Techno-Economic Analysis of Hydrogen and Ammonia Production in Isolated Microgrids for Sustainable Development

A Dissertation

Submitted to the National Graduate Institute for Policy Studies (GRIPS) in Partial Fulfillment of the Requirements for the Degree of

Ph.D. in Public Policy

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National Graduate Institute for Policy Studies

September 2024

Keywords

Isolated microgrids, Thermal load, Reformer, Electrolyzer, Hybrid renewable, Gas prices, Hydrogen, Ammonia.

Abstract

Sustainable economic development strategies aim to achieve a balance among environmental protection, social equity, and economic growth, thereby promoting long-term climate resilience and overall well-being. This research endeavors to devise frameworks and approaches for hydrogen and ammonia production within hybrid renewable isolated grids. The ultimate goal is to enhance efficiency and make a substantial contribution to sustainable development.

Firstly, we conduct a thorough techno-economic and environmental analysis of a hybrid renewable energy system (HRES) isolated microgrid comprising solar photovoltaics (PV), wind units, battery storage, microturbines, and steam reformers for grey hydrogen production. We formulate a thermodynamic model to supply the necessary heat for steam methane reforming (SMR) through combined heat and power (CHP), gas, electric, and hybrid boiler systems. The analysis examines the effect of thermal sources on the isolated grid net present cost (NPC), CO2 emissions, and optimal dispatch, with and without considering CO2 penalty costs. Using an isolated microgrid in East Owienat, Egypt. We find that the levelized cost of hydrogen (LCOH) ranges from 2.1 to 2.8 \$/kg. The CHP boiler system exhibits the lowest NPC and levelized cost of hydrogen (LCOH), even after considering CO2 penalty costs.

Secondly, we undertake an economic analysis of an HRES isolated microgrid that produces green and grey ammonia by integrating, wind units, battery storage, microturbines with electrolyzer and steam reformer. The study assesses the economic feasibility of green and grey ammonia production considering seasonal gas price fluctuation. We apply two gas prices reflecting off-peak and peak gas demand seasons, adopting three systems with different ammonia storage strategies. This approach aims to minimize ammonia production during peak demand while increasing production and using storage during off peak demand. We evaluate the influence of gas price fluctuations on the grid's NPC and the levelized cost of ammonia (LCOA) across these systems. Using an isolated microgrid in East Owienat, we conclude that at a low gas price difference, resorting to an electrolyzer supported by surplus energy for storing ammonia in the second system is preferable, while at a high gas price

difference, eliminating the electrolyzer and increasing the reformer capacity for storing ammonia is more efficient.

Our study offers insights into the potential of efficiently utilizing resources and reducing emissions.

Acknowledgements

Completing this Ph.D thesis has been a challenging yet deeply rewarding journey. I am grateful for the support and guidance I have received from many individuals and institutions. First and foremost, I would like to express my sincere gratitude to my main supervisor, Prof. Makoto Tanaka, for his continuous support, patience, and immense knowledge. His guidance has been invaluable, from the initial stages of formulating the research questions to the final steps of writing the thesis. I would also like to thank my sub-advisors, Prof. Hisanori Nei, Prof. Michiko Iizuka, and Prof. Sumikura Koichi for their insightful feedback and encouragement throughout my research.

I extend my appreciation, to the administrative staff at the National Graduate Institute for Policy Studies for their help with the administrative aspects of my research.

I express my deepest gratitude to

Eng. Gaber Desouki: The chairman of the Egyptian Electricity Holding Company & Dr. Ahmed Mohamed Mohina: The First Undersecretary of Research, Planning, and Authorities Follow-up of Egypt, for facilitating my study requirements in Japan.

I am deeply grateful for the financial support provided by JICA, which made this research possible.

Finally, I would like to express my heartfelt gratitude to my family and friends. To my parents, for their unwavering support and encouragement.

This thesis is a testament to the collective support and encouragement of all these individuals, and I am deeply thankful for their contributions.

Research output

Publications

Mishref, M. M., & Tanaka, M. (2024). Techno-economic and environmental analysis of heat sources for steam methane reforming in microgrids. *International Journal of Hydrogen Energy*, 53, 1387-1395. https://doi.org/10.1016/j.ijhydene.2023.11.355

Presentation in academic conferences

- Optimal Hybrid Renewable Combination For cost and emission minimization of Mini-grids. Presentation: IAEE-43 conference at National Graduate Institute for Policy Studies, Tokyo.
- Optimal planning and operation of isolated micro-grid for sustainable development-Presentation: IAEE-44 conference at King Abdullah Petroleum Studies and Research Center, Riyadh.

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List of Abbreviations

HRES	Hybrid Renewable Energy System
SMR	Steam Methane Reforming
CHP	Combined Heat and Power
NPC	Net Present Cost
CO2	Carbon Dioxide
LCOH	Levelized Cost of Hydrogen
PV	Photovoltaic
LCOA	Levelized Cost of Ammonia
UNESCO	United Nations Educational, Scientific and Cultural Organization
SDGS	Sustainable Development Goals
UNDP	United Nations Development Programme
FCEV	Fuel Cells Powering Electric Vehicles
BEV	Battery-Electric Vehicles
CCS	Carbon Capture and Storage
GHG	Greenhouse Gas Emissions
FCH J.U	Fuel Cell and Hydrogen Joint undertaking
R&D	Research and Development
IEA	International Energy Agency
HB	Haber Bosh
IRENA	International Renewable Energy Agency
NZE	Net Zero Emission
MG	Microgrid
LNG	Liquified Natural Gas
kWh	Kilowatt hour
BAU	Business-as-Usual

EEHC	Egyptian Electricity Holding Company
GW	Gigawatt
SAS	Sustainable African Scenario
PEM	Proton Exchange Membreane
AE	Alkine Elecrolyzer
SOEC	Solid Oxide Electrolyzer Cell
GDP	Gross Domestic Product
EAPIC	East Africa Power Industry Conversion
SOFC	Planner Oxide Fuel Cell
fyDOM	Finite Volume Discrete Oriented Method
ISCCS	Integrated Solar Combined Cycle System
LCOE	Levelized Cost of Energy
CAPEX	Capital Expenditures
OPEX	Operating Expenditure
P2G	The Power-to-Gas
BTU	British Thermal Unit
GJ	Giga joule
CSP	Concentrated Solar Thermal
EEX	European Energy Exchange
TTF	Title Transfer Facility
GOG	Gas-on-Gas Competition Mechanism
MMT	Million Metric Tons
VOC	Volatile Organic Compounds
GGFR	Global Gas Flaring Reduction public-private partnership

List of Symbols

NH_3	Ammonia
O_2	Oxygen
N_2	Nitrogen
H_2	Hydrogen
NO	Nitrogen Oxide
CO	Carbon Monoxide
CH_4	Methane
ΔH°,	Enthalpy Change
C	Capital Cost,
R	Replacement Cost
O&M	Operation and Maintenance Cost
S	Salvage Costs.
SO_2	Sulfur Dioxide
NO_x	Nitrogen Oxides

Chapter 1: Introduction

1.1 Background

The concept of sustainable development encompasses a long-term vision of a more sustainable world, while sustainability itself is a normative concept. United Nations Educational, Scientific and Cultural Organization (UNESCO) distinguishes between them by reviewing sustainability as the ultimate goal, while sustainable development involves the various processes and pathways to achieve that goal (UNESCO, 2015). Sustainable Development Goals (SDGs) comprise frameworks that emphasize climate action as a key objective alongside social, economic, and environmental objectives. These inclusive strategies guarantee that climate mitigation efforts align with broader development objectives (UNDP, n.d).

Technology plays a vital role in providing solutions to the climate crisis, offering pathways for mitigation, adaptation, and sustainability. This transition involves shifting energy production and consumption towards renewable sources such as solar, wind, hydroelectric, and geothermal power, which generate electricity without emitting greenhouse gases (Wang et al., 2021). Additionally technological innovations in energy efficiency (Trianni et al., 2014), Electric vehicles (Greene et al., 2020), Carbon capture and storage (CCS) (Wang et al., 2021), Climate Modeling and Monitoring, Nature-based solutions (Chrysoulakis et al., 2021), smart grids (Delfino et al., 2018), climate adaptation (Abbass et al., 2022), circular economy (Reindle et al., 2024) Hydrogen and ammonia (IRENA, 2022c) play a pivotal role in mitigating the climate crisis.

1.1.1 The role of hydrogen and ammonia for sustainable economy

Hydrogen is the simplest and lightest element. It is a colorless, odorless, and tasteless gas under standard conditions (Najjar., 2013). Hydrogen offers a sustainable alternative to fossil fuels, particularly in hydrogen fuel cells powering electric vehicles (FCEVs), providing zero-emission transportation with superior range and refueling convenience compared to battery-electric vehicles (BEVs) (Fakhreddine et al., 2023). Furthermore, hydrogen is a valuable energy storage medium for renewable sources such as solar and wind power, capable of enhancing the energy supply-demand balance (Liu et al., 2023). Hydrogen's industrial utility spans heating for buildings, water, and industrial processes CHP and power generation (Nyangon and Darekar, 2024). Hydrogen can play a pivotal role as a feedstock in processes such as petroleum refining and chemical synthesis, yielding essential products such as ammonia for fertilizers and methanol for various industries (Manna et al., 2021). Transportation and heating sectors are responsible for over 25% of global greenhouse gas emissions (GHG) and pose significant challenges to decarbonization efforts (Rüdisüli et al., 2022). Hydrogen stands out as one of the rare energy carriers capable of meeting the energy demands of heavy-duty transport with nearly zero emissions (Greene et al., 2020). Even in challenging-to-decarbonize sectors like long-haul freight transport, hydrogen emerges as one of the few feasible clean alternatives (FCH J.U, 2019). Future projections anticipate the widespread adoption of technologies that depend on hydrogen (Narula et al., 2019). However, for these approaches to effectively reduce carbon emissions, it is crucial to ensure that the entire supply chain for electricity and hydrogen – from production to utilization – maintains low carbon intensity (Rüdisüli et al., 2019; Brey, 2021).

Hydrogen is typically produced in established forms, the most famous are green, grey and blue hydrogen. Green hydrogen refers to hydrogen gas that is produced using renewable energy sources such as solar, wind, and hydropower through the electrolysis process**:** it is a clean energy source. Grey hydrogen is produced via a SMR: This process involves reacting steam with natural gas (methane) in the presence of a catalyst, it yields CO2 emissions as a byproduct. Blue hydrogen is produced from fossil fuels of natural gas, with carbon capture and storage (CCS) technologies, it offers lower emissions compared to grey hydrogen by capturing and storing CO2 (Ji and Wang, 2021). Grey hydrogen stands as the most prevalent due to the comparatively high costs associated with green hydrogen and the technical complexities surrounding CCS in blue hydrogen (Ajanovic et al., 2022). Most of the hydrogen used currently is grey, accounting for around 90 million tons per annum (Mtpa) (Gulli et al., 2024).

Hydrogen utilization typically necessitates extensive long-term planning to provide a comprehensive analysis of the role of hydrogen and its supply chains at various scales and for different end uses. This analysis encompasses the microeconomic level, focusing on individual facilities such as hydrogen stations and refinery enterprises (Gokcek and Kale, 2018), and the macroeconomic level, examining its long-term impact on the entire economy (Ozawa et al., 2018).

The growing interest in national hydrogen strategies and policies worldwide can be attributed to the numerous advantages of shifting towards an economy powered by hydrogen. These strategies outline a nation's approach to harnessing the potential of hydrogen across different sectors and play a crucial role in stimulating investment, technology development. (Raksha et al., 2020). Hydrogen technologies have garnered substantial attention and investment in research and development (R&D) long before the adoption of national hydrogen strategies. Examples of pioneering initiatives include South Korea's National R&D Program, emphasized by Yoo and Park (2023), and Germany's National Innovation Program for Hydrogen and FuelCell Technology, managed by Projektträger Jülich (2023). This sustained R&D effort has led to notable progress and increased recognition of hydrogen technologies, as evidenced by the surge in publications, patents, and standardization activities related to hydrogen (Ashari and Blind, 2024).

The relationship between economic development and climate change is complex, requiring a balanced approach that promotes sustainable growth, reduces emissions, fosters innovation, and enhances resilience to climate impacts. Many countries have set net-zero emission targets as part of their efforts to decarbonize the economy, primarily through the use of green hydrogen technologies that have a high cost (IEA, 2021d). However, the economic disparities between countries can lead to variations in achieving these targets. For instance, countries with rapid economic development, like China, may experience delays in transitioning to net-zero emissions, extending their target timeline to 2060. They are using other means to reduce greenhouse gas emissions such as carbon taxes, emission trading systems, or technological innovations (Zhang and Chen, 2022). These tools may be effective in bridging the gap between economic development and environmental sustainability.

Ammonia (NH_3) is a colorless gas noted for its distinctive pungent odor and lighter-than-air properties (Zhang et al., 2020). Its unique characteristics make it highly versatile across various industrial applications. Particularly noteworthy is its high density, which positions it as a highly efficient energy carrier (Del Pozo and Cloete, 2022). It is easy to convert ammonia to a liquified state followed by compression to become readily transportable at a reduced cost compared to hydrogen (Andriani and Bicer, 2023). Importing ammonia as a hydrogen carrier emerges as a critical strategy for many nations grappling with energy sources deficit in achieving their net-zero emission targets (Aziz et al., 2020). Low transportation, costs render ammonia as a viable option as a hydrogen carrier for long-distance (The Royal Society, 2020). German-Australian joint research found that transporting ammonia over 20,000 km from Australia to Germany is less expensive where the transporting cost of ammonia is 0.030 AU$ per ton-km, while hydrogen is 0.090 AU$ per ton-km (Daiyan et al., 2021). However, a notable challenge arises from the losses incurred during the reconversion process from ammonia to hydrogen, typically between 13 and 34% (IRENA, 2022b). Harnessing ammonia directly in specific sectors such as fertilizer production and bunkering present significant opportunities for energy savings (IRENA, 2022b).

Approximately 70% of the ammonia produced is utilized in agriculture, while the remainder finds application in various other industrial sectors such as plastic manufacturing, explosives production, refrigerant use, and fuel for internal combustion engines (IEA, 2021c). Ammonia is used as fertilizer in various forms, including salts, solutions, and anhydrous variants (Saabas et al., 2022). It holds the distinction of having the highest nitrogen content among all commercial fertilizers, with anhydrous NH_3 containing 82% nitrogen (Havlin et al., 1999).

The Haber-Bosch (HB) process is the predominant industrial method for ammonia production. It employs an iron metal catalyst to facilitate the conversion of atmospheric nitrogen (N_2) into ammonia through a reaction with hydrogen (H_2) under high temperatures and pressures (Xiao et al., 2022; Armijo & Philibert, 2020). The reaction is exothermic exhibiting an enthalpy change of -92 kJ/mol. It operates within a pressure range of 150 to 350 bar and temperatures between 350 and 550 degrees Celsius. These conditions are necessary to overcome the reaction's activation energy barrier of 225 kJ/mol (Kyriakou et al., 2020).

Ammonia is typically classified based on the HB's process hydrogen source. Previous studies have mostly focused on green ammonia derived from renewable energy, and blue and grey ammonia from natural gas (Oh et al., 2024). Ammonia production from fossil fuels remains widespread due to the relatively high cost of green ammonia (Wang et al., 2023). The current ammonia market, responsible for 1.3% of global CO2 emissions (450 Mt) (IEA, 2021c), has an annual production capacity of approximately 175 million tons (MacFarlane et al., 2020). The global demand for ammonia is projected to reach 700 Mt per annum by 2050, aligning with the 1.5° C scenario (IRENA, 2022a). However, replacing the current fossil-fuel ammonia would necessitate 1750 TWh of renewable electricity (approximately 10 MWh per ton NH3) (IRENA, 2022a).

Sustainable development encompasses more than just reducing emissions; it also considers cost as a critical factor. While ambitious goals exist for achieving net-zero emissions and fully decarbonizing sectors using hydrogen and ammonia, the journey to these objectives requires substantial efforts. Achieving total transformation to a Net Zero Emission (NZE) economy is still in its early stages and may not be realized immediately. However, it's important to note that we lack clear evidence indicating that a transition to a net-zero emission economy is achievable. The ongoing advancements in technology, policy frameworks, and societal awareness are paving the way for significant progress in sustainability initiatives. Therefore, while challenges remain, there is optimism that with continued dedication and innovation, the vision of a net-zero emission economy can become a reality.

1.1.2 The role of HRES microgrids with access to gas resources for sustainable development

The concept of an HRES microgrid entails a self-contained electrical power system that encompasses a limited number of distributed energy resources. It can include renewable and conventional sources, such as PV, wind turbines, hydroelectric generators, and internal combustion engines (Hassan et al., 2023a). They typically serve a cluster of loads, providing electricity to a specific area or community. For many, microgrids represent a promising solution for achieving greater energy independence, sustainability, and resilience (Mariam. et al., 2013). Despite the growing need to curb CO_2 emissions, the intermittent nature of renewable energy sources limits the isolated microgrids reliability (Parhizi et al., 2015). The intermittency of renewable energy sources of solar and wind power underscores the importance of considering backup storage systems (Koohi-Fayegh and Rosen, 2020). However, maintaining reliability in off-grid systems poses a challenge, especially concerning the oversizing of renewable energy components, and storage capacity (Malheiro et al., 2015; Odou et al., 2020). Hybrid energy systems composed of renewable and nonrenewable sources for electricity generation can enhance the reliability of isolated microgrids by incorporating active backup generators such as diesel, microturbines, and fuel cells (Granovskii et al., 2007; Hassan et al., 2023a). Hybrid renewable energy systems that combine renewable and non-renewable energy sources offer a promising solution to reduce the levelized cost of energy (LCOE) for isolated grids (Malheiro et al., 2015). Malheiro et al. (2015) reported that incorporating a diesel generator as a backup energy source for an isolated grid can reduce the required size of battery storage. They found that without using diesel, the battery storage size is three times larger. Using a diesel generator as a backup source for an isolated grid reduced the required battery size by 70% compared to a scenario without it (Odou et al., 2020).

More than 13% of the global population lives in remote areas, principally in sub-Saharan Africa and Asia (Ninad et al., 2020). Approximately 622 million people lack access to electricity in Africa. Out of this substantial population, the majority, of 621 million individuals, reside in Sub-Saharan Africa, while approximately 1 million people are from Northern Africa (IEA, 2019c). In the Egyptian context, approximately 167,000 individuals are grappling with power outages or lack of access to electricity (NREA, 2015). Linking the main electric grids to remote locations with low population densities is challenging because of the high associated costs. Remote locations contribute significantly to global carbon emissions because diesel is typically used for power generation (Vera et al., 2020). The global direction is to adopt microgrids and mini-grids as a key solution to address the climate crisis and achieve sustainable development in isolated locations (Chowdhury et al., 2009). Sub-Saharan Africa's power generation capacity is notably lower than any other region. While other developing regions such as Latin America, the Caribbean, Eastern Asia and the Pacific, the Middle East, North Africa, and Southern Asia have experienced notable growth in their power capacity, Sub-Saharan Africa's growth has stagnated. The lack of access to electricity in sub-Saharan Africa hampers economic development, restricts educational opportunities, and compromises healthcare services. (Bazilian et al., 2011).

Many studies have investigated the importance of isolated grids for rural electrification. E.g., electrifying rural areas using microgrids can be a game-changer, fostering industrial and agricultural growth, and creating income opportunities (Azoumah et al, 2011). Microgrids have brought several economic benefits, and improved operating efficiencies for utility companies (Zeng, 2021). Microgrid solar investment and manufacturing in Sub-Saharan Africa have created plenty of job opportunities (IEA, 2019c). Microgrids in Sub-Saharan Africa can lead to substantial reductions in transmission and distribution losses, particularly significant given the challenges posed by aging infrastructure in the region. The standard of transmission and distribution losses globally is around 6-8% of generated energy, but in Sub-Saharan Africa, this figure can be as high as 15%. (Siemens, 2011).

HRES-isolated microgrids with access to onshore gas resources can produce green and grey hydrogen and ammonia. Africa has bountiful solar irradiance resources, distributed fairly uniformly, over 85% of the lands with an average of about 2000 kWh/ (m2 year) (Trieb, 2005). The continent has a theoretical reserve of more than 60 MTWh/year of solar energy, accounting for approximately 40% of the global total (Liu, 2015). Two-thirds of African wind potential is located in areas with an average wind speed of around 7.5 meters per second. This represents the ideal working conditions for wind turbines. The technical wind potential in Africa is 180000 terawatt-hours per year, sufficient to meet the continent's electric power needs 250 times (World Bank 2021). Notably, countries like Ethiopia, Kenya, Senegal, and South Africa are expected to lead the expansion of wind energy capacity (IEA, 2019 c). Regarding gas resources, Africa produces 6% of global gas, with the expectation to increase in the future due to increasing demand (KPMG, n.d). Between 2010 to 2020, Africa accounted for 40% of global gas discoveries, the majority were in Mozambique, Tanzania, Senegal, Mauritania, Egypt, and South Africa. This contributed to a 20% increase in natural gas production in sub-Saharan Africa (IEA, 2022c). However, the growth in gas production surpasses the increase in demand, positioning Africa led by countries like Mozambique and Egypt as a significant supplier of liquefied natural gas (LNG) to global markets. The projected increase in the share of gas in Africa's energy mix represents a significant shift in the continent's energy landscape. As energy demand continues to rise with economic growth and urbanization, natural gas is increasingly seen as a crucial component in meeting these energy needs while also reducing reliance on more polluting fuels like coal and oil (IEA, 2019 c).

As previously mentioned HRESs are more reliable and economically viable compared to using renewables with battery storage as a backup energy source. Additionally natural gas is the most environmentally friendly fossil fuel since it emits less than 50 to 60% CO_2 emissions than oil and coal (MET, 2023). It is a part of the solution for achieving sustainable development goals by lifting people out of poverty, creating jobs, mitigating deforestation, and integrating with renewable energy to support resilience. Moreover, using gas reduces pollution in coal-dependent areas and aids the transition to a low-carbon economy. (Hamel, 2023). Safari et al. (2019) argued that natural gas is an indispensable complementary fuel to support renewable energy in short-term and mid-term applications. They also argued that it has an important role in providing a low-carbon innovation industry for renewable energy. Therefore, HRES with access to diverse onshore gas resources is an affordable and reliable approach that could achieve sustainable development in isolated grids.

1.1.3 Egypt energy sector overview

Egypt has a rich variety of energy resources in good supply encompassing conventional and renewable energy. This diverse energy portfolio not only enhances the country's energy self-sufficiency but also drives its economic advancement. According to the Egyptian New Renewable Energy Authority (NREA, 2021) report, Egypt resides within the sunbelt, receiving annual direct solar radiation in the range of 2,000 to 3,200 kWh/m2/year. The country revels in an average of 9-11 hours of sunshine per day, spanning from north to south, occasionally interrupted by cloudy days amidst its radiant skies. The wind speed varies across different regions and seasons. The Gulf of Suez and the Red Sea coast are highly promising sites for wind energy production, with average wind speeds ranging from 8 to 10 meters per second. The unique geography of the area, with its narrow channel between the Sinai Peninsula and the Egyptian mainland, further enhances its potential for wind power production. Typically, the prevailing winds blow from the north in the summer months, while in the winter, they tend to come from the northeast. These winds are quite strong at times, making the Gulf of Suez a favorable location for wind energy generation. Egypt is distinguished as one of the few nations that have compiled and published an atlas detailing their solar and wind energy resources (NREA, 2021; Salah et al., 2022). Egypt ranks as the third-largest gas producer in Africa, boasting a gas reserve of 2,209 billion cubic meters, it is the largest non-OPEC oil producer, with an oil reserve of 3.3 billion barrels (IEA, 2021b; Aliyu et al., 2018).

Recent advancements in gas production, notably with the discovery of new reserves in the Mediterranean Sea. For example, the Zuhr field, has bolstered production to 66.6 cubic meters. This surplus has allowed Egypt to address its domestic demand, providing the luxury of working in a business-as-usual (BAU) situation, while also facilitating gas exports (Esily et al., 2022). According to the International Energy Agency (IEA, 2021b) Egypt's total primary energy supply reached 3,674,061 TJ, with the majority, approximately 92%, sourced oil and gas (EEHC, 2021). Natural gas consumption in Egypt is divided into four main sectors: power generation, non-energy use, residential, and transportation. Power generation is the largest consumer, accounting for 62% of the total consumption (IEA, 2021b). Oil contributes 35% to Egypt's total primary energy supply. Its peak production occurred in 1996, but it has since declined due to a lack of discoveries (EEHC, 2021).

Egypt has committed to combatting the climate crisis by signing the Paris Agreement, aiming to limit the global average temperature increase to 1.5°C. Despite its relatively low contribution to global CO2 emissions, accounting for approximately 0.6% (250 million tons) annually, Egypt remains one of the most highly vulnerable nations to the impacts of climate change (Abdallah and El-Shennawy, 2020). The economic situation in Egypt following the 2011 and 2013 revolutions was characterized by considerable challenges until the presidential elections in 2014. These challenges had a notable adverse impact on the energy sector, which experienced severe shortages in energy supply.

In 2015, after the stabilization of the political situation, energy authorities embarked on a comprehensive plan to reform the energy sector. Their top priorities were to ensure a stable electric power supply and to achieve sustainable development. The reform path has encompassed several dimensions, including improving the efficiency of existing capacity, enhancing transmission and distribution networks, increasing (Renewable and combined cycle) generation, and phasing out low-efficiency power stations (EEHC, 2021). After six years of extensive work, by the end of 2021, the total installed capacity has reached 59 GW, of which 6.3 GW (11%) came from renewables. This included 2.8 GW from hydropower, 2.528 GW from solar power, and 2.800 GW from wind power (NREA, 2021). For example, The Benban solar complex is one of the largest installations in the world, with a total capacity of 1,465 MW (Abubakr et al., 2022). Egypt is ranked thirty-first in solar generation (IRENA, 2021).

