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Abstract

The Dudgeon Offshore Wind farm is located off the coast of the seaside town of Cromer in North Norfolk in the UK. After the final financial investment decision was made in mid-2014, the wind farm started construction in early 2015 and was completed in late 2017. The wind farm consists of 67 turbines with a total installed capacity of 402MW. In recent years, an increasing number of companies have started investing in offshore wind projects. Increased interest makes for more competitive bidding on Contracts for Differences (CfD), resulting in lower strike prices. The Dudgeon Offshore Wind farm was one of the first UK offshore wind projects to be awarded a CfD and as a result received a strike price of £150/MWh compared to the anticipated £46/MWh in allocation round 4.

In the thesis, the profitability of Dudgeon Offshore Wind is analyzed at different stages. Firstly, the profitability at the investment decision in 2014 is evaluated, before it is compared with an updated analysis of the project outcome as of 2022. After, a third analysis is performed to assess the economics of constructing a similar wind farm today with larger more modern wind turbines, but with a lower CfD strike price.

The results show that the Dudgeon Offshore Wind project so far has been more profitable than what was expected at the investment decision, mainly due to a reduction in capital expenditure and increased future electricity price estimates. The analysis covering the construction of a similar wind farm today shows that the farm is unlikely to turn out profitable due to the lower CfD strike prices awarded in 2022.

Acknowledgment

This master thesis marks the end of the Master of Science Programme in Industrial Economics at the University of Stavanger. With backgrounds in Structural Engineering and Electrical Engineering, we found it interesting to study the economical side of the fast-growing offshore wind market. The learning outcomes will be beneficial for both of us when entering the labor market, as both will be working in companies with an increasing focus on offshore wind and renewable energy.

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Mats H. Hansen

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Abbreviations

CfD	Contract for Difference
LCOE	Levelized Cost of Electricity
RO	Renewable Obligation
ROC	Renewable Obligation Certificate
FiT	Feed in Tariff
OPEX	Operational expense
CAPEX	Capital expenditure
WACC	Weighted Average Cost of Capital
DOW	Dudgeon Offshore Wind
PV	Present Value
NPV	Net Present Value
DCF	Discounted Cash Flow
IRR	Internal Rate of Return
MW	Megawatt
MWh	Megawatt hours
GW	Gigawatt
GWh	Gigawatt hours
EMR	Electricity Market Reform
DC	Direct Current
AC	Alternating Current
HVDC	High Voltage Direct Current
HVAC	High Voltage Alternating Current
OFTO	Offshore Transmission Owner
ETUoS	Embedded Transmission Use of Systems

SPV	Special Purpose Vehicle
C	Cash flow
r	Discount rate
E	Market value of equity
D	Market value of debt
R_E	Cost of Equity
R_D	Cost of Debt
T	Corporate tax rate
R_F	Risk-free rate
B	Beta
R_M	Market risk premium
CAPM	Capital Asset Pricing Model
ARMA	Autoregressive Moving Average

1. Introduction

The purpose of this thesis is to learn from the development in the offshore wind space. How has the industry changed since 2014 and where is the development headed? We will analyze and compare the profitability of Dudgeon offshore wind farm located off the UK coast, from the investment decision in 2014 and today (2022). In addition, we will analyze the profitability of constructing a similar windfarm starting in 2022. In the thesis we will be looking at what has changed, and what the major drivers are for the project's profitability. In short, a case study of the Dudgeon Offshore Wind (DOW) will be performed with the thesis question as follows:

“How has development in external factors and technology influenced the profitability of a wind farm? What can we learn from studying these factors, and how might it affect future offshore wind projects?”

The case study will include NPV calculations of Dudgeon in both 2014 and 2022, using the information available at those times. As well as an NPV analysis estimating the profitability assuming a similar project is initiated in 2022. The results and differences will be discussed and evaluated in relation to how the global situation affects the energy market.

1.1 Limitations

The thesis will be based solely on publicly available information. Assumptions and simplifications will be made where information is not available or highly uncertain.

2. Theory

2.1 Wind power

Wind is a renewable energy source that can be converted to electricity using wind turbines. Wind originates from pressure and temperature changes in the atmosphere. In simple terms, the wind causes the turbine to rotate, creating kinetic energy. With the help of gearing and a generator, it converts this energy into electricity.

The turbines are heavily dependent on wind conditions, which vary depending on geographical location [1]. Higher and more consistent wind speeds offshore generate more electricity at a steadier rate than the onshore counterpart [2]. The turbines have grown in both hub and rotor size by around 59% and 150%, respectively [3]. Larger turbines are being constructed to utilize the wind more effectively. Higher towers and larger rotors mean that each turbine can sweep a larger surface area. The wind also generally increases and is less turbulent at higher altitudes [3]. In the last few years, technological advancement in both onshore and offshore wind turbines have pushed down prices, with the most significant price reductions being offshore [4]. With larger turbines capturing more energy and having a higher power rating, it reduces the number of turbines needed to reach a specified installed capacity. For scale, both GE and Siemens have recently installed two massive prototype turbines with a 220-meter and 222-meter diameter rotors, with a capacity of up to 14-15 MW. This is more than twice the diameter of the average onshore turbine, which is set to be commercially available in just a few years [5], [6].

2.2 Wind farms

Wind farms are clusters of turbines that are connected to the power grid via a single electricity-producing power station. The capacity of different wind farms varies, but it is generally common to see modern farms with capacities in the hundreds or even thousands of MW. The wind farms can be either onshore or offshore. Offshore wind farms are considered more effective than onshore, but they are also more expensive to construct and install [7]. Both require a lot of land or space to be efficient, for example due to the blockage and wind-wake effects [8]. These effects will be explained in further detail when discussing capacity factors. With the enormous size of the turbines and the required space to create wind farms, these projects are quite obtrusive to the environment.

An advantage of farms being offshore is that the visual pollution and noise are mitigated by the long distance from civilization.

2.3 Offshore foundations

Offshore foundations can be separated into two categories, bottom-fixed, and floating substructures. The most common foundation type is the bottom-fixed monopile, which make up 80% of all foundations currently installed [9]. Monopiles are constructed by driving a 10-20m steel pipe into the seabed. Depending on the ground type, it requires little to no preparation of the seabed, but it does require heavy duty piling equipment. The diameter is around 3.5-4.5m and the monopile is effectively an extension of the turbine tower [10]. The floating substructures are still uncommon due to high cost, representing a total of 0.2% of all foundations installed, consisting mostly of pilot and prototype projects.

2.4 Electricity generation – past, present, and future

Wind energy is one of the fastest-growing renewable sources of electricity globally [11]. The turbines are becoming bigger and more efficient. Reports from 2021 show that new wind installations amounted to 17.4 GW in Europe, with around 3.4 GW being offshore [12]. Although this was a record year for overall wind installation, yearly installed offshore wind has decreased since 2019 and the total installation is 11% lower than forecasted. A significant factor causing commissioning delays for new wind farms are permit bottlenecks and upsets in the global supply chain [12].

2.5 The Levelized Cost of Electricity (LCOE)

The "Levelized Cost of Electricity" measures the lifetime costs of producing a unit of electricity. Developers and investors, among others, can use the LCOE to compare the attractiveness of various technologies, as well as understanding the long-term economic trend [13]. This can be a useful tool when comparing the cost of electricity from different energy sources. A decrease in the LCOE will increase the competitiveness of an electricity source. The LCOE in wind energy has declined gradually since 2010 [4]. The reduction in the LCOE can come from “reduced costs, increased energy production efficiency or changes in financing and lifetime of the project” [14].

2.6 Economics and incentives for Wind

Wind power projects have historically been dependent on subsidies to be economically viable. Governments have used subsidies and incentives to stimulate the deployment of renewable energy production [15]. There are several different types of subsidies and incentives for wind, and they vary from country to country [16].

Contract for Difference (CfD) is commonly used to incentivize investments in renewable energy as it provides stability and predictability in an otherwise unpredictable business environment. A CfD in the wind industry, is a contractual agreement between a generator and a Low Carbon Contracts Company (LCCC). The agreement effectively means that the electricity generator is paid a fixed price for the duration of the contract regardless of the reference price being above or below the strike price, eliminating the exposure to volatile market prices [17]. Contracts in the UK typically have a duration of 15 years.

Before the CfD scheme was fully implemented, a “Final Investment Decision Enabling for Renewables” acted as a temporary solution to help developers make final investment decisions. The Government was fully committed to avoid any hiatus in investment under the Electricity Market Reform (EMR) [18]. This was an invitation for projects that needed financial incentives to be initiated. The project needed to demonstrate credible plans regarding timeframe, size, and risks, in addition to a capacity of 100MW or greater. Generation had to initiate between 2014/15 and 2018/19 in accordance with the “First Delivery Plan” [18].

Renewable Obligation Certificates (ROC), which were certificates issued by the Office of Gas and Electricity Markets (Ofgem), was another tool used to accredit renewable generators. The operators could trade the ROCs with one another, and the certificates were ultimately used to verify that the suppliers had fulfilled their commitments to deliver a certain amount of eligible renewable electricity to the end user. Depending on the advancements of the technology used, the ROCs for each MWh varied. For instance, offshore wind typically got 2 ROCs per MWh, while onshore wind got 0.9 ROCs for the same amount [19]. The final certificates were issued in 2017, making new installations having to apply for CfDs instead [20].

A third option, which were handed out until 2019, was Feed-in-tariffs (FiT). These are similar to CfDs in the sense that risk for the generators is reduced by a fixed price for each wattage produced. However, in this case, the fixed price came in addition to the market price. This was mainly done to promote smaller-scale generation. The number of installations that could receive FiT each month were capped at a certain amount after 2016 [21].

2.7 Consents and environmental assessments

Before initiating a wind project, consents and environmental assessments are required. Regulations vary between different countries and locations. The assessments include all parts of construction, both on- and offshore. In the case of Dudgeon Wind Farm, consent from the Department of Energy and Climate Change, North Norfolk District Council, and Breckland Council were required. The consents for Dudgeon Offshore Wind Farm were in place by late 2012, with several revised versions approved by then [22]. The consents and assessments are important to protect the environment, the residents nearby and to make sure the project is done in a safe and timely matter.

2.8 CAPEX – Capital Expenditure

Capital expenditures are investment costs. To be considered a capital expenditure, the investment must have a useful life of more than one accounting period. These expenses can be found in the cash flow statement. The CAPEX is usually available as an estimate of overall investment. However, the timing of the expenses is not always available, and because of this assumptions and estimates can be made based on the duration of construction [23]. Offshore wind project refers to CAPEX as the spending leading up to energy production, unless long term upgrades increasing lifespan and production happens during the lifecycle.

2.9 OPEX – Operating Expenses

Operating expenses refers to day-to-day expenses to keep a business operational. These costs first occur when the project is up and running and include salaries, rent, property taxes, and more. The operating costs of offshore wind farms will vary depending on several factors. To simplify, the driving cost can be divided into two categories, operation, and maintenance, with maintenance being the most significant factor [14].

2.10 Transferring energy - Transmission loss

The two main ways of transferring energy from sea to shore is with high voltage direct current (HVDC) and high voltage alternating current (HVAC). When deciding on transmission method, the transfer distance is significant. The newer technology, HVDC, has lower losses over longer distances than the HVAC counterpart. The higher cost for HVDC converter stations, because of back-and-forth conversion between HVAC and HVDC, means that over shorter distances HVAC is more cost efficient [24]. The HVDC cables have a smaller cross-section for the equivalent power, which is cheaper to manufacture and easier to handle during installation, which compensates for the higher HVDC converter costs [24]. For longer distances the lower losses and the cheaper cabling makes HVDC more viable. HVAC is as a result of all these factors the most common transmission method, however the technology for HVDC is maturing [24].

2.11 Capacity factor

The capacity factor describes the average output relative to the maximum power capacity. Newer offshore wind projects in Europe have a capacity factor of 45-50% according to the Wind Energy Outlook Special Report by the IEA [25]. The capacity factor exceeds solar photovoltaic system (solar PV), onshore wind, and gas, and is on par with coal. This comes as a result of technological advancements and larger, more efficient turbines [25].

Offshore wind energy produced can fluctuate up to 20% hourly while solar PV varies by up to 40%. As a result, the IEA places offshore wind into its own category based on its high capacity factors and lower variability - “a variable baseload technology” [25]. Newer turbines promise capacity factors over 60%, however it is likely that this is calculated before wind wake and blockage losses [6]. IEA also simulated the seasonality of both offshore wind and solar PV. For offshore wind in the UK, US and China, winter yields the highest capacity factors while the opposite is true for India. The simulation also shows how solar PV can complement offshore wind generation as they have inverse seasonality [25].

2.11.1 Blockage and wind-wake effect

In 2019, the Danish energy company Ørsted warned about the industry-wide problem of underestimating the wake and blockage effects by placing the turbines too close together, thus lowering the overall capacity factor [26]. The blockage effect is when wind slows down and divert as it approaches an obstacle, which in this case is the wind turbine. The wind-wake effect on the other hand, refers to the change in wind speed after impacting the wind turbines. This results in lower wind speed for the turbines standing in each other's wakes, reducing energy production. The severity of the effects also depends on factors such as turbine characteristics, wind farm layout and atmospheric site conditions [27]. DNV GL has estimated that the blockage effects could represent an overestimation of 0-4% of yearly energy production [28].

2.12 Capture price

A capture factor is needed to better predict the price the generator is actually paid, rather than the average spot price for a given day [29]. The wind production varies over time, and the electricity prices need to be estimated at the time of production. High wind speeds means that there is high energy production, which results in lower spot price. Therefore, a large share of wind energy is often produced when spot prices are low, at times even negative. This means that the capture price for wind farms will be lower than the average spot price [29].

2.13 Leasing and Transmission tariff

The wind farms must pay to lease the seabed from the Crown Estate and pay transmission fees to maintain the National Grid. A separate transmission company is established to construct the necessary cables and substations to deliver power to the National Grid. However, according to UK law, it is not allowed to own both transmission and production [30]. This essentially means that after the wind farm is complete, the transmission company must go through a competitive tender process before it is transferred to an Offshore Transmission Owner (OFTO) [31].

The offshore wind transmission fees vary and are based on three tariff components: substation, circuit, and Embedded Transmission Use of Systems (ETUoS). These reflect the cost of offshore networks connecting offshore generation [32]. The report "Transmission Cost for Offshore Wind" from 2016 by the Offshore Wind Programme Board from Catapult concludes that transmission fees for offshore wind have and can continue to be held around the £10-12/MWh range despite the increased distances between offshore and onshore substations [33]. The primary reasons for this conclusion are higher capacity factors and upgraded export cables.

2.14 Special Purpose Vehicles – SPV

Offshore wind farms are often organized as special purpose vehicle (SPV) companies with their own management team and financial reporting. The SPV can raise capital by issuing shares in the project or raising its own debt which can be used to develop the project [34]. The risk is heavily mitigated by organizing a project as a SPV, as only the assets of the project itself are recourse for compensation if the project fails to repay the debt [35]. This company structure isolates the financial risk.

2.15 Decommissioning Program

The removal of all wind turbines and returning the land to its original state is known as decommissioning [36]. It is a requirement under Section 105 of the Energy Act 2004 to prepare and ultimately carry out a decommissioning program [37]. The decommissioning applies to all offshore components, excluding the assets transferred to OFTO. Usually all components are removed, however the monopiles can be cut, leaving some of the foundation in the seabed. One of the reasons for this is called the "reef effect", where the foundations over the years of operation have been colonized by different species [36]. The wind farm is said to have a lifetime of 25 years, and with that, it is assumed that the costs associated with the decommissioning will have changed significantly. The cost of decommissioning can be estimated but is highly uncertain [38].

2.16 Dudgeon Wind Farm

The focus of the thesis will be on Dudgeon Offshore Wind Farm, which is located off the coast of the seaside town of Cromer in North Norfolk in the UK. After all the construction consents were in place late 2012, the final investment decision was made in mid-2014. The wind farm started construction in early 2015 and was completed in late 2017. The wind farm has an installed capacity of 402MW consisting of 67 turbines, supplying 410 000 UK homes with renewable energy [38]. Each of the turbines has a capacity of 6MW and is built on monopile foundations at a depth of around 18-25 m. The wind farm is owned by Equinor, Masdar, and China Resources (Holdings) through the joint venture vehicle Dudgeon Offshore Wind Limited, with Equinor being the operator [38]. Dudgeon Wind Farm was one of the first UK offshore wind projects to be awarded a CfD. This is the only form for subsidies or incentives the farm has received [39].

3. Valuation theory

3.1 Net present value (NPV)

Present value is today's value of a future cash flow. The cash flow is discounted at a rate to represent the time value of money. The net present value is defined as the present value of cash flows, subtracted the present value of investments. In *Corporate Finance* by Berk and DeMarzo, the NPV is described by the formula below [40].

$$NPV = PV(Benefits) - PV(Costs)$$

The mathematical NPV equation is written below.

$$\text{NPV} = -I + \frac{Cf_1}{(1+r)} + \frac{Cf_2}{(1+r)^2} + \cdots + \frac{Cf_n}{(1+r)^n} = -I + \sum_{t=1}^{n} \frac{Cf_t}{(1+r)^t}$$

I is the initial investment made at year 0 of the project and is not discounted. Cf_n is the free cashflow at year *n*, discounted at rate *r*. The free cash flow is typically EBIT – tax – CAPEX + depreciations. The net present value model can be used to determine a fair price of an investment. If the NPV is positive, the investment should be made, and if the NPV is negative, the investment should be viewed as not profitable and thus not made.

3.2 Terminal value

Estimating terminal value is a tool that can be used to put a value on investments without a final date. NPV analysis can be used to assess investments in businesses without a final stop date, and terminal value is therefore a useful tool to the analysis. The terminal value can be calculated in different ways, depending on the situation. The simplest case is when you have a defined investment period, and the terminal value is zero. In this case, the investment is written off and there is no salvage value by the end of the project. When there is a terminal value, there are two normal ways of calculating it, the exit multiple, and the Gordon growth model [41].

The exit multiple option is when the investment period is defined, or for simplicity, a defined period is modeled, but there is a salvage value by the end of the period [41]. In this case, the salvage value becomes the terminal value, and this can be discounted and added to the NPV. This method implies that the business, equipment, etc. are sold by the end of the period.

The other option is using the Gordon growth model, which uses perpetual growth. In this model, a project or business is assumed to have everlasting cash flows. These cash flows are applied to a perpetual growth rate before they are discounted and added to NPV [41].

