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The cost of regulatory delay: quantifying how permitting timelines
affect offshore wind energy costsRudolph Santarromana^{1,2,4,*} , Ahmed Abdulla³ , M Granger Morgan¹ and Joana Mendonça² ¹ Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213, United States of America² Center for Innovation, Technology, and Policy (IN+), Department of Engineering and Management, Instituto Superior Técnico—Universidade de Lisboa, Lisbon 1049-001, Portugal³ Department of Mechanical and Aerospace Engineering, Carleton University, Ottawa, ON K1S 5B6, Canada⁴ Present Address: Laboratory for Energy Systems Analysis, PSI Centers for Nuclear Engineering and Sciences & Energy and Environmental Sciences, Paul Scherrer Institute, Villigen, Switzerland.

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E-mail: rsantarr@alumni.cmu.edu**Keywords:** offshore wind energy, decarbonization, energy transition, regulatory obligations, levelized cost of energy, power to hydrogen
Supplementary material for this article is available [online](#)**Abstract**

Rapid deployment of offshore renewable energy and transmission infrastructure can be a major contributor to energy system decarbonization. However, regulatory obligations frequently impose deployment delays that are typically not quantified in cost terms. The costs of such delays should be incorporated in project and technology assessments. Here, a framework is developed that treats the development lag between project inception and operation as a temporal proxy for regulatory and related obligations, and propagates it through a levelized-cost-of-energy calculation to quantify the cost of delay. This framework is used to compare, on a common basis, conventional high-voltage cable transmission with offshore power-to-hydrogen (PtH) alternatives. The framework is applied to three strategies to move energy to shore from offshore wind facilities. The results show that for an example, one gigawatt plant, deploying one year sooner can save €110 million—a relevant metric to gauge the cost of policy designed to expedite deployment. In scenarios where the PtH can be deployed faster than high-voltage cables, the results suggest a limited decision space in which PtH transmission is cheaper, indicating that it will need to realize other benefits to compete with high-voltage cable transmission on cost. Profitability between electricity-based and hydrogen-based transmission is then compared, considering differences in deployment time. There are existing conditions of hydrogen and electricity prices that indicate PtH pathways may be more profitable when a difference in deployment lag is applied. In the example considered here, a lag difference can result in a greater number of exploratory price scenarios where PtH is more profitable. This framework is useful to quantify the implications of regulatory obligations and tune policies to accelerate low-carbon energy deployment.

1. Introduction

Offshore wind (OSW) can be an important contributor to decarbonization pathways in many jurisdictions. However, the regulatory barriers to deploying OSW and its transmission infrastructure impose costs that are rarely quantified. As with most infrastructure projects, it takes several years to develop and deploy an OSW project. Before construction can begin, permits and other agreements must be secured

from regulators, energy system operators, and other parties. While OSW turbine installation itself can take from two to four years [1, 2], the permitting and development process may require two or three times as long depending on the jurisdiction. This can bring the whole project execution time—from inception to the start of operations—to an average of 7–11 years according to one global OSW developer with plants developed in the US, UK, and France [3]. A non-exhaustive list of typical permits required for projects

to proceed are summarized in table 1 to illustrate examples of the types of permits necessary for OSW deployment.

Transmission system deployment entails several obligations regardless of technology: gaining public acceptance [9]; securing permits and rights of way [10]; and conducting interconnection studies and waiting in interconnection queues [8]. A lack of suitable grid infrastructure in coastal areas compounds this challenge [7] and in the U.S., as much as 80% of the decarbonization promised under the 2022 Inflation Reduction Act may not occur if future transmission deployment does not exceed past rates [11]. While building in deeper waters with floating unmoored turbines can reduce environmental interactions and potentially lead to faster permitting and deployment [12], transmission lines traversing the shore, and the accompanying approvals are still unavoidable—a lack of approvals for an export cable traversing a public beach has contributed to U.S. cancellations [13, 14]. When project deployment timelines are long, project finances become more uncertain: market conditions and costs may change, and there is a risk of market shocks, all of which have been cited as reasons for OSW project cancellations [15]. Long timelines are a real barrier for developers, who must carry costs without returns for years, and without guarantee that the project will ever receive a permit [16].

Despite the real duration and uncertainties with project deployment, energy systems models commonly adopt an ‘overnight’ capital-cost convention, treating projects as if they were deployed ‘overnight’—disregarding the ‘lag’ between inception and the beginning of operations, though it has significant implications on project economics. The ‘overnight’ convention denotes cost as if construction were instantaneous, excluding financing and construction time [17]. A related literature conceptualizes or measures policy and regulatory risk as a cost or investment-return factor [18–22], though generally within a single technology or from an investor-return perspective rather than as a comparable cross-technology deployment cost. This issue is of growing importance: a recent study found that plant commissioning time has *increased* over the last two decades globally, for all renewable energy technologies—even after 2015, when the Paris Agreement was adopted leading to global recognition that quicker clean energy deployment is needed [23]. Quantifying the cost of this trend is therefore essential for energy systems modeling and technology comparisons.

Regulatory obligations are key contributors to project deployment timelines, but difficult to quantify because they vary across jurisdictions, involve fragmented agencies and overlapping responsibilities, and are interwoven among social, administrative, environmental, and political processes that differ for every project and technology. While the predictors

of acceptance and resistance have been investigated across wind, hydrogen, and transmission infrastructure, studies that operationalize these factors in energy-system models to understand how they may affect project and system outcomes are few (see supplementary note 1 for a detailed review, including onshore-wind permitting and policy-risk literature). The impact of socio-political factors on renewable energy acceptance and deployment has been explored in the literature [24]. Survey-based studies across multiple jurisdictions have documented how demographic, political, and project-structural factors shape public acceptance of wind, hydrogen, and transmission infrastructure [25–32], though the link between acceptance, deployment timeline, and project cost has been established for some onshore contexts—for example, Schmid (2024) for Swiss onshore wind [33]—but has not been systematically quantified for OSW and its transmission infrastructure. While the predictors of acceptance or resistance have been investigated, studies that attempt to operationalize these factors in energy system models to understand how they may affect project and system outcomes are few [34–36]. The contribution of the present work is therefore to operationalize an otherwise-unquantified deployment lag as a temporal proxy within a standard leveled-cost framework, and apply it to compare transmission technologies—high-voltage cable versus power-to-hydrogen (PtH)—on a common cost basis, including a lag differential and a profitability exploration not previously combined. Developing a framework to quantify the cost of regulatory obligations across competing transmission technologies is the aim of the present work. The analysis is deliberately technology-focused and jurisdiction-agnostic: it isolates the comparative effect of deployment lag across topologies under common assumptions rather than estimating costs for any specific country, and all monetary results are reported in euros. Because a socially adequate development duration is not zero, the cost of lag is evaluated relative to a faster-deployment counterfactual rather than relative to instantaneous deployment.

