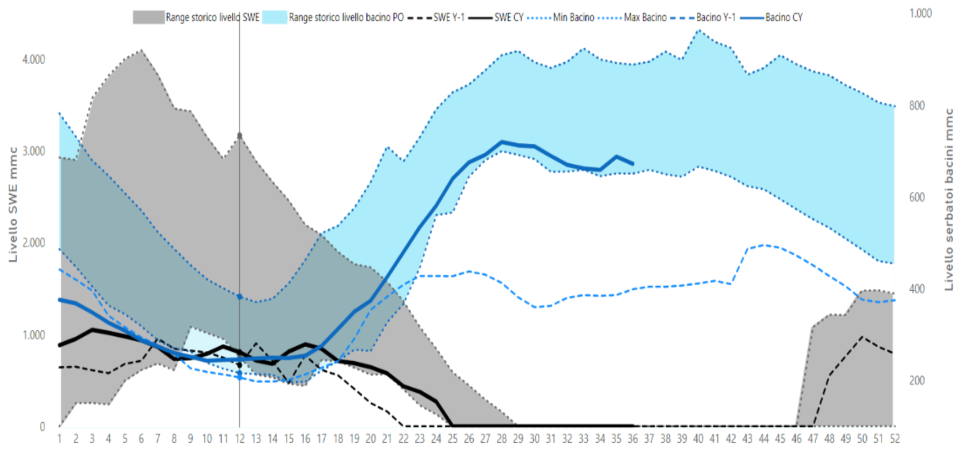


Figure 4.3 On the left y axis: SWE level. On the right y axis: Storage volumes. [SWE: snow water equivalent, how much snow in water]

That causes uncertainty for the future of hydropower deployment.

This can clearly be seen in the following graph in Figure 4.4, where it has been reported the electricity produced by hydro in 2022, comparing it to the years 2020, 2021 and 2023.

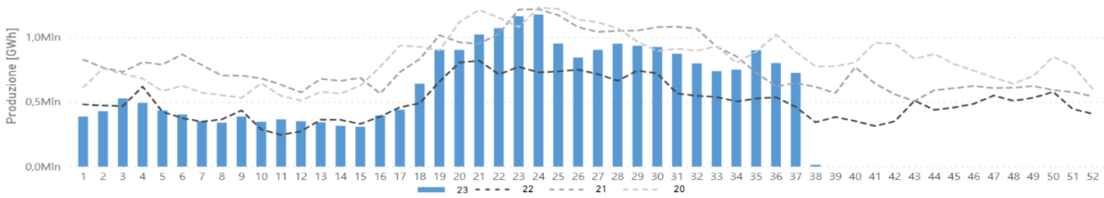


Figure 4.4 Hydropower electricity production from 2020 to 2023

In 2022 the decrease in production is noticeable particularly in spring and summer. Meanwhile, it can be noted that for 2023 the production from hydropower started similarly to the previous year 2022, but then it increased due to strong precipitation in the spring.

When the future of the Italian energy system is analysed, Fit-for-55 is the main policy that states the energy objectives for the future, which are a series of legislative proposal, put forward by the European Commission in 2021 to reach the goals stated in the Green New Deal, and enhanced by the EU commission's Repower EU in 2022, after the start of the war in Ukraine, with the goal of ensuring energy security for the European Union through the diversification of the supply source.

They are an extension of Next generation EU, approved in 2020, with the goal of helping the recovery after the recession due to the SARS - Covid 2020 pandemic, by investing in Italy around 60 billion euros for the energy transition.

The goals of Fit-for-55 are to reduce GHG emissions by 55% compared to the 1990's level, increase the penetration of VRE to 65% and to have around 80 GW of new installed solar and wind capacity, all of that by the year 2030.

It can be understood what a massive accomplishment that is, and why Italy is already behind on its own stated goals. In the following paragraphs, the magnitude of the investment will be shown by means of the new installed capacity needed to reach the Italian goals.

In the Figure 4.5 it is reported the increase in installed capacity in various region of Italy, right away it can be noted the role of the southern regions of Italy to the energy transition thank to their more available sun and windy site.

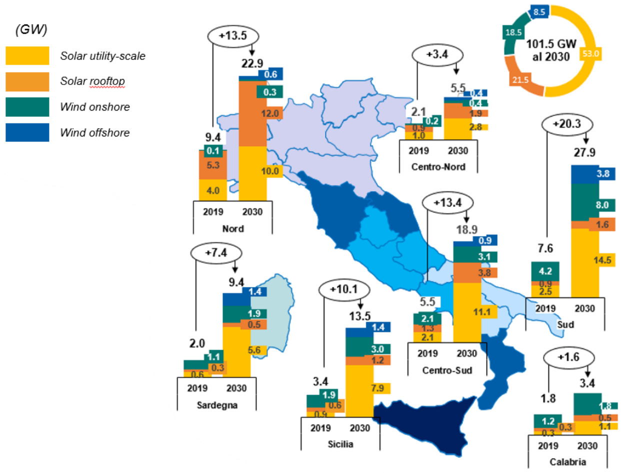


Figure 4.5 New installed capacity to reach Fit-for-55 by 2030

But that may cause issues of its own, since the power generation will be in the south, meanwhile the consumption is mainly located in the north. This will cause congestion on the grid, as it can be seen in the Figure 4.6, where it is reported the need of increasing the transport capacity of the transmission lines. Congestion can also lead to an increase in electricity prices and cause technical issue like higher energy losses and a decrease in the global efficiency of the grid.

The plan of Terna is to increase the transport capacity by 16,5 GW.

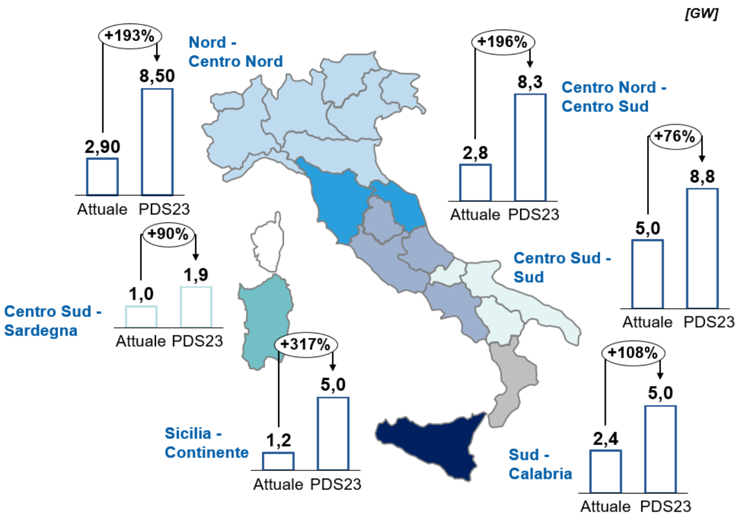


Figure 4.6 Need to increase transport capacity of the transmission grid

To solve the grid congestion, storage systems can play a fundamental role in lieu of new transmission lines, even though there are, to this day, some project underway or under consideration as it can be notice in the Figure 4.7.

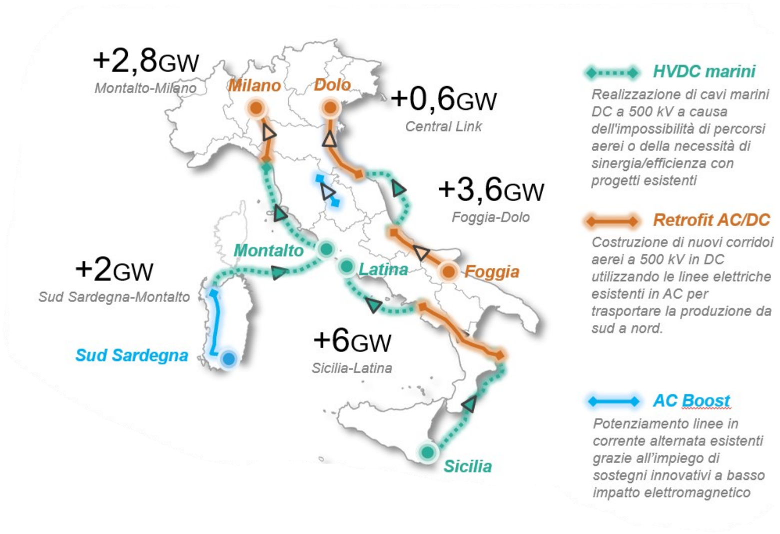


Figure 4.7 New transmission line project currently underway or under consideration

The goal is clearly to move energy from the south, where it is produced, to the north, where it is needed. The development of new electric storage capacity will be fundamental, as it can be seen in the Figure 4.8, particularly in the South of Italy where most of the new VRE capacity will be installed.

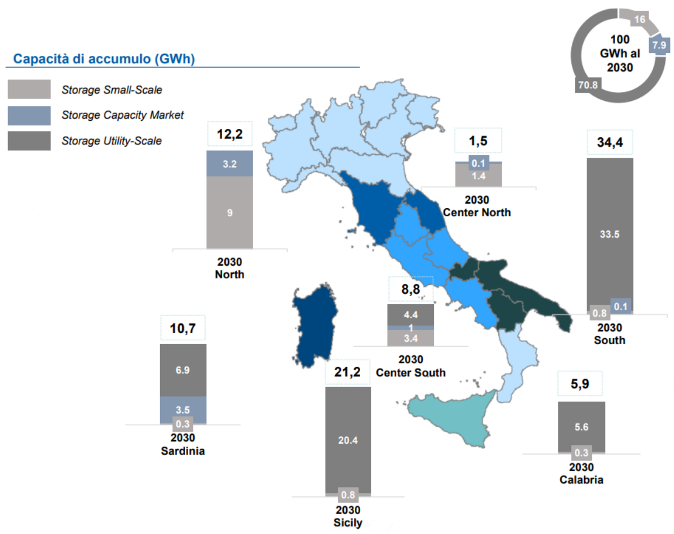


Figure 4.8 Projected storage capacity (GWh)

The Fit-for-55 plan calls for the installation of 100 GWh of storage by 2030 in Italy. This will mainly come from utility size storage, around 71 GWh or around 9 GW in installed capacity, but there will be also space for more distributed energy storage.

At last, the TSO is facing a new challenging environment due to the increase penetration of VRE sources on the network, combined in Italy with the closure of old coal power plant.

It must be introduced the concept of residual curve, defined as the demand curve minus the production curve from renewables. The expected residual curve by 2030 in the Fit-for-55 plant is shown in the Figure 4.9.

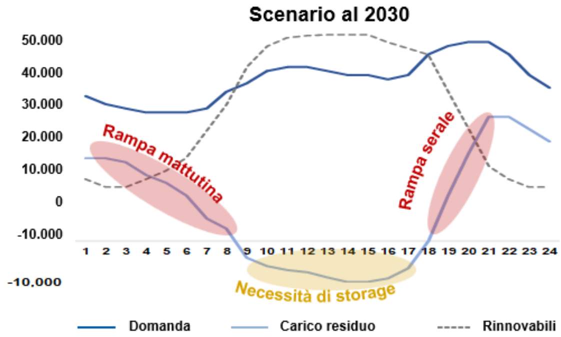


Figure 4.9 Projected residual curve for the Italian grid in 2030

The issue that the TSOs are facing concern the ramps in power production in the morning and in the evening, the reduced regulation capacity, low reserve margin, increase in the grid congestion, increase in overgeneration by VRE and a more challenging environment when controlling the voltage level, the frequency of the grid and more in general the power quality.

The variability of the residual load gives us a way to quantify the need for storage. In the figure below it can be noticed how moving forward from the 2030 scenario to the 2040 scenario, the residual load increases and so does the need for storage (Figure 4.10).

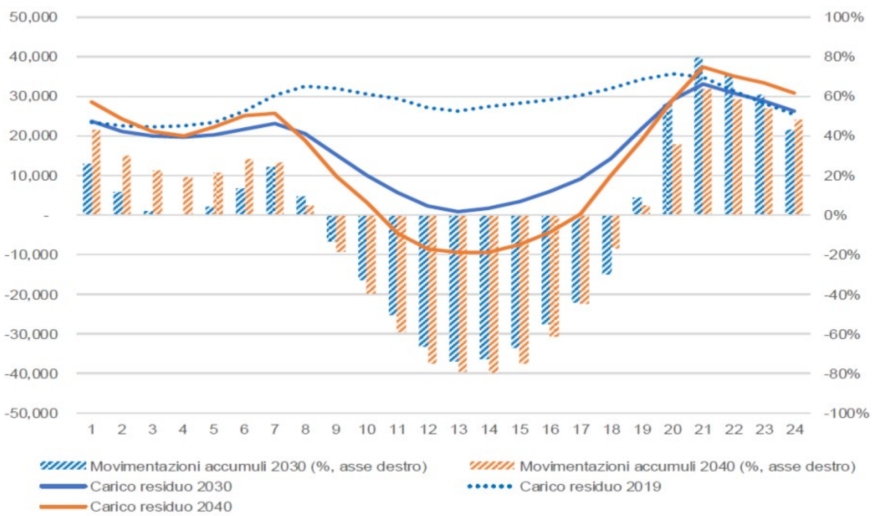


Figure 4.10 The need for storage considering the residual curve for 2030 and 2040

To support storage system there are several mechanisms, but the three mains are:

- Through tax incentives (like super bonus 110%).
- Direct investment.
- Self-consumption, like energy communities, which is the instantaneous or delayed by storage systems consumption of the electric energy produced inside a defined area.

To understand better the energy transition in Italy it is interesting to look at the role of the distribution grid, as shown in [12]. In the past the electrical grid was built radially from large power plant and the substation to the final users, it had a unidirectional power flow with no generating capacity on the low and medium voltage grids.

Nowadays the distribution network is ever more important since a lot of new generation capacity (mainly renewables like solar, wind and biomass) is added there, where in the past it was not present.

In 2022 for example, in the distribution grid of e-distribuzione, around 2,3 GW of new capacity was installed. The constant increase in number of connection and installed capacity can be seen in the Figure 4.11 and Figure 4.12.

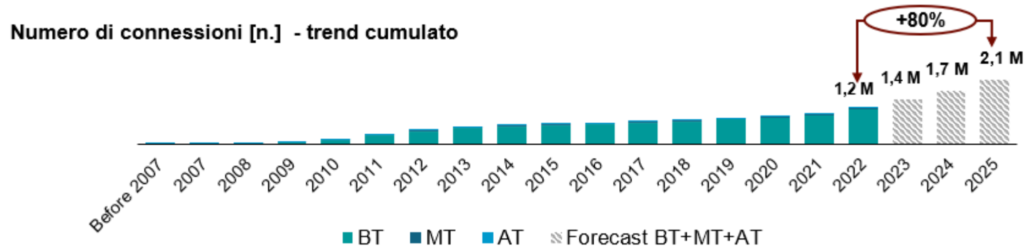


Figure 4.11 Cumulative trend of connection

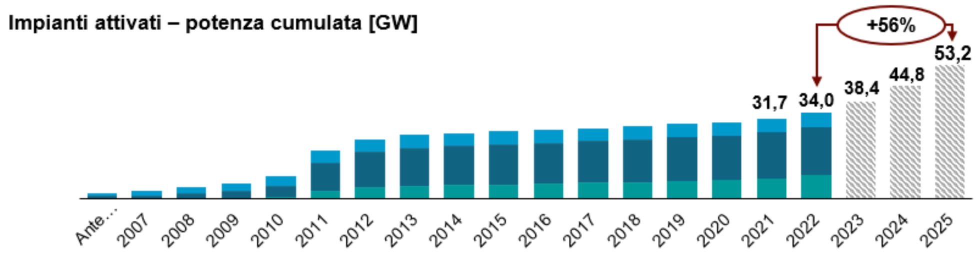


Figure 4.12 Cumulative installed capacity (GW)

Considering the energy mix on the distribution grid in 2022, it gives a clear indication of which energy sources are installed. As it can be noted in the Figure 4.13, the largest share is taken by PV solar, followed by wind, biomass, and hydro.

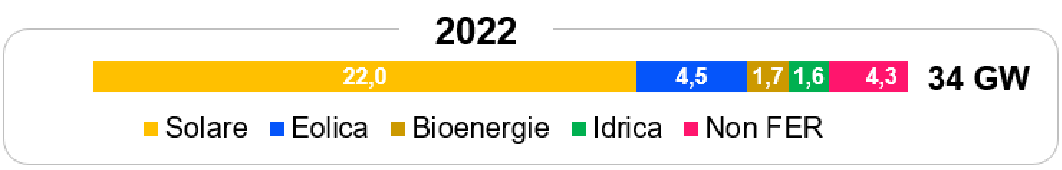


Figure 4.13 Energy mix on the distribution grid of e distribuzione in 2022

In the approval process phase there are, in Italy, more than 38 GW of new installed capacity in the distribution network.

One of the effects of having generation on the distribution network is that it may happen that for some hours over the year, the energy flows are reverse, from the distribution network to the transmission network. This is clearly something new since in the old days the electric power system was built as a unidirectional system, as said before. Substation HV/MV need to be upgraded to allow for the bidirectional flow of power.

It is interesting to look at the Figure 4.14 where it is reported the percentage of substation that had experienced inverse power flow in Italy.

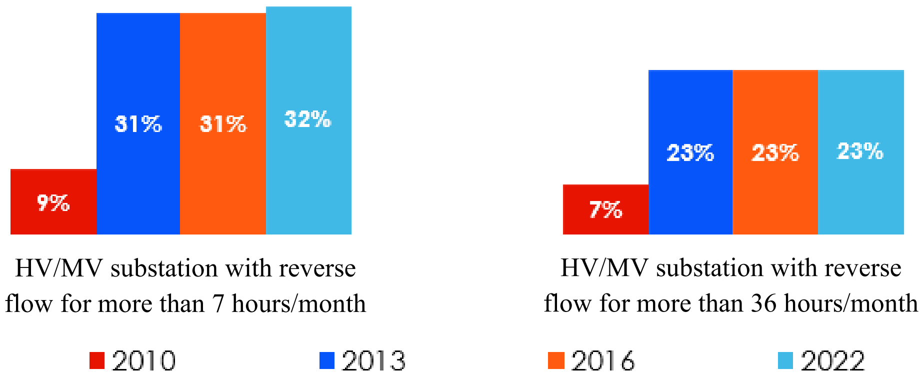


Figure 4.14 Percentage of HV/MV transformer that experience reverse power flow

As it can be seen in the figure above, there was a rapid increase from 2010 to 2013 that was driven thanks to tax incentives. When they expired the boom in new installation stopped.

But now the grid is experiencing one other boom in the installation of these power plant due to the goal set by EU and Italian legislation and regulation.

The increase of the inversion phenomena will also increase the likelihood of stopping the power plants connected to the high voltage grid, creating grid congestion, overloading, and saturation of the interconnection.

So, it is fundamental for the energy transition to consider this effect since it would transform some distribution network into "equivalent generator". To achieve this, a very flexible grid is needed and that is where the storage and smart grids can play a key role.

5. Regulatory environment for storage in Italy

5.1 European directives

The goal of these directives, included in the Clen Energy Package, is to reduce the regulatory obstacle in the deployment of the storage systems [10].

The two main directives linked to the storage are:

- Directive 2019/943 – regulatory framework for the internal electrical energy market.
- Directive 2019/944 – common regulatory environment across EU member states, like on generation, transmission, distribution, and storage.

An important part of the directive 2019/944 involves the managers of the energy related service, GSE in Italy. The directive states that the storage services should be based on the market, and they must be implemented in a competitive environment.

The other important pillar of the European directives is the directive 2019/943 on the internal electric energy market, which reviews the norms and the principles of the energy market, to the end of guarantee the correct operation, competitiveness and enhance the decarbonization of the EU energy sector by reducing the obstacle to the movement of energy across countries' borders.

The principles behind this approach can be summarized in:

- The prices are decided between demand and offers.
- The consumer will be active participant on the market, for example the prosumers.
- The incentives for the production from low carbon sources will follow market logic.
- Removal of obstacle to the flow of energy.
- The producers will be responsible for the electricity they sell.
- Member state will have to invest into capacity mechanism (long terms contract awarded through competitive bids).

The role of storage systems will be fundamental.

5.2 Italian legislation

The two European directives were received, and they form the basis for the “Decreto Legislativo dell’8 Novembre 2021 (n.210)”. This decree will set the stage for the introduction a new mechanism to incentivize the development of storage capacity through ARERA and Terna.

The goal of this decree, in line with the European directives, is to maximize the utilization of energy produced by VRE and allow their integration in the energy market and in the market of the ancillary services.

Inside the decree there is also set, for the development of storage capacity, a system of competitive bidding (“Aste concorrenziali”) with the goals of being transparent and non-discriminatory, done by Terna to minimize the cost to the clients (final users).

The principles at the base of these biddings are:

- Only new storage can participate.
- There must be technology neutrality, having defined minimum requirements by the TSO.
- After the bids, an annual remuneration is guaranteed for all the length of the contract expressed in the bid.
- There must be a guarantee from the successful bidder.

In this environment created by the decree, ARERA has these goals:

- Determine the bid criteria.
- Ways to cover the investment of the storage capacity.
- If part or all the storage capacity goes uncovered, then Terna will cover the remaining following the directives, modalities, and development strategy from ARERA.
- Criteria for the functioning of the whole storage system available to the market through a dedicated platform.
- Utilization of storage capacity by the market’s operator.
- Monitoring the effects of the storage system on the system and on the markets.

After the definition of these principles, Terna will create one or more standard contract schemes. These will be based on different very important parameters, reported as follows:

- Planning horizon, time between bid and delivery time.
- Delivery time.
- Storage duration time.
- Number of cycles of the storage system.
- Place of delivery, defined as the node in the grid where the storage unit is placed.
- Other minimum technical requirements from Terna.

When considering the current regulatory environment for the PHS system, as reported in the “Piano di Sviluppo 2021” of Terna, the market instrument and the current regulatory scheme is not able to guarantee the economic viability of the PHS.

To allow for new installed capacity of PHS it is necessary to introduce long term contracts to make them viable.

The high capital intensity and the long-life span of the PHS project do not allow the deployment of new facilities bases on to price signals (spot price) or on the capacity market (characterize by a lifespan and economic condition not suited).

Terna stated that after the construction of these PHS there is a need to guarantee, through long term contractual schemes, an optimal use of the plant, maximizing the benefits for the electric power system.

Two possible alternatives for the regulation of PHS in Italy are explored in the paper by The European House Ambrosetti [10], that allows for some interesting consideration.

For both it is present a fixed and guaranteed income over at least 30 years.

“DECLINAZIONE DCO 393 ARERA” MODEL”

ARERA has defined the modalities in covering the costs, the modalities in the utilization of the storage capacity and the monitoring of the storage system.

The main characteristic of this plant is that the operator has not a lot of freedom in how it operates.

On the market side there must be a bid on the markets but at the same time there is a guaranteed remuneration with an eventual restitution (or recovery) in case of positive (or negative) differential with respect to the actual market profit.

ARERA assumes a public procedure for the storage capacity contract in which a fix sum is guaranteed.

This PHS will work for the time shift market through Terna (which will create restriction on the day before market - MGP or Mercato del Giorno Prima) and that will follow the obligations on the offers in the MSD (mercato per i servizi di dispacciamento) at a predefined price.

At the end the plant operator will have to give back extra profits or be recompensated for the losses.

The main benefit of this model is the certainty of the investor to receive a remuneration. The main drawback is that there is no incentive to utilize the storage in an efficient manner. Then this model looks not in line with the European directives that stress the importance of competitiveness.

The fixed remuneration has the most impact on the final consumers.

“IN PARTE A MERCATO” MODEL”

The objectives in this model are to minimize the impact of the fixed guarantee return on the final consumers and obtaining changes of the incentive base on the market.

With this model the European directives are better implemented and followed, but more importantly the model pushes the operator to a better management of the PHS even through signals from the spot market.

For the MGP the model will provide time shift products. In fact, the TSO will collect offering and create a theoretic programme of operation for the PHS operator.

But here it is allowed, inside limits defined by the TSO, that the operator manages autonomously its program and works out with the TSO the economic value of its service.

Meanwhile, for the MSD (capacity market – dispatchment market) the model of the PHS works inside a range of prices already defined by the TSO.

The main benefit of this model is that there is a better link between the PHS and the spot market, and at the same time it allows for an efficient management of the plant.

As reported in the paper [10], the “in parte a mercato” model has a lower final cost for the consumer thanks to the more efficient operation due to the signals from the spot market and the modulation of the incentive’s value.

5.2.1 Directives from ARERA

In the paper “Criteri e condizioni per il sistema di approvigionamento a termine di capacità di stoccaggio elettrico” by ARERA [13], two main markets in the current Italian electricity energy system are identified, the energy market and the ancillary services market. In recent year a new market has flourish, the one to preserve the adequacy of the system itself, the remuneration mechanism of the production capacity also known as capacity market (remuneration of the power flexibility).

A high penetration of VRE has a production that is dependent on the presence of Sun and/or wind and the presence of VRE plant where these sources are most present. This create issue that needs to be manage by the TSO.

- There may be hours where the production is higher than the consumption (overgeneration), followed by hours where the production is not sufficient to cover the load, and this is traduced in steeper ramps.
- Increase of congestion due to the volatility in production and location not coordinated with the transmission capacity.
- To ensure the inertia of the grid, due to the decrease in thermal generation, the power production of VRE must be decrease.
- Increase in the volatility of energy prices in time and space, so a riskier environment to invest.

To pursue the decarbonisation objectives, with the goal of keeping prices low for the final user without affecting the energy security and most important the adequacy of the system, it is important a better integration of the various sources on the production side, the various storage technologies, and transmission infrastructure.

Nowadays the risk associated with investment in the electric energy storage in the market "energy only", so without specific market, is very high. Storage technologies are usually characterized by high fixed costs and all the revenues are characterized by a high degree of uncertainty since they cannot be predicted by the investor.

In this scenario, the Italian legislator, with the d.lgs. 210/2021, has introduce the architecture for a new energy market for the electric storage systems to work with the other three markets: energy, ancillary services, and capacity. In Appendix 2 more information is available.

With the d.lgs. 210/2021 the legislator wants to ensure an adequate storage capacity to the grid, to reach the decarbonization objectives, having in mind the economic efficiency and the security of the electrical network.

The tool identified by the legislator, to define the criteria and conditions for the supply of the storage capacity, is the introduction of a system of forward contracting in which the system itself, through Terna, express the minimum requirements for this type of resource, contributing into covering the investment cost and assuming the risk on the storage capacity installed.

The criteria, which will be defined by ARERA, must be designed so that:

- They promote competition, with the objective of minimising the cost for the customers.
- They build a link between the installation of new VRE capacity and the installation of new storage systems and grid improvements, connecting this market to the capacity market.
- They promote an efficient use of the storage systems.

In the following paragraph, the tool will be explored in more detail.

STANDARD SUPPLY CONTRACT FOR THE STORAGE CAPACITY – contratto standard di approvvigionamento della capacità di stoccaggio

When building a contract for storage systems there are some parameters that must be considered. They are:

- The maximum power in charging and discharging mode, expressed in MW.
- The energy storage capacity, expressed in MWh.
- The efficiency of the charge/discharge cycle, expressed as
$$\frac{energy\ OUT - discharge\ mode}{energy\ \ IN - \ charging\ mode}$$
- The storage discharge time, expressed in hours and define as
$$\frac{maximum\ energy\ that\ can\ be\ stored}{maximum\ power}$$

- The cyclicity of the storage, which is the maximum time between charging and discharging phase without impacting the energy stored, it can be daily, weekly, monthly, or even seasonal.
- The response time to act on request, expressed in seconds or minutes.
- The density, max energy that can be stored per unit volume.
- The time for the construction.
- The lifespan.

These contracts have then specified different parameter, which can be:

- The planning horizon, the time between the bid and the start of operation of the plant (delivery time).
- The delivery time.
- The storage duration.
- The storage cyclicity.
- The place of delivery (node of the grid).
- Other minimum requirements from Terna.

The different storage technologies have very different parameter, for example construction time or lifespan.

The definition of a single contract able to accommodate all these different characteristics is much more complex if compared to the capacity market.

For example, let’s consider two of the more mature storage option: Lithium-ion batteries and PHS. The time required to build the storage system go from 1 to 3 years for the batteries and from 6 or more for the PHS. But when considering the lifespan of the plant the batteries have a lifespan of 10 to 15 years, depending also on the worsening of performance and number of cycles, to the at least 40 years for the PHS. So very different indeed.

To understand the cost associated with storage, and so to understand better which storage mix allows for the lower cost to the consumer, and by that the most cost-effective solution, Terna performs every one to two years a study of a range of technologies. This is also done to recalibrate the incentives.

When trying to understand how these contracts are created, it is important to make sure that all factors are considered to keep various competing option open.

The construction of a single unified standard contract presents some challenges also due to the difference in the performance parameters considered. The solution is doing different bids for different technologies.

The technical neutrality will be preserved by the sequence of the bids and their technical-economic parameters, so on how there are build.

The standard supply contract for storage capacity is created in line with the European directives reported in 5.1 European directives.

Rights and obligation

The winner of the bid has the right to receive, for the whole delivery time, a yearly sum defined by the bid.

For the technologies with a very long lifespan, longer than the delivery time, there could be a clause in the contract to extend the contract's obligations and reassess the yearly sum depending on extraordinary maintenance to the end of guaranteeing the use by the owner.

The obligation must reflect the service that the storage system is going to provide, and they can be defined in two main types: time shifting on the energy market, and ancillary service supply to Terna like frequency regulation, black start, etc.

Considering the current dynamic on the grid there is a reason to expect that since the penetration of VRE will increase, the role of storage systems will mainly be of time shifting, allowing storage managers to create revenues from the prince differentials on the energy markets.

Guarantees and penalties

A penalties scheme must be designed in a way that:

- They will not apply in schedule maintenance periods or when the storage system cannot operate due to local grid constraints.
- They incentivize the capacity to maximize their availability to the system.

Requirements definition and evaluation of extra-services

The requirements can be defined in energy terms (MWh) or capacity terms (MW) to which it is associated a storage duration time (h).

Every participant to the bid will have to formulate its offer as determined by ARERA.

The yearly sum will be expressed in €/MWh/year or €/MW/year.

The extra-services can be made available on the markets, or they can already be included in the contract and in this case work with Terna in the pooling mechanism.

The pooling mechanism allows for:

- Make the time shift product independent with respect to the storage technology used, and that reduces the risks.
- Terna allocates the stored capacity.
- Increase liquidity in the market of time shifting.

6. Pumped hydro storage

PHS is a proven and mature technology for the storage of energy, and it is very well understood from the technical point of view (Figure 6.1). It constitutes more than 94% of the grid scale energy storage systems, with an installed capacity of 160 GW (2018) of which 50 GW are in Europe. By 2026 it is expected that the worldwide installed capacity will reach 200 GW.

Figure 6.1 Upper reservoir of a PHS scheme

It can give reliable storage capacity for daily, weekly, monthly, or seasonal applications depending on project scale, scope, and configuration.

From [14], it is reported that currently most pumped-hydro storage plants only store energy in daily storage cycles however, this might not be competitive in the future due to the reduction in cost of other storage systems like batteries.

As reported in previous chapters, PHS can offer a competitive alterative in the grid scale storage system when compared to other storage technologies.

VRE sources are by nature intermittent and hard to predict (Figure 6.2), even though in recent years there has been a lot of improvement in the weather forecast. PHS can be coupled with VRE for time shift, renewable energy time shift and capacity firming.

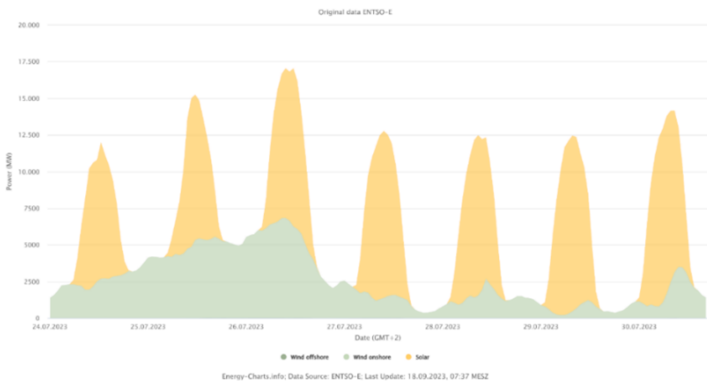


Figure 6.2 Public net electricity generation in Italy in week 30 2023

The PHS relies on the potential energy present in a cubic meter of water placed at a certain level higher than the hydraulic machine (Figure 6.3).

In these plants two reservoirs are present, one at a lower level and the other at a higher level. Between these two reservoirs a pump, a turbine and a generator are placed. A penstock is used to connect the two reservoirs and the powerhouse.

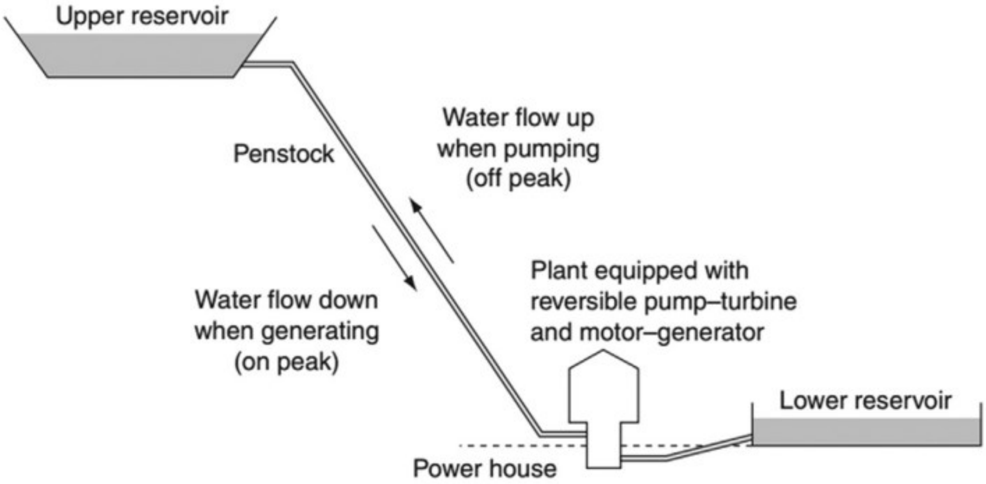


Figure 6.3 Overview of a pumped hydro energy storage system

As said before the functioning of the power plant is intuitive, the upper reservoir will be charged when the demand is low, and the prices are also low. Meanwhile, the upper reservoir's water will go through the turbine when the demand is at its peak, or when for example a VRE starts to diminish rapidly.

From the energy point of view this entail a loss of energy since there are the processes efficiencies in between. At the end there will be only 80% of the electric energy used for the pumping (Figure 6.4). But from the economic point of view, this is economically sustainable since off peak the electric energy is far cheaper than on peak.

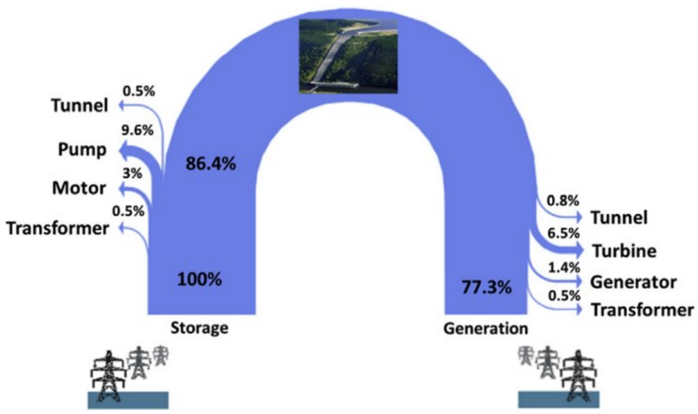


Figure 6.4 Efficiencies during the PHS operation

The economic sustainability of the PHS is based on the differential between on peak and off-peak prices.

As reported in [14], the PHS site for energy storage and for peaking generation should have short horizontal and high vertical distance between the upper and lower reservoir.

The ratio between these two dimensions H/L, where H is the head in meter and L is the length of the tubes in kilometres, is useful in the evaluation of the convenience, the higher the better. It starts from 40 and can go up to 400.

A good engineering practice is to reduce the length of the tunnels as much as possible. Thus, the penstock is in most cases build vertically to reduce its the length. If the slope of the mountain is very high, the penstock and the powerhouse can be constructed close to the slope, which reduces the costs of access tunnels to the powerhouse.

The need of having storage and flexibility on the grid is increasing with the increase in the generation mix of variable renewable energy [15]. PHS can be useful in supporting a grid with a high penetration of VRE. Other than compensating the production variability, the PSH can give other grid services such as mechanical inertia, frequency and voltage control, operating reserve, and black starts. All of these are going to be more important going forward with the energy transition.

Considering their characteristics, it can be said that PHS and battery storage can be complementary to each other. Fast response and relatively short storage capabilities of the batteries compared with a longer response time but also longer storage capacity, just remember that seasonal storage have a discharge time greater than 400 h (season storage).

PHS can provide a wide range of services, that have been explained in chapter 3. They are:

- Support a grid with a high penetration of VRE.
- Provide large storage capacity or large time shifting. This helps to reduce the curtailment of the VRE, so better exploiting the renewable source which we cannot control.
- Offers rotational inertia to stabilize the grid during disturbances such in case of transmission or generation outage.
- It reduces the need for operating reserves from conventional thermal power plants (hot and cold reserve).
- Reducing the ramping up, start/stop or partial load of conventional generation fleet.
- Provide black start service to restore the power after a black out. There are power plants designated at a national level with this role.

In the past there was no need of storage since the electricity was generated according to demand.

To have a flexible and stable power grid it must be kept in mind the flexibility characteristic, which mainly depending on the time that it takes for them to act when called upon, to manage the change in supply and demand.

Currently, the installed capacity of PHS worldwide is located as reported in the Figure 6.5.

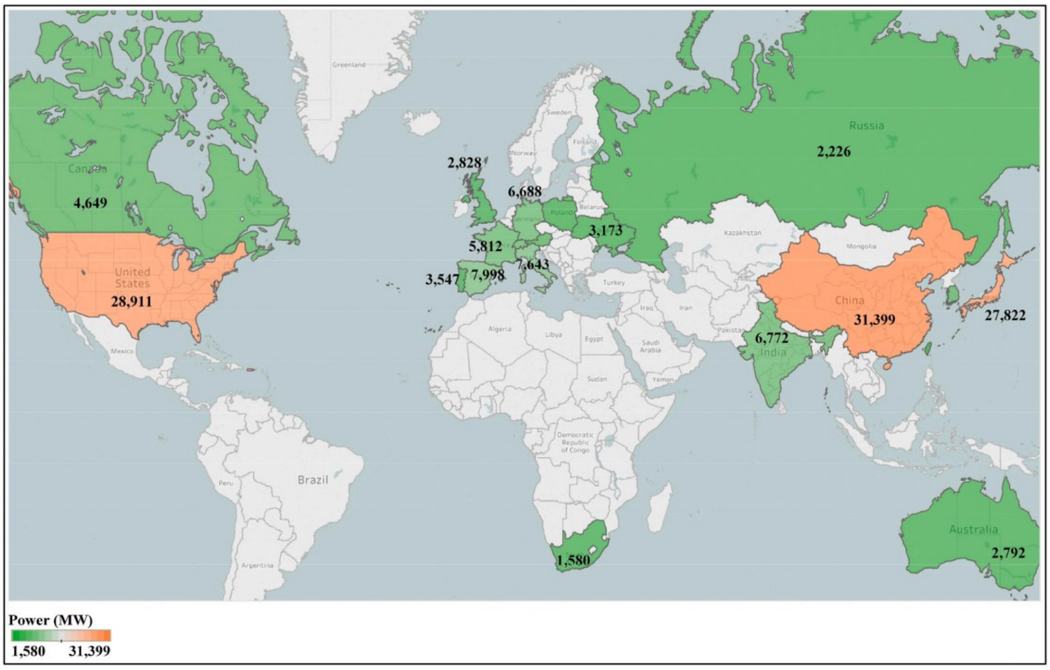


Figure 6.5 Global distribution of pumped hydro storage with the capacity limited to a lower value of 1580 MW

There have been recently new announced investments in the PHS sector, recognizing the importance of PHS for the storage of electricity in the grid of the future (Figure 6.6).

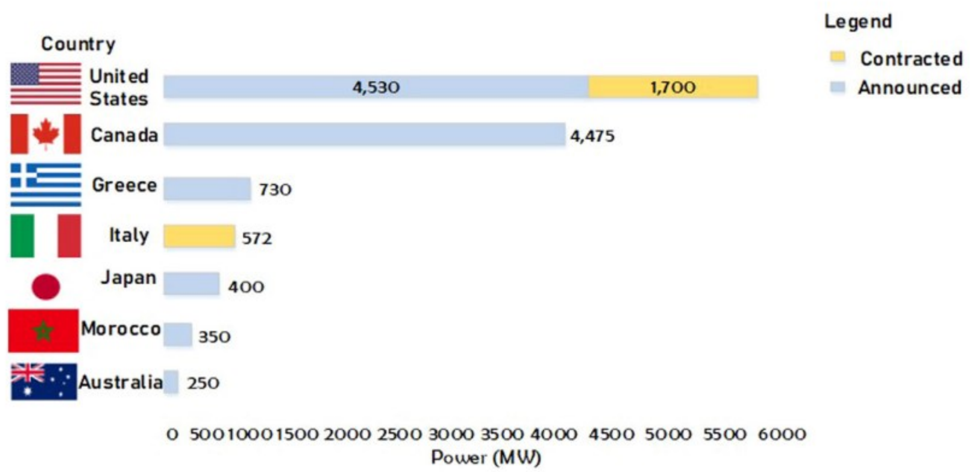


Figure 6.6 New PHS units announced and contracted by different countries, 2021

6.1 State of the art of the technology behind pumped hydro

Pumped hydro storage plants can be classified in several ways (Figure 6.7), as reported in [16]. The classification follows three main categories which are the penstock, the reservoir configuration, and the operation.

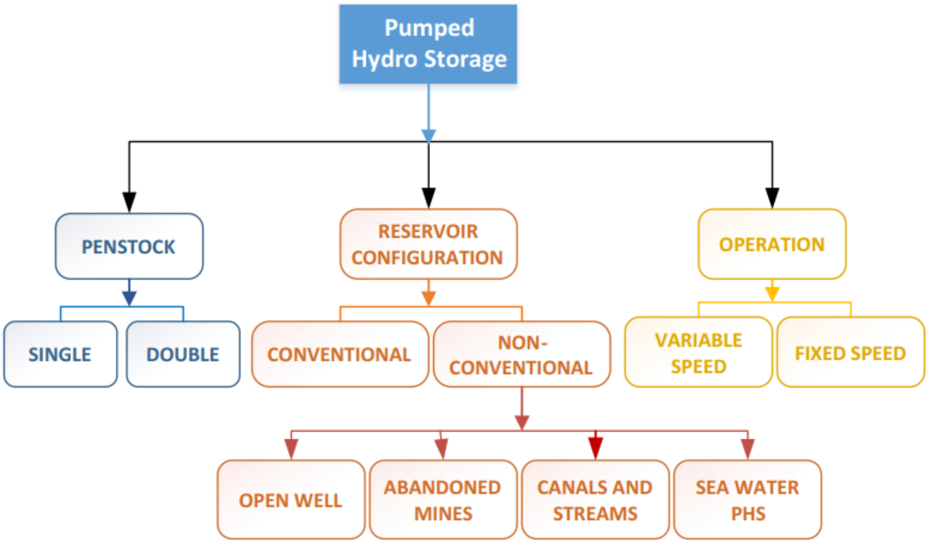


Figure 6.7 Different classification of PHS systems

Some other characteristics of the PHS are reported in the Table 4.

Table 4 Pumped hydro storage characteristics

Characteristic	
Lifespan [years]	>50
Number of cycles	>50000
Discharge duration at rated power	1 to 24 hours
Round trip efficiency	70% to 80%
Optimal operating range (state of charge) [%]	0 to 100
Response time	Minutes
Yearly loss in performance capacity	Negligible
Construction time [years]	5 to 7
Operational temperature [°C]	/
Self-discharge [%]	Negligible for daily cycles
Active power regulation in charging phase	Yes, but only for PHS double fed or full converter
Restart capability	Black start
Voltage regulation	Yes
Inertia	Yes (no with full converter)

6.1.1 The penstock

The penstock links the upper reservoir to the powerhouse, where the electromechanical equipment is located. It must be designed to withstand the maximum internal pressure during normal or abnormal operation, primarily due to water hammer phenomena.

Various materials can be used for the penstock such as steel, cast iron, reinforced or pre-stressed concrete, plastic, and glass fibre-reinforced plastic, etc.

There are two penstock design option:

- Single: there is only one circuit for both pumping and turbining. It is the cheaper option.
- Double: there are two independent circuits, one for pumping and the other for turbining. It gives much more flexibility in the operation, so a faster response when the turbine is needed.

The penstock internal diameter is sized according to the flow rate and to keep the water flowing inside under a certain limit of velocity depending on the pipe material (for concrete up to 3 m/s, for steel 6 m/s); this with the aims to limit the friction, avoiding damaging the pipe internal surface and to reduce the energy loss [17].

Velocity and head loss decreases with an increase in pipe diameter, but the pipe cost grows greatly with an increase in diameter.

The choice of type and size of a penstock depends on several factors, such as length, cost, and maximum head loss acceptable.

6.1.2 The reservoir

The reservoir can be classified based on the natural water inflow in the basin. If there is a natural inflow the PHS is called open loop, meanwhile if it there is no natural inflow it will be called closed loop, this reduces the impact on the ecosystem due to damming.

There are three types of pumped hydro storage:

- Closed loop (Figure 6.8): where water is simply moved between two reservoirs at a different elevation, without any significant natural flow input. These are mainly built in wet environments to compensate for the evaporation of water.
  Closed loop have less environmental issues than open loop since the damage on the aquatic and terrestrial habitats is minimized.
  The aquatic resources include surface water, groundwater, and aquatic ecology. Meanwhile terrestrial resources include geology, soils, terrestrial ecology, land use, recreation, visual resources, and cultural resources.

Figure 6.8 A closed loop pumped hydro energy storage station in Ireland's Wicklow Mountain

- Open loop: in this case in the upper reservoir there is both the pumped water and the natural inflow of the environment, so it is located "on-stream". In open loop there is a share of the power production that can be generated as a conventional hydropower plant.
- Pump back, where water is continuously pumped back and forth between the two very close reservoirs.

Usually, the reservoirs are linked to high investment cost, long construction time and environmental issue, but nowadays new alternatives are being considered, such the use of quarries, to reduce the environmental concerns.

But, as reported in [18], abandoned mines and quarries linked to unconfined aquifers have been already used as auxiliary reservoirs to realize PHS scheme. However, cyclic injection and pumping of water into the mine pit, induce sinusoidal stress to the adjacent aquifer.

The hydrological impact and interactions between mine and aquifer have been analysed in various works. It is recommended to carry out a preliminary study of hydrological interactions at the potential site to avoid catastrophe.

6.1.3 The powerhouse

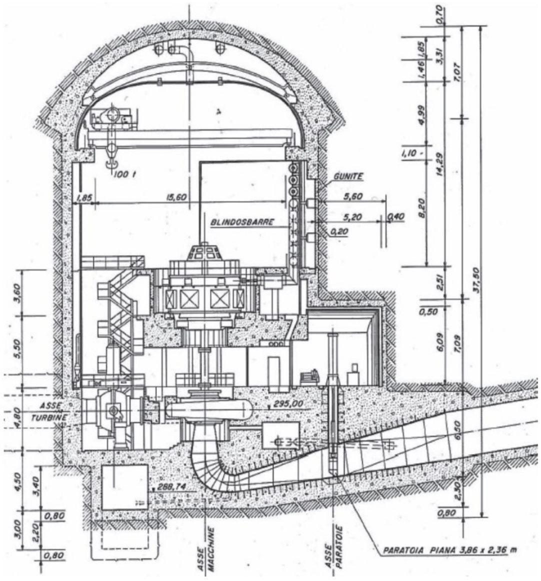


Figure 6.9 Taloro PHS (Nuoro, Italy) binary unit (reversible Francis turbine)

As reported in [17], the powerhouse can be located underground or the surface.

An underground type of powerhouse (Figure 6.9), will generally comprise one or more caves dug in solid rock, with access via tunnel or shaft. The reason to choose an underground power plant is usually to reduce the headrace conduits length and by doing so, the energy losses in the water circuit. However, this solution may require a long and wide pressurized outlet conduit (tail tunnel) to reach the lower reservoir. The underground solution permits to install lower cost and higher-speed generating and pumping units in the powerhouse, smaller in size, without incurring in significant cost penalty for the required deeper submergence.

Normally upstream each hydraulic machine (on the high-pressure side), is located a spherical valve (or ball valve) as a wicket gate and downstream, in the tail conduit (on the low-pressure side), a butterfly valve or a sluice gate. The first valve must be able to close against flow under the maximum head and the latter, to avoid the powerhouse flooding from the lower reservoir.

Surge tanks are required for long water conduits. They are placed at the end of the head tunnel (the upper penstock end) and at the end of the pump suction tunnel. The lower surge tank may lack when the underground powerhouse is close to the lower reservoir and the suction tunnel is short. A surge tank mainly consists of a cylindrical vertical shaft, dug in solid rock; at the upper end it may have an expansion chamber.

Normally each unit has its own transformer, to ensure all the possible flexibility and independence. The transformers must be installed in separate armoured cells, to protect them and prevent the risk of fire and explosion. The cables connecting the outside switchyard, normally go under the vault of the access tunnel.

A less expensive surface powerhouse, is usually the preferred option for low water head projects.

6.2 PHS cost and impact on the larger economy

6.2.1 Cost and comparison with other storage technologies

It is interesting, following [15], to compare PHS, which is a mature technology with a high roundtrip efficiency, with its main competitors particularly for long term grid scale storage.

US DOE has assess the cost and performance characteristics of energy storage technologies for 100 MW and 4-hour duration systems and for 1,000/100 MW and 10-hour duration systems in shown in Figure 6.10 and Figure 6.11, respectively.

Comparison metrics	Type of energy storage	Pumped Storage Hydro	Li-Ion Battery Storage (LFP)	Lead Acid Battery Storage	Vanadium RF Battery Storage	CAES compressed air	Hydrogen bidirect. with fuel cells
		100 MW / 4hr	100 MW / 4hr	100 MW / 4hr	100 MW / 4hr	100 MW / 4hr	100 MW / 10hr
Technical Capabilities	Technical readiness level (TRL)	9	9	9	7	7	6
	Inertia for grid resilience	Mechanical	Synthetic	Synthetic	Synthetic	Mechanical	no reference
	Reactive power control	Yes	Yes	Yes	Yes	Yes	Yes
	Black start capability	Yes	Yes	Yes	Yes	Yes	Yes
Performance Metrics	Round trip efficiency (%*)	80%	86%	79%	68%	52%	35%
	Response time from standstill to full generation / load (s*)	65...120 / 80...360	1...4	1...4	1...4	600 / 240	< 1
	Number of storage cycles (#*)	13,870	2,000	739	5,201	10,403	10.403
	Calendar lifetime (yrs*)	40	10	12	15	30	30
Costs 2020	avg. power CAPEX (USD/kW*)	2,046	1,541	1,544	2,070	1,168	3.117
	avg. energy CAPEX (USD/kWh*)	511	385	386	517	292	312
	avg. fixed O & M (USD/kW/yr*)	30	3.79	5	5.9	16.2	28.5
	effective CAPEX (USD/kW based on PSH life of 80 years and 6% discount rate**)	2,710	4,570	5,070	8,370	3,340	8,900
Estimated costs 2030	avg. power CAPEX (USD/kW*)	2,046	1,081	1,322	1,656	1,168	1.612
	avg. energy CAPEX (USD/kWh*)	511	270	330	414	292	161
	avg. fixed O & M (USD/kW/yr*)	30	3.1	4.19	4.83	16.2	28.5
	effective CAPEX (USD/kW based on PSH life of 80 years and 6% discount rate**)	2,710	3,210	3,920	4,910	3,340	4,620

Figure 6.10 Comparison of energy storage technologies for 100 MW and 4-hour duration in 2020 and 2030

Comparison metrics	Type of energy storage	Pumped Storage Hydro	Li-Ion Battery Storage (LFP)	Lead Acid Battery Storage	Vanadium RF Battery Storage	CAES compressed air	Hydrogen bidirect. with fuel cells
		1000 MW / 10hr	100 MW / 10hr	100 MW / 10hr	100 MW / 10hr	1000 MW / 10hr	100 MW / 10hr
Costs 2020	avg. power CAPEX (USD/kW*)	2,202	3,565	3,558	3,994	1,089	3.117
	avg. energy CAPEX (USD/kWh*)	220	356	356	399	109	312
	avg. fixed O & M (USD/kW/yr*)	30	8.82	12.04	11.3	8.74	28.5
	effective CAPEX (USD/kW based on PSH life of 80 years and 6% discount rate**)	2,910	10,570	11,720	16,170	3,110	8,890
Estimated costs 2030	avg. power CAPEX (USD/kW*)	2,202	2,471	3,050	3,187	1,089	1.612
	avg. energy CAPEX (USD/kWh*)	220	247	305	319	109	161
	av. fixed O & M (USD/kW/yr*)	30	7.23	9.87	9.26	8.74	28.5
	effective CAPEX (USD/kW based on PSH life of 80 years and 6% discount rate**)	2,910	8,130	9,050	9,450	3,110	4,600

* Source: US DOE, 2020 Grid Energy Storage Technology Cost and Performance Assessment
** Estimation based on the value of initial investment at end of lifetime including the replacement cost at every end of life period.

Figure 6.11 Comparison of energy storage technologies for 1000/100 MW and 10-hour duration in 2020 and 2030

Looking at these figures some consideration can be made.

The response time is time that is takes the energy storage system to respond to a request from the grid. So how fast can it be dispatched. In this case all the technologies are very flexible and can be placed in operation very fast. Batteries, of course, represent the fastest option, as they can be dispatched in a matter of some milliseconds. Meanwhile PHS may takes some minutes, depending on the plant configuration.

The roundtrip efficiency, defined as the electrical output of the storage compared to the input, it is generally high but not for all technologies. For PHS it is between 70-85%.

One other consideration can be done about the technology's lifetime and number of storage cycles. PHS has a lifetime between 40 and 80 years, by far longer than any battery system which is about 20-25 years. And the PHS plant lifetime can also be extended by revamping the turbine, generators, etc. During its whole lifetime, an PHS is expected to do more than 14000 cycles. Much more than the other systems considered.

When considering the cost, the CAPEX represents the cost for the construction of the facility. For PHS the CAPEX is high, as for any large infrastructure project. Considering the Figure 6.11, the 2020 costs are reported in Table 5

Table 5 2020 costs for a PHS for 1000 MW and 10-hour storage

Average cost reported in the literature for PHS project	
Average CAPEX cost based on power	2202 $/kW
Average CAPEX cost based on energy	220 $/kWh
Average fixed O&M	30 $/kWh/year
Effective CAPEX based on an 80-year lifespan and 6% discount rate	2910 $/kW

An analysis for the different storage time can give an interesting result. For the 4 h storage it can be seen how the pumped hydro is the cheapest option. But the real difference can be notice when the 10 h storage is taken into consideration.

Of course, with the evolution and development thanks to the research in the field of electrochemical storage, the cost of the batteries will decrease, becoming more competitive with respect to the PHS.

But the CAPEX on its own is not a good enough indicator of the financial viability of the storage system, since PHS has a much longer lifecycle compared with other technologies. Let's consider the effective lifecycle cost. Considering a storage duration of 10 h it can be shown that the PHS is by far the cheapest solution, even considering the price reduction by 2030 of the battery energy storage.

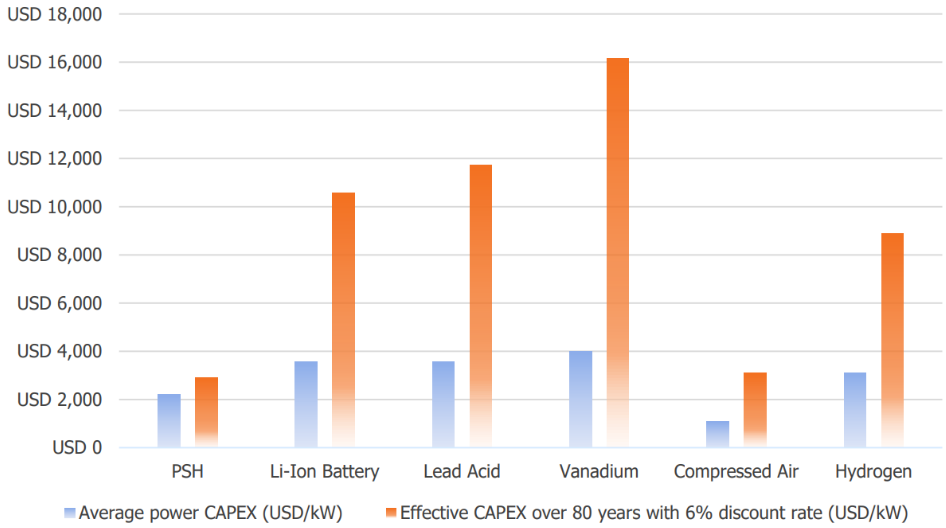


Figure 6.12 Comparison of the CAPEX between different technologies

As said before, considering only the CAPEX is the wrong approach, that can then lead to wrong decisions. The cost over its life cycle must be considered, knowing that the PHS has a lifespan of 80 years and low OPEX costs (Figure 6.12). With this consideration the PHS can be cheaper than lithium-ion batteries, when considering utility scale storage (in the GWh scale).

The costs of the PHS as a function of installed capacity and discharge duration are reported in the following Figure 6.13 from [19].

2021 & 2030 PSH
Installed Costs & Performance Parameters

			100 MW				1,000 MW			
			4 hr		10 hr		4 hr		10 hr	
			2021	2030	2021	2030	2021	2030	2021	2030
ESS Installed Cost	ESS	Storage System	Reservoir Construction & Infrastructure ($/kWh)	$81.00	$81.00	$76.00	$76.00	$68.00	$68.00	$64.00	$64.00
ESS Installed Cost	ESS		Powerhouse Construction & Infrastructure ($/kW)	$742.00	$742.00	$742.00	$742.00	$623.00	$623.00	$623.00	$623.00
ESS Installed Cost	ESS		Electromechanical ($/kW)	$467.00	$467.00	$467.00	$467.00	$392.00	$392.00	$392.00	$392.00
ESS Installed Cost			Contingency Fee ($/kW)	$511.00	$511.00	$656.33	$656.33	$429.00	$429.00	$551.67	$551.67
			Total Installed Cost ($/kWh)	$511.00	$511.00	$262.53	$262.53	$429.00	$429.00	$220.67	$220.67
			Total Installed Cost ($/kW)	$2,044	$2,044	$2,625	$2,625	$1,716	$1,716	$2,207	$2,207

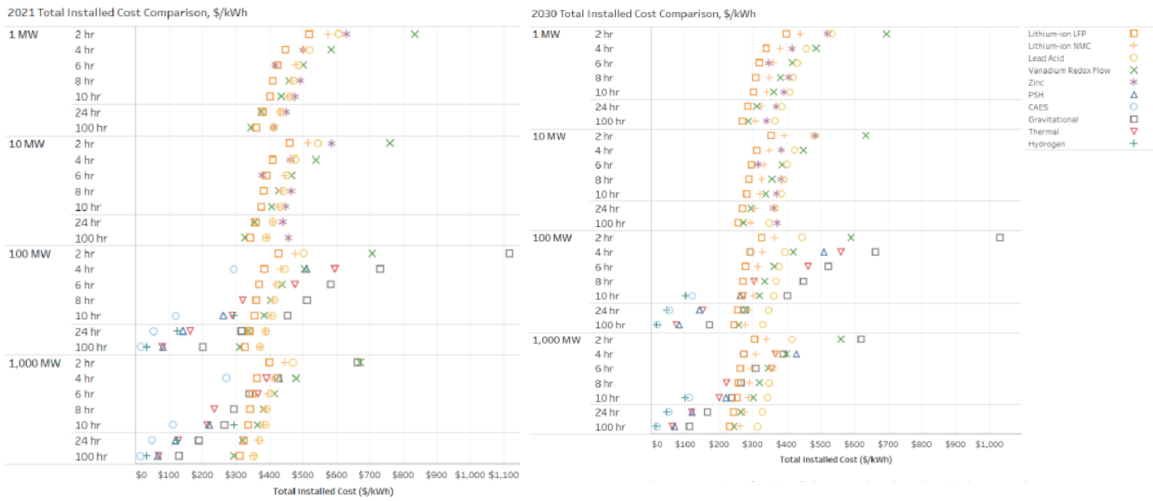
Fonte: «Energy Storage Grand Challenge Cost and Performance Assessment 2022”

Figure 6.13 2021 and 2030 PHS – Installed costs & performance parameters

From the start it can noticed some key differences that will be analyse in the following chapters.

1. It can be noticed that the scale, when considering PHS, is very different from Li-ion’s kW to MW, it is from hundreds to thousands MWs.
2. The time of discharge is higher for PHS, in fact as the time of discharge increases the Li-ion batteries became more expensive then PHS.

Meanwhile, when considering a far wider range of technologies, since Li-ion and PHS are not the only two technologies on the market or being a matter of research at this time, for different installed capacity it is useful to compare the cost of storage, based on a unit of energy stored, for multiple competitive technologies as it can be seen in the Figure 6.14.

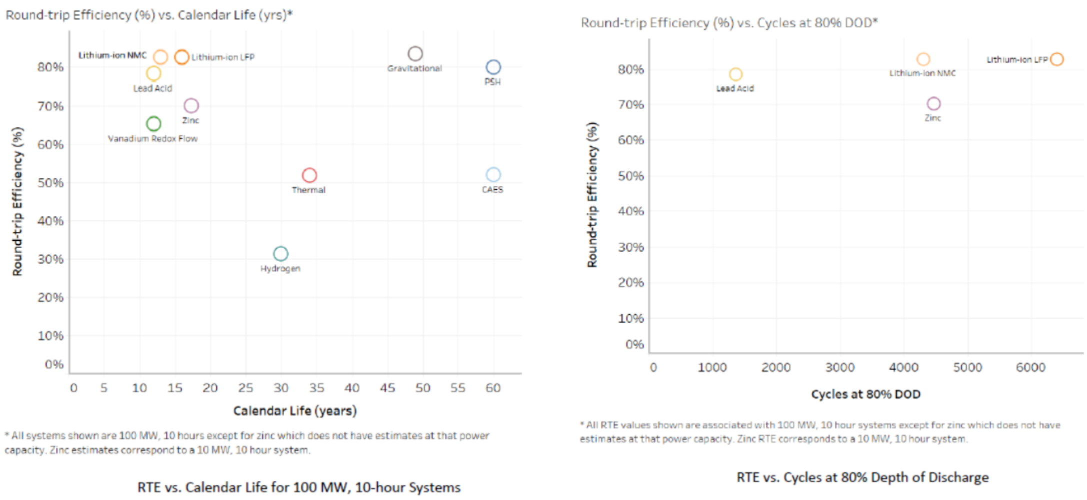


Fonte: «Energy Storage Grand Challenge Cost and Performance Assessment 2022"

Figure 6.14 Comparison of total installed costs estimated by technology (2021 on the left and 2030 on the right)

Here it can be noted again that PHS is more competitive for utility scale storage, and looking at the upper part of the graph it can be said that it expected a strong reduction in the price for the lower capacity installed applications.

One last consideration that can be made is on the round-trip efficiency and the lifespan of a technology (Figure 6.15). This confirms the long lifespan and high round trip efficiency nature of PHS.



Fonte: «Energy Storage Grand Challenge Cost and Performance Assessment 2022"

Figure 6.15 Round trip efficiency (RTE) plots

In the paper [7] different storage technologies were compared, starting with a qualitative description of their applications. The technologies considered are PHS, compressed air, flywheel, lithium ion, sodium sulfur, lead acid, vanadium redox flow, hydrogen, and supercapacitor.

It can be noted that one area where PHS, and hydrogen, shine is in the seasonal storage field since the seasonal storage must account for months of storage capacity. For the PHS it is generally considered seasonal storage when the parameter T is greater than 400 h or around 17 days. With T defined as the volume of the reservoir divided by the flow rate going through the turbines.

As seen in chapter 3.2 Levelized cost of storage (LCOS), the most important factors influencing the LCOS are the nominal power capacity, discharge duration, annual cycles (which affects the project lifetime) and electricity prices (which affects the charging cost). All of which are set by the respective application of the storage system.

These technologies were tested to see which was the cheapest option for different application.

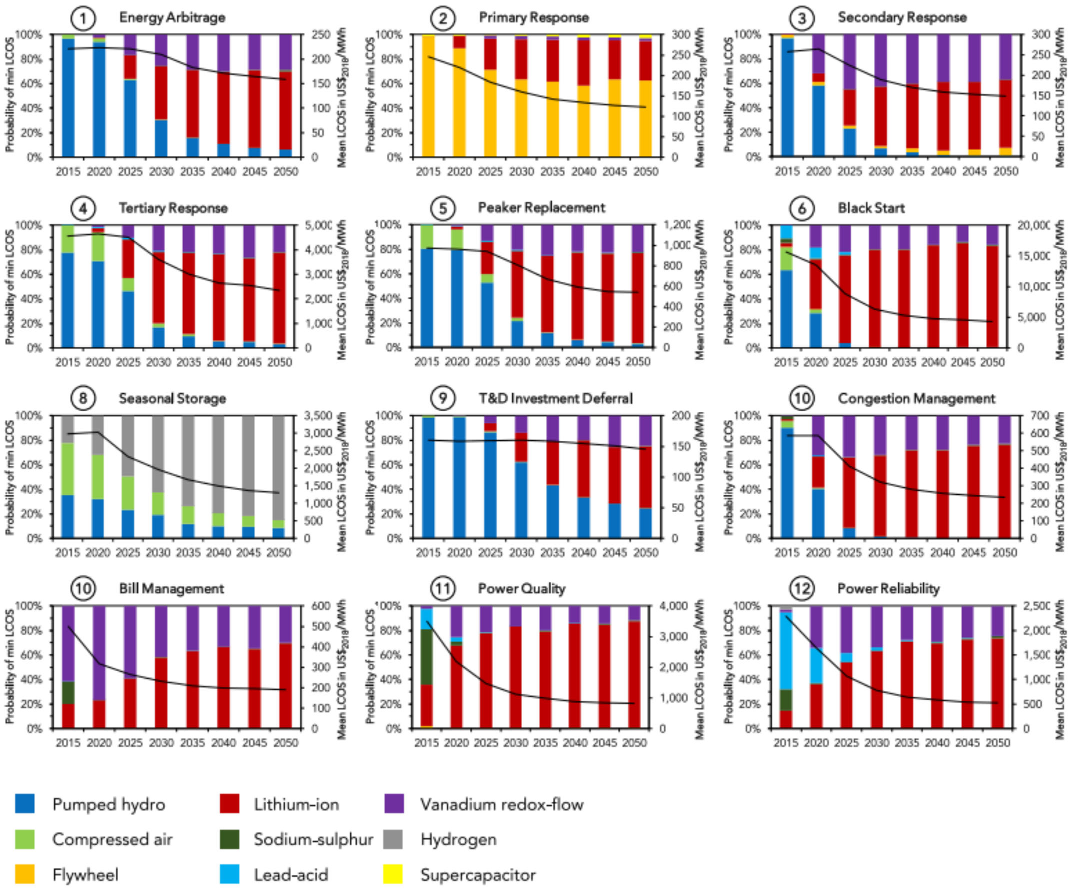


Figure 6.16 Probability of min LCOS for different technologies in various applications

It can be seen how, even in applications where the PHS is now dominant as in the energy arbitrage, secondary and tertiary response, black start and congestion management, the cheapest option in the long run will be the lithium-ion batteries. But the minimum LOCS is just one parameter. Lithium-ion batteries will be the most competitive in most applications from 2030 (apart from long term storage), but PHS, CAES and hydrogen will dominate the long-term energy storage. So, what it is needed is a mix of these technologies. But, considering only the CAPEX is not acceptable when considering long term scenarios, since no other parameter is considered. In the Figure 6.17 it is reported the future electric storage mix in a graph discharges per year vs duration with the different applications highlighted.

