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Article

Economic sustainability of small-scale hydroelectric plants on national scale – The Italian case study

Anita Raimondi*[1], Filippo Bettoni[2], Alberto Bianchi[1] and Gianfranco Becciu[1]

[1]Dipartimento di Ingegneria Civile e Ambientale, Politecnico di Milano
[2] Professional Engineer
* Correspondence: anita.raimondi@polimi.it

Abstract: The feasibility of hydroelectric plants depends on a variety of factors: water resource regime, geographical, geological and environmental context, available technology, construction cost and economic value of produced energy. Choices about the building or renewal of hydroelectric plants should be based on the forecast of the future trend of these factors at least during the project life of the system. Focusing on the economic value of the produced energy this paper examines its influence on the feasibility of hydroelectric plants. Analysis, referred to Italian case, were based on three different phases: i) the economic sustainability of small-scale hydroelectric plants under a minimum price guaranteed to the hydroelectric operator; ii) the estimate of the incentives to reach the thresholds of "acceptability" and "bankability" of the investment; iii) the analysis of results obtained in the previous phases using a model of the evolution of the electricity price in the period 2014-2100.

Keywords: economic sustainability; mini hydroelectric plants; tariff; incentive; climate change

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1. Introduction

Hydropower accounts for about 20% of the worldwide electrical power production, with higher percentage in mountain regions [1]. It is a clean source of energy well as an economic resource for regions rich in usable water. Hydroelectric production mainly depends on water availability and electricity price [2]. The demand and price of electricity depends upon societal and economic development, but it is subject to a seasonal, weather dependent variability, and to long-term variation under climate change [3-4]. Hydropower energy depends largely upon meteorological conditions and, therefore, productivity can have significant variations seasonally, and from year to year. Climate conditions influence the hydrological cycle, the energy demand, and the electricity price. These three factors influence hydroelectric production because energy managers need to manage water storages, to cover periods of peaking electricity prices resulting from high energy demand, to reach the goal of maximum profit. Often, hydropower comes largely from cold water, originating from ice/snow melt in the mountain areas subject to rapid cryosphere wasting due to global warming [5]. This could be a concern, especially for Alps, with a large share of hydropower depending upon cryosphere water. In the Alpine region, the rising temperatures have resulted in the loss of more than half of the glaciers volume since 1900. With a global temperature increased by 2–4 degrees, 50%–90% of the ice mass coming from mountain glaciers could disappear by the end of this century [6]. With earlier snow melting and rainfall variation, inter-annual run-off is changing towards less water during summer and more during the winter-season. Depending on the watershed, the water quantity may increase initially due to the loss of ice stock [7]. Changes in temperatures and precipitation patterns can involve profound effects on water systems and cause important changes on uses highly dependent on hydrological regime, such as hydropower production modifying total annual inflow volumes and their seasonal distribution [8]. River hydroelectric plant production depends on available water annual volume and it is strictly related to annual rainfall volume; reservoir hydroelectric plants are instead related to the discharge-duration curve. Hydropower plays a double role among the issues that are most relevant in the study of climate change. On one hand, hydropower plants will be affected by the change in water availability; on the other hand, as the present major source of renewable energy, it is useful to support and increase the energy production and to reduce the human induced climatic changes [9]. In areas where a large share of hydropower production depends upon ice melt, the expected future lack of water due to glaciers reduction may affect energy production and requires adaptation strategies [10]. Energy and climate policy, as well as electricity market design and dynamics play a pivotal role for the future of the sector [11].

Several studies analyzed climate changes impacts on hydropower production [1, 4, 5, 12, 13, 14, 15]. Other underlined the strengths and weaknesses of technical, physical and economical aspects concerning hydropower management [11].

The focus of the paper is on Italian scenario, especially the economic sustainability of small-scale hydroelectric plants on national scale. Among the Italian renewable sources, according to the GSE (Energy Services Operator) statistical report hydroelectricity is the largest, both in power and in annual production. It results the most efficient source because with the same installed power and incentive paid, produces more energy than other sources, since its useful life is much longer. Hydroelectric plants have a much higher investment cost than other energy production technologies, but operating costs are extremely lower since no type of fuel is required, which is often the most important cost component. The relationship between the energy produced in useful life and the one consumed to build, install and to dispose of it at the end of its life is of an order of magnitude higher than that other types of renewable sources. Moreover, it ensures the security of energy supply since it is the only one programmable renewable source; tank plants produce only when necessary, stabilize the National Transport Network and allow the Italian electricity system to adapt to our consumption hour by hour. Even running water systems have a perfectly predictable production in the short term and therefore a qualitatively better production of wind power plants or photovoltaic. Anyway, there are two main critical issues that undermine the economy of an investment in hydroelectric plants: the cost of water and the lack of economies of scale since they are tailor-made for their respective sites.

The objective of the following study is to analyze the economic sustainability of small-scale river hydroelectric plants with a concession power of up to 1 MW in the current regulatory context, to provide the renewable community and the legislator with reflections useful for the transition to a new configuration of incentive mechanisms. The choice of focusing on small-scale hydroelectric plants is due to the peculiarity of the territory. The Alps and the Apennines are completely saturated and it results impossible to build large systems. The design of small-scale hydroelectric plants is a challenge involving more factors: hydrological, technological, environmental and social. Moreover, each plant must undergo to a strict and selective authorization process, facing the regulatory uncertainties regarding possible incentives.

The study was divided into three phases. i) The first is an analysis of the economic sustainability of hydroelectric plants with concession power up to 1,000 kW in the absence of incentives for the first 1,500,000 kWh produced. Particular attention was paid to the incidence of water concession fees on the economic evaluation of the investment. ii) The second phase is the estimate of the value of the incentive needed to achieve the economic sustainability for hydroelectric plants, compared to the investment "acceptability" and "bankability" thresholds typical for these types of plants. iii) The last consists in an evaluation of the sustainability of the plants in the complicated context of climate change, with reference to the most influential factors that govern the phenomenon in such a way as to offer the most reliable and truthful forecast possible. The aim is to understand if the incentives can be considered the shock absorber capable of effectively meeting the economic needs of the hydroelectric sector to ensure that the latter remain strategic in the Italian production system.

2. Feasibility criteria

To evaluate the economic suitability of small-scale hydroelectric plants, two levels of feasibility were adopted:

a) economic feasibility: the profitability rate, that is the Internal Rate of Return (IRR), between 7% and 9%. It represents a profitability range typically considered acceptable by the entity that promotes the investment.

b) banking feasibility: rates higher than 9%, on average considered acceptable by credit institutions to guarantee the bankability of a hydroelectric project.

Economic analysis of the suitability of small hydroelectric plants can be conducted with different methods. The simplest is to compare the relationship between the total investment and the installed power or the ratio between total investment and energy annual yield. These criteria do not identify the convenience of the systems, since the revenues are not considered; they can be used only to have general indications on the investment. In this study the Net Present Value methodology (NPV) was used. It allows to obtain a faithful estimate of the profitability of the project through the estimate of the IRR. The NPV is nothing more than the difference between income and expenses, throughout the duration of the investment, both discounted at a rate, called discount rate. The formula to calculate the NPV, if the cash flows occur at regular time intervals, the first flow occurs at the end of the first period and the subsequent cash flows occur at the end of the subsequent periods, results:

$$NPV = \sum_{i=0}^{n} \frac{R_i - (I_i + O_i + M_i)}{(1+r)^i} + V_r \qquad (1)$$

I_i: investment in period i,
R_i: entry into period i,
O_i: operating costs in period i,
M_i: maintenance and repair costs in period i,
V_r: residual value of the investment at the end of its lifetime
r: discount rate or opportunity cost of capital,
n: number of considered periods.

