



Cogeneration of green hydrogen in a cascade hydropower plant

David Jure Jovan^{*}, Gregor Dolanc, Boštjan Pregelj

Department of Systems and Control, Jožef Stefan Institute, Jamova cesta 39, 1000 Ljubljana, Slovenia

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ABSTRACT

Hydrogen is today an indispensable feedstock in various process industries, but the method of its production is mostly not in line with accepted environmental guidelines. With emerging electro-energetic systems with a large share of renewable sources, hydrogen is also becoming an important energy carrier, which with the possibility of storing surplus energy ensures greater stability of power system operation and energy supply. Therefore, the use of electricity from renewable sources is important for the production of green hydrogen using electrolysis. The first part of the article describes the possibilities for hydrogen cogeneration in one of the run-of-river hydropower plants in Slovenia. The implementation costs of the necessary equipment for hydrogen production in the case-study power plant, its production costs and the profitability of hydrogen production compared to the sale of electricity are estimated. The criteria according to which the production of hydrogen is more profitable than the sale of electricity at current prices and guaranteed sales is also defined. In the second part of the article, a scenario for the use of hydrogen for heating and mobility needs in the nearby local community is presented. For the regular supply of hydrogen in the range of up to 30 kg/h, the necessary investment costs for the installation of the appropriate equipment in the hydropower plant are calculated along with an estimation of the payback period of the investment.

Introduction

Increasing global energy consumption, climate changes, and air pollution encourage the transition of energy systems all over the world towards more efficient and carbon-free power generation. The electric power sector is responding to this challenge by integrating more renewable power sources (RES-hydropower, photovoltaics, wind turbines) into the electricity system. As a result, a high share of renewable energy sources (RES), due to their weather dependency, cause challenges in the management of the electricity network and the volatility of electricity prices.

Therefore, new solutions and technologies are needed that ensure network balance and enable the storage of excess energy. The promising option for solving these problems is the introduction of Power-to-gas (P2G) technology [1–3] into the electro-energetic system, which can provide a conversion of excess renewable energy into hydrogen, supports the transition to sustainable energy systems, can be a source for renewable gases (hydrogen, oxygen, synthetic natural gas), and can also play an important role in the market pricing of electricity. Hydrogen produced with electricity from RES has a special value because its production does not cause CO₂ emissions, and it is called “green hydrogen”

[4]. In general, RES hydropower plants are the least sensitive to weather conditions and, therefore, the most suitable for regular cogeneration of electricity and green hydrogen.

Hydrogen is already an important feedstock for industry today. The global supply of hydrogen to industrial users is an important economic activity worldwide and, in 2018, exceeded 74 million tons. Demand for hydrogen, which has grown more than threefold since 1975, is still rising and is mostly produced from fossil fuels (grey and brown hydrogen), where 6% of natural gas and 2% of coal goes to hydrogen production [5]. Therefore, its current production methods are not in accordance with long-term climate and energy goals. Today, in the EU industry, an on-site steam methane reforming (SMR) is the most common and cost-effective method for hydrogen production. As this technology is mature, fluctuations in the cost of hydrogen production today largely depend on the price of natural gas [6] and the price of hydrogen ranges from 2 to 3 €/kg [7]. The steam reforming process generates CO₂ emissions, so the final product is not green hydrogen. As a result, global hydrogen production from fossil fuels is currently responsible for around 830 million tons of CO₂ emissions per year.

Thus, it is even more important that in the future we produce green hydrogen using P2G technology [8,9]. It should be noted that today green hydrogen technologies are hardly economically viable. The reason

^{*} Corresponding author.

E-mail address: david.jovan@ijs.si (D.J. Jovan).

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Nomenclature			
<i>Acronyms</i>			
RES	renewable energy sources	Q	amount of water per second (m^3/s)
P2G	power-to-gas systems	Q_i	water flow from i-th hydropower plant (m^3/s)
CO_2	carbon dioxide	d_i	internal water flow (m^3/s)
CO	carbon monoxide	x_0	initial water level (m)
SMR	steam methane reforming	x	denivelation (m)
HPP	hydro power plant	P	installed electric power (W)
NPP	nuclear power plant	η	efficiency of the entire power plant (/)
TPP	thermal power plant	h	available (installed) drop - the difference between the lower and upper water level (gross head) (m)
FCV	fuel cell vehicles	S	surface of the accumulation (m^2)
NOx	nitrogen oxides	T	time of observation (s)
VAT	value added tax	m	mass (kg)
<i>Parameters and variables</i>		CapEx	capital expenditure costs (€)
LHV	hydrogen lower heating value (MJ/kg)	OpEx	operational costs (€/year)
ρ	water density (kg/m^3)	BoP	various supporting and auxiliary components (€)
g	gravitational acceleration (m/s^2)	PC	production costs (€/kg)
		PBP	payback period (year)

is that the current price of technological equipment for green hydrogen production, storage, and distribution, which is not yet a subject of mass production, is still highly priced. This leads to high capital expenditures of systems based on green hydrogen technologies, which results in a high price of generated green hydrogen. This reduces hydrogen's economic competitiveness in comparison to other fuels, particularly natural gas, and disables green hydrogen technologies from being widely adopted. In the EU's wholesale market, electricity prices in the last decade vary around an average of 50 €/MWh [10], where the production price is around 30% lower. To accelerate the adoption of green hydrogen technologies, the cost of electricity to produce green hydrogen with the P2G system should be optimised. At the same time, we need to amend the regulations governing the use of hydrogen in a way that favours the production and use of green hydrogen. Industrial and social sectors, where the use of green hydrogen is desirable (i.e., heating and mobility sectors), will have to implement the economics of green hydrogen use by enforcing environmental incentives.

Cogeneration is defined as the generation of two different forms of useful energy from a single primary energy source [11]. In the context of the article, cogeneration means production of both electricity and green hydrogen in a HPP from available water energy. Although the possibilities and methods for hydrogen production in a HPP have been presented for some time [12], this topic has not attracted much attention in the academic sphere. During the last decade, all conditions for increasing the production of hydrogen in an ecologically acceptable and efficient way have been established (i.e. consensus for environment decarbonisation, maturity of technological equipment for hydrogen production-P2G systems, increased hydrogen consumption in industry, the emergence of the electricity market with a significant share of RES, increased dynamics of the electricity sector, requirements for greater profitability of power facilities), so there are more articles in the literature that deal with these topics.

In [9], the authors present a study on the option to decarbonise hydrogen production using hydropower at the European level. The results show that such transformation is possible and compatible with the ongoing transition towards carbon-neutral power systems in the European Union. Also, other countries, especially those rich in hydropower, are also intensively involved in its use for hydrogen production [13,14]. Some articles define the role of P2G systems in future electro-energetic systems with a high share of RES. The authors in [2,3,15] found that P2G technology is a feasible option for storing energy for the long term, but cost reduction of electrolysis is essential to make power-to-gas attractive. The article [16] gives a worldwide overview on several P2G

projects producing hydrogen or renewable substitute natural gas in Germany, Denmark, the United States and Canada. The results show substantial cost reductions for electrolysis during the recent years and a further price decline to less than 500 €/kW electric power input for P2G technology until 2050 if cost projection follows the current trend.

