Master's thesis

NTNU
Norwegian University of Science and Technology
Faculty of Economics and Management
Department of Industrial Economics and Technology Management

Mathilde Knobel Christensen,
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Power purchase agreement vs. investment in power generation:

Analysing the trade-offs for a large industrial power consumer considering wind power in the Norwegian market

Master's thesis in Industrial Economics and Technology Management

Supervisor: Verena Hagspiel and Lars Hegnes Sendstad

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Problem description

In recent years, there has been two significant developments in Norwegian wind power. Firstly, wind power projects are about to become profitable without government support. Secondly, using power purchase agreements (PPAs) in combination with wind power is increasingly popular. In this thesis we examine the impact of both these trends, from the perspective of a large power consumer situated in Norway. We compare developing and operating an onshore wind power plant to entering a wind power PPA. The purpose is to identify which of the positions poses the best alternative for covering the power demand of the consumer.

To investigate the problem, we first provide background information regarding both positions. Furthermore, we apply discounted cash flow and Monte Carlo simulation models to investigate a case study representing the current Norwegian market. This is to evaluate the financial aspects. Lastly, a qualitative risk assessment is conducted.

We aim to provide relevant insight for industrial companies considering the two positions. Therefore, we apply modeling approaches intuitive to the industry.

Abstract

In recent years, there are two major developments in Norwegian wind power emerging. Firstly, wind power projects are about to become profitable without government support. Secondly, power purchase agreements (PPA) related to wind power arise in the market. Many of the largest wind power projects in Norway have been realized because of funding from international investors, who require a PPA to enter a project. In this thesis we examine the two market tendencies, taking the perspective of a large power consumer situated in Norway. We will investigate whether to develop and operate an onshore wind power plant, or entering a wind power PPA, is a more beneficial position to cover the power demand of the consumer.

To examine the problem, we provide relevant background information, consisting of common contract terms of PPAs and characteristics of recent Norwegian wind projects. Moreover, we propose several models to evaluate the financial aspects of the two positions, including discounted cash flow (DCF) and Monte Carlo simulation. These approaches are chosen based on what is predominantly used in the industry, with the aim to make the results intuitive to industry professionals. Gathering characteristics of recent Norwegian wind projects, we create a case of input values representing the current market. The case is analysed using the presented models, to obtain numerical results to evaluate the positions. Lastly, a qualitative risk assessment is undertaken, where relevant risk categories are examined, emphasizing examples regarding Norway.

When conducting our financial analyses of the two positions, we consider three price forecasts for the Norwegian market, originating from credible sources; the Norwegian grid operator Statnett, the Norwegian Water Resources and Energy Directorate (NVE) and Wattsight, a consulting company within the power industry. From our DCF analyses, we find that the value of both positions is very sensitive to which price forecast is used. Additionally, we use Monte Carlo simulation to be able to account for variation in daily power prices and power production. The daily price paths are calibrated by using the variance in historical data and the average levels of price forecasts. We find that the resulting net present values (NPVs) display less sensitivity toward the simulated variability of production and prices, compared to the impact of using different price forecasts to set the average power price level. We obtain

NPV results for our wind power case plant within the range of -646 and 525 MNOK, using the various predicted paths of the forecasts. There is no available information about actual PPA prices in the Norwegian market. However, based on the current level of levelized cost of electricity (LCOE) for recent wind projects, a PPA price in the interval 250-300 NOK/MWh, is assumed reasonable. Applying this, the resulting NPV from the DCF analysis for the PPA position is between -345 and 1009 MNOK. Hence, our results indicate that using different forecasts has vast impact on the project value and emphasize the sensitivity of the positions toward future power prices. However, the numerical results indicate that the PPA position has the potential to deliver the highest project value and lowest losses compared to the wind power plant position. Nevertheless, concluding which position is preferable would demand insight into existent PPA prices in the market.

We have also identified the prominent risk categories for each of the positions. Market/sales and strategic/business risks are considered as most significant to the wind power plant position. This is primarily due to uncertainty regarding future power prices and technological development. The prices will vastly impact the project profitability, and the current rapid technological evolution within wind power makes investments risky, as the technology of today may be outdated shortly after project initiation, rendering it a competitive disadvantage. Pricing/market and volume/shape risks are considered as the most prominent risk categories for the PPA position. Pricing/market risk is concerned with that market prices stay below the PPA price for extensive periods, making the contract a competitive disadvantage. Companies regard this as the most severe risk of a PPA. Volume/shape risk is related to trading in the market because of mismatch between production and consumption, exposing the PPA customer to the great uncertainty regarding future power prices.

Comparing the positions, most risks are of similar impact and probability, except the development/construction and counterparty/credit risks. For the PPA position, the counterparty risk is more prominent, whereas the development risk is lower, compared to the plant position. To the plant position, a bankruptcy or plant default constitutes the worst potential scenario. The worst outcome for a PPA customer, caused by default or bankruptcy of the producer, is termination of the PPA, incurring the need to acquire a new contract. Hence, the impact for the plant position is always more severe than for the PPA position.

Overall, our results suggest that, of the positions considered, a PPA is preferable considering both profitability and risk exposure. This will be valid as long as its price is below the current average LCOE level found in the wind power market.

Keywords: Power purchase agreement, wind energy, wind power plant investment, discounted cash flow analysis, Monte Carlo simulation, Weibull distribution, qualitative risk assessment

Sammendrag

De siste årene har man observert to tydelige utviklingstrekk innenfor norsk vindkraft. Det første er at vindkraftprosjekter begynner å bli lønnsomme uten statlige subsidier. Nummer to er den økte bruken av såkalte kraftkjøpsavtaler (PPA) i markedet. Mange av de største vindprosjektene i Norge er finansiert av utenlandske investorer, på det grunnlag at prosjektet har en PPA. I denne oppgaven undersøker vi disse tendensene sett fra perspektivet til en bedrift med høyt kraftforbruk, en stor kraftkonsument, med tilholdssted i Norge. Vi ønsker å finne ut om kraftkonsumenten vil være best tjent ved å konstruere sitt eget landbaserte kraftverk eller å inngå en PPA for å dekke sitt energibehov.

Relevant bakgrunnsinformasjon som typiske vilkår for en PPA og karakteristiske verdier for et gjennomsnittlig norsk vindkraftverk presenteres for å gi økt innsikt til problemstillingen. Videre foreslår vi ulike modeller for å evaluere de økonomiske aspektene ved begge alternativer, inkludert diskonterte kontantstrømmer (DCF) og Monte Carlo simulering. Disse tilnærmingene er valgt basert på deres utbredte anvendelse i industrien, ettersom formålet med oppgaven er å gjøre resultatene intuitive for aktører innenfor vindkraft. Vi bygger et case studie representativt for det nåværende markedet ved å benytte karakteristiske verdier for nylige norske vindkraftprosjekter. Deretter analyseres case studiet ved å bruke modellene som er foreslått, med formål om å oppnå numeriske resultater nyttige for å vurdere de to alternativene kraftkonsumenten står mellom. Til slutt er det foretatt en kvalitativ risikovurdering, hvor relevante risikokategorier er undersøkt, underbygget av eksempler fra det norske markedet.

Tre ulike prisprognoser er benyttet for å analysere de finansielle aspektene, alle fra troverdige kilder; den norske nettoperatøren Statnett, Norges vasskraft og energidirektorat (NVE) og Wattsight, et konsulentselskap med fokus på energibransjen. Fra DCF-analysen fremkommer det tydelig at verdien av investeringen for hvert av alternativene sterkt avhenger av hvilken prisprognose som benyttes. I tillegg benyttes Monte Carlo simulering for å ta hensyn til variasjon i daglige strømpriser og kraftproduksjon. Prisbanen for hver dag lages ved å benytte variansen i historiske data og gjennomsnittlige prisnivåer fra hver av prognosene. Videre finner vi at valg av prisprognose påvirker de resulterende nåverdiene (NPV) i mye

større grad enn valget å bruke simulering for å ta hensyn til variasjon i daglige strømpriser og produksjon. Ved å benytte de forskjellige prisprognosene får vi NPV-resultater for vindkraftinvesteringen i intervallet -646 og 525 MNOK. Det er ingen tilgjengelig informasjon om faktiske PPA priser i det norske markedet. Uansett, det nåværende nivået på levelized cost of electricity (LCOE) tatt i betraktning, vil en PPA-pris i området 250-300 NOK virke rimelig. Ved å benytte denne antakelsen, blir resulterende NPV fra DCF-analysen for PPA-alternativet mellom -345 og 1009 MNOK. Resultatene understreker påvirkningskraften fra valg av prisprognose. Videre virker PPA-alternativet å ha potensiale for størst prosjektverdi og de minste tapene. Vi kan likevel ikke konkludere med hvilket alternativ som er foretrukket uten innsikt i faktiske PPA-priser i markedet.

I tillegg har vi identifisert de mest fremtredende risikokategoriene for hvert av alternativene. Marked-/salgsrisiko og strategi-/businessrisiko er begge vurdert til å ha størst betydning i alternativet med å bygge og operere et vindkraftverk. Dette skyldes hovedsakelig usikkerhet rundt fremtidige strømpriser og teknologisk utvikling. Prisene vil påvirke lønnsomheten på et prosjekt betraktelig. Samtidig, den nåværende og hurtige teknologiske utviklingen innenfor vindkraftindustrien fører til at investeringer i vindkraft er risikabelt, fordi teknologien kan være utdatert kort tid etter at anlegget er åpnet. Dette vil være en konkurransemessig ulempe mot andre energikilder. Pris-/markedsrisiko og volum-/formrisiko er de mest fremtredende risikofaktorene for PPA-alternativet. Pris-/markedsrisikoen er risikoen for at strømprisene holder seg under PPA-prisen over en lengre tidsperiode, noe som fører til at kontrakten blir en konkurransemessig ulempe. Denne risikoen betraktes av mange selskaper som den mest betydelige. Volum-/formrisiko stammer fra behovet for å handle med markedet etter uoverensstemmelse mellom produksjonen fra vindkraftverket og kraftkonsumentens energibehov. Dette eksponerer kraftkonsumenten for stor usikkerhet vedrørende fremtidige strømpriser.

Ved sammenlikning ser man at de fleste risikokategoriene har liknende konsekvenser og sannsynlighet, med unntak av utvikling-/konstruksjonsrisiko og motpart-/kredittrisiko. For PPA-alternativet er motpartsrisikoen betydelig, mens utviklingsrisikoen er lavere sett i forhold til vindkraftsalternativet. For vindkraftsalternativet er konkurs eller anleggssvikt de verste mulige utfallene. Dersom det skulle skje, vil konsekvensen for PPA-kunden være at kontrakten termineres og de vil måtte inngå en ny kontrakt med en annen leverandør. Dermed vil de verste konsekvensene alltid være størst for eieren av et vindkraftverk enn for en PPA-kunde.

Resultatene våre indikerer at PPA-alternativet er foretrukket av de to mulighetene som er vurdert, når både lønnsomhet og risikoeksponering er tatt i betraktning. Konklusjonen blir derfor at så lenge strømprisene er under det gjennomsnittlige LCOE-nivået for et vindkraftverk i Norge, vil å inngå en PPA være mest fordelaktig.

Preface

This master thesis is written as the conclusion of our Master of Science degrees in Industrial Economics and Technology Management, with specialization in Financial Engineering, at the Norwegian University of Science and Technology (NTNU).

We would like to thank our supervisors, Professor Verena Hagspiel and Postdoctoral Fellow Lars Hegnes Sendstad, for their valuable guidance and detailed feedback throughout the work.

Trondheim, June 10, 2019

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List of abbreviations

BEPE break-even price of energy.

CVaR conditional value-at-risk.

DCF discounted cash flow.

FiT feed-in-tariff.

GIEK the Norwegian Export Credit Guarantee Agency.

IRR internal rate of return.

LACE levelized avoided cost of electricity.

LCOE levelized cost of energy.

NPV net present value.

OTC over-the-counter.

UN United Nations.

VaR value-at-risk.

Nomenclature

As produced-PPA Power is supplied directly to the consumer as it is produced.

Base supply-PPA The producer obliges to provide a constant base power output to the customer.

Position 1 Develop and operate a wind power plant.

Position 2 Entering a PPA with a wind power project.

REE Abbreviation for realized energy expenditure. It is a total cost measure for energy procurement. It states the actual cost per unit of energy, including expenses of power from producing plant and necessary trading in the market.

1 Introduction

In recent years, there has been a significant increase in the number of power purchase agreement (PPA) acquisitions for onshore wind power plants in Norway. Anders Lenborg, a partner in the international law firm DLA Piper, states that, "A corporate PPA is a determining factor for the realization of a wind power plant, as they are crucial to obtain a certain return for investors. Without a PPA, some of Norway's largest wind projects would not have been realized" (Adolfsen, 2016). Wind power producers offer PPAs in order to assure steady income for their projects, thus reducing uncertainty to the investors. Large power consumers are often the offtakers in the contracts. They seek a predictable power cost because volatile prices of the Nordic power market pose a large risk factor to their business. A fixed PPA price eases the process of estimating their power costs. Note that with the term PPA price we refer to the unit price of power supplied by the PPA producer, not the price of procuring the contract.

Multiple examples of PPA procurement are reported in recent news. For instance, Google will purchase the entire power production from the 12 first operational years of Tellenes wind power plant, with 160 MW installed capacity, to supply their European data centres. In 2018, Facebook committed to a PPA, obliging them to buy the entire production output for 15 years forward from the Bjerkreim plant, located in the Stavanger region, with 294 MW installed capacity. Facebook states that, "Signing this PPA contributes to the strategic objective of powering 100% of our global operations by renewables as soon as possible"

(Energiteknikk.net, 2018).

Customers of Norwegian PPAs are not limited to international corporations, as demonstrated by large industrial consumers Alcoa Norway and Hydro, who both recently entered PPAs. Alcoa Norway agreed to purchase 15 years of production output from the Nordlicht project, with 281 MW installed capacity, and the Øyfjellet wind power plants, having 330 MW installed capacity (Hovland, 2018a). Hydro has signed a PPA constituting to purchase 1 TWh annually from the Fosen project (Ånestad, 2018; Hovland, 2018b). All mentioned wind power projects above are partly or fully financed by international investors. For instance, the American investment fund BlackRock has provided funding to the Tellenes project, and the German investment company Luxcara to the Bjerkreim plant.

We only consider onshore wind power in this thesis, because all the PPAs traded in the market that we have knowledge of are related to such projects. There are many underlying factors explaining the increased application of PPAs in the Norwegian wind power industry. First, onshore wind power is considered as the best option for new renewable power development. Since the hydro power resources are fully exploited, the great wind conditions available, in combination with the fact that wind power is close to achieving profitability in the current market, contributes to making wind power a promising alternative (Statkraft, 2019). Due to borderline profitability, wind power projects are still considered risky investments. To reduce the price risk of wind projects, which is considered to be a major risk factor, PPAs may be signed to secure a certain income. In fact, this is often required by banks and investors to be willing to provide funding (Lindblom, 2016).

The wind industry intelligence service A Word About Wind suggests potential reasons for why the Scandinavian countries are more attractive, compared to the rest of Europe, when it comes to PPAs. Firstly, many data centres have been located in this region due to cool climate, easy access to large quantities of renewable energy at relatively low prices, and grid connections to other major countries. Some of the most recently signed PPAs supply power intensive data centres. Additionally, the organization emphasizes that the area has a steady, liquid and transparent energy market in a predictable political environment.

A guarantee, provided by the Norwegian Export Credit Guarantee Agency (GIEK), ensures that Norwegian PPA customers within certain industries fulfil their payment obligations to the wind power plant owners in case of economic distress, providing security for the seller (GIEK, 2018). To qualify for the guarantee, the power customer needs to be a company operating within certain areas of the lumber processing, chemical or metal industries and have an annual consumption of minimum 10 GWh. Additionally, the agreement needs to have a minimum total volume of 35 GWh. The GIEK guarantee makes Norwegian power consumers attractive PPA customers (GIEK, 2018).

Entering a wind power project and signing a PPA pose two interesting positions to procure power for industrial firms operating in Norway. The advantages of establishing a wind power plant are access to renewable energy and retaining full control of the construction and operation processes. However, the disadvantages are the responsibilities imposed by the same processes and the unpredictable prices affecting project income, causing large risk. As a PPA customer, the significant risk in development and maintenance is left to the contract counterparty, and green power is procured at a fixed price. However, control of construction and operation is abandoned, increasing the counterparty risk. Which of the positions, i.e. whether to develop and operate a wind power plant or entering a PPA with an equivalent plant, is most preferable, constitutes an interesting problem to investigate. In the following paragraph, we present our related research questions.

The first research question is how PPAs are priced in the literature. To answer this, we will conduct a literature review on the topic, to achieve insight for our next question. The second question we aim to answer is which of the positions is most beneficial considering the financial aspects of profitability and power costs. We will propose models using discounted cash flow (DCF) and Monte Carlo simulation. The industry commonly utilize DCF analyses when evaluating investment projects (Fleten et al., 2016). Hence, by applying this, our analyses are aimed to be intuitive for industry professionals. Monte Carlo simulation is frequently used by the industry to account for uncertainty in investment analyses. Third, we seek to investigate the question of what risk exposure is faced in each of the positions, and what constitutes the main differences regarding risk. We intend to identify all relevant risk factors and their impacts, to provide an overview for the industry, emphasizing examples from the Norwegian market.

In what follows, we will introduce relevant literature closest related to our research questions. In Chapter 2, we will in detail discuss the literature of PPA pricing and investment analysis of wind power projects. As PPA prices are considered company secrets, there is no publicly available information regarding the actual price levels in the market. Therefore, we research the literature to investigate fair methods for determining the PPA price.

To the best of our knowledge, the only paper considering a problem statement similar to ours is Jin, Shi, and Park (2018). The authors compare constructing onsite generation and holding a PPA, to realise eco-economic benefits. They formulate an optimization model which seeks an optimal mix of onsite generation of solar and wind power, and a PPA. Additionally, the authors consider which of the alternatives are most beneficial under different conditions, given government carbon incentives and utility pricing policy. The aim of their study is to minimize levelized cost of energy (LCOE) for a necessary energy production. Jin, Shi, and Park (2018) assume the PPA price to be \$50/MWh. This value is based on the paper by Bolinger, Weaver, and Zuboy (2015), where the authors try to validate whether the announced price of $50/MWh for solar power PPAs, in the US in 2015, could be plausible. Jin, Shi, and Park (2018) do not assess potential PPA prices for wind power. Our work differs from Jin, Shi, and Park (2018) because we will focus on the choice between a wind power plant and a PPA, and not the optimal combination. Furthermore, we will put emphasis on the Norwegian environment and discuss reasonable PPA prices here.

We find that the literature considering pricing of PPAs is rather sparse. In general, methods proposed may be grouped into four approaches: I) basing the price on LCOE; (Miller et al., 2017; Bruck, P. Sandborn, and Goudarzi, 2018; Ryor and Tawney, 2014; Lei and P. A. Sandborn, 2018), II) use the break-even price of energy (BEPE); (Garcia-Barberena, Monreal, and Sánchez, 2014), III) LCOE combined with levelized avoided cost of electricity (LACE); (Bruck, P. Sandborn, and Goudarzi, 2018), and IV) setting the price equal to the feed-in-tariff (FiT); (Ryor and Tawney, 2014). All approaches aim to cover the cost of the underlying production unit and a reasonable return to investors. A comprehensive literature review considering PPA pricing is presented in Section 2.1.

When comparing the positions, we will apply different models for financial analyses and qualitative risk assessment. Financial analyses of wind power projects are comprehensively appraised in existing academic literature, often applying DCF and Monte Carlo simulation for the evaluation; (Gass et al., 2011; Afanasyeva et al., 2016; Khindanova, 2013; Çevik et al., 2015; M. Albadi, El-Saadany, and H. Albadi, 2009; Li, Lu, and Wu, 2013; Caralis et al., 2014; Yang et al., 2010; Salles, Melo, and Legy, 2004). We intend to use these methods in our thesis. A thorough presentation of the mentioned papers may be found in the literature review in Section 2.2. Real options valuation also poses an alternative for assessing wind power investments; (Myran and Heggelund, 2014; Çevik et al., 2015; Munoz et al., 2009; Lee, 2011; Abadie et al., 2014; Kitzing et al., 2017; Çevik et al., 2015). However, we refrain from doing so because we aim to perform an analysis based on what is current industry standard.

Moreover, no literature is assessing wind power investments in Norway during recent years, from 2016 to 2019, where the wind power market has experienced extensive growth. In 2016, the installed capacity was 873 MW, while in the end of 2018, the capacity constituted 1695 MW. In 2017 and 2018, a construction record was set (Vindportalen, 2019[e]). Furthermore, projects installed in 2019 will render the largest installation amounts ever seen in Norway, by construction of 1000 MW of new capacity. Hence, the market experienced a doubling of capacity in two years, indicating radical changes in the conditions for wind power. This supports that reassessing this market is interesting. There exist some articles which consider profitability of wind power in Norway written before this rapid market development; (Dale and Husabø, 2013; Yari, 2015). Both papers choose a DCF approach and conclude that Norwegian wind power is not profitable. Also, both emphasize that wind power projects are heavily dependent on increased future power prices to obtain positive return.

To the best of our knowledge, there is no literature that provides a financial analysis of PPAs related to wind power projects or assesses PPAs as a standalone investment. However, some authors investigate financial and risk aspects of PPAs related to other power sources or as part of a power plant project. An example of this is Jenkins and Lim (1999), who evaluate a gas turbine generation plant with a signed PPA to secure income. Since the considered project is in a region of India frequently experiencing power shortages, the local state electricity board engages in PPAs with individual producers to increase the power production in the region. Jenkins and Lim (1999) apply a financial model for the gas plant project, including a PPA, to identify how the different contract variables impact the overall project. They perform a DCF analysis, from the perspective of both the producer and the utility company, to find the project NPV. Furthermore, a sensitivity analysis of the input factors for the NPV is presented. Our work diverges from this paper as we consider a PPA as a standalone investment, and not as a part of a power project. Additionally, Jenkins and Lim (1999) consider a project in India, while we focus on the Norwegian market.

Lastly, we will perform a qualitative assessment of the two positions. Gatzert and Kosub (2016) is, to the best of our knowledge, the only paper which presents a complete risk categorization for wind power projects. Current risks within the renewable energy sector are identified, particularly focusing on wind power in Europe, and tools for managing each risk are suggested. The authors claim to find no evidence of similar work in the literature. Gatzert and Kosub (2016) propose the following categorization: strategic/business risk, transport/-construction/completion risk, operation/maintenance risk, liability/legal risk, market/sales risk, counterparty risk and political/policy/regulatory risk. Furthermore, the authors discover that insurance is the most common approach for risk mitigation. Gatzert and Kosub (2016) also find that policy and regulatory risks are the most significant barriers for investment in renewable energy. Additionally, mitigation solutions for these risks are limited. Gatzert and Kosub (2016) mention that the literature related to risks and risk management in renewable energy primarily emphasizes on selected risks, as opposed to considering the entire risk spectrum. The focus of Wing (2015), for example, lies on the above-mentioned significant policy risks and how to manage them. Proposed mitigation actions are portfolio management, thereby diversification of projects, in addition to scenario analysis and different simulations using a mean-variance approach. Additionally, Wing (2015) lists the risks of credit, market, operational, liquidity and policy as important for renewable energy projects. In our thesis, we will apply the risk framework provided by Gatzert and Kosub (2016). However, we assess each risk category with regards to the Norwegian market environment, illustrated by recent examples from Norwegian wind power projects. Furthermore, our discussion is focused on a case study, representing the average market conditions, rather than providing a general risk discussion.

The literature includes, to the best of our knowledge, no paper classifying all risk aspects of PPAs, neither any analyses from the perspective of a PPA customer. The work by Ruiu and Swales (1998) is the only article found to consider risks in PPAs. The authors claim that the main risks in such contracts are commercial, regulatory and force majeure, and that it is preferable to allocate such risks to the party capable of holding them with the least discomfort. Some of the identified risks are; risk that the facility is not completed, delays of the initiation of commercial operation, capacity and energy not delivered according to the terms, costs are higher than estimated, the fixed price exceeds the market price, and a customer demand being lower than expected. The authors suggest applying a risk matrix to identify the risks, possible causes and the potential time of occurrence. Additionally, for quantification purposes, the potential cost and probability of each undesirable incident must be found. Ruiu and Swales (1998) present the following steps to quantify risks: identify uncertainties, develop a business/value model which uses simulation to calculate the expected financial outcome of the contract, and performing a sensitivity analysis on the input variables. Moreover, assessing probabilities associated with the independent variables is necessary, thereafter interpreting the results and ultimately analysing proper risk mitigation measures. In our thesis, we will apply Monte Carlo simulation to account for uncertain factors when entering a PPA, inspired by the approach suggested by Ruiu and Swales (1998). Furthermore, we will apply a matrix structure, similar to what is suggested by these authors.

To the best of our knowledge, the available literature does not investigate our problem statement. Therefore, the main contribution of this thesis is threefold. First, we provide a comprehensive summary of existing articles regarding PPA pricing. Second, we perform financial analyses of a wind power plant and PPA with the same plant as underlying. Assessing wind power projects in Norway under the current market conditions is, to the extent of our knowledge, not conducted in the literature, neither is a financial analysis of a wind power PPA. Third, we evaluate and compare the risk exposure of both positions. While risk categorisation of wind power projects in Europe in general is present in existent literature, no authors particularly consider it in Norway. Regarding PPAs, no risk categorization is available for any production technologies or countries.

The remainder of this thesis is organized as follows. Chapter 2 presents a detailed literature review of PPA pricing and financial analyses of wind power investments. Chapter 3 provides background information regarding the two positions, either entering a wind power project or signing a PPA with a wind power plant. Chapter 4 outlines the proposed models for assessing the value and risk aspects of the positions. Chapter 5 presents a case study to evaluate our problem description, consisting of realistic values representing the current Norwegian wind power plant market. Chapter 6 presents our results. Chapter 7 concludes the thesis, in addition to providing suggestions for future research.

2

Literature review

This chapter presents literature of PPA pricing and financial analyses of wind power investments. The literature is summarized in the introduction, but a more extensive overview of the mentioned papers is presented here, due to space considerations.

2.1 PPA pricing

In this section, we provide a review of papers addressing PPA pricing. This is one of our contributions to the literature as, to the extent of our knowledge, no other article presents such an overview. Furthermore, we will incorporate our findings when we later discuss reasonable PPA price levels in the Norwegian market.

2.1.1 Background

We find that the literature regarding pricing of PPAs is rather sparse. In general, the methods proposed can be categorized into four approaches, listed below.

I. Base the price on the LCOE of the associated project

II. Base the price on the BEPE

III. Combining LCOE with LACE

IV. Setting the price to the FiT

A summary of the sources applying or discussing each of the methods is presented in Table 2.1. The column *Application* details how the pricing method is used in the article; whether it is mentioned, recommended or applied by the authors.

Reference	**Country**	**Year**	**Method for pricing PPAs**	**Application**
Miller et al. (2017)	Canada	2017	LCOE	Applies
Bruck, P. Sandborn, and Goudarzi (2018)	USA	2018	LCOE Combining LCOE and LACE	Applies Mentions
Ryor and Tawney (2014)	World Resources Corporation, global research initiative	2014	LCOE FiT	Mentions Mentions
Lei and P. A. Sandborn (2018)	USA	2018	LCOE	Mentions
Garcia-Barberena, Monreal, and Sánchez (2014)	Spain	2014	BEPE	Applies

Table 2.1: Overview of the literature considering PPA pricing: author(s), country of origin, year, method applied or discussed, and how it is used.

2.1.2 Approaches to price PPAs

LCOE

In the literature, LCOE is a common measure to express the cost level of different renewable energy technologies (Miller et al., 2017). The LCOE expresses the average cost of producing one unit of energy during the lifetime of a generation unit. The factors normally included in this cost measure are costs related to investment, operation and maintenance, as well as annual production, lifetime and required interest rate. The main argument for using LCOE for PPA pricing is that the available literature accentuates this approach compared to the other approaches. According to Miller et al. (2017), applying LCOE to negotiate PPAs is essential because the contract price needs to exceed this cost measure to make the project profitable and realizable for the developer. Bruck, P. Sandborn, and Goudarzi (2018) also claim that LCOE is used for setting a fair price for PPAs. Their view is supported by a report, Finance Quarterly - Europe's PPA Revolution, published by A Word About Wind (2018) in 2018, deliberating on the state of PPAs in Europe, particularly focusing on lessons to be learned from the Scandinavian market, where PPAs are thriving. A Word About Wind (2018) claims that low power prices in the region have forced wind power producers to enter PPAs to secure income for covering costs, however at quite low PPA prices due to the low power price level in the market. The fact that LCOE is a method of measuring the cost of energy, provides motivation to use it as a starting point for pricing power in long-term contracts. In the following paragraphs, papers considering pricing of wind power PPAs by using the LCOE are presented.

Miller et al. (2017) claim that a correct estimate of the LCOE of a wind power plant is crucial when negotiating the price of PPAs. Reported values for LCOE of different plants vary substantially in size. Addressing this difference, the authors seek to investigate the different inputs used for LCOE calculations. Miller et al. (2017) argue that there are large differences to what constitutes the LCOE, making it difficult to determine a specific definition. Moreover, they conclude that some of the factors frequently left out of the formula, such as costs related to transmission grid and environment, might have major impact on the estimates and therefore should be included.

Bruck, P. Sandborn, and Goudarzi (2018) also apply LCOE as a basis for PPA pricing. They argue that the delivery limits set forward by the contracts impose costs to a producer which need to be included in the LCOE, to set a correct PPA price. Currently, these costs are rarely included in the LCOE, as there has been little research on the topic of LCOE for plants with PPAs. A PPA customer has the liberty of determining terms specifying the amount of power they are obliged to purchase, and the maximum and the minimum required power delivery from the producer. If the power supply exceeds or falls short of these limits, it may incur a penalty for the producer. Thus, Bruck, P. Sandborn, and Goudarzi (2018) provide a revised model for the LCOE, where penalties are included, aimed at wind power plants holding PPAs.

Lei and P. A. Sandborn (2018) consider wind power plants with PPAs. The problem investigated in the paper is how to schedule predictive maintenance for a wind power plant with a PPA, using a real options model. Additionally, the authors claim that the price of a PPA results from negotiations based on the LCOE of the wind power plant, incorporating adjustments due to risks. This is argued by referring to the above paper by Bruck, P. Sandborn, and Goudarzi (2018), without further elaboration. Moreover, the authors make the following additional assumptions regarding the PPA; that the buyer acquires energy at a fixed price and that the supplied amount should be within an upper and lower bound. If the supply exceeds the upper limit, the customer can choose to purchase the overshooting power at a lower price, or not at all. On the other hand, if the amount supplied is less than the lower bond, the producer is required to compensate for the shortfall at a settled price. Thereafter, Monte Carlo simulation, including simulation of revenues and drawing wind speeds from the Weibull distribution, is applied to a case study. Lei and P. A. Sandborn (2018) use a PPA price of \$20/MWh in their case. The over-delivery price is set to \$10/MWh, and \$40/MWh is assumed the cost of purchasing power to cover for shortfall of supply. The prices are set without further elaboration.

BEPE

Another possible approach to PPA pricing is to use the BEPE. According to Garcia-Barberena, Monreal, and Sánchez (2014), BEPE is the best measure for evaluating power projects, pricing PPAs and set FiTs. BEPE is the necessary selling price a producer needs to receive in the market to achieve the required rate of return from a renewable power project. Garcia-Barberena, Monreal, and Sánchez (2014) claim that in spite the extensive usage of LCOE when comparing renewable energy projects, it is not applicable if aiming to choose between mutually exclusive projects. Additionally, Garcia-Barberena, Monreal, and Sánchez (2014) state that LCOE is inappropriate for setting FiT. Furthermore, it is claimed that a financial indicator for comparing projects should be based on the revenues of projects rather than the costs. Therefore, the BEPE, representing the minimum price that producers can accept in order to meet their required return on equity, is appropriate for calculating FiTs (Garcia-Barberena, Monreal, and Sánchez, 2014). However, calculating it requires computing all cash flows during the entire lifespan of the project, considering both costs and benefits, making it rather complicated compared to LCOE computations.

LACE

LACE poses an alternative to LCOE for profitability analysis of renewable energy projects, including projects with a PPA (Bruck, P. Sandborn, and Goudarzi, 2018). As the source only slightly mentions LACE, they refer to the work by U.S. Energy Information Administration (2018) for further elaboration on the subject.

U.S. Energy Information Administration (2018) describes LACE as a measure of competitiveness between generation technologies. LACE, or the avoided cost, quantifies the cost of producing an amount of energy by a power system instead of producing it with a new production unit, in this case being renewable. When using this measure, it is not required that the technologies considered are renewable. Still, it is commonly applied in this context. In short, LACE is the alternative cost of not investing in new production capacity, while still producing the same amount of energy from the total power system. Thus, the avoided costs constitute the value of the considered new project. It can be levelized over the lifespan of the project and divided by the annual production to obtain the LACE of the project. LACE may then be compared to LCOE to consider whether the value of the project exceeds its cost or not. U.S. Energy Information Administration (2018) states that using the two cost measures in combination, rather than separately, provides a better evaluation of overall competitiveness of a power project. However, LACE is complicated to calculate compared to LCOE. The avoided cost is, in the discussion of U.S. Energy Information Administration (2018), based on the marginal value of energy and capacity of the power system that would result from adding a unit of the technology of the new project. Due to difficulties of valuing the LACE, and the fact that it is not a widespread concept in the literature, we will not elaborate this concept further.

FiT

The last pricing option proposed by the literature, is to calculate a PPA price using FiT. Ryor and Tawney (2014) support computing the PPA price by the use of LCOE, but state that as an alternative approach, the price could be set to the FiT, without further elaborating this view.

FiT is a widely discussed topic in the literature. It has been used as a support scheme for renewable energy in several countries. Before auctions became popular, it was considered the most efficient renewable subsidy. FiT schemes assure producers a fixed price for the entire production output, guaranteed by the Government who compensates the producer for the difference between the spot price and the fixed price per kWh produced. Hence, it can be viewed as a PPA between a renewable power plant and the Government. The subsidy is efficient because it provides long-term financial stability to investors of renewable projects. However, the fixed price is often set above market levels, thus constituting an additional cost to society, as the FiT is essentially paid for by the consumers. Therefore, it is important to set this fixed price at a level that ensures increased investment in capacity, whilst still keeping costs at a reasonable level (Lesser and Su, 2008). How to determine the value of the FiT is an interesting question discussed in the literature, which we will present now.

Determining FiT levels

Klein et al. (2010) discuss different ways of determining FiT levels. The first approach introduced, is basing the tariff on the electricity generation costs from renewable energy sources. Another possibility is to use the avoided external costs induced by including renewable energy sources as a foundation. Applying the first method, costs related to investment, operation and maintenance, and fuel, in addition to inflation, interest rates for capital and profit margins for investors, expected electricity generation and lifetime of the plant, can be used to calculate the production cost of energy, which is basically the LCOE. Klein et al. (2010) state that this is the approach most commonly applied in Europe. Using the second approach, the avoided costs are the base of the FiT, incorporating expenses of climate change, health issues due to pollution, agricultural loss, material damage and effects on energy supply security. Furthermore, the costs of producing the energy from the renewable project using conventional production instead, may be included. This method is applied in Portugal, where green producers receive a monthly payment calculated based on the investment cost of conventional power plants needed without the green producer. Moreover, it is based on the power generation costs of this hypothetical conventional plant, as well as cost of CO2 emissions from the alternative production, adjustment for inflation and avoided electrical losses in the grid (Klein et al., 2010).

Cory, Couture, and Kreycik (2009) also investigate the design of FiT policies. The authors claim that there are two main categories for these payments; using either the levelized cost of renewable generation as base, or the value that the green generation poses to the society. Applying the second approach, the FiT may be set to the avoided cost of the utility or the external costs of conventional generation. However, a problem with this approach is that the resulting value may not match the actual costs of the renewable production. Thereby, this method may lead to slow development in green production.

Lesser and Su (2008) seek to design an economically efficient FiT structure. According to the authors, the main challenge faced by regulators when designing a FiT, is to encourage renewables growth at the lowest possible cost. If the long-term price determined far exceeds the market average, it will cause the spot price to rise, implying reduced socioeconomic welfare. However, if the prices are too low, the renewable capacity development desired will not be realized. The authors find that current tariff designs share certain characteristics. Firstly, they pay above market rate to generators, and hence motivate maximization of power output. Secondly, the schemes are time limited, and often include decline of payments with time to account for technology improvements. Additionally, the terms of a FiT commonly depend on the type of generation technology. Furthermore, Lesser and Su (2008) introduce attributes which, in their opinion, constitute those of the ideal FiT. Primarily, the optimal tariff should encourage new capacity development and generation. Moreover, the price must not be too high or low, to avoid either increased market price for consumers or under-stimulate renewable development. It is neither desirable for the scheme to be distorting market power prices, nor create public opposition to the scheme. To achieve this, it is necessary to link the FiT to production. Also, a too high tariff could slow down technology development. The authors suggest a two parts model for price structure of the scheme, consisting of a capacity payment determined through an auction and an energy payment tied to the spot price. First, the Government should set a goal for renewable development, and then arrange auctions to attract developers to settled projects. The interested developers then submit their bids for capacity payments, at the necessary level to be able to enter the capacity investment. The price is set for a predetermined number of years. The second part of the suggested model is that the developers themselves decide how they wish to sell their electricity, to either spot market or through bilateral contracts, rather than set a fixed FiT energy price. Hence, the support is through capacity payments, instead of through a fixed price for production.

2.1.3 Summary

In conclusion, within the limited available literature regarding PPA prices, many approaches are proposed. Because the contracts are traded over-the-counter (OTC), no industry standard exist. However, all the four approaches to PPA pricing share the same characteristics that the price must cover the cost of generation for the renewable technology in question, including a decent return to the investors.

Among the methods introduced in the considered papers, the LCOE is the most prevalent measure. A suggested expansion to the LCOE is to include LACE in the calculations. Since both BEPE and LACE are considered more complicated to calculate than LCOE, LCOE may be the preferred option. Using FiT schemes provides an alternative approach to PPA pricing, but the methods are many, and often comprehensive, potentially making it complex in contrast to LCOE. Because LCOE is the most common approach in the literature, we choose to proceed using this methodology in our master thesis.

2.2 Financial analyses of wind power investments

This section will present available literature concerning financial analyses of wind power investments, using DCF and Monte Carlo approaches. The topic is well covered in existing academic papers.

There is no literature evaluating wind power investments in Norway during the last few years. The market conditions for wind power has been in great development, and hence we will reassess this topic in our thesis. There were, however, authors evaluating this topic some years ago; (Dale and Husabø, 2013; Yari, 2015). These will be presented in the next three paragraphs.

Dale and Husabø (2013) assess costs and profitability of Norwegian onshore wind power in 2013, as well as the development towards 2020 and 2030, based on available market information in 2013. The authors perform a thorough analysis of LCOE based on 33 wind power projects receiving construction concession from 2009 to 2013. Moreover, they discuss the dynamics of Norwegian power prices. Based on a comparison of LCOE and expected prices, Dale and Husabø (2013) conclude that Norwegian wind power is not profitable and will be dependent on subsidies at least until 2020, perhaps even towards 2030.