Only projects whit positive NPV can be considered acceptable. The IRR indicates the rate of return expected from an investment: the higher the IRR is, the more convenient the investment. The limit condition results:

$$NPV = f(IRR) = 0 \qquad (2)$$

3. Case study

In Italy there are 3,700 hydroelectric plants, that achieve a total production of 42.4 TWh, about 14% of the country's production [16]. Most such plants are small and have marginal influence. In 2015, 77% of Italian hydropower was produced by plants with power >10 MW, covering merely 17% of the total energy electric production. The distribution of hydroelectric plants is quite heterogeneous as well the density of national installed power. The largest number of plants in Italy is in the northern regions with very high percentages in Piedmont, Lombardy and Trentino Alto-Adige. According to data provided by the GSE (year 2016), over 55% of the total plants are installed in these three regions alone, with a considerable density in Piedmont and Lombardy where there are 36% of all plants installed, which generate a total of 42% of the national installed hydroelectric power [16] Lombardy was chosen as case study, given the high presence of hydroelectric plants and because it is a virtuous example regarding the canons of concession for small plants. As consequent, if the results were not advantageous for this type of plants and in this context where the ferment and private initiative are the masters, they would not be advantageous even in other regions, where the overall rents are higher. In the calculation, the following standard sizes were used: 100 kW, 250 kW, 500 kW and 1000 kW, that is in the category of micro-hydroelectric plants.

3.1. The Italian fare system

One of main concern with economic sustainability of hydroelectric plants in Italy is that while the average energy price is constantly decreasing, about 20% less from 2012, the sum of the water concession fees/surcharges continue to rise (in some regions there was an increase in taxes related to the use of water resources by local authorities by almost +160%) [16]. Figure 1 shows the growing trend of water concession fees in recent years for the two regions "at the extreme" as regards the values for small plants in comparison to the National Single Price (PUN). After the peak of 2012, the PUN went down (-17% overall from 2009 to 2018), while the water concession fees, especially the Piedmont, have increased significantly (+ 159% from 2009 to 2018). The increase in Lombardy is less marked and more gradual (+ 12% in the period 2009-2019). The trend

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is rather disconcerting, considering that the fees are fixed costs for the hydroelectric operator not related to either the economic value of the production or the actual water availability [16].

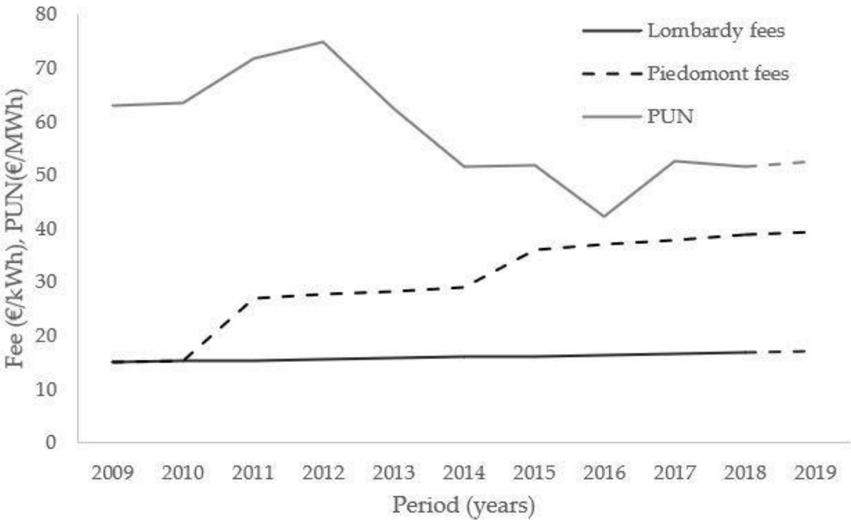

Figure 1. Water concession fees in the period 2009-2019.

The water concession fee varies according to the Region, while above a predefined threshold (220 kW), it is necessary to pay "Surcharges", defined by a national standard. Table 1 shows an example of annual water fees for Lombardy.

Table 1. Annual water fees for Lombardy.

Annual water fees in Lombardy	
Water concession fee	16,19 €/kW
Extra charge for BIM	30,67 €/kW
Extra charge for local authorities	5,78 €/kW
Ichthyogenic fee	0,85 €/kW
Royalties	3% on revenues

The investment in a small hydroelectric plant involves several payments distributed over the life of the project and provides incomes, also distributed over time. Outputs include a fixed component such as the cost of capital, insurance, taxes other than income taxes, etc. and a variable component represented by operating expenses and maintenance, costs which absolutely cannot be ignored for a correct assessment of economic profitability and above all with a view to efficient operation throughout its useful life. At the end of the project, generally coinciding with the duration of the concession, the residual value should be positive. The sale price of the energy produced is defined through the so-called PMG (Minimum Guaranteed Prices), or according to a simplified tariff mechanism that allows producers to sell the electricity fed into the grid, transferring it directly to the GSE who remunerate it based on precise and variable rates every year, paying a price for each kilowatt hour withdrawn. In this economic model it is assumed that the PMG are constant for the entire duration of the plant concession. Choice dictated in the first place by the awareness that in the last ten years these rates have remained virtually unchanged and secondly by the desire to recognize them more and more strategic importance for the support of the sector, so that the study can constitute an alternative founded for a possible future proposal of legislation devoted to environmental protection. Tables 2 and 3 show respectively PMGs until 2013 and PMGs in force (2019).

Table 2. PMGs, 2013.

Guaranteed minimum prices (€/MWh)	**2013**
0-250,000 [kWh]	158.7
250,000-500,000 [kWh]	100.5
500,000-1,000,000 [kWh]	86.7
1,000,000-1,500,000 [kWh]	80.6

Table 3. PMGs, 2019.

Guaranteed minimum prices (€/MWh)	2019
0-250,000 [kWh]	156.1
250,000-500,000 [kWh]	107.2
500,000-1,000,000 [kWh]	67.7
1,000,000-1,500,000 [kWh]	58.5

Table 4 shows the incentive plans proposed in recent years for flowing water systems; in the last decade incentive dropped by about 30%.

Table 4. Tariff associated to different power for different DM (Ministerial Decree).

Flowing water	Power (kW)	Rate (€/MWh)
	1<P≤20	257
DM July 6th 2012	20<P≤500	219
	500<P≤1000	155
	1<P≤250	210
DM June 23rd 2016	250<P≤500	195
	500<P≤1000	150
	1<P≤400	155
DM July 4th 2019	400<P<1000	110
	P≥1000	80

The incentive tariffs provided for medium-large size of plants undergone a percentage decrease in the incentive tariffs higher than all the other sizes.

3.2. The economic value of produced energy

Several models aimed at estimating the electricity prices were recently introduced in Europe in the wake of the liberalization of the energy market at the end of the 1990s. Such liberalization brought to the country-wise definition of the free market [17]. In Italy, the Legislative Decree 79/1999, allowed such liberalization. Energy prices after energy liberalization are continuously made available by the Energy Markets Operator (GME), an Italian authority with the mission of promoting the development of a national competitive electricity system, according to the criteria of neutrality, transparency, and objectivity. Competition in the electricity market is guaranteed by the Borsa Elettrica, an electricity stock market. It promotes the application of efficient equilibrium prices, allowing the sale and purchase of electricity according to the greater economic convenience. It is organized as a real physical market, with the definition of sales and purchases through hourly charts, according to the criterion of economic merit. This consists of considering, for sales, the prices in increasing order and, for purchases, the prices in decreasing order. Price definition takes place as in a physical market, according to matching of supply and demand. Electricity offers are accepted in order of economic merit, i.e., in order of increasing price, until their sum in terms of kWh completely meets the demand. The kWh price of the last accepted bidder, i.e., the one with the highest price, is attributed to all offers, and according to European Directive 2009/28, renewable energies, like hydropower, have priority in terms of access to the market. In so doing, in each zone of the Italian territory with given technical constraints, the equilibrium prices are defined, i.e., those that are found at the intersection of the supply and demand curves. Subsequently, the PUN is established by GME. The economic value of electricity is difficult to express with a relationship between the independent variables, already only at a national level. These can be physical, economic, social, political variables and are therefore all specific to a socio-political context, generally referable to a national scale. In literature, there have been proposed some models of the economic value of electricity linked to more general quantities useful if future projections are to be made [18, 19]; among them there are multi-agent models [20], parametric models [21], stochastic models [22, 23, 24] and computational models [25]. Also, hybrid, or mixed, models were developed [3, 4, 26, 27, 28, 29]. The availability of water resources for next years, strongly influenced by climatic changes [18] strictly will influence hydroelectric production and consequently, the economic value of produced energy. Moreover, hydroelectric energy is greatly affected by weather conditions; its productivity can be subject to significant seasonal and annual variations. The climatic conditions affect both the hydrological cycle, energy demand and the price of electricity. Bombelli et al., [3, 4] investigated how hydroelectric production is influenced by climate, fluctuations in demand and price constraints, extrapolating a hypothetical trend of electricity price up to the end of the 21st century (Figure 2).

