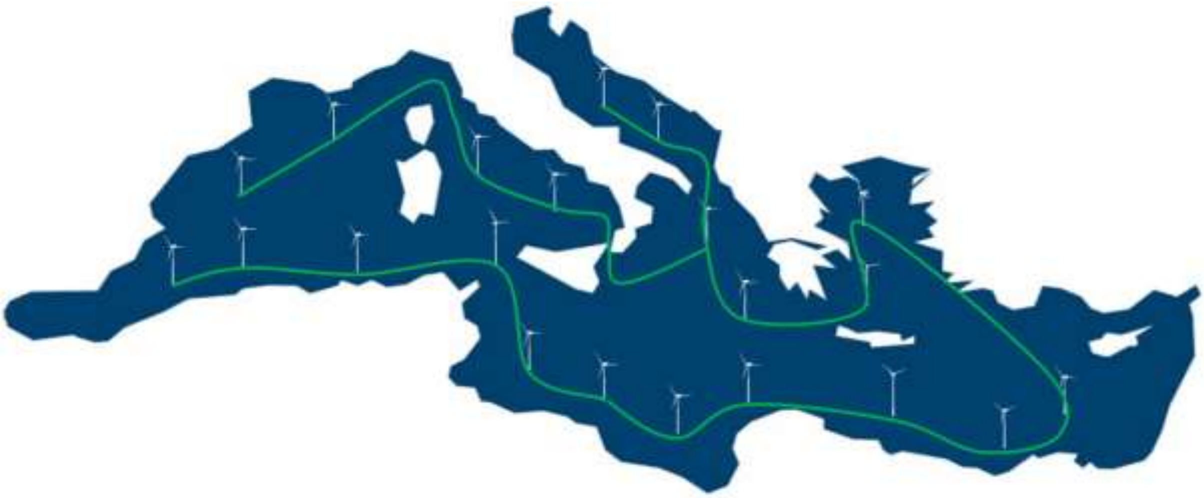

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Methodology for a comparative assessment of energy transfer solutions

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Abbrevations

Most frequent abbreviations only, 1 page max.

Abbreviation	Full Form
AHP	Annual Hydrogen Production
ANP	Annual Ammonia Production
CAPEX	Capital Expenditure
DECEX	Decommissioning Expenditure
HVDC	High-Voltage Direct Current
HVAC	High-Voltage Alternating Current
LCOA	Levelized Cost of Ammonia
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
LCOT	Levelized Cost of Transport
MW_{el}	Megawatt (electrical, electrolyzer input)
NH_3	Ammonia
NPV	Net Present Value
OPEX	Operational Expenditure
OWF	Offshore Wind Farm
PEM	Proton Exchange Membrane (electrolyzer)
PtX	Power-to-X
TSO	Transmission System Operator

Executive summary

This study presents a comprehensive techno-economic simulation to compare five offshore wind farm energy transfer scenarios: (1) Centralized offshore electrolysis, (2) Centralized onshore electrolysis, (3) Decentralized offshore electrolysis, (4) Offshore hybrid (wind farm with both grid export and offshore hydrogen production), and (5) Onshore hybrid. These configurations encompass dedicated hydrogen production (offshore vs. onshore), ammonia production, transportation through pipeline and shipping for both Hydrogen and ammonia, and hybrid setups combining electrical grid connection and power-to-hydrogen conversion. The scope aligns with WP3 objectives to develop methods for the comparative assessment of energy transfer solutions for offshore wind farms. The methodology follows following steps:

1. **Wind Power Simulation**

An hourly wind power profile for one year was generated using the wind resource datasets collected in WP1. These data, processed and validated in earlier stages, were used to produce Weibull-distributed wind speeds representative of offshore Mediterranean conditions.

2. **Hydrogen and Ammonia Production Modeling**

Hydrogen output is calculated using an electrolyzer efficiency curve. A Proton Exchange Membrane (PEM) electrolyzer model is used, incorporating operational constraints (minimum 10% of wind farm capacity to avoid inefficiencies). Losses due to wake effects, electrical conversion, and transmission are considered for both offshore and onshore scenarios.

A detailed Haber–Bosch synthesis loop model was integrated into the system model. The model simulates the integration of the ammonia synthesis loop (Haber–Bosch process) to evaluate the conversion of H_2 to NH_3.

3. **Transportation Options**

Delivery of energy carriers was evaluated via pipelines and shipping:

Evaluation of Levelized Cost of Hydrogen (LCOH) at production and Levelized Cost of Transport (LCOT) for delivery via pipelines versus shipping, including liquefaction or ammonia conversion for long-distance export was conducted. Key losses (wind farm wake losses, electrical conversion losses, transmission/pipeline losses, boil-off in shipping, etc.) and operational constraints (e.g. minimum electrolyzer load 5% of capacity) are incorporated at each stage to ensure realistic performance.

4. **Techno-Economic Analysis**

The levelized cost results enable direct comparisons of delivering energy as electricity vs. as hydrogen-based fuels. Pipelines are generally the lowest-cost transport for moderate distances, outperforming shipping up to regional ranges (under 500km). However, for international export distances, converting hydrogen to ammonia (NH_3) for shipment can achieve lower delivered cost (owing to NH_3's higher energy density and existing transport infrastructure) e.g. large-scale NH_3 shipping can approach \$1/kg-H_2 (equivalent) for very long distances, significantly cheaper than liquid hydrogen transport. Ammonia's advantages include mature handling infrastructure and higher carrier capacity (NH_3 tankers carry 4 times more hydrogen by energy than LH_2 ships), though reconversion (cracking NH_3 back to H_2) incurs efficiency losses that can be accounted for in the delivered cost.

5. **Comparison**

Results identify how each scenario's economics vary with site conditions. Centralized onshore electrolysis (all wind power brought ashore via cable, H_2 produced on land) tends to yield the lowest LCOH in locations with strong wind resources and relatively short transmission distances to shore. Centralized offshore electrolysis (H_2 produced at a single offshore platform with pipeline transport) avoids high-capacity electrical cables and becomes more competitive as distance to shore grows, literature indicates a break-even around 100–150 km where HVDC transmission overtakes HVAC in cost, and beyond which offshore H_2 pipelines can become more economical for very large projects.

Decentralized offshore electrolysis (electrolyzers distributed at each turbine) eliminates a massive central platform and can reduce inter-array power losses, but involves many smaller units (duplicating some balance-of-plant costs), which can raise LCOH in some cases. Hybrid configurations provide valuable operational flexibility: a hybrid project can capture multiple revenue streams. Our model confirms that keeping a grid connection (hybrid) adds resilience to market uncertainties; it doesn't rely entirely on one commodity and can adapt to price signals, by exporting power to the grid during high electricity price periods and producing H_2 during low-price periods

In conclusion, no single energy transfer pathway is universally "best", each has merits under certain conditions. The methodology developed under WP3.3 quantifies these trade-offs as a function of distance, scale, and cost parameters, ensuring that at any given site the optimal solution can be identified. For near-shore projects with existing grid infrastructure, onshore electrification with hydrogen production at the coast is often most viable; in remote deepwater sites, offshore hydrogen (pipeline to shore or ammonia export) may minimize total costs. Hybrid solutions frequently improve economics by combining the strengths of both approaches and thus represent a robust strategy in the face of future price and technological uncertainties.

1. INTRODUCTION

Offshore wind energy is a rapidly growing renewable resource and is poised for enormous growth as nations seek to meet climate targets. The European Union, for example, targets around 450 GW of offshore wind capacity by 2050 [1]. Wind farms located far offshore can thus generate large amounts of clean electricity, with winds at sea typically higher and more stable than onshore. However, the intermittency of wind output can challenge grid balancing and utilization. Additionally, transmitting electricity from far-offshore wind farms via undersea cables is expensive and incurs losses over distance [2]. Beyond a certain distance or scale, the cost and losses of purely electrical transmission become prohibitive. This motivates exploring alternative energy carriers for transmission. In particular, converting electricity to hydrogen (via electrolysis) for pipeline transport is attracting interest, as hydrogen pipelines have negligible energy loss (< 0.1%) even over long distances. Green hydrogen, produced by electrolyzing water using renewable electricity, also offers a way to store excess energy and decarbonize hard-to-electrify sectors [3]. Also, coupling offshore wind with electrolyzers can create a hybrid system that both exports power to the onshore grid and produces hydrogen when advantageous.

Determining the most cost-effective energy transfer solution is a critical planning step for large-scale offshore wind projects. Within the SPOWIND project, in particular, Task 3.3 focuses on developing a methodology to compare these solutions, from conventional AC/DC grid connections to novel power-to-hydrogen strategies, as well as hybrid combinations of both, using consistent techno-economic metrics.

Previous tasks in WP3 laid the groundwork for this analysis. Activity 3.1 studied offshore wind power transmission strategies (e.g. export cable configurations) and provided cost estimation methods for grid connection. Activity 3.2 explored power-to-X solutions (power-to-hydrogen and ammonia along with their transportation) as alternatives to direct grid connection. It introduced feasibility metrics like the Levelised Cost of Hydrogen (LCOH) and Levelized Cost of Transport (LCOT). Building on those, Activity 3.3 integrates the insights into a unified comparative framework. The objective is to identify the optimal energy transfer solution for a given wind farm based on a techno-economic assessment of full project life-cycle costs, leveraging data from WP1 (site resource and constraints repositories) and the modeling approaches from WP2 and earlier WP3 deliverables. Importantly, hybrid solutions (combining electrical and hydrogen pathways) are included to determine if and when they outperform single-mode solutions.

1.1 Methodology Overview

The comparative assessment uses a consistent evaluation framework for all scenarios. The life-cycle cost breakdown and economic parameters defined in the project's techno-economic assessment framework (Deliverable 2.3.1) are adopted to ensure compatibility across analyses. This means all configurations are assessed in terms of capital expenditures (CAPEX), operational expenditures (OPEX), and decommissioning costs (DECEX) over the project lifetime, with results reported as levelized unit costs (€/MWh or €/kg). For electrical delivery, the Levelized Cost of Energy (LCOE) is used, whereas for hydrogen, the Levelized Cost of Hydrogen (LCOH) metric is applied, and LCOA for Ammonia. These metrics are calculated as the total discounted costs divided by total energy output (electricity or hydrogen) over the project life. The analysis also defines a Levelized Cost of Transport (LCOT) to capture the additional cost per unit of energy to deliver the produced hydrogen to end-use points (whether via pipeline or shipping), and revenue calculation for sizing the electrolyzer in the hybrid scenarios. By using these uniform metrics, the study can directly compare scenarios on economic viability.

1.2 Objectives and Structure

This report aims to develop and demonstrate a methodology for comparative assessment of offshore wind energy transfer solutions. The goal is to determine the viable scenario for energy transfer (electrical, hydrogen and its derivatives (ammonia), and hybrid). Key objectives include:

- **Methodology Development for Energy Transfer Pathways:** Formulate a step-by-step assessment method, including techno-economic modelling of offshore wind farm, hydrogen production modeling, Ammonia synthesis modelling, and (levelized cost analysis) for different scenarios. And compare the energy transfer solutions (e.g., hydrogen, ammonia, hybrid) for offshore wind farms in the Mediterranean.
- **Techno-Economic Evaluation:** Calculate metrics like Levelized Cost of Energy (LCOE) for electricity and Levelized Cost of Hydrogen (LCOH) and LCOA for Ammonia in each scenario, and assess sensitivity to factors such as distance to shore, and scale (MW) to identify viability and trade-offs.
- **Integrate Results into the WebGIS Tool:** Implement the developed assessment methods into the WebGIS platform to provide policymakers, TSOs, and industry stakeholders with a decision-support framework for selecting optimal energy transfer solutions.

2. Energy Transfer Solutions: Grid, Power-t-X, and Hybrid Approaches

Offshore wind farms traditionally export power via undersea electric cables to onshore grids (the "all electricity" route). In emerging concepts, wind-generated electricity can also be converted into hydrogen (H_2) or other fuels (e.g. ammonia) on-site, which are then transported to shore (the "all hydrogen" route). This power-to-X (PtX) approach effectively shifts the energy delivery from electrons to molecules, potentially avoiding expensive high-capacity electrical lines and offering new market pathways for the energy. In between these extremes lies the hybrid approach, wherein an offshore wind farm is both grid-connected and equipped for hydrogen production. A hybrid system can dynamically allocate power between electrical export and on-site H_2 production depending on operational strategy or market prices. The energy transfer solutions are defined below:

All-Electric Transmission (Grid Connection)

In this conventional mode, each turbine's output is collected via inter-array cables to an offshore substation, stepped up in voltage, and transmitted to shore via export cable. Two main technologies are used: HVAC (high-voltage AC) for shorter distances (typically <100 km) and HVDC (high-voltage DC) for longer distances (100–200 km or more) where AC losses and reactive compensation become impractical. The cost of grid connection rises with distance and power capacity.

Power-to-Hydrogen (PtX) Offshore

In a power-to-hydrogen solution, the wind farm's electrical output is fed into electrolyzer systems that split water into hydrogen and oxygen. Alternatively, hydrogen can also be converted to ammonia due to its relative advantages for energy density, storage, and transport. The hydrogen/ammonia can then be transported to shore via subsea pipeline or stored and shipped via tankers (after compression or liquefaction). Hydrogen transport can be advantageous for very large projects or distant sites as studies indicate that beyond a certain distance threshold, shipping energy as hydrogen becomes more economical than HVDC transmission [4].

This approach essentially replaces the high-voltage cable with a pipeline (or tanker route) and moves the energy in chemical form. It can be advantageous if electrical grid expansion is prohibitively expensive or if there is a strategic demand for green hydrogen as a product.

Key trade-offs include: Eliminating export cables and onshore grid connection can save on transmission CAPEX, but it introduces new capital components, notably the electrolyzers, their offshore platforms or housing, additional compression and treatment systems, ammonia synthesis units, and the transport pipeline or loading facilities.

Hybrid Systems

A hybrid offshore wind–hydrogen system combines both of the above pathways. In a typical hybrid configuration, the wind farm maintains a grid connection (perhaps of reduced capacity) and has an electrolyzer installation (offshore or onshore) to produce hydrogen [5], which then may be converted to ammonia. Power can be flexibly split: when electricity prices are high or the grid is available, more power is sent to the grid; when prices are low or grid capacity is constrained, more power is diverted to hydrogen production. Hybrid systems aim to maximize revenues and asset utilization, essentially arbitrage between two markets (electricity and hydrogen). They also offer redundancy: if one pathway is unavailable (e.g. grid downtime or low hydrogen demand), the other can take more load, improving overall capacity usage. From a cost perspective, hybrids require investment in both cable and pipeline (or transport) infrastructure, so avoiding under-utilization of either is crucial for economic viability. The model must allocate costs and benefits between the two outputs. Indeed, a study in Denmark found that a hybrid mode (producing hydrogen mainly during low-price hours and selling power during high-price hours) had greater economic return than either option alone [6].

