A Study on Site Suitability Assessment Based on Engineering Cost Models for Offshore Wind Farm

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Abstract

This study presents a comprehensive approach to identifying suitable sites for offshore wind power in Japan by integrating two models: an engineering-based cost model that estimates component-specific costs of offshore wind facilities, and an energy technology selection model covering about 129 regions. This integration allows for the estimation of both the generation cost at each offshore location and the broader integration cost within the power system. The results reveal a clear difference between locations selected based solely on wind power generation costs and those chosen when system-wide integration costs are considered. This indicates that focusing only on the cost of generation may lead to suboptimal decisions for the energy system as a whole. By incorporating grid integration impacts, the proposed method identifies locations that help minimize total system costs. This approach offers valuable insights for policymakers and planners aiming to expand renewable energy effectively. It also contributes to a more economically efficient and balanced energy transition, particularly in countries like Japan, where geographical diversity and grid limitations strongly influence energy infrastructure development.

Keywords: Offshore wind, Renewable energy, Cost model, Spatial analysis, Energy policy

1. Background

For carbon neutrality, offshore wind power has attracted increasing attention as a main power source of Japan's future energy system. The Public–Private Council on the Offshore Wind Industry Vision has set a deployment target of 30–45 GW by 2040. In addition, in June 2025, the Act on Promoting the Utilization of Sea Areas for the Development of Marine Renewable Energy Power Generation Facilities (the Act) was amended, extending the areas eligible for project development from territorial waters and internal waters (within 22.2 km from the coast) to the Exclusive Economic Zone (EEZ), with a maximum distance from shore of 370.4 km.

Despite these policy developments, several challenges remain for the large-scale deployment of offshore wind power. The first challenge is the increase in the renewable energy surcharge borne by electricity consumers. Following the widespread deployment of solar photovoltaics under the Feed-in Tariff (FIT) scheme, which initially offered relatively high FIT prices, the surcharge rate has continued to rise and reached 3.98 JPY/kWh in fiscal year 2025. Offshore wind power is among the most capital-intensive renewable energy technologies, and a detailed understanding of its cost structure, together with the design of appropriate support levels, is essential for limiting the future burden on the public.

Since the capital cost of offshore wind projects varies substantially depending on water depth and distance from shore, it is important to quantitatively evaluate site-specific capital costs.

The second challenge is the increase in system integration costs associated with the large-scale deployment of offshore wind power. In countries such as the United Kingdom and Germany, where offshore wind deployment has progressed more rapidly, rising costs have been reported for grid reinforcement due to long-distance transmission from generation sites to demand centers, as well as for securing balancing capacity to maintain supply–demand equilibrium[1]. Although offshore wind deployment in Japan is still at an early stage, future large-scale expansion will require site selection that explicitly accounts for the minimization of total energy system costs.

While numerous previous studies have examined site selection for offshore wind power, most of them have focused primarily on natural conditions and legal constraints. Only limited attention has been paid to studies that simultaneously consider detailed, site-specific capital cost estimation and the system-wide cost impacts on the energy system as a whole[2)-4)].

In this study, we integrate an engineering-based cost model that estimates component-level costs of offshore wind projects (the cost model) with a technology selection model that minimizes total energy system costs while accounting for interregional grid constraints onshore. Based on this integrated framework, we develop a method to evaluate the optimal spatial deployment of offshore wind power by simultaneously considering site-specific capital costs and system-wide costs. The proposed approach provides policy-relevant scientific insights for the design of

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zoning policies that aim to minimize total system costs in the future deployment of offshore wind power.

2. Methodology

2.1 Overview of the assessment framework

In this study, we developed an integrated assessment framework for offshore wind site evaluation that simultaneously accounts for site-specific capital costs and system integration costs arising in the power system as a whole. An overview of the framework is shown in Fig. 1.

First, site-specific capital costs for offshore wind power were estimated using an engineering-based cost model. Next, legally eligible sea areas were identified using a Geographic Information System (GIS) by incorporating the legal constraints stipulated under the Act. The extracted sea areas were then divided into 492 subareas, for each of which the average capital cost, wind conditions, and the upper limit of installable capacity were estimated. Finally, these data were provided as inputs to a technology selection model, and the optimal spatial deployment of offshore wind power was evaluated by minimizing total energy system costs under the deployment target for 2040 (30–45 GW) set by the Public–Private Council.