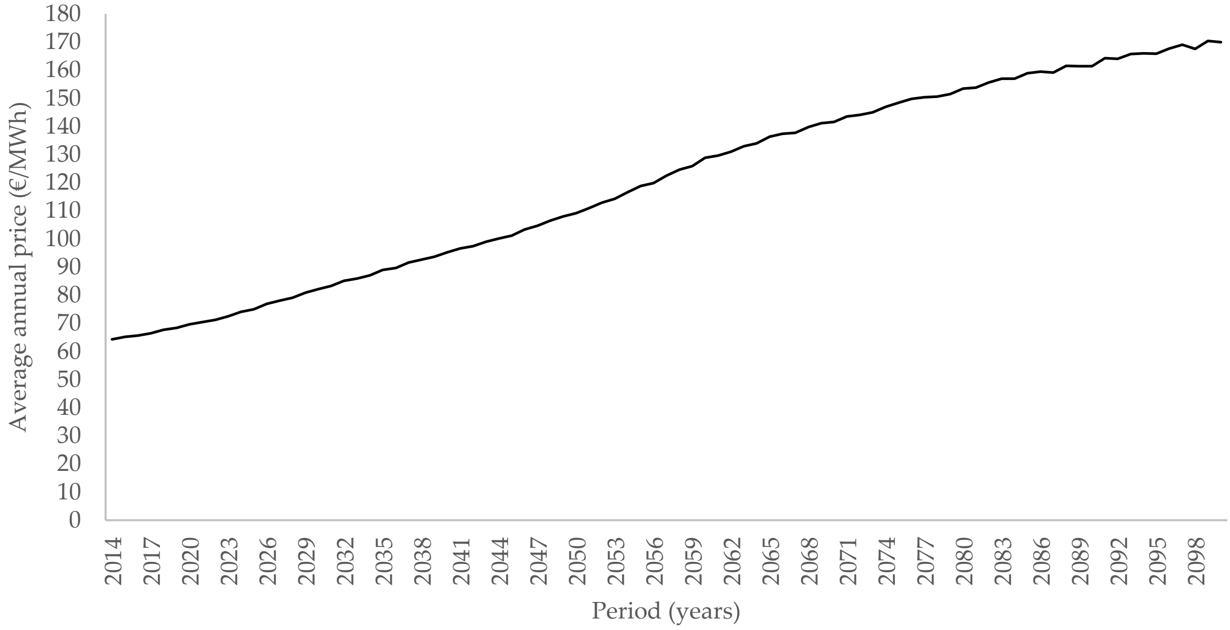

Figure 2. Trend of average annual prices of electricity over the period 2014-2100.

The average annual price of energy will undergo a significant increase over the analyzed 87 years, going from about 64 €/MWh to about 169 €/MWh. The immediate outcome of a similar projection is the increase in expectations of the entire hydroelectric sector. If currently the economic sustainability of a hydroelectric project cannot be separated from incentive policies, a similar scenario may instead reserve the possibility of investing in the sector without the need to rely on subsidized tariffs.

3.3. Phase 1

In phase 1 the economic sustainability of hydroelectric plants with concession power up to 1,000 kW in the absence of incentives and access to the PMG for the first 1,500,000 kWh produced was analyzed. The energy exceeding the threshold of PMG is sold at the market price, that is the average value of the last 5 years of the PUN on the day before market, was assumed. Moreover, particular attention was paid to the incidence of water concession fees on the economic evaluation of the investment. In calculation energy was weighted by a reduction coefficient equal to 0.85 to consider that a plant is not always at its maximum potential due to periods of inactivity or other external factors that the operator cannot exclude. These could be periods of drought (in which the plant runs at reduced power), periods of full extremes (in which it runs at maximum power or is stopped). From this point of view, the economic simulation of the profitability of a plant that results from it is certainly more reliable and representative of reality because it considers the unpredictability. Furthermore, according to this logic, the average hours of operation considered are effective (non-operating hours for maintenance excluded). The calculation is usually carried out over 30 years, because, due to the discounting, both expenses and income weigh shortly after many years. This aspect, which could be considered a "limit" of this economic model, is not however influential in this analysis since it is customary to consider a duration equal to the period of concession of the plants, which in the greatest number of cases is around 20-30 years.

Figure 3 shows the trend of the IRR varying the average annual hours of operation between 3,000 and 8,000 hours and the CAPEX (unit installation cost) between 4,000 and 7,000 €/kW for sizes of 100 kW, 250 kW and 500 KW, and between 3,000 and 6,000 €/kW for size 1,000 kW. In each graph, two areas were highlighted to mark the investment acceptability threshold in orange (for profitability rates between 7% and 9%) and the

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investment convenience threshold in green (for rates higher than 9%). Although the average operation of the entire national hydroelectric park, including the reservoir plants, is equal to 3,370 h/year, the analyzed plants are generally characterized by greater hours of operation; this because little run-of-river systems which guarantee a more persistent functioning throughout the year that easily reaches 6,000-7,000 h/year, were considered.

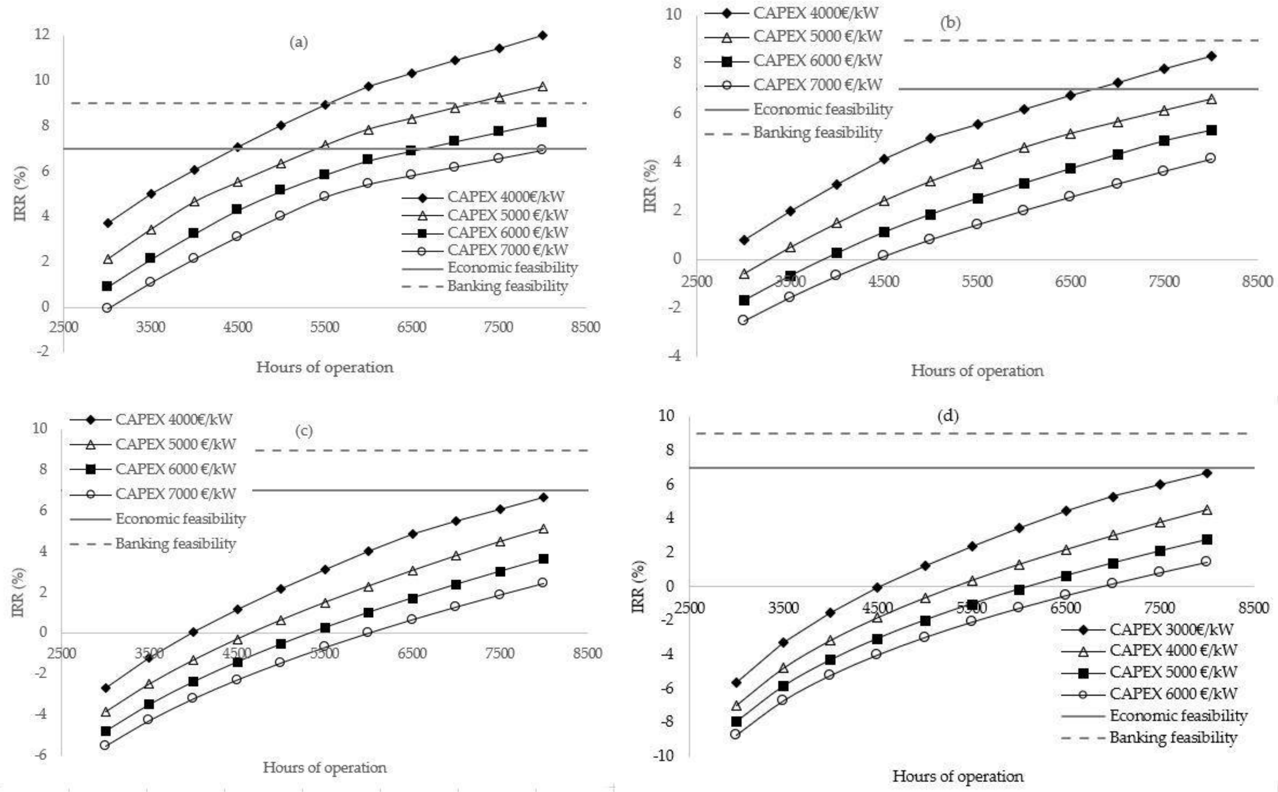

Figure 3. TIR trend-Hours of operation for different CAPEX for system of 100 kW (a), 250 kW (b), 500 (c) kW and 1,000 Kw (d).