In summary, the spectrum of energy transfer solutions ranges from pure grid export to pure hydrogen/ammonia export (P-to-X), with hybrids in between. The following section defines the five specific scenarios evaluated in this study, which represent practical realizations of these approaches. Each scenario description includes its layout, key components, and distinct considerations in the modeling.

2.1 System Layouts Evaluated (Five Scenarios)

To systematically compare options, five representative system layouts for a floating offshore wind project have been defined. These scenarios are derived from combinations of electrolyzer placement (offshore vs. onshore), distribution (centralized vs. decentralized), and the presence of a grid connection. They encompass the main configurations discussed in Section 2. Figure 1 illustrates these concepts (a–e), and detailed descriptions are given below:

Scenario 1 – Centralized Onshore Electrolysis

Wind turbines generate electricity that is transmitted to shore via undersea cable (HVAC or HVDC depending on distance). Once on land, electricity is diverted to an electrolyzer for onshore hydrogen production. Onshore Centralized means a single large hydrogen production plant is sited at the onshore grid connection point (e.g. near the landing substation). The electrolyzer and associated hydrogen facilities (compression, storage, etc.) benefit from onshore environment for easier maintenance, no offshore platform needed, but the system incurs the full cost of transmitting power to shore. This scenario essentially represents a traditional grid-connected wind farm plus an onshore power-to-hydrogen facility. The hydrogen produced could be injected into a gas pipeline network, sent to industrial users, or further converted (e.g. to ammonia) at the coastal site. The assumption for Scenario 1 is that all wind energy is ultimately used for H_2 (electricity is simply the transmission medium to get to the onshore electrolyzer). Losses considered: transmission losses (cable), converter losses (if HVDC), and electrolyzer efficiency loss.

Scenario 2 – Centralized Offshore Electrolysis

In this layout, hydrogen is produced directly offshore at a central platform within the wind farm. The wind farm's inter-array network delivers power to a dedicated offshore electrolyzer plant (central H_2 platform) instead of exporting electricity to shore. Hydrogen gas is then transported to land via a subsea pipeline. Centralized Offshore means all electrolyzer capacity is consolidated in one installation (potentially composed of multiple modules, but co-located on a platform or anchored structure). This approach leverages efficient bulk hydrogen transport: pipelines generally have high throughput capacity and, beyond a certain distance, can be more cost-effective than cables for moving energy. The configuration eliminates the need for high-capacity export cables entirely. Key components include: an offshore H_2 production platform (which may be a retrofitted oil & gas platform, a new-build floating barge, or a fixed island if shallow enough), housing electrolyzers, transformers/rectifiers, desalination units (for water supply), and compressors; and a pipeline to shore sized for the hydrogen flow.

Losses: there is a pipeline pressure loss and recompression cost (modeled via booster compressors if distance is long), and a small leakage or boil-off risk is generally negligible for pipelines. One advantage is that by producing offshore, grid connection upgrades onshore are not needed, which can be a major factor in regions with weak grid capacity. This scenario is particularly attractive for very large wind projects or clusters of projects, where a single pipeline can aggregate production.

Scenario 3 – Decentralized Offshore Electrolysis

This is a variant of offshore hydrogen production where electrolyzers are distributed across the wind farm, rather than centralized on one platform. In the decentralized approach, each (or a group of a few) wind turbine has its own electrolyzer unit, typically installed on the turbine platform or an attached auxiliary structure. Hydrogen is generated at or near each turbine and then collected via a network of small-diameter inter-array pipelines which connect the turbines. These H_2 gathering lines feed into a common trunk line (manifold) that transports the combined hydrogen flow to shore via a main pipeline. Effectively, this mirrors the electrical collection system but for hydrogen: the wind farm becomes a network of “hydrogen-producing turbines” linked by pipelines instead of cables. The decentralized scheme eliminates the need for a massive centralized H_2 platform, which can be an advantage in deep waters (avoiding one very large floating structure). Instead, each turbine’s foundation or floater is adapted to support the added electrolyzer and equipment. The electrolyzer units at individual turbines are smaller (dividing total capacity by N turbines), which could lead to some economy-of-scale loss; however, modular electrolyzers may scale fairly linearly, and the parallel operation provides redundancy (one unit offline only knocks out one turbine’s H_2 output). Losses in this scenario include minimal electrical transmission loss (only short cable runs if any, from turbine generator to its electrolyzer) and some manifold piping losses, but those are small due to stepwise collection.

Scenario 4 – Offshore Hybrid (Centralized)

This hybrid scenario assumes the wind farm is equipped with an offshore H_2 electrolyzer (centralized) and retains a grid export cable, but importantly, the grid connection in this case is used only to export electricity, not to import it for H_2 production. In other words, the offshore electrolyzer is powered exclusively by the wind farm (no drawing power from the onshore grid), and any wind power not consumed by the electrolyzer is sent to the onshore grid for sale. In this concept, the energy from the OWF is only subject to wake losses and a small amount of electrical losses in the site network and the AC–DC converter (if HVDC export is used). The presence of the cable introduces an AC–DC conversion step for the portion of power that goes to shore, but we assume the electrolyzer is fed from the AC collection system directly. In this scenario, there is a central offshore electrolyzer platform and an HVDC/HVAC export system.

We consider a base case where the electrolyzer is sized to use a certain fraction of the wind farm capacity (for example, 90% and 80% of peak power), so that during high wind periods excess power goes via cable. The cable is sized for the maximum simultaneous export expected. In a fully optimized scenario, the electrolyzer might be slightly undersized relative to the farm to allow some spillover to the grid at peak times, which avoids oversizing the electrolyzer that would be underutilized. Conversely, during low wind, the electrolyzer might operate at part load or even idle, and most power (if there is demand) could go to the grid. The economic advantage is two revenue streams: hydrogen sales and electricity sales. By design, this hybrid can capture high electricity prices by curtailing H_2 production in those moments, and vice versa. The $LCOH_2$ in a hybrid is computed by allocating a portion of wind farm cost to hydrogen production, and we also calculate an LCOE for the electricity portion, but since one influences the other, a straightforward LCOH comparison must be accompanied by an understanding of revenue balancing.

Scenario 5 – Onshore Hybrid:

This scenario is similar to Scenario 1 (onshore electrolysis) but with the change that not all power has to go to hydrogen, the wind farm can also feed the grid directly. Practically, this means the wind farm is grid-connected via HVDC/HVAC and delivers power to an onshore substation; at that point, some of the power is routed to an onshore electrolyzer (central plant), and the rest can be sold as electricity. Onshore Hybrid avoids offshore H_2 equipment entirely as the electrolyzer is on land, but like Scenario 4, it involves dual use of the energy. One could also convert the hydrogen to ammonia onshore if targeting export markets; indeed, Scenario 5 could be coupled with an onshore ammonia plant at the landing point, allowing the hybrid project to export ammonia via port when international demand justifies it (though ammonia conversion adds costs, it might piggyback on existing port facilities). For our core analysis, we treat Scenario 5 as having the same physical components as Scenario 1 plus the option to sell power. Losses include cable transmission loss and any converter loss, as well as electrolyzer efficiency loss for the portion used for H_2. Because the electrolyzer is onshore, no dedicated offshore platform is needed, and maintenance is easier, this tends to reduce the OPEX compared to offshore electrolysis.

From a flexibility standpoint, this onshore hybrid is very powerful: the operator can choose at any given time to either sell all power, produce hydrogen, or split, maximizing revenue. The analysis in this report, however, focuses on levelized costs and thus treats each scenario in a steady-state allocation sense (not simulate real-time market operations).

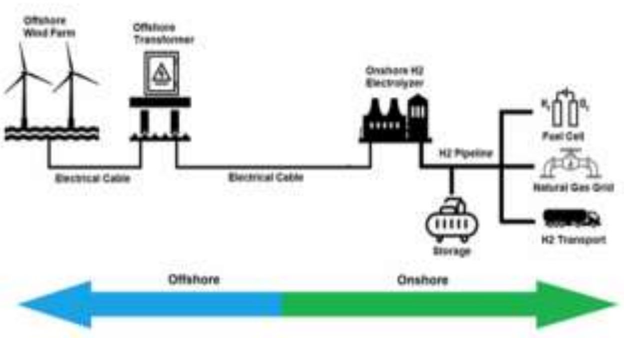

Figure 1 (a). Centralized Onshore Scenario

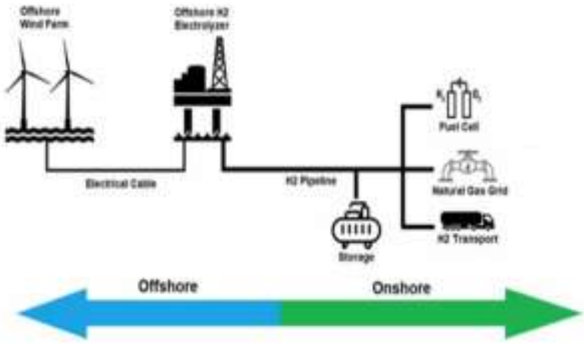

Figure 1 (b). Centralized Offshore Scenario

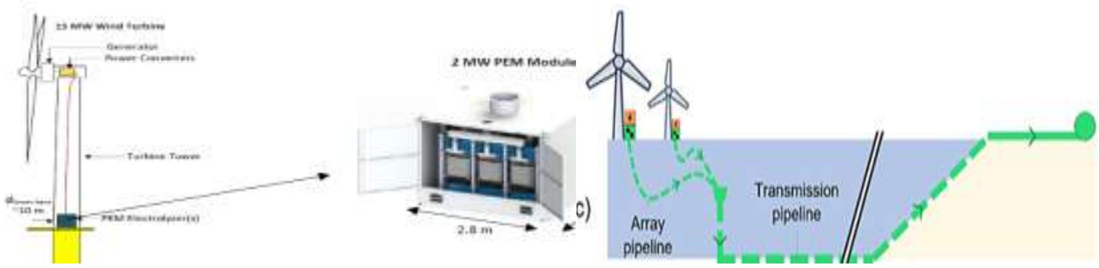

Figure 1 (c). Decentralized Offshore Scenario

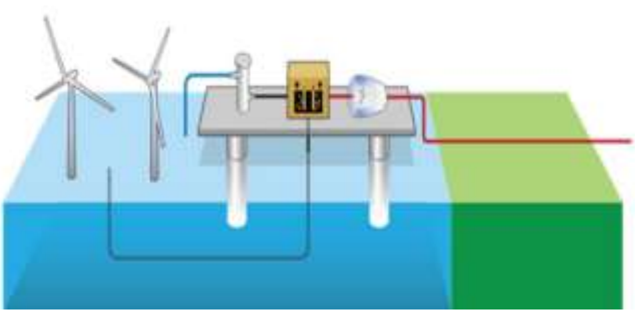

Figure 1 (d). Hybrid Offshore Centralized Scenario

Figure 1 (e). Hybrid Onshore Centralized Scenario

Figure 1. (a-e) Illustration of the five scenarios considered for techno-economic analysis in this study

2.2 Literature Benchmarks and Hybrid Scenario Insights

Calado et al. [7] performed a detailed analysis of offshore vs. onshore electrolysis for a 500 MW wind farm. They similarly found that offshore hydrogen production is technically feasible and can avoid the high installation cost of long electrical cables, but that an onshore electrolyzer gives more operational flexibility in terms of grid integration.

Another study looked at a hybrid strategy (dynamic mode) and found the hybrid yielded greater economic interest than either pure sale or pure hydrogen. Most hydrogen was produced when electricity prices were lowest, and power was sold to the grid when the prices were high, maximizing the revenue [8]. Our methodology can emulate that logic by using time-of-day pricing, the result indeed shows higher project NPV for the hybrid dispatch.

Peng Hou et al. [6] examined two scenarios for an offshore wind farm: (1) all energy to H_2 and then re-converted to electricity via fuel cell at peak times, and (2) flexible direct sale or electrolysis with grid energy purchases at low price periods. They found the first scenario (round-trip back to electricity) was not economic, the round-trip losses were too high but the second flexible scenario achieved payback in a reasonable time for certain hydrogen prices. This implies that using hydrogen as a storage medium to reconvert to power is generally inefficient (due to 60% electrolyzer * 50% fuel cell = 30% round-trip efficiency), so a better use is to supply hydrogen for external end-uses (mobility, industry) where it displaces expensive fossil hydrogen, and use direct grid power for electricity markets. The implication for hybrid solutions is that they should focus on complementarity: provide hydrogen for fuel markets and electricity for power markets, rather than converting back and forth just to arbitrage electricity.

Another relevant study by Loisel et al. [9] investigated multiple applications for an offshore wind farm's output (power, hydrogen for transport, hydrogen for grid support via fuel cells). They concluded that focusing on power-to-gas (hydrogen) was the most economically viable approach, given a hydrogen price of about €4.2/kg. At that price, the hydrogen pathway yielded better returns than storing hydrogen to generate electricity later. This aligns with the assumption of this study that if hydrogen can be sold into industrial or transport markets at a few euros per kg, it likely beats using that hydrogen just to produce peak electricity (unless peak power prices are extraordinarily high). In essence, hydrogen has more value as a fuel than as an inefficient battery for power in most cases. Our economic model, when run with reasonable hydrogen and electricity prices, confirms that: selling hydrogen at €5/kg can be more profitable than selling electricity at €50/MWh except during the highest price hours.

From a technical performance viewpoint, our analysis and literature highlight that an offshore electrolyzer must handle variable loads and possibly ramp down to low power during lull periods. PEM electrolyzers have good part-load capability (down to 5–10% as used in this methodology). Onshore electrolyzers have easier maintenance access and can be built larger, but they require the HVDC link which introduces inflexibility if a fault occurs (i.e. if the cable fails, the wind farm might have to shut down since there's no alternate path, whereas an offshore H_2 system could potentially keep producing hydrogen during a cable outage). This touches on reliability as in practice, a combination might even enhance reliability; a wind farm with both cable and pipeline could still operate if one system goes down, as long as the other can take some load [10].

In terms of energy delivery capacity, hydrogen pipelines can scale up to huge capacities (GW-scale energy flow) more easily than electrical cables. A single pipeline can carry the energy equivalent of many GW if the hydrogen is pressurized. For example, the European Hydrogen Backbone initiative suggests repurposed natural gas pipelines could transport 100 TWh/year of energy (several GW continuous) over long distances [11]. This suggests that for massive offshore energy hubs (tens of GW), chemical carriers like hydrogen or ammonia might be the only feasible way to export all that energy. Indeed, proposals for energy islands in the North Sea envision producing hydrogen on-site to complement electrical interconnectors. We included in our methodology the possibility of incorporating such hybrid hubs.