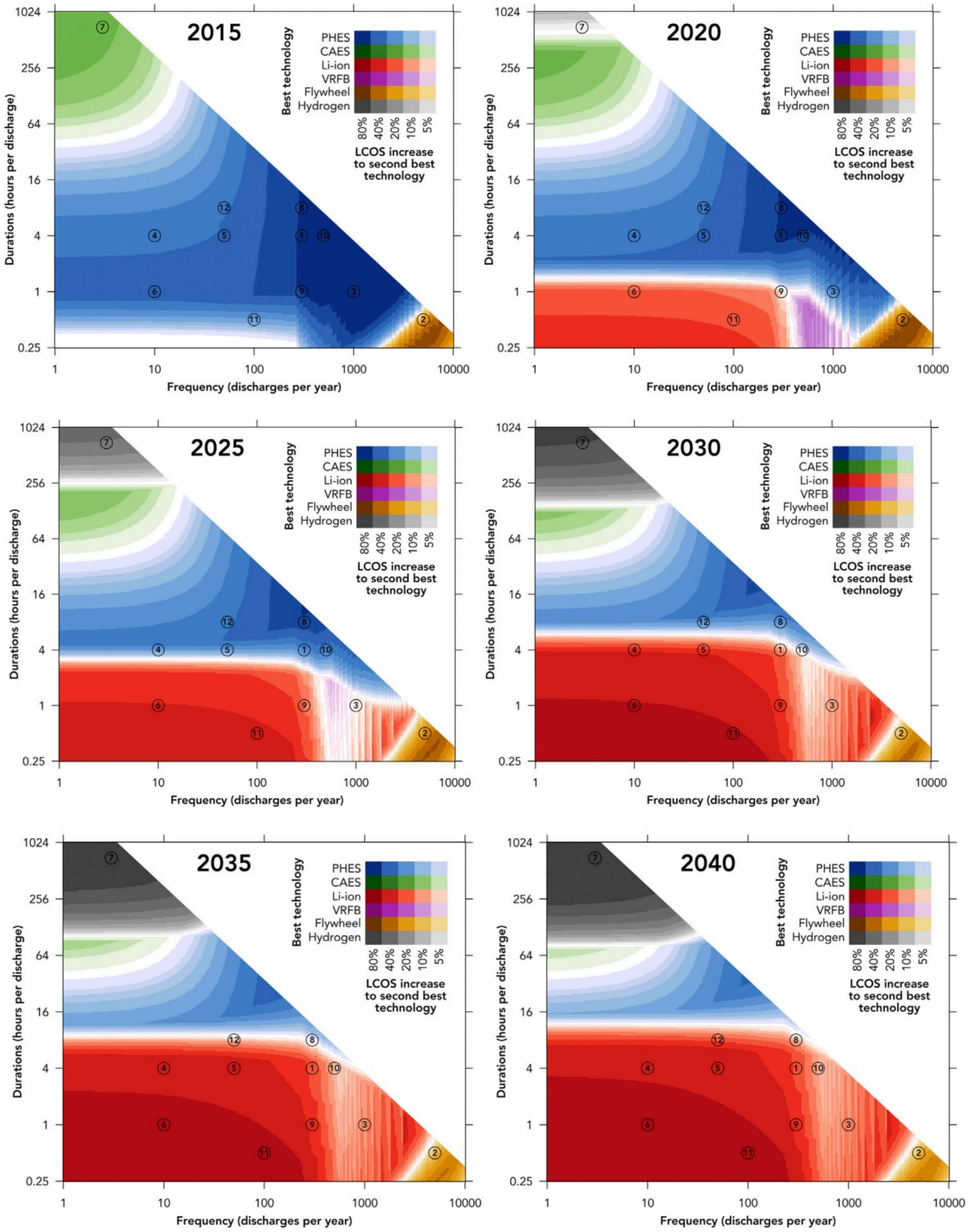


Figure 6.17 Energy storage mix evolution from 2015 to 2040 [1, Energy Arbitrage; 2, Primary Response; 3, Secondary Response; 4, Tertiary Response; 5, Peaker Replacement; 6, Black Start; 7, Seasonal Storage; 8, T&D Investment Deferral; 9, Congestion Management; 10, Bill Management; 11, Power Quality; 12, Power Reliability.]

This shows how, for long duration the lithium-ion batteries do not represent a good option. Here the most suitable technologies are PHS and hydrogen, even though in the 2040 scenario the lithium-ion batteries will be the cheapest technology.

The pumped hydro storage system can continue to play a role in the long-term storage field even in the 2040 scenario, thanks to its long-life cycle combined with a moderate power specific investment cost. But in the long run it will find a competitor in hydrogen, particularly for very long storage time as it can be seen in the bottom right of Figure 6.17. Pumped hydro offers services such as system inertia, frequency control, voltage regulation, storage and reserve power with rapid mode changes, and black-start capability. All of these are vital to support the ever-growing proportion of variable renewables. Pumped hydro excels at long discharge duration and its high-power capacity will be crucial in avoiding curtailment, reducing transmission congestion, and reducing overall costs and emissions in the power sector.

New advances in the PHS technology will be analyzed in the following chapters, they are adjustable speed, closed loop, and modular designs. That can further facilitate integration of variable generation, such as wind and solar.

6.2.2 Impact of the hydropower sector on the economy

From [10], it is evaluated that the economic value of the hydropower sector in Italy is 27.7 billion of Euro as for 2020. As it can be seen in the Figure 6.18 below, Italy is one of the leaders in this sector in the EU.

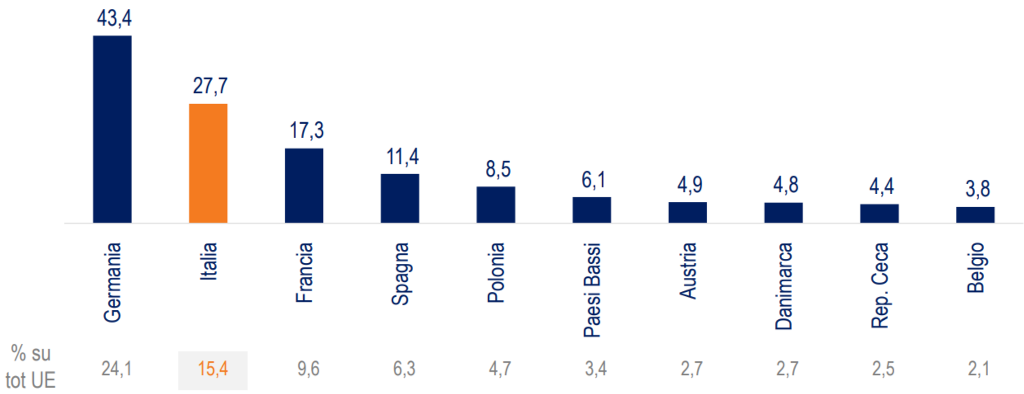


Figure 6.18 First 10 EU countries for economic value of HP sector (values in billions of Euro)

The hydroelectric value chain is also relevant to the Italian export, with a value of 15.4 billion of Euro.

From these data it can be noted the role of the hydroelectric value chain as a fundamental asset for the industrial and technological competitiveness of Italy.

The security of the supply chain and the low dependency on critical rare earth materials are two important benefits behind this technology.

Inside the economic impact of these investments, it may be interesting also to investigate the impact on the employment created by new investments. The hydropower sector, other than being capital intensive, it is also a high employment and high technical innovation sector. The hydropower sector employs around 15294 units per year ("unità lavorative per anno"), the most inside the renewables sector. It is followed by 4598 in the PV solar, 3605 in the wind sector and 689 in the geothermic.

In the coming 10 years, with the increase in the investments to reach the 2030 target, it expected that the hydropower sector will add 1086 units per year.

To quantify the investment needed in storage to fulfil the commitment defined by the Fit-for-55, taking the estimate of new PHS capacity from Terna and Snam at 35 GWh over 8 hours, and the average investment for a PHS at around 2,33 million Euro per installed MW. It is possible to quantify the necessary investment at 10,5 billion Euro. Meanwhile considering its the effect on the Italian economy, thanks to the input/output matrix, an estimation can be made at 31 billion Euro.

6.3 Technologies behind pumped storage

In the powerhouse four electromechanical components need to be present: a turbine, a pump, a generator, and a motor. Usually, the generator and the motor are the same component, meanwhile the pump and turbine can be separate or the same hydraulic machine, also called reversible. In the next subchapter these components are going to be analyze in more details [20].

The main distinction is between a fixed speed generator or a variable speed generator. As shown in the Figure 6.19.

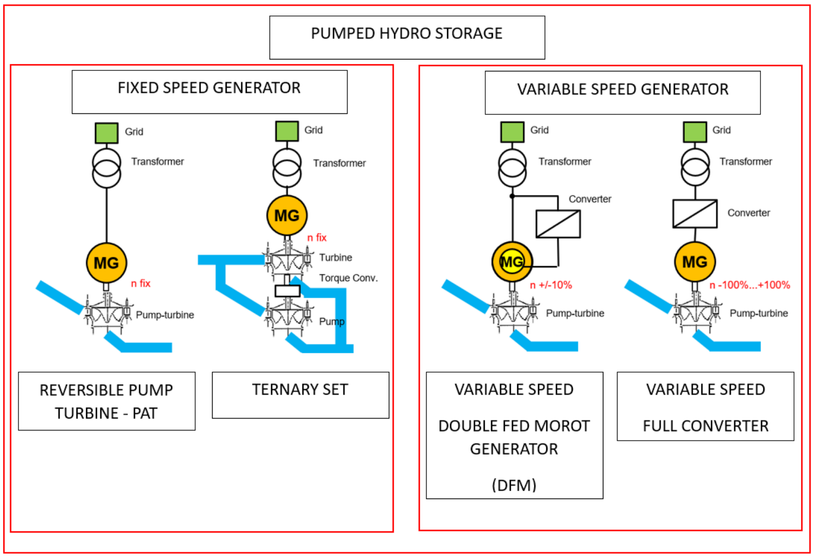


Figure 6.19 Fixed speed vs variable speed classification

6.3.1 Ternary group

The scheme of the ternary set can be seen in the Figure 6.20.

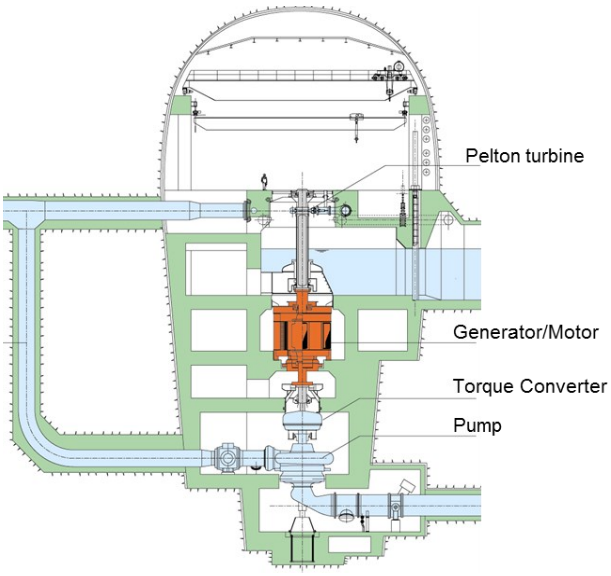


Figure 6.20 Possible scheme for a ternary group with a vertical axis

One other option for this configuration can be found by using a multistage centrifugal pump as shown in Figure 6.21.

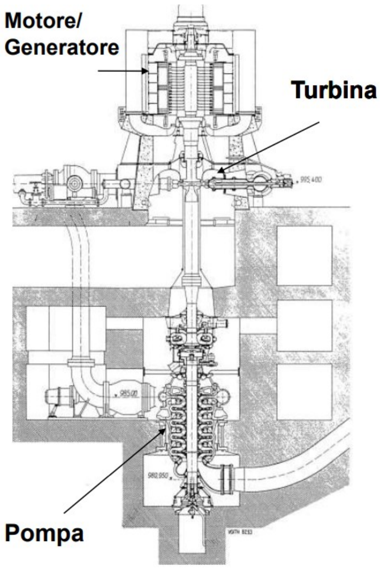


Figure 6.21 Ternary group configuration with multistage pump

In this case there is the generator/motor, the turbine, and the pump all on the same shaft generally in a vertical position, working with a fixed speed and the same direction.

This configuration allows the designer to place the generator/motor and the turbine above the water level and the pump below that level.

The pump is placed on the bottom to avoid cavitation issue, since it is, generally, the most problematic component, and there is of course the need to avoid cavitation in the working range of the pump.

Cavitation happens when the pressure, at the inlet of the pump, decreases below the saturation pressure. Here bubbles are formed, and they are brought inside the rotor. These bubbles explode creating pressure waves that hit the rotor blades and that generate hotspots. This causes erosion of the machine's blade. Cavitation happens also at the outlet of the turbine, but the issue is less problematic. This must be avoided.

If the ternary units are installed with the horizontal axis configuration, there may be a requirement to adopt a booster-pump to avoid cavitation risk when the unit starts pumping.

The advantages of this configuration are that there is a fast mode change between turbine operating mode and pump operating mode and vice versa. In fact, the pump can start without dewatering.

Since the pump and the turbine are two separate machines, their geometry can be optimized to maximize the efficiency. Furthermore, there is the possibility of hydraulic short-circuiting to regulate the energy.

The disadvantages are mainly linked to the fact that the project will incur in higher cost (about 20% more expensive), so increased investment and there is also the need for additional space requirement and additional valves, all of this is linked to the fact that the configuration has two separate machines: a pump and a turbine.

Francis and Pelton turbines are used in ternary group.

The ternary PHS is activated by starting the pump, and then load is transferred gradually to the motor generator. Both the pump and the turbine can be regulated from 0% to 100% of unit output.

As reported in [17], during the operation in pump mode, a by-pass conduit excludes the water from the turbine, which remains connected to the shaft and rotates with the pump. The turbine chamber is first emptied by injection of pressurized air, to reduce the weight of the rotating mass, the friction and therefore the energy losses while pumping.

In turbine mode, a coupling joint placed on the shaft between the pump and the turbine, disconnects the pump, because the latter lies under the downstream static water level, and it cannot be easily emptied.

Multistage pumps are a feature in ternary units if the head is higher than 700 to 800 meters.

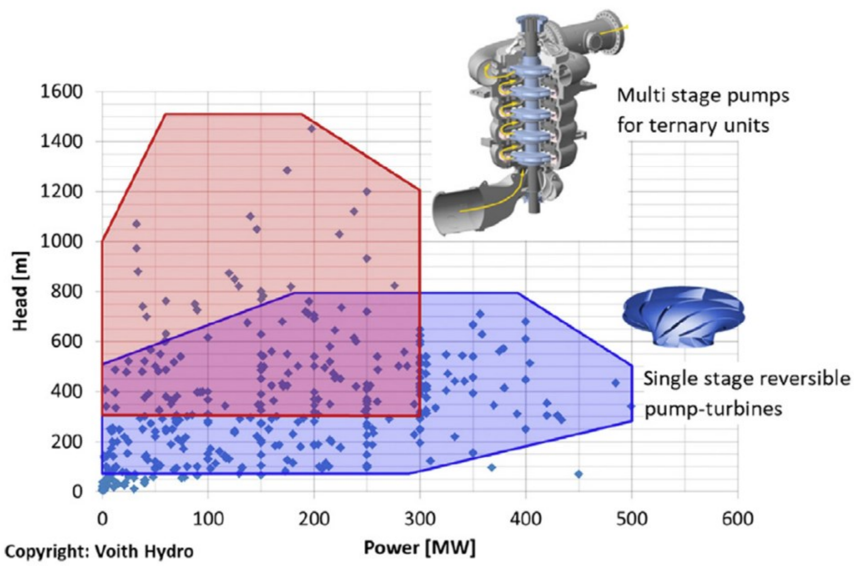


Figure 6.22 Operation ranges for single stage reversible pump turbines (charging and discharging) and multistage pump for high heads (charging)

PHS with high head are interesting because they require low water flow and smaller tube diameter. This also reduce the footprint of the upper reservoir.

6.3.2 Quaternary group

With a quaternary arrangement, the pump and the turbine are installed as distinct and autonomous components, each equipped with their own electric machine (motor or generator).

In a PHS project, this arrangement allows to obtain the maximum performance either in generating and pumping modality by sizing pump and turbine without constraints, each of them for the highest possible efficiency.

On the other hand, this arrangement may be very expensive, because the hydraulic circuits for pump and turbine are distinct and this requires a greater number of electro-mechanical components; furthermore, the overall dimensions of the units are higher, and the powerhouse results necessarily larger.

They are not very widespread.

6.3.3 Pump as Turbine or reversible pump-turbine or binary

The binary arrangement is the most widely used for pumped storage units [17].

The configuration of a reversible pump or binary scheme is shown in the Figure 6.23.

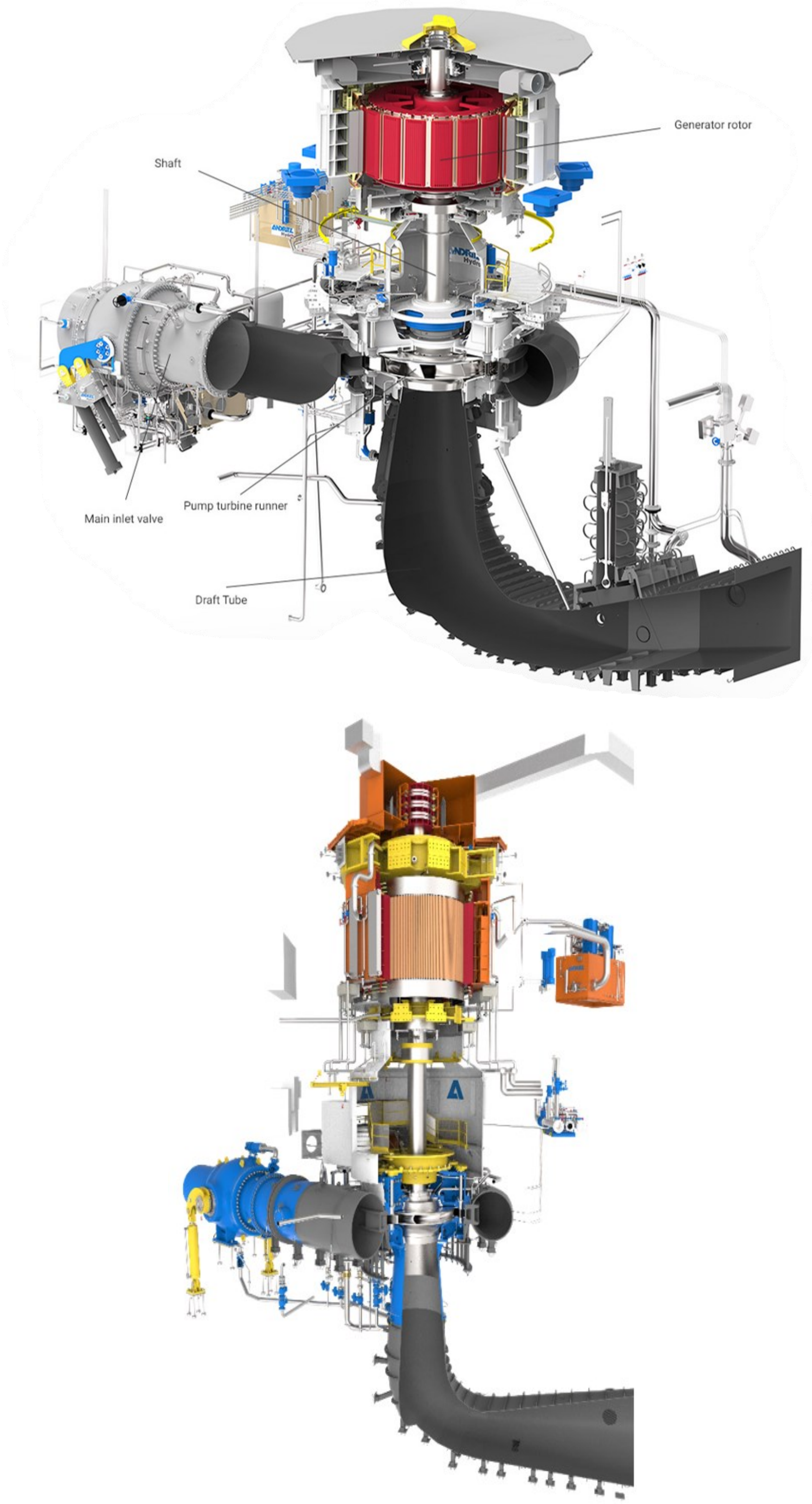


Figure 6.23 Binary configuration with reversible pumped turbine

One other possible configuration is with a multistage pump, as it can be seen in the Figure 6.24.

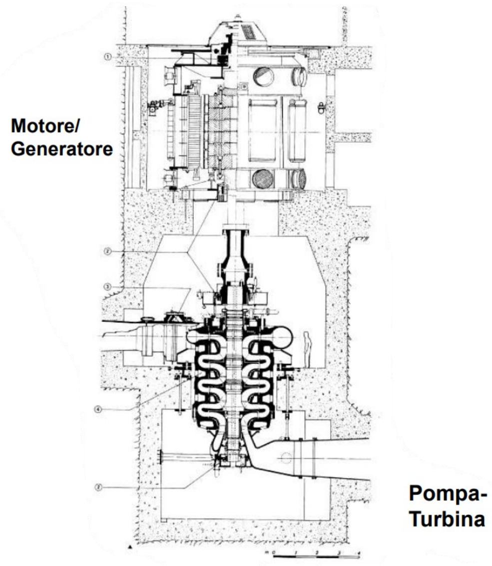


Figure 6.24 Binary configuration with multiple stage pump

In this scheme there is only one hydraulic machine that works both a as pump and as a turbine. The PaT and the generator are placed on the same shaft, generally in a vertical position, but do not rotate in the same direction.

This configuration allows to place the generator/motor above the water level, meanwhile the reversible pump-turbine is placed below that level. But here there may be an issue of cavitation in pumping mode, so the designer must be very careful.

It is made for heads up to 700 m for the single stage configuration and up to 1200 m for the multistage pump turbine.

It is generally coupled with a synchronous generator.

The clear advantage of this scheme is a compact powerhouse, so a reduction in the civil works and thanks to that this is the most cost-effective solution.

The disadvantages are that the time to move from pump mode to turbine mode increases, also because the pump requires water depression to start.

In fact, the changeover mode between the turbine and the pump in the reversible PHS is achieved using the pony motor which speeds off the train from standstill to the synchronous rotational speed. In other situations, the start-up could be done in the pump mode whereby a static frequency converter is fed to the synchronous machine with variable frequency. Conventionally, the reversible PHS is operated with constant speed, but it can also be operated with variable speed. [2]

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[2] [16]

6.3.4 Fixed rotational speed

Fixed speed generators are directly connected to the grid, and they must rotate at the grid's frequency with a fixed speed plus or minus the slip factor. The link can be shown by the following Equation 3, with n [rpm] as the machine speed:

Equation 3 Generator rotational speed equation

$$n = \frac{60f'}{p}(1 - s)\ \ with\ s\ as\ the\ slip\ factor$$

In which f is the frequency of the grid (50 Hz for European grid and 60 Hz for the American one), and p is the number of pole pairs. The slip is zero for synchronous generator.

Most of PHS have fixed speed generator.

In the Figure 6.25, it is reported a schematic diagram of the fixed speed PHS where the synchronous machine is connected to the grid.

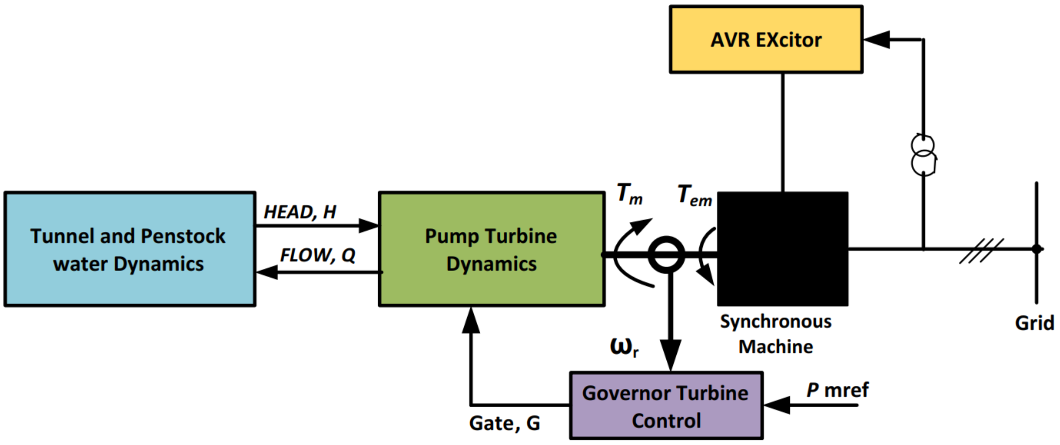

Figure 6.25 Fixed speed pump turbine system

The active power is controlled by actuating the turbine control and the governor. The voltage and reactive power regulation is done using the excitation system of the synchronous machine. The synchronous machine is not able to give frequency regulation since its velocity is dependent on the grid's frequency.

In the turbine operation mode, the unit is unable to operate at maximum efficiency during partial load.

To understand better the application of fixed rotational speed the hydraulic characteristics of a fixed speed pump turbine must be considered.

In a reversible PT (Pump Turbine) the pump can act as a turbine if it is rotating in the opposite direction. Why it is not said, "the turbine can act as a pump if it is rotating in the opposite direction?" Because generally the pump has a more challenging behaviour, for example the issue of cavitation. Meanwhile the turbine is a more "robust" machine.

In the design process of the PT there is a need to find a compromise between the performances of the turbine and the pump.

In the pump, for example, it is recommended the input power to be constant, at the point where the efficiency is maximum. When deciding the working point, consideration on cavitation and stability must be considered.

An example of the diagrams for the characteristic of the pump and the turbine are reported in the Figure 6.26.

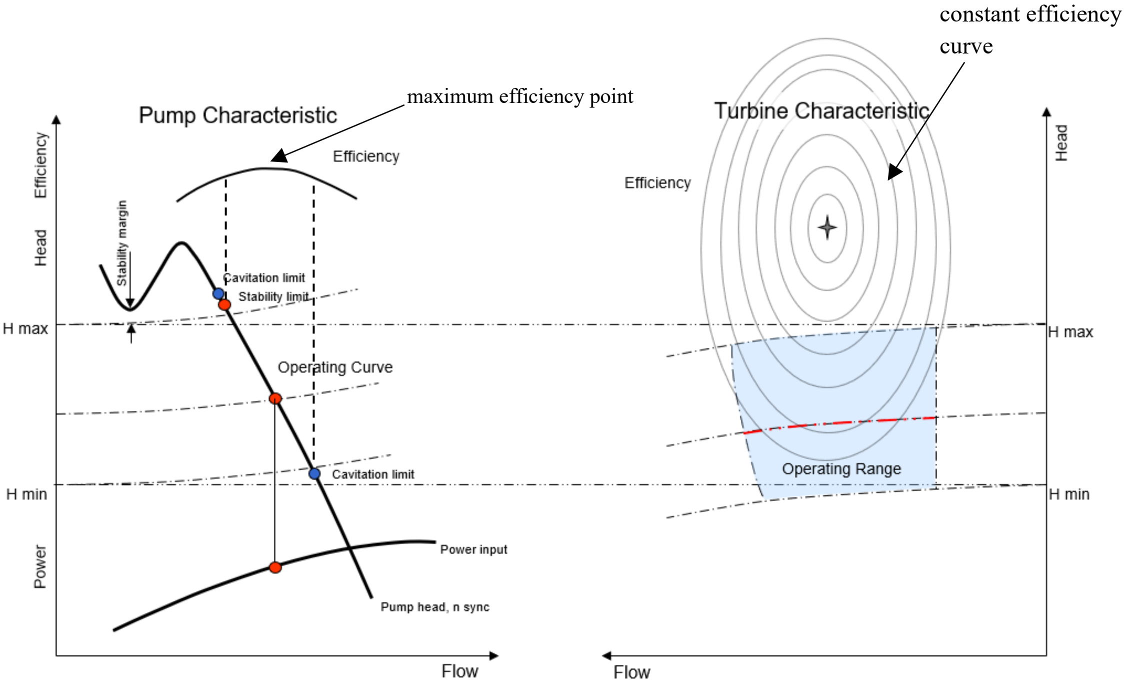

Figure 6.26 Hydraulic characteristic curve for a fixed speed pump turbine

The operating range of the pump sits where the efficiency is maximum. It can also notice that the stability limit is present at high head and low flow rates, and the upper and lower cavitation limit of the machine are also present.

6.3.5 Variable rotational speed (double fed or inverter)

The variable speed is advantageous because it allows the machine to be operated in the working range with the highest efficiency even at partial load (Figure 6.27).

For the hydraulic characteristics of a variable speed reversible pump turbine, it can be said that with this configuration there is the ability to change the input power of the pump. This allows for a higher hydraulic efficiency of the pump and a better turbine operation. It also increases the operating range of the pump, which is no longer limited at one point.

That means reduced pressure pulsation and reduce vibration, which are linked to an increase in the lifespan of the hydraulic machines thanks to a reduction in the dynamic loads.

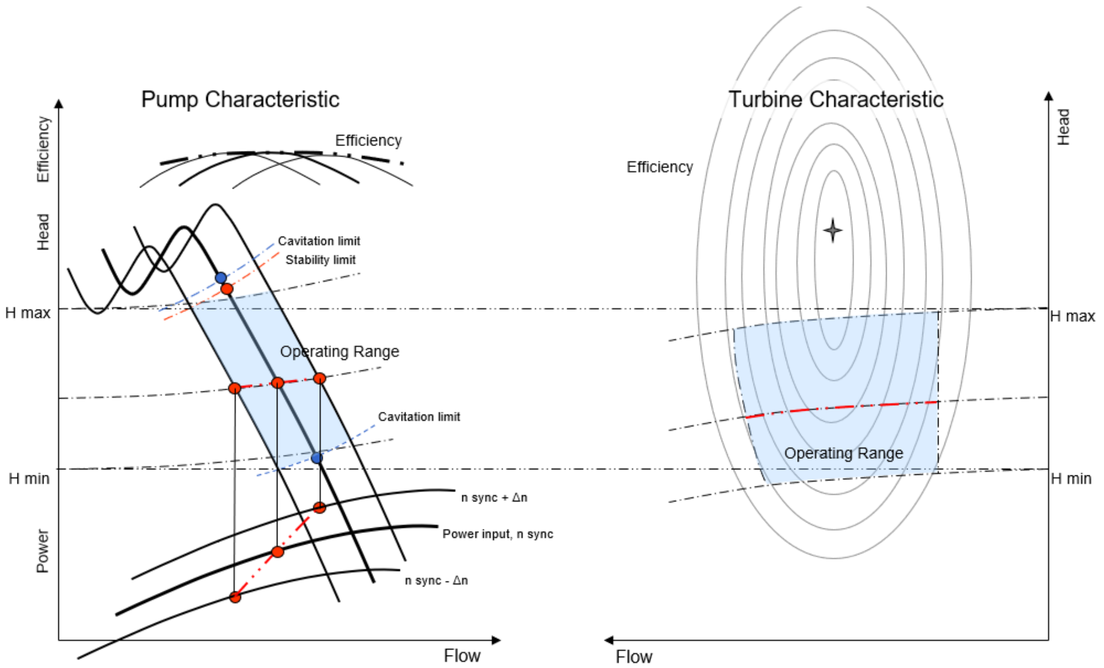

Figure 6.27 Hydraulic characteristic curve for a variable speed pump turbine

The next step is how to control the rotational speed of the generator/motor. Starting from the equation for the rotational speed (Equation 3).

$$n = \frac{60 * f}{p}(1 - s)$$

Where n is the rotational speed in round per minute, f is the frequency of the grid in Hz, p is the number of polar couples and s is the slip factor.

PHS can be forced to work for a long time at partial load, and they must be able to swich from pump to turbine mode and vice versa very rapidly when necessary. Unfortunately, pump turbines suffer from instabilities, thereby constituting a limit when considering their exploitation in a wider continuous working range.

The variable speed of the turbine allows for flexible ramping up capacity, which allows for it to increase or decrease very rapidly its output capacity to match the forecasted load variation associated with changes in the generation of VRE. It can attain full capacity within less than 30 seconds when connected to the grid network.

They allow for fast power response compared to fix rotational speed PHS.

The power consumed in pumping mode is not constant, but it changes over a wide range of operation, this allows the plant to work at high efficiency for varying speeds and conditions to improve the grid's stability.

Grid operators usually require that the generation and pumping mode periods to be chosen in advance of the day-ahead market, and then they decide the commitment status, energy, and ancillary services schedules of the plant in that operation mode. But in the future use of PHS an optimization must be done to reduce the need for fossil fuel peaking power plant.

An analysis of the Iberian power system has shown that the pay back periods can be reduced significantly if the plant is equipped with variable speed units.

There are two parameters inside this Equation 3 that are useful for the control. The first one is the slip coefficient, and the second one is the frequency. This gives a hint about which are the two methods.

6.3.5.1 Converter in rotor circuit or double fed generator

In this configuration the slip is going to be modified (Figure 6.28), it offers less control on the speed since it can move only ±10% of n.

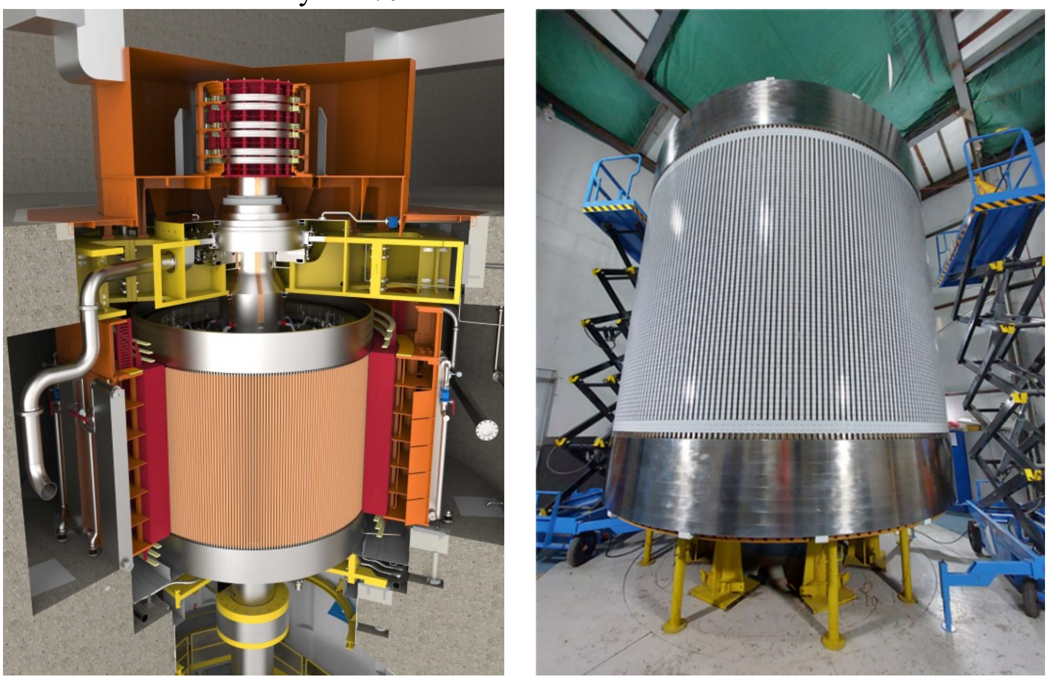

Figure 6.28 Double fed generator

The challenges of the double fed generator stem from the fact that there will be high voltage and high current in the rotor, up to 6600 V and 8000 A, this causes very high stresses. So,

the rotor coil must be carefully designed to accommodate this. They must be strongly attached at their ends. Meanwhile, the stator is connected directly to the electric grid.
Since very high current are present on the slip ring (or spazzole), located in the upper left side of Figure 6.28, they must be large enough to handle the current passing through, and they must be insulated.

6.3.5.2 Converter in stator circuit or full-size converter

In this configuration the inverter adjusts the stator infeed frequency, so it is possible to have a larger flexibility, over all the range ±100% of n.
The inverter is an electrical device that can vary the frequency and the power quality at the output.

6.3.6 Comparison between the characteristics curve for fixed and variable rotational speed

Comparing the two pump characteristics, as in Figure 6.29, it can be noted that the variable speed operation allows to work with higher efficiencies by working on different performance curves at different rotational speeds.

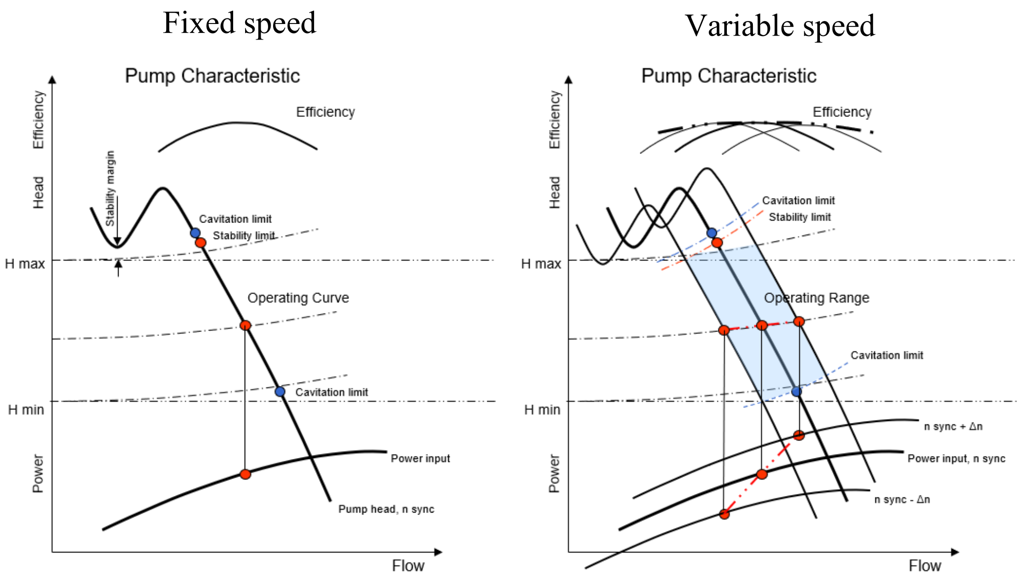

Figure 6.29 Pump characteristics for fixed and variable speeds

Meanwhile, for the two turbines, shown in Figure 6.30, it can be noted an elongation and expansion of the efficiency lines and that makes the whole working range work at higher efficiencies.

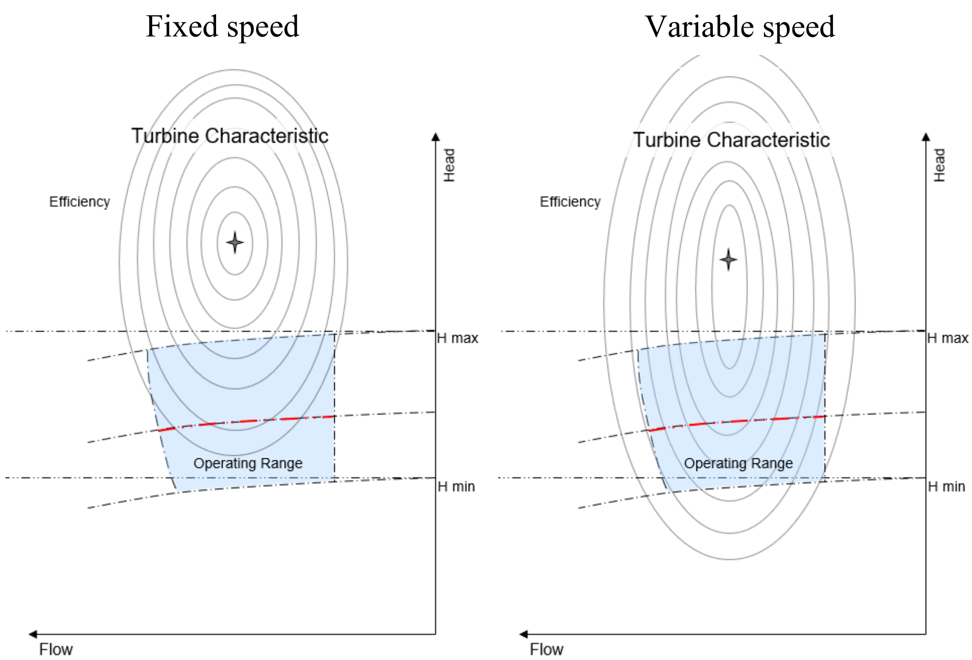

Figure 6.30 Turbine characteristic for fixed and variable speeds

Based on increase variability in pumping and generation (in grid with high VRE penetration), and increase variability of the head, variable speed turbine, even if they are still the minority, will have a bigger role in the future.

Variable speed turbine cost around 30% more, but in the future, it is expected a decrease in the price.

Fixed speed pump can only increase the pumping capacity by limited step, since it is linked to the rotation speed which is fixed (Figure 6.32). This is an added rigidity of the system as it can be seen in Figure 6.31.

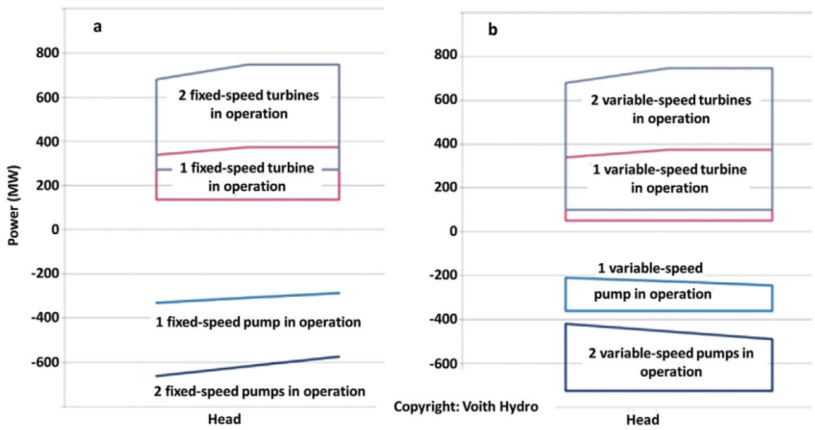

Figure 6.31 Power consumption (a) and generation (b) for units with variable and fixed rotational speed

The flexibility allows for better integration of VRE, better utilization of VRE and higher operational range (higher head variation).

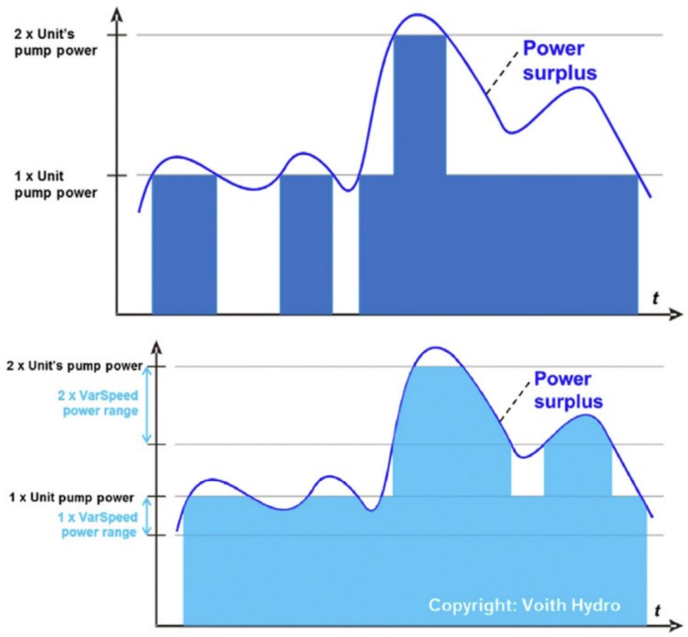

Figure 6.32 Flexibility for integrating surplus power supply power from the grid with (top) two units with fixed speed and (bottom) two units with variable speed

Allowable head variation may be a factor when choosing the correct pump-turbine, since the manufacturer must guarantee its correct operation over the whole range of heads.

One last consideration can be done on the efficiency of these configurations (Figure 6.33).

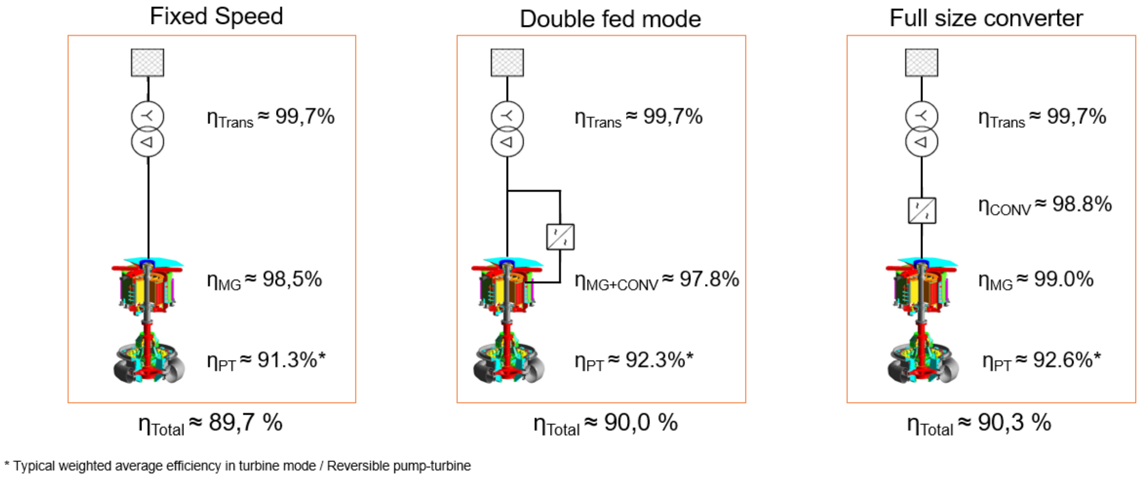

Figure 6.33 Typical weighted average efficiencies in turbine mode for reversible pump turbine

It can be noticed that the efficiency of these configurations is very high, with a range from 89,7% to 90,3%, since the converters and transformers have very high efficiency. But also, the hydraulic machine shows high efficiency, and this is one other reason why PHS is so appealing for these large utility scale.

After this analysis, the consideration on the different technologies for PHS can be summarized in the following Figure 6.34.

		Fixed speed		**Variable speed**	
	🔴 **worse** 🟡 **medium** 🟢🟡 **almost best** 🟢 **best**	Reversible Pump Turbine	Ternary unit	DFIM (doubly fed induction MG, asynchronous)	FSC (salient pole MG with a full size converter)
	system efficiency	🟡	T: 🟢 P: 🟢🟡	T: 🟢🟡 P: 🟢	T: 🟡 P: 🟢
	control range (Power +/- 100% output)	🔴	🟢	🟡	🟢🟡
	mode change times	🔴	🟢	🟡	🟢🟡
	reaction time on failure (frequency changes)	🟡	🟢	🟡	🟢
Grid stability	power factor adoption (voltage changes in the grid)	🟡	🟢🟡	🟡	🟢
	synchronous condenser mode	rotating hydraulic machine	rotating hydraulic machine	rotating hydraulic machine	in standstill
	space requirements (Volume)	100%	150%-200%	115%-125%	125% - 150%
	world wide references	>300	only a few	>10	less
	costs of the E&M equipment	$	$$$	$$	$$$

Figure 6.34 Final consideration on the various configuration reported in Figure 6.19

6.4 Conventional and non-conventional configurations

In this subchapter, some of the most common configurations are explored, and some of the non-conventional ones are introduced to give the reader an overview of the future of PHS, moving from a daily storage system to a seasonal storage system [14].

In the future there is the expectation that monthly and seasonal PHS will become more common than daily or weekly PHS.

The configurations from 6.4.3 to 6.4.5 have not been implemented yet but may become an interesting solution in the future.

6.4.1 Seasonal storage configuration

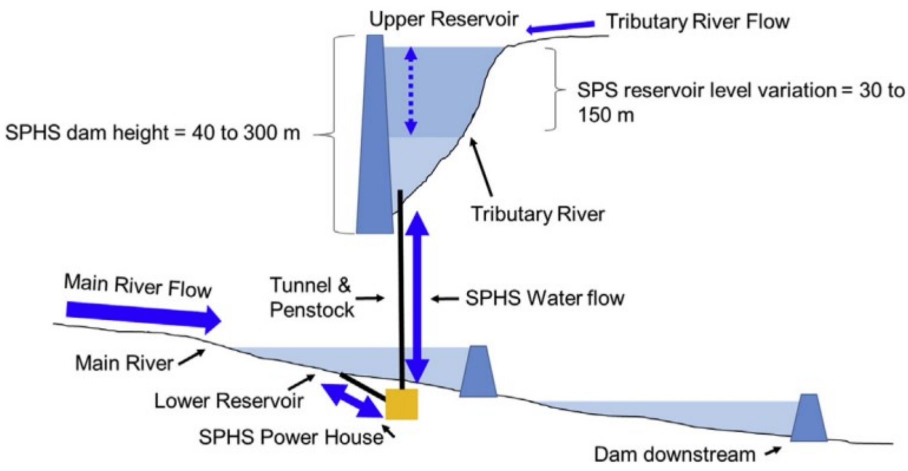

Figure 6.35 Diagram of seasonal pumped hydro storage plant

It consists of two reservoirs. The lower reservoir may be of small capacity, typically monthly. The upper reservoir has a very high capacity to accommodate large amounts of water in the wet periods. In the dry periods it releases that water downstream generating electricity and regulating the river flow for the optimization of hydropower generation (Figure 6.35).

The upper reservoir allows for large level variation, up to 150 m, reducing the land requirement. This configuration also results in low evaporation from the upper reservoir, in fact it is ideal in regions where the evaporation has a large impact on the water management.

This type of sites is not common.

6.4.2 Conventional configuration

To minimize the impact of on the river flow, open loop schemes may make use of existing dams, using its reservoir as a lower reservoir. If the powerhouse is built downstream of the dam, there will be no need for excavation since the lower reservoir itself will provide the pressure to avoid cavitation (Figure 6.36).

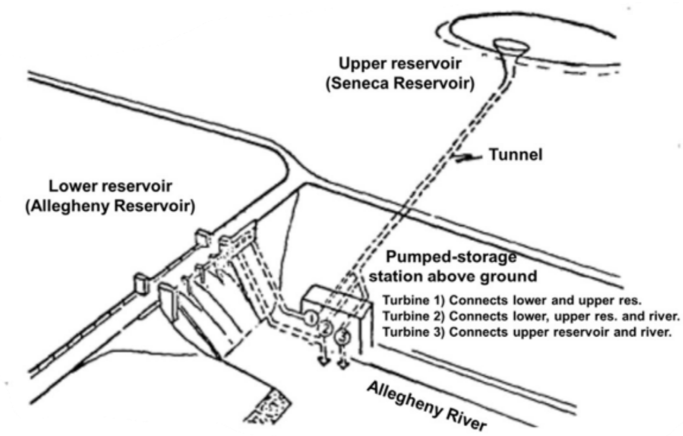

Figure 6.36 Conventional PHS storage scheme

In closed loop systems the environmental impact is lower compared to open loop since no natural flow of river is touched. However, they are usually limited to daily or weekly storage cycles.

Pump-back storage consists of installing pump-turbine where the other reservoir is immediately downstream. This allows for water movement back and forth between the reservoirs. This arrangement increases the flexibility and operational range as the pump-turbine can be used for both hydropower and energy storage. The pump-back plants can also be used as part of a water supply solution.

The run of river with SPHS plant (Figure 6.37) can store water from the main river, without the need to dam it, this reduces the social and environmental impacts.

Run of river usually work with a fixed flow rate, the excess can be pumped in the upper reservoir and then release that water later when the river has low flowrates, by that reducing the impact of the river flow variation.

The lower reservoir is not on the main river, and it offers increased flexibility. The high head pump turbine can move water from the lower reservoir or the riverbed to the upper reservoir or vice versa.

To increase the flexibility of the plant a low head pump can be used to constantly pump water from the river to the lower reservoir.

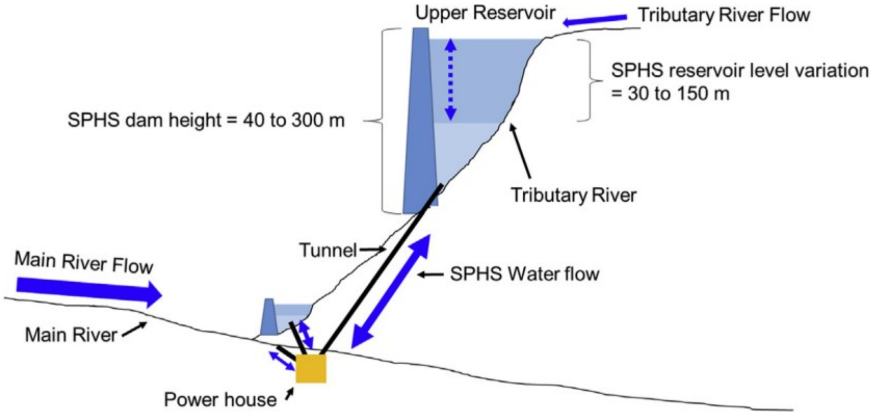

Figure 6.37 Run of the river seasonal pumped hydro storge with large upper reservoir and a small lower reservoir

6.4.3 Combined short- and long-term cycle seasonal storage

It allows to increase the head variation in places where conventional dams are not suited. In this arrangement water can be shifted between these three reservoirs to full fill short- and long-term storage requirements.

In this arrangement three configurations are proposed.

In the first one there is a small reservoir on the river, an intermediate large reservoir, and a small upper reservoir (Figure 6.38). All the reservoirs are linked to the power station but at high head the pump cannot reach the intermediate reservoir from the lower one. One kind of operation may be that pumped water to the upper reservoir goes to the intermediate generating power and recharging the seasonal storage. This is a combination of short- and long-term cycle.

This arrangement is useful when the topography does not allow large reservoir.

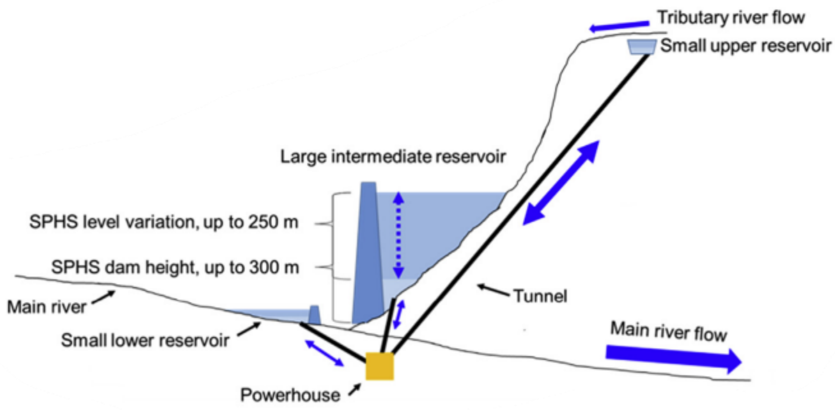

Figure 6.38 First proposed arrangement with large intermediate reservoir

In the second configuration, two medium-size reservoirs are built, plus a lower small reservoir on the main riverbed. The operation would be similar to the first one, but the storage potential is splitted between the two medium-size reservoirs. It shows higher flexibility compared to the first case, since the reservoirs have long term storage cycles. (Figure 6.39)

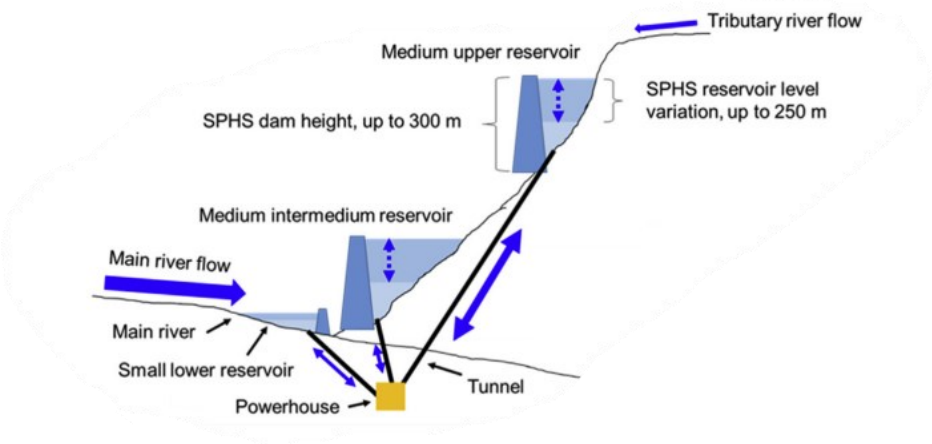

Figure 6.39 Second proposed arrangement with two medium size intermediate reservoirs

At last, the third configuration is the one the allows the highest water level change, which contributes to the smallest land requirements. (Figure 6.40)

In this arrangement, the intermediate reservoir would be filled up with water coming from the lower reservoir when the intermediate reservoir is high and from the upper reservoir when the intermediate reservoir level is low.

This change in operation is done because the pump turbine cannot work in the range of excursion of the intermediate reservoir water level.

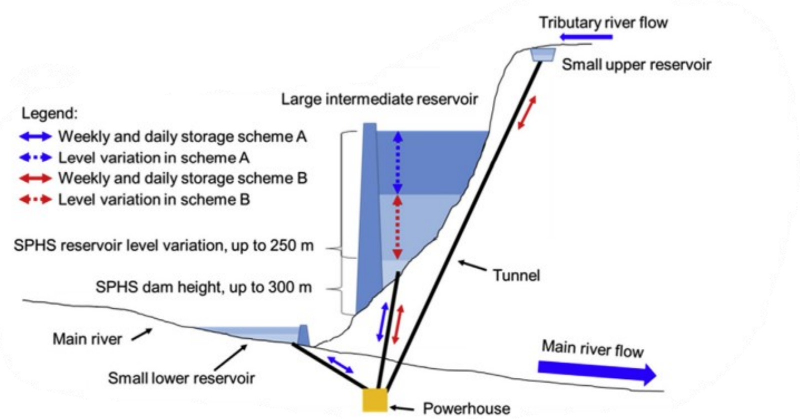

Figure 6.40 Third proposed configuration with a large intermediate reservoir plus a small upper one

6.4.4 Combined hydropower and pumped hydro storage

The lower reservoir is built on the main river, and the powerhouse is built downstream the dam. This arrangement does not require excavation, since the pressure that is exerted by the lower reservoir avoids the cavitation on the pump-turbine. This reduces the project cost. It offers high flexibility; the water can be directly turbined if high river flow rate or pumped hydro can help managing the grid or increase the river flow in dry periods (Figure 6.41).

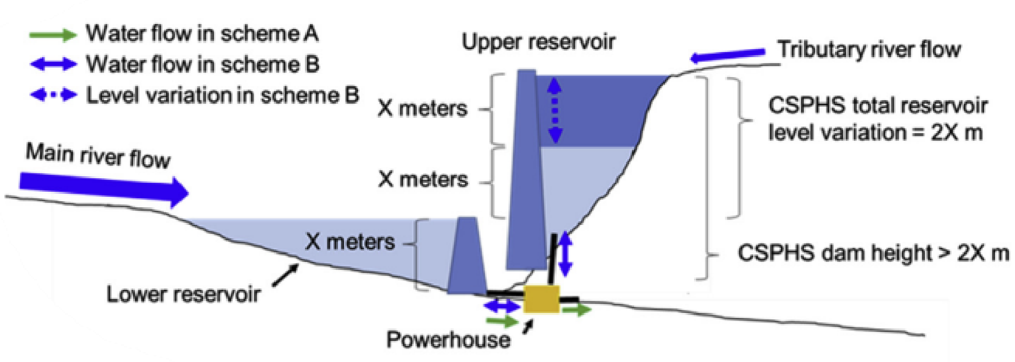

Figure 6.41 CHPHS with two reservoirs

One other CHPHS configuration has the powerhouse excavated below the lower reservoir. Three or more reservoirs are present in this scheme, of which two, the intermediate and the lower reservoirs, are built on the main river. The reservoirs are connected by tunnels to the same pump-turbine, providing high flexibility but a very high cost (Figure 6.42).

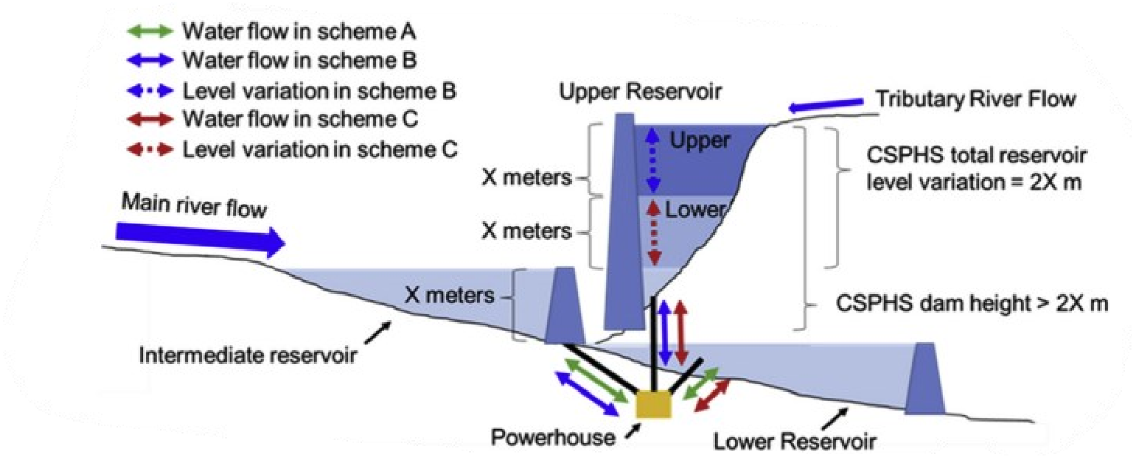

Figure 6.42 CHPHS with three or more reservoirs

6.4.5 Integrated pumped hydro reverse osmosis (IPHRO) system

Fresh water scarcity will be one of the main issues in the future, that could also cause regional conflicts. In recent years, desalination plants have offered a solution to the lack of fresh water, but they are expensive and very energy intensive.

The reverse osmosis is one of the ways for the desalination of seawater (Figure 6.43), together with distillation. Desalination is a process that requires a lot of energy. This integration is interesting because the upper reservoir gives the high pressure needed at the membrane of the reverse osmosis and it maintains that pressure constant, increasing the efficiency and decreasing the cost of the whole process. One other important benefit is that the brine exiting the plant is less concentrated.

The main issue is finding an economically viable site.

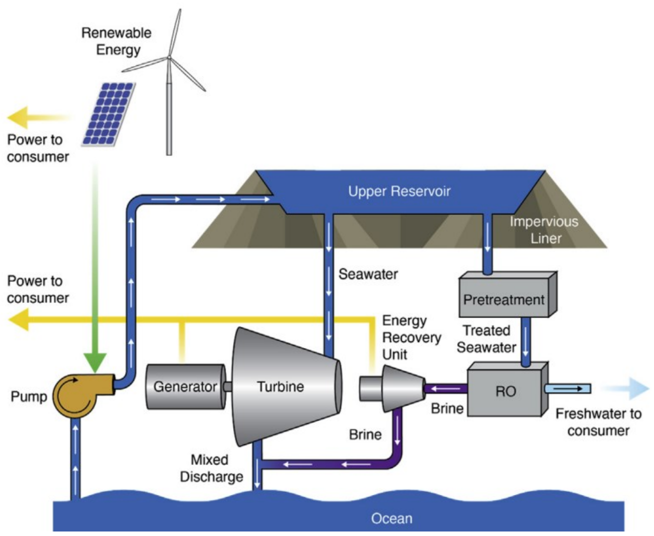

Figure 6.43 Diagram describing an integrated pumped hydro reverse osmosis plant

6.5 Methods to analyze the PHS plant

It is known that PHS project cost, impact and performances are highly site-specific. There are three main methods to analyze the plant [8]:

- Multicriteria analysis (MCA): it is used when the designer is interested in knowing if PHS is the right energy solution or if the designer is interested in identifying the correct site. This criterion combines technical and non-technical factor of different nature. It is a rigorous and transparent analysis.
  The issue must be clear, after having define the goals, from different perspectives, from the corporate to the environmental one.

- Economic analysis: This kind of analysis has the goal of assessing the economic viability of a project.

- Life Cycle Analysis: It is a standardize method to assess the environmental impact of a product or a service though their entire lifecycle (raw materials, construction, operation and maintenance, and decommissioning).
  If the LCA is done for electric power project or storage project, it must follow the ISO 14040-44 standards.
  As with all the LCA analysis the designer must pay attention to the functional unit used, which usually it is 1 kWh, and the boundary used in the analysis to include the whole lifecycle and explicit all the assumptions that are made. All of which must be stated clearly.
  But the LCA has some limits. For example, it does not cover the full range of environmental impacts that have to be studied to clearly assess the impact of PHS system such as on the ecological continuity (impact on fish movement and habitat) and sediment management.
  LCA cannot be used alone, but it can complement the other analysis to make the most correct choice.
  One issue is that it uses an average electric energy mix for evaluating the impact of the charging phase. A grid with a lower carbon intensity, so without the curtailment of VRE, will cause an overestimation of the GWP impact of the charging phase and vice versa.

Specific attention must be given to the emissions from the reservoir itself during operation, that are usually not considered. They are not different with respect of conventional hydropower.

6.6 Critical issue of site evaluation

PHS require very site-specific conditions: high head, good geotechnical condition, access to transmission grid and water availability. So, a clear issue of pumped hydro storage is where to find the location of a site that is economically viable. Almost more than that, bureaucracy and local opposition can damp future development projects.

Pumped storage hydropower represents the bulk of the United States' current energy storage capacity: 23 gigawatts (GW) of the 24 GW national total.

To evaluate the economically suitability of a site, models can be used. A bottom-up cost modelling, using GIS data, will allow an evaluation of the site, starting from scratch, computing the expected costs, using formulas from industries and data from real plants in operation [21].

A tool has been developed by the NREL for the United States[3]. Using this model, more than forty thousand economically suitable sites have been found in the contiguous and non-contiguous US as well in the Commonwealth of Puerto Rico (Figure 6.44).

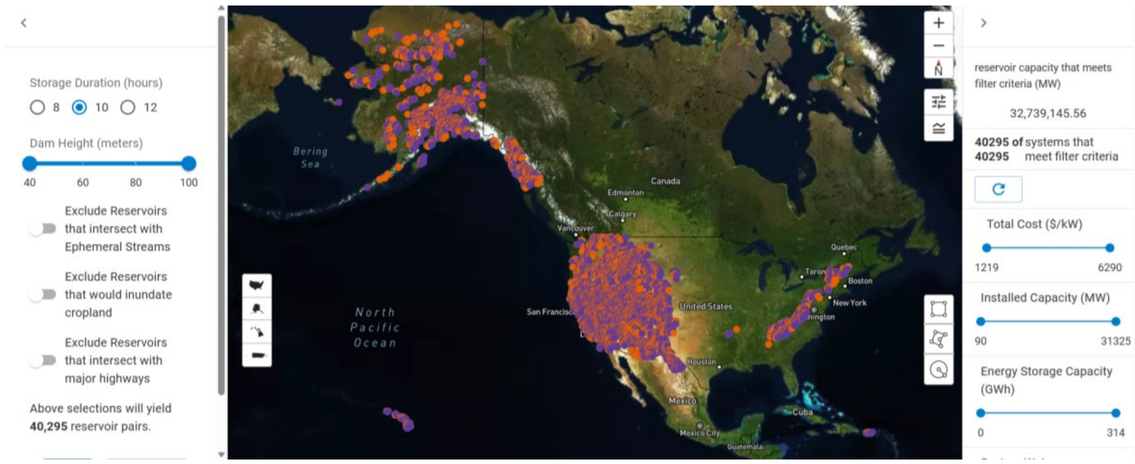

Figure 6.44 Results from the NREL tool

In this model the variables are:

- Total Cost ($/kW)
- Installed Capacity (MW)
- Energy Storage Capacity (GWh)
- System Water Requirement (Gigalitres)
- Head Height (m)
- Storage Duration (hours)
- Dam height (m)

Also, the distance between the two reservoir and the distance from transmission lines are considered.

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[3] https://www.nrel.gov/gis/psh-supply-curves.html

From the map reported in Figure 6.44, it can be noted that a lot of potential is present on the Appalachian Mountain range and in the chains over the continental divide between east and west, and Alaska. Two interesting future developments for the site evaluation is the opening of low head sites for pumped storage and the huge availability of non-power producing dams.