3.3 Weighted average cost of capital (WACC)

The most common way to estimate the rate *r* in an NPV-analysis is using the weighted average cost of capital method (WACC). The WACC model considers the financing of an investment and calculates a project or business' capital cost from various sources. It is often used because it represents the required return for both equity and debt holders. The relation between equity and debt is calculated and used as a foundation for the final WACC [42].

$$WACC = \frac{E}{E + D} \cdot R_E + \frac{D}{E + D} \cdot R_D \cdot (1 - T)$$

E - Market value of equity

D - Market value of debt

R_E - Cost of equity

R_D - Cost of debt

T - Corporate tax rate

The market value of both equity and debt is used in the WACC formula. The market value of these gives an understanding of future expectations, in opposition to book value, which is based on a recorded history [43].

3.4 Cost of equity (CAPM)

The capital asset pricing model (CAPM) is used to find the expected return on equity for an investment. The formula is shown below and consists of a risk-free rate, a beta value and a market risk premium [44].

$$R_E = R_f + \beta \cdot (R_m - R_f)$$

R_f - Risk-free rate

B - Beta

R_m - Expected market return

$(R_m - R_f)$ - Market risk premium

3.4.1 Risk-free rate

The risk-free rate is used as an alternative cost component in the CAPM, to compensate for the time value of money. It is the interest an investor would expect from a risk-free investment. In real life, it is impossible to find an investment that carries absolutely no risk, as everything carries some risk at a minimum. Government bonds that are unlikely to face default or bankruptcy are therefore often used when assessing the risk-free rate.

The US three-month treasury bill is often used as the risk-free rate, as it is seen to be at a very low risk of default. The treasury bill is backed by the US government and has a large liquidity. It is therefore seen as liable to use as a risk-free rate. For long-term investments, a bond like the US 10-year bond is often used. The advantage of using a long-term bond is more stability, which is beneficial when you are discounting future cash flows. The long-term bond also carries the risk of inflation and is therefore more suitable for long-term investments [45].

If the business or project operates with another currency than the US dollar which is used when trading US bonds, it may be beneficial to consider other bonds. An investor will incur a currency risk if it uses a risk-free rate with a different currency than the home market. This risk can be hedged at a cost, but if the business operates with a stable currency, it may be better to use a bond using that same currency [45].

3.4.2 Beta

To understand beta, it is important to distinguish between systematic and unsystematic risk.

Systematic risk, also referred to as market risk, is the general risk of being invested in a market, or within a specific segment of the market. The systematic risk is viewed as undiversifiable, as the systematic risk is expected to influence the whole market. These can be economic factors such as a rise in interest rates, recessions, and inflation, or other events such as wars and pandemics [46].

Unsystematic risk is a company-specific risk that is diversifiable. These can be events such as new competitors in the market gaining market share, bad financial reporting sending the share price down, new laws and regulations affecting the business, newer technology making the business' product less demanded, and so on. By diversifying a portfolio, it is possible to eliminate unsystematic risk. Diversifying means investing in several companies across multiple segments. An event that influences one company negatively may be positive for another and should overtime cancel each other out. This should over time make such events insignificant for the entirety of the portfolio [46].

The beta value is a numerical value that describes the volatility of investing in a specific project or company, relative to a market or index. If the systematic risk of the investment is the same as the market or index, theoretically the beta will be 1.0. If it carries less systematic risk than the market, the beta will be below 1, and similarly, if the investment involves a higher systematic risk than the market, the beta will be above 1. By using the beta parameter, the CAPM expects a greater return from higher beta investments. In other words, beta is the parameter that makes the CAPM great for risk-neutral investors. Risk-neutral investors want the highest risk-adjusted return on their investments [47].

The beta can be calculated as shown below, by dividing the covariance between the asset and the market, by the variance of the market [48].

$$\beta = \frac{Cov(R_e, R_m)}{Var(R_m)}$$

Another common way to estimate the beta, which is a bit more complex, is to calculate the beta by comparing it to other companies within the same industry. To do this, it is important to distinguish between the unlevered beta which assumes the company or project is fully financed through equity, and the levered beta which takes the financial structure into account. The steps are listed below.

1. Calculate or find the levered beta, also called equity beta, of all companies. It can for instance be calculated by the method shown above [49].

2. Calculate unlevered betas, with the levered betas as a starting point. This is done using the formula below [49]:

$$\beta_a = \frac{\beta_e}{\left[1 + (1 - tax) \cdot \left(\frac{debt}{equity}\right)\right]}$$

B_a - Asset beta/unlevered beta

B_e - Equity beta/levered beta

Tax - Corporate tax rate

3. Find the average of the unlevered betas calculated in step 2. Use that as the unlevered beta and find the levered beta of the company in question, using its own financial structure. It can be calculated using the formula below [49].

$$\beta_e = \beta_a \cdot \left[1 + (1 - tax) \cdot \left(\frac{debt}{equity}\right)\right]$$

3.4.3 Market risk premium

The market risk premium is the difference between the expected market return and the risk-free rate. The expected market return is the return an investor can expect by being invested in a market portfolio. The market risk premium represents the systematic risk an investor is exposed to by being invested in a specific market in comparison to being invested in a risk-free asset. Thus, the market risk premium will vary across different markets depending on the associated risk. For example, given all other factors being equal, a country with an unstable government would have a higher market risk premium than a country with a stable government. The market risk premium is assessed by looking at historical returns, as well as the required returns from investors and expected future returns [50].

There are two main ways the market risk premium is extracted.

- The first method is by performing queries. Investors and professionals give their opinion on what to expect for the market risk premium in the future. This method is expected to factor in market knowledge and give a realistic assessment of what the sum of investors expects the market to yield forwards. A disadvantage is that the people questioned might be biased towards historical returns [51].
- The second one is calculating the average historical return of a market. This does not consider any expectations regarding the current situation nor the future and is highly dependent on how far back historical data are extracted [51].

3.5 Cost of debt

The cost of debt is the interest rate a company pays on its loans and bonds. The interest rate is normally highly dependent on the rate of government bonds because of the loan structure. The loans and bonds have a floating interest rate, meaning the loan is constructed by a fixed rate representing the risk the lender takes on, and a floating rate representing the lending rate in the market [52].

There are different methods of finding the cost of debt of a company:

- Firstly, if available, it is possible to process each bond the company has issued. That method is straightforward if the fixed rate and the floating interest are stated in financial reports. If not, it is possible to find the credit rating of the company and use the market interest rate for a company with the same credit rating to get an estimate. This method revolves around the interest rate the company will pay depending on the interest rate in the market.

- Secondly, it is possible to find the interest expense paid by the company over a time period, for instance, the last year, and then divide it by the total debt of the company during that period. This will provide the historical interest rate and is not necessarily the correct way to describe the future interest rate. Elements such as credit rating, floating interest, and the financial state of the company are subtle to change. Therefore, the first method will provide a more realistic cost of debt expectation.

3.6 Tax shield

As the CAPM model shows, a tax shield comes into effect when using debt financing. The tax shield is equal to the interest rate of the debt multiplied by the corporate tax rate the company pays.

3.7 Declining balance method

The declining balance method is a way of depreciating investments. This method is commonly used for most projects in the UK, including offshore wind projects. In the UK, 18% of the remaining book value can be depreciated each year [53]. It is known as an accelerated depreciation method, due to more of the investments being depreciated in the early stage, with diminishing depreciation further out in the project [54].

3.8 Sensitivity analysis

Sensitivity analysis is used to analyze how a value change by varying its input variables. In a net present value analysis, a sensitivity analysis can be conducted to see how large of an impact an input variable may have on the final net present value. The sensitivity analysis can therefore be used to identify any weaknesses in the NPV model. For example, if the NPV switches from positive to negative due to a small change in net margin, there is large uncertainty connected to whether a project will be profitable or not depending on the assumption of net margin.

3.9 Scenario analysis

In a project it is possible to use scenario analysis to analyze different economic outcomes. In a sensitivity analysis, the effect of one variable is measured. In a scenario analysis, the effect of changing many variables at the same time can be measured. Often the scenarios are divided into a normal scenario, best-case scenario, and worst-case scenario. Identifying different scenarios may help to understand the uncertainty and risk associated with a project or business model.

3.10 Internal rate of return (IRR)

The internal rate of return is the discount rate of a company or project, such that the net present value equals zero. IRR can be used to assess the attractiveness of a project or business model, as it measures the yearly return. If the internal rate of return of a project is higher than the business` discount rate, the project will be viewed as profitable [55].

3.11 Payback period

The payback period is the length of time from the initial investment in a project is made, until it is repaid. This happens when the sum of cash flows received exceeds the initial investment. The payback period method can be useful if a business has a set time in which they expect to have recouped the initial investment. If the payback period is shorter than the maximal time period to recoup the investment, the project is seen as attractive.

This method favors cash flows early in the project, as cash flows after the payback period is not considered. Cash flows closer in time are often easier to estimate and involve less uncertainty than cash flows far ahead in time. Also, for businesses with low liquidity, it can be advantageous to recoup their initial investment early, so that the money can be used to invest in other projects. A disadvantage of using this method is the potential rejection of profitable projects with a long lifespan [56].

4. Macro situation

The offshore wind space is heavily influenced by the global macro situation. Low interest rates combined with high inflation are affecting the financial markets, making for lower rates of return on investments. A global pandemic has resulted in supply chain issues and lowered investments in energy production. The Russian invasion of Ukraine have led to sanctions towards Russia, causing a lot of uncertainty in European energy markets. What do all these events mean for the offshore wind segment?

4.1 The global financial situation

In the financial crisis beginning in 2008, national banks across the globe lowered the official interest rates. The federal reserve in the US, which is the largest global economy and governing for the rest of the global economy, lowered the federal funds rate toward zero in an attempt to aid the economy [57]. Since 2008 the federal funds rate in the US was held on a low level until 2016, when it was gradually increased upwards to 2,5%, see the figure below. During the Covid-19 pandemic the Federal reserve again lowered the rate to a close to zero rate. The UK official bank rate also plummeted during the financial crisis, and due to uncertainty regarding Brexit, remained low in the same period the US federal rate increased in 2016.

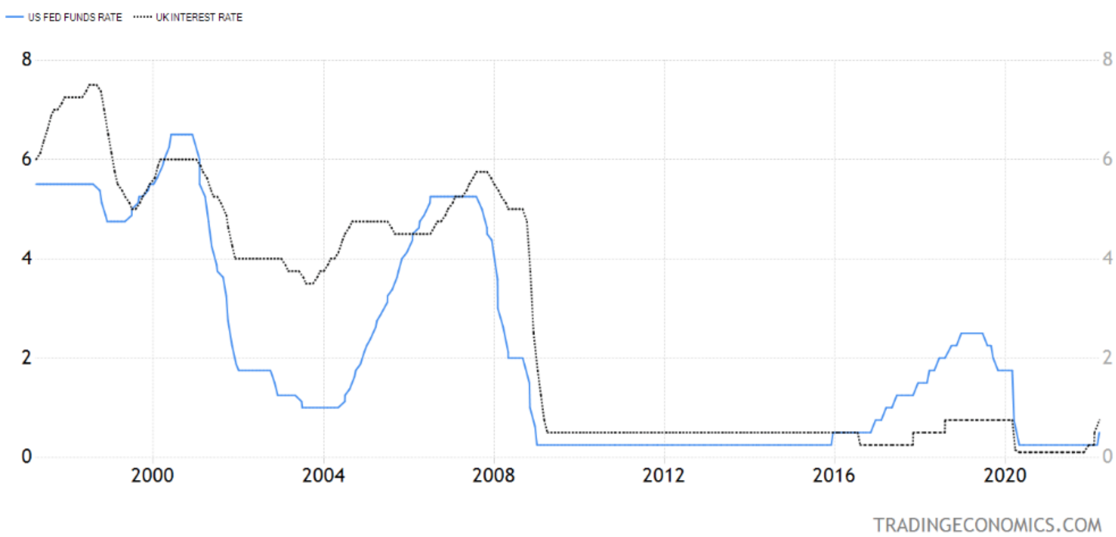

Figure 1: Historical US federal rate and UK official bank rate (as of March 2022) [57], [58].

While the global inflation targets are around 2%, the current inflation rate is much higher. At the beginning of 2022, the US inflation rate is closer to 8% [59] and the UK inflation rate at 6% [60], both rapidly increasing. The high inflation is mostly a consequence of the pandemic. Due to the sudden lapse in global demand of goods and services at the outbreak of the pandemic, businesses and governments had to take measures. Businesses had to let employees go and reduce production and investments. In a further effort to aid the economy, the US pumped a massive amount of money into the economy by buying bonds [61] and handing out stimulus checks to all adult Americans [62]. The total amount of US dollars has close to doubled between the beginning of 2020 and the entry to 2022 [63]. Also, other countries globally have increased the supply of their currency, contributing to boosting inflation.

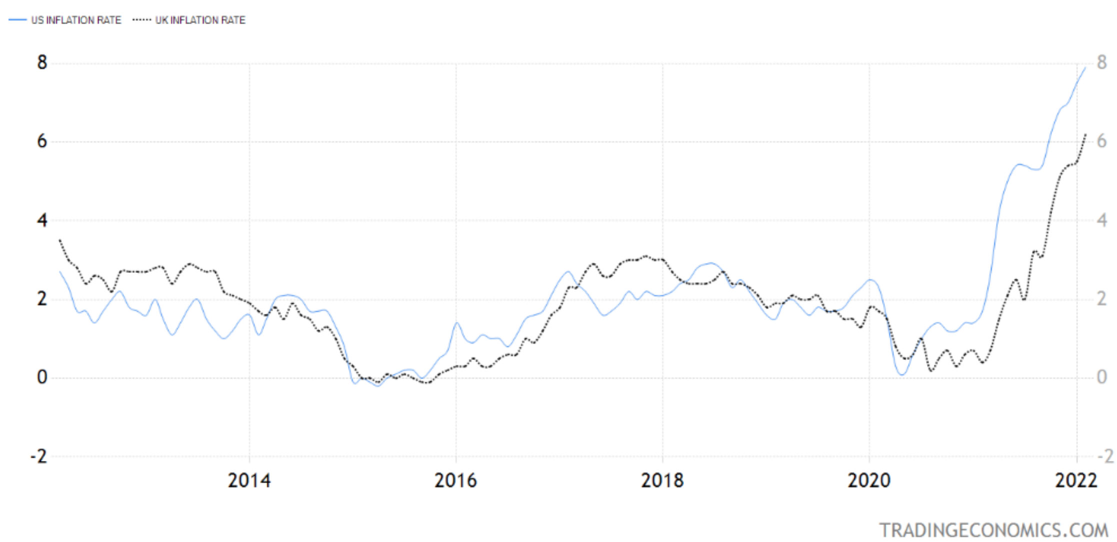

Figure 2: US and UK historical inflation (as of March 2022) [59], [60].

Because of the low economic activity during the pandemic, inflation has skyrocketed as the economic activity is increasing. Combined with businesses having to offer higher wages to compete for employees, resulting in higher costs and increased product prices. Consumers are willing to pay more for products and services as wages increase, and many have more money to spend due to low consumption during the pandemic.

Increasing interest rates is a tool government can use to deal with inflation. When the official bank rate in the UK or the federal funds rate in the US, which is the short-term borrowing rate banks can lend money at, increases, it becomes more expensive for businesses and consumers to take on and maintain loans. For businesses, an increased interest means a lower will to make investments. When businesses invest less, there is less demand for products and services. This means slowing down the demand, making prices come down. The same principle also applies to consumers, as more of their wages are bound up towards interest payments, and they have less money to spend on consumer goods. For central banks, increasing interest rates can be viewed as a tool to break economic growth, again reducing inflation [64].

Due to the current inflation situation, central banks across the globe have guided to increase the interest rates in the coming years. This will increase the cost of debt in projects, as the direct cost of lending money will increase. The cost of equity is also affected, as the risk-free rate is increased.

The alternative to making high-risk investments is becoming more attractive than in the current market. Today, inflation is higher than the interest rate, meaning money on savings accounts and in low-risk bonds is losing its value. Therefore, the only alternative over the last couple of years to maintain or increase the monetary value of capital has been to invest it in high-risk bonds, projects, and companies. If the interest is increased and inflation comes down to a normal level, investing in bonds will become more attractive. Due to the increased alternative cost obtained by not investing in low-risk bonds, the required rate of return when investing in projects and companies will increase.

The increased required rate of return will lower the present value of future cash flows. When using a discounted cash flow model, the net present value of an investment will decrease as the weighted average cost of capital input value is increased due to higher interest rates. For offshore wind projects, which often are considered a low-margin business with a lot of cash flows far in the future, an increased interest rate can mean tipping a project from profitable to unprofitable for investors.

When short-term interests are increased by governments, long-term bonds decrease in value. This is because investors now can buy new bonds with a higher yield. When long-term interests become lower than short-term interest, investors expect poor economic growth. Investors normally expect a risk premium to invest in long interests, because they are more volatile and have a larger risk of default due to the time aspect. The inverted interest curve has historically been a warning of stagflation. Characteristics of stagflation are low economic growth, combined with high unemployment rates and strong inflation [65]. Stagflation is a situation most governments want to avoid, which means breaking economic growth through increasing interests must be handled with care. The fear of stagflation may mean the interest rates won't be increased to pre-financial crisis levels, as governments may be careful with increasing short-term interest rates towards the long-term interest rates.

4.2 Low investments during the pandemic

In addition to affecting interest rates and inflation, Covid-19 had many other economic impacts. Due to the sudden removal of people's need for transportation and lower economic activity, global oil consumption fell drastically in a short time period. The oil price fell well below break-even rates for most companies, resulting in negative net cash flows. Because of the abrupt removal of cash flows combined with the uncertainty surrounding the duration of the pandemic, investments in oil and gas were cut massively. A report from Rystad states that investments in the petroleum industry were cut by 27% in 2020 and 2021 [66]. The oil industry is dependent on steady investments to maintain its production capacity. In addition, the current production was lowered. The lowering of production takes time, and simultaneously production cannot be reversed to pre-pandemic levels overnight.

As the economy is accelerating and people are starting to be more mobile, the global demand for energy are steadily returning to pre-pandemic levels. According to the IEA, the global oil demand is expected to be back to pre-pandemic levels during 2022 [67]. This has created a spread between supply and demand, making the oil price increase. The gas price, which is important for the European energy market, also follows this trend, and has had an even higher price spike than oil. With the fossil energy prices being that high, other energy sources such as wind and water generated electricity also rise in price as people look for alternatives, increasing the demand for renewable energy.

4.3 Geopolitics increase uncertainty in the European energy market

In the middle of an energy crisis partly caused by the pandemic, a war in Europe has commenced. The largest supplier of oil and gas to Europe, Russia, has invaded Ukraine. The western countries are among the countries to condemn the invasion and have issued massive sanctions on Russia. Most goods and services have stopped trading between Russia and western countries, but the heavy dependence on Russian oil and gas in Europe are per 24.03.22, forcing European countries to continue the import of these products. This has raised a debate in Europe, stating the problem of Europe's heavy dependence on Russian oil and gas. Politicians want to increase the production of energy in Europe, partly through the construction of more renewable energy production facilities [68]. Increased demand for alternative energy sources may lead to more government incentives toward investments in offshore wind.

