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A Techno-Economic Approach for Green Transition of an Oil-Exporting Country to a Solar, Hydrogen, and Gas Turbine Economy

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Abstract

This study develops a national-scale techno-economic framework to assess how an oil-exporting country could transition from fossil-fuel dependence toward a solar-hydrogen-gas turbine energy economy by 2050. Unlike previous studies that mainly examine sectoral decarbonisation or renewable deployment in isolation, this work links domestic energy self-sufficiency, hydrogen export replacement, solar PV deployment, electrolyser sizing, hydrogen storage, backup H2CCGT capacity, and capital and operational expenditure within a staged transition pathway. Two scenarios are analysed: first, a winter self-sufficiency scenario designed to meet domestic electricity and hydrogen demand under the most restrictive seasonal conditions; and second, an export scenario in which green hydrogen replaces 2100 $PJ \cdot yr^{-1}$ of current fossil-energy exports. The results indicate that by 2050 Libya would require approximately 268 GW of solar PV for domestic winter self-sufficiency and 657 GW for the hydrogen export scenario, corresponding to solar farm areas of approximately 4900 km^2 and 12,033 km^2, respectively. The export scenario requires approximately 491 GW of electrolyser capacity, 78,614 tonnes of hydrogen storage, and 54 H2CCGT units. The estimated total transition cost is approximately USD 1796.9 billion, including USD 1097 billion CAPEX and USD 699.64 billion OPEX. These findings highlight the scale of infrastructure, investment, and policy coordination required for fossil-fuel-exporting economies to maintain energy revenues while decarbonising domestic and export systems.

Keywords

Electrolysis, Renewable Energy, Decarbonisation, Solar Photovoltaics

1. Introduction

The global transition toward low-carbon energy systems has accelerated significantly in response to climate change commitments and the need for sustainable economic development. A substantial body of literature has examined pathways for decarbonisation, with particular emphasis on renewable energy deployment, hydrogen production, and integrated energy systems.

Existing studies have established that large-scale deployment of renewable energy technologies, particularly solar photovoltaics (PV), wind, and hydropower, is essential for achieving net-zero emissions targets. For example, Song *et al.* [1] and Murugesan *et al.* [2] demonstrate that renewable electricity systems can significantly reduce carbon emissions when supported by appropriate policy frameworks and infrastructure investments. Similarly, studies focusing on hydrogen as a clean energy carrier highlight its potential role in decarbonising hard-to-abate sectors such as heavy industry, aviation, and long-distance transport [3] [4]. These studies collectively confirm that hydrogen, particularly when produced via renewable-powered electrolysis, is likely to play a critical role in future energy systems.

In parallel, research on energy transitions in the Middle East and North Africa (MENA) region has highlighted the strategic importance of leveraging high solar irradiation for renewable energy generation and hydrogen export. Benasla *et al.* [5] and Müller *et al.* [3] [4] emphasise that countries with abundant solar resources can become key exporters of green hydrogen to energy-importing regions such as Europe. Furthermore, techno-economic assessments of hydrogen systems have demonstrated that the integration of renewable electricity with electrolysis and storage can enable flexible and scalable energy systems, although significant cost and infrastructure challenges remain [6]-[9].

Libya has significant potential for renewable energy production in addition to its fossil fuel resources. Solar photovoltaics (PV) has been used in Libya since the 1970s, for applications such as rural electrification, communication repeaters, cathodic protection for oil pipelines, and water pumping. However, the adoption of renewable energy in Libya has been slower compared to other African nations [10]. Despite this, Libya is strongly interested in future green hydrogen exports due to its excellent renewable energy potential, proximity to European markets, and existing pipeline infrastructure.

Despite these advances, several critical gaps remain in the literature. First, most studies focus on sector-specific decarbonisation (e.g., electricity or transport) rather than adopting a holistic, country-level perspective that integrates domestic energy demand, export potential, and infrastructure requirements. Second, while techno-economic analyses exist for hydrogen production and renewable deployment, few studies explicitly link these components within a unified framework that considers solar PV generation, hydrogen production, storage, dispatch, and backup generation using hydrogen-fuelled gas turbines. Third, limited attention has been given to the specific challenges faced by oil-exporting countries, where decarbonisation must be achieved without compromising energy export revenues that are central to national economies.

These gaps are particularly important for countries such as Libya, where the transition to a low-carbon economy must simultaneously address domestic energy security, economic diversification, and the replacement of fossil fuel exports. The absence of integrated modelling frameworks that combine renewable energy generation, hydrogen production, storage systems, and export strategies creates uncertainty in planning long-term decarbonisation pathways for such economies.

To address these limitations, the present study develops a comprehensive techno-economic framework that integrates national energy demand projection, solar PV deployment, electrolyser capacity, hydrogen storage, and hydrogen-fuelled combined cycle gas turbine (H2CCGT) backup systems within a phased transition pathway to 2050. Unlike previous studies, this work explicitly considers both domestic energy self-sufficiency and the replacement of fossil fuel exports with green hydrogen. By linking technical infrastructure requirements with economic evaluation across multiple stages, the study provides new insights into the scale, cost, and feasibility of transitioning an oil-exporting country to a solar-hydrogen-based energy economy [11]-[14].

This synthesis-based approach moves beyond descriptive literature review by critically identifying what is known, what remains uncertain, and how the proposed framework contributes to closing these gaps. As such, the study offers both methodological and practical contributions to the field of energy transition planning.

2. Energy Demand Prediction for Libya in 2050

The urgent need for global decarbonization efforts is evident, highlighted by calls for substantial investments [15] [16]. These investments are crucial not only to maintain progress in alleviating global poverty [17] but also to align environmental preservation with sustained economic growth and prudent resource usage. Major investors, such as the United Nations Principles for Responsible Investment [18] are gearing up for forthcoming transformative changes, protecting the environment, sustaining economic growth, and ensuring the prudent use of natural resources must progress in tandem. A central aspect of this illustration is the promotion of parallel economic and environmental sustainability, emphasizing the global nature of the issue and the importance of nurturing young talent [17]. Coordinated efforts across sectors within large economic entities are vital to leverage economies of scale and shared experiences. Detailed and coordinated transition strategies spanning multiple economic sectors are imperative. Addressing a knowledge gap, the author introduces a novel techno-economical approach, offering a clear perspective on challenges and requirements. This method contributes to a staged time-based quantitative country-level replacement analysis not yet available in the public domain.

The chosen unit for gradual decarbonizations, projected to conclude by 2050 is Libya, a significant oil-exporting country. Libya's size makes it a suitable candidate for decarbonization, particularly when considering the replacement of hydrocarbon exports with green energy, for the analysis both useful and representative. A critical question for an oil-exporting country is how to decarbonize its energy sector while simultaneously generating energy-based wealth for both its citizens and the global community. Selecting a baseline for study is not easy given the volatile political situation in the country [19]-[22].

2.1. Key Modelling Assumptions and Parameter Justification

The techno-economic analysis presented in this study is based on a set of engineering and economic assumptions derived from peer-reviewed literature, international energy reports, and industry benchmarks. These assumptions are selected to provide a consistent and transparent basis for national-scale system evaluation.

The population and energy demand growth rate is assumed to be 2% annually, which is consistent with historical trends and projections for developing economies in North Africa. This value represents a moderate growth scenario suitable for long-term planning.

Solar PV efficiency is assumed in the range of 14% - 24%, depending on technology and deployment conditions, consistent with values reported by the International Energy Agency (IEA, 2023) and International Renewable Energy Agency (IRENA, 2022). System-level derating factors are applied to account for real operating conditions, including weather variability, fouling, availability, and spacing.

Electrolyser efficiency is assumed to be approximately 70% for gaseous hydrogen production and 55% for liquefied hydrogen systems, based on current PEM electrolyser performance reported in the literature [6]-[9] [23]. The electrolyser capacity factor is not fixed but varies with solar availability, resulting in an effective range of 30% - 50%, which is consistent with renewable-powered hydrogen systems reported in international studies [24].

Hydrogen-fuelled combined cycle gas turbines (H2CCGT) are assumed to operate at an efficiency of approximately 60%, based on advanced turbine performance reported in the literature [6]-[9].

System lifetimes for major components are assumed to be approximately 25 years for solar PV systems, electrolysers, and power generation units, consistent with industry standards and lifecycle assessments.

Cost parameters (CAPEX and OPEX) are derived from literature sources published between 2017 and 2023 [6]-[9] and are harmonised to a common base year. These values represent typical ranges reported in techno-economic studies and are scaled to reflect large-scale deployment.