Based on the maximum recorded load in 2022, Egypt achieved self-sufficiency in its electric power supply, with a spare capacity of around 25 GW (Egypt era, 2022). Egyptian energy demand is increasing by 2% per year (Egypt Era, 2022), while economic growth rose from 1.8% to 5.6% in 2019 (World Bank, 2018). The government plans to increase the generation capacity of clean energy, targeting 42% of the total energy mix. This goal will be achieved by adding nuclear generation and increasing the contribution of renewable energy. By the end of 2030, nuclear energy will account for 3% (4,800 MW) of the total capacity, PV will contribute 22%, concentrated solar power (CSP) 4%, and wind power 14% (NREA, 2021). Since nuclear power is an energy source that not only used for electric power generation, it will also be utilized for water desalination and potentially for hydrogen production. Egypt aims to achieve an 8% share of global green hydrogen production (Esily et al., 2022).

Notably, prioritizing combined cycle generation for reforming the Egyptian power sector could create controversy, especially considering the European Union's recent policy to curve dependency on Russian oil and gas, and rapidly expanding renewable capacity (EU, 2022; IEA, 2022b). This policy emerged from the geopolitical ramifications of the conflict between Russia and Ukraine, which undermined the EU's imports of gas and oil from Russia. However, the two contexts are different. Egypt prioritizes grid resilience and reliability by means of high-inertia generation of combined cycle capacity. This approach ensures that the grid can later accommodate the intermittent nature and low inertia of the added renewable capacity, without destabilizing the entire grid. In contrast, the EU benefits from its unified grid that contains a fleet of nuclear reactors, advanced technology, and various ancillary services that maintain the integrity, rigidity, and stability of its transmission and distribution networks. Consequently, the urgent addition of PV and wind capacity is more feasible and effective for the EU case.

1.1.4 Africa energy sector outlook overview

According to the International Energy Agency, in the Sustainable African Scenario (SAS), Africa's modern primary energy supply is projected to increase by 3% annually between 2020 and 2030, while traditional primary energy supply is expected to fall by 13% by 2030. Despite efforts towards involving clean energy, oil and gas will dominate energy use in North Africa, coal will be predominant in South Africa, while in contrast, renewables will lead in sub-Saharan Africa. The share of oil and gas in the primary energy supply in North Africa is projected to decrease from 91% in 2020 to 85% by 2030, driven by a 4% increase in renewable energy capacity. In South Africa, renewables will replace the majority of phased-out coal, while natural gas will gradually increase its share in the energy supply in sub-Saharan Africa.

The energy demand is significantly changing across three different regions. Car ownership in North Africa is ten times higher than in sub-Saharan Africa, so energy consumption will continue to be led by the transport sector. In South Africa, the industrial sector remains dominant, accounting for around 40% of total final consumption. In sub-Saharan Africa, the household sector currently dominates energy consumption. Between 2020 and 2030, the demand for fossil fuels in Africa is expected to increase, except for coal. About 80% of the oil demand increase will be from the mobility of cars and trucks. Electricity use is projected to increase in all sectors, especially in households, which represent half of the growth due to increased efforts for energy access. Consequently, electricity use per capita will rise by 40%, compared to one-quarter of other developing countries and emerging markets. The demand for household coal is expected to be phased out, while industrial gas demand is on the rise.

Many African countries can produce electricity using their domestic energy sources. Natural gas is the largest contributor, accounting for 40% of total power generation, followed by coal. Gas generation is mainly existing in North Africa, while coal is predominant in South Africa. Many African companies rely on backup diesel generators, which greatly increase operating costs and undermine energy efficiency. In sub-Saharan Africa alone, this capacity amounted to 45 GW in 2021, more than all the renewables-based generating in the region, of this, 13 GW is in Nigeria, where 40% of the total electricity is auto-generated by industrial commercial firms and households using oil products. However, by 2030 PV and wind are projected to be eight times their 2020 levels. Sub-Saharan Africa has the highest share of renewable energy, particularly PV and hydropower, expected to reach 50% by 2030. Oil-based generation is expected to increase slightly as it is typically used in small-scale applications, such as diesel generators for residential loads. Natural gas will remain the dominant source of electric power generation in North Africa by 2030. PV in Africa increased in 2019, mostly due to the added capacity of the Egyptian Benban mega PV plant (1.465 GW), however, the solar contribution is only 1% of the global PV installed capacity. The future projection is to increase PV to 45%, replacing existing coal power generation, with the expectation to reach 120 GW, representing 40% of the continent's total increased capacity. Wind is also expanding, especially in North and East Africa. The total generation capacity in Africa is expected to double from 260 GW in 2020 to 510 GW in 2030, with most of the new capacity coming from clean energy sources, particularly PV and hydropower. Sub-Saharan African countries have scaled back their future coal production from 50 GW to 26 GW. Additionally, eight countries—Morocco, Egypt, Angola, Ethiopia, Mauritania, Somalia, Mauritius, and Zambia—have committed to ending any new power generation projects based on coal-fired power plants (IEA, 2022c).

1.1.5 The steam methane reforming process

SMR is a process that involves the reaction of methane (natural gas) with steam to generate a mixture of hydrogen and carbon monoxide, known as syngas, which can be further processed for various industrial applications. It requires significant energy input, primarily in the form of heat, to drive the reaction between methane and steam. The process typically operates at temperatures ranging from 200°C to 1100°C to facilitate the chemical reaction. It uses catalysts, to enhance the reaction rate and efficiency of hydrogen production. Efficient heat exchange systems are often used to maximize energy efficiency. SMR is one of the most common methods for large-scale production of hydrogen used in industries such as refineries, chemical processing, and ammonia production (He and Li, 2014; Wang et al., 2019).

The primary drawback of SMR is the generation of CO2 as a byproduct, which contributes to greenhouse gas emissions unless captured and sequestered using CCS technologies (De Falco et al., 2014). Implementing CCS technologies to mitigate CO2 emissions from SMR adds complexity, cost, and technical challenges to the process (Oh et al., 2024). The heat source for supplying the SMR process often be from non-renewable sources, leading to environmental concerns and high operating costs. The efficiency and performance of SMR are sensitive to the type and quality of catalysts used (Cetinkaya et al., 2012; He & Li, 2014). Catalyst degradation and fouling can reduce the effectiveness of the process and require frequent catalyst replacement (Zhang et al., 2022).

1.1.6 The electrolysis process

Electrolysis processes involve using electrical energy to drive a non-spontaneous chemical reaction, typically used for producing hydrogen or other chemicals. Water electrolysis is the most common form, where water (H2O) is split into hydrogen (H2) and oxygen (O2) using an electrolyzer (El-Shafie, 2023). Hydrogen production through electrolysis is still in its early stages and currently represents only 2% of global hydrogen production (IEA, 2019b).

The electrolyzers have many types the most common are:

Proton exchange membrane (PEM) electrolyzer: uses a solid polymer electrolyte membrane to separate the hydrogen and oxygen produced (Sin et al., 2024).

Alkaline electrolyzer (AE): operates in an alkaline environment and uses potassium hydroxide as the electrolyte (Kumar and Lim., 2022).

Solid oxide electrolyzer cell (SOEC): Operates at high temperatures and is capable of directly converting CO2 to CO and O2 (Kumar and Lim., 2022).

Electrolyzers produce hydrogen using electricity, often from renewable energy sources like PV or wind power. This process generates hydrogen without greenhouse gas emissions, making it a contributor to cleaner energy production. Electrolyzers allow excess renewable energy to be stored as hydrogen. This stored volume can be converted back to electricity through fuel cells or used directly in various applications when demand exceeds supply, enhancing energy system flexibility and stability (Ikuerowo et al., 2024).

While electrolysis is a valuable method for hydrogen production, it faces certain challenges. Electrolysis is an energy-intensive process, as it requires a significant amount of electricity to split water molecules into hydrogen and oxygen. This energy demand can be a limiting factor, especially when considering the source of electricity used, which may contribute to carbon emissions if derived from non-renewable sources. Typically, renewable facilities support electrolyzers using surplus energy from PV and wind to leverage the waste energy. However, directly supporting the electrolysis process using renewable energy sources that have a low-capacity factor necessitates additional renewable units, increasing the overall cost of hydrogen production (Yerga et al., 2009; Song et al., 2022b). The cost of electrolysis equipment, particularly for advanced electrolyzer technologies like PEM is high (IRENA, 2020). Electrolysis processes are not always highly efficient in converting electric energy into hydrogen, some energy is lost as heat or due to inefficiencies in the electrolyzer itself, leading to a lower overall energy conversion efficiency compared to other hydrogen production methods (Navarro et al., 2010; Agyekum et al., 2022). Electrolysis systems may have operational constraints related to pressure, temperature, and electrolyte composition. These constraints can affect the performance and reliability (Lopez, 2023). It also requires a source of water as a feedstock. In regions with limited water resources or where water conservation is a concern, electrolysis may face challenges related to water availability and usage. Scaling up electrolysis for hydrogen production can be challenging due to the need for substantial electrical infrastructure, water supply, and space for equipment installation (Tonelli et al., 2023).

Despite these limitations, ongoing research and development efforts are focused on improving electrolysis technology, increasing energy efficiency, reducing costs, and exploring alternative electrolyte materials to address the above challenges and make electrolysis a more viable and sustainable option for hydrogen production.

1.2 Study aims and motivation

Isolated grids with access to natural gas can produce grey and green hydrogen and ammonia. This study presents innovative frameworks for implementing hybrid renewable energy systems that produce hydrogen and ammonia in isolated grids. The primary objective is to achieve cost-effectiveness and emissions reduction while maintaining reliability, resilience, and affordability. Despite green energy being more environmentally sustainable, our study considers grey hydrogen and ammonia for two reasons. Firstly, most isolated grids, particularly in some regions, such as sub-Saharan Africa, often face economic challenges and have limited budgets to transition smoothly from no energy to full energy access. In these contexts, the cost of green hydrogen remains prohibitively high, especially when prioritizing essential household energy needs. On the contrary, grey hydrogen is more economically viable and can offer an affordable solution, particularly for agricultural applications. Therefore, hybrid renewable energy systems that use renewable and nonrenewable sources for supporting residential loads and producing green and grey hydrogen and ammonia could be more effective for sustainable development in remote locations.

Second, HRESs are already used in other applications that could benefit from natural gas, such as gas and oil refineries in Bishnoi and Chaturvedi (2021, 2022). These systems integrate gas turbines with renewable sources like PV and wind energy. Therefore, our analysis could hold promise for effectiveness in such locations.

Our primary targets are isolated microgrids with access to diverse onshore natural gas resources to produce grey and green hydrogen and ammonia. However, providing natural gas resources is challenging in isolated grids, so, we confine our model to specific applications and regions such as:

- Remote grids that use diesel generators and changed to natural gas after discoveries, for example, Barbosa et al. (2023) examined the use of natural gas in isolated microgrids in the Amazonas state in Brazil, where many isolated grids changed to natural gas after discoveries (Peyerl et al., 2022).

- Microgrids in suburban areas where microgrids operate as independent systems although they can be connected to the main grid (Delfino et al., 2018). Such suburban microgrids have greater access to natural gas infrastructure, such as gas pipelines.
- Gas flaring locations: for example: Bishnoi and Chaturvedi (2021, 2022) studied HRESs that utilized waste flare gas from onshore natural gas fields in Assam, India. Previous studies focused on the electric power supply; however, we can extend the work to include hydrogen and ammonia.
- More broadly in Sub-Saharan Africa region, where more than 621 million people live. Most of the power generation depends on diesel generators. This region has many challenges, such as 1) Reliability and resilience issues, because of the weak generation, transmission, and distribution infrastructure, and 2) Having a vast agriculture area and importing most of their ammonia needs from other countries. In this case, most of the population is regarded as living in isolation, so the intervention by the government to apply large scale microgrids that rely on HRESs could support reliability and resilience and produce ammonia at affordable prices.

Our thesis is structured around two primary case studies, delineated as follows:

The first case study: Techno-economic and environmental analysis of heat source for SMR in isolated grids.

Q1**:** *What is the impact of SMR heat source for grey hydrogen production on HREs isolated microgrids cost and emissions?*

The steam methane reforming process is the main method for industrial-scale grey hydrogen production due to its efficiency and ability to utilize readily available natural gas feedstocks. However, it produces carbon dioxide as a byproduct, making it a source of greenhouse gas emissions. While many studies have concentrated on the technological aspects of decarbonizing steam methane reforming, there has been less attention to the economic analysis. This study undertakes an isolated grid supported by HRES, comprising PV, wind power generation, battery storage, microturbines, and SMR for producing grey hydrogen. SMR process necessitates superheated steam at high temperatures to facilitate hydrogen separation from methane products. Typically, the required heat is supplied using gas boiler and electric boiler technology. However, in this study, we propose additional implementation of the CHP boiler system and Hybrid boiler system. The gas boiler operates independently, supported by an external gas source, and remains disconnected from the isolated grid components. The CHP boiler system relies on an external gas source and a surplus heat generated by the microturbines. It is considered an extension of the gas boiler accompanied by microturbines. The hybrid boiler system represents a fusion of the CHP boiler system and the electric boiler system. The rationale behind suggesting the hybrid boiler system lies in avoiding the trade-off between cost and emissions. Relying on renewable energy to support the electric boiler might increase the costs while diminishing emissions. Conversely, relying on gas or the CHP boiler potentially decreases costs but elevates CO2 emissions. We developed a thermodynamic model to determine the necessary heat for SMR, and subsequently, we studied the impact of supporting heat using different mechanisms on the isolated grid NPC, CO2 emissions, optimal dispatch, and LCOH.

Our study's motivation is to understand the economic feasibility of decarbonization strategies. The choice of heat source can impact the environmental footprint of SMR. By studying different heat sources, including renewable options, it's possible to minimize greenhouse gas emissions and other environmental impacts associated with SMR operations. Researching heat sources for SMR encourages technological innovation. It can lead to the development of new heat transfer techniques, materials, and energy sources that can improve the overall performance and sustainability of SMR processes. Diversifying heat sources for SMR contributes to energy resilience. By exploring renewable and alternative heat sources, industries can reduce dependence on fossil fuels and build more resilient and sustainable energy systems.

This case study is located in an isolated grid in East Owinat, Egypt. However, it's findings are not limited to this location; they can be generalized to many other places with similar conditions. Our primary targets are isolated microgrids with onshore natural gas resources to produce grey hydrogen. For example, Barbosa et al. (2023) examined the use of natural gas in isolated microgrids in the Amazonas State in Brazil, where onshore reserves of natural gas were discovered and infrastructure such as gas pipelines were constructed (Peyerl et al., 2022). For the initial assessment, they chose 14 isolated microgrids out of 95 similar microgrids near the Urucu-Manaus gas pipeline and Azulão and Japiim production fields. They suggested transitioning from diesel to natural gas to generate electricity in isolated systems. As another example, Bishnoi and Chaturvedi (2021, 2022) studied HRESs that utilized waste flare gas from onshore natural gas fields in Assam, India. They considered systems with microturbines that used waste flare gas, hydrokinetic river turbines, and other renewables. In Africa, Algeria ranks tenth and third in global natural gas and shale gas reserves, respectively, along with its rich potential for renewable energy (Abada and Bouharkat, 2018). Indeed, 26 isolated southern microgrids rely on microturbines and small diesel generators (Amrouche et al., 2017). Isolated microgrids consisting of microturbines, PVs, and wind turbines have also been investigated in the context of Egypt, which is the third largest natural gas producer in Africa after Algeria and Nigeria (Abo-Elyousr and Elnozahy, 2018; Abubakr et al. 2022). More broadly, isolated microgrids with diverse types of onshore natural gas sites are suitable for hydrogen production, as proposed in our study. Furthermore, it is worth noting that our approach is applicable not only to isolated microgrids but also to microgrids in suburban areas where microgrids operate as independent systems although they can be connected to the main grid (Delfino et al., 2018). Such suburban microgrids have greater access to natural gas infrastructure, such as gas pipelines. Therefore, we believe that our approach applies to more general microgrids spanning rural to suburban areas.

The second case study: Economic feasibility of producing ammonia in isolated microgrids considering Seasonal gas price flexibility.

Q2: *Given two gas prices, what is the best way, operation and configuration to produce ammonia in HRES-isolated grids?*

The study aims to explore the feasibility of producing grey and green ammonia in hybrid renewables isolated grids, considering seasonal gas price fluctuation. We consider two gas price scenarios representing off-peak and peak gas demand and evaluate three systems that have different ammonia storage operations. These systems aim to reduce gas procurement during peak demand periods and increase production and use storage during the off-peak demand season. We examine the impact of seasonal gas price fluctuations on the grid systems NPC and LCOA. This approach is potentially crucial for motivating changing operational strategies to improve economic viability. Furthermore, it helps to understand how changes in gas prices affect ammonia production in isolated grids to provide valuable insights for decision-making for the planning process. Overall, the study aims to identify configurations and operational strategies that maximize economic benefits and sustainability within hybrid renewable isolated grids. It appears to be motivated by the need to align grid operations and resource utilization with real-world conditions, such as seasonal variations in gas prices.

Our approach targets isolated grids in agricultural areas with access to onshore natural gas resources. In the context of Egypt, data from the New and Renewable Energy Authority (NREA, 2015) report indicates that around 167,000 individuals are currently experiencing power outages or lack access to electricity, spread across 264 remote villages and nine towns. Of these villages, 211 are entirely disconnected from the main grid. Isolated microgrids supported by HRESs, incorporating microturbines and diesel generators as backup, have been studied in Egypt, which ranks as Africa's third-largest natural gas producer (Abo-Elyousr and Elnozahy, 2018; Abubakr et al., 2022). Given that agriculture is the third largest economic sector in Egypt, with participation in gross domestic product (GDP) by 11.3 % in 2021, It serves as the primary source of livelihood in Egyptian villages, and accounts for 28 % of all jobs (USAID, 2022). Therefore, our model could prove particularly suitable for addressing energy needs in such contexts. Additionally, our case study focuses on an isolated grid dedicated to agricultural purposes in East Owinat, Egypt. The HRES model provides electricity for a 100-acre farm, which includes residential loads for 50 workers and submersible pumps for irrigation. The total area of East Owinat spans over 500,000 acres, with significant agricultural investments from the governmental and private sectors (Kamel and Dahl, 2005). Thus, our model has the potential for broader application across multiple locations within East Owinat. Notably, many countries have plans to connect remote areas to the main grid to enhance the resilience and reliability of power supply. Connecting the main grid to East Owinat is crucial, particularly to foster investment and food security. However, given the large size of this location, establishing distribution networks may be prohibitively expensive in certain areas, especially in villages with small populations and limited land area, which are similar to our case study. All in all, this location could include isolated grids, even if it can access the main grid. Egypt is one of the highest ammonia producers in Africa (AU, 2019). However, producing ammonia in East Owinat could be beneficial, as it would reduce transportation costs associated with importing ammonia from urban areas. This localized production could enhance the efficiency and cost-effectiveness of ammonia supply for agricultural purposes.

More broadly, according to the International Energy Agency (IEA, 2019c) report approximately half of the African population lacks access to electricity, with the majority residing in Sub-Saharan Africa. Moreover, millions of households heavily rely on biomass for cooking, contributing to roughly 500,000 premature deaths annually. Africa is rich in renewable and nonrenewable resources, with abundant solar potential and widespread wind availability across many countries. Sub-Saharan Africa, holds significant oil and gas reserves, representing half of the continent's total resources. More than 60% of the population in Sub-Saharan Africa live on small farms, with agriculture contributing 23% to the region's total GDP (Goedde et al., 2019). Despite this, agricultural productivity in Sub-Saharan Africa is lower than anywhere else in the world. The region has an average fertilizer application rate of 22 kg per hectare, which is seven times lower than the global average. Another challenge is the high cost of fertilizer in Sub-Saharan Africa compared to other regions. For instance, the fertilizer price is four times higher than the price in Europe. This is due to high transportation costs, the elevated cost of raw materials, and the significant energy requirements for fertilizer production. Providing energy for fertilizer production at an affordable price is difficult in Sub-Saharan Africa, which accounted for 2% of the total primary energy supply in 2014 (Gro Intelligence, 2016).

Fertilizer production of in Africa is concentrated in Egypt, South Africa, Tunisia, Nigeria, Algeria, and Morocco, while Sub-Saharan Africa imports a significant amount of its ammonia needs (Fig.3) (AU, 2019). Notably, the electric power situation in the Sahara region in North Africa (Fig.1), e.g., Egypt, and the Sub-Saharan region (Fig.2), e.g., Uganda, is different. Countries in the Sahara region typically have robust electric power systems, with remote residents representing only 1% of the total population. In contrast, Sub-Saharan Africa has a weak electric power generation, transmission, and distribution infrastructure, with a significant number of the population residing in isolated areas. To address residential energy needs in Sub-Saharan Africa, many photovoltaic projects are underway, albeit with high costs and low reliability (IEA, 2022c). According to East Africa Power Industry Conversion, (EAPIC, n.d.) weak gas infrastructure is another challenge, despite natural gas production and ongoing discoveries. Securing funds for producing green ammonia, which involves high capital costs, poses a significant challenge in one of the world's poorest regions. Therefore, we believe that strengthening gas distribution networks to scale up our approach "HRES" in Sub-Saharan Africa could substantially improve electric power resilience and facilitate affordable ammonia production. Importantly, our approach is not limited to remote locations but also extends to agricultural areas in suburban settings, where residents prefer independence despite, they can access the main grid. The availability of onshore natural gas in many suburban communities reinforces the applicability of our approach across a spectrum of agricultural settings, spanning from rural to suburban areas.

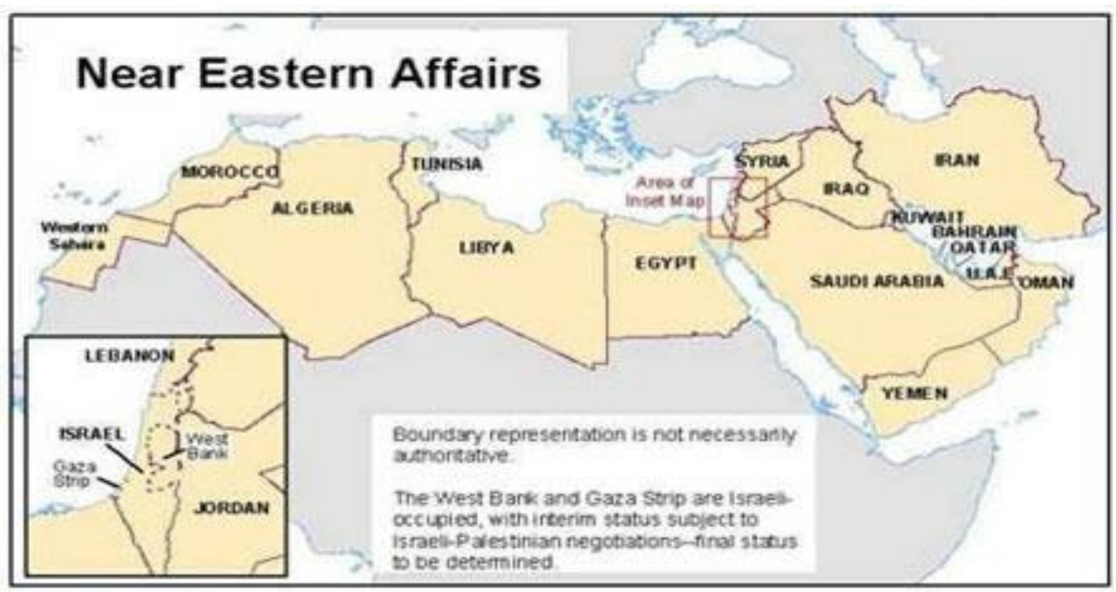

Fig. 1. North Africa Countries
(US Department of state, n.d.b). https://2009-2017.state.gov/p/nea/ci/

Fig. 2. Sub-Saharan African countries
(US Department of state., n.d.a). https://2009-2017.state.gov/p/af/ci/

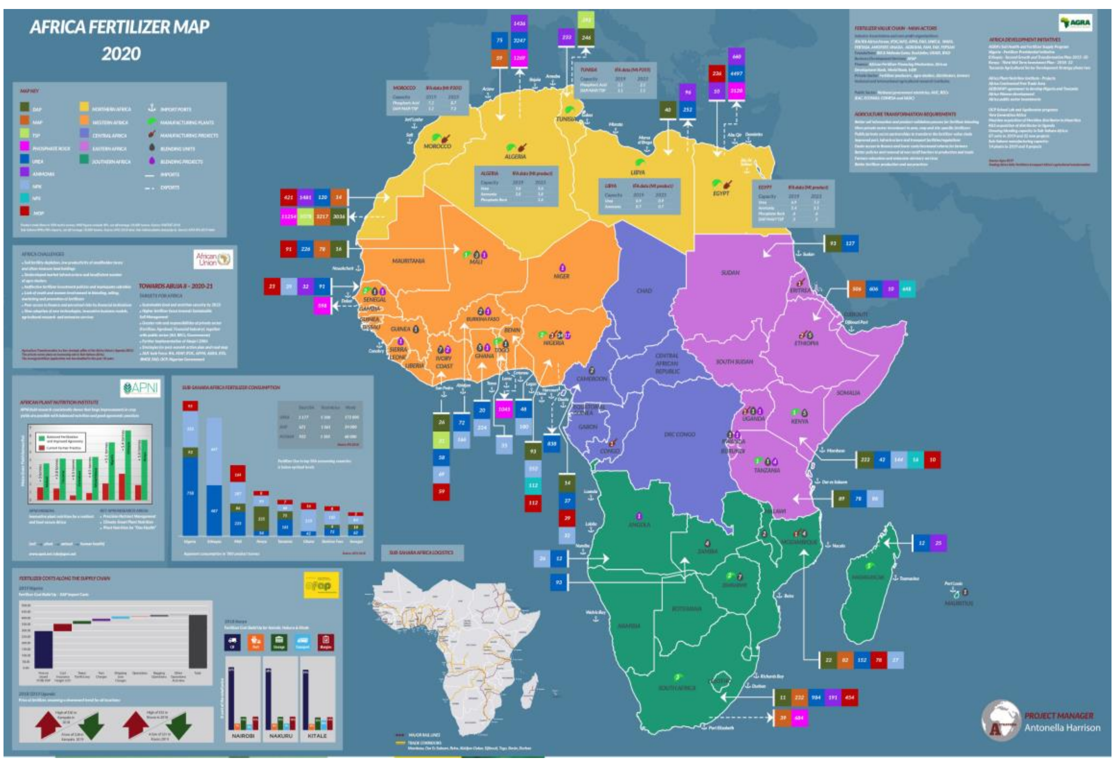

Fig. 3. Africa fertilizer map 2021
(Africa fertilizer map, 2021) https://www.africafertilizermap.com/

1.3 Contributions

Decarbonizing the heat source of SMR for grey hydrogen production is essential for driving technological innovation, and seizing market opportunities in the transition to a low-carbon energy future (Calisan et al., 2019). The economic aspects of the decarbonization methods of the SMR are crucial for evaluating its competitiveness in the hydrogen market and informing strategic decision-making regarding investment, technology selection, and operational optimization. Furthermore, economic considerations may also extend to environmental and regulatory factors, such as compliance with emissions standards and potential costs associated with CCS technologies to mitigate greenhouse gas emissions. However, most studies have focused on the technological aspects of SMR, examining factors such as reactor design, catalyst performance, operating conditions, and process optimization for reducing emissions in the context of hydrogen stations. Additionally, investigating economic and environmental analysis that combines HRES with the SMR heat sources has not been undertaken. Our first study introduces four approaches, that provide heat to the SMR process in the HRES isolated grids: CHP boiler, gas boiler, electric boiler, and hybrid boiler. It analyzes the impact of heat sources on the overall system NPC and CO2 emissions. These findings provide valuable guidance for policymakers seeking to decarbonize the heating source for SMR in isolated grids and offer insights into the economic and environmental implications of different heat support methods.