There are already some ongoing projects in Europe that use hydropower for green hydrogen production. One of the demonstration plants is located at the Gösgen hydropower plant [17]. With a capacity of 2 MW, it is the largest plant in Switzerland for the production of green hydrogen for commercial use in emission-free heavy goods traffic. The plant can produce up to 300 tons of green hydrogen per year, thus ensuring an annual consumption of around 40–50 fuel cell electric trucks or 1700 fuel cell passenger cars. A similar facility with a smaller capacity of green hydrogen production is located in Aarau, Switzerland [18]. The facility is located at the run-of-the-river plant of IBAarau. The green hydrogen is planned for use as fuel for vehicles. The electrolyser plant supplies sufficient hydrogen for the annual consumption of approximately 170 fuel cell cars. In Iceland, a green hydrogen production facility at the 16-MW Ljósifoss Hydropower Station near Reykjavík will be built [19]. The facility will be housed in a 700 m^2 building that will be adequate for maximum production at 10 MW, although the electrolysis will be built out in phases, increasing in capacity as demand increases. At full capacity, the station will produce enough green hydrogen to power the Reykjavík area's entire public transportation fleet.

The abovementioned open issues and the ongoing demonstration projects led us to perform the feasibility study [20], where we tried to estimate the economic issues of green hydrogen production in a case-study Slovenian hydro power plant (HPP) and possibilities for its use. Namely, the HPP's management is considering the possibility of cogeneration of green hydrogen from existing hydropower reserves with the aim of increasing the profitability of HPP operations. The produced green hydrogen would serve the needs of the local community, especially in the fields of heating, local transport and, due to the favourable location of the HPP, also for the needs of international heavy transport.

The article presents some results and conclusions from the abovementioned study and is organised as follows. In chapter "Hydrogen production in a hydropower plant", the management of the electro-energetic system in Slovenia is briefly described along with the possibilities for green hydrogen production in the case-study HPP and the limitations imposed by the fact that the HPP is one in a chain of several HPPs along the river. The next chapter deals with the economic viability of cogeneration of hydrogen along with regular production of electricity

and defines the rule when hydrogen production is more economically justified than production of electricity on a free electro-energetic market. Chapter “Use of hydrogen for the needs of the local community” provides possibilities for the usage of the produced green hydrogen in the nearby local community and describes the techno-economic analysis of the implementation of the P2G system for the regular production of a limited amount of green hydrogen. Conclusions and the benefits of P2G system implementation in the case-study HPP are described in the last chapter.

Hydrogen production in a hydropower plant

Management of an electro-energetic system is focused on the continuity of the balance between consumption and export on the one hand and production and imports on the other. The quality of balance as well as the quality of operation of the power system is shown in frequency. Any deviation from equilibrium results in a deviation from the nominal frequency of the system, where an excessive consumption causes a decrease in frequency, and excessive production causes an increase. An electro-energetic system operator with adequate regulations responds to deviations and trigger actions (increase/decrease of current production in particular power plants) to return the system to equilibrium [21].

The Slovenian system operator has at its disposal three types of facilities for the production of electricity: the nuclear power plant, thermal power plants, and RES, where hydroelectric power plants predominate (in Slovenia today, around 23% of electric energy is produced from renewable energy sources, where a vast majority comes from hydro power plants).

The diagram in Fig. 1 shows the daily energy needs in Slovenia. From Fig. 2, we can see that the tracking of dynamic electricity consumption is ensured mainly by the production of electricity from hydropower sources. In order to coordinate the anticipated electricity consumption for the next day, the system operator distributes daily the hourly operation production schedule for the next day to all power plants. Deviations that occur during the day between the production and consumption of electricity are solved by the system operator by continuously correcting the planned schedules and using specific system services – ancillary services [21].

The tracking of planned consumption in a load diagram requires a dynamic provision of production power. A system that has storage power plants of sufficient power easily provides variations in the load diagram. It can also provide them in an economical way, as hydropower plants are perfect for dynamically adapting their production to needs.

The Slovenian system operator takes into account the need for obtaining electricity from renewable sources as much as possible. For this reason, the daily load schedule is made in such a way as to make the

most of the potential of hydropower plants. However, the schedule is prepared on the basis of models of available production capacities, estimated consumption, the state of river flows and weather forecasts, so a certain level of water potential exploitation reserve is envisaged. The actual demands for electricity are solved by the system operator by timely activation of appropriate ancillary services. Thus, a hydropower plant in reality can exploit unused surplus hydropower to produce electricity to produce hydrogen with the P2G system.

In general, hydropower plants can be constructed in a variety of sizes and with different characteristics [22,23]. The following three categories can be considered as the main types of hydropower plants:

Reservoir hydropower plants: Reservoir (storage) hydropower plants have the ability to store a large amount of water behind the dam. In this way, it is possible to de-couple generation of electricity from water hydro inflows. So, they effectively act as an electricity storage system. As with other hydropower systems, the amount of generated electricity is determined by the volume of water flow and the amount of available water net head. In Slovenia, there are no such hydropower plants.

Pumped storage hydropower plants: Pumped storage hydropower schemes use off-peak electricity to pump water from a reservoir located after the tailrace to the top of the reservoir. In this way, the pumped storage hydropower plant can generate electricity at peak times. Slovenia has one hydropower plant of this type.

Run-of-river hydropower plants: Run-of-river hydropower plants have no or limited storage capacity behind the dam and generation is dependent on the timing and size of river flows. Run-of-river hydropower plants with storage are said to have “pondage”. This allows short-term water storage (hourly or daily). Plants with pondage can regulate water flows to some extent and shift generation a few hours or more over the day to when it is most needed. This type of hydropower plant often occurs in a cascade, where the first power plant usually has a larger water accumulation, which is then used by downstream hydropower plants, see Fig. 3.

Fig. 3 illustrates a cascade of run-of-river hydropower plants, where

- Q_{i-1} : water flow from $(i - 1)$ -th hydropower plant in cascade (m^3/s),
- Q_i : water flow from i -th hydropower plant in cascade (m^3/s),
- d_i : internal water flow (m^3/s),
- x_0 : initial water level (m),
- x : denivelation (m).

Each HPP in the cascade has restrictions on the use of the water basin, which are given by the maximum and minimum water level of the pool (denivelation) and the discharge rate. Denivelation should only move within the permitted range.

Its power is defined primarily by the installed water drop (h) and

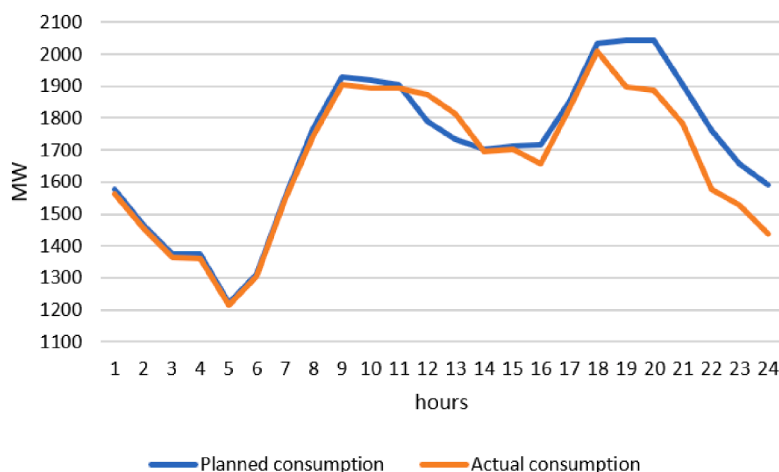


Fig. 1. Predicted and actual daily electric energy consumption, 6 Jan. 2021.

