methane

Article

Methane Capture and Hydrogen Production from Coal Mine Methane: A Sustainable Path for Energy Transition

Marek Borowski [1,2,*], Klaudia Zwolińska-Glądys [1,2,*], Jianwei Cheng [3], Artur Badylak [1] and Magdalena Wojtowicz [2]

[1] Faculty of Civil Engineering and Resource Management, AGH University of Krakow, 30-059 Krakow, Poland; abadylak@agh.edu.pl
[2] Methane Research Centre, AGH University of Krakow, 30-059 Krakow, Poland; magwojt@agh.edu.pl
[3] School of Safety Engineering, China University of Mining and Technology (CUMT), Xuzhou 221116, China; cheng.jianwei@cumt.edu.cn
* Correspondence: borowski@agh.edu.pl (M.B.); kzwolinska@agh.edu.pl (K.Z.-G.)

Abstract

Methane emissions from coal mines pose significant environmental and operational challenges. Methane can be released from coal seams and surrounding rock layers as a result of mining operations. These emissions pose environmental risks and can lead to fire and explosion hazards. Therefore, reducing coal mine methane emissions is essential for both protecting miners' safety and cutting greenhouse gas emissions. Additionally, capturing methane before it escapes into the atmosphere can be economically beneficial and used as a valuable energy source. This study proposes an integrated approach that combines advanced methane capture and hydrogen production technologies to enhance both environmental performance and energy recovery in coal mining operations. By combining methane capture with hydrogen production, the study presents a practical solution for lowering greenhouse gas emissions in the coal sector. This strategy promotes the adoption of low-carbon energy sources and offers a sustainable path forward for coal-dependent regions facing decarbonization challenges. A scenario-based techno-economic analysis is presented, including investment and operating costs, hydrogen yield, energy generation potential, and greenhouse gas mitigation. Further research should focus on process optimization, the integration of carbon capture technologies, and the valorization of by-products to further reduce the environmental footprint.

Keywords: coal mine methane; coalbed methane; methane capture; hydrogen production; energy transition; greenhouse gas mitigation

Academic Editors: Elodie Fourré, Xiaohai Zheng and Jeffrey D. Moore

Received: 19 June 2026
Revised: 29 July 2026
Accepted: 31 July 2026
Published: 5 August 2026

1. Introduction

Methane (CH_4) is a significant greenhouse gas. Methane is responsible for approximately 16% of the radiative forcing driving global climate change, making it the second most important greenhouse gas after CO_2, with atmospheric concentrations having risen to around 260% of pre-industrial levels [1]. Its relevance to climate change is increasingly underscored in scientific literature and policy documents. Methane's 100-year global warming potential (GWP) is 28 times that of carbon dioxide (CO_2), making reducing methane emissions one of the most effective ways to limit short-term global temperature increases. In addition to its impact on climate, the presence of methane in the atmosphere promotes the formation of tropospheric ozone, which is detrimental to human and biosphere health, affecting air quality and increasing the risk of respiratory disorders [2].

A particular source of anthropogenic methane emissions is underground coal mines, where the gas is released both during operation—coal mine methane (CMM)—and after its completion—abandoned mine methane (AMM)—as well as a result of long-term drainage of gases from the deposit—coalbed methane (CBM), which in many countries (e.g., India) is becoming a priority area for emission reduction. Globally, coal mining accounts for approximately 10–12% of total anthropogenic methane emissions, with CMM and CBM representing a significant share in major coal-producing countries such as China, the USA, and Australia. In Poland, coal mine methane constitutes a substantial portion of the country's methane emissions inventory [3]. These emissions not only contribute to the deterioration of the energy sector's climate balance but also pose a direct threat to occupational safety. Methane mixed with air creates explosive atmospheres, hazardous when mining deep seams or under conditions of dynamic barometric pressure changes. Therefore, effective ventilation systems, methane drainage systems, and continuous monitoring of the mine atmosphere are fundamental elements of modern gas hazard management [4].

In response to the growing importance of methane in climate policy, the European Union adopted Regulation (EU) 2024/1787 of the European Parliament and of the Council of 13 June 2024 on the reduction in methane emissions in the energy sector [5]. This act requires mine operators to implement systems for monitoring, reporting, and reducing methane emissions, and promotes the use of methane capture and management technologies. In this context, a particularly promising direction is the use of methane as an energy resource to produce hydrogen, a fuel with zero emissions upon final combustion, playing a key role in the European decarbonization strategy. Similar legislative trends can also be observed in other countries, both developed and developing. For instance, the United States has implemented methane rules under the EPA's Greenhouse Gas Reporting Program, while China has introduced its Methane Emission Control Action Plan as part of its broader climate strategy. India has also prioritized CBM extraction and emission reduction [6].

Methane-based hydrogen production, achieved using processes such as steam reforming (SMR) or autothermal reforming (ATR), can bridge the gap between current fuel technologies and future developments in renewable energy. However, for this process to be considered environmentally sustainable, it is necessary to implement solutions enabling the capture and utilization of the carbon dioxide produced (so-called blue hydrogen) or to develop emission-free methane pyrolysis technology (turquoise hydrogen), the research potential of which is steadily increasing [7].

In Poland, one of the largest coal producers in the European Union, methane emissions from mines reach approximately 820 million m^3 annually [8]. It represents approximately 30–35% of Poland's total methane emissions and constitutes a significant share of the EU's total methane emissions from the energy sector, which are estimated at approximately 14 million tonnes CO_2-equivalent annually. The main sources of emissions are ventilation air contaminated with methane (VAM) and methane drainage systems, whose utilization efficiency is about 60–70%. The utilization efficiency of methane drainage systems is defined here as the ratio of methane captured and commercially used (e.g., for electricity generation or heating) to the total methane drained from the seam, considering both the capture efficiency and the subsequent utilization rate. A particular area of concentration of the problem is the Upper Silesian Coal Basin, where Jastrzębska Spółka Węglowa S.A. (JSW, Jastrzębie-Zdrój, Poland), the main producer of coking coal in the country, operates. The exploitation of deep and methane-bearing seams, coupled with the obligation to transform towards climate neutrality by 2050, requires the implementation of technologies that allow for the capture, processing, and storage of mine gases in a safe and energy-efficient manner [9].

https://doi.org/10.3390/methane5030022

Several previous studies have examined methane capture and hydrogen production separately, but few have addressed their integration in a coal-mining context. Prior work on coal mine methane utilization has focused predominantly on direct combustion for electricity and heat, including trigeneration applications [2,10]. Separately, the hydrogen production literature has compared SMR, ATR, pyrolysis and gasification largely for natural gas or general industrial feedstocks, without reference to mine-gas-specific constraints such as variable methane concentration, drainage system pressure profiles, or the safety requirements of underground operations [11–14]. Techno-economic assessments of hydrogen production exist for renewable- and natural-gas-based routes [15,16], and reviews of coal mine methane management describe drainage and utilization technologies in detail [17–22], but none of these bodies of work jointly quantify the technical and economic performance of coupling enhanced methane drainage (LRDD) with on-site reforming to hydrogen under the specific geological, regulatory, and infrastructure conditions of Polish hard coal mines. This is where the present work adds novelty: rather than treating methane capture, hydrogen production, and policy compliance as separate questions, we bring them together in a single techno-economic framework, combining enhanced methane capture through LRDD, conversion of the captured methane to hydrogen via SMR/ATR with CCS, and a direct check of how the resulting system aligns with EU and Polish regulations.

The paper aims to analyze the potential for integrating innovative technologies for methane capture and its conversion to hydrogen in Polish coal mines. Specifically, the paper discusses the application of Long Reach Directional Drilling (LRDD), which enables effective drainage of methane from difficult-to-access deposit areas, as well as SMR and ATR processes for industrial hydrogen production. A technical and economic assessment of the considered system was conducted, including energy efficiency, CO_2 emissions, capital and operating costs, and potential return on investment. Particular emphasis was placed on the potential for integrating the proposed technologies with existing mining infrastructure, including methane drainage installations and power systems. The results presented in this paper can serve as a basis for developing scenarios for the transformation of the hard coal sector towards low-emission and economically viable hydrogen energy in regions dependent on the mining industry.

2. Methodology

2.1. Methodological Framework

This study integrates a review of the advanced methane capture techniques and hydrogen production processes, supported by a comprehensive techno-economic and environmental analysis. The methodological framework adopted in this study is based on a critical review and synthesis of scientific literature, industry reports, and policy documents related to methane capture in coal mining and hydrogen production technologies. The approach integrates technical, economic, and regulatory aspects to provide a coherent concept for methane-to-hydrogen conversion in coal-dependent regions. It consolidates existing data from peer-reviewed publications, official statistical sources, and technical feasibility studies to identify best practices, technological pathways, and potential integration schemes. Policy alignment is assessed by evaluating the proposed system's compliance with existing and planned EU and national regulations, such as the EU Methane Regulation (2024/1787) and the Polish Hydrogen Strategy, and its potential to contribute to their emission reduction targets. This assessment considers both current policy frameworks and anticipated regulatory developments. Methane sources, including coalbed methane (CBM), coal mine methane (CMM), and abandoned mine methane (AMM), were characterized using documented geological, operational, and gas quality parameters reported in the literature. Technology performance indicators, cost estimates, and environmental impact data were compiled from studies and technical assessments. These references provided the basis for qualitative comparisons and scenario discussions.

This paper was developed as part of the preparation for a research project that will be implemented in the subsequent years. As a result, the analysis relies on international experience and case studies, adapting them to the specific geological, operational, and policy conditions of the Polish mining sector. The integrated methodological approach enables a systematic assessment of the feasibility, performance, and policy alignment of methane-to-hydrogen conversion systems in coal-dependent regions. By combining synthesized literature data, adapted process parameters, and scenario-based economic and environmental analysis, the study provides a base for technology deployment within the broader context of energy transition and greenhouse gas mitigation.