Combined with the environmental focus in society to reduce and eventually remove fossil energy sources, the energy crisis may accelerate renewable energy production. A simple way for governments to increase investments is to either make it costlier to produce and sell fossil energy, leading to higher energy prices, or to make it more lucrative to produce renewable energy. At historical spot prices, excluding the recent price spike, industries such as offshore wind would not have been profitable. Without CfDs, offshore wind would probably not have been constructed commercially. The LCOE measure, which is the cost of produced energy, in offshore wind have been lowered yearly due to advancements in technology and increased scale [25]. Moving forward, the downwards LCOE trend might end due to increased material costs and high inflation. Still, the cost is higher than the spot price of electricity most people are used to. Therefore, the cost of offshore wind must be lowered, or the average market spot price of electricity must increase to make offshore wind commercially viable without subsidies/CfDs from governments.

In addition to energy prices rising, other commodities such as metals have risen in price. A lot of input components in offshore wind have seen a steep price increase in the last two years (leading up to March 2022), e.g., steel up ~40% [69], copper up ~100% [70], and aluminum up ~100 [71]. Material costs are significant in offshore wind constructions, thus price increases in metals and other components will have a remarkable effect on projects' capital expenditures.

4.4 Energy situation in Europe

In Europe, different sources make up the electricity generation. Coal, gas, nuclear, hydro, wind, and solar are the six largest electricity generating sources [72]. While nuclear power has a stable production over time, coal, gas, hydro, wind, and solar energy vary in production. Nuclear power takes a lot of time to start and stop, thus the production cannot be varied. In hydropower facilities, certain water levels need to be maintained, but production can be adjusted according to demand and the market price of electricity. Electricity generation by wind is uneven because of large varieties in operation time due to unstable wind conditions. Solar-generated electricity has a negative correlation to output from wind turbines in Europe. In the winter, wind turbines generate more electricity due to better wind conditions, while more solar energy is generated during the summer months due to larger solar radiation. Gas and coal electricity generation are easier to regulate according to demand.

Europe is guiding to increase electricity production from wind. An issue with onshore and offshore wind is unstable production. In periods with sufficient constant wind, a lot of electricity will be generated at the same time. When there is a lot of capacity on the supply side, the price of electricity will go down. This means that if the share of electricity production from wind is large in a region, owners of wind production facilities will receive a lower capture price for their delivered electricity. This is because they will deliver electricity to the grid in periods with large supply, because most of the wind farms will deliver simultaneously. This is referred to as cannibalism. On the other hand, when there is not sufficient wind for wind turbines to produce electricity, there will be a shortage of electricity in the market. In this situation, the supply side is limited, and prices will be higher. The lack of storability of wind energy will create a problem in the future as it creates uncertainty on how periods with low generation will be handled. Thermal power plants are currently used to contribute to this flexibility and will most likely have to do so in the coming years. Decommissioning of thermal power plants due to lifetime and regulation changes make this challenging, and it is likely to see a volatility increase as a result of this flexibility decrease [73]. There can also be a challenge to supply adequate electricity to meet the critical demand from industries and consumers in certain energy scenarios.

Solar electricity production, which is negatively correlated with wind electricity production, can be used to produce electricity when wind is lacking. An issue with using the combination of wind and solar power is that solar power is not optimal for all areas and is not necessarily optimal for the areas with wind conditions appropriate for wind farms. This could require long transportation distances for the generated electricity. Therefore, gas and coal are today the most viable options to be used to compensate for variation in wind production. Gas and coal powerplants can start and stop production in a short time period in comparison to alternatives like nuclear powerplants but are very expensive to keep in a "ready state". In addition, hydropower can be used to replace supply when wind conditions are poor. A problem with hydropower is its scaling limitations, as it requires suitable geographical areas. Most areas optimal for hydropower are already built out to a large degree, making it hard to increase capacity.

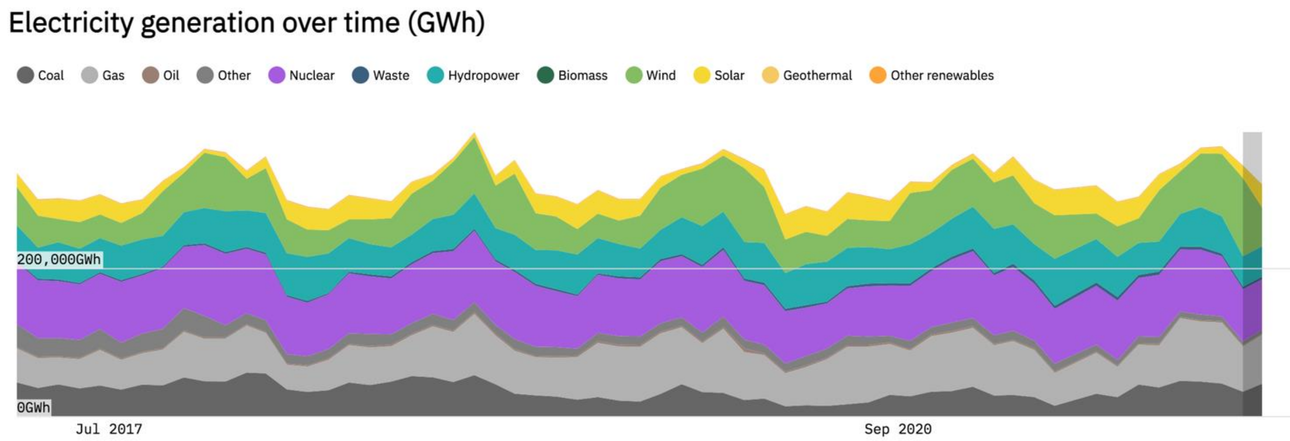

Figure 3: Electricity generation by source in the EU [72].

4.5 Energy situation in the UK

In the last 30 years from 1990, the UK have been through an extensive energy transformation. In 1990, coal was the main source for electricity generation, see the graph below. In 2020, coal constitutes a marginal share of the total electricity supply after being gradually replaced by gas. Since 2010, the share of gas generated electricity has been reduced due to the entry of wind and solar power, with wind being the largest contribution. Nuclear electricity supply has been at a constant rate the last 30 year. Due to a direction towards zero carbon emission, non-carbon electricity sources such as wind and nuclear are forecasted to make up more of the electricity generation in the UK moving forward [74]. While nuclear power can produce electricity at a constant rate regardless of external conditions, wind and solar is, as mentioned earlier, dependent on weather and climate conditions.

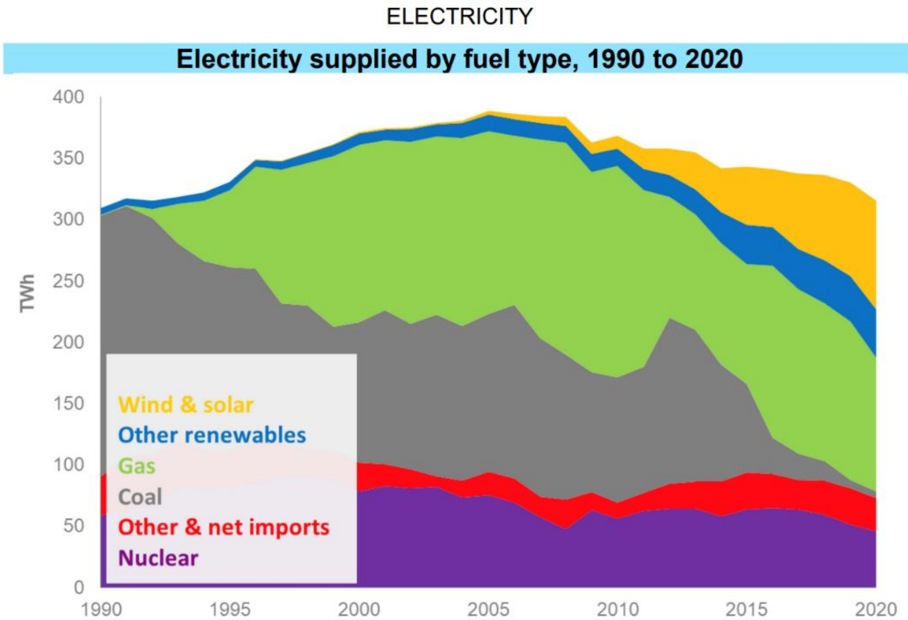

Figure 4: UK supply of electricity by source [75].

Without a proper way to store large amounts of electricity, the grid is dependent on a supply that always matches the demand from consumers and industries. High supply in relation to demand results in low prices, while a large demand followed with a limited supply give high prices of electricity. In the last quarters, electricity prices in the UK have been at a historically high rate, making consumers struggle to pay electricity bills, and electricity heavy industries to feel the increased energy cost in the accounts. The expensive electricity is a consequence of the increased price of gas in Europe due to the increased demand after the pandemic, combined with limitations on the supply side. The war in Ukraine has also affected the UK, which is a net importer of gas, causing an uncertainty towards the gas deliveries from Russia to Europe. Both uncertainty towards reliability of the deliveries and the ethical aspect of trading with a war aggressor.

Moving forward, UK wants to be more self-sufficient on energy, with offshore wind being a large investment area. In offshore wind leasing round 4, which is ongoing, 7 GW of new offshore wind projects are planned [76]. The UK has recently, in April 2022, updated their target for offshore wind capacity to 50 GW by 2030 [77]. This will increase the total share of wind power, making the electricity price in the UK heavily dependent on wind conditions. For owners of wind farms that operate in the spot price market, this can be catastrophic for profitability. In periods where they produce a lot of electricity, the electricity price in the UK will be lowered due to the large supply of electricity from wind farms, reducing the capture price for wind generators. In practice this means that electricity produced from wind farms will have a lower capture price than electricity generated from other sources.

5. Analyses

To better understand the development in the offshore wind space, three analyses of the DOW project will be made. Given the first discounted cash flow analysis is being made to assess the profitability of the Dudgeon project at the time of the investment decision back in 2014, a lot of the information and inputs in the DCF-analysis are historical. When making the updated analysis to compare the project outcome with the original assumptions, updated information and inputs will be used. For the updated DCF-analysis, the data in the years between the initiation of the project and 2020 will be replaced by data from the financial reports of DOW Limited. The third analysis will estimate profitability assuming a similar project were initiated in 2022, with parameters updated accordingly. Each of the three analyses will be thoroughly explained through separate parts. The procedure for calculating NPV is inspired by Osmundsen et al. [78].

6. Analysis 1: Economic analysis at investment decision in 2014

The investment decision of the DOW project was made in 2014, with project completion being in 2017. The wind farm consists of 67 6MW wind turbines, making the total capacity of the farm 402MW. Being one of the early offshore wind projects in the UK, DOW received a CfD strike price of £150 in 2012 money. In this analysis, estimations and assumptions are made based on historical sources that were available at the time. Where historical sources were not available, assumptions are made based on newer sources.

6.1 Revenue

Revenue streams must be separated by the revenue based on a CfD for the first fifteen years, and the years in the remaining life span of the wind farm. The revenue used in the calculations is derived from the capacity of the wind farm, the efficiency or capacity factor, and the price obtained from the electricity generated. The calculation for estimating the revenues for one year is shown in the equation below.

$$Revenue(£) = Capacity\,(MW) \cdot (24 \cdot 365)(Hours) \cdot Efficiency \cdot \mathrm{Pr}\,ice\left(\frac{£}{MWh}\right)$$

In the revenue equation, the capacity is multiplied by the number of hours in a year. This is to convert the capacity (MW) to megawatt-hours (MWh). Since the payment is based on MWh, the quantity of electricity produced must also be in MWh in the revenue calculation.

Since the price received per MWh of electricity produced is fixed, and the capacity of the wind farm is constant, efficiency is the most sensitive part of the calculation. The capacity factor estimate is therefore important for the final net present value (NPV) presented in this thesis.

6.2 Capacity and capacity factor

The capacity is calculated by multiplying the capacity of a turbine by the total number of turbines. The Dudgeon farm consists of 67 6MW turbines, giving the Dudgeon offshore wind farm an installed capacity of 402MW.

$$Capacity\colon 67(mills) \cdot 6MW(capacity\ per\ turbine) = 402MW$$

The capacity factor used in this analysis will be 0,483, with a sensitivity +/- 5%. This is based on the statement from Dudgeon that they will produce 1,7 GWh of electricity each year. The installed capacity is 3,52GWh. The calculation is shown below.

$$\frac{1{,}70\ GWh}{3{,}52\ GWh} = 0{,}483$$

6.3 Electricity price

The Dudgeon project was one of the first to be offered an investment contract on the 23rd of April 2014, receiving one of the first CfDs introduced through the EMR [79]. They were issued a strike price of £150/MWh for the first 15 years of production. The strike price is issued in 2012 money and will be adjusted for inflation when estimating future revenues.

The electricity price in the remaining years after the CfD expires is unknown and quite uncertain. There are many different factors to counter, and many potential scenarios. Since the cashflows made up of these prices are more than 15 years in the future, the sensitivity of the electricity price estimate is lower than if they were closer in time.

The European integrated electricity grid is likely to expand in the coming years. This will affect prices and volatility and needs to be considered when estimating future electricity prices. Estimations in this thesis will be based on prices in the British (UK) and both Danish markets (DK1 and DK2) from the last 3 years leading up to 2014. The Danish market has for a long time had a higher percentage of wind power in overall energy production and could be more representative of the future British market [72]. It can be discussed whether it is viable to base the electricity prices on a three-year period, however estimations based on a longer period would not change the estimate significantly as the prices during these years have been stable. Building on the Osmundsen et al. calculation where the future electricity price was equally based on UK and Danish prices [78], our estimate for the electricity spot price will be weighted 2/3 towards the Danish market.

The historical monthly market prices are gathered from the Office of Gas and Electricity Markets (Ofgem) and Nordpool. Both DK1 and DK2 market prices are converted at the appropriate conversion rate to GBP currency. @RISK version 7.6 and the time series analysis function is used to estimate the future market prices of electricity.

The analysis uses the given series of variables, in this case the average monthly market price from the 3 years prior to 2014, to estimate the pattern of these historic prices. @RISK can then use this information to forecast the future prices based on the pattern detected. When using this method, the program also needs some input from the user. Namely to define if the forecast is to start at the end or beginning of the historic values. In this case, as this is a forecast of future prices, the end value is chosen. As the historical prices are not stationary with a constant mean and standard deviation, the function "Auto Detect" is used to transform the series, as well as the function "Fit" to be able to find a suitable time series model. There are several different time series models, such as ARMA (autoregressive moving average), GBM (geometric Brownian motion) and ARCH (autoregressive conditional heteroscedasticity) to name a few [80]. The software can either use Akaike Information Criterion (AIC) or Bayesian Information Criterion (BIC) to identify the best fit. Both provide the same information, with nearly the same ranking of the different time series models.

The time series model ARMA is used when estimating the future electricity prices. The ARMA process is characterized by two integer values, p and q, where p is the number of autoregressive terms and q is the number of moving average terms. The common version which is used in @RISK is where p + q is less than or equal to 2 [80]. Given historical data, the ARMA model can understand and predict future values from the dataset. The projected time series calculations are done separately for the UK, DK1 and DK2 before averaging out the result to create an electricity price estimate 2/3 weighted towards the Danish market for reasons stated in a paragraph above. The time series model for the UK market can be seen in figure 5 below.

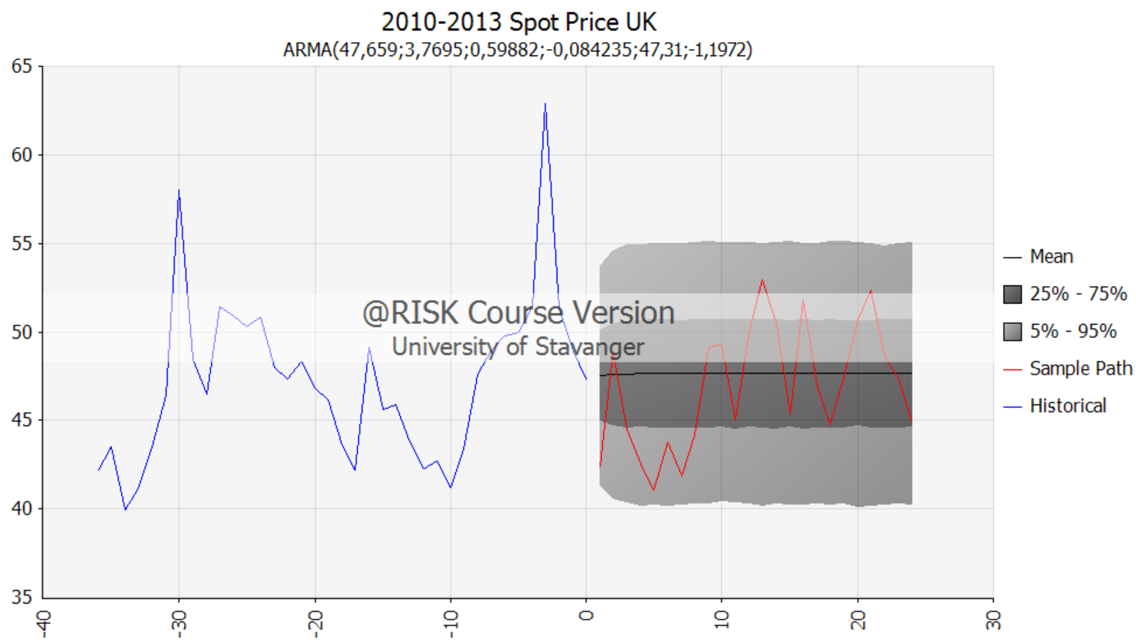

Figure 5: UK electricity spot price estimate based on historical data from 2010-2013

Simulating this result using Monte Carlo with 10 000 iterations gives a 90% confidence interval of the electricity prices in the UK market as displayed below.