7. Benefit, criticalities, and environmental impact

7.1 Local benefit of PHS

From the “Working paper on sustainability of pumped storage hydropower”[8] some local benefits behind pumped hydro storage project can be analysed. This has become increasingly important to win local opposition against these particularly large project, even in power plant with reservoir already present and in operation.

In the past, projects were presented from a technical and economic perspective without considering the advantages or disadvantages to the local community or more generally its impact on the local environment.

This approach usually has led to delay due to local opposition, so nowadays it is seen as counterproductive.

Now, not all the impacts of these large project may be avoidable, but there may be a concrete effort on the side of the project designer to reduce them and to show the benefits of these kind of projects by following industries and/or ministerial best practices.

It is not surprising that even the local benefits depend on the type of project, the country and local conditions. The local benefits can be one time or permanent.

These benefits, which are expected by the public to increase overtime, are:

- Financial mechanisms such as taxes, royalties and fees, equity shares and development funds.
- Helping build capabilities of local institutions.
- Workforce training and local employment.
- Local procurement of raw materials and workforce.
- Livelihoods development.
- Social services.
- Economic infrastructure of the region (and development).
- Electrification and electricity subsidies to have a reliable, independent, and sustainable power supply for the affected communities.
- Reservoir use and operational management (flood protection and water management).
- Use of abandoned open pit or underground mines, quarries and similar “brownfield” sites may make the project more acceptable.

Of course, these benefits are in addition to the ones related to the electricity grid and transmission.

When considering the numbers behind these benefits, it can be said that they should be commensurate with the scale of generation and revenue of the PHS project.

An environmental benefit associated with the PHS, is that it can offer a positive impact on the surrounding environment, is for example the regulation of the flow of rivers in case of flood events through the flood lamination (Figure 7.1) and then guaranteeing water for drinkable and/or agricultural usages, as in the case study that will be presented in this thesis.

Figure 7.1 Ponte Pià lake (TN) in October 2018

7.2 Criticalities of pumped hydro storage

Clearly PHS, due to damming, has a large impact on the natural river flow and ecosystem, due to restriction of the river, flooding of forest and/or agricultural areas and changes in water quality [6].

Other than the search of the suitable sites, one other of the critical aspects of PHS [19], [22] is the risk behind the project, due to its long lifespan and its long construction time. Utility scale Li-ion battery require around 1 to 3 years to complete. Meanwhile large infrastructure projects like pumped hydro requires longer times in the order of 5 to 7 years to complete.

On the paper [8], one other consideration is done concerning the retrofitting of older power plant, increasing the turbine power, and adding the pumping capacity using existing reservoir both upper and lower. Which is a way to limit the impact since the environmental damage done by these plants has already occurred.

But moving from a conventional to a PHS, means new pattern of filling and emptying the reservoir, increasing the daily or short-term fluctuations in the water level as a function of operating mode of the plant based on the grid's request. These frequent changes can alter the stratification patterns which are linked to water temperature patterns, that affects the growth of species, the life cycle of organisms, the water quality and the reduction of ice cover which increases the energy consumption of fishes which may reduce their winter survival chances.

One other unintended consequence of this is that, with the water level continuously changing, there will be an increase in the risk of bank erosion.

As for all the consideration made, this depends on location, operation, and local condition.

At last, from the paper [14], it can be reported that PHS project have much smaller sedimentation rates compared to conventional plant, since they have a smaller catchment area. Conventional dam could lose their storage capacity in 50 years due to sedimentation.

7.3 Emission from the reservoir

As reported in [8], one fundamental source of emission that usually is not known to the wider public is the GHG emission that come from the reservoir.

Meanwhile a lot of studies have been done on the GHG emission from conventional HP's reservoir, there is almost no specific value for pumped hydro's reservoir. But nowadays the understanding is that there is no difference between the emissions of the conventional PH and of the PHS.

Of course, when considering the GHG emissions for pumped storage's reservoir, methane (CH4) and not carbon dioxide is the main source of emission. It is known that beneath the water level there are processes that decompose the organic matter and that produce methane. Methane has a big impact on the greenhouse effect, about 24 times more than carbon dioxide, considering an analysis done with the GWP 100a.

From the literature it is found that the global average emission rate was estimated to be 70 g_C02_eq/kWh (Maek et al., 2013).

GHG emissions from the decomposition of organic material are predominantly an issue in tropical regions [23].

But as always with hydropower it must be considered the high variability from site to site.

7.4 Critical earth material

As reported by the report from the European Ambrosetti house [10], the acceleration behind the energy transition has caused an increase in the demand of some critical raw materials like rare earths (Figure 7.2).

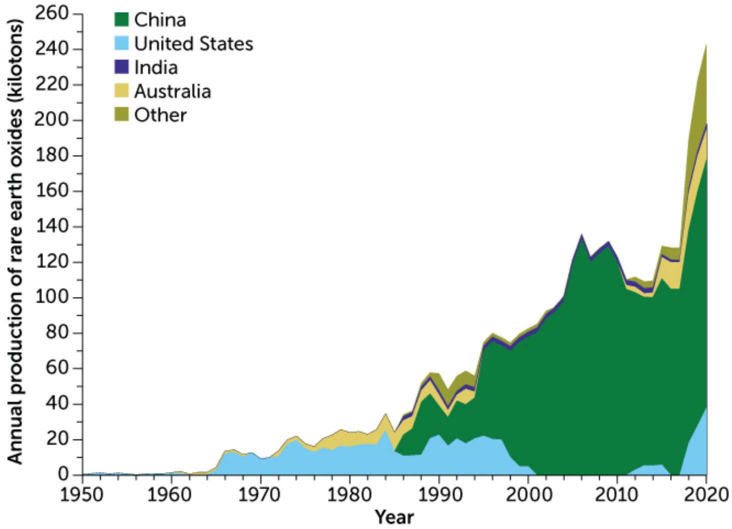


Figure 7.2 Annual production of rare earth oxides and share of main producing countries

Rare earths are not rare, as the name suggests, but they are found at low concentration in the Earth crust, and their extraction is a complex, often environmentally challenging, and expensive process. They are mined in open large pits, contaminating the environment, groundwater and disrupting the habitats.

Rare earth elements are extremely chemically similar to each other, this makes it very difficult to separate them because they tend to stick together. Forcing them apart requires multiple steps and a set of powerful solvents to separate them one by one. Meanwhile other steps involve organic molecules called ligands.

But there aren't a lot of studies on the impact of the extraction, most of what is known is linked to the toxicity of known elements but, for example, radioactive element may be not as dangerous as previously thought due to the extremely low concentration.

Since acids and solvents are used in the process to obtain the concentrated rare earth ore, the water residues, if not well regulated, will be polluted with acids, heavy metals, and radioactive elements like thorium.

An example of these impact was seen in 2010, when officials in a city nearby a mine, Baotou, noted that arsenic- and fluorine- containing mine waste was being dumped on farmland and local water supplies, as well as into the nearby Yellow river. The air was polluted by fumes and toxic dust reduced the visibility. Residents complained of nausea, dizziness, migraines, and arthritis. Some had lesions and discolored teeth, signs of prolonged exposure to arsenic; others exhibited signs of brittle bones, indication of skeletal fluorosis.

This was also noted by the China's State Council in 2010, which stated that the country's rare earth industry was causing severe damage to the ecological environment (destruction of vegetation, pollution of surface and ground water, and farmland) due to the release of various pollutants.

The excessive rate of mining has also caused landslides and clogged rivers.

This has moved the Chinese central government to reduce the export and reduce the production, also to preserve the rare earth resources. This has increase investment in other location around the globe.

A way to reduce the dependence on new mining may be the recycle of rare earth materials, an interesting research subject.

Nowadays China is the main supplier for the 66% of all the critical raw materials. Meanwhile, the current situation for the rare earth materials is that China is almost the sole supplier with 98%. This very strong dependency is not only with China, but for different minerals there are different countries. For example, 78% of the lithium coming to the EU is from Chile.

Also, in the US there is this issue of dependency on foreign suppliers, in fact the only US mine for rare earths elements is on the Mountain Pass (Figure 7.3), in southeastern California. One of the goals of this mine project was to reduce the environmental impact experienced for example in China.

Figure 7.3 Mountain pass mine, California, US

This was in fact declared a matter of national security by the Biden administration in early 2021.

In Europe there is a very limited internal production of these critical materials, as it can be seen in the Figure 7.4, which shows the main suppliers for critical raw materials in the EU.

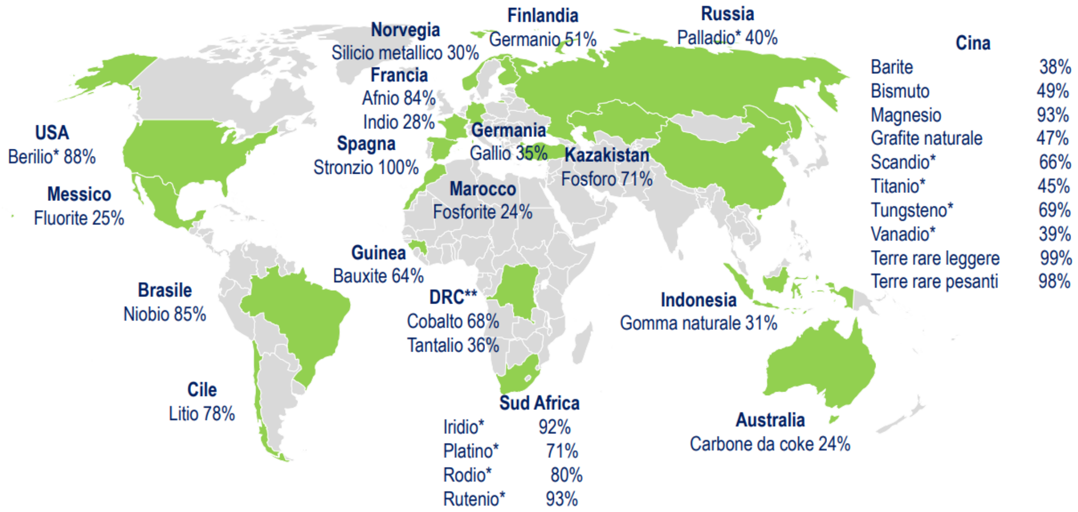


Figure 7.4 Main supplier of rare earth in the EU in 2020

Looking at the future, to reach the near zero emission scenario (Figure 7.5), there is to notice the importance of having a secure supply of these fundamental minerals.

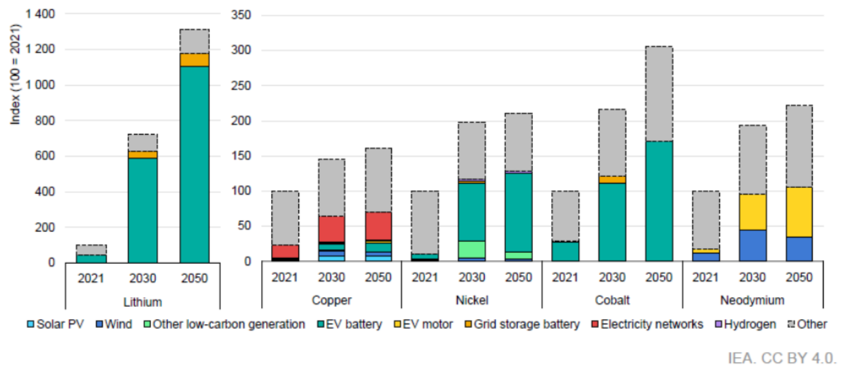


Figure 7.5 Demand for critical material increases rapidly in the NZE scenario, driven mainly by clean energy technologies and infrastructure [IEA Energy Technology Perspectives 2023]

For example, Li-ion battery demand is expected to increase by 6 times (Figure 7.6).

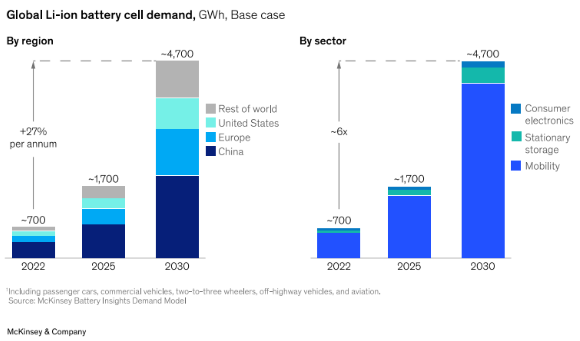


Figure 7.6 Global Li-ion battery cell demand

This rush to extract the finite resource will, of course, cause supply issue if no other mine project is activated. And this is true for other critical minerals.

It can also be noted how only a few countries, Australia, Chile and China, control almost all the resources and how that will cause geopolitical and economic tension between states.

When considering a storage option, it may be interest also to consider their dependence on these critical resources.

The raw material for hydropower and PHS come, in a greater amount from local level. In this way there is an increase in the energy security, reducing the dependence from foreign supplier. Meanwhile battery technology makes large use of critical raw materials, in particular cobalt and lithium.

The average cost of batteries has decreased significantly over the last few years, reaching 137 dollars/kWh in 2020, but that means rare earths now represent the greater amount of the total cost of the batteries ranging from 50 to 70%.

As said before, for the energy transition critical material are fundamental, but their use varies for different technology.

In the following table (Table 6) the dependence of the technologies for different critical materials is shown.

Table 6 Impact of rare earths on different generation and storage technologies [10]

	Copper	Cobalt	Nickel	Lithium	Rare earths	Platinum	Chromium	Zinc	Aluminium
PV solar	High	Low	Low	Low	Low	Low	Low	Low	High
Wind	High	Low	Medium	Low	High	Low	Medium	High	Medium
Hydro	Medium	Low	Low	Low	Low	Low	Medium	Medium	Medium
Biomass	High	Low	Low	Low	Low	Low	Low	Medium	Medium
Geothermic	Low	Low	High	Low	Low	Low	High	Low	Low
Hydrogen	Low	Low	High	Low	Medium	High	Low	Low	Medium
Chemical batteries	High	High	High	High	High	Low	Low	Low	High
Electric grid	High	Low	Low	Low	Low	Low	Low	Low	High
Nuclear	Medium	Low	Medium	Low	Low	Low	Medium	Low	Low

Dependence on the critical material: High | Medium | Low

This is one other advantage of using PHS compared with other storage technologies.

7.5 Life cycle assessment analysis for a closed loop PHS in the United States

Nowadays the impact on the greenhouse gas emissions of the lifecycle of the PHS is not well understood. The goal of the LCA is to understand what the impact of this technology is for evert 1 kWh stored, so getting to know the GWP for every kWh stored.

As it is reported in the paper from [24], which takes a comprehensive look from the facility construction to the decommissioning, the results are that the impact is from 58 to 530 g_{CO_2}/kWh_{stored}. With the stored energy from the grid having the largest impact, followed by the construction of the plan. As it can be seen in Figure 7.7, the PHS is a competitive option when evaluating its GWP compared to its direct competitors.

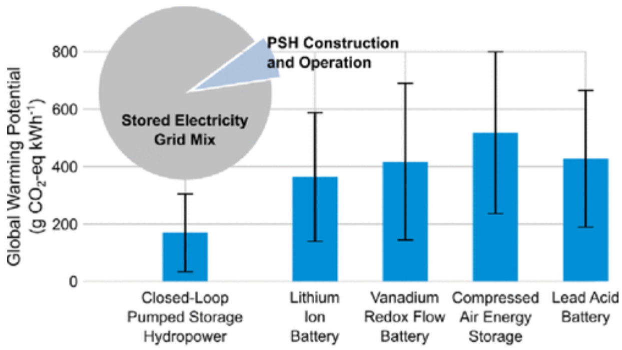


Figure 7.7 LCA analysis results

Of course, this very wide range of results is due to the site characteristic, that have a massive impact on the GWP of the scheme.

The Life Cycle Assessment or LCA is a well-known method to evaluate the GWP of a technology, to make comparisons with others and to evaluate the GWP in different steps of the process. Using this approach, it allows us to evaluate the impact of both direct and indirect greenhouse gas emissions.

This is also useful to avoid "problem shifting", which for example can be related to the change a component into one more efficient, to reduce the GWP. But that doesn't happen, because to make that more sophisticated component the GHG emissions in the production phase, nullifying the global decrease.

It is known that the most important step in the LCA is the determination of the scope and system boundary of the analysis, so how far in detail are we willing to go. This LCA analysis will take into account GHG emissions from the raw materials, for the construction, to the decommissioning as can be seen from the Figure 7.8.

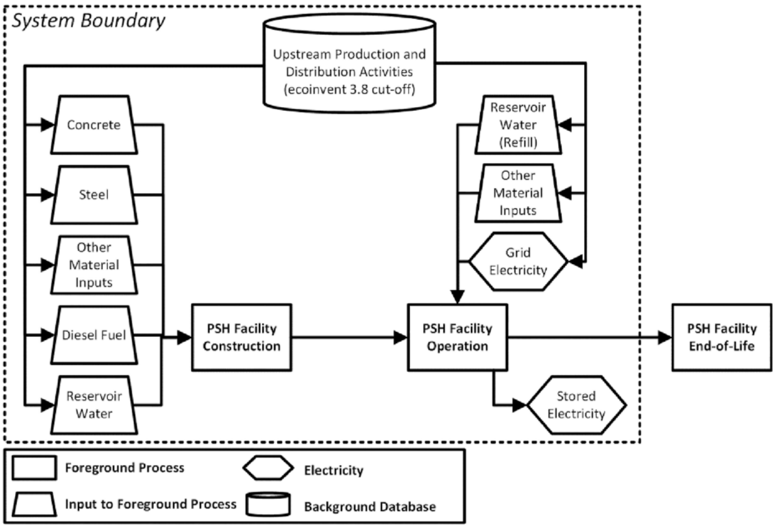


Figure 7.8 System boundary conditions for the LCA

The LCA reported in [24] will consider a close loop PHS facility in the US.

The construction impact contains all the materials and energy streams needed. So, if not already available, the construction of the upper reservoir and/or the lower reservoir, pipes, penstock, dam, channels, the powerhouse, the electrical scheme, the link to the transmission grid and all the mechanical components as valves, turbines, etc.

Meanwhile for the O&M cost it is assumed that the equipment will be replace in 40 years over the lifetime of 80 years. Of course, it can be said that by using already build dam the impact on the greenhouse gas emissions decrease, since a lot of the civil works result already done.

With these considerations done, it can be shown that the PHS has the lowest carbon footprint of the analyzed technologies (Figure 7.9).

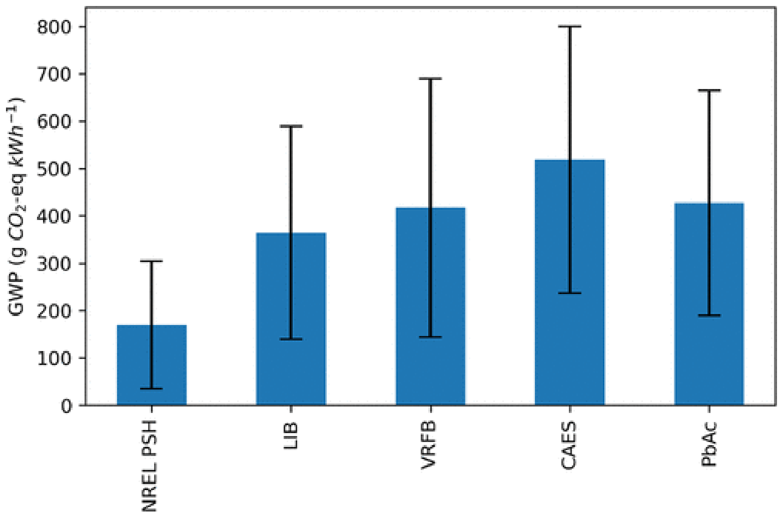


Figure 7.9 GWP comparison between different storage technologies

In all the scenarios the source of the stored electric energy has the greatest impact of the GWP of the storage system.

Considering the impact of the PHS over 100 years scenario, the various contribution can be shown in the diagram (Figure 7.10).

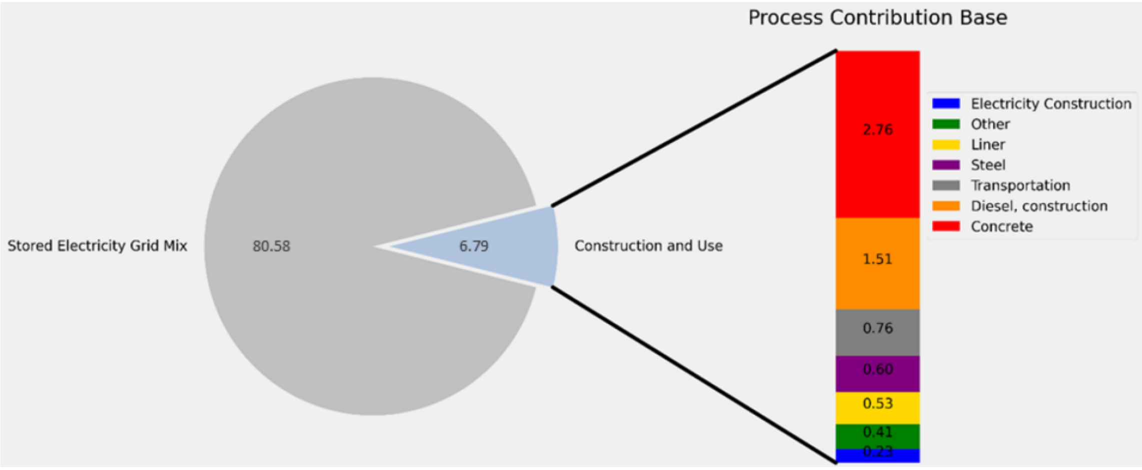


Figure 7.10 GWP contribution for the PHS

Not surprisingly in the impact from construction and use, the largest share is the concrete, which is one the largest worldwide emission sector.

Two other important considerations are:

- For the impacts of the installed capacity (Figure 7.11), there is a very small difference between the emissions from large or small storage systems, even though an impact of the economy of scale is still visible since that for small plant we have a footprint of 65 g_co2_eq/kWh meanwhile for the large we have 58 g_co2_eq/kWh.

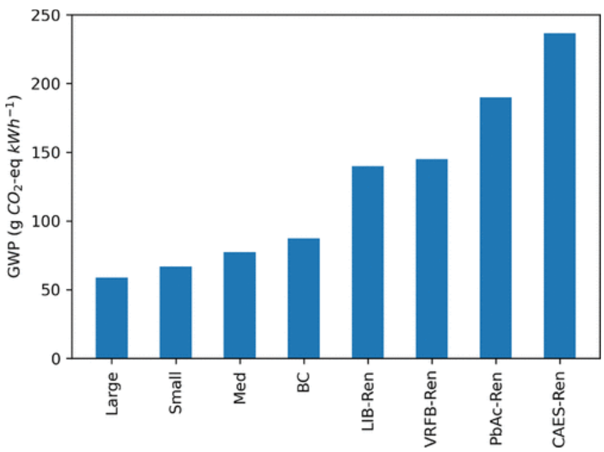


Figure 7.11 Impact on GWP of PHS' size

- Meanwhile for the site condition it can be said that in the graph (Figure 7.12) it can be shown the difference between building in a brownfield (BF) or greenfield (GF). The brownfields have a 30% lower impact on the GWP, since do not require an excavation for the reservoir.

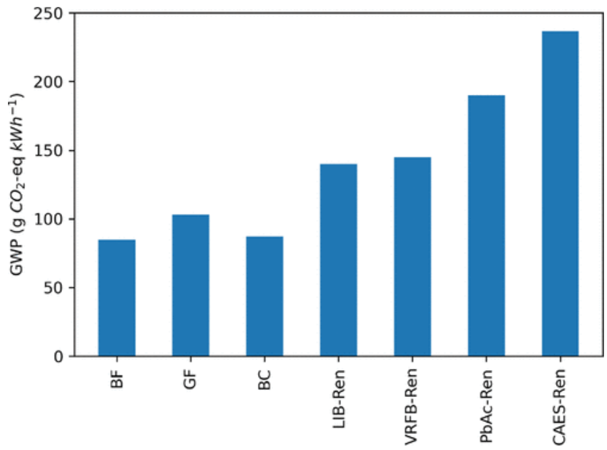


Figure 7.12 GWP for different site configuration

At last, it can be noticed how different grid scenario increase or decrease the GWP of pumped hydro. If the grid is fossil intensive than the impact on the GWP is going to be high, and vice versa. But even in the high case with a lot of fossil fuels, the PHS results the one with the lower GWP.

So, as previously said a majority of the GWP of the storage system depends on the carbon intensity of the grid [8]. In Figure 7.13 it is shown that as the grid becomes more carbon intensive the greenhouse gas emissions skyrocket from 20 g_CO2_eq/kWh to close to 1000 g_C02_eq/kWh.

The higher the carbon intensity of the grid, the higher the GHG emissions in the operation phase and the lower the overall impact of the construction and decommissioning.

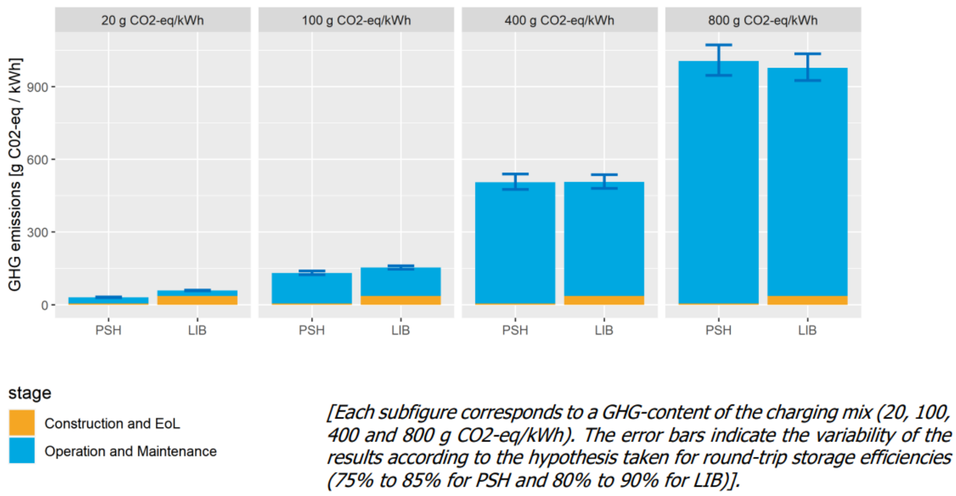


Figure 7.13 Influence of the GHG content of the charging mix and of the round-trip storage efficiencies on the life cycle GHG emissions per kWh generated for the two storage technologies PHS and Li-ion

The main difference between different technologies is that the construction and end of life phases do not depend on the charging mix nor the system efficiency. These emissions are more important for lithium-ion batteries compared to PHS. Meanwhile operation and maintenance costs depend on the charging mix.

To conclude this analysis, the PHS clearly shows its environmental benefits when compared to other technologies. As said before, the largest component in the GWP is the energy stored by the plant itself and the use of brownfield can result in about 20% reduction in the GWP, so it would be interesting to use these sites, like already build dam or mine site. Using economy of scale and the correct choice of materials, the impact on the GWP can be decrease even more, since large plant have a lower impact.

This shows how important is the decision making when building a PHS.

7.6 Climate change impact on PHS and its infrastructure

Climate change impacts the development of PHS in various ways, for example by changing the rainfall and water availability patterns, and by changing the ambient temperature regimes [25]. Higher ambient temperatures mean enhanced evaporation making periods of low precipitation dryer. This worsens drought conditions.

Furthermore, the long lifespan of HP project exposes their operation to the impact of a changing climate. Small-scale HP is more impacted, since they mainly are run of river, so the functioning depends on the availability of natural flow of the river.

PHS is considered less vulnerable than conventional hydropower since the water movement may be considered like the system is in a closed loop, but in the long-term water volumes reduction due to drought conditions will lead to a decrease in the generation.

Engineers and designers must consider this variability when building new PHS, considering both short term and long-term effects of climate change.

An interesting approach is to install over the lake some floating photovoltaic panels (Figure 7.14), this reduces the evapotranspiration of the reservoir, thus limiting the effect of higher ambient temperatures. This is also beneficial to the PV panels since they are kept at a lower temperature and that increases the efficiency of the panel and the electric energy generation.

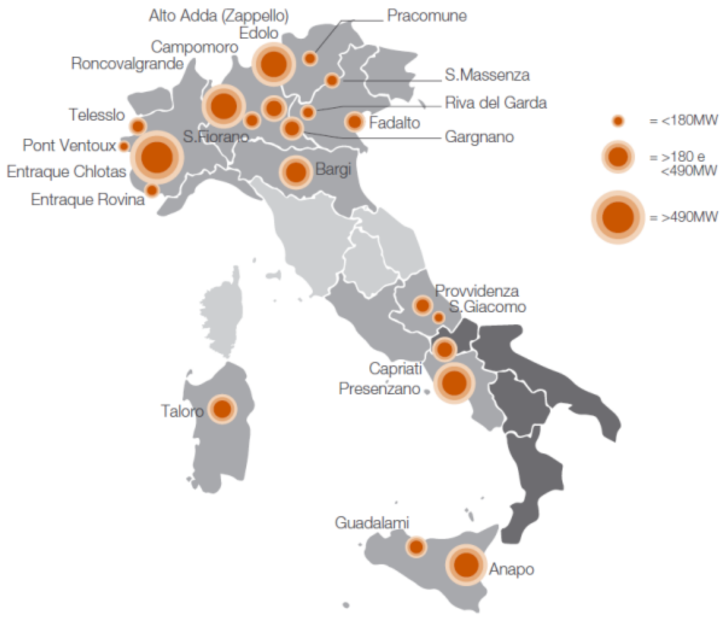
Figure 7.14 Floating PV panels (4 MW) over the Alqueva lake, Alentejo region, Portugal

As stated in [16], to build more sustainable PHS, the impacts on water resources must be considered, in line with the sustainable development goal set by the UN, a Pareto optimum between the utilization of land, water consumption and energy production must be found, to reduce its impact on the environment.

Water resources are limited, particularly in a dry season, and a lot of stakeholders compete for them, from industry and irrigation to recreation and transportation.

8. Pumped hydro storage in Italy

As reported in [22], PHS in Italy is well developed, mainly in the north due to geographic constraints, as it can be seen in the Figure 8.1. There are about 22 plants with a pumping capacity of 6.5 GW, a turbine installed capacity of 7.6 GW and a storage capacity of 53 GWh.



Fonte: PdS 2021 Terna

Figure 8.1 PHS systems in Italy

As reported in [10] the Italian PHS are not used at capacity. The PHS installed storage capacity is about 8 GWh. Nowadays, looking at the data available the storage capacity used in 2021 is closer to 2 GWh, as it can be seen in the Figure 8.2 below.

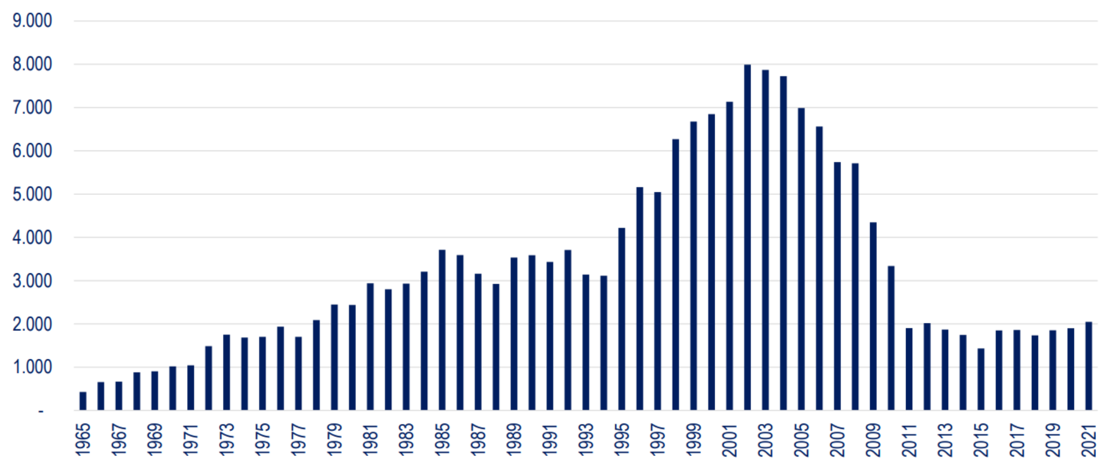


Figure 8.2 Gross hydroelectricity production of PHS in Italy (GWh)

The reasons behind this trend are mainly due to two factors. The first one is linked to the fact that PHS plant are mainly located in northern Italy, meanwhile most of the VRE installed capacity is in the South. The second one is linked to the lower differential of prices (between charging and discharging) to make the system economically viable by covering at least the losses due to the efficiencies of the PHS.

If the differential was 42 Euro/MWh in 2010, in 2020 it had decreased to 23 Euro/MWh.

The selling price must be at least 40% higher than the charging price.

The under-utilization of the Italian PHS causes the impossibility to store large amounts of solar and wind energy, so it makes it difficult to manage disturbances on the grid and swings in prices.

To solve these issues there is the need to build regulatory and contractual scheme that correctly remunerate the storage as reported in the previous chapter 5.

In Italy, in the last few years there has been the interest for new storage capacity both distributed and grid scale, which has been growing exponentially, unfortunately not in the regions where it will be most needed.

9. Case study of Tirso 1 and Tirso 2 power plants

In the following chapter, the objective is to evaluate the possibility of building a pumped hydro storage facility where nowadays there is only a conventional HP plant.

In the future this will be one of the most promising ways for the construction of new PHS capacity since most of the civil works, which constitute most of the cost of large hydropower project, are avoided.

The plants Tirso 1 and Tirso 2 are in the middle of Sardinia, in the province of Oristano.

The scheme is made of a lower and an upper reservoir, both on the Tirso river.

The Tirso is the main river in Sardinia, it has its source up in the Goceano mountains (880 msl) and it ends in the gulf of Oristano. It has various tributaries, like the Taloro and the Flumineddu.

Between the years 1918 and 1921 an interest in the use of the Tirso river's water had grown, with the main goals to provide water to the agricultural sector and for hydroelectricity.

The upper reservoir is formed by the Eleonora D'Arborea dam (Figure 9.1), which was inaugurated in 1997, and it is one of the largest dams in Sardinia. It was built to substitute the Santa Chiara dam which was failing due to structural issue.

Figure 9.1 Eleonora D'Arborea dam

Some of the main characteristics of the reservoir, which is called Cantoniera or Omedeo lake, are reported in the Table 7.

Table 7 Data of the Eleonora D'Arborea dam and Omodeo lake

DATA ON THE DAM	
Height of the dam	100 m
Height of the crest	120 msl
Crest's length	582 m
Volume of the dam	1071000 m^3
Type of dam	Gravity dam

DATA ON THE LAKE	
Maximum lake height	118 msl
Maximum regulation head	116.5 msl
Maximum area of the lake	29.37 km^2
Total volume	792.84 *10^6 m^3
Useful regulation volume (between 116,5 and 55,45 msl)	745 * 10^6 m^3
Lamination volume (between 118 and 116,5 msl)	44.64 *10^6 m^3
Dead volume (at 55,45 msl)	3.2 *10^6 m^3
Catch basis area	2056 km^2

The usefulness of this dam comes from its multipurpose nature, like the supply of water for agriculture, drinkable water, industrial needs, hydroelectricity, and lamination of the floods. In fact, on the right side of the river there are two pipes, one 800 mm in diameter, for the agricultural use, and the other 1200 mm for the drinkable water network.

Meanwhile the lower reservoir is formed by the Pranu Antoni dam, which is far smaller than the Eleonora D'Arborea dam. Both reservoirs are managed by STE and are property of ENAS or Ente Acque della Sardegna (Figure 9.2).

Tirso 1 (or 1° salto) is located between the upper and lower reservoirs. Meanwhile, at the base of the Pranu Antoni dam it is present a smaller HP plant, called Tirso 2 (or 2° salto).

Figure 9.2 Geographical configuration of the plants

In the following subchapters the status of the plant will be analyzed, and future expansion options will be discussed.

9.1. Current state of the plants

9.1.1 Tirso 1 HP plant

The Tirso 1 HP plant is located at the base of the Eleonora D'Arborea dam, as it can be seen in the Figure 9.3.

The power plant consists of one Francis turbine with an installed capacity of 21.5 MW.

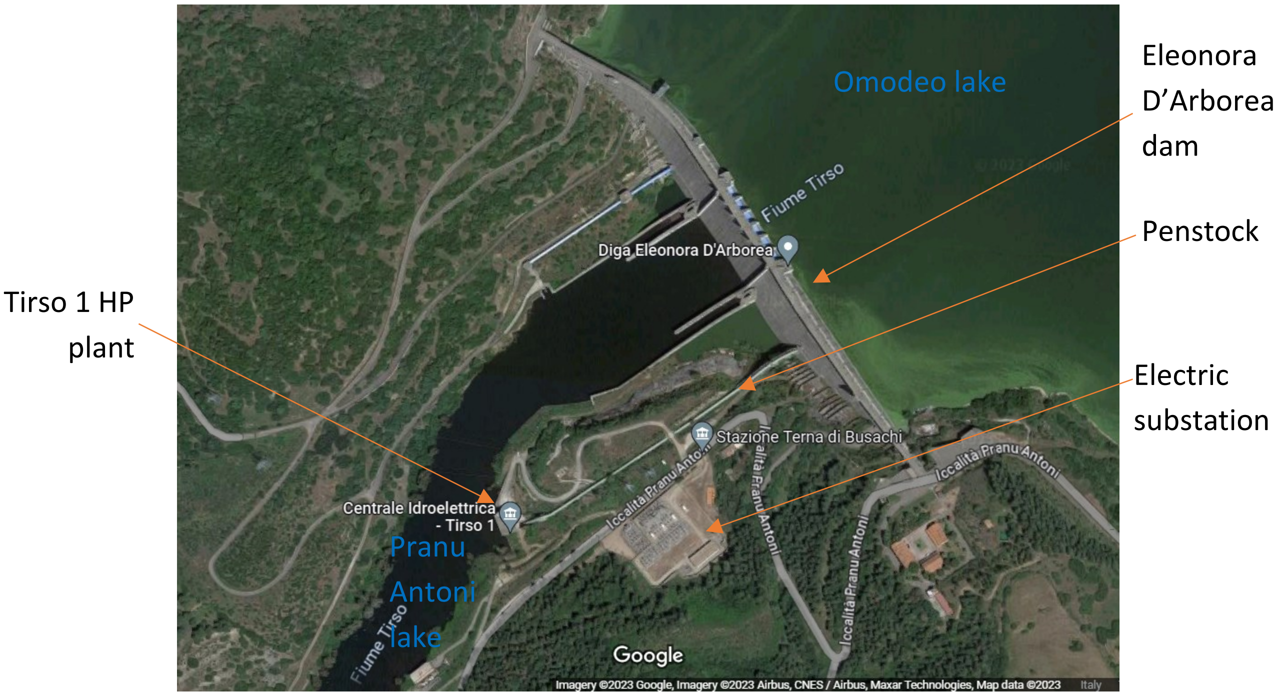


Figure 9.3 Tirso 1 configuration

The substation is placed downstream of the dam, as it can be seen in the figure above.

The electric scheme of the substation and power plant is reported in Figure 9.4. The transformer in this power plant is the same for both Tirso 1 and Tirso 2 as it is reported in the electric scheme. The transformer has a rated power of 32 MVA, this limits the turbine and pump power addition without building a new transformer and switch yard, which is an additional cost.

The substation links the power plants to the Italian grid which is managed by Terna.

Some of the main components present in the substation are:

- Switches.
- Transformer.
- TV – safety transformer for the voltage to protect the circuit.
- TA – safety transformer for the current.

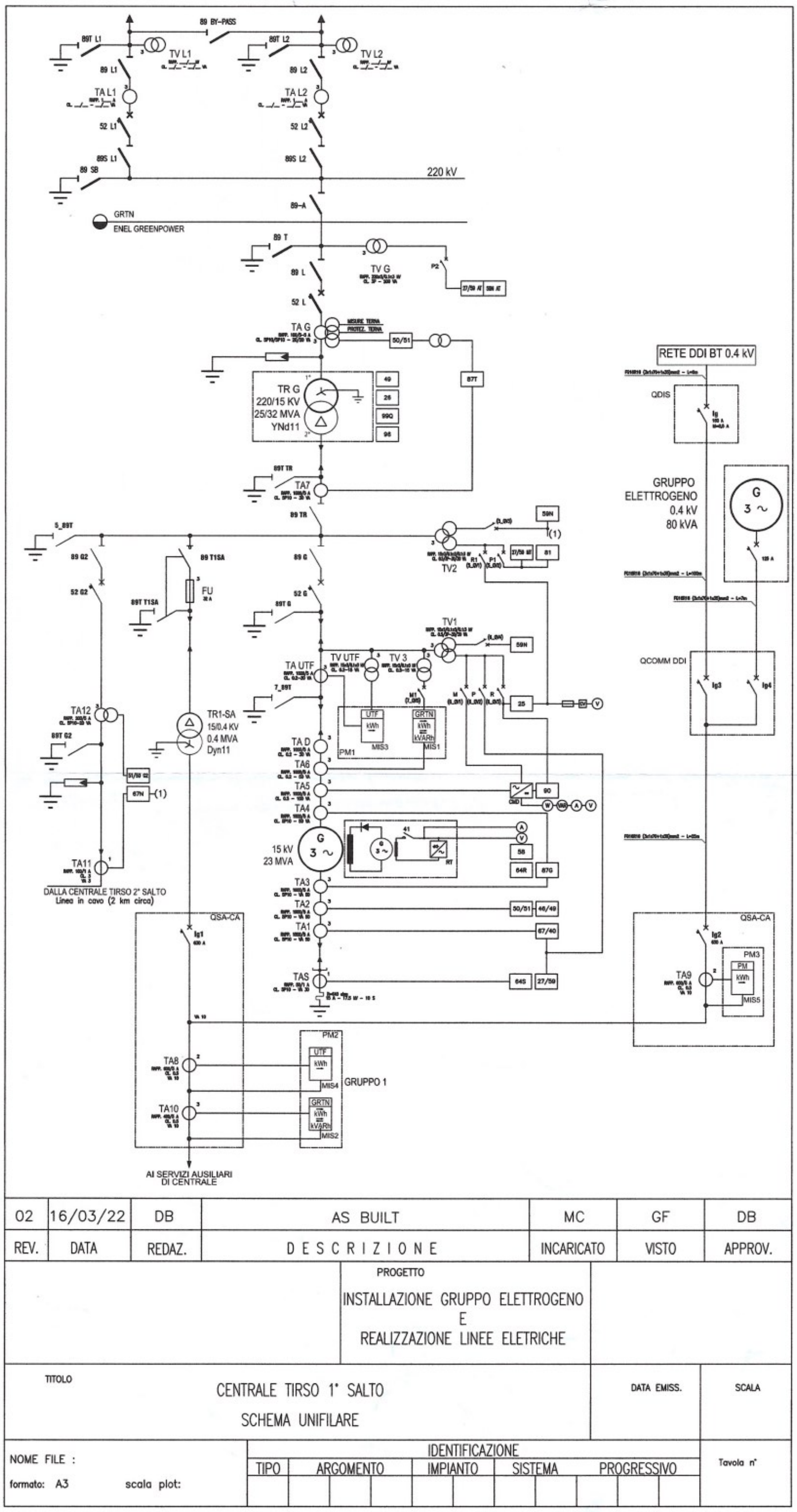


Figure 9.4 Electric scheme of the power plant

From the technical data sheets provided, the most important parameters, for the definition of the operation of the PHS scheme, are reported in Table 8.

Table 8 Maximum and minimum water level and characteristics of the Tirso 1's Francis turbine

Description	Unit	Data
Maximum water level downstream the dam	msl	45
Minimum water level downstream the dam	msl	37
Maximum head of Tirso 1's Francis	m	80.50
Minimum head of Tirso 1's Francis	m	54.00
Nominal head of Tirso 1's Francis	m	78.20
Nominal flow rate of Tirso 1's Francis	m^3/s	30
Nominal power of Tirso 1's Francis	MW	21.5
Nominal rotational speed of Tirso 1's Francis	rpm	333.33
Run-away speed of Tirso 1's Francis	rpm	650
Frequency	Hz	50

In the following Table 9, the operational limits of the two reservoirs and of Tirso 1 are reported, which in the proposed scheme will be the limits of the upper and lower reservoirs.

Table 9 Upstream and downstream water level for Tirso 1

Upstream the Tirso 1 power plant	
Maximum water level (maximum regulation level)	116.5 msl
Minimum water level (minimum level of the lake Omodeo)	80.00 msl
Downstream the Tirso 1 power plant	
Minimum water level (water discharge level)	37.00 msl
Maximum water level (maximum level of Pranu Antoni lake)	45.00 msl

In Figure 9.5, it is shown the flow rate vs electric power characteristic as a function of the head.

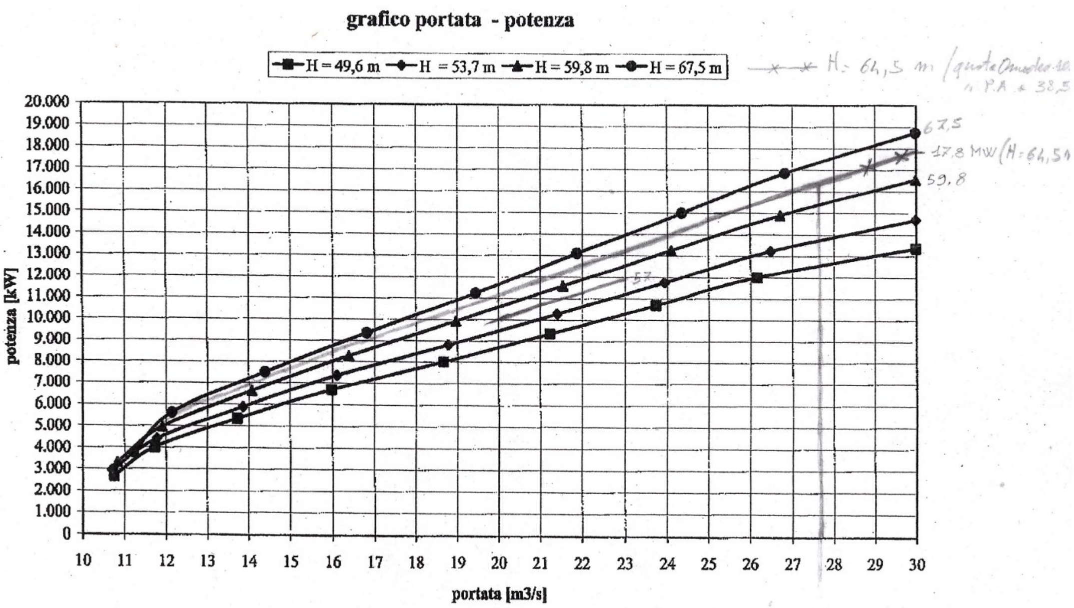


Figure 9.5 Flow rate vs power graph for Tirso 1

The penstock has a diameter of 3 meters, it is 350 meters long and it is made from steel.

It starts at 68.70 msl in the valve chamber and it arrives at 37 msl before entering in the Francis turbine distributor.

The generator is a synchronous three phase brushless type, in a vertical configuration. The three electrical phases are connected in a wye configuration. The generator is connected to the shaft of the turbine, and it generates power at 15 kV. The electric power is then transmitted to the Italian national grid and elevated to 220 kV thanks to a transformer.

The reservoir curve for the Omodeo lake is reported in Figure 9.6.

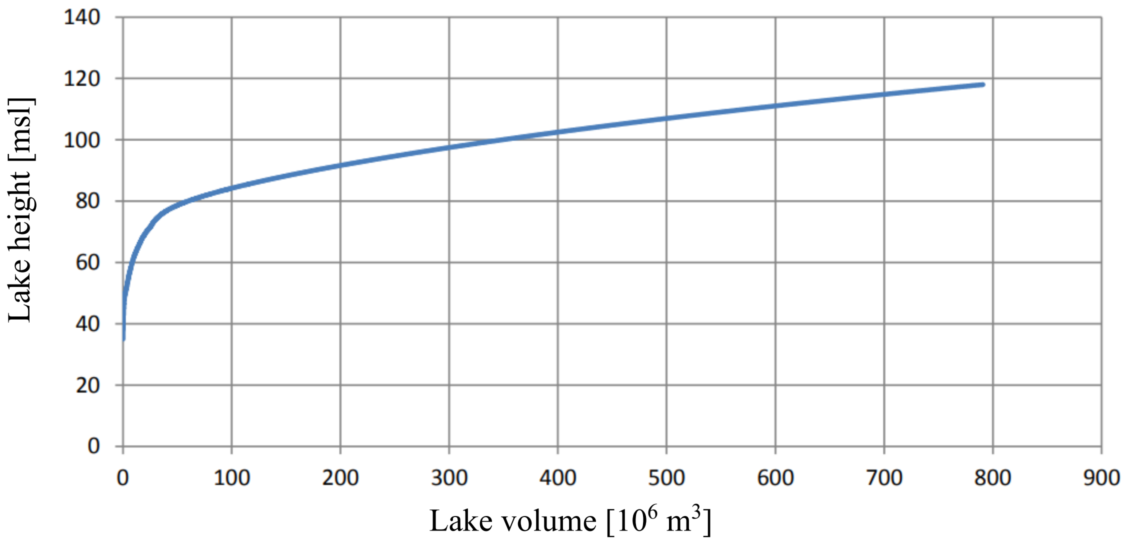


Figure 9.6 Reservoir curve for Omodeo lake

9.1.2 Tirso 2 HP plant

The Tirso 2 hydropower plant was built in 2004 and it consists of one Kaplan turbine with the following characteristics as reported in Table 10.

Figure 9.7 Pranu Antoni power dam and power plant

The power plant is built at the base of the Pranu Antoni dam, which forms the Pranu Antoni lake (Figure 9.7).

Table 10 Tirso 2's Kaplan turbine characteristics

Maximum head	16 m
Nominal head	15,75 m
Minimum head	12 m
Maximum flow rate	30 m^3/s
Nominal flow rate	30 m^3/s
Minimum flow rate	6 m^3/s (20%)
Electrical power	At Hmin 490 kW, at Hmax 4216 kW
Efficiency at maximum head Hmax	92.91%
Efficiency at nominal head Hnom	92.8%
Efficiency at minimum head Hmin	91.09%

The Kaplan turbine is characterized as a S, full regulating Kaplan with a horizontal rotational axis. It is connected to a synchronous three phase brushless electric generator with 8 poles, 6000 V and apparent power of 4700 kVA (and 4300 kW active power with power factor equal to 0.8), which is water cooled.

The three phases are connected in a wye configuration. The electric power is produced at 6 kV, and it is connected to the national grid with the Tirso 1's transformer. The nominal rotation speed is 265 rpm at a frequency of 50 Hz, meanwhile the run-away speed is 670 rpm.

The HP plant has the following characteristic concerning the flow rate Q and electric power Pel (Figure 9.8).

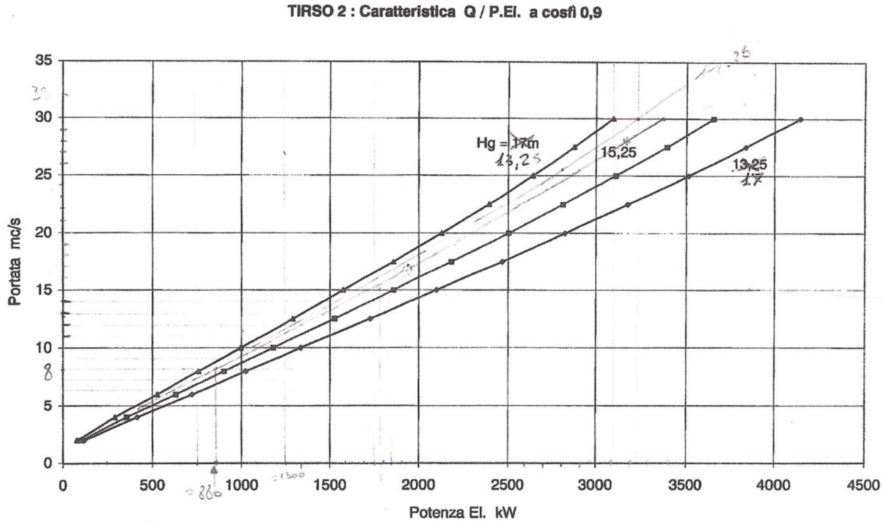


Figure 9.8 Electric power vs flow rate characteristic

The lake has a useful regulation volume of 9 Mm^3, plus 0.3 Mm^3 for flood lamination. The water levels below and above the dam are reported in Table 11.

Table 11 Operating water levels of Tirso 2

Above the power plant:	
Maximum regulation level	45 msl
Minimum safety level for the operation of Tirso 2	42 msl
Minimum level of the lake	36 msl
Below the power plant:	
Discharge level	28 msl
Discharge level when Tirso 2 is in operation	29 msl

The main characteristic of the lake can be described by the reservoir curve (or curva di invaso) for areas and volumes (Figure 9.9).

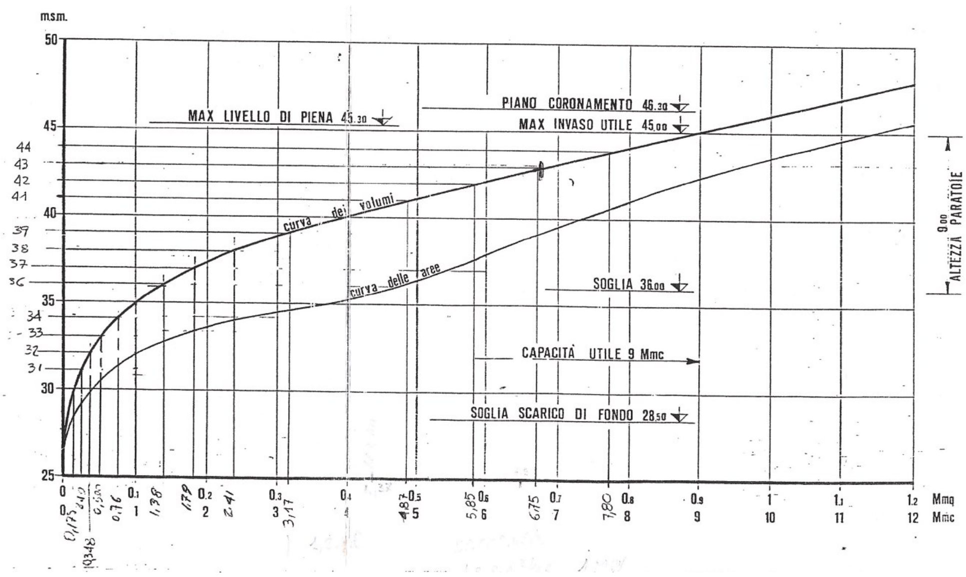


Figure 9.9 Reservoir curve of the Pranu Antoni lake for areas and volumes

The penstock starts at the base of the dam (30 msl) and finishes at 27 msl before entering in the distributor of the Kaplan turbine. It has a diameter of 3.5 meter, it is 50 meter long and it is made out of steel (Figure 9.10).

Figure 9.10 Tirso 2 HP plant and Pranu Antoni dam

9.2. Evaluation of the PHS investment

At first, a hypothesis was made that the power plant would work in the day ahead market. So, the interface with the grid is defined by the electricity prices present on the Sardinian network, also defined as SARD, since Sardinia has its own local market, different from the Italian peninsula. Sardinia is connected to the Italian peninsula through a cable line, and it is a net producer of energy since the installed capacity on the island is greater than its needs.

The prices that are going to be used are the one for the SARD 2021 [€/MWh] taken from the GME website[4], where for each day of the year the hourly prices were reported. This is done because the prices were higher than 2020 due to the reopening of the economic activities but they were still lower than 2022, which was due to the increase in geopolitical tension in eastern Europe. This can be noted in Figure 9.11. One other fact that reinforces this choice is that 2021 was a wet year, in line with the previous 3 years, contrary to 2022.

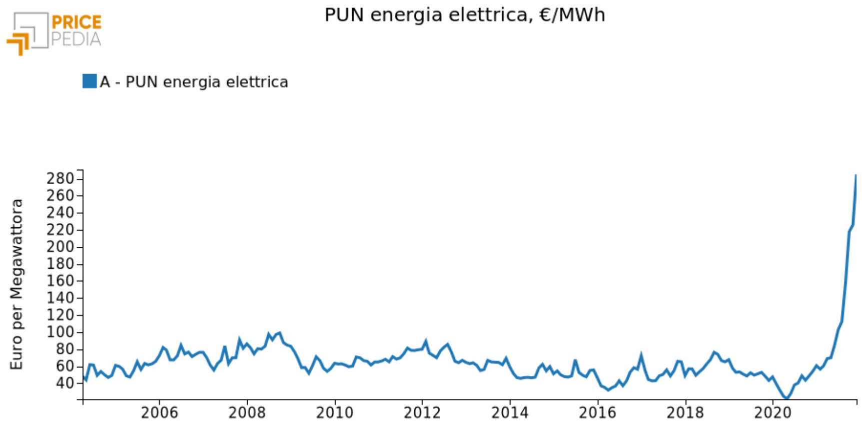


Figure 9.11 PUN trend in Italy

The prices SARD 2021 are reported in the Figure 9.12 below.

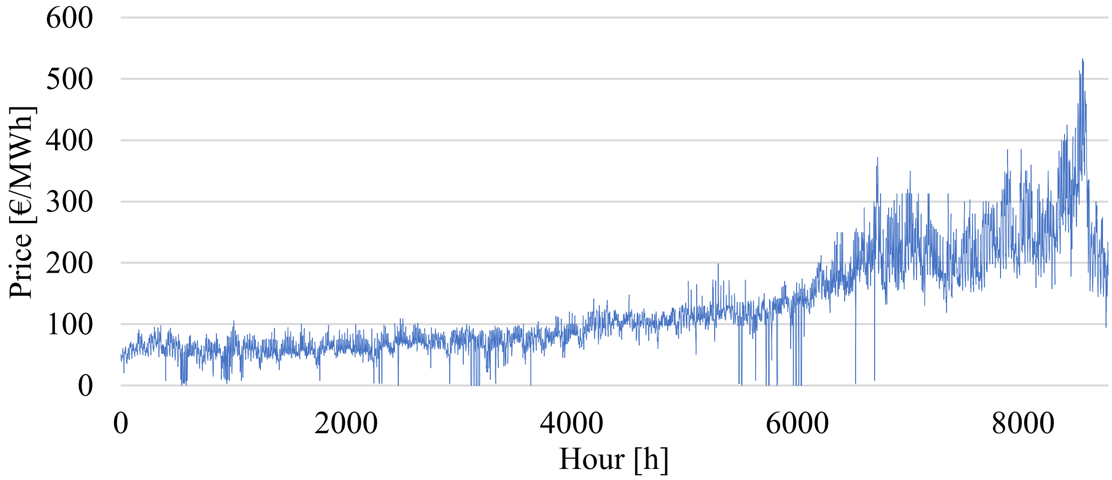


Figure 9.12 Day ahead spot price over the year 2021

[4] https://www.mercatoelettrico.org/It/default.aspx

Nowadays, the two plants are used in the following way: from contractual commitments Tirso 2 must work to guarantee a certain amount of water downstream the Pranu Antoni dam, and there are no incentives present. Meanwhile Tirso 1 has frequent turn on and off, it works mainly during the night, when prices are not high, to fill the Pranu Antoni lake in order to maximized the power production of the Tirso 2 power plant and to released downstream the prescribed amount of water. This can be seen in the following figures from Figure 9.13 to Figure 9.16. In winter the Omodeo lake is used only to storage the rainfalls for the dryer periods over the summer.

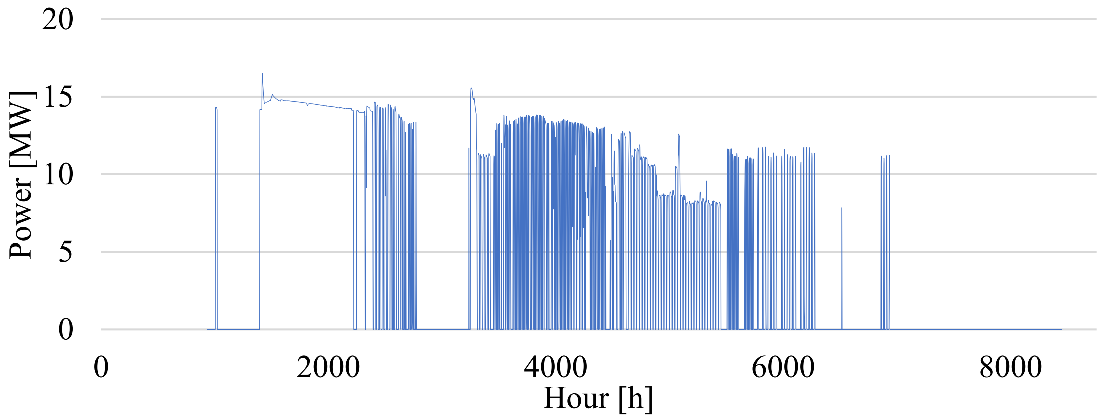


Figure 9.13 Tirso 1 operating mode – power generation for the year 2021

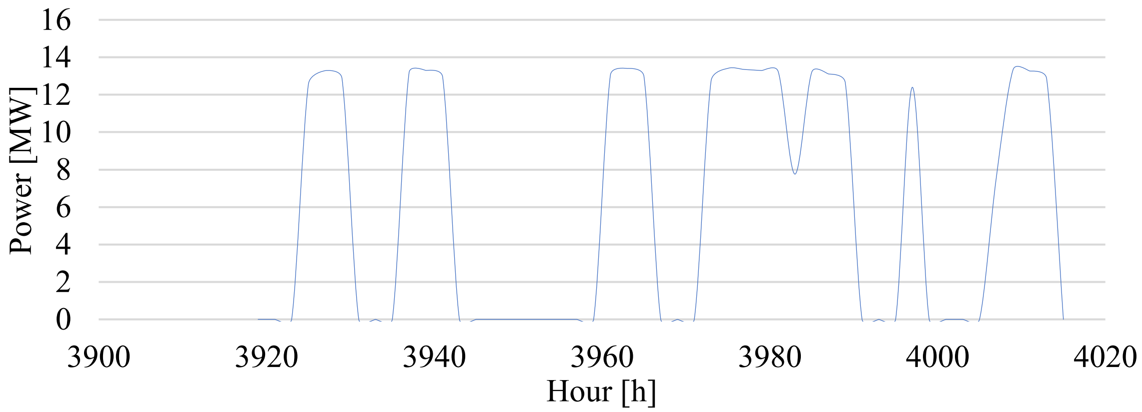


Figure 9.14 Tirso 1 operating mode - power generation from 26/06/21 to 29/06/21

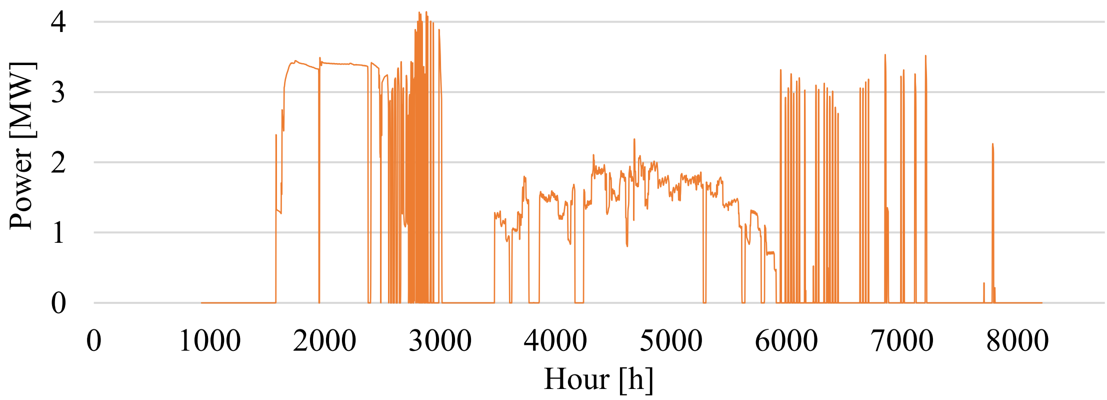


Figure 9.15 Tirso 2 operating mode - power generation for the year 2021

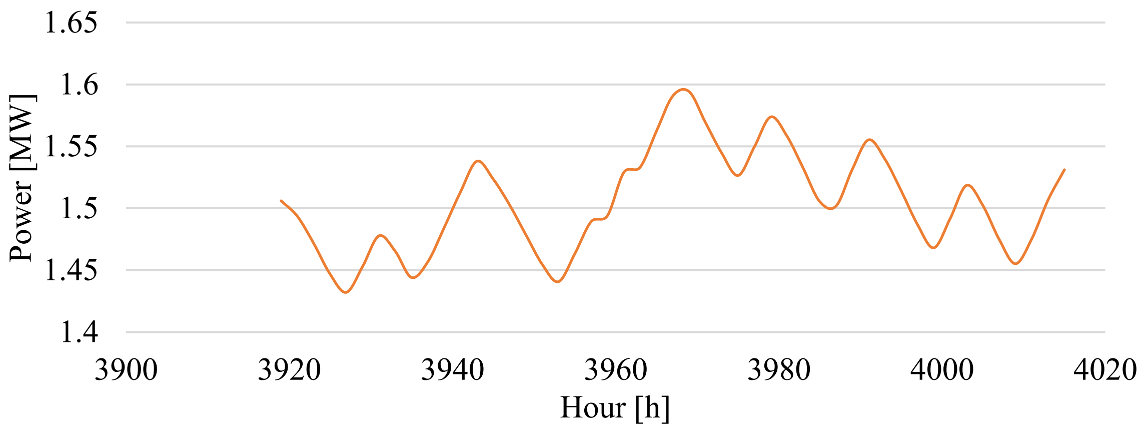


Figure 9.16 Tirso 2 operating mode - power generation from 26/06/21 to 29/06/21

It is also interesting to compare the two generation profiles in Figure 9.17. Tirso 1 is operated with very frequent on/off, meanwhile the production of Tirso 2 is quite constant, but at a lower power than the nominal one.

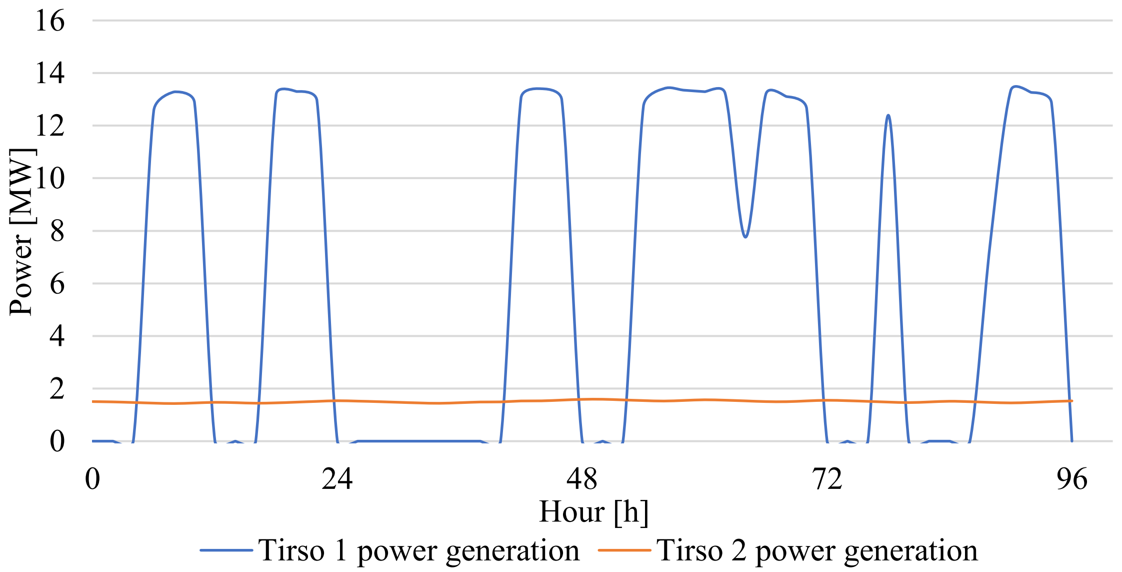


Figure 9.17 Comparison between Tirso 1 and Tirso 2 operation mode – power generation from 26/06/21 to 29/06/21

This will need to be changed since in the case study reported in this master's thesis the goal will be to implement the storage and to respond the grid's request, so there is the necessity to change the contracts. When considering the operation of Tirso 1 and Tirso 2 power plants it must be considered that there are other power plants and reservoirs downstream.

