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Conceptual Design for Substituting Coal as Fuel in Units A1 and A2 of Nikola Tesla Thermal Power Plant Through the Application of Hydrogen Technologies Combined with Renewable Energy Sources

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Original scientific research article

Highlights

- The key technological principles, limitations, and advantages of modern green hydrogen production methods were analyzed, with a focus on electrolysis.
- The challenges and solutions related to hydrogen storage were examined.
- Technological trends accelerating the adoption of hydrogen in energy systems were presented, including the growth of electrolyzer capacities, cost reductions, and improved integration with renewable energy sources.
- The paper highlights the importance of infrastructure optimization and the development of cost-effective solutions as prerequisites for the wider use of hydrogen in the decarbonization process.

Abstract

The integration of renewable energy sources (RES) into power systems (PS) represents a challenge due to their variable and non-dispatchable nature, which complicates the balancing of electricity generation and consumption. Stable operation of the power system requires dispatchable energy sources. On the other hand, the phase-out and shutdown of thermal power plants in the decarbonization process, as envisaged by the Integrated National Energy and Climate Plan, reduces the availability of dispatchable energy, thereby threatening balancing conditions and the energy independence of the power system. One of the proposed solutions is the utilization of surplus energy from renewable sources for the production of hydrogen and its derivatives, which can be stored and later used in gas-fired power plants as dispatchable energy sources.

This paper analyzes the conditions for establishing an energy complex for the production, storage, and utilization of hydrogen at the site of the existing Nikola Tesla A Thermal Power Plant . The basic concept is that the power plant would not be decommissioned in the future, but would instead transition from lignite to renewable fuel by replacing conventional boilers and steam turbines with gas turbine units adapted for hydrogen combustion. In this way, key infrastructure is preserved, particularly the grid connection facilities and the well-developed interconnection links of this important generation hub.

The potential for hydrogen production from photovoltaic power plants to be built in the area of the former Kolubara open-pit mines was also analyzed. A conceptual technological scheme of the process of hydrogen production, compression, storage, and utilization is presented, along with a calculation of the overall energy efficiency of the complete system. Based on available data, a preliminary estimate of the expected cost of generated electrical energy was carried out.

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Note:

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The concept assumes that during periods of low electricity market prices, energy from photovoltaic plants or the transmission grid is directed to electrolysis, while the produced hydrogen is stored and used during periods of high demand and insufficient energy from available primary sources in the system. Additionally, the heat generated during electrolysis and hydrogen combustion can be utilized for thermal energy storage and for supplying thermal consumers, thereby increasing the overall efficiency of the system.

Keywords

Decarbonization, Hydrogen, Nikola Tesla Thermal Power Plant, Renewable Energy Sources

1. INTRODUCTION

The depletion and declining quality of coal reserves, together with the aging of thermal power units in Serbia, pose significant challenges to the long-term sustainability of electricity generation in thermal power plants. Serbia also faces local air pollution in many cities, partly associated with electricity generation in thermal power plants and heat production in small-scale combustion installations. In addition to these local concerns, electricity generation from thermal power plants is not sustainable in the long term because of the contribution of CO_2 emissions to global warming and the resulting exposure of thermal power plants to carbon taxes. At the same time, the electrification of transport and continued industrial development require an increase in electricity generation.

Under these conditions, the global energy sector faces the challenges of decarbonization and the transition to renewable energy sources, with hydrogen and its derivatives emerging as promising options in this transition. The principal challenge associated with integrating renewable energy sources into power systems is power-system balancing, specifically matching RES generation profiles with electricity demand. Because RES generation is intermittent and non-dispatchable, dispatchable generation sources are required to ensure stable power-system operation and a reliable electricity supply. Conversely, the phase-out and shutdown of thermal power plants as part of the decarbonization process reduce the available dispatchable generation capacity, thereby jeopardizing power-system balancing and the energy independence of the power system.

Hydrogen has emerged as a potential solution for storing energy generated from RES through water electrolysis, enabling its subsequent conversion back into electricity in gas turbines or fuel cells, as illustrated in Figure 1. The use of green hydrogen in a power-to-power cycle represents an environmentally acceptable method of energy storage.

Hydrogen is already used across various sectors worldwide to support decarbonization and energy storage. In the energy sector, Denmark uses wind energy to produce green hydrogen as part of the H2RES project. Vienna is testing the use of hydrogen at the Donaustadt combined heat and power plant to reduce CO_2 emissions [2]. In the transport sector, Germany and Japan have developed hydrogen-powered trains, including the Alstom Coradia iLint [3] and the Hydrogen Hybrid Train, while South Korea uses hydrogen-powered buses in urban transport [4]. Hydrogen is also being deployed in the industrial sector. Shell is constructing Europe's largest green hydrogen production facility, while the Norwegian company Yara uses hydrogen to produce ammonia, thereby replacing natural gas in the production process [5]. Dubai has developed a solar-powered hydrogen production facility that enables surplus energy to be stored for subsequent use [6].

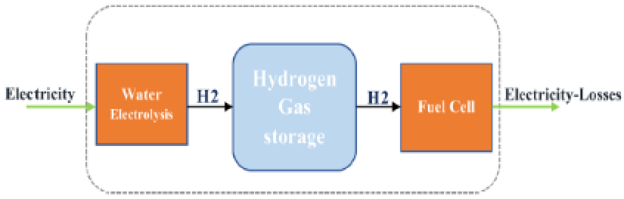

Figure 1. Schematic representation of a hydrogen production, storage, and fuel-cell conversion system, [1]

2. ENERGY CHARACTERISTICS OF HYDROGEN

Hydrogen was identified as a distinct substance by Henry Cavendish in 1766. The term "hydrogen" is derived from Greek words meaning "water-former." Water is the principal product of hydrogen oxidation. Hydrogen is the third most abundant element on the Earth's surface, after oxygen and silicon. Although it is one of the most abundant elements, molecular hydrogen (H_2) is rarely found freely in nature and must instead be extracted from chemical compounds, primarily water, which requires an energy input. For this reason, hydrogen is regarded as an energy carrier and a means of energy storage. Energy must first be supplied to produce hydrogen and can subsequently be recovered through hydrogen combustion or direct electrochemical conversion into electricity in fuel cells. Hydrogen has the highest gravimetric energy density of all conventional fuels: 1 kg of hydrogen contains approximately the same amount of energy as 2.8 kg of gasoline [7].

Its natural abundance, high energy content, and relatively favorable environmental characteristics when used as fuel are among the principal reasons why hydrogen strategies are being developed at both the global and national levels. These strategies examine the potential of hydrogen as a major energy carrier in the energy transition. Nevertheless, hydrogen production, storage, and utilization involve numerous challenges, attracting considerable attention from the scientific community, which has studied hydrogen as an energy carrier for several decades. Reference [8] provides a review and analysis of three decades of hydrogen-energy research, covering the period from 1990 to 2023, with particular emphasis on the development of renewable hydrogen production technologies. The study examines research trends, technological advances, and the interdisciplinary cooperation required to improve the performance of hydrogen systems to a level that would enable their widespread technical and economic viability. These developments could contribute to addressing some of the key challenges associated with sustainable energy systems.

2.1 Hydrogen Energy Density

The energy density of hydrogen is a key factor in its use as an energy carrier, particularly when it is compared with conventional fossil fuels. It can be considered in terms of two principal measures: gravimetric and volumetric energy density.

2.1.1 Gravimetric Energy Density (by Mass). Hydrogen has a high gravimetric energy density of approximately 142 MJ/kg, based on its higher heating value (HHV). This gives hydrogen a significant advantage over fossil fuels, particularly in transport applications such as aircraft and road vehicles, where fuel mass directly affects vehicle performance, including efficiency, acceleration, and range [9].

2.1.2 Volumetric Energy Density (HHV per Unit Volume). In contrast to its high gravimetric energy density, hydrogen has a relatively low volumetric energy density compared with most conventional fossil fuels. Consequently, substantially more storage volume is required to store an equivalent amount of energy. Typical volumetric energy-density values for hydrogen are as follows [9]:

- Under standard atmospheric conditions, gaseous hydrogen has a volumetric energy density of approximately 0.012 MJ/L.
- When hydrogen is compressed to 700 bar, its volumetric energy density reaches approximately 5.6 MJ/L.
- Liquid hydrogen has a volumetric energy density of approximately 10.1 MJ/L.

By comparison, conventional fuels have substantially higher volumetric energy densities: approximately 36.7 MJ/L for kerosene, 34.6 MJ/L for diesel fuel, and 34.2 MJ/L for gasoline [9].