The IRR of the investment is less than 7% for almost all cases, except the first. The worsening as the size increases, is substantially due to the lesser relevant of the PMG provided for plants with a concession power less than 1,000 kW, within the first 1,500,000 kWh produced. Only the smaller plants can take advantage of these subsidized prices for all the produced energy, while the larger ones must operate mainly on the market price. As shown in Figure 3, a 100 kW system is the only interesting: it achieves the threshold of acceptability for CAPEX of 4,000 €/kW, 5,000 €/kW and 6,000 €/kW respectively after 4,500, 5,500 and 6,500 hours. For plants with an installed power of 250 kW, the area of acceptability is only slightly crossed with CAPEX of 4,000 €/kW. Systems with the most expensive installation costs (CAPEX equal to 6,000 €/kW and 7,000 €/kW) achieve very low IRR. When a plant exceeds 5,000,000 kWh of energy production, according to PMG 2019, the price of energy undergoes a sharp decrease of approximately 37%, from 107,2 to 67,6 €/MWh. The cash flow is therefore gradually reduced as the production and consequently also the IRR. As shown in Figure 3c and 3d, the situation worsens for plants of 500 and 1,000 kW, as these can reach very high productions, respectively of about 3,000,000 and 7,000,000 kWh. In such cases, the effort to use substantial resources for development is not rewarded at all by the high productions, because the subsidized tariff plan does not reward them. The simulation concerning the 1,000 kW system has the lowest CAPEX, between 3,000 and 6,000 €/kW, to consider the scale factor; unit installation costs too high would lead to a huge unreliable investment. The rents (in which royalties are also considered) have a strong impact on the profitability of the plant: these represent an average annual cost equal to approximately 6% of the revenues for a 100 kW plant, also exempt from the payment of BIM and local authorities, between 9% and 12% for a 250 kW plant, between 15% and 17% for the 500 kW one and between 19% and 22% for a 1,000 kW system. If incentive tariffs on the same cases were applied, any implant size would become economically sustainable, even hitting profitability peaks of over 25%. Figure 4 reports results for the following incentives: 0.219 €/kWh for 250 kW plant (a), 0.179 €/kWh for 500 kW plant (b), 0.1561 €/kWh for 1,000 kW plant (c). To consider the scale factor, the rate is discounted as the size increases.

Despite this, all lines intersect the areas of acceptability and convenience. While the depreciation acts negatively on incoming flows, the increase in production due to the increase in size makes it possible to abundantly fill this difference and still guarantee sustainability.

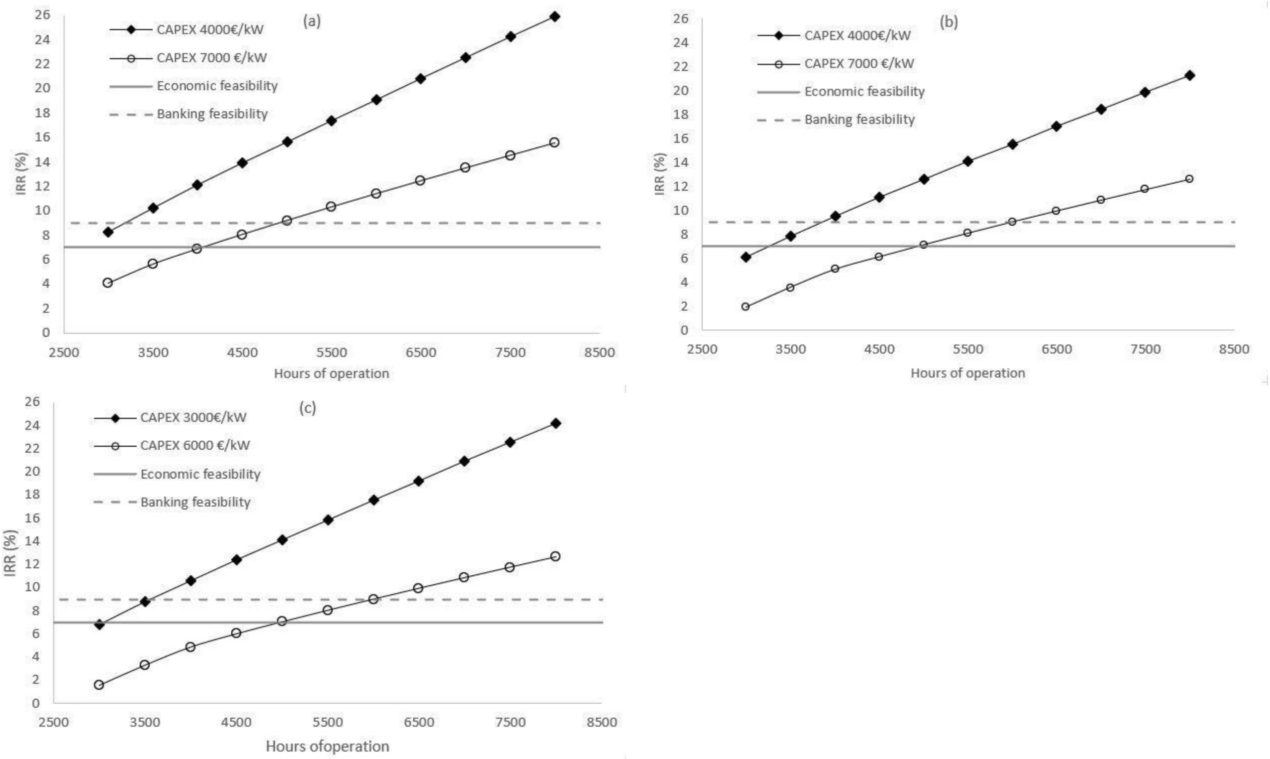

Figure 4. TIR trend-Hours of operation for plants of 250 kW with an incentive of 0.219 €/kWh (a), 500 kW with an incentive of 0.179 €/kWh (b), 1,000 kW with incentives of 0.156€ /kWh (c).

In Figure 4 only the minimum and maximum CAPEX were represented. The IRR achieves the profitability threshold for all combinations even for the highest CAPEXs. This proves that, in a regulatory context that supports the sector with advantageous tariffs, there could be significant sustainable development rates for all plant sizes without no longer concerns about investment attractiveness. Newly built plants to which the PMGs are applied, according to the current thresholds, do not appear economically sustainable. They were extended to up to 2,000,000 kWh to highlight the positive influence produced by GMPs, especially for high hours of operation. Given the low price guaranteed for the last bracket, between 1,000,000 kWh and 1,500,000 kWh, instead of increasing the latter, it was decided to add the 500,000 additional kWh that are missing to reach 2,000,000 kWh in equal measure (i.e., 250,000 kWh each) in the two central brackets. For all plant sizes, the curves at CAPEX 4,000 €/kW were compared with two alternative tariff plans: the tariff plans PMGs 2013, that shows more favorable prices and PMGs 2019, extended G to 2,000,000 kWh (Figure 5).