It should be noted that these assumptions are not intended to represent exact project-specific values, but rather to provide representative and consistent parameters suitable for evaluating national-scale energy transition pathways over long horizons.

2.2. Energy Demand Projection and Decarbonisation Methodology

The decarbonised electricity supply considered in this study is based exclusively on utility-scale solar photovoltaic (PV) generation. Wind energy was not explicitly modelled within the present framework because Libya possesses one of the highest solar irradiation resources in the MENA region, making solar PV the primary renewable energy source considered for long-term system planning. Consequently, all electricity demand, electrolysis requirements, hydrogen production, and H_2CCGT backup generation are sized based on solar PV generation profiles.

A consistent and transparent methodology is required to project Libya's future energy demand and to translate it into a decarbonised energy system based on electricity and hydrogen. The approach adopted in this study combines demand forecasting, sectoral energy substitution, and system-level energy conversion modelling. The baseline energy demand is derived from 2020 national data collected from multiple sources [25], standardised in petajoules (PJ). Future demand for 2050 is estimated using a compounded annual growth rate of 2%, representing population growth and economic expansion. The projected demand is calculated as:

$$E\{2050\} = E\{2020\} \times (1 + g)\ \hat{}\{n\}$$

where g = 0.02 and n = 30 years, resulting in a growth factor of 1.81. This produces Column 2 of **Table 1** from Column 1.

Following demand projection, a decarbonisation strategy is applied by replacing fossil fuel consumption with a combination of direct electrification and hydrogen-based energy carriers. This transformation is represented in **Table 1** through a structured column-based methodology.

Table 1. Decarbonized libyan energy consumption for 2050 based on current energy needs [25].

Future Libya Energy Panorama Including Oil Exports											
n	**Column** Item	**1** Current Energy Use 2020, (PJ)	**2** 2050 Energy Demand (PJ)	**3** Replacement Factors to Decarbonise	**4** Need to Replace (PJ)	**5** Replacement	**6** Electricity to Satisfy Direct Electrical Demand (PJ)	**7** Electricity for Hydrogen (PJ)	**8** H2 FCV (PJ)	**9** H2 (kt)	**10** H2 use (%)
1	Motor gasoline	227.01	410.9	0.8	328.7	Electricity	70.44				
				0.2	82.2	H2 Gas		58.70	41.09	342.4	1.83
2	Diesel for transport	165.60	299.7	0.8	239.8	Electricity	85.64				
				0.2	59.9	H2 Gas		71.37	49.96	416.3	2.22
3	Jet fuel	24.49	44.3	0.15	6.6	Electricity	2.85				
				0.85	37.7	LH2		75.36	41.45	345.4	1.85
4	Other (marine, etc.)	2.87	5.2	0.7	3.6	Electricity	1.56				
				0.3	1.6	H2 Gas		2.23	1.56	13.0	0.07
5	Liquid fossil fuel for electricity	9.66	0.0	Replaced with PV Solar power for electricity demand							

Continued

6	Gas for electricity	337.50	0.0	Replaced with PV Solar power for electricity demand							
7	Gas: domestic	21.60	39.1	1	39.1	Electricity	39.10				
8	Gas: other	20.70	37.5	0.7	26.2	Electricity	11.24				
				0.3	11.2	H2 Gas		16.06	11.24	93.7	0.50
9	Solar PV	0.04	0.1		0.1	Electricity	0.07				
10	Electricity from gas	104.83	189.7		189.7	Electricity	189.75				
11	Electricity from liquid fossil fuel	3.46	6.3		6.3	Electricity	6.26				
12	Energy Exports	2100	2100	1	2100	H2 Gas		3000	2100	17,500	93.53
	Total requirement	2909.47	3132.8				406.89	3223.70	2245.29	18,711	100
	Total electricity	108.32	196.1	Total Electricity 2050		3630.59					

Column 3 defines the replacement factors, which represent the proportion of each energy demand substituted by electricity and hydrogen. For example, in the transport sector, gasoline and diesel are assumed to be replaced by 80% electricity and 20% hydrogen, while aviation relies predominantly on hydrogen (85%) due to limited electrification potential. These values are scenario assumptions reflecting technological feasibility and sector-specific constraints.

Column 4 (energy to be replaced) is calculated as:

$$E\{rep\} = E\{2050\} \times f\{rep\}$$

where f {rep} is the replacement factor from Column 3. This determines the energy demand allocated to either electricity or hydrogen.

Column 6 represents the direct electrical energy required to deliver the same service as the original fuel, accounting for efficiency differences between combustion and electric systems. This is calculated as:

$$E\{elec\} = E\{rep\} \times (\eta\{fuel\}/\eta\{elec\})$$

where η {fuel} is the efficiency of the original fuel system (e.g., gasoline engine ≈ 0.15) and η {elec} is the efficiency of electric systems (≈ 0.7). This reflects the higher efficiency of electric technologies compared to internal combustion systems.

Column 8 defines the hydrogen energy requirement, which is derived directly from the replacement energy allocated to hydrogen:

$$E\{H2\} = E\{rep, H2\}$$

This energy is then converted into electrical input required for hydrogen production via electrolysis (Column 7):

$$E\{el, H2\} = E\{H2\}/\eta\{el\}$$

where $\eta\{el\}$ is the electrolyser efficiency, assumed to be 70% for gaseous hydrogen and 55% for liquefied hydrogen systems.

The hydrogen demand is further converted into mass (Column 9) using the lower heating value of hydrogen (120 MJ/kg):

$$M\{H2\} = (E\{H2\}/120) \times 1000$$

yielding hydrogen production in kilo tonnes per year.

Finally, Column 10 expresses the relative contribution of each sector to total hydrogen demand:

$$H2\{share\} = (m\{H2, i\}/m\{H2, total\}) \times 100$$

This enables identification of dominant hydrogen-consuming sectors within the national system.

The results show a significant structural transformation of the energy system. While total primary energy demand increases moderately from 3132.8 PJ to approximately 3630.6 PJ, the electrical energy requirement increases dramatically due to electrification and hydrogen production. Of the total electricity demand, approximately 406.9 PJ is used directly, while the remaining 3223.7 PJ is required for hydrogen generation.

In addition to domestic demand, the model incorporates the replacement of fossil fuel exports with hydrogen exports, estimated at 2100 PJ annually. This corresponds to approximately 17.5 million tonnes of hydrogen and represents a dominant share of total hydrogen production.

To support this transformation, an integrated system model is established linking solar PV generation, electrolysis, hydrogen storage, and hydrogen-fuelled combined cycle gas turbine (H2CCGT) systems. The system boundary therefore captures the complete energy transformation pathway in this framework; solar PV provides the primary energy input. Electricity generated is first used to satisfy direct demand, while surplus electricity is allocated to electrolysis. Produced hydrogen is then distributed between domestic use, storage, export, and power generation via H2CCGT during periods of low renewable availability. External factors such as international hydrogen pricing, downstream industrial use in importing countries, and global trade dynamics are not explicitly modelled and are treated as boundary conditions.

Although desalination is not costed separately, the implied water requirement can be estimated from the stoichiometric water requirement for electrolysis. Using approximately 9 kg of water per kg of hydrogen, the production of 17.5 million tonnes of hydrogen per year would require about 157.5 million tonnes of water per year, equivalent to approximately 157.5 million m^3/year before accounting for desalination losses and water treatment requirements.