PtH transmission pathways are considered as a possible substitute for cable transmission for several reasons. First, transmission systems that involve lower spatial requirements and interact less with the environment may reduce the extent of the needed studies or permits, and consequently may reduce deployment timelines. Second, transmission systems that do not interconnect with the grid can forgo time-consuming interconnection studies [37], and thus reduce deployment time. An offshore hydrogen production plant and pipeline may be several times cheaper than an electric substation and a cable and may avoid some cost and permitting delays according to a project developer [38]. A recent report also finds that a PtH transmission system can save about 60% of the time to deploy a cable [39]. Third, hydrogen is seen by

Table 1. Summary of typical permits for OSW projects. This is an illustrative, non-exhaustive overview of the kinds of obligations for project deployment across jurisdictions, and not a set of jurisdiction-specific inputs to main study. Some permits can be pursued in parallel. A detailed list of US permits is found in [4] and a review of US wind energy permitting processes is found in [5].

Permit type (level)	Description	Typical timeline
Wildlife protection (Federal)	Required for projects that may affect endangered species, fisheries, any natural body of water, marine mammals, and other wildlife [6].	2 year surveys [2]
Air and water protection (Federal, Regional)	Required if a project may impact the air or water [6].	3 years [2]
Protected land usage (Federal, Regional, Local)	Required from the land administering agency should a project use federally owned or protected land [6].	Varies by location and level
Public and local inquiries (Local)	Projects typically allow periods of public comment where concerns on the development may be raised and may require the developers to address them [7].	Varies by location
Interconnection (Federal, Regional)	If a renewable energy project must connect to the electric grid, approval from the transmission network is required.	2-4 years [8]

some as a key energy vector that can be used to decarbonize hard-to-abate sectors like steel production, the chemical industry, and perhaps some aviation. Thus, PtH could serve as a substitute for cable transmission and simultaneously address challenges with renewable energy deployment, transmission deployment, and energy decarbonization. Recent work found that OSW plants with PtH realize fewer environmental impacts than cable-based plants, albeit at greater cost—although differential deployment times were not considered in the study [40]. Prior studies have found the break-even transmission distance between various types of hydrogen transport alternatives and electricity transmission exceeds 1000 km [41, 42], or 740 km for pipelines in one German case study [43]. These distances indicate that PtH might only be a potential substitute for transmission cables for long-distance subsea interconnectors as opposed to OSW export cables. However, differences in deployment time between PtH and cable transmission [39] may alter this break-even distance, a gap this study addresses by quantifying the value of reduced regulatory burdens and expedited deployment across technology options.

Here, a strategy to quantify the cost of regulatory obligations through the project development duration is demonstrated and used to compare three ways to move energy to shore from an OSW plant: a) high-voltage cable transmission; b) hydrogen electrolysis offshore, with the hydrogen brought to shore via pipelines; and c) hydrogen electrolysis offshore, with the hydrogen brought to shore via ships [44]. Several policy and regulatory initiatives are aimed at expediting renewable energy deployment—giving special consideration to renewable energy deployment relative to existing stakeholders [45], reducing permitting time [46], and reforming interconnection processing [47]. A quantitative assessment of the type demonstrated here can inform both project developers and policymakers about the potential value of reducing

these barriers, and is especially relevant in the context of climate targets given that each year of delay represents foregone carbon abatement. The balance of this paper describes the analytical framework (section 2), the results and discussion (section 3), and conclusions (section 4).

2. Materials and methods

The analysis proceeds in three parts: (1) valuing shorter deployment times considering a baseline cable transmission system; (2) assessing the regulatory difference needed for PtH transmission to be cost-competitive; and (3) sensitivity analyses and profitability assessment. The cost-of-energy calculation method for each topology is summarized in this Section.

2.1. Transmission system topologies

Figure 1 summarizes the three topologies: Topology A uses high-voltage direct current (HVDC) cables (baseline); Topology B transports hydrogen via pipeline [48]; and Topology C ships liquified hydrogen [44, 49].

Conversion losses are accounted for throughout this analysis: electrolyzer, liquefaction, and downstream efficiencies are specified in table S2 of the supplementary material and propagate into the cost of energy, and electrolyzer efficiency—commercially in the range reviewed by Sorrenti and colleagues [50]—is treated as a key sensitivity parameter. Because the topologies considered deliver hydrogen as an end medium rather than reconverting it to electricity, reconversion losses fall outside the present comparison.

2.2. Cost and performance

The main assumptions regarding the cost and performance of the relevant components are given in

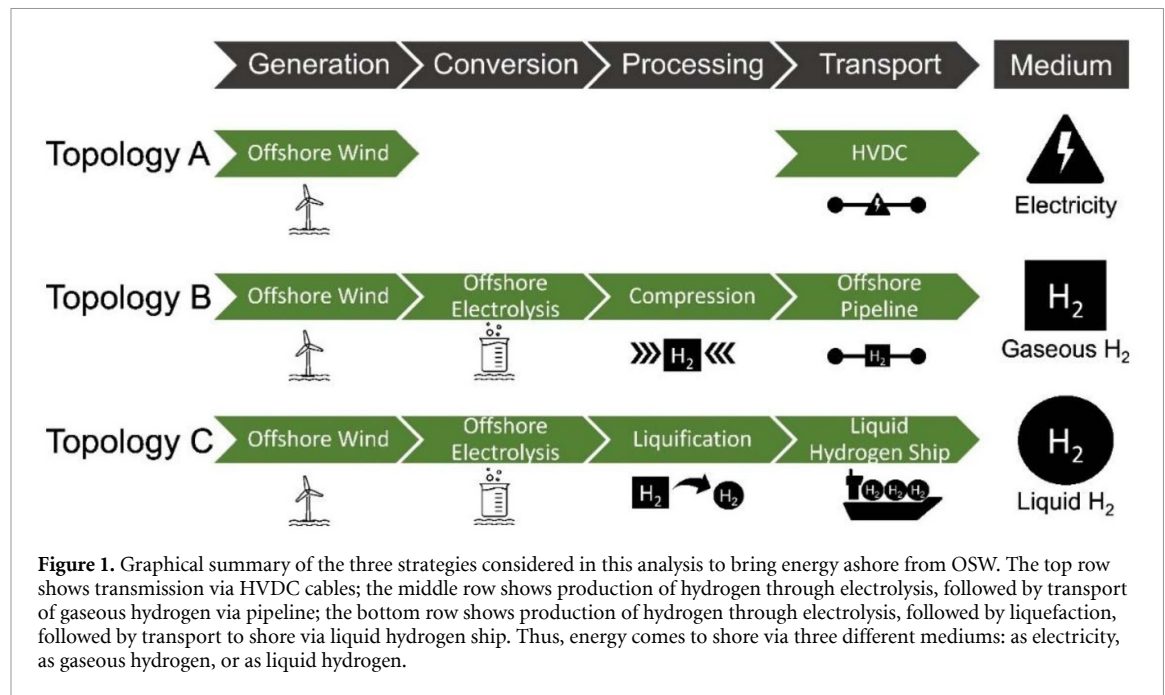


table S2 of the supplementary material. The cost and annual energy output can be computed by combining the components required for each topology considering plant size, capacity factor (assumed to be 50% throughout—the midpoint of the range of projected OSW capacity factors until 2050 [51]) and a distance to shore. For Topology A in figure 1, several cable types are considered (see table S3 of the supplementary material) and formulas from Xiang and colleagues [52] are used to compute cable requirements; the lowest-cost cable option is used to compute the cost of energy from Topology A.