Yari (2015) analyses the main reasons for the modest progress witnessed for the Norwegian wind power industry compared to other European countries. The author examines the differences in support schemes between countries and the factors that industry actors believe causes the slow development. Lastly, the author assesses the profitability of a case wind power plant, resembling the Norwegian market. The author analyses the net present value (NPV) and internal rate of return (IRR) for the case, modeling constant production and a price set to the average Norwegian spot price in 2011-2014. The conclusion is that wind power is highly dependent of investment support, green certificates or higher power prices to become profitable.

To sum up, both papers include simple DCF approaches to wind investment evaluation and conclude that wind power in Norway is highly dependent on increased future power prices to obtain profitability.

Authors applying Monte Carlo simulation in wind power assessments are widely present in literature. However, these are mainly considering other countries than Norway.

For instance, Gass et al. (2011) apply statistical simulation methods to examine the uncertainty in profitability of wind power, imposed by intermittent wind conditions. Using simulated wind speed data, the authors assess profitability by using IRR as the indicator, and conditional value-at-risk (CVaR) to estimate a probability for each IRR. Gass et al. (2011) claim to suggest a general methodology applicable to evaluate wind sites based on measured wind speed distributions and CVaR, contributing to the existing literature. A case study, where daily mean wind speeds at a specific site are used to generate wind data for the whole project lifetime, is applied on an MCP method. MCP is a statistical technique used for predicting the long-term wind resource at a proposed wind power plant site, relating short-term measurements to long term at the meteorological site. Thereafter, the production is calculated by using the power curve for the respective wind turbine and multiplying by 24 hours per day. The resulting annual cash flows are found from annual production, a price set by the FiT in the case study location Austria, operational costs and tax. These are used to calculate IRR and CVaR.

Another example is Afanasyeva et al. (2016). The authors propose a technical and economic wind farm model which analyses uncertainty in input variables, both by conducting a sensitivity analysis for each variable and using Monte Carlo simulation. The purpose of the model is to assess how uncertain input factors affect the financial risks of a wind project. The economic evaluation focuses on NPV, and modeling investment and operational costs and income as uncertain. The technical analysis focuses on the unpredictable annual energy production, accounting for wind directions and wakes when using the Weibull distribution. The authors evaluate the uncertainty factors of measurement, long-term resource estimation, site assessment and wind resource variability, all related to the wind conditions. The Monte Carlo model includes probability density functions for those parameters where a reasonable distribution is available. The other parameters are assessed using a sensitivity analysis. The model is applied to a case plant in Finland. The resulting output is a histogram of annual production and project NPVs, with a sensitivity analysis of all input parameters, varied by +/- 5%.

Khindanova (2013) is a third relevant paper. The authors analyse a wind power generation investment. A case study is investigated through a deterministic NPV model, including a sensitivity analysis. Moreover, the authors conduct a Monte Carlo analysis of the investment, modeling electricity price, load factor, construction and operational costs as uncertain. Parameterized normal distributions for each of these are applied in the simulation. The authors generate a distribution for NPV for a base case using different discount rates. It is concluded that compared to a single point estimate of NPV, the probability distributions make it possible to observe the range of possible NPV values with their probabilities. This provides much more insight in the profitability question.

Furthermore, Çevik et al. (2015) investigate risk of wind energy investments in Turkey. Applying real option and Monte Carlo based methods, they consider three factors as variable; power prices, production and investment cost. Wind speeds are simulated using the Weibull distribution and power prices are assumed to follow a geometric Brownian motion. Thereafter, the production and prices are simulated to calculate the income. Thereafter, production costs are included to compute NPV and real option values. The results for the investment case are displayed by histograms and graphs of resulting NPV, to illustrate the risk exposure in the project.

M. Albadi, El-Saadany, and H. Albadi (2009) perform a techno-economic examination of a wind power project in Oman, focusing on NPV and IRR. Applying wind speed data from a specific location, the parameters of the Weibull distribution are estimated and used along with the turbine power curve. By integrating the power curve and estimated Weibull distribution, the average power production of the plant is found. Thereafter, this is multiplied by the number of hours per year to determine the annual production. M. Albadi, El-Saadany, and H. Albadi (2009) use FiT to specify the price of the produced power. Additionally, they perform a sensitivity analysis on different input parameters.

Li, Lu, and Wu (2013) assess the investment risk of wind power projects in China, obtaining project NPV from Monte Carlo simulation. The paper includes various Chinese support policies and regulations regarding power in the analysis. The authors identify relevant risk factors and view them as random variables, to further use Monte Carlo simulation to calculate NPVs. The risk factors are assumed to be investment cost, operational costs, electricity connected to the grid, and subsidies. The annual production is found using Weibull and the power curve to calculate the annual average production. The authors present the average NPV from their simulations as their result, for different ratios of grid connected energy to valid generated electricity. This constitutes their measure of risk.

Caralis et al. (2014) evaluate attractiveness of different wind energy regions in China, considering the investment risks of wind potential, wind curtailment, grid access and macroeconomic parameters. The Monte Carlo approach is used integrated in a financial model, simulating parameters from underlying probability distributions. The uncertain parameters investigated are wind capacity factor, investment cost, interest rate and FiT. The uncertain factors are simulated using triangular distributions, calibrated using data from 500 randomly selected sites, and already realized, Chinese wind projects. The results are confidence intervals for IRR of the different regions.

Yang et al. (2010) seek to quantify wind energy investment risk premiums and evaluate uncertainty due to Clean Development Mechanism benefits. The project NPV is investigated. Carbon and certificate prices are assumed to follow a stochastic process as a combination of a mean-reverting process and a mean drifting like a random walk. Policy uncertainty is modeled as a discrete shock in price at some known time in the future. A cash flow model is suggested. Revenue comes from electricity sales and CER credits, and costs include those related to capital, operation, maintenance and taxes. NPV is calculated based on these, and a distribution is presented.

Salles, Melo, and Legy (2004) present methodologies appropriate for financial analysis of wind power projects, focusing on wind speed uncertainty. Monte Carlo simulation and Box Jenkins approach are emphasized by the authors. The methods are specifically employed using wind speed data from a wind power plant site in Brazil, to simulate wind speed sequences. The results are probability distributions used to calculate risk measures, for instance the probability of negative returns.

All the mentioned authors use Monte Carlo simulations to obtain confidence intervals or histograms for NPV or IRR, to evaluate profitability and risk in wind power projects. The authors model different underlying factors as uncertain; power prices, production, wind conditions, investment cost, operational costs, policies, interest rate and FiT. Some of these are accounted for in the Monte Carlo simulation, while others are through sensitivity analyses, dependent on information regarding the probability distribution of the underlying factors. We will assess the wind power plant position in our thesis by using DCF and Monte Carlo methods, similar to what is mentioned above. However, we focus on a case study representing the Norwegian market conditions. Moreover, we will include power prices and production as uncertain input factors. Argumentation for this is found in Chapter 4.

3

Background

Primarily, our purpose is to investigate whether a large power consumer situated in Norway should engage in an onshore wind power project or a PPA to cover their own power demand. Henceforth, we refer to these two alternatives as Position 1 and Position 2, respectively. This chapter provides background information relevant for understanding and evaluating the positions, as well as the assumptions made. First, we consider Position 1, before Position 2 is examined.

3.1 Position 1: Develop and operate a wind power plant

Taking the first position, the large power consumer chooses to construct an onshore wind power plant to cover their energy consumption.

In the following subsections, we introduce factors relevant for comprehending Position 1: overview of a wind power plant project, relevant cost categories and data of wind projects currently under construction in Norway.

3.1.1 Overview of a wind power plant project

Figure 3.1 provides a visual overview of what constitutes a wind power plant.

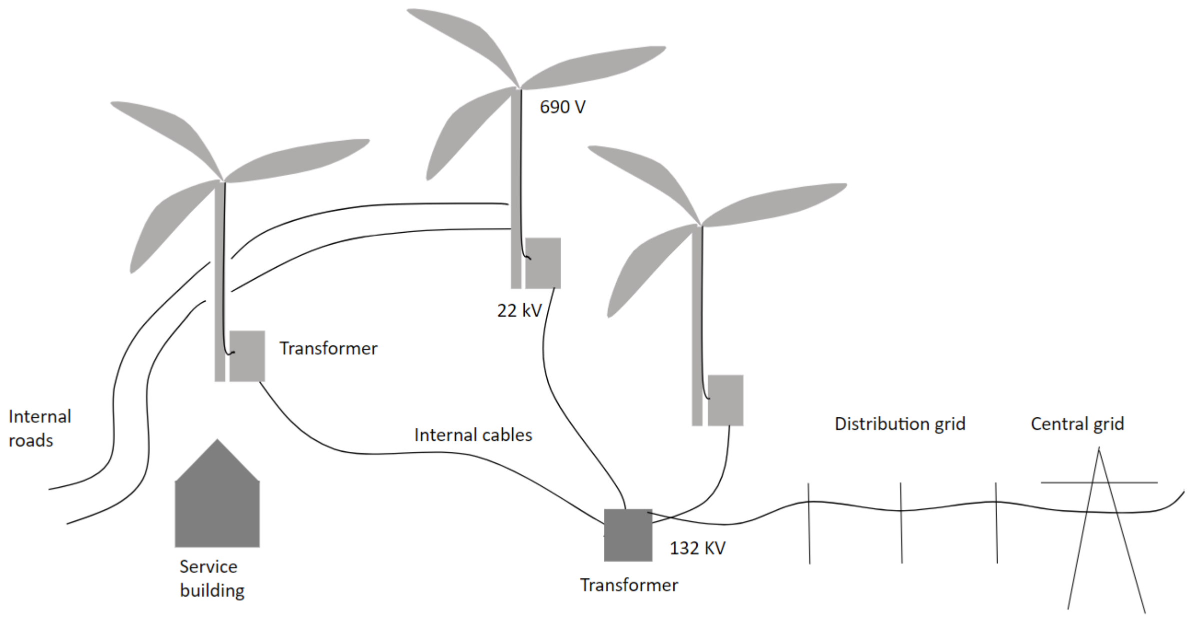

Figure 3.1: Overview of the wind power plant site. It is necessary to establish infrastructure and connect to the central power grid. The plant consists of turbine bases, turbines, internal power grid with transformers, grid to connect the plant to the central grid, as well as internal roads and service buildings.

The plant consists of turbines and transformers, internal and external grid, and internal roads.

The phases of a wind power project are shown in Figure 3.2.

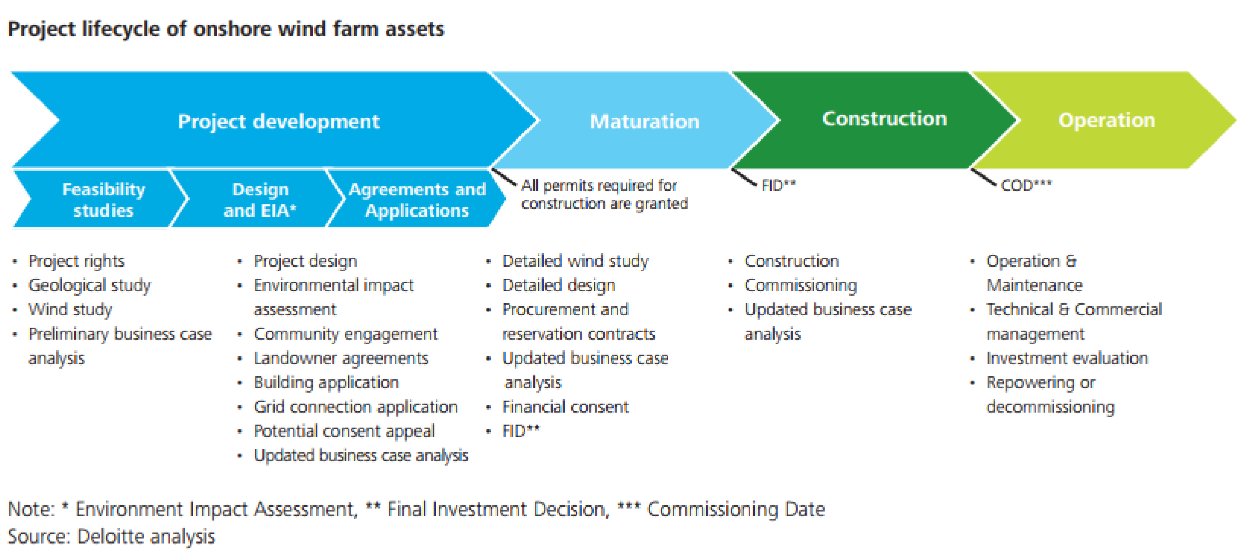

Figure 3.2: Phases of a wind power project. The process consists of a development phase, maturation, construction phase and operational phase. Source: Deloitte (2014)

The first step of the wind power plant establishment process is the development phase, focusing on conducting the steps necessary to obtain a concession, i.e. granting a permission from the authorities to realize the project. If concession is given, a maturation phase where all plans are finalized follows, before the actual plant is built in the construction phase. Lastly, the plant is commercialized and enters the operational phase.

3.1.2 Cost categories

The costs associated with a wind power project are separated into three categories; investment, operational and capital costs. Investment expenditures are all costs incurred before the operation commences, including those imposed during construction and procurement of the installations presented in Figure 3.1. Expenses related to the operational phase of the plant, i.e. balancing, maintenance and other daily concerns are regarded as operational costs. Capital costs includes interest rates and expenditures regarding payments of the upfront costs to banks and investors. Additionally, the concession process incurs expenses.

3.1.3 Plants under construction

Table 3.1 lists the different projects under construction, as of the first quarter of 2019, and their associated investment cost, year of completion, number of turbines, installed capacity and annual production.

Plant	Estimated investment cost [MNOK/ MW]	Number of turbines	Installed capacity [MW]	Yearly production [GWh]	Year of completion
Frøya	8.93	14		200	2020
Hundhammerfjellet	8.93	14		210	2020
Stokkfjellet	8.93	21		310	2021
Sørmarkfjellet	8.93	31		440	2021
Måkaknuten	8	24	100	330	2020
Skorveheia		9	36	95	2020
Bjerkreim Søndre Klynge	8.5	70	294	1000	2019
Storheia	10.41	80	288	1000	2019
Kvenndalsfjellet	10.41	27	113.4	384	2020
Hardbarksfjellet	10.41	30	126	433	2020
Geitfjellet	10.41	43	180.6	584	2020
Hitra II	10.41	26	93.6	290	2019
Kvitfjell/Raudfjell		67	281.4		2019
Sørfjord		23	96.6	325	2019
Hennøy	9.92	12	50.4	171.4	2019
Tonstad		51	200	600	2019

Table 3.1: Overview of current developing and planned wind power plants by 2021.

The table provides background necessary to substantiate some of the case values selected in Chapter 5. A blank cell indicates that the value is not publicly available. Various sources are used; (Statkraft, n.d.; Norsk Vind Energi, 2019; Nea Radio, 2019; NVE, 2019[c]; Bygg.no, 2018; Vindportalen, 2019[e]; Nordkraft, 2019; Aadland, 2017; Bjerkreim kommune, 2017; Frafjord, 2017; SFE, 2018).

3.2 Position 2: Entering a PPA with a wind power project

Taking the second position, the large power consumer chooses to enter a PPA with a wind power producer. When considering the contract, we put emphasis on the customer side, as this is the perspective of the consumer.

In the following subsections, we introduce factors relevant to comprehend Position 2: definition of a PPA, motivation for the contractual parties, types of PPAs, including indepth examination of those used in the thesis. Lastly, we discuss common contract terms.

3.2.1 Definition of PPA

A PPA is a contract between two parties. The customer obliges to purchase a predetermined power quantity from the producer, at a fixed price. Such contracts are commonly applied for renewable energy (Thumann and Woodroof, 2009). Furthermore, Thumann and Woodroof (2009) state that, as a consequence of the complexity of the contracts, they are primarily used for large power intensive projects.

The underlying power plant is constructed and operated by the producer. The PPA customer has no responsibilities beyond purchasing the power, whilst still receiving the benefits of green energy at a predictable cost.

3.2.2 Motivations

Customer side. By entering a PPA, the customer acquires power at a fixed rate, thus receiving a hedge against the volatile price changes in the electricity market. Additionally, a PPA incorporating green energy provides corporations with the opportunity to consume renewable power and promote a greener image. Thereby, the consumer may benefit from renewables while avoiding to establish own production facilities, and being exposed to any of the related risks (WBCSD, 2019).

For instance, Google (2019) states that, "As data centres are one of the world's fastest-growing electricity users, it's good business sense for Google to go sustainable and good corporate citizenship to help others move in that direction". Therefore, the company procures PPAs to solve their issue of acquiring sufficient renewable energy supply for their power intensive data centres. Google participates in the global corporate leadership initiative RE100, which gather influential corporations who are committed to 100 % renewable energy in their operations (RE100, 2019). To reach the goal of 100 % carbon neutrality, Google finds it important that the energy consumed in their operations originates from renewable sources. As the ideal location of a green energy plant rarely coincides with that of a data center, their opportunities for establishing their own plants are limited. Thus, Google considers PPAs as an ideal way of accomplishing their objectives (Google, 2019).

Producer side. Without a PPA, the producer must interact with the power market, making it exposed to the volatile spot prices. If the average power price is less than the LCOE, the levelized unit cost of power production, investing in the plant can render unprofitable.

A PPA, providing a steady income, solves this issue and provides security for investors. This can potentially ease project financing of green plants (WBCSD, 2019).

For instance, the Tellenes wind power plant would not have acquired financing from BlackRock without the entire production of 12 years being purchased by Google (Hersvik, 2018). This demonstrates the role of the PPA in mitigating the risks by providing a certain cash flow, which attracts investors.

Thereby, a PPA provides mutual benefit to both parties, but the question of who will benefit the most depends on the contract terms and the average power price level.

3.2.3 PPA categories

Physical PPA. A physical, or sleeved, PPA requires that the customer and the producer are connected to the same grid (WBCSD, n.d.[a]). In this type of PPA, the grid is used to transport power from where it is produced to the location of consumption. The producer will supply power, which must be consumed by the customer in real time, and a fixed price is paid by the customer to the producer. This type of contract is a bilateral agreement between two parties supplying and demanding a physical product (Norton Rose Fulbright, 2017).

Financial PPA. A financial, or synthetic or virtual, PPA do not require that the producer and consumer are connected to the same grid. Such a contract is frequently applied in the UK and US. WBCSD (n.d.[a]) explains the transactions involved: The production is sold at spot price, and the consumer purchase power from the spot market at market price. Afterwards, the parties compensate each other, making the customer pay the agreed fixed PPA price.

3.2.4 Examples of PPAs

In Norway, all producers and customers are connected to the same physical grid. Therefore, physical PPAs are discussed in the following section. There are mainly two types of this PPA; *As produced* and *Base supply* (Renewable Choice Energy, 2016).

Contract type 1: *As produced-PPA*

In an *As produced-contract*, the power is supplied directly to the consumer as it is produced. The quantity delivered is the produced output of the plant, which varies with time. The customer pays a fixed price per MWh supplied, and must adjust potential deficit in supply by trading in the spot market.

In Table 3.2 the most important features of a generic *As produced-PPA* is presented.

Feature	Contract specification	Comments
Type of contract	Physical contract	Producer and customer are connected to the same power grid, and a physical power flow is resulting from the contract.
Production quantity	*As produced*	The customer is promised an estimated annual power supply, but receives the continuous variable production. It must buy all supplied power, independent of deviation from the estimate.
Price	Fixed price per MWh	Price is set for the entire project lifetime.

Table 3.2: Generic features of *As produced-PPA*.

The supply and demand relationships in an *As produced-PPA* are illustrated in Figure 3.3.

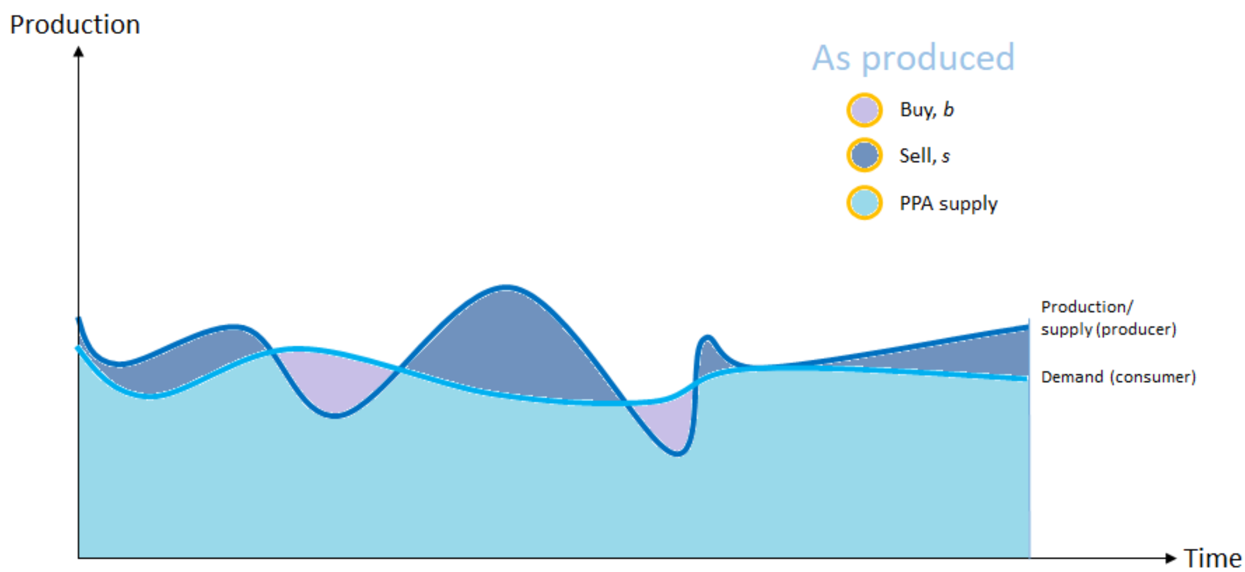

Figure 3.3: Supply and demand of power in an *As produced-PPA*.

An *As produced-contract* provides the developer with a certain cash flow over the duration of the PPA. The customer will have a known power cost for the share of consumption provided through the PPA. However, it always has to adjust the amount supplied by the producer to their own demand. In this case, the customer can trade power on the spot market themselves, or outsource the trade to another company, for instance another power supplier, producer or utility. Both outsourcing and handling the trading internally comes at a cost (WBCSD, n.d.[b]). The resulting cash flows of the two contract parties are shown in Table 3.3.

	Year 0	Year 1	Year 2	...	Year N
Cash flow producer	$-I$	$CF_{PPA}-c$	$CF_{PPA}-c$	...	$CF_{PPA}-c$
Cash flow consumer		$-CF_{PPA}+s_c-b_c$	$-CF_{PPA}+s_c-b_c$	...	$-CF_{PPA}+s_c-b_c$

Table 3.3: Cash flows of producer and consumer holding an *As produced-PPA*.

I denotes the initial project investment cost, c is the annual operational costs, while the lifetime of the project is represented by N. b_c is the cost of the amount of power purchased by the customer, and s_c represents the revenue from sold amounts by the customer.

The resulting cash flow from the PPA, CF_{PPA}, is computed as

$$CF_{PPA} = Q_{annual} \cdot P_{PPA}, \tag{3.1}$$

where Q_{annual} denotes the annual production and P_{PPA} is the price of the PPA. s is the cash flow from power sales to the spot market, while the expenditure from buying power is denoted by b.

Purchasing additional power is necessary for the customer when the power supplied by the PPA does not match the demand. The expressions for s and b are respectively given by

$$s = \int P_t \cdot (Q_t - D_t) \cdot dt, \;\; \forall \;\; t \in [0, T], \;\; Q_t > D_t, \tag{3.2}$$

and

$$b = \int P_t \cdot (Q_t - D_t) \cdot dt, \;\; \forall t \in [0, T], \;\; D_t > Q_t. \tag{3.3}$$

Here, P_t is the spot price at time t, Q_t represents the power supply at time t, and the demanded power at time t is D_t.

Contract type 2: *Base supply-PPA*

In a *Base supply-PPA*, the producer obliges to provide a constant base power output to the customer. Regardless of the production output from the wind power plant, the producer is responsible for supplying the base. Therefore, in case of production deficit, the producer is obliged to procure the remaining power from the market. Superfluous production is also sold on the market at spot price. As the customer may have a constant or temporary power demand which exceeds the base supply, they also conduct additional market trade to satisfy their need. The base power also has a fixed price.

As purchasing a specific quantity practically is a transfer of risk from the customer to the producer, the producer requires a higher price than for an *As produced-PPA*.

The basic features of a generic *Base supply-contract* are presented in Table 3.4.

Feature	**Contract specification**	**Comments**
Type of contract	Physical contract	Producer and customer are connected to same power grid, and a physical power flow is resulting from the contract.
Production quantity	Constant power supply	Customer receives a constant power supply over the whole year but may have a variable demand. It must buy all supplied power and trade on the market to match supplied power with own demand.
Price	Fixed price per MWh	Fixed over the entire project lifetime.

Table 3.4: Generic features of *Base supply-PPA*.

The supply and demand relationships in an *Base supply-contract* are illustrated in Figure 3.4.

Figure 3.4: Supply and demand of power in a *Base supply-PPA*.

The resulting cash flows of the two contract parties are shown in Table 3.5.

	Year 0	Year 1	Year 2	...	Year N
Cash flow producer	$-I$	$CF_{PPA}+s_p-b_p-c$	$CF_{PPA}+s_p-b_p-c$	...	$CF_{PPA}+s_p-b_p-c$
Cash flow consumer		$-CF_{PPA}+s_c-b_c$	$-CF_{PPA}+s_c-b_c$	...	$-CF_{PPA}+s_c-b_c$

Table 3.5: Cash flows of producer and consumer with a *Base supply-PPA*.

Here, I is the investment cost of the wind power plant, CF_{PPA} is the fixed annual cash flow paid for the base supply provided by the PPA, while s_p represents the cash flow from sale to spot market by the producer. The cash flow from the producer purchasing power at the spot market is b_p. s_c denotes the cash flow from sale to spot market conducted by the customer, and b_c is the cash flow from the customer buying power at the spot market.

CF_{PPA}, the cash flow provided by the PPA, is given by

$$CF_{PPA} = P_{PPA} \cdot BS \cdot t, \tag{3.4}$$

where P_{PPA} is the fixed PPA price and BS represents the constant power base supply. Time, denoted by t, is the number of hours in a year, in order to make the cash flow representing annual PPA cost.

3.2.5 Contract terms of PPAs

The most important contract terms of a PPA are as follows; agreed fixed price for energy, duration of the contract and supplied power amount. Another distinctive feature of PPAs is the duration, typically 20 years (Lei and P. A. Sandborn, 2018; Huneke et al., 2018). Furthermore, Daniels (2007) discusses specific characteristics of wind power PPAs. The author regards specified delivery point and transaction scheduling amongst these contract terms. If the PPA is signed prior to construction initiation, it should include some criterion regarding the timing of the milestones of the construction process. These criteria specify the rights and obligations of the parties in case of default, delays and other undesirable events that may occur before the plant reaches operation, including force majeure incidents. Such events could exempt the contractual parties from their payment obligations. Moreover, other specifications that may be included are demands for which insurances the producer must acquire, requirement of necessary liquidity for both parties, and termination rules; describing the consequences for each party in case of ending the contract. Lastly, the responsibilities of the parties in case of possible changes in tax or other policies harming the producer, must be considered.

To the extent of our knowledge, there is no public information available concerning common PPA terms in the Norwegian market. The contracts are negotiated OTC and may be tailored to each specific case.

4

Decision models

In this chapter, we propose models to evaluate the two positions. Firstly, we introduce methods to examine profitability and risk, considering each of the positions as an investment. Thereafter, we present models to assess the cost of power supply from wind power plant and PPA separately. Lastly, we suggest a risk categorization for the positions, to evaluate all associated risks qualitatively.

4.1 Financial and cost models

The following section first focuses on financial valuation of the positions, followed by a cost assessment. The purpose of the analyses is to assist the decision-making process of Norwegian industrial companies considering investing in either of the positions. These firms commonly use DCF analysis when evaluating investment opportunities (Khatib, 2003). Initially, we apply this approach to provide insight intuitive to the industry. To account for uncertainty in the input parameters of the investment case, we choose to extend the DCF model to a Monte Carlo simulation model. Generating a distribution for the NPV through simulation provides a more comprehensive assessment compared to finding only one static value, and may therefore be used to consider risks imposed by variation in the input factors (Khindanova, 2013). Our models are based on available approaches presented by authors of papers assessing wind power investments, among others those introduced in the literature review in Section 2.2. Similar to Montes et al. (2011), we model power prices and power production as the principal uncertain input parameters. The DCF and Monte Carlo models are used to examine NPV, IRR and investor return, regarded as the measures considered most interesting to companies evaluating potential investment projects (Gallant, 2018). Lastly, we look into cost modeling; examining LCOE of a wind power plant and realized energy expenditure (REE) of covering a power load. LCOE is a measure frequently applied in the industry, while REE is a new term, introduced in our thesis and further elaborated on page 48.

When production from the wind power plant does not coincide with the demand of the consumer, market trading is necessary to balance the two power levels. We choose the following approach to account for balancing. For Position 1, all production from the wind power plant is sold to the market, and the quantity necessary to cover the demand is purchased back from the market. Moreover, for Position 2, all power from the PPA producer is bought by the PPA customer, thereafter sold to the market and the necessary quantity is then repurchased.

In what follows, we introduce theory related to our proposed models: spot price forecasts considering the Norwegian market, the use of simulation to account for uncertainty, and approaches for simulating power prices and the power production from a wind power plant.

Future of the Nordic prices

When performing investment analyses of power related investment projects, insight regarding future power prices is necessary. The common practice is to utilize power price forecasts from reliable sources for this purpose, and hence, we also adapt this approach. We will now present the most recent forecasts for Norway originating from credible sources, which we apply in our models. They are provided by Statnett, NVE and Wattsight. Statnett is the Norwegian grid operator, NVE is the regulator of the Norwegian power industry, while Wattsight is a consultant agency, specializing in power price forecasts. As the forecast providers are all experienced actors with different roles within the Norwegian power industry, we regard their predictions as among the best available sources.

Figure 4.1 shows the prognosis published by Statnett in December 2018.

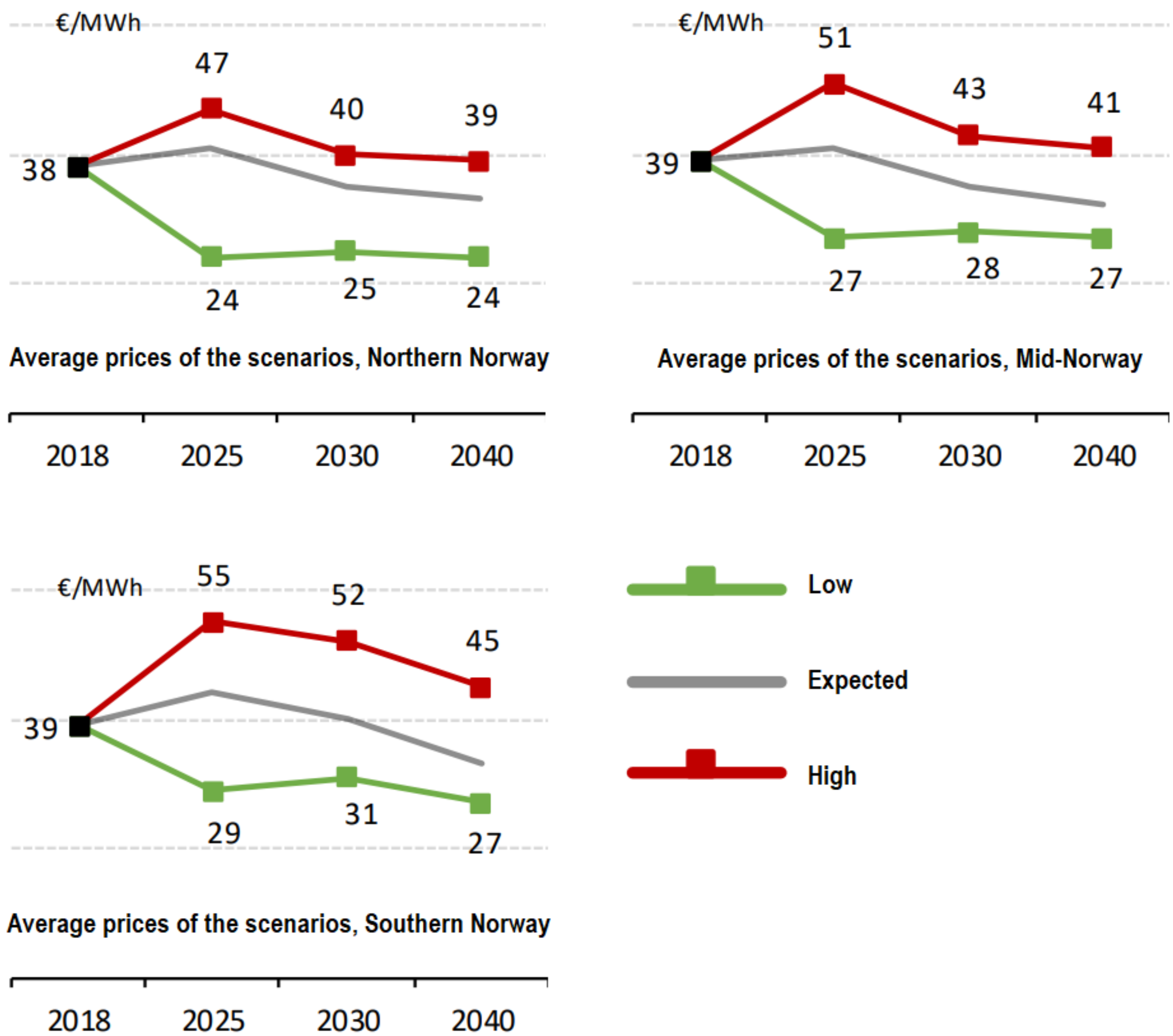

Figure 4.1: Forecast of future power prices by Statnett. Average annual prices from 2018 to 2040, for high, expected and low scenarios in three Norwegian regions, are shown. The numbers are in EUR/MWh. Source: Statnett (2018b).

Statnett suggests three possible price scenarios; high, expected and low. Furthermore, the forecasts are separated into three different regions in Norway; Northern Norway, Mid-Norway and Southern Norway. High future gas and carbon prices, combined with discontinuation of nuclear power in Sweden, are factors increasing the price and can lead to realization of the high price path. Statnett also expects increased consumption in the future, contributing to increased prices (Statnett, 2018b). However, they assume that, if implemented, new subsidy schemes for wind power will lead to increased development and therefore contribute to a potential long-term price decrease.

NVE published a prognosis of the future power prices in October 2017, presented in Figure 4.2.

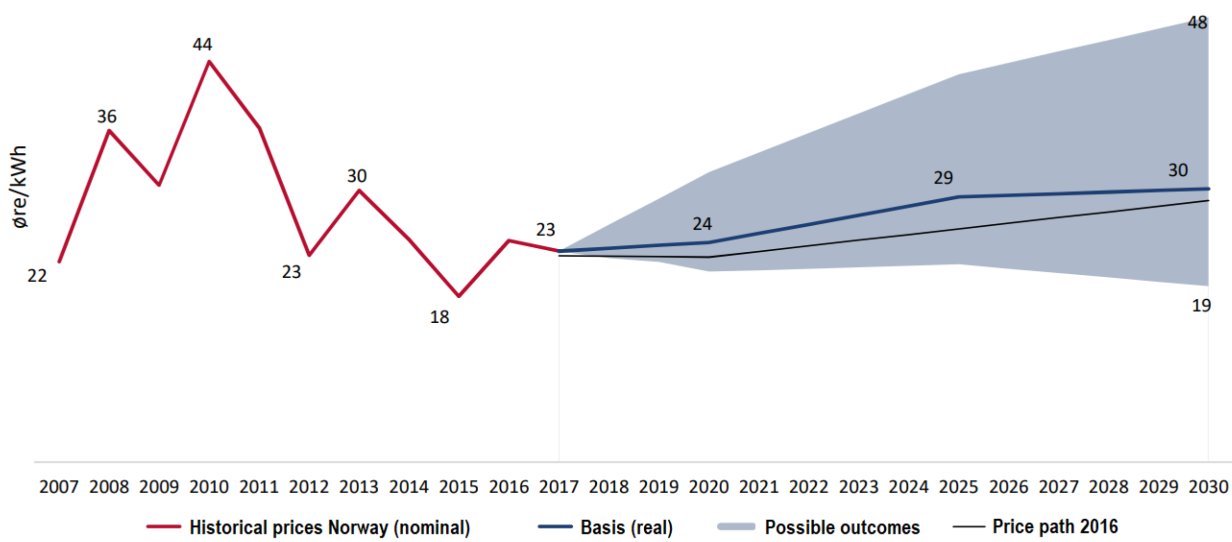

Figure 4.2: Forecast of future power prices by NVE. Expected annual prices from 2018 to 2030 are shown. A grey space indicates the potential outcome for the prices. The numbers are in øre/kWh. Source: NVE (2017).

Like Statnett, NVE also predicts an expected path for power prices. Moreover, they suggest a range within which they anticipate the future power prices will be. The size of the region of expected prices increases with time, ranging from 19 to 48 øre/KWh in 2030. NVE refers to the uncertainty regarding future coal and gas prices to explain this. Currently, the Nordic power prices are heavily impacted by the production costs of coal, a tendency NVE predicts will change around 2025, assuming coal power is replaced by gas. Additionally, NVE anticipates greater regional differences in Norwegian power prices, resulting from bottle necks in the grid in the north and cables connected to the European market in the south. According to calculations performed by NVE, increased interaction with European markets results in an average price elevation of 1-2 øre/kWh for the Norwegian power prices within 2030 (NVE, 2017). Furthermore, increased cable transfer capacity contributes to decrease the effect of seasonality on the power prices, according to NVE. This is because the surplus production during summer is sold to Europe and the expanding wind power capacity reduces the prices in the winter. Beyond 2030, NVE expects stabilizing or a decrease of the power prices, as increased intermittent renewable penetration reduces the average prices (NVE, 2017).

Since the forecast by NVE originates from a report published in 2017, the abnormally high power price levels of 2018 are not accounted for. By including the impact of this irregular price movement, the Statnett and Wattsight, discussed next, distinguish from the NVE forecast.

Wattsight published a forecast of future power prices in March 2019, plotted in Figure 4.3.

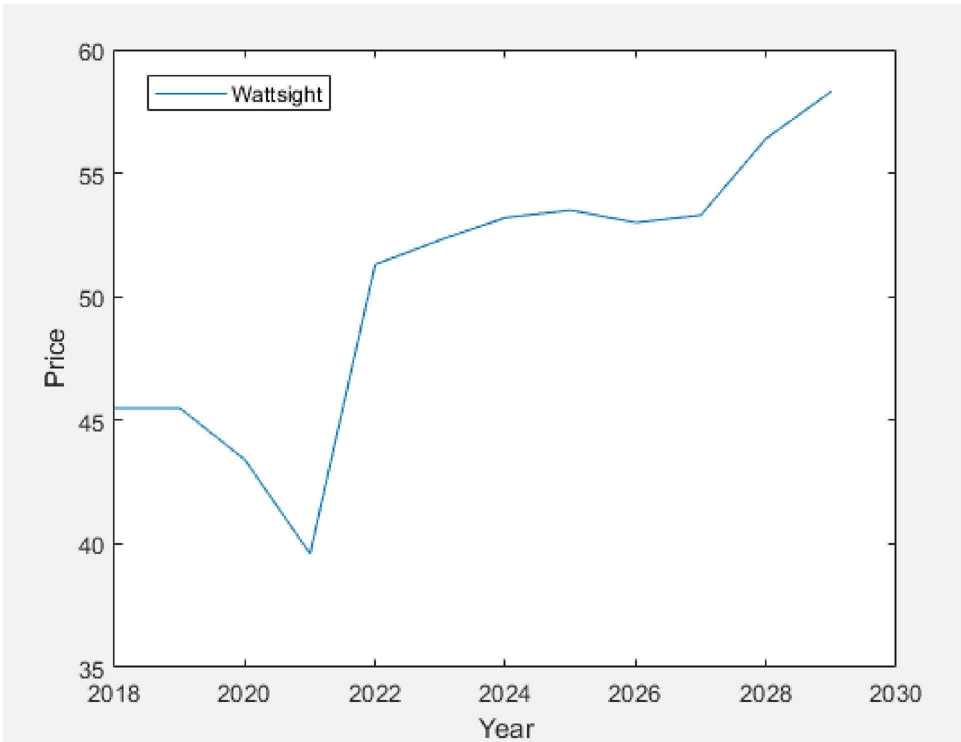

Figure 4.3: Forecast of future power prices by Wattsight. Plotted with values from Barstad (2019). The numbers are in EUR/MWh.

