



Orsted

# Investor letter

Hedging, intermittency, and balancing costs

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# Investor letter - Hedging, intermittency and balancing costs

## Introduction

The world and not least Europe is in a highly unusual and volatile period with war, sanctions, political instability, extremely high inflation, threatening recession, and steeply increasing interest rates. In Europe, the energy crisis continues to significantly impact households, companies, and countries. And although gas and power prices have fallen from the peak late August, prices remain extremely high and volatile compared to any period before 2022. These sad and undesired developments have had significant impact on our earnings.

In the next few pages, we aim to explain the most relevant factors related to the high and volatile energy prices.

## Background

Market and credit risks are a natural part of our business activities and a precondition for being able to create value. We use risk management to monitor our risks and reduce them to our desired level. As a consequence of the soaring energy prices during the last year, we have seen significant accounting effects from our hedging policies.

Over a multi-year period, around 90 % of Ørsted's earnings come from regulated activities or contracts with partners, including long-term fixed-price agreements with governments and companies with a large consumption of renewable electricity. As such, the remaining 10 % is exposed to the market prices. For many years, we have sought to reduce this exposure to market prices by entering into fixed-price financial agreements on exchanges several years ahead.

## Offshore generation

Earnings from power generation from offshore wind farms mainly comprise:

- fixed tariffs in Denmark, Germany, the Netherlands, the UK (CFD wind farms), the US, and Taiwan
- guaranteed minimum prices for green certificates in the UK (ROC wind farms)
- long-term power purchase agreements
- sale of power from our wind farms at market price with market price risks.

## Onshore generation

In Onshore, a large part of our power generation is in the US, which comprises tax incentives, such as production tax credits (PTCs) or investment tax credits (ITCs). The tax incentives have a fixed value. However, the price risk associated with power generation is reduced by entering into CPPAs. At the end of 2021, the CPPAs covered approx. 75 % of the expected generation (a CPPA normally covers a 10-15 year period and they are valid from when the wind farm is fully commissioned). The CPPAs are entered into with large corporations or financial institutions with robust credit ratings.

## Combined heat and power generation

Our CHP plants consist of biomass- and fossil-fuelled plants in Denmark. Heat generation accounts for a large share of the earnings and does not give rise to price risks, as the associated costs are covered by the heat customers. However, there is a price risk when we generate power together with heat. The profitability of power generation is determined by the difference between the selling price of power and the purchase price of fuel and, for other fuels than biomass, carbon emission allowances. If the spreads are

attractive, we provide condensing power generation in addition to the CHP generation. These volumes are unhedged in nature as we only generate this power when it is profitable.

## Hedging

We apply hedge accounting to our energy, commodity, currency, interest, and inflation hedges, which entails that we need to live up to certain requirements under IFRS 9.

Where possible, we use hedging instruments which hedge the desired risk one-to-one. The GBP exposure, for example, is hedged using GBP forward exchange contracts, GBP swaps, or GBP loans. Thus, there are no significant sources of ineffectiveness.

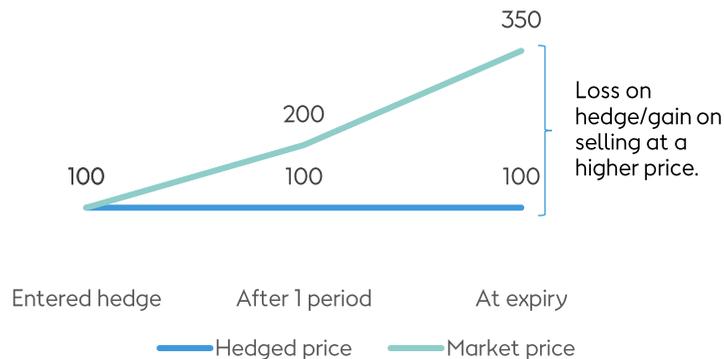
To the extent that we want to hedge a risk, and no fully effective one-to-one instrument is available in the market, analyses are performed of the expected effectiveness of alternative hedging instruments before the hedging transaction is concluded (also referred to as proxy hedging). In this case, the ratio between the hedged risk and the hedg-

ing instrument may deviate from the one-to-one principle and can lead to price ineffectiveness.

If we have hedged too many volumes, or the value of the hedge changes more than the value of the exposure, the hedges become ineffective (see examples of volume and price ineffectiveness below).

In the short-term, we mostly hedge our generation with instruments that are directly one-to-one linked to the product and the market where we generate power. These hedges are deemed effective and have no impact on our 'profit and loss' (P&L) before they expire. In cases where no fully effective one-to-one instrument is available in the mar-

### Hedge example



ket, we mostly hedge our generation with instruments that we see as best related with the underlying exposure (i.e. UK gas as hedge for UK power exposure). This can lead to ineffectiveness if the instrument we have used to hedge our future generation does not correlate fully with the price in the market in which we will sell our future generation.

When we enter into a hedge, we take out a sell (short) position as we aim to fix our future sales price and income related to power generation. When the market price is higher than our hedged price, we take a contractual loss on the trade, which is then offset by selling the power to the market at the market price.