To ensure reproducibility, the following methodological details are provided: (1) references were selected based on their relevance to methane capture, hydrogen production technologies, and techno-economic assessments, prioritizing peer-reviewed journal articles, official statistical sources, and technical feasibility studies published after 2010; (2) scenarios were developed using a three-tier approach (conservative, central, and optimistic) based on literature-derived ranges for key parameters such as CAPEX, OPEX, hydrogen price, and electricity price; (3) technical parameters (methane capture efficiency, hydrogen yield, conversion efficiency) were estimated from published data [11,13,14,20,21] and adapted to Polish mining conditions using project-specific assumptions from the METH2GEN project.

2.2. Subject of Analysis

Potential coalbed methane resources in Poland are estimated at approximately 350 billion m^3 [23]. Coalbed methane deposits have been properly documented only in the Upper Silesian Coal Basin. The exploration of methane conditions in the Lower Silesian Coal Basin and the Lublin Coal Basin is limited due to lower methane concentrations. The Prospective Balance of Mineral Resources in Poland [24] states that, based on the applicable criteria for deposit designation and after analyzing the geological conditions, total prospective resources can be estimated at 111.27 billion m^3 for the three Coal Basins mentioned above. The largest resources are in the Upper Silesian Coal Basin, where the documented recoverable balance values determined for 65 deposits amount to approximately 105.45 billion m^3, while off-balance values are estimated at 9.41 billion m^3. Industrial methane resources determined for 31 deposits in Poland amount to approximately 10.66 billion m^3 and are of significant economic importance, particularly in the context of their use as fuel for power generation installations and the reduction in greenhouse gas emissions [8].

Total methane emissions from hard coal mines in Poland totaled approximately 795 million m^3 per year in 2023, of which the largest portion, approximately 474 million m^3, constitutes ventilation air emissions. The remaining portion, approximately 285 million m^3, originates from methane drainage systems, only a portion of which is commercially utilized; the rest is emitted into the atmosphere [9]. Methane drainage systems in Polish hard coal mines typically utilize 60% to 70% of the methane that can be captured. This means that of the approximately 285 million m^3 of methane captured annually in methane drainage processes, approximately 214 million m^3 is commercially utilized. Notably, the remaining approximately 71 million m^3 is emitted into the atmosphere due to technological limitations and the lack of adequate infrastructure for its utilization [9]. To put these figures in perspective, the total annual consumption of natural gas in Poland is approximately 15–17 billion m^3, making the captured CMM (approximately 214 million m^3/year commercially utilized) a significant, albeit smaller, local energy source. Currently, the captured methane is primarily used for on-site electricity and heat generation in gas engines, with limited utilization for trigeneration systems in some mines [10,23].

3. Emission Reduction Technologies and Mining Sector Challenges

3.1. Coal Methane Emissions—Basics

Methane in coal mining comes primarily from three key sources: CBM, CMM, and AMM. These three categories differ in both their characteristics and the methods of their capture and management. These emissions have various environmental and technological characteristics, requiring dedicated technologies for their effective utilization. CBM is a gas adsorbed in the coal structure, which can be released both during mining operations and through specialized drilling. The process of extracting CBM from coal seams requires advanced technologies, such as horizontal drilling and flow intensification through gas injection, e.g., carbon dioxide or nitrogen. CBM is characterized by high purity (up to 98% methane), making it a valuable energy source [23]. CMM is methane released during coal mining. A significant portion of this gas is discharged from mines in VAM, which contains low methane concentrations, typically below 0.5%. The difficulty in its management stems from high ventilation airflows and low gas concentrations. VAM combustion technologies, including catalytic and thermal flow reactors, are continually being refined to increase their efficiency. AMM originates from decommissioned mines, where methane accumulates in the voids left by the mine. This gas can be used as an energy source. Due to the difficulty of capturing it and the risk of atmospheric emissions from natural outflows, from leaking shafts, or other sites, it often poses challenges. Solutions include the use of underground gas storage facilities or drilling to enable efficient AMM exploitation [24]. The flow rates of these methane sources are not constant; they vary significantly over time and space. CMM flow rates are closely linked to mining activities and can be highly variable, fluctuating with extraction rates and geological conditions. AMM emissions depend on the state of mine flooding and can be more stable but diffuse. CBM extraction from virgin seams tends to be more predictable after initial dewatering and production stabilization [24]. This variability has important implications for the design and sizing of treatment systems.

Currently used technologies for reducing methane emissions in coal mines include methane drainage systems. Drainage systems effectively capture coalbed methane before it is released into the atmosphere, which not only reduces emissions but also reduces the risk of explosions during mining operations. Methane captured from methane drainage systems is primarily used for electricity and heat production, where the methane is burned in gas engines and turbines, allowing for local energy use within the mine or in adjacent installations, as well as in trigeneration systems, enabling the simultaneous production of electricity, heat, and cooling [10,23]. The use of methane in trigeneration systems represents an innovative approach to managing captured gas in hard coal mines. These systems facilitate the simultaneous production of electricity, heat, and cooling, significantly increasing energy efficiency and reducing methane emissions to the atmosphere. Examples of such technologies could be found in Polish mines, where methane captured during methane drainage is used as fuel in gas engines. The thermal energy produced has the potential to power local heating systems, and the cold is used to air-condition mine workings. In such trigeneration systems, the waste heat from electricity generation in gas engines is used for heating, while a portion of this heat can also drive absorption chillers to produce cooling for air-conditioning mine workings. This approach significantly increases overall energy efficiency compared to separate generation of electricity, heat, and cooling [10].

Technological limitations and the inefficiency of existing systems result in the low methane recovery rate in many mines. This proves the need for further investment in the development of methane drainage technologies and increased efficiency, which will allow for fuller utilization of this resource's energy potential. Ventilation air, rich in methane at concentrations too low for conventional combustion, can be used in catalytic or thermal reactors. These innovative technologies offer promising solutions for utilizing the methane contained in VAM. These advanced reactors efficiently convert methane into carbon dioxide and heat, which can be used for energy purposes. However, the main challenge in their application is the very low methane concentration in VAM, often below 0.5%. At such low concentrations, additional gas concentration or mixing technologies are necessary to achieve levels that allow the reactors to operate autothermally. Despite these limitations, flow reactors are an essential element of methane emission reduction strategies in mines, and further work on their optimization could considerably improve their efficiency and industrial utilization. Another emerging approach for VAM treatment involves the use of bioreactors containing methanotrophic bacteria, which can oxidize methane at ambient temperatures and pressures. While this biological method offers the advantage of low energy consumption, significant challenges remain in terms of cost, scalability for large airflows, and maintaining optimal conditions for bacterial activity in the harsh mine environment [17].

Summarizing, the challenges associated with methane emissions in coal mining require urgent action, both in terms of minimizing environmental and safety risks and in the efficient use of this gas for energy production. Innovative methane capture technologies offer a response to these challenges, offering new opportunities for emission reduction and improved gas management effectiveness [18].

3.2. Methods for Enhanced Methane Recovery

Reducing methane emissions in coal mining is one of the most important challenges in the context of environmental protection and improving occupational safety. Traditional methane capture methods, such as methane drainage and ventilation systems, despite their effectiveness in basic applications, are not always sufficient to address contemporary climatic and technological difficulties. Innovative methane recovery technologies developed in recent years offer more advanced and effective solutions that not only minimize emissions but also enable methane utilization as a valuable energy resource [19,25].

LRDD technology is an advanced method used in the mining industry that significantly improves the efficiency of coalbed methane capture. LRDD involves drilling long, directional holes in deposits, enabling precise access to zones containing high methane concentrations and enhancing the performance of mine degassing and drainage [20]. This technology enables drilling holes up to 2000 m long, which is important for reaching reservoirs where methane is accumulated [21,22]. The effectiveness of methane drainage using LRDD technology depends largely on the accurate assessment of deposit parameters and appropriate well design. CBM deposits are characterized by low permeability, the presence of gas adsorbed on the coal surface, and a "cleat" fracture structure that is sensitive to stress changes. Therefore, detailed geological modeling is necessary to identify zones with the greatest drainage potential [20,25,26]. In the case of CMM, emissions also fluctuate over time and space, specifically in post-mining and disturbed areas, requiring continuous monitoring [19].

The use of various drilling geometries, including branches, fans, and radial drilling configurations, allows for increased contact area with the seam and improved gas flow efficiency towards the borehole. Appropriate placement and orientation of laterals, especially in loose or faulted zones, amplifies methane recovery and reduces the risk of technological failures [21]. Furthermore, the use of real-time monitoring systems (e.g., borehole pressure, gas concentration, rock gas content) supports ongoing optimization of drilling and drainage parameters. Integrating data with control algorithms improves the operational safety and effectiveness of LRDD technology, making it a scalable solution for deep mines with complex rock mass geometry [27]. Directional drilling techniques, as illustrated in

Figure 1, encompass various configurations such as stacked, planar, and radial well designs, which are tailored to optimize resource extraction from complex geological formations [11].

