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Financial Investment Analysis of Residential Rooftop Solar PV Systems in Norway

A Model-Based Approach to Analyse Profitability and the Effect of Key Variables Under Current Market Conditions

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Summary

In light of increased electricity prices and high demand for renewable energy, solar PV deployment has risen rapidly and is expected to increase further, both globally and in Norway. Although a large part of the growth is related to utility-scale parks, rooftop systems on houses represent a significant potential for future deployment. Consequently, this thesis aims to build a general model for evaluating the profitability of residential rooftop solar PV systems in Norway. The profitability is not evaluated for specific projects but typical residential projects in Norway.

The profitability question is evaluated using the net present value method. A cash flow model is developed for typical solar PV systems in six Norwegian cities. Initial investment costs are estimated from regressions on installation offers collected in the fall of 2022. Future electricity price scenarios are constructed using a combination of Nasdaq futures prices and long-term market analyses from NVE and Statnett. Sensitivity analyses are performed for variables like electricity price, initial investment cost, cost of capital, and share of generated electricity consumed internally.

The thesis concludes that residential rooftop PV systems in Norway are not profitable unless electricity price scenarios well above historical prices are assumed. The geographic differences are strongly apparent, with the most profitable profiles located in Oslo, Kristiansand, and Bergen and the least profitable profiles located in Tromsø. The geographic differences are driven by meteorological conditions and differences in investment costs. Out of the variables that can be affected by the project owner, we found that the share of generated electricity consumed internally is the variable with the highest effect on profitability. We also argue that a reduction in investment cost is likely due to temporary high prices. This would have a strong positive impact on the profitability analysis.

Contents

List of figures

List of tables

Abbreviations

Abbreviation	**Explanation**
kWp	Kilowatt-peak. Peak power generation capacity under standard test conditions
kWh	Kilowatt-hour
NPV	Net present value
IRR	Internal rate of return
PV	Photovoltaics
PV-systems	Photovoltaic systems. Solar panels combined in a system that generates electricity.
LID	Light-induced degradation. The initial degradation of a solar panel.
TMY	Typical Meteorological Year
Energy yield	Energy generated each unit of installed capacity. Measured in annual kWh/kWp.

Throughout this paper, the word “project” is used when talking about investments in rooftop solar PV systems. Depending on the context, the “project” can mean both the model as a hole or a more specific profile.

1. Introduction

The European energy situation in 2021 and 2022 has clearly illustrated the need for a broader energy supply. Solar PV is a rapid-growing source of electricity anticipated to play a significant role in the future energy mix. In addition to being renewable, it is expected to be one of the most cost-competitive energy sources in the future. Another benefit is that solar panels can generate electricity without covering valuable acreage if installed on rooftops.

Investments in rooftop solar PV systems in Norway have historically been low. In light of the high current electricity prices and the recent increase in the Enova subsidy, it is interesting to examine if rooftop solar panels are now a viable investment for Norwegian households. Therefore, this thesis aims to answer the following question:

How profitable are residential rooftop solar photovoltaic systems in Norway, and how do changes to key variables affect the profitability evaluation?

This thesis will evaluate the profitability of typical residential rooftop solar PV systems in Norway with project start in 2023 and a lifetime of 30 years. We do not analyse specific projects but build a model to evaluate projects with different characteristics. Systems are evaluated in Oslo, Kristiansand, Stavanger, Bergen, Trondheim and Tromsø. The thesis is limited to grid-integrated systems without storage options. Building-integrated PV or wall-mounted panels are not examined. The analysis is relevant for single-family houses and units in chained houses, while apartment buildings are not covered due to differences in regulation. The system is assumed to be bought and owned by the household and not leased. The analysis does not consider non-financial aspects such as environmental impact.

In the following, a short literature review will be presented to look at some relevant previous works. Chapter three provides the reader with background information about trends in solar PV deployment and a basic introduction to the most important technical aspects. The problem definition and the main evaluation criterion are introduced in chapter four, while chapter five explains the cash flow model and the key assumptions underlying our calculations. The results are presented in chapter six and further analysed and discussed in chapter seven. Chapter eight concludes the analysis before some fundamental limitations are presented in chapter nine. Lastly, chapter ten outlines some non-financial aspects that are not included in the analysis but could be relevant to investigate in further research.

2. Literature Review

Several papers have evaluated the feasibility of rooftop solar PV systems in Norway in recent years. While some papers mainly focus on the technical aspects, like the expected energy yield of a Norwegian PV project, others focus more on the profitability perspective. Most papers either base the analysis on the levelised cost of energy (LCOE) or the net present value (NPV) for the profitability evaluation. LCOE measures the cost of energy from a given technology by dividing the lifetime costs by lifetime electricity generation, both discounted at the average cost of capital for this technology (IRENA, 2021). The NPV method discounts all future cash flows to find the present value of the project. In the following, three papers using these methods will be presented.

Solbakken (2014) evaluates the LCOE of small-scale grid-connected solar PV systems in Norway. The analysis calculates the maximum LCOE where the project is cost-competitive with the alternative of buying electricity from the grid to 0.91 NOK/kWh. For comparison, the thesis calculates the average LCOE for small-scale solar PV systems in Norway to be in the range of 1.81 - 2.44 NOK/kWh. Thus, the LCOE is found to be more than double the maximum limit it could be to be competitive with buying electricity from the grid, and the project is not considered profitable following a pure financial evaluation.

Mekki & Virk (2016) perform an NPV analysis of a specific rooftop solar PV project in Bergen. The paper aims to calculate the profitability of rooftop PV systems under different regulatory conditions by conducting a bottom-up cash flow analysis. Electricity prices are forecasted using historical prices. Furthermore, the paper considers expected generation and consumption patterns to estimate how much electricity will be consumed internally and how much will be sold to the grid. Lastly, investment and operational costs are estimated, and all cash flows are discounted using an 8% WACC. In the base scenarios, NPV is negative for all profiles, ranging from NOK -16 000 to NOK -8 000 in their base scenarios. Further sensitivity analyses are conducted focusing on changes to the initial investment cost, electricity prices and cost of capital, which are considered to be the most relevant determinants of the project NPV.

Bøhren, Gjærum, & Hasle (2021) evaluate the profitability of a 12 kWp residential rooftop solar PV projects in Bergen and Sandefjord from the perspective of private households using the NPV method. The analysis concludes that the net present value is NOK -29 000 in

Bergen and NOK 7 000 in Sandefjord. The analysis further concludes that the socio-economic profitability of the projects is negative in both cases. The socio-economic profitability is lower because a large part of the benefit of the project for a private household is the lower fees and taxes paid on electricity, which can be viewed as government transfers. The profitability evaluation is strongly affected by the low historical electricity prices in Norway. For example, the authors find that the same project in Frankfurt would have been significantly more profitable because electricity prices are higher.

In addition to the economic analysis, Bøhren (2021) evaluates the lifetime emissions of the project. The analysis concludes that the total emission reduction of residential solar PV systems in Norway is limited. The main reason is that solar panels are produced in Asian countries with high emissions and are used to replace Norwegian electricity with very low emissions. The report finds the CO2 reduction in Sandefjord, Norway, to be 2 tons, while it in Frankfurt, Germany, is 84 tons. This difference is explained by the German electricity mix having four times as high emissions as the Norwegian. These results imply that installing solar panels in Norway is questionable from a purely environmental perspective because of the low emissions in the Norwegian electricity mix. However, the report finds that solar panels in Norway could have contributed to lower global emissions if they were produced with a cleaner electricity mix.

3. Background

3.1 Global Development of Solar Energy

3.1.1 Historical Development and Future Scenarios

Solar PV is expected to account for a significant share of future renewable electricity generation. According to the International Energy Agency (IEA), the global installed PV capacity was 884.5 GW in 2021. IEA's net zero emissions (NZE) scenario describes the measures IEA considers necessary to reach net zero emissions by 2050 and limit global warming to 1.5 degrees Celsius (IEA, 2021). Following this scenario, the total installed PV capacity needs to reach 5 042 GW in 2030, which implies a compound annual growth rate of 21% between 2021 and 2030 (IEA, 2022a). For comparison, historical numbers imply a compound annual growth rate of 33% between 2010 and 2021. Although the majority of installed capacity will naturally be utility-scale PV systems, IEA expects the global number of rooftops with solar panels installed to increase from 25 million in 2020 to 100 million in 2030 and 240 million in 2040.

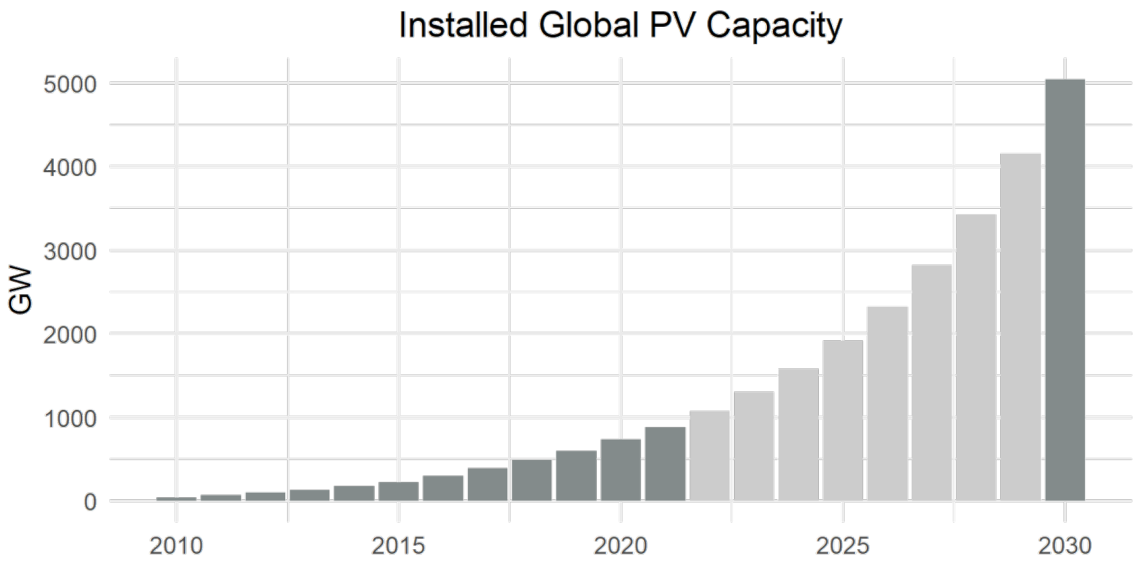

Figure 3-1: Historical solar PV deployment and target installed capacity by 2030, following IEA's NZE scenario.

Solar is also an essential part of the EU's energy transition scenarios. REPowerEU is a new plan by the European Commission in response to the Russian invasion of Ukraine aiming to accelerate the energy transition (European Commission, 2022a). Although an ambitious plan, it may be considered more realistic than IEA's NZE scenario because it is backed by policy changes. In 2020, installed solar PV capacity in the EU was 136 GW. According to REPowerEU, the ambition is to increase solar PV deployment to 320 GW in 2025 and 600 GW in 2030, implying a compound annual growth rate of 16%. (European Commission, 2022b).

3.1.2 Main Drivers Behind the Rapid Growth in PV Deployment

The most apparent driver behind the rapid growth of solar PV is cost reductions. The cost of different energy sources is often compared using the LCOE. According to IRENA (2021), the global weighted average LCOE for newly commissioned utility-scale solar PV projects decreased by 88% from 2010 to 2021. The rapid cost decrease has improved the competitiveness of solar PV, and it is now among the most cost-efficient renewable energy sources, as seen in figure 3-2. Another interesting observation is that solar PV is the energy source with the most significant cost reduction over the period. In this way, solar PV is the energy source with the best relative increase in competitiveness over the period.

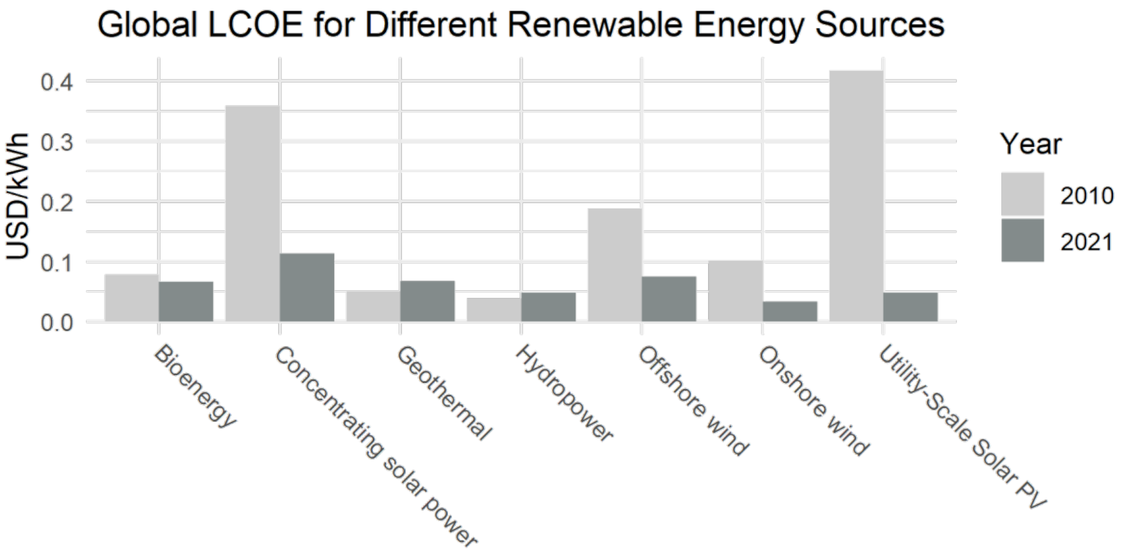

Figure 3-2: Levelised Cost of Energy for different renewable energy sources. Source: IRENA, 2021.

A breakdown of the decrease in solar PV LCOE is shown in figure 3-3. The main driver is declining panel costs, and hardware costs account for 62% of the total LCOE reduction. With the expected growth in PV deployment, there is reason to believe that the hardware price will continue to decrease as manufacturers benefit from higher economies of scale. However, as the panel cost constitutes a smaller part of the total cost, the pace of the cost reduction in solar PV systems is likely to decrease. The reason is that with lower materials cost, a larger part of the total cost is constituted by labour costs of installation, with less potential for cost reductions.

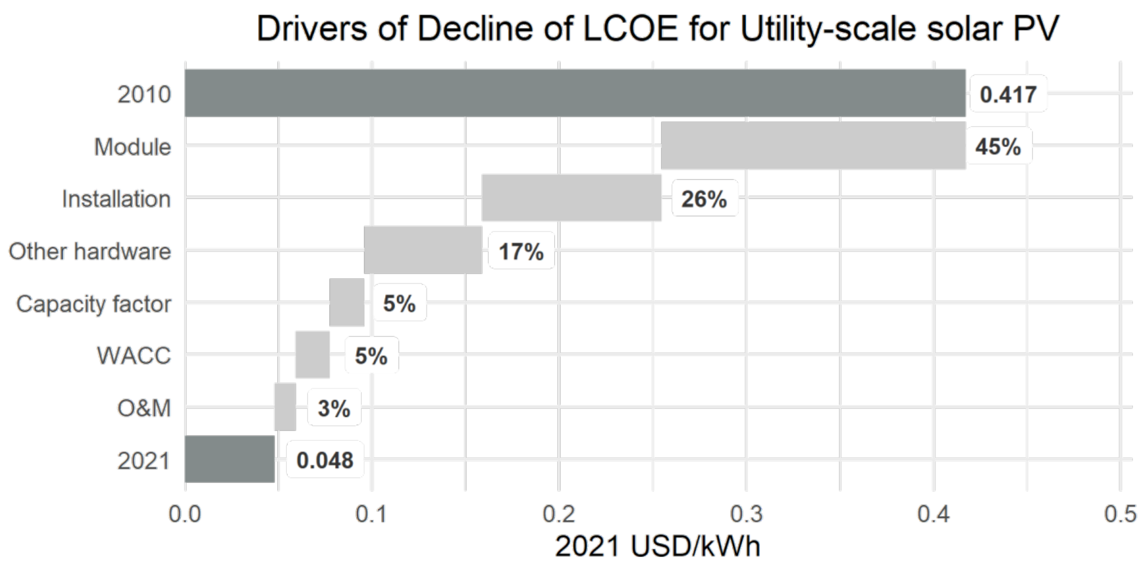

Figure 3-3: Breakdown of utility-scale solar PV cost reductions from 2010 to 2021. Source: IRENA 2021

The LCOE numbers reported in figure 3-2 are calculated for utility-scale solar PV systems. For residential rooftop solar, costs will naturally be higher because of the smaller scale. However, as panel cost is the most important contributor to cost reductions, there is reason to believe that a similar development in cost reduction also applies to residential rooftop systems.

The low-cost argument of Solar PV is also related to operation and maintenance (O&M) costs. An important advantage of solar panels is the lack of moving parts, which results in a longer expected lifetime and very low operational costs. Furthermore, solar panels do not require any fuel to generate electricity, as opposed to electricity generated by fossil fuels. O&M costs are mainly related to preventive measures like services. Cleaning the panels may be necessary in some cases, but rainfalls will often be sufficient. Beyond this, O&M costs mainly consist of replacements of defective components, although these costs are usually covered by guarantees (SolenergiFusen, 2022). It should also be noted that inverters have a shorter expected lifetime than the rest of the system, and a provision for inverter replacement is therefore recommended. The low level of maintenance is especially important for the deployment of residential rooftop solar, as the owner needs minimal knowledge to own and operate a solar PV system.

In addition to cost decreases and low maintenance requirements, there are several other advantages that drive the rapid deployment of solar PV. One essential benefit is that solar panels are quiet and can be installed in residential areas, for example on rooftops. If installed on rooftops, it is less visible and will probably lead to less conflict. These features are advantageous to solar PV compared to onshore wind, which often meets complaints from the local population because of the obstructed view and noise pollution. Another vital benefit of rooftop solar is that it does not cover acreage that could have otherwise been used for other purposes like agriculture. The decentralized energy generation that rooftop solar offers may also benefit the grid, as more of the energy needs are covered by local generation, reducing the need for transmission (Multiconsult, 2022).

3.1.3 Challenges for Solar PV Deployment

Variability in power generation

The ongoing energy transition entails a rapid deployment of intermittent electricity sources like wind and solar. The main feature of these energy sources is that electricity generation is variable and depends on external factors that cannot be controlled (Energy Education, 2022a). As for solar PV, power is only generated when the sun shines, and the panels are directed towards the sun. This means that the panel owner has minimal ability to align PV generation with consumption, as opposed to fossil energy sources, where production can be adjusted according to consumption patterns. This is often referred to as the intermittency problem of renewable energy.

In a typical Norwegian household, electricity demand is expected to be high in the morning and the afternoon (Ericson & Halvorsen, 2008). This consumption pattern differs strongly from PV generation, which is typically highest in the middle of the day. Consequently, electricity generation will typically be higher than consumption in the middle of the day. As electricity needs to be utilized at the moment it is generated, this excess production in the middle of the day either needs to be sold to the grid or stored locally in batteries.

The variability in solar PV power generation is not only an issue for the individual household but can also cause problems for the overall energy system in areas with high PV penetration. Figure 3-4 shows how Statkraft expects the future demand pattern for flexible electricity generation in Germany to develop (Statkraft, 2017). Flexible electricity generation refers to the sources of electricity that can be adjusted to meet demand, like dammed hydropower and gas turbines. The figure shows that when solar power generation is highest in the middle of the day, there is a low need for electricity generated by flexible sources. In the future, if PV penetration is high enough, generation from variable sources may, at times, be higher than total electricity demand. Similarly, we see that in the evening and night, when solar PV generation wanes and electricity demand is high, there is a need for increased generation from flexible sources. This curve is often referred to as the duck curve.

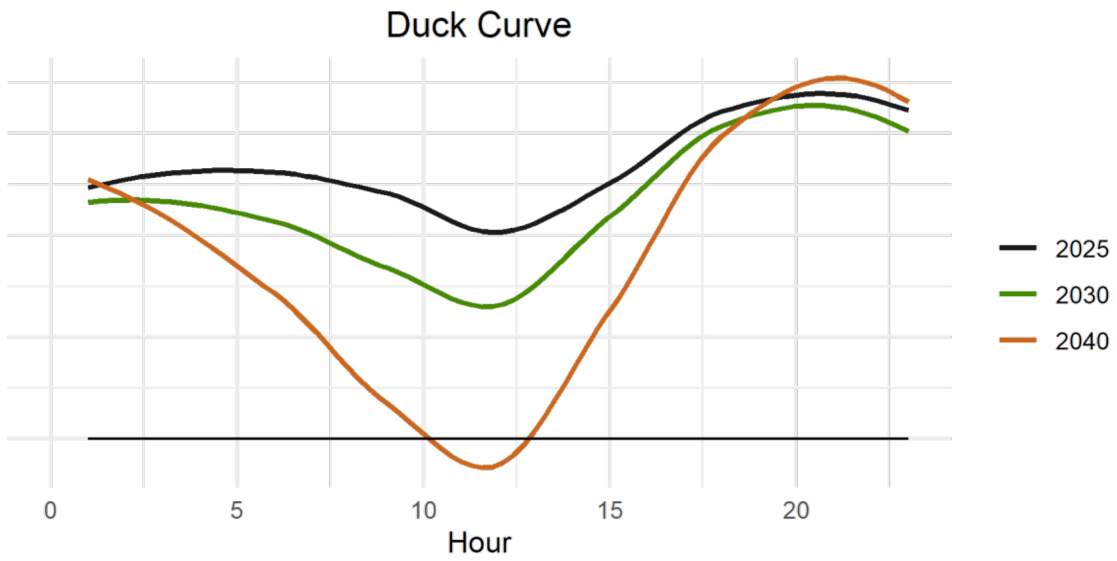

Figure 3-4: "The duck curve". Expected development in hourly demand for flexible electricity production. Source: (Statkraft, 2017).

The duck curve shows that increased PV penetration requires rapid development in flexible energy sources. For Norway, hydropower is well suited to fulfil this role because of its high reservoir capacity and quick responsiveness. However, in areas less suited for dammed hydropower, flexible renewable energy sources are less accessible. The duck curve shows that large-scale solar PV deployment will be problematic unless efficient solutions for electricity storage, flexible energy generation and flexible consumption are developed. One solution is to integrate large-scale batteries in the grid to store excess electricity generated by solar PV during the day to use in the evening. Another solution, with higher emissions, is to continue using fossil power generation as a flexible energy source. Lastly, digitalisation and smart devices can help manage demand to align better with electricity generation.

Other challenges with PV

Another critical issue with solar PV is access to suitable acreage. Utility-scale solar PV parks are typically built in large flat areas. These areas could often have been utilized for other purposes, like agriculture. Thus, the conflict of interest is apparent and an important issue to resolve to facilitate further growth in solar PV. One solution is to combine solar panels with agriculture, so-called agrivoltaics (Dreves, 2022). Another solution is to install more solar panels on rooftops where this conflict of interest is less apparent.

Another issue is cost competitiveness. As shown in figure 3-2, IRENA calculates the LCOE of utility-scale solar PV to be in line with hydropower and higher than onshore wind. LCOE is likely considerably higher for small residential rooftop systems because of the low scale. This shows that although costs for solar PV have decreased rapidly over the past years, it is still not the least expensive available source.

Although solar PV is considered a renewable energy source, there are emissions throughout the lifetime of a solar PV system. Due to a lack of reporting, it is not easy to calculate the total lifetime emissions of solar panels. A study by NREL shows that average lifetime greenhouse gas emissions per kilowatt-hour from a utility-scale solar PV system are about 43 grams of CO2-equivalents per kWh, which is higher than for hydropower and wind turbines (Schroeder, 2021). The majority of emissions come from the extraction of raw materials and assembly of solar panels. Thus, although solar PV is considered a renewable energy source, critics can still be directed towards the lifetime emissions of solar panels.

Another possible limitation to the growth in solar PV deployment is the supply chain and access to raw materials. From 2010 to 2021, China increased its share of global solar PV manufacturing capacity to more than 80%, entailing a political risk (IEA, 2022b). The COVID-19 pandemic illustrated the vulnerability in the supply chain of solar panels and led to slowdowns in PV deployment (U. S. Department of Energy, 2022). Robust supply chains are necessary to facilitate the high expected growth in PV deployment.

3.2 Solar Energy in Norway

3.2.1 Historical Development

Although the conditions for solar PV are not as good in Norway as in countries further south, there has been a rapid growth in solar deployment over the past years. According to the Norwegian Water Resources and Energy Directorate (NVE), cumulative installed grid-connected solar PV capacity in Norway reached 186 MWp in 2021, after a rapid growth in the previous years (NVE, 2022a). The Norwegian Solar Energy Cluster (2022) expects the installed capacity to be around 300 MWp by the end of 2022. Figure 3-5 shows that a considerable part of the growth is driven by systems smaller than 20 kWp, which is the typical size of residential solar PV systems.