In the economic analysis three option will be explored:

1. Case 1: A PaT with an installed capacity of 30 MW in addition to the Tirso 1's Francis turbine.
2. Case 2: A centrifugal pump with an installed capacity of 30 MW in addition to the Tirso 1's Francis turbine.
3. Case 3: Removal of the Tirso 1's turbine and installation of a new PaT with an installed capacity of 30 MW.

From the literature [10]; it is reported that it is needed a markup lower than 40% to have a profitable operation. The markup is defined as the relative difference between the discharging and charging prices. To determine the range of the prices at which the turbine or pump are in operation the markup is used. The markup has the following Equation 4:

Equation 4 Markup equation

$$\frac{c_{turbine} - c_{pump}}{c_{turbine}} \geq markup \qquad for\ each\ day$$

Meanwhile, the daily average price is defined as in Equation 5.

Equation 5 Daily average price equation

$$c_{average} = \frac{1}{24}\sum_{i=1}^{24} c_i$$

Where c_i is the hourly price. To create a range where the PHS will not operate the mark up is added or subtracted to the daily average price. For the upper limit the Equation 6 is used.

Equation 6 Band upper limit equation

$$c_{upper\ limit} = c_{average}\left(1 + \frac{markup}{2}\right)$$

Meanwhile, for lower limit Equation 7 is used.

Equation 7 Band lower limit equation

$$c_{lower\ limit} = c_{average}\left(1 - \frac{markup}{2}\right)$$

This creates a band in which the plant will not operate. The next step is to implement the control. If the spot price is higher than the upper limit then the turbine will be in operation, meanwhile if the spot price is lower than the lower limit then the pump will be in operation. In the Figure 9.18 it is reported the price control in action for a markup of 0.3.

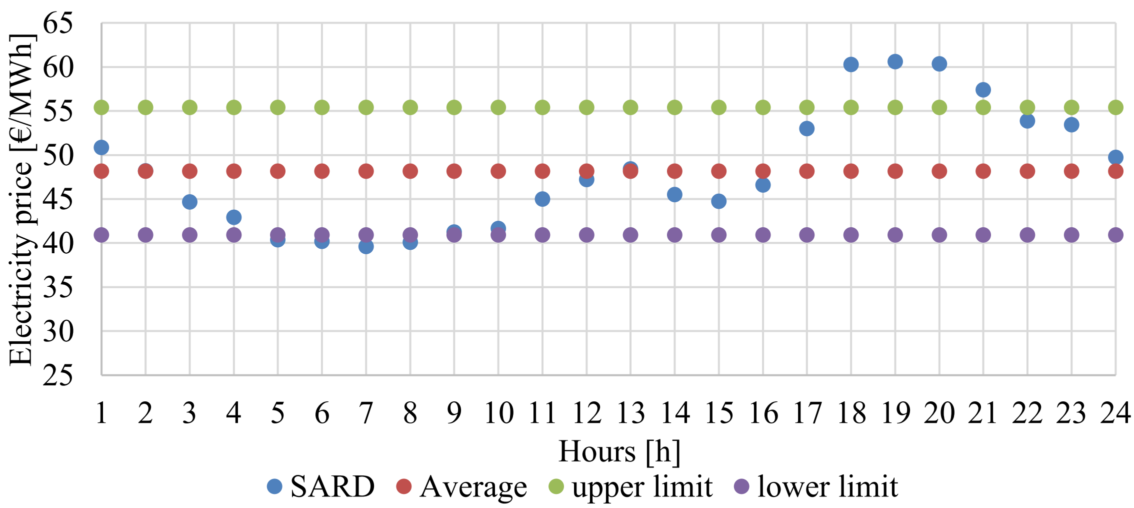


Figure 9.18 Price reported for 01/01/21 with a 0.3 markup

At last, this is done for every day of the year, resulting in the following graph presented in Figure 9.19.

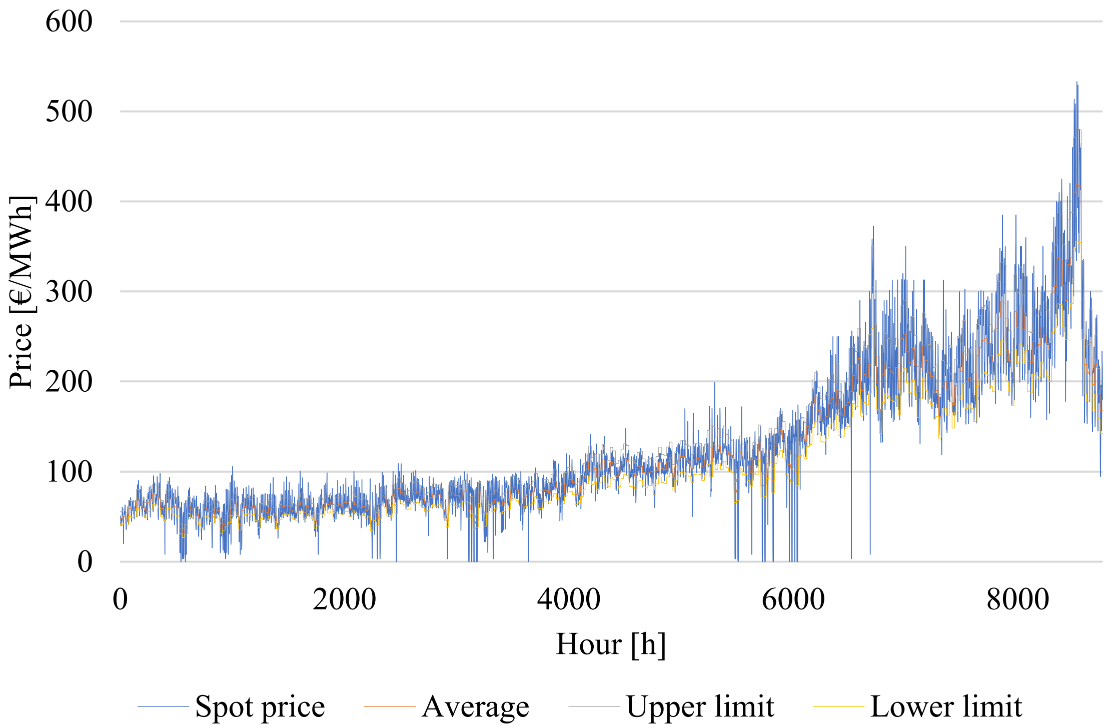


Figure 9.19 Prices over the year 2021 with a 0.3 markup

In the following Figure 9.20, only the average, the upper limit and the lower limit are reported.

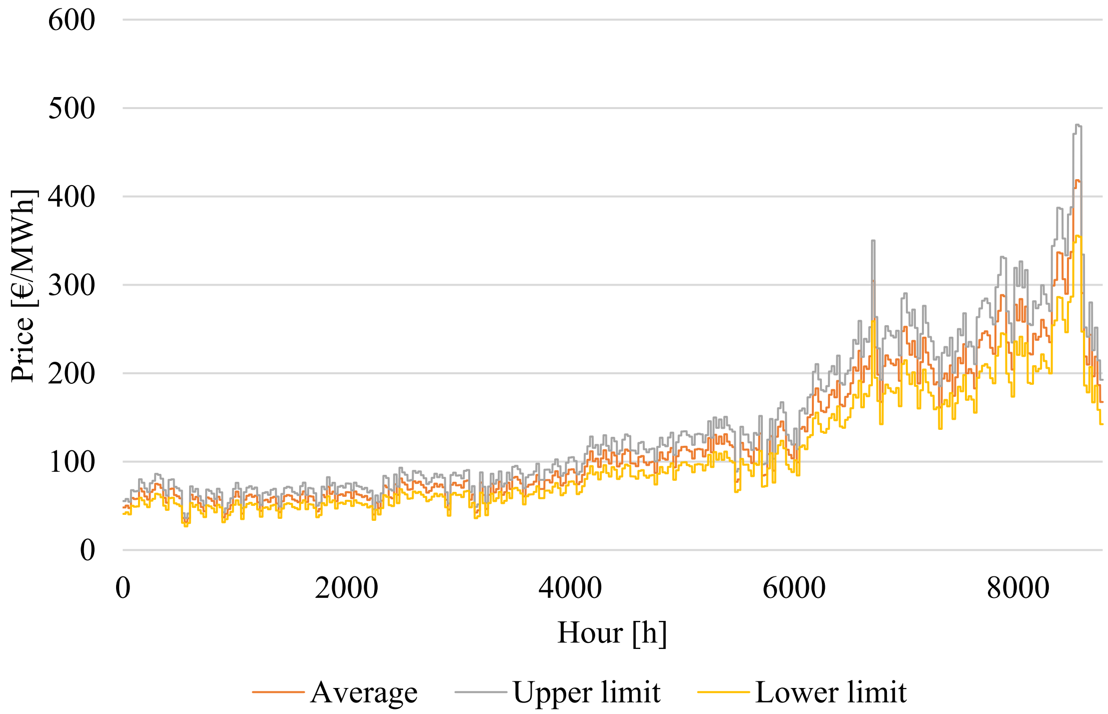


Figure 9.20 Average and boundary limits for 2021 with a 0.3 markup

Now it is fundamental to establish the starting conditions of the reservoirs, and their characteristics like regulation volume, lamination volume, total volume, and reservoir's curve. The characteristics of the hydraulic machines, like flow rate, head, and efficiency, are also stated (Figure 9.21).

RESERVOIRS DATA														V_start	463.716	*10^6 m^3	(from real data)
	Omodeo				Tirso 1				New Tirso 1	PaT				g	9.81	m/s^2	
	h max	116.5	m		h nom	78.2	m							rho	1000	kg/m^3	
	hmin	80	m		Pn	21.5	MW		Pn	30	MW						
	A max	29.37	km^2		Qn	30	m3/s		head same as T1								
		29370000	m^2		h max	80.5	m		Qn	39.10619	m3/s						
	V reg	745	*10^6 m^3		h min	54	m										
	V max	792.84	*10^6 m^3														
	Pranu Antoni				Tirso 2												
	h max	45	m		Qn	30	m^3/s	Q min	6	m^3/s							
	h min op Tirso 2	42	m		hmin	12	m	eta_min	0.9109				ideal case				
	h min	36	m		hn	15.75	m	eta_n	0.928				V tot turb_2	259.7287	*10^6 m^3		
	V initial	8	*10^6m^3		hmax	16	m	eta_max	0.9291				V tot pomp	123.6068	*10^6 m^3		
	h min a valle	28	m		α	0.00455											
	V_u reg	9	*10^6m^3	h=45 m				Pn	4.2	MW			Diff T-P	136.1219	*10^6 m^3		
	MARK UP	0.4															

Figure 9.21 Starting condition of the reservoirs and machine characteristics

After having fixed the nominal power of the PaT machine at 30 MW, the nominal flow rate is found through the Equation 8.

Equation 8 PaT flow rate equation

$$Q_{PaT,[m^3/s]} = \frac{P_{n,[W]}}{\rho_{[\,kg/m^3]} * g_{[\,m/s^2]} * h_{n,Tirso\ 1,[m]}}$$

With P_n as the nominal power, ρ the water density, g the gravity acceleration and h_n as the nominal head.

Then, the inflows and outflows of water not related to the power generation are evaluated. Some models will be used, combining real data with statistical methods.

At first, the Pranu Antoni lake has a tributary which is called Flumineddu. Its flow rate is measured at the station numbered F35 located in Allai, which is just upstream of the Pranu Antoni lake (Figure 9.22).

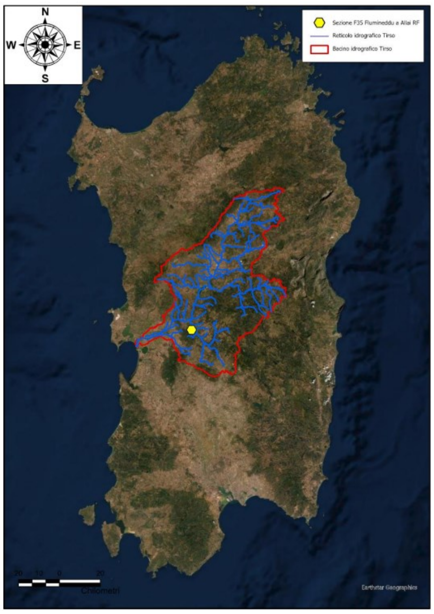


Figure 9.22 Position of the F35 measurement station inside the Tirso river system

The data is reported in the document "Annali Idrologici 2021" (Hydrological annals for 2021) [26]. In the following figure is reported the hydrometric height measured at the station (Figure 9.23).

Giorno	**Flumineddu a Allai RF** (Ie) TIRSO (44,59 m.s.m.)											
	G	F	M	A	M	G	L	A	S	O	N	D
1	1,80	2,27	1,35	1,18	1,08	0,91	**0,73**	0,52	0,48	0,48	*0,64*	2,00
2	2,42	2,20	1,33	1,17	**1,10**	0,90	0,71	0,52	0,48	0,47	1,19	**3,08**
3	2,17	1,95	1,33	1,16	1,08	0,88	0,69	0,52	**0,49**	0,48	1,23	2,49
4	1,89	1,83	1,32	1,16	1,08	0,87	0,68	0,52	0,49	0,48	1,64	2,00
5	2,53	1,75	1,32	1,22	1,07	0,88	0,67	**0,53**	0,47	0,46	1,24	2,07
6	2,21	1,66	1,30	1,15	1,07	0,87	0,68	0,51	*0,46*	*0,45*	1,08	2,39
7	1,91	1,62	1,30	1,12	1,05	0,85	0,67	0,52	0,48	0,46	1,01	1,93
8	1,93	1,80	1,35	1,14	1,06	0,86	0,65	0,52	0,49	0,47	1,01	1,81
9	**3,16**	**3,47**	**1,73**	1,12	1,04	0,86	0,65	0,50	0,48	0,46	1,00	2,33
10	2,36	2,36	1,49	1,13	1,02	**1,23**	0,64	0,51	0,48	0,48	1,14	2,19
11	2,16	2,75	1,40	1,13	1,00	1,07	0,64	0,50	0,47	0,48	1,29	2,59
12	2,11	2,21	1,35	1,13	1,05	1,15	0,62	0,50	0,48	0,48	1,43	2,14
13	1,94	2,87	1,32	1,13	1,03	1,00	0,59	0,50	0,48	0,48	1,25	1,92
14	1,88	2,18	1,30	1,12	1,01	0,94	0,60	0,51	0,47	0,47	1,15	1,80
15	1,80	1,99	1,30	*1,10*	1,05	0,91	0,57	0,50	0,47	0,47	1,11	1,71
16	1,91	1,87	1,54	1,11	1,05	0,88	0,57	0,51	0,48	0,50	1,47	1,63
17	1,77	1,80	1,41	1,16	1,00	0,85	0,57	0,49	0,47	0,49	1,48	1,57
18	1,76	1,74	1,37	1,15	0,99	0,85	0,56	0,51	0,47	0,49	1,32	1,52
19	1,66	1,68	1,38	1,19	0,97	0,82	0,54	0,51	0,49	0,49	1,20	1,48
20	1,63	1,63	1,35	1,19	0,96	0,81	0,56	0,48	0,46	0,49	1,13	1,46
21	*1,58*	1,58	1,33	1,14	0,98	0,81	0,53	0,47	0,48	0,49	1,10	1,43
22	1,58	1,52	1,30	1,11	0,97	0,79	0,56	0,49	0,47	0,50	1,12	1,41
23	1,83	1,50	1,28	**1,32**	0,96	0,80	0,53	0,49	0,48	0,50	1,43	1,38
24	1,96	1,46	1,25	1,27	0,96	0,79	0,54	0,48	0,48	0,50	1,24	1,37
25	2,16	1,44	1,21	1,18	0,95	0,75	0,55	*0,46*	0,48	0,52	1,24	*1,35*
26	2,11	1,41	1,23	1,12	0,95	0,77	0,54	0,48	0,48	0,51	2,03	1,48
27	1,91	1,40	1,23	1,13	0,93	0,77	0,53	0,49	0,48	0,51	2,24	1,89
28	1,91	*1,39*	1,19	1,10	0,94	0,76	0,53	0,47	0,47	0,53	2,55	1,82
29	1,82		1,19	1,13	0,91	0,76	0,54	0,50	0,46	0,53	**3,04**	1,67
30	1,74		1,19	1,13	*0,90*	*0,72*	0,52	0,48	0,47	0,54	2,27	1,61
31	1,70		*1,18*		0,91		*0,51*	0,49		**0,62**		1,55
Medie	1,98	1,88	1,33	1,16	1,00	0,87	0,60	0,50	0,48	0,49	1,40	1,86
	Media annua: 1,12											

Figure 9.23 Hydraulic height measured at the station F35 for 2021

Through some empirical equation it is possible to find the flow rate (Equation 9).

Equation 9 Characteristic of the F35 measurement station

$$\begin{cases} 0.5995 \le h \le 1.73\ m & Q_{\left[\frac{m^3}{s}\right]} = 9.8426\left(h_{[m]} - 0.5995\right)^{2.3860} \\ 1.73 \le h \le 3.6330\ m & Q_{\left[\frac{m^3}{s}\right]} = 59.5827\left(h_{[m]} - 1.73\right)^{1.8679} + 13.1901 \end{cases}$$

If the hydraulic height is lower than 0.5995 m the measured flow rate will be zero, but that is not true as it can be seen in the Figure 9.23 above. The Flumineddu river is not dry, for all the measurements below 0.5995 m a fixed flow rate of 0.01 m^3/s will be taken.

The resulting flow rates are reported in Figure 9.24.

Flumineddu a Allai RF

(Q) Bacino: TIRSO (44,59 msm)

PORTATE MEDIE GIORNALIERE IN m³/s												
Giorno	Gennaio	Febbraio	Marzo	Aprile	Maggio	Giugno	Luglio	Agosto	Settembre	Ottobre	Novembre	Dicembre
1	13,94	32,87	5,22	2,64	**1,89**	0,53	**0,06**	***0,00***	***0,00***	*0,00*	*0,00*	20,83
2	38,12	25,19	4,93	2,58	1,82	0,49	0,05	0,00	0,00	0,00	1,22	**109,23**
3	28,29	16,72	4,65	2,51	1,73	0,47	0,03	0,00	0,00	0,00	6,48	50,90
4	16,02	14,01	4,49	2,75	1,72	0,42	0,03	0,00	0,00	0,00	10,91	18,99
5	50,04	13,09	4,43	3,18	1,79	0,42	0,03	0,00	0,00	0,00	3,54	21,27
6	31,46	11,58	4,20	2,42	1,66	0,38	0,01	0,00	0,00	0,00	1,73	37,53
7	16,94	11,10	4,13	2,28	1,52	0,36	0,01	0,00	0,00	0,00	1,19	17,06
8	18,67	13,75	5,17	2,27	1,46	0,37	0,01	0,00	0,00	0,00	1,28	16,23
9	**83,06**	60,18	**11,12**	2,17	1,36	0,70	0,00	0,00	0,00	0,00	1,19	35,37
10	37,49	72,93	7,92	2,07	1,28	**2,11**	*0,00*	0,00	0,00	0,00	4,23	47,29
11	27,84	**86,32**	5,87	2,13	1,24	1,66	0,00	0,00	0,00	0,00	4,57	55,59
12	24,60	29,18	5,14	2,13	1,38	2,04	0,00	0,00	0,00	0,00	6,02	25,66
13	16,95	57,09	4,71	2,09	1,33	1,20	0,00	0,00	0,00	0,00	3,59	16,16
14	14,84	27,66	4,38	2,05	1,27	0,77	0,00	0,00	0,00	0,00	2,36	13,69
15	13,90	18,15	4,43	*1,99*	1,50	0,58	0,00	0,00	0,00	0,00	2,02	12,63
16	16,24	15,04	7,38	2,00	1,35	0,45	0,00	0,00	0,00	0,00	5,45	10,83
17	13,54	13,71	6,20	2,35	1,14	0,35	0,00	0,00	0,00	0,00	7,00	9,34
18	13,50	13,08	5,31	2,37	1,03	0,31	0,00	0,00	0,00	0,00	4,40	8,26
19	11,99	11,76	5,35	2,69	0,95	0,26	0,00	0,00	0,00	0,00	2,87	7,42
20	10,54	10,38	5,26	2,75	0,92	0,24	0,00	0,00	0,00	0,00	2,17	6,77
21	9,51	9,30	4,59	2,28	0,91	0,23	0,00	0,00	0,00	0,00	1,84	6,21
22	*9,23*	8,27	4,25	2,48	0,88	0,21	0,00	0,00	0,00	0,00	3,12	5,84
23	13,28	7,54	3,90	**5,65**	0,84	0,20	0,00	0,00	0,00	0,00	6,14	5,45
24	38,53	6,94	3,63	3,69	0,82	0,18	0,00	0,00	0,00	0,00	3,56	5,13
25	28,90	6,53	3,46	2,68	0,81	0,16	0,00	0,00	0,00	0,00	4,17	*5,02*
26	23,74	6,09	3,32	2,28	0,78	0,15	0,00	0,00	0,00	0,00	28,24	12,54
27	16,14	5,81	3,18	2,15	0,70	0,13	0,00	0,00	0,00	0,00	33,00	18,01
28	16,43	*5,57*	3,02	2,11	0,65	0,12	0,00	0,00	0,00	0,00	41,89	13,94
29	13,70		2,89	2,13	0,61	0,11	0,00	0,00	0,00	0,00	**88,56**	11,81
30	12,98		2,79	2,15	0,58	*0,08*	0,00	0,00	0,00	0,00	40,64	10,08
31	15,95		*2,70*		*0,55*		0,00	0,00		**0,00**		8,72

ELEMENTI CARATTERISTICI PER L'ANNO 2021													
	Anno	Gennaio	Febbraio	Marzo	Aprile	Maggio	Giugno	Luglio	Agosto	Settembre	Ottobre	Novembre	Dicembre
Q max [m³/s]	109,23	83,06	86,32	11,12	5,65	1,89	2,11	0,06	0,00	0,00	0,00	88,56	109,23
Q media [m³/s]	6,98	22,46	21,78	4,78	2,50	1,18	0,52	0,01	0,00	0,00	0,00	10,78	20,77
Q minima [m³/s]	0,00	9,23	5,57	2,70	1,99	0,55	0,08	0,00	0,00	0,00	0,00	0,00	5,02
Q media [1/s Km²]	8,97	28,85	27,97	6,14	3,21	1,52	0,67	0,01	0,00	0,00	0,00	13,85	26,68
Deflusso [mm]	282,87	77,27	67,68	16,44	8,32	4,06	1,73	0,03	0,00	0,00	0,00	35,89	71,45
Afflusso meteorico	836,23	147,07	76,76	51,78	64,93	13,97	22,93	0,62	0,45	6,32	58,68	250,47	142,25
Coeff. di deflusso	0,34	0,53	0,88	0,32	0,13	0,29	0,08	0,06	0,00	0,00	0,00	0,14	0,50

DURATA DELLE PORTATE	
Giorno	[m³/s]
10	89,29
30	36,85
60	14,50
91	8,71
135	4,35
182	1,97
274	0,00
355	0,00

SCALA NUMERICA DELLE PORTATE							
Altezza idrometrica [m]	Portata [m³/s]	Altezza idrometrica [m]	Portata [m³/s]	Altezza idrometrica [m]	Portata [m³/s]	Altezza idrometrica [m]	Portata [m³/s]
0,51	0,00	1,39	5,61	2,12	23,45	2,85	86,82
0,75	0,10	1,48	7,26	2,21	28,31	2,94	98,25
0,84	0,32	1,57	9,16	2,30	34,04	3,03	110,45
0,93	0,70	1,66	11,32	2,39	40,60	3,12	123,40
1,02	1,24	1,75	13,23	2,48	48,00	3,21	137,11
1,11	1,97	1,84	14,15	2,57	56,21	3,31	153,21
1,20	2,91	1,93	16,13	2,66	65,21	3,40	168,47
1,29	4,06	2,02	19,09	2,75	75,01	3,63	210,79

Figure 9.24 Data for the characterization of the Flumineddu river

With this data available it is possible to create the curve for the flow rate during the year 2021 of the Flumineddu river (Figure 9.25).

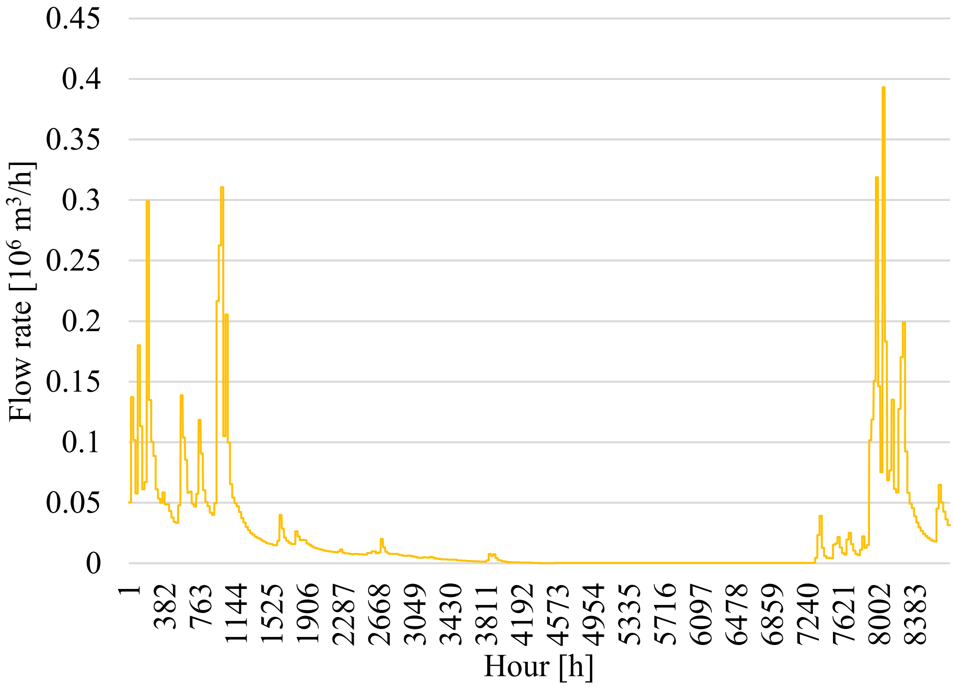


Figure 9.25 Flumineddu river flow rate

It can be noted that the Flumineddu is highly influenced by rainfalls, mainly present in autumn and winter. Meanwhile there is large portion of the year where the flow rate is low. This shows the importance of flood lamination and water storage in Sardinia.

Meanwhile, for the Omodeo lake is known that its water is used for agricultural and drinkable water purposes. To model these usages the following models were used.

For the agricultural use a model is presented in [27], it is based on the use of monthly fraction to distribute the consumption over the year as reported in Table 12.

Table 12 Monthly fraction for the usages estimation model

Monthly fractions	
January	0.0162
February	0.0162
March	0.0292
April	0.0616
May	0.1086
June	0.1864
July	0.248
August	0.1831
September	0.0745
October	0.0405
November	0.0211
December	0.0146

Then it is essential to estimate the need of water, which reported in [28]. The water losses are considered as 10% of the water need.

Table 13 Agricultural water requirements

Agriculture water	148	10^6 m^3
Water losses	14.8	10^6 m^3
Water requirement	162.8	10^6 m^3

The water request modelled is reported in the following graph (Figure 9.26).

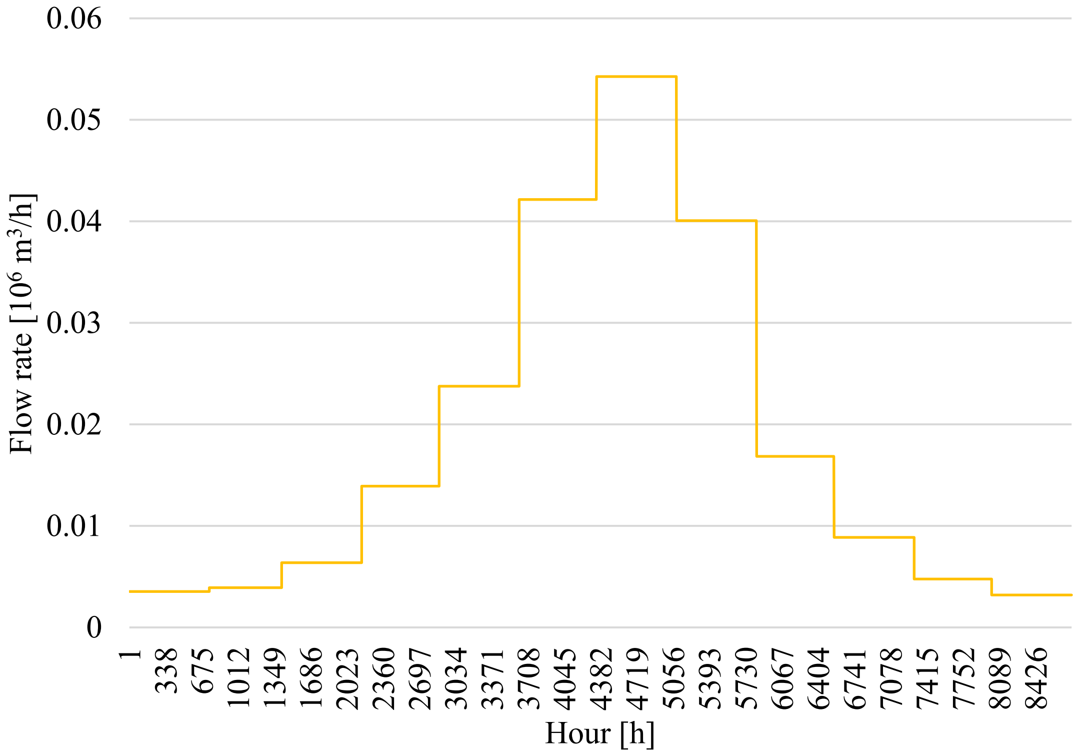


Figure 9.26 Agricultural water needs

Then the drinking and industrial water needs are evaluated considering the extraction of freshwater resources data for 2021 reported by ISTAT in the "Report per la giornata mondiale dell'acqua" [29] and an estimation of 120000 users.

Table 14 Data for the estimation of domestic water consumption

DATA 2021		
Pro capita extraction	422*(1+0.1875) =501.125	L/day/person
Pro capita in household due to losses	215	L/day/person
Inhabitants in the region	120000	Inhabitants

Then it is necessary to add 18.75% that represent the need for the industry, which was determined from the following Figure 9.27, which represents the final users of water extraction from groundwater and surface water.

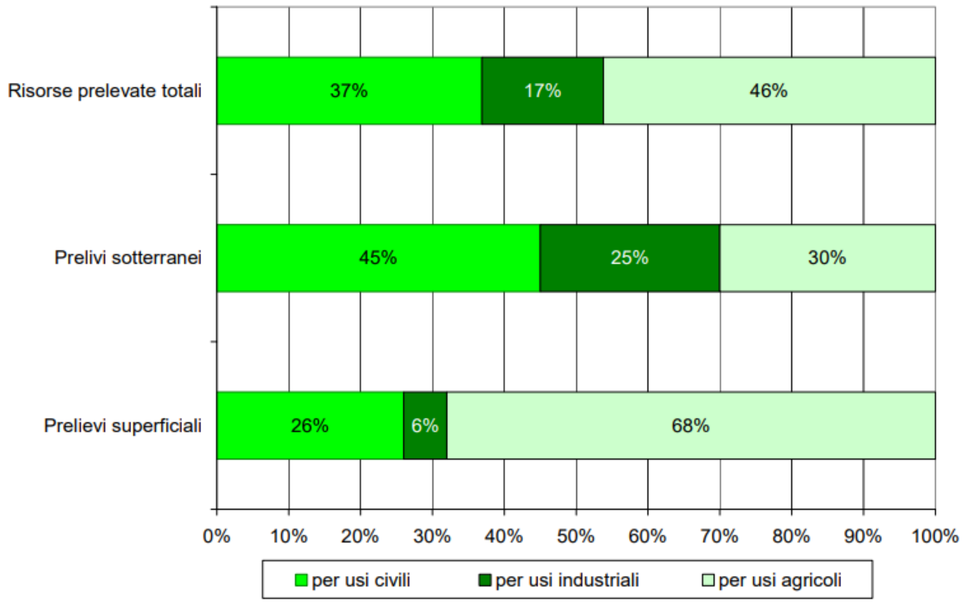


Figure 9.27 Distribution of water extraction between surface water and groundwater for the different usages: domestic, industrial, and agricultural

It is hypothesized that a fixed amount of water is taken each hour from the Omodeo lake, the flow rate is found with the following Equation 10.

Equation 10 Domestic and industrial needs estimation

$$Q_{domestic\&industry_{[Mm^3/h]}} = pro\ capite\ extraction_{[L/day/person]} * 10^{-3} * \frac{10^{-6}}{24} * inhabitants$$

The total need is estimated at 21.949 10^6 m^3.

Finally, the Tirso river is a tributary of the Omodeo lake. Since there is no useful measurement available, the flow rate of the Tirso river was found using this arrangement.

These rivers are mainly alimented by rainfall, and since they are in the same region of Sardinia it can be said that the rainfall can be considered constant all over the area. So, the flow rates of the two rivers are proportional to the ratio of their catchment areas (Table 15).

Table 15 Flumineddu and Tirso river catchment area

Flumineddu catchment area	778.57	km^2
Tirso catchment area	2056	km^2
Ratio	2.64073879	

With these considerations the following Equation 11 can be used for the evaluation of the Tirso river flow rate (Figure 9.28).

Equation 11 Tirso flow rate curve

$$Q_{Tirso_{[10^6\ m^3/h]}} = Q_{Flumineddu\ ad\ Allai_{[10^6\ m^3/h]}} * \frac{A_{Tirso_{[km^2]}}}{A_{Flumineddu\ ad\ Allai_{[km^2]}}}$$

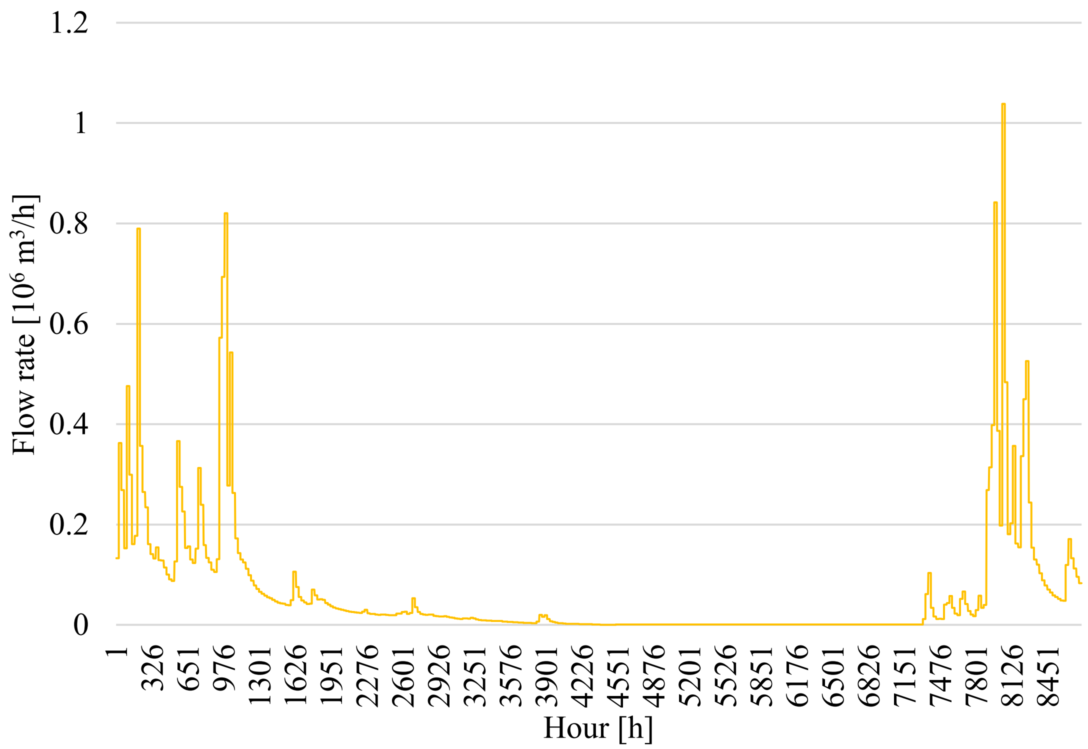


Figure 9.28 Tirso river flow rate

At last, it is interesting to see the following graph which shows the faction of the use of water from the Omodeo reservoir, other than the hydroelectric use (Figure 9.29).

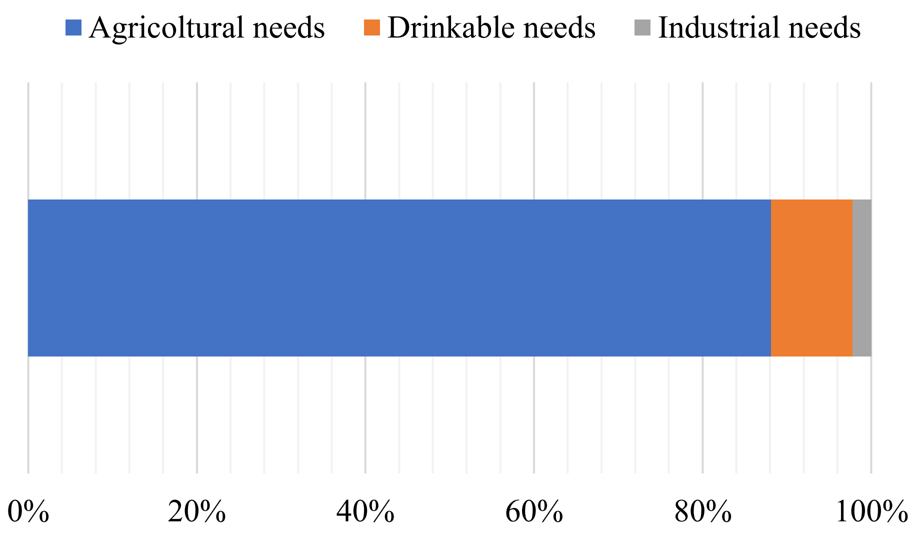


Figure 9.29 Fraction of use for Omodeo lake (excluding hydroelectric use)

At last, it is essential to talk about the DMV or minimum vital flow. To evaluate it, the reference paper is [30].

The DMV is defined as:

Equation 12 DMV equation

$$DMV = \alpha * Q_n$$

Where:

- α is a coefficient which states the hydraulic condition of the river. Since both rivers do not show chronic lack of water the coefficient is taken as 0.1.
- Q_n is the natural flow, which would happen in absence of extraction or artificial discharges, with the recreation of natural flow variability.

The DMV's flow rate curve is reported in Figure 9.30.

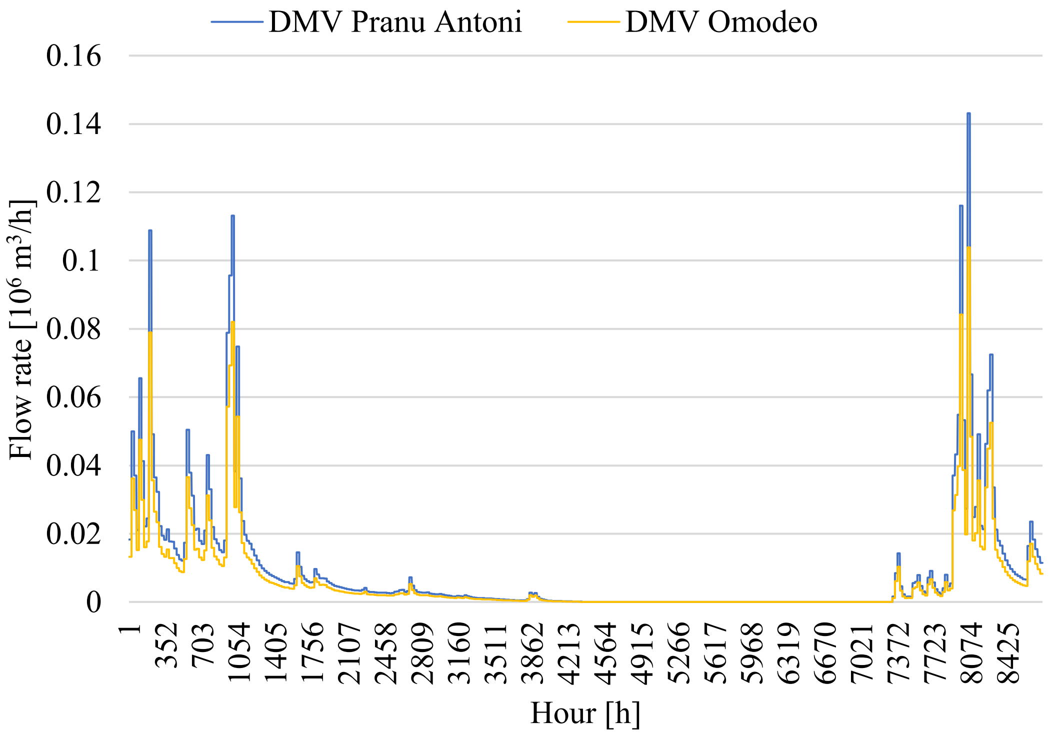


Figure 9.30 DMV's flow rate chart

9.2.1 Power plant regulation and operational constraints

After having define the general configuration and the inlet and outlet flows of the two reservoirs, except for the hydropower use, it is useful to define the regulation of the two power plants, Tirso 1 and Tirso 2.

The regulation is based on two bases:

- Regulation on water volumes, which thanks to the available reservoir curve is a regulation on the height of the water level knowing the maximum height of the reservoirs.
- Regulation on the head of the turbine or pump. Machines characteristics are guaranteed for a certain range of head and flow rates. It is essential to stay within those limits.

The next step is the evaluation of the mass balances of the entire system. The mass balances can be translated into volume balances since the density of water can be taken as a constant.

Equation 13 Link between mass flow rate and volumetric flow rate

$$\dot{m}_{[kg/s]} = \rho_{[kg/m^3]} * \dot{V}_{[m^3/s]}$$

$$\rho_{water} = 1000\ kg/m^3$$

And since the hourly balance is used in the spreadsheet, the balance can be written as a sum of volumes. But first the boundaries of the system must be defined (Figure 9.31).

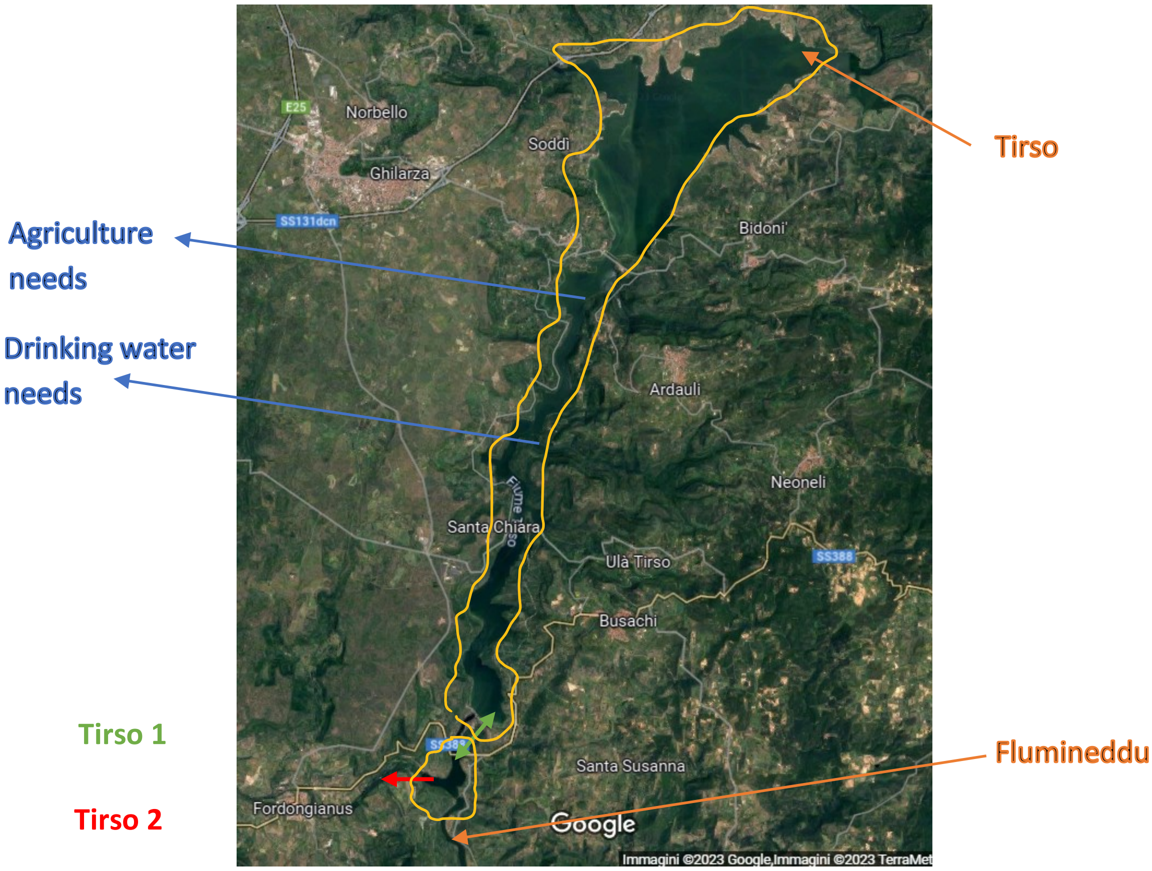


Figure 9.31 Boundary condition for the mass balances

With reference to the previous Figure 9.31 the mass balance can be written in the following form considering hourly balances. All the balances do not consider the evaporation.

At first the stationary volume balances are presented in Equation 14 and Equation 15:

Equation 14 Stationary volume balance in pump mode

$$pump\ mode \begin{cases} Q_{Tirso} - Q_{agricolture} - Q_{drinkable\ water} + Q_{pump,T1} = 0 & for\ Omodeo\ lake \\ -Q_{pump,T1} + Q_{Flumineddu} - Q_{turb,T2} = 0 & for\ Pranu\ Antoni\ lake \end{cases}$$

Equation 15 Stationary volume balance in turbine mode

$$turbine\ mode \begin{cases} Q_{Tirso} - Q_{agricolture} - Q_{drinkable\ water} - Q_{turb,T1} = 0 & for\ Omodeo\ lake \\ Q_{turb,T1} + Q_{Flumineddu} - Q_{turb,T2} = 0 & for\ Pranu\ Antoni\ lake \end{cases}$$

It must be specified that positive flows are entering flows, meanwhile negative flows are exiting flows.

But this model is not good enough since the volume of the lake is not stationary. The following equation are the one implemented for the modelling of the reservoirs. Considering the same boundary conditions as reported in Figure 9.31, the balances can be written as:

Equation 16 Omodeo lake volume variation over time

$$\frac{dV_{Omodeo}}{dt} = Q_{Tirso} - Q_{drinkable\ water} - Q_{agricolture} - Q_{turb,T1} + Q_{pump,T1} - Q_{spilled,Omodeo} - DMV_{Omodeo}$$

Equation 17 Pranu Antoni lake volume variation over time

$$\frac{dV_{Pranu\ Antoni}}{dt} = Q_{Flumineddu} + Q_{turb,T1} - Q_{pump,T1} - Q_{turb,T2} - Q_{spilled,Pranu\ Antoni} + Q_{spilled,Omodeo} - DMV_{Pranu\ Antoni}$$

Taking as a reference the Omodeo lake, it possible to integrate the flow rates Q over the time.

Equation 18

$$\int_{V^*}^{V} dV_{Omodeo} = \int_{t^*}^{t} (Q_{Tirso} - Q_{drinkable\ water} - Q_{agricolture} - Q_{turb,T1} + Q_{pump,T1} - Q_{spilled,Omodeo} - DMV_{Omodeo})\, dt$$

Equation 19

$$\int_{V^*}^{V} dV_{Omodeo} = \int_{t^*}^{t} Q_{Tirso} dt - \int_{t^*}^{t} Q_{drinkable\ water} dt - \int_{t^*}^{t} Q_{agricolture} dt - \int_{t^*}^{t} Q_{turb,T1} dt + \int_{t^*}^{t} Q_{pump,T1} dt - \int_{t^*}^{t} Q_{spilled,Omodeo} dt - \int_{t^*}^{t} DMV_{Pranu\ Antoni} dt$$

Equation 20

$$V - V^* = \int_{t^*}^{t} Q_{Tirso} dt - \int_{t^*}^{t} Q_{drinkable\ water} dt - \int_{t^*}^{t} Q_{agricolture} dt - \int_{t^*}^{t} Q_{turb,T1} dt + \int_{t^*}^{t} Q_{pump,T1} dt - \int_{t^*}^{t} Q_{spilled,Omodeo} dt - \int_{t^*}^{t} DMV_{Pranu\ Antoni} dt$$

The integral can be discretized in interval of one hour each (dt = 1 h), this becomes a sum of the various volumes entering or exiting the system each hour, that can be written as:

Equation 21 Omodeo lake volume balance for one hour

$$V_{Omodeo} = V^*_{Omodeo} + Q_{Tirso} - Q_{drinkable\ water} - Q_{agricolture} - Q_{turb,T1} + Q_{pump,T1} - Q_{spilled,Omodeo} - DMV_{Omodeo}$$

Meanwhile, for Pranu Antoni lake the volume balance (for each hour) can be written as:

Equation 22 Pranu Antoni lake volume balance for one hour

$$V_{Pranu\ Antoni} = V^*_{Pranu\ Antoni} + Q_{Flumineddu} + Q_{turb,T1} - Q_{pump,T1} - Q_{turb,T2} - Q_{spilled,Pranu\ Antoni} + Q_{spilled,Omodeo} - DMV_{Pranu\ Antoni}$$

In both the equation above, V^* is the initial volume or the volume at the time T-1.

The two considered reservoirs are multi-purpose, which is one of the ways in which large HP project can be incentivize. Other than the providing water for agriculture, industries and drinking water, the Omodeo lake and the Pranu Antoni offer also the lamination of the floods as reported in the previous chapter, even though the lamination volume of Pranu Antoni is far smaller than the Omodeo lake, as it can be seen in Table 16.

Table 16 Lamination volumes of the upper and lower reservoirs

Omodeo lake lamination volume	44.64	$*10^6$ m^3
Pranu Antoni lake lamination volume	0.3	$*10^6$ m^3

The presence of flood control and its modelling is fundamental to have a realistic operating model. This is even more critical in the Pranu Antoni lake, because the lamination volume is very small (Figure 9.32).

Figure 9.32 Pranu Antoni dam's spillway in operation

To understand, better the terminology the figure below offers a panoramic view of the different fundamental parameters of the dam and of the reservoir (Figure 9.33).

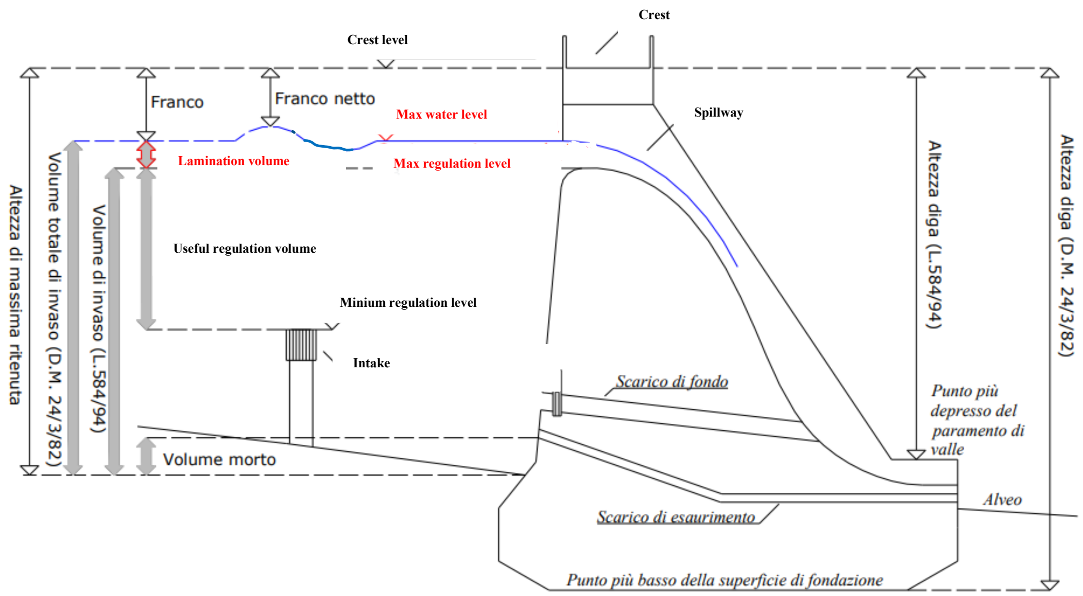


Figure 9.33 Dam profile

The regulation water level is defined the level at which water starts to spill from the top of the dam.

The minimum regulation level is the level where the catchment device is located.

The useful regulation volume is the volume of water between the minimum regulation level and the maximum regulation level.

Meanwhile the lamination volume is the volume of water between the maximum regulation level and the maximum reservoir level.

The spillway works inside the lamination volume, so if the water volume behind the dam is higher than its useful regulation volume. The flow rate spilled by the spillway is driven by the water head over the maximum regulation level.

To model the overflow the Creager-Scimemi efflux law (or legge di efflusso) of the spillway will be used. The equation of the law is reported as follows (Equation 23):

Equation 23 Creager-Scimemi efflux law

$$Q_{spilled,[m^3/s]} = \mu * L_{e,[m]} * h_{[m]}^{3/2} * \sqrt{2g_{[m/s^2]}}$$

With:

- µ is the efflux coefficient, taken as 0.4.
- Le is the useful length taken as the real length of the spillway (Equation 24).

Equation 24 Equation for the effective length of the spillway

$$L_e = L - N * L_{piles} - 2 * \left(k_{shoulder} + N * k_{piles}\right) * h \quad [m]$$

$k_{shoulder}$ and k_{piles} are loss coefficient, both taken as zero since it is assumed that shaping is as an ogive (0.05 for blunt spillway). N is the number of piles and L_{piles} is the length of the piles in meters. L is the total length in meters.

- h is hydraulic head (Equation 25).

Equation 25 Hydraulic head equation

$$h = h(V(t)) - h_{max\, reguation}\ [m]$$

- g is the gravity acceleration, taken as 9.81 m/s^2.

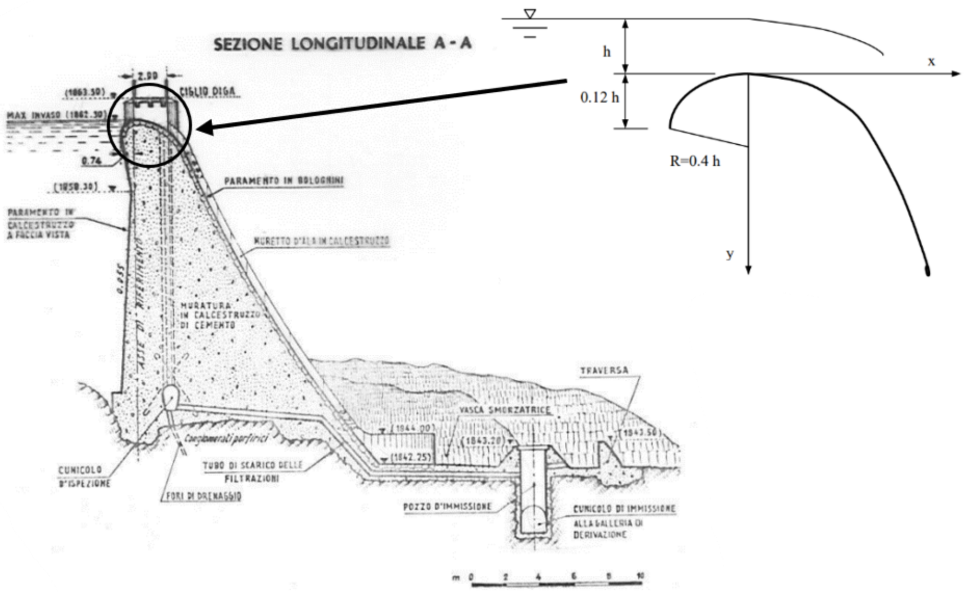


Figure 9.34 Dam's spillway operating principle

The profile by Creamer-Scimemi is reported in Equation 26.

Equation 26 Creamer-Scimemi profile equation

$$\frac{y}{h} = 0.48\left(\frac{x}{h}\right)^{1.80}$$

For the two dams the data of the spillway is reported in Table 17.

Table 17 Spillway characteristics for the dams

Pranu Antoni dam		
Length of the spillway	13	
Number of spillways	5	
Maximum reservoir level	45	msl
Eleonora D'Arborea dam		
Length of the spillway	13	
Number of spillways	6	
Maximum reservoir level	116.5	msl

Essential to the regulation are the reservoir volume curves, which must be known because they allow for the evaluation of the height of the reservoir. At first the curve for Pranu Antoni can be linearized to simplify the calculation reported in Figure 9.9.

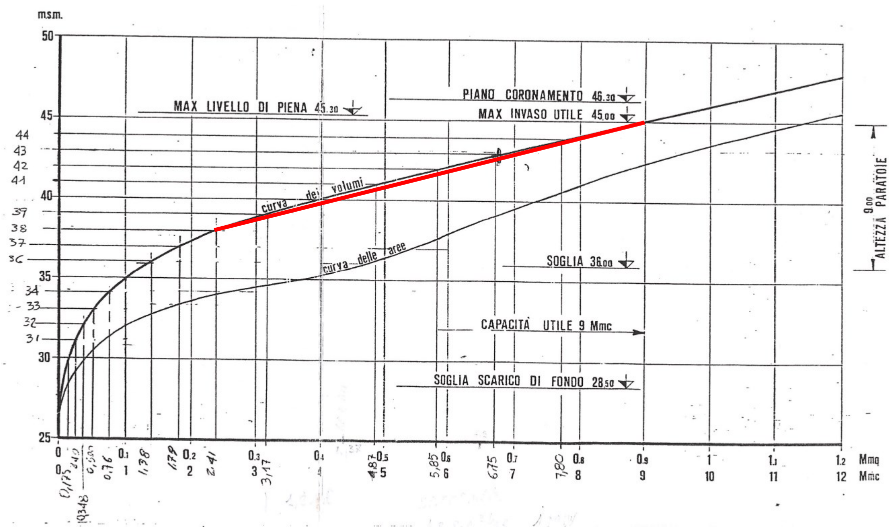


Figure 9.35 Pranu Antoni reservoir curve

The curve can be linearized in its operating range, as it can be shown in Figure 9.35 Pranu Antoni reservoir curve, with the red line. So, for height higher than 38 meters the following Equation 28 can be used.

Equation 27

$$V_{Pranu\ Antoni,[10^6\ m^3]}(h) = 2.41 + \frac{9 - 2.41}{45 - 38}\left(h_{Pranu\ Antoni,[msl]} - 38\right)$$

Equation 28

$$V_{Pranu\ Antoni,[10^6\ m^3]}(h) = 2.41 + 0.9428\left(h_{Pranu\ Antoni,[msl]} - 38\right)$$

But in the spreadsheet, it is useful to know the water level from the volume of water inside the reservoir, so Equation 29 can written in the following way:

Equation 29 Water level in the Pranu Antoni lake as as a function of the Pranu Antoni lake's volume

$$h_{Pranu\ Antoni,[msl]}(V) = 38 + \frac{V_{Pranu\ Antoni,[10^6\ m^3]} - 2.41}{0.9428}$$

The same procedure is applied to Omodeo lake's reservoir curve found in Figure 9.6.

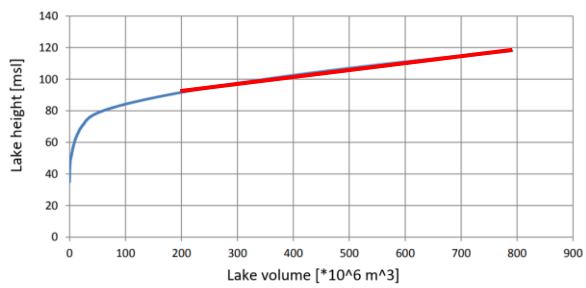


Figure 9.36 Omodeo's reservoir curve

The same linear trend can be found in the reservoir curve after 100 million cubic meters. From the linearization it is possible to obtaining Equation 30 and Equation 31.

Equation 30

$$V_{Omodeo,[10^6 m^3]}(h) = 200 + \frac{745 - 200}{116.5 - 92}\left(h_{Omodeo,[msl]} - 92\right)$$

Equation 31 Water level in the Omodeo lake as a function of the Omodeo lake's volume

$$h_{Omodeo,[msl]}(V) = 92 + \frac{116.2 - 92}{745 - 200}\left(V_{Omodeo,[10^6\, m^3]} - 200\right)$$

After having defined the water level as a function of the water volume, the next step is to fix the operating range of the machines and of the lakes. These parameters are reported in Table 18.

Table 18 Operational limits of the PHS Tirso 1 and HP Tirso 2

Tirso 1 operation		
Minimum operating water level	80	msl
Maximum operating water level	116.5	msl
Minimum head	54	m
Maximum head	80.5	m
Tirso 2 operation		
Minimum operating water level	42	msl
Maximum operating water level	45	msl
Minimum head	12	m
Maximum head	16	m

So, if the operation is inside the stated limits, then the turbine or pump will be ON, otherwise it will be OFF. For each 1 h interval, the volume of water pumped or turbined are:

Equation 32 Volume pumped in the operation of the PHS plant

$$V_{pumped,[10^6\, m^3]} = \frac{Q_{pump,[m^3/s]} * [P\ ON/OFF] * 60 * 60}{10^6}$$

Equation 33 Volume turbined in the operation of the PHS plant

$$V_{turbined,[10^6\, m^3]} = \frac{Q_{turb,[m^3/s]} * [T\ ON/OFF] * 60 * 60}{10^6}$$

After having defined these limits and the operation of the plant, the next step is to calculate the energy consumed by the pump and produced by the turbines of Tirso 1 and Tirso 2, and at last the annual net profit of Tirso 1, which is essential to the economic analysis of the case study.

To evaluate the energy production, it is first essential to evaluate the effective heads presented in the Equation 34 and Equation 35.

Equation 34 Effective Tirso 1 head

$$h_{T1,[m]} = h_{Omodeo,[msl]} - h_{Pranu\ Antoni,[msl]}$$

Equation 35 Effective Tirso 2 head

$$h_{T2,[m]} = h_{Pranu\ Antoni,[msl]} - 29$$

Where $h_{T1;[m]}$ is the head of Tirso 1, $h_{Omodeo,[m]}$ is the water level inside the Omodeo dam, $h_{Pranu\ Antoni,[m]}$ is the water level inside the Pranu Antoni dam, $h_{T2,[m]}$ is the head of Tirso 2 and 29 msl is the discharge level of Tirso 2 when it is in operation.

Then the ideal hydraulic power, expressed in W, is calculated (Equation 36).

Equation 36 Hydraulic power

$$P_{id} = \rho g Q h$$

Where ρ is the water density in kg/m^3, g is the gravity acceleration in m/s^2, Q is the volumetric flow rate in m^3/s, and h is the head in meters.

The next step is to consider the efficiency curves for the different machines. For Tirso 2's Kaplan the data for the efficiency curve for the nominal flow rate is provided by the characteristics of the machine [31] reported in Table 19.

Table 19 Tirso 2' Kaplan characteristics

Tirso 2					
Qn	30	m^3/s	Q min	6	m^3/s
Hmin	12	m	eta_min	0.9109	
Hn	15.75	m	eta_n	0.928	
Hmax	16	m	eta_max	0.9291	
α	0.00455				
			Pn	4.2	MW

From the data it is useful to use linear interpolation to find a useful curve.

$$\begin{cases} 12 < h < 15.75\,m & \eta(h) = 0.9109 + 4.56 * 10^{-3}(h - 12) \\ 15.75 < h < 16\,m & \eta(h) = 0.928 + 4.4 * 10^{-3}(h - 15.75) \end{cases}$$

With h as the head in meters. For simplicity a single equation can be used (Equation 38):

Equation 37

$$\eta = 0.9109 + \frac{0.9291 - 0.9109}{16 - 12}(h - 12)$$

Equation 38 Efficiency curve for Tirso 2

$$\eta = 0.9109 + \alpha_0\left(h_{[m]} - 12\right) \quad with\ \alpha_0 = 4.55 * 10^{-3}$$

Where h is the effective head expressed in meters.

At the end the following efficiency curve can be plotted (Figure 9.37).

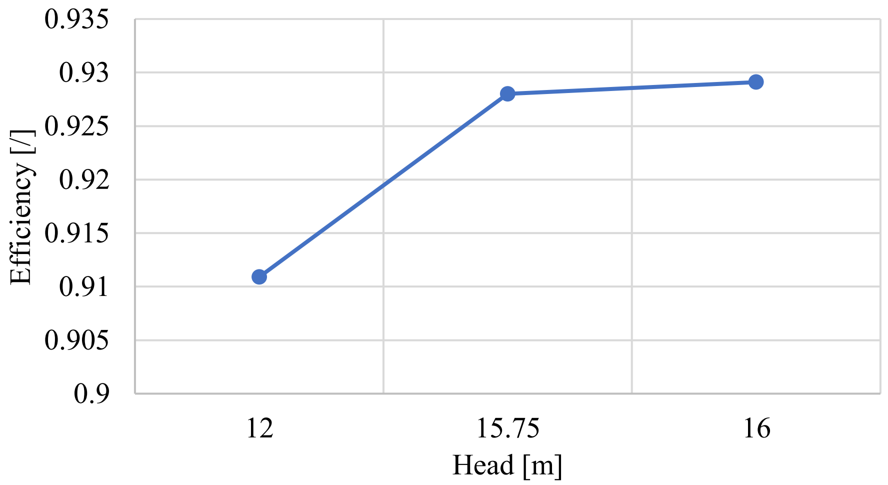


Figure 9.37 Tirso 2 efficiency curve

Meanwhile for Tirso 1's Francis turbine the data for the efficiency curve are taken from Figure 9.5 and are reported in Table 20.

Table 20

Tirso 1's Francis efficiency - at 30 m^3/s			
h [m]	**Pel [MW]**	**Pidr [MW]**	**effT1 [/]**
49.6	13.3	14.59728	0.911129
53.7	14.6	15.80391	0.923822
59.8	16.5	17.59914	0.937546
64.5	17.8	18.98235	0.937713
67.5	18.6	19.86525	0.936308
80.5		23.69115	0.930221

Resulting in the following efficiency curve (Figure 9.38).

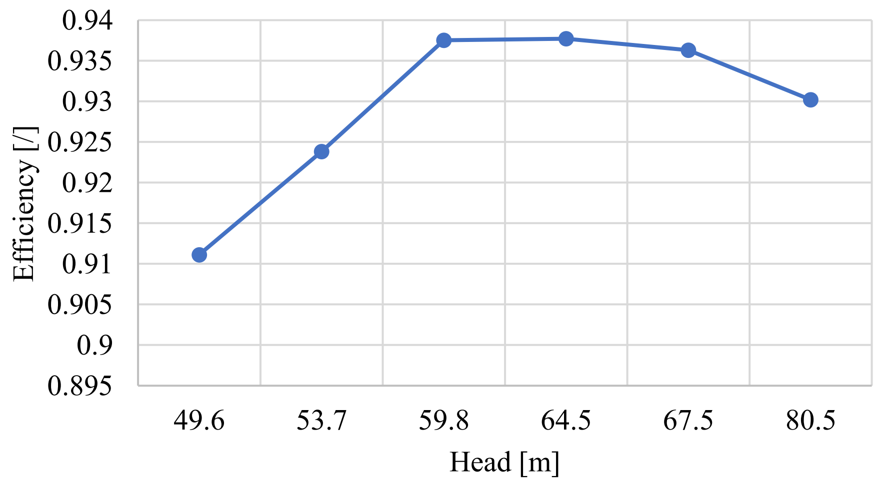


Figure 9.38 Tirso 1'Francis efficiency curve

For the implementation of the curve the following criteria is applied (Equation 39).

