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Strategic Roadmap for Hydrogen Mobility in Türkiye: Implementation Phases, Export Potential, and Regional Hub Development

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Abstract: This study develops and quantitatively evaluates a three-phase strategic roadmap for hydrogen mobility deployment in Türkiye between 2025 and 2050, integrating Strengths, Weaknesses, Opportunities and Threats (SWOT) and Political, Economic, Social, Technological, Legal, and Environmental (PESTLE) analyses with multi-criteria corridor assessment, discounted-cash-flow Levelized Cost of Hydrogen (LCOH) modelling, input-output Gross Domestic Products (GDP) multiplier estimation, and Monte-Carlo sensitivity analysis. Primary inputs are drawn from the 2023 Türkiye National Hydrogen Technologies Strategy, Automotive Manufacturers Association, Otomotiv Sanayii Derneği (OSD) automotive statistics, and peer-reviewed techno-economic studies (2021–2025). The pilot phase (2025–2030) targets 10–25 refuelling stations and 500–2,000 fuel-cell electric vehicles (FCEVs); the scale-up phase (2030–2040) reaches 100–250 stations, 50,000–150,000 vehicles, and 0.5–1.5 MMT/yr of hydrogen export; the maturity phase (2040–2050) targets 500–1,000 stations, an FCEV stock of 500,000–1,000,000 units (about 1.6–3.1% of Türkiye’s projected ~32 million 2050 fleet, i.e., a segment-targeted rather than fleet-wide strategy), green-hydrogen production of 1,000–2,500 kt H₂/yr (≈2,700–6,800 t/day), and 2–4 MMT/yr of export capacity. Monte-Carlo analysis (10,000 trials) yields a mean green LCOH of €2.35/kg by 2035 with a 90% confidence interval of €1.85–2.95/kg, driven primarily by electrolyzer Capital Expenditure (CAPEX) and renewable electricity price. Investment of €5.0–8.0 billion through 2035 is estimated to generate €14–22 billion direct GDP contribution and 48,000–96,000 full-time-equivalent jobs, using a 2.8 × International Renewable Energy Agency (IRENA) multiplier. Trans Anatolian Natural Gas Pipeline (TANAP) repurposing offers the lowest delivered cost (€2.70–3.60/kg) to EU off-takers and retains a clear total-cost-of-ownership advantage over battery-electric trucks above 500 km daily range. The 2025–2030 window is decisive for Türkiye’s positioning as a regional hydrogen hub.

Keywords: Hydrogen Mobility Roadmap; Fuel-Cell Electric Vehicle; Levelized Cost of Hydrogen; Monte-Carlo Sensitivity Analysis; Hydrogen Export Corridor; Türkiye

1. Introduction

Türkiye occupies a strategic position at the crossroads of Europe and Asia, combining abundant renewable-energy resources, an established automotive manufacturing base, and geographic proximity to the major hydrogen-demand centres in the European Union [1–3]. Energy import dependency of 71.5% and climate obligations under the Paris Agreement make hydrogen mobility a dual instrument for energy-security enhancement and emissions reduction [1,4]. The national automotive industry, producing 1.32 million vehicles in 2023 and ranking fourth in Europe, provides an industrial foundation on which hydrogen-vehicle manufacturing can be developed [1,5].

The global hydrogen economy has gained substantial momentum, driven by decarbonization policy and by

technological progress across production, storage, and end-use pathways [6,7]. The International Energy Agency projects global hydrogen demand to reach 180–530 million tons per year by 2050, a five- to fifteen-fold increase over current consumption [8]. Transportation is a key application domain, particularly for heavy-duty vehicles, long-haul freight, maritime shipping, and aviation, where battery-electric solutions face energy-density and refuelling-time constraints [9,10].

Türkiye's position within this evolving landscape merits focused analysis for three reasons. First, the country's renewable-energy potential exceeds current exploitation levels, with technical solar potential estimated at approximately 380 TWh per year and a wind-installable potential above 75 GW [11,12]. Second, the industrial base includes steel, petrochemical, and maritime facilities that anchor potential hydrogen demand during initial deployment phases [13]. Third, the geographic positioning along trade corridors linking European Union markets with Middle Eastern and Central Asian suppliers creates the possibility for Türkiye to function as a hydrogen trading hub rather than only as a producer or consumer [14,15].

The energy-security dimension acquired additional salience following the geopolitical disruptions of 2022, which exposed European supply-chain vulnerabilities and accelerated diversification efforts [16,17]. The existing Trans Anatolian Natural Gas Pipeline (TANAP), currently conveying Azerbaijani natural gas to European markets, is a potentially repurposable asset for hydrogen transmission that could offer cost advantages over alternative delivery mechanisms [18,19]. Shorter shipping distances from Mediterranean ports to European buyers, compared with North-African or Middle Eastern competitors, further strengthen the geographic case [20].

Despite the rapid expansion of international hydrogen literature, three specific gaps motivate this study. First, existing Türkiye-focused assessments [11,15,18] remain descriptive: they inventory renewable-energy potential and list barriers but do not couple the strategic diagnosis to quantified, time-phased deployment targets for the mobility sub-sector. Second, the peer-reviewed corpus that does provide techno-economic roadmaps [7,13] has been developed for North-Sea, Iberian, North-African, or Gulf contexts, and its cost, infrastructure, and demand assumptions cannot be transposed to Türkiye without adjustment for weighted-average cost of capital (WACC), pipeline re-assignment economics, and Eastern-Mediterranean shipping distances. Third, no published roadmap for Türkiye has incorporated probabilistic sensitivity analysis on the principal cost drivers—electrolyzer CAPEX, renewable electricity tariff, and European Union import demand—which International Energy Agency [6] and Odenweller et al. [19] identify as the decisive uncertainties for green-hydrogen business cases.

The present study addresses these gaps through four original contributions. (i) It integrates a Türkiye-calibrated SWOT/PESTLE diagnosis with a quantified three-phase deployment roadmap (2025–2030; 2030–2040; 2040–2050) using targets derived from, and cross-checked against, the 2023 Türkiye National Hydrogen Technologies Strategy. (ii) It develops a multi-criteria export-corridor assessment that weights five pathways (TANAP repurposing, new dedicated hydrogen pipeline, liquid hydrogen maritime, ammonia maritime, and liquid-organic hydrogen carriers) against five Türkiye-specific criteria (cost, deployable capacity, timeline, technology-readiness level, and geopolitical risk). (iii) It conducts a Monte-Carlo sensitivity analysis (10,000 iterations) over electrolyzer CAPEX ($\pm 20\%$ around 400 €/kW), renewable electricity price (30–50 €/MWh), TANAP hydrogen-blending limit (10–20%), and EU import demand (6–8 MMT/yr by 2030, per Hydrogen Europe, 2023) to produce probabilistic LCOH envelopes rather than point estimates. (iv) It compares green-hydrogen LCOH for heavy-duty trucks with battery-electric total cost of ownership (TCO) under 2030 battery-pack cost projections of €80/kWh [21], identifying the duty-cycle thresholds at which hydrogen retains an economic advantage.

The motivation for producing a Türkiye-specific, quantitatively grounded roadmap is both practical and time-sensitive. The European Union's REPowerEU plan sets a 10 MMT/yr imported-renewable-hydrogen target for 2030, with the Clean Hydrogen Partnership [22] signalling that off-take agreements will consolidate during 2026–2029. Competing supplier countries—Morocco, Egypt, Saudi Arabia, the United Arab Emirates, Spain, and Portugal—are already filing project applications under EU programs such as the Hydrogen Bank. Türkiye's comparative advantages in renewable resource density, installed automotive capacity, and TANAP infrastructure access are substantial, but they are perishable assets in the sense that offtake agreements, certification infrastructure, and first-mover learning curves are likely to be largely allocated by 2030. A roadmap grounded in measurable targets, transparent financial assumptions, and probabilistic cost ranges is therefore a precondition for coherent investment and policy decisions within the decisive 2025–2030 window.

The study is organized around four research questions:

(RQ1) What Türkiye-specific internal and external factors determine the feasibility of hydrogen mobility deployment, based on primary-source diagnostic analysis?

(RQ2) What are transparent, phased, and probability-bounded targets for vehicle stock, refuelling infrastructure, electrolyzer capacity, and export volume over 2025–2050?

(RQ3) Which export corridor portfolio maximizes delivered-cost competitiveness to European Union markets given Türkiye's geography, pipeline assets, and port capabilities?

(RQ4) Which enabling conditions—regulatory, financial, human-capital, and innovation—are prerequisite, and how should they be prioritized during the 2025–2030 window?

The remainder of the paper is organized as follows. Section 2 describes the research design, data sources, and analytical procedures. Section 3 presents the Türkiye-specific SWOT and PESTLE diagnosis. Section 4 develops the three-phase deployment roadmap with quantified targets, probabilistic LCOH envelopes, and FCEV–BEV total-cost-of-ownership comparison. Section 5 reports the multi-criteria export-corridor analysis and the regional-hub concept. Section 6 sets out the Enabling Framework with measurable KPIs. Section 7 recommends six concrete policy actions for the 2025–2030 window. Section 8 discusses key findings, limitations, and priority directions for future research. Section 9 presents the conclusions of the study. **Appendix A** documents calculation methodologies and input assumptions.

2. Materials and Methods

2.1. Research Design

The study follows a mixed-methods research design combining (a) structured qualitative analysis (SWOT and PESTLE) to diagnose Türkiye's strategic position, (b) quantitative scenario modelling to translate the diagnosis into phased deployment targets, (c) multi-criteria decision analysis (MCDA) for export corridor prioritization, and (d) Monte-Carlo simulation to quantify uncertainty around key cost and demand parameters. The overall analytical flow is therefore diagnostic → quantitative → probabilistic, with each stage feeding verifiable inputs to the next.