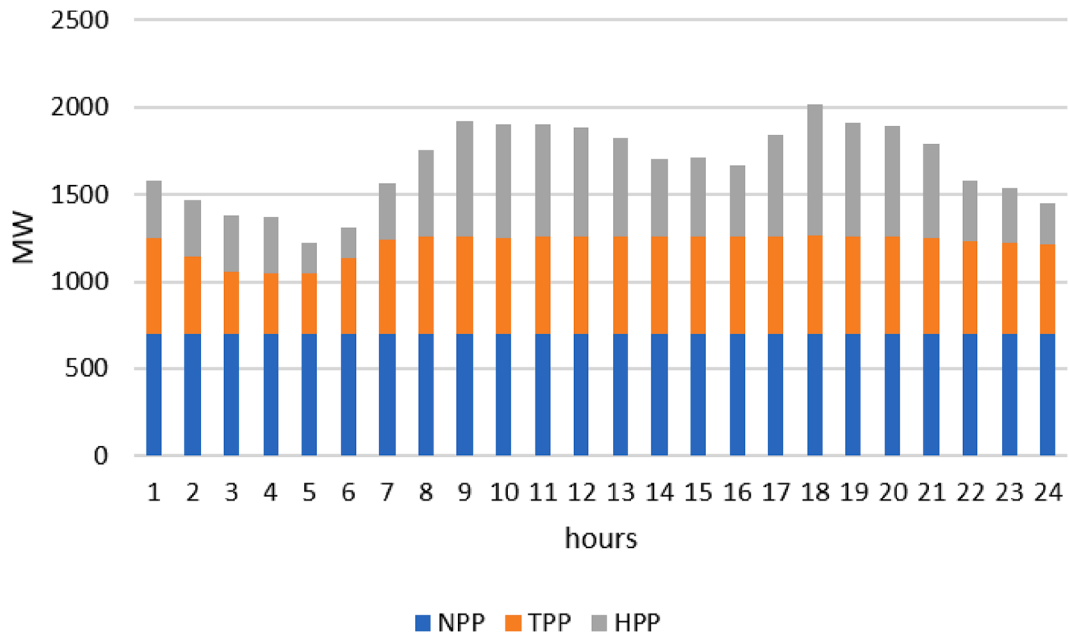


Fig. 2. Structure of electric energy production, 6 Jan. 2021(blue-nuclear power plant, orange-coal-fired power plants, grey-hydroelectric power). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

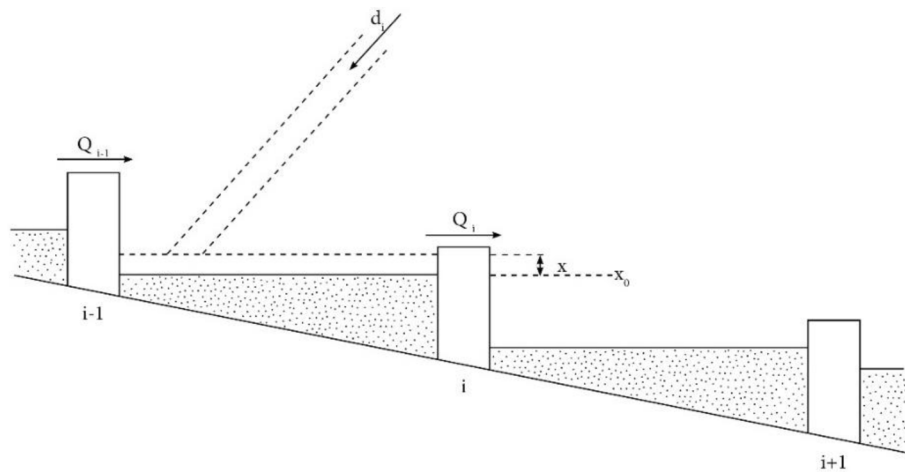


Fig. 3. Three hydropower plants in a cascade.

flow (Q) through the turbine. Both give installed electric power as

$$P = \eta \cdot \rho \cdot g \cdot Q \cdot h, \tag{1}$$

where

- P : installed electric power (W),
- η : efficiency of the entire power plant,
- ρ : water density (kg/m^3),
- g : gravitational acceleration (m/s^2),
- Q : amount of water per second (m^3/s),
- h : available (installed) drop – the difference between the lower and upper water level (m).

The Slovenian hydropower system has no big water accumulations; it has only flow-through hydropower plants with smaller hourly and daily accumulations, which are used to the maximum extent to cover variable energy needs as well as in certain periods for ancillary services. From the point of view of the volume of green hydrogen production in Slovenia,

its production is therefore limited. Hydrogen could be produced from surplus electricity from thermal power plants, but it is not green hydrogen. The share of photovoltaic and wind electricity in Slovenia is negligible. Therefore, the only realistic option is the production of green hydrogen using hydroelectric power plants, even though they are built in chains along the main Slovenian rivers and do not have a large accumulation of hydropower.

Therefore, in the text that follows, we will assess the possible volume of green hydrogen production in the case-study Slovenian hydroelectric power plant and give an assessment of the economic justification of its production.

Case-study hydro power plant

The case-study HPP is a hydroelectric power plant of the run-of-river and reservoir type, with three vertical generating units (around 16 MW of power each) with a combined rated discharge of $500 \text{ m}^3/\text{s}$ and five spillways. The installed plant capacity is around 50 MW (theoretical annual production is thus around 400 GWh), while the actual average

power is around 18.4 MW (annual production output around 160 GWh) due to the limitations in seasonal river water flow, see Fig. 4. This particular HPP accounts for approximately one percent of Slovenia's today annual electricity production and also provides the possibility of implementing ancillary services.

An additional advantage of the case-study HPP is its location; namely, it is located near two towns with a total population of 15,000 people, near a highway, and is also close to a natural gas distribution network. So, hydrogen could potentially be delivered to hydrogen filling stations located in both cities and along the highway or injected into the natural gas grid.

In the EU's wholesale market, electricity prices in the last decade vary around an average of 50 €/MWh [10], where the production price is around 30% lower. The market situation in Slovenia is similar.

The main technical characteristics of the case-study HPP are given in Table 1.

From the data in Table 1, the efficiency factor of the case-study HPP as the ratio between actual average electric power and average water potential power can be calculated as

$$\eta = 0.8227,$$

and also, by using Eq. (1), the necessary water flow needed for production of 1 MW of electric power

$$Q_{1\text{MW}} = 11.26\text{m}^3/\text{s}.$$

Due to its flat position and inclusion in the chain with other hydropower plants, the case-study HPP has limited possibilities for water accumulation and cogeneration of hydrogen. Since the HPP's maximal denivelation is limited to 1.1 m, it makes sense to calculate how much the additionally required water flow for 1 MW of additional power (used to produce hydrogen) affects the reservoir denivelation. Using Eq. (2) and assuming the worst case/no water inflow ($Q_{i-1} = 0$, $d_i = 0$) and the outflow $Q_{1\text{MW}} = 11.26\text{m}^3/\text{s}$, the hourly denivelation is

$$x_{1\text{MWh}} = -0.013\text{ m/h or maximal } -0.312\text{ m/day}.$$

$$S \cdot x = \int_0^T (Q_{i-1} + d_i - Q_i) dt \quad (2)$$

where

- S: surface of the accumulation, ($S = 3.09\text{ km}^2$), (m^2),
- Q_{i-1} : water flow from ($i - 1$)-th hydropower plant (m^3/s),
- d_i : internal water flow (m^3/s),
- Q_i : water flow from i -th hydropower plant (m^3/s),
- x : denivelation (m),
- T: time of observation (s).

Table 1

Basic technical characteristics of the case-study HPP (provided by HPP's technical staff).