Equation 39 Efficiency curve for Tirso 1

$$\begin{cases} 49.6 < h < 59.8\,m & \eta(h) = 0.91129 + \dfrac{0.937546 - 0.91129}{59.8 - 49.6}\left(h_{[m]} - 49.6\right) \\ 59.8 < h < 80.5\,m & \eta = 0.937546 \end{cases}$$

Meanwhile, the PaT can be modelled by using the efficiency curves of Tirso 1. The efficiency curve of the PaT the curve of the Francis turbine is multiplied by some coefficients as reported in the Equation 40 and Equation 41 below.

Equation 40 Effeciency curve for the PaT in turbine mode

$$\eta_{PaT,Turbine}(h) = 0.957 * \eta(h)_{Francis,Tirso\ 1}$$

Equation 41 Effeciency curve for the PaT in pump mode

$$\eta_{PaT,Pump}(h) = 0.9343 * \eta(h)_{Francis,Tirso\ 1}$$

With the efficiency curves, it is possible to evaluate the real power for the turbine (Equation 42) and for the pump (Equation 43).

Equation 42

$$P_{real,T,[W]} = \eta_{turbine} * \rho g Q h$$

Equation 43

$$P_{real,P,[W]} = \frac{\rho g Q h}{\eta_{pump}}$$

Where η is the efficiency, ρ is the water density in kg/m^3, g is the gravity acceleration in m/s^2, Q is the volumetric flow rate in m^3/s, and h is the head in meters.

For every hour, the energy produced can be calculated since energy is defined as the power multiplied the time (Equation 44).

Equation 44

$$energy = power * time \rightarrow energy_{1\,h,[Wh]} = P_{real\,,[W]} * 1\,h$$

The next step is to sum all the various hourly energy terms (Equation 45 and Equation 46).

Equation 45 Energy consumed

$$energy\ consumed_{T1,[Wh]} = \sum_{i=1}^{8760} energy_{1h,pump,[Wh]_i}$$

Equation 46 Energy produced

$$energy\ produced = \sum_{i=1}^{8760} energy_{1h,Francis,[Wh]_i} + \sum_{i=1}^{8760} energy_{1h,PaT,[Wh]_i} + \sum_{i=1}^{8760} energy_{1h,Tirso\ 2,[Wh]_i}$$

$$energy\ produced_{T1,[Wh]} = \sum_{i=1}^{8760} energy_{1h,Francis\ ,[Wh]_i} + \sum_{i=1}^{8760} energy_{1h,PaT,[Wh]_i}$$

$$energy\ produced_{T2,[Wh]} = \sum_{i=1}^{8760} energy_{1h,Tirso\ 2,[Wh]_i}$$

At last, it is also interesting to look at the utilization coefficient (Equation 47), which gives an idea of how much the power plant is working during the year. This is usually high for hydropower project, and it is defined as:

Equation 47 Utilization coefficient

$$f_{[\ /]} = \frac{E_{produced,[MWh]}}{P_{n,[MW]} * 8760}$$

One other fundamental parameter is the equivalent hours, which gives the hours that which the plant should be working at the nominal power to produce or consume the amount of energy E.

Equation 48 Equivalent hour for the turbine operation

$$h_{eq,turbine,[h]} = \frac{E_{produced,[MWh]}}{P_{n,[MW]}}$$

Equation 49 Equivalent hour for the pump operation

$$h_{eq,pump,[h]} = \frac{E_{consumed,[MWh]}}{P_{pump,MAX,[MW]}}$$

The energy produced and consumed is calculated, then for each hour the hourly energy is multiplied by the hourly cost found in the day ahead market for SARD (Figure 9.12).

Equation 50 Cost related to the energy consumption of the pump

$$C_{i,[€]} = c_{i,[€,MWh]} * energy\ consumed_{i,[MWh]}$$

Equation 51 Revenues related to the energy production by the turbines

$$P_{i,[€]} = p_{i,[€,MWh]} * energy\ produced_{i,[MWh]}$$

And then all those terms must be summed (Equation 52 and Equation 53).

Equation 52 Total cost equation

$$total\ cost_{[€]} = \sum_{i=1}^{8760} C_{i,[€]} = \sum_{i=1}^{8760} c_{i,[€,MWh]} * energy\ consumed_{i,[MWh]}$$

Equation 53 Total revenue equation

$$total\ revenue_{[€]} = \sum_{i=1}^{8760} P_{i,[€]} = \sum_{i=1}^{8760} p_{i,[€,MWh]} * energy\ produced_{i,[MWh]}$$

The annual net profit is at last defined in Equation 54, this parameter is fundamental for the economic analysis of the PHS case study.

Equation 54 Annual net profit equation

$$annual\ net\ profit_{[€]} = total\ revenue_{[€]} - total\ cost_{[€]}$$

The last part of the regulation consists in the implementation of the energy storage system. One of the useful applications of pumped hydro is the time shifting of the energy to optimize the renewable energy generation.

The discharge time requested is in the range from 2 to 8 hours.

The issue with the implementation of the control is the small useful regulation volume of the Pranu Antoni lake. The lower reservoir will not be considered in the model and the idea is that if the water level of the lower reservoir during the discharge phase of the upper reservoir increases higher than the dam height, then the water will spill downstream the Pranu Antoni dam.

The storage can be limited by the forecasting of intense meteorological events, in fact the whole system has multipurpose nature, ranging from agricultural to flood control. In this case the time shift service may be lacking.

The Omodeo lake, with its 745 million cubic meter of useful regulation volume, helps the implementation of the control, since the water level inside the lake remain high, but more frequent drought conditions may change the reservoir dynamics, with more evapotranspiration and more extraction for agricultural purposes.

The control is constructed in a way that there will always be the prescribed water volume behind the Eleonora D'Arborea dam for the discharge.

The proposed project can be classified as an OPEN LOOP PUMP BACK PHS with daily storage and single penstock. The hydraulic machine has fixed rotational speed, but in the future, it may be interesting to switch to a variable rotation machine to allow for increased flexibility in the operation. As said before variable speed machines are about 30% more expensive compared to fixed speed machines.

Table 21 Data for the storage

Volume of water needed for 8 h storage				
$Q_{turbined\_tot}$ (Francis + 30 MW PaT)	30+39.1=69.1	m^3/s		
Volume needed	1990258	m^3	1.99	$10^6\ m^3$
$T_{storage\ discharge}$	8	h		
Tirso 1's Francis turbine power	21.5	MW		
PaT installed capacity	30	MW		
Energy stored	412	MWh		

The energy stored is found with following Equation 55.

Equation 55

$$E_{stored,[MWh]} = P_{[\,MW]} * T_{discharge,[h]}$$

The volume of water needed for the storage is defined in Equation 56.

Equation 56

$$V_{[10^6\,m^3]} = Q_{turb,[m^3/s]} * 3600_{[s]} * T_{discharge,[h]} * 10^{-6}$$

But, for this configuration of PHS plant a pumped back configuration may be preferable, with continuous water movement between the two reservoirs depending on the electricity prices. That means that the water movements between the two reservoirs are only dependent on the price of the energy in the regional SARD market and on operational constraints.

9.2.2 Economic analysis

The economic analysis consists in the evaluation of some economic parameters. Firstly, the discounted cash flow is introduced (Equation 57).

Equation 57 DCF equation

$$DCF = \frac{FV_1}{1+k} + \frac{FV_2}{(1+k)^2} + \cdots + \frac{FV_n}{(1+k)^n}$$

FV is the future value, which may be both positive and negative. $FV/(1+k)^n$ represents the future value reported to the present. The discounted cash flow considers the value of money in time with the use of the compounded interest (Equation 58), this is done to bring the FV to the present.

Equation 58 Compounded interest

$$(1+k)^n$$

In which k is the interest rate (cost of capital) and n being the number of years.

There are two criteria for choosing between investment alternatives:

- Arithmetic methods, which do not consider the changing value in time, like Pay Back Time or ROI.
- Geometric methods, which weight in the time factor, like NVP and IRR.

The PBT is an arithmetic parameter (Equation 59), and it is easy to be understood and used, but at the same time it is useful only in short time. It represents the time that it takes to recover the investment.

Equation 59 PBT equation

$$\sum_{i=0}^{PBT} D_i = \sum_{j=0}^{n} I_j = I_0 \rightarrow PBT = \frac{I_0}{D}$$

D_i is the cash flow, and I_j is the investment. A more reliable formulation includes the DCF (Equation 60).

Equation 60 PBT with DCF equation

$$PBT = \frac{I_0}{DCF}$$

One other arithmetic parameter is the Return on Investment, which is defined as the ratio between the average annual net profit and the investment (Equation 61).

Equation 61 ROI equation

$$ROI = \frac{\sum_{j=1}^{n} \frac{D_j - A_j}{n}}{\sum_{j=1}^{n} I_j}$$

The different terms are D_j the positive and A_j the negative cash flows, n is the number of years and I_j is the cash flow related to the investment.

Probably the most important parameter for the evaluation of the investment is the Net Present Value, which is useful to define its feasibility.

Equation 62 NPV equation

$$NPV = -\sum_{j=1}^{n} I_j(1+k)^{-j} + \sum_{j=1}^{n} D_j(1+k)^{-j} = I_0 + \sum_{j=1}^{n} D_j(1+k)^{-j}$$

Which can be read as:

Equation 63

$$\begin{cases} NPV > 0 & benefit > cost \rightarrow feasible \\ NPV < 0 & benefit < cost \rightarrow not\ feasible \end{cases}$$

The interest rate k can be calculated from the WACC, but in this case it is necessary to have data on the company liquidity and the financing mechanism of the project. The document [5] by IRENA suggests using k=10%. One other parameter is the Profitability Index, which is defined as the ratio of the NPV over the investment I_0 (Equation 64).

Equation 64 IP equation

$$IP = \frac{NPV}{I_0} = \frac{\sum_{j=1}^{n} D_j(1+k)^{-j}}{I_0} - 1$$

The last economic parameter considered is the Internal Rate of Return, which is the discount rate that makes the discounted cash flow equal to the investment, making the NPV=0.

Equation 65 IRR definition

$$I_0 = \sum_{j=0}^{n} D_j(1+IRR)^{-j}$$

Some of the empirical equations found in the literature use values of the money related to different years. To account for that difference the inflation rate for the Eurozone must be used. The average inflation rate for the Eurozone from 2013 to 2023 was 2.43%.[5] The following Equation 66 is used to report the result of the equation to the considered year.

Equation 66 Inflation relationship between present value and future value

$$PV = \frac{FV}{(1+i)^n}$$

Where PV is the present value, FV is the future value, i is the inflation rate and n is the number of years.

[5] https://tradingeconomics.com/european-union/inflation-rate#:~:text=Inflation%20Rate%20in%20European%20Union%20averaged%202.43%20percent%20from%202000,percent%20in%20January%20of%202015.

After having defined the economic parameters, the next step is to quantify the investment in terms of CAPEX and OPEX. The OPEX is usually defined as a fraction of the CAPEX.

The CAPEX represents the cost related to the infrastructure and project management; it has several components which are:

- Electromechanical equipment.
- Civil cost.
- Indirect cost.

From the papers "Accurate estimation model for small and micro hydropower plants costs in hybrid energy systems modelling" [32] and "Cost Models for Pumped Hydro Storage System" [33] , several formulas are available. For the electromechanical equipment, the Equation 67 is chosen because it is a formula tested at a European level.

Equation 67 Electromechanical cost

$$C_{EM-PaT,[10^6€]_{2018}} = 13.39 * P_{[MW]}^{0.5825} * H_{[m]}^{-0.3359} \quad \begin{cases} 74\ MW < P < 1000\ MW \\ 72\ m < H < 630\ m \end{cases}$$

The transformer and switch yard cost can be estimated with the following Equation 68.

Equation 68 Transformer and switch yard cost

$$c_{TRANSF,[€,2010/kW]} = 249.66 * P_{[kW]}^{-0.1803} * H_{[m]}^{-0.2073}$$

The civil costs are related to the civil infrastructure; it can be noted that there a no cost related to the reservoirs, since they are already present, and all the land is already own by the manager of the reservoir.

The penstock cost is evaluated by the Equation 74, which first suggests the calculation of the optimal diameter (Equation 69).

Equation 69 Optimal diameter of the penstock

$$D_{opt,[m]} = \frac{1.12 * Q_{\left[\frac{m^3}{s}\right]}^{0.45}}{H_{[m]}^{0.12}}$$

Equation 70 Penstock thickness

$$t_{pipe\ thickness,[m]} = \frac{0.1 * H_{[m]} * D_{opt,[m]}}{2 * \sigma_{[N/m^2]}}$$

With Q as the flow rate, H as the nominal head and σ as the admissible stress of the steel. This implies the choice of the material.

Figure 9.39 Tirso 1 steel penstock

The penstock will be made of ASTM A537, which is a specification that covers heat-treated carbon-manganese-silicon steel plates intended for fusion-welded pressure vessels. The steel plates specified under ASTM A537 are commonly used in applications where improved notch toughness is required, such as in the construction of boilers and pressure vessels (Equation 71).

Equation 71 ASTM A537 characteristics

$$\sigma = 310\ N/mm^2 \qquad \rho = 7800\ kg/m^3 \qquad c_{steel} = 1.4\ €/kg$$

Then it follows with the calculations of the weight of the penstock in Equation 72.

Equation 72 Weight of the penstock

$$w_{penstock,[kg]} = t_{pipe\ thickness,[m]} * D_{opt,[m]} * \rho_{steel,[kg/m^3]} * L_{penstock,[m]}$$

From the Figure 9.40 it can be noted that the horizontal length of the penstock is , knowing the drop in elevation of the penstock, from 68.7 msl to 37 msl, the length of the penstock is evaluated in Equation 73.

Equation 73 Length of the penstock

$$L_{penstock,[m]} = \sqrt{horizontal\ lenght_{[m]}^2 + vertical\ length_{[m]}^2}$$

$$= \sqrt{335.34^2 + 31.7^2} = 336.83\ m$$

Figure 9.40 Penstock location on the power plant

The total cost of the penstock can be written as:

Equation 74 Penstock cost equation

$$c_{pen,exp} = c_{pen,excavation} + c_{pen} + c_{concreting}$$

With the various terms defined as:

Equation 75 Excavation cost related to the penstock

$$c_{pen,excavation} = 1.39 * D_{opt}^2 * c_{ex} * L_{penstock}$$

The excavation cost c_{ex} is considered negligible because the penstock will be external (Equation 75).

Equation 76 Steel cost related to the penstock

$$c_{pen} = \frac{0.1 * D_{opt}^2}{2\sigma} \rho_{steel} * c_{steel}$$

The real penstock cost is mainly linked to the cost of steel c_{steel} (Equation 76).

Equation 77 Concreting cost of the penstock

$$c_{concreting} = 0.6 * D_{opt}^2 * L_{penstock} * c_c$$

With c_c as the concrete cost. The concreting cost (Equation 77) is considered negligible.

Moving on to the cost related to the transmission lines, which is considered equal to zero because it is assumed that the capacity on the transmission grid is already there since this is a well-connected site.

At last, the cost of the powerhouse is evaluated with the following empirical Equation 78.

Equation 78 Powerhouse cost

$$c_{ph,[€/kW],2021]} = 3041.22 * P_{[kW]}^{-0.238} * H_{[m]}^{-0.0602}$$

The hypothesis in this thesis is that the powerhouse will be located on the surface.

All the costs above are considered the direct cost. The indirect cost which includes the engineering, taxes, etc. part of the project are evaluated as 50% of the direct costs.

The equation for the CAPEX cost is (Equation 79):

Equation 79 CAPEX equation

$$\begin{aligned} CAPEX &= direct\ cost + indirect\ cost \\ &= C_{EM} + C_{TRANSF} + C_{pen} + C_{ph} + indirect\ cost \end{aligned}$$

As said before the annual OPEX cost are defined as a fraction of the CAPEX which ranges from 2 to 2.5% for large HP and from 2 to 6% for small HP. For this case study 2% will be chosen. For the case study the OPEX is considered also as a function of the markup, since lower markup means more frequent turn on and off the plant, which increase OPEX cost (Equation 80).

Equation 80 OPEX equation

$$OPEX_{\left[\frac{€}{year}\right]} = 2\% * CAPEX_{[€]}\ for\ markup \geq 0.3$$

$$OPEX_{\left[\frac{€}{year}\right]} = 2.5\% * CAPEX_{[€]}\ for\ markup < 0.3$$

The end-of-life cost, which is fundamental of the estimation of the LCOS, can be estimated as a function of the CAPEX cost as presented in Equation 81.

Equation 81 End of life cost equation

$$End\ of\ life\ cost = \frac{0.25 * CAPEX}{(1+k)^{end\ of\ life+1}}$$

The lifespan of the PHS plant is 40 years, then it will be necessary an extraordinary maintenance or repowering of the plant. The true-life span of the plant is in the order of 80 years. In the CAPEX estimation, the costs related to the dams are not considered since they are already present. Meanwhile for the LCOS the Equation 1 will be used.

The presence of the dams reduces greatly the construction time and the investment to transform the HP in a PHS plant. The investment can be concentrated in one year.

9.3. Comparison and choice of the preferred configuration

The analysis of the case study consists mainly of the economic analysis of the three preferred configuration that gives some important parameters for the evaluation of the investment opportunity.

9.3.1 Case 1: Tirso 1's Francis turbine and a 30 MW PaT

In the first configuration a PaT is place in parallel to the Francis turbine already present. Some characteristics are reported in the following Table 22.

Table 22 Machines' characteristics

Tirso 1's Francis turbine		
Nominal power	21.5	MW
Nominal flow rate	30	m^3/s
Minimum head	54	m
Nominal head	78.2	m
Maximum head	80.4	m
Tirso 1's PaT		
Nominal power	30	MW
Nominal flow rate	39.1	m^3/s
Minimum head	54	m
Nominal head	78.2	m
Maximum head	80.4	m
Tirso 2's Kaplan turbine		
Nominal power	4.2	MW
Nominal flow rate	30	m^3/s
Minimum head	12	m
Nominal head	15.45	m
Maximum head	16	m

With the implementation of the control explained in the previous chapters, the goal is not to maximize the power production of Tirso 2, but to maximize the operation as a PHS of Tirso 1 keeping the water commitment downstream of the Pranu Antoni dam.

Firstly, it is interesting to see through some graphs how the regulation of the two reservoirs is working and then moving to the economic analysis, a markup of 0.3 is taken as a reference.

The following figures represent the curves of operation of the different project variable like the water volume, the water level, and the river flow downstream of the Pranu Antoni dam during the year.

In Figure 9.41 it is reported the water volume inside the upper and lower reservoirs.

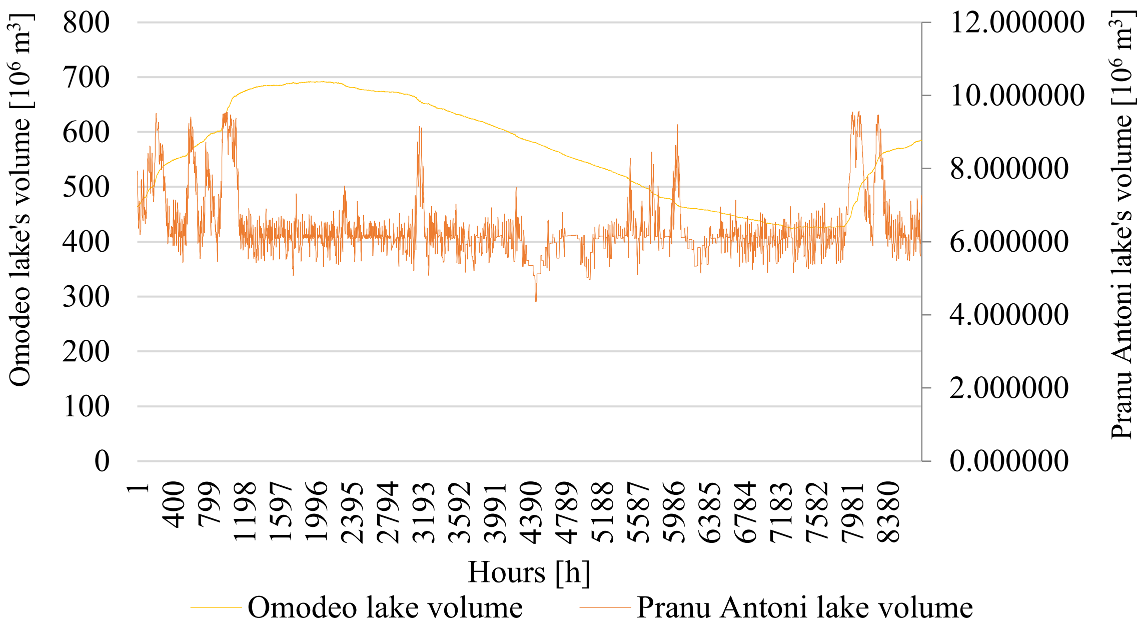


Figure 9.41 2021 reservoirs' volume with markup=0.3

The graph is obtained though the reservoir's volume balance equation curves (Equation 21 and Equation 22). It can be noted that there are a lot of oscillation in the water volume of the Pranu Antoni lake, since it has a small useful regulation volume. The operation of the different machines can be clearly seen in action. Meanwhile the Omodeo lake has a different behavior, mainly linked to the flow rate of the Tiso river and of the extraction of water for agricultural purposes mainly in summer. The water level inside the reservoir can be found through reservoir curve, as reported in Figure 9.42.

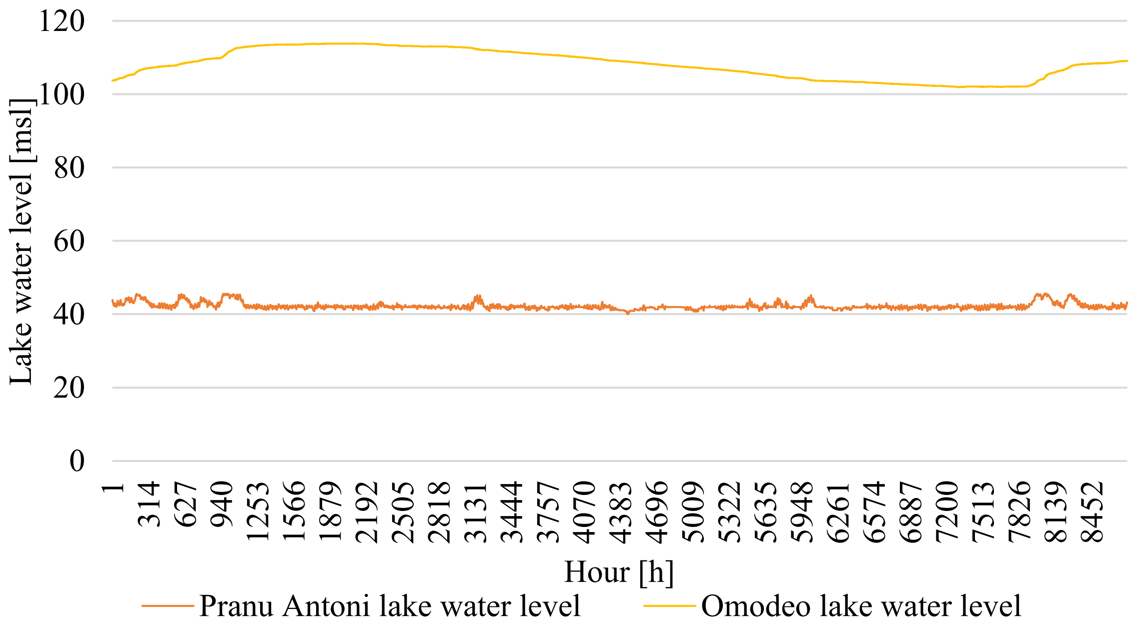


Figure 9.42 2021 reservoirs' water level with a markup=0.3

The two water level profile can be seen in more detail in the following Figure 9.43 for the lower reservoir and Figure 9.44 for the upper reservoir.

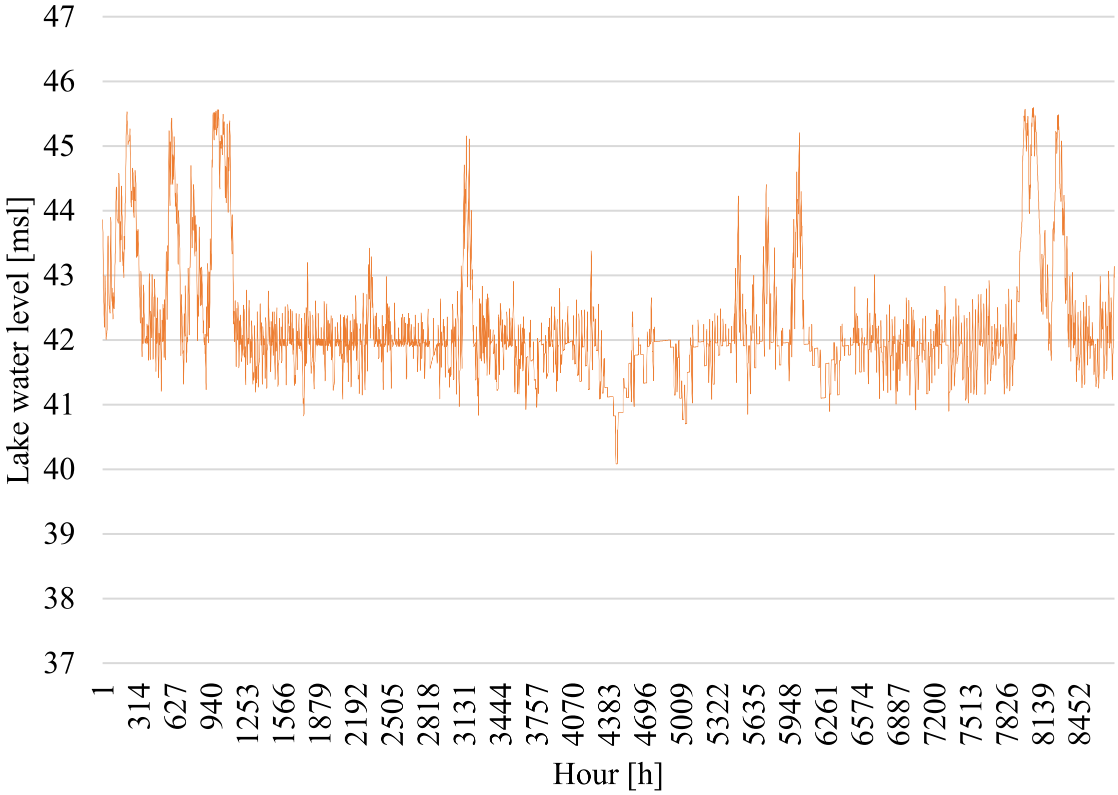


Figure 9.43 Lower reservoir's level over the year 2021

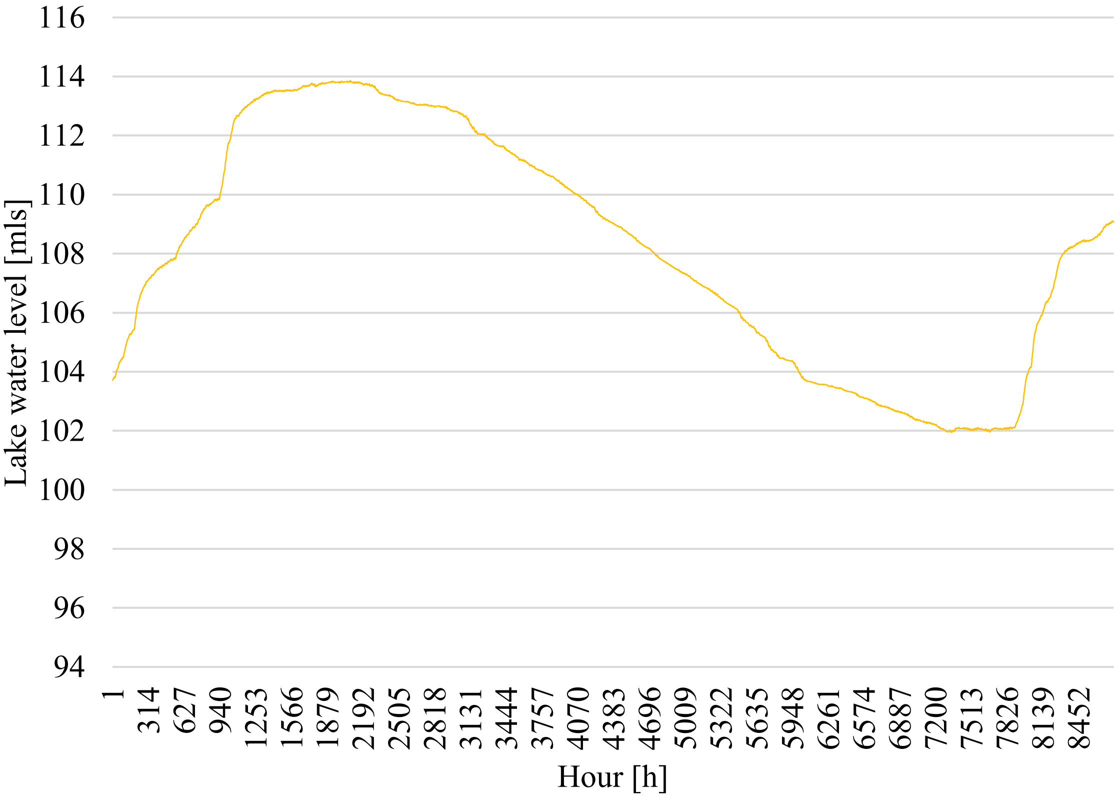


Figure 9.44 Upper reservoir's level over the year 2021

It is also interesting to evaluate the flow of the river downstream the Pranu Antoni dam with the Equation 82.

Equation 82 Downstream flow rate

$$Q_{downstream,Pranu\ Antoni} = DMV_{Pranu\ Antoni} + Q_{Tirso\ 2} + Q_{spilled,Pranu\ Antoni} \quad [m^3/s]$$

Meanwhile in the Figure 9.45 the downstream river flow profile is shown. It can be noted the flood lamination service provided by the two reservoirs, even though the Pranu Antoni dam is a limiting factor due to its low lamination volume.

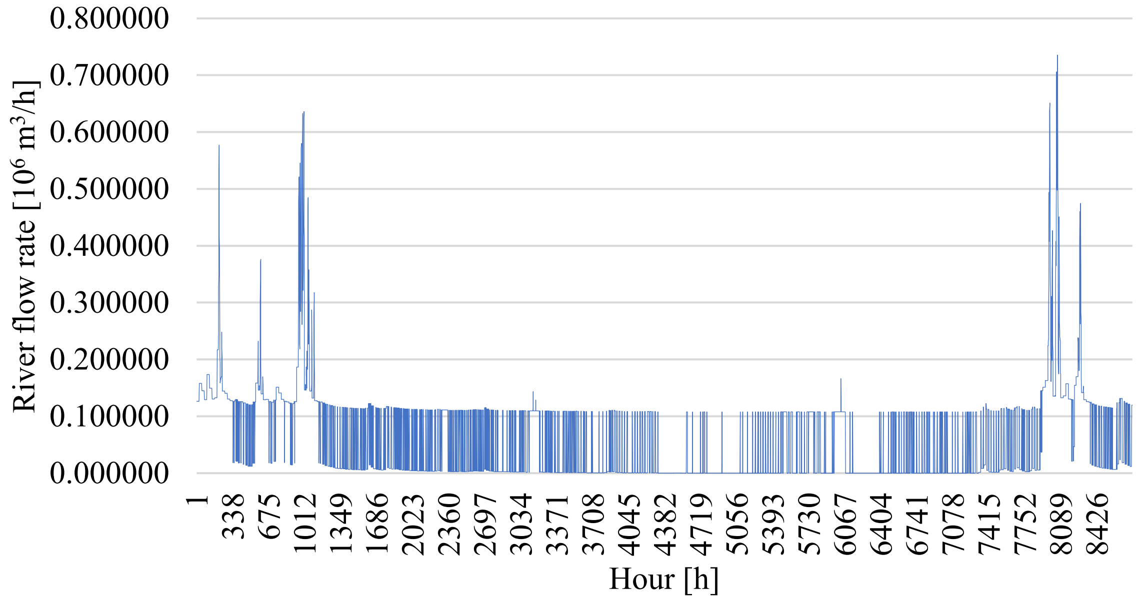


Figure 9.45 Downstream Tirso river flow in 2021

To understand better how the control works the following graph in Figure 9.46 provides the volumes in the two reservoirs for the first 48 hours of the year.

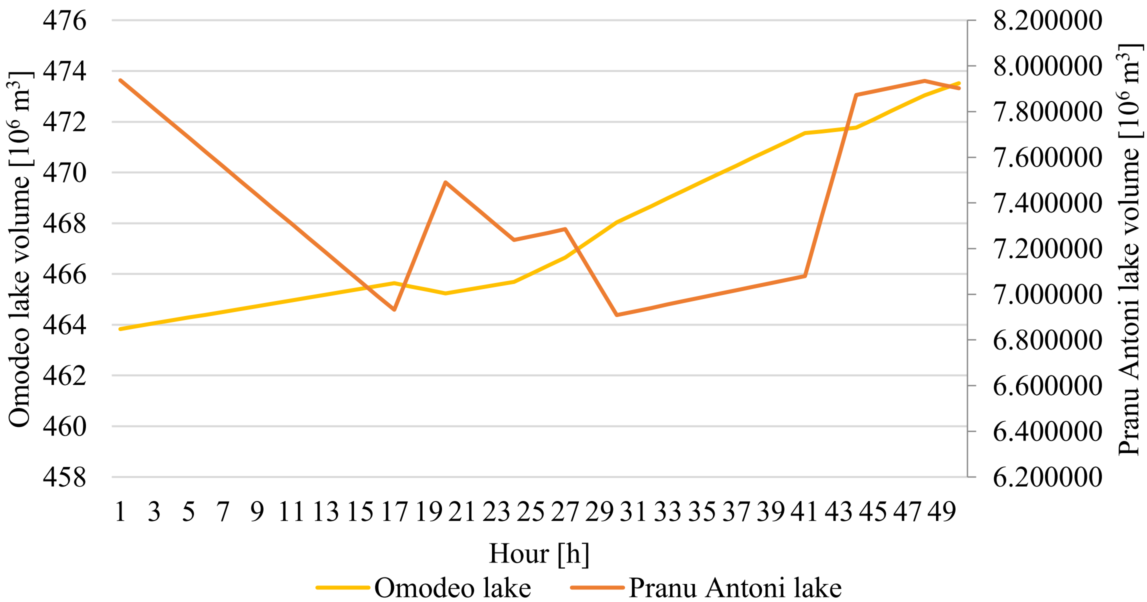


Figure 9.46 Reservoirs' volumes over the first 48 hours of the 2021

In the following graphs the profile of production and consumption are reported.

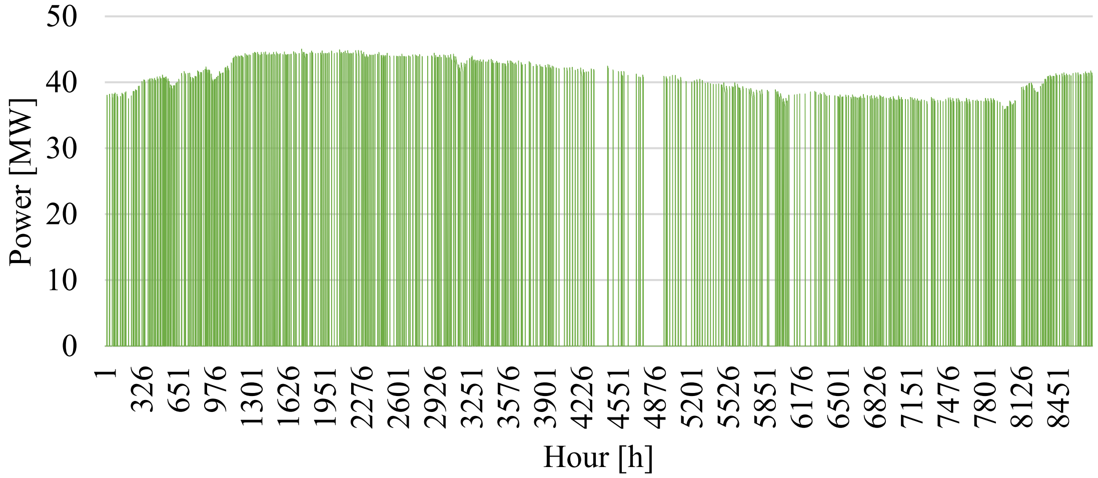


Figure 9.47 Turbine power generation from Tirso 1 (Francis and PaT)

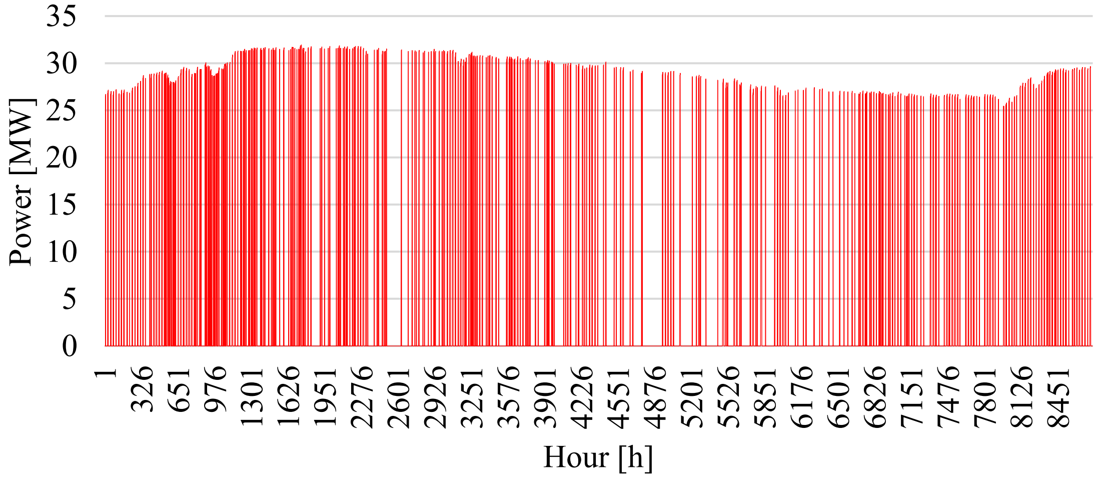


Figure 9.48 Pump power consumption from the PaT

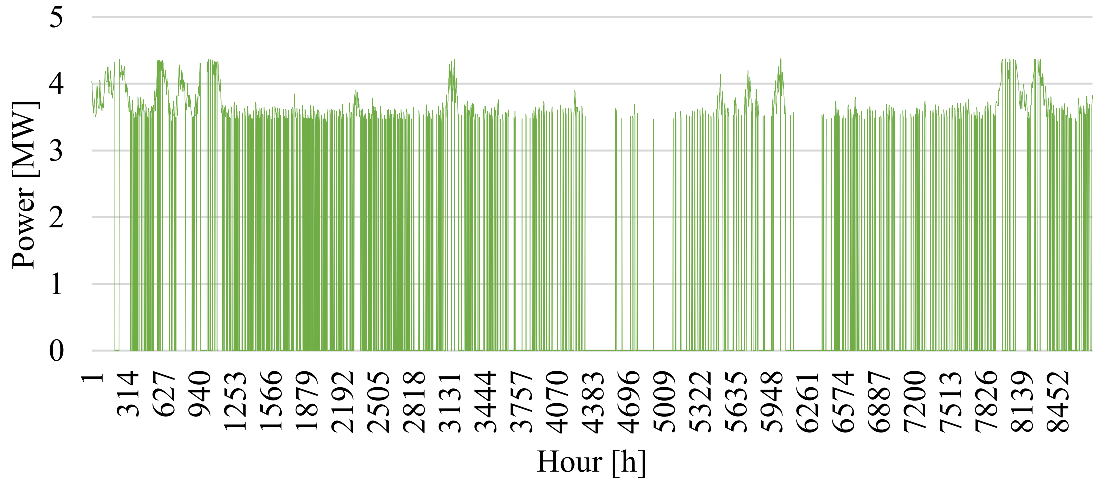


Figure 9.49 Turbine power generation from Tirso 2

Then it is also interesting to consider the maximum water level variation of the two reservoirs. It is usually not possible to have large water level variation, seasonal storage PHS may have up to 150 meters of allowable level variation. This is not possible in this case; it would also imply a much harder authorization process also known as VIA and increased local opposition to the project.

For example, in the Ledro and Molveno lakes, both located in the Provincia Autonoma di Trento, and both used as an upper reservoir of a PHS scheme, the maximum water level variation is limited due to recreational/tourist activities located on the lake's shore.

For the case with the markup equal to 0.3, Table 23 gives the maximum and lower water level for both reservoirs.

Table 23 Maximum and lower water level for case 1 with markup=0.3

MAX Pranu Antoni level	45.5956	msl	MIN Pranu Antoni level	40.0802	msl
MAX Omodeo level	113.865	msl	MIN Omodeo level	101.944	msl
MAX diff Pranu Antoni	5.51538	m	MAX diff Omodeo	11.9203	m

It can be noted that the Omodeo lake experienced higher water levels drop, mainly due to the extraction of water for agricultural purposes. For the purposes of this analysis the reservoir's water level drop are deemed to be acceptable.

At the end of the analysis of the functioning of the Tirso 1 power plant, it is interesting to look at energy consumed by the pump and produced by the turbines (Table 24).

Table 24 Energy consumption and production of Tirso 1 for markup=0.3

Energy consumed T1	39522799360	Wh	(Equation 45)
	39522.79936	MWh	
Energy produced T1	67395612383	Wh	(Equation 46), T1
	67395.61238	MWh	

The parameter that gives the utilization of the power plant is the utilization factor as defined in Equation 47. The results are:

Table 25 Utilization factor and equivalent hours for Tirso 1 with markup=0.3

Utilization factor and equivalent hour for Tirso 1					
Turbine mode	14.9389	%	1308.652	h	(Equation 48)
Pump mode	14.1222	%	1237.109	h	(Equation 49)

Meanwhile for Tirso 2 the result is shown in Table 26.

Table 26 Energy produced by Tirso 2 and equivalent hours with markup=0.3

Energy produced T2	12105417942	Wh			(Equation 46), T2
	12105.41794	MWh			
Utilization factor for Tirso 2					(Equation 47)
	32.90	%	2882.24	h	(Equation 48)

The utilization coefficient of Tirso 2 is fundamental to understand the water releases downstream. From measurements, in the year 2021 the utilization coefficient was 10.24%.

If the calculated utilization coefficient in Table 26 is higher, than the water releases will be greater than the ones currently released. This is a positive feature of the project.

Then a price is associated with the energy produced or consumed (Table 27). The revenues from the turbine generation, the cost associated with the pumping and the differential between turbine generation and pump consumption is calculated for Tirso 1 and Tirso 2.

Table 27 Tirso 1 and Tirso 2 revenues and cost for markup=0.3

Tirso 1			
Yearly sum pumping cost	3.43173361	M€	(Equation 52)
Yearly sum sale revenues	9.595831571	M€	(Equation 53)
Yearly differential sum "profit"	6.164097961	M€	(Equation 54)
Tirso 2			
Yearly sum sale revenues	1.444431798	M€	(Equation 52)

In the economic analysis, the CAPEX is estimated following the equations presented in 9.2.2 Economic analysis, from Equation 67 to Equation 81.

						average inflation EU	0.0243						
	CAPEX												
c_EM	25.3169523	M€											
C_trasf	14.3670682	€,2010/kW	431012.0454	€ 2,010	0.43101	M€,2010	0.58890149	M€,2023					
Penstoks													
D_opt	3.45576089	m		sigma_steel	310	N/mm^2	0.00031	N/m^2					
t_pipe	43.5871776	mm		ASTM A537									
	0.04358718	m		safety factor	1	/							
weight_p	395743.896	Kg											
				steel density	7800	kg/m^3							
penstock lenght	336.834983	m											
				steel cost	1.4	€/kg							
vertical distance	31.7	m	(da dati)							End of life cost		0.24788	M€
horizontal distance	335.34	m	(da maps)								fraction	0.25	
The cost of the penstock		554041.4551	€	0.671366463	M€								
Power house cost,2021		201.1508781	€/kW	6034526.342	€	6.33136765	M€						
		CAPEX	49.36288183	M€ --------->	1.64543	€/W	1645.42939	€/kW	From literature between 600 and 3000 €/kW				
		OPEX	0.987257637	M€									

Figure 9.50 Results from the cost estimate of case 1

The two main result of this analysis are the CAPEX and the OPEX costs, which are reported in Table 28.

Table 28 CAPEX, OPEX and specific cost based on the installed capacity for case 1

CAPEX	49.36	M€	1645.43	€/kW
OPEX_30 MW	0.987	M€		

It can be noted in the Table 28 above that the unitary cost for a kW is in the middle range of the prices found in the literature, which ranges from 600 to 3000 €/kW.

Then the NPV for the Tirso 1 PHS is calculated with the Equation 62, with a lifespan of 40 years.

Equation 83 NPV equation for Tirso 1

$$NPV = -CAPEX + \sum_{i=1}^{40} \frac{T1\, yearly\;\; differential\, sum}{(1+k)^n} - \sum_{i=1}^{40} \frac{OPEX}{(1+k)^n}$$

It is also interesting to evaluate the effect of the cash flow rate related to the Tirso 2 power plant on the NPV of Tirso 1. In that case the following Equation 84 will be implemented.

Equation 84 NPV equation for Tirso 1 and Tirso 2

$$NPV = -CAPEX + \sum_{i=1}^{40} \frac{T1\, yearly\;\; differential\, sum}{(1+k)^n} - \sum_{i=1}^{40} \frac{OPEX}{(1+k)^n} + \sum_{i=1}^{40} \frac{T2\, yearly\, sales\, revenue}{(1+k)^n}$$

The investment for the transformation of Tirso 1 power plant to a PHS can be concentrated in one year.

For the economic analysis an interest rate of 10% is used, and that gives as a result the following Table 29 representing the cash flows over the lifespan of the plant.

Table 29 Cumulative cash flows for case 1 with markup=0.3 and k=10%

Year	Revenues		k	0.1		
			Cumulative		Cumulative with Tirso 2	
0	-49.363	M€	-49.363	M€	-49.363	M€
1	4.706	M€	-44.657	M€	-43.344	M€
2	4.278	M€	-40.378	M€	-39.185	M€
3	3.889	M€	-36.489	M€	-35.404	M€
4	3.536	M€	-32.953	M€	-31.966	M€
5	3.214	M€	-29.739	M€	-28.842	M€
6	2.922	M€	-26.816	M€	-26.001	M€
7	2.657	M€	-24.160	M€	-23.419	M€
8	2.415	M€	-21.745	M€	-21.071	M€
9	2.195	M€	-19.549	M€	-18.937	M€
10	1.996	M€	-17.553	M€	-16.997	M€
11	1.814	M€	-15.739	M€	-15.233	M€
12	1.650	M€	-14.089	M€	-13.629	M€
13	1.500	M€	-12.590	M€	-12.172	M€
14	1.363	M€	-11.227	M€	-10.846	M€
15	1.239	M€	-9.987	M€	-9.642	M€
16	1.127	M€	-8.861	M€	-8.546	M€
17	1.024	M€	-7.837	M€	-7.551	M€
18	0.931	M€	-6.905	M€	-6.646	M€
19	0.846	M€	-6.059	M€	-5.823	M€
20	0.770	M€	-5.290	M€	-5.075	M€

21	0.700	M€	-4.590	M€	-4.395	M€
22	0.636	M€	-3.954	M€	-3.777	M€
23	0.578	M€	-3.376	M€	-3.215	M€
24	0.526	M€	-2.850	M€	-2.704	M€
25	0.478	M€	-2.372	M€	-2.239	M€
26	0.434	M€	-1.938	M€	-1.817	M€
27	0.395	M€	-1.543	M€	-1.433	M€
28	0.359	M€	-1.184	M€	-1.084	M€
29	0.326	M€	-0.858	M€	-0.767	M€
30	0.297	M€	-0.561	M€	-0.478	M€
31	0.270	M€	-0.292	M€	-0.216	M€
32	0.245	M€	-0.046	M€	0.022	M€
33	0.223	M€	0.177	M€	0.239	M€
34	0.203	M€	0.379	M€	0.436	M€
35	0.184	M€	0.563	M€	0.615	M€
36	0.167	M€	0.731	M€	0.778	M€
37	0.152	M€	0.883	M€	0.926	M€
38	0.138	M€	1.022	M€	1.060	M€
39	0.126	M€	1.147	M€	1.182	M€
40	0.114	M€	1.262	M€	1.294	M€

A graphical representation is more useful to understand the cumulative cash flows and the payback time of the investment (Figure 9.51).

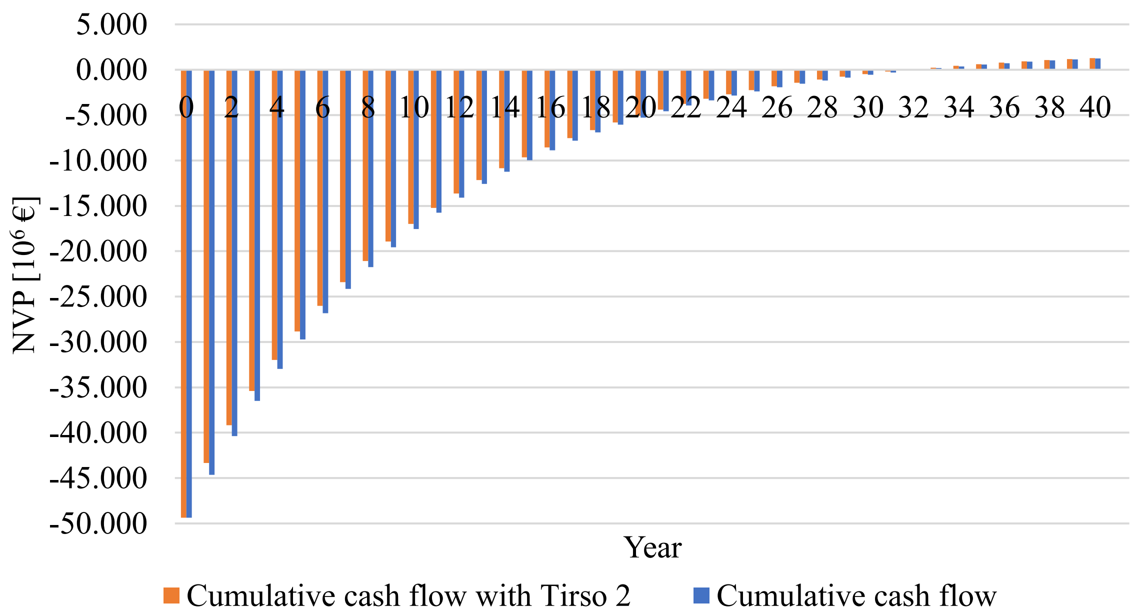


Figure 9.51 Cumulative cash flows for Tirso 1 PHS and Tirso 2 PH (markup=0.3 and k=10%)

As it can be seen from the Figure 9.51 above, the payback time will be reached in 33 years considering only the PaT and the Francis in Tirso 1, and in 32 years also considering the revenues of Tirso 2 which are considered since its production is dependent from Tirso 1.

In this configuration the investment is economically viable.

The last step of the economic analysis is the calculation of the economic parameters (Figure 9.52), like the DCF (Equation 57), NPV (Equation 62), IP (Equation 64) and LCOS (Equation 1).

Discounted cash flow	50.6245841	M€				
ROI - Return On Investment	0.09533922		9.533921647	%		
NPV - Net Present Value	1.26170226	M€	OK			
IP - profitability index	0.02555974					
LCOS levelized cost of storage	0.00015749	€/Wh	0.157488625	€/kWh	157.489	€/MWh

Figure 9.52 Economic parameters for markup=0.3

The IRR, defined in Equation 65, for the different markup is reported in Table 30.

Table 30 Markup vs IRR for case 1

Markup	IRR [%]
0.1	13.524
0.2	12.7
0.3	10.27
0.4	6.564
0.5	3.595
0.6	0.363

These data can be plotted in Figure 9.53, where the linear trend is present, similar to the trend of the NPV (Figure 9.54).

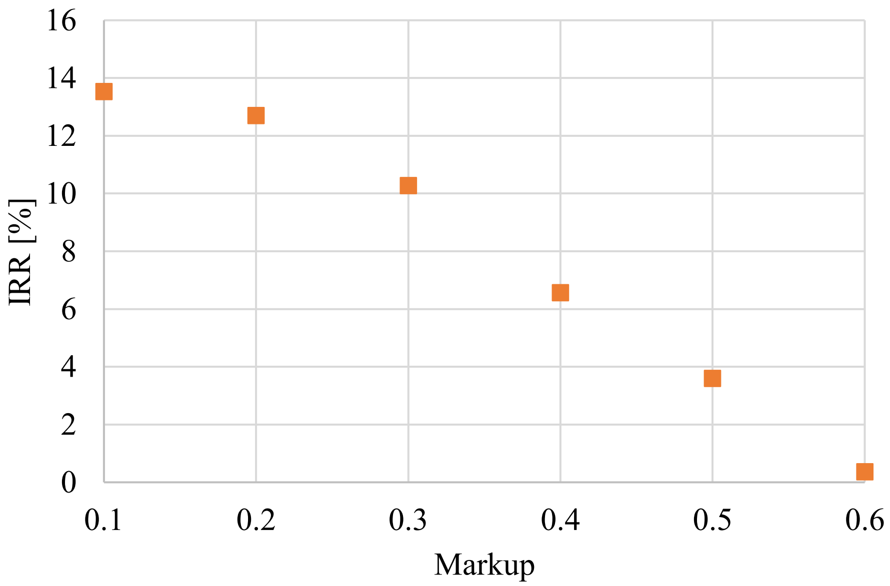


Figure 9.53 Markup vs IRR plot for case 1

Given that hydropower is very capital-intensive, has low O&M costs and no fuel costs, the LCOS is very sensitive to investment costs (CAPEX) and interest rates but less sensitive to the lifetime [5], given the lifetime range typical for hydropower (Table 31).

Table 31 LCOS for PHS with markup=0.3

Interest rate	LCOS [€/MWh]
3%	104.946
5%	118.416
10%	157.489

As stated in the previous chapters, one of the first hypotheses made to understand when the PHS plant was working is the markup, defined in Equation 4. Keeping unchanged all other parameters it is interesting to change the markup and plotting the NPV and the PBT. Two of the most important parameters when considering the investment.

Table 32 Markup vs the NPV and the PBT for case 1

Markup	NPV [millions of €]	PBT [years]
0.1	16.32913565	14
0.2	12.44867422	16
0.3	1.261702262	33
0.4	-14.97289475	
0.5	-26.42325082	
0.6	-36.37494892	

The correlation between markup vs NPV, and markup vs PBT can be better seen in Figure 9.54. The clear trend that can be seen from the figure is that the NPV strongly decreases with increasing markups, meanwhile the PBT increases exponentially with increasing markups.

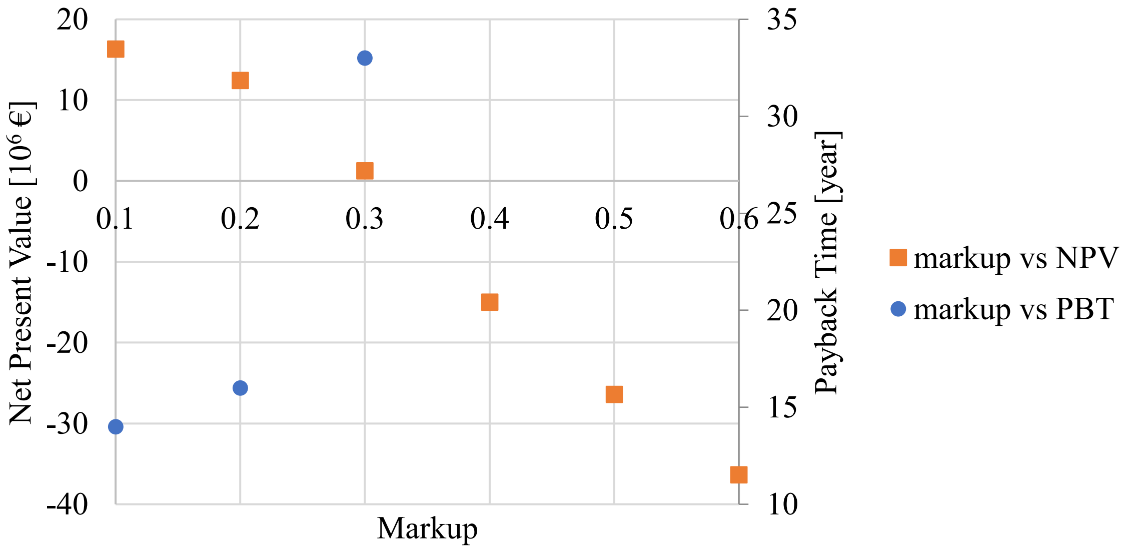


Figure 9.54 Markup vs NPV and Markup vs Payback Time graph with k=10%

Meanwhile the LCOS is not as sensitive to the lower markups as for the interest rate, but for markup higher than 40% the LCOS becomes very sensitive to the interest rate and the markup, as it can be noted in Table 33, Table 34 and Table 35.

Table 33 Sensitivity of the LCOS to the markup with k=10%

Markup	LCOS [€/MWh]
10%	129.752
20%	141.349
30%	157.489
40%	195.625
50%	247.18
60%	336.252

Table 34 Sensitivity of the LCOS to the markup with k=5%

Markup	LCOS [€/MWh]
10%	108.542
20%	113.05
30%	118.416
40%	139.483
50%	166.818
60%	218.949

Table 35 Sensitivity of the LCOS to the markup with k=3%

Markup	LCOS [€/MWh]
10%	101.23
20%	103.294
30%	104.946
40%	120.128
50%	139.114
60%	178.509

From the graph in Figure 9.55 representing the markup vs LCOS, it can be shown that the LCOS reaches its minimum at markups between 0.1 and 0.3 and then it increases, particularly for higher markup and higher interest rates. For lower interest rates the price remains relatively constant. This shows that for low interest rates the LCOS is less influenced by the markup coefficient.

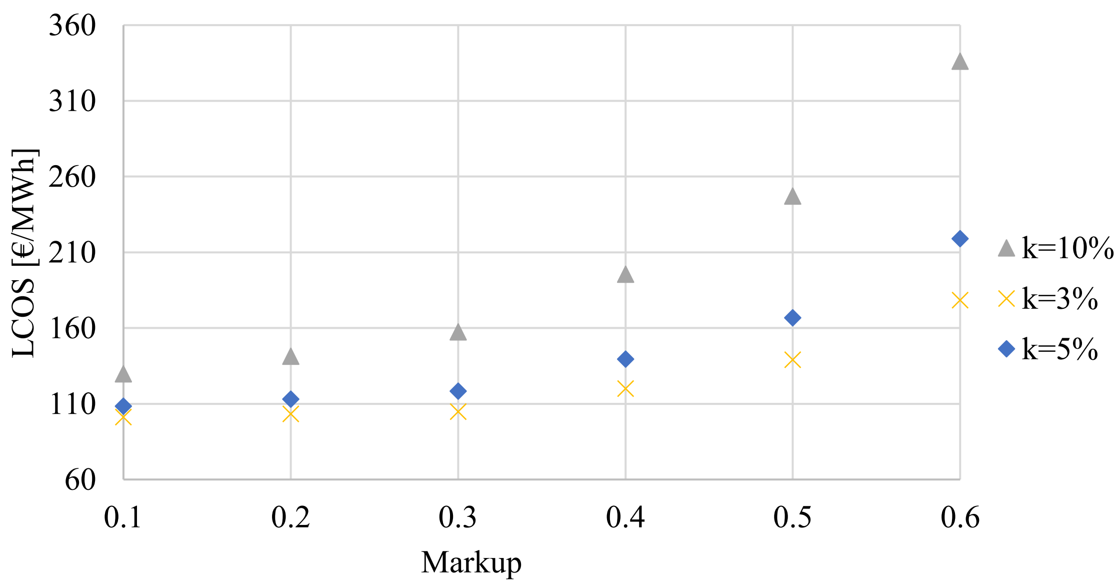


Figure 9.55 Markup vs LCOS for different interest rate k

From literature it is known that the LCOE varies between 0.02 and 0.19 $/kWh for large hydropower and between 0.02 to 0.10 $/kWh for small hydropower.

The following Table 36, Table 37 and Table 38 represent the NVP sensitivity analysis.

Table 36 Sensitivity of the NPV to the markup with k=10%

Markup	NPV [10^6 €]
10%	16.32913565
20%	12.44867422
30%	1.261702262
40%	-14.97289475
50%	-26.42325082
60%	-36.37494892

Table 37 Sensitivity of the NPV to the markup with k=5%

Markup	NPV [10^6 €]]
10%	65.90546406
20%	59.09650328
30%	39.46696834
40%	10.98047614
50%	-9.111213163
60%	-26.5732401

Table 38 Sensitivity of the NPV to the markup with k=3%

Markup	NPV [10^6 €]
10%	105.91354
20%	96.74128151
30%	70.29860182
40%	31.9248354
50%	4.859593868
60%	-18.66326525

From the graph in the Figure 9.56, it can be notated that the NPV increases for fixed markup and lower interest rate, meanwhile it decreases linearly with fixed interest rate and increasing markup.

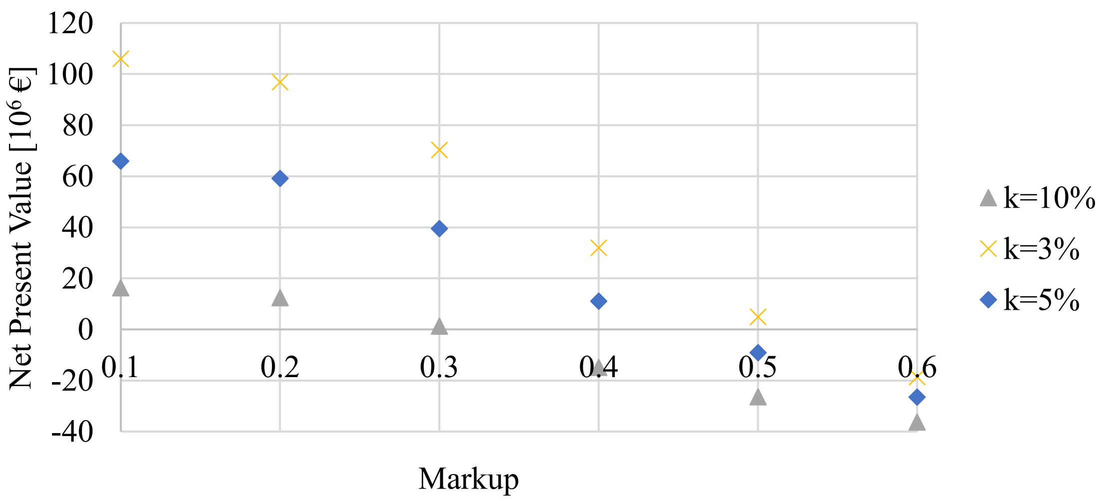


Figure 9.56 Markup vs NPV for different interest rate k

The plot of the net profit from the turbine and pump configuration can be seen in Figure 9.57 (and reported in Table 39), which is similar to Figure 9.53, which represent the IRR.

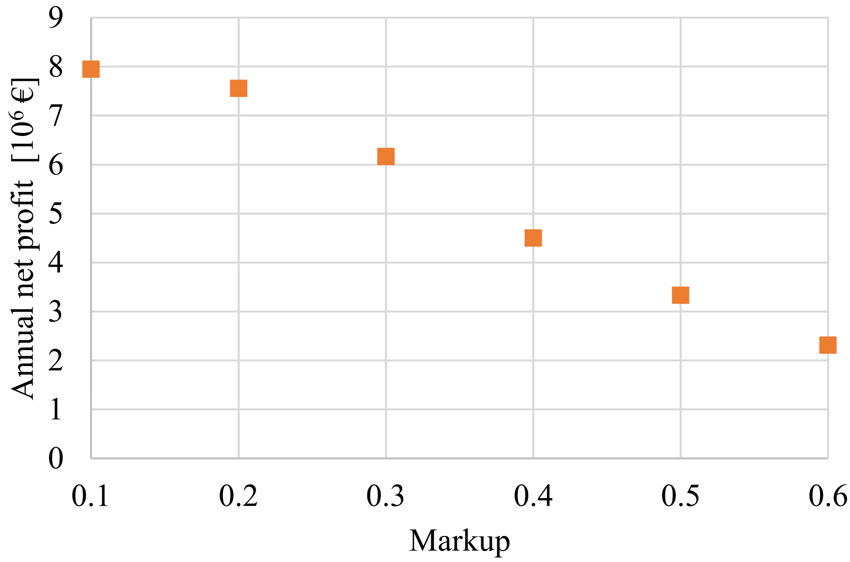


Figure 9.57 Mark up vs Annual net profit

Table 39 Annual net profit with changing markup

Markup	Annual net profit Tirso 1	
0.1	7.951	M€
0.2	7.554	M€
0.3	6.164	M€
0.4	4.503	M€
0.5	3.333	M€
0.6	2.315	M€

A linear trend can be seen for markup greater than 0.2, but the increase in profitability decreases since the machines are working more, but the differential between the two prices does not present a large new net profit since the prince differential between the sale and the buying price is between 10% and 20%. This can also be seen in the markup vs NPV (Figure 9.56) particularly for high interest rate.

In fact, it is suggested to operate the power plant with a markup between 0.2 and 0.3.

This is done to limit the times the machines must be turn on and off, limiting the fatigue, and to recover the investment in an “industry sound” time.

With lower markup, the utilization coefficient of both the power plant will increase, increasing the NPV and reducing the PBT. This makes the investment more attractive since it is reported in [5] that for PHS, and more in general PH project, the optimal PBT is usually in the range of 10 to 15 years. But lower markup means that the PHS is working in a price range where there is not a large difference between the selling and buying prices. This means a smaller “profit”. This is why the LCOS stops decreasing for small markups (Figure 9.55).

As lower markup also means a higher opportunity for the pump and/or turbine to work, but that also means more frequent fluctuations in the water level of the reservoirs. This is particularly critical and visible in the Pranu Antoni lake, due to its small regulation volume compared to the Omodeo lake. More oscillation of the water level may cause hydrologic stress on the lake's shore. A geotechnical analysis may be needed to avoid landslides into the lake. So, it does not make sense to work for example with markup equal to 0.1.

It is also interesting to notice the effect of the markup on the functioning of Tirso 2, which is placed downstream of the Pranu Antoni dam. From the Figure 9.58 reported below (Table 40) it can be noted that the decrease in markup increases the possibility for Tirso 2 to operate, since the operation of Tirso 2 depends on the water availability in the Pranu Antoni lake, and that is linked to the exchange of water between Pranu Antoni lake and the Omodeo lake due to the very large useful regulation volume of the Omodeo lake itself.

Table 40 Markup vs Tirso revenues

Markup	Tirso 2 revenues	
0.1	1.87	M€
0.2	1.68	M€
0.3	1.44	M€
0.4	1.19	M€
0.5	1.063	M€
0.6	0.934	M€

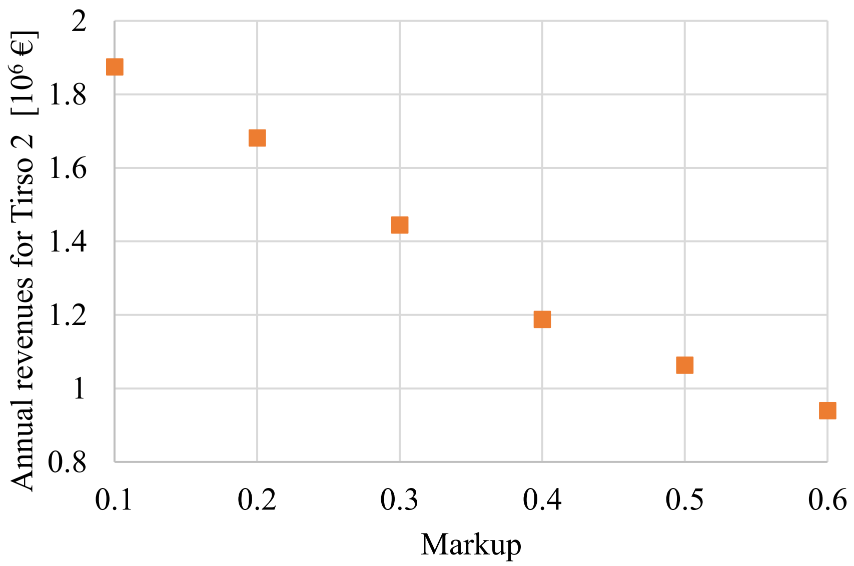


Figure 9.58 Tirso 2 revenues with changing markup

The next step is to evaluate the different operation for the various markups, to see which is the most competitive from the economic point of view, keeping the interest rate k at 10%. This can be noticed in the following cases.