Finally, the comparative evaluation must note the role of future cost trajectories. The economics of these solutions are moving targets: electrolyzer costs are projected to fall (potentially halving by 2030 with gigawatt-scale manufacturing), offshore wind costs continue to decline, and carbon prices or incentives could boost hydrogen's market value. The methodology developed in this report can easily accommodate updated inputs to re-evaluate in the future. For instance, if electrolyzer efficiency rises to 70% and cost drops 50%, Concept 1 becomes markedly more favorable. If HVDC technology improves or if there is already a grid backbone offshore, Concept 2 could remain competitive even at longer distances. The hybrid approach is inherently robust to uncertainties since it does not "bet" entirely on one commodity; it can adapt to price signals. This flexibility has a real option value not fully captured by LCOH alone, something project developers consider qualitatively as well.

In conclusion, the analysis shows that each energy transfer solution has merits under certain conditions. The methodology developed here allows quantifying those conditions (distance, cost, price scenarios) and thus supports strategic decisions. The next section examines the safety, environmental, and regulatory aspects, which also critically influence the choice and implementation of these solutions.

3. Methodology

All scenarios are evaluated with a unified modeling framework comprising energy production simulation, conversion processes, and cost analysis. The methodology draws heavily from the techno-economic assessment methods established in earlier project deliverables

(Deliverable 2.3.1 and Deliverable 3.2) to maintain consistency in assumptions and calculation methods.

The core steps are: **(a)** Offshore wind power generation modeling; **(b)** Hydrogen production modeling via electrolysis and Ammonia production; **(c)** two main transportation routes for hydrogen and ammonia (for offshore electrolysis scenarios, pipeline and shipping); and **(d)** Techno-economic evaluation (cost modeling and LCOE/LCOH/LCOA calculations for each concept, including hybrid operational modes). The approach combines physical modeling (for energy yields and losses) with economic modeling (for costs and revenues), as summarized below Key outputs include the optimal electrolyzer size, the trade-off between annual hydrogen production (in tons) and electricity exports (in MWh), and revenue breakdowns.

Offshore Wind Power Simulation:

The wind inputs used in this deliverable are taken from the WP1 Metocean repository (open datasets consolidated under Activity 1.1), which organises wind and wave parameters and documents data sources and post-processing (see D.1.1.1 and D.1.1.2).

In D3.3, we use the hub-height wind speed time series/statistics provided by WP1 as inputs to the energy-production and LCOE calculations. The conversion from wind to energy follows the productivity methodology defined in WP2 (Activity 2.2) and is applied consistently across the assessed energy-transfer options. Any assumptions on turbine model, hub height, air-density correction, and availability follow the WP2 method. Energy production is computed using the WP2 productivity methodology, which applies OEM/lookup power-curve tables to the WP1 metocean time series; no additional synthetic power-curve modelling is introduced here. For each case, hourly farm output is obtained by scaling a normalized production profile pt $\in [0,1]$ from WP2 with the chosen capacity and net loss factors. Annual energy follows $E = \sum_t P_t$ and capacity factor $CF = E / (W_{inst} \cdot 8760)$. Any assumptions on cut-in/cut-out/rated behavior, air-density correction, wake and availability are those embedded in the WP2 method and data, ensuring consistency across scenarios.

Hydrogen and Ammonia Production Modeling:

The core of scenarios involving hydrogen is the electrolyzer system model. A PEM electrolyzer was chosen for its flexibility and fast response. Key parameters assumed:

Efficiency: 52–55 kWh of electricity per kg H_2 produced (65–60% efficiency, lower heating value basis) [12]. This implies 1 MWh can produce 19–20 kg of H_2. However, efficiency may drop slightly at partial loads and frequent ramping can cause degradation [13], but PEM technology has proven capable of dynamic operation with minimal efficiency loss. The resulting hydrogen LHV energy efficiency is 60–64%, consistent with industry benchmarks (PEM systems typically consume 50–55 kWh/kg). It is noteworthy that in this report, hydrogen output is calculated using an electrolyzer efficiency curve rather than a single value. Any waste heat or oxygen from electrolysis is also not monetized.

Ramp Rate: PEM electrolyzers can ramp from 0 to 100% in seconds, allowing near-instantaneous switching between grid export and hydrogen production modes. The electrolyzer can track wind output and market signals each hour without limitations. This is reasonable since PEM units have high part-load flexibility and fast response, unlike some conventional generators [14]. It is noted that very rapid fluctuations (sub-second) could slightly reduce stack life [13], but the hourly model used in this report doesn't capture those transients.

Sizing and Modularity: The electrolyzer is assumed to be a modular PEM system that can be sized anywhere from 0 up to the wind farm capacity. For each scenario, the electrolyzer capacity (MW_{el}) is a key design parameter. In centralized cases, we choose a capacity roughly equal to the wind farm capacity for pure-H_2 cases, and somewhat lower for hybrids (to reflect that not all power will go to H_2 all the time). In decentralized case (3), the total electrolyzer capacity is essentially the sum at all turbines, which equates to the wind farm capacity as well (assuming each turbine has electrolyzer sized to its rated power). For Hybrid scenarios, the electrolyzer consumes whatever portion of the wind power is available up to E; any wind power above E goes to the grid. No grid electricity is purchased to run the electrolyzer (only wind is used), ensuring the hydrogen is purely green. The electrolyzer can ramp virtually instantaneously compared to hourly timesteps (ramp rate 10%–80% per second, effectively allowing full range adjustment in <10 s), so it smoothly follows wind output fluctuations. A minimum turndown of 0% (idle) to 10% is assumed, meaning during very low wind periods the electrolyzer can simply sit idle or at a small sustaining load. The electrolyzer design life is 20–30 years; the economic analysis in this report uses 25 years to match the wind farm life.

For scenarios where ammonia production is considered, we also model a basic ammonia synthesis module. The Haber–Bosch process consumes hydrogen (and nitrogen from an air separation unit) to produce NH_3. We incorporate a conversion efficiency (around 80% of hydrogen's energy ends up in NH_3, the rest lost as heat) and an operating cost for the ammonia plant. Ammonia yield (in tonnes) can be calculated from the hydrogen throughput (17 kg NH_3 per 3 kg H_2).

Transport and Delivery Modeling (LCOT)

The transportation of hydrogen and ammonia through pipelines and shipping is modelled in detail in deliverable 3.2 and is adopted here. The modelling includes various consideration such as hydrogen pipeline pressure drop is accounted for with recompression every 200 km to keep flow moving. Energy for compressors (if any) slightly reduces net delivered H_2 or is counted in OPEX. The pipeline OPEX (inspection, maintenance) is taken as a small % of CAPEX annually.

For scenarios involving shipping, we consider two shipping methods: liquid hydrogen (LH_2) tankers and ammonia tankers. Shipping introduces additional steps: liquefaction of H_2 (cooling to –253°C), plus storage, loading, voyage, and unloading/regas or cracking (for NH_3 back to H_2). NH_3 shipping is less loss-prone (NH_3 is transported at –33°C in refrigerated tanks at 1 atm, facing minimal boil-off with reliquefaction).

From these transport computations, we derive the Levelized Cost of Transport (LCOT) for each mode in €/kg. The LCOT is then added to the production cost (LCOH) to get a Levelized Cost of Delivered Hydrogen to the end-point. In some scenario analyses, we will differentiate between LCOH at the production site and delivered cost including transport (especially for central offshore scenario, where pipeline vs. ship options are compared).

CAPEX & Lifetime:

Deliverable 3.2 of WP3 details capex modelling for wind turbines, foundations, and electrolyzers. A PEM electrolyzer capital cost of €1,000/kW (fully installed) for 2025 is considered [15]. Thus a 100 MW electrolyzer costs around €100 million, and a 1 GW (1000 MW) electrolyzer €1 billion. This is in line with industry data ($1,000–1,500/kW today for large PEM systems) [15]. A 25-year project lifetime, matching the wind farm, with electrolyzer stack replacements every 80,000 hours is considered. A stack replacement at year 10 and year 20, costing 30% of the initial electrolyzer CAPEX each time is considered [16]. This reflects the need to replace degraded PEM stacks after 10 years of operation (80k hours) to maintain performance. Future cost reductions are anticipated i.e. by 2030 PEM capex could drop to $540/kW [17] (€500/kW), but the base case uses current costs to be conservative.

OPEX:

Annual fixed O&M for the electrolyzer is taken as 4% of its capex [12] (covering maintenance, labor, parts excluding stack, and utilities like water). For example, a 1000 MW electrolyzer incurs around €40 million/yr OPEX. Variable costs (water consumption, compressor electricity, etc.) are minor; water electrolysis requires 9 liters of water per kg H_2, so even at full scale (200k+ tons H_2/year) water costs are negligible compared to energy costs. Any oxygen credit is also neglected (oxygen byproduct could potentially be sold, but the market is limited and revenues are small relative to H_2).

Financial Assumptions:

A discount rate of 10% is used for NPV calculations, reflecting a moderate cost of capital typical for large infrastructure projects with some revenue certainty [16]. The initial capital investment includes the wind farm and electrolyzer CAPEX. For instance, for the 3000 MW offshore wind farm, a CAPEX of around €3.5 million/MW (€10.5 billion total) is considered, which is in line with recent offshore projects (offshore wind costs have risen to 2015 levels by 2023 due to inflation and supply chain issues [18] to around $4 million/MW). Annual wind O&M is taken as 3% of wind CAPEX (around €315 million/yr). Electrolyzer CAPEX is as given above, and electrolyzer O&M 4%/yr of its CAPEX. The two major stack replacement expenditures in years 10 and 20 (each 30% of initial electrolyzer CAPEX) are calculated [16]. No residual value is assumed at year 25 (the wind farm might be repowered or decommissioned, and electrolyzer stacks would be due for another replacement). NPV is calculated as the sum of discounted cash flows, and IRR as the rate that yields zero NPV. The simple payback period is also reported (years to recoup initial investment from undiscounted net cash flow). All monetary values are in euros (€) in 2025 price terms.

The amount of hydrogen that could be produced using electricity supplied by the wind farm on an hourly basis, $W_{H2,theoretical}$ (kgH2), can be estimated using Eq. (1) [19]

$$W_{\mathrm{H2,theoretical}}(t) = \frac{P_{farm}(t)}{\frac{E_{elec}}{\eta_{conv}} + E_{aux}} \qquad (1)$$

Where η_{conv} is the conversion efficiency, E_{elec} is the LHI of hydrogen (in kWh, i.e 33.33), and E_{aux} represents the electricity consumed by auxiliary components such as desalination, hydrogen compression, and liquefaction.

The electrolyzer plant size ($P_{H_2,plant}$ in MW) depends on the amount of offshore wind electricity allocated to hydrogen production. Its theoretical maximum capacity can be calculated as the product of the maximum theoretical hydrogen output ($W_{H_2,theoretical}$) and the energy content (LHI) of hydrogen (E_{elec}), as shown in Eq. (2) [20].

$$P_{\mathrm{H_2,plant}} \leq W_{\mathrm{H_2,theoretical}}(t) \cdot E_{elec} \qquad (2)$$

The operation of the electrolyzer is suspended when the available wind power from the offshore wind farm falls below a certain threshold, due to potential inefficiencies and the risk of accelerated degradation of the electrolyzer system. A threshold value equal to 5% of the wind farm's rated power ($P_{farm,low}$) is assumed as the minimum required for electrolyzer operation [5].

Sizes simulated: 0.99 GW, 1.5 GW, 3 GW, for 10 MW fixed and 10 MW floating turbine cases (depth-appropriate). **Cost & performance libraries:** electrolyzer efficiency, CapEx, lifetimes and carrier transport costs follow the techno-economic table compiled in deliverable 3.2. For each scenario, hydrogen and ammonia production and transportation by ship and pipeline are simulated for comparison.

For hybrid offshore centralized scenario, the energy from the OWF is only subject to wake losses and a small amount of electrical losses in the site network and the AC–DC converter before being supplied to the electrolzer, Figure 2. The hydrogen obtained will then be transported to onshore infrastructure by pipeline or ship. The losses incurred by pipeline transmission are very low, as shown in Table 1.

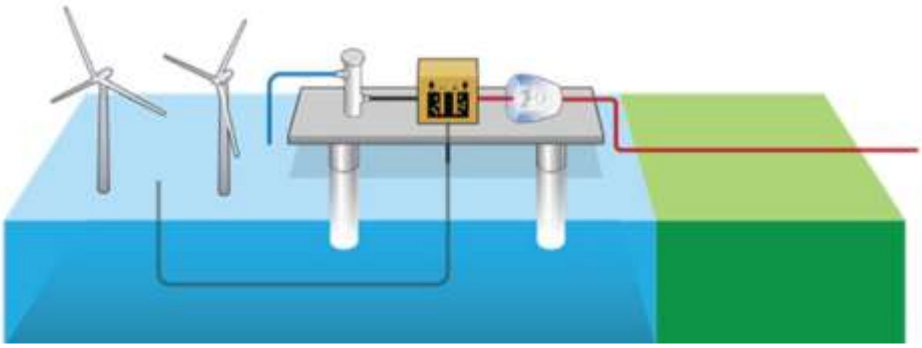

Figure 2. Schematic illustration of a centralized offshore wind farm with offshore hydrogen production and grid connection

Table 1. Efficiency and losses of components of transmission system, taken from [21]

Efficiency	**Value**
AC-DC converter (εACDC)	98.2%
DC-AC converter (εDCAC)	98%
Transformer (ε_tf)	99.4%
Losses	**Value**
DC cable loss (LossDCCABLE)	Eqn. **Errore. L'origine riferimento non è stata trovata.**)
Pipeline loss ($Loss_{pipe}$)	0.1%

. The electrolyzer power in offshore electrolyzer concept is given by eq. (3):

$$P_{EL} = P_{farm}\ x\ (1 - Loss_{wake})\ x\ \varepsilon ACDC$$	(3)

Where $Loss_{wake}$ accounts for energy reduction due to turbine-turbine interference, this adjusts the theoretical output to a more practical net power after aerodynamic and electrical losses. $Loss_{wake}$ is taken as 0.1 [22]

Cable Cost Calculation:

Cable cost depends on the length, required power capacity, and unit cost per MW per km.

$$Costcable = Pcable, max \times D \times Cunit$$	(4)

Where, Pcable,max: maximum cable power capacity (in MW). D is transmission distance (km) and Cunit is the cost per MW per km of cable (in line with study [23]). Only excess (non-used by offshore electrolyzer) power is sent to shore. The cable size for this can be calculated using eq :

$$Pcable, offshore(t) = Pfarm(t) \times (1 - Losswake) - PEL(t)$$	(5)

Where cable,1(t) is power to be transmitted through the cable to shore.