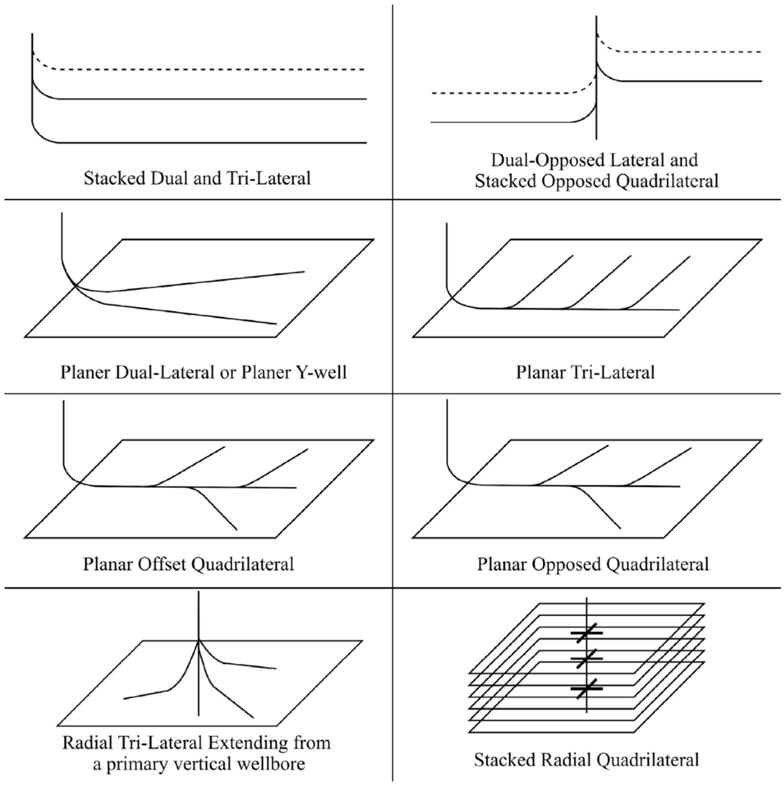

Figure 1. Directional Drilling—an overview [28].

Directional drilling techniques, such as planar multilateral and radial trilateral wells, enable access to difficult-to-reach coal seams and the effective removal of methane from remote seam areas (Figure 1). A key advantage of LRDD is the ability to drill holes at various angles, allowing for better placement of degassing points and increased gas capture area. Methane capture efficiency with this technology increases from the typical 35% to as much as 70%, significantly reducing methane emissions to the atmosphere [20,21]. This technology also facilitates the capture of gas with high methane concentrations, reaching up to 98% [21]. Furthermore, this technology is supported by advanced real-time monitoring and control systems that enable dynamic adjustment of drilling parameters such as torque, drilling fluid pressure, and hole inclination angle. This allows precise drilling in challenging geological conditions, including coal seams at depths exceeding 1000 m. Selecting the relevant well geometry in LRDD technology is crucial for increasing the effectiveness of coalbed methane drainage. Depending on the geological structure, permeability parameters, gas pressure, and rock mass structural conditions, three basic well configurations are used: planar, stacked, and radial [22]. The planar configuration involves the propagation of multi-branch wells in a single plane, parallel to the seam slope. This configuration is particularly effective in homogeneous deposits with good horizontal continuity, permitting effective degassing of large areas without the need to interfere with other layers. Conversely, the stacked configuration is based on the arrangement of wells in vertical layers (stages), allowing for the simultaneous drainage of gas from several levels of the coal formation. This is an optimal solution for complex structures with multiple seams or where the gas content varies significantly vertically [20,25]. The most complex configuration is the radial configuration, in which the side branches of the well radiate from the main wellhead. This variant ensures maximum drainage reach with minimal disturbance to the seam structure, amplifying the contact area with the seam several times compared to a straight borehole. Radial branch distribution is particularly effective in seams with isotropic permeability and under conditions of moderate lateral stress. The use of the above-mentioned well geometries, shown in Figure 1, allows for adapting the drainage system to variable geological conditions and maximizing methane capture performance. Their selection should be based on an analysis of the reservoir model and preliminary drilling tests, considering local pressure zones, fracture patterns, and the risk associated with rock mass movement [21].

Effective coalbed methane drainage, especially when using LRDD technology, requires not only precise well geometry design but also continuous and integrated monitoring of operating parameters. Modern monitoring systems enable real-time recording and analysis of key variables, such as borehole pressure and temperature, gas volume flow, methane concentration, CO_2 content, and changes in rock mass stress [20]. The use of pressure and flow sensors allows for the assessment of dynamic changes in drainage efficiency and the identification of potential blockages or excessive gas saturation. Simultaneously, measurements of methane concentration and humidity permit rapid response in situations that pose a risk to operational safety (e.g., approaching explosive mixture levels). Monitoring data is integrated with digital reservoir models and control systems, which automatically adjusts operating parameters, such as system vacuum, valve opening, and drainage configuration changes [25]. In advanced systems, drainage process control is performed using predictive modules based on artificial intelligence and machine learning algorithms, which estimate changes in well efficiency and allow for optimal planning of follow-up drilling schedules. Integrating environmental monitoring with methane drainage systems is now an essential element of effective and safe methane management in underground mines, aligning with the sector's climate goals and energy transition [27].

4. Hydrogen Production from Methane

4.1. Hydrogen Production Systems

Producing hydrogen from methane can be a fundamental element in the transition to low-emission energy sources, while also offering a solution for utilizing fossil gases as part of the global energy transformation. Methane-based hydrogen production is primarily achieved using technologies such as steam methane reforming, autothermal reforming, and coal gasification [12].

Steam methane reforming is a process in which natural gas, consisting primarily of methane (CH_4), reacts with water vapor (H_2O) in the presence of a catalyst at high temperatures (approximately 700–1000 °C). This process produces hydrogen (H_2) and carbon monoxide (CO). The carbon monoxide can then be converted into additional hydrogen via the water-gas shift (WGS) reaction, in which carbon monoxide reacts with water vapor to form hydrogen and carbon dioxide (CO_2). SMR is characterized by high efficiency and relatively low costs of hydrogen production, making it the preferred method for industrial-scale hydrogen production. However, the major drawback of this technology is the emission of significant amounts of CO_2. For every kilogram of hydrogen produced, approximately 9–11 kg of CO_2 are released into the atmosphere [15,16,29,30].

In autothermal reforming technology, methane is converted into hydrogen by the combustion of some natural gas with the addition of steam. This process is energy self-sufficient, as part of the energy required for the reaction comes from the combustion of methane itself [31]. Nonetheless, as with SMR, ATR leads to high CO_2 emissions [13].

Steam methane reforming is the most common method and forms the basis for producing grey hydrogen. Alternatively, ATR combines the combustion of a portion of natural gas with the addition of steam, making the process energy-sufficient. Coal gasification, although less popular, allows the production of hydrogen from solid fuels, but generates significant amounts of CO_2 [13]. While ATR is energy self-sufficient due to the internal combustion of a portion of the methane feed, this combustion results in a lower overall hydrogen yield compared to SMR, as part of the feed gas is oxidized rather than converted to hydrogen [13,31]. All these technologies are efficient, but their high emissions pose a challenge to meeting climate targets [11,12]. Depending on the origin of the primary energy used for hydrogen production, it is feasible to categorize the generated hydrogen using the color terms gray, blue, turquoise, and green [32]. Conventional hydrogen produced by various processes that use fossil fuels without CO_2 emissions mitigation is called gray hydrogen. These include steam reforming of natural gas, coal gasification, or separation from coke oven gas. It accounts for as much as 76% of the hydrogen produced worldwide [33]. Its production is mainly based on processes using fossil fuels, making it a high-carbon and emission-intensive form of hydrogen. The main method for producing gray hydrogen is SMR, which, despite high CO_2 emissions, is the most cost-effective and widely used technology in industry [14].

A critical aspect of the SMR process not yet fully addressed in the current project concept is the source of thermal energy required for the endothermic reforming reaction. In conventional SMR, the required heat is supplied by burning a portion of the methane feed, which contributes to the overall CO_2 emissions of the process (approximately 3178 t CO_2/year from reformer heating in the present scenario, in addition to the process-related 3822 t CO_2/year). An alternative approach, electrified SMR (e-SMR), uses renewable electricity to provide the process heat, significantly reducing direct CO_2 emissions. However, e-SMR is currently at a lower technology readiness level (TRL 6-7) and requires a reliable supply of renewable electricity. In the Polish context, with a coal-dominated electricity grid (0.720 kg CO_2/kWh in 2025), e-SMR would not currently offer significant emissions reductions unless coupled with dedicated renewable energy sources. Therefore, the present scenario assumes conventional SMR with CCS integration as the most practical near-term solution, while acknowledging that e-SMR could become viable as Poland's electricity mix continues to decarbonize towards 0.200 kg CO_2/kWh by 2050 [14,34].

In addition to steam and autothermal reforming, another promising route to hydrogen production from methane is thermal methane cracking, also known as methane pyrolysis. This method produces hydrogen without releasing carbon dioxide, making it a viable route to CO_2-free utilization of fossil methane. According to Weger et al. [35], methane cracking can serve as a bridge technology during the energy transition, decarbonizing sources of natural gas and coalbed methane while producing solid carbon as a byproduct, not gaseous carbon [7]. The solid carbon produced by methane pyrolysis typically takes the form of a fine powder or granular material, known as carbon black or solid carbon, which has a high surface area and can be used as an industrial raw material in applications such as tyre manufacturing, battery anodes, and as a reducing agent. This contrasts with the more porous, charcoal-like structure of biochar produced from biomass pyrolysis [7,35]. This method has the advantage of eliminating direct greenhouse gas emissions, provided the thermal energy is derived from renewable or nuclear sources. Furthermore, the solid carbon produced can be stored, used industrially, or incorporated into building materials, thus completely avoiding carbon dioxide emissions. Current technological advances are aimed at enhancing reactor design, improving energy efficiency, and catalyst stability to make this solution commercially scalable [3,34].

