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Japan Fixed-Bottom Offshore Wind

Cost Drivers and the 2040 Outlook

April 2026

FOREWORD

This report was jointly produced by Renewable Energy Institute (REI) and Aegir Insights as an independent research initiative. The study was conducted without external funding or commercial sponsorship. Aegir Insights contributed its analytical capabilities and the Aegir Quant™ techno-economic model on a pro bono basis. Neither organization has commercial interests in the outcomes of this analysis.

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About Renewable Energy Institute

Renewable Energy Institute is a non-profit think tank which was established in August 2011, in the aftermath of the Fukushima Daiichi Nuclear Power Plant accident. It aims to build a safe and secure society based on renewable energy, along with a sustainable energy system and economy that mitigates climate change.

About Aegir Insights

Aegir Insights is a market intelligence provider for the global renewables sector, offering software, data, and analytical products across more than 60 markets. The company serves clients across the corporate, supply chain, governmental, and advisory segments. Aegir Insights combines data science with industry expertise to contextualize complex market information, drawing on its advanced techno-economic modeling tool Aegir Quant^{TM}, developed in cooperation with industry and academic partners.

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EXECUTIVE SUMMARY

Japan's offshore wind sector stands at a crossroads. Despite the government's project pipeline targets of 10 GW by 2030 and 30–45 GW by 2040, development remains constrained by a combination of structural physical conditions and early-stage market factors — the consequences of which are now visible in high-profile project cancellations such as Mitsubishi Corporation's withdrawal from approximately 1.7 GW across three sea areas.

To enable acceleration of fixed-bottom offshore wind in Japan, this report clarifies current cost premiums between Europe and Japan as well as the potential for cost reductions towards 2040. This is done through benchmarking of the capital expenditure (CAPEX) of fixed-bottom offshore wind in Japan against a European reference case, using the Aegir Quant™ techno-economic model. Japan's institutional framework differs materially from Europe in terms of both policy framework and physical conditions that include severe metocean seasonality, complex and highly variable seabed geology, and compounding seismic and typhoon design requirements — factors that add to engineering and construction costs relative to European conditions.

The 2030 results quantify a 21% CAPEX premium between the Japanese and European reference cases (3.91 mEUR/MW vs. 3.22 mEUR/MW). Turbine supply is the single largest cost driver, reflecting typhoon and earthquake certification requirements, while installation costs also add significantly, driven by weather downtime and hard seabed geology requiring drilling at a material share of foundation positions. Out of the total EUR 307m premium, approximately EUR 223m (≈73%) is attributable to physical and design constraints that are less directly reduced by market maturation, while EUR 84m (≈27%) reflects addressable market conditions. Additionally, Japan's grid connection cost-allocation framework, under which developers currently fund TSO substation reinforcements, adds to upfront CAPEX. This reflects a policy design choice that is open to review and addressing it could directly reduce the cost burden on developers.

By 2040, CAPEX per MW could decline by approximately 18%, led by turbine upscaling, improved vessel availability, and market maturation. However, Japan is expected to retain a structural cost premium over European markets over the long term.

These findings carry direct policy implications. While Japan's structural physical conditions impose unavoidable cost uplifts, these are not in themselves decisively unfavorable for offshore wind development. The more addressable cost drivers relate to market maturity and institutional design. Drawing on European experience and the calculated cost-out potential towards 2040, four priority areas for Japan's offshore wind market stand out:

(i) Establishing commissioning-based pipeline targets with a stable auction cadence to enable supply-chain investment in vessels, ports, and workforce.

(ii) Strengthening contractual and policy frameworks to absorb post-auction economic shocks.

(iii) Reviewing the grid connection cost-allocation framework, where requiring developers to fund TSO substation reinforcements may concentrate risk on first movers and increase overall system costs.

(iv) Addressing regulatory constraints, including cabotage rules and port land-use restrictions, that limit logistical efficiency and cost-effective project delivery.

1. Introduction

1.1. Background and Problem Statement

The Japanese government positions offshore wind as one of the key pillars of both renewable energy expansion and industrial policy. As of March 2026, several offshore wind farms located within port areas under the Port and Harbour Act, such as those in Noshiro (Akita), Ishikari, and Kitakyushu, have commenced commercial operation, with total installed capacity reaching approximately 0.5 GW.

In addition, since 2021, the government has conducted three rounds of public tenders under the Act on Promoting the Utilization of Sea Areas for the Development of Marine Renewable Energy Power Generation Facilities (hereinafter the Promotion Act), covering general sea areas and totaling approximately 4.6 GW of capacity. As policy targets, the government has set a project allocation pipeline of 10 GW by 2030 and 30–45 GW by 2040. Of this total, 15 GW is expected to be included as floating offshore wind by 2040.

However, offshore wind development in Japan is at a critical juncture. A symbolic case is the consortium led by Mitsubishi Corporation, which won key sea areas in the Round 1 auction (2021) but withdrew in August 2025 from developing three areas in Akita and Chiba (approximately 1.7 GW in total), stating that continued project execution was no longer feasible. This outcome has been attributed to the breakdown of the assumptions prevailing at the time of bidding due to inflation, rising interest rates, and supply-chain constraints, and the company recorded losses associated with the withdrawal and the projects (METI & MLIT, 2025). Moreover, the legal and institutional framework under the Promotion Act was not designed to flexibly accommodate sharp inflation shocks—given that auction bids effectively assumed fixed-price conditions—so that it was difficult to adjust and absorb such cost shocks within the existing framework. This case can therefore be seen as highlighting the challenges of steadily nurturing Japan's nascent and still-fragile offshore wind industry while providing an appropriate degree of resilience against exogenous shocks.

A key near-term cost challenge is the need for a more quantitative assessment of offshore wind construction costs, which are highly sensitive to inflation and rising interest rates. Specifically, IRENA (2025) reports a weighted-average total installed cost for offshore wind in the European markets in 2024 of USD 3,389/kW (JPY 513,000/kW[1]). On the other hand, a survey conducted by

[1] 2024 USD is converted to JPY at an exchange rate of average in 2024: 151.4JPY/USD.

the Japan Wind Power Association (JWPA) of developers already selected through Japan's public tender process indicates that the corresponding figure for Japan averages JPY 908,000/kW (JWPA, 2025). While these figures are not strictly comparable, they nevertheless suggest a substantial difference in cost levels between Japan and European markets.

Against this backdrop, most notably Mitsubishi Corporation's withdrawal and the conditions that led to it, debate in Japan has expanded beyond arguments that offshore wind should simply be continued through incremental improvements to the institutional framework. In some parts of public discourse, there are calls to reconsider the overall approach to promoting offshore wind, and even to reassess broader policy packages premised on large-scale deployment.

In response, it is important to move the debate beyond qualitative arguments and to examine future options based on a quantitative understanding of current costs. In particular, it is essential to identify what drives the difference between Europe and Japan and to what extent the gap reflects Japan-specific physical conditions (e.g., metocean constraints, seabed conditions, distance to shore, and water depth) or reducible factors associated with an early-stage market, such as limited supply-chain maturity and incomplete learning and standardization. The relative importance of these drivers would materially affect judgments about Japan's offshore wind pathway. If the latter factors are significant, then nurturing the domestic offshore wind industry—through supply-chain development, improved installation capability, and standardization—could potentially enable meaningful cost reductions over time.

1.2. Study Objectives

Building on the above problem statement, this report benchmarks the construction costs (on a total installed cost basis), referred to as Capital Expenditures (CAPEX), of fixed-bottom offshore wind in Japan in 2030 against those in Europe's mature offshore wind markets, while taking Japan's institutional and market context, as well as physical conditions, into account. We then quantify which cost components are particularly elevated in Japan. The cost gap is decomposed into: (i) factors driven by exogenous physical conditions such as metocean constraints, seabed and ground conditions, water depth, and distance to shore; and (ii) addressable factors that can be improved through industry and policy action, including installation practices, supply-chain development, ports and other enabling infrastructure, standardization and learning effects, and policy and regulatory design. Assuming progress on these addressable factors, such as supply-chain build-out and improved installation capability, we finally assess how much cost reduction could be achieved toward 2040 and identify the key bottlenecks that may constrain such cost declines.

1.3. Scope and Assumptions

This report focuses on fixed-bottom offshore wind, and on projects using monopile foundations, which have been the dominant foundation type in European markets (although jacket foundations are also widely used in parts of Asia).

The principal cost metric analyzed in this report is offshore wind construction cost, expressed as Capital Expenditures (CAPEX). CAPEX is a critical component of overall project economics because it accounts for a large share of LCOE and is directly affected by changes in material prices, labor costs, and installation conditions. In the Japanese context, many of the main cost drivers are expected to be reflected in CAPEX, including installation constraints as well as limitations related to ports and installation vessels. Accordingly, this report focuses on CAPEX to clarify Japan's current cost position and the scope for future cost reductions.

For analytical purposes, the report further distinguishes two broad sources of CAPEX uplift: (i) exogenous physical factors, such as seabed and ground conditions, metocean constraints, distance to shore, and water depth; and (ii) addressable factors, such as installation efficiency, supply-chain development, and market maturity.

At the same time, the definition of CAPEX can vary by context and may in some cases include items such as interest during construction (IDC), taxes and statutory charges, and decommissioning costs. Because these items are highly sensitive to institutional and financial conditions, simple cross-country comparisons can be misleading. To ensure consistency in international comparison, this report's analytical baseline uses construction-stage costs, including equipment procurement, manufacturing, transport, and installation. Items that are particularly sensitive to policy and regulatory differences, such as IDC, various taxes and charges, and decommissioning costs, are therefore excluded from the core comparison or presented separately. The detailed boundary definitions and treatment of each cost item are set out in Chapter 3.

For comparability, European cost figures presented in this report are converted into Japanese yen using an exchange rate of JPY 160/EUR based on 2024 average exchange rate. In addition, the 2030 and 2040 cost estimates are expressed on a 2026 price basis. This point should be borne in mind when interpreting cost differences between Europe and Japan, particularly considering recent exchange-rate movements and broader price volatility.

1.4. Structure of This Report

The remainder of this report is structured as follows. Chapter 2 provides an overview of differences between Europe and Japan in their institutional and market context, as well as physical conditions, and clarifies the conditions underlying the cost gap. Chapter 3 sets out the methodology used to estimate and compare total CAPEX costs, including an overview of Aegir's techno-economic model and the CAPEX module, and the design of sensitivity and scenario analyses. Chapter 4 presents the results: a comparison of 2030 CAPEX costs between Europe and Japan, a driver decomposition of the cost gap, and an outlook for cost reductions toward 2040. Finally, Chapter 5 synthesizes the key findings and discusses the outlook and remaining challenges for reducing the costs of offshore wind development in Japan.

2. Overview of the Status in Europe and Japan

2.1. Market size & supply chain

2.1.1 Market size

Offshore wind construction costs depend not only on the physical conditions of individual projects, but also to a significant extent on the maturity of the supply chain, which is shaped by market scale and the continuity of project development.

Europe hosts most of the world's leading offshore wind markets, where large-scale projects have been continuously developed, particularly in the North Sea. In 2025, offshore wind capacity in Europe increased by just over 2 GW, bringing cumulative installed capacity to approximately 37.3 GW by the end of 2025. The average annual addition since 2015 has been 2.7 GW per year, indicating a sustained pace of deployment (Aegir Insights, 2026). Such continuous market formation has supported investments in mass production of key components (e.g., turbines, foundations and cables), ensured the availability of installation and support vessels, and enabled the development of experienced contractors. As a result, it has contributed to the stabilization of construction costs at relatively lower levels.

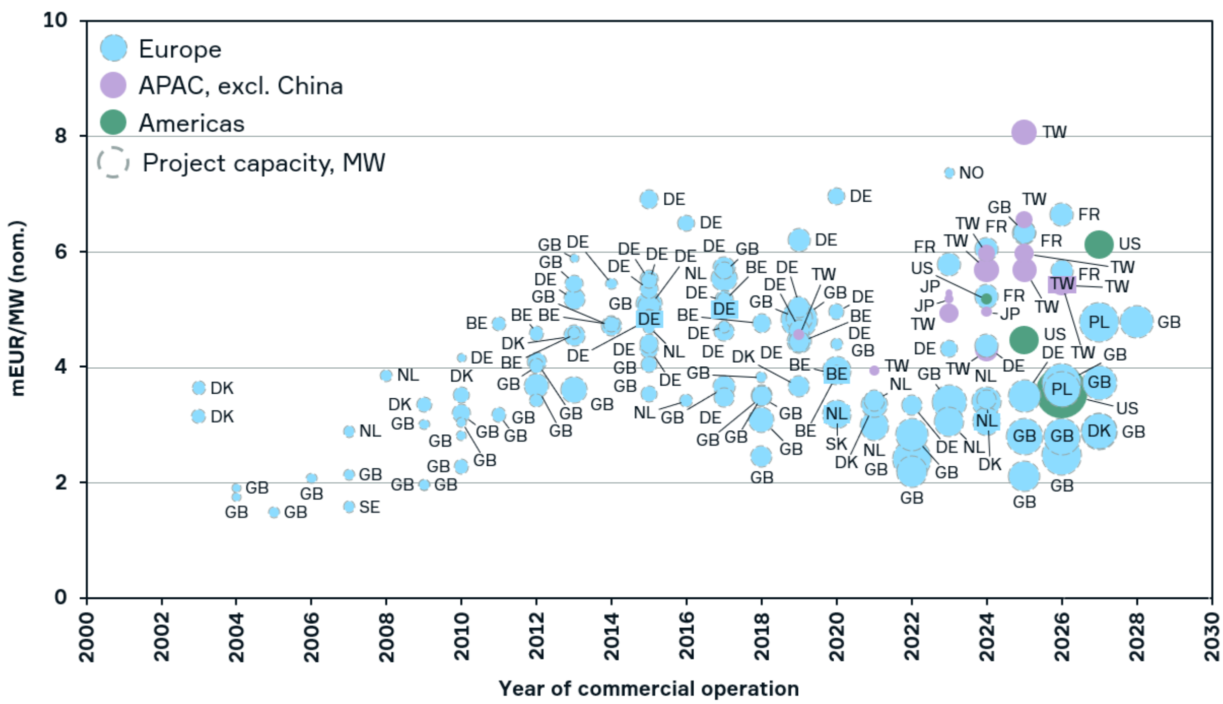
In contrast, Japan added only 0.1 GW of new offshore wind capacity in 2024-2025, with cumulative installed capacity reaching 0.3 GW by the end of 2025 (Aegir Insights, 2026)[2]. Annual additions remained close to zero until 2021, with deployment only beginning to accelerate from 2022, starting with projects in port areas. As of 2026, Japan has not yet reached a stage where a consistent level of annual construction demand has been established over an extended period, as seen in Europe. The lack of market scale and continuity in construction demand can become a key driver of cost differentials, through its impact on vessel specialization and long-term availability, as well as the feasibility of parallel project execution.

[2] As of February 2026, an additional 0.23 GW has commenced operation, bringing the total to approximately 0.53 GW.

2.1.2 Supply chain maturation

The European markets nurtured the development of offshore wind technology through relatively forward-thinking and stable policies from the period of 2010 onward. Today, offshore wind is a multi-billion-dollar industry with developed supply chains in leading markets that span development, project construction and installation, operation and maintenance, and decommissioning activities. The European offshore wind industry saw dramatic cost reductions from around 2016 to 2022 as seen in Figure 1, where the advent of 'subsidy free' bids also happened in Germany, Denmark, and the Netherlands.

Figure 1: Historical development in CAPEX cost[3]



Source: Aegir Insights

The European industry's rapid cost decline came about through several factors, including but not limited to historically low capital costs, rapid scaling up of turbine capacities, moving to continuous supply chain 'factory' operation and continuous offshore installation activities. Furthermore, the supply chain has demonstrated that its industrialized approach can deliver very low construction risk premiums.

[3] Chart shows projects >50MW. In cases where transmission scope is excluded from project, additional transmission CAPEX is added based on market specific transmission estimate.

