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UTILITY SCALE SOLAR POWER IN THE ARCTIC – IS IT FEASIBLE AT 69°N?

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ABSTRACT

Norway needs to increase its power production to meet the future increase in electricity use. Hydro power is estimated to only have 23 TWh of additional available capacity and wind power has met strong resistance lately. Solar power is still only implemented on small scale in Norway but is predicted to increase rapidly in the near future. It is steadily being implemented further north, however there are still no utility scale solar power in northern Norway. This study investigates the feasibility of such an installation close to Skibotn at 69°N. This is done by simulating different PV-systems in PVSyst where the results from the simulations is then used to investigate the economic feasibility through the concepts levelized cost of energy (LCOE) and net present value. The carbon footprint of the solar power produced is also investigated through a life cycle analysis and compared to other sources of electricity. The study includes a literature study which is the basis of the background chapter. It is clear that the research on solar power in snowy areas as well as the modelling of bifacial modules are rather new. There are some knowledge gaps in the literature, especially regarding snow soiling values. These values caused the greatest uncertainty when performing the simulation. The simulation in PVSyst is carried out on 1 MW systems where different set ups of monofacial and bifacial modules are compared. Irradiation data has been gathered on site with a pyranometer for five years and weather data were collected from nearby Kilpisjärvi. The results show that bifacial modules produce roughly 15 % more than their monofacial counterpart. The system that resulted in the highest yield was the bifacial system facing true south with tilt 45°. The two vertical systems, facing South-North and East-West, showed similar yield but different production profiles.

The LCOE is 36 NOK-øre/kWh in the baseline scenario. However, it is 32 NOK-øre/kWh when the life time is set to 40 years, something that is very reasonable in this Nordic location. Both of these scenarios are profitable when comparing with future predictions of the electricity price in electricity price area NO4. It should be noted that these calculations are performed with a low real weighted average cost of capital of 1.39 %. Nevertheless, this is consistent with discount rates used in Sweden and Germany lately. The carbon intensity is 28 g CO_2-eq./kWh which is roughly double that of mixed wind power and 4 times more than hydro power. If the production of PV-modules would be placed in Europe or Norway then the carbon intensity would be 22 g CO_2-eq./kWh and 17 g CO_2-eq./kWh respectively. This shows that if the modules are produces in a region with a low-carbon grid mix then solar power can meet the carbon footprint of mixed wind power, also in a high latitude area. Solar power shows to be a good match to wind power when comparing the two production profiles. Wind power produces energy mainly during winter and the opposite is true for solar power. The yearly production profile gets smoother if the two power sources are combined. There is a possibility to implement new solar power in conjunction with already existing wind power, that way there is less need to use new areas for power production. Also, infrastructure such as roads and grid connection are already in place and the capacity factor of these power lines will increase in such a system. The findings in this paper show that solar power in northern Norway could be economically feasible already today if the discount rate is as low as in Sweden lately. In addition, Swedish industry leader predicts that the capital expenditure will go down by 40 % in ten years. Such a cost reduction would give an LCOE of 27 NOK-øre/kWh and makes solar power very interesting from an economical point of view. This cost reduction is in line with the predictions of the International Renewable Energy Agency which estimates the LCOE to go down by 58 % on average between 2019-2030 in the G20 countries. Utility scale solar power in the Arctic should be further investigated considering the results in this pre-study. Especially snow soiling data from an actual utility scale system would be beneficial for further research and for the industry.

SAMMANFATTNING

Norge behöver utöka sin elproduktion för att möta ett framtida ökat elbehov. Vattenkraften i Norge uppskattas endast ha 23 TWh kapacitet kvar att bygga ut och vindkraft har mött starkt motstånd på senare tid. Solkraft finns fortfarande bara på liten skala i landet men uppskattas öka kraftigt i närtid. Solkraft installeras hela tiden längre norrut men än finns ingen storskalig solkraft i norra Norge. Den här studien undersöker möjligheten för en sådan installation i närheten av Skibotn som ligger på 69°N. Detta görs genom att simulera olika solkraftssystem i PVSyst där resultaten sedan används för att undersöka lönsamheten genom koncepten levelized cost of energy (LCOE) samt net present value. Klimatavtrycket från solkraftsproduktionen beräknas genom en livscykelanalys och resultatet jämförs sedan med andra energislag. Studien inkluderar en litteraturundersökning vilken utgör basen för bakgrundskapitlet. Det är tydligt att forskning på solkraft i snöiga klimat samt simulering med bifacial teknik är relativt nytt då det finns kunskapsluckor i litteraturen, speciellt när det gäller värden på snöskuggning. Dessa snöskuggningsvärden orsakar den största osäkerheten i simuleringen. Simuleringnen i PVSyst utfördes med 1 MW system där olika uppsättningar av monofacial och bifacial moduler jämfördes. Instrålningsdata har samlats under fem år med en pyranometer och väderdata har insamlats från närliggande Kilpisjärvi. Resultaten visar att bifacial moduler producerar ungefär 15 % mer än motsvarande monofacial system. Det system som producerar mest är det system som utgörs av bifacial moduler med 45° lutning som vetter mot söder. De två vertikala bifacial system, som vetter mot Syd-Nord samt Öst-Väst, ger liknande produktionsvärden men med olika produktionsprofiler.

LCOE är 36 NOK-øre/kWh i bas-scenariot. Med en livslängd på 40 år, vilket är högst möjligt här i Norden, blir LCOE 32 NOK-øre/kWh. Båda dessa scenarier är lönsamma när man inkluderar framtida uppskattningar av elpriset i prisområde NO4. Det bör noteras att dessa uträkningar är med en låg real weighted average cost of capital på 1.39 %. Detta är dock i linje med de diskonteringsräntor som rapporterats i Sverige och Tyskland på senare tid. Klimatavtrycket för solkraft i Skibotn är 28 g CO_2-ekv./kWh vilket är ungefär dubbelt så mycket som för vindkraft och fyrdubbelt det för vattenkraft. Om modulerna vore producerade i Europa eller Norge så vore klimatavtrycket 22 g CO_2-ekv./kWh och 17 g CO_2-ekv./kWh för de respektive regionerna. Detta visar att om modulerna är tillverkade där elen har ett lågt klimatavtryck så kan solkraftens klimatavtryck vara i samma storlek som vindkraft, även långt norrut. Solkraftens produktionsprofil överlappar med vindkraftens då solkraft producerar mest om sommaren och vindkraft om vintern. Den kombinerade produktionsprofilen blir således jämnare om de två kraftslagen kombineras. Ny solkraft kan byggas där det redan finns vindkraft, på så sätt lägger solkraften inte beslag på nya landområden. Dessutom så finns infrastruktur, så som vägar och nätanslutning, redan på plats och kapacitetsutnyttjandet av dessa kraftledningar blir högre i ett kombinerat system. Resultaten av denna studie visar att solkraft i arktiska Norge kan vara ekonomiskt lönsamt redan idag, givet att diskonteringsräntorna är så pass låga som de varit i Sverige på senare år. Dessutom så tror svenska ledare inom industrin att kapitalkostnaderna kommer att fortsätta att gå ner med 40 % de närmsta 10 åren. En sådan kostnadsminskning skulle ge ett LCOE på 27 NOK-øre/kWh för solkraft i Skibotn och göra en sådan investering mycket intressant från en ekonomisk synvinkel. En sådan kostnadsminskning är i linje med projektionen från International Renewable Energy Agency då de uppskattar att LCOE kommer att gå ner med 58 % i genomsnitt mellan 2019-2030 i G20-länderna. Storskalig solkraft i norra Norge bör utredas vidare med tanke på resultaten i denna studie. Speciellt snöskuggningsförluster för storskaliga system kan med fördel studeras vidare.

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NOMENCLATURE LIST AND LIST OF ACRONYMS

BG	Bifacial gain represents how much more electricity a bifacial module produces compared to a monofacial module of the same rating.
Bifacial	A PV-technology in which the module produce electricity from both the front and back side.
BOS	All the auxiliary products needed, other than the module, to produce electricity such as structures, inverters and cabling.
IRENA	International Renewable Energy Agency.
LCA	A Life Cycle Analysis is a systematic analysis of the potential environmental impacts of products or services during their entire life cycle.
WACC	Weighted Average Cost of Capital is the cost of capital and the required return from the investor's. Many companies use WACC as their discount rate when planning new projects. WACC includes cost of equity and cost of debt.
NO4	An electricity price area in Norway that covers the northernmost part of the country.
LCOE	Levelized Cost Of Energy is the price at which the generated electricity should be sold for the investment to break even financially.
NPV	Net Present Value is a way to calculate the profitability of an investment in today's money value.
Monofacial	The technology of conventional PV-modules that only produces electricity from front side irradiance.
Discount rate	The discount rate is the interest rate used to determine the present value of future cash flows.
Azimuth	It is the angle of the solar module relative to south. True south is thus 0°.
GWP	Global Warming Potential aggregates greenhouse gases emitted and express them in CO_2-eq. based on their contribution to the greenhouse effect.
NVE	Norwegian Water Resources and Energy Directorate.
O&M	Operation and management is the use-stage in the life cycle of a PV-system.

GOs	Guarantee of Origins is the commodity sold in the Guarantee of Origin market system. One GO represent 1 MW of produced electricity from renewable sources.
CAPEX	Capital Expenditure is the capital costs and include land cost and system costs. System costs consist of modules, inverters, substructures, racking, cabling etcetera.
GHI	Global Horizontal Irradiance is made up of direct, diffuse and reflected light. It is measured on a horizontal surface.
Pitch	It is defined as the length from the front of one row to the front of the row behind.
EPD	An Environmental Product Declaration present transparent, verified and comparable information about the life-cycle environmental impact of products and services.

1 INTRODUCTION

Norway has a surplus of renewable energy today. However, the electrification of society together with the development of electricity intense industries could challenge this in the future. The electricity production in Norway is estimated to increase with 28 TWh to 2040 but the increase could be up to 42 TWh to meet the need of electricity intensive industries (Haukeli et al., 2021). Hydropower is the backbone in Norwegian power supply but it cannot be increased indefinitely. NVE (Norwegian Water Resources and Energy Directorate) claims that only 23 TWh of additional hydropower is available through new projects as well as increasing or renewing old projects (Henriksen et al., 2020). Wind power was installed on scale in 2018 and 2019 but lately it has met strong local resistance and many plans are now being stopped (Tornes Espeseth et al., 2022; Amundsen, 2021). This is why NVE predicts that there will not be any major new installations of land based wind power before 2030 (Haukeli et al., 2021). The market for solar power is strongly emerging in Norway but the installed capacity is still very limited. NVE predicts that solar power will increase with 7 TWh by 2040, more than land based wind power and similar to offshore based wind power (Veie et al., 2019)(Haukeli et al., 2021). These predictions are based on the rapid price reduction in photovoltaic (PV) technology which is driven by lower manufacturing costs and higher efficiencies (Wilson et al., 2020). The global weighted average price fall for utility scale PV power production was 85 % between 2010 and 2020 (IRENA, 2020b). The costs reduction is predicted to continue with an average levelized cost of energy reduction of 58 % between 2019-2030 for the G20 countries (IRENA, 2020a). This has led to solar power steadily being implemented further and further north (Frimannslund et al., 2021). However, the installed solar power is still very scarce at high latitudes. Bifacial PV modules is a new technology that has the potential to change this as these modules converts sunlight into electricity on both the front and backside of the module. The output of these modules benefit from a high albedo environment as the backside receives light that is reflected on the ground. Other parameters which benefits bifacial PV modules are high proportion of diffuse light and low temperatures which are both common in high latitude areas. The market share of bifacial modules are increasing rapidly and predicted to make up 60 % of the global market by 2029 (IRENA, 2020b). The price reduction of these modules has been significant lately. Bifacial modules was 21 % more expensive compared to monofacial modules in December 2019 but the difference was down to 6 % by December 2020 (IRENA, 2020b). The bifacial gain (BG) represents how much yield the bifacial PV module produces relative to a monofacial PV module of the same rating and can be as high as 25-45 % in high latitude areas (Lewis et al., 2019). The reduction in costs together with the favourable characteristics for high latitude areas makes bifacial PV an interesting technology far north even though the solar irradiation is rather low (Frimannslund et al., 2021).

Utility scale solar power is starting to emerge in Sweden where a few systems are already bifacial. Norway got its first utility scale solar power plant in 2021 which consist of bifacial modules (Tekniske nyheter, 2021). A result of the lack of large scale systems is that NVE has to rely on estimations from industry leaders in their cost-analysis of utility scale solar power as they don't have any data from actual systems (NVE, 2022a). NVE also states that the prediction for future solar power hold a lot of uncertainty as it is difficult to predict the development of such a fast emerging market (Veie et al., 2019)(Haukeli et al., 2021). The recent development of bifacial technology also adds on the complexity of such predictions.

One way to reduce the uncertainty of solar power in the north is through pre-studies. No such studies could be found for solar power in northern Norway. Therefore, this paper aim to perform such a feasibility study by investigating utility scale solar power production for an location in Arctic Norway. Feasibility refers to the economic feasibility as well as the carbon performance compared to other sources of energy. This study is located in Gálggojávri, 20km southeast of Skibotn, in northern Norway. The area around Skibotn is known to be one of Norway's driest with 300 mm precipitation per year and hence suitable for solar power (Ovhed, 2016). Irradiation data has been collected on site with a pyranometer between 2017-2021 and this data is used in simulations together with weather data from the Finnish meteorological institutes observation station in nearby Kilpisjärvi. The simulation is carried out in PVSyst where different systems of both monofacial and bifacial modules were compared against each other. A net present value- (NPV) and a levelized cost of energy (LCOE) analysis has been carried out and compared with future electricity prices to evaluate the economic feasibility of the project. An life cycle analysis (LCA) has also been conducted to include the environmental performance of a proposed power plant. This amounts to a holistic evaluation of solar power in this location.

Originally there were plans of installing a PV-system on a site in the vicinity of Skibotn but in the stipulated time we were unable to find a site. Production data is instead gathered from the simulation. The supervisor at the University of Tromsø has been working with solar power in the north for more than 10 years and he proposed the following system types to be investigated:

- 10° tilt East and West facing monofacial PV modules
- 45° and 60° tilt South facing monofacial PV modules
- 45° and 60° tilt South facing bifacial PV modules
- Vertical South-North facing bifacial PV modules
- Vertical East-West facing bifacial PV modules

Each setup is simulated on 1 MW scale and the modules are monocrystalline silicon modules. Over 90 % of the worlds modules are mono- or polycrystalline (Louwen et al., 2017).

1.1 Objective of the study

The objective of this study is to investigate the feasibility of utility-scale grid connected solar power production for a site close to Skibotn (69°N) in northern Norway. One goal is to test different PV-system types to find the most productive one, this includes the bifacial technology. Another goal is to evaluate the economic feasibility of such a system and to compare the carbon intensity of the produced electricity with other power production types. This paper aims to contribute to knowledge development by providing a wholistic feasibility-study of solar power in a region where no such utility scale production exists.

The objective is intended to be achieved by answering the following research questions:

- What is the energy yield of PV-power production on a location in northern Norway?
- How does the yield differ between different PV-systems; including type, tilt and azimuth?
- Is utility scale solar power economically feasible in Arctic Norway?
- What is the carbon intensity of solar power in such a high latitude area and how does it compare to other energy sources?

1.1.1 Scope

This paper combines three different analyses to provide a wholistic investigation of solar power in Arctic Norway. The most suitable PV-system type is decided by analysing several different systems in the PV-simulation program PVSyst. This result is then used in the two other analysis of economy and carbon intensity. The economic analyses consists of a NPV- and LCOE-analysis and is carried out for two different financial set ups to investigate how different set ups influence the result. These are based on general values as no site specific estimation for roads etc. has been performed. A full scale LCA is beyond the scope of this paper. Instead a simplified study was performed where data from a Chinese power plant is recalculated to fit the system in this study. This is considered sufficient to fulfil the goal of comparing the carbon intensity of solar power with other types of power production. There are some literature that points out that bifacial PV modules perform well when they are mounted on sun trackers (Burnham et al., 2019a). This is not analysed in this study as experience from a Nordic PV owner show that they are prone to serious and frequent malfunctioning in this Nordic environment (Lindh et al., 2020). This was also the opinion of the PV expertise in the project (Boström, 2021).