Coal gasification involves the chemical conversion of solid fossil fuels, such as coal, into a gaseous form containing hydrogen. Gasification involves the partial combustion of coal with a limited supply of oxygen and steam, producing synthesis gas. The produced syngas

https://doi.org/10.3390/methane5030022

is mainly composed of hydrogen, carbon monoxide, and carbon dioxide. Although this technology enables the extraction of hydrogen from coal, it generates a considerable amount of carbon dioxide emissions, making it a high-emission technology. Coal gasification is recognized as the core technology of clean coal utilization, converting coal into syngas rich in hydrogen, carbon monoxide, and methane by reacting it with steam, air, or oxygen. While gasification enhances syngas production and offers hydrogen-rich output, it inherently generates substantial CO_2 emissions unless advanced methods or capture technologies are employed. Nevertheless, the developed gasification technology could provide a feasible solution for efficient and clean conversion and utilization of coal, while allowing for hydrogen production and reducing carbon dioxide emissions [36].

The production of grey hydrogen is closely linked to CO_2 emissions, which contribute to climate change. Therefore, attention is increasingly directed toward transitioning from fossil fuel-based production methods to more sustainable technologies, such as blue hydrogen (produced from fossil fuels with CO_2 capture and storage) and green hydrogen (produced from renewable energy sources) [30]. Despite its carbon footprint, grey hydrogen remains the dominant form in industrial production, particularly in the chemical, refining, and petrochemical sectors, where hydrogen is a key raw material. Transitioning to lower-emission hydrogen production methods is an integral part of the climate policy of many countries, including Poland, which aims to reduce CO_2 emissions in line with EU climate targets [37]. To support the selection of SMR over the alternative routes discussed above, Table 1 summarizes their relative maturity, emissions, and yield/cost characteristics as reported in the literature cited in this section.

Table 1. Qualitative comparison of methane-based hydrogen production technologies [12–16,29–36].

Hydrogen Production	Maturity	CO_2 Emissions (Relative)	Yield/Cost Notes
SMR (with CCS)	Most mature; TRL 9 [12–14,32,33]	~9–11 kg CO_2/kg H2 before capture [15,16,29,30]	Highest H_2 yield of the routes compared here; most cost-effective at industrial scale [14]
ATR	Mature, industrially proven	Similarly high to SMR [13]	Energy self-sufficient, but lower H_2 yield than SMR since part of the feed is combusted for process heat [13,31]
Methane pyrolysis	Emerging; reactor design and catalyst stability still under development [34,35]	Near-zero direct CO_2 emissions if process heat is renewable or nuclear	Produces solid carbon by-product instead of CO_2; not yet commercially scalable
Coal gasification	Established for solid fuels [36]	High; among the most carbon-intensive of the routes compared here	Produces H_2-rich syngas, but requires advanced capture methods to be low-emission

In summary, while SMR remains the most mature and cost-effective technology for industrial-scale hydrogen production, ATR offers advantages in terms of energy self-sufficiency at the cost of lower hydrogen yield. Both technologies, however, require integration with carbon capture and storage (CCS) to align with climate neutrality goals. The selection of the most appropriate technology depends on site-specific factors, including methane composition, available infrastructure, and project economics.

4.2. Integration of Methane Capture and Hydrogen Production

The proposed solution integrates methane capture with its conversion to hydrogen, providing a comprehensive approach to reducing methane emissions and effective management [17,19]. The process begins with the capture through a methane drainage system. LRDD technology plays a key role in increasing methane capture efficiency, which contributes to improving mine safety and supports the achievement of global climate targets [20–22,25]. This solution is an example of a transformation towards sustainable development in the mining sector [38].

The following key assumptions underpin the presented analysis: (a) the methane capture system using LRDD provides a steady supply of 5.0 million m^3/year of pure methane, split into two equal streams; (b) 2.5 million m^3/year (50%) is allocated to electricity generation in a gas engine with an electrical efficiency of 40%, producing 10,000 MWh/year; (c) the remaining 2.5 million m^3/year is processed in an SMR unit for hydrogen production. These assumptions are based on literature data [11,13,20] and adapted to Polish mining conditions. It is assumed that methane from drainage will be used to generate electricity at a level of 10,000 MWh/year, half of which can be used directly for local needs, reducing the need for external energy sources. The next stage of the process is the conversion of methane to hydrogen using steam reforming technology. Hydrogen production reaches 700 tons/year, providing industrial and transportation-grade fuel [11,12,14]. This process produces carbon dioxide, which is collected and processed into food-grade products in a form similar to dry ice. Excess CO_2 can also be injected in liquid form into depleted coal seams, further preventing endogenous fires [38,39]. A flowchart of the methane emission reduction process utilizing hydrogen production in hard coal mines through LRDD technology is shown in Figure 2.

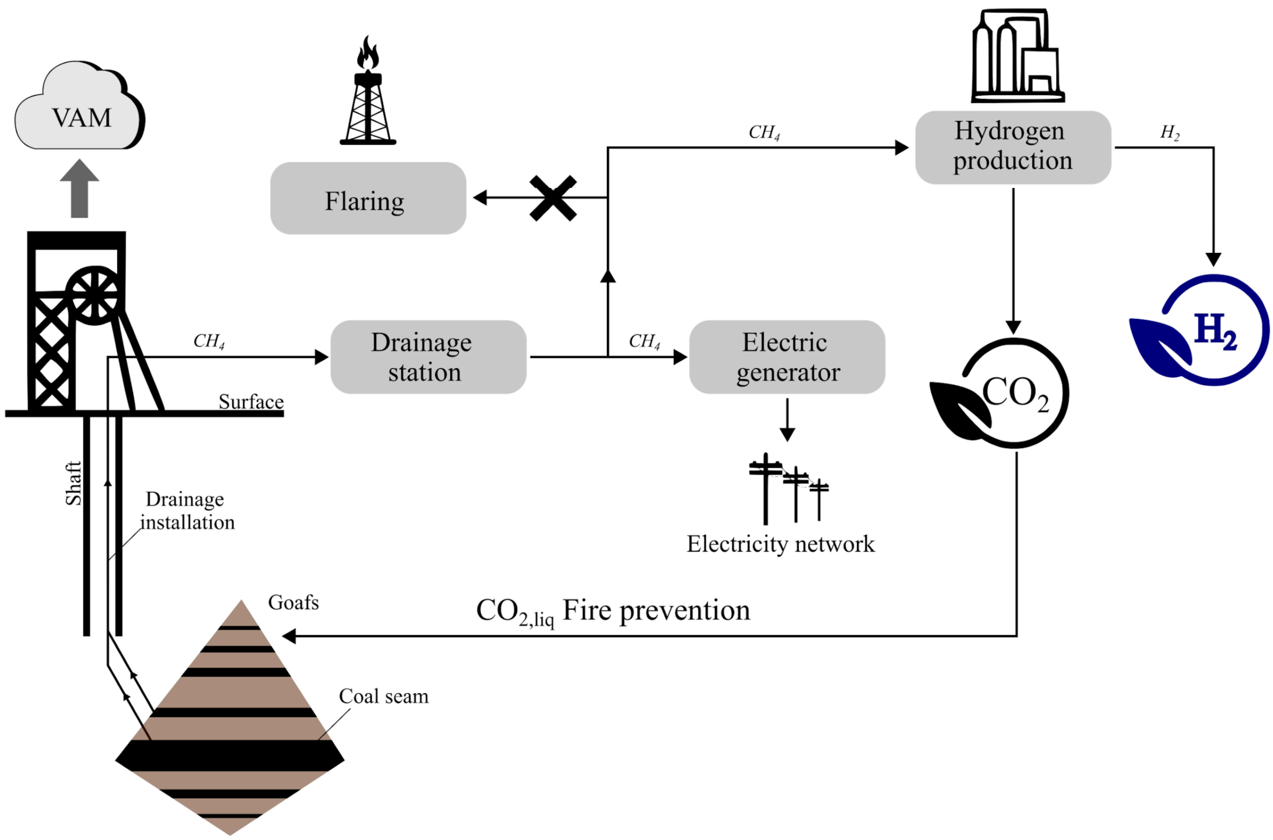

Figure 2. Schematic diagram of the process of hydrogen production in hard coal mines.

The methane-to-hydrogen conversion system is a technologically advanced system that enables the efficient use of methane collected from mine ventilation air. The process begins at the methane removal station, where gas at low pressure (0.16 bar, V = 500 m^3) and high pressure (40 bar) is captured and transported to subsequent stages. Producing

700 tons of hydrogen requires approximately 2,500,000 m^3 of pure methane. Assuming methane constitutes 40% of the mixture, approximately 6,250,000 m^3 of the gas mixture will be required. Therefore, the minimum intake of a 40% methane gas mixture required for hydrogen production is approximately 12 m^3/min [11].

To prepare the gas for further technological processes, the methane is compressed to a higher pressure, enabling its processing in decarbonization modules such as the DeOxo. In this step, contaminants, including oxygen, water vapor (H_2O), and nitrogen (N_2), are removed, yielding a clean gas [13,34]. The gas is then subjected to the Pressure Swing Adsorption (PSA) process, which eliminates remaining contaminants such as carbon dioxide (CO_2) and carbon monoxide (CO), and methane is directed to the HyGEN module. In this module, operating at a pressure of 30–35 bar, methane is converted to hydrogen (H_2) and CO_2 via steam or autothermal reforming processes [11,12,14]. The gas residues are further processed in the Loop module, allowing for energy recovery and maximizing production effectiveness. The hydrogen produced is compressed to a pressure of 350 bar and stored in cylinders or tanks, ready for industrial applications [15,34,40]. Carbon dioxide, a byproduct, is stored and can be processed into dry ice, further minimizing emissions. Figure 3 shows a diagram of the hydrogen production facility.