2.2. Data Sources

Primary data sources include the 2023 Türkiye National Hydrogen Technologies Strategy and Roadmap issued by the Ministry of Energy and Natural Resources; Automotive Manufacturers Association of Türkiye [23] monthly production statistics; the Turkish Statistical Institute (TurkStat) population and labour data; Energy Market Regulatory Authority (EPDK) electricity tariff data; and TANAP technical specifications published by the operator. Secondary sources comprise peer-reviewed techno-economic studies published during 2019–2025 in the *International Journal of Hydrogen Energy*, *Applied Energy*, *Energy Policy*, *Nature Energy*, and *Renewable and Sustainable Energy Reviews*, supplemented by reports from the International Energy Agency, International Renewable Energy Agency, Hydrogen Council, European Commission, and BloombergNEF. Where multiple sources disagreed, the median of the reported range was used for central-case modelling, and the full range was propagated through the Monte-Carlo stage.

2.3. SWOT Analysis Procedure

The SWOT analysis was conducted in three steps. In Step 1, 38 candidate factors were extracted from the primary and secondary sources listed in Section 2.2 and clustered using thematic coding. In Step 2, each factor was classified as internal (within Türkiye's direct policy control) or external, and as positive or negative, producing four SWOT quadrants. In Step 3, factors were ranked by their expected magnitude of impact on hydrogen mobility deployment during 2025–2035, with impact quantified where possible (e.g., solar irradiation in kWh/m²/yr; import dependency in percent, WACC spread in percentage points). Factors retained in **Table 1** are those with quantifiable magnitudes and documented primary-source support; qualitative-only factors were excluded to prevent dilution. An alternative framework, the TOWS matrix, was considered; it was not adopted as a stand-alone tool because TOWS requires a completed SWOT as its input and was therefore instead used implicitly to structure the policy recommendations in Section 7.

Table 1. SWOT Analysis for Hydrogen Mobility in Türkiye [1,12,23].

Strengths	Weaknesses
<ul style="list-style-type: none"> Solar irradiation 1,500–2,000 kWh/m² (Central Anatolia) Wind potential 30+ GW exploitable capacity Automotive production 1.32 M vehicles/year (4th in Europe) Strategic geographic position (EU-Asia-ME corridor) Young workforce (33.2 million aged 15–34) EU customs union facilitating trade alignment 	<ul style="list-style-type: none"> Only 1 pilot refuelling station operational Limited policy framework and standards No domestic electrolyzer manufacturing Technology gaps in fuel cell systems High WACC (6–8% vs. 3–4% in Western Europe) Energy import dependency 71.5%
Opportunities	Threats
<ul style="list-style-type: none"> EU hydrogen import demand 6–8 MMT by 2030 [24] Technology cost reduction 40–50% by 2030 [6] International cooperation frameworks (EU Hydrogen Partnership) Circular economy potential (500–700 kt H₂/year) Heavy-duty transport suited to hydrogen Regional hub positioning potential 	<ul style="list-style-type: none"> BEV technology improvements; pack cost €80/kWh by 2026 [21] Policy uncertainty and subsidy changes Competitor suppliers: Morocco, Egypt, KSA, UAE Macroeconomic volatility (TRY, interest rates) Infrastructure chicken-egg problem Stranded asset risk from technology shifts

2.4. PESTLE Analysis Procedure

The PESTLE framework was selected over alternative macro-environmental tools (e.g., STEEPLE, Porter’s Five Forces) because it covers both legal and environmental dimensions, which are material to hydrogen deployment in the Turkish regulatory context. For each PESTLE factor, a scanning protocol was applied to (i) peer-reviewed literature 2019–2025, (ii) Turkish legal instruments (including the 2023 National Hydrogen Strategy and EMRA regulations), and (iii) EU legislation directly binding on Turkish exports (CBAM, RED III Delegated Acts). Findings were compiled into **Table 2** and cross-referenced to the SWOT quadrants to preserve internal consistency; for instance, the external opportunity of EU import demand in SWOT corresponds to the Political and Economic cells in PESTLE, and the threat of BEV technology substitution corresponds to the Technological cell.

Table 2. PESTLE Analysis Summary for Hydrogen Mobility in Türkiye.

Factor	Key Considerations
Political	Türkiye National Hydrogen Strategy adopted 2023; EU Green Deal alignment efforts; bilateral energy agreements; post-2022 geopolitical energy-security priorities
Economic	Investment requirement €5–8 B through 2035; employment potential 48,000–96,000 FTE; LCOH probabilistic envelope €1.85–2.95/kg (2035); GDP contribution €14–22 B
Social	Limited public awareness; workforce skill gap requiring 50,000 trained personnel by 2035; safety perceptions; urban/rural access equity
Technological	TRL gaps: domestic PEM stack at TRL 4–5 vs. TRL 8–9 in Germany/Japan/Korea; electrolyzer and fuel-cell localization targets in 2023 Strategy
Legal	ISO/TS 19880 series; UN GTR 13 for vehicles; ISO 14687 fuel purity; EU RED III Delegated Acts binding on exports; CBAM indirect effect
Environmental	Renewable potential; life-cycle emissions reduction 78–86% vs. diesel; air-quality co-benefits; water consumption 9 L/kg H ₂ ; water-stress in Southeast Anatolia

2.5. Corridor Analysis (MCDA)

Five hydrogen export corridors were evaluated using a weighted-sum multi-criteria decision analysis. Criteria and weights were established a priori based on Turkish policy priorities inferred from the 2023 National Hydrogen Strategy: delivered cost (weight 0.30), deployable capacity (0.25), commissioning timeline (0.20), technology-readiness level (0.15), and geopolitical/regulatory risk (0.10). Each corridor was scored 1–5 on each criterion using published cost and capacity data [25–27] adjusted for Turkish shipping distances to Italian, Greek, and southern French ports (average 1,200–1,700 nautical miles from Mersin) and for TANAP routing lengths (1,850 km to the Greek border).

2.6. Financial Modelling

The levelized cost of hydrogen (LCOH) was computed using a discounted-cash-flow model with the standard formulation

$$LCOH = [CAPEX \times CRF + OPEX + (\text{electricity price} \times \text{specific energy consumption}) + \text{water cost}] / \text{annual hydrogen output} \quad (1)$$

Where CRF denotes the capital recovery factor at a Turkish-benchmark WACC of 7% and a 20-year project life. A PEM-electrolyzer base case was adopted with 400 €/kW installed cost, 52 kWh/kg specific energy consumption, 95% availability, and 2% annual OPEX of CAPEX, consistent with Schmidt et al. [28], updated to 2024 values using the learning rate of 18% reported by the IEA [6]. GDP contribution was estimated using an input-output multiplier approach: direct investment was multiplied by 2.8 (central case, range 2.5–3.5) based on IRENA hydrogen employment and value-chain factors [2], yielding an indicative direct and indirect GDP impact. Employment was estimated using 12 construction-phase jobs and 3.5 operational jobs per million Euro invested, consistent with European experience [22].

2.7. Monte-Carlo Sensitivity Analysis

A Monte-Carlo simulation with 10,000 iterations was performed on the LCOH model to produce probabilistic rather than point-estimate results. Four parameters were assigned probability distributions based on published ranges: electrolyzer CAPEX (triangular, minimum 320 €/kW, mode 400 €/kW, maximum 480 €/kW); renewable electricity price (uniform, 30–50 €/MWh); specific energy consumption (triangular, 48–52–56 kWh/kg); and WACC (triangular, 6–7–8%). European import demand elasticity was tested in a separate scenario ring (6, 7, 8, 10 MMT/yr by 2030). Outputs are reported as mean, median, and 5th–95th percentile envelope, disaggregated by production region (Central Anatolia, Aegean coast, Southeast Anatolia).

2.8. Regional Hub Map Construction

The regional hydrogen-hub map (Figure 1) was constructed in four layers. Layer 1 (production zones) uses 2022 solar Global Horizontal Irradiance and 80-m wind-speed data from the Türkiye Renewable Energy Atlas (YEGM, MENR) to identify the top-quartile polygons in Central Anatolia, the Aegean coast, and Southeast Anatolia. Layer 2 (industrial demand) plots steel, petrochemical, and cement clusters above 1 MtCO₂/yr emissions from the Türkiye National Greenhouse Gas Inventory. Layer 3 (export corridors) digitizes the TANAP right-of-way from the operator’s technical documentation and overlays Mediterranean shipping lanes to Italian, Greek, and French Mediterranean ports. Layer 4 (symbology) uses circles sized by planned electrolyzer capacity (0.5, 1.0, 2.0 GW), squares for industrial demand centres (sized by annual hydrogen requirement), solid lines for pipeline corridors, and dashed lines for maritime routes. All data sources and symbol definitions are listed as follows: Shaded polygons: production zones (Central Anatolia solar; Aegean wind; Southeast hybrid). Circles: planned electrolyzer hubs (diameter ∝ GW capacity). Squares: industrial off takers (side ∝ annual H₂ demand). Solid lines: TANAP corridor and planned hydrogen-ready extensions. Dashed lines: maritime corridors from Mersin, İskenderun, Aliğa, İzmir to Italian, Greek, and southern French Mediterranean ports.