Wattsight is confident in their prediction of increased future price levels, even though their anticipated price levels by far exceeds those suggested by Statnett and NVE. Wattsight analyst Olav Botnen argues that a price increase is likely due to new cables further integrating the Norwegian and European markets, enabling sale of superfluous power. Tor Reier Lilleholt, Head of analysis at Wattsight, concurs, stating that the Nordics cannot be considered as a separate power market, but as an integrated part of the European market (Ballestad, 2019). Furthermore, the Wattsight analysts claim that coal and carbon prices, in addition to an extensive development of wind power, are the main factors currently influencing the European power market. These measures derive from the implementation of ambitious renewable goals, set forward by EU, to initiate a long-term replacement of coal by wind power. Coal is phased out at a faster pace than its replacement is installed, creating a temporary gap in production, which can be filled by, for instance, Nordic production surplus, states Lilleholt (Ballestad, 2019).

In Figure 4.4, the three forecasts are combined with energy futures prices published by Barstad (2019).

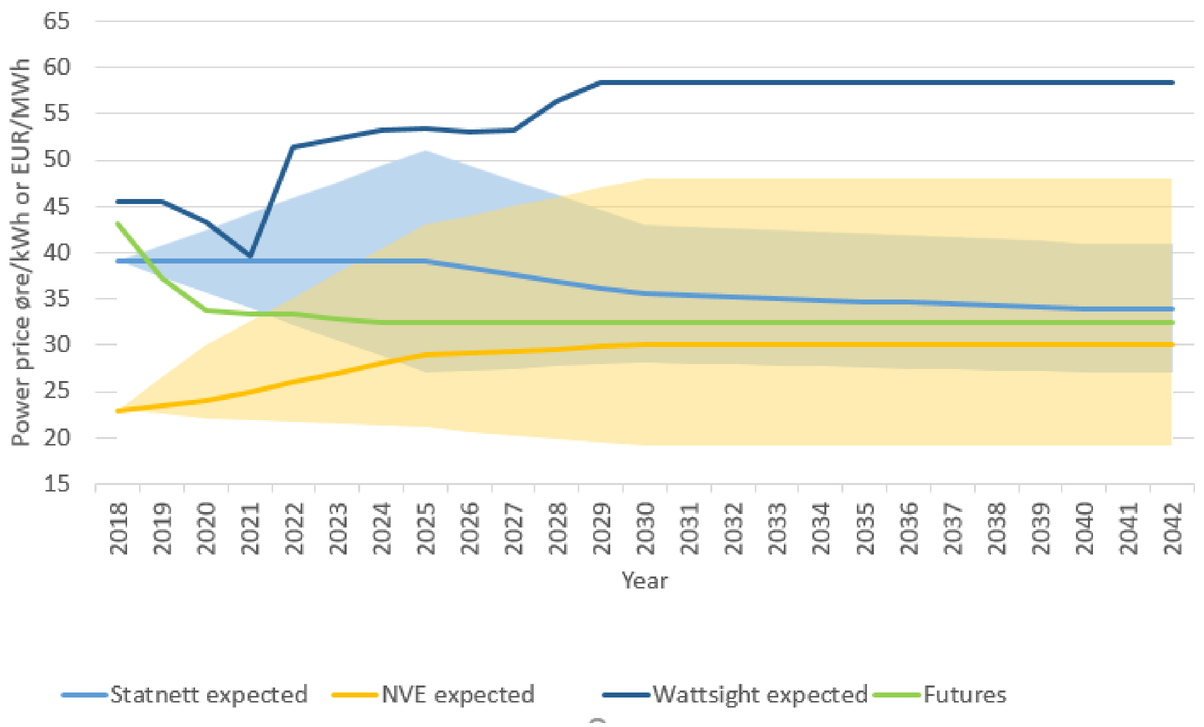

Figure 4.4: Forecast of future expected mean power prices by Statnett, NVE and Wattsight, along with the low and high cases expressed as shaded areas around the expected paths. Prices are given in EUR/MWh, using an exchange rate of 10 NOK/EUR.

For simplicity purposes, the forecasts, all provided in different currencies, are converted to EUR/NOK using the exchange rate of 10 NOK/MWh, a round-off of 9.8040 NOK/EUR from March 3, 2019 (Norges Bank, 2019[b]). Future prices, when available, can be used as an indicator of future power prices. However, using data from Nord Pool in the interval from 1996 to 2006, Botterud, Kristiansen, and Ilic (2010) find that prices of long-term contracts tend to exceed the spot prices.

Concurrent with the findings of Botterud, Kristiansen, and Ilic (2010), NVE anticipates prices to be lower than futures, whereas Statnett expects future power prices to slightly exceed the future prices. Compared to the other forecasts and the future prices, Wattsight claims significantly higher prices during most of the time period considered. Statnett, NVE and Wattsight all suggest the same factors will influence the prices, namely carbon prices, cables and increased renewables penetration. However, Wattsight puts greater emphasis on the impact of the new cables to Europe than Statnett and NVE.

Both Statnett and NVE provide multiple paths for the development of future power prices. Statnett suggests a high, expected and low scenario, while NVE proposes an expected path and an interval in which they anticipate the future power price will be. As opposed to the others, Wattsight only presents one path for future price development, suggesting a major price increase. Contrary to Wattsight, NVE and Statnett anticipate a short-term price increase, equalized in the long term by extensive renewable development.

Monte Carlo simulation and value-at-risk

As a wind power investment depends on uncertain underlying factors, we need a method to evaluate projects which accounts for this. Monte Carlo simulation is a common approach when assessing profitability and risk of wind power projects, for instance performed by Falconett and Nagasaka (2010), Caralis et al. (2014), and Montes et al. (2011).

Performing a Monte Carlo simulation requires three steps: I) identify the uncertain input parameters in the problem, II) select a probability distribution for these parameters and III) generate the output parameter(s) of interest, by randomly selecting values for the input factors for a large number of iterations (Caralis et al., 2014).

Value-at-risk (VaR) is a simple risk measure used in finance. It indicates the maximum loss incurred by a firm or an investor at a certain probability during a specified period. The common approach is to, based on the probability distribution of the return, or NPV of a portfolio or investment project over the relevant period, consider the left tail of the distribution. Here, the value of which for instance 99 or 95 % of the distribution exceeds is found, which is the VaR at a the specified probability (Christoffersen, 2003).

To calculate the VaR of an investment project, it is necessary to obtain a probability distribution for the project NPV. This may be conducted using simulation to generate paths for the uncertain input parameters, and thereafter assess the resulting histogram or confidence interval of the NPV. The purpose of this approach is to produce possible outcomes of the project by including probable developments of the uncertain input variables.

Many authors apply Monte Carlo simulation for this context; (Caralis et al., 2014; Li, Lu, and Wu, 2013; Çevik et al., 2015; Khindanova, 2013; Afanasyeva et al., 2016). The input factors used to calculate the NPV for a wind power investment project is power prices, power production, investment cost, operation and maintenance cost, project lifetime and interest rate, as explained earlier. In principle, all of these may be considered uncertain. However, many authors investigating risks of wind power investment choose to only focus on some of the factors, modeling others as constants.

As seen from the literature review in Section 2.2, there are several examples of papers where this approach is applied. Li, Lu, and Wu (2013) assume investment cost, operational cost, FiT and other support mechanisms as uncertain. Salles, Melo, and Legy (2004) only consider variability in production. Çevik et al. (2015) mainly look at power prices, power production and investment costs as the factors most significant to the uncertainty of wind power investments. Caralis et al. (2014) investigate wind capacity factor, investment cost, interest rate and FiT as stochastic variables, while Khindanova (2013) consider it to be electricity price, load factor, construction and operational costs. Moreover, Afanasyeva et al. (2016) incorporate wind and power production, but examine uncertainty of the other input factors to NPV using a sensitivity analysis.

Afanasyeva et al. (2016) apply Monte Carlo simulation to assess the risks where the probability distribution is known. In their analysis this is wind speeds and production. For the purpose of our analyses, we intend to follow this approach, as we believe we have found a reasonable probability distribution for both power production and power prices. Therefore, we perform Monte Carlo simulations for these input factors, while the others remain constant. This is because we have not identified any suitable distributions of future investment costs, operational costs or interest rate of our case plant.

The literature concerning the potential risks of a PPA is rather sparse. However, Ruiu and Swales (1998) provide a method of evaluating the risks of PPAs; focusing on the quantitative assessment of risk through integration of probability and consequence analyses. The first step of this process is to identify uncertainties in the input factors to a business model developed to simulate the expected behaviour of the contract. Ordinarily, the input is interest rate values, fuel prices, labour price, electricity price or similar. The variable which is beyond the control of the buyer needs to be identified. Thereafter, the business model is formulated to calculate the expected financial outcome of the agreement. Furthermore, the input to the models should also be probability distributions for each of the uncertain variable. Thus, the probabilities associated with the uncertain variables must be identified. What constitutes an appropriate probability distribution for a variable input could be based on expert judgement, historical values or forecasts from viable sources. Thereafter, the confidence interval for the value of the PPA can be determined using the simulations. Hence, this is a similar approach to those applied when considering wind power projects.

Modeling power prices

Commodity prices are generally assumed to be mean reverting (Schwarts, 1997). However, most authors add some extensions to that in the modeling; amongst others, Jabłońska-Sabuka, Nampala, and Kauranne (2011) and Weron, Simonsen, and Wilman (n.d.), who model Nordic power prices. As we focus on the long-term perspective, such extensions are omitted.

Similarly to Myran and Heggelund (2014), who evaluate the profitability of a Norwegian wind power project, we apply the mean-reverting Ornstein-Uhlenbeck process to model power prices. The process is given by

$$dE_t = \kappa(\theta - E_t)dt + \sigma dW_t, \tag{4.1}$$

where E_t is the power price at time t, speed of reversion is denoted by κ, θ is the long-term power price level, while W_t is a Wiener process.

The parameters can be determined by performing a regression using historical data. The process is in essence an AR(1) process which can be transformed to the following structure

$$E_{t+1} = a + bE_t + \xi_t. \tag{4.2}$$

Here, a and b are estimated through ordinary least square regression, to deduce κ, σ and θ in

$$E_{t+1} = \kappa\theta dt - (\kappa dt - 1)E_t + \sigma\sqrt{dt}\epsilon_t. \tag{4.3}$$

Modeling variable wind power production

The Weibull distribution is commonly used as a probability distribution of wind speeds at a location; (Dorvlo, 2002; Garcia et al., 1998; Musgrove, 1987; Darwish and Sayigh, 1988; Masters, 2004). The analytical form of the probability density function is given by

$$f(v, c, k) = \frac{k}{c} \cdot \left(\frac{v}{c}\right)^{k-1} \cdot e^{-\frac{v}{c}k}, \text{ where } \forall \ v > 0. \tag{4.4}$$

Wind speed is denoted by v, while c is the scale factor and k the shape factor.

The Weibull distribution vary a lot in shape, dependent on the factor values. An example is shown in Figure 4.5, having a constant scale factor of 8 and different shape factors.

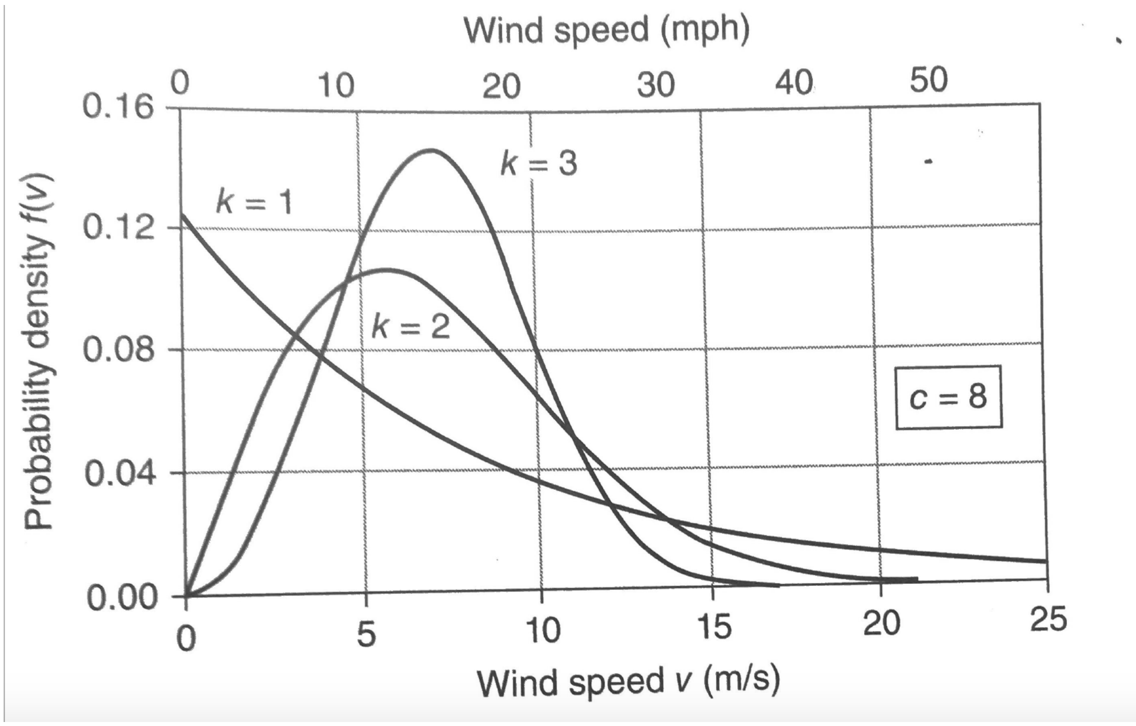

Figure 4.5: The Weibull distribution for constant scale factor and varying shape factor. Source: Masters (2004).

Regardless, a shape factor of 2 is commonly regarded as suitable when the distribution is applied for wind speed probability (Masters, 2004).

The scale factor c can be determined from the average wind speed at a location, $\overline{v}$, through the relationship of

$$\overline{v} = \frac{\sqrt{\pi}}{2} \cdot c. \tag{4.5}$$

The power output from a turbine is dependent on the wind speed, in a manner shown in Figure 4.6.

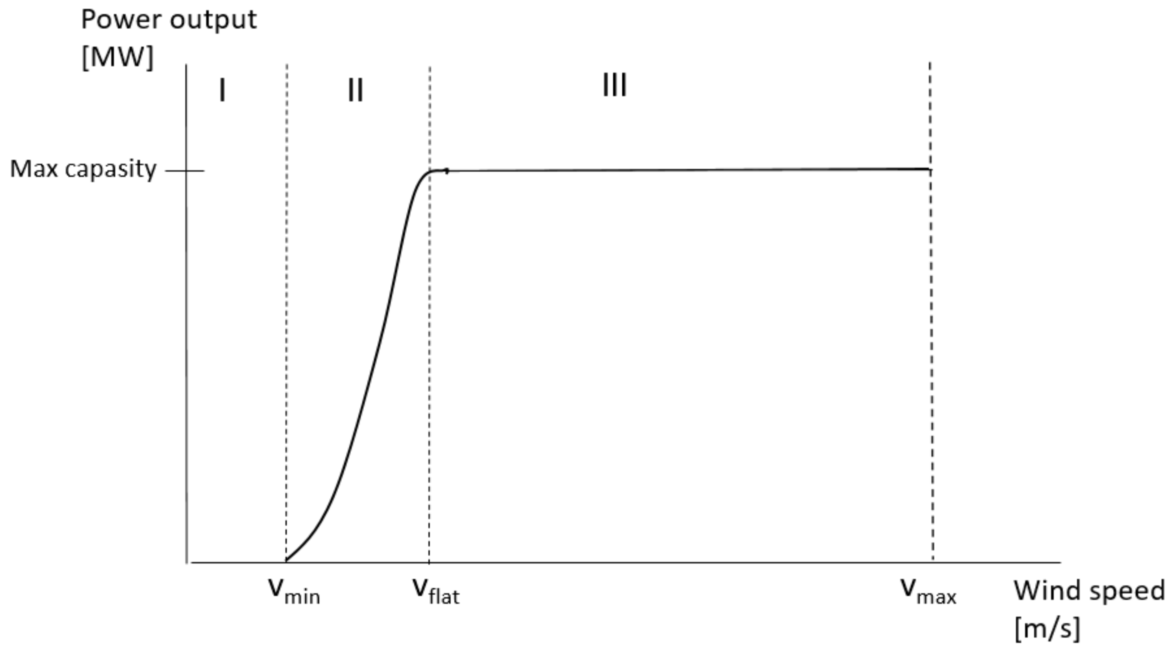

Figure 4.6: Power curve of a wind turbine. The output power varies with different wind speeds. The curve is divided into three regions. Source: Masters (2004).

Masters (2004) distinguishes the production from a turbine in different regions for simplification of modeling, given by

$$P_{wind}(v) = \begin{cases} 0, & \forall\ v < v_{min} \\ \frac{1}{2} \cdot C_p \cdot \rho_{air} \cdot A \cdot v^3, & \forall\ v_{min} < v < v_{flat} \\ K, & \forall\ v_{flat} < v < v_{max} \\ 0, & \forall\ v > v_{max}. \end{cases} \tag{4.6}$$

The power coefficient of the wind turbine is denoted C_p, ρ_{air} is the air density, A the turbine blade swiped area, while v is the wind speed and K the max capacity of the turbine.

In region I, which is below the cut-in wind speed, v_{min}, no power is produced. In region II, the production is amplified with increasing speed. Next, in region III, for wind speeds exceeding v_{flat}, production equals the max capacity of the plant regardless of increased wind speed. When the speed is more than v_{max}, called cut-out speed, the turbine must be shut down to avoid damages.

C_p denotes the share of mechanical power which is possible to extract from the kinetic wind energy. It is defined as

$$C_p = \frac{P_{mechanical}}{P_{E_k,wind}}. \tag{4.7}$$

Assuming Weibull is an appropriate estimate of the wind speed distribution, the average power production from a wind turbine is calculated using

$$P_{avg} = \int_{v=0}^{v=\infty} p(v) \cdot W(v) dv. \tag{4.8}$$

P_{avg} is the average power production from the turbine, $p(v)$ is the power produced at wind speed v, from the power curve, and $W(v)$ is the probability of wind speed v, found by using the Weibull distribution (Masters, 2004).

Applying the Weibull distribution and the power curve to model wind speed probability and wind power production at a location is an approach applied in several papers, for instance Dorvlo (2002), Garcia et al. (1998), Gupta (1986), Justus et al. (1977), Lun and Lam (2000), Stevens and Smulders (1979), and Seguro and Lambert (2000). By drawing wind speeds from the distribution and calculate the resulting power output from the power curve, specified by the chosen parameters, it is possible to randomly generate power production data for a plant site. We use this approach to simulate wind power production in our Monte Carlo model.

4.1.1 Financial models

Position 1.
In the following section, we propose a DCF model for wind power investment, which is further extended to incorporate Monte Carlo simulation. First, we apply simulation to include paths of varying production, holding annual prices constant. Thereafter, we consider varying daily prices and constant annual production, before we are simulating paths for both production and prices. By selecting this approach, we seek to investigate which of the chosen variables impacts the resulting NPV, IRR and investor return to the greatest extent. Additionally, by comparing the results of the two model types, we can examine whether performing the more advanced simulation model provides significantly different results or corroborates the values from the DCF model.

Financial Model 1.I: DCF model with constant annual production and annual prices.
As the industry standard is DCF modeling of investment projects, this will be our starting point.

The annual production of the plant is based on expected full-load hours, while the annual prices are based on price data, either historical or forecasts. Using price prognoses for this purpose is common within the industry, and considering the deliberation on price forecasts earlier in this section, they appear to provide expected annual values. For basic financial evaluation of wind power investments, assuming constant annual production is commonly used in practice by the industry. Moreover, full-load hours is a common way to express annual production of a wind power plant within the industry (Vindportalen, 2019[a]). It refers to the number of hours that a plant would have to operate at full capacity to obtain the annual estimated electricity production. It is computed as

$$FLH = \frac{\text{Annual production [MWh]}}{\text{Total installed capacity [MW]}}. \tag{4.9}$$

We formulate the model based on public available data for wind power projects. In the industry, the investment cost for plants is usually specified per installed capacity, and operational costs for each unit produced, rendering it easier to compare different projects (Vindportalen, 2019[c]).

Based on the above-mentioned logic, the NPV of a wind power plant investment is calculated as follows

$$NPV = -I \cdot K \cdot N + \sum_{t=1}^{t=n} \frac{(1-\tau) \cdot FLH \cdot N \cdot K \cdot (E_t - OM)}{(1+r)^t}, \tag{4.10}$$

where I denotes the total plant investment cost per installed plant capacity, K is the turbine capacity and N the number of turbines. Full-load hours are represented by FLH. E_t is the power price in year t, the tax rate is τ, OM denotes the operation and maintenance cost per produced unit of power, while r is the discount rate and n the lifetime of the plant.

IRR is computed as

$$0 = -I \cdot K \cdot N + \sum_{t=1}^{t=n} \frac{(1-\tau) \cdot FLH \cdot N \cdot K \cdot (E_t - OM)}{(1+IRR)^t}. \tag{4.11}$$

This equation must be solved by iteration, as there is no analytical expression for it.

Based on IRR, the return to investors is calculated by subtracting the capital cost to debt holders, as in

$$r_i = \frac{IRR - r_D \cdot D}{E}. \tag{4.12}$$

Here, r_i and r_D are return to investors and debt holders, respectively. D denotes the debt share, while E is the equity share.

Financial Model 1.II: Monte Carlo model.

To account for uncertainty in input parameters, we formulate a Monte Carlo simulation model based on the DCF model. Because we assume that the investment decision is made under current market conditions, investment costs, operational costs and discount rate is assumed known and equal to the representative values given the current market. Hence, future wind conditions and power prices are the factors we consider as uncertain for the analyses.

Because all wind sites are subject to variable wind conditions, and thereby variable production, we assume this variance as a crucial factor to consider in an investment analysis. Furthermore, as described above, many authors apply the Weibull distribution to incorporate variable production.

In the Monte Carlo model, daily power price and production are simulated for the lifetime of the project, along with NPV, IRR and investor return for the project, all of which constitutes one iteration. Each iteration differs due to randomness in the generated data. Therefore, according to industry standard, 10,000 iterations must be simulated to achieve reasonable confidence intervals (Maverick, 2015). Contrary to *Financial Model 1.I*, the results are confidence intervals of the output parameters. Thereafter, this confidence interval is used to assess the VaR, selected as our major risk measure.

A new formulation for NPV per iteration i is given by

$$NPV_i = -I \cdot K \cdot N + \sum_{t=1}^{t=n} \frac{\sum_{d=1}^{d=y}(1-\tau) \cdot Q_{t,d} \cdot (E_{t,d} - OM)}{(1+r)^t}. \tag{4.13}$$

Here, a daily production is denote by $Q_{t,d}$, while $E_{t,d}$ is the daily power price of day d in year t. y is the number of days in a year.

The expression for IRR is similar to that of the DCF model, making the same adjustments as in Equation (4.13) to Equation (4.11).

We conduct simulations for this model by applying approaches for varying production and power prices, first separately, in respective order as mentioned, and at last simulated paths for both power production and prices are included. These are presented in the following submodels.

Financial Model 1.IIa: Monte Carlo model with varying daily production and constant annual prices.

Firstly, we consider daily variable production, leaving the power prices constant per year.

We simulate daily production by drawing a random daily wind speed from the Weibull distribution, thereafter, calculating a daily power output from the power curve, as elaborated on page 38.

A wind speed $v_{i,d}$ for day d in simulation path i is drawn as

$$v_{i,d} = c \cdot (-ln(1-u))^{\frac{1}{k}}, \text{ where } u \sim U(0,1). \tag{4.14}$$

Here, the value from the Weibull distribution has the shape factor k and scale factor c. u is a uniformly distributed random variable between 0 and 1.

Based on the daily wind speed, a daily power amount is calculated by

$$P_{i,d} = \begin{cases} 0, & \forall \ v < v_{min} \\ \frac{1}{2} \cdot N \cdot C_p \cdot \rho_{air} \cdot A \cdot v_{i,d}^3, & \forall \ v_{min} < v < v_{flat} \\ K \cdot N, & \forall \ v_{flat} < v < v_{max} \\ 0, & \forall \ v > v_{max}. \end{cases} \tag{4.15}$$

This is based on the power curve introduced above. The daily power produced is multiplied by the amount of hours per day, i.e. 24, to be converted into a daily energy production $Q_{t,d}$. This approach is also applied by Gass et al. (2011).

$E_{t,d}$ is set equal for each day for the equivalent year in each iteration.

Financial Model 1.IIb: Monte Carlo model with constant annual production and varying daily prices.
Evident from historical data, the spot price for power is very volatile, making the large variations an important feature of the prices (Nord Pool, 2019).

In this version of the model, we choose to simulate daily power prices by use of the mean-reverting Ornstein-Uhlenbeck process, as described on page 37. The daily power prices $E_{i,d}$ in each price path i is given by

$$E_{i,d+1} = \kappa\theta dt - (\kappa dt - 1)E_{i,d} + \sigma\sqrt{dt}\epsilon_t. \tag{4.16}$$

$Q_{t,d}$ is set to the annual full-load hours divided by number of days in a year, and will hence be equal for all days in the simulation iterations.

Financial Model 1.IIc: Monte Carlo model with daily varying production and prices.
For the last version of the model, where paths for both price and production are simulated, we apply the same methods used in *Financial Model 1.IIa* and *Financial Model 1.IIb* to simulate production and prices, respectively. Hence, the effect of both daily varying prices and production in combination is examined.

Position 2.
Financial Model 2.I: Break-even PPA price model.
Considering a PPA as an investment opportunity, we conduct a DCF analysis to examine the potential for profitability. Since a PPA does not incur any upfront costs, it may be examined as an investment project with zero initial payments. The cash flows of the PPA customer

consist of income from selling power to the market at spot price and purchasing power from the PPA producer at the PPA price.

Due to lack of publicly available information regarding PPA prices in the Norwegian market, we are unable to analyse the NPV without making qualified assumptions regarding this price. Initially, we propose a model which calculates the PPA price that yields zero NPV, called the break-even PPA price. This price provides an indication of the maximum price which a customer is willing to accept in order to make the PPA profitable. Thus, a company negotiating a PPA can use the break-even price as a reference to compare prices proposed to assess the potential profitability of the contract.

In this model, we seek to identify a reasonable range of PPA prices for the Norwegian wind power market. By comparing the break-even prices to the LCOE of Norwegian wind power plants and the market price levels, we will gain insight that can prove useful in a decision-making process.

The break-even PPA price level differs, depending on the required rate of return of the PPA investment. Risk imposed to the PPA customer because of the contract determines the required return. However, this is difficult to quantify. To the extent of our knowledge, no corporations have PPAs as their core business, therefore, there are no comparable betas publicly available in the market. Furthermore, we have no information regarding what constitutes a suitable PPA price. To examine this, we calculate the break-even PPA price for different discount rates. Moreover, as a PPA does not require any investment costs, it does not incur any bank loans. Thus, the discount rate of the PPA is equal to the return of the PPA customer.

The break-even PPA price is calculated based on a classical DCF approach, as in *Financial Model 1.I*, including constant values for both annual production and power prices.

The break-even PPA price P_{PPA} is found by

$$0 = \sum_{t=1}^{t=n} \frac{(1-\tau) \cdot FLH \cdot K \cdot N \cdot (E_t - P_{PPA})}{(1+r)^t}. \tag{4.17}$$

Here, t denotes year, n is the duration of the PPA, while FLH represent full-load hours of produced energy, received by the PPA customer. The annual power price is E_t and P_{PPA} is the fixed PPA price over the contract period, yielding zero NPV at discount rate r. No analytical solution exists for this equation, hence, a solver or any appropriate tool must be applied.

Financial Model 2.II: DCF model of constant annual production and annual prices.
Another way of dealing with valuation of the PPA is to assume some PPA prices within a reasonable range and calculate the associated NPV.

The expression for NPV is then given by

$$NPV_j = \sum_{t=1}^{t=n} \frac{(1-\tau) \cdot FLH \cdot K \cdot N \cdot (E_t - P_{PPA,j})}{(1+r)^t}, \tag{4.18}$$

where j denotes the number of PPA price possibilities.

IRR is calculated by

$$0 = \sum_{t=1}^{t=n} \frac{(1-\tau) \cdot FLH \cdot N \cdot K \cdot (E_t - P_{PPA,j})}{(1+IRR_j)^t}. \tag{4.19}$$

Financial Model 2.III: Monte Carlo model with variable daily prices and production.
Monte Carlo models, similar to those formulated for Position 1, may also be formulated for Position 2. Thus, changing the calculation of NPV and IRR in *Financial model 1.IIa* and *Financial model 1. IIb* for each iteration to the formulations of NPV and IRR presented in the DCF model for Position 2, in Equation 4.18 and 4.19.

4.1.2 Cost models

In the previous subsection, we considered the positions as investments. However, we believe that the main motivation of the large power consumer for acquiring a PPA is minimizing the power costs. Therefore, in the following we propose an approach which aims to investigate the cost of power. For Position 1, the LCOE constitutes this, whereas to the PPA customer, it is the fixed PPA price. Regardless, the procurement price deviates from the realized total costs of covering the demand of the large power consumer. This is because of additional expenditure incurred by trading in the spot market when the supplied amount differs from the customer demand. To provide a thorough cost assessment, these costs need to be included.

In what follows, a LCOE model for a wind power plant is formulated, followed by a model considering the total costs of covering a certain demand, examining both positions.

LCOE

When performing a profitability analysis, assessing the production cost of a power generating plant or comparing the costs of different generation technologies, LCOE is a common measure to apply; (Ueckerdt et al., 2013; Miller et al., 2017; Ragheb, 2017; Breeze, 2016; Clark, Forsyth, and Oteri, 2014). The LCOE of a wind power plant is an expression of the production cost during the entire lifetime of the project, per unit of energy produced. Thus, making the costs of one power plant comparable to expenses of other power generating units, which may have differing cost structures, lifetime and production. Additionally, the LCOE can be compared to the market price of power in order to assess project profitability. From the above-mentioned sources, due to its simplicity and intuitive logic, LCOE is applied for all types of energy generating projects.

Miller et al. (2017) state that LCOE consists of five key components: investment cost, annual operating costs, annual energy production, discount rate and operational lifetime of the plant.

For the purpose of finding the profitability of the project and identify the least expensive power source, the LCOE can be compared to the spot price, as well as the PPA price. Furthermore, we will contrast the calculated LCOE of our case plant to that of a typical Norwegian wind power plant, using LCOE values from NVE, to evaluate our input values relative to the current market.

Cost Model 1.I: LCOE of wind power plant.
Our formulation of LCOE for a wind power plant, based on Miller et al. (2017), is given by

$$LCOE = \frac{I \cdot K \cdot N \cdot a + OM}{Q}. \tag{4.20}$$

Here, the upfront cost constitutes the investment cost per capacity, I, multiplied by the number of turbines, N, and the turbine capacity, K. OM is the annual operational costs, while the energy production per year is denoted Q. Furthermore, a represents the annuity factor, which is the factor that converts an initial cash flow to an annual fixed cost for each year in the project. a is calculated as

$$a = \frac{r}{1-(1+r)^{-n}}, \tag{4.21}$$

where r denotes the discount rate and n is the lifetime of the project.

We choose to express the annual production from the wind power plant by using full-load hours, hence, given by

$$Q = FLH \cdot K \cdot N. \tag{4.22}$$

Moreover, the annual operation and maintenance costs are expressed as a fixed amount per produced unit. We get that

$$OM = om \cdot Q, \tag{4.23}$$

where om is the maintenance cost per unit produced. This is a common way to express operational costs in the industry (Vindportalen, 2019[b]).

Furthermore, it is possible to conduct a sensitivity analysis of the LCOE by changing one variable in Equation (4.20) at a time, within a reasonable interval of values. For the purpose of our analysis, we select this approach.

Total costs

Cost Model 1.I only provides information regarding the costs of the power produced from the wind power plant. Moreover, as the annual production is assumed constant, the calculations do not incorporate variable wind conditions.

The models proposed in the following, examines the total costs of covering the constant consumer demand. For this purpose, Monte Carlo simulation is applied, incorporating varying paths for power prices and production. Because we want to assess the cost of balancing imposed by variability of production, the model must include this extension. Thereafter, the market trading required is computed based on production, demand and prices.

For the aim of this analysis, we formulate a new measure relevant for cases where the power supplied by a variable power source and the consumption it is supposed to cover, does not coincide. This is a contribution to the literature; called REE, with the purpose of being a total cost measure for energy procurement. It is the realized cost of covering the customer demand per unit of energy, when including cost of energy from the wind power plant and necessary trading. By incorporating the annual net cost of production, purchase and sale cost in the LCOE formula, we obtain an expression for REE as follows

$$REE = \frac{F + OM + C_{buy} - C_{sell}}{D}. \tag{4.24}$$

Here, F is the fixed costs and OM the operation and maintenance costs. C_{buy} represents the costs of buying necessary power from the spot market, while C_{sell} is the revenues from selling power to the market. Energy demand of the customer is represented by D. All values are per year. Following the logic behind LCOE calculations, the costs in the numerator must be annualized values of the present value of the annual costs of each project year.

We claim that REE is a measure that can provide interesting insight to our analysis of the two positions. To substantiate this, we argue that a power consumer seeking to cover their own energy demand is most concerned about the total cost of energy procurement. Thus, only considering the costs from one production facility, supplying only parts of the demand, is insufficient. In the following, REE constitutes one of the most important outputs from the models proposed.

Position 1.

Cost Model 1.II: Monte Carlo model.

For this model, the daily values of production and power prices during the lifetime of the wind power plant are simulated. To determine the production quantity, we apply the same approach as described for *Financial Model 1.IIa*.

The method described in *Financial Model 1.IIb* is applied to simulate daily power prices. However, it is possible to perform any analysis where prices are simulated based on both historical and predicted prices.

Furthermore, the amount of energy necessary to trade, for each iteration and each day, must be calculated. The required amount of daily buying, $Q_{buy:i,d}$, is given by

$$Q_{buy:i,d} = \begin{cases} (L - P_{i,d}), & \text{if } L \;>\; P_{i,d} \\ 0, & \text{otherwise.} \end{cases} \tag{4.25}$$

Here, L is the constant energy demand of the consumer, while $P_{i,d}$ denotes the daily energy produced.

$Q_{sell:i,d}$ denotes the required amount of daily selling and is computed as

$$Q_{sell:i,d} = \begin{cases} (P_{i,d} - L), & \text{if } L \;\leq\; P_{i,d} \\ 0, & \text{otherwise.} \end{cases} \tag{4.26}$$

The costs associated with this trading, $C_{buy:i,d}$ and $C_{sell:i,d}$, denoting buying and selling, respectively, are found by multiplying the energy amounts from above with the accompanying simulated power price for the same day. The costs of buying are given by

$$C_{buy:i,d} = Q_{buy:i,d} \cdot E_{i,d}, \tag{4.27}$$

while selling costs are calculated as

$$C_{sell:i,d} = Q_{sell:i,d} \cdot E_{i,d}. \tag{4.28}$$

Moreover, this model converts to annual values for production, sold and purchased amounts of energy, with associated costs, by summing the daily simulations.

Finally, the LCOE and REE are computed. The resulting expression for LCOE of iteration i is given by

$$LCOE_i = \frac{(\sum_{y=1}^{y=n} \frac{C_{prod:i,y}}{(1+r)^y} + I \cdot K \cdot N) \cdot \mathrm{a}}{\frac{\sum_{y=1}^{y=n} Q_{prod:i,y}}{n}}. \tag{4.29}$$

Here, $I \cdot K \cdot N$ are the total investment costs, n is the lifetime of the project and a is the annuity.

REE for an iteration is represented as

$$REE_i = \frac{(\sum_{y=1}^{y=n} \frac{C_{tot:i,y}}{(1+r)^y} + I \cdot K \cdot N) \cdot \mathrm{a}}{L \cdot 365}. \tag{4.30}$$

The total costs of the project in each iteration and year, $C_{tot:i,y}$, is computed by

$$C_{tot:i,y} = C_{buy:i,y} - C_{sell:i,y} + C_{prod:i,y} \cdot OM. \tag{4.31}$$

Position 2.
A total cost model, similar to the one proposed for Position 1, is introduced for this position. A significant difference is that costs directly related to the plant, i.e. investment, and operation and maintenance, are now omitted, as they are not relevant for a PPA customer. Moreover, the calculations of LCOE is left out, as it is not applicable for this position. On the other hand, the PPA price replaces the operational costs.

Cost Model 2.I: Monte Carlo model.
The changes mentioned above alter Equation (4.30) for REE, and $C_{tot:i,y}$ in Equation (4.31). Respectively they result in

$$REE_i = \frac{\sum_{y=1}^{y=n} \frac{C_{tot:i,y}}{(1+r)^y} \cdot a}{L \cdot 365}, \tag{4.32}$$

and

$$C_{tot:i,y} = C_{buy:i,y} - C_{sell:i,y} + C_{prod:i,y} \cdot P_{PPA}. \tag{4.33}$$

Here, P_{PPA} denotes the PPA price. To conduct a thorough investigation of the impact of the PPA price, we test different price values. This is conducted because, as mentioned earlier, there is no publicly available data of the prices.

The analysis may be performed using historical price data and price forecasts to parameterize the price simulation process.

4.2 Qualitative risk assessment

Although financial and cost analyses provide a good understanding of an investment, a qualitative approach is needed to achieve a profound understanding of the overall picture of the difference in risk exposure between the positions. Furthermore, the results obtained from applying the following proposed models can potentially modify the conclusions from the numerical analyses.

In this section, we first introduce a generic chart used for qualitative risk evaluation, before the risk categories within each position are given.

Probability impact chart

Maylor (2010) states that risk management is mainly based on qualitative data, i.e. gathering perceptions from people to rank the associated project risks. Typically, these are presented in a probability impact chart, with axes of probability and impact measured as low, medium, and high, as shown in Table 4.1.

