Norwegian Offshore Wind Auctions

Recommendations on the support scheme and auction design (Report on tasks 3 and 4)

Prepared for:

Norwegian Ministry of Petroleum and Energy

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Executive Summary

The following table provides a summary of our recommendations on the support scheme and auction design for Sørlige Nordsjø II (SN II), the first offshore wind auction in Norway (Report on tasks 3 and 4).

Design element	Recommendation
1. Support scheme	
Form of support	The Ministry has determined **two-sided CfDs** as the preferred form of support for the first offshore wind auction in Norway
Determination of electricity market reference price period	The decision on the length of the reference period implies a trade-off between revenue certainty and allocating more market price risk to producers. The Ministry has expressed a preference for reducing market price risk for bidders in the initial phases of the Norwegian offshore wind support scheme. Hence, **hourly CfDs**, in principle, are a feasible option in the initial phases of the Norwegian offshore wind support scheme. Hourly CfDs also entail advantages in terms of not requiring additional design elements to avoid distorted dispatch signals that arise with longer reference periods. Alternatively, **CfDs with a monthly reference period** could be considered. A monthly reference period may provide a good balance between providing sufficient market integration incentives as well as enabling a relatively stable and certain cash flow for projects.
Rules to mitigate specific dispatch challenges	**Rules to avoid feed-in at negative prices**: Implement a rule of "no CfD payment in times of negative prices" in line with state aid requirements.
	Rules to avoid stop of feed-in at positive prices (not relevant for hourly CfDs): No action is required in case of an hourly reference period. In case of longer than hourly reference periods (e.g., monthly or annual), the following options are feasible: - *Option 1* (if a simple rule is preferred and some oversubsidization is acceptable): Implement a discontinuation of the payback obligation from the RE producers whenever the spot market price in a given hour is smaller than the payback amount - *Option 2* (if the focus is on support cost-effectiveness, i.e., avoiding overcompensation, and creating a steady revenue profile for the developer): Implement a dynamic adaptation of CfD repayment through recalculation of hourly day-ahead spot market rule for cases where the spot market price is smaller than the payback amount (i.e., the negative CfD premium).

Billing	In general, payments should be based on metered output, which is used to determine the difference between the strike price and the reference price for each hour. An **aggregated daily, weekly, or even monthly payment of the net premium for the billing period** (i.e., either positive or negative) is advisable. A responsible party executing and monitoring payments, typically the TSO or a dedicated government agency, should be determined to ensure the reliability of payments. Delays beyond a pre-defined deadline in issuing billing statements as well as payments to and from the generator should be avoided. CfD payments can be made in local currency, i.e., Norwegian Kroner.
Inclusion of PPA	**Define boundaries between the CfD and a potential PPA** and require a meter to be installed at the onshore injection point.
Duration of support	A **15-year duration** as suggested by the Ministry, in principle, is well in line with international best practices. If the goal would be to further increase revenue certainty for bidders, a longer support period of up to 20 years could be considered.
Caps on support payments and/or payback	If the Ministry is legally required to implement a **cap on support**, and the goal is to limit revenue risks for bidders, the approach to calculating the cap as the total net amount of subsidies (i.e., deducting payback amounts from the aggregated support payments) seems adequate. The support cap should be set at a sufficiently high level so that the project by default can benefit from the support scheme over the whole support period under normal conditions. If a net cap is chosen, the determination of whether a support payment has been achieved should ideally be aligned with the billing period. We advise against a dedicated **cap on paybacks**. A cap on paybacks could create unintended effects, such as the winner's curse problem or incentivizing (multiple) zero bids.
Inflation indexation of the strike price	A regular (e.g., annual) **adjustment of strike prices based on CPI or PPI index** throughout the whole support period is not per se required (see justifications above). However, an indexation of the strike price provides certainty about the (real) expected level of revenue needed to recoup the investment over the support duration. This higher level of comfort to bidders can encourage lower bids in the auction. Alternatively, and especially in the case of a very early auction and long periods between the auction award and FID, a **once-off adjustment of strike prices before COD** may be considered to compensate bidders for potential price increases between award and FID. Should the Ministry decide for a regular (e.g., annual) adjustment of the CfD strike price throughout the support period, the use of a Norwegian PPI index specifically measuring changes in the prices paid to producers of goods and services may be appropriate. Alternatively, a **Norwegian CPI index** in line with existing country experiences may be used. We do not recommend indexation against a single commodity such as steel or copper prices.
Auction volume	No changes needed. The current approach of defining a maximum and minimum installed capacity seems adequate.

Reservation price	The reservation price could be set based on an LCOE calculation making use of the LCOE estimates provided by NVE for SN II. In the LCOE-based approach, **the reservation price should be set slightly above the LCOE level** and should be calculated from the perspective of a typical investor, taking regulatory framework conditions such as taxes and financing conditions as well as transaction costs into account. To ensure a sufficient margin between the assumptions made by NVE and project developers, we would recommend adding a margin of e.g., 15%. In a dynamic auction planned for SN II disclosing the ceiling price is implied in the auction format (i.e., the reservation price defines the starting point of the auction). Communicating the reservation price as one of the central design elements together with the auction announcement (e.g., between 4-6 months and 1 year from the auction date) to create certainty among potential bidders is advisable.
Duration of concession	Regarding a possible extension of the concession, the criteria based on which an application for extension beyond the 30-year baseline concession period is assessed should be clear at the time of the publication of the tender documents. Moreover, bidders should know from the tender documents by how much time a concession may be extended. The number of months or years is an important factor in business case calculations.
Responsibility for site-pre-development	Already defined by the Ministry
Grid connection regime	To a large degree pre-defined by the Ministry. Further considerations on the planning, construction, operation, financing ownership and, classification of the radial connection are provided in section 1.9.5.

2. Auction design	
Auction procedure	The auction is implemented as an Anglo-Dutch auction or, if preferred by the ministry, as an English auction. The auction platform by Procurex can accommodate either of these auction types. Regardless of whether an Anglo-Dutch or an English auction are implemented, consider defining the following parameters in the auction: • Auction clock showing the start date/time and end date/time of the auction. • Start price or the maximum bid price allowable (i.e., reservation price). • Automatic extension whereby a bid made within the last 10 minutes of the auction extends the duration by at least 20 minutes. • In an Anglo-Dutch auction, only allow the top 2 ranked bidders to move to the sealed-bid (“final blind”) stage. • Bid feedback whereby a bidder is shown their current position among all bidders, either via a numeric rank, (“1” being the current leader), or via a “lead/not lead. A bidder must enter a bid price to see the bid feedback. • Minimum decrement and no-tie rule whereby bidders are required to reduce their next bid price by a minimum amount – usually about ½% of the expected bid price. The auction should not allow bid ties (e.g., 2 bidders or more offering the same price). • Acceptable bid range to prevent errant bids and excessively long auction duration. Alternatively, a descending clock auction with pre-defined decrements / bidding stages may be implemented. However, we see no clear advantages compared to the model outlined above. We suggest discussing these parameters with the Ministry in more detail in a meeting to lay down the foundation of the auction platform.
Award criteria	All bidders will compete in a purely price-based auction after a pre-qualification stage (decided by Ministry).
Project realization deadlines	The following **project realization milestones** are recommended: - **Milestone 1:** Submission of EIA and concession application 2 years after approved EIA-plan - **Milestone 2:** Submission of detailed plan 1 year after approved concession - **Milestone 3:** FID 6 months after the approved detailed plan - **Milestone 4:** Start of operations 5 years after approved detailed plan

Penalties	Confiscation of **bid bond** (to be paid at bid submission) in case of • Withdrawal from project after award: 100% of bid bond • Delayed submission of EIA and concession application (milestone 1): 5% of bid bond • Delayed submission of the detailed plan (milestone 2): 15% of bid bond • Delayed proof of FID (milestone 3): 25% of bid bond Confiscation of **completion bond** (to be paid after FID): Escalating penalties after a grace period of up to 6 months for delayed start of operation (milestone 4) starting at a confiscation of 10% of completion bond and up to 100% of completion for delays > 24 months. Alternatively, a daily delay payment could be defined, which would be calculated using the total value of the completion bond divided by the number of days the project could be delayed before the contract would be terminated. In any case, once a penalty was paid, the completion bond must be topped up to its full value so that further penalties can be applied if necessary. If the project developer does not top up the completion bond, a termination of the contract could be considered. **Reduction of overall support period:** In case of a delayed start of operation by > 24 months: Reduction of support period by the delay (+ 100% penalty applied to completion bond) **Termination of the contract and concession:** In case of a delayed start of operation of > 36 months. As a last resort before the termination of contract and concession a negotiation between the government and the project developer could be scheduled. The government would have the right to terminate the contract but may wish to not do it if the project developer can provide sufficient information on the next steps and project realization.

1. Support scheme

In this section, we present considerations and recommendations on the support scheme design for Sørlige Nordsjø II (SN II), the first offshore wind auction in Norway. Our analysis considers the Ministry's priority of reducing risks for bidders as part of the support scheme (e.g., limiting revenue and price risks) while preventing project failure (due to the "winner's curse"). For the relevant design parameters discussed below, we will also point out potential trade-offs, in particular with respect to creating revenue certainty on the one hand, and providing market integration incentives for bidders, on the other hand. Moreover, we consider the feedback provided during the stakeholder consultation process, as well as other objectives as we understand them from previous exchanges with the Ministry.

1.1 Form of support

In the task 1 report, upfront investment subsidies and two-sided Contracts for Difference (CfDs) were initially presented as the most promising forms of support. Weighing various advantages and disadvantages, two-sided CfDs (especially with shorter reference period) have been considered favorable in terms of reducing the risk of overly ambitious bidding (winner's curse), while entailing relatively few market integration incentives.

The Ministry has determined **two-sided CfDs as the preferred form of support** for the first offshore wind auction in Norway**.** This form of support has also been communicated to interested parties during the stakeholder consultation. All consortia and industry organizations expressed their support for the use of a two-sided CfD. We thus refrain from a detailed discussion of alternative options, but refer to the task 1 report, where such discussion of support scheme options has been conducted in more detail. In the remainder of this report, we assume two-sided CfDs as the chosen form of support.

1.2 Determination of electricity market reference price period

Another important aspect in the CfD design is the determination of the applicable electricity market reference price and in particular the reference period. Depending on the length of the reference period (e.g., hourly, monthly average or annual average), the reference price can create an incentive to optimize the dispatch of the plant for the respective time interval in relation to the electricity price signal (see below for more details on the functioning of these incentives). Hence, different reference price options differ in terms of the extent of revenue certainty provided and thus the implied level of short- or long-term market integration (i.e., from no incentives to react to market price signals to a within or across seasons optimization of dispatch decisions). For variable renewable energy (RE) plants such as offshore wind, it should be noted that these resulting market integration incentives generally have a limited and potentially theoretical effect (see below for details) and primarily relate to the optimization of maintenance scheduling (e.g., in low price periods) and plant design (e.g., whether to include storage, low-wind speed turbine).

In case of **hourly market references prices**, the RE plant operator has no incentive to react to wholesale power market price signals, since a low power price in one hour will be matched by a higher premium payment for the same hour. This implies a very high level of revenue certainty and neither short- nor long-term market price risk for the developer since subsidy payments will be adjusted for each hour, which in turn may have positive effects on financing costs for bidders. An hourly CfD's incentive structure is therefore very similar to a fixed feed-in tariff (FiT). In case of **longer reference periods** (e.g., monthly, or annually), the CfD premium/payback is calculated as the difference between the (weighted) average spot price and the CfD strike price over a defined period, e.g., a month or a year. This implies that (positive or negative) subsidies are adjusted not every hour but, depending on the defined period, every month or year. Longer reference periods thus imply that the total revenue of the RE plant operator in the given period will depend on the market value of the realized spot market prices, i.e., spot market prices +/- the regularly adjusted CfD premium that is fixed for the time of the reference period.

For example, an annually determined reference price implies that RE plant operators have incentives to react to intra-annual market price signals. This includes incentives to optimize their dispatch decisions within and across seasons (limited for non-dispatchable variable RE plants such as offshore wind), and to shift regular maintenance work to times of low spot prices. Moreover, price signals may potentially create economic incentives to include storage or other adjustments in the plant set-up to benefit from higher-than-average market values. On the other hand, an annual premium calculation would shield RE plant operators from longer-term average market price developments and provide a certain long-term revenue certainty. A monthly reference period provides more revenue certainty to developers than an annual adjustment of premiums, while keeping a certain degree of incentives for optimal dispatch and maintenance scheduling compared to an hourly reference period.

In the task 1 report, a one-year CfD reference price period has been considered positively in terms of incentivizing efficient operating and maintenance decisions. As outlined above, with an annual reference period, the idea is to allow for short-term and seasonal market integration by keeping sub-annual market price signals in place, while shielding offshore wind farms from long-term price developments (since price levels are adjusted every year – similar to a fixed premium that is adjusted each year). However, the report has emphasized that the extent to which market integration incentives are effective (or in other words, to what extent offshore wind farm operators can adequately address the related market price risks), crucially depends on whether developers are in fact able to respond to variable prices and thus maximize their value of production, in practice.

Stakeholders in the public consultation have largely argued against the use of annual reference prices and instead support the use of shorter reference periods, preferably hourly, emphasizing that offshore wind farms will have limited scope for adapting production, e.g., according to seasonal variation. For example, our understanding is that maintenance of SN II would have to be conducted in the summer months and other factors (e.g., weather conditions) play a more significant role in the exact timing of maintenance works than potential incentives to schedule such works in low price periods. Hence, the operator of SNII would arguably have very limited potential to react to the seasonal variation in electricity prices in Norway, for example, with higher prices on average during the winter and early spring, when heating needs are higher and hydroelectric production is lower.