Ammonia is essential for decarbonizing many sectors and for the fertilizing process in agriculture. However, producing green and grey ammonia in isolated grids supported by HRES has not been investigated. Another concern is that grey ammonia production is impacted by gas price fluctuation. However previous research focused on using fixed gas prices for the planning process. Indeed, many countries are experiencing peak demand seasons for natural gas. Hence, fixed pricing does not reflect the dynamic change of the gas market. To tackle these issues, our second study examines the feasibility of producing ammonia in the context of HRES isolated grids considering two gas prices representing peak and off-peak demand seasons and suggests changing the operation and configuration of ammonia production using three systems. These systems increase production and use storage during the off-peak demand to support the ammonia load during the peak demand aiming at improving ammonia operation efficiency and achieving more benefits. We examined the impact of multiple gas prices on the HRES isolated grid NPC and the LCOA before and after applying the systems. Adapting the operation and configuration of ammonia production using multiple prices shows a holistic approach to optimizing energy use and costs that can better reflect market conditions with the fluctuations in demand throughout the year. It provides valuable insights into the economic feasibility and benefits of these pricing models for grid operators, and the gas market.

Our approaches for hydrogen and ammonia production in isolated grids extend beyond isolated microgrids in remote locations to include suburban microgrids, which operate independently, although they can connect to the main grid. Such microgrids often have better access to natural gas infrastructure, including gas pipelines. As a result, the methodologies and findings of our study are applicable to a broader range of microgrid settings, spanning from rural to suburban areas. Our study goes beyond new technical and innovative analysis; it extends to formulating a policy framework tailored for small-scale and regional areas like sub-Saharan Africa for achieving sustainable development. We took into account various aspects, notably the environmental, and economic landscape and the reliability of power supply. This study marks the first time that a specific analysis has been conducted, combining grey and green ammonia within isolated grids that can access natural gas resources. We are confident that this contribution will prompt policymakers to reconsider the feasibility of hydrogen and ammonia production using HRES.

The main contribution and novelty of our study can be summarized as follows:

- The techno-economic and environmental aspects of heat sources for SMR are thoroughly studied, specifically in terms of the total costs of the entire system over the project lifetime. This contrasts with most existing studies that focus on the technological aspects of heat sources.

- Four different approaches for supplying heat, crucial for the endothermic process of SMR, are compared in detail in the context of isolated microgrids with HRESs, which contrasts with most existing studies that examined a single heat source.

- This study explores the economic feasibility of ammonia production within isolated microgrids supported by HRES, expanding beyond previous research that mainly focused on hydrogen production. We compare various systems for seasonal green and grey ammonia production and storage subject to multiple gas prices, thus diverging from the existing studies that typically consider fixed single gas prices.
- Our approach applies to microgrids spanning rural to suburban areas that have access to diverse natural gas resources. We emphasized the importance of scaling up our model for sustainable development because the literature examines mainly technical aspects of hydrogen production, and overlooks the need for critical policy recommendations and strategies for entering new markets.

1.4 Thesis outlines

- This chapter, Chapter 1, is an introduction that outlines the study overview by providing the background context, outlining the purpose, and highlighting the research contributions.
- In Chapter 2, is a literature review that highlights the existing approaches for hydrogen, ammonia, and gas prices in the context of stations and isolated grids.
- In Chapter 3, presented the first study; Techno-Economic and Environmental Analysis of Heat Source for Steam Methane Reforming in Isolated Microgrids.
- In Chapter 4, Presented the second study: Economic Feasibility of Producing Ammonia in isolated Microgrids considering Seasonal Gas Price Flexibility.
- In Chapter 5, is the conclusion summarizes the research work, exploring policy implications, acknowledging limitations, and outlining avenues for future work.

Chapter 2: Literature Review

2.1 Perspectives and considerations of SMR for grey hydrogen production in different contexts

Hydrogen is increasingly recognized as a vital element in the transition to cleaner and more sustainable fuel alternatives. It has the potential to transform several industries, including transportation, power generation, and industrial processes, largely because after the end of use it has ability to generate energy without emitting harmful substances (Hassan et al., 2023b; Hassan et al., 2024). According to the IEA's Stated Policies Scenario in 2021, global demand for hydrogen exceeded 94 million tons and is expected to increase to 115 Mt by 2030 (IEA, 2022a). Hydrogen can be produced using various techniques, notably SMR, water electrolysis, biomass conversion, and thermochemical water splitting, among others. Grey hydrogen is primarily produced through SMR, which uses superheated steam to extract hydrogen from methane products (Azizimehr et al., 2024). Although this method emits CO2 emission, grey hydrogen from SMR is widely used since its cost is lower than that of other forms (He and Li, 2014). SMR is an endothermic process; it requires heat to drive the syngas reaction, however, the heating sources of the SMR process contribute to CO2 emissions, particularly when reliant on fossil fuels (De Falco et al., 2014). The first study "**Techno-economic and environmental analysis of heat source for SMR in isolated grids**" primarily focuses on the impact of the SMR heat source on the overall cost and emissions of HRES isolated grids, so we have divided the literature review into two sections relevant to our perspectives. The first covers the context of hydrogen stations (Section 2.1.1), and the second is isolated micro and mini grids (Section 2.1.2).

2.1.1 Context of hydrogen stations

A substantial number of studies have investigated the technological, thermodynamic, and thermochemical aspects of SMR in hydrogen stations for mitigating emissions and enhancing efficiency.

Le Corre et al. (2011) investigated the efficiency of hydrogen production by means of SMR within a CHP plant employing an internal combustion engine. The autothermal process relied on the oxygen concentration in the exhaust gases during hydrogen generation. Through experimental methods, they examined the effect of adjustments of gas flow rate and air-to-fuel ratio on hydrogen volume and emissions. There was a 6-10% variation in hydrogen volume with a twofold change in air-to-fuel ratio and a fourfold increase in natural gas flow rate. Additionally, reduction 18% in nitrogen oxide (NO) and an increase in carbon monoxide (CO) emissions by 14%.

Dubinin et al. (2019) applied a thermodynamic model to facilitate heat for SMR within a mini-CHP system consisting of planar oxide fuel cell (SOFC) stacks. This setup generated both electricity and superheated steam. The findings showed that syngas containing 55% of hydrogen could be produced by the reactor configuration.

Chen et al. (2019) used the finite volume discrete oriented method (fyDOM) to determine the temperature distribution and the radiation heat transfer of the solar thermochemical reactor for hydrogen syngas. The study examined the effect of several key parameters on the thermal performance of the reactor (such as absorptivity, emissivity, reflection-based radiation scattering, and carrier gas flow inlet velocity). There was a significant temperature difference, with an increase in radiation emissivity; this indicates thermal non-equilibrium in the radiation inlet region. The distribution of incident radiation flux was found to have a substantial effect influence on the temperature profile across the reactor. The results indicated that temperature drops due to radiation heat loss should be considered in the thermal performance analysis of solar thermochemical reactors.

Song et al. (2022a) implemented achieved electrical steam methane reformer by integrating power-to-gas technology. Electrical equipment was incorporated into the process to reduce emissions. The optimal performance of the E-reformer was examined using an innovative framework that combined chemical equilibrium and mass-energy conservation methods; focusing on varying the steam-to-carbon ratio, and reforming temperature and pressure. The results showed an 18% improvement in thermal efficiency, and economic analysis indicated a cost reduction of 2.47 $/kg H2 via the proposed process.

Petrasch and Steinfeld (2007) formulated a dynamic model to facilitate heat supply for SMR using concentrated solar thermal energy to achieve superheated steam. The model integrated mass and energy equations involving conduction, convection, and radiation heat transfer, along with temperature-dependent chemical reactions, for forecasting responses under various transient operational conditions such as startup, shutdown, purging, thermal testing, and chemical reaction phases of a solar reformer. The results were compared using an existing model in a solar facility for the purpose of validating the model.

Calisan et al. (2019) investigated the incorporation of concentrated solar thermal energy to enhance SMR, factoring in solar irradiance fluctuations. Concentrated heat was attained by means of a 70 cm parabolic mirror directing solar flux to a focal area of approximately 3 cm. The results indicated that methane (CH4) transformation rates greater than 90% across varying solar irradiance levels.

Pashchenko (2023) compared the performance of an integrated solar combined cycle system (ISCCS), where solar energy supports the SMR process, with the original system that only utilizes solar energy to provide steam for the steam turbine. The SMR inclusion led to an overall efficiency increase of 3.5%. Moreover, if the water from the reforming process were condensed from the exhaust gases, the efficiency rises to 6.2%.

Wójcik et al. (2024) conducted a review comparing the mathematical analysis of both separate reforming and reforming within the fuel cells. Their comparison encompassed a range of parameters, including reaction time, temperature, steam-to-carbon ratio, and numerous other factors.

Muritala et al. (2020) provided an in-depth analysis of various technologies utilized in high-temperature processes for hydrogen production using fossil fuels. The study outlined methods like SMR and gasification, emphasizing their efficiency while addressing challenges, especially related to CO2 emissions. Furthermore, it explored the existing gaps in hydrogen production across different resources, considering renewable and non-renewable sources. The paper also delved into the anticipated future trends within the hydrogen market over the forthcoming decades.

Previous studies have extensively explored the technological and thermochemical aspects of heat sources for SMR in hydrogen stations, However, there has been relatively less focus on the economic aspects; particularly, a thorough evaluation of the entire system's costs, including operational and initial costs over the project's lifespan.

2.1.2 Context of isolated grids

Electrification of isolated grids powered by renewable energy paves a promising pathway toward sustainability (Blechinger et al., 2016). The rapid decline in the cost of renewable energy technologies, and storage systems, has made them highly effective solutions for off-grid electrification (IRENA, 2019). Relying on renewable energy presents a sustainable alternative for replacing off-grid systems, heavily dependent on diesel generators. This shift helps avoid the high costs associated with connecting to the main grid while also promoting environmentally friendly energy solutions (Marocco et al., 2020). However, HRESs incorporating renewable and nonrenewable energy sources are more stable and reliable for isolated grids (Hassan et al., 2023a).

A substantial number of studies in recent years have examined HRESs for isolated microgrids. These studies have addressed the issues of system configuration, sizing of generation units, and energy management and control strategies for establishing effective HRESs (Nehrir et al., 2011). Isolated microgrids with HRESs have already been installed in rural areas in developing countries that lack access to the main grids (Zebra et al., 2021). Additionally, isolated microgrids with HRESs that incorporate electrolyzers to produce hydrogen have received some attention (Obara et al., 2011; Jaramillo and Weidlich, 2016; Abdin et al., 2019; Colombo et al., 2020). For example, Yildirim (2021) proposed a controller design for an islanded microgrid system comprising a wind turbine, PV cells, fuel cells, electrolyzers, battery energy storage, and residential and commercial loads. Although less investigated, some studies have incorporated steam reformers in addition to electrolyzers. HassanzadehFard et al. (2020) argued that SMR coupled with electrolysis could reduce methane consumption by 10% when producing hydrogen in a microgrid with wind turbines, PV, fuel cells, and hydrogen storage systems. Lim et al. (2020) adopted a multicriteria decision-making approach to study the technology allocation of hydrogen production between SMR and electrolysis in the context of a microgrid system in South Korea. Morgenthaler et al. (2020) compared the techno-economic performances of high-temperature co-electrolysis and SMR in local European communities. Lykas et al. (2023) provided a detailed review of multigeneration systems for hydrogen production, including SMR.

Another application of hydrogen in micro and mini grids is the Power-to-Gas (P2G), concept refers to a technology that converts surplus electricity, typically from renewable sources like wind and solar power, into hydrogen or methane. This process involves electrolyzing water to produce hydrogen, which can then be combined with carbon dioxide to create methane through methanation. The produced gases can be stored and utilized as energy carriers for various applications, such as power generation, transportation, heating, fertilizer, steel, and cement. P2G plays a crucial role in grid balancing, and decarbonization efforts by enabling the integration of intermittent renewable energy sources into the energy system and providing a means to store excess energy for later use (Saeedmanesh et al., 2018; Davis, 2018; Yazdani et al., 2019). P2G technology represents the interdependence of gas and electric networks, offering a solution to alleviate the high demand for renewable energy sources (He et al., 2017; Yang et al., 2019). Hydrogen storage exhibits capabilities for hourly, daily, and seasonal load shifting, making it a versatile option for energy management. Scaling up hydrogen storage is a feasible strategy due to the widespread adoption of various renewable generation utilities, and increasing the market demand for hydrogen, especially for supporting electric vehicles (Maton et al., 2013). P2G hydrogen can be converted back into electric power to support fuel cells and engines, or it can be transformed into other chemical liquids and gases for use in the chemical industry (Shaffer et al., 2015). By relying on P2G technology for long-term hydrogen storage, islands could increase the share of renewable energy, thereby reducing the transportation cost of relying on fossil fuels (Duic and Carvalho, 2004). P2G technology finds application in numerous microgrid scenarios. For instance: A microgrid project in Chile integrates renewable energy sources with energy storage technologies to establish a flexible and efficient energy system. This system comprises a PV facility coupled with a storage system that encompasses hydrogen and lithium-ion capacity (ENEL, 2017). A microgrid in the Sonoma region of California leverages excess electricity from renewable sources to produce hydrogen through electrolysis, storing it for long-term use. The generated hydrogen serves various applications, including fuel for vehicles and as an energy source within the microgrid (Stone Edge Farm Microgrid, n.d). Another application of P2G technology is demonstrated in a microgrid in California. The hydrogen is produced from a PV system and subsequently utilized as fuel for a gas turbine within a combined cycle power plant (First Power-to-Gas projects in the US feature Proton electrolyzes, 2015).

Previous studies have mainly focused on decarbonizing microgrids and mini-grids through using renewable and hybrid renewable energy sources, with or without considering hydrogen production. In cases where hydrogen was considered, many studies examined the economic feasibility of stored green hydrogen supported by grid surplus energy (P2G). Other studies concentrated on technical aspects, particularly control models designed to enhance grid resilience and stability, in addition the economic viability of combining electrolysis and SMR reformer has received some attention. However, the impacts of supplying heat for the SMR process on microgrids and mini grids with HRESs have not been studied.

The research gaps are summarized as follows:

- Previous studies have mostly investigated the technological aspects of the heat source of SMR, while the economic aspects, particularly for the entire system, have received less attention.
- There is a market death of studies investigating the impact of heat sources for the SMR on microgrids and mini-grids with HRESs.

To understand the impact of the heat source for SMR on HRES isolated grids, our study conducts a techno-economic and environmental analysis of an isolated grid that utilizes HRES for producing grey hydrogen. The grid comprises PV, wind, battery storage, microturbines, and steam reformer. We propose four approaches for supplying heat to SMR: CHP; gas; electric; and hybrid boilers. Using a thermodynamic model, we examined the impact of the thermal source of SMR on grid NPC, CO2 emissions, and optimal dispatch. We used Homer Pro software to model an isolated grid in the east Owinat region of Egypt. Our study provides the flexibility to decarbonize SMR heat sources in various scenarios.

2.2 Advances in ammonia production: review of technologies, economic viability, and sustainability

The potential of ammonia in the energy sector represents a significant step toward achieving sustainability. It is a versatile fuel for various applications including transportation energy storage, and agriculture. It can burned directly in internal combustion engines or be used in fuel cells to generate electricity, emitting only water and nitrogen as byproducts. Its high energy density makes it a promising candidate for long-term energy storage, helping stabilize renewable energy grids by storing excess energy in times of high demand (Elbaz et al., 2022). Ammonia has long been used in agriculture as a crucial component of fertilizers, particularly in the form of ammonium nitrate and urea. These fertilizers provide essential nitrogen to crops, promoting healthy growth and increasing crop yields (Wyer et al., 2022).

Ammonia is typically classified based on its hydrogen source for the HB process. Previous research has primarily focused on green ammonia derived from renewable energy, as well as blue and grey ammonia from natural gas (Oh et al., 2024). Ammonia production from fossil fuels remains prevalent due to the relatively high cost of green ammonia (Wang et al., 2023). The second study, "**Economic feasibility of producing ammonia in isolated microgrids considering seasonal gas Price flexibility**" examines the impact of seasonal gas price fluctuations on ammonia production in isolated grids with HRESs. Consequently, we have divided the literature review into two sections relevant to our approaches. The first addresses ammonia production in isolated grids (Section 2.2.1), whereas the second gas prices (Section 2.3).

2.2.1 Ammonia production

In the context of ammonia stations, recent studies have concentrated on applying thorough investigations into various SMR technologies, aiming at reducing CO2 emissions and enhancing economic feasibility (Cloete et al., 2021; Pereira et al., 2022; Mattisson et al., 2018; Nazir et al., 2021; Xiang and Zhou, 2018). In another context. Mayer et al. (2023) conducted a techno-economic and environmental comparison between blue and green ammonia production, focusing on climate change impact. Despite the environmental advantages associated with blue ammonia, its widespread adoption has been hindered by economic and technological challenges, consequently, grey ammonia continues to dominate the market (Abu Hasan et al., 2012). Nevertheless, grey ammonia has received comparatively less attention in research, particularly in terms of an integrated SMR-HB process. Recently, Oh et al. (2024) conducted an economic analysis to evaluate the feasibility of transitioning from grey to blue ammonia at varying carbon tax levels. Their findings indicated that blue ammonia becomes more economically viable when carbon taxes exceed 62 dollars per ton.

Despite the techno-economic analysis of green hydrogen has received considerable attention in recent studies (Blanco et al., 2022), a handful have focused on green ammonia. Several studies have explored optimal configurations of renewable systems considering the HB flexibility. For example: Armijo and Philibert (2020) conducted a study on the techno-economic analysis of integrating PV and wind energy compared to standalone PV systems. Using data from four world-class locations renowned for high irradiance in the Atacama Desert, Chile, and strong winds in the Patagonian steppes, Argentina. Their findings revealed that hybridizing PV and wind energy is superior to standalone PV systems for reducing ammonia production costs. Moreover, hybridization enhances power supply stability and reduces the need for additional storage. Wang et al. (2023) examined the feasibility of producing green ammonia competitively in Australia. They considered factors such as the quality of renewable resources, off-grid plant operation modes, and complementary trade buyers. Using an optimization model that integrates PV, wind energy, storage, and flexibility changes in the HB process, they found that system flexibility and optimized PV and wind usage can reduce storage costs. Based on their findings, by 2030, green ammonia could be cost-competitive at a natural gas price of $14 per million BTU. They estimated the LCOA to be $765 per tonne in 2025 and $659 per tonne in 2030.

In a different context, Osman et al. (2020) adopted an inflexible HB approach in designing a water desalination unit supported by renewable energy in the United Arab Emirates. They derived hydrogen from the desalination unit, and then merged it with nitrogen from an air separation unit. The desalination plant components were simulated using Aspen Plus software, while optimal dispatch of PV and storage systems was determined employing linear programming optimization technique. The optimal system configuration comprised 3.5

GW of PV capacity, and 0.24 GW of battery storage, achieving an efficiency of 37%. The LCOA was estimated at $718 per ton of NH3.

Gallardo et al. (2021) compared flexible and inflexible HB systems supported by solar energy in the Atacama Desert. The primary objective of their study was to assess the feasibility of hydrogen generation and utilizing ammonia as a hydrogen carrier for exporting purposes. They comprehensively examined the entire supply chain of the solar system and hydrogen production in 2018, along with projection scenarios spanning from 2025 to 2030. The study incorporated technical data from real PV projects and purchase agreement prices, including transportation costs to Japan. A MATLAB/Simulink model was employed to determine the LCOH for large-scale utility multi-megawatt applications. Their findings revealed that the LCOH for HB can reach 2.2 $/ kg in 2018 and 1.67 $/kg in 2025. Additionally, competitive hydrogen can be exported to Japan via NH3 carrier in 2018 and 2025 based on the target price.

Furthermore, various studies have identified the geographical locations with the lowest levelized cost of ammonia. Kakavand et al. (2023) conducted an extensive technical and economic analysis to evaluate the potential for green ammonia production in diverse locations across Iran characterized by high wind speed and irradiance. They specifically selected three locations renowned for their exceptional irradiance and wind speed levels. Employing Homer Pro software, they modeled renewable energy and electrolysis systems. The primary objective was to assess the economic feasibility of ammonia production, intended for exportation. Transportation costs were incorporated, due to the distances from harbors, to accurately reflect the real cost of green ammonia. Additionally, recognizing water scarcity in those regions, the study considered seawater desalination and transportation costs. Through these analyses, the study aimed to provide valuable insights into the actual pricing of ammonia in Iran. Fasihi et al. (2021) investigated the global prospects of producing ammonia from PV and wind plants, using comprehensive global weather data. Their findings revealed that the producing ammonia in the best sites worldwide could range between €440–630 per ton of NH3 in 2020, €345–420 in 2030, €300–330 in 2040, and €260–290 in 2050. They anticipated that by the end of the current decade, green ammonia could gain dominance, as the projected decline in gas prices will neutralize by increasing the carbon tax to €75 per ton of CO_2. The top nine locations for green ammonia production could exhibit a maximum difference of €75 per ton of NH_3 by 2040. Nayak-Luke and Bañares-Alcántara (2020) conducted a comprehensive analysis to examine the future competitive landscape of green ammonia production, scrutinizing 534 locations across 70 countries. Their study revealed a noteworthy enhancement in the flexibility of the LCOA up to 56%. Furthermore, they identified the potential limits for electrolyzer capital and operational costs for shaping competitiveness by 2030.

The economic impact of substituting diesel fuel with green ammonia on Monhegan Island in the USA using onshore wind energy has been investigated by Morgan et al. (2014). Using an analytical model, they evaluated the comprehensive life cycle cost of the system, comparing it with a conventional setup that only relies on diesel generators. Their findings indicated that wind ammonia systems could offer a viable alternative for energy storage on remote islands, mitigating the substantial costs associated with diesel operation.

There has been relatively less focus on minimizing the LCOA, as highlighted by Salmon et al. (2021). In a comparative study, they examined the efficacy of grid connections versus renewable energy sources for ammonia production across many locations in Australia, considering different electricity price scenarios from the primary utility provider. Their analysis consistently demonstrated the superiority of grid connections over renewables and storage methods with the lowest reduction of 11%, equivalent to $2.5 per gigajoule (GJ) across all price scenarios. They concluded that despite the associated emissions of the grid connections, it offers a lower LCOA compared to renewable energy sources. This suggests that, from a purely economic standpoint, utilizing grid connections for ammonia production may be more cost-effective, even though it involves emissions. These findings highlighted the complex trade-offs involved in energy production decisions, balancing economic considerations with environmental impacts.

In the context of hybrid renewable isolated grids several studies have investigated optimizing the dispatch to minimize the NPC (Nehrir et al., 2011; Amrouche et al., 2017; Bishnoi, 2022; Ninad et al., 2020**)**, as well as exploring various methods for producing green and grey hydrogen **(**HassanzadehFard et al., 2020; Morgenthaler et al., 2020; Abdin et al., 2019). However, the economic feasibility of ammonia production in isolated microgrids and mini-grids powered by HRESs remains unexplored.

