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# Wind power deployment in the Swedish-Norwegian tradable electricity certificate market

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# Excecutive summary

This thesis examines the market-based common Swedish-Norwegian tradable electricity certificate support scheme for investments in new electricity generating capacity from renewable energy sources, with a particular focus on deployment of wind power in Norway. We evaluate the costs of onshore wind power projects in the pipeline and their potential to contribute to the quantitative target of adding new renewable electricity generation corresponding to 26.4 TWh per year by 2020. We present relevant theory on electricity certificate markets and available data on the Swedish-Norwegian electricity certificate market. We show how several features of the policy design are likely to result in high risk and uncertainty to potential investors. In particular, there is a risk of overshooting the quantitative target, resulting in certificate price spoilage, due to a lack of information regarding the supply and demand for electricity certificates over the duration of the scheme. The large electricity generation potential of the projects in the pipeline reinforces the risk of overinvestment. Risk and uncertainty is likely to contribute to high risk-premiums and increase the capital costs of new investment. These costs, which ultimately are covered by the electricity consumers in Norway and Sweden, have the potential to weaken the cost-effectiveness of the policy. Improved systems for information in the market, increased transparency in electricity certificate trade and more frequent corrections of demand deviation are suggested as viable measures that the regulators can take in order to reduce risk and uncertainty faced by the market participants.

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# 1 Introduction

## 1.1 Market background

The global trend of implementing environmental policy measures has come as a result of the need to limit greenhouse gas (GHG) emissions and the human impact on the climate. Promoting the deployment of renewable energy sources for electricity production (RES-E) has been recognised as an important measure due to the low carbon footprint of such technologies. Historically, Norway has had sufficient hydropower capacity to cover electricity demand and has not had the need for or willingness to set ambitious targets for RES-E deployment beyond what is economically profitable based on revenues from power sale. As a result of negotiations with the EU, Norway implemented the EU Renewable Energy Directive with a binding national target of increasing its share of renewable energy use from 58% in 2005 to 67.5% by 2020, which is roughly calculated as the renewable energy production plus the direct use of bio energy divided by the total energy consumption (Olje- og energidepartementet, 2009). In addition to GHG emissions reduction, the renewables target may be seen as a way of reducing local air pollution, promoting job opportunities, regional development and industries, as well as adding to the power balance and strengthening the security of supply.

Recognising that wind power and other RES-E technologies typically remains uncompetitive at current electricity wholesale prices, Norway chose a marked based incentive scheme to promote RES-E deployment were suggested. In December 2010, Norway and Sweden signed a protocol to create a common tradable electricity certificate market that has been in operation since January 2012. The policy is designed to promote new, RES-E projects corresponding to 26.4 TWh of electricity generation per year by 2020 in the common market. Prescribed by the Electricity Certificate Act, Norway and Sweden are each financing 13.2 TWh of the new RES-E capacity, irrespective of the location of the new production capacity (Olje- og energidepartementet, 2012).

The thesis aims to clarify how the common Swedish-Norwegian tradable electricity certificate market works, evaluate the cost-effectiveness of the policy instrument, the main challenges for potential investors in new RES-E generation capacity and how the market risk and uncertainty in the regulatory framework affect investment behaviour and potentially the policy outcome. Throughout the thesis, we will use onshore wind power projects in Norway as a base case.

## 1.2 Purpose and structure

There is a sizeable amount of potential wind power projects in Norway that have a licence to build, but seem to face challenges in reaching a positive investment decision. The motivation for the thesis is to identify the challenges to investors in new RES-E capacity under the Swedish-Norwegian electricity certificate market, and elaborate on risks and uncertainty in the current market conditions, focusing on regulatory risk, market and operational risks and technology risk. We discuss how the perceived risks and uncertainty in the market may affect the decision to invest in RES-E technologies, and the effect of an uncertain investment level on the policy outcome. Lastly, we evaluate how and whether the regulatory framework could be altered in order to reduce the risk and uncertainty faced by the market participants. In short, the thesis aim to answer the following:

*How does the risk to investors in new RES-E generation capacity under the common Swedish-Norwegian electricity certificate market affect investment behaviour, and the policy outcome?*

Cleijne and Ruijgrok (2004) suggest that risk in relation to investments in renewable energy projects can be defined as uncertainties in future developments which have a negative impact on the operation and profit of a company. We suggest that three types of risks should be rewarded in the case of RES-E projects, namely technology risks, market and operational risks and regulatory risk. Technology risk is related to uncertainty in the development of technology costs and efficiency over time due to technology learning. Market and operational risk includes factors that can influence the performance of a power producer during normal operation, including price risk and volume risk in both inputs and outputs in the power market. For RES-E generators, price and volume risk in the market for electricity certificates is also prevalent. Uncertainties related to the current regulatory framework and expectations regarding support for RES-E investments in the future is referred to as regulatory uncertainty.

In section 2, we consider the RES-E project pipeline, the investment decision process and the role of different types of RES-E investors and financiers. In section 3, the cost structure of RES-E technologies and the expected development of energy costs are considered. In section 4 we consider the Nordic electricity market, with a particular focus on how power prices are formed and how uncertain and volatile prices can be hedged in the financial market. Section 5 is concerned with the Swedish-Norwegian electricity certificate market. In sections 6, 7 and 8, we outline the risk and uncertainty faced by RES-E investors and financiers who operate in the electricity certificate market, how the risk and uncertainty could affect policy outcome, and we suggest potential risk reducing alterations to the policy design.

## 1.3 Scope and limitations

The thesis assess the Swedish-Norwegian electricity certificate market analytically with the objective to illustrate how the mechanism encourages investments in new RES-E technologies, in particular onshore wind power in Norway. It describes the challenges faced by different market participants and how risk and uncertainty may affect the market performance and policy outcome.

We do not engage in comparing the policy measure employed in Norway/Sweden to alternative policies to stimulate RES-E investments. Moreover, we study investments in RES-E production plants and not investments into RES-E technology development. In the thesis, the renewable target is taken as a premise and we will neither question whether a renewable target must be part of an efficient climate policy nor the motivation behind supporting the deployment of RES-E technologies. Furthermore, it is not discussed whether the quantitative mandate for RES-E deployment agreed in the common Swedish-Norwegian electricity certificate market is the best approach for Norway and Sweden to reach their respective renewables targets. Moreover, the effect of RES-E deployment on the global $CO_2$ emission level or complementary environmental policies such as energy efficiency schemes or $CO_2$ emissions trading is not studied.

# 2 Market background

## 2.1 The RES-E project pipeline

In this section, we describe the process from planning a RES-E project through the stages leading up to the potential realization. We first consider the concession process in Norway and the current status of Norwegian onshore wind power projects in the concession process. Moreover, we describe the project pipeline of onshore wind power projects in Norway, and evaluate the scope of potential new RES-E projects that could come online in Norway and Sweden by 2020.

A concession, which is the same as a permission, permit or license, is generally needed in order to build a power plant. In Norway, the first instance authority to grant licenses is the Norwegian Water Resources and Energy Directorate, from now on referred to as NVE. Concessions are issued on the basis of economical viability and an environmental impact assessment. The process of obtaining a licence starts with a notification from the developer to NVE, a preliminary assessment and a formal application from the developer including an impact assessment. The license application is approved or a rejected by NVE and either way, the decision may be subject to appeals that are handled by the Ministry of Petroleum and Energy, from now on referred to as OED. The concession process in Norway is fully transparent and to a large extent centralized (NVE e, 2015). The Swedish Energy Agency (Energimyndigheten) has a similar function in Sweden, however the concession process is less centralized in Sweden where municipalities have a more formal role in the ruling.

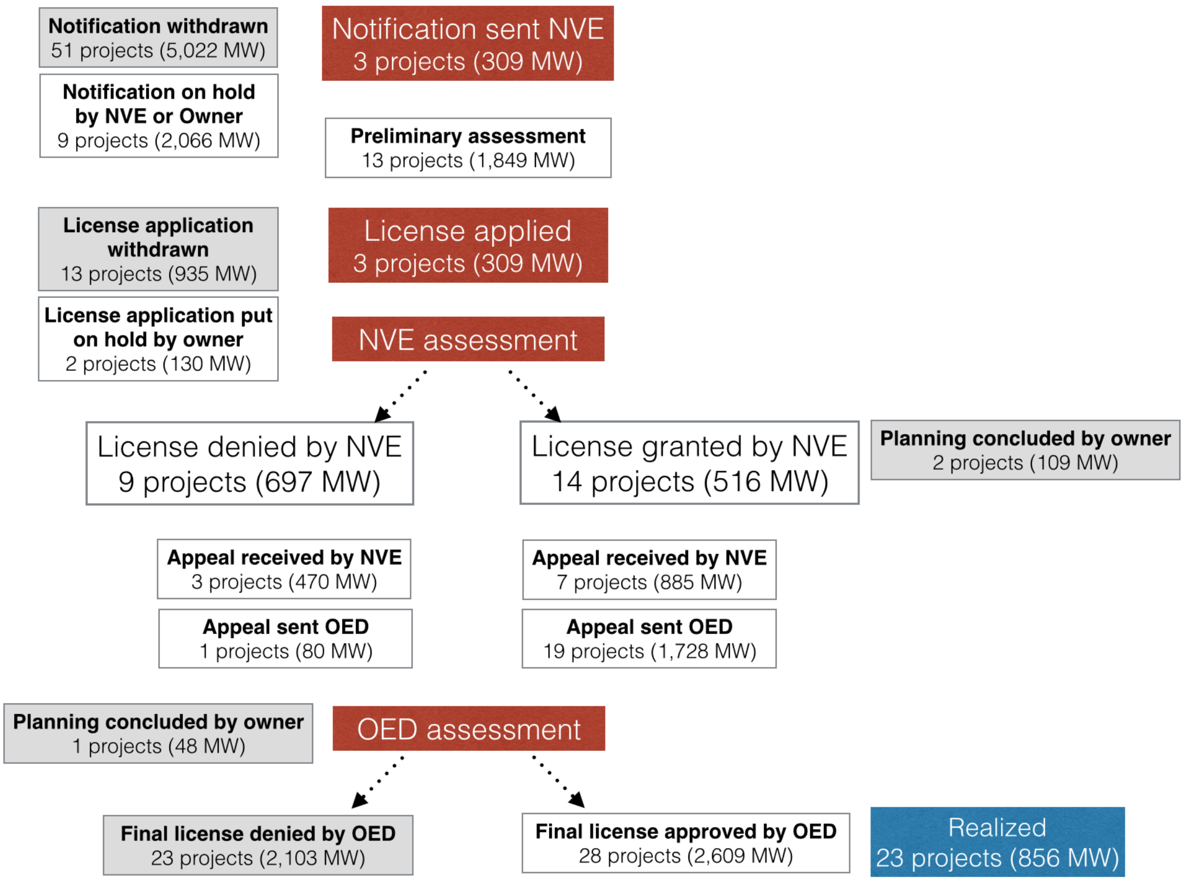


**Figure 1: Current status of concession process for onshore wind projects (NVE b, 2015)**

Figure 1 illustrates the current status[1] of onshore wind power projects in Norway that can be found at different stages in the concession process, either at NVE or OED. The description of the concession process in Figure 1 is static and each project only appears at one stage. Thus, it neither captures how much time the projects spend at the different stages nor their probability of receiving a licence. The concession processing time can vary significantly across projects, and in the period 2009-2013, the average concession process in Norway was 5.5 years for wind power projects and 3.5 years for small-scale hydropower projects, with an additional two years in the

[1] The current status per April 21, 2015, provided in a detailed listing of the NVE concession process (NVE b, 2015).

case of appeals handled by OED (Riksrevisjonen, 2014). Currently, 68 active[2] projects have a license from NVE, with a total installed capacity of 5,738 MW and an electricity generation potential of more than 16 TWh in total. However, 26 projects are appealed to OED and projects that are denied a licence from NVE may still be granted licence from OED after an appeal process. We consider the amount of wind power projects that have a licence to be sizeable.

For a wind power investor, the complete process from the early sketch phase to the plant is in operation is far more extensive than the concession process. Hours of preliminary site studies are necessary prior to the licence processing in NVE, and only after a licence is secured is the investor in the clear to make an investment decision, enter into contracts with equipment suppliers and secure financing. An illustration of the pipeline stages that onshore wind power projects may be in is shown in Figure 2:

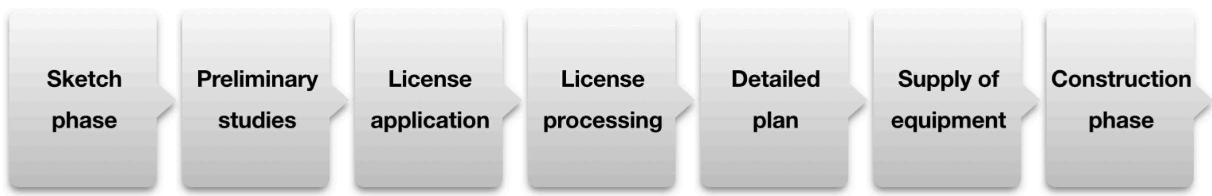


**Figure 2: Project pipeline onshore wind power Norway**

The thesis focus is on the investment decision process following a granted licence. Nonetheless, considering the total project pipeline of all RES-E projects in Norway and Sweden is crucial in order to evaluate which projects have the potential to be realized and enter the Swedish-Norwegian electricity certificate market by 2020.

In 2014, NVE conducted a quantitative analysis of the volume of RES-E projects possible to invest in by the end of 2020, under the condition that they are granted a licence and access to the central grid. NVE estimate that current and future licence rulings can deliver project licences in

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[2] An additional 2 projects have a license from NVE, but the developer has concluded the project planning.

due time before the end of 2020[3] corresponding to an annual potential production of 27 TWh from new wind- and hydropower projects. By taking into consideration restrictions in the central grid, NVE conclude that with today's central grid capacity, only 11.9 TWh of the potential generation capacity could come online by 2020, whereas over 20 TWh are considered "investable" by the end of 2020 provided that all planned investments in the central grid are implemented by 2019 (NVE c, 2014). The "investable" volume must be understood as an estimate of projects expected to be granted a licence and grid access and therefore is considered possible to invest in by the end of 2020. It should not be confused with an investment prognosis, which unarguably relies on additional factors such as economical viability and access to funding. In a similar analysis, the Swedish Energy Agency have estimated that the volume of investable new RES-E projects could contribute to an estimated annual electricity generation of 17 TWh onshore wind and 8.5 TWh offshore wind power projects, 3.5 TWh from biomass and 1.1 TWh from hydropower (Energimyndigheten a, 2014). We will apply these estimates of realisable (by 2020) potential RES-E generation capacity when we later evaluate the scope of new RES-E project to come online under the Swedish-Norwegian electricity certificate market by 2020. NVE and the Swedish Energy Agency estimate that over 50 TWh of new RES-E generation capacity in total is investable by 2020 in Norway and Sweden, thus our key takeaways from this section is that there is clearly a sufficient amount of available RES-E projects in order to meet the RES-E quantitative mandate of 26.4 TWh by 2020 in the common Swedish-Norwegian electricity certificate market. However, the concession process and grid expansion could prove to be a bottleneck for many RES-E projects.

## 2.2 The investment decision process

In general, an investment is a decision that locks in liquid assets, such as capital, into something that generates a cash flow to be returned to the owner that is expected to have a larger net present value than the initial investment. Since the investment today is compared with an uncertain

[3] NVE assume the time from the project is granted a final licence to commissioning to be 2.5-3.5 years for small-scale hydropower projects and 2 years for wind power projects.

future cash flow, investors will require a risk premium, captured by the discount rate. Profit maximizing, rational investors will make their investment decision based on a profitability calculation such as the Net Present Value (NPV) approach:

$$V_{NPV} = -I + \sum_{t=0}^{T} \frac{C_t}{(1+r)^t}$$

Where $I$ is the initial capital investment, and $C_t$ the annual expected cash flow discounted at a rate $r$ over the project lifetime $T$.

A licence to develop a wind farm or alternative RES-E project may be valued as a real option, implying that the investor owns an exclusive right, but not an obligation, to pay the investment cost needed to receive the present value of the project. An investment is generally considered irreversible and hence the flexibility of the real option is applicable in the investment decision phase (Fleten & Ringen, 2009). By deferring an investment decision, the investor can potentially reduce the uncertainty in future costs and revenues. A value of waiting may for example arise from a possible implementation of a new support scheme (Linnerud, Fleten, & Andersson, 2014), the prospect of higher future subsidies or an expected release of a more efficient wind turbine (Narbel, Lien, & Hansen, 2014). The real option value investment rule can take the value of waiting into account by integrating it into the simple NPV investment rule and may significantly affect the optimal timing of the investment.

## 2.3 Debt and equity providers

Access to capital and funding is necessary for taking an investment decision. In the capital markets, only the best projects will attract capital. In order to study RES-E investments, an understanding of who the investors that provide equity and financiers who provide debt are, is needed. Lenders and equity providers tend to include different criteria in their analysis of project performance. Equity providers have the potential for unbounded return and are willing to take on risk if the potential upside is large. Lenders do not face a similar upward potential and will therefore seek to remove risk that can threaten the project cash flow. Up to a limit of unacceptable risk, lenders will charge a higher interest rate and stricter terms on investments that are perceived more risky. Factors such as stricter requirements on banks and changes in the investment environment thus impact the development of new RES-E in Norway and Sweden.

Different types of investors may be involved in a RES-E project at different stages in the project pipeline. Equity investors can vary from power companies to pension funds depending on where the project is in its lifetime. In the early stages of planning and construction, project developers are typically involved, securing finance and early operation. The planning phase is considered highly risky to the developer due to the possibility that the project never leaves the drawing board. Once a project is constructed and enters normal operation, other equity contributors, such as pension funds, insurance companies or municipalities could replace the developer (Dunlop, 2006). The typical debt providers are banks or bond issuers that lend capital to a project. Debt providers generally get involved in the final phase of the planning process. The main difference between equity and debt providers is that debt owners get their principal returned at maturity in addition to the interest, and that they have first priority on the cash flow. Equity providers, on the other hand, receive what is left of the cash flow when the debt is paid, and they do not necessarily get the principal returned at the end of the project lifetime.

## 2.4 The role of different types of RES-E investors

An understanding of different types of RES-E investors in Norway and Sweden is needed in order to study potential investments in new RES-E and investment behaviour in terms of risk. Policymakers should find it relevant because RES-E support schemes affect the investment behaviour of a heterogeneous group of investors differently.

Bergek et al (2013) have conducted a detailed empirical study on the heterogeneity of RES-E investors in Sweden in a categorization presented in Table 1:

| Name | Description |
|---|---|
| *Utility type* | State or privately owned utilities, privately owned energy companies and municipal energy companies, who owned the transmission and distribution networks for electricity, the local heating system and the majority of electricity production capacity prior to the liberalization of the electricity market in Sweden. |
| *Publicly owned non-energy companies* | Companies or organizations owned or controlled by national, regional or municipal governments, with another main area of business. |
| *Independent power producers (IPPs)* | Privately owned companies whose main area of business is electricity production. |
| *Farmers* | Privately owned companies, sloe traders or partnerships whose main area of business is agriculture (e.g. grains or animal keeping). |
| *Diversified companies* | Privately owned companies with other main area of business than energy production (e.g. Pulp and paper). |
| *Power project developers* | Privately owned companies whose main area of business is to plan, build and initially operate power plants for other owners. |
| *Sole traders* | Individuals or partnerships owning one or several power production plants; specialized on this or with other main area of activity. |
| *Associations* | Associations, e.g. economic associations and churches that own one or several power plants. |

**Table 1: Categories of RES-E investors (Bergek, Mignon, & Sundberg, 2013)**

The main finding of the study is that investors with non-traditional background in electricity generation are responsible for an increasing share of RES-E investments in Sweden. Utility type investors have decreased their overall share of total investment in RES-E capacity, although they remain the dominant investor type in biomass and hydropower projects. Independent power producers increasingly dominate wind energy projects, although wind power investors are a diverse group. Adjusting for the project size in terms of installed capacity, the study shows that different investor types are involved in different sized projects. Wind projects were on average 2 MW for utility type investors, 2.6 MW for project developers and considerably lower with 825 kW for farmers. The study concludes that RES-E investors are a heterogeneous group with different market experience, risk profiles, access to information, motives and access to finance and alternative investments (Bergek, Mignon, & Sundberg, 2013).

In a recent study, Linnerud et al. (2014) followed potential investors with licences to construct small run-of-the-river hydropower plants, aiming to examine whether the prospect of the common Swedish-Norwegian electricity certificate market affected their investment timing. Local landowners generally control the resource, and can choose whether to manage the resource themselves, or have a professional party to manage the resource. In the study, the projects are categorized into two models for ownership and operation under the labels 'non-professional investor' and 'professional investor' depending on project characteristics (e.g. profitability, risk and size) and/or characteristics of the group of local landowners (e.g. risk preference and access to funding). Among their results, traditional utilities and other professional investors in the energy market practiced a real options approach, implying that the expectation of future subsidies delayed their investment decision. Farmers and other non-professional investors, on the other hand, treated the investment decision more in line with a simple NPV approach, consequently ignoring the opportunity to create additional value by incorporate timing considerations in their investment decisions. Moreover, they found that non-professional investors are generally involved in smaller hydropower projects than professional utility type investors (Linnerud, Fleten, & Andersson, 2014). To our knowledge, no similar study on the investment behaviour of potential investors in Norwegian onshore wind power projects is conducted. However, the results may be relevant for wind power investments since such investments are also available for both small, private investors and large utilities.

## 2.5 Investor types in Norwegian wind power projects

We review the ownership structures Norwegian wind power projects that have the potential to be included in the Swedish-Norwegian electricity certificate system. We rely on the classification framework of Bergek et al. (2013), presented in Table 1. Although the selection is insufficient for generalisation, we believe that it is worthwhile in order to understand what types of investors are currently involved in Norwegian wind power projects. Since the review is static, it will not capture possible dynamics of ownership changes over the project lifetime.

First, we consider the wind parks in Norway that are currently recipients of electricity certificates. Raggovidda wind farm and Midtfjellet wind park[4] are considered the only commercially sized wind parks in Norway that has been developed on the basis of the common electricity certificate system. In addition, two smaller wind power plants are recipients of electricity certificates, of which Valsneset is a single prototype wind turbine. Table 2 provides an overview of the investor type owner categories:

| **Wind power project** | **Installed capacity** | **Owner** | **Shareholders** | **Ownership category** |
|---|---|---|---|---|
| *Midtfjellet* | *57.5 MW* | *Midtfjellet Vindkraft AS* | *Fitjar Kraftlag SA, Østfold Energi Vind AS, Vardar Boreas AS, EB Kraftproduksjon AS* | *Utility types (municipal energy companies)* |
| *Raggovidda* | *45 MW* | *Varanger KraftVind AS* | *Varanger Kraft AS* | *Utility types (municipal energy companies)* |
| *Valsneset* | *3 MW* | *Blaaster Valsneset AS* | *Blaaster Wind Technologies AS* | *Independent power producer (test facility)* |
| *Åsen II* | *1.6 MW* | *Solvind Åsen AS* | *Solvind Project AS, Solvind AS and private investors* | *Independent power producer* |

**Table 2: Norwegian wind power generators under the electricity certificate scheme.**

Since the thesis focus is on potential investments in wind power and other RES-E projects, we are interested in the investor types of the projects that are in the pipeline. The following review is limited to the 68 onshore wind power projects in Norway that currently have a licence from NVE, but have not yet reached an investment decision. What is important to note about these projects, is that the ownership stakes are not necessarily established since an investment decision is not reached. The ownership structures of some wind power projects can be somewhat complex. Many wind power projects are organized as project companies with the sole purpose of constructing and operating a wind farm. The project company can be owned by several energy companies, which in turn are cooperatives of private investors or have local municipalities or

[4] The total installed capacity of the Midtfjellet wind farm is 110 MW, while only the second stage of construction is eligible for electricity certificates, corresponding to 57.5 MW (23 turbines).

private investors as shareholders. Such projects are classified according to the parent companies' investor type.

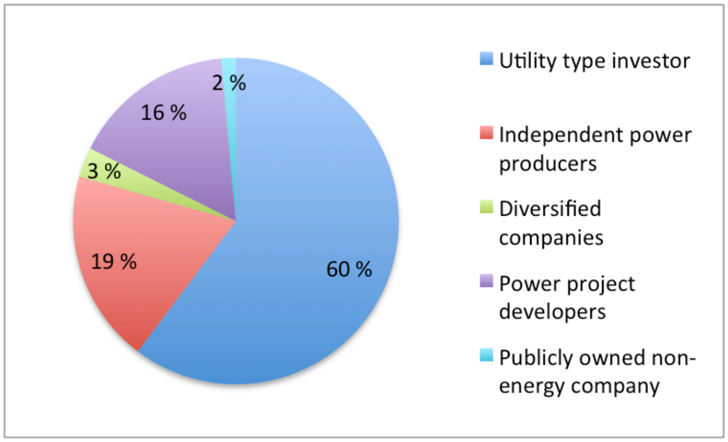


**Figure 3: Investor types in onshore wind power projects in Norway**

Figure 3 shows the investor types and their share of the 68 projects in the Norwegian onshore wind power pipeline, and the details are provided in Appendix A. Utility type investors are the larger contributor to the project pipeline in terms of the number of projects, followed by power project developers, independent power producers, diversified companies and publicly owned non-energy companies. The utility type investor group is defined broadly, including traditional utility type owners, municipal energy companies and professional, international energy companies (e.g. E.ON.) Moreover, we find that the wind power projects that we have classified as IPPs are typically involved in smaller projects in terms of installed capacity (MW), although a few large projects fall under this category. The utility type investors engage in projects with a wide range of different sizes and project developers are, on average, involved in the largest wind power projects. Diversified companies include two projects initiated by a grocery distributor in the wholesale industry (ASKO) whose motivation for investing in wind power is to minimize its carbon footprint. The publicly owned non-energy company category comprises one wind power project, initiated by Statskog whose main area of business is to manage state property.

From the empirical studies of Linnerud et al. (2014) and Bergek et al. (2013), as well as our own review of Norwegian potential wind power projects, it is clear that RES-E investors should be treated as a heterogeneous group and that they may have.

## 2.6 Financing renewable energy projects

Debt financing may be provided either through public markets (bonds) or private markets, through bank loans and institutional debt (Pickle & Wiser, 1998). Banks have to consider the total level of risk in their loan portfolio and by financing RES-E projects, banks expose themselves to risks of credit loss, market price volatility, technical and operational failures and regulatory changes affecting the project. Identifying, managing and mitigating such risk is a fundamental role of a financing institution. RES-E investments in Norway and Sweden are usually financed through non-recourse project finance, on-balance sheet corporate financing or bonds.