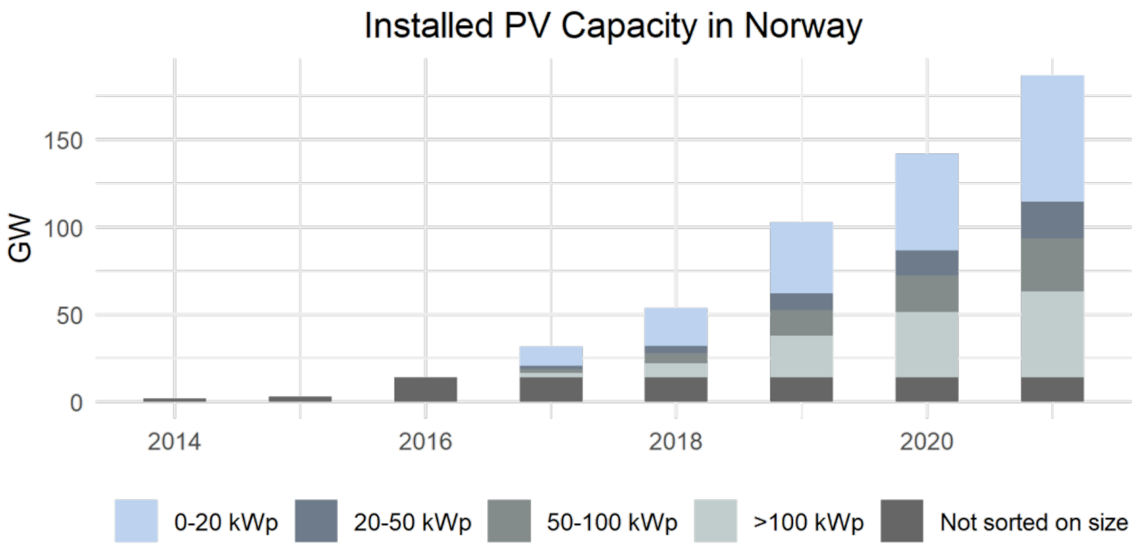

Figure 3-5: Installed PV capacity in Norway. Source: (NVE, 2022a)

The installed capacity is not evenly distributed throughout the country. As shown in figure 3-6, almost half of the installed capacity is in NO1 (NVE, 2022a). Together, 78% of the total installed capacity is located in NO1 and NO2. This is not surprising given that these two zones are the most populous and have the best climatic conditions for solar PV.

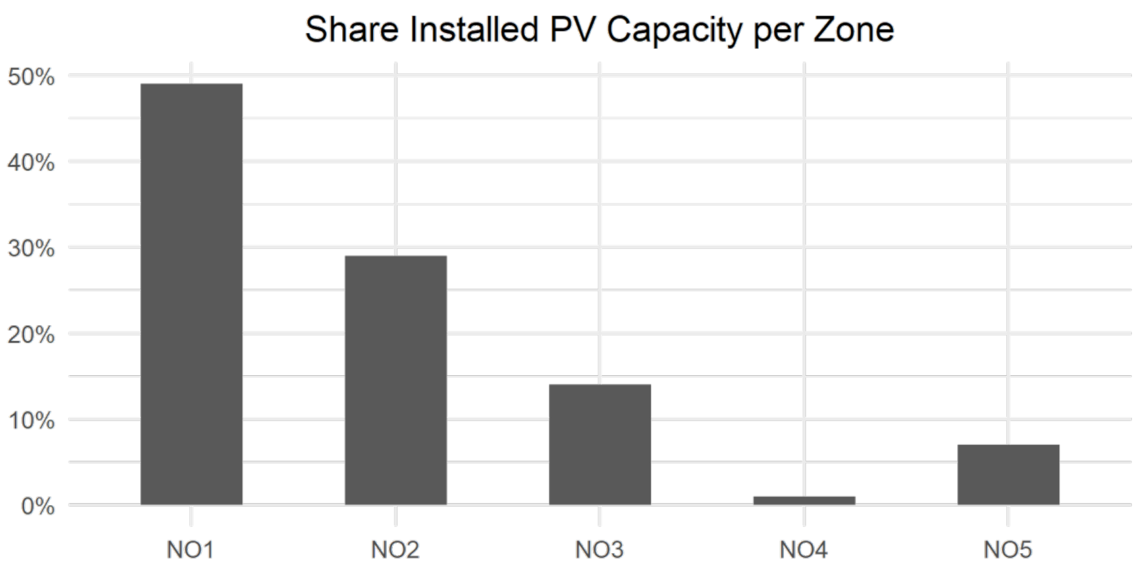

Figure 3-6: Geographic distribution of installed PV capacity in Norway

Norway compared to Sweden and Denmark

Even though Norway has experienced rapid growth in installed solar PV capacity in recent years, the deployment of solar energy in Norway is significantly lower than in the neighbouring countries. In Sweden, cumulative installed PV capacity reached 1 586 MWp in 2021, of which 50% were systems smaller than 20 kWp (Energimyndigheten, 2022). This means that Sweden has an installed PV capacity 8.5 times larger than Norway. For systems smaller than 20 KWp, the typical size for residential systems, installed capacity is 11 times higher in Sweden. In Denmark, installed PV capacity reached 2 339 MWp in Q2 2022, even higher than in Sweden (Energistyrelsen, 2022). Although differences in population and climate may partly explain the relatively low PV deployment in Norway, the data from Denmark and Sweden demonstrate Norway's high growth potential for solar PV.

3.2.2 Current Situation

The market for residential rooftop solar PV systems in Norway is characterised by a few major players. The three largest installers are Solcellespesialisten, Solenergi Fusen, and Kverneland Energi, of which Solcellespesialisten is the leading installer (Ånestad, 2022). However, most residential PV systems are not ordered directly through an installer but sold through intermediaries facilitating turnkey solutions for private customers. The most prominent intermediary in the Norwegian market is Otovo, claiming to have a market share of 50% (Otovo, 2022a). Otovo is a marketplace for household PV systems. Through Otovo's platform, private customers can ask for a price estimate, and Otovo will gather offers from local installers to give the customer the best available deal. None of the three major installers sells directly to customers or via Otovo's platform. Solenergi Fusen and Kverneland Energi primarily focus on large non-residential systems. Solcellespesialisten installs residential PV systems, but sales and marketing are done through partners such as Fjordkraft and Lyse.

3.2.3 Future

The rapid growth in Norwegian solar PV is expected to continue. In a 2020 report produced by the research centre Susoltech in collaboration with the Norwegian Solar Energy Cluster, installed solar PV capacity in Norway is expected to reach 2-4 GWp by 2030. This requires an annual growth rate of 30-40% (Susoltech, 2020). In NVE's long-term power market analysis for 2021, they expect total energy generation in Norway to increase by 28 TWh towards 2040, of which 20% of the growth will come from solar PV (NVE, 2021). In 2040, NVE expects that 3.6% of the total electricity generation in Norway will come from solar

PV. This is equal to the expected output from offshore wind, while the onshore wind is expected to make up 11%. Despite the growth in wind and solar, hydropower will still account for the vast majority of Norwegian electricity production.

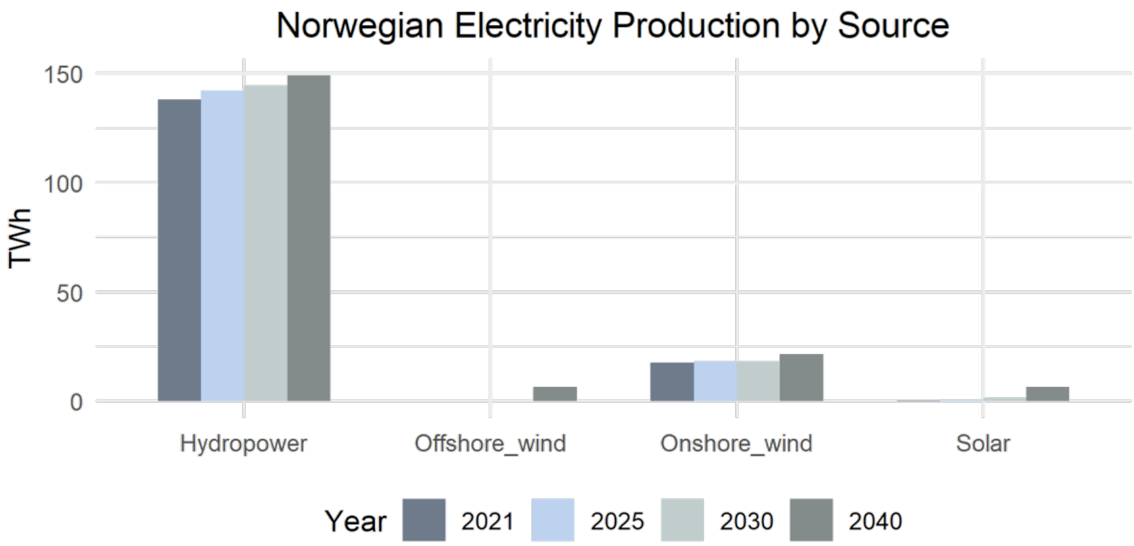

Figure 3-7: Expected development of Norwegian electricity generation. Source: Susoltech, 2020

As a result of the current energy shortage in Europe and soaring electricity prices, interest in solar PV has soared in Norway. Reports from the leading installers in Norway show that interest in solar PV is record-high, suggesting that the growth in solar PV will be strong in the coming years (Ånestad, 2022). However, the high interest has led to long waiting times, delivery issues and increasing prices. These factors can slow down the deployment of solar energy in Norway in the short term.

3.2.4 Financing of Residential Solar PV Systems in Norway

The installation of a rooftop solar PV system is a considerable investment for most households, with costs typically ranging between NOK 100 000 and NOK 300 000. The investment can be equity financed, but many households will choose to take on debt to finance part of the investment. Most Norwegian banks offer long-term loans for the installation of solar panels. These are normally closely connected to the mortgage and uses the house as collateral. In this way, the bank can offer low interest rates and long duration. In addition, the installation of solar panels will often qualify for green loans, which give a slightly lower interest rate than the interest on a regular mortgage. If the system owner cannot provide the house as collateral, loans may still be given but at a higher interest and shorter duration.

Another possible way of financing the installation of solar panels is through leasing. In Norway, Otovo is a major provider of leasing solutions for residential rooftop solar PV systems. When choosing the leasing option, Otovo is the owner of the panels, and the household pays a monthly amount to Otovo. The standard duration of the leasing agreement is 20 years. If the household wishes, it can cancel the agreement at an extra cost or buy the system from Otovo. As Otovo is the owner of the panels, Otovo is also responsible for service, maintenance, and repairs (Otovo, 2022c).

For the household, the leasing option can be compared to a situation where panels are purchased with full debt financing from a bank and the household only pays a monthly amount to cover interest costs and instalments. However, the bank will usually require the project to be partly equity-financed, meaning that the household must have an initial outlay. Thus, leasing is often the only option when the household does not wish to have an initial outlay. Another benefit of the leasing model is that Otovo is responsible for technical issues, which allows the household to install solar panels with very limited technical knowledge. The leasing model is also flexible as the customer can choose to cancel the agreement before 20 years have gone.

3.3 Characteristics of Solar Energy

3.3.1 How Photovoltaics Work

Photovoltaic cells utilize the photovoltaic effect to capture energy from solar irradiation to create an electric current (Energy Education, 2022b). In this way, solar cells transform the energy in solar irradiation into usable electricity. Multiple solar cells are connected and distributed as a single solar panel. The panels can be installed alone or grouped in arrays (Knier, 2022). This way, solar PV systems are easily scalable to the owner’s needs.

The electricity generated by solar cells is direct current (DC), while most electricity distribution grids use alternating current (AC). Therefore, the electricity generated from solar panels needs to be inverted to be used in everyday appliances (EIA, 2022). This inverter accounts for a significant share of the total investment cost and will typically need to be replaced at least once during the system's lifetime (Otovo, 2022b). Inverters come in different sizes and should be scaled according to the installed capacity of the PV system. Usually, a degree of inverter undersizing is recommended because the system rarely generates full power (Solar Victoria, 2022).

3.3.2 Applications

Solar PV systems can be used in everything from small single-cell systems powering devices like watches and calculators to utility-scale plants with an installed capacity of several gigawatts. The focus of this thesis is residential rooftop-mounted grid-connected solar panels. These will typically have a capacity between 5 and 20 kWp, and the average size of residential solar PV systems in Norway is nine kWp (Dalen, Halvorsen, & Larsen, 2022).

For households, the solar PV system will usually not cover the total electricity needs of the household but be combined with electricity purchased from the grid. In periods with high PV generation and low consumption in the household, electricity is fed into the grid. Alternatively, households can choose to install batteries to save energy in times with high generation for use at times with low generation. The typical solar PV system in Norway will generate 650-1000 kWh annually for each kWp of installed capacity (NVE, 2022a). For the average Norwegian residential rooftop system of nine kWp, this means that the expected annual electricity generation should be between 6 000 and 9 000 kWh. For comparison, the average single-family home in Norway consumes 26 000 kWh annually (ELVIA, 2022).

3.3.3 Determinants of Electricity Generation

Photovoltaic cells generate electricity by transforming the energy in solar irradiation into an electric current. Thereby, the two most important determinants of electricity generation are solar irradiation and the panel's efficiency in converting sunlight into electric current.

Solar irradiation

Geographical differences in irradiation

The amount of energy generated for each kWp of solar PV capacity installed varies globally in line with variations in solar irradiation. The map in figure 3-8 is provided by PVGIS, a tool developed by the European Commission to estimate solar irradiation and power generation potential from solar PV (PVGIS, 2022). Solar irradiation is highest in southern Europe, almost twice as high as in Norway. The difference in solar irradiation translates to differences in energy yield. In southern Europe, electricity generation is estimated to be more than 1 650 kWh annually for each kWp installed capacity. The energy yield in northern Europe and south-eastern parts of Norway is closer to 1 000 kWh/kWp. The expected generation is lower in the western and northern parts of Norway.

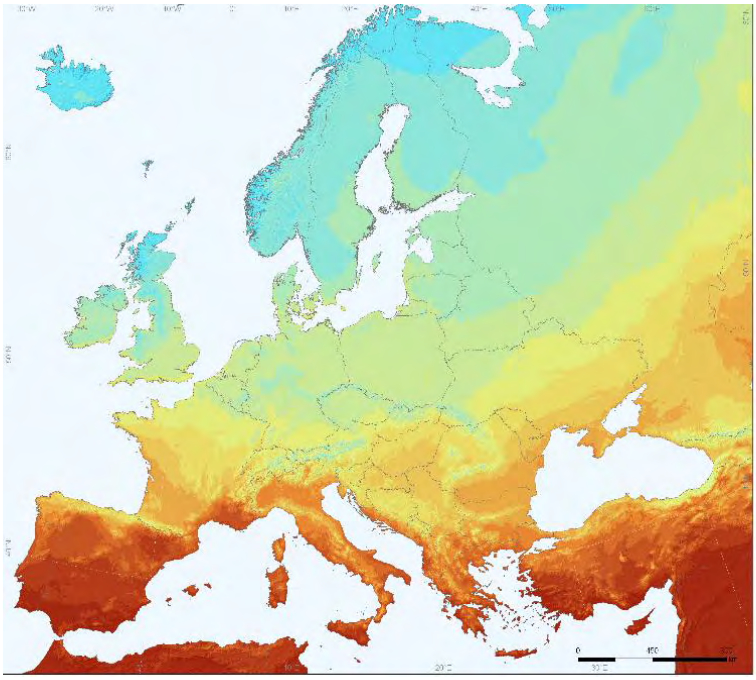

Figure 3-8: Overview of solar irradiation in Europe. Warm colours indicate high irradiation and cold colours indicate low irradiation (PVGIS, 2012)

As the map shows, latitude is an essential determinant of solar irradiation. In general, areas closer to the equator receive more irradiation because the sunrays travel a shorter distance and hit the surface at close to a 90-degree angle (Office of Energy Efficiency and Renewable Energy, 2022). In addition to the distance to the sun, solar irradiation is affected by disturbances in the atmosphere, like thick clouds, pollution, vapour, or dust. Solar irradiation is also highly variable over the day and through the year. Naturally, the solar influx is at its highest in the middle of the day and zero during the night. Furthermore, irradiation varies throughout the seasons, especially at higher and lower latitudes.

Irradiation on the panel

As explained above, geographic location determines solar irradiation on a horizontal surface. However, more specific factors need to be considered when assessing the irradiation on a solar panel. The first important factor is shading. Far shadings are elements like mountains and hills that can shade an area during parts of the day. Furthermore, near shadings like trees and buildings should be considered in each project. In addition, elements like leaves, dust, and other debris may cover the panels and limit the irradiation available for absorption. The panels should therefore be swept or cleaned when necessary. In Norway, snow and ice may also cover the panels. However, as irradiation is usually low during the winter, the loss caused by snow and ice is of little importance.

Irradiation on the panel is also strongly affected by the plane orientation of the panels. Most solar panels are not installed horizontally but are tilted to increase irradiation on the panel. This is especially relevant at higher latitudes where the sun is shining at a lower angle. For example, Oslo's optimal tilt angle is found to be 40 degrees (Jacobson & Jadhav, 2018). For comparison, the optimal tilt angle in Singapore, which is almost on the equator, is 0 degrees. When solar panels are tilted, the direction of the panels becomes relevant. In the northern hemisphere, the sun is in the south in the middle of the day, when irradiation is strongest. This means that tilted panels directed toward the south are exposed to more direct sunlight than panels directed toward the east or west. North-facing panels receive little or no direct sunlight.

Solar panels are also exposed to indirect sunlight in the form of reflections. The reflected rays may come from the ground or other surrounding elements like buildings. White surfaces will naturally reflect more light than darker surfaces. This is especially relevant for Norway, where snow surrounding the solar panels will increase reflections (Homer Energy, 2022).

Conversion efficiency

To estimate the actual output from a panel, it is necessary to assess the conversion efficiency. Generally, standard panels on the market can utilise 15-20% of the irradiation, although some models have shown considerably higher efficiencies (Center for Sustainable Systems, 2022). Under Norwegian conditions, Otovo states that the typical panel will have 16-20% efficiency, while their premium panels can provide efficiencies of up to 22.7% (Otovo, 2022d). In addition to panel quality, temperature is an important determinant of efficiency. High temperatures will lead to overheated panels, leading to lower efficiency. An IEA report finds the optimal temperature for PV production to be below -5 degrees Celsius, all else equal (van Sark & Nordmann, 2014). This shows that the low irradiation in Norway is somewhat offset by low temperatures leading to lower efficiency losses.

Degradation

Solar panels will degrade over time. When a solar panel is first exposed to light, the effect will be reduced. This degradation is referred to as light-induced degradation (LID) (PVsyst, 2022a). Furthermore, the panels will degrade due to wear and tear over time. Important contributors to degradation are heat, rapid temperature changes, extreme weather, heavy rainfalls, hailstorms, and lack of maintenance (Otovo, 2022e). In addition, one should account for some wear and tear on wiring, inverters, and other components. Typically, higher-quality panels will have lower degradation rates, resulting in higher energy yield and possibly extending the economic life of the system.

3.4 The Norwegian Power Market

Norwegian power-generating companies generate about 150 TWh annually, while the consumption is 140 TWH (Energy Facts Norway, 2021; Statnett, 2022a). Even though Norway has a surplus of electricity, electricity is both sold to and purchased from other Nordic and European countries. The trading occurs on the Nordic electricity exchange Nord Pool. This trading is possible due to the onshore and subsea interconnectors to several Nordic and European countries. Hydropower plants are the largest contributor to Norwegian electricity generation, with approximately 90% (NVE, 2022c). The remaining 10% mainly consists of wind power and some solar power, natural gas, and other sources.

3.4.1 Transmission Capacity

The Norwegian transmission grid for electricity

Electricity must be consumed at the same moment as it is produced, as large-scale storage is currently difficult and expensive. A well-functioning electricity market, therefore, depends on a well-functioning grid to distribute electricity from the producers to the consumers.

The Norwegian electricity market is divided into five zones. The zones have practically no internal grid capacity constraints, and electricity is traded internally. In addition, electricity is traded across the zones and to connected zones in neighbouring countries. However, capacity constraints limit these transmissions, leading to price differences. High price differences over extended periods are likely to increase investments in transmission capacity. One example that this expansion has already begun is a new cable currently being built across the Sognefjord (Norwegian Government, 2022). The Nord Pool trading section below explains more about the price formation in the different trading zones.

International interconnectors

The Norwegian grid is closely connected to neighbouring countries through interconnectors onshore and subsea. The first connection was made to Sweden in 1960, to Denmark in the 1970s, and from the 2000s until today, several subsea interconnectors to Denmark, the Netherlands, Germany, and Great Britain have opened. The interconnectors enable Norway to trade electricity with several European countries.

Among other purposes, the interconnectors serve as a supply security measurement. In an average year, Norway has a surplus of electricity it can sell to other countries. In dry years, when hydropower generation is reduced, electricity is imported. In addition, the high level of flexibility in Norwegian hydropower allows for more short-term trading through the interconnectors. Continental Europe is, to a larger extent, dependent on variable energy sources like wind. If heavy wind drives prices down, Norway can import cheap electricity and reduce hydropower generation. Similarly, if variable generation in Europe is low and prices high, Norway can increase hydropower generation and export at high prices.

Table 3-1 is based on figures from Statnett and shows that the interconnectors are used for both import and export of power every year (Statnett, 2022a). It also shows that the amount imported and exported varies. This is due to fluctuating prices throughout the year.

Power balance	Import	Export	Import TWh	Export TWh
2022*	34%	66%	12	23
2021	24%	76%	8	25
2020	15%	85%	4	25
2019	50%	50%	12	12

*Table 3-1: Overview of imported and exported electricity. *2022 is from January to November. Source: (Statnett, 2022a)*

3.4.2 Power Trading

Nord Pool trading

Physical electricity is traded on the Nord Pool electricity exchange in two ways: intraday trading and day-ahead trading. In the day-ahead market, market participants report their expected generation or consumption for the day ahead. Nord Pool then uses this information to form the hour-by-hour market price for the next day. However, this is not enough to clear the market. Real-time clearance is done in the intraday market.

System price

The day-ahead market forms the Nordic system price. This is a price for the whole Nordic region. The price is based on the complete order book for the Nordic region and ignoring transmission capacities between areas (Nord Pool, 2022).

Area prices

As previously explained, there is limited transmission capacity between the zones. To ensure that the market clears within each zone, Nord Pool also forms different prices for different zones called bidding zones or price areas. Nord Pool defines these as follows: “A bidding zone is the largest geographical area within which market participants can exchange energy without capacity allocation” (Nord Pool, 2022). In Norway, there are five bidding zones, NO1 to NO5, as shown in figure 3-9. The area prices are also formed on a day-ahead basis with real-time balancing trading.

Figure 3-9: Map of electricity price areas in Norway

Nasdaq

Nasdaq Commodities offer futures contracts on Nordic electricity prices. Futures are traded on both the system price and as Electricity Price Area Differential (EPAD) to replicate the area prices. In the short term, futures are traded as daily and monthly contracts, while quarterly and yearly contracts trade up to several years into the future. The futures have daily mark-to-market to the Nord Pool system price (Nasdaq Commodities, 2022). Settlement is financial, meaning that no physical electricity is transferred.

The participants in this market are primarily power producers, large industrial power consumers, and electricity distributors, who want to hedge their future production or consumption. Futures are currently mainly traded on the system price. The market for futures on differential contracts is highly illiquid due to the recent extreme fluctuations in electricity prices. The market for futures on system price is significantly more liquid, but some of these contracts do also suffer from limited liquidity.

Historical prices

Historically, the electricity prices in Norway have been low compared to the rest of Europe. The average Nordic system price has been 42 EUR/MWh from 2010 until 2022. In Germany, as a proxy for the European electricity price, the average electricity price from 2000-2022 was 52 EUR/MWh (Trading Economics, 2022a). In both markets, the prices have fluctuated severely recently. In the Nordics, the average price in 2022 (January to July) was ten times higher than the average price in 2020. Looking at 2010-2020 and 2021-2022 separately, the average prices have been 34 and 87 EUR/MWh, respectively. This illustrates the current extreme situation in the Norwegian, Nordic and European markets. These fluctuations must be considered when discussing future electricity prices.