2.3. Integrated System Workflow

To improve transparency and reproducibility, **Figure 1** summaries the integrated

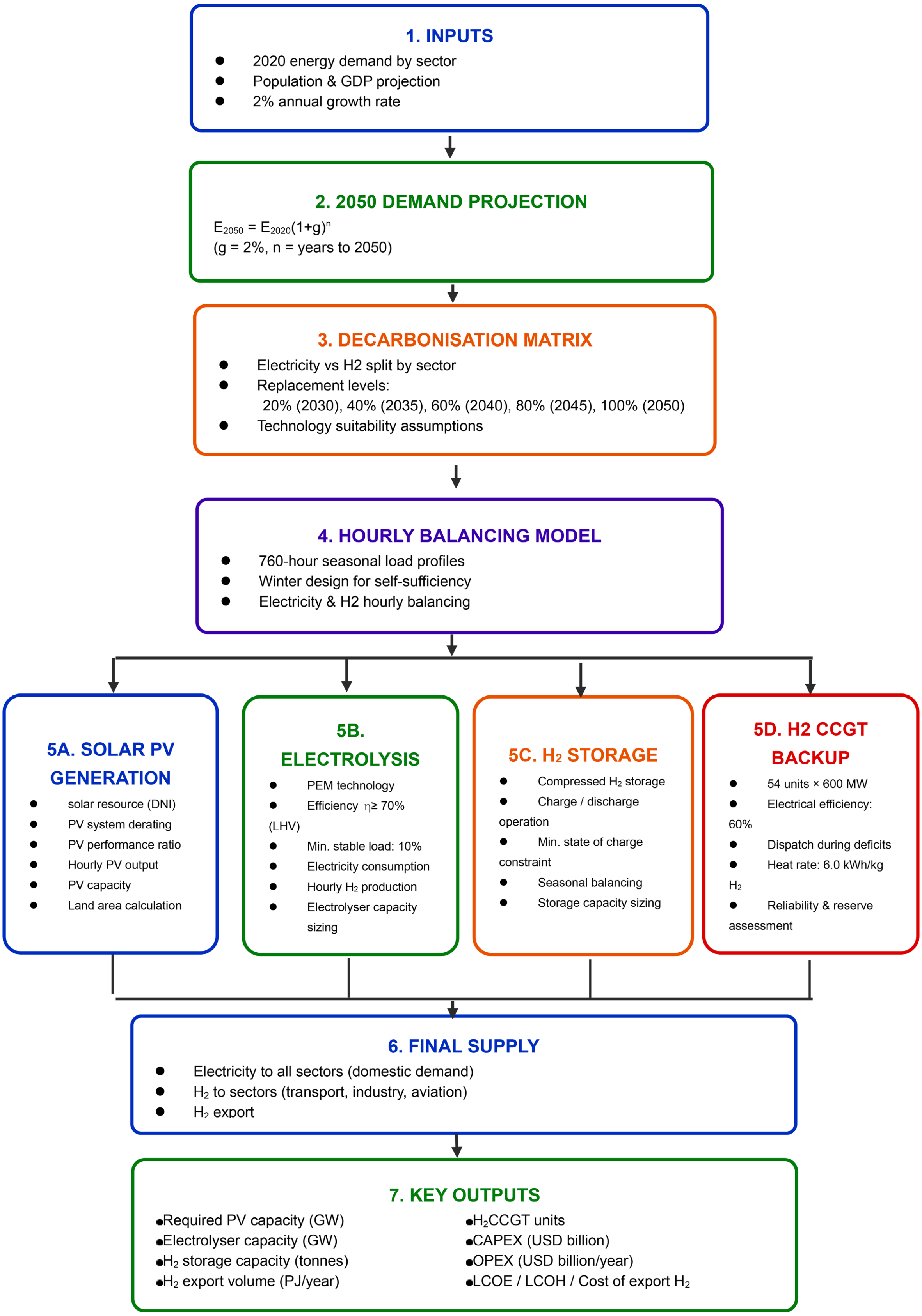

Figure 1. Methodological workflow of the integrated solar-hydrogen energy system model.

modelling framework adopted in this study. The workflow links national energy demand projection, sectoral decarbonisation, hourly balancing, solar photovoltaic generation, hydrogen production through electrolysis, hydrogen storage operation, and hydrogen-fuelled combined cycle gas turbine (H2CCGT) dispatch within a unified techno-economic framework. The model uses projected 2050 energy demand as the primary input and determines the infrastructure requirements necessary to satisfy domestic energy demand and hydrogen export targets under winter self-sufficiency conditions. The principal outputs include required PV capacity, electrolyser capacity, hydrogen storage requirements, H2CCGT backup capacity, hydrogen export volumes, and associated CAPEX and OPEX estimates.

3. Evaluation of Winter Season-Based Requirements.

The present scenario considers the replacement of conventional fossil fuel energy sources with solar PV farms linked to electrolysers, hydrogen storage, and hydrogen-fuelled combined cycle gas turbine (H2CCGT) backup generation. The system is not assumed to operate continuously at maximum capacity; instead, solar output is estimated using seasonal radiation profiles and derating factors representing availability, weather, fouling, spacing, and contingency.

As shown in **Figure 2**, to capture temporal variability, the annual demand profile was divided into four representative seasons: winter, spring, summer, and autumn, each comprising 91.25 days [25]. Each season was represented by 24 hourly demand values, allowing the model to account for daily and seasonal variation in electricity demand, solar availability, hydrogen production, hydrogen storage, and H2CCGT dispatch. Winter was selected as the principal design case because it represents the most restrictive operating condition. During winter, electricity demand is highest while solar availability is reduced due to shorter

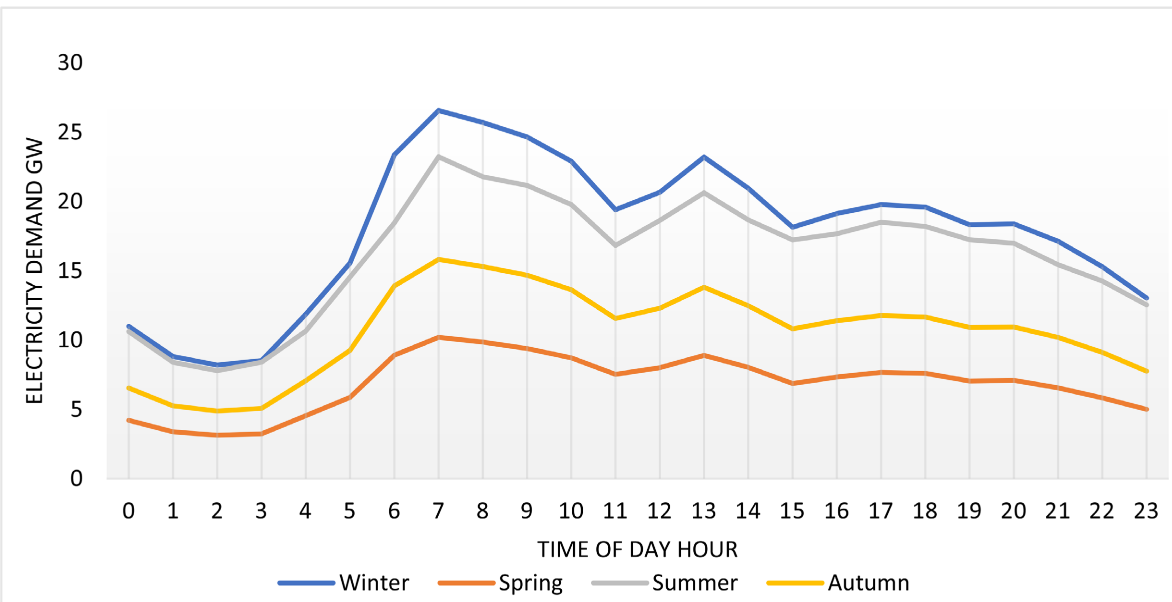

Figure 2. 2050 Seasonal demand patterns in Libya [25].

daylight duration and lower solar inclination. Therefore, sizing the system around winter demand provides a conservative basis for infrastructure estimation and improves confidence that demand can be met throughout the year.

The proposed solar PV farms are in sparsely populated desert regions in southern Libya, around latitude 25˚N, where land availability and solar irradiation are favourable. Electrolysers, hydrogen storage, and H2CCGT units are assumed to be located closer to coastal demand and export centres to reduce hydrogen transport requirements and support access to seawater and port infrastructure. In the present study, H2CCGT units are assumed to be 600 MW single-shaft units delivering an effective output of approximately 500 MW, accounting for hot-day operation, off-design performance, degradation, and availability. A thermal efficiency of 60% is assumed for these units [26]. Consequently, in addition to the hydrogen required for the replacement scenario shown in **Table 1**, additional hydrogen must be produced and stored for dispatchable power generation during periods of low or zero solar output, particularly overnight.

The next step for this present study is to investigate the optimal deployment of solar farms to maximize their capacity, by considering site-specific factors like geo-graphic location and solar illumination. The focus is on desert areas in Libya at a latitude of 25˚N, chosen for their sparse population and location in the country's southern region. The effective output of solar farms is calculated using a series of derating factors that reflect real operating conditions:

Pv eff = P installed × f availability × f weather × f fouling × f spacing × f contingency.

where P inst is the installed PV capacity, and the factors represent availability (0.9), weather impact (0.7), fouling losses (0.8), panel spacing (0.75), and contingency margin (0.8). The weather factor (0.7) reflects the impact of variations such as cloud cover, reducing available solar radiation to 70% of optimal levels, while the availability factor (0.9) accounts for system operational uptime, assuming functionality 90% of the time. Fouling (0.8) represents efficiency losses due to dust and debris accumulation, reducing output by 20%.

The calculations were subsequently extended to estimate the solar farm area required to meet hydrogen production targets for export until 2050, resulting in a total area requirement of 12,033 km^2, as shown in **Table 2**.

