THE FEASIBILITY OF ADOPTING

A

HYDROGEN POWERED FLEET OF VEHICLES

BY

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ABSTRACT

This study assessed whether a UK depot could convert a 20-truck, back to base fleet from diesel to hydrogen while meeting strict service, safety, reliability, cost, and emissions thresholds. The duty was fixed at 6,000 miles per day across two return peaks. Using published energy rates, daily hydrogen need was sized at 882 kg for typical days and 1,206 kg for stress duty; a 20% buffer for heat, clustering, and timing drift raised these to 1,058 kg and 1,447 kg. SAE J2601 limits, a two-wave queue model, and evidence on pre-cooling bottlenecks guided dispenser count, storage, and chiller sizing. Availability targets used predictive health monitoring to reach at least 97% during operating windows. Layout checks followed recognised siting rules. Three supply routes were tested: onsite PEM electrolysis, buy-in compressed or liquid hydrogen, and a hybrid with onsite baseload plus delivered peaks. Onsite gave strong control over purity and timing but exposed cost to power price and stack ageing. Buy-in lowered capital but imported delivery and price risk and still required robust station conditioning. The hybrid right-sized onsite production to about 60–70% of a hot-day load and used contracted deliveries to cover peaks and outages. The hybrid met wait targets (mean ≤10 minutes; P95 ≤20 minutes) more reliably at the study depot and sat mid-range on cost, while emissions results depended on the supply pathway and verified certificates. The study therefore recommended a hybrid baseline with firm clean-power contracts, supplier redundancy, multi-bank storage, strong pre-cooling, inline impurity monitoring, and simple queue controls throughout.

Keywords: hydrogen depot, fuel-cell trucks, SAE J2601, pre-cooling, queueing, onsite electrolysis, delivered hydrogen, hybrid supply, predictive maintenance, well-to-wheel emissions.

DECLARATIONS

I hereby declare that this dissertation is the result of my own independent work and research, carried out under the supervision of Mr. Andrew Thorn at the University of Wales Trinity Saint David (UWTSD).

It has not been submitted, either in whole or in part, for any other degree or qualification at this or any other institution. All sources of information and assistance have been duly acknowledged and referenced in accordance with university regulations.

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LIST OF ABBREVIATIONS/ACRONYMS

AEL	Alkaline electrolysis
AFDC	Alternative Fuels Data Center (U.S. DOE)
ALARP	As Low As Reasonably Practicable
ATR	Autothermal reforming
ATEX	ATmosphères EXplosibles Directive (EU)
BNEF	BloombergNEF
BoP	Balance of plant
CARB	California Air Resources Board
CGH_2	Compressed gaseous hydrogen
CH_4	Methane
CHJU	Clean Hydrogen Joint Undertaking (EU)
CO	Carbon monoxide
CO_2	Carbon dioxide
DSEAR	Dangerous Substances and Explosive Atmospheres Regulations (UK)
DVSA	Driver and Vehicle Standards Agency (UK)
EBMUD	East Bay Municipal Utility District (California)
EDI	Electrodeionization
ESD	Emergency shutdown
GGE	Gasoline gallon equivalent
GO-Biz	California Governor's Office of Business & Economic Development
H_2	Hydrogen
H2A	Hydrogen Analysis (NREL cost framework)
H2FCP	Hydrogen Fuel Cell Partnership
H35	35 MPa hydrogen fueling protocol
H70	70 MPa hydrogen fueling protocol
H70-HD	70 MPa heavy-duty fueling protocol (SAE J2601-2)

HAZID	Hazard identification
HAZOP	Hazard and operability study
HGV	Heavy goods vehicle
HVAC	Heating, ventilation and air conditioning
ICCT	International Council on Clean Transportation
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
ISO 17268	Fueling connectors standard for hydrogen vehicles
J2601	SAE hydrogen fueling protocol standard
J2601-2	SAE J2601 Part 2 heavy-duty fueling protocol
kg	Kilogram
KPI	Key performance indicator
kWh	Kilowatt-hour
LBST/H2Stations	Ludwig-Bölkow-Systemtechnik Hydrogen Stations database
LH_2	Liquid hydrogen
LHV	Lower heating value
LOHC	Liquid organic hydrogen carrier
LOPA	Layers of protection analysis
MOC	Management of change
MOT	UK annual vehicle test (Ministry of Transport test)
mpg	Miles per gallon
mph	Miles per hour
MPGe	Miles per gallon equivalent
NFPA	National Fire Protection Association
NOx	Nitrogen oxides
NREL	National Renewable Energy Laboratory

OEM	Original equipment manufacturer
O&M	Operations and maintenance
PGM	Platinum-group metal
PHM	Prognostics and health monitoring (predictive health monitoring)
PPA	Power purchase agreement
ppm	Parts per million
PRD	Pressure relief device
PTO	Power take-off
QRA	Quantitative risk assessment
RO	Reverse osmosis
SAE	SAE International (Society of Automotive Engineers)
SMR	Steam-methane reforming
SOEC	Solid-oxide electrolyser cell
S&P	S&P Global
TOC	Total organic carbon
TR	Tons of refrigeration
UK	United Kingdom
UPS	Uninterruptible power supply
US	United States
WTO	World Trade Organization

CHAPTER 1 – INTRODUCTION

1.1 Scenario, purpose, and five-day mileage

Company X is a UK fleet operator running 20 Class-8 tractors on a back-to-base model with two return peaks, one late morning and one late evening. For example, Hyundai (2024) reports a 30-truck heavy-duty fuel-cell deployment in Oakland and Richmond and shows that commercial drayage can be supported by high-throughput hydrogen stations; this serves here as a real-world analogue for depot scale and cadence. The Port of Oakland (2024) confirms the same partners and the presence of a dedicated heavy-duty station near EBMUD, which is used as external evidence for a depot-centric refuelling strategy rather than reliance on public retail sites. Electrive (2024) describes the Oakland heavy-duty station layout with multiple dispensers and strong pre-cooling, which is relevant because clustered returns in the UK scenario still demand fast, temperature-controlled fills.

Each truck is scheduled to travel an average of 300 miles per day. The daily fleet mileage is 6,000 miles per day (20×300); the five-day total is 5×6,000 per day = 30,000 miles per week; 52×30,000 per week = 1,560,000 miles per year. However, because of the two-day Easter holidays and three bank holidays, 50 weeks is considered. Therefore, the average mileage is 50 × 30,000 per week = 1,500,000 miles per year. The payload plan that will be carried through the evaluation assumes an average payload of 18 tonnes, a maximum of 22 tonnes, and a load factor of 0.82. Magnino et al. (2024) synthesise heavy-duty evidence and show that route type, hill gradients, and payload push energy per mile more than small differences in rated efficiency; this implies the study must test both average and stress conditions. Brown and Kisting (2022) analyse observed station logs and find that peak clustering, not daily averages, drives wait times unless service-rate headroom is designed in; this sets the central problem for depot sizing. SAE (2023) codifies the J2601 heavy-duty protocol and sets pressure and temperature limits that bound true service rate; this tells us that nozzle and chiller limits, not nominal compressor nameplates, govern throughput in practice. Saur et al. (2023) run controlled tests and show that pre-cooling capacity becomes the dominant bottleneck during clustered heavy-duty fills, while Sprik et al. (2024) validate heavy-duty test rigs that expose valve and hose thermal limits; these results explain why hot-hour sequences are the failure point. The purpose of this chapter is to state the operating problem, size daily and five-day hydrogen demand with a safety factor that reflects peak behaviour, define the three supply scenarios that will be evaluated, and fix feasibility criteria that reflect protocol limits, queue dynamics, reliability, and site constraints.

1.2 Scope and baseline operation (diesel to hydrogen)

The scope keeps the same UK routes, driver rosters, dispatch windows, and yard circulation that Company X runs today with diesel, but replaces the vehicles with fuel-cell tractors and adds a depot system designed to heavy-duty J2601 with high-flow dispensers and pre-cooling. Saur et al. (2023) show that pre-cooling duty grows fastest exactly when arrivals cluster; this matters because the design must meet peak-hour thermal load rather than the 24-hour mean. Brown and Kisting (2022) find that small service-rate shortfalls during peaks cascade into long queues; this means the station model must include queue mechanics, not just pump capacity. Kurtz et al. (2024) at NREL pilot predictive health monitoring at stations and report measurable uptime gains for compressors and chillers; this supports treating availability as a first-order design lever in the service-rate calculation.

The costing and environmental boundaries are defined to keep results credible. DOE (2024) quantifies levelised hydrogen cost for electrolysis and shows that electrolyser capital cost, utilisation, and power price are the three dominant drivers, while stack degradation and balance-of-plant maintenance need explicit inputs to avoid optimistic parity. H2A/NREL (2025) provides the cash-flow framework and parameter ranges used to stress-test those levers; this framework will be applied to the on-site production scenario. He et al. (2021) set a well-to-wheel accounting frame and show that climate benefits for fuel-cell trucks hold only when hydrogen has low upstream emissions and the electricity used for production is not carbon-intense; this is why the study reports pathway-dependent results.

The safety and permitting frame is aligned to the UK site, while US materials are used as practical analogues. NFPA (2023) codifies separation distances, hazardous zones, and equipment classes for hydrogen systems, and GO-Biz (2020) translates those rules into California siting workflows with setbacks, vent stacks, and circulation; these sources are referenced for layout practice observed in Oakland. AFDC (2025) maintains live counts of U.S. hydrogen stations and shows a sparse, regionally concentrated network; this supports a depot-centric approach for early fleets. CARB (2024) monitors California stations and links many outages to compressor and chiller subsystems during busy hours; this confirms the reliability priorities above.

1.3 Demand sizing (daily, five-day) with factor of safety)

ICCT (2022) synthesises heavy-duty trials and estimates tractor energy use at 9–9.2 kg per 100 km, which converts to 0.145–0.148 kg per mile; for design, the study adopts 0.147 kg per mile as a mid-band value. ICCT (2024) reports about 12.5 kg per 100 km for stop-go vocational cycles, which is 0.201 kg per mile; this is used as a stress bound to cover heavy, congested service. Applying these rates to the fixed duty gives the anchor quantities. The daily hydrogen demand at the mid-band is 6,000×0.147 = 882 kg, and the five-day total is 5×882 = 4,410 kg. The daily stress-case demand is 6,000×0.201 = 1,206 kg, and the five-day stress total is 5×1,206 = 6,030 kg. The per-truck mid-band check for dispenser planning is 300×0.147 = 44.1 kg per truck per day.

Brown and Kisting (2022) show from station logs that clustered returns, not daily averages, create long waits, and Saur et al. (2023) demonstrate in controlled tests that pre-cooling becomes the limiting subsystem exactly during those peaks; together these results justify adding a demand buffer to cover hot hours, arrival clustering and minor schedule drift. ICCT (2022) places modern heavy-duty fuel-cell use at 0.147 kg per mile, so BaySpan's fixed duty of 20 trucks at 300 miles each gives 6,000 miles per day and a base demand of 6,000 × 0.147 = 882 kg. Applying a central factor of safety of 20% to represent peak-hour stress raises this to 882 × 1.20 = 1,058 kg per day. ICCT (2024) reports a stop-go rate of 0.201 kg per mile for vocational cycles, which yields a stress-case base of 6,000 × 0.201 = 1,206 kg and, with the same 20% buffer, 1,206 × 1.20 = 1,447 kg per day. Magnino et al. (2024) and Danielis (2024) show that payload, gradients and congestion shift real-world use more than small efficiency differences, while Pereira et al. (2024) maps steady auxiliary loads from refrigeration and HVAC, which is why the study carries a 10–30% range and tests both the mid-band and stress figures in Chapter 4.

1.4 Feasibility scenario to be evaluated

The three scenarios are assessed against the same duty of 6,000 miles per day and the same five-day totals, with the chosen safety factor. Every scenario uses heavy-duty J2601 fills with pre-cooling, and every scenario is judged on demand coverage, queue performance, reliability, space and safety fit, permitability, and cost.

1.4.1 On-site Scenario

The on-site production scenario installs a grid-tied PEM electrolyser sized to steady baseload, with water treatment, compression, cascade storage, and high-flow dispensers with adequate pre-cooling. DOE (2024) shows that capex, utilisation, and power price dominate levelised hydrogen cost and warns that thin treatment of stack ageing and balance-of-plant maintenance can make results look better than they will be in service; this is why the model will include explicit ageing and O&M inputs. H2A/NREL (2025) provides the transparent cash-flow method to stress-test those inputs; this creates a consistent way to compare onsite cost under different capacity factors and power contracts. Kurtz et al. (2024) pilot predictive health monitoring and report improved uptime for compressors and chillers at stations; this supports including PHM in the service-rate assumption so that availability gains can be counted and tested. GO-Biz (2020) and NFPA (2023) are used as analogue siting references for equipment placement; this matters because setbacks and hazardous zones observed in Oakland inform yard layout constraints even as the UK site governs.

1.4.2 Buy-to-store Scenario

The buy-and-store scenario takes compressed or liquid hydrogen by tube-trailer or tanker and conditions and stores it on site for high-flow dispensing. Yang et al. (2023) compare storage options and show that liquid hydrogen offers higher volumetric density but introduces boil-off losses and cryogenic complexity, which add cost and potential failure modes; this implies the depot must price liquid's thermal penalties and procedures. Xie et al. (2024) synthesise mobility logistics and show that delivery cadence and conditioning often dominate delivered cost at depots; this implies that trailer arrival windows, turning radii, and local road access must be part of the risk analysis. CARB (2024) links many field downtime events to compressor and chiller subsystems at busy hours; this shows that delivered supply does not remove the need to design for thermal bottlenecks and availability at the station. AFDC (2025) shows that public hydrogen remains sparse in most regions; this reinforces the decision to plan a depot-centric solution instead of relying on public stations for contingency.

1.4.3 Hybrid Scenario

The hybrid scenario right-sizes the PEM plant to cover a steady base and uses delivered hydrogen to ride peaks and outages. IRENA (2024a) sets out auction-style contracts and power purchase agreements that stabilise utilisation and reduce financing cost for on-site plants when offtake is credible; this supports using contracting to harden the business case. DOE (2023) describes the hydrogen hub programme and expects regional supply build-outs with private co-investment; this can stabilise delivered price in some locations but not immediately. BNEF (2024) and S&P Global (2024) warn that near-term delivery can lag policy ambition; this implies the hybrid route should carry storage buffers and supplier redundancy. Raab et al. (2021) and Hurskainen and Ihonen (2020) compare liquid-organic carriers and show that LOHC is competitive only when waste heat is available and delivery cadence fits dehydrogenation; because the Oakland analogue has no dependable waste-heat source, LOHC is kept as a boundary check rather than a core option.

1.5 Significance for emissions, air quality, and operations

He et al. (2021), demonstrate that on a well-to-wheel basis that fuel-cell climate benefits hold only when hydrogen has low upstream emissions and the electricity used for production is not carbon-intense; this means the study will report CO_2 outcomes by pathway rather than as a single number. IEA (2024) reviews the global hydrogen sector and shows that mobility is still an early niche within a larger market; this matters because depot buyers must judge local supply rather than assume that global volumes guarantee local availability. Saur et al. (2023) and Sprik et al. (2024) identify pre-cooling and valve temperatures as the practical limits on refuelling time, while Brown and Kisting (2022) show that arrival clustering is the main driver of waits; these results explain why the feasibility criteria below focus on service rates and peak windows, not just daily kilogram totals. The local air-quality case is straightforward because fuel-cell trucks remove tailpipe NOx and particulates in the yard and on port approaches, which reduces exposure for staff and neighbours. The operational risk shifts away from diesel fuel handling towards thermal management, queue control, and component availability in hot hours, which the station design and reliability plan must address.

1.6 Aim, objectives, and research questions

Aim. To develop a depot-level feasibility plan for converting Company X's 20-truck fleet from diesel to hydrogen at a UK depot that stays robust to peak-hour refuelling, reliability constraints, supply route choice, and local permitting and space limits.

Objectives

1. To build a heavy-duty SAE J2601 service model with pre-cooling and cascade logic that sets dispenser count and buffer storage for hot, clustered peaks. Include predictive-maintenance availability in the service rate (Peak-aware sizing).
2. Quantify demand. Fix daily and five-day hydrogen demand with a justified factor of safety. Keep per-truck daily kilograms for dispenser and queue sizing. Carry payload and weather bins into sensitivity analysis.
3. Compare scenarios. Evaluate on-site electrolysis, buy-and-store, and hybrid for demand coverage, queue performance, reliability, space and safety fit, permitability, and cost band using transparent inputs for utilisation, power price, and degradation.
4. State adoption gates. Identify permits, standards, and actor roles. Use adoption and transition frames to sequence actions so that feasibility is not defined by price alone.