While we can neither fully verify nor dismiss the arguments brought forward by stakeholders empirically as part of this report, they are valid to the extent that offshore wind farms are indeed not able to adjust to market price signals. Under this assumption, annual reference periods would not entail relevant advantages over shorter reference periods, since CfD payments for average plants would be identical in total for annual and monthly reference periods due to the symmetrical nature of a CfD. Deviations could only be expected if the operator can achieve a generation profile that differs from that of the average plant, which stakeholders imply is not a realistic assumption. Moreover, to the extent that longer reference periods expose offshore wind farms to revenue risks that cannot be adequately managed by the plant itself (i.e., unproductive risks), an annual reference period may imply risk premia on bid prices compared to shorter reference periods.

Moreover, we agree that optimizing production by offshore wind farms may be to some extent less relevant in Norway due to the high share of flexible hydropower in the power system. However, while these flexible plants in Norway's power system imply that electricity prices may be less variable than in other European countries, a support scheme design that incentivizes production when it is most valuable to the system remains a valid goal, in our view. Especially when considering the rollout of further offshore wind capacities in Norway in the future, these incentives could become increasingly important.

Finally, even in case of longer-than-hourly reference periods, the "cannibalizing" price effect of additional offshore wind development brought forward by some stakeholders, i.e., arguably reduced revenues for offshore wind developers over time because of decreasing market revenues, would be largely addressed by a wind-weighted calculation of reference prices. Thus, in case of annual or monthly CfD recalculation, a wind-weighted approach (i.e., a weighted price average by hourly offshore production volumes) is advisable.

Recommendation: As outlined above, the decision on the length of the reference period entails a trade-off between revenue certainty and allocating more market price risk to producers (i.e., which market fluctuations bidders should be shielded from and which market price risks they can assume).

- As outlined above, the Ministry has expressed a preference for reducing market price risk for bidders in the initial phases of the Norwegian offshore wind support scheme. Against the background of the above considerations and the preferences expressed by the Ministry, **hourly CfDs,** in principle, are a feasible option under the assumption that the goal is to increase revenue certainty / reduce market risks for bidders to the extent possible in the initial phases of the Norwegian offshore wind support scheme, Moreover, the allocation of more market price risks to bidders may not be a priority at this stage of offshore wind penetration in the electricity mix, given that price signals may create limited actual incentives for an efficient plant design and maintenance scheduling for SN II, as pointed out in the stakeholder consultation and further considered above. It should be noted, however, that in this case, the hourly CfD would offer a similar revenue certainty than a fixed feed-in tariff since premium payments are adjusted in each hour shielding RE producers from almost all market price developments. On the other hand, hourly CfDs entail advantages in terms of not requiring additional design elements to avoid distorted dispatch signals that arise with longer reference periods (see section 1.3.2) and they may enable discovery of real costs, since bidders need to bid at or close to their LCOE. Moreover, hourly reference prices avoid some of the dispatch challenges (avoid stop of feed-in at positive prices – see section 1.3) and may be easier to administrate (they create a straightforward billing procedure, but also require an adjustment of premium payments in each hour – see section 1.4).

- An alternative to the initially recommended annual reference period is a **monthly weighted average of the technology-specific (here: offshore wind) market value** as the reference price. A monthly reference price is based on the applicable spot market prices for each calendar month. In this case, a re-calculation of the (positive or negative) CfD premium occurs ex-post per each calendar month and according to calculated values for the respective month. A monthly reference period may provide a good balance between providing sufficient market integration incentives as well as enabling a relatively stable and certain cash flow for projects.

1.3 Rules to mitigate specific dispatch challenges

To ensure a two-sided CfD maintains efficient dispatch signals from a system perspective, payment modalities or rules need to be established for two specific scenarios: (a) negative price periods (section 1.3.1) and (b) periods with small positive market prices when developers have a payback obligation (section 1.3.2). Please note that dispatch challenge (b) is not an issue for hourly CfDs since the premium payment would be adjusted for each hour so that negative premiums would not be higher than the positive market value of that hour.

The rules mitigating specific dispatch challenges are discussed in more detail below.

1.3.1 Rules to avoid feed-in at negative prices

In general, negative spot market prices signal an oversupply of electricity, i.e., additional feed-in is not required from a system perspective. In general, support schemes should therefore not incentivize the feed-in of electricity in times of negative prices. However, for CfDs (and other forms operating aid, including one-sided CfDs / sliding premiums), the incentive to not produce at negative prices only applies if prices fall below the negative value of the premium payment, since any prices above this level would still generate net benefits for the producer. Without a specific rule, a positive CfD premium can therefore lead to an overall positive payout expectation for the plant operator and thus provide feed-in incentives even if spot prices are negative, i.e., whenever the absolute value of the hourly spot price is smaller than the value of the premium payment.

One of the primarily implemented negative price rules is that the CfD payment is discontinued if the market price is negative (e.g., Denmark, United Kingdom). This is also in line with the revised EU Climate, Energy and Environmental State Aid Guidelines (CCEAG).[1] Other currently (but increasingly phased out) or previously practiced rules are to specify a certain threshold of consecutive hours beyond which payment of the CfD would be stopped (e.g., 4 consecutive hours). Under the German one-sided CfD / sliding premium, no premium payment occurs in case of 4 consecutive hours of negative prices, and the support period is extended by the time in which no premium has been paid due to negative prices to alleviate the adverse effects for RE producers. However, given the clear statement in the CCEAG ("no aid in any negative price periods"), it is unclear if these rules would continue to be deemed compliant with state aid guidelines in the future.

Recommendation: Implement a rule of "no CfD payment in times of negative prices" in line with state aid requirements.

1.3.2 Rules to avoid stop of feed-in at positive prices (not relevant for hourly CfDs)

In times where the (positive) spot market price the RE producers receives in a given hour is smaller than the (negative) premium to be paid to the government or support counterparty, the producer has no incentives to continue production and would stop feed-in, if not otherwise mitigated. The following example is intended to demonstrate this effect (for simplicity's sake assuming a monthly re-calculation of the CfD premium): A strike price of 500 NOK/MWh is determined. In a certain month, the average market value is higher than the strike price, e.g. 700 NOK/MWh. The difference between the two values, i.e. 200 NOK/MWh, must then be paid as a negative premium (repayment) for each MWh generated in this month. In the month under consideration, however, there may be individual hours in which the market price falls below 200 NOK/MWh and thus the sum of market revenue and repayment becomes negative. Since the plant under consideration would make losses in these hours with low electricity prices, due to the repayment, it would stop production and no longer feed in during these hours. Consequently, the generation of emission-free electricity would stop at positive market prices, which should generally be avoided.

The simplest rule to maintain dispatch incentives in these scenarios, is to **discontinue the payback obligation** from the RE producers whenever the spot market price in a given hour is smaller than the payback amount (i.e., the negative CfD premium), a rule that e.g., Denmark

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[1] Point 123, CCEAG: «beneficiaries [...] must not receive aid for production in any periods in which the market value of that production is negative». **https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52022XC0218(03)&from=EN**

initially considered in its Thor offshore wind tender allocating CfDs with an annual reference period.[2] Under this rule, paybacks are discontinued whenever the spot market price is smaller than the negative premium (i.e., the payback). The developer will benefit from market revenues instead (until negative premium and market price are equal, which in the example below would occur at 200 NOK/MWh). Once the spot market price rises above the negative premium to be paid by the developer, the CfD payment obligation continues, and the developer would receive the difference between the spot market price and the negative premium as revenue. As can be seen in the figure below, this creates unsteady revenues for the developer and incentives to stay below the cut-off (if possible).

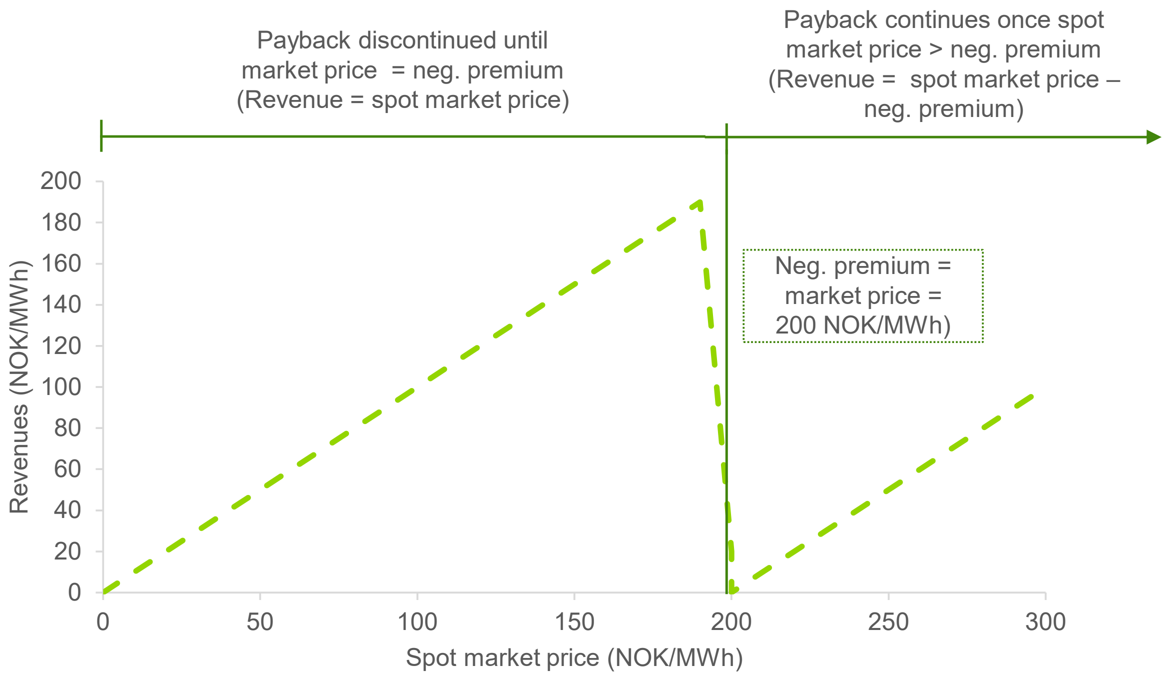

Figure 1. Revenue depending on spot market price with discontinuation of negative payback (here: 200 NOK/MWh) whenever the spot market price in a given hour is smaller than the payback amount. Source: Guidehouse based on Fraunhofer ISI.

However, this rule leads to a somewhat inefficient use of subsidies, since whenever the spot market price in a given hour is smaller than the payback amount (a situation that may occur rather frequently for specific hours throughout a month), the producer would not be required to pay back the otherwise applicable negative CfD premium and additionally receive the full spot market price in that hour (see Figure 1). This could potentially result in over-subsidization for the bidder and lead to an uneven revenue profile for the developer, whenever the spot market price in a given hour is smaller than the (negative) premium to be paid to the government or support counterparty. More specifically, in an applicable low-price period (market) revenues for the developer would increase up to the point where the negative market premium equals the spot market price (200 NOK / MWh in the below example), at which point revenues fall to zero before increasing again.

Beyond this simple rule, additional (but more complex) options exist to mitigate the above feed-in challenge, which are outlined in more detail below:

[2] In the end, Denmark implemented a dynamic adaptation of repayment through recalculation of hourly day ahead spot market, as outlined below.

Dynamic adaptation of repayment through recalculation of hourly day ahead spot market: Analogous to the final Danish tender design for the Thor Offshore Wind Farm Tender, the undesirable dispatch signal outlined above can be remedied by introducing an administratively determined imputed variable, the "minimum settlement price". The minimum settlement price effectively determines a price at which the operator would still have an incentive to continue production (i.e., marginal operating cost and direct marketing costs plus a margin). By setting a minimum settlement price (application explained below), the over-subsidization that arises when merely discontinuing the payback whenever the spot market price in a given hour is smaller than the payback amount, is thus limited to the pre-defined minimum settlement price.

With the minimum settlement price = x, the following rule applies to the settlement:

- if spot market price (h) - negative premium > x, then revenue = spot market price (h) - negative premium
- if spot market price (h) - negative premium <= x, then revenue = x
- if spot market price (h) <= x, then revenue = spot market price (h) and negative premium = 0

With the example of a negative premium of 200 NOK/MWh in the reference period and a minimum settlement price of x = 50 NOK/MWh, the rule results in the revenue for the plant operator shown in Figure 2 as a function of the spot market price.

This rule would result in plant operators making their dispatch decisions according to the estimated marginal costs of the RE plant in the event of a negative premium in the reference period and stopping their production during the transition to negative electricity prices. The scheme would be considered in the final settlement when actual electricity prices and average market values are determined.

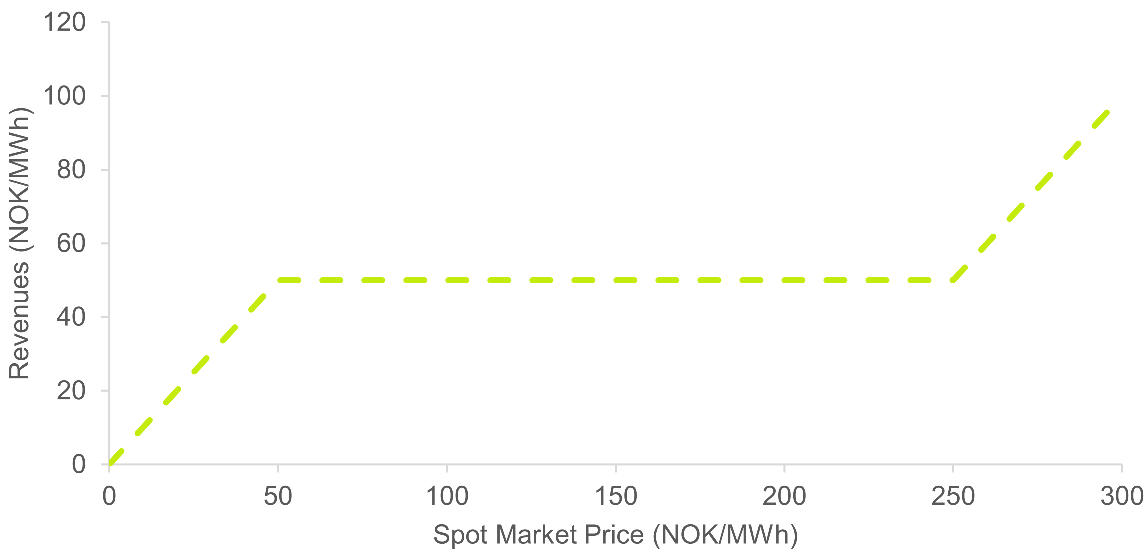

Figure 2. Revenue depending on spot market price with dynamic adaptation of repayment / negative market premium. Source: Guidehouse based on Fraunhofer ISI

Repayment of CfD premium regardless of production: Stopping feed-in of RE plants in the event of positive market prices can also be avoided with a "feed-in independent repayment". This refers to a correction calculation based on the possible power generation in the relevant time intervals and not on the actual feed-in. The rule would take effect if spot market price (h) – negative premium <= 0 (in case of positive spot market prices). If the actual feed-in is lower than the determined possible production, the possible production is used for billing and the repayment is determined on this basis for the hours in question, unless the plant operator proves that a lower actual production is due to feed-in management, plant failure or maintenance.