1.2 METHOD

This study consists of a pre- and literature study, simulations as well as a LCA and economic analyses. The pre- and literature study investigates the current state of knowledge on PV-technology in high latitude areas where a special focus is on bifacial technology. The goal is to give the author as well as the reader an understanding of solar power in Nordic conditions, the status of bifacial technology and some key parameters used in the PV-simulation. The LCA is carried out in order to compare the carbon footprint of solar power in this region with other power production types. It is common practise to use the life cycle perspective in such comparisons. The economic analyses is carried out as an LCOE and NPV analysis. LCOE is the most common way to compare the cost of different power production types and NPV is one way to calculate the present value of a proposed project. The execution of these analyses is explained in detail in chapter 3 and 4. The LCA is presented in full in chapter 6, including a description of the method.

The prestudy started with participation in two webbinars:

- *Sol på en fredag – Bifacial special* held by Solenergiklyngen
- *Online Workshop on Ethics and Methods in Arctic Research* held by www.arctic-ethics.org

The first one treated the status of bifacial PV-technology in Norway where a focus was on simulation. This was used as a guide in the further search for information. The second workshop dealt with how natural sciences can better be carried out in collaboration with the native communities in the Arctic. This was supposed to prepare the project to better collaborate with the local community where the planned pilot system would be installed. The search for literature and information was carried out on Google, Google Scholar, where access through Lund University was used to get access to a handful of the references, as well as LUBSearch which is the search engine from Lund University Library that searches in many databases. Search phrases included, but not limited to: “PV Arctic”, “PV high latitude”, “Bifacial high latitude”, “Bifacial simulation”, “Soling values PV”, “Snow soiling PV”, “Bifacial simulation PVSyst”, “Bifacial simulations 2-d view model”, “LCA PV”, “Life cycle analysis solar PV” and “LCOE PV”. A snowball approach was adopted where new papers was found in the references of others. The references were chosen based on abstract and publication date. Bifacial PV technology is rather new and fast developing which is why date of publication was an important criteria.

1.3 DISPOSITION

The thesis is divided on 8 chapters, excluding references and appendix.

Chapter 1 - Introduction: The introduction puts the study in context by describing the future electricity need in Norway as well as looking into the status for solar power in high latitude areas. A special focus is directed towards the bifacial technology. This chapter also includes the objective and method of the study.
Chapter 2 - Background: The background gives the reader an understanding of the different challenges and possibilities that are tied to solar power in a snowy and cold climate. The simulation model and economic theory is also explained.
Chapter 3 - Simulation: This chapter explains how the simulation was performed. It starts with explaining the environmental conditions at the site of the pyranometer. Then follows how weather- and irradiation data was obtained and controlled as well as how some key parameters are chosen.
Chapter 4 – Economic evaluation: This chapter gives a detailed description of the economic calculations which includes a table of all parameters.
Chapter 5 – Result of simulated production and economic evaluation: This chapter presents the results from the simulation and economic investigation. It also includes sensitivity analyses performed on some key parameters.
Chapter 6 – Carbon footprint (LCA): This chapter contains the full life cycle analysis. This includes result, discussion and conclusion. However, the discussion and conclusion in chapter 9 and 10 puts these LCA-results in a context.
Chapter 7 – Discussion: This chapter discusses the results from the simulation, economic evaluation and LCA. It also deals with how well solar power fits in the electricity system. It is finished with an outlook that presents knowledge gaps and recommendations for future research.
Chapter 8 – Conclusion: The main findings are presented in this final chapter.

2 Background

This chapter treats aspects of solar power that are specifically important in the Nordic climate such as irradiation, temperature, albedo, degradation and snow soiling. This is followed by a thorough explanation of the simulation model and the theory of the economic calculations.

2.1 Future electricity projections in Norway

The electricity production in the Nordic countries was 420 TWh in 2019 (Veie et al., 2019). NVE forecasts a 22 % increase to 510 TWh in 2040, see figure 1.

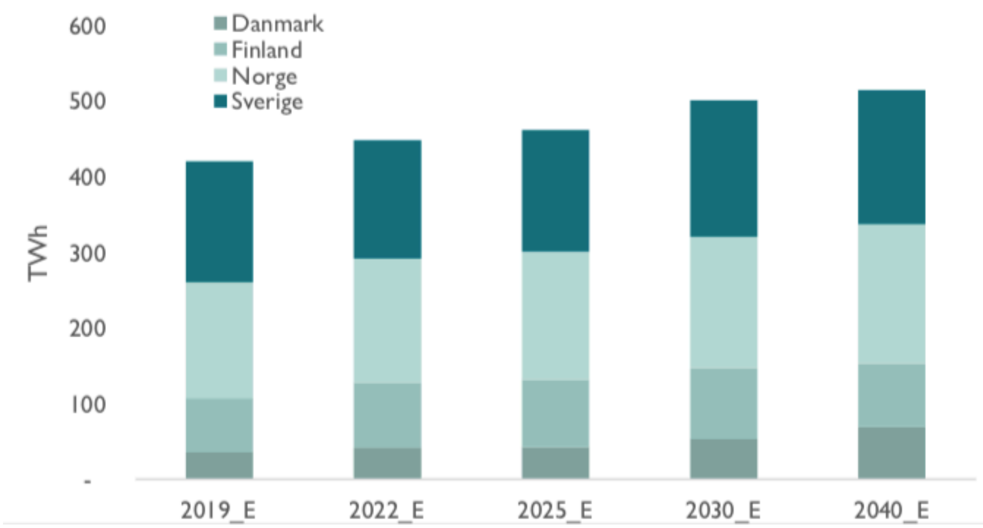

Figure 1. NVEs prognosis for the electricity production in the Nordic countries: Denmark, Finland, Norway and Sweden. Source: (Veie et al., 2019)

The electricity production in Norway is estimated to increase from 158 TWh in 2021 to 186 TWh in 2040 in NVE's baseline scenario (Haukeli et al., 2021). This increase by 28 TWh is divided on offshore- and land based wind power, solar power and hydro power as can be seen in figure 2, where solar is estimated to increase with 6 TWh.

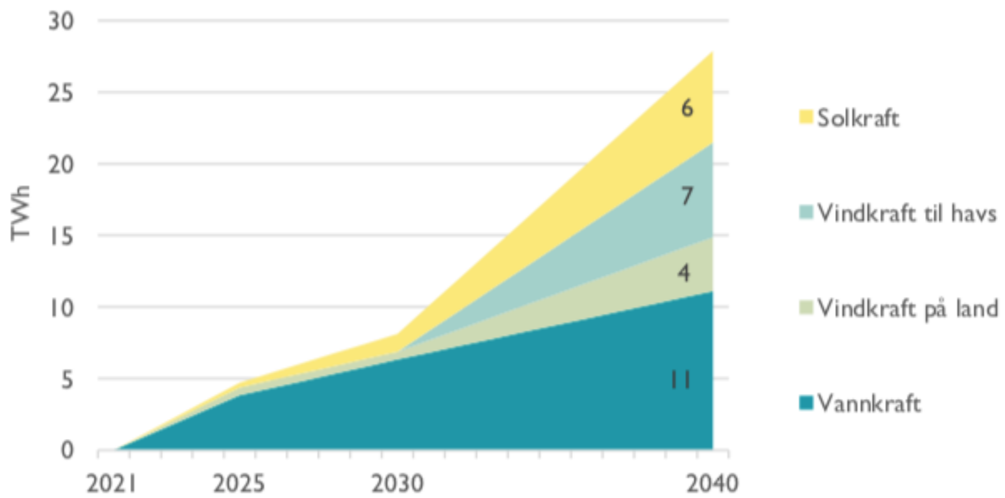

Figure 2. The development of new electricity production in Norway relative to 2021. Source: (Haukeli et al., 2021)

The electricity use in Norway is predicted to increase from 138 TWh in 2019 to 174 TWh in 2040, an increase with 36 TWh, according to NVE's baseline scenario. This is driven by the electrification of the transport sector and petroleum industry as well as new electricity intense industry e.g. battery factories. The production of hydrogen through electrolysis also has the potential to increase the need for electricity. The electricity use could rise to 200 TWh in 2040 if the new industry projects exceeds the estimation in the baseline scenario (Haukeli et al., 2021).

Solar power is strongly emerging in the Nordic countries. NVE estimate that it will grow from 1 TWh in 2019 to 21 TWh in 2040, see figure 3 (Veie et al., 2019). The expansion is happening fast but the amount of installed capacity by now is still low. NVE states that the prognosis hold a lot of uncertainty and that it is difficult to predict the development of such a fast emerging market (Veie et al., 2019; Haukeli et al., 2021).

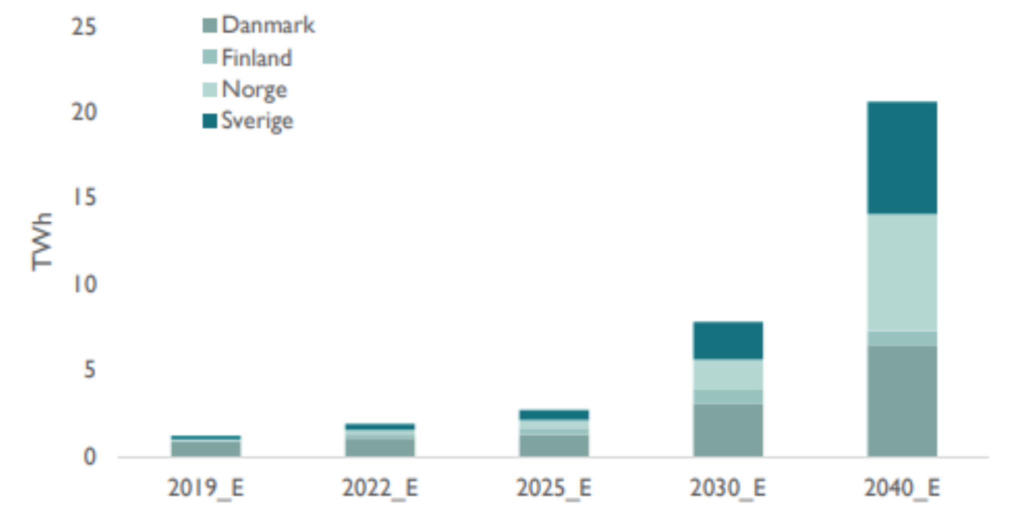

Figure 3. NVEs projection for solar power production in the Nordic countries: Denmark, Finland, Norway and Sweden. (Veie et al., 2019)

There was 68 MW of installed solar power in Norway by the end of 2018 (Multiconsult, 2019). This amounts to around 0.06 TWh (Veie et al., 2019). Sweden and Denmark had 411 MW and 1040 MW, respectively, installed at the same time, far more than Norway. The most common type of solar power in Norway used to be free-standing PV-systems as these are widely used in holiday homes. However, larger grid connected systems have grown rapidly in recent years and constitutes the majority of new installed capacity, see figure 4 (Veie et al., 2019).

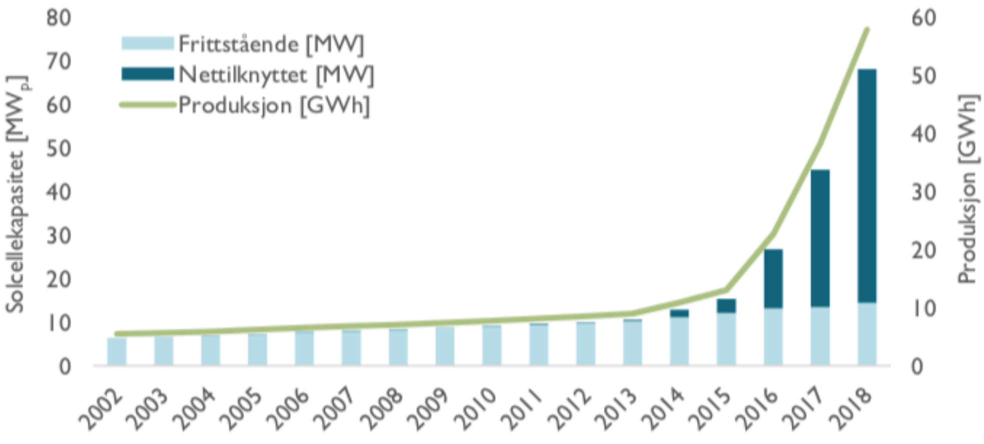

Figure 4. The development of installed solar power in Norway from 2002-2018. Light blue is free standing systems, dark blue is grid connected systems and green line represent the total production. Source: (Veie et al., 2019).

The driving force behind the increase of solar power in the Nordic countries is the costs reductions in the technology. NVE predict that these will continue to fall and states that the costs for the produced electricity might even become lower than the price for hydro or wind, also in Norway (Haukeli et al., 2021).

2.2 Solar irradiation in high latitudes

Sunlight consists of direct and diffuse irradiation which is made up of the direct sun beam and scattered light, respectively. The duration of periods with low solar angels increases with increasing latitude (Chiang et al., 2019). This results in longer atmospheric paths and thus increased scattering of incoming light. High latitudes areas is thus subjected to a large proportion of diffuse light (Lewis et al., 2019). Reflected light can be viewed as a third component of irradiation and consists of irradiation that is reflected by a surface. A PV-module receives irradiation from all of these three components which together make up the global horizontal irradiance (GHI). Another aspect of high latitude areas is the phenomenon of polar nights and midnight sun. The sun does not go above the horizon during the polar night and the opposite happens during the midnight sun, as the sun never drops below the horizon. The polar night takes place between November 27th – January 15th and midnight sun between May 20th – July 22nd in Tromsø at 69.7°N (Pedersen, 2013).

2.3 Temperature dependence of solar cells

Less than 20 % of the solar irradiation is transformed into electricity by the solar cell. The majority of the remaining energy is transformed into heat which makes the solar cell temperature higher than the ambient air (Bayrakci et al., 2014). The power output of a crystalline solar cell depends on the temperature where an increase in temperature decreases the cell voltage and also increases the current slightly. The overall result is a change of power output with -0.35 %/K to -0.5 %/K (Frimannslund et al., 2021). This is confirmed by Hasanuzzaman *et al.* (2016) and Solanki (2016) who finds this number to be -0.4 %/K to -0.5 %/K and -0.45 %/K respectively. These numbers apply to crystalline solar cells and make them suitable for colder climates. Other technologies have different characteristics.

2.4 DEGRADATION

The efficiency of the solar module decreases each year due to wear on the components, something that is expressed as degradation rate (%). Common degradation factors include humidity, UV radiation and temperature. All of these are relatively low in the Nordic climate and thus favours low degradation. It can be expected a couple of tenths percentage points less degradation in northern Norway compared to e.g. Munich (Lindh et al., 2020). Lindahl *et al.* (2021) investigated the economics behind six recent PV-projects in Sweden and found that the degradation rate used in these projects varied between 0.2 %-0.4 %, with an average of 0.27 %. This is lower than many other studies and an indication that the Swedish projects are informed about the lower degradation rates of colder climates. The electricity yield needs to be adjusted with the degradation rate for each year of the life time of the system. This is done with the following equation (EPD International AB, 2021):

$$E_L = E_1 * (1 + \sum_{n=1}^{L-1}(1 - deg)^n) \quad (1)$$

Where E_L is the total energy yield over the lifetime of the system, E_1 is the energy yield at year 1, L is the life time of the system and deg is the degradation rate.

2.5 BIFACIAL PV-MODULES

A bifacial module produces electricity from both the front and back side, as opposed to regular monofacial modules which only produce electricity from irradiance on the front. Bifacial solar modules thus benefit from additional electricity production from the backside, either from direct irradiation or reflected from the ground. A schematic illustration of the two types of modules are shown in figure 5. The rear side usually produces less than the frontside given the same irradiance. The bifaciality factor defines how much the backside produces relative to the frontside, given the same irradiance, and is given in percent.