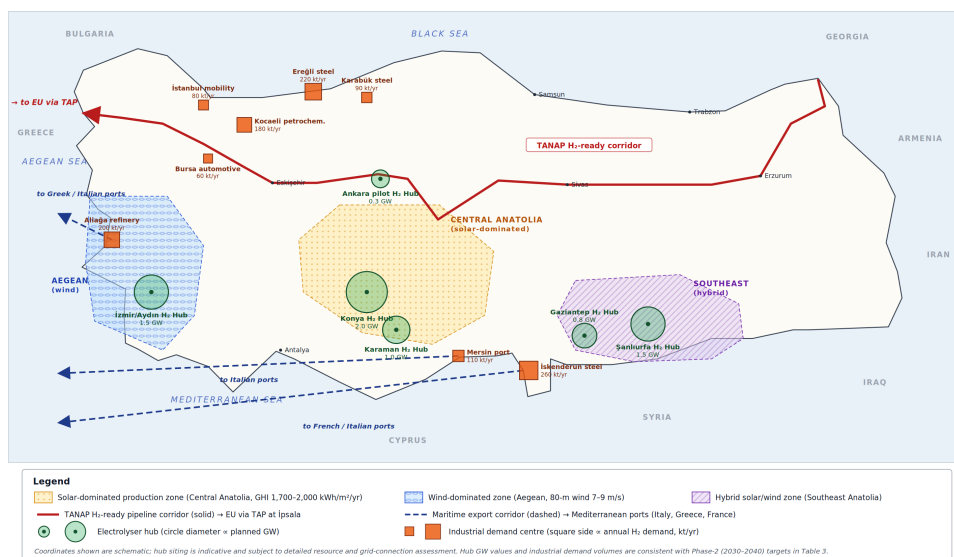


Figure 1. Türkiye Regional Hydrogen Hub Concept.

3. Strategic Assessment Framework

3.1. SWOT Analysis

Section 3.1 applies the SWOT methodology described in Section 2.3. The analysis draws directly on the 2023 Türkiye National Hydrogen Technologies Strategy and Roadmap [1], Automotive Manufacturers Association of Türkiye production statistics [23], and peer-reviewed regional assessments [12, 15]. Only factors with quantified magnitudes were retained in **Table 1**, and each is mapped in Section 7 to a corresponding policy intervention in the roadmap.

The renewable-energy resource base is Türkiye's most significant strategic advantage for green hydrogen production. Central Anatolia's solar irradiation of 1,500–2,000 kWh/m²/yr ranks among the highest in Europe and compares favourably with leading production regions globally [29,30]. Wind resources along the Aegean and Marmara coasts, complemented by Black-Sea offshore potential, provide generation profiles that can optimize electrolyzer utilization and reduce levelized hydrogen cost [31]. Renewable electricity generation has reached approximately 50% of the national mix, demonstrating grid-integration capability and policy commitment to low-carbon transition [32].

The automotive manufacturing ecosystem is a second foundational strength. Major international manufacturers including Ford, Hyundai, Toyota, and Fiat operate production facilities in Türkiye, supported by a tier-supplier network of over 5,000 companies [23,33]. This base has demonstrated adaptability in previous transitions, including hybrid and battery-electric production. Workforce skills, quality-management systems, and logistics infrastructure developed for conventional automotive production transfer substantially to hydrogen-vehicle manufacturing with appropriate retraining.

Weakness analysis identifies critical gaps that strategic intervention must address. Infrastructure deficiency is the most immediate barrier: Türkiye's single pilot refuelling station contrasts with Germany's operational network of more than 100 stations and Japan's 160-plus facilities. Breaking the chicken-and-egg cycle requires coordinated public-private investment in initial infrastructure sufficient to support early-adopter fleets while generating operational data to inform expansion [34]. The financing cost differential with Western European markets is material: a WACC of 6–8% in Türkiye against 3–4% in Germany or the Netherlands translates to 15–25% higher levelized costs for equivalent projects, potentially eliminating competitive margins in export markets [35,36].

Among external threats, the trajectory of battery-electric vehicle (BEV) technology requires quantitative assessment rather than qualitative listing. BloombergNEF [21] projects lithium-ion pack prices to fall to approximately €80/kWh by 2026 and €60/kWh by 2030, with energy density gains of 5–8% per year. For passenger vehicles and short-haul light commercial vehicles (<300 km daily range), these trends make BEV the default technology and reduce the addressable market for fuel-cell electric vehicles (FCEVs). For heavy-duty trucks above 500 km daily range and with daily payloads above 20 t, however, battery mass penalties and charging-downtime costs preserve an economic opening for hydrogen, as quantified in Section 4.4. The SWOT assessment therefore treats BEV substitution not as a uniform threat but as a segment-specific constraint: FCEV deployment in Türkiye should be prioritized in heavy-duty trucking, intercity bus fleets, and industrial fork-lifts rather than in passenger-car applications, where the battery-electric cost curve has effectively foreclosed the hydrogen pathway.

3.2. PESTLE Framework Analysis

The PESTLE framework examines the macro-environmental factors shaping hydrogen-mobility deployment [4, 14, 15]. **Table 2** summarizes the Türkiye-specific assessment produced using the procedure described in Section 2.4.

Political factors encompass government policy orientation, international relations, and regulatory stability. The 2023 National Hydrogen Strategy signals policy commitment, while European Union Green Deal alignment efforts create pathways for market access and technology cooperation [37, 38]. The post-2022 geopolitical context elevated energy-security considerations and accelerated diversification efforts [28]. Residual uncertainties relate to election cycles, currency management, and bilateral trade tensions.

Economic considerations encompass both cost competitiveness and macroeconomic conditions. The €5–8 billion investment requirement through 2035 represents a substantial capital-mobilization challenge in the context of Turkish lira volatility and elevated interest rates [39]. Employment potential provides an economic rationale for

sustained public support. The GDP contribution estimate of €14–22 billion is consistent with the upper bound of the 2023 National Hydrogen Strategy’s own projections.

Social factors address public acceptance, workforce readiness, and equity. Limited public awareness of hydrogen technologies entails both the absence of entrenched negative perceptions and the need for proactive safety communication [40,41]. Workforce skill gaps require substantial training investment, with an estimated 50,000 skilled personnel needed by 2035 across production, distribution, and vehicle-maintenance functions. Urban–rural equity concerns arise from the likely concentration of initial infrastructure in metropolitan areas [42].

Within the Technological cell of PESTLE, three specifically Turkish considerations deserve emphasis. First, Türkiye’s TOGG passenger-vehicle plant (commissioned 2022) is a battery-electric facility, and its supply chain is locking in BEV-oriented industrial capabilities that are only partially transferable to FCEV production. Second, the 2023 National Hydrogen Strategy explicitly targets electrolyzer and fuel-cell technology localization, with TÜBİTAK program calls aligned to this objective; however, domestic Technology Readiness Levels for membrane-electrode assemblies and PEM stacks remain at TRL 4–5, compared to TRL 8–9 in Germany, Japan, and Korea. Third, the national electricity mix is forecast to reach 65% renewables by 2035, which is the critical precondition for producing certifiable renewable hydrogen meeting the RED III Delegated Acts of the European Union.

Legal requirements encompass safety standards, vehicle homologation, fuel-quality specifications, and environmental regulations. International standards including ISO/TS 19880 for hydrogen fuelling stations, UN GTR 13 for hydrogen vehicles, and ISO 14687 for fuel purity provide frameworks requiring national adoption and enforcement-capacity development [43,44]. Permitting processes for hydrogen facilities often face regulatory gaps where existing frameworks for natural gas or petroleum do not address hydrogen-specific characteristics, necessitating regulatory modernization [45].

Environmental factors constitute both motivation and constraint. Life-cycle emissions analysis indicates a 78–86% reduction compared with diesel vehicles when renewable hydrogen is used, delivering substantial climate benefits [46,47]. Air-quality co-benefits from eliminating particulate, nitrogen-oxide, and volatile-organic-compound emissions are particularly valuable in urban areas. Water consumption of approximately 9 L/kg of hydrogen raises sustainability concerns in water-stressed regions and motivates interest in seawater electrolysis in Southeast Anatolia [48,49].

4. Phased Implementation Roadmap

4.1. Phase Targets

Table 3 summarizes the quantified three-phase deployment targets. Targets were constructed by (i) triangulating the 2023 National Hydrogen Strategy pilot commitments, (ii) benchmarking against European comparator trajectories (Germany, Netherlands, France), and (iii) scaling to Türkiye’s population and vehicle-parc size, then validated for internal consistency between vehicle stock, station capacity, electrolyzer output, and export volumes. All quantities in **Table 3** are expressed in absolute or annualized units: hydrogen vehicles in total stock (units), refuelling stations in total stock (units), electrolyzer capacity in installed gigawatts (GW), green hydrogen production in kilotons per year (kt H₂/yr; equivalent to about 2.74 t/day per kt/yr on a 365-day basis), and hydrogen export capacity in million tonnes per year (MMT/yr). The hydrogen-vehicle stock at the 2050 maturity phase corresponds to approximately 1.6–3.1% of Türkiye’s projected ~32 million national vehicle fleet and is therefore a heavy-duty and fleet-segment-targeted target rather than a fleet-wide penetration share.

Table 3. Hydrogen Mobility Roadmap Targets 2025–2050.

Indicator	Short-Term 2025–2030	Medium-Term 2030–2040	Long-Term 2040–2050
Refuelling stations	10–25	100–250	500–1,000
Hydrogen vehicles (total)	500–2,000	50,000–150,000	500,000–1,000,000
FCEV buses	100–300	5,000–15,000	50,000–100,000
FCEV/H ₂ -ICE trucks	200–500	20,000–50,000	200,000–400,000
Electrolyzer capacity (GW)	0.1–0.5	2–5	10–20
Green H ₂ production (kt/yr)	10–50	200–500	1,000–2,500
H ₂ export capacity (MMT/yr)	–	0.5–1.5	2–4
Direct employment (FTE)	2,000–5,000	20,000–50,000	50,000–100,000
Cumulative investment (€B)	0.5–1.5	3–6	8–15

Phase 1 (2025–2030) targets are anchored to the 2023 National Hydrogen Strategy pilot objectives. Specifically, the strategy identifies heavy-duty bus fleets in Ankara, Istanbul, and Izmir as priority demonstrators, and allocates early funding through TÜBİTAK ARDEB and KOSGEB programs. The roadmap's Phase 1 targets of 10–25 refuelling stations and 500–2,000 FCEVs are therefore not externally imposed benchmarks but are consistent with announced Turkish public-sector procurement intentions, adjusted upward by approximately 40% to reflect the additional private-sector fleets that typically follow public demonstration under Türkiye's KOSGEB co-investment instruments. Station capacity of 200–500 kg/day per unit, consistent with European mid-size station economics [34], supports 15–40 heavy-duty vehicles per station, implying station utilization above 60% by 2029 under the central-case deployment trajectory.