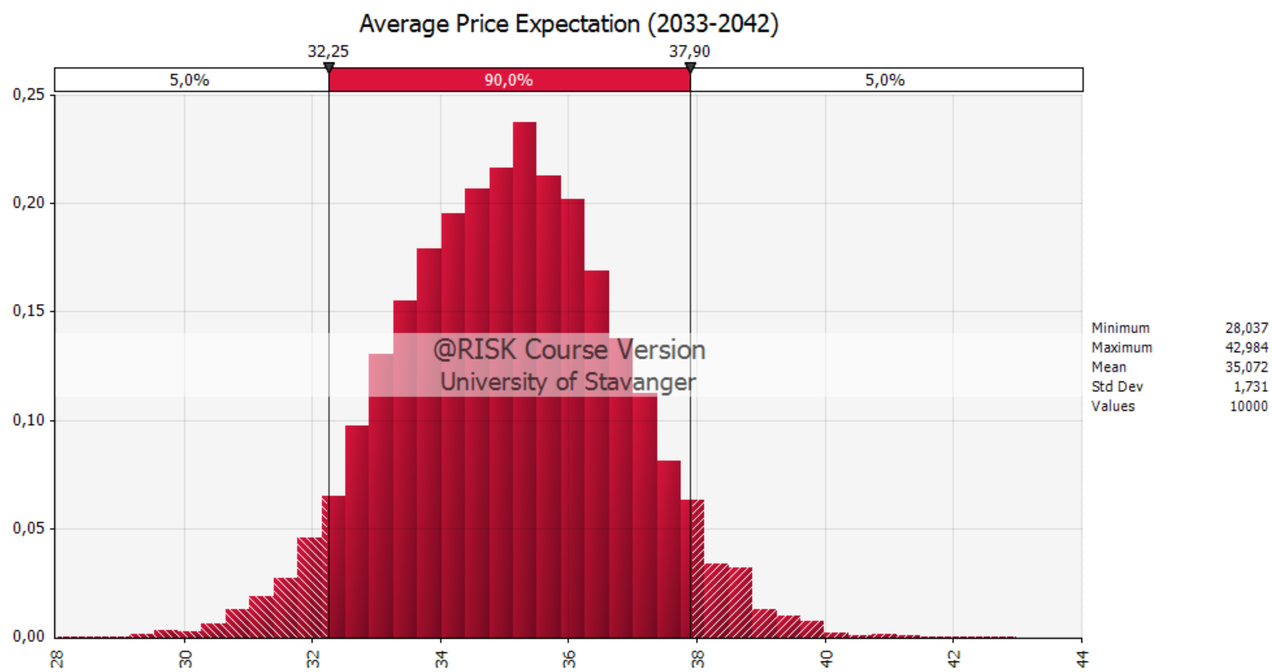

Figure 6: Simulated average electricity price expectation (2033-2042), based on historical data from 2010-2013

The future electricity price will according to the estimate end up in the interval of £32,3 and £37,9 per MWh. The estimate is based on the years 2010-2013. The mean spot price estimate of £35,1 will be used as the base in the NPV analysis, with a sensitivity +/- 25% due to uncertainty.

An important factor to consider is the capture price, which means that on average the wind farms will earn less than the average future electricity price. According to a journal by Blume-Werry et al. the capture price can be estimated around 0,7-0,9 of the average electricity price [81]. As a basis for our analysis, we have selected 0,8 as our capture price factor, with a sensitivity of +/- 10%. This means we assume the generator is paid 80% of the future average expected spot price.

6.4 Royalty

As mentioned earlier, the UK has a 1% royalty fee on gross wind revenue. This must be subtracted from revenue in the DCF-analysis. Therefore, the revenue the company will receive after royalty is described by the equation below. It is like the earlier revenue equation, but the royalty is accounted for.

$$Revenue(£) = \left(Capacity\ (MW) \cdot (24 \cdot 365)(Hours) \cdot Efficiency \cdot \mathrm{Pr}\,ice\left(\frac{£}{MWh}\right)\right) \cdot (1 - Royalty)$$

6.5 Transmission loss and tariffs

Due to the losses when transporting electricity, a transmission loss must be accounted for in the income streams. In the case of Dudgeon Offshore Wind farm (DOW), a 134 kV cable stretches around 39 km to the shore, and from shore connects to the National Grid via a 48 km long underground cable to the Necton substation. The distance between substations is conclusively around 87 km which is less than the 100-150 km, depending on cable quality [24]. This is the so-called cable “critical length” to avoid substantial transmission losses. DOW uses AC to transfer the power to shore. As far as calculations go, it is difficult to find the exact transmission loss without having all the data from the substations. Simplification is therefore needed, and we will assume a transmission loss of 5% which is in line with reports by the National Grid ESO, as well as publications by the UK Parliament [82], [83].

$$Revenue\ (£) = \left(Capacity\ (MW) \cdot (24 \cdot 365)(Hours) \cdot Efficiency \cdot \Pr ice \left(\frac{£}{MWh}\right)\right) \cdot (1 - Royalty)\ (1 - Transmission\ loss)$$

The transmission cost that Dudgeon is required to pay is based on three tariff components: substation, circuit, and ETUoS which reflect the cost of offshore networks connecting offshore generation [32]. Based on the analysis of similar offshore wind farms in the UK area, the report has estimated the transmission tariff for Dudgeon Wind Farm to be around £12.4/MWh [33]. This fee is included in the OPEX estimate.

6.6 *Operating expenses*

In addition to the investment cost of building an offshore wind farm, there are significant operating expenses. The operating costs are related to operations and maintenance, insurance, transmission charges, seabed rent, and more. Given the rough conditions offshore compared to onshore, offshore wind farms have higher maintenance costs than onshore wind. The operational cost is more difficult to estimate than the CAPEX, as it is a variable component depending on several factors.

There are a variety of estimates on how much of the LCOE is related to operational expenses. According to SINTEF, estimates from different studies of operations and maintenance costs in wind farms range from 22% to 40% [84]. A study performed by The Crown Estate 2012 shows that the total operational cost of a wind farm is in the range of £164-167k/MW [85].

The Crown Estate 2012 study was performed focusing on UK wind projects and suppliers, and therefore contains similarities with the DOW project. If this estimate is applied to the capacity of the Dudgeon offshore wind farm with a capacity of 402MW, the annual OPEX will be in the range of £65,9 – £67,1 million in 2012 prices. As the turbines in Dungeon offshore wind farm were installed in 2017 and may require less maintenance and repairs than the older wind turbines used in The Crown Estate 2012 study, we estimate the OPEX using the low range estimate of £65,9 million from The Crown Estate, with a sensitivity of +/- 20% due to uncertainty [85]. Even though there will be fluctuations in OPEX as the farm gets older and need for maintenance and repairs increases, this estimate will be used for all the operational years, only adjusted for inflation. A linear estimate is used due to the complexness of estimating OPEX, and the lack of studies found on the topic.

6.7 Capital expenditure

6.7.1 Initial investment

The total investment of building the Dudgeon offshore wind farm is stated to be £1,5B [86]. This is spread across different contracts with large companies within the offshore wind industry.

Due to confidentiality surrounding the payment structure of the contracts, the total sum of £1,5B will be assumed spread between the years of planning and construction in the NPV-analysis.

Table 6-1: CAPEX distribution over the construction period.

GBP (million)			
Year	2015	2016	2017
CAPEX	500	500	500

The investment can be broken down into categories such as turbine, tower and foundation, substations and cables, and project development and management. This is based on an HM Government Offshore Wind Industrial Strategy Report which emphasizes the average cost of each category and what percentages of the overall CAPEX these presents [87]. As the spending in each category is unknown, the percentages can be used to estimate:

Turbine:

- Rotor (14%) + Nacelle (20%) + Turbine installation (6%) = 40%

Tower & Foundation:

- Tower (5%) + Foundation (17%) + Foundation installation (11%) = 33%

Substations & Cables:

- Electrical infrastructure (11%) + Cables (7%) + Installation (6%) = 24%

Project Development & Management:

- Combined (3%)

Thus, the investment cost would be as follows, in 2014 terms.

Table 6-2: Distribution of investment costs by category.

Category	**CAPEX**	**2014**
Turbine	40%	600 000 000
Tower & Foundation	33%	495 000 000
Substations & Cables	24%	360 000 000
Project Development & Management	3%	45 000 000
Total		1 500 000 000

6.7.2 Decommissioning

After completion of the wind farm's lifetime, it must be decommissioned. As mentioned, this means removing all offshore components, excluding the assets transferred to OFTO. The decommissioning cost is faced a long time in the future and are sometimes neglected from the economics of an offshore wind farm. Removal of the wind farm can be quite expensive depending on water depth and weather conditions in the area. There is also uncertainty connected to an operation far ahead in time. Environmental requirements regarding the decommissioning may change, making decommissioning more costly. What counts in favor of viewing the decommissioning cost as insignificant is the decreasing value of an expense a long time in the future. Depending on the lifespan of the wind farm, the decommissioning cost will most likely be paid in 20-30 years. Due to the time value of money, the decommissioning will be heavily discounted in the NPV-analysis.

There are several different studies containing various estimates of the decommissioning cost. In a study by Douglas Westwood 2010, it is stated that decommissioning costs can be calculated as one year of revenue stream, however, this is significantly lower than other studies performed. Our estimate is based on a case study done by BVG Associates based on a 1GW wind farm [88].

Table 6-3:Calculated decommissioning cost based on BVG report [88].

Average estimate from BVG	**Cost**
Report based on 1GW farm (100 turbines)	
Turbine	45 000 000
Foundation	75 000 000
Cable (60km from shore)	140 000 000
Substation	65 000 000
Sum	325 000 000
Average estimate for Dudgeon based on BVG report	
Calculated for Dudgeon (402MW, 67 turbines)	
Turbine	30 150 000
Foundation	50 250 000
Cable (38km from shore, assumed 50/50 between export cable and internal cabling)	91 233 333
Substation	65 000 000
Sum	236 633 333
Inflation adjusted (expected lifespan)	380 609 868
Inflation adjusted (long lifespan)	428 628 530
Inflation adjusted (short lifespan)	351 624 685

To calculate the estimate for Dudgeon, the values are adjusted to represent the 402MW wind farm as opposed to the 1GW used in the case study. The turbine and foundation costs are calculated to represent 67 turbines, as opposed to the 100 turbines in the report. The cable costs are adjusted according to length, assuming a 50/50 split between export and internal cables. Substation costs will remain the same, as it is not affected by the size difference in this case. The decommissioning estimate for Dudgeon Offshore wind farm ends up at an estimated £380 million given the expected 10-year market price period.

6.7.3 Corporate income tax

At the time of making the investment decision for Dudgeon in mid-2014, the corporate income tax in the UK was at 21%. Previously the tax had been gradually lowered from 28% in 2010. It was also guided to be lowered further to 20% in mid-2015 [89]. When making the initial DCF, 20% will be used as the tax rate throughout the lifetime of the project.

6.7.4 Depreciation

There are no special tax regulations for offshore wind farms in the UK. The same rules apply for all industries. All companies either located in the UK or with operations in the UK are obligated to pay tax on their profits. Offshore wind farms are depreciated using the declining balance method [53]. 18% of P&M, plant and machinery, can be deducted each year. For simplicity we depreciate 18% of the remaining Capex of the project each year starting from 2018 which we have stated as the first production year. This method will be similar for all the DCF models in the thesis.

6.7.5 Inflation

The inflation rate in the UK has varied historically. In the 20 years leading up to 2015, the average inflation rate was 2,8%. This is significantly higher than Bank of England's inflation target of 2%. Given the complexity of assessing future inflation, the UK inflation target of 2% will be used exclusively in this thesis despite the current inflation situation [90].

6.8 WACC

6.8.1 Capital structure

The discount rate is calculated based on the equity and debt share of the project, and not the market value of these. This is because of DOW being a private project company organized as an SPV with multiple owners, making it more complex to find the market value of equity.

Given the different phases of the Dudgeon project, one discount rate would not be representative for the entire analysis. In the construction phase, the project is financed solely by equity, and the investments are going towards delivery of the wind farm. For the second phase, which is production with fixed electricity prices (CfD), capital will be borrowed to extract equity from the project. We will assume that the capital structure will stay the same through the entire production phase. The project capital expenses related to wind farms ex. transmission system, are normally financed with 70% debt, and the transmission system is financed with 90% debt [78]. Based on the earlier estimation, the cost of the transmission system is £360 million. The debt ratio for the entire project is therefore estimated to be 0% during the construction phase and 74,8% in the production phase. Based on the earlier estimation, the cost of the transmission system is £360 million. The debt ratio for the entire project is therefore estimated to be 0% during the construction phase and 74,8% in the production phase.

Table 6-4: Equity/debt ratio in different project stages.

	Construction phase 2015-2017	Production phase 2018-2042
Wind farm ex. transmission systen		
Equity ratio	100 %	30 %
Debt ratio	0 %	70 %
Wind farm transmission system		
Equity ratio	100 %	10 %
Debt ratio	0 %	90 %

6.8.2 Beta

According to Damodaran, the levered beta for the green & renewable energy sector in Europe is 0,87 [91]. The average E/(D+E) ratio of the sector, which is equity divided by the sum of debt and equity, is 67,48%. The unlevered beta for the industry becomes 0,61 when using the average industry tax rate of 12,31% extracted from [91]. Due to lack of beta values for the green and renewable sector in 2014, the industry beta from 2022 is used. When using the unlevered industry beta, the project levered beta for the Dudgeon project becomes 0,61 for the construction phase, and 2,20 for the production phase when levering the unlevered beta. In the period after the CfD expires, a risk premium of 0,3 is added to the beta due to the increased uncertainty surrounding the electricity spot price. The high beta is a consequence of the high debt ratio in the project.

6.8.3 Risk-free rate

UK 10y governmental bonds will be used as the risk-free rate in WACC calculations. In 2014 at investment decision for DOW, the 10y UK governmental bond was at approximately 2,7% [92]. Due to this being a peak in the rate at the moment, we used this rate for the construction phase and 2,5% as the risk-free rate after the 3-year construction phase.

6.8.4 Market risk premium

From Damodaran, the market risk premium in the UK was 5,17% by 01.01.2014 [93]. This will be the market risk premium in the CAPM model for the 2014 perspective.

6.8.5 Cost of equity

Due to the different phases of the project, three different costs of equity will be used. In the first phase, which is 100% equity financed, the cost of equity will be used as the discount rate. The cost of equity for this project is estimated to be 5,83% for the construction phase, 13,87% for the CfD fixed price period and 15,44% for the post CfD period. The significant difference between the cost of capital in the construction phase and the first production phase comes down to the large beta value associated with taking on a large amount of debt.

6.8.6 Cost of debt

The interest surrounding green and renewable projects has had an upwards trend for many years [35]. Governments, banks, and investors' willingness to invest in green companies and projects have increased simultaneously.

Banks want to increase their share of green loans, and therefore the interest rate in these projects has come down, as it is competition between banks and investors to secure these projects in their portfolio. In addition to increasing popularity surrounding the projects, governments have worked to make it more attractive to invest in green projects. Due to the low margin nature of offshore wind projects, the projects must be presented to investors as low risk. This is because a high discount factor would make most of the projects unprofitable. The introduction of CfDs has contributed to making the required rate of return of wind projects lower by reducing income risk. The interest rate in wind projects has decreased from LIBOR + 325 in 2011 to LIBOR + 150 in 2019, following a heavily downwards trend, see figure below. In 2014 when the investment decision was made for Dudgeon, the industry interest rate was at approximately LIBOR + 250 with a downward trend. Due to this trend, we see it as reasonable to expect a lower interest rate moving forward. The project had secured a 15-years CfD at £150 per MWh, which contributed to strengthening the investment case. Therefore, an interest rate of LIBOR + 200 basis point is used as the cost of debt estimation for the production phase.

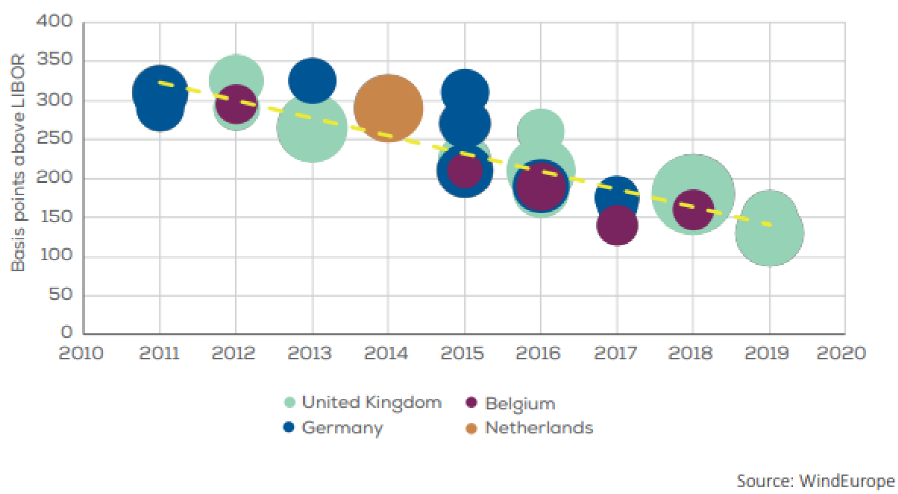

Figure 7: Interest risk premium development on wind energy loans [35].

The 3M LIBOR in July 2014 was at 0,24% [94]. Due to the long time period of the project, and a low historical LIBOR at the time, the LIBOR should on average be expected at a higher level. Loan financing was not to start until 4 years after the financial decision was made, therefore we estimate a LIBOR of 2% throughout the project. This estimate is significantly higher than what the interest rate was at the time, but still on the lower side looking at the historical rate.

6.8.7 WACC

By using the debt structure, cost of capital, cost of debt and tax rate accounted for earlier in the thesis, the WACC is calculated and shown in the table below. The WACC in the construction phase and the 15-year CfD period are similar. The second Modigliani Miller proposition, states that required return on equity is increasing accordingly as leverage increase, as a company runs a higher risk of bankruptcy [95]. Simultaneously, NPV, and thus required rate of return, should be the same independent of the capital structure [96]. The WACC in the spot price period is a bit higher because a risk premium is added to the beta making up the cost of equity. This is to compensate for uncertain income when the CfD ends.

Table 6-5: WACC calculations 2014

	Construction phase 2015-2017	CfD strike price 2018-2032	Spot electricity price 2033-2042
Financial structure			
Equity/(Debt+Equity)	100,00 %	25,20 %	25,20 %
Debt/(Debt+Equity)	0,00 %	74,80 %	74,80 %
Cost of equity	5,83 %	13,89 %	15,44 %
Cost of debt		4,00 %	3,70 %
Tax rate	20 %	20 %	20 %
WACC	5,83 %	5,89 %	6,11 %

7. Analysis 1: Results

Table 7-1: Results from perspective at investment decision 2014 (Million £).