Project financing is a means of financing a project, such as a wind farm, that is separated from the investing company by establishing a single purpose entity where several investors can partake. Project financing is generally non-recourse, meaning that the financier will take security solely in the future cash flows generated during the operation of the entity rather than its sponsors' balance sheets. If the project company should default, the risk and hence the effect on the parent company's creditworthiness is limited since lenders do not have recourse in the parent company. With uncertain protracted cash flows, project financing often turns out to be expensive because extensive due diligence[5] is necessary. Banks will require that a number of measures be taken to reduce their exposure to project risks, such as contractual relationships between various parties involved in the project. The fundamental principle of project finance is that the various risk factors related to the project is be allocated to the party that is best suited to handle and control it. Technical risk is generally managed through contracts and insurances, such as

[5] Due diligence is an investigation or audit of potential investment.

procurement and construction contracts to remove risk associated with the project development and construction phase. With uncertain or unspecified revenue streams, banks are likely to require that financial instruments be used to secure stable cash flows, such as long-term power purchase agreement (PPA). Some downsides to project financing may be large transaction costs, higher debt costs and extensive loan covenants (Pickle & Wiser, 1998).

Corporate financing refers to investments that are financed across the balance sheet[6] of the project developer, and lenders therefore consider the entire balance sheet for assurance that the firm is able to repay its debt. If the company has a high credit rating, the bank is generally willing to lend more capital at more attractive interest rates. However, higher debt implies higher payables and lenders will therefore restrict the issuing of company debt beyond certain limits (Pickle & Wiser, 1998). Banks are exposed to regulatory and legal liquidity requirements that may affect their appetite for financing RES-E investments. An example is the Basel accords, which requires that banks set aside adequate capital for financial and operational risk in their loan portfolio. Since banks face stricter capital and liquidity requirements, available capital for bank financing of renewable energy projects is likely to be restricted. This may make financing more expensive for capital-intensive RES-E technologies that generally rely on long-term financing. Due to stricter regulations that favour large players with strong balance sheet, traditional bank financing can prove challenging for high capital cost projects (Narbel, 2013).

The bonds market is becoming an increasingly important source of funding RES-E projects, and in 2014, the debt issued as (corporate) bonds by Norwegian utilities amounted to approximately NOK 80 billion in bonds with maturity greater than one year, and NOK 10 billion in bonds with a shorter maturity (DNB, 2015). Bond investors face strict solvency rules, which imply that they

[6] Financing across the balance sheet means that the external capital (debt) is borrowed against the company's total assets.

can only buy bonds from companies with an approved credit rating[7]. In effect, the bonds market is primarily accessible to large players and not appropriate for funding a single wind power project in the development and early operating phase. A relatively new approach to financing RES-E is through the issuing of *Green Bonds*. Companies, organisations or public institutions can issue green bonds as long as the proceeds are directed at environmentally friendly, sustainable purposes. In accordance with International Green Bonds Principles, the best practice of labelling a bond “green” involves the approval from a neutral third party. In 2014, EUR 23 billion worth of green bonds were issued globally and EUR 1.625 billion was issued in the Nordic bond market, and the trend is growing, reflecting an increasing international interest in sustainable investments (DNB, 2015).

[7] In general, credit ratings are comprehensive evaluations of companies’ ability to repay debt, based on its solvency, industry risk, cash flow uncertainty and debt to equity ratio.

# 3 Costs

In this section, we first consider which type of costs is relevant for different decisions, in particular the investment decision and short-term operational decisions. We present the Levelized Cost of Energy (LCOE) model, which is regarded as an appropriate measure of Long Run Marginal Cost (LRMC). Through a case study of onshore wind power projects in Norway, we estimate the LCOE and discuss the sensitivity of the overall energy cost with respect to the different parameters. Lastly, we address the technology risk related to potential changes in the LCOE parameters over time due to technological progress and industry learning.

## 3.1 Relevant costs in the long run and short run

In the long run, both the composition of and total installed generation capacity can be altered by investments or dismantling. Investment decisions are based on a Long Run Marginal Cost (LRMC) evaluation, which includes an average per unit repayment of fixed costs, Short Run Marginal Costs (SRMC) and average per unit risk premium (Lemming, 2003). The risk premium is included in the cost of capital. The investment costs for RES-E generation capacity include the costs related to the technology (e.g. wind turbines), land rent, grid connection, equipment, licencing and work related to installation and infrastructure, which in total contribute to high average fixed costs per unit (Cerdá & del Río, 2014). Investments are generally considered irreversible, and once the plant is built the investment cost become a sunk cost that is irrelevant for short run decisions. Short run operational decisions are based on the SRMC relative to market price. SRMC can be defined as the change in short run total cost for an incremental change in output and is directly connected to the operation of the plant. The SRMC encompass variable cost of production and in the case of wind power these are the operation and maintenance costs (O&M), although fuel cost and opportunity costs are relevant for other technologies.

## 3.2 LCOE model and assumptions

The LCOE model is regarded as a good measure of Long Run Marginal Cost (LRMC). It can be used to compare electricity-producing technologies on a unit cost basis, or rather the average cost of generating one MWh of electricity during one year of operation. The LCOE consists of three separate cost components; a capital investment cost, a series of annualized fixed and variable operation and maintenance costs (O&M) and fuel costs. The cost components are discounted over the power plant lifetime, with a net present value formula that allows for adjustment of increases in O&M and fuel cost. The levelized cost of electricity of a power plant can be calculated by (Narbel, Lien, & Hansen, 2014):

$$C_{LCOE} = \left[\frac{R \cdot c_p}{H \cdot f}\right] + \left[l \cdot \left(\frac{c_o}{H \cdot f}\right)\right] + \left[l \cdot \left(\frac{c_f}{H \cdot f}\right)\right]$$

$$R = \frac{r \cdot (1+r)^T}{(1+r)^T - 1}$$

$$l = \frac{r \cdot (1+r)^T}{(1+r)^T - 1} \cdot \frac{(1+e)}{(r-e)}\left[1 - \left(\frac{1+e}{1+r}\right)^T\right]$$

The capital investment cost ($c_p$) is given as a monetary unit by unit of installed capacity (e.g. NOK/MW). In order to account for the economic plant life and the time value of money, the capital recovery factor ($R$) is included. The capital recovery factor is the share of the capital cost that the revenue from one year of operation needs to cover in order for the project to balance out at the end of the plant life and depends on the discount rate ($r$) and the plant life ($T$).

The capacity factor ($f$) is needed to convert the investment cost into an energy unit cost basis (e.g. NOK/MWh). The capacity factor expresses the power produced over a period of time as a percentage of the theoretical production, as if the plant was running at full capacity over the period considered. The typical time period considered is a year ($H = 8{,}760\ hours$).

The second cost component represents fixed and variable O&M costs ($c_o$) given as a monetary unit by unit of installed capacity (e.g. NOK/MW), and includes both H and capacity factor ($f$) in order to present the cost on an energy unit cost base. The levelization factor ($l$) depends on the discount rate ($r$), plant life ($T$) and escalation rate ($e$). The escalation rate is the rate at which O&M costs are assumed to grow from year to year, for example due to the need for more frequent maintenance and a higher risk of major failures as the plant ages. In a similar approach, the fuel cost component ($c_f$) can be transformed into a unit cost basis.

## 3.3 LCOE limitations

In reality, a number of other costs than those included in the LCOE model can potentially affect profitability, both directly and indirectly. The relevance of such costs could depend on whether profitability is considered in a societal or an investor perspective. A policy maker could be interested in including environmental externalities of electricity generation, such as $CO_2$ emissions, noise or environmental destruction.

The LCOE method is static and does not account for specific market risk or technology risk, and will not reflect yearly fluctuations in the cost flows. Moreover, the LCOE model ignores costs arising in the power system due to the inclusion of new generation capacity. In particular, the intermittent production profile of wind power can lead to excessive stress on the power grid and increase the need for grid extensions or strengthening. Some of these costs are to a certain extent reflected in power market mechanisms and producers' balancing obligation, yet the socioeconomic costs may be substantially higher.

The LCOE model can be expanded or adapted for different purposes, for example including applicable tax benefits or other specific financial incentive instruments. Such modifications may increase the model relevance to private investors, however, as a basis for decision-making, it should be combined with other and more detailed analyses that take greater account of risk and uncertainty. Although the LCOE calculations will not provide sufficient information about market risk and uncertainty, we consider it an adequate tool for the assessment of the potential of projects in the RES-E pipeline to be realized.

## 3.4 LCOE calculations onshore wind

We provide LCOE calculations for the Norwegian onshore wind power plants that are currently in operation and receive electricity certificates for their production and explain the different components of the LCOE in relation to wind power projects. We provide LCOE estimates for wind power projects in the pipeline that have received a license from NVE and define a reference wind power project based on their average parameter values, that we use to describe the LCOE sensitivity to changes in the input variables.

We first consider the three commercial wind power plants in Norway that receive electricity certificates, which excludes *Valsneset testpark* constituting a single prototype 3.0 MW wind turbine that is a constructed with the purpose of testing, certifying and demonstrating a new technology innovation. Total investment and O&M costs are therefore not known, but could be expected to be considerably higher than in the case of a commercial wind turbine. The reason for looking into the costs of these wind power plants is that they based their investment decision on the current support scheme for RES-E, which involve fundamentally different economic conditions for investments than wind power plants that came in operation prior to 2012[8]. The data we use for the LCOE calculations are based on extended background reports from the NVE licencing process, communication with the project owners and the authors' own assumptions. We discuss each of the LCOE parameters in relation to wind power projects and present the calculations.

The total capital investment cost comprises various cost components, and Figure 4 illustrates their typical shares of the total investment cost:

[8] Wind power projects installed prior to 2012 in Norway received direct governmental funding through ENOVA.

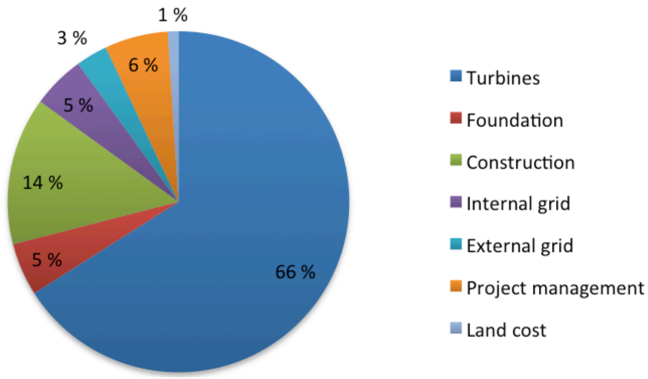


**Figure 4: Investment cost components (NVE d, 2015)**

Total plant costs may vary considerably across projects due to site-specific factors such as grid connection and construction costs, which may be larger in areas that are isolated or in rough terrain. Some sites require adaptations such as de-icing systems for turbine blades. Turbine prices constitute the largest share of total capital expenditure, and often include shipping and installation costs.

Compared to other power generating technologies, the operation and maintenance costs for wind power are low. The wind is provided without cost and in the absence of extreme weather or other unforeseen events, the need for maintenance is low. O&M costs include costs of labour, insurance, overhead, spare parts, land rent and balancing costs[9] (NVE d, 2015). In order to account for likely increases in O&M cost over time, we assume an escalation rate of 1 per cent.

The economic plant life of an onshore wind park is determined mainly by the technical lifetime of the wind turbine itself. Normally, the certified lifetime of an onshore wind turbine is set to 20 years, which in turn decides the economic plant life of the wind farm. The actual economic plant life may vary across projects due to different turbine technologies and weather conditions.

[9] Balancing costs refer to costs occurring from the difference between planned (notified) and actual delivery of electricity volume.

We describe the capacity factor of a wind farm by defining the concept of full load hours:

$$Full\ load\ hours\ (h) = \frac{Actual\ electricity\ production\ (MWh)}{Installed\ capacity\ (MW)}$$

Full load hours is a measure of the annual electricity generation of a wind farm, represented by the theoretical number of hours $(h)$ that the wind power plant must operate at full power to achieve the same annual production. The capacity factor is then the number of full load hours $(h)$ divided by the number of hours corresponding to a year of operation $(H = 8760)$, expressed as a percentage. The concept of full load hours is a theoretical simplification of real production patterns. In reality, turbines will generate electricity at different wind speeds from around 3-4 m/s, reaching full capacity at wind speeds around 11-13 m/s. Although the wind speed and wind patterns on the site is the main variable deciding the actual electricity output of a wind turbine, the actual production is influenced by additional factors such as the availability of the turbines and any production losses from external influences (Narbel, Lien, & Hansen, 2014). In 2014, average full load hours for Norwegian wind power plants in normal operation were 2,701 hours, corresponding to a capacity factor of approximately 31%. However, there were large geographical variations, and newer plants generally had higher capacity factors (NVE a, 2015). In our LCOE calculations for the wind power plants that receive electricity certificates (EC), we base the full load hour estimates on the expected annual production (MWh) assumed by the project owners. The assumptions and results are presented in Table 3 below:

| **Name** | **In operation** | **Installed capacity (MW) eligible for EC** | **Expected generation (MWh) eligible for EC** | **Full load hours (h)** | **Capacity factor (f)** |
|---|---|---|---|---|---|
| *Midtfjellet* | *December 1, 2013* | *57.5* | *181,386* | *3,154* | *36.0 %* |
| *Raggovidda* | *September 25, 2014* | *45.0* | *189,000* | *4,200* | *47.9 %* |
| *Åsen II* | *March 4, 2012* | *1.6* | *4,200* | *2,625* | *29.9 %* |

**Table 3: Capacity factor assumptions**

We notice that the expected output in relation to installed capacity, and thus the capacity factors vary considerably across the projects, and we recognize that the actual electricity generation over the plant life are likely to deviate from the expectations of the project owners, in particular due to the relatively short period of time that the plants have been in operation. In 2014, Midtfjellet wind farm had an actual electricity production corresponding to 2,884 full load hours, while Åsen II generated electricity corresponding to 2,500 full load hours in 2013 and 2,906 in 2014 (NVE a, 2015). The Raggovidda wind farm stands out with high a capacity factor expectation. The wind farm has only been in operation since September 2014, and had a record capacity factor in its first months of operation[10].

The LCOE calculations are based on a discount rate of 7.7 per cent, which is suggested by Johnsen and Gjølberg (2009) as an appropriate cost of capital for renewable energy projects. In reality, the discount rate varies according to project specific parameters such as technology, ownership, financing and perceived risk. Table 4 summarizes the LCOE assumptions and results:

| Name | Discount rate r | Plant life T (years) | Escalation rate e | Capital cost (NOK/MW) | O&M costs (NOK/kWh) | Capacity factor (f) | LCOE (NOK/MWh) |
|---|---|---|---|---|---|---|---|
| *Midtfjellet* | *7.7 %* | *20* | *1 %* | *11,100* | *0.060* | *36.0 %* | *415.6* |
| *Raggovidda* | *7.7 %* | *20* | *1 %* | *13,800* | *0.125* | *47.9 %* | *462.9* |
| *Åsen II* | *7.7 %* | *20* | *1 %* | *10,000* | *0.100* | *29.9 %* | *487.9* |

**Table 4: LCOE of onshore wind power plants eligible for electricity certificates in Norway**

The calculated LCOE of the onshore wind farms in Norway that currently receive electricity certificates for their production is in the range of 415.6-487.9 NOK/MWh. There are large uncertainties connected to these LCOE values since we do not have information on the actual costs of developing or operating the wind parks nor their project-specific cost of capital.

[10] In the period from October 1, 2014 to February 26, 2015, Raggovidda wind farm generated 112 MWh, corresponding to a capacity factor of 58.8%. The high capacity factor is attributed to a well-suited site for wind farm location due to high average wind speeds, low losses due to storms and a turbine technology well suited for the site.

We are interested in studying the energy cost of the Norwegian wind power projects in the pipeline in order to evaluate their potential to come online under the Swedish-Norwegian electricity certificate system. This implies that they need to be fully operational by the end of 2020, and since it takes years to build a wind power plant we only included wind power projects that have been granted a license from NVE in our assessment[11]. In order to be granted a licence, the project must be deemed economically viable by NVE. The background reports that provide the basis for a positive licence ruling is made publicly available by NVE (NVE e, 2015). In the background reports, we find data on the project's capital investment costs, O&M costs and the expected number of full load hours. For some of the projects, the report includes several alternatives for technology, installed capacity and number of turbines, with correspondingly different assessments of costs and full load hours. In such cases, we use the average costs and full load hours in the different alternatives. Of the 70 projects that have been granted a licence from NVE (status April 21, 2015), we have excluded projects that were granted a licence earlier than 2010 and projects that are smaller than 30 MW of installed capacity because small plants have a small potential to contribute to the quantitative target and several of them are test turbines with less representative costs, while plants with a licence older than 5 years are less likely to be realized and may have out-of-date cost evaluations.

The NVE background reports suggest capital investment costs varying between 8.3 and 13.4 million NOK/MW, O&M costs in the range of 0.10 and 0.17 NOK/kWh and the expected number of full load hours for the projects varies between 2,600 and 3,700. In Appendix B, the projects are presented together with their corresponding data on costs and full load hours as well as parameter assumptions on plant life, escalation rate and discount rate. The calculated LCOE varies from the least expensive project with an LCOE of 438 NOK/MWh to 617 NOK/MWh.

[11] From Figure 1, the projects with the status "Licence granted by NVE", "Appeal on granted licence received by NVE", "Appeal sent to OED" and "Final licence approved by OED" are included because these projects have all received a licence from NVE.

Due to the considerable variations and uncertainty in the LCOE parameters included in the calculations, we conduct a sensitivity analysis. A LCOE value for a *reference project* is calculated by using the average capital cost, O&M costs and capacity factor of the RES-E projects in the pipeline as input parameters. The LCOE parameters for the reference project is summarized in Table 5[12]:

| | Discount rate (r) | Plant life T (years) | Escalation rate | Capital cost (NOK/MW) | O&M costs (NOK/kWh) | Capacity factor (f) | LCOE (NOK/MWh) |
|---|---|---|---|---|---|---|---|
| *Reference project* | *7.7 %* | *20* | *1 %* | *11,715* | *0.135* | *34 %* | *538.7* |

**Table 5: LCOE of reference wind power project**

The reference project is not intended to provide a comprehensive profitability assessment of wind power projects in Norway. Rather, we use the reference project LCOE to conduct a sensitivity analysis, demonstrating how varying each of the input parameters by a given percentage (+/- 40%) gives rise to an absolute change in the output, i.e. the reference project LCOE. Since the parameters are changed one at the time, the sensitivity analysis does not capture possible interactions between the parameters. Nevertheless, the sensitivity analysis provides valuable information on which input parameters that has a particularly large effect on the overall LCOE of a wind power project.

[12] A complete table of input parameters and LCOE assumptions is provided in Appendix B.

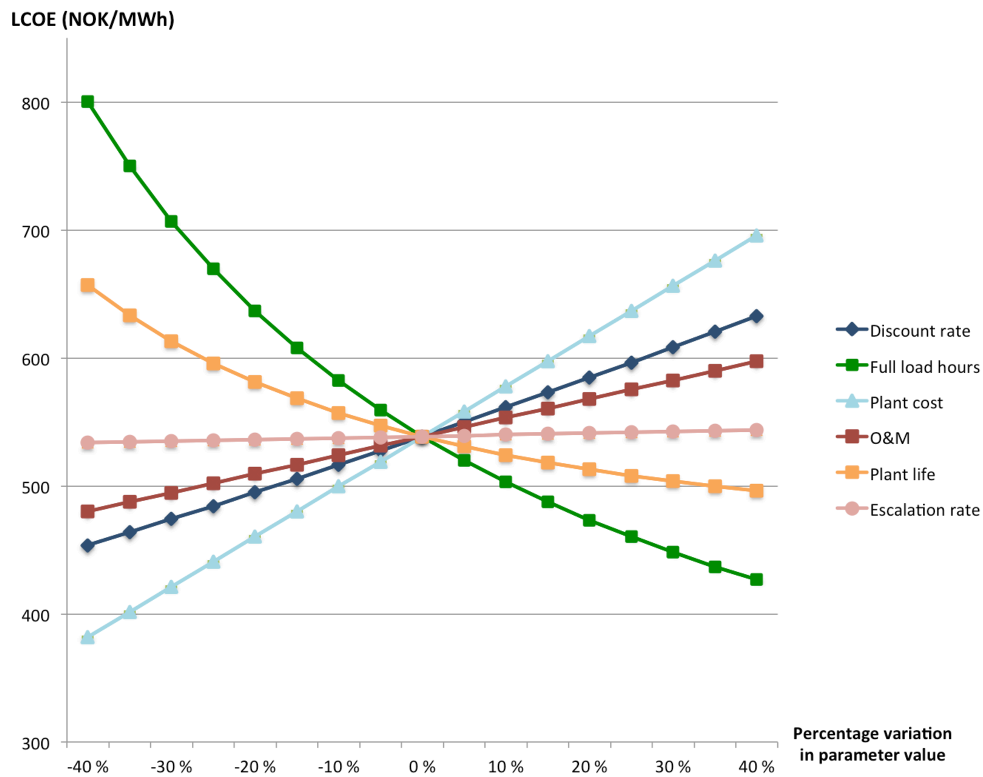


**Figure 5: Sensitivity analysis**

The sensitivity analysis (Figure 5) shows that the reference project's LCOE vary significantly in absolute value with variations in the number of full load hours and the plant investment cost. The parameter values of plant life and discount rate are also very decisive for the LCOE value. The LCOE variation with respect to full load hours stresses the importance of efficient turbines and suitable wind resource sites. The LCOE sensitivity to plant investment cost, discount rate and plant life reflect the capital-intensiveness of wind power plants. Conversely, the LCOE is not very sensitive to changes in O&M costs or the escalation rate assumed for these costs.

## 3.5 Technology risk

Over time, the long-run marginal cost of power generating technologies has the potential to change due to cost reducing technological innovations, standardisation and economies of scale.

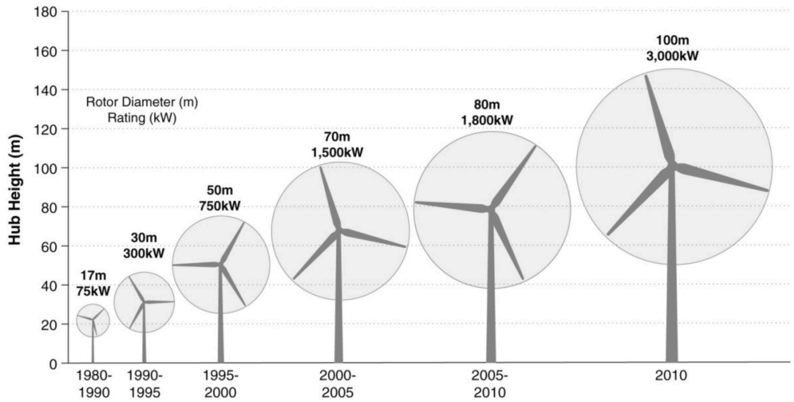


**Figure 6: Development in representative turbine architecture (IEA Wind, 2012)**

Figure 6 depicts the development in hub height, rotor diameter and capacity of representative wind turbines over the past decades. In order to improve turbine performance, manufacturers could for example construct taller towers that would allow potential of stronger and less turbulent winds to be exploited. However, increasing turbine size does not necessarily improve its ability to extract energy from a given amount of available energy, which would depend on technological innovations in turbine design that improve the efficiency of wind turbines (IEA Wind, 2012). Norway follows a global trend in wind turbine development and can therefore be considered a price taker in the market for wind turbines. In addition to global demand for wind turbines, the price on input factors into turbine production such as steel, copper, aluminium influence turbine prices.

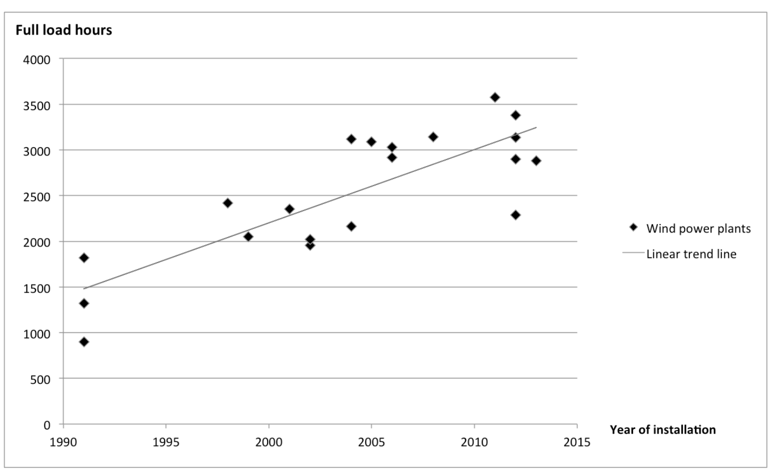


**Figure 7: Number of full load hours in 2014, by year of installation (NVE a, 2015)**

Figure 7 shows the actual number of full load hours[13] of onshore wind power plants located in Norway in 2014, by year of installation (1991 to 2015). We rely on power production data for Norwegian wind power producers that were in normal operation in 2014 (NVE a, 2015). From graphical inspection, we observe that older wind power plants had a significantly lower number of full load hours than more recently installed plants. The positive trend is partly attributed to technological advancement and industry learning. Furthermore, the number of full load hours largely depends on geographical wind conditions, efficient operation and the chosen technology's suitability to the site's wind resources. The sensitivity analysis (Figure 5) demonstrated that the number of full load hour is an important determinant for the LCOE for wind power projects, thus a positive development in the number of full load hours has the potential to reduce future energy costs. When we considered the expected full load hours of wind power projects in the Norwegian RES-E project pipeline that have a licence from NVE, we found expected full load hours of these plants to be on average in the range of 2,600 to 3,700, which implies that potential new wind power plants are expected to have a similar or higher number of full load hours relative to wind parks in operation today.

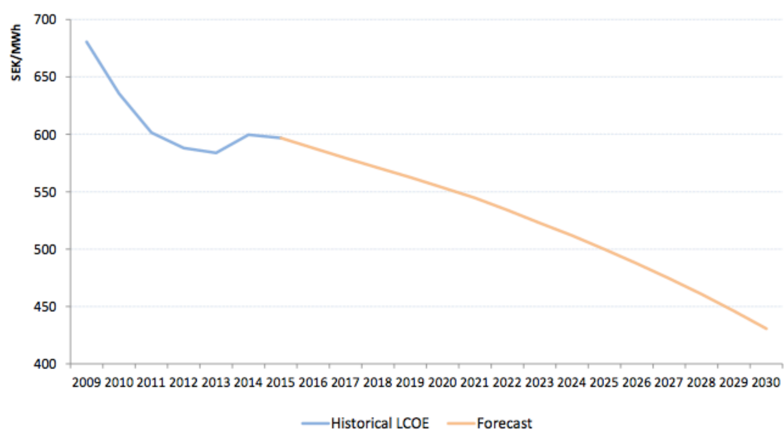


**Figure 8: Expected development in LCOE of wind power (Bergen Energi, 2015)**

[13] Calculated as the actual power production in 2014 divided by installed capacity. 3 wind power plants are excluded because they were not under normal operation throughout the year (Hundhammerfjellet, Raggovidda, Valsneset testsenter).