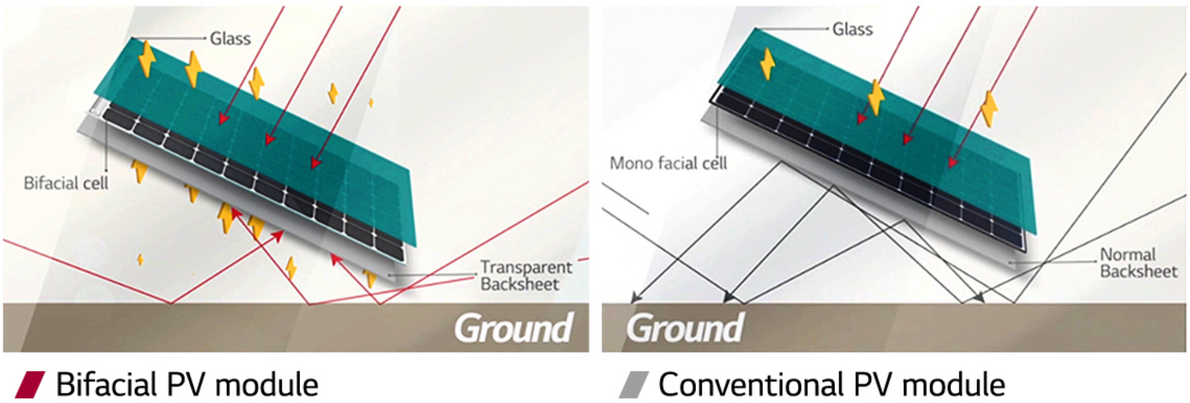

Figure 5. Structural difference between a bifacial solar module and a conventional monofacial solar module. The bifacial panel produces electricity from both the front and backside as oppose to only frontside production of the monofacial panel. Source: (Maltby, 2019)

The increase in produced energy relative to a monofacial module is called bifacial gain (BG) and is given in percent. It represents how much more energy a bifacial module produces compared to a monofacial module of the same rating (Riedel-lyngskær et al., 2020). This relationship is shown in equation 2:

$$BG[\%] = \left(\frac{E_{BF}/_{P_{STC,BF}}}{E_{MF}/_{P_{STC,MF}}} - 1 \right) * 100 \quad (2)$$

E_{BF} and E_{MF} are produced energy and $P_{STC,BF}$ and $P_{STC,MF}$ are the frontside ratings of the bifacial and monofacial systems respectively.

BG increases strongly with the albedo of the surrounding ground. An explanation of albedo follows in chapter 2.6. An experiment in Amsterdam compared East-West facing bifacial modules with south facing monofacial modules and showed bifacial gains of 10 % at albedo 0.2 and 30 % at albedo 0.5 (Janssen et al., 2015). A theoretical study in Oslo found a linear relationship between BG of 6 %-16.5 % with respect to albedo in the range of 0-0.5 (Yusufoglu et al., 2015). A recent B.Sc study by Børsheim (2021) analysed the BG of solar panels mounted on the university rooftop in Tromsø, 60 km west of Skibotn . She concluded that the most favourable system, in terms of BG, was a south facing system with 60° tilt. This setup resulted in a BG of 16.2 % over the three years the study was performed. The other three set-ups were 40°, 40° and 20° tilt, all south facing, which resulted in a BG of 9.1 %, 10.8 % and 12.7 % respectively, see table 1.

Table 1. Experimentally determined values of bifacial gain (BG) from a three year study on a rooftop in Tromsø, northern Norway. Source: (Børsheim, 2021).

Tilt	Azimut	BG (%)
20°	0° (S)	12,7
40°	0° (S)	9,1
40°	0° (S)	10,8
60°	0° (S)	16,2

2.6 ALBEDO

The albedo is a measurement of how much of the irradiation that is reflected by a surface. Albedo is given in the range 0 to 1 where 0 is represents a surface that reflects no light while 1 represents a surface that reflects all incident light. Albedo for some common substrates are shown in table 2. The amount of irradiance that is reflected by a surface is thus directly proportional to the albedo. The backside of a bifacial solar panel receives a large portion of indirect light reflected from the surrounding ground. Albedo is thus a primary contributor of BG which makes bifacial modules particularly interesting in high albedo environments. This can be artificially created environments such as white roofs and enhanced ground substrates or naturally environments such as deserts and snowy terrain (Burnham et al., 2019b).

Table 2. Albedo values for different surfaces. Source: (Quaschning, 2014).

Surface	Albedo
Grass (Summer)	0.25
Soil	0.17
Gravel	0.18
Woods	0.05-0.18
Heathland and sand	0.10-0.25
Fresh snow cover	0.80-0.90
Old snow cover	0.45-0.70

New and old snow have very different albedo, as shown in table 2. A study by Burnham *et al.* (2019) measured daily average albedo in the winter months in Vermont, see figure 6. They show that the value varies greatly from day to day due to snow characteristics such as compaction, height, age, etc. Nevertheless, 40 % of the days had albedo values above 0.80 and 72 % had values of at least 0.60 which indicates that this site had winter albedo values in the upper part of the snow-interval of table 2. Albedo values exceeding one are an anomaly and is due to build-up of snow and ice on the sensor.

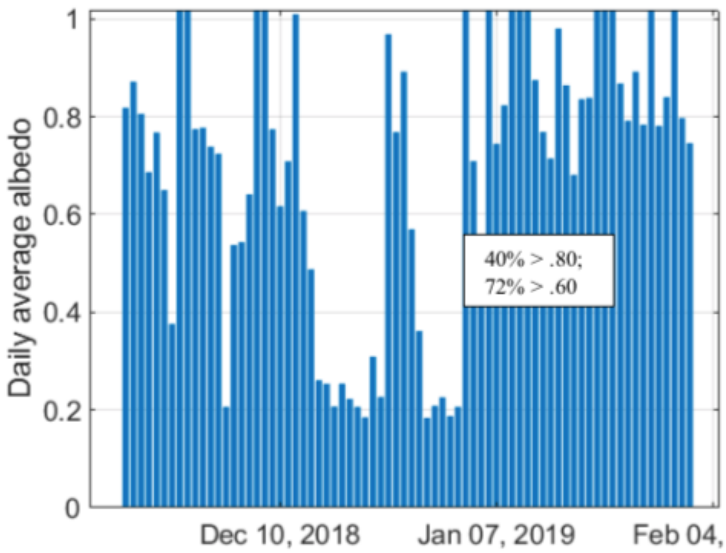

Figure 6. Winter albedo measurements in Vermont. The albedo varies heavily from day to day. This is due to snow characteristics (compaction, height, age, etc.) and irradiance levels. 40 % of days had albedo values above 0.80 and 72 % of the days had values of at least 0.60. Source: (Burnham et al., 2019b)

2.7 Snow soiling

The authors of *The handbook for Nordic solar power* states that soiling by snow is by far the most important parameter for Nordic conditions (Lindh et al., 2020). Soiling of solar panels reduces the yield where a 10 cm cover on a sunny day would result in almost no electricity production. The electricity yield can be highly effected even if the module is only partly shaded. This is because the solar cells in the module are serial connected in a number of strings. These strings are connected with bypass diodes which can bypass a string if parts of it is shaded. This is done in order to prevent the cells from being damaged by overheating, a phenomenon induced by partial shading. This effect is illustrated in figure 7. Here it is also shown how it is possible to install the modules in landscape orientation, as in (b), to reduce the effect of partial snow coverage at the base on the module. By applying this installation method one can minimize the bypassing of strings to only one bypass diode. If the module is installed in portrait orientation, as in (a), then snow will cover all the lowest cells and all of the strings will get bypassed and the module will not produce any electricity. It is often at the base of the module that snow or ice accumulates since the shedding is hindered either by the frame, other surfaces or from build-up of snow under the module (Lindh et al., 2020).

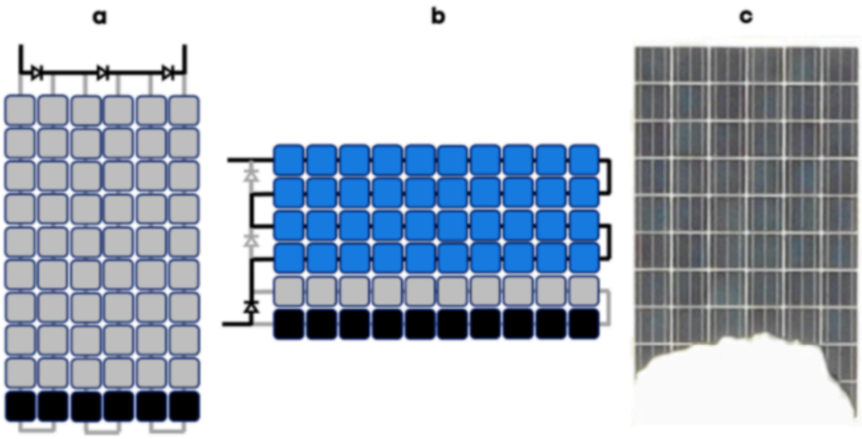

Figure 7. An illustration of the layout of a normal 60-cell silicon module. The cells are producing current when blue, covered by snow when black and bypassed when grey. The bypass diode is active when black and non-active when greyed out. The figure shows how the current is affected by partial snow coverage in (a) portrait- and (b) landscape oriented installation. (c) show snow coverage of the lower part of the module. Source: (Lindh et al., 2020)

The snow losses are largely decided by how early in the year the module is snow free. Snow cover in winter coincides with very low irradiation in high latitude areas and thus losses are small. However, during spring the irradiation is strong and snow coverage at this time will highly influence the yield. Hence snow removal in spring can be a way to mitigate yield losses. There are very little experimental data of snow losses available in the literature. There is one study conducted in Sweden but apart from that there is no data from systems north of 51°N (Lindh et al., 2020). The Swedish study was only conducted for two winters and showed great variations which makes it difficult to draw definite conclusion. Most other studies are from North America on relatively low latitudes (37–51 °N). Nevertheless, there are some guideline-values for snow loss one can apply when simulating a PV-power plant in Norway. These values are included in standards often used by the construction industry, i.e. NS3031:2014 which concerns calculation of energy performance of buildings. These losses should however been seen as rough guiding values as every system has its own losses that depends on the local conditions as well as the design of the system. Table 3 includes values for system with tilt between 25°-40° in Tromsø, which is located 62 km northwest of Skibotn:

Table 3. Soiling values for Tromsø. Tableted values often used by the construction industry. Source: (Øgaard, 2022)

Month	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Okt**	**Nov**	**Dec**
Soiling [%]	25	25	25	25	2	2	2	2	2	10	15	20

Another way to estimate snow losses is through the online tool *Snö och solel* (http://snosolel.ri.se/) which was developed by RISE and SMHI in Sweden. The project also produced maps of yearly losses due to snow coverage as in figure 8 below. The tool is based on the Marion model which is a model proposed in 2013 and that has become the most widely recognized snow loss model. When four snow loss model where tested in Norway this model showed the best results (Øgaard, Aarseth, et al., 2021). The model is also verified in Norway by Øgaard, Riise, et al. (2021). The online tool demands some user defined parameters which includes location, tilt, azimuth amongst others before the program can calculate yearly snow losses. Again, these are only guiding values as local conditions and system design influence the snow loss value.

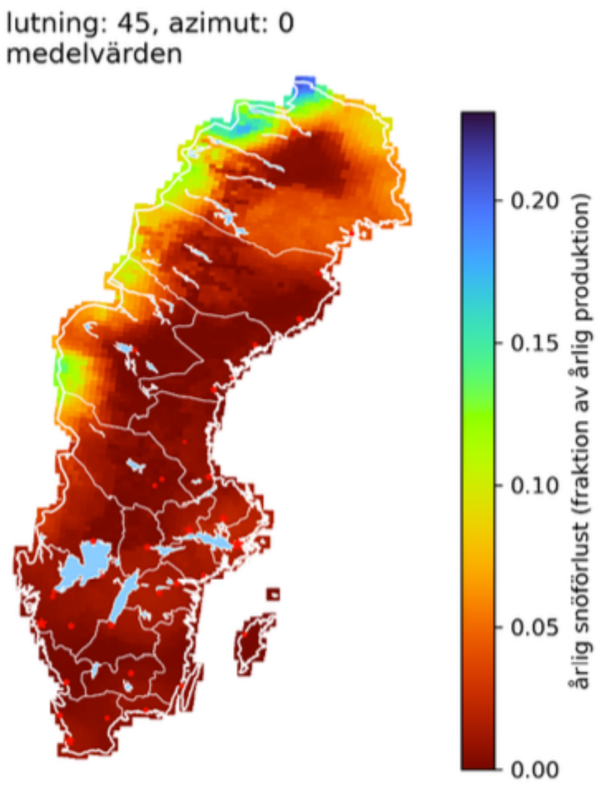

Figure 8. An estimation of snow losses in Sweden, expressed as a fraction of yearly yield. Tilt 45° and azimuth 0°. Source: (Noord et al., 2021)

A study by Burnham *et al.* (2019) indicates that bifacial solar panels shed snow faster than regular panels. This is illustrated in figure 9 where the bifacial modules on the outer ends are partly snow free while the monofacial modules in the middle are totally snow covered. Granlund, Narvesjö and Petersson (2019) point out that bifacial modules are typically frameless which means that no frame edges will hinder the snow from sliding of the module.

Figure 9. The bifacial modules (partly snow free) in this setup shed snow faster than the monofacial modules (snow covered). The bifacial modules on the left are framed while the bifacial modules on the right are frameless. Source: (Burnham et al., 2019b)

Burnham *et al.* (2019) explain the enhanced snow shedding with three processes. Firstly, the irradiance on the backside of bifacial modules warms the panel which favours shedding. Secondly, the frameless design of bifacial modules also reduces the structural support which favours snow shedding to occur. Lastly, high tilt angles facilitates shedding. This is not a characteristic of bifacial modules, however, bifacial modules are thought to benefit from higher tilt angles. Andrews, Pollard and Pearce (2013) also show that higher tilt angels correlates with faster shedding. However, Frimannslund *et al.* (2021) argue that these studies do not necessarily have to be applicable to systems that are placed in windy, unsheltered areas where snow distribution are dominated by snow drift. In these places snow deposits could be a larger contribution to soiling and the authors claim that snow fence theory could be applicable to predict snow covering in these situations. In an experiment on Svalbard snow deposits were visible on the leeward side of the panels shortly after installation and after some time a row became partially buried. This indicates that installations in this kind of locations need to be adapted to manage this. Snow fences are a widely used solution but other solutions could be in the design of the system itself so that less snow accumulates or that snow accumulates in designated areas. This could be possible as solar power systems are flexible in design (Frimannslund et al., 2021).

An experiment with frameless bifacial modules in Sweden at 65°N showed that low tilt <25° is subjected to more snow soiling than higher tilted modules, where tilt is given relative to the horizontal surface (Granlund et al., 2019). No difference in shading was observed for tilts between 25°-70° but higher tilts resulted in less shading, see figure 10. It should be noted that this study was only performed in one winter and on one module per tilt angle.

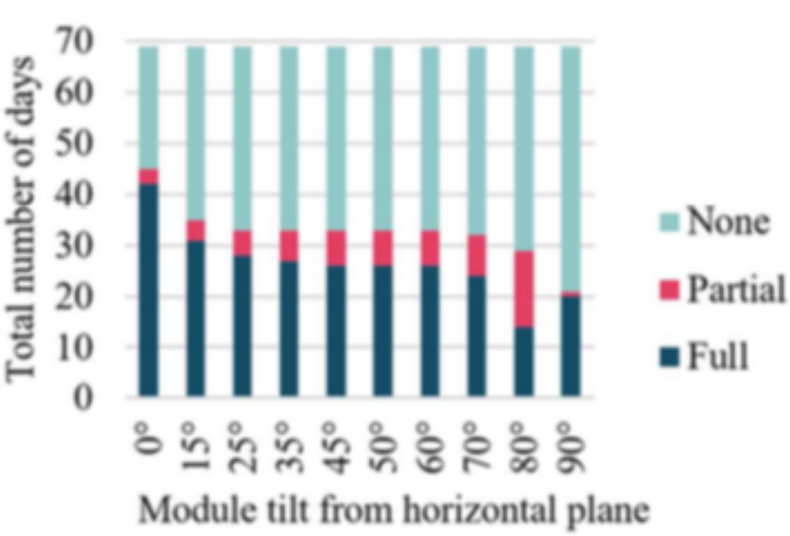

Figure 10. Number of days with snow cover, measured between January 22 to March 31 in Sweden 65°N. Time resolution 1 day. Source: (Granlund et al., 2019).