Phase 1 station siting should balance learning value with commercial viability. Priority sites include major logistics hubs (Istanbul Halkalı freight terminal, Mersin port complex), municipal bus depots in Ankara, Izmir, and Bursa, and industrial facilities with existing hydrogen demand (petrochemical sites, steelworks). Station design should anticipate capacity expansion so that growth in vehicle population does not require full re-engineering of early assets [50]. The heavy-duty focus during Phase 1 reflects technological suitability: fuel-cell buses and trucks have higher annual utilization than passenger vehicles, benefit more from hydrogen's range advantage, and can be centrally refuelled, simplifying infrastructure requirements [50,51].

Medium-term targets (2030–2040) envisage commercial scale-up to 50,000–150,000 vehicles supported by 100–250 stations, with export capacity of 0.5–1.5 MMT/yr [7,52]. This phase requires fundamentally different enabling conditions: vehicle costs must decline to achieve TCO parity with conventional alternatives, station economics must support private investment without ongoing subsidy, and supply chains must scale to meet expanding demand [53]. Phase 2 infrastructure follows a hub-and-spoke pattern radiating from Phase 1 corridor nodes, with metropolitan areas (Istanbul, Ankara, Izmir, Antalya, Bursa) forming primary hubs served by multiple stations.

Long-term targets (2040–2050) project 500,000–1,000,000 vehicles with a 5–15% share of the projected EU hydrogen import market, equivalent to substantial revenue streams and establishing Türkiye as a major participant in hydrogen trade [6–8]. Achievement depends on Phase 1 and Phase 2 establishing foundations and remains contingent on global technology evolution and market development.

4.2. Financial-Modelling Summary

The investment requirement of €5.0–8.0 billion through 2035 is composed of approximately 40% for production facilities (electrolyzer, supporting renewables), 35% for distribution and refuelling infrastructure, and 25% for vehicle acquisition support and enabling activities, consistent with European benchmark allocations reported by the Hydrogen Council [53]. Applying the input–output multiplier methodology documented in Appendix A.2 (central multiplier 2.8), this investment yields an estimated GDP contribution of €14–22 billion. Direct and indirect employment of 48,000–96,000 full-time equivalents is estimated from construction-phase and operational-phase factors of 12 and 3.5 FTE per €M respectively [22].

4.3. Probabilistic LCOH and Sensitivity Analysis

Probabilistic cost envelopes are essential because point-estimate LCOH values have systematically under-represented the uncertainty inherent in hydrogen project economics [19]. Using the methodology described in Section 2.7, 10,000 Monte-Carlo trials were run on the LCOH model for the Central Anatolia solar-dominated production region with commissioning in 2030 and full ramp-up by 2035. The simulation yields a mean LCOH of €2.35/kg with a 90% confidence interval of €1.85–2.95/kg. Electrolyzer CAPEX explains approximately 48% of the variance, followed by renewable electricity price (31%), specific energy consumption (14%), and WACC (7%). The same simulation for the Aegean-coast wind-dominated region yields a mean LCOH of €2.18/kg (90% CI €1.72–2.78/kg), reflecting the higher capacity factor and lower curtailment losses of wind production against solar PV. These results confirm that meeting the EU REPowerEU import-parity target of approximately €2.50/kg by 2035 is probabilistically achievable for Türkiye but conditional on electrolyzer CAPEX falling below 380 €/kW and renewable power-purchase agreements below 42 €/MWh. Two conditions that fiscal and procurement policy can directly influence. **Table 4** summarizes the Monte-Carlo outputs.

Table 4. Probabilistic LCOH Envelope from 10,000-Iteration Monte-Carlo Simulation.

Region	Mean (€/kg)	Median (€/kg)	5 th Pct (€/kg)	95 th Pct (€/kg)	Dominant Driver
Central Anatolia (solar)	2.35	2.32	1.85	2.95	Electrolyzer CAPEX
Aegean coast (wind)	2.18	2.15	1.72	2.78	Capacity factor
Southeast Anatolia (hybrid)	2.08	2.05	1.65	2.65	PPA electricity price
National weighted average	2.22	2.19	1.76	2.82	Electrolyzer CAPEX

4.4. Hydrogen vs. Battery-Electric Total-Cost-of-Ownership Comparison

A direct comparison of delivered-energy cost between hydrogen fuel-cell and battery-electric heavy-duty trucks is essential for calibrating the roadmap’s modal scope. Drawing on IEA [6] and BloombergNEF [21] data, **Table 5** reports the total cost of ownership (TCO) per kilometre for three reference duty cycles: urban distribution (daily range 250 km), regional haul (daily range 500 km), and long-haul (daily range 900 km). Under the 2030 central-case inputs (battery pack €80/kWh; diesel €1.50/L; green hydrogen €2.80/kg delivered; FCEV fuel-cell stack €75/kWh), FCEV TCO is €0.58/km for long-haul versus €0.67/km for BEV, an 13% advantage. For regional haul the two technologies converge to within €0.02/km, and for urban distribution BEV retains a €0.08/km advantage. These results support concentrating Turkish FCEV deployment in long-haul freight corridors (Istanbul–Ankara, Istanbul–Izmir, Ankara–Mersin, Ankara–Erzurum), while accepting that urban and short-haul segments will be served by BEV. Sensitivity analysis confirms that the long-haul FCEV advantage is preserved unless delivered hydrogen cost exceeds €4.20/kg, which lies above the 95th percentile of the Monte-Carlo envelope reported in Section 4.3.

Table 5. Total cost of ownership comparison for heavy-duty trucks in Türkiye, 2030 central case (€/km).

Duty Cycle	Daily Range (km)	Diesel	BEV	FCEV (Green H ₂)	FCEV Advantage vs. BEV
Urban distribution	250	0.72	0.49	0.57	-0.08
Regional haul	500	0.69	0.58	0.60	-0.02
Long-haul	900	0.68	0.67	0.58	+0.09
Long-haul (95 th pct H ₂)	900	0.68	0.67	0.71	-0.04

Station deployment leads vehicle deployment to mitigate the chicken-and-egg problem. The S-curve shows stations growing slightly ahead of vehicles during Phase 1, then converging to a stable ratio of approximately 1,000 vehicles per station at maturity (**Figure 2**). Electrolyzer capacity leads both vehicles and stations to ensure hydrogen availability, with capacity consistently exceeding domestic mobility demand; the surplus is allocated to exports. Three points of cross-reference between **Figure 2** and **Table 3** are worth making explicit. First, the 2050 hydrogen-vehicle target of 500,000–1,000,000 units represents only about 1.6–3.1% of Türkiye’s projected ~32 million national vehicle fleet by 2050; the roadmap is therefore a heavy-duty- and fleet-segment-targeted strategy, not a fleet-wide replacement of the conventional vehicle parc, consistent with the BEV/FCEV segment analysis in Section 3.1. Second, the 2050 annual green-hydrogen production of 1,000–2,500 kt H₂/yr in **Table 3** is equivalent to approximately 2,700–6,800 t/day on a 365-day basis; readers converting between annual and daily units should use this conversion to avoid the apparent inconsistency that a low daily figure (e.g., ~1,200 t/day) would imply only ~440 kt/yr, well below the **Table 3** minimum. Third, electrolyzer capacity in **Figure 2** is plotted in real gigawatts on its own right-hand logarithmic axis, with the 2050 endpoint annotated explicitly as 10–20 GW and matching the corresponding cell of **Table 3** directly.

5. Export Potential and Regional Hub Positioning

The European Union’s REPowerEU plan targets 10 million tons of domestic renewable hydrogen production and 10 million tons of imports by 2030, creating substantial export opportunities for neighbouring producers [7,16]. Hydrogen Europe [24] revises the likely 2030 import volume to 6–8 MMT/yr, which is still sufficient to accommodate multiple supplier countries. Türkiye’s geographic position enables competitive delivery through pipeline transport via TANAP reassignment (potential 1.0–1.5 MMT/yr at €0.50–0.70/kg) and Mediterranean maritime shipping for liquid hydrogen, ammonia, or LOHC carriers [9,13,25,26].

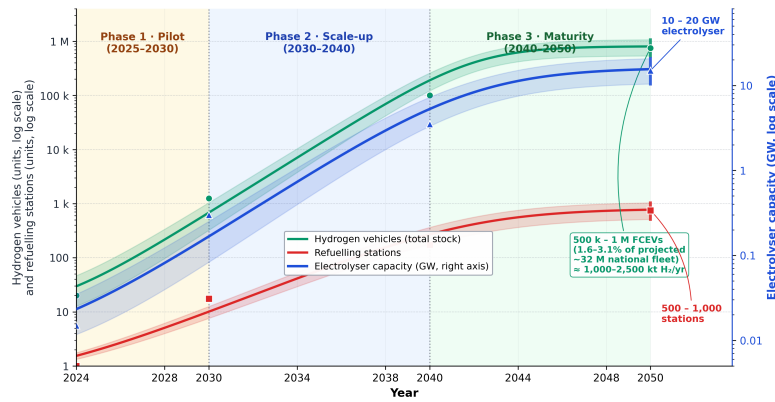


Figure 2. Türkiye hydrogen mobility deployment trajectory, 2024–2050.