2.3 Gas Prices

Fluctuations in gas prices impact the grey ammonia industry (Isella et al., 2023). One of the main causes of this issue is the high gaps in seasonal gas consumption. Many countries, particularly those in the European Union (EU), experience peak gas demand during the heating season, which destabilizes the gas market (Erias and Iglesias, 2022). Gas prices in the energy industry are diverse and can vary depending on factors such as the type of gas supply (pipeline natural gas, liquefied natural gas, etc.); stage in the supply chain; market structure; regulatory frameworks; and regional market conditions (Han et al., 2021).

Regulated gas pricing is often implemented to achieve various policy objectives, such as ensuring affordability, promoting energy security, and protecting vulnerable populations from price volatility (Direct Energy, 2024). However, regulated gas pricing can also have drawbacks. It may lead to inefficiencies, disincentivize investment in gas exploration and production, and result in supply shortages or surpluses due to mismatches between regulated prices and production costs. Additionally, price controls may distort market signals and hinder the development of a fully competitive and efficient gas market (Putriastuti et al., 2021).

Many studies have used gas prices as a constant value of gas market facilities or official data in their economic assessment. These analyses include grey hydrogen and ammonia stations (e.g., in sections 2.1.1, and 2.2.1) (Song et al. 2022a; Do et al. 2023; Oh et al.,2024; Mayer et al., 2023), as well as micro- and mini-grids (e.g., in sections 2.1.2, and 2.2.1) (HassanzadehFard et al.,2020; Morgenthaler et al., 2020; Abdin et al., 2019; Barbosa et al. 2023; Peyerl et al., 2022). However, economic assessment of using multiple gas prices on ammonia production in HRESs isolated grids has not been undertaken. In that light, changing ammonia operation and configuration mechanisms could be effective.

The research gaps are summarized as follows:

- Previous studies have focused on the economic feasibility of ammonia production is ammonia stations, while in the context of HRESs isolated grids have not been studied.

- The impact of seasonal gas price fluctuation on grey ammonia production has not been investigated.

To address the research gaps and understand the impact of seasonal gas price fluctuation on ammonia production in hybrid renewable isolated grids. We conduct a techno-economic analysis of an isolated grid supported by HRES to produce grey and green ammonia. We considered the gas price flexibility by applying two prices, representing the peak and off-peak demand seasons. We adopt three systems that increase production, use storage during the off-peak demand, and reduce production during the peak demand. The first system stores grey ammonia, the second stores green, and the third stores grey and green ammonia. Using various values of the two gas prices we examine whether we need to resort to an electrolyzer supported by surplus energy for storing ammonia or increase the reformer capacity. Additionally, we examine the potential benefits of the grid consumers and the gas producers' after applying the three systems. Our study could help in achieving better resource allocation and management.

Chapter 3: Techno-Economic and Environmental Analysis of Heat Source for Steam Methane Reforming in Isolated Microgrids

3.1 Introduction

Hydrogen plays a significant role in decarbonizing and providing modern energy for various industrial and agricultural applications including micro and mini grids (Colombo et al., 2020; ENE., 2017). Although green hydrogen is a carbon free energy, but remains costly (IEA, 2023a). SMR with CCS technologies, e.g., blue hydrogen, contributes to reducing CO2 emissions, but technical challenges related to CCS technology have limited its large-scale adoption (IEA, 2023a). The SMR process without CCS technology, known as grey hydrogen, remains the most commonly used commercial method for large-scale hydrogen production (Alhamdani et al., 2017; El-Shafie et al., 2019). This process is mature and has a low cost and high energy conversion efficiency, ranging from 74% to 85% (Nikolaidis and Poullikkas, 2017). Hydrogen production via SMR is typically conducted onsite by oil refiners as a byproduct of petrochemical production and in locations externally supported by natural gas resources (IEA, 2021a). Most countries still heavily rely on grey hydrogen. For instance, in the United States, 10 million metric tons (MMT) of grey hydrogen were produced in 2020 (out of a global total of 70 MMT), accounting for 14.3% of global hydrogen production (US Department of Energy, 2020b). The majority of US hydrogen is derived from fossil fuels, primarily natural gas (99% fossil fuels, 1% green hydrogen in 2020, resulting in 41.3 MMT of CO2 emissions) (USEPA, 2020). Although the end use of grey hydrogen is carbon emission-free, the SMR process requires a high temperature to separate hydrogen from methane products; which contributes significantly to greenhouse gas emissions (Alhamdani et al., 2017; Sun et al., 2019). Some studies have indicated that the heat source for SMR contributes between 72% and 80% of total process emissions (Cetinkaya et al., 2012; Hajjaji et al., 2013; Hajjaji et al., 2016).

Existing studies have extensively investigated the thermodynamic and thermochemical technologies of heating sources for SMR in grey hydrogen stations. For example, Muritala et al. (2020) detailed industrial technologies for high-temperature processes to produce hydrogen using fossil fuel resources. Some studies have used CHP to produce electricity and superheated steam for SMR (Le Corre et al., 2011; Dubinin et al., 2018). Fluid dynamics simulations were conducted to verify the effectiveness of high-temperature exhaust gas as a heat source (Chen et al., 2019). The incorporation of electric equipment has also recently been studied to substitute the conventional gas-fired heating SMR (Song et al., 2022a; Do et al., 2023). Song et al. (2022a) and Do et al. (2023) respectively conclude that the cost of hydrogen could be 2.47 and 2.91 $/kg by utilizing electrified SMR. Another approach involves using concentrated solar radiation as a source of high-temperature heat for the SMR process (Petrasch and Steinfeld, 2007; Calisan et al., 2019). More recent studies have discussed the advancements in broad SMR technologies (Pashchenko 2023; Wójcik et al., 2024; Esfandiary et al, 2024; Sheu et al., 2023). However, most existing studies have primarily focused on the technological aspects of heat sources for SMR, whereas economic aspects, particularly in terms of the total cost of the entire system, including operation and investment costs over the project lifetime, have received less attention.

On the other hand, hydrogen has been investigated in microgrids through various approaches. Yazdani et al. (2019) analyzed Power-to-Gas (P2G) technology from economic and environmental perspectives. Obara et al. (2011) and Jaramillo and Weidlich (2016) explored optimal hybrid renewable energy systems (HRES) that incorporate electrolysis. Lim et al. (2020) examined optimal HRES configurations involving electrolyzers and reformers. However, to the best of our knowledge, different methods for supplying heat, which is crucial for the endothermic process of SMR, have not been fully studied in the context of isolated microgrids with HRESs.

This study conducted a techno-economic and environmental analysis of a hybrid renewable isolated microgrid with a steam reformer that produces grey hydrogen, supported by heat generated by different approaches. We consider an HRES comprising PVs, wind units, battery storage systems, microturbines, and steam reformers. Based on the thermodynamic models, heat for SMR is provided by four different approaches: CHP; gas, and electric boiler systems; and a hybrid of these components. In our study, the CHP boiler system combines waste heat from a microturbine with heat from a gas boiler using natural gas. The electric boiler uses electricity generated by a PV system, wind turbine, and microturbine in a microgrid. In the hybrid boiler system, the CHP and electric boilers supply heat in tandem. We evaluated the impact of different thermal sources of SMR on the optimal configuration and sizing, NPC and CO_2 emissions of a hybrid renewable microgrid. To evaluate the impact on emissions, NPCs are compared with and without considering the CO_2 penalty cost (e.g., carbon tax payment) in the optimization. Using the HOMER Pro software, our models are applied to an isolated microgrid in East Owienat, Egypt, as a case study.

Our study contributes to the existing literature in several ways:

- Techno-economic and environmental analysis of the entire system: We conducted a thorough examination of the techno-economic and environmental aspects of supporting heat sources for SMR within HRES isolated grids, whereas previous studies have concentrated on the technological aspects.

- Innovative heat sources support SMR: Through the use of a thermodynamic model, we investigated four approaches to support heat for SMR in HRESs. This enriches the literature on grey hydrogen production, which only has focused on SMR in hydrogen stations considering a single heat source.

- Pioneering Integration of HRES with grey Hydrogen Production: Our study is the first to combine HRES with a thermodynamic model for grey hydrogen production. This integration opens new metaphors for sustainable energy solutions.

- Introducing a hybrid boiler approach: We propose–and evaluate a hybrid boiler that harnesses renewable and non-renewable energy sources. This contribution enhances the understanding and adds new aspects to boiler technology.

- Advocacy for sustainable development: We emphasized the importance of scaling up our model for sustainable development. We argue that the literature examines mainly technical aspects of hydrogen production, and overlooks the need for critical policy recommendations and strategies for entering new markets. Our study bridges the gap between technical feasibility and sustainable policy, offering a holistic perspective integrating hybrid renewable energy systems with grey hydrogen production.

This chapter has five sections. Section 3.2 presents the methodology for formulation of the thermodynamic model for SMR, identifies the operational principles of different boiler types, and evaluates the system objective function and levelized cost of hydrogen. Section 3.3 shows the grid component data for grey hydrogen production. Section 3.4 presents the outcomes derived from the simulated scenarios, such as the grid's optimal NPC considering CO2 penalty costs. It discusses the primary findings, identifying the best-case scenario in terms of cost and emissions. Finally, Section 3.5 presents the conclusion identifies the limitations of the study, offers recommendations, and suggests directions for future research.

3.2 Methodology

3.2.1 Steam reforming and thermal load

SMR is an endothermic reaction that needs heat to produce hydrogen from methane, described as $CH_4 + H_2O\ (+heat) \rightarrow CO + 3H_2$. Hydrogen is generated by the reaction of the superheated steam with the methane in the presence of the catalyst under the pressure of 1.02–30 bar and temperature between 200–1,000 °C (Lougou et al., 2017). The required amount of heat, Q J/h, for the SMR process in the isolated microgrid is calculated as follows (Elsaraf et al., 2021; Wang et al., 2019):

$$Q = \dot{m} * C_p(T_{in} - T_{out}) \tag{1}$$

where $\dot{m}$ is the mass flow rate of water (kg/h); C_p is the specific heat of water equal to 4,200 J/kg; T_{in} is the input temperature of water (°C); and T_{out} is the outlet steam temperature (°C). In this study, the hydrogen load is assumed to be 100 kg/h. One kilogram of hydrogen requires 4.5 kg of water for the reforming process **(**Saulnier et al., 2020**)**. The difference in the required temperature is assumed to be 600 °C. From Equation (1), the necessary amount of heat Q is derived as 1,134,000 kJ/h. This amount is equivalent to a thermal load of 315 kWh (= 1,134,000 kJ/h / 3600 kJ), which is used for the calculations in HOMER Pro.

Given a hydrogen load of 100 kg/h, the required annual amount of natural gas used for steam reforming can be calculated from the following reformer efficiency:

$$Reformer\ efficiency = \frac{Amount\ of\ hydrogen\ output\ *Hydrogen\ lower\ heating\ value}{Amount\ of\ \ natural\ gas\ input * Natural\ gas\ lower\ heating\ value} \quad (2)$$

where the efficiency rate is set at 0.76 (Younas et al., 2022).

3.2.2 Configurations of isolated microgrid

Figures 4 and 5 illustrate the configurations of the HRES in the isolated microgrid with SMR in our study. Electric loads for consumers and thermal loads for SMR are supplied by this system, which mainly consists of a PV, wind turbine, battery storage, microturbine, and steam reformer. Microturbines are chosen as backup sources in HRES because of their lower CO_2 emissions compared to diesel generators. Boiler systems are required to supply heat in the SMR process. First, we choose a conventional gas boiler or an electric boiler from a practical perspective.[1] We also consider a CHP boiler system as an extension of a gas boiler by taking advantage of the surplus heat from microturbines in microgrids. Thus, a CHP boiler can be regarded as an extended gas boiler system accompanied by microturbines to improve efficiency. Moreover, we examine a combination of CHP and electric boilers as a hybrid boiler system to obtain further insights. Figure 4 shows the use of CHP, gas, and electric boiler systems to support the thermal load of an SMR, while Figure 5 indicates the case of a hybrid boiler system, in which we assume that half of the heat is provided by a CHP boiler and half by an electric boiler. The heat from these boiler systems is temporarily stored in a thermal tank for use with the steam reformer. Although this study does not encompass all aspects of boiler technologies, we aim to present techno-economic and environmental analyses of several representative boiler types. Given our assumption of a hydrogen load of 100 kg/h, the thermal load for SMR based on Equation (1) is the same for each configuration.

[1] Electric boilers are also called electric steam boilers or electric steam generators.

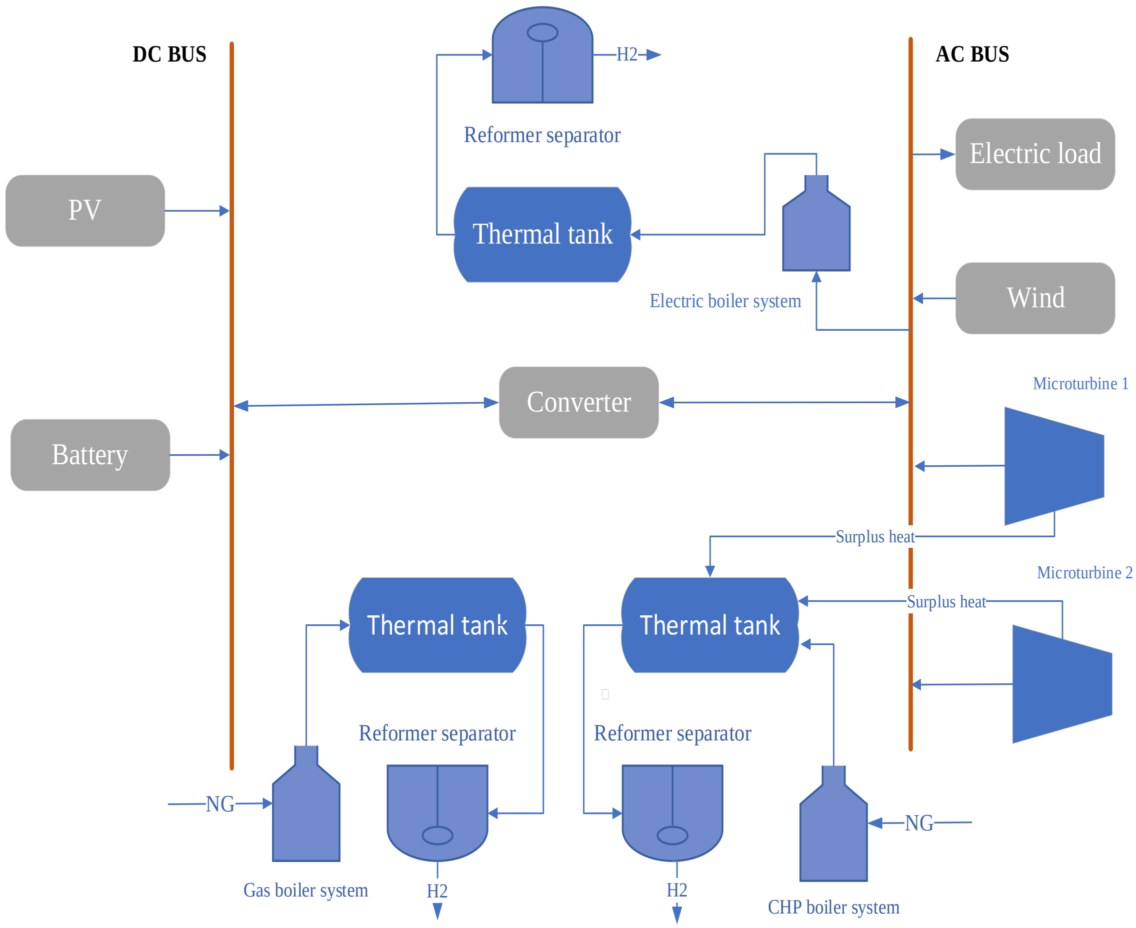

Fig. 4. Overview of isolated microgrid with CHP, gas, and electric boiler systems.

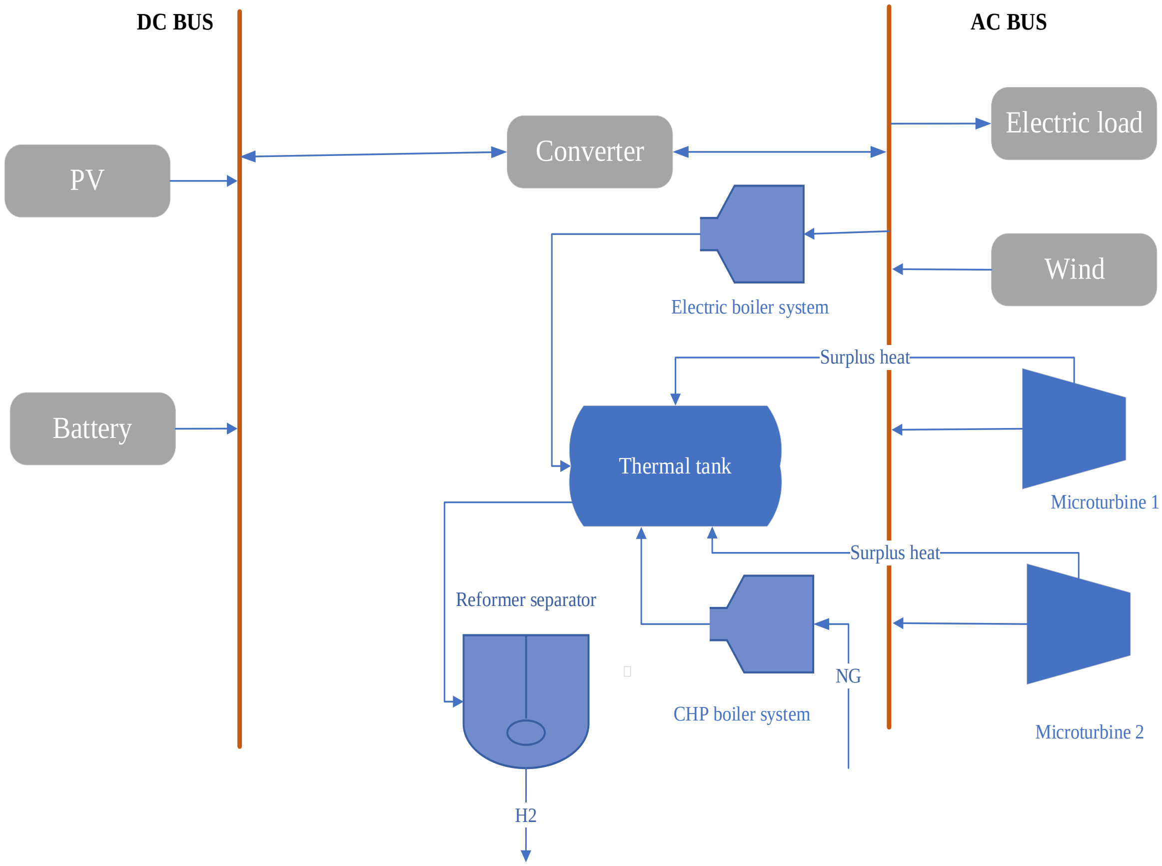

Fig. 5. Overview of isolated microgrid with hybrid boiler system.

3.2.3 Modeling of the microgrid components

HOMER Pro calculates the output power P_{PV} of the PV array as follows:

$$P_{PV} = Y_{PV}\, F_{PV} \left(\frac{G_T}{G_{STC}}\right) [1 + \alpha\, (T_C - T_{STC})] \tag{3}$$

where Y_{PV} is the rated power; F_{PV} is the derating factor; G_T is the incident radiation; G_{STC} is the standard condition of the incidence radiation; α is the power temperature coefficient; and T_{STC} is the temperature of PV under standard condition 25 °C.

HOMER Pro determines the output power P_W of the wind turbine at the selected wind-hub height as follows:

$$P_W = \frac{\rho}{\rho_0} P_{STC} \tag{4}$$

where P_{STC} is the output power at the standard temperature and pressure; ρ is the actual air density; and ρ_0 is the standard air density

HOMER Pro can simulate various types of generators and identify fuel consumption values. Equation (5) calculates the final fuel consumption F_C of the microturbine:

$$F_C = F_0\, Y_{GEN} + F_1\, P_{GEN} \tag{5}$$

where F_0 is the fuel curve intercept; F_1 is the fuel curve slope; Y_{GEN} is the rated capacity of the generator; and P_{GEN} is the electrical output power of the generator

3.2.4 Minimizing of net present cost

We minimize the objective function representing the NPC in $ for the hybrid renewable isolated microgrid with and without considering the CO_2 penalty cost for energy production, as illustrated in the flowchart in Figure 6.[2]

$$Min{:}\ NPC\ \ \textit{excluding } CO_2 \textit{ penalty cost} \tag{6}$$

$$Min{:}\ NPC\ \ \textit{including } CO_2 \textit{ penalty cost} \tag{7}$$

The NPC is the present value of all the costs of the system over its project lifetime, including capital cost, replacement cost, operation and maintenance cost, fuel cost, and salvage value.

The net present cost is calculated using equation 8.

$$NPC = \frac{C_{a,t}}{CRF} \tag{8}$$

Where Ca, t is the total annualized cost ($/year) & CRF is the capital recovery factor, given in equation 9.

$$CRF = \frac{i(i+1)^n}{(i+1)^n - 1} \tag{9}$$

The real discount rate (i) is determined using equation 10.

[2] For optimization, the HOMER Pro software mainly uses the "grid search" algorithm that simulates all the feasible system configurations defined in the search space. HOMER Pro then displays a list of configurations, sorted by the NPC. It works based on energy balance calculations for each interval (time step) over the year, comparing the generation and demand to calculate the energy flow from and to each component (Elsaraf et al., 2021).

$$i = \frac{i' - f}{i - f} \tag{10}$$

where i' is the nominal discount rate (the rate you could borrow the money) & f is the expected inflation rate. We assume the real discount rate of 6% to align with the rate used by Homer Pro. In many countries, the discount rate can change annually or even multiple times a year due to challenges such as high inflation rates. Homer Pro uses a real discount rate, disregarding inflation, and typically assumes a project lifetime of 25 years, which we have also adopted. Homer Pro follows suit of many power projects in lifetime and discount rates [3]. E.g., Bøckman et al. (2006) used a 5.8 % discount rate based on the risk-free rate for a hydropower energy project, which is near to that of the Homer Pro value. They have mentioned that the project's lifetime should be at least 25 years.

The CO_2 penalty cost can be regarded as the carbon tax payment (carbon tax×CO_2 pollution), which would induce emissions reduction The International Energy Agency (IEA, 2019a) projected that the CO_2 penalty in advanced economies would range from 5 to 16 US$/ton in 2020, growing to 100 US$/ton in 2030, while that for emerging economies would increase from 5 US$/ton in 2020 to 75 US$/ton in 2030. Our study assumes 50 US$/ton for the CO_2 emissions penalty. When the NPC is minimized without a penalty, the realized or ex-post value of the CO_2 penalty is added to the NPC.

The HOMER Pro software can model the steam reformer by adding capital costs to the NPC. However, HOMER Pro cannot directly design the thermal load for SMR in an isolated microgrid because the reformer is treated as an external device. Hence, we add the total cost of the reforming process to the NPC after optimizing the isolated microgrid. This treatment does not affect the optimization because the amounts of hydrogen produced and the natural gas required for steam reforming are fixed and constant. Other studies have adopted similar approaches to incorporate elements that HOMER Pro cannot handle. For example, Elsaraf et al. (2021) analyzed the impact of adding a solar thermal system to reduce

[3] The standard hydrogen project lifetime typically is 20 to 25 years (McKinsey& Company, 2023). The expected practical discount rates for the DCF (Discount cash flow) models usually fall within the 6-12% range, https://www.oldschoolvalue.com/investing-strategy/explaining-discount-rates/

the reliance on fossil fuels in isolated microgrids in Canada. As HOMER Pro cannot model the solar thermal load, they added the cost of the thermal system to that of the electric water heater.

