Small Hydro Going Smart – Small hydro pumped storage and its contribution to smart grids

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1. Introduction

The electric energy market is rapidly changing and it's greatly changed already in the last few years due to the increasing role of the intermittent renewable energy sources in the portfolio of many countries.
In this context, the function of large hydropower and of large conventional pumped storage plants, is rapidly changing as well, shifting from mainly load levelling to supplying ancillary services to the grid (frequency and voltage control, etc.).
In a medium-long term perspective – when all the benefits from incentives (if any and in any form designed) are expired - small hydropower plants – whatever the definition set for "small" – will be under pressure from many sides: economical – due to decreasing prices of energy and generally high operation costs –environmental, because of the increasing competition for the use of the water resources – and hydrological – due to the potential effects of climate changes which can reduce the production (and hence the revenues from energy selling) as the distribution of rainfall during time will have more intense events of short duration.
A final element of the picture given above are the increasing importance of smart grids and of distributed generation.
Based on the said premises, in the paper is described a possible new role which could be played by many SHPs if they had been turned in small pumped storage plants in smart grids of local energy communities. This solution can take advantage of the benefits of small hydro, pumped storage and smart grids:

- Small hydro (Reliability, Predictability, Flexibility)
- Pumped storage (Load levelling, Quality of electric supply, Energy storage, Backup facility to intermittent RES, Standby and reserve duties, environmentally friendly)
- Smart grids and local energy communities (Demand response, Integration of RES, Distributed generation, Price signalling)

Many issues are still open and are discussed in the paper

- Location of the reservoirs to keep small hydro pumped storage plants environmentally friendly
- Few specific research on small hydro equipment
- Transposition of the experience acquired for large installations to small ones
- Interaction with intermittent RES and optimization of small distributed generation grids (e.g. load levelling by pumping during period of high availability of intermittent RES and low energy consumption/demand)
- Stricter technical requirements for EM equipment than conventional small hydro at new sites and to adapt existing ones
- High marginal costs of production is expected
- High investment costs for matching the pumping mode (e.g. transients management, air chambers needed, underground installation…)
- Pricing of the services supplied by the plants which should reflect the cost of production and should offset the strategic role played by pumped storage

In the paper the outcomes of the general analysis have been applied a one case study: a closed-loop micro-hydro pumped storage plant (approx. 50 kW).
The outcomes of the analysis are quite different and discussed.

2. General framework for the small hydro pumped storage development

The recent EU Directive 2018/2001 of 11 December 2018 set the general framework for the promotion of the use of energy from renewable sources.
The art. 22 provides the definition of *Renewable Energy Community* (REC) and provides a full set of general rules for

the promotion designed to provide an enabling framework to promote and facilitate the development of renewable energy communities.
The energy community is made by producers and consumers.
Typically, in a renewable energy community:

- the participants are connected to a LV network
- the producers are mainly from PV household plants
- the consumers can be both household and small industries

A renewable energy community can be also be conceived at a larger scale. In this case:

- the participants are connected to a MV network
- the producers are from PV household plants and from small wind farms, too
- the consumers can be both household and SMEs

In both cases the problems of intermittent Renewable Energy Sources are well known and they don't need to be repeated in detail here.
In this framework closed- or open-loop Small Pumped Storage Plants (SPSPs) can play the usual beneficial role of Pumped Storage Plants (PSPs) of even larger size.
The idea of SPSPs is not quite new and some suggestions can be found at least ten years ago.
But almost everywhere small hydro, even though in a quite different extent in the different EU countries was benefitting of some incentives so that it didn't make much sense to deeply investigate the problems and the opportunities connected to turn an existing SHP into a SPSP.
But in ten years the whole RES world change radically and the issue of the EU Directive 2018/2001 is a clear sign of this change and suggested to us to try to better understand whether in this new context now it makes sense to turn an existing SHP into a SPSP. In the following chapters you can find some detail about that.