One of the key drivers of lower offshore wind prices is the declining costs of wind turbines as turbine supply makes up ≈40% of total project CAPEX (≈45% including transport & installation). The offshore wind industry has a relatively low number of offshore wind turbine suppliers compared to the onshore wind industry, mostly due to company consolidations and challenges regarding profitability for new entrants. Up until 2020, there have generally only been two to three offshore wind turbine manufacturers with bankable technology in play; Vestas and Siemens. The resulting limited competition led to offshore wind turbine prices not experiencing the substantial price decline of the parallel onshore wind segment during most of last decade. However, towards the end of the 2020s, General Electric (GE) made a credible entry into the European market, while the Asian markets saw the emergence of offshore wind turbine suppliers from their existing onshore base. This increasingly competitive environment in conjunction with competitive tenders has already contributed to substantial cost reduction, and turbine prices are expected to fall incrementally going forward. However, this is contingent on a credible project pipeline at scale, which will unlock the regional procurement scaling and viability, which have been seen in Europe over the past decade.

In addition, offshore wind turbines have also continuously increased in size, providing substantial benefits in terms of economies of scale for their own cost base, and affecting the balance of plant in a positive way due to fewer turbines being required to achieve the same capacity. The tradeoff from turbine evolution is that the surrounding supply chain must remain highly adaptable and dynamic in order to keep up to speed. An example of this is offshore wind foundations. Monopile foundations account for over 85% of offshore wind installations to date and have been forced to continuously scale up due to increased loads from heavier and taller wind turbines. Monopiles are now increasingly reaching the limits of what can feasibly be installed, but tonnage savings and new vessels are expected to maintain the position of the monopile as the leading foundation technology for now.

The Japanese domestic supply chain is naturally at a very early stage, which means that component supply is predominately sourced from Europe. When there is a clear project pipeline in place with a significant scale, making the large supply chain investments feasible needed to establish a competitive local or regional supply chain, real CAPEX cost-out for future Japanese projects will become tangible.

2.1.3 Vessel availability and bottlenecks

Given the significant difference in market scale between Europe and Japan as described above, there is also a substantial gap in the overall depth of the supply chain. In particular, in offshore wind construction, the availability of installation vessels—such as wind turbine installation vessels (WTIVs) and jack-up vessels, commonly referred to as self-elevating platform (SEP) vessels—has a direct impact on both project timelines and costs. As wind turbines continue to increase in size, requirements for crane capacity and operational limits have become more demanding, necessitating substantial investment in appropriately capable installation vessels (Early, 2021).

In Europe, dedicated vessel fleets and specialized operators have been developed over many years, particularly in the North Sea. As of 2025, there are 31 foundation installation vessels globally (excluding China), the majority of which are operating in Europe (Aegir Insights, 2026).[4] With regard to wind turbine installation vessels, the 17 vessels are capable of supporting 15 MW turbine installation in Europe and globally in the late 2020s, while only three vessels will be available in the Asia-Pacific region (excluding China) (Aegir Insights, 2026).

In Japan, while project development is beginning to expand, the domestic fleet of specialized vessels and the accumulation of operational know-how based on a continuous project pipeline remain limited compared to Europe. When vessel availability becomes a binding constraint at the individual project level, it can hinder the optimization of construction schedules, potentially leading to project delays and increases in indirect costs.

2.1.4 Feasibility of Parallel Construction

When market scale is large and multiple projects are developed in geographically proximate areas, contractors and developers can coordinate to maximize vessel utilization, thereby reducing overall vessel demand. In Europe, in addition to the large market scale, maritime transport markets are, in principle, liberalized within the EU, allowing operators to access and deploy vessels across member states. This enables efficient allocation and shared use of vessels across multiple projects and markets, improving overall system efficiency. For example, an analysis of vessel demand in the Baltic Sea indicates that, through coordination between contractors and project developers to maximize vessel utilization, the number of required vessels could be reduced from nine to five in 2026, and from thirteen to seven in 2030 (H-BLIX, 2022). Another part of the explanation is the sector downturn as the forecasted project build-out has been

[4] This includes only vessels capable of supporting installation of XL-size monopiles (6-8 m outer diameter).

pushed to early 2030s, as a consequence of sector calibration after unsuccessful auctions outcome and project delays.

In contrast, in Japan, the limited number of projects and the lack of continuity in project development make it more difficult to optimize the allocation of vessels and personnel on the assumption of parallel construction. Where parallel execution is not feasible, vessel utilization rates may decline, construction activities may become more sequential, and idle time may increase. These factors can lead to higher construction-phase costs, particularly in installation and indirect cost components.

2.1.5 Long-term charter agreements

Offshore wind power developers with multiple projects may enter into long-term charter agreements for installation and support vessels. Such long-term arrangements are not only contingent on the existence of a continuous pipeline of projects on the market but are also important from the perspective of ensuring vessel supply. In particular, highly specialized installation vessels for offshore wind projects can face challenges in securing financing, which may constrain supply. Under these conditions, developers have increasingly moved to secure installation of vessels in advance through long-term contracts to support their project pipelines. An example of this approach is Ørsted's long-term agreement with Cadeler for a WTIV covering the period from Q1 2027 to the end of 2030 (NREL, 2024). The report highlights that by providing suppliers with visibility and scale of demand, developers can facilitate investment, which in turn can contribute to expanding the supply of installation vessels.

Moreover, developers with multiple projects can secure access to suitable vessels on a priority basis through such long-term agreements. Indeed, European analyses of vessel supply and demand indicate that entities with multi-project portfolios that are able to enter into long-term charter contracts are more likely to obtain preferential access, potentially affecting vessel availability for other market participants (H-BLIX, 2022).

In Europe, where multiple projects have been developed continuously in geographically proximate sea areas, both developers and major contractors are better positioned to structure long-term vessel contracts, thereby enhancing the certainty of vessel availability. In contrast, in Japan, where project development is still in an expansion phase and where cabotage regulations apply, the continuity and simultaneity of construction demand is limited. Under such conditions, optimization based on long-term contracting does not necessarily materialize.

2.2. Permitting and Cost burden

2.2.1 Multi-Stage Permitting Processes

Offshore wind projects are required to address multiple procedures and coordination processes prior to reaching the construction stage. These include procedures related to sea area utilization, environmental impact assessments, grid connection negotiations, maritime safety measures, and coordination with local stakeholders, including fisheries.

In Japan, in addition to the distinction between port areas and general sea areas under different regulatory frameworks, environmental assessments, grid connection, maritime safety, and stakeholder coordination are often handled as separate processes. As a result, project development tends to follow a “sequential” or stepwise progression, where one procedure becomes a prerequisite for the next. For example, progress in sea area utilization or stakeholder coordination can affect the completion of environmental assessments and the finalization of construction plans; without a finalized construction plan, key assumptions required for grid connection discussions (such as technical specifications and connection timing) remain uncertain. Consequently, even if individual procedures proceed as planned, the overall project schedule is still affected by delays or uncertainties in other areas.

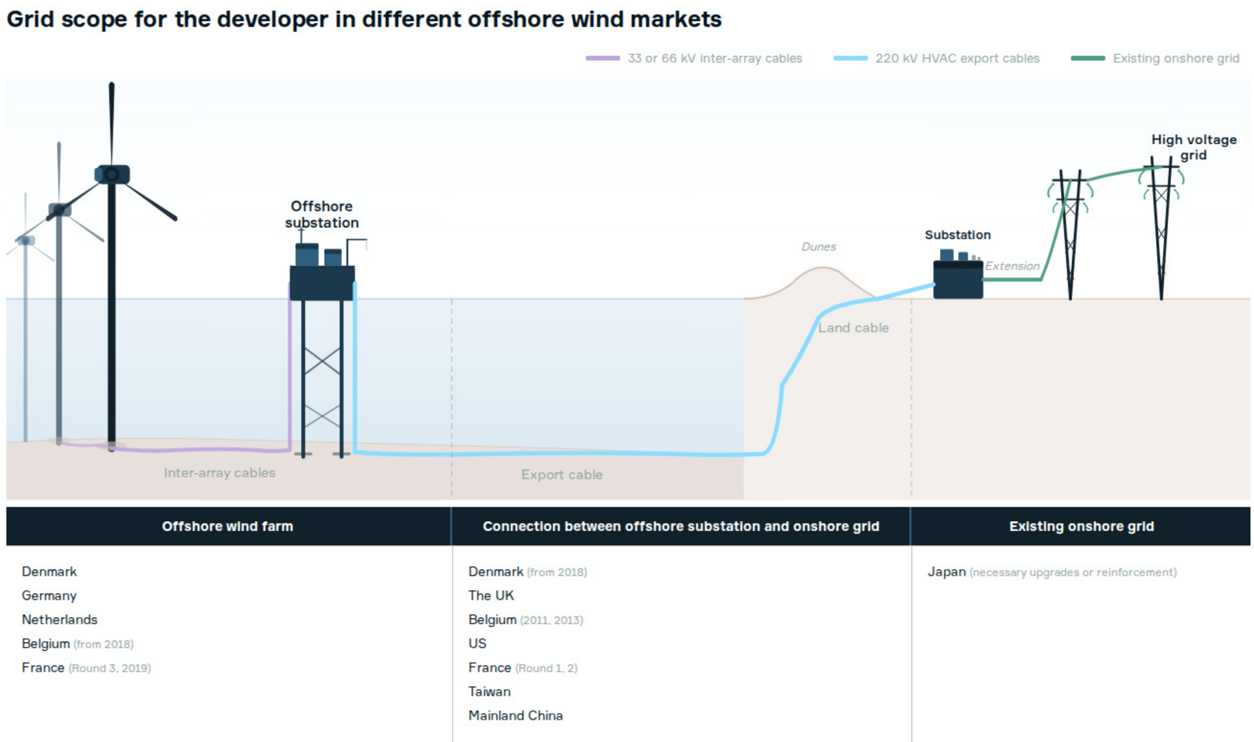
In contrast, while there are differences across mature offshore wind markets in Europe, key elements such as maritime spatial planning, environmental and technical requirements, and grid connection frameworks are generally structured within established regulatory systems. This provides developers with relatively clear and standardized reference conditions. However, it is important to note that permitting acceleration remains an ongoing challenge across the EU, and there are significant differences between countries.

As described above, factors such as the number of required procedures, the degree of interdependency among them, and the clarity of requirements can materially affect project risks, timelines, and costs at the development stage.

2.2.2 Institutional Framework for Grid Connection and Cost Allocation

One of the key institutional factors influencing offshore wind project costs and risks is the framework governing grid connection and cost allocation. Offshore wind projects are typically located in coastal areas and are often distant from major demand centers. As such, the arrangements for the development and operation of grid infrastructure, including onshore transmission lines and substations following landfall, form a critical part of the project's underlying conditions.

Figure 2: Cost Burden Concepts for Grid Connection of Offshore Wind Power



Source: Aegir Insights; GWEC; TenneT (2020)

In Europe, while there are variations across countries and regions, the general principle for cost allocation is that developers are responsible for the connection of assets linking the generation facility to the existing transmission or distribution network. Costs associated with reinforcements or upgrades of the existing grid are typically borne by transmission system operators (TSOs). This approach is commonly referred to as the "shallow connection" regime. In addition, in some countries, the responsibility of TSOs extends beyond the onshore grid to include offshore transmission infrastructure, such as export cables up to offshore substations. These arrangements can help reduce both the cost burden and risk exposure for project developers.

In contrast, in Japan, when the development of a power plant necessitates reinforcement or extension of the existing transmission network—including upgrades to transmission lines or substations—the associated costs are generally borne by the project developer. This approach, often referred to as a “deep connection” regime, results in a relatively higher cost burden on developers compared to European cases.

Furthermore, in Japan, institutional developments since the 2010s—such as the introduction of balancing markets and non-firm connection schemes—have improved the framework for integrating variable renewable energy. However, remaining transmission constraints, limited availability of balancing capacity, and increasing curtailment indicate that the system for fully accommodating variable renewable energy is still evolving. To enable large-scale deployment of offshore wind, further development of both inter-regional and intra-regional transmission networks will be required, along with the establishment of market mechanisms capable of providing sufficient flexibility to respond to short-term supply–demand fluctuations.

2.2.3 The Institutional Design of Port Policies for Offshore Wind

In scaling offshore wind deployment, ports are not merely logistics nodes; they are critical infrastructure that enables storage and handling of large components, assembly and pre-assembly, and homeport functions for installation vessels. As monopiles scale up (>10 m in outer diameter and >2,000 t weight) and turbines become larger (around the 15 MW class), ports are required to provide high-load-bearing yards (typically 20–30 t/m² or more), deep-water quays (generally around 12 m or more), space for large cranes, and compatibility with wind turbine installation vessels and jack-up operations.

In Europe, particularly in North Sea coastal countries such as the UK, the Netherlands, Germany, and Denmark, ports have been developed as part of long-term offshore wind expansion strategies, and privatization/commercialization progressed relatively early. As a result, port investments often take a hybrid form combining public support (e.g., subsidies) with investment decisions by port operators, and in many cases, land remains publicly owned while facilities and operations are private. Developers can typically select from multiple ports and allocate different port functions to different project phases. In addition, major ports often secure adjacent industrial land, enabling clustering of manufacturing, assembly, and logistics functions.

In Japan, the 2016 amendment of the Port and Harbor Act and the 2020 introduction of the Base Port (Kichi-Kōwan) scheme positioned offshore wind ports explicitly within the institutional framework. Under this scheme, the Minister of Land, Infrastructure, Transport and Tourism designates specific ports and establishes a framework that enables long-term leasing to offshore wind developers. As a result, projects tend to be planned around designated base ports. At the same time, institutional and physical constraints, including coordination with existing cargo functions, plot-by-plot leasing, and land-use restrictions, mean that flexible spatial use remains more limited than in Europe.

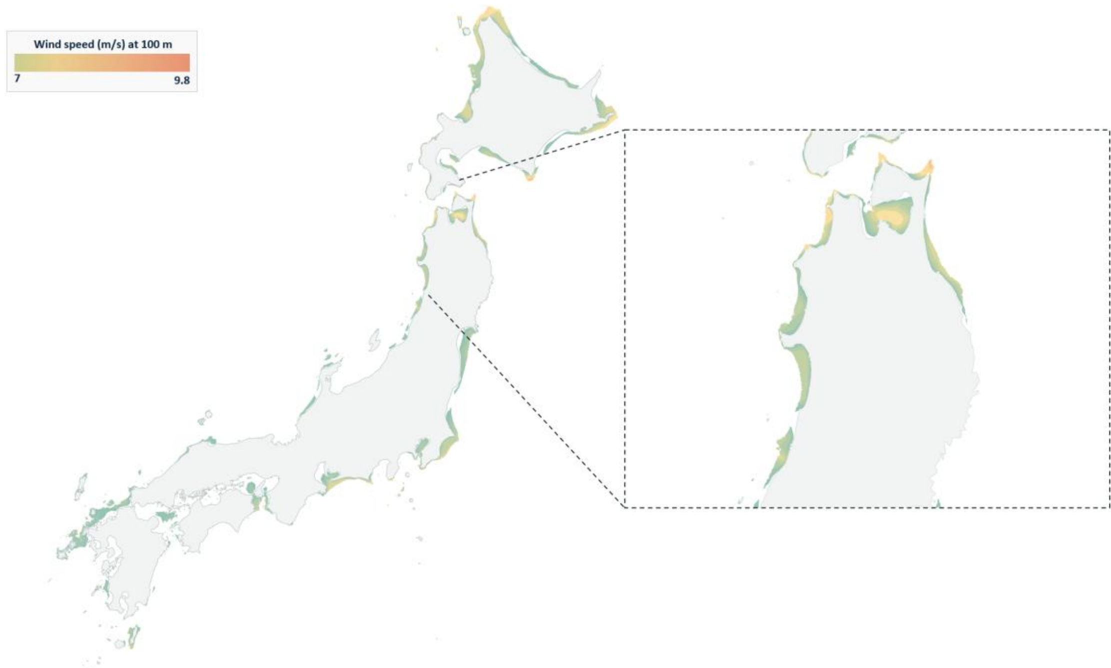
These institutional differences can affect both the level and flexibility of port-related costs. In Europe, competition among ports more readily creates pressure to improve service conditions and moderate prices, whereas in Japan, the early fixation of the port, through base port designation and related arrangements, can limit competition-driven improvements. Moreover, constraints on adjacent land availability and land-use restrictions can make it difficult to deploy long-term storage, pre-assembly, and industrial clustering in an integrated manner near the port. This can increase port-related costs and construction overheads through additional yard procurement costs, secondary transport, and less efficient work and logistics flows.