The hybrid onshore concept transmits electricity through a HVDC transmission line from the OWF to the onshore electrolyzer, Figure 3. Therefore, besides the wake effect, energy is also lost by transmission system components (transformer, converter, HVDC cable). The efficiency and loss parameters of components are presented in Table 1. The hydrogen produced can be stored at the site before being distributed for use. The electrolyzer power in this concept is given in eq. (6)

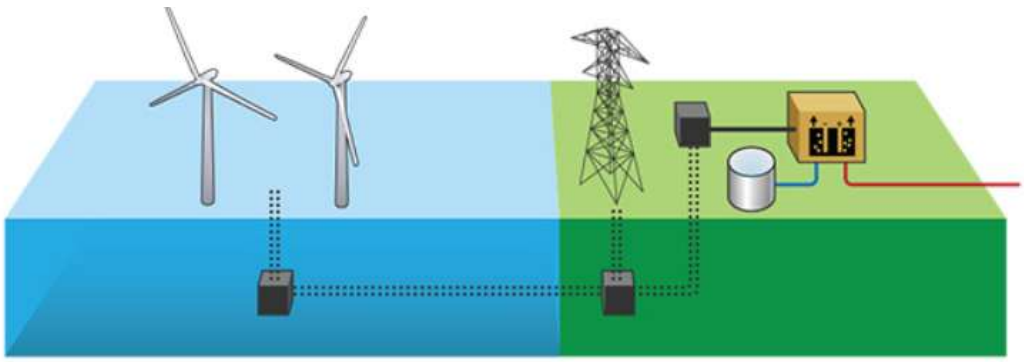

Figure 3. Schematic illustration of offshore wind farm with onshore hydrogen production and grid connection.

$$P_{EL} = P_{farm}\ x\ (1 - Loss_{wake})\ x\ \varepsilon_{tf}{}^{2}\ x\ \varepsilon^{2}ACDC\ x\ (1 - Loss_{DCcable})\ x\ \varepsilon DCAC$$	(6)

To estimate the percentage energy loss in the HVDC cable, Eqn. (7), source [21].

$Loss_{DC\ cable} = 0.0057\ x\ D\ x\ 0.0003$	(7)

For Scenario 2, Onshore electrolyzer, eq.

$Pcable, onshore(t) = Pfarm(t) \times (1 - Losswake)$	(8)

Where D is the transmission distance in km.

Then the LCOH can be calculated as follows:

Estimating Total Costs using discounted cash flows over the project lifetime N years, eq. (9):

$Total\ Cost = \sum_{t=0}^{N} \frac{CAPEX_t + OPEX_t}{(1 + r)^t}$	(9)

Where, r = discount rate and CAPEX & OPEX include electrolyzer, platform, wind farm, cables, etc.

The cost model for transmission and inter-array cable are taken from A3.1 report of the WP3.

Now, estimate the annual revenue from Electricity Sales (Only the electricity not used for H_2 is sold to the grid), eq. (10):

$R_{elec,ann} = E_{to\ grid}\ x\ Price_{elec}$	(10)

$Price_{elec}$ is selling price of electricity EUR/kWh (taken as LCOE). $E_{to\ grid}$ is the electricity sold to grid. r is the discount rate.

Calculate LCOH through the Generalized equation (11) **to calculate LCOH (for both scenarios i.e. offshore and onshore electrolysis):**

$LCOH_2 = \frac{\sum_{t=0}^{N} \frac{C_t - R_{elec,t}}{(1 + r)^t}}{\sum_{t=0}^{N} \frac{H_{2,Prod}(t)}{(1 + r)^t}} = \frac{CAPEX_{tot}\ x\ CRF + O\&M_{tot,t} - R_{elec,t}}{H_{2,Prod}}$	(11)

C_t indicates the whole cost thus: $C_t = CAPEX_{tot} + O\&M_{tot,t}$

And $CAPEX_{tot}$ considers all the investment cost, thus:

$$CAPEX_{tot} = CAPEX_{OWT} + CAPEX_{ELY} + CAPEX_{cable}\ [€]$$

The same also for yearly $O\&M_{tot,t}$:

$$O\&M_{tot,t} = O\&M_{OWT,t} + O\&M_{ELY,t} + O\&M_{cable,t}\ [€/year]$$

Capital Recovery factor, CRF, is given by:

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

The annualized costs for electrolyzer, wind farm, and transmission cable are calculated using following equations:

$C_{el,ann} = (CAPEX_{el} \times CRF) + O\&M_{el,ann}$	(12)

Similarly, annualized cost is calculated for wind farm and export cable:

$C_{wf,ann} = (CAPEX_{wf} \times CRF) + O\&M_{wf,ann}$	(13)

$C_{cable,ann} = (CAPEX_{cable} \times CRF) + O\&M_{cable,ann}$	(14)

Capital Recovery factor, CRF, is given by:

$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$	(15)

Where r is the discount rate and N is the project lifetime (in years).

For LCOE:

$LCOE = \sum_{t=1}^{N} \frac{\frac{CAPEX_t + OPEX_t}{(1 + r)^t}}{\frac{E_{Prod,t}}{(1 + r)^t}}$	(16)

Total Revenue can be calculated by summing revenue from electricity sales (R_{elec}) and hydrogen sales. Given by eq (17):

$R_{total} = R_{elec,ann} + (m_{H2,ann} \times P_{H2})$	(17)

Annual profit can

$\Pi ann = R_{total} - (C_{wind,ann} + C_{el,ann} + C_{cable,ann})$	(18)

The net present value NPV can be calculated using (19)

$NPV = \sum_{t=0}^{N} \frac{Rt - Ct}{(1+i)^t}$	(19)

It is to be noted that this methodology reuses and extends the modeling framework from prior

SPOWIND deliverables. The cost breakdown structure (DEVEX, CAPEX, OPEX, DECEX) comes from the WP2 techno-economic model. The LCOE and availability calculations for the wind farm are as per Deliverable 2.3.1, ensuring that capacity factor reductions due to downtime, cable losses, etc., are handled in the same way. The LCOH definition and inclusion of transmission distance effects follow the literature review and methodology outlined in Deliverable 3.2. Notably, the influence of distance on scenario choice. All modeling equations (for wind power, electrolyzer sizing, pipeline sizing, etc.) were implemented in the MATLAB simulation code, and the results have been checked to align with the expected trends from those earlier studies.

4. Scenario results and discussion

4.1 Centralized Onshore Scenario

Annual Hydrogen Production (AHP).

This scenario's performance is strongly tied to wind resource quality and cable distance to shore. Annual Hydrogen Production AHP (Figure 4) is highest in areas combining strong winds and short grid connections. In the mediterranean context, the Aegean archipelago and North Aegean corridor, the Sicily–Tunisia channel, and segments of the Northern Adriatic emerge as hotspots. These areas reach the upper legend classes (180–220 kton $H_2 \cdot y^{-1}$), driven by strong wind resource and short cable runs to suitable landfalls. Lower bands (40–100 kton$\cdot y^{-1}$) occur along near-shore strips with weaker wind or siting constraints.

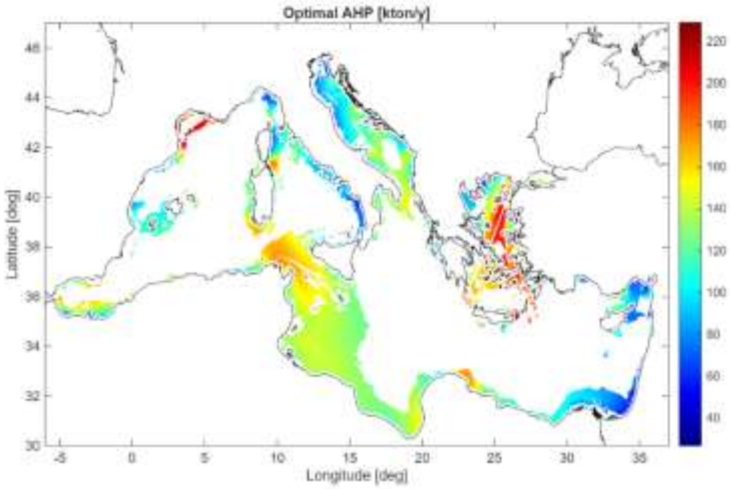

Figure 4. Optimal Annual Hydrogen Production (AHP) [kton $H_2 \cdot y^{-1}$] for Centralized Onshore Scenario

Annual Ammonia Production (ANP).

When translated to Annual Ammonia Production (ANP) (if that hydrogen were converted to NH_3 onshore), the same favored regions produce on the order of 700–1000 kton NH_3 per year. This indicates significant export potential in those hubs, which coincidentally align with existing port infrastructure (e.g. in Sicily or near Athens) (Figure 5), easing the path for export.

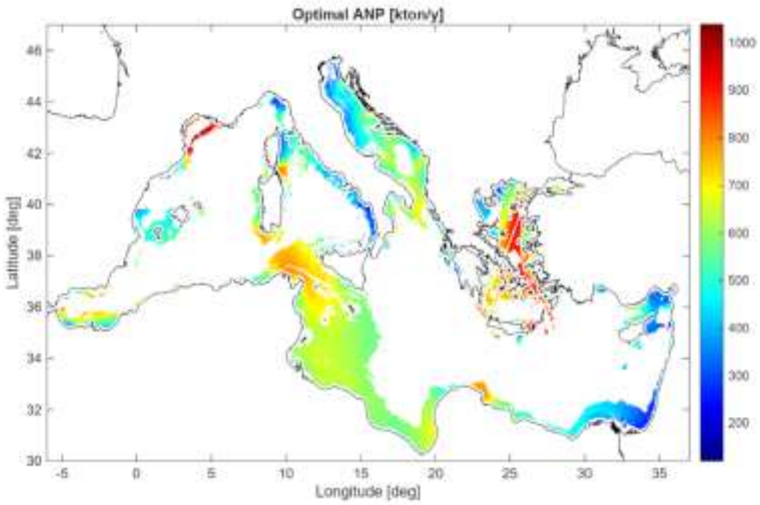

Figure 5. Optimal Annual Ammonia Production (ANP) [kton $NH_3 \cdot y^{-1}$] for Centralized Onshore Scenario

Levelized Cost of Hydrogen (LCOH).

The LCOH surface (Figure 6) shows the lowest costs (deep blue areas, <€3/kg) along continental shelves with good resource and short, direct grid connections, notably the Northern Adriatic, Aegean straits, and parts of the Sicily–Tunisia channel. Adriatic and Aegean Straits show very competitive LCOH due to steady winds and proximity to coast (some locations benefiting from existing grid infrastructure, e.g. northern Greece). In contrast, higher LCOH (yellow to red zones, >€5/kg) appear in more remote or deepwater areas where either wind quality doesn't compensate the added cable losses/costs, or where very long export cables are needed.

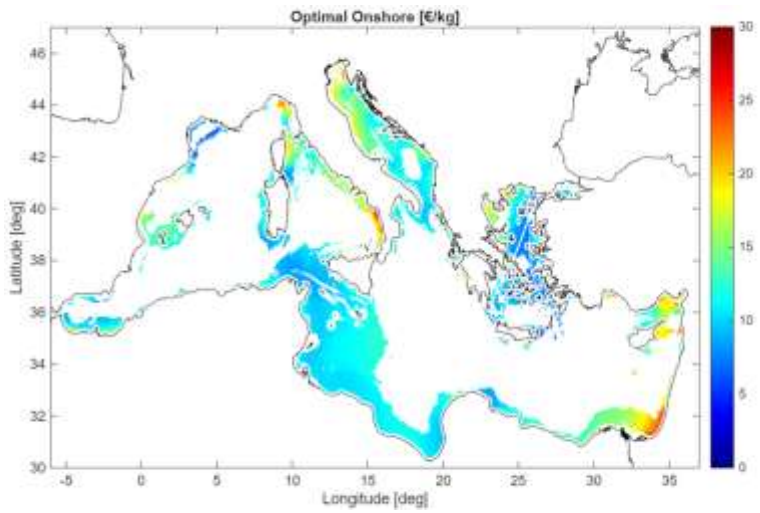

Figure 6. Levelized Cost of Hydrogen (LCOH) [€/kg H_2] for Centralized Onshore Scenario

Levelized Cost of Ammonia (LCOA).

LCOA (Figure 7) mirrors the LCOH pattern: the most competitive NH_3 arises where onshore electrolysis is cheapest and port/industrial access is strong; peripheral areas show cost penalties from longer power export and logistics.

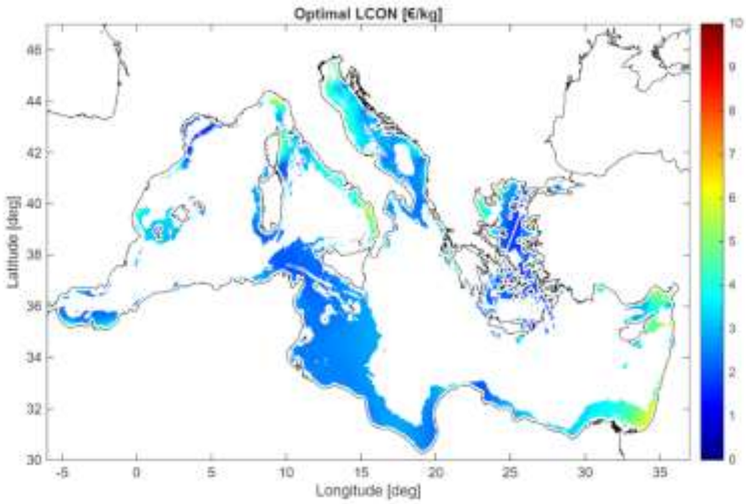

Figure 7. Levelized Cost of Ammonia (LCOA) [€/kg NH_3] for Centralized Onshore Scenario

Platform selection.

Onshore electrolysis can potentially handle large input, the model allowed farm capacities of 1 GW, 1.5 GW, or 3 GW. We found that in many high-resource areas, the model selected the largest size (3 GW) to maximize economies of scale, except where space or environmental constraints limited the feasible footprint. Additionally, foundation type mapping (Figure 8) shows floating semisubmersible platforms dominate most sites (since many prime wind areas are in >50 m depth), with monopiles only in a few shallow near-shore belts (e.g., parts of the Adriatic). This confirms that floating technology is central to Mediterranean offshore wind, which in turn influences costs.

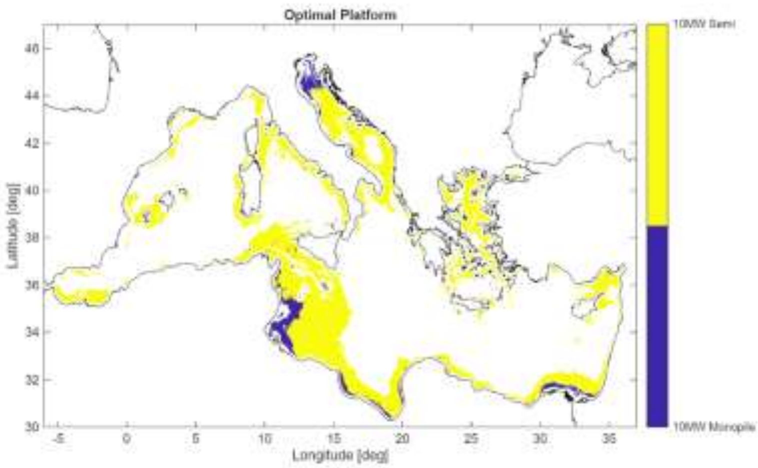

Figure 8. Optimal Platform/Foundation Type (10 MW class) for Centralized Onshore Scenario

Project size.