1.7 Feasibility criteria, decision rules, and chapter map

The project is considered feasible only if all of the following thresholds are met at the same time during the late-morning and late-evening peaks:

- Service: The average waiting time must not be more than 10 minutes, and even in the busiest cases, no truck should wait longer than 20 minutes. These limits reflect evidence from Brown and Kisting (2022), who showed clustered arrivals quickly create long queues if waiting times rise above these levels.
- Throughput: The station must meet the total daily hydrogen demand, which is 882–1,206 kg depending on duty, plus a safety margin of 10–30%. This buffer accounts for hot weather, clustering, and schedule drift, which Saur et al. (2023) and Elgowainy et al. (2017) found to reduce effective flow.

- Availability: The station must achieve at least 97% uptime during operating windows, supported by predictive maintenance. Kurtz et al. (2024) showed that health monitoring improves compressor and chiller reliability, which is why this threshold is critical.
- Safety and compliance: Layouts and operations must meet NFPA (2023) code and GO-Biz (2020) permitting rules without requiring special waivers.
- Cost: The price of hydrogen, whether produced onsite or bought in, must fall within parity bands defined by DOE (2024) and H2A/NREL (2025), with sensitivity to utilisation, power price, and degradation.

Decision rule is to select the lowest-risk scenario that meets all thresholds in both mid-band and stress cases and that is permit-ready for the UK site. Progressing from this first introductory chapter, the next chapter (Chapter 2) will review literature and methods including hydrogen types, handling, storage, renewable production, and health and safety. Chapter 3 is a fuel-supply primer with hydrogen types and production routes, diagrams, and key equations. Chapter 4 evaluates the three scenarios, including driver behaviour, traffic, weather, scarcity of public stations, storage vessel options and materials, and embrittlement controls. Chapter 5 presents the risk analysis.

CHAPTER 2 – LITERATURE REVIEW

2.0 Introduction and review logic

IEA (2019) maps the hydrogen value chain end to end and shows that feasibility for a 20-truck depot is a linked system where vehicle energy use determines daily kilograms, production and delivery determine price and carbon, and station design and reliability determine whether those kilograms can be dispensed when trucks return together. IEA (2023) updates costs and deployment and warns that claims are highly sensitive to utilisation and supply maturity, while IEA (2024) sets regionally transferable baselines for pathways and infrastructure. DOE (2024) quantifies electrolyser performance and cost drivers and H2A/NREL (2025) provides the cash-flow frame for comparing onsite cases. Brown and Kisting (2022) show peaks, not averages, govern wait times; Kurtz et al. (2024) show prognostics raise station uptime; and He et al. (2021) show climate results depend on pathway and grid. Rogers (2003) and Geels (2011) finally explain why adoption follows networks and niches rather than price alone.

2.1 Demand, refuelling and station performance fundamentals

2.1.1 Duty and queue behaviour

Brown and Kisting (2022) analyse logs from real hydrogen stations and find that arrival clustering in back-to-base fleets drives wait times unless the site has service-rate headroom. This finding means a 20-truck, 6,000-mile-per-day depot must be sized for the worst hours, not the 24-hour average. Muratori et al. (2018) model routing with station layout and show that coupling shift patterns to dispenser count reduces peak compression, which shifts feasibility work from mere hardware sizing to dispatch policy. GO-Biz (2020) turns those insights into California siting practice and shows how setbacks, vent stacks and circulation either amplify or relieve peaks in actual yards. AFDC (2025) maintains live counts and shows a sparse, regionally concentrated U.S. hydrogen network; CARB (2024) reports few contingency options at busy windows. IEA (2024) therefore treats depot-centric planning as the baseline, and Hydrogen Council (2024) adds that simply adding more stations does not remove shift-change peaks.

2.1.2 Protocol and thermal limits at the nozzle

SAE (2023) codifies J2601 heavy-duty control and sets pressure and temperature ramps that bound true fill speed. Saur et al. (2023) run controlled station tests and show pre-cooling capacity is the dominant bottleneck when fills are clustered, while Sprik et al. (2024) validate heavy-duty test rigs and reveal valve and hose thermal limits that appear at hot peaks. Reddi et al. (2017) simulate lookup versus model-based control and quantify throughput gains from better control logic, and Genovese et al. (2023) compile how protocol, nozzle hardware and thermal management combine to set real refuelling time. Taken together, these studies explain why a depot must budget chiller capacity, cascade banks, and control strategy with the same seriousness as compressor nameplates.

2.1.3 Reliability as a first-order design variable

Kurtz et al. (2024) pilot prognostics and health monitoring at stations and report measurable uptime gains for compressors and chillers, which raises effective service rate without oversizing hardware. CARB (2024) supports this emphasis by linking many field outages exactly to those subsystems in busy windows. Earlier synthesis by H2FCP (2021) collects operational practices that reduce downtime, and GO-Biz (2020) notes that redundancy and access pedestals enlarge permitting footprints, which makes reliability a layout question as much as a maintenance one.

2.1.4 Operational context variables that move demand

Magnino et al. (2024) model heavy-duty routes and show payload, gradient and stop-go traffic shift energy per mile more than small differences in rated efficiency; Danielis (2024) aggregates fleet records and reaches the same conclusion for observed duty cycles. Pereira et al. (2024) map auxiliary loads such as refrigeration and HVAC that add steady draw, and He et al. (2021) show pathway and grid mix dominate well-to-wheel totals, which requires regional inputs. Liu et al. (2024) demonstrate how methane leakage and boundary choices widen climate results, reinforcing method discipline. NFPA (2023) connects safety distances to storage choice, and GO-Biz (2020) shows circulation and setbacks constrain dispenser space, while Genovese et al. (2023) bring nozzle and protocol constraints back into operations planning.

2.2 Hydrogen supply pathways and quality

2.2.1 How the “types” were identified (method)

IEA (2019) introduces the colour labels and shows they are only shorthand; feasibility should instead be anchored in how hydrogen is produced, what energy powers it, how carbon and methane are handled, and what purity is delivered. IEA (2024) updates pathway maturity and advises buyers to require certificates that state impurity limits, metering boundaries and guarantees of origin. Chen et al. (2025) propose harmonised well-to-wheel boundaries and show that time-matching of electricity and treatment of methane leakage can reorder climate rankings; this is why the typology below is process-based, not colour-only. Osman et al. (2024) review PEM sensitivity and show that trace CO, sulfur and moisture can damage stacks and void warranties, which makes purity specifications a core part of type selection for a fuel-cell truck depot.

2.2.2 Brown hydrogen (coal gasification → shift → H_2)

IEA (2019) describes brown hydrogen as hydrogen produced by coal gasification, typically by gasifying coal to syngas then water-gas shifting CO to CO_2 and H_2, followed by purification. IEA (2019) shows this route is mature but high-emissions even after standard clean-up, which conflicts with a fleet decarbonisation goal. For the UK depot, brown hydrogen would undermine well-to-wheel outcomes set out by He et al. (2021), so it serves only as a background reference rather than a candidate supply.

2.2.3 Grey hydrogen (SMR of natural gas, no capture)

IEA (2019) documents steam-methane reforming (SMR) without carbon capture as today's dominant low-cost industrial source. The process reforms methane with steam to H_2 and CO, then shifts to H_2 and CO_2 and purifies. IEA (2019) notes high process CO_2 and upstream methane sensitivity, while He et al. (2021) show that such upstream effects drive well-to-wheel totals. Because PEM stacks require clean gas, Osman et al. (2024) add that even grey supply must meet impurity limits. Operationally, grey could bridge commissioning, but it would not satisfy the depot's emissions aim and would be presented, at most, as a short transitional option.

2.2.4 Blue hydrogen (SMR/ATR with carbon capture)

IEA (2019) sets the conditions under which SMR or auto-thermal reforming (ATR) with carbon capture can out-price green hydrogen in the near term. Hren et al. (2023) review pathway studies and show the climate case hinges on capture rate and methane leakage along the gas chain; small parameter shifts erase apparent gains. Osman et al. (2024) warn that impurities and leakage also matter for PEM warranty compliance. On the commercial side, HE (2024) traces how taxonomy and certificate rules affect premiums, IRENA and WTO (2024) codify certificate requirements, and IEA (2023) notes continuing investor caution; together these sources flag contract risk that must be priced. For the UK depot, blue supply is viable only with verified capture performance, metered methane and batch impurity certificates.

2.2.5 Green hydrogen (electrolysis powered by renewables)

DOE (2024) quantifies electrolysis and shows that electrolyser capex, utilisation and power price dominate levelised hydrogen cost for alkaline (AEL), PEM and SOEC. H2A/NREL (2025) provides the transparent cash-flow model used to stress-test those levers. Rezaei et al. (2024) test renewable-coupled operation and find that highly dynamic operation raises cost unless electricity is very cheap, which steers depots toward firm-power PPAs or auction-backed contracts. Wang et al. (2025) review stack materials and report that PEM offers fast ramping but needs PGMs and ultra-pure water, while SOEC promises higher-temperature efficiency but faces durability that is often under-priced; DOE (2024) lists current benchmarks consistent with those trade-offs. For the UK depot, green onsite production aligns with the emissions target but must carry explicit ageing and O&M in cost tests, as IEA (2023) cautions.

2.2.6 Other practical types seen in depots (brief)

IEA (2019; 2024) recognise additional labels that appear in fleet planning. For example, Pink hydrogen, which refers to electrolysis powered by nuclear electricity; the production step is electrolysis as above, but the carbon profile depends on the nuclear grid context that Chen et al. (2025) would require to be boundary-declared. Another is Turquoise hydrogen which refers to methane pyrolysis to solid carbon and H_2; IEA (2024) notes emerging status, with climate performance dependent on methane supply and carbon handling. Then, there is Biogenic/by-product hydrogen, which uses waste streams or industrial off-gas; Hren et al. (2023) show potential where flows are steady and nearby, but volume and purity variability demand robust clean-up and certification. These routes may supplement, but for a 20-truck urban depot they are better treated as niche or pilot supplies until volume, logistics and certification mature.

2.2.7 Quality, certificates and station-side conditioning (what the depot must check)

Genovese et al. (2023) compile station subsystem limits and show that purification, compression and pre-cooling determine whether protocol-compliant fast fills can be sustained. Elgowainy et al. (2017) quantify compression and pre-cooling penalties and show thermal duty grows fastest when fills cluster, exactly the condition seen in Brown and Kisting (2022). Park and Joe (2024) and Oh et al. (2024) simulate cascade sizing and control and show multi-bank storage and protocol-aware logic reduce queues when chiller capacity is adequate, while Reddi et al. (2017) show model-based control shortens fill time relative to look-up tables. Translating those results into procurement, IEA (2024) advises that each delivery or onsite batch should carry a certificate stating impurity ranges and boundary assumptions; Osman et al. (2024) explain why this protects PEM stack life and warranties. For the UK depot, the action items are therefore to: require CO, sulfur and moisture specifications on supply contracts; design water treatment to PEM needs (Wang et al., 2025); and size pre-cooling and cascades for clustered peaks so that quality at the nozzle and service rate match the duty.

2.3 Fleet supply-chain design and station layout

2.3.1 Make, buy or hybrid supply

H2A/NREL (2025) shows that onsite generation moves the business case to electrolyser capex, utilisation and power price rather than trucking fees, which is attractive where purity control and delivery timing matter. IEA (2024) adds that water, grid access and permitting often become the limiting inputs at depots, so site readiness can decide schedule more than technology. IRENA (2024a) explains how PPAs and auctions stabilise utilisation and reduce financing cost for onsite plants with credible offtake. IEA (2024) documents price volatility for delivered hydrogen in early markets, so fixed delivered prices are uncertain. Muratori et al. (2018) simulate mixed supply and find modest onsite capacity plus trucked top-ups smooths peaks and reduces outage risk; Basma et al. (2023) and BNEF (2024) reach similar conclusions from cost and delivery risk angles. IRENA and WTO (2024) note auctions and PPAs stabilise price only with high utilisation, a point IEA (2023) reinforces, which is why hybrid designs are practical for early depots.

2.3.2 Storage options and sizing logic

Rivard et al. (2019) review compressed storage at 350 and 700 bar and show why fast fills and familiar upkeep make it the depot default. Yang et al. (2023) compare media and show liquid hydrogen offers higher volumetric density but introduces boil-off and cryogenic complexity, which increase cost and failure modes. Xie et al. (2024) synthesise mobility logistics and show carrier choice and conditioning dominate delivered cost when deliveries are discrete, not continuous. Raab et al. (2021) find LOHC can compete when waste heat is available and distances are long, while Hurskainen and Ihonen (2020) show compression penalties are acceptable only if dehydrogenation heat is recovered. Penev et al. (2019) provide inventory logic for buffer size under variable deliveries, and NFPA (2023) with GO-Biz (2020) show how storage choice fixes setbacks and space.

2.3.3 Distribution choices and dispenser-side design

Penev et al. (2019) describe how tube trailers fix yard circulation and turning radii, while short pipelines simplify logistics but require street works and multi-party coordination. Muratori et al. (2018) show onsite production removes delivery risk yet increases electrical interconnection and water needs, which shifts the permitting path. IEA (2019) lists dispenser-side components most exposed under peaks: compression stages, pre-cooling, storage banks and controls. GO-Biz (2020) shows setbacks and hazardous zones are negotiated early, which sets much of the footprint. SAE (2023) defines J2601 targets; Reddi et al. (2017) quantify how control strategies change fill time; and Chochlidakis and Rothuizen (2020) compare control efficiency. Saur et al. (2023) and Sprik et al. (2024) reveal recurring thermal bottlenecks, while CARB (2024) reports similar issues in field stations. These studies justify a protocol-aware, thermally robust layout.

2.3.4 Reliability, training and factor-of-safety

Brown and Kisting (2022) show small service-rate losses at peak create long queues, making availability a primary gate. Kurtz et al. (2024) demonstrate that prognostics lift uptime by anticipating compressor and chiller failures, and Kurtz et al. (2019) compile earlier availability lessons. H2Tools (2015) and Barilo and Weiner (2017) emphasise quantitative risk assessment and operator training, and Chauhan et al. (2023; 2024) measure human-factor contributions to incidents. These findings justify both an explicit factor of safety in sizing and a reliability plan that includes PHM and training.

2.4 Vehicle energy use and external drivers

2.4.1 Driving behaviour and depot discipline

Danielis (2024) aggregates trials and fleet logs and shows higher cruising speeds and harsh braking raise hydrogen use per mile, while smoother driving and regenerative strategies lower it. Brown and Kisting (2022) show arrival discipline changes queues even when hardware is fixed.

CARB (2024) notes that staggering returns shortens waits without capital spend, and H2FCP (2021) documents nozzle discipline that avoids partial fills and overheating; these are immediate operational levers.

2.4.2 Traffic and weather

CARB (2024) compiles telemetry and shows congestion raises idling and auxiliary loads, while heat and cold change thermal management and stack water balance in ways that raise energy use. Danielis (2024) confirms similar patterns outside California, which supports transferability with care. IEA (2024) provides baselines for climate and urban form and warns that penalties differ by region; this is why the case swaps local inputs when transferring results. Kurtz et al. (2024) show predictive monitoring catches failures before hot spells, and Saur et al. (2023) isolate the subsystems that lose thermal headroom first, while GO-Biz (2020) outlines site design that mitigates temperature and wind exposure.

2.4.3 Payload, gradient and routing

Magnino et al. (2024) model payload and grade and show heavier loads and steeper routes shorten range, while route choice and speed management recover part of the loss. Link et al. (2024) quantify component cost declines that improve parity on long, steady routes at high utilisation, and Danielis (2024) ties those trends to observed cycles. Basma et al. (2023) argue high-utilisation freight can favour fuel cells if fuel price and uptime targets are met, and Ledna et al. (2024) show delivered price per kilogram drives competitiveness across scenarios. He et al. (2021) and Wang et al. (2022) finally show environmental benefits depend on low-carbon hydrogen, not technology labels.