2.3. Physical Conditions

2.3.1 Wind Resource

Japan's bathymetry limits the area available for fixed-bottom development. Water depths increase rapidly with distance from shore, restricting suitable fixed-bottom areas to within approximately 15 km of the Pacific coastline and similar narrow strips along the Sea of Japan. Hokkaido has the most evenly distributed fixed-bottom resource, with suitable water depths found within around 10 km of shore along most of its coastline. Areas near the Tsugaru Strait combine eligible water depths with relatively high wind speeds, though these represent a small share of total technical potential. Below the conventional 60m fixed-bottom depth threshold, Japan's technical potential is estimated at 148 GW. The wind resource within this envelope is largely moderate: 98 GW falls within the 7–8 m/s range, 49 GW within 8–9 m/s, and only 1.3 GW exceeds 9 m/s. Japan also has large areas of seabed between 60 and 100m water depth. Some argue that fixed-bottom foundations could be deployed at these depths, which would significantly shift the balance between fixed-bottom and shallow-water floating potential. Under a 100m depth threshold, the fixed-bottom technical potential more than doubles to 316 GW (Aegir Insights).

Figure 3: Wind map around Japan with water depth below 60 m



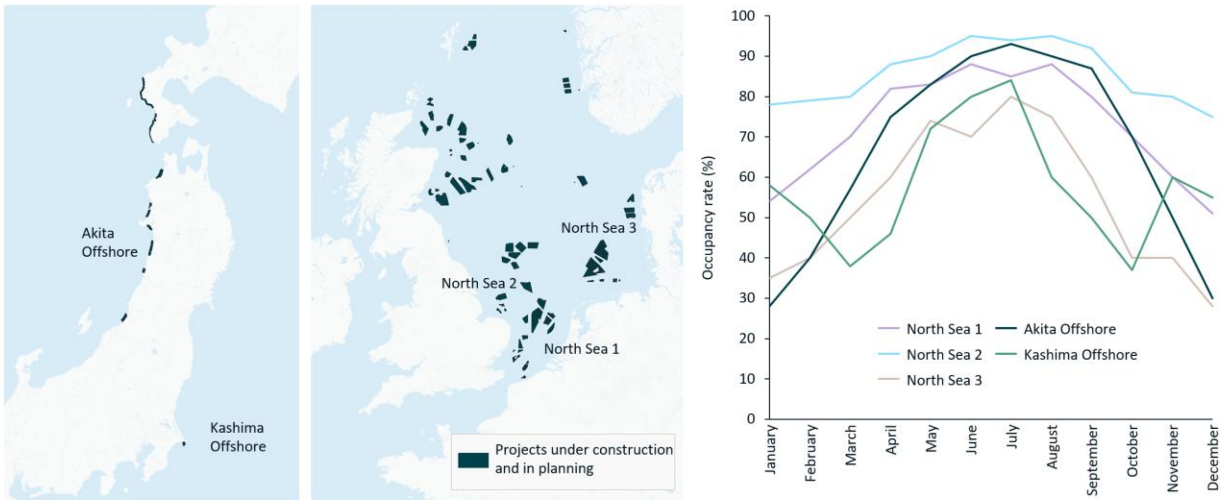
Source: DTU Global Wind Atlas (2026); Aegir Insights

By comparison, the North Sea is one of the world's most resource-rich regions for fixed-bottom offshore wind development. According to the Global Wind Atlas, mean wind speeds across the central and southern North Sea at 100m height are broadly in the range of 9–11 m/s on an annual basis. At this hub height, North Sea wind speeds exhibit strong seasonal variability, ranging from approximately 7–8.5 m/s in summer to 10–11.5 m/s in winter. These conditions translate into some of the highest capacity factors globally for offshore wind. On bathymetry, optimal sites in the North Sea are typically found in water depths of less than 60m, and monopiles have been widely used as the chosen foundation type with only few exceptions. Together, an exceptional wind resource and largely accessible bathymetry have established the North Sea as the global benchmark for utility-scale fixed-bottom offshore wind development.

2.3.2 Metocean Conditions

Japan experiences high waves and gusts due to frequent typhoons in autumn and the effects of rapidly developing low-pressure systems. Due to these factors, the estimated operability of a self-elevating platform (SEP) vessel is approximately 80% in the summer and around 40% in spring and autumn as jack-up/-down operation requires a significant wave height of 1.5 m or less with a wave period of 12 seconds or less (Figure 4).

Figure 4: SEP vessel operational rates by month

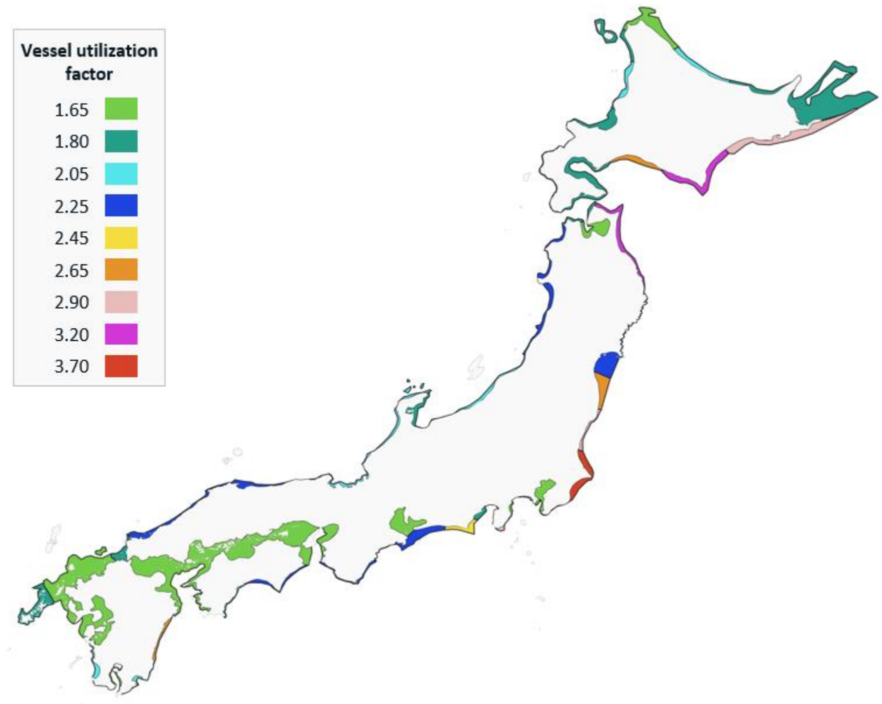


Source: Aegir Insights (2026); Ports and Harbours Bureau, Ministry of Land, Infrastructure, Transport and Tourism (2021)

In addition, there are significant regional differences in metocean conditions across Japan. Operability on the Pacific side is lower than on the Sea of Japan side, which can be attributed to swell conditions.[5] The ratio of calendar days (365 days per year) to the number of workable days is referred to as the vessel utilization factor (WDF). For Japan, NEDO (2024) compiles sea-area-specific WDF values and reports a median of 2.05 (mean: 2.21) excluding the Seto Inland Sea and remote island areas (Figure 5). By contrast, typical European offshore wind projects benefit from more favorable operating conditions, with vessel utilization factors commonly closer to 1.5. A utilization factor of 2.05 therefore implies that, on average, only about 49% of the deployed time is productive, with the remainder lost to weather and logistical downtime. In sea areas where operational limits driven by significant wave height and wind speed are more frequently binding—and where weather downtime is more common—the factor tends to be higher. This can be interpreted as one channel through which exogenous physical conditions (metocean constraints) affect installation efficiency. Applied to installation activities, this results in downtime of a similar magnitude to productive working time.

[5] "Swell" refers here to waves that have propagated into an area without wind, or waves remaining after winds have weakened.

Figure 5: Vessel utilization factor by sea area



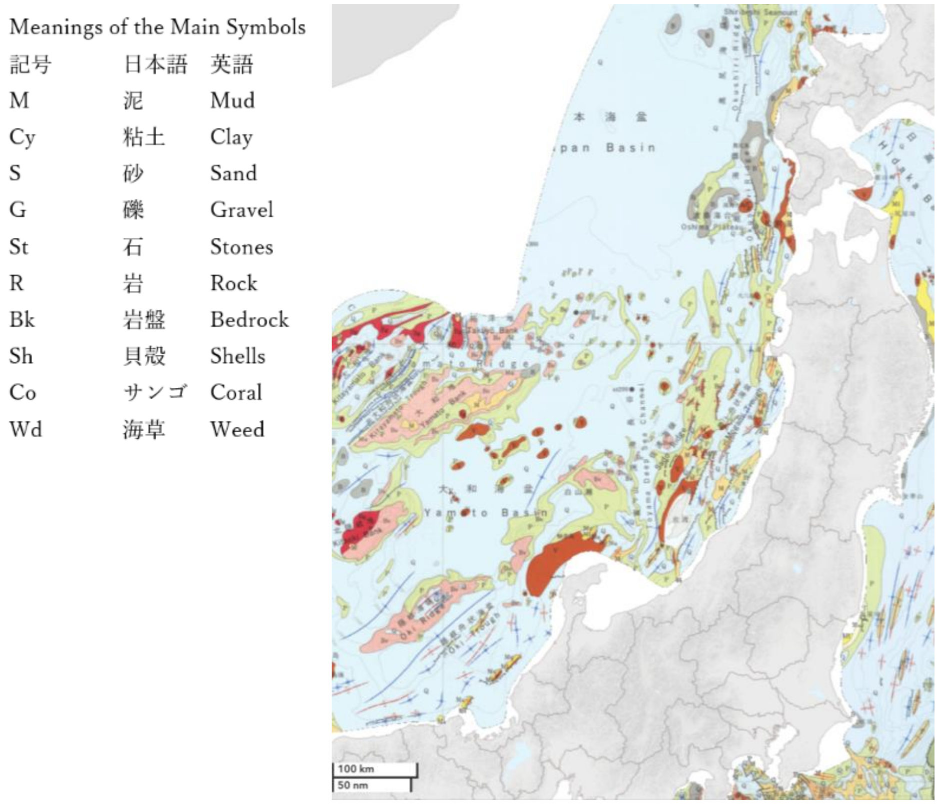
Source: NEDO (2024)

By comparison, installation, maintenance and servicing of offshore wind farms in the North Sea also pose significant challenges. However, the North Sea weather environment is driven primarily by Atlantic low-pressure systems rather than typhoons, which produces wave conditions that are more predictable in their seasonality. In the summer, lower average wave heights, lower wind speeds, and better lighting conditions mean that operators plan regular construction and maintenance activities during this time. A significant wave height limit of 1.5 m is commonly applied for crew transfer vessel operations in the North Sea, consistent with the thresholds used in Japan, though the frequency and duration of suitable weather windows across the construction season is generally higher in European waters than in Japan, where spring and autumn operability is further constrained by episodic severe weather events.

2.3.3 Seabed Ground Conditions

Japan's seabed conditions are considerably more complex than those typically encountered in the North Sea. Rather than the relatively uniform sandy seabed that has facilitated standardized foundation design in Europe, Japan's offshore areas exhibit highly variable soil profiles, with rapid lateral transitions between soft clays, dense sands, gravel layers and hard bedrock. Sandy seabed and rock are frequently intermixed, while soft ground is commonly in ports and enclosed bays (Figure 6).

Figure 6: Marine geological map of Japan



Source: Marine Science & Technology Center (MSIL) Marine Geoscience Information Portal, Japan

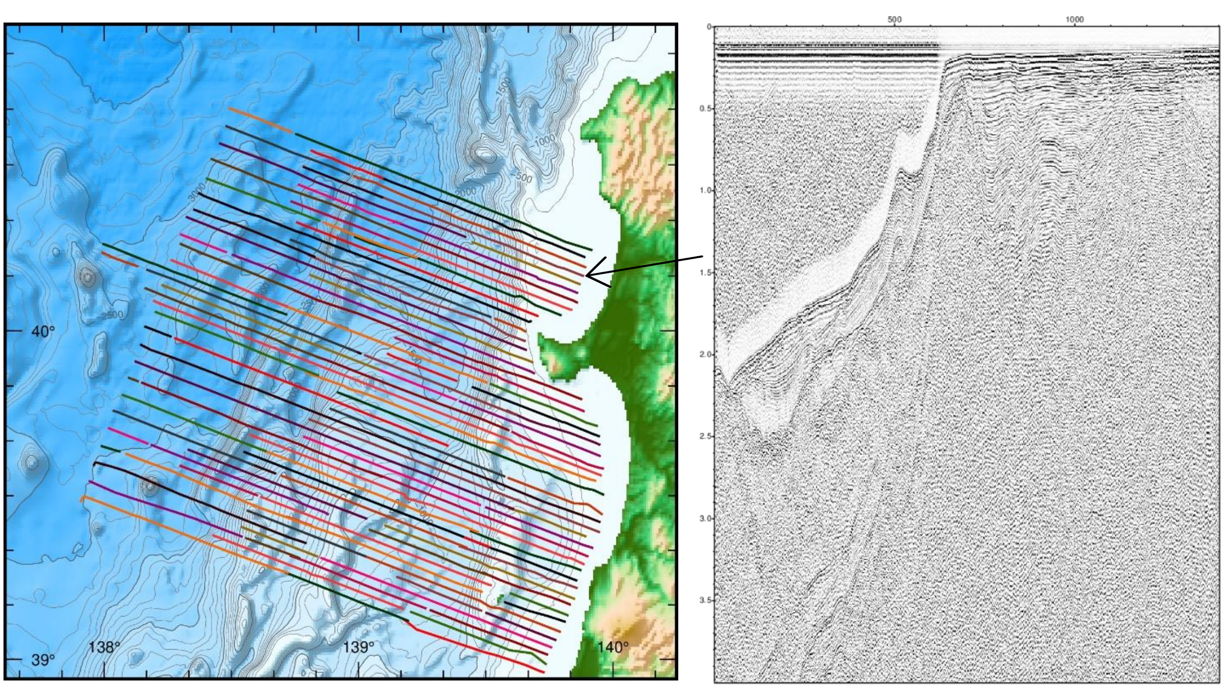
Much of Japan's offshore area is covered by soft surface sediments, mainly clay and clay-rich deposits. These data describe only the material at the seabed surface and do not provide information on sediment thickness or subsurface conditions.

To address this limitation, seismic sections from the Marine Seismic Database were examined. As an illustrative example, a representative seismic exploration profile from the Akita offshore area is presented (Figure 7). Akita is one of the core development areas for Japan's offshore wind program, with several projects in the Round 2 and Round 3 pipeline located off the Akita coast.

The seismic reflection profile from the Akita offshore area (Figure 7) shows a thin, continuous sediment layer overlying a strong acoustic basement. Near the seabed, reflectors are relatively flat and weakly layered, consistent with soft surface sediments such as clay or clay-rich deposits. At the same time, the shallow depth to the acoustic basement and the limited sediment thickness imply that hard geological layers may be encountered relatively close to the seabed in parts of the area. From a foundation perspective, this suggests that monopile installation may meet hard layers or bedrock at shallow embedment depths, potentially requiring drilling or modified installation methods. The profile also indicates that seabed surface conditions can differ materially from the ground conditions encountered at depth, increasing geotechnical uncertainty.