Figure 8 illustrates the expected development in LCOE of wind power projects globally. The expected decrease in overall generation costs should be attributed to decreasing turbine prices, higher capacity factors, more efficient wind turbines and industry learning. Expected decreasing costs in the wind power industry deriving from technological development and learning implies that there is a technology risk present to investors. Once an investment decision is made, the technology is in effect chosen. The technology risk translates into an opportunity cost to the investor since, once the investment decision is taken, he can no longer benefit from further cost-reducing technological development. Agnolucci (2007) argues that new plants should demand a risk premium proportional to technological change, and the faster the trend, the higher the risk premium investors of new plants should demand. Technology risk should therefore be considered in the investment decision process, potentially influencing the timing of the investment.

In the following, we consider the revenue side for RES-E projects. RES-E investors included in the Swedish-Norwegian electricity certificate market are subject to two revenue flows; one from the sale of power and one from the sale of electricity certificates. First, we provide an overview of the Nordic power market, with a particular focus on the price formation and the price and financial risks in a liberalized electricity market. Next, the market mechanism and design of the common Swedish-Norwegian electricity certificate system is described analytically as a basis for evaluating the risks to potential RES-E investors.

# 4 The Nordic electricity market

The Nordic electricity market was originally regarded as a natural monopoly, and state regulators were concerned with balancing the need for security of supply, economic efficiency and environmental protection. The deregulation of the Nordic power market in the early 1990s rendered the system requirements unchanged, although they are now to be provided by the market mechanism. The liberalization process was gradual, and changes and improvements are continuously implemented to improve market integration and harmonization. The deregulation came as a response to the accumulated overcapacity and the goal was to increase the efficiency of capacity, improve cost efficiency of supply and introduce consumer choice.

The properties of electricity affect supply and demand in a complex way, and is therefore worthwhile reviewing in order to understand how deregulation has introduced market uncertainty. Electricity is a flow commodity that cannot be stored[14] and must therefore be consumed simultaneously as it is produced. Mismatches in electricity demand and generation must be covered instantly, resulting in short-term price spikes or troughs and periods of high volatility. Failing to balance supply and demand results in voltage and frequency fluctuations, which may damage equipment connected to the grid and compromise reliable supply of high quality electricity (i.e. correct voltage and frequency). Furthermore, transmission is restricted by Kirchhoff's law, making the grid into a shared pool of electricity with multiple entry and exit points. This implies that electrons cannot be traced from producer to consumer, making the consumers inseparable.

The Nordic electricity market is comprised of a financial wholesale market, a physical wholesale markets, a retail market and ancillary markets (real time). There is no market for electricity generation capacity, meaning that the price signal from the wholesale electricity market guides

[14] A large-scale technology that allows for practical and economical electricity storage does not exist to date, although potential energy can be stored in hydro reservoirs.

consumer and producer behaviour and investment decisions. Figure 9 illustrates when the different markets are relevant:

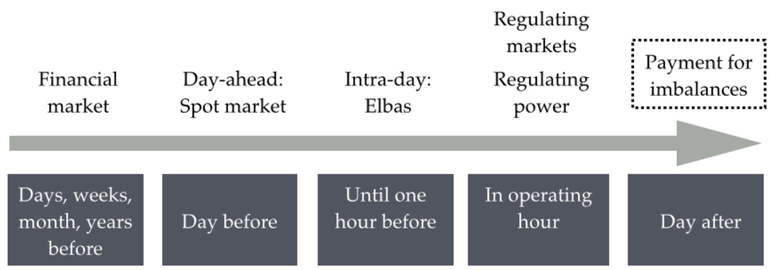


**Figure 9: Sub-markets in the Nordic power market**

## 4.1 The financial market

The deregulation of the Nordic electricity market restructured the financial risks to the sector stakeholders. By holding decision makers financially rather than politically responsible, the entire supply chain from consumers, suppliers, generators, investors and financiers now have to incorporate financial risk factors into their decisions. Stakeholders should find it beneficial to use financial contracts for managing the price and volume risk associated with the physical electricity market prices. There is no physical settlement of financial contracts, although the financial market is closely connected to the wholesale power market. Stakeholders can hedge financial risk on a long-term basis through bilateral agreements, brokers or clearinghouses. Financial contracts are traded through the Nasdaq OMX Commodities exchange, which offers derivatives trade in Futures contracts, Deferred Settlement (DS) Future contracts, Options and Electricity Price Area Differentials (EPADs), using the Nordic system price as a reference. Contracts are currently traded up to six years in advance, covering quarterly, monthly, weekly and daily contracts. In 2014, the Nasdaq OMX had a turnover of 1,564 TWh in the Nordic market, approximately four times the physical turnover (Nasdaq OMX Group Inc., 2015). The Nordic electricity market is generally regarded as a transparent and efficient market with available mechanisms for the market participants to hedge their positions. Different market participants have different motives for trading in financial contracts. In order to obtain funding, investors may be required by financiers to secure the future cash flow through long-term contracts such as Power Purchase Agreements (PPAs) or futures. Generators may trade in financial contracts in order to hedge their physical production obligations and suppliers to secure prices for future purchases. The main element in the pricing of futures and forward contracts is thus the market participants' collective expectations of the future system prices.

## 4.2 The physical wholesale market

In the physical wholesale market, electricity trade is arranged at the Nord Pool Spot day-ahead market and the Elbas intraday-market. In both markets, contracts for physical delivery of power are made between buyers and sellers. At Nord Pool Spot, power is traded in much the same ways as other commodity exchanges. However, since electricity is a flow commodity, the electrical energy is sold in categories according to the time of power delivery. Participants trading on Nord Pool Spot include power producers, the industrial sector, suppliers, brokers and dealers. Nord Pool Spot is organized into several bidding areas[15] and on a daily basis, an auction is facilitated where buyers and sellers enter their bids and offers based on the energy they are willing to buy or sell at different price levels for each of the 24 hours in the coming day. The price steps chosen by the bidder must include the theoretical maximum and minimum price (EUR -500 and EUR 3000) and the bids can be single hour bids or block bids, which set an all or nothing condition for several consecutive hours. When the auction closes at 12 pm, the bids are aggregated into supply and demand curves for each of the next 12 to 36 hours for each of the bidding areas. Whenever there are transmission capacity constraints in the power grid, the market is divided into price areas to allow for prices that reflect supply and demand within each area. The interaction between supply and demand also determines a System price for each of the hours under the assumption that there are no bottlenecks in the transmission of power between regional bidding areas. An example of supply and demand curves and the corresponding system price is shown in Figure 10.

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[15] Currently, there are five bidding areas in Norway, two in Denmark, four in Sweden, while Finland, Latvia, Lithuania and Estonia each constitute one bidding area.

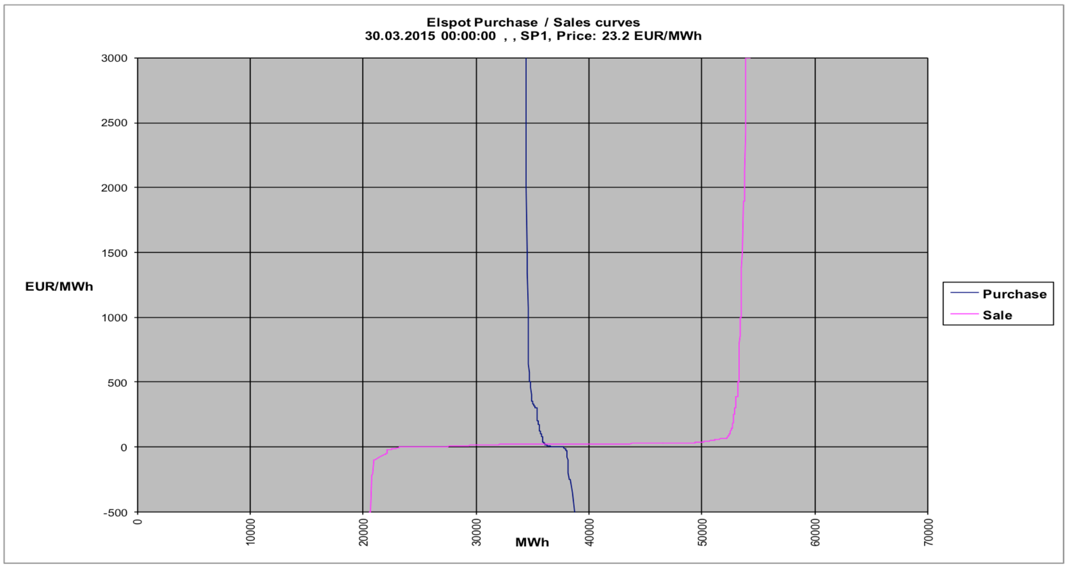


**Figure 10: Market cross determining the System price (Nord Pool Spot b, 2015)**

The Elbas intra-day market supplement the Elspot market in securing the necessary balance between supply and demand in the Nordic market. Here, sellers and buyers can trade electricity volumes close to real time and thus adjust for unforeseen imbalances due to for example operational failure of a nuclear plant. In 2014, the turnover at Nord Pool Elspot (day-ahead market) amounted to 361 TWh, while the total traded volumes on Elbas (intra-day market) was 4.9 TWh (Nord Pool Spot d, 2015)

Transportation of electricity and system operation is bundled in the Nordics and each country has a transmission system operator[16] (TSO) responsible for maintaining transmission grid stability and security of supply. Grids are regarded as natural monopolies, corresponding to national, regional and local grids of different voltages. Sub-transmission operators are responsible for regional grids and local grids are operated by Distribution System Operators (DSOs), which role is to deliver power to the end-user. Since grid operators are natural monopolies in their respective areas, they operate under close inspection and various control mechanisms to ensure

[16] Nordic TSOs are Fingrid in Finland, Svenska Kraftnät in Sweden, Energinet.dk in Denmark and Statnett in Norway.

this public service remains cost efficient (NordREG, 2014). The Nordic power market is becoming increasingly interlinked due to interconnectors, transmission connections and regulatory cooperation.

## 4.3 The Retail market

Electricity suppliers first buy power directly from a producer or at Nord Pool Spot, before reselling it to end-users. Electricity consumers choose their preferred supplier and type of power contract[17], resulting in competition between electricity suppliers within each country. Electricity price fluctuations are not necessarily reflected in the power price to consumers because, in the absence of real time metering, the price to consumers is not time differentiated, but rather based on averages. Moreover, the power price in the retail market differs from the wholesale electricity price by including grid payments, taxes and fees. Figure 11 shows the total electricity costs to end-users in Norway in 2013:

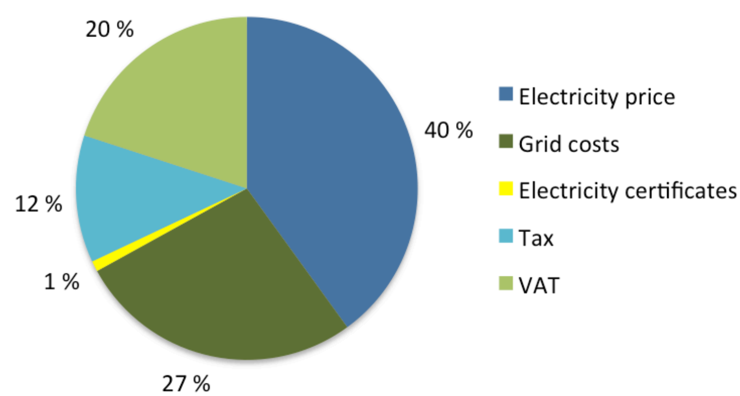


**Figure 11: Total electricity costs to end-consumers in Norway, 2013 (NordREG, 2014)**

[17] The majority of Norwegian electricity consumers have spot contracts with an add-on fee on top of the Day-ahead spot market price, although fixed-price contracts and standard variable contracts (a mix between fixed-price and spot contracts) are also offered in Norway (NordREG, 2014).

## 4.4 Electricity generation

The Nordic and Baltic region has an annual average electricity generation of around 420 TWh. Hydropower plays a dominant role in the Nordic power market, covering roughly half of the Nordic electricity consumption in years with normal precipitation and inflow. The Nordic countries have a diverse production mix. While hydropower accounts for nearly all electricity generation in Norway, Denmark use most thermal power although they have been switching to RES-E such as wind power and biofuels over the last decades. Sweden and Finland have a diverse mixture of different sources for electricity generation, including nuclear, hydro, thermal, biofuels and wind energy (Nord Pool Spot c, 2015).

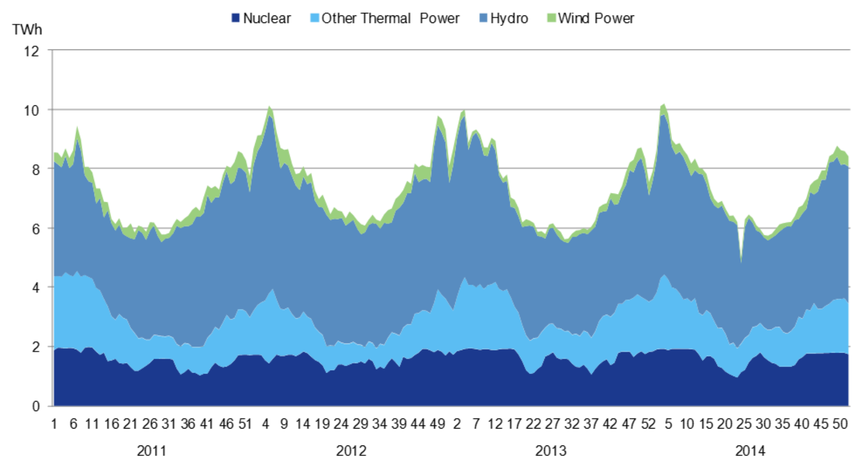


**Figure 12: Nordic electricity generation 2011-2014 by source (Nord Pool Spot c, 2015)**

Figure 12 depicts the electricity generation in the Nordic region over the last four years by energy source. The category other thermal power includes both renewable energy sources such as biofuels and waste and non-renewable sources such as coal and natural gas. Remembering that production needs to match power consumption at all times, the clear seasonal pattern over the course of a year is explained by the seasonal variations in consumption.

## 4.5 Price formation

At Nord Pool Spot, sellers and buyers of electric power place bids on the amounts of electricity they are willing to sell or buy at chosen price levels, and power prices for the following day are calculated based on these bids (Elspot). Power producers base their price bids on their short run marginal cost (SRMC), which is the relevant cost in the short run. The production cost varies across different producers and energy sources used for electricity production. The equilibrium price is set by the SRMC of the marginal producer needed to meet the electricity demand, who is generally a fuel intensive thermal technology with a high SRMC. Electricity generating technologies with lower fuel and operation costs are willing to dispatch their production at lower price levels. The supply side can be illustrated in a so-called merit order curve, which categorizes the typical available electricity generating technologies by their SRMC of electricity generation. We present an illustrative merit order curve for the Nordic power market in Figure 13, and explain the price formation in two different situations; one with normal demand and one with high demand and the corresponding prices $p_1$ and $p_2$.

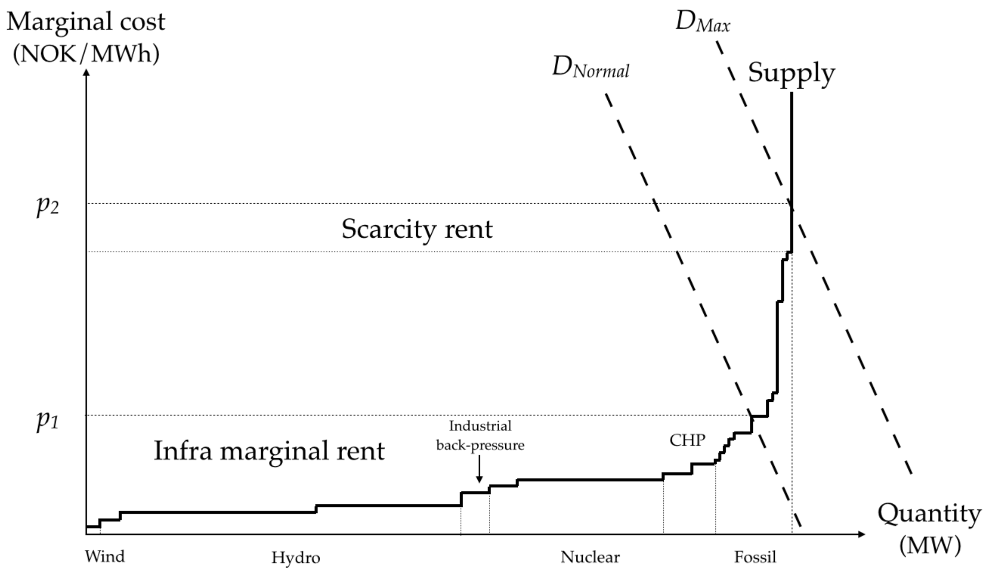


**Figure 13: Illustrative Nordic Merit order curve**

If we consider the situation with the normal demand, all generators receive the market price $p_1$ per unit of electricity sold. In the long run, the differences between the spot prices and their respective SRMCs, which is referred to as the infra marginal rent, should cover their average fixed cost. Situations can occur where demand is at maximum high and supply is insufficient to cover demand. The resulting supply constraint implies that the price ($p_2$) is set by demand since there simply is not sufficient capacity available. The price $p_2$ incorporates a scarcity rent, which is the differential between $(p_2)$ and the SRMC of the marginal producer. The scarcity rent is necessary in order to provide an incentive for capacity to be available in such occasions, and can be interpreted as a compensation for lying idle most days the year. The price $(p_2)$ is capped by the market regulator at EUR 3000 per MWh at Nord Pool Spot. Since all generators receive the scarcity rent, the regulators pay close attention to the price formation to ensure that exploitation of market power does not occur.

In the Nordics, power prices are highly correlated with weather conditions. Temperatures are important for electricity consumption, generally pushing prices up in the cold winter months in the Nordics. Typical daily demand variation has a peak in the morning and an extended peak in the afternoon, and the demand is higher during the day than at night due to the higher activity. The demand for electricity is highly price inelastic due to consumers' lack of exposure to real time pricing. On the supply side, electricity generation from different energy sources have different effects on the power price. The relatively large share of hydropower in the Nordics has a smoothing effect on prices due to its ability to store energy and dispatch electricity for demand response or for balancing purposes. Inflow during summer when demand is low can be stored for winter when the demand normally increases. Wind power is non-dispatchable and has a negligible short-run marginal cost, which implies that it will produce electricity when the wind is blowing. Nuclear power plants serve as a base load[18] in the Nordics and have a minor impact on prices despite its significant contribution to the total electricity generation, although unexpected failures to produce can result in price spikes. Combined heat and power (CHP) plants contribute to reduce the effect of demand fluctuations due to temperatures when their main product is heat, since increased heat production also increases power generation.

[18] Base load refers to electricity supply at the bottom of the merit order that covers the minimum level of demand in the system.

A fluctuating supply of electricity generation and an inelastic demand results in volatile spot prices. These price fluctuations have great impact on the various stakeholders in the market and generate a need for a marketplace where consumers, producers, suppliers, investors and traders can hedge or mitigate some of their financial risk.

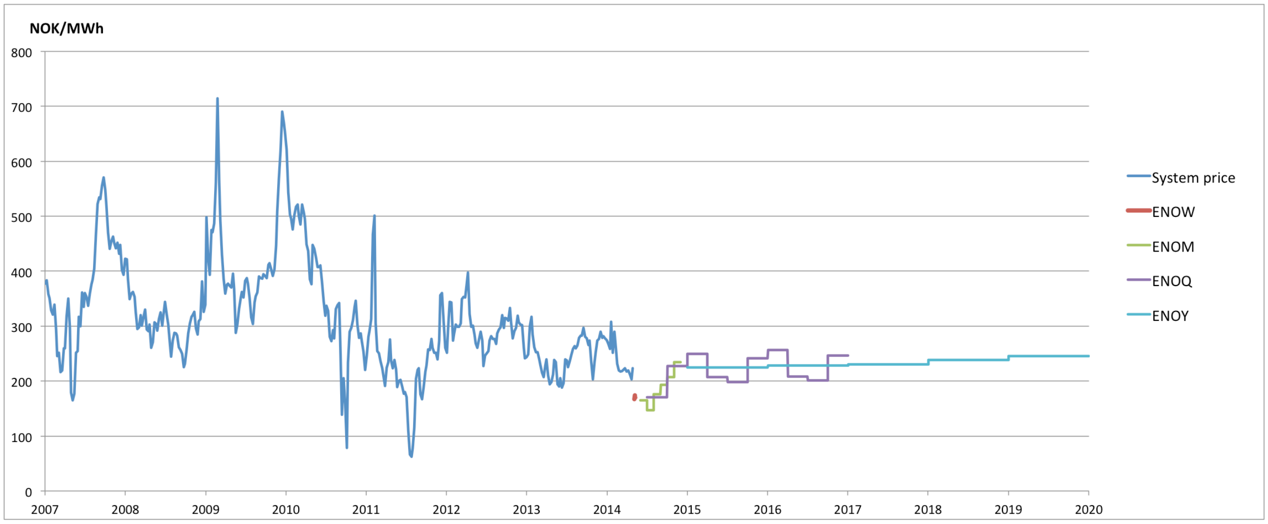


**Figure 14: Nordic power prices, status May 9, 2015 (Nord Pool Spot d, 2015) (Nasdaq OMX, 2015)**

Figure 14 shows the development in the weekly average system price (nominal) from 2008 to 2015 available from Nord Pool Spot (Nord Pool Spot a, 2015), weekly Futures (ENOW) and the monthly (ENOM), quarterly (ENOQ) and yearly (ENOY) DS Futures prices[19] traded on the Nasdaq OMX (Nasdaq OMX, 2015). The figure shows that large price peaks have not occurred since winter 2011 and the unstable power prices from 2007 to 2011 seem to be replaced by a neutral or even declining price trend the last four years. The quarterly DS futures prices (ENOQ) depicts expectations of seasonal price variations, while the yearly DS Future prices (ENOY) indicate that prices are expected to remain at a relatively low level over the next five years.

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[19] Nasdaq OMX contracts are only given in EUR/MWh and we have converted them into NOK/MWh using the current exchange rate 8.4 EUR/NOK (May 9, 2015).

## 4.6 Long-term Nordic power price drivers

The dynamics of the Nordic electricity market rely on the market participants' expectations about various factors that affect long-term power prices. Long-term power price forecasting must take into account that the generation mix could be altered. Ambitious targets to raise the share of RES-E capacity in the generation mix have led to the implementation of support schemes to encourage RES-E deployment that are not necessarily rooted in a market demand for new generation capacity. The basis for investments in new RES-E capacity in the Nordic power market is unlike that of most other European countries. While new RES-E capacity in the rest of Europe largely replace polluting coal- and gas-fired power plants, new RES-E generation capacity is generally added to the power mix in Norway and Sweden. Hence, investments in new RES-E capacity in the Nordics have a larger impact on the power balance in the long term. A potential Nordic power surplus would put a downward pressure on the Nordic power price. Moreover, the low SRMC of producing electricity of many RES-E technologies could alter the merit-order and thus affect the price formation. In Figure 15, we have added *more* wind generation capacity to the illustrative merit order curve in order to exemplify the merit-order effect of more wind generation capacity. In periods of high wind power generation, the supply curve is shifted out, size putting a downward pressure on wholesale power prices depending on the demand[20]. If the wind is blowing at peak power demand ($D_{day}$), generators at the steep part of the supply curve set the price and the wholesale power price could fall from $p_{day}$ to $p'_{day}$ with the additional wind generation. The impact on the power price of high wind power generation at night, when demand is lower ($D_{night}$), would typically be less dramatic ($p_{night}$ to $p'_{night}$).

[20] The size of the price drop depends on the price elasticity of demand.

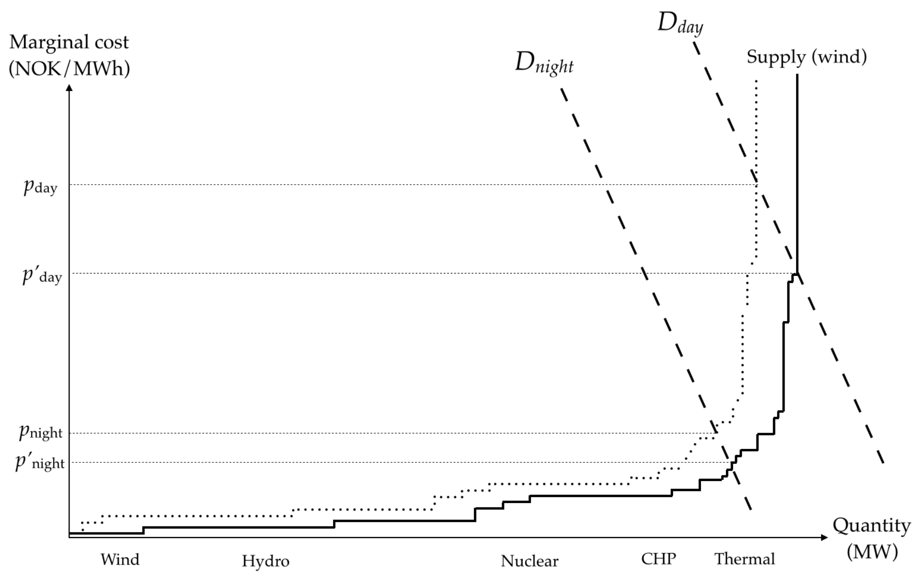


**Figure 15: Merit order effect of more wind power generation**

Furthermore, periods with high wind power generation may result in transmission congestion in some areas. It is generally not considered economical or environmental friendly to limit wind power production, and a resulting excess supply in the pricing area would lead to lower prices in the congested sub-market. Expectations regarding planned investments in transmission capacity and interconnector capacity to bordering markets are therefore important for future power prices.

The complexity of neighbouring fuel markets has a significant impact on the Nordic power price. A low price of $CO_2$ emissions[21] has made electricity generation from burning fossil fuels relatively cheaper. If the fuel and $CO_2$ prices are not expected to pick up, it will contribute to a continued downward pressure on the power price since coal generators are often the marginal producer in the Nordic power system. Furthermore, expectations regarding electricity consumption affect the power demand forecasting. Factors that are likely to affect the electricity consumption in the Nordics are targets for energy efficiency and increased flexibility on the

[21] In 2014, the average EU-ETS CO2 price was EUR 5 per ton CO2 (NordREG, 2014).

consumer side with the implementation of smart metering which exposes consumers to real-time prices (NordREG, 2014).