2.2 Engineering-based cost model

Offshore wind power technologies can be broadly classified into bottom-fixed systems, which are suitable for shallow waters up to approximately 60 m in depth, and floating systems, which are suitable for deeper waters. Both systems consist of major components such as turbines, foundation, array cables, and export cables.

For bottom-fixed systems, increases in water depth lead to larger and longer support structures and greater material requirements, particularly for steel, resulting in higher capital costs. For floating systems, in addition to the floating substructure, mooring lines and anchors are required, and their lengths and quantities increase with water depth. In both systems, a greater distance from shore also leads to higher capital costs due to the increased length of transmission cables.

To accurately reflect these cost structures, this study adopted a component-based engineering cost model that estimates costs based on the material quantities required for each component. Specifically, for bottom-fixed systems, we referred to models developed by the New Energy and Industrial Technology Development Organization (NEDO, 2024)[5], Ioannou et al. (2018)[6], and the European Environment Agency (EEA, 2009)[7]. For floating systems, we referred to NEDO (2024) and Maienza et al. (2020).

Although the referenced models consist of multiple equations and variables and a full description is omitted here, as an illustrative example, the cost of the monopile foundation for a bottom-fixed turbine in Ioannou et al., denoted as CF_{pa} [£], is estimated as a function of water depth WD [m], wind farm capacity $P_{W,T}$ [kW], hub height h [m], and rotor diameter d [m] using Eqs. (1) and (2):

$$CF_{pa} = 320{,}000 \cdot P_{W,T} \cdot \left(1 + 0.02 \cdot (WD - 8)\right) \cdot Cor \text{.........(1)}$$

$$Cor = (1 + 8 \cdot 10^{-7}) \cdot \left(h \cdot \left(\left(\frac{d}{2}\right)^2\right) - 100{,}000\right) \text{..................(2)}$$

When estimating the site-specific levelized cost of electricity (LCOE) based on the capital cost, a discount rate of 7% and an operational lifetime of 25 years were assumed. The capacity factor was assigned on a site-specific basis using the GIS data described in the following section.

2.3 Geo-information System

To evaluate site-specific capital costs for offshore wind power, we compiled marine spatial datasets using a GIS. Specifically, following the methodology of Obane et al.[3], the territorial waters and the EEZ were divided into 500 m grids, and for each grid cell, data were prepared on vessel traffic density, water depth, distance from shore, annual mean wind speed, capacity factor, and the presence of designated natural parks.

The capacity factor was derived from the gross capacity factor based solely on wind conditions and then uniformly adjusted by accounting for wake losses (15%), transmission losses (2.5%), and availability (0.9). This procedure enables the evaluation of site-specific capital costs while comprehensively reflecting legal, natural, and technical conditions.