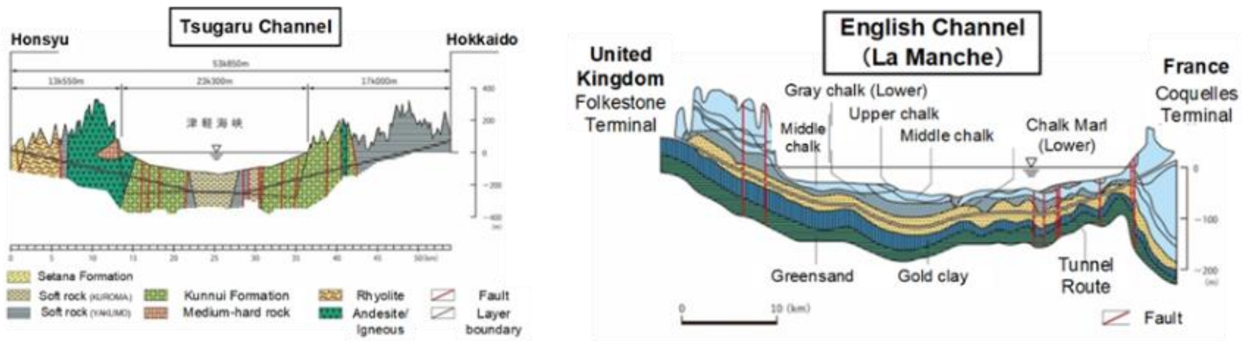
Where pre-surveys and geophysical investigations indicate broadly similar ground structures and soil properties, sites can be grouped and assessed collectively, reducing the number of investigations required. In Japan, however, rapid lateral variability often makes such grouping difficult, and multi-location surveys are typically needed—adding time and cost to site investigation programs. Additional complexity arises from differences in standard investigation methods: Japan commonly uses the Standard Penetration Test (SPT), whereas the Cone Penetration Test (CPT) is widely used in Europe. If CPT is applied in Japan, SPT–CPT correlation and integrity must be demonstrated. While IEC 61400-3-1 specifies a single soil boring near the CPT location for calibration, Japanese guidance—given spatial variability—often recommends comparison data from multiple locations, effectively increasing calibration requirements across a project site. This increases survey costs and can indirectly raise foundation costs, as higher uncertainty must be addressed through more conservative design assumptions and/or additional engineering analysis.

Figure 7: Sonic exploration profile of Akita, Japan



Source: Marine Seismic Database, Geological Survey of Japan (GSJ), National Institute of Advanced Industrial Science and Technology (AIST)

Figure 8: Seabed Ground Conditions of Tsugaru Channel and of English Channel

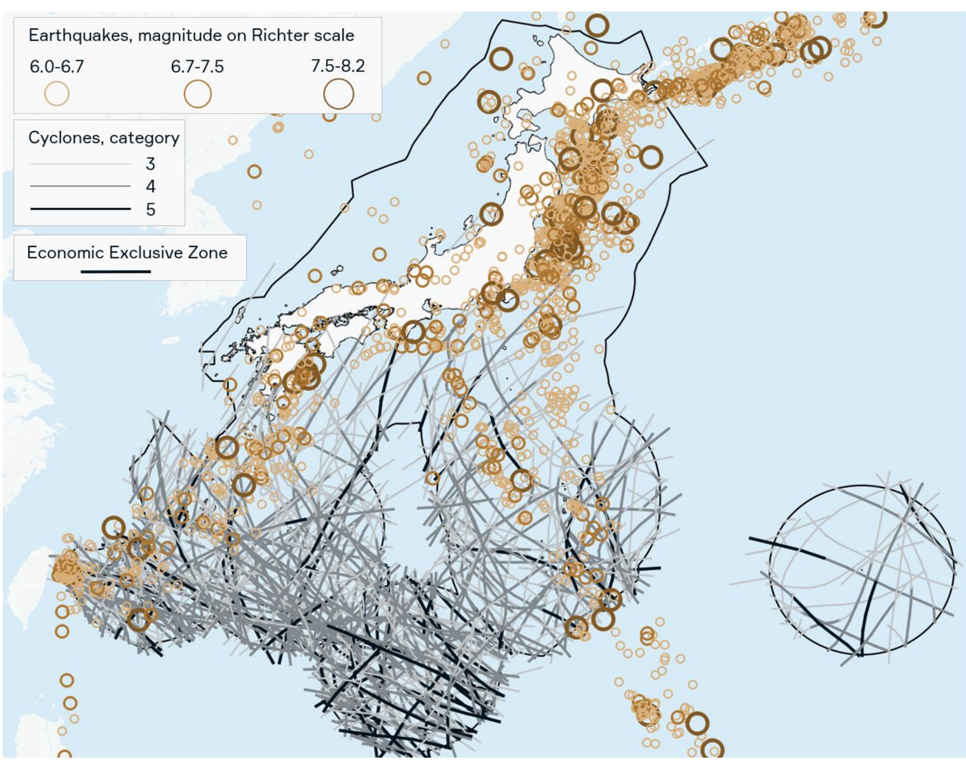


Sources: Ports and Harbours Bureau, Ministry of Land, Infrastructure, Transport and Tourism, (2021)

2.3.4 Earthquakes and Seismic Load Evaluation

In addition to complex seabed conditions, Japan is highly exposed to natural hazards due to its location along active tectonic plate boundaries, resulting in frequent earthquakes and the potential for tsunamis. The country also experiences regular typhoons, particularly affecting the southern regions. Most typhoons fade before reaching land, but offshore wind projects are at greater risk of being hit by typhoons.

Figure 9: Earthquakes and cyclones in Japan



Source: Japan Seismic Hazard Information Station

In Japan, seismic wave periods are classified into three ranges: less than 0.16 seconds, between 0.16 seconds and 0.64 seconds, and more than 0.64 seconds. Japan requires confirmation of safety against both (i) ground motions that occur infrequently (indicative: 50-year return period) and (ii) ground motions that occur extremely infrequently (indicative: 500-year return period).

Under the IEC 61400 series, seismic load evaluation can be performed using either the response spectrum method or the time-history response analysis method. In earthquake-prone Japan, seismic loads are evaluated through combined analysis of load effects obtained via time-history response analysis and the load effects of annual average wave and wind conditions. This is a more demanding analytical framework than is typical in Europe, where general integrated load analyses are conducted across selected fatigue and ultimate load cases, and where survey and analysis methods are not prescribed in the same level of detail.

The consequence is a materially more complex and costly design process for Japanese projects. The need for site-specific time-history analyses, informed by detailed seismic hazard assessments, adds to the survey burden at the front end of a project. At the structural design stage, the additional seismic load combinations must be explicitly accounted for in the dimensioning of both the tower and the monopile, typically resulting in heavier and more conservatively designed structures than would be required for an equivalent project in European waters. Together with the geotechnical survey costs discussed above, this represents a compounding structural cost premium that is largely absent from the European offshore wind cost base.

3. Methods

CAPEX is the up-front investment required to build or acquire long-term assets, such as infrastructure or equipment. In offshore wind, it covers procurement, installation, and construction costs up to Commercial Operation Date (COD) of all positions. CAPEX is a useful metric as it captures the majority of a project's lifetime costs and enables comparison across projects and markets, reflects differences in technology, supply-chain maturity, and policy design, and helps forecast future cost-reduction pathways as markets scale.

Industry and policymakers commonly use CAPEX as a measure to compare capital requirements across power-generation technologies and to inform decisions on future energy pathways. By using CAPEX, this report provides a quantitative assessment of the current cost gap between Europe and Japan for fixed-bottom offshore wind and identifies the main drivers by component. CAPEX is calculated for Europe and Japan respectively using representative reference cases with site characteristics that capture the general conditions of each of the two regions.

3.1. Model Overview

The cost model used in this study, Aegir Quant™ 2025.4, is provided by Aegir Insights. This is a proprietary techno-economic offshore wind performance model which has been developed by the company in cooperation with industry and academic partners. Aegir Quant™ is an advanced investment intelligence solution designed to optimize business case calculations for offshore wind projects and portfolios. It integrates a combination of surrogate machine learning models, engineering models, and parametric cost models to support technically robust analysis of offshore wind scenarios in seconds.

3.1.1 Model Architecture

The CAPEX model can be understood as a baseline cost structure that is adjusted through three main layers:

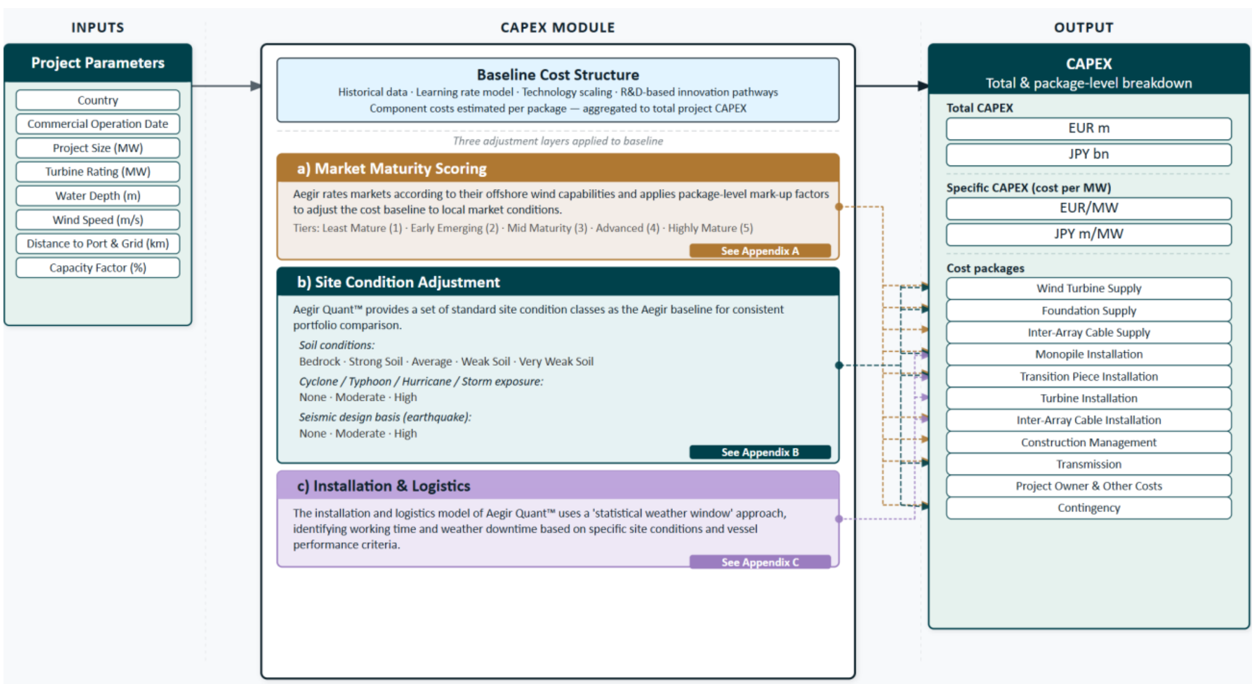
(i) design and site-condition adjustments (e.g., soil, seismic and cyclone exposure) that affect component design and selected cost drivers;

(ii) installation and logistics modeling that estimates workable time and weather downtime based on site metocean conditions and vessel workability criteria; and

(iii) market-maturity adjustments that apply package mark-ups and contingency[6] to reflect execution uncertainty and local contracting conditions.

These layers are applied to distinct aspects of the cost build-up and are implemented to avoid double counting of the same effect (e.g., downtime or standby risk) across modules. Figure 10 illustrates the overall structure of Aegir Quant™, summarizing the model inputs, the three CAPEX adjustment layers, and the resulting outputs. The figure also show the appendices where each adjustment is documented in further detail.

Figure 10: Aegir Quant™ CAPEX model architecture



3.1.2 Validation Approach and Evidence

Aegir Quant™ undergoes continuous validation across all sub-models — spanning technical models for energy production, foundation and electrical system design, installation logistics, and operations and maintenance, as well as cost models for CAPEX, OPEX, and DEVEX. This process is conducted in collaboration with industry partners and leading academic institutions and employs a range of validation methods including benchmarking against real-world project data, scenario analysis under varying market and technology conditions, and ongoing expert review and calibration. These diverse techniques collectively ensure that the outputs of Aegir Quant™ are

[6] Contingency is a budget allowance added to the estimated project costs to cover unforeseen risks and uncertainties. It accounts for risks such as design changes, weather delays, productivity shortfalls, and cost overruns that are not fully captured in individual cost items. In Aegir Quant™, it is calculated as a percentage of total CAPEX, with the rate determined by the market maturity score and site condition adjustments.

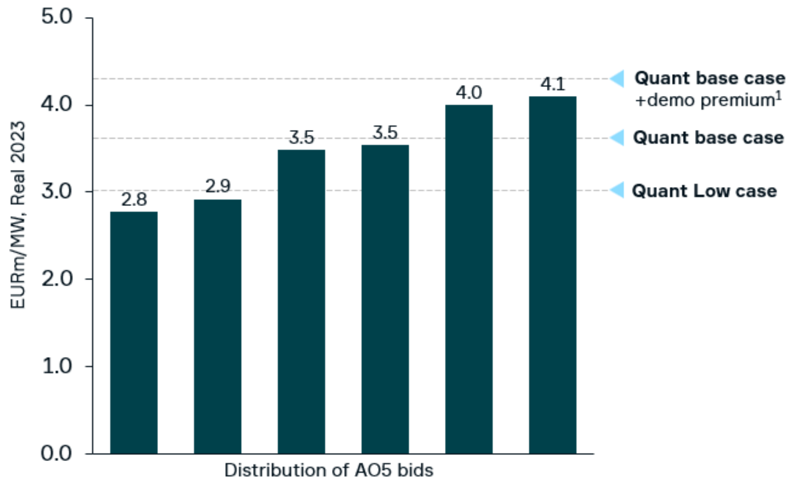
robust, accurate, and reflective of real-world conditions across both mature and emerging offshore wind markets. Appendix D details the key models and development partners for Aegir Quant™ and Appendix E shows the validation methods used for the development of the model.

The CAPEX model of Aegir Quant™ is used to estimate costs, based on project configurations and installation campaigns, drawing on comprehensive data from industry reports, proprietary databases, and historical project records. Cost reduction pathways are modelled using learning rate methodology, which tracks cumulative production experience across global offshore wind capacity, while market maturity factors adjust the cost baseline to reflect local supply chain capabilities and contracting conditions. Future CAPEX trajectories incorporate expected trends in technology scaling, materials, and manufacturing advancements.

Validation of the Aegir Quant™ CAPEX model follows a structured, multi-layered approach. First, model outputs are systematically benchmarked against actual project costs from realized offshore wind projects across multiple markets, ensuring that the model's predictions fall within the range of observed real-world outcomes. Second, scenario analysis is conducted across a range of market conditions, technological trajectories, and policy environments to stress-test the robustness of CAPEX estimates and identify potential sensitivities. Third, the model's assumptions and parameters are subject to continuous review by industry experts and academic partners, whose feedback is used to refine methodological choices and maintain alignment with current industry practice and emerging market developments.

Validation is further grounded in direct comparison with public auction disclosures, which provide an independent and transparent reference point for cost benchmarking. As a concrete example, benchmarking against the six bids submitted in the 2024 French AO5 auction yields a CAPEX/MW deviation of within 1.5% relative to the Aegir Quant™ base case, a level of precision that demonstrates strong alignment with independently derived market estimates and underscores the reliability of the model for cross-market cost assessment.

Figure 11: CAPEX model validation: Aegir Quant™ validation against recent auction results in France (2024)



Note: 1) A demo premium is used when analyzing floating projects with a capacity of less than 200 MW

The CAPEX cost divisions used for this study are based on the scope of the activities and contracts according to common industry practice. These cover the main wind farm components such as turbines, foundations, array cables, export cables, and substations split on supply and installation contracts.

3.2. Case Definitions

To clearly differentiate the European reference case and the Japanese reference case, the model applies a market-maturity scoring framework. Aegir Quant™ uses a Market Maturity score (1–5) to apply an execution risk premium on top of a baseline offshore wind cost structure. A higher score indicates a market that can deliver offshore wind repeatedly with stable outcomes, typically supported by a stronger project track record, deeper supply chain and competition, more predictable permitting and grid processes, and well-established contracting and delivery infrastructure (ports, marine execution and certification pathways). In Aegir Quant™, higher maturity therefore implies fewer interface issues, less rework and standby time, and fewer unexpected scope or schedule changes, which translates into lower package markups and lower contingency. Lower maturity increases markups and contingency to reflect higher execution uncertainty.

The European reference case is classified as having ‘advanced maturity’ scoring (4) in 2030. Advanced maturity refers to a market where commercial delivery has been proven across multiple project cycles; while some bottlenecks may remain, outcomes are generally predictable. Japan is classified as a ‘mid-maturity’ (3) market in 2030 and ‘advanced maturity’ (4) in 2040. Mid-maturity categorization reflects a market in which commercial delivery is underway and scaling, but constraints persist, resulting in higher interface risk and greater variability in delivery outcomes. Appendix A provides details on which cost packages are affected by the market maturity score and the magnitude of the impact.

When assessing the commercial attractiveness and economic viability of an offshore wind market, reference cases are developed to indicate how a generic offshore wind project would perform in a given area. These sites are chosen to represent typical conditions in the area. Reference cases are well suited to comparing CAPEX levels between different regions and across energy sources, both domestically as well as internationally.