2.4.4 Auxiliary loads and idle

Danielis (2024) highlights refrigeration, HVAC and PTO as steady draws that shift daily kilograms and push queues in hot or cold periods. Pereira et al. (2024) document depot practices that cut these loads without new hardware, while CARB (2024) links higher auxiliary use to seasonal queue spikes. SAE (2023) supports night refuelling and protocol-consistent top-offs that reduce daytime temperature stress. Reddi et al. (2017) show throughput gains from correct protocol use, and Brown and Kisting (2022) observe shorter waits with better dispenser discipline.

2.5 Evidence, models and remaining gaps

2.5.1 Evidence base and methods

Danielis (2024) synthesises bus and truck operations and shows field TCO pivots on price per kilogram and stack life, not model averages, which pushes planners to use price bands and life distributions. CARB (2024) tracks stations as systems and links availability and waits to component causes, validating queue-aware design. IEA (2024) assembles deployment and cost baselines for cross-region comparison. Saur et al. (2023) and Sprik et al. (2024) expose component limits under controlled loads, Kurtz et al. (2024) implement prognostics with measurable uptime gains, and CHJU (2024) compiles European infrastructure status to calibrate maturity outside the United States.

2.5.2 Economic models for decision making

Basma et al. (2023) set parity bands and show competitiveness requires low fuel price, high miles and adequate stack life. Ledna et al. (2024) confirm with a total-cost-of-driving frame that the flip to competitiveness happens only under low price and high utilisation. Rout et al. (2022) illustrate sensitivity with tornado charts placing fuel price and capital recovery at the top. Link et al. (2024) connect learning to future cost bands for trucks, while DOE (2024) with H2A/NREL (2025) link supply-side levers to the onsite LCOH tests used in this study.

2.5.3 Environmental models and harmonisation

He et al. (2021) show well-to-wheel rankings reorder when pathway and grid change, so climate claims must be pathway-specific. Wang et al. (2022) model long-haul and show blue outcomes turn on capture rate and upstream methane control. Osman et al. (2024) show impurity control and logistics widen the real-world spread. Chen et al. (2025) recommend harmonised boundaries for procurement, and Zhao et al. (2024) show method choices change policy conclusions; these guides are applied to keep comparisons consistent.

2.5.4 Operations models for queues, inventory and heat

Brown and Kisting (2022) verify with observed data that peak-hour behaviour governs performance, which requires queueing models to set dispenser count and manage arrivals. Zheng et al. (2014) produce allocation rules that cap waits at targets. GO-Biz (2020) embeds queue-aware layout in permitting steps. Park and Joe (2024) and Oh et al. (2024) show how cascade staging and control protect fill time through sequences, Sadi and Deymi-Dashtebayaz (2019) analyse storage-to-cylinder losses, and Saur et al. (2023) pinpoint subsystems that lose thermal headroom first; CARB (2024) ties those subsystems to field outages.

2.5.5 Adoption and transition framing

Geels (2011) sets a multi-level perspective and shows transitions occur when niches, regimes and landscape pressures align; price-optimal is not the same as adoptable. Rogers (2003) explains that perceived advantage, compatibility and trialability drive early uptake; Küffner et al. (2022) identify freight niches where range and payload constraints bind. Tornatzky and Fleischer (1990) provide the TOE audit for organisational readiness, and NFPA (2023) with SAE (2023) anchor the code and protocol environment that controls timing.

2.5.6 Synthesis map for a 20-truck, 6,000-mile-per-day depot and Gaps

Brown and Kisting (2022) show the sizing must be built from in-service consumption and arrival timing because peaks govern throughput. SAE (2023) defines the protocol envelope for fast fills. Kurtz et al. (2024) show predictive maintenance increases availability by catching compressor and chiller failures early. H2A/NREL (2025) provides LCOH inputs and sensitivities for onsite cases, while IEA (2024) notes water, grid and permitting often set timing. Rivard et al. (2019) explain why compressed storage remains the default, and He et al. (2021) anchor environmental claims to pathway and boundaries; Osman et al. (2024) add purity risks and Chen et al. (2025) add harmonisation rules. The integrated picture is a queue-aware, thermally robust, reliability-led depot with pathway-specific emissions and scenario-tested costs.

Reddi et al. (2017) show protocol control changes throughput, yet few studies combine protocol-accurate control with real peak traffic in high heat, leaving the worst hours thinly evidenced. Kurtz et al. (2024) show what prognostics can do, while CARB (2024) documents outages without linked control experiments; these gaps justify field trials in Chapter 4. DOE (2024) lists electrolysis targets but has limited field ageing curves, H2A/NREL (2025) offers a framework that still needs richer degradation inputs, and Wang et al. (2025) argue durability must be priced explicitly; these motivate conservative onsite cost cases. Raab et al. (2021) and Hurskainen and Ihonen (2020) show LOHC needs waste heat and cadence that many depots lack; Xie et al. (2024) warn corridor logistics can erase gains, which is why LOHC stays a boundary check. IEA (2024) and AFDC (2025) show transferability is often assumed rather than tested against local coverage and siting, and Rogers (2003) with Geels (2011) remind that adoption needs actor coordination, not prices alone; these gaps shape the scenario tests and risk analysis in later chapters.

CHAPTER 3: FUEL SUPPLY FOR A 20-TRUCK HYDROGEN FLEET

3.1 Purpose, scope, and method

This chapter converts Company X's 6,000-mile daily service demand into a workable hydrogen supply plan for its UK depot. It focuses on the supply and operational side, defining what must be produced, processed, stored, and dispensed each day to ensure all trucks receive safe and compliant fills during busy return periods. Building on earlier chapters that set the energy rates, safety factors, and system limits, it now translates those findings into practical fuel pathways and depot integration options. Drawing on global evidence, it highlights that most hydrogen still comes from fossil sources, so genuine decarbonisation requires careful pathway certification. The discussion also shows how onsite electrolysis, power contracts, and strong station conditioning sustain reliable, low-emission operations.

3.2 Hydrogen "types" in detail: what they are, how they are produced, and why purity is decisive

3.2.1 Grey and brown hydrogen

Steam-methane reforming without capture, commonly called grey hydrogen, is the dominant incumbent because it is mature and can be low cost at the plant gate. The reformer creates synthesis gas via $CH_4 + H_2O \rightleftharpoons CO + 3H_2$, the shift reactor raises hydrogen yield via $CO + H_2O \rightleftharpoons CO_2 + H_2$, and pressure swing adsorption polishes the product (IEA, 2019). Coal gasification follows an analogous route for brown hydrogen, beginning with $C + H_2O \rightarrow CO + H_2$ before shift and clean-up. IEA (2024) quantifies typical life-cycle emissions around 10–12 kg CO_2-eq per kilogram of hydrogen for unabated natural-gas routes and substantially higher values for coal-based hydrogen, often above 20 kg CO_2-eq per kilogram. Those intensities explain why grey and brown hydrogen cannot credibly serve a decarbonisation goal for heavy-duty fleets, even if they can be procured reliably.

A commissioning bridge is the only plausible role for Company X, and even that role requires strict quality discipline. Proton-exchange membrane stacks are sensitive to traces of carbon monoxide, sulfur species and excessive moisture; contamination at even a few parts per million can poison catalysts or degrade membranes and can void warranties. Osman et al. (2024) review these sensitivities and recommend that buyers require ISO-type impurity limits at the delivery flange and maintain station-side filtration and drying as part of normal operations. A depot that ever receives grey or brown hydrogen must therefore treat quality certificates and inline monitoring as part of fuel supply, not as afterthoughts.

3.2.2 Blue hydrogen

SMR or autothermal reforming coupled with carbon capture can lower plant emissions materially and can undercut green hydrogen on headline cost in many regions today. Autothermal reforming couples partial oxidation with steam reforming inside one vessel, which improves heat balance and can simplify high-rate capture integration. IEA describes capture rates above 90% as technically feasible and notes conditions where blue hydrogen is currently cost-competitive, especially where gas is inexpensive and transport and storage for CO_2 already exist (IEA, 2019; IEA, 2024). A comprehensive lifecycle review by Hren and co-authors then shows why capture rate alone is not sufficient. Small upstream methane leakage, even at one to two% of gas supply, can erase much of the climate benefit, so buyers must insist on verified capture performance and credible methane accounting in addition to price (Hren et al., 2023).

Quality remains a separate gate for PEM trucks even when carbon performance is verified. Capture and acid-gas removal do not automatically guarantee the very low carbon monoxide, sulfur and moisture levels PEM warranties require. Osman et al. (2024) emphasise that suppliers must commit to impurity specifications for every shipment and that depots should add their own polishing and monitoring steps to protect stacks over time. For Company X, a blue-hydrogen contract is therefore viable only if it marries a bankable price with certificate-based carbon declarations and ISO-conforming impurity limits at the gate.

3.2.3 Green hydrogen

Electrolysis powered by clean electricity is the only pathway that maps directly to Company X's emissions aim while preserving control over purity and cadence at the depot. DOE's (2024) latest assessment puts present clean-power electrolysis around 6–8 USD per kilogram for commercial alkaline and PEM systems and shows that the cost is dominated by electrolyser capital cost, utilisation and the price paid for electricity. Those levers are actionable at depot scale through right-sizing, availability management and firm power contracts. IEA (2024) documents a rapid rise in announced low-emission capacity from a small base, which suggests future cost relief but does not remove the need to plan reliability and cost exposure carefully in the near term.

The cell-level chemistry is straightforward. The overall reaction $2H_2O \rightarrow 2H_2 + O_2$ is supported in PEM by the anode half-reaction $2H_2O \rightarrow O_2 + 4H^+ + 4e^-$ and the cathode half-reaction $4H^+ + 4e^- \rightarrow 2H_2$. Materials and stack reviews report that PEM's rapid ramping and compact footprints suit peaky depots, while the use of platinum-group catalysts and the need for ultra-pure water bring cost and maintenance obligations that must be priced explicitly (Wang et al., 2025). Operational studies show that frequent cycling to follow variable renewables raises cost unless electricity is extremely cheap, which is why power-purchase agreements that deliver firm clean electricity or tariff structures that stabilise utilisation are recommended for onsite plants (Rezaei et al., 2024; IRENA, 2024a). For Company X, the main advantage of onsite green hydrogen is direct control of purity and schedule. The design obligations are to budget stack ageing and balance-of-plant maintenance into levelised cost, to install robust water treatment to PEM specifications, and to size compressors, cascades and chillers so that hot-hour sequences can be sustained without breaching queue targets.

3.2.4 Turquoise and other emerging options

Methane pyrolysis splits methane into solid carbon and hydrogen using high temperatures or plasma assistance. The standard reaction $CH_4 \rightarrow C(s) + 2H_2$ has a reaction enthalpy near 37.7 kJ per mole of hydrogen, which looks favourable compared with routes that require steam generation, but practical systems must add energy for reactor heat losses and for continuous carbon handling (Sánchez-Bastardo et al., 2021). Research on molten-metal reactors seeks to mitigate coking and ease solids removal; however, reviews of these concepts judge them pre-commercial for near-term depot fuel, particularly in small urban settings where solids logistics are problematic (Neuschitzer et al., 2023). The prudent stance for Company X is to track turquoise projects rather than to bank on them for primary supply.

3.2.5 Quality, certificates and conditioning at the station

The station must turn whatever arrives at the gate into protocol-compliant, fast fills during clustered peaks. Genovese et al. (2023) collate subsystem limits and show that purification, compression and pre-cooling determine whether stations can sustain fast fills without trips.

Argonne modelling quantifies that pre-cooling and compression duty rise steeply when arrivals cluster (Figure 3), which is exactly the pattern of back-to-base fleets (Elgowainy et al., 2017). NREL test programmes then show that pre-cooling capacity and hose and valve thermal limits recur as bottlenecks at high throughput, while model-based fill control and multi-bank storage shorten fill time relative to static look-up tables when chiller capacity is adequate (Saur et al., 2023; Reddi et al., 2017; Sprik et al., 2024). For Company X, those results translate into procurement and design rules. Every batch, produced onsite or delivered, must come with impurity certificates aligned to ISO-type limits for PEM use and with declared system boundaries for carbon accounting. The station should monitor moisture and carbon monoxide downstream of storage to catch ingress from cycles, fittings or valves. The conditioning system must include enough chiller tonnage, compressor headroom and cascade banks to hold mean and 95th-percentile waits within the Chapter 1 targets during the late-morning and late-evening peaks.

3.3 Production technologies and unit operations: performance, costs and integration

3.3.1 Electrolysis technologies and the water plant you actually need

The practical differences between alkaline, PEM and solid-oxide electrolysis matter at depot scale because they change footprint, dynamics and maintenance. Alkaline systems are mature, have lower specific capex and use aqueous KOH, but they ramp more slowly and typically require larger balance-of-plant. PEM systems start and ramp quickly, tolerate frequent transients and are compact, which fits clustered returns and tight yards, but they require ultra-pure water and use platinum-group metals, so water treatment quality and stack-ageing provisions must be priced rather than assumed away. Solid-oxide electrolysis can achieve high electrical efficiency when low-cost heat is available, but durability and tolerance to start-stop cycling remain the main uncertainties for real depots (Wang et al., 2025). DOE’s (2024) benchmarking gathers these trade-offs in a single frame and confirms that levelised cost is controlled by capital cost, utilisation and electricity price, which Company X can address through sizing and contracting rather than through speculative technology bets.

Water treatment is not a side module but a core reliability system. PEM stacks require low conductivity and very low silica to protect membranes, which implies a train of pre-filtration, reverse osmosis and either deionisation or EDI followed by polishing, with online monitoring for resistivity and total organic carbon (Figure 4). Skimping on this plant does not save money; it simply moves cost into unplanned downtime and shortened stack life. The compressor, cascade and chiller selection must then be co-sized with the electrolyser so that production cadence and dispensing peaks are matched. Rezaei and colleagues show that frequent cycling of electrolysers to follow variable renewables increases cost unless electricity is extremely cheap, which pushes a depot toward firm clean power or shaped tariffs and away from aggressive load-following that would force oversized storage and chilling (Rezaei et al., 2024). The integration principle is therefore simple. A right-sized PEM, steady firm power, and robust conditioning hardware are more valuable to a small urban depot than chasing temporarily lower wholesale prices with a highly cycled plant.

3.3.2 Thermal routes with and without carbon capture

Unabated SMR and coal gasification are incompatible with Company X's climate aim, but the underlying unit operations are worth understanding because they reappear in blue hydrogen supply chains (Figure 5). A blue plant will include a reformer or ATR, shift reactors, acid-gas removal, CO_2 capture and compression, and hydrogen polishing via PSA. IEA summarises the typical emissions for unabated plants and explains the conditions under which capture integration can be cost-effective (IEA, 2019; IEA, 2024). Hren et al. (2023) then show that lifecycle results vary widely with capture rate and methane leakage, which is why buyers must focus on verifiable capture performance, credible leakage assumptions and electricity carbon intensity for auxiliaries when assessing delivered blue hydrogen. From Company X's vantage point, the engineering takeaway is contractual. The depot will not build these units, but it must insist that a blue supplier declare boundaries and meet impurity specifications that protect PEMs, and it must carry storage buffer and supplier redundancy in case a single plant outage or pipeline restriction interrupts deliveries.

3.3.3 Methane pyrolysis

The appeal of pyrolysis is obvious on paper because the process can avoid process CO_2 formation and produce solid carbon as a co-product (Figure 6). The same reviews that report the favourable standard reaction enthalpy also make clear that real reactors face high-temperature materials challenges, continuous solids removal and de-coking, and non-trivial energy inputs for heat and solids logistics (Sánchez-Bastardo et al., 2021; Neuschitzer et al., 2023). Those realities put present costs and risks above bankable levels for a small urban depot. The sensible action for

Company X is therefore to track technology progress and potential regional offtakers for solid carbon rather than to plan on turquoise hydrogen within the time horizon of this project.

3.3.4 Biogenic and by-product routes

Biomass and waste-based hydrogen routes can provide low-carbon gas where stable feedstocks occur near the load, but IEA and IEA Bioenergy report variability in volume and impurity that complicates mobility fuel without robust cleanup and certification (Figure 7) (IEA, 2019; IEA, 2024). The unit operations typically include gasification or reforming of biogenic streams, shift, cleanup and hydrogen polishing (Wan et al., 2025). The feasibility hinge for Company X is not chemistry; it is logistics and quality. Unless there is a proximate contracted stream with assured quality and volume, biogenic hydrogen is better treated as a supplemental source than as a primary supply for an 882–1,447 kg per day depot with tight peak windows.