3. General approach

The approach used is shown in the following scheme:

1. Collection of data of different LV and MV electrical cabinets within an existing distribution network suited to be turned into REC according to the following main criteria:
    a. Excess of energy production from RES within the day and within the seasons and year
    b. Excess of energy demand in the complementary periods to those of excess of energy production
    c. Availability in the nearby areas of a suitable head for the PSP operation
2. Selection of a LV and MV electrical cabinet as case study
3. Implementation of the rough energy model:
    a. Choice of the size and numbers of the pumping/generation units
    b. Estimation of the water volume necessary to meet the requirements of the grid both in pumping and generating mode
    c. Assessment of the operation mode which is binding for the choice of the volume of the upstream and downstream ponds
4. Energy Model refinement
    a. Assessment of the constraints and implications of the use of a Pump As Turbine (PAT) in the model
    b. Dynamic response calculations
5. Implementation of the economic model
    a. Technical and economical optimization of the Electromechanical Equipment and of the civil works
    b. Addition of the tariffs and incentives framework
    c. Application of the NPV method to the case study
    d. Re-assessment of the tariffs and incentives needed to make the REC economically viable

4. Case Study - closed-loop micro-hydro pumped storage plant

According to the general approach set at the previous chapter, amongst tens of LV cabinets of a DSO in Northern Italy, the one which best complies with the above mentioned was selected.
In the following chart the load profile shows that in principle in the whole part below zero there is an excess of RES production suitable for pumping water uphill.
As you can see, as all the RES in the REC are PV plants, the excess energy strongly depends on season and it's higher in summer and lower in winter.

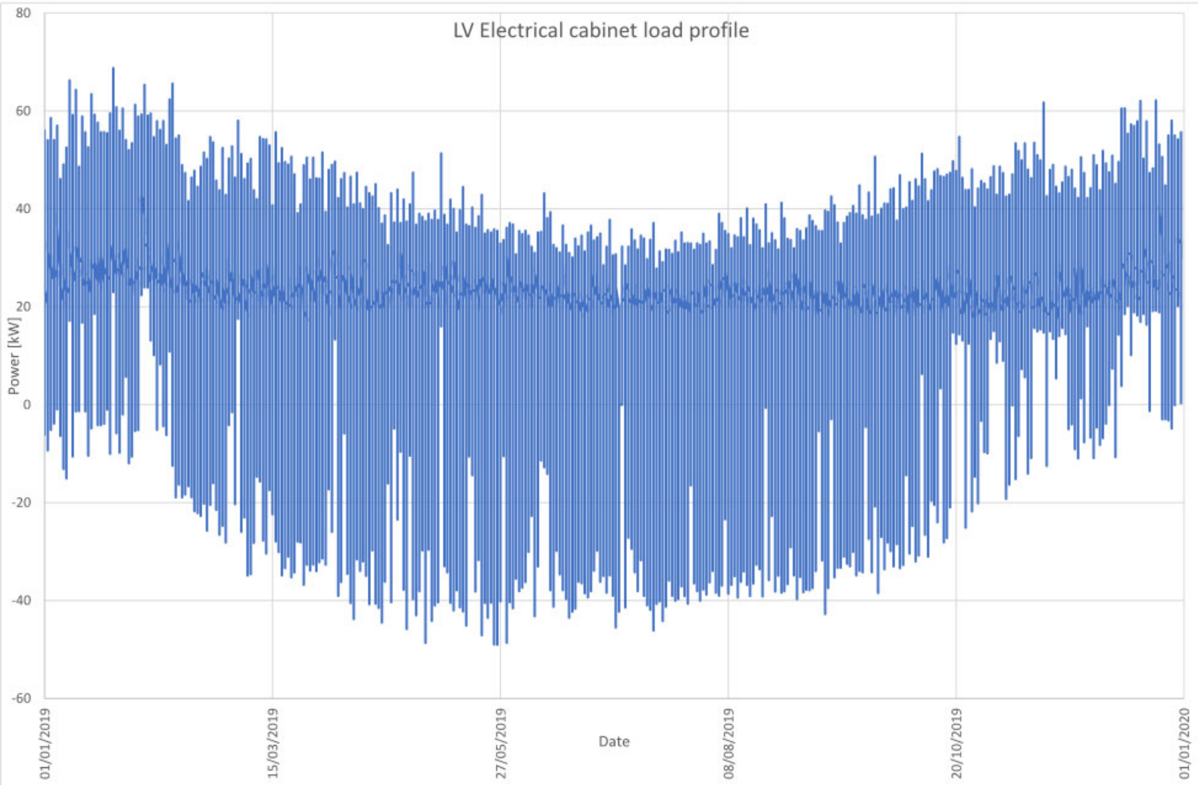

Figure 1 - Load profile all 2019 long

The selected cabinet is close to mountain area which provides good opportunities to locate both the downstream and the upstream pond and to connect them with a penstock running with a good slope and a short route. The chart below shows the longitudinal profile of the penstock.