HPP data	Values
Number of turbines	3
Nominal power (MW)	47.4
Nominal water flow (m^3/s)	500
Nominal water drop (m)	11
Average annual production (GWh)	161
Power plant dam point (meters above sea level)	153
Maximum operating denivelation (m)	1.1
Average annual water flow (m^3/s)	207
Total water accumulation volume (m^3)	19,300,000
Usable water accumulation volume (m^3)	3,400,000
Nominal water power (MW)	53.96
Average water power (MW)	22.34
Actual average electric power (MW)	18.38
Capacity of usable water accumulation (MWh)	101.92

The cogeneration of hydrogen along with regular production of electricity in a HPP requires (i) a suitable system for hydrogen production – P2G system, (ii) free capacities to produce additional electricity for the P2G system and (iii) sufficient water reserves.

From Fig. 5, it can be seen that the daily average water level in the accumulation basin of the case-study HPP is usually close to the middle of the allowed denivelation. Thus, the generation of additional electricity on a smaller scale for hydrogen production in the range of a few MWs can be more or less uninterrupted.

The supply of electricity for hydrogen cogeneration should, therefore, only be interrupted in the following cases:

- when the production of electricity due to the system operator's timetable is close to the maximum possible electricity production at the current water inflow;
- there is a need for the system service (secondary regulation) by the system operator, which requires an additional supply of electricity to the network;
- when the level in a water reservoir approaches the lower allowable value.

In these cases, the supply of electricity to the P2G system shall be temporarily reduced/stopped until the situation changes.

The constant consumption of water for hydrogen production gradually reduces water reserves in the dam. Consumed water is replaced during occasional inflows of excess water that would otherwise spill. Another option in the shortage of water is the use of electricity from a photovoltaic field, which is already being built along the case-study HPP.

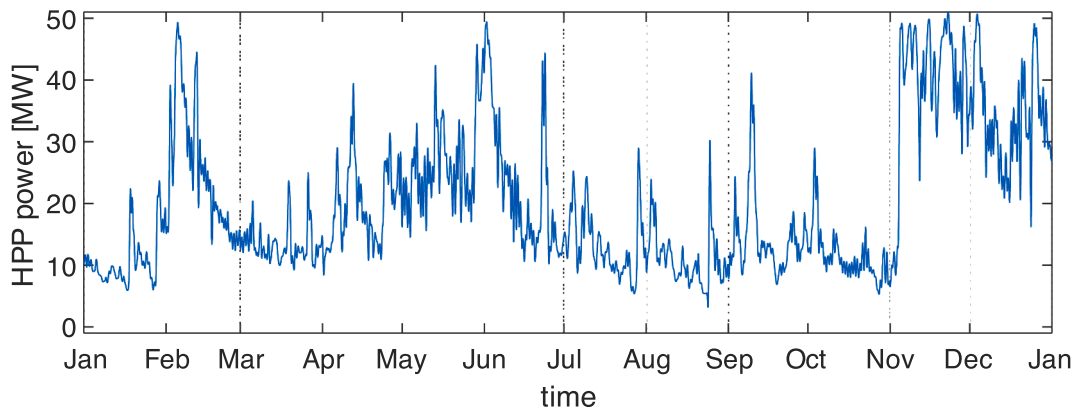


Fig. 4. Actual electricity production of the case-study HPP through the year.

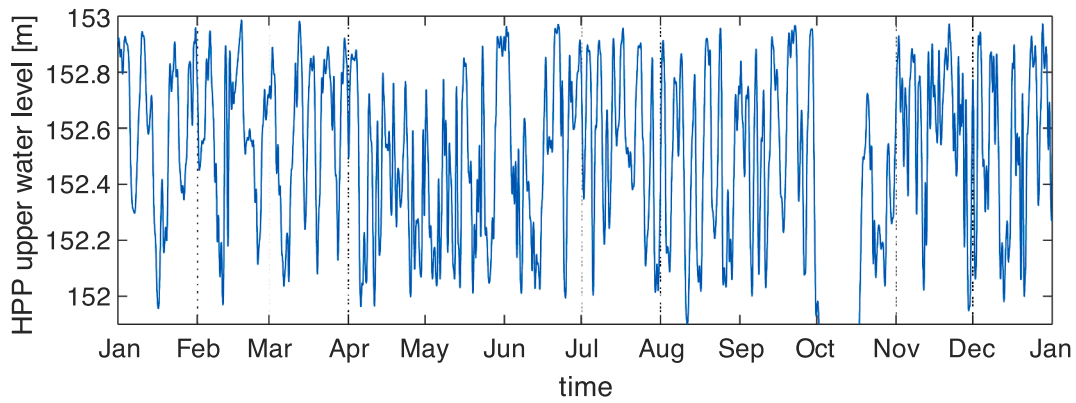


Fig. 5. Water denivelation of the case-study HPP reservoir (dam point–153 m above sea level, some data in October are missing due to a malfunction of the measuring sensor).

Economy of hydrogen production in the case-study HPP

From the previous chapter, it can be concluded that the case-study HPP, in today’s operating conditions, has enough water and production reserves to produce the few MWh of additional electric energy needed for hydrogen production. In this chapter, the conditions under which hydrogen cogeneration is economically viable are assessed. First, we will estimate the costs of purchasing and operating the necessary equipment for hydrogen production, then we will determine the production price of hydrogen and the conditions under which its production is economically justified.

Equipment for hydrogen production

The primary step for the conversion of excess electric energy into

hydrogen is an upgrade of the existing HPP technological equipment with an appropriate P2G system (Fig. 6), where the three main building blocks are an electrolyser, a hydrogen buffer tank system together with water fraction separation components, and final storage before distribution of the hydrogen to consumers or for further processes. P2G technology has made significant advances in recent years [1,2,3,24]. In anticipation of the electricity market with high shares of renewable energy, P2G technology is moving from innovation to commercialization [16] and there is already a number of P2G systems providers.

For calculations of green hydrogen production costs in the case-study HPP facility, technical specifications of one of the commercially available P2G systems [25] are used (Table 2).

For the next calculations, the following data about hydrogen are used:

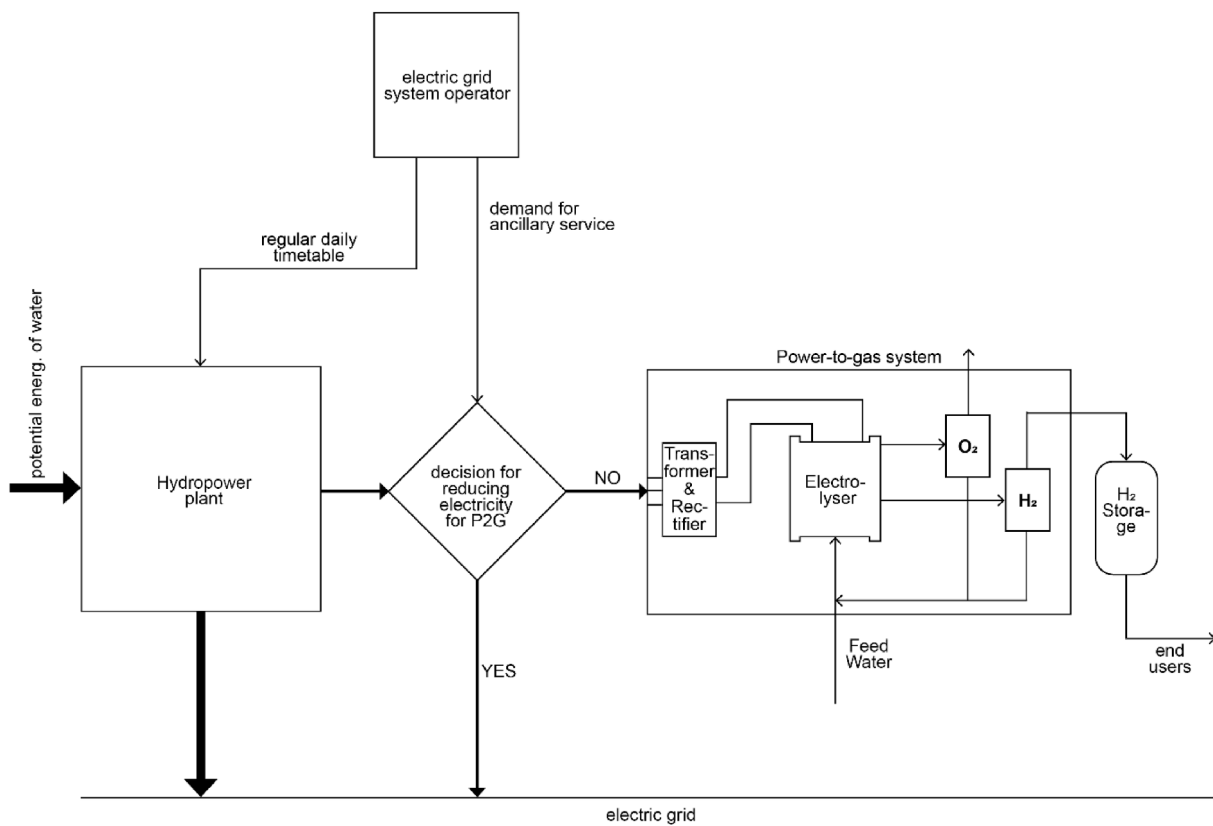


Fig. 6. Cogeneration of electricity and hydrogen.

Table 2
Technical specifications of the P2G system.

Technical Parameters	Values
Nominal power	1 MW
Net production rate	up to 300 Nm ³ H ₂ /h
Production capacity dynamic range	15–100% of flow range
Power consumption at stack	3.8–4.4 kWh/Nm ³ of H ₂
Delivery pressure	from 30 bar to 200 bar

Specific density: 0.08988 kg/Nm³.

Lower heating value (LHV): 119.96 MJ/kg (i.e., 33.32 kWh/kg or 3.00 kWh/Nm³).

Using these data and the assumed P2G system specifications, the maximum daily production of hydrogen (27 kg/h or 647 kg/day) and the electric power consumption at the maximum production rate (48.95 kWh/kg) can be calculated.

The cost of setting up a P2G system is still relatively high today. On the basis of some P2G system commercial providers' offers and literature data [1,3,26–29], the main estimated costs for an implementation a P2G system of around 1 MW are listed in Table 3.

In this way, capital expenditure costs (CapEx) and operational costs (OpEx) for the 1 MW P2G system installation and operation (Table 1) can be estimated. Their respective values are a CapEx value of 2,200,000 € and an OpEx value of 110,000 €/year, where OpEx is calculated as 5% of CapEx.

Hydrogen production cost in case-study HPP

This subchapter specifies the cost of hydrogen production obtained from green electric energy and using a P2G system in the HPP. The production cost of hydrogen consists of two parts:

PC1—cost related to CapEx and OpEx of P2G system's equipment and maintenance,

PC2—cost of electric energy for operation of P2G system and hydrogen generation.

Considering the technical characteristics of the 1 MW P2G system (Table 2), PC1 is calculated as

$$PC1 = (CapEx + OpEx)/m_{(total)} \\ = (2,200,000 \text{ €} + 15 \cdot 110,000 \text{ €})/2,833,860 \text{ kg} = 1.36 \text{ €/kg}, \quad (3)$$

where total hydrogen production during the 15 year lifetime of the P2G system is calculated under the assumption that the system operates 80% of the time

$$m_{(total)} = 647 \text{ kg/day} \cdot 365 \text{ days/year} \cdot 15 \text{ years} \cdot 0.8 = 2,833,860 \text{ kg} \quad (4)$$

and, PC2 is calculated as

$$PC2(\text{€/kg}) = \text{price of electric energy}(\text{€/kWh}) \\ \cdot H_2 \text{ production power onsumption}(\text{kWh/kg}). \quad (5)$$

Results of the calculations are summarised in Table 4, which shows the structure of the hydrogen production price at different electricity

Table 3
The estimated cost of the components of P2G systems.

Main P2G System Implementation Costs	Estimated Cost
Project documentation	100,000 €
Electrolyser	1,600,000 €
High pressure storage	200,000 €
BoP 1 components	120,000 €
Electric connection to HPP	100,000 €
Construction and assembly works	80,000 €
Total costs	2,200,000 €

¹ BoP: various supporting and auxiliary components.

Table 4
Hydrogen production price depending on the price of electric energy.

Electricity Costs	PC1	PC2	PC (Total)
35 €/MWh	1.36 €/kg	1.75 €/kg	3.11 €/kg
50 €/MWh	1.36 €/kg	2.50 €/kg	3.86 €/kg
120 €/MWh	1.36 €/kg	6.00 €/kg	7.36 €/kg

costs and at the assumed consumption of the electrolyser (rounded to 50 kWh/kg). In Table 4, PC1 refers to the P2G system equipment and maintenance costs, PC2 to the cost of required electric energy for the operation of the P2G system, and PC (Total) to the total production cost of green hydrogen. In the EU's electricity market, the prices in the last decade vary around an average of 50 €/MWh [10]. It is estimated that the production price is around 30% lower. The electricity market prices in Slovenia are similar. Therefore, for further analysis of hydrogen production economic viability, it is assumed that 1 MWh of electric energy can be sold on the electricity market for 50 €, while the production price of electrical energy in a HPP is 35 €/MWh.

The hydrogen's production costs from Table 4 exclude Value-Added Tax (VAT) and other charges.

Economic viability of hydrogen production in HPP

This subsection analyses at which price production and selling of hydrogen becomes more profitable than selling the electric energy. In the case that the selling price of hydrogen equals production price (3.86 €/kg), the CapEx and OpEx costs of the P2G system and the costs of electric energy are covered, but there is no extra profit. The economic effect from the perspective of the HPP is the same as if the HPP sells its electric energy on a commercial market at a price of 50 €/MWh.

In the case that a hydrogen selling price higher than 3.86 €/kg is achieved, the production and selling of hydrogen becomes more profitable than selling the electric energy. Table 5 shows the profit from the sale of hydrogen at different selling prices.

As an example, suppose a selling price of hydrogen of 6.00 €/kg. The HPP can sell 1 MWh of electric energy for 50 €. On the other hand, from 1 MWh of electric energy, the HPP can produce 20 kg of hydrogen that can be sold at 6 €/kg and earn 120.00 €. As 27.20 € covers the costs of CapEx and OpEx equipment and 50.00 € is to cover the cost of electricity (this is what the HPP would earn when selling 1 MWh of electricity), the remaining profit is 42.80 €. The additional profit can be even higher if hydrogen is produced from an available surplus of electric energy, which cannot be sold on the market. In this case, the price of electric energy for hydrogen production is 0.0 €/MWh.

From the above, it can be estimated that the cogeneration of hydrogen in the case-study HPP is already economically justified at today's prices of electricity and hydrogen, and the guaranteed regular consumption of hydrogen. Under certain conditions, the profitability of the case-study HPP can be further improved by including it in the ancillary services system.

Table 5
Profit at different selling prices of hydrogen.