3.3.5 Delivery modes, carriers and conditioning at the gate

The "last mile" can dominate delivered cost and reliability for a depot, and recent comparative reviews make the trade-offs explicit. Compressed-gas tube trailers suit modest volumes and short distances but require frequent arrivals and yard access during busy hours. Liquid hydrogen increases volumetric density and can support larger depots and longer corridors, yet it brings boil-off and cryogenic complexity that must be managed through procedures, insulation and vapour handling. Liquid-organic carriers move as conventional liquids and are easy to store, but they require sustained dehydrogenation heat and suffer reconversion losses, which narrow their competitiveness to cases with good heat integration or long haul distances (Xie et al., 2024; Hurskainen and Ihonen, 2020). Practical depot reviews converge on compressed storage as the default because hardware and operations are familiar, while liquid becomes attractive at scale if boil-off is well managed and logistics favour fewer, larger drops (Rivard et al., 2019).

Conditioning must be engineered for clustered returns rather than day-average flow. Argonne modelling and NREL station tests show that pre-cooling capacity, storage-bank configuration and compressor headroom set the practical service rate, and that model-based control improves throughput when coupled with adequate chiller tonnage (Elgowainy et al., 2017). For Company X, those results translate into a clear design brief. The depot needs multi-bank high-pressure storage, a chiller sized for heavy-duty sequences in hot hours, compressors with predictive maintenance to hold availability above target, protocol-aware control to keep nozzle temperatures within J2601 limits, and yard circulation that accommodates tube-trailer or cryogenic truck turnarounds without blocking tractor access to dispensers.

Table 3.2: Delivery mode versus depot implications—energy penalty, yard space, safety and dispenser service rate.

Delivery mode	**Energy penalty (indicative)**	**Yard space & logistics**	**Safety & permitting**	**Dispenser service-rate implication**
Compressed gas (CGH_2) tube-trailer	Compression ≈ 5–10% of H_2 LHV; additional pre-cooling power at station	Multiple drops/day at BaySpan scale; trailer turning radii; moderate bank footprint (350/700 bar cascades)	High-pressure hazards; embrittlement controls; NFPA setbacks for banks and compressors	Nozzle throughput still limited by J2601 pre-cooling and bank pressure; model-based fills recommended
Liquid hydrogen (LH_2) tanker	Liquefaction ≈ 25–35% of H_2 LHV; boil-off to manage	Fewer, larger drops (≈3–4 t per tanker); larger cryogenic tank and exclusion zones	Cryogenic risks, boil-off, oxygen condensation; bigger hazard zones and training burden	High station throughput possible, but pre-cooling and vaporisation control remain the bottlenecks
LOHC (e.g., MCH/toluene)	Low reconversion efficiency; continuous dehydrogenation heat at ≈ 250–320°C	Reactor/heater skid plus storage; steady heat supply; more complex yard services	Flammable liquid handling; hot-oil operations; catalyst management	Dispenser rate depends on dehydrogenation capacity; typically less responsive to peaks without

				thermal headroom
Short lateral pipeline (CGH_2)	Compression at source; minimal on-site energy use beyond polishing and pre-cooling	Small on-site footprint; no truck logistics; high upfront street-work/capex	Pipeline permitting and third-party coordination; integrity management	Best nozzle stability; still bound by J2601 and pre-cooling during clustered fills

3.4 What BaySpan must decide now: onsite, buy-in or hybrid

IEA shows low-emissions hydrogen is still a small share and often costlier than unabated supply; DOE shows the electrolysis cost curve falls with higher utilisation, scale and firm clean power (IEA, 2024; DOE, 2024). The choice is therefore practical, not ideological: pick the configuration that meets queue targets, availability, safety, space and cost at the UK depot.

3.4.1 On-site

On-site green hydrogen (PEM) aligns with the decarbonisation aim and gives control over purity and schedule. Levelised cost sits in the 6–8 USD/kg range under today's commercial assumptions and is highly sensitive to capacity factor and power price (DOE, 2024). Site feasibility: assume 5 acres (~20,200 m²). This is sufficient for a PEM building with water treatment and deionisation, compressor house, chiller farm, 350/700-bar cascades, dispenser islands, traffic aisles, and code setbacks. Production target (from Chapter 1 demand): design for ~1.06 t/day (mid-band +20% headroom) with stress up to ~1.45 t/day; either (a) size PEM for full daily mass, or (b) size for ~60–70% baseload and cover peaks with storage/top-ups.

Storage options:

- Gas (CGH_2): multi-bank 350/700-bar storage sized to hold ≥ one wave (~0.53 t); fast-fill depends on bank pressure + pre-cooling.
- Liquid (LH_2): on-site 3–5 t cryogenic tank plus vapouriser; manage latent heat of vaporisation (~0.45 MJ/kg) and boil-off; liquefaction penalty remains offsite but affects gate price.

Refuelling modes: J2601-2 fast-fill (H70-HD) with strong pre-cooling for clustered returns; H35 time-fill/top-off overnight to relieve peaks; mobile dispenser only as contingency. Health & safety: DSEAR/ATEX zoning, gas detection and ventilation, crash barriers, traffic separation for tractors and deliveries, ice/fog controls at vapourisers, wind/rain canopies, hot-day thermal management, emergency shutdown, QRA, and trained operators. Risks: grid interconnection lead time; stack ageing; chiller/compressor availability (mitigate with PHM and spares).

3.4.2 Buy-in

Buy-in reduces capex and can start quickly, but price and reliability hinge on mode and distance. CGH_2 suits modest volumes but needs multiple daily drops, robust turning radii and delivery windows outside peaks. LH_2 enables fewer, larger drops and smaller footprint per kilogram stored, but adds cryogenic hazards, boil-off handling and vapouriser duty at the nozzle (latent heat management). Storage: CGH_2 cascades sized similar to on-site; LH_2 tank 3–5 t with fenced exclusion and vent stacks. Refuelling: still J2601-2; pre-cooling and cascades remain the bottlenecks under clustered arrivals. Health & safety: traffic plans to avoid congestion at peak refuelling, bollards and barriers at loading bays, weather procedures for high winds/heavy rain, and contingency for delivery delays. Trade-off: faster deployment and lower capex vs gate-price volatility and delivery risk.

3.4.3 Hybrid

Hybrid right-sizes PEM for ~60–70% of a hot-day (e.g., ~0.65–0.75 t/day), keeps CGH_2/LH_2 contracts to ride peaks/outages, and uses multi-bank storage + strong pre-cooling to hold mean waits ≤10 min and 95th-percentile ≤20 min. This avoids oversizing electrolyser and chiller assets while protecting uptime. Space: same 5-acre plot accommodates a smaller PEM block plus either CGH_2 banks or one LH_2 tank and safe circulation. Safety/operations: same DSEAR/ATEX controls; add supplier redundancy and delivery SLAs. Decision lens: if firm clean power and high utilisation are bankable, hybrid gives cost stability (onsite baseload) and service resilience (delivered peaks).

Common operational obligations (all options): UK HGV annual test (MOT) and DVSA compliance; OEM fuel-cell service intervals; hydrogen leak checks; brake/tyre/steering inspections; driver training in nozzle discipline and hot/cold-weather SOPs. Fuel economy for planning uses kg/mile (with MPGe if needed); note mph = miles per hour and mpg = miles per gallon—for hydrogen, 1 kg ≈ 1 gasoline gallon equivalent, but queue and thermal limits are set by J2601-2 and station hardware, not by published MPGe.

CHAPTER 4 — EVALUATION

4.0 Chapter purpose and evaluation method

This chapter evaluates three fuel-supply configurations for Company X's UK depot against the fixed duty of 6,000 miles per day and the performance, safety and cost criteria defined in Chapter 1. The analysis converts miles into hydrogen demand bands with a 10–30% factor of safety, models peak-hour service rate under SAE heavy-duty constraints at the nozzle, and compares onsite green hydrogen, buy-in hydrogen, and a hybrid configuration on throughput, queueing, availability, safety and cost. ICCT (2022) places modern heavy-duty fuel-cell tractors at 0.145–0.148 kg per mile; ICCT (2024) supplies a 0.201 kg per mile stress bound for stop-go duty. Brown and Kisting (2022) show that clustered returns rather than daily averages drive wait times, which is why peak-hour service rate is the binding constraint. SAE (2023) defines J2601 heavy-duty limits for temperature and pressure that set true nozzle mass-flow. Saur et al. (2023) demonstrate in controlled tests that pre-cooling capacity becomes the dominant bottleneck during clustered heavy-duty fills, and Sprik et al. (2024) validate heavy-duty test rigs that expose hose and valve thermal limits. DOE (2024) quantifies electrolysis cost sensitivities to capex, utilisation and power price, while NREL/H2A (2025) provides the transparent cash-flow framework for scenario comparisons.

4.1 Demand, operations, and risk inputs

This section estimates Company X's daily hydrogen demand and applies realistic operating factors to set design targets. Based on ICCT (2022), heavy-duty trucks consume about 0.147 kg per mile. For 6,000 miles per day across the fleet, this equals 882 kg/day or 44.1 kg per truck. For stop-go vocational cycles, ICCT (2024) gives 0.201 kg per mile, producing a stress-day demand of 1,206 kg/day. These are not 24-hour averages but fuel loads that must be dispensed within two clustered return waves.

To absorb clustering, heat, and timing drift, a 10–30% factor of safety is used. Thus, 882 × 1.20 = 1,058 kg/day for typical hot days and 1,206 × 1.20 = 1,447 kg/day for stress days. Five-day totals are 4,410 kg (mid-band) and 6,030 kg (stress), forming the design basis for storage and chiller sizing.

Brown and Kisting (2022) show that arrival clustering drives queuing unless stations have service-rate headroom, while Saur et al. (2023) identify thermal overloads from consecutive heavy fills. Danielis (2024) links higher speeds and braking to fuel intensity, and Magnino et al. (2024) confirm that payload and gradients dominate consumption variation, validating the 18-tonne average and 22-tonne maximum payload bins. CARB (2024) adds that congestion and temperature spikes worsen both usage and queuing. Pereira et al. (2024) show refrigeration and HVAC loads can raise daily demand under extreme weather. AFDC (2025) data confirm limited regional hydrogen coverage, and CARB (2024) reports frequent chiller and compressor faults at peak hours. Together, these findings support Company X's depot-centred model with on-site buffering, predictive maintenance, and redundant supply to maintain reliability.

4.2 Station performance and queue model

This section translates protocol and hardware limits into a station performance model that reports mean and 95th-percentile wait times for the two daily return waves, establishing the service-rate requirements that each fuel-supply scenario must meet.

SAE (2023) defines the J2601 heavy-duty pressure and temperature envelopes for compliant fast fills, while Genovese et al. (2023) show how storage pressures, compressor staging, and pre-cooling capacity control real mass-flow. Elgowainy et al. (2017) find that pre-cooling and compression penalties rise sharply during clustered arrivals, and Saur et al. (2023) identify pre-cooling as the main bottleneck. Sprik et al. (2024) validate test methods for thermal limits, and Reddi et al. (2017) show that model-based fill control shortens fuelling time with multi-bank cascades. These studies define Company X's design for chiller tonnage, compressor headroom, and storage layout. Kurtz et al. (2024) demonstrate that predictive maintenance improves uptime, so both base and PHM-enabled availability are simulated. Brown and Kisting (2022) describe the clustered demand waves used in the model that outputs service rates, wait times, and storage performance.

4.3 Scenario A — Onsite green hydrogen (PEM)

This section evaluates onsite electrolysis as a self-reliant route that maximises control over hydrogen purity and supply cadence. The analysis addresses how to size the PEM plant, storage, and chilling systems so that clustered vehicle returns can be served within wait-time targets, what power contracting is needed to stabilise utilisation and cost, and how permitting and space constraints are managed at the UK depot, with the Oakland evidence used as an analogue.

4.3.1 System Architecture, Sizing and Operational Design

DOE (2024) identifies capital cost, utilisation, and electricity price as key cost drivers for electrolysis, while NREL/H2A (2025) provides the financial model using realistic stack-life and O&M inputs. Wang et al. (2025) stress the need for ultra-pure water and strict thermal and pressure control for PEM durability. Company X's system includes PEM electrolysers, water treatment, dryers, multi-stage compression, storage banks, and pre-cooled dispensers. Rezaei et al. (2024) show that variable renewables raise costs unless power is cheap, so a firm clean-power PPA is assumed. Two sizes are modelled: a 60–70% baseload system with storage for peaks, and a full-load system with less storage. DOE (2024) gives cost sensitivities, while Elgowainy et al. (2017) and Saur et al. (2023) identify compression and pre-cooling as bottlenecks, with Reddi et al. (2017) showing that model-based control reduces chiller load and ensures compliance with service limits.

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4.3.2 Layout, Quality Assurance and Risk Management

Compliance with permitting and spatial requirements is central to feasibility. GO-Biz (2020) translates NFPA standards into California siting workflows, including setbacks, venting and circulation, while NFPA (2023) specifies separation distances and hazardous zone classes. Those rules provide a conservative analogue for UK layout checks. Equipment placement, access, egress and dispenser islands are arranged to avoid conflicts with delivery lanes and tractor movements. Quality assurance protects PEM warranties and long-term performance. Osman et al. (2024) note PEMs' vulnerability to CO, sulfur and moisture, recommending certificate-backed deliveries combined with inline monitoring. The scenario implements inline CO and humidity sensors downstream of storage, filter media maintenance schedules, and alarm-based bank isolation to prevent contamination without disrupting overall operation.

Cost and reliability considerations are assessed in detail. DOE (2024) provides the baseline LCOH sensitivity framework, and the scenario runs multiple cases across capacity factor and electricity price bands, while including stack replacement and BOP allowances. Kurtz et al.

(2024) show that prognostics and condition monitoring raise availability for critical subsystems, so Company X's design includes PHM and critical spare parts to keep operating-window availability above 97%. Identified risks include grid interconnection lead times, PEM stack ageing, and water quality deviations. Mitigation strategies include temporary mobile supply during commissioning, redundant polishing stages in the water system, and acceptance tests simulating peak hot-day loads before committing to full fleet conversion.

Detection and emergency shutdown (ESD) are engineered as a single control layer that prevents small leaks becoming station outages. Fixed catalytic or ultrasonic H_2 detectors are placed in the compressor house, around 350/700-bar banks, and beneath dispenser canopies. Alarms trigger at 0.4% vol (warn) and 1.0% vol (action) with automatic isolation of affected banks, compressor trip, and dispenser interlock. ESD closes fail-safe valves, halts chillers and compressors, and posts alerts. Vent stacks discharge ≥6 m above grade and ≥3 m from openings, verified by dispersion checks. Monthly function tests use bump gas and pushbuttons; logs close faults within 24 h. Detector setpoints, isolation timing, vent heights and proof-test cadence follow Appendix C Table C-3, with drill targets in Table C-5

4.4 Scenario B — Buy-in and store (compressed or liquid)

This section evaluates delivered hydrogen as a way to reduce capital expenditure and enable faster project start-up, while recognising that feasibility depends heavily on gate price, delivery reliability, and onsite conditioning. The analysis compares compressed-gas and liquid deliveries, while keeping LOHC only as a boundary case where waste heat is not assured.

4.4.1 Delivery Logistics and Yard Operations

Xie et al. (2024) show that delivery mode and distance dominate gate price outcomes, with compressed hydrogen suiting short-haul corridors and liquid hydrogen enabling larger drop sizes, fewer truck arrivals and longer transport distances. Rivard et al. (2019) identify compressed storage as the default for most depots, while Hurskainen and Ihonen (2020) note that LOHC is only competitive when dehydrogenation heat is available or when long-haul deliveries are required. Without dependable waste heat, LOHC remains a boundary option.

Operational implications of deliveries are equally critical. GO-Biz (2020) provides yard design norms to keep delivery lanes separate from dispenser islands, ensuring driver and equipment safety. The plan specifies arrival windows that avoid congestion during peak fuelling, with turning radii checked for both tube-trailers and cryogenic trucks. The delivery model tests whether two to three compressed-gas drops or one liquid-hydrogen drop per day can sustain mid-band plus factor-of-safety demand without queue failures during dual peak waves.

Storage and space requirements also shape feasibility. NFPA (2023) defines setbacks and hazard-zone separations for high-pressure banks and cryogenic tanks, while GO-Biz (2020) translates these into clear siting practices. The scenario compares footprints and hazard zones of CGH_2 banks versus LH_2 tanks and specifies vent stack placement and traffic separation from loading docks and driver marshalling areas.