2.3. Levelized cost of energy (LCOE)

The LCOE for each topology is computed considering distance to shore, which impacts the lengths of cable, pipeline, and trip needed to ship liquid hydrogen to shore, increasing hydrogen ‘burn-off’ losses. The LCOE for a baseline plant of 1000 MW is computed as the ratio of discounted cash flows to the sum of discounted energy flows:

$$\text{LCOE} = \frac{\sum_{t=0}^T \frac{\text{CAPEX}_t + \text{OPEX}_t}{(1+r)^t}}{\sum_{t=0}^T \frac{E_t}{(1+r)^t}} \quad (1)$$

where capital expenditure (CAPEX) and operational expenditure (OPEX) in each year, are represented by CAPEX_t and OPEX_t respectively; E_t is the energy produced in year t ; r is the discount rate; t is the year index; and T is the total lifetime of the project in years.

2.4. Operationalizing regulatory obligations

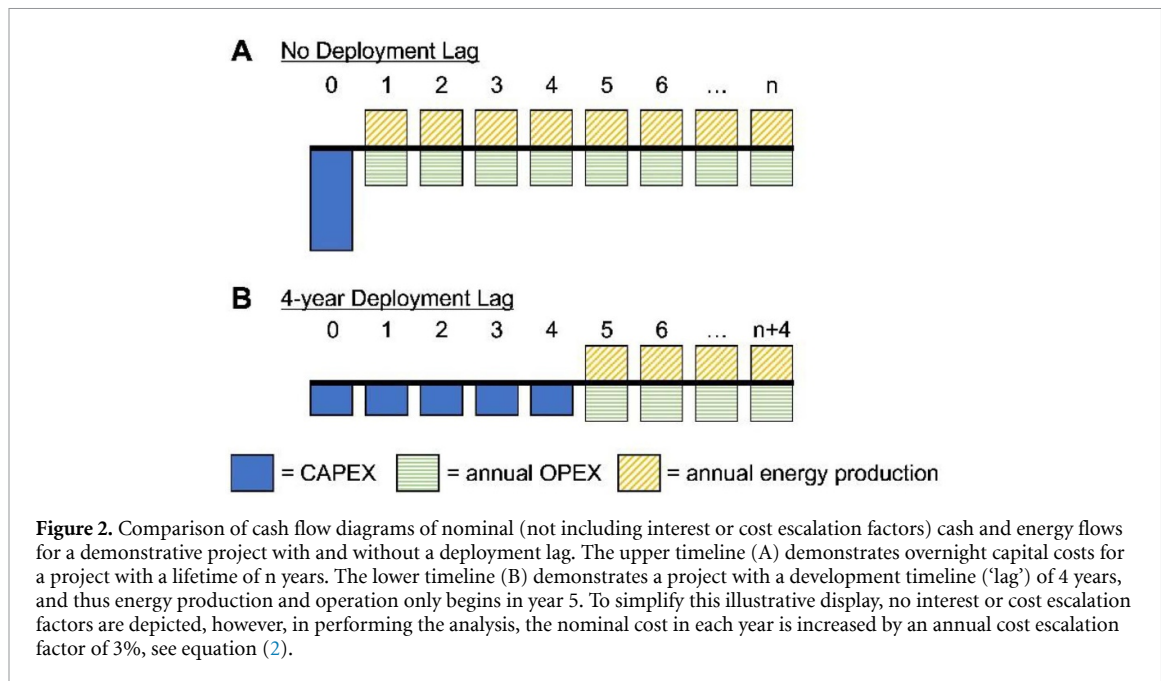
The cash-flow structure and energy flows are shown in figure 2. Whereas figure 2(A) demonstrates how

overnight costs are calculated, figure 2(B) illustrates a deployment ‘lag’ between a project’s inception and when its operations begin. The CAPEX is spread across the lag years. Here, project inception (year 0) denotes the start of the permitting and development process—the point at which project-specific development expenditures begin. The interval from inception to the start of operations comprises the permitting and development activities that precede construction, together with the two- to four-year construction period. Certain activities may precede this definition (such as seabed-lease acquisition and preliminary desktop or feasibility studies) and are not resolved separately here because their timing and scope vary substantially across jurisdictions. As in any forward-looking cost model, absolute costs are projected rather than known; however, the distribution of the CAPEX in the development years is inconsequential to the final LCOE, as confirmed by the CAPEX-distribution sensitivity (supplementary note 4, figures S3 and S4), where the LCOE changes little across distributions except when all CAPEX is committed in year zero (a ‘worst-case’ cost scenario). Thus, the levelized distribution is used in the main analysis as it yields similar results while requiring fewer assumptions.

When the lag is greater than zero, the CAPEX in each subsequent year is inflated by a cost escalation factor. The cost escalation factor is determined by the average annual change of the building cost index (BCI). This is expressed as:

$$\text{CAPEX}_{t,\text{escalated}} = \text{CAPEX}_t \times (1 + \Delta)^t \quad (2)$$

in which the escalated CAPEX value is represented by $\text{CAPEX}_{t,\text{escalated}}$, Δ is the annual escalation factor over the number of years, t . An escalation factor of 3%



per year is used in this analysis which the Engineering News Record reports is the average change in the BCI for the period 1980–2004 [53]. Because this historical average may understate escalation during recent inflationary and supply-constrained periods—for example, a short-term capital cost increase factor of 20% is used to adjust for supply chain and macroeconomic shocks stemming from the COVID-19 pandemic in OSW technology forecasts [54]—a range of annual escalation factors up to 10%, is additionally evaluated in the sensitivity analysis of this study, representing a sustained elevated rate over the development horizon. Henceforth, the word 'nominal' will be used when referring to the pre-escalated CAPEX values during the development years. The resulting costs are all computed considering annual cost escalations.

In this analysis, a uniform discount rate of 5.2% is assumed for all years, which is the weighted average cost of capital for OSW plants according to the National Renewable Energy Laboratory's (NREL, rebranded as the National Laboratory of the Rockies, NLR, in 2025) Annual Technology Baseline for OSW [17], and does not consider a duration-dependent financing rate. Because financing exposure and risk premiums may rise with development duration, excluding them makes the cost-of-delay estimates presented here conservative; incorporating financing costs would be expected to increase the estimated cost-of-delay. A sensitivity analysis on the discount rate is also performed and provides a first-order proxy for this effect, as financing risk is expressed through the cost of capital. The absolute CAPEX is assumed constant regardless of lag duration, albeit spread across lag years. Supplier prices are assumed not to change over the course of

the development and deployment process. In future analyses, differential costs of capital that are based on the maturity of the project and even its location could be considered [55, 56]. Several cash flow distributions over the development years are also assessed to quantify the impact of this modeling choice (see supplementary note 4).