Ammonia (NH_3) is also a potentially valuable hydrogen carrier with a favorable volumetric energy density. At ambient pressure, liquid ammonia has an energy density of approximately 11.5 MJ/L. This value is substantially higher than that of gaseous hydrogen under standard conditions and also exceeds the volumetric energy densities of compressed and liquid hydrogen.

Ammonia is therefore an attractive option for long-term energy storage and transport. The low volumetric energy density of hydrogen, particularly in its gaseous state, requires advanced storage technologies and represents one of the principal challenges to its efficient use as an energy carrier.

2.2 Classification of Hydrogen by Production Pathway

Separating hydrogen from naturally occurring chemical compounds requires an energy input. Hydrogen can be produced through several methods, each of which has a different environmental impact, particularly with respect to greenhouse gas emissions. The hydrogen "color" system is a classification framework used to categorize hydrogen according to its production pathway and the associated greenhouse gas (GHG) emissions. This terminology distinguishes between different types of hydrogen in terms of their environmental impact and sustainability in the context of the global energy transition. Figure 2 illustrates the principal hydrogen categories according to the energy source and production method used. It should be noted that this classification is not standardized. The literature may therefore include additional categories, such as black and brown hydrogen, as well as pink hydrogen, which refers to hydrogen produced using electricity generated by nuclear power plants.

2.2.1 Grey/Black Hydrogen. This category refers to hydrogen produced from fossil fuels without carbon capture. For example, "natural gas without carbon capture, utilization, and storage (CCUS)" and "coal gasification without CCUS" represent production pathways associated with substantial emissions. This is considered hydrogen production from unabated fossil fuels. These methods have a high carbon footprint and represent conventional hydrogen production methods that the energy transition seeks to replace.

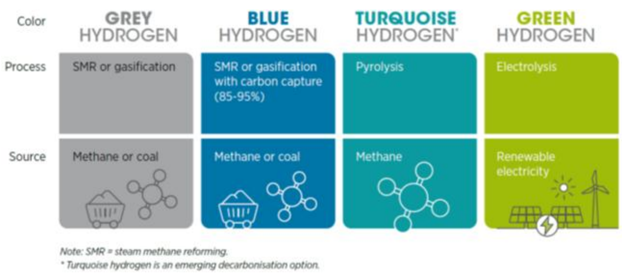

Figure 2. Classification of hydrogen according to the energy source and production method, [10]

2.2.2 Blue Hydrogen. Blue hydrogen is produced from fossil fuels, such as natural gas or coal, in combination with carbon capture, utilization, and storage (CCUS) technology. For example, hydrogen production through steam methane reforming (SMR) with CCUS or coal gasification with CCUS falls within this category. The objective of CCUS is to reduce the carbon footprint of hydrogen produced from fossil fuels. Certification criteria for "low-carbon" or "blue" hydrogen require substantial reductions in greenhouse gas emissions, typically of at least 30% and, in some cases, of 70% or 73%, relative to hydrogen production from unabated fossil fuels. These reduction levels may be used as quantitative thresholds for classifying hydrogen as blue [11].

2.2.3 Turquoise Hydrogen. Turquoise hydrogen is produced using natural gas as a feedstock. The principal production process is methane pyrolysis. Unlike conventional fossil-fuel-based hydrogen production methods, methane pyrolysis does not directly produce CO_2 emissions. Instead, the carbon contained in methane is converted into solid carbon, commonly referred to as carbon black. Solid carbon is substantially easier to store than gaseous CO_2.

2.2.4 Green Hydrogen. Green hydrogen is defined as hydrogen produced through water electrolysis using electricity generated from low-emission sources, particularly renewable energy sources such as photovoltaic power plants and wind power plants. Green hydrogen production therefore represents a pathway with no direct CO_2 emissions, making it the hydrogen category most extensively examined in hydrogen strategies for sustainable energy systems. Although green hydrogen is produced using renewable energy sources, completely eliminating CO_2 emissions is practically impossible because the manufacture of renewable-energy equipment used to generate electricity for hydrogen production also results in CO_2 emissions. No uniform certification standards for green hydrogen have been established. For example, the Indian green hydrogen standard specifies a maximum emissions intensity of 2 kg CO_2-eq/kg H_2, whereas the corresponding threshold in the European Union is 3.4 kg CO_2-eq/kg H_2.

2.2.5 Low-Emissions Hydrogen. In addition to color-based classifications, the International Energy Agency (IEA) frequently uses the broader term low-emissions hydrogen, which generally encompasses both green and blue hydrogen. According to the report cited in [11], low-emissions hydrogen includes hydrogen produced through water electrolysis using electricity from low-emission sources, including renewable or nuclear energy, as well as hydrogen produced from biomass or fossil fuels in combination with CCUS. This term serves as an overarching category that includes both green and blue hydrogen and emphasizes efforts to reduce greenhouse gas emissions associated with hydrogen production.

Uniform standards for classifying low-emissions hydrogen have likewise not been established. For example, the threshold in Brazil is 7 kg CO_2-eq/kg H_2, whereas the corresponding threshold in the United States is 4 kg CO_2-eq/kg H_2 [11].

Green hydrogen is an energy carrier that can be used in many different applications. However, its actual use remains very limited. Present-day hydrogen production is predominantly based on natural gas and coal, which together account for approximately 95% of total production. At present, hydrogen from renewable energy sources is not yet produced on a significant scale. Nevertheless, the subject is receiving considerable attention within the scientific community, both in terms of technological development and the integration of hydrogen systems into future power systems.

3. TECHNOLOGICAL TRENDS IN GREEN HYDROGEN PRODUCTION AND STORAGE

The development of hydrogen production and storage technologies is focused on improving efficiency and reducing process costs, thereby facilitating the wider commercial deployment of hydrogen as a sustainable energy solution. Several hydrogen production methods are currently available, among which water electrolysis is the most promising when electricity from renewable energy sources is used. Modern water electrolysis technologies convert electrical energy into the chemical energy of hydrogen and oxygen through electrochemical water-splitting reactions. In the context of large-scale energy systems and the integration of renewable energy sources, three principal technological platforms are currently used:

1. *Alkaline electrolysis (AEL – Alkaline Electrolysis)*
2. Proton exchange membrane electrolysis (PEM – *Proton Exchange Membrane Electrolysis*)
3. Solid oxide electrolysis (SOEC – *Solid Oxide Electrolysis Cell*)

Each of these technologies has specific technical characteristics, advantages, and limitations, as well as a different technology readiness level (TRL). Because the Nikola Tesla A Thermal Power Plant (TENT A) is a large-scale generation facility, a detailed understanding of the performance, limitations, and dynamic characteristics of PEM electrolysis, which was selected for this conceptual design, is essential [12].

Table I. Comparative characteristics of AEL, PEM, and SOEC technologies, [13]

Parameter	AEL	PEM	SOEC
Operating temperature	70–90°C	50–80°C	700–850°C
Operating pressure	1–30 bar	<30 bar	~1 bar
Efficiency (LHV)	50–68%	50–68%	75–85%
Start-up time to rated output	<50min	<20min	>600min
Technology maturity	High	High	Low
Capital cost	Lowest	High	Highest
Load-following capability	Poor	Excellent	Poor

For applications characterized by substantial power variability and dynamic operation, PEM electrolysis is currently the only technology capable of following the output profile of a photovoltaic (PV) power plant and responding to electricity-price signals. This is primarily due to its rapid response, wide operating range, and ability to operate under variable loading conditions [12].

Hydrogen storage represents a technological barrier to its integration into the global economy. Large-scale storage capacity is required to store energy in quantities measured in GWh and TWh. Geological formations, including salt caverns and depleted oil and gas reservoirs, offer considerable storage potential because of their capacity, safety, and favorable economic and technical characteristics [14]. In addition to underground storage systems, aboveground solutions include high-pressure compressed-hydrogen storage tanks and cryogenic storage tanks for liquid hydrogen. Alternative concepts under development include liquid organic hydrogen carriers (LOHCs), which enable hydrogen to be stored under moderate conditions and allow existing infrastructure to be used [14].

Although physical hydrogen storage methods, including compressed and liquid hydrogen and LOHC systems, are important for short- and medium-term balancing, chemical hydrogen carriers are receiving increasing attention for long-term energy storage. Among these, ammonia (NH_3) is particularly significant. Its high hydrogen storage density, well-developed global logistics infrastructure, and potential for direct combustion in gas turbines make it one of the most promising options for seasonal energy storage and energy conversion in large-scale power plants [15], [16]. For these reasons, ammonia plays an important role in the proposed conceptual design as a key component for seasonal power-system balancing as a means of supplementing the available hydrogen fuel supply.