4.4.2 Conditioning, Reliability and Cost Exposure

Maintaining fuelling performance requires careful conditioning. Genovese et al. (2023) show that purification, compression and pre-cooling directly affect whether stations can sustain fast fills without trips, while Elgowainy et al. (2017) demonstrate that thermal duty rises sharply under clustered arrivals. Accordingly, the scenario specifies dryer duty, final PEM-grade filtration, compressor staging, multi-bank storage, model-based fill control, and chiller capacity sized to the same hot-peak stress tests used in Scenario A.

Reliability is another determinant of viability. CARB (2024) links downtime events at many stations to compressor and chiller subsystems during busy periods, showing that delivered fuel does not eliminate the need for robust thermal and mechanical design. Osman et al. (2024) recommend impurity certificates and inline monitoring to safeguard PEM stacks. Company X's plan includes receiving-flange sampling, online CO and humidity sensors, redundancy via two contracted suppliers, and contractual delivery windows with penalties to mitigate traffic delays or upstream outages.

Cost risk is significant in buy-in models. IEA (2024) highlights that low-emission hydrogen remains costlier than unabated supply and that delivery projects face timing uncertainties as they transition from announced to operational. The scenario therefore builds gate-price bands by mode and distance and runs volatility sensitivities to assess exposure. The analysis concludes that buy-in reduces capex and accelerates deployment but imports price volatility and logistics dependency that onsite production scenarios avoid.

4.5 Scenario C — Hybrid (onsite baseload + delivered peaks)

This section evaluates a hybrid design that combines onsite PEM baseload with delivered hydrogen for peaks and outages. Muratori et al. (2018) show that hybrid depots lower outage risk by integrating production with scheduled deliveries. Company X applies this by sizing PEM capacity at 60–70% of the mid-band day and using deliveries to cover factor-of-safety–adjusted peaks. The queue model, confirms that multi-bank storage and pre-cooling maintain both mean and 95th-percentile wait times during two-wave demand sequences. IRENA (2024a) recommends auction-style contracts and firm clean-power PPAs to stabilise utilisation and reduce financing costs. Accordingly, Company X pairs a fixed PPA for baseload generation with framework supply agreements that define delivery timing, quality standards, and price collars. Elgowainy et al. (2017) and Saur et al. (2023) guide thermal management and cascade design, Reddi et al. (2017) supports fill control logic, and Sprik et al. (2024) validates station capacity modelling. DOE (2024) and NREL/H2A (2025) provide LCOH baselines, while Xie et al. (2024) and Hurskainen and Ihonen (2020) supply delivered price bands. Table 4.5 summarises the blended outcome, showing that the hybrid model balances capital efficiency, operational reliability, and cost stability under both normal and stress-day conditions.

4.6 Cross-scenario comparison and decision framework

This section compares the three scenarios using a consistent framework covering throughput, service, availability, safety, cost, and emissions. Throughput measures daily hydrogen delivered under a fixed safety factor, while service evaluates whether waiting times stay within ten to twenty minutes. Availability must exceed 97% uptime, and safety and permitting follow NFPA (2023) and GO-Biz (2020) standards. Costs are shown as levelised hydrogen prices with key sensitivities, and emissions use harmonised well-to-wheel boundaries. He et al. (2021) and Wang et al. (2022) confirm that only low-carbon and tightly controlled hydrogen achieves real climate benefit, while Chen et al. (2025) call for consistent procurement boundaries. Using these principles, emissions are computed for green, blue, and hybrid pathways with verified certificates. Layout and safety compliance are checked through footprint and clearance audits to meet UK codes without waivers. Finally, sensitivity testing based on DOE (2024), Saur et al. (2023), and Sprik et al. (2024) examines capacity factor, electricity price, clustering, and thermal limits to reveal when scaling electrolysers or switching delivery modes becomes the most reliable, cost-effective, and low-risk option.

4.7 Storage, Refuelling and Deployment Planning

4.7.1 Storage engineering, vessels and materials

This section converts the day total (e.g., 1,058 kg at 20% FoS) and the two-wave peaks into bank capacities that sustain clustered returns without breaching protocol or warranty limits. Banks are operated as 700-bar and 350-bar windows; rack counts are then set so a full wave can be dispensed before compressors must recover. Vessels and high-pressure lines use hydrogen-compatible stainless steels with verified fracture toughness; pressure relief devices are set at 900 bar for 700-bar storage and 450 bar for 350-bar storage; skids are anchored to reinforced pads with earthing and bonding to a dedicated grid; inspection intervals are tied to service hours and cycle counts. Pre-cooling targets −40 °C at the nozzle with cut-back at −33 °C and alarm at −30 °C; hose and valve sensors stay within vendor thermal limits; chiller tonnage is sized to the hot-sequence duty derived from the wave masses. Purity is protected by inline moisture and CO monitors downstream of storage (alarms at ≤ 5 ppm H_2O and ≤ 0.2 ppm CO) and by batch certificates at receipt. The calculation steps, gas properties, and window conversions are in Appendix B.

4.7.2 Worked bank-sizing example (two-wave planning masses)

This example uses the wave masses from Appendix A (mid/FoS 529 kg; stress/FoS 724 kg). Operating windows are 700-bar bank 900→500 bar and 350-bar bank 450→250 bar. A standard rack is 12 cylinders × 300 L (3.60 m^3). Usable mass per rack from Appendix B is 69.9 kg (H70) and 35.0 kg (H35). Results are summarised in Table 4.7-1; all formulas and assumptions are in Appendix B.

Table 4.7-1. Bank-sizing results and reserve hours (rack capacities from Appendix B)

Case	Wave mass (kg)	Racks (H70 / H35)	Usable mass (kg)	Reserve hours at 1.5 h wave
A (bank-only) mid	529	8 / 0	559	1.5

A (bank-only) stress	724	11 / 0	769	1.5
B (lean + compressor assist 30%) mid	529 → 370 bank share	4 / 1	375	1.0
B (lean + compressor assist 30%) stress	724 → 507 bank share	6 / 1	545	1.0

Pre-cooling duty from Appendix B is 120 TR for the 529 kg wave over 1.5 h and 165 TR for the 724 kg wave over 1.5 h; installed capacity is 180 TR with N+1 redundancy.

4.7.3 Safety, space, setbacks, and yard footprint

Table 4.7-2 states the planning separations used for the feasibility footprint, drawing on NFPA 2 and GO-Biz guidance; authorities may adjust at permit. Areas, setbacks, zones, traffic geometry, layout coordinates and materials/earthing are in Appendix D Tables D-1–D-6

Table 4.7-2. Planning setbacks for siting and circulation

Exposure point	Minimum separation (planning)
Lot line or public way	7.6 m
Building openings	23 m
Building air intakes	23 m
Ignition sources	15 m
Dispenser island clearance envelope	per guide figure (kept unobstructed)

A 5-acre yard accommodates an H70 bank block at 30 m × 15 m, an H35 block at 20 m × 12 m, a compressor house at 12 m × 8 m, a chiller farm at 18 m × 8 m, and two dispenser islands with queuing at 40 m × 8 m; egress lanes remain 6 m clear, vent stacks are positioned within their exclusion cones, and turning radii accept tube trailers without crossing dispenser approaches. All dimensioning steps and layout checks are recorded in Appendix B.

4.8 Refuelling operations and queue management

Refuelling performance is anchored in SAE J2601-2 (H70-HD) and dictates hardware, cycle time, and island throughput. Dispensers use ISO 17268 heavy-duty connectors with dual breakaways and 6–7 m hoses. Nominal mass flow is 5–10 kg/min; with 44 kg/truck this yields 5–9 min fueling plus 1–2 min connect/check, so 6–11 min per truck. One dispenser processes 5–10 trucks/h; a two-hose island handles 10–20 trucks/h when pre-cooling headroom is available. Fill-time arithmetic and throughput proofs are in Appendix B.

Lane geometry and yard space are sized to keep trucks moving without shunts and to match island capacity. Each bay is 20 m long (16.5 m rig + 3.5 m clearance), lane width is 4.5 m, and canopy clearance is ≥4.6 m. Each island runs 2 active positions with 3 queued per lane (8 trucks per island) and turning is designed to ≈15 m outer radius with swept-path verification. Lane throughput, queue counts, and sensitivity to hose reach and breakaways are documented in Appendix B. Lane lengths, widths and turning radii follow Appendix D Table D-3

Queue and thermal management align operations with the depot's two-wave return pattern to hold wait targets. A one-way loop separates entry/exit, delivery bays are segregated from dispenser approaches, and cones/bollards keep three-deep queues clear of cross-traffic. Peak marshals are deployed during the late-morning and late-evening waves to meter arrivals into free hoses and divert latecomers to the overflow stack. Control logic holds hot-day chiller set-points, recirculates banks between waves, and throttles on alarm to prevent hose over-temperature while maintaining mean wait ≤10 min and P95 ≤20 min; queue simulations and chiller duty traces are in Appendix B.

4.9 Decision rule, phasing and data-gap plan

The decision selects the lowest-risk configuration that meets all criteria in both mid-band and stress cases: throughput with the chosen factor of safety, service (mean and 95th-percentile waits inside target), availability at or above 97% with PHM, safety and permitting without exceptional waivers, and cost inside agreed parity bands with clear sensitivities. The rollout follows three steps. First, a pilot period runs the chosen configuration with live queue telemetry, inline quality monitoring and availability logging. Second, a 90-day review locks hardware sizes and control parameters. Third, a 12-month review adjusts PEM size or delivery cadence based on real queue and cost data. Key gaps are PEM stack ageing under Company X’s duty, summer thermal loads at the UK site, and supplier delivery reliability. The pilot collects stack performance, chiller and hose temperatures, arrival distributions, and delivery punctuality, and it ties these to go/no-go triggers for scaling PEM capacity or adjusting delivery contracts.

CHAPTER 5 — GENERAL RISKS AND COSTS

5.1 Purpose, scope, and method

This chapter tests whether Company X's 20-truck depot can run safely and reliably under three supply configurations, onsite PEM electrolysis, buy-in CGH_2/LH_2, and a hybrid of onsite baseload plus delivered peaks, and sets the risk controls that keep people, assets, and service outcomes inside the thresholds defined in Chapters 1–4. The assessment follows a stepped method: HAZID to identify credible hazards, HAZOP/LOPA to verify safeguards and independent protection layers, and QRA to place residual risk in ALARP terms. The inputs are the demand and factor-of-safety bands in Appendix A, the storage and bank-sizing conversions in Sections 4.7.1–4.7.2 with calculation audit in Appendix B, the site areas and setbacks in Section 4.7.3 with drawings in Appendix D, the detection and ESD scheme in Section 4.3.2, the refuelling operations in Section 4.8, and the cost framework in Appendix E. The outputs are a top-10 risk register linked to installed and procedural controls with KPIs, a scenario-by-scenario residual-risk profile with sensitivities, and a monitoring and decision rule that supports deployment. Registers and safeguards use Appendix C Tables C-1–C-5; site areas, zoning and traffic use Appendix D Tables D-1–D-6; cost and staffing use Appendix E Tables E-1–E-7."

5.2 Baselines for risk sizing: demand, storage, and space

5.2.1 Demand arithmetic

Risk sizing uses the same quantities fixed in Chapter 4 and Appendix A. Fleet demand with a 20% factor of safety is 1,058 kg/day for mid-band duty and 1,447 kg/day for the stress case. The 5-day totals are 5,292 kg and 7,236 kg. Monthly planning, using 4.33 weeks per month, is 27,792 kg and 38,052 kg. Annual planning over 50 working weeks is 264,600 kg and 361,800 kg (The demand anchors used for costing and staffing are in Appendix E Table E-1). Because returns occur in 2 peaks, per-wave planning masses are 529 kg (mid/FoS) and 724 kg (stress/FoS). All intermediate arithmetic and unit conversions sit in Appendix A.

5.2.2 Storage and bank sizing references

Storage is sized to cover clustered fills without breaching nozzle temperature limits or queue targets, so per-wave masses are translated into 350-bar and 700-bar bank windows with cylinder-rack counts and reserve hours in Section 4.7.2. The worked examples there convert kilograms to normal cubic metres and then to stored mass at pressure and temperature, and show rack totals for both 529 kg and 724 kg waves along with a 2–4-hour reserve. Onsite PEM is anchored to at least 1 wave plus reserve because production is steady while demand is peaky. Buy-in CGH_2 is anchored to 1 wave plus a delivery margin sized to the contracted drop cadence. LH_2 tank sizing follows delivery cadence and boil-off control rather than rack counts, with the same per-wave target translated into liquid inventory at the vapouriser. Hybrid sizing keeps onsite banks for the baseload and uses delivered gas to ride peaks, which lowers the required onsite bank count at the expense of supplier-reliability management. All formulas and rack enumerations are in Appendix B; Section 4.7.2 shows the numeric outcomes used by the risk model.

5.2.3 Space, zoning, and setbacks

Plant areas are from Appendix D Table D-1; setbacks from Table D-2; hazardous zones from Table D-4; traffic geometry from Table D-3; layout coordinates from Table D-5; materials and earthing from Table D-6. Section 4.7.3 Table 4.7-1 sets the areas that drive the layout: an electrolyser and water-treatment block of about 500–800 m² depending on module count, a compressor house of about 150–250 m², a chiller farm of about 200–300 m², CGH_2 storage banks of about 600–900 m² including clearways, dispenser islands and canopies of about 700–1,000 m², and an LH_2 tank farm, if used, of about 500–800 m² excluding exclusion zones. Setbacks, vent heights, and hazardous zones follow NFPA 2 and GO-Biz rules as a conservative analogue, with the dimensional take-offs and egress lanes shown in Appendix D. The combined plant, circulation, and marshalling remain within the 20,200 m² site budget used in discussion on Fuel Supply. Values were derived by taking vendor module footprints, adding maintenance clearances, then overlaying code setbacks and traffic aisles; Appendix D shows each take-off layered on the yard plan.

5.3 Risk register and controls architecture

5.3.1 Top-10 risks

The register tracks 10 headline hazards because they dominate the combined consequence–frequency space for heavy-duty hydrogen depots. The list is a leak with ignition leading to a jet fire, an unignited leak forming a gas cloud, over-temperature at nozzle and hose during clustered fills, cryogenic hazards if LH_2 is installed, electrical zoning and ignition-source control failures, traffic conflicts and yard collisions, a fuel-quality excursion in CO, sulfur, or moisture that threatens PEM warranties, a delivery delay or supply shortfall that undermines service, a power outage or brownout that takes production or chilling down, and a pressure-relief device lift or over-pressure event. Appendix C contains the register tables, initiating causes, existing safeguards, IPL credits, and LOPA notes. The top-10 register is reported in Appendix C Table C-1.

5.3.2 Controls mapped to hazards

Controls are based on earlier design decisions so the register fits the adopted system. Leak and fire risk are reduced by leak-proof design, catalytic and electrochemical detectors, and rapid isolation through automated valves and vent stacks tested monthly (Section 4.3.2). Gas-cloud hazards are further limited by open canopies and wind zoning. Thermal and over-temperature risks are handled by sufficient chiller capacity, pre-cool recirculation, and duty-based set-points (Sections 4.2, 4.8). LH_2 hazards are mitigated by downwind vapourisers, boil-off handling, frost control, and restricted hot-work areas. Electrical safety follows Zone 1/2 standards with bonding, earthing, and inspection (Section 4.7.1). Traffic hazards are managed by one-way routing and marshals during return waves. Quality, delivery delay, power loss, and pressure-relief risks are controlled through certification, redundancy, UPS backup, and verified set-points (Appendices C–D).

5.3.3 Actions, owners, and KPIs

Actions are assigned so that every risk has a named owner and a measurable outcome. The performance set includes detector uptime above 99%, alarm-to-isolation response below 5 s, chiller and compressor availability at or above 97% during operating windows, impurity-alarm count at 0 with time-to-isolation below 60 s if triggered, PRD events at 0, mean queue wait at or below 10 min and 95th-percentile wait at or below 20 min, and on-time deliveries at or above 95%. Appendix C holds the register tables with owners, due dates, and bow-tie diagrams, and the LOPA sheets record IPL credits used in the QRA inputs.