To establish comparable benchmarks for cost levels and development, the approach in this study has been to define one generic reference case for Europe in 2030 and two for Japan: a 2030 reference case, and a scaled-up 2040 case reflecting larger deployment volumes and a more mature supply chain. The cases are not specific to any one place in either Europe or Japan but are rather generally representative of conditions in the two regions. Model parameters are adjusted to reflect the key site characteristics that drive offshore wind project value, including wind speed, water depth, and distances to ports and grid connection points. These factors are the primary drivers of cost and value differences when applying consistent technology assumptions across offshore locations.

Europe 2030 reference case: A representative 450 MW fixed-bottom offshore wind project is assumed, with a site water depth of 30 m, average wind speeds of 10.2 m/s, and utilizing 15 MW turbines. The project is located 50 km from the construction port, and the total distance to the grid connection point is assumed to be 45 km, comprising 30 km offshore and 15 km onshore. A capacity factor of 54% is assumed for this case, in line with Aegir Quant™ assumptions.

In Japan, two reference cases were defined to capture expected technology maturation and cost reductions toward 2030 and 2040. While both cases share a common set of baseline assumptions, key project attributes differ to reflect anticipated industry evolution.

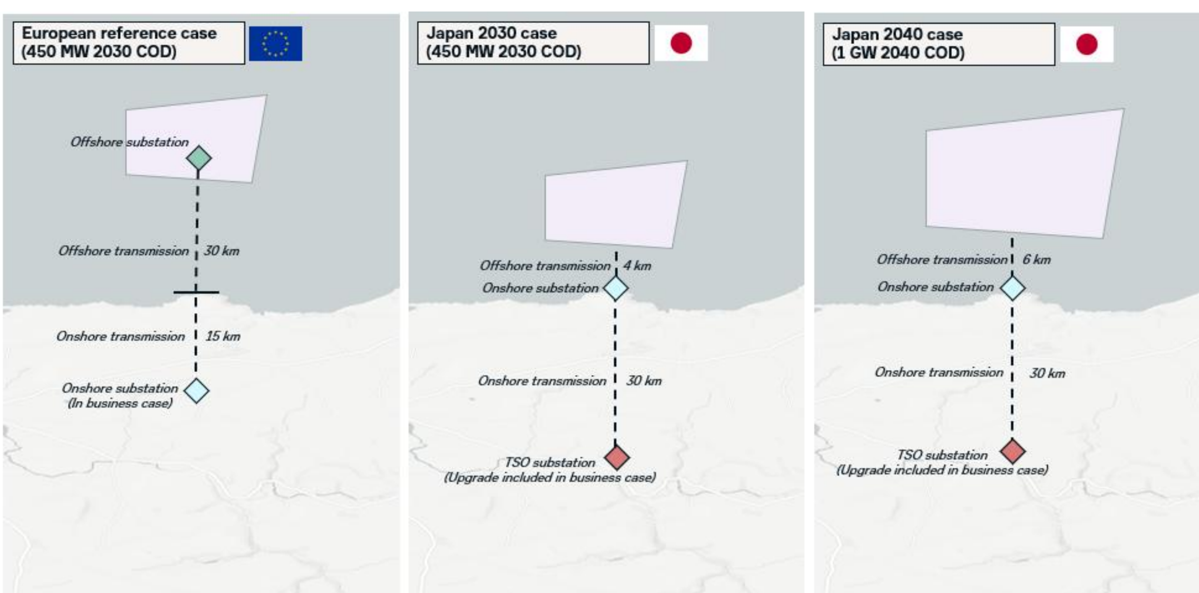
Japan 2030 reference case: A 450 MW fixed-bottom offshore wind project is assumed, using 15 MW turbines and located in 20 m water depth. The site has an average wind speed of 7.9 m/s and is situated 50 km from the construction and O&M port. The 34 km distance to the grid connection point is assumed to comprise 4 km offshore and 30 km onshore. A 37% capacity factor is assumed.

Japan 2040 reference case: Reflecting scale-up and further technology optimization, the 2040 case assumes a 1,000 MW project with 20 MW turbines in 30 m water depth. The 36 km distance to the grid connection point is split into 6 km offshore and 30 km onshore. A modest performance increase is captured through a 39% capacity factor. Similarly to the 2030 case, the average wind speed is 7.9 m/s and the distance to the construction and O&M port is 50 km.

Table 1: Characteristics of reference cases in Europe and Japan

	Europe 2030	Japan 2030	Japan 2040
Size (MW)	450	450	1000
Turbine rating (MW)	15	15	20
Water depth (m)	30	20	30
Annual mean wind speed at 100m height (m/s)	10.2	7.9	7.9
Distance to grid (offshore) (km)	30	4	6
Distance to grid (onshore) (km)	15	30	30
Distance to construction and O&M port (km)	50	50	50
Capacity factor (%)	54	37	39

Figure 12: Project scope differences between Europe and Japan



The European reference case project connects via an offshore substation with 30 km of offshore transmission and 15 km onshore transmission to a developer-owned substation. In contrast, Japan's bathymetry requires projects to be located much closer to shore—approximately 4 km offshore in the 2030 case and 6 km in the 2040 case—removing the need for an offshore substation. Power is transmitted directly to shore to an onshore substation and then carried via around 30 km of onshore transmission infrastructure to a Transmission System Operator (TSO) substation. In the Japanese cases, both the onshore transmission and the required upgrades to the TSO substation are borne by the developer and are therefore included in the CAPEX model.

3.3. Data

Japan-side input parameters are set primarily based on publicly available information and prior studies and are supplemented where necessary by interviews with industry stakeholders, including project developers/contractors and the Japan Wind Power Association (JWPA). Assumptions for vessel utilization factors and related parameters draw on a report published by the New Energy and Industrial Technology Development Organization (NEDO) (NEDO, 2024). These inputs are incorporated into the Japan 2030 reference case and the relevant analysis. The integration of Japan-specific assumptions is described in further detail in the following section.

Information on port lease fees and the cost-sharing structure for port upgrades is based on a combination of a prior study by the Renewable Energy Institute (Renewable Energy Institute, 2025) and JWPA interview inputs, reflecting the fact that port-related charges can vary materially by port upgrade requirements and the number of users sharing such costs. Where available, interviews with developers/contractors are also used to complement selected parameters, such as vessel charter cost assumptions, subject to confidentiality constraints.

In addition, installation durations for foundations and turbines are derived from public information (including Aegir Insights' Project Database) for four Japanese fixed-bottom offshore wind projects constructed between 2021 and 2025. To ensure comparability with European datasets, the approach to organizing installation durations follows Lacal-Arántegui et al. (2018): for each project, the installation period (days) is calculated from the start and completion dates of installation activities and then normalized by the number of installed units to obtain metrics in “days per foundation” and “days per turbine.” Average turbine installation durations, expressed in days per turbine, are derived from the observed four operational projects that total nearly 500 MW, providing a relatively robust data set in an emerging market like Japan. Average monopile installation durations are based on two projects, which used monopile foundations, as the remaining projects employed jacket foundations. As a result, the monopile installation benchmarks are drawn from a smaller sample, which introduces a higher degree of uncertainty. With respect to transit and mobilization time, publicly available information and the characteristics of the Japanese projects suggest that the contribution of port-to-site transit is likely to be limited; accordingly, we interpret the derived installation durations with care so as not to overstate this component. Definitions of the adopted input values, ranges and uncertainty treatment, and how these inputs are implemented in the model are provided in the next section (Section 3).

In this analysis, uncertainty in CAPEX is addressed through the application of a contingency allowance. Contingency is set at 8.6% for Japan and 6% for Europe in 2030, reflecting differences in market maturity as captured by the market-maturity scoring framework and the site condition adjustments.

3.4. Integration of Japan inputs into the Quant™ model

Japan-specific inputs are integrated by using the same CAPEX package structure as the European benchmark as a common framework and then replacing only those parameters where Japan-Europe differences are material with Japan-specific values. The parameters replaced are site and design conditions, installation durations, vessel utilization assumptions, vessel charter rates, port lease rates, stakeholder compensation and transmission upgrades. Where robust Japan-specific evidence is not available, Aegir Quant™ default assumptions are applied.

3.4.1 Assumptions based on Japan's physical conditions

In Aegir Quant™, local site conditions and related design requirements adjust the baseline offshore wind cost structure of the model. The framework translates physical drivers such as metocean severity, soil conditions, sea ice, seismic design basis, and tropical cyclone exposure into targeted cost adjustments. Aegir Quant™ provides a set of standard classes as the Aegir baseline to enable consistent portfolio comparison. In Japan, factors driven by exogenous physical conditions such as metocean constraints, seabed and ground conditions, water depth, and distance to shore are unlikely to decrease with market maturation.

Complex seabed **soil conditions** represent a significant structural cost driver for offshore wind projects in Japan. Japan has a more challenging seabed compared to the North Sea. Japan's offshore areas exhibit highly variable soil profiles, with rapid transitions between soft clays, dense sands, gravel layers and hard bedrock. These conditions increase the likelihood of requiring drilling, alternative installation methods, or design adaptations. The seismic profile of Japan presented in Section 2.3.3. supports the use of shallow bedrock as a conservative and representative benchmark assumption for the Japanese reference case. Accordingly, bedrock or very competent ground condition (characterized by short embedment and the potential requirement for drilling) is selected from the Aegir Quant™ soil categories. Contingency is modestly reduced relative to weaker soil conditions, where ground model confidence and drivability uncertainty are typically larger. The impact of bedrock soil conditions on the individual CAPEX packages is described in detail in Appendix B.

For current commercial-scale projects in Japan, **monopiles** are the primary fixed-bottom solution. They are suitable for water depths up to about 60 m and can be fabricated and installed relatively efficiently once local manufacturing capacity is in place. Japan's first monopile manufacturing facility was completed in 2024 in Kasaoka City, marking a major milestone in the development of a domestic offshore wind supply chain. JFE Engineering has established large-diameter monopile production capacity to support upcoming fixed-bottom projects. Given this emerging domestic capability, monopiles for the reference cases are assumed to be manufactured in Japan.

In addition, Japan is highly exposed to **natural hazards** due to its location along active tectonic plate boundaries, resulting in frequent earthquakes and the potential for tsunamis as presented in Section 2.3.4. Accordingly, the reference case assumes a high seismic design basis (earthquake) and high tropical cyclone exposure (typhoons). These design requirements lead to increased structural loads, resulting in heavier monopile foundations and the need for turbine design adjustments. Turbine supply costs include a small uplift to reflect additional certification and verification scope related to the project design basis and interfaces. Contingency is increased to reflect design iteration and approval risk arising from both seismic requirements and cyclone-driven design integration and seasonal disruption. Appendix B details how the geohazard risks affect the different CAPEX packages.

The Aegir Quant™ model combines the effects of different site conditions, such as typhoons, earthquakes, and bedrock soil condition, using a root-sum-square approach where these factors affect the same CAPEX package. This method avoids unrealistic cancellation between opposing effects while preserving the overall direction of the impact. By combining largely independent drivers in this way, the model represents underlying uncertainty more realistically than a simple additive approach. This results in a 17% increase in monopile weight, a 14% increase in turbine supply costs, and a 0.65% increase in contingency. These combined effects are also summarized in Appendix B.

3.4.2 Assumptions based on Japan's industry and policy conditions

The following section outlines the key addressable factors that can be improved through targeted industry and policy action, including installation works, supply-chain development, port and enabling infrastructure, standardization and learning effects, as well as policy and regulatory design.

Supply Chain

Japan's domestic **turbine** supply chain remains less developed than its foundation manufacturing capabilities, and there are currently no concrete plans for significant expansion. Hitachi's nacelle plant closed in 2019, and proposed facilities such as the Toshiba-GE nacelle plant are unlikely to proceed following GE's withdrawal from new offshore wind contracts. Vestas has also paused plans for a local nacelle assembly facility. Given this situation, turbines for reference cases are assumed to be supplied from Europe.

Several OEMs have developed turbines specifically engineered and certified for typhoon-prone environments. Siemens Gamesa's SG8.0-167 DD — tailored for typhoon and seismic conditions and the first dedicated offshore turbine to receive ClassNK certification in Japan — is deployed at the Ishikari project (112 MW). The current-generation SG14-222 DD carries T-class certification and is contracted for the Hai Long 2A, 2B, and 3 projects in Taiwan, with nacelle production based in Taichung. Similarly, Vestas has deployed typhoon-certified turbines across three Japanese offshore projects: the V117-4.2 MW Typhoon variant at Akita and Noshiro (139 MW); the V174-9.5 MW at Hibikinada (220 MW); and the V236-15.0 MW — designed for IEC I/S/T conditions including typhoon markets and type-certified in 2023 — ordered for Oga-Katagami-Akita (315 MW) and for CIP's Fengmiao I in Taiwan (495 MW). Offshore wind farms in Japan are expected to incur higher turbine-related costs due to the need for typhoon-certified technologies, enhanced structural resilience, and more intensive maintenance requirements.

The availability of wind turbine installation vessels (WTIVs) and other specialist construction vessels in Japan remains limited and is consistently identified as a key bottleneck, alongside port readiness and grid constraints. In addition, maritime cabotage regulations restrict the use of foreign-flagged vessels and foreign crews within Japan's territorial waters, further reducing the pool of available installation assets and increasing scheduling and charter risk. As of 2026, Japan's offshore wind market is supported by six WTIVs serving domestic projects. This fleet comprises a combination of purpose-built and upgraded vessels, led by Shimizu's Blue Wind, which is capable of installing 14–15 MW turbines, with several vessels also able to handle the monopile sizes required for current projects. However, compared with the latest generation of European WTIVs, the Japanese fleet remains more limited in capability, particularly in terms of lifting capacity, jack-up performance, and suitability for next-generation, larger-scale turbines. For the Japan reference case, installation vessels are assumed to be sourced domestically or from the wider region, such as vessels operating in Taiwan or South Korea, without any additional mark-up for cabotage restrictions. On this basis, a mobilization time of 14 days is assumed.

Installation Duration

Installation activities offshore are a major cost component within total installed costs, and installation duration is a key input because longer campaigns increase variable costs such as vessel day rates and offshore labor. For the Japan reference case, installation durations are specified in days per turbine and days per foundation, following the approach in Lacal-Arántegui et al. (2018): for each project, the installation period is measured between start and completion dates and normalized by the number of installed units. European benchmark inputs are derived from the installation and logistics model of Aegir Quant™. A detailed description of the underlying methodology and model validation is provided in Appendix C. Japan benchmarks are derived from four fixed-bottom projects[7] constructed between 2021-2025 using public sources and Aegir Insights' Project Database (Table 2).

Table 2: Installation durations

	Aegir Quant™ (2025.4)	**Japan (2021-2025)**
Days/turbine	1.24	3.58
Days/foundation (all)	3.57	7.25
(monopile only)	(2.86)	(4.03)
Weighted average turbine size (MW)	9.7	6.8

Source: Aegir Quant™; Japan's value is calculated based on public information and Aegir Insights' Project Database. Notes: 1) Aegir Quant™ figures include weather and technical downtime.

As shown in Table 2, average turbine installation duration in Japan is 3.58 days/turbine, approximately three times longer than the Aegir Quant™ European benchmark of 1.24 days/turbine. This gap reflects Japan's more challenging operating environment, including adverse weather windows driven by typhoon seasonality, constrained port logistics, and the smaller average turbine size of 6.8 MW in Japan versus 9.7 MW in Europe — with smaller turbines generally associated with less optimized installation sequencing and lower economies of scale per lift operation. Foundation installation durations are similarly longer in Japan. For international

[7] This includes Akita Port (54.6 MW), Noshiro Port (84 MW), Ishikari Bay New Port (112 MW), and Hibikinada (230 MW).

comparison, we focus on monopile-only figures. Japan averages 4.03 days/foundation compared to the European benchmark of 2.86 days, an approximately 40% increase attributable to a combination of weather downtime, soil conditions, and structural market factors.

Looking ahead, Japan's complex soil conditions are expected to become an increasingly significant cost driver as the market transitions toward larger 15–20 MW turbines, which will require deeper and larger monopile foundations. Historical installation data suggests that drilling activities are not captured in the reported durations, yet some degree of drilling is likely to be required at a meaningful share of future Japanese sites, particularly in areas with hard geological layers. To account for this, the reference case applies working hours from Aegir Quant™ with an assumed 25% of foundations requiring drilling, meaning drilling is required at approximately every fourth foundation position on average.