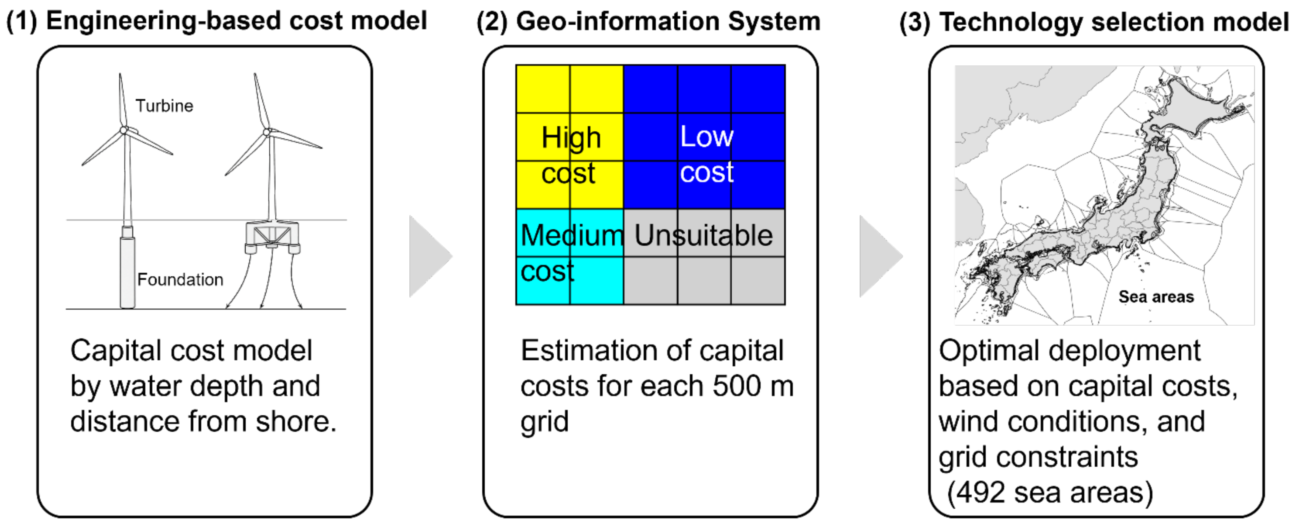


Fig. 1. Overview of the assessment framework.

2.4 Technology selection model

The technology selection model used in this study is based on the linear programming model developed by Watanabe and Otsuki (2025)[9]. The model estimates the optimal technology mix and deployment levels that minimize total energy system costs, given inputs such as the capital costs, fuel costs, and operation and maintenance costs of each energy technology. The set of technologies covered by the model includes approximately 350 technologies across the power generation sector, other energy conversion sectors, industry, transport, residential, and commercial sectors, thereby comprehensively representing energy flows from primary energy supply to final energy consumption.

In this study, we construct a single-year energy system model. The objective function is defined as the total annual energy system cost, which is expressed as the sum of the annualized capital costs, operation and maintenance costs, and fuel costs of energy technologies, as shown in Eq. (3). Capital costs are annualized by taking equipment lifetimes into account. The target year of the analysis is fiscal year 2040.

$$min \sum_{n=1}^{N} \{ivc_n + foc_n + voc_n + flc_n\} \quad \text{......................} (3)$$

$$ivc_n = \sum_k \left\{C_{k,n} \cdot xk_k / \sum_{j=1}^{LIFE_k} (1+HR)^{-j}\right\} \quad \text{.............} (4)$$

Here, N denotes the set of regions ($N = 129$), and k denotes the set of technologies. The variable ivc_n represents the capital cost at node n (JPY/year), foc_n the fixed operation and maintenance cost at node n (JPY/year), voc_n the variable operation and maintenance cost at node n (JPY/year), and flc_n the energy supply cost at node n (JPY/year). $C_{k,n}$ denotes the capital cost of technology k at node n (JPY/original unit), x_k denotes the installed capacity of technology k (original unit), HR is the subjective discount rate for investment, and $LIFE_k$ is the lifetime of technology k (years). In Eq. (4), the parameter $C_{k,n}$ for offshore wind power is specified by classifying sites into water depth categories (0–15 m, 15–30 m, 30–45 m, 45–60 m, 60–100 m, 100–200 m, and ≥200 m), and the estimated capital costs obtained from the cost model described in Section 2.2 are applied.

3. Key assumption

3.1 Assumptions for capital cost estimation

Although the variables used in the cost models differ depending on the specific model, in this study, we set the major common variables based on the specifications of offshore wind projects planned under the most recent auction (Round 3) conducted pursuant to the Act. The assumed parameters are summarized in Table 1.

The target year of the analysis is 2040; however, it is difficult to accurately predict exchange rates, material costs, and general price inflation for that year. Therefore, the evaluation is conducted using real prices for fiscal year 2025, based on the average exchange rates over the most recent year and the material cost data reported in the literature. As a result, recent sharp increases in material prices may not be fully reflected, and the estimated capital costs may be underestimated relative to current market conditions. This point should be kept in mind when interpreting the absolute cost levels.

For floating offshore wind systems, taking technical constraints into account, we assume a transition from semi-submersible to spar-type platforms at a water depth of 100 m.

Table 1: Common assumptions for the cost models.

Turbine capacity	15 MW/turbine
Number of turbines	35
Rotor diameter	200 m
Hub height	140 m
Exchange rate (Euro)	165 JPY/€
Exchange rate (pound sterling)	198 JPY/ £
Exchange rate (US dollar)	150 JPY/USD
Export cable cost	648,000 £ /km
Number of export cables	2

3.2 Suitable areas

Under the Act, the designation of "promotion areas" is subject to multiple requirements that take into account potential impacts on vessel navigation, environmental conservation, and fisheries activities.