DCF	Life expectancy		
	20 years	25 years	30 years
2015	-500,00	-500,00	-500,00
2016	-472,45	-472,45	-472,45
2017	-446,41	-446,41	-446,41
2018	163,63	163,63	163,63
2019	157,61	157,61	157,61
2020	151,40	151,40	151,40
2021	140,17	140,17	140,17
2022	130,64	130,64	130,64
2023	122,44	122,44	122,44
2024	115,31	115,31	115,31
2025	109,04	109,04	109,04
2026	103,46	103,46	103,46
2027	98,43	98,43	98,43
2028	93,87	93,87	93,87
2029	89,69	89,69	89,69
2030	85,82	85,82	85,82
2031	82,23	82,23	82,23
2032	78,86	78,86	78,86
2033	-12,07	-12,07	-12,07
2034	-11,60	-11,60	-11,60
2035	-11,15	-11,15	-11,15
2036	-10,72	-10,72	-10,72
2037	-10,31	-10,31	-10,31
2038	-89,88	-9,91	-9,91
2039		-9,53	-9,53
2040		-9,16	-9,16
2041		-8,80	-8,80
2042		-8,46	-8,46
2043		-72,33	-8,14
2044			-7,82
2045			-7,52
2046			-7,23
2047			-6,95
2048			-60,55

NPV	Life expectancy		
	20 years	25 years	30 years
2015	-500	-500	-500
2016	-972	-972	-972
2017	-1419	-1419	-1419
2018	-1255	-1255	-1255
2019	-1098	-1098	-1098
2020	-946	-946	-946
2021	-806	-806	-806
2022	-675	-675	-675
2023	-553	-553	-553
2024	-438	-438	-438
2025	-329	-329	-329
2026	-225	-225	-225
2027	-127	-127	-127
2028	-33	-33	-33
2029	57	57	57
2030	143	143	143
2031	225	225	225
2032	304	304	304
2033	292	292	292
2034	280	280	280
2035	269	269	269
2036	258	258	258
2037	248	248	248
2038	158	238	238
2039		228	228
2040		219	219
2041		210	210
2042		202	202
2043		130	194
2044			186
2045			179
2046			171
2047			164
2048			104

As shown in the table above, all three lifetime expectancy scenarios result in a positive net present value. Due to the removal of CfD strike prices in 2033, the discounted cash flows become negative. The low, medium, and high life expectancy gives an internal rate of return of respectively 7,50%, 7,30% and 7,09%. The project has the highest net present value and the highest IRR for the short life expectancy scenario of 20 years. From looking at the numbers, all cash flows after 2032 have a negative contribution greater than the beneficial effect of delaying payment of the decommissioning cost. Meaning from an economic perspective, the project should shut down after the 15-year CfD period rather than produce until the technological capabilities occurs.

7.1 Sensitivity of Internal Rate of Return

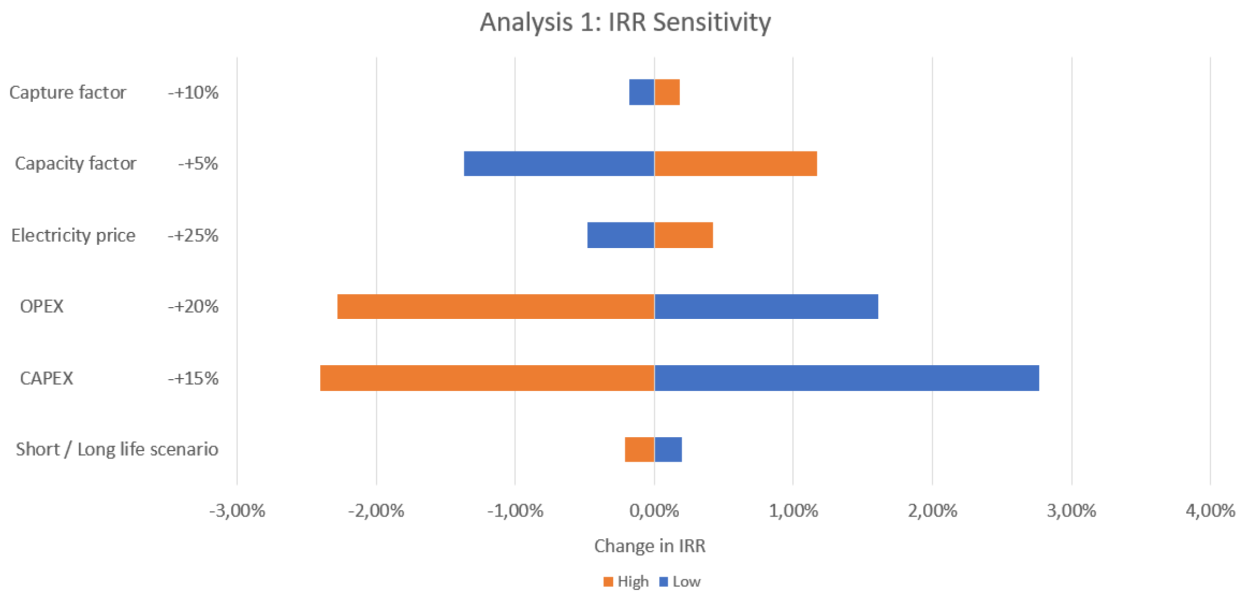

Figure 8: Sensitivity of internal rate of return, analysis 1.

In the tornado graph above, the sensitivity of different inputs in the analysis are displayed. The graph shows how different scenarios will affect the internal rate of return. In declining order are a 15% change in CAPEX, 20% change in OPEX and a 5% change in capacity factor the scenarios with the largest impact on profitability. The 25% change in electricity price and 10% change in captive factor are of less importance since they only come to play after the 15 years CfD expire. Changing the lifespan of the wind farm also has a small effect on profitability compared to changes in CAPEX, OPEX and capacity factor.

8. Analysis 2: Updated economic analysis performed in 2022

To study the projects development, the initial analysis of the profitability of DOW will be updated. The estimations and assumptions will be based on historical data from the first years of operation of DOW, as well as newer sources not available in 2014. By conduction this analysis we can first of all get a better picture of the project's profitability. In addition, we can study what input factors in the analysis have changed, to get an understanding of the historical development in the offshore wind space.

8.1 Revenue

The revenue is calculated using the same method as in analysis 1. The only difference is the projected electricity price that will be explained later in the chapter.

8.2 Capacity and capacity factor

The total capacity of the wind farm remains the same as in analysis 1. However, the capacity factor can be projected based on data from the three first full production years at Dudgeon and other similar wind farms from a study conducted by Lu et al. [97].

Table 8-1: Calculated capacity factor from accounting data.

GWh produced	1,58	1,584	1,728
GWh capacity	3,52152	3,52152	3,52152
Capacity factor	0,449	0,450	0,491

Based on the historical data, the capacity factors for the first three years end up being 0.449, 0.450 and 0.491 as the calculation above shows. Looking at data belonging to similar wind farms, such as Sheringham Shoal, which is located in the same area closer to the mainland, we can make an estimation of future capacity factors. An increase in the first years of production is expected and over time it is expected that the capacity factor will fall unless substantial maintenance is carried out [97]. The assumed capacity factor is based around 0,48 as calculated in analysis 1, with a sensitivity of +/- 5%. The estimations are shown below.

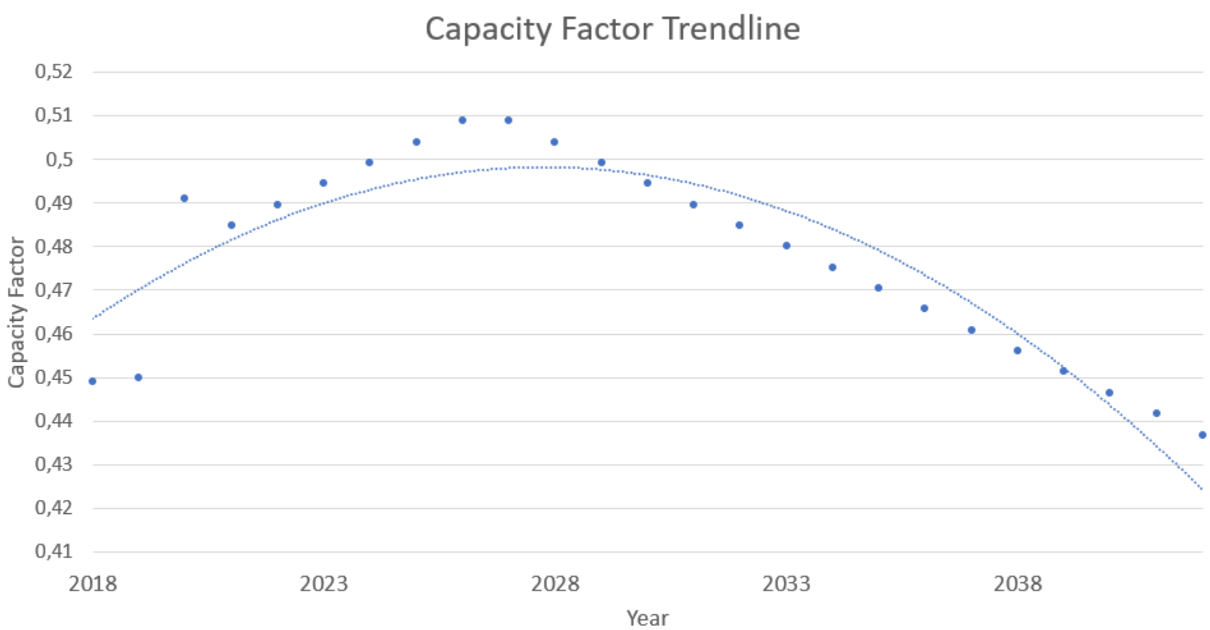

Figure 9: Capacity factor projection with trendline. The first three dots represent the actual capacity factors for DOW.

8.3 Electricity price

For the first 15 years of production the electricity price remains the same due to the fixed price contract with a strike price of £150/MWh in 2012 prices.

The electricity price in the remaining years after the CfD is, as mentioned in analysis 1, quite uncertain. Estimations can be done in several different ways, and projected prices can vary a lot. The European energy market is more connected than ever, and price fluctuations now affect a larger part of the market. With offshore and onshore wind becoming a greater part of the overall energy generation, it causes an increase in price volatility [73].

The electricity price estimates are calculated using the same method as in analysis 1, but now using updated data from the years 2019-21. It is unknown whether the current high electricity prices will continue, or if they will return to the price level seen historically. To compromise for this uncertainty, the three-year span includes two years of "normal" prices and one year of high prices.

This means that the current DCF incorporates the recent spike in energy prices. The time series for the UK market can be seen below.

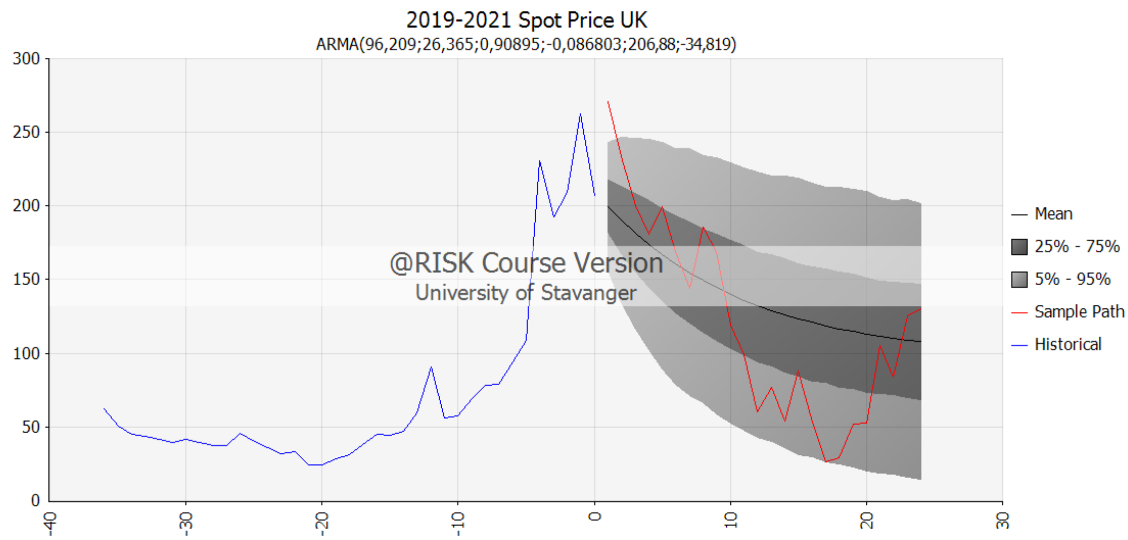

Figure 10: UK electricity spot price estimate based on historical data from 2019-2021.

Simulating using Monte Carlo with 10 000 iterations results in a 90% confidence interval of the forecasted electricity prices in the British market. The average expected price interval is shown below.

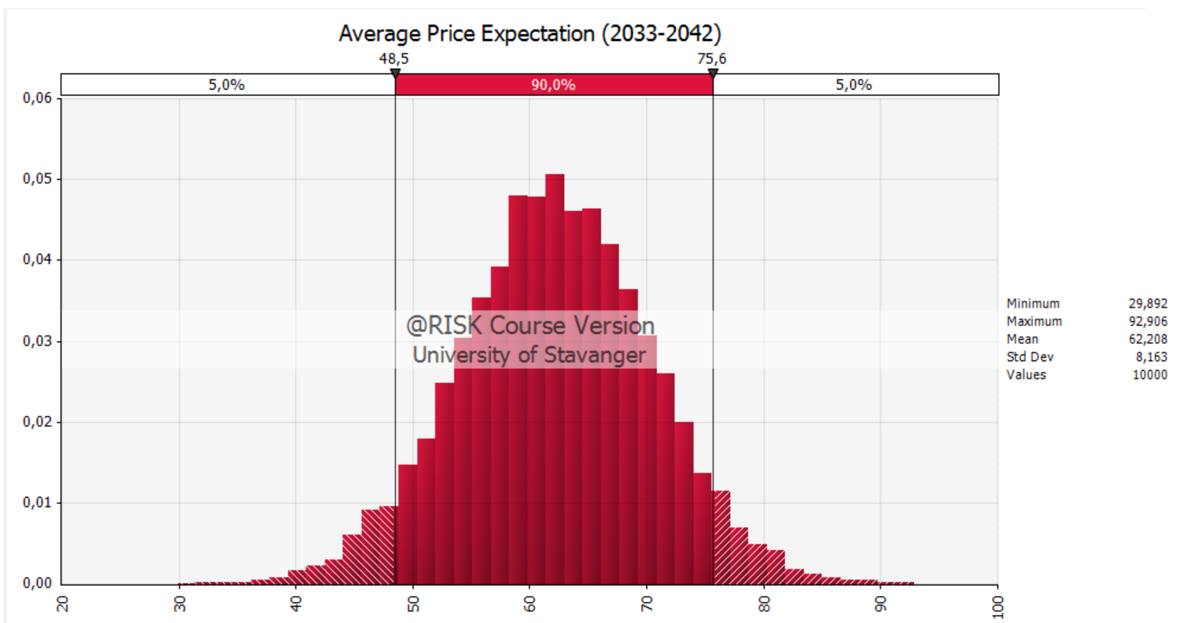

Figure 11: Simulated average electricity price expectation (2033-2042), based on historical data from 2019-2021.

The future electricity price will according to the estimate end up in the interval of £48,5 and £75,6 per MWh. To emphasize, this is a predicted average price and fluctuations in the future market may become severe. It is likely to see negative prices, but prices could also reach thousands per MWh [73]. The mean spot price estimate of £62,2 per MW will be used as a base in the NPV analysis, with a sensitivity of +/- 25% due to uncertainty. Like the estimation in analysis 1, a capture factor of 0,8 will be used, again with a sensitivity of +/- 10%.

8.4 Royalty

The royalty fee remains at 1% in 2022.

8.5 Transmission loss and tariffs

The transmission system remains the same, and therefore the transmission loss estimate of 5% will be used. The tariff also remains the same and is included in the OPEX estimate.

8.6 Operating expenses

The operating expenses for this DCF are based on the same study as the initial DCF and will therefore remain the same [85]. This is justified by the fact that the turbines are installed in 2017, and the technology used in the turbines is unchanged, regardless of the perspective of the profitability analysis.

8.7 Capital expenditure

8.7.1 Initial investment

The total investment of building the Dudgeon offshore wind farm was stated to be £1.5B. However, the CAPEX ended up at £1.25B upon completion [86]. Due to confidentiality surrounding the payment structure of the contracts, the CAPEX will also in this DCF be assumed spread evenly between the years of planning and construction in the NPV-analysis.

Table 8-2: CAPEX distribution over the construction period.

GBP (million)			
Year	2015	2016	2017
CAPEX	417	417	417

The investment can, in the same way as in analysis 1, be broken down into categories such as turbine, tower and foundation, substations and cables, and project development and management. Due to the uncertainty of where the savings commenced, the same distribution of CAPEX between categories is assumed. The new investment cost table is shown below to reflect the change in CAPEX.

Table 8-3: Distribution of investment costs by category.

Category	**CAPEX**	**2022**
Turbine	40%	500 000 000
Tower & Foundation	33%	412 500 000
Substations & Cables	24%	300 000 000
Project Development & Management	3%	37 500 000
Total		1 250 000 000

8.7.2 Decommissioning

The same decommissioning estimate will be used here as in analysis 1. It is a lot of uncertainty connected to the decommissioning cost, and therefore it is kept the same as it is difficult to make a better estimate. Thus, the decommissioning cost will still be £380 million given the expected 10-year market price period.

8.7.3 Corporate income tax

After being lowered from 28% in 2010, to 20% in 2015. The corporate income tax in the UK was lowered further to 19% in 2017. In 2023, this rate is expected to increase to 24%. Therefore, in the 2022 DCF, the corporate tax rate will vary as shown in the table below [98].

Table 8-4: Corporate income tax used in the analysis.

Year	Corporate income tax
2015 - 2016	20 %
2017 - 2022	19 %
2023 -	24 %

8.7.4 Depreciation

The declining balance method will be used in the same manner as in analysis 1, with 18% annual depreciation of remaining CAPEX [53].

8.7.5 Inflation

The inflation rate estimate will remain at 2 %.

8.8 WACC

8.8.1 Capital structure

The same financial structure for both construction and production phase will be used in this analysis as well. Also, in this calculation does the debt and equity share of the project make up the WACC, rather than the market value of these. With the assumption that the cost of transmission system is £300 million, the debt makes up 0% of the financing for the construction phase and 74,8% for the production phase.

Table 8-5: Equity/debt ratio in different project stages.

	Construction phase 2015-2017	Production phase 2018-2042
Wind farm ex. transmission systen		
Equity ratio	100 %	30 %
Debt ratio	0 %	70 %
Wind farm transmission system		
Equity ratio	100 %	10 %
Debt ratio	0 %	90 %

8.8.2 Beta

The same beta estimation is used in all analysis. From Damodaran, an unlevered beta of 0,61 is achieved [91]. When adjusting for debt financing in the production phase, the levered beta becomes 2,20. When production goes from CfD strike price to spot price, a premium of 0,3 is added to the beta to compensate for increased risk.