Ammonia, which contains approximately 18% hydrogen by mass, has an approximately 50% higher hydrogen storage density than compressed or liquid hydrogen, while its energy density is almost three times greater. One of its principal advantages is the existence of well-developed global infrastructure for ammonia production, long-term storage, transport, and distribution [15]. Its main disadvantages are its toxicity, the potential hazards associated with leakage, and the additional capital costs associated with constructing an ammonia production plant. Ammonia has traditionally been produced primarily through the Haber–Bosch process, in which nitrogen and hydrogen react at elevated temperatures and pressures in the presence of a catalyst [16]:

$$N_2 + 3H_2 \rightleftharpoons 2NH_3 + \text{heat} \tag{1}$$

The conventional Haber–Bosch process relies on steam methane reforming (SMR) to produce hydrogen:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{2}$$

The carbon monoxide is subsequently converted into carbon dioxide through the water–gas shift reaction:

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{3}$$

The principal disadvantage of the conventional Haber–Bosch process is its high level of CO_2 emissions, because most ammonia is produced using natural gas. An alternative method of reducing emissions is to produce ammonia from green hydrogen obtained through water electrolysis using surplus electricity from RES. The resulting product, commonly referred to as green ammonia, would be used in the proposed conceptual design [16]. Ammonia may also be synthesized directly through electrochemical processes in which electricity is used to combine nitrogen and hydrogen. This approach could reduce the need for high pressures and temperatures. Electrochemical ammonia synthesis remains at an early research and development stage and has not yet achieved technological maturity. However, it could potentially consume less energy than the conventional Haber–Bosch process [16]. Green ammonia is expected to become more economically viable than fossil-fuel-based alternatives by 2035. The overall energy efficiency of the ammonia production and combustion cycle ranges from approximately 30% to 48%. Ammonia combustion in power plants can achieve an efficiency comparable to that of conventional thermal power processes, indicating its potential as a carbon-free fuel [17].

In addition to compressed and liquid hydrogen, LOHC systems, and ammonia, solid-state hydrogen storage should also be considered. This approach is based on binding hydrogen within solid materials, most commonly metal hydrides such as MgH_2, $LaNi_5H_6$, TiFe-based hydrides, and high-entropy alloys [18]. The principal advantage of these systems is their greater safety, because hydrogen is not stored as a free gas under high pressure but is instead bound within the material structure, thereby reducing the risk of leakage and explosion. Nevertheless, because of the greater mass of storage materials, the need for temperature control, slower kinetics, and higher costs, this technology is not considered in this paper as the primary solution for large-scale seasonal storage. Instead, it is regarded as a promising option for future applications [18].

Hydrogen-capable gas-turbine technologies are becoming increasingly important. Modern gas turbines, including those developed by Siemens Energy and General Electric, can already use hydrogen–natural gas blends, while fully hydrogen-fired gas turbines are under development [19]. Their deployment at thermal power plants such as TENT A could substantially reduce CO_2 emissions while preserving existing power-generation capacity and infrastructure.

Despite considerable technological progress, key challenges remain. These include reducing equipment costs, increasing the efficiency of hydrogen production and storage, and developing infrastructure for hydrogen transport and distribution. These challenges raise important questions concerning the integration of hydrogen into existing thermal power systems, which will be analyzed in the following sections.

4. CONCEPTUAL DESIGN OF THE INTEGRATED ENERGY COMPLEX

The transition to environmentally sustainable energy generation as part of the decarbonization process requires a shift toward renewable energy sources. Since TENT A is an important generation hub within the Serbian power system, a conceptual design involving the construction of a photovoltaic power plant near TENT A is proposed to preserve the existing centralized infrastructure. This development would support the replacement of coal with green hydrogen-based fuel. The initial phase would involve implementing this change in Units A1 and A2, thereby initiating the transition toward environmentally sustainable generation sources. The underlying objective is to replace the electricity generated by these two oldest thermal power units with electricity from a photovoltaic power plant and hydrogen-fired gas-turbine systems, while maintaining the dispatchability of generation and improving overall system flexibility.

The low power density of solar radiation at the Earth's surface requires photovoltaic modules to cover large areas. To minimize adverse environmental effects, such power plants should be constructed on degraded or previously disturbed land. In this context, areas degraded by decades of coal extraction and the disposal of overburden and ash associated with thermal power generation represent suitable locations for photovoltaic installations.

The proposed concept envisages constructing photovoltaic power plants in these degraded areas, particularly within parts of the Kolubara open-pit mining region. Hydrogen and ammonia production and storage facilities would be installed within the existing thermal power complex. Another important advantage for hydrogen production is the already developed water-supply system drawing water from the Sava River. This would reduce costs and enable the existing infrastructure to be used. The new power plant would use gas-turbine systems instead of conventional boiler and steam-turbine systems. These systems would combust hydrogen and ammonia, thereby enabling the preservation of the existing infrastructure, including the power plant's grid connection and switchyard facilities, while also maintaining the existing power flows within the transmission grid.

The photovoltaic power plant would serve two functions. It would directly inject the electricity generated into the 400 kV transmission grid through the existing TENT A grid connection point, specifically the Mladost grid connection switchyard. It would also supply electricity to the hydrogen production system. Hydrogen storage capacity would be designed to balance daily and weekly variations in electricity generation and consumption. A portion of the hydrogen would be used for ammonia synthesis. Because ammonia has more favorable storage characteristics, it would provide a means of long-term energy storage. The proposed concept is illustrated in Figure 3.

4.1 Proposed Construction of a Photovoltaic Power Plant on Degraded Land in the Kolubara Mining Basin

To utilize degraded land, the photovoltaic power plant would be constructed within the Kolubara open-pit mining areas. The use of these locations represents an optimal solution because it would avoid the occupation of land of agricultural or infrastructural value, eliminate land-expropriation costs, and improve the environmental and social acceptability of the project.

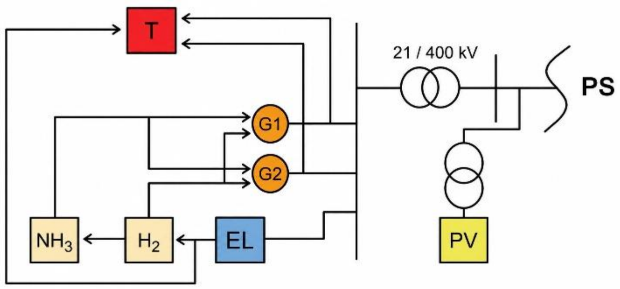

Figure 3. Schematic representation of the operation of the integrated energy complex based on a photovoltaic power plant and green hydrogen-based fuels

The Kolubara mining complex covers several thousand hectares of land that has become infertile or has low agricultural value because of coal extraction and overburden disposal. Considering these circumstances, the infertile land could be used for the construction of large-scale photovoltaic power plants. The proposed concept envisages a phased transition of TENT A to hydrogen-based fuels and a gradual reduction in coal production. During the initial stages, the construction of the photovoltaic power plants would therefore have to be coordinated so as not to interfere with existing and planned coal production. The currently available area, presented in Appendix 1, Figure A.1, is approximately 1,000 ha. This is more than sufficient for constructing the proposed photovoltaic power plant, which would be developed during the proposed phase of the decarbonization of electricity generation in the existing Units A1 and A2. Before construction begins, the terrain would have to be leveled and the area prepared for the installation of the PV modules and their support structures.

The proposed photovoltaic power plant would have a total installed capacity of 500 MWp. The modules would be ground-mounted using fixed, tent-shaped support structures arranged as a dual-pitch roof, with the two planes facing east and west and the module rows extending in a north–south direction. The modules would have a tilt angle of 15° toward the east and west relative to the ground. Calculations performed using the PVGIS tool indicate that a photovoltaic system with an installed capacity of 1 MWp and the proposed module configuration could generate an average of approximately 1,044 MWh annually. Accordingly, the proposed 500 MWp power plant would generate approximately 522 GWh of electricity per year.

This module configuration represents a favorable solution in terms of capital costs, installation requirements, and land-use efficiency. In addition, the temporal generation profile of this configuration is more favorable than that of south-facing modules. The sites of the proposed photovoltaic power plant are approximately 25 km from TENT A. The grid connection could be implemented by constructing a transformer substation and establishing a loop-in/loop-out connection to the existing 400 kV Overhead Transmission Line No. 436. The route of this line is located in the immediate vicinity of the open-pit mines and would directly connect the proposed photovoltaic power plant to the TENT A grid connection switchyard.