The required solar farm area is derived from the relationship between solar irradiance, PV efficiency, and system losses:

Table 2. National requirements – two scenarios: (a) meeting winter demands and (b) exporting yearly 2100 PJ of hydrogen using solar PV farms to their full capacity [25].

Scenario	Solar Farm (GW)	Solar Farm (km^2)	600 MW H_2 CCGTS	Electrolysers (GW)	Storage H_2 (tonnes)	Transmission (GW)	H_2 Export (PJ)
(a)Winter Self Sufficiency	268	4900	54	199	28,889	218	481
(b) Export 2100 PJ of H_2	657	12,033	54	519	78,614	491	2100

$$A\ PV = E\ total/(G \times \eta\ PV \times \Pi\ fi)$$

where A_PV is the solar farm area (km^2), E total is the total annual electrical energy demand, G is the average solar irradiance (~2300 kWh/m^2/year for Libya), η PV is the PV efficiency (≈0.14 - 0.24 depending on technology), and a spacing factor (0.75), which accounts for the gaps between panels to avoid shading and allow maintenance. A contingency factor (0.8) was included to account for uncertainties, meaning that only 80% of the expected capacity is assumed to be realised, and $\Pi\ f\ i$ represents the product of all derating factors.

An iterative process was used to determine the necessary area for a solar farm to meet total electricity demand. Also, using this formulation, the required solar farm area is estimated at approximately:

- 4900 km^2 for domestic winter self-sufficiency.
- 12,033 km^2 for combined domestic demand and hydrogen export.

These values are consistent with large-scale desert PV deployment studies in high-irradiance regions.

The electrolyser system, hydrogen storage facility, and H_2CCGT units are treated as integrated components of a single hydrogen production and utilisation plant. Their capacities were determined through the same hourly balancing procedure used within the techno-economic framework. At each hourly timestep, solar PV generation is first allocated to direct electricity demand, with surplus electricity supplied to the electrolysers for hydrogen production. Produced hydrogen is subsequently distributed between domestic hydrogen demand, export demand, storage charging, and H_2CCGT operation.

Hydrogen storage capacity was determined iteratively to ensure that sufficient hydrogen remained available throughout periods of reduced solar generation, particularly during the winter design case. The governing storage requirement is therefore the longest continuous period of renewable energy deficit encountered during the balancing analysis. Similarly, H_2CCGT capacity was sized to satisfy the maximum domestic electricity deficit observed during winter operation.

As a result, the number of H_2CCGT units remains unchanged between the two scenarios because the governing domestic peak electricity demand remains the same. Increasing hydrogen export targets primarily increases solar PV and electrolyser capacity requirements rather than backup generation capacity. Consequently, while export volume, hydrogen production, and PV deployment increase substantially, the required H_2CCGT backup fleet remains fixed at 54 units.

Solar farms are strategically located in the southern region for better illumination, and a hydrogen grid proposed near the coast for proximity to sea-water electrolysis. Given freshwater scarcity, seawater is a necessity. The placement of electrolysis, hydrogen fueled combined cycle gas turbines (H2GCCTs), and storage farms near the coast minimize hydrogen transmission inland. An electrical grid would be distributed across the country, with a hydrogen grid would be concentrated near the Mediterranean coast [25].

An iterative approach is used to ensure system feasibility:

- First iteration: match hydrogen production with export and power generation requirements.

- Second iteration: adjust storage capacity to always ensure $S_t \geq 0$.

This ensures that the system operates without energy deficit and that storage sizing is sufficient to cover seasonal and diurnal variability.

H2CCGT systems are assumed to operate at 600 MW nominal capacity with an effective output of 500 MW, accounting for real operating conditions. A thermal efficiency of 60% is assumed, consistent with advanced hydrogen turbine designs.

For the project's five implementation phases, a uniform and systematic decarbonisation pathway is assumed, whereby each phase achieves an equal 20% increment in decarbonisation. This approach ensures a linear and cumulative transition over the full project horizon, spanning Phase I (2025 - 2030), Phase II (2030 - 2035), Phase III (2035 - 2040), Phase IV (2040 - 2045), and Phase V (2045 - 2050). Under this framework, decarbonisation progresses steadily from 20% in the first phase to 100% by the final phase (2045 - 2050), thereby establishing a clear and predictable transition trajectory over the 25-year period. In parallel, the assumed annual growth rates increase progressively across the phases, rising from 1.22% in Phase I to 1.81% in Phase V, as presented in **Table 3**. This structured allocation provides methodological consistency and analytical clarity in modelling the long-term decarbonisation pathway.

Table 3. Transition of libyan energy exports: Green Hydrogen vs. Fossil Fuel (2025-2050).

Year	Assumed Annual Growth %	Decarbonisation Level %
2025-2030	1.22	20%
2030-2035	1.35	40%
2035-2040	1.49	60%
2040-2045	1.65	80%
2045-2050	1.81	100%

Table 4 presents cumulative metrics for decarbonisation efforts spanning 2020-2050, calculated for each stage within the specified scenarios. Numbers presented encapsulate the progressive accumulation of infrastructure and capacity over time, derived from the cumulative calculation of each column for every stage within both scenarios. In 2050, under the "Winter Self Sufficiency" scenario, and as outlined in **Table 2**, solar farm energy demand reaches 268 GW, with a solar farm area at 4900 km^2, with 54 units of 600 MW H2CCGTS. The electrolysis demand is 199 GW, H2 storage reaches 28,889 tonnes, and transmission amounts to 218 GW. Conversely, in the "H2 Export" scenario for 2050, solar farm demand peaks at 657 GW, the solar farm area expands to 12,033 km^2, 600 MW H2CCGTS remain at 54 units. The electrolysis requirement climbs to 491 GW, H2 storage reaches 78614 tonnes, and transmission registers at 510 GW. This representation underscores the cumulative impact of decarbonization strategies, showing an

evolving landscape of renewable energy deployment and hydrogen usage, as iteratively calculated across stages and scenarios. Detailed findings are presented in Table 4 and illustrated graphically for staged and cumulative energy demand in Figure 3 and Figure 4.

Table 4. Cumulative decarbonization metrics and scenarios: 2025-2050.

Years 2025 to 2050	scenario's	Solar Farm GW	Cumu-lative Solar Farm GW	Solar Farm km²	Cumu-lative Solar Farm km²	600 MW H2 CCGTS	Cumu-lative 600 MW H2 CCGTS	Electro-lyser GW	Cumu-lative Electro-lyser GW	Storage H2 tonnes	Cumu-la-tive Stor-age H2 tonnes	Trans-mission GW	Cumu-la-tive Trans-mission GW
2025-2030	Winter self Sufficiency	54	54	980	980	4	4	15	15	2161	2161	19	19
	H2 export	120	120	2198	2198	8	8	91	91	5855	5855	93	93
2030-2035	Winter self sufficiency	53	107	980	1960	4	8	24.21	39.21	3541.1	5702.1	30	49
	H2 export	128	248	2601	4799	8	16	107	198	8550	14,405	110	203
2035-2040	Winter self Sufficiency	54	161	980	2940	6	14	36	75	5356	11,058	49	98
	H2 export	130	378	2124	6923	11	27	86	284	8175	22,580	90	293
2040-2045	Winter self Sufficiency	54	215	980	3920	9	28	31.6	106.6	4710	15,768	45	143
	H2 export	134	512	2454	9377	12	39	99	383	7608	30,188	104	397
2045-2050	Winter self Sufficiency	53	268	980	4900	7	54	25.3	131.9	4232.2	20,000.2	20.21	163.21
	H2 export	145	657	2656	12033	15	54	108	491	13540	43,728	113	510