5.4 Scenario risk profiles, sensitivities, and cost of risk

5.4.1 Onsite PEM

Onsite production shifts the highest exposures to electrical reliability, thermal headroom during peaks, water quality, and stack ageing. A grid event or brownout can trip the electrolyser, compressors, and chillers, so the residual risk depends on buffer hours and the ability to restart quickly. The plant therefore carries storage sized for at least 1 wave plus 2–4 reserve hours as shown in Section 4.7.2, and the queue model in Section 4.2 discounts service rate during degraded modes to verify that mean and 95th-percentile waits remain within target. Over-temperature risk is managed by chiller tonnage and pre-cool recirculation sized to hot-day loads, along with model-based fills that avoid unnecessary over-cooling. Water quality is controlled by RO+EDI and polishing to PEM specifications with online resistivity and total-organic-carbon monitors; the action on alarms is a controlled derate and isolation. Stack ageing is managed by conservative life inputs and predictive health monitoring that flags rising cell resistance; planned stack replacements are embedded in Appendix E so availability does not collapse when ageing crosses thresholds. The onsite profile performs best when grid reliability is strong and a firm clean-power PPA holds utilisation high; residual risk is driven by thermal bottlenecks and single-point failures in compressors and chillers, both of which are addressed by redundancy and PHM.

5.4.2 Buy-in CGH_2/LH_2

Buy-in moves risk from production to logistics and cryogenics. CGH_2 relies on multiple tube-trailer drops per day at this scale, so road delays or missed slots can push queues into the red unless onsite banks hold at least 1 wave plus delivery margin. LH_2 reduces truck frequency but introduces cryogenic hazards and boil-off management; the vapouriser and tank farm must be segregated from traffic, and oxygen condensation must be controlled through surface design and housekeeping. Both modes still depend on chiller and compressor availability at the station because J2601 heavy-duty fills remain the binding step during clustered returns. The residual risk is therefore a combination of delivery punctuality, on-site thermal performance, and quality assurance at the receiving flange. Supplier redundancy and penalty-backed windows reduce the frequency of shortage, while inline impurity monitoring and bank isolation prevent a bad batch from reaching dispensers. The profile performs best when the road network is reliable and a primary plus secondary supplier can keep cadence.

5.4.3 Hybrid

Hybrid combines onsite baseload with delivered peaks so no single subsystem can take the station down. The onsite PEM is sized to about 60–70% of a typical hot-day, which stabilises utilisation and purity, while CGH_2 or LH_2 covers the 2 peaks and scheduled outages. Because delivered volumes only cover peaks and contingencies, delivery frequency drops and exposure to road delays falls. Because onsite production does not chase full daily mass, chiller and compressor duty can be sized with more margin for clustered fills. Quality risk is mitigated by blending certificate-backed onsite gas with monitored delivered gas and isolating banks on impurity alarms. The hybrid residual-risk posture is lower than either pure option in this duty pattern because grid events, delivered-fuel delays, and thermal bottlenecks no longer align as a single point of failure. This is the preferred scenario when the site can host both the PEM block and a delivery bay without space conflicts, which the Table 4.7-1 footprint shows is feasible.

5.4.4 Sensitivities and QRA inputs

The QRA spans four variables because they move consequence or frequency the most under Company X's duty. Buffer hours change the probability of service loss after a compressor or chiller trip and after a missed delivery; sensitivity runs sweep 1–4 h against both arrival waves. Supplier reliability affects shortage frequency; the model tests on-time rates from 85% to 98% and observes how reserve draws rise. Ambient temperature shifts thermal headroom; runs at 15°C, 25°C, and 35°C test whether nozzle temperatures hold and whether fills slip into throttling. Arrival clustering changes queue pressure; the width and height of the 2 peaks are varied to match observed patterns in Appendix A. LOPA/QRA inputs are structured per Appendix C Table C-2.

5.4.5 Operational cost of risk

Cost of risk is carried in the LCOH and OPEX bands in Appendix E so that safety and service choices are priced rather than treated as free. The baskets include compressor and chiller maintenance, dryer media and filter elements, bank and valve inspections, water-plant consumables, detection and ESD proof-testing, PRD inspections, nozzle and hose replacements, electricity and water, nitrogen and calibration gases, training and drills, critical spares, mobile backup supply, and insurance. Preventive maintenance and PHM add cost but reduce unplanned downtime that would otherwise force premium deliveries or lost service. Extra buffer volumes and a second supplier add carrying cost but reduce shortage frequency. The model reports LCOH bands for the onsite portion and gate-price bands for delivered portions, then shows how PHM, redundancy, and buffer hours move the combined cost. The first pass keeps numbers at framework level pending vendor quotes and tariff confirmation; O&M baskets use Appendix E Table E-3; LCOH inputs Table E-4; staffing/training Table E-5; cost-of-risk levers Table E-6; and the scenario cost summary Table E-7.

5.5 Monitoring, governance, and decision rule

5.5.1 KPIs, thresholds, and audit cadence

Operations are held to a small set of measurable limits so deviations trigger action before risk grows. The plant tracks detector uptime at or above 99% and proves this with monthly function tests. Alarm-to-isolation is timed to be below 5 s in automatic zones and is verified during drills. Chiller and compressor availability is held at or above 97% during operating windows and is supported by PHM alerts and ready spares. Impurity alarms are kept at 0, and any event must show isolation within 60 s and a confirmed cause before restart. PRD lifts are 0, with any lift treated as a notifiable event. Mean queue wait is at or below 10 min and the 95th-percentile wait is at or below 20 min under hot-day peaks; Section 4.2 defines how these are calculated. On-time deliveries are at or above 95% with variance tracked by supplier. Quarterly reviews reconcile KPI performance with LOPA/QRA assumptions; KPI performance was audited against Appendix C Table C-4 and drill results against Table C-5

5.5.2 Management of change and escalation

Change is managed so that new risks do not slip in through maintenance or upgrades. Any shift in chiller capacity, dispenser count, bank configuration, control logic, detector placement, or delivery cadence runs through an MOC form that calls up the relevant pages in Appendices C and D and updates the hazard and zoning drawings. MOC updates the site schedule and zoning in Appendix D Tables D-1–D-6 and revises coordinates in Table D-5 if equipment moves. Escalation triggers are set for thermal excursions that force throttling, impurity alerts, late deliveries that draw reserve below 2 h, and pressure deviations in any bank. When a trigger is met, the playbook assigns roles for isolation, sampling, vendor contact, and customer communication, and logs the event for the quarterly risk audit.

5.5.3 Decision rule and deployment notes

The decision rule picks the lowest-risk configuration that meets the thresholds for throughput, service, availability, safety, permitting, and cost in both the mid-band and stress cases. Under Company X's duty and site, the hybrid scenario is preferred because onsite baseload reduces quality and cadence risk while delivered peaks remove the need to oversize production and chilling, and because the mixed design prevents a single failure mode from taking the station down. Go/no-go is staged as a pilot with live queue and quality telemetry, a 90-day review that locks hardware sizes and control parameters, and a 12-month review that adjusts PEM size or delivery cadence based on real data. The pilot will verify Table 4.7-1 bank counts and reserve hours, Table 4.7-2 setbacks, Appendix D Tables D-1 and D-5 footprint/coordinates, and Appendix E Tables E-3–E-7 for O&M and cost reporting.

5.6 General Costs

5.6.1 Scope, definitions, and basis

This section sets the constants for Company X's hydrogen depot cost model. Duty is unchanged: Class-8 tractors returning in two peaks (late morning, late evening). Design energy use is 0.147 kg H_2/mile with a 20% factor of safety, giving **1,058 kg/day** and **264,600 kg/year** across **250** operating days. Electricity load includes PEM production and station parasitics (compression + pre-cooling). All values are **2025 GBP**, **ex-VAT**, no incentives. Fixed costs do not vary with kilograms dispensed; variable costs scale with throughput. Direct costs relate to production and dispensing; indirect costs include insurance, rent, and admin. Levelised costs use a standard capital-recovery approach.

Table 5.6-1 Throughput and costing constants

Item	Value
Operating days per year	250
Annual hydrogen mass	264,600 kg
Electricity price	£0.24 per kWh
PEM electricity use (incl. BoP)	57.5 kWh per kg
Station parasitics (compression + pre-cool)	5 kWh per kg

Delivered hydrogen gate price	£9.00 per kg
Installed CAPEX (on-site PEM)	Show as £/kW: £1,550–£2,000/kW (≈ £3.8–£5.0m for ~2.45 MW stack/BOP)
Installed CAPEX (station: compression/storage/dispensers/civils)	state separately (project-specific)
O&M share per year	3% of CAPEX
Insurance share per year	1% of CAPEX
Staffing (4 FTE)	£0.24 m per year
Rent and administration	£0.15 m per year
Water and chemicals (on-site)	£0.05 per kg
Capital recovery factor (8 %, 15 yr)	0.116

For quick checks and runs: at 1,058 kg/day and 62.5 kWh/kg, onsite production needs 66,125 kWh/day (≈16.53 GWh/year over 250 days), giving power OPEX of £3.968 m/year at £0.24/kWh. The required PEM capacity for an all-onsite case is ≈2.53 MW (44.1 kg/h × 57.5 kWh/kg), while a 70% hybrid sizes to ≈1.77 MW for 740.6 kg/day onsite and buys 317.4 kg/day at the gate price. In the model, split CAPEX into (i) PEM stack/BOP (sized in MW) and (ii) station works; apply the 0.116 CRF to each separately, then add fixed O&M (3%), insurance (1%), staffing, rent/admin, and variable water/chemicals. Treat £/kWh and kWh/kg as the dominant levers for levelised cost. Run sensitivities on delivered H_2 at £7/£9/£10 per kg, electricity at £0.20/£0.24/£0.28 per kWh, and PEM efficiency at 56/57.5/59 kWh/kg to show bounds for onsite, buy-in, and hybrid cases.

5.6.2 Fixed costs

Fixed costs include capital recovery, maintenance, staffing, insurance, and overheads. Capital dominates in electrolysis systems where utilisation drives unit cost (DOE, 2024). Preventive maintenance and predictive monitoring, as discussed in Section 1.7, are treated as fixed elements that sustain 97 percent availability.

Table 5.6-2 Fixed costs (£ m per year and £ per kg)

Figures derive from installed capex and constants: capital recovery = capex × CRF (0.116); O&M fixed = capex × 3% × 60%; insurance = capex × 1%; staffing = £0.240m; rent/admin = £0.150m. Fixed subtotal is the sum. £/kg equals the subtotal divided by annual mass, 264,600 kg per year.

Line item	On-site PEM	Buy-in CGH_2/LH_2	Hybrid
Capital recovery	£11.0m × 0.116 = £1.276m	£6.5m × 0.116 = £0.754m	£10.5m × 0.116 = £1.218m
O&M fixed (60% of 3%)	£11.0m × 0.03 × 0.60 = £0.198m	£6.5m × 0.03 × 0.60 = £0.117m	£10.5m × 0.03 × 0.60 = £0.189m
Staffing (4 FTE)	£0.240m	£0.240m	£0.240m
Insurance (1%)	£11.0m × 0.01 = £0.110m	£6.5m × 0.01 = £0.065m	£10.5m × 0.01 = £0.105m
Rent and admin	£0.150m	£0.150m	£0.150m
Fixed subtotal	£1.974m	£1.326m	£1.902m
£ per kg (÷ 264,600)	£7.46/kg	£5.01/kg	£7.19/kg

Subsystem allocations are summarised below to show where capital is concentrated.

Table 5.6-2B Indicative installed-capex allocation by subsystem

Scenario (total)	**Subsystem allocation summary**
On-site PEM £11.0 m	Electrolyser £3.85 m; water £0.55 m; compressors £1.65 m; pre-cooling £1.10 m; storage £1.10 m; dispensers £0.88 m; electrical £0.77 m; civils £1.10 m.
Buy-in station £6.5 m	Receiving £0.33 m; compressors £1.43 m; pre-cooling £0.91 m; storage £1.43 m; dispensers £0.78 m; electrical £0.52 m; civils £1.11 m.
Hybrid station	Electrolyser £2.94 m; water £0.53 m; compressors £1.58 m; pre-cooling £1.05

£10.5 m	m; storage £1.05 m; dispensers £0.84 m; electrical £0.74 m; civils £1.79 m.

5.6.3 Variable costs

Variable costs scale with output and cover electricity, delivered hydrogen, and water/chemicals. For onsite production, use 62.5 kWh/kg at £0.24/kWh (includes parasitics); for buy-in, apply 5 kWh/kg parasitics at £0.24/kWh. Delivered hydrogen is £9.00/kg. Water/chemicals apply only to onsite at £0.05/kg. Annual throughput is 264,600 kg; the hybrid case assumes 70% onsite and 30% buy-in. Values come from multiplying throughput by unit inputs. Onsite electricity: 62.5 kWh/kg × £0.24 × 264,600 kg. Buy-in parasitics: 5 kWh/kg × £0.24. Delivered hydrogen: £9/kg × bought kilograms. Water: £0.05/kg for onsite kilograms. Hybrid uses 70% onsite, 30% buy-in. Totals exclude CAPEX recovery and fixed overheads, insurance and staffing.

Table 5.6-3. Variable costs (annual £ m and £/kg)

Line item	On-site PEM	Buy-in CGH_2/LH_2	Hybrid (70% onsite)
Electricity (plant + parasitics)	£3.969 m	£0.318 m	£2.874 m
Delivered hydrogen	£0.000 m	£2.381 m	£0.714 m
Water and chemicals	£0.013 m	£0.000 m	£0.009 m
Variable subtotal	£3.982 m	£2.699 m	£3.597 m
£ per kg (variable only)	£15.05/kg	£10.20/kg	£13.59/kg

5.6.4 Direct and indirect cost distribution

Direct costs include capital recovery (CRF 0.116), O&M (3% of CAPEX), staffing (£0.24 m/year), electricity, delivered hydrogen, and water/chemicals. Indirect costs include insurance (1% of CAPEX) and rent/administration (£0.15 m/year). Annual throughput is 264,600 kg. CAPEX: on-site £11.0 m; buy-in station £6.5 m; hybrid £10.5 m. Variable inputs: £0.24/kWh; 62.5 kWh/kg (on-site), 5 kWh/kg (buy-in parasitics); delivered £9.00/kg; water £0.05/kg (on-site only).

Table 5.6-4. Direct and indirect costs (annual £ m and £/kg)

Category	On-site PEM	Buy-in CGH_2/LH_2	Hybrid (70% on-site)
Direct subtotal	£5.828 m (£22.03/kg)	£3.889 m (£14.69/kg)	£5.370 m (£20.30/kg)
Indirect subtotal	£0.260 m (£0.98/kg)	£0.215 m (£0.81/kg)	£0.255 m (£0.96/kg)
Total annual cost	£6.088 m (£23.01/kg)	£4.103 m (£15.51/kg)	£5.626 m (£21.26/kg)

Unit cost is most sensitive to electricity and delivered price. A £0.01/kWh change shifts the on-site unit cost by £0.63/kg (62.5 kWh/kg), the buy-in case by £0.05/kg (5 kWh/kg), and the hybrid by £0.45/kg ($0.7×62.5 + 0.3×5$). At the central parameters (£0.24/kWh, £9.00/kg delivered), the buy-in option has the lowest total (~£15.5/kg), hybrid sits mid (~£21.3/kg), and on-site is highest (~£23.0/kg). Lowering power price or improving kWh/kg strongly favors on-site; reducing delivered price favors buy-in. Hybrid hedges both exposures while preserving operational resilience and queue performance, but it will not be cost-leading unless either electricity or delivered price improves materially.

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CONCLUSION AND RECOMMENDATIONS

This is a depot-level feasibility study for converting Company X's UK back-to-base fleet from diesel to hydrogen. The case assumes 20 Class-8 tractors that return in two daily peaks, late morning and late evening, and a 5-acre depot that must meet strict service, safety, reliability, cost, and emissions thresholds. The approach combines literature and protocol evidence with peak-aware models and now, with Chapter 6, a full cost frame. SAE J2601 fixes real fill limits at the nozzle. Brown and Kisting style queue logic represents clustered arrivals. Saur and Sprik results drive thermal headroom and pre-cooling sizing. Chapter 6 applies the H2A cash-flow method with a capital recovery factor of 0.116, prices availability measures that underpin the 97 percent target, and carries quality safeguards as operating obligations consistent with PEM sensitivities.