4.2 Development of a Green Hydrogen Production and Local Storage System at the TENT A Site

The proposed green hydrogen production technology, with PEM electrolysis assessed as the most suitable option, encompasses several processes integrated into a single system centered on the electrolyzer as the principal component of the facility. These processes may be divided into the following stages:

- water supply;
- electrolyzer;
- hydrogen storage.

4.2.1 Water Supply. TENT A has access to water resources from the Sava River, enabling an efficient and stable water supply for electrolysis. The theoretical specific water consumption of PEM electrolysis is approximately 9 L/kg of hydrogen produced. Under actual operating conditions, however, technological losses and auxiliary processes increase this figure to approximately 11–14 L/kg H_2. PEM electrolyzers require highly purified water with an electrical conductivity below 1 μS/cm to prevent membrane degradation and prolong system service life. To achieve the required water quality, the water first undergoes filtration, followed by reverse osmosis, while final purification is performed through deionization using ion-exchange resins. This multistage treatment produces the ultrapure water required for the uninterrupted operation of PEM cells.

Constructing the electrolysis system near TENT A would provide a significant advantage by allowing the existing infrastructure to be used. In particular, the existing water-filtration system could be upgraded, thereby optimizing both costs and resource use.

4.2.2 PEM Electrolyzer. The PEM electrolyzer (PEMEL) would form the central part of the hydrogen production facility. Its principal advantages are its relatively high energy efficiency at high power density and its pronounced operational flexibility, making it suitable for systems with a high share of renewable energy sources.

For modern industrial PEM electrolyzers, energy efficiency varies with the selected operating point and generally ranges from approximately 50% to 68%, calculated relative to the lower heating value of hydrogen. Increasing the current density increases the electrolyzer's hydrogen production capacity but reduces its efficiency. The selected operating regime therefore represents a compromise between maximizing hydrogen production and maximizing the overall energy efficiency of the system. The operational flexibility of a PEM electrolyzer is reflected in its broad dynamic operating range, extending from approximately 5% to 120% of rated capacity [13]. Owing to its very rapid response, with a response time or ramp rate on the order of seconds, an electrolyzer can adapt to changes in input power without adversely affecting system stability. Its cold-start time is less than 20 minutes, making it suitable for operation under conditions characterized by the pronounced intermittency and non-dispatchability of renewable energy sources.

Because of their favorable dynamic characteristics, electrolyzers may represent a significant centrally controlled demand-side resource capable of providing balancing services through the regulation of active power in the power system.

Hydrogen production under the proposed project would depend directly on electricity-price fluctuations in the market. The electrolyzers would be configured to operate at maximum capacity during periods when the electricity price falls below a predefined threshold, for example, below 25% of the annual average price. During periods when the electricity price ranges between 25% and 150% of the annual average, the electrolyzers would operate at reduced load only when electricity generated by the photovoltaic power plants cannot be delivered to the power system because of potential operational constraints in the transmission grid.

The initial phase of the project envisages the construction of a PEM electrolyzer with an installed capacity of 400 MW. It would partially provide the gaseous fuel required by the combined-cycle power plant intended to replace Units A1 and A2 at TENT A. At this installed capacity, expected hydrogen production would be up to approximately 8,000 kg/h, depending on the selected operating regime and the energy efficiency of the system.

The estimated service life of modern PEM electrolyzers is approximately 60,000–80,000 operating hours. During operation, system performance gradually deteriorates, most commonly through an increase in operating voltage and a decrease in energy efficiency. Typical degradation rates range from 0.5% to 2.5% annually [20]. These parameters substantially affect the project's overall economic viability and must be considered when planning plant operation.

The electrolyzer facility would require an area of approximately 8 ha. Ideally, the facility would be located in the immediate vicinity of the thermal power plant to reduce infrastructure costs and facilitate its integration into the existing energy system. The most suitable solution would involve using part of the existing ash-disposal site. In addition to hydrogen production, the system could subsequently be expanded to include oxygen storage if market demand for larger quantities of oxygen emerges. This could further increase the plant's overall utilization and the project's economic benefits. Appendix 1, Figure A.2, presents an example of the equipment layout for such a facility.

4.2.3 Hydrogen Storage. Hydrogen storage represents a particular challenge. As noted previously, because hydrogen has an exceptionally low volumetric energy density at atmospheric pressure and storage volume must be minimized as far as practicable, it must be stored under high pressure, potentially at pressures of up to 800 bar. Hydrogen, as the element with the lowest atomic mass, tends to permeate materials and cause embrittlement. Hydrogen leakage and material embrittlement therefore represent additional challenges in the construction of storage facilities. Nevertheless, the advantages of this storage method include rapid and straightforward operation and relatively simple infrastructure. Industrial compressors and storage tanks are already commercially available, while leakage-related challenges are expected to be addressed through continued research and rapid technological development.

This analysis assumes that hydrogen storage capacity would be dimensioned according to daily or weekly requirements, while long-term storage would be planned through ammonia production. Hydrogen production and compression release substantial quantities of heat; the integrated energy complex would therefore also include thermal energy storage. Figure 4 presents the proposed site for constructing the integrated energy complex for hydrogen production and storage, together with the infrastructure required for a pit thermal energy storage system. The proposed location is situated on part of the existing ash-disposal site. Before any construction begins, ash disposal at the site would have to cease, the disposal area would have to be stabilized, and sufficient time would have to be allowed for intensive settlement to stop. Considering that certain sections of the ash-disposal site have been closed for many years, areas suitable for the proposed purpose may already be available under the existing conditions. The designated area covers approximately 60 ha and is sufficient to accommodate all infrastructure components of the integrated energy complex. The existing ash-handling pipelines would have to be reorganized to use the remaining disposal cells. The site is particularly suitable for the installation of hydrogen production and storage systems and pit thermal energy storage. Its principal advantages include the following:

- The site is located only approximately 700 m from TENT A. It could therefore form part of the thermal power plant complex, and the electrical, thermal-energy, and road infrastructure required for the operation of all system components could be readily constructed.
- The site is located in the immediate vicinity of the Sava River, enabling the straightforward installation of heat-pump systems for thermal energy storage and water-supply systems for electrolysis.
- The site does not occupy land with agricultural value, and no adverse effects on the surrounding area are expected because it consists of infertile an artificial hill.
- The site is elevated approximately 30 m above the surrounding terrain, protecting it from flooding and from groundwater, the presence of which would be highly unfavorable for the construction of pit thermal energy storage. Consequently, the use of active ash-disposal cells would have to be planned so that they do not interfere with the thermal storage facility.
- Dry ash is an effective thermal insulator and could support efficient heat storage.
- The terrain is suitable for constructing underground hydrogen-storage tanks.
- The TENT A electrolyzer and generation units would be located close to the proposed pit thermal energy storage facility, making the construction of infrastructure for storing waste heat generated by these processes cost-effective and efficient.

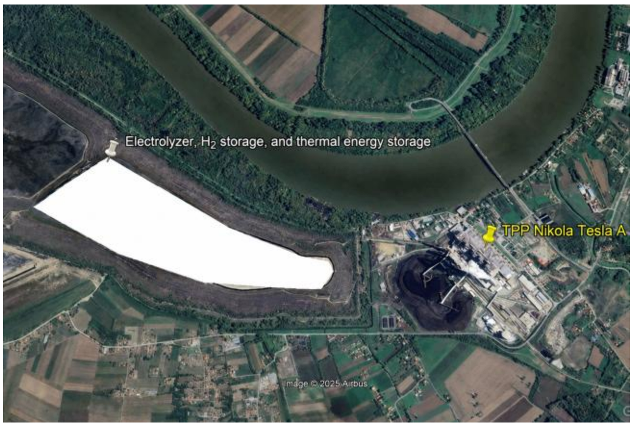

Figure 4. Proposed site for constructing the integrated energy complex for hydrogen production and storage and a pit thermal energy storage system at the TENT A site

4.3 Development of an Ammonia Synthesis and Local Seasonal Storage System

When the hydrogen storage facility is full but conditions remain favorable for continued hydrogen production, the surplus hydrogen would be used to produce ammonia. The ammonia would be stored over the long term and used primarily during winter, when electricity generation from photovoltaic power plants is reduced and market electricity prices are higher. This would enable seasonal balancing of the power system.