2.8 SIMULATION MODELS

The simulation tool in this study is PVSyst v7.2 which is the latest update of the program (spring 2022). PVsyst was developed at the University of Geneva in 1992 and is geared towards engineers, architects and researchers. It has included bifacial models since 2017 (Kang et al., 2019). There are mainly two different models used in simulation of bifacial PV panels, 2-D view factor and 3-D ray tracing (Phetdee et al., 2020). PVSyst uses 2-D view factor which is a simplified model that makes computation time more reasonable (minutes). The model calculates the fraction of light reaching the front and backside of the panel by including a view factor. The view factor represents the fraction of radiation from one point that is received in another point (Kang et al., 2019). This is based on geometric calculations and often assumes isotropic distribution of reflected irradiance. This assumption is true for the 2-D view factor model used in PVSyst (Wittmer, 2019). The model includes direct light, diffuse light and reflected irradiance which stems from both direct and indirect light. This is illustrated in figure 11.

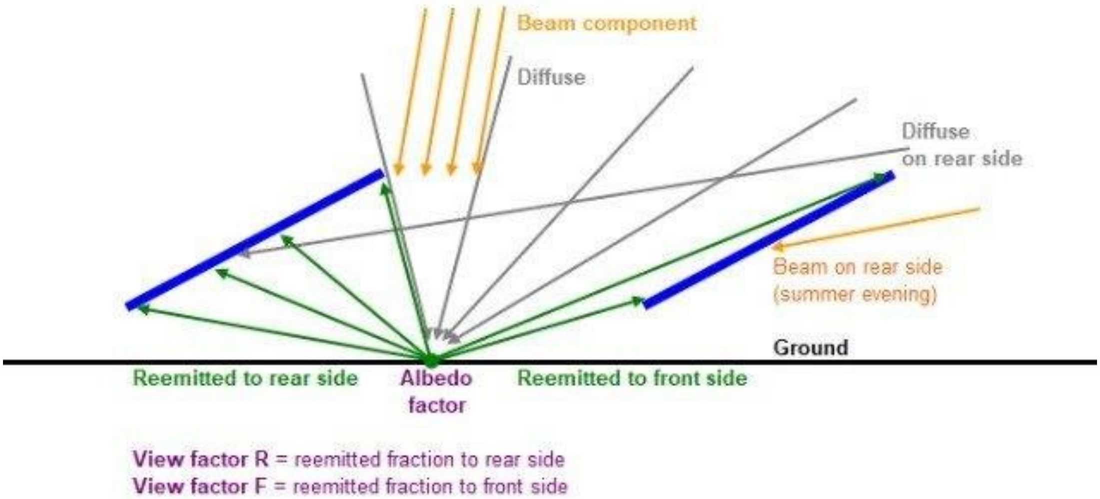

Figure 11. Illustration of the 2-D view factor model used in PVSyst. Source: (Phetdee et al., 2020)

The drawback is that it doesn't include edge effects, instead it assumes infinite long rows. The model also makes it difficult to include shadowing from construction or opening between panels. The omission of edge effects makes the model prone to under-prediction of produced energy for small PV systems since the extra backside irradiance on outer modules is neglected (Asgharzadeh et al., 2019). Shoukry *et al.* (2016) performed a simulation of BG that included edge effects and the results can be seen in figure12. The panels at the outer edges show higher BG than the panels in the middle which are subjected to more ground shading. However, Asgharzadeh *et al.* (2019) observed overestimation of backside irradiance in the 2D-view factor model and therefore argues that edge effects are less important than the complexity of the construction.

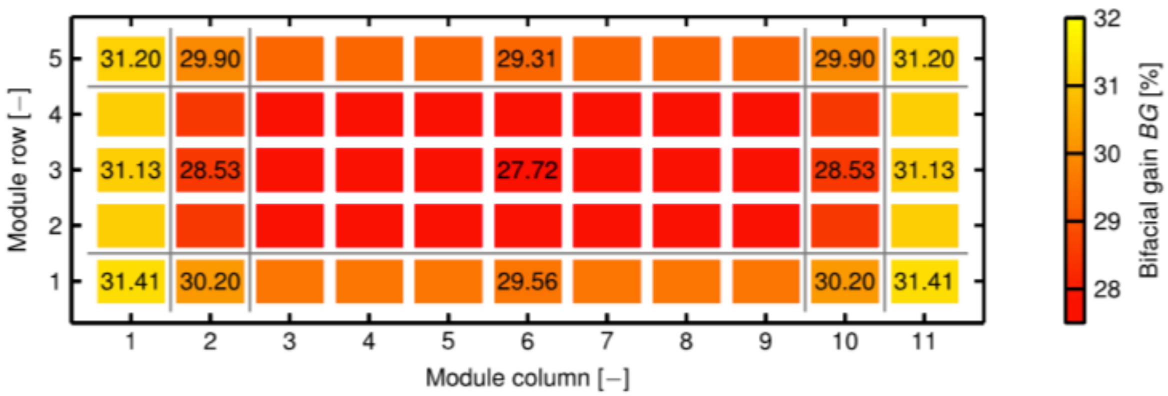

Figure 12. Simulated bifacial gain for 5 rows of PV modules. The panels on the edge show higher bifacial gain than the panels in centre due to less ground shading. Source: (Shoukry et al., 2016)

Since the model does not directly include the effects of non-linear backside irradiance and complex shading loss it is up to the user to define a rear shading loss factors to compensate for these effect. The user also has to define a transmission factor that represents how much light that passes through the rows of modules and contributes to the reflected irradiance (Phetdee et al., 2020). Phetdee *et al.* (2020) argues that the PV industry is years away from having access to validated numbers of irradiance non-linearity, shading-loss and transmission factors that can be used in simulations. All of these variables have impact on the model and depend on the design of the PV plant which constitutes a challenge of using 2-D view factor modelling. The model is best suited for long and regular rows which limits the loss of edge effects (Wittmer, 2019).

The other model is 3-D ray tracing which is more realistic and makes it easy to include shadowing from complex constructions and edge effects. This takes away the need for user defined factors, as is the case with the 2-D view factor model. The drawback is that the computation is heavier, in the scale of hours to days (Phetdee et al., 2020). Shadowing from complex structures and non-uniform irradiance is a key challenge of modelling bifacial PV systems. This all adds up to the task of estimating the back side irradiance which is fundamental in bifacial modelling (Riedel-lyngskær et al., 2020).

Bifacial solar power systems have not been built in utility-scale for long which makes validation of simulation software not readily available (Kang et al., 2019). Most validation studies that have been performed have been on smaller scales which omit the prominent self-shading of many and long rows. However, the studies that have been carried out show mostly good agreement between modelled and measured values (Riedel-lyngskær et al., 2020). A validation study from Denmark (56°N) performed a comparison between modelled and measured energy production. They used on site measurements as input into the two models and compared the results with the actual production from racks of utility scale. The comparison showed that the 2-D view factor simulated BG within ±1 % of the actual BG for the fixed tilt system. For single-axis tilt tracker was the simulation within approximately 2 % and 1 % of the measured BG for 2-D view factor and 3-D ray tracing respectively (Riedel-lyngskær et al., 2020). Another study by Asgharzadeh *et al.* (2019) compared results from four simulation tools (including PVSyst) with measurements from a fixed tilt site in Albuquerque, USA. The results showed agreement within 1 % for all software. The authors argue that the 2D models are accurate enough to predict energy production even though 3D modelling offers higher resolution and flexibility. They add that this holds true as long as the systems are well-characterized in the model. These errors presented above are much smaller than typical errors in PV-yield assessments which lies between 5 % - 10 % (Chiodetti et al., 2018).

2.9 ECONOMIC THEORY

Various methods can be applied when calculating the economic feasibility of a PV-project but levelized cost of energy (LCOE) is most common when comparing different production methods (Hernández-Moro & Martínez-Duart, 2013) (IEA, 2020). LCOE is defined as the total cost of the project divided by the total energy produced. Hence, LCOE is the cost of producing energy averaged over the life time of the project. LCOE is expressed in cost per energy carrier, usually kWh in PV-projects, and can be written as:

$$LCOE = \frac{I_0+\sum_{t=1}^{n}\frac{C_t}{(1+r)^t}}{\sum_{t=1}^{n}\frac{E_t}{(1+r)^t}} \qquad (3)$$

where I_0 is the initial cost at year zero, C_t is the annual cost in year *t*, E_t the energy produced in year *t*, r the discount rate and *n* the lifetime of the system (Hernández-Moro & Martínez-Duart, 2013). LCOE is thus the average electricity price needed over n years for the project to break even financially while producing a return dictated by the discount rate *r*. The discount rate decides how much future money is worth in today's money value and is explained thoroughly below. Note that I_0 is not discounted in equation 3. This is because the construction of a PV-power plant usually is carried out in less than one year and thus there is no need to discount this investment (Lindahl et al., 2021). This is true for all of the six PV-power plants in Sweden, commissioned between 2019-2020, that Lindahl *et al.* (2021) performed an economic analysis of. Another way of estimating profitability of a project is through net present value (NPV). NPV is a concept from financial mathematic that re-calculates future costs and revenues in their present value, so called NPV. This is done using discounted cash flows with a discount rate *r*:

$$NPV = \sum_{t=1}^{n}\left(\frac{R_t-C_t}{(1+r)^t}\right) - I_0 \qquad (4)$$

where R_t is revenues in year t. Equation two is rewritten from Hernández-Moro and Martínez-Duart (2013). A negative NPV-value means that the investment is unprofitable whereas a positive value shows how much the investment is profitable by in today's money value. Below follows an in-depth analysis of discount rate, costs and revenues tied to these calculations of a PV-project.

2.9.1 Discount rate and WACC

The discount rate is one of the most important assumptions to make in an LCOE or NPV analysis. It should reflect both the inflation rate as well as the risk of the investment and the required rate of return. It decides how one should value future costs and revenues in today's money value. Rodríguez-Gallegos *et al.* (2018) uses a DR of 4.88 % for PV-investments in Norway. Another way of discounting future costs in PV-projects is through weighted average cost of capital (WACC). WACC is the cost of capital and is an investor's required return. The investor wants to receive an interest on the capital invested and WACC shows how large this return has to be to be satisfactory. Many companies use WACC as their discount rate when planning new projects (Majaski, 2022). WACC includes cost of equity and cost of debt. Cost of equity is what the owner requires in return for owning the investment and hence bearing the risk of ownership. If a project was fully financed by loans then the WACC would be equal to the cost of debt. However, PV projects are often financed by a combination of the two and then WACC becomes the weighted sum of these (Majaski, 2022; Lindahl et al., 2021). The nominal WACC can be calculated as:

$$WACC_n = \frac{D*C_d*(1-CT)+E*C_e}{D+E} \qquad (5)$$

Where D is amount of debt, C_d and C_e are the interest rate of debt and equity financing respectively, CT is the corporate tax rate and E is the amount of equity. If the LCOE calculations are carried out in present values, i.e. real values, then future costs need to be discounted with a real WACC, $WACC_r$, which is adjusted with the inflation rate, *Infl*. $WACC_r$ can be calculated in the following way:

$$WACC_r = \frac{1+WACC_n}{1+Infl} - 1 \quad (6)$$

The central bank of Norway targets 2 % inflation rate (Norges Bank, 2021). It is common to have a distribution of 60 % debt and 40 % equity in utility-scale PV-projects, something that the well-renowned financial analysis firm LAZARD also uses in their LCOE-analysis of energy production (LAZARD, 2021; Rodríguez-Gallegos et al., 2018). IRENA uses a WACC of 7.5 % for PV-projects in the Organisation of Economic Co-operation and Development (OECD) countries. This is based on the fact that borrowing costs are low and stable rules and policies reduce the risk of these projects (IRENA, 2020b). Lindahl *et al.* (2021) investigated the economics behind six PV-projects commissioned in Sweden between 2019-2020 and found that the $WACC_n$ varied between 0.75 % and 6.5 % with an average of 4.72 %. With an inflation rate of 2 % this results in an average annual $WACC_r$ of 1.39%. C_d varied between 1.0 % and 3.1 % with an average of 2.09 %. C_e varied between 0.0 % and 6.5% with an average of 4.72 %. These numbers seem low compared to the ones used by IRENA. However, Egli, Steffen and Schmidt (2018) showed the strongly declining trend for cost of capital for PV-projects and presented PV WACC-values from Germany similar to the ones used in the Swedish projects. One out of the six PV-projects investigated in Sweden were financed entirely through debt, two where fully equity financed and the other three were financed through a mix of debt and equity (Lindahl et al., 2021). PV-projects have a high proportion of investment costs compared to operating costs which makes the financial set up important for the LCOE.

2.9.2 Capital costs

Capital costs, also called capital expenditure (CAPEX), include land cost and system cost. System costs consist of modules, inverters, substructures, racking, cabling etcetera. Lindahl *et al.* (2021) found that the factors that had the greatest impact on the variation in CAPEX were system size and location. These dictate costs for ground preparation and access to roads and grid. The average CAPEX was 6690 NOK/kW_p for the six recent Swedish projects. NVE (The Norwegian Water Resources and Energy Directorate) estimates CAPEX to 6000 NOK/kW_p for a 10MW_p PV power plant (NVE, 2022). This includes all costs regarding initial investments. However, there are no PV installations in Norway of this size so NVE has no actual data to base its cost estimates on. Instead, these numbers are estimates that NVE has gotten from talking to different actors in the industry. This number is most likely based on monofacial panels. Rodríguez-Gallegos *et al.* (2018) claimed bifacial panels to be 11.2 % more expensive than monofacial panels in 2018. The International Renewable Energy Agency (IRENA) states that bifacial panels were 21 % more expensive in 2019 but that this number dropped to 6 % in December 2020 (IRENA, 2020b). NVE's CAPEX would be 6360 NOK/kW_p with a 6 % cost increase. LAZARD uses 7232-8588 NOK/kWp as CAPEX in their LCOE-analysis (LAZARD, 2021). There are no cost-data from utility-scale bifacial solar power in Norway. However, Solgrid are planning to build a 7 MW facility in Stor-Elvdal municipality and their concession application are in review at NVE. Solgrid estimates the system costs to be 5000-5500 NOK/kW_p for a turn key ready facility (Solgrid, 2021). This includes grid fees, projecting, materials and equipment as well as installation. Lindahl *et al.* (2021) report that Swedish industry leaders expect that CAPEX will go down by 40 % in the next ten years for PV-systems larger than 0.1MW. This might seem a lot but is in-line with the cost predictions of IRENA as they estimate the LCOE of solar power to go down by 58 % on average between

2019-2030 in the G20 countries (IRENA, 2020a). CAPEX from the different sources are presented in table 4.

Table 4. CAPEX for utility scale solar power from different sources.

Source	CAPEX (NOK/kW_p)	New inverters (NOK/kW_p)
NVE (2022a) (mono)	6000	No information
NVE (2022a) (BiFi)	6360	No information
Solgrid (BiFi)	5000-5500	Included in O&M
LAZARD (2021) (mono)	7232-8588	No information
Lindahl *et al.* (2021) (mono)	6690	540
Rodríguez-Gallegos *et al.* (2018)	No information	480

The inverters life time is between 10 and 15 years and thus it needs to be replaced at least once during the lifetime of a PV-system. The first major reinvestment is on average 540 NOK/kW_p for the six projects in Sweden according to Lindahl *et al.* (2021). This reinvestment mainly consists of inverters and five out of six projects planned this reinvestment after 15 years. Only one planned this investment after 25 years but this project had an expected life time of 45 years. Some of the projects planned this investment from the current prices of inverters while others used a lower price, considering that inverter prices will continue to fall. Rodríguez-Gallegos *et al.* (2018) estimates inverter prices in figure 13 after analysing different inverter suppliers. The authors estimated the price to around 480 NOK/kW_p in 2022, similar to the costs reported in Sweden lately (Lindahl et al., 2021).