5.1. Multi-Criteria Corridor Analysis

The corridor analysis implements the weighted-sum MCDA described in Section 2.5. Table 6 presents the resulting scores. Delivered-cost scoring uses Türkiye-specific inputs: TANAP reassignment cost from Cerniauskas et al. [27] methodology applied to 56-inch (142.24 cm) pipeline length of 1,850 km with assumed three compressor station upgrades; ammonia maritime shipping uses a reference distance of 1,200 nautical miles from Mersin to Genoa and 1,650 nm to Fos-sur-Mer; liquid-hydrogen maritime shipping uses the same port pair with Tanaka and Nishiumi [54] boil-off and liquefaction energy data; and liquid-organic hydrogen carrier (LOHC) cost uses Niermann et al. [55] techno-economics with dehydrogenation heat supplied from waste industrial heat at the receiving port. Weights reflect the 2023 National Hydrogen Strategy’s explicit prioritization of cost competitiveness, which receives the highest single weight.

Table 6. Multi-criteria scoring of hydrogen export corridors (1 = worst, 5 = best; weighted sum).

Corridor	Cost (w = 0.30)	Capacity (w = 0.25)	Timeline (w = 0.20)	TRL (w = 0.15)	Risk (w = 0.10)	Weighted Score
TANAP repurposing	5	4	3	3	3	3.90
New dedicated H ₂ pipeline	5	5	2	2	3	3.75
Ammonia maritime (Mersin)	3	4	5	5	4	4.05
Liquid H ₂ maritime	2	3	4	4	4	3.15
LOHC shipping	2	2	3	3	3	2.45

Notes: Weighted score = $\sum(\text{score} \times \text{weight})$. Scores are rounded to one decimal. Ammonia maritime ranks highest for near-term (pre-2030) deployment; TANAP repurposing ranks highest for pipeline-connected industrial offtake in the 2030–2035 horizon.

The scoring produces a ranked portfolio rather than a single-winner selection. Ammonia maritime ranks highest overall (4.05) owing to its TRL 8–9 maturity and near-term deployability, making it the preferred pathway for first export volumes before 2030. TANAP repurposing ranks second (3.90) and becomes the volume backbone for 2030–2040 once pipeline conversion investments commission. A new dedicated hydrogen pipeline (3.75) represents the long-term scale solution but is constrained by timeline. The recommended corridor portfolio for Türkiye is therefore (i) initial ammonia exports from Mersin and Aliğa during 2026–2030, (ii) TANAP repurposing commissioned in phases during 2030–2035, and (iii) a dedicated Türkiye–Greece hydrogen pipeline as part of the European Hydrogen Backbone post-2035. Liquid-hydrogen and LOHC pathways should remain under technology watch but are not recommended for commercial commitment before 2035.

5.2. Corridor Characteristics

Pipeline transport offers the most cost-effective corridor. TANAP repurposing studies indicate technical feasibility for 10–20% hydrogen blending by 2030 and dedicated hydrogen transmission by 2035 [9,56]. The existing TANAP system comprises 1,850 km of 56-inch (142.24 cm) diameter pipeline with 16 billion m³ per year of natural-gas capacity, portions of which could be converted to hydrogen service as European gas demand declines [57]. Technical challenges include hydrogen embrittlement of steel, seal compatibility, and compression requirements due to

hydrogen’s lower energy density per volume; solutions such as polymer linings, upgraded seals, and additional compression stations are technically proven but capital-intensive [27,58].

A dedicated hydrogen pipeline represents the optimal long-term solution, offering the lowest transport cost and the highest capacity while avoiding technical compromises associated with natural-gas-system conversion. The European Hydrogen Backbone initiative envisages interconnected hydrogen pipelines spanning 28 countries, with connections to North Africa and potential links to Türkiye via Greece or Bulgaria [59]. Türkiye’s participation would provide access to integrated European markets and could serve as a transit route for Central Asian hydrogen reaching European customers [60].

Ammonia maritime shipping has reached TRL 8–9 and offers near-term export capability (2026–2030) at a cost of €0.80–1.20/kg of equivalent hydrogen [26]. Ammonia serves as an effective hydrogen carrier, with established global trade infrastructure handling approximately 20 million tons annually for fertilizer applications [61]. Conversion-efficiency losses (approximately 15% for synthesis and 15–20% for cracking) represent cost penalties but are avoided in applications using ammonia directly as fuel or feedstock [62,63]. Türkiye’s Mediterranean ports at Mersin, Iskenderun, and Aliğa offer strategic locations for ammonia export terminals with short shipping distances to Italian, Greek, and southern French markets.

Liquid hydrogen shipping, while technically mature, incurs higher costs (€1.00–1.50/kg) owing to cryogenic handling at –253 °C [25]. The energy penalty for liquefaction (approximately 30% of hydrogen energy content) materially affects delivered-cost economics; liquid hydrogen can nevertheless provide purity advantages and direct utilization without reconversion, justifying cost premia for specific applications [64]. Japan’s pioneering liquid-hydrogen supply chain from Australia demonstrates technical feasibility while highlighting the economic challenges [54].

Liquid Organic Hydrogen Carriers (LOHCs) represent an emerging pathway using ambient-temperature transport in existing oil-product infrastructure. While transport cost is competitive, dehydrogenation requires substantial heat input and catalyst infrastructure, adding €0.50–1.00/kg to total system cost [55,65]. LOHC pathways may prove advantageous for specific applications or routes where alternatives face constraints.

5.3. Regional Hub Concept

Figure 1 illustrates the integrated regional hub concept resulting from the layered methodology described in Section 2.8. Three shaded polygons identify production zones: Central Anatolia (solar-dominated, mean GHI 1,700–2,000 kWh/m²/yr), Aegean coast (wind-dominated, mean 80-m wind speed 7–9 m/s), and Southeast Anatolia (hybrid solar/wind). Circles represent planned electrolyzer hubs with diameter proportional to planned GW capacity; squares represent heavy industrial off takers (steel, petrochemicals, cement) with side length proportional to annual hydrogen demand (kt/yr). Solid lines mark the TANAP corridor and planned hydrogen-ready extensions; dashed lines indicate maritime corridors from Aliğa, İzmir, Mersin, and İskenderun ports to Italian, Greek, and southern French Mediterranean ports. The figure makes explicit the geographic logic of the hub concept: production zones feed both domestic industrial clusters and export corridors, with TANAP serving as the principal trunk for European pipeline delivery and Mediterranean shipping providing diversified maritime access.

6. Enabling Framework

Successful roadmap implementation depends on six enabling categories, presented here as the “Enabling Framework” consolidated from the diverse requirements identified in Sections 3–5. Each enabler is assigned (i) a measurable key performance indicator (KPI), (ii) a target value with an associated deadline, (iii) a lead institution, and (iv) a priority rank informed by an interaction analysis that evaluates which enabler failures would most severely constrain subsequent roadmap stages. Enablers are numbered E1–E6 and their inter-dependencies are summarized in **Table 7** and **Figure 3**.

Table 7. Enabling Framework with measurable KPIs, targets, and lead institutions.

ID	Enabler	KPI	Target (Year)	Lead Institution	Priority
E1	Regulatory framework	ISO/TS 19880 adopted into Turkish Standards; Certify-compatible G0 registry operational	2027	EMRA, TSE, MENR	1 (prerequisite)
E2	Human capital	Cumulative certified technicians and engineers	50,000 by 2035	TÜBİTAK, YÖK, MEB	2

Table 7. Cont.

ID	Enabler	KPI	Target (Year)	Lead Institution	Priority
E3	R&D infrastructure	Accredited hydrogen test laboratories; electrolyzer pilot line (≥ 10 MW/yr)	2028	TÜBİTAK MAM, Universities	2
E4	International cooperation	Signed EU Hydrogen Partnership; bilateral agreements with Germany, Japan, Korea	2026	MFA, MENR	1 (prerequisite)
E5	Finance	Issued green bonds for hydrogen projects; PPP framework for refuelling stations	€2 B cumulative by 2030	Treasury, Development Bank	3
E6	Public awareness	National hydrogen-safety communication program; stakeholder engagement events	Annual from 2026	MENR, MoIT	4

Notes: Priority ranking reflects interaction analysis: E1 and E4 are prerequisites because certification (E1) and EU market access (E4) are both necessary for Türkiye to capture export premium pricing. E2 and E3 are prerequisites for domestic value-chain capture and ranked jointly second. E5 and E6 are important but can proceed in parallel.

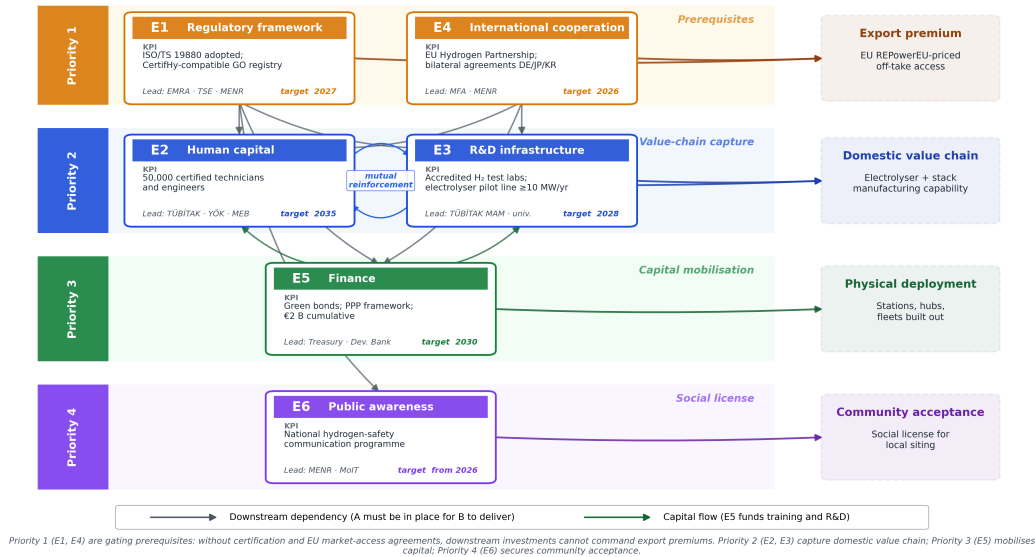


Figure 3. Enabling Framework Inter-dependencies (E1-E6), four priority tiers, dependency flows, and unlocked outcomes.