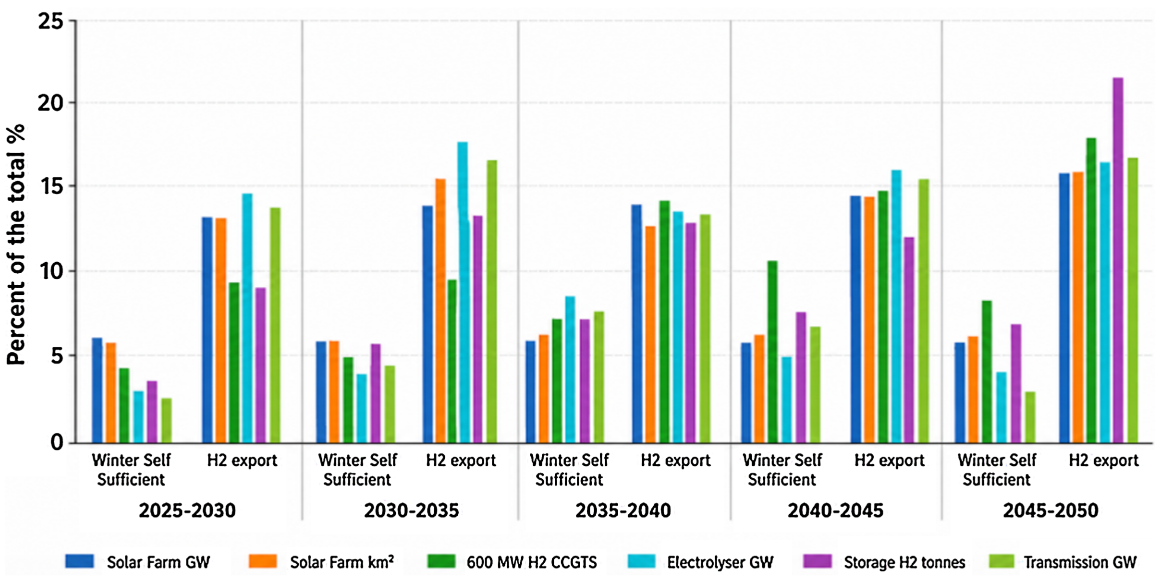

Figure 3. Decarbonisation metrics for solar and hydrogen infrastructure: 2025-2050.

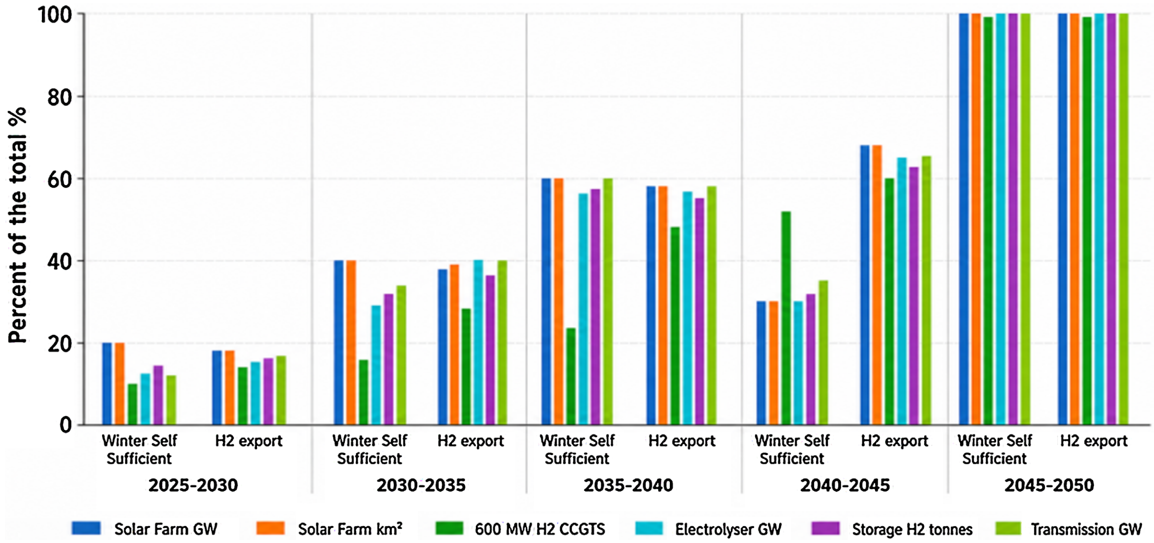

Figure 4. Cumulative decarbonisation metrics for solar and hydrogen: 2025-2050.

4. Component Costs

The transition toward a solar-hydrogen energy system requires a comprehensive techno-economic assessment to quantify the capital and operational costs associated with large-scale infrastructure deployment. This study evaluates the costs of solar PV systems, hydrogen production (electrolysers), hydrogen storage, transmission infrastructure, and hydrogen-fuelled combined cycle gas turbines (H2CCGTs) over the period 2025-2050. Table 5 provides a summary of estimated Capital Expenditure (CAPEX) and Operational Ex-pedicure (OPEX), replacement costs, and

Table 5. Financial expenditure for green energy infrastructure (2025-2050).

Components	Expenditure Categories	2025-2030 B-USD	2030-2035 B-USD	2035-2040 B-USD	2040-2045 B-USD	2045-2050 B-USD	Cost O&M B-USD	lifetime [Years]
				Power Generation				
PV System	CAPEX	139.68	165	135	156	169		25
	Annual OPEX	174.6	165.29	101	78	42	560.89	
H2CCGT	CAPEX	3.35	3	4.6	5.02	6.27		25
	Annual OPEX	1.67	1.34	1.38	1.004	0.63	6.024	
Transmission	CAPEX	0.0043	0.0051	0.0041	0.0048	0.0052		/
	Annual OPEX	0.00107	0.00101	0.0006	0.00048	0.00026	0.00342	
				H2 Production				
Electrolyser	CAPEX	54.6	64.2	52	59	65		25
	Annual OPEX	40.95	38.52	23.22	17.82	9.72	130.23	
Hydrogen Storage	CAPEX	2.05	2.99	2.86	3	4.75		25
	Annual OPEX	0.512	0.599	0.429	0.266	0.237	2.043	
Total Cost O&M							699.2	

lifetimes associated with various components of a necessary hydrogen production plant supported by solar PV.

Cost data for individual components were obtained from literature sources published between 2017 and 2023 [6]-[9]. To ensure consistency, all cost values were harmonised to a common base year using inflation-adjusted scaling. These literature values are used to define unit costs, while total system costs are derived from the required infrastructure capacity calculated in previous sections.

The total capital expenditure (CAPEX) is calculated as:

$$\text{CAPEX total} = \Sigma\,(\text{Ci} \times \text{Xi})$$

where Ci represents the unit capital cost of component i and Xi represents the installed capacity or number of units required for that component.

Operational expenditure (OPEX) is calculated as a fraction of CAPEX:

$$\text{OPEX annual} = \text{CAPEX i} \times \text{ri}$$

where ri is the operation and maintenance (O&M) rate for component i. The total operational cost over the project lifetime is then:

$$\text{OPEX total} = \Sigma\ \text{OPEX annual} \times \text{N years}$$

where N years represents the operational period of each phase.

The analysis is conducted over five implementation phases (2025-2030, 2030-2035, 2035-2040, 2040-2045, and 2045-2050). Infrastructure deployment increases cumulatively across these phases, and therefore total costs represent the aggregated investment required to achieve full system deployment by 2050.

The capital cost for solar photovoltaic (PV) systems was estimated based on a unit panel price of $384.12 for a 330 W module, with an associated operation and maintenance (O&M) rate of 0.05 [6]-[9] and subsequently scaled from panel-level costs to gigawatt-scale deployment, reaching up to 657 GW in the export scenario, thereby resulting in substantial cumulative capital investment requirements.

Similarly, the capital cost of hydrogen production via proton exchange membrane (PEM) electrolysis was estimated based on modular 100 MW units, each with a capital outlay of approximately $60,000,000 and an associated operation and maintenance (O&M) rate of 0.03 [6]-[9], with system costs subsequently scaled to reflect large-scale deployment exceeding 490 GW in the export scenario, resulting in significant aggregate investment requirements.

The capital cost of hydrogen-fuelled combined cycle gas turbine (H2CCGT) systems was estimated based on 600 MW units, each requiring an investment of approximately $418.2 million with an associated operation and maintenance (O&M) rate of 0.02 [6]-[9] and operating at an effective output of 500 MW, with total system deployment resulting in an aggregate capital expenditure of $22.58 billion and cumulative O&M costs of $6.024 billion.

Hydrogen storage and transmission infrastructure costs are comparatively lower than the previously discussed system components and are estimated using capacity-based scaling approaches, whereby hydrogen storage capital costs are evaluated on a per-kilogram basis at approximately $350/kg with an associated

O&M rate of 0.01 [6]-[9], while transmission infrastructure costs are derived per unit capacity at around $54,000 per GW with a similar O&M rate of 0.01 [23], reflecting their relatively reduced contribution to total system expenditure.

It is important to note that the reported CAPEX values (e.g., $765 billion for PV systems) represent cumulative national-scale investment rather than individual project costs. Likewise, OPEX values represent total expenditure over the system lifetime with annual operating costs.

The total system cost is therefore calculated as:

$$\text{Total Cost} = \text{CAPEX total} + \text{OPEX total}$$

For the export scenario, the total estimated cost of the transition is approximately $1796.9 billion, comprising approximately $1097 billion CAPEX and $699.6 billion OPEX.