In this study, following the methodology of Obane et al. (2021), we exclude from the eligible areas all sea areas where the traffic of vessels equipped with the Automatic Identification System (AIS) exceeds 31 vessels per month (approximately one vessel per day), as well as coastal protection zones, natural park areas, and waters deeper than 500 m. Under these criteria, we extract sea areas that are legally and technically suitable for offshore wind development.

3.3 Assumptions of the technology selection model

The main assumptions of the technology selection model are based on Watanabe and Otsuki[9)] and Obane et al[10)]. Interregional grid constraints are represented with reference to the standard power system model of the Institute of Electrical Engineers of Japan. With respect to carbon dioxide emissions, a constraint is imposed such that total emissions in 2040 correspond to a 70–71% reduction relative to 2013 levels, i.e., no more than 365 Mt-CO_2, in accordance with the national plan under the Act on Promotion of Global Warming Countermeasures.

The upper bounds on the deployment of solar photovoltaics and onshore wind power are based on the technical potentials reported by Obane et al.[11)], which take regional ordinances into account, with additional capacity added for facilities estimated to be installed in forest areas. Specifically, the upper limits are set to 123.1 GW for ground-mounted photovoltaics, 49.3 GW for south-facing residential rooftop photovoltaics, 97.1 GW for east–west-oriented residential rooftop photovoltaics, 137.2 GW for photovoltaics on public and non-public buildings, and 23.8 GW for onshore wind power. Import prices of fossil fuels are based on the cost, insurance, and freight (CIF) prices in the trade statistics for fiscal year 2022, and are extrapolated to 2040 using the price increase rates in the Net Zero Emissions by 2050 Scenario of the IEA World Energy Outlook 2025.

Service demands are estimated by regression based on future projections of population and GDP per capita. The major demand indicators in 2040 are assumed to be 90.4 Mt for crude steel production, 5.14 Mt for ethylene, 49.2 Mt for cement, 19.8 Mt for pulp and paper, 693.5 billion passenger-kilometers for passenger transport, and 242.2 billion ton-kilometers for freight transport by trucks.

Under these settings, a future scenario is constructed that consistently reflects both the energy supply–demand structure and the drivers of economic growth.

4. Result

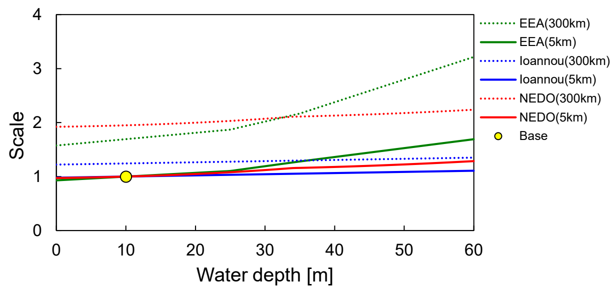
4.1 Capital cost by cost model

Fig.2 shows the relative increase in capital expenditure (CAPEX) as a function of water depth and distance from shore, estimated using the different cost models. For bottom-fixed turbines, a site with a distance from shore of 5 km and a water depth of 10 m is used as the reference point, while for floating turbines, a site with a distance from shore of 5 km and a water depth of 60 m is used as the reference (indicated by the yellow circles in the figure). The figure illustrates the percentage increase in CAPEX relative to these reference conditions for different combinations of water depth and distance from shore.

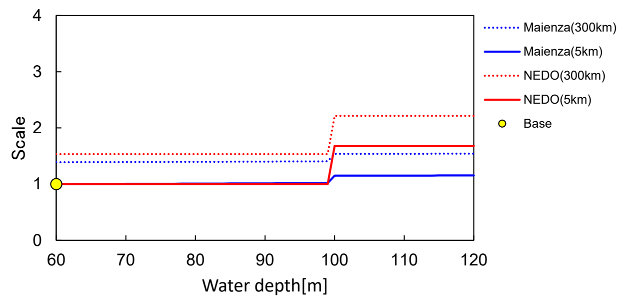
Focusing first on bottom-fixed turbines, the EEA model exhibits behavior that differs from the Ioannou and NEDO models. This is because the EEA model estimates capital costs by applying scale factors derived from empirical data to a baseline cost, resulting in scaling characteristics that differ from those of the other models. In particular, a sharp increase in CAPEX is observed in areas with greater water depth and longer distances from shore. By contrast, while the NEDO and Ioannou models show similar increasing trends with respect to water depth, the NEDO model exhibits a larger increase in CAPEX as the distance from shore increases. This difference arises from the assumption embedded in the NEDO model that installation costs increase in proportion to distance from shore.