	EUR/MWh						NOK/kWh
Period	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**	**System**	**System**
Average 2010-2022*	47	49	34	32	47	42	0.42
Average 2010-2020	33	32	34	33	32	34	0.34
Average 2021-2022*	127	141	30	24	127	87	0.88

*Table 3-2: Historical area and system prices. *2022 is from January to July. EUR/NOK 10.04. Source: Nord Pool*

Average area price difference from system price

Year	**NO1**	**NO2**	**NO3**	**NO4**	**NO5**
Average 2010-2022*	7%	9%	-7%	-11%	6%
Average 2010-2020	-4%	-5%	2%	-1%	-6%
Average 2021-2022*	68%	85%	-55%	-62%	68%

*Table 3-3: Area prices deviation from system price. *2022 is January to July Source: Nord Pool*

Furthermore, it is relevant to examine how the area prices historically have differed from the system price. Table 3-3 shows that form 2010-2020, the average prices in NO3 and NO4 were close to the system price, while prices in NO1, NO2, and NO5 were slightly below the system price. In the 2021-2022 period, there is a dramatic shift. NO1, NO2 and NO5 were 68%, 85% and 68%, respectively, above the system price, while NO3 and NO4 were 55% and 62% below the system price.

European electricity prices started rising in 2021. Rising coal and gas prices, in combination with rising prices on CO2 certificates, can explain some of this development. At the start of 2022, the threat and execution of Russia's invasion of Ukraine lead to record-high prices of coal and natural gas (Trading Economics, 2022b). As of 2019, 40% of electricity generation in Europe consisted of coal, gas, and oil (IEA, 2020). The price increases on these commodities are, therefore, important drivers of the high European electricity prices.

As a result of the interconnectors to continental Europe, the price in southern Norway is affected by the high prices in continental Europe. Furthermore, the level of the hydro reservoirs in southern Norway was low in 2022 (NVE, 2022f). These two aspects are part of the explanation for the abnormally high prices in NO1, NO2, and NO5. The prices in NO3 and NO4 have been well below the system price in the latter period. The transmission capacity limits the amount of electricity that can be transferred from north to south. This means that European prices have less influence on the price in this region. In addition, the hydro reservoir levels in northern Norway were high in both 2021 and 2022.

3.4.3 Consumer Market

Most Norwegian households purchase electricity at spot contracts. Only 4% of households have had fixed-price electricity tariffs in the last decade (Energi Norge, 2022). In Denmark and Finland, the rates are 57% and 52%, respectively. In Q2 2022, the share of Norwegian households with fixed-price contracts had increased to 8%. The consultancy firm Thema argues that the Norwegian Consumer Council's push for spot price contracts is the main reason for the low percentage of fixed price contracts in Norway (Hentschel et al., 2022). The spot price contracts are based on the day-ahead market price from Nord Pool with a mark-up. In addition to the two contract types discussed, some contracts are based on the spot price but are fixed for a shorter time, for example, a few weeks.

Grid fees and taxes

In Norway, there are 106 (2020) grid-owning companies (NVE, 2020a). These companies own and operate the grid in an area as natural monopolists. As these companies operate as monopolists in their area, their price-setting is regulated by NVE.

Each consumer connected to the grid pays a fee based on a two-part model. The first part is a fee per kilowatt-hour used. Part two is a flat fee for the month. Both parts of the fee differ from between companies but are generally at the same level as NVE oversees their activities.

In addition to the grid fee paid to the grid-owning company, every consumer pays an electrical power tax for every kilowatt-hour used. For 2022, the tax was 15.41 øre/kWh without VAT (The Norwegian Tax Administration, 2022). However, due to the extraordinarily high electricity prices, the tax was reduced to 8.91 øre/kWh for January, February, and March 2022. Some areas in Troms and Finnmark are exempted from this tax. The electrical power tax includes 1 øre/kWh to Enova, the Norwegian state-owned organization that supports companies and private households with climate-friendly investments. For example, Enova subsidizes rooftop solar.

A 25% value-added tax (VAT) applies to the electricity, grid fee and electrical power tax. Northern Norway (NO4) is exempted from this VAT (Departementenes sikkerhets- og serviceorganisasjon, 2019).

Electricity price subsidies

In December 2021, the Norwegian government implemented a support scheme for private consumers to help with the soaring electricity prices (Regjeringen, 2021). This scheme has been adjusted multiple times, and as of October 2022, the government subsidises 90% of the average monthly price above 0.70 NOK/kWh (Regjeringen, 2022). The government has also prolonged the support scheme throughout 2023 with the following specifications: the current support scheme will continue until the end of March, from April to September, the subsidies will be 80% of the price above 0.70 NOK/kWh and then 90% from October to December.

This support scheme does impact the profitability of rooftop solar, as the electricity price is the opportunity cost of generating electricity from rooftop PV systems. By reducing the price, the household needs to pay for electricity, this scheme reduces the opportunity cost of buying electricity from the grid, which reduces the income of the rooftop solar PV system. The support scheme will only affect the value of the electricity the household consumes internally because excess generation sold to the market is still sold at spot electricity prices.

3.5 Regulations and Support Schemes for Residential Solar PV in Norway

3.5.1 Subsidies

Enova SF is owned by the Norwegian government through the Ministry of Climate and Environment. Their task is to support investments that reduce greenhouse gas emissions and help accelerate green technologies (Enova, 2018). For private households, Enova supports multiple types of investments in energy reduction or generation in private homes and vacation houses. Among others, Enova supports investments in rooftop solar PV systems. The support scheme is designed to include almost every household that wishes to invest in solar panels (Enova, 2022). When investing in rooftop solar, a private household can receive an investment subsidy of NOK 7 500 and NOK 2 000 per kWp installed, limited to 20 kWp. The maximum grant a household can get is then NOK 47 500 for a 20 kWp or larger system.

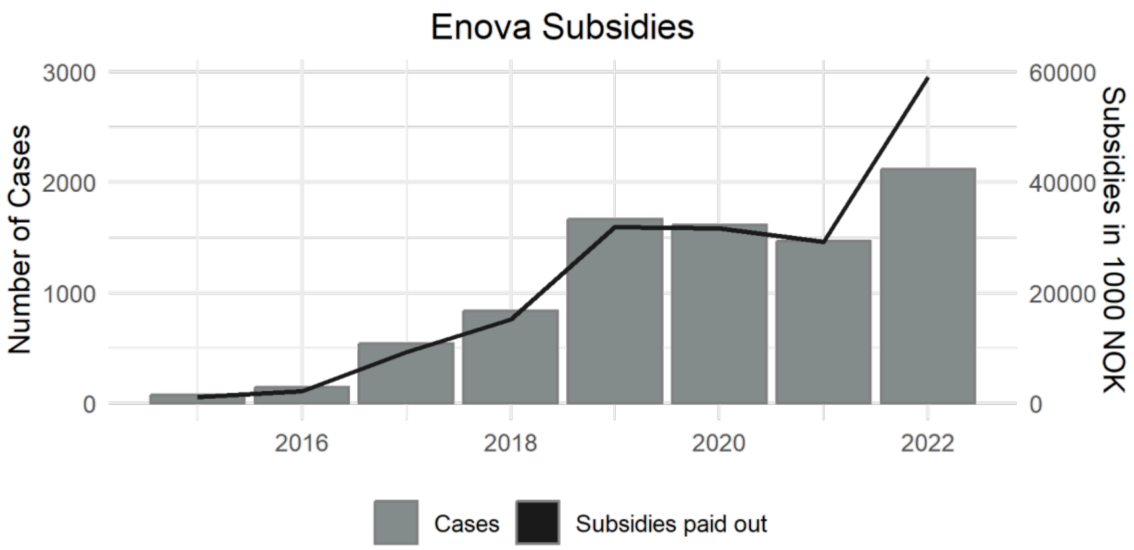

Figure 3-10: Enova subsidies. Paid-out amount and number of cases.

Figure 3-10 shows the development in cases where Enova has given investment subsidies to private rooftop solar PV projects. The trend is increasing, and the numbers for 2022 (January-August) imply that the higher electricity prices have led to a sharp increase in rooftop solar investments in Norway. The development in the amount paid out follows the number of cases. However, it is also apparent that the paid-out amount for 2022 has increased relatively more than the number of cases. This is due to an increase in the subsidies in February 2022. The previous subsidy was 1 250 NOK/kWp, limited to 15 kWp, while the fixed amount is kept unchanged at NOK 7 500 (Simenergi, 2022).

3.5.2 Plus Customer Regulation

One criterion for receiving subsidies from Enova is that the household must be a plus customer. The plus customer scheme regulates households that both consume and generate electricity and are connected to the grid. To be included in the scheme, the household cannot feed more than 100 kW into the grid at any time. If a household does so, it will be classified as a power producer and must follow the corresponding regulations. However, rooftop solar PV systems on a regular house will not surpass this limit. In this paper, it is assumed that every household investing in rooftop solar PV falls within the plus customer regulation.

All plus customers must have an agreement with their power company to buy the excess electricity. Most power companies offer to buy electricity from plus customers at the Nord Pool spot price. Some electricity providers offer other solutions for buying back surplus electricity, for example, a solar account where customers can "store" electricity for later use. Plus customers do not pay grid fees or electricity tax on the electricity sold to the grid. When buying electricity from the grid, the plus customer is treated like any other private consumer and pays the spot or fixed electricity price, grid fees, VAT, and the electrical power tax.

To be a plus customer, the physical conditions of the grid connected to the household must be within the regulatory standards. If grid improvements are necessary, the plus customer can be obliged to contribute to financing the improvements. However, this will normally not be necessary as there is usually excess capacity in the grids. As of June 2022, there were 10 026 households registered as Plus customers (NVE, 2022b). The number has increased rapidly from 3 039 in 2019. About 8000 of the plus customers are located in NO1 and NO2.

3.5.3 Legal Considerations

When installing a residential rooftop solar PV system in Norway, there are some legal issues to consider. Installation of solar panels will, in some cases, require an application and approval from local governments, depending on the size and local regulations (Sæther, 2019). Thus, the legal aspect should be considered in each project. Furthermore, there are naturally strict regulations on fire safety, certification of installers and equipment, and more. As most Norwegian customers are likely to order and install their PV systems through a turnkey provider like Otovo, these considerations are less relevant for the customer.

4. Problem Definition

Chapter three shows that solar PV deployment grows at a high rate both globally and in Norway and that this growth is expected to continue in the following decades. Key drivers are technological development, cost reductions, and subsidies. Previous works have generally concluded that rooftop solar PV systems in Norway are not profitable. However, the recent increase in electricity prices, combined with further technological developments, indicates that profitability might have been improved. Therefore, this thesis aims to answer the following question:

How profitable are residential rooftop solar photovoltaic systems in Norway, and how do changes to key variables affect the profitability evaluation?

Profitability is evaluated for systems in Oslo, Kristiansand, Stavanger, Bergen, Trondheim, and Tromsø, with the project starting in 2023 and a 30-year expected economic life. This choice of locations represents densely populated regions in Norway and covers most parts of the country. The thesis is limited to grid-integrated systems without storage options. Building-integrated PV or wall-mounted panels are not examined. The results found in the analysis are relevant for single-family houses and units in chained houses, while differences in regulation make the analysis invalid for apartment buildings.

The analysis assumes that the PV system is bought and owned by the household and not leased. As the investment is considered from the point of view of a private household, relevant subsidies, support schemes, and taxes are included in the profitability evaluation. The analysis is purely financial and does not include aspects like environmental considerations. However, chapter ten presents some non-financial considerations relevant to the investment decision.

Previous works have evaluated the profitability of solar PV using the LCOE or the NPV method. The NPV method directly answers the profitability evaluation by projecting all future cash flows. A challenge with the NPV method is that it requires a broad set of inputs, increasing the complexity of the calculation. LCOE, on the other hand, requires fewer inputs and is possible to calculate without estimating future electricity prices. However, the LCOE method is cost-focused, and a secondary analysis of future electricity prices is necessary to conclude the profitability evaluation. This comparison is further complicated because generated electricity is both consumed internally and sold to the grid. Thus, we choose the net present value to be the main evaluation criterion in the profitability evaluation.

The NPV is the difference between the present value of future cash inflows and the present value of cash outflows, including the initial investment. All profiles with a positive NPV will be considered profitable, given the assumptions used in the calculation. The formula for the NPV calculation is given below. C_t is the cash flow in period t. The discount rate for each period is denominated as r. T is the total number of periods.

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

This thesis calculates NPV by building a general cash flow model with the possibility of varying inputs. The model includes systems from each of the six cities, with varying plane orientations. The key input variables are shown in table 4-1 and can be varied to simulate the cash flows of PV systems with various characteristics.

Key variables
Electricity price
Electricity generation
Initial investment cost
System size
Cost of capital
Share of generated electricity consumed internally

Table 4-1: Key variables for determining the profitability of rooftop PV systems

The precision of the analysis is limited by the uncertainty in projecting future cash flows. For a solar PV project, this includes detailed projections of electricity generation and electricity prices. As a result, the NPV calculations will be imprecise and can, in some situations, be misleading. However, by performing sensitivity analyses on the most relevant variables, we believe the analysis will give a balanced answer to the problem definition.

5. The Model

This chapter presents the inputs used in the model step-by-step. The chapter is structured after the four primary categories income, capital expenditure, operational expenditure and maintenance, and cost of capital. Monthly cash-flows from 2023 to 2052 are modelled based on the inputs. These cash-flows are used to calculate NPV, IRR, and other key figures.

5.1 Income

5.1.1 How Income From Rooftop Solar Is Calculated

A residential rooftop PV system generates income in two ways. Firstly, the household will receive a cash flow from the electricity sold to the market. In addition, the generated electricity consumed internally in the household is recognized as income, valued at the opportunity cost of buying the same amount of electricity from the market.

The electricity sold to the market is assumed to be sold at the Nord Pool spot price without any taxes or fees. Electricity consumed internally is valued at the opportunity cost of buying the same amount of electricity from the grid. This includes the electricity price, VAT, grid fee, and electricity fee. All consumers are assumed to be exposed to spot electricity prices.

5.1.2 Foreign Exchange Rate

Throughout this paper, values in both Norwegian kroner (NOK) and Euro (EUR) will be used. The final calculations are done in NOK, assuming a EUR/NOK exchange rate of 10.04 for all calculations, based on the average of Norges Banks' daily foreign exchange rate for EUR/NOK for the twelve months between 26.10.2021 and 25.10.2022 (Norges Bank, 2022).

5.1.3 Electricity Prices

Future electricity prices are, together with estimates of total electricity generation, the most crucial determinant of income generated from a rooftop solar PV system. As a result of the high uncertainty, a prediction of future electricity prices is outside the scope of this thesis. We will therefore use the market prices from Nasdaq futures and long-term power market analyses to form a reference scenario for future prices. The high level of uncertainty is accounted for by also calculating results for higher and lower scenarios.

Another important factor regarding future electricity prices is seasonal variation. In Norway, solar energy generation varies significantly during the year. To account for this in the model, we have therefore used quarterly futures prices for the periods where it is available. Seasonal variations beyond the futures contract period are modelled using historical seasonal variations in the Nord Pool system price.

Nasdaq Nordic electricity price futures

The model uses quarterly futures for 2023 and 2024, as these are the periods in which quarterly prices are available. Yearly futures are used from 2025 to 2030. Future contracts beyond 2030 are not used, as there are few or no transactions. Table 5-1 displays future prices for the Nordic system price used in the model. The prices are calculated as a volume-weighted average of all transactions in the three months between 24.06.2022 and 21.09.2022.

Quarters	Price EUR/MWh
Q1-23	323
Q2-23	127
Q3-23	71
Q4-23	145
Q1-24	175
Q2-24	66
Q3-24	42
Q4-24	83

Years	Price EUR/MWh
2023	166
2024	87
2025	67
2026	64
2027	63
2028	67
2029	68
2030	67

Table 5-1: Weighted-average future prices on Nordic Electricity System Price. Source: Nasdaq

Long-term power market analysis

As relevant market prices from Nasdaq futures are unavailable beyond 2030, we base the price scenarios for this period on long-term market reports from NVE and Statnett (NVE, 2021; Statnett, 2020). NVE's base price is 0.5 NOK/kWh (50.2 EUR/MWh) in 2040, while Statnett's updated estimate is 30 to 50 EUR/MWh (Statnett, 2021). The prices are in real 2021 value. The reference scenario in the model is at the higher end of this range with 0.5 NOK/kWh.

Seasonal variation

As previously explained, electricity prices experience seasonal patterns that should be included in the model. Quarterly futures prices are not available beyond 2024, and we have therefore modelled the variation in 2025 and beyond based on historical prices. The input used in the model is based on the quarterly variation in the Nordic system price between 2010 and 2020, as shown in table 5-2. Prices from 2021 and 2022 are omitted because the extraordinarily high prices in the period would have disturbed the seasonal fluctuations.

Quarter	**Deviation from average yearly price**
Q1	13.4%
Q2	-7.5%
Q3	-10.4%
Q4	4.6%

Table 5-2: Nordic electricity pot price quarterly deviation from the yearly average price. Nord Pool

Area prices

As discussed in section 3.4.2, there have historically been some differences between the area prices. However, the price relationships between areas have not been stable. In the model, it is therefore assumed that future electricity prices will be equal in all price areas. If the reader finds this assumption unreasonable, a different price scenario can be used for different cities. See appendix C for more information.

Electricity price subsidy

In section 3.4.3, we described the electricity price subsidy that the Norwegian government has implemented to help consumers cope with the surging prices. The subsidy is adopted through 2023. Therefore, we have implemented the effect of the subsidy on electricity prices for households for 2023 to the model. It is difficult to say whether the subsidy will be extended further. The argument for introducing the scheme was that the prices rose faster and higher than ever before and that support was necessary to help households cope with the sudden increase in expenses. If the prices are to stabilise at a high level, it could be argued that the consumers will adapt over time, and the support scheme would likely be phased out. In the model, electricity price subsidy is not implemented beyond 2023.

Electricity price scenarios

Based on the inputs above, we have modelled five scenarios as presented in figure 5-11:

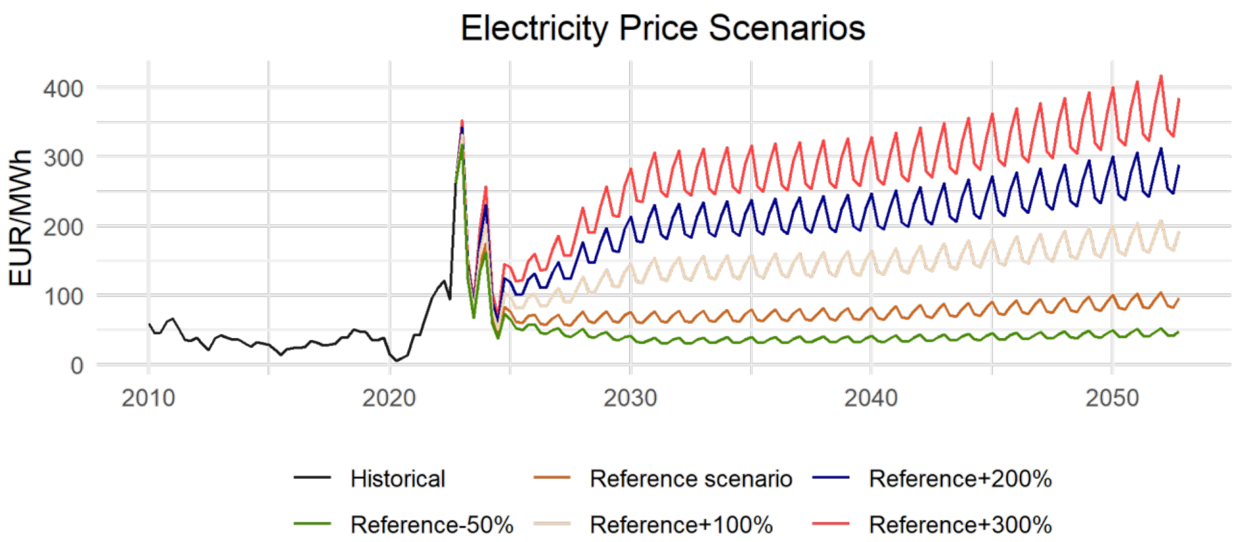

Figure 5-1: Electricity Price Scenarios

For further information about the background and creation of the price scenarios, see appendix C. The average prices in 2023-value for each of these scenarios are as follows:

Average electricity prices

Scenarios	**EUR/MWh**	**NOK/kWh**
Reference +300%	204	2.0
Reference +200%	156	1.6
Reference +100%	108	1.1
Reference scenario	60	0.6
Reference -50%	36	0.4

Table 5-3: Electricity price scenarios, the average price in 2023-value. EUR/NOK 10.04.

Taxes and grid tariffs

As previously explained, the grid fee is divided into a flat fee and a variable fee for each kWh consumed. In the model, only the variable fee is relevant, as the flat fee is assumed to be independent of consumption. The average fee for each price area was calculated by collecting data from the four to five largest grid-owning companies in each price area. Some companies have different prices for day and night, and weekdays and weekends. As PV systems mainly generate electricity during the daytime, we have only included daytime prices. The electricity generation is not affected by the day of the week, so the weighted average fee between working days and weekends is used for the grid companies where this is relevant. Table 5-4 displays the average grid fee in each price area. The underlying data is included in appendix C.

Grid fees

Zone	Observations	Average NOK/kWh
NO1	4	0.43
NO2	5	0.50
NO3	5	0.40
NO4	5	0.28
NO5	4	0.43

Table 5-4: Grid fee. Number of observations and the average fee

5.1.4 Electricity Generation

Introduction to PVsyst

To estimate the electricity generation of the PV systems, we have used simulations from the PVsyst software, version 7.2 (PVsyst, 2022b). PVsyst is a tool developed by the University of Geneva to simulate power generation from solar PV systems. It is based on extensive meteorological databases, which form the foundation for the simulations. Furthermore, PVsyst utilizes a comprehensive database of PV tools, including panels, inverters and batteries (PVsyst, 2022c). In this way, the user can give detailed inputs on their system design and receive an estimate on electricity generation. To perform a simulation, the user needs to define the geographical location, system size, panel direction and choice of tools. The most important inputs are explained in the following, with more details in section D in the appendix.

Simulation inputs

Locations and meteorological data

To perform our simulations, we first defined one location in each of the six cities. The exact locations are shown in table d-0-7 in the appendix. Meteorological data for each of the six locations were imported from the PVGIS database and used to estimate a typical meteorological year.

In each city, we chose central residential areas with a high density of single-family homes. Furthermore, we tried to avoid locations shaded by mountains. In this way, the production results in the model may be higher than what is the case for other areas in the six cities.

Plane orientation

The simulations were performed in six different plane orientations in each location, as shown in table 5-5. The plane orientations were chosen based on a typical plane orientation for a residential rooftop solar PV system. Slope and direction are the two inputs required to define the plane orientation.

We defined three types of roofs; flat, sloped, and gable. Sloped roof refers to systems where all the panels are installed on the same sloped roof plane, while gable roofs are roofs with solar panels distributed evenly on two sloped roof planes. Sloped and gable roofs were assumed to have a 30-degree angle to represent a typical Norwegian house. Panels installed on flat roofs were assumed to have a 10-degree angle. The reason why 10 degrees was used for flat roofs instead of 0 degrees is that solar panels on flat roofs typically will be installed with some angle to increase energy yield (Solcellespesialisten, 2022a).

The directions simulated for sloped roofs were south-east, south, and south-west, as these are the directions with the highest expected energy yield. Flat roofs were simulated with a tilt towards the south and in an east/west configuration. This configuration is relevant as it is often preferred before a pure south-facing system because it gives a more even production throughout the day. Gable roofs were simulated with an east/west configuration.

Roof type	**Angle**	**Azimuth**
Sloped roof	30°	South
Sloped roof	30°	South-East
Sloped roof	30°	South-West
Flat roof	10°	South
Flat roof	10°	East/West
Gable roof	30°	East/West

Table 5-5: Plane orientations simulated in each city

Simulation results

Six different plane orientations were simulated in each city, resulting in 36 separate simulations. The simulation output used in the cash flow model is the monthly kWh/kWp ratio, referred to as the energy yield. This is a normalized performance indicator and is thus independent of the system size. PVsyst reports energy yield with and without losses, and we use the energy yield after losses to estimate the system's useful electricity output. However, the actual efficiency losses may differ strongly from the PVsyst estimates, depending on the choice of panel and inverter, technological development, maintenance, and other factors.

kWh/kWp for different profiles

Roof type	**Direction**	**Oslo**	**Kristiansand**	**Stavanger**	**Bergen**	**Trondheim**	**Tromsø**
Sloped roof 30°	South	1 029	1 089	939	906	848	870
Sloped roof 30°	South-East	962	1 006	869	853	803	808
Sloped roof 30°	South-West	961	1 037	897	850	792	827
Flat roof 10°	South	915	973	844	811	758	744
Flat roof 10°	East/West	820	874	763	733	685	661
Gable roof 30°	East/West	791	844	740	712	666	677

Table 5-6: Annual energy yield, all profiles. Source: PVsyst

The estimated annual energy yield for each profile is presented in table 5-6. The monthly energy yields for all profiles in each city are presented in table d-0-8 and table d-0-9 in the appendix. In all cities, the best plane orientation is the south-facing sloped roof. Figure 5-2 shows each city's monthly energy yield for a south-facing sloped roof.