In this case, the plant operator has an ex-ante incentive to generate electricity even at low positive exchange prices, since the revenues from marketing on the exchange minimize the negative total revenue in these hours (over the entire year, revenue certainty would continue to be ensured with regard to the annual marginal market value, since the low hourly prices are included here). However, the expected losses in these hours (analogous to the losses due to negative prices) must be estimated over the entire term and included in the determination of the strike price.

The process is susceptible to manipulation (e.g., claimed turbine failure, wind measurement error, etc.) and entails associated investigative effort to prevent possible manipulation. For example, the possible generation can be made plausible by wind measurements or actual feed-in of neighboring wind farms. Despite these inaccuracies, the above procedure used to be an established procedure for feed-in management between plant operators and grid operators (curtailment) in Germany (so-called “Einspeisemanagement”). An application in the context of CfDs is conceivable but entails significant design complexities and the establishment of an additional monitoring and review process. Hence, additional consultation and involvement of the grid operator would be required in this case to define the process and the methodology (e.g., certification of the wind measurement, determination of the correction factor of the power curve of the wind turbines, etc.).

Recommendation:

No action is required in case of hourly reference period (see section 1.2).

In case of longer than hourly reference periods (e.g., monthly or annual), the following options are feasible:

- **Option 1** (if a simple rule is preferred and some oversubsidization is acceptable): **Implement a discontinuation of the payback obligation** from the RE producers whenever the spot market price in a given hour is smaller than the payback amount, or

- **Option 2** (if the focus is on support cost effectiveness, i.e., avoiding overcompensation, and creating a steady revenue profile for the developer): **Implement a dynamic adaptation of CfD repayment through recalculation of hourly day ahead spot market rule** for cases where the spot market price is smaller than the payback amount (i.e., the negative CfD premium). The administratively determined minimum settlement price should in this case be set at a level at which the operator would still have an incentive to continue production (i.e., operating cost and direct marketing costs plus a margin). The exact size of this settlement price would have to be determined in a separate process and is outside the scope of this paper.

1.3.3 Other considerations

Rules to avoid production if marginal cost higher than market price: During the stakeholder consultation, Statnett argued that the support system should give incentives to produce when the market price is higher than the marginal cost and stop production when the market price is lower than the marginal cost. In general, we do not think that a dedicated rule is necessary to avoid production at times when the market price is lower than marginal costs. Marginal costs for offshore wind are rather low, thus production in times where market prices are lower than marginal costs would not create major inefficiencies. Moreover, the government would have to assume marginal costs for specific plants, which entails risks for miscalibration.

Participation in balancing markets: In the public consultation, Statnett also argued that the support model should give the producer incentives to participate in the balancing market. In general, offshore wind farms can participate in balancing markets, and this is well in line with European regulation and other European countries allow VRE to participate in balancing markets (e.g., Germany). According to Article 6 of EU Regulation 2019/943 "balancing markets shall ensure non-discriminatory access to all market participants, individual or through aggregation, including for electricity generated from variable RES, demand response, and energy." However, the rules for participation and corresponding incentives are typically not addressed in the support (CfD) contract, but in relevant energy regulation.

To the extent that offshore wind farms can participate in balancing markets in Norway[3], they should not receive CfD support for volumes or capacities that are committed on any balancing market in order to avoid double compensation. This rule should ideally be defined in the relevant law and referenced in the CfD contract for the avoidance of doubt.

No support for imbalances between actual and forecasted production: In the public consultation, Statnett argued that offshore wind producers should not receive support for the volume that they are in imbalance. We do not fully agree with this suggestion. As a general principle, producers should be compensated for energy delivered, while the cost for deviations from production forecasts should already be reflected in the imbalance charges. In this context, the CfD payment is paid to maximize production (i.e., paid per metered production), while the balancing market aims to balance out deviations between actual production and forecasted production (until gate closure). The corresponding imbalance charges provide incentives to predict output as exactly as possible and thus to reduce forecasting errors to the extent possible. In our view, these imbalance charges should therefore provide sufficient disincentives for forecasting errors.

Curtailment compensation: In addition, Statnett recommends that support should be paid for any volume that is downregulated by the system manager. Curtailment is a reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis. These are the general principles that should guide curtailment and its compensation:

- Curtailment of electricity should be only applied when needed and when other cheaper redispatch options were used or are not available (Regulation (EU) 2019/943)
- RES producers should be curtailed after other non-RE sources were curtailed (Article 13 Regulation EU 2019/943)
- Curtailment shall be based on objective, transparent and non-discriminatory criteria (Article 16 RES Law and Regulation (EU) 2019/943)

[3] For example, Ørsted's North Sea wind farm "Borkum Riffgrund 1 is the first offshore wind farm in Germany that has been officially prequalified for the balancing energy market. Ørsted uses 30 MW (around one tenth of the plant's capacity) to stabilize Tennet's German transmission grid. The direct marketer Energy2Market (E2M) created the prequalification concept and integrated 30 MW of the wind farm into its virtual power plant. **https://www.energate-messenger.com/news/222554/-rsted-first-north-sea-wind-farm-on-the-balancing-energy-market**

- Curtailed renewable electricity shall be compensated as a principle, with limited exceptions, such as force majeure (Regulation (EU) 2019/943)

According to Art. 12, EU Regulation 2019/943, financial compensation in case of curtailment shall be at least equal to the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation:

- (a) additional operating cost caused by the redispatching (mainly relevant for plants that have high operational / fuel costs)
- (b) net revenues from the sale of electricity on the day-ahead market that the power-generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed, financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues

1.4 Billing

Responsibilities and procedures for the billing process should be determined to ensure that RE producers reliably receive (pay) the positive (negative) CfD premium. The decision on billing modalities should consider and weigh administrative burden as well as liquidity requirements of bidders.

Billing procedures tend to become more complex with longer than hourly reference periods (e.g., potentially involving advance payments and their adjustment throughout the year). For our recommendations, we focus on hourly CfDs as the preferred option (see section 1.2), and do not provide details on billing and payment modalities for longer reference periods.

Recommendations:

- In general, payments should be based on metered output, which is used to determine the difference between the strike price and the reference price for each hour. However, this does not mean that the actual payment of the premium payment occurs per hour, i.e., the billing period may differ from the reference period (see below)

- Weighing transaction costs for the support counterparty and liquidity requirements for the support recipient, an aggregated daily, weekly or even monthly payment of the net premium for the billing period (i.e., either positive or negative) is advisable.

- A responsible party executing and monitoring payments, typically the TSO or a dedicated government agency, should be determined to ensure reliability of payments.

- Delays beyond a pre-defined deadlines in issuing billing statements as well as payments to and from the generator should be avoided. As an indication, statements may be issued no later than 7 business days after the billing period. Payments to the generator may have to be paid withing 30 business days after issuance of the statement. In case of payments from the generator, negative premia may have to be paid within 10 business days following the billing statement. In case of non-compliance with these deadlines, appropriate penalties may be imposed. For example, for late payments (after the agreed due date and assuming they have not been disputed by the counterparty), the party owing payment could pay interest on the amount due.

- Against the recommendation provided by one respondent in the stakeholder consultation, CfD payments can be made in local currency, i.e., Norwegian Kroner, without any downsides for market participants. While Euro is the official day-ahead market trading currency, Nord Pool offers a currency (conversion) service, so that all customers can choose to trade in either EUR or NOK (as well as SEK or DKK).[4]

1.5 Inclusion of PPA

The Ministry is considering allowing for a portion of the electricity generated from SN II to be sold outside of the support scheme. The CfD support scheme will cover max. 1,400 MW (measured at an onshore metering point, see below). We understand that the amount and offtaker (e.g., an offshore consumer such as Ekofisk oil field or an onshore consumer) of the electricity sold outside of the support scheme will be decided by the auction winner. For offshore offtakers, there will be a rule in the CfD contract that regulates that the Ministry must approve offshore offtake from SN II. Furthermore, the rule will specify that the Ministry can set conditions to the offtake. We recommend that the CfD contract defines the boundaries between the CfD and the PPA and requires that the contracted capacity under the PPA is reported to the Ministry.

The potential offshore offtaker – the Ekofisk oil field – has a stable demand for electricity. The expectation is hence that the offtaker would likely require a PPA providing a stable supply of electricity, e.g., 100 MW per hour (limited of course by the hours in which the offshore wind park produces). Under this contract construct, the offshore wind park would have to give priority to supplying Ekofisk to fulfill the PPA contract. Any remaining electricity may then be supplied to shore. The electricity amount metered onshore would then be covered by the CfD contract.

Arrangements regarding metering of the generated output also need to be defined to ensure the CfD covers only electricity supplied to shore. While the configuration of the project will determine the exact location of the meter, a meter at the onshore injection point ensures only the volume of electricity that is sold at the market (i.e., excluding grid losses) is covered.

Recommendation

The Ministry has already stated that it will include define rules in the CfD contract regarding offshore offtakers. We recommend that the CfD contract defines the boundaries between the CfD and the PPA and requires that the contracted capacity under the PPA is reported to the Ministry.

We recommend requiring a meter to be installed at the onshore injection point.

1.6 Duration of support

The Ministry has communicated in the public consultation a proposed **support period of 15 years**. The public consultation showed that some respondents are in favor of a longer support period of 20 years. Most countries currently have support periods of between 15 and 20 years. Both the Ministry's proposal as well as the public consultation responses fall into this bandwidth.

In general, shorter support periods can increase the plant operator's exposure to long-term market price risk and thus stimulate long-term market integration. Also, shorter CfD terms incentivize bidders to include expected revenues from the end of the contract term until the end of plant operation into the bid calculation. This may result in bidders with a market value

[4] **https://www.nordpoolgroup.com/en/trading/Day-ahead-trading/Preliminary-prices-and-exchange-rates/**

expectation of the post-support period >LCOE to submit bids below their LCOE, i.e., lower strike prices. On the other hand, bidders with a market value expectation < LCOE and a 15-year term, are expected to submit higher bids compared to a 20-year term. As a result, a shorter duration tends to strengthen larger, financially strong bidders, with the ability to absorb higher risks. It is our general expectation though that the potential bidders in the auction all fall into this category of large, financially strong bidders.

For the specific context of SN II, the determination of whether to use a 15 or 20-year support period thus depends on several factors including:

- **Availability of budget**: Would there be sufficient budget available to support the project for 20 instead of 15 years? On the one hand, a shorter support period implies a shorter duration during which support must be paid, which reduces overall support costs. On the other hand, a prolonged support period may lead to a somewhat lower strike price. However, this effect is likely small in an hourly CfD as bidders are encouraged to bid at or close to their LCOEs. We are skeptical, whether the potentially lower strike price could outweigh the certain effect of not having to pay support for an additional 5 years.

- **Market price expectations**: What are electricity market price expectations in Norway until 2046 (i.e., 15 years from start of operations in 2031)? Are market value expectations lower or higher than LCOE beyond 15 years from Commercial Operations Date (COD), and can bidders thus be expected to bid lower or higher with a 15 year vs. a longer support duration?

- **Ability to include expected market developments in bid**: In case recovery of investment costs cannot be completed in a shorter support period of 15 years, would bidders be able to assume market price risks by including expected revenues from the end of the contract term until the end of plant operation into the bid calculation?

- **Level of competition**: Can a sufficient level of competition in the auction amongst potential project developers be expected for a 15-year duration?

- **Concession**: How likely is the possible extension of the concession, allowing the project developer more time to earn market revenues?

Recommendation: The Ministry already indicated in the January meeting a preference to keep the 15-year duration. In principle, this is well in line with international best practices. If the goal would be to further increase revenue certainty for bidders, a longer support period up to 20 years could be considered.

We would argue that since participating consortia are predominantly made up of large and experienced actors of the offshore wind industry, they should be able to assume market price risks beyond the 15 years support duration and competition should not be negatively affected, therefore. Whether this shorter support duration of 15 years would lead to lower or higher bid prices compared to a situation with a 20-year support period depends on actual market price expectations of bidders and how much risk they are willing to assume. A shorter 15-year support duration could have the advantage of reducing overall required support compared to a longer period and thus increases budget certainty for the government, even though a support cap would have a similar effect in this regard (see next section).

1.7 Caps on support payments and/or payback

We refrain from a detailed discussion on caps on payments and payback volumes in this report but refer to the task 1 report for additional details. It should be noted that most stakeholders have argued against the introduction of caps on support and payback.

Our recommendations considering the opinions expressed in the stakeholder consultation are outlined below.

Recommendation:

- If the Ministry is legally required to implement a cap on support, and the goal is to limit revenue risks for bidders, the approach to calculate the cap as the total net amount of subsidies (as implemented in the Danish Thor tender, i.e., deducting payback amounts from the aggregated support payments) seems adequate. In any case, the support cap should be set at a sufficiently high level (e.g., assuming the reservation price times rated capacity of the plant times maximum full load hours over the whole support duration) so that the project by default is able to benefit from the support scheme over the whole support period under normal conditions. In other words, the offshore wind farm should be expected to be profitable even with pessimistic assumptions on costs and market prices.[5]

- Compared to the Danish Thor tender with an annual reference period, hourly CfDs make the implementation of a net cap more complicated, since once the cap is reached, it would theoretically have to be re-determined for each hour thereafter whether the cap is reached or not. For example, if the cap is reached in hour t, leading to the stop of support payments in t+1, but in t+2 a payback from the producer is applicable, support could be disbursed again in t+3 and so forth. If a net cap is chosen, the determination of whether a support payment has been achieved should therefore ideally be done for a longer period (e.g., aligned with the billing period), so that too frequent changes between times where the cap becomes applicable and non-applicable are avoided.