Next, turning to floating turbines, the increasing trend with respect to water depth is broadly consistent between the NEDO model (excluding installation costs) and the Maienza model, whereas the effect of distance from shore is larger in the NEDO model. Around a water depth of 100 m, both models show an increase in CAPEX, reflecting the assumed transition from semi-submersible to spar-type platforms due to technical constraints. However, in the NEDO model, CAPEX is found to decrease with increasing water depth in some ranges. This is likely because the length of mooring lines is estimated using a regression equation, and, due to the fitting characteristics of the model, greater water depth leads to a shorter estimated mooring length.

Based on these results, we adopt the NEDO model as the representative model for bottom-fixed turbines and the Maienza model, which yields increasing capital costs with water depth, as the representative model for floating turbines. Fig. 3 shows the estimated component-wise capital costs as a function of water depth for each of these models, with the distance from shore fixed at 5 km. In the bottom-fixed NEDO model, the capital cost of jacket foundations becomes lower than that of monopile foundations at around a water depth of 34 m, and beyond this depth the rate of increase in total CAPEX becomes more moderate. In the Maienza model, although mooring line length increases with water depth, the relatively low material costs result in a gradual increase in CAPEX. Moreover, for spar-type platforms, the number of mooring lines decreases from six (for semi-submersible platforms) to three, leading to a reduction in mooring-related costs.



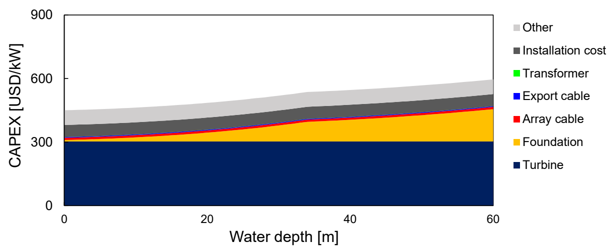
(A) Bottom-fixed wind turbines



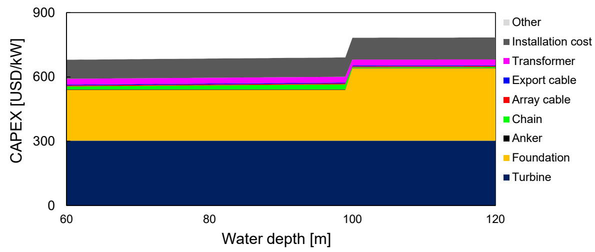
(B) Floating turbines

Fig. 2. Relative increase in capital cost by water depth and distance from shore for each model.

Note: The values in parentheses in the figure indicate the distance from shore.



(A) Bottom-fixed turbines (NEDO model)



(B) Floating turbines (Maienza model)

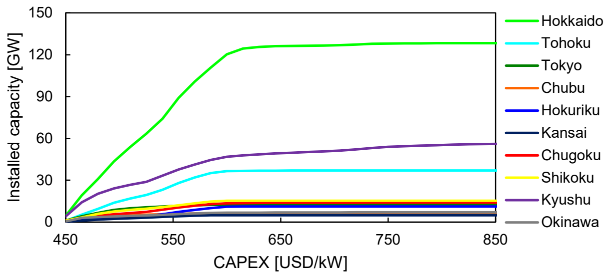
Fig. 3. Component-wise capital costs (distance from shore: 5 km).

4.2 LCOE—technical potential curves

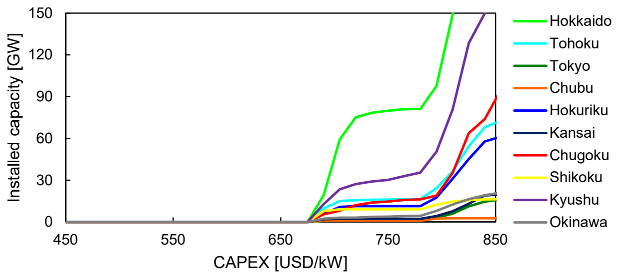
By applying the cost model to the marine spatial data on a 500 m grid basis, we estimate the capital cost–technical potential curves (Fig. 4) and the LCOE–technical potential curves (Fig. 5) for offshore wind power. In these figures, the horizontal axis represents capital cost or LCOE, while the vertical axis shows the cumulative installable capacity of offshore wind power below each threshold value.