As an example, we have a hedge for 1,000 MWh, our hedged price is GBP 100/MWh, but at the time of delivery, the market (spot) price is GBP 350/MWh. We settle the hedge at a loss of  $(100-350) * 1,000 = \text{GBP } -250,000$ . Simultaneously, we sell the power to the market for  $350 * 1,000 = \text{GBP } 350,000$ , which is 250,000 more than it was worth at the time of our hedge  $(100 * 1,000 = \text{GBP } 100,000)$ . As long as production is equal to our hedged volumes, this has no effect on our earnings.

### Volume-ineffectiveness

Volume-ineffectiveness is when we have hedged more (based on expected production) than what we actually generate. This mostly affects Offshore, as we have hedged close to 100 % of the expected generation in 2022 and 2023, whereas it affects Onshore and Bioenergy & Other less. The causes of volume ineffectiveness are lower wind speeds, lower availability, or delayed ramp-up.

This was the case with our Hornsea 2 Offshore Wind Farm, where we hedged the expected ramp-up production during 2022 when the construction progress was on track. As the ramp-up phase was subsequently delayed, we had to settle the hedges in the market,

realising a loss – without getting the positive impact from selling underlying power at a corresponding higher price. Using the example above, we lost GBP 250 per MWh we had hedged and not sold in the market.

### Price-ineffective hedges

When we use proxy hedging, the hedges will be deemed ineffective under IFRS 9 if our hedged instrument moves more than the underlying exposure with which we are hedging it. Thus, we need to book losses (or gains) from these hedges on a rolling basis (end of every period). This means that if we, for instance, have used gas to hedge our sales price for power generation, and the gas price increases more than the underlying power price we use to hedge it, we need to book this net loss immediately, and not when the hedge expires.

As an example, we hedged 200 MW of gas to cover 100 MW of power in three years' time (2 units of gas to cover 1 unit of power). The gas price at the time of the hedge was GBP 50/MWh, and the price of power was GBP 100/MWh. One year later, the price of gas with the same delivery time as our hedge is now GBP 150/MWh, whereas the price of power is GBP 200/MWh.

Here, the gas price has increased 200 % whereas the power price has only increased 100 %. As we use 2 units of gas to hedge 1 unit of power, the calculation would look like this:

2 units of gas to cover 1 unit of power is now priced at  $2 \times \text{GBP } 150 = \text{GBP } 300$ , whereas the power is now only at GBP 200. Because we have hedged our power generation using gas, and the loss on the gas hedge is larger than the change in the value of the exposure (power), we have to book a loss that equals the difference between the two, which is  $\text{GBP } 300 - \text{GBP } 200 = \text{GBP } 100/\text{MWh}$ .  $100 \text{ MWh} \times -\text{GBP } 100 = -10,000$ .

The overall value creation from our power trading activities continues to be positive, as it has been in recent years, and our trading portfolio has a low risk given our conservative 'value-at-risk' mandates. However, in 2022, our EBITDA has been negatively impacted by hedges that we cannot document as being effective under IFRS 9. Therefore, we have had to recognise a loss in the P&L immediately. This creates a skewed view between years, as all the value created by our trading team will not be booked before the financial contracts expire, which can be anywhere from 1 month to several years in the future. We

do expect large parts of it to be booked next year.

#### Balance sheet impact (hedge reserve)

In addition to impacting our EBITDA, the value of our current hedges also impacts our balance sheet.

As energy prices have increased significantly, the market value of our hedges has become negative. The negative development of our hedges is continuously booked to our balance sheet with a negative market value, as the forward price is higher than our hedged price. At the end of June 2022, the post-tax hedging and currency translation reserve amounted to DKK 49.2 billion.

The reserve will be matched by higher future revenue from the underlying activities when the contracts fall into delivery. Based on forward prices and positions as of 30 June 2022, approx. 25 % the reserve will materialise before 31 December 2022 and an additional 35 % before 2023, thus gradually increasing equity again. Furthermore, a decline in energy prices will also lead to a decrease in our hedge reserve.

#### Collateral

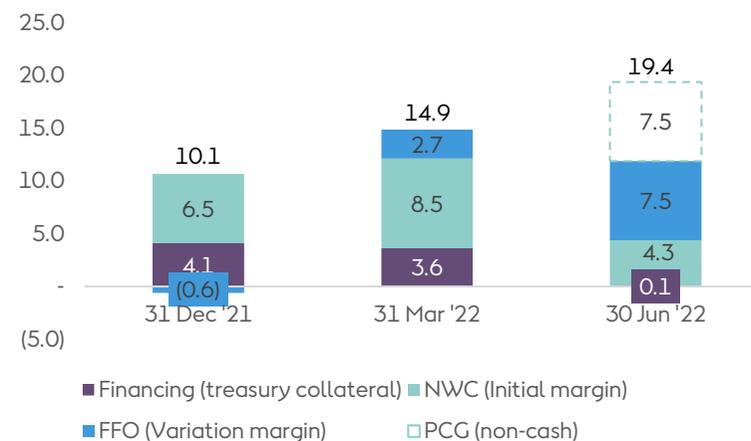
We hedge our energy exposure through exchanges and directly with other parties, over the counter (OTC). The part of our hedging that is done over exchanges requires us to post collateral. Approx. 1/3 of all our energy trades are posted at exchanges and the remaining 2/3 at OTCs where we don't post collateral. Three types of collateral posting affect our cash flows: variation margin, initial margin, and treasury collateral.