Ammonia would be produced by combining hydrogen with nitrogen separated from air using the Haber–Bosch process at temperatures of 400–500°C, pressures of 100–200 bar, and in the presence of an iron-based catalyst, as illustrated in Appendix 1, Figure A.3.

The ammonia synthesis and storage infrastructure would be installed at the hydrogen storage site to ensure the efficient use of space and existing infrastructure. Nitrogen, the second required process component, would be separated from air using a cryogenic air separation unit (ASU), which represents the most suitable solution for producing large quantities of high-purity nitrogen. The ASU system would be supplied continuously with electricity from the grid and would consist of compressor units, heat-exchange systems, and distillation columns for separating gaseous components.

Following preparation, hydrogen and nitrogen would be introduced into the synthesis loop, whose principal components would include compressors, heat exchangers, and ammonia-synthesis reactors. The final product would be liquid ammonia (LNH_3). Waste heat generated during the synthesis process would be partially reused within the process itself, while the remaining heat could be transferred to thermal energy storage, thereby further increasing the overall energy efficiency of the system.

Ammonia storage requires a specialized approach because of its toxicity and its potential to cause steel corrosion. Three principal ammonia storage methods are used in energy facilities: pressurized storage in steel tanks, refrigerated storage at atmospheric pressure and low temperatures, and combined systems operating at moderate temperatures and pressures. For storing large quantities of ammonia, refrigerated storage represents the most favorable option because, in the event of damage to a storage tank, ammonia is released more slowly than from a high-pressure storage system.

One of the significant challenges associated with using ammonia in energy systems is the emission of nitrogen oxides (NO_x), particularly during combustion at the high temperatures and pressures encountered in gas turbines. Selective catalytic reduction (SCR) is the most effective method of reducing NO_x emissions. This process uses catalysts and reducing agents, most commonly ammonia or urea, to convert nitrogen oxides into nitrogen and water vapor. The technology is compatible with modern gas-turbine plants and is already used in thermal power plants. Despite the application of NO_x-emission-control systems, the direct combustion of ammonia in gas turbines remains technologically challenging because of its unfavorable combustion characteristics. It is therefore considered preferable not to use ammonia directly as a fuel, but rather as a hydrogen carrier. Under the proposed concept, green ammonia would be decomposed into hydrogen and nitrogen in a dedicated ammonia-cracking facility, after which the recovered hydrogen would be used in the gas turbines. This approach would reduce NO_x emissions and enable the use of technologically mature gas-turbine solutions, while the direct combustion of ammonia would remain a prospective option for long-term development.

4.4 Construction of Gas-Turbine Power Plants at the Sites of the Existing Thermal Power Units

The existing Units A1 and A2 would be replaced with gas-turbine power plants. Instead of the existing coal-fired boiler systems and steam turbines, gas-turbine units could be installed at the same sites. During the initial development phases, these units would use a blend of natural gas and hydrogen, before gradually transitioning to the combustion of 100% green hydrogen and ammonia once such facilities become technologically mature and economically viable. From a spatial perspective, the new gas-turbine units could use the existing grid connection equipment, including the unit transformers and switchyard equipment. The condition of the generators in these units would have to be assessed; however, the installation of new generating units is recommended.

A gas-turbine system comprises three principal sections: multistage compression with intercooling, a combustion chamber, and an expansion turbine. Fuel-conversion efficiency depends on the turbine operating temperature. Higher temperatures produce greater efficiency and therefore more economical operation. Combustion products in a conventional gas turbine may reach temperatures of approximately 1,260°C. However, critical metal components within the turbine can withstand temperatures of only approximately 815–926°C. Compressor discharge air is therefore used to cool the principal turbine components, which ultimately reduces thermal efficiency. Advances in cooling technologies and high-temperature-resistant materials have enabled modern gas turbines to achieve turbine inlet temperatures of up to 1,427°C, approximately 167°C higher than those of previous turbine generations. A further method of improving efficiency is to install a recuperator or a heat recovery steam generator (HRSG), enabling energy to be recovered from the turbine exhaust gases. A recuperator captures waste heat from the turbine exhaust and uses it to preheat compressor discharge air before it enters the combustion chamber. An HRSG uses the waste heat contained in the gas-turbine exhaust gases to generate steam. These boilers are also known as heat recovery steam generators. The high-pressure steam generated in the HRSG can drive a steam turbine to produce additional electricity, creating a combined-cycle power plant. A simple-cycle gas turbine can achieve an energy-conversion efficiency of approximately 20–35%. Future hydrogen-fired combined-cycle gas turbines are expected to achieve efficiencies of 60% or more. If the waste heat generated by these systems is also used to supply the proposed thermal energy storage facility, the overall efficiency of the energy cycle could reach approximately 80%.

This analysis assumes that gaseous fuel is combusted in the presence of air and argon, which is used as an inert gas to reduce the flame temperature. The principal combustion products are nitrogen (N_2) and water (H_2O). Because the total installed capacity of Units A1 and A2 is approximately 400 MW, a gas-turbine capacity of 400 MW would also be required to use the existing infrastructure and maintain the same electricity injection capacity into the transmission grid. However, because this is an alternative facility, two or three lower-capacity gas-turbine generating units could be installed instead of a single large-capacity unit. This configuration could provide greater operational flexibility, more reliable operation, and easier system maintenance.

4.5 Development of a Waste-Heat Storage System for Heating Purposes

The efficient utilization of waste heat from energy facilities represents an important means of increasing energy efficiency and reducing overall system losses. A substantial quantity of waste heat is generated by the electrolyzer and, to a lesser extent, by the power plant. Gas-turbine power plants operating on a blend of natural gas and hydrogen, or on pure hydrogen, also generate substantial quantities of waste heat during combustion. This energy could be supplied to district-heating systems or industrial processes or stored in thermal energy storage systems for subsequent use.

This analysis proposes the use of pit thermal energy storage systems with water-filled surface reservoirs. Water as a thermal storage medium allows energy to be readily transferred to district-heating systems.

Because TENT A is located near urban areas with an established district-heating system, waste heat from the power plant could be used directly to heat the water stored in the pit thermal energy storage facility. The stored heat could subsequently be used to heat water within the district-heating network. This arrangement would reduce the need to combust additional fuels, thereby lowering greenhouse gas emissions and increasing the overall efficiency of the power plant. A particular advantage of this concept is the planned district-heating pipeline between Belgrade and TENT A, which would allow the thermal energy storage facility to be integrated into the Belgrade district-heating system.

With the introduction of a waste-heat utilization system, the overall efficiency of the gas-turbine power plant could increase from the standard range of 55–60% to more than 80%. This would simultaneously reduce heating costs and improve the economic viability of the energy facilities. Furthermore, using thermal energy storage in industrial or district-heating systems reduces the need for additional energy resources and contributes to the development of sustainable solutions in the energy sector.

5. Simulation of Energy Flows in the Proposed Integrated Energy Complex

To provide a more detailed analysis of the energy performance of the proposed system, energy flows through its principal components were simulated. The simulation provides insight into the distribution and efficiency of energy use, identifies potential losses, and enables the overall energy efficiency of the system to be assessed.

As previously stated, the electrolyzers would operate during periods of low electricity prices. For this analysis, a low-price period was defined as one in which the electricity price falls below 25% of the annual average price. In the graph presented in Appendix 1, Figure A.4, this threshold is indicated by the green line. The gas turbines would operate when the electricity price on the reference exchange exceeds 150% of the annual average price, corresponding to prices above the red line in the graph presented in Figure A.4. Based on this operating strategy and the hourly electricity prices in EUR/MWh recorded on the HUPX electricity exchange during 2024, the annual operating hours and threshold prices for both systems were calculated. The results are presented in Appendix 1, Figure A.4, and Table II.