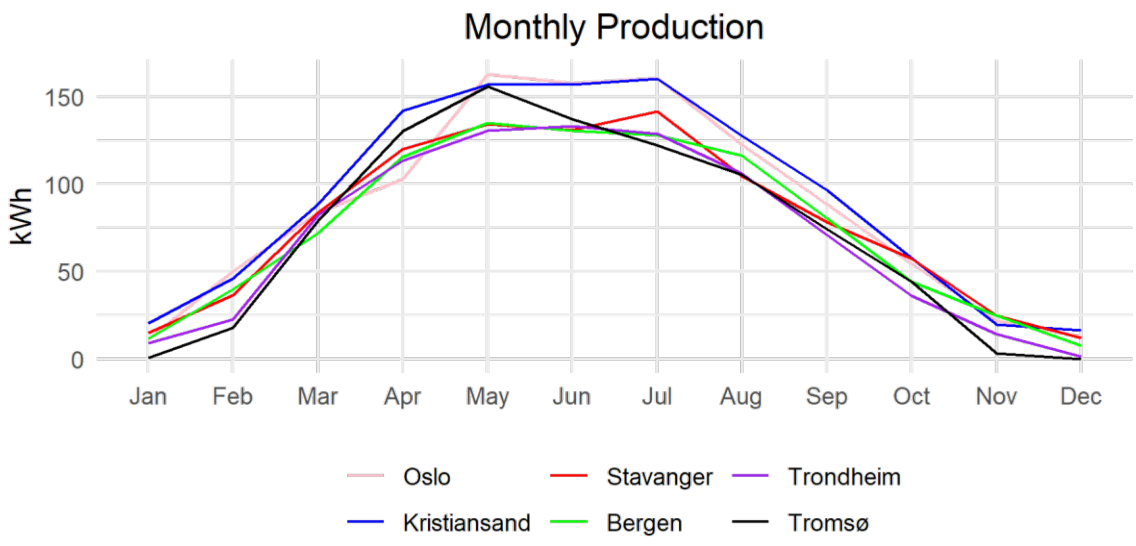

Figure 5-2: Monthly production pattern for each city. Source: PVsyst

The highest energy yield for the south-facing sloped roof is found in Kristiansand with 1089 kWh/kWp/year, and the lowest yield for a south-facing sloped roof is found in Trondheim with 848 kWh/kWp/year. As expected, there is considerable seasonal variation throughout the year. One surprising observation is that the energy yield in some profiles is higher in Tromsø than in Trondheim, despite a much higher latitude and fewer hours of sun (Nilsen, 2014). This may be explained by the fact that the meteorological data for Tromsø is gathered from another database than the other cities. Other possible explanations are uncertainty in the simulation precision and choice of location.

Intraday generation pattern

This thesis is generally limited to monthly data, and we have not considered the intraday fluctuations in electricity generation, electricity prices and other factors in the cash flow model. However, some remarks about the intraday generation pattern are presented below and further discussed in chapter seven.

South-facing panels will have a high peak in electricity generation in the middle of the day and a low generation in the morning and evening. On the other hand, panels in an east/west configuration will have a lower total electricity generation but a more even production throughout the day. Figure 5-3 displays the average hourly output for a 12 kWp system in Oslo in June from the PVsyst simulations. We see that the south-facing sloped roof has a 14% higher output than the gable roof in an east/west configuration, but the gable roof has higher output in the morning and evening. The same tendency is also seen when comparing panels on flat roofs. However, it is apparent that the extra electricity generation in the mornings and evenings from an east/west system is much lower for the flat roof systems.

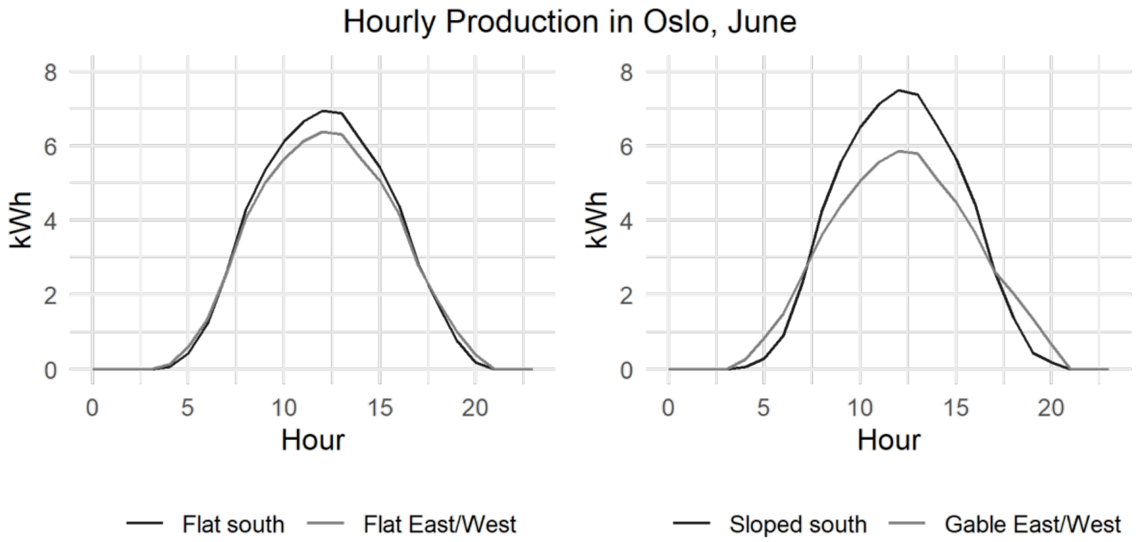

Figure 5-3: Intraday generation pattern. Oslo, June. Source: PVsyst

The higher electricity generation of east/west-configured systems in the morning and the evening is mainly present during summer when the sun rises early and sets late. Figure 5-4 compares sloped roofs and gable roofs in March. In March, the sun rises late and sets early, so the east- and west-facing panels are exposed to less direct sunlight. Thus, the gable roof’s lower production in the middle of the day is not weighed up by the higher generation in the morning and evening.

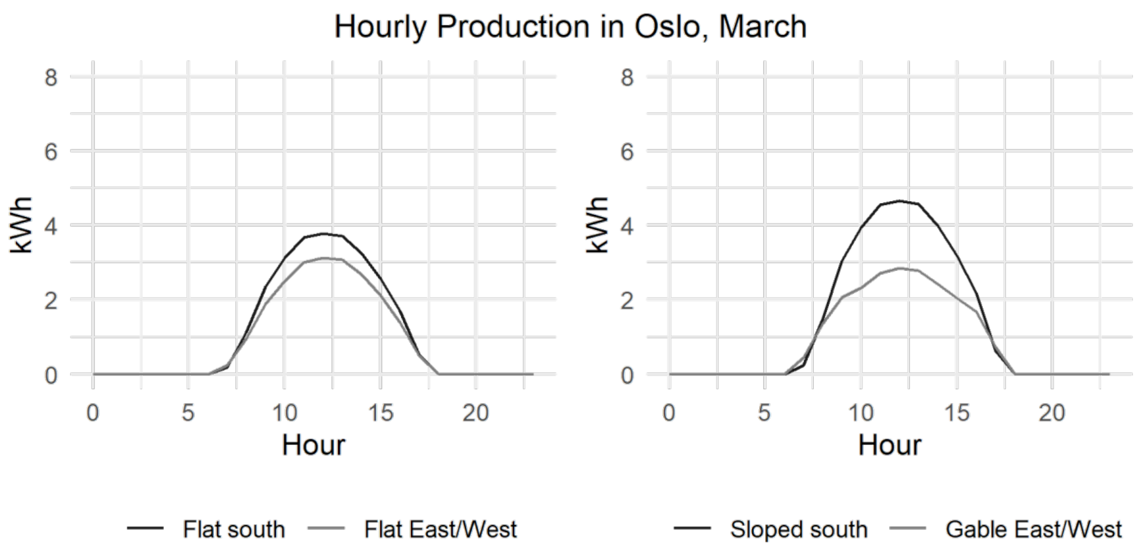

Figure 5-4: Intraday generation pattern. Oslo, March. Source: PVsyst

Simulation limitations

An essential variable when estimating electricity generation from a solar PV system is solar irradiation and other meteorological elements. In PVsyst, these values are estimated using satellite data. The precision of PVsyst's simulation tool is limited for projects in Norway (Bentsen, 2014). Access to meteorological data from local weather stations would increase the accuracy of the simulations.

Another significant limitation of the simulations is that near shadings are not considered. In all real-life projects, considering shade from objects like other buildings, trees, and utility poles is vital. Our simulations do not include shade from such objects, so they are likely to give a higher energy yield than a typical real-life project where some near shade is present.

The simulation results are dependent on the choice of tools. We have chosen generic tools available in PVsyst. In real-life projects, higher- or lower-quality tools may be selected, which can alter conversion efficiency.

5.1.5 Degradation

Solar panels will degrade over time, which the model needs to account for. The energy yield from PVsyst is reported before degradation. To make a realistic model, we need to estimate the typical degradation rate and implement this in the model. In an article review performed by NREL, the actual degradation rates from about 2 000 PV installations were compared, and annual degradation rates were found to have a median of 0.5% and an average of 0.8%

(NREL, 2012). As this review was published in 2012, it is reasonable to assume that the expected degradation rate of new panels is lower today and will continue to decrease.

Another way of estimating PV degradation rates is to look at guarantees. Otovo’s best-selling panel in Norway is FuturaSun FU 400 M Silk Plus - All Black (400 W), which Otovo refers to as their premium panel (Otovo, 2022f). This panel guarantees a 97% performance after one year and a maximum annual degradation of 0.5% (FuturaSun, 2022). The guarantee is even better for Otovo’s highest-quality panels, which are sold with a guaranteed minimum of 98% output after one year and a maximum annual degradation of 0.25% (Otovo, 2022d). Based on the observations above, the model uses an initial 2% light-induced degradation and 0.5% annual degradation rate. The annual degradation is included from the beginning of each year, including year one.

5.1.6 Share of Generated Electricity Consumed Internally

The effect of intermittency on a residential rooftop PV system

As previously explained, electricity consumed internally in the household is valued higher than electricity sold to the grid. This means that, all else equal, a higher share of PV production consumed internally will increase the NPV of the project. An estimate of the share of generated electricity consumed internally is, therefore, necessary.

The share of electricity consumed internally firstly depends on the PV system's scale compared to the household's annual electricity consumption. A small PV system on a house with high electricity consumption will naturally lead to a high share of internal consumption and vice versa. Furthermore, solar PV is a highly variable source of electricity, as explained in section 3.1.3. Thus, the relationship between consumption and generation patterns in the household is an important determinant of the share of electricity consumed internally.

Accounting for intermittency in the model

In Norway, the share of generated electricity consumed internally is not measured directly, as the power meters only measure electricity purchased from the grid and electricity fed to the grid. This means that the meter never records electricity produced and consumed internally. Therefore, the true share of internal consumption is not publicly available and needs to be predicted (Elhub, 2022).

In a 2022 report, SSB estimates the total solar PV generation from the average Norwegian plus customer and compares this to the electricity sold to the grid (Dalen, Halvorsen, & Larsen, 2022). Based on this report, we can calculate the monthly share of generated electricity consumed internally for the average plus customer in Norway to use in the cash flow model. The calculated figures are presented in table 5-7. More details on the SSB report and our calculations are attached in appendix E.

Month	Share of generated electricity consumed internally
January	97%
February	88%
March	77%
April	52%
May	51%
June	44%
July	43%
August	43%
September	55%
October	75%
November	85%
December	94%

Table 5-7: Monthly share of generated electricity consumed internally. SSB base scenario

The share of generated electricity consumed internally seems to be highest during the winter. This is in line with expectations as electricity consumption is high in the winter due to heating, and generation is low. In the summer, when generation is high and the need for heating is limited, a larger share of the generated electricity is sold to the grid.

The share of generated electricity consumed internally will vary between households, and the estimate based on the average Norwegian plus customer household may differ strongly from the actual share. Among others, different panel orientations will have different generation patterns throughout the day, which affects the share consumed internally. There is also reason to believe that the pattern differs between cities. For example, Tromsø has low production and a high expected need for heating, which indicates a higher share consumed internally than cities further south. Furthermore, the age and size of the house, the number of household members and other individual factors will strongly impact the share of electricity consumed internally. Sensitivities are shown in section 7.1.2.

5.2 Capital Expenditure

Capital expenditure is an essential factor in the NPV calculations. Changes to the initial investment cost directly affect the net present value. For a rooftop PV system with a 30-year investment horizon, the capital expenditure consists of two parts; the initial investment consists of solar panels, inverter, installation, and other relevant costs at the installation time. Secondly, the inverter must be replaced around midway through the system's lifetime.

5.2.1 Initial Investment Cost

382 price estimates are collected from Otovo and Fjordkraft. As explained in section 3.2.2, Otovo is a marketplace for rooftop solar PV systems, collecting offers from local installers. Fjordkraft markets and sells on behalf of the largest installer in Norway, Solcellespesialisten. By choosing these suppliers, we aim to find a realistic market price. The price estimates were collected for different cities, addresses, house types and roof types. The data consist of PV systems between 5 and 20 kWp. For more information about the data collection, see appendix F.

The collected data form the basis of a regression analysis used to estimate the initial investment cost in the model. The independent variables in the regression are system size, dummy variables for different cities, a dummy variable for roof type and a dummy variable for the supplier. The coefficients from the regression results are shown in table 5-8.

Coefficients from regression.

Variable	**Coefficient**
Intercept	100 338
kWp	18 054
D_Kristiansand	27 395
D_Stavanger	25 687
D_Bergen	-20 447
D_Trondheim	-13 908
D_Tromsø	17 624
D_Sloped_Roof	13 545
D_Fjordkraft	-68 147

Table 5-8:Coefficients from regression on initial investment cost

The coefficients are implemented in the model without modifications, except for the dummy variable for Fjordkraft. As we have not done any market analysis, we choose to use the average of the two suppliers in the model.

5.2.2 Inverter Replacement

In section 3.3.1, it was established that an inverter's expected lifetime is shorter than the expected lifetime of a PV system. This means that it must be replaced once during the investment period. The model assumes the change will take place after 15 years. The price for this inverter replacement is based on collected online price data. See appendix for details.

As explained in section 3.3.1, the inverter should, in most cases, be undersized compared to the PV system. According to Otovo, the undersizing should be around 15-20% (Otovo, 2022b). For the standard system of nine kWp, we have assumed that a seven kWp inverter would be suitable. The current price for this inverter is 20 096 NOK in the model. This does not include installation, meaning that our cost estimate may be too low.

5.3 Operational Expenditures and Maintenance

Except for the inverter replacement, there are little or no costs that accumulate in the operational phase of the PV system's lifetime. In the model, it is assumed that there are no such costs, in line with what most installers claim. In a real-life project, some costs for surveillance and check-ups from an electrician would likely occur. Other possible costs could also occur, such as the replacement of defective parts. Therefore, one can argue that an annual provision of 0.5% to 1% is reasonable. This is exemplified in section 7.3.

5.4 Cost of Capital

In this thesis, the profitability of residential rooftop solar PV systems in Norway is evaluated using the net present value. As solar PV systems generate cash flows over a long period, here assumed to be 30 years, the choice of discount rate is an essential input factor. In the following, the CAPM is used to estimate the cost of capital of a typical household PV project.

5.4.1 Theoretical Background

Introducing opportunity cost of capital

The required rate of return on investment is determined by the opportunity cost of capital. The opportunity cost of capital refers to the expected return of engaging in an alternative investment opportunity of a similar term and risk level (Berk & DeMarzo, 2019. P. 1131).

When discussing the cost of capital, it is essential to distinguish between the cost of capital of the project and the cost of capital of debt and equity. The project cost of capital is the minimum acceptable expected return of the project, given the risk and financing of the project. (Berk & DeMarzo, 2019. P. 380) For a project financed by debt and equity, the project cost of capital is found as the weighted average cost of capital (WACC) for the different financing sources.

Following the Modigliani-Miller theorem and its assumptions, WACC is independent of the financing decision (Modigliani & Miller, 1958). The true cost of capital is the cost of equity in the case where the project is fully equity-financed, referred to as the unlevered cost of capital. As a result of the Modigliani-Miller theorem, the unlevered cost of capital will also be the project cost of capital even though the project has leverage, given that the assumptions behind the theorem are not violated. In a real-world application, several assumptions behind the theorem are violated. The most critical violation is the assumption that there are no taxes. In a real-life scenario, interest costs will typically be tax-deductible, which results in lower WACC for projects with leverage.

For the residential rooftop solar PV system in question, we use the unlevered WACC in our calculations. This WACC is relevant for evaluating the profitability of an all-equity financed investment. In a realistic scenario, households may take on debt to finance the investment, resulting in tax-deductible interest costs and a lower WACC. The formula for calculating the equity cost of capital for a levered project is shown below (Berk & DeMarzo, 2019. P. 465). τ refers to the tax rate on interest cost deductions.

$$r_{levered} = r_{unlevered} - \frac{D}{E + D} * \tau * r_{debt}$$

In the analysis, we assume the project to be all-equity financed and use the unlevered WACC in the calculations. However, we will also show an example calculation of the levered WACC.

Introducing CAPM

In this thesis, the unlevered WACC of the project is estimated using the Capital Asset Pricing Model (CAPM). The CAPM is a model used to determine the opportunity cost of capital of an investment of similar risk in the capital markets. The CAPM formula defines the expected return of an asset i as follows:

$$E(R_i) = R_{rf} + \beta_i[E(R_m) - R_{rf}]$$

As the CAPM formula shows, the expected return of asset i ($E(R_i)$) consists of two components. Firstly, the investor should expect to be compensated for the time value of money, as measured by the risk-free rate (R_{rf}). Furthermore, the investor should expect compensation for risk. The CAPM measures risk as fluctuations in the market value of the investment (i) relative to the fluctuations in the market value of the market portfolio (m). This risk measurement is referred to as beta, and the formula is shown below. The risk premium is found by multiplying beta with the expected excess return of the market.

$$\beta_i = \frac{cov(r_i, r_m)}{var(r_m)}$$

The beta explained above is called the levered beta, as it is found by comparing stock returns with market returns. For companies with leverage, this beta will reflect the fluctuations in the market value of the firm's equity, not the firm's assets, because of the leverage effect. To find the unlevered WACC, we need the beta on the firm's assets, referred to as the unlevered beta. This is found by adjusting the levered beta for the leverage effect with the following formula:

$$\beta_{unlevered} = \frac{\beta_{levered}}{1 + (1 - tax) * \frac{debt}{equity}}$$

The CAPM builds on some critical assumptions. Among others, it assumes markets to be efficient and that all investors can buy and sell all securities at competitive market prices without taxes or transaction costs. This includes borrowing and lending at the risk-free rate. Furthermore, it assumes that all investors are rational and well-diversified and have the same access to information. Another important characteristic, as seen from the CAPM formula, is that the only risk the investor should expect compensation for is the systematic risk. The discussion below examines some violations of these assumptions in light of the project.

5.4.2 Estimating Project Cost of Capital

To estimate a suitable unlevered beta, and thereby unlevered cost of capital, for the project, we have estimated the unlevered beta of comparable stocks. The goal is to find the unlevered beta of listed companies with asset risk as close to our project as possible and use these as an approximation to the asset risk of our project. The estimated beta value can then be used in the CAPM to find an estimated cost of capital for our project. Thus, we need to estimate a suitable unlevered beta for our company, the risk-free rate and the equity risk premium.

Defining comparable firms

The project's unlevered beta is estimated using the unlevered betas of comparable firms. When selecting comparable firms, the ideal aim is to find listed companies whose market values fluctuate in line with fluctuations in the project's net present value. For our project, once the initial investment cost is undertaken and the PV system is in operation, the primary determinant of the project's net present value is changes to the expected future electricity prices. Therefore, comparable stocks should be companies where the net present value of future cash flows is mainly determined by changes in expected future electricity prices.

One possible category of comparable stocks is firms that generate and sell electricity. Changes to expected future cash flows will cause the market value of these companies to fluctuate. As in our project, listed power producers will have low variable costs, and future cash flows will mostly depend on the price at which the electricity is sold. However, a major difference is that utility-scale power producers often sell a significant part of the generated energy on long-term contracts at fixed prices. In this way, they have less exposure to expected future electricity prices than our project. Another critical difference is that large, listed power companies continuously invest in new plants in new areas, which involves new political and operational risks.

We choose to include five power producers in our list of comparable firms. These are Ørsted, Verbund, EDP Renovaveis, Scatec, and Solaria Energia Y Medio Ambi. Ørsted is primarily focused on wind energy, while Verbund primarily generates hydropower. EDP Renovaveis primarily focuses on wind energy and, in addition, own several solar PV plants. Scatec and Solaria Energia Y Medio Ambi are mainly exposed to solar PV plants.

Another category of comparable stocks is firms that deliver raw materials and equipment to the solar PV sector. The rationale is that demand for these products, and thereby the companies' earnings, will increase with higher expected electricity prices. This way, their market values are expected to fluctuate with expectations on future electricity prices, which corresponds to the fluctuations in the net present value of the residential rooftop solar PV project. The comparable firms used are REC Silicon and SolTech Energy Sweden.

Calculating the unlevered beta of comparable firms

Unlevered betas for the comparable stocks are found by calculating equity beta and adjusting for the leverage effect. Equity beta is measured against the MSCI Europe index, which is a broad index with 429 constituents covering 15 developed countries in Europe (MSCI, 2022). Equity beta is calculated based on monthly returns over the past five years. The equity betas are then adjusted for the leverage effect using the average effective tax rate and average debt-to-equity ratio over the past five years to find the unlevered beta of the comparable firms. Table 5-9 sums up the results. The detailed calculations are found in appendix G.

The table shows that the unlevered beta differs strongly between the comparable companies. The average unlevered beta among the seven companies is 0.7. Scatec and Solaria Energia Y Medio Ambi are owners and operators of solar PV plants and can thus be considered the most relevant comparable firms for our project. These have an average beta of 0.7, which is in line with the average of all the comparable companies. Altogether, this indicates that the unlevered beta of a renewable energy company focused on solar PV is around 0.7.

Calculating unlevered beta of comparable firms.

Security	Levered beta	Tax rate	D/E ratio	Unlevered beta
Ørsted A/S	0.57	12%	0.03	0.56
Verbund AG	1.08	41%	0.19	0.98
EDP Renovaveis SA	0.49	46%	0.31	0.42
Scatec ASA	1.27	23%	0.70	0.82
Solaria Energia Y Medio Ambi	0.80	0%	0.39	0.58
REC Silicon	0.21	9%	0.07	0.20
SolTech Energy Sweden	2.04	0%	0.59	1.28

Table 5-9: Comparable firms' levered beta, unlevered beta and inputs used to calculate unlevered beta

Risk-free rate

The risk-free rate is used to calculate the WACC used in the CAPM formula and to calculate excess return on the benchmark stock index. The risk-free rate used in our calculations is the 10-year yield on European government bonds. We use an index from the European Central Bank, consisting of all European government bonds with an AAA rating. The current risk-free rate, as of 01.11.2022, is 2.254% (European Central Bank, 2022).

Equity risk premium

Estimating equity risk premium using historical returns

The CAPM further requires an estimation of the equity risk premium. One way to estimate equity risk premium is to calculate the average excess return of the market, approximated by calculating the average excess returns of the benchmark index. As the beta values are calculated based on MSCI Europe, this index is also used to estimate equity risk premium.

Historical excess return is found by subtracting the risk-free rate from the index's total return. We use the yearly average of the European risk-free rate introduced above. The excess return of MSCI Europe over the past ten years is shown in table 5-10. The average annual excess return was 5.6% both in the latest five-year period and the latest ten-year period. Thus, the historical returns indicate that the equity risk premium in the European market is around 5.6%.

MSCI Europe Historic Returns.