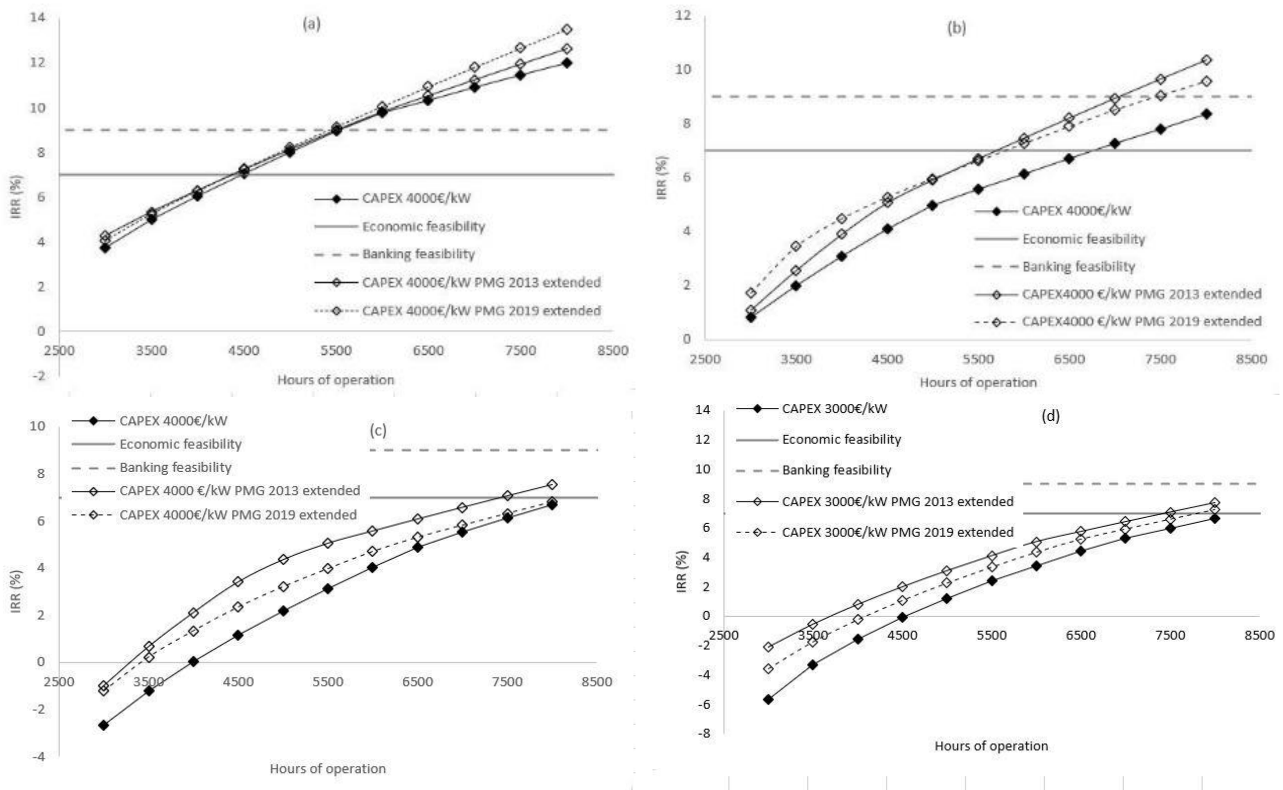

Figure 5. TIR trend-Hours of operation comparing PMG 2019 with PMG 2013 extended to 2,000,000 kWh for CAPEX 4,000 €/kW for different plant sizes: 100 kW (a), 250 kW (b), 500 kW (c) and 1000 kW (d).

For all plant sizes both alternatives involve advantages, except for the minimum size of 100 kW, characterized by low energy production that does not benefit from the extension of the PMGs or from the increase in prices. With reference to the PMG 2013, there is an increase of profitability of approximately 21%, 40% and 46% in plants with installed power equal to 250, 500 and 1,000 kW, respectively, while with the PMG 2019 slightly lower percentages were recorded: about 17%, 18%, and 23% for same plant sizes.

Concluding, the PMGs in force ensure the complete profitability only for smallest plants size, with an installed power less than or equal to 100 kW, whose operating and maintenance costs are not compensated from the sale of the energy produced at market prices. For other sizes, there is a deterioration in the profitability of investments as the installed power increases, due to the lower impact of the PMG. To make the development of new medium-large plants more attractive, the extension of the PMGs is needed.

3.4 Phase 2 – Remodulation of the tariff plan

The aim of this phase is to identify a so-called AT (All-inclusive Tariff) for economically support the micro-hydroelectric sector guaranteeing the maintenance of the minimum plants profitability. AT provided by the DM July 4th 2019 was 0.080 €/kWh, AT provided by DM July 6th 2012 and DM June 23rd 2016 were respectively equal to 0.155 €/kWh and 0.150 €/kWh. The same thresholds of investment acceptability and bankability of phase 1 were adopted. Also, in this case, the cash flows were discounted assuming that the time life of the hydroelectric project is 30 years and produced energy was sold to the PUN. Following figures show, varying the hours of operation and the CAPEX, the value of AT to reach a TIR equal to the two pre-established thresholds (7% and 9%) for plant size of 100 kW, 250 kW, 500 kW and 1,000 kW.

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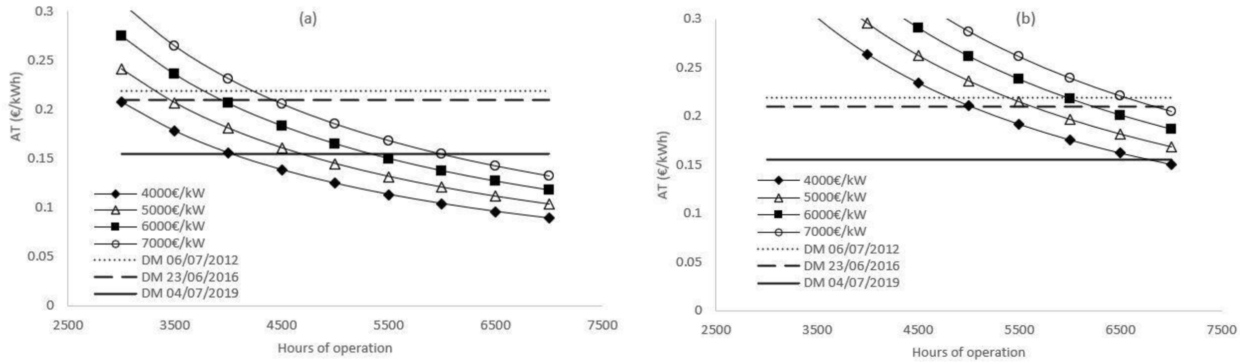

Figure 6. AT-Hours of operation for different CAPEX to reach IRR of 7% (a) and 9% (b), plant size 100 kW.

The current AT (DM July 4th 2019) is suitable to guarantee a net economic return of 7% but not to reach 9%, while AT of DM July 6th 2012 and DM June 23rd 2016 would be sufficient for both the profitability thresholds. The AT to reach an IRR of 7% and 9%, averaging the values associated with the various CAPEX and assuming 6,000 hours of operation, would be 0.129 €/kWh and 0.208 €/kWh respectively.

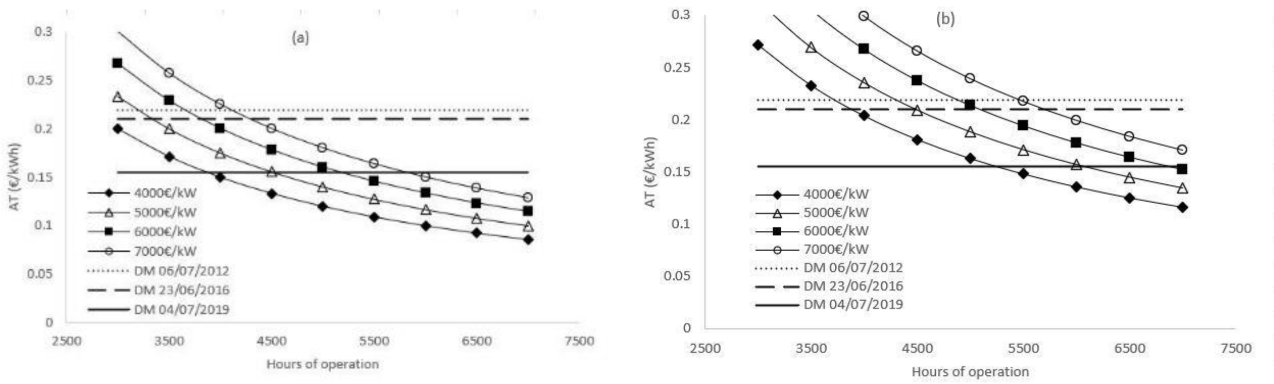

Figure 7. AT-Hours of operation for different CAPEX to reach IRR of 7% (a) and 9% (b), plant size 250 kW.