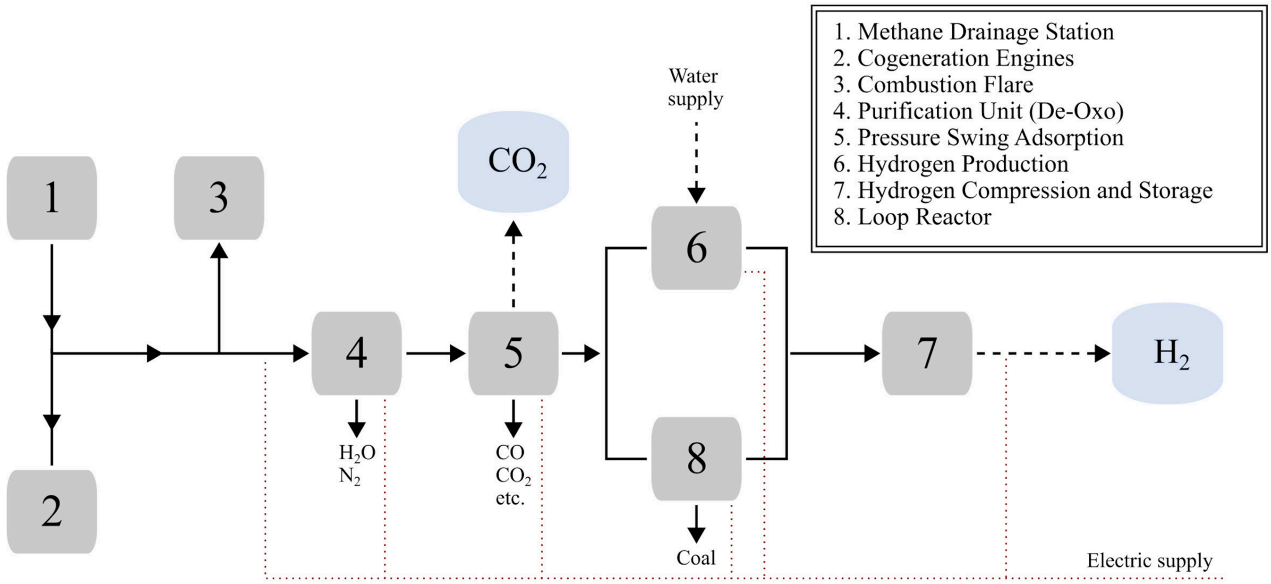

Figure 3. Example diagram of a hydrogen production installation.

Implementing a methane capture and hydrogen conversion system involves significant investment and operating costs. The investment costs associated with implementing this system are considerable and include the construction of a methane drainage station and CMM capture systems (estimated at EUR 1.5–2.5 million), installation of SMR or ATR modules for hydrogen production (EUR 3–5 million) [13,14], and integration of PSA and DeOxo modules for gas purification (EUR 1–2 million). The purchase and installation of hydrogen compression systems (up to 350 bar pressure) and hydrogen and CO_2 storage devices is an additional expense of EUR 1.5–2 million [32]. The development of LRDD technology, which increases methane capture efficiency, can cost approximately EUR 2–3 million, while monitoring and process automation systems add another EUR 0.5–1 million. Operating costs include energy consumption for gas compression and reforming processes, which generate an expense of EUR 200,000–400,000 per year, infrastructure maintenance, and parts replacement costs (EUR 150,000–300,000 per year), water consumption in reforming processes (EUR 50,000–100,000 per year) [14], and salaries for plant personnel

(EUR 300,000–500,000 per year). Regulatory costs, such as plant certification and meeting greenhouse gas emission standards, can amount to EUR 50,000–100,000 per year, while potential environmental fees for unused methane or CO_2 are difficult to estimate and depend on the emission level [39,40]. Total investment costs can amount to approximately EUR 9.5–15.5 million, and annual operating costs range from EUR 0.7 to 1.3 million. To provide a more transparent breakdown of the investment requirements, Table 2 presents the estimated costs by major system component.

Table 2. Breakdown of Investment Costs by Component.

Component	Estimated Cost (EUR)
Methane drainage station and CMM capture systems	1.5–2.5 million
SMR/ATR modules for hydrogen production	3.0–5.0 million
PSA and DeOxo gas purification modules	1.0–2.0 million
Hydrogen compression and storage systems	1.5–2.0 million
LRDD technology development	2.0–3.0 million
Monitoring and process automation	0.5–1.0 million
Total	9.5–15.5 million

To demonstrate the consistency of the proposed process, a simplified mass and energy balance is presented below. On the mass balance side, considering the inputs and outputs on an annual basis, 2.50 million m^3 of pure methane is allocated to hydrogen production, yielding 700 tons of hydrogen, while an equal stream of 2.50 million m^3 of methane is used for electricity generation, yielding 10,000 MWh of electricity; together these amount to a total methane feed of 5.00 million m^3 per year, which is accompanied by process water consumption for the SMR reaction of approximately 2.25 million kg, and results in CO_2 emissions from process and heat generation of approximately 7000 tons, along with solid carbon and other byproducts as applicable. On the energy balance side, taking methane's lower heating value (LHV) as 9.94 kWh/Nm^3, the methane allocated to hydrogen production contributes 2.50 million $Nm^3 \times 9.94$ kWh/Nm^3 = 24,850 MWh/year, and the methane allocated to electricity generation contributes an identical 24,850 MWh/year, for a total methane energy input of 49,700 MWh/year; on the output side, the 700 tons/year of hydrogen corresponds to an energy content of 700 tons $\times$ 33.33 kWh/kg = 23,300 MWh/year (LHV), which combined with the 10,000 MWh/year of electricity output gives a total useful energy output of 33,300 MWh/year, and dividing this by the total energy input yields an overall energy efficiency of 33,300/49,700 $\approx$ 67%. This simplified balance confirms that the 700 tons/year hydrogen production is consistent with the 2.50 million m^3/year methane feed and the 77.8% conversion efficiency, while the 10,000 MWh/year electricity generation represents a separate methane stream that must be allocated in addition to the hydrogen feed. The mass balance also confirms that the 7000 tons CO_2/year emissions are consistent with the stoichiometry of the SMR reaction, comprising approximately 3822 t CO_2 from the reaction itself plus approximately 3178 t CO_2 from reformer heat generation.

The time required for such an investment, including design, construction, and commissioning, is estimated at 2–4 years, depending on the scale of the installation, location conditions, and regulatory procedures required in a given region [13]. Despite the high initial costs, the proposed solution offers economic benefits that make the project profitable in the medium and long term. A key source of revenue is the sale of hydrogen, with annual production of 700 tons generating potential revenues of EUR 2.5–3.8 million at an average price of 3.6–5.5 EUR/kg [32,40]. Fuel-grade hydrogen is being applied more extensively in the transportation and industrial sectors, increasing its market value. The return on investment in a hydrogen production system can occur in a relatively short time, making this technology highly advantageous from an economic perspective [14,34]. An additional source of revenue, if sold, could be electricity production. Approximately 5000 MWh of electricity can be sold annually, generating revenues of € 0.5–0.6 million at current energy prices (€100–120/MWh). Combustion of methane to produce electricity would result in a payback period of approximately 3.6 years. Captured carbon dioxide, processed into dry ice or other products, can also be sold on the industrial and food markets, generating additional revenues based on the price of food-grade CO_2 (€80–120/t) [7,38,39].

Environmental fees for greenhouse gas emissions, such as methane (CH_4) and carbon dioxide (CO_2), are regulated by the EU Emissions Trading Scheme (EU ETS) and national environmental regulations. Under the EU ETS, the cost of emitting one tonne of CO_2 in 2024 is estimated at around EUR 85–100, which represents a notable financial burden for companies emitting greenhouse gases. In the case of methane, although its emissions are not directly covered by the EU ETS, the EU regulations being implemented to reduce methane emissions in the energy and mining sectors may introduce fees for its emissions in the future, given its high greenhouse gas potential (28 times greater than CO_2) [39,41,42]. For companies operating in the mining sector, this means reducing emissions to avoid high costs. For example, with annual CO_2 emissions of 100,000 tonnes, fees can amount to as much as EUR 8.5–10 million, which motivates companies to invest in emission-reducing technologies, such as methane capture systems or hydrogen conversion plants. Reducing greenhouse gas emissions not only reduces the risk of environmental fees but also increases the competitiveness of enterprises in the market in line with the EU climate targets [39,42,43].

4.3. Case Studies from Coal-Dependent Regions

Coal-dependent regions face enormous challenges related to the necessary energy transition aimed at achieving climate neutrality. Examples of these regions, such as the Ruhr area in Germany and Appalachia in the United States, demonstrate that this transition requires not only technological modernization but also socio-economic measures to minimize the negative impacts on local communities, which should be undertaken while mining operations are still ongoing. Regions heavily dependent on the coal industry, such as Upper Silesia in Poland and Appalachia in the United States, encounter several limitations due to the energy shift. Economic dependence on coal means that mine closures lead to mass unemployment and economic stagnation, as observed in Upper Silesia during the restructuring of heavy industry. The social costs of these changes are considerable. Mine closures cause social tensions, economic migration, and difficulties in reintegrating workers into other sectors of the economy. Additionally, these regions face environmental problems, such as the need to reclaim mining land and manage waste, which pose significant challenges for local communities. Examples related to the transformation are presented below.