- Following the arguments brought forward in the stakeholder consultation, if a cap is implemented, it should be adjusted for inflation / based on real prices (i.e., net, not gross amount), so that inflation has no impact on achieving the support cap.

- We would advise against the implementation of dedicated cap on paybacks. A cap on paybacks could create unintended effects, such as the winner's curse problem (i.e., bidders overestimating market revenues and underestimating corresponding support needs / submitting bid prices that turn out to be too low) or incentivizing (multiple) zero bids in case bidders place a higher value on the project than the cap which would no longer allow a price-based winner selection. Without a cap on paybacks, zero bids are unlikely / not a rational bidding choice due to the symmetric nature of the (hourly) CfD.

- While zero bids would be less likely in case of hourly CfDs compared to CfDs with longer reference periods (both with a payback cap), this scenario cannot be excluded (depends on bidders' market price expectations). In the Danish Thor tender a cap on paybacks (albeit with annual CfDs) resulted in multiple bids at the same level close to zero, so that the auction had to be eventually cleared by the drawing of lots. A similar situation should

[5] However, it should be noted that a very high cap that almost never becomes binding has limited practical effect in reducing support costs beyond satisfying budgetary rules in terms of creating budget certainty (but assuming a very high support volume). A (too low) cap, on the other hand, would increase revenue risks for generators after the cap is achieved and may result in unintended bidding behavior depending on individual market price expectations (see task 1 report). In practice, an adequate reservation price and contract period (see section 1.9.2) would likely achieve similar results in terms of budgetary certainty, in practice.

be avoided for the offshore wind tender in Norway, as otherwise alternative winner selection mechanisms in case of a tie between at least two bids would have to be found. The ministry's proposal to use the pre-qualification criteria amplifies the negative effects of the beauty contest in our view (see our previous memo on this topic). It also "leaves money on the table", as it wouldn't allow the discovery of bidders' real willingness to pay for the concession (which is capped at the amount set for the payback ceiling).

1.8 Inflation indexation of the strike price

A CfD support scheme may additionally shield generators from inflation though indexing the strike price to a Producer Price Index (PPI) or Consumer Price Index (CPI) or potentially other more specific indices like a raw material (e.g., steel or copper) price index.

In the United Kingdom (UK), CfD contracts are adjusted annually in line with a CPI index published each month by the Office for National Statistics to make the contract broadly long-term neutral to inflationary developments. The adjustment occurs each year on 1st of April and the adjustment must be notified to the Generator no later than 5 Business Days thereafter.[6] Moreover, France recently announced that it would change their CfD terms for onshore wind and solar PV to index prices to inflation.[7]

During the stakeholder consultation, a number of respondents have argued in favor of an indexation approach. Offshore industry actors in other countries have requested indexed CfDs as well, justifying their demand with the price increases especially for relevant raw materials (i.e., those that are part of core components such as turbines, rotors and tower) and resulting supply chain disruptions due to the Corona pandemic and Russia's invasion of Ukraine.[8]

One of the arguments often brought forward in this context are price developments in the period between contract award and final investment decision. If the price increase for needed components is significant (and unexpected) during this period, bidders may not be able to compensate their higher costs with corresponding higher market revenues. Due to the nature of the CfD, the generator is unable to benefit from electricity market price increases over time. Not compensating for inflation as part of the support scheme will thus require bidders to price in expected inflation over time in the business case since, e.g., if service contracts are indexed, the related costs for the developer increase over time.

On the other hand, a number of downsides for additional indexation of CfD strike prices should be considered:

An hourly CfD already provides a very high level of revenue certainty by largely levelling out (nominal) market price fluctuations on the revenue side. Additionally balancing out inflation throughout the support period by regularly (e.g., annually) adjusting strike prices in terms of general price developments (e.g., CPI or PPI) would constitute a rather generous support package for bidders, also in comparison with other European offshore schemes, even though some countries have implemented indexation in their support schemes (e.g., UK, see above).

For offshore wind, costs mainly arise as CAPEX until the commercial operations date (COD). Typically, prices are only locked in at the time of taking the financial investment decision

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[6] **https://www.lowcarboncontracts.uk/payments**

[7] **https://www.reutersevents.com/renewables/wind/frances-contract-action-highlights-threats-renewables-growth**

[8] **https://www.energate-messenger.com/news/222121/bwo-wants-indexation-of-contracts-for-difference**

(FID) which may be 3 to 5 years after committing to a specific bid price in the auction. Until then, the risk of raw material and other input price increases thus lies with the developer. To the extent that the relatively large and experienced offshore industry players can be expected to adequately estimate and assume risks related to general price developments that impact the cost of required components during that period, a blanket indexation under which the government assumes such price risks for the bidder may not be necessary. Assuming that project-specific estimates of price increases by developers are more specific and could be even lower than the overall price development reflected in an index, indexed strike prices may even lead to higher support costs for the government than without such indexation. In general, our assumption is that the large offshore wind players expected to participate in the first Norwegian offshore wind auction should under normal circumstances (e.g., not assuming recent price shocks as mentioned above) be in good position to estimate which prices they will have to pay for the required equipment in the next 5 years. In our view, inflation should thus be a manageable uncertainty that bidders will usually price in adequately into their bid, even in the absence of a dedicated indexation rule.

Finally, any indexation rule, including if linked to specific relevant raw materials, will always approximate actual price developments that the bidder is exposed to, and this may result in unintended effects in the worst case. For example, if CfD prices are indexed to (relatively volatile) steel prices, but the bidder has secured a purchase price for a core component in advance, steel price increases would let the CfD price adjust upwards, while the bidder would not be subject to the increased price level in reality. In this case, the bidder would thus benefit from unnecessary windfall profits. On the other hand, unless the indexation to any specific raw material manages to perfectly capture the cost structure of building the plant (which seems unrealistic), indexation to a rather volatile price index may introduce additional risks for the bidders.

Recommendation:

- In our view, a regular (e.g., annual) adjustment of strike prices based on CPI or PPI index throughout the whole support period is not per se required (see justifications above). An indexation of the strike price provides certainty about the (real) expected level of revenue needed to recoup the investment over the support duration. This higher level of comfort to bidders may encourage lower bids in the auction. However, the Ministry should carefully assess whether it deems the additional attractiveness provided by inflation indexation crucial enough to justify the assumption of inflation risks away from market participants and onto the taxpayer. Alternatively, and especially in case of a very early auction and long periods between the auction award and FID, a once-off adjustment of strike prices before COD may be considered to compensate bidders for potential price increases between award and FID.

- Should the Ministry decide for a regular (e.g., annual) adjustment of the CfD strike price throughout the support period, the use of a Norwegian PPI index specifically measuring changes in the prices paid to producers of goods and services may be appropriate (to the extent it is available and widely used). Alternatively, a Norwegian CPI index in line with existing country experiences may be used. The use of a CPI index has also been supported by range of respondents during the stakeholder consultation and there is international experience with using this type of index (i.e., UK – see above). The ministry should be aware, however, that a continuous adjustment of strike prices throughout the operational period would constitute an attractive, and, especially combined with hourly CfDs, generous support package by international standards, as these adjustments would make the CfD contract broadly long-term neutral to inflation. The corresponding inflation risks are thus assumed by the government to a large degree.

- We do not recommend indexation against a single commodity such as steel or copper prices. In our view, any single commodity price index would not sufficiently correlate with actual cost developments for offshore wind developers, may be volatile and could thus lead to unintended effects and increase risks for bidders, as outlined above. Moreover, if at all, indexing against e.g., the steel price, by definition, would only make sense if the idea is to hedge against cost increases of relevant components between bid award and FID at which point prices to procure such components will be locked in by the developer. For the operational phase thereafter, a PPI or CPI index capturing overall inflation are the more adequate option, if indexation of the strike price is pursued.

- Independent of the discussion around an indexation of the strike price, an indexation of ceiling / reservation prices in case they are not re-determined individually for each auction round may be considered for future rounds. Since this is the first offshore wind auction, ceiling prices should be based on a realistic estimation of LCOEs until COD (i.e., adequately estimating cost developments until projected COD). Otherwise, competition levels may be negatively affected (see also section 1.9.2) if bidders perceive the reservation price as too low.

1.9 Other considerations

1.9.1 Auction volume

In renewable energy auctions, the auctioned good and its volume can be defined in terms of capacity (in MW), energy production (in MWh) or in terms of budget (NOK). In practice, auction volumes in terms of **capacity** have been the most used form. The bidder commits in the auction to install the offered capacity within the specified delivery period.

The Ministry has proposed in the public consultation a bandwidth for the installed capacity of maximum 1,500 and minimum 1,400 MW. 1,400 MW is the system limit in the Nordics that can be received in one point in the grid.

Recommendation: No changes needed. The current approach of defining a maximum and minimum installed capacity seems adequate.

1.9.2 Reservation price

Reservation prices, also known as ceiling prices, define the maximum subsidy level per kWh. They provide safeguards against very high support costs for governments/consumers in case of uncertain or limited competition in the auction or collusive behavior between bidders. The reservation price should be set to allow sufficient room for competitive price discovery and should thus not be set too low. If the reservation price is set too low, it may prevent potential bidders from participating in the auction. As outlined above, its primary goal is to provide a safeguard against excessive costs for the government. In most cases, the reservation price should thus not become binding, meaning there should usually be sufficient bids below the reservation price.

Recommendation: Reservation prices are typically determined administratively using an LCOE calculation (plus a reasonable margin). The reservation price could be set based on an LCOE calculation making use of the LCOE estimates provided by NVE for Sørlige Nordsjø II. In the LCOE-based approach, the **reservation price should be slightly above LCOE level**. The LCOE calculation depends strongly on the assumptions and input data. Generally, the LCOE-based reservation price should be calculated from the perspective of a typical investor, taking regulatory framework conditions such as taxes and financing conditions as well as transaction costs into account. To ensure that there is sufficient margin between the assumptions made by NVE and project developers, we would recommend adding a margin of e.g., 15%.

Besides the level of the reservation price, another question is whether the reservation price should be disclosed to bidders or not. Disclosing the reservation price to bidders in advance has the advantage that it prevents otherwise qualifying bids from being rejected simply because bidders did not know the reservation price. The disclosure of the reservation price also gives bidders more planning security, increasing the acceptance of the auction. A disadvantage of disclosing ceiling prices in sealed-bid auctions where competition is low is that it can weaken the competitive pressure of the auction if bidders orient their bids toward the ceiling price. In the dynamic auction planned for SN II disclosing the ceiling price is implied in the auction format (i.e., the reservation price defines the starting point of the auction). Communicating the reservation price as one of the central design elements together with the auction announcement (e.g., between 4-6 months and 1 year from auction date) to create certainty among potential bidders is advisable.

1.9.3 Duration of concession

The concession grants the project developer the right to construct and operate an offshore wind farm on the site. The duration of the concession/permit should weigh the possible downsides of providing a longer claim to a scarce area and the promise of technological advancements (with a new concession holder) that would enable providing greater societal benefits from the same area against the upside of reduced cost of energy as a result of longer operation.

Recent offshore wind auctions in the North Sea saw concession durations of between 30 years ("license for electricity production" for Thor, DK) and 35 years (Hollandse Kust West, NL). According to the regulations to the Offshore Energy Act (cf. havenergilovforskrifta, §8), a license **for Sørlige Nordsjø II** may be granted for up to **30 years** starting from when the offshore wind farm is put into operation, which may be extended by the Ministry upon application.

Recommendation:

On the possible **extension of the concession**, the following points should be considered:

- The criteria based on which an application for extension beyond the 30-year baseline concession period is assessed should be clear at the time of the publication of the tender documents. Bidders need this information to assess their likelihood of getting the extension.

- An extension would then mean that the project can earn revenues from the electricity market for some additional time. These additional revenues are a factor to consider in the business case analysis and resulting calculation of support needs.[9]

- Bidders should know from the tender documents by how much time a concession may be extended. The numbers of months or years is an important factor in the business case calculations. In the Thor tender, the Danish Energy Agency provided an option for a five-year extension. In Germany, a one-time extension of maximum 10 years may be granted. Industry experts indicated in a consultation in the Netherlands that an operational lifetime of 35 years is already feasible and could

[9] As an indication, 1 NOK earned 31 years from now is worth 30 øre at a real discount rate of 4 per cent. Hence the period 31-60 years should be a factor in business case analysis. In addition, there is the option value of smarter technology on a site.

possibly be extended even further in the future.[10] This insight could be used to qualify the possible additional time an extension could provide.

1.9.4 Responsibility for site pre-development

The time before operation of the offshore wind farm can be roughly divided into three stages: a development phase including elements such as environmental planning, site design, assessment of wind potential, technology review and component selection, feasibility studies and permit applications, a pre-construction phase including the detailed design of the wind farm and its construction strategy, as well as the development of the chosen site, and finally a construction phase. The Offshore wind energy act and associated regulation put forward requirements for pre-development applications and permits that the winner of the SNII auction needs to undertake within pre-defined time limits. Since these elements are already defined, we do not provide more detailed considerations at this point.

1.9.5 Grid connection regime

The plan is that SN II will be connected to shore with a radial connection. **The starting point of the Ministry** is that the radial connection is planned, built, operated, financed, and owned by the project developer. The connection is planned to be customer-specific and will not be part of the transmission network. Statnett would be responsible for potential onshore grid reinforcements. Statnett is currently in the process of identifying connection points in the onshore grid that have sufficient capacity.

RME was tasked to assess if there are conditions that speak against the Ministry's starting point. Based on RME's report and our own insights, we would like to provide some further considerations and recommendations.