Year	Total return	Risk-free rate	Excess return
2012	13.6%	2.2%	11.4%
2013	9.9%	2.0%	7.9%
2014	8.4%	1.4%	6.9%
2015	-6.4%	0.6%	-7.1%
2016	9.1%	0.2%	8.9%
2017	11.6%	0.4%	11.1%
2018	-9.3%	0.5%	-9.8%
2019	11.9%	-0.2%	12.1%
2020	-3.7%	-0.4%	-3.3%
2021	17.4%	-0.3%	17.7%
Average	6.2%	0.6%	5.6%

Table 5-10: MSCI Europe Historical total and excess returns

Estimating equity risk premium from a survey

As investors are forward-looking, the equity premium used in the CAPM should also be forward-looking. Consequently, historical returns could be misleading. An alternative way to measure the equity risk premium is to investigate which equity risk premium market participants use in their calculations. In an annual survey amongst Norwegian financial analysts and economists, PWC aims to estimate the equity risk premium in the Norwegian market as perceived by financial analysts. As shown in table 5-11, the perceived equity risk premium in Norway seems to be relatively stable at around 5% (PWC, 2021).

	2017	2018	2019	2020	2021	Average
Perceived equity risk premium	5.0%	5.0%	4.9%	4.8%	4.8%	4.9%
Implicit equity risk premium	5.6%	6.0%	7.0%	6.1%	4.9%	5.9%

Table 5-11: Historical perceived and implicit equity risk premium. Source: PWC

The same surveys calculate implicit equity risk premium in Norway by comparing the stock price of the 40 shares with the largest market capitalisation, with the expected dividend payments. The average implicit equity risk premium over the five years is 5.9%. These observations do not differ too much from the observed excess return of MSCI Europe of 5.6%. Thus, an equity risk premium of 5.6% is applied in the further calculations.

Conclusion on project cost of capital using CAPM

As discussed above, the average unlevered beta of comparable firms seems to be around 0.7. The current 10-year risk-free rate is 2.25%, and the equity risk premium is estimated at 5.6%. Applying the CAPM formula gives a project cost of capital of 6.2%.

$$Project\ cost\ of\ capital = 2.25\% + 0.7 * 5.6\% = 6.17\%$$

As previously discussed, the unlevered cost of capital is relevant if the project is to be evaluated as an all-equity financed project. Tax-deductible interest payments will result in a lower WACC if the project is financed partly with debt. In an exemplifying scenario with a constant debt-to-value ratio of 0.5, a tax rate of 22% and a cost of debt of 3.75%, the equity cost of capital can be calculated as follows:

$$r_{levered} = r_{unlevered} - \frac{D}{E+D} * \tau * r_{debt} = 6.17\% - 0.5 * 22\% * 3.75\% = 5.76\%$$

The 22% tax rate is the current rate on tax deductions on interest payments for individuals in Norway. The 3.75% cost of debt is based on the interest rate on green loans to private customers offered by major Norwegian banks (Sparebank1 SMN, 2022; DNB, 2022; Sparebanken Vest, 2022; Nordea, 2022).

In the example, leverage lowers the WACC by 0.4 percentage points. As this difference is small compared to the general uncertainty in the cost of capital estimation, we will not present results as if the project was levered.

Limitations of using CAPM to estimate the cost of capital

The unlevered beta of the project is estimated from the unlevered beta of comparable firms. Thus, the choice of comparable companies is important. Ideally, the comparable firms should be stocks whose market values fluctuate in line with the market value of our project. For our project, the primary determinant of the net present value of future cash flows from the project is the future electricity prices. We have included five power producers in the list of comparable firms, as the net present value of future cash flows of these companies is also susceptible to changes in expected future electricity prices.

A critical difference between our project and the comparable power producers is that these companies sell a large part of their electricity on long-term contracts, while our project is assumed to be fully exposed to spot electricity prices. This indicates that the asset risk is higher in our project, which should be compensated with a higher cost of capital. It is difficult to determine how much our project's capital cost should be increased due to this difference. We choose to increase the risk premium by 1.3% to account for this, leading to an unlevered WACC of 7.5%. However, this additional risk premium is highly arbitrary, and the NPV should be evaluated for higher and lower costs of capital.

Conclusion on project cost of capital

The unlevered WACC of our project is calculated to be 6.2% using CAPM. However, we argue that the volatility in the market value of our project is expected to be higher than the comparable firms because of spot exposure to electricity prices. To account for this, we have arbitrarily adjusted the unlevered WACC up to 7.5% as our base case. In chapters six and seven, a 7.5% cost of capital is used as the base case. Still, results are also presented for higher and lower discount rates to account for the high level of uncertainty in determining the appropriate cost of capital. Some non-financial aspects that could affect the cost of capital are presented in chapter ten.

6. Results

In this chapter, the general findings will be presented, while chapter seven presents sensitivities, deeper analysis, and discussion. Unless otherwise specified, the results are presented for a system under the standard assumptions, as shown in table 6-1. All numbers are reported including the Enova subsidy and electricity price subsidies through 2023. The profiles presented and discussed will generally be the most profitable ones. Results for more profiles are shown in the appendix.

Variable	Standard assumption
Size	9 kWp
Cost of capital	7.5%
Light-induced degradation	2.0%
Annual degradation	0.5%
Share of generated electricity consumed internally	SSB scenario

Table 6-1: Standard assumptions in the model

6.1 Net Present Value

South-facing roofs. 9 kWp system. 7.5% WACC. 1000 NOK.

City	Roof type	Reference	Reference +100%	Reference +200%	Reference +300%
Oslo	Flat	-113	-61	-9	43
Oslo	Sloped	-112	-53	6	66
Kristiansand	Flat	-129	-74	-18	37
Kristiansand	Sloped	-127	-64	-1	61
Stavanger	Flat	-142	-94	-45	3
Stavanger	Sloped	-142	-88	-34	21
Bergen	Flat	-104	-58	-12	34
Bergen	Sloped	-106	-54	-2	51
Trondheim	Flat	-119	-76	-33	10
Trondheim	Sloped	-121	-73	-24	24
Tromsø	Flat	-165	-128	-91	-54
Tromsø	Sloped	-166	-123	-79	-36

Table 6-2: NPV for various electricity price scenarios. More profiles are in the appendix.

Table 6-2 shows the NPV for south-facing sloped and flat roofs in each city for four different electricity price scenarios under the standard assumptions. The NPVs of more profiles are shown in table a-0-1 and table a-0-2 in the appendix. In general, NPV increases with higher electricity prices, as expected. Comparing the cities, it is clear that Oslo, Bergen, and Kristiansand achieve higher NPVs than the other cities. Tromsø is the least profitable city, and the NPV is negative even for the highest electricity price scenario.

6.2 Internal Rate of Return

Table 6-3 displays the internal rate of return (IRR) corresponding to the same profiles and premises as in table 6-2. The IRR is the discount rate that gives the project an NPV of zero. In other words, the IRR is the maximum cost of capital that will result in a non-negative NPV. In the table, green cells indicate that the IRR is above 7.5%, which is the cost of capital defined in the standard assumption. The profiles with yellow cells have an IRR between the risk-free rate of 2.25% and 7.5% and could thus be considered profitable if the applied risk premium was lower. The red cells indicate that IRR is lower than the risk-free rate. As expected, the IRR follows the NPV from table 6-2, and it is apparent that the profiles and scenarios with IRR above 7.5% are the same as the ones with positive NPV. Table 6-2 Further, the IRR increases with the electricity price, as expected.

South-facing roofs. 9 kWp system.

City	Roof type	Reference	Reference +100%	Reference +200%	Reference +300%
Oslo	Flat	0.6%	4.3%	7.1%	9.3%
Oslo	Sloped	1.2%	5.0%	7.8%	10.1%
Kristiansand	Flat	0.6%	4.1%	6.7%	8.9%
Kristiansand	Sloped	1.2%	4.8%	7.4%	9.7%
Stavanger	Flat	-0.4%	3.0%	5.6%	7.6%
Stavanger	Sloped	0.2%	3.6%	6.2%	8.3%
Bergen	Flat	0.4%	4.1%	6.9%	9.1%
Bergen	Sloped	0.9%	4.7%	7.4%	9.7%
Trondheim	Flat	-0.5%	3.1%	5.8%	8.0%
Trondheim	Sloped	0.0%	3.7%	6.4%	8.6%
Tromsø	Flat	-2.8%	0.7%	3.2%	5.1%
Tromsø	Sloped	-2.0%	1.5%	4.0%	6.1%

Table 6-3: IRR for various electricity price scenarios

The highest IRRs are achieved for the highest electricity price scenario are 9-10% in Oslo, Kristiansand and Bergen. For Stavanger and Trondheim, the maximum IRRs are around 8%. This means that in the highest electricity price scenario, projects in these five cities could be considered profitable even with slightly higher costs of capital than our standard assumption of 7.5%. Tromsø, on the other hand, achieves a maximum IRR of 6.1% in the highest electricity price scenario and would thus need a lower WACC than the standard assumption to be considered profitable. In the reference electricity price scenario, none of the profiles achieves an IRR higher than the risk-free rate. This implies that none of the projects would be considered profitable in the reference electricity price scenario as long as a negative risk premium is not applied. Some profiles in Tromsø, Trondheim and Stavanger even have negative IRRs, meaning that the investment is not even paid back over the project's lifetime.

6.3 Break-even electricity price

As seen from the tables above, the choice of electricity price scenario strongly impacts the project's NPV and IRR. The break-even electricity price is the project's average electricity price necessary to achieve an NPV of zero. It is a very relevant measure as it is easy to compare the break-even electricity price with historical electricity prices.

Break-even NOK/kWh.

City	Roof	Break-even
Oslo	Flat roof	1.4
Oslo	Sloped roof	1.3
Kristiansand	Flat roof	1.5
Kristiansand	Sloped roof	1.4
Stavanger	Flat roof	1.8
Stavanger	Sloped roof	1.6
Bergen	Flat roof	1.5
Bergen	Sloped roof	1.4
Trondheim	Flat roof	1.7
Trondheim	Sloped roof	1.6
Tromsø	Flat roof	2.3
Tromsø	Sloped roof	2.1

Table 6-4: Break-even electricity prices in 2023 value. NOK/kWh

Table 6-4 shows the break-even spot electricity prices in NOK/kWh, excluding taxes and fees for different profiles. The prices are in real 2023 value and discounted with a 2% annual inflation rate. To calculate the break-even electricity prices, we have assumed the same electricity price throughout the year, not including seasonal variations. The prices are the actual prices in the periods when the PV systems generate electricity. As a result of intraday and seasonal fluctuations, the break-even prices calculated above may differ from the average annual electricity price required for the project to break even.

As expected, the break-even results follow the NPV and IRR. The lowest break-even price is found in Oslo, with NOK 1.3 for a south-facing sloped roof and NOK 1.4 for a system on a flat roof tilted towards the south. At the opposite end, the highest break-even price is found for a flat roof system in Tromsø with a break-even price of NOK 2.3.

All these break-even prices are well above the historical electricity prices. As discussed in chapter three, the average Nordic system price was 0.42 NOK/kWh between 2010 and 2022. Compared to the electricity price scenarios in table 5-3, the break-even prices are also well above the reference electricity price scenario with an average price of 0.6 NOK/kWh.

6.4 Payback time

Another key figure is the payback time, measuring how long it takes before the initial investment is paid back in nominal figures. Table 6-5 shows the payback time for a sloped, south-facing system in each of the six cities for different electricity price scenarios.

Payback time in years. 9 kWp system. South-facing sloped roof.

Electricity price scenario	Oslo	Kristiansand	Stavanger	Bergen	Trondheim	Tromsø
-50%	>30	>30	>30	>30	>30	>30
Reference	26	26	29	27	>30	>30
+100%	17	18	20	18	20	25
+200%	12	13	15	12	14	19
+300%	10	11	12	11	11	15

Table 6-5: Payback time for various electricity price scenarios

In the reference -50% electricity price scenario, none of the projects are paid back over the 30-year period that is assumed to be the economic life of the project. Projects in Trondheim, and Tromsø are not even paid back over the expected lifetime in the reference scenario. However, payback time is dramatically reduced in the higher electricity price scenarios.

7. Analysis of Results

This chapter will discuss the results from chapter six in light of the standard assumptions and variable inputs used in the model. More specifically, we will discuss the effect of energy yield, the share of generated electricity consumed internally, initial investment cost, system sizing, operational expenditures and cost of capital. In some sections, a variable's effect will be discussed based on the results from only one profile. In these cases, the profile chosen will be the nine kWp south-facing sloped roof in Oslo. This profile is selected as it is generally the most profitable one, as seen in chapter six.

7.1 Income

7.1.1 Electricity Generation

A vital input when estimating future cash flows from a solar PV system is the amount of electricity generated from the system. In the model, electricity generation estimates are obtained from simulations in PVsyst. The following discussion will further examine the impact of panel orientation on electricity generation, how higher and lower efficiency affects the present value of income and the effect of different degradation rates.

Panel orientation on electricity generation

A critical determinant of electricity generation from a solar PV system is panel orientation. In areas far north, like Norway, the sun will shine from the south in the middle of the day when solar irradiation is most intense. Therefore, south-facing panels will generate more electricity than panels with other directions. In addition, the angle of the panels will affect the amount of direct solar irradiation on the panels. The following discussion will illustrate the effect of panel orientation on profitability.

Table 7-1 shows the percentage difference between each profile’s output and the output of a south-facing sloped roof in the same city. As seen, sloped roofs directed towards the south-west and south-east are the second-best orientation with 4-8% lower energy output than the south-facing sloped roofs. Flat roofs with panels tilted towards the south are the fourth-best orientation in all cities, with 10-14% lower energy yield than a sloped south-facing roof. Lastly, sloped roofs towards east and west, gable roofs with east/west configuration and flat roofs with east/west configuration are the orientations with the lowest outputs.

kWh/kWp relative to south-facing sloped roof

Roof type	Direction	Oslo	Kristiansand	Stavanger	Bergen	Trondheim	Tromsø	Average
Sloped roof 30°	South	0%	0%	0%	0%	0%	0%	0%
Sloped roof 30°	South-East	-6%	-8%	-7%	-6%	-5%	-7%	-7%
Sloped roof 30°	South-West	-7%	-5%	-4%	-6%	-7%	-5%	-6%
Flat roof 10°	South	-11%	-11%	-10%	-10%	-11%	-14%	-11%
Flat roof 10°	East/West	-20%	-20%	-19%	-19%	-19%	-24%	-20%
Gable roof 30°	East/West	-23%	-22%	-21%	-21%	-22%	-22%	-22%

Table 7-1: Percentage difference in energy yield from a south-facing sloped roof.

The difference in energy yield between panels oriented in different directions is naturally transferred to differences in the present value of income. In the model, the direction of the roof does not affect the estimated investment cost. This means that all else equal, a system installed on a sloped roof will have lower NPV if it is facing south-west or south-east, compared to a south-facing system. However, the effect on income is not perfectly linear with the effect on energy yield, as different panel directions give different seasonal production, and the electricity price is modelled with seasonal variations.

When comparing sloped roofs and flat roofs, the effects are less straightforward. Table 7-1 shows that flat roofs generally have lower power generation than sloped roofs facing south, south-east or south-west. However, when looking at the total NPV of the project, flat roofs with panels tilted towards the south are often better than systems on sloped roofs towards the south-west and south-east. The reason is that investment cost is lower for systems mounted on flat roofs. From the initial investment cost regressions, the sloped roof dummy coefficient is 13 545. This means that, all else equal, a flat roof will have a higher NPV than a sloped roof if the difference in the present value of cash inflows is lower than 13 545.

Efficiency in generation

In the model, generation is based on simulations from PVsyst. A critical limitation of these simulations is that it excludes near shadings. For a real-life PV system, some degree of shading from nearby trees, buildings or utility poles will often be present. Furthermore, other inefficiencies and losses may result in lower energy yield than the simulations indicate. On the other hand, actual energy yield may also be higher than the PVsyst results, for example because of higher-quality panels. Therefore, it is relevant to discuss how NPV is affected by changes in electricity generation.

Changes in electricity generation directly impact the NPV. As an example. A 10% reduction in electricity production leads to a 10% reduction in income, all else equal. For profiles with positive NPV close to zero, the NPV may become negative if near shadings or other inefficiencies lead to lower electricity generation. Table 7-2 shows the NPV of various profiles from each city with sensitivities on energy yield, given the standard assumptions and the reference +300% electricity price scenario.

In the base case for energy yield, ten out of the twelve main profiles have positive NPV. If actual electricity generation is 10% lower than the base case, for example as a result of near shadings, only seven of the profiles will be profitable. If electricity generation is reduced by 20%, NPV is only positive for one profile. This clearly shows that our results are sensitive to inaccuracies in the generation estimates from the PVsyst simulations. On the other hand, the results are also exposed to changes to the upside. With the rapid technological development and cost reductions in the solar industry, it is not unrealistic with higher energy yields and thereby higher NPV.

NPV. Sensitivies on energy yield. Reference +300% electricity price. NOK 1000.

City	Roof type	-20%	-10%	Base case	+10%	+20%
Oslo	Flat	-8	17	43	68	94
Oslo	Sloped	7	37	66	95	124
Kristiansand	Flat	-18	9	37	65	92
Kristiansand	Sloped	-2	30	61	93	124
Stavanger	Flat	-45	-21	3	27	51
Stavanger	Sloped	-34	-6	21	48	75
Bergen	Flat	-11	11	34	57	79
Bergen	Sloped	-1	25	51	76	102
Trondheim	Flat	-32	-11	10	31	51
Trondheim	Sloped	-23	1	24	48	72
Tromsø	Flat	-89	-72	-54	-37	-19
Tromsø	Sloped	-77	-57	-36	-15	6

Table 7-2: NPV with sensitivities on energy yield in reference +300% electricity price scenario. 1000 NOK.

Degradation

In our base case, we have assumed 2% initial light-induced degradation (LID) and 0.5% annual degradation based on the warranties of standard panels. However, the experienced degradation may be higher because of lack of cleaning, extreme weather and other factors. On the other hand, technological development may lead to lower degradation rates, as found on the highest-quality panels available today. Therefore, it is relevant to study sensitivities on degradation. Table 7-3 shows the electricity generation of a south-facing system in Oslo on a sloped roof as a percentage of nominal power. LID is assumed to be unchanged at 2%, and the table shows electricity generation after 10, 20 and 30 years for various annual degradation rates. Degradation is assumed to be compounded annually.

	Annual degradation						
	0%	**0.25%**	**0.5%**	**1%**	**2%**	**3%**	**4%**
Year 10	98%	96%	93%	89%	80%	72%	65%
Year 20	98%	93%	89%	80%	65%	53%	43%
Year 30	98%	91%	84%	72%	53%	39%	29%
Lifetime average	98%	94%	91%	84%	73%	63%	55%

Table 7-3: Effect of degradation on output after 10, 20, and 30 years.

Minor changes to the annual degradation rate have a rather significant impact on electricity generation. The table shows that if degradation rates are higher than the standard assumption of 0.5%, the energy output from the system will decrease quickly, and the system's economic life may be reduced. For example, the inverter replacement after about 15 years may not be profitable if the system's remaining effect is too low.

The effect of degradation on electricity generation naturally affects NPV. However, discounting reduces this effect. Table 7-4 shows the present value of income for the standard south-facing sloped system of nine kWp in Oslo, assuming 2% LID. We see that the NPV effect of changes in degradation rate is highly dependent on electricity price scenarios.

PV Income. 1000 NOK.	**Annual degradation**						
	0%	**0.25%**	**0.5%**	**1%**	**2%**	**3%**	**4%**
Reference -50%	88	86	84	80	73	67	62
Reference	120	117	114	108	97	88	81
Reference + 100%	184	178	173	163	146	131	118
Reference + 200%	247	240	232	219	194	174	156
Reference + 300%	311	301	292	274	243	216	194

Table 7-4: Present value of income for various annual degradation rates and electricity price scenarios.

A lower degradation rate is often used as a selling point for higher-quality panels. One example is Otovo's performance panels which guarantee a maximum of 0.25% annual degradation, compared to the premium panels, which guarantee a maximum of 0.5% annual degradation. The table shows that the value of reducing annual degradation from 0.5% to

0.25% is NOK 2 000 in the lowest electricity price scenario and NOK 9 000 in the highest electricity price scenario. This difference can be used as a starting point to determine how much extra the investor should be willing to pay for higher-quality panels. However, higher-quality panels usually offer other advantages that further increase willingness to pay.

7.1.2 Share of Generated Electricity Consumed Internally

Sensitivities

In section 5.1.1, we explained that electricity sold to the grid is valued differently than the electricity consumed internally in the household. Therefore, the share of generated electricity consumed internally is an essential input factor in the profitability analysis.

We used SSB's estimated average share of generated electricity consumed internally in the model. Considering the electricity generation pattern of a south-facing sloped roof system in Oslo, the SSB estimate gives a weighted average share of consumed internally of 55%. However, the share consumed internally is affected by numerous factors, and the precision of the estimate is highly limited. The following section discusses how changes to the share consumed internally will affect profitability measures. All sensitivities are based on a south-facing sloped roof system in Oslo under the standard assumptions.

Table E-0-11 in the appendix displays the scenarios for the share of generated electricity consumed internally. The scenarios have a weighted average share of kilowatt-hours generated consumed internally of 0%, 20%, 80% or 100%. The distribution between the months is based on the SSB scenario.

Table 7-5 shows how the net present value for a nine kWp south-facing sloped roof system in Oslo varies with changes in share consumed internally and electricity prices. The table shows that the share of electricity consumed internally strongly affects the project's net present value. In the reference electricity price scenario, the effect on NPV of going from 0% to 100% share consumed internally is NOK 73 thousand. In comparison, the effect in the reference +300% electricity price scenario is NOK 112 thousand. The impact of changes to share consumed internally is larger for higher electricity prices because the VAT, which is recognised as revenue for electricity consumed internally and not for electricity sold, increases with spot electricity prices.

NPV. 1000 NOK.	Power price scenario			
Share consumed internally	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
0%	-153	-101	-49	3
20%	-138	-84	-29	26
SSB	-112	-53	6	66
80%	-94	-31	31	94
100%	-80	-15	50	115

Table 7-5: NPV for different scenarios on the share of generated electricity consumed internally

The example above shows that the share of electricity consumed internally can significantly impact NPV and, in some cases, determine if the project is profitable. For example, in the reference +200% electricity price scenario, the NPV will be negative with 0% and 20% share consumed internally and positive in the SSB, 80% and 100% scenarios. Thus, the household should strive to increase the share of electricity consumed internally to improve the project's profitability.

Table 7-6 displays the present income value change when the share consumed internally varies from the SSB scenario. The table shows that the effect of changes in share consumed internally is more substantial for low electricity price scenarios than for high electricity price scenarios. This is because taxes and grid fees constitute a larger share of the total electricity cost in low-price scenarios.

PV income %change from SSB scenario.

Share consumed internally	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
0%	-36%	-28%	-24%	-22%
20%	-23%	-18%	-15%	-14%
SSB	0%	0%	0%	0%
80%	16%	12%	11%	10%
100%	29%	22%	19%	17%

Table 7-6: Percentage change to PV of income for various scenarios on the share of generated electricity consumed internally

The tables above show that a higher share consumed internally can greatly impact profitability. The effect is also evident in the break-even prices. Table 7-7 displays the break-even prices for various shares consumed internally and various WACCs. Break-even prices are reported in 2023-value, discounted with an assumed 2% inflation rate. With the standard assumption of 7.5% WACC, the break-even electricity price is reduced from 1.8 to 1.1 when the share consumed internally changes from 0% to 100%. In a more realistic scenario, when changing the share consumed internally from the SSB scenario to 80%, the break-even electricity price is reduced by 0.1 NOK/kWh. Although this may seem low, it is considerable compared to the historical average Norwegian price of 0.42 NOK/kWh. This shows that the household can increase the probability of breaking even on the investment by increasing the share of generated electricity consumed internally.

Break-even power price, NOK/kWh	Cost of capital				
Share consumed internally	**4.5%**	**6%**	**7.5%**	**9%**	**10.5%**
0%	1.3	1.5	1.8	2.0	2.3
20%	1.1	1.4	1.6	1.8	2.1
SSB	0.9	1.1	1.3	1.6	1.8
80%	0.8	1.0	1.2	1.4	1.6
100%	0.7	0.9	1.1	1.3	1.5

Table 7-7: Break-even prices for various shares of generated electricity consumed internally and cost of capital

Factors influencing the share of generated electricity consumed internally

The sensitivity tables above clearly show that an increased share of generated electricity consumed internally increases the profitability of a residential rooftop solar PV system. The following discussion will examine some measures that can increase the share of generated electricity consumed internally and thereby positively affect profitability.

System size

A factor that can considerably affect the share consumed internally is the size of the PV system. As larger systems generate more electricity, it is natural to assume that the share consumed internally will be lower. For a smaller system, it would be the opposite, with lower production and a higher share consumed internally. This indicates that the household should not necessarily opt for the largest possible system because a large part of the additional electricity this would generate would be sold to the grid and valued lower than the electricity consumed internally.