The priority ranking reflects a structured dependency analysis: E1 (regulatory) and E4 (international cooperation) are gating conditions because renewable-hydrogen certification and bilateral market-access agreements are jointly necessary for Turkish exports to command the EU REPowerEU premium. Without both, physical capacity can be built but revenues will be stranded in domestic offtake only. E2 (human capital) and E3 (R&D infrastructure) are the principal levers for domestic value-chain capture: absent their development, electrolyzer stacks, and storage vessels must be imported, which increases capital outflows and exposes deployment to supply-chain disruption. E5 (finance) mobilizes capital but follows rather than leads: green-bond issuance at competitive spreads requires the certification and partnership platforms provided by E1 and E4. E6 (public awareness) is necessary but lowest risk; Türkiye’s public has not developed the negative perception barriers observed in some European markets.

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Regulatory framework development (E1) must achieve European-Union alignment through adoption of ISO/TS 19880 safety standards, GO certification systems, and streamlined permitting with a target of six-month approval

timelines [20,66]. Failure to achieve certification compatibility would exclude Turkish hydrogen from premium-priced EU markets, fundamentally undermining the export-oriented strategy. Permitting streamlining addresses a frequently underestimated barrier: current permitting processes, designed for conventional fuel facilities, often require multiple agency approvals with inconsistent hydrogen-specific requirements [67].

Workforce development (E2) targets 50,000 skilled personnel by 2035 and requires €50–100 million investment in training infrastructure and curriculum development [5,11]. Skill requirements span research scientists and engineers, technicians for installation and maintenance of production and refuelling equipment, FCEV servicing technicians, safety and compliance specialists, and commercial and project-management professionals [68,69]. Dedicated hydrogen-engineering specializations should be developed within existing mechanical, chemical, and electrical engineering departments.

R&D infrastructure (E3) requires €200–400 million investment through 2035 to establish domestic capabilities in technology development and adaptation [70]. Priority facilities include accredited hydrogen-testing laboratories, fuel-cell and electrolyzer pilot production lines, vehicle testing facilities for homologation and performance validation, and demonstration projects generating operational data under Turkish conditions [71,72]. International technology-transfer arrangements with Germany, Japan, and Korea should complement domestic R&D through joint ventures, licensing agreements, and collaborative research [73].

International cooperation (E4) extends beyond technology transfer to market access, regulatory harmonization, and joint project development [74,75]. A bilateral EU Hydrogen Partnership is the principal near-term deliverable. Regional cooperation with Greece, Bulgaria, and Azerbaijan enables coordinated infrastructure development and market integration.

Financial mechanisms (E5) must mobilize the capital requirements while managing risks inherent in emerging-technology deployment. Green bonds and sustainability-linked instruments can access growing pools of ESG-oriented capital [76]. Public–private partnerships enable risk sharing, with government absorbing demand risk during early deployment phases while private partners manage construction and operational risk [77]. Export-credit guarantees from development-finance institutions can reduce financing costs for export-oriented production facilities [78]. The interaction of carbon pricing, electricity cost, and technology efficiency determines the evolving competitive landscape between green hydrogen and alternatives [22,79].

Public awareness (E6) addresses the social-license dimension of hydrogen deployment. Safety communication must proactively address concerns about hydrogen’s flammability and high-pressure storage while contextualizing risks relative to familiar fuels [22,79]. Demonstration projects provide tangible evidence of hydrogen-vehicle operation, building public familiarity. Stakeholder engagement with affected communities, particularly those hosting production facilities or facing employment transitions, builds support while identifying legitimate concerns.

Infrastructure Deployment Challenges: Water, Permitting, Financing, and Supply-Chain Localization

While the discussion of Enablers E1–E6 above and the six policy actions in Section 7 set out the institutional agenda, four infrastructure deployment challenges merit fuller elaboration because they cut across multiple enablers and frequently determine project feasibility at site level: (i) water resource availability; (ii) permitting and regulatory procedures; (iii) financing uncertainties; and (iv) the localization of hydrogen supply chains and related technologies. **Table 8** summarizes these challenges, their Türkiye-specific quantified scale, and the principal mitigation levers; the paragraphs that follow elaborate on each in turn.

Table 8. Infrastructure deployment challenges and principal mitigation levers for Türkiye’s hydrogen mobility programme.

Challenge Area	Quantified Scale/Drivers (Türkiye)	Principal Mitigation Levers
Water resource availability	9 L H ₂ O/kg H ₂ (electrolysis) + pre-treatment/cooling → 18–24 L/kg total withdrawal; 18–60 million m ³ /yr at 2050 production target; siting mismatch with water-stressed basins (Tigris–Euphrates, Konya)	Coastal RO desalination at Aliğa, Mersin, İskenderun (+€0.10–0.20/kg); treated municipal wastewater re-use; produced-water reclamation; mandatory project-level water-balance assessment under DSI envelope

Table 8. Cont.

Challenge Area	Quantified Scale/Drivers (Türkiye)	Principal Mitigation Levers
Permitting and regulatory procedures	Fragmented jurisdictions (MoEUCC, EMRA, MoT, municipalities); no hydrogen-specific EIA template; aging separation-distance codes; baseline timelines 18–30 months	Single-window coordination under EMRA; ISO/TS 19880-1:2020 adoption (Rec. 7.1); model hydrogen EIA template by 2027; trained inspectorate cohort per metro region by 2028; target 6–9 months' timeline
Financing uncertainties	Sovereign WACC 6.5–8.5% vs. 3.5–4.5% (N. Europe); each 1pp WACC reduction lowers LCOH by €0.18–0.22/kg; ±18% TRY/EUR volatility (2020–2024); EU offtake-pricing valley of death 2027–2032	Blended finance (EIB/EBRD senior debt, climate-fund first-loss tranches) to compress effective WACC by 150–250 bps; multi-currency project finance and partial revenue hedging; contracts-for-difference (Rec. 7.3); EU offtake allocation (Rec. 7.4)
Localization of hydrogen supply chains	PEM stack manufacturing at prototype scale only; Type-IV vessels, 700-bar compressors, dispenser nozzles imported; 2023 Strategy localization targets 40% (2030), 60% (2035)	250-MW electrolyzer tender with 30–50% domestic content (Rec. 7.3); JV with Nel, ITM Power, Toshiba, Doosan; tier-1 automotive suppliers (Bursa-Kocaeli belt) for balance-of-plant; FCEV stack co-development with Ford Otosan and TEMSA

Water resource availability: Green-hydrogen electrolysis consumes approximately 9 L of demineralized water per kg H₂ produced [48]; after including feedwater pre-treatment losses and cooling requirements, total raw-water withdrawal rises to roughly 18–24 L/kg. At the 2050 production target of 1,000–2,500 kt H₂/yr, this corresponds to an annual freshwater demand of approximately 18–60 million m³, equivalent to the municipal consumption of a city of 200,000–700,000 inhabitants. The geographic mismatch between Türkiye's best solar resource (Southeast Anatolia) and its most water-stressed basins (Tigris–Euphrates, Konya closed basin) is therefore a binding constraint on regional siting and is consistent with the water-stress signal already noted under the Environmental cell of **Table 2**.

Three site-level mitigation pathways are available. First, coastal seawater desalination paired with electrolyzer co-location at Aliğa, Mersin, and İskenderun, where coupling renewable electricity with reverse-osmosis pre-treatment adds approximately €0.10–0.20/kg to LCOH but releases scarce inland freshwater for agricultural and municipal use. Second, treated municipal wastewater re-use in industrial clusters, applicable where electrolyzers are sited within 10–20 km of large wastewater-treatment plants such as those at Adana and Gaziantep. Third, produced-water reclamation for the limited number of facilities sited near oil-and-gas operations in Southeast Anatolia. Project-by-project water-balance assessment, conducted under the State Hydraulic Works (DSİ) permitting envelope and the Türkiye Water Footprint methodology, should be mandatory at investment-decision stage and integrated into the regional siting overlay shown in **Figure 1**.

Permitting and regulatory procedures: The current Turkish permitting regime treats hydrogen facilities under the framework originally developed for natural-gas and petrochemical assets, which produces three deployment-slowing inefficiencies. First, jurisdictional fragmentation across the Ministry of Environment, Urbanization and Climate Change, EMRA, the Ministry of Industry and Technology, and municipal authorities lengthens approval pathways. Second, the absence of a single hydrogen-specific environmental-impact-assessment (EIA) template requires applicant-by-applicant negotiation of scope. Third, separation-distance and pressurized-storage code provisions have not yet been updated to the latest ISO/TS 19880-1:2020 specifications.