The lag used here aggregates the pre-operation, project development and commissioning interval—encompassing regulatory review, administrative and environmental processes, interconnection studies and queue time, other approvals, and project construction and commissioning time—into a single temporal variable. It does not separately resolve construction duration, which is treated as fixed, nor developer-side commercial delays. The resulting figures therefore represent the cost of total development lag rather than the cost of permitting alone.

3. Results and discussion

The results are presented considering a baseline plant of 1000 MW and a distance to shore of 20 km, reflecting the global average distance of operating wind farms [57]. Throughout, HVDC cables are assumed to be used as these would be preferred to 50/60 Hz high-voltage alternating current (HVAC) cables, and probably even lower-frequency HVAC over long distances [52]. In the following figures, the construction time estimate of 3-years is often shown directly (the mid-point estimate of construction duration), and overnight costs (0 years of lag) is also shown as a theoretical comparison of how the results compare with overnight costs.

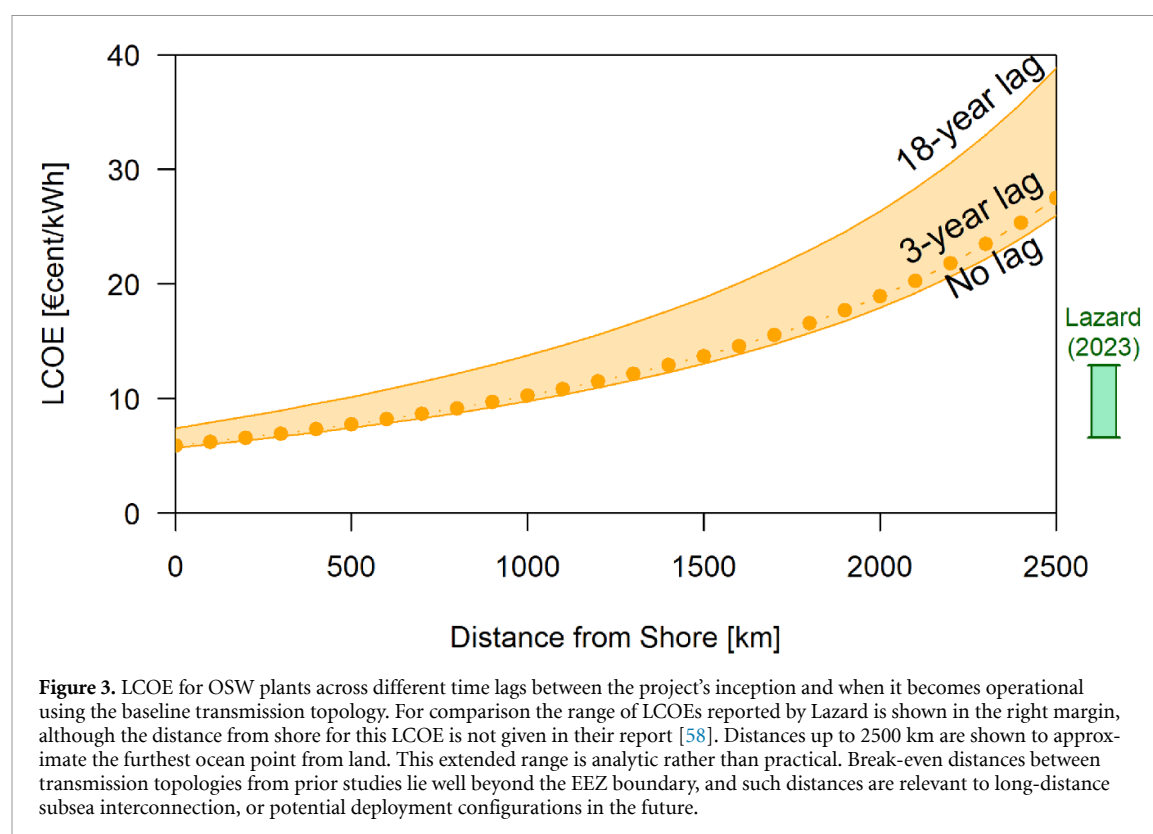


Figure 3. LCOE for OSW plants across different time lags between the project's inception and when it becomes operational using the baseline transmission topology. For comparison the range of LCOEs reported by Lazard is shown in the right margin, although the distance from shore for this LCOE is not given in their report [58]. Distances up to 2500 km are shown to approximate the furthest ocean point from land. This extended range is analytic rather than practical. Break-even distances between transmission topologies from prior studies lie well beyond the EEZ boundary, and such distances are relevant to long-distance subsea interconnection, or potential deployment configurations in the future.

Table 2. LCOE for an OSW plant with different years of lag between the project's inception and when it becomes operational. This considers a plant 20 km offshore and demonstrates how the lag can impact the cost of energy.

Years of Lag	LCOE [€/MWh]
0 (overnight cost)	57.6
3	59.7
6	62.1
9	64.8
12	67.9
15	71.4
18	75.3

3.1. Valuing quicker deployment

Figure 3 demonstrates how the LCOE for an OSW plant that uses the baseline transmission topology (Topology A in figure 1) changes with different lag periods between the project's inception and when it becomes operational. The mid-cost scenarios (table S2 of the supplementary material) are used in figure 3 and the deployment time lag is the only parameter that changes across the scenarios. Table 2 provides results across a range of time lags.