From the capital cost–technical potential curves, it is found that, for both bottom-fixed and floating systems, areas with relatively low capital costs are widely distributed in Hokkaido, Kyushu, and Tohoku areas. Furthermore, the LCOE–technical potential curves that incorporate wind conditions, together with the spatial visualization of LCOE by sea area (Fig. 6), indicate that low-LCOE areas are heavily concentrated in Hokkaido. In addition, within Hokkaido, such low-LCOE areas are predominantly located on the Sea of Okhotsk side and off the coast of Nemuro, where direct transmission to Honshu is difficult.

These results imply that, if offshore wind power were to be deployed on a large scale in Hokkaido, there would be a high likelihood of output curtailment due to grid constraints, such as the capacity limits of the Hokkaido–Honshu interconnection and intraregional transmission lines.

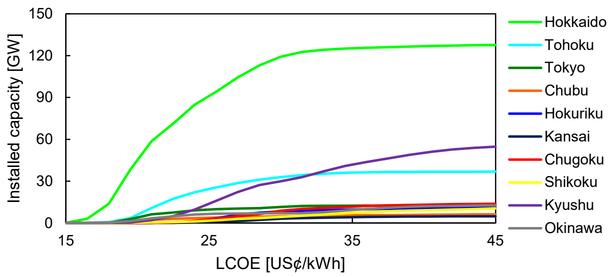


(A) Bottom-fixed turbines (NEDO model)

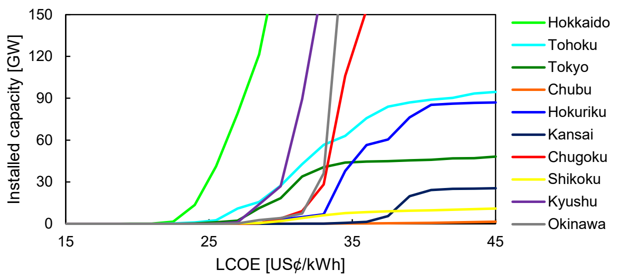


(B) Floating turbines (Maienza model)

Fig. 4. Capital cost-technical potential curves.

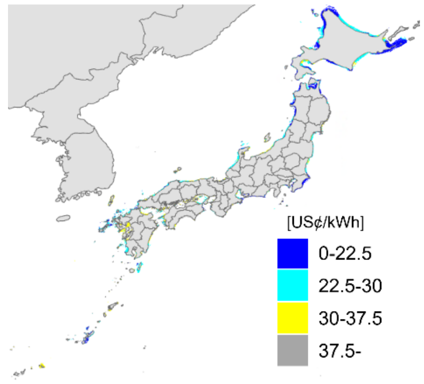


(A) Bottom-fixed turbines (NEDO model)

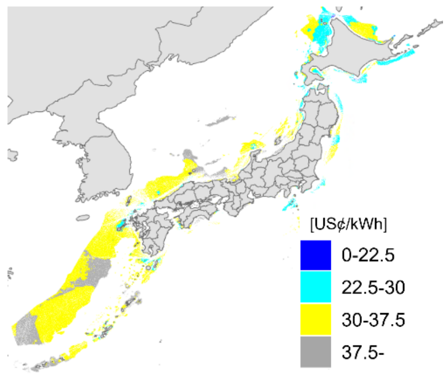


(B) Floating turbines (Maienza model)

Fig. 6. LCOE-technical potential curves.



(A) Bottom-fixed turbines (NEDO model)



(B) Floating turbines (Maienza model)

Fig. 6. LCOE by sea area.