The Ruhr region is a model example of the transformation of a region dependent on the coal industry into a highly developed economy based on services and technology. This process was facilitated by coordinated political support, which included extensive investments in education, research, and infrastructure. EU and national programs supporting the creation of technology parks and attracting high-tech investors have played a critical role. Once dominated by mines and steelworks, this region is now a center of innovation, home to advanced laboratories and research institutes such as the Fraunhofer Society. The Ruhr region demonstrates that successful transformation depends on long-term planning and comprehensive socioeconomic support [44,45]. The Appalachian region in the US, known for its long-standing dependence on the coal industry, is undergoing a difficult transformation. While initiatives such as retraining programs for mine workers have been implemented, their overall success has been mixed. Studies indicate that despite significant federal investment, the transition to renewable energy employment has been challenging due to geographic mismatches between job locations and mining communities, differences in skill requirements, and limited economic diversification in the region. Nevertheless, the region has seen some successful demonstration projects, such as the transformation of former mining lands into solar farms and pumped storage hydroelectric facilities [46,47], which highlight the potential for repurposing post-mining infrastructure. These initiatives focus on retraining workers for renewable energy sectors, such as solar panel installation, wind turbine construction, and green technologies. Local initiatives supported by the federal government are pivotal, as they provide access to training, educational funding, and job creation assistance. Appalachia demonstrates that successful transformation requires investment in human capital and a sustainable strategy to support local communities [48]. An analysis of demonstration projects under the Clean Energy Demonstration Program on Current and Former Mine Land demonstrates the potential for transforming former mining lands into clean energy sources. For example, the A Model for Transition: Coal-to-Solar in West Virginia project in Nicholas County, West Virginia, envisions transforming former mining lands into a 250 MW solar farm capable of powering approximately 39,000 homes. This initiative not only promotes renewable energy sources but also creates new jobs by supporting the local economy and offering training programs for coal workers, enabling them to acquire green energy qualifications [49]. Similarly, the Lewis Ridge Pumped Storage Project in Bell County, Kentucky, plans to utilize former coal mine lands to build a pumped-storage hydroelectric power plant, increasing energy supply reliability and supporting the integration of renewable energy sources into the grid. These initiatives emphasize the importance of investing in clean energy infrastructure in post-mining areas, contributing to greenhouse gas emissions reductions, diversifying local economies, and promoting sustainable development [50].

These experiences can serve as a model for other regions around the world, including Poland, where transforming post-mining areas into clean energy production centers can contribute to achieving climate and economic goals.

4.4. Policy and Regulation Framework

Hydrogen policy and regulations are essential in the process of decarbonizing the economy and developing hydrogen-related technologies, providing a foundation for the energy transition and increasing the share of renewable energy sources. They support the implementation of innovative solutions, creating stable and predictable conditions for investors, and ensuring compliance with international standards and climate targets. At both the EU and national levels, these policies aim to build a comprehensive legal framework that supports the development of hydrogen production, transport, and storage infrastructure. According to the International Renewable Energy Agency [44], large-scale hydrogen trade will play a crucial role in achieving the established climate goal. It requires coordinated international policy frameworks, investment in infrastructure, and harmonized certification systems to ensure the environmental integrity of hydrogen supply chains. While the technical potential for green hydrogen production is substantial, costs vary markedly across regions. Regions with superior renewable resources and low development costs possess a competitive advantage, though land and water constraints may limit production. Anticipated growth in hydrogen trade is prompting regulatory measures to ensure compliance with domestic sustainability standards, particularly emissions intensity. The European Union has advanced frameworks in place, whereas other prospective importing markets are still formulating policies, warranting further examination of their eventual implications [44].

The European Union is playing a leading role in promoting the hydrogen economy, introducing core strategies and regulations such as the European Green Deal, the RED II Directive, and the REPowerEU program. The REPowerEU strategy sets an ambitious target of producing 20 Mt of renewable hydrogen by 2030, of which 10 Mt is to be sourced from EU domestic production, and a further 10 Mt is to be imported. Renewable hydrogen, produced through electrolysis using renewable energy, is seen as a key element of the energy transition, supporting the decarbonization of the industrial, transport, and energy sectors [44,45,51].

In Poland, the development of a hydrogen economy is a priority identified in strategic documents such as the Polish Hydrogen Strategy for 2030–2040 [33]. This strategy sets goals for the implementation of hydrogen technologies in major economic sectors and the development of infrastructure for hydrogen production, distribution, and storage. It also envisages the creation of hydrogen valleys and support mechanisms for technological innovation, particularly in the area of green hydrogen production. International cooperation and compliance with EU regulations constitute integral components of these efforts, ensuring access to funding and supporting the integration of hydrogen technologies within the EU single market [33,48].

The legal framework also supports the financing and development of research into hydrogen technologies. Mechanisms such as the Innovation Fund, Horizon Europe, and national research programs enable financing for projects related to the development of hydrogen production, storage, and applications in industry and transport. Regulatory predictability and policy stability are key to attracting investors and creating long-term plans for hydrogen infrastructure development [45,49,50].

The EU legal framework, particularly Horizon Europe, the Innovation Fund, InvestEU, and the Clean Hydrogen Partnership, underpins the financing of hydrogen research, production, storage, and application developments. These mechanisms offer long-term grants, competitive auctions, and private-public co-funding, while regulatory predictability and policy stability are recognized as essential to promoting investment and allowing coherent planning for hydrogen infrastructure deployment.

The proposed solution fits within the policy and regulatory framework supporting the development of hydrogen technologies, emphasizing the importance of the efficient use of hydrogen as an energy carrier in the energy transition. Its main goal is to develop innovative solutions for obtaining and converting methane into hydrogen, which directly supports the decarbonization of industry and the reduction in methane emissions—a high-potential greenhouse gas. The project is consistent with the Polish Hydrogen Strategy [33], which emphasizes the development of hydrogen production and storage infrastructure and supports innovation in the energy and industrial sectors.

5. Discussion

The results of the scenario-based analysis, developed from literature data and project-specific assumptions, indicate significant potential environmental and economic benefits of methane capture and hydrogen production integration in coal mines. By using LRDD technology and advanced SMR methods with carbon capture and storage (CCS), the developed approach enhances methane recovery efficiency and supports the global transition towards low-emission energy sources [52].

LRDD technology has proven to be an effective method of methane drainage in coal mines. The proposed solution will achieve 70% methane capture effectiveness, significantly exceeding the efficiency of conventional methane drainage systems, which operate at 35–50% [20,21]. This increased performance results from the use of extended directional drilling (up to 2000 m), which allows access to deeper gas-bearing formations. Furthermore, optimized drilling layout improves gas flow and reduces gas losses. Real-time monitoring and automatic control also optimize capture capacity and operational safety [17]. The reviewed evidence confirms that modern methane removal methods can significantly reduce methane emissions to the atmosphere, minimizing their impact on climate change while maximizing energy recovery potential [53].

To assess the economic feasibility of the proposed methane-to-hydrogen conversion system, the most relevant quantitative parameters are summarized in Table 3. The table includes technological performance indicators (e.g., methane capture rate, hydrogen yield), energy production, carbon dioxide emissions, and economic indices such as capital costs, operating costs, and return on investment. The techno-economic estimates presented in Table 3 are based on indicative values from literature and technical reports, complemented by project-specific assumptions reflecting Polish mining conditions. This scenario-based approach adapts data from previous studies [11–14,20,21,32,34,39,40] to the context of an integrated methane-to-hydrogen system in coal-dependent regions. This comprehensive review supports the case for industrial implementation of the system in coal-dependent regions.

Table 3. Summary of expected techno-economic parameters of the integrated methane-to-hydrogen system [11–14,20,21,32,34,39,40].

Parameter	Value
Methane capture efficiency (LRDD)	70%
Captured methane volume	5.0 million m^3/year (pure CH_4; 50% to H_2, 50% to electricity)
Hydrogen production capacity	700 tons/year
Energy generation potential	10,000 MWh/year
CO_2 emissions from hydrogen production	≈7000 tons CO_2/year
CO_2 mitigation (with CCS)	up to 30% reduction
Initial investment cost	9.5–15.5 million EUR
Annual operating cost	0.7–1.3 million EUR
Annual hydrogen revenue	2.5–3.8 million EUR
Annual electricity sales revenue	0.5–0.6 million EUR

Methane captured from the rock mass drainage process will be converted into hydrogen via SMR and ATR, achieving an 85% hydrogen production efficiency. Annual hydrogen production was estimated at 700 tons, based on compiled literature data and assumptions. Compared to previous studies [11], where the efficiency of the standard SMR process was in the range of 70–75%, applying CCS in the considered scenario could increase effectiveness by around 10%, while simultaneously reducing CO_2 emissions by 30%. The results obtained indicate that integrating modern methane capture and hydrogen production methods is a more sustainable and economically viable strategy compared to conventional methods of mine methane management.

Implementing an integrated methane capture and hydrogen production system provides several environmental and economic benefits:

- Methane emission reduction—prevents the release of up to 250,000 m^3 of methane per year, corresponding to 6.25 million kg of CO_2 equivalent greenhouse gas emissions.
- Low-carbon energy production—the hydrogen produced has an energy potential of 10,000 MWh per year, which can power industrial processes, transportation, or mining operations.

Further research should focus on optimizing the CO_2 capture process, improving hydrogen storage methods, and analyzing policy mechanisms supporting the large-scale implementation of the technology.

https://doi.org/10.3390/methane5030022

The selection of the final process configuration was directly informed by the bibliographical review. Specifically, LRDD technology was selected because the literature [20,21] demonstrated its superior methane capture efficiency (up to 70%) compared to conventional methods (35–50%), providing the necessary methane supply for downstream conversion. SMR was selected as the preferred hydrogen production technology because the review of hydrogen production technologies [12–14,32,33] highlighted it as the most mature (TRL 9) and cost-effective option for industrial-scale production, with lower hydrogen production costs than ATR or methane pyrolysis. CCS integration was included because the review of carbon management technologies [38,39] demonstrated that CO_2 capture and utilization/sequestration is necessary to align the process with EU climate neutrality goals. Finally, the policy framework review [5,33,44,45] confirmed that the proposed configuration aligns with current EU and Polish regulations and funding mechanisms, supporting its practical feasibility.