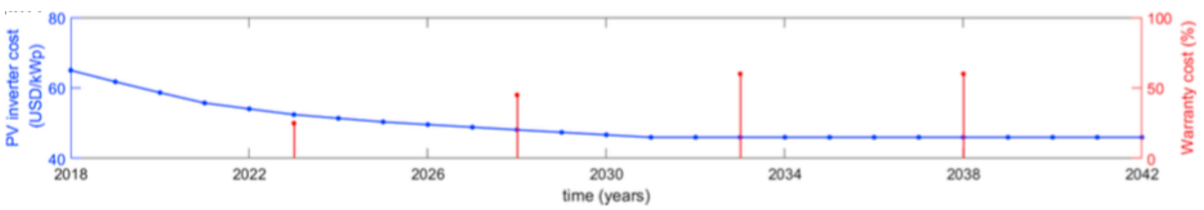

Figure 13. Acquisition cost of inverter [USD/kWp] (blue) and warranty cost of inverter [%] (red). Source: (Rodríguez-Gallegos et al., 2018).

It is common to use an inverter which is dimensioned slightly lower than the maximum output of the modules as inverters are expensive. This is because the cost saving of a smaller inverter is greater than loss of production. When the modules produce more electricity than what the inverter can handle then the production is limited by the inverter size, this is called clipping. However, for bifacial systems it is common to use a slightly oversized inverter to be able to handle the BG and Rodríguez-Gallegos *et al.* (2018) proposes an oversize factor of 1.2.

A common life time in LCOE-calculations of PV-projects is 30 years. This value stems from the warranty of, usually, 30 years that the producer puts on the modules (Hernández-Moro & Martínez-Duart, 2013; Lindahl et al., 2021). Five out of the six projects in Sweden had a lifetime of 30-45 years while one had a lifetime of only 20 years. This was due to limitations of land use and not technical degradation. Solgrid uses 40 years as life time in their concession application for a 7 MW bifacial PV-system in Norway (Solgrid, 2021)

2.9.3 Annual costs

A PV-power plant has no fuel cost but there are still some annual running costs to take into consideration. The following costs were all common for the six investigated projects in Sweden: "costs for electrical maintenance and production monitoring, site maintenance costs, administrative costs, physical monitoring costs, insurance costs, annual fixed grid costs, operation electricity costs, land leasing costs and property tax" (Lindahl et al., 2021).

All of these costs can be seen as operation and maintenance (O&M) costs, although land leasing costs are often omitted. Different papers include different cost items in their O&M costs which makes a straight comparison sometimes difficult. For example, some include grid fees and insurances while others do not (Lindahl et al., 2021). NVE estimates O&M-costs to 90 NOK/kW$_p$/year (NVE, 2022a). This is once again based on estimations from talking to the industry and not actual cost data from projects in Norway. This is in line with IRENA which also reports an average O&M cost of 90 NOK/kW$_p$/year for utility scale PV in Europe (IRENA, 2020b). Solgrid estimates their annual O&M costs to 2 % of the initial investment in their concessions application. This amounts to 110 NOK/kW$_p$/year and includes grid fees, other fees related to selling electricity, security systems, internal energy use as well as new inverters after 15-20 years (Solgrid, 2021). The average O&M costs of the six PV-power plants studied in Sweden were 81 NOK/kW$_p$/year which includes fixed grid costs and insurance (Lindahl et al., 2021). This is considerably lower than what has been reported in Germany in 2017 and the authors argue that either do the Swedish project owners underestimate their costs or the O&M costs have continued to decline after 2017, a trend that has been prominent the last decade. The O&M costs from the different sources are presented in table 5.

Table 5. Annual costs related to PV-projects. The annual cost is only made up of O&M.

Source	**O&M (NOK/kW$_p$/year)**
NVE (2022a)	90
IRENA (2020)	90
Solgrid (2021)	110 (incl. inverters)
Lindahl *et al.* (2021)	81

There are very few PV-system that have completed their life cycles and thus there are very little data on costs tied to decommissioning of PV-systems. Energiforsk (2021) investigated six projects in Sweden where five of them assume that the scrap value of cables, racking together with the increased value of land, where there is now a grid connection of high capacity, are equal to the cost of cleaning up the location. None of the six projects see any value in the modules after their life time. The residual value is thus zero for these project. The tax on sold electricity can also be seen as an annual cost. The tax rate is 22 % in Norway. However, the tax can be deducted through write-offs. That is, the loss in value of the PV-system can be withdrawn from the tax. It is not clear which deduction group that utility scale solar power belongs to but wind power belongs to deduction group D which means that the write off is 20 % per year during 10 years. Part of the construction tied to wind power, such as the tower and service buildings, are part of different deduction groups where different deductions rules apply (Skatteetaten, 2021).

2.9.4 Revenues

The revenues in equation 4 consist of electricity that is sold and fed into the grid as well as possible subsidies. The revenues are thus highly dependent on the electricity price. NVE predicts that the Norwegian electricity prices will become higher than what has been seen historically (Haukeli et al., 2021). This is driven by an increase in transmission capacity between the Nordic countries and the rest of Europe as well as a high price to emit CO_2. Electricity is fed from the southern parts of Norway and Sweden to European countries and high European prices pushes the prices up in these regions. The electricity price is lower in northern Norway compared to the south. The difference between north and south is expected to decrease in the future, although there will still be a difference (Haukeli et al., 2021)(Endresen Haukeli et al., 2020). The declining difference can be attributed to new electricity intense industry and electrification of the transport sector, as well as increased transmission capacity between north and south. Especially, the enhancement in capacity between the two electricity pricing areas SE2 and SE3 in Sweden will act as an equalizer of the north-south price difference in both Sweden and Norway. The installation of new renewable electricity production will lower the overall price from 2030 onwards. NVE did a prognosis in 2021 of future electricity prices for Norway, see figure 14 below. *Basis* is the baseline scenario and *Hoy* and *Lav* are connected to high or low estimates of future fuel and CO_2-prices.

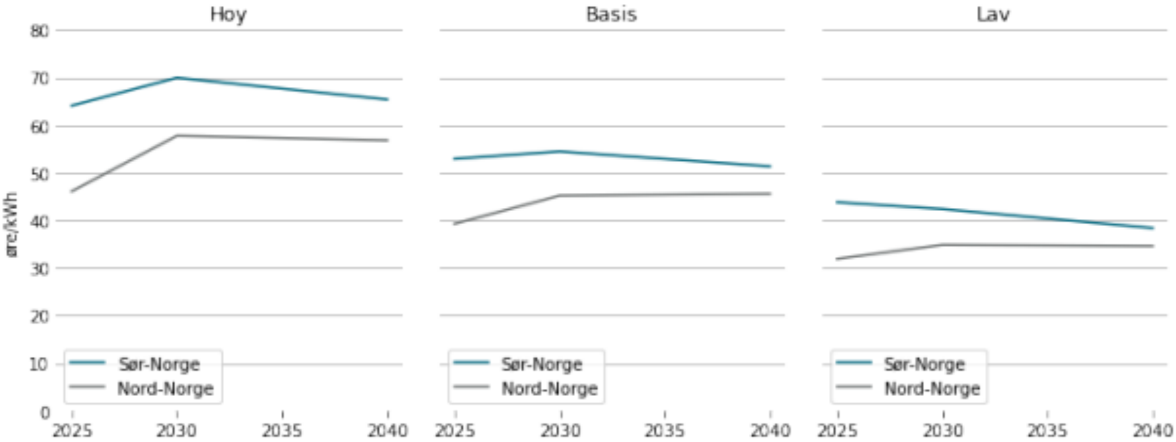

Figure 14. Prediction of electricity prices in south and north of Norway, represented by blue and grey line respectively. High, basis and low predictions. Estimate made by NVE in 2021. Source: (Haukeli et al., 2021).

The electricity use in Norway is predicted to increase from 138 TWh in 2019 to 174 TWh in 2040 according to NVE's baseline scenario (Haukeli et al., 2021). NVE estimates that the electricity price would go up with 10-13 NOK-øre/kWh if the electricity use would go up to 200 TWh by 2040, a 26 TWh increase from the baseline scenario. This is under the assumption that the production would remain unchanged from the baseline scenario. One factor that could increase the electricity use above the baseline scenario is if the plans to build electricity intensive battery factories becomes a reality.

An utility scale PV-park in Norway is not eligible to any subsidies, however, it can obtain revenues through the guarantee of origin (GO) system in Europe. Smaller PV-systems (<15kW) can apply for subsidies however (Norsk solenergiforening, 2022). Solar power used to be entitled to the green certificate scheme for renewable electricity production but this system has now been cancelled. The GO system in Europe is a certification trading system where the commodity is a certificate of produced renewable electricity. It gives the consumer the possibility to actively choose renewable electricity. However, it is only an accounting system and isn't connected to the physical delivery of electricity. Each GO represent 1 MW of produced electricity and wind, solar PV, hydro power, biomass and geothermal are included production types in the system. The GO system was enrolled as a part of EU's first Renewable electricity directive (2001/77/EC) in 2001 and Norway took part in the market 2006 in connection with the common energy market under the Agreement on the European Economic Area. Statnett is the issuing body of certificates in Norway (NVE, 2022). There were 1290 Norwegian power plants in the system by the end of 2018 and they issued 138 million GOs which is equal to 138 TWh. 20 TWh was sold which is equal to 14 % of the GOs issued. The analytic and counselling bureau Oslo Economics did a calculation in 2018 where they concluded that Norwegian producers receive between 600 million and 2 billion NOK yearly in revenue from the system (Andrews, 2020). The price of GOs are volatile and was historically high in 2018 when they sold for 9-23 NOK. The price was down to 4-5 NOK in 2019 and then back up to 7-8 NOK in 2020 (Lie, 2019). GOs sold for 9 NOK in late 2021 (Greenfact, 2021).

The aim of the GO system is to increase the viability of renewable energy projects. The consumer can benefit from the system in different ways. Utilities and power suppliers in Europe are required to show their energy sources and associated environmental impacts. GOs provide a simple measure to provide this information. Also, GOs give the suppliers a possibility to provide green tariffs and products to their customers. Another big buyer of GOs are companies who use the certificates to achieve their environmental commitments. A main aspect is that the company can claim null carbon impact in their carbon footprint report for the electricity used if they possess corresponding GOs. Also, they can buy certificates from a specific producer or location and thus use this in marketing (Track my Electricity, 2022). This gets accelerated by initiatives such as RE100 which is a corporate renewable energy initiative where companies commit to 100 % renewable electricity (RE100, 2022). This increases the demand for GOs both direct and indirect as these companies also demand 100 % renewable energy use by their subcontractors. RE100 included 152 companies and 184TWh by the end of 2018 (Tennbakk, 2019). The GO system is about to get enhanced as part of EU's "Fit for 55" plan. Although, Norway's recent government has stated that they want out of the system. This claim is part of their platform "Hurdalsplattformen" (Hurdalsplattformen, 2021). No decision has been made up to date however.

3 SIMULATION

This chapter provides a detailed walk-through of how the simulation was conducted. It starts with an explanation of the location which is followed by acquisition and processing of weather data. After this the simulation is explained which includes the optimization tool and a detailed explanation of some key user defined parameters.

3.1 LOCATION

Skibotn is a small community in northern Norway. It is situated at the end of Skibotndalen which is a valley that stretches from Skibotn to Kilpisjärvi in Finland. The main road E8 runs from Skibotn eastward into Finland. The pyranometer is located by Gálggojávri (Galgo lake) 503 m.a.s.l which is situated on the Norwegian side of the border, see figure 15. Weather data has been collected from the Finnish meteorological institutes (FMI) observation station in Kilpisjärvi, 10 km south east of Gálggojávri. FMI has two stations in Kilpisjärvi, one in the village 482 m.a.s.l and one on the mountain 1008 m.a.s.l. Data is collected from the one in the village since it is more representative for the location of the pyranometer.

Fig 15. Location of pyranometer and Killpisjärvi weather station. (Source: Google maps).

The landscape surrounding the pyranometer is made up of forest, lakes, moors and heathlands as shown in figure 16. The valley consists mainly of forest while moors and heathlands take over further up the mountain sides. Bare rock is dominant high up the mountains. The albedo around the pyranometer is estimated to 0.20 in summer time, using the values listed in table 2.

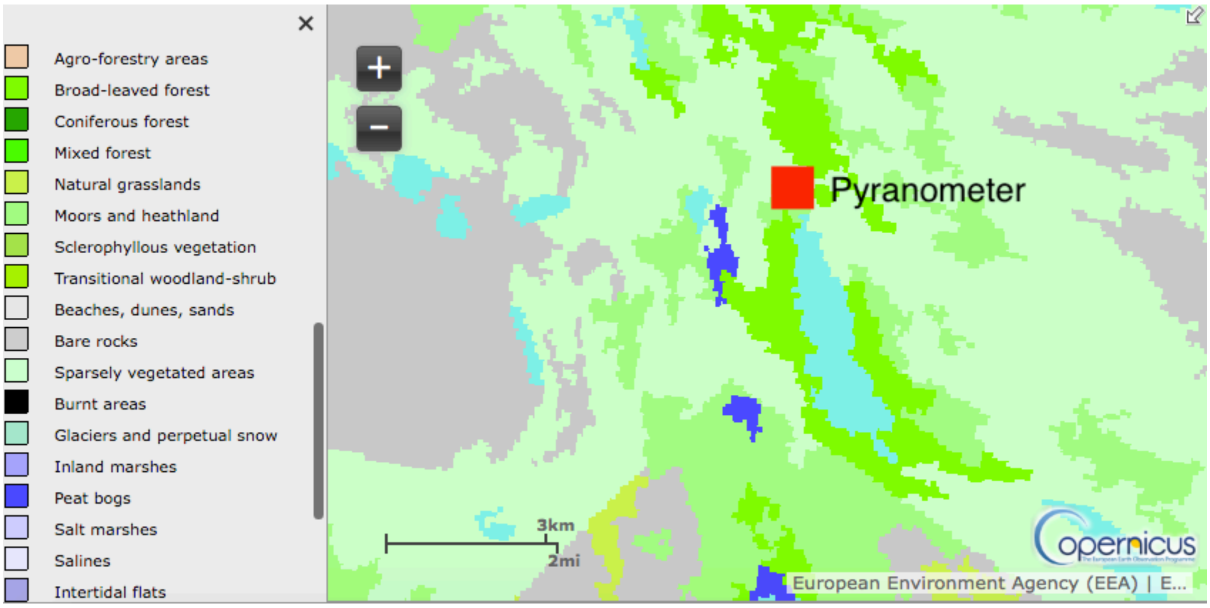

Figure 16. Vegetation types in Skibotndalen close to the pyranometer at Gálggojávri. The valley consist of forest, the mountainsides of moors and heatland and the top of the mountains of bare rock. Source: (Copernicus, 2018)

The area around Skibotn is one of Norway's driest areas with only 300 mm precipitation per year (Ovhed, 2016). This makes the area suitable for solar power and is why the pyranometer was placed in this area.

3.2 Irradiation data

Irradiation data was collected with a pyranometer located next to Gálggojávri, see figure 15, which uploads the data through a data logger connected to a GSM-modem (Ingebrigtsen, 2017). The sensor creates hourly averages from measurements every 10 seconds and has been collecting data for 5 full years between 2017-2021. The model is called *SP-230* and is a product of *Apogee Instruments*. It's a silicon cell sensor that measures both direct and diffuse shortwave radiation on a horizontal surface, so called global radiation. It's spectral range is 360nm – 1120nm which covers around 80 % of the total solar irradiation but the sensor is calibrated so that it estimates the total irradiation in the whole solar spectrum. The model has an inbuilt heater which minimizes errors from build-up of ice or snow and it is rated down to -40°C which makes it suitable for the cold environment in Skibotndalen (Apogee Instruments, 2021). The pyranometer should ideally be mounted true south as to minimize shading from the mast but due to restrictions from Vegvesenet is was mounted S-SE (Ingebrigtsen, 2017). This increases the shading slightly which reduces the risk of overestimating the irradiation. The mast with the pyranometer is shown in figure 17.