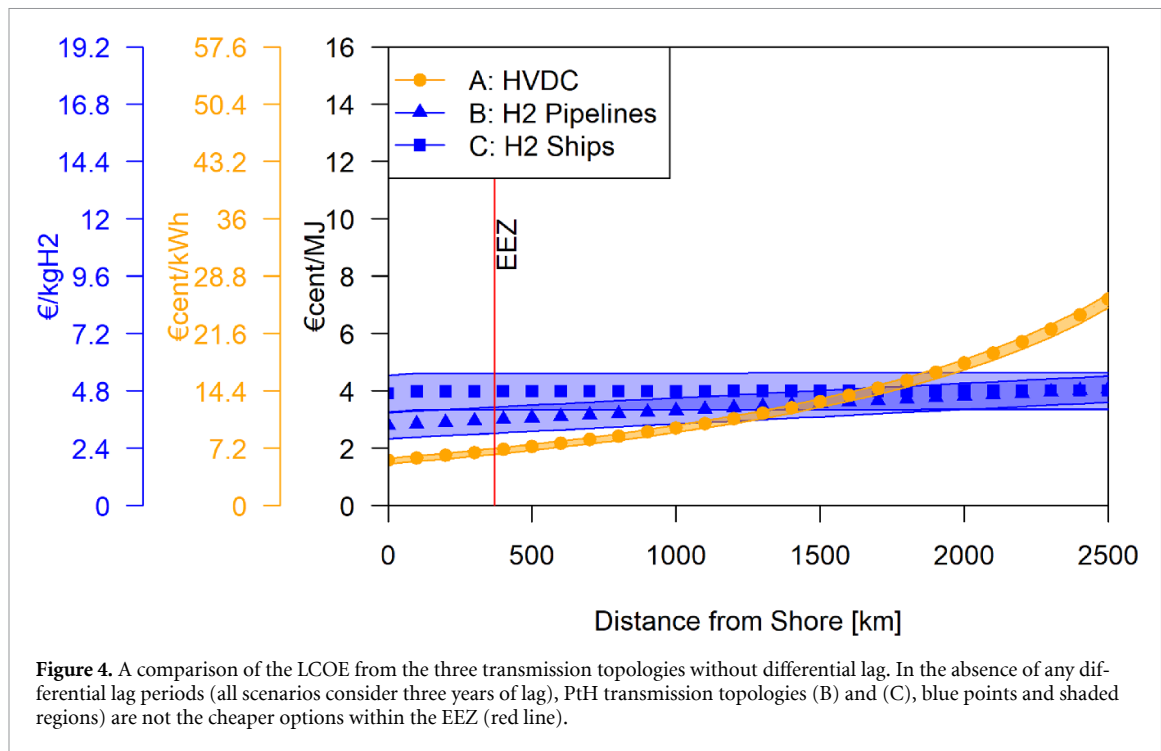
The average cost of energy increase is 1 €/MWh per additional year of lag. Considering a 1 GW plant and a capacity factor of 50%, this equates to €110 million over its 25 year lifetime. Beyond financial cost, each year of delay also represents foregone carbon abatement—for a 1 GW plant with 50% capacity factor, a one-year delay defers approximately 4.4 TWh of zero-carbon electricity generation. To achieve the

same monetary savings through a direct financial benefit (tax credits or subsidies), a developer would require a 4% reduction in capital expenses through an investment tax credit (ITC)—approximately €35 million investment through policy or government incentives per plant.

3.2. Baseline is cheaper in many scenarios

Considering all three topologies based only on the range of component cost and performances, the resulting LCOEs are shown in figure 4. These are expressed in eurocents per megajoule (MJ) to account for the difference in delivered energy medium—electricity or hydrogen. PtH topologies are less sensitive to distance from shore than the cable topology. Topology C—which does not have any longitudinal infrastructure in cables or pipelines—is the least sensitive to distance from shore, since the main cost as plants move farther offshore is the increased ship travel distance which results in more lost hydrogen (in the form of 'burn-off' from storage) and requires more fuel. Transmission topologies that use PtH do not achieve a lower cost of energy within the exclusive economic zone (EEZ) where projects are likely to be deployed (within 200 nautical miles, NM of shore); only at very great distances from shore (>1000 km) do these topologies begin to be cheaper than the baseline topology when there is no difference in lag between the technologies, echoing prior findings [41, 42].

When three scenarios of lag between project inception and commissioning are considered for each



topology (0 years, 3 years, and 20 years) the result is as demonstrated in figure 5. Given a high lag scenario for the baseline topology (A), the PtH topologies (B and C) begin to be cheaper at a distance that is closer to shore than found in figure 4. However, these PtH topologies barely become competitive with the baseline topology from a cost of energy standpoint within the EEZ (only topology B does), even when the worst-case scenario of the baseline topology competes against the best-case scenario of the PtH topologies. The assumed 20 year lag differential between scenarios depicted in figure 5 is unlikely to reflect real conditions, making cost-competitiveness within the EEZ doubtful even under the most favorable assumptions for PtH.

As discussed earlier, there are other reasons besides regulatory deployment obligations or delays that might lead a developer to consider a PtH transmission topology instead of cable transmission. Therefore, one additional strategy is explored—OSW ‘overplanting’ (when the capacity of the turbine array deployed is greater than the capacity of the export transmission system [59]). As a result of overplanting, the generator can provide a more consistent power level, even when the energy source is variable. This implies that a considerable amount of power is curtailed (less power than is available from the array at a given time is provided by arresting turbines, or ‘disconnecting’ generators [60]). Some estimates for overplanted generators indicate that levels of curtailment up to 35% [59] are possible, while even greater than 50% curtailment can be economically rational [61]. For the PtH topologies, the hydrogen generated can be stored, meaning that the plant would

not have to curtail OSW production to accommodate the transmission system or demand constraints. Therefore, an overplanted scenario (up to 35% annual curtailment) is considered in addition to the lag differential in defining the low, middle, and high scenarios of the cost of energy from the different topologies. These results are depicted in figure 6. When adding curtailment scenarios, the PtH transmission topologies realize comparable (possibly lower) costs of energy than the baseline transmission topology within the EEZ and potentially close to shore.

In summary, PtH transmission is not cost-competitive with HVDC in the absence of differential lags; competitiveness only emerges under large lag differences combined with high curtailment. The analysis elucidates the specific regulatory and curtailment policies or conditions under which PtH becomes a viable alternative to HVDC.

3.3. Sensitivity analyses

Sensitivity analyses on discount rate, years of lag, escalation factor, distance to shore, electricity cost, and project size are conducted to examine which of these variables most greatly affect the cost of energy in the baseline topology. The results are depicted in figure 7 with detailed results on the input and outcome parameters for each given in table S5 and S6 of the supplementary material.

Figure 7 shows that five of the six parameters are positively correlated with LCOE; only project size is inversely related, reflecting economies of scale [62]. The discount rate has the largest impact on LCOE, consistent with International Energy Agency findings [63]. Years of lag has the next largest impact, followed