Optimal hub sizing (Figure 9) skews toward the 3 GW class across extensive contiguous areas, with ~1–1.5 GW footprints emerging where environmental/siting constraints reduce developable area.

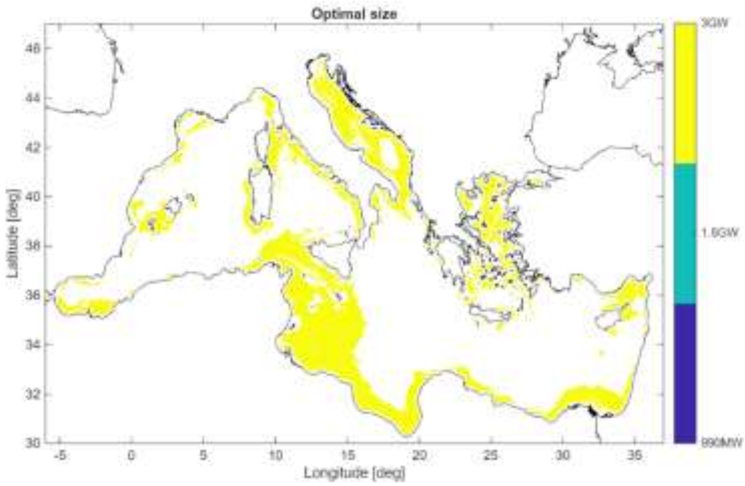

Figure 9. Optimal Project Size (Hub Capacity) [0.99, 1.5, 3 GW] for Centralized Onshore Scenario

4.2 Centralized Offshore Scenario

Annual Hydrogen Production (AHP).

The AHP map (Figure 10) for centralized offshore still shows the Aegean and Sicily-Tunisia regions as top performers with 180–220 kton H_2/y classes, similar to Scenario 1, because the wind resource pattern is the same.

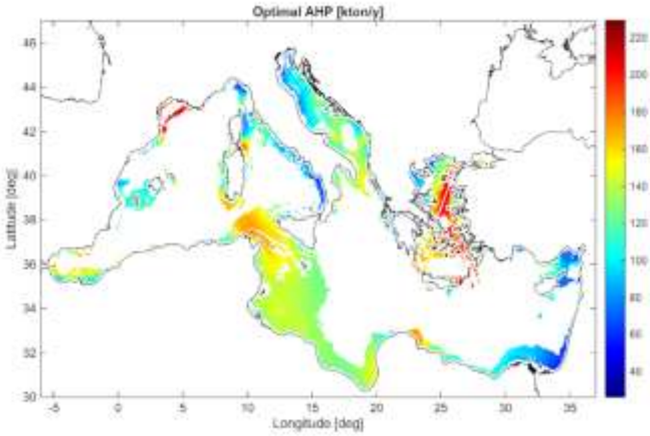

Figure 10. Optimal Annual Hydrogen Production (AHP) [kton $H_2 \cdot y^{-1}$] for centralized offshore scenario

Annual Ammonia Production (ANP).

If the exported H_2 is converted to NH_3 onshore, the ANP distribution (Figure 11) mirrors AHP, peaking along the same corridors (700–1,000 kton $NH_3 \cdot y^{-1}$ equivalent). These areas align with plausible export hubs and existing port/industrial infrastructure.

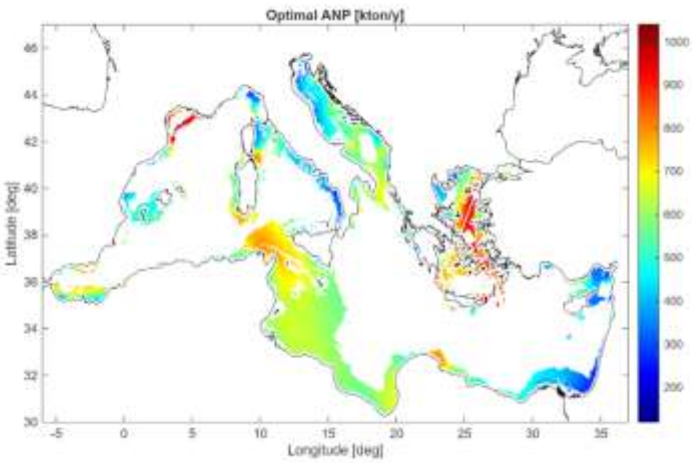

Figure 11. Optimal Annual Ammonia Production (ANP) [kton $NH_3 \cdot y^{-1}$] for centralized offshore scenario

LCOA (NH_3).

The basin-wide LCOA (Figure 12) points to lowest NH_3 costs (blue–cyan) across continental shelves with short logistics to shore; higher costs (yellow–red) emerge around remote/deeper tracts. Disaggregated views show that pipeline-based LCOA (Figure 13) is most competitive along narrow shelves/short landfalls (e.g., Northern Adriatic, Aegean straits), whereas ship-based LCOA (Figure 14) smooths penalties for island clusters and deeper water.

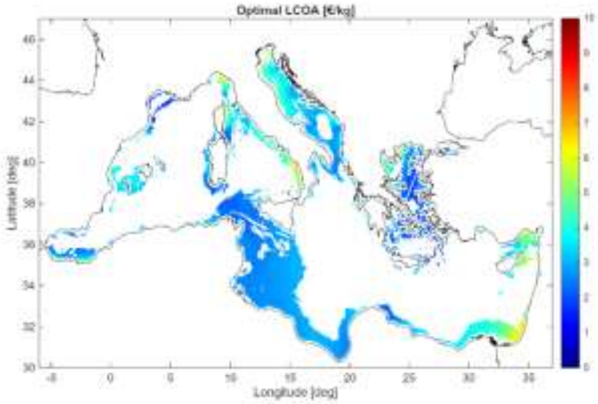

Figure 12. LCOA (NH_3) — All Routes [€/kg NH_3] for centralized offshore scenario

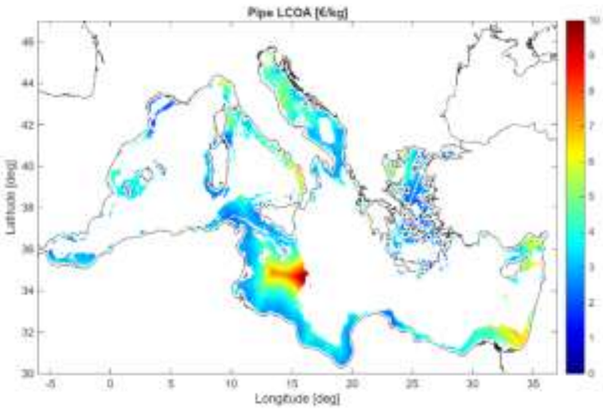

Figure 13. LCOA (NH_3) — Pipeline only [€/kg NH_3] for centralized offshore scenario

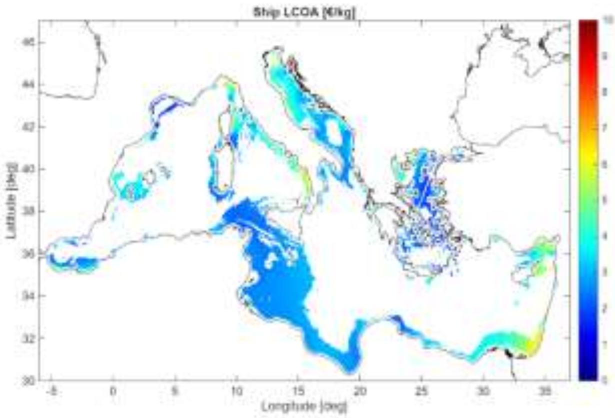

Figure 14. LCOA (NH_3) — Ship only [€/kg NH_3] for centralized offshore scenario

LCOH (H_2).

The combined LCOH surface (Figure 15) follows a similar gradient. By mode, pipeline LCOH (Figure 16) yields the lowest values where seabed routes are short and straightforward, while ship LCOH (Figure 17) becomes relatively more attractive in deeper, distant areas where pipelines are costly.

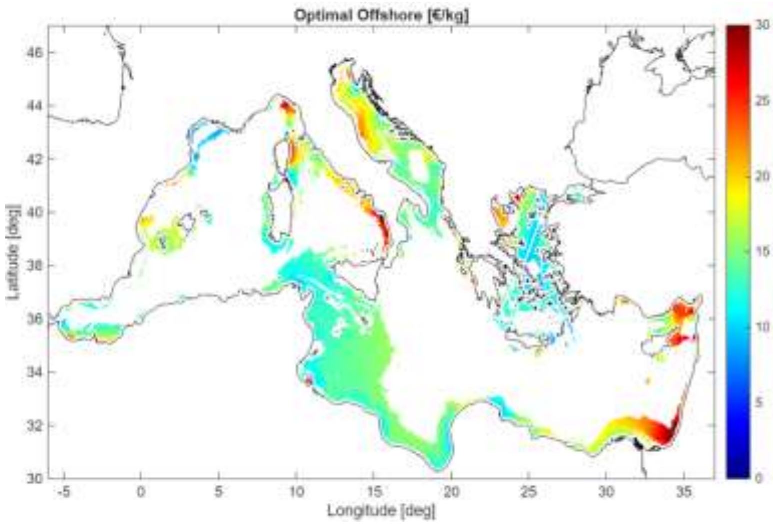

Figure 15. LCOH (H_2) — All Routes [€/kg H_2] for centralized offshore scenario

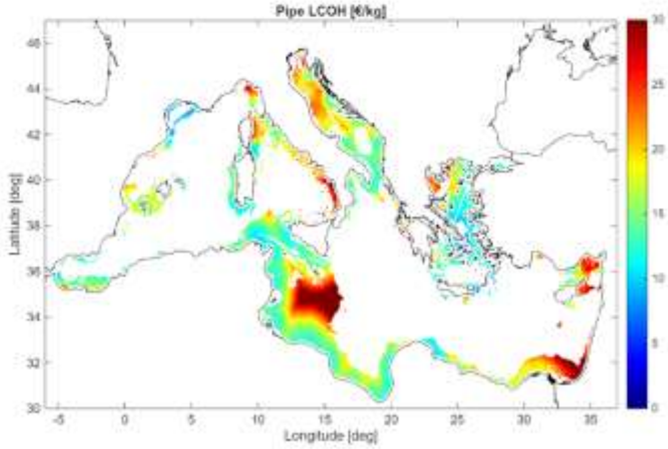

Figure 16. LCOH (H_2) — Pipeline only [€/kg H_2] for centralized offshore scenario

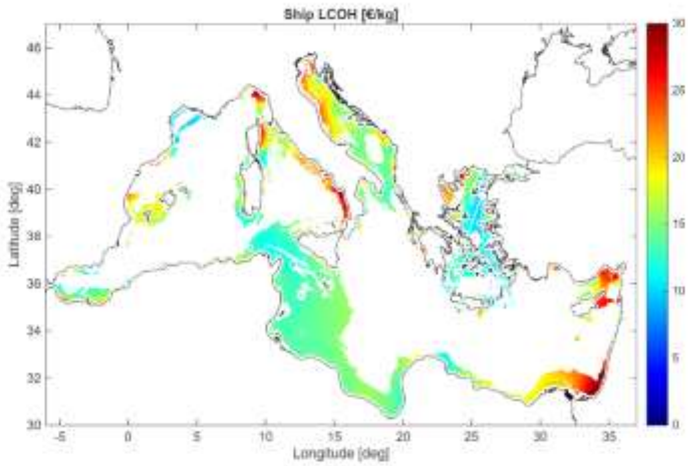

Figure 17. LCOH (H_2) — Ship only [€/kg H_2] for centralized offshore scenario

Optimal H_2 transport mode.

Mode selection (Figure 18) tracks the cost splits above: pipeline dominates near-shore shelves and straits; ship prevails in deeper/off-shelf zones and around islands.

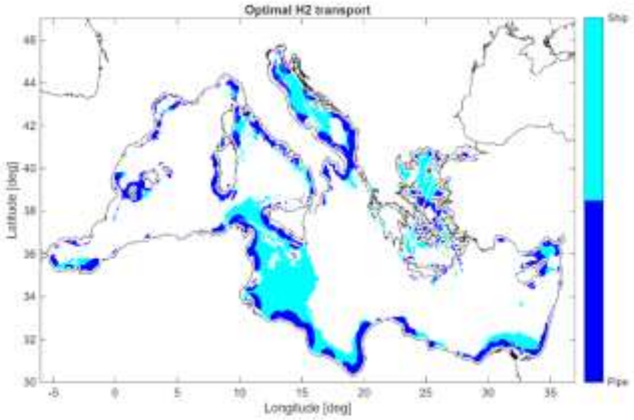

Figure 18. Optimal H_2 Transport Mode [pipeline vs ship] for centralized offshore scenario

Offshore Scenario's takeaway: For moderate-range projects (50–200 km offshore) and large scale, centralized offshore H_2 can compete well, hitting LCOH in the mid €2–4/kg range for many 2030+ projections. Indeed, literature points out by 2030, offshore H_2 could reach €4/kg and by 2050 €2.5/kg in favorable cases, and our findings are in line with that trajectory in the best locations.

Platform/foundation selection.

Preferred foundations (Figure 19) follow bathymetry: semi-submersibles across most of the Mediterranean's deeper shelves; monopiles confined to shallow belts near shore, consistent with installation limits and metocean exposure.

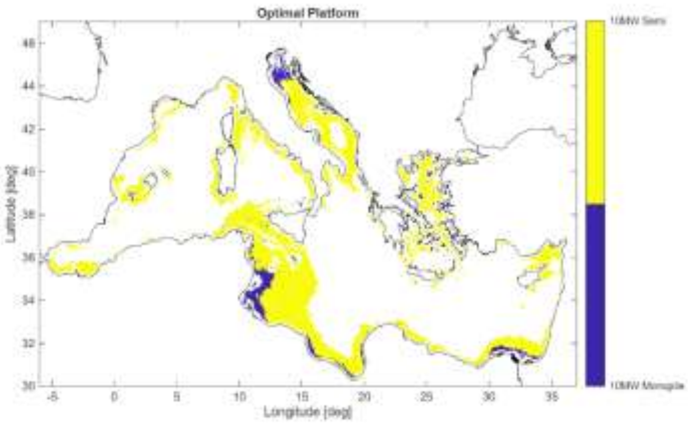

Figure 19. Optimal Platform/Foundation Type (10 MW class) for centralized offshore scenario

Project size.