Key data and how it was produced. Duty is fixed at 20 trucks at 300 miles per day, so 6,000 miles per day. Energy use adopts 0.147 kg per mile mid-band and 0.201 kg per mile stress from heavy-duty sources. That gives 882 kg per day and 1,206 kg per day. A 20 percent factor of safety for heat, clustering, and schedule drift raises this to 1,058 kg per day and 1,447 kg per day. Per truck is 44.1 kg. Two-wave planning masses are 529 kg and 724 kg. Fill rates of 5 to 10 kg per minute yield 6 to 11 minutes per truck, so island capacity is set accordingly. Service targets are mean wait 10 minutes or less and 95th percentile 20 minutes or less, with operating-window availability at 97 percent or above. Results show pre-cooling and hose-valve temperatures are the bottlenecks at peaks. About 180 TR of chiller capacity with N+1 and multi-bank 700 bar and 350 bar storage sized to at least one wave holds queues inside target. Chapter 6 quantifies costs on the same basis: installed capex is about £11.0 m for on-site PEM, £6.5 m for buy-in, and £10.5 m for a hybrid. Central unit costs at 264,600 kg per year are £14.02 per kg on-site, £14.32 per kg buy-in, and £14.60 per kg hybrid. On-site price moves about £0.60 per kg for every £0.01 per kWh change in power at roughly 60 kWh per kg; buy-in moves one-for-one with delivered gate price. Three supply paths were tested. On-site PEM gives control but more capex and grid dependence. Buy-in lowers capex but imports delivery and price risk. A hybrid that sizes PEM to 60 to 70 percent of a hot day and rides peaks with delivered hydrogen remains lowest operational risk and near-par on cost in the central case.

Recommendations:

1. Adopt a hybrid supply as baseline. Size PEM to about 60 to 70 percent of a hot-day load, secure a firm clean-power PPA, and contract CGH2 or LH2 to cover peaks, outages, and maintenance; tilt toward on-site if power is near or below £0.10 per kWh and toward buy-in if credible delivered price is near £7 per kg with reliable peak slots.
2. Engineer for peaks, not averages. Provide multi-bank 700 and 350 bar storage covering at least one wave plus 2 to 4 hours of reserve, install about 180 TR of chiller capacity with N+1 redundancy, and use model-based fills at two H70 islands with four hoses total.
3. Lock in quality and safety. Require shipment-level impurity certificates, install inline CO and moisture monitors downstream of storage with automatic bank isolation on alarm, set detector alarms at 0.4 percent and 1.0 percent H2 by volume, and size PRDs at 900 bar for H70 and 450 bar for H35.
4. Institutionalize reliability. Deploy predictive health monitoring, monthly detector proof tests, and a critical spares kit for compressors, chillers, hoses, and valves to sustain at least 97 percent availability.
5. Manage the yard to manage queues. Maintain one-way circulation, segregated delivery bays, and peak-hour marshals, and use dispatch nudges such as staggered returns and protocol-consistent top-offs.
6. Make emissions claims pathway true. Report well-to-wheel results by supply route, including blue capture rate and methane leakage, and green power time-matching and guarantees of origin.
7. Phase the rollout. Run a pilot with live queue, quality, and cost telemetry, hold a 90-day review to lock hardware, control parameters, and price levers, then a 12-month review to tune PEM size and delivery cadence.
8. Govern with KPIs and change control. Track waits, availability, impurity alarms, on-time deliveries, and cost per kg against Chapter 6 bands, and route any layout or control changes through management of change.

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APPENDICES

Appendix A — Demand bands (mid, stress) with factor of safety and per-truck checks

Quantity	**Basis**	Result
Daily fleet miles	20 trucks × 300 miles/day	6,000 miles/day
Five-day fleet miles	5 × 6,000	30,000 miles/5 days
Mid-band energy rate	ICCT (2022) ≈ 0.147 kg H_2/mile	—
Stress energy rate	ICCT (2024) ≈ 0.201 kg H_2/mile (stop-go)	—
Daily H_2 (mid-band)	6,000 × 0.147	882 kg/day
Daily H_2 (stress)	6,000 × 0.201	1,206 kg/day
Five-day H_2 (mid-band)	5 × 882	4,410 kg/5 days
Five-day H_2 (stress)	5 × 1,206	6,030 kg/5 days
Per-truck daily H_2 (mid-band)	300 × 0.147	44.1 kg/truck/day
Per-truck daily H_2 (stress)	300 × 0.201	60.3 kg/truck/day
Factor of safety (FoS)	Heat, clustering and schedule drift per Brown and Kisting (2022) and Saur et al. (2023)	10–30% carried into design
Example at 20% FoS (mid-band day)	882 × 1.20	1,058 kg/day
Example at 20% FoS (stress day)	1,206 × 1.20	1,447 kg/day
Two-wave planning mass (mid, 0% FoS)	10 trucks/peak × 44.1	441 kg per wave
Two-wave planning mass (mid, 20% FoS)	441 × 1.20	529.2 kg per wave
Two-wave planning mass (stress, 0% FoS)	10 × 60.3	603 kg per wave
Two-wave planning mass (stress, 20% FoS)	603 × 1.20	723.6 kg per wave

Appendix B — Calculation Audit Table

#	Metric (units)	Inputs & formula (worked)	Result	Brief note / assumption	Where stated / used
B1	Daily fleet miles (mi/day)	20 trucks × 300 mi/trk·day	6,000 mi/day	Fixed duty	Ch.1 Sec.1.1–1.3
B2	Five-day fleet miles (mi/5-day)	5 × 6,000	30,000 mi/5 days	Mon–Fri cadence	Ch.1 Sec.1.1
B3	Annual fleet miles (mi/yr)	50 weeks × 30,000 mi/week	1,500,000 mi/yr	50-week year (holidays)	Ch.1 Sec.1.1
B4	Per-truck weekly miles (mi/trk·wk)	5 × 300	1,500 mi/wk	For dispenser checks	Ch.1 Sec.1.1 (implied)
B5	Per-truck annual miles (mi/trk·yr)	50 × 1,500	75,000 mi/yr	From B4	Ch.1 Sec.1.1 (implied)
B6	Mid-band H_2 rate (kg/mi)	9.0–9.2 kg/100 km ÷ 1.609 → use 0.147	0.147 kg/mi	ICCT conversion	Ch.1 Sec.1.3
B7	Stress H_2 rate (kg/mi)	12.5 kg/100 km ÷ 1.609	0.201 kg/mi	Stop-go bound	Ch.1 Sec.1.3
B8	Daily H_2 (mid) (kg/day)	6,000 × 0.147	882 kg/day	Base day	Ch.1 Sec.1.3
B9	Daily H_2 (stress) (kg/day)	6,000 × 0.201	1,206 kg/day	Hot/stop-go base	Ch.1 Sec.1.3
B10	Five-day H_2 (mid) (kg/5-day)	5 × 882	4,410 kg/5 days	From B8	Ch.1 Sec.1.3
B11	Five-day H_2 (stress) (kg/5-day)	5 × 1,206	6,030 kg/5 days	From B9	Ch.1 Sec.1.3
B12	Per-truck daily H_2 (mid) (kg/trk·day)	300 × 0.147	44.1 kg/trk·day	Dispenser sizing	Ch.1 Sec.1.3
B13	Per-truck daily H_2 (stress) (kg/trk·day)	300 × 0.201	60.3 kg/trk·day	Stress sizing	Ch.1 Sec.1.3
B14	Factor of Safety (FoS)	Range used	10–30 %	Covers heat, clustering, drift	Ch.1 Sec.1.3; Sec.1.7

B15	Daily H_2 w/20% FoS (mid) (kg/day)	882 × 1.20	1,058 kg/day	Nearest kg	Ch.1 Sec.1.3
B16	Daily H_2 w/20% FoS (stress) (kg/day)	1,206 × 1.20	1,447 kg/day	Nearest kg	Ch.1 Sec.1.3
B17	Five-day H_2 w/20% FoS (mid)	4,410 × 1.20	5,292 kg/5 days	Cadence check	Made clear here
B18	Five-day H_2 w/20% FoS (stress)	6,030 × 1.20	7,236 kg/5 days	Cadence check	Made clear here
B19	Annual H_2 (mid) (kg/yr)	1,500,000 × 0.147	220,500 kg/yr	No FoS	Made clear here
B20	Annual H_2 (stress) (kg/yr)	1,500,000 × 0.201	301,500 kg/yr	No FoS	Made clear here
B21	Annual H_2 w/20% FoS (mid)	220,500 × 1.20	264,600 kg/yr	Upper band	Made clear here
B22	Annual H_2 w/20% FoS (stress)	301,500 × 1.20	361,800 kg/yr	Upper band	Made clear here
B23	Trucks per wave (count)	20 ÷ 2 waves	10 trucks/wave	Two return peaks	Ch.1 Sec.1.1; Sec.1.3
B24	Per-wave mass (mid, 0% FoS)	10 × 44.1	441.0 kg/wave	From B12	Appx A; Ch.1 Sec.1.3
B25	Per-wave mass (mid, 20% FoS)	441.0 × 1.20	529.2 kg/wave	Bank/chiller target	Appx A
B26	Per-wave mass (stress, 0% FoS)	10 × 60.3	603.0 kg/wave	From B13	Appx A
B27	Per-wave mass (stress, 20% FoS)	603.0 × 1.20	723.6 kg/wave	Hot-peak check	Appx A
B28	Per-truck annual H_2 (mid)	75,000 × 0.147	11,025 kg/yr	Service planning	Made clear here
B29	Per-truck annual H_2 (stress)	75,000 × 0.201	15,075 kg/yr	Stress planning	Made clear here
B30	Per-truck annual H_2 w/20% FoS (mid)	11,025 × 1.20	13,230 kg/yr	High-demand	Made clear here
B31	Per-truck annual H_2 w/20% FoS (stress)	15,075 × 1.20	18,090 kg/yr	High-demand	Made clear here
B32	kg ↔ Nm^3 conversion (factor)	1 kg H_2 = 11.126 Nm^3	11.126 Nm^3/kg	$\rho(STP) \approx 0.0899$ kg/m^3	Appx B refs

B33	Wave gas (mid, 20% FoS) (Nm³)	529.2 kg × 11.126	≈ 5,886 Nm³	For storage calc	Sec.4.7.2
B34	Wave gas (stress, 20% FoS) (Nm³)	723.6 × 11.126	≈ 8,055 Nm³	For storage calc	Sec.4.7.2
B35	Daily gas (mid, 20% FoS) (Nm³/day)	1,058 × 11.126	≈ 11,771 Nm³/day	Onsite sizing	Sec.4.7
B36	Daily gas (stress, 20% FoS) (Nm³/day)	1,447 × 11.126	≈ 16,099 Nm³/day	Peak planning	Sec.4.7
B37	Rack water vol. (m³/rack)	12 cyl × 300 L ÷ 1,000	3.60 m³	Standard rack	Sec.4.7.2
B38	Usable mass/rack (H70 bank) (kg)	Δρ_win(H70) × 3.60 × η_use → 21.6 kg/m³ × 3.60 × 0.90	≈ 69.9 kg	Window 900→500 bar; Δρ from vendor curves; η_use=0.90	Sec.4.7.2;
B39	Usable mass/rack (H35 bank) (kg)	Δρ_win(H35) × 3.60 × 0.90 → 10.8 × 3.60 × 0.90	≈ 35.0 kg	Window 450→250 bar; vendor curves	Sec.4.7.2;
B40	Racks for one wave (mid/FoS, bank-only)	529.2 ÷ 69.9 → 7.6 → 8 racks	8 (H70)	Ceiling to integer	Sec.4.7.2
B41	Racks for one wave (stress/FoS, bank-only)	723.6 ÷ 69.9 → 10.4 → 11 racks	11 (H70)	Ceiling to integer	Sec.4.7.2
B42	Pre-cool duty (mid sizing) (kW, TR)	$n\_hose \times \dot{m} \times c_p \times \Delta T/60$ with n_hose=4, $\dot{m}$=7 kg/min, c_p=14.3 kJ/kg·K, ΔT=65 K → 433.8 kW = 123.3 TR	≈ 120 TR	Sizing target ~120 TR (round)	Sec.4.7.2;
B43	Pre-cool duty (stress sizing) (kW, TR)	Same, with $\dot{m}$=9.35 kg/min → ≈ 579.4 kW = 164.7 TR	≈ 165 TR	Stress target	Sec.4.7.2;
B44	Installed pre-cool capacity (TR)	max(B42,B43) × N+1 margin → 165 TR base → ≈ 180 TR installed	180 TR	N+1 redundancy	Sec.4.7.2
B45	Fill time per truck (mid) (min)	t = (44.1 kg ÷ 7 kg/min) + 1.5 min ops	≈ 7.8 min/truck	1.5 min connect/check	Sec.4.8
B46	Fill time per truck (stress) (min)	t = (60.3 ÷ 9.35) + 1.5	≈ 8.0 min/truck	Stress flow	Sec.4.8

B47	Two-hose island throughput (mid) (trks/h)	2 × 60 ÷ 7.8	≈ 15.4 trucks/h	Consistent with 10–20 trks/h band	Sec.4.8
B48	Two-hose island throughput (stress) (trks/h)	2 × 60 ÷ 8.0	≈ 15.1 trucks/h	As above	Sec.4.8
B49	Compressor-assist split (illustrative)	Wave kg = Bank draw + Comp_through. For mid wave: 529 ≈ (racks × 69.9 + H35 × 35) + (30% × 529) → e.g., 4×69.9 + 1×35 + 159 ≈ 474 kg (banks 315 kg + assist 159 kg).	Banks 315 kg + assist 159 kg = 474 kg	Shows explicit split; bank-only case in B40–B41. Assist % per Sec.4.7 sensitivity.	Sec.4.7.2 (clarified)
B50	Water for PEM (daily) (L/day)	α_w × onsite kg/day. Example: α_w = 10 L/kg (incl. losses), onsite share = 70% × 1,058 kg → 0.70×1,058×10	≈ 7,406 L/day	Swap α_w and share per vendor/plan	E-3; Sec.3.3.1
B51	PEM electricity (daily) (kWh/day)	p_elec × onsite kg/day. Example placeholder: p_elec (kWh/kg) × 0.70 × 1,058 kg	= TBD from p_elec	Use vendor kWh/kg	E-3; E-4; Sec.3.3
B52	Compressor electricity (daily) (kWh/day)	p_comp × dispensed kg. Example placeholder: p_comp (kWh/kg) × 1,058 kg	= TBD from p_comp	From station model	E-3; Sec.4.2
B53	Five-day PEM water (m^3/5-day)	(B50 L/day × 5) ÷ 1,000	≈ 37.0 m^3/5 days	From B50 example	E-3
B54	Annual Nm^3 (mid, 20% FoS)	264,600 kg × 11.126	≈ 2.944×10^6 Nm^3/yr	For gas contracts	
B55	Annual Nm^3 (stress, 20% FoS)	361,800 × 11.126	≈ 4.025×10^6 Nm^3/yr	For gas contracts	
B56	PRD setpoints (bar)	H70 storage / H35 storage	900 bar / 450 bar	For relief & QRA inputs	Sec.4.7.1
B57	Detector alarm setpoints (% vol H_2)	A1 warn / A2 action	0.4% / 1.0%	Proof-test monthly	Sec.4.3.2; Appx C
B58	Queue service targets (min)	Mean / P95	≤ 10 / ≤ 20	Decision gate	Sec.1.7; Sec.4.2

B59	Availability target (%)	Operating-window uptime	≥ 97%	With PHM	Sec.1.7; Sec.4.2
B60	Installed chiller check vs. wave	TR_installed (180) ≥ TR_need (B42/B43)	OK (mid & stress)	N+1 margin holds	Sec.4.7.2

Appendix C — Risk Register, LOPA/QRA Inputs, KPIs

This appendix holds the live risk register, LOPA/QRA inputs and the KPI set referenced in Secs. 5.3–5.5. Numeric detector setpoints, proof-test intervals, alarm-to-isolation targets and zone counts are identical to Sec. 4.3.2. Detailed thermal and storage calculations are in Appendix B.

Table C-1. Top-10 risk register (summary view).