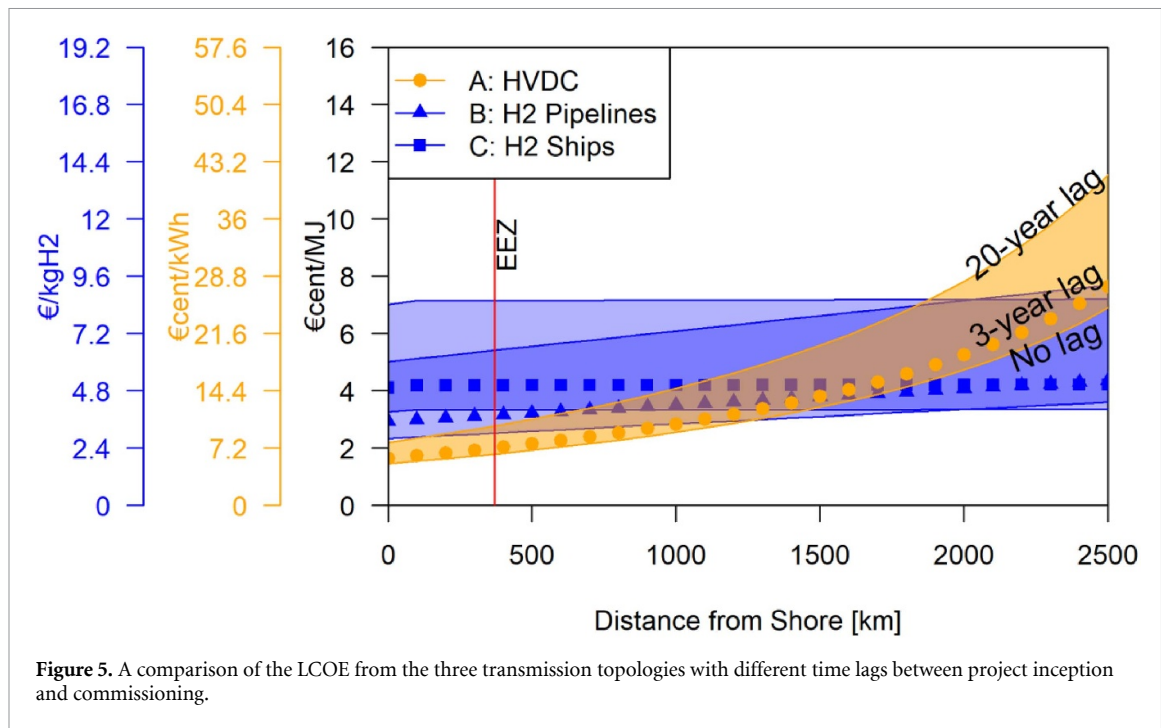


Figure 5. A comparison of the LCOE from the three transmission topologies with different time lags between project inception and commissioning.

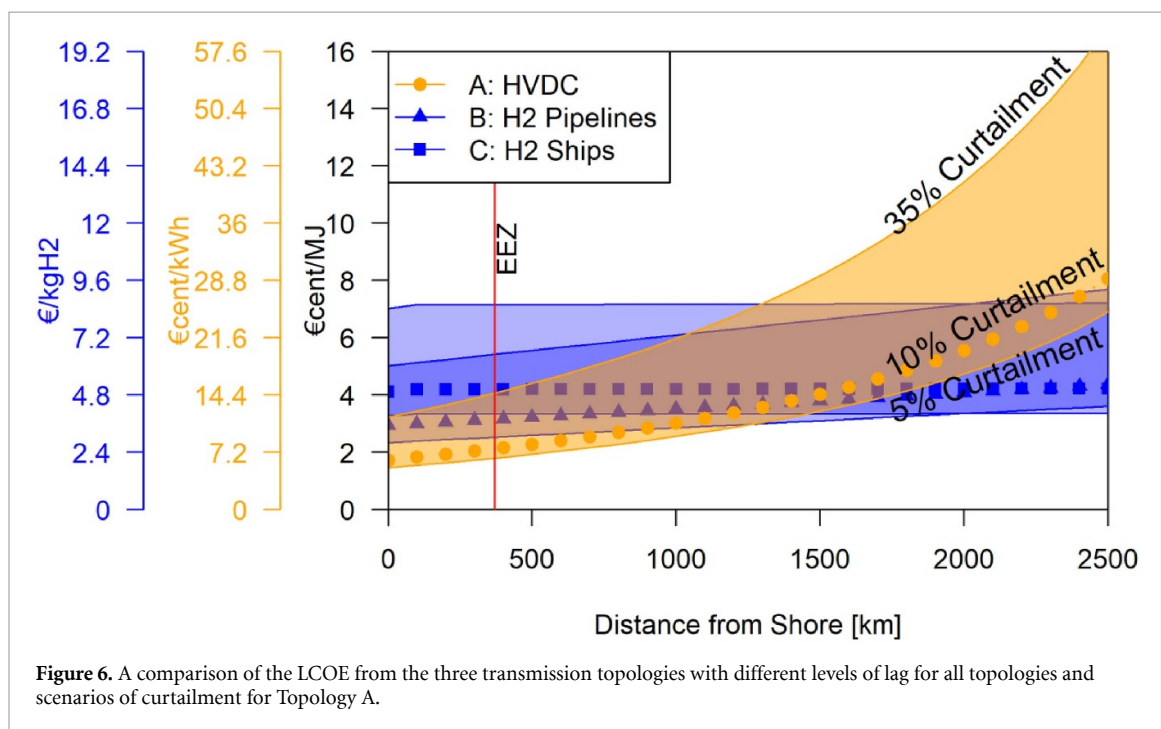


Figure 6. A comparison of the LCOE from the three transmission topologies with different levels of lag for all topologies and scenarios of curtailment for Topology A.

by the CAPEX escalation factor, distance to shore and electricity cost, with project size the least influential. To understand how component cost and performance parameters impact the cost difference between the two PtH topologies and the baseline topology, a sensitivity analysis is presented in figure 8.

In figure 8, steeper lines indicate greater sensitivity to cost-competitiveness. Hydrogen shipping has only been explored theoretically [44, 64], thus its cost is uncertain, though small relative to total plant costs, and thus ship costs are insensitive to

LCOE differences—the same rationale is true for the pipeline. Both topology comparisons are insensitive to OSW electricity costs (which also affects Topology A). Electrolyzer cost and efficiency are dominant: a 21% cost reduction improves PtH competitiveness by 17%–24%; raising electrolyzer efficiency to 70% (from the baseline efficiency of 64.2%) yields an improvement in cost competitiveness of 13%–19%. The assumed distribution of CAPEX across development years has minimal effect on LCOE; the lag duration itself, not the cash flow profile, drives the