Empirical European experience indicates that hydrogen-specific permitting timelines fall from an initial 18–30 months to 6–9 months once dedicated templates, single-window coordination, and trained inspectorate capacity are in place. The Phase 1 policy recommendation in Section 7.1 (adoption of ISO/TS 19880 and the Guarantee-of-Origin registry) should therefore be coupled with a parallel permitting-reform package: designation of EMRA as the single-window coordinator for hydrogen production and refuelling assets, issuance of a model hydrogen EIA template by 2027, and training of a dedicated inspector cohort in each metropolitan region by 2028. Without these complementary measures, Phase 1 station deployment is exposed to slippage of 12–24 months relative to the schedule in **Figure 2**.

Financing uncertainties: Three categories of financing uncertainty must be managed concurrently. First, Türkiye's sovereign weighted-average cost of capital (WACC) for clean-energy projects in 2024–2025 lies in the 6.5–8.5% range, against 3.5–4.5% for comparable Northern-European projects [21]. The Monte-Carlo sensitivity reported in Section 4.3 shows that each one-percentage-point reduction in WACC lowers LCOH by approximately €0.18–0.22/kg, so blended-finance instruments that compress the effective WACC by 150–250 basis points—such as EIB or EBRD senior debt at concessional spreads, climate-fund first-loss tranches, and sovereign-guaranteed

offtake—materially shift project economics.

Second, currency-mismatch risk arises because revenues from EU offtake are euro-denominated while a non-trivial share of CAPEX (civil works, balance-of-plant, labour) is Turkish-lira-denominated, exposing developers to exchange-rate volatility that has averaged approximately $\pm 18\%$ per year over 2020–2024. Multi-currency project-finance structures and partial revenue hedging through the Turkish development banks can mitigate but not eliminate this exposure. Third, demand-side uncertainty over the EU CBAM trajectory, REPowerEU import volumes, and competing-supplier final investment decisions creates a financing “valley of death” between project commissioning (2027–2030) and stable offtake pricing (post-2032). Contracts-for-difference (Section 7.3) and indicative EU offtake allocation (Section 7.4) are the principal instruments for bridging this valley; their successful negotiation during 2026–2027 is therefore a critical-path activity for the entire roadmap.

Localization of hydrogen supply chains and related technologies: Supply-chain localization is both an industrial-policy objective and a risk-management imperative, with three distinct value-chain segments requiring coordinated action. On the production side, electrolyzer-stack manufacturing in Türkiye is currently limited to small-scale prototype assembly; delivering the 250-MW Phase 1 tender (Section 7.3) at 30–50% domestic content requires investment in membrane-electrode-assembly lines, bipolar-plate stamping, and stack-integration testing, with an indicative CAPEX of €120–180 million over 2026–2028. Joint-venture arrangements with established European, Japanese, and Korean technology providers (e.g., Nel, ITM Power, Toshiba, Doosan) are the most pragmatic route, leveraging Türkiye’s automotive-grade precision-manufacturing base.

On the balance-of-plant side, 700-bar-and-above compressors, Type-IV composite high-pressure storage vessels, and dispenser nozzles are currently fully imported. Tier-1 automotive suppliers concentrated in the Bursa–Kocaeli industrial belt have the technical baseline to enter these segments during 2027–2030 under technology-licensing arrangements, particularly if the Phase 1 tender embeds non-discriminatory domestic-content schedules consistent with WTO disciplines. On the downstream side, fuel-cell stack production for heavy-duty trucks and buses can be developed in parallel with the Ford Otosan and TEMSA platforms, building on existing electrified-powertrain capabilities and Türkiye’s position as the fourth-largest commercial-vehicle producer in Europe. The 2023 National Hydrogen Strategy’s localization-rate targets (40% by 2030, 60% by 2035) are achievable only if the Phase 1 tender, R&D programmes (E3), and bilateral cooperation agreements (E4) advance in coordinated sequence rather than as parallel but uncoordinated tracks; failure to coordinate would replicate the early-stage import dependency that characterized Türkiye’s wind and solar deployments during 2010–2015 and would materially weaken the GDP-multiplier estimate reported in Section 4.2.

7. Policy Recommendations for the 2025–2030 Window

The 2025–2030 window is decisive because three time-bounded external events will shape opportunity space. First, the EU Hydrogen Bank is allocating production premia during 2024–2027 auction rounds, with bilateral partnership clauses advantaging signatories. Second, the European Hydrogen Backbone consortium is finalizing inter-connector commitments during 2025–2028. Third, competing suppliers (Morocco, Egypt, UAE, Saudi Arabia) are advancing final investment decisions on megaprojects during the same window. The roadmap therefore recommends six concretes; each tied to a lead institution and a deadline.

7.1. Adopt ISO/TS 19880 as Turkish Standard and Establish a GO Registry (2026)

The Turkish Standards Institution (TSE) should formally adopt ISO/TS 19880-1 through ISO/TS 19880-8 as Turkish Standards during 2026, accompanied by enabling regulations under EMRA. A Guarantee of Origin (GO) registry compatible with the Association of Issuing Bodies European Energy Certificate System should be established before the first export volumes commence, because retrofit certification is both more expensive and more vulnerable to EU audit challenge than prospective certification.

7.2. Commission Three Corridor-Pilot Refuelling Stations on the Istanbul–Ankara–Izmir Triangle (2026–2028)

Initial pilot stations should be sited at Kocaeli, Ankara, and Manisa to cover the Istanbul–Ankara and Istanbul–Izmir highway freight corridors, each capable of 500 kg/day dispensing and co-located with municipal bus depots

or logistics hubs. Public co-funding at 40–50% of station CAPEX during 2026–2028 is consistent with German H2 Mobility subsidy levels during equivalent market-formation phases [80].

7.3. Launch an Initial 250 MW Electrolyzer Tender with Domestic-Content Rules (2027)

A public tender for 250 MW of electrolyzer capacity co-located with renewable generation assets, with domestic-content requirement of at least 30% rising to 50% by 2030, would anchor domestic electrolyzer assembly capability while remaining compatible with World Trade Organization disciplines and EU partnership provisions. The tender should use double-sided contracts-for-difference for hydrogen price, not fixed feed-in premium, to distribute risk efficiently.

7.4. Sign EU Hydrogen Partnership with Offtake Allocation (2026–2027)

Negotiation with the European Commission for a dedicated Hydrogen Partnership should be prioritized in 2026, seeking at minimum: (i) eligibility of Turkish renewable hydrogen under CertifHy and EU RED III Delegated Acts; (ii) indicative offtake allocation of 0.5 MMT/yr by 2030 rising to 2 MMT/yr by 2035; (iii) joint financing facility with the European Investment Bank.

7.5. Scale TÜBİTAK Hydrogen Technology Calls and Accredite Three Test Laboratories (2026–2028)

TÜBİTAK ARDEB 1001, 1003, and 1005 program calls should be expanded with hydrogen-dedicated funding envelopes totalling at least €100 million over 2026–2028, focused on PEM membranes, stack manufacturing, and high-pressure storage. Concurrently, three accredited test laboratories covering station safety, fuel-cell performance, and fuel purity [43] should be operational by 2028.

7.6. Issue the First Turkish Hydrogen Green Bond and Launch a Blended-Finance Facility (2027)

A sovereign green-bond issuance with a hydrogen project pipeline use-of-proceeds, sized at approximately €500 million, would establish the spread benchmark for subsequent corporate issuances. A blended-finance facility combining Turkish Development Bank equity, EIB and EBRD senior debt, and climate-fund first-loss tranches should be structured to crowd in commercial capital for station networks and mid-scale electrolyzer projects.

8. Discussion, Limitations, and Directions for Future Research

8.1. Key Findings

The quantitative analyses presented in this study yield four main findings. First, Türkiye can probabilistically meet the EU import-parity LCOH target of approximately €2.50/kg by 2035 in three production regions, with the principal determinants being electrolyzer CAPEX and renewable-electricity PPA price. Second, green hydrogen retains a clear TCO advantage over battery-electric technology in long-haul (>500 km daily range) heavy-duty trucking, which should be the principal focus of FCEV deployment. Third, a diversified corridor portfolio (ammonia near-term, TANAP reassignment mid-term, dedicated long-term pipeline) outperforms single-corridor strategies on combined cost, capacity, and risk metrics. Fourth, the 2025–2030 window determines whether Türkiye captures a meaningful share of the EU hydrogen import market, because offtake agreements and certification infrastructure will consolidate within that period.

Table 9 synthesises the headline findings of the study, the principal quantified evidence supporting each, and the cross-references to the sections and tables where the underlying analysis is documented. The synthesis adds two findings to the four narrative findings above by separating out the macro-economic effect of the investment programme and the deployment-readiness implications of the infrastructure challenges analysed in Section 6.

Table 9. Synthesis of key findings: headline statements, quantified evidence, and cross-references.

#	Finding (Headline)	Quantified Evidence	Probability/Cost Driver	Cross-Reference
1	EU import-parity LCOH (~€2.50/kg) achievable in three Türkiye regions by 2035	Mean LCOH €2.35/kg; 90% CI €1.85–2.95/kg; Aegean wind €2.18/kg; SE-Anatolia hybrid €2.08/kg	Electrolyzer CAPEX 48% of variance; PPA price 31%; SEC 14%; WACC 7%	Section 4.3, Table 4

Table 9. Cont.