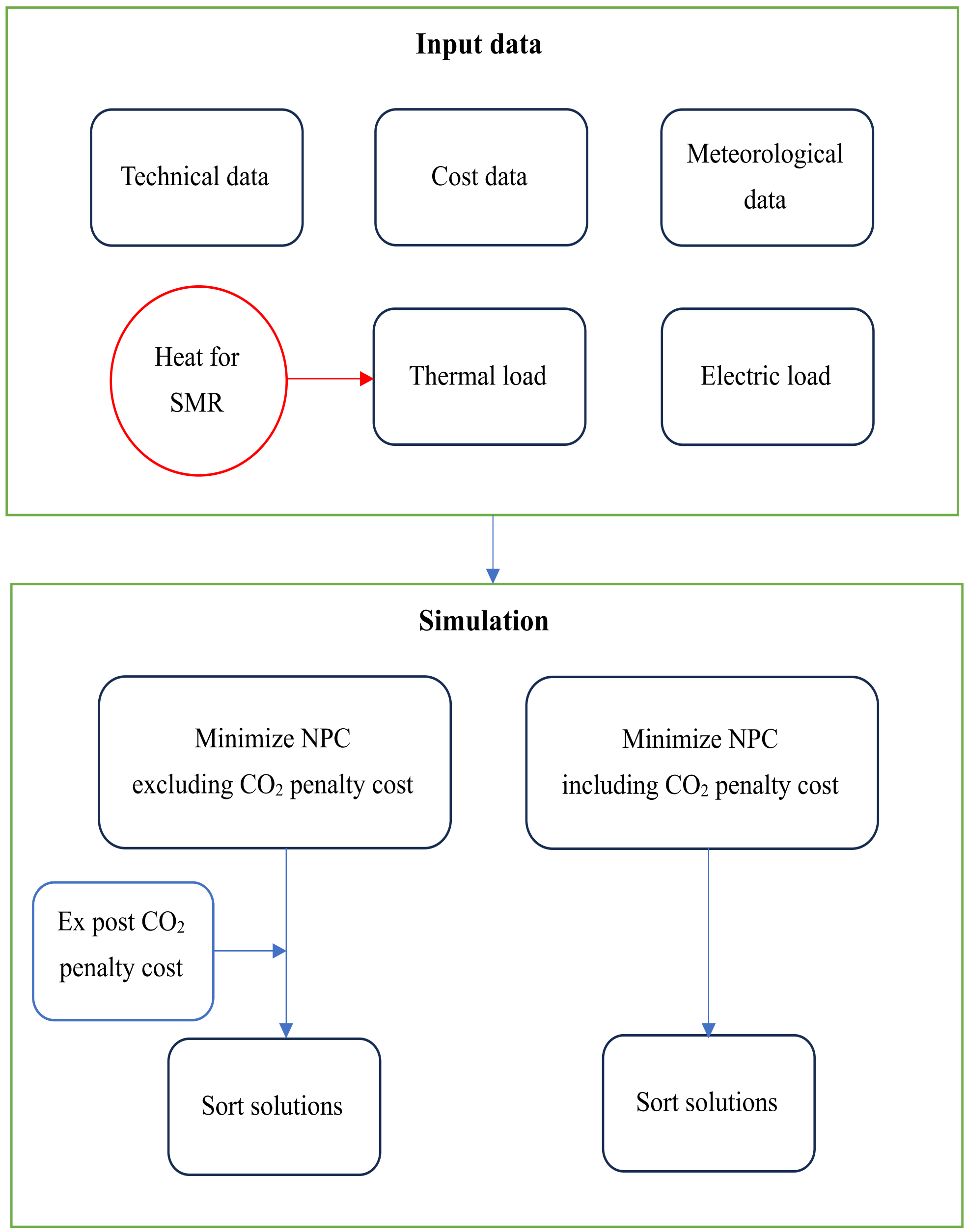

Fig. 6. Flowchart of optimization

3.2.5 Levelized cost of hydrogen

The NPC of the hybrid renewable isolated microgrid in our study consists of two major parts: one stemming from energy production and the other from hydrogen production.

$$NPC = NPC\ for\ energy\ production + NPC\ for\ hydrogen\ production \quad (11)$$

We consider cases with and without SMR, which allows us to calculate the total NPC and the NPC for energy production. The difference between these two values yields the NPC required for hydrogen production. The NPC for hydrogen production includes the CO_2 penalty associated with steam reforming. The LCOH is derived using the net present value of the hydrogen consumption over the project lifetime.

3.3 Data

3.3.1 Load profile

An isolated microgrid in East Owienat, Egypt (Kamel and Dahl, 2005) is used for the case study**.** It is located in the western desert of Egypt 380 km from the main grid. There are two types of electric loads in the system:1) residential demand, with a total annual amount of 36,683 kWh or 101 kWh/d, and 2) irrigation pumps for land reclamation, with a total annual amount of 582,973 kWh or 1,597 kWh/d. Because the original load data are based on 2005 data, this study assumes a 3% growth in the electric load for analysis.[4] The original system does not assume a thermal load.

To analyze the production of grey hydrogen in the isolated microgrid, we assume a constant hydrogen consumption of 876,000 kg/y or 100 kg/h in industrial facilities. Because the reforming process is complicated, we focus on the constant hydrogen consumption. As described in Section 2.1, the necessary amount of heat or thermal load for SMR is derived as 1,134,000 kJ/h or 315 kWh, which is used in CHP, gas, electric, and hybrid boiler systems.

[4] We follow Mondal et al. (2019), which assumed an average annual growth rate of 4.46% until 2050 for national electricity demand in Egypt. A slightly lower annual growth rate of 3% is assumed in our study because our focus is on isolated areas in Egypt.

3.3.2 Cost of microgrid components

The cost data for the major components are listed in Table 1, obtained from DOE (2016), IEA (2019a), Chintada (2019), and Al-Badi et al. (2022). The operation and maintenance costs of the converter, boiler, and thermal tank are regarded as negligible. The capital cost of a hybrid boiler system is assumed to be the average of those of gas and electric boilers, i.e., 47,250 \$/MW. The technical details of these components are provided in Appendix A.

Table 1. Cost of microgrid components for grey hydrogen production

Type	Cost
PV: a)	
Capital cost	1,000 \$/kW
Operation and maintenance cost	10 \$/kW/y
Wind turbine: a)	
Capital cost	900 \$/kW
Operation and maintenance cost	36 \$/kW/y
Battery storage: a)	
Capital cost	203,000 \$/MW
Operation and maintenance cost	10 \$/kW/y
Converter: a) Capital cost	500 \$/kW
Microturbine: b)	
Capital cost	2,500 \$/kW
Operation and maintenance cost (without fuel cost)	1.2 ¢/kWh
Reformer: c)	
Capital cost	910 \$/kWh
Operation and maintenance cost (without fuel cost)	4.7% of capital cost/year
Gas boiler: d) Capital cost	52,500 \$/MW (50,000 €/MW, 1 €=1.05 \$)

Electric boiler: [d] Capital cost	42,000 \$/MW (40,000 €/MW, 1 €=1.05 \$)
Thermal tank: [d] Capital cost	2,100 \$/MW (2,000 €/MW, 1 €=1.05 \$)
Price of natural gas [e]	0.3 \$/m^3

Source: a) Al-Badi et al. (2022); b) DOE (2016); c) IEA (2019a); d) Chintada (2019); e) Gas Regulatory Authority (GASREG), https://www.gasreg.org.eg/natural-gas-pricing/.

3.4 Results and discussion

Tables 2, 4, 6, and 8 present the results of system optimization with and without adding a CO_2 penalty cost to the objective function, corresponding to the cases of CHP, gas, electric, and hybrid boiler systems, respectively. The optimal case with the minimized NPC is displayed in the first row of each table. The second row reports the second-lowest NPC. For comparison, the third row shows the lowest NPC without microturbines that use fossil fuels. It turns out that the optimal hybrid configuration consists of a PV cell, wind turbine, microturbine 1 (MT1), microturbine 2 (MT2), and battery storage in all cases. Appendix C shows the possible hybrid configurations that the HOMER Pro software considers for the calculation.

Tables 3, 5, 7, and 9 list the optimal sizes of each component of the system. The sizes of the components in Tables 3, 5, 7, and 9 correspond to the optimal systems, that is, the first rows in Tables 2, 4, 6, and 8. Note that the converter operates in both directions, i.e., inversion from DC to AC and rectification from AC to DC. The converter capacity is based on the maximum conversion rate, either for inversion or rectification. For example, although the PV capacity and number of battery strings increase from the left to the right column in Table 9, this does not necessarily mean that the capacity of the converter should increase.

Table 2.

Panel A: CHP boiler: optimization of the system without CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbine heat (%)
PV, Wind, MT1, MT2, battery	38,960,742	8,868,165	5,736,200	33.2	66.8
PV, Wind, MT1, battery	39,583,083	8,821,632	5,706,101	35.0	65.0
PV, Wind, battery	44,586,492	8,434,417	5,455,638	100	0

Panel B: CHP boiler: optimization of the system with CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	41,166,792	8,555,395	5,533,891	49.7	50.3
PV, Wind, MT1, battery	42,523,522	8,510,201	5,504,658	56.8	43.2
PV, Wind, battery	44,586,492	8,434,417	5,455,638	100	0

Table 3. CHP boiler: optimal sizing with and without adding CO_2 penalty cost in the objective function

Component	Without adding CO_2 penalty cost in objective function	With adding CO_2 penalty cost in objective function
PV (kW)	2,258	3,314
Wind (number & kW)	627 & 2,006	528 & 1,690
Battery (strings)	9	15

Converter (kW) (inversion/rectification)	1,167	1,206

Table 4.

Panel A: Gas boiler: optimization of the system without CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	40,831,995	8,860,238	5,731,072	100	0
PV, Wind, MT1, battery	42,236,733	8,759,497	5,665,910	100	0
PV, Wind, battery	44586492	8,434,417	5,455,638	100	0

Panel B: Gas boiler: optimization of the system with CO2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	42,281,112	8,669,655	5,607,798	100	0
PV, Wind, MT1, battery	43,145,026	8,574,571	5,546,294	100	0
PV, Wind, battery	44586492	8,434,417	5,455,638	100	0

Table 5. Gas boiler: optimal sizing with and without adding CO_2 penalty cost to the objective function

Component	Without adding CO_2 penalty cost in objective function	With adding CO_2 penalty cost in objective function
PV (kW)	3,322	3,687
Wind (number & kW)	582 & 1862	601& 1923

Battery (strings)	12	16
Converter (kW) (inversion/rectification)	1,077	1,118

Table 6.

Panel A: Electric boiler: optimization of the system without CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	46,516,184	7,972,691	5,156,980	100	0
PV, Wind, MT1, battery	47,637,056	7,910,281	5,116,611	100	0
PV, Wind, battery	48,532,074	0	0	100	0

Panel B: Electric boiler: optimization of the system with CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	47,653,904	7,852,834	5,079,453	100	0
PV, Wind, MT1, battery	48,356,799.50	7875408	5,094,054.327	100	0
PV, Wind, battery	48,532,074	0	0	100	0

Table 7. Electric boiler: optimal sizing with and without adding CO_2 penalty cost to the objective function

Component	Without adding CO_2 penalty cost in objective function	With adding CO_2 penalty cost in objective function

PV (kW)	4,993	5,471
Wind (number & kW)	1,105 & 3,536	8,79 & 2,812
Battery (strings)	23	27
Converter (kW) (inversion/rectification)	1,607	1,828

Table 8.

Panel A: Hybrid boiler: optimization of the system without CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	43,065,808	8,399,423	5,433,001	41.5	58.5
PV, Wind, MT1, battery	44,150,845	8,363,100	5,409,508	44.4	55.6
PV, Wind, battery	46,616,381	8,115,408	5,249,294	100	0

Panel B: Hybrid boiler: optimization of the system with CO_2 penalty cost in the objective function

Hybrid configuration	NPC ($)	CO_2 emissions (kg/y)	NPC-CO_2 ($)	Boiler heat (%)	Microturbines heat (%)
PV, Wind, MT1, MT2, battery	44,940,726	8,192,143	5,298,928	70.1	29.9
PV, Wind, MT1, battery	45,761,730	8,156,547	5,275,904	80.1	19.9
PV, Wind, battery	46,425,843	8,115,408	5,249,294	100	0

Table 9. Hybrid boiler: optimal sizing with and without adding CO_2 penalty cost to the objective function

Component	Without adding CO_2 penalty cost in objective function	With adding CO_2 penalty cost in objective function
PV (kW)	3,563	4,287
Wind (number & kW)	984 & 3,149	716 & 2,291
Battery (strings), (kW)	16	23
Converter (kW) (inversion/rectification)	1,722	1,451

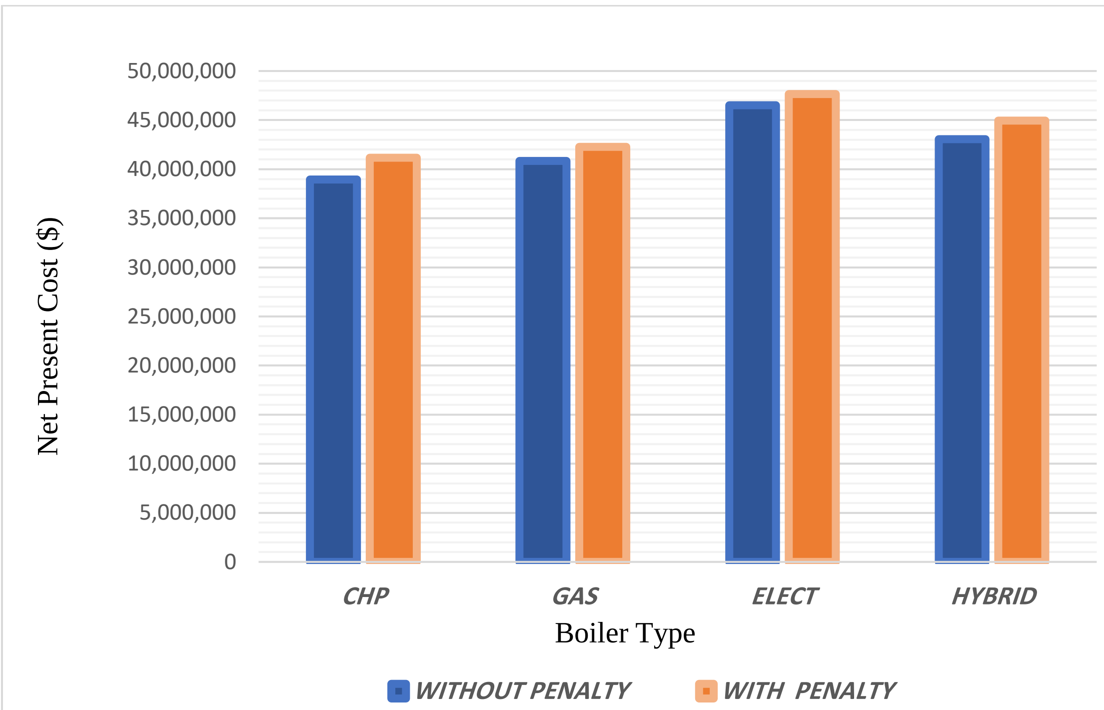

Fig. 7. NPC with and without adding CO_2 penalty cost to the objective function

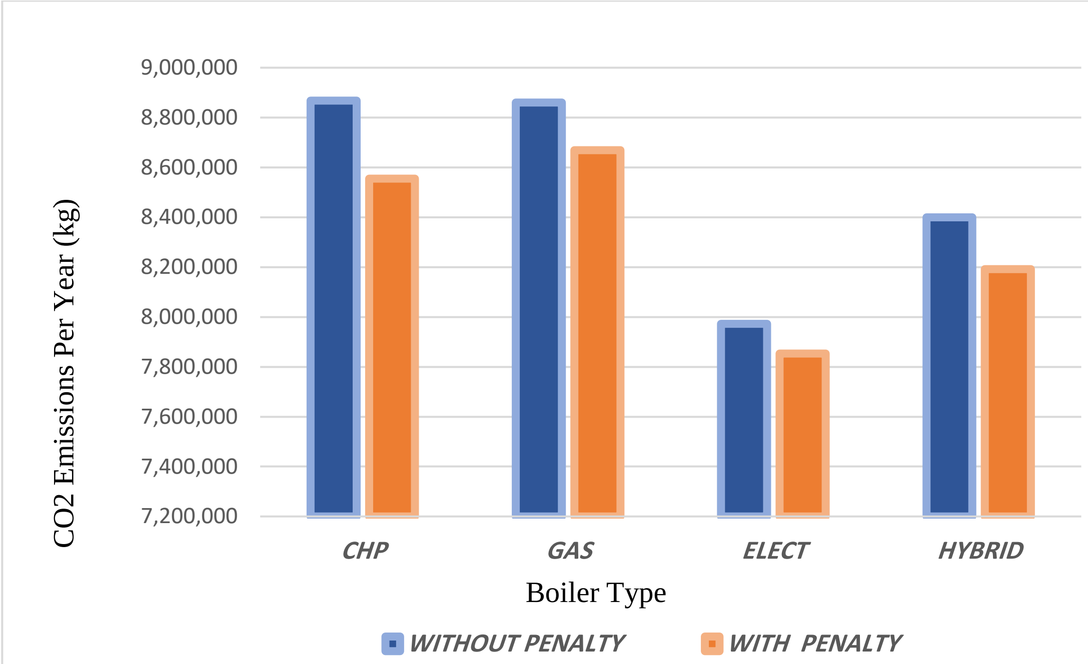

Fig. 8. CO_2 emissions per year with and without adding penalty cost to the objective function

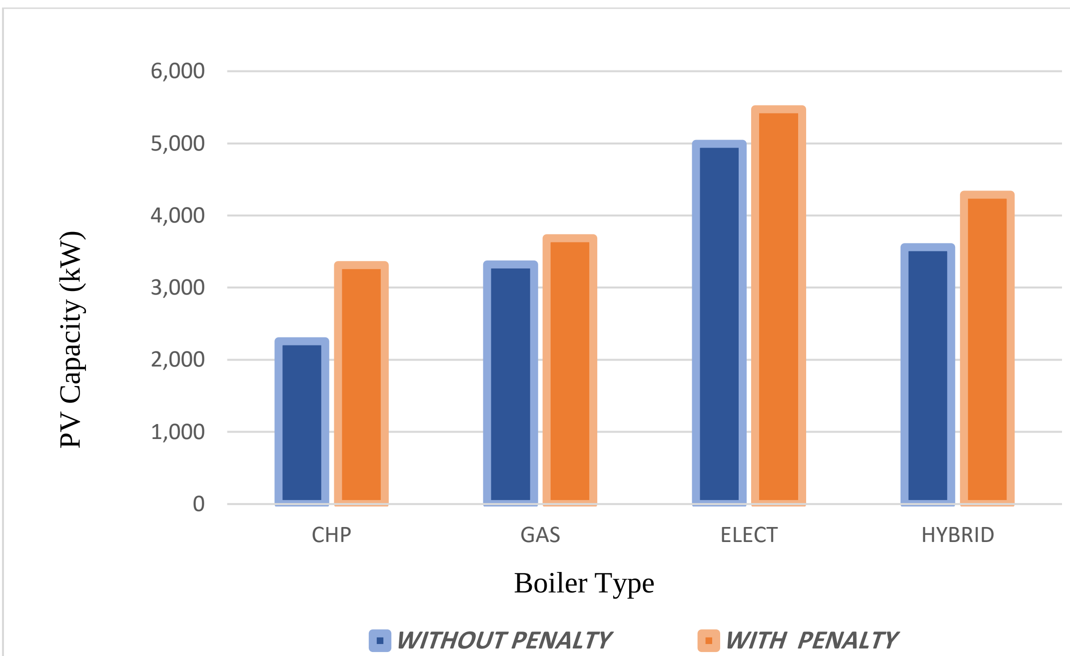

Fig. 9. PV capacity with and without adding CO_2 penalty cost to the objective function

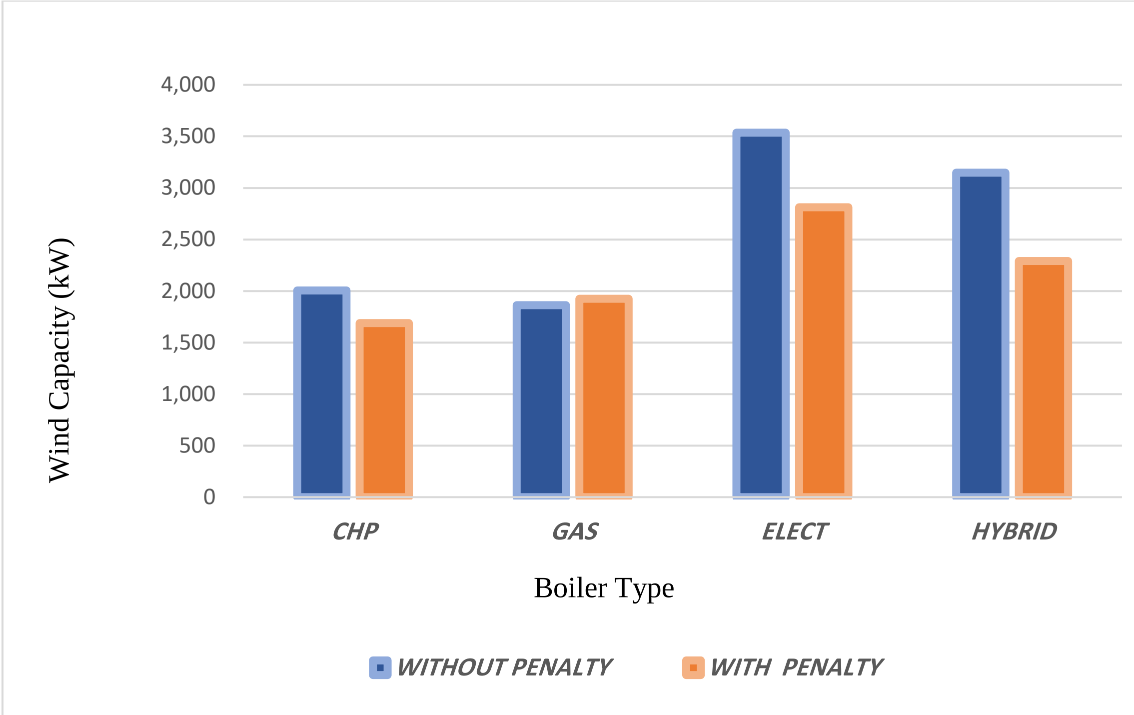

Fig. 10. Wind capacity with and without adding CO_2 penalty cost to the objective function.

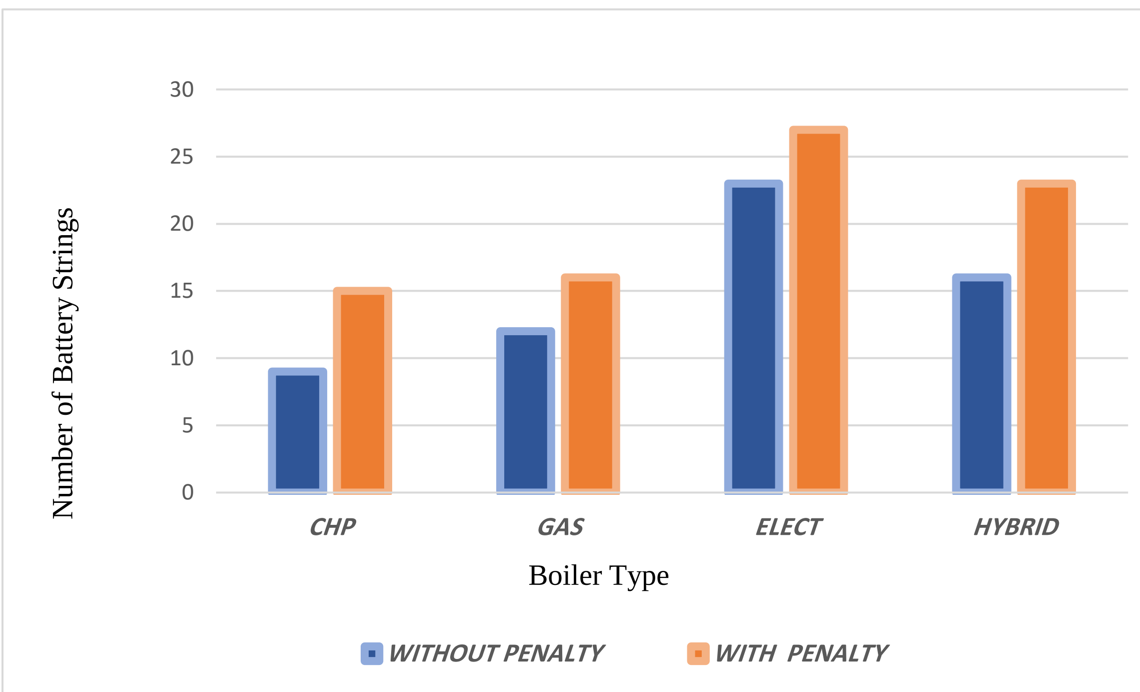

Fig. 11. Number of battery strings with and without adding CO_2 penalty cost to the objective function

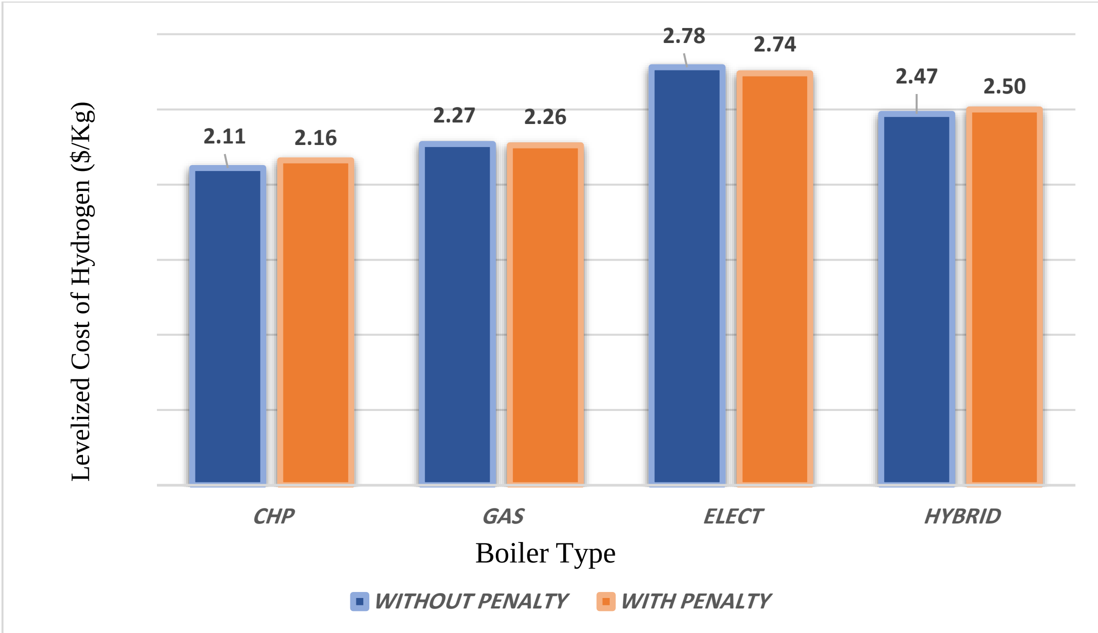

Fig. 12. LCOH with and without adding CO_2 penalty cost to the objective function

Figures 7–11 compare the results of the CHP, gas, electric, and hybrid boiler systems for the optimal cases (i.e., first rows in Tables 2, 4, 6, and 8). First, Figure 7 reports on the NPC. The NPCs of the CHP boiler is the lowest ($38,960,742 and $41,166,792 without and with a CO_2 penalty cost, respectively) because of its efficiency in partially supplying heat as a byproduct from microturbines. The NPCs are the highest when using an electric boiler ($46,516,184 and $47,653,904 without and with a CO_2 penalty cost, respectively) because it requires a greater amount of electricity generation and hence, greater capacities for PV, wind turbines, and battery storage, which incur higher costs. Specifically, the NPCs of the CHP boiler are lower than those of the electric boiler by 16.2% and 13.6% without and with a CO_2 penalty cost in the optimization, respectively. The NPC values of the gas boiler are slightly higher than those of the CHP boiler (less than 5% difference). As expected, the NPCs of the hybrid boiler are between those of the CHP and electric boilers. That is, the NPCs of the CHP boiler are 9.5% and 8.4% lower than those of the hybrid boiler without and with the CO_2 penalty cost, respectively. Overall, adding a CO_2 penalty cost to the objective function increases the NPCs in all cases because it increases the reliance on PV and wind turbines.