The optimal hub capacity (Figure 20) skews strongly toward the 3 GW class across most contiguous shelves, with smaller footprints (1–1.5 GW or ~1 GW) only where environmental/siting limits or fragmented lease areas reduce developable area. This supports targeting ≥ 3 GW hub modules for procurement and infrastructure planning (electrolyser blocks, export lines, O&M).

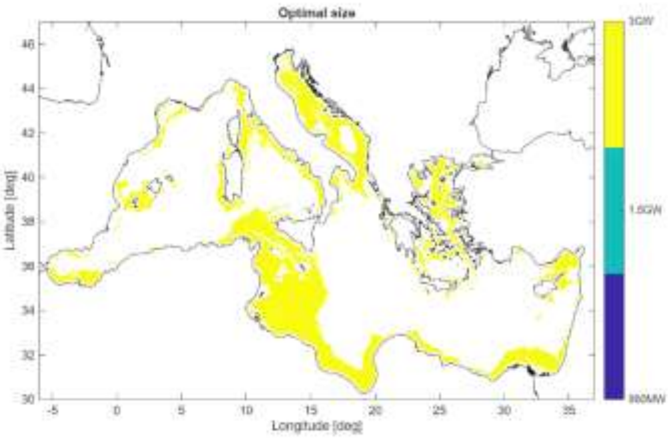

Figure 20. Optimal Project Size (Hub Capacity) [0.99, 1.5, 3 GW] for centralized offshore scenario

4.3 Decentralized Offshore Scenario

Annual Hydrogen Production (AHP).

The decentralized layout preserves the same first-order geography of hydrogen potential (Figure 21): the Aegean archipelago/North Aegean corridor and the Sicily–Tunisia channel show the highest AHP classes (180–220 kton $H_2 \cdot y^{-1}$ at cluster scale), with additional high bands in the Northern Adriatic. Compared with centralized-offshore, AHP is more spatially fragmented, reflecting site-by-site sizing and electrolyser siting limits.

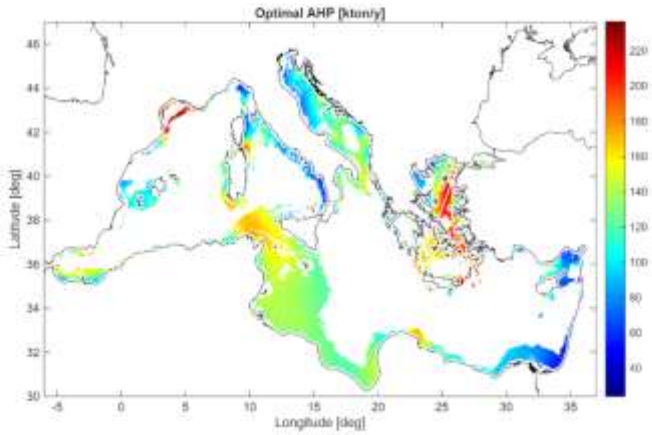

Figure 21. Optimal Annual Hydrogen Production (AHP) [kton $H_2 \cdot y^{-1}$] for decentralized offshore scenario

Levelized Cost of Hydrogen (LCOH).

The basin-wide LCOH (Figure 22) indicates lowest costs (blue–cyan) on continental shelves with good wind and short export distances. Higher costs (yellow–red) concentrate in deeper or remote tracts where each farm bears duplicated balance-of-plant and export infrastructure. Mode-specific maps show pipeline LCOH (Figure 23) outperforming along narrow shelves/short landfalls (Adriatic, Aegean straits), while ship LCOH (Figure 24) is relatively more attractive for deeper/off-shelf sites and islands where pipelines become expensive. LCOH tends to be slightly higher than Scenario 2 in many areas, due to duplication of equipment and lower economies of scale. Our model indicates that *if* all else is equal, decentralized electrolyzers add about 10–20% to the LCOH relative to a centralized offshore electrolyzer, for a given site.

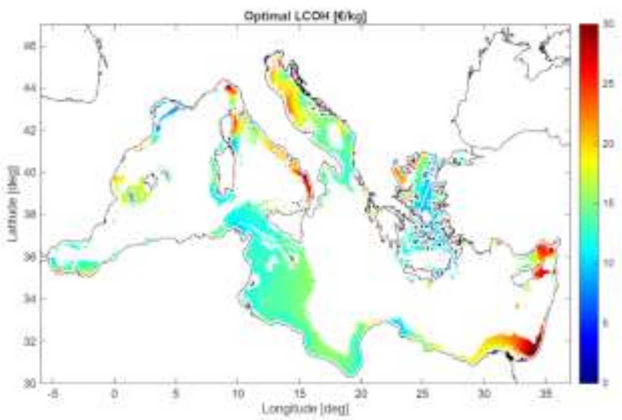

Figure 22. LCOH (H_2) — All Routes [€/kg H_2] for decentralized offshore scenario

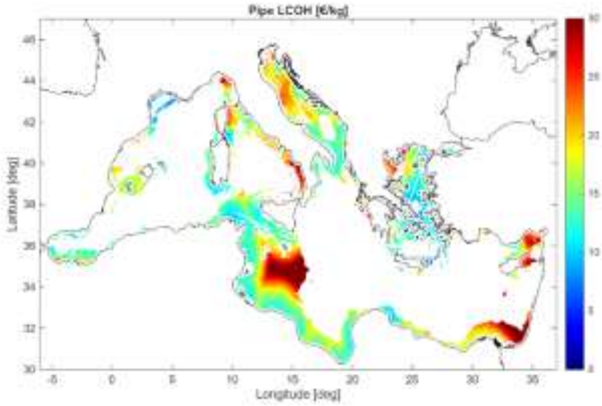

Figure 23. LCOH (H_2) — Pipeline only [€/kg H_2] for decentralized offshore scenario

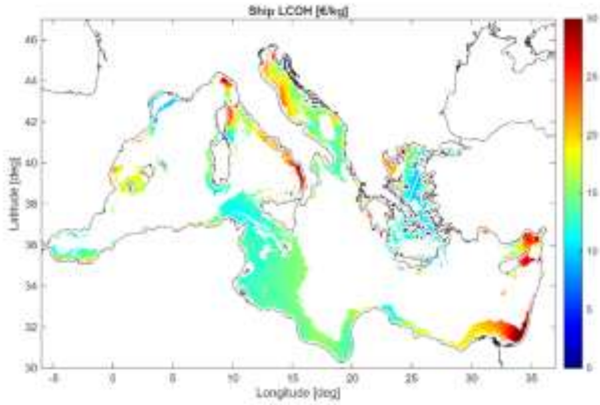

*Figure 24. LCOH (H_2) — **Ship** only [€/kg H_2] for decentralized offshore sceanrio*

Optimal H_2 transport mode.

The mode selection (Figure 25) mirrors the cost splits: pipeline dominates close-in shelves and straits; ship prevails across deeper or fragmented zones, consistent with decentralised loading from multiple small terminals.

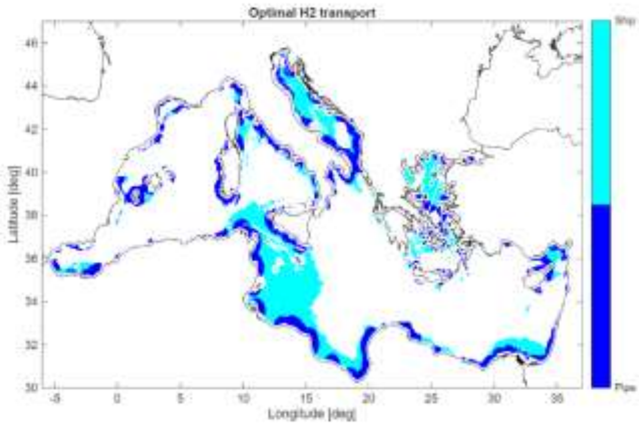

Figure 25. Optimal H_2 Transport Mode [pipeline vs ship] for decentralized offshore scenario

Platforms and project size.

Foundation choice (Figure 26) follows bathymetry, semi-subs across most offshore tracts, monopiles limited to shallow belts. Optimal hub capacity (Figure 27) still tends to the 3 GW class where contiguous developable areas exist; however, more 1–1.5 GW footprints appear than in centralized layouts, due to decentralized processing and spatial constraints.

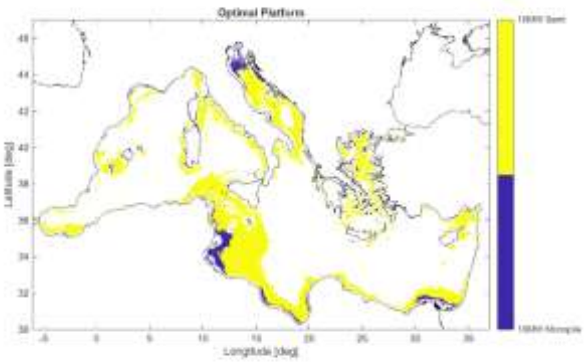

Figure 26. Optimal Platform/Foundation Type (10 MW class) for decentralized offshore scenario

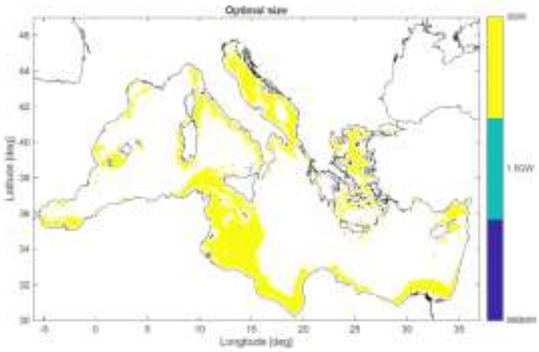

Figure 27. Optimal Project Size (Hub Capacity) [≈0.99, 1.5, 3 GW] for decentralized offshore scenario

4.4 Hybrid Offshore Centralized

Annual Hydrogen Production (AHP).

The optimal AHP distribution (kton H_2 y^{-1}) highlights several Mediterranean “hot spots” where the hybrid layout delivers strong hydrogen yields (Figure 28). The Aegean (Cyclades/North Aegean corridor) and Sicily–Tunisia channel show the highest classes (approaching the >180–200 kton y^{-1} band, slightly lower than in the pure Power-H_2 cases as a fraction of power now goes to grid), followed by the Northern Adriatic and Alboran margins. Sheltered gulfs and very near-coast strips with lower wind resource or siting constraints fall into the 40–80 kton y^{-1} range.

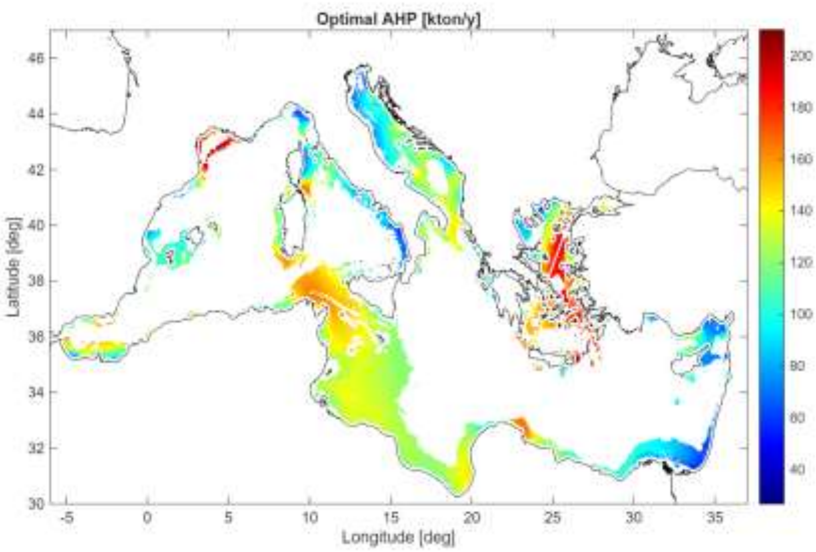

Figure 28. Optimal Annual Hydrogen Production (AHP) [kton H_2·y^{-1}].

Annual Ammonia Production (ANP).

Converting the H_2 stream to NH_3 (assumed onshore Haber–Bosch) amplifies the mass output accordingly (Figure 29). The same corridors dominate, with Aegean sites peaking near the top legend class (900 kton NH_3 y^{-1}), reflecting both robust H_2 supply and short logistics to coastal industrial nodes. This map is useful for indicating export-oriented hubs where NH_3 shipping infrastructure would be justified.

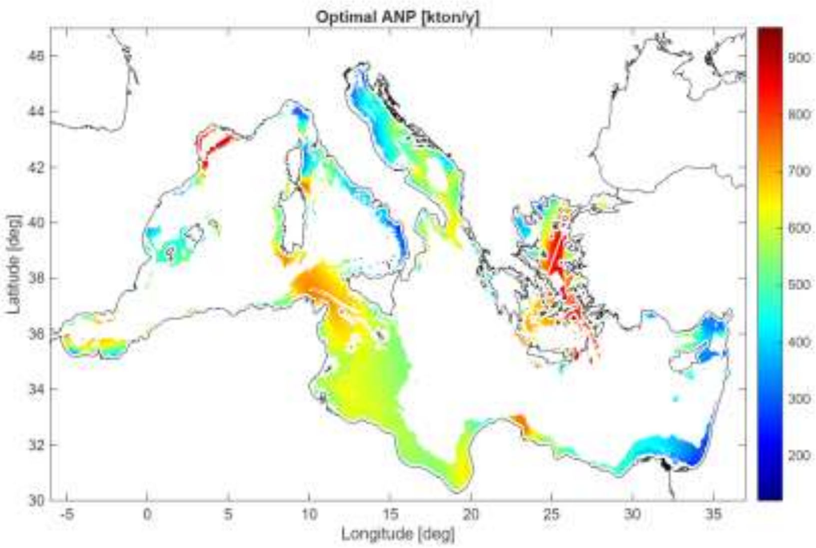

Figure 29. Optimal Annual Ammonia Production (ANP) [kton $NH_3 \cdot y^{-1}$]

Costs: LCOH and LCOA (relative spatial patterns).

The finding was that hybrid scenario can achieve near-lowest LCOH in many places while also providing electricity revenue, effectively raising overall project value. The LCOH surface for H_2 (€/$MWh_{(H_2)}$ equivalent) shows lowest bands (blue) along continental shelves with good wind and short pipeline runs (Northern Adriatic; parts of the Aegean and Sicilian channels), and higher bands (yellow–red) for remote/deep sites where shipping or long cables dominate (Figure 30). The LCOA (€/$MWh_{(NH_3)}$ equivalent) exhibits a similar gradient (Figure 31); the most competitive NH_3 arises where H_2 is already low-cost and port access is strong. (Absolute legend values are scenario-specific; we use the maps to compare relative spatial competitiveness across the basin.)