Consumption pattern

The consumption pattern also affects the share of generated electricity consumed internally. We have previously established that there is a mismatch between the generation pattern of a

PV system and the typical consumption pattern of a Norwegian household. With the help of smart devices, it could be possible to shift some of the consumption to a period of high solar production. Examples of such devices are time-controlled appliances such as smart dishwashers, washing machines, and warm water heating. Shifting consumption to the daytime during weekends is maybe just as realistic.

Even though it might be obvious, it is necessary to point out that increasing consumption during the daytime without reducing consumption at other times does not improve profitability. For the consumption of generated electricity to be recognised as income, it must replace electricity that would otherwise be purchased. This means that if the household cannot shift the consumption pattern, its excess electricity should be sold to the market instead of consuming it unnecessarily.

Battery

As previously explained, solar electricity generation is an intermittent energy source, meaning that generation cannot be adjusted to coincide with consumption. So far, the analysis has assumed that excess electricity is sold to the grid. However, it is also possible to store electricity in batteries for some time, and thereby increase the share of generated electricity consumed internally. Assuming that the initial share of generated electricity consumed internally is 55%, the value of installing a battery allowing for a 100% share of electricity consumed internally will be NOK 32 thousand in the reference electricity price scenario and NOK 44 thousand in the reference +200% scenario. This serves as an indication of the maximum willingness to pay for a battery.

Historically, batteries with large enough capacity have been considered too expensive to be suitable for PV systems in Norway. In the global market for batteries, there are, however, large transformations ongoing. This development means that the availability of batteries will likely increase, and the prices could decrease due to the higher supply and technological developments (Thorsheim, 2021).

The effect of panel orientation on the share of generated electricity consumed internally

As discussed in section 5.1.4, panel orientation affects the intra-day electricity generation pattern. In general, south-facing systems have high generation in the middle of the day, while panels in an east/west configuration will have a more even generation throughout the day. In this way, panel orientation also affects the share of electricity consumed internally.

Norwegian household electricity demand peaks in the morning, afternoon, and evening (Ericson & Halvorsen, 2008). From this, we can assume that an east/west-oriented system allows for a higher share of generated electricity consumed internally than a south-facing system, all else equal. In this way, the lower total electricity generation from east/west-oriented systems is somewhat compensated by a higher share of generated electricity consumed internally.

The discussion about south-facing and east/west-oriented panels is particularly relevant for flat roofs, where the owner can choose to install the panels with a tilt towards the south or in an east/west configuration. According to the PVsyst simulations, a flat roof system in Oslo tilted towards the south will have a 12% higher energy yield than an east/west configurated system. This means that all else equal, the south-facing system gives a higher NPV. However, as explained above, the east/west configuration can allow for a higher share of electricity consumed internally, which can weigh up for the lower electricity generation.

For example, we can assume that the east/west configuration increases the average share of electricity consumed internally to 80% instead of the 55% in the SSB scenario. For a system in Oslo, under standard assumptions, the NPV will be higher with the east/west configuration in the reference electricity price scenario. In this way, the lower energy yield of the east/west configuration is weighed up by the increased share of generated electricity consumed internally. However, in the reference +300% scenario, the south-tilted system will have the highest NPV. This is in line with expectations, as the effect of changes in share consumed internally is highest for low electricity price scenarios because taxes and grid tariffs constitute a higher share of the total power cost. Thus, the east/west orientation is only preferred before south-facing panels if expectations for future electricity prices are low.

	Reference		Reference + 300%	
	South	**East/West**	**South**	**East/West**
Initial kWh/kWp	915	820	915	820
NPV 55% share consumed internally	-113	-125	43	14
NPV 80% share consumed internally		-110		37

Table 7-8: NPV in 1000 NOK. Comparison of south vs east-west on a flat roof.

7.2 Capital Expenditures

7.2.1 Initial Investment Cost

The estimated initial investment cost in the model is based on a regression of 382 price estimates obtained from Otovo and Fjordkraft. Although the data is based on actual estimates, there is high uncertainty and great variation. Therefore, we will present some sensitivities on how changes to initial investment cost affect NPV. Furthermore, we will discuss how the initial investment cost is affected by various variables and point at some indicators for future development in the initial investment cost.

Sensitivities

In the regression model on initial investment cost, we found that the total cost correlates strongly with the size of the system. Furthermore, the dummy variables for the cities and sloped roofs were significantly different from zero. Lastly, the dummy variable for Fjordkraft indicates that the offers from Fjordkraft were significantly lower than those from Otovo, with a coefficient of -68 thousand NOK.

The data collection and regression analysis are done to find a proxy for the initial investment cost. Figure F-0-5 in the appendix shows that there is high variability for similar houses, meaning that the individual aspects of each house should be considered. To account for the uncertainty in the model, we present sensitivity tables and discuss how the profitability evaluation would be affected by changes in initial investment cost. In an actual investment decision, where the project is evaluated for a specific building, a price estimate could easily be gathered from websites such as Otovo and Fjordkraft.

Table 7-9 shows the NPV given the reference +200% electricity price scenario and standard assumptions, for higher and lower initial investment costs. Table F-0-14 in the appendix shows the break-even spot electricity prices in 2023 value for different sensitivities on initial investment cost. As seen from the NPV table, only one profile has a positive NPV in the base investment cost scenario. If the initial investment cost is reduced by 15%, eight out of twelve profiles are profitable for this electricity price scenario. If the investment cost is reduced by 30%, all profiles except the ones in Tromsø are considered profitable. This shows that changes to the initial investment cost can significantly impact the profitability analysis. The effect of changes to the initial investment cost is also seen in the break-even electricity prices, as shown in table f-0-14 in the appendix. If the initial investment cost is reduced by 30%, the break-even in the best profile is reduced from NOK 1.3 to 0.9.

NPV. Reference +200% scenario power price.

City	Roof	-45%	-30%	-15%	Base	+15%	+30%	+45%
Oslo	Flat roof	82	52	21	-9	-40	-70	-101
Oslo	Sloped roof	104	72	39	6	-26	-59	-91
Kristiansand	Flat roof	85	51	16	-18	-53	-88	-122
Kristiansand	Sloped roof	108	72	35	-1	-38	-75	-111
Stavanger	Flat roof	58	23	-11	-45	-80	-114	-148
Stavanger	Sloped roof	75	39	3	-34	-70	-106	-143
Bergen	Flat roof	70	43	15	-12	-40	-67	-94
Bergen	Sloped roof	87	57	28	-2	-31	-60	-90
Trondheim	Flat roof	52	24	-5	-33	-61	-90	-118
Trondheim	Sloped roof	67	37	6	-24	-55	-85	-115
Tromsø	Flat roof	8	-25	-58	-91	-124	-157	-190
Tromsø	Sloped roof	26	-9	-44	-79	-114	-150	-185

Table 7-9: NPV for various levels of initial investment cost in reference +200% electricity price scenario. 1000 NOK.

Size of PV-system

The results presented in chapter six are based on the average Norwegian residential system of nine kWp. Table 7-10 illustrates how changes to system capacity affect profitability for a south-facing system on a sloped roof in Oslo. The table shows the IRR for systems of various sizes, given various electricity price scenarios. System size varies from 6 to 18 kWp to cover the range of most residential systems. Table 7-11 shows the NPV for the same system, given a WACC of 7.5%.

IRR.

kWp	Reference -50%	Reference	Reference +100%	Reference +200%	Reference +300%
6	-2.4%	0.2%	3.8%	6.4%	8.5%
9	-1.5%	1.2%	5.0%	7.8%	10.1%
12	-0.8%	1.9%	5.8%	8.7%	11.1%
15	-0.5%	2.4%	6.3%	9.3%	11.7%
18	0.0%	2.8%	6.8%	9.7%	12.2%

Table 7-10: IRR for various system sizes and electricity price scenarios.

The IRR table shows that large systems have higher IRR than smaller systems in all electricity price scenarios. Changes in system size affect the cash flow through income and investment costs. Income increases linearly with size. This means that an 18 kWp system will have twice the present value of income as a nine kWp system. However, larger systems have an advantage on investment cost as the cost per kWp installed capacity will decrease with size. An 18 kWp system will have twice the income of a nine kWp system, but the investment cost will not be twice as high. Therefore, IRR will always be higher for larger systems.

NPV. 1000 NOK

kWp	Reference -50%	Reference	Reference +100%	Reference +200%	Reference +300%
6	-119	-99	-59	-20	20
9	-142	-112	-53	6	66
12	-163	-124	-45	35	114
15	-186	-136	-37	62	160
18	-205	-146	-27	92	210

Table 7-11: NPV for various system sizes and electricity price scenarios. 1000 NOK.

When looking at NPV, large systems are only better than small systems in the high electricity price scenarios. In the reference and reference -50% scenarios, smaller systems have higher NPV than large systems, although IRR is always higher for larger systems. This is because, in the lower electricity price scenarios, the value of the higher production from the large systems will not be enough to compensate for the higher investment cost. In higher price scenarios, however, the benefit of higher production is higher than the disadvantage in investment cost, and larger systems will generate a higher NPV.

Difference between cities

The coefficients in table 5-8 show large differences in investment costs between the cities. The most expensive cities are Kristiansand and Stavanger, while Bergen is the least expensive. The difference between Kristiansand and Bergen is NOK 48 thousand. This means that if the investment in Kristiansand were the same as in Bergen, it would be 18% lower for a nine kWp system. As table 7-9 shows, both the flat and sloped south-facing roof in Kristiansand turns profitable when the initial investment cost is reduced by 15%, given the reference +200% electricity price scenario. This means that these profiles would be profitable if investment costs in Kristiansand were the same as in Bergen. From the break-even table, we see that the effect is about NOK 0.2, which is not a negligible amount. In this way, the difference in investment cost estimates between the cities has an essential impact on the profitability analysis. Some possible explanations for the significant difference between cities are presented below.

Discussion on current price levels

The high electricity prices in Norway in 2021 and 2022 have strongly impacted the demand for residential solar panels and caused prices to increase rapidly. Trine Berentsen, CEO of The Norwegian Solar Energy Cluster, claims that panel prices have increased by 50% and total systems costs have increased by about 20% (The Norwegian Solar Energy Cluster, 2022; Barstad, 2022). The price increase is mainly driven by higher panel costs caused by high global demand and supply chain issues. In addition, the high interest in solar panels has caused pressure on local installers (Bøhren, 2022).

Current prices are high because of supply chain issues and the rapid recent growth in demand. Based on this, one can argue that current price levels are temporary and are likely to drop if the supply and demand situation normalises. The descending future curve for electricity prices may support that the demand for solar panels will normalise. Furthermore, the current strong demand can lead to high investments in supply chains and installations, which will increase future supply. In this way, supply and demand is likely to balance out and lead to lower prices in the coming years. In addition, the long-term trend indicates that prices will keep decreasing as technology advances and the industry benefits from higher economies of scale. On the other hand, projections on PV deployment indicate strong demand in the coming years. This way, prices may remain high for an extended period.

To conclude, a drop in investment cost will strongly impact the profitability evaluation in all profiles. If the investment cost normalises and decreases further in the coming years, a break-even electricity price below NOK 1.0 seems realistic in the best profiles. Thus, the conclusions of this thesis would have been more positive if the investment cost was not so strongly affected by the recent price increase.

From the regression model on initial investment cost, we see a significant difference between the cities. If panel costs are assumed to be equal, not accounting for possible differences in shipping cost, the difference between cities must be explained by installation cost. One possible explanation is that the recent surge in PV installations has caused high pressure on installers in some cities. As labour and panel costs are assumed to be more or less equal between the cities in the long term, we expect the current price differences to even out in the future. Kristiansand and Stavanger, the most expensive cities, will probably experience higher profitability by this logic. The third most expensive city is Tromsø, but the relatively high price here may also be explained by higher shipping costs, a small market, and other geographical factors that will not necessarily even out over time.

7.2.2 Inverter Replacement

In the model, we have assumed that all systems will need to replace the inverter after 15 years. The price estimate of this inverter replacement is based on prices available today, adjusted with 2% annual inflation until 2038. For the standard nine kWp system, the present value of the inverter replacement is NOK 9 141, assuming a 7.5% discount rate. This shows that the inverter replacement has a relatively low effect on NPV, but it can still affect the profitability evaluation for projects with NPV close to zero. It is also worth noting that the cost development towards 2038 is highly uncertain, and actual prices in 2038 may differ strongly from our estimate. Despite the high uncertainty, we choose not to present sensitivities on inverter replacement because of the limited expected effect on NPV.

7.3 Operational Expenditures and Maintenance

In the model, the inverter replacement after 15 years is assumed to be the only expenditure after the initial investment. However, some operational costs might be necessary in a real-life example. As mentioned in section 5.3, it could be necessary with some service and check-ups from specialists or replacement of defective parts. For example, one could set a provision of NOK 1 000 yearly. This would reduce the NPV with 14 420 NOK if the yearly provision is inflation adjusted and then discounted with the reference WACC of 7.5%.

As seen from the NPV table in chapter six, a reduction in NPV of NOK 14 420 could change the conclusion on the profitability evaluation in several profiles. One example is the south-facing sloped roof system in Oslo that has a positive NPV of NOK 6 485 in the reference +200% electricity price scenario. This illustrates that for profiles and scenarios with NPV close to zero, operational expenditures should be considered more carefully than we have done in the model.

7.4 Cost of Capital

In chapter five, the project cost of capital was estimated to be 7.5% using CAPM. First, we found the unlevered beta of comparable firms and used CAPM to arrive at an unlevered WACC of 6.2%. Then we added an extra risk premium to account for the spot exposure to electricity prices and arrived at an unlevered WACC of 7.5%. Other investors may have different views on the project's cost of capital, especially when considering the uncertainty caused by the lack of relevant comparable companies. The following discussion will present sensitivities on the cost of capital. Some non-financial aspects that can be used to argue for a higher or lower cost of capital are presented in chapter ten.

The importance of the cost of capital is apparent from the IRR values in table 6-3. In the reference +200% electricity price scenario, one of the twelve profiles is profitable with a 7.5% cost of capital, while all profiles except Tromsø are profitable at a 5% cost of capital. Table A-0-3 in the appendix shows the NPV in the reference +200% for various costs of capital.

South-facing systems. 9 kWp. NOK/kWh.

City	Roof	4.50%	6.00%	7.50%	9.00%	10.50%
Oslo	Flat roof	1.0	1.2	1.4	1.7	1.9
Oslo	Sloped roof	0.9	1.1	1.3	1.6	1.8
Kristiansand	Flat roof	1.0	1.3	1.5	1.8	2.0
Kristiansand	Sloped roof	1.0	1.2	1.4	1.6	1.9
Stavanger	Flat roof	1.2	1.5	1.8	2.1	2.4
Stavanger	Sloped roof	1.1	1.4	1.6	1.9	2.2
Bergen	Flat roof	1.0	1.2	1.5	1.7	2.0
Bergen	Sloped roof	1.0	1.2	1.4	1.6	1.9
Trondheim	Flat roof	1.2	1.4	1.7	1.9	2.2
Trondheim	Sloped roof	1.1	1.3	1.6	1.8	2.1
Tromsø	Flat roof	1.7	2.0	2.3	2.7	3.1
Tromsø	Sloped roof	1.5	1.8	2.1	2.4	2.8

Table 7-12: Break-even electricity price for various cost of capital levels

Another way to view the effect of changes to the cost of capital is to look at the break-even electricity prices in table 7-12. The most profitable profile is the south-facing sloped roof in Oslo. With the standard 7.5% cost of capital, break-even is NOK 1.3. With a 3% higher or lower cost of capital, the break-even price will range from NOK 0.9 to 1.8. With the high uncertainty in future electricity prices, this example clearly shows that the probability of considering a project to be profitable is highly dependent on the choice of cost of capital.

The results above show that the cost of capital strongly impacts the profitability evaluation. The Modigliani-Miller theorem states that the cost of capital is unaffected by capital structure, under certain assumptions. However, assuming that interest costs are tax-deductible, leverage can decrease the WACC of the project and thus increase profitability for debt and equity holders. The 7.5% WACC used in this thesis is the unlevered WACC, assuming the project to be all-equity financed. As the example in section 5.4.2 shows, leverage can decrease the WACC from 6.2% to 5.7%, before adding the additional risk premium accounting for spot electricity price exposure. Thus, if the investor uses leverage to finance the project, the WACC can be somewhat reduced and increase the probability of achieving a positive NPV.

One limitation of the cost of capital calculation is that it is based on the CAPM, which builds on several strict assumptions. The CAPM assumes that all investors are well-diversified and should only expect to be compensated for systematic risk. When a household considers investing in solar panels, this assumption may be violated, causing the household to demand higher compensation for risk. Another important limitation, as discussed in chapter five, is the choice of and access to relevant comparable companies.

In addition, several qualitative factors can justify a higher or lower discount rate. Some of these are discussed in chapter ten.

8. Conclusion

Conclusion on profitability

The main criterion for the profitability analysis is the net present value. Under the standard assumptions and the reference electricity price scenario, the NPV is strongly negative in all profiles. To achieve positive NPVs, electricity prices need to be well above historical prices.

Under the standard assumptions, the lowest break-even electricity price is found for a sloped roof in Oslo, directed towards the south, with a break-even in real 2023 value of NOK 1.3. Kristiansand, Stavanger, Bergen, and Trondheim have break-even prices of NOK 1.4-1.6 for the best profiles, while the lowest break-even price in Tromsø is NOK 2.1. Assuming equal electricity prices throughout the country, the analysis finds that solar PV systems in Oslo are the most profitable and systems in Tromsø are the least profitable. As the break-even electricity prices are considerably higher than historical prices, futures prices and the price levels indicated in long-term forecasts, the analysis concludes that investments in residential rooftop solar PV systems are not profitable.

The low profitability of the project is also reflected in the IRR. The analysis uses a cost of capital of 7.5%, although both a higher and lower cost of capital can be justified. In the reference electricity price scenario, none of the profiles has IRRs above the applied risk-free rate of 2.25%, and several profiles have negative IRRs. This confirms that the projects will only be profitable under the standard assumptions if the electricity prices are considerably higher than the reference scenario.

Main variables affecting profitability

Besides the future electricity prices, we found the initial investment cost to impact the overall profitability evaluation greatly. Chapter three explains that costs have generally decreased over the last decade. However, the recent surge in electricity prices and the associated increased demand for solar PV systems in Norway have caused investment costs to increase sharply. If the market situation normalises and prices drop to previous levels or lower, the profitability evaluation would be significantly improved. However, the future development in installation costs is uncertain and not influenceable by the household.

On the other hand, a variable that can be influenced is the share of generated electricity consumed internally in the household. Electricity consumed internally should be valued at the opportunity cost of buying electricity from the grid, including taxes and grid fees. As electricity sold to the grid is assumed to be sold at the spot electricity price, the profitability evaluation is improved by increasing the share of generated electricity consumed internally. With new and smart devices, it is possible to shift more consumption to the hours with high solar generation and, in this way, increase the value of the investment.

The system size is another variable that is, to some degree, influenceable. The analysis shows that all else equal, larger systems will have higher IRRs because the investment cost per kWp installed capacity is lower. This indicates that the investor should opt for the largest possible system that the house can fit. On the other hand, a larger system will result in a lower share of electricity consumed internally, all else equal. In this way, the benefit of lowering cost per kWp must be weighed against the lower share of generated electricity consumed internally.

To conclude, the pure financial analysis indicates that residential rooftop solar PV systems in Norway are not profitable under the standard assumptions. The critical determinant of the profitability evaluation is the development of future electricity prices. As this variable is highly uncertain and beyond the control of the individual households, the owner should strive to affect other variables to lower the break-even electricity price and increase the probability of making a profitable investment. The main actions the owner can take to increase profitability are to increase the share of generated electricity consumed internally and to choose the right system size. Furthermore, sources indicate that the current initial investment costs are temporarily high. Thus, a reduction in investment cost is expected, which would strongly improve the profitability evaluation.

9. Limitations of the Paper

Intraday price fluctuations

In this paper, we have not considered intraday price fluctuations. PV electricity generation occurs during the daytime, with a peak in the middle of the day. In the model, electricity prices are modelled using average quarterly prices and not hour-by-hour prices, because of the high uncertainty in future prices. The results may be affected if the electricity price during daytime is consistently different from the average price.

Future electricity prices

Electricity prices are an essential part of the profitability evaluation, and as underlined numerous times, future electricity prices are afflicted with severe uncertainty. We have not forecasted the electricity price but instead tried to illustrate the effect of the uncertainty by using high and low scenarios.

The scenarios in the model are based on Nasdaq futures for 2023-2030. The data for these futures were collected over three months, from June to September 2022. Due to high fluctuations, the choice of collection period may have altered the results. We have aimed to eliminate some of these fluctuations by averaging the prices over three months.

Investment cost

The capital expenditure used in the model builds on collected price estimates. It is difficult to make a general estimate because individual features of each house can strongly influence the initial investment cost. The actual investment cost in a real project can differ significantly from the cost used in the analysis. As shown in section 7.2.1, changes to the investment cost will strongly impact profitability.

From the regression results, we found significant price differences between Otovo and Fjordkraft. We chose to average out this difference without further analysis. A market analysis could have given a deeper insight into this price difference.

Share of generated electricity consumed internally

The discussion shows that the share of generated electricity consumed internally can strongly impact profitability, especially in low electricity price scenarios. In the model, the share of generated electricity consumed internally is obtained from an SSB study. This study is not based on actual measurements of electricity generation and consumption but on estimated power demand in the average household, with a limited number of observations. In a real-life application, the share consumed internally will vary significantly between projects. Among others, the size of the system compared to the house, the house's age and the household members' lifestyle will be important determinants of the share consumed internally. A further weakness is that the SSB report estimates the average share of generated electricity consumed internally for the country as a whole. It is natural to assume that the significant climatic differences between the cities will also strongly affect the share consumed internally.

Electricity generation

A critical weakness of the model is that electricity generation is estimated from simulations in PVsyst. The meteorological data used in these simulations is satellite-based and not collected from actual weather stations. Furthermore, the electricity generation numbers in the simulations are derived from meteorological data and not gathered from actual installations. Thus, the achieved energy yield of a real-life system may differ strongly from the simulation results. Another weakness of the model is that near shadings and other inefficiencies are not accounted for, although they may often be present in real-life installations. In this way, the model may overstate profitability.

The relevance of the simulations can also be discussed. The choice of location in the six cities is somewhat arbitrary, and energy yields may differ substantially between areas within the same city. Furthermore, we have assumed all flat roofs to have panels installed at a 10˚ angle and sloped roofs to be 30˚. Other choices of location and panel angle may have led to different conclusions.

Subsidies

The model accounts for the national subsidy from Enova. Subsidies from local governments, grid-owning companies or others are exempted. This means that subsidies beyond the Enova support are available in some projects, which would impact the profitability evaluation positively. However, the general insights provided in this paper are, in most cases, still relevant.

10. Non-financial Aspects

The analysis above is a pure financial profitability analysis, concluding that the project is not profitable unless very high electricity prices are assumed. However, profitability will not necessarily be the only relevant consideration when a household considers investing in a rooftop solar PV system. The following discussion will introduce some non-financial aspects that could be relevant to the project and discuss how these would influence the investment decision.

10.1 Environmental Considerations

A critical weakness of the cash flow model is that it only includes pure financial costs and benefits. However, the investor may also experience utility from other factors. For a solar PV project, one prominent aspect is the environmental contribution. By installing solar panels, the investor may experience utility from contributing to renewable energy generation. For a rapid-growing technology like solar PV, the investment will also contribute to the development of technology and the supply chain.

In a survey, Cherry & Sæle (2020) asked respondents if they had considered installing a PV system in their household. Of the respondents that did not already own a PV system, 11% reported that they considered installing a PV system, 74% did not consider it, and the remaining 15% did not know. Among the respondents considering installing a PV system, 84% reported that contributing to a better environment was a factor affecting their consideration. Furthermore, 65% reported that they considered installing a PV system to support the market for solar, and 55% reported that they considered it because of an interest in exploring the technology. 68% of respondents answered that saving money on the electricity bill was an important factor (Cherry & Sæle, 2020). These numbers confirm that the environmental contribution is an important consideration underlying the investment decision for many investors.

The cash flow model does not account for the environmental benefits. Thus, although the cash flow model indicates that the investment is not profitable, the individual investor could conclude that the investment is profitable when including the positive effects on the environment. Two possible ways to include this in the cash flow model are to recognize these benefits as an income or lower the discount rate. Chapters six and seven exemplify this with a range of WACCs, and we see that lowering the WACC could change the profitability conclusion in several profiles.