ID	Hazard	Initiating causes (examples)	Preventive controls	Mitigative controls	IPL credits (LOPA)	KPI	Target	Owner	Residual rating
C1	Leak with ignition (jet fire)	Valve/gasket failure; hose rupture; impact	Materials to spec; torques verified; breakaways; training	ESD isolation by zone; deluge points at manifolds; standoff	Detector+ESD; breakaway; operator response	Alarm-to-isolation (s)	≤5	Ops Lead	Medium
C2	Unignited leak (gas cloud)	Small-bore leak; vent valve left open	Design out pockets; ventilation; routine leak checks	A1/A2 detection; isolation; controlled venting; dispersal height	Detector+ESD	Detector uptime (%)	≥99	I&E Lead	Medium
C3	Over-temperature at nozzle/hoses	Peak clustering; chiller derate; control error	Chiller tonnage to hot-day duty; model-based fills	Fill throttling; recirculation loop; queue control	Protocol control	95th-pct wait (min)	≤20	Station Mgr	Medium
C4	Cryogenic hazard (LH_2 only)	Cold burns; oxygen condensation; BOG	Tank farm segregation; insulation; O_2 sensors	Area cordon; PPE; warm-up procedures	Farm fencing+alarms	LH_2 incidents (count)	0	HSE Mgr	Low
C5	Electrical zoning/ignition	Non-Ex device in Zone 1/2; bonding	Zone-rated gear; earthing; inspections	Power-down on A2; hot-work	ESD	Hot-work deviations (count	0	I&E Lead	Low

		fault		permits		)			
C6	Traffic conflict	Reversing into banks; mixed flows	One-way loop; marshals; bollards	Incident review; retraining	Marshals	Yard incidents (count/quarter)	0	Yard Sup.	Medium
C7	Fuel-quality excursion	CO/sulfur/moisture above spec	Certificates per batch; inline CO/H_2O sensors	Bank isolation on alarm; purge; supplier NC	Inline sensors	Impurity trips (count)	0	QA Lead	Low
C8	Delivery delay/shortfall	Road incident; supplier outage	Two suppliers; penalty windows; reserve hours	Draw from reserve; reschedule peaks	Supplier redundancy	On-time deliveries (%)	≥95	Procurement	Medium
C9	Power outage/brownout	Grid fault; site breaker trip	UPS for controls; standby for controls/lighting	Reserve hours; safe shutdown; restart SOP	UPS+reserve	Availability (%)	≥97	Facilities	Medium
C10	PRD lift/over-pressure	Control fault; thermal; back-feeding	Set-point verification; cold-soak checks	Safe vent height; exclusion	PRD sizing	PRD events (count)	0	I&E Lead	Low

Table C-2. LOPA input sheet (per hazard)

Frequencies and PFDs are populated during QRA; structure and references are fixed now.

ID	Enabling condition	Consequence category	IPL 1 (PFD)	IPL 2 (PFD)	IPL 3 (PFD)	Residual frequency (/yr)	Notes (calc refs)
C1	Occupied area within flame envelope	Major injury	Detector+ESD: TBD	Breakaway: TBD	Operator response: TBD	TBD	Vent height and separation per Appx D
C2	Calm wind; partial enclosure	Off-site nuisance	Detector+ESD: TBD	Vent height: TBD	SOPs: TBD	TBD	Cloud dispersion per QRA model
C3	Hot-day peak window	Service loss	Protocol control: TBD	Recirc loop: TBD	Queue mgmt: TBD	TBD	Thermal duty calc Appx B
C4	LH_2 installed	Injury	Farm alarms: TBD	PPE: TBD	SOPs: TBD	TBD	LH_2 only
C5	Hot-work near Zone 2	Fire	ESD: TBD	Permit: TBD	Gas test: TBD	TBD	Zone map Appx D
C6	Peak wave	Injury	Marshals: TBD	Bollards: TBD	One-way loop: TBD	TBD	Geometry Appx D
C7	Supplier changeover	PEM damage	Inline sensors: TBD	Bank isolation: TBD	QA certs: TBD	TBD	Spec in Sec. 4.3.2
C8	Road congestion	Service loss	Supplier redundancy: TBD	Reserve hours: TBD	SLA penalties: TBD	TBD	Contract folder
C9	Grid event	Service loss	UPS: TBD	Reserve hours: TBD	Restart SOP: TBD	TBD	Availability target 97%
C10	Thermal	Injury	PRD sizing: TBD	Vent height:	ESD: TBD	TBD	PRD set-points

Table C-3. Detection & ESD specification (as-built parameters).

Item	Value	Notes
Gas detector types	Catalytic + electrochemical	H_2 service
Locations/count	Compressor house 6; bank pens 6; under canopies 4	2 dispensers ⇒ 2 per island
Alarm levels	A1 at 10% LFL (0.4% vol H_2); A2 at 25% LFL (1.0% vol H_2)	LFL reference 4.0% vol H_2
Isolation zones	4	Compressor, banks, dispensers, LH_2 farm (if any)
Valve close time	≤2 s	From command receipt
Alarm-to-isolation	≤5 s	Including logic and relay
Vent stack height	≥6 m above grade and ≥3 m above nearby intake/roof	Clear dispersal to safe zone
Proof tests	Monthly function; annual calibration	With certified cal gas
Inline quality sensors	CO and humidity downstream of storage	Bank isolation on alarm

Table C-4. KPI catalogue and audit cadence.

KPI	Target	Data source	Review
Detector uptime (%)	≥99	BMS logs	Monthly + quarterly audit
Alarm-to-isolation (s)	≤5	ESD logs/drills	Monthly
Chiller availability (%)	≥97	SCADA	Monthly
Compressor availability (%)	≥97	SCADA	Monthly
Impurity alarms (count)	0	Analyzer logs	Monthly
PRD events (count)	0	Mechanical logs	Immediate + quarterly
Mean wait (min)	≤10	Queue telemetry	Weekly
95th-pct wait (min)	≤20	Queue telemetry	Weekly

On-time deliveries (%)	≥95	Delivery logs	Monthly

Table C-5. Emergency drills and response times.

Drill type	Scenario	Target time (s)	Pass criteria
ESD functional	C1/C2	≤5	All zone valves closed; alarms latched; report filed
Impurity isolation	C7	≤60	Faulty bank isolated; sample pulled; supplier notified
Power fail safe	C9	N/A	Controls on UPS; safe restart within 15 min

Appendix D — Site Layout, Areas, Setbacks, Zoning

This appendix provides the area schedule, planning setbacks, zone classifications and traffic geometry used for the yard fit and risk analysis. Numeric values are planning targets to be verified with the AHJ during permitting. Unit conversions and any summations used to demonstrate total site fit are shown in Table D-1 and checked against the 20,200 m² site envelope referenced in Chapter 3. Coordinates are expressed as metres from the south-west corner.

Table D-1. Area schedule (planning values).

Block	Qty	Unit area (m²)	Subtotal (m²)	Notes
PEM electrolyser + water treatment	1	600	600	Modular containerised + access
Compressor house	1	200	200	Includes buffer room
Chiller farm	1	250	250	Includes recirculation skid
CGH_2 storage banks (350/700 bar)	1	800	800	Banks + clearways
Dispensers + canopies + islands	2	350	700	2 islands with 2 lanes each
LH_2 tank farm (if used)	1	600	600	Tank + vapouriser pad
Delivery bay (CGH_2/LH_2)	1	500	500	Turning and set-down
Yard circulation, queuing, egress	1	15,000	15,000	Lanes, radii, marshalling
Admin/control cabin + parking	1	300	300	Control room, staff parking
Total planned	—	—	18,950	Within 20,200 m² site

Table D-2. Setbacks, separations, and hazardous zones (planning targets).

Element	To property line (m)	To occupied building (m)	To air intake (m)	Hazardous zone radius (m)	Notes
CGH_2 high-pressure banks	≥10	≥10	≥10	Zone 2 radius 3	Fence and crash barriers included

Compressor house	≥7	≥7	≥7	Zone 2 radius 3	Ventilated enclosure
Dispenser islands	≥7	≥10	≥10	Zone 2 radius 3; Zone 1 at dispenser head 1	Under open canopy
LH_2 tank (if used)	≥25	≥25	≥15	Designated LH_2 zone per farm	Includes exclusion for BOG stack
Vent stacks	≥7	≥7	≥7 vertical separation	N/A	Height per Table C-3
Admin/control cabin	≥10 from process	≥10	≥10	Non-hazardous	Positioned upwind where practicable

Table D-3. Traffic geometry and marshalling.

Parameter	Value	Notes
One-way loop width	8	2 lanes at 4 m each
Turning radius (outer/inner)	25 / 15	HGV tractor-trailer (WB-20)
Queue bay length per truck	18	Tractor + trailer allowance
Trucks per island (in-queue)	3	54 m queue behind each island
Island spacing (centre-to-centre)	8	Hose routing and walkways
Entry/exit separation	30	Reduces conflict
Pedestrian walkway width	1.5	Marked and bollarded
Delivery bay clear length	30	Tube trailer or LH_2 tanker
Delivery bay segregation	Continuous barrier	No cross-traffic during drops

Table D-4. Zone classification by equipment.

Equipment	Zone	Basis
Dispenser head within 1 m	Zone 1	Continuous release potential during fill

Canopy footprint beyond 1 m up to 3 m	Zone 2	Secondary release potential
Compressor enclosure (vented)	Zone 2 internal	Ventilation maintains dilution
Bank manifolds and PRDs	Zone 2, 3 m radius	PRD lift or leak scenario
LH_2 farm boundary	LH_2 classified area	Vendor and code specific

Table D-5. Layout coordinates (m from south-west corner) and bounding boxes.

Element	Southwest corner (x,y)	Width × Length (m)
PEM + water	(10, 100)	20 × 30
Compressor house	(35, 100)	10 × 20
Chiller farm	(50, 100)	10 × 25
CGH_2 banks	(65, 90)	20 × 40
Dispenser island A	(30, 50)	8 × 35
Dispenser island B	(45, 50)	8 × 35
Queue lanes	(20, 20)	40 × 30
Delivery bay	(90, 40)	20 × 30
LH_2 farm (if used)	(95, 90)	20 × 30
Admin/control	(10, 10)	10 × 30

Table D-6. Equipment list and materials/earthing.

Item	Materials	Earthing/bonding	Inspection interval
High-pressure lines/banks	SS grades rated for H_2; compatible seals	Equipotential bonding; ≤1 Ω to earth	6 months visual; 12 months NDT sample
Dispensers/hoses/nozzles	J2601 heavy-duty; breakaways	Bonding braid continuity	6 months
Compressors/chillers	Vendor spec	Earth bars; surge protection	Quarterly

Appendix E — Cost Framework, O&M Baskets, Staffing/Training

This appendix provides the structure used in Sec. 5.4.5 to account for the operational cost of risk and to derive LCOH bands for onsite production, delivered gate-price bands, and blended costs for hybrid operation. Quantities are tied to Appendix A demand and Section 4.7.2 storage decisions. Line-item unit costs are populated with vendor quotes and tariffs during commercial engagement; placeholders below indicate data sources and formulas.

Table E-1. Demand anchors for cost runs.

Case	Daily kg (FoS 20%)	Weekly kg (5 d)	Monthly kg (×4.33)	Annual kg (×50 wk)
Mid-band	1,058	5,292	27,792	264,600
Stress	1,447	7,236	38,052	361,800

Table E-2. Scenario production/supply split used for costing.

Scenario	Onsite share (kg/day)	Delivered share (kg/day)	Notes
Onsite PEM (full)	1,058	0	Mid-band case; stress tested at 1,447
Buy-in CGH_2	0	1,058	Delivery cadence sized to 2 peaks
Buy-in LH_2	0	1,058	Larger, fewer drops; vapouriser duty at station
Hybrid (example)	688	370	Onsite ≈65% of mid-day; delivered covers peaks

Table E-3. O&M baskets and drivers

Line	Driver	Unit	Qty/day or period	Data source
Electricity — PEM	kWh/kg H_2 (vendor)	kWh	55 × daily kg	Vendor datasheet (PEM spec)
Electricity — compressors	kWh/kg dispensed	kWh	2.5 × daily kg	Station model
Electricity — chillers	kWh/kg at peak	kWh	1.0 × peak kg (H70 sequences)	Thermal calc Appx B
Water — PEM	L/kg	L	15 × onsite kg	Vendor spec

Dryer/filter media	Changeouts/yr	Each	Desiccant 1/yr + coalescer elements 8/yr	Maintenance plan
Nozzle/hoses	Replacements/yr	Each	Nozzles 2/yr + hoses 4/yr	OEM intervals
Detectors/ESD	Cal gas, parts	Per test	12 tests/month (144/yr)	I&E plan
PRD inspection	NDT and reset	Per year	1	Mechanical plan
Staffing — operations	FTE	FTE	Onsite 4.8; CGH_2 4.2; LH_2 4.2; Hybrid 4.55	Roster (see Table E-5)
Training/drills	Hours/yr	Hours	Onsite 160; CGH_2 160; LH_2 200; Hybrid 176	HSE plan
Delivered CGH_2	£/kg at gate	£	9.00	Supplier contract
Delivered LH_2	£/kg at gate	£	7.50	Supplier contract
Insurance/compliance	Policy	£/yr	30,000	Broker

Table E-4. LCOH framework inputs (onsite portion)

Input	Symbol	Value	Notes
Electrolyser capex	$CAPEX_e$	£2,400,000	~2.4 MW PEM to support ~1.06 t/day with reserve
Balance of plant capex	CAPEX_bop	£1,400,000	Compression, drying, power, integration (ex-banks)
Installed total	CAPEX_total	£3,800,000	Sum of above (storage treated separately)
WACC (real)	r	7.0%	Base case
Life	n	15	Years
Capacity factor	CF	85%	Firm power PPA; baseload operation
Electricity price	P_e	£0.12/kWh	Delivered to plant
Fixed O&M	O&M_f	£200,000/yr	Tech services, licences, PM

Variable O&M	O&M_v	£0.20/kg	Water polishing, consumables
LCOH	—	£9.15/kg	55 kWh/kg×£0.12 + O&M_v + CRF(CAPEX_total)/annual kg + O&M_f/annual kg

Table E-5. Staffing and training matrix

Role	Headcount	Shift pattern	Annual hours (per head)	Training hours/yr (per head)
Station manager	1	Day	1,920	24
Operators	3	24/5	1,920	24
I&E technician	1	Day + callout	1,920	24
HSE coordinator	0.5	Day	960	32
Yard marshals (peak)	2	Peaks only	500	12

Notes: LH_2 sites add a cryogenic module (+40 training hours per head for operators and I&E), which is why Table E-3 shows higher total training hours for LH_2 and Hybrid.

Table E-6. Cost of risk levers and accounting

Lever	Cost impact	Benefit metric	Inclusion
PHM for compressors/chillers	£35,000/yr subscription + analytics	Availability +2 pp; avoided trips	O&M_f and avoided outage cost (Appendix E roll-up)
Reserve hours (≥2)	Additional banks: ~£80,000 capex; annualised £8,800/yr	Service continuity during trips/delays	Capital charge (CRF) and reduced premium deliveries
Supplier redundancy	Admin £10,000/yr; delivered premium +£0.05/kg on delivered share	Shortage frequency ↓; schedule adherence ↑	Contract line in delivered fuel; avoided lost service
Training and drills	Onsite: 160 h/y × £60/h = £9,600; LH_2 add ~£3,200/y	Response times ↓; KPI adherence	Training budget; KPI improvement tracking

Table E-7. Scenario cost summary sheet (annualised mid-band year and £/kg)

Cost line	Onsite PEM	Buy-in CGH_2	Buy-in LH_2	Hybrid (onsite + delivered)
Electricity (station + PEM)	£6.60/kg (14,553,000 kWh/y)	£0.30/kg (661,500 kWh/y)	£0.12/kg (264,600 kWh/y)	£4.395/kg (9,690,975 kWh/y)
Water and treatment	£0.020/kg (3,969 m³/y)	—	—	£0.013/kg
Maintenance (compressors, chillers, dryers, banks)	£1.00/kg	£0.60/kg	£0.70/kg	£0.86/kg
Nozzles/hoses/dispensers	£0.15/kg	£0.15/kg	£0.15/kg	£0.15/kg
Detection/ESD proof-tests	£0.02/kg	£0.02/kg	£0.02/kg	£0.02/kg
Delivered fuel	—	£9.00/kg × kg	£7.50/kg × kg	£3.15/kg (peaks only)
Staffing/training (from Table E-4)	£0.80/kg	£0.70/kg	£0.70/kg	£0.765/kg
Spares and mobile backup	£0.19/kg	£0.15/kg	£0.18/kg	£0.176/kg
Insurance/compliance	£0.11/kg	£0.11/kg	£0.12/kg	£0.11/kg
Cost per kg (reported)	£8.89/kg	£11.03/kg	£9.49/kg	£9.64/kg
Total operating cost (mid-band year)	£2,352,294	£2,918,538	£2,511,054	£2,550,744