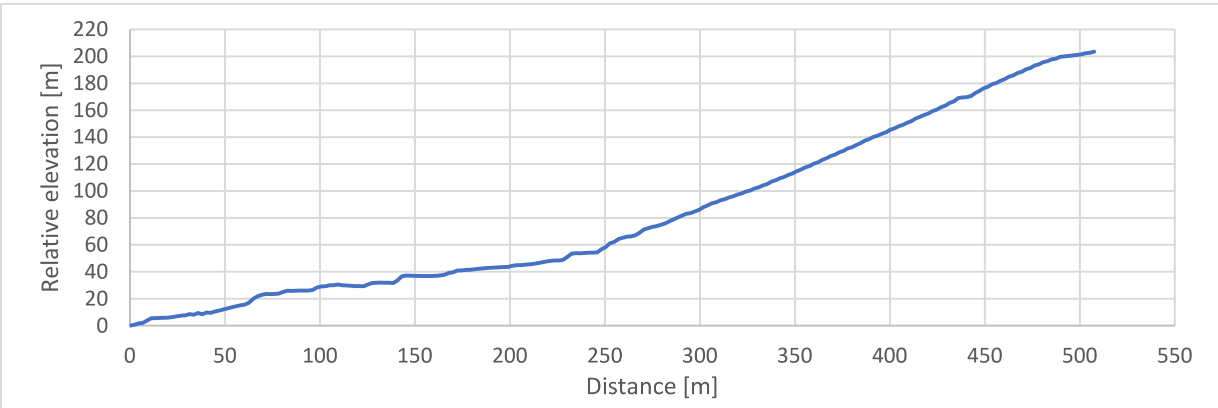

Figure 2 - Longitudinal profile of the penstock

Given:

- Power demand/excess
- Duration of the power demand/excess
- Gross head available
- Pump/Turbine efficiency

You can estimate:

- Number of pumps/turbines needed to meet the network requirements
- Rated flow of the Pump/Turbine

- Volume of the Upstream and Downstream ponds to meet the power demand/excess

In the case at hand there is the opportunity to locate the upstream pond more or less wherever we want along the mountainside so that the choice of the volume of the ponds must be made according to some kind of optimisation criteria, by keeping in mind that the pond volume decreases with the increase of the head, but the length (and the cost) of the penstock increases with the head.
Another main constraint comes from pumps. In order to meet the energy excess on the grid coming from PV production, as this production is not only intermittent during the day following the sun cycle, but it is also variable, even suddenly, during the day due to cloud cover. To meet this high variability, variable speed pumps (VSP) must be installed equipped with a power-electronic Variable Speed Drive (VSD) which increase the cost of the equipment and slightly reduce the overall efficiency of the system. To prevent cavitation and an unacceptable drop in the efficiency VSPs can usually operate only in an interval between approx. 50 to 100/110% of the nominal head and flow rate: this requirement impose a further constraint to the design choices and it actually force to install at least two units to meet PV power output variations.