Figure 5 and Figure 6 illustrate the staged and cumulative cost evolution across

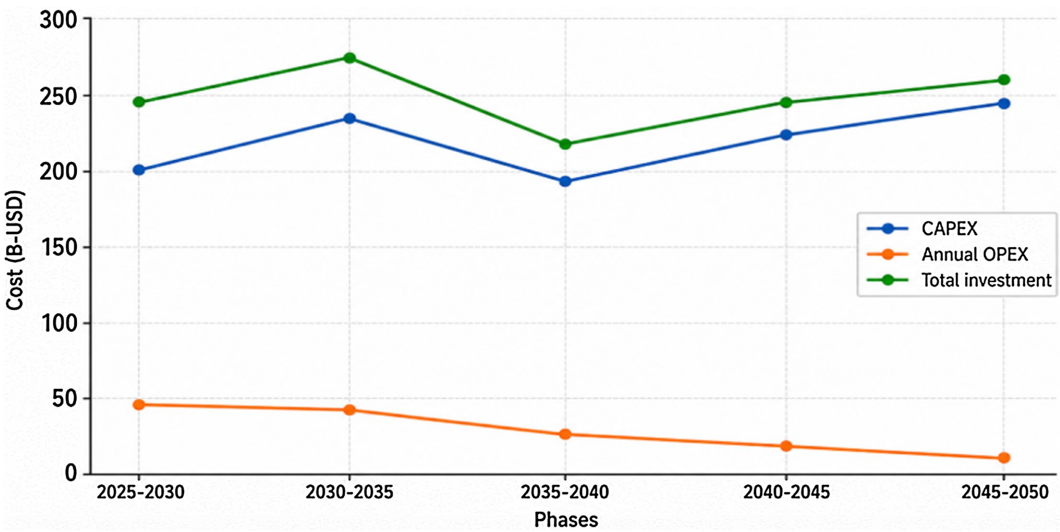

Figure 5. Financial expenditure for green energy infrastructure (2025-2050).

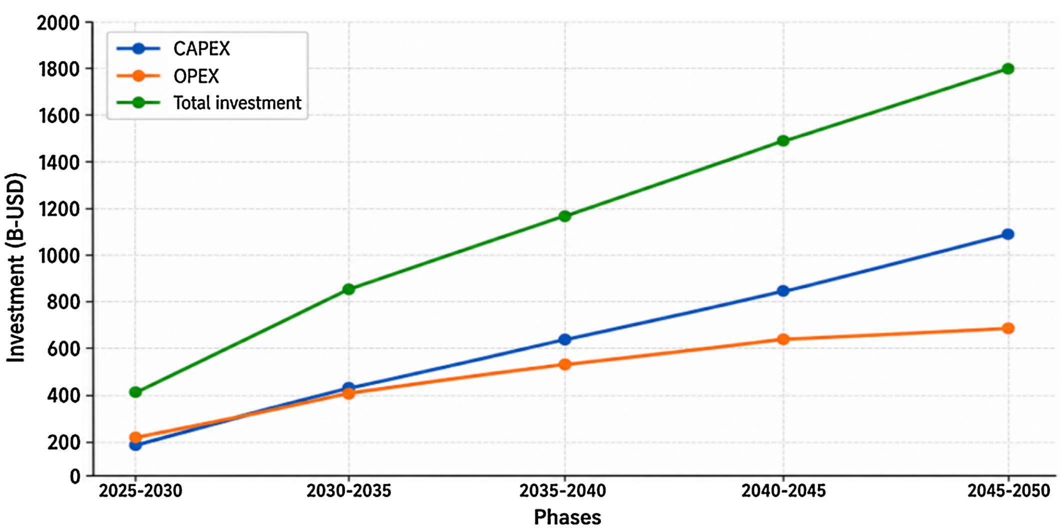

Figure 6. Cumulative financial expenditure for green energy infrastructure (2025-2050).

the transition period. The results indicate that while initial investment is high, cost growth stabilises in later phases due to infrastructure saturation and improved system efficiency.

This techno-economic framework provides a transparent and scalable approach for evaluating large-scale energy transitions, particularly for oil-exporting economies transitioning toward hydrogen-based export systems.

Table 6 sets out the financial expenditure categories associated with various components of exporting hydrogen from Libya between 2020 to 2050. Consideration is given to both specific CAPEX and specific annual OPEX of each component. The components should enable delivery for power generation, which includes the solar PV system and hydrogen fueled combined cycle gas turbines (H2 CCGT), as well as that for transmission. Power generation components show a steady increase in both specific CAPEX and specific annual OPEX throughout the project's timeline. Transmission, an integral part of the infrastructure, incurs relatively lower costs compared to other components, with consistent values for both specific CAPEX and specific annual OPEX. Additionally, the components encompass hydrogen production, including electrolysis and hydrogen storage demonstrating fluctuations in their specific CAPEX and specific annual OPEX over the project's duration. These fluctuations reflect the dynamic nature of the project's requirements and technological advancements within the renewable energy and electrolysis sectors over time.

Table 6. Specific capital and operational expenditures for all components of the green hydrogen production plant.

Component	CAPEX [B-USD]	Annual OPEX [B-USD]	Lifetime [Years]
Power Generation			
PV System	765	561	25
H2 CCGT	23	6 .02	25
Transmission	0.023	0.0034	/
Hydrogen Production			
Electrolyser	295	130.23	25
Hydrogen Storage	15	2.04	25

To further validate the robustness of the proposed modelling framework, the results were compared with established energy system models widely used in the literature. Large-scale global energy transition studies commonly rely on optimisation-based models such as MESSAGE-GLOBIOM, developed by the International Institute for Applied Systems Analysis (IIASA), and TIMES, developed under the IEA Energy Technology Systems Analysis Programme (ETSAP), which simulate long-term energy system evolution under different policies and technology scenarios [27] [28]. In addition, open-source frameworks such as OSeMOSYS are frequently used for national-level energy planning, particularly in developing economies.

These models typically operate at aggregated temporal resolutions (annual or seasonal) and focus on system-wide cost optimisation. In contrast, the present study adopts a high-resolution, bottom-up hourly simulation approach, explicitly capturing diurnal and seasonal solar variability, hydrogen production dynamics, and storage behavior. This approach is conceptually aligned with high-resolution power system models such as PyPSA which emphasise temporal granularity in renewable-dominated systems [29].

Despite methodological differences, the hydrogen production scales and infrastructure requirements estimated in this study are consistent with the order of magnitude reported in global modelling frameworks such as MESSAGE and TIMES, as well as international scenario analyses (IEA, 2023; IRENA, 2022). This agreement supports the validity of the proposed framework while highlighting its contribution in providing enhanced temporal resolution and system-level operational insights.

4.1. Power Generation

The proposed solar PV system is designed to meet both direct electricity demand and the additional electrical requirements associated with hydrogen production in 2050. The system is based on a total installed solar capacity of approximately 657 GW, corresponding to a land area of around 12,033 km^2, as derived in Section 3.

The capital and operational expenditures associated with the PV system are summarized in **Table 6**. The total capital investment required for solar PV deployment is estimated at approximately $765 billion, with cumulative operational expenditure over the project lifetime estimated at $561 billion. These values reflect large-scale national deployment rather than project-level costs and are consistent with the infrastructure requirements necessary to support both domestic demand and hydrogen export.

To ensure system reliability during periods of low or zero solar generation (e.g., nighttime operation), 54 units of 600 MW hydrogen-fuelled combined cycle gas turbines (H2CCGTs) are incorporated into the system. These units operate at an effective output of approximately 500 MW and provide dispatchable backup power. The associated capital cost is estimated at $23 billion, with cumulative operational expenditure of approximately $6.02 billion over the system lifetime.

In addition, a high-capacity transmission network of approximately 510 GW is required to connect solar generation sites, hydrogen production facilities, and demand centers. The associated capital and operational costs are comparatively small, estimated at $0.023 billion and $0.0034 billion, respectively, reflecting the lower cost contribution of transmission relative to generation and conversion technologies.

The power generation system represents the largest share of total investment, with solar PV deployment dominating both CAPEX and OPEX due to the scale required for national energy supply and hydrogen export.

4.2. Hydrogen Production

Hydrogen production in this study is based on large-scale deployment of proton exchange membrane (PEM) electrolysers, using modular units rated at 100 MW. This modular approach enables scalability and reflects current industrial practices in electrolyser system design.

The hydrogen production system is based on modular proton exchange membrane (PEM) electrolysers, with a nominal unit size of 100 MW. This capacity is selected as it represents a realistic industrial scale for near-term large hydrogen projects and allows flexible system expansion through modular deployment.