Figure 7 shows some improvement for the bankability threshold: the AT of DM July 4th 2019 (0.155 €/kWh) allows to reach the profitability for all systems of this size whose installation cost is between 4,000 €/kW and 5,000 €/kW. Higher CAPEXs are unsustainable for this incentive rate. The AT that would be necessary to reach an IRR of 7% and 9%, averaging values of different CAPEX and assuming 6,000 hours of operation, would be respectively 0.125 €/kWh and 0.168 €/kWh.

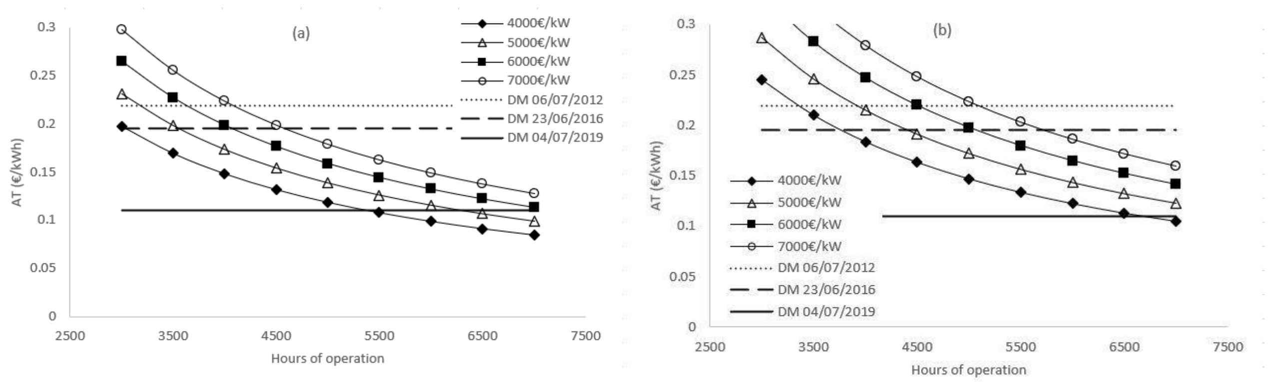

Figure 8. AT-Hours of operation for different CAPEX to reach IRR of 7% (a) and 9% (b), plant size 500 kW.

With the increase in installed power, the remuneration conferred by the DM July 4th 2019 fell to 0.110 €/kWh with significant repercussions on the economic sustainability of a hydroelectric project (Figure 8). The minimum profitability limit is not guaranteed neither for IRR of 7% (for CAPEX of 6,000 and 7,000 €/kW) nor for IRR of 9%. The AT to reach these profitability thresholds, averaging values of different CAPEX and assuming 6,000 hours of operation, would be respectively 0.124 €/kWh and 0.155 €/kWh.

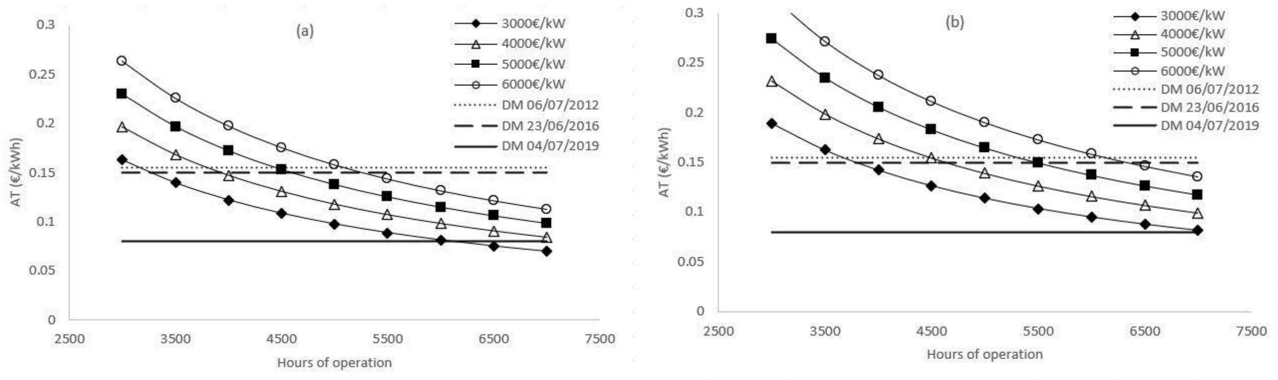

Figure 9. AT-Hours of operation for different CAPEX to reach IRR equal to 7% (a) and 9% (b), plant size 1,000 kW.

For 1,000 kW systems, the AT provided by the DM July 4th 2019 is insufficient to guarantee the economic sustainability of 7% and 9% (Figure 9). On the contrary, the AT established by the previous Ministerial Decrees DM July 6th 2012 and DM June 23rd 2016 would be sufficient for both profitability thresholds. The AT to reach these profitability thresholds, averaging of the values of different CAPEX and assuming 6,000 hours of operation, would be respectively 0.107 €/kWh and 0.127 €/kWh. Whit AT guaranteed by the DM June 23rd 2016, almost all plants reach acceptable yields around 6,000 hours of operation differently that with the last tariff plan (DM July 4th 2019). Only systems with installed power less than or equal to 250 kW (for any CAPEX) and those of 500 kW for small CAPEX (about 4,000 €/kW) guarantee the minimum profitability of 7%, for the same number of operating hours. All other combinations do not guarantee the achievement of the minimum economic sustainability. Table 5 summarizes the values of the AT resulting from analysis.

Table 5. Remodeling of the tariff plan.

Power (kW)	AT-7% (€/MWh)	AT-9% (€/MWh)
1<P≤100	129	208
100<P≤250	125	168
250<P≤500	124	155
500<P≤1000	107	127

The current AT (DM July 4th 2019) is insufficient for the development of plants larger than 250 kW. If in the past the incentive policies allowed a transversal development of the micro-hydroelectric, affecting all sizes, today they are excessively restrictive and risk paralyzing not only the increase in total installed power but also any technological development.

3.5 Phase 3 – Economic sustainability of micro-hydroelectric plants in the period 2014-2100

The evaluation of the effect of the price of energy on production is important when studying the profitability and benefits associated with energy systems. As previously discussed, the demand and the price of electricity depend not only on economic and social developments but may also be subject to seasonal variability and other medium-long term variations due to climate change. With reference to the model of Figure 3, the benefit that an increase of the electricity price would bring to the economic profitability of small-scale hydroelectric plants was explored. Simulations were performed by applying the NPV methodology; the cash flows to discount over 30 years of the investment life were updated from year to year according to the kilowatt hours of energy produced and the average annual price. Two different analysis were carried out: the first compares the performance of hydroelectric projects undertaken in two opposing scenarios, the second investigates the evolution of the IRR from 2020 to 2070.

ANALISYS 1: comparison of performances for two opposite scenarios

For each plant size, the trend of the IRR for two opposite scenarios, characterized by regimes of electricity prices at the extremes of the pre-established temporal projection (periods 2020-2049 and 2070-2099 respectively) were compared. Consistently with previous phases CAPEX was varied from 4,000 €/kW to 7,000 €/kW for plants with installed power of 100 kW, 250 kW, 500 kW, and from 3,000 €/kW to 6,000 €/kW for 1,000 kW systems. To consider the uncertainty linked to future changes in water concession fees from now up to 2100 in calculations two distinct criteria were adopted:

- Approach 1: relying on the trend in the average annual energy price according to the projection of Figure 3, the NPV was estimated calculating the updated cash flows from year to year according to the electricity price of the current year.
- Approach 2: the calculation of the NPV was developed by assuming the price of electricity constant over time, so that all cash flows calculated for the entire useful life of the investment are equal. Figure 10 and 11 compare results of the two approaches.