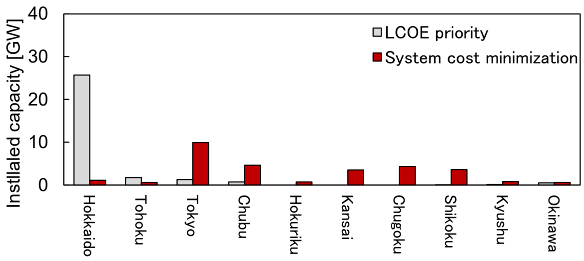
4.3 Site selection of offshore wind power considering grid constraints

To evaluate the optimal spatial deployment of offshore wind power under grid constraints, the site-specific capital costs and wind conditions defined for the 492 nodes are provided as inputs to the technology selection model. Two cases are analyzed for the year 2040, assuming total installed capacities of 30 GW and 45 GW, respectively (Fig. 7).

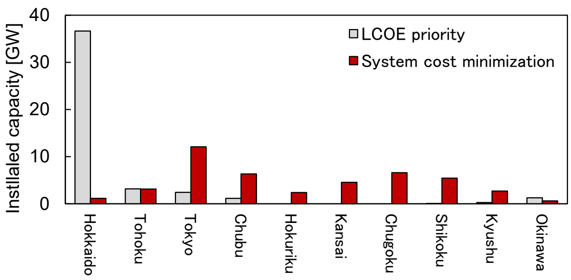
In Fig. 7, the gray bars represent the case in which offshore wind power is deployed in ascending order of LCOE (LCOE priority case), while the red bars represent the optimal allocation that minimizes total energy system costs while accounting for interregional transmission constraints (the system cost minimization case).

The results show that, in the LCOE priority case, deployment is heavily concentrated in Hokkaido, where wind conditions are particularly favorable. By contrast, when grid constraints are taken into account, a more geographically diversified deployment, including the Tohoku and Chubu areas, is found to be economically preferable. Based on the analysis of total energy system costs defined in Eq. (3), the cost reduction achieved by shifting from a single-region concentration to a multi-region distributed deployment is estimated to be 1.6 trillion JPY in the 30 GW case and 2.3 trillion JPY in the 45 GW case. Furthermore, in the 45 GW, the combined curtailment of solar and wind power generation in Hokkaido reaches 59 TWh in the LCOE priority case, whereas it is reduced to only 2 TWh in the system-cost-minimization case.

These results indicate that site selection based solely on generation costs at individual power plants does not necessarily lead to the minimization of total energy system costs. As offshore wind power is scaled up in the future, it will be increasingly important to move beyond LCOE-based site selection and to consider location optimization that explicitly incorporates grid constraints.



(A) Offshore wind installed capacity: 30 GW



(B) Offshore wind installed capacity: 45 GW

Fig.7. Regional allocation of offshore wind power by the technology selection model.

5. Conclusion

In this study, we evaluated the optimal spatial deployment of offshore wind power by jointly considering site-specific capital costs and total energy system costs. The main findings of this study can be summarized as follows.

First, by comparing multiple capital cost models, we clarified the characteristics and limitations of existing cost models. In particular, for bottom-fixed turbines, the magnitude of capital cost increases with respect to water depth and distance from shore differs substantially across models, highlighting the risk of relying on a single model in policy assessments. For floating turbines, we also pointed out that there is room for improvement in the cost estimation methods of mooring systems and floating substructures in some of the models that are widely used in Japan. In the future, further accumulation of empirical data will be required to improve and generalize cost models that can be applied to a wide range of site conditions.

Second, although the designation of promotion areas under the current Act has mainly focused on areas such as Hokkaido and Tohoku, where generation costs are relatively low, our results show that, under large-scale deployment of offshore wind power, such an approach is not necessarily optimal from the perspective of minimizing total energy system costs. At present, candidate promotion areas are proposed in a bottom-up manner by local governments; however, our findings suggest that a complementary top-down approach by the central government, taking into account grid constraints and interregional supply–demand balance, will also be necessary.

At the same time, this study has several limitations. For example, the cost models used in this study may not fully reflect the recent surge in material prices, and therefore, the absolute levels of capital costs are subject to uncertainty. In addition, due to the limited availability of empirical data for floating offshore wind systems, further improvements in the accuracy of cost models for mooring systems and floating substructures remain an important future task.

Nevertheless, the integrated assessment framework proposed in this study demonstrates the importance of shifting the basis for offshore wind deployment from LCOE-priority approach to one that aims at minimizing total energy system costs. The proposed approach provides a useful analytical foundation for the design of future zoning policies for offshore wind power.

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