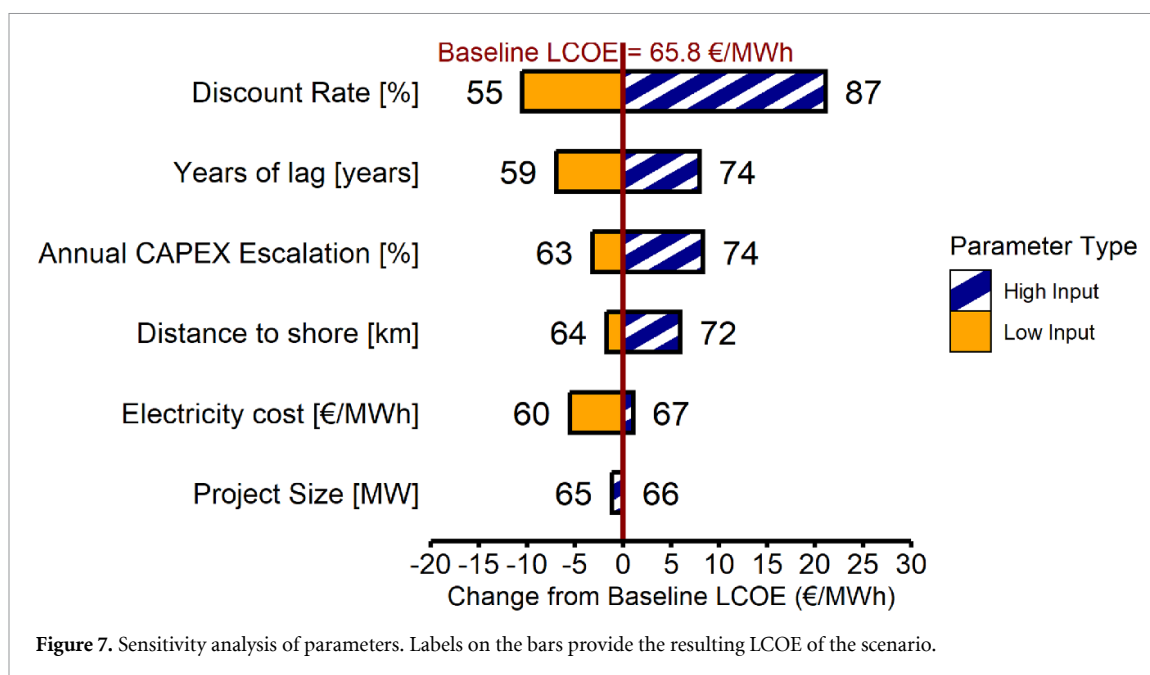


Figure 7. Sensitivity analysis of parameters. Labels on the bars provide the resulting LCOE of the scenario.

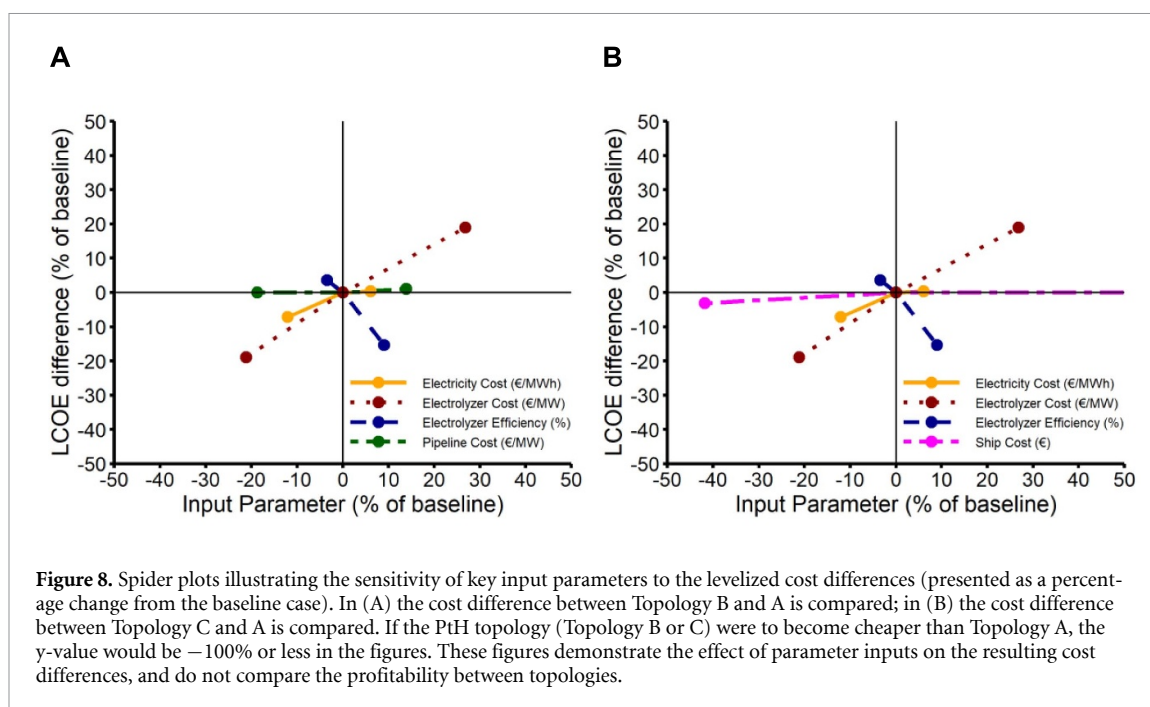


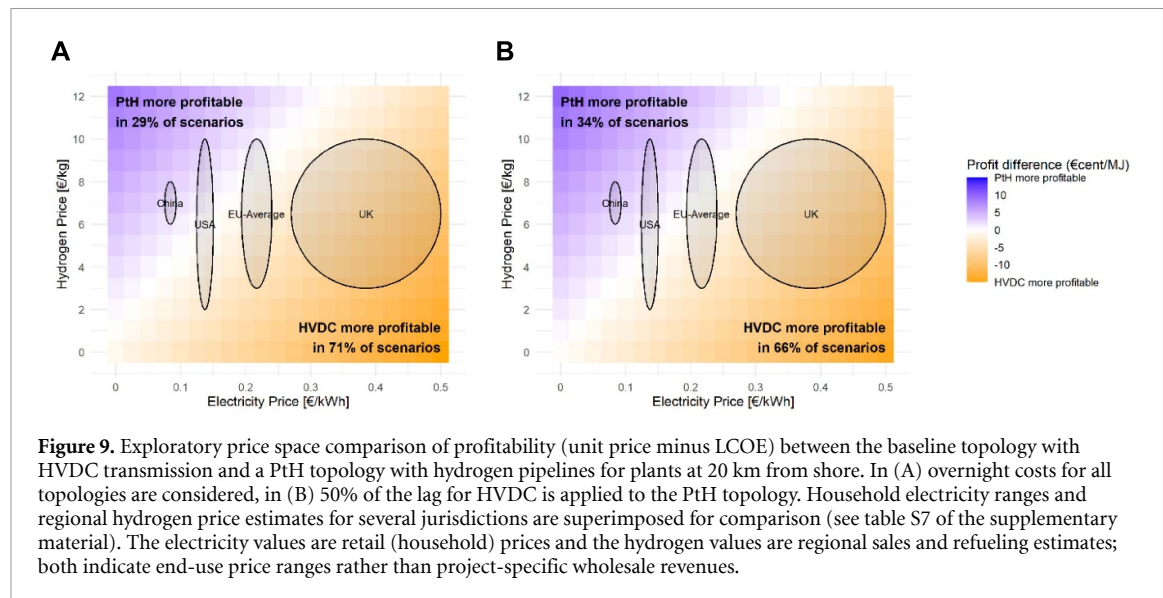
Figure 8. Spider plots illustrating the sensitivity of key input parameters to the levelized cost differences (presented as a percentage change from the baseline case). In (A) the cost difference between Topology B and A is compared; in (B) the cost difference between Topology C and A is compared. If the PtH topology (Topology B or C) were to become cheaper than Topology A, the y-value would be -100% or less in the figures. These figures demonstrate the effect of parameter inputs on the resulting cost differences, and do not compare the profitability between topologies.

cost impact (see note 4 of the supplementary materials).