The Nordic electricity market is referred to as an energy-only market since the driver for investments in new generation capacity is the expected price of electric power sales. The ability of liberalized power markets to deliver investments in new capacity from various generation sources has been subject to studies (Owen, 2014), however the focus of this thesis is on investments in wind power production capacity and other RES-E technologies. An energy-only market is characterised by an increasing financial risk of not achieving full capital cost recovery, in particular for investors in generation technologies that exhibit high capital costs and low operating costs. (Owen, 2014). Grid parity for onshore wind power may be defined as the moment in time when wind turbines can generate electricity at an energy cost that is competitive to other technologies. Onshore wind power is expected to achieve lower costs in the future, and the concept of grid parity is thus relevant. When wind power reaches grid parity, it will be able to compete at the applicable wholesale prices, without subsidies. Grid parity of an emerging technology will not occur at a particular point in time, but rather differ between locations. We found that the LCOE of wind power projects in Norway that have a licence to build were in the range of 438-617 NOK/MWh. The current power price is approximately 240 NOK/MWh[22], which implies that wind power cannot be assumed to have reached grid parity in Norway. With an overview of the cost structure of onshore wind power and the price mechanism in the Nordic electricity market, we will now consider the market mechanisms in the Swedish-Norwegian tradable electricity certificate market.

[22] Average system price Elspot January – April 2015.

# 5 The Swedish-Norwegian electricity certificate market

A tradable electricity certificate market, also termed renewable portfolio standard or renewable obligations, is a market-based mechanism constructed with the purpose of stimulating investments in electricity generation from renewable energy sources without using direct governmental subsidies. With a political mandate to increase its renewables share, the Norwegian authorities decided to enter into a bilateral agreement with Sweden on the facilitation of a common electricity certificate market designed to incentivize private investments in *new* RES-E technologies.

The market consists of buyers and sellers of so-called electricity certificates that are traded on an open market, separate from the wholesale electricity market. Electricity certificates are granted to producers of new renewable electricity. Renewable electricity includes electricity production from small-scale hydro, geothermal, wave, solar and wind energy, as well as biomass. One electricity certificate is issued for each MWh of new renewable electricity delivered to the grid. Each month, the renewable electricity producer receives a number of electricity certificates corresponding to its actual electricity generation. By selling its electricity certificates, the RES-E generator is provided with a source of revenue in addition to the power price charged from the production. The prospect of additional revenues should incentivize investments in new renewable electricity generation capacity. Producers that are entitled to receive electricity certificates can only do so for a maximum of 15 years, and no longer than ultimo 2035. Buyers of electricity certificates are suppliers who, on behalf of electricity consumers, are obliged to purchase a given amount of certificates in order to fulfil an imposed quota. The quota is given as a percentage of their total consumption that needs to be covered by new renewable electricity through the purchase of electricity certificates.

The Swedish electricity certificate system came online May 1, 2003 with a quantitative mandate of adding 10 TWh of new renewable electricity generation to the power balance by 2010. The quantity mandate was later raised to 25 TWh by 2020. January 1, 2012 Norway and Sweden agreed to establish a common market for electricity certificates with a joint target of adding 26.4 TWh of new RES-E generation per year between 2012 and 2020. Each participating country shall finance half (13.2 TWh), regardless of where the new capacity is built. Figure 16 illustrates the expected contribution (in TWh) of new RES-E generation capacity that has entered the common electricity certificate market so far, including the direction towards 26.4 TWh by 2020.

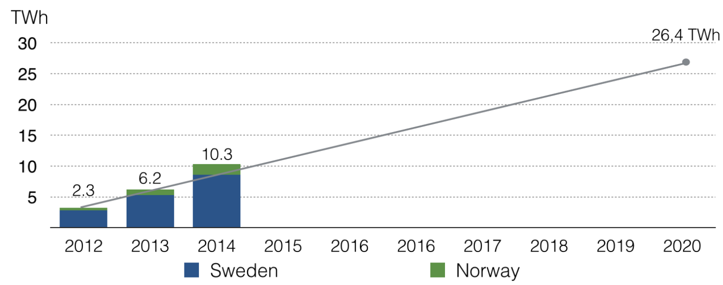


**Figure 16: Expected new RES-E generation capacity**

Figure 17 below shows which RES-E plants that have been built in each country after 2012, by source, given as the expected electricity production (in TWh) as of January 1, 2015.

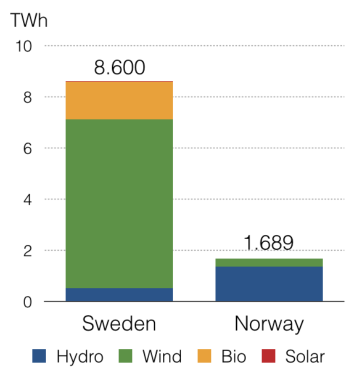


**Figure 17: Expected electricity generation from plants in operation per January 1, 2015 (NVE, Energimyndigheten, 2015)**

## 5.1 Support scheme design

The market price for electricity certificates is determined by the interaction between supply and demand. Figure 18 depicts the supply and demand in a tradable electricity certificate market. The marginal cost (MC) curve of renewables represent the supply in the market, and $P_E$ is the market price of electricity. If no quota obligation were imposed on the end-consumers, meaning that there would be no demand for additional RES-E generation capacity, only renewable electricity generation corresponding to A would be profitable at the electricity price level $P_E$. $Q_{Target}$ represents the politically determined objective of increasing renewable electricity generation. In order to supply electricity corresponding to the quantitative mandate $Q_{Target}$, renewable electricity producers would require higher revenue than that provided by the electricity price. The additional revenue required to introduce $Q_{Target}$ renewable electricity generation would be the difference between the MC of the marginal plant needed to reach the target (MC*) and the electricity price $P_E$.

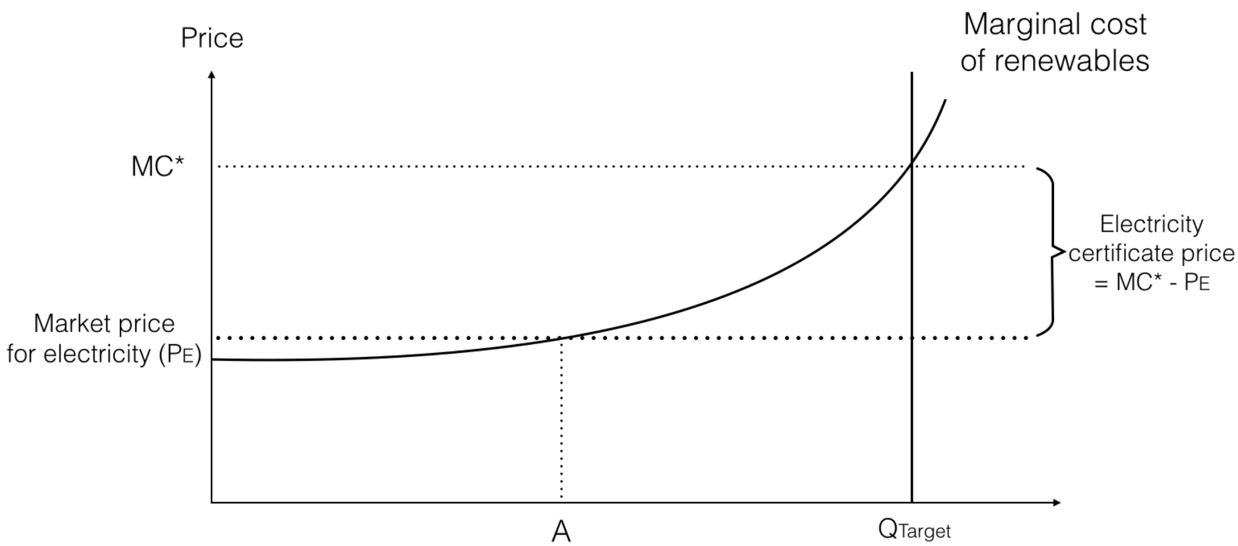


**Figure 18: Tradable electricity certificate market equilibrium, based on (Bergek & Jacobsson, 2010)**

The Swedish-Norwegian electricity certificate market design is somewhat complex, and in the following the demand and supply of electricity certificates are described analytically.

## 5.2 The electricity certificate demand

The demand for electricity certificates is created by a quota requirement that is given in the Electricity Certificate Act (Olje- og energidepartementet, 2012). The quota obligation is imposed on electricity suppliers who, on behalf of the electricity consumers in Norway and Sweden, are required to cover a certain proportion (quota) of their electricity consumption by new RES-E through the purchase of electricity certificates. The imposed quota on their annual electricity sales or use determines the number of electricity certificates that must be purchased in order to fulfil their quota obligation. For example, if the annual quota is 10 % and a supplier has used or sold 1,000 MWh of electricity in the corresponding year, he is required to purchase 100 electricity certificates (100 MWh). Every year, no later than March 1st, the quota-obliged party submits details on the electricity sold and consumed in the previous year and they have until end of March to acquire the sufficient number of certificates to comply with the quota. Then, on April 1 each year the electricity certificates are redeemed, or “cancelled”. Failing to hold the number of certificates necessary to meet their quota obligation triggers a charge corresponding to a penalty price for each certificate they are short of. The penalty price is set to 150 per cent of the average certificate price in the previous year. The annual cancellation of electricity certificates implies that a continuous demand for electricity certificates is created since the quota-obliged actors must purchase new electricity certificates in the following period to meet the quota obligation.

The annual quota obligation is given as a percentage of estimated electricity consumption. The so-called *quota curves* for each of the participating countries establish the annual percentage quota over the duration of the electricity certificate market (2003-2035). The quota curves for Norway and Sweden are presented in Figure 19, where the solid lines represent the applicable quotas in the Swedish and Norwegian Electricity Certificate Act and the stipulated curves are adjustments suggested by the regulators (Appendix C).

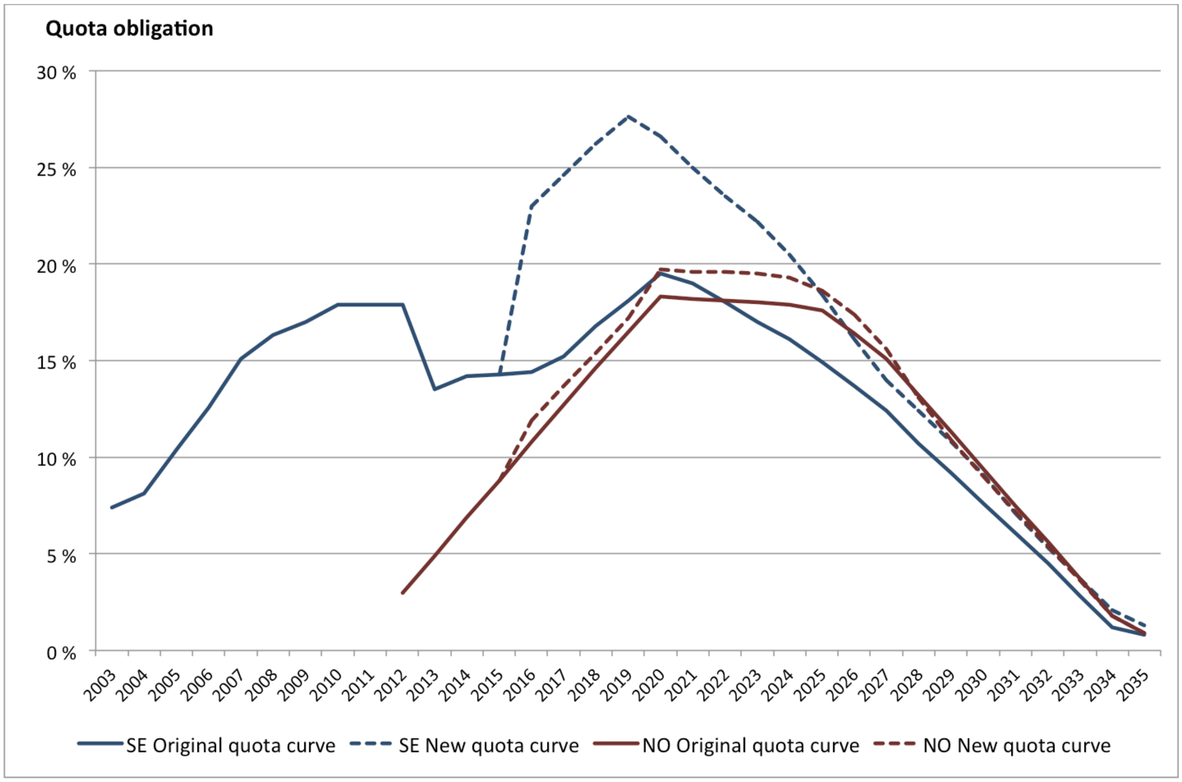


**Figure 19: Quota curves (NVE c, 2014) (Energimyndigheten a, 2014)**

The figure 19 shows how the quota obligation[23] is increased towards 2020 in order to increase demand for electricity certificates and thus stimulate RES-E investments. Since electricity certificates will not be issued after 2020 and RES-E production is only eligible for receiving electricity certificates for a period of 15 years, the quota obligation is gradually decreased in the period 2020-2035.

The total demand for electricity certificates over the duration of the scheme is most easily understood if the yearly quota obligation is given as a number of cancelled electricity

[23] The annual quota is derived from the formula:

$$\frac{New\ RESE\ generation + Generation\ from\ transition\ period + Technical\ adjustments}{Relevant\ electricity\ consumption\ (estiamted)}$$

certificates. Figure 20 depicts the historic and projected number of electricity certificates cancellations each year in million electricity certificates (Appendix D).

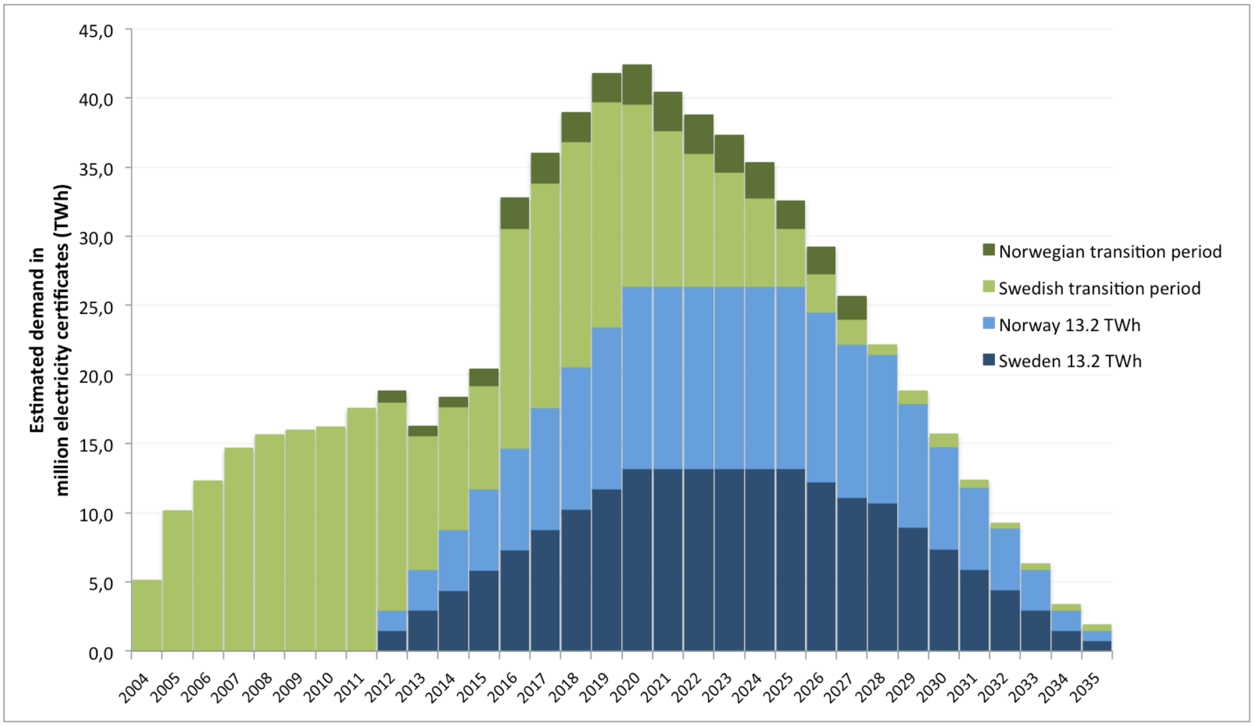


**Figure 20: Total demand for electricity certificates**

The blue bars describe the number of electricity certificates estimated to be to be cancelled by Norway and Sweden within the common electricity certificate market over the period 2012-2035. The Swedish RES-E producers that came into operation between 2003 and 2012 should, however, continue to receive electricity certificates for 15 years as they were offered in the first place. In addition, some RES-E producers that went into operation prior to 2012 in Norway receive electricity certificates for their production. The electricity generation from these plants is referred to as the country-specific transition periods. Each country's transition period into the common market implies that not all the electricity certificates that are cancelled will count towards the quantitative target in the common electricity certificate market and is the main reason why the Norwegian and Swedish quota curves differ. The country-specific quota curves are the regulatory authorities main tool for achieving the politically determined quantitative target. During system reviews, scheduled every four years, the quota curves can be adjusted with the sole purpose that the demand should stimulate investments corresponding to the quantitative mandate. The stipulated curves in Figure 19 represent the suggested adjustments to the quota curves from the on-going system review. The adjustments are suggested by the countries' respective regulatory authorities and are highly likely to be implemented. The main reasons for the upward adjustments are the larger than expected electricity generation from older RES-E producers receiving certificates and lower electricity consumption than initially assumed (NVE c, 2014). The demand for electricity certificates is highly inelastic since it is based on a given percentage of electricity consumption, which in turn is deemed inelastic.

## 5.3 The electricity certificate supply

The supply of electricity certificates comes from RES-E producers whose production is eligible for electricity certificates. In order to be eligible for receiving certificates, power producers' actual electricity production must satisfy the requirements of the Electricity Certificate Act and be approved by NVE or the Swedish Energy Agency. All or part of the power production may be eligible for receiving electricity certificates, and one electricity certificate corresponds to one MWh of electricity produced. The number of issued certificates in a year thus depends on how much new RES-E generation capacity that comes in to the market and the actual electricity generation of all RES-E plants that are eligible for electricity certificates. The number of issued certificates and thus the supply to the market is therefore hard to predict and can differ considerably from year to year. A RES-E generator with a negligible short-run marginal cost of producing electricity and certificates (e.g. wind) will produce what is feasible dependent on availability of the plant and weather conditions. The possibility of banking electricity certificates implies that producers can save certificates in years with excess supply or low prices and sell them in years when supply is low. Banking does, however, represent an opportunity cost since the capital is tied up and unavailable for other investments.

All information on issued and cancelled electricity certificates in Norway and Sweden is registered in NECS and Cesar, which are the respective electricity certificate registers in Norway and Sweden. The two registers show the same information and all participants in the electricity certificate market have an account in the registers and all transactions are recorded. The development of yearly issued electricity certificates and corresponding cancellation over the period 2003-2015 is presented in Figure 21 (status per March 31, 2015).

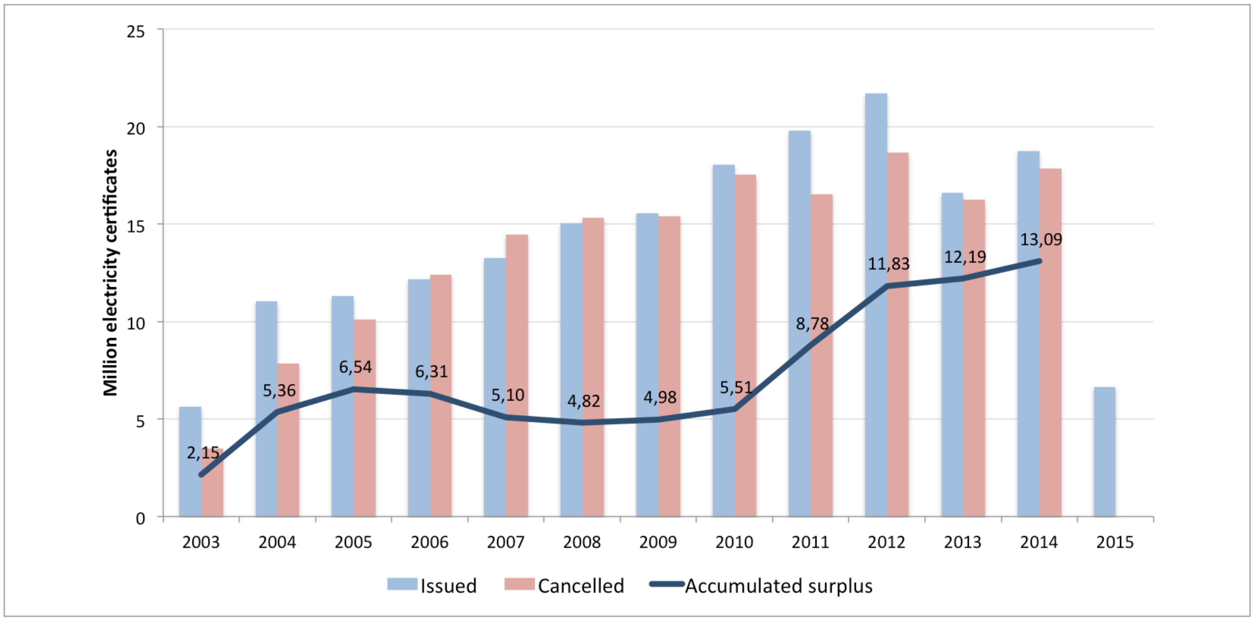


**Figure 21: Issued and cancelled electricity certificates 2003-2015 (Statnett NECS, 2015)**

Certificates that are issued but not cancelled become the reserve in the market. A certain reserve in the market is necessary to ensure market liquidity, since there are no possibilities for certificate borrowing (shorting) between periods. When Norway entered the market in 2012, the reserve was 8.78 million electricity certificates, which was accumulated between 2003 and 2012 (NVE & Energimyndigheten, 2014). Following the 2015 cancellation of electricity certificates, the accumulated certificate surplus was 13.09 million electricity certificates (Statnett NECS, 2015).

## 5.4 The market price for electricity certificates

Trade in the Swedish-Norwegian electricity certificate market is exercised on an open market where certificates are traded freely across the countries' border. The trade is carried out either through bilateral contracts, directly between electricity producers and suppliers or through brokered transactions. Examples of market places where electricity certificates are traded are

SKM (Svensk Kraftmäkling), ICAP and Cleanworld. We rely on SKM electricity certificate price data because SKM is the only marketplace with public price quotations and the SKM closing price determines the market price.


**Figure 22: Electricity certificate spot and forward prices 2005-2015 (SKM, 2015)**

In Figure 22, we present historic electricity certificate prices over the last 10 years, based on weekly averages of nominal spot prices and physically settled forward contracts. The certificate price development describes relatively low, decreasing prices until 2006, when prices started increasing sharply in the years 2007-2008. After a period of high certificate prices, a stepwise downward trend towards 2012 followed. When Norway joined the electricity certificate market, prices picked up in the first year before settling at a relatively low price level. From graphical inspection we observe that the prices are quite volatile and have varied considerably from the all-time-high weekly average spot price of 376.0 SEK/MWh in 2008 to an all-time-low weekly average spot price of 136.8 SEK/MWh observed just recently (Week 13, 2015). The forward prices are presented at their historic nominal price level, such that in any year “F March +1” refers to the price of a contract with delivery in March the following year. “F March” refers to short-term contracts for the closest March with forward prices quoted only for the first 12 weeks of each year. As would be expected, forward contracts with longer maturity are priced higher relative to the spot market price. We do, however, note that the forward prices follow the spot prices very closely, which may indicate that market participants find future price changes hard to predict or that the market mechanisms are difficult to interpret. In the following we will consider the long-term certificate price formation and short-term certificate market price influences.

## 5.5 The long-run price formation

Figure 23 depicts a graphical illustration of the expected long-run equilibrium price level in a tradable electricity certificate market[24].

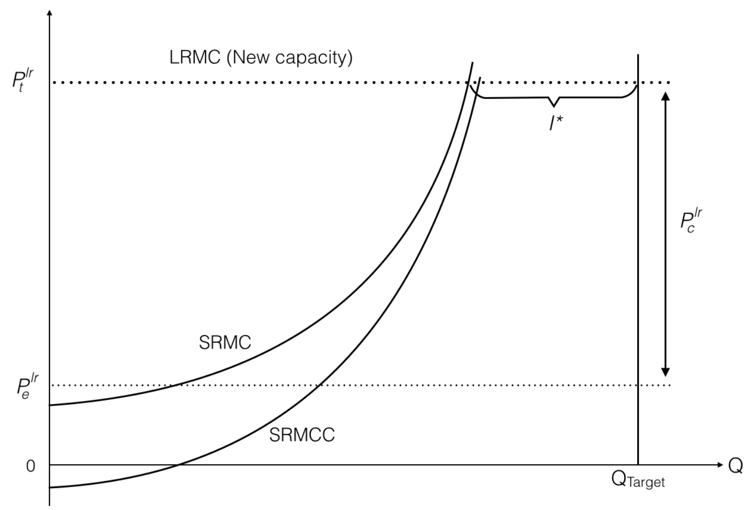


**Figure 23: Long-run electricity certificate price equilibrium, based on (Kildegaard, 2008)**

Previously established RES-E in the electricity certificate market will supply electricity according to their SRMC, which is their relevant cost for operational decisions. These power producers are willing to sell their electricity certificates at a price equal to the difference between their SRMC and the power price ($p_e^{lr}$), defined as the short-run marginal cost curve for certificates (SRMCC). The quota target ($Q_{Target}$) for new RES-E generation capacity is set at a level that is not satisfied by the existing capacity in the electricity certificate market. In order to reach Q, additional investments in new RES-E generation corresponding to $I^*$ is needed. In order

[24] Underlying assumptions of perfect competition in power and electricity certificates, a fixed electricity price Pe since the quota is small relative to the overall power market and constant returns to scale in the renewable technologies (Kildegaard, 2008).

to take an investment decision, potential RES-E investors need to have an expectation that the total expected income from the sale of power and electricity certificates exceeds their LRMC. The LRMC includes the SRMC, average per unit repayment of fixed costs and an average per unit risk premium (Lemming, 2003). By assuming a flat $LRMC(New\ capacity)$ curve for new potential RES-E generation capacity, its intersection with the quota target $Q_{Target}$ should reflect the revenue generating long-run total price ($p_t^{lr}$) to the producers, consisting of the long-run electricity certificate price ($p_c^{lr}$) and the long-run power price ($p_e^{lr}$). Since the LRMC of the new capacity needed to reach the quantitative target is not known, it is the market participants' collective expectations of the LRMC of the marginal RES-E producer needed to fulfil the quota mandate that determines the certificate price. Between now and the long-run equilibrium depicted in Figure 23, the electricity certificate price is decided by where the existing short-run supply curve meets the demand for new RES-E (Kildegaard, 2008).

Once new RES-E investments materialize, the relevant cost for short run operational decisions become the SRMC. The RES-E project pipeline in Swedish and Norwegian consist of mainly wind, small-scale hydro or other RES-E technologies with very low O&M costs and large average fixed costs (AFCs).