Table II. Annual Operating Hours of the Electrolyzer and Gas Turbines

Average annual electricity price (HUPX-2024) [eur/MWh]	100.81
PEMel price threshold (H2 production) [eur/MWh]	25.20
Gas-turbine plant electricity price threshold (hydrogen consumption) [eur/MWh]	151.22
PEMel full-capacity operating hours (price below 25%)	785.00
Gas turbine operating hours (price above 150%)	1,058.00

This analysis assumes that a 400 MW electrolyzer would be installed within the integrated energy complex during the initial phase. The hydrogen produced would meet part of the gas turbine's fuel requirements, while the remaining fuel demand would be met by natural gas. With a PEM electrolyzer of this capacity operating according to the proposed strategy, approximately 340 GWh of electricity would be consumed annually, producing approximately 6,140 t of hydrogen. This amount represents slightly less than 50% of the hydrogen required to replace the entire blended fuel supply with pure hydrogen. Energy losses are unavoidable. Losses upstream of the electrolysis process are generally on the order of several percent, most commonly within the range of approximately 5–10% [21]. PEM electrolysis subsequently takes place at an efficiency of approximately 65%, while the remaining energy is converted into waste heat. A portion of this heat could be used to heat water in the thermal energy storage system. Hydrogen would therefore supply approximately half of the energy required to operate the gas turbines, while the remaining energy would be supplied by natural gas. Since the lower heating value (LHV) of natural gas is 13.894 kWh/kg, the required annual natural-gas quantity can be calculated as approximately 15,718 t. The hydrogen mass fraction in the fuel blend is 28%. The calculated fuel quantities, energy contents, and blending ratio are presented in Tables III and IV.

The efficiency of the combined-cycle power plant, comprising both gas and steam turbines, is approximately 60%. Accordingly, the final available electrical energy amounts to approximately 254 GWh.

During their operating cycles, both the gas turbine and the electrolyzer generate losses in the form of waste heat. A portion of this heat, available at a suitable temperature level, could be technically recovered and stored in thermal energy storage systems. Such thermal energy storage is primarily intended for short-term or immediate use because thermal storage systems inevitably experience heat losses. For this preliminary assessment, the technically recoverable waste heat from the PEM electrolyzer is assumed to equal 14–15% of the electricity supplied directly to the electrolyzer stack [22]. The amount of energy available for storage as heat is presented in Table V.

Table III. Required Fuel Quantities and Energy Parameters

Installed gas turbine capacity [MW]	400.00
Installed electrolyzer capacity [MW]	400.00
Specific system energy consumption [kWh/kg-H2]	55.30
Specific electrolyzer energy consumption [kWh/kg-H2]	51.10
Hydrogen energy content – LHV [kWh/kg]	33.33
Methane energy content – LHV [kWh/kg]	13.89
Gas turbine efficiency	40%
Additional energy recovery via the HRSG and steam turbine	20%
Total plant efficiency (combined cycle)	60%
Electrolyzer efficiency	65%
Natural gas required for gas turbines (100% methane) [t]	30,459.19
Hydrogen required for gas turbines (100% hydrogen) [t]	12,697.27
Hydrogen produced (fuel blend) [t]	6,144.81
Natural gas required for gas turbines (fuel blend) [t]	15,718.54

Table IV. Energy Content and Fuel Shares

Energy content of the total hydrogen produced [GWh]	204.81
Natural gas energy content [GWh]	218.39
Energy output from gas turbines [GWh]	253.92
Hydrogen energy share	48%
Natural gas energy share	52%
Hydrogen blending percentage (by mass)	28%

Table V. Waste Heat

Recoverable heat released during electrolysis [GWh\TJ]	47.10	169.56
Recoverable heat released during turbine operation [GWh\TJ]	84.64	304.70
Total energy that can be stored as heat [GWh\TJ]	131.74	474.26

When the complete annual energy cycle is considered from the electrical energy supplied for producing hydrogen as an energy carrier to the electricity subsequently regenerated by the gas turbines, the efficiency of the overall process can be determined. The annual energy flow and cycle efficiency are presented in Table VI. The cycle efficiency including heat recovery refers to a scenario in which part of the waste heat generated by the gas turbine and electrolyzer is recovered through thermal energy storage systems.

Under the stated assumptions, electricity generation by the gas-turbine power plants would occur during periods of very high electricity-market prices. Consequently, each MWh generated by these plants would have a high market value. Table VII presents the estimated gross annual revenue of the analyzed facility.

It should be noted that the estimated gross annual revenue does not include annual maintenance costs, which are currently difficult to assess. Evaluating the economic viability of the proposed project requires data on capital investment in equipment and system construction. Technologies for hydrogen production, storage, and utilization are developing rapidly. However, commercially available solutions remain limited, and their application is not yet widespread. Current research is therefore primarily focused on improving the energy efficiency of these systems and optimizing energy-conversion processes. The comprehensive economic viability of constructing hydrogen-based systems can be assessed more realistically once these technologies achieve a higher level of commercial maturity, with the anticipated reduction in capital costs and improvement in efficiency.

Table VI. Cycle Efficiency

Energy input into the PEMel system (including system losses) [GWh]	339.81
PEMel energy input used for electrolyzer operation [GWh]	314.00
Energy content of the total hydrogen produced [GWh]	204.81
Energy content of the total natural gas required [GWh]	218.39
Energy output from gas turbines [GWh]	253.92
Total energy that can be stored as heat [GWh]	131.74
Cycle efficiency without heat recovery	45%
Cycle efficiency (with short-term heat storage)	69%

Table VII. Gross Annual Revenue

Average electricity price (below 25% of annual average) [eur/ MWh]	0.71
Average electricity price (above 150% of annual average) [eur/ MWh]	254.62
Average gas price [eur/MWh]	45.00
Cost of purchased gas [eur]	9,827,700.59
Cost of electricity purchased for hydrogen production [eur]	242,428.27
Revenue from electricity generated using hydrogen [eur]	64,652,690.40
Gross annual revenue [eur]	54,582,561.54

6. CONCLUSION

This paper analyzed a conceptual design for converting Units A1 and A2 at TENT A from fossil-fuel-based thermal power units to gas-turbine systems using hydrogen as the primary fuel. Technological trends in green hydrogen production and storage were examined, together with the integration of renewable energy sources for the decarbonization of the electric power sector.

One of the principal challenges associated with this transition is the efficiency of converting electricity into hydrogen through electrolysis, as well as the losses incurred during combustion in gas turbines. The efficiency indicators for these processes were analyzed. The results indicate that significant energy losses occur, although the development of new technologies could contribute to the optimization of the overall system.

Particular attention was also given to the storage of hydrogen and its derivatives, including ammonia, as potential solutions for seasonal power-system balancing. The potential use of waste heat for heating purposes was also considered, as this could further improve the energy efficiency of the integrated energy complex.

The proposed design includes constructing a photovoltaic power plant with 500 MWp of installed PV-module capacity within parts of the Kolubara mining basin. The plant would generate approximately 522 GWh of electricity annually. Hydrogen would be produced during periods of low electricity prices on the regional market. Data from the HUPX electricity exchange were used to calculate hydrogen-production costs and the revenue that could be generated through the operation of the gas-turbine power plant. The results indicate that gross annual revenue could exceed EUR 50 million.

Overall, the results indicate that converting coal-fired thermal power plants into hydrogen-fired gas-turbine power plants is technically feasible. However, the process is currently very expensive and requires further investment in research and development to improve the efficiency of the entire energy production, storage, and conversion chain. Nevertheless, the proposed transition could be implemented in stages. During the initial phase, gas-turbine generating units could be constructed to operate on natural gas. As hydrogen technologies develop, hydrogen could then be introduced gradually through blending. The system should therefore be designed and technologically equipped to operate at any hydrogen blending ratio, including operation on 100% hydrogen. This approach would enable the transition to be completed using the same technological platform, contributing to the stability of the power system and the gradual decarbonization of electricity generation within the Serbian power system. In addition, this approach would strengthen Serbia's energy independence because, ultimately, all the electricity required for hydrogen production would be generated by photovoltaic and wind power plants located within Serbia.

The proposed approach would also enable the decarbonization of part of the thermal power sector, making a substantial contribution to addressing poor air quality. It would require only minimal changes to the overall energy concept and the construction of the missing transmission-grid infrastructure. Because it would use an existing energy hub, the proposed approach could substantially reduce the cost of integrating renewable energy sources into the Serbian power system.