- 30 MW PaT with Francis turbine – markup=0.1

When operating at a 0.1 markup there is an increase in the water level oscillation and but also in the equivalent hours. In the ideal case, where no limits are imposed on the reservoir levels, there will be a very large volumes movement between the two reservoirs, as it can be seen in Table 41.

Table 41 Water's volumes movements for markup=0.1

Ideal case		
V tot turb	807.05	10^6 m^3
V tot pomp	454.304	10^6 m^3
Diff T-P	352.745	10^6 m^3

This may be not optimal, since the first goal of the Omodeo reservoir is to storage water for agricultural usages. 2021 was a wet year and that clearly helps the operation and economic feasibility of this site.

In Figure 9.59 it is reported the Pranu Antoni lake's water level during the year 2021.

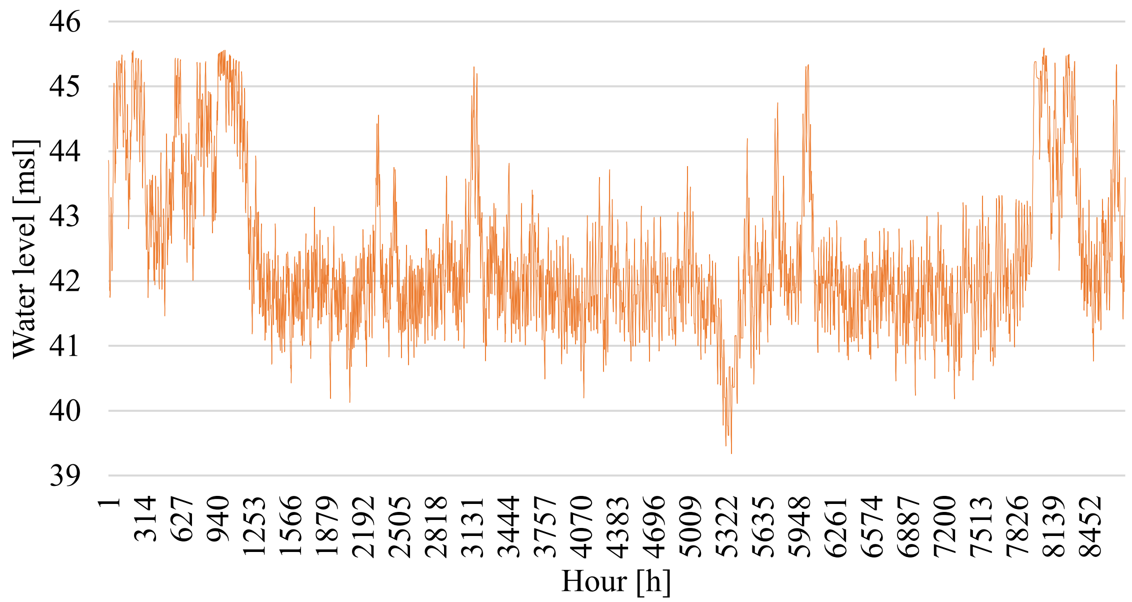


Figure 9.59 Pranu Antoni lake's water level oscillation in 2021 for markup=0.1

In Figure 9.60 it is reported the Pranu Antoni lake volume for the year 2021.

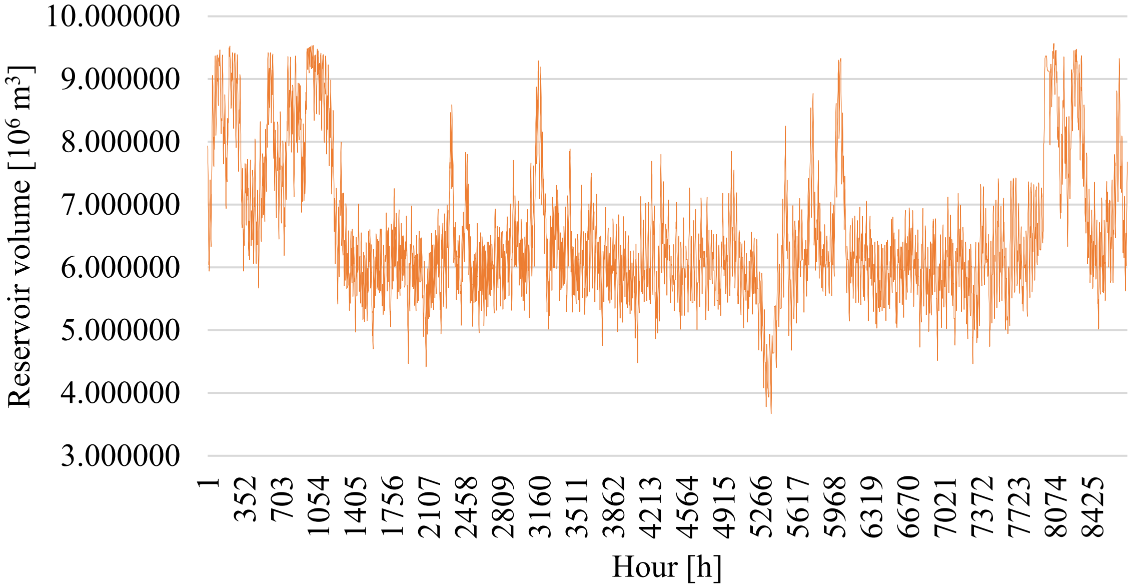


Figure 9.60 Pranu Antoni lake's volume oscillation over 2021 for markup=0.1

It is interesting to see the graphs comparing the two reservoirs. Figure 9.61 represent the water level oscillations on the two reservoirs during 2021.

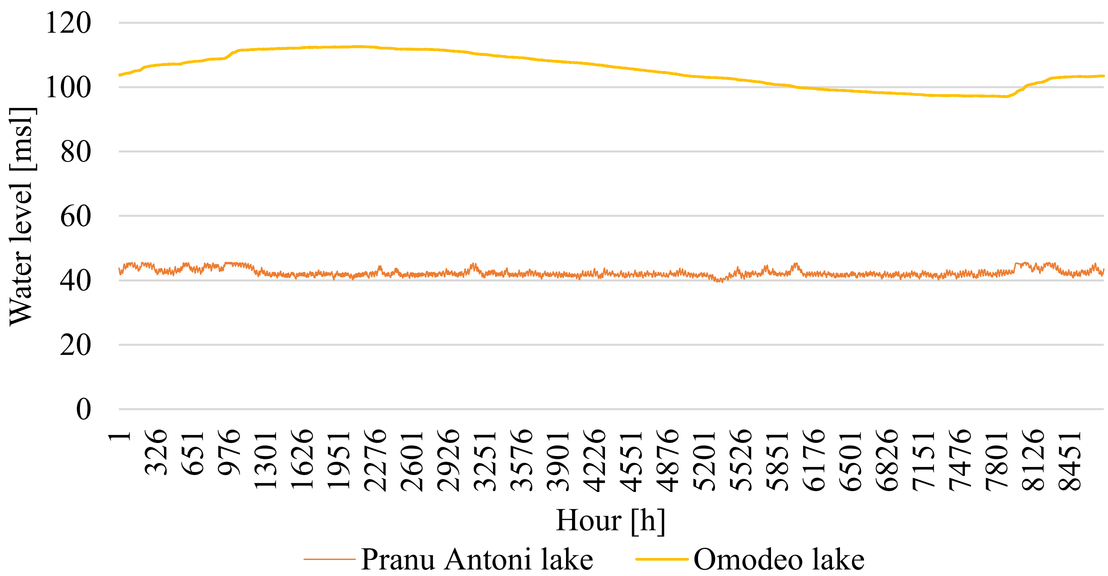


Figure 9.61 Water level oscillations in the upper and lower reservoirs over 2021 for markup=0.1

Meanwhile the next Figure 9.62 represents the comparison between the two reservoirs' water volume during 2021, meanwhile in Figure 9.63 are reported the first 48 hours of the year.

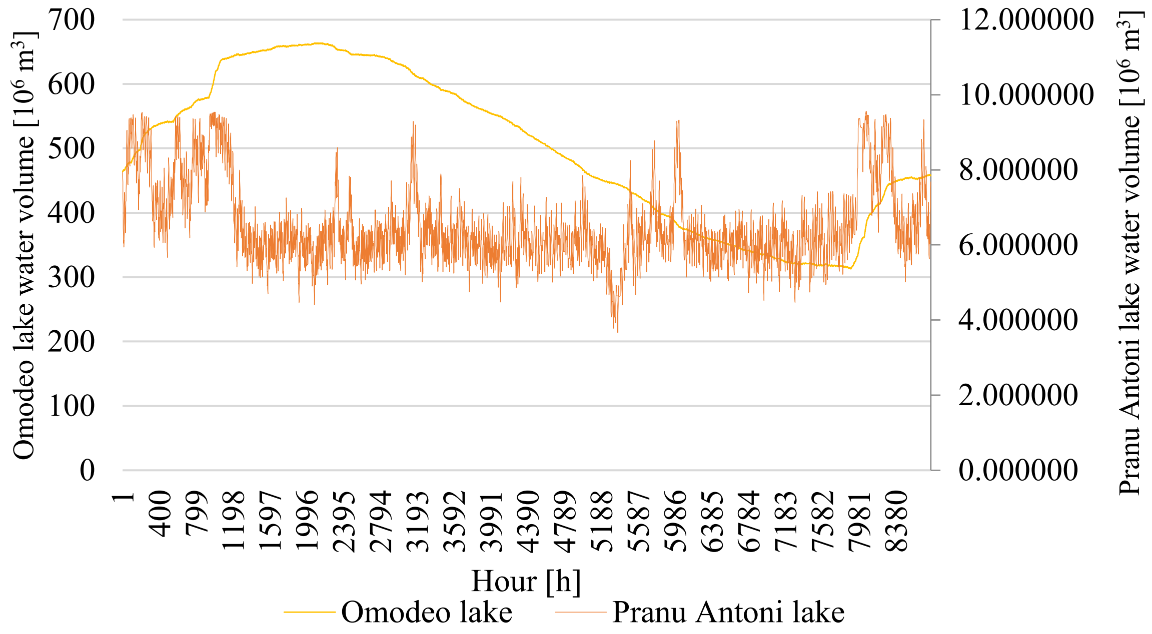


Figure 9.62 Reservoirs volume oscillation over 2021 with markup=0.1

It can be noted that at the end of the year the water volume inside the Omodeo lake is lower compared to the start of the year. This may pose a challenge since it can become an issue if the following year is dry, as it was the case in 2022.

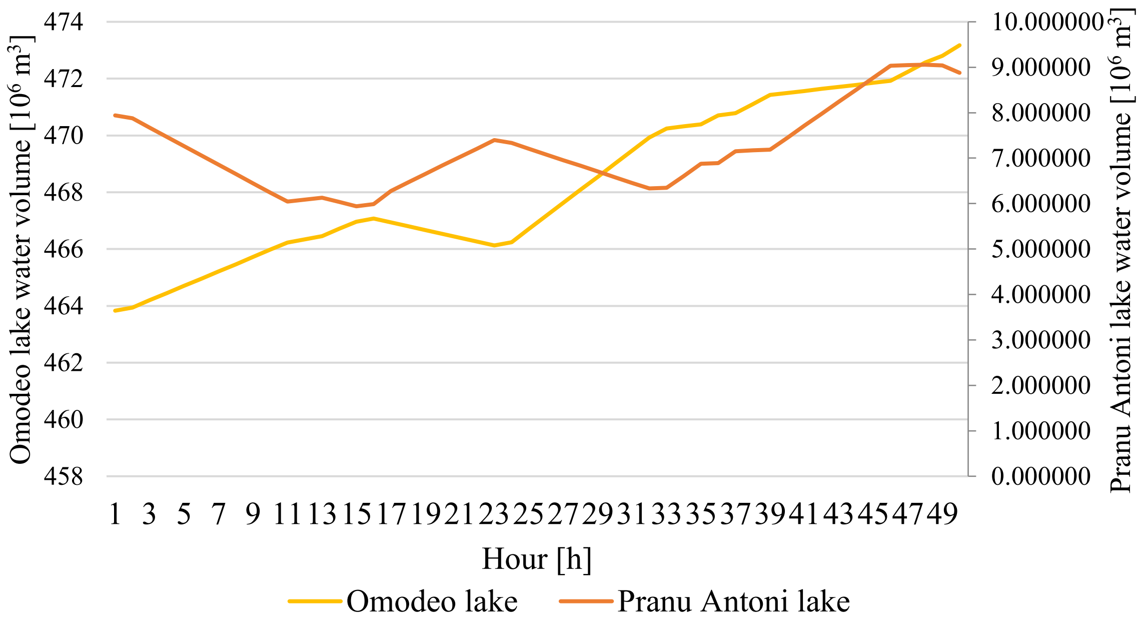


Figure 9.63 Water volume movement in the first 48 hours of the year

At the end of this analysis, the maximum and minimum water levels for this configuration are reported in Table 42.

Table 42 Maximum and minimum water levels with markup=0.1

MAX Pranu Antoni level	45.5907	msl	MIN Pranu Antoni level	39.3364	msl
MAX Omodeo level	112.589	msl	MIN Omodeo level	97.0135	msl
MAX diff Pranu Antoni	6.25433	m	MAX diff Omodeo	15.5754	m

As for the case with the markup equal to 0.3, the energy consumption and production is evaluated and reported in Table 43 together with the utilization coefficient and the energy production in Tirso 2.

Table 43 Energy production and consumption for Tirso 1 and Tirso 2 with markup=0.1

Energy consumed T1	88899120457	Wh		
	88899.12	MWh		
Energy produced T1	$1.24156*10^{11}$	Wh		
	124155.76	MWh		
Utilization factor and equivalent hours				
Turbine mode	27.52044963	%	2410.791	h
Pump mode	31.97800899	%	2801.274	h
Energy produced T2	15339733847	Wh		
	15339.73385	MWh		
Utilization factor and equivalent hours				
	41.69312309	%	3652.318	h

In the economic analysis the cash flow must be evaluated, they are reported in Table 44.

Table 44 Revenues and cost of the energy produced and consumed in Tirso 1 and Tirso 2 with markup=0.1

Tirso 1				
Yearly sum pumping cost	8680374.2	€	8.68037	M€
Yearly sum sale revenues	16632073	€	16.6321	M€
Yearly differential sum "profit"	7951699.3	€	7.9517	M€
Tirso 2				
Yearly sum sale revenues	1874731.9	€	1.87473	M€

The economic analysis returns the following results reported in Figure 9.64.

Discounted cash flow	65.6920175	M€					
ROI - Return On Investment	0.1237151		12.37150998	%			
NPV - Net Present Value	16.3291356	M€	OK				
IP - profitability index	0.33079786						
LCOS levelized cost of storage	0.00012975	€/Wh	0.129752319	€/kWh		129.752	€/MWh

Figure 9.64 Economic parameters for markup=0.1 and k=10%

In Figure 9.65 the cumulative cash flow movement for this operating mode is reported.

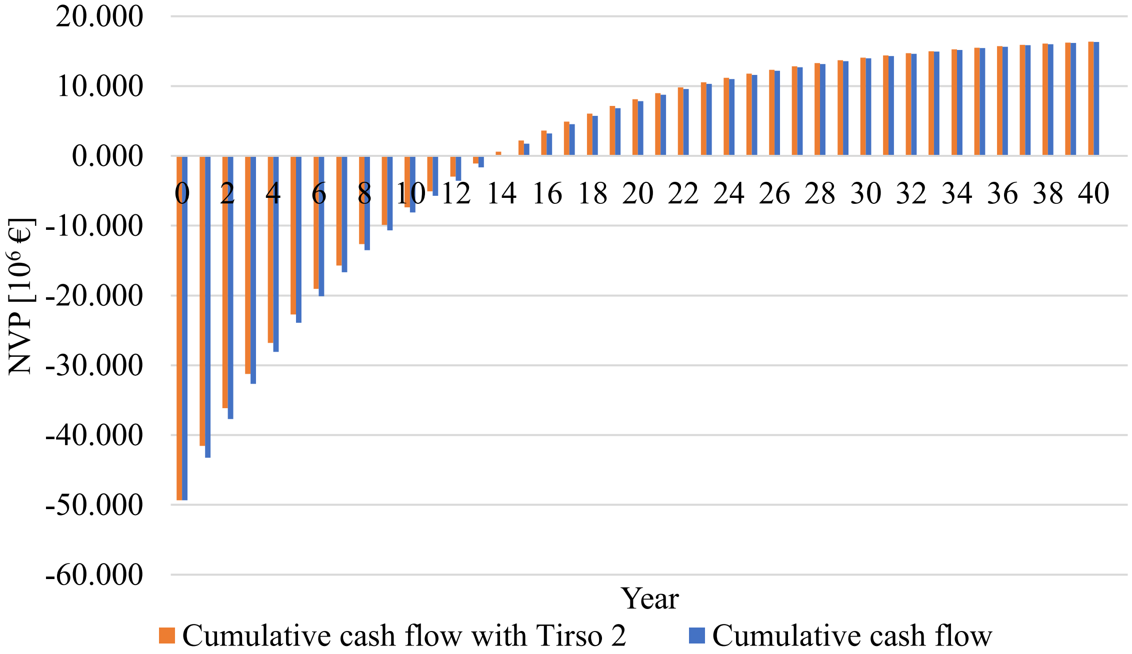


Figure 9.65 Cumulative cash flow with k=10% and markup=0.1

In this configuration the payback time is 14 years.

- 30 MW PaT with Francis turbine – markup=0.2

At first it can be noticed a smaller movement of water between the two reservoirs (Table 45).

Table 45 Water's volumes movements for markup=0.2

Ideal case		
V tot turb	578.916	10^6 m^3
V tot pomp	302.26	10^6 m^3
Diff T-P	276.657	10^6 m^3

The operation with a markup equal to 0.2 results in the following operation curve (Figure 9.66, Figure 9.67), where it can be noted that there are less oscillations compared to 0.1.

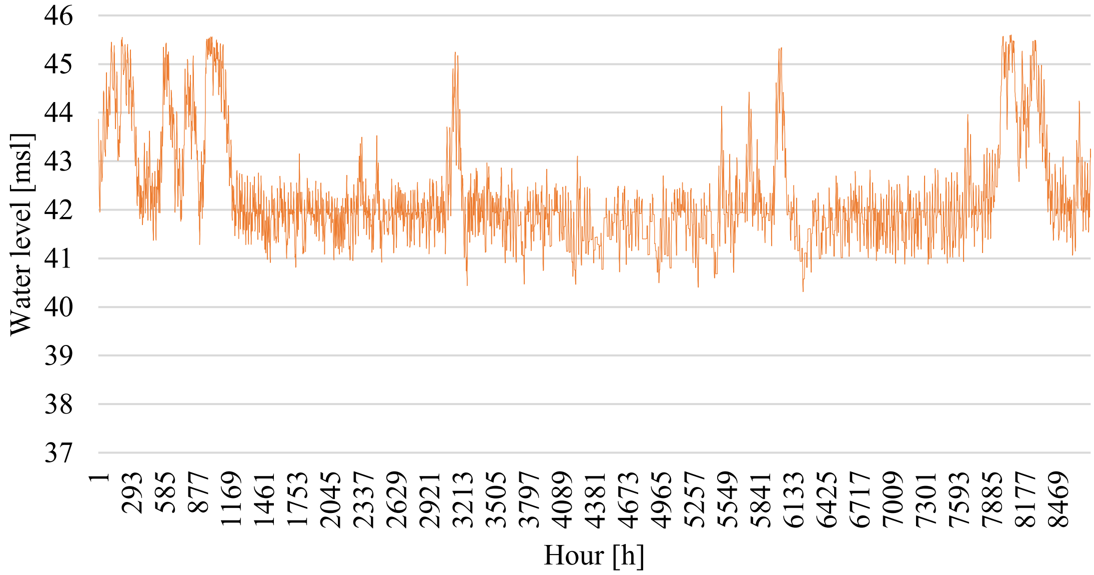


Figure 9.66 Water level in operation for Pranu Antoni lake in 2021 with markup=0.2

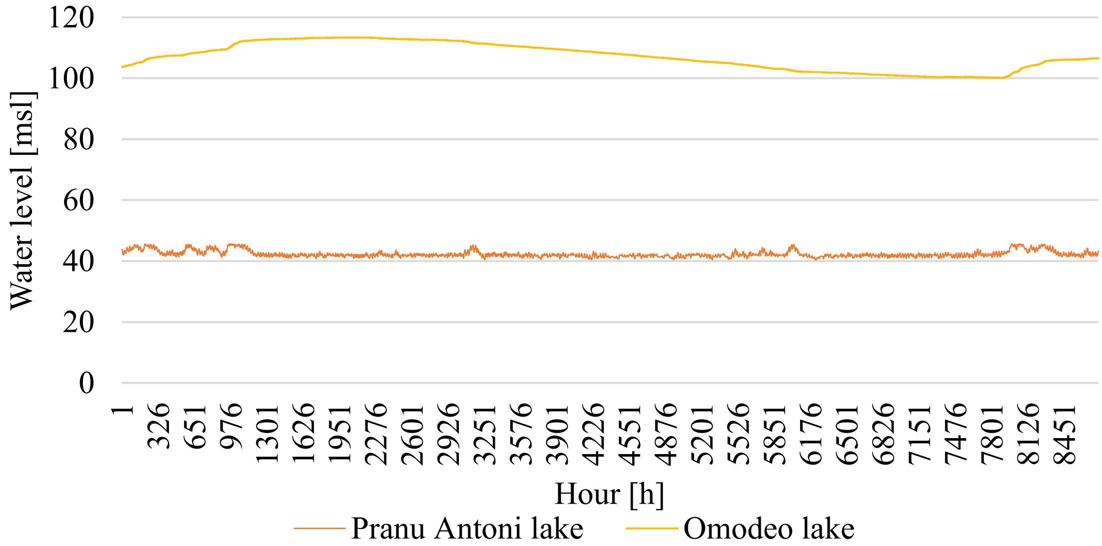


Figure 9.67 Water level oscillation in the reservoirs during 2021 with markup=0.2

The reservoirs volume oscillation is shown in Figure 9.68.

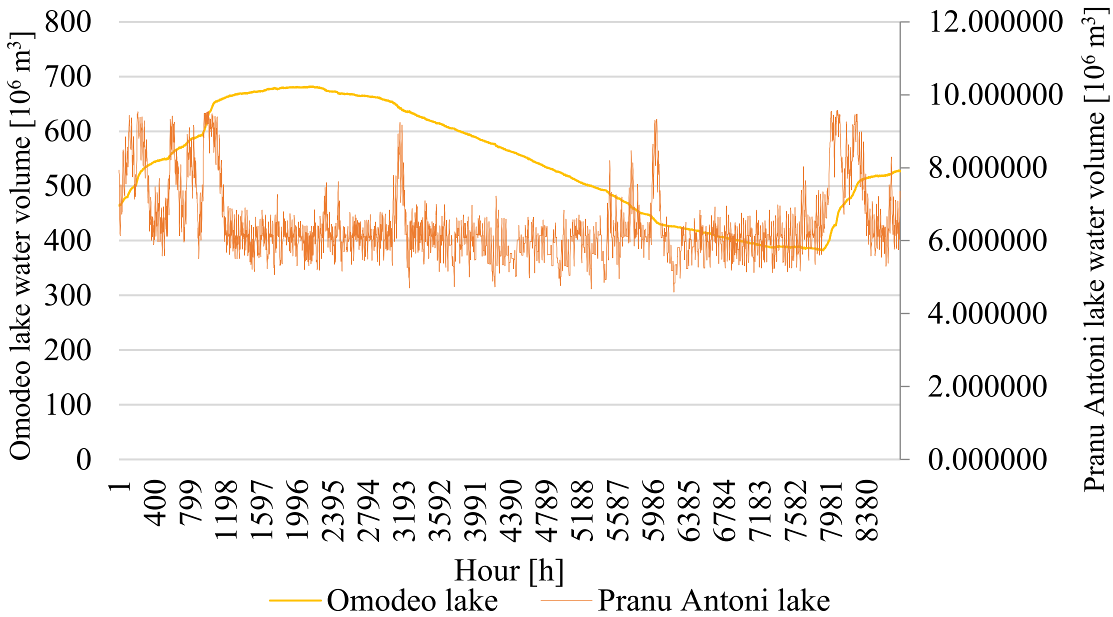


Figure 9.68 Reservoirs volume oscillation over 2021 with markup=0.2

The maximum and minimum water level are reported in Table 46.

Table 46 Maximum and minimum water levels with markup=0.2

MAX Pranu Antoni level	45.5989	msl	MIN Pranu Antoni level	40.3124	msl
MAX Omodeo level	113.391	msl	MIN Omodeo level	100.084	msl
MAX diff Pranu Antoni	5.28642	m	MAX diff Omodeo	13.3065	m

The energy consumed and produced is reported in Table 47 together with the utilization factor.

Table 47 Energy production and consumption for Tirso 1 and Tirso 2 with markup=0.2

Energy consumed T1	61227470184	Wh		
	61227.47018	MWh		
Energy produced T1	93053742089	Wh		
	93053.74209	MWh		
Utilization factor and equivalent hour				
Turbine mode	20.62635592	%	1806.869	h
Pump mode	22.02478334	%	1929.371	h
Energy produced T2	13577498712	Wh		
	13577.49871	MWh		
Utilization factor and equivalent hour				
	36.90339941	%	3232.738	h

The revenues and cost associated with the turbine and the pump are reported in Table 48.

Table 48 Revenues and cost of the energy produced and consumed in Tirso 1 and Tirso 2 with markup=0.2

Tirso 1				
Yearly sum pumping cost	5723885.1	€	5.72389	M€
Yearly sum sale revenues	13278771	€	13.2788	M€
Yearly differential sum "profit"	7554885.6	€	7.55489	M€
Tirso 2				
Yearly sum sale revenues	1681515.7	€	1.68152	M€

The results of the economic analysis are reported in Figure 9.69 and Figure 9.70.

Discounted cash flow	61.8115561	M€				
ROI - Return On Investment	0.11640718		11.64071849	%		
NPV - Net Present Value	12.4486742	M€	OK			
IP - profitability index	0.25218694					
LCOS levelized cost of storage	0.00014135	€/Wh	0.141348515	€/kWh	141.349	€/MWh

Figure 9.69 Economic parameters for markup=0.2 and k=10%

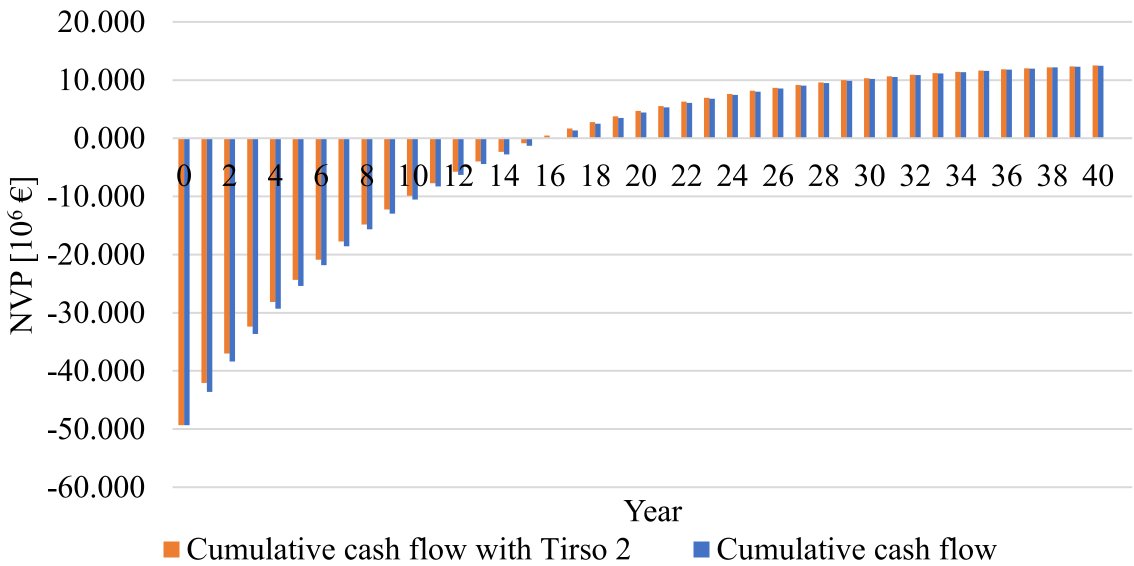


Figure 9.70 Cumulative cash flow with k=10% and markup=0.2

With this operating mode the payback time is 16 years.

- 30 MW PaT with Francis turbine – markup=0.4

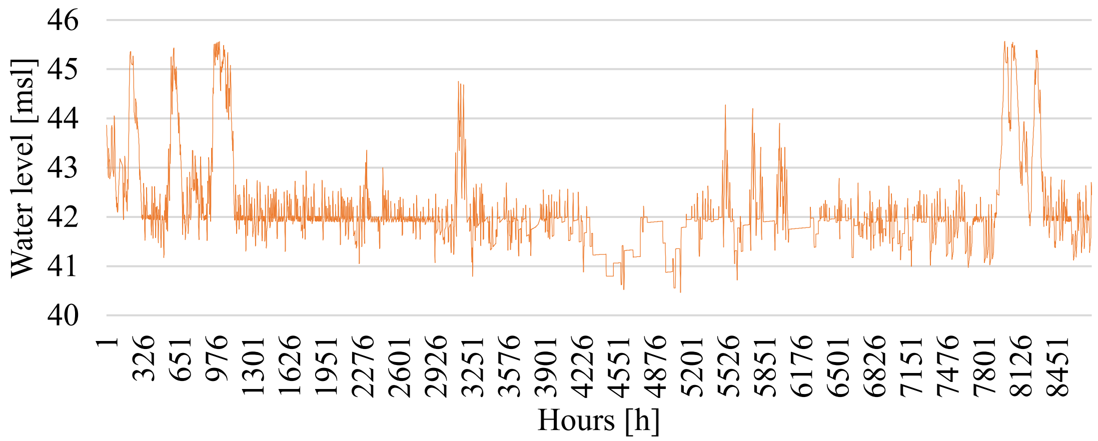


Figure 9.71 Pranu Antoni lake level in the operating mode with markup=0.4 for the year 2021

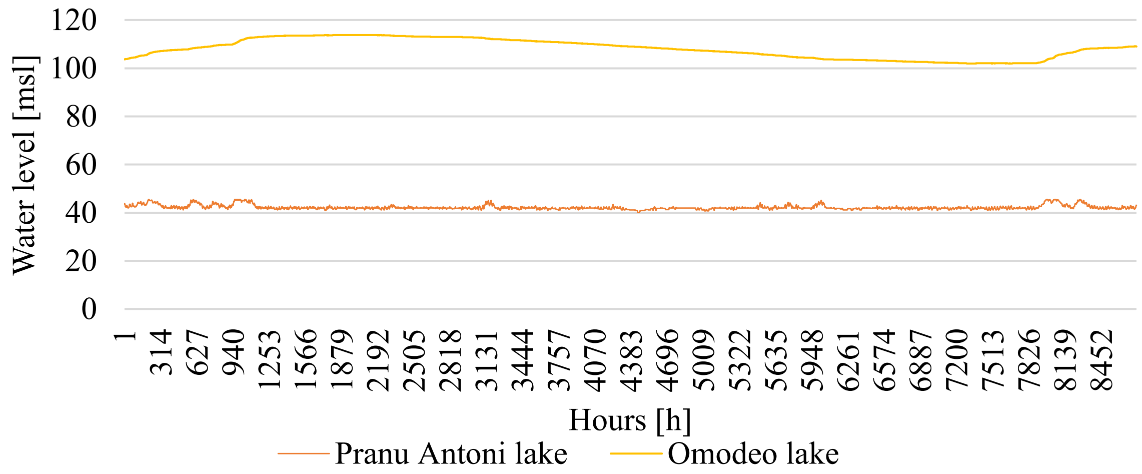


Figure 9.72 Reservoirs level in the operating mode with mark-up=0.4 for 2021

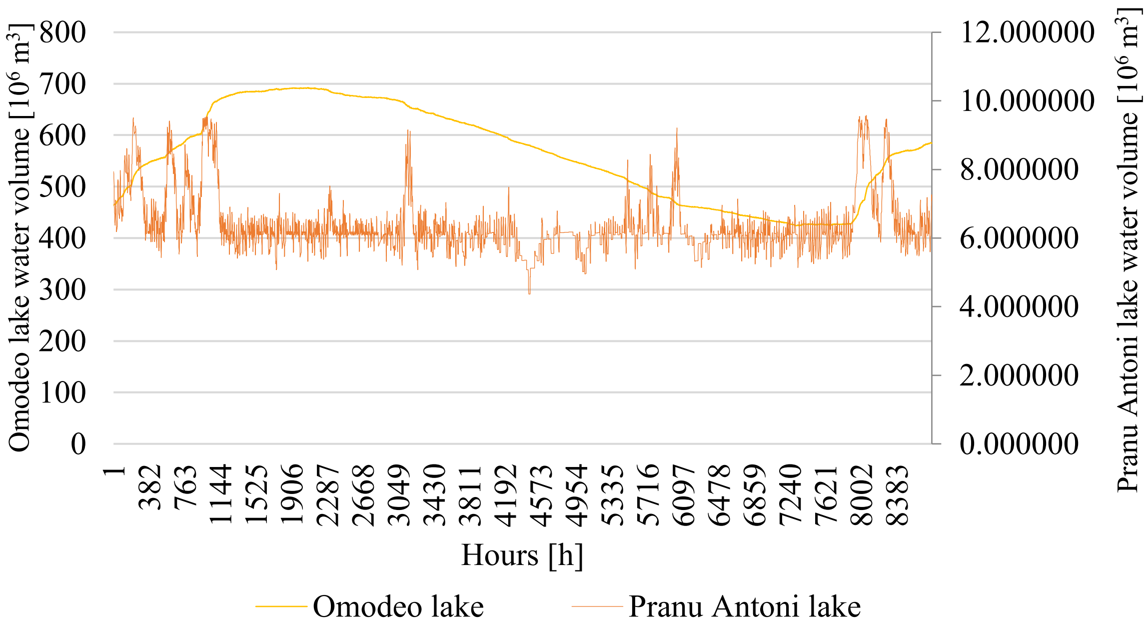


Figure 9.73 Lake's volume profile for 2021

From the reservoir curve the maximum and minimum height of the reservoir's level can be found. The results are reported in Table 49.

Table 49 Maximum and minimum water levels with markup=0.4

MAX Pranu Antoni level	45.567	msl	MIN Pranu Antoni level	40.4635	Msl
MAX Omodeo level	114.111	msl	MIN Omodeo level	103.715	Msl
MAX diff Pranu Antoni	5.10346	m	MAX diff Omodeo	10.3958	M

The energy consumed and produced is reported in Table 50 together with the utilization factor for both Tirso 1 and Tirso 2.

Table 50 Energy production and consumption for Tirso 1 and Tirso 2 with markup=0.4

Energy consumed T1	25855604171	Wh		
	25855.60417	MWh		
Energy produced T1	46904460007	Wh		
	46904.46001	MWh		
Utilization factor and equivalent hours				
Turbine mode	10.39687459	%	910.7662	h
Pump mode	9.239447791	%	809.375	h
Energy produced T2	10195684082	Wh		
	10195.68408	MWh		
Utilization factor and equivalent hours				
	27.71168755	%	2427.544	h

In the following Table 51 there are reported the annual revenues and cost related to the turbine and pump operation. Tirso 2 is also reported.

Table 51 Revenues and cost of the energy produced and consumed in Tirso 1 and Tirso 2 with markup=0.4

Tirso 1				
Yearly sum pumping cost	1993385.6	€	1.99339	M€
Yearly sum sale revenues	6497343.2	€	6.49734	M€
Yearly differential sum "profit"	4503957.6	€	4.50396	M€
Tirso 2				
Yearly sum sale revenues	1187982.6	€	1.18798	M€

The economic parameters are reported in Figure 9.74.

Discounted cash flow	34.3899871	M€				
ROI - Return On Investment	0.06476526		6.476526142	%		
NPV - Net Present Value	-14.972895	M€	NO			
IP - profitability index	-0.3033229					
LCOS levelized cost of storage	0.00019563	€/Wh	0.195625199	€/kWh	195.625	€/MWh

Figure 9.74 Economic parameters with markup=0.4 and k=10%

It can be noted that with a cost of capital k=10% the investment is not economically viable, as it can be shown in the Figure 9.75, which represents the cumulative cash flow for this operation mode.

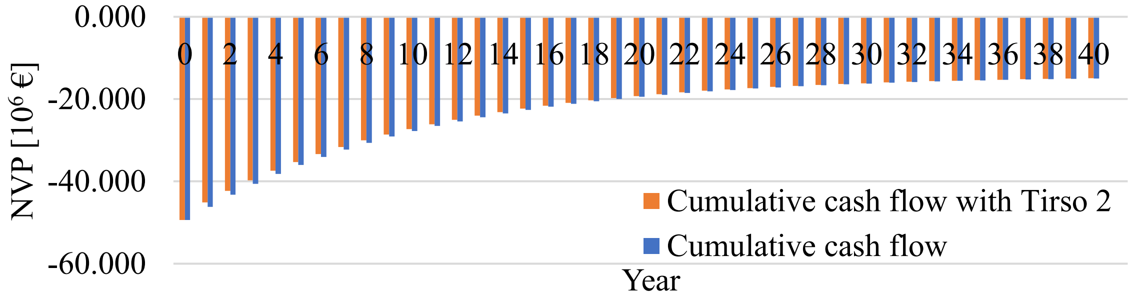


Figure 9.75 Cumulative cash flow with k=10% and markup=0.4

At last, it is interesting for this operating mode, to consider the effect of the cost of capital on the NPV, as noted in the previous pages (Figure 9.76).

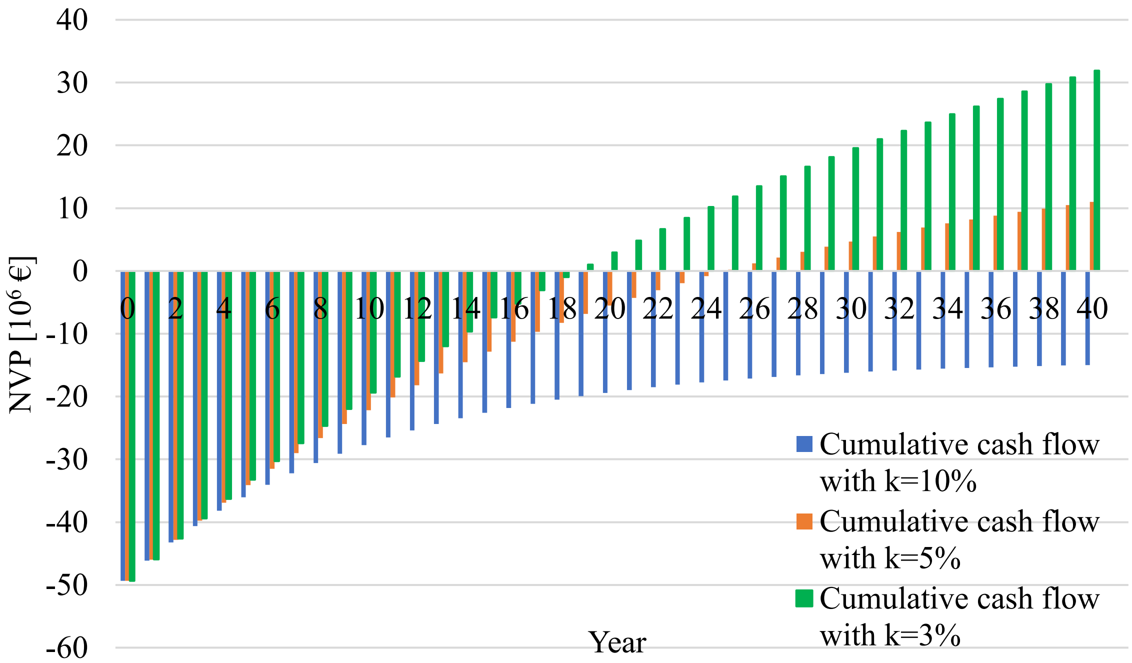


Figure 9.76 Effect of the interest rate k on the cumulative cash flow

The feasibility of the project is directly linked to the interest rate k.

- 30 MW PaT with Francis turbine – markup=0.5

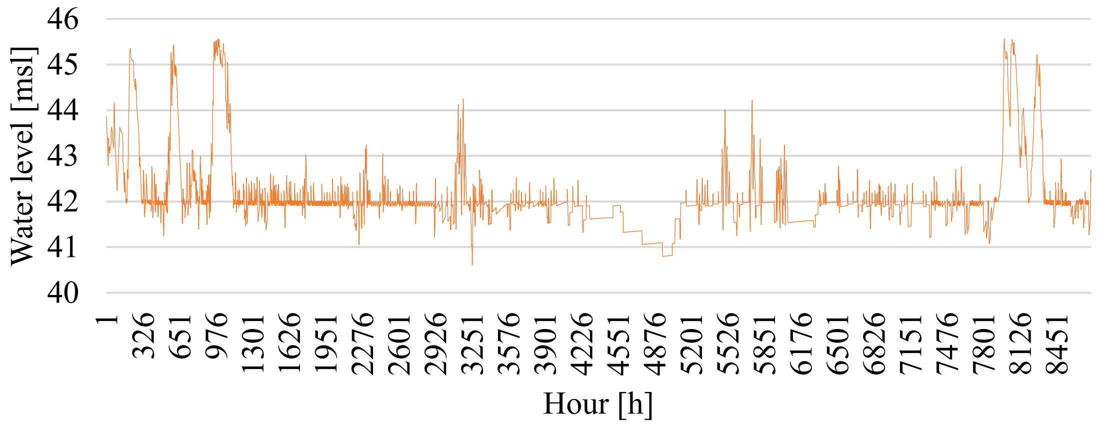


Figure 9.77 Pranu Antoni lake water level variation over 2021 for markup=0.5

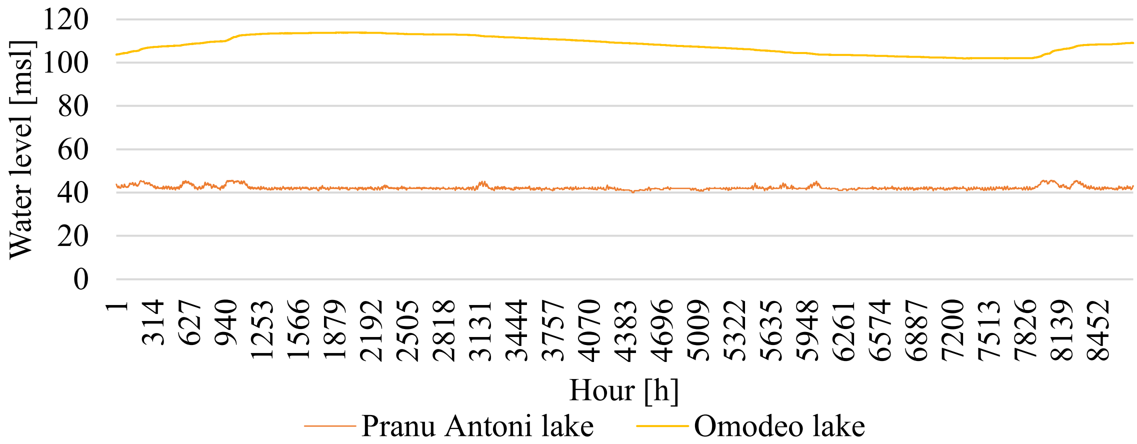


Figure 9.78 Reservoirs water level variation over 2021 for markup=0.5

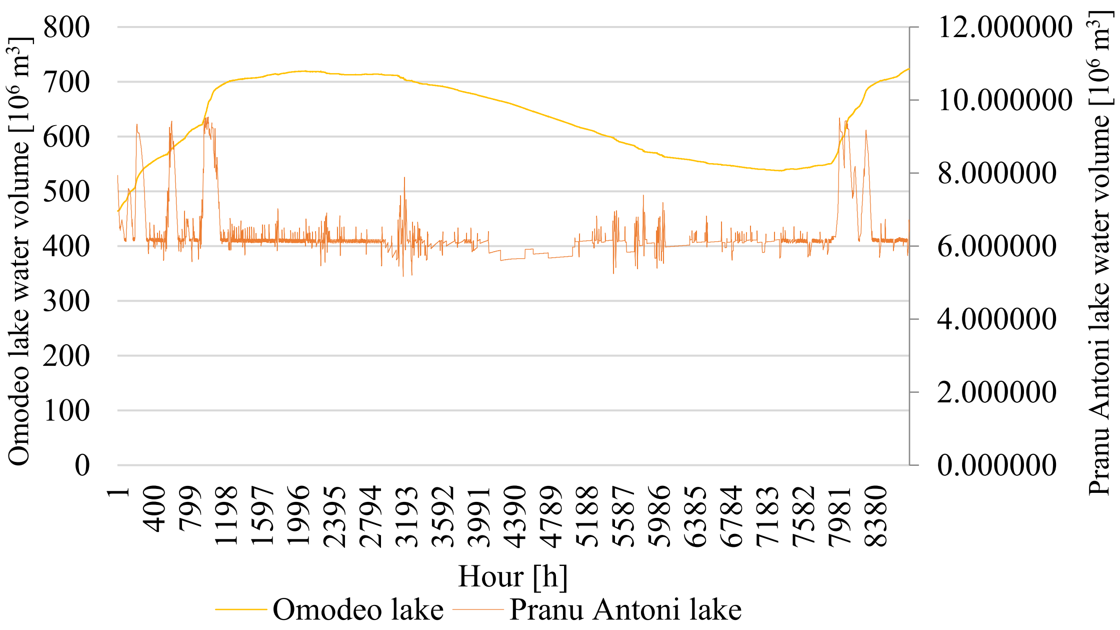


Figure 9.79 Reservoirs volume variation over 2021 for markup=0.5

The maximum and minimum water levels are reported in Table 52.

Table 52 Maximum and minimum water levels with markup=0.5

MAX Pranu Antoni level	45.5607	msl	MIN Pranu Antoni level	40.6097	Msl
MAX Omodeo level	114.643	msl	MIN Omodeo level	103.715	Msl
MAX diff Pranu Antoni	4.95095	m	MAX diff Omodeo	10.9282	M

The energy produced and consumed in this configuration is reported in Table 53.

Table 53 Energy production and consumption for Tirso 1 and Tirso 2 with markup=0.5

Energy consumed T1	16258554115	Wh		
	16258.55412	MWh		
Energy produced T1	32768540668	Wh		
	32768.54067	MWh		
Utilization factor and equivalent hour				
Turbine mode	7.263497067	%	636.2823	h
Pump mode	5.763484593	%	504.8813	h
Energy produced T2	8997529835	Wh		
	8997.529835	MWh		
Utilization factor and equivalent hour				
	24.45512566	%	2142.269	h

The economic value associated with this energy is reported in Table 54.

Table 54 Revenues and cost of the energy produced and consumed in Tirso 1 and Tirso 2 with markup=0.5

Tirso 1				
Yearly sum pumping cost	917403.79	€	0.9174	M€
Yearly sum sale revenues	4250454.7	€	4.25045	M€
Yearly differential sum "profit"	3333050.9	€	3.33305	M€
Tirso 2				
Yearly sum sale revenues	1063390.3	€	1.06339	M€

At last, the economic parameters are reported in Figure 9.80.

Discounted cash flow	22.939631	M€				
ROI - Return On Investment	0.04320127		4.320127238	%		
NPV - Net Present Value	-26.423251	M€	NO			
IP - profitability index	-0.5352858					
LCOS levelized cost of storage	0.00024718	€/Wh	0.247179531	€/kWh	247.18	€/MWh

Figure 9.80 Economic parameters for k=10% and markup=0.5

This shows that the investment is not economically sustainable with the interest rate equal to 10%.

- 30 MW PaT with Francis turbine – markup=0.6

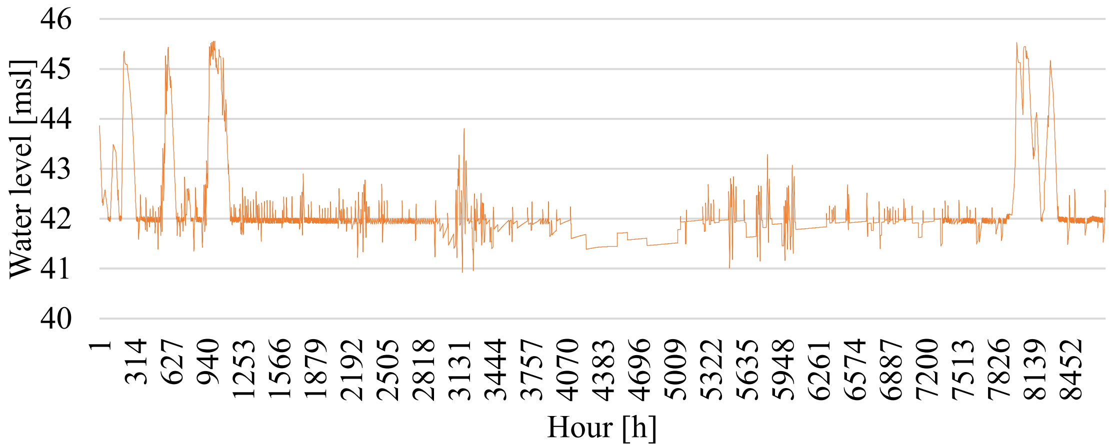


Figure 9.81 Pranu Antoni lake water level variation over 2021 for markup=0.6

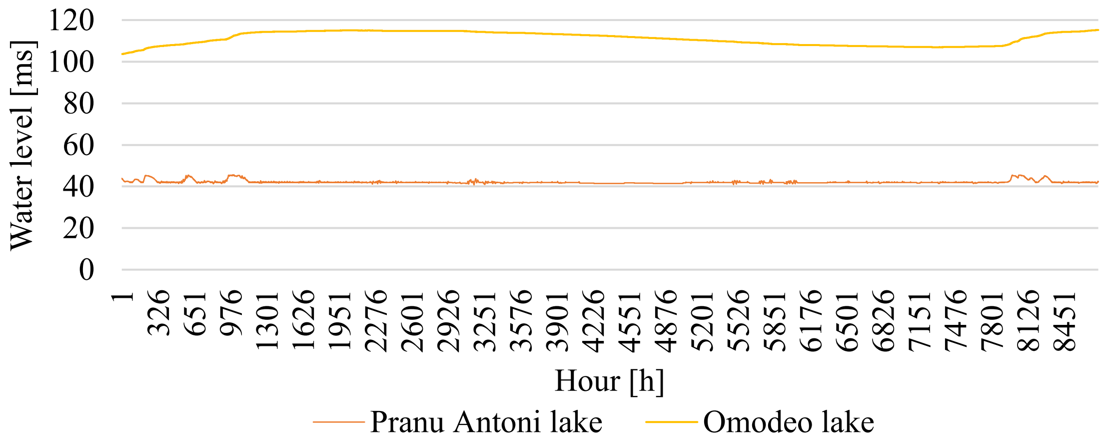


Figure 9.82 Reservoirs water level variation over 2021 for markup=0.6

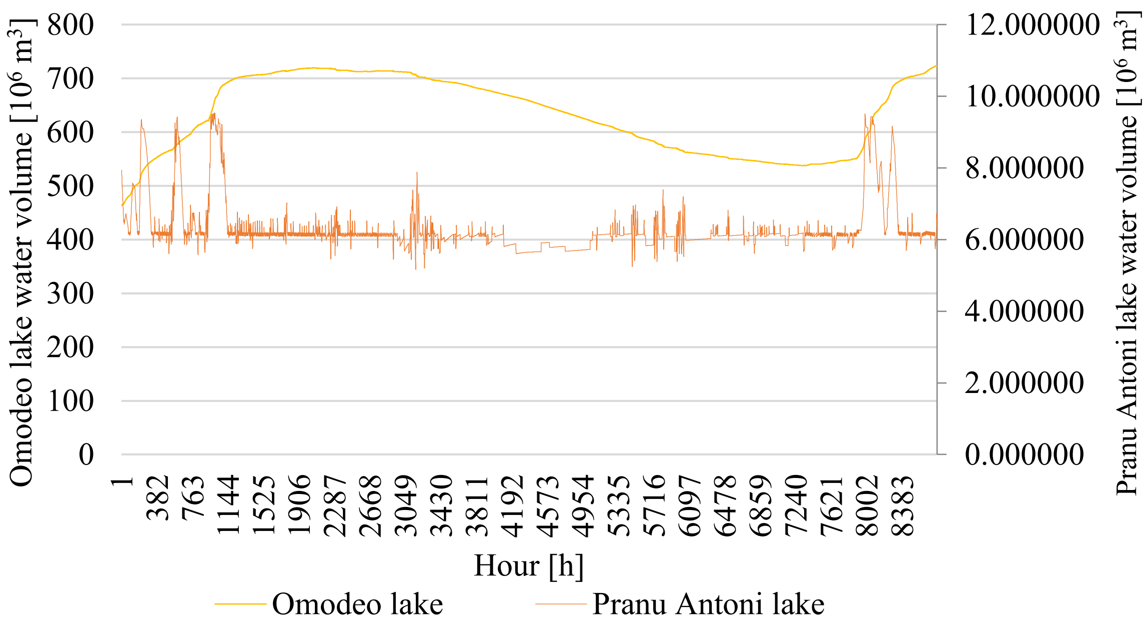


Figure 9.83 Reservoirs volume variation over 2021 for markup=0.6

The maximum and minimum water levels of the two reservoirs are reported in Table 55.

Table 55 Maximum and minimum water levels with markup=0.6

MAX Pranu Antoni level	45.5551	msl	MIN Pranu Antoni level	40.9218	Msl
MAX Omodeo level	115.249	msl	MIN Omodeo level	103.715	Msl
MAX diff Pranu Antoni	4.63334	m	MAX diff Omodeo	11.534	M

The energy production and consumption are reported in Table 56.

Table 56 Energy production and consumption for Tirso 1 and Tirso 2 with markup=0.6

Energy consumed T1	10818204323	Wh		
	10818.20432	MWh		
Energy produced T1	22448958373	Wh		
	22448.95837	MWh		
Utilization factor and equivalent hour T1				
Turbine mode	4.976051419	%	435.9021	h
Pump mode	3.819824076	%	334.6166	h
Energy produced T2	7835921969	Wh		
	7835.921969	MWh		
Utilization factor and equivalent hour T2				
	21.2978962	%	1865.696	h

The economic value of the energy produced and consumed is reported in Table 57.

Table 57 Revenues and cost of the energy produced and consumed in Tirso 1 and Tirso 2 with markup=0.6

Tirso 1				
Yearly sum pumping cost	366189.97	€	0.36619	M€
Yearly sum sale revenues	2681586	€	2.68159	M€
Yearly differential sum "profit"	2315396.1	€	2.3154	M€
Tirso 2				
Yearly sum sale revenues	939813.82	€	0.93981	M€

The economic parameters are shown in Figure 9.84.

Discounted cash flow	12.9879329	M€				
ROI - Return On Investment	0.02445964		2.445964484	%		
NPV - Net Present Value	-36.374949	M€	NO			
IP - profitability index	-0.7368887					
LCOS levelized cost of storage	0.00033625	€/Wh	0.336251623	€/kWh	336.252	€/MWh

Figure 9.84 Economic parameters for k=10% and markup=0.6

This clearly shows that the project is not financially viable.

9.3.2 Case 2: Tirso 1's Francis and a 30 MW centrifugal pump

The machines present in the plant have the following characteristics as reported in Table 58.

Table 58 Machines' characteristics

Tirso 1's Francis turbine		
Nominal power	21.5	MW
Nominal flow rate	30	m^3/s
Minimum head	54	M
Nominal head	78.2	M
Maximum head	80.4	M
Tirso 1's centrifugal pump		
Nominal power	30	MW
Nominal flow rate	39.1	m^3/s
Minimum head	54	M
Nominal head	78.2	M
Maximum head	80.4	M
Tirso 2's Kaplan turbine		
Nominal power	4.2	MW
Nominal flow rate	30	m^3/s
Minimum head	12	m
Nominal head	15.45	m
Maximum head	16	m

The only change compared to case 1 is the cost of the centrifugal pump can be evaluated with the following Equation 85.

Equation 85 Electromechanical costs for a centrifugal pump

$$C_{EM,[10^6€]_{2018}} = 2.929 * P_{[MW]}^{1.174} * H_{[m]}^{-0.4933}$$

The cost estimate for this configuration is reported in Figure 9.85.

						average inflation EU	0.0243						
c_EM	20.8343544	M€											
Penstoks													
D_opt	3.45576089	m		sigma_steel	310	N/mm^2	0.00031	N/m^2					
t_pipe	43.5871776	mm		ASTM A537									
	0.04358718	m		safety factor	1	/							
weight_p	395743.896	Kg											
				steel density	7800	kg/m^3							
penstock lenght	336.834983	m											
				steel cost	1.4	€/kg				Pump			
vertical distance	31.7	m	(da dati)							End of life cost		9.48992	M€
horizontal distance	335.34	m	(da maps)								fraction	0.25	
The cost of the penstock		554041.4551	€	0.671366463	M€								
Power house cost,2021		201.1508781	€/kW	6034526.342	€	6.33136765	M€						

Figure 9.85 Cost estimates for case 2

From which the CAPEX and OPEX are obtained (Table 59).

Table 59 CAPEX, OPEX and specific cost based on installed capacity for case 2

CAPEX	41.75	M€	1391.854	€/kW
OPEX	0.835	M€		

The starting volumes and reservoirs characteristics are the same in all the different cases. To have a more stable control the pump will not be in operation when the turbine is working.

In the operating mode with markup 0.3 the following operational profile result from the analysis. Using the volume balances the volume inside the reservoir can be found, and then with the reservoir curve the height of the reservoir is estimated.

The water volumes in the two reservoirs are reported in Figure 9.86.

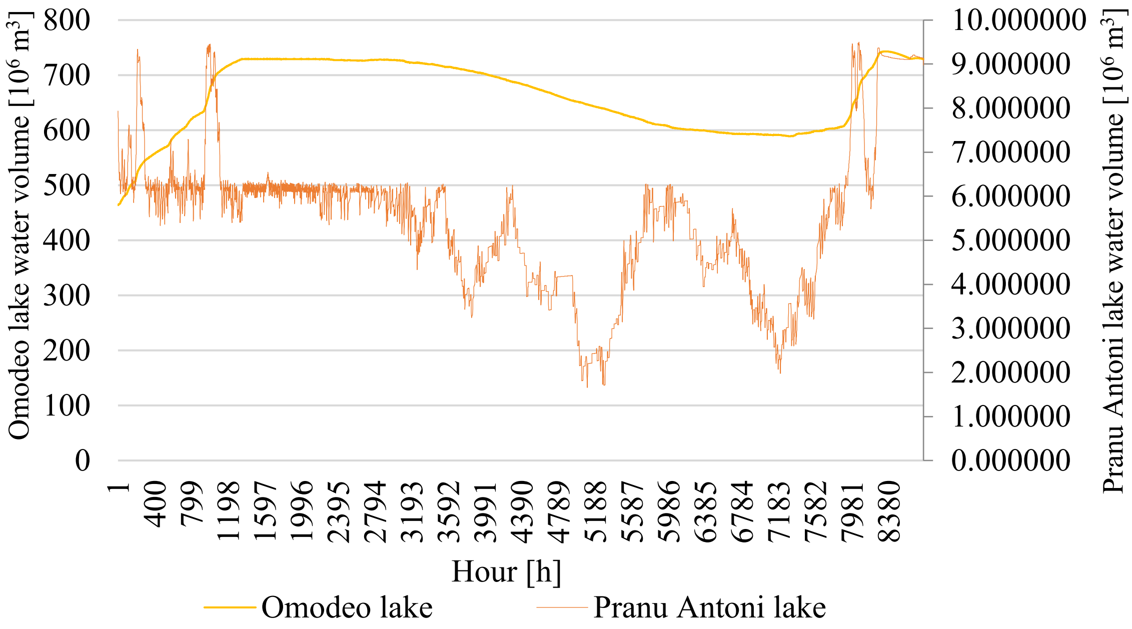


Figure 9.86 Reservoirs' volume over 2021 for markup=0.3

From which the water level of the reservoirs can be found through the reservoirs curve (Equation 29 and Equation 31).

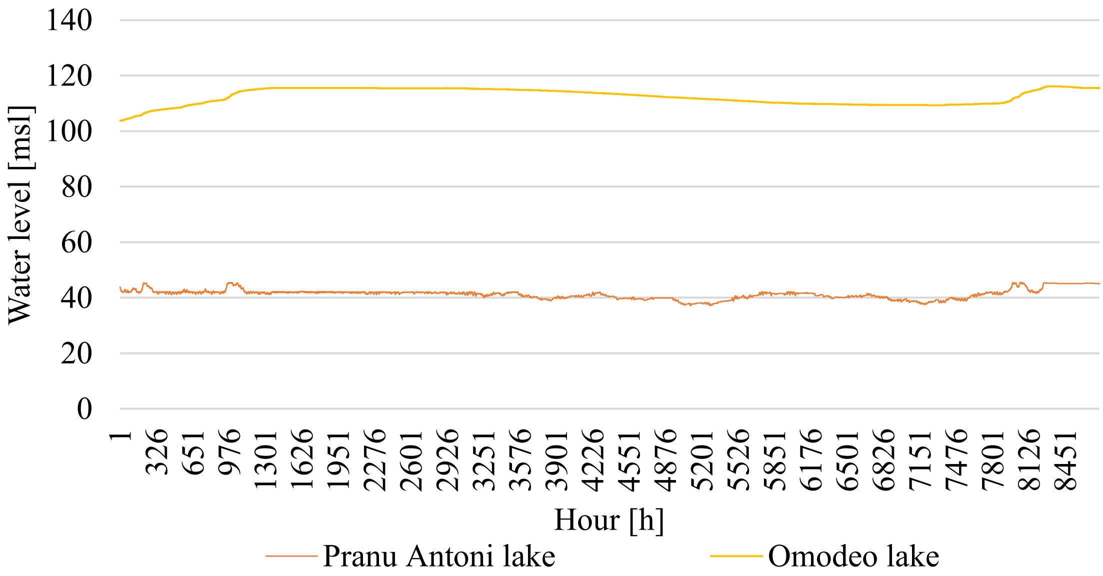


Figure 9.87 Water level of the reservoirs in 2021 for markup=0.3

The water level profile of the Pranu Antoni lake is reported in the Figure 9.88 below since it is more effected by the level change.

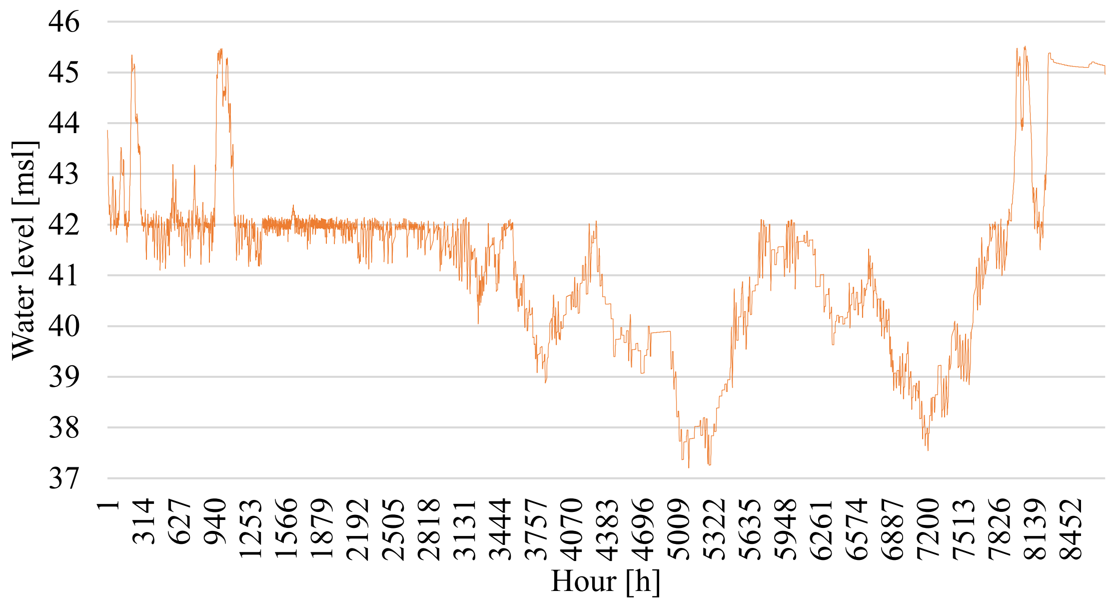


Figure 9.88 Pranu Antoni lake water level variation over 2021 for markup=0.3

The maximum and minimum level of the two reservoirs are reported in Table 60, meanwhile in Table 61 it is reported the ideal volume exchange between the two reservoirs.

Table 60 Maximum and lower water level for the upper and lower reservoirs

MAX Pranu Antoni level	45.5201	msl	MIN Pranu Antoni level	37.2054	msl
MAX Omodeo level	116.107	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	8.31474	m	MAX diff Omodeo	12.3921	m

Table 61 Ideal volume movements for case 2 with markup=0.3

Ideal case		
V tot turb	243.432	10^6 m^3
V tot pomp	169.22	10^6 m^3
Diff T-P	74.2117	10^6 m^3

The next step is the evaluation of the energy produced and consumed by the power plant (Table 62).

Table 62 Energy produced and consumed by Tirso 1 and Tirso 2

Energy consumed T1	37239673593	Wh		
	37239.67359	MWh		
Energy produced T1	44188899363	Wh		
	44188.89936	MWh		
Utilization factor and equivalent hour				
Turbine mode	23.46230188	%	2055.298	h
Pump mode	12.82967032	%	1123.879	h

Energy produced T2	5507100760	Wh
	5507.10076	MWh

Utilization factor and equivalent hour

14.96820167	%	1311.214	h

An economic value is associated with this energy (Table 63).

Table 63 Revenues and pumping cost of Tirso 1 and Tirso 2

Tirso 1				
Yearly sum pumping cost	2984791.2	€	2.98479	M€
Yearly sum sale revenues	7031064.7	€	7.03106	M€
Yearly differential sum "profit"	4046273.6	€	4.04627	M€
Tirso 2				
Yearly sum sale revenues	522412.11	€	0.52241	M€

Knowing the yearly differential profit, the economic analysis gives the following result as reported in Figure 9.89 and Figure 9.90.

Discounted cash flow	31.402	M€				
ROI - Return On Investment	0.06991242		6.991241683	%		
NPV - Net Present Value	-10.354	M€	NO			
IP - profitability index	-0.2479552					
LCOS levelized cost of storage	0.00020503	€/Wh	0.205034382	€/kWh	205.0343822	€/MWh

Figure 9.89 Economic parameters for markup=0.3 and k=10%

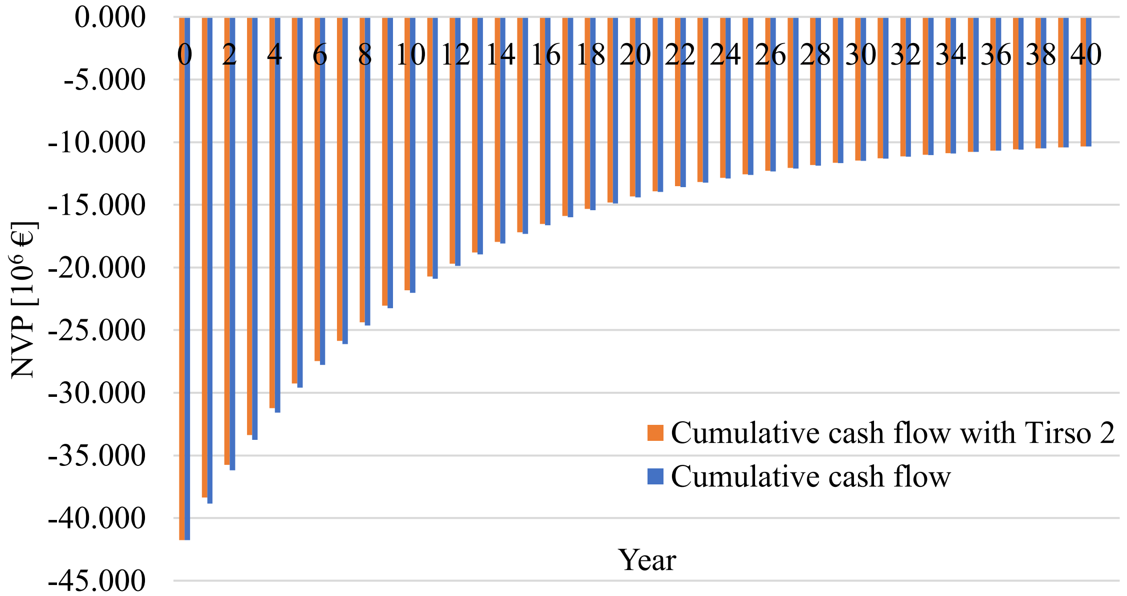


Figure 9.90 Cumulative cash flow with k=10% and markup=0.3

With a cost of capital k equal to 10% the investment is not considered feasible.