Figure 8 shows the annual CO_2 emissions from energy and hydrogen production. In particular, the CO_2 emissions from the CHP boiler (8,868,165 and 8,555,395 kg/y) are greater than those from the electric boiler (7,972,691 and 7,852,834 kg/y) by 11.2% and 8.9%, without and with a CO_2 penalty cost in the optimization, respectively. CO_2 emissions can be reduced in electric and hybrid boilers compared with gas and CHP boilers because of their greater reliance on PV and wind turbines. The CO_2 emissions in the case of the CHP boiler are similar to those of the gas boiler because the CHP system needs to increase the output from microturbines to supply heat while reducing the use of the gas boiler. Adding a CO_2 penalty cost to the objective function has the effects of disincentivizing and reducing CO_2 emissions in all cases.

Figures 9–11 compare the optimal component sizes. Overall, the dependence on renewable sources and battery storage is the highest for electric boilers, which necessitates a greater amount of electricity generation. Notably, the CO_2 penalty cost has an asymmetric impact on the sizes of the PV and wind units. Specifically, when the CO_2 penalty cost is added to the objective function, the capacities of the PV units increase (Figure 9), whereas those of the wind units generally decrease (Figure 10). These asymmetric changes in the PV and wind units are mainly due to the role of the converters. On one hand, the CO_2 penalty cost leads to a greater reliance on battery storage (Figure 11). On the other hand, given the increase in battery storage, it is generally less costly to charge a battery with excess energy from PV than from wind power because adding more wind units to charge a battery increases the cost of converters (AC to DC), whereas this is not the case for PV (DC to DC). All in all, adding a CO_2 penalty cost to the objective function incentivizes more PV units than wind units.

Finally, Figure 12 reports the calculated LCOH, which ranges from 2.1 to 2.8 \$/kg. The LCOH is the lowest for the CHP boiler and the highest for the electric boiler. The CHP boiler exhibits the lowest NPC and LCOH values although its CO_2 emissions are relatively high. It is worth noting that the overall NPC takes account of the CO_2 penalty cost, which can be regarded as the monetary value of environmental damage, over the project lifetime in our study. Therefore, the CHP boiler system for SMR in a microgrid environment exhibits the best performance, even if we consider the impact of CO_2 emissions.

3.5 Conclusion

This study conducted techno-economic and environmental analyses of a hybrid renewable isolated microgrid with onshore natural gas resources. The HRES consisted of a PV, wind, battery storage, a microturbine, and a steam reformer that produced grey hydrogen. Based on thermodynamic models, the heat for the SMR process was provided by four different approaches, i.e., CHP, gas, electric, and hybrid boiler systems. We examined the impacts of different thermal sources for SMR on the optimal configuration and sizing, NPC, and CO_2 emissions of a hybrid renewable isolated microgrid in East Owienat, Egypt, with and without considering the CO_2 penalty cost in the optimization.

Our main findings are as follows: (1) The CHP boiler system outperforms the other types of boilers in terms of NPC. In particular, the NPCs of the CHP boiler are lower than those of the electric boiler by 16.2% and 13.6% without and with a CO_2 penalty cost in the optimization, respectively. (2) In contrast, the CO_2 emissions from the CHP boiler are greater than those from the electric boiler by 11.2% and 8.9% without and with a CO_2 penalty cost, respectively. (3) The CO_2 penalty cost has an asymmetric impact on the sizes of the PV and wind units; that is, it incentivizes more PV units than wind units. (4) The LCOH ranges from 2.1 to 2.8 $/kg. Specifically, the LCOH is the lowest for the CHP boiler, whereas it is the highest for the electric boiler.

One may think that the CHP boiler system faces a trade-off between the NPC and CO_2 emissions. However, we emphasize that the overall NPC in our study considers the CO_2 penalty cost as a monetized environmental impact. Thus, the CHP boiler system for SMR in microgrids outperforms other boiler options, even when the impact of CO_2 emissions is considered. This study provides practical insights into the approaches for supplying heat to the SMR process in isolated microgrids. Furthermore, our approach is applicable to more general microgrids, spanning from rural to suburban areas that have access to diverse types of natural gas resources.

Our focus was on SMR, while there are other emerging technologies for hydrogen production, such as electrolysis. The combination of SMR and electrolysis to produce hydrogen in a hybrid renewable isolated microgrid is another direction for future research.

We investigated four available and representative heat source options for the SMR process. However, this study did not encompass all the aspects of boiler technologies and heat sources. Future work should aim to explore other heat sources, such as concentrated solar power.

Chapter 4: Economic Feasibility of Producing Ammonia in isolated Microgrids considering Seasonal Gas Price Flexibility.

4.1 Introduction

Ammonia is a versatile and essential chemical that plays critical roles in agriculture, industry, the energy sector, and achieving environmental sustainability. Its ability to serve as a hydrogen carrier, energy storage medium, and clean fuel makes an important element of the transition to a low-carbon economy (Bora et al., 2024). Leveraging ammonia's potential, we can enhance food security and mitigate climate change (IEA, 2021c). Ammonia produced in microgrids can be used as a fertilizer in local agricultural activities, enhancing the sustainability of rural communities (Edmonds et al., 2022). Ammonia production and utilization in microgrids are also an emerging area of interest: microgrids can house small-scale ammonia production facilities (decentralized); reduce dependency on large, centralized plants; and minimize transportation costs and emissions (Tonelli et al., 2024).

Ammonia production from fossil fuels remains widespread, largely due to the relatively high cost of green ammonia (Wang et al., 2023). Recent studies have explored blue ammonia, investigating various SMR technologies, aiming to reduce CO2 emission and enhance the economic viability (Cloete et al., 2021; Pereira et al., 2022; Mattisson et al., 2018). Despite the environmental advantages of using blue ammonia, widespread adoption has been hindered by many challenges specifically widespread adoption of CCS technology. Consequently, grey ammonia continues to dominate the market (Abu Hasan et al., 2012). Nevertheless, grey ammonia has received relatively little research attention, particularly in terms of an integrated SMR-HB process (Mayer et al., 2023). Oh et al. (2024) evaluated of the economic feasibility of transitioning from grey to blue ammonia at varying carbon tax levels.

Many studies have conducted a techno-economic analysis of green hydrogen (Blanco et al., 2022) while green ammonia has received relatively less research attention.

Some studies have explored optimal configurations of renewable systems considering the flexibility of the HB process. For example, Armijo and Philibert (2020) studied the techno-economic impact of integrating PV and wind energy, versus PV systems. Wang et al. (2023) examined the impact of optimizing PV and wind on reducing the storage cost requirements. Osman et al. (2020) adopted an inflexible HB approach in designing a water desalination unit supported by renewable energy. Gallardo et al. (2021) compared flexible and inflexible HB systems supported by solar energy. Furthermore, various studies have identified geographical locations that have the lowest LCOA (Kakavand et al., 2023; Fasihi et al., 2021). The economic impact of replacing diesel fuel with green ammonia in an isolated grid has also been investigated by (Morgan et al., 2014) while minimizing LCOA has received less research attention (Salmon et al.,2021).

Isolated grids in remote locations often face electricity deficits due to their heavy reliance on diesel generators (Granovskii et al., 2007). Several studies have investigated the optimization of the HRES isolated grids for minimizing the NPC, or explored methods for producing green and grey hydrogen (Weidlich, 2016; Abdin et al., 2019). However, the economic feasibility of ammonia production in isolated microgrids and mini-grids powered by HRESs remains unexplored, whereas many studies have focused on ammonia production in the context of conventional stations.

Natural gas, which is used in the SMR process, is subject to fluctuating market prices determined by demand and supply. Particularly, high price during the peak demand and a low price during the off-peak demand are typical in gas markets such as the European Energy Exchange. High gas demand poses a significant challenge; surges in gas prices in many countries, e.g., the European Union experience of heightened demand during the winter heating season (IEA, 2023b); Egypt’s elevated summer demand due to peak power generation (Rashad and El Safty., 2024). Although many studies have investigated gas markets and prices across different countries and regions (Aune et al., 2009; Niyazmuradov and Heo, 2017, Shahrukh et al., 2019; Abada et al., 2017), to our knowledge, a lack of studies has examined the impact of gas price fluctuations on ammonia production in isolated microgrids with HRESs. Adjusting the microgrid's operations to accommodate seasonal gas price fluctuation could enhance ammonia production.

To address existing research gaps, this study conducts a techno-economic analysis of an isolated microgrid supplied by HRES for producing green and grey ammonia. the HRES comprises PV, wind, battery storage, converter, microturbines, SMR, electrolyzer, HB unit, and ammonia storage. We consider the gas price flexibility through applying two gas prices, high price during the peak demand and low price during the off-peak demand. changing ammonia operation and configuration based on changing the seasonal gas price could be effective. Therefore, we suggest three systems that have different ammonia generation and configuration. These systems adjust ammonia generation and storage strategies during low gas-price periods to avoid the burden of expenses during high gas-price periods. Specifically, during low gas-price periods, the first system stores grey ammonia, while the second system stores green ammonia. In the third system, green and grey ammonia are stored during low gas-price periods. Using various values of the two gas prices a comparative analysis of NPC and LCOA before and after applying three systems are conducted. HOMER Pro software is used to model an isolated grid supporting an agricultural area in East Owienat, Egypt.

Our study contributes to the literature in several ways:

- Extension of HRES Literature: This study extends the current research on HRESs, which has only focused on hydrogen. We examine the economic feasibility of ammonia production in HRESs and its impact on the total system NPC and the LCOA.
- Analysis of multiple gas price scenarios: unlike previous studies that considered a single gas price in their project planning, our study considers multiple gas prices, providing a more comprehensive analysis of the economic and dynamic aspects of gas procurement. This approach also applies to other entities that rely on natural gas and have affordable storage infrastructure.
- Innovative operation and configuration mechanisms: Our study evaluates different operational and configuration mechanisms for green and grey ammonia production. While previous studies have considered a single configuration. multi-configuration offers a more nuanced understanding of the factors influencing ammonia production.

- Focus on isolated grids with natural gas resources: We examine the use of isolated grids with broader access to natural gas resources, thus contributing to the literature by applying energy models to specific locations with defined resources. Previous studies have often overlooked policy implications, concentrating instead on technical aspects of energy models. Our study innovatively incorporates policy considerations in the research design.

Given the above features, our study broadens the scope of existing research and provides valuable insights into the economic and operational aspects of ammonia production in the context of HRESs.

This chapter consists of five sections. Section 4.2 details the methodology, including the ammonia load for HB, configuring the suggested systems that use multiple gas prices, and estimating the grid NPC and LCOA. Section 4.3 outlines the cost data for the isolated grid components of green and grey ammonia production systems, including capital and operating costs. Section 4.4 discusses the outcomes of the simulated scenarios, comparing the different systems' NPC and LCOA, using multiple gas prices, and It closes with a discussion of best system scenarios. Finally, Section 4.5 draws the conclusion and suggests a direction for future work.

4.2 Methodology

4.2.1 Ammonia load and hydrogen source for HB

Producing ammonia through the HB process is based on the following chemical reaction between hydrogen and nitrogen (Zhadan et al., 2021):

$$3H2 + N2 = 2NH3, \qquad \Delta H\circ = 91.8\ kJ/mol \qquad (12)$$

Where the enthalpy change, $\Delta H\circ$, is a parameter that determines whether a chemical reaction releases or absorbs heat. Positive values of $\Delta H\circ$ indicate heat absorption (in J/mol). We assume that the hydrogen load is 100 kg/hr. Every tone of ammonia encompasses 177 kg of hydrogen and 823 kg of nitrogen (Rivarolo et al., 2019); therefore, we assume an ammonia load of 565 kg/hr and nitrogen of 465 kg/hr, neglecting HB losses. An air separation unit provides the nitrogen for the HB process, while the electrolyzer and reformer supply the hydrogen. We assume the electrolyzer size is 1.6 MW. The capacity of 3.2 MW can absorb all excess renewable energy and is selected by gradually increasing the electrolyzer capacity in HOMER Pro until all excess energy is converted into hydrogen. The capacity of 1.6 MW (half of the full 3.2 MW) is to assess the case where half of the excess renewable energy is discarded given that the cost for electrolyzers is still expensive. The required amount of natural gas required for (SMR) grey ammonia production can be calculated from the following reformer efficiency:

$$Reformer\ efficiency = \frac{Amount\ of\ hydrogen\ output\ * Hydrogen\ lower\ heating\ value}{Amount\ of\ natural\ gas\ input * Natural\ gas\ lower\ heating\ value} \tag{13}$$

where the efficiency rate is set at 0.76 (Younas et al., 2022).

4.2.2 Isolated grid configuration with multiple gas prices

Fig. 13 illustrates the main components of the isolated microgrid. The HRES comprises PV panels, wind turbines, battery storage, and microturbines. We selected microturbines over diesel generators as a backup source in light of their lower CO2 emissions and the availability of natural gas. The hydrogen required for the HB process is supplied by a steam reformer using natural gas, and an electrolyzer powered by excess energy from PV and wind. We assume that natural gas used in the SMR process is subject to multiple prices with two seasons, i.e., a high price with peak gas demand and a low price with off-peak gas demand.[5]

We examine three grid systems, each aiming to reduce gas procurement during the peak demand while increasing it during the off-peak demand. This is achieved by increasing ammonia production when the gas price is low (off-peak demand) and storing it to meet the demand during a high gas price period (peak demand). The first system (System 1) depends on generating and storing grey ammonia without resorting to an electrolyzer. The second system (System 2) produces grey and green ammonia using a steam reformer and an electrolyzer but stores only green ammonia. The third system (System 3) combines System

[5] This is not assumed for microturbines because we don't store gas at all. Also, they are backup sources with a limited contribution to the HRES and do not participate in ammonia production.

1 and System 2 by generating and storing grey and green ammonia. In our approach, we consider storing grey ammonia in systems 1 and 3 necessitates a doubling of reformer capacity, since full scale ammonia generation is during off peak demand, while in the second system the capacity remains constant in the two seasons as only green ammonia is stored. Based on various values of the two gas prices, we analyze whether relying on the reformer in System 1 is a better approach or leveraging the grid's excess energy through the use of an electrolyzer in Systems 2 and 3 yields better results. To examine the effectiveness of applying the three systems, we compare them with baseline systems with and without an electrolyzer, where ammonia is not stored at all. This specifically facilitates an analysis of the economic feasibility of ammonia storage during low gas price periods.

4.2.3 Total net present cost

We minimize the NPC of the system (in dollars) as follows:

$$\text{Min: NPC} = C_{\square} + R_{\square} + O\&M_{\square} - S_{\square} \tag{14}$$

Where NPC represents the present value of all costs incurred throughout the lifespan of the project, including capital cost (C), replacement cost (R), operation and maintenance cost (O&M), and salvage costs (S). Optimization of the NPC for the HRES components assumes a timeframe of 25 years, using a 6% discount rate.

Given the negative societal impact of CO2 emissions, we consider CO2 penalty costs, which can be regarded as a carbon tax payment (carbon tax × CO2 pollution). For instance, according to the International Energy Agency (IEA, 2019a), CO2 penalty costs, would be $16/ton in 2020, and are projected to increase to $75/ton by 2030 in developing economies. We assume a CO2 penalty of $50/ton. Although HOMER Pro can add CO2 penalty cost into the objective function, we deliberately omit this option since we are not focusing on the impact of CO2 penalty costs on the optimal NPC. Instead, we treat it as a monetized representation of environmental impact, factoring it in as an ex-post addition to the NPC after optimization.

HOMER Pro enables the integration of the electrolyzer and reformer in the HRESs, however, it has certain limitations for conducting their seasonal analysis and lacks HB functionality. Therefore, once the optimization of the HRES is completed, the costs of these components are added to the NPC. This approach does not affect the optimization process because these components are treated as independent elements, with a fixed ammonia load. Similar approaches have been adopted in other studies to add external devices that HOMER Pro cannot handle. For example, Elsaraf et al. (2021) investigated the impact of using a solar thermal system in isolated microgrids in Canada, which HOMER Pro is unable to model. They added solar thermal cost to that of the electric heater. Notably, the inflexibility of the HB process has been considered in other studies where the HB unit operates independently and does not influence the optimization process. Moreover, some of these studies have used HOMER Pro software in scenarios involving HB with PVs, highlighting the adaptability of methodologies despite inherent limitations (Kakavand et al., 2023).

4.2.4 Levelized cost of ammonia

The total NPC of the system in our study is comprised of two fundamental elements: one from energy production and the other from ammonia production.

$$NPC = NPC\ for\ energy\ production + NPC\ for\ ammonia\ production \tag{15}$$

We consider cases with and without the reformer, electrolyzer, and HB, allowing us to calculate the total NPC and the NPC for energy production. The difference between these two values yields the NPC required for ammonia production. The LCOA is then determined based on the net present value of ammonia consumption over the project's lifetime.

4.3 Data

4.3.1 Load Profile

The case study is in East Owienat, a remote agricultural area in Egypt's western desert. It spans over five hundred thousand acres and relies on underground water for irrigation (Kamel and Dahl, 2005). Our HRES supplies a small-scale area, approximately 100 acres. There are two types of loads: 1) residential demand (36,683 kWh/year or 101 kWh/d), and 2) submersible irrigation pumps for land reclamation (582,973 kWh/year or 1597 kWh/day). The load data were acquired in 2005 (Kamel and Dahl, 2005), so we estimate a 3% annual load growth (Mondal et al., 2019). We assume a constant hydrogen consumption for HB unit of 876000 kg/y or 100/kg/h for agriculture facilities. Although East Owinat is an agricultural region, to our knowledge, it doesn't have ammonia projects.

4.3.2 Cost of microgrid components

Table 10 presents cost data for components sourced from DOE (2016), IEA (2019a), Canada (2019), Al-Badi et al. (2022), and Armijo and Philibert (2020). The operating and maintenance costs for the converter, boiler, and thermal tank are regarded as negligible.

Table 10. Cost of microgrid components for grey and green ammonia production

Type	Cost
PV: [a]	
Capital cost	1,000 $/kW
Operation and maintenance cost	10 $/kW/y
Wind turbine: [a]	
Capital cost	900 $/kW
Operation and maintenance cost	36 $/kW/y
Battery storage: [a]	
Capital cost	203,000 $/MW
Operation and maintenance cost	10 $/kW/y
Converter: [a] Capital cost	500 $/kW
Microturbine: [b]	
Capital cost	2,500 $/kW
Operation and maintenance cost (without fuel cost)	1.2 ¢/kWh
Reformer: [c]	
Capital cost	910 $/kWh
Operation and maintenance cost (without fuel cost)	4.7% of capital cost/year
Electrolyzer: [c]	
Capital cost	900 $/kWh
Operation and maintenance cost	

	1.5 % of capital cost/year
Gas boiler: d) Capital cost	52,500 \$/MW (50,000 €/MW, 1 €=1.05 \$)
Thermal tank: d) Capital cost	2,100 \$/MW (2,000 €/MW, 1 €=1.05 \$)
Average price of natural gas: e)	0.4 \$/m^3
Ammonia Storage: f)	0.14\$/ kWh
Hydrogen buffer (HBF): f) Capital cost	580 \$/kW (LHV-H2)
Air separating unit (ASU): f) Capital cost Operation and maintenance cost	 224 \$/kW (LHV-H2) 2 % of capital cost/year
Electicity HBF-ASU: f)	0.64 MWh/t NH3
Electicity pre-compression: f)	0.26 MWh/t NH3
H_2 storage for HB: f) * Capital cost Operation and maintenance cost	 12 \$/kWh (LHV-H2) 1% of capital cost/year
The power needed for the H2 compression before storage: f)	1.5 kWh/kg H2

Source: a) Al-Badi et al. (2022); b) DOE (2016); c) IEA (2019a); d) Chintada (2019); e) Gas Regulatory Authority (GASREG), https://www.gasreg.org.eg/natural-gas-pricing/.; f) Armijo and Philibert (2020).

Note: * HB typically uses storage for hydrogen (cylinder storage in our model).

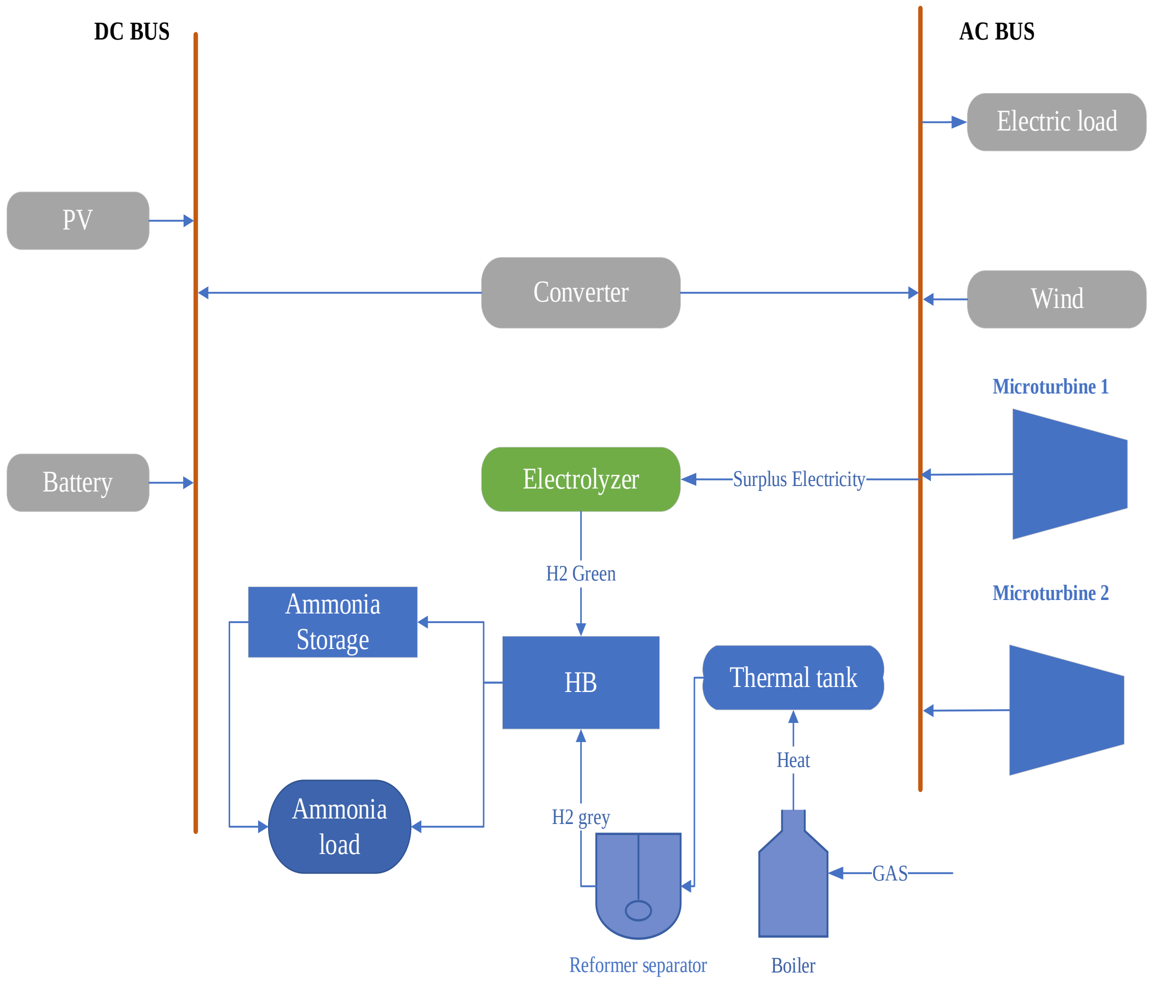

Fig. 13. Overview of the isolated microgrid with HB and ammonia storage

4.4 Results and discussion

Using various values of the two gas prices we compared baseline cases without and with applying the three systems. Figures (14-17) illustrate the NPC and LCOA for the baseline cases and the three systems using various values of the two gas prices ranging from 0.02, 0.78 $/m3 to 0.38, 0.42 $/m3, with a step difference of 0.02 $/m3. We have two cases 1) Case A uses an electrolyzer size of 3.2 MW in Figures 14 and 15 2) Case B uses an electrolyzer of 1.6 MW in Figures 16 and 17. These Figures show the best cost option at each price point and the range of gas prices for each system, which allow for cost savings to the isolated grid.