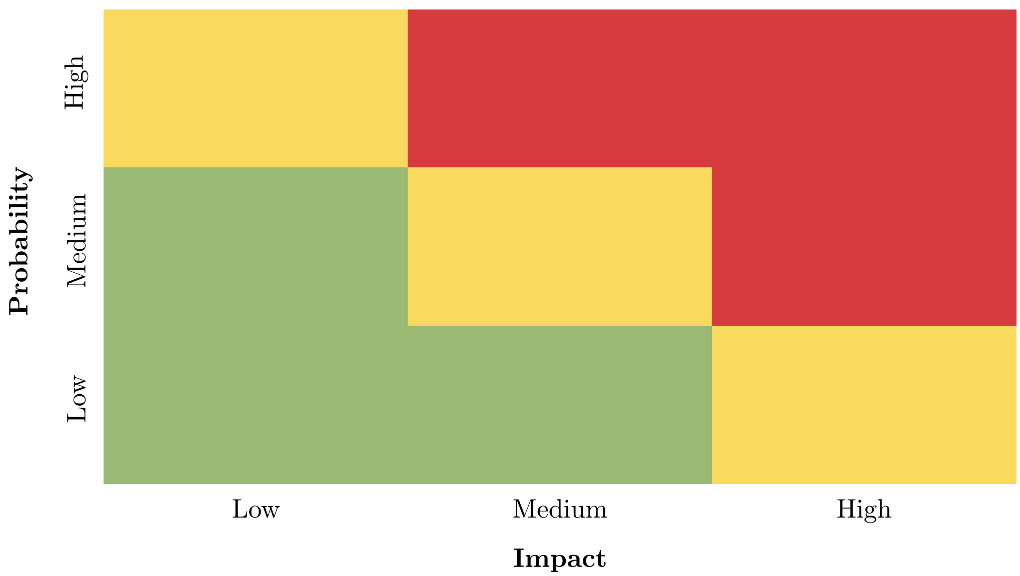

Table 4.1: Illustration of a probability impact chart for qualitative risk assessment.

We will use the above chart to sum up our findings from the qualitative risk discussion based on the risk categories for the two positions, presented in the following.

Position 1.

Gatzert and Kosub (2016) provide an overview of risks in onshore wind projects. The overall categories presented are strategic/business, transport/construction/completion, operation/maintenance, liability/legal, market/sales, counterparty, and political/regulatory risks. These are explained in the following bullet points.

- *Strategic/business* is risk related to scarcity of capital and insufficient management of the project. It also includes risks associated with rapid technological development, rendering installed equipment outdated. Finally, risk associated with an inefficient and expensive concession process, and insufficient public acceptance of the project is included.

- *Transport/construction/completion* is risk from disruptions, damages or theft in the transportation and construction phase, leading to start-up delays.
- *Operation/maintenance* is risk of damages, wear and tear, defect components and accidents during the operational phase, all due to normal operation or severe weather.
- *Liability/legal* is risk of liabilities to third parties due to environmental damages or unpredictable legal disputes.
- *Market/sales* is risk related to uncertainty regarding future wind conditions and energy prices, as well as limitations in grid management. It also includes the risk of superfluous wind power production reducing the power prices.
- *Counterparty* is risk associated with the credit quality of all counterparties.
- *Political/regulatory* is risk from uncertainty of changes in policies regarding wind energy.

All the factors mentioned may, according to Gatzert and Kosub (2016), incur revenue losses, which is what the developer seeks to avoid.

Position 2.

To the best of our knowledge, there is no literature analysing risk exposure of a PPA customer. Hence, the risks listed in the following are a combination of categories described by various articles and sources; (Renewable Choice Energy, 2016; Walet, 2019; WBCSD, n.d.[b]; Fucci, 1999; Baker&McKenzie, 2015). Based on these, a customer entering a physical PPA is exposed to development, volume/shape, pricing/market, counterparty/credit, force majeure and political/regulatory risks, which are outlined in the following bullet points.

- *Development risk* is the risk of anything interrupting the planning or construction phases of the wind power plant in the contract, rendering it unfinished or delayed.
- *Volume/shape* is risk arising from the intermittency of production from the wind power plant, creating uncertainty. It also captures the risk that the output from the PPA producer differ from the generation forecasts and are inconsistent with the load of the consumer. In such events, the additional power must be purchased from the market or by other means, incurring uncertain costs.
- *Pricing/market* is the risk that market power prices stay below the PPA price in long periods. This will cause the PPA to become a competitive disadvantage for the customer.
- *Counterparty/credit* concerns the liquidity of the developer/producer. Should it declare bankruptcy, the customer will need to procure a new PPA.

- *Force majeure* is the risk that extraneous events occur during construction or operation, which neither the developer nor the PPA customer can control. This may delay completion of the project, or influence generation.
- *Political/regulatory* is the risk that regulations regarding renewable power or PPAs change, affecting the PPA customer.

5

Parameterization

In this chapter, we present a case study of input values to be evaluated by the decision models presented in the previous chapter. We are focusing on the current Norwegian wind power market and choose the case values to represent the most recent wind power plant projects here. This allows us to provide decision support when evaluating which position to undertake.

5.1 General assumptions

Prior to considering each position individually, we present some underlying assumptions that apply to both positions. Primarily, we assume that the large power consumer needs to cover a constant power demand for its business.

For simplification purposes, we assume that the production and consumption of power occur in the same price area of the spot market, avoiding the issue of area pricing. Area pricing is present in the Norwegian market, where slightly different prices are observed in distinct market zones. This is due to bottlenecks in the grid and mismatch between supply and demand within each area (Wangensteen, 2011).

5.1.1 Parameter values

Table 5.1 summarizes the parameter values for the wind power plant assumed both in Position 1, but also as the underlying wind power plant of the PPA in Position 2.

Symbol	**Feature**	**Value**
I	Investment cost	9.5 MNOK/MW
OM	Operation and maintenance cost	110 NOK/MWh
N	Number of turbines	25
$years$	Lifetime of plant	25 years
C_p	Coefficient of power	0.35
FLH	Full-load hours	3500 h
K	Capacity of turbines	4.2 MW
rot	Rotor diameter	136 m
v_{min}	Cut-in wind speed	3 m/s
v_{max}	Cut-out wind speed	25 m/s
v_{avg}	Average wind speed	7.5 m/s
ρ_{air}	Air density	1.247 kg/m^3
$r_{discount}$	Discount rate	6 %

Table 5.1: Parameter values for the wind power plant.

The values presented above were chosen based on published reports, and news about current and imminent wind investments in Norway. We will now present argumentation and sources for each value following the order of Table 5.1.

Investment costs. Depending on the wind project, the turbine expenses often constitute 65-75 % of total investment costs. Other primary expenditures are base construction, roads and power grid. The upfront costs accumulate to approximately 9-11 MNOK/MW, as of January 2019. Costs related to extension of the grid prove to be most difficult to generalize, as these are heavily area-dependant (Vindportalen, 2019[c]).

Table 3.1 provides an overview of data related to wind power plants under construction in Norway. From this information, we have calculated the average investment cost for a project to be 9.52 MNOK/MW.

Operational costs. According to Vindportalen (2019[c]), operational costs of new wind power plants are approximately 10 øre/kWh, as of January 2019. Here, about 50 % constitute daily operation and maintenance, and are to a large extent covered by negotiated service contracts. Other potential costs are power transfer in the grid, balancing, property tax, rent of grounds, maintenance of roads, cables and lines, insurance, administration and salaries. As the plant ages, costs may increase due to attrition (Vindportalen, 2019[c]). We incorporate this by selecting a level slightly exceeding the proposed value above, ending on 11 øre/kWh.

Number of turbines. Again considering data from Table 3.1, we derive that 26.5 turbines is the median of number of turbines per wind power plant. Rounding off, we assume 25 turbines to be a suitable number for the case plant.

Lifetime. Vindportalen (2019[d]) estimates that the economic lifetime of a wind power plant is 25 years. In addition, NVE provides concessions for 25-30 years, which supports that making an operational life span of 25 years is a reasonable assumption (Vindportalen, 2019[d]).

Coefficient of power. The coefficient of power is the share of the energy in the available wind resources a turbine manages to harness. Good turbines ordinarily have a coefficient of 35-45 %, while the theoretical maximum lays at 59.3 %, called Betz limit (Educational Innovations Inc., n.d.). We choose a coefficient of power of 35 %.

Full-load hours. The Norwegian information site of wind power, Vindportalen (2019[f]), recently updated the estimates for full-load hours. They state that projects in operation prior to 2018 obtain 2900 full-load hours, while plants in operation from 2018 and onward are expected to obtain 3500 full-load hours. Once again, we consider Table 3.1. Here, projects listed with values in both the columns *Installed capacity* and *Yearly production*, provide an average number of full-load hours of 3248. However, as the values are expected and the list is not complete due to data availability, applying 3500 h is regarded as reasonable.

Capacity of turbines, rotor diameter and wind speeds. Looking at Table 3.1, we see that the plants at Frøya, Hundhammerfjellet and Stokkfjellet are currently under construction. They will all utilize 4.2 MW V136 turbines from the well-known manufacturer Vestas (Nea Radio, 2019). The turbines have a rotor diameter of 136 m, a cut-in wind speed of 3 m/s and a cut-out of 25 m/s (Vestas, 2019[b]). We regard this type of turbine as an example of the Norwegian conditions, and therefore choose these characteristics for our case.

NVE has published a map of wind conditions in Norway, and from here 7.5 m/s is the approximated average wind speed along the coast (NVE, 2019[c]). We therefore set v_{avg} equal to this.

Air density. The air density, needed for calculation of power produced from a wind turbine under certain wind conditions, is set to 1.247 kg/m^3, which is given under a temperature of $10°C$ and atmospheric pressure (Engineers Edge, 2019). According to Dannevig and

Harstveit (2019), the mean temperature is $8°C$ along the Norwegian coast and we therefore assume the above value to be applicable in our case study.

Discount rate. NVE suggests using a discount rate of 6 % for renewable energy projects, referring to recommendations from the Ministry of Petroleum and Energy, as of 2019. They also proposes 4 % when investigating the impact of the rate, however, without arguing for this choice (NVE, 2019a). In a power cost evaluation report from 2015, NVE used both 4 and 6 % for wind power (NVE, 2015). We choose the discount rate to be equal to 6 % for Position 1. As no standard of reasonable PPA discount rate is publicly available, we choose to use the same rate for Position 2. We argue this by the fact that both positions are exposed to the same price and production uncertainty.

5.2 Position 1

5.2.1 Assumptions

We assume that the large power consumer has already obtained a concession to construct a wind power plant. Therefore, this process is disregarded from the case study, along with the associated costs. Furthermore, it is assumed that the company in question is well established and has solid liquidity. It is also assumed to have the competence necessary to build a wind power plant. The plant site area is rented. A thorough analysis regarding the wind conditions is performed and found to be satisfying. Moreover, the company has signed a service agreement with a provider of high quality, at a fixed price.

5.2.2 Parameter values

Table 5.2 summarizes the additional parameter values for the case of Position 1, adding to Table 5.1.

Symbol	Feature	Value
rf	Risk-free rate	1.88 %
r_{bank}	Capital cost bank	3 %
D	Debt share	60 %

Table 5.2: Parameter values for the case of Position 1.

The values presented above were chosen based on published reports. We will now present argumentation and sources for each value following the order of Table 5.2.

Risk-free rate. A common approach to find the risk-free rate is using government bonds. However, as the Norwegian ones only are available with maturity of 3, 5 and 10 years, extrapolation is necessary as the lifetime of a wind power plant clearly exceeds these maturities. 10 year government bonds are the most used proxy for the risk-free rate in the Norwegian market (PwC, 2018). According to Norges Bank, 1.88 % was the average value in 2018 and we are using this (Norges Bank, 2019[a]).

Capital costs and debt share. The cost of capital of any investment, wind projects being no exception, depends on the risk associated with the project. Typically, a wind power plant is financed using a combination of equity and debt. Different capital providers require individual returns, depending on their risk exposure and aversion. For instance, a bank lending money to the project receives a low and fixed return along with the repayments. It has no additional benefit if the project is a success. However, if the project defaults, the bank risks that the developer is unable to fulfil their debt obligations. This implies that the bank should require an interest rate slightly exceeding the risk-free rate. We choose it to be equal to 3 %.

Debt share. According to a report by Deloitte (2014), usual debt share for wind projects are 50-70 % of debt. We choose to apply the mean value of 60 %.

5.3 Position 2

5.3.1 Assumptions

Table 5.3 summarizes the associated PPA terms to our case study. This will also indicate relevant risk factors.

Term	
Type of contract	Physical *As generated*
PPA price	Fixed
Duration of PPA	25 years
Expected production	3500 full-load hours
Construction	Fixed completion date, compensation to customer if violated
Credit	Both contract parties are credible due to funds or insurance
Force majeure	Insurance, compensation to customer
Regulation	Do not affect PPA price
Repeal	Not possible to repeal the contract

Table 5.3: Contract terms of the case study PPA.

We will now present argumentation and sources for each contract term following the order of Table 5.3.

Type of contract. To the best of our knowledge, there is no public information of whether an *As generated-PPA* or *Base supply-PPA* is most common in the Norwegian market. However, we choose to base our analyses on a physical *As generated-PPA*, as we consider it to be most similar to owning a plant. Both the PPA and the wind power plant provides the same output to the large power consumer, because we choose the plants to share equal characteristics. Thereby, the customer is in either position exposed to the risk imposed by intermittent wind power production.

Since there is no publicly available information about common terms of Norwegian PPAs, we are forced to make some assumptions regarding these. We do so by considering features of similar contracts in other countries, see Section 3.2.5. These sources show that the terms of the PPAs often depend on the specifics peculiar to each contract.

PPA price and duration of PPA. We choose that the PPA has a fixed price per MW. Moreover, it has a duration of 25 years, equal to the lifetime of the wind power plant producing power to the PPA. This is common for PPAs, as argued in Section 3.2.5.

Expected production. Due to the intermittency of wind power, the supplied amount will vary over time, however with an expected production of 3500 full-load hours annually. Further argumentation for this can be found in Section 5.1.1.

Risks: construction, credit, force majeure, regulation and repeal. A PPA is often used to transfer risk to the customer to ease the process of procuring financing for the plant developer. However, we assume that the PPA customer will require some of the risks to be mitigated by insurance, to avoid carrying all of them. Moreover, we assume that the producer is obliged to finish construction of the plant and initiate operation within an agreed date. Any violations will lead to required compensation for the power not received. However, in any event of a postponement of the plant construction, it may incur large expenses for the developer, rendering them unable to fulfil any redress. Thus, this risk factor is impossible to completely mitigate.

We assume that both the producer and the power consumer are required to retain a certain economical buffer in funds or through insurance to mitigate credit risk.

The producer is obliged to insure against losses caused by force majeure events or other operational interruptions. Thus, it must compensate the consumer for any additional costs incurred because of having to trade power in the market. A common insurance for wind turbines includes coverage for damages from such occasions not caused by the operator. For our case study, this expense is included in the operational costs (Codan Forsikring, 2019; Vindportalen, 2019[b]).

In the contract it is specified that possible regulatory changes, e.g. regarding tax or subsidies, do not impact the PPA price.

Finally, the contractual parties do not have the opportunity to terminate the PPA, unless the plant defaults and is not rebuilt. The PPA customer will never be obliged to pay for power not delivered.

6

Results

In this chapter, results obtained from applying the proposed models in Chapter 4, with case values from Chapter 5, are presented. We have used the same structure here as in Chapter 4, i.e. first performing financial and cost analyses, before looking at the accompanying risks.

All numerical results related to the analyses in this chapter are found in Appendix A.

6.1 Financial and cost analyses

6.1.1 Financial analyses

Position 1.

Financial Analysis 1.I: DCF model with constant annual production and annual prices.
Given constant annual production and annual prices, we obtain values for NPV, IRR and investor return of Position 1 in our case study. These will be references when we later investigate the impact from varying production and prices. Additionally, the output values will indicate whether the current wind power plant market is interesting to enter. (Results from *Financial Model 1.I*, page 41, with numerical values in Table A.1; MATLAB script in B.1.1).

In this analysis, we apply the three price forecasts presented on page 31. We expect the results to depend heavily on the price forecast used. This is due to the large span between the forecasts, in addition to knowing that the current LCOE level of Norwegian wind power is about 340 NOK/MWh (NVE, 2019a).

The results are visualized in Figure 6.1. Regarding the forecasts by Statnett and NVE, the error bars show the distance between high, expected and low cases.

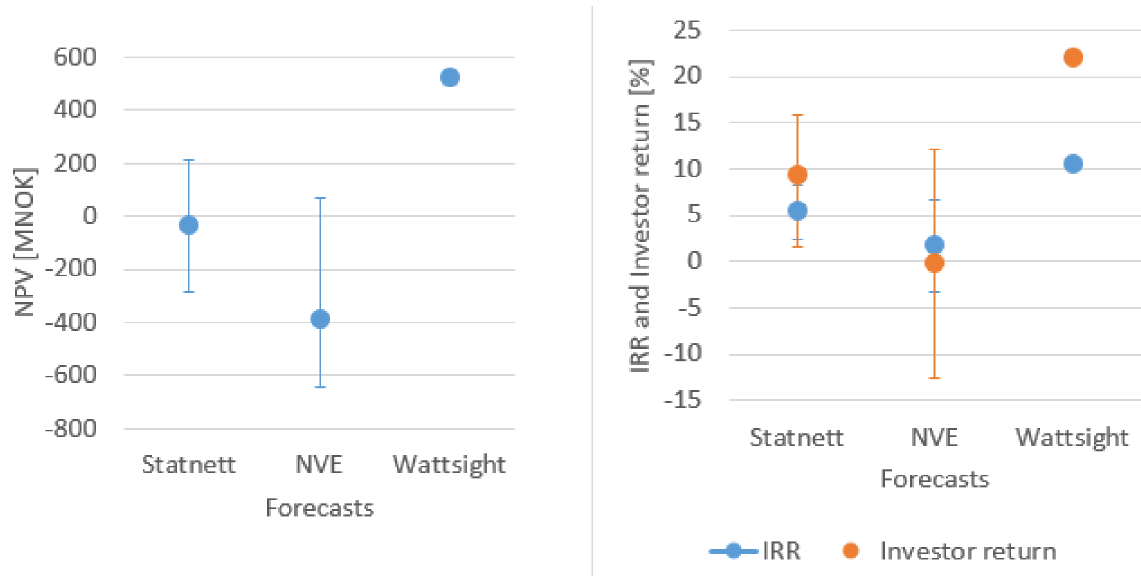

Figure 6.1: Results from DCF analysis with constant power production and constant annual prices based on forecasts. The error bars show the results from high and low case paths compared to expected paths in the NVE and Statnett forecasts.

Considering a positive NPV as the condition for profitability, only the high price cases of Statnett and NVE, and the expected path by Wattsight, provide a profitable project. Hence, the profitability of wind power is questionable in the Norwegian market.

Moreover, it is evident that the price forecasts render extremely different values for NPV and return. For instance, the expected path of NVE yields an NPV of -386.03 MNOK, whilst the prediction provided by Wattsight gives NPV of 524.57 MNOK. The IRR spans between -3.26 and 10.60 %, while the investor return is in the range of -12.65 and 21.99 %, considering all forecast paths.

Comparing the expected paths by all forecast providers, the IRR spans from 1.75 to 10.60 %, whilst investor return is in the range of -0.13 and 21.99 %. This illustrates an extreme difference in NPV and return, due to using different forecasts. The variation is so large that the analysis simultaneously signals a project to be a very interesting investment and a huge loss project. The results make sense related to the current hesitation among investors to enter wind power projects in Norway. It is impossible to predict the level of future prices, and the price risk has so immense impact on return, making risk averse investors sceptical to enter this market.

We conclude this analysis by emphasizing that choice of forecast in a wind power plant profitability analysis has enormous effect on the results. The analysis has accentuated how sensitive the profitability measures, i.e. NPV, IRR and investor return, are to future spot prices.

To assess whether our results are reasonable, we will compare our numerical results to the results obtained by another author considering profitability of wind power in Norway. For instance, Yari (2015) analyses a case plant in Norway in 2015, using DCF analysis. The author applies a constant power price of 28 øre/kWh and a certificate price of 15 øre/kWh, a constant production of 2692 full-load hours, 20-year lifetime, 11.5 MNOK/MW investment cost and 13.4 øre/kWh in operational costs. Hence, the case used reflect the market a few years ago. Yari (2015) finds the NPV of the case plant to be around -450 MNOK, at a discount rate of 6.5 %. Moreover, it obtains that, by performing a sensitivity analysis on NPV by varying the power price, the NPV changes from about -450 to 500 MNOK when the power price increases by 0.3 NOK/kWh from the base price used. This supports our conclusion that power price variation has a huge impact on wind power profitability. Moreover, it is seen that the values of and span in NPV due to power price levels are similar in magnitude as our results. This confirm that our analysis provides reasonable results.

Financial Analysis 1.IIa: Monte Carlo model with varying daily production and constant annual prices.
We will investigate the impact of daily variation in production on the output profitability measures. This is done by obtaining confidence intervals for NPV, IRR and investor return, and comparing these results to the numerical values from *Financial Analysis 1.I*, with numerical values in Table A.2; (Results from *Financial Model 1.IIa*, page 43; MATLAB script in B.1.2).

We expect the inclusion of the variability in production to impact the profitability significantly. Moreover, we expect that the values found in *Financial Analysis 1.I* are included in the ranges for the different profitability measures.

Power production. Simulation of annual full-load hours is performed to assess whether Weibull gives a reasonable range for annual production, given our chosen case values. The resulting histogram of annual full-load hours is given in Figure 6.2.

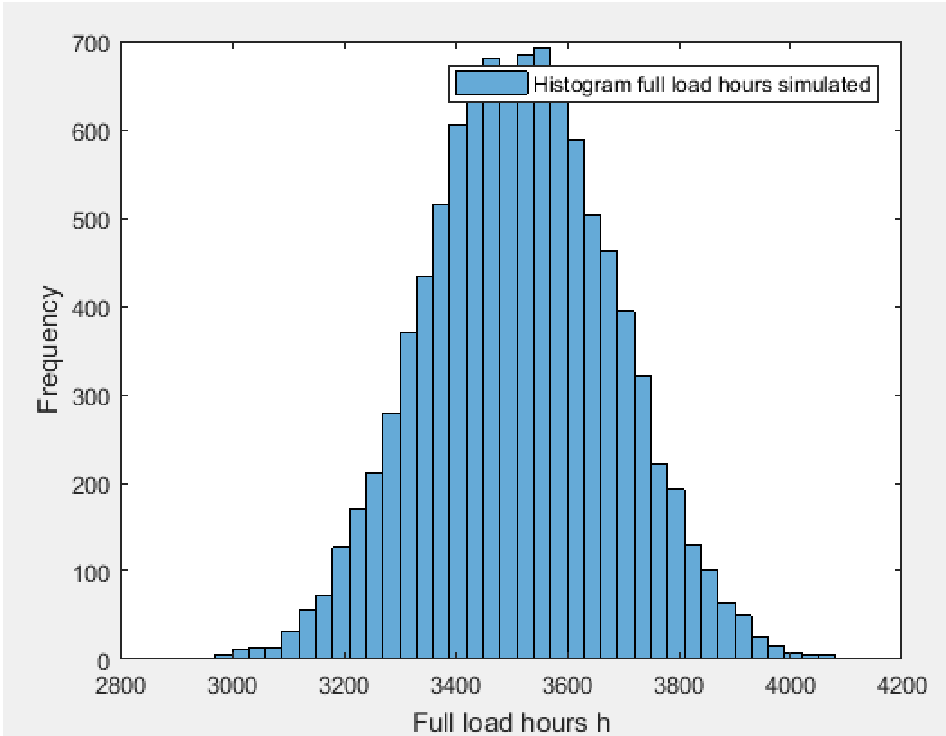

Figure 6.2: Histogram of simulated annual full-load hours.

The 95 % confidence interval is [3192.7, 3845.1] full-load hours, with a 50 percentile of 3515.4 h. This is assumed to be a decent distribution for the annual variation of full-load hours. Moreover, it provides a good fit to the expected value of 3500 h, which is assumed for Norwegian wind power plants constructed in 2018 or later (Vindportalen, 2019[f]). Hence, we believe the Weibull distribution to be a good approximation for the real probability distribution of the wind speeds on the plant site.

The resulting NPV values are visualized in Figure 6.3, where the confidence intervals found here are presented along with the static values from *Financial Analysis 1.I.*

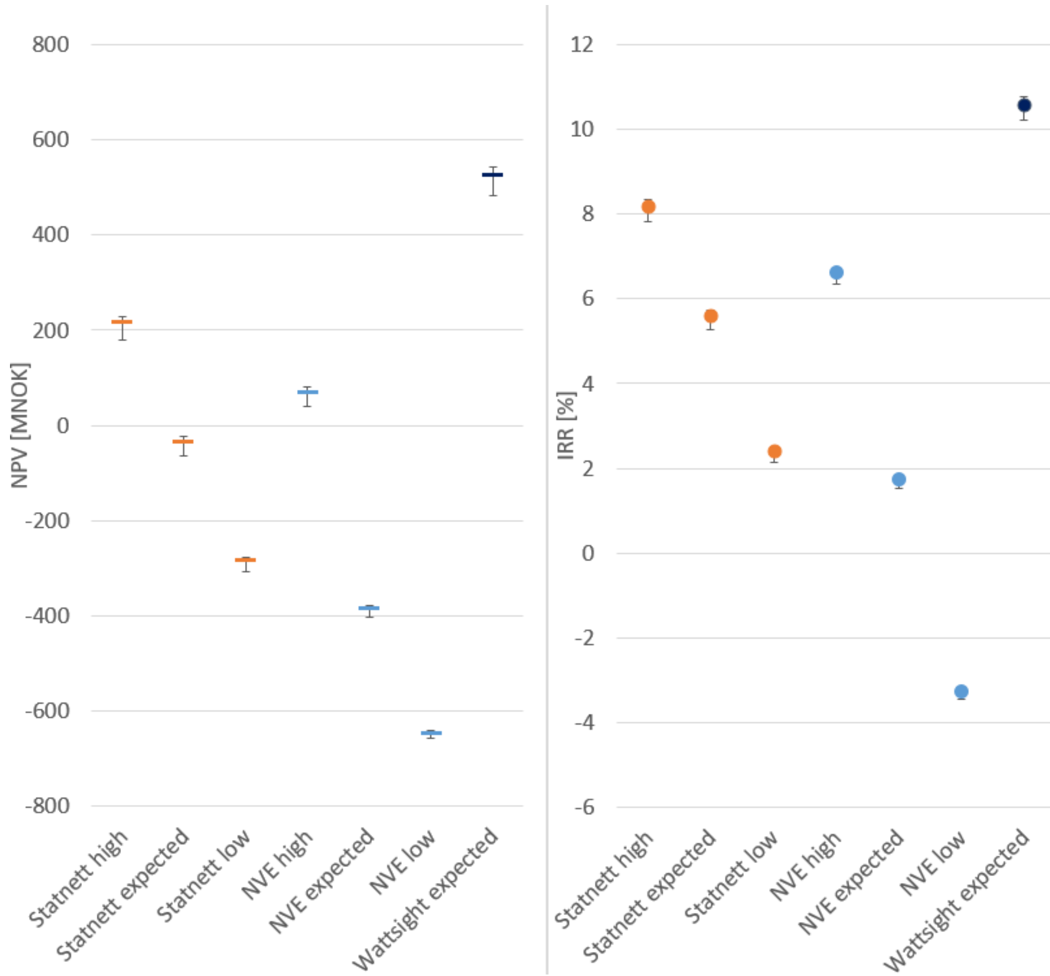

Figure 6.3: Results of Monte Carlo analysis with Weibull simulated production and constant annual prices. The figure shows the static NPV values for each price forecast from *Financial Analysis 1.I* along with confidence interval values from this analysis; *Financial Analysis 1.II*.

The results show, as expected, that the intervals from this analysis enclose the output values from *Financial Analysis 1.I*. Moreover, the lengths of the confidence intervals for NPV are between 15 and 60 MNOK dependent on the different forecasts. The IRR confidence intervals have lengths between 0.26 and 0.53 %. However, from Figure 6.3 it is visually shown that the different forecasts, from the first analysis, have much larger impact on the range of NPV, compared to the impact from production variation. Hence, the project profitability appears to not be very sensitive towards varying production compared to the trend of future power prices. The analysis will only provide information on the sensitivity of variation in annual production because the prices are fixed per year.

To be able to evaluate whether our results are reasonable, we want to compare them to authors assessing similar cases. Gass et al. (2011) present a statistical simulation model to account for risk in stochastic wind speeds in wind power profitability analysis. The authors generate long-term wind data for a specific plant site using short-term real data and calculate IRR. A FiT of 75.3 EUR/MWh is used as power price value and assumed to be constant for the whole project. Energy output is generated using the Weibull distribution and power curve, calibrated using the real data, for a 1.3 MW turbine and rated speed of 13 m/s. Simulation of production results in a histogram of the annual electricity of values ranging from 3500 to 6500 MWh, representing 2692 to 5000 full-load hours. Hence, this interval is somewhat broader than our annual production histogram, which is assumed to be due to the higher rated speed and shape factor. The annual production is found by generating a power production per day from the Weibull distribution and power curve, multiplying it by 24 hours, and adding up to the annual production. This is similar to our approach. The resulting IRR is between 8 and 10.5 %. This is a quite narrow range; however our calculated interval is even narrower, and probably due to our smaller range of annual production. This comparison shows that it is not unlikely to obtain a narrow range for IRR, thereby supporting that our simulation provides viable results.

Financial Analysis 1.IIb: Monte Carlo model with constant annual production and varying daily prices.
Given constant annual production and varying daily prices, we obtain confidence intervals for NPV, IRR and investor return of Position 1 in our case study. We will investigate the impact of variance in daily prices on the profitability measures, by comparing the result to the numerical values from *Financial Analysis 1.I*; (Results from *Financial Model 1.IIb*, page 44, with numerical values in Tables A.3 and A.4; MATLAB script in B.1.3).

We expect that including variable daily prices will have a significant impact on the profitability measures and implicate broad confidence intervals. Furthermore, that historical prices will not yield a profitable project because this has been an issue in the market up until 2018 (Bjartnes, 2019).

Power prices. In this analysis, we apply a mean-reverting process for simulation of power prices. We use estimated coefficients found from regression on the market data from 2013 to 2018, in the region NO3 of the Nordic power market. This time period is chosen because it is what is available of daily prices from Nord Pool. The coefficients are listed in Table 6.1.

Parameter	Value
κ	169.6
θ	282.4
σ	1574.6
dt	$\frac{1}{2129} = 0.00047$

Table 6.1: Estimated parameters for the Ornstein-Uhlenbeck model for forecasting power prices. This is based on historical data of daily power prices for NO3 in 2013-2018.

Figure 6.4 shows 10,000 simulated daily power prices, compared to the real daily prices in the time period 2013-2018.

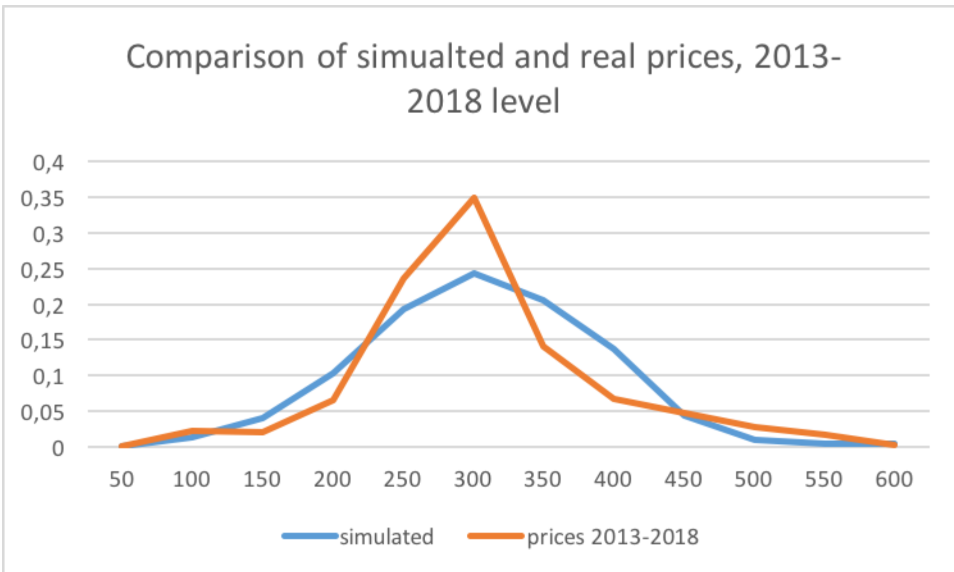

Figure 6.4: Simulated power prices compared to real values.

The 95 % confidence interval for daily simulated prices is [84.77, 475.26] NOK/MWh. It is evident from the figure that the stochastic process used does not generate power prices with the exact same probability distribution as the historical prices. The real price distribution incorporates a higher peak around the average power price. However, we assume that the mean-reverting model is applicable to our case. There is no guarantee that using this approach will provide price levels which are correct for the future years, but it is an initial approach for the Monte Carlo analysis.

We also want to incorporate variable power prices based on available forecasts, to extend our analysis from historical prices. Hence, we assess the case using both realized data and data predicted for the future. A mean-reverting process incorporating the parameter values presented in Table 6.1 and the annual forecast values given by the three forecasts on page 31, are inputs for simulation of daily prices. For each forecast, the average values are calculated over three intervals; 2018-2025, 2025-2030 and 2030-2040. Since some of the forecasts do not approach 2040, the value of the last year predicted is kept constant until 2040, to make the forecasts comparable. The resulting average levels used are found in Table 6.2.

Expected forecast	**2018-2025**	**2025-2030**	**2030-2040**
Statnett	39	37	34.5
NVE	25.7	29.5	30
Wattsight	48.4	54.9	58.3

Table 6.2: Average levels of predicted power prices in Norway [EUR/MWh].

The numerical values in the table are applied as theta values in the simulation.

The resulting NPV values are presented graphically in Figure 6.5. IRR and investor return is not included in the figure, as the resulting outcome is evident from the NPV visualization.

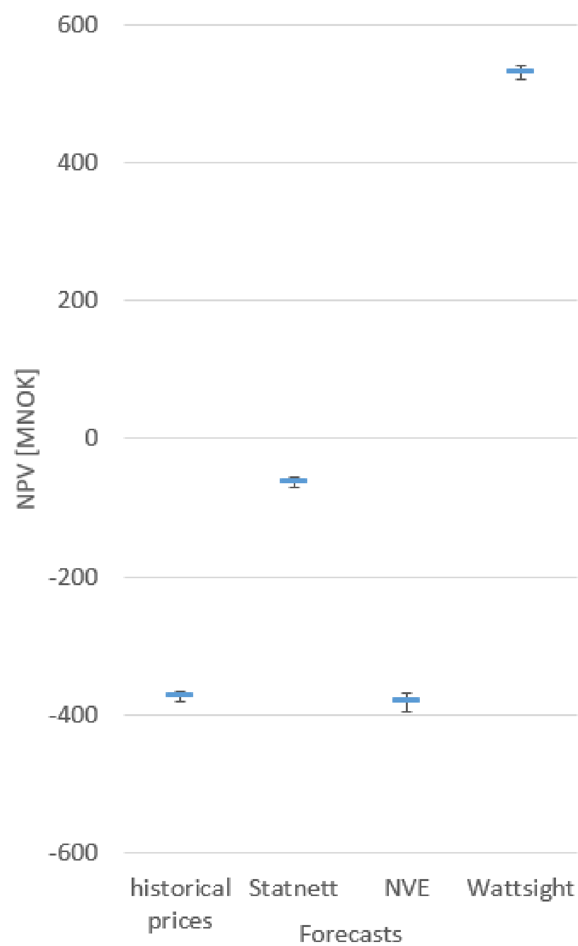

Figure 6.5: NPV using mean-reverting prices and constant production. Simulated priced based on historical prices in 2013-2018, and Statnett, NVE and Wattsight price forecasts is used. The figure shows the expected cases of the forecasts and compares confidence intervals with the static NPV value.

Evident from the results, if the level of the power prices during the next 25 years remains the same as for 2013-2018, the wind power plant considered in the case study will not be a profitable investment. Moreover, the lengths of the NPV confidence intervals are from about 13 to 27 MNOK, which is quite narrow. Hence, we see that assuming mean-reverting power prices and constant annual production imply very little uncertainty in the project value. Still, the results emphasize how the trend in future power prices, here represented by the different forecasts, affects the value much more than daily variation in power prices.

Financial Analysis 1.IIc: Monte Carlo model with daily varying production and prices. Given both varying production and prices, we obtain confidence intervals for NPV, IRR and investor return of our case study. We will investigate the impact of daily variance in both production and prices on the measures, by comparing the results to the numerical values in *Financial Analysis 1.I*, but also to *Financial Analysis 1.IIa* and *Financial Analysis 1.IIb*.

(Results from *Financial Model 1.IIc*, page 44, with numerical values in Table A.5; MATLAB script in B.1.4).

We expect that including variation in both production and prices may have a large impact on the project value. This is due to the possibility of amplifying, since the two variables are multiplied in the NPV calculation.

Only forecasted prices are applied in this analysis, as this is regarded to best reflect the future, while the historical price variation is still incorporated. Moreover, the approach for these prices in *Financial Analysis 1.IIb* is used.

In Figure 6.6, the results from this analysis are compared to the static NPV value from *Financial Analysis 1.I*.

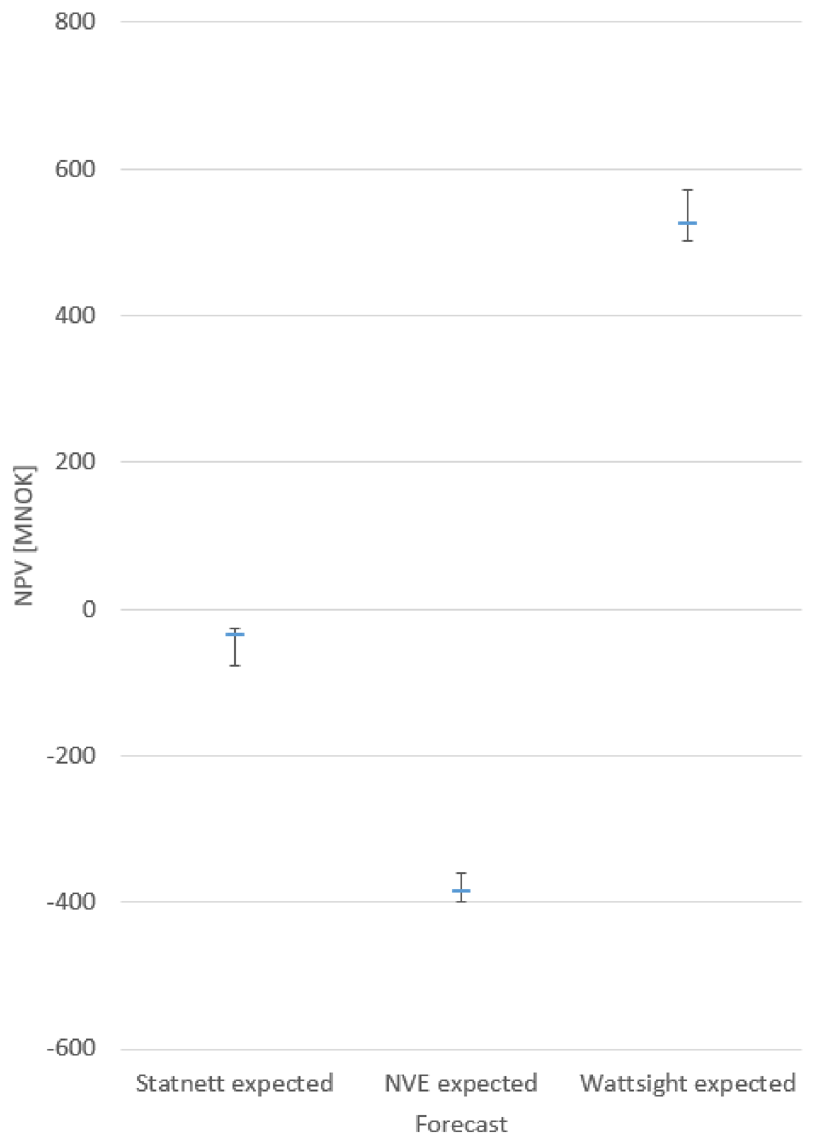

Figure 6.6: NPV using mean-reverting prices and varying production. The figure shows the expected cases of the forecasts and compares confidence intervals with the static NPV value.