8.8.3 Risk-free rate

UK 10y governmental bonds is also used in this analysis as the risk-free rate in WACC calculations. Between 2015 and 2017, the risk-free rate was at approximately 1,30% [92]. Between 2018 and today, 2022, the risk-free rate has been at around 1,0% [92]. We have used a higher rate, 2,5%, from 2023 due to guiding on increased interest.

8.8.4 Market risk premium

From Damodaran, the market risk premium in the UK was 4,84% [99]. This will be the market risk premium used in the DCF.

8.8.5 *Cost of equity*

Due to the different phases of the project and different tax rates, five different values for cost of equity will be used in the DCF model. The cost of equity for this project is estimated to 4,26% for the construction phase, 11,66% and 13,16% for the CfD fixed price period and 14,62% for the post CfD period. The changes in cost of equity in the production phase are due to different beta values and risk-free rates.

8.8.6 *Cost of debt*

In the later years, the debt risk premium rates for offshore wind have continued to fall. A lower risk premium will be added when calculating interest rate to be used in the cost of debt calculations. We will assume the interest rate to be 100 basis points above LIBOR from 2023. Between 2018 and the beginning of 2022, LIBOR has been at around 1,5% on average [94]. Moving forward, interest guiding is projecting increased interests as discussed earlier in the thesis. We are using an average LIBOR of 2,5% from 2023 to decommissioning of the farm.

8.8.7 *WACC*

By using the debt structure, cost of capital, cost of debt and tax rate accounted for earlier in the thesis, the WACC is calculated. Unlike the WACC values in the first analysis, they vary more in this analysis due to different interest levels for different time periods.

Table 8-6: WACC calculations 2022 perspective.

	Construction phase 2015-2016	Construction phase 2017	CfD strike price 2018-2022	CfD strike price 2023-2032	Spot electricity price 2033-2042
Financial structure					
Equity/(Debt+Equity)	100,00 %	100,00 %	25,20 %	25,20 %	25,20 %
Debt/(Debt+Equity)	0,00 %	0,00 %	74,80 %	74,80 %	74,80 %
Cost of equity	4,26 %	4,26 %	11,66 %	13,16 %	14,62 %
Cost of debt			3,00 %	3,50 %	3,50 %
Tax rate	20 %	19 %	19 %	24 %	24 %
WACC	4,26 %	4,26 %	4,76 %	5,31 %	5,67 %

9. Analysis 2: Results

Table 9-1: Results from updated analysis (Million £).

DCF	Life expectency			NPV	Life expectency		
	20 years	25 years	30 years		20 years	25 years	30 years
2015	-416,67	-416,67	-416,67	2015	-417	-417	-417
2016	-399,64	-399,64	-399,64	2016	-816	-816	-816
2017	-325,02	-325,02	-325,02	2017	-1141	-1141	-1141
2018	148,42	148,42	148,42	2018	-993	-993	-993
2019	141,05	141,05	141,05	2019	-852	-852	-852
2020	163,85	163,85	163,85	2020	-688	-688	-688
2021	150,61	150,61	150,61	2021	-537	-537	-537
2022	144,05	144,05	144,05	2022	-393	-393	-393
2023	128,96	128,96	128,96	2023	-264	-264	-264
2024	123,18	123,18	123,18	2024	-141	-141	-141
2025	118,25	118,25	118,25	2025	-23	-23	-23
2026	113,96	113,96	113,96	2026	91	91	91
2027	108,89	108,89	108,89	2027	200	200	200
2028	103,03	103,03	103,03	2028	303	303	303
2029	97,66	97,66	97,66	2029	401	401	401
2030	92,70	92,70	92,70	2030	493	493	493
2031	88,08	88,08	88,08	2031	581	581	581
2032	83,77	83,77	83,77	2032	665	665	665
2033	-0,58	-0,58	-0,58	2033	665	665	665
2034	-0,91	-0,91	-0,91	2034	664	664	664
2035	-1,22	-1,22	-1,22	2035	662	662	662
2036	-1,50	-1,50	-1,50	2036	661	661	661
2037	-1,76	-1,76	-1,76	2037	659	659	659
2038	-98,90	-2,01	-2,01	2038	560	657	657
2039		-2,23	-2,23	2039		655	655
2040		-2,44	-2,44	2040		652	652
2041		-2,63	-2,63	2041		650	650
2042		-2,80	-2,80	2042		647	647
2043		-81,25	-2,96	2043		566	644
2044			-3,11	2044			641
2045			-3,24	2045			638
2046			-3,35	2046			634
2047			-3,46	2047			631
2048			-69,45	2048			561

The results from the analysis with updated 2022 estimates shows a positive NPV for all three lifetime scenarios. The project reaches break-even at the very beginning of 2026, and have an IRR for the low, expected, and high lifetime scenario at 11,22%, 11,33% and 11,38% respectively. Much due to an increased electricity price estimate, most of the negative cash flows after 2032 has changed from negative in the 2014 analysis, to more neutral in the updated analysis in the years after the 15 years CfD period. The effect of having a net cash flow around break-even levels, is that the decommissioning cost can be transferred further away in time, lowering the net present value of that expense. Due to this effect, the 30-year life expectancy scenario has the highest IRR. What happens though, is due to the negative cash flows towards the end of the project, NPV is slightly higher for the expected lifetime scenario, even though the IRR is marginally higher for the long lifespan scenario.

9.1 Sensitivity of Internal Rate of Return

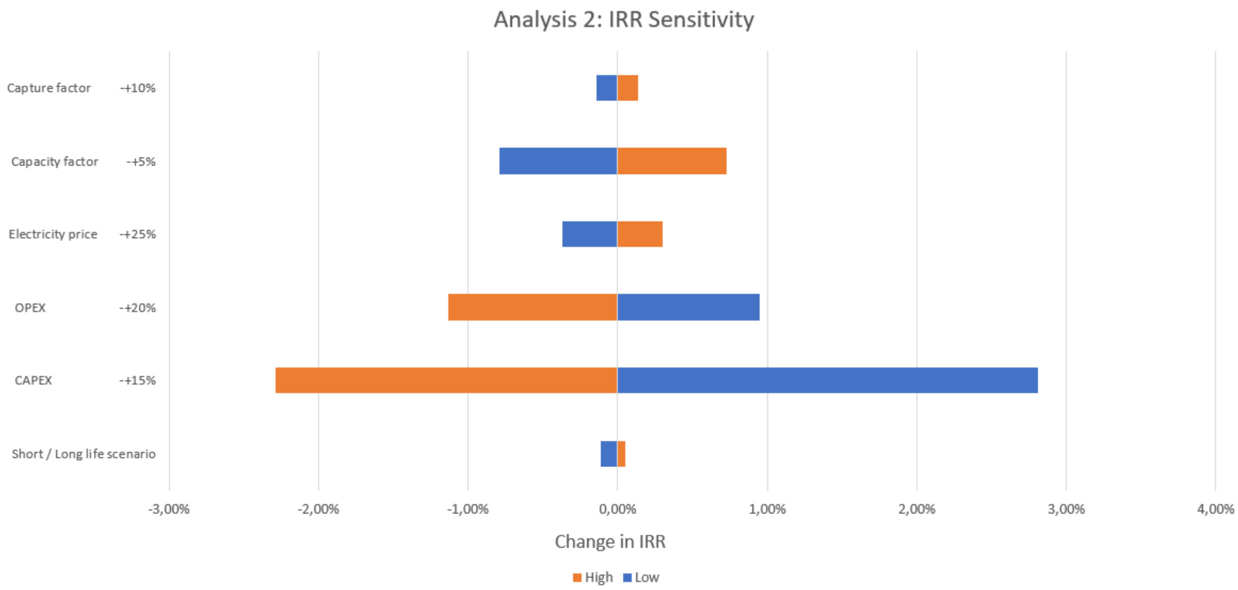

Figure 12: Sensitivity of internal rate of return, analysis 2.

Also in this analysis, a scenario of 15% change in CAPEX show the biggest change in IRR. In this instance though, CAPEX is already known to be £1,25 billion, meaning a 20% change in OPEX and a 5% change in capacity factor is the inputs that potentially can impact IRR the most. Electricity price and capture factor is like in analysis 1 of less significance, and the lifespan of the wind farm is of small importance for IRR.

10. Analysis 3: Constructing a similar hypothetical project from 2022

Since the DOW project was initiated, CfD strike prices have dropped drastically. The strike price issued in round 4 in 2021 is about 1/3 of the price provided to DOW initially. With the prerequisites in the first analyses, the project would be unprofitable if 2/3 of the income was removed in the first 15 production years. Today, newer technologies and advancement can help to bring costs down. Moving forward, 14 MW wind turbines are starting to be commercialized, meaning DOW could reach the same capacity using 29 14MW turbines as they did with 67 6MW turbines. In this part we will analyze the economics of a hypothetical project similar to DOW, with assumed construction start in 2022.

10.1 Revenue

The revenue is calculated using the same method as in the previous analyses.

10.2 Capacity and capacity factor

The total capacity of the wind farm with 29 14MW turbines is 406MW, which is similar to the 402MW used in the earlier analyses. However, the slight increase in capacity increases the theoretical annual production with 35000MWh.

$$Capacity\colon\ 29(mills)\ \cdot\ 14MW(capacity\ per\ turbine)\ =\ 406MW$$

Due to development in technology on the supplier side, we assume the new wind turbines to have a significantly higher capacity factor. The assumptions are based on numbers from suppliers but have been slightly adjusted. The base capacity factor is assumed to be 0,58, with a sensitivity of +/- 5%, as opposed to the 0,60-0,64 stated by GE [6]. Whether the capacity factor of a wind farm with these turbines will reach the stated numbers remain to be seen as they have yet to be constructed commercially.

Using the same assumption as in analysis 2 based on the study by Lu et al. it is expected that the capacity factor increases in the first years of production, before it eventually reaches a high point [97]. Over time the capacity factor will fall unless substantial maintenance is carried out.

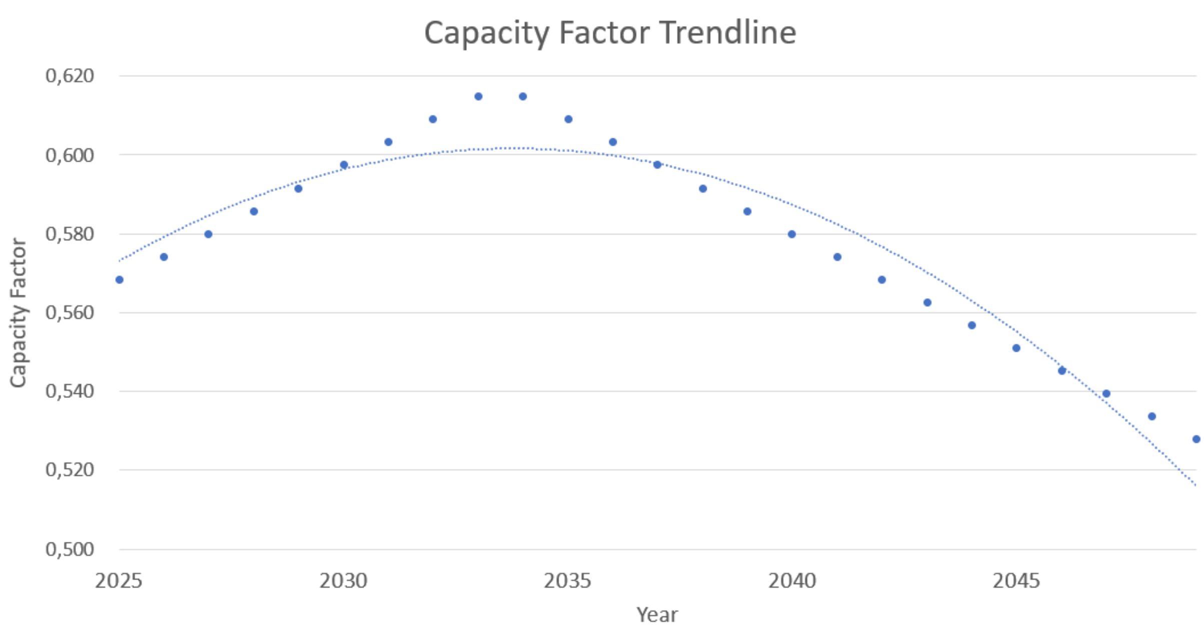

Figure 13: Capacity factor projection with trendline.

10.3 Electricity price

For the first 15 years of production the electricity price remains fixed due to a CfD with an assumed strike price of £46/MWh in 2012 prices [100].

The electricity price estimates are calculated using the same method as in analysis 2, as the calculations are based on the same base year. This means that the average spot price estimate of £62,2/MWh is used in the NPV analysis, with the same sensitivity of +/- 20%. The capture factor of 0,8 will also be used in this analysis. Depending on the extent of expansion in offshore wind the capture factor is likely to decrease. Like in the other analyses, a sensitivity of +/- 10% is measured to study the effects of a change in capture factor.

10.4 Royalty

The royalty fee remains the same at 1%.

10.5 Transmission loss and tariffs

Due to the complexity and required information needed to calculate the exact transmissions loss, the same estimate of 5% will be used. The tariff for renting the transmission facility after it being sold are also in this analysis included in the OPEX estimate.

10.6 Operating expenses

The operating expense is based on a BVG Associate study from 2019 [88], which estimated the overall OPEX to £75 million for a 1GW offshore wind farm. As the farm in this analysis is about half the capacity, we approximate the OPEX to be around £40 million, with a sensitivity of +/- 20%. Some of the OPEX are present regardless of the number of turbines. Therefore, the estimate is not solely approximated based on the difference in MW from the report, but adjusted upwards to compensate for some of the fixed costs unrelated to capacity. Like the previous analyses, the OPEX is assumed flat only adjusted for inflation, as there still seem to be little studies on variations in OPEX at different life stages of a wind farm.

10.7 Capital expenditure

10.7.1 Initial investment

The total investment cost of building an offshore wind farm like Dudgeon is unknown and needs to be estimated. The calculation is based on the farm having 29 14MW turbines, as shown in table 10-1 below.

Tabell 10-1: Calculated investment costs based on BVG and Rystad reports (estimated in £) [88], [101]

	Cost per turbine	Total cost
Wind turbine incl. tower	11 000 000	319 000 000
Foundation	2 800 000	81 200 000
Onshore substation		30 000 000
Offshore substation		120 000 000
Operations base		3 000 000
Export cable		130 000 000
Array cabling	350 000	10 150 000
Cable protection	20 000	580 000
Installation and commissioning	6 500 000	188 500 000
Sum		882 430 000
Inflation adjusted		936 441 775

According to statements from Rystad Energy, a 14MW turbine is estimated to cost around £11 million [101], while the rest of the costs are based on a BVG Associate study from 2019 [88]. Some of the costs are related to the number of turbines, while others are unchanged regardless of the size difference from the 1GW farm the BVG report is based on. Wind turbines incl. tower, foundations, array cabling, cable protection and installation and commissioning are all costs related to the number of turbines constructed. Onshore and offshore substations, operations base and the export cable are needed regardless of the size. In reality, you could need more substations or export cables, but in this case where we are downsizing compared to the report, we assume the costs to stay the same. The estimated total investment cost ends up at £936 million in 2022 prices. Due to the high uncertainty, we round up to £950 million and consider a sensitivity of +/- 15%. The cost is distributed equally over the three assumed construction years as shown below.

Table 10-2: The assumed CAPEX distribution over the construction period.

GBP (million)			
Year	2022	2023	2024
CAPEX	317	317	317

10.7.2 Decommissioning

The decommissioning estimate is based on the same study as before but calculated to accommodate the big reduction in turbines [88].

Table 10-3: Calculated decommissioning cost based on BVG report (estimated in £) [88]

Average estimate from BVG	**Cost**
Report based on 1GW farm (100 turbines)	
Turbine	45 000 000
Foundation	75 000 000
Cable (60km from shore)	140 000 000
Substation	65 000 000
Sum	325 000 000
Theoretical farm average based on BVG	
Calculated for theoretical farm (406MW, 29 turbines)	
Turbine	13 050 000
Foundation	21 750 000
Cable (38km from shore, assumed 50/50 between export cable and internal cabling)	64 633 333
Substation	65 000 000
Sum	164 433 333
Inflation adjusted (expected lifespan)	309 881 291
Inflation adjusted (long lifespan)	342 133 985
Inflation adjusted (short lifespan)	280 669 033

The turbine and foundation costs are now calculated to represent 29 turbines. The cable length is similar to previous analyses, but now internal cabling will cost less. Substation costs will again remain the same. As a result, the decommissioning cost will be £310 million given the expected 10-year market price period. However, due to the time value of money, this cost will be heavily discounted in the NPV analysis.

10.7.3 Corporate income tax

The corporate income tax in the UK was lowered to 19% in 2017. In 2023, this rate is expected to increase to 24% [98]. Therefore, the corporate tax rate will vary as shown in the table below.

Table 10-4: Corporate income tax used in the analysis.

Year	Corporate income tax
2022	19 %
2023 -	24 %

10.7.4 Depreciation

The declining balance method will be used in the same manner as in the first two analyses, with 18% annual depreciation of remaining CAPEX [53].

10.7.5 Inflation

Even though, as mentioned earlier in the thesis, the UK inflation rate is higher in mid-2022, the inflation rate estimate will remain at 2% [90].

10.8 WACC

10.8.1 Capital structure

The same financial structure is used for both construction and production phase. With the assumption that the cost of transmission is the same percentage as in the previous analysis, the debt makes up 0% of the financing for the construction phase and 74,8% for the production phase.

Table 10-5: Equity/debt ratio in different project stages.

	Construction phase 2015-2017	Production phase 2018-2042
Wind farm ex. transmission systen		
Equity ratio	100 %	30 %
Debt ratio	0 %	70 %
Wind farm transmission system		
Equity ratio	100 %	10 %
Debt ratio	0 %	90 %

10.8.2 Beta

The same beta estimation is also used in this analysis. From Damodaran, an unlevered beta of 0,61 is achieved [91]. When adjusting for debt financing in the production phase, the levered beta becomes 2,20. When production goes from CfD strike price to spot price, a premium of 0,3 is added to the beta to incorporate increased risk.

10.8.3 Risk-free rate

UK 10y governmental bonds is used as the risk-free rate. Between 2018 and today, 2022, the risk-free rate has been at around 1,0% [92]. However, we have used a higher rate of 2,5% through the entire project lifetime due to guiding on increased interest.

10.8.4 Market risk premium

From Damodaran, the current market risk premium in the UK is 4,84% [99]. This will be the market risk premium used in the analysis.

10.8.5 Cost of equity

Three different costs of equity will be used for this DCF model. The cost of equity for this project are estimated to 5,46% for the construction phase, 13,16% for the CfD period and 14,62% for the spot price period. The changes in cost of equity in production are due to different beta values.