The total electrolyser capacity is determined by scaling the number of units required to meet hydrogen demand:

$$N\ el = P\ el,\ total/100$$

where N el is the number of electrolyser units and P el, total is the total installed electrolyser capacity (MW). This modular approach enables phased expansion aligned with the transition pathway.

Hydrogen production is directly related to the electrical energy supplied to the electrolysers and their efficiency:

$$H\ prod = (E\ el \times \eta\ el)/LHV\ H2$$

where E el is the electrical input, η el is the electrolyser efficiency (assumed to be approximately 70% for gaseous hydrogen and 55% for liquefied hydrogen), and LHV H2 is the lower heating value of hydrogen.

The electrolyser capacity factor is not assumed to be constant but is governed by the availability of solar PV generation. As a result, electrolysers operate flexibly, with higher utilisation during peak solar production and reduced operation during low irradiance periods. This results in an effective capacity factor lower than baseload systems, typically in the range of 30% - 50%, depending on seasonal variation and system balancing requirements

In addition, the analysis acknowledges the impact of technological learning and economies of scale on electrolyser cost. While a fixed unit cost is used in this study for consistency, it is expected that large-scale deployment will lead to cost reductions through manufacturing scale-up, improved system efficiency, and technological advancements. This modelling approach provides a realistic representation of large-scale hydrogen production systems integrated with variable renewable energy sources.

The total installed electrolyser capacity increases progressively across the project phases, reaching approximately 491 GW in the export scenario by 2050. The corresponding hydrogen production is estimated at approximately 17.5 million tonnes per year for export, in addition to domestic hydrogen demand.

The total capital expenditure associated with electrolysis is estimated at approximately $295 billion, with cumulative operational expenditure of approximately $130.23 billion over the system lifetime. These costs are strongly influenced by unit capital cost, system efficiency, and manufacturing scale, with potential cost reductions expected due to technological learning and economies of scale.

Hydrogen storage is incorporated as an essential component of the system to balance temporal mismatches between production and demand. By 2050, the required storage capacity is estimated at approximately 78,614 tonnes. The associated capital cost is approximately $15 billion, with cumulative operational expenditure of approximately $2.04 billion.

Although hydrogen storage and transmission contribute a smaller share of total cost compared to PV and electrolysis, they play a critical role in ensuring system flexibility, reliability, and continuity of supply, particularly under variable renewable energy conditions.

Together, the electrolysis and hydrogen storage systems form the core of the hydrogen production infrastructure, enabling large-scale energy conversion, storage, and export within the proposed solar-hydrogen energy framework.

It is important to note that the techno-economic approach adopted in this study differs from conventional project-level financial evaluation methods such as levelised cost of energy (LCOE), net present value (NPV), or internal rate of return (IRR). Instead, the analysis focuses on a system-level, capacity-driven assessment, where infrastructure requirements and associated costs are derived directly from projected energy demand and decarbonisation targets over the period 2020-2050. This approach enables the evaluation of large-scale national energy transitions by quantifying cumulative capital and operational requirements rather than optimising individual project profitability. Consequently, the results should be interpreted as indicative of total system investment needs and structural transformation pathways, rather than as project-specific financial performance metrics.

5. A Foundation Baseline for Future Policy and R&D Investments

The present study provides insights into shaping national and international research, development, and financial agendas in the field of electricity generation and energy store-age. The focus is on a comprehensive approach involving solar energy and H2CCGTs, along with ancillary systems. The study serves as a valuable baseline for evaluating alternatives and establishing R&D requirements essential for a country's decarbonization agenda, despite uncertainties and alternative approaches. Key R&D challenges include hydrogen production, with options like seawater electrolysis and a two-step process involving desalination and will be the focus of a future study. Demand patterns are explored, and demand management is suggested to optimize cost benefits by aligning peak demand with solar supply. The study also addresses the social duty of oil-exporting countries, such as Libya, to consider alternative energy exports since environmental policies will impact oil demand. The discussion extends to the potential export of hydrogen to Europe, raising questions about the mode of transport (liquid vs. gaseous) and electricity export. The study assumes gaseous hydrogen export, but a mix of options is likely. The choice of energy storage alternatives, including technologies such as batteries and compressed air storage, can vary, recognizing that different regions may require diverse solutions.

Table 7 outlines the financial considerations, with the total capital expenditure (CAPEX) calculated at $1097 billion, total operational expenditure (OPEX) at $699.64 billion, resulting in a total cost of $1796.9 billion.

Table 7. Total capital and operational (in Billion USD).

Total costs for green hydrogen production and export	Billion USD
Capital Cost	1097
O&M	699.64
Total Cost	1796.9

The study considered the design and operation of solar PV cells, considering factors like inclination, foundations, and redundancy for maintenance. It advocates for improvements in solar farm design and operation to enhance cost benefits. Hydrogen systems in large farms or parks are highlighted for economies of scale and experience. The choice of electricity sources, including solar, wind, and wave energy acknowledges the need for a detailed techno economic. Realistic assumptions are made regarding redundancy and capacity constraints, paving the way for a more detailed techno-economic optimization, and costing of the transition to a decarbonised economy.

5.1. Feasibility of a Green Transition for Libya

Libya's vast solar potential, alongside its existing energy infrastructure, positions the country as a promising candidate for this proposed transition to a carbon-neutral economy by 2050, centred around solar power, hydrogen production, and gas turbines. As detailed in the study, the country could generate sufficient renewable energy to meet both domestic needs and hydrogen production requirements for export. However, the scale of this transition is monumental. The projected total cost of $1.796 trillion under-scores the scale of investment needed in solar photovoltaic farms, hydrogen production facilities, and associated technologies such as electrolysers and storage systems. These financial commitments represent a significant challenge, especially considering Libya's current economic and political instability.

Despite these challenges, the transition to a green economy is not just a technical or economic necessity but a geopolitical one. Libya's proximity to European markets, coupled with its strong existing infrastructure, positions it as an attractive hydrogen ex-porter. The ability to leverage this infrastructure and diversify energy exports is critical, as the global demand for green hydrogen is expected to rise sharply in the coming decades, particularly in countries like Germany, Japan, and the broader European Un-ion, which are increasingly investing in renewable hydrogen production.

5.2. Balancing Domestic Needs and Export Demands

A key aspect of Libya's transition is the balance between meeting domestic energy needs and fulfilling export commitments, particularly in the form of hydrogen. The study highlights the staged transition of Libya's energy export mix, with a gradual in-crease in green hydrogen exports at the expense of oil exports. By 2050, hydrogen ex-ports could comprise a substantial portion of the country's total energy exports, representing a shift away from fossil fuel dependence. The challenge, however, lies in ensuring that domestic energy needs are not compromised in this transition. Libya's energy demand is expected to increase over the coming decades, driven by both population growth and industrial expansion. Solar power, while abundant, is intermittent, and backup systems, such as hydrogen-fuelled gas turbines, will be crucial for ensuring re-liability, particularly during the winter months when electricity demand peaks and solar power availability declines.

5.3. Technological and Infrastructure Challenges

Technologically, the development of large-scale hydrogen production via electrolysis, along with the necessary infrastructure for storage and transport, presents a formidable challenge. The study identifies the need for 12,033 km^2 of solar farms to meet hydrogen production goals, a vast area that will require significant land use planning, investment, and coordination with local communities. Moreover, the efficiency of electrolysis and storage technologies must improve to reduce costs and increase output. Current projections suggest that electrolysis efficiency will need to reach higher levels to meet the ambitious hydrogen production targets, and scaling up electrolyser capacity will require substantial investment in both R&D and manufacturing. Additionally, the integration of hydrogen storage and transportation infrastructure will require strategic planning.

5.4. Discussion: Linking Technical Requirements and Economic Implications

The analysis shows that Libya's transition toward a solar–hydrogen energy system is technically feasible in principle, but economically and infrastructurally demanding. The main driver of system scale is not domestic electricity demand alone, but the additional requirement to replace fossil fuel exports with green hydrogen. This creates a direct link between hydrogen export ambition and the required solar PV capacity, electrolyser deployment, storage, transmission, and overall investment.

The domestic winter self-sufficiency scenario requires 268 GW of solar PV and approximately 4900 km^2 of land. In contrast, the hydrogen export scenario requires 657 GW and approximately 12033 km^2 of solar farm area. This increase demonstrates that export replacement substantially changes the nature of the transition from a domestic decarbonisation challenge to a national industrial transformation.