Figure 17. The pyranometer is mounted S-SE on the mast of Vegvesenet, next to Gálggojávri. The pyranometer is the black vertical cylinder on the right hand side of the mast. Source: (Boström, 2022a)

PVSyst requires monthly averages as input and these were calculated from the hourly averages obtained from the pyranometer. The data was checked for negative, missing or unrealistically large values. The dataset contained no negative values but there were missing logs from 11th – 31st of October 2017. No values were used from October 2017, instead the October average was calculated from the October values of 2018-2021.

3.3 WEATHER DATA

Weather data was gathered from the Finish meteorological institutes observation station in Kilpisjärvi 482 m.a.s.l. The station is located 10 km south east of the pyranometer, see figure 15, and it measures wind, humidity, visibility, cloud cover, pressure, and snow depth and the data is publicly available on FMI's website, www.fmi.fi. Snow depth data was acquired in order to estimate how long the ground is snow covered, something that is important for albedo estimations. Daily measurements are available and the first day of snow coverage was observed in the data, if there were any subsequent days without snow, then the date was pushed back with the same number of days. The same method, but opposite, was used when deciding snow disappearance date. The timeseries stretches back to 1990 and no missing data was observed. Monthly temperature averages was downloaded for the years 1990-2021. The only missing data is for January 1992. Average values were calculated for each month and put into PVSyst. Wind and humidity data was obtained for the years 1999-2020. In 1999-2006 the values are logged every 4th hour whereas there are values every 10 minutes between 2007-2020. There is lack of data between September – December 2011. Monthly averages for wind and humidity were calculated and put into PVSyst. No unrealistically large or negative values were found.

3.4 PVSYST SIMULATION

The PV simulation software PVSyst 7.2 is used in this study. The simulation model is described in detail in chapter 2.8. An overview of the program is as follows. The user starts the simulation by either choosing a predefined location or creating a new one, either from coordinates or from a map. A meteorological datafile is created, either manually or synthetically by the software. Then the system needs to be defined, this is where the modules and inverters are chosen as well as the design of the system. The orientation, azimuth and layout of rows are defined. It is now possible to run a simulation to get a first idea of the performance of the system. The user also has the possibility to go into the detailed losses and chose which loss-parameters that should be included and how much they contribute. It is possible to view the simulation results in a generic report. This includes a loss diagram which helps to point out large losses in the system (PVSyst, 2021). There are also many non-loss parameters that are user-defined when designing the system. One that is difficult to estimate but of particular importance, especially for bifacial systems, is albedo. Summer albedo is less challenging as it is decided by the landscape, winter albedo is more difficult since it depends on the characteristics of the snow, see chapter 2.6. Chapter 4.3.2 explains how these key parameters are chosen. The simulation in this paper is based on a synthetic meteorological datafile which is then modified with the following data: global horizontal irradiation (GHI), temperature, wind speed and humidity. This approach is recommended by PVSyst. The horizon is imported from the PV-GIS source in PVSyst and the simulation is carried out for the following seven systems:

- 10° inclination East and West facing monofacial PV modules
- 45° and 60° inclination south facing monofacial PV modules.
- 45° and 60° inclination south facing bifacial PV modules.
- Vertical South-North facing bifacial PV modules
- Vertical East-West facing bifacial PV modules

Note that in the first system half of the modules are facing east and half of the modules are facing west. PVSyst does not show the ground area of the system as an output. This can, however, be calculated by using the total module area and ground cover ratio (GCR) as follows:

$$Area(system) = \frac{Area(modules)}{GCR} \qquad (7)$$

The energy density can then be calculated by dividing the yearly yield by the area of the system. This does not consider roads or other service building, only the rows of module and the spacing in between. This is not a life cycle approach as only the land use of the system is included and not any land that is used in other phases of the life cycle. However, indirect land use due to manufacturing of modules and BOS are insignificant compared to the direct land use (Fthenakis & Kim, 2009).

Production data for wind power is included in this study to compare the production profile of wind power with solar power. Average monthly production values for wind power in NO4 for the years 2012-2021 was obtained from NVE's website (NVE, 2022c).

3.4.1 OPTIMIZATION OF PARAMETERS

PVSyst has an optimization tool in which the user can select one, two or three parameters to be changed independently. The optimization was carried out with bifacial modules to assist in the design of the system. The user sets an interval in which the selected parameters are to be changed, as well as the number of steps in the interval, where a simulation is carried out for each step. This renders a graph which illustrates how different sets of parameters result in different output values. The output value can be selected for a number of different parameters but the following optimization was only carried out with regard to yield. First the input parameters azimuth and tilt was optimized in the interval -15° to 15° and 35° to 60° respectively, with 10 steps in each interval. An energy output maximum was detected for azimuth -1.7 ° and tilt 43.3 °. Then another optimization was carried out for heigh above ground, pitch and tilt with intervals 0.5-5m (10 steps), 3-15m (10 steps) and 40-45° (5 steps) respectively. Pitch is defined as the distance from the front of a panel to the front of the panel in the row behind. The optimization shows that the produced electricity does not depend heavily on height above ground, as can be seen in figure 18. The increase in production is very slim for heights above 1.5m although the maxima is at 3.5m. The cost increases with height as fundaments and structures need to be more robust. However, if the modules are placed too close to the ground then they might be partly covered by snow which decreases the production substantially, see chapter 2.7. A height of 1.5 m will be used in the following simulations.

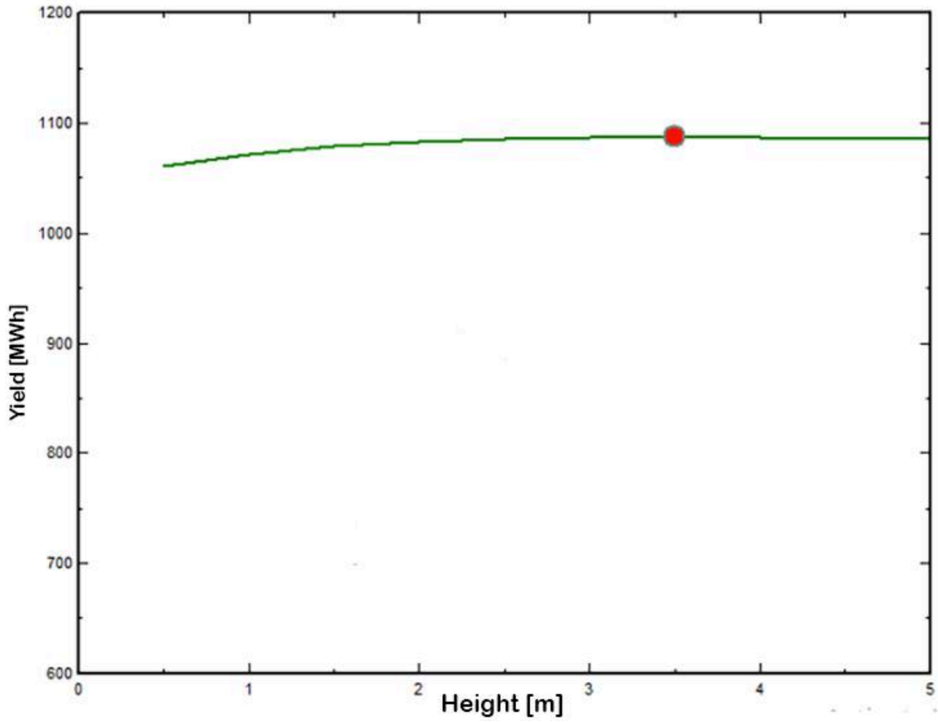

Figure 18. Electricity output as a function of height above ground. Pitch is 9.7m and tilt 43.75. Electricity production maxima of 1087 MWh for a height of 3.5m. Note that this optimization was not carried out with the final set of parameters which makes the energy yield not applicable to the final system.

The pitch is the distance between rows and its effect on yield can be seen in figure 19. The yield clearly increases with pitch although the trend is declining for larger pitches. This is because larger pitch means less shading from the panels in the row in front. The trade-off with pitch is higher yield versus land costs.

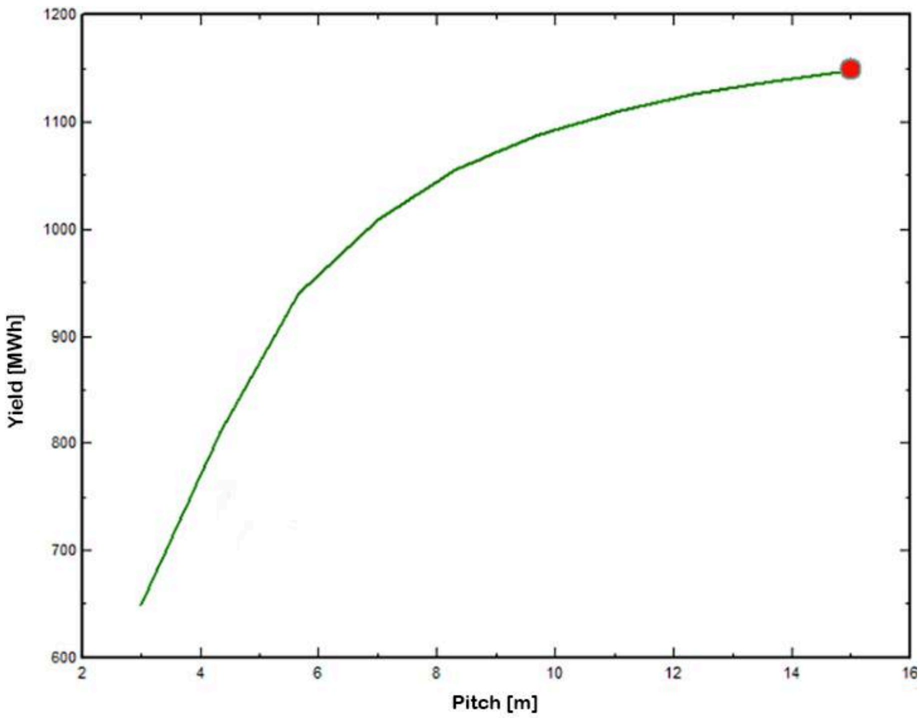

Figure 19. Energy output as a function of pitch. Tilt is 43.75° and height 3m. Maximum energy output is 1148.5 MWh/year for pitch 15. Note that this optimization was not carried out with the final set of parameters which makes the energy yield not applicable to the final system.

Solgrid states that they aim for 10 m as pitch in their proposed bifacial power plant in Stor-Elvdal (Solgrid, 2021). The same value is used in the following simulations, also considering that the increase in yield decreases for pitch above 10 m as is shown in figure 19.

The above optimization-simulations were carried out for 5 rows. This was changed to 30 rows because a 5 row system would become very long, 30 rows are more reasonable. The energy yield will decrease with increased rows because of more shading from other modules. With pitch set as 10m and height above ground to 1.5m the following simulations were carried out:

Table 6. These two simulations were not simulated with the final set of parameters which makes the yield not applicable to the final result.

Tilt	Azimuth	Yield
43.3°	-1.7°	891 kWh/kW$_p$/year
45°	0°	889 kWh/kW$_p$/year

This is in line with the result from the optimization tool which implied that tilt 43.3° and azimuth -1.7° would yield the highest energy output. The difference is so slim that the system with 45° tilt and 0° azimuth will be used in the following simulations. This is because it is a standard system that makes the result from this study readily comparable with other studies.

3.4.2 User defined parameters

The bifacial module used in the simulation is RSM144-6-420-BMDG which is a 420 W$_p$ bifacial perc monocrystalline solar module from Risen Energy, see figure A2 and A3 in appendix for more details. The bifaciality factor is 70 % for this module. The monofacial model used is RSM-144-6-420-M which is a 420 W$_p$ mono-crystalline module. The layout of the system is 30 rows with 79 modules in each, totalling 2375 modules. The snow loss values that are used in the construction industry are given for tilt between 25°- 40° in Tromsø, see chapter 2.7. However, Skibotn receives less precipitation than Tromsø and the modules are tilted 45°-60°, except for the 10° system, which means faster snow shedding and thus less soiling. In addition, these values are for monofacial modules and bifacial modules have been shown to shed snow faster as explained in chapter 2.7. It could therefore be argued that these values are a bit too high for this simulation. Also, a 2 % soiling value during summer can be seen as a conservative value. However, the supervisor in the project recommend using soiling values of 50 % for November-March (Boström, 2022b). Vertical modules have been shown to have less days of snow soiling compared to non-vertical modules, see chapter 2.7. No guiding values for snow soiling on vertical modules could be found in the literature. Instead a Swedish study performed at 65°N is used to estimate vertical values. This study is explained in chapter 2.7 where figure 10 shows that the vertical module had 20 days of snow soiling while modules with 25°-45° tilt had 33 days of coverage, a 39 % difference. The modified snow soiling values are thus scaled with this percentage to estimate values for the vertical modules. The snow soiling values are shown in table 7. The online tool http://snosolel.ri.se/, explained in chapter 2.7, could not produce values close to the site so no values were obtained from this tool.

Table 7. Soiling values [%] per month. The Standard values refer to tabulated values for Tromsø, used by construction industry. The modified values are values used after recommendations from Professor Tobias Boström who is involved in the project. Vertical values are estimated from a Swedish study and are applied for vertical systems.

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Okt**	**Nov**	**Dec**
Standard	25	25	25	25	2	2	2	2	2	10	15	20
Modified	50	50	50	25	2	2	2	2	2	10	50	50
Vertical	30	30	30	15	1.2	1.2	1.2	1.2	1.2	6.1	30	30

It is not a trivial task to choose inverters to a PV system. A too small inverter will not be able to transform all the electricity produced at high production times and this will be lost by so called clipping. An oversized inverter will on the other hand be expensive so there is a balance act to choose the right size and configuration. It is more important to avoid clipping than to cost optimize in this simulation and thus a generic 1000 kW-AC inverter was selected. It is slightly oversized according to PVSyst. However, Rodríguez-Gallegos *et al.* (2018) proposes using an oversized inverter when simulating bifacial modules so that the inverter can handle the bifacial gain. The inverter loss during operation amounts to 2.4 % which is assumed reasonable.

The shed transparent factor is 0 % which means that the simulation assumes that no irradiance passes through the row of modules and contributes to rear side irradiance through reflection on the ground. This is the predefined value in PVSyst and recommended except for systems with spacing in the row of modules. The rear shading factor determines how much of the backside irradiance that is blocked. This could be from the supporting structure etc. This is left at 5 % which is the predefined value.

4 Economic evaluation

The financial set up has impact on the cost of capital and thus also the LCOE and NPV, as stated in chapter 2.9. Two different set ups are used in order to investigate what the implications become for this project. In the first set up the entire initial invested capital is attributed to year 0, so there is no discounting of this cost. This is represented by I_0 in equation 3. The annual cost C_t consists only of O&M and real WACC is used as discount rate r. The real WACC used in these calculations is taken from six recent projects in Sweden. Lindahl *et al.* (2021) investigated costs related to these projects and found an average real WACC of 1.39 %.

The other financial set up consists of 40 % equity and 60 % debt, a common division for PV-projects, where the equity is attributed to year zero and the other debt are paybacks on the bank loan. The annual cost C_t then consist of both O&M as well as amortization and interest on the loan. The loan is assumed to be an annuity loan and the debt tenor in this study is set to 10 years. This parameter is highly project specific as every project has their own financial set up, Rodríguez-Gallegos *et al.* (2018) do however use 10 years as debt tenor when they estimate financial costs related to PV-projects. With an interest rate on debt and equity of 2.09 % and 4.72 % respectively then the nominal WACC is 2.88 % and the real WACC 0.85 % according to equation 5 and 6.

The cost of initial investment and O&M are gathered from Solgrids concession application (Solgrid, 2021).These values are most applicable to the project in this study as they are for a utility scale bifacial PV-system in Norway. Also, these values are very up to date. The parameters used in the calculations are shown in table 8 below. The O&M costs are claimed to be 2 %/year of initial investment in Solgrids concessions application, this is shown as NOK/year in the table.

Table 8. Economic parameters used in the economic calculations for two different financial set ups.