Compared to the results of *Financial Analysis 1.IIb*, where prices are variable and production is constant, we find that the confidence intervals now are broader and have lengths between 41 and 69 MNOK. The forecast predicting the highest future price level induces larger uncertainty in project value. The results imply that both variation in daily prices and production should be considered in a valuation analysis of a wind power investment. This is to get a correct impression of the uncertainty involved in the project. Moreover, it is evident that the different forecasts used have much larger impact on the project value than the combination effect of variation in daily power prices and production.

Considering each price forecast, the confidence intervals for NPV may be used to find the VaR of the project. They are calculated using the expected price paths of the three forecasts, and render the 97.5 % VaR of 77.84, 399.54 and -502.14 MNOK, trusting Statnett, NVE or Wattsight respectively.

Summarizing the results.
Our main conclusion from the above section is that the use of different forecasts in the investment analyses is the factor with the largest impact on the results. Hence, we have found that the profitability question is very dependent on what prediction is incorporated and trusted. The uncertainty in project value due to daily variation in power prices and production is found to be significant, but small compared to that caused by the possible paths for future power prices. To illustrate this, the effect of uncertainty in daily prices and production imply a difference of maximally 69 MNOK in our analyses, while the uncertainty due to using the different expected price paths of the forecasts gives NPV values differing by 910 MNOK. This constitutes an uncertainty about 13 times larger.

For our case study, the price forecasts applied provide very different results for the NPV. Ranging from hundreds of millions above and below zero, specifically -657 to 572 MNOK, the interval is quite extreme. These large variations in NPV are solely determined by one parameter, i.e. the anticipated power prices.

Despite originating from credible and respected sources in the power industry, it is impossible to determine the probability of any of the forecasted price paths being realized. Therefore, all of them are considered as likely to occur. Our analyses, particularly with respect to the great variations found in NPV and IRR, show the risks imposed by investing in the Norwegian wind power market.

Considering the static DCF model for a wind investment and applying the expected price scenarios anticipated by Statnett and Wattsight, we get decent returns to investors of 9.50 and 21.99 %, respectively. The expected price path of NVE, on the other hand, yields -0.13 % return. Hence, the question of whether to invest in wind power is not straightforward to answer.

Position 2.

Financial Analysis 2.I: Break-even PPA price model.
Given different price forecasts and discount rates, we will now find break-even PPA prices for our case study, indicating a reasonable range of PPA prices for the Norwegian wind power market. (Results from *Financial Model 2.I*, page 44, with numerical values in Table A.6; Excel sheet in B.1.5).

The analysis is performed for all price forecasts introduced. This is because we expect prices to have a large impact on the investment of PPA, as was evident considering the wind power plant investment.

We expect the break-even PPA prices to be in similar magnitudes as the levels of the power prices of the forecasts and the LCOE values for Norwegian wind power. The PPA price is the procurement price of the wind power produced at the plant, therefore it should exceed the LCOE to render the plant profitable. The selling price to the market is the income. Hence, the market selling price and LCOE indicate the upper and lower thresholds, respectively, for the PPA price.

The results are shown graphically in Figure 6.7.

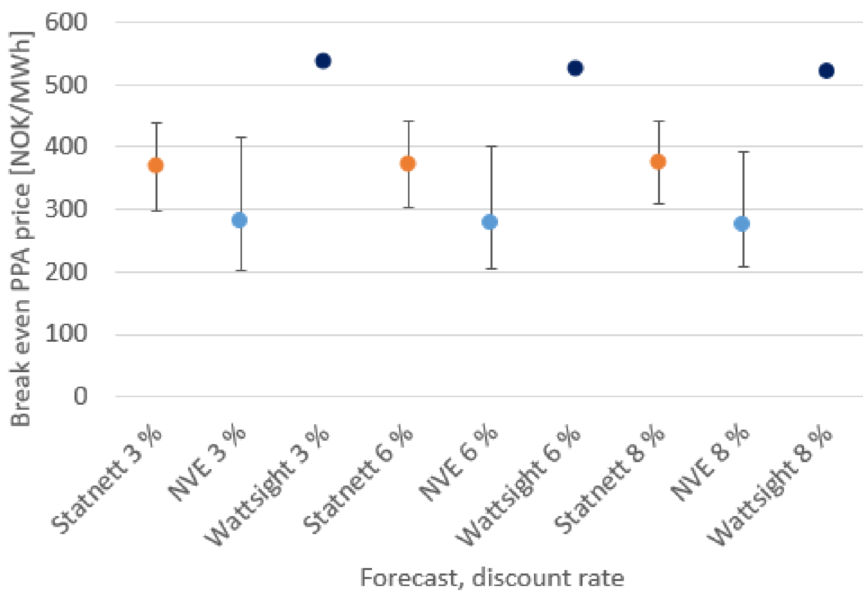

Figure 6.7: Break-even PPA prices in NOK/MWh from DCF analysis of constant production and annual prices based on forecasts. The error bars show the distance from the expected case to the high and low cases in the Statnett and NVE forecasts.

We find that using different discount rates does not significantly impact the break-even PPA price. Furthermore, it is evident that the forecast anticipating high future spot price levels provide the highest break-even PPA prices. Considering that higher selling prices for power, i.e. spot prices, permit higher power costs, or in this case PPA price, this is reasonable.

Examining the expected price scenarios, the PPA price using a 6 % interest rate ranges from 276.87 to 525.37 NOK/MWh. Thus, providing an indication of what is the upper bound of acceptable price for a PPA customer. However, due to the huge capital investment of owning a wind power plant, we believe the risk of entering a PPA to be lower, hence, a discount rate of 3 % may be more reasonable. Applying 3 %, the maximum PPA price should be in the interval of 281.21 to 535.34 NOK/MWh.

The large price range illustrate how the PPA break-even price depends heavily on the price forecast chosen. Considering the prediction by Wattsight as too optimistic, thus focusing on the expected paths of the other forecasts, the PPA break-even price interval is 276.87 to 372.47 NOK/MWh, given a discount rate of 6 %. The low limit is close to the assumed LCOE for new Norwegian wind power plants in 2020; 270 NOK/MWh (NVE, 2019a). However, 372.47 NOK/MWh is approximately 30 % higher. Hence, the assumption that a reasonable PPA price slightly exceeds the LCOE of a new wind power plant is fair, due to the differences in risk between holding a PPA and owning a wind power plant.

Financial Analysis 2.II: DCF model of constant annual production and annual prices. Given constant annual production and annual prices, we will now evaluate the profitability of entering a PPA in our case study. We also want to investigate to what extent each of the forecasts affect the NPV of a PPA, relative to the wind power plant project. (Results from *Financial Model 2.II*, page 45, with numerical values in Table A.7; MATLAB script in B.1.6).

Reasonable PPA prices. We do not know the level of PPA prices in the Norwegian market. From our literature review on PPA pricing, presented in Chapter 2.1, we found that the LCOE of the plant considered in the PPA is often used as the foundation for determining the PPA price. Therefore, to perform an NPV analysis for Position 2, we assume multiple realistic scenarios for PPA prices, and analyse the resulting valuation measures of the PPA investment for each price forecast. These PPA prices are based on LCOE estimates published by trustworthy sources, discussed in the following.

NVE has calculated the LCOE of potential wind power plant locations in their recently published national framework for wind power. They estimate LCOEs within the interval of 26-44 EUR/MWh (NVE, 2019[b]). Statnett anticipates, in a report from November 2018, that the LCOE will be reduced to 25-30 EUR/MWh by 2025 (Statnett, 2018c). Based on this, the following analysis will be performed using the PPA price scenarios of 250, 300, 350 and 400 NOK/MWh. An exchange rate of 10 NOK/EUR is used in the conversion.

The results are shown visually in Figure 6.8.

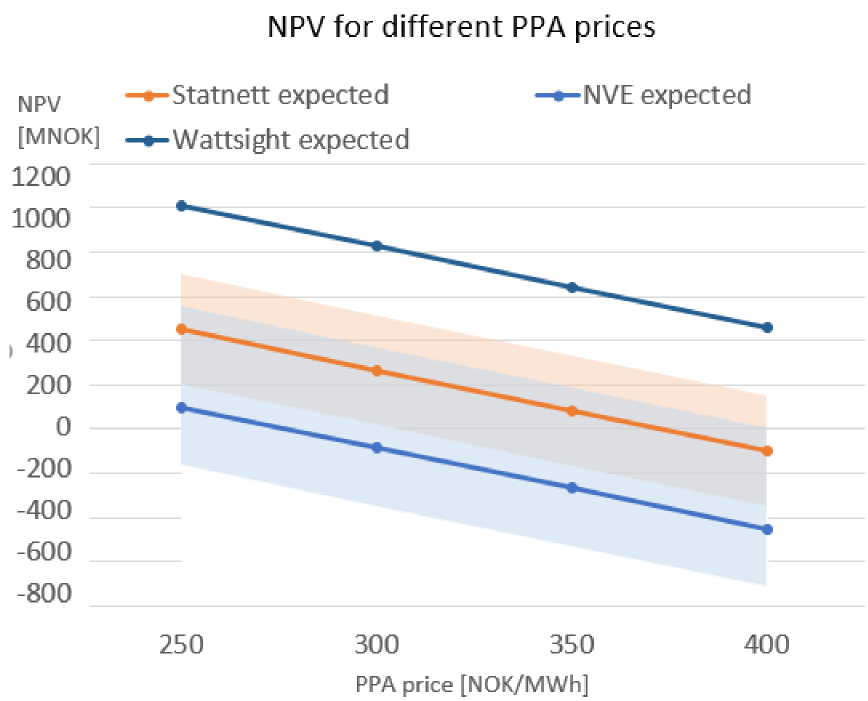

Figure 6.8: NPV for Position 2 for different PPA prices based on constant power production and annual predicted prices.

Here, the shaded areas provide information of the distance between the measures for the high, expected and low cases of the forecasts of Statnett and NVE.

Evident from the results, the NPV of the PPA is heavily dependent on which price forecast is applied. Using the prediction by Wattsight, all the PPA prices render the project profitable. The expected paths predicted by Statnett and NVE imply a PPA price below approximately 370 and 270 NOK/MW, respectively, to be profitable.

Financial Model 2.III: Monte Carlo model with variable daily prices and production.
Given daily variable production and prices, we will now evaluate the profitability of entering a PPA in our case study. (Results from *Financial Model 2.III*, page 46, with numerical values in Table A.8; MATLAB script in B.1.7).

The resulting confidence intervals for NPV are shown visually in Figure 6.9, together with the static NPV values from *Financial model 2.II.*

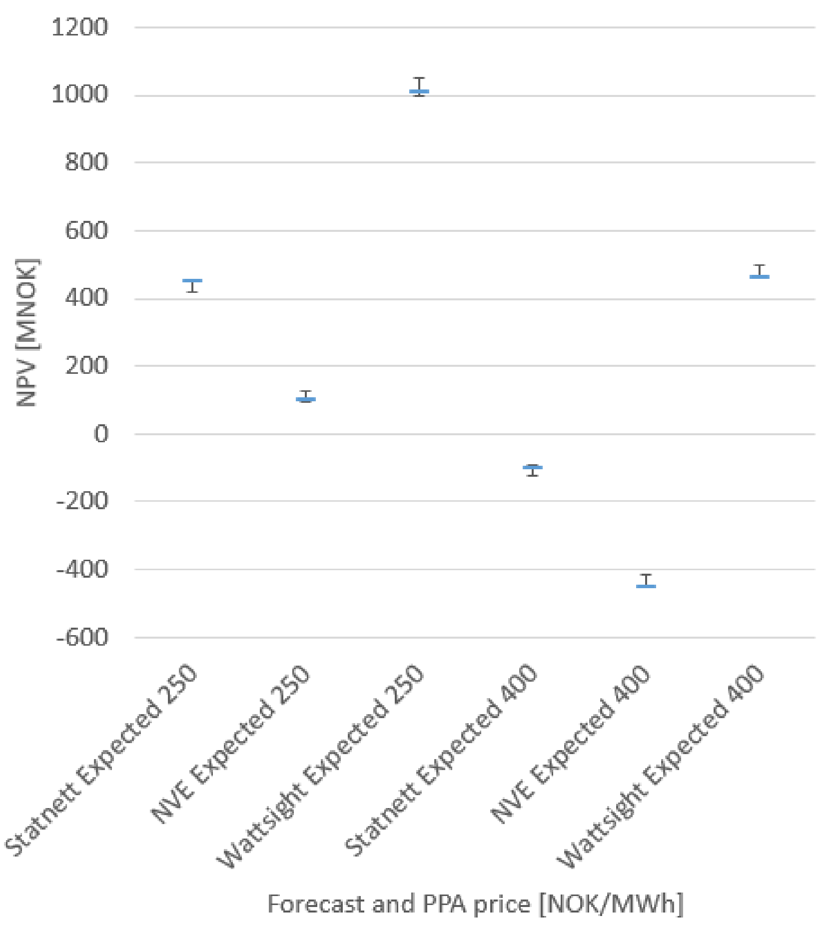

Figure 6.9: 95 % confidence intervals for NPV for Position 2 for different PPA prices based on daily varying production and prices, along with the static NPV values. Conducted using expected price paths from forecasts and two different PPA prices; 250 and 400 NOK/MWh

The results here also show how the different forecasts impact NPV to a large extent, while daily production and price variation have a small impact in comparison. Additionally, it is evident how much the NPV value is dependent on the PPA price.

Considering each price forecast, the confidence intervals for NPV may be used to find the VaR of the project. They are calculated using the expected price paths in the three forecasts, and render the 97.5 % VaR of -417.19, -93.38 and -1000.20 MNOK, trusting Statnett, NVE or Wattsight respectively, at a PPA price of 250 NOK/MWh. At a PPA price of 400 NOK/MWh the 97.5 % VaRs are 124.83, 454.32 and -462.50 MNOK, respectively. Hence, the potential loss in Position 2 is not unambiguous and highly dependent on PPA price and future power prices.

Summary and comparison of the positions.
To be able to give advice regarding the choice between the positions, we will now compare

the results from the financial analyses.

As previously discussed, the profitability measures exhibit most sensitivity towards which price forecast is used. Therefore, we seek to identify how the future power prices affect the NPV for both positions, thereby which position is most exposed to the volatile nature of power prices. Because of the secrecy of actual PPA prices in the Norwegian market, we compare the wind power plant case to four possible PPA prices, as presented in *Financial Analysis 2.II*. The static NPV values are the focus in the following discussion, since the impact from the forecasts is well illustrated by these results.

Given a discount rate of 6 %, Figure 6.10 shows the comparison of the wind power plant NPV to PPAs having different fixed PPA prices, for all scenarios of the price forecasts.

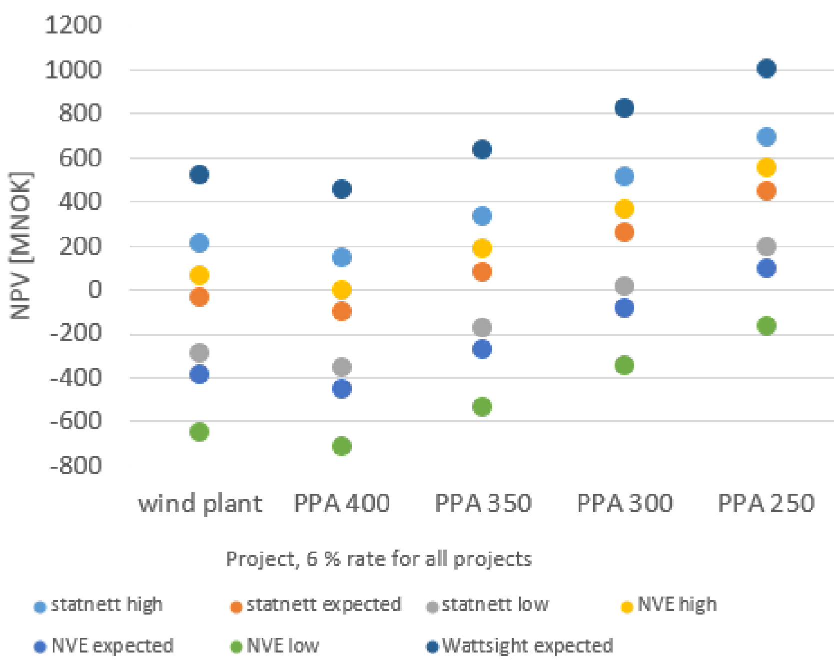

Figure 6.10: Comparison of NPV in the two positions. A discount rate of 6 % discount rate is applied for all cases. The PPA prices are given in NOK/MWh.

Along the vertical axis, the resulting NPV values are presented, portrayed as a spread per project. The respective projects are displayed on the horizontal axis; consisting of the wind power plant and the PPAs with four different prices. Each dot represents the resulting NPV given a specific price path. From the graph, we find that the spreads for NPV are parallel displaced among the projects, keeping the same distance between the largest and smallest NPV value. Thus, the projects are equally sensitive towards future power prices, rendering the project with most positive values for NPV as the preferable choice. Here, it is the PPA with a price of 250 NOK/MWh.

In Figure 6.11 the same projects are compared, however now with a discount rate of 3 %

for the NPV of the PPAs. As mentioned above, since the risk of holding a PPA is considered lower than owning a plant, accepting a lower rate for these projects may be reasonable. 6 % is kept for the wind power plant.

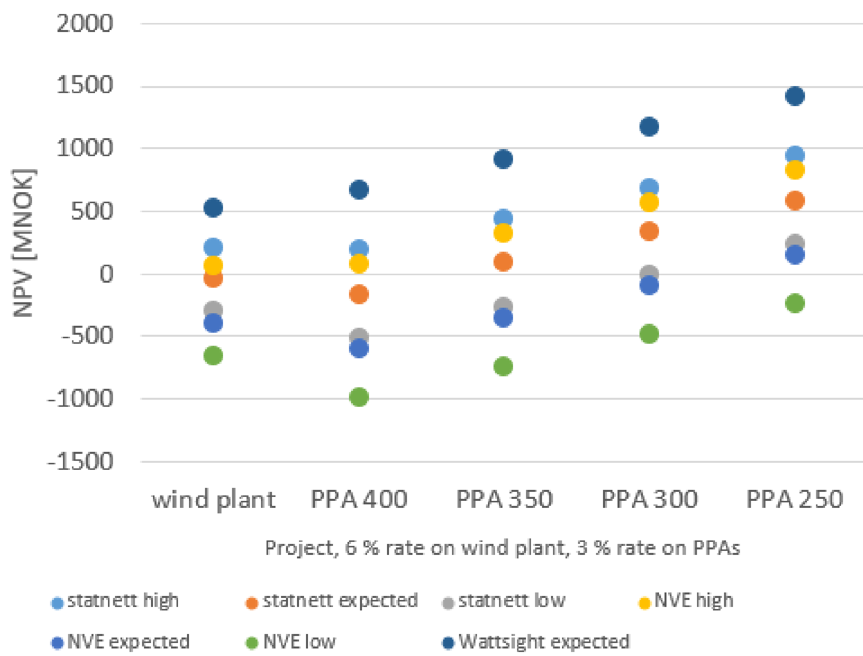

Figure 6.11: Comparison of NPV in the two positions. 6 % discount rate is used for the wind power plant, and 3 % is used for the PPA. The PPA prices are given in NOK/MWh.

In Figure 6.10, it is seen how the distance between the lowest and highest NPV value is equal for all PPAs and the wind power plant project. As opposed to this, Figure 6.11 displays different distances between the NPVs for the wind power plant than for the PPAs. However, among the PPA projects the ranges are equal in size. This is consistent with the fact that a low discount rate increases the value of money in the future, relative to money discounted with a high rate. Hence, large differences in price levels in the future affect the NPV of a project with a low discount rate to a greater extent than one with a high rate.

Evident from Figure 6.10, the least preferable investment is the PPA with a fixed price of 400 NOK/MWh, followed by the wind power plant and the PPAs with fixed prices of 350, 300 and 250 NOK/MWh, respectively. Hence, the break-even price of a PPA, which makes the PPA and wind power plant NPV values equal, is approximately 370 NOK/MWh. Assuming a discount rate of 3 % to be reasonable for the PPA projects, the wind power plant seems the least preferable position in terms of upside potential. However, considering the downside risk, a PPA with a price of 400 NOK/MWh is the least profitable position.

The low price path prediction by NVE is the most unfavourable one of the forecasts investigated, thus, it is possible to regard it as a worst-case scenario. Examining the loss here may provide insight to the choice of position. From Figure 6.11, the worst-case scenario values for each of the projects are as follows; -646.4 MNOK for the wind power plant and -982.2, -732.7, -483.1 and -233.5 MNOK for a PPA with prices of 400, 350, 300 and 250 NOK/MWh, respectively. Hence, the PPA prices of 400 and 350 NOK/MWh incur larger losses in the worst-case price scenario than owning a wind power plant, whereas PPAs priced at 250 and 300 NOK/MWh cause smaller.

Considering each price forecast, the confidence intervals for NPV from *Financial Model 2.III* may be used to find the VaR of the wind power plant project. They are calculated using the expected price paths in the three forecasts, and render the 97.5 % VaR of 77.84, 399.54 and -502.34 MNOK, trusting Statnett, NVE or Wattsight respectively. The 97.5 % VaR of a PPA with price of 250 NOK/MWh is -417.19, -93.38 and -1000.20 MNOK, indicating Statnett, NVE or Wattsight respectively. At a PPA price of 400 NOK/MWh the 97.5 % VaRs are 124.83, 454.32 and -462.50 MNOK, respectively. Hence, our analyses suggest that the low PPA price is an obvious valuable investment for all forecast scenarios, while the wind power plant project is riskier. However, comparing the wind power plant and the high price PPA, the wind power plant investment appears less risky.

In summary, this discussion provides no obvious answer to the question of whether to invest in a wind power plant or enter a PPA. However, given any opportunity of a PPA price around 370 NOK/MWh or less, entering a PPA seems to be the preferable position.

6.1.2 Costs

LCOE

Cost Analysis 1.I: LCOE of wind power plant.

We will now calculate the LCOE of the plant in Position 1 of our case study. Additionally, we perform a sensitivity analysis of all input factors to investigate how the LCOE measure depends on its inputs. The LCOE will be used to assess how representative of our case plant is of the current marked, and to be compared with PPA prices to contrast the costs in each of the positions. (Results from *Cost Model 1.I*, page 47; MATLAB script in B.1.8).

As the parameter values of the case plant are chosen from what is typical observed in the current Norwegian market, we expect that the LCOE obtained for our case wind power plant is in the range of what reliable sources, e.g. NVE, specify.

LCOE of the plant is found to be 322.30 NOK/MWh. It slightly exceeds the average spot price found using market data from Nord Pool, i.e. 282.4 NOK/MWh, presented in Table 6.1. Applying the forecasts, resulting average values are 54.197, 28.413 and 36.663

EUR/MWh for the predictions by Wattsight, NVE and Statnett, respectively. Using an exchange rate of 10 NOK/EUR, the amounts are converted to 541.97, 284.13 and 366.63 NOK/MWh, respectively. Hence, the LCOE is below the average levels of Statnett and Wattsight, but above the prediction by NVE. Additionally, NVE published a report in 2019 regarding the current LCOE values for wind power, claiming that 340 NOK/MWh in 2018 and 270 NOK/MWh in 2020 are fair estimates (NVE, 2019a). All of the estimates are displayed in Figure 6.12.

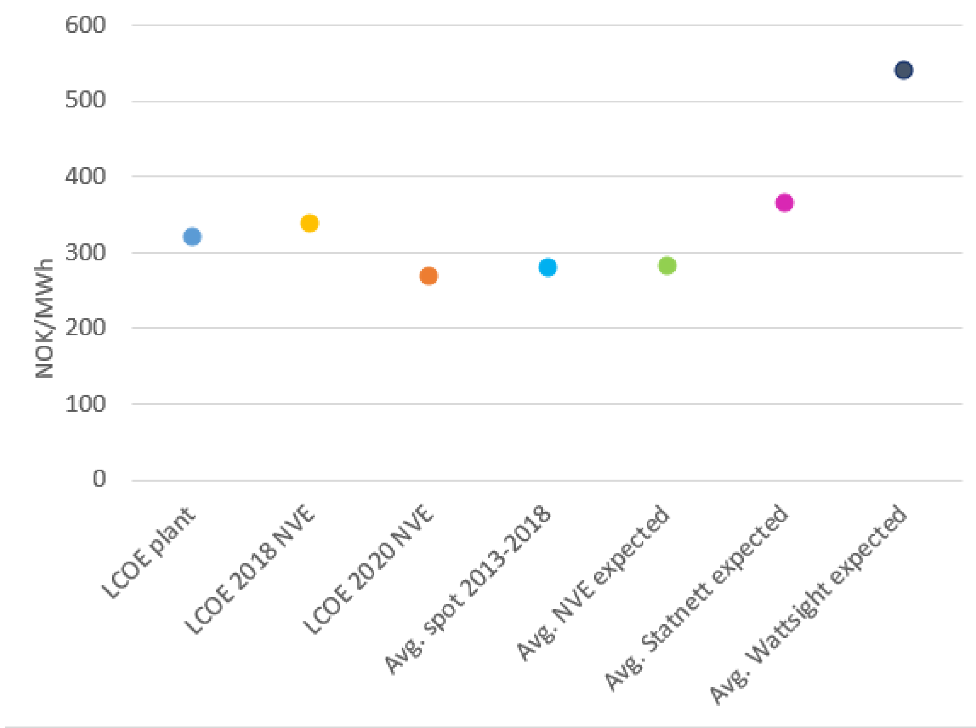

Figure 6.12: Comparison of estimated LCOE to relevant numbers.

Judging from the values exhibited in Figure 6.12, our LCOE calculated for the case plant seems to be within a reasonable range, particularly as it approximates the estimate for 2018 by NVE. Thus, we claim that our case values are representative for the current Norwegian market. Also evident from the graph, historical prices and the NVE expected prices are too low to achieve profitability for our wind power plant. If either of the expected forecasts by Statnett and Wattsight is correct, the prices are above any LCOE estimate, making the plant profitable. These findings are in accordance with our results from the profitability analyses conducted above.

Performing a sensitivity analysis for different intervals of the input parameters helps understanding their impact on the LCOE. It is conducted by changing one variable at a time, whilst the others remain as presented in Chapter 5.

In Figure 6.13, the LCOE corresponding to different investment costs, for three different levels of operation and maintenance expenses, are plotted.

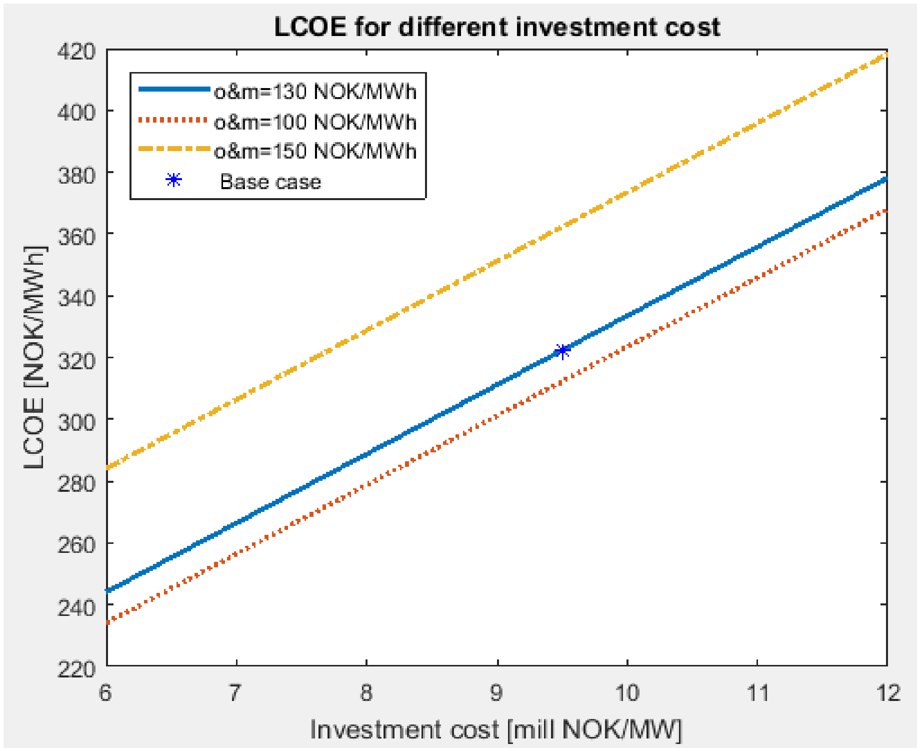

Figure 6.13: LCOE for different investment cost, associated with different levels of operation and maintenance cost.

As discussed on page 55, the average investment cost for recently initiated plants in Norway is 9.5 MNOK/MWh. A few years ago, it was assumed to be within the range of 10-12 MNOK/MWh. Hence, it might be reasonable to assume that these expenditures approximate 6-7 MNOK/MWh in some years. The operation and maintenance costs are set between 10-15 NOK/MWh, which resemble those values presented on page 55. It is evident from the figure that the LCOE ranges from about 240 to 420 NOK/MWh in these scenarios.

Figure 6.14 displays the resulting LCOE using different values of interest rate, given possible constant annual production represented by full-load hours.

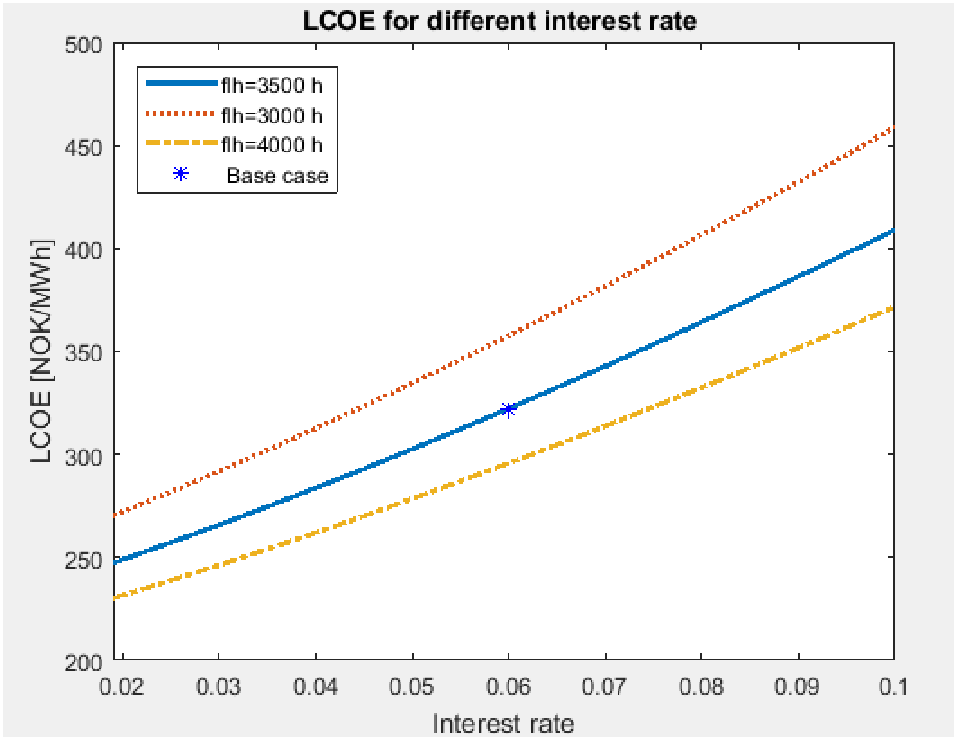

Figure 6.14: LCOE for different interest rate, associated with different values of full-load hours.

As stated on page 56, wind power plants that are recently developed or under construction in Norway, are assumed to have a production of 3500 full-load hours. However, just a few years ago, this value was 2900 h. Hence, it is not unreasonable to expect that 4000 full-load hours soon is a realistic value for productivity of wind power plants. For the purpose of our sensitivity analysis, values within this range is selected. From the plot, we find that the resulting LCOE is in the interval from 225 to 455 NOK/MWh.

Considering both the sensitivity analyses presented in Figures 6.13 and 6.14, the LCOE appears within the range of 225 and 455 NOK/MWh. The results support how our case values are representative of the current market. Comparing the expected LCOE to our expected PPA price interval presented in *Financial Analysis 2.II*, we see that there is a fair chance that power from the wind power plant will be cheaper than from a PPA. If the PPA price is above 322 NOK/MWh Position 1 is preferable considering production cost. The LCOE value appears around the centre of our expected PPA price interval, making it difficult to say which position is most likely to provide lowest power costs.

Total costs

Position 1.

Cost Analysis 1.II: Monte Carlo model.

We will now evaluate costs of our case plant, with emphasis on LCOE and REE. (Results from *Cost Model 1.II*, page 48, with numerical values in Tables A.9, A.10, A.10 and A.11; MATLAB scripts in B.1.9 and B.1.10, indicating historical and forecast prices, respectively).

The main difference between the positions is the cost of the energy produced from the wind power plant. The unit cost of power is the LCOE in Position 1, and the PPA price for Position 2. Apart from this, the positions are fairly similar in regard to production; the plant constructed is chosen to be equivalent to the plant of the PPA producing party. Furthermore, the market exposure will be dependent on how much additional trading is required, which we consider relying on the difference between the average production output and the consumption.

We expect the REE in Position 1 to appear in the interval between the LCOE value and the average power price level. Exactly where within this range is believed to depend on the relation between the customer demand and the capacity of the plant. If the demand is high compared to the capacity of the plant, more purchasing from the market is necessary, thus, yielding a REE closer to the average market price level. The opposite is believed when the demand is low. Moreover, we expect that the REE of the two positions will be close if the LCOE and PPA price are similar.

We select two arbitrarily customer demand levels to illustrate the impact on power costs by the relation between demand and plant capacity. In the analyses, the customer demands are assumed constant. The first level, referred to as demand one, approximates the average production of the wind power plant. It is 42.15 MW, yielding an annual consumption of 369.23 GWh. The second demand level, referred to as demand two, represents the maximum capacity of the plant. This is 105 MW and results in an annual consumption of 919.8 GWh. As we apply equal cost data and same simulation method for prices as in previous analyses, ranges for daily prices and LCOE are similar regardless of load.

We first analyse the model using historical prices. The most important values are presented graphically in Figure 6.15.

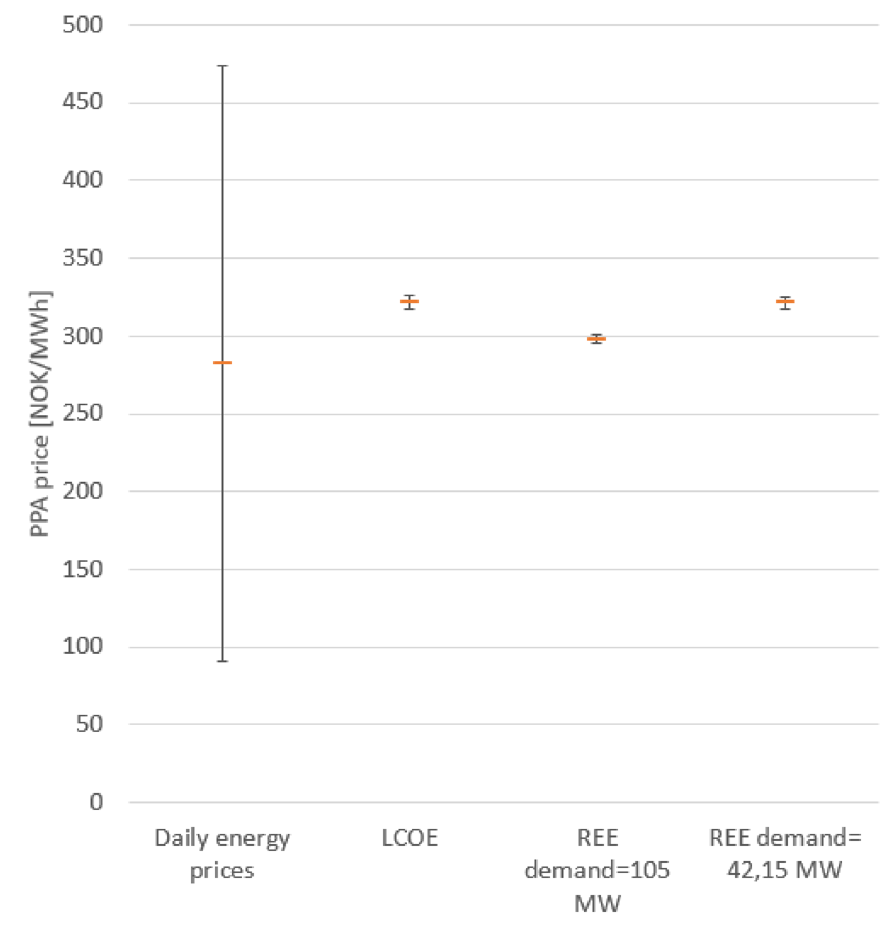

Figure 6.15: Confidence intervals for power prices, LCOE and REE for the plant simulations. REE is included for both demand levels.

Considering demand one, the confidence intervals of LCOE and REE are approximately equivalent. This is reasonable because the quantity of power sold and purchased from the market is quite similar, i.e. they even out, resulting in a modest market exposure.

A customer requiring a power quantity equivalent to demand two will never experience excess production, thus, only purchases from the market. On the other hand, production shortfall will be a common occurrence, rendering it necessary to purchase a significant power quantity from the spot market. In our simulation, about twice the produced must be purchased. Compared to demand one, the REE is now smaller in size; it exceeds the average market price but are lower than LCOE. This makes sense as the power procured from the market comes at less cost than plant power. As illustrated by the results, the relationship between demand and plant capacity determines the resulting costs, coherent with our expectations.

Furthermore, it is noticed that the confidence intervals for LCOE and REE are both quite narrow, and not far apart. This indicates that, given current cost levels of wind power and price levels of 2013-2018, there is insignificant difference in market exposure and power costs regardless of demand, as the average power price level is quite similar to the LCOE.

We now analyse the model using forecasted prices. The most important values are visualized in Figure 6.16.