In the Japan reference case, the vessel utilization factor (WDF) is set to 2.05 (median; mean 2.21) based on NEDO (2024). This assumption is used to translate calendar-time installation durations into productive working time and weather/logistics downtime in the installation and logistics module (see Section 2.3.2 for the definition and broader discussion). A WDF of 2.05 implies that only about 49% of deployed time is productive on average, with the remainder being downtime.

The historical Japan installation durations utilized as basis for this analysis are measured on a calendar-day basis from the start to completion dates of installation activities and therefore already embed weather downtime and interruptions. Accordingly, the observed turbine installation duration of 3.58 days/turbine is applied directly to the 2030 reference case, with the WDF used to decompose this into 1.75 working days and 1.83 days of downtime. For monopile installation, the working day assumption from Aegir Quant™ is applied with a 25% drilling share, resulting in 2.77 working days per monopile excluding weather and technical downtime. Applying the Japan-specific WDF adds 2.92 days of weather-related downtime, resulting in an adjusted total installation duration of 5.69 days per monopile for the 2030 case.

Port Lease Fees

Port-related costs include port lease fees for base ports. Using the average level reported by the Renewable Energy Institute (2025), the fee was converted into an annual amount assuming a 30-year utilization period to estimate the portion attributable to the construction phase by taking three years' worth of payments. On this basis, the port lease fee in the reference case is approximately JPY 3,000/kW, which was also confirmed to be broadly consistent with input obtained through interviews with JWPA.

At the same time, as noted by the Renewable Energy Institute (2025), the current cost-allocation mechanism under the tripartite lease agreement can leave substantial uncertainty in both the cost level and the predictability of the burden: if future entry of additional users is uncertain, the cost burden may be disproportionately concentrated on the first project to use the port.

Considering this, the port lease fee from the reference case in the CAPEX in 2030 is set JPY3,000/kW. By 2040, as Japan's port infrastructure matures and converges toward international standards, lease fees are assumed to align with European benchmarks.

Vessel Day Rates

European benchmark vessel day rates are applied in this study to reflect both the limited availability of capable installation vessels in Japan and the expectation that, as the market scales and competition for specialized assets increases, vessel pricing will converge toward international levels. Evidence from other Asian offshore wind markets such as Taiwan supports this assumption where installation vessels ultimately operated at day rates comparable to those in Europe. In Aegir Quant™, the vessel day rate represents the total cost of the installation campaign, covering not only the base charter fee but also all vessel-related activities and equipment required for installation, including hammers, grillages, noise-mitigation systems, grouting, lifting and installation spreads, as well as fuel. In addition, the European baseline medium-vessel day rate is derived from a broad market distribution across multiple regions, collected over time, and positioned close to a market average/median level (excluding China). Given that day rates differ significantly due to variations in regional supply-demand dynamics, project complexity and risk, contract structure, a broad market-based baseline assumption provides a more balanced and representative benchmark. Accordingly, European vessel rates are adopted to represent long-term vessel costs in the Japanese offshore wind market.

Transmission

In Europe, TSO substation upgrade costs are usually borne by the network operator rather than the developer. However, in Japan, these costs fall on the developer and must therefore be included in project CAPEX. To estimate the magnitude of this cost, the model applies 70% of the onshore substation cost derived from European benchmark data as a proxy for the grid upgrade expenditure required in Japan, in the absence of established Japan-specific cost references for developer-borne connection work-related costs.

Community co-existence fund

In Japan, a community co-existence fund is established to promote coexistence with local communities and the fisheries sector, to which offshore wind developers are required to contribute. The fund is used to support regional development initiatives, including improvements to fishing ground environments, support for younger fishers, and the development of local infrastructure. The government presents, as a reference, the fund size calculated based on the following formula:

$$\textit{Installed capacity (kW)} \times \textit{JPY 250} \times \textit{30 years}$$

(Agency for Natural Resources and Energy, METI; Ports and Harbours Bureau, MLIT, 2024)

For CAPEX estimation, the portion of the fund included is limited to the payments incurred between the certification of the occupancy plan (typically around one year after developer selection) and the COD. In this study, this period is assumed to be four years.

Limitations

Several cost elements specific to Japan are not explicitly differentiated in this study and are treated equivalently to Europe. These include monopile and transition piece fabrication costs[8], cable fabrication costs, and vessel day-rates, which in practice may carry a premium in Japan relative to European benchmarks. Cabotage restrictions and any associated cost premiums arising from the use of foreign-flagged vessels have similarly not been explicitly modelled for Japan.

[8] The robust requirements related to geophysical design and related weight increase are included, but the cost basis is treated equivalent to Europe.

3.5. Boundary Definitions

In Aegir Quant™, the CAPEX model is structured into the following cost packages:

Table 3: CAPEX packages in Aegir Quant™

CAPEX
Wind turbine supply
Foundation supply
Inter-array cable supply
Monopile installation
Transition piece installation
Turbine installation
Inter-array cable installation
Construction management
Transmission
Project owner and other costs
Contingency

Construction management costs include offshore support services (such as crew transfer vessels, guard vessels, and anchor handling vessels, including fuel), equipment, materials, communications, boulder clearance, and lump-sum compensation for offshore and onshore disruptions to stakeholders. Disruption compensation costs are not differentiated by region and are applied using European reference values for both Europe and Japan. Construction management also includes harbor leases and site offices, calculated based on a fixed daily rate applied consistently across both regions.

Project owner and other costs comprise a lump-sum allowance for operations preparation, applied using the same value for Europe and Japan, insurance costs calculated as 1.5% of CAPEX without transmission, and guarantee costs calculated as 0.25% of CAPEX without transmission.

Contingency is applied as a percentage of CAPEX, reflecting each market's maturity level and site condition adjustments. The rate applied is 8.6% for Japan in 2030, declining to 6.6% by 2040 as the market matures, compared with 6.0% for the European benchmark.

Finally, definitions of CAPEX may, depending on context, include items such as interest during construction (IDC), taxes and statutory charges, and decommissioning costs. These items can vary materially across countries due to differences in institutional settings and financial conditions, and simple like-for-like comparisons of CAPEX can therefore be misleading. To ensure the consistency of international comparisons, this report uses as its analytical baseline construction-stage costs (including equipment procurement, manufacturing, transport, and installation), while items that are particularly sensitive to policy and regulatory differences — for example, grid connection costs, IDC, various taxes and charges, and decommissioning costs — are excluded.

3.6 Scenario Design

Two deployment scenarios are defined for the 2040 fixed-bottom case, reflecting alternative deployment pathways provided by REI. METI and MLIT have set offshore wind targets of 10 GW of project allocation pipeline by 2030 and 30–45 GW by 2040, including at least 15 GW of floating offshore wind. Their deployment target for 2030 is 5.7 GW of installed capacity (METI, 2025). In contrast, REI has set more ambitious targets, projecting 10.1 GW by 2030 and 32.4 GW by 2040 for commercial operation (REI, 2023), later revised to 35 GW by 2040 (REI, 2024).

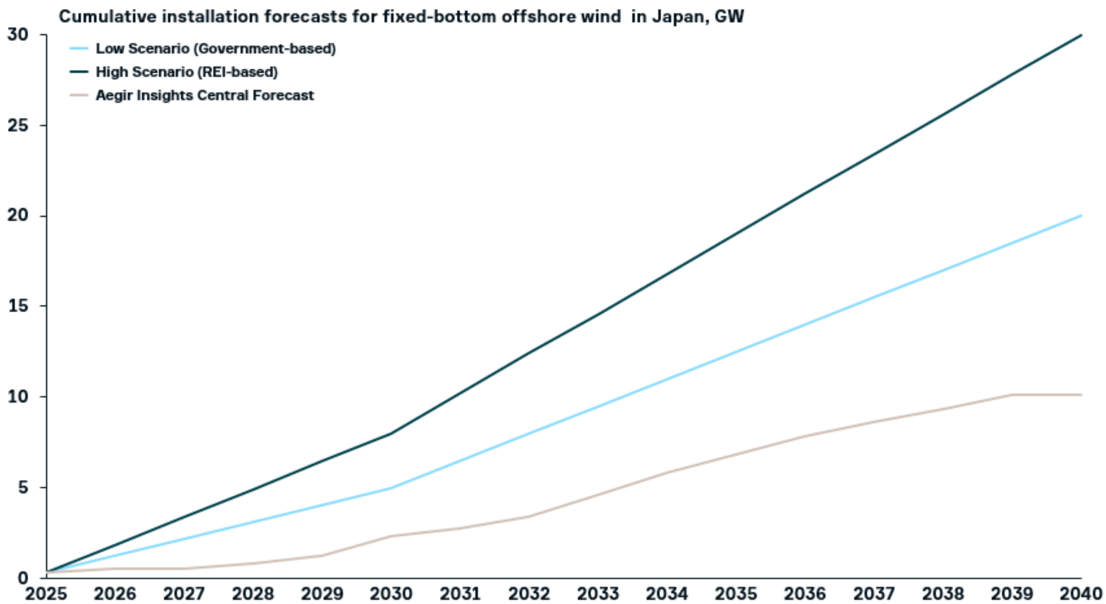
Based on these differing outlooks, two deployment scenarios are defined. The Low scenario is based primarily on government targets and assumptions. It assumes that the Round 1 auction is re-tendered and that operational dates follow project pipeline formation timelines. Under this scenario, the 2030 deployment target of 5.7 GW is achieved in 2031, the 2030 pipeline target of 10 GW becomes operational in 2035, and the 2040 pipeline target of 30 GW becomes operational in 2045. The High scenario is based primarily on REI projections. It also assumes the re-tendering of the Round 1 auction but reflects faster deployment consistent with REI's outlook. Considering recent cost increases and other market factors, the scenario maintains a total deployment level of 40 GW by 2050, while incorporating a modest schedule delay relative to earlier projections.

Aegir Insights also prepares its global market forecast on a quarterly basis based on an in-depth review at a project- and market-level to determine an initial realistic bottom-up view per market and technology (fixed-bottom and floating). This view is then capped based on global factors that limit developments. Based on conditions for each market, capping is applied to create individual growth scenarios for each market, region and technology. The result is three scenarios: Low, Central (Aegir Market Forecast main case), and High cases. In Aegir Insights' Central Case, Japan's fixed-bottom offshore wind capacity is projected to reach 2.3 GW operational by 2030, increasing to 6.8 GW by 2035 and 10 GW by 2040. Deployment is expected to remain relatively slow throughout the 2020s, reflecting project delays, cancellations, regulatory adjustments following the Mitsubishi cancellations, and challenges faced by FiP-supported projects. From the early 2030s onward, however, growth is forecast to accelerate significantly.

Table 4: Fixed-bottom offshore wind build-out scenarios in Japan by 2030 and 2040

	Low scenario (Government-based)	High scenario (REI-based)	Aegir Forecast (Central scenario)
2030	5 GW	8 GW	2.3 GW
2040	20 GW	30 GW	10 GW

Figure 13: Cumulative installation forecasts for fixed-bottom offshore wind in Japan, GW



In Aegir Quant™, learning effects are incorporated in the 2040 case through the application of a learning rate. As a result, several cost items are assumed to decline over time, including monopile and transition piece fabrication costs, support vessel day rates, average array cable prices (static cables), array installation vessel day rates, and turbine supply prices per MW for complete wind turbine supply. In addition, Japan is classified as an advanced market in 2040, equivalent to Europe in 2030. Accordingly, package mark-ups are reduced by 50% relative to earlier-stage market assumptions. Additional information is available in Appendix A.

For the 2040 Japan case, we assume that the institutional framework has matured and that cost allocation mechanisms have aligned more closely with established European offshore wind markets. Under this assumption, the developer-borne share of port-related costs is expected to converge toward the European reference case. As a result, the elevated port fees assumed in the 2030 Japan case will be removed from the model and replaced with the Aegir Quant™ European reference case assumption, which is approximately 50% lower.

The Japan-specific inputs for installation durations and vessel utilization factor are not adjusted in the 2040 case. The installation time per position or per turbine is not assumed to decrease significantly over time, as these activities are largely driven by physical processes and site conditions. Instead, reductions in overall installation duration are primarily driven by improvements in logistics efficiency, including the ability of vessels to transport and install more monopiles or turbines per cycle. This is further supported by the expected availability of a larger fleet of next-generation installation vessels by 2040, with higher lifting capacities and greater deck space, enabling more efficient campaign execution. In the 2040 case, 20 MW turbines are assumed, which require larger and heavier foundations compared to the 2030 case. As a result, monopiles are expected to have greater diameter and weight, slightly reducing the number of units that can be transported per vessel per trip. At the same time installation vessel day rates are also assumed to increase, reflecting the requirement for larger, next-generation vessels capable of installing 20 MW turbines. Installation and support vessel day rates are assumed to be elevated at 110% of the baseline level in 2025, reflecting prevailing market tightness and limited availability of suitable installation vessels. Rates are projected to increase further to 122% by 2030, driven by peak installation activity and strong competition for specialized assets. Thereafter, day rates are expected to gradually moderate, returning to 110% by 2040 as additional next-generation vessels enter the market and supply–demand conditions rebalance.

4. Results

Having described the model structure and the assumptions underlying the Japan 2030 and 2040 reference cases, this section presents the resulting CAPEX estimates and discusses the key drivers of cost variation across markets and the outlook for cost reduction in Japan through 2040.

4.1 2030 reference cases comparison

The following table compares estimated CAPEX across key cost packages for a reference fixed-bottom offshore wind project in Europe and Japan in 2030. Table 5 presents the full package-level breakdown in both total and unit cost terms.[9]

Table 5: Europe vs Japan CAPEX package break-down in 2026 prices, Aegir Quant™

	EUROPE (450 MW 2030)				JAPAN (450 MW 2030)			
CAPEX PACKAGE	**mEUR**	**mEUR/MW**	**bnJPY**	**mJPY/MW**	**mEUR**	**mEUR/MW**	**bnJPY**	**mJPY/MW**
Wind turbine supply	659	1.46	105.4	234.2	825	1.83	132.0	293.4
Foundation supply	199	0.44	31.9	70.9	197	0.44	31.5	69.9
Inter-array cables supply	46	0.10	7.3	16.3	47	0.11	7.6	16.9
Monopile installation	65	0.14	10.4	23.2	111	0.25	17.7	39.3
Transition piece installation	46	0.10	7.4	16.4	56	0.12	8.9	19.9
Turbine installation	40	0.09	6.4	14.2	88	0.20	14.1	31.4
Inter-array cables installation	23	0.05	3.7	8.3	26	0.06	4.1	9.1
Construction management	16	0.04	2.6	5.8	28	0.06	4.6	10.1
Transmission	242	0.54	38.7	86.0	203	0.45	32.5	72.1
Project owner and other costs	33	0.07	5.2	11.6	38	0.08	6.0	13.4
Contingency	82	0.18	13.1	29.2	140	0.31	22.4	49.8
TOTAL	**1,451**	**3.22**	**232.2**	**516.0**	**1,758**	**3.91**	**281.3**	**625.2**

For the 2030 reference case, total CAPEX for a 450 MW fixed-bottom offshore wind project is estimated by Aegir Quant™ at EUR 1,451m (JPY 232bn) in Europe compared to EUR 1,758m (JPY 281bn) in Japan, equivalent to 3.22 EUR/MW (516 mJPY/MW) and 3.91 EUR/MW (625 mJPY/MW) respectively. Japan carries a total CAPEX premium of approximately 21% over the European

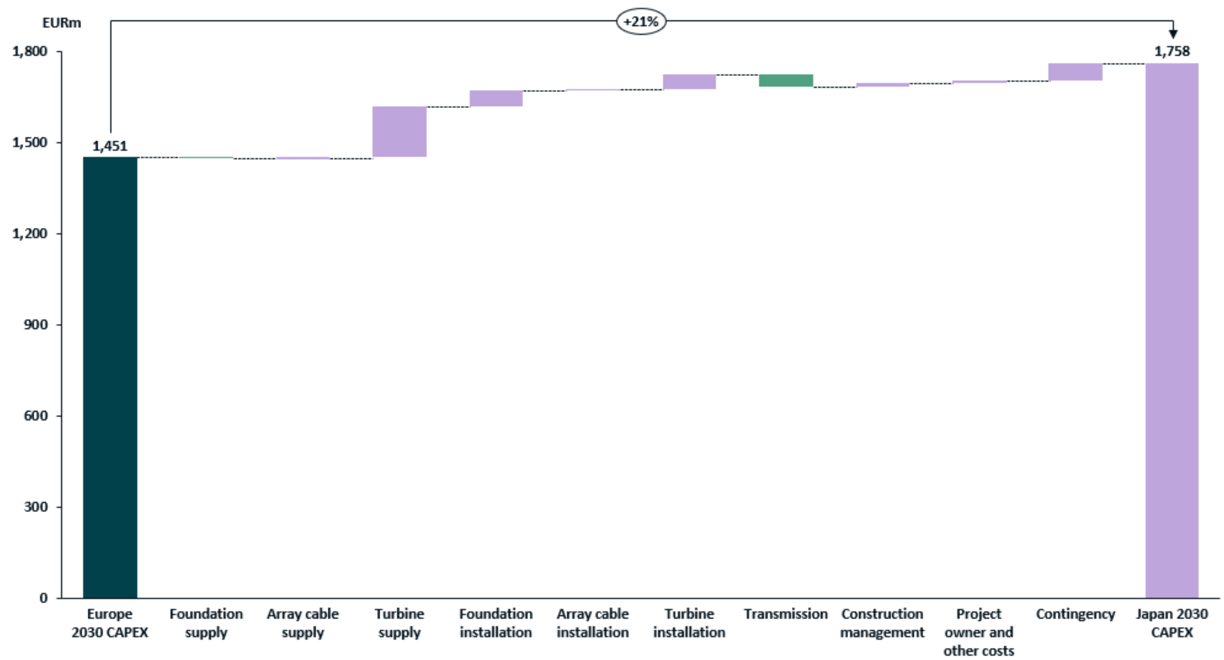
[9] All EUR figures have been converted to JPY at an exchange rate of 160 JPY/EUR.

reference case, reflecting higher costs across installation, wind turbine supply, and contingency packages. The cost drivers underlying this premium are analyzed in detail in the following section.