Finally, a relevant consideration is how profitability compares between the topologies, acknowledging that the price per unit of energy for electricity and hydrogen differs. To investigate this comparison, an exploratory price-space analysis is developed. Because no mature hydrogen market exists to establish reference prices, the range of electricity and hydrogen prices over which each pathway would be more profitable if the assumed price combination scenarios were realized is presented, rather than asserting a definitive profitability ranking. European household electricity price ranges from 0.19 to 0.24

€/kWh [65], and the price for hydrogen ranges from 3 to 10 €/kg according to regional estimates [66] (no hydrogen market exists, so country pricing data for hydrogen are still sparse), although prices for hydrogen at refueling stations has even exceeded 20 €/kg in some instances [67–69]. Figure 9 illustrates the difference in unit profit (profit per MJ) between a PtH topology and the baseline topology, calculated as the unit price minus the LCOE. This gives an indication of how profitable PtH might be when compared to the baseline topology.

Figure 9 demonstrates that when a lag difference is considered instead of overnight cost, the impact on comparisons between topologies is slight, but $\sim 5\%$



more price scenarios favor PtH. In figure 9(B) the PtH topology is deployed in seven years, the low end of average OSW development times [3]. The HVDC topology is deployed in 14 years in figure 9(B) given that one estimate finds it may take more than double the time to deploy HVDC compared to PtH transmission [39]. As would be expected, most of the scenarios considered find the baseline HVDC transmission pathway more profitable, however, the more profitable transmission strategy is not as clear as one might expect. For plants at this distance from shore (20 km), price estimates in China, USA, and the EU could favor PtH transmission from a profitability standpoint even without a difference in lag considered (figure 9(A)). When plants move further offshore to 1000 km, many more price scenarios become more profitable for PtH (see figure S5 of the supplementary material). While price formation is complex and not independent from the cost of production and regulatory factors, this analysis indicates that even for plants close to shore, there are price scenarios where PtH may still be more profitable than HVDC transmission, even though the LCOE at this distance (see figure 5) is greater for PtH than HVDC.

The quantitative framework presented here should be considered alongside political realities that affect low-carbon energy deployment with examples including Spanish support for solar energy deployment in the 2010s [70], and recent policy enactments in the United States [71]. In this study, the consequence of delay is primarily cost escalation, but a further dimension of delay risk is a risk of exposure to policy change, which can shift abruptly across technologies. In the United States, the 2025 reconciliation act requires wind projects to either begin construction within a narrow window of enactment or be placed in service by the end of 2027 to retain the technology-neutral tax credits [71, 72]. Where

such deadlines interact with the 7–11-year execution timelines typical of OSW [3], regulatory delay becomes more than only a matter of escalating nominal cost; it can threaten a project's eligibility for support. Retroactive policy change carries similar risks outside the United States: Spain's successive reforms to renewable energy support between 2008 and 2013 (including retroactive limits on remuneration for existing plants and, ultimately, a moratorium on support for new projects) undermined investor confidence in the stability of its regulatory framework [70]. A pathway that can be deployed faster spends less time exposed to this type of risk—an instance of the greater 'technological forgiveness,' in which adoption is less sensitive to institutional instability [73]. This reinforces the central finding from a different perspective: the value of shorter deployment lies not only in avoided cost escalation but in reduced exposure to abrupt policy changes or reversal, a consideration that can weigh differently on cable- versus hydrogen-based transmission.

4. Conclusions

The pace of OSW deployment is directly tied to national and international climate commitments, a fact that makes the economic cost of regulatory delay not only a financial issue for developers, but a climate issue for policymakers. Project execution in the real world—whether for OSW projects or for many other technologies—can take years owing to regulatory requirements and other factors that differ across jurisdictions and contexts. For OSW, although project construction may last two to four years, the overall timeline may require 11 years or more depending on the jurisdiction, their regulatory requirements, and potential stakeholder resistance which has delayed

OSW projects in the US in the past [74, 75], and commissioning times have grown globally over the last two decades despite Paris Agreement commitments [23], with interconnection queues lengthening in parallel [8]. This study demonstrates a framework to quantify the monetary implications of regulatory delay and compare its differential effect across transmission technologies.

For the example considered here, reducing deployment time by one year saves 1 €/MWh, or €110 million over a 25 year operational life. To put that reduction in perspective, achieving a similar reduction in cost of energy for the same plant would require a 4% ITC—or €35 million per plant. These savings compound, considering all plants in a jurisdiction with quickened deployment would benefit, providing a tractable benchmark for evaluating permitting reform policies.

This framework is used to compare the cost of energy between three specific transmission deployment topologies and find that there are few scenarios that favor PtH transmission as a substitute for high-voltage cables. PtH transmission only becomes cost-competitive when high levels of curtailment and large differential lags in favor of PtH projects are considered, both of which may occur in some situations. However, the competitiveness of the PtH topologies is found to be sensitive to the cost and performance of electrolyzers, indicating that in the future, once the technology becomes more mature, PtH transmission may make more economic sense. Finally, by comparing several price scenarios, the results indicate that there are jurisdictions where PtH may be more profitable than HVDC, even for plants close to shore—an observation that becomes more apparent when a lag difference between the PtH and HVDC topology is considered.

Some limitations include constant assumptions of escalation factors, discount rates, and unit costs; annual fluctuations would improve project-specific applicability. In particular, regulatory and policy risk is unlikely to follow a constant compound rate—abrupt, non-linear shifts are possible (as discussed in section 3.3)—so the constant-rate treatment should be read as a first-order approximation that the discount-rate and elevated-escalation sensitivities only partially bound. Project scale could also warrant further attention: smaller projects have shorter deployment timelines, which could limit the effect of regulatory easing. Future work could address time-varying cost of capital, macroeconomic shocks, sector/region-specific price formation; non-monetary indicators could also be incorporated in a multi-criteria extension. The present analysis assumes projects reach completion regardless of timeline; future work incorporating abandonment probability—which likely increases with development duration—would likely raise the estimated cost of delay.

Finally, it is important to note that these results quantify the effects of delay on cost; they do not measure the full social value or cost of regulation. Regulatory processes also realize social benefits not incorporated in this analysis, for example, they protect environmental quality, fisheries, coastal communities, indigenous rights, and marine ecosystems. Reducing avoidable delays may therefore yield economic and climate benefits (through expedited low carbon energy deployment), but poorly designed acceleration measures can impose social or ecological costs of their own. The framework presented here quantifies one side of that balance—the cost of delayed deployment—and is not, by itself, a case for streamlining any particular regulatory requirement.

This work demonstrates one way to operationalize regulatory obligations. In energy system models, the impact of regulatory obligations, permitting, and other socio-political requirements are difficult to quantify, but have a relevant effect when reflected through a temporal proxy as shown here. As governments design permitting reform and interconnection policy, a framework like the one demonstrated here could provide a tractable basis for comparing the climate and cost value of regulatory streamlining against other decarbonization interventions.

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Data availability statement

The data that support the findings of this study are openly available at the following URL/DOI: <https://doi.org/10.5281/zenodo.10730745> [76].

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