1.9.5.1 Planning of radial connection

A significant uncertainty is related to the so far undetermined connection point to shore. Statnett has concluded on the most likely point of connection in the transmission grid (Kvinesdal, Kristiansand as back-up). Further assessments are planned, which however will extend beyond the timeline of the auction. The final connection point will thus be unknown at the time of bid submission. The possible area identified by Statnett has significantly varying distances to shore (shortest connection: 205 km, longest: 250 km). Offshore wind transmission assets are highly capital intensive. The question of how long the connection to shore will be is thus central to the business case analysis. Any uncertainty in this regard will lead to larger risks, which lead to higher bid prices as bidders price in the longest connection, or the bidder with the most optimistic expectation, i.e. the shortest interconnection, wins, potentially causing a winner's curse problem. The first-best option would thus be to have the assessments completed before the auction.

We understand however that the assessments by Statnett cannot be done faster than scheduled and that the auction timeline shouldn't be delayed either. Against this background the following measures to reduce risks could be considered:

- For the sake of transparency, we would recommend that the Ministry points out this uncertainty in the tender documentation and provides a clear timeline on next steps especially regarding the finalization of assessments by Statnett.

- The Ministry could initiate conversations with all municipalities with possible connection points. This may make it easier for the project developer to then receive

[10] **https://www.rijksoverheid.nl/documenten/rapporten/2022/09/01/eindrapport-policy-options-offshore-wind-2040**

the necessary permits for the onshore export cable and converter station in the municipality of the finally determined connection point.

- In case of delays, an extension for permitting should be considered if the project developer can provide plausible documentation (e.g., showcasing lengthy discussions with local municipalities) explaining the delay.

Furthermore, we would recommend making penalty payments adequately high so that the project developer will construct the project regardless of the finally determined connection point. A significant penalty can help ensure that developers do not calculate with the cheapest (i.e., shortest) option and therefore do not experience the "winner's curse" in case a landing point with a longer distance is chosen. On the downside, a higher penalty has the negative effect of increasing the capital costs and thus making the project more expensive overall. In this respect, there are two sides to this measure.

1.9.5.2 Construction of radial connection

Offshore wind transmission assets include both offshore assets (array cables, offshore platforms, and offshore export cable) and onshore assets (onshore export cable and onshore converter stations). All these elements would – according to the current planning by the Ministry - be constructed by the project developer. Furthermore, onshore grid reinforcements might also be required to ensure sufficient hosting capacity on the onshore grid. Onshore grid reinforcements in this case are defined as the reinforcements required beyond the onshore connection station. These reinforcements would be in the responsibility of Statnett.

Under the envisaged distribution of competencies, the project developer does not depend on Statnett for the timely construction of the offshore wind transmission. The developer would however be dependent on onshore grid reinforcements by Statnett. Usually, any delays to the start of operation would warrant a penalty (see also section 2.4). However, the project developer should only have to pay a penalty when the delay in question is within the project developer's scope of influence. In case of a delayed grid reinforcement by Statnett, we would recommend that no penalties are applied to the project developer for the delayed start of operations and that in turn penalty payments by Statnett to the project developer are considered to make up for unrealized revenues during the time of delay.

1.9.5.3 Operation of radial connection

In most North Sea countries, the party responsible for the construction and financing of the offshore wind transmission assets is also responsible for operation and maintaining reliability and availability (exception: UK). In case ownership and operation is split, or both are transferred to a third party, incentives regarding the maintenance regime and maximizing the availability are no longer aligned between wind farm operator and offshore grid operator. It may require compensation schemes to re-align incentives. In the case of SNII, the wind farm developer would also be responsible for the operation of the radial connection. In case of a change in ownership (see below), the responsibility over operation could also transfer to Statnett. The transfer of ownership or operation may introduce transaction costs that can be avoided by retaining ownership and operation of the grid with the wind farm developer.

1.9.5.4 Financing of radial connection

In a developer-built model, the project developer is responsible for the financing and construction of the grid connection to the shore (sometimes called a "deep cost charging regime"). Assuming that SN II's radial connection is classified as "customer-specific grid infrastructure", the producer will cover the entire cost of the grid infrastructure in line with applicable regulation. In addition, the producer will cover a proportionate share of any necessary investments in the onshore grid triggered by the connection of the offshore wind farm (cf. *forskrift om økonomisk og teknisk rapportering, intektsramme for nettvirksomheten og tariffer*). If the radial connection is owned and operated by the wind farm developer, there is no clear/convincing argumentation to include the cost of the radial connection in a regulated asset base of the TSO.

Allocating financing, construction and operation responsibilities to the same party avoids unintended incentives. General onshore grid reinforcements that are required, may however arguably be borne by the rate payers. In other countries, costs for reinforcements beyond the onshore substation that is part of the national transmission grid are typically covered by the TSO (and by extent the rate payers). As outlined by law, developers are required to partially finance reinforcements of the onshore grid infrastructure. In the spirit of creating or rather maintaining a level-playing field for onshore and offshore renewable energy developments, we would recommend maintaining this scheme also for offshore wind developments.

1.9.5.5 Classification of radial connection & third-party access

As outlined above, the radial connection will be classified as a customer-specific grid infrastructure. Third-party access in this context may relate to a meshed grid but also a (single) offshore connection of the Ekofisk to SN II. In their report, RME argues that offshore grids generally should have third-party access, as it may allow for a more efficient use of the grid infrastructure. However, according to RME, a general investment duty for the offshore wind producer in terms of (substantial) alterations in offshore grid installations to connect new offshore wind farms (beyond certain pre-investments to potentially connect one or few electricity users such as Ekofisk) is not advisable. Since changes to offshore grid installations once they are in operation are costly and technically challenging, offshore wind producers should therefore only commit to certain pre-investments and construct the HVDC-substation so that third parties (such as Ekofisk) may connect to the AC-side.

Beyond the connection of one or few electricity consumers (e.g., Ekofisk), third-party access has benefits from a systemic point of view as it may enable a meshed grid at sea in the future and may allow for a more efficient use of the infrastructure. Third-party access requirements enabling a more comprehensive meshed grid (i.e., connecting multiple OWF), however, also have the downside that additional investments by the project developer, e.g., a switchboard during construction, higher voltage interconnection and offshore converter station, would likely become necessary. The project developer would in this case need very specific requirements from the Ministry with regards to the design of the offshore substation.

According to Statnett, a voltage level of 320 kV for the cable and offshore substation seems most likely if the grid infrastructure is only used to supply SN II and potentially third-party access for an offshore consumer such as Ekofisk. In case of third-party access by Ekofisk, this would require adaptations in the offshore converter station and the construction of a cable to Ekofisk. This means that a 320 kV cable would exclude connecting additional producers but would allow additional offshore power consumers (e.g., Ekofisk). By contrast, enabling a more extensive meshed grid connecting additional offshore wind production would require installing a more costly higher-voltage 525 kV-cable and offshore converter station (estimated by Statnett to equal +30 % of total grid investments). However, according to Statnett, already with the second phase of SNII a separate radial connection would be required, since even for a 525 kV-cable the maximum capacity would be ~2 GW, i.e., not sufficient to evacuate power of both offshore wind farms to shore at full capacity.

In Norway, the onshore grid regulation implies that third-party access applies to all owners of grid infrastructure, even if the network only supplies a single producer (e.g., the planned customer-specific grid infrastructure connecting SN II). However, the party that wants to connect to the network must cover any investments triggered by the connection. That is, a customer-specific grid infrastructure in Norway is generally compatible with third-party access. As long as the grid infrastructure only supplies “one or a few” producers/consumers, a re-classification of the radial connection as a public infrastructure owned by Statnett would not be necessary.

Against this background, the following **models** are feasible **for the first phase of SN II**:

1. Radial connection is a customer-specific, developer-built connection with no third-party access (neither additional offshore consumers nor offshore producers)

2. Currently envisaged model (see above for more details): the radial is classified as customer-specific grid and is owned, developed, and operated by the producer. Third party access is possible (if there is available capacity and it is deemed economically beneficial by the developer). However, the developer has no investment duty to allow for further connections (e.g., additional offshore wind producers/consumers) to its grid infrastructure.

3. Have Statnett build and operate the (possibly larger) radial connection, making it a regulated third-party access asset. This would allow a central planning and construction of the offshore grid, and potentially lay the ground for development of a real meshed offshore grid, including both offshore consumers and additional producers.

While the currently envisaged option 2 is generally feasible, a more centralized planning of the grid interconnection by Statnett may be advisable to reap additional benefits in terms of facilitating the development of a future-proof meshed grid beyond connecting single offshore consumers. Option 1 is closely aligned with the current thinking around having the developer be at the core of developments, but would not allow any kind of third-party access, including potential offshore consumers.

1.9.5.6 Ownership of radial connection

Usually, the party that develops, builds, and operates the connection is also the owner. In case of SNII, the project developer would hence also be the owner of the radial connection. Should an ownership transfer of the interconnection from the developer to Statnett be considered (e.g., after the concession has expired), the project developer will usually have to be reimbursed for its costs. Instead of price determination through competitive bidding (like in the UK’s OFTO model[11]), the value of the infrastructure asset may be determined through negotiations using guidance on relevant criteria provided by the Ministry. Alternatively, a cost disclosure requirement could be imposed on the developer. From the point of view of the project developer, it must be clear at the time of auction, whether a later change in ownership is considered, against which criteria the value of the radial connection will be assessed and what the tariff regime for use of the radial connection will look like.

[11] In the UK’s Offshore Transmission Owner (OFTO), the project developer constructs the cable connecting to grid. Following the construction phase, the asset is auctioned to third parties that bid to receive the ownership and operation mandate of the connection. The offshore wind farm developer pays a tariff for its use of the infrastructure which partly covers the revenues received by the OFTO. A key difference between Norway and UK is that there are no OFTOs in Norway, only Statnett. An auction as in the UK would hence not make sense in the Norwegian market.

1.9.6 General considerations on a developer-led vs. a TSO-led grid connection regime

For SNII, a developer-led grid connection regime (instead of a TSO-led regime) was chosen. The government has stated ambitions to allocate areas with the potential for 30 GW offshore wind production on the Norwegian continental shelf by 2040. Looking ahead to this significant **future roll-out**, we would like to share some high-level considerations of advantages and disadvantages of the two regimes along the dimensions discussed above (see Table 1). Overall, we would recommend a **TSO-led grid connection regime** for large-scale roll-out given potential for faster lead times, higher efficiency of space and other resources, cost reduction and others. This recommendation seems to be largely in line with the recommendation by RME in their report.

Table 1 Advantages and disadvantages of a TSO-led vs. a developer-led grid connection regime

		TSO-led	Developer-led
Planning and design	Advantages	• Holistic and transparent view on future developments, including short-, medium-, and long-term onshore and offshore grid development needs. This enables proactive grid planning and development, e.g. anticipatory investments. • Optimized grid expansion (including permitting, design, and procurement) and onshore grid reinforcements. • Opportunity to standardize transmission asset design for economies of scale. • Shared assets (a single connection for several wind farms) could reduce environmental impact due to an optimization of the number of onshore landing points. • Non-mature technologies and strategic projects can be specified and developed (high potential for futureproofing).	• A single party coordinates both offshore wind farm and transmission asset development. • Potential to enhance design efficiencies/compatibility between offshore transmission assets and wind farm for single projects through integrated design, and tailored transmission asset configurations.

Disadvantages	• Standardization of transmission assets could hamper innovative solutions from developers or the supply chain. • Needs of developers may not be fully reflected in design and procurement process of transmission assets, e.g. capacity for future additions. • Potentially larger and more complex projects, which could increase risk of transmission asset delays for wind farm developers if TSO is not able to timely develop offshore transmission assets.	• Transmission asset development is not the core business of wind farm developers; may limit competition. • Transmission assets tailored to wind farm specificities on a project-by-project basis with a potential higher environmental impact through an increased number of onshore landing points. • Risk of non-future proof system and use of different designs per project, preventing standardization and asset sharing. • Developers must wait for the TSO to complete onshore grid reinforcements before connection to the grid. Risk of stranded assets for developer remains if TSO is not incentivized for time delivery. • Non-mature technologies are only included if directly cost-effective. • Lack of system perspective: potential onshore capacity reinforcements beyond developer’s scope.

Commercial and finance	Advantages	• A government-backed TSO typically has more favorable financing conditions (lower debt and equity return rates) compared to a commercial developer. • Potential cost reduction of procurement and project management costs through stable project pipeline. • Risk of delayed grid connection delivery by TSO could be (partially) offset through compensation scheme to developers. • Operation of multiple standardized grid connections could result in reduced OPEX.	• Cost optimization on a project-by-project basis. • Developers operate in competitive market environment which results in downward pressure on wind farm and transmission asset costs. • Commercial developers and OFTOs have more flexible financing options, rendering them more competitive than government backed TSOs. • Flexible financing structures for commercial parties, e.g., higher debt shares, could result in lower WACC than for TSOs.
	Disadvantages	• High CAPEX investment for TSOs to develop and operate transmission assets. For state-owned TSOs, governments need sufficient capital available to take on the risk. Investments can be held back if shareholders are hesitant to provide equity. • Construction of all offshore assets by a single party; TSO needs to have sufficient capital to take on risk. • TSOs are not exposed to same competitive cost pressure that developers are driven by to be competitive in tenders.	• Potential higher cost of capital for a commercial party due to increased return rates on equity and increased debt rates, and transaction costs from developer to OFTO. • Cost and investments of transmission assets are not necessarily optimized from a societal LCOE perspective but on an individual project basis.
Construction	Advantages	• Coordinated and holistic offshore wind deployment and onshore capacity reinforcements by single party (TSO) responsible for both onshore and offshore transmission assets. Large TSOs can coordinate offshore work across their portfolio.	• Reduced risk of construction delays due to a single party coordinating offshore wind farm and transmission asset development. • Offshore interfaces during construction managed by the same party, which provides greater control and increased flexibility.