4.2 Main cost drivers of Japanese premium

Figure 14 shows a detailed breakdown of the Aegir Quant™ CAPEX differences between the European and Japan reference cases in 2030 at the package level. Starting from the European reference case, the key cost differences are evident within turbine supply, foundation installation, turbine installation as well as transmission costs.

Figure 14: Waterfall breakdown of CAPEX differences in Europe and Japan in 2030 (mEUR), Aegir Quant™



The largest cost driver is wind turbine supply, adding EUR 166m to the European reference case. Turbine supply costs are higher in Japan due to additional design requirements driven by earthquake and typhoon conditions, which require turbines and associated components to be engineered for higher extreme loads and structural robustness, increasing manufacturing complexity and cost. Beyond design requirements, the absence of an established domestic manufacturing base means turbines are largely sourced internationally.

Monopile (including transition pieces) and turbine installation costs account for a combined increase of EUR 103m, which is split into EUR 55m and EUR 48m respectively. Installation is longer in duration and more costly due to more restrictive weather conditions and additional logistical constraints. The pure working time per turbine is assumed to be 0.83 days longer, primarily reflecting early-stage market maturity and lower installation efficiency in Japan as the data is based on the first offshore wind projects that are already operational. As a result, the total turbine installation campaign duration increases from 64 days in Europe to 134 days in Japan, representing an additional 70 vessel days and an estimated cost increase of EUR 32m, including turbine installation vessel and support vessel costs.

Monopile installation carries an additional cost driver: the hard seabed geology prevalent in Japanese waters is expected to require drilling at a significant proportion of foundation positions, extending campaign durations. Construction management adds a further EUR 12m, reflecting the greater coordination complexity of operating in this environment.

Contingency adds EUR 58m, reflecting the higher execution risk applied under Japan's current market maturity score and the additional design uncertainty associated with seismic and cyclone loading conditions and regulatory requirements (see more in Appendix A and B).

Two packages partially offset the premium. Transmission is EUR 39m lower in Japan, compared with Europe, as projects are currently located close to shore within territorial waters, allowing power to be exported directly to the onshore grid — eliminating the need for an offshore substation and requiring less export cables to be supplied. Foundation supply is marginally lower at EUR 3m, despite the need to design for seismic and cyclone loading conditions, which add structural requirements and material content. The reason is a combination of a higher water depth in the European reference case combined with bedrock soil conditions in Japan, which allow monopiles to be somewhat shorter. These parameters broadly offset the uplift from enhanced design standards. However, the same hard soil conditions drive higher installation costs, as competent bedrock at shallow depth necessitates drilling at a significant proportion of foundation positions, adding vessel time.

Cost differences driven by physical and logistical constraints, such as longer installation durations due to typhoon seasonality and hard seabed geology, are structural in nature and will persist even as the market matures, meaning a residual cost premium over Europe is expected to remain in the long term. Cost differences driven by market conditions, by contrast, are cyclical. Port lease fees, supply chain mark-ups reflect the current early stage of market development and are expected to narrow materially as the Japanese offshore wind sector scales and domestic supply chains develop. Of the EUR 307m CAPEX difference, approximately EUR 84m is attributable to early-stage market maturity and Japan’s institutional costs allocation framework. Early-stage market conditions include learning curve effects, port lease fees, and stakeholder compensation (approximately EUR 58m). Under Japan's institutional cost allocation framework on grid connection, developers are required to fund TSO substation reinforcements under the 'causer pays' principle (approximately EUR 26m). The remaining EUR 223m is driven by physical constraints, such as weather downtime, seismic and typhoon-related design requirements, typhoon seasonality, and seabed geology. While market maturation could reduce around 27% of the CAPEX gap over time, around 73% of the difference is driven by geographic and environmental conditions, which are unlikely to change significantly. As a result, Japan is likely to remain a structurally higher-cost offshore wind market than Europe, although technology and supply-chain adaptations to Japan’s conditions could partially narrow the gap over time. This distinction between maturity-related and physical cost drivers is central to understanding the expected CAPEX trajectory in Japan through 2040, as examined in the following section.

4.3 2040 outlook

To assess whether higher cumulative deployment materially accelerates learning-driven CAPEX reductions by 2040, a sensitivity analysis is conducted across the three deployment scenarios defined in Section 3.6 — the REI Low, REI High, and Aegir Central Case. These are designed to test whether a more accelerated deployment pathway would unlock significantly greater cost reductions through learning effects by 2040, relative to the Aegir Central forecast, which assumes the most conservative build-out for Japan.

The sensitivity analysis shows that varying deployment paces have a negligible effect on total CAPEX outcomes. The difference between the lowest and highest deployment scenarios amounts to less than 0.4% of total CAPEX — a result that reflects the structural behavior of learning curves at this stage of market maturity. Learning-driven cost reductions are not linear with deployment volume; rather, their marginal impact diminishes as cumulative capacity grows. Most of the cost reductions achievable through learning are therefore already captured under the lowest deployment pathway, and increasing deployment beyond this level does not significantly alter the learning trajectory by 2040. Even under the Aegir Central Case, the cumulative capacity reached is sufficient to unlock the substantial majority of projected learning effects.

Given the limited sensitivity observed across the scenario range, the Aegir Central Market Forecast is applied as the basis for learning rate calculations and for defining the 2040 case throughout this chapter. The full scenario comparison is available in Section 3.6.

Table 6: Japan 2040 case CAPEX packages in 2026 prices, Aegir Quant™

	JAPAN (1 GW 2040)			
CAPEX PACKAGE	**mEUR**	**mEUR/MW**	**bnJPY**	**mJPY/MW**
Wind turbine supply	1,629	1.63	260.6	260.6
Foundation supply	436	0.44	69.8	69.8
Inter-array cables supply	67	0.07	10.7	10.7
Monopile installation	142	0.14	22.7	22.7
Transition piece installation	54	0.05	8.6	8.6
Turbine installation	153	0.15	24.4	24.4
Inter-array cables installation	37	0.04	6.0	6.0
Construction management	37	0.04	5.9	5.9
Transmission	397	0.40	63.6	63.6
Project owner and other costs	64	0.06	10.2	10.2
Contingency	200	0.20	32.1	32.1
TOTAL	**3,216**	**3.22**	**514.5**	**514.5**

Table 6 presents the Aegir Quant™ CAPEX estimate for a 1 GW fixed-bottom offshore wind project in Japan in 2040. Total project CAPEX is estimated at EUR 3,216m (JPY 515bn), equivalent to 3.22 mEUR/MW (514.5 mJPY/MW). Compared with the 2030 reference case, CAPEX per MW falls by approximately 18%, from 3.91 mEUR/MW to 3.22 mEUR/MW, reflecting the combined effects of technology learning, turbine scaling, supply chain maturation, and improving market maturity over the decade. Figure 15 breaks down this reduction at the package level, illustrating the contribution of each cost component to the overall decline.

Figure 15: Waterfall breakdown of CAPEX differences in Japan between 2030 and 2040 (mEUR/MW), Aegir Quant™

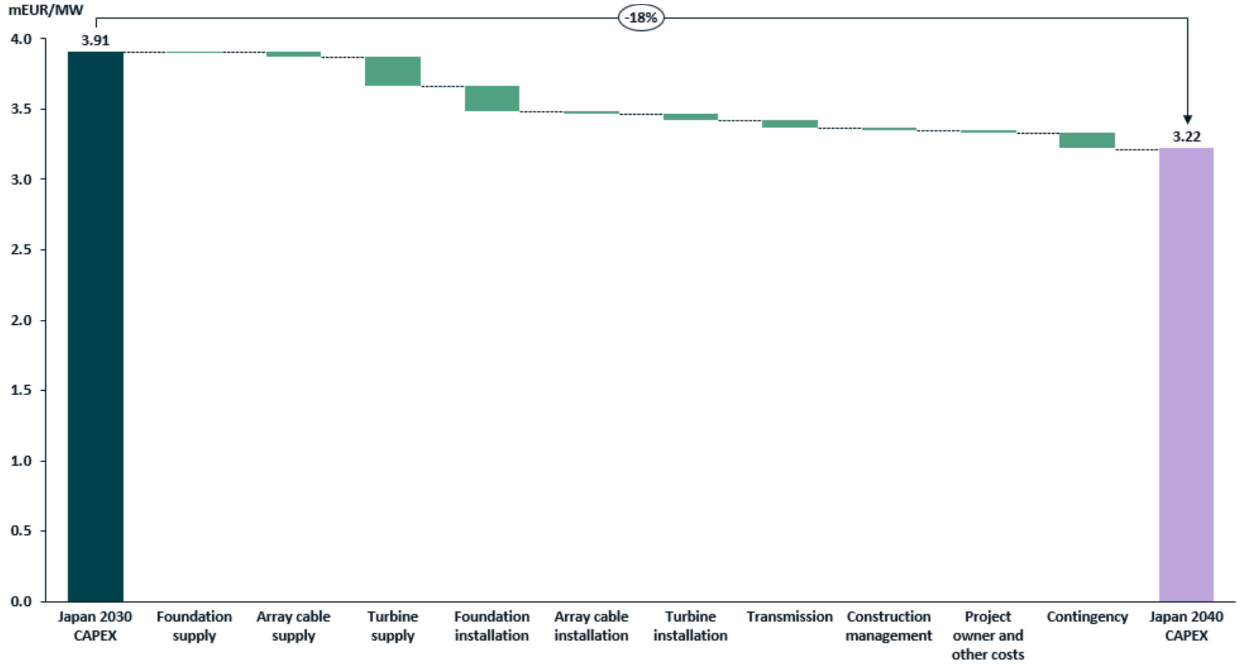


Figure 15 highlights that cost reductions in Japan from 2030 to 2040 are broadly distributed across packages. The largest contributors to the CAPEX reductions are wind turbine supply (-0.2 mEUR/MW), foundation installation costs including transition piece (-0.17 mEUR/MW), and contingency (-0.11 mEUR/MW), accounting for approximately 70% of the total reduction.

Turbine cost reductions reflect the global expectation that per-MW turbine prices will decline through 2040, driven by continued upscaling of turbine ratings and maturing supply chains, while the decline in monopile installation costs is driven by improved vessel availability. The significant reduction in contingency reflects improving market maturity and a lower execution risk profile as Japan is expected to build a project delivery track record. Foundation supply, inter-array cable supply, turbine installation, and transmission show more modest reductions, consistent with the more structural nature of the cost drivers in these packages.

Looking ahead to 2040, CAPEX per MW cost reductions in Japan are expected to be driven primarily by two factors — turbine supply and installation costs — with the remainder spread across several smaller packages. Turbine prices per MW are expected to decline as turbine ratings continue to increase and cumulative build-out grows, delivering greater power output per foundation position and spreading fixed costs across more megawatts. Vessel rates and installation costs are expected to decrease as the global installation fleet expands, fleet availability improves, and installation methods become faster and more efficient, reducing both campaign durations and day-rate premiums. These two drivers together account for approximately 0.44 mEUR/MW of the total 0.69 mEUR/MW reduction through 2040, representing approximately 64% of the decline.

The remaining reduction is distributed across several packages. Contingency shows the largest nominal contribution among the secondary packages at 0.11 mEUR/MW, but this reduction is largely a passive outcome of market maturation as execution risk decreases and design standards for seismic and cyclone conditions become better established, contingency allowances normalize rather than reflecting active cost engineering. It is therefore better understood as a consequence of broader market development than as a lever available to developers or the supply chain.

Among the other secondary contributors, monopile and transition piece fabrication costs[10] are expected to fall as the industry moves toward design standardization, greater automation, and optimized steel use. On an absolute basis, foundation supply costs increase, reflecting both the larger project size and the step up to 20 MW turbines requiring heavier and wider monopiles. However, on a per MW basis the cost remains broadly unchanged, declining by just 327 EUR/MW (0.44 mEUR/MW in both periods), as fabrication learning effects and design optimization broadly offset the structural demands of the larger turbine class. Inter-array cable supply prices (measured as average supply price per meter) are expected to decline with expanded manufacturing capacity and more optimized cable specifications as project volumes scale, contributing approximately 0.04 mEUR/MW. Construction management, project owner costs, and transmission each contribute reductions in the range of 0.02–0.05 mEUR/MW, reflecting efficiency gains from repeated project delivery, a maturing local supply chain, and the benefits of larger project scale. Together, these secondary packages account for approximately 0.25 mEUR/MW of the total 0.69 mEUR/MW reduction by 2040. However, given that copper typically accounts for a significant share of cable cost, copper price volatility remains a source of uncertainty in the cable cost reduction trajectory through 2040.

[10] Measured as cost per ton including plate rolling, welding, testing, turning, machining, and coating.

5. Conclusions & Implications

In this report, the Aegir Quant™ model was used to estimate CAPEX for fixed-bottom offshore wind projects in Japan in 2030, incorporating Japan's regulatory framework, market conditions, and physical environment. The results are compared against the European CAPEX estimate to quantify which cost components are particularly elevated in Japan, followed by an analysis of the outlook for cost reduction in Japan through 2040.

5.1. Key Conclusions

For the 2030 reference cases, the estimated CAPEX for a fixed-bottom offshore wind project in Japan is expected to be approximately 21% higher than in the European reference case. This premium totals EUR 307m (JPY 49.1bn) in CAPEX difference between the 2030 reference cases. The results indicate that this premium is driven not only by structural physical constraints (i.e., geography- and environment-related conditions), but also by early-stage market maturity and institutional factors.

The CAPEX increase driven by structural physical constraints reflects Japan's metocean conditions and seabed geology, as well as the additional design requirements associated with natural hazards such as earthquakes and typhoons (i.e., higher extreme-load requirements). In this analysis, the incremental CAPEX attributable to structural physical constraints is estimated at EUR 223m (JPY 35.7bn). A major contributor is the impact of meeting earthquake- and typhoon-driven robustness requirements on wind turbine supply costs (the wind turbine supply premium is estimated at EUR 166m). In addition, more restrictive weather conditions are expected to increase weather downtime, and hard/complex seabed conditions are expected to require drilling at a significant proportion of foundation positions, extending installation campaign durations and increasing installation costs. At the same time, several factors partially offset the premium: competent bedrock at shallow depth can allow monopiles to be shorter (and in some cases smaller in diameter), reducing foundation supply costs; and the proximity of many current project locations to shore allows power to be exported directly to the onshore grid, eliminating the need for an offshore substation as well as reducing cable runs.