The proposed CO_2 management strategy requires critical assessment of technical and market realities. Dry ice production from captured CO_2 is technically feasible but faces challenges: the food-grade CO_2 market is relatively small (estimated at several million tonnes annually in Europe) and requires high purity (>99.5%). The METH2GEN project would need to meet these purity requirements through additional purification steps, which would add to CAPEX and energy consumption. CO_2 injection into coal seams for enhanced coalbed methane recovery (ECBM) has been demonstrated at pilot scale but faces challenges including injectivity limitations, CO_2 breakthrough, and long-term storage integrity. The suitability of Polish coal seams for CO_2 injection would require detailed geological assessment of permeability, adsorption capacity, and sealing integrity. CO_2 transportation would require either pipelines (economically viable for large-scale projects) or truck transport (feasible for smaller volumes but with higher costs and emissions). Long-term storage permanence depends on adsorption capacity, sealing integrity, and site-specific geological conditions, requiring long-term monitoring. These challenges indicate that a diversified CO_2 management strategy combining utilization and sequestration may be the most robust approach in the Polish context.

6. Conclusions

The analysis highlights the crucial role of advanced methane capture and hydrogen conversion technologies in reducing greenhouse gas emissions and supporting the energy transition in coal-dependent regions. Methane, a greenhouse gas with a warming potential 28 times greater than CO_2, poses a significant environmental challenge in the mining industry. The use of LRDD technology allows for increasing methane capture efficiency from 35% to 70%, contributing to significant emissions reductions and improved work safety in mines.

A key component of the proposed solution is the conversion of captured methane to hydrogen using SMR and CCS technology, which not only reduces emissions but also provides a valuable energy resource. Hydrogen production of 700 tons per year, while simultaneously utilizing CO_2 (e.g., for dry ice production), demonstrates the technology's potential as an element of an industrial decarbonization strategy. Integrating modern methane capture and hydrogen production methods into existing mine structures, supported by monitoring and automation systems, can substantially increase the energy and economic effectiveness of the entire process. The projected return on investment, estimated from literature values and project assumptions, suggests that the concept can be both ecologically sound and economically viable.

Further research is recommended into the optimization of LRDD and SMR technologies, the development of effective hydrogen storage methods, and the integration of

https://doi.org/10.3390/methane5030022

solutions with hydrogen and climate policies at the EU and Member State levels. The proposed approach provides a scalable and integrated model for energy transition that can be applied in regions with high methane emissions and developed mining infrastructure.

Converting captured methane into hydrogen using reforming technology may be a crucial element of the energy transition process in mining regions. This solution not only reduces methane emissions, a greenhouse gas with high global warming potential, but also enables the optimal use of hydrogen as a zero-emission energy source. Industrial-scale hydrogen production, especially when combined with carbon capture and utilization or geological storage technologies, supports climate policy and decarbonization goals and fosters the development of a hydrogen economy in areas undergoing the restructuring of the coal industry.

It is important to note that the findings presented in this study are based on a scenario-based techno-economic analysis using literature data and project-specific assumptions from the METH2GEN project. The quantitative results, including hydrogen production capacity, investment costs, and return on investment, are derived from preliminary calculations and should be considered as indicative rather than definitive. Experimental validation, detailed process simulation, and pilot-scale implementation are required to confirm the technical feasibility and economic viability of the proposed system. The results presented here should therefore be considered as preliminary indications of potential rather than confirmed operational outcomes.

Author Contributions: Conceptualization, M.B. and J.C.; methodology, M.B.; software, A.B.; validation, K.Z.-G., A.B. and M.W.; formal analysis, J.C. and M.W.; investigation, K.Z.-G.; resources, A.B.; data curation, M.W.; writing—original draft preparation, A.B. and M.W.; writing—review and editing, K.Z.-G.; visualization, K.Z.-G.; supervision, J.C.; project administration, M.W.; funding acquisition, M.B. All authors have read and agreed to the published version of the manuscript.

Funding: This work is supported by the AGH University of Krakow, Faculty of Civil Engineering and Resource Management (subsidy No. 501.00-100302-10000) and by the project METH2GEN—Methane to Hydrogen: Demonstration of technologies for sustainable energy transition funded by the Research Fund for Coal and Steel (RFCS), Grant Agreement No. 101193747.

Institutional Review Board Statement: Not applicable.

Data Availability Statement: Data is contained within the article.

Conflicts of Interest: The authors declare no conflicts of interest.

Abbreviations

The following abbreviations are used in this manuscript:

AMM	Abandoned Mine Methane
ATR	Autothermal Reforming
CBM	Coalbed Methane
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
CMM	Coal Mine Methane
GWP	Global Warming Potential
LRDD	Long Reach Directional Drilling
PSA	Pressure Swing Adsorption
SMR	Steam Methane Reforming
WGS	Water-Gas Shift
VAM	Ventilation Air Methane

References

1. United Nations Environment Programme; Climate and Clean Air Coalition. *Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions*; United Nations Environment Programme: Nairobi, Kenya, 2021. Available online: https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions (accessed on 28 July 2026).
2. Borowski, M.; Zwolińska-Glądys, K.; Szmuk, A. An analysis of the potential use of methane from hard coal mines in a trigeneration system to reduce emissions into the atmosphere. *Min.—Inform. Autom. Electr. Eng.* **2023**, *61*, 19–30.
3. Singh, U.; Singh, A.K. Improved climate change understanding and projections for coal businesses create urgent need to initiate stronger measures toward coalbed methane in India. *Carbon Manag.* **2018**, *9*, 83–85. [CrossRef]
4. Song, W.; Cheng, J.; Wang, W.; Yi, Q.; Wang, Z.; Borowski, M.; Wang, Y.; Tukkaraja, P. Underground mine gas explosion accidents and prevention techniques—An overview. *Arch. Min. Sci.* **2021**, *66*, 297–312.
5. European Parliament and Council. Regulation (EU) 2024/1787 of the European Parliament and of the Council of 13 June 2024 on the Reduction of Methane Emissions in the Energy Sector and Amending Regulation (EU) 2019/942. *Off. J. Eur. Union* **2024**, *202*, 1–63. [CrossRef]
6. Olczak, M.; Piebalgs, A.; Balcombe, P. A global review of methane policies reveals that only 13% of emissions are covered with unclear effectiveness. *One Earth* **2023**, *6*, 519–535. [CrossRef]
7. Abánades, A.; Rubbia, C.; Salmieri, D.C. Thermal cracking of methane into Hydrogen for a CO_2-free utilization of natural gas. *Int. J. Hydrogen Energy* **2013**, *38*, 8491–8496. [CrossRef]
8. Polish Geological Institute—National Research Institute. *Bilans Zasobów Złóż Kopalin w Polsce wg Stanu na 31 XII 2024 r.*; Polish Geological Institute—National Research Institute: Warsaw, Poland, 2025. (In Polish)
9. Industrial Development Agency. *Informacja o Odmetanowywaniu i Zagospodarowaniu Metanu Pochodzącego z Kopalń Węgla Kamiennego w Polsce*; Industrial Development Agency JSC Branch Office in Katowice: Katowice, Poland, 2024. (In Polish)
10. Borowski, M.; Życzkowski, P.; Cheng, J.; Łuczak, R.; Zwolińska, K. The combustion of methane from hard coal seams in gas engines as a technology leading to reducing greenhouse gas emissions—Electricity prediction using ANN. *Energies* **2020**, *13*, 4429. [CrossRef]
11. Nikolaidis, P.; Poullikkas, A. A Comparative Overview of Hydrogen Production Processes. *Renew. Sustain. Energy Rev.* **2017**, *67*, 597–611. [CrossRef]
12. Dincer, I.; Acar, C. Innovation in hydrogen production. *Renew. Sustain. Energy Rev.* **2017**, *42*, 14843–14864. [CrossRef]
13. Cho, H.H.; Strezov, V.; Evans, T.J. Environmental Impact Assessment of Hydrogen Production via Steam Methane Reforming Based on Emissions Data. *Energy Rep.* **2022**, *8*, 13585–13595. [CrossRef]
14. Jahami, M.; Singh, P.; Khandelwal, B. Life cycle assessment of SMR and Electrified-SMR with renewable energy systems: Projecting emissions and optimizing hydrogen production for California's 2035 goals. *Renew. Energy* **2025**, *243*, 122501. [CrossRef]
15. Shahabuddin, M.; Rhamdhani, M.A.; Brooks, G.A. Technoeconomic Analysis for Green Hydrogen in Terms of Production, Compression, Transportation and Storage Considering the Australian Perspective. *Processes* **2023**, *11*, 2196. [CrossRef]
16. Katebah, M.; Al-Rawashdeh, M.; Linke, P. Analysis of hydrogen production costs in Steam-Methane Reforming considering integration with electrolysis and CO_2 capture. *Clean. Eng. Technol.* **2022**, *10*, 100552. [CrossRef]
17. Borowski, M.; Zwolińska-Glądys, K.; Cheng, J. Methane Emissions from Coal Mines: Quantification, Capture, and Utilization Strategies for Atmospheric Impact Mitigation—A Case Study from Poland. *Atmosphere* **2025**, *16*, 174. [CrossRef]
18. Talkington, C.; Kong, K.P.; Ruiz, F. Achieving Near-Zero Methane Emissions Coal Mining. In *14th Greenhouse Gas Control Technologies Conference Melbourne 21–26 October 2018 (GHGT-14)*; Social Science Research Network: Rochester, NY, USA, 2018. [CrossRef]
19. Koroviaka, Y.; Pinka, J.; Tymchenko, S.; Rastsvietaiev, V.; Astakhov, V.; Dmytruk, O. Elaborating a scheme for mine methane capturing while developing coal gas seams. *Min. Miner. Depos.* **2020**, *14*, 21–27. [CrossRef]
20. Wang, F.; Ren, T.X.; Tu, S.; Hungerford, F.; Aziz, N. Implementation of underground longhole directional drilling technology for greenhouse gas mitigation in Chinese coal mines. *Int. J. Greenh. Gas Control* **2012**, *11*, 290–303. [CrossRef]
21. Leśniak, G.; Brunner, D.J.; Topór, T.; Słota-Valim, M.; Cicha-Szot, R.; Jura, B.; Skiba, J.; Przystolik, A.; Lyddall, B. Application of long-reach directional drilling boreholes for gas drainage of adjacent seams in coal mines with severe geological conditions. *Int. J. Coal Sci. Technol.* **2022**, *9*, 88. [CrossRef]
22. Shi, Z.J.; Zhao, Y.Z.; Qi, H.J.; Liu, J.; Hu, Z. Research and Application of Drilling Technology of Extended-reach Horizontally-intersected Well Used to Extract Coalbed Methane. *Procedia Earth Planet. Sci.* **2011**, *3*, 446–454. [CrossRef]
23. Nawrat, S.; Kuczera, Z.; Łuczak, R.; Życzkowski, P.; Napieraj, S.; Gatnar, K. *Utylizacja Metanu z Pokładów Węgla w Polskich Kopalniach Podziemnych*; Uczelniane Wydawnictwa Naukowo-Dydaktyczne AGH: Kraków, Poland, 2009.
24. Polish Geological Institute—National Research Institute. *Bilans Perspektywicznych Zasobów Kopalin Polski wg Stanu na 31.12.2018 r.*; Polish Geological Institute—National Research Institute: Warsaw, Poland, 2020. (In Polish)