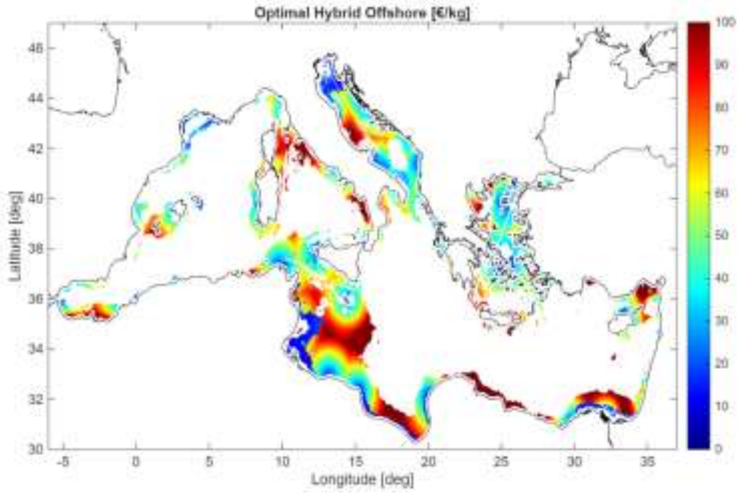

Figure 30. Levelized Cost of Hydrogen (LCOH) [€/MWh $_{(H_2)}$].

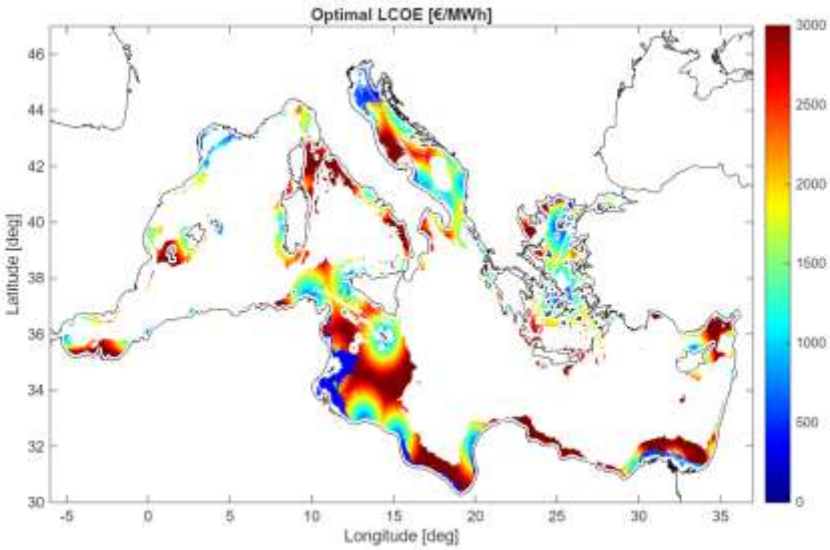

Figure 31. Levelized Cost of Ammonia (LCOA) [€/MWh $_{(NH_3)}$].

Optimal H_2 share in the hybrid dispatch

The "H_2 percentage" map (Figure 32) indicates the fraction of farm output routed to electrolysis under the optimal hybrid rule. Darker areas (≥80–90%) cluster where electricity export is relatively less attractive (distance to grid, high cable cost/losses) or where H_2 logistics are advantaged; lighter areas indicate more frequent power-to-grid operation. This confirms the hybrid's role as a flexible splitter: maritime corridors with strong pipelines tend to run "H_2-heavy," while grid-proximate shallows send more electrons ashore.

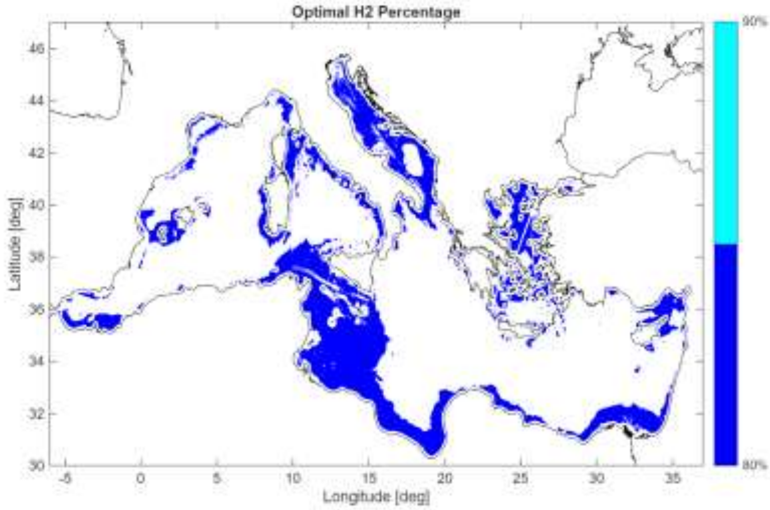

Figure 32. Optimal H_2 Percentage in Hybrid Dispatch [%]

Optimal H_2 transport mode.

The (Figure 33) illustrates the optimal hybrid offshore hydrogen transport configurations in the Mediterranean, indicating whether pipeline or ship transport is favored. The color scale reflects the electrolyzer sizing at offshore platforms, set at either 80% or 90% of full capacity, depending on cost efficiency. Labels like "HybOff 90% ship" or "HybOff 80% pipe" denote the dominant transport mode and the corresponding electrolyzer size.

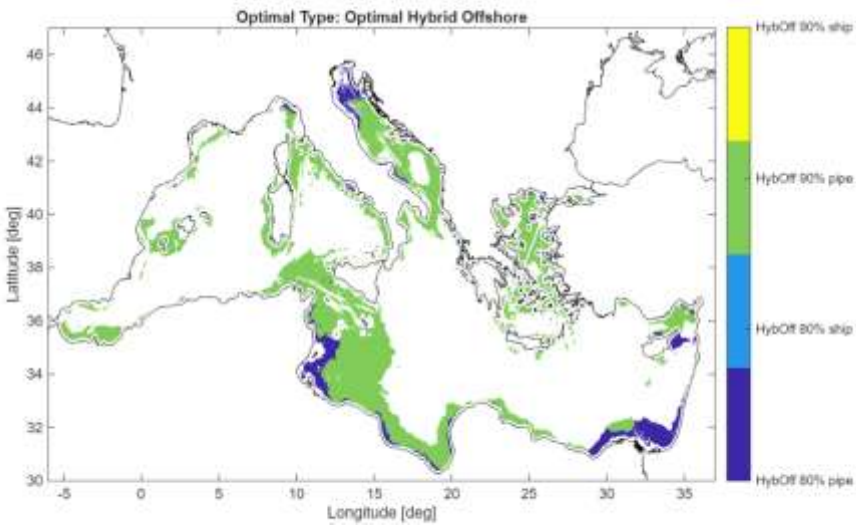

Figure 33. Optimal H_2 Transport Mode [pipeline vs ship].

Platform concept and array size.

The platform map Figure 34 favors 10 MW semi-submersible foundations (yellow) over most of the Mediterranean's deeper shelves, with 10 MW monopiles (purple) limited to shallow near-shore strips—consistent with the regional bathymetry. Optimal project size Figure 35 leans towards the 3 GW class across extensive areas; 1.5 GW and 1 GW footprints appear where spatial/environmental constraints reduce contiguous developable area. These layers help bundle sites into bankable hub sizes.

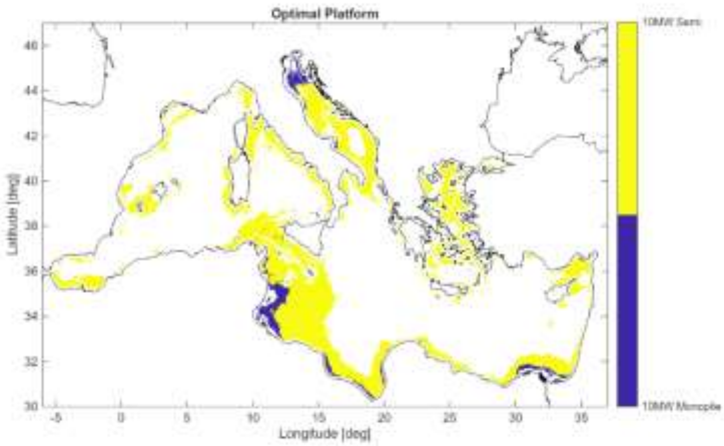

Figure 34. Optimal Platform/ Foundation Type [10 MW class].

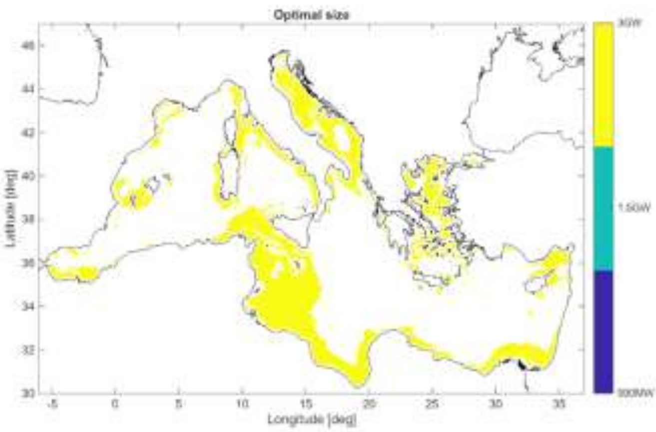

Figure 35. Optimal Project Size (Hub Capacity) [0.99, 1.5, 3 GW].

4.5 Hybrid Onshore Scenario

Annual Hydrogen Production (AHP).

The AHP map (Figure 36) highlights strong hydrogen potential in the Aegean archipelago/North Aegean corridor and the Sicily–Tunisia channel, with additional high bands in the Northern Adriatic. These zones reach the top legend classes (~180–200+ kton $H_2 \cdot y^{-1}$), reflecting good wind plus short, low-loss cable routes to suitable landfalls.

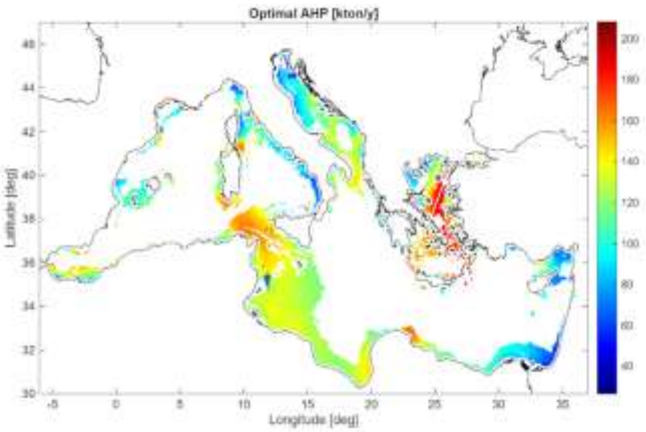

Figure 36.Optimal Annual Hydrogen Production (AHP) [kton $H_2 \cdot y^{-1}$] for hybrid onshore scenario

Annual Ammonia Production (ANP).

If onshore H_2 is converted to NH_3, **ANP** (Figure 37) mirrors AHP and peaks along the same corridors (~700–900+ kton $NH_3 \cdot y^{-1}$ equivalent), aligning well with ports and industrial clusters suitable for export terminals.

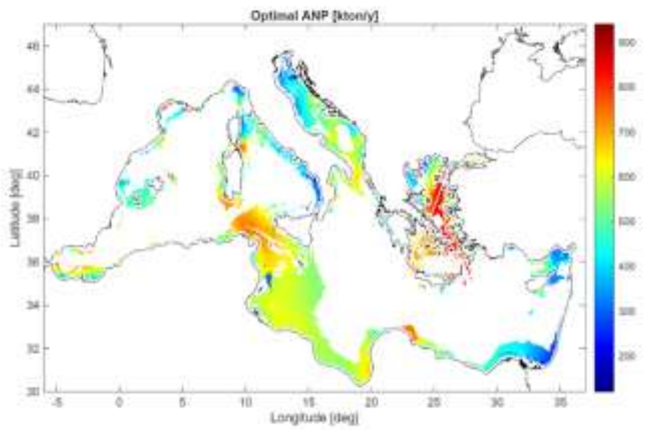

Figure 37.Optimal Annual Ammonia Production (ANP) [kton $NH_3 \cdot y^{-1}$] for hybrid onshore scenario

LCOH and LCOA (relative spatial patterns).

The LCOH surface (Figure 38) shows lowest costs (blue–cyan) on shelves with strong wind and short grid connections (Northern Adriatic, Aegean straits, parts of the Sicily–Tunisia corridor). The LCOA surface (Figure 39) follows a similar gradient: most competitive NH_3 occurs where H_2 is already low-cost and port access is strong. (Values are scenario-specific; maps are used primarily for relative spatial ranking.)

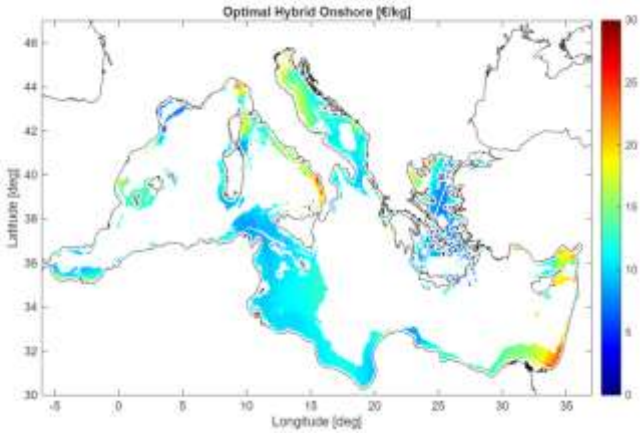

Figure 38. Levelized Cost of Hydrogen (LCOH) [€/MWh(H_2) or €/kg H_2] for hybrid onshore scenario

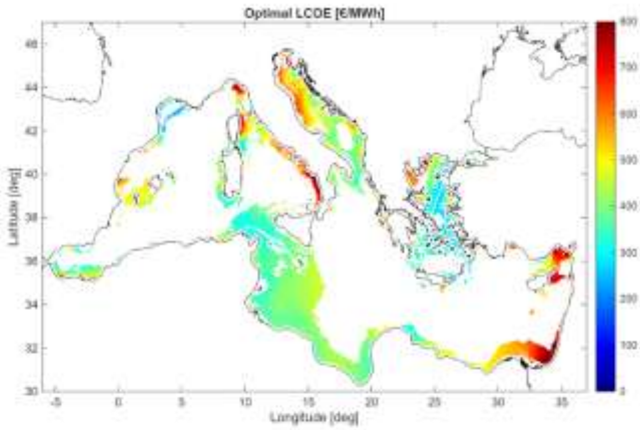

Figure 39. Levelized Cost of Ammonia (LCOA) [€/MWh(NH_3) or €/kg NH_3] for hybrid onshore scenario

Optimal H_2 share of output.

The optimal H_2 percentage map (Figure 40) quantifies how often the hybrid favors electrolysis versus grid export. High shares (≥80–90%) appear where electricity export is less attractive (longer cables, weaker grid nodes) or where H_2/NH_3 logistics are advantaged; lower shares occur near grid-proximate shallows with robust interconnection.