In parallel, this study highlights CAPEX uplifts associated with early-stage market maturity and Japan's institutional cost allocation framework, which totals approximately EUR 84m (JPY 13.4bn). Based on Japanese installation time data, the assumed pure working time per turbine (excluding downtime) is 0.83 days longer in Japan than in Europe, which increases vessel days and thereby raises installation costs. In addition, the model applies a relatively high contingency rate (8.6%) reflecting Japan's current market maturity score, which further increases total CAPEX. Lastly, it should not be overlooked that in Japan, the cost and responsibility of upgrading substations on the TSO side is also borne by the project developer, contributing to an increase in overall capital expenditure due to the institutional cost allocation framework.

Looking ahead to 2040, the results suggest that CAPEX per MW in Japan could fall by approximately 18% relative to the 2030 Japan reference case, reflecting the combined effect of technology learning, market maturation, and improving delivery experience. The main contributors to the reduction are expected to be:

(i) **Lower wind turbine supply costs driven by global turbine upscaling and maturing supply chains;**

(ii) **Lower installation costs are supported by improved vessel availability and faster, more efficient installation methods; and**

(iii) **A material reduction in contingency reflecting improving market maturity and a lower execution-risk profile as Japan builds a project delivery track record.**

Other cost components are expected to contribute more modest reductions, but additional gradual improvement is anticipated as cumulative volumes increase, and domestic supply chains develop.

5.2. Policy & Market Design Implications

This section examines the policy and market-design implications for reducing the cost of offshore wind in Japan, drawing on the findings in Chapter 4. Chapter 4 shows that Japan's CAPEX premium in the 2030 reference case is driven by:

(i) **Structural physical constraints—including requirements associated with typhoon and seismic conditions, as well as metocean and seabed geology;**

(ii) **Early-stage market maturity factors, such as lower installation efficiency and less mature risk assessment; and**

(iii) **Additional grid connection costs for upgrading substation of TSO are also clarified.**

Regarding (i), while Japan's geography and physical environment inevitably impose additional costs that are structural in nature. Of Japan's 21% CAPEX premium over the European reference case, approximately 15% are attributable to structural physical conditions. Physical constraints are therefore the dominant driver of the cost difference with Europe, and a residual premium is expected to persist over the long term. That said, the magnitude of the structural premium is not necessarily fixed. The potential offshore wind market in East Asia—including Japan and other markets with broadly similar seismic and typhoon exposure—is substantial. As deployment scales across the region over time, technological innovation, standardization, and manufacturing solutions tailored to these conditions could gradually compress the associated cost premium. This represents a meaningful long-term opportunity, though one contingent on sustained regional deployment.

Regarding (ii), the results suggest that the CAPEX uplift attributable to early-stage market maturity and transmission scope requirements together account for the remaining approximately 6% of Japan's 21% CAPEX premium over Europe. These maturity-related costs can be reduced more directly through sustained scale-up and institutional design that reduces uncertainty. In this report, we apply lessons from Europe's offshore wind experience over a roughly 10–15-year development horizon to assess the potential for cost reductions in Japan toward 2040.

Regarding (iii) the cost burden for substation reinforcement of the TSO, the fundamental principle governing grid connection cost allocation in Japan is based on the so-called "causer pays" principle. Under this framework, any network reinforcements required because of a new grid connection by a power generator are to be borne by the project developer. As a result, this cost allocation mechanism is estimated to increase the CAPEX of offshore wind projects in Japan by EUR 26m, corresponding to JPY 9,244/kW in 2030.

Addressing these issues requires coherent and durable policy and market design. In Europe, the foundations for cost reduction were laid by a combination of policy and market conditions, including:

a) Sustained political commitment to creating frameworks that shared risk between the state and market actors;

b) Continuous pipelines of lease and offtake auctions that provided scale and long-term predictability for the supply chain;

c) Coordinated transmission grid build-out; and

d) Targeted investment in dedicated supply chain infrastructure such as port facilities.

These conditions enabled supply-chain participants to invest with confidence, driving costs down through scale, competition, and specialization. On the technology side, turbine upscaling was a primary driver of rapid reductions in generation costs, delivering greater power output per foundation position and spreading fixed costs across more megawatts. As the market grew, the supply chain consolidated around the key European markets, creating the economies of scale and logistical efficiency needed for cost-effective project delivery.

Applying these considerations to Japan, several challenges remain:

1. **Targets and pipeline visibility**: Government targets are largely expressed in pipeline terms rather than as targets anchored in commissioning (COD). In addition, targets are often stated in 10-year blocks and do not necessarily guarantee a stable cadence of auctions year-on-year. Under these conditions, the supply chain may find it difficult to commit to investment plans that depend on predictable throughput, including port-yard capacity, pre-assembly set-ups, and workforce training. This can delay improvements in installation efficiency and the realization of learning effects, making it harder to reduce installation costs and contingency over time. From a policy perspective, it is important to make commissioning volumes and the project supply schedule as specific as possible, thereby increasing long-term visibility and predictability.

2. **Exposure to post-auction changes:** While site selection and offtake auctions are being conducted on a continuing basis, recent market developments (for example, the withdrawal by Mitsubishi Corporation in Round 1) highlight that the current framework may not adequately absorb sharp economic changes after an auction. As a result, investors can perceive greater uncertainty around investment recoverability. For addressing this issue, revisions to the auction guidelines in 2025 included a new structure for price bids as well as a price adjustment mechanism.[11]

3. **Responsibility of grid connection costs:** The question of who should bear costs related to necessary grid upgrades represents a major policy challenge. Japan's cost causation principle has a certain degree of economic rationale, as it encourages efficient investment decisions by developers through cost internalization while also helping to prevent excessive grid investment. However, in the context of offshore wind power, site selection is largely determined through government-designated development zones, limiting developers'

[11] The price adjustment mechanism is a one-time inflation adjustment for 68.6% of the price bid (the capital cost component), triggered when cost changes between the bidding period and the construction commencement notification exceed ±1%, with upper and lower limits to be set separately.

locational discretion and thereby reducing the risk of moral hazard. In addition, when project developers are required to bear the cost of substation reinforcements of TSOs, this can increase uncertainty in both project timelines and costs. Moreover, since the cost of capital for developers is generally higher than that of TSOs, such an arrangement may lead to an increase in overall system costs. Furthermore, although grid infrastructure is inherently shared across multiple projects, attributing these costs to individual projects risks concentrating the financial burden on first movers and may weaken investment incentives.

4. **Regulatory constraints within ports and transmission expansion:** Japan still has areas where institutional arrangements have not fully kept pace with the needs of steady offshore wind market development — particularly around coordinated transmission expansion, the cost-allocation framework for port upgrades and port use, and regulatory constraints such as cabotage-related rules. Addressing these regulatory and institutional challenges will be critical for lowering offshore wind costs in Japan and enabling sustained market growth.

5.3. Limitations & Future Work

This analysis has several limitations. First, there are Japan-specific data constraints. Because Japan has a limited number of offshore wind projects to date, the available evidence base for installation performance and cost data remains limited. As a result, it is difficult to assess precisely any divergence from global benchmark pricing, as well as the level and dispersion of installation efficiency. Similarly, for physical conditions such as metocean and seabed geology, the availability of Japan-specific empirical data is still constrained, and many assumptions are therefore required; the validity of these assumptions should be tested and updated as additional project data becomes available. In addition, some regulatory and institutional factors (e.g., practical constraints around vessel sourcing and operations, and the rules and cost allocation associated with port access and use) are simplified in the reference case set-up. The results may therefore be sensitive to the real-world implementation of these frameworks and to future policy and regulatory changes.

Second, there are limitations in the cost scope. To ensure consistency in international comparisons, the CAPEX definition used in this report is bound to a defined set of construction-stage cost items and excludes certain components that can be material for total project economics—such as development costs and interest during construction (IDC). These excluded items can also be influenced by early-stage market maturity and institutional uncertainty. Accordingly, when assessing total project costs and project viability in Japan, additional work is needed to incorporate these components explicitly.

Third, there is uncertainty related to macro assumptions such as exchange rates and inflation, as well as uncertainty in longer-term projections. While the analysis is reported primarily in EUR (with JPY equivalents shown), sharp movements in exchange rates and inflation — particularly for equipment with high import content — could materially affect the results. Moreover, the 2040 cost outlook depends on assumptions around technology learning, supply-chain maturation, and an expanding global installation fleet. At the same time, it is exposed to external drivers such as commodity price volatility (e.g., copper and steel), vessel supply-demand dynamics, OEM pricing strategies and profitability, and broader financial conditions. The 2040 estimates should therefore be interpreted as indicative projections subject to these uncertainties, rather than as point forecasts.

Finally, the analysis is based on defined reference cases. Actual project CAPEX will vary by site-specific conditions (e.g., location, port constraints, seabed conditions, and grid constraints). Going forward, it will be important to continue validating and updating assumptions as more domestic and international project data becomes available, and to strengthen robustness through additional analyses such as explicitly incorporating currently excluded cost items and conducting sensitivity analysis to macro assumptions and key external drivers.

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APPENDICES

APPENDIX A – Market maturity class assumptions

Index		3 – Mid maturity	4 - Advanced
Monopile supply	Package markup	10%	5%
MP & TP installation	Package markup (Monopile installation)	10%	5%
MP & TP installation	Package markup (Transition piece installation)	10%	5%
Array cable supply	Package markup	10%	5%
Array cable installation	Package markup	10%	5%
Wind turbine supply	Package markup	10%	5%
Wind turbine installation	Package markup	10%	5%
Transmission and grid	Package markup	10%	5%
Construction setup	Package markup	10%	5%
Contingency	% of total budget	8%	6%

APPENDIX B – Site conditions

Soil conditions		**Bedrock**
Monopile supply	Monopile weight	-15%
Project assumptions	Positions required drilling (Monopiles)	25%
Contingency	% of total budget	-0.2%
Tropical cyclone exposure (typhoon / hurricane)		**Extreme**
Monopile supply	Monopile weight	20%
Wind turbine supply	Turbine supply adjustment	12.5%
Contingency	% of total budget	0.6%
Seismic design basis (earthquake)		**Extreme**
Monopile supply	Monopile weight	25%
Wind turbine supply	Turbine supply adjustment	6%
Contingency	% of total budget	0.6%
Combined effects of site conditions		
Monopile supply	Monopile weight	17%
Project assumptions	Positions required drilling (Monopiles)	25%
Wind turbine supply	Turbine supply adjustment	14%
Contingency	% of total budget	0.65%

APPENDIX C – Installation and Logistics model of Aegir Quant™

The installation and logistics model of Aegir Quant™ uses a 'statistical weather window' approach, identifying working time and weather downtime based on specific site conditions and vessel performance criteria. The method for developing the Installation and Logistics model involved key steps:

1. **Data utilization**: Aegir Quant™ employs the ERA5 reanalysis dataset, which includes 30 years of global met-ocean data. This dataset provides detailed information on wind and wave conditions.

2. **Statistical weather downtime analysis**: We analyze historical weather data to identify weather downtime worldwide for various weather windows of wind and waves throughout the year. This involves assessing data on wind and wave conditions.

3. **Global Weather window scaling:** Using the ERA5 dataset, we assign interpolation factors to offshore wind areas based on their latitude and longitude. These factors adjust weather availability curves to specific locations. This results in site-specific statistical weather windows that identifies the weather availability during the installation campaign.

4. **Vessel workability and duration:** The statistical weather windows are combined with vessel limitations and durations to calculate weather downtime. The criteria for workability and installation durations are derived from research on actual project performance, permitting documentation, and performance data from vessel owners.

The validation of Aegir Quant™ Installation and Logistics model includes several key steps:

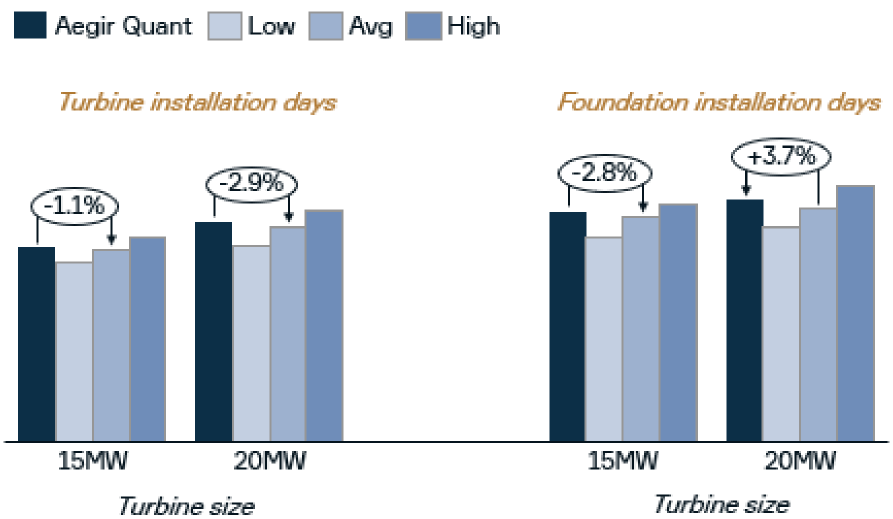
1. **Benchmarking against real-world data**: The model's simulation results are compared with historical data from completed offshore wind projects.

2. **Benchmarking against engineering models**: Aegir Quant™ participated in a topic specific benchmarking study along with the Danish Technical University, ORE Catapult, the National Renewable Energy Laboratory, and Fraunhofer-Gesellschaft Institute. Aegir's results were compared with those of the high-fidelity engineering simulation models for a range of sites with varied conditions and agreed with average estimates within a few percent.

3. **Industry feedback**: Leading industry experts continuously challenge the model's assumptions, providing critical insights to refine parameters. This rigorous process ensures the model meets and exceeds industry standards, enhancing reliability.

4. **Robustness Testing:** We systematically vary key parameters to assess their influence on outcomes, validating the model's robustness. This helps ensure reliable predictions under diverse scenarios by identifying critical performance factors

Aegir Quant™ participated in a campaign with several leading research organizations and consultancies to benchmark pre-construction cost modeling for offshore wind projects, focusing on installations and logistics. Aegir Quant™ results are within 1-4% of the average across all estimates for turbines as well as monopile and transition pieces.



APPENDIX D - Key models and development partners for Aegir Quant™

Model	**Method used**	**Validation performed**	**Development partners and key sources**
CAPEX	Parametric cost model	Yes	Public disclosures on project and component costs, validation with wind turbine OEMs and developers (confidential)
OPEX	Parametric cost model	Yes	Public disclosures on project and component costs, validation with wind turbine OEMs and developers (confidential)
DEVEX	Parametric cost model	In progress	Public disclosures on project costs, ORE Catapult
Annual energy production	Machine Learning model	Yes	European based-developer, Danish Energy Agency, Danish Technical University
Monopile foundations	Regression model based on public and confidential data sources	Yes	European based-developer, Danish Energy Agency, Danish Technical University
Floating foundations	Regression model based on public data sources	Yes	European-based Technology-supplier
Electrical system	Engineering model	Yes	
Installation and logistics	Engineering model	Yes	
Operations and maintenance	Engineering model	Yes	

APPENDIX E - Validation methods used for development of Aegir Quant™

Methodology	Level of validation precision	Advantages	Limitations
Benchmarking against higher precision technical models	High	Transparency; leverages trusted/certified engineering models	Scope coverage of full range of real-world conditions
Expert elicitation	Medium	Contextual data	Subject to survey biases
Auction results analysis	Medium	Based on current commercial data	Results can be distorted by external competitive factors
Supplier surveys	Medium	Contextual data	Competitive environment limits disclosure
Contractual disclosures	Low	Based on current commercial data	Competitive environment limits disclosure
Financial statement disclosures (e.g. project company, annual reports)	Low	Based on current commercial data	Competitive environment limits disclosure
Regulatory disclosures (e.g. OFGEM, National Grid)	Medium	Based on current commercial data	Competitive environment limits disclosure
Permitting disclosures	High	Based on current technical and commercial data	Commonly disclosed as ranges or conservative estimates
Academic research papers	High	Independence of data and findings, often through industry cooperation	Varying degrees of industry involvement
Industry research papers	High	Direct industry involvement	Subject to industry group and participant biases

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April 2026

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