Now it is interesting to see the behavior of the plant for different operating mode (different markup) and analyze the sensitivity of the LCOS and NPV to the markup and to the cost of capital.

As for the previous case, three cost of capital k 3%, 5% and 10 % will be taken in consideration. In the following table the results of the sensitivity analysis are reported.

Table 64 Results of the sensitivity analysis of NVP and LCOS

k	10%	
Markup	**NPV [10^6 €]**	**LCOS [€/MWh]**
0.1	-15.01913685	177.0464
0.2	-12.16523333	190.772918
0.3	-10.35352724	205.034382
0.4	-11.41381209	230.832429
0.5	-14.52000035	260.663541
0.6	-14.48412848	288.035976

k	5%	
Markup	**NPV [10^6 €]**	**LCOS [€/MWh]**
0.1	5.158311714	148.135734
0.2	10.16599379	152.481519
0.3	13.34495482	154.625624
0.4	11.48449619	164.199582
0.5	6.0341356	175.722533
0.6	6.097079185	187.805273

k	3%	
Markup	**NPV [10^6 €]**	**LCOS [€/MWh]**
0.1	21.44150413	138.168874
0.2	28.18728457	139.280681
0.3	32.46961977	137.247366
0.4	29.96342123	141.22812
0.5	22.62131458	146.439392
0.6	22.70610502	153.251057

From the sensitivity analysis on the NPV it can be said that there is a markup which maximizes the NPV, which is 0.3 as it can be noted from Figure 9.91. Increasing or decreasing the markup beyond 0.3 means a decrease in the NPV. It can also be noted that the NPV is strongly dependent on the cost of capital k. In fact, there is no markup which returns a positive NPV for k=10%.

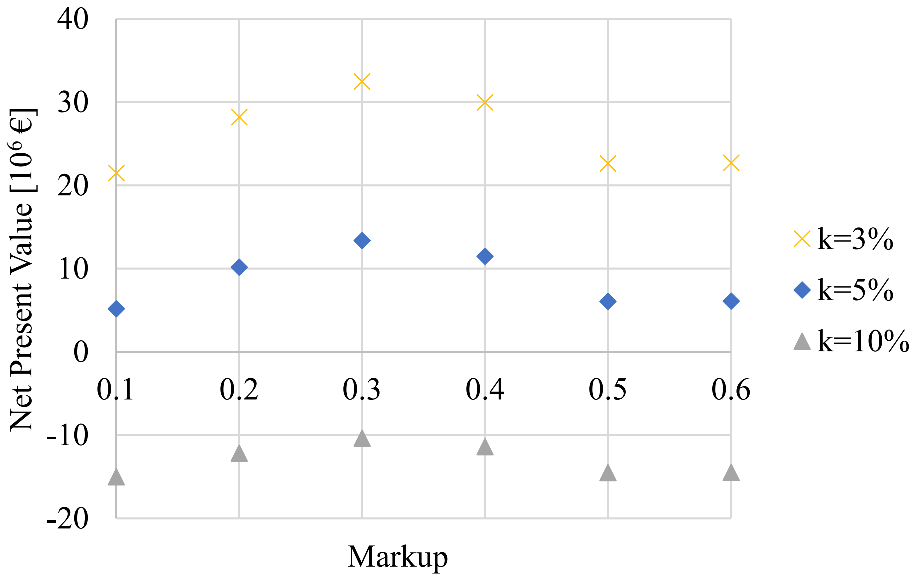


Figure 9.91 Sensitivity analysis of the NPV

Meanwhile for the LCOS it can be said that it increases faster for increasing markup if the interest rate is high. The LCOS seem not to be influenced by the markup for low interest rate. The difference between the prices for fixed markup increase with increasing markup.

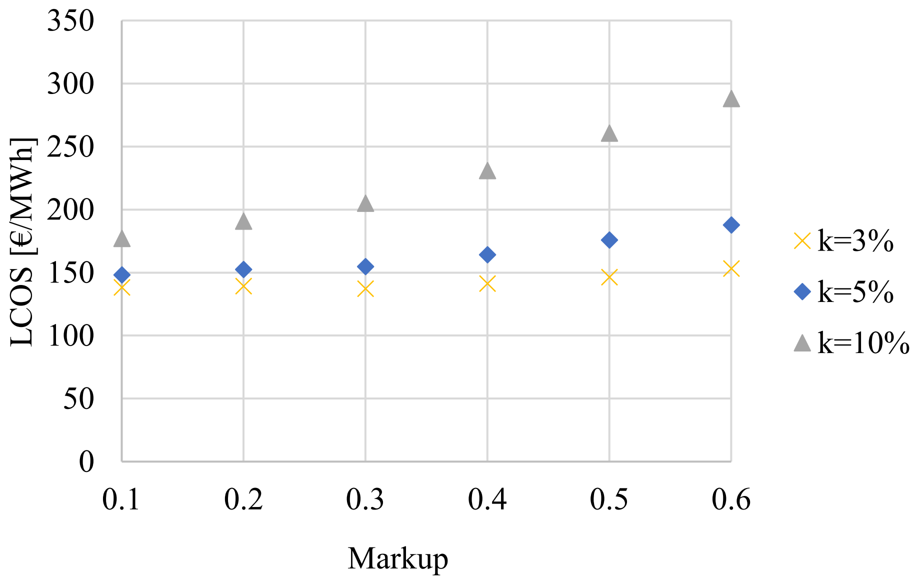


Figure 9.92 Sensitivity analysis of the LCOS

One other important parameter for the evaluation of the investment is the IRR, which is reported in Table 65 and shown in Figure 9.93.

Table 65 Markup vs IRR for case 2

Markup	IRR	
0.1	5.882	%
0.2	6.707	%
0.3	7.217	%
0.4	6.918	%
0.5	6.028	%
0.6	6.038	%

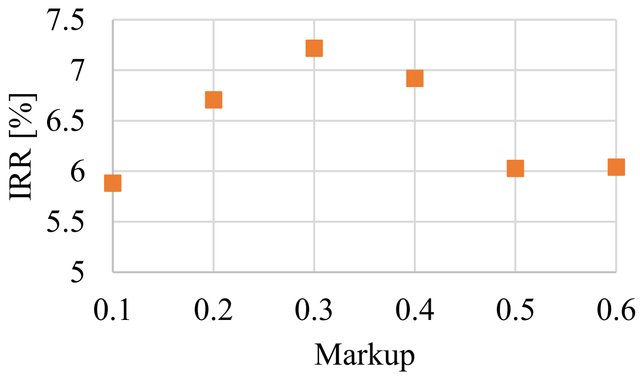
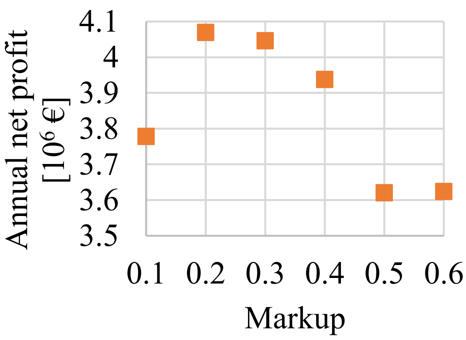


Figure 9.93 Markup vs IRR

The annual net profit from the operation of Tirso 1 and the revenues of Tirso 2 are reported in Table 66 and shown in Figure 9.94.

Table 66 Markup vs annual net profit and Tirso 2 revenues for case 2

Markup	Annual net profit		Tirso 2 revenues	
0.1	3.777949239	M€	0.482616181	M€
0.2	4.069787742	M€	0.527273788	M€
0.3	4.046273582	M€	0.52241211	M€
0.4	3.937849473	M€	0.555377905	M€
0.5	3.620212481	M€	0.732736409	M€
0.6	3.623880717	M€	0.678507411	M€



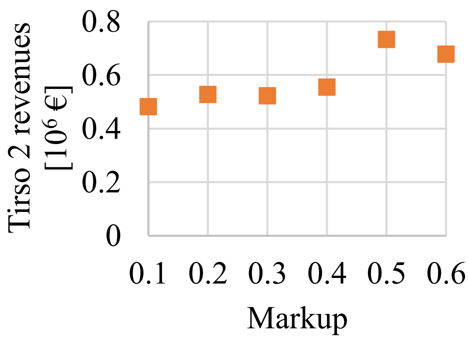


Figure 9.94 Markup vs annual net profit (left) and markup vs Tirso 2 revenues (right) for a 30 MW pump + Francis

At last, the different operating mode show different operational profile which are reported below.

- 30 MW centrifugal pump with Francis turbine – markup=0.1

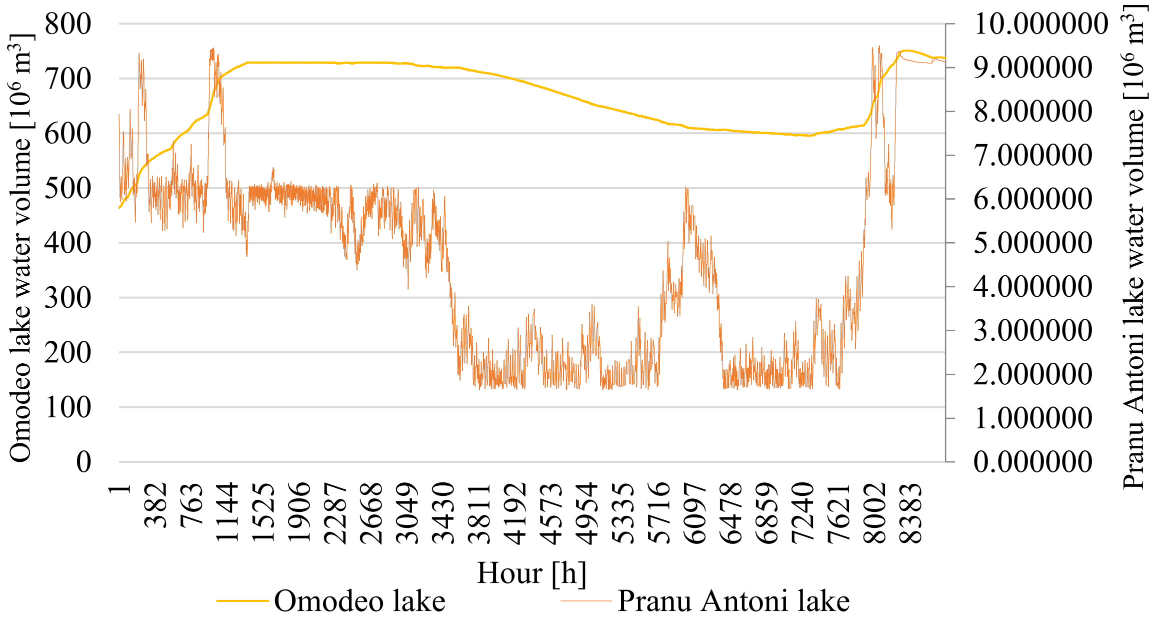


Figure 9.95 Reservoirs' volume over 2021 for markup=0.1

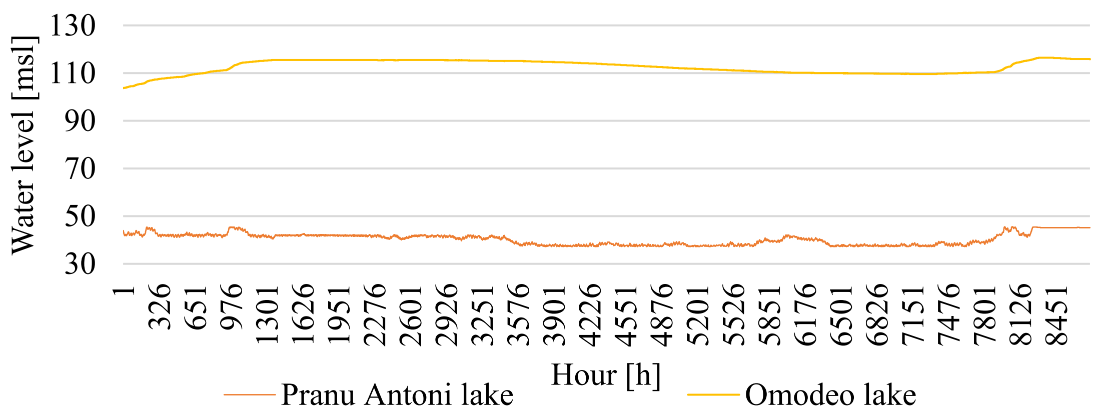


Figure 9.96 Reservoirs' water level over 2021 for markup=0.1

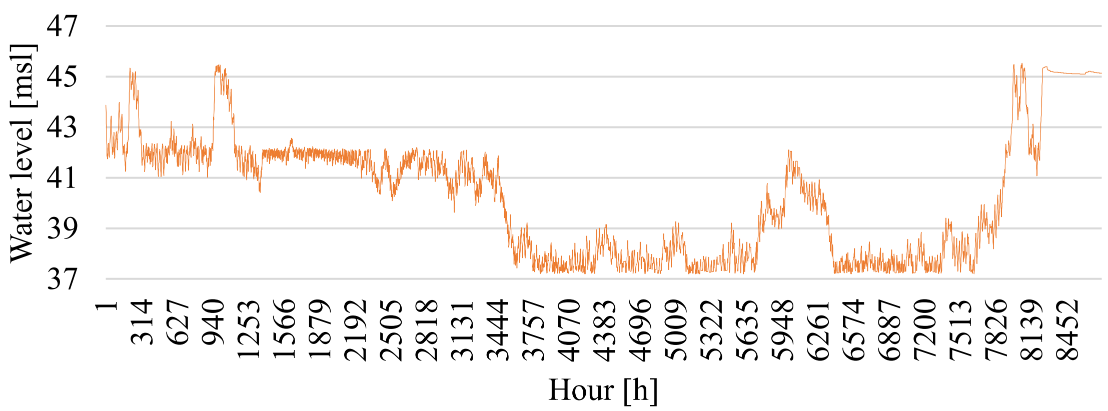


Figure 9.97 Pranu Antoni lake level variation over 2021 for markup=0.1

Table 67 Characteristic level of the reservoir for markup=0.1

MAX Pranu Antoni level	45.5234	msl	MIN Pranu Antoni level	37.1934	msl
MAX Omodeo level	116.468	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	8.33008	m	MAX diff Omodeo	12.7532	m

Table 68 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.1

Energy consumed T1	79079312302	Wh		
	79079.3123	MWh		
Energy produced T1	77047949571	Wh		
	77047.94957	MWh		
Utilization factor and equivalent hour				
Turbine mode	40.9089676	%	3583.626	h
Pump mode	26.53641644	%	2324.59	h
Energy produced T2	5280492667	Wh		
	5280.492667	MWh		
Utilization factor and equivalent hour				
	14.35228492	%	1257.26	h

Table 69 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.1

Tirso 1				
Yearly sum pumping cost	7356831.4	€	7.35683	M€
Yearly sum sale revenues	11134781	€	11.1348	M€
Yearly differential sum "profit"	3777949.2	€	3.77795	M€
Tirso 2				
yearly sum sale revenues	482616.18	€	0.48262	M€

The economic parameters like NVP, IRR and LCOS are reported in Table 64 and Table 65.

- 30 MW centrifugal pump with Francis turbine – markup=0.2

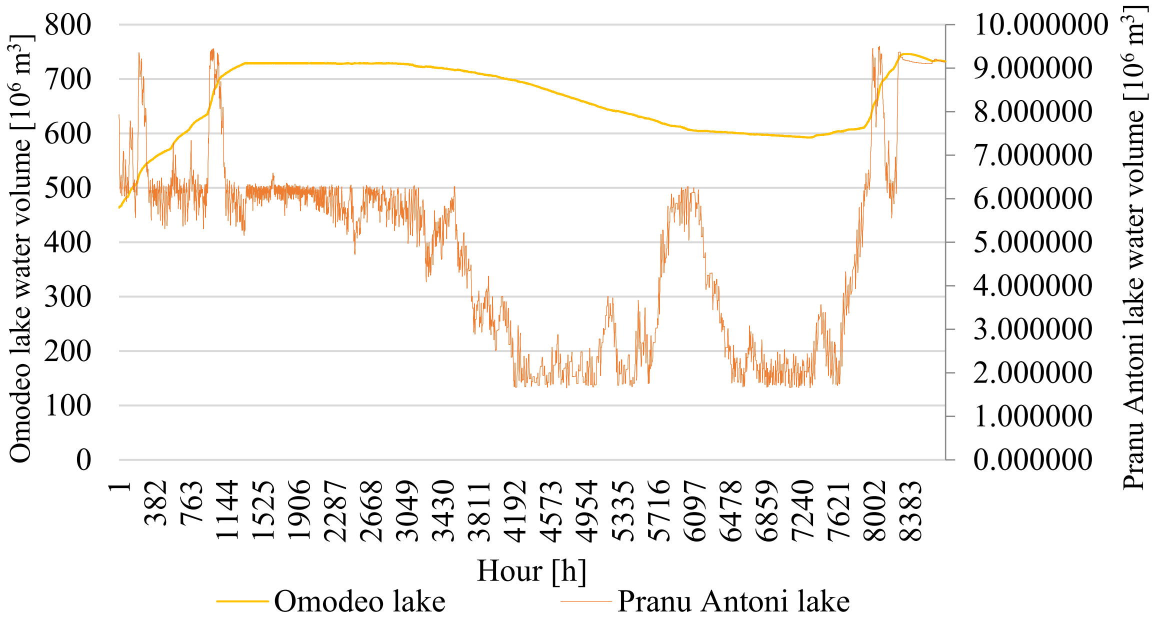


Figure 9.98 Reservoirs' volume over 2021 for markup=0.2

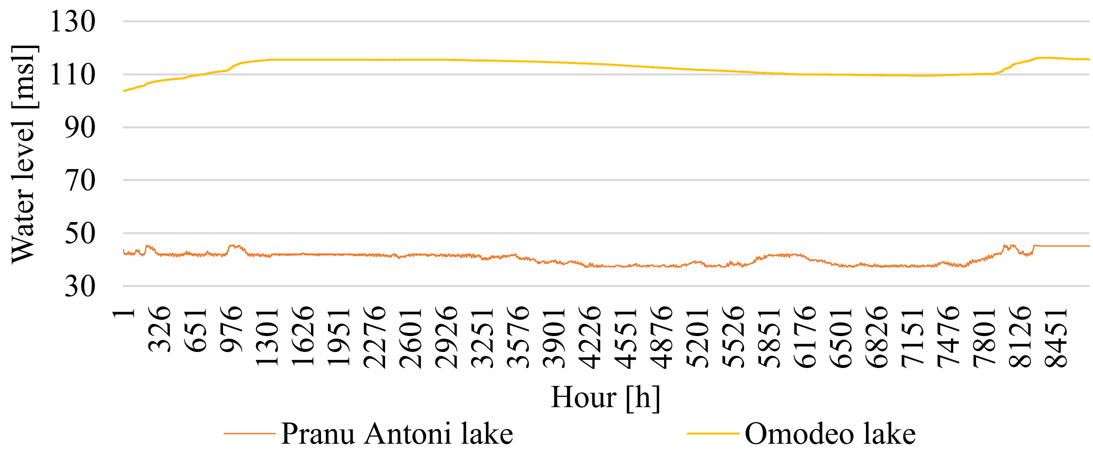


Figure 9.99 Reservoirs' water level over 2021 for markup=0.2

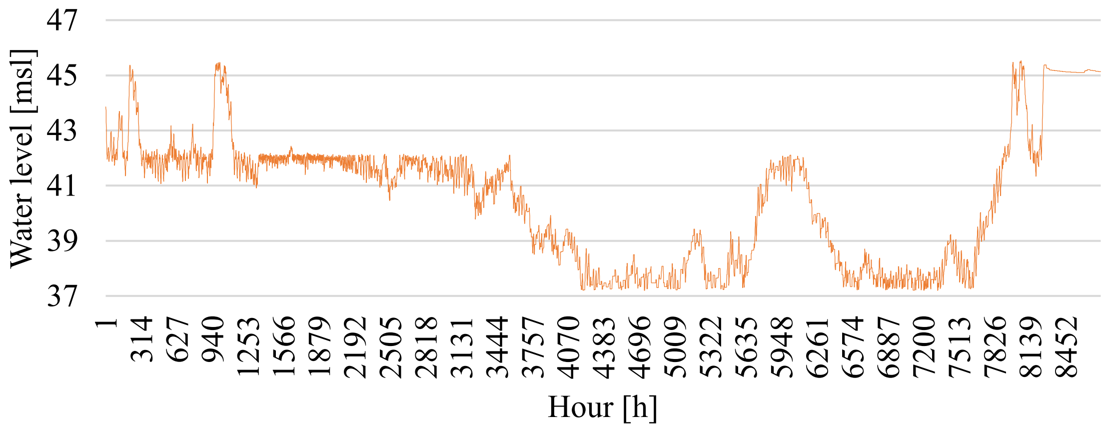


Figure 9.100 Pranu Antoni lake level variation over 2021 for markup=0.2

Table 70 Characteristic level of the reservoir for markup=0.2

MAX Pranu Antoni level	45.5228	msl	MIN Pranu Antoni level	37.2001	msl
MAX Omodeo level	116.255	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	8.32278	m	MAX diff Omodeo	12.5405	m

Table 71 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.2

Energy consumed T1	55009419898	Wh		
	55009.4199	MWh		
Energy produced T1	58172528199	Wh		
	58172.5282	MWh		
Utilization factor and equivalent hour				
Turbine mode	30.88697473	%	2705.699	h
Pump mode	18.64528829	%	1633.327	h
Energy produced T2	5501956940	Wh		
	5501.95694	MWh		
Utilization factor and equivalent hour				
	14.95422086	%	1309.99	h

Table 72 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.2

Tirso 1				
yearly sum pumping cost	4813512.3	€	4.81351	M€
yearly sum sale revenues	8883300	€	8.8833	M€
yearly differential sum "profit"	4069787.7	€	4.06979	M€
Tirso 2				
yearly sum sale revenues	527273.79	€	0.52727	M€

The economic parameters like NVP, IRR and LCOS are reported in Table 64 and Table 65.

- 30 MW centrifugal pump with Francis turbine – markup=0.4

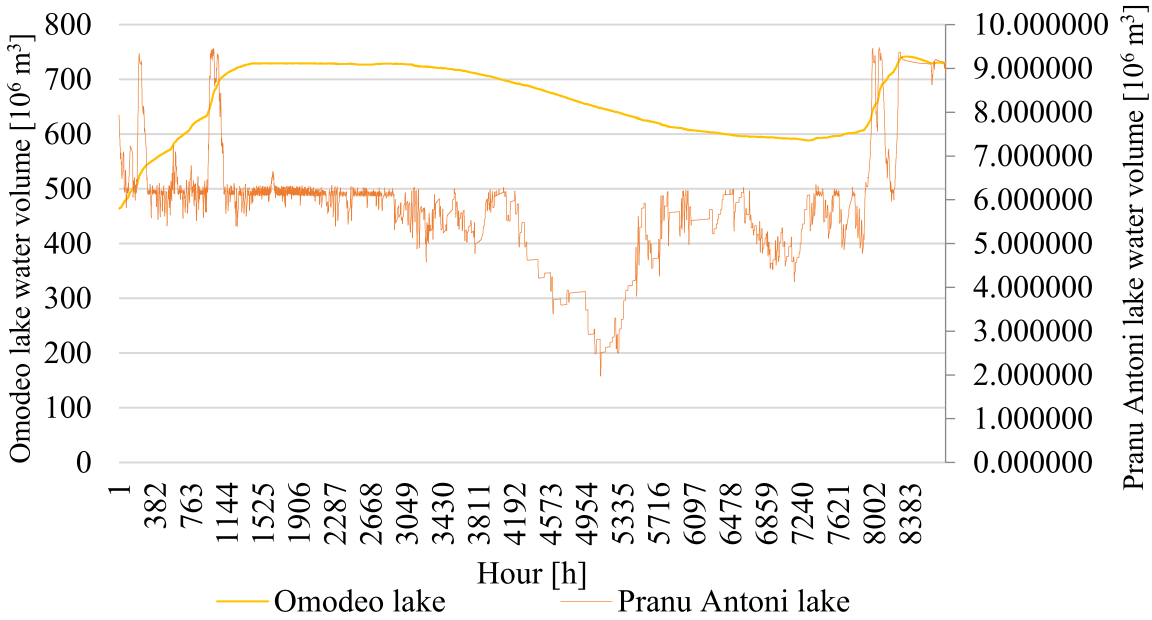


Figure 9.101 Reservoirs' volume over 2021 for markup=0.4

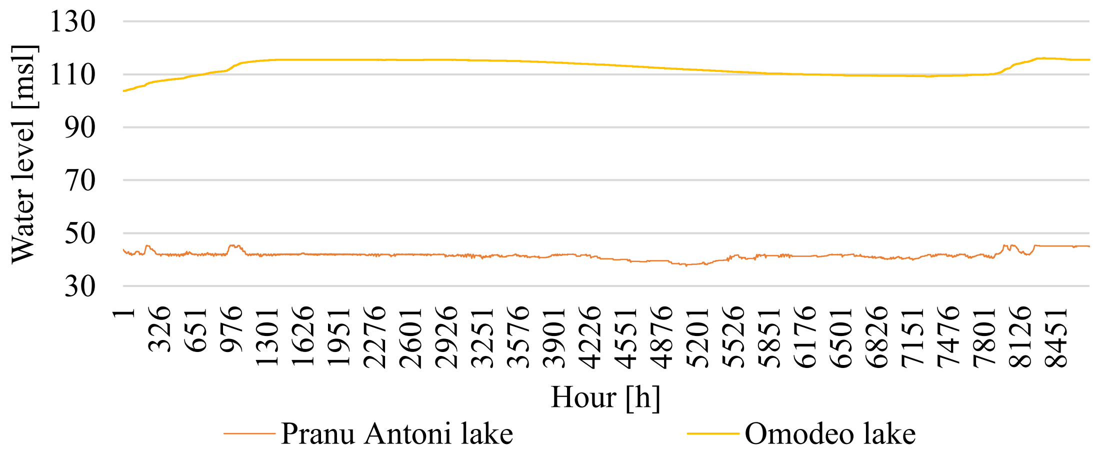


Figure 9.102 Reservoirs' water level over 2021 for markup=0.4

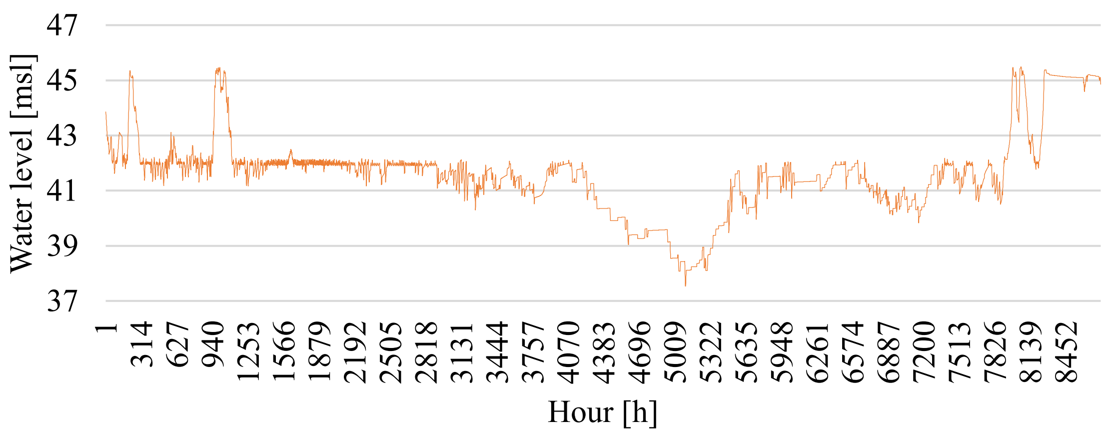


Figure 9.103 Pranu Antoni lake level variation over 2021 for markup=0.4

Table 73 Characteristic level of the reservoir for markup=0.4

MAX Pranu Antoni level	45.4936	msl	MIN Pranu Antoni level	37.5377	msl
MAX Omodeo level	116.05	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	7.9559	m	MAX diff Omodeo	12.3351	m

Table 74 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.4

Energy consumed T1	24134716240	Wh		
	24134.71624	MWh		
Energy produced T1	33429571488	Wh		
	33429.57149	MWh		
Utilization factor and equivalent hour				
Turbine mode	17.74958665	%	1554.864	h
Pump mode	8.390698296	%	735.0252	h
Energy produced T2	5571419030	Wh		
	5571.41903	MWh		
Utilization factor and equivalent hour				
	15.14301759	%	1326.528	h

Table 75 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.4

Tirso 1				
Yearly sum pumping cost	1641176.7	€	1.64118	M€
Yearly sum sale revenues	5579026.1	€	5.57903	M€
Yearly differential sum "profit"	3937849.5	€	3.93785	M€
Tirso 2				
Yearly sum sale revenues	555377.9	€	0.55538	M€

The economic parameters like NVP, IRR and LCOS are reported in Table 64 and Table 65.

- 30 MW centrifugal pump with Francis turbine – markup=0.5

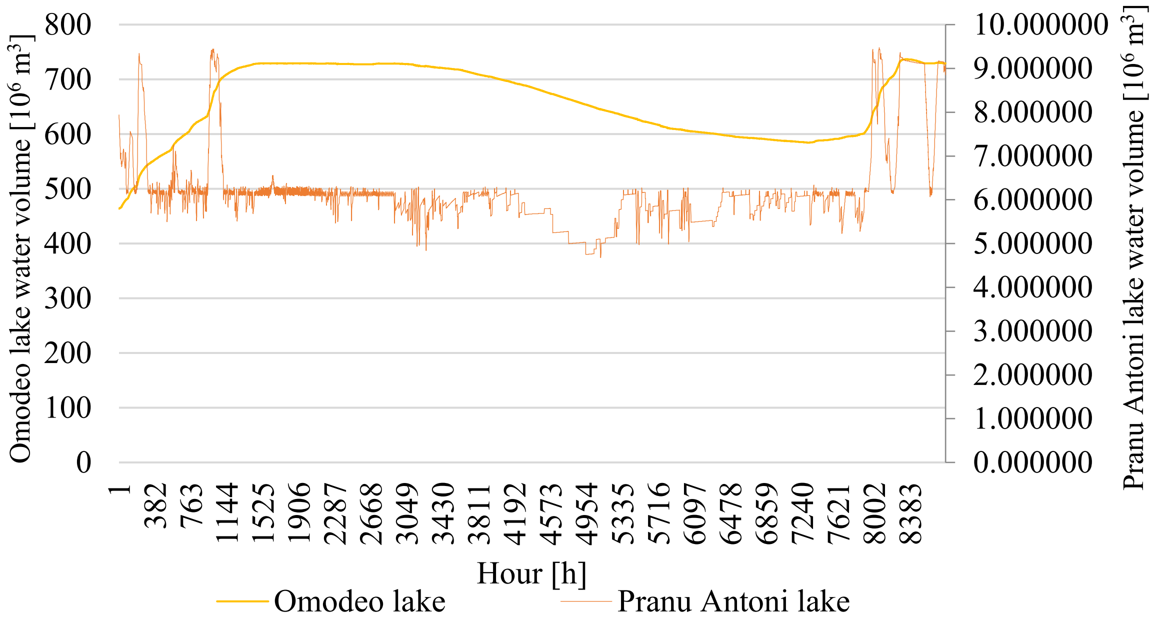


Figure 9.104 Reservoirs' volume over 2021 for markup=0.5

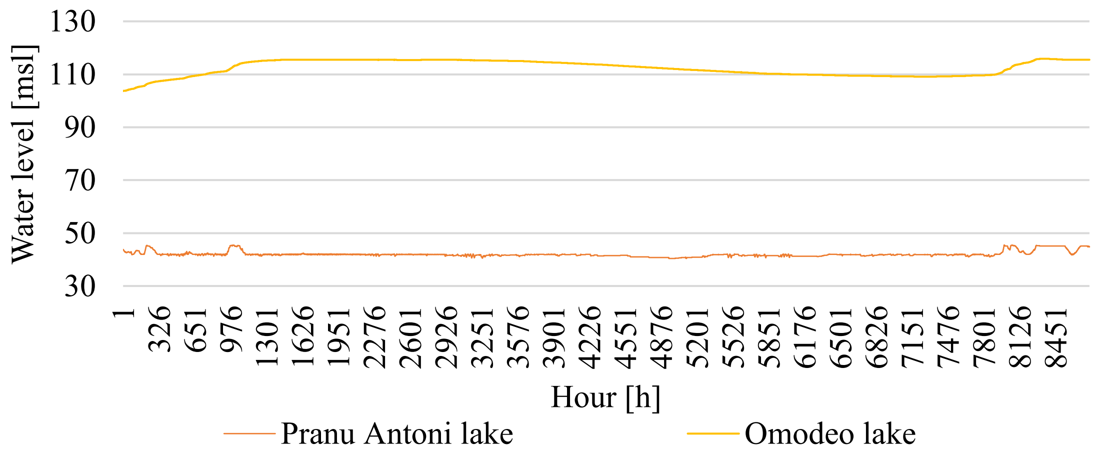


Figure 9.105 Reservoirs' water level over 2021 for markup=0.5

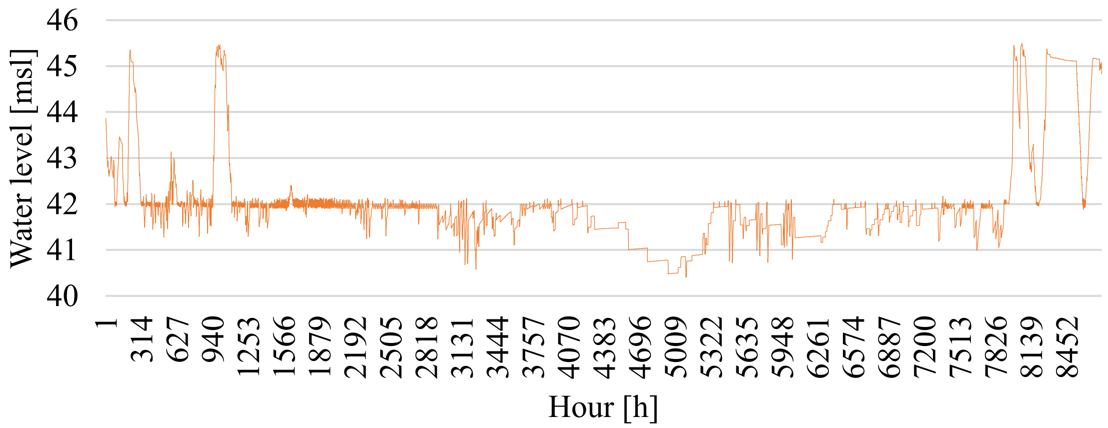


Figure 9.106 Pranu Antoni lake level variation over 2021 for markup=0.5

Table 76 Characteristic level of the reservoir for markup=0.5

MAX Pranu Antoni level	45.4936	msl	MIN Pranu Antoni level	40.4109	msl
MAX Omodeo level	115.833	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	5.0827	m	MAX diff Omodeo	12.1183	m

Table 77 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.5

Energy consumed T1	15388534966	Wh		
	15388.53497	MWh		
Energy produced T2	26224171376	Wh		
	26224.17138	MWh		
Utilization factor and equivalent hour				
Turbine mode	13.9238459	%	1219.729	h
Pump mode	5.367713535	%	470.2117	h
Energy produced T2	6203043524	Wh		
	6203.043524	MWh		
Utilization factor and equivalent hour				
	16.8597617	%	1476.915	h

Table 78 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.5

Tirso 1				
Yearly sum pumping cost	760232.84	€	0.76023	M€
Yearly sum sale revenues	4380445.3	€	4.38045	M€
Yearly differential sum "profit"	3620212.5	€	3.62021	M€
Tirso 2				
Yearly sum sale revenues	732736.41	€	0.73274	M€

The economic parameters like NVP, IRR and LCOS are reported in Table 64 and Table 65.

- 30 MW centrifugal pump with Francis turbine – markup=0.6

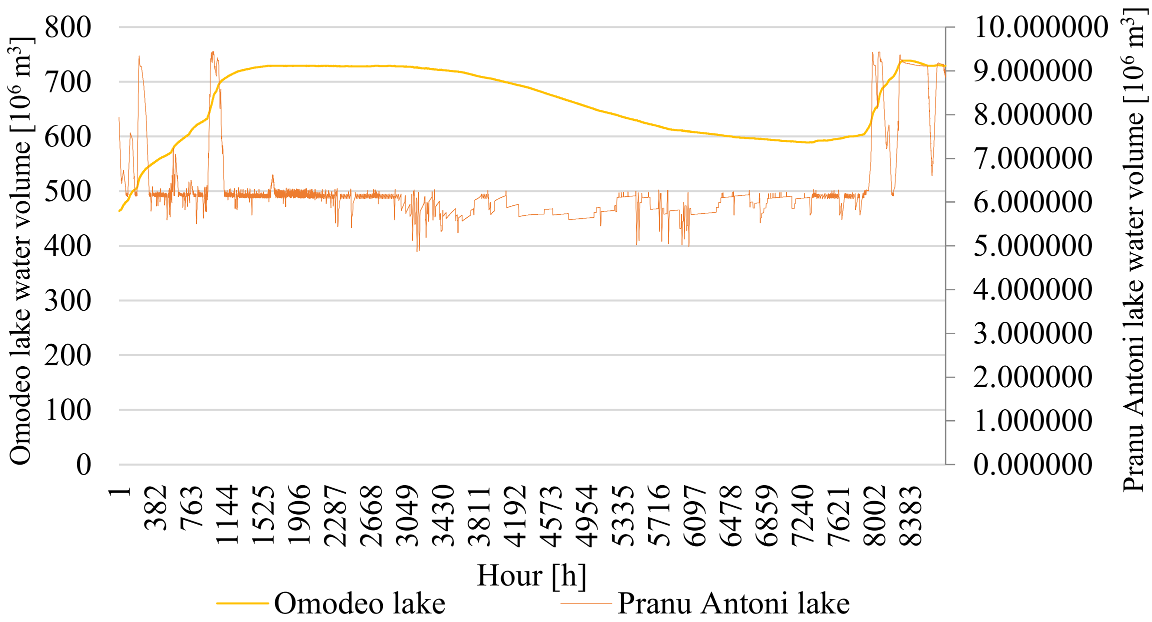


Figure 9.107 Reservoirs' volume over 2021 for markup=0.6

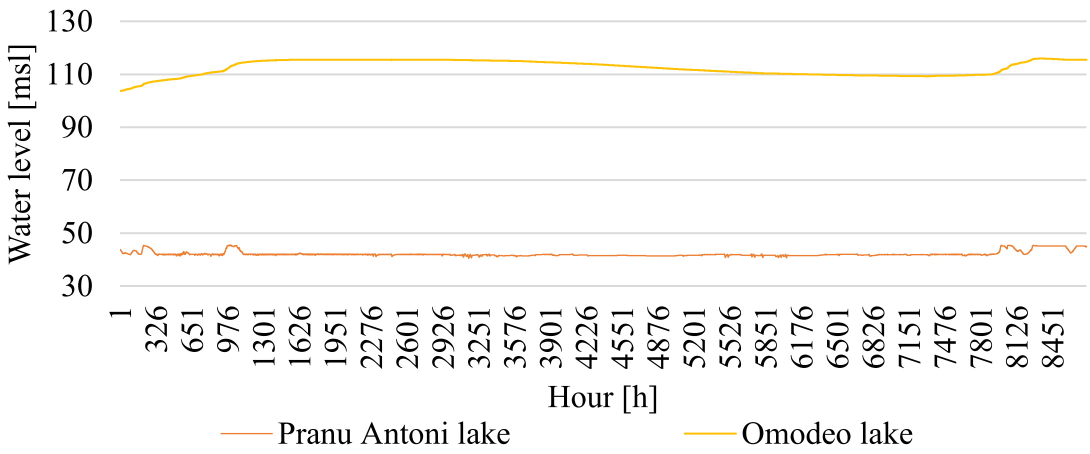


Figure 9.108 Reservoirs' water level over 2021 for markup=0.6

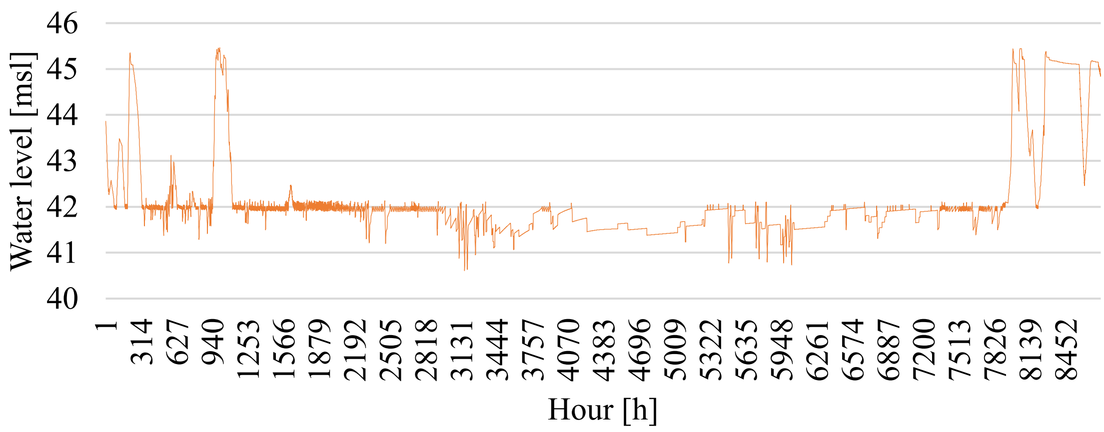


Figure 9.109 Pranu Antoni lake level variation over 2021 for markup=0.6

Table 79 Characteristic level of the reservoir for markup=0.6

MAX Pranu Antoni level	45.4646	msl	MIN Pranu Antoni level	40.6069	msl
MAX Omodeo level	115.934	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	4.85771	m	MAX diff Omodeo	12.2192	m

Table 80 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.6

Energy consumed T1	10506889192	Wh		
	10506.88919	MWh		
Energy produced T1	22223804265	Wh		
	22223.80426	MWh		
Utilization factor and equivalent hour				
Turbine mode	11.79983236	%	1033.665	h
Pump mode	3.661928828	%	320.785	h
Energy produced T2	6020940705	Wh		
	6020.940705	MWh		
Utilization factor and equivalent hour				
	16.36480948	%	1433.557	h

Table 81 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.6

Tirso 1				
Yearly sum pumping cost	325802.63	€	0.3258	M€
Yearly sum sale revenues	3949683.3	€	3.94968	M€
Yearly differential sum "profit"	3623880.7	€	3.62388	M€
Tirso 2				
Yearly sum sale revenues	678507.41	€	0.67851	M€

The economic parameters like NVP, IRR and LCOS are reported in Table 64 and Table 65.

9.3.3 Case 3: 30 MW PaT

Meanwhile in this case, the machines present in the plant configuration have the following characteristics as reported in Table 82.

Table 82 Machine's characteristics

Tirso 1's PaT		
Nominal power	30	MW
Nominal flow rate	39.1	m^3/s
Minimum head	54	m
Nominal head	78.2	m
Maximum head	80.4	m
Tirso 2's Kaplan turbine		
Nominal power	4.2	MW
Nominal flow rate	30	m^3/s
Minimum head	12	m
Nominal head	15.45	m
Maximum head	16	m

One interesting analysis that can be done on this case is the evaluation of the lost production due to the removal of the Tirso 1's Francis turbine. This loss of revenues will not be considered in the economic analysis since they are two different investments. The annual revenues for 2021 can be found from the measurement at the electric meter of Tirso 1.

The 2021 annual revenues from the sales of electricity amounted to 3.26 million of euro.

Then it may also be interesting to evaluate the decommissioning cost associated with the Francis turbine, which are defined as a fraction of the turbine cost.

The Francis turbine cost can be found through an empirical equation found in [33] (Equation 86).

Equation 86

$$C_{EM,Francis,[10^6€]_{2018}} = 2.929 * P_{[MW]}^{1.174} * H_{[m]}^{-0.4933} \quad \begin{cases} 1\,MW < P < 32\,MW \\ 17\,m < H < 573\,m \end{cases}$$

Meanwhile, the decommissioning cost is defined in Equation 87.

Equation 87 Decommissioning cost equation

$$C_{decomminsioning\ Francis,[10^6€]} = 0.25 * C_{EM,Francis,[10^6€]}$$

The results of the decommissioning analysis are reported in the following Table 83.

Table 83 Decommissioning cost computation

Francis' cost	14.09	M€
Average inflation EU	0.0243	
Annual revenues T1	3.26	M€
Francis' decommissioning cost	3.53	M€

If the annual revenues are considered constant for the next 20 years an estimated loss of revenues of 54.744 million of euro can be found.

One other consideration is that since pump and turbine are the same machine, they cannot be operating at the same time. The turbine operation is favored between the two. That has been done to avoid the overtopping of the reservoir's dam and the following loss of water. In fact, this is done only when the water level of the Omodeo lake reaches 115.5 msl.

The cost estimation of this configuration is reported in Figure 9.110.

						average inflation EU	0.0243	
	CAPEX							
c_EM	25.3169523	M€						
Penstoks								
D_opt	3.45576089	m		sigma_steel	310	N/mm^2	0.00031	N/m^2
t_pipe	43.5871776	mm		ASTM A537				
	0.04358718	m		safety factor	1	/		
weight_p	395743.896	Kg						
				steel density	7800	kg/m^3		
penstock lenght	336.834983	m						
				steel cost	1.4	€/kg		
vertical distance	31.7	m	(da dati)					
horizontal distance	335.34	m	(da maps)					
The cost of the penstock		554041.4551	€	0.671366463	M€			
Power house cost,2021		201.1508781	€/kW	6034526.342	€	2.53254706	M€	
		CAPEX	42.78129871	M€ --------->	1.42604329	€/W	1426.04329	€/kW
		OPEX	0.855625974	M€				
		direct costs	28.52086581	M€				
		indirect cost	14.2604329	M€				
LIFE SPAN	40	years						

Figure 9.110 Cost estimation for case 3

In the operating mode with markup equal to 0.3 the following operational curve for Pranu Antoni is obtained (Figure 9.111).

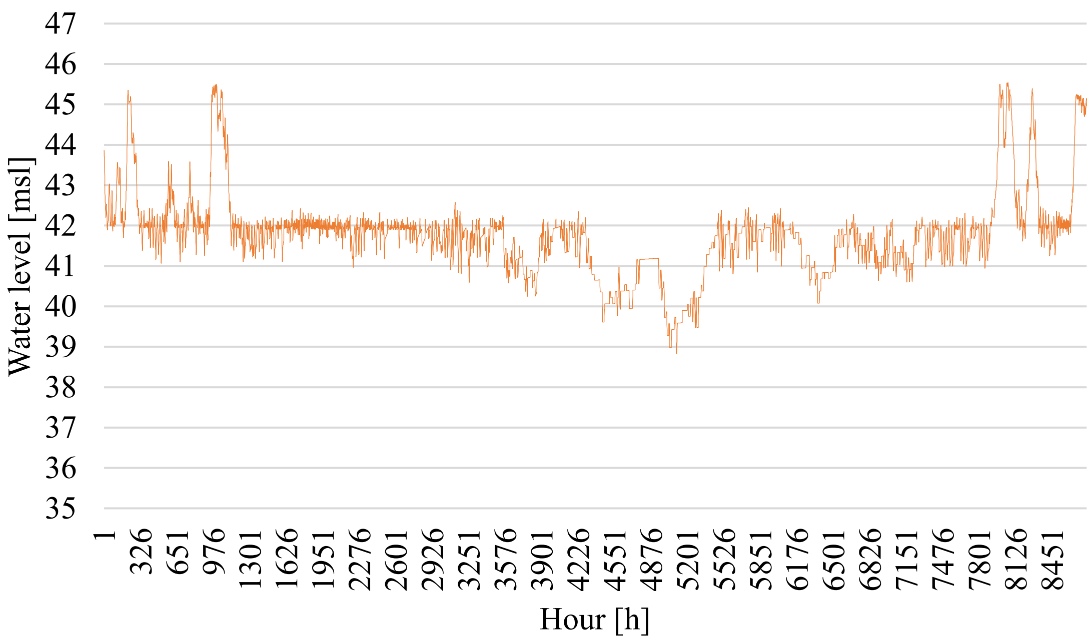


Figure 9.111 Pranu Antoni lake level variation over 2021 for markup=0.3

The water levels of the two reservoirs over the year 2021 are reported in Figure 9.112.

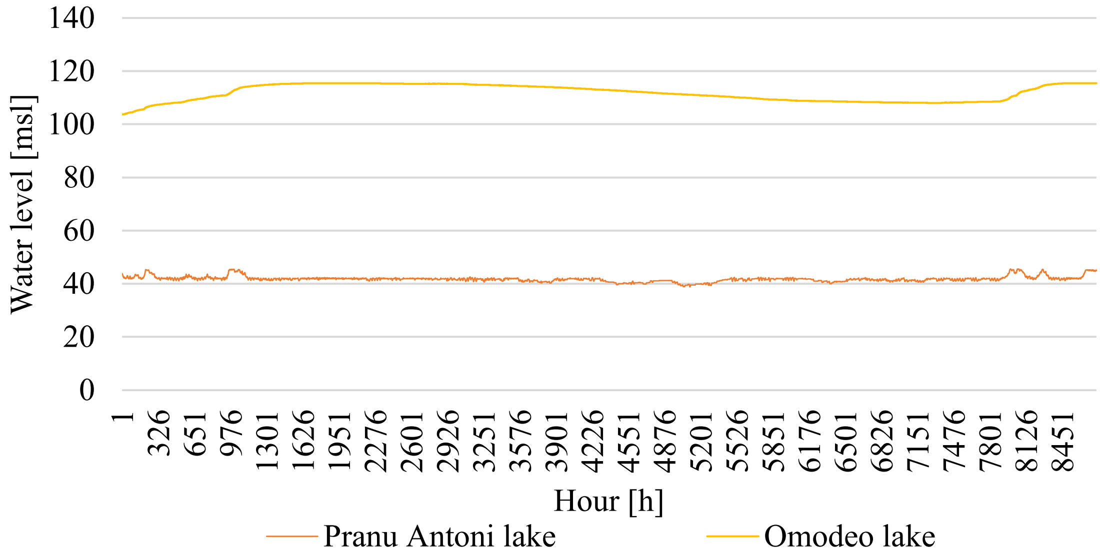


Figure 9.112 Reservoirs' water level over 2021 for markup=0.3

It is interesting to evaluate some critical parameters of the reservoirs' height since the water level controls the operation of the power plant (Table 84).

Table 84 Maximum and minimum water levels for the upper and lower reservoirs for markup=0.3

MAX Pranu Antoni level	45.5397	msl	MIN Pranu Antoni level	38.8366	msl
MAX Omodeo level	115.51	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	6.70306	m	MAX diff Omodeo	11.7952	m

The water volume oscillation over the year shows the effect of the extraction from the Omodeo lake, the operation of the power plant and the flood control by the two dams (Figure 9.113).

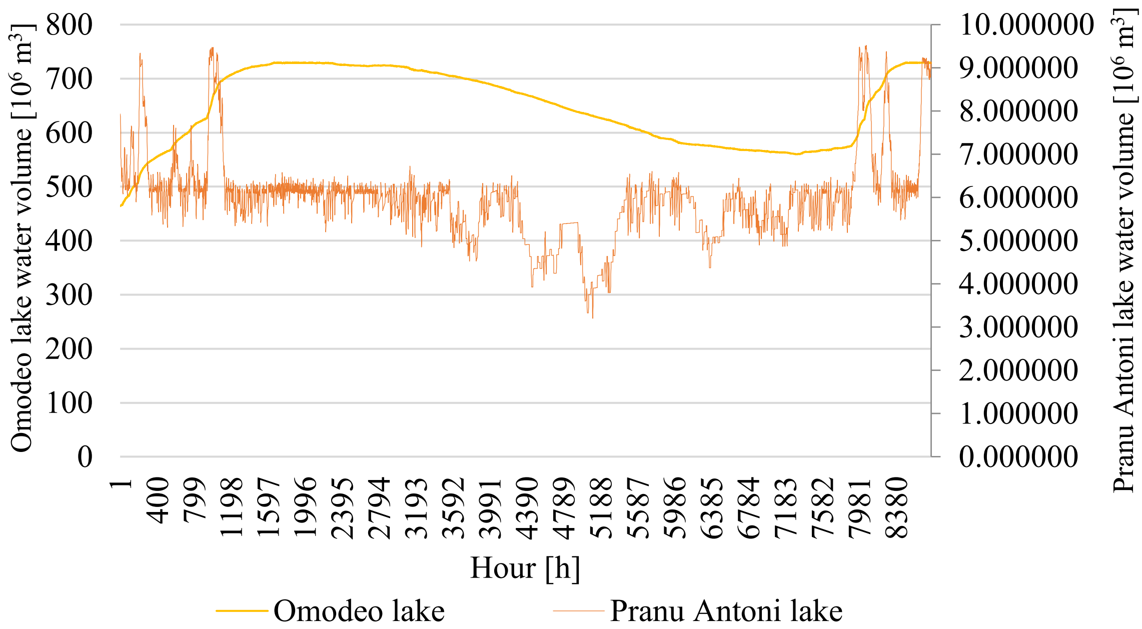


Figure 9.113 Reservoirs' volume over 2021 for markup=0.3

The Tirso river downstream flow is shown in Figure 9.114, where it can be noted the effect of flood lamination and of the operation of Tirso 2 power plant.

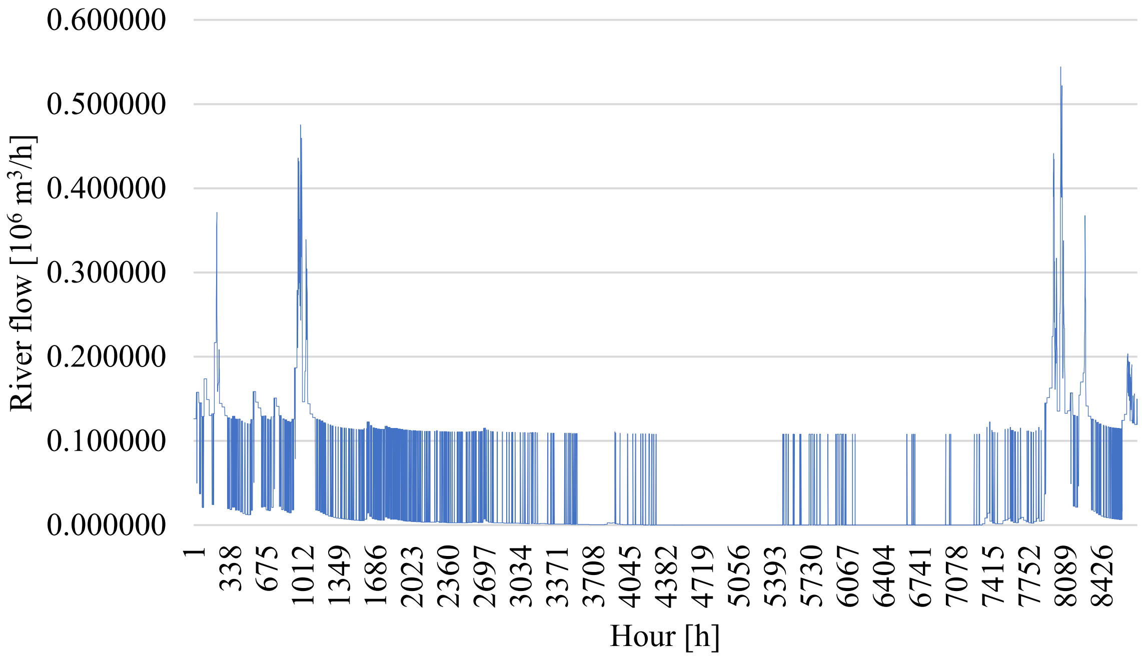


Figure 9.114 Tirso river's flow downstream the Pranu Antoni dam with markup=0.3

Next the electric power profiles for the turbine and the pump are reported in Figure 9.115.

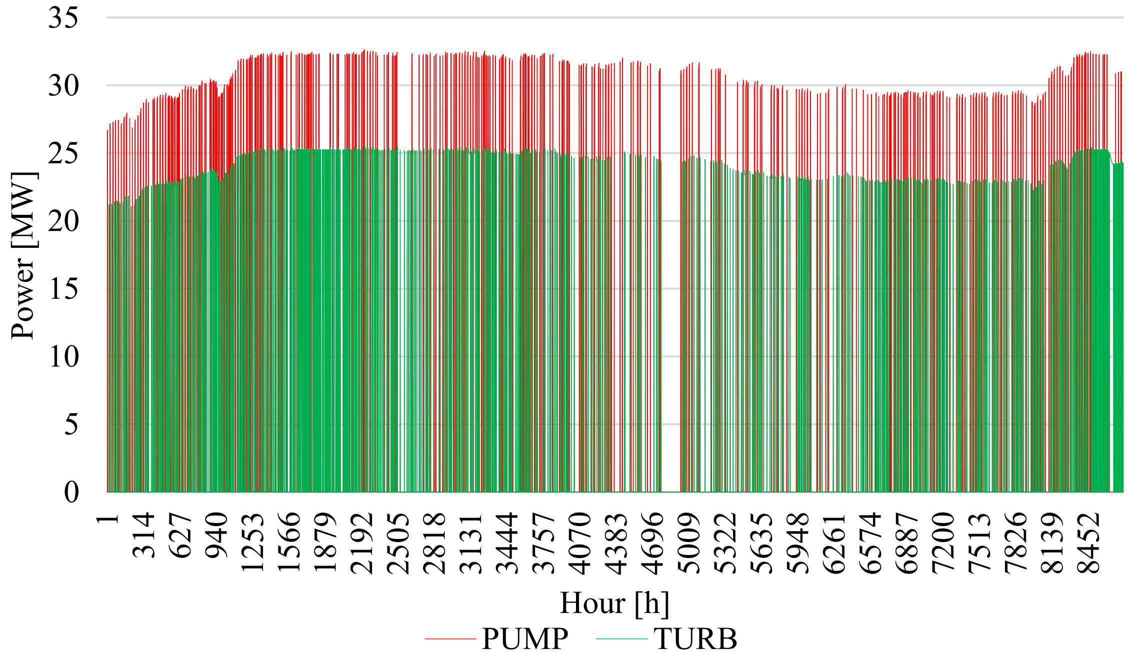


Figure 9.115 Consumption (red) and production (green) profile of the PaT for markup=0.3

As it can be seen from the figure above, the pumping power is around 33 MW. This must be considered when buying a new PaT.

With this profile it is possible to evaluate the energy consumption and production of the power plant (Table 85).

Table 85 Energy produced and consumed by Tirso 1 and Tirso 2 for markup=0.3

Energy consumed T1	39898264374	Wh		
	39898.26437	MWh		
Energy produced T1	44227810548	Wh		
	44227.81055	MWh		
Utilization factor and equivalent hour				
Turbine mode	16.82945607	%	1474.26	h
Pump mode	13.95117614	%	1222.123	h
Energy produced T2	7510740477	Wh		
	7510.740477	MWh		
Utilization factor and equivalent hour				
	20.4140587	%	1788.272	h

Meanwhile the economic value of this energy show in Table 86.

Table 86 Revenues and pumping cost of Tirso 1 and Tirso 2 for markup=0.3

Tirso 1				
Yearly sum pumping cost	3449557.4	€	3.44956	M€
Yearly sum sale revenues	6450786	€	6.45079	M€
Yearly differential sum "profit"	3001228.5	€	3.00123	M€
Tirso 2				
Yearly sum sale revenues	935648.31	€	0.93565	M€

The economic parameters of this operation mode are reported in Figure 9.116 and Figure 9.117.

Discounted cash flow	20.9819561	M€					
ROI - Return On Investment	0.04559347		4.559346792	%			
NPV - Net Present Value	-21.799343	M€	NO				
IP - profitability index	-0.5095531						
LCOS levelized cost of storage	0.00021874	€/Wh	0.218736682	€/kWh		218.7366823	€/MWh

Figure 9.116 Economic parameters for markup=0.3 and k=10%

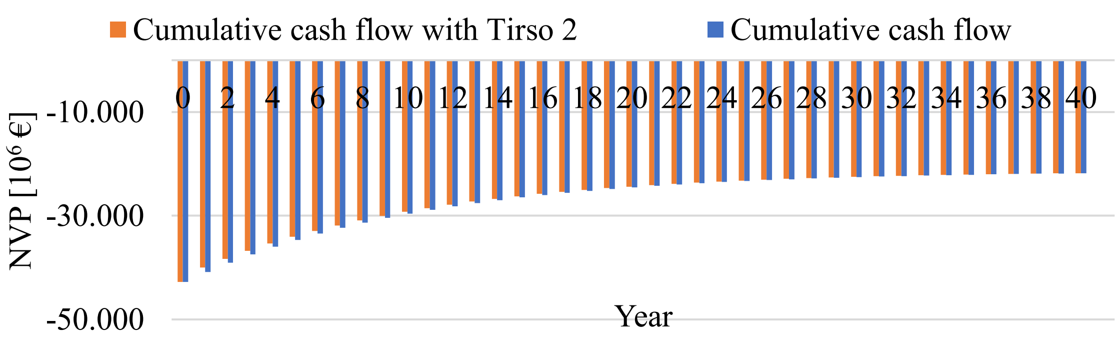


Figure 9.117 Cumulative cash flow for markup=0.3 with k=10%

One of the most important indicators of the project feasibility is the IRR which is reported in Figure 9.118.

Table 87 Markup vs IRR for case 3

Markup	IRR [%]
0.1	3.466
0.2	4.502
0.3	4.23
0.4	4.992
0.5	4.568
0.6	4.795

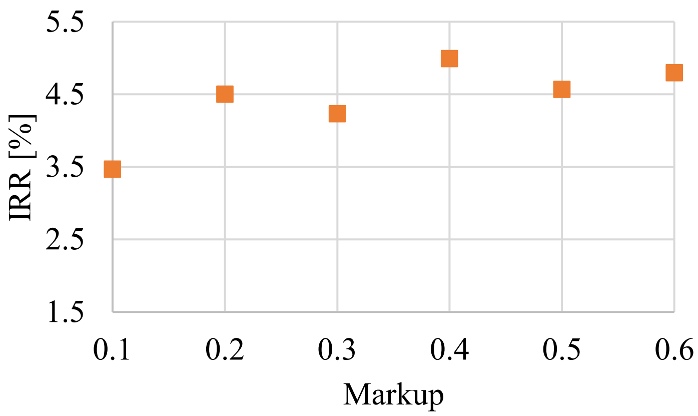


Figure 9.118 Markup vs IRR plot

It is also interesting to consider the change in annual net profit and of the Tirso 2 revenues with changing markup. It can be noted that the annual net profit stays relatively constant with changing markup, this is due to the fact the difference between turbined and pumped volumes stays the same.

The revenues of Tirso 2 remain relatively unchanged in all the operating mode of the power plant.

Table 88 Markup vs annual profit and Tirso 2 revenues for case 3

Markup	**Annual net profit**		**Tirso 2 revenues**	
0.1	3.147244681	M€	0.955715331	M€
0.2	3.362872776	M€	1.041579404	M€
0.3	3.001228522	M€	0.935648315	M€
0.4	3.221518284	M€	1.017755378	M€
0.5	3.081908155	M€	1.04079885	M€
0.6	3.158617344	M€	0.894081566	M€

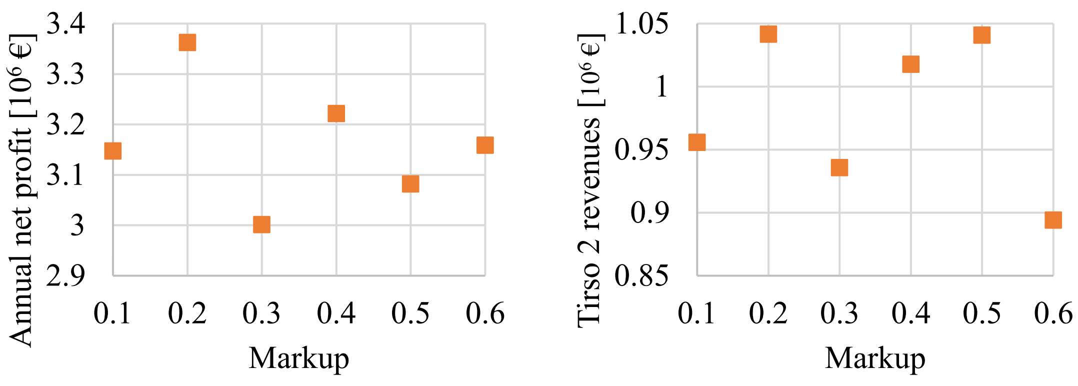


Figure 9.119 Markup vs annual net profit (left) and markup vs Tirso 2 revenues (right) for a 30 MW PaT

The final step of the economic analysis consists in the sensitivity analysis of the NPV and of the LCOS for the different operating mode (markup). The results of the analysis are reported in Table 89.

Table 89 Sensitivity analysis of NPV and LCOS

k	10%	
Markup	**NPV [10^6 €]**	**LCOS [€/MWh]**
0.1	-22.4632456	181.544
0.2	-20.35460753	197.693
0.3	-21.79934258	218.737
0.4	-19.64511782	245.425
0.5	-21.01037235	277.715
0.6	-20.2602293	307.522

k	5%	
Markup	**NPV [10^6 €]**	**LCOS [€/MWh]**
0.1	-7.129655424	154.9
0.2	-3.429674329	160.963
0.3	-5.96471932	167.135
0.4	-2.184748271	176.244
0.5	-4.580330524	188.138
0.6	-3.264070926	200.55

k	3%	
Markup	**NPV [10^6 €]**	**LCOS [€/MWh]**
0.1	5.244545328	145.715
0.2	10.22873957	148.3
0.3	6.813814919	149.346
0.4	11.90576254	152.394
0.5	8.678706248	157.256
0.6	10.45182166	163.672

The result of the analysis can be more clearly seen in the following figures.

As for case 2, the NPV in case 3 is strongly dependent on the cost of capital k. The NPV reaches its maximum for markup of 0.2 and 0.4 (Figure 9.120).