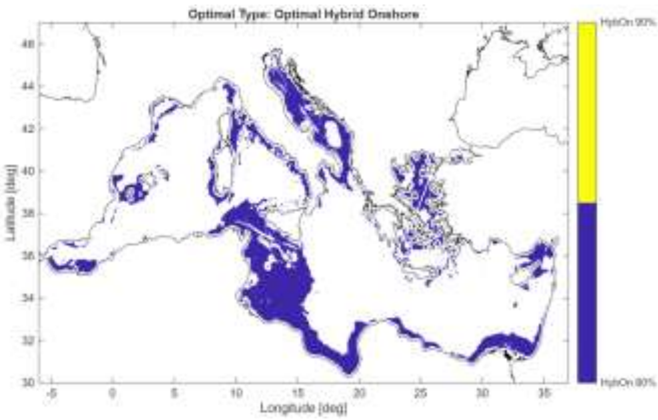

Figure 40. Optimal H_2 Percentage in Hybrid Dispatch [%] for hybrid onshore scenario

Platforms and project size.

Foundation choice (Figure 41) follows bathymetry—semi-submersibles dominate across deeper shelves; monopiles remain confined to shallow belts. Optimal hub capacity (Figure 42) skews toward the 3 GW class across contiguous shelves, with ~1–1.5 GW footprints where siting or environmental constraints reduce developable area.

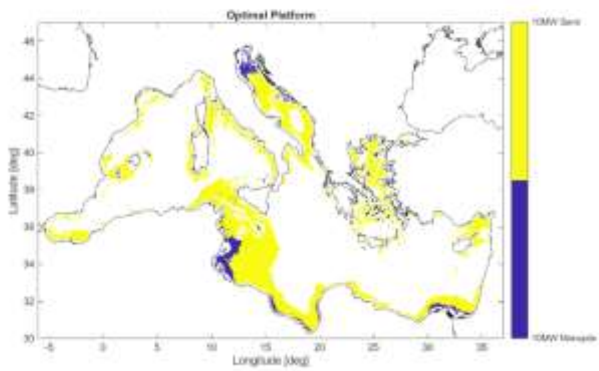

Figure 41. Optimal Platform/Foundation Type (10 MW class) for hybrid onshore scenario

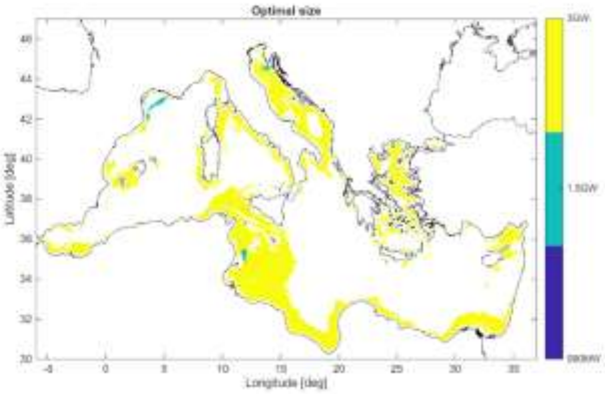

Figure 42. Optimal Project Size (Hub Capacity) [0.99, 1.5, 3 GW] for hybrid onshore scenario

The conclusion for onshore hybrid is that in areas where Scenario 1 was optimal (good wind + short distance), adding the hybrid option doesn't harm the feasibility and in fact adds value by allowing some power sales. The electricity LCOE for the portion sold might be slightly above a pure wind farm's LCOE because we include the cable cost fully but only some energy goes through it. Yet, if that electricity is sold at a premium (peak times), the hybrid could achieve better economics than either alone.

4.6 Overall Optimal Scenario

The overall optimal scenario compares all five layouts at each location and selects the minimum LCOH (€/kg

H_2) after including transport to shore/port and, where relevant, conversion to NH_3.

Cost surface.

The basin-wide optimal LCOH (Figure 43) forms a continuous low-cost belt along continental shelves, with the Northern Adriatic, Aegean straits/archipelago, and the Sicily–Tunisia channel consistently in the lowest bands. Costs rise toward deeper or remote tracts and at long landfalls.

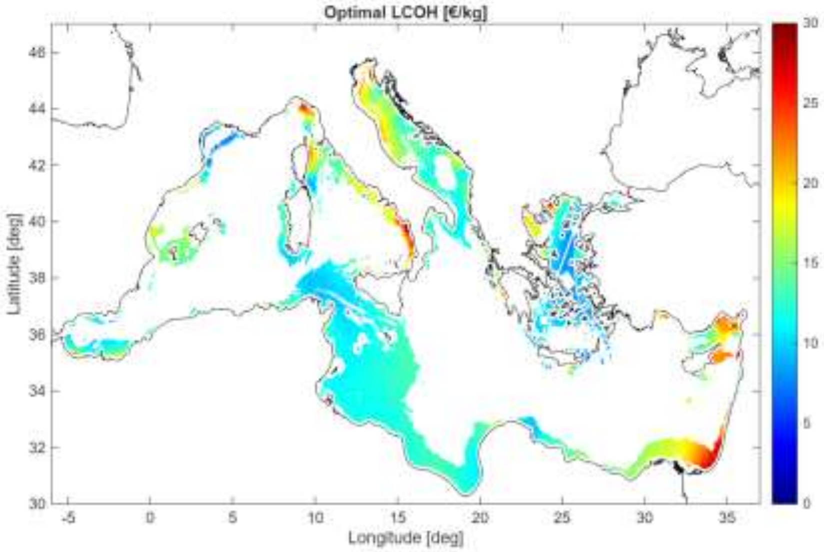

Figure 43. Overall Optimal LCOH [€/kg H_2].

4.7 Best-choice layout by location.

The layout selection map (Figure 44) shows a clear hierarchy:

- Centralized Onshore dominates most of the Mediterranean shelves (blue), leveraging short cables to strong grid nodes and onshore electrolysis near ports/industry.
- Centralized Offshore – Pipeline appears as narrow corridors (cyan) where pipeline landfalls are short and benign (e.g., parts of the Adriatic and Aegean).
- Centralized Offshore – Ship (green) emerges in deeper or islanded pockets where laying large-bore H_2 pipelines is costly.
- Decentralized Offshore (yellow/orange, pipe/ship) is rarely the cost minimum, appearing only in isolated fragments where farm-level siting or spacing penalizes centralization

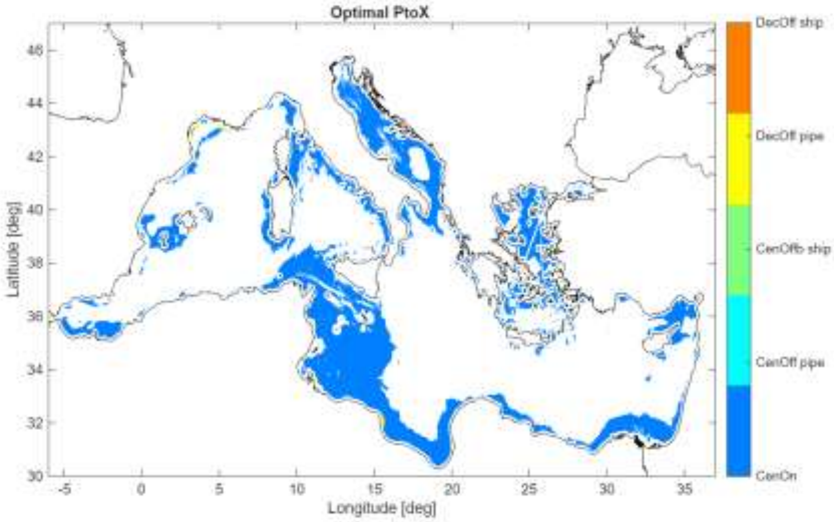

Figure 44. Optimal Power-to-X Layout by Location.

Optimal Hybrid Offshore

Figure 45 shows the optimal offshore hydrogen transport configurations in the Mediterranean, including both pure and hybrid systems. Colors indicate the dominant transport mode, pipeline or ship, and the electrolyzer sizing at offshore platforms, set at either 80% or 90% of capacity for hybrid cases. The classification supports identifying cost-effective hydrogen infrastructure layouts by region.

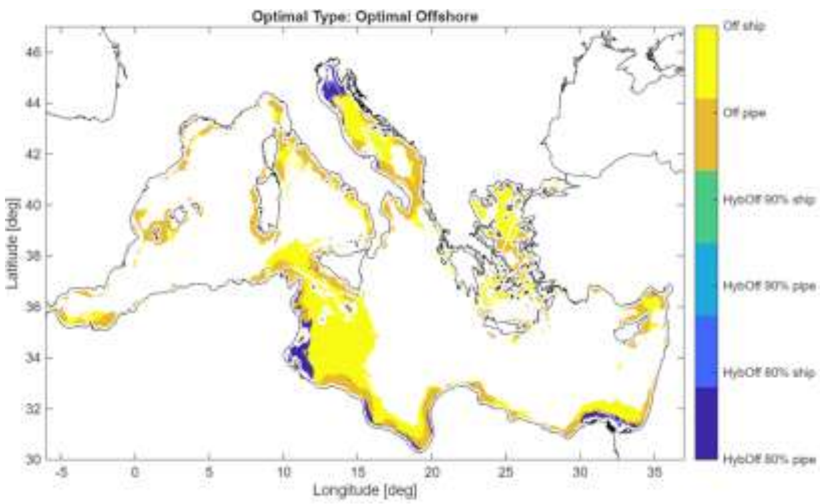

Figure 45. Optimal offshore hydrogen transport types and electrolyzer sizing

Optimal Hybrid Onshore

Figure 46 shows the optimal onshore hydrogen transport configurations around the Mediterranean, including both pure onshore and hybrid onshore systems. The colors represent the electrolyzer sizing for hybrid setups (80% or 90%) and whether a fully onshore solution is optimal. These results help identify where integrating offshore electrolyzers with onshore transport is most cost-effective.

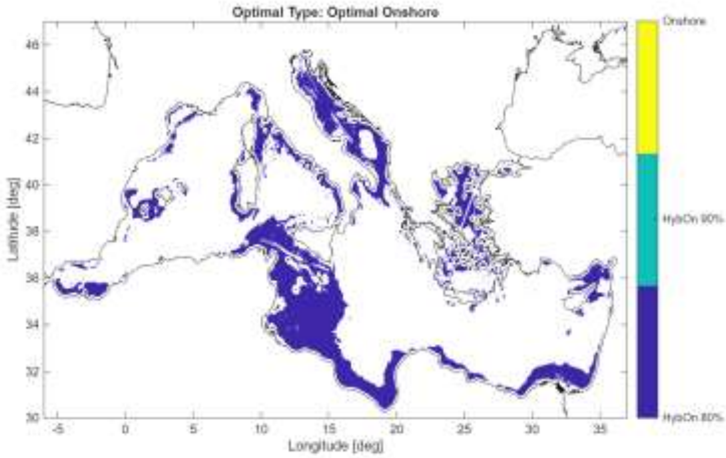

Figure 46. Optimal onshore hydrogen transport types and electrolyzer sizing

5. Conclusions

This report delivered a methodology and comparative assessment of different energy transfer solutions for offshore wind farms, aligned with the objectives of WP3.3 and consistent with earlier project findings. Five system layouts were evaluated, ranging from pure grid connection to pure hydrogen and hybrids, using a unified techno-economic model. The results demonstrate that the optimal solution is case-dependent, chiefly on factors like distance to shore, project scale, and market conditions, confirming the need for a comparative approach as envisioned in the project proposal.

Key conclusions are: (1) Centralized onshore electrolysis offers the lowest hydrogen production cost for projects not too far from shore, leveraging existing grid and onshore industrial infrastructure. (2) Centralized offshore electrolysis with pipeline transport becomes more economical as offshore distance and project size increase, potentially unlocking remote wind resources without massive grid investments. (3) Hybrid configurations (offshore or onshore) provide valuable flexibility and often the highest project value, by diversifying revenue and reducing exposure to any single commodity market. We found that hybrids can outperform single-mode strategies in terms of economic return, even if their calculated LCOH is slightly higher, an insight that aligns with external studies. (4) Decentralized electrolysis is technically feasible but not cost-competitive under base assumptions; it may require further innovation to reduce unit costs or could serve niche situations.

For each scenario, we compared LCOH and LCOT. Pipelines are confirmed as the cheapest transport for moderate distances (a few hundred km), whereas ammonia shipping becomes attractive for very long hauls. These findings can guide infrastructure planning e.g., regions identified with large offshore wind potential and >150 km from shore should consider investing in hydrogen pipeline corridors and related onshore facilities, as this could be the most viable export route.

Final selection recommendation: Project developers and policymakers should avoid a one-size-fits-all mandate. Instead, apply this comparative methodology early in the planning stage to determine the best-fit solution for each offshore wind development. In some cases, a hybrid approach will be the prudent choice, offering a hedge against uncertainties in electricity vs. hydrogen markets. In other cases, focusing purely on electrical grid upgrades or purely on hydrogen pipelines will make more sense. Our framework provides a quantitative basis to make these decisions, by calculating at each prospective site what the levelized cost of delivering energy would be under each scenario. This directly supports the project's mission to help TSOs, developers, and regulators in strategic planning.

Implications for SPOWIND spatial planning. The maps and cost surfaces indicate where "electricity-first" (Centralized Onshore) should be prioritized, where dedicated hydrogen corridors (pipeline) deserve safeguarding, and where ammonia-enabled shipping pathways could unlock distant or islanded resources. In practical terms, planning should (i) protect near-shore pipeline and cable landfalls in the low-cost belts; (ii) reserve port and industrial sites for onshore electrolysis and potential NH_3 synthesis; and (iii) support hybrid nodes where both grid and hydrogen outlets can be staged and expanded over time. Together, these steps hedge market and technology uncertainty while accelerating bankable build-out.

Limitations and next steps. While the present analysis standardizes technical and cost inputs across scenarios, further work should add (a) explicit grid-congestion and curtailment modeling; (b) dynamic electrolyzer degradation and stack replacement scheduling; (c) detailed permitting timelines and seabed route constraints; and (d) endogenous learning curves and policy instruments at NUTS-2/port level. Nonetheless, the core conclusion stands: there is no single "best" pathway everywhere—but there is a clearly best pathway somewhere at each location, and hybrids often raise project value by keeping multiple doors open.

In sum, SPOWIND's comparative framework provides a decision-ready basis for sequencing transmission and PtX investments. Build cables where shelves are short and grids are strong; lay hydrogen pipelines where landfalls are favorable; use shipping (preferably via NH_3) to tap deeper or fragmented resources; and deploy hybrids to capture flexibility and resilience benefits. This portfolio logic turns spatial diversity into an asset, accelerating offshore wind's contribution to regional decarbonization while managing cost, risk, and time to market.

Tables and figures

List of sources

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