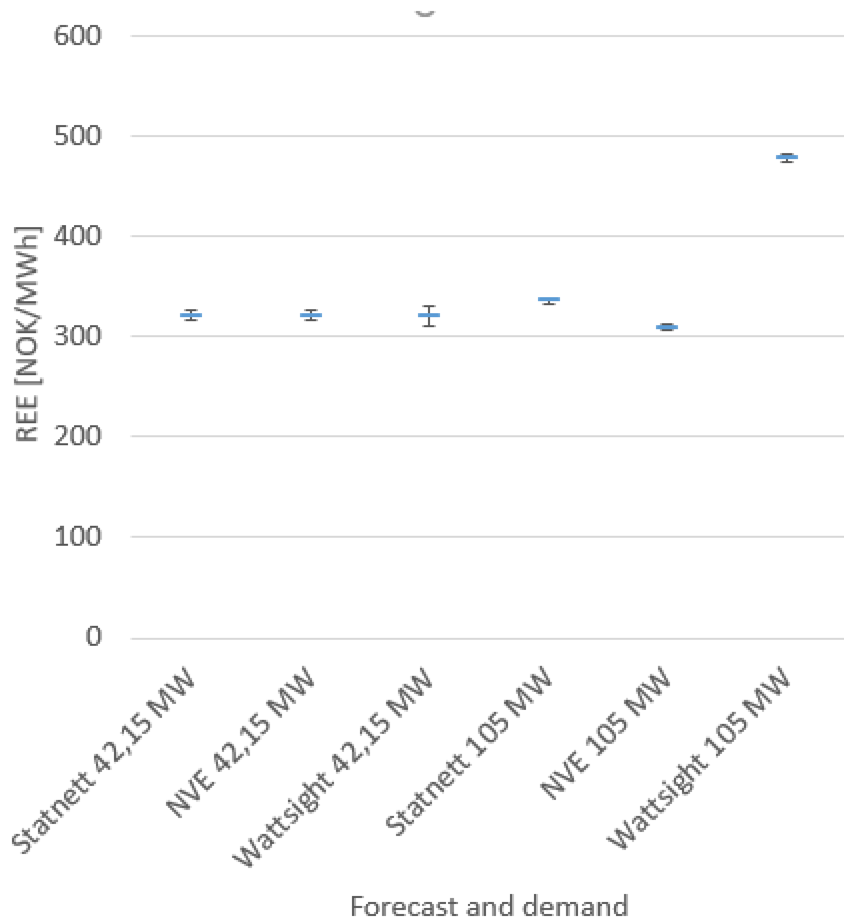

Figure 6.16: Comparing REE from simulation with different forecasts and demand levels. Expected paths in forecasts are used.

Applying demand one, the choice of price forecast has little impact on REE. The REE levels are approximately the same for all the forecasts, because the amount sold approaches the quantity purchased. Additionally, since the prices are mean reverting and even out the effect in the long run, we see that given this demand level the power costs are not very sensitive to prices in the market. This is coherent with our finding using historical price data.

Applying demand two, REE is larger than for demand one for the Statnett and Wattsight forecast. Applying Statnett forecast, only a slight increase appears, while using the predictions by Wattsight, the REE has increased by almost 50 %. This is because the NVE forecast is close to historical price levels, while the other forecasts predict higher levels. Hence, applying demand two, purchasing increases exposure towards the market prices. REE is more dependent on the forecast chosen at this demand level.

Position 2.

Cost Analysis 2.I: Monte Carlo model.

We will now evaluate costs of our case PPA, with emphasize on REE. (Results from *Cost Model 2.I*, page 50, with numerical values in Tables A.12, A.13, A.14 and A.15; Matlab scripts in B.1.11 and B.1.12, indicating historical and forecast prices, respectively).

We will apply the two PPA prices 250 and 400 NOK/MWh in our analysis. These are regarded as the upper and lower limits for a reasonable PPA price, based on the discussion in *Financial Analysis 2.II.*

We expect the results of REE to significantly differ for the two PPA price levels when the load is equal to the max capacity, but not when the load equals the average production, as we expect the purchasing and sale to market to even out in this case, as Position 1.

We first analyse the model using historical prices. The most important values are visualized in Figure 6.17.

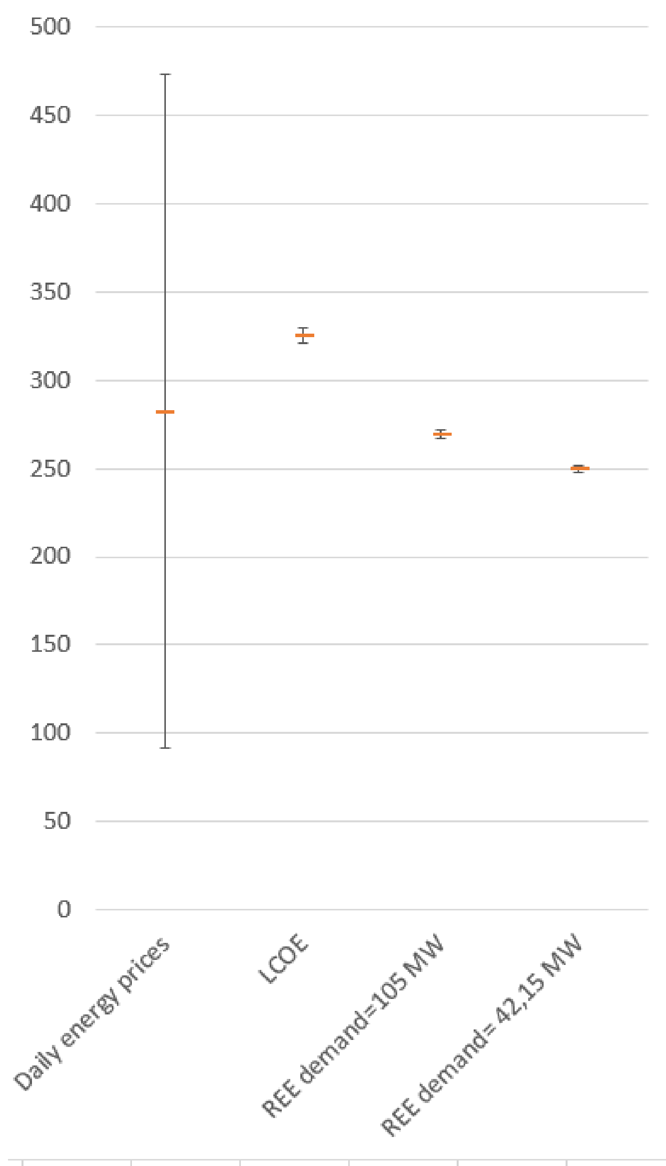

Figure 6.17: Confidence intervals for power prices, LCOE and REE for the PPA simulations. REE is included for both demand levels.

From the results, we find that the PPA price is slightly lower than the average power price level. Therefore, using the market for balancing will incur additional costs compared to the bare cost of production from the wind power plant. We find that at demand one, the REE is almost equal to the PPA price, coherent with our expectation as the PPA price is now the cost of power. At demand level two, REE exceeds the PPA price, as necessary trading increases the power costs.

We now analyse the model using forecasted prices. Both consumer demand levels are applied for each PPA price. The most important values are visualized in Figures 6.18 and

6.19, showing results at a PPA price of 250 and 400 NOK/MWh, respectively.

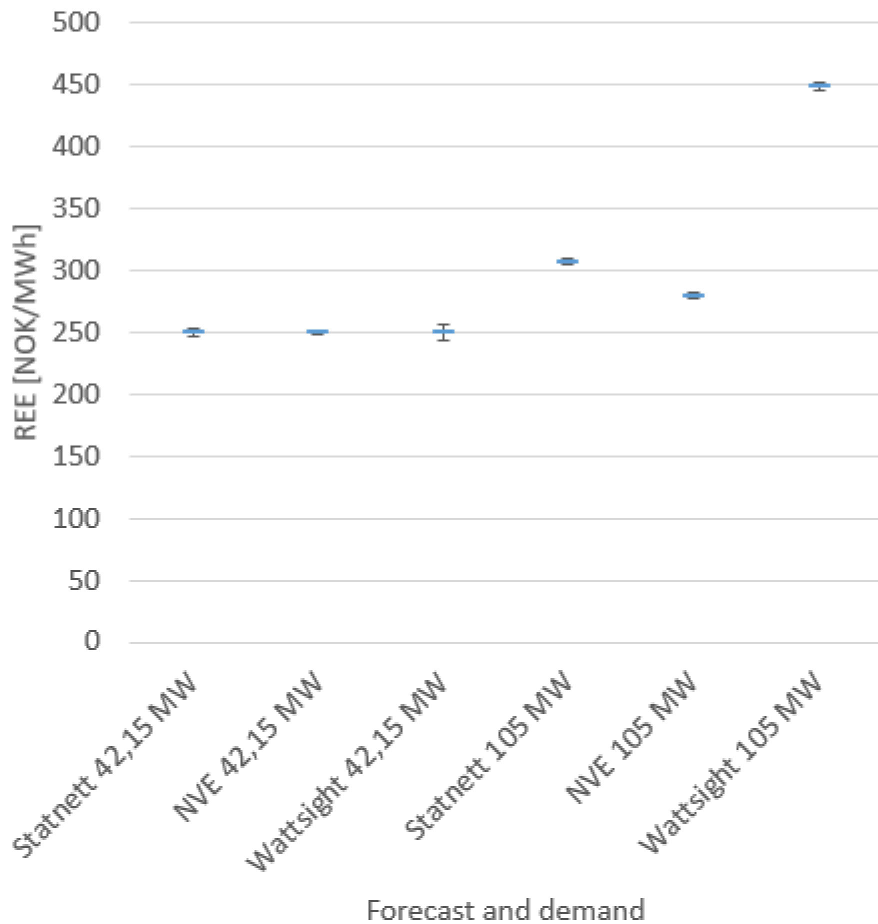

Figure 6.18: REE values for demand levels and forecasts with a PPA price of 250 NOK/MWh.

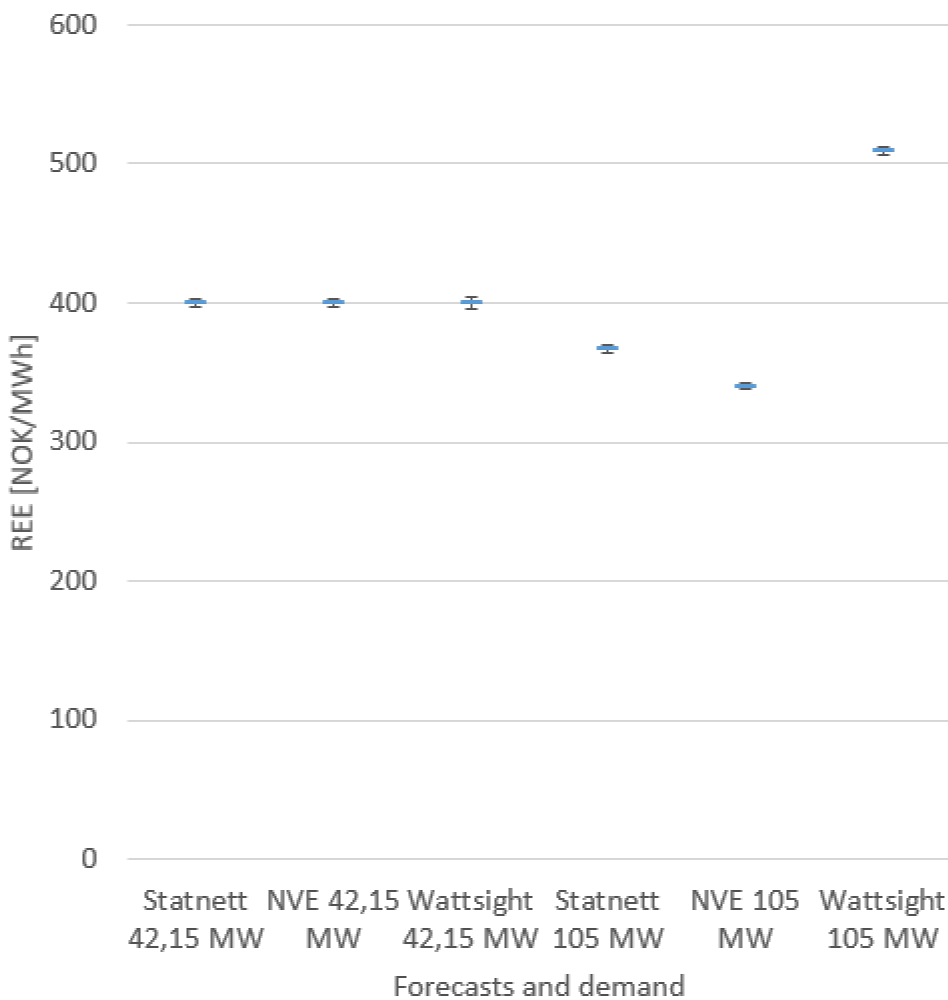

Figure 6.19: REE values for demand levels and forecasts with a PPA price of 400 NOK/MWh.

For demand one, the predictions by all forecasts render almost the same value for REE. We see that in the confidence interval for the Wattsight case, the REE may become slightly lower than the PPA price. This could be possible if a large share of the power is sold at high prices, making the market exposure a benefit. Thus, contrary to expectations, for demand one, the REE is not always within the interval between the power cost and the average power price.

For demand two and a PPA price of 250 NOK/MWh, the values for REE increase significantly. As stated above, which forecast is applied has greater impact when there is a lot of procurement from the market. Statnett and NVE predict prices averaging around 250 NOK/MWh, so when using their forecasts the impact from the market is low. Applying the high price level by Wattsight, purchasing from the market is expensive, rendering the REE to exceed the PPA price by about 80 %.

Given a PPA price of 400 NOK/MWh, the REE increases significantly for all forecasts compared to a PPA price of 250 NOK/MWh. For many of the forecasts, the PPA price will frequently exceed the spot price during the contractual period, thus rendering a higher realized cost of energy. For the second demand, the REE is below the PPA price for the NVE and Statnett forecasts, due to purchasing at lower prices from the market. For the prediction by Wattsight, the REE increases compared to the results using demand one.

Summary and comparison of the positions.
In comparison to current LCOE values provided by NVE, i.e. 340 NOK/MWh, 322.30 NOK/MWh as the LCOE of our case study seems reasonable. Thus, we confirm that the case parameter values selected are representative for the current Norwegian market. Comparing this to PPA price levels, which we expect to be in the interval 250-400 NOK/MWh, the LCOE of our case plant appears around the centre of the PPA price interval, making it possible to get power cheaper from a PPA than from the representative Norwegian wind power plant.

The cost analyses conducted reveal that the total cost of power, i.e. REE, depends on the ratio between the constant demand and the maximum capacity of the plant. This relation determines the quantity necessary to trade in the market to cover the demand. Considering a demand equivalent to the average production of the wind power plant, the potential gains and losses from trading in the market evens out when prices are mean reverting around a constant value. Thus, rendering the REE equal to the power costs; either LCOE or the PPA price. On the other hand, if the demand is equal to the maximum capacity of the plant, only purchasing from the market is relevant, and hence the position is more sensitive to the market. Thereby, in a market where the average power price exceeds the PPA price or LCOE, the REE will also exceed the power price. It is opposite in a market where prices are lower than the PPA or LCOE. Additionally, we find that the REE does not necessarily lie within the interval between the cost of power and the average power price, as balancing may lead to increased income from market selling if the power prices are high. As a result, the REE may be less than the power cost. Moreover, we see that the REE is not very different between our proposed cases when the power price level is similar to the power cost from the wind power plant, i.e. LCOE or PPA price. Hence, there must be a significant difference between power costs and power prices to induce market exposure to be a real issue.

The largest difference between the positions is the potential deviation among the PPA price and the LCOE, causing various REEs. Furthermore, entering a PPA can make it difficult to scale the wind power plant to the specific demand of the consumer, which may be easier to impact when constructing an own plant. We find that the plant capacity compared to the demand is a determining factor for the total power costs and market exposure of the positions, and hence this issue may be a significant difference between the positions.

The main conclusion from our cost analyses is that if the large power consumer manages to obtain a PPA with a fixed price below the wind power plant LCOE values of new projects, Position 2 will be most beneficial. However, this depends on whether the PPA is related to a wind power plant with a size similar to the customer demand, as the market exposure depends heavily on this factor.

6.2 Qualitative risk assessment

We now discuss the risk categories for each position, as presented in Section 4.2, with focus on examples from Norway. Firms commonly perform a specific risk assessment for an individual project since all projects involve different considerations. Hence, it is difficult to provide a general evaluation within the Norwegian market and our results are given by considering the case study.

Position 1.

(Results from qualitative risk assessment of Position 1, page 51).

The result of the qualitative risk evaluation in Position 1 is summarized in Table 6.3.

Probability \ **Impact**	Low	Medium	High
High			Strategic/business Market/sales
Medium		Transport/construction/completion Counterparty	
Low		Operation/maintenance Liability/legal Political/regulatory	

Table 6.3: Summary of the results from qualitative risk assessment in Position 1.

As shown in the matrix above, market/sales and strategic/business risks are placed in the red squares, indicating that these are the most severe risk categories. This is primarily due to uncertainty about future power prices and technological development.

An overview of the underlying factors that constitute the result in Table 6.3 is presented in Table 6.4.

Risk category	**Relevant factors**	**Risk assessment**	
		Probability	***Impact***
Strategic/business	• Scarcity of capital/ liquidity of company	Low	High
	• Competence and management know-how	Low	Medium
	• Technological evolution	High	High
	• Public approval	Low	High
Transport/construction/completion	• Turbine transportation	Low	Medium
	• Construction accidents	Low	Medium
	• Problems regarding local utilization of the area	Medium	Medium
	• Preservable historical objects	Low	Medium
	• Construction delay	Medium	Medium
Operation/maintenance	• Defective wind turbines	Low	Low
	• Plant site conditions; weather and wildlife	Low	Medium
Liability/legal	• Legal disputes	Low	Medium
Market/sales	• Wind speeds	Low	Low
	• Power prices	High	High
	• Cannibalization effect	Medium	Low
	• Regional price differences	Medium	Low
Counterparty	• Problems imposed by subcontractors	Medium	High
Political/regulatory	• Change in legislation, e.g. subsidies and tax rate	Low	Medium

Table 6.4: Summary of relevant factors found for each risk category in Position 1, associated with risk assessment.

Each factor is assigned a probability and impact, leading to an overall classification of the risk categories. Argumentation for the above outcome is found the following section, given in the same order as Table 6.4.

Strategic/business. We assess the risk category strategic/business to have high probability and high impact.

Scarcity of capital/ liquidity of company. Procuring capital for wind power investments at an economically sustainable capital cost is important for a project to become profitable. During recent years, there has been increased wind power development in Norway, primarily financed by international investors (Parr, 2018), indicating that procuring capital might not be the main challenge facing developers. Evaluating our case, the project will be financed by the investors of the large power consumer, as well as loans granted by financial institutions. Therefore, the liquidity of the consumer becomes the question considered by potential lenders, as it represents their security for the loan. Otherwise, if their liquidity is not considered enough to justify for the risk incurred, the consumer risks being unable to realize the project due to scarce financing. Because we regard the consumer to have high liquidity, we assess the risk of scarce capital to be of low probability, but of high impact as this will be a problem should it occur. Lack of access to sufficient capital may result in termination of the project.

Competence and management know-how. Lack of competence and management know-how of wind power plant construction and operation incur risk of additional costs, derived from less optimal project management. Moreover, lack of relevant competence about wind power can result in mistakes that can lead to accidents or unexpected costs to repair the damage imposed, where the severity of the potential impact depends on the type of mistake and time of discovery. However, we assume that the consumer possesses the competence necessary to construct a plant and is in control of every aspect of the project, except construction, maintenance and manufacturing performed by subcontractors. If the developer does not have the necessary competence, an option would be to hire external consultants. This would likely incur uncertain additional costs, as each wind power plant project has individual characteristics making it difficult to correctly anticipate the required hours to finish the project. Nevertheless, as we consider the consumer to have the required knowledge, we regard this risk to be of low probability and having medium impact.

Technological evolution. Rapid technological evolution within the turbine industry implies the risk that the technology specified at the time of concession approval is outdated even before the plant is installed, or shortly following project completion. This may be a competitive disadvantage if competitors, installing somewhat later, obtain increased project value and return to investors due to better technology.

Currently, there is massive development in wind turbine technology. Turbines gain better performance by increased hub height and blade length (Roberts, 2019). A recent example of rapid technological development related to a Norwegian wind project is the Frøya project, which was granted concession for 135 m turbines in 2012. By construction initiation in 2019, the developer reapplied to install 180 m high turbines (Rasmussen, 2019).

Furthermore, offshore wind is beginning to pose an alternative to onshore wind. Offshore plants not only face engineering challenges, but far less public opposition than onshore projects. The larger the turbine, the steadier the production, which simplifies the process of grid integration. According to Roberts (2019), "Wind power is already outcompeting other sources in many markets, and after a few more generations of growth, it won't even be a competition anymore" (Roberts, 2019). According to energy analyst Ramez Naam, "The ultimate potential for wind power is 60 % capacity factor, which at current power price levels will be tremendously more valuable than it is now" (Roberts, 2019). Considering this, it is reasonable to conclude that the technological risk in wind power is large under the current market conditions. Particularly, the risk that offshore wind power will be the next evolutionary step for the industry in coming years, pose a threat to onshore wind projects. We regard technological development risk to be the most prominent factor within the category of strategic/business risk and assess it to have high probability with high impact.

Public approval. The risk of insufficient public approval has been continuously present in Norway, as many consider wind turbines to be an intrusive intervention in the pristine nature. Thomas Lindblad, head of construction and operation at Res Nordisk vindkraft in Scandinavia, states that they experience increased opposition to wind power projects (Akhtar, 2019). Protesters argue that the turbines may be harmful to the local biological diversity, destroy popular hiking areas, or violate the rights of the indigenous Sápmi people. Such issues are supposed to be addressed during the concession process, thus ensure that the opinions of the opposing parties are considered, and measures to reduce their inconveniences are implemented. Regardless, Friends of the Earth Norway, a group devoted to preserve the Norwegian nature, states their intentions to support opposition of wind power plants which they consider as harming the nature, despite the projects being approved by NVE (Kleven, 2019).

Public opposition can interfere with the construction process. This is the case for the Frøya wind project, where construction was prevented from being initiated within the expiration of the building permit, thus starting a bureaucratic process aimed at terminating the construction (Rasmussen, 2019). For several months, the project has obstructed from continuation, incurring costs of about half a million per day. Furthermore, due to strong local opposition, also in the municipality, there is a possibility that the whole project will be terminated (Egge et al., 2019). This illustrates the potential threat local opposition may pose to current and future wind power developments. We consider the risk of public opposition as highly probable, as most wind projects in Norway are subject to some discontent among the local public. However, the risk that such opposition results in severe problems for a project when granted concession, which is assumed in our case, is of low probability.

A potential high impact, as illustrated by the Frøya case, is present.

Transport/construction/completion. We assess transport/construction/completion risk to have medium probability and medium impact.

Turbine transportation. Prior to construction, all turbines and associated equipment must be transported from the production facility, often located abroad, to the plant site. In Norway, this typically involves moving massive turbines on narrow country roads to remote locations. Additionally, such transportation requires police escort, making it the most expensive part of the transportation process (Moan, 2012). However, with the strict security measures required there is low probability of damage to the turbines during transportation, and we regard this risk factor to have low probability (Moan, 2012). Any damage would cause delays, entailing increased costs related to other transport, construction and even completion of the project. Hence, we assess the impact to be medium.

Construction accidents. Unforeseen incidents may occur during construction, for instance accidents due to misconduct, incompetence, and human or technical failure. Hiring qualified subcontractors contribute to mitigate this risk. To the extent of our knowledge, no public information regarding accidents in construction of wind power plants in Norway are available, and hence we assume the occurrence of such events are rare. Hence, we regard this risk factor to be of low probability, but medium impact, because an accident may lead to delays in the construction process.

Problems regarding local utilization of the area. Construction may interfere with the local utilization of the area, requiring developers to adjust the construction process so that the activities may be performed as before during this period. The developers of the Fosen projects were required to implement measures ensuring that the reindeer activity could proceed uninterrupted by the construction process, incurring an additional cost of 9 MNOK (Fosen Vind, 2019). Due to many uncertain subfactors, we regard this to have medium probability, and medium impact.

Preservable historical objects. In the rare occasion that an automatically preservable historical object, for instance a Viking burial site, is discovered after construction is initiated, the developer is obliged to pay for a safe removal (Lovdata, 1979). However, due to strict guidelines when performing the consequence analysis during the concession process, such incidents seldom occur, implying low probability. Additionally, we assess this factor to have medium impact because such events will rarely terminate a project, only potentially incur significant cost to remove preservable objects (Henriksen, 2018).

Construction delay. Subcontractors of the project require payments; thus, any postponement of the project may cause large, additional costs to the developer. For instance, the construction stop of the wind power plant at Frøya may have resulted in an additional cost of

20 MNOK (Viseth, 2019). Since a delay can be incurred by all the above-mentioned factors, we regard construction delay to have medium probability and be of medium impact.

Operation/maintenance. We assess operation/maintenance risk to have low probability and medium impact.

Defective wind turbines. Defective wind turbines impose operational risk to the plant, as downtime imply loss of potential income (D'Amico, Petroni, and Prattico, 2014). Therefore, limiting repair time is of importance. Regular maintenance is part of preserving the turbines, to conserve a satisfying production (Vindportalen, 2019[b]).

Norwegian developers commonly engage in service and maintenance agreements with their turbine supplier, having an average duration of five years (Døscher, 2014; Byggfakta.no, 2011). Vestas is one of the turbine suppliers offering such agreements, where fixed payments covers all maintenance incidents, initially for ten years, but with a potential extension of five years (Vestas, 2019[a]). These contracts provide service specifically adapted to optimize either production output or the time the plant is operating, guaranteeing a 97 % operational time (Vestas, 2019[a]). Hence, having a service agreement, the project will not be exposed to large risk of unforeseen cost due to maintenance and not great losses in revenue during 97 % of the operational time. Hence, we assess this risk factor to have low probability with the right agreement, and low impact, due to extensive operational time.

Plant site conditions; weather and wildlife. Turbines are exposed to the given weather conditions on the plant site. Particularly in Scandinavia, snow and ice attach to the turbine blades. If not handled properly, these iced rotor blades can lead to accidents. In Sweden, where this problem is more prominent because the turbines are placed at higher altitudes, operators remove the ice on blades using hot water from helicopters (Nilsen, 2015).

Norwegian plant owners are also obliged, as a condition of the concession, to implement measures to mitigate the occurrence of ice throwing, otherwise, the consequences could be fines or in worst case a revoked concession (Butt, Dalen, and Lundsbakken, 2018). Extreme wind conditions can also lead to turbine damages, as experienced in the US, where a turbine snapped in two due to too strong wind (Nilsen, 2007). Additionally, birds, particularly eagles, occasionally crash into turbines, potentially causing further damage (Eggen, 2018). Such incidents are hard to predict, but costs can be reduced by insurance (Codan Forsikring, 2019). We consider this risk factor to have low probability due to seldom occurrence. However, we consider it to have medium impact because severe incidents will cause delays and extra workload. In the worst-case scenario, it will revoke the concession. However, insurance can provide some coverage.

Liability/legal. We assess the risk category of liability/legal to have low probability and medium impact.

Legal disputes. Disputes regarding property where a voluntary agreement is reached, should be disclosed prior to concession is granted (NVE, n.d.). Otherwise, an application for expropriation, which means that the property may be taken involuntarily at a compensation similar to a voluntarily settled case, is filed along with the concession application (NVE, n.d.). If it is denied, the developer cannot acquire the land, which is a significant issue. For our case, we assume that the property is rented voluntarily, thus avoiding expropriation.

Concerning other potential legal disputes, these and measures to reduce their impact, are proposed prior to concession approval, and documented in the consequence analysis (NVE, n.d.). An example of this not being the case, is evident regarding the Fosen project. Fosen Vind, the developers of the Fosen project, is currently involved in an ongoing dispute regarding compensation to reindeer farmers during the operational lifetime of the plant (Fosen Vind, 2019). Compensation for the construction phase was settled, yet the issue of the operational lifetime of the plant remains unresolved. As the plant is an environmental intervention, the developers are obliged to reimburse the reindeer farmers for their economic losses resulting from the wind power plant. The farmers, which are the indigenous Sápmi people, filed a complaint to the United Nations (UN) Committee on the Elimination of Racial Discrimination, resulting in a resolution from the UN requesting the Norwegian Government to terminate the construction until the dispute is settled (Thobroe, 2018). Arguing that no rights had been violated, the Government permitted the construction to continue (Thobroe, 2018). Such conflicts are unfortunate for the developers, as they may result in large compensation requirements, legal fees and negative press. Additionally, delay of production could be a consequence, which would have been the case for the Fosen project if the Government had followed up on the resolution.

Since the concession is already given in our case study, thus all anticipated legal disputes are settled, we assume this risk factor to be of low probability, but with medium impact as conflicts still may continue after concession is granted.

Market/sales. We assess market/sales risk to have high probability and high impact.

Wind speeds. Wind power is an intermittent energy source, difficult to accurately predict. Huneke et al. (2018) state that, based on data from the European Commission, the power generation of wind turbines may vary by 20 % on an annual basis. For the case study we consider the long-term wind speed at our location to be within this variation per year, thus uncertainty regarding future wind conditions does not represent an important risk. We asses this risk factor to have low probability and low impact.

Power prices. The uncertainty regarding future power prices pose a significant risk, as the price determines the income of the plant. To our plant, where a steady production is assumed, the price is the most significant factor to the revenue. The level of power prices is influenced by a complex set of factors, ranging from gas prices to local consumption (NVE, 2017). As of the last seven years excluding 2018, the prices have not been particularly beneficial for producers (Aanensen, 2019). Such extensive periods of low prices can render the plant unprofitable.

To assess the price risk in the future, knowledge of anticipated prices is necessary. Several credible industry actors, among others NVE, Statnett and Wattsight, provide forecasts for future power prices, all showing distinct price paths leading to very different results for the profitability of a plant (NVE, 2017; Statnett, 2018b; Barstad, 2019). The vast difference between the anticipations of each forecast, accentuates the difficulty of accurately predicting future power prices. Summarizing, the great uncertainty surrounding future power prices impose much risk to the revenue of the plant. Hence, we regard this risk factor to be of high probability and high impact.

Cannibalization effect. Rapid development of wind power in the Scandinavian countries, particularly in Denmark, has caused a cannibalization effect. Concurrent production from multiple wind power plants lead to periods of supply exceeding demand in the power market, resulting in lower realized power prices (Blaker, 2019). According to Gottlieb (2018), this has even given negative power prices at times. NVE (2017) claims that because Norway has significantly lower share of wind power compared to for instance Denmark, and the wind conditions are more variable, cannibalization will not impact the realized future power prices for wind towards 2030. Statnett draws similar conclusions, claiming that the value factor for Norway will decline from 1 in 2030 to 0.9 in 2040 (Statnett, 2018a). Hence, the realized value of energy projects during periods of extensive renewables development in the market will be reduced by approximately 10 %. This is a low impact compared to other Scandinavian countries (Statnett, 2018a). We therefore regard this risk factor to have medium probability in the long term, but with low impact. The uncertainty imposed by this factor is negligible compared to the impact from uncertain future power price levels, as the different forecasts imply price variations far exceeding a 10 % change.

Regional price differences. Nord Pool organizes the physical power trade in the Nordic power market, receiving bids from producers and consumers in the whole market, including Norway, Sweden, Denmark, Finland and the Baltic countries (EnergiFakta, 2019). The market price is settled based on the market cross resulting from all bids. However, the market is separated into different price areas, and the spot price in each area deviates somewhat from the overall system price in the whole market. The area prices result from bottlenecks in the power grid and unbalance between consumption and production within each of the price areas (Wangensteen, 2011). Norway consist of four different price regions (EnergiFakta, 2019). Because of area pricing, the location of the plant can affect the revenue. However, the observed price differences between Norwegian price areas are considered minor. NVE finds from their analyses that, between Northern and Southern Norway, it may be 2 to 4 øre/kWh in 2030 (NVE, 2017). Hence, this constitutes a small problem. We assess this factor to have medium probability and low impact.

Counterparty. We assess risk category of counterparty to have medium probability and medium impact.

Problems imposed by subcontractors. Planning and constructing a wind power plant is a complex and extensive process, including several different factors and which the developer holds the overall responsibility for. Additionally, there are many external subcontractors involved in a project, such as entrepreneurs, turbine and technology providers, and service companies. All these parties impose counterparty risk to the developer, as they make financial decisions beyond the control of the plant owner. If any subcontractor experiences financial difficulties, it could result in construction delays and additional costs. For instance, if any of them goes bankrupt, thus rendering them unable to complete their assignment, the entire project can be postponed, particularly if the assignment is essential to the construction process. The more subcontractors involved, the greater the risk. As construction of a wind power plant is a rather complex task, there are bound to be several actors involved, further increasing this risk.

Trouble with technology providers can incur delays or in worst case terminate the project. For instance, if the turbine supplier declares bankruptcy after the turbines are paid for, constituting 65-75 % of the total investment costs, this could severely impact the economy of the project, potentially even ending it.

For the case plant, the maintenance is outsourced to external service providers. The worst-case scenario of a bankruptcy would be that the consumer needs to hire a new service provider. As service and maintenance is not pivotal to the daily operation of the plant, it is likely that the consumer finds a new provider within acceptable time.

Conducting background checks of subcontractors can contribute to reduce this risk to some extent. However, as any of the subcontractors may have engaged their own subcontractors, it can be difficult to properly investigate all.

During the construction phase this risk factor is prominent, since there are multiple subcontractors involved, yet proper background check and follow-ups can mitigate the risk to some extent. The consequences to the consumer of financial difficulties for the different subcontractors vary from insignificant to severe, making it difficult to determine one that fits all. Hence, an assessment of the average impact of such an incident determines the impact. We assess the factor to have medium probability, as the firm may choose serious and trustworthy subcontractors. Moreover, to be of high impact to our case, since if some problem occurs it may incur large costs and delays.

Political/regulatory. We assess category of political/regulatory risk to have low probability and medium impact.

Change in legislation. In general, Norway is considered to be a country with a stable political environment, both regarding social and business-related legislation. If a project receives a concession from the regulator NVE, the project may be realized according to the approved plans with low risk of interference. Legislation regarding wind power in Norway has thus far always been announced in proper time prior to implementation. For instance, ending of the green certificate scheme was announced in 2011, 11 years prior to the implementation in 2022 (Lovdata, 2017). This provides stakeholders, e.g. developers and investors, with enough time to adjust. Therefore, the potential consequences imposed by legislative changes can be addressed during the consequence analysis or in the project phase.

Disagreement between public entities may also cause issues for developers. As an example, TrønderEnergi and Stadtwercke München experienced a dispute resulting in an unforeseen project cost of 20 MNOK. In short, the conflict originated from Frøya municipality suspending a building permit, arguing that it had expired. The developer, on the other hand, blamed public opposition for preventing them from initiating construction within the permission deadline (Viseth, 2019). After 40 days, the county authorities of Trøndelag, supporting the developer, determined the suspension as invalid without further opportunity to appeal (Jordheim, 2019). Tord Lien, regional manager of NHO, claimed related to this event that, "Permitting protesters and local authorities to overturn a concession issued by the authorities, thus undermining the power of the elected Government, could have significant impact on Norwegian industry" (Cadamarteri, 2019). Furthermore, TrønderEnergi considers promoting claims to Frøya municipality for their losses (Viseth, 2019).

Abrupt changes in legislation can affect an entire industry. For instance, as part of a compromise resulting from recent negotiations, the Government decided that electricity purchased to mine bitcoins would be subject to the same tax rules as apply to ordinary power consumers (Hovland, 2018c). A tax increase of 15.83 øre/kWh as of March 2019, constitutes significantly higher costs for data centres involved in bitcoin mining (Skatteetaten, 2019). As a result, many Norwegian data centres have lost large contracts (Hovland, 2018c). If any such legislation was introduced for renewables, it could have severe consequences for the wind power industry.

Considering the history of Norwegian power legislation, a long time period between the announcement and implementation of changes in regulation is commonly applied. Moreover, the Norwegian Government frequently expresses "interest in supporting further development of the Norwegian wind industry", as stated by Kjell-Børge Freiberg, secretary of the Ministry of Petroleum and Energy in 2018 (Freiberg, 2018). The general impression is that the Government supports expansion of the wind power industry and wants to provide stable conditions for new projects. Hence, we assess this risk factor to have low probability, with medium impact should any changes be present. We do not believe any severe changes to be implemented because the Norwegian Government has little incentive to induce problems for existent wind power projects operating without subsidies.

Position 2.

(Results from qualitative risk assessment of Position 2, page 52).

The result of the qualitative risk evaluation in Position 2 is summarized in Table 6.5.

Probability \ Impact	Low	Medium	High
High			Volume/shape Pricing/market
Medium			Counterparty/credit
Low	Development	Force majeure Political/regulatory	

Table 6.5: Summary of the results from qualitative risk assessment in Position 2.

As indicated above, pricing/market and volume/shape risks are considered as the most prominent risk factors. The main reason is the large uncertainty regarding future power prices.

An overview of the underlying factors that constitute the result in Table 6.5 is presented in Table 6.6.

Risk category	**Relevant factors**	**Risk assessment**	
		Probability	***Impact***
Development	• Construction delay	Medium	Low
Volume/shape	• Production volume vs. demand, costs related to market trading	High	High
Pricing/market	• Level of PPA price vs. market price level	High	High
Counterparty/credit	• Credible developer, including any subcontractors	Low	High
	• Credible producer	Low	High
Force majeure	• Severe events, e.g. extreme weather	Low	Medium
Political/regulatory	• Legislation for wind power plants	Low	Medium

Table 6.6: Summary of relevant factors found for each risk category in Position 2, associated with risk assessment.

Each factor is assigned a probability and impact, leading to an overall classification of the risk categories. Argumentation for the above outcome is found the following section, given in the same order as Table 6.6.

Development. We assess the risk category development to have low probability and low impact.

Construction delay. Any potential delays occurring during the construction phase, which postpone the initiation date for production, extends the period of market exposure for the PPA customer. Thus, the intended hedge provided by the fixed PPA price does not apply in then. The customer may include penalties for delays in the contract, to be compensated for any loss. Regardless, it is not obliged to pay for power not received. In the worst case, the customer must acquire a new PPA if the plant is not completed, implying additional expenses.

We consider the scenario of termination of the construction after initiation as unlikely, particularly since the case plant is granted concession and has a PPA. However, arguing that a delay in this phase is likely, the risk factor of prolong of the construction phase is regarded as having medium probability. However, it will never be very extensive, as the constructing process in total constitutes maximum 1-2 years (Enova, 2014). Considering the length of the PPA, this will have a minor impact. In addition, the customer is not obliged to pay for power not received and may be granted compensation for the delay. Hence, this risk factor will have a low impact.

Volume/shape. We assess volume/shape risk to have high probability and high impact.

Production volume vs. demand. A customer of an *As produced-contract* is only entitled to the realized production of the plant. Thus, if this output is lesser than the customer demand, the remaining power quantity needs to be procured through the market, exposing the PPA customer to market risk. However, if production exceeds the demand, the customer sells the superfluous amount to the market at spot price. By interacting with the market, the customer faces the risk of selling and buying power at unfortunate price levels compared to the fixed PPA price. The daily or hourly production from a wind power plant might be very unpredictable, yet long term, we assume it to be steadier, as argued considering Position 1.

With the purpose of addressing the problem that volume/shape risk poses to customers of *As produced-PPAs*, Microsoft has developed a new type of PPA, called *Proxy generation-PPA*. This PPA ensures that the customers only are obliged to purchase the expected generation predicted by a frequently adjusted forecasting method (Davies, John, and Taylor, 2018), seeking to address the unpredictability of wind power. Combined with a volume firming agreement, a contract offsetting risk to an interested party, typically an insurance company, Microsoft believes to have solved the issue of volume/shape risk (Davies, John, and Taylor, 2018). That Microsoft have invented this risk mitigation product is a clear sign that the volume risk of a PPA is a severe risk factor.

Even if a wind power plant experiences quite stable annual production from year to year, the daily production will always vary significantly. Hence, deviation between production and consumption will be common. Moreover, due to high future power price uncertainty, discussed earlier, this is one of the major risk factors of a PPA. Hence, we regard this risk factor to have high probability and high impact.

Pricing/market. We assess the category of pricing/market risk to have high probability and high impact.