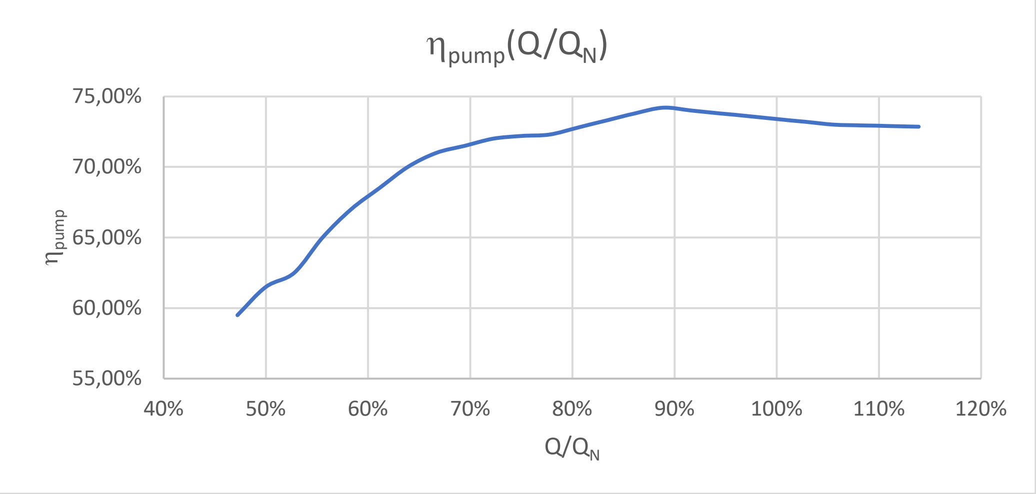

Figure 3 – Variation of the pump efficiency with the flow rate under variable speed conditions

The role of PV is very clear: when the sun rises high in the sky, PV production rises as well and the energy flow at the cabinet is negative (excess of production). The pumps start operation according and the US pond is filled as much as possible. When the sun sets in the evening the PV production decreases, the energy flow becomes positive (excess of demand) and the turbines start working.

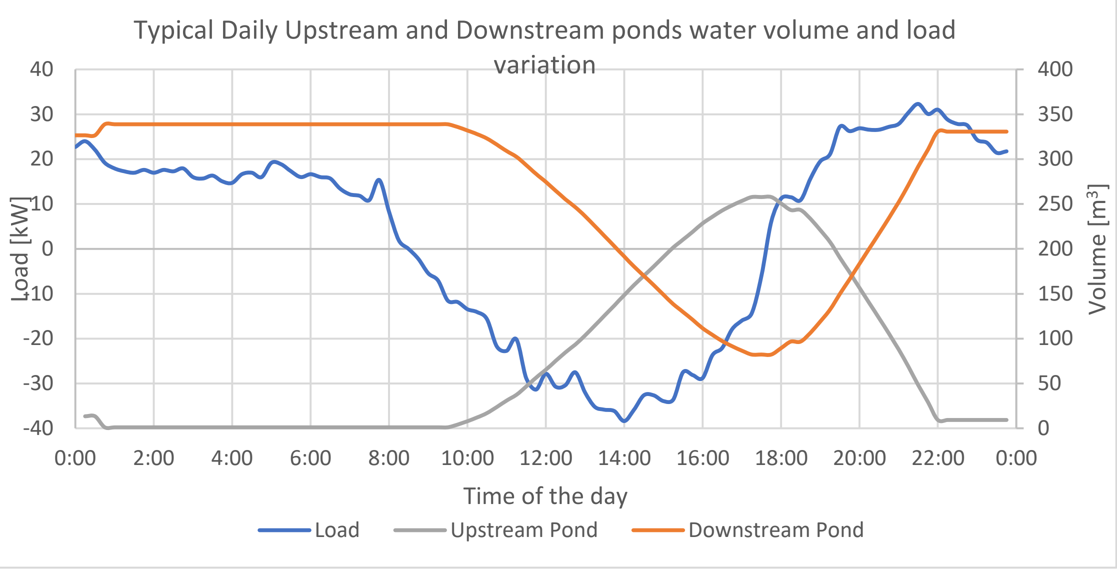

Figure 4 – Detail of the daily load and upstream and downstream impoundment variation

Looking at the chart above, it's clear that the daily basis is not good enough to estimate the optimum operation of the system. In fact, overnight, as the US pond is still empty due to the operation during the day before, the load on the grid can't be met by the turbines.
The only way to meet both energy demand and energy excess is to largely oversize the ponds, but, as we'll see shortly, this choice is totally not compatible with the economics of the system.
In the chart below, the weekly trend of the energy flows is shown. It's clear that there's no way to meet both pump-mode requirements and turbine-mode requirements. Anyway there are other weeks when both US and DS ponds are fully exploited.