Critics of the environmental argument

Although solar PV is viewed as a renewable energy source, the environmental effects are ambiguous. The main issue is emissions related to panel production and disposal, which NREL finds to be higher than for hydropower and wind energy. Thus, for the total environmental effect of solar panels to be positive, the panels need to replace enough non-renewable energy throughout the lifetime to compensate for the emissions in production and disposal.

Bøhren, Gjærum, & Hasle (2021) calculates the average emissions for the Norwegian electricity mix to be around 33 grams of CO2-equivalents per kWh. The number is calculated to be 73 in the Nordics, 355 in Germany, 674 in Poland and 274 for the EU in total. In the USA, it is calculated to be 397 and 555 in China. NVE estimates that electricity generated from coals emits 1000 grams of CO2/kWh, and electricity from gas emits 364 grams/kWh (NVE, 2022c). This shows that the Norwegian electricity mix is considerably cleaner than in most other countries.

As previously discussed, NREL found the average lifetime emissions for solar PV systems globally to be 43 grams/kWh. As solar panels in Norway have a low energy yield because of less irradiation, this number is likely to be higher for Norwegian systems. Although there is high uncertainty and geographical differences in these numbers, it seems that the lifetime emissions from electricity generated by solar panels in Norway will be higher than the average emissions in the Norwegian electricity mix. In this way, replacing units of energy produced from the average Norwegian energy mix with electricity from solar panels will not have a positive impact. However, as Norway is connected to the European electricity market, one can assume that the increased electricity generation in Norway is, to some degree, used to offset European electricity with considerably higher emissions. This way, solar PV deployment in Norway will contribute to lowering global emissions.

Another possible objection to the environmental argument of rooftop solar PV is the cost-benefit relationship. The low scale of residential rooftop PV systems leads to high LCOE compared to other renewable energy sources like onshore wind (NVE, 2022e). This indicates that the money spent on rooftop solar systems could have been used more efficiently by investing in onshore wind. However, this is not directly accessible to the typical household. Other investments that households can consider are heat pumps, geothermal heating, or re-insulation.

10.2 Higher Electricity Consumption

In the model, we have assumed that the household's total electricity consumption is unaffected by the installation of solar panels. By this, we assume that the generated electricity is either sold to the grid or used to replace electricity that would otherwise be purchased from the grid. However, consumers might be less rational than the model assumes, and the installation of solar panels can lead to higher consumption in the household. The reason is that the household may feel that they have access to “free” electricity as the opportunity cost of consuming electricity internally instead of selling it to the grid is less visible than the cost of buying electricity from the grid. In this way, installing solar panels may lead to higher consumption in the household and, thus, higher utility. The additional utility of being able to use more electricity without thinking as clearly about the cost of this electricity may compensate for the lack of profitability in the project.

10.3 Hedge Strategy Against High Electricity Prices

When a household considers a PV investment, the upside and downside fluctuations may be considered differently. As previously discussed, once the PV system is installed, the market value of the system will primarily be dependent on expected future electricity prices. It can be argued that the uncertainty in future electricity prices is asymmetric. Assuming that electricity prices cannot be negative, there is a lower limit on the NPV of the project. This is especially apparent if the share of generated electricity consumed internally is high because the opportunity cost of each kilowatt-hour produced will always be equal to or higher than the grid fee. On the upside, however, there is no limit on how high electricity prices can go, as illustrated by the recent fluctuations. As a result, some possible investors may consider investing in a solar PV system as a hedging strategy against high future electricity prices. In this way, the project can be accepted, although the profitability analysis concludes that profitability is low.

10.4 Security in Energy Supply

Even though the electricity supply in Norway is mostly stable, short-term power outages occur occasionally. By installing solar panels, a household will reduce its dependence on the electricity grid and cover some of its electricity demand with internally generated electricity. If combined with a battery, solar panels can cover a household's most basic electricity needs. In areas with low stability in electricity supply, the ability to cover the most fundamental needs for electricity through internal generation can be very valuable. Examples of situations where stability in electricity supply is limited can be areas with a weak grid or where political conditions threaten stability in supply.

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Appendix

Results

A. Net Present Value All Profiles

Oslo

Roof type	Azimuth	Reference	Reference +100%	Reference +200%	Reference +300%
Sloped roof	South	-112 162	-52 839	6 485	65 808
Sloped roof	South-West	-120 712	-65 666	-10 621	44 424
Sloped roof	South-East	-120 320	-65 120	-9 920	45 281
Flat roof	South	-113 317	-61 303	-9 288	42 727
Flat roof	East/West	-124 756	-78 538	-32 320	13 898
Gable roof	East/West	-140 982	-96 257	-51 532	-6 808

Kristiansand

Roof type	Azimuth	Reference	Reference +100%	Reference +200%	Reference +300%
Sloped roof	South	-127 206	-64 349	-1 492	61 365
Sloped roof	South-West	-134 330	-74 834	-15 337	44 159
Sloped roof	South-East	-137 616	-79 799	-21 981	35 836
Flat roof	South	-129 289	-73 830	-18 372	37 086
Flat roof	East/West	-141 862	-92 481	-43 100	6 281
Gable roof	East/West	-158 269	-110 417	-62 566	-14 714

Stavanger

Roof type	Azimuth	Reference	Reference +100%	Reference +200%	Reference +300%
Sloped roof	South	-142 425	-88 035	-33 644	20 746
Sloped roof	South-West	-148 285	-96 643	-45 000	6 642
Sloped roof	South-East	-151 300	-101 201	-51 102	-1 003
Flat roof	South	-141 878	-93 632	-45 386	2 860
Flat roof	East/West	-152 168	-108 888	-65 609	-22 329
Gable roof	East/West	-167 967	-125 881	-83 795	-41 709

Table A-0-1: NPV all profiles. Oslo, Kristiansand, Stavanger.

Bergen

Roof type	Azimuth	Reference	Reference +100%	Reference +200%	Reference +300%
Sloped roof	South	-105 756	-53 630	-1 505	50 620
Sloped roof	South-West	-112 804	-64 201	-15 598	33 006
Sloped roof	South-East	-112 175	-63 308	-14 440	34 428
Flat roof	South	-104 310	-58 210	-12 109	33 992
Flat roof	East/West	-113 766	-72 466	-31 166	10 134
Gable roof	East/West	-129 221	-88 996	-48 771	-8 547

Trondheim

Roof type	Azimuth	Reference	Reference +100%	Reference +200%	Reference +300%
Sloped roof	South	-121 127	-72 622	-24 117	24 388
Sloped roof	South-West	-127 766	-82 706	-37 646	7 414
Sloped roof	South-East	-126 655	-80 987	-35 319	10 350
Flat roof	South	-118 703	-75 878	-33 053	9 773
Flat roof	East/West	-127 218	-88 823	-50 428	-12 032
Gable roof	East/West	-142 409	-104 961	-67 513	-30 064

Tromsø

Roof type	Azimuth	Reference	Reference +100%	Reference +200%	Reference +300%
Sloped roof	South	-166 234	-122 745	-79 256	-35 766
Sloped roof	South-West	-170 576	-129 419	-88 262	-47 105
Sloped roof	South-East	-172 156	-131 902	-91 647	-51 393
Flat roof	South	-164 803	-127 920	-91 038	-54 156
Flat roof	East/West	-172 667	-140 099	-107 531	-74 963
Gable roof	East/West	-184 659	-151 249	-117 838	-84 428

Table A-0-2: NPV all profiles. Bergen, Trondheim, Tromsø

NPV. Reference +200% electricity price scenario.		WACC				
City	**Roof type**	**4.50%**	**6.00%**	**7.50%**	**9.00%**	**10.50%**
Oslo	Flat	73	26	-9	-37	-59
Oslo	Sloped	101	47	6	-25	-51
Kristiansand	Flat	71	21	-18	-49	-72
Kristiansand	Sloped	101	43	-1	-36	-63
Stavanger	Flat	32	-12	-45	-71	-92
Stavanger	Sloped	55	5	-34	-63	-87
Bergen	Flat	60	19	-12	-36	-56
Bergen	Sloped	81	34	-2	-29	-51
Trondheim	Flat	33	-4	-33	-55	-73
Trondheim	Sloped	51	9	-24	-50	-70
Tromsø	Flat	-36	-67	-91	-109	-124
Tromsø	Sloped	-14	-51	-79	-101	-119

Table A-0-3: NPV in reference +200% electricity price scenarios for various WACCs

B. Internal Rate of Return

Oslo — Electricity price scenario

Roof type	**Azimuth**	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
Sloped roof	South	1.2%	5.0%	7.8%	10.1%
Sloped roof	South-West	0.6%	4.3%	7.0%	9.3%
Sloped roof	South-East	0.7%	4.3%	7.1%	9.3%
Flat roof	South	0.6%	4.3%	7.1%	9.3%
Flat roof	East/West	-0.3%	3.3%	6.0%	8.1%
Gable roof	East/West	-0.9%	2.6%	5.1%	7.2%

Kristiansand — Electricity price scenario

Roof type	**Azimuth**	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
Sloped roof	South	1.2%	4.8%	7.4%	9.7%
Sloped roof	South-West	0.7%	4.3%	6.9%	9.1%
Sloped roof	South-East	0.5%	4.0%	6.6%	8.8%
Flat roof	South	0.6%	4.1%	6.7%	8.9%
Flat roof	East/West	-0.3%	3.2%	5.7%	7.7%
Gable roof	East/West	-0.8%	2.5%	4.9%	6.9%

Stavanger — Electricity price scenario

Roof type	**Azimuth**	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
Sloped roof	South	0.2%	3.6%	6.2%	8.3%
Sloped roof	South-West	-0.2%	3.2%	5.7%	7.7%
Sloped roof	South-East	-0.4%	2.9%	5.4%	7.5%
Flat roof	South	-0.4%	3.0%	5.6%	7.6%
Flat roof	East/West	-1.1%	2.2%	4.6%	6.6%
Gable roof	East/West	-1.7%	1.6%	3.9%	5.9%

Table B-0-4: IRR all profiles. Oslo, Kristiansand, Stavanger

Bergen		Electricity price scenario			
Roof type	**Azimuth**	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
Sloped roof	South	0.9%	4.7%	7.4%	9.7%
Sloped roof	South-West	0.3%	4.0%	6.7%	9.0%
Sloped roof	South-East	0.4%	4.1%	6.8%	9.0%
Flat roof	South	0.4%	4.1%	6.9%	9.1%
Flat roof	East/West	-0.4%	3.2%	5.8%	8.0%
Gable roof	East/West	-1.1%	2.5%	5.0%	7.1%

Trondheim		Electricity price scenario			
Roof type	**Azimuth**	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
Sloped roof	South	0.0%	3.7%	6.4%	8.6%
Sloped roof	South-West	-0.6%	3.1%	5.7%	7.8%
Sloped roof	South-East	-0.5%	3.2%	5.8%	8.0%
Flat roof	South	-0.5%	3.1%	5.8%	8.0%
Flat roof	East/West	-1.3%	2.3%	4.8%	6.9%
Gable roof	East/West	-1.9%	1.6%	4.1%	6.1%

Tromsø		Electricity price scenario			
Roof type	**Azimuth**	**Reference**	**Reference +100%**	**Reference +200%**	**Reference +300%**
Sloped roof	South	-2.0%	1.5%	4.0%	6.1%
Sloped roof	South-West	-2.4%	1.1%	3.6%	5.6%
Sloped roof	South-East	-2.5%	1.0%	3.4%	5.4%
Flat roof	South	-2.8%	0.7%	3.2%	5.1%
Flat roof	East/West	-3.6%	-0.2%	2.2%	4.1%
Gable roof	East/West	-3.7%	-0.3%	2.0%	3.9%

Table B-0-5: IRR all profiles. Bergen, Trondheim, Tromsø

The Model

C. Electricity Prices

Nord Pool

For this thesis, we were granted access to historical price data from Nord Pool. These prices were used to examine historical development, seasonal variations, and differences between price areas. All calculations are made based on the daily prices from the day-ahead market.

Nasdaq futures

The future prices were manually collected using Nasdaq's online overview of transactions (Nasdaq Commodities, 2022a). This overview lists all transactions for the last three months. We have used the yearly and quarterly futures with cash settlements called ENOFUTBLYR-[YY] and ENOFUTBLQ[Q]-[YY]. All transactions between June 24. and September 21. 2022 were collected and used to find a volume-weighted average price. The yearly futures spend from 2023 to 2030, while the quarterly futures spend from Q1 2023 to Q4 2024. Normally, one would use the latest price as the true price for a listed security. For the Nordic futures, however, the relatively small volume likely impacts the price setting. By using the volume-weighted prices over three months, we aim to marginalise some of this effect and thereby arrive at values closer to the "true" future prices.

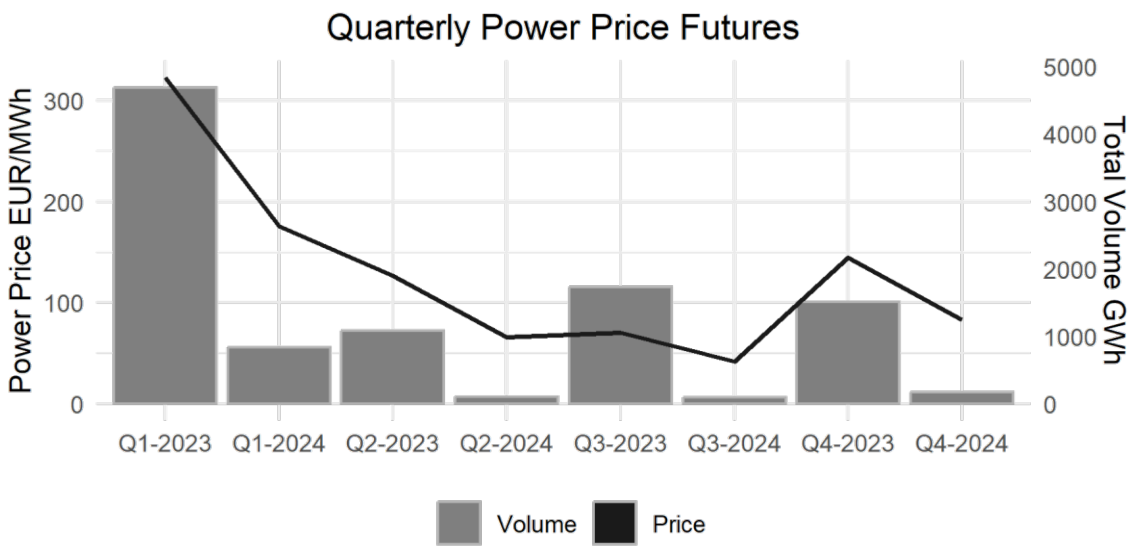


Figure C-0-1:Quarterly electricity price futures, price (line) and volume (column) Q1 2023 to Q4 2024. Data collected from transactions between 24.06.2022 and 21.09.2022.

Figure C-0-1 and figure c-0-2 present the volume and the volume-weighted prices. The volume is sharply decreasing when moving out on the curve. This weakens the assumption that the futures reflect the market's view on prices in the years up to 2030. We have used these futures prices in the model due to the lack of better estimates.

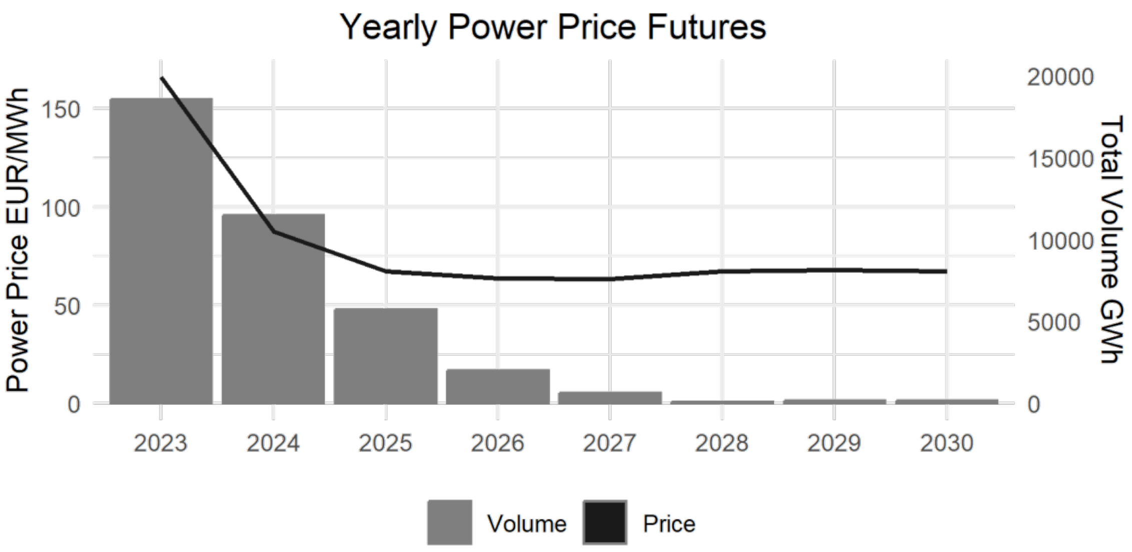


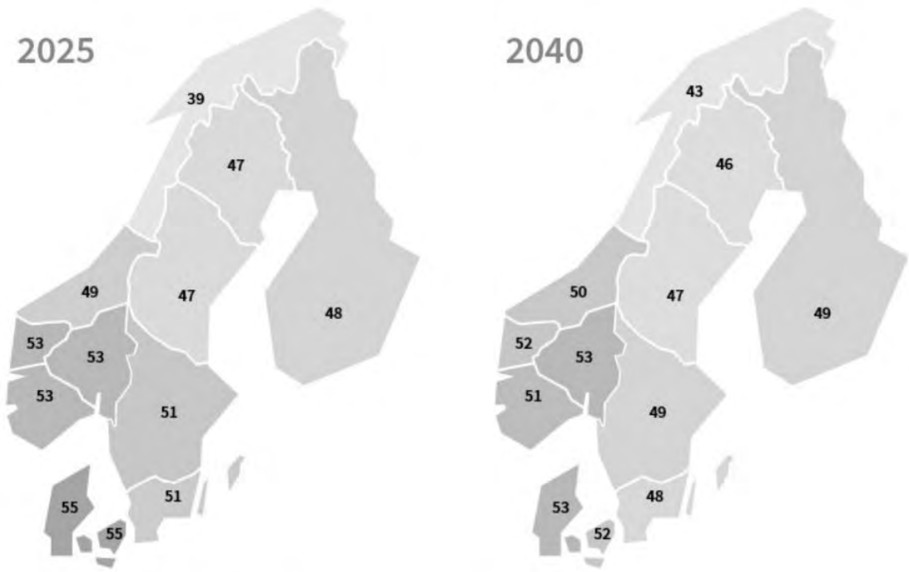
Figure C-0-2: Yearly electricity price futures, price (line) and volume (column) 2023 to 2030. Data collected from transactions between 24.06.2022 and 21.09.2022.

Long-term power market analysis

As explained in section 5.1.3, there are few or no Nasdaq futures transactions available beyond 2030. We have, therefore, used long-term power market analyses from NVE and Statnett for this period. In their latest report from 2021, NVE’s base scenario indicates that the Nordic system price will be 0.5 NOK/kWh in 2040 (NVE, 2021). Furthermore, NVE made a low scenario where the estimated prices are 0.38 NOK/kWh and a high scenario of 0.63 NOK/kWh. All prices are in real 2021-NOK.

Statnett estimates the electricity price to be between 30 to 50 EUR/MWh from 2030 to 2040 in their long-term market analysis from 2020 and in an addition to the report from July 2021 (Statnett, 2020; Statnett, 2021). Compared to NVE’s report, Statnett’s estimate is lower, but the main report is a year older. From 2020 to 2021, NVE increased their estimate from 40 to 50 EUR/MWh. With this in mind, we argue that a price of around 50 EUR/MWh, or 0.5 NOK/kWh, is the stakeholders’ best estimate for the electricity price in 2040. In addition, the recent surge in electricity prices supports a higher expected future electricity price.

NVE's report also studies the differences in area prices in the future. They point to the price differences apparent in 2021, where southern Norway experienced considerably higher prices than northern Norway. As previously shown, this difference has increased in 2022. Figure C-0-3 is from the NVE report and shows that NVE estimates that the differences will decrease in 2040.



Figur 5-6 Utvikling i kraftprisene i de nordiske prisområdene fra 2025 til 2040

Figure C-0-3: NVEs estimated area prices in øre/kWh for 2025 and 2040. Source: (NVE, 2021)

The report points to bottlenecks in the grid as reasons for the current and future price differences. Most of the interconnectors to Europe are from NO2, which is an important explanation for the higher prices in southern Norway. Bottlenecks in transmission capacity to northern Norway prevent the high prices in Europe and southern Norway from spreading further north. NVE expects that grid capacity will be built in Norway and Sweden to improve the transmission capacity between the north and south, thereby reducing the price differences. As a result of the expected increase in transmission capacity, and the high uncertainty related to the system price, we choose not to differentiate between the price areas in the model.

Creating the electricity price scenarios

The electricity price scenarios are based on the reference scenario, which aims to reflect the market players' beliefs about the future electricity price. As electricity generation from solar PV varies throughout the year, we have modelled the electricity prices quarterly. In the near end, we have used the quarterly futures shown in table 5-1 for 2023 and 2024. From 2025 to 2030, we have used the yearly futures shown in the same table as the reference. To model the quarterly price variation for these years, we have adjusted these prices by the historical price variation shown in table 5-2.

The Norwegian government has passed legislation adopting the current electricity price subsidy to at least December 2023, as explained in section 3.4.3. For the price used to calculate the opportunity cost of consuming electricity generated internally, this subsidy is accounted for by subtracting the subsidy for the months eligible for it based on the electricity price scenarios. The value of excess electricity sold to the grid is not affected by this subsidy.

The long-term power market reports estimated price is used for the year 2040. NVE estimates this price to be 50.2 EUR/MWh in real 2021 value. To get the real price in 2040, we have an inflation-adjusted price with a yearly inflation of 2%, which gives a price in 2040 of 72.55 EUR/MWh. For the years 2031-2040, a linear development is used to go from the latest Nasdaq futures price of 67 EUR/MWh in 2030 to the 2040 price of 72.55 EUR/MWh. These prices are also adjusted for quarterly variation using the historical variation. For the years 2041 to 2052, the prices are adjusted with 2% yearly inflation and adjusted for quarterly variation.

The lower and higher scenarios are calculated based on the reference scenario. The idea is to consider the market players' opinions but simultaneously show the uncertainty it contains based on historical price fluctuations. In general, one can argue that the uncertainty is larger further into the future. Therefore, we have adjusted the percentage difference to the reference scenario in the near future. This adjustment is a linear increase in the percentage change from the reference scenario until 2030, where the whole difference is shown. For example, in the reference +200% scenario, the 200% to be added to the reference scenario is divided by 32, the number of quarters from 2023 until 2030. This gives a 6.25% of the reference scenario increase in the difference cumulative each quarter. This means that by the end of 2023, the difference between the reference scenario and the +200% scenario is 25%, and in Q4 2026, it is 100%.

Grid fees

Grid fees		*Øre/kWh included VAT*		
Company	**Zone**	**Weekday price**	**Weekend price**	**Weighted price**
Elvia AS	NO1	43.1	36.85	41.31
ETNA NETT AS	NO1	31.59		31.59
GLITRE ENERGI NETT AS	NO1	47.25		47.25
RAKKESTAD ENERGI AS	NO1	53.51	47.26	51.72
Agder Energi Nett AS	NO2	48.51	38.51	45.65
Enida AS	NO2	49.26		49.26
VEST-TELEMARK KRAFTLAG NETT AS	NO2	60.51		60.51
LNETT AS	NO2	48.6	40.6	46.31
Fagne AS	NO2	51.51	41.51	48.65
Tensio TS AS	NO3	36.26		36.26
TENSIO TN AS	NO3	42.26		42.26
MØRENETT AS	NO3	40.51		40.51
Romsdalsnett AS	NO3	43.11	30.61	39.54
NETTSELSKAPET AS	NO3	40.64		40.64
Arva AS	NO4	31.91		31.91
Hålogaland Kraft Nett	NO4	17.21		17.21
ISalten Nett AS	NO4	32.24	22.24	29.38
LINEA AS	NO4	36.41	27.61	33.90
KYSTNETT AS	NO4	30.01		30.01
BKK Nett AS	NO5	49.9	39.9	47.04
Sygnir AS	NO5	44.86		44.86
Breheim Nett AS	NO5	28.64		28.64
Vonett AS	NO5	49.9		49.90

Table C-0-6: Grid fees including VAT and electrical fees used in the model

D. PVsyst Inputs

Location and choice of meteorological database

The exact locations of our simulations are shown in table d-0-7. The table also shows the database used and the years from which the meteorological data are collected.