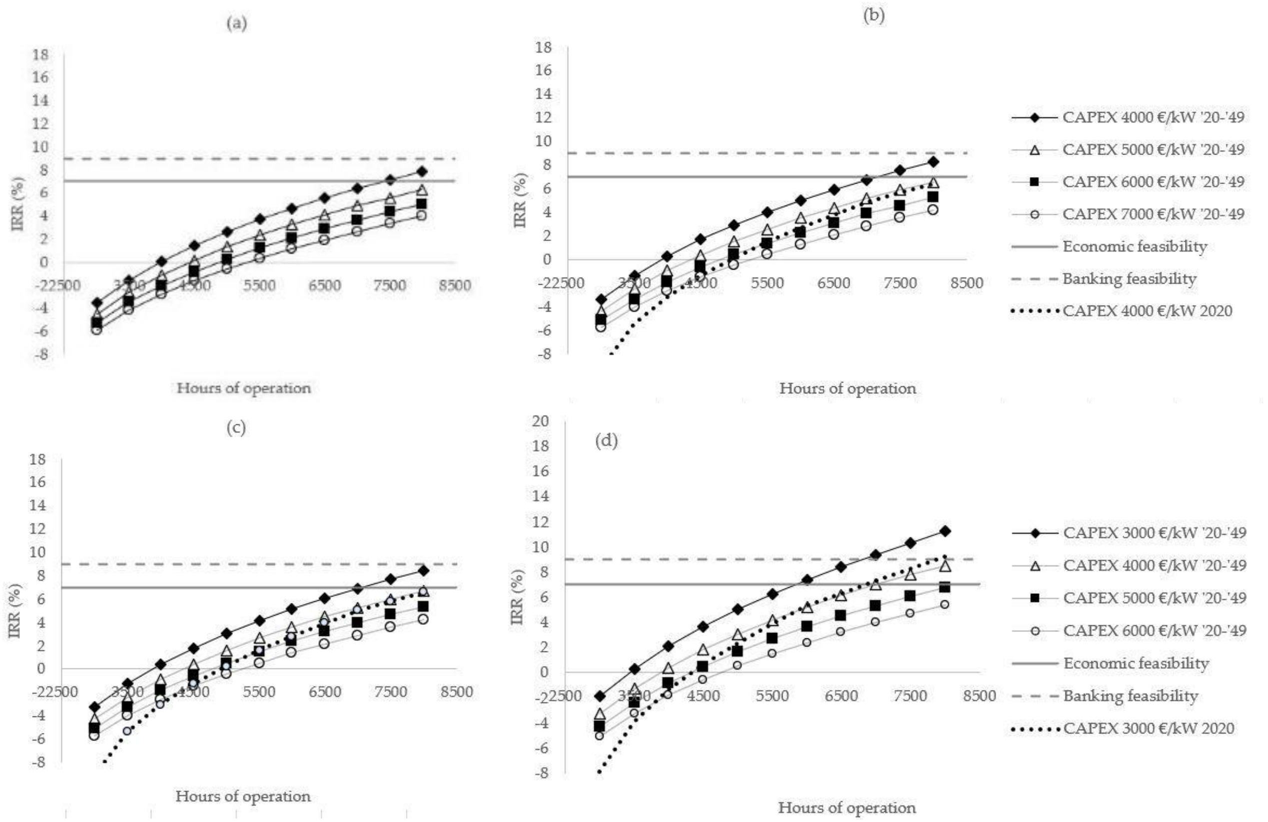

Figure 10. IRR-Hours of operation, comparing scenarios 2020-2049 for Approach 1 and Approach 2: 100 kW (a), 250 kW (b), 500 kW (c), 1,000 kW (d).

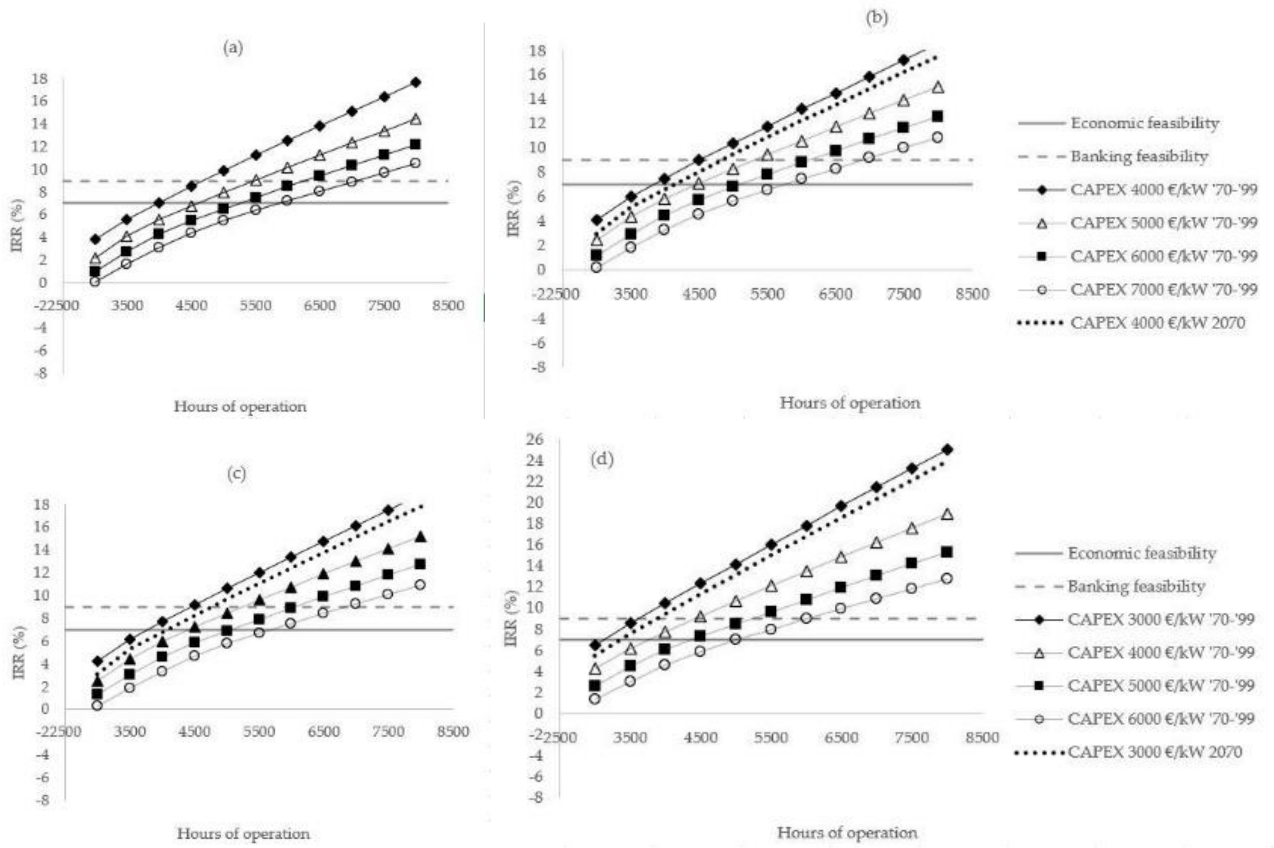

Figure 11. IRR-Hours of operation, comparing scenarios 2070-2099, for Approach 1 and Approach 2: 100 kW (a), 250 kW (b), 500 kW (c), 1,000 kW (d).