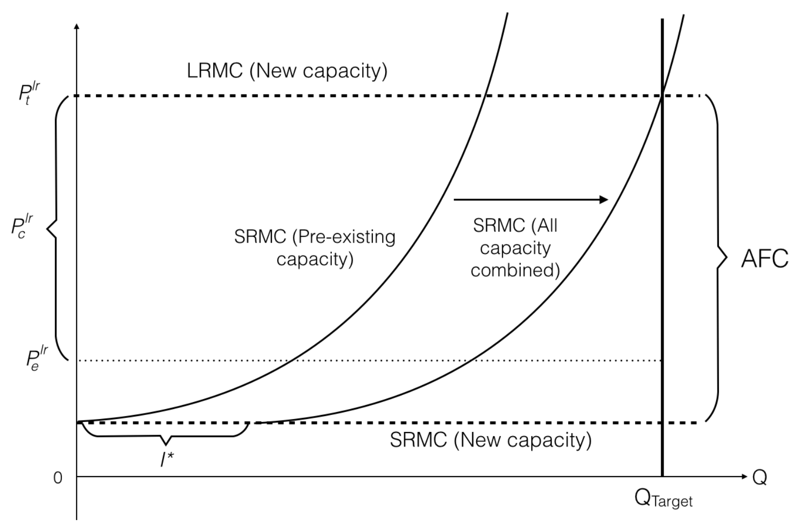


**Figure 24: New RES-E investments (Kildegaard, 2008)**

Since AFCs are not relevant for short run operational decision, these are subtracted from the LRMC of the potential new entrants, $LRMC$ ($New\ capacity$), in Figure 24. The resulting low $SRMC$ ($New\ capacity$) is likely to be lower than the assumed long-run electricity price ($p_e^{lr}$), which implies that these generators will not consider the marginal cost of producing certificates in their short-run production decisions. Investments corresponding to $I^*$ shifts the SRMC curve out, and the certificate prices is continued to be set by the SRMCC of older plants and where it meets the demand for certificates (Kildegaard, 2008).

## 5.6 Short-term electricity certificate price influences

An electricity certificate system is a long-term policy instrument since it presupposes that the market participants consider the quota target achievement and long-term expected power- and electricity certificate prices rather than current market prices when they decide whether to invest in new RES-E generation capacity or not. Nevertheless, the short-term market price for certificates seems to be important for investment behaviour, thus we discuss factors that influence the short-term certificate price.

According to Kildegaard (2008), the banking of certificates can level out certificate price fluctuations from certain types of symmetric risk. For example, fluctuations in electricity certificate supply due to annual weather and wind variations (volume risk) for a wind farm could be considered to average out over its lifetime and banking of certificates during high wind years, and vice versa, would therefore be rational (Kildegaard, 2008). The possibility of certificate banking may add to the accumulated surplus of electricity certificates (reserve) in the market, which is an important electricity certificate price determinant. The accumulated surplus of electricity certificates is determined by the balance between issued and cancelled certificates, which is influenced by banking since more certificates will be saved if the market participants expect higher future prices. The accumulated surplus of electricity certificates is presented in Figure 24 together with the yearly average electricity certificate market price.

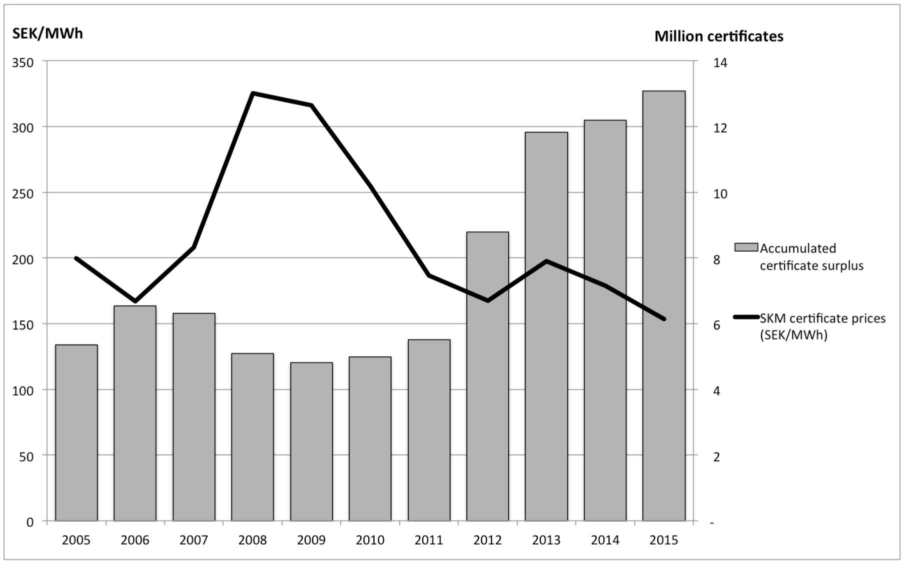


**Figure 25: Relation between yearly average certificate price and accumulated certificate surplus (SKM, 2015) (Statnett NECS, 2015)**

Figure 25 shows that the electricity certificate price increased substantially between 2006 and 2008 when the accumulated electricity certificate surplus decreased. Conversely, the electricity certificate price has decreased in the last couple of years at the same time as the accumulated certificate surplus has increased. The electricity certificate reserve seems to be important for pricing, providing a negative relation between certificate prices and accumulated certificate surplus over time. A large accumulated electricity certificate surplus implies a low probability of short-term shortages. If the market believes that the certificate reserve in the market will retain since certificates are banked in anticipation of higher prices in the future, the certificate price will remain low. If, on the other hand, market participants expect certificate shortages, the certificate prices are likely to increase, encouraging investments in new RES-E generation capacity. The considerable surplus of electricity certificates that has accumulated in the Swedish-Norwegian market may provide the wrong price signal for the need for investment. The risk is that low prices cause potential investors to assume that other investors are already entering the market making them hesitant to enter themselves. If the downward pressure on certificate prices is caused by the accumulated certificate reserve in the market, the reserve should eventually be gradually reduced, providing higher prices to signal a need for more investments. However, even though the prices are gradually raised, the market may be sluggish in delivering new investments due to long lead times, from the investors reaction on the higher price signal to the plant is fully operational. The trend in the Swedish-Norwegian electricity certificate market so far has been that more investment decisions are taken in periods when the power prices and electricity certificate prices are high, and fewer investment decisions when prices are low, which is the situation today. Such cyclical investment phases may pose a risk to achieving the quantitative mandate by the end of 2020 if investment decisions are delayed for too long, rendering too little time for construction (NVE c, 2014).

From the discussion on long term market price formation, it is reasonable to believe that the power market and electricity certificate market provide a relationship between the power price and the electricity certificate price; the prospect of higher power prices should make investors willing to invest at a lower future certificate price, and conversely lower power price forecasts will make investors demand a higher electricity certificate price. In the short term, such a relation between the power prices and electricity certificate prices does not seem to materialize.

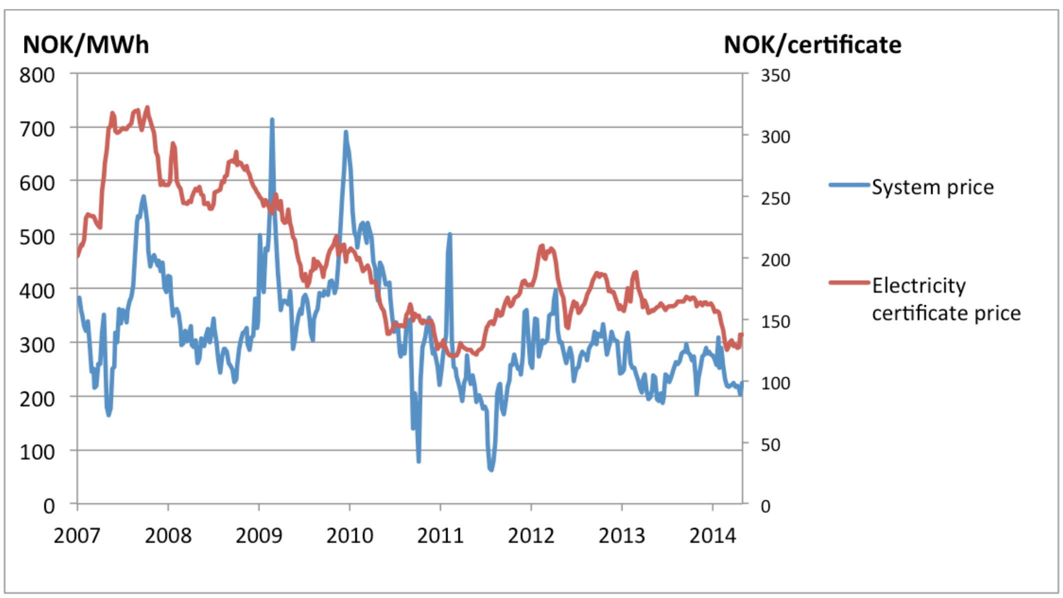


**Figure 26: System price of power and electricity certificate spot price (SKM, 2015) (Nord Pool Spot a, 2015)**

Figure 26 shows the nominal system price on the left axis and the nominal electricity certificate spot price on the right axis. Both price series are in NOK/MWh (one electricity certificate corresponds to one MWh) and both series show weekly average prices. In the last years, a situation with relatively low electricity certificate prices and low Nordic power prices has emerged, putting a "double" pressure on RES-E producers and a "double" disincentive for investments in new RES-E generation capacity. The electricity certificate spot price is very sensitive to new information to the market that may affect the balance between issued and cancelled certificates, such as announcements about investment decisions in new RES-E capacity, legislative changes or political signals.

In conclusion, the main determinant for the electricity certificate price is the market participants' expectations about the LRMC of the market clearing technology. The short-term electricity certificate price is decided by where the existing short-run supply of RES-E generation meets the quota obligation. However, short-term price influences such as the accumulated electricity certificate reserve in the market and new information largely dictates the market price for certificates. In order to understand what will drive the future electricity certificate price, the balance between issued and cancelled electricity certificates over the duration of the market must be estimated. While the number certificates to be cancelled each year is more or less given by the applicable quota curve, the number of issued certificates over the electricity certificate market duration is highly uncertain because it depends on how much new RES-E generation capacity that will enter the market by 2020.

## 5.7 Static cost-effectiveness

Static cost-effectiveness is an important criterion in the evaluation of support scheme adequacy and is commonly understood as reaching the target at minimum costs. The subject of cost-effectiveness was a major driver in the design of a technology-neutral electricity certificate market in Norway and Sweden (Bergek & Jacobsson, 2010). We discuss the principle of cost-effectiveness in light of the Swedish-Norwegian electricity certificate market.

The expectation to the Swedish-Norwegian tradable electricity certificate market is that it will deliver new RES-E generation according to the quantitative target at the lowest total costs. In a static perspective, the long run marginal cost of generation for a given RES-E technology increases with installed capacity (or generation). The reason for this is that the sites with the most suitable renewable energy resource (e.g. wind) will be used first, and locating the technology at gradually less suitable sites becomes costlier. The long-run marginal cost curves also differ between the various RES-E technologies.

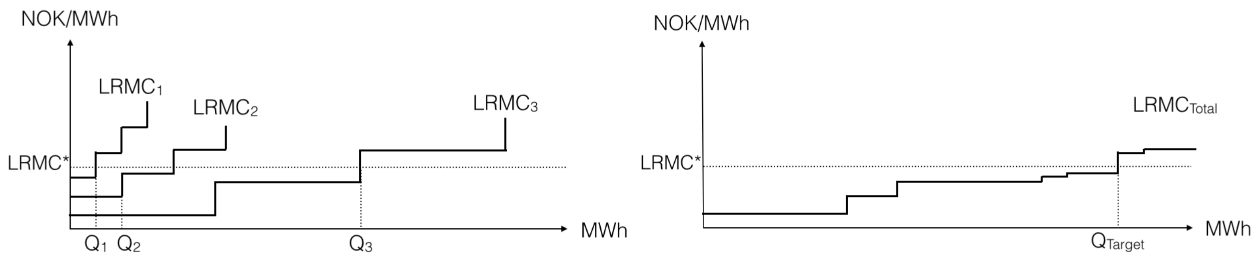


**Figure 27: a) Technology cost resource curves** **b) Aggregated cost resource curve**

A cost resource curve represents the long run marginal cost of the additional realisable potential of *new* RES-E generation (TWh) to count towards the quantitative target ($Q_{Target}$). Figure 27a depicts hypothetical long run marginal cost curves for different RES-E technologies and their corresponding potential in terms of expected electricity generation. Figure 27b is the result of adding parts of these RES-E technology cost curves into an aggregated cost resource curve. In order to reach the quantitative target, additional RES-E generation capacity corresponding to $Q_{Target}$ must be realised. The long-run marginal cost of the last unit of RES-E necessary to reach the target is LRMC*. At this level, only the cheaper projects from each RES-E technology, i.e. those projects with an overall energy cost lower than LRMC*, will be realized. From Figure 27a, these projects will contribute to $Q_{Target}$ with $Q_1$, $Q_2$ and $Q_3$ respectively. Since the LRMC of the last unit from each technology ($Q_1$, $Q_2$ and $Q_3$) needed to fulfil the quantitative target ($Q_{Target}$) will equal LRMC*, the mechanism is referred to as the equimarginal principle and represents the least costly way to meet the target (Cerdá & del Río, 2014).

The implications of the cost-effectiveness principle is that the RES-E technologies with the lowest costs are deployed first and the projects with the most favourable sites or resources within each technology should be prioritized. Then, in order to meet the quantitative target, increasingly more expensive new RES-E projects is needed. In principle, this implies that in the early phases of a technology-neutral quota scheme there will be a greater deployment of low-cost technologies and locations. Cheaper technologies are generally those that are more mature and available, whereas less mature technologies are likely to be locked out of the market due to higher costs (e.g. offshore wind), depending on the availability of other RES-E projects and their costs.

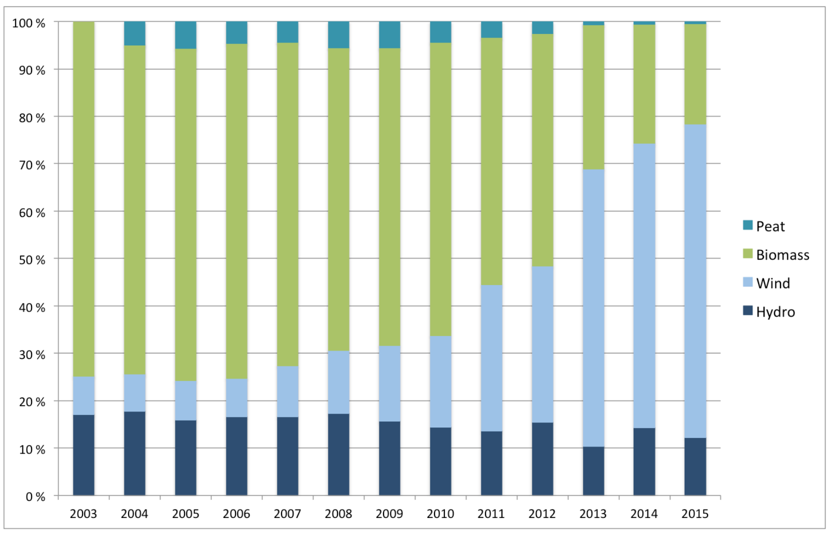


**Figure 24: Issued certificates, by source (Statnett NECS, 2015)**

Figure 28 depicts the development in each RES-E technology's share of the annual number of issued electricity certificates[25] to RES-E producers in Norway and Sweden. In the first years of the electricity certificate scheme, the cheapest way to increase RES-E generation in Sweden was by increasing the power output in biomass CHP (Combined Heat and Power) plants or through fuel switching from fossil fuels to biofuels. As expected, it took time for investments in new plants to materialize, due to factors such as the licencing process and long lead-time. Over time,

[25] For 2015, we consider the number of electricity certificates issued so far this year (status per May 12, 2015).

wind power has become the major recipient of electricity certificates, reflecting its decreasing costs and a reduced availability of low-cost projects (Bergek & Jacobsson, 2010).

## 5.8 Supply of new RES-E projects in Norway and Sweden

The potential of the RES-E projects in the pipeline to come online by 2020 and their potential contribution towards the 26.4 TWh target can be described in a static cost resource curve. We construct an aggregated cost resource curve for the additional realisable potential of new RES-E in Norway and Sweden up to 2020. So far, 10.3 TWh[26] of new RES-E generation capacity has come online in the common electricity certificate scheme. This implies that the additional RES-E generation capacity needed by 2020 in order to meet the quantitative target of 26.4 TWh is 16.1 TWh. Some of the 16.1 TWh of new generation capacity scheduled to enter the electricity certificate system are likely to have already made an investment decision or they are currently under construction. However, no publicly available register of the status of the RES-E project pipeline following the concession process exists.

As described in section 2, the RES-E project pipeline includes a considerable number of projects that have the potential to come online by 2020. However, not all of these potential projects are realisable under the Swedish-Norwegian electricity certificate scheme because the target would be overshot if more than 16.1 TWh new RES-E enter the electricity certificate market. In order to construct technology cost resource curves, we need an estimate of the additional realisable (by 2020) generation capacity. For this, we use what was termed by NVE and the Swedish Energy Agency as the *investable volume of RES-E projects by 2020*. Furthermore, we assume LCOE ranges for the RES-E projects in the pipeline. For each RES-E technology, we apply relatively wide LCOE ranges that are meant to reflect representative energy costs for various potential projects in Norway and Sweden. The LCOE ranges are based on representative LCOE estimates as suggested by the regulatory authorities, supplemented with the author’s own assumptions and

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[26] Status per January 1, 2015 (NVE, Energimyndigheten, 2015)

input from market actors (Energimyndigheten, 2014) (NVE d, 2015). For the purpose of constructing a cost resource curve, we use the LCOE intervals presented in Figure 29:

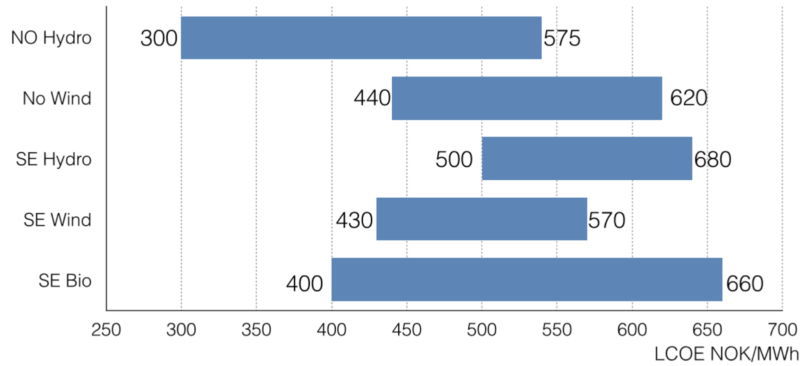


**Figure 25: Assumed LCOE ranges (NOK/MWh)**

Technology cost resource curves can now be constructed. Since we cannot know exactly which projects that will be realised, their expected generation or costs, we need to make some simplifying assumptions to construct the cost resource curves. The assumed LCOE cost ranges (Figure 29) are divided into stepwise cost-levels corresponding to intervals of 0.5 TWh of investable volume. Figure 30 depicts the cost resource curve for the additional (by 2020) realisable potential of Norwegian wind power projects and its assumed cost levels. Similar cost resource curves are constructed for the other RES-E technologies.

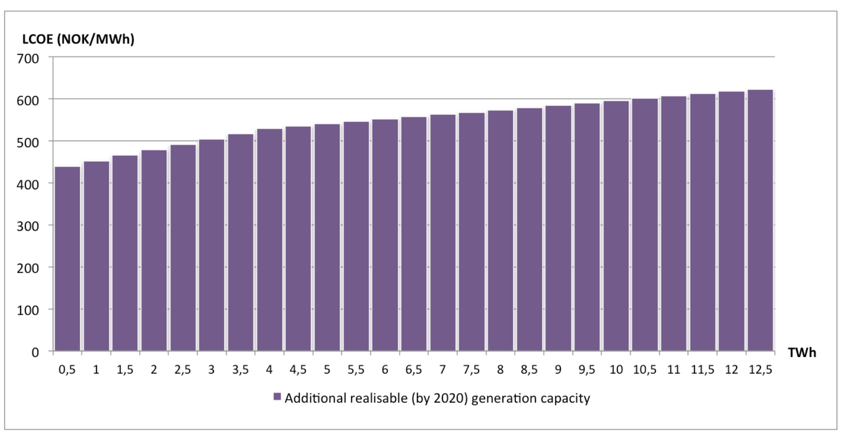


**Figure 30: Cost resource curve for additional realisable (by 2020) onshore wind power projects, Norway**

By aggregating the RES-E cost resource curves, we arrive at a complete cost resource curve for the Swedish-Norwegian electricity certificate market, presented in Figure 31:

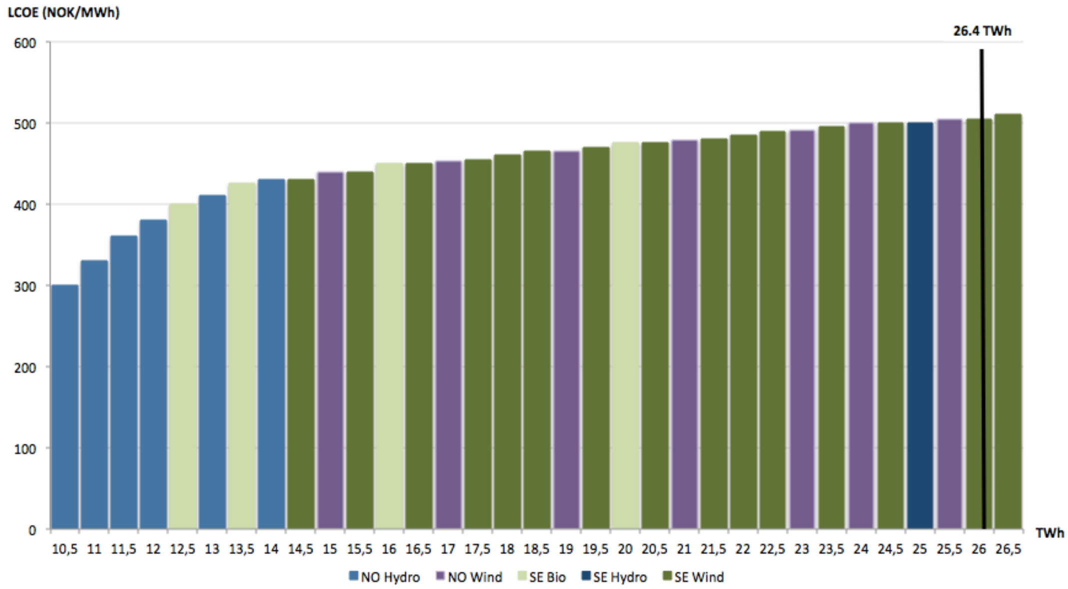


**Figure 26: Static cost resource curve for additional potential generation capacity by 2020**

The static cost resource curve shows the long run marginal costs and generation potential of the various RES-E technologies that are expected to enter the electricity certificate market by 2020. Assuming that 16.1 TWh of new RES-E generation capacity come online and the quantitative target of 26.4 TWh is reached in 2020, we find that Norwegian hydro and Swedish bio are currently the cheapest builds, although quite a lot of wind power projects need to be realized, both in Norway and Sweden in order to reach the quantitative target. An additional 3.5 TWh of new wind power generation and 2 TWh of small-scale hydropower generation will be built in Norway. In Sweden, wind power is expected to be the largest contributor with 7.1 TWh. Moreover, Sweden is estimated to realise 2 TWh bio power and 0.5 TWh of hydropower. Sweden is experiencing an expansive growth in solar power projects. Although the new solar power generation is expected to contribute to the electricity certificate RES-E target, these projects have a relatively small generation potential and are therefore excluded.

Our cost resource curve suggests that an additional 3.5 TWh of new wind power generation capacity could come online in Norway by 2020 under the common electricity certificate system. Although there are currently no wind power projects under construction in Norway, there is a significant amount of projects in the process of taking an investment decision. To our knowledge, two relatively small wind power projects have announced a positive investment decision, namely ASKO  (50 GWh) and Roan (36 GWh). Several large wind power projects that are deemed profitable by NVE are expected to make a decision within the year. In mid-Norway, ten wind power projects are expected to reach investment decisions in the near future. If all these wind parks come online before 2020, they have the potential to add approximately 4.4 TWh of new RES-E generation, exceeding our estimate in the cost resource curve. Another large cluster of new wind power projects, located in Bjerkreim is considered as a possible addition to the new RES-E generation in Norway. The investors in the cluster are currently unable to reach investment decisions due to uncertainty regarding the grid connection.

Furthermore, our cost resource curve indicates that a Swedish wind power project will be the market clearing technology required to fulfil the quota target, with an estimated LRMC of around 510 NOK/MWh. The expected, revenue-generating long-run electricity certificate price should then be determined as the difference between this LRMC and a medium to long-term power price. For a rudimentary long-term power price estimate, we rely on the average system price over the last 5 years of 312 NOK/MWh [27].

[27] Average system price 2029-2014 (Nord Pool Spot a, 2015).

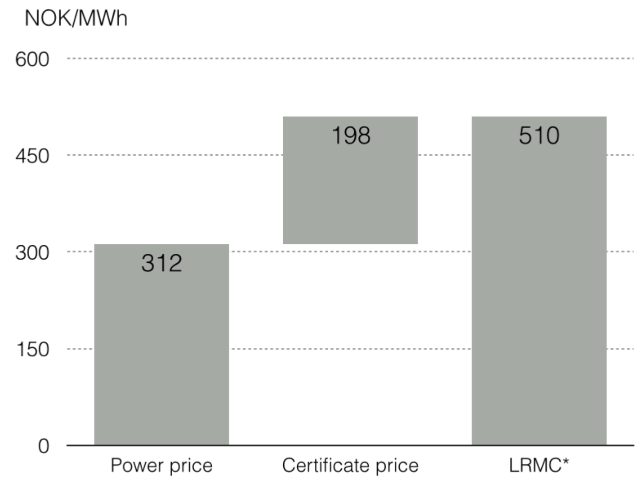


**Figure 32: LRMC clearing technology**

Under these assumptions, the expected revenue generating electricity certificate price should settle around 200 NOK/MWh. Still, the cost resource curve is static and it does not take into account the possibility of a decreasing long-run marginal cost over time due to technology learning.

There are large uncertainties related to the cost resource curve that we have presented, both in terms of which RES-E technologies that will enter the electricity certificate market by 2020, their expected electricity generation potential and at what energy cost. Also, there is a risk that the quota target is not met or overshot.

## 5.9 Evaluation of the cost-effectiveness criteria

The effectiveness of a policy instrument rests on its ability to achieve a set target. The Swedish-Norwegian electricity certificate market is not designed to stimulate a rapid deployment of new RES-E capacity; rather it is designed to be effective in terms of meeting the politically planned quantitative target at the lowest total generation costs.