	Disadvantag es	• Stranded asset in case of construction delays, projects not realized. • A significant offshore interface between developer and TSO.	• Increased project management requirements to address transmission asset developments. • Onshore grid reinforcements still require coordination with TSO.
Operation	Advantages	• Greater control over grid operation by transmission responsible party. • Reduced number of involved stakeholders along the value chain. • Reliability determined by the government. • Availability of offshore wind transmission assets is incentivized through specific mechanisms; part of the financial claim shall be borne by the TSO. • Potential OPEX reduction due to a larger asset base and standardized equipment.	• Risk of transmission asset failure lies with party most affected. • Reliability is incentivized through direct revenue impact (non-OFTO) or an availability target (OFTO). • In case of non-OFTO developer operated projects, O&M of the wind farm and grid connection can be aligned.
	Disadvantages	• Regulatory framework needed to incentivize high availability of the grid connection system. • Unavailability penalties might be less effective with a large publicly owned organization as ultimately costs could be (partially) socialized.	• Mismatch between operating duration of the transmission asset, which is typically longer than that of the offshore wind farm. This could leave utilization of the full asset lifetime in the long term uncertain.

2. Auction design

In this section, we present considerations and recommendations on the auction design for the first offshore wind auction in Norway. Our considerations and recommendations consider the feedback provided during the stakeholder consultation process as well as priorities and objectives as we understand them from previous exchanges with the Ministry.

2.1 Auction procedure

The task 1 report recommended an Anglo-Dutch auction as the auction procedure for SNII. In an Anglo-Dutch auction, the strike price starts high and gradually decreases until two bidders remain. The last two bidders submit sealed final bids for the strike price. The bidder that submits the lowest bid wins the auction.

The responses from the public consultation can be grouped in two categories: those specific to the auction procedure and those focusing on other parameters of the auction procedure. Our responses to the arguments given by stakeholders and the consultant's recommendations are provided below.

2.1.1 Auction procedure

Stakeholder feedback on the auction procedure can be grouped into four groups:

(i) those that prefer the proposed auction model (i.e., an Anglo-Dutch auction)
(ii) those that prefer an ascending auction (i.e., English auction)
(iii) those that prefer a single price sealed-bid auction
(iv) those that prefer an auction with qualitative criteria, i.e., not a pure monetary auction

There is no consensus regarding what auction type is preferable, even though a majority support some form of open bidding. It is expected from theory that stronger bidders, but also that bidders with less confidence in their cost estimates and therefore more utility from price discovery, prefer open bidding. Weaker bidders will prefer a wholly or partially closed auction, as this gives some chance of winning. Bidders with a perceived advantage in qualitative criteria, will prefer an auction that incorporates that. The responses are largely in line with these expectations.

The preference of most bidders for open bidding, despite first-price sealed-bid auctions being the simplest and most common in European offshore wind auctions, can be interpreted as support for some form of price discovery. The proposed Anglo-Dutch auction gives a good opportunity for price discovery.

Thus, we still think our initial recommendation of an Anglo-Dutch auction is the best option and an English auction being the second best. We provide arguments below qualifying the inputs by stakeholders and cementing our initial recommendation.

Stakeholder feedback in group (i) – Supporting proposed model (Anglo-Dutch auction)

Stakeholders supporting the proposed Anglo-Dutch auction model generally have few comments to the model. Some underscore that all bidders in the auction will be pre-qualified by strict criteria, and a final sealed-bid stage is deemed acceptable.

Stakeholder feedback in group (ii) – Supporting ascending model ("English auction")

Stakeholders supporting an ascending ("English") auction express a worry that a sealed-bid stage following the open-bid stage can give rise to strategic bidding and increase the risk of the "winner's curse", as well as undermine other goals in the auction.

The criticism raised by several respondents that the sealed-bid stage for the two last bidders will give rise to a winner's curse or speculative bidding, is not particularly convincing. The sealed-bid phase is between only two bidders, both of which have gone through several rounds of open bidding. The price discovery in the open-bid stage ensures that the expectations are well anchored, meaning there is little risk of a winner's curse. Speculative bidding (or option bidding) is a risk in all auction types, and this risk is best dealt with by adequate penalties.

The criticism against a final sealed-bid stage is most likely motivated by the fact that this stage will force the two final bidders to submit their true best bid (as opposed to the ascending auction where the winner pays incrementally above the final bid of the competitor). This is in line with the goal of the auction as an optimal allocation mechanism, which is to minimize support/maximize payment.

Several stakeholders indicate that a so-called descending clock auction with reasonably wide decrements between rounds and the possibility of giving an "exit bid" in between the increments, is the type of auction they have in mind when referring to an "English" auction (see in section 2.1.2 for a comparison of the descending clock auction procedure with pre-defined bidding stages and the recommended Procurex' dynamic auction model, with or without a final sealed-bid stage). We understand "exit bids" to be a format whereby a bidder enters their "very best" bid and effectively "exits" the auction, meaning they are unwilling or unable to bid any further. This parameter informs other bidders at which price their competitor left the auction, which provides the price discovery mechanism.

It should be noted that, if there are only two bidders left at a given increment, and neither of them intend to bid all the way down to the next increment, the English auction will have the same outcome as the Anglo-Dutch auction: their last "exit bids" would be identical as the sealed bids in the Anglo-Dutch auction, as long as the bids happen simultaneously.

The difference between the auction described above and an Anglo-Dutch auction arises if the second-best bidder in the last round gives an exit bid, whilst the best bidder gives a bid at the next increment in the descending clock auction while being willing to go below that increment. In this case the state will end up with a slightly higher support than necessary, thus leaving money on the table. Furthermore, it is completely arbitrary whether, by chance, there happens to be a bid increment between the valuation of the best and second-best bidder. Therefore, it is not possible to argue that the descending clock auction described by some stakeholders is systematically better with regards to winner's curse or speculative bidding.

Finally, the fact that a well-known auction format only needs some slight adjustments in the last round to function as an "Anglo-Dutch" auction, is an argument that the proposed auction type is not needlessly complex.

Whether an Anglo-Dutch or an English auction are implemented, the auction platform by Procurex can build in the flexibility for bidders to bid as few or as many times as they wish.

Stakeholder feedback in group (iii) – Supporting sealed-bid model

Stakeholders supporting a sealed-bid auction argue that this type of auction is the most widely used auction and that it is likely to give the same result as an Anglo-Dutch auction. In addition, it was argued that the sealed-bid stage for the last two bidders risks resulting in a winner's curse. Lastly, some bidders argued that an Anglo-Dutch auction may incentivize bidders to "compromise" on plans presented in the pre-qualification stage.

The simplicity and widespread use are indeed arguments in favor of a sealed-bid auction. However, an Anglo-Dutch auction can work well, as shown by Procurex' experience running open-bid auctions for various customers (e.g., federal and state government agencies, as well as utilities) in the U.S. for the past 20 years. While the majority of stakeholders support an open-bid auction, it is not uncommon for some bidders to be resistant to this type of auctions initially. Increasing trust in an open-bid auction, like an Anglo-Dutch auction, can be done by the auctioneer by ensuring that the process is fair and only qualified bidders are invited to the auction stage. Similarly, clearly communicating the requirements and factors that determine the final awardee and ensuring that all bidders have sufficient time to ask questions and get answers prior to the auction stage, increases acceptance, and supports an adequate functioning of the auction.

Ensuring only bids comparable in quality progress to the auction stage is done by defining robust qualification requirements and penalties, regardless of the auction type. Therefore, we disagree that an Anglo-Dutch auction can lead bidders to lowering the ambition or "compromise" on what was proposed for the project on the pre-qualification stage compared to another auction type. Moreover, we propose below a penalty if the bidder does this in the licensing process.

While the claim that the results in an Anglo-Dutch auction and a sealed-bid auction are likely the same would be best verified by comparing the auction results in a country implementing both auction procedures, an auction that enables direct competitive bidding can spur better prices since bidders can adapt their bids in response to other bidders (either by lowering or exiting the auction, if the price level is below the estimated project costs).

Stakeholder feedback in group (iv) – Supporting only qualitative criteria

Stakeholders supporting an auction with qualitative criteria argue that a pure monetary auction will press the margins in the entire supply chain.

The award criteria of an auction can indeed be a combination of criteria including price and other project qualities desired by the auctioneer. However, criteria other than price can still be considered in a price-only auction: in fact, the ministry is preparing criteria for the pre-qualification stage related to sustainability ("environmental footprint" and "coexistence with the fishing industry") and positive local benefits created by the winning project. An advantage of price-only auctions, compared to multi-criteria auctions, is the simplicity of implementation for the auctioneer and bidders and the higher level of transparency and objectivity in the qualification process. Multi-criteria auctions, on the other hand, allow projects more flexibility on how to comply with secondary criteria and give more weight to other project attributes besides price.

If the ministry has a strong preference for implementing a multi-criteria auction for SNII, whereby a bid's final score is made of price and other criteria, it is important to define quantitative and/or qualitative benchmarks to compare bids and to communicate these to bidders before the auction.

Recommendation

- As mentioned in the task 1 report, consider the implementation of an Anglo-Dutch auction for SNII to encourage price discovery and define robust qualification criteria to prevent the winner's curse and reduce the risk that the awarded bid fails to build the project. An English auction can, however, also work well. Details on parameters for the auction are provided in section 2.1.2.

- Further increase the acceptance of an Anglo-Dutch or an English auction by announcing and planning Q&A sessions from bidders once the auction is announced. Indeed, the ministry requested the consultant in the tendering of this assignment to prepare an auctioneer and bidder manual and provide technical support during the auction.

- If the ministry prefers an English auction (i.e., like the Anglo-Dutch auction but without a sealed-bid stage following the open-bid stage), a sealed-bid auction, or a multi-criteria auction, the auction platform by Procurex can be designed to support any of these options. In principle, the Procurex auction platform would also allow the implementation of a descending clock auction procedure with pre-determined bidding stages instead of a purely market-driven lowering of bids as currently recommended (see Box 1 in the next section for a discussion of pros and cons).

2.1.2 Parameters of the auction procedure

In this section, we present a selection of key parameters that determine the functioning of the auction. These are common to both types of open-bid auctions. .

Auction Clock: Auctions are created showing the start date/time, and end date/time. Once the auction opens for bidding (i.e., the start time has arrived), the auction clock constantly shows the time remaining in the auction.

The auction platform can be built to conduct any auction duration needed. In our experience, most typical auctions last for less than two hours. However, given the size and complexity of this auction, we would recommend a longer auction duration to allow all bidders sufficient time to bid, see their updated position, analyze their potential re-bid, and enter new bid prices.

Start Price: The maximum bid price allowable (i.e., reservation price). We recommend the use and disclosure of the start price/reservation price prior to the auction.

Pre-bid auction: The buyer (i.e., the Ministry) can require invited bidders to enter an opening bid price into the auction some number of days prior to the live auction start time. Bidders do not see any bid feedback during the “pre-bid” stage. When the live auction opens, at that point bidders see the bid feedback and can immediately begin to enter new bids.

Auction stages: An open-bid auction can have an open-bid or “regulation” stage only, known as an English auction, or consists of two stages – an open-bid stage (“regulation” stage) followed by a sealed-bid or “final blind” stage, known as an Anglo-Dutch auction.

In the open-bid (“regulation”) stage in both types of auctions, bidders can bid as many times as they wish, see the bid feedback (see below), and rebid to try to capture a better rank. A bid ranked as number 1 corresponds to the lowest bid submitted at the time. The open-bid (“regulation”) stage can either have a pre-set end time or have a pre-set period that allows for **automatic extensions**.

In an *English auction* with an automatic extension, the auction would continue auto-extending until no more bids are submitted by any bidders. When the clock runs to zero, the auction ends, and bidders have no further opportunity to bid. The auction winner will be the bid ranked in the first place.

In an *Anglo-Dutch auction*, only bidders who were ranked in the top ranks e.g., the 3 to 5 top ranked bidders, are eligible to participate in the sealed-bid ("final blind") stage. In this stage, eligible bidders can submit one, and only one, final bid. It is not mandatory for an eligible bidder to enter a bid in the sealed-bid ("final blind") stage, as they may wish not to lower their price any further. We recommend to only allow the top 2 ranked bidders to move to the sealed-bid ("final blind") stage. During this stage, "sealed/blind" refers to the fact that bidders do not see any bid feedback until after the auction ends. After the sealed-bid/final blind clock runs out, the auction ends and at that point bidders see their final rank and the lowest overall bid. The auction winner will be the bid ranked in the first place.

Automatic Extension: A parameter of the auction in which the time remaining in the auction automatically extends based on pre-defined time rules. For example, "any bid entered within the final 5 minutes of the auction by any bidder will extend the auction clock by 5 minutes." Any number of minutes for the auto-extension rule can be done. Automatic extensions give all bidders more time to see any "late" bids and respond as they wish. This ensures that all bidders have every opportunity to see and respond to any new bids placed. We recommend that any new, "late" bid (within the last 10 minutes) of the auction, will automatically extend the auction end time by (at least) 20 minutes. An optional parameter is to allow an **automatic extension on low bid only**, whereby the auto-extension will only occur when the new late bid is a new low bid.

Bid feedback: Bidders must enter a bid price in the live auction in order to see the bid feedback. Immediately after a bidder places a valid bid, that bidder is shown their current position among all bidders, either via a numeric rank, ("1" being the current leader), or via a "lead/not lead", which shows only whether they are the low bidder or not. A "view lead/not lead" would be used when the buyer (the Ministry) does not wish to reveal to bidders how many other bidders are in the auction.

Minimum decrement and no-tie rule: A minimum decrement requires that bidders reduce their next bid price by a minimum amount – usually about ½% of the expected bid price. After a bidder submits their first bid, any subsequent bids that bidder enters must be lower than their previous bid by at least the minimum decrement. The minimum decrement, in conjunction with the automatic extension rule, is used to prevent very long auction durations. For example, if bidders were allowed to reduce a $100,000 bid by only one penny, there could theoretically be an auction which lasts for many hours. Moreover, we recommend to not allow bid ties (e.g., 2 bidders or more offering the same price) in the auction. Allowing ties is not recommended because the auction would need to select the winner based on criteria other than price in case of a tie.