With reference to Approach 1, The IRR at 6,000 hours of operation for the period 2020-2049 never reaches profitability values equal to or greater than 7% for any CAPEX. Considering the scenario 2070-2099 the IRR always exceed the 7% threshold, up to reaching values that exceed the minimum investment convenience limit (9%) for CAPEX below 6,000 €/kW. The different profitability between the two stages is underlined if the situation is analyzed at 7,000 average hours of operation: if in the first scenario the IRR reaches acceptable values only for installation costs equal to 4,000 €/kW, in the second scenario the IRR exceed the 9% for all types of investments (CAPEX of 4,000, 5,000, 6,000 and 7,000 €/kW). Considering a system characterized by an installed power of 1,000 kW, both scenarios benefit of more favorable IRR. The average annual production for 6,000 hours, in the 2020-2049 scenario exceeds the minimum limit of 7% only with the minimum CAPEX, while in the 2070-2099 scenario all the IRR record a profitability of over 9%, with values even close to 18%. The same trend occurs for 7,000 average hours of production: while in scenario 1 acceptable investment are achieved only for CAPEX of 3,000 €/kW and 4,000 €/kW, in scenario 2 all the CAPEXs exceed the convenience threshold of 9%. The positive effect on IRR of the increase in electricity prices over the course of the century is significant and reflects the expectations of the sector. On average, the increase recorded between scenario 1 and scenario 2, at the threshold of 6,000 average hours of operation, even exceeds 100%; that is, profitability doubles. Comparing results from Approach 1 and Approach 2, in all simulations the difference of TIR is appreciable. Over the useful life of a hydroelectric plant operating in the free market, the factor with the most relevant specific weight for its profitability is the price of energy. To consider the future evolution of the price of electricity is important for the evaluation of the suitability and reliability of an investment.

ANALISYS 2: IRR evolution in the period 2020-2070

The aim is to trace the trend of the investment profitability over the years, calculating the IRR by discounting the cash flows envisaged by the NPV methodology over the entire useful life of the system and associating the IRR to the year in which the investment is undertaken. Resulting curve indicates, for each year, the percentage of the IRR of the investment, calculated by discounting the cash flows over the next 30 years

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(i.e., the value of profitability associated with the year 2032 is the result of the economic analysis carried out using the NPV method considering the cash flows in the years 2032-2061 and the corresponding energy prices. The simulations were carried out sequentially from 2020 to 2070. For each case study (100 kW, 250 kW, 500 kW, 1,000 kW) the trends of the IRR corresponding to the minimum and maximum CAPEX were calculated, to highlight the range within which the investment profitability of similar projects can fluctuate (Figure 12).

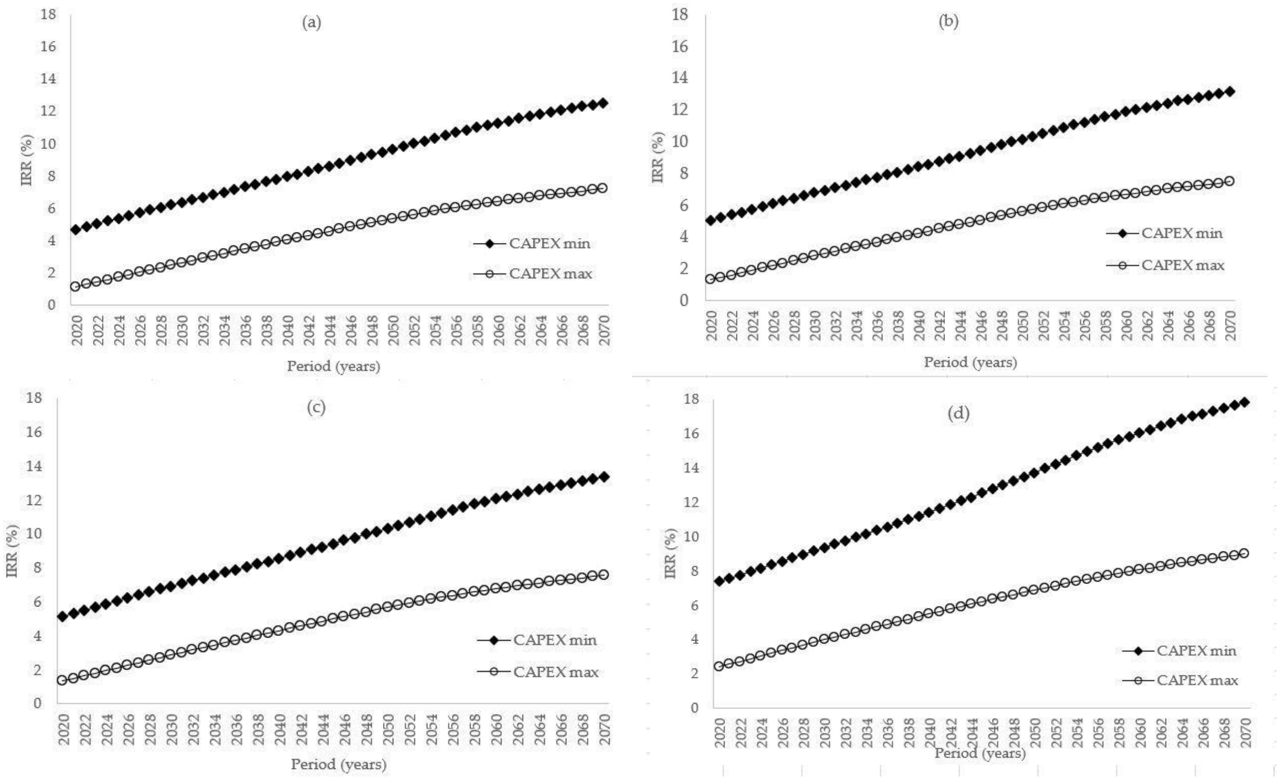

Figure 12. IRR-Period 2020-2070 for CAPEX of 4,000 €/kW and 7,000 €/kW, assuming an average operation of 6,000 hours: 100 kW (a), 250 kW (b), 500 kW (c), 1,000 kW (d).

Between one-unit installation cost and the other there is a difference ranging from 3 to 5 percentage points at the beginning of the projection (2020) and from 8 to 10 percentage points at the end of the projection (2070). The IRR grows with an almost linear trend, as expected from the trend in the price of electricity. Considering the maximum CAPEX of 7,000 €/kW, starting from an IRR of approximately 1%, within 50 years an IRR of almost 8% is reached; considering the minimum CAPEX of 4,000 €/kW, the initial IRR settles around 5% and the final one around 12.5%. The influence of the CAPEX on the marginal growth of the IRR was confirmed. Even in the case of a 1,000 kW system, the TIR trend remains increasing. However, the marginal growth of this parameter is different for the two considered CAPEX. For the minimum CAPEX (3,000 €/kW), the IRR recorded in 2020 is about 7.5%, while in 2070 it settles around 18%. For the maximum CAPEX (€ 6,000/kW) the IRR starts from a value of 1% and grows up to just over 8%. In the period 2020-2070, the increase of the IRR for the maximum CAPEX is approximately 7%, for the minimum CAPEX is greater (about 11%). This trend can be traced back to the economic investment costs associated with the size of the plant: for the same installed power and for the maximum sizes of the micro-hydroelectric, the CAPEX assumes a greater specific weight in the projection of the IRR. For smaller CAPEX there is a marginal increase in the IRR, higher than the value for the same unit installation cost, for the smaller sizes. For this reason, the two curves of Figure 11d are not parallel but diverge. Rely the feasibility analysis of a hydroelectric project to an accurate model of future projections of the value of electricity is certainly a more truthful approach, despite the uncertainties connected to this kind of models.

4 Conclusions

In the study the evolution of the profitability of an investment, according to the plant sizes and the economic context, was analyzed for Italian scenario, as function of the tariffs recognized by the hydroelectric energy market, the unit cost of installing the plants and their average hours of operation. Three phases were distinguished: the first, was characterized by the analysis of the economic sustainability of the micro-hydroelectric plants under the PMG; in the second, the value of the incentive to reach the thresholds of "acceptability" and "bankability" of the investment, for the same hydroelectric plants of the phase 1, was estimated; in the third, an analysis of the results obtained in the previous phases was conducted using a model of the evolution of the price of electricity in the period 2014-2100. Obtained results suggest that, to maintain the attractiveness of the sector, it is necessary to safeguard access to the PMG. With PMG 2019, complete sustainability is only achieved for plants with P≤100 kW. For the remaining sizes, investments under current conditions would not be profitable. The extension of PMGs could make new medium-large plants (500-1000 kW) more attractive. The current incentive policy (DM July 4th 2019) is not effective for the development of plants larger than 250 kW; systems with lower CAPEX should be preferred. Uncertainty about the evolution of the price of energy over time is a concern for the sector; the use of evolutionary models of technical economic analysis tries to reduce these criticalities and shows that they can be transformed into opportunities. Profitability due to the growing trend expected for the price of energy cannot be highlighted by a traditional analysis.

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