25. Zou, Q.L.; Lin, B.Q.; Zheng, C.S.; Hao, Z.Y.; Zhai, C.; Liu, T.; Liang, J.Y.; Yan, F.Z.; Yang, W.; Zhu, C.J. Novel integrated techniques of drilling-slotting-separation-sealing for enhanced coal bed methane recovery in underground coal mines. *J. Nat. Gas Sci. Eng.* **2015**, *26*, 960–973. [CrossRef]
26. United Nations Economic Commission for Europe (UNECE). *Best Practice Guidance for Effective Management of Coal Mine Methane at National Level: Monitoring, Reporting, Verification and Mitigation*; ECE Energy Series No. 71; United Nations: Geneva, Switzerland, 2021.
27. Lu, Y.; Li, R.; Xian, X.; Xia, B. Discussion on the efficient exploitation method of deep coalbed methane with pressure relief by ground directional well and hydraulic slotting. *J. China Coal. Soc.* **2021**, *46*, 876–884.
28. Islam, M.R.; Hossain, M.E. Chapter 3—Advances in directional drilling. In *Drilling Engineering*; Gulf Professional Publishing: Houston, TX, USA, 2021; pp. 179–316. [CrossRef]
29. Lower Silesian Institute for Energy Studies. *Green Hydrogen from RES in Poland. The Use of Wind and PV Power for the Production of Green Hydrogen as an Opportunity to Implement the Assumptions of the EU Climate and Energy Policy in Poland*; Lower Silesian Institute for Energy Studies, Polish Wind Energy Association: Wrocław, Poland, 2021. Available online: https://dise.org.pl/Report-Green-hydrogen-from-RES.pdf (accessed on 15 May 2025).
30. Maniscalco, M.P.; Longo, S.; Cellura, M.; Miccichè, G.; Ferraro, M. Critical Review of Life Cycle Assessment of Hydrogen Production Pathways. *Environments* **2024**, *11*, 108. [CrossRef]
31. Zahedi, N.M.; Rowshanzamir, S.; Eikani, M.H. Autothermal reforming of methane to synthesis gas: Modeling and simulation. *Int. J. Hydrogen Energy* **2009**, *34*, 1292–1300. [CrossRef]
32. Hren, R.; Vujanović, A.; Van Fan, Y.; Klemeš, J.J.; Krajnc, D.; Čuček, L. Hydrogen production, storage and transport for renewable energy and chemicals: An environmental footprint assessment. *Renew. Sustain. Energy Rev.* **2023**, *173*, 113113. [CrossRef]
33. Ministry of Climate and Environment. *Polish Hydrogen Strategy Until 2030 with an Outlook Until 2040*; Ministry of Climate and Environment: Warsaw, Poland, 2021.
34. Yan, J.; Liu, H.; Dai, Y.; Rong, C. Advancing solar-powered hydrogen generation: A comparative analysis of efficiency, emissions, and economic viability. *Int. J. Hydrogen Energy* **2025**, *131*, 255–272. [CrossRef]
35. Weger, L.; Abánades, A.; Butler, T. Methane cracking as a bridge technology to the hydrogen economy. *Int. J. Hydrogen Energy* **2017**, *42*, 720–731. [CrossRef]
36. Dai, F.; Zhang, S.; Luo, Y.; Wang, K.; Liu, Y.; Ji, X. Recent Progress on Hydrogen-Rich Syngas Production from Coal Gasification. *Processes* **2023**, *11*, 1765. [CrossRef]
37. Bertagni, M.B.; Pacala, S.W.; Paulot, F.; Porporato, A. Risk of the hydrogen economy for atmospheric methane. *Nat. Commun.* **2022**, *13*, 7706. [CrossRef] [PubMed]
38. Prabu, V.; Mallick, N. Coalbed methane with CO_2 sequestration: An emerging clean coal technology in India. *Renew. Sustain. Energy Rev.* **2015**, *50*, 229–244. [CrossRef]
39. Olczak, M.; Piebalgs, A.; Balcombe, P. Methane regulation in the EU: Stakeholder perspectives on MRV and emissions reductions. *Environ. Sci. Policy* **2022**, *137*, 314–322. [CrossRef]
40. Ghisellini, P.; Passaro, R.; Ulgiati, S. Is Green Hydrogen an Environmentally and Socially Sound Solution for Decarbonizing Energy Systems Within a Circular Economy Transition? *Energies* **2025**, *18*, 2769. [CrossRef]
41. Saunois, M.; Stavert, A.R.; Poulter, B.; Bousquet, P.; Canadell, J.G.; Jackson, R.B.; Zhuang, Q. The global methane budget 2000–2017. *Earth Syst. Sci. Data* **2020**, *12*, 1561–1623. [CrossRef]
42. Cael, B.B.; Goodwin, A.P. Global methane pledge versus carbon dioxide emission reduction. *Environ. Res. Lett.* **2023**, *18*, 104015. [CrossRef]
43. Mar, K.A.; Unger, C.; Walderdorff, L.; Butler, T. Beyond CO_2 equivalence: The impacts of methane on climate, ecosystems, and health. *Environ. Sci. Policy* **2022**, *134*, 127–136. [CrossRef]
44. IRENA. *Global Trade in Green Hydrogen Derivatives: Trends in Regulation, Standardisation and Certification*; International Renewable Energy Agency: Abu Dhabi, United Arab Emirates, 2024.
45. Vivanco-Martín, B.; Iranzo, A. Analysis of the European Strategy for Hydrogen: A Comprehensive Review. *Energies* **2023**, *16*, 3866. [CrossRef]
46. Stack, S.; O'Rourke, D. Concentrated declines, distributed growth, and the challenges of balancing the green energy transition in the US. *PLoS Sustain. Transform.* **2026**, *5*, e0000217. [CrossRef]
47. U.S. Department of Energy, Office of Clean Energy Demonstrations. Funding Notice: Clean Energy Demonstration Program on Current and Former Mine Land. Available online: https://www.energy.gov/oced/CEML (accessed on 20 July 2026).
48. Jaradat, M.; Almashaileh, S.; Bendea, C.; Juaidi, A.; Bendea, G.; Bungau, T. Green Hydrogen in Focus: A Review of Production Technologies, Policy Impact, and Market Developments. *Energies* **2024**, *17*, 3992. [CrossRef]
49. Petersen, M.; Hordvei, E.; Hummelen, S.E.; Backe, S.; Andreae, E.; You, S.; Cronin, A.; Mortensen, H.B. The role of financial mechanisms in advancing renewable energy and green hydrogen. *J. Clean. Prod.* **2025**, *519*, 146048. [CrossRef]
50. Jayawardhana, P.; Kiehle, J.; Calò, A.; Pongrácz, E. Hydrogen pipedreams or a new industrial revival: Industrial hydrogen demand by 2030 in Finland and Europe. *Renew. Sustain. Energy Rev.* **2025**, *222*, 115966. [CrossRef]

51. Pandey, G.; Poothia, T.; Kumar, A. Hydrate based carbon capture and sequestration (HBCCS): An innovative approach towards decarbonization. *Appl. Energy* **2022**, *326*, 119900. [CrossRef]
52. Nwe, S.Y.; Kyaw, A.M.T.; Srinophakun, P.; Thanapimmetha, A.; Saisriyoot, M.; Chiarasumran, N. Life cycle assessment on alternative hydrogen production for greener technology. *Sci. Eng. Health Stud.* **2024**, *18*, 24040009. [CrossRef]
53. Jura, B.; Krawczyk, P.; Sliwińska, A.; Skiba, J.; Karbownik, M.; Howaniec, N. Eco-efficiency and life cycle assessment of the long reach directionally drilled and cross-measure boreholes methane drainage technologies employed in bituminous coal mine on the basis of the pilot scale experimental data. *J. Sustain. Min.* **2025**, *24*, 189–202. [CrossRef]