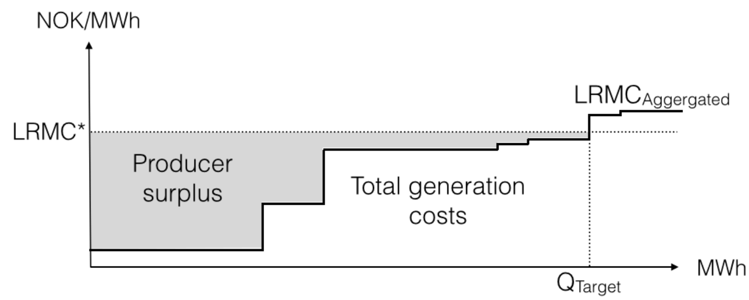


**Figure 33: Distributional effects**

Even if the cost-effectiveness criteria ensure minimization of total generation costs, any distributional effects between producers and consumers are disregarded. In Figure 33, the area below the cost resource curve ($LRMC_{Aggregated}$) up to $Q_{Target}$ represents the total generation costs of reaching the quantitative target. The difference between the cost-minimizing compensation level LRMC* and the cost resource curve ($LRMC_{Aggregated}$) results in a producer surplus, illustrated by the shaded area in Figure 33. A uniform support level LRMC* for all projects entails that low-cost technologies receive an excessively high compensation and the cheapest RES-E projects included in the electricity certificate market may reap windfall profits (Haas, Resch, Panzer, Busch, Ragwitz, & Held, 2010).

The electricity consumers in Norway and Sweden are the ones that will ultimately pay the cost of the certificate scheme through the quota obligation. Even though total generation costs are minimized, the total policy cost is not necessarily minimized since low cost technologies could have been sufficiently compensated at a lower support level than LRMC*. It follows that there is an unnecessary large transfer from consumers to producers (Cerdá & del Río, 2014).

In a study of the distribution of costs and benefits across producers and consumers in the Swedish electricity certificate market, Bergek and Jacobsson (2010) find that the support scheme brought considerably higher costs to consumers than expected because of large rents to RES-E generators that were profitable before being granted extra payments and excessive rents to sub-marginal plants, i.e. technologies that would be profitable at lower levels of support than that set by the marginal producer (Bergek & Jacobsson, 2010). If there is a concern that the overall policy costs for consumers will become excessively high, policy makers may choose a technology-specific support schemes[28] instead, which compensates high-cost technologies relatively more than low-cost technologies.

The costs of the support scheme to electricity consumers are expected to increase towards 2020, before gradually declining, in line with the quota curve. The total cost to electricity consumers depends on the development in certificate prices. We have estimated the cost of the support scheme, to be paid by Norwegian electricity consumers over the period 2012-2035, to total a present value NOK 38.69 billion. The estimate is found by multiplying the expected number of cancelled certificates per year by a corresponding electricity certificate price and the details of the calculation can be found in Appendix E. This corresponds to NOK 2.58 billion per TWh of new RES-E generation capacity[29] financed by Norway. Although the cost is highly uncertain due to the uncertainty in both future electricity certificate prices and the number of electricity certificates that will to be cancelled, it provides a rudimentary estimate of the total policy cost to be borne by the Norwegian electricity consumers. Swedish electricity consumers will pay more because they support more RES-E production that came online before 2012.

Since two countries are jointly partaking in the scheme, the certificate market encompasses two different business environments. Differences in the regulatory conditions between Norway and Sweden have been used to explain why more RES-E facilities have materialized in Sweden than in Norway since 2012. Different labour costs, grid connection costs or wind conditions are factors that can hardly be attuned. However, more favourable tax depreciation rules and other technology- or country specific indirect subsidies on top of the electricity certificates for Swedish RES-E investors has been an important factor in distorting the location of generation capacity (THEMA Consulting Group, 2015). It is important to keep in mind that the bilateral

[28] This could be achieved through technology-banding within the quota or technology-specific Feed-in-Tariff.
[29] Based on 13.2 TWh of new RES-E generation.

agreement between Norway and Sweden is on the financing of RES-E investments, and not on where new RES-E projects are installed. Thus, we will argue that distortionary rules and regulations is not necessarily a risk factor in terms of reaching the quantitative mandate. Projects that would have been similarly profitable in Norway and Sweden under equal rules and regulation, may be built in the country with more favourable conditions. For the policy outcome, this implies that the best projects and locations are not necessarily utilized, and that the total cost of the support scheme becomes higher. By aligning the regulatory framework in the two countries, the gains from cost-efficiency would be assured since only then the best projects are realized. Moreover, there may be within-country differences in rules and regulations may between RES-E technologies. For example, a suggestions to align the Norwegian tax depreciation rules for wind power with Sweden is sent to parliamentary hearing, while small-scale hydropower are not suggested to will not receive more favourable conditions. This asymmetry may lead to some small-scale hydropower projects, currently more profitable than wind power projects, being displaced by wind power projects under more favourable tax depreciation rules. In order to ensure cost-effectiveness, regulatory differences between the countries and between different RES-E technologies should be avoided.

Employing a static cost-effectiveness criteria in policy design may result in a situation where promising RES-E technologies are not developed fully, resulting in a foregone cost reducing technology learning in the long term. This is refereed to as dynamic efficiency, and rests on the support scheme's ability to generate a continuous incentive for technical improvements and cost reductions in existing RES-E technologies. Since the basic principle of the Swedish-Norwegian electricity certificate market rests on the competition between different RES-E technologies to ensure that the cheapest projects are built first, it can be reasoned that less mature, currently expensive technologies are not given sufficient incentive to technology improvements and dynamic efficiency is not guaranteed. Bergek and Jacobsson (2010) argue that the technology neutral support scheme is, in fact, deliberately designed to avoid creating markets for new RES-E technology inventions since mature, low-cost technologies are favoured.

To sum up, a technology-neutral tradable electricity certificate market is designed to be a cost-effective policy, ensuring that a RES-E quantitative target is met the lowest total generation costs. Although the common Swedish-Norwegian electricity certificate market has shown relatively low effectiveness with respect to deployment of the less mature RES-E technologies, this is not an unintended consequence of the regulatory framework. Rather, it reflects the basic principle that investments should be made at a rate that is economically justified and not prematurely.

# 6 Risks and uncertainty in the electricity certificate market

In the following, we discuss risks and uncertainty resulting from the design of the Swedish-Norwegian electricity certificate system. We consider regulatory uncertainty, the risk of overinvestments due to lack of perfect information and the role of long-term contracts.

## 6.1 Regulatory uncertainty

Regulatory uncertainty may arise from the risk that existing support schemes are replaced or removed, or the uncertainty regarding changes to the existing regulatory framework. Following a turbulent European economy, several countries have been forced to reduce existing support to RES-E because the policies became too expensive. Such retroactive policy changes may discredit the regulatory stability, and is a risk borne by RES-E investors and potentially the financiers (DNB, 2015). We consider the risk of significant retroactive changes to the current Swedish-Norwegian electricity certificate market to be very low. Nevertheless, the current policy will only support new RES-E generation that come online by 2020, and there is not yet any information available as to whether there will be a support scheme for RES-E investments after 2020. Until it this is clear, the market participants can only interpret political signals. Policy uncertainty can be powerful in preventing and deferring investments, and expectations regarding future support for RES-E are likely affect investment behaviour.

Political signalling and information related to changes in the regulatory framework are important drivers for the electricity certificate price. Hakvoort and Fagiani (2014) define regulatory risk as the risk that a change in the support scheme will exacerbate the certificate price risk, reflected in market price volatility. In the period from 2007 to 2013, they find evidence of increased certificate price volatility around periods that regulatory changes were made in the Swedish certificate market. They further suggest that the process leading up to the joint Swedish-Norwegian electricity certificate market led to a period of high volatility (Hakvoort & Fagiani, 2014).

## 6.2 Risk of overinvestment and the 2020 deadline

The investment phase in Swedish-Norwegian electricity certificate market expires by the end of 2020 resulting in a deadline for receiving support in the form of electricity certificates. In section 3, we described how wind energy is subject to cost reducing technological learning over time, which implies a value of waiting for wind power investors. The deadline for market participation reduces the value of waiting since constructing a wind park takes years and therefore gives rise to a concern, particularly in Norway, that those who start building close to 2020 will not reach the deadline. There are several likely risk factors that may arise due to the time pressure. In order to deliver the produced electricity to the consumer, a wind power plant is reliant on connection to a local, regional or central grid with available transmission capacity. The lack of grid capacity or grid connection possibilities is currently a bottleneck for several wind power projects in Norway (NVE c, 2014). Delays in power plant construction or grid expansion scheduled to be ready by 2020, exposes the investor to the risk of not becoming eligible for electricity certificates. Furthermore, time pressure may increase investment costs due to constraints in the supply chain and project quality may be deteriorated due to hurried decisions. Additionally, there is the risk that some projects, which would have been profitable in the certificate market, may be abandoned due to the risk of not receiving electricity certificates (Lind & Rosenberg, 2014). Swedish RES-E investors can be eligible for receiving electricity certificates even if their production commences after 2020, however only up to 2035, and are therefore less exposed to the 2020 deadline risk.

The certificate supply is determined by the electricity generation of the accumulated investments in new RES-E generation up to 2020, which implies that there is a risk of overinvestment or underinvestment relative to the target. In the investment phase, the market mechanism should correct a potential shortfall in investments through temporarily high certificate prices. If, at the end of 2020, there is insufficient investment, the flexibility in Sweden to issue certificates after 2020 could reduce such a deficit. Industry-wide overinvestment, on the other hand, will result in prolonged certificate price spoilage, a depression of the certificate price until the physical excess capacity is depreciated away or the quota target is expanded to absorb the slack. As described in section 5, certificate banking could practically eliminate volume risk or similar symmetric risks, however it cannot eliminate the asymmetric downside risk of price spoilage due to overinvestment. The reason for this is that overinvestment does not only relocate the timing of the cash flow, but reduces its present value (Kildegaard, 2008).

Figure 34 below captures the risk of overinvestment in a graphical illustration:

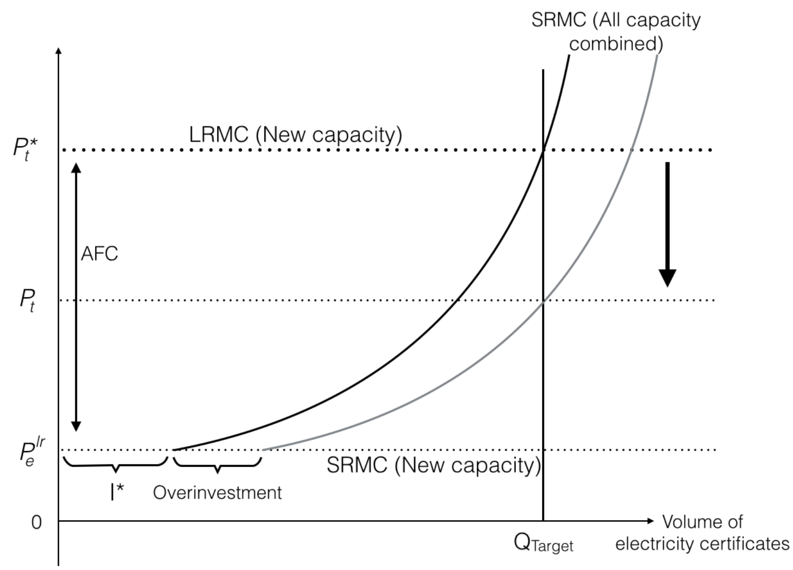


**Figure 34: The risk of overinvestment, based on (Kildegaard, 2008)**

As described in the section 3 on costs, many RES-E projects, in particular wind power, have low variable costs of electricity generation, and consequently a negligible marginal cost of producing electricity certificates once built. Large average fixed costs (AFCs) from the irreversible investment is irrelevant in short-term operational decisions, meaning that a competitive power producer will not include AFCs in his offer price. In Figure 34, large AFCs are subtracted from the $LRMC\ (New\ capacity)$, displaying the SRMC of new projects at a low level ($SRMC(New\ capacity)$). If, by 2020, the optimal level of investments ($I^*$) corresponding to the quota mandate ($Q_{Target}$) enters the electricity certificate market, the total price to RES-E producers settles at $P_t^*$. This price level is, however, very sensitive to the quantity of investments in new RES-E generation capacity. Whereas the optimal level of new investment of $I^*$ results in a price level $P_t^*$, an *overinvestment* would shift the $SRMC$ $(All\ capacity\ combined)$ curve to the right resulting in a decrease to $P_t$ in the total price to all RES-E producers. Unless the quota obligation (demand) is increased to absorb the oversupply, RES-E producers will face low prices after 2020. A price level of $P_t$ would imply that the new RES-E producers with a cost level of $LRMC$ $(New\ capacity)$ would suffer capital losses because they are unable to recover their average fixed costs (AFC). The risk of electricity certificate price spoilage due to industry-wide overinvestments is currently highly present in the Swedish-Norwegian electricity certificate market.

## 6.3 The role of information

A fundamental source of uncertainty in the Swedish-Norwegian electricity certificate market is the lack of information regarding the electricity certificate supply and the status of the RES-E project in the pipeline. If investors lack perfect information about what production volumes are entering into the electricity certificate system or have taken an investment decision, they cannot know whether their own project will contribute to increase the electricity certificate reserve or whether their expected contribution is necessary to meet demand. Efficient market equilibrium requires that all potential investors have the same set of information. In section 2, we described how the concession process is fully transparent through publicly available registers. On the other hand, there is no notification requirement or similar register on projects that have reached an investment decision or are under construction. Since there is no mechanism to ensure that such information is available in perfect form, market actors cannot know how much new RES-E capacity will enter the electricity certificate market, which is essential information in order to predict the supply curve and the future certificate price level.

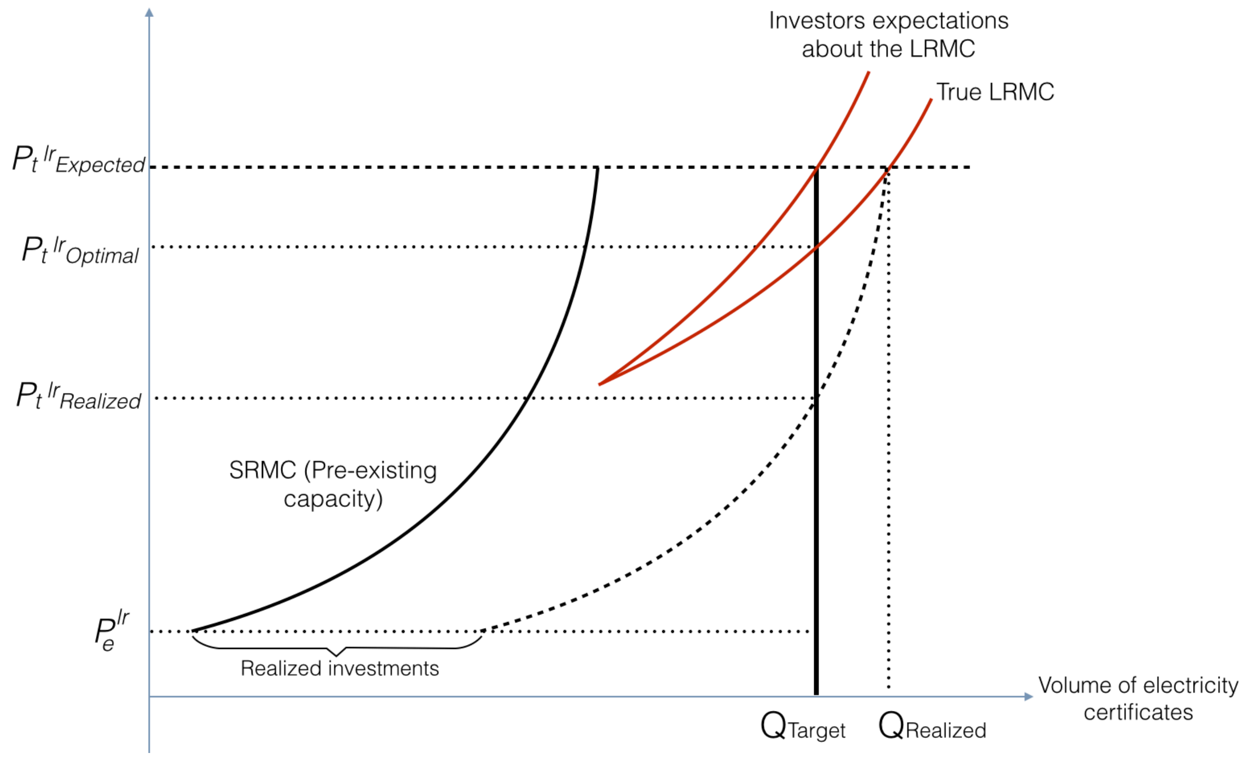


**Figure 35: Imperfect information, based on (Agnolucci, 2007) and (Lemming, 2003)**

Figure 35 illustrates how the lack of perfect information about what production volumes are entering into the electricity certificate system could affect the investment level and long-run electricity certificate price. The SRMC curve is relevant for operational decisions while the LRMC curve is relevant for the investment decisions of potential new RES-E generation capacity. New investments will shift the SRMC curve of existing capacity to the right with the level of realized investments. Perfect information about the true LRMC curve that represents potential new entrants would result in an optimal level of investments according to the quantitative target and a long-run price level $P_t^{lr}{}_{Optimal}$. If investors are not informed about all the production volume that will enter the market, they are likely to assume a LRMC curve that is steeper[30] than the true one at a corresponding expected long-run price level, $P_t^{lr}{}_{Expected}$ that does not reflect the real market situation. Since the expected long-run price level is inflated, investors will collectively invest in too much production volumes and the quantitative target will be overshot $(Q_{Realized} > Q_{Target})$. The SRMC curve is shifted to the right with the level of *Realized investments* and with a given demand set by the quota, the price drops to $P_t^{lr}{}_{Realized}$. Overinvestments resulting from the lack of information regarding the true supply curve affect prices negatively and contribute to a possible price collapse if the overinvestments are sufficiently high. If the true market situation is not fully reflected in the certificate price due to market participants' lack of information, the expected price level will not signal correctly the need for higher or lower rate of investments in new generation capacity. The uncertainty regarding new production volumes that are entering into the electricity certificate system will become particularly important closer to 2020 because of the risk of industry-wide overinvestment and price spoilage.

The lack of perfect information and market transparency could encourage the market actors to take on unproductive costs related to information gathering. Information asymmetry is present if some market participants have more information than others. A large power producer with a diversified portfolio of RES-E projects is likely to have more information about the RES-E project pipeline, whereas a small wind power producer would not necessarily engage in costly information gathering on the status of the complete RES-E project pipeline in both countries. Moreover, smaller market actors are likely to have limited information about electricity certificate prices and forecasts because they do not necessarily have the capacity, knowledge or resources to conduct such analyses themselves or to purchase it from external parties.

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[30] By adding the LRMC curve for ”unknown” entrants, the true LRMC curve becomes flatter (assuming that the LRMC of the ”unknown” potential entrants are similar to the ”known” potential entrants). A similar mechanism is displayed in Figure 27 a and b.

Even if the 2020 target of adding 26.4 TWh new RES-E generation is fulfilled, the actual generation from to year to year and the total production over the whole period up to 2035 is uncertain. Volume variations in the production of electricity based on renewable energy sources are generally large and since the actual production determines the number of certificates obtained, both the generated electricity and the number of obtained certificates are stochastic variables. Volume fluctuations affect short-term generation and thus the SRMC supply curve. The quota obligation may also contribute to some volume risk. Since the demand for certificates is given as a share of the actual electricity consumption, any deviations from the expected electricity consumption assumed in the quota curve will result in too many or too few cancelled certificates. The currently large reserve of electricity certificates in the market makes the volume risk on the demand side less critical, although it may become more apparent if the certificate surplus diminishes.

The market participants expectations to the balance between issued and cancelled electricity certificate in each year over the remaining duration of the electricity certificate market (2015-2035) will determine their expectations to the certificate price. If the market actors believe that there will be a future shortage of certificates, prices will stay positive. However, with a prolonged certificate surplus and insufficient demand to absorb the issued certificates in each year and the certificate stock over the entire balancing period, the certificate price is likely to collapse. Worst-case scenario, established RES-E producers are not able to recover their capital costs, and bankruptcy may prevail. The regulators may choose to intervene by adjusting the quota curve upwards, introduce a price floor or back-load certificates,[31] which will be discussed in section 8.

[31] Back-loading refers to a market intervention where electricity certificates are temporarily withdrawn in order to keep the price at a higher level.

## 6.4 Price risk and the role of long-term contracts

In this section, we elaborate on how the uncertainty in future certificate prices and short-term price volatility may affect different types of RES-E investors and the possibilities for price hedging in the electricity certificate market. In general, a liquid forward market for hedging purposes is considered essential for attracting new investors to a commodity market. A solid hedging strategy should manage the market risk and make it easier to obtain external financing, while at the same time create acceptable revenue stability for investors without taking away any upward potential. We identify some issues that obscure the liquidity of the Swedish-Norwegian electricity certificate market, namely the low turnover rate and trading volumes, high volatility and lack of transparency. First, we discuss theory on the role of long-term contracting in a technology-neutral tradable electricity certificate market, before we consider the implications for RES-E investors the Swedish-Norwegian electricity certificate system.

In the literature, long-term certificate contracts have been identified as important for the success of tradable certificate markets (Agnolucci, 2007) (Kildegaard, 2008). Financiers cannot take on significant risks and if they are concerned with the extent of the price and volume risks they will require long-term contracts to secure stable cash flows. If there are low volumes of available long-term contracts, this poses a risk of not obtaining financing if the investor is unable to meet the requirements of the financier.

Kildegaard (2008) argues that RES-E investors (and financiers) will require a substantial risk premium ($\rho$) due to the asymmetric downside risk of overinvestment and subsequent price spoilage. The risk premium in consideration results from a lack of coordination among market agents, and not the characteristics of the technology or environment. Kildegaard (2008) argues that the risk of overinvestment could be eliminated through a contracting mechanism that coordinates the market agents since the obliged party will not enter into contracts for more certificates than what is necessary to fulfil the quota (Kildegaard, 2008).

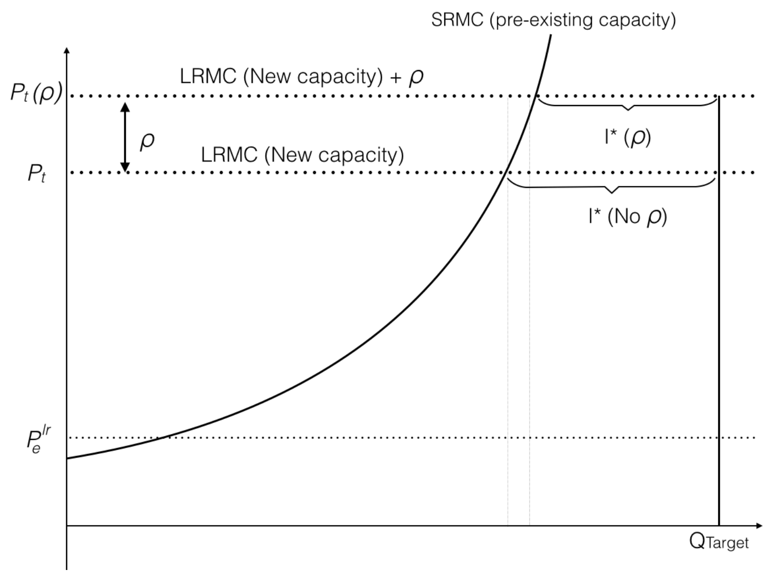


**Figure 36: The effect of coordination risk, based on (Kildegaard, 2008)**

In figure 36, the coordination risk $\rho$ results in a higher cost of financing that shifts the LRMC of potential new capacity upwards. If the price does not cover the LRMC and $\rho$, capital-intensive technologies such as wind will not be established if they must rely on spot sale of certificates. In order for long-term contract to develop, the welfare of both eligible and obliged parties must be maintained or improved. Investor will accept long-term contracts as long as the total price is equal to $P_t$ or higher. Certificate-obliged consumers can reduce their certificate costs by entering long-term contracts at $P_t$ $(\rho)$ or lower, which they will do if their cost reduction is valued higher than the option value of buying certificates from the next generation technology more cheaply in the spot market. This option is forfeit once the consumer enters into a long-term contract with a producer. By taking into consideration additional risk factors such as regulatory uncertainty, it seems likely that the risk premium is considerably larger than the option value of buying certificates at the spot market from the next generation technology. If this is the case, then equilibrium occurs where it is the best interest of consumers to eliminate the coordination risk $\rho$ through long-term contracting for a price level at $P_t$ (Kildegaard, 2008).

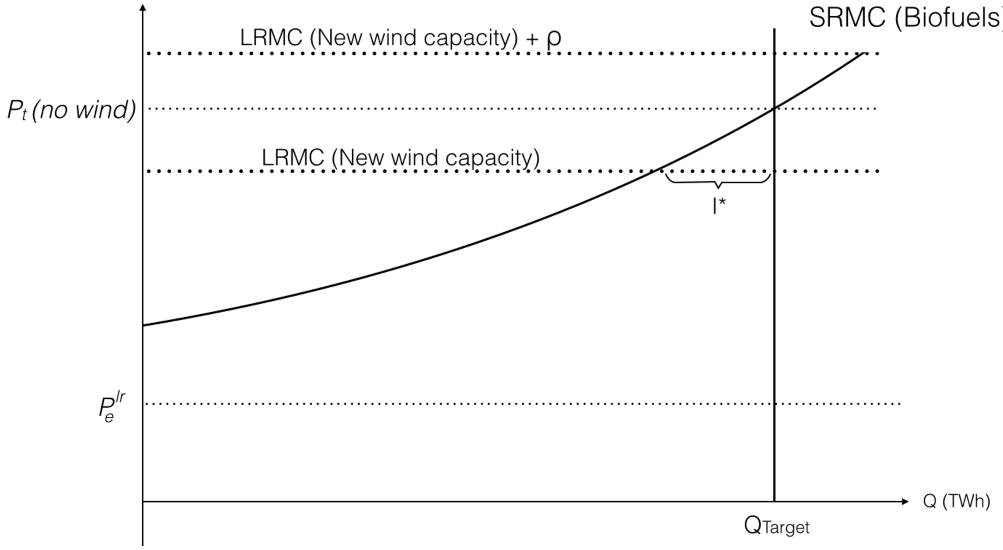


**Figure 37: Long-term contracts in a technology neutral certificate market, based on (Kildegaard, 2008)**

With a similar reasoning, it can be shown that a technology-neutral certificate market where both low fixed cost technologies (e.g. biofuels) and capital-intensive technologies (e.g. wind) are eligible for certificates may result in a lower volume of long-term contracts being offered. In Figure 37, the inclusion of low fixed cost technologies gives a more elastic supply curve $SRMC(Biofuels)$. If we consider the case where there are no investments in high fixed cost technologies such as wind initially, the total price will be $P_t(No\ wind)$. New wind capacity is not established if the investor must rely on spot sale of certificates since $P_t(No\ wind)$ is not sufficient to cover the $LRMC$ and $\rho$. The criterion for consumers to offer long-term contracts becomes stricter because the option value of buying certificates from future technologies on the spot market must now be valued less than $P_t(No\ wind) - LRMC(New\ wind\ capacity)$, which is smaller than the coordination risk premium ($\rho$). Since the condition for consumers to be willing to offer long-term contracts becomes stricter under a technology-neutral electricity certificate scheme where low fixed cost technologies are present, it is less likely that long-term contracts will be offered (Kildegaard, 2008). With less available long-term contracts, the RES-E composition could potentially be shifted away from capital-intensive technologies that require long-term contracts in order to secure financing. It should, however, be noted that an introduction of long-term contracting is not unproblematic. Short-term certificate spot market liquidity would suffer, and long-term competition between successive technology vintages may be lost.