Selling Price of Hydrogen (€/kg)	Income (€/MWh)	P2G Equipment Costs (€/MWh)	Electricity Costs (€/MWh)	Extra Profit (€/MWh)
3.86	77.20	27.20	50.00	0.00
4.00	80.00	27.20	50.00	2.80
5.00	100.00	27.20	50.00	22.80
6.00	120.00	27.20	50.00	42.80
7.00	140.00	27.20	50.00	62.80
8.00	160.00	27.20	50.00	82.80

Ancillary services

The economy of electricity and hydrogen cogeneration can be significantly improved if the HPP is included in the system of ancillary services of the electric grid [30]. Ancillary services, as a part of the electric energy system's management activities, are used to balance the temporal deviations between electric energy production and consumption. Thus, ancillary services are provided to ensure the safe and uninterrupted operation of the electric energy system [21]. In general, electricity facilities included in ancillary services generate additional electric power in case of a lack of electric power and provide additional consumption or energy storage when there is excess electric power in the system. It should be mentioned that the operation of sustainable power sources (hydro, photovoltaic and wind) strongly depends upon weather and, therefore, cannot follow actual energy demands. This problem becomes more serious with the installation of many new sustainable power sources. It is estimated that for every 100 MW of newly installed sustainable power sources, 4–10 MW of ancillary services are needed to keep the grid well balanced [21].

In Slovenia, ancillary services are organised as a three-level hierarchical structure consisting of primary, secondary, and tertiary voltage and frequency control. Based on the properties of each control level, and due to the desire for as high as possible hydrogen generation, it is considered that a P2G system in the range of a few MW could be integrated into the secondary control/frequency control (SC). The properties of the SC are described in the case of Slovenia, but the mechanism is similar in the rest of Europe:

- The service is activated automatically by the remote command given by the electric grid operator.
- The service has to start within 30 s after the command and it has to reach the demanded power within 15 min after the command has been given.
- Service providers are paid extra by the grid operator. They are paid for their readiness by a flat rate of 183,000 €/MW/year.
- Additionally, service providers are paid for actually supplied electric energy during the activated SC, at the price, which equals the current stock exchange price, increased by certain factor.

From the point of view of the profitability of HPP operation, it is important in which case the HPP ceases to produce hydrogen and re-directs the energy needed for hydrogen production into the supply of additional electricity in the context of performing ancillary service for SC. For example, let's assume a selling price of 6 €/kg for hydrogen and a selling price of 90 €/MWh for extra electric energy supplied during active SC. An important quantity is the difference between the cash flow generated by hydrogen production and the cash flow generated by extra electric energy production (see Table 6). The cash flow difference is expressed as

$$\text{CashFlowDiff} = \text{Power}_{\text{H}_2} \cdot \text{Price}_{\text{H}_2} \cdot \text{Cons}_{\text{H}_2} - \text{Power}_{\text{EE}} \cdot \text{Price}_{\text{EE}}. \quad (6)$$

If the difference is positive, then hydrogen generation is more

Table 6
Descriptions of the variables and their assumed values.

Variable	Variable description	Assumed value
$\text{Power}_{\text{H}_2}$	Electric power used for hydrogen generation	1 MW
$\text{Price}_{\text{H}_2}$	Selling price of hydrogen	6 €/kg
Cons_{H_2}	P2G consumption of electricity per unit of mass of generated hydrogen	50 kWh/kg (0,05 MWh/kg)
Power_{EE}	Electric power of extra electric energy supplied during active SC	1 MW
Price_{EE}	Selling price of extra electric energy supplied during active SC	90 €/MWh

desirable than supplying the extra electric energy in the context of SC ancillary service. In the case of a negative difference, supply of extra electric energy becomes more attractive than hydrogen generation. Finally, at zero difference, the financial effect is the same during hydrogen generation and during the supply of extra electric energy.

Use of hydrogen for the needs of the local community

Today's production of hydrogen in Slovenia is around 90,000 kg H₂/year or 1,000,000 m³ H₂/year. It is extracted from natural gas by steam reforming and used as a feedstock in the chemical industry and in steel production. There is potential for significantly higher hydrogen consumption in Slovenia within the heating and transport sectors. In energy transition from fossil fuels towards green fuels, we can expect that the heating and transport sectors will be the main entry points for the upcoming enforcement of hydrogen technologies.

In the case of hydrogen based heating systems, green hydrogen can be mixed with natural gas or it can substitute a gas completely. However, the main reason inhibiting the use of hydrogen for heating is the low price of thermal energy (€/MWh) generated from fossil fuels, in particular, natural gas. Fig. 7 provides the data for Slovenia, where it is evident that heating energy from natural gas is much cheaper than heating energy from green hydrogen, sold slightly above its production price (for 4 €/kg).

A much more promising utilization of green hydrogen is in transport and mobility, where green hydrogen could completely supplement and outperform traditional fossil fuels (diesel, gasoline, liquefied petroleum gas, natural gas) in fuel cell vehicles (FCV). It is well known that transport contributes almost a third of greenhouse gas emissions and is an important cause of urban air pollution. The use of green hydrogen in transport brings important environmental benefits, such as elimination of air pollution (CO, NO_x, PM10 particles, etc.) in urban areas, and a reduction of overall CO₂ emissions to the atmosphere.

In Slovenia, taxes represent up to 60% of the final fuel price and they are the highest in the case of gasoline and diesel fuel. Fig. 8 shows the price structure of particular hydrocarbon fuels and green hydrogen (sold at 4 €/kg). It is assumed that green hydrogen is not a subject of environmental taxes, but only a subject of VAT. Due to the low environmental impact of green hydrogen, this is a reasonable expectation. Under this assumption, hydrogen is already competitive, especially when compared to gasoline (Euro Super 95).

It has to be noted that green hydrogen is not equally convenient for all transport and mobility applications. Applications with the following properties could benefit the most from green hydrogen technologies:

- applications engaging a limited number of vehicles;
- applications with large vehicles, so that the cost of the fuel cell propulsion system represents a lower part of the total vehicle costs than in the case of, e.g., passenger cars;
- daily travel distance of each vehicle should be substantial and should significantly exceed the capacity of the electric battery, so battery propulsion is not the optimum option;
- vehicles operate over a limited geographical region, so all vehicles can be refuelled at just one or a few (e.g. 2–3) refuelling stations;
- longer stop time (as usually required for battery recharge) is not acceptable; vehicles must operate almost continuously, so quick refuelling is mandatory.