To detail our results, we have confined our analysis using three price points representing three values of the two gas prices (0.3, 0.5; 0.2, 0.6; 0.1,0.7). These prices have low and high gas price differences with an average equal to the fixed gas price of the baseline cases. By leveraging the three systems, our analysis is focused on achieving two key goals. The first is to identify the best cost system. The second is to identify the grid savings ($) and the gas market savings (m3).

4.4.1 The grid's best cost system

Tables 11-18 elaborate on the total NPC with and without applying systems. Tables 11-14 show Case A using a 3.2 MW electrolyzer, and Tables 15-18 Case B using a 1.6 MW electrolyzer. The first and second rows for all tables refer to the NPC for baseline systems without and with an electrolyzer, where ammonia is not stored at all. System 1's NPC remains the same in Cases A and B because it only depends on the reformer.

As a reference, Tables 11 and 15 display the NPC for baseline systems without ammonia storage. The NPC in the first and second rows of Table 11 is identical to its counterpart in rows in Tables 12, 13, and 14, and similarly for Tables 15, 16, 17, and 18. This consistency arises because ammonia is not stored in the baseline system, and the average of the two gas prices equals the fixed price.

Table 11. Case A: Isolated grid at baseline system & gas price of 0.4 $/m3.

Grid system	Electrolyzer capex ($)	Electrolyzer opex ($)	Reformer capex ($)	Reformer opex ($)	Ammonia storage cost ($)	Gas cost low-price period ($)	Gas cost high-price period ($)	NPC ($)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	10,463,959	10,463,959	50,694,833
Baseline with electrolyzer	2,881,440	43,221	2,779,358	130,629	0	9,511,739	9,511,739	51,164,636

Table 12. Case A: Isolated grid at baseline and varied systems & gas prices 0.3 & 0.5 $/m^3

Grid system	Electrolyzer capex ($)	Electrolyzer opex ($)	Reformer capex ($)	Reformer opex ($)	Ammonia storage cost ($)	Gas cost low-price period ($)	Gas cost high-price period ($)	NPC ($)

Baseline without electrolyzer	0	0	3,057,600	143,707	0	7,847,969	13,079,949	50,694,833
Baseline with electrolyzer	2,881,440	43,221	2,779,358	130,629	0	7,133,804	11,889,677	51,164,636
System 1	0	0	6,115,200	287,414	2,796,192	15,695,938	0	51,460,352
System 2	2,881,440	43,221	3,057,600	143,707	253,456	7,847,969	10,709,864	50,551,557
System 3	2,881,440	43,221	4,965,542	233,380	2,542,736	14,274,887	0	50,554,506

Table 13. Case A: Isolated grid at baseline and varied systems & gas prices 0.2 & 0.6 \$/m^3

Grid system	Electroly-zer capex (\$)	Electroly-zer opex (\$)	Reformer capex (\$)	Reformer opex (\$)	Ammonia storage cost (\$)	Gas cost low-price period (\$)	Gas cost high-price period (\$)	NPC (\$)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	5,231,979	15,695,938	50,694,833
Baseline with electrolyzer	2,881,440	43,221	2,779,358	130,629	0	4,755,871	14,267,612	51,164,636
System 1	0	0	6,115,200	287,414	2,796,192	10,463,959	0	46,228,373
System 2	2,881,440	43,221	3,057,600	143,707	253,456	5,231,979	12,851,837	50,077,540
System 3	2,881,440	43,221	4,965,542	233,380	2,542,736	9,515,925	0	45,796,544

Table 14. Case A: Isolated grid at baseline and varied systems & gas prices 0.1 & 0.7 \$/m^3

Grid system	Electroly-zer capex (\$)	Electroly-zer opex (\$)	Reformer capex (\$)	Reformer opex (\$)	Ammonia storage cost (\$)	Gas cost low-price period (\$)	Gas cost high-price period (\$)	NPC (\$)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	2,615,989	18,311,928	50,694,833
Baseline with electrolyzer	2,881,440	43,221	2,779,358	130,629	0	2,377,935	16,645,547	51,164,636
System 1	0	0	6,115,200	287,414	2,796,192	5,231,980	0	40,996,394
System 2	2,881,440	43,221	3,057,600	143,707	253,456	2,615,989	14,993,809	49,638,437
System 3	2,881,440	43,221	4,965,542	233,380	2,542,736	4,757,962	0	41,038,581

Table 15. Case B: Isolated grid at baseline system & gas price of 0.4 $/m3

Grid system	Electrolyzer capex ($)	Electrolyzer opex ($)	Reformer capex ($)	Reformer opex ($)	Ammonia storage cost ($)	Gas cost low-price period ($)	Gas cost high-price period ($)	NPC ($)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	10,463,959	10,463,959	50,694,833
Baseline with electrolyzer	1,440,720	21,611	2,874,144	135,085	0	9,867,514	9,867,514	50,638,124

Table 16. Case B: Isolated grid at baseline and varied systems & gas prices 0.3 & 0.5 $/m^3$

Grid system	Electrolyzer capex ($)	Electrolyzer opex ($)	Reformer capex ($)	Reformer opex ($)	Ammonia storage cost ($)	Gas cost low-price period ($)	Gas cost high-price period ($)	NPC ($)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	7,847,969	13,079,949	50,694,833
Baseline with electrolyzer	1,440,720	21,611	2,874,144	135,085	0	7,400,635	12,334,392	50,638,124
System 1	0	0	6,115,200	287,414	2,796,192	15,695,938	0	51,460,352
System 2	1,440,720	21,611	3,057,600	143,707	159,392	7,847,969	11,588,836	50,079,606
System 3	1,440,720	21,611	5,766,634	271,031	2,643,027	14,801,270	0	50,764,064

Table 17. Case B: Isolated grid at baseline and varied systems & gas prices 0.2 & 0.6 $/m^3$

Grid system	Electrolyzer capex ($)	Electrolyzer opex ($)	Reformer capex ($)	Reformer opex ($)	Ammonia storage cost ($)	Gas cost low-price period ($)	Gas cost high-price period ($)	NPC ($)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	5,231,979	15,695,938	50,694,833
Baseline with electrolyzr	1,440,720	21,611	2,874,144	135,085	0	4,933,757	14,801,270	50,638,124
System 1	0	0	6,115,200	287,414	2,796,192	10,463,959	0	46,228,373
System 2	1,440,720	21,611	3,057,600	143,707	159,392	5,231,979	13,906,603	49,781,383
System 3	1,440,720	21,611	5,766,634	271,031	2,643,027	9,867,514	0	45,830,308

Table 18. Case B: Isolated grid at baseline and varied systems & gas prices 0.1 & 0.7 $/m^3

Grid system	Electrolyzer capex ($)	Electrolyzer opex ($)	Reformer capex ($)	Reformer opex ($)	Ammonia storage cost ($)	Gas cost low-price period ($)	Gas cost high-price period ($)	NPC ($)
Baseline without electrolyzer	0	0	3,057,600	143,707	0	5,231,979	15,695,938	50,694,833
Baseline with electrolyzer	1,440,720	21,611	2,874,144	135,085	0	2,466,879	17,268,150	50,638,124
System 1	0	0	6,115,200	287,414	2,796,192	5,231,980	0	40,996,394
System 2	1,440,720	21,611	3,057,600	143,707	159,392	2,615,989	16,224,370	49,483,160
System 3	1,440,720	21,611	5,766,634	271,031	2,643,027	4,933,757	0	40,896,551

Table 19. The grid and gas market saving using the three systems

Grid savings ($)		
Prices 0.3-0.5 $/m^3		
Grid system	Case-A savings ($)	Case-B savings ($)
System 1	No	No
System 2	143,276	615,227
System 3	140,327	No
Prices 0.2-0.6 $/m^3		
Grid system	Case-A savings ($)	Case-B savings ($)
System 1	4,466,460	4,466,460
System 2	617,293	913,450
System 3	4,898,289	4,864,525
Prices 0.1-0.7 $/m^3		
Grid system	Case-A savings ($)	Case-B savings ($)
System 1	9,698,439	9,698,439

System 2	1,056,396	1,211,673
System 3	9,656,252	9,798,282
	Gas market savings (m^3)	
	Case-A savings (m^3)	Case-B savings (m^3)
System 1	2,022,160	2,022,160
System 2	182,398	115,262
System 3	1,838,952	1,906,898

For Case A: In Table 11, leveraging a reformer presents clear advantages. Given that green ammonia has a higher levelized cost than grey ammonia, integrating the electrolyzer tends to elevate total NPC. For Tables 12, 13, and 14, System 2, System 3, and System 1 emerge as the most cost-effective choices respectively. In Table 12, at a low-price difference resorting to an electrolyzer supported by surplus energy for storing ammonia in system 2 is better than increasing the reformer capacity. In Table 13, as the price difference increased, resorting to an electrolyzer supported by surplus energy and increasing the reformer capacity for storing ammonia in System 3 is the best option. When the price difference becomes significant in Table 14, eliminating the electrolyzer and increasing the reformer capacity for storing ammonia in System 1 is more favorable. It should be noted that high price differences prove more advantageous for System 1 and System 3 since they generate grey ammonia during low gas price season.

For Case B: In Table 15 adding the electrolyzer is better because the levelized cost of green ammonia is lower than that of grey. It is worth noting that the levelized cost of green ammonia varies between cases A and B. The electrolyzer remains idle at times due to insufficient excess energy availability. Hence, opting for a larger electrolyzer size “Case A” yields higher capital expenditure (CAPEX) and operational expenditure (OPEX), which elevates the LCOA. The best cost options for Tables 16 and 17 are System 2 and System 3, respectively, which align with Tables 12 and 13 results for case A. In Table 18, System 3 has the lowest cost, however, if the price difference becomes higher, e.g., (0.06, 0.74), eliminating the electrolyzer and increasing the reformer capacity for storing ammonia in the first system is preferable like that is Case A table (14), more details are in Appendix D.

Notably, System 1 has the highest gas volume during the low gas-price season, followed by System 3 and then System 2. Consequently, System 1 generally achieves the lowest cost with a significantly large gas price difference, while System 2 offers the lowest cost at a smaller gas price difference. Note that if the gas price difference is significantly small, which is not the focus of this study, the baseline without an electrolyzer can yield the least cost. All in all, cases A, and B have the same results for the low and high gas price difference which ensures the homogeneity of the results using different electrolyzer sizes.

4.4.2 Grid and gas market savings using the three systems

The grid and gas market can achieve savings after applying the three systems. Although the grid saves in gas costs ($) by reducing the gas purchase during the peak demand, it incurs excess cost ($) by augmenting the components capacity during the off-peak demand. The grid can benefit ($) if the savings in gas cost outweigh the excess cost of the components. On the other hand, the gas market achieves gas volume saving (m3) by increasing ammonia production during the off-peak demand and reducing it during the peak demand.

Table 19 illustrates the grid and gas market savings for cases A and B, after applying the three systems.

- **The grid savings ($)**

a) System 1 saving is constant for both cases because it neglects using the electrolyzer.

In Systems 2 and system 3:

-Levelized cost of green ammonia (LCOGA) case B is lower than Levelized cost of green ammonia LCOGA case A.

-The gas purchase savings of case A is higher than the gas purchase savings of case B

-E.g., If the savings in gas purchase case A outweigh the savings in LCOGA in case B, Case (A) has better savings, and vice versa.

b) For system 2: at all gas price differences Case B achieves better saving

-The saving in the LCOGA of case B Outweights The saving in the gas purchase in case A.

c) For system 3

At a low-price difference case A is better

-The gas purchase savings of case A outweighs the savings in LCOGA in case B.

At a high price difference case B is better

-The saving in the LCOGA of case B outweighs the saving in the gas purchase in case A.

- **Gas market savings during the peak demand (Exempted consumption (m3))**

a) System 1 saving is constant for both cases because it neglects using the electrolyzer.

b) The second system, case A achieves better savings because it doesn't store grey ammonia at all. It only stores green ammonia. This case has a bigger electrolyzer size that manages it to store more green ammonia volume during off peak demand compared to case B, which can replace bigger grey ammonia volume during peak demand.

c) The third system, case B achieves better savings because it stores all grey ammonia during the off-peak demand. Case B uses a lower electrolyzer size, so it can store more grey ammonia volume during off peak demand, compared to case A, which can replace bigger grey ammonia volume during peak demand.

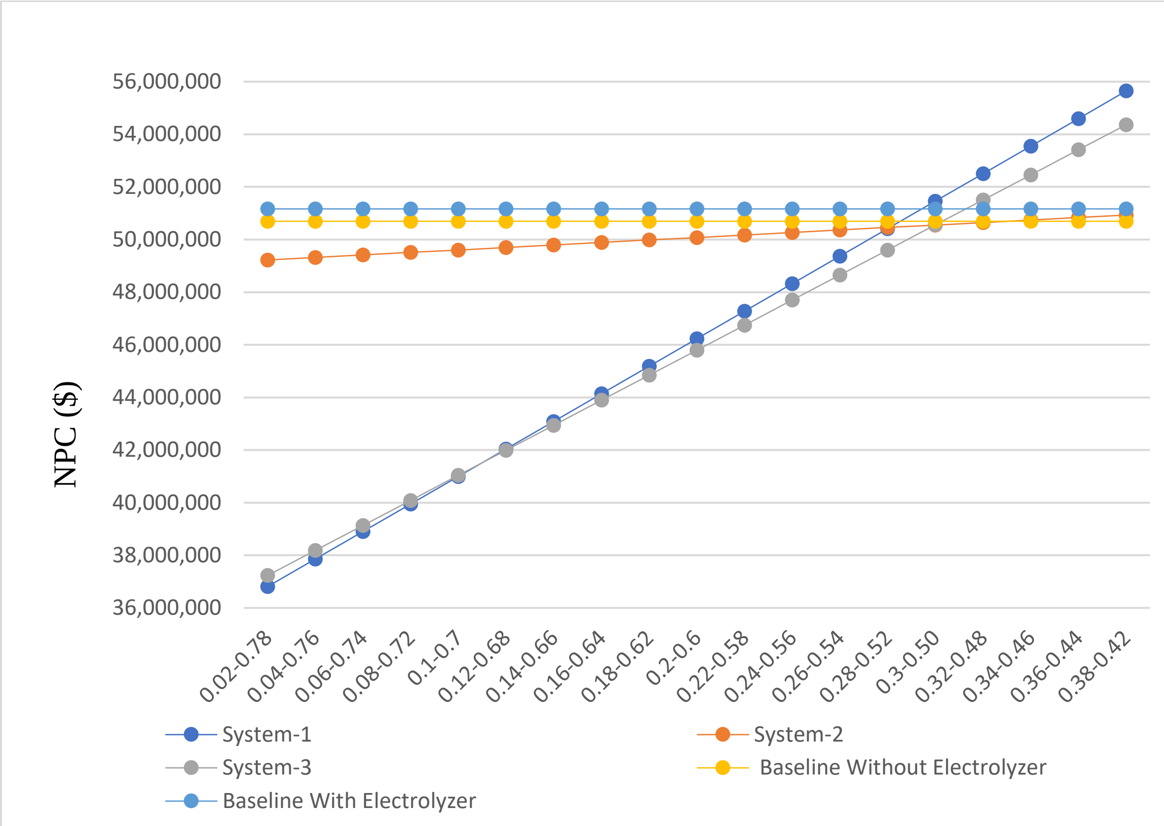

Fig. 14. Case A: isolated grid net present cost

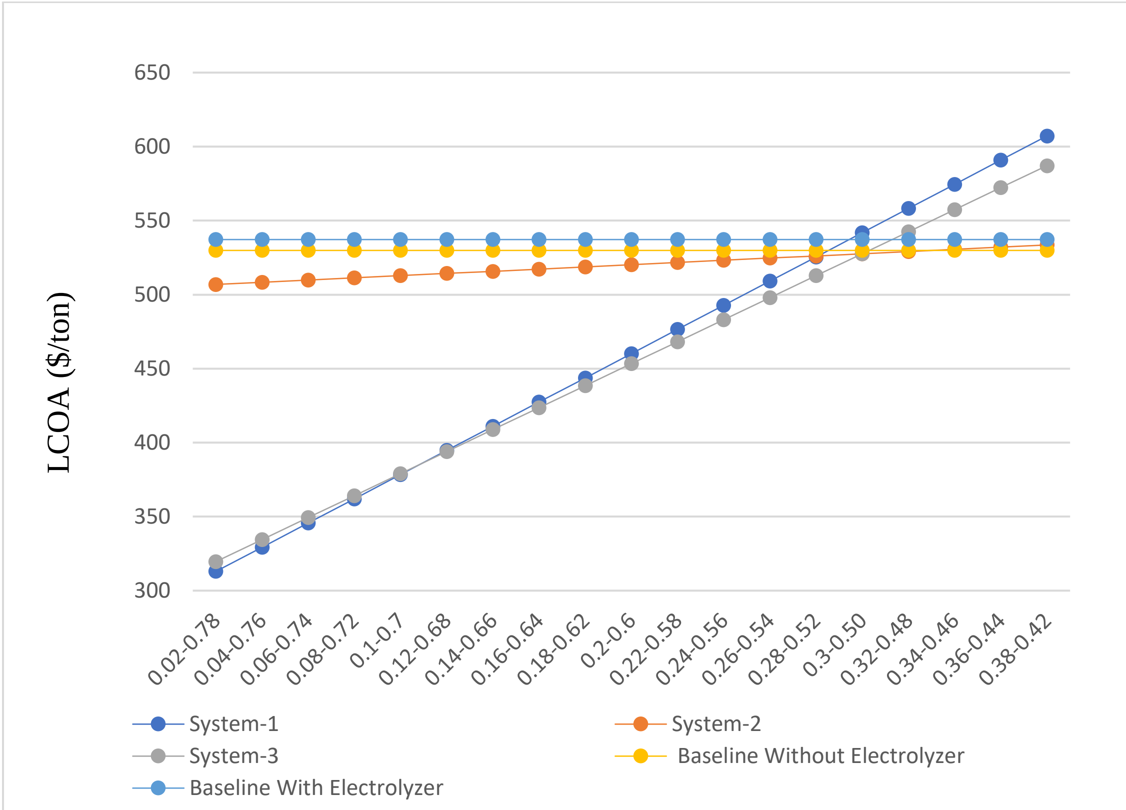

Fig. 15. Case A: isolated grid Levelized cost of ammonia

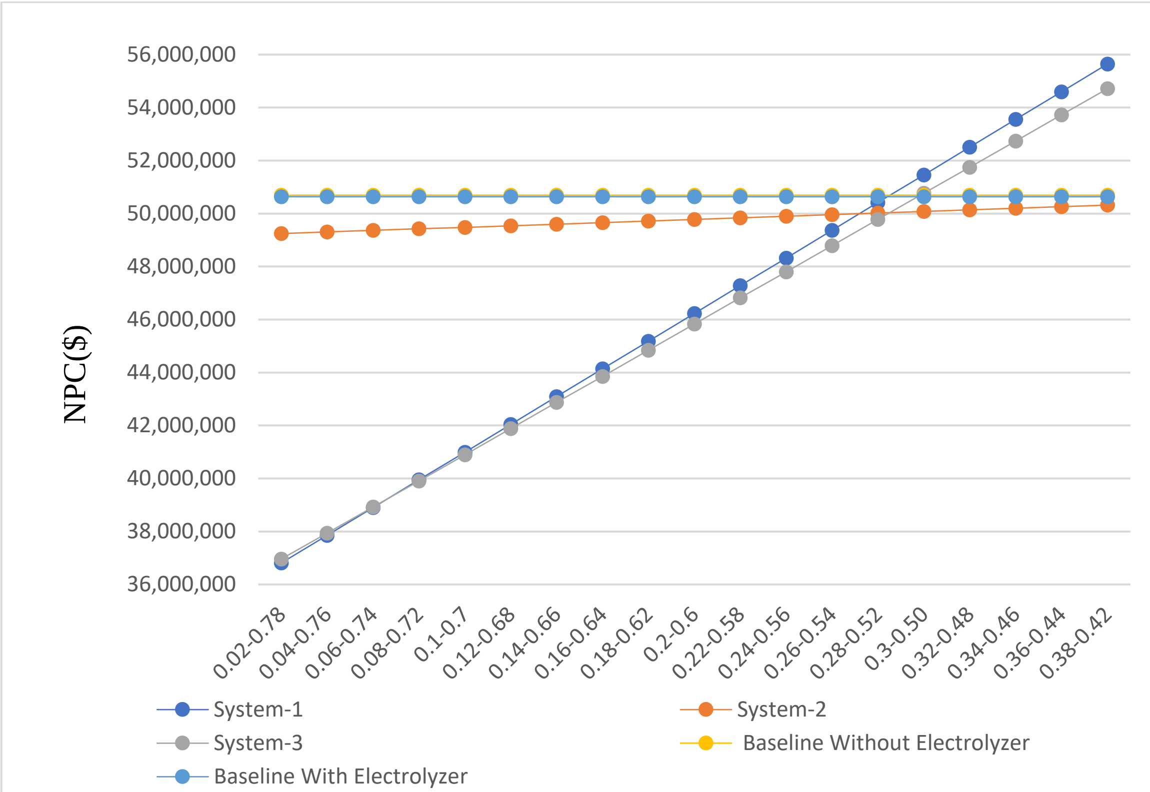

Fig. 16. Case B: isolated grid net present cost

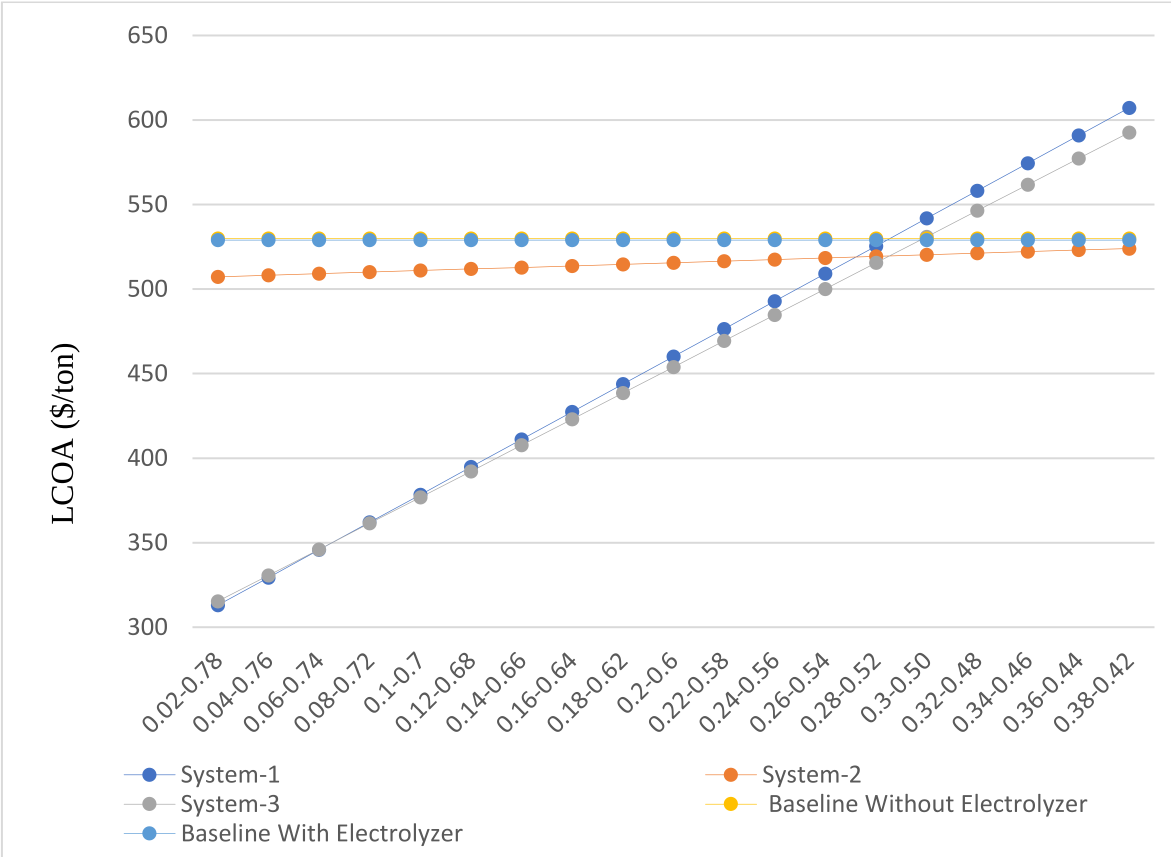

Fig. 17. Case B: isolated grid levelized cost of ammonia

4.5 Conclusion

This study conducted an economic analysis of a hybrid renewable isolated microgrid with onshore natural gas resources for ammonia production. The HRES comprised PV panels, wind turbines, battery storage, a microturbine, an electrolyzer, and a steam reformer to produce grey and green ammonia through the HB process. We considered seasonal gas price fluctuation by applying two gas price scenarios, representing peak and off-peak demand for natural gas. We adopted three systems that adjusted the ammonia production and storage during the off-peak demand for reducing the gas purchase burdens during the peak demand. System 1 relied on the reformer for producing and storing ammonia. System 2 used an electrolyzer and reformer for producing ammonia, while only electrolyzer for storing ammonia. System 3 utilized electrolyzer and reformer for generating and storing ammonia. We examined the impact of changing seasonal gas prices on the grid NPC and LCOA with and without using the three systems to identify, whether we need to use an electrolyzer supported by surplus energy for storing ammonia in systems 2 and 3 or to increase the reformer capacity in the first system. The analysis considered two electrolyzer sizes of 3.2 MW (Case A) and 1.6 MW (Case B). Our key findings are:

Using a 3.2 MW electrolyze:

1) At a fixed gas price, relying on the reformer for ammonia production was more favorable than adding an electrolyzer.
2) At a low-price difference (0.3, 0.5) relying on the electrolyzer supported by excess energy in the system 2 for storing ammonia is better than increasing the reformer capacity.
3) As the gas price difference increased (0.2, 0.6) better to use an electrolyzer and increase the reformer capacity in system 3.
4) Further increases in price difference (0.1, 0.7) favored to increasing the reformer capacity and eliminating the electrolyzer in system 1.