#	Finding (Headline)	Quantified Evidence	Probability/Cost Driver	Cross-Reference
2	Green H ₂ retains a clear TCO advantage over BEV in long-haul heavy-duty trucking	FCEV €0.58/km vs. BEV €0.67/km at 900 km daily range (2030 central case); BEV better ≤500 km	Advantage preserved up to delivered H ₂ €4.20/kg (above 95th-percentile of Monte-Carlo)	Section 4.4, Table 5
3	Diversified export-corridor portfolio outperforms any single-corridor strategy	Ammonia maritime weighted score 4.05 (near-term); TANAP repurposing 3.90 (mid-term); dedicated H ₂ pipeline 3.75 (long-term)	Weights: cost 0.30, capacity 0.25, timeline 0.20, TRL 0.15, risk 0.10	Section 5.1, Table 6
4	Roadmap delivers material macro-economic and employment benefit	Investment €5.0–8.0 B (through 2035); €14–22 B GDP contribution; 48,000–96,000 FTE	IRENA multiplier 2.8× (range 2.5–3.5); 12 construction-phase + 3.5 operational FTE per €M	Section 4.2, Appendix A.2
5	Infrastructure deployment is gated by four cross-cutting challenges	Water 18–60 M m ³ /yr (2050); permitting 18–30 mo → 6–9 mo with single-window; WACC spread 3 pp lifts LCOH by €0.18–0.22/kg; localization at 30–50% by 2030 needs €120–180 M MEA/stack capex	Mitigation levers: RO desalination, ISO/TS 19880 + EIA template, blended finance, JV technology licensing	Section 6, Table 8
6	2025–2030 window is decisive for Türkiye's hub positioning	EU Hydrogen Bank auctions 2024–2027; European Hydrogen Backbone interconnector commitments 2025–2028; competing-supplier FIDs (Morocco, Egypt, UAE, KSA) consolidate in same period	Six concrete policy actions (Sections 7.1–7.6) anchored to lead institutions and deadlines	Section 7

8.2. Limitations

The analysis is subject to four principal limitations. First, the Monte-Carlo simulation treats parameter distributions as independent; in practice, electrolyzer CAPEX and renewable-electricity price are correlated through shared learning rates and commodity markets and modelling them jointly would likely narrow the LCOH confidence interval slightly. Second, the MCDA weights reflect policy priorities inferred from the 2023 National Hydrogen Strategy; alternative weighting schemes (e.g., prioritizing capacity over cost) would reorder the corridor ranking. Third, LCOH calculations use a fixed 20-year project life and 7% WACC; actual projects will face varying debt structures and tenors that this study does not individually model. Fourth, the study does not quantify water-stress constraints on electrolyzer siting in Southeast Anatolia, an increasingly material issue under climate-change projections [49].

8.3. Directions for Future Research

Five priority research lines follow from the present study. First, primary techno-economic studies of TANAP reassignment, using Turkish steel specifications and compression equipment, are needed to replace the current reliance on transferred cost data. Second, empirical operational data from the initial Phase 1 pilot stations should be systematically collected and published to reduce the operational-performance uncertainty band. Third, water-energy-nexus modelling should be integrated into regional siting optimization, particularly for Southeast Anatolia. Fourth, behavioural-economic analysis of Turkish logistics-fleet operators is needed to understand adoption thresholds and non-price barriers. Fifth, integrated system modelling coupling the power, gas, and transport sectors under Turkish-specific constraints is required to evaluate dispatchability and sector-coupling benefits with appropriate granularity.

9. Conclusions

This study developed a quantitatively grounded, Türkiye-specific strategic roadmap for hydrogen mobility deployment between 2025 and 2050 by integrating SWOT and PESTLE analyses with multi-criteria corridor evaluation, discounted-cash-flow LCOH modelling, input-output GDP multiplier estimation, and Monte-Carlo sensitivity analysis. The principal quantified outputs are a probabilistic LCOH envelope of €1.85–2.95/kg (mean €2.35/kg) for 2035 Central Anatolia production, a diversified export-corridor portfolio led by ammonia maritime and TANAP reassignment, a total investment requirement of €5.0–8.0 billion through 2035, and an estimated €14–22 billion GDP impact and 48,000–96,000 jobs based on an input-output multiplier of 2.8×. Heavy-duty long-haul trucking is identified as the principal FCEV application where hydrogen preserves a clear total-cost-of-ownership advantage over battery-electric technology under 2030 cost projections. The Enabling Framework of six categorized conditions (regulatory, human capital, R&D, cooperation, finance, awareness) with measurable KPIs and prioritized

dependencies translates the roadmap into an operational policy agenda. Six concrete actions for the 2025–2030 window are recommended. The window is decisive because EU offtake allocations, certification infrastructure, and competing-supplier final investment decisions consolidate within that period; delayed action would cede market position that is unlikely to be recoverable at comparable cost. Limitations include the independence assumption in the Monte-Carlo parameters, fixed WACC and project life, and the omission of water-stress constraints, which define the priority agenda for future research.

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The author declares no conflict of interest.

AI Use Statement

During the preparation of this work, the author used Claude.Ai in order to literature review related to the study, drawing figures from the simulation results and error-free editing of the English version of the article. After using this tool/service, the author reviewed and edited the content as needed and takes full responsibility for the content of the published article.

Appendix A. Calculation Methodologies and Input Assumptions

Appendix A.1. LCOH Discounted-Cash-Flow Model

The levelized cost of hydrogen is computed as

$$\text{LCOH} = [\text{CAPEX} \times \text{CRF} + \text{OPEX}_{\text{fixed}} + (P_e \times \text{SEC}) + C_{\text{water}}]/(8,760 \times \text{CF} \times P_{\text{out}}/\text{SEC})$$

Where:

CAPEX × CRF: The annualized capital investment. The Capital Recovery Factor (CRF) spreads the initial cost of the equipment (electrolyzers, tanks, etc.) over its expected lifetime, accounting for the interest rate,

CRF = $[r(1 + r)^n]/[(1 + r)^n - 1]$ with $r = \text{WACC}$ and $n = \text{project life}$,

OPEX_{fixed}: Fixed operating and maintenance costs that don't change regardless of how much hydrogen is made (e.g., insurance, staffing, routine maintenance),

$P_e \times \text{SEC}$: The variable electricity cost with $P_e = \text{Price of electricity } (\$/\text{kWh})$ and $\text{SEC} = \text{Specific Energy Consumption (the amount of electricity needed to produce 1 kg of H}_2\text{)}$,

C_{water} : The cost of the water feedstock and any necessary treatment,

8,760: Total hours in a year,

CF: Capacity Factor (the percentage of the year the plant is actually running).

P_{out} : The rated power output of the plant.

$P_{\text{out}}/\text{SEC}$: This converts the power capacity into the physical amount (kg) of hydrogen produced per hour.

Central-case values: CAPEX 400 €/kW electrolyzer installed; project life 20 years; WACC 7%; PPA electricity price 40 €/MWh; specific energy consumption (SEC) 52 kWh/kg H₂; capacity factor 55%; water cost €0.005/kg

H₂; OPEX_{fixed} 2% of CAPEX/yr. The resulting central-case LCOH is €2.28/kg, consistent with Fraunhofer ISE (2024) European benchmarks adjusted for Turkish WACC.

Appendix A.2. GDP Multiplier (Input–Output) Estimation

Indirect and induced GDP contribution is estimated as

$$\text{GDP}_{\text{total}} = \text{Investment} \times M$$

Where:

Investment (Initial Spending): The direct expenditures, such as capital expenditure (CAPEX) or operational expenditure (OPEX) in a new project, company, or industry.

M: economic multiplier (Leontief output multiplier) is a standard approach in economic impact analysis. A number representing the total economic activity (direct + indirect + induced) generated per unit of investment, typically derived from input-output tables. Following the IRENA [2] hydrogen-value-chain analysis, M = 2.8 is adopted as the central case (low 2.5, high 3.5). Total investment of €5.0–8.0 billion through 2035 therefore yields a GDP contribution of €14–22 billion under the central multiplier, consistent with the 2023 National Hydrogen Strategy's own €15–25 billion estimate at the upper end.

Appendix A.3. Employment Estimation

Direct jobs are estimated using 12 construction-phase full-time-equivalent jobs per million Euro invested and 3.5 permanent operational jobs per million euro of installed capacity [22]. For the €5.0–8.0 billion Phase 1–2 investment, this produces 48,000–96,000 full-time-equivalent jobs across the 2025–2035 deployment horizon, with approximately 70% in construction/installation and 30% in operations.

Appendix A.4. Monte-Carlo Parameter Distributions

Electrolyzer CAPEX: triangular (320, 400, 480) €/kW. Renewable electricity price: uniform (30, 50) €/MWh. Specific energy consumption: triangular (48, 52, 56) kWh/kg. WACC: triangular (6%, 7%, 8%). Capacity factor: scenario-based (solar 0.22, wind 0.35, hybrid 0.48). 10,000 iterations run with Latin-hypercube sampling: convergence verified by comparing 5,000- and 10,000-iteration distributions.

Appendix A.5. TCO Model for Heavy-Duty Trucks

$$\text{TCO per km} = (\text{CAPEX} \times \text{CRF} + \text{Annual O\&M} + \text{Annual Energy Cost} + \text{Driver} \times \text{Labour Rate}) / \text{Annual km}$$

Where:

CAPEX (Capital Expenditure): The initial purchase price of the vehicle, including battery (for EVs) and charger installation if applicable,

CRF (Capital Recovery Factor): A formula used to convert the initial purchase price into an annual cost over the vehicle's lifespan, accounting for depreciation and interest rates,

Annual O&M (Operations & Maintenance): Yearly costs for repairs, tires, insurance, registration, and maintenance,

Annual Energy Cost: Yearly cost of fuel (diesel/gas) or electricity,

Driver & Labour Rate: Total annual cost of the driver (salary, benefits),

Annual km: Total distance driven in one year.

Central-case inputs for 2030 long-haul reference vehicle: FCEV purchase price €280,000, 10-year life, 150,000 km/yr, fuel cost €2.80/kg delivered × 7.5 kg/100 km; BEV purchase price €250,000 with €80/kWh pack cost, 600 kWh battery, €0.15/kWh depot charging; diesel purchase price €140,000, 30 L/100 km × €1.50/L. Driver labour and other OPEX held constant across technologies.

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