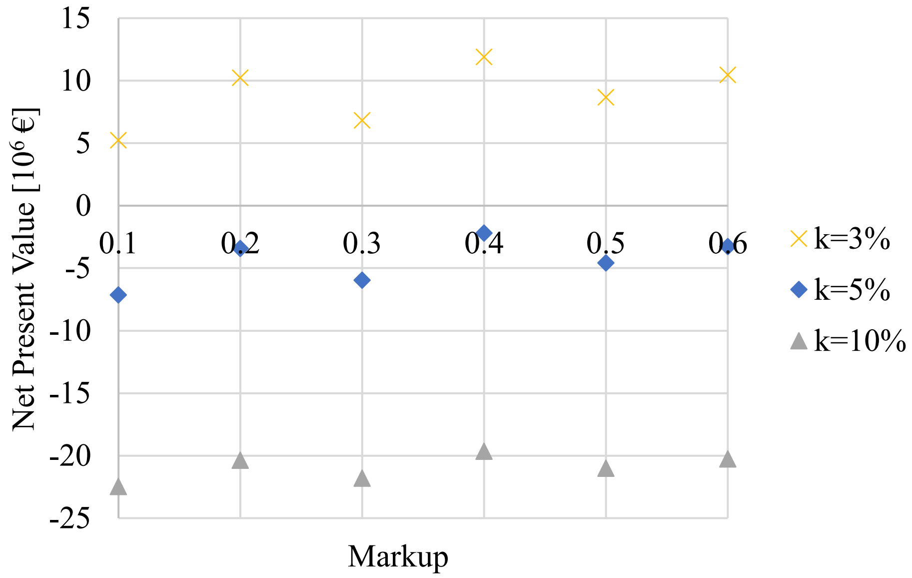


Figure 9.120 Sensitivity analysis of the NPV

Meanwhile for the analysis of the LCOS it can be noted in Figure 9.121 that it increases for increasing markup, particularly for high cost of capital. Low cost of capital means that the LCOS is less influenced by the operating mode. For low markup, in particular for cost of capital k=5% and k=3%, the LCOS remains almost constant until 0.3/0.4.

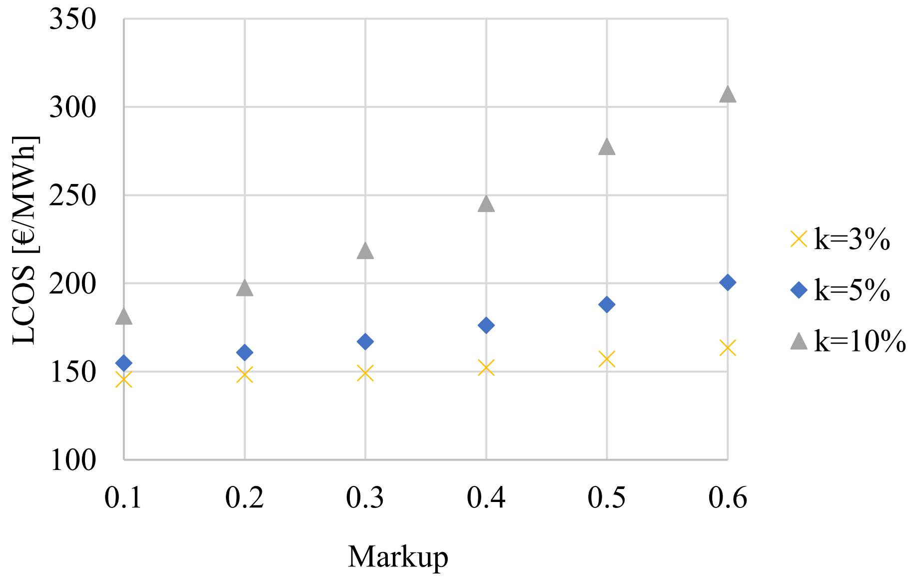


Figure 9.121 Sensitivity analysis of the LCOS

At last, the different operating mode show different operational profile which are reported below.

- 30 MW PaT – markup=0.1

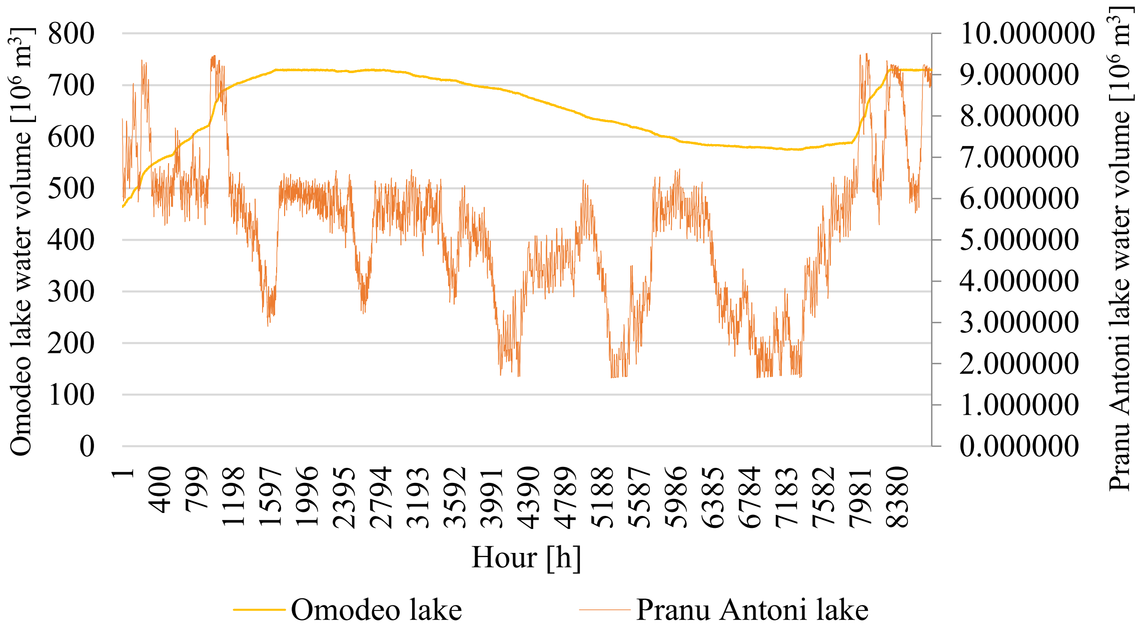


Figure 9.122 Reservoirs' volume over 2021 for markup=0.1

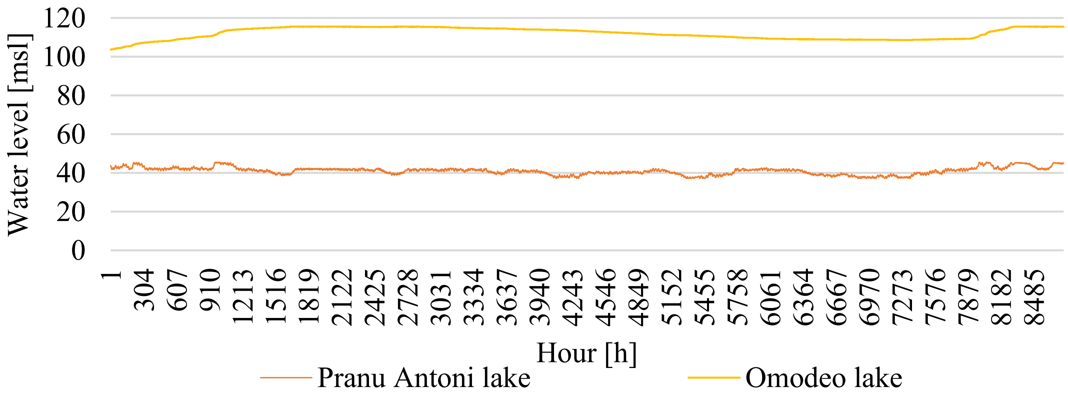


Figure 9.123 Reservoirs' water level over 2021 for markup=0.1

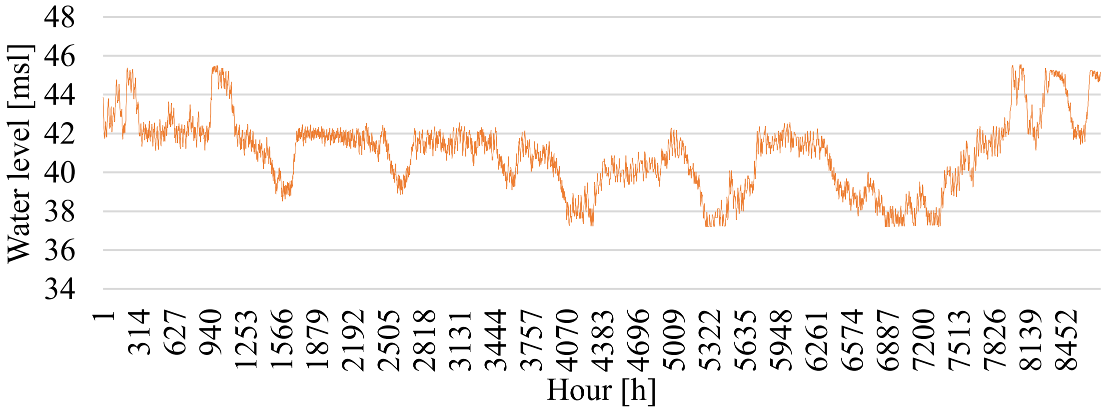


Figure 9.124 Pranu Antoni lake level variation over 2021 for markup=0.1

Table 90 Characteristic level of the reservoir for markup=0.1

MAX Pranu Antoni level	45.5435	msl	MIN Pranu Antoni level	37.2019	msl
MAX Omodeo level	115.516	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	8.34165	m	MAX diff Omodeo	11.8015	m

Table 91 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.1

Energy consumed T1	92852543059	Wh		
	92852.54306	MWh		
Energy produced T1	85658345897	Wh		
	85658.3459	MWh		
Utilization factor and equivalent hour				
Turbine mode	32.59449996	%	2855.278	h
Pump mode	31.55185184	%	2763.942	h
Energy produced T2	7322331441	Wh		
	7322.331441	MWh		
Utilization factor and equivalent hour				
	19.9019663	%	1743.412	h

Table 92 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.1

Tirso 1				
Yearly sum pumping cost	9112126.5	€	9.11213	M€
Yearly sum sale revenues	12259371	€	12.2594	M€
Yearly differential sum "profit"	3147244.7	€	3.14724	M€
Tirso 2				
Yearly sum sale revenues	955715.33	€	0.95572	M€

- 30 MW PaT – markup=0.2

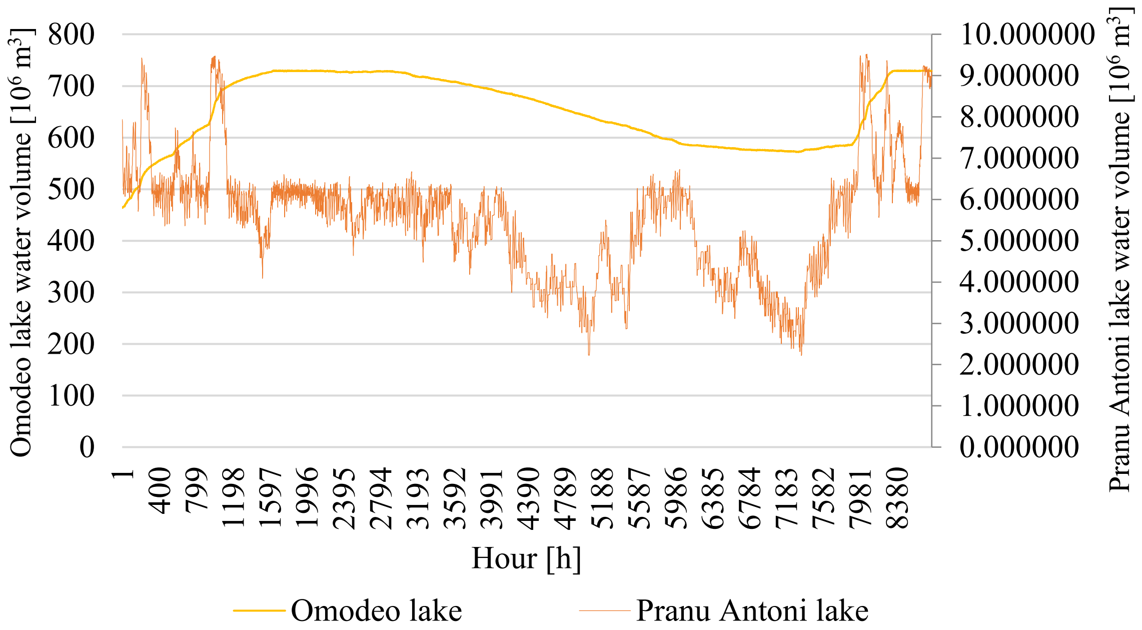


Figure 9.125 Reservoirs' volume over 2021 for markup=0.2

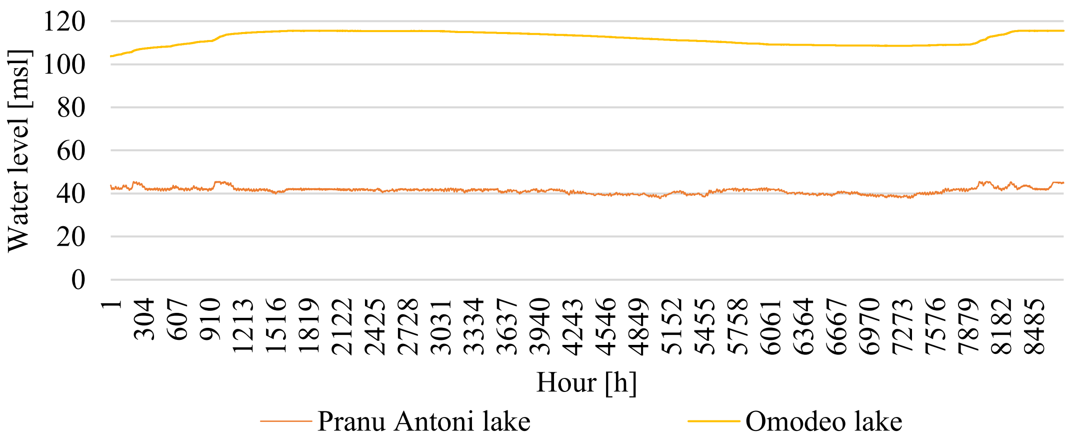


Figure 9.126 Reservoirs' water level over 2021 for markup=0.2

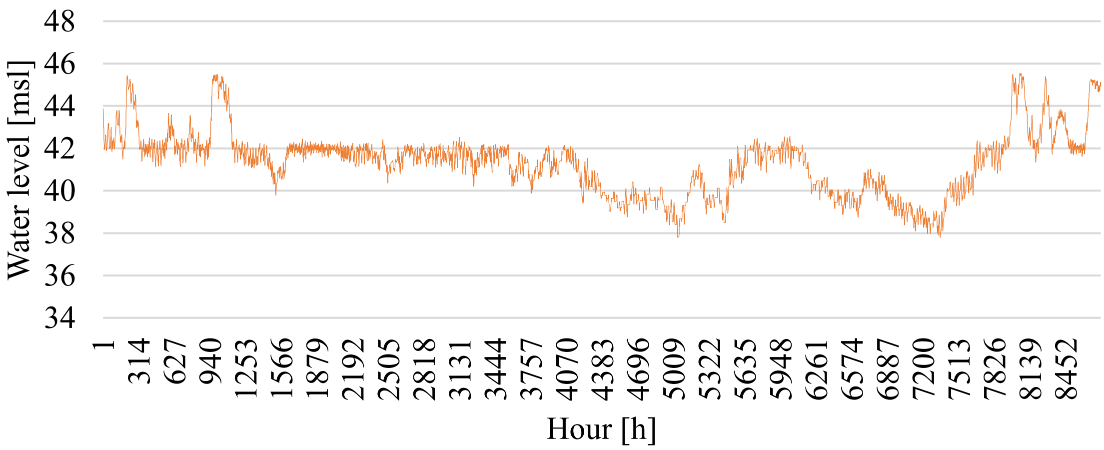


Figure 9.127 Pranu Antoni lake level variation over 2021 for markup=0.2

Table 93 Characteristic level of the reservoir for markup=0.2

MAX Pranu Antoni level	45.5428	msl	MIN Pranu Antoni level	37.7995	msl
MAX Omodeo level	115.516	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	7.74327	m	MAX diff Omodeo	11.8015	m

Table 94 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.2

Energy consumed T1	62729778156	Wh		
	62729.77816	MWh		
Energy produced T1	62135077039	Wh		
	62135.07704	MWh		
Utilization factor and equivalent hour				
Turbine mode	23.64348441	%	2071.169	h
Pump mode	21.65123377	%	1896.648	h
Energy produced T2	7648106799	Wh		
	7648.106799	MWh		
Utilization factor and equivalent hour				
	20.78741791	%	1820.978	h

Table 95 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.2

Tirso 1				
Yearly sum pumping cost	5845075.1	€	5.84508	M€
Yearly sum sale revenues	9207947.9	€	9.20795	M€
Yearly differential sum "profit"	3362872.8	€	3.36287	M€
Tirso 2				
Yearly sum sale revenues	1041579.4	€	1.04158	M€

- 30 MW PaT – markup=0.4

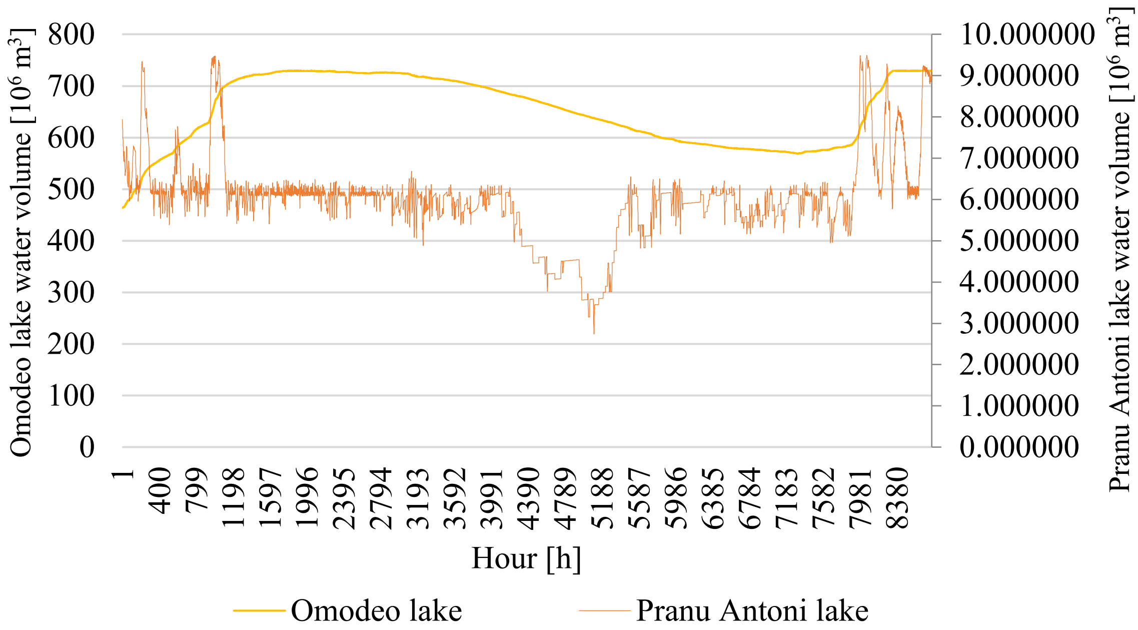


Figure 9.128 Reservoirs' volume over 2021 for markup=0.4

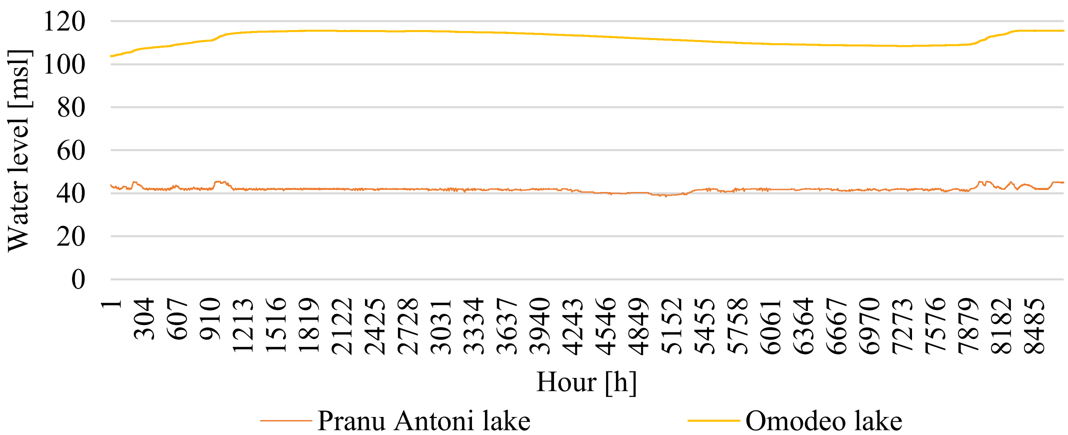


Figure 9.129 Reservoirs' water level over 2021 for markup=0.4

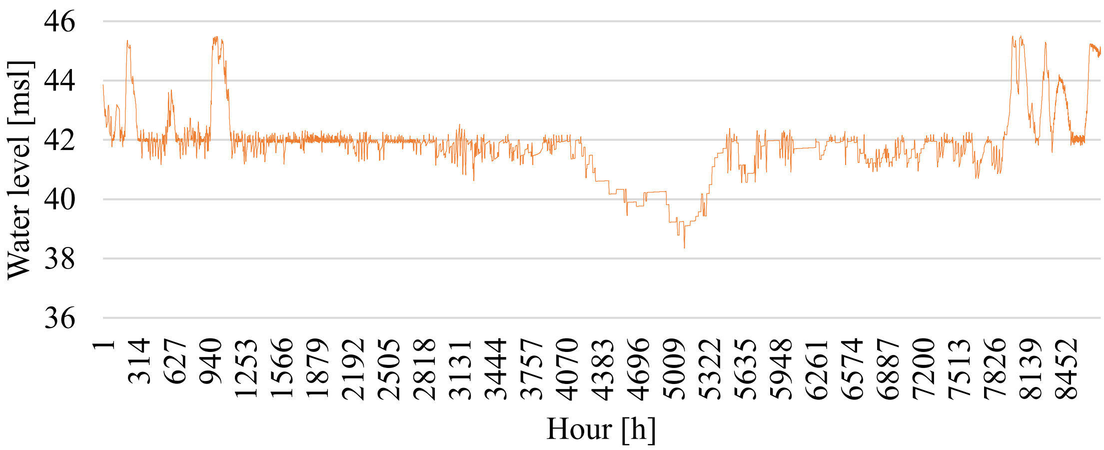


Figure 9.130 Pranu Antoni lake level variation over 2021 for markup=0.4

Table 96 Characteristic level of the reservoir for markup=0.4

MAX Pranu Antoni level	45.5074	msl	MIN Pranu Antoni level	38.3532	msl
MAX Omodeo level	115.511	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	7.15427	m	MAX diff Omodeo	11.7956	m

Table 97 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.4

Energy consumed T1	25477371111	Wh		
	25477.37111	MWh		
Energy produced T1	32989030543	Wh		
	32989.03054	MWh		
Utilization factor and equivalent hour				
Turbine mode	12.55290355	%	1099.634	h
Pump mode	8.925651568	%	781.8871	h
Energy produced T2	7468631395	Wh		
	7468.631395	MWh		
Utilization factor and equivalent hour				
	20.29960697	%	1778.246	h

Table 98 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.4

Tirso 1				
Yearly sum pumping cost	1871654.9	€	1.87165	M€
Yearly sum sale revenues	5093173.2	€	5.09317	M€
Yearly differential sum "profit"	3221518.3	€	3.22152	M€
Tirso 2				
Yearly sum sale revenues	1017755.4	€	1.01776	M€

- 30 MW PaT – markup=0.5

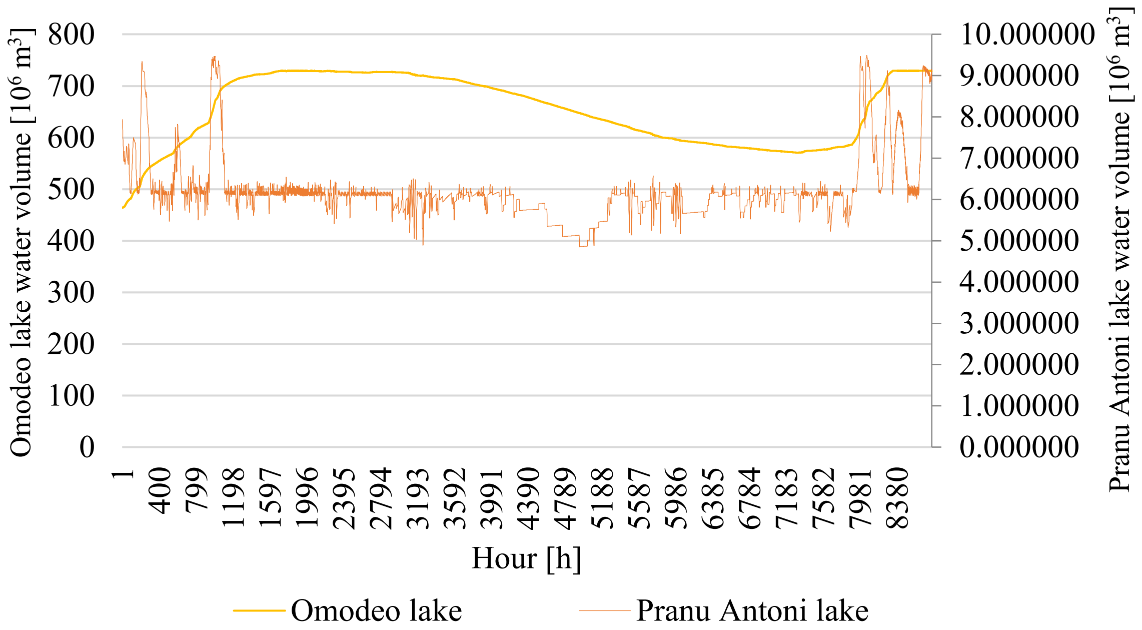


Figure 9.131 Reservoirs' volume over 2021 for markup=0.5

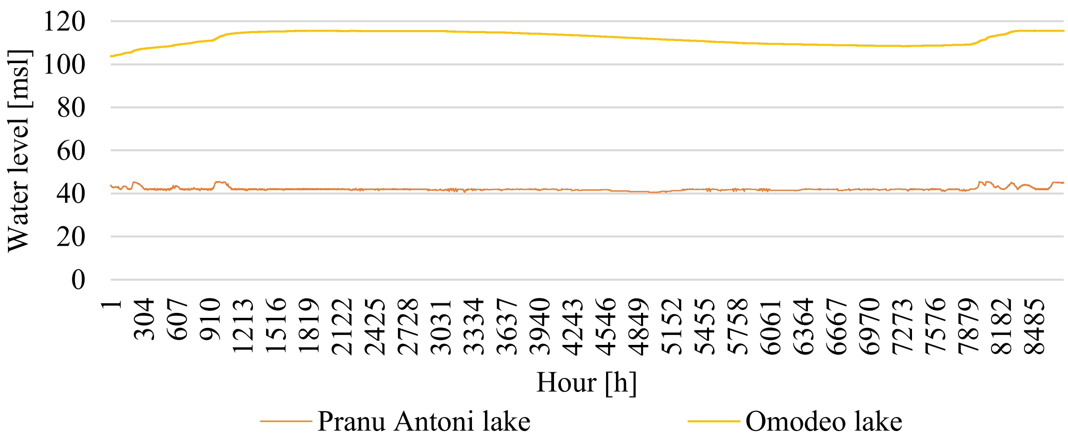


Figure 9.132 Reservoirs' water level over 2021 for markup=0.5

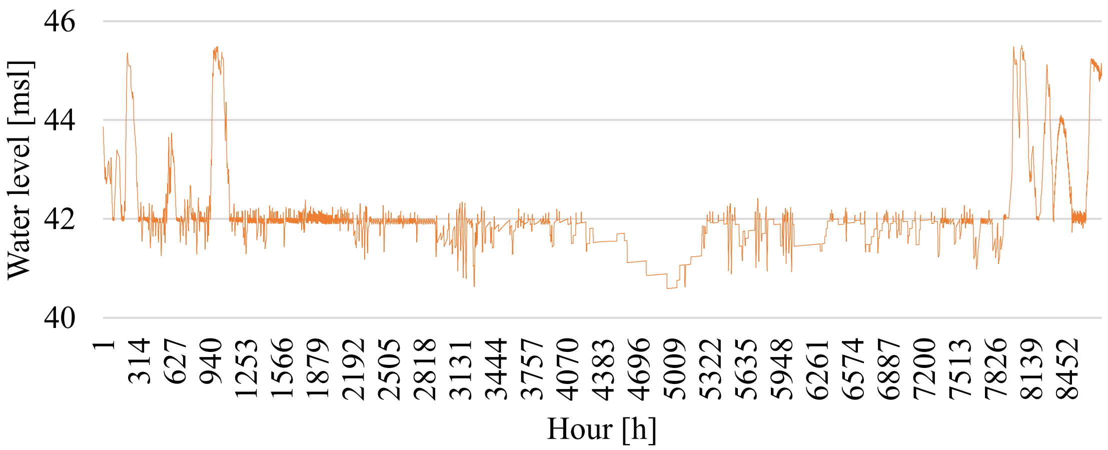


Figure 9.133 Pranu Antoni lake level variation over 2021 for markup=0.5

Table 99 Characteristic level of the reservoir for markup=0.5

MAX Pranu Antoni level	45.5074	msl	MIN Pranu Antoni level	40.5924	msl
MAX Omodeo level	115.51	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	4.91503	m	MAX diff Omodeo	11.7952	m

Table 100 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.5

Energy consumed T1	15918237802	Wh		
	15918.2378	MWh		
Energy produced T1	25477708355	Wh		
	25477.70836	MWh		
Utilization factor and equivalent hour				
Turbine mode	9.694713986	%	849.2569	h
Pump mode	5.570150897	%	487.9452	h
Energy produced T2	7477071036	Wh		
	7477.071036	MWh		
Utilization factor and equivalent hour				
	20.32254576	%	1780.255	h

Table 101 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.5

Tirso 1				
Yearly sum pumping cost	850854.07	€	0.85085	M€
Yearly sum sale revenues	3932762.2	€	3.93276	M€
Yearly differential sum "profit"	3081908.2	€	3.08191	M€
Tirso 2				
Yearly sum sale revenues	1040798.8	€	1.0408	M€

- 30 MW PaT – markup=0.6

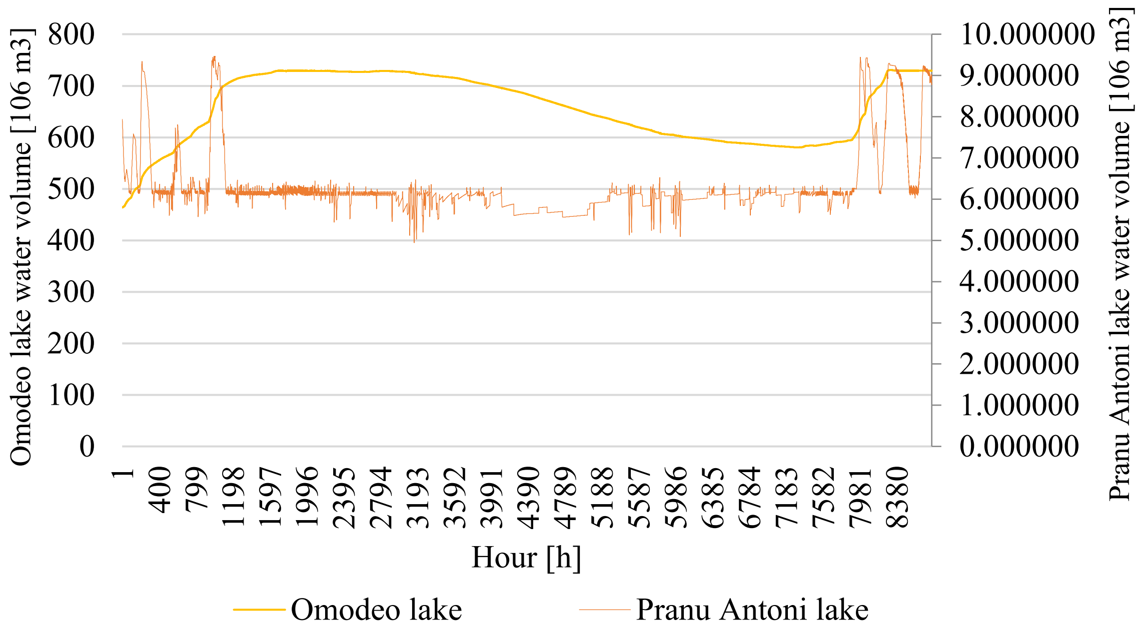


Figure 9.134 Reservoirs' volume over 2021 for markup=0.6

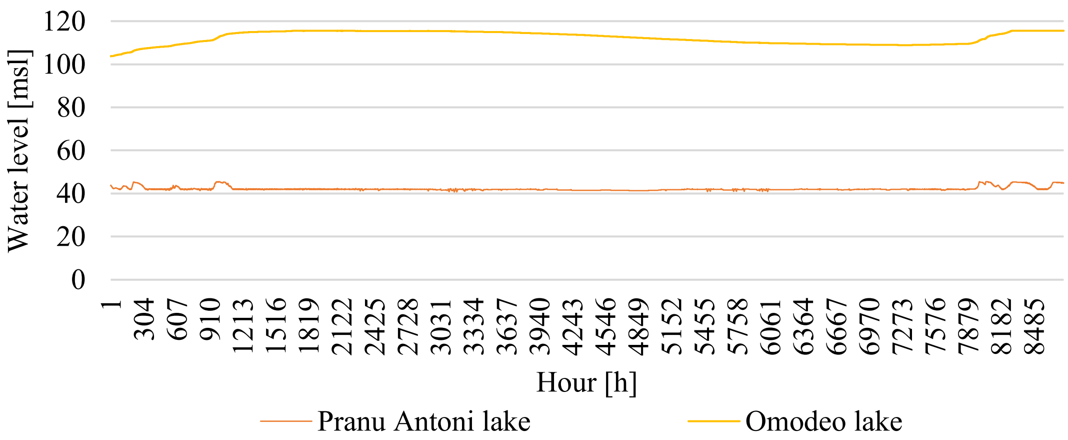


Figure 9.135 Reservoirs' water level over 2021 for markup=0.6

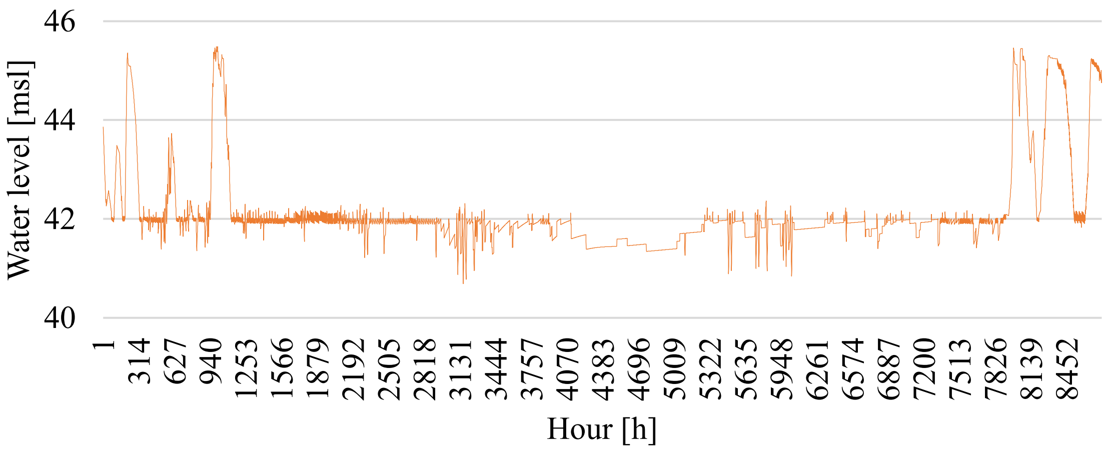


Figure 9.136 Pranu Antoni lake level variation over 2021 for markup=0.6

Table 102 Characteristic level of the reservoir for markup=0.6

MAX Pranu Antoni level	45.4882	msl	MIN Pranu Antoni level	40.6899	msl
MAX Omodeo level	115.57	msl	MIN Omodeo level	103.715	msl
MAX diff Pranu Antoni	4.79827	m	MAX diff Omodeo	11.855	m

Table 103 Energy consumed, produced by Tirso 1 and Tirso 2 for markup=0.6

Energy consumed T1	10665327332	Wh		
	10665.32733	MWh		
Energy produced T1	21334847844	Wh		
	21334.84784	MWh		
Utilization factor and equivalent hour				
Turbine mode	8.118283046	%	711.1616	h
Pump mode	3.723761951	%	326.2015	h
Energy produced T2	6828919366	Wh		
	6828.919366	MWh		
Utilization factor and equivalent hour				
	18.56088108	%	1625.933	h

Table 104 Tirso 1 and Tirso 2 revenues and pumping cost for markup=0.6

Tirso 1				
Yearly sum pumping cost	336248.46	€	0.33625	M€
Yearly sum sale revenues	3494865.8	€	3.49487	M€
Yearly differential sum "profit"	3158617.3	€	3.15862	M€
Tirso 2				
Yearly sum sale revenues	894081.57	€	0.89408	M€

9.3.4 Comparison and analysis

From the data obtained in the analysis of the three cases it is possible to compare the result of the economic analysis of the LCOS, of the NPV and of the IRR.

The Table 105, Table 106 and Table 107 report the LCOS respectively for cost of capital 10%, 5% and 3%.

Table 105 LCOS comparison between the three cases with k=10%

Markup	LCOS [€/MWh]		
	Case 1	Case 2	Case 3
0.1	129.752	177.046	181.544
0.2	141.349	190.773	197.693
0.3	157.489	205.034	218.737
0.4	195.625	230.832	245.425
0.5	247.18	260.664	277.715
0.6	336.252	288.036	307.522

Table 106 LCOS comparison between the three cases with k=5%

Markup	LCOS [€/MWh]		
	Case 1	Case 2	Case 3
0.1	108.542	148.136	154.9
0.2	113.05	152.482	160.963
0.3	118.416	154.626	167.135
0.4	139.483	164.2	176.244
0.5	166.818	175.723	188.138
0.6	218.949	187.805	200.55

Table 107 LCOS comparison between the three cases with k=3%

Markup	LCOS [€/MWh]		
	Case 1	Case 2	Case 3
0.1	101.23	138.169	145.715
0.2	103.294	139.281	148.3
0.3	104.946	137.247	149.346
0.4	120.128	141.228	152.394
0.5	139.114	146.439	157.256
0.6	178.509	153.251	163.672

Meanwhile, the Table 108, Table 109 and Table 110 report the NPV respectively for cost of capital k 10%, 5% and 3%.

Table 108 NPV comparison between the three cases with k=10%

Markup	NPV [10^6 €]		
	Case 1	Case 2	Case 3
0.1	16.32913565	-15.01913685	-22.4632456
0.2	12.44867422	-12.16523333	-20.35460753
0.3	1.261702262	-10.35352724	-21.79934258
0.4	-14.97289475	-11.41381209	-19.64511782
0.5	-26.42325082	-14.52000035	-21.01037235
0.6	-36.37494892	-14.48412848	-20.2602293

Table 109 NPV comparison between the three cases with k=5%

Markup	NPV [10^6 €]		
	Case 1	Case 2	Case 3
0.1	65.90546406	5.158311714	-7.129655424
0.2	59.09650328	10.16599379	-3.429674329
0.3	39.46696834	13.34495482	-5.96471932
0.4	10.98047614	11.48449619	-2.184748271
0.5	-9.111213163	6.0341356	-4.580330524
0.6	-26.5732401	6.097079185	-3.264070926

Table 110 NPV comparison between the three cases with k=3%

Markup	NPV [10^6 €]		
	Case 1	Case 2	Case 3
0.1	105.91354	21.44150413	5.244545328
0.2	96.74128151	28.18728457	10.22873957
0.3	70.29860182	32.46961977	6.813814919
0.4	31.9248354	29.96342123	11.90576254
0.5	4.859593868	22.62131458	8.678706248
0.6	-18.66326525	22.70610502	10.45182166

To find the best configuration it is necessary to fix the cost of capital and then changing the different operating mode (markup) report the different LCOS.

- k=10%

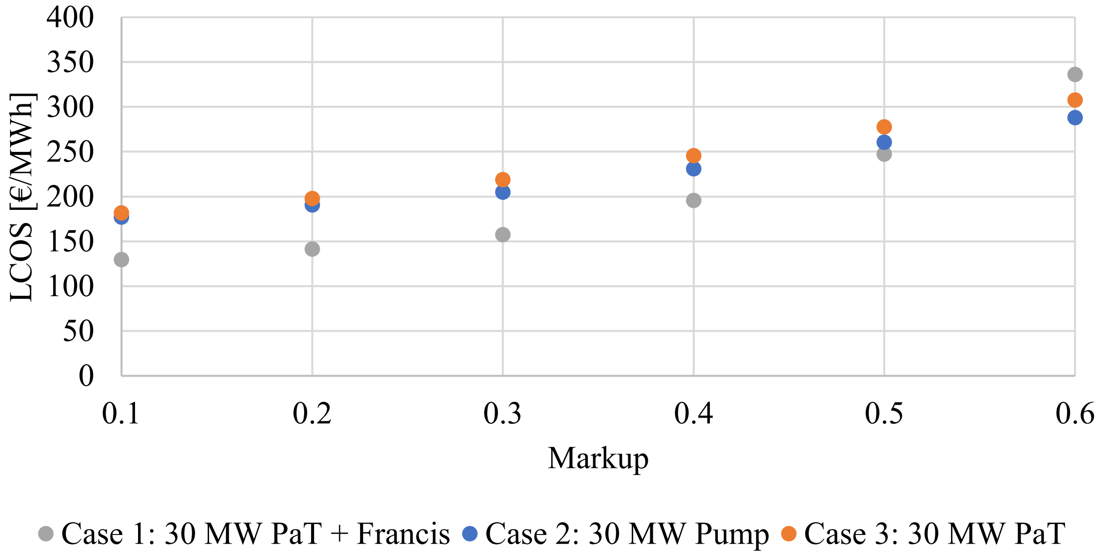


Figure 9.137 Markup vs LCOS for the three cases with k=10%

From the Figure 9.137 it can be noted that the LCOS increase dramatically with increasing markup and with high interest rate. This is particularly true for case 1, in which the price almost triples. The cheapest configuration for most of the operating mode remains the case 1. Meanwhile, considering the NPV in 40 year it can be noted the strong effect of the cost of capital and of the annual net profit (Table 112), which is far higher in case 1, for low markup, than case 2 and 3 due to the presence of the Francis turbine which almost doubles the installed turbine capacity. This is a typical configuration in PHS plant around the world. In the other two cases the net profits remain more constant with changing markup as it can be noted in Figure 9.138.

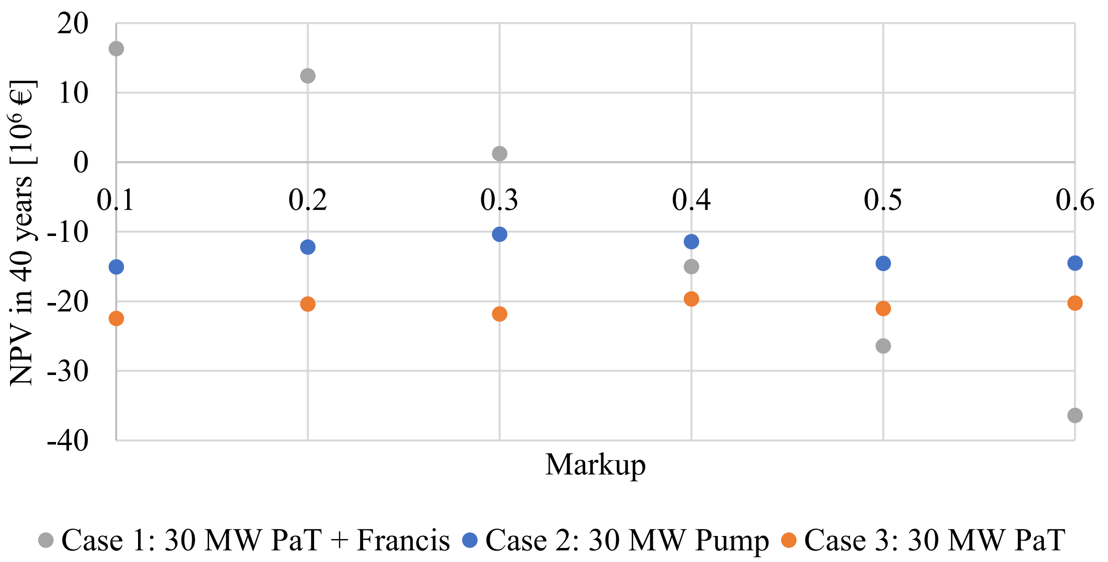


Figure 9.138 Markup vs NPV for the three cases with k=10%

- k=5%

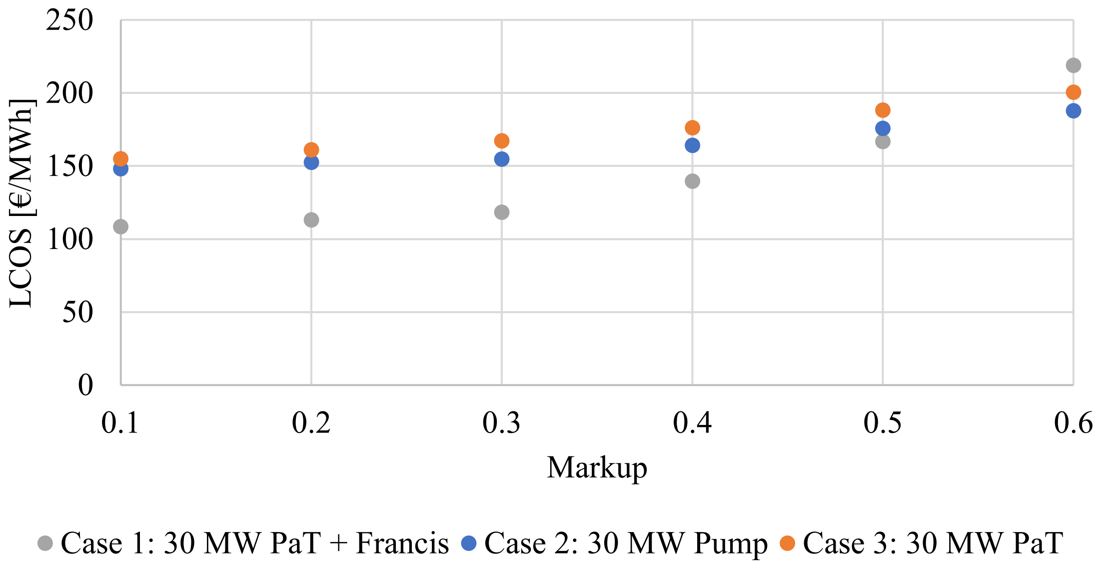


Figure 9.139 Markup vs LCOS for the three cases with k=5%

From Figure 9.139, and this is true for all cases and different cost of capital, it can be noted that the LCOS for case 2 and 3 are very close to each other with markup lower than 0.3, and then that difference increases increasing the markup.

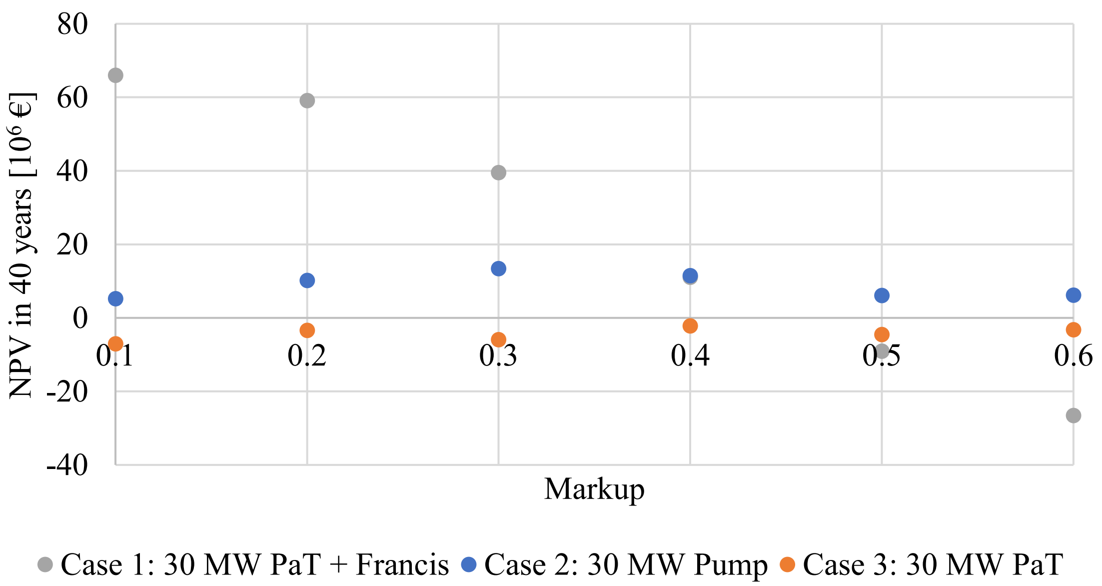


Figure 9.140 Markup vs NPV for the three cases with k=5%

With a decrease in the cost of capital, it can be noticed a decrease in the LCOS and an increase in the NPV compared to the case k=10%, but with the same trends.

- k=3%

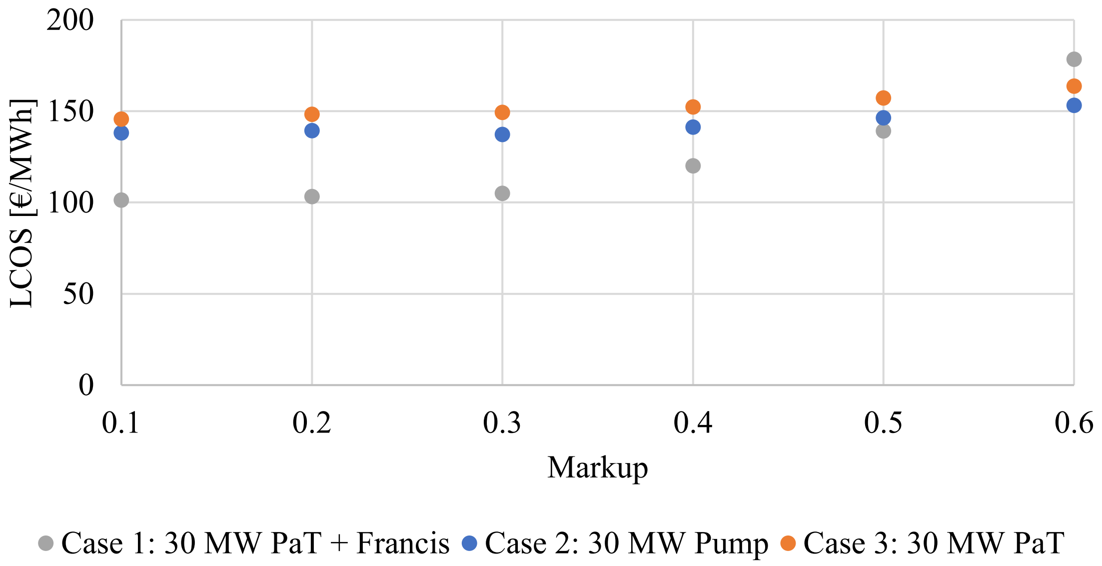


Figure 9.141 Markup vs LCOS for the three cases with k=3%

As for all capital-intensive project the LCOS is strongly dependent on the cost of capital. Decreasing again the cost of capital k causes the price to remain more constant with changing markup, particularly with case 2 and case 3.

With k=3%, the LCOS for case 3 remains almost constant for the all the operating modes but is remains higher than all other case. This is due to the fact the case 2 has lower CAPEX cost and better operation during the year.

The NPV for case 2 and case 3 is strongly dependent on the cost of capital, more than case 1. At last, it can be noted the maximum for the NPV curve in 0.3 for case 2.

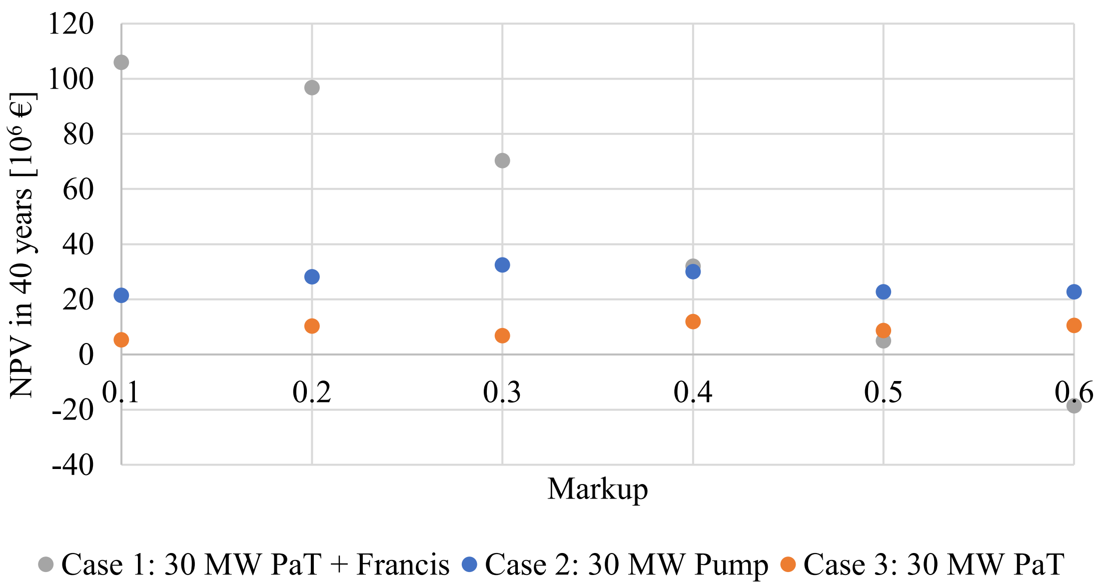


Figure 9.142 Markup vs NPV for the three cases with k=3%

The values of IRR for the three cases are reported in Table 111.

Table 111 IRR comparison between the three cases

Markup	IRR [%]		
	Case 1	Case 2	Case 3
0.1	13.524	5.882	3.466
0.2	12.7	6.707	4.502
0.3	10.27	7.217	4.23
0.4	6.564	6.918	4.992
0.5	3.595	6.028	4.568
0.6	0.363	6.038	4.795

When looking at curves for the IRR, it must be remembered that the IRR represents the maximum cost of capital that the company can afford to keep the project economically viable.

If the IRR is greater or equal to the cost of capital, the company would accept the project as good investment (Figure 9.143). So, to keep the NPV positive the interest rate of the project must be lower than IRR.

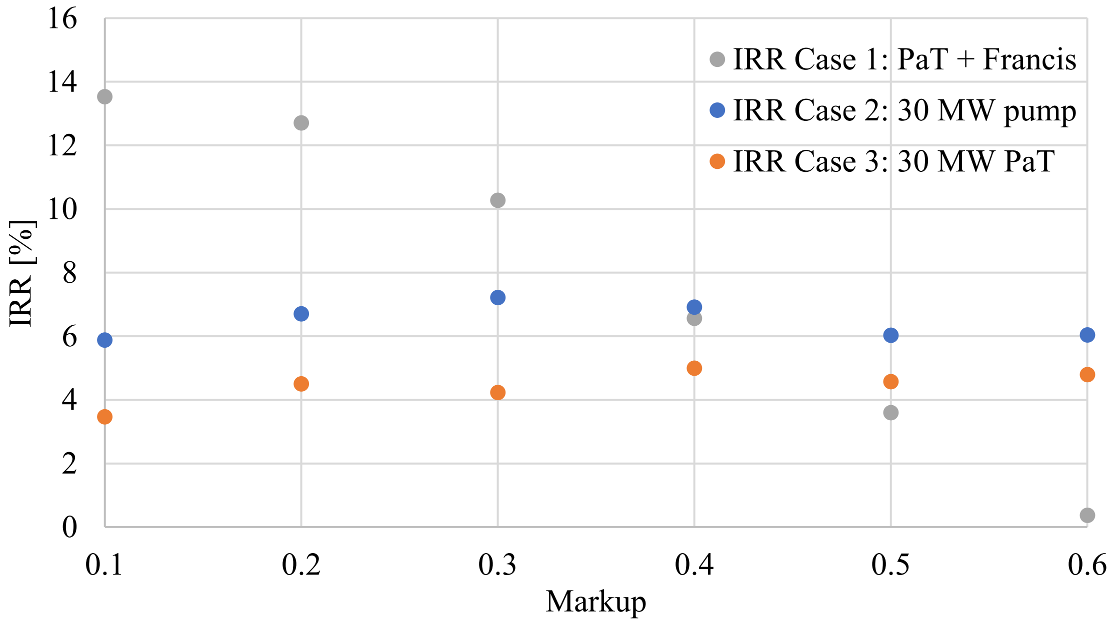


Figure 9.143 Markup vs IRR for the three cases

After having considered all the presented configuration, from the analysis of the IRR it can be said that the best configuration is case 1 when the power plant is operating between markups of 0.2 and 0.3. Meanwhile if the markup is greater than 0.3, than the best option will be case 2.

Of course, the profitability of the investment depends also strongly by the annual net profit. In fact, the curves for the annual net profit have the same trend of the IRR as reported in Figure 9.144.

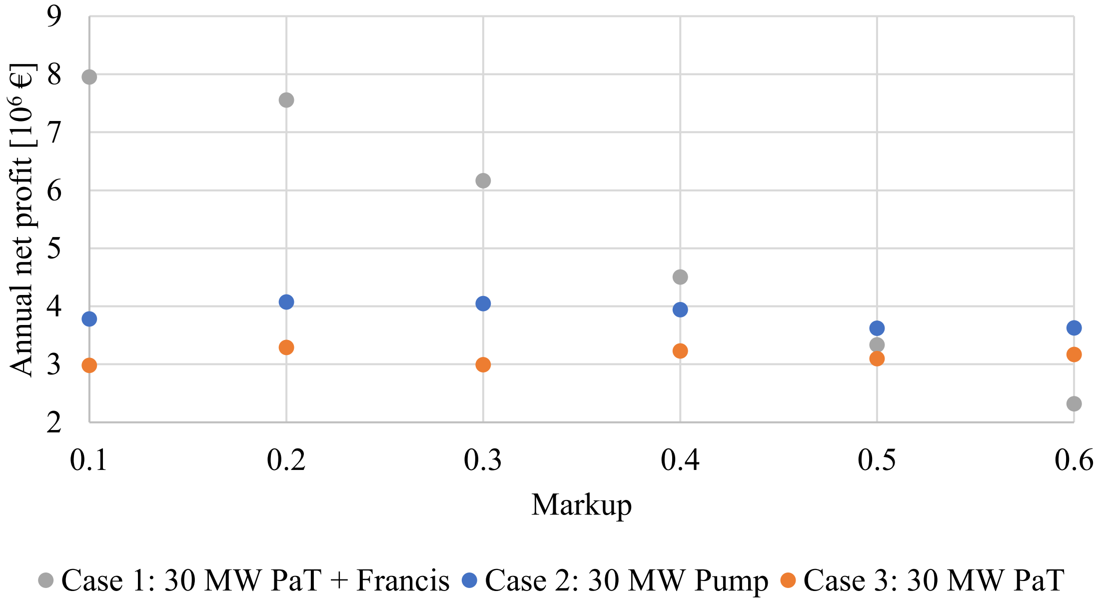


Figure 9.144 Markup vs Annual net profit for the three cases

The annual net profit of case 3 remains more constant with changing markup because the power plant is pumping and turbining about the same volumes of water for the various operating mode. Decreasing the markup, the opportunity to use the power plant increases. It is possible to turbine water at lower prices, but that also means that the pump will be used at higher prices. At the end these incremental revenues and incremental cost cancel each other, resulting in an incremental profit of zero or even a loss, as it can be seen in the case 2 (Figure 9.91) where there is an evident maximum in markup 0.3 and then there is a decrease on both sides. This also explains the loss of the linear increase of the annual net profit decreasing the markup in case 1.

It can be noticed a large difference in the trends between case 1 and the other two cases (case 2 and case 3). On the left side of the graph in Figure 9.144 this can be explained by the fact that the turbine capacity is almost doubled in case 1 compared to case 2 and case 3. Meanwhile, considering for example case 3, it can be noted that the electricity cost for the pump remains almost constant between case 1 and case 3. This can be explained by the fact that the installed capacity of the PaT, working in pump mode, is the same in both cases. The main difference stems from the revenues related to the turbine. Since in case 1, the level at which the turbine operates no matter the price on the grid, which for this case study was fixed at 115.5 msl, is not reach in all the different operating modes, meanwhile in case 2 and case 3 this water level is reached and that inflates the turbine revenues.

In all the three costs of capital considered, the economic parameters of the case 3 seems to be the worse. This can be explained by the fact that in the case 3 it seems like the turbine and the pump are more used but the increase in cost for the pumping decreases the annual net profit, and by that decreasing the feasibility of this option.

A way to increase the productivity of the turbine may be for example to decrease the height at which the turbine will always work, to avoid water spill from the dam's crest. Because even though it is true that the cost of fuel for HP and PHS project is zero, at the same time a cost can be associated to the flow rate which does not run through the turbine, and it is "lost". This can be done but there is a lost in the useful water storage capacity. The first goal of the Omodeo lake is to storage water for the dry periods in summer. It is not possible to know in advance if the next summer will be dry or wet. It is better to stay on the cautionary side of the dam operation.

The annual net profits of Tirso 1 for the different case study are reported in Table 112.

Table 112 Annual net profit comparison between the three cases

Markup	Annual net profit [10^6 €]		
	Case 1	Case 2	Case 3
0.1	7.9517	3.77795	2.98169
0.2	7.55489	4.06979	3.28933
0.3	6.1641	4.04627	2.99307
0.4	4.50396	3.93785	3.22682
0.5	3.33305	3.62021	3.09557
0.6	2.3154	3.62388	3.16547

10. Conclusions

From the economic analysis presented in the previous chapter, it can be said that the preferred configuration is the one in case 1, which shows the lowest LCOS, as it can be seen from Figure 9.137, taking the worst-case scenario with k=10% and operating mode with markup between 0.2 and 0.3.

Case 1 is also the most positive because it is the least change case between the three considered. The present-day plant is fully maintained, and a 30 MW PaT is added. In the operation of course the power will chance due to the efficiencies, from 27 MW from the turbine to 35 MW of pumping power.

Of course, all these result from the economic analysis strongly depend on the interest rate which depend on the WACC, which would entail the need of knowing the liquidity of the company, and the cost estimate. Cost estimates are particularly difficult for hydropower since they are strongly site dependent. There are empirical formulas available, but they may be too inaccurate. To have accurate estimates the only way is to design the plant but that goes beyond the scope of this thesis. Large companies may emit bonds, which are at a lower interest rate compared to bank loans.

An interesting comment that can be made on the cost estimate of the case study is that in the CAPEX the electromechanical components cost is around 50% of the total in all the three cases. This is generally the case for small HP plant. This can be explained by the fact that most of the civil works are already done. The cost estimate in the three cases places the power plant in the middle of the price range for the industry which is between 600 and 3000 €/kW.

An interesting future development of the thesis, after obtaining the data of the rivers flow rates, it is interesting to consider the use of the Tirso 1 PHS facility in the capacity market and for ancillary services.

The capacity market has begun in Italy in 2022 and it can prove an interesting way to improve the feasibility of the investment since the power plant has to guarantee the availability for 500 hours during the year, which are identified by Terna. These critical hours are remunerated in a different way, at a much higher rate compared to the day ahead market.

Either way, this case study shows a positive feasibility of many operating mode inside the three cases, particularly case 1. Tirso 1 PHS could play a role in the stabilization of the Sardinian market and of the grid by providing ancillary services, capacity market, time shift and capacity firming of new renewable energy capacity installations.

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Thomas Manica

Appendix

Appendix 1

Table 113 Generation technology classification in the 2022 Standard Scenarios

Technology Group	Technologies
Established	• Electric batteries • Biopower • Coal • Concentrating solar power (CSP) with and without thermal energy storage • Distributed rooftop solar photovoltaics (PV) • Natural gas combined cycles (NG-CC) • Natural gas combustion turbines (NG-CT) • Conventional geothermal • Hydropower • Landfill gas • Conventional nuclear • Oil-gas-steam (OGS) • Pumped storage hydropower • Utility-scale PV • Utility-scale PV-battery hybrids[a] • Onshore wind • Fixed-bottom offshore wind
Nascent	• Biopower CCS • Coal CCS • Enhanced geothermal systems • Floating offshore wind • Natural gas CCS (NG-CC-CCS) • Nuclear small modular reactors (SMR) • Renewable fuel combustion turbine (RE-CT)

[a] PV-battery hybrids are considered an established technology, but they are not included in the Mid-case set of assumptions (and therefore in most scenarios) because data was lacking for modeling it in the "Low Renewable Resource" sensitivity. To enable users to see how its presence influences the projections, it is included in the sensitivities that bear its name. For additional analysis of PV-battery hybrids by NREL, see (Murphy, Brown, and Carag 2022)

Scenario Viewer (nrel.gov) - https://scenarioviewer.nrel.gov/

Appendix 2

Nel dettaglio, l'articolo 18 del d.lgs. 210/2021 stabilisce, tra l'altro, quanto segue:

a) il Gestore della rete di trasmissione nazionale (di seguito: Terna), in coordinamento con i Gestori delle reti di distribuzione, sottopone all'approvazione del Ministro della Transizione Ecologica (di seguito: Ministro), sentita l'Autorità, una proposta di progressione temporale del fabbisogno della capacità di stoccaggio, articolato su base geografica e sotto il profilo del tipo di accumulo in relazione al tipo di funzione cui si riferisce il fabbisogno. Detta proposta è definita:
   i. con la finalità di ottimizzare l'utilizzo dell'energia elettrica prodotta da fonte rinnovabile, di favorirne l'integrazione nei mercati e di assicurare la maggiore flessibilità del sistema;
   ii. ii) tenendo conto dei fabbisogni già individuati nel Piano nazionale integrato per l'energia e il clima o PNIEC, della presumibile concentrazione geografica delle richieste di connessione alla rete elettrica di impianti di produzione alimentati da fonte rinnovabile, in particolare FRNP, degli sviluppi di rete e delle esigenze di servizio;

b) l'Autorità definisce i criteri e le condizioni sulla base dei quali Terna elabora e presenta al Ministro, per la relativa approvazione, una proposta di disciplina del sistema di approvvigionamento a lungo termine della capacità di stoccaggio, basato su aste concorrenziali, trasparenti e non discriminatorie, svolte da Terna, e fondato sui seguenti principi generali:
   i. minimizzazione degli oneri per i clienti finali;
   ii. approvvigionamento di capacità di stoccaggio di nuova realizzazione, secondo aste periodiche e contingenti di capacità;
   iii. approvvigionamento effettuato secondo criteri di neutralità tecnologica nel rispetto di requisiti tecnici definiti da Terna, in funzione delle finalità di cui alla precedente lettera a) e delle esigenze di sicurezza del sistema elettrico;
   iv. in esito alle aste, è riconosciuto ai titolari della capacità di stoccaggio aggiudicata il diritto a ricevere una remunerazione annua per l'intero orizzonte di consegna, a fronte dell'obbligo di rendere disponibile detta capacità a soggetti terzi per la partecipazione ai mercati dell'energia e dei servizi connessi;
   v. l'aggiudicazione in esito alle aste è subordinata al rilascio di apposite garanzie;

c) ai sensi del comma 7 del d.lgs. 210/21, l'Autorità stabilisce:
   i. i criteri di aggiudicazione della capacità di stoccaggio, tenendo conto dei costi di investimento, dei costi operativi delle diverse tecnologie, nonché di un'equa remunerazione del capitale investito;
   ii. le modalità di copertura dei costi di approvvigionamento della capacità di stoccaggio, attraverso meccanismi tariffari idonei a minimizzare gli oneri per i clienti finali;
   iii. le condizioni e le modalità per lo sviluppo della capacità di stoccaggio direttamente da parte di Terna, nel caso in cui i soggetti terzi non abbiano manifestato interesse a sviluppare in tutto o in parte la capacità di stoccaggio necessaria, fermo restando che Terna non potrà gestire la capacità realizzata;

iv. le condizioni in base alle quali la capacità di stoccaggio aggiudicata è resa disponibile al mercato attraverso la piattaforma centralizzata gestita dal Gestore dei mercati energetici (di seguito: GME), nonché i criteri e le condizioni per l'organizzazione della piattaforma medesima;
v. le modalità di utilizzo della capacità di stoccaggio da parte degli operatori di mercato, anche attraverso aggregatori;
vi. le modalità per il monitoraggio degli effetti del sistema di approvvigionamento sul sistema e sui mercati, anche in relazione agli obiettivi della misura.