10.8.6 Cost of debt

In the later years the risk premium rates for debt in offshore wind have continued to fall. We will assume the interest rate to be 100 basis points above LIBOR from 2025.

Between 2018 and the beginning of 2022, LIBOR has been at around 1,5% on average [94]. Moving forward, interest guiding is projecting increased interests as discussed earlier in the thesis. We are using a LIBOR of 2,5% from 2025 to decommissioning of the farm.

10.8.7 WACC

By using the debt structure, cost of capital, cost of debt and tax rate accounted for earlier in the thesis, the WACC is calculated as shown below. Like analysis 1, the WACC values are more similar to each other, due to the use of the same interest rate estimate throughout the analysis.

Table 10-6: WACC calculations 2022 perspective.

	Construction phase 2022	Construction phase 2023-2024	CfD strike price 2025-2039	Spot electricity price 2040-2050
Financial structure				
Equity/(Debt+Equity)	100,00 %	100,00 %	25,20 %	25,20 %
Debt/(Debt+Equity)	0,00 %	0,00 %	74,80 %	74,80 %
Cost of equity	5,46 %	5,46 %	13,16 %	14,62 %
Cost of debt			3,50 %	3,50 %
Tax rate	19 %	24 %	24 %	24 %
WACC	5,46 %	5,46 %	5,31 %	5,67 %

11. Analysis 3: Results

Tabell 11-1: Results, constructing new project in 2022

DCF	Life expectency			NPV	Life expectency		
	20 years	25 years	30 years		20 years	25 years	30 years
2022	-316,67	-316,67	-316,67	2022	-317	-317	-317
2023	-303,73	-303,73	-303,73	2023	-620	-620	-620
2024	-291,32	-291,32	-291,32	2024	-912	-912	-912
2025	64,41	64,41	64,41	2025	-847	-847	-847
2026	63,74	63,74	63,74	2026	-784	-784	-784
2027	63,07	63,07	63,07	2027	-720	-720	-720
2028	62,38	62,38	62,38	2028	-658	-658	-658
2029	61,69	61,69	61,69	2029	-596	-596	-596
2030	58,49	58,49	58,49	2030	-538	-538	-538
2031	57,51	57,51	57,51	2031	-480	-480	-480
2032	54,90	54,90	54,90	2032	-426	-426	-426
2033	51,52	51,52	51,52	2033	-374	-374	-374
2034	48,14	48,14	48,14	2034	-326	-326	-326
2035	44,68	44,68	44,68	2035	-281	-281	-281
2036	41,65	41,65	41,65	2036	-240	-240	-240
2037	38,97	38,97	38,97	2037	-201	-201	-201
2038	36,57	36,57	36,57	2038	-164	-164	-164
2039	34,42	34,42	34,42	2039	-130	-130	-130
2040	25,31	25,31	25,31	2040	-104	-104	-104
2041	23,75	23,75	23,75	2041	-81	-81	-81
2042	22,32	22,32	22,32	2042	-58	-58	-58
2043	21,00	21,00	21,00	2043	-37	-37	-37
2044	19,78	19,78	19,78	2044	-17	-17	-17
2045	-78,94	18,65	18,65	2045	-96	1	1
2046		17,59	17,59	2046		19	19
2047		16,60	16,60	2047		35	35
2048		15,67	15,67	2048		51	51
2049		14,79	14,79	2049		66	66
2050		-66,15	13,96	2050		0	80
2051			13,17	2051			93
2052			12,43	2052			105
2053			11,72	2053			117
2054			11,06	2054			128
2055			-55,44	2055			73

In the third analysis, all the discounted cash flows from operating years are positive. This is mostly due to a lower OPEX estimate than what are expected for the turbines constructed in 2017. Even though the cash flows after from the years of operating in the spot market are stronger in this analysis, the effect of lower CfD strike price reduce the cash flows in the first 15 years of operation drastically. This results in a negative NPV for the low lifetime scenario, an NPV of zero for the expected lifetime scenario, and a positive NPV only for the long lifetime scenario, with 30 years of operation.

11.1 Sensitivity of Internal Rate of Return

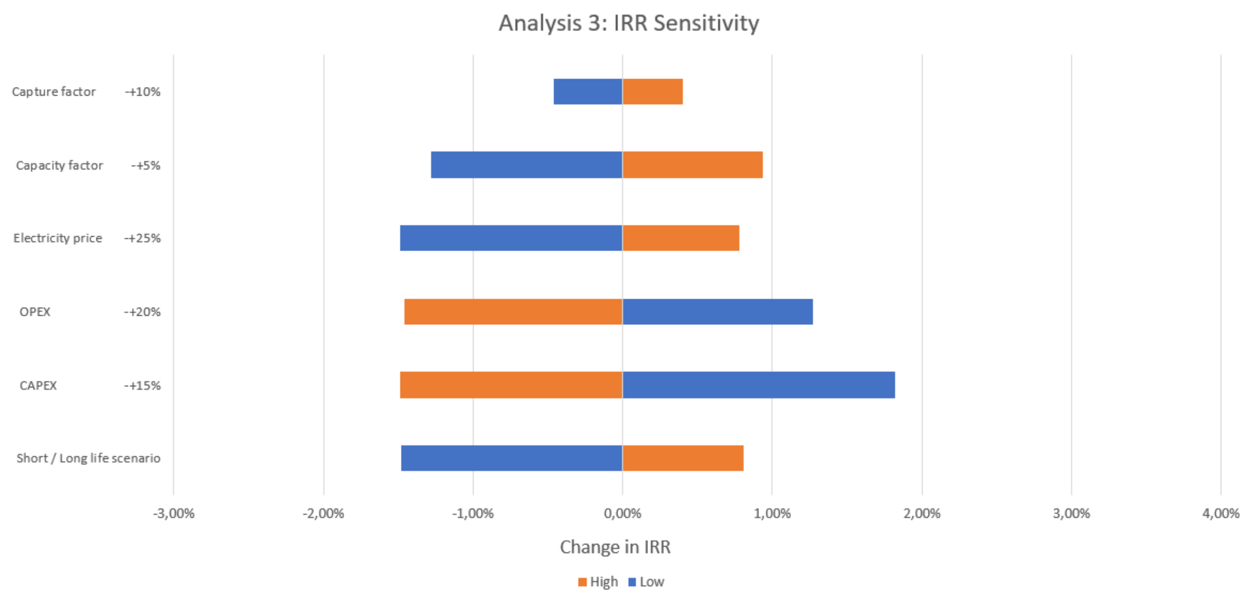

Figure 14: Sensitivity of internal rate of return, analysis 3.

The sensitivities of different scenarios of change in inputs are not as consistent as in analysis 1 and 2. The scenarios for change in CAPEX, OPEX and capacity factor are still impactful on IRR, but the scenarios for lifespan and electricity price are almost equally as important. The reason for lifespan being more important in this analysis, is the added positive cash flows from operating in the spot price market much due to the OPEX estimate being lower.

12. Examining the economic development of DOW

The results from the two investment perspectives of the DOW farm are significantly different from each other. The investment analysis with expected lifetime (25 years) from when the investment decision was made in 2014, resulted in a net present value of £130 million and an IRR of 7,30%. On the other hand, analysis 2, made using updated knowledge for the expected lifetime scenario, resulted in a net present value of £566 million and an IRR of 11,33%. The results from the updated analysis are substantially better than initially planned for. The reasons for these improvements will be studied throughout this chapter.

To understand the reasoning behind the different results, the timing of the cash flows need to be examined further. In the graph below, the discounted cash flows of the two perspectives of the expected lifetime scenario are compared. The orange line, which is cumulated NPV from the 2022 perspective is above the blue line which is the same values for the 2014 perspective for the entire project duration. It is starting to form a difference in the three years of construction, and this difference is gradually increasing during most years of production.

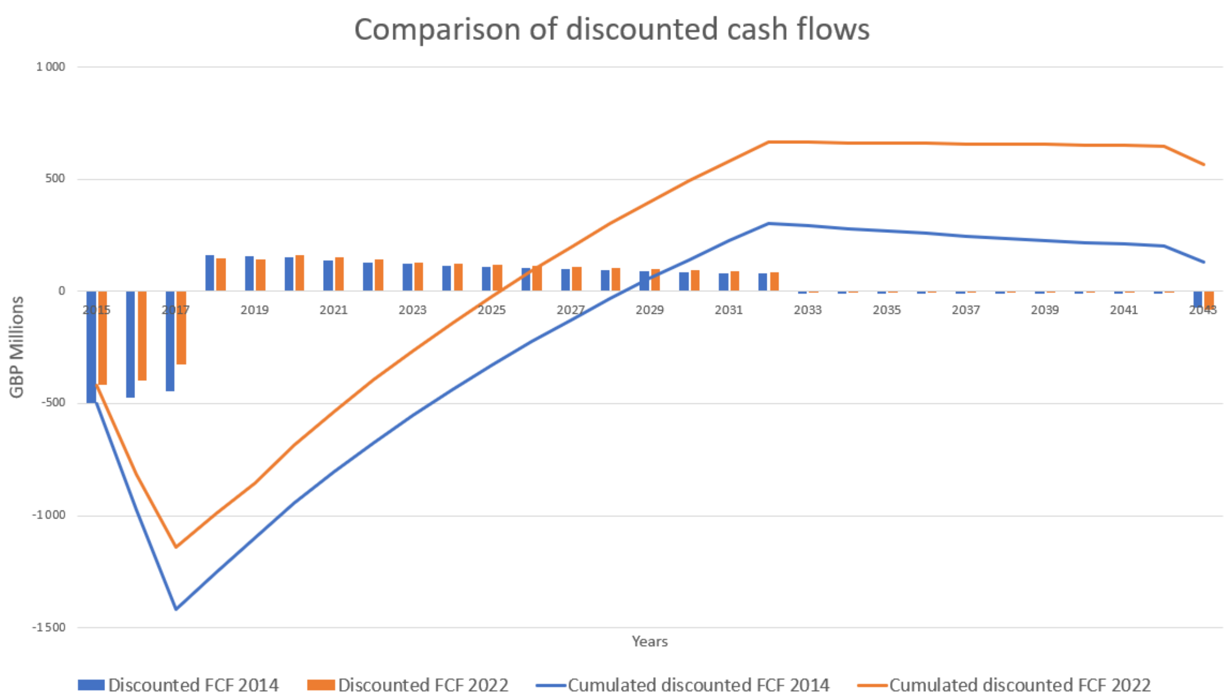

Figure 15: Comparison of discounted cash flows.

12.1 Reduction of CAPEX

The first significant change explaining the difference in NPV is capital expenditure. The project was initially projected as an investment of £1,5 billion, but ended up at £1,25 billion, reducing costs by around 17%. The difference in NPV the three first years is almost solely explained by this decrease. According to Equinor's executive vice president for technology, projects and drilling in 2017, Margareth Øvrum, this came as a result of years of hard work "to reduce costs, improve efficiency and increase profitability in both [their] oil and gas projects and [their] renewable projects" [86]. This cost is, as mentioned before, distributed over the three years of construction, and will affect the project's result in a considerable way. The reduction of £250 million will lead to an increase in net present value of nearly the whole reduction in CAPEX. CAPEX is therefore very important, and any cost overrun could impact the project significantly because of the low margins.

12.2 Operating Expenses

The running operational expense is one of the largest parts of the LCOE. As technology has advanced, and the scale of offshore wind has increased, the operating cost per MW for offshore wind has shown a downward trend [14]. However, once a wind farm has been constructed, the operating cost of that specific farm will be high in the first years, as it takes some time to get a wind farm up and running. Siemens were responsible for both operation and maintenance in the first two years of production [102]. Once the farm is running smoothly, the OPEX is assumed to be lower for several years, before maintenance and repair costs will bring OPEX up, further out in a wind farm's lifetime. In this thesis we chose a study using a linear approach to OPEX due to the uncertainty and lack of sources regarding swings in OPEX.

There are small changes in OPEX between the two analyses, with the only change being the numbers from the accounts of DOW replacing the estimate in the years 2017 to 2020. The account values are slightly higher than the linear estimate used. This coincides well with the theory of higher OPEX in the first years of operation. It remains to be seen if OPEX is reduced over the coming years to confirm the theory of somewhat declining OPEX after the startup problems of a wind farm is resolved, before it again increases as the farm gets older.

12.3 Change in capacity factors

In the description of the Dudgeon offshore wind project, the developers states that the wind farm will provide 1,7 GWh each year. Given the maximum capacity of the farm, this results in an expected capacity factor of 0,48. In reality, this capacity factor is not linear. According to the study by Lu et al., capacity factors tend to be somewhat lower than expected in the first years after construction, before reaching a peak after some years [97]. From the peak, the capacity factor will decline towards the end of the wind farms lifespan. The study is based on data from 36 wind farms, and cover wind farms consisting of different turbines and based in different locations.

In the Dudgeon case, we modelled the capacity factors using the study by Lu et al., over the 25 years expected lifetime of the wind farm [97]. The 3 first data points between 2018 and 2020, are extracted from the reports of the wind farm, and are expected to be real. We can spot a correlation between the 3 first data points and the research used. The graph below shows that when using the non-linear capacity factor approach, the wind farm is estimated to produce more electricity between year 3 and 15, and less electricity between year 1 and 2, and year 16 to decommissioning.

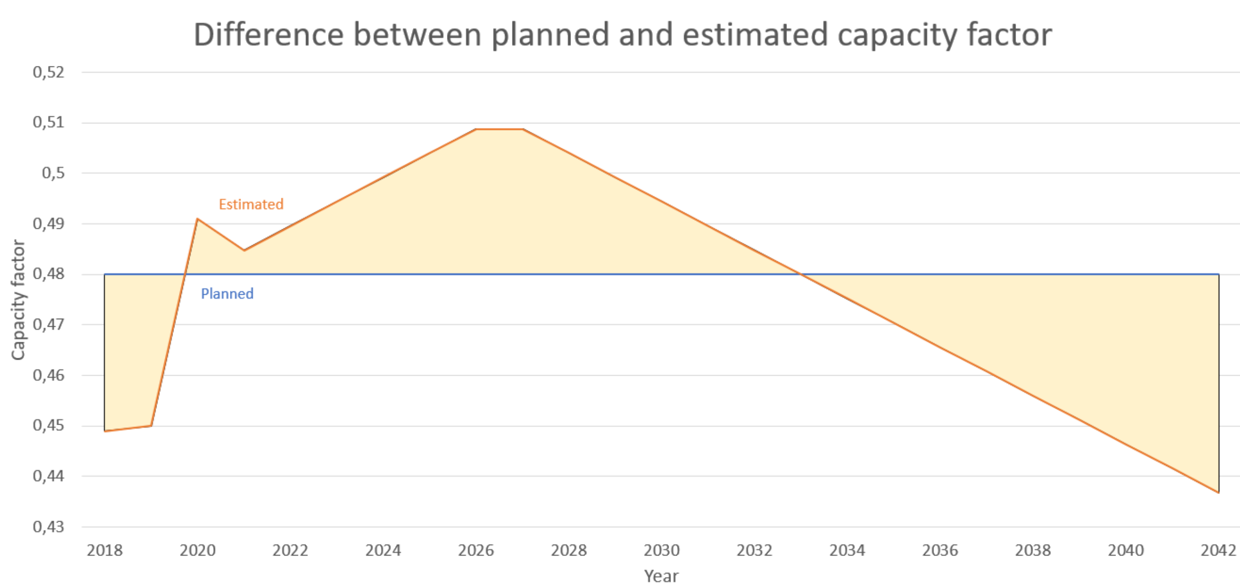

Figure 16: Difference between planned and estimated capacity factor

In the 15 first years of production, the income per MWh of produced electricity is significantly higher, meaning more electricity can be sold at the favorable CfD strike price. The cash flows received from the increased production are also closer in time than the decreased cash flow obtained between year 16 and decommissioning, meaning the effect of time value of money, will also contribute to a higher net present value. The first 2 years of production will be lower than previously expected, but the effect of the following 13 years of increased production will be positive for the NPV of the entire project. The decreased capacity factor further out in time, may lead to changes in the profitability of operating the wind farm for a long period after the CfD expire.

12.4 Higher electricity prices and cannibalism in the wind market

Another estimate explaining the difference between the two scenarios is the electricity price used after the CFD expiration. While the inflation adjusted electricity price estimate in 2033 based on historical data in the years 2010-2013 was at £50,99 per MWh, the price estimate obtained based on the period 2018-2021 was at £77,35 per MWh.

The updated estimate based on data between 2018 and 2021 is significantly higher than the first estimate. This is due to higher average prices and more volatility in electricity prices in more recent years. As discussed earlier, energy market conditions have changed a lot. Lower investments in the petroleum sector, partly due to the recent pandemic and partly due to a green transition have led to shortage on the supply side for oil and gas. Europe also wants to free themselves from dependence on importing Russian energy, making the future of energy supply in Europe highly uncertain. European governments are projecting huge investments in green energy sources to replace the supply, with wind being a large investment area. Due to the unstable production of wind, the increased share of wind energy may increase the effect of market cannibalism for wind generators in the electricity market. The capture factor, which as mentioned, is a factor for measuring the reduced average price electricity generators receive per unit of electricity sold, may decrease drastically for wind energy producers if wind energy makes up too large shares of the total energy generation.

In addition to being negative for wind producers, too large wind shares in the energy market will make electricity prices volatile for consumers. In periods with slight wind, prices can become drastically higher due to shortages on the supply side. The problem for wind producers is that in periods with high prices, their electricity production is minimal. In periods with much wind, the total energy supply in the market will be higher, meaning lower prices for wind generators. The significance of the cannibalism effect is that even though average electricity prices may end up being a lot higher in the future, the income for wind generators will not necessarily increase correspondingly if a lot of wind farms are constructed.

The CfDs wind farms in the UK have received, securing locked income per MWh the first 15 years of production, have been crucial to profitability. Historical average electricity prices have been below LCOE, meaning operating in the spot market would have been a losing project. Not only have CfDs been above the average spot price, but the effect of wind cannibalism has been eliminated, due to wind generators receiving the same price regardless of market conditions.

12.5 Changes in tax regulations

The tax rate is also important for the final profitability of the wind farm. The amount of tax paid is subtracted from the free cash flow. Some of the taxes are deductible in form of the tax shield obtained through the interest paid, incorporated in the WACC. In addition, a fair bit of the taxes is avoided due to depreciation of CAPEX through the balance depreciation method, meaning very low taxes are paid towards the beginning of the project. When initiating the project in 2014, the corporate tax rate in the UK was at 21%, with guiding to be lowered to 20% in 2015 [89]. The tax rate was kept at20% throughout the project, as any predictions of change in tax rate would be made with low certainty. Since then, the tax rate was first lowered, before guided to be increased to 24% [98]. This means approximately a 20% increase in tax rate for the whole project period, not accounting for tax shields. The increased tax rate is negative to the project profitability, but the effects are reduced due to tax shields and depreciation. In addition, the fact that little tax is paid towards the beginning of the project is positive for the profitability due to the reducing net present value of future expenses.