Parameter	**Financial set up 1**	**Financial set up 2**
Equity [%]	100	40
Debt [%]	0	60
Nominal WACC [%]	3.42	2.88
Real WACC [%]	1.39	0.85
Debt tenor	N.a.	10 years
Annual inflation rate [%]	2	
Corporate tax [%]	22	
Interest rate of debt financing [%]	2.09	
Interest rate of equity financing [%]	4.72	
CAPEX [MNOK/MW]	5.5	
O&M [NOK/year]	110 000	

Electricity prices used in the NPV-calculations in this study are based on a prognosis made by NVE in 2021, see figure 14 in chapter 2.9.4. Skibotn is located in north of Norway so the electricity prices used are represented by the grey line in the figure. Prices per year can be found in table A1 in appendix. These price projection only stretches to 2040, a constant value from 2040 to 2052 is therefore assumed. The price of GOs was set to 8.4 NOK as this was the most up to date price found. Degradation rate is set to 0.27 % according to the average from six recent PV-projects in Sweden (Lindahl et al., 2021). The calculations are carried out for life times of 30 year and 40 years. 30 years is a common value in PV-calculations, however 40 years is not uncommon in Nordic conditions and is what Solgrid uses in their concession application. LCOE and NVP was calculated with equation 3 and 4 respectively. It is not clear what tax deduction group that utility scale solar power belongs to. Since it has many similarities to wind power it was assumed to belong to deduction group D, where a majority of wind power installations belong. The write-offs are thus set to 20 % during 10 years. Past electricity prices were obtained from the electricity marketplace Nordpool (Nordpool, 2022).

5 RESULT OF SIMULATION AND ECONOMIC EVALUATION

This chapter includes weather- and irradiation data as well as the results from the simulations and the economic calculations. It also includes sensitivity analyses on some key parameters from the simulation and economic calculations. The LCA results are found in chapter 6.4.

5.1 WEATHER AND IRRADIATION

The mean start of snow cover is on October 17th and its disappearance on May 28th, which adds up to almost 6.5 months of snow. The albedo is estimated to 0.9 for November through March when there is heavy snowfall and 0.7 during April and May when more old snow is present, see chapter 2.6. Since the snow arrives in the middle of October the mean value of 0.2 and 0.9 was applied for this month. The albedo values are presented in table 9 together with the weather data gathered from the meterological station in Kilpisjärvi.

Table 9. Weather parameters used in simulation. Temperature, wind and humidity are gathered from the Finish meteorological institutes observation station in Kilpisjärvi. Albedo is estimated from snow depth data and vegetation maps.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Temp. [°C]	-12.4	-12.1	-8.7	-3.5	2.2	7.8	11.7	10.2	5.7	-0.5	-6.6	-10.0
Wind [m/s]	3.33	3.43	3.42	3.61	3.59	3.71	3.69	3.56	3.77	3.75	3.68	3.41
Relative humidity [%]	83.1	84.9	79.3	80.4	76.6	71.9	75.6	79.5	83.4	88.5	91.0	86.0
Albedo [-]	0.90	0.90	0.90	0.70	0.70	0.2	0.2	0.2	0.2	0.55	0.90	0.90

The highest measured value from the pyranometer was 1270 W/m^2 and is likely due to cloud enhancement, the highest hourly average was 875 W/m^2. Both values seem non-corrupt. PVSyst can create synthetic meteorological data from a chosen location that is then used in simulations. Monthly irradiation values from the pyranometer and PVSyst are presented in table 10. The irradiation values created by the program are 8 % lower than the measured values from the pyranometer, averaged over the whole year.

Table 10. Irradiation values from the pyranometer and from the synthetical meteorological weather file created by PVSyst. The pyranometer values are averaged over 2017-2021.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Pyranometer [W/m2]	1	20	81	169	224	221	196	128	69	22	3	0
PVSyst [W/m2]	0	17	71	149	193	204	182	130	70	24	3	0

The irradiance measured by the pyranometer is shown for each month of each year in figure 20, note the different unit compared to table 10.

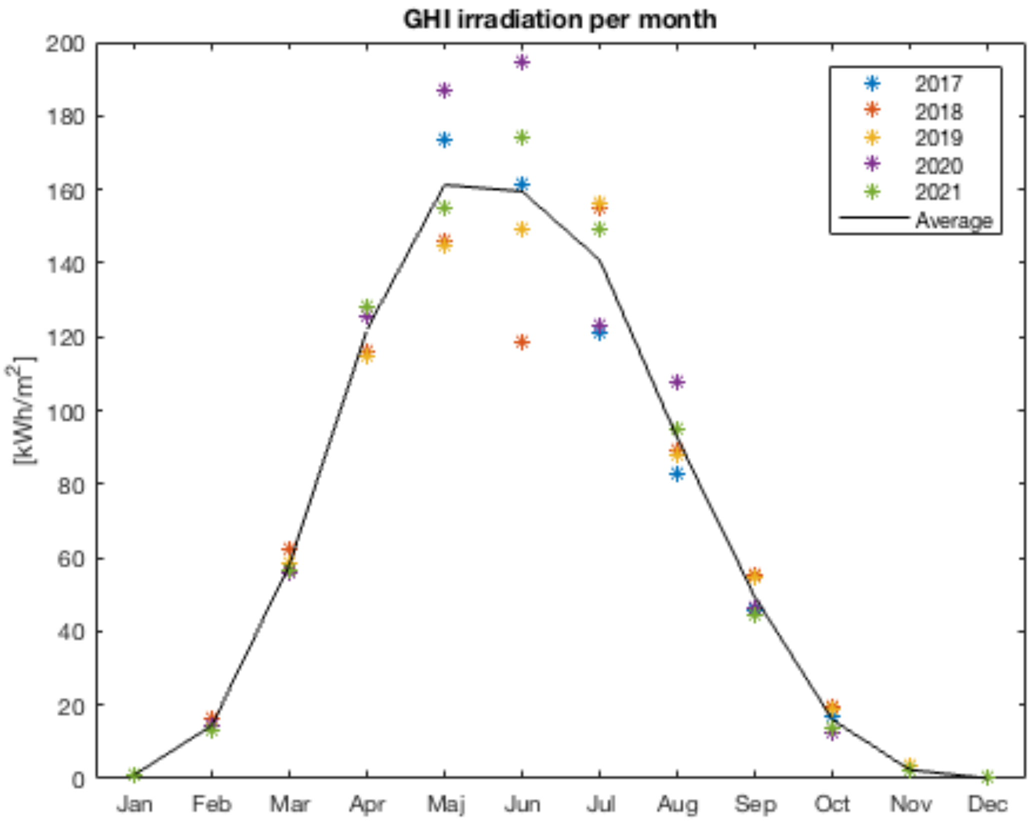

Figure 20. Global Horizontal Irradiance data gathered with a pyranometer at Gálggojávri between 2017-2021. Black line represent the average.

The yearly average GHI is 829 kWh/m^2. This can be compared to Stockholm and Oslo where the averages are 950 kWh/m^2 and 931 kWh/m^2 respectively (Vartiainen et al., 2015) (Sierra Rodriguez et al., 2020).

5.2 Simulated production

Bifacial systems have higher yields compared to monofacial systems as can be seen in figure 21. The BG's are 14 % for 45° tilt and 17 % for 60° tilt. The bifacial system with 45° tilt and facing true south has the highest yearly energy yield, followed by the bifacial 60° tilt system which is also facing true south. The vertical bifacial systems show similar yield independent of azimuth. The monofacial system of 10° tilt, facing East and West produce substantially lower than all other systems.

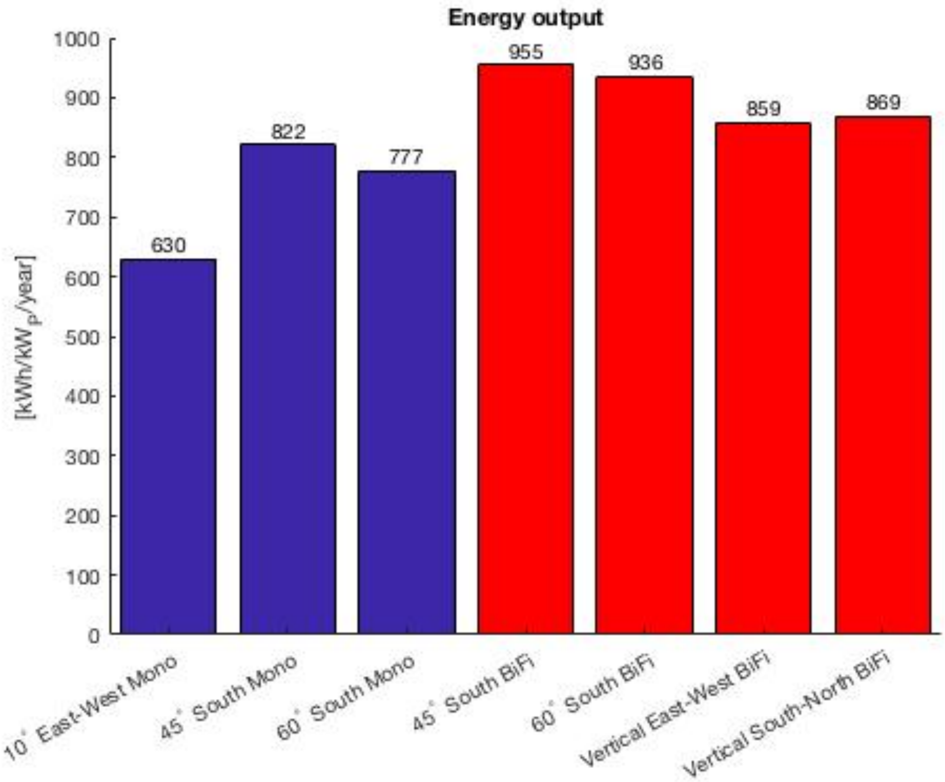

Figure 21. The energy yield for the different systems simulated in PVSyst. Blue bars for monofacial modules and red bars for bifacial modules.

The monthly yield for all systems are presented in figure 22. It can be seen that the vertical bifacial system facing South-North produces substantially more than all other system in February and March but less than all other bifacial systems during summer.

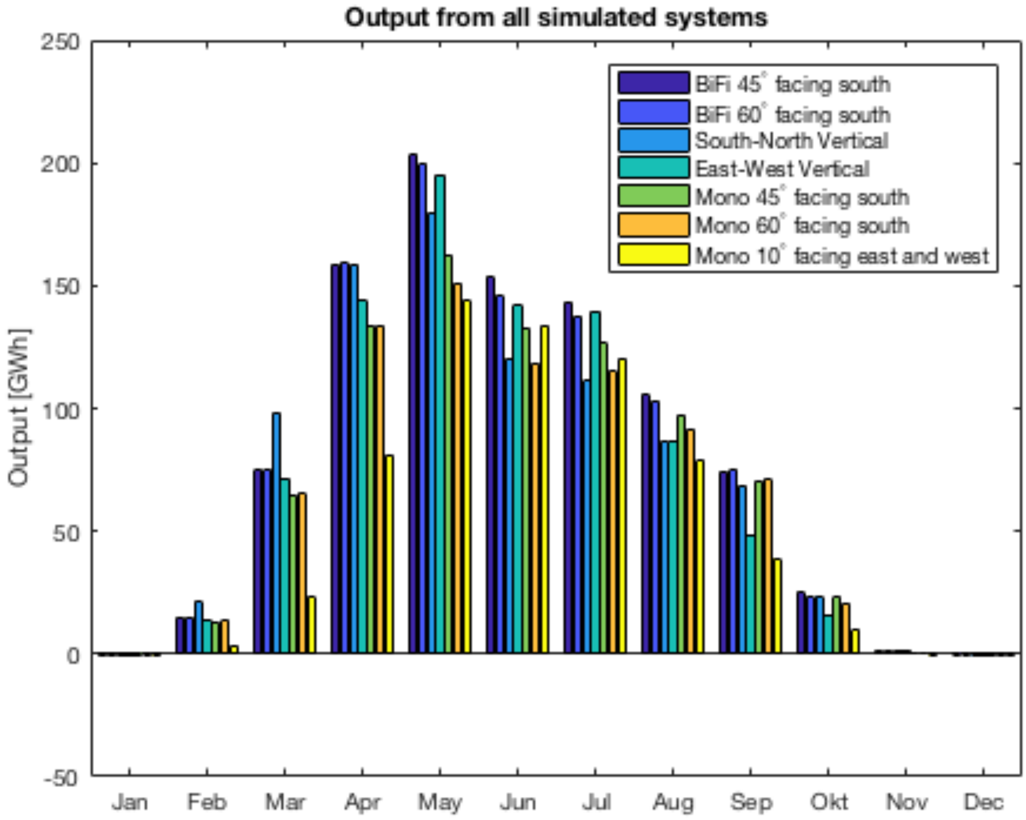

Figure 22. Monthly output values for all systems simulated in this study. BiFi and mono represent bifacial and monofacial systems. The vertical systems are bifacial. Negative values arise when the self-consumption of the system is higher than the yield. 1 GW systems simulated in PVSyst.

The daily production profile varies between the systems. Figure 23 illustrates the hourly mean values in June for all systems. The system with 45° tilt and facing south is the most productive one during this month as shown in figure 22. The vertical system that faces South-North has a similar daily production profile as the non-vertical systems facing south, with a distinct top on mid-day. However, this system shows slightly more production in the morning and evenings than the non-vertical systems. The vertical system facing East-West has a profoundly different production pattern than all other systems, with two distinct peaks in the morning and afternoon. The monofacial system with 10° tilt facing east and west has the smoothest production curve, however, the yield is substantially lower than the other systems as shown in figure 21.

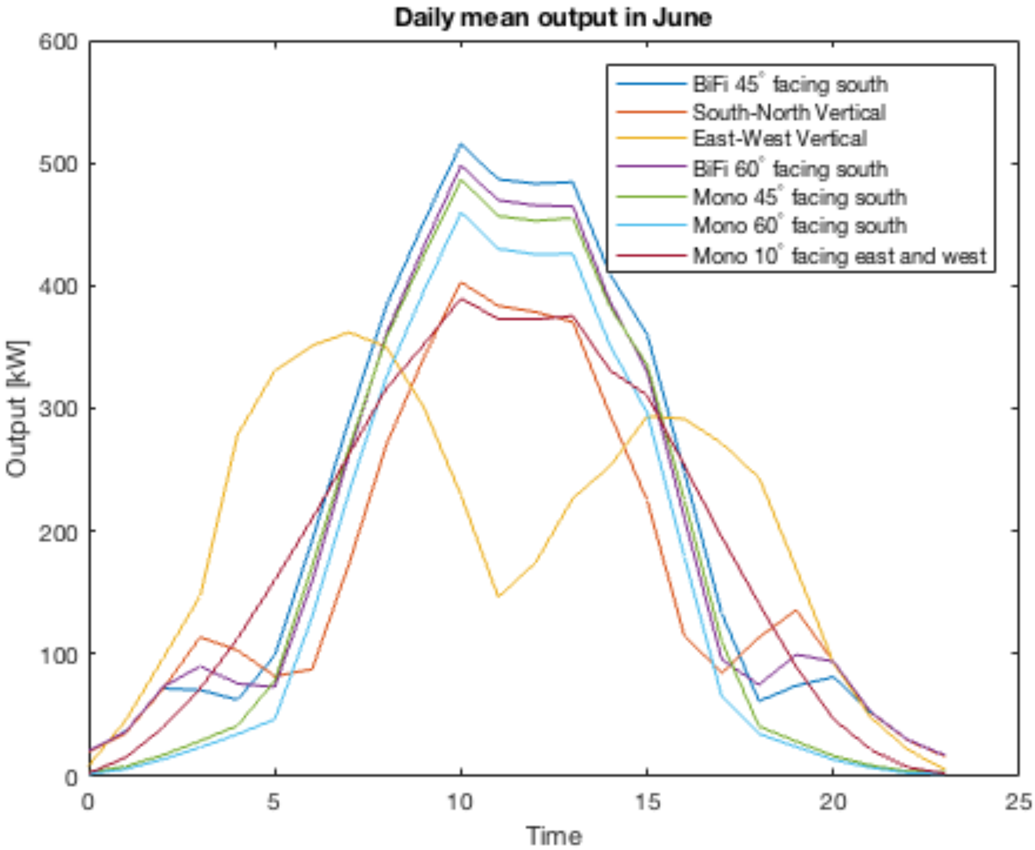

Figure 23. Daily mean output in June for all simulated systems. Each system simulated on 1 MW scale in PVSyst.