## 6.5 Trading in the Swedish-Norwegian electricity certificate market

In the early phases, brokerage and advisory services facilitated trading in electricity certificates, generally in non-standardised contracts. As the certificate volumes increased, trading through energy brokers, specialising in the RES-S market, offering standardised or semi-standardised products has emerged. Currently, electricity certificate trading occurs through bilateral agreements, directly between producers and the quota-obliged buyers or through brokered transactions. The Swedish-Norwegian electricity certificate market has yet to see significant trading volumes on transparent exchanges such as Nasdaq OMX.

The electricity certificate registers NECS and Cesar reported total transaction volume of 47,705,332 electricity certificates (corresponding to 47.7 TWh) in the period 1 April 2013 to 31 March 2014 (Statnett NECS, 2015). About half of the electricity certificates in the Swedish-Norwegian electricity certificate market are traded through bilateral contracts or directly between generators and those having quota obligation (Hakvoort & Fagiani, 2014). Both volume and price on all transactions are registered in NCES and Cesar. However, since there can be a lag between the contract is entered and physical transaction, the prices in the registers does not provide an accurate market spot price. Rather, the result of brokered transactions on the major brokered trading places is the commonly recognised market spot price. In the period April 1 2013 to March 31 2014, SKM, ICAP and Clean World, reported that approximately 29 TWh were traded through brokered transactions[32] (NVE & Energimyndigheten, 2014). Figure 38 displays the volume of electricity certificates traded in different types of contracts.

[32] Publicly available records on traded volumes through brokered transactions are not provided by neither of the brokers SKM, ICAP or Clean World.

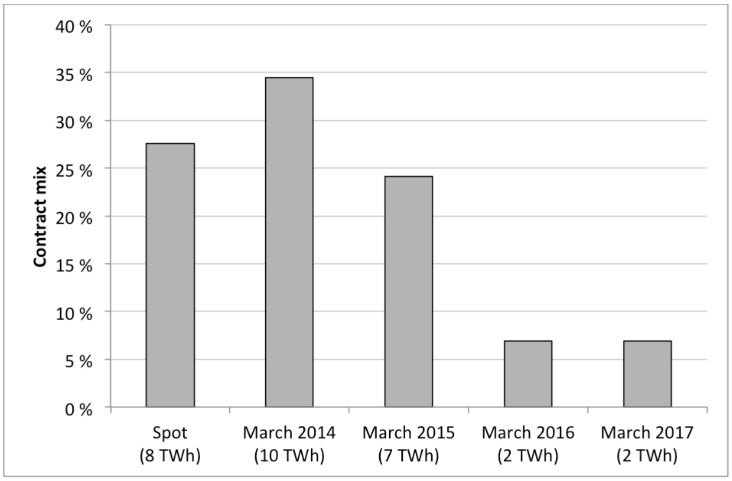


**Figure 38: Certificate trading volumes by type of contract (NVE & Energimyndigheten, 2014)**

Over 60 per cent of total traded volumes at brokerages were spot contracts and the closest forward contract, i.e. for the following March. The low volumes of trade in the forward contracts and their limited maturity (maximum 5 years) limit the possibility for investors to secure future cash flow through semi-standardised[33] contracts. In order to fulfil the financiers' requirements to a secure cash flow, investors may therefore seek actors in the market who would be willing to sign long-term contracts. These could be anyone with a quota obligation, although power-intensive industry and large electricity suppliers with a quota obligation are most likely to be interested in long-term contracts for electricity certificates. The terms of such contracts are normally not publicly available and remain hidden from other market participants. For potential investors, long-term contracts can be critical in order to make an investment decision or obtain financing. If it is difficult to find market actors that are willing to sign long-term contracts, the market uncertainty increases. Hedging fees are likely to vary depending on the type of trade. Midttun & Gundersen (2003) suggest that hedging fees decrease as transactions become more transparent and contracts are standardised. Since a large share of the volume in electricity

[33] Semi-standardised contracts are traded over the counter (OTC) at brokerages such as SKM, where trade entries are usually multiples of 5,000 certificates.

certificates are traded in non-standardised contracts and only semi-standardised brokered trading, the hedging fees are likely to be relatively high (Midttun & Gundersen, 2003).

The precarious design of the Swedish-Norwegian electricity certificate market may entail large risks and uncertainty to RES-E investors who rely on the electricity certificate price, together with the power price, to cover their long run marginal cost. The motivation for the following is to discuss how the risk and uncertainty may influence RES-E investors under the Swedish-Norwegian electricity certificate market and whether it can potentially affect the policy outcome.

# 7 The effect of risk and uncertainty

As we saw in section 3, the LCOE is sensitive to variations in the cost of capital, in particularly for high capital cost technologies such as wind power. In the following, we present the Weighted Average Cost of Capital (WACC) and a brief literature review to provide a basis for a discussion on the potential effects of the risk related to wind power investments under the Swedish-Norwegian electricity certificate system on the cost of capital of projects, and whether risk mitigation has the potential to lower the overall costs of RES-E deployment.

## 7.1 The cost of capital

The cost of capital reflects both the total required rate of return for investors and the cost of debt, and takes into account that projects are financed by both equity and debt. To invest in projects with higher risks investors will require a higher rate of return. In a similar fashion, financiers will charge a higher interest rate on loans issued to more risky investments. We present the Weighted Average Cost of Capital (WACC), which includes the total required return on a project by combining the requirements of the equity (owner) and debt (lender) providers. The cost of equity and the interest rate on debt are weighted by the equity share and debt share of the total investment, respectively. It is generally accepted that risk levels can be reflected in the cost of capital required for funding RES-E projects. One reason for this is that higher project risks, particularly in the form of uncertain future cash flows, limits the amount of debt that can be raised.

The weighted average cost of capital (WACC) summarizes the required return on debt and equity by the respective weight, as shown in the formula:

$$WACC = \frac{E}{E+D} \cdot r_e + \frac{D}{E+D} \cdot r_d \cdot (1-s)$$

Where $r_e$ is the required return of equity and $r_d$ is the cost of debt. $E$ is equity and $D$ is debt and $(1-s)$ is the effect of corporate tax. In general, interest on debt paid to a lender is tax deductible and the tax effect reduces the overall WACC. This is one of the reasons why debt has a lower required rate of return than equity. Moreover, senior debt is placed high in the capital hierarchy resulting in a prioritized stake in the company's revenue stream. In the case of liquidation, the senior debt provider will have the first claim on company assets. An increased level of debt results in higher risk for the owner, keeping the total company risk constant. Different projects or firms may have different combinations of debt and equity. Since equity is generally more expensive than debt, the debt-to-equity ratio can have a significant impact on the average cost of capital of a project (Johnsen & Gjølberg, 2009).

For an investor, the required rate of return may be defined as the expected return that the capital market offers on a similarly risky investment. A renowned method for estimating appropriate level of required return on equity is the capital asset pricing model (CAPM):

$$E(r_i) = r_f + \beta \cdot E\left(r_m - r_f\right)$$

Where $E(r_i)$ is the expected return, $r_f$ is the risk free interest rate, $\beta$ is systematic risk and $E\left(r_m - r_f\right)$ is the expected market premium (above the risk free $r_f$).

The risk-free rate $r_f$ simply reflects the time value of money. The second term of the formula reflects the additional expected return that the investor requires in order to take on risk. The market premium is the expected excess return above the risk free rate on a well-diversified market portfolio. Assuming that investors hold relatively well-diversified portfolios, they will only require compensation for systematic, non-diversifiable risk. The $\beta$ factor measures the non-diversifiable risk in comparison to the market portfolio risk, and gives an indication of the investment risk relative to the market as a whole (Johnsen & Gjølberg, 2009).

Under the CAPM, investors are only compensated for systematic risk, while non-systematic (idiosyncratic) risk is assumed removed completely through diversification. Although the CAPM is a commonly used method for estimating the cost of equity by firms or investors, it may not necessarily capture their actual required return since it is not necessarily the case that investors have fully diversified portfolios. Moreover, the CAPM is normally based on the achieved return of larger publicly traded companies, hence a liquid asset. If the CAPM is used for estimating the required rate of return for small or private firms, it may be desirable to add a liquidity premium, representing the owner's risk related to being locked into the investment.

## 7.2 Literature review

The cost of capital of a project is generally considered confidential and sensitive information to competition. The complexity of ownership structures, varying level of debt, different types of debt and investors' risk preferences suggests that the WACC may vary across projects. We discuss a few studies that consider appropriate rates of return on investments in RES-E technologies.

In a study of Norwegian investments in renewable energy, Johnsen and Gjølberg (2009) suggest a cost of capital of 7.7 per cent after tax[34], assuming an equity share of 60 per cent. The calculation is based on a version of the CAPM, adjusted for weighted average cost of capital. The risk free interest rate and the market premium are both set at 5 per cent and the beta value is 0.7. The study is based on representative listed companies that are used as proxies to develop beta values for various RES-E technologies. The study suggests beta values of 0.6 for biomass, 0.7 for hydropower and 0.8 for wind power investments. Moreover, a liquidity premium would be appropriate to add since most owners of wind energy are not listed companies.

Based on data from Europe, the U.S. and Canada, Dunlop (2006) construct a benchmark for the return on equity in wind energy investments of 12 per cent and assumes that the rate will drop to 9 per cent with time. The benchmark is constructed by adding a risk free interest rate of 3 per

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[34] Assuming a tax level of 28 per cent. Without tax the cost of capital is 10.7 per cent

cent, an equity risk premium of 4 per cent, fund management expenses of 2 per cent and an illiquidity premium for non-listed investments of 3 per cent. Furthermore, Dunlop (2006) suggest a plus or minus 3 per cent adjustment depending on regulatory risk. Germany is mentioned as an example of low risk due to the Feed-in-Tariff system guaranteeing a fixed price level, while the U.K. is identified with the highest risk due to its market-based Renewable Obligation Certificate system, which has some similarities with the Swedish-Norwegian electricity certificate market. Based on the findings of Dunlop (2006) we argue that the regulatory uncertainty arising from a tradable certificate system is likely to increase the risk premium, although the relation between regulatory risk and cost of capital requires further study.

It is not the goal of this thesis develop estimates of an appropriate cost of capital for investments in new RES-E under the Swedish-Norwegian electricity certificates scheme. However, we aim to identify whether the different features of the current support scheme are likely to influence the cost of capital using economic reasoning.

## 7.3 The effect of risk and uncertainty in the Swedish-Norwegian electricity certificate system

The thesis has identified various risks and uncertainties faced by investors in new RES-E capacity under the Swedish-Norwegian electricity certificate system. In the following, we discuss whether the risk factors could have an impact on investment decision and the cost of capital. While some factors are outside the control of a particular RES-E project developer, other factors may be technology-related and project specific.

Even with a risk premium that is, in principle, a question of the systematic risk (i.e. the risk that cannot be diversified through a broad portfolio), some more fundamental questions relating to the stability of the regulatory and political regime may be relevant in a risk premium assessment. In a politically imposed market such as the Swedish-Norwegian electricity certificate scheme, investors are exposed to risk of policy changes. Regulatory risk contributes to higher risk premium if the expected changes to the policy are asymmetric, meaning that there is a greater likelihood that the changes will weaken the future cash flow than increase it. In the section 8, we evaluate how and whether the regulators can potentially reduce the uncertainty in the regulatory framework.

In section 2 we discussed how the technology risk results in a value of waiting for investors. For an investor it may be beneficial to delay an investment decision as long as possible to ensure access to state of the art technology at lower costs. However, since new RES-E investments under the electricity certificate support scheme needs to be operational by the end of 2020, the value of waiting is reduced due to the risk of not receiving electricity certificates. It can be argued that investors should demand a risk premium due to technological progress, since once the plant is built it may risk being undercut by newer versions of the same technology that has lower costs. If market participants expect that the market clearing technology will have a lower total cost of electricity generation, the long-term expectations for the electricity certificate price will fall.

A solid understanding of the price and volume risk in both the power market and the electricity certificate market is an important foundation for investment decision. Due to the considerable cash flow uncertainty, investors and financiers will surely require a risk premium. For a potential investor, this risk must be reduced to acceptable levels in order to reach an investment decision. Marginal investors relying on the sale of electricity certificates to cover their fixed costs are likely to require a higher rate of return, resulting in a higher cost of capital to compensate for the risk. Different investor types will have different risk appetite and ability to manage risk. The lack of information about and uncertainty regarding the future supply and demand for electricity certificates introduces an asymmetric downside risk of industry-wide overinvestments, which poses a threat of certificate price collapse in the period after 2020. Furthermore, if financiers are concerned about project's price and volume risk, they may charge higher interest rates, adding to the cost of capital. The limited liquidity in the markets for electricity certificate forward contracts and limited information about the availability of long-term contracts poses a challenge to some projects that are in the process of securing financing.

In Norway, several of the wind power projects in the pipeline require extensions of the central or regional grid in order to be realized. Possible delays in planned grid expansions therefore pose a risk to the deployment of new generation capacity. For a particular investor, grid connection is a prerequisite for an investment decision rather than an investment driver, since it cannot be realized without grid connection. Thus, it is not likely to have any effect on the cost of capital. However, it could imply that economically viable projects under the certificate scheme are delayed or stranded.

Through the discussion on various risk factors faced by investors in new RES-E capacity under the Swedish-Norwegian electricity we find indications that a significant risk premium may be present. While some risk factors originate from the design of the support scheme, others can be traced back to the characteristics of the technology. If the perceived risk to capital cost recovery is significantly large, investors may be hesitant to enter the market. If the risk premium raises the cost of capital and thus the LRMC of potential projects, the policy outcome could be altered. In the following, we describe how a potentially large risk premium can affect the policy outcome in terms of cost-effectiveness and welfare allocation.

The technology-neutral Swedish-Norwegian electricity certificate scheme was based on the cost-effectiveness principle to ensure that the quantitative target for RES-E deployment is reached at the lowest total generation costs. A risk premium arising from the uncertainty regarding capital cost recovery would be included in the LRMC calculation of the potential investor. In a simple cost resource curve, it can be shown that a risk premium could add to the total generation costs of potential investors and thus the costs to electricity consumers.

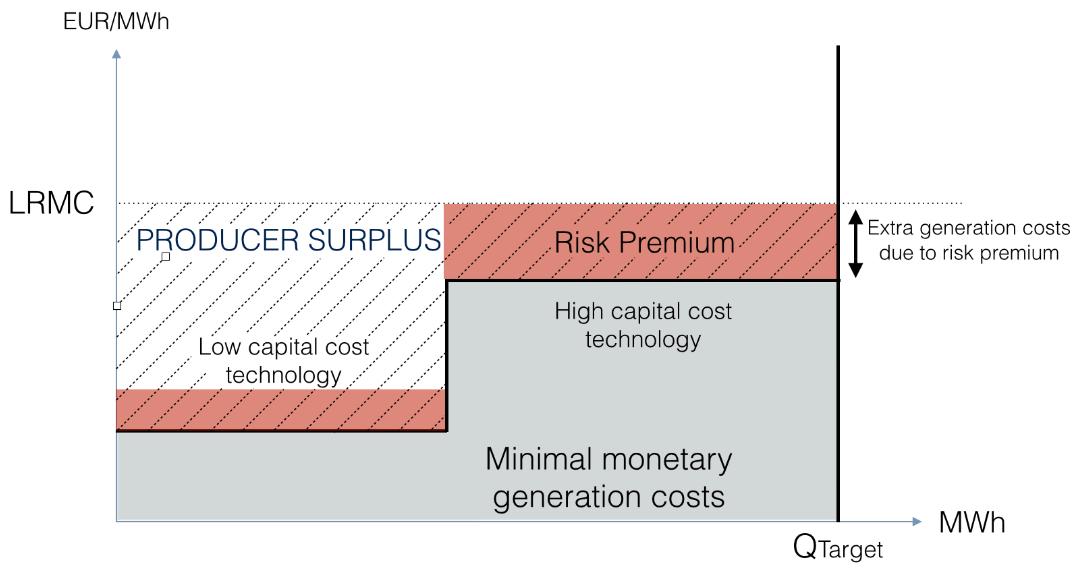


**Figure 39: Risk premium with high and low capital cost, based on (Haas, Resch, Panzer, Busch, Ragwitz, & Held, 2010)**

Moreover, it may be argued that the risk premium raises the cost of capital more for high capital cost technologies such as wind power, as displayed in figure 39 (Haas, Resch, Panzer, Busch, Ragwitz, & Held, 2010). Johnsen and Gjølberg (2009) found indications that the systematic risk, represented by the beta, varies with technology and that there is a higher risk associated with wind energy investments compared to biomass or hydropower investments. Assuming that wind power will be the market clearing technology, a particularly high cost of capital for potential wind power investments results in a higher overall policy cost since new investments require a higher long-run compensation level. At a higher total price paid to all RES-E producers, the producer surplus increases. Since electricity consumers in Norway and Sweden will ultimately pay for the support scheme, a larger producer surplus implies large transfers from consumers to producers.

In the more sophisticated graphical illustration (Figure 40), it can be shown that a high risk premium ($\rho$) shifts in LRMC of new capacity upward. The figure illustrates how the introduction of a risk premium would lead to lower investment in new RES-E capacity ($I^*(Risk)$ than the optimal quantity ($I^*(No\ risk)$ and higher long run certificate price ($P_C(Risk)$.

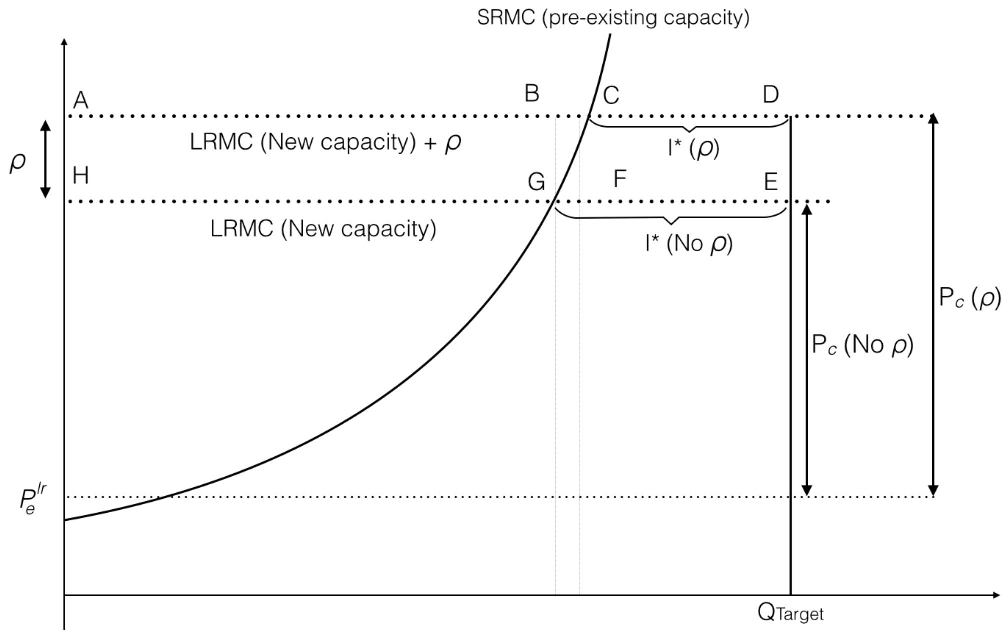


**Figure 40: Welfare effects of risk premium, Kildegaard (2008)**

The welfare effects of a higher risk premium could be read from the graphical illustration. The area ADEH indicates a loss to consumer surplus. For existing producers, there is a gain in surplus corresponding to the area ACGH because all RES-E producers in certificate market are paid the higher certificate price $P_C(\rho)$. The area CDEF represents the expected gain to new producers, due to the increase in certificate price. In total, the area CDEG is the net welfare loss due to a high risk-premium. Kildegaard (2008) argues that this additional transfer from consumers to producers cannot be regarded as a welfare gain because it is due to a socially unproductive risk that could have been eliminated if the market participants were informed about supply and demand or could coordinate through long-term contracts such that investors in new capacity were guaranteed a certificate price for a period. (Kildegaard, 2008).

Through a revision of the Swedish-Norwegian electricity certificate marked, we find indications of a high degree of uncertainty in the market. Risk factors may potentially affect investments in new RES-E generation capacity, lead to high cost of capital and increase the total policy cost. Possible gains of reducing the risk premium related to the support scheme design should be relevant for regulators. In the next chapter, we discuss whether the regulators could make alterations to the electricity certificate market design in order to reduce the negative effects of risk and uncertainty. In particular, we consider the coordination risk due to lack of information, risk related to the 2020 deadline and how the regulators can play a role in reducing demand side uncertainty.

# 8 Reducing risk and uncertainty in the Swedish-Norwegian electricity certificate market

The consequences of risk and uncertainty for potential investors in new RES-E generation capacity under the Swedish-Norwegian electricity certificate market discussed in the previous chapter stresses the possible benefits of reducing unnecessary uncertainty. We discuss how the regulators may play a role in reducing risk through possible policy design alterations.

## 8.1 Price floor

Low electricity certificate prices may lead to a severe slowdown in investment decisions. Due to the short time frame of the market, delays in investments decisions poses a risk that developers may have too little time to realize the projects. A price floor could be set as a guaranteed minimum certificate price or a lower bound for the sum of the power and certificate price combined. With a price floor, the risk for investors would be lower since the price floor, which is activated if the price falls below the floor, would provide a higher remuneration than without a price floor. However, by obscuring the information in the price signals, prices could be kept artificially high in periods where low prices should reflect a large certificate surplus. Artificially high prices would in turn encourage a too high investment level, fuelling the risk of overinvestment in too many and too expensive RES-E projects. Due to large potential production volumes available in the RES-E project pipeline and the risk of overinvestment, we do not recommend that the regulators introduce a price floor. Moreover, a price floor could give a higher total support level, thus creating a greater add-on to consumer costs, in particular if too many and too expensive RES-E plants are built.

## 8.2 Borrowing

A borrowing mechanism implies that the obliged party can borrow certificates from future production (shorting) and therefore do not have to cancel the exact number of certificates corresponding to the quota obligation. Borrowing is currently not possible in the Swedish-Norwegian electricity certificate market. If the regulators are concerned with end-user costs becoming excessively high in situations with certificate shortages and high penalty fees, the flexibility in a borrowing mechanism could limit the end-user costs. Moreover, it has been suggested in the literature that borrowing, at least to a limited extent, may also reduce price fluctuations more than what certificate banking does (Amundsen, Baldursson, & Mortensen, 2006). We consider the main drawback of introducing a borrowing mechanism to be that the currently considerable certificate surplus could retain towards 2035 and therefore remove expectations of certificate shortages. Moreover, the regulatory framework may become overly complicated and make it increasingly difficult to process and predict market developments.

## 8.3 Information to the market

The lack of perfect information regarding the supply and demand in the certificate market was discussed in section 6. We believe that the regulators could minimize the risk to the investors by increasing market transparency. On the supply side, increased transparency regarding the status of RES-E projects in the pipeline could reduce the risk of overinvestment and provide potential investors with sufficient information necessary to assess future prices and thus the expected return on investment. This could be achieved by introducing a common register including the status of RES-E projects in the pipeline in Norway and Sweden. We believe that such a register should, at least, contain the RES-E projects that have reached an investment decision and those that are under construction together with information on the project's planned installed capacity and expected electricity production contributing towards the quota target. Moreover, we suggest that potential investors should be obliged to notify the regulatory authorities once they make an investment decision and that it is the role of the regulatory authorities to make the information publicly available. It is crucial that the same set of information is provided in both countries at the same time, in order to avoid information asymmetry. By providing the market with sufficient information to make informed decisions, regulators can contribute to a more predictable investment environment. The regulatory authorities should investigate whether the savings to society from reducing supply uncertainty is greater than the cost of developing and maintaining such a register, in which case a register should be implemented. Furthermore, the regulatory authorities in Norway and Sweden play a key role in the distribution of information regarding changes to the policy. Since the market price is highly sensitive to such information, it is crucial that it is made available in equal form and at the same time to all market participants.

## 8.4 Quota curve adjustments

Electricity certificate prices are sensitive to the given quota, and regulators could reduce uncertainty on the demand side. Currently, the quota obligation is given as a percentage of electricity consumption, and the actual electricity consumption may deviate from what was forecasted for the policy period. Since the quota obligation is written in law, quota curve adjustments is an extensive process and are therefore scheduled to be revised only every four years. We believe that the short time frame of the system requires more frequent adjustments to reduce uncertainty regarding the demand for certificates. If there are large deviations between actual and forecasted demand, imbalances between issued and cancelled certificates occur, affecting electricity certificate prices. By regularly updating the quota curve to new forecasts, for example every year, market participants would be provided with a more correct signal on whether there is a need for more or less investments in order to meet the quantitative target. Furthermore, the regulators could require more frequently updated information on electricity consumption and corresponding certificate demand and make such information available to market participants. This could possibly contribute to increased trade in electricity certificates throughout the year and more accurate electricity certificate prices and therefore reduce the uncertainty related to the demand. Furthermore, if a situation of overinvestments arises in 2020, the regulators may choose to interfere in the market to keep the certificate price at an appropriate level. If a price floor is not introduced, the regulators could apply a mechanism referred to as back-loading in which certificates are temporarily withdrawn from the market in order to reduce the oversupply.

In the on-going system review, it has been suggested that quota curves for Norway and Sweden should be given as an absolute number of certificates (TWh) to be cancelled rather than percentages of expected electricity consumption. This could reduce the uncertainty concerning certificate demand and completely remove the uncertainty related to regulatory adjustments due to forecasting errors. Figure 41 shows what an absolute quota obligation could look like.