Acceptable Bid Range: An auction can be set in which bidders must enter a price within a pre-defined acceptable range. This prevents errant bids and excessively long auction duration. For example, if market knowledge reveals that bid prices are known to be close to $100, an Acceptable Bid Range could be set as $20 to $200.

Recommendation

- Regardless of whether an Anglo-Dutch or an English auction are implemented, consider defining the following parameters in the auction:
    - Auction clock showing the start date/time and end date/time of the auction.
    - Start price or the maximum bid price allowable (i.e., reservation price).
    - Automatic extension whereby a bid made within the last 10 minutes of the auction extends the duration by at least 20 minutes.

- In an Anglo-Dutch auction, only allow the top 2 ranked bidders to move to the sealed-bid ("final blind") stage.
- Bid feedback whereby a bidder is shown their current position among all bidders, either via a numeric rank, ("1" being the current leader), or via a "lead/not lead. A bidder must enter a bid price to see the bid feedback.
- Minimum decrement and no-tie rule whereby bidders are required to reduce their next bid price by a minimum amount – usually about ½% of the expected bid price. The auction should not allow bid ties (e.g., 2 bidders or more offering the same price).
- Acceptable bid range to prevent errant bids and excessively long auction duration.

- As described above, the Procurex auction platform would also allow the implementation of a descending clock auction procedure with pre-determined bidding stages instead of a purely market-driven lowering of bids as currently recommended (see Box 1 for a discussion of pros and cons). We do not see clear advantages of a descending clock auction procedure compared to the suggested model, which allows for a purely market driven price discovery, is easier to implement and avoids some design complexities such as setting adequate decrements / biddings stages. We would thus recommend implementing the procedure outlined above and demonstrated in a dedicated auction simulation on 14 March.

Box 1. Pros and cons of descending clock procedure vs. no pre-defined bidding stages (Procurex model) in case of an Anglo-Dutch or English auction

Both an English auction and an Anglo-Dutch auction could also be implemented as a descending clock auction with pre-determined decrements or bidding stages and potentially the possibility to submit an "exit bid" between the decrements. This is an alternative to the recommended approach outlined above and was suggested by some stakeholders. The following overview of pros and cons aims to inform the decision for either of the options.

No pre-defined bidding stages (Procurex model)	With discrete bidding stages (Descending clock auction procedure)
Pro	**Pro**
- Allows for a purely market-driven price discovery. - Easier to implement than descending clock auction with bidding stages.	- Procedure makes it transparent if a bidder drops out of the auction. - Some stakeholders are more familiar with this type of auction procedure.
Con	**Con**
- Bidders may be less aware of this procedure (however, auction process is straightforward and intuitive).	- More complex to design since adequate increments need to

		be determined by the auctioneer beforehand. - Too wide increment can lead to suboptimal results (e.g., not leading to price discovery of the lowest bid).	

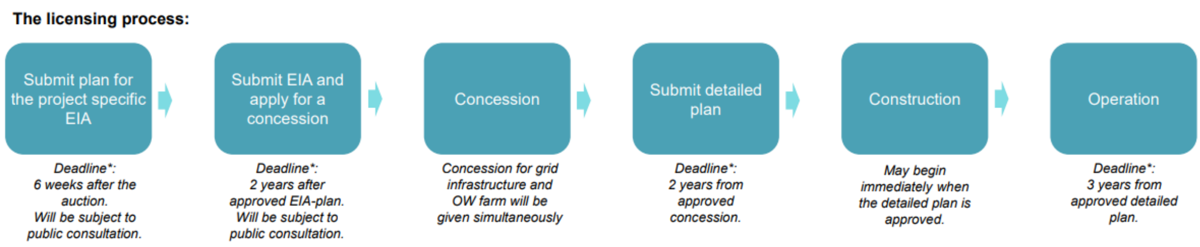
2.2 Award criteria

The Ministry has decided that bidders will compete after a pre-qualification stage in a purely price-based auction. Here, the bidder with the lowest support need wins. We do not provide any further consideration as this matter has already been decided by the Ministry.

2.3 Project realization deadlines

The realization / delivery period specifies the time during which projects need to be commissioned, i.e., the validity of the award. In general, excessively long realization deadlines are undesirable because they encourage speculative bids (e.g., developers speculating on equipment costs to fall). Nonetheless, they should allow for project completion times that are realistic given the complexities of offshore wind farms. The project realization deadlines/milestones would need to be specified in the tender documents. A well-designed combination of pre-qualification criteria and penalties can ensure timely realization. If the realization period is exceeded, i.e., a project fails to be completed in time, penalties can be imposed. The simplest way to define a project realization deadline is to set a date for the start of operations which the project developer will have to achieve. If the start of operations is delayed, penalties will be applied. The definition of project milestones is an important pre-requisite for the penalty regime. We describe the penalties regime in detail in section 2.4.

For SN II, the licensing process is defined in the applicable provisions in the Offshore Energy Act (Havenergilovforskrifta – see Figure 3). We provide below some recommendations on the timeline embedded in this process. We understand that the auction design would have to follow this licensing process rather than set a definite start of operations deadline. We base our following recommendations regarding milestones on this assumption.



*All deadlines may be extended by the Ministry upon application.

Figure 3 Licensing process as designed by the Ministry

Recommendations:

The licensing process is at the core of the project realization process. Based on our industry expertise as well as insights from other auctions, we would like to share some recommendations on the timelines envisioned for the different phases of the licensing process:

- Generally, milestones should be defined in a way where they can be overachieved by the project developer rather than underachieved, thereby making sure that the overall timeline is realistic. This is not the case for the construction timeline. The 3-year period given for construction from approval of the detailed plan is not realistic from our perspective. Supply chains in the offshore wind sector are currently very stretched, especially for crucial elements such as HVDC cables for which there are very few manufacturers. Also, while the offshore wind farm construction may be achievable in a shorter time frame, the fabrication and construction of the HVDC radial connection is likely to take more than 3 years. Against this background, we would recommend extending the construction timeframe to 5 years.

- To (partially) make up for additional time required for construction, the time between the award of the concession and the submission of the detailed plan could be reduced from 2 years to 1 year. To ensure that the project developer can meet this deadline, it would be recommendable for the Ministry/competent authority to provide a clear template which the developer will need to use for the detailed plan. The template can ensure that all required information is included while cutting out time losses for unrequested information.

- We would recommend maintaining the 2-year period for the EIA. The amount of time required by the project developer for the EIA crucially depends on the level of detail required by the Ministry. By taking an efficient stance on requirements, it can be ensured that the 2-year period is sufficient despite complexities related to the novelty of the process in the Norwegian context.

- We would also recommend keeping the option for extension of deadlines upon application by the bidder. Especially in this novel market environment, such an option could prove very helpful.

- Despite the above proposed changes, the process is still rather ambitious and will require commitments from all sides. Close cooperation and a pro-active involvement by the Ministry/the competent authorities will be necessary. In a best-case scenario, the Ministry/the competent authorities would set themselves deadlines for the time needed to review and approve documents. This provides project developers with more transparency on the process and ensures that next steps are lined up after the Ministry/the competent authorities have completed their assessment.

With the above recommendations, the licensing process will take in total 1 year longer than currently envisioned. We think this is necessary to reflect current challenges in the offshore wind industry leading to longer construction period and the novelty of the system. With the above recommendations, the licensing process would look like shown in Figure 4.

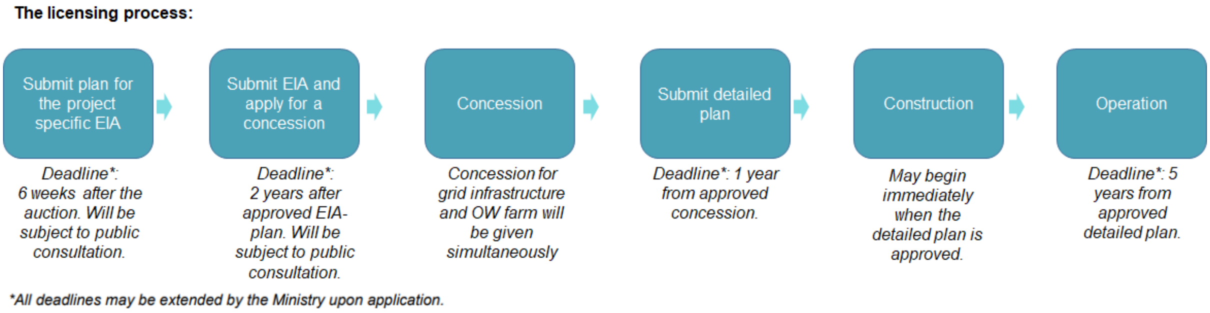


Figure 4 Licensing process as proposed by Guidehouse

We assume the licensing process as demonstrated in Figure 4 to be the applicable framework for the definition of milestones to be later used in the penalty regime. However, not all phases in the licensing process are equally suitable to be defined as milestones. Furthermore, there are numerous elements still to be clarified before the auction, for which we point out the open questions. We share our considerations below:

- Phase 1: Submission of the plan for a project-specific EIA after 6 weeks
    - If this phase were a milestone, it would be very shortly after the auction (just 6 weeks). The plan submission date could be used as a milestone, but we would recommend against it, as the bidder will likely not have new information that would trigger him to withdraw from the project. This milestone would thus not have a large benefit, while simultaneously creating administrative burden. If it is nonetheless desired, this phase could be defined as a milestone, however without a penalty attached to it.
    - Open questions to be assessed prior to the auction (as they affect project realization, scope, costs, etc.): How long will it take the government to approve the plan? How will the project developer have to consider the outcomes of the public consultation? Under which conditions would an extension be granted by the Ministry?
    - It should be also considered that the landing point on shore for the radial connection must be known and communicated to the project developer by this time, as the EIA will be done for the exact project design, not variations thereof.
- Phase 2: Submission of EIA and concession application 2 years after approved EIA-plan
    - This stage in the licensing process lends itself well as a possible milestone and we would recommend using it. The milestone can be well-defined and is placed at a good temporal distance from other milestones in the licensing process, ensuring consistent incentives to fulfil the deadlines.
- Phase 3: Granting of concession
    - This phase does not lend itself as a milestone, as the concession granting is in the hands of the Ministry, not the project developer. The project developer hence has no direct influence over the duration of this process.
- Phase 4: Submission of detailed plan 1 year after approved concession

- We would recommend defining this phase as a milestone. The drafting of the detailed plan is within the scope of the project developer, and it can thus take on the risks attached to delayed submission.
- The Norwegian Authorities are considering a change so that the detailed plan for construction and operation is submitted with the concession application and processed simultaneously. If implemented, this adjustment will imply that the construction of the offshore wind project may begin immediately after being granted the concession.
- Open questions to be assessed prior to the auction: How long will it take the government to grant the concession? Under which conditions would an extension be granted by the Ministry? What type of information do bidders have to provide in the detailed plan? How will bidders have to prove compliance with the commitments made in the pre-qualification phase?

- Phase 5: Construction (immediately after detailed plan is approved)
    - This phase does not lend itself as a milestone, as the term construction is not specific enough.
    - Instead, the Final Investment Decision (FID) could be used as a milestone. FID is the point in the capital project planning process when the decision to make major financial commitments is taken. It usually only takes place after all elements of the pre-development and pre-construction phases are finalized. Only then, the project developer will have all the information necessary to come to FID.
    - If the desire is to have a milestone in the context of construction, the start of offshore construction could also be used as another milestone. We would in this case recommend defining it without a penalty. The FID will take place in temporal proximity to the start of offshore construction (with a period of detailed design, certification and fabrication in between), so the incentive would be rather small to have two milestones somewhat close after one another. Additionally, the commercial operations date (COD) is defined as a milestone (see below), which means that the project developer will have an incentive to start construction early anyways.
    - Open questions to be assessed prior to the auction: How long will it take the government to approve the detailed plan? Under which conditions would the deadline be extended? What kind of feedback can the bidder expect from authorities?
- Phase 6: Operation 5 years after approved detailed plan
    - The construction must be completed, and the offshore wind project must be in operation within five years from submission of the detailed plan. Instead of operation, we would recommend defining COD as the milestone. The completion of construction and start of operations is within the scope of the project developer, and it can thus take on the risks attached to a delayed start of operation.
    - Open questions to be assessed prior to the auction: Under which conditions would the timeline be extended?

We have noted above under the different phases several **open questions**. These questions must be clarified before the auction and requirements must be specified in the tender documents. It must become clear from the tender documents what kind of monitoring or reporting responsibilities the project developer has during the licensing process, how proof of reaching milestones must be presented, when the support agreement will be signed (directly after award, with approval of the concession or at FID), and whether an implementation plan must be presented by the bidder. Also, the authorities involved should be specified.

Especially for elements which are both phases in the licensing process and milestones in the context of the auction design, it would be desirable to have authorities work closely together to reduce administrative efforts on all sides (i.e., bidders do not need to prove compliance twice, but just once within the licensing process). For critical phases in the licensing process, it would be recommendable to have the project developer work closely with the relevant authorities, so that e.g., the EIA is almost co-developed, thereby ensuring a positive assessment and timely submission. The EIA and permitting process ensures that the plans of the project developer are within the set bandwidth of what is acceptable to the Ministry. If the project developer's plans for construction are inconsistent with the EIA and permit, it will need to go through a permit modification process. The requested changes can be denied by the Ministry/competent authority, forcing the developer to build according to original permit specs.

Based on the above recommendations, we would propose implementing the following **project realization milestones**:

- Milestone 1: Submission of EIA and concession application 2 years after approved EIA-plan
- Milestone 2: Submission of detailed plan 1 year after approved concession
- Milestone 3: FID 6 months after approved detailed plan
- Milestone 4: Start of operations 5 years after approved detailed plan

Using some high-level assumptions with regards to the duration of the public consultations, the approval of EIA-plan and the granting of the concession, the combined licensing and milestone process could look like shown in Figure 5. A completion of constructions in 2030 (as suggested at one point in the public consultation documentation) is from our perspective unrealistic. In a best-case scenario, construction could be completed in 2032, possibly somewhat later given the complexities of a novel licensing system.