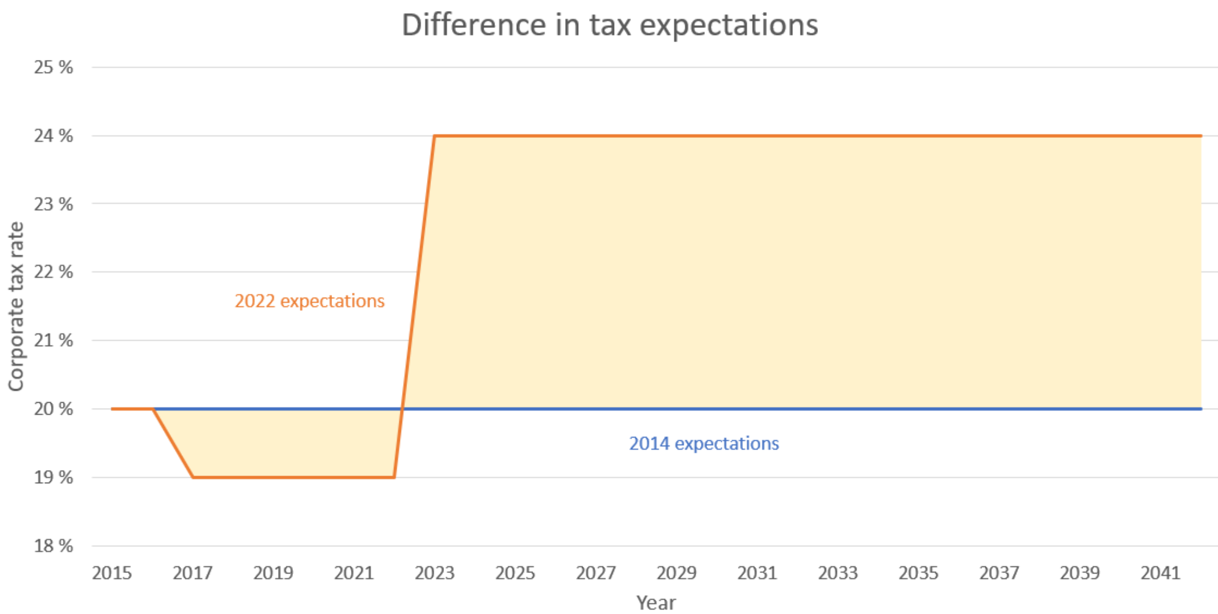

Figure 17: Difference in tax expectations.

12.6 *Different interest rates make for different discount rates*

The discount rates used in the project vary dependent on interest rates, beta, risk premium, tax rate and financial structure. The large difference in WACC during the construction phase and the production phase is mostly explained by different risk-free rates. At investment decision in 2014, the 10Y UK governmental bond were at ~2,6% [92]. In hindsight, the risk-free rate for the construction period averaged ~1,3% [92]. Meaning a ~1,3% difference in risk-free rates, a value which is largely reflected in the discount rates. In addition to different risk-free rates, the market risk premium has been lowered from 5,17% [93] in 2014 to 4,84% [99] in 2022. The market risk premium is used for the DCF analysis of the respective year. Arguably a different market risk premium representing each of the years between 2014 and 2022 could be used in the WACC calculations for the updated DCF analysis. However, the effect of doing so would be minor because of the small variation in UK market risk premium.

When debt financing comes into play from the operation phase at approximately the beginning of 2018, differences in cost of debt also plays in on different WACC values. Lower risk premiums on renewable loans in 2022 than in 2014 are a factor explaining higher cost of debts in the investment analysis made from the investment decision perspective. Another factor explaining difference is the LIBOR. The LIBOR which is the floating interest component making up the cost of debt, have been at a historically low-level from 2014 until today [94]. Even though it has been at a low level, the future LIBOR estimate in the updated DOW analysis have been adjusted upwards due to the guiding on increased interest rates mentioned earlier.

The discount rates are very sensitive to changes in interest rates. An interest rate increase of several percent would endanger the profitability of the DCF with the perspective at investment decision. The NPV will be reduced, and if WACC exceeds the IRR, which is 7,30% in the first analysis, the project would be viewed as unprofitable from an investment point of view. For the updated DOW analysis, the interest rate would have to increase drastically to threaten the profitability. Due to some of the factors mentioned earlier, with reduction in CAPEX being a large reason, the profitability of the updated DOW analysis is unlikely to be overturned from an interest increase. The NPV for the expected scenario of £566 million means the WACC would have to exceed the IRR of 11,33% for the project not to be profitable. An increased interest could mean shutting down the wind farm earlier would be more profitable, due to the expected low margins after the CfD period. For wind farms operating on lower CfD strike prices or in the spot market, increased interest rates can relatively quickly make the low margin projects become unprofitable.

12.7 Decommissioning

Decommissioning is a controversial topic within the wind industry. Large constructions need to be removed which is an extensive process. There are several decommissioning estimates, but in addition to the cost of decommissioning, the timing of when the decommissioning is done is important. The net present value of the decommissioning cost is dependent on the timing of the expense. If decommissioning is pushed further out in time, the NPV of the cost will decrease. In addition to the NPV of decommissioning, the timing of when to shut down production in a wind farm is important. As discussed, older wind farms require an increased amount of maintenance and repairs, which is directly increasing OPEX in those years. Depending on the electricity price, the cost of operating could be greater than the income from generated electricity.

In the initial analysis of DOW, the NPV decreases as the wind farm continue to operate after the CfD expire. From an economic point of view, this would mean closing the wind farm would be the best option given the electricity price estimates and captive factor used in that analysis. In the updated DOW analysis, with increased electricity price estimates, NPV is higher in the expected lifetime scenario than the low lifespan scenario. It is important to keep in mind that the linear OPEX estimate might underestimate the increased maintenance and repair costs as the wind farm ages.

13. Initiating a similar project in 2022

By comparing the initial economics of DOW with the economic outcome of the wind farm so far, we have studied how changes in different input factors can impact the profitability of an already constructed wind farm. Another situation to examine is how the economics have changed for constructing new wind farms. Therefore, we have analyzed the profitability of constructing a similar wind farm as DOW with initiation in 2022. The NPV of the analysis for the expected lifetime scenario of 25 years ends up at around £0, with an IRR of 5,42%, meaning from an economic view an investor is indifferent whether to invest or not. Throughout this chapter we will discuss the estimates used in the analysis.

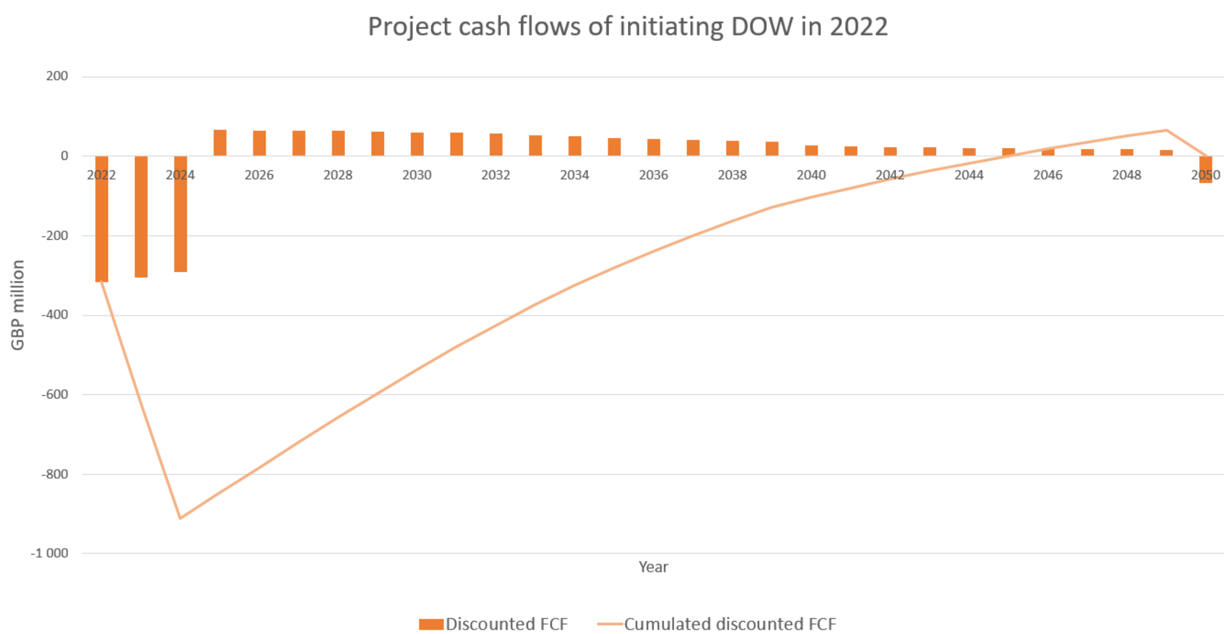

Figure 18: Project cash flows of initiating DOW in 2022.

13.1 CAPEX

Larger and fewer wind turbines are used in the analysis to reach the same capacity of just above 400MW as the initial DOW project. The reduction of wind turbines means less foundations and less cables between turbines and offshore substation. The cost reduction of this measure is uncertain, but by using reports from BVG and Rystad we estimated a CAPEX of £950 million in 2022 money [88]. The report from Rystad which are used to estimate the price of a wind turbine was published in 2020 and does not consider the increased commodity prices of different materials the last couple of years leading up to 2022 [101]. As discussed earlier, the price increase of materials is significant. Since the project is starting construction in 2022, we assume that the project had already secured contracts before the increase in material costs and bottlenecks in the supply chain. If a wind project were to be initiated and go through the contract process in 2022, it is likely that CAPEX would be significantly higher than the estimate of £950 million for a wind farm of that scale. Considering the projects NPV of £0, an increase in CAPEX will make the project unprofitable. By increasing CAPEX 15%, the sensitivity analysis shows that IRR will drop by approximately 1,5%.

13.2 OPEX

Increased volume in the offshore wind industry creating more competition, as well as improvements in technology and larger wind turbines have resulted in studies showing lower OPEX per MW of capacity. An OPEX estimate of £40 million in 2019 money is a significant reduction from the estimated OPEX used in the first analyses covering the DOW project fully constructed in 2017. A lower OPEX means increased cash flows during all production years given identical income.

13.3 Capacity factor

The capacity factor used in the calculations for the newer 14MW wind turbines use 0,58 as the starting point, 0,10 higher than for the wind farm consisting of 6MW turbines. Since the 14MW turbines are not commercially available yet, there are large uncertainties connected to the actual capacity factor over time in different wind conditions. A 5% reduction in capacity factor will reduce IRR by more than a percent, again making the project unprofitable given the expected lifetime scenario.

13.4 Lower CfD strike prices

The CfDs have been lowered since DOW received theirs in 2014. The most recent CfDs that were handed out to offshore wind farms in 2021 in the 4th allocation round, had a strike price of £46 per MWh in 2012 prices, and is the strike price used in this analysis [100]. This is less than a third of the strike price in DOWs CfD. The trend for strike prices in CfDs for offshore wind in the UK is clearly pointing downwards and is closer to the spot prices than what is the case for CfDs handed out in earlier rounds. This means that significant cost reductions are needed to protect project economies. However, rising commodity prices in recent years are not helping. The issue regarding revenue reduction and lack of profitability in wind farms is not only related to the UK, but a global issue according to Wood Mackenzie [103].

13.5 Electricity prices

The electricity prices used after the CfD expire are identical to the prices used in analysis 2 when using the same model for simulation, only adjusted for inflation. This is because they are based on the same three years of historical data prior to 2022 and lay a long time in the future. A question that arises is what the capture price will be so far in the future. As discussed earlier, if wind make up to big share of the total energy production in a market, the wind generators get paid less for their electricity. A 10% lower capture factor, than 0,8 which is used in the analysis, will lower IRR by approximately a half percent, making the project unprofitable. Also, a 25% reduction in electricity price would decrease IRR by around 1,5%.

13.6 Lifespan

Unlike in the first two analyses, where shorter/longer lifespan is of minor significance from an economic view, analysis 3 are dependent on the lifespan of the wind farm to be profitable. The decreased OPEX with the same electricity estimates as in analysis 2, gives positive cash flows through all production years. For the short lifetime scenario, the NPV is negative £96 million with an IRR of 3,94%. The long lifetime scenario on the other hand, with 30 years of operation gives an NPV of £73 million with an IRR of 6,23%.

This adds another uncertainty for the profitability of the project, will the wind farm be able to operate for 25+ years? And if so, will the needed maintenance and repair expenses increase drastically?

14. Conclusion

In this study, the economics of Dudgeon offshore wind farm located in the UK have been thoroughly examined. The focus has been on comparing the profitability of the wind farm through the perspective the investment team would have had at investment decision in mid-2014, and how the outcome for the project's profitability looks like today in 2022. As well as a third analysis covering the profitability of constructing a similar wind farm today with changed market conditions. Discounted cash flow analysis has been performed for all analysis and net present value and internal rate of return have been used as measures for profitability.

Different studies have been used to create estimates which are used as inputs in the analysis. For the analysis made with the investment perspective of 2014 in mind, sources dating back from before 2014 have been used to the extent they are possible to obtain. In the updated analysis made to analyze the outcome of the project so far, updated sources have been used to the extent they exist and act as beneficial to replace with the sources used in the earlier analysis. Some of the information in the updated analysis between the years 2017 and 2020 are extracted from financial reports of DOW. In the final analysis for studying the construction of a new wind farm in 2022, in addition to using some of the same estimates as for analysis 2, new estimates for CAPEX, OPEX and capacity factor are used.

14.1 Factors explaining increased profitability after initiation of DOW

By interpreting the results and sensitivity analysis from the DCF analysis, we can point at the differences between the two perspectives and look at what have changed from the investment decision was made back in 2014. From studying the results, we can see that both the analysis has a positive NPV, meaning the project would been considered profitable in both perspectives. However, the updated analysis has a considerable higher profitability than what could be expected at investment decision. In our profitability analysis made with information mostly available at investment decision in 2014, the project has a net present value of £130 million and an internal rate of return of 7,30%. Analyzing the DOW economics with information available in 2022, gives an NPV of £566 million and an IRR of 11,33%.

The difference in profitability between the two perspectives is explained by different developments in input factors. The biggest change being the £250 million reduction in project CAPEX announced in 2017 which is almost directly transferred to the NPV due to the reduction in negative cash flow being in the beginning of the project. Another important difference in the two analyses is the change in capacity factor in the updated analysis, meaning more electricity is generated earlier in the project. Increased electricity generation towards the first half of the expected project lifespan means that more electricity is sold at the beneficial CfD strike price, and the cash flow is received earlier in the project, resulting in a higher NPV.

The final change in input factor we have assessed as most considerable is the increased future electricity price estimate. When the CfD expire after 15 years of production, the electricity price received are important for whether it is profitable to operate the wind farm or not. With the lower electricity price estimate made with basis on historical data from the years prior to 2014, the wind farm would be unprofitable to operate, meaning the project should be shut down from an investment point of view. Today, with changed market conditions in the energy market, the electricity estimate made with historical data from 2018 to 2021 are higher than the first estimate. With this estimate the wind farm would approximately be at break-even in the years after the CfD expires. From an investors point of view, the added NPV of delaying the decommissioning expense would mean that it is beneficial to continue to operate the wind farm.

In addition to these factors, interest rates are crucial for the profitability of a wind farm. Wind projects are characterized by high debt financing, and low margins. Increase in interest rates can possibly push capital costs above the internal rate of return, making the net present value of the project become negative. In the DCF analysis made with the perspective of 2014 in mind, an increase of 2 % in interest rate would make the average project WACC exceed IRR, and thus make the NPV negative. As discussed in the thesis, a higher interest rate scenario is very likely moving forward and could be challenging for wind farms operating at low margins.

14.2 Changed market conditions have challenged the profitability of offshore wind

While the updated analysis for DOW showed improved profitability, the economics of launching a new similar wind farm in 2022 is not as promising. There are a lot of challenging considerations when deciding input parameters, and smaller changes in one input factor may have large effects on profitability. The sum of our estimates and assumptions gives an NPV for the expected lifetime scenario of around zero, with some of the inputs being on the optimistic side. Like mentioned earlier, a small rise in interest rates will increase WACC. For this investment case with an NPV around break-even, an increase beyond our relatively low interest rate estimate will push WACC above IRR, making NPV negative.

Capital expenditures, which for wind farms is made in the first years of the project, have a large impact on the LCOE. In the DOW project, CAPEX per MW of capacity constructed was lowered mainly due to increased efficiency and work on cost reductive measures. In the new analysis made to look at the profitability of constructing the farm today, the CAPEX estimate is further lowered with £300 million. A problem with the estimate is that the study dates a couple of years back and does not filter in increased material costs following the release of the study. The increased price of materials seen today, will contribute to increase CAPEX and are therefore likely to ruin the profitability of the project.

In addition to a large decrease in the CAPEX estimate, the OPEX estimate have been lowered significantly in our analysis. Fewer and more modern turbines are said to be cost reducing, but due to the largest turbines not yet being commercially available and smaller more modern turbines having limited operational years to study, there are a lot of uncertainties connected to that assertion. Like the OPEX estimate, the capacity factor used in the analysis has been adjusted in a favorable way due to improvements in technology. Whether the turbines will be able to produce at the anticipated capacity factor remains to be seen, as no wind farms today have been able to operate steadily at a capacity factor of 0,58.

Another factor of major importance for the profitability of constructing a similar wind farm today, is the amount of production years. For the 25 years scenario, the farm is just able to produce an NPV of zero with optimistic inputs in the analysis, but if we look at the low, 20 years of operation, scenario the NPV is negative £96 million with optimistic inputs. Given most commercial offshore wind farms are constructed in the last decade, there are large uncertainty connected to how long wind farms will be able to operate without costly investments in upgrades and repairs. The high dependence on being able to operate for a long period without significant upgrades to break-even is therefore adding risk to the potential investment.

Even though most inputs in the analysis are changed to strengthen the economy of the project, the decrease in CfD strike price from £150 to £46 per MW in 2012 money of electricity is what changes the profitability of the project drastically. The early phase wind projects in the UK like DOW were able to secure lucrative CfD strike prices, while todays projects are suffering from a more competitive bidding situation to secure CfDs.

15. Further studies

To further evaluate the profitability of offshore wind, there are several aspects to consider:

- Analyzing the profitability of constructing wind farms of different capacities and size of turbines.
- Analyzing wind farms in different countries and locations with different regulations

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