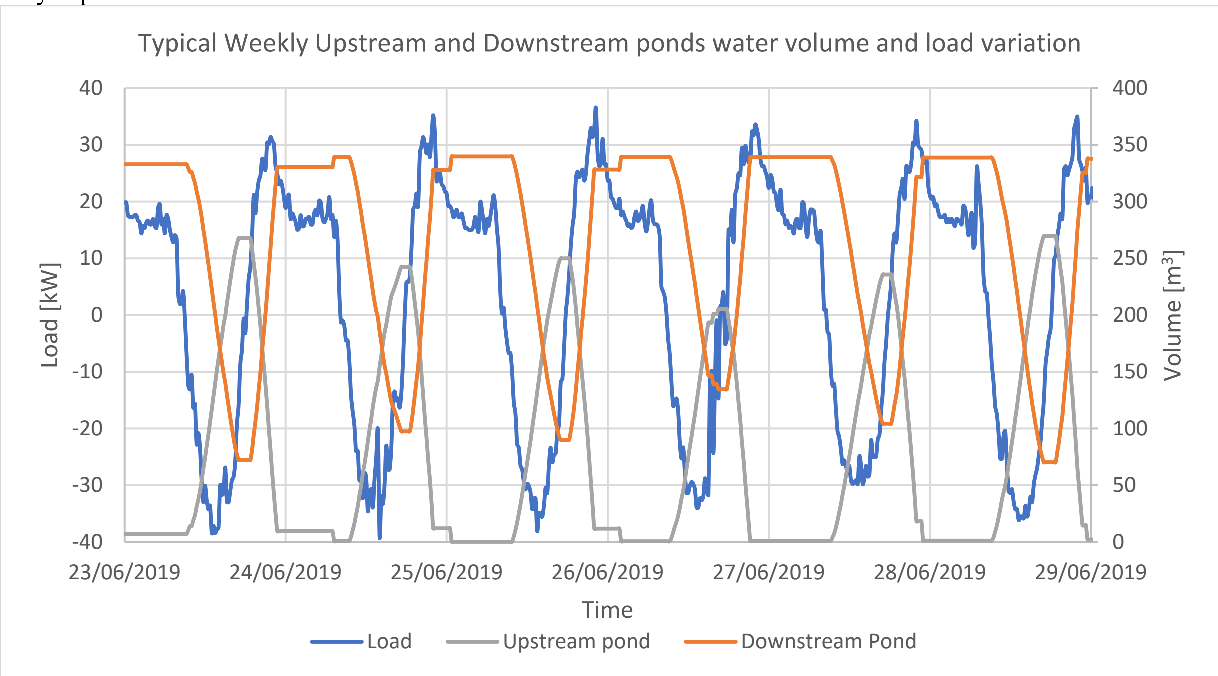

Figure 5 – Detail of the weekly load and upstream and downstream impoundment variation

It must be kept in mind that the main goal of this plant is to consume the excess of energy coming from intermittent RES and not to provide energy when required by the REC consumers.
That's why the optimization of the volume had been made by meeting the pumping requirements. This approach is possible because at the time being, according to the current legislation, RECs operate connected to the DSO grid so that the energy unbalances on the REC can be covered by the DSO.
In the current preliminary study, a simplified approach to the volume optimisation has been made by searching for the minimum value of the mathematical function of the total cost of the component of plant which more strongly depends on the head.
From the load profile it results:

- P = maximum power required in pumping mode = 50 kW
- η = efficiency of the pump at the rated power = 75 %
- γ = acceleration due to gravity = 9,81 m/s^2
- T = maximum duration of the pumping mode ~ 5 h

So that the volume of the pond is:

$$V = \frac{\eta \cdot P \cdot T}{\gamma \cdot H} = \frac{\lambda}{H}$$

The two reinforced concrete ponds (assumed square in shape) have the following dimensions:

- h_w = depth of water in the pond = 3 m
- f_w = freeboard = 0,3 m
- z_w = height of the wall = $h_w + f_w$
- t_w = thickness of the wall assumed constant = 0,3 m

so that the area of the pond is:

$$A_{pond} = \frac{V}{h_w} = \frac{\lambda}{H \cdot h_w}$$

The side and the perimeter of the pond are respectively:

$$b_{pond} = \sqrt{A_{pond}}$$

$$P_{pond} = 4 \cdot b_{pond} = 4 \cdot \sqrt{A_{pond}} = 4 \cdot \sqrt{\frac{\lambda}{H \cdot h_w}}$$

The total volume of the reinforced concrete of the wall is:

$$V_{conc\_wall} = z_w \cdot t_w \cdot P_{pond} = z_w \cdot t_w \cdot 4 \cdot \sqrt{\frac{\lambda}{H \cdot h_w}}$$

And the total volume of the concrete of the baseplate of the pond (thickness assumed equal to t_w) is:

$$V_{conc\_base} = t_w \cdot A_{pond} = t_w \cdot \frac{\lambda}{H \cdot h_w}$$

Said UP_{conc} the unit price of the reinforced concrete (including excavations, backfill, formworks, reinforcing steel, etc.), the total cost of the two ponds, assumed equal, is:

$$C_{ponds} = UP_{conc} \cdot 2 \cdot V_{conc\_base}\left(V_{conc\_wall} + V_{conc\_base}\right) = UP_{conc} \cdot 2 \cdot \left(z_w \cdot t_w \cdot 4 \cdot \sqrt{\frac{\lambda}{H \cdot h_w}} + t_w \cdot \frac{\lambda}{H \cdot h_w} \right)$$

The cost of the penstock depends on:
UP_{penst} = unit price of the penstock
W_{penst} = weight of the penstock = $L_{penst} \cdot \pi \cdot D \cdot t \cdot \gamma_{steel}$
In this specific case, in the range of expected heads and flow rates, the diameter D and the thickness t of the pipe are assumed constant (200 mm and 4 mm respectively), and the length of the penstock is linearly dependent on the head:
$L_{penst} = m \cdot H + b$ where m = 2,2376 and b = 114,17 m
Under those simplifying assumptions, the total cost of the components of the plant depending on the head (we assume that the cost of the pumps is weakly dependent on head in this case) is:

$$C_{total} = UP_{conc} \cdot 2 \cdot \left(z_w \cdot t_w \cdot 4 \cdot \sqrt{\frac{\lambda}{H \cdot h_w}} + t_w \cdot \frac{\lambda}{H \cdot h_w} \right) + UP_{penst} \cdot (m \cdot H + b) \cdot \pi \cdot D \cdot t \cdot \gamma_{steel}$$

With the unit prices typical of these kind of components for Italy (UP_{conc} = 400 €/m^3 and UP_{penst} = 4 €/kg, including erection and civil works) you can easily calculate the derivative of the function C_{total} and set it to zero to find the optimal head. The chart below shows the shape of the curve $C_{total}(H)$.