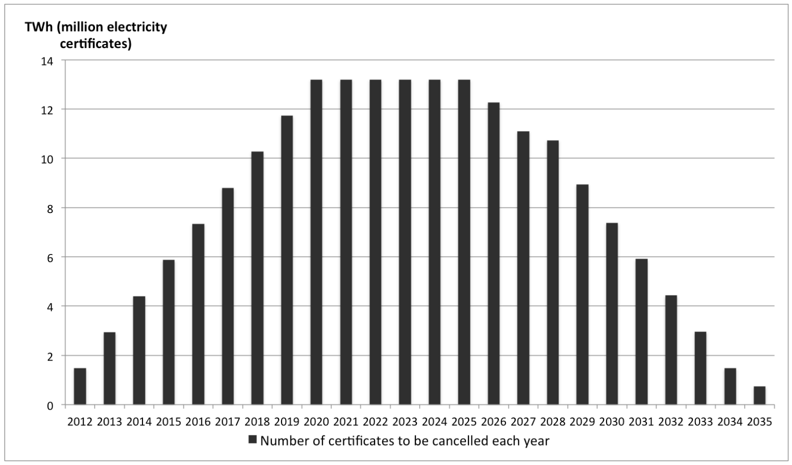


**Figure 41: An absolute quota obligation in Norway**[35]

## 8.5 Long-term contracts

Long-term contracts may be necessary to secure financing and reduce price uncertainty for investors. Today, price and volume information on long-term contracts are publicly available through NECS and Cesar when the transaction is made, but not on the date of agreement. Publicly available information on the agreed price and volume in long-term contracts for future delivery should be made available in order to improve the market transparency and price signal. Furthermore, improved transparency in the financial markets for electricity certificates could further reduce price uncertainty.

We believe that facilitating for increased trade on an exchange, such as Nasdaq OMX, would improve the functioning of the market since the exchange provides a transparent price signal to the market. As the market is expected to encompass an increasingly higher volume of certificates this type of trade in electricity certificates could develop naturally. More standardised products

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[35] Based on Norway's obligation to finance 198 TWh of new RES-E capacity over the period 2012-2035 (13.2 TWh for 15 years). Generation from the transition period will come in addition since their production cannot be known on beforehand.

are likely needed, in particular in contracts with a maturity of 5 years or more. Allowing a third party exchange to make transfers between accounts in NECS/Cesar with stringent requirements for reporting would be one way to facilitate transparent trade.

## 8.6 Gracing period

The 2020 deadline in Norway poses a risk to investors of not becoming eligible for electricity certificates due to project delays. The risk could be reduced by adding more flexibility to the time limit (gracing period) or by setting the limit according to the 26.4 TWh quantitative target without a time limit.

A gracing period similar to Sweden would reduce the risk of non-completion of projects that are under construction in Norway close to 2020. A gracing period is unlikely to incentivise investors to defer investments since projects that enter during the gracing period will not receive certificates for the full 15 years. We believe that an introduction a gracing period of at least a year would considerably reduce this risk of exclusion from the support scheme due to project delays that arise from factors outside the control of the investor. However, such a solution would not mitigate the risk of overshooting the quantitative mandate. A deadline that is disconnected from a specific point in time, but rather related to the target of 26.4 TWh could reduce the risk of over- or underinvestment. Downsides to such a solution could be that a rush of investments occurs because of a time pressure to be included in the 26.4 TWh target. The time pressure could potentially distort the quality of the projects that are included, resulting in a situation where it is not necessarily the best projects that are realized due to project deferring factors such as grid connection.

We believe that a hybrid solution would the best option for the Swedish-Norwegian electricity certificate market. By keeping the 2020 deadline, market participants will continue to plan according to the time limit. If, however, at the end of 2020, the quota target of 26.4 TWh is not met, RES-E projects according to the remaining capacity could be realized in order to fulfil the quota. Regardless, we deem it essential that the same time limit apply in both countries.

# 9 Conclusion

In 2012, Norway and Sweden introduced a common, market-based tradable electricity certificate system to stimulate investments in new RES-E capacity corresponding to 26.4 TWh each year by 2020. The purpose of this thesis was to evaluate the risk and uncertainty related to investments in new RES-E generation capacity under the Swedish-Norwegian electricity certificate market, both in terms of risks faced by potential wind power investors and potential effects on the policy outcome.

Potential investors will base their decision on an expectation that future price of power and electricity certificates cover their LRMC, including SRMC, average fixed costs and a risk premium. Based on LCOE calculations, we estimate that the LRMC of Norwegian wind power projects that have received a licence are in the range of 438-617 NOK/MWh. RES-E investors in the Nordic energy-only power market face uncertain revenues due to price and volume risk. Power prices are highly volatile and difficult to forecast, although the financial market provides possibilities for price hedging. The sale of electricity certificates provides RES-E generators with an additional source of income, however the uncertainty related to future electricity certificate prices is a concern to both potential investors and financiers. The electricity certificate market is a long-term policy in which the electricity certificate price should signal the need for more or less investments in new RES-E capacity in order to reach the politically determined quantitative target in a cost-effective manner. The demand for certificates is ensured by imposing a quota obligation on electricity suppliers that is gradually increased towards 2020 in order to stimulate supply of new RES-E investments. The supply side consists of the electricity certificates issued to RES-E generation eligible for electricity certificates, and the LRMC of the last project needed to reach the target should signal the revenue-generating price level needed to stimulate new RES-E investments corresponding to the quantitative target. So far, 10.3 TWh of new RES-E capacity counting towards the target has come online and we construct a static cost resource curve to evaluate the additional realisable potential of new RES-E projects in Norway and Sweden. Despite the sizable amount of Norwegian wind power projects in the pipeline, we estimate that only an additional 3.5 TWh has the potential to contribute to the quantitative target, which implies that only the very best projects should come online. We find that the marginal project is likely to be a Swedish wind power plant with a LRMC around 510 NOK/MWh. Technology learning has the potential to reduce future energy costs, which influences the expected long run electricity certificate price.

The currently low power- and electricity certificate prices are delaying investments in wind power because market actors are hesitant to invest when prices are low, and financiers generally require long-term contracts to provide non-recourse financing. We identify challenges to potential investors and discuss how the precarious design of the market mechanism influences current and expected certificate prices. Fundamentally, the lack of information and uncertainty related to the supply and demand for certificates introduces a risk that the quantitative target is missed. In particular, the sizable amount of RES-E projects in the pipeline introduces an asymmetric downside risk of due to industry-wide overinvestment and price spoilage after 2020, which makes it plausible that investors demand a risk premium. Moreover, the availability of long-term contracts for hedging of future electricity certificate prices is identified as a key for realizing investments, particularly for wind power, due to relatively high capital costs. We find indications that the presence of a risk premium could increase the cost of new capacity and potentially result in a higher policy cost for the electricity consumers in Norway and Sweden.

We suggest how the regulators of the common Swedish-Norwegian electricity certificate market could play a role in reducing the risks related to the demand and supply of certificates by modifying some of the market design elements. We find that the key to ensure deployment of new RES-E within the current policy at the lowest cost to the consumers is improved transparency regarding the RES-E project pipeline status and in the trading places for electricity certificates. Moreover, the regulators should take measures to ensure that the demand for certificates provides more correct signals to potential investors of how much new RES-E capacity is needed in order to reach the quantitative target.

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# Appendix

## Appendix A: Investor type classification

| Utility type owners<br>Project name | Licence applicant | Licenced capacity (MW) |
|---|---|---|
| Roan | FOSEN VIND AS | 300 |
| Storheia | FOSEN VIND AS | 220 |
| Geitfjellet (SAE Vind DA) | STATKRAFT AGDER ENERGI VIND DA | 210 |
| Tellenes | TELLENES VINDPARK DA | 200 |
| Guleslettene | GULESLETTENE VINDKRAFT AS | 160 |
| Songkjølen and Engerfjellet | E.ON WIND NORWAY | 155 |
| Bjerkreim (Eikeland-Steinsland) | BJERKREIM VIND AS | 150 |
| Svarthammaren/Pållifjellet | STATKRAFT AGDER ENERGI VIND DA | 150 |
| Sørmarkfjellet | SAREPTA ENERGI AS | 150 |
| Dalsbotnfjellet | ZEPHYR AS | 150 |
| Remmafjellet | STATKRAFT AGDER ENERGI VIND DA | 130 |
| Hamnefjell | HAMNEFJELL VINDKRAFT AS | 120 |
| Kvenndalsfjellet | FOSEN VIND AS | 120 |
| Innvordfjellet | ZEPHYR AS | 115 |
| Kvitvola/Gråhøgda | AUSTRI KVITVOLA DA | 110 |
| Raskiftet | AUSTRI RASKIFTET DA | 110 |
| Hitra 2 | STATKRAFT AGDER ENERGI VIND DA | 110 |
| Harbakfjellet | TRØNDERENERGI KRAFT AS | 90,75 |
| Høgås and Joarknatten | E.ON Vind Sverige AB | 90 |
| Sørfjord | NORDKRAFT VIND AS | 90 |
| Stokkfjellet | TRØNDERENERGI KRAFT AS | 90 |
| Storehei | E.ON WIND NORWAY | 80 |
| Haram | HARAM KRAFT AS | 66 |
| Måkaknuten | LYSE PRODUKSJON AS | 66 |
| Frøya | SAREPTA ENERGI AS | 60 |
| Kvinesheia | STATKRAFT AGDER ENERGI VIND DA | 60 |
| Ånstadblåheia | VESTERÅLSKRAFT VIND AS | 50 |
| Lutelandet | LUTELANDET ENERGIPARK AS | 45 |
| Kjølberget | AUSTRI VIND DA | 40 |
| Hennøy | VESTAVIND KRAFT AS | 35 |
| Bukkanibba | LYSE PRODUKSJON AS | 30 |
| Svåheia | BJERKREIM VIND AS | 24 |
| Vågsvåg | ZEPHYR AS | 24 |
| Okla | VESTAVIND KRAFT AS | 21 |
| Testområde Stadt | VESTAVIND KRAFT AS | 10 |
| Vikna | NTE ENERGI AS | 9 |
| Haugøya testturbin | STATKRAFT AS | 8 |
| Bessakerfjellet II | TRØNDERENERGI KRAFT AS | 4 |
| Hundhammerfjellet - demo II | NTE ENERGI AS | 3 |
| Mehuken 3 (+ tidl. Mehuken 1) | KVALHEIM KRAFT DA | 2,75 |
| Hundhammerfjellet - demo I | NTE ENERGI AS | 1,65 |

**Investor type: Individual Power Producer (IPP)**

| Project name | Licence applicant | Licenced apacity (MW) |
|---|---|---|
| Kalvvatnan | FRED OLSEN RENEWABLES AS | 225 |
| Gilja | FRED OLSEN RENEWABLES AS | 135 |
| Egersund | NORSK VIND EGERSUND AS | 110 |
| Gravdal | FRED OLSEN RENEWABLES AS | 90 |
| Skinansfjellet | NORSK VIND SKINANSFJELLET AS | 90 |
| Dalbygda | DALBYGDA VINDKRAFT AS | 42 |
| Tysvær | ALPIQ ECOPOWER SCANDINAVIA AS | 39 |
| Skorveheia | NORSK VIND ENERGI AS | 36 |
| Gismarvik | FRED OLSEN RENEWABLES AS | 15 |
| Storøy | SOLVIND PROSJEKT AS | 6 |
| Vardøya | NORD-NORSK VINDKRAFT AS | 6 |
| Friestad | SOLVIND PROSJEKT AS | 2,4 |
| Røyrmyra | NORSK VIND ENERGI AS | 2,4 |

**Diversified company**

| Project name | Licence applicant | Licenced capacity (MW) |
|---|---|---|
| Skurvenuten | ASKO ROGALAND AS | 10 |
| Tindafjellet | ASKO ROGALAND AS | 10 |

**Developer**

| Project name | Licence applicant | Licenced capacity (MW) |
|---|---|---|
| Øyfjellet | EOLUS VIND NORGE AS | 330 |
| Kvitfjell | NORSK MILJØKRAFT TROMSØ AS | 200 |
| Tonstad | TONSTAD VINDPARK AS | 200 |
| Andmyran | ANDMYRAN VINDPARK AS | 160 |
| Skveneheii | SKVENEHEII VINDKRAFT AS | 120 |
| Raudfjell | NORSK MILJØKRAFT RAUDFJELL AS | 100 |
| Faurefjellet | HYBRID TECHNOLOGY AS | 60 |
| Vardafjellet | VARDAFJELLET VINDKRAFT AS | 30 |
| Dønnesfjord | VINDKRAFT NORD AS | 10 |
| Maurneset vindkraftverk | VINDKRAFT NORD AS | 10 |
| Sandhaugen teststasjon | NORSK MILJØKRAFT FORSKNING & UTVIKLING AS | 9 |

**Publicly owned non-energy company**

| Project name | Licence applicant | Licenced capacity (MW) |
|---|---|---|
| Stigafjellet | STIGAFJELL VIND AS | 30 |

## Appendix B: LCOE calculations and assumptions

| Name | Expected installed capacity MW | Expected generation GWh | Full load hours | Capacity factor | O&M cNOK /kWh | Investment cost, million NOK/MW | LCOE NOK/ MWh |
|---|---|---|---|---|---|---|---|
| Kvitvola/Gråhøgda | 110,0 | 376,8 | 3425 | 39 % | 12,5 | 11,4 | 467 |
| Raskiftet | 110,0 | 357,5 | 3250 | 37 % | 13,5 | 12,6 | 532 |
| Kjølberget | 40,0 | 119,6 | 2990 | 34 % | 12,5 | 13,1 | 572 |
| Dalbygda | 29,9 | 91,8 | 3070 | 35 % | 15,5 | 11,6 | 545 |
| Høgås and Joarknatten | 62,1 | 198,9 | 3203 | 37 % | 12,5 | 11,5 | 493 |
| Songkjølen and Engerfjellet | 144,5 | 433,5 | 3000 | 34 % | 12,5 | 11,4 | 514 |
| Storehei | 87,0 | 282,9 | 3252 | 37 % | 12,5 | 12,6 | 523 |
| Øyfjellet | 314,5 | 1163,7 | 3700 | 42 % | 13,5 | 11,9 | 466 |
| Roan | 300,0 | 870,0 | 2900 | 33 % | 10,0 | 12,0 | 521 |
| Storheia | 220,0 | 616,0 | 2800 | 32 % | 10,0 | 12,0 | 535 |
| Kvenndalsfjellet | 100,0 | 260,0 | 2600 | 30 % | 10,0 | 12,0 | 568 |
| Gilja | 135,0 | 405,0 | 3000 | 34 % | 13,5 | 12,0 | 544 |
| Kalvvatnan | 216,0 | 648,0 | 3000 | 34 % | 17,0 | 11,0 | 550 |
| Guleslettene | 144,0 | 432,0 | 3000 | 34 % | 12,0 | 10,0 | 462 |
| Hamnefjell | 120,0 | 340,0 | 2833 | 32 % | 13,5 | 13,4 | 617 |
| Faurefjellet | 60,0 | 180,0 | 3000 | 34 % | 15,0 | 12,8 | 588 |
| Lutelandet | 45,0 | 121,5 | 2700 | 31 % | 14,0 | 11,5 | 576 |
| Måkaknuten | 66,0 | 195,7 | 2965 | 34 % | 15,0 | 12,5 | 583 |
| Bukkanibba | 30,0 | 90,0 | 3000 | 34 % | 15,5 | 11,3 | 543 |
| Sørfjord | 72,0 | 227,2 | 3155 | 36 % | 15,0 | 11,7 | 531 |
| Raudfjell | 100,0 | 284,0 | 2840 | 32 % | 16,5 | 11,1 | 569 |
| Egersund | 105,0 | 304,5 | 2900 | 33 % | 13,5 | 12,0 | 558 |
| Skorveheia | 36,0 | 104,4 | 2900 | 33 % | 11,5 | 11,0 | 503 |
| Sørmarkfjellet | 150,0 | 420,0 | 2800 | 32 % | 10,0 | 12,0 | 535 |
| Frøya | 60,0 | 160,0 | 2667 | 30 % | 12,5 | 11,6 | 568 |
| Skveneheii | 90,0 | 270,0 | 3000 | 34 % | 15,0 | 11,5 | 545 |
| Hitra 2 | 58,9 | 164,9 | 2800 | 32 % | 13,5 | 13,0 | 609 |
| Kvinesheia | 60,0 | 162,0 | 2700 | 31 % | 14,0 | 9,0 | 484 |
| Geitfjellet | 159,0 | 429,9 | 2704 | 31 % | 13,5 | 11,5 | 570 |
| Svarthammaren/Pållifjellet | 150,0 | 405,0 | 2700 | 31 % | 13,5 | 11,8 | 581 |
| Remmafjellet | 130,0 | 384,8 | 2960 | 34 % | 13,5 | 11,2 | 523 |
| Stigafjellet | 27,8 | 84,5 | 3037 | 35 % | 13,0 | 13,0 | 567 |
| Tellenes | 192,0 | 518,4 | 2700 | 31 % | 14,6 | 10,8 | 556 |
| Tonstad | 192,0 | 622,1 | 3240 | 37 % | 15,0 | 11,0 | 501 |
| Stokkfjellet | 80,0 | 252,0 | 3150 | 36 % | 16,5 | 11,1 | 530 |
| Vardafjellet | 30,0 | 90,0 | 3000 | 34 % | 15,0 | 8,3 | 438 |
| Hennøy | 33,0 | 99,0 | 3000 | 34 % | 13,5 | 11,5 | 528 |
| Ånstadblåheia | 32,2 | 86,9 | 2700 | 31 % | 14,0 | 12,0 | 595 |
| Dalsbotnfjellet | 150,0 | 450,0 | 3000 | 34 % | 13,5 | 11,2 | 518 |
| Innvordfjellet | 115,0 | 341,2 | 2967 | 34 % | 11,0 | 12,0 | 522 |
| Gravdal | 86,0 | 267,1 | 3106 | 35 % | 15,0 | 13,3 | 589 |
| Skinansfjellet | 90,0 | 297,0 | 3300 | 38 % | 13,0 | 12,5 | 518 |
| Bjerkreim(Eikeland-Steinsland) | 146,1 | 427,0 | 2922 | 33 % | 15,0 | 13,1 | 608 |
| Andmyran | No information available | | | | | | |
| **Reference project** | **108,8** | **326,4** | **2975** | **34 %** | **13,5** | **11,7** | **538,9** |

**LCOE assumptions**: Escalation rate (e): 1%, Plant life (T): 20 years, Discount rate (r) 7.7%, Hours per year (H): 8760. Information on operation and maintenance costs were missing for 8 projects, in which case the average of the other project's O&M costs, 13.5 cent NOK/kWh, are assumed.

## Appendix C: Quota curves for Sweden and Norway

| Year | Quota curve Sweden* | New quota curve Sweden** | Quota curve Norway* | New quota curve Norway*** |
|---|---|---|---|---|
| 2003 | 7,4 % | | | |
| 2004 | 8,1 % | | | |
| 2005 | 10,4 % | | | |
| 2006 | 12,6 % | | | |
| 2007 | 15,1 % | | | |
| 2008 | 16,3 % | | | |
| 2009 | 17,0 % | | | |
| 2010 | 17,9 % | | | |
| 2011 | 17,9 % | | | |
| 2012 | 17,9 % | | 3,0 % | |
| 2013 | 13,5 % | | 4,9 % | |
| 2014 | 14,2 % | | 6,9 % | |
| 2015 | 14,3 % | 14,3 % | 8,8 % | 8,8 % |
| 2016 | 14,4 % | 23,0 % | 10,8 % | 11,9 % |
| 2017 | 15,2 % | 24,6 % | 12,7 % | 13,7 % |
| 2018 | 16,8 % | 26,2 % | 14,6 % | 15,4 % |
| 2019 | 18,1 % | 27,6 % | 16,5 % | 17,2 % |
| 2020 | 19,5 % | 26,6 % | 18,3 % | 19,7 % |
| 2021 | 19,0 % | 25,0 % | 18,2 % | 19,6 % |
| 2022 | 18,0 % | 23,5 % | 18,1 % | 19,6 % |
| 2023 | 17,0 % | 22,2 % | 18,0 % | 19,5 % |
| 2024 | 16,1 % | 20,5 % | 17,9 % | 19,3 % |
| 2025 | 14,9 % | 18,4 % | 17,6 % | 18,6 % |
| 2026 | 13,7 % | 16,1 % | 16,4 % | 17,4 % |
| 2027 | 12,4 % | 14,0 % | 15,1 % | 15,6 % |
| 2028 | 10,7 % | 12,4 % | 13,2 % | 13,1 % |
| 2029 | 9,2 % | 10,8 % | 11,3 % | 10,9 % |
| 2030 | 7,6 % | 9,1 % | 9,4 % | 9,0 % |
| 2031 | 6,1 % | 7,1 % | 7,5 % | 7,2 % |
| 2032 | 4,5 % | 5,3 % | 5,6 % | 5,4 % |
| 2033 | 2,8 % | 3,7 % | 3,7 % | 3,6 % |
| 2034 | 1,2 % | 2,1 % | 1,8 % | 1,8 % |
| 2035 | 0,8 % | 1,3 % | 0,9 % | 0,9 % |

* Original quota curves, stipulated in the Swedish and Norwegian Electricity Certificate Act (Olje- og energidepartementet, 2012)
** New quota curve for Sweden after 2015 adjustment, suggested by the Swedish Energy Agency (Energimyndigheten a, 2014)
*** New quota curve for Norway after 2015 adjustment, suggested by NVE (NVE c, 2014)

**Appendix D: Estimated demand for electricity certificates in TWh (million certificates)**

| Year | Sweden 13.2 TWh | Norway 13.2 TWh | Swedish transition period | Norwegian transition period |
|---|---|---|---|---|
| 2004 | | | 5,1 | |
| 2005 | | | 10,1 | |
| 2006 | | | 12,3 | |
| 2007 | | | 14,6 | |
| 2008 | | | 15,6 | |
| 2009 | | | 16,0 | |
| 2010 | | | 16,2 | |
| 2011 | | | 17,5 | |
| 2012 | 1,5 | 1,5 | 15,08 | 0,8 |
| 2013 | 2,9 | 2,9 | 9,67 | 0,7 |
| 2014 | 4,4 | 4,4 | 8,84 | 0,7 |
| 2015 | 5,9 | 5,9 | 7,45 | 1,2 |
| 2016 | 7,3 | 7,3 | 15,91 | 2,2 |
| 2017 | 8,8 | 8,8 | 16,24 | 2,2 |
| 2018 | 10,3 | 10,3 | 16,32 | 2,1 |
| 2019 | 11,7 | 11,7 | 16,25 | 2,1 |
| 2020 | 13,2 | 13,2 | 13,16 | 2,8 |
| 2021 | 13,2 | 13,2 | 11,25 | 2,8 |
| 2022 | 13,2 | 13,2 | 9,60 | 2,8 |
| 2023 | 13,2 | 13,2 | 8,22 | 2,7 |
| 2024 | 13,2 | 13,2 | 6,36 | 2,6 |
| 2025 | 13,2 | 13,2 | 4,15 | 2,0 |
| 2026 | 12,3 | 12,3 | 2,72 | 2,0 |
| 2027 | 11,1 | 11,1 | 1,79 | 1,7 |
| 2028 | 10,7 | 10,7 | 0,67 | |
| 2029 | 8,9 | 8,9 | 0,94 | |
| 2030 | 7,4 | 7,4 | 0,93 | |
| 2031 | 5,9 | 5,9 | 0,54 | |
| 2032 | 4,4 | 4,4 | 0,37 | |
| 2033 | 3,0 | 3,0 | 0,40 | |
| 2034 | 1,5 | 1,5 | 0,43 | |
| 2035 | 0,7 | 0,7 | 0,44 | |

Demand is found by multiplying the annual percentage quota obligation by yearly expected electricity consumption in TWh

* Demand prior to 2015 are based on actual certificate cancellations, while demand estimates as of 2015 are based on suggested new quota curves

## Appendix E: Policy cost calculation

| Year | Quota obligation (TWh)* | Price (NOK/MWh)** | Additional cost (NOK/MWh)*** | Nominal cost (MNOK) | Present value (MNOK)**** |
|---|---|---|---|---|---|
| 2012 | 2.23 | 140.8 | 45.8 | 415.92 | 415.92 |
| 2013 | 3.64 | 177.3 | 57.6 | 855.38 | 855.38 |
| 2014 | 5.13 | 164.2 | 53.4 | 1 115.25 | 1 115.25 |
| 2015 | 7.05 | 137.8 | 44.8 | 1 287.01 | 1 287.01 |
| 2016 | 9.53 | 132,8 | 43.1 | 1 677.10 | 1 677.10 |
| 2017 | 10.98 | 135.0 | 43.9 | 1 964.10 | 1 916.19 |
| 2018 | 12.35 | 137.7 | 44.7 | 2 252.65 | 2 144.11 |
| 2019 | 13.79 | 141.3 | 45.9 | 2 582.50 | 2 398.11 |
| 2020 | 16.02 | 144.9 | 47.1 | 3 074.97 | 2 785.77 |
| 2021 | 15.95 | 155.0 | 50.4 | 3 275.88 | 2 895.40 |
| 2022 | 15.97 | 155.0 | 50.4 | 3 279.16 | 2 827.61 |
| 2023 | 15.90 | 155.0 | 50.4 | 3 265.69 | 2 747.31 |
| 2024 | 15.75 | 155.0 | 50.4 | 3 235.43 | 2 655.47 |
| 2025 | 15.20 | 155.0 | 50.4 | 3 120.92 | 2 499.01 |
| 2026 | 14.23 | 155.0 | 50.4 | 2 922.49 | 2 283.04 |
| 2027 | 12.77 | 155.0 | 50.4 | 2 622.78 | 1 998.94 |
| 2028 | 10.73 | 155.0 | 50.4 | 2 204.67 | 1 639.29 |
| 2029 | 8.94 | 155.0 | 50.4 | 1 836.25 | 1 332.06 |
| 2030 | 7.38 | 155.0 | 50.4 | 1 515.67 | 1 072.68 |
| 2031 | 5.91 | 155.0 | 50.4 | 1 213.75 | 838.05 |
| 2032 | 4.44 | 155.0 | 50.4 | 911.22 | 613.82 |
| 2033 | 2.96 | 155.0 | 50.4 | 608.09 | 399.63 |
| 2034 | 1.48 | 155.0 | 50.4 | 304.35 | 195.14 |
| 2035 | 0.74 | 155.0 | 50.4 | 152.33 | 95.28 |
| **Sum** | **229.07** | | | **45 693.55** | **38 687.57** |

* Quota obligation for Norway includes demand from transmission period and new generation

** We use actual, average certificate prices for 2012 – 2015 (NOK), Forward prices for 2016 - 2020 (available 12.05.15) (SKM, 2015), while prices 2020 – 2035 are assumed to be the average of historic prices (2012-2015) All prices are converted using exchange rate SEK/NOK = 0.9.

*** VAT of 25 per cent and administration costs of 7.5 per cent (NVE c, 2014) are assumed.

**** Present value is based on a 2.5 per cent discount rate equal to the Norwegian inflation target.