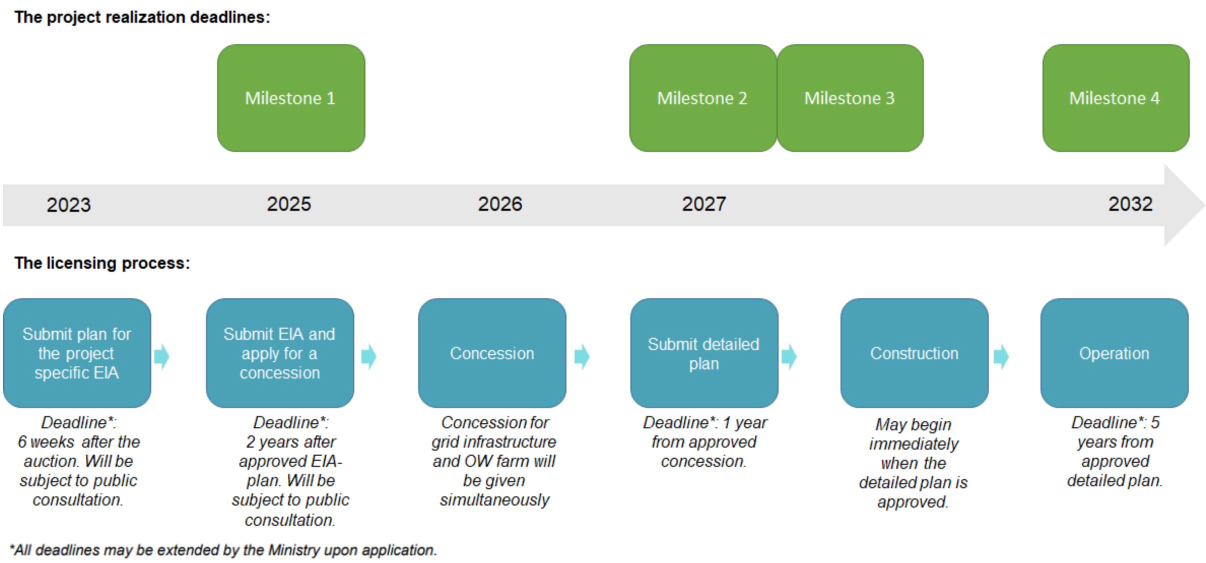


Figure 5 Project realization milestones and licensing process over time

2.4 Penalties

Penalties are sanctions that introduce costs to bidders in case of non-compliance with contractual obligations. In a legal context, they are often called liquidated damages. They can help reduce the possibility of delays, underperformance, and project failures by increasing the cost of non-compliance with contractual obligations for bidders. They also reduce incentives for underbidding by pushing bidders toward more cost-reflective bids. International experiences show that in the absence of sufficient penalties, the risk of delays and project non-realization is higher. Generally, it is advisable to escalate penalties over time to account for the extent of delays or deviation from contractual obligations.

Penalties can take different forms and be applied to different financial streams:

- During the pre-construction and construction phase, penalties can be linked to **financial guarantees**. Often, bidders must present financial guarantees when entering the auction (so-called bid bonds) and after award (so-called completion and performance bonds).
    - **Bid bonds** aim to ensure the successful bidder's commitment to sign a contract after being awarded. Bid bonds must be paid with submission of the bid. Unsuccessful bidders will receive their bid bond back. Successful bidders can either receive their bid bond back and pay the completion bond in full or top the bid bond up so that it has the value of the required completion bond (see below).
    - **Completion and performance bonds** protect the auctioneer against project delays, non-completion, and underperformance during the operation phase. The auctioneer collects a completion bond in the case that an awarded project is not commissioned by the agreed commercial operations date; otherwise, the bidder receives the bond back. The completion bond can be required after award, with the approval of the concession or with FID. We assume for all recommendations below that the completion bond will be paid after the FID. With regards to performance bonds, it is important to acknowledge that the CfD is a production subsidy meaning that the producer is only paid when it produces. This creates strong incentives for production. Hence, we lay the focus in this section on the construction period because the incentives from the support scheme do not apply

there. In any case, the CfD agreement – like any other contract – can include details on rights and responsibilities for all parties.

- The auctioneer can collect the bonds in form of a **bank guarantee, cash deposit or parent company guarantee**.

    - Bank guarantee: When a bank guarantee is required, the project developer will have to negotiate with a bank of its choice the conditions for the guarantee. Depending on the project developer's relation with the bank and the project developer's credit worthiness, it may have to deposit the entire value of the bond with the bank or only a share of it. The project developer will be provided with a letter by the bank which proves the guarantee. The government/competent authority can use this letter to claim the bond partially or fully depending on the applicable penalty. The bank charges the project developer a fee for this service, which usually a low single-digit percentage of the value of the guarantee.[12] This fee usually must be paid monthly. To reduce costs for the project developer, for SNII an option could be to require the guarantee as late in the process as possible. In fact, we are proposing below to only request the completion bond after FID.

    - Cash deposit: A cash deposit (sometimes also called reserve account) provides a high degree of certainty to the government as the entire value of the bond must be transferred to a bank account set up by the Ministry/competent authority. The Ministry/competent authority can then easily and without any intermediary parties access the bond in case of penalties. This however requires confidence by the project developers that the government would not embezzle the cash. We assume this confidence as given. The cash flow implications on the project developer would likely be higher compared to a bank guarantee. Here, the full value of the bond must be transferred to the bank account, while in a bank guarantee the project developer may only have to transfer a part (depending on the negotiated conditions with the bank). Also, the cash would be depreciating while being deposited. On the other hand, the project developer would save the cost of the fees.

    - Parent company guarantee: This option would require a contractual reach beyond the usually set up so-called special purpose vehicle (SPVs) to the parent company. In general, these guarantees are legally feasible in the Norwegian context but the details and their applicability for the offshore wind context would have to be verified. For example, in case the parent company has its seat in another country, their feasibility would have to be re-assessed by a legal expert. A parent company guarantee requirement may disadvantage bidders which do not have a large parent company behind them (even though several bidders intending to participate in the auction for SN II are backed by financially strong parent companies).

[12] In the tender for Hollandse Kust West, a fee of 1% of the value of the guarantee is assumed. Source: https://zoek.officielebekendmakingen.nl/stcrt-2022-7101-n1.html

    - Given the above arguments, especially with a view to the cash flow implications of the large sums potentially transferred, we would recommend asking bidders for a bank guarantee.[13]

- Penalties for delays until COD can also relate to **support payments** within the CfD.
    - The government can **reduce the overall support period** by the duration of the delay. As a result, the project developer's exposure to long-term market price risk is increased. However, as the support duration is shorter than the concession, this is a risk the project developer will face anyways and should hence be able to manage. This penalty type is therefore less likely to cause default before completion of project, compared to a support level reduction.

    - Furthermore, the government could administratively **reduce the strike price** by the duration of the delay or for the entire duration of the contract. For the first option, an important consideration is when this reduction is applied. During the first years of the project, the project developer will use most revenues to serve its debt. A reduction in revenues during this point would be a strong penalty. The latter option – reduction for the entire duration of the contract - would significantly affect revenue streams of the project developers and in turn its ability to pay back loans it had to take out. Setting the support level reduction appropriately can be challenging. On the one hand, a too high support reduction in case of delay can render the project unprofitable, and the bidder may choose non-completion instead of realizing the project with delay. On the other hand, too little reduction will have no effect. Against these uncertainties, we recommend to not use the reduction of the strike price as a penalty.

    - The government could as a last resort **terminate the CfD contract** and invalidate the rights to the concession with the project developer. In this case, the auction could be repeated, or the second-best bidder could be asked whether they would still be interested in doing the project. As mentioned, this would be a last resort option. We recommend combining the termination of the CfD contract with the termination of the concession. Not ending the concession would mean that the producer can still use the site. The legal feasibility of terminating the rights to the concession alongside the CfD contract would need to be verified for the Norwegian context.

- Irrespective of any payment flows, the government could as a penalty also **exclude bidders from future auctions**. The legal basis for this would need to be verified. This penalty could however have adverse effects on competition in future rounds. Furthermore, the reasons for delay may be primarily linked to the specific project context, rather than the capabilities of the project developer. Lastly, the legal feasibility of applying this penalty beyond the SPV (which would not compete again), would have to be checked.

Guarantee and penalty size should be tailored to the context-specific project costs and risks. Excessive penalties can increase risks for bidders and bid prices. Overly harsh penalties may also deter project developers from participating and result in lower competition levels. If penalties are too low, the risk of bidders gaming the process is higher. While bidders usually have an intent to realize the project at the time of bidding, economic rationales may change during the project development process. For example, an increase in costs at the time of construction may lead to abandonment of the project if alternative investments are deemed more profitable and the penalty is cheaper than the sunk costs.

[13] In the Netherlands, bidders for the Hollandse Kust West tender had the option to submit a parent company guarantee to score points for the 'certainty the wind farm will be built' criterion.

Developers may also want to delay commissioning if the anticipated benefits exceed applicable delay penalties. On the other hand, the expected large, well-known developers that we expect to participate in the auction will likely not want to risk any reputation damages by abandoning the project. Also, the project developers have a major incentive to get the project done so that they can earn revenues on their investment. Auction designers must consider these incentives and set the size of guarantees and penalties at a level that provides an incentive to complete the project on time.

Auction designers can set financial guarantees and penalties as a lump sum payment per unit of capacity (in kW or MW), in absolute numbers or as a share of total investment costs. Germany requires a payment per kW whereas Denmark and Netherlands required a lump sum payment in recent tenders (see Table 2).

Table 2 Size of financial guarantee in other countries

Country	Size of financial guarantee (bid + completion bond)
Germany	100 EUR/kW, 25% of total sum must be paid as bid bond with bid submission, remaining 75% must be paid latest 3 months after award. This corresponds to a full bond of ~1100 NOK/kW.
Denmark	1.1 bn DKK or ~ € 148 mio. for Thor tender (1000 MW), i.e., 148 €/kW. This corresponds to ~ 1600 NOK/kW. Bond must be provided before conclusion of the concession agreement.
Netherlands	70 mio. EUR for Hollandse Kust West (700 MW), i.e., 100 €/kW. This corresponds to ~1100 NOK/kW. Bond must be provided in form of a bank guarantee four weeks after award of concession.

The above countries required financial guarantees (both bid and completion bond) of between ~ 1100 and 1600 NOK per kW installed capacity. Based on examples from other countries as well as our own expertise, we would recommend as a first indication, that the size of the bid bond should be around **1% of investment costs** while the completion bond should be in the range of **4 to 5% of investment costs**. According to NVE, the total investment costs of the OWF incl. grid connection are estimated to amount to ~40 bn. NOK. For SN II, this would indicate a completion bond of ~ 1300 NOK per kW, and a bid bond of ~ 300 NOK per kW, i.e., the full financial guarantee (both bid and completion bond) would amount to ~ 1600 NOK per kW.

Penalties should in all cases be a **measure of last resort**. There must be measured progress, milestones, and defined penalties, but these penalties should only be implemented in very specific instances. The preferable solution would be to use the flexibility the licensing process foresees, e.g., by extending deadlines if the reasons for delay brought forward by the project developer are plausible, and to develop a cooperative process between the project developer and the Ministry/competent authorities. While a project is under construction, there are many things that can cause delays. Unforeseeable geological conditions could hamper foundation installation, bad weather could delay work, cranes can malfunction, or contractors could default. In circumstances which are outside the plausible reach of the project developer, an extension of deadlines should be considered by the Ministry. The cooperative process should ensure that all parties are aligned early in the process which can help avoid unnecessary delays and extra review loops.

We would recommend maintaining some **discretion** for all penalties proposed below in deciding whether a penalty immediately becomes necessary or whether a process of notification and rectification could be attempted first. In the end, it is both in the Ministry's and project developer's interest to realize the project as quickly as possible.

- **Bid bond** (to be paid at bid submission)
    - Withdrawal from project after award: 100% of bid bond
    - Delayed submission of EIA and concession application (milestone 1): 5% of bid bond
    - Delayed submission of detailed plan (milestone 2): 15% of bid bond
    - Delayed proof of FID (milestone 3): 25% of bid bond
- **Completion bond** (to be paid after FID)
    - Delayed start of operation (milestone 4):
        - Grace period for delays up to and including 6 months
        - Delay by 7 months: 10% of completion bond
        - Delay by 8 months: 15% of completion bond
        - Delay by 9 months: 20% of completion bond
        - Delay by 10 months: 25% of completion bond
        - Delay by 11 months: 30% of completion bond
        - Delay by 12 months: 35% of completion bond
        - Delay by 13 months: 40% of completion bond
        - Delay by 14 months: 45% of completion bond
        - Delay by 15 months: 50% of completion bond
        - Delay by 16 months: 55% of completion bond
        - Delay by 17 months: 60% of completion bond
        - Delay by 18 months: 65% of completion bond
        - Delay by 19 months: 70% of completion bond
        - Delay by 20 months: 75% of completion bond
        - Delay by 21 months: 80% of completion bond
        - Delay by 22 months: 85% of completion bond
        - Delay by 23 months: 90% of completion bond
        - Delay by 24 months: 95% of completion bond

        - Delay by > 24 months: 100% of completion bond

    - Alternatively, a daily delay payment could be defined, which would be calculated using the total value of the completion bond divided by the number of days the project could be delayed before the contract would be terminated.

    - Generally, the consideration is that any one penalty should have a strong enough incentive to ensure that no further penalties will be necessary. Any percentages provided are a first indication and can be altered in discussion with the Ministry and its legal advisors.

    - In any case, once a penalty was paid, the completion bond must be topped up to its full value so that further penalties can be applied if necessary. If the project developer does not top up the completion bond, a termination of the contract could be considered.

- **Reduction of overall support period**
    - In case of delayed start of operation by > 24 months: Reduction of support period by the delay (+ 100% penalty applied to completion bond)

- **Termination of contract and concession**
    - In case of a delayed start of operation of > 36 months

    - As a last resort before the termination of contract and concession a negotiation between government and project developer could be scheduled. The government would have the right to terminate the contract but may wish to not do it if the project developer can provide sufficient information on next steps and project realization.