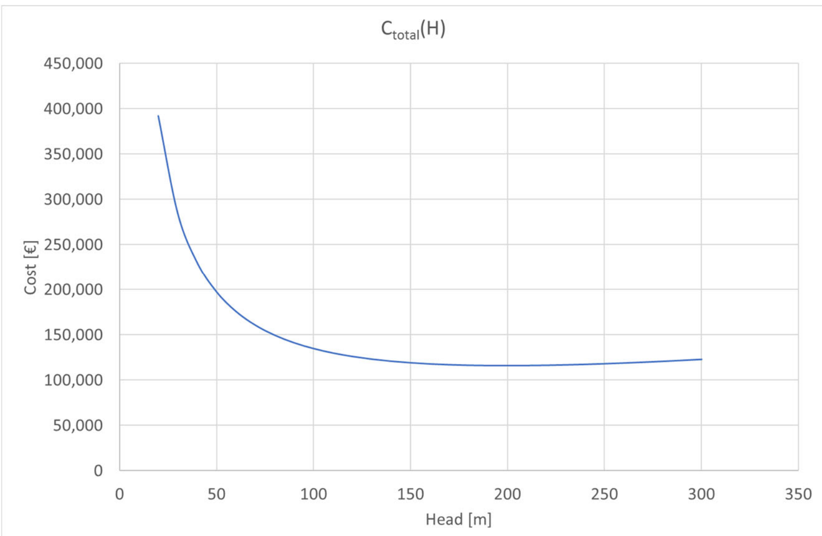

Figure 6 – Total costs of the head-dependent components

Under the above-mentioned simplifying assumptions, the minimum cost is reached at 199 m head. As for high heads the curve is almost flat, due to topographic reasons and the availability of an existing road at a little bit higher head the design head has been set at 203 m corresponding to a cost of approx. 130 k€.
The final cost of the project, including, pumps, valves, automation, design and supervision has been estimated at:
***C_{final}* = 170,000 €**
The energy model can be refined by analysing the dynamic response of the system to a sudden change in the load profile.
Unfortunately, at the time being the load profile at the cabinet is available only at 15 minutes interval so that no simulation of the behaviour of the plant in case of sudden changes can't be tested on real data, but only synthetically.
In the following chart the response to a 10 kW and 20 kW step is shown.

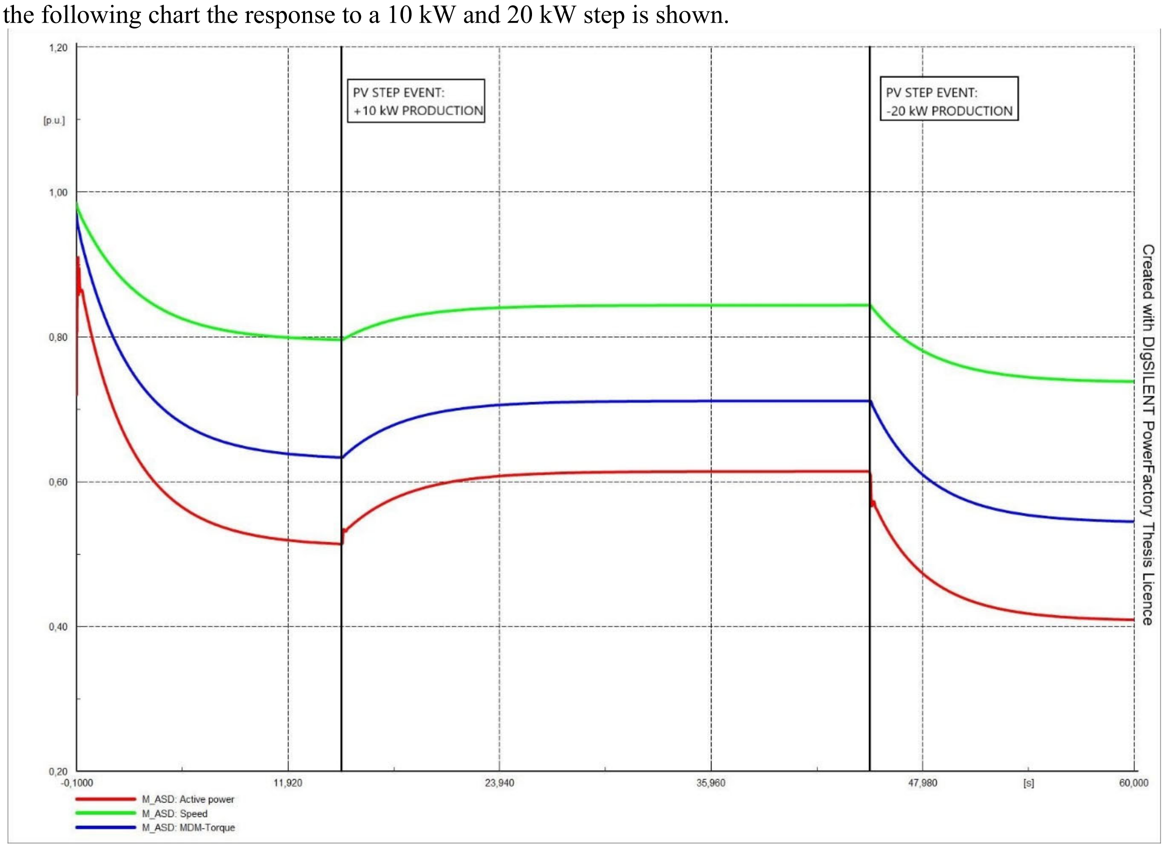

Figure 7 – Dynamic response of the plant to a 10 - and 20- kW step variation

In order to assess the economic feasibility of the project, it is necessary to establish the regime of the incentives for the community. According to the current Italian regulation, inside a REC:

- the producer sells the energy for the common price of electricity plus an incentive equal to 110 €/MWh for the produced energy that is consumed inside the REC;
- the consumer purchases the energy for the common price of electricity minus a discount equal to 8,2 €/MWh if the purchased energy comes from the REC.