City buses, in particular, are very close to the ideal green hydrogen application. Usually (at least in minor cities), all buses are refuelled at just one or few dedicated refuelling stations, which greatly reduces the costs of hydrogen refuelling infrastructure. Due to economic reasons, city buses have to be in permanent operation, without long stops, so the possibility of quick refuelling is very important. The daily travel distance of city busses significantly exceeds the distance allowed by the capacity of batteries, so battery propulsion is not ideal for city busses. Most

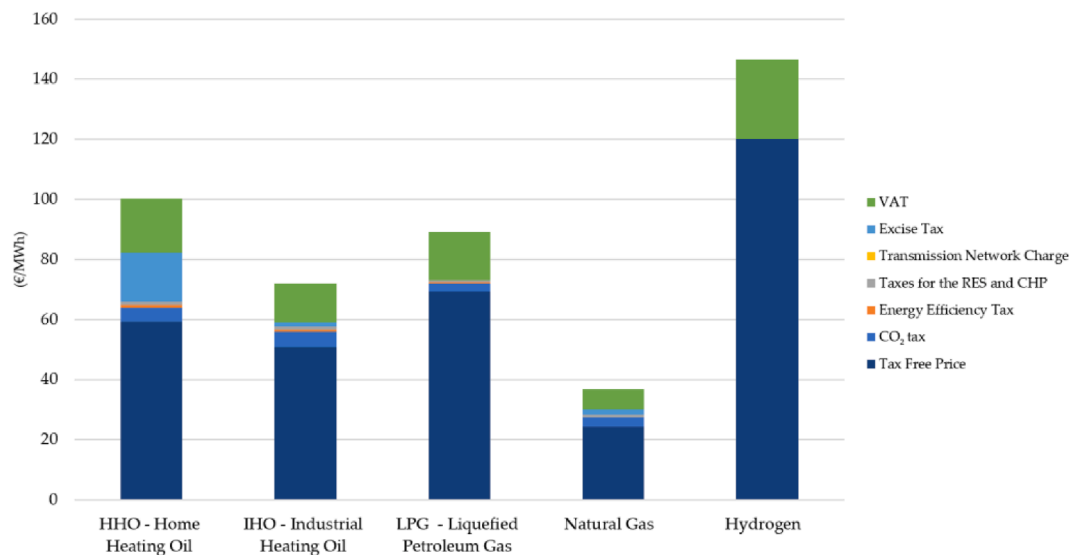


Fig. 7. Comparison of current heating fuel prices in Slovenia (in €/MWh).

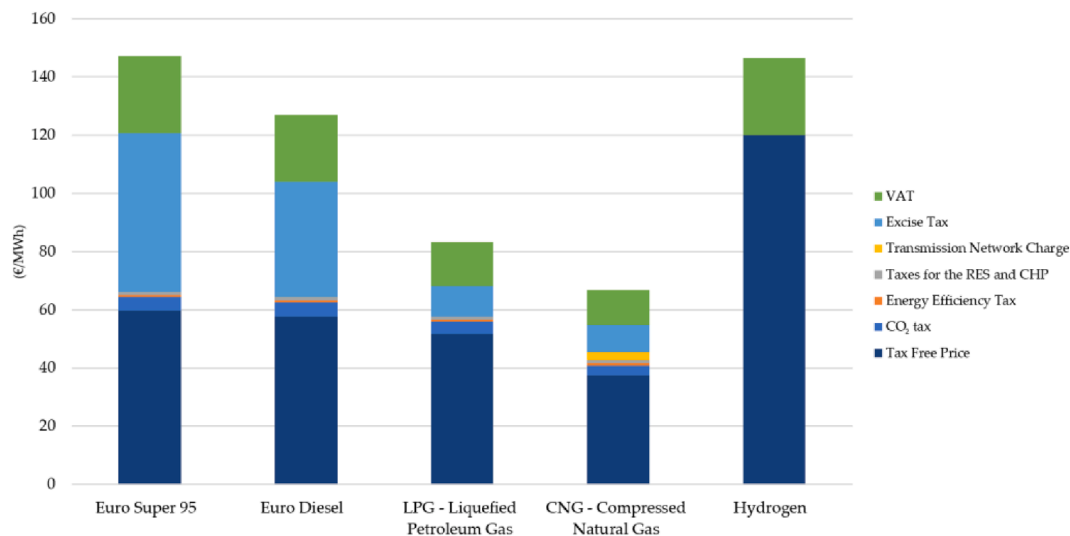


Fig. 8. Comparison of current transport fuel prices in Slovenia (in €/MWh).

importantly, vehicles fuelled by green hydrogen and powered by fuel cells have no emissions and generate much less noise than internal combustion engines fuelled by hydrocarbon fuels [13,31].

Another potential for selling green hydrogen is its use in international heavy truck transport, where fuel cell based truck propulsion allows faster filling operation, more useful cargo space, and greater utilization of trucks compared to battery powered versions [32].

Basic requirements

Given the interest of the local community in the vicinity of the case-study HPP to use green hydrogen mainly for heating and decarbonisation of local transport facilities and in anticipation of the possibility of selling hydrogen for future international freight transport/heavy trucks, the feasibility study [30] provided the main technical and economic aspects of limited green hydrogen production and consumption. The main requirements were as follows:

- regular supply of green hydrogen (up to 30 kg/h),

- use of hydrogen for heating two nonresidential buildings (local school, municipal building),
- use of hydrogen for carbon-free transport, in the first phase for the supply of local buses, from the perspective of international transport heavy trucks and buses.

The assumptions for further calculations are the following:

- the area of the heated buildings is 6,000 m², heating infrastructure already exists, it is necessary to buy hydrogen burners, heating is seasonal (200 days/year);
- up to 16 bus or heavy truck charges per day;
- the selling price of hydrogen is 10 €/kg, the current production price is 3.86 €/kg;
- the costs of preparing the project documentation amount to 5% of the purchase costs of the investment (CapEx) in the P2G system;
- the operating costs of the P2G system are 5% CapEx per year;
- to produce 1 kg of hydrogen 50 kWh of electric energy is needed;
- the cost of upgrading the connection of the P2G system to the switchyard in the HPP is estimated at around 100,000 €.

Table 7

The cost of implementation of the 2 MW P2G system.

Main P2G System Implementation Costs	Estimated Cost
Project documentation	250,000 €
Electrolyser	3,400,000 €
High pressure compression and storage	2,400,000 €
BoP 1 components	250,000 €
Electric connection to HPP	150,000 €
Hydrogen dispensers	100,000 €
Hydrogen burners	100,000 €
Construction and assembly works	150,000 €
Total costs	6,800,000 €

¹ BoP: various supporting and auxiliary components.

Hydrogen consumption

The estimated annual energy consumption for nonresidential buildings is 130 kWh/m². Assuming two buildings, each of 3,000 m², results in an energy consumption of 780,000 kWh/year, or 3,900 kWh/day, if heating is active 200 days in a year. The lower calorific value of hydrogen (LHV) is 33.32 kWh/kg. So, for daily heating for 200 days we need 117 kg H₂/day, or 23,402 kg/year.

For a daily production of 117 kg H₂ we need an electrolyser with power:

$$P = 50 \text{ kWh/kg} \cdot 117 \text{ kg} / 24 \text{ h} = 244 \text{ kW.}$$

Heating a building with hydrogen requires an installation of a new hydrogen burner with capacity:

$$P = 130 \text{ kWh/m}^2 \cdot 3,000 \text{ m}^2 / 200 \text{ days} / 24 \text{ h} = 81.25 \text{ kW.}$$

Each of the two assumed buildings should be therefore equipped with a 100 kW hydrogen burner.

To estimate the daily amount of hydrogen needed to supply vehicles, it is assumed that a hydrogen truck or bus has a tank that accepts 40 kg of hydrogen under high pressure. The estimated daily capacity of the hydrogen filling station is thus 40 kg · 16 charges = 640 kg H₂ per day. For a daily production of 640 kg H₂, we need an electrolyser with power:

$$P = 50 \text{ kWh/kg} \cdot 640 \text{ kg} / 24 \text{ h} = 1,333 \text{ kW.}$$

Based on the above, a 2 MW electrolyser can be chosen (e.g., NEL Proton PEM M400 [33], capacity up to 400 Nm³/h or 864 kg/day H₂, operating range from 20% to 100% of rated power). Charging of hydrogen vehicles requires high-pressure compression of the produced hydrogen, so the purchase and installation of additional equipment (compressor, high-pressure hydrogen storage tank, charging station) is required.