Using 1.6 MW electrolyzer:

1) Adding the electrolyzer was preferable at a fixed gas price.
2) For price differences of (0.3, 0.5) and (0.2, 0.6), similar results were observed as that with the 3.2 MW electrolyzer,
3) For a higher price difference (0.1, 0.7) favored System 3, with the electrolyzer's presence, while to eliminate the electrolyzer such as case A further increase in the price difference is required.

We analyzed the cost savings realized by the isolated grid through applying the three Systems, furthermore, we determined the reduction in gas consumption during the peak demand season. All in all, adjusting the grid's seasonal systems in response to fluctuating gas prices appears to be a favorable approach. Lower gas prices during periods of low demand may encourage grid operators to increase production and use storage, taking advantage of cost savings. On the other hand, during peak periods when gas demand falls, this adaptive strategy may allow for more efficient resource allocation and management.

Chapter 5: Conclusion

5.1 Summary

Isolated grids are self-sustaining electrical systems that operate independently of larger interconnected grids. They often exist in remote or isolated regions where connecting to a broader network is impractical or not economical. They typically draw upon local power sources, including diesel generators, which support the electricity requirements of the local community or facility they serve, offering a localized solution to energy needs in areas beyond the reach of centralized infrastructure. Isolated grids pose significant challenges to exacerbating the climate crisis. These hurdles arise from the grid's dependence on conventional energy sources, and the necessity for sustainable development approaches. While dependency on renewable energy as a primary power source for electricity generation is more environmentally friendly, its intermittent nature significantly reduces the system's reliability. Hybrid renewable energy systems that integrate renewable and non-renewable energy sources are indeed essential for isolated grids. These systems offer several advantages that enhance off-grid locations. Hybrid systems achieve reliability by seamlessly integrating renewable with non-renewable energy sources. These combinations ensure a consistent and reliable electricity supply, especially during periods of low renewable energy generation or when energy storage is depleted. The inclusion of non-renewable sources enhances overall grid stability and cost-effectiveness. They prioritize renewable sources whenever feasible and only resort to non-renewable sources when necessary. By incorporating renewables, hybrid systems can reduce carbon emissions, support–environmental sustainability and mitigate climate change. Scalability and Flexibility are inherent in hybrid renewable energy systems**;** they can be designed to be scalable and adaptable to the specific needs of isolated grids. Easily expanded or modified over time, they can flexibly meet changing energy demands-and adopt new technologies, ensuring a reliable, secure, and sustainable energy supply in isolated grids.

Hydrogen and ammonia are versatile and offer numerous benefits to isolated grids in various sectors. They act as efficient energy storage solutions, capturing excess energy from renewable sources such as solar and wind. This stored energy, vital during periods of low renewable generation or high demand, can bolster-grid stability and reliability. Furthermore, hydrogen and ammonia in fuel cells or combustion engines can power local electricity generation, delivering a dependable and eco-friendly energy source for isolated grids. In terms of transportation, hydrogen fuel cells are ideal for powering vehicles such as trucks and–small-scale fleets in remote areas. Similarly, ammonia can fuel internal combustion engines or serve as feedstock for fuel cells in vehicles. Their versatility extends to industrial applications, supporting processes such as chemical synthesis and providing heat for industrial needs. Moreover, hydrogen is a clean alternative for heating and cooking in residential or commercial buildings within isolated grids; it reduces reliance on traditional fossil fuel-based systems. Hydrogen and ammonia serve as emergency backup power sources during grid outages and disruptions, ensuring that critical services and infrastructure remain operational.

Transitioning to zero-emission solutions in isolated grids will surely-face significant hurdles. The transition from energy deprivation to the adoption of energy based on green hydrogen and ammonia technologies in poor areas poses significant challenges, including the high costs involved and difficulties regarding reliability, resilience, and affordability. Using grey hydrogen and ammonia presents a unique solution for isolated grids, especially considering the comparatively high costs of green alternatives and the technical complexities associated with implementing CCS for blue hydrogen. In this study, we have applied various strategies to enhance the sustainability of producing grey and green hydrogen and ammonia in isolated grids, to address the challenges presented within such contexts.

First, we conducted a thorough techno-economic and environmental analysis of an HRES isolated grid for grey hydrogen production. This grid comprises PVs, wind turbines, battery storage, and SMR. To support heat in the SMR process, we applied a thermodynamic model employing four approaches: CHP boiler, electric boiler, gas boiler, and hybrid boiler, each with varying cost and emission profiles. The gas boiler utilizes an external gas source, the CHP boiler system harnesses surplus heat from the microturbine and external gas supply, the electric boiler directly taps into the grid HRES components and the hybrid boiler combines elements of both the CHP and electric boiler systems. We minimized the NPC of the isolated grid, with and without adding a CO2 penalty cost to the objective function. This allowed us to assess the impact of using different heat methods for SMR on NPC, CO2 emissions, and optimal components dispatch. Our framework filled a critical gap in existing research by considering multiple heat sources and their broader implications on system performance beyond mere technological considerations. Using Homer Pro software, we modeled an isolated grid in the East Owinat region of Egypt. Our key findings are as follows:

- Adding a CO2 penalty cost into the objective function increased the grid NPC while reducing CO2 emissions across all approaches.
- The CHP boiler system exhibited the lowest NPC, and LCOH before and after adding of CO2 penalty costs to the objective function; although its CO2 emissions are relatively high.
- The electric boiler demonstrated the lowest emissions but incurred the highest cost.
- The gas boiler, while slightly more expensive than the CHP option, also produced high emissions.
- The hybrid boiler system leveraging a hybridization of the electric and CHP boiler systems, offered a balance between cost and emissions.
- The LCOH ranged from \$2.1 to \$2.8 per kilogram across all options, before and after adding CO2 penalty costs into the objective function.

Second, we conducted an economic analysis of a hybrid renewable isolated grid designed for producing green and grey ammonia. We addressed the issue of seasonal gas price fluctuations, a factor often overlooked in previous studies that typically assumed fixed gas prices. Recognizing the dynamic nature of the gas market, characterized by seasonal demand variations, we proposed using two gas prices to represent distinct seasons, which are peak and off-peak demand seasons. Furthermore, we introduced three systems aimed to optimize the production of green and grey ammonia in response to seasonal gas price fluctuation. These systems involved applying operational strategies and adjusting configurations to minimize gas procurement during periods of high demand and maximize generation and using storage capacities during periods of low demand. Specifically, the first system utilized a steam reformer for ammonia storage. The second, a reformer and an electrolyze that only store green ammonia. The third is an electrolyzer and a reformer for storing green and grey ammonia. Using various values of the two gas prices gas prices, we determined the best grid System NPC and LCOA. Our analysis was particularly relevant for isolated grids supporting agricultural areas with access to onshore natural gas reserves. Drawing insights from a case study of an isolated grid in East Owinat, Egypt, our key findings are as follows:

- Utilizing an electrolyzer supported by surplus energy for storing ammonia is preferable at low price differences.
- Eliminating the electrolyzer and relying on the reformer for storing ammonia is better at high price difference.

Our study offers valuable insights into the economic assessment of ammonia production in isolated grids, accounting for seasonal gas price fluctuations and diverse access to natural gas resources, thereby informing decision-making processes in sustainable energy development.

5.2 Implications

Decarbonizing the heat source of SMR is crucial in the transition to a sustainable and low-carbon energy future. Our study provides valuable approaches for supporting heat to SMR within HRES isolated grids, this empowers decision-makers to devise effective and sustainable energy strategies. Policymakers aiming for cost minimization should prioritize the CHP boiler, regardless of whether CO2 penalty costs are considered. Conversely, those prioritizing emission reduction should favor the electric boiler. The hybrid boiler, supported by renewable and non-renewable sources, offers a promising alternative that facilitates the tradeoff between cost and CO2 emissions. Moreover, our thermodynamic model has applications beyond isolated microgrids, which can potentially benefit other boiler technologies in various contexts. This study is also relevant in the context of HRESs isolated grids for blue hydrogen production, which typically involves SMR with CCS. All in all, using different approaches for decarbonizing SMR contributes to environmental sustainability by reducing CO2 emissions which minimizes the ecological footprints. Our research and development targeted decarbonization of the SMR heat source drives technological innovation in clean energy technologies; and it could open up new SMR market opportunities for renewable energy developers, technology providers, and project investors.

Adjusting seasonal configuration and operation in response to fluctuating gas prices emerges as a favorable approach for ammonia producers, as it reduces gas purchases during peak demand periods. Lower gas prices during periods of low demand may incentivize grid operators to ramp up production and storage, profiting on cost savings. Conversely, during peak demand periods, reduced gas consumption facilitates more efficient resource allocation and management. This approach is not limited to ammonia production but is also applicable to other products that depend on natural gas and leverage affordable storage systems. Overall, research on market gas prices helps in formulating effective energy policies and strategies. Decision-makers can depend on insights from these studies to design policies that promote energy security, affordability, and sustainability.

Our approaches to hybrid renewable energy systems are versatile and applicable to various isolated grids, not just remote locations but also areas close to main grids that prefer independence. Our case study in East Owinat, supporting residential loads and irrigation pumps for agricultural reclamation, highlights the potential of these systems even in large-scale projects. While some regions are considering connecting isolated locations to the main grid, factors like the vast area of East Owinat make complete coverage with distribution networks challenging. In these cases, hybrid renewable systems offer a viable alternative for reliable energy supply, especially for projects like hydrogen and ammonia production.

Scaling up our approaches for hydrogen and ammonia production using HRESs to broader locations, particularly in sub-Saharan Africa, could be effective. Most of the population lives in remote areas, lacking access to the main grid, relying heavily on diesel for electricity generation, and importing ammonia with high costs for fertilizers. By implementing our perspectives and studies on HRES isolated grids, reliable and affordable electric support can be provided. This not only addresses energy access challenges but also contributes to sustainability and economic development by reducing reliance on diesel and enabling local production of essential resources like ammonia for agriculture. It is a win-win solution for both energy supply and environmental concerns.

Our HRES isolated grid for hydrogen production finds a great opportunity to be applied in oil and gas production locations, especially by leveraging the flaring gas to support HRESs. Gas flaring is the controlled burning of natural gas that occurs during various oil and gas production processes, particularly during the extraction and processing of crude oil and natural gas. It typically occurs when natural gas produced alongside crude oil cannot be effectively captured, processed, or utilized. Instead of being captured and transported for use or sale, the associated natural gas is burned or flared at the wellhead or processing facilities. Flaring is often used as a safety measure to burn off excess gas that cannot be processed or stored safely due to operational constraints or emergencies (Sotoodeh et al., 2021). In some regions, regulations require oil and gas operators to flare associated gas to prevent the release of harmful gases into the atmosphere or reduce the risk of explosions. Flaring may occur during equipment maintenance, shutdowns, or startup operations when normal gas processing operations are temporarily suspended. Gas flaring releases various pollutants and greenhouse gases into the atmosphere, including CO2, CH4, sulfur dioxide (SO2), nitrogen oxides (NOx), and volatile organic compounds (VOCs). These emissions contribute to air pollution, climate change, and environmental degradation, affecting local air quality, human health, and ecosystems. Flaring represents a significant waste of valuable energy resources, as the burned natural gas could otherwise be captured, processed, and utilized for power generation, heating, industrial processes, or sold as a commercial product (Sotoodeh et al., 2021; Blundell et al., 2022). Gas flaring is a global issue, with significant flaring activities occurring in various oil-producing regions worldwide, including Russia, the United States, Nigeria, Iraq, and Iran (World Bank, 2023). Global Gas Flaring Reduction Partnership (GGFR) aims to reduce gas flaring through policy advocacy, technology transfer, and capacity building initiatives. Efforts to reduce gas flaring include the implementation of flaring reduction policies and regulations, investment in gas capture and utilization technologies, deployment of flaring monitoring and measurement systems, promotion of alternative uses for associated gas (such as power generation or conversion to liquefied natural gas) (World Bank, 2023). Hybrid renewable models are also appropriate in those locations for reducing greenhouse gas emissions (Bishnoi and Chaturvedi, 2021, 2022). Leveraging waste gas instead of flaring it in hydrogen and ammonia production could be beneficial. In that light, we believe that our HRES for hydrogen production could be applicable in such an environment and may be a supportive factor for the sustainable development of gas flaring locations globally.

5.3 Limitations and future work

- Our study focused on SMR, but there are many other emerging technologies for hydrogen production, such as electrolysis. Studying the integration of SMR and electrolysis for hydrogen production in a hybrid renewable isolated microgrid is a promising opportunity for future research.
- While we investigated four representative heat sources for the SMR process, our study did not consider all aspects of boiler technologies and heat sources. Future research should explore additional heat sources, including concentrated solar power.
- We applied static setting on prices and technology in our study. Our analysis focuses on an HRES for a 100-acre area, whereas the location spans more than 500,000 acres. Studying the future outlook of this location using the expected costs such as renewable components, and gas could be effective for the future application of our model in this region. Future work would aim at applying the dynamic price and potential of technological change to investigate different types of policy implications. Future analysis can help identify the cost thresholds at which renewable energy technologies become economically competitive. For instance, it could determine the cost at which an electric boiler becomes competitive with a CHP boiler, helping policymakers in planning the adoption of clean versus polluting boiler technologies[6].

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[6] Other studies have adopted similar methods for example, Fasihi et al. (2021) investigated the global prospects of producing ammonia from PV and wind plants, using comprehensive global weather data to identify optimal locations. They found that the LCOA ranges from €345–420 in 2030, €300–330 in 2040, and €260–290 in 2050. They anticipated that by the end of the current decade, green ammonia could gain dominance, as the projected decline in gas prices will neutralize by increasing the carbon tax to €75 per ton of CO2.

- The study considered two gas prices, but in certain regions, there may be multiple peak gas demand seasons. Therefore, future investigations should explore more than two gas prices so as to capture a broader range of market dynamics and variations in gas demand.
- Hydrogen typically plays a pivotal role in ammonia production. Our study centers on the using the gas boiler option in grey hydrogen production to supply the Haber-Bosch unit. However, future research, should investigate other heating approaches, which are examined in Chapter 3 .
- Although our study examined application to an isolated grid in Egypt, the main finding of this study applies to a variety of locations., so future work should include other locations, particularly in sub-Saharan Africa.

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Appendices

Appendix A. Components specifications

Table A.1 Components specifications

Device	Specification
PV cell	Generic flat plate, 1 kW
Wind turbine	Ennera winderaS, 3.2 kW, hub height 12 m
Battery storage	Generic 1 MWh Li-Ion, rated voltage 600V, efficiency 90%
Microturbine	Avus 500, 550 kW, lower heating value 45 MJ/kg, fuel carbon content 67%
Reformer	Efficiency 76%, emission factor 8.9 kg-CO_2/kg-H_2
Gas boiler	Efficiency 0.85 [p.u]
Electric boiler	Efficiency 0.99 [p.u]
Heat tank	Storage loss 0.00005 [p.u/h]

Appendix B. Radiation, temperature, and wind speed

The software accesses and downloads the required data.

Fig. B.1 illustrates the solar irradiance in East Owienat according to the National Renewable Energy Laboratory (NREL) Database 2020 (https://nsrdb.nrel.gov/). The scaled average irradiance is 6.26 kWh/m^2/d

. Fig. B.2 shows the monthly average air temperature over 30 years according to the prediction of worldwide energy resources by the National Aeronautics and Space Administration (NASA) (https://power.larc.nasa.gov/data-access-viewer/).

Fig. B.3 shows the monthly average wind speed over 30 years estimated by NASA (https://power.larc.nasa.gov/data-access-viewer/).

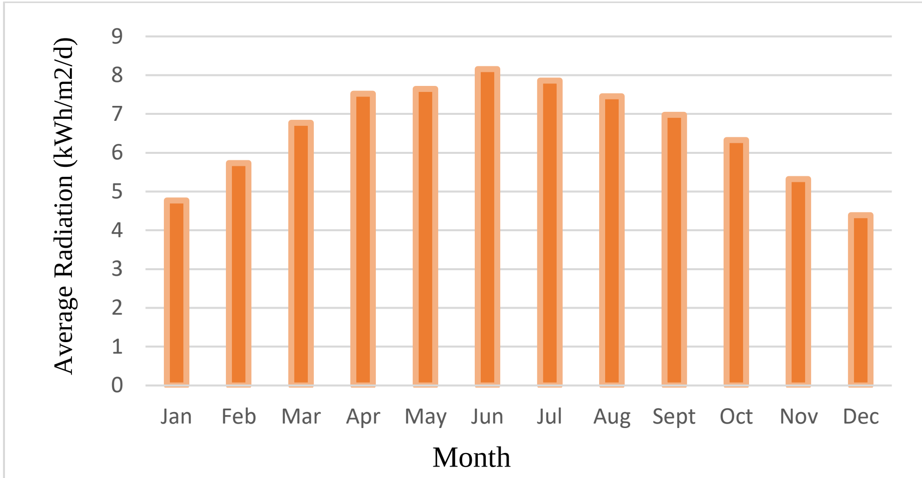

Fig. B.1 Monthly average radiation

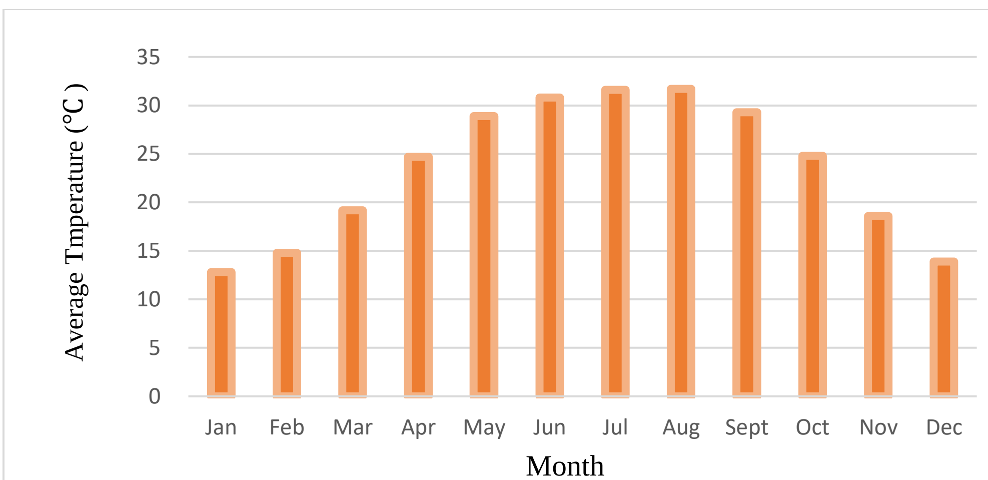

Fig. B.2 Monthly average temperature

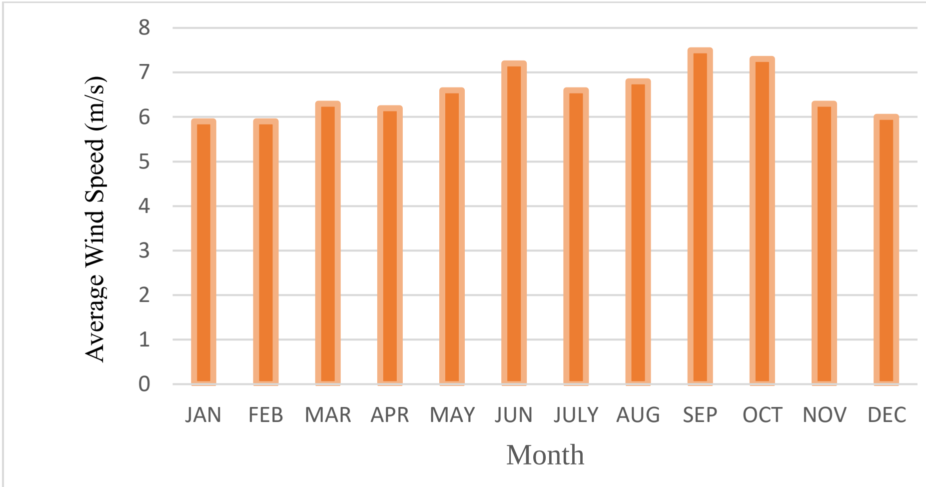

Fig. B.3 Monthly average wind speed

Appendix C. System configurations

HOMER Pro considers 12 dissimilar cases and calculates the NPC. Tables 2, 4, 6, and 8 list only three of these owing to space limitations.

1. PV, Wind, MT1, MT2, Battery, converter, boiler.
2. PV, Wind, MT1, Battery, converter, boiler.
3. PV, Wind, MT2, Battery, converter, boiler.
4. PV, MT1, MT2, Battery, converter, boiler.
5. PV, MT2, Battery, converter, boiler.
6. PV, Wind, Battery, converter, boiler.
7. PV, MT1, Battery, converter, boiler.
8. Wind, MT1, MT2, Battery, converter, boiler.
9. Wind, MT1, Battery, converter, boiler.
10. Wind, MT2, Battery, converter, boiler.
11. PV, Battery, converter, boiler.
12. Wind, Battery, converter, boiler.

Appendix D

Table D.1

Gas price ($)	Case A NPC ($)			Case B NPC ($)		
	System 1	System 2	System 3	System 1	System 2	System 3
0.02-0.78	36,810,810	49,224,310	37,232,211	36,810,810	49,244,583	36,959,545
0.04-0.76	37,857,212	49,319,113	38,183,804	37,857,212	49,304,227	37,936,297
0.06-0.74	38,903,602	49,413,916	39,135,396	38,903,602	49,363,871	38,923,048
0.08-0.72	39,949,997	49,508,720	40,086,989	39,949,997	49,423,515	39,909,799
0.1-0.70	40,996,394	49,603,522	41,038,581	40,996,394	49,483,160	40,896,551
0.12-0.68	42,042,789	49,698,327	41,990,174	42,042,789	49,542,806	41,883,302
0.14-0.66	43,089,185	49,793,130	42,941,766	43,089,185	49,602,450	42,870,054
0.16-0.64	44,135,581	49,887,933	43,893,359	44,135,581	49,662,093	43,856,805
0.18-0.62	45,181,977	49,982,736	44,844,951	45,181,977	49,721,738	44,843,556
0.2-0.6	46,228,373	50,077,540	45,796,544	46,228,373	49,781,383	45,830,308
0.22-0.58	47,274,769	50,172,343	46,748,136	47,274,769	49,841,027	46,817,059
0.24-0.56	48,321,164	50,267,146	47,699,729	48,321,164	49,900,671	47,803,810

0.26-0.54	49,367,560	50,361,950	48,651,321	49,367,560	49,960,316	48,790,561
0.28-0.52	50,413,956	50,456,753	49,602,914	50,413,956	50,019,961	49,777,313
0.3-0.50	51,460,352	50,551,557	50,554,506	51,460,352	50,079,606	50,764,064
0.32-0.48	52,506,748	50,646,359	51,506,099	52,506,748	50,139,250	51,750,816
0.34-0.46	53,553,144	50,741,163	52,457,691	53,553,144	50,198,895	52,737,567
0.36-0.44	54,599,540	50,835,966	53,409,284	54,599,540	50,258,539	53,724,318
0.38-0.42	55,645,935	50,930,769	54,360,876	55,645,935	50,318,184	54,711,070

Table D.2

Gas price ($)	Case A LCOA ($/ton)			Case B LCOA ($/ton)		
	System 1	System 2	System 3	System 1	System 2	System 3
0.02-0.78	313.02	506.89	319.60	313.02	507.21	315.34
0.04-0.76	329.36	508.37	334.46	329.36	508.14	330.60
0.06-0.74	345.70	509.85	349.32	345.70	509.07	346.01
0.08-0.72	362.05	511.34	364.19	362.05	510.00	361.42
0.1-0.70	378.39	512.82	379.05	378.39	510.94	376.83
0.12-0.68	394.73	514.30	393.91	394.73	511.87	392.24
0.14-0.66	411.07	515.78	408.77	411.07	512.80	407.65
0.16-0.64	427.42	517.26	423.63	427.42	513.73	423.06
0.18-0.62	443.76	518.74	438.50	443.76	514.66	438.47
0.2-0.6	460.10	520.22	453.36	460.10	515.59	453.89
0.22-0.58	476.45	521.70	468.22	476.45	516.53	469.30

0.24-0.56	492.79	523.18	483.08	492.79	517.46	484.71
0.26-0.54	509.13	524.66	497.94	509.13	518.39	500.12
0.28-0.52	525.47	526.14	512.81	525.47	519.32	515.53
0.3-0.50	541.82	527.62	527.67	541.82	520.25	530.94
0.32-0.48	558.16	529.10	542.53	558.16	521.18	546.35
0.34-0.46	574.50	530.58	557.39	574.50	522.11	561.76
0.36-0.44	590.84	532.06	572.25	590.84	523.05	577.18
0.38-0.42	607.19	533.55	587.12	607.19	523.98	592.59