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APPENDIX 1

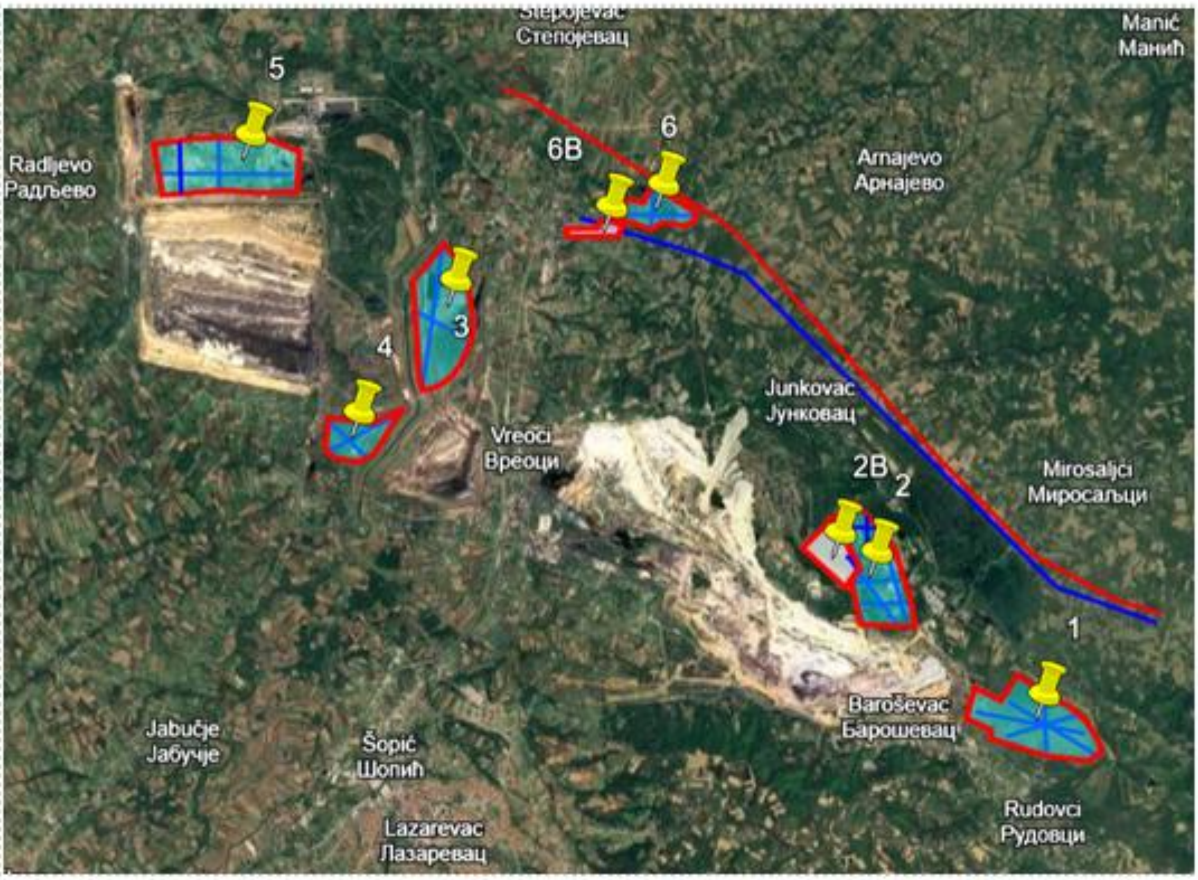

Figure A.1. Currently available areas in the Kolubara mining basin where the construction of a photovoltaic power plant could be planned

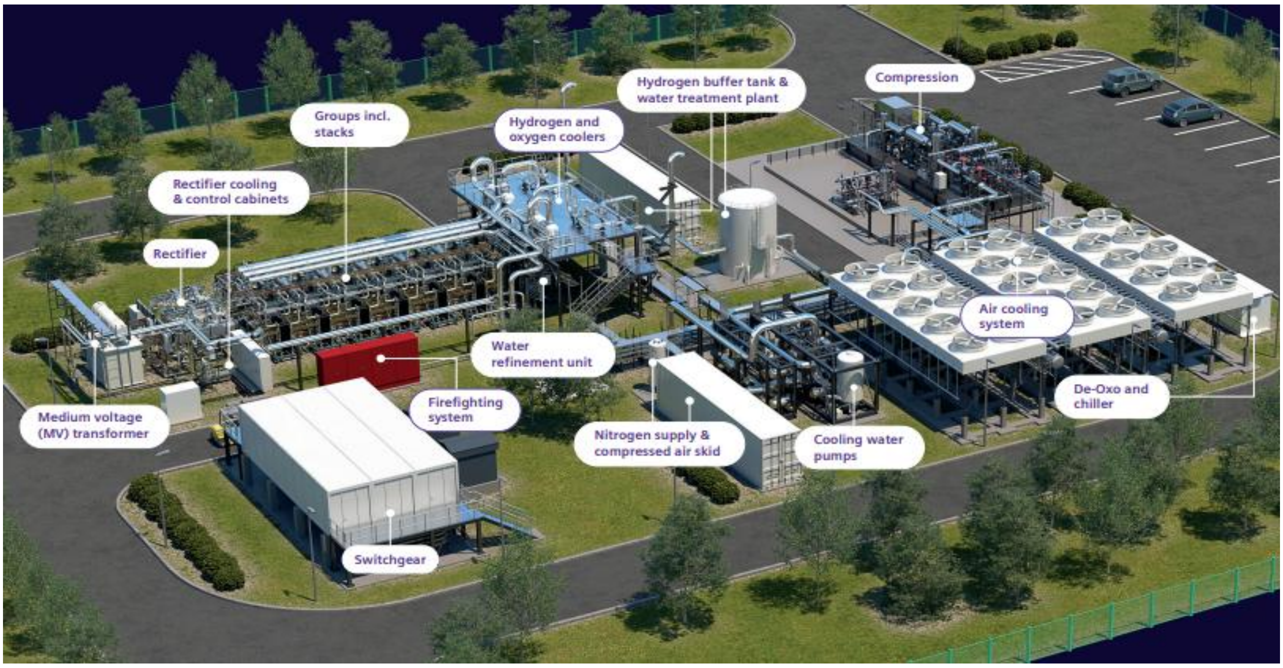

Figure A.2. Equipment layout of the hydrogen production system, [23]

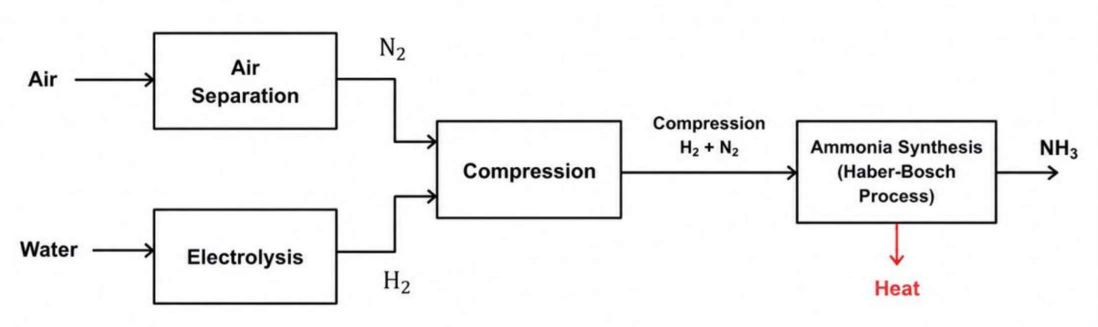

Figure A.3. Conceptual diagram of ammonia production using the Haber–Bosch process, [24]

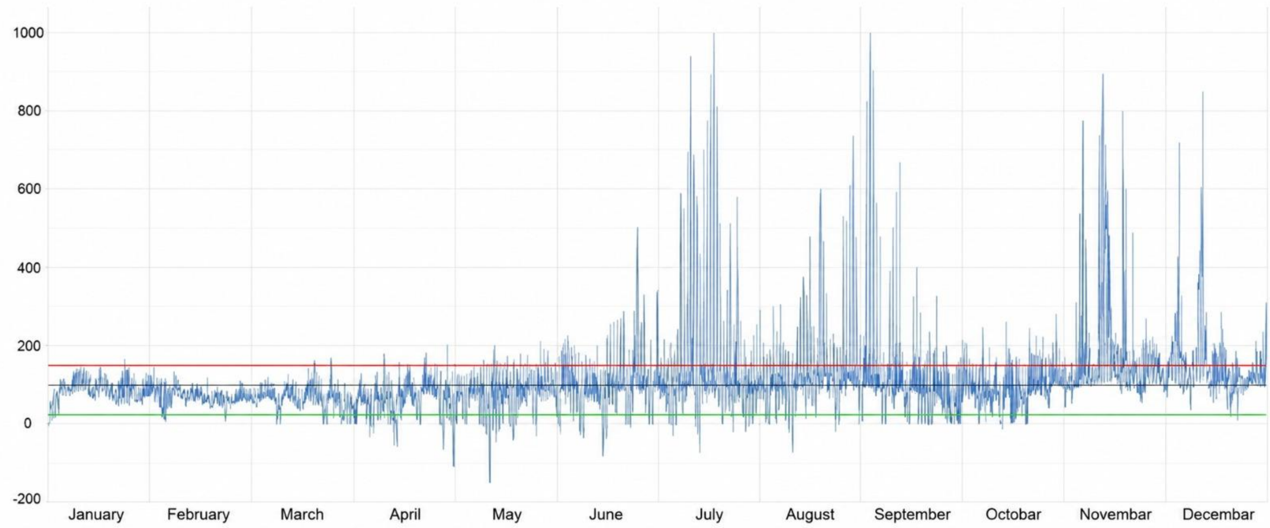

Figure A.4. Electricity prices on the HUPX electricity exchange in 2024, with the threshold values governing electrolyzer and gas-turbine operation indicated

BIOGRAPHIES

Jelica Janićijević was born in Belgrade, Republic of Serbia, in 2003. She completed the seventh and eighth grades of primary school and her secondary education in a specialized mentoring class at the Mathematical Grammar School in Belgrade. She is currently a fourth-year undergraduate student in the Power Engineering program at the University of Belgrade School of Electrical Engineering.