Level of PPA price vs. market price level. According to an enquiry conducted by Baker&McKenzie (2015), companies are most concerned about pricing/market risk when assessing risks of PPAs. Specifically, the PPA customers worry that average long-term power prices stay below the fixed PPA price, so that their procurement price exceeds the average market price. As a result, the PPA can become a competitive disadvantage. The average spot price in Norway during recent years, in the period 2013 to 2018, is 28.2 øre/kWh. The average LCOE of new Norwegian power plants is 34 øre/kWh in 2018, and expected to be

27 øre/kWh in 2020, according to NVE (Buvik et al., 2019). Hence, the occurrence of power prices being stable below the average LCOE of a wind power plant is a probable scenario for the Norwegian market (Nord Pool, 2019; Weir, 2018). However, assuming that the forecasts by Statnett and Wattsight, which indicate increasing power price levels, to be correct, basing the PPA price on the LCOE of the plant could become beneficial in the future (Barstad, 2019; Statnett, 2018b; NVE, 2017). Regardless, it becomes a question of the potential benefit of exploiting low prices in the market compared to the value of avoiding exposure to the high prices. In order to properly consider this, a PPA customer has to be able to predict an extremely volatile market 10-20 years into the future, which is a nearly impossible task (Renewable Choice Energy, 2016).

Furthermore, Renewable Choice Energy (2016) argues that market insight can provide current or future PPA customers with a better starting point for making informed decisions. Nonetheless, the customer still needs to decide which of vastly different price forecasts to believe.

This risk feature is assumed dependent on the PPA price, but regardless of which PPA price is obtained, this factor will incur large risk. There is great uncertainty regarding the outcome of future power prices. Hence, we assume this factor to have high probability and high impact.

Counterparty/credit. We assess counterparty/credit risk to have medium probability and high impact.

Credible developer. The counterparty/credit risk category is evident for two phases of the life span of the underlying plant; planning and operational. Conducting a thorough background inquiry of the PPA producer will be an important prerequisite to ensure a reliable counterparty for the customer when entering a PPA. The credibility of the developer and its subcontractors may also affect the customer, particularly if the PPA contains no specifications regarding how to handle delays caused by external parties. Thereby, poor choice of counterparties may cause delays of construction, and the parties may possibly also go bankrupt. This will lead to termination of the contract. Hence, the consumer must sign a new contract or trade in the market, incurring uncertain costs.

The PPA consumer may be able to choose a trustworthy developer. However, the developer may sign contracts with less credible counterparties. This is beyond the control of the PPA customer. Hence, we regard the risk factor of credible developer to incur severe problems of the project to have low probability but having high impact should such events occur.

Credible producer. During the operational lifetime of the plant, the PPA customer is exposed to risks related to the liquidity of the producer. Because a PPA is negotiated OTC, specifications regarding the consequences of bankruptcy and other events can be included. This provides a great opportunity for the customer to mitigate most of this risk factor. For instance, the customer can ensure that it is relieved of its payment obligations if the power production is significantly delayed or terminated. The worst-case scenario constitutes that the customer needs to procure a new PPA, incurring additional expenses. It will always hold some risk due to this factor, regardless of contract, because it is impossible to include strategies considering all possible incidents in the contract terms. We assess the risk factor of credible producer to have low probability and high impact.

Force majeure. We assess force majeure risk to have low probability and medium impact.

Severe events. Severe events such as extreme weather, vandalism or grid shutdown can cause the wind power plant to shut down. The probability of such an incident in Norway is considered low, yet it would have great impact on the plant. Regardless, these risks can be mitigated to some extent by insurance, which the producer can also include as a term for the PPA. Considering this, the risk factor is regarded to have low probability and medium impact.

Political/regulatory. We assess the risk category political/regulatory to have low probability and medium impact.

Legislation for wind power plants. Any legislation that impact the wind power producer will not necessarily affect the PPA customer, unless the producer goes bankrupt. Examples of possible legislation changes are further elaborated on page 100. If the customer becomes aware of future changes that may especially be a disadvantage for the producer, terms protecting the customer from any influencing can be included in the PPA. Furthermore, changes in taxation or other aspects regarding PPA customers may be implemented, if this position is considered highly beneficial by the Government in the future. As we regard the Norwegian Government to be interested in contributing to a healthy and well-functioning wind power industry, we regard the implementation of regulations that inhibit this industry to be of low probability. As PPA customers are important for the functioning of this industry, we assume that this is also the case considering PPAs. Hence, we assess this risk factor to be of low probability and medium impact, as the effect of such changes being introduced could be significant, but not extreme.

Summary and comparison of the positions.

For Position 1, market/sales and strategic/business risks are considered the most significant categories. Market/sales risk concerns risks related to trading in the volatile electricity spot market. The prices are affected by a complex set of factors, making them a prominent source of uncertainty. Particularly in Norway, where long-term low power prices have occurred, this incurs great risk to a developer. As for the strategic/business risk, the developer takes the risk of procuring sufficient capital, acquiring the competence necessary, technological evolution and public disapproval. Particularly the rapid technological development within the wind power industry poses a severe risk. Due to this and the extensive duration of the concession application process, there is great risk that the turbines initially approved are outdated when the plant is initiated. This will constitute a competitive disadvantage for the plant owner.

Transport/construction/completion risk is assessed to be of medium impact and medium probability, because of the many potential incidents that may result in construction delays. Examples are turbine faults, construction mistakes and finding preservable historical objects. However, these events can incur some additional costs, but they will rarely be significant enough to terminate the project. Additionally, counterparty risk is assessed to be of medium probability and medium impact because of the many subcontractors involved in the construction process. If any of the subcontractors incur financial difficulties affecting their ability to perform their task, it may result in unexpected expenses. However, although this risk category is significant, the impact can be mitigated to some extent by hiring qualified subcontractors.

Liability/legal risk is considered low in the plant position because we assume that a concession already is granted, which induces low probability of further disputes. Operation/maintenance risk is also regarded as low because we assume the project to have a service agreement with the turbine supplier, taking all costs and risk of continuous maintenance. Furthermore, we assume the project to have insurance protecting it from force majeure incidents. Moreover, political/regulatory risk is considered to be low because we believe that the Norwegian Government has little incentive to initiate laws or schemes which pose a significant issue for wind power projects that operates without subsidies.

The risk categories most severe to a company in Position 2 are pricing/market and volume/shape risks. Pricing/market risk is regarded the most prominent risk by companies, as how the PPA price is relative to the average market price level is what determines the profitability of a PPA. Since future power prices are very uncertain, this category vastly impacts the PPA customer. Volume/shape risk also poses a severe risk because balancing through the spot market exposes the PPA customer to uncertain market prices, thus, as previously mentioned, imposes a great risk. Counterparty/credit risk is regarded as a significant risk for the PPA customer, as the responsibility for construction and operation of the underlying production facility is left to external providers. Hence, the PPA customer has less control of the production, management decisions and credit worthiness of subcontractors compared to a plant owner.

Development risk is considered as low for the PPA position, because we consider it unlikely that a power plant with a PPA and granted concession is not completed. However, some delays in construction are likely, but we regard this to have minor impact on the PPA customer. Force majeure risk is also assessed to be low because wind power plants usually acquire insurance to protect their investment in case of such severe incidents. Lastly, the risk category of political/regulatory is regarded as low. Same reasoning as for Position 1 applies here.

In conclusion, comparing the two positions, most risk categories are characterized similarly in with respect to probability and impact. However, the exposure towards development/construction and counterparty/credit risks significantly differ for the positions. Compared to the plant position, for the PPA position, the counterparty risk is greater, but the development risk is lower. Additionally, the liability/legal risk is only relevant for Position 1. Furthermore, it is crucial to discuss to what extent the different risks may impact each of the positions. To a company in the plant position, the worst-case scenario is bankruptcy or default of the plant. For the PPA position, the worst outcome is that the developer defaults or goes bankrupt, leading to a termination of the PPA and the need to acquire a new contract. Hence, the worst-case scenario is always less severe in Position 2 compared to Position 1.

7 Conclusion

In this master thesis, we examine the problem of whether to invest in an onshore wind power plant or procure a PPA with wind power as underlying production technology. Taking the perspective of a large power consumer in Norway, that seeks to cover own power demand, we evaluate the positions. Our main objective is to provide analyses and information that may assist industrial companies in Norway that consider entering either of the positions.

To investigate the problem, we first provide background information regarding both positions. Furthermore, different models to evaluate the financial aspects are presented, including DCF and Monte Carlo simulation. These methods are selected to provide analyses intuitive for industry professionals. Thereafter, we apply the proposed models on a case study with input variables reflecting the current market. Lastly, the relevant risk categories in each position are identified and discussed with emphasis on examples from Norway.

In order to address our first research question, we performed a detailed review of the existing literature of PPA pricing. Several approaches are found; LCOE, LACE, BEPE and FiTs. Despite some differences between the approaches, all methods share a common goal of achieving a reasonable return to the investors, while covering the costs of the underlying production facility. Considering the available literature, LCOE appears to be the most frequently applied method for pricing PPAs.

To evaluate our second research question, where we consider the financial aspects, DCF, Monte Carlo and cost analyses considering both positions are performed. Here, we apply three different power price forecasts for the Norwegian market, originating from credible sources. From the DCF analyses we obtain NPVs within the range of -646 to 525 MNOK for the case plant. Using only the expected price paths of each forecast, the NPV becomes negative for two of them. Thus, we conclude that the profitability of a wind power project is heavily dependent on future power prices. The analyses also indicate the immense difference in calculated project value found by using different price forecasts, which is commonly used in practice.

Furthermore, we apply a Monte Carlo model to the case plant, where simulation of varying paths for daily power prices and production are included. Using the expected price paths of each forecast as average level in the stochastic paths simulated, we obtain confidence intervals for the NPV of the project. Here, the difference between the highest and lowest value varies from 41 to 69 MNOK. Hence, the project value displays significant sensitivity towards the uncertainties in these underlying factors. However, this impact becomes small compared to the effect from using different price forecasts. The DCF analyses using the expected price paths of the forecasts result in a difference between the NPV values of 910 MNOK, approximately 13 times the size of the interval found by incorporating daily production and price variation. Thus, our main finding is that the value of a wind power project is difficult to predict due to large power price uncertainty.

From our research we find that, currently, there is no method for valuing a wind power PPA available in the literature. Therefore, we propose a PPA model based on the DCF and Monte Carlo models used for the wind power plant, including relevant adjustments to evaluate the financial aspects of a PPA. Initially, the break-even price, constituting the maximum PPA price acceptable to a customer, is derived. Different discount rates and future spot price forecasts are utilized in the analyses. We find that the break-even PPA price displays little dependency towards discount rate. However, it is highly sensitive to which price forecast is applied. The expected spot price scenarios of the forecasts render reasonable PPA prices between 274 and 535 NOK/MWh. This is an extensive range of prices, but all exceed the expected LCOE of new wind power plants in Norway in 2020, i.e. 270 NOK/MWh. Summarizing, the expected future power prices vastly impact what constitutes a reasonable PPA price for a power consumer in Norway.

Examining the NPV of our PPA case, in accordance with the approach suggested by literature of PPA pricing, we apply PPA prices based on LCOE values for the Norwegian wind power market published by NVE. We use the PPA prices 250, 300, 350 and 400 NOK/MWh, which result in NPV values from -712 to 1009 MNOK in our DCF analyses when applying forecasted paths. This illustrates an immense difference. Considering only the expected paths, the NPV values range between -451 and 1009 MNOK. By applying PPA prices in the interval 250-300 NOK/MWh, regarded as reasonable considering the LCOE levels of new wind power plants, the NPV values range from -345 to 1009 MNOK. These results illustrate the sensitivity of the PPA investment towards future power prices. Comparing this last interval to the values from the DCF results of the plant, it seems that a PPA has greater upside potential, i.e. probability of positive project value, in comparison to owning a plant. Additionally, the PPA appears to have the lowest downside potential, i.e. probability of negative project value. Furthermore, provided that the PPA price is below 370 NOK/MWh, the PPA case is profitable for two out of three considered price forecasts. We regard this price realistic for the current Norwegian market, as the LCOE of a typical Norwegian wind power plant is 340 NOK/MWh, as of 2018. Moreover, this is expected to decrease to 270 NOK/MWh by 2020, according to NVE. Thus, we believe that a PPA with a fixed price below 370 NOK/MWh is likely to be profitable in the current market.

As the final part of assessing the financial aspects, we examine the total cost of covering a specific power demand using either a wind power plant or a PPA. Here, we include the expenses from any necessary market trading. For the purpose of these analyses we propose a new concept, called REE, which is an extension of LCOE. Contrary to LCOE, REE includes the trading costs, thus constituting the total cost per unit of covering the demand of the customer. REE, as part of the contribution in our thesis, provides power consumers with a measure to assess the actual power costs from all potential sources of power supply. Our analyses show that the relation between the capacity of the plant and the demand of the consumer is crucial in determining the total power costs. Moreover, in a scenario where the LCOE or PPA price approaches the average power price, trading with the market has little impact on the costs. This renders the REE close to the PPA price or LCOE, dependent on the position. Lastly, we find that the power costs are quite similar for both positions if the LCOE of the plant is close to the PPA price. However, a PPA price less than the LCOE makes a PPA preferable as long as the supply from the PPA and wind power plant are similar.

To answer the third research question, the risks faced by a company in each position are assessed using different categories, illustrated by examples from the Norwegian market.

We evaluate market/sales and strategic/business risks to be the most severe risk categories for the plant position, primarily caused by uncertainty regarding future power prices and technological development. The prices vastly impact the project profitability. Moreover, the current rapid technological development of wind power renders investing risky, as the newest technology may be outdated shortly following project initiation. As a result, this can become a competitive disadvantage.

Pricing/market and volume/shape risks are considered as the most prominent risk categories for the PPA position. Pricing/market risk is concerned with that market prices stay below the PPA price for extended periods, rendering the contract a competitive disadvantage. Companies regard this as the most severe risk of a PPA. Volume/shape risk concerns trading in the market due to mismatch between production and consumption, exposing the PPA position to the great uncertainty regarding future power prices.

Comparing the positions, most risks are of similar impact and probability, except the development/construction and counterparty/credit risks. For the PPA position, the counterparty risk is more prominent, and the development risk is lower, compared to the plant position. To the plant position, a bankruptcy or plant default constitutes the worst potential scenario. The worst outcome for a PPA customer is termination of the PPA, caused by default or bankruptcy of the producer, incurring the need to acquire a new contract. Hence, the impact for the plant position is always more severe than for the PPA position.

Concluding which position is preferable cannot be fully answered without access to actual PPA prices. However, assuming a PPA price of approximately 250-300 NOK/MWh to be reasonable, the results of the financial analyses suggest that the PPA position seems to have the largest upside and lowest downside potential of the two positions.

Considering the qualitative risk, risk related to uncertain market prices are present in both positions. Development risk is more prominent in the plant position and counterparty risk is greater in the PPA position. The remaining categories are similar in both positions. However, the worst-case scenarios are significantly different. In case of plant default, the plant position will experience much severe consequences than the PPA position.

In conclusion, our results suggest that, of the positions considered, a PPA is preferable, as long as its price is below the current average LCOE level found in the wind power market. Another important conclusion is that the estimated value of investments related to the power industry, display great sensitivity towards selection of price forecast. Hence, when such projects are evaluated, it is of vast importance to include different price forecasts and be aware of the extreme impact of future price uncertainty.

Through our analyses of PPAs, the lack of available data regarding prices and contract terms in the Norwegian market has posed a challenge, forcing us to make qualified assumptions. Investigating contract standards in this market could be an interesting topic for further research. However, this requires access to sensitive information from large corporations, often considered as trade secrets.

From the literature regarding pricing of PPAs, we found that the common approach is to base the price on the LCOE of the underlying production unit. However, this is mainly a cost-based approach, therefore it could be interesting to investigate pricing of PPAs from a market perspective. As PPAs are heterogeneous products traded between market participants with different level of market power, it is, based on economic theory, reasonable to assume that the price in practice results from the participants' market power distributions. Thus, modeling this market power relationship to find a theoretical PPA price could be a topic of future research.

Moreover, when considering a PPA as an investment, which discount rate to apply was a challenge for our thesis. A rate based on a relevant beta of a project or company is often applied in this context. However, determining what beta to use for a PPA is difficult as we are not familiar with any comparable firm having PPA investment as their core business. Hence, this poses an interesting future research question.

Our analyses have focused on PPAs of the type *As generated*. Another possible topic for future research could be to compare this contract form to the *Base supply*. For instance, comparing risk exposure of the different PPA types, and assess in which situations each contract is more beneficial.

As we have performed DCF and Monte Carlo analyses of a PPA, a natural step further in the research would be to apply a real option approach. This may aim to evaluating risk under different PPA prices and market price scenarios. Furthermore, examining optimal entry timing for various PPA price levels may also be an interesting topic. In our thesis, we have disregarded concession, and assumed it to already be obtained by the developer. In a real options model, the concession issue could be included by investigating when to optimally apply for concession, and when to start construction.

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A

Numerical results

This appendix provides the numerical results obtained in Chapter 6 and are the basis for the discussions found there. We have used the same structure here as applied for that chapter.

A.1 Financial and cost analyses

A.1.1 Financial

Position 1.

Financial Analysis 1.I: DCF model with constant annual production and annual prices.
In Table A.1, the resulting values of NPV, IRR and investor return of the case wind power plant are presented.

Forecast	Case	NPV [MNOK]	IRR	Investor return
Statnett	High	214.36	0.0819	0.1590
	Expected	-35.73	0.0560	0.0950
	Low	-285.81	0.0241	0.0153
NVE	High	70.02	0.0662	0.1204
	Expected	-386.03	0.0175	-0.0013
	Low	-646.40	-0.0326	-0.1265
Wattsight	Expected	524.57	0.1060	0.2199

Table A.1: Results from DCF analysis with constant power production and constant annual prices based on forecasts.

Financial Analysis 1.IIa: Monte Carlo model with varying daily production and constant annual prices.

The 95 % confidence intervals for NPV, IRR and investor return are found in Table A.2.

Forecast	Case	NPV [MNOK]	IRR	Investor return
Statnett	High	[179.56, 228.95]	[0.0783, 0.0834]	[0.1507, 0.1635]
	Expected	[-64.21, -23.31]	[0.0528, 0.0574]	[0.0870, 0.0985]
	Low	[-307.22, -275.86]	[0.0214, 0.0252]	[0.0085, 0.0180]
NVE	High	[40.34, 82.08]	[0.0636, 0.0672]	[0.1140, 0.1230]
	Expected	[-402.89, -378.89]	[0.0153, 0.0183]	[-0.0067, 0.0008]
	Low	[-656.70, -641.72]	[-0.0345, -0.0319]	[-0.1313, -0.1247]
Wattsight	Expected	[482.64, 542.40]	[0.1023, 0.1076]	[0.2107, 0.2240]

Table A.2: Results of Monte Carlo analysis with Weibull simulated production and constant annual prices.

Financial Analysis 1.IIb: Monte Carlo model with constant annual production and varying daily prices.

Tables A.3 and A.4 show the resulting NPV, IRR and investor return, when incorporating historical power prices and prices based on available forecasts, respectively.

Forecast	NPV [MNOK]	IRR	Investor return
Mean-reverting historical power prices	[-379.48, -366.59]	[0.0153, 0.0168]	[-0.0067, -0.0030]

Table A.3: Results of Monte Carlo analysis with variable simulated power prices based on historical data from 2013-2018 and constant annual production.

Expected forecast	NPV [MNOK]	IRR	Investor return
Statnett	[-69.00, -54.32]	[0.0523, 0.0539]	[0.0857, 0.0897]
NVE	[-394.88, -367.92]	[0.0162, 0.0192]	[-0.0045, 0.0030]
Wattsight	[520.51, 541.15]	[0.1065, 0.1086]	[0.2212, 0.2265]

Table A.4: NPV and IRR for a simulated project with power prices simulated from forecasted prices and constant annual production.

Financial Analysis 1.IIc: Monte Carlo model with daily varying production and prices.
The results from this analysis are found in Table A.5.

Expected forecast	NPV [MNOK]	IRR	Investor return
Statnett	[-77.84, -22.40]	[0.0513, 0.0570]	[0.0833, 0.0975]
NVE	[-399.54, -358.83]	[0.0153, 0.0202]	[-0.0068, 0.0055]
Wattsight	[502.14, 571.71]	[0.1049, 0.1114]	[0.2170, 0.2335]

Table A.5: NPV and IRR for a simulated project with daily power prices simulated from forecasted prices and daily varying production. The expected price paths are used as average values of the price simulation.

Position 2.

Financial Analysis 2.I: Break-even PPA price model.
Table A.6 presents the resulting break-even PPA prices for discount rates of 8 %, 6 % and 3 %.

		PPA price [NOK/MWh]		
Forecast	**Case**	**8 %**	**6 %**	**3 %**
Statnett	High	441.20	440.72	439.21
	Expected	374.77	372.47	368.64
	Low	308.34	304.22	298.06
NVE	High	391.84	401.33	415.77
	Expected	274.01	276.87	281.21
	Low	207.56	205.82	203.22
Wattsight	Expected	518.94	525.37	535.34

Table A.6: Break-even PPA prices from DCF analysis of constant production and annual prices based on forecasts.

Financial Analysis 2.II: DCF model of constant annual production and annual prices.
Table A.7 shows the NPVs given different PPA prices.

		NPV [MNOK], given PPA price [NOK/MW]			
Forecast	**Case**	**250**	**300**	**350**	**400**
Statnett	High	698.85	515.63	332.40	149.20
	Expected	448.77	265.55	82.33	-100.89
	Low	198.68	15.47	-167.75	-350.97
NVE	High	554.51	371.29	188.08	4.86
	Expected	98.46	-84.75	-267.97	-451.19
	Low	-161.91	-345.13	-528.35	-711.57
Wattsight	Expected	1009.10	825.84	642.62	459.41

Table A.7: NPV from DCF analysis of PPA with constant production and annual prices based on forecasts.

Financial Analysis 2.III: Monte Carlo model with varying daily production and prices.
The NPV results from this analysis is given in Table A.8.

		NPV [MNOK], given PPA price [NOK/MW]	
Forecast	**Case**	**250**	**400**
Statnett	Expected	[417.19, 455.56]	[-124.83, -92.41]
NVE	Expected	[93.38, 125.70]	[-454.32, -415.57]
Wattsight	Expected	[1000.20, 1051.70]	[462.50, 499.45]

Table A.8: Confidence intervals for NPV from Monte Carlo simulation of PPA with daily varying production and prices.

A.1.2 Costs

Total costs

Position 1.

Cost Analysis 1.II: Monte Carlo model.

This analysis is first using historical prices. Tables A.9 and A.10 present the results for demand one and demand two, respectively.

Variable	**95 % confidence interval**	**Unit**
Energy price, daily	[91.1485, 473.6332]	NOK/MWh
Production quantity, daily	[0, 2520]	MWh/day
Production quantity, annual	[334.21, 404.72]	GWh/year
LCOE, lifetime of plant	[317.2654, 325.5091]	NOK/MWh
Purchasing quantity, daily	[0, 1011.6]	MWh/day
Purchasing quantity, annual	[135.48, 165.94]	GWh/year
Selling quantity, daily	[0, 1508.4]	MWh/day
Selling quantity, annual	[128.08, 173.92]	GWh/year
REE, lifetime of plant	[317.3850, 325.3779]	NOK/MWh

Table A.9: Confidence intervals of simulated values in Position 1, based on historical power prices; 10,000 projects and a consumer demand of 42.15 MW.

Variable	**95 % confidence interval**	**Unit**
Energy price, daily	[91.2049, 473.6380]	NOK/MWh
Production quantity, daily	[0, 2520]	MWh/day
Production quantity, annual	[334.20, 404.53]	GWh/year
LCOE, lifetime of plant	[317.2552, 325.5752]	NOK/MWh
Purchasing quantity, daily	[0, 2520]	MWh/day
Purchasing quantity, annual	[515.27, 585.60]	GWh/year
Selling quantity, daily	[0, 0]	MWh/day
Selling quantity, annual	[0, 0]	MWh/year
REE, lifetime of plant	[295.1850, 300.8954]	NOK/MWh

Table A.10: Confidence intervals of simulated values in Position 1, based on historical power prices; 10,000 projects and a consumer demand of 105 MW.

Thereafter, price forecasts are incorporated. The resulting confidence intervals of simulated daily energy prices, LCOE and REE are listed in Table A.11. Quantities sold and purchased are found from the script, however, omitted from the table as they are mainly the same as when using historical prices, making the forecasts comparable. The numbers are available upon request.

	95 % confidence interval		
	Statnett	**NVE**	**Wattsight**
Energy price, daily [NOK/MWh]	[153.7704, 536.2771]	[108.7930, 491.2590]	[391.7388, 774.2698]
LCOE, lifetime of plant [NOK/MWh]	[317.3090, 325.5396]	[317.3361, 325.5904]	[317.2104, 325.5136]
REE, lifetime of plant [NOK/MWh]: 42.15 MW	[316.0413, 326.6933]	[316.8969, 325.7830]	[311.4329, 331.2973]
REE, lifetime of plant [NOK/MWh]: 105 MW	[332.3291, 338.6370]	[305.6477, 311.4940]	[473.2711, 482.6242]

Table A.11: Confidence intervals of simulated values in Position 1, based on forecasted power prices; 10,000 projects and a consumer demand of 42.15 MW and 105 MW.

Position 2.

Cost Analysis 2.I: Monte Carlo model.

The analysis is first applying historical prices. Tables A.12 and A.13 present the results for demand one and demand two, respectively.

Variable	**95 % confidence interval**	**Unit**
Energy price, daily	[91.1697, 473.6284]	NOK/MWh
Production quantity, daily	[0, 2520]	MWh/day
Production quantity, annual	[334.37, 404.74]	GWh/year
Purchasing quantity, daily	[0, 1011.6]	MWh/day
Purchasing quantity, annual	[135.61, 165.97]	GWh/year
Selling quantity, daily	[0, 1508.4]	MWh/day
Selling quantity, annual	[128.15, 173.97]	GWh/year
REE, lifetime of plant	[247.8861, 252.0991]	NOK/MWh

Table A.12: Confidence intervals of simulated values in Position 2, based on historical power prices; 10,000 projects, a consumer demand of 42.15 MW and PPA price of 250 NOK/MWh.

Variable	**95 % confidence interval**	**Unit**
Energy price, daily	[91.0889, 473.6535]	NOK/MWh
Production quantity, daily	[0, 2520]	MWh/day
Production quantity, annual	[334.34, 404.49]	GWh/year
Purchasing quantity, daily	[0, 2520]	MWh/day
Purchasing quantity, annual	[515.31, 585.46]	GWh/year
Selling quantity, daily	[0, 0]	MWh/day
Selling quantity, annual	[0, 0]	MWh/year
REE, lifetime of plant	[266.8485, 271.8747]	NOK/MWh

Table A.13: Confidence intervals of simulated values in Position 2, based on historical power prices; 10,000 projects, a consumer demand of 105 MW and PPA price of 250 NOK/MWh.

The second part incorporate price forecasts. Tables A.14 and A.15 list the confidence intervals for simulated daily energy prices and REE, given a PPA price of 250 NOK/MWh and 400 NOK/MWh, respectively. Quantities of selling and buying are also omitted here, as they are the same as for the wind power plant simulation. However, they are available upon request.

	95 % confidence interval, given PPA price of 250 NOK/MW		
	Statnett	**NVE**	**Wattsight**
Energy price, daily [NOK/MWh]	[153.7411, 536.2305]	[108.7212, 491.2337]	[391.7038, 774.1986]
REE, lifetime of plant [NOK/MWh]: 42.15 MW	[247.2055, 252.8537]	[247.7500, 252.3091]	[242.8004, 256.9004]
REE, lifetime of plant [NOK/MWh]: 105 MW	[304.2919, 309.5236]	[277.4023, 282.4334]	[445.6252, 452.9412]

Table A.14: Confidence intervals of simulated values in Position 2, based on forecasted power prices; 10,000 projects, a consumer demand of 42.15 MW and 105 MW, and PPA price of 250 NOK/MWh.

	95 % confidence interval, given PPA price of 400 NOK/MW		
	Statnett	**NVE**	**Wattsight**
Energy price, daily [NOK/MWh]	[153.7911, 536.2289]	[108.7880, 491.2468]	[391.7028, 774.2296]
REE, lifetime of plant [NOK/MWh]: 42.15 MW	[397.7448, 402.2436]	[397.1955, 402.8634]	[395.8158, 404.3501]
REE, lifetime of plant [NOK/MWh]: 105 MW	[364.5604, 369.6746]	[337.5019, 342.7389]	[506.6072, 512.4529]

Table A.15: Confidence intervals of simulated values in Position 2, based on forecasted power prices; 10,000 projects, a consumer demand of 42.15 MW and 105 MW, and PPA price of 400 NOK/MWh.

B

Matlab scripting and Excel implementation

B.1 Financial and cost analyses

B.1.1 *Financial Analysis 1.I: DCF model with constant annual production and annual prices.*

```
clc
clear

I = 9.5*10^6 ; %  Investment cost NOK/MW

om = 110; % Operation and maintenance cost NOK/MWh

Q_annual = 25*4.2*3500; % Annual prodcution MWh

N = 25; % Turbines
K = 4.2; % MW/turbine
n = 25;  % Lifetime years
r_D = 0.03; % Interest on debt
D = 0.6; % Debt share
tau = 0.22; % Tax
```

```
t1=(12/7); % constant


% Power prices forecast mid Norway 2018-2040, Statnett
P1 = [ [39:t1:51] [49.4:-1.6:43] [42.8:-0.2:41] 41 41 , %High scenario, i=1

39.*ones(1,8) [38.3:-0.7:35.5] [35.35:-0.15:34] 34 34, % Expected scenario, i=2

[39:-t1:27] [27.2:0.2:28] [27.9:-0.1:27] 27 27 ]*10; % Low scenario, i=3

%NVE price forcast 2018-2013
P2 = [ 23 26.5 30 [32.6:2.6:43] [44:1:48] 48*ones(1,12); % high case i=1
       23 23.5 24 25 26 27 28 29 [29.2:0.2:30] 30*ones(1,12); % expected scenario i=2;
       23 22.5 [22:-0.2:21] [20.6:-0.4:19] 19*ones(1,12)]*10;

% Wattsight price prognosis 2018-2030
P3= [45.5 45.5 43.3 39.6 51.3 52.3 53.2 53.5 53.0 53.3 56.4 58.3 58.3*ones(1,13)]*10; ...
    %expected case

r = [0.06 0.06 0.06]; %Discount rate

P=P3; % Chose which power price forecast to use

% Calculate IRR for each price scenario

% for each price scenario i
for i=1:1
    % calculate NPV
    %calculate cashflow for each year
    for j=1:n

    CF(i,j)=(1-tau)*(Q_annual*(P(i,j)-om)); % cashflow , price scenario i and year j

    PV_CF(i,j)=(1-tau)*(Q_annual*(P(i,j)-om))/(1+r(i))^j;
    end

    NPV(i)=-I*K*N+sum(PV_CF(i,:)); % NPV for price scenario i

    IRR(i) = irr([-I*K*N CF(i,:)]); % IRR for price scenario i

    r_i(i)=(IRR(i)-r_D*D)/(1-D); % Calculate investor return from found IRR
end
```

B.1.2 *Financial Analysis 1.IIa: Monte Carlo model with varying daily production and constant annual prices.*

```
clc
clear

%%% Costs
% Investment cost [kr/MW]
I = 9.5*10^6;

% Operation and maintenance cost [kr/MWh]
OM = 110;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

%%% Interest rates
% Capital cost to bank
r_bank = 0.03;

% Capital cost to investors
r_investor = 0.08;

% Discount rate
r_wacc = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r_wacc / (1 - (1+r_wacc)^(-years));

%tax
tax = 0.23;

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;
```

```

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);

% Cut out wind speed [m/s]
v_max = 25;

% Consumer demand [MWh] (constant in this simulation)
%cons_demand = 67.43*24; %N*K*24;

t1=(12/7); % constant

%Power prices
% Power prices forecast mid Norway 2018-2040, Statnett
P1_high = [ [39:t1:51] [49.4:-1.6:43] [42.8:-0.2:41] 41 41 ]*10; %High scenario, i=1

P1_exp=[ 39.*ones(1,8) [38.3:-0.7:35.5] [35.35:-0.15:34] 34 34]*10; % Expected scenario, i=2

P1_low=[ [39:-t1:27] [27.2:0.2:28] [27.9:-0.1:27] 27 27 ]*10; % Low scenario, i=3

%NVE price forcast 2018-2013
P2_high = [ 23 26.5 30 [32.6:2.6:43] [44:1:48] 48*ones(1,12)]*10; % high case i=1
P2_exp= [ 23 23.5 24 25 26 27 28 29 [29.2:0.2:30] 30*ones(1,12)]*10; % expected scenario i=2;
P2_low=[ 23 22.5 [22:-0.2:21] [20.6:-0.4:19] 19*ones(1,12)]*10;

% Wattsight price prognosis 2018-2030
P3= [45.5 45.5 43.3 39.6 51.3 52.3 53.2 53.5 53.0 53.3 56.4 58.3 58.3*ones(1,13)]*10; ...
    %expected case

P=P3 % Chose which price forecast to include

% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
prod_its = zeros(iterations,tot_days);

% Daily energy prices [kr/MWh]
e_prices=[];

for year=1:years
```

```
    e_prices=[e_prices P(year)*ones(1,days)];
end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;    % [MWh]

        % income from sale
        income_its(iteration,day) = (1-tax)*(prod_its(iteration,day).*(e_prices(day)-OM));
    end
end

prod_years = zeros(iterations,years);

PV_prod_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
    index_day_stop = 365;

    year=1;
    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));

        income_sum_y = sum(income_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;

        PV_prod_years(iteration,year) = OM * prod_sum_y / ((1+r_wacc)^year);
        PV_income_years(iteration,year) = income_sum_y/((1+r_wacc)^year);
        income_year(iteration,year) = income_sum_y;

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    NPV_its(iteration) = -K*N*I+sum(PV_income_years(iteration,:));
    prod_avg = sum(prod_years(iteration,:)) / years;
```

```

    IRR_its(iteration)=irr([-K*N*I income_year(iteration,:)]);
end

conf_prod_day = prctile(prod_its(:),[2.5 97.5]);
conf_prod_year = prctile(prod_years(:),[2.5 97.5]);
disp('Production, day:')
disp(conf_prod_day)
disp('Production, year:')
disp(conf_prod_year)

disp('--')

conf_NPV = prctile(NPV_its(:),[2.5 97.5]);
disp('NPV:')
disp(conf_NPV)

disp('--')

conf_IRR = prctile(IRR_its(:),[2.5 97.5]);
disp('IRR:')
disp(conf_IRR)
```

B.1.3 *Financial Analysis 1.IIb: Monte Carlo model with constant annual production and varying daily prices.*

```
% Calculate average power prices per year per Monte Carlo iteration
clc
clear

%Power prices
%%% Variable energy prices: Ornstein-Uhlenbeck mean-reverting process
% Time increment
dt = 1/365;

% Long-term mean of energy prices:
% 282.4 kr/MWh for price level in 2013-2018,
% 407.6 kr/MWh for price level in 2018
%theta = 282.4;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Number of iterations in Monte Carlo simulation
iterations = 10000;
days=365;
years=25;

tot_days = days*years;

% Historical prices
P0=[282.4 282.4 282.4];

% Forecasts
%statnett
P1=[39 37 34.5]*10;
%nve
P2=[25.7 29.5 30]*10;
%wattsight
P3=[48.4 54.9 58.3]*10;

theta = P3(1); % chose which forecats average value to use

for iteration=1:iterations
    % Initial value, only applicable for first day
    e_prices_its(iteration,1) = theta;
```

```

    for day = 2:tot_days
        if day<=(7*365)
            theta=P3(1); % chose forecast
        elseif day>(7*365) && day<=(12*365)
            theta=P3(2); % chose forecast
        elseif day>(12*365)
            theta=P3(3); % chose forecast
        end

        %Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        %Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
        end
    end

    index_day_start = 1;
    index_day_stop = 365;

    for year=1:years
        price_average_y(iteration,year) = ...
            sum(e_prices_its(iteration,index_day_start:index_day_stop))/365;

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end
 end


 %%% Costs
% Investment cost [kr/MW]
I = 9.5*10^6;

% Operation and maintenance cost [kr/MWh]
OM = 110;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

%%% Interest rates
% Capital cost to bank
r_bank = 0.03;

% Capital cost to investors
```

```
r_investor = 0.08;

% Discount rate
r_wacc = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r_wacc / (1 - (1+r_wacc)^(-years));

%tax
tax = 0.23;

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);

% Cut out wind speed [m/s]
v_max = 25;

% Consumer demand [MWh] (constant in this simulation)
%cons_demand = 67.43*24; %N*K*24;

t1=(12/7); % constant

%Power prices
%%% Variable energy prices: Ornstein-Uhlenbeck mean-reverting process
% Time increment
dt = 1/365;

```

```
% Long-term mean of energy prices:
% 282.4 kr/MWh for price level in 2013-2018,
% 407.6 kr/MWh for price level in 2018
theta = 282.4;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Number of iterations in Monte Carlo simulation
iterations = 10;

prod_year = (N*K*3500);    % [MWh]

for iteration = 1:iterations
    for year=1:years
        income_its_y(iteration,year) = (1-tax)*(prod_year.*(price_average_y(iteration,year)-OM));

        PV_income_years(iteration,year) = income_its_y(iteration,year)/((1+r_wacc)^year);
    end

    NPV_its(iteration) = -K*N*I+sum(PV_income_years(iteration,:));

    IRR_its(iteration)=irr([-K*N*I income_its_y(iteration,:)]);
end

conf_NPV = prctile(NPV_its(:),[2.5 97.5]);
disp('NPV:')
disp(conf_NPV)

disp('--')

conf_IRR = prctile(IRR_its(:),[2.5 97.5]);
disp('IRR:')
disp(conf_IRR)
```

B.1.4 *Financial Analysis 1.IIc: Monte Carlo model with daily varying production and prices.*

```
clc
clear

%%% Costs
% Investment cost [kr/MW]
I = 9.5*10^6;

% Operation and maintenance cost [kr/MWh]
OM = 110;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

%%% Interest rates
% Capital cost to bank
r_bank = 0.03;

% Capital cost to investors
r_investor = 0.08;

% Discount rate
r_wacc = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r_wacc / (1 - (1+r_wacc)^(-years));

%tax
tax = 0.23;

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;
```

```

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);

% Cut out wind speed [m/s]
v_max = 25;

% Consumer demand [MWh] (constant in this simulation)
%cons_demand = 67.43*24; %N*K*24;

t1=(12/7); % constant

%Power prices

dt = 1/365;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Power prices forecast mid Norway 2018-2040, Statnett
%P1_high = [ [39:t1:51] [49.4:-1.6:43] [42.8:-0.2:41] 41 41 ]*10; %High scenario, i=1
%P1_exp=[ 39.*ones(1,8) [38.3:-0.7:35.5] [35.35:-0.15:34] 34 34]*10; % Expected scenario, i=2
%P1_low=[ [39:-t1:27] [27.2:0.2:28] [27.9:-0.1:27] 27 27 ]*10; % Low scenario, i=3

%NVE price forcast 2018-2013
%P2_high = [ 23 26.5 30 [32.6:2.6:43] [44:1:48] 48*ones(1,12)]*10; % high case i=1
%P2_exp= [ 23 23.5 24 25 26 27 28 29 [29.2:0.2:30] 30*ones(1,12)]*10; % expected scenario i=2;
%P2_low=[ 23 22.5 [22:-0.2:21] [20.6:-0.4:19] 19*ones(1,12)]*10;

% Wattsight price prognosis 2018-2030
%P3= [45.5 45.5 43.3 39.6 51.3 52.3 53.2 53.5 53.0 53.3 56.4 58.3 58.3*ones(1,13)]*10; ...
    %expected case

%P=P3; % Chose which price forecast to include

% Forecasts
```

```
%statnett
P1=[39 37 34.5]*10;
%nve
P2=[25.7 29.5 30]*10;
%wattsight
P3=[48.4 54.9 58.3]*10;

% chose which forecasts average value to use

% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
prod_its = zeros(iterations,tot_days);

% Daily energy prices [kr/MWh]
for iteration=1:iterations
    % Initial value, only applicable for first day
    e_prices_its(iteration,1) =P3(1);

    for day = 2:tot_days
        if day<=(7*365)
            theta=P3(1); % chose forecast
        elseif day>(7*365) && day<=(12*365)
            theta=P3(2); % chose forecast
        elseif day>(12*365)
            theta=P3(3); % chose forecast
        end

        %Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        %Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
        end
     end
end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

```

```
        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;   % [MWh]

       % income from sale
       income_its(iteration,day) = ...
           (1-tax)*(prod_its(iteration,day).*(e_prices_its(iteration,day)-OM));
    end
end

prod_years = zeros(iterations,years);

PV_prod_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
    index_day_stop = 365;

    year=1;
    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));

        income_sum_y = sum(income_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;

        PV_prod_years(iteration,year) = OM * prod_sum_y / ((1+r_wacc)^year);
        PV_income_years(iteration,year) = income_sum_y/((1+r_wacc)^year);
        income_year(iteration,year) = income_sum_y;

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    NPV_its(iteration) = -K*N*I+sum(PV_income_years(iteration,:));
    prod_avg = sum(prod_years(iteration,:)) / years;

    IRR_its(iteration)=irr([-K*N*I income_year(iteration,:)]);
end

conf_prod_day = prctile(prod_its(:),[2.5 97.5]);
conf_prod_year = prctile(prod_years(:),[2.5 97.5]);
disp('Production, day:')
disp(conf_prod_day)
disp('Production, year:')
disp(conf_prod_year)
```

```
disp('--')

conf_NPV = prctile(NPV_its(:),[2.5 97.5]);
disp('NPV:')
disp(conf_NPV)

disp('--')

conf_IRR = prctile(IRR_its(:),[2.5 97.5]);
disp('IRR:')
disp(conf_IRR)
```

B.1.5 *Financial Analysis 2.I: Break-even PPA price model.*

Figure B.1 shows the Excel sheet used for calculation of break-even PPA prices, while the associated Solver setup is displayed in Figure B.2.