PVsyst simulation locations.

City	Borough	Latitude	Longitude	Database	Years
Oslo	Blindern	59.9385	10.7245	PVGIS-SARAH2	2005-2020
Kristiansand	Vågsbygd	58.1227	7.9622	PVGIS-SARAH2	2006, 2008, 2010, 2012, 2014, 2016, 2018, 2020
Stavanger	Stokka	58.9648	5.6939	PVGIS-SARAH2	2005-2020
Bergen	Sandsli	60.3020	5.2979	PVGIS-SARAH2	2005-2020
Trondheim	Tyholt	63.4215	10.4319	PVGIS-SARAH2	2005-2020
Tromsø	Bjerkaker	69.6389	18.9243	PVGIS-ERA5	2008, 2010, 2015, 2017, 2019

Table D-0-7: PVsyst simulations exact locations and meteorological data source

Meteorological data can be imported to PVsyst from several databases, including Meteonorm, PVGIS and NREL (PVsyst, 2022d). The user can choose to base the simulation on meteorological data from one particular year or to construct a typical meteorological year (TMY) based on meteorological time series over multiple years (PVsyst, 2022e). The meteorological data is a TMY based on data imported from PVGIS.

PVGIS is a tool developed by the EU Science Hub, designed to estimate PV system performance based on solar irradiation (European Commission, 2022c). PVGIS-SARAH2 is PVGIS' default database for Europe and utilizes satellite data. PVGIS-SARAH2 data is used for all cities except Tromsø, where it is not available. Therefore, data for Tromsø are imported from the PVGIS-ERA5 database that uses atmospheric reanalysis produced by ECMWF (European Commission, 2022d). One weakness of the PVGIS database is that it utilizes satellite data and not actual observations from weather stations in proximity. This limits the precision of the estimate. The comparison between results from Tromsø and other cities should be made with caution, as the simulations build on different underlying data.

System

The system parameters were the same in all our simulations. We simulated a 12 kWp system with 30 standard 400 Wp panels. The standard panel used in the simulations is a generic 400 Wp 32V monocrystalline panel with 72 cells from the PVsyst tool database. The system uses a generic 12 kWac inverter with an operating voltage of 350-600V. By choosing these generic tools, we aim to design the system close to how a typical residential solar PV system in Norway would be designed.

In the PVsyst simulations, we used a generic 12 kWp inverter on a 12 kWp system. In many cases, the owner of a PV system will choose to undersize the inverter by 15-20% compared to the installed kWp, because the solar panels usually run below peak power due to degradation and suboptimal conditions (Otovo, 2022b). Electricity generation can be slightly limited during peak hours in systems with an undersized inverter because the inverter is not scaled for peak generation. Thus, our simulation results may be somewhat higher than a real-life example with an undersized inverter.

Energy yield for all profiles

City	Roof type	Direction	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Oslo	Sloped roof	South	11	50	84	103	163	158	161	122	89	55	22	13	1 029
Oslo	Sloped roof	South-East	9	42	77	98	158	153	153	114	83	48	17	10	962
Oslo	Sloped roof	South-West	9	42	73	98	156	153	157	119	79	47	18	10	961
Oslo	Flat roof	South	6	33	67	95	156	155	155	113	76	40	13	6	915
Oslo	Flat roof	East/West	4	23	55	87	146	148	146	104	66	31	8	3	820
Oslo	Gable roof	East/West	4	25	55	84	139	138	137	100	64	32	8	4	791
Kristiansand	Sloped roof	South	20	46	88	142	157	157	160	128	97	58	20	16	1 089
Kristiansand	Sloped roof	South-East	17	39	78	133	148	154	153	120	85	50	16	13	1 006
Kristiansand	Sloped roof	South-West	16	38	82	135	153	156	158	124	94	51	17	12	1 037
Kristiansand	Flat roof	South	12	32	72	127	150	157	157	119	83	43	13	9	973
Kristiansand	Flat roof	East/West	8	24	60	114	141	151	148	109	72	33	9	5	874
Kristiansand	Gable roof	East/West	8	25	60	112	132	143	140	104	71	35	9	5	844
Stavanger	Sloped roof	South	15	36	84	120	134	131	142	105	78	57	25	12	939
Stavanger	Sloped roof	South-East	12	31	74	115	126	128	133	99	72	51	20	9	869
Stavanger	Sloped roof	South-West	12	31	77	113	135	129	144	103	73	50	21	9	897
Stavanger	Flat roof	South	9	26	69	109	130	131	139	99	67	42	16	6	844
Stavanger	Flat roof	East/West	6	19	57	99	123	127	133	92	59	33	11	3	763
Stavanger	Gable roof	East/West	7	20	57	98	118	119	126	89	58	35	11	4	740

Table D-0-8: Simulated monthly initial energy yield for all profiles. PVsyst

City	Roof type	Direction	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Bergen	Sloped roof	South	11	40	72	116	135	131	128	116	80	44	25	7	906
Bergen	Sloped roof	South-East	9	34	65	113	131	127	120	112	75	41	20	6	853
Bergen	Sloped roof	South-West	9	33	65	106	132	130	129	111	74	37	19	6	850
Bergen	Flat roof	South	7	27	59	104	131	131	126	108	69	33	14	4	811
Bergen	Flat roof	East/West	4	19	49	94	124	125	120	100	61	26	9	2	733
Bergen	Gable roof	East/West	5	20	49	92	118	119	113	96	61	27	10	2	712
Trondheim	Sloped roof	South	9	22	82	113	131	133	129	106	71	36	14	1	848
Trondheim	Sloped roof	South-East	7	20	73	104	126	132	129	101	68	31	11	1	803
Trondheim	Sloped roof	South-West	7	18	74	109	128	128	122	100	64	31	11	1	792
Trondheim	Flat roof	South	4	15	64	101	126	131	126	98	59	26	8	0	758
Trondheim	Flat roof	East/West	2	11	53	90	119	126	119	90	51	20	4	0	685
Trondheim	Gable roof	East/West	2	11	55	88	114	119	113	86	51	21	5	0	666
Tromsø	Sloped roof	South	1	18	79	130	156	137	122	105	74	44	3	0	870
Tromsø	Sloped roof	South-East	0	15	69	120	148	133	116	104	66	35	2	0	808
Tromsø	Sloped roof	South-West	0	14	69	123	155	139	125	98	66	36	3	0	827
Tromsø	Flat roof	South	0	10	56	108	144	134	116	92	56	25	2	0	744
Tromsø	Flat roof	East/West	0	7	42	93	135	130	111	83	44	15	1	0	661
Tromsø	Gable roof	East/West	0	8	45	97	135	129	111	86	47	18	1	0	677

Table D-0-9: Simulated monthly initial energy yield for all profiles. PVsyst

E. Share of Generated Electricity Consumed Internally

SSB base case scenario

Norwegian power meters only measure electricity sold to and purchased from the grid, meaning that electricity generated and consumed internally is never recorded in Elhub. Thus, the total electricity generation from a PV system needs to be predicted to calculate the share of generated electricity consumed internally.

SSB proposes two approaches to predict total PV production from plus customers. The first approach is to predict production based on factors like installed capacity and meteorological data. The other approach is to use available information about the household to predict the total electricity consumption in the household. The report uses the second approach and estimates total electricity consumption for plus customers. Based on this, total PV generation can be found by the following relationship:

$$Total\ generation\ =\ kWh\ sold\ +\ (kWh\ consumed - kWh\ purchased)$$

In this equation, electricity sold and purchased is measured and registered in Elhub, while the total electricity consumed in the household is predicted. SSB predicts total electricity consumption for the average plus-customer household using a panel data regression on 5000 non-plus-customers in the 24 months from May 2019 to April 2021. The variables used in the model are monthly average and maximum temperature, dummy variables for each month, and a dummy variable to adjust for COVID-19-related restrictions. The regression is based on non-plus customers because their total consumption is measurable as they do not have any production.

Based on the regression model, SSB predicts total electricity consumption for the typical plus customer household for the period. PV generation can then be calculated from the formula above. When total generation is predicted, we can subtract the electricity sold to calculate the predicted share consumed internally, as seen in table e-0-10.

Month	Predicted electricity generation (kWh)	Observed sale (kWh)	Share consumed internally
May 19	796	358	55%
Jun 19	689	355	49%
Jul 19	914	525	43%
Aug 19	708	389	45%
Sep 19	491	214	57%
Oct 19	296	73	75%
Nov 19	73	16	78%
Dec 19	153	9	94%
Jan 20	478	16	97%
Feb 20	501	41	92%
Mar 20	592	132	78%
Apr 20	668	310	54%
May 20	873	461	47%
Jun 20	938	561	40%
Jul 20	806	460	43%
Aug 20	779	455	42%
Sep 20	477	226	53%
Oct 20	299	78	74%
Nov 20	230	22	91%
Dec 20	152	8	95%
Jan 21	14	10	31%
Feb 21	201	30	85%
Mar 21	639	150	77%
Apr 21	761	372	51%

Table E-0-10: Average plus customer predicted generation, observed sale and share of generated electricity consumed internally

Figure E-0-4 shows the share of electricity consumed internally each month, according to SSB's predictions. As seen, there is a trend that most of the produced electricity is consumed internally during winter and that less than half of the electricity is consumed internally in the middle of the summer. This is in line with our expectations. January 2021 attracts attention with a very low share of own consumption. The predicted generation in the period is only 14 kWh, which seems very low compared to the other winter months. If the electricity generation prediction is too low, the share consumed internally will be understated, and we suspect this is the case in this report. The authors also confirmed that January 2021 was a particularly cold month and that the model did not fully reflect how the cold weather led to higher electricity consumption. Therefore, we choose not to consider the estimated share consumed internally from January 2021. We do not make any other adjustments.

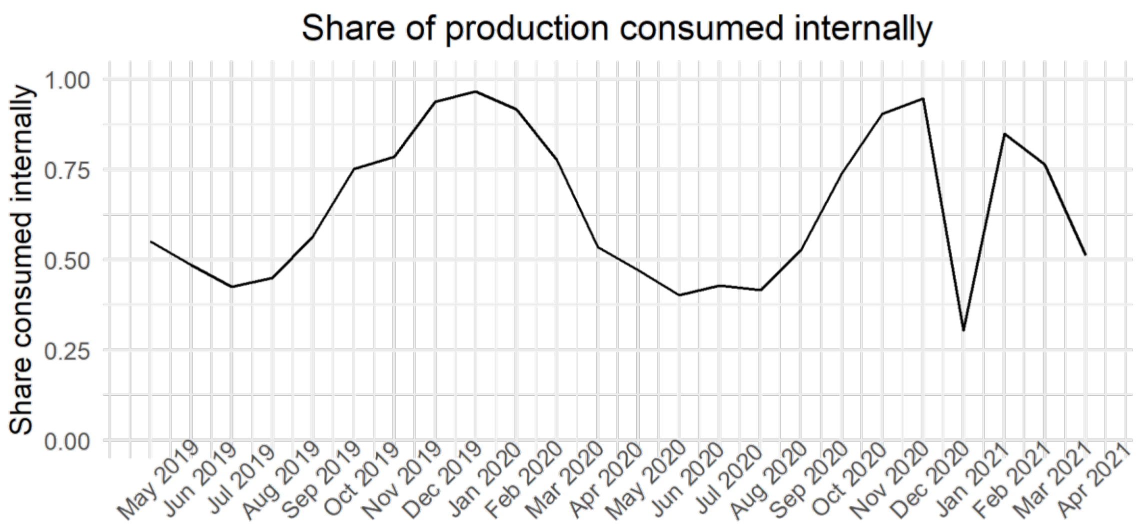


Figure E-0-4: SSB's estimated share of generated electricity consumed internally. Source: (Dalen, Halvorsen, & Larsen, 2022)

In the model, the inputs for the share of generated electricity consumed internally are based on the SSB report. For all months except January, we use the average of the two observations in table e-0-10. For January, we only use the estimate for 2020. Based on this, we get the input shown in table 5-7.

Scenarios used for sensitivities

Profiles for share of electricity consumed internally.

Month	0%	20%	SSB	80%	100%
January	0%	35%	97%	100%	100%
February	0%	32%	88%	100%	100%
March	0%	28%	77%	100%	100%
April	0%	19%	52%	82%	100%
May	0%	19%	51%	80%	100%
June	0%	16%	44%	69%	100%
July	0%	15%	43%	67%	100%
August	0%	16%	43%	68%	100%
September	0%	20%	55%	85%	100%
October	0%	27%	75%	100%	100%
November	0%	31%	85%	100%	100%
December	0%	34%	94%	100%	100%

Table E-0-11: Scenarios for share of generated electricity consumed internally.

The scenarios are calculated based on a south-facing sloped roof system in Oslo. The monthly values are weighted with the monthly generation so that the weighted-average number of kilowatt-hours consumed internally equals 0%, 20%, 80% and 100%, respectively. For other profiles, the generation pattern will be slightly different, which could alter the numbers in the scenario above. Ideally, the scenarios in table e-0-11 should be calculated separately for each profile. However, as the analysis is focused on the direction of effects, and not the nominal effect, we consider this an appropriate simplification.

F. Capital Expenditures

Initial investment

Data collection

The data on initial investment costs are collected from Otovo's and Fjordkraft's online tools. Price estimates were collected for Oslo, Kristiansand, Stavanger, Bergen, Trondheim and Tromsø. Within these six cities, data were collected on houses with either flat or sloped roofs. For each address, we have collected initial investment costs on systems between 5 and 20 kWp. We have also used both Fjordkraft and Otovo to collect data on the same addresses. One exception from this is for Tromsø, where Otovo does not operate, meaning that we only have data from Fjordkraft.

Data on both single-family houses and chained houses have been collected. However, we did not find any difference in initial investment cost between the house types and merged the data to get a larger dataset. Further, we collected data for both flat roofs and sloped roofs. Sloped roofs are also used as a proxy for gable roofs. No data were collected on direction, as we consider the initial investment cost to be independent of the direction, and hence the variation in this parameter does not affect the cost side of the calculations. The collected data are summed up in table f-0-12.

City	Number of observations	Number of adresses	Average kWp	Average NOK/kWp	Min NOK/kWp	Max NOK/kWp
Oslo	57	33	9.9	25 382	18 532	36 986
Kristiansand	47	23	11.2	28 305	23 275	36 410
Stavanger	80	32	10.0	28 445	18 297	44 476
Bergen	82	32	10.1	23 941	16 338	34 203
Trondheim	72	31	10.5	24 248	17 377	34 536
Tromsø	44	29	9.2	25 066	20 806	29 655
Total/average	382	180	10.2	25 898	19 104	36 044

Table F-0-12: Descriptive statistics of initial investment cost collected

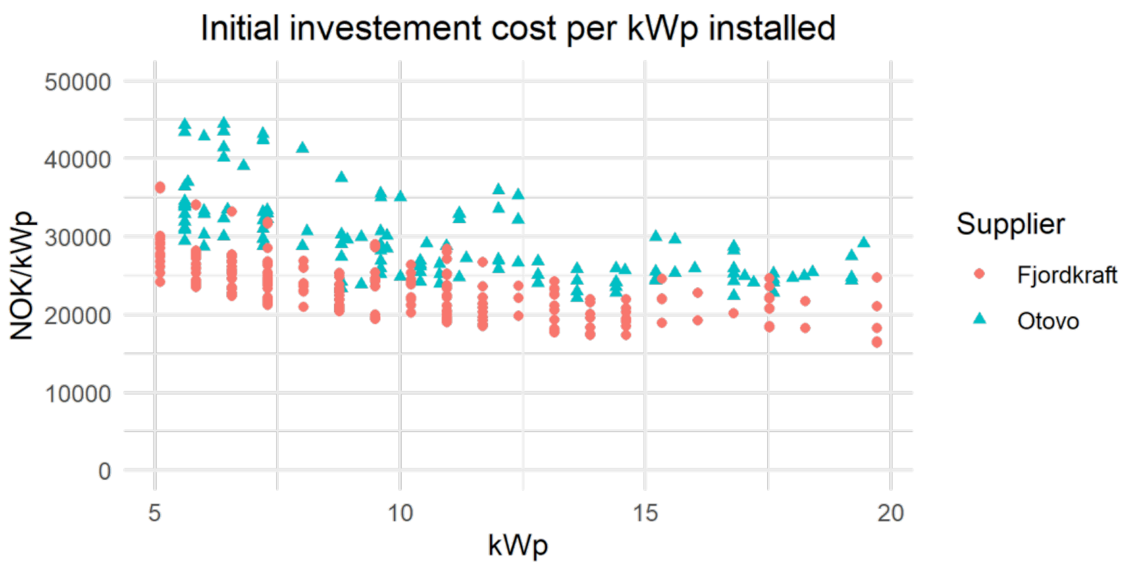


Figure F-0-5: Plot of initial investment cost as NOK/kWp

Regression

The regression is performed with the price before subsidies as the explained variable, while kWp and several dummy variables are explanatory variables. It gives an intercept value and a value per kWp. In addition, dummy variables for cities, roof types, and suppliers. Table F-0-13 summarizes the regression output.

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.96
R Square	0.93
Adjusted R Square	0.93
Standard Error	23 110.26
Observations	382.00

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	8	2.55879E+12	3.19849E+11	598.8729549	1.2666E-207
Residual	373	1.99213E+11	534084189.9		
Total	381	2.758E+12			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	100 338	5 022	20.0	0.000%	90 462	110 213	90 462	110 213
kWp	18 054	315	57.4	0.000%	17 435	18 673	17 435	18 673
D_Kristiansand	27 395	4 616	5.9	0.000%	18 319	36 471	18 319	36 471
D_Stavanger	25 687	4 010	6.4	0.000%	17 803	33 571	17 803	33 571
D_Bergen	-20 447	3 992	-5.1	0.000%	-28 298	-12 597	-28 298	-12 597
D_Trondheim	-13 908	4 135	-3.4	0.085%	-22 039	-5 777	-22 039	-5 777
D_Tromsø	17 624	4 761	3.7	0.025%	8 261	26 986	8 261	26 986
D_Skråtak	13 545	2 486	5.4	0.000%	8 657	18 433	8 657	18 433
D_Fjordkraft	-68 147	2 573	-26.5	0.000%	-73 206	-63 088	-73 206	-63 088

Table F-0-13: Regression output, initial investment cost

To get distinct values for each city, we have used a dummy variable for all cities except Oslo, which is used as the basis. We have also used a dummy variable to differentiate between flat and sloped/gable roofs. The last dummy is for Fjordkraft, meaning that the base results are for Otovo. All variables are statistically significant, with a P-value below 0.1%.

Sensitivities

Break-even electricity prices, 2023 value. NOK/kWh. Sensitivies on initial investment

City	Roof	-45%	-30%	-15%	Base	+15%	+30%	+45%
Oslo	Flat roof	0.7	1.0	1.2	1.4	1.7	1.9	2.2
Oslo	Sloped roof	0.7	0.9	1.1	1.3	1.6	1.8	2.0
Kristiansand	Flat roof	0.8	1.0	1.3	1.5	1.8	2.0	2.3
Kristiansand	Sloped roof	0.7	0.9	1.2	1.4	1.6	1.9	2.1
Stavanger	Flat roof	0.9	1.2	1.5	1.8	2.0	2.3	2.6
Stavanger	Sloped roof	0.8	1.1	1.4	1.6	1.9	2.2	2.5
Bergen	Flat roof	0.8	1.0	1.2	1.5	1.7	2.0	2.2
Bergen	Sloped roof	0.7	0.9	1.2	1.4	1.6	1.9	2.1
Trondheim	Flat roof	0.9	1.1	1.4	1.7	1.9	2.2	2.5
Trondheim	Sloped roof	0.8	1.1	1.3	1.6	1.8	2.1	2.3
Tromsø	Flat roof	1.3	1.6	2.0	2.3	2.7	3.1	3.4
Tromsø	Sloped roof	1.1	1.4	1.8	2.1	2.4	2.7	3.1

Table F-0-14: Break-even electricity prices in 2023 value for various levels of initial investment cost.

Inverter replacement

Table F-0-15 presents an overview of the prices of inverters implemented in the model for the inverter replacement. The data on inverter prices are collected from Solcellespesialisten, Provolt and Batteributikken on inverters from Growatt and SCCS. The inverters range in size between 4 and 17 kWp as this suit the model containing PV systems between 5 and 20 kWp. The 2038 prices are the 2023 prices inflation adjusted by 2% yearly.

Overview of inverter prices .

System kWp	Inverter kWp	Undersizing	2023 Price NOK	2038 Price NOK
5	4	20%	12 547	16 887
6	5	17%	13 337	17 950
7	6	14%	13 337	17 950
8	7	13%	17 672	23 784
9	7	22%	20 096	27 047
10	8	20%	23 280	31 331
11	9	18%	24 199	32 569
12	10	17%	22 916	30 842
13	10	23%	22 916	30 842
14	12	14%	27 999	37 683
15	12	20%	27 999	37 683
16	12	25%	27 999	37 683
17	15	12%	27 999	37 683
18	15	17%	26 063	35 077
19	15	21%	26 063	35 077
20	17	15%	36 993	49 788

Table F-0-15: Inverter prices used in the cash flow model

G. Estimating the Unlevered Beta of Comparable Firms

Equity betas for the comparable firms are calculated from monthly returns in the five years from November 2017 to October 2022. The benchmark index is the broad MSCI Europe index. The calculated equity betas are found in Table G-0-16:

Equity betas.

Security	Levered Beta
Ørsted A/S	0.57
Verbund AG	1.08
EDP Renovaveis SA	0.49
Scatec ASA	1.27
Solaria Energia Y Medio Ambi	0.80
REC Silicon	0.21
Soltech	2.04

Table G-0-16: Equity betas, comparable companies

To use the betas of comparable firms to estimate the asset risk of a residential rooftop solar PV project, it is necessary to calculate the unlevered betas. This is done by adjusting the equity beta for the leverage effect, as explained above. This calculation requires the companies' tax rates and debt-to-equity ratios.

The effective tax rate is measured as tax cost divided by profit before tax, found in the consolidated income statements. The debt-to-equity ratio is calculated as net debt divided by market capitalisation. Ideally, the ratio should be based on market values for both debt and equity, but book values for debt are used as an approximation. All companies report net debt in their annual reports, and we have not adjusted these numbers. Market capitalisation is calculated as the number of shares outstanding times stock price at year-end. All numbers are found for the past five years, and the average is used to convert levered beta to unlevered beta. Table G-0-17 and table g-0-18 show the companies' effective tax rate and D/E ratio.

Effective tax rate comparable companies.

Security	2021	2020	2019	2018	2017	Average	Value used
Ørsted A/S	18%	10%	31%	17%	12%	18%	12%
Verbund AG	10%	8%	15%	20%	41%	19%	41%
EDP Renovaveis SA	14%	17%	31%	45%	46%	31%	46%
Scatec ASA	40%	-55%	16%	30%	5%	7%	23%
Solaria Energia Y Medio Ambi	15%	-49%	-309%	-187%	-94%	-125%	0%
REC Silicon	0%	33%	0%	2%	-75%	-8%	9%
SolTech Energy Sweden	10%	-11%	4%	1%	-2%	0%	0%

Table G-0-17: Effective tax rate comparable companies used for unlevered beta calculation

Debt-to-equity ratio comparable companies.

Security	2021	2020	2019	2018	2017	Average
Ørsted A/S	0.07	0.02	0.06	-0.01	-0.01	0.03
Verbund AG	0.10	0.08	0.15	0.20	0.41	0.19
EDP Renovaveis SA	0.14	0.17	0.31	0.45	0.46	0.31
Scatec ASA	0.86	0.12	0.75	0.86	0.94	0.70
Solaria Energia Y Medio Ambi	0.24	0.11	0.27	0.41	0.92	0.39
REC Silicon	0.01	0.01	0.21	0.07	0.02	0.07
Elkem	0.25	0.49	0.40	0.31	-	0.36
SolTech Energy Sweden	-0.12	0.32	1.02	1.54	0.18	0.59

Table G-0-18: Debt-to-equity ratio comparable companies used for unlevered beta calculation

For the tax rate, we make three adjustments. Scatec's effective tax rate in 2020 is negative 55%. In the 2020 annual report, the firm explains that this is mainly a result of non-recurring non-deductible costs. Consequently, we exclude 2020 from the calculation of the average tax rate. For Solaria Energia Y Medio Ambi, the tax rate is strongly negative in most years. This is due to tax credits offered by governments to support renewable energy deployment. To adjust for this, we use an effective tax rate of 0% for Solaria. REC Silicon's effective tax rate in 2017 was negative 75%. As explained in the 2017 annual report, this is mainly due to write-downs in deferred tax assets. It is therefore considered non-recurring and not included.