During her primary and secondary education, she participated in and received awards at national physics and mathematics competitions. She was also a member of the Petnica Science Center. During her university studies, she participated in projects involving the design of several power substations. She is the author of a student technical paper presented at the CIGRE Serbia 2025 Conference, where it received the award for the most outstanding student paper. She is also the author of a paper presented at the CIRED Montenegro 2026 Conference, which was likewise recognized as the most outstanding paper in its session. She received the Gordana Jokić Kašiković and Dragiša Kašiković Foundation Award for the best student paper of 2025. She is a recipient of a scholarship awarded by the Ministry of Education of the Republic of Serbia to gifted students. In recognition of her high academic achievement, she was also awarded a scholarship by Elektromreža Srbije. For her exceptional academic performance, she was also recognized as the best student in the Power Engineering program in both her third and fourth years of study.

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Danilo Vlahović was born in Vršac, Republic of Serbia, in 2003. He completed his primary education at Jovan Sterija Popović Primary School as the highest-achieving student of his graduating class. He subsequently attended Borislav Petrov Braca Grammar School in Vršac. He is currently a fourth-year undergraduate student in the Power Engineering program at the University of Belgrade School of Electrical Engineering.

He is a recipient of a scholarship awarded by the Ministry of Education of the Republic of Serbia to exceptionally gifted pupils and students, a scholarship awarded by Elektromreža Srbije, and a scholarship from the Studenica Foundation. Throughout his education, he achieved notable results in national mathematics and physics competitions, including first prize at the national physics competition and qualification for the Serbian Physics Olympiad. He also participated in the international FYKOS team physics competition.

As part of his project activities, he completed a project entitled "Acoustic Levitator," which was awarded second place at the national competition. He also authored a student paper presented at the CIGRE Serbia 2025 Conference, where it received the award for the most outstanding student paper. This paper also received the Gordana Jokić Kašiković and Dragiša Kašiković Foundation Award for the best student paper of 2025. He is also the author of a paper presented at the CIRED Montenegro 2026 Conference, which was recognized as the most outstanding paper in its session. His principal research interests include renewable energy sources, hydrogen, power systems, the energy transition, and energy storage.

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Aleksandar Latinović was born in Bihać, Bosnia and Herzegovina, in 1986. He completed primary school in Lazarevo, a village near Zrenjanin, and subsequently graduated from Zrenjanin Grammar School. He completed his undergraduate and master's studies at the University of Belgrade School of Electrical Engineering, Department of Power Engineering. From 2010 to 2025, he was employed by EPS AD, where his work included ancillary services, system software used to manage power-generation and maintenance processes, SCADA systems, and the development and construction of renewable energy projects. He is a member of the CIGRE C2 Study Committee. He also served on several working groups of the Ministry of Mining and Energy responsible for drafting and harmonizing technical regulations and legislation aimed at integrating renewable energy sources into the power system of the Republic of Serbia. Since 2025, he has worked as an independent consultant specializing in the technical aspects of power system balancing.

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He has been employed at the University of Belgrade School of Electrical Engineering since 2001, where he progressed through all academic and teaching ranks, and since 2023, he has held the rank of Full Professor. He is Head of the Laboratory for Power Plants. His research is primarily focused on the planning, integration, and operation of renewable energy sources in power systems. He is the co-author of four textbooks and approximately 300 scientific and professional papers, 40 of which have been published in international SCI-indexed journals. He has supervised seven doctoral dissertations and approximately 300 undergraduate and master's theses at the Schools of Electrical Engineering in Belgrade and East Sarajevo.

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Idejno rešenje supstitucije uglja kao goriva u blokovima A1 i A2 TE „Nikola Tesla" primenom vodoničnih tehnologija sa obnovljivim izvorima energije

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Originalni naučno-istraživački rad

Ključne poruke

- Analizirani su ključni tehnološki principi, ograničenja i prednosti savremenih metoda proizvodnje zelenog vodonika, sa fokusom na elektrolizu
- Sagledani su izazovi i rešenja u skladištenju vodonika
- Prikazani su tehnološki trendovi koji ubrzavaju primenu vodonika u energetskim sistemima: rast kapaciteta elektrolizera, pad troškova i unapređena integracija sa OIE
- Rad ističe značaj optimizacije infrastrukture i razvoja isplativih rešenja kao preduslova za širu upotrebu vodonika u procesu dekarbonizacije

Kratak sadržaj

Integracija obnovljivih izvora energije (OIE) u elektroenergetske sisteme (EES) predstavlja izazov zbog njihovog varijabilnog i neupravljivog karaktera, što otežava bilansiranje proizvodnje i potrošnje. Stabilan rad EES-a zahteva upravljive izvore energije. S druge strane, potiskivanje i gašenje termoelektrana u procesu dekarbonizacije, koja su predviđena integrisanim nacionalnim i klimatskim planom, smanjuje raspoloživu upravljivu energiju što ugrožava uslove bilansiranja i energetske nezavisnosti EES-a. Jedno od rešenja jeste korišćenje viškova energije iz OIE za proizvodnju vodonika i njegovih derivata, koji se mogu skladištiti i koristiti u gasnim elektranama kao upravljiv izvor energije.

U ovom radu analizirani su uslovi formiranja energetskog kompleksa za proizvodnju, skladištenje i upotrebu vodonika na lokaciji postojeće TE „Nikola Tesla A". Osnovna ideja je da se elektrana u budućnosti ne ugasi, već da pređe sa lignita na obnovljivo gorivo, zamenom konvencionalnih kotlova i parnih turbina gasnoturbinskim postrojenjima prilagođenim sagorevanju vodonika. Na taj način zadržava se ključna infrastruktura, naročito priključno razvodno postrojenje i razvijena interkonektivna veza ovog važnog generatorskog čvorišta.

Analiziran je i potencijal proizvodnje vodonika iz fotonaponskih elektrana koje bi bile izgrađene na prostoru nekadašnjih Kolubarskih kopova. Prikazano je idejno rešenje tehnološke šeme procesa proizvodnje, kompresije, skladištenja i upotrebe vodonika, uz proračun energetske efikasnosti kompletnog sistema. Na osnovu dostupnih podataka izvršena je preliminarna procena očekivane cene proizvedene električne energije.

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Napomena:

Ovaj članak predstavlja proširenu, unapređenu i dodatno recenziranu verziju studentskog rada *„Idejno rešenje dekarbonizacije proizvodnje električne energije u TE 'Nikola Tesla' primenom vodoničnih tehnologija sa obnovljivim izvorima"* (https://doi.ub.kg.ac.rs/doi/cigre37-c3-1/), nagrađenog u Studijskom komitetu STK-C3 *Održivost EES-a i performanse zaštite životne sredine,* na 37. Savetovanju CIGRE Srbija, Zlatibor, 26-30. maja 2025.

Koncept podrazumeva da se u periodima niskih tržišnih cena električne energije energija iz fotonaponskih postrojenja ili prenosne mreže usmerava na elektrolizu, dok se proizvedeni vodonik skladišti i koristi u periodima visoke potrošnje i nedostatka energije iz raspoloživih primarnih izvora u sistemu. Dodatno, toplota dobijena tokom elektrolize i sagorevanja vodonika može se koristiti za skladištenje i snabdevanje toplotnog konzuma, čime se povećava ukupna efikasnost sistema.

Ključne reči

Dekarbonizacija, obnovljivi izvori energije, TE „Nikola Tesla”, vodonik