	A	B	C	D	E	F	G	H	I	J
1			prices							
2			high statnett	exp statnett	low statnett	high NVE	exp NVE	low NVE	Wattsight	years
3		1	390	390	390	230	230	230	455	1
4		2	407,1428571	390	372,8571429	265	235	225	455	2
5		3	424,2857143	390	355,7142857	300	240	220	433	3
6		4	441,4285714	390	338,5714286	326	250	218	396	4
7		5	458,5714286	390	321,4285714	352	260	216	513	5
8		6	475,7142857	390	304,2857143	378	270	214	523	6
9		7	492,8571429	390	287,1428571	404	280	212	532	7
10		8	510	390	270	430	290	210	535	8
11		9	494	383	272	440	292	206	530	9
12		10	478	376	274	450	294	202	533	10
13		11	462	369	276	460	296	198	564	11
14		12	446	362	278	470	298	194	583	12
15		13	430	355	280	480	300	190	583	13
16		14	428	353,5	279	480	300	190	583	14
17		15	426	352	278	480	300	190	583	15
18		16	424	350,5	277	480	300	190	583	16
19		17	422	349	276	480	300	190	583	17
20		18	420	347,5	275	480	300	190	583	18
21		19	418	346	274	480	300	190	583	19
22		20	416	344,5	273	480	300	190	583	20
23		21	414	343	272	480	300	190	583	21
24		22	412	341,5	271	480	300	190	583	22
25		23	410	340	270	480	300	190	583	23
26		24	410	340	270	480	300	190	583	24
27		25	410	340	270	480	300	190	583	25
28										
29	PPA price	6 % rente	440,7158408	372,4682026	304,2205643	401,3262	276,8707	205,8138	525,3721	NPV
30	PPA price	8 % rente	441,2036982	374,7724455	308,3411927	391,839	274,0121	207,4695	518,9474	NPV
31	PPA price	3 % rente	439,2106651	368,6365682	298,0624714	415,7684	281,2075	203,2163	535,3415	NPV

	K	L	M	N	O	P	Q
1	cashflows						
2	high statnett	exp statnett	low statnett	high NVE	exp NVE	low NVE	Wattsight
3	-17423480,63	5181598,419	27786677,5	-55070215	-14976337,2	7666631	-21759888,8
4	-10731617,87	4797776,314	20327170,5	-39963419,2	-12291618,8	5523372,3	-20148045,2
5	-4935540,092	4442385,475	13820311	-26792498,8	-9922461,8	3655566,9	-25073731
6	60743,54294	4113319,885	8165896,23	-17784659	-6486229,92	2844537,2	-33210986
7	4343918,163	3808629,523	3273340,88	-9964304,39	-3504625,19	2133602,1	-1487536,99
8	7992215,096	3526508,817	-939197,46	-3204936,98	-929149,949	1512382,8	938524,3122
9	11076188,65	3265285,942	-4545616,8	2607716,482	1284003,176	971489,05	2798898,475
10	13659424,21	3023412,909	-7612598,4	7576821,49	3174379,98	502429,26	3187219,107
11	9706151,08	1512565,93	-6681019,2	8853990,408	3306923,713	-270153,7	2031921,326
12	6263599,216	208958,7608	-5845681,7	9900375,335	3402413,615	-931036,7	2392079,456
13	3277797,69	-909820,822	-5097439,3	10743158,71	3465611,878	-1492529	7100936,36
14	699968,9607	-1864001,83	-4427972,6	11406762,24	3500778,5	-1965728	9347787,894
15	-1513944,389	-2671830,53	-3829716,7	11913106,76	3511719,549	-2360635	8655359,161
16	-1652039,226	-2661596,31	-3671153,4	11030654,41	3251592,175	-2185773	8014221,445
17	-1761368,603	-2638218,02	-3515067,4	10213568,89	3010733,495	-2023864	7420575,412
18	-1845436,348	-2603699,08	-3361961,8	9457008,236	2787716,199	-1873948	6870903,16
19	-1907385,039	-2559818,24	-3212251,4	8756489,107	2581218,703	-1735137	6361947,37
20	-1950030,294	-2508151,85	-3066273,4	8107860,285	2390017,317	-1606608	5890692,009
21	-1975891,973	-2450094,1	-2924296,2	7507278,041	2212978,998	-1487600	5454344,453
22	-1987222,537	-2386875,35	-2786528,2	6951183,371	2049054,627	-1377408	5050318,938
23	-1986032,842	-2319578,75	-2653124,7	6436280,9	1897272,803	-1275378	4676221,239
24	-1974115,571	-2249155,3	-2524195	5959519,351	1756734,077	-1180905	4329834,48
25	-1953066,522	-2176437,51	-2399808,5	5518073,474	1626605,627	-1093431	4009106
26	-1808394,928	-2015219,92	-2222044,9	5109327,29	1506116,321	-1012436	3712135,186
27	-1674439,748	-1865944,37	-2057449	4730858,602	1394552,149	-937440,6	3437162,209
28							
29	8,10251E-07	-9,7416E-07	1,8254E-07	-9,9652E-08	1,6694E-07	-3,19E-08	1,11759E-08
30	-9,58564E-07	-9,8394E-07	9,1037E-08	-6,9849E-08	9,16189E-07	-3,47E-08	8,21427E-07
31	-3,11993E-07	-3,241E-07	-3,139E-07	-9,2946E-07	-8,3027E-07	-4,38E-08	2,36556E-07

Figure B.1: Excel sheet for calculation of break-even PPA prices.

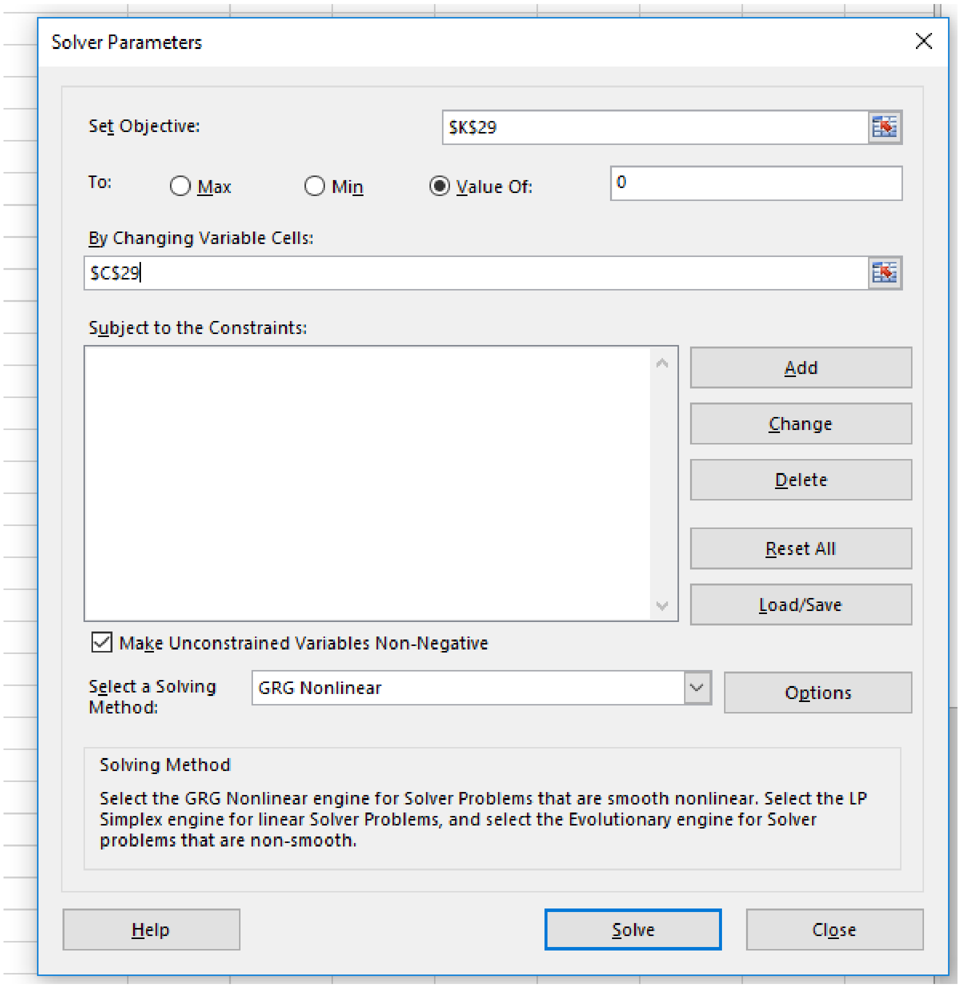

Figure B.2: Solver used for calculation of break-even PPA prices.

For each price path, the annual cash flows for the whole project were calculated, using constant production and the case study values. The NPV was computed by discounting all the cash flows. In the cash flow formulas, the PPA price was set in the cells below the price paths. Thereby, the Excel Solver was used to calculate the break-even PPA price by fixing the NPV cell to zero, with the cell of PPA price as the adjustable. The computations were performed for three different discount rates.

B.1.6 *Financial Analysis 2.II: DCF model of constant annual production and annual prices.*

```
clc
clear

I = 9.5*10^6 ; %  Investment cost NOK/MW

om = 110; % Operation and maintenance cost NOK/MWh

Q_annual = 25*4.2*3500; % Annual production MWh

N = 25; % Turbines
K = 4.2; % MW/turbine
n = 25;  % Lifetime years
r_D = 0.03; % Interest on debt
D = 0.6; % Debt share
tau = 0.22; % Tax

t1=(12/7); % constant


% Power prices forecast mid Norway 2018-2040, Statnett
P1 = [ [39:t1:51] [49.4:-1.6:43] [42.8:-0.2:41] 41 41 , %High scenario, i=1
    39.*ones(1,8) [38.3:-0.7:35.5] [35.35:-0.15:34] 34 34, % Expected scenario, i=2
    [39:-t1:27] [27.2:0.2:28] [27.9:-0.1:27] 27 27 ]*10; % Low scenario, i=3

%NVE price forcast 2018-2030
P2 = [ 23 26.5 30 [32.6:2.6:43] [44:1:48] 48*ones(1,12); % high case i=1
    23 23.5 24 25 26 27 28 29 [29.2:0.2:30] 30*ones(1,12); % expected scenario i=2;
    23 22.5 [22:-0.2:21] [20.6:-0.4:19] 19*ones(1,12)]*10;

% Wattsight price prognosis 2018-2030
P3= [45.5 45.5 43.3 39.6 51.3 52.3 53.2 53.5 53.0 53.3 56.4 58.3 58.3*ones(1,13)]*10; ...
    %expected case

r = [0.06 0.06 0.06]; %Discount rate

P=P3; % Chose which forecast to use

% Calculate IRR for each price scenario

P_PPA=300;

% for each price scenario i
for i=1:3
    % calculate NPV
    %calculate cashflow for each year
    for j=1:n

```

```
    CF(i,j)=(1-tau)*(Q_annual*(P(i,j)-P_PPA)); % cashflow , price scenario i and year j

    PV_CF(i,j)=(1-tau)*(Q_annual*(P(i,j)-P_PPA))/(1+r(i))^j;
    end

    NPV(i)=sum(PV_CF(i,:)); % NPV for price scenario i

    S=solve(NPV(i)==0,P_PPA); %find the PPA price yielding NPV equal to zero
end
```

B.1.7 *Financial Model 2.III: Monte Carlo model with variable daily prices and production.*

```
clc
clear

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

% Discount rate
r_wacc = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r_wacc / (1 - (1+r_wacc)^(-years));

%tax
tax = 0.23;

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);

% Cut out wind speed [m/s]
```

```
v_max = 25;

% Consumer demand [MWh] (constant in this simulation)
%cons_demand = 67.43*24; %N*K*24;

t1=(12/7); % constant

P_PPA=250;

%Power prices

dt = 1/365;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;


% Power prices forecast mid Norway 2018-2040, Statnett
%P1_high = [ [39:t1:51] [49.4:-1.6:43] [42.8:-0.2:41] 41 41 ]*10; %High scenario, i=1

%P1_exp=[ 39.*ones(1,8) [38.3:-0.7:35.5] [35.35:-0.15:34] 34 34]*10; % Expected scenario, i=2

%P1_low=[ [39:-t1:27] [27.2:0.2:28] [27.9:-0.1:27] 27 27 ]*10; % Low scenario, i=3

%NVE price forcast 2018-2013
%P2_high = [ 23 26.5 30 [32.6:2.6:43] [44:1:48] 48*ones(1,12)]*10; % high case i=1
%P2_exp = [ 23 23.5 24 25 26 27 28 29 [29.2:0.2:30] 30*ones(1,12)]*10; % expected scenario i=2;
%P2_low =[ 23 22.5 [22:-0.2:21] [20.6:-0.4:19] 19*ones(1,12)]*10;

% Wattsight price prognosis 2018-2030
%P3= [45.5 45.5 43.3 39.6 51.3 52.3 53.2 53.5 53.0 53.3 56.4 58.3 58.3*ones(1,13)]*10; ...
    %expected case

%P=P3; % Chose which price forecast to include

% Forecasts
%statnett
P1=[39 37 34.5]*10;
%nve
P2=[25.7 29.5 30]*10;
%wattsight
P3=[48.4 54.9 58.3]*10;

% chose which forecasts average value to use

```

```
% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
prod_its = zeros(iterations,tot_days);

% Daily energy prices [kr/MWh]

for iteration=1:iterations
    % Initial value, only applicable for first day
    e_prices_its(iteration,1) =P3(1);

    for day = 2:tot_days
        if day<=(7*365)
            theta=P3(1); % chose forecast
        elseif day>(7*365) && day<=(12*365)
            theta=P3(2); % chose forecast
        elseif day>(12*365)
            theta=P3(3); % chose forecast
        end

        %Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        %Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
        end
    end
end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;   % [MWh]
```

```

        % income from sale
        income_its(iteration,day) = ...
            (1-tax)*(prod_its(iteration,day).*(e_prices_its(iteration,day)-P_PPA));
    end
end

prod_years = zeros(iterations,years);

PV_prod_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
    index_day_stop = 365;

    year=1;
    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));

        income_sum_y = sum(income_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;

        PV_prod_years(iteration,year) = OM * prod_sum_y / ((1+r_wacc)^year);
        PV_income_years(iteration,year) = income_sum_y/((1+r_wacc)^year);
        income_year(iteration,year) = income_sum_y;

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    NPV_its(iteration) = sum(PV_income_years(iteration,:));
    prod_avg = sum(prod_years(iteration,:)) / years;
end

conf_NPV = prctile(NPV_its(:),[2.5 97.5]);
disp('NPV:')
disp(conf_NPV)
```

B.1.8 *Cost Analysis 1.I: LCOE of wind power plant.*

```
clc
clear

I = 9.5 ; % kr/MW

om = 110 ; % kr/MWh

t = 0.23;

n = 25;

N = 25; % turbines

FLH = 3500; % h

K = 4.2; % MW

W_annual = N*FLH*K; % MWh

r_bank = 0.03; %

r_investor = 0.08; %

r_wacc = 0.06 ; %

a = r_wacc/(1-(1+r_wacc)^(-n)); % P/PV

F_annual = I * K * N * a * 10^6; % kr

OM_annual = om * W_annual; % kr

LCOE = (OM_annual + F_annual) / W_annual;
```

B.1.9 Cost Analysis 1.II: Monte Carlo model - historical prices.

```
clc
clear

%%% Costs
% Investment cost [kr/MW]
I = 9.5*10^6;

% Operation and maintenance cost [kr/MWh]
OM = 110;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

% Discount rate
r = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r / (1 - (1+r)^(-years));

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);
```

```
% Cut out wind speed [m/s]
v_max = 25;

% Consumer demand [MWh] (constant in this simulation)
cons_demand = 42.15*24; %N*K*24;

%%% Variable energy prices: Ornstein-Uhlenbeck mean-reverting process
% Time increment
dt = 1/365;

% Long-term mean of energy prices:
% 282.4 kr/MWh for price level in 2013-2018,
% 407.6 kr/MWh for price level in 2018
theta = 282.4;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
e_prices_its = zeros(iterations,tot_days);
prod_its = zeros(iterations,tot_days);
purchasing_its = zeros(iterations,tot_days);
prod_under_its = zeros(iterations,tot_days);
selling_its = zeros(iterations,tot_days);
prod_over_its = zeros(iterations,tot_days);
LCOE_its = zeros(iterations,1);      % Levelized cost of generation
REE_its = zeros(iterations,1);       % Realized energy expenditure

% Daily energy prices [kr/MWh]
for iteration = 1:iterations
    % Initial value, only applicable for first day
    e_prices_its(iteration,1) = theta;

    for day = 2:tot_days
        % Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        % Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
```

```
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
        end
    end

end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;   % [MWh]

        if prod_its(iteration,day) < cons_demand
            prod_under_its(iteration,day) = cons_demand - prod_its(iteration,day);   % [MWh]
            purchasing_its(iteration,day) = prod_under_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end

        if prod_its(iteration,day) > cons_demand
            prod_over_its(iteration,day) = prod_its(iteration,day) - cons_demand;    % [MWh]
            selling_its(iteration,day) = prod_over_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end
    end
end

% Annual production, purchasing and selling
% Annual costs over lifetime of the plant: LCOE and REE
prod_years = zeros(iterations,years);
purch_years = zeros(iterations,years);
prod_under_years = zeros(iterations,years);
sell_years = zeros(iterations,years);
prod_over_years = zeros(iterations,years);
PV_prod_years = zeros(iterations,years);
PV_totcost_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
```

```
    index_day_stop = 365;

    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));
        purch_sum_y = sum(purchasing_its(iteration,index_day_start:index_day_stop));
        prod_under_y = sum(prod_under_its(iteration,index_day_start:index_day_stop));
        sell_sum_y = sum(selling_its(iteration,index_day_start:index_day_stop));
        prod_over_y = sum(prod_over_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;
        prod_under_years(iteration,year) = prod_under_y;
        purch_years(iteration,year) = purch_sum_y;
        prod_over_years(iteration,year) = prod_over_y;
        sell_years(iteration,year) = sell_sum_y;
        PV_prod_years(iteration,year) = OM * prod_sum_y / ((1+r)^year);
        PV_totcost_years(iteration,year) = (purch_years(iteration,year) - ...
            sell_years(iteration,year) + OM * prod_years(iteration,year)) / ((1+r)^year);

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    prod_avg = sum(prod_years(iteration,:)) / years;
    LCOE_its(iteration,1) = ((sum(PV_prod_years(iteration,:)) + I*K*N) * annuity) / prod_avg;
    REE_its(iteration,1) = ((sum(PV_totcost_years(iteration,:)) + I*K*N) * annuity) / ...
        (cons_demand*365);
end

% Confidence intervals
conf_price_day = prctile(e_prices_its(:),[2.5 97.5]);
disp('Confidence intervals')
disp('Energy prices, day:')
disp(conf_price_day)

disp('--')

conf_prod_day = prctile(prod_its(:),[2.5 97.5]);
conf_prod_year = prctile(prod_years(:),[2.5 97.5]);
disp('Production, day:')
disp(conf_prod_day)
disp('Production, year:')
disp(conf_prod_year)

disp('--')

conf_LCOE = prctile(LCOE_its(:),[2.5 97.5]);
disp('LCOE:')
disp(conf_LCOE)

disp('--')

conf_purchased_day = prctile(prod_under_its(:),[2.5 97.5]);
```

```
conf_purchased_year = prctile(prod_under_years(:),[2.5 97.5]);
disp('Purchased quantity, day:')
disp(conf_purchased_day)
disp('Purchased quantity, year:')
disp(conf_purchased_year)

disp('--')

conf_sold_day = prctile(prod_over_its(:),[2.5 97.5]);
conf_sold_year = prctile(prod_over_years(:),[2.5 97.5]);
disp('Sold quantity, day:')
disp(conf_sold_day)
disp('Sold quantity, year:')
disp(conf_sold_year)

disp('--')

conf_REE = prctile(REE_its(:),[2.5 97.5]);
disp('REE:')
disp(conf_REE)
```

B.1.10 *Cost Analysis 1.II: Monte Carlo model - forecasted prices.*

```
clc
clear

%%% Costs
% Investment cost [kr/MW]
I = 9.5*10^6;

% Operation and maintenance cost [kr/MWh]
OM = 110;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

% Discount rate
r = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r / (1 - (1+r)^(-years));

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);
```

```

% Cut out wind speed [m/s]
v_max = 25;

% Consumer demand [MWh] (constant in this simulation)
cons_demand = 42.15*24; %N*K*24;

%%% Variable energy prices: Ornstein-Uhlenbeck mean-reverting process
% Time increment
dt = 1/365;

% Long-term mean of energy prices:
% 282.4 kr/MWh for price level in 2013-2018,
% 407.6 kr/MWh for price level in 2018
theta = 282.4;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
e_prices_its = zeros(iterations,tot_days);
prod_its = zeros(iterations,tot_days);
purchasing_its = zeros(iterations,tot_days);
prod_under_its = zeros(iterations,tot_days);
selling_its = zeros(iterations,tot_days);
prod_over_its = zeros(iterations,tot_days);
LCOE_its = zeros(iterations,1);     % Levelized cost of generation
REE_its = zeros(iterations,1);      % Realized energy expenditure

%%% Forecasts, *10 to convert from \{o}re to kr
%Statnett
P1 = [39 37 34.5]*10;
%NVE
P2 = [25.7 29.5 30]*10;
%Wattsight
P3 = [48.4 54.9 58.3]*10;

% Daily energy prices [kr/MWh]
for iteration = 1:iterations
    % Initial value, only applicable for first day
```

```
    % set correct P-forecast
    e_prices_its(iteration,1) = P1(1);

    for day = 2:tot_days
        if day <= (7*365)
            % set correct P-forecast
            theta = P1(1);
        elseif (day > (7*365)) && (day <= (12*365))
            % set correct P-forecast
            theta = P1(2);
        elseif day > (12*365)
            % set correct P-forecast
            theta = P1(3);
        end
    end

    for day = 2:tot_days
        % Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        % Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
        end
    end

end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;   % [MWh]

        if prod_its(iteration,day) < cons_demand
            prod_under_its(iteration,day) = cons_demand - prod_its(iteration,day);   % [MWh]
            purchasing_its(iteration,day) = prod_under_its(iteration,day) .* ...
                e_prices_its(iteration,day);
```

```
        end

        if prod_its(iteration,day) > cons_demand
            prod_over_its(iteration,day) = prod_its(iteration,day) - cons_demand;    % [MWh]
            selling_its(iteration,day) = prod_over_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end
    end
end

% Annual production, purchasing and selling
% Annual costs over lifetime of the plant: LCOE and REE
prod_years = zeros(iterations,years);
purch_years = zeros(iterations,years);
prod_under_years = zeros(iterations,years);
sell_years = zeros(iterations,years);
prod_over_years = zeros(iterations,years);
PV_prod_years = zeros(iterations,years);
PV_totcost_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
    index_day_stop = 365;

    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));
        purch_sum_y = sum(purchasing_its(iteration,index_day_start:index_day_stop));
        prod_under_y = sum(prod_under_its(iteration,index_day_start:index_day_stop));
        sell_sum_y = sum(selling_its(iteration,index_day_start:index_day_stop));
        prod_over_y = sum(prod_over_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;
        prod_under_years(iteration,year) = prod_under_y;
        purch_years(iteration,year) = purch_sum_y;
        prod_over_years(iteration,year) = prod_over_y;
        sell_years(iteration,year) = sell_sum_y;
        PV_prod_years(iteration,year) = OM * prod_sum_y / ((1+r)^year);
        PV_totcost_years(iteration,year) = (purch_years(iteration,year) - ...
            sell_years(iteration,year) + OM * prod_years(iteration,year)) / ((1+r)^year);

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    prod_avg = sum(prod_years(iteration,:)) / years;
    LCOE_its(iteration,1) = ((sum(PV_prod_years(iteration,:)) + I*K*N) * annuity) / prod_avg;
    REE_its(iteration,1) = ((sum(PV_totcost_years(iteration,:)) + I*K*N) * annuity) / ...
        (cons_demand*365);
end

% Confidence intervals
conf_price_day = prctile(e_prices_its(:),[2.5 97.5]);
```

```
disp('Confidence intervals')
disp('Energy prices, day:')
disp(conf_price_day)

disp('--')

conf_prod_day = prctile(prod_its(:),[2.5 97.5]);
conf_prod_year = prctile(prod_years(:),[2.5 97.5]);
disp('Production, day:')
disp(conf_prod_day)
disp('Production, year:')
disp(conf_prod_year)

disp('--')

conf_LCOE = prctile(LCOE_its(:),[2.5 97.5]);
disp('LCOE:')
disp(conf_LCOE)

disp('--')

conf_purchased_day = prctile(prod_under_its(:),[2.5 97.5]);
conf_purchased_year = prctile(prod_under_years(:),[2.5 97.5]);
disp('Purchased quantity, day:')
disp(conf_purchased_day)
disp('Purchased quantity, year:')
disp(conf_purchased_year)

disp('--')

conf_sold_day = prctile(prod_over_its(:),[2.5 97.5]);
conf_sold_year = prctile(prod_over_years(:),[2.5 97.5]);
disp('Sold quantity, day:')
disp(conf_sold_day)
disp('Sold quantity, year:')
disp(conf_sold_year)

disp('--')

conf_REE = prctile(REE_its(:),[2.5 97.5]);
disp('REE:')
disp(conf_REE)
```

B.1.11 *Cost Analysis 2.I: Monte Carlo model - historical prices.*

```
clc
clear

%%% Costs
% PPA price [kr/MWh]
PPA = 250; %250, 350;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

% Discount rate
r = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r / (1 - (1+r)^(-years));

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);

% Cut out wind speed [m/s]
v_max = 25;
```

```
% Consumer demand [MWh] (constant in this simulation)
cons_demand = 42.15*24; %N*K*24;

%%% Variable energy prices: Ornstein-Uhlenbeck mean-reverting process
% Time increment
dt = 1/365;

% Long-term mean of energy prices:
% 282.4 kr/MWh for price level in 2013-2018,
% 407.6 kr/MWh for price level in 2018
theta = 282.4;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
e_prices_its = zeros(iterations,tot_days);
prod_its = zeros(iterations,tot_days);
purchasing_its = zeros(iterations,tot_days);
prod_under_its = zeros(iterations,tot_days);
selling_its = zeros(iterations,tot_days);
prod_over_its = zeros(iterations,tot_days);
LCOE_its = zeros(iterations,1);     % Levelized cost of generation
REE_its = zeros(iterations,1);      % Realized energy expenditure

% Daily energy prices [kr/MWh]
for iteration = 1:iterations
    % Initial value, only applicable for first day
    e_prices_its(iteration,1) = theta;

    for day = 2:tot_days
        % Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        % Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
```

```
        end
    end

end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;   % [MWh]

        if prod_its(iteration,day) < cons_demand
            prod_under_its(iteration,day) = cons_demand - prod_its(iteration,day);   % [MWh]
            purchasing_its(iteration,day) = prod_under_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end

        if prod_its(iteration,day) > cons_demand
            prod_over_its(iteration,day) = prod_its(iteration,day) - cons_demand;    % [MWh]
            selling_its(iteration,day) = prod_over_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end
    end
end

% Annual production, purchasing and selling
% Annual costs over lifetime of the plant: LCOE and REE
prod_years = zeros(iterations,years);
purch_years = zeros(iterations,years);
prod_under_years = zeros(iterations,years);
sell_years = zeros(iterations,years);
prod_over_years = zeros(iterations,years);
PV_totcost_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
    index_day_stop = 365;

    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));
```

```
        purch_sum_y = sum(purchasing_its(iteration,index_day_start:index_day_stop));
        prod_under_y = sum(prod_under_its(iteration,index_day_start:index_day_stop));
        sell_sum_y = sum(selling_its(iteration,index_day_start:index_day_stop));
        prod_over_y = sum(prod_over_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;
        prod_under_years(iteration,year) = prod_under_y;
        purch_years(iteration,year) = purch_sum_y;
        prod_over_years(iteration,year) = prod_over_y;
        sell_years(iteration,year) = sell_sum_y;
        PV_totcost_years(iteration,year) = (purch_years(iteration,year) - ...
            sell_years(iteration,year) + PPA * prod_years(iteration,year)) / ((1+r)^year);

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    prod_avg = sum(prod_years(iteration,:)) / years;
    REE_its(iteration,1) = (sum(PV_totcost_years(iteration,:)) * annuity) / (cons_demand*365);
end

% Confidence intervals
conf_price_day = prctile(e_prices_its(:),[2.5 97.5]);
disp('Confidence intervals')
disp('Energy prices, day:')
disp(conf_price_day)

disp('--')

conf_prod_day = prctile(prod_its(:),[2.5 97.5]);
conf_prod_year = prctile(prod_years(:),[2.5 97.5]);
disp('Production, day:')
disp(conf_prod_day)
disp('Production, year:')
disp(conf_prod_year)

disp('--')

conf_purchased_day = prctile(prod_under_its(:),[2.5 97.5]);
conf_purchased_year = prctile(prod_under_years(:),[2.5 97.5]);
disp('Purchased quantity, day:')
disp(conf_purchased_day)
disp('Purchased quantity, year:')
disp(conf_purchased_year)

disp('--')

conf_sold_day = prctile(prod_over_its(:),[2.5 97.5]);
conf_sold_year = prctile(prod_over_years(:),[2.5 97.5]);
disp('Sold quantity, day:')
disp(conf_sold_day)
disp('Sold quantity, year:')
```

```
disp(conf_sold_year)

disp('--')

conf_REE = prctile(REE_its(:),[2.5 97.5]);
disp('REE:')
disp(conf_REE)
```

B.1.12 *Cost Analysis 2.I: Monte Carlo model - forecasted prices.*

```
clc
clear

%%% Costs
% PPA price [kr/MWh]
PPA = 250; %400;

%%% Lifetime of plant [years]
years = 25;

%%% Number of days in a year [days]
days = 365;

% Discount rate
r = 0.06;

%%% Annuity - converting a present value to an annual value
annuity = r / (1 - (1+r)^(-years));

%%% Production
% Coefficient of power
C_p = 0.35;

% Density of air [kg/m^3]
rho_air = 1.247;

% Radius of turbine swiped area [m]
rad = 136/2;

% Turbine swiped area [m^2]
A = pi*rad^2;

% Number of turbines
N = 25;

% Capacity of turbines [MW]
K = 4.2;

% Average wind speed [m/s]
v_avg = 7.5;

% Cut in wind speed [m/s]
v_min = 3;

% Speed where max production is reached [m/s]
v_flat = ((K*10^6) / (0.5 .* C_p .* rho_air .* A))^(1/3);

% Cut out wind speed [m/s]
v_max = 25;
```

```

% Consumer demand [MWh] (constant in this simulation)
cons_demand = 42.15*24; %N*K*24;

%%% Variable energy prices: Ornstein-Uhlenbeck mean-reverting process
% Time increment
dt = 1/365;

% Long-term mean of energy prices:
% 282.4 kr/MWh for price level in 2013-2018,
% 407.6 kr/MWh for price level in 2018
theta = 282.4;

% Variance:
% 1574.65 kr/MWh for price level in 2013-2018,
% 1543.97 kr/MWh for price level in 2018
sigma = 1574.65;

% Speed of reversion:
% 169.6 for price level in 2013-2018,
% 54.52 for price level in 2018
kappa = 169.6;

% Number of iterations in Monte Carlo simulation
iterations = 10000;

tot_days = days*years;

% Pre-allocation
e_prices_its = zeros(iterations,tot_days);
prod_its = zeros(iterations,tot_days);
purchasing_its = zeros(iterations,tot_days);
prod_under_its = zeros(iterations,tot_days);
selling_its = zeros(iterations,tot_days);
prod_over_its = zeros(iterations,tot_days);
LCOE_its = zeros(iterations,1);     % Levelized cost of generation
REE_its = zeros(iterations,1);      % Realized energy expenditure

%%% Forecasts, *10 to convert from EUR to NOK
%Statnett
P1 = [39 37 34.5]*10;
%NVE
P2 = [25.7 29.5 30]*10;
%Wattsight
P3 = [48.4 54.9 58.3]*10;

% Daily energy prices [kr/MWh]
for iteration = 1:iterations
    % Initial value, only applicable for first day
    % set correct P-forecast
    e_prices_its(iteration,1) = P3(1);

```

```
    for day = 2:tot_days
        if day <= (7*365)
            % set correct P-forecast
            theta = P3(1);
        elseif (day > (7*365)) && (day <= (12*365))
            % set correct P-forecast
            theta = P3(2);
        elseif day > (12*365)
            % set correct P-forecast
            theta = P3(3);
        end
    end

    for day = 2:tot_days
        % Change in power price
        d_e_prices_its = kappa * (theta - e_prices_its(iteration,day-1)) * dt + sigma * ...
            sqrt(dt) * normrnd(0,1);
        % Remaining values
        if (d_e_prices_its < 0) && (d_e_prices_its > e_prices_its(iteration,day-1))
            e_prices_its(iteration,day) = 0;
        else
            e_prices_its(iteration,day) = e_prices_its(iteration,day-1) + d_e_prices_its;
        end
    end

end

for iteration = 1:iterations
    for day = 1:tot_days
        % Windspeed [m/s], hourly
        v = wblrnd(((2*v_avg)/(pi^0.5)),2);

        % Energy based on wind speed
        if (v < v_min) || (v > v_max)
            p_d = 0;

        elseif (v_min <= v) && (v <= v_flat)
            p_d = N .* (1/10^6) .* 0.5 .* C_p .* rho_air .* A .* v.^3;

        elseif (v_flat < v) && (v < v_max)
            p_d = N*K;
        end

        prod_its(iteration,day) = p_d*24;   % [MWh]

        if prod_its(iteration,day) < cons_demand
            prod_under_its(iteration,day) = cons_demand - prod_its(iteration,day);   % [MWh]
            purchasing_its(iteration,day) = prod_under_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end

        if prod_its(iteration,day) > cons_demand
```

```
            prod_over_its(iteration,day) = prod_its(iteration,day) - cons_demand;    % [MWh]
            selling_its(iteration,day) = prod_over_its(iteration,day) .* ...
                e_prices_its(iteration,day);
        end
    end
end

% Annual production, purchasing and selling
% Annual costs over lifetime of the plant: LCOE and REE
prod_years = zeros(iterations,years);
purch_years = zeros(iterations,years);
prod_under_years = zeros(iterations,years);
sell_years = zeros(iterations,years);
prod_over_years = zeros(iterations,years);
PV_totcost_years = zeros(iterations,years);

for iteration = 1:iterations
    index_day_start = 1;
    index_day_stop = 365;

    for year = 1:years
        prod_sum_y = sum(prod_its(iteration,index_day_start:index_day_stop));
        purch_sum_y = sum(purchasing_its(iteration,index_day_start:index_day_stop));
        prod_under_y = sum(prod_under_its(iteration,index_day_start:index_day_stop));
        sell_sum_y = sum(selling_its(iteration,index_day_start:index_day_stop));
        prod_over_y = sum(prod_over_its(iteration,index_day_start:index_day_stop));

        prod_years(iteration,year) = prod_sum_y;
        prod_under_years(iteration,year) = prod_under_y;
        purch_years(iteration,year) = purch_sum_y;
        prod_over_years(iteration,year) = prod_over_y;
        sell_years(iteration,year) = sell_sum_y;
        PV_totcost_years(iteration,year) = (purch_years(iteration,year) - ...
            sell_years(iteration,year) + PPA * prod_years(iteration,year)) / ((1+r)^year);

        index_day_start = index_day_start + 365;
        index_day_stop = index_day_stop + 365;
    end

    prod_avg = sum(prod_years(iteration,:)) / years;
    REE_its(iteration,1) = (sum(PV_totcost_years(iteration,:)) * annuity) / (cons_demand*365);
end

% Confidence intervals
conf_price_day = prctile(e_prices_its(:),[2.5 97.5]);
disp('Confidence intervals')
disp('Energy prices, day:')
disp(conf_price_day)

disp('--')

conf_prod_day = prctile(prod_its(:),[2.5 97.5]);
```

```
conf_prod_year = prctile(prod_years(:),[2.5 97.5]);
disp('Production, day:')
disp(conf_prod_day)
disp('Production, year:')
disp(conf_prod_year)

disp('--')

conf_purchased_day = prctile(prod_under_its(:),[2.5 97.5]);
conf_purchased_year = prctile(prod_under_years(:),[2.5 97.5]);
disp('Purchased quantity, day:')
disp(conf_purchased_day)
disp('Purchased quantity, year:')
disp(conf_purchased_year)

disp('--')

conf_sold_day = prctile(prod_over_its(:),[2.5 97.5]);
conf_sold_year = prctile(prod_over_years(:),[2.5 97.5]);
disp('Sold quantity, day:')
disp(conf_sold_day)
disp('Sold quantity, year:')
disp(conf_sold_year)

disp('--')

conf_REE = prctile(REE_its(:),[2.5 97.5]);
disp('REE:')
disp(conf_REE)
```

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