This means that, with the presence of an accumulation system inside the REC, it is possible to guarantee two advantages for both producers and consumers: the producers can get more incentives, since the excess energy can be stored inside the community, and the consumers are able to obtain the discount for a longer period (when PV don't work, the energy purchased comes from the accumulation system). However, the accumulation system doesn't get the same amount of advantages: in fact, since the produced energy is smaller than the consumed energy, the incentives may not be sufficient to cover the costs of the purchase of energy (even considering the discount).
Under these circumstances, it is interesting to consider two different economic analysis:

A. NPV from the point of view of the pumped storage plant only
B. NPV from the point of view of the whole REC

NPV formula is the following:

$$NPV = \sum_{i=1}^{n} DCF \equiv \sum_{i=1}^{n} \frac{CF}{(1+t)^i} \equiv \sum_{i=1}^{n} \frac{R_i - C_i}{(1+t)^i}$$

In which:
R_i = Revenues for the year i [€]
C_i = Costs for the year i [€]
t = discount rate [-]
n = reference period [years]
CF = Cash Flow for the year i [€]
DCF = Discounted Cash Flow [€]
In these analyses the following data are assumed:

- average cost of energy 50 €/MWh,
- reference period 50 years
- discount rate equal to 1,5 %

Scenario A: NPV from the point of view of the pumped storage plant only
On average, in one year the plant is able to absorb 30,975 kWh and to produce 15,316 kWh. This means that every year the revenues coming from the sale of energy is equal to 15,316 kWh · (50 €/MWh + 110 €/MWh) ~ 2,450 €, while the cost associated to the purchase of energy is equal to 30,975 kWh · (50 €/MWh – 8.2 €/MWh) ~ 1,290 €. As a first approximation, O&M cost are estimated in 1,000 €/year; Therefore, the overall costs for an average year is equal to 2,290 €. It is clear that the difference between the revenues and the costs are almost null.
The resulting NPV is equal to - 164.380 €.

Scenario B: from the point of view of the whole REC
Thanks to the accumulation system, PV plants are able to store inside the REC 30,975 kWh, meaning that inside the REC there are higher revenues coming from the incentives: 30,975 kWh · 110 €/MWh ~ 3,410 €. This adds up with the incentives coming from the energy production of the pumped storage plant, equal to 15,316 kWh · 110 €/MWh ~ 1,680 €. Costs related to the selling and the purchase of energy inside the REC cancel each other. Moreover, the consumers can get a higher discount, equal to 15,316 kWh · (8.2 €/MWh) ~ 130 €. Therefore, thanks to the pumped storage system, on an average year the revenues of the REC can be considered equal to 3,410 € + 1,680 € + 130 € = 5.220 €.
The cost that the REC must bear are only equal to the cost connected with O&M costs (1,000 €/year).
The resulting NPV is equal to - 22.300 €.

Given the results, it may be interesting to estimate what the amount of the incentive should be in order to get a null value for the NPV. In scenario A, the amount should be equal to 416 €/MWh, while in scenario B it should be equal to 124 €/MWh.

5. Conclusions

The results coming from the economic analysis are clear:

- there are no technical impediments towards the realization of a pumped storage plant, the main problem regards the economic feasibility
- in the case study, the economic feasibility of the pumped storage is absolutely unsustainable if we assume that the pumping system belongs to a private entity; the results seems more promising if the realization of the pumped storage is sustained by the whole REC, but the results are still disappointing
- when starting this analysis, the data available were related to few LV and MV cabinets: with more data it may be possible to find cabinets that are more suitable for the creation of a small pumped storage plant.

The Authors

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