Due to the requirement for constant availability of hydrogen, a hydrogen storage tank as a buffer is necessary to enable the supply of hydrogen in cases that its production is reduced or interrupted. For a two-day supply of hydrogen (maximum 2.757 kg, pressure 350 bar), a storage tank of around 16 m³ is an appropriate choice.

Calculation of CapEx and OpEx

The roughly estimated costs for the implementation of a 2 MW P2G system are listed in Table 7.

The respective CapEx value is thus

$$\text{CapEx}_{\text{P2G}} = 6,800,000 \text{ € and OpEx (calculated as 5\% of CapEx)}$$

$$\text{OpEx}_{\text{P2G}} = 340,000 \text{ €.}$$

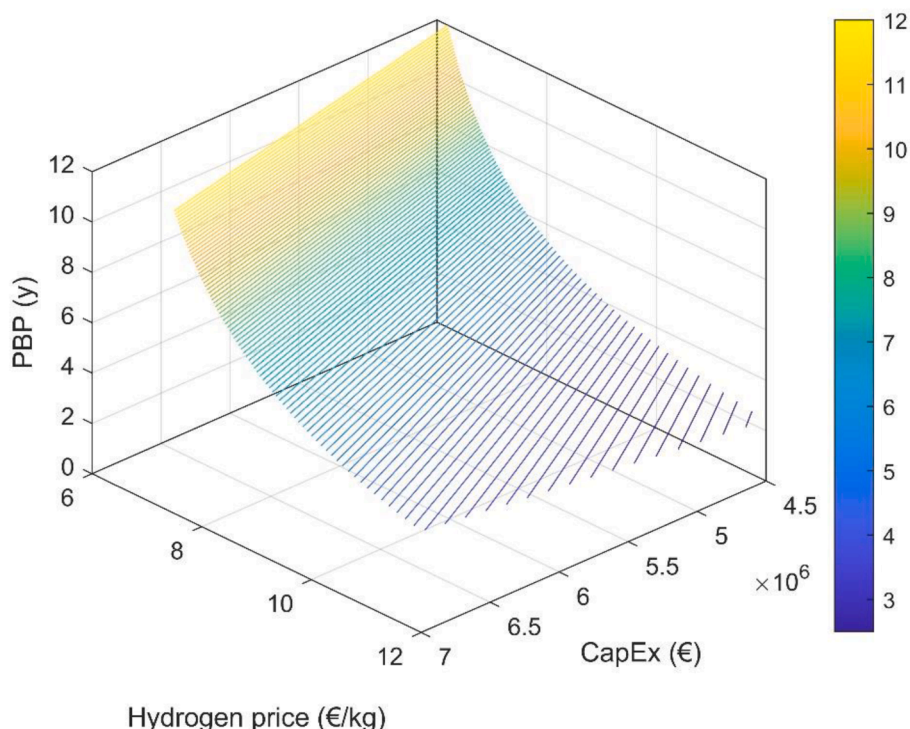
Payback period for investment

The required annual hydrogen production of the proposed 2 MW P2G system with regards to the above mentioned needs is 640 kg · 365 days for the hydrogen supply for mobility and 117 kg · 200 days for heating, thus altogether 257,000 kg yearly. In this case, the efficiency of the P2G system is around 80% of its nominal power, and the annual revenue from the sale of hydrogen

$$\text{revenue}_{\text{H}_2} = 257,000 \text{ kg/year} \cdot (10 - 3.86) \text{ €/kg} = 1,557,980 \text{ €/year.} \quad (7)$$

Using the simplest calculation for the payback period of the investment

$$\text{PBP}_{\text{P2G}} = \text{CapEx}_{\text{P2G}} / (\text{revenue}_{\text{H}_2} - \text{OpEx}_{\text{P2G}}), \quad (8)$$

**Fig. 9.** Payback period for investment.

the estimated payback period of the P2G system investment is 5.49 years.

The above estimate of the payback period of the investment in the implementation of the P2G system is probably optimistic today, as the market for the sale of hydrogen in the mobility sector is still in its infancy. Also, the selling price of hydrogen will be lower in the next few years. On the other hand, the price of equipment is also expected to be lower in the coming years [34] and actual hydrogen consumption will increase. The sensitivity graph regarding future hydrogen prices and equipment costs can be seen in Fig. 9.

Conclusions

Hydrogen technologies in combination with electro-energetic systems with a high share of renewable sources enable the production of green hydrogen for storage of surplus electricity, for use as a feedstock in various process industries, and as a clean fuel in the heating and transport sectors. In this way, production of green hydrogen leads to the connection of different sectors, especially energy, transport, and manufacturing. Green hydrogen is thus crucial for cross-sectoral integration to achieve the transition to a low-carbon society, and an essential part of the European strategy to become a carbon-neutral society by 2050. Being aware of the necessary energy transition, European policy makers are already implementing the necessary measures. As an example, in June 2020, Germany, as the most ambitious European country in the field of hydrogen technology, adopted the national strategy "German Hydrogen Strategy for Global Leadership in the Energy Transition" [35]. According to this strategy, "only hydrogen produced on the basis of renewable energy sources (green hydrogen) is sustainable". Therefore, the goal of the German government is to produce and use green hydrogen, support the rapid growth of the green hydrogen market, and establish appropriate value chains.

Slovenia, as a part of the European Union, has not yet adopted a hydrogen strategic plan, but there are already some initiatives [36,37] for the production and use of hydrogen. In the article, one such initiative is presented with the aim of assessing an implementation cost of a P2G system for the production of green hydrogen in the case-study HPP.

It is confirmed that the case-study HPP in its current operating mode has enough water reserves for regular production (cogeneration) of a limited amount of green hydrogen, although it does not have a large water accumulation. On the basis of the necessary investment costs for the P2G system, the production price for green hydrogen generation was assessed to be 1.36 €/kg in the case when the needed electricity comes from an excess electricity production. Additionally, the production price was found to be 3.86 €/kg in the case when electricity for P2G operation can be otherwise sold on the free market for 50 €/MWh. Since the current price of hydrogen is around 10 €/kg, any selling price of hydrogen above 3.86 €/kg could bring additional profit to the case-study HPP. In the second part of the article, options for the use of hydrogen for heating and mobility needs in the HPP's nearby local community was presented. For the regular supply of hydrogen using a 2 MW P2G system, we calculated the necessary investment costs for the installation of necessary equipment in the HPP, and estimated the revenue from the sale of hydrogen and the payback period of the investment.

Considering all of the opportunities for green hydrogen production from an excess of available hydropower, and taking into account that the costs of already commercially available P2G systems are falling and the needs for green hydrogen are increasing, we believe that cogeneration can contribute additional profits to the operation of the case-study HPP. To verify this hypothesis, the next stage of the research will be the development of the case-study HPP's detailed model, which will contain both a physical model and an economic model of its operation. The model will serve as a basis for a series of simulation runs in which we will realistically assess the idea of cogeneration by using real data on the case-study HPP's operating conditions, electricity and hydrogen

production requirements, their current market prices and some additional parameters. If the hypothesis is confirmed, we will then design an appropriate control system for the cogeneration of electricity and hydrogen in the case-study HPP.

CRedit authorship contribution statement

David Jure Jovan: Conceptualization, Data curation, Formal analysis, Investigation, Methodology, Project administration, Writing - original draft, Writing - review & editing. **Gregor Dolanc:** Formal analysis, Funding acquisition, Investigation, Methodology, Supervision, Writing - review & editing, Supervision, Methodology, Investigation, Funding acquisition, Formal analysis. **Boštjan Pregelj:** Data curation, Visualization, Visualization, Data curation.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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