Economically, the same pattern is observed. The largest cost components are solar PV and electrolysers, because they determine the primary energy supply and hydrogen conversion capacity. Therefore, any reduction in PV or electrolyser unit cost would have a significant effect on total system cost. Conversely, storage and transmission are smaller cost components but remain essential for system reliability and operational flexibility.

The results also show that H2CCGT systems play a strategic role rather than a dominant cost role. Their primary value lies in ensuring dispatchable power during periods of low solar generation. This is important because a solar-dominated system without backup would be vulnerable to seasonal and diurnal variability.

The phased transition pathway provides a practical mechanism for spreading infrastructure investment over time. However, the assumption of equal 20% decarbonisation per phase should be interpreted as a structured scenario rather than a forecast. Real deployment may be nonlinear, depending on policy stability, financing availability, technological learning, supply chain constraints, and international hydrogen market development.

The study shows that Libya's green transition is not constrained by solar resource availability alone. The main challenges are financial mobilisation, infrastructure coordination, technology deployment at scale, and the creation of reliable hydrogen export markets.

6. Policy and Strategic Considerations

Libya's transition toward a solar-hydrogen energy system depends not only on technical feasibility and cost competitiveness, but also on regulatory, institutional, and socio-economic conditions. Recent international studies emphasis that large-scale hydrogen deployment requires coherent policy frameworks, certification mechanisms, safety standards, infrastructure regulation, and long-term investment signals to enable project bankability and market development [24] [30] [31]. Without such enabling conditions, even technically viable systems may face delays or fail to materialize on scale.

In this context, Libya's ability to successfully transition to a green hydrogen economy will depend heavily on political stability and sustained policy commitment. The development of clear national strategies to support renewable energy deployment, hydrogen production, and export is essential. In addition, strategic investments in research and development, particularly in electrolysis, hydrogen storage, and system integration are required to improve efficiency and reduce long-term costs. International collaboration will also play a critical role, especially with European partners, to ensure market access, competitiveness, and alignment with emerging hydrogen certification standards.

The proposed transition pathway explicitly integrates spatial and temporal planning considerations. Solar PV farms are in the southern desert regions of

Libya, where high solar irradiation, low population density, and land availability make large-scale deployment feasible. In contrast, electrolysers, hydrogen storage systems, H2CCGT units, and export infrastructure are positioned near coastal regions and major urban centres to minimise hydrogen transport distances, facilitate access to seawater resources for electrolysis or desalination processes, and enable integration with existing port and energy infrastructure. This spatial configuration is consistent with international hydrogen supply chain strategies, which emphasise the co-location of production and export facilities to reduce system losses and infrastructure costs [24] [30] [31].

The transition timeline adopted in this study reflects practical implementation requirements. The baseline year is defined as 2020, followed by a preparatory phase from 2020 to 2025, during which essential enabling activities are undertaken. These include policy development, regulatory framework establishment, feasibility studies, permitting, environmental assessment, financing arrangements, and initial civil infrastructure works. Such lead times are consistent with large-scale energy infrastructure development and are widely recognised as critical for project readiness and risk reduction [24] [30] [31].

Following this preparatory stage, the transition is implemented in five-year increments from 2025 to 2050, representing progressive infrastructure expansion and decarbonisation. This phased approach enables alignment between technical deployment, institutional capacity building, and financial mobilisation, which is particularly important for oil-exporting economies undergoing structural transformation.

In addition to institutional challenges, socio-economic factors play a central role in determining the feasibility of the transition. The replacement of fossil fuel exports with hydrogen exports implies a fundamental restructuring of national revenue streams, workforce requirements, and industrial capabilities. This transition requires workforce reskilling, development of new industrial value chains, and alignment with international hydrogen certification standards to ensure market acceptance, particularly in European export markets [24] [30] [31]. At the same time, land-use planning, community engagement, water resource management, and safety regulation must be carefully addressed to support large-scale deployment.

Libya's role in the global energy market is therefore expected to evolve significantly. The transition toward hydrogen and renewable energy provides an opportunity to diversify the national economy, reduce dependence on fossil fuel exports, and strengthen its position in emerging low-carbon energy markets.

Hydrogen production, storage, transport, and utilisation at the scale considered in this study present significant technical and operational challenges that extend beyond the simplified representation adopted in the modelling framework. Large-scale electrolysis systems require substantial water resources, high system reliability, and careful thermal and operational management to maintain efficiency over long operating periods. In addition, hydrogen compression, liquefaction, and storage introduce further energy penalties and infrastructure complexity, particularly when considering long-duration storage and export-scale logistics. Safety considerations are also critical, as hydrogen has a wide flammability range and low ignition energy, requiring stringent design standards, monitoring systems, and regulatory frameworks to ensure safe operation across the value chain. These challenges are widely recognised in global hydrogen assessments and are key factors influencing deployment feasibility and cost (IEA, 2023; IRENA, 2022).

Furthermore, hydrogen transport and storage infrastructure require careful material selection and system design due to issues such as hydrogen embrittlement in pipelines, leakage risks, and boil-off losses in cryogenic storage. At large scales, the integration of hydrogen systems with existing energy infrastructure introduces additional complexity, particularly in balancing production, storage, and end-use demand. While the present study captures the energy and infrastructure requirements at a system level, these detailed engineering, safety, and operational constraints are not explicitly modelled and are treated as implementation challenges that must be addressed during project development and deployment phases. Incorporating these aspects in future work would further enhance the realism and applicability of the proposed framework.

The large-scale deployment of solar PV and hydrogen infrastructure presents significant challenges in terms of grid stability, transmission expansion, and system integration. The results indicate that transmission capacity increases progressively from 93 GW in 2025-2030 to approximately 510 GW by 2050, reflecting the need for substantial grid reinforcement to accommodate geographically distributed solar generation and coastal hydrogen production hubs. Such expansion introduces challenges related to grid balancing, voltage stability, and transmission losses, particularly under high penetration of variable renewable energy.

To address intermittency, the proposed system integrates hydrogen storage and H2CCGT units, which provide dispatchable power during periods of low solar availability, thereby enhancing grid flexibility and reliability. This hybrid configuration effectively acts as a long-duration energy storage mechanism, supporting system stability. However, large-scale integration of these technologies requires advanced grid management strategies, including flexible operation, demand-side management, and coordinated infrastructure planning. These aspects are not explicitly simulated but are recognised as critical considerations for real-world implementation.

7. Conclusions

This study developed a national-scale techno-economic framework to evaluate the transition of an oil-exporting country toward a solar-hydrogen-gas turbine energy system by 2050. The framework integrates energy demand projection, solar PV sizing, electrolyser deployment, hydrogen storage, H2CCGT backup generation, phased infrastructure expansion, and cumulative cost assessment.

For Libya, the domestic winter self-sufficiency scenario requires approximately

268 GW of solar PV capacity, 4900 km^2 of solar farm area, 199 GW of electrolyser capacity, 28,889 tonnes of hydrogen storage, and 54 H2CCGT units. When hydrogen export replacement is included, the required solar PV capacity increases to approximately 657 GW, corresponding to 12,033 km^2 of solar farm area, 491 GW of electrolysis, 78,614 tonnes of hydrogen storage, 510 GW of transmission capacity, and 2100 PJ of annual hydrogen export.

The estimated total system cost for the export scenario is approximately USD 1796.9 billion, comprising around USD 1097 billion in CAPEX and USD 699.6 billion in cumulative OPEX. The cost structure is dominated by solar PV and electrolyser deployment, indicating that future reductions in PV and electrolyser costs will have the greatest effect on improving economic feasibility.

The study contributes to the literature by providing an integrated system-level framework for assessing how an oil-exporting country could transition from fossil fuel dependence toward renewable hydrogen production and export. Unlike studies focused on individual technologies or single-sector decarbonisation, this work links domestic demand, export replacement, infrastructure sizing, backup generation, and cost assessment within one national-scale pathway.

The findings suggest that Libya has strong technical potential for a solar-hydrogen transition due to its solar resource, land availability, coastal access, and proximity to European markets. However, successful implementation would require long-term policy stability, major investment mobilisation, international partnerships, technology cost reduction, and coordinated infrastructure planning. Despite the study being conducted for Libya, global applicability of the principles is highlighted.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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Nomenclature

FCV	Fuel Calorific Value
GJ/T	Gigajoules/tonne
H2	Hydrogen
H2TGTCC	Hydrogen fuel gas turbine combined cycle
kTonne	Kilo Tonne
MT	Mega Tonnes
MTOE	Million tonne oil Equivalent
NOx	Nitrogen Oxides
PJ	Petajoules
TJ	Terajoule