Variation margin relates to the underlying development of our energy hedges. These are part of our accounting FFO and are calculated based on the mark-to-market value of our hedges. Let us

assume we have hedged 100 MWh of power at GBP 100/MWh. One quarter later, the price of the contract has increased to GBP 350/MWh. We are then required to post GBP 250/MWh as collateral at the exchanges (GBP 25,000 in total). Variation margin payments on unrealised hedges are presented as part of 'Change in derivatives' in our cash flow statement.

Initial margin is collateral posted at exchanges based on the positions we open/have opened on the exchange. The initial margin works as a guarantee that the counterparties and exchanges get the money they are owed if a company should default, and thereby protects the investments of its clients. The

#### Collateral development



initial margin is calculated by the exchange and is based on short-term historical volatility and price level. This means that the risk which the exchanges have to cover increases as prices and volatility increases, and therefore the clients need to post more collateral. The initial margin requirements are updated by the exchanges on an ongoing basis. Initial margin payments at clearing houses are presented as part of 'Change in trade receivables' and included in net working capital in our cash flow statement.

Treasury collateral mainly relates to hedging of inflation, interest rates, and currency. Treasury collateral payments (CSA) are part of cash flow from financing activities and are included as interest-bearing net debt items in the balance sheet, thus not impacting our total NIBD.

All three types of collateral postings are temporary effects. Collateral postings correlate with energy prices, and once the hedge product is delivered, the funds are returned to our account.

On the bottom of the previous page you can find the development of our posted collateral since the end of 2021. During

Q2 2022, we replaced part of our cash collateral with a parent company guarantee (PCG).

### Intermittency costs

When we trade in the physical power market (intraday), our generation is traded on an hourly, half-hourly, or 15-minute basis. Every hour, half-hour or 15-minute period has a linked price to the volume traded. This implies that when wind farms are generating more wind, the price is usually pushed down as the demand is stable and not dependent on wind speeds. This daily fluctuation in price (volume-weighted average) is usually referred to as the wind capture price.

When we hedge our expected power generation financially, we assume a flat volume profile and average market price profile. This is usually referred to as the base load price. We use these hedges when we hedge our power generation on a monthly, quarterly, and yearly basis, as there are no price curves in the market for the intraday volatility in volume and market price.

The intermittency cost is the difference between our base load hedged price and the, usually lower, wind capture price on which the revenue from our power generation is dependent, as described above.

To cater for the intermittency costs (i.e. that the wind capture price is lower than the baseload price), the volume we hedge is lower than the volume we expect to generate. For instance, if we expect a 10 % intermittency cost, we will reduce our hedged volumes by 10 %.

As an example, we forecast to generate 100 MWh in September, of which we hedge 90 (100 MW x 90%) MWh at a baseload price of 50 EUR/MWh (our total hedge now matches our expected exposure: 90 MW hedged x 50 EUR/MWh = EUR 4,500; 100 MW sold x 45 EUR/MWh (expected capture price) = EUR 4,500).

When September ends, we had generated exactly what was forecasted (100 MWh). However, when we receive the revenue from the power generation, the wind capture price was lower than



expected at 44 EUR/MWh (vs 45 EUR/MWh as expected). The intermittency cost is thus EUR 100 (EUR 4,400 - EUR 4,500) or EUR 1/MWh (sold 90 MWh × 50 EUR/MWh upfront, receiving 100 MWh × 44 EUR/MWh).

### Balancing costs

The cost of settling intraday differences between forecasted power generation, traded in the day-ahead auction, and the actual delivered generation.

Our forecasted generation for the next day, is traded in a day-ahead merit-based hourly auction. Changes between

the forecasted generation and the actual generation is traded in the bid/offer intra-day markets, where market conditions are reflected. Typically, this means that if wind generation is considerably higher than expected the day before, the intra-day price trades below the day-ahead price secured in the day-ahead auction and vice versa.

The balancing costs is defined as the difference between the two. i.e. the difference between the theoretical revenue (day-ahead price × actual generation) and the realised revenue (See calculation in table below).

For further information, please contact:

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### Imbalance cost example

Generation forecast, day-ahead, MWh	10
Day-ahead auction price, GBP/MWh	250
Actual generation, MWh	13
Additional intraday sales, MWh	2
Intraday market price, GBP/MWh	200
Imbalance settlement, MWh	1
Imbalance price, GBP/MWh	190
Theoretical revenue	3,250
<b>Actual revenue*</b>	<b>3,090</b>
Imbalance cost	160
<b>Imbalance cost, GBP/MWh</b>	<b>12.3</b>

\* Calculated as 10 MW at day-ahead auction price, (10 \* 250 = 2,500, 2 MW \* Intraday market price (2 \* 200 = 400), and 1 MW \* Imbalance price (1 \* 190 = 190). (2,500 + 400 + 190 = 3,090)