The energy density of the different systems are shown in figure 24. The energy density of the different systems follows the yield of the systems as they occupy the same area but have different yields. The area does not change with tilt as the pitch is defined as the length from the front of the row to the front of the row behind. The pitch is 10 m in the baseline scenario. The energy density increases when the pitch is changed to 7 m. However, the yield decreases as can be seen in figure 27 and 28.

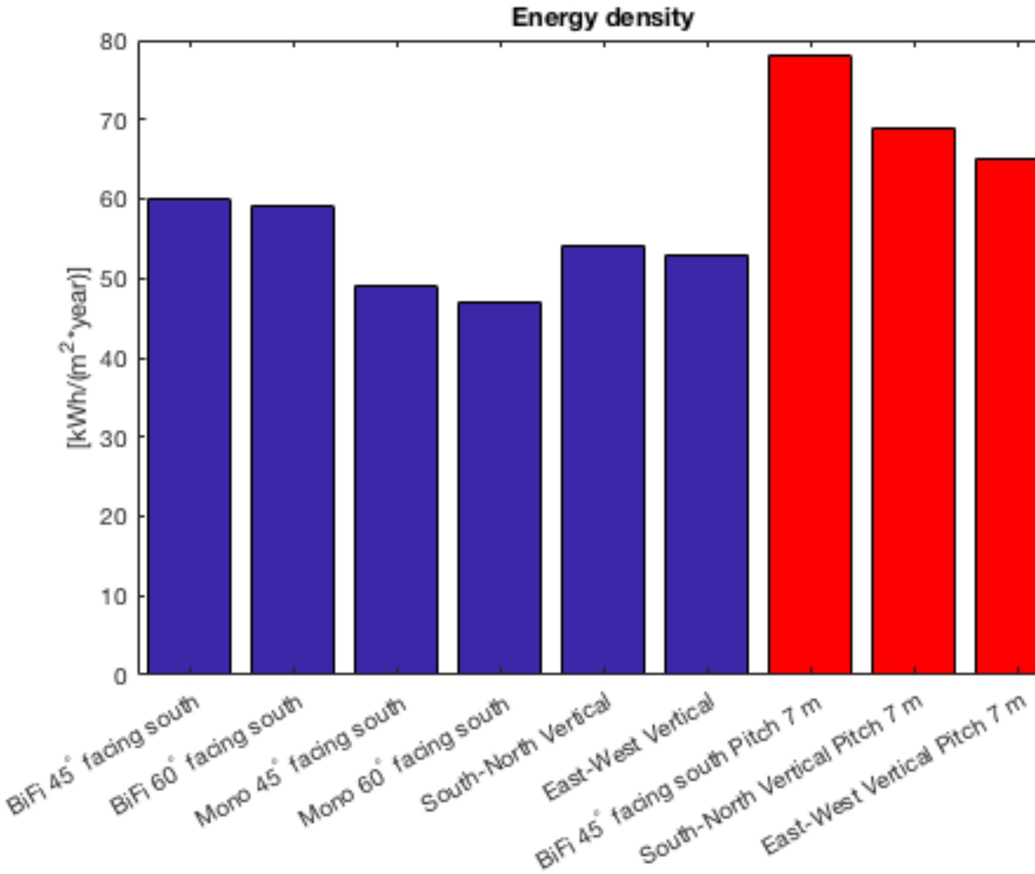

Figure 24. The energy density of different systems. The relative difference between the systems follow the yield of the systems as they occupy the same area. Shorter pitch increases the energy density but decreases the yield.

Figure 25 show the monthly production values for wind power in NO4 averaged over the past ten years. On top of this has the production profile of solar power in Gálggojávri been added, but scaled up to 100 MW of installed capacity.

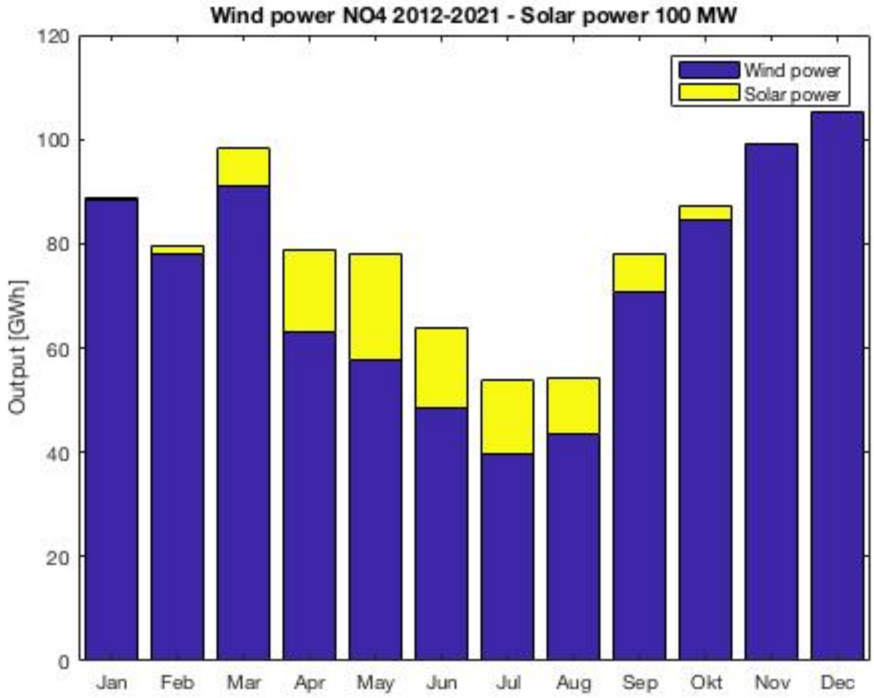

Figure 25. Average monthly production values for wind power in price area NO4 for the years 2012-2021. Solar power production profile is taken from simulation but scaled up to 100 MW of installed capacity. Bifacial PV-system facing true south with 45° tilt.

5.3 Economic evaluation

The first financial set up, without loans, has a LCOE of 36 NOK-øre/kWh and a NPV of 71 664 NOK. If all of the GOs that the projects generate are sold then the NVP would become 247 461 NOK, an increase in NVP of 175 797 NOK. The second set up, which is partly financed with loans, has a LCOE of 35 NOK-øre/kWh and a NPV of 259 620 NOK. If all of the GOs that the projects generate are sold then the NVP is 448 668 NOK, an increase in NVP with 189 048 NOK. These were calculated with a life time of 30 years. It is not uncommon to have a life time of 40 years in Nordic conditions so LCOE and NVP are also shown 40 years life times in table 11. The LCOE is lowered by 4 NOK-øre/kWh and 5 NOK-øre/kWh respectively for the two setups when the life time is increased. The table also includes a situation where CAPEX is lowered by 40 %, something that Swedish industry leaders think will become a reality within ten years, see chapter 2.9.2. This leads to a cost reduction of 9 NOK-øre/kWh and 10 NOK-øre/kWh for the two setups.

Table 11. Economic results for the two different financial set ups. Shown for life times of 30 and 40 years as well as a price reduction in CAPEX of 40 %. The first set up is without loans while the second set up is partly financed by loans.

	First set up	**Second set up**
Life time 30 years		
LCOE [NOK-øre/kWh]	36	35
NPV [NOK]	71 664	259 620
NPV incl. GO-revenue[NOK]	247 461	448 668
CAPEX -40 %		
LCOE [NOK-øre/kWh]	27	25
NPV [NOK]	2 271 664	2 549 384

NPV incl. GO-revenue[NOK]	2 447 461	2 738 432
Life time 40 years		
LCOE [NOK-øre/kWh]	32	30
NPV [NOK]	1 186 725	1 606 927
NPV incl. GO-revenue[NOK]	1 400 130	1 841 420

An investment is profitable if the LCOE is the same or less than the electricity price. Figure 26 shows the LCOE for the second set up in comparison with past and future electricity prices. The set up have a LCOE that is less than the projected electricity price in the baseline scenario. However, if the electricity price would be at a historical level also in the future, or in line with the low scenario, then the project would be unprofitable. If CAPEX would be 40 % lower than in the baseline scenario, or the life time 40 years, then the project would be profitable even if the price would be in accordance with NVE's low price prediction.

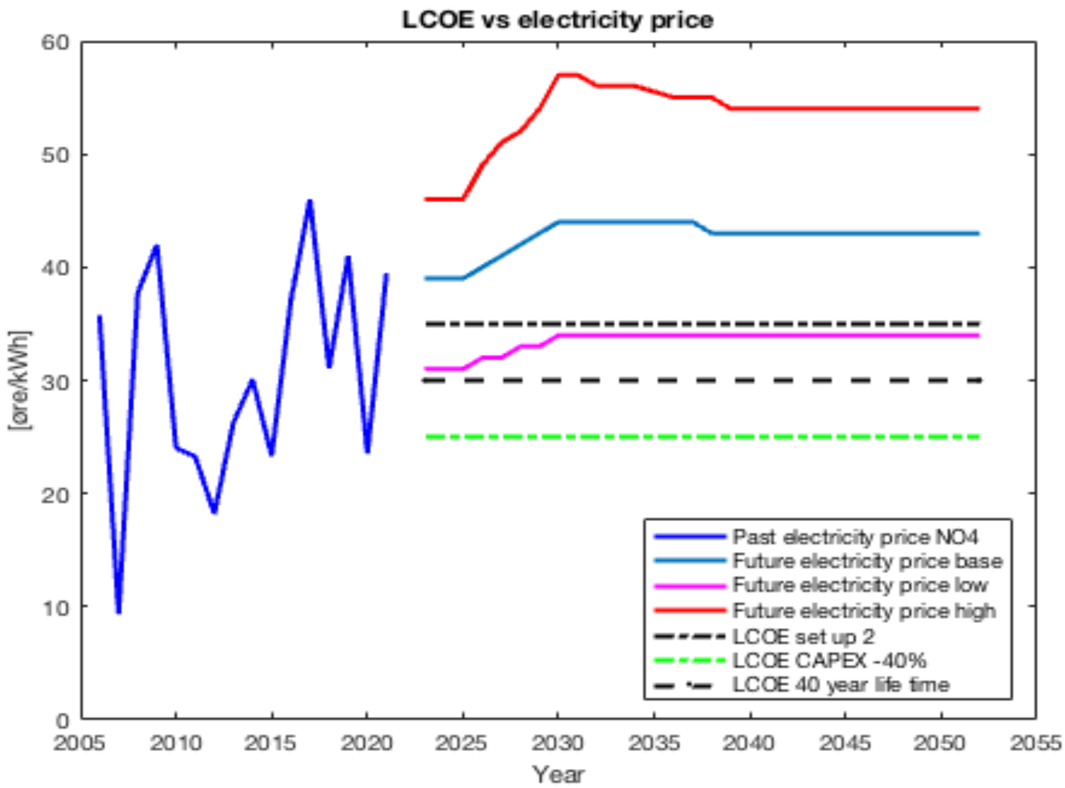

Figure 26. A comparison of LCOE for the financial set up 2 with past and future electricity prices. 40 year life time and -40 % CAPEX is shown for set up 2. Future price estimations by NVE for NO4 and past electricity price from Nordpool. Set up 2 is shown in full in table 8 in chapter 5.

5.4 Sensitivity analysis

Albedo and soiling loss, that is used in the simulations, has been pointed out in literature as particularly important but difficult to estimate. Hence these are included in the sensitivity analysis. The albedo value is changed with +/- 20 % for each month. The soiling values proposed for Tromsø in table 7 is also used instead of the modified values. Solar cells have a temperature dependence which is described in chapter 2.3. A temperature increase of 2°C has been included as to investigate how global warming could affect the yield. The pitch is also changed from 10 m to 7 m. The most important parameter in the LCOE calculations is the discount rate. A sensitivity analysis is therefore carried out on real WACC which is the discount rate used in this study. The vertical snow soiling values hold a lot of uncertainty, therefore a sensitivity analysis on the vertical systems are also included.

The sensitivity analysis is carried out for the baseline scenario, that is the bifacial system tilted 45°, facing true south with 30 year life time and 10 m pitch. All changes are relative to this scenario.

5.4.1 Simulation

The biggest difference came from changing the pitch, this resulted in a decrease in yield with -7.4 %, see figure 27. The changed soiling values resulted in a +4.3 % increase in energy yield. Changing the Albedo with +/- 20 % changed the energy yield with +1.9 % and -2.0 % respectively. A temperature increase of +2°C would lower the yield with -0.7 %.

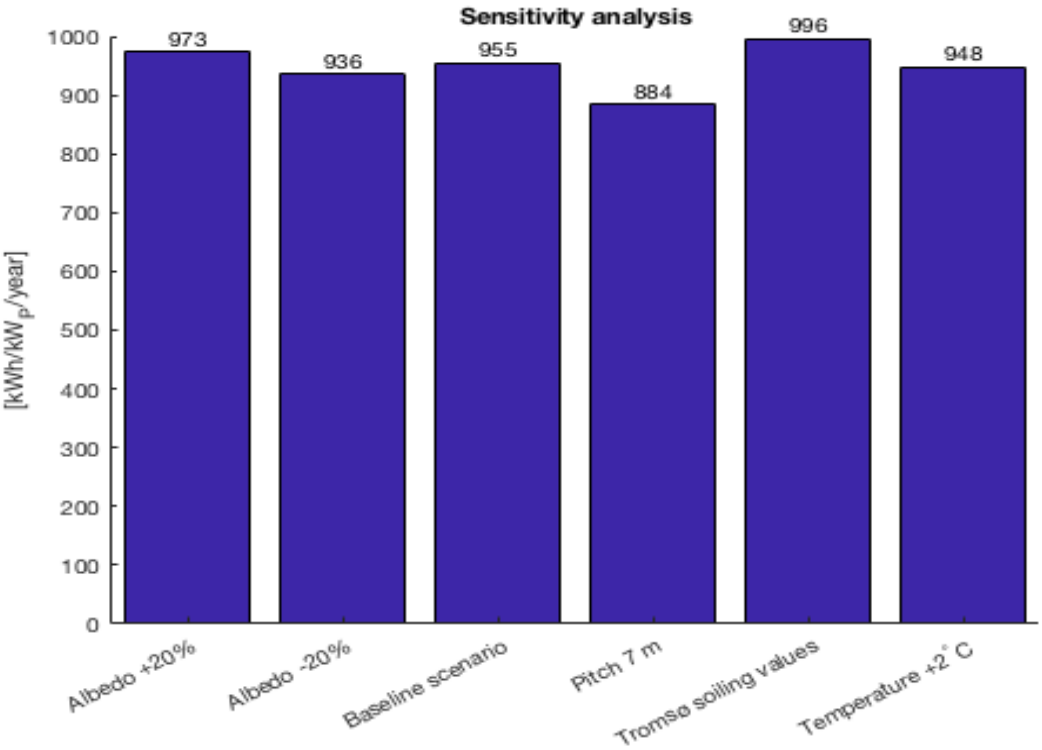

Figure 27. The result of the sensitivity analysis where yearly yield is output. Albedo has been adjusted with +/- 20 %, baseline scenario represent the unchanged system, pitch is changed to 7 m instead of 10 m, the soiling values from Tromsø has been applied instead of the modified values and the temperature have been increased with +2°C.

A sensitivity analysis of the two vertical systems is also included. The respective baseline scenario is compared to a change in pitch to 7 m and by applying zero soiling value. The change in pitch resulted in a decrease with -10.9 % and -14.2 %, while no soiling results in an increase with +8.2 % and +3.6 %, for the South-North and East-West facing system respectively, see figure 28. The East-West facing system is thus more sensitive to changes in pitch but gains less from no soiling. The South-North facing system produces more than the East-West facing system during the months of snow soiling, see figure 22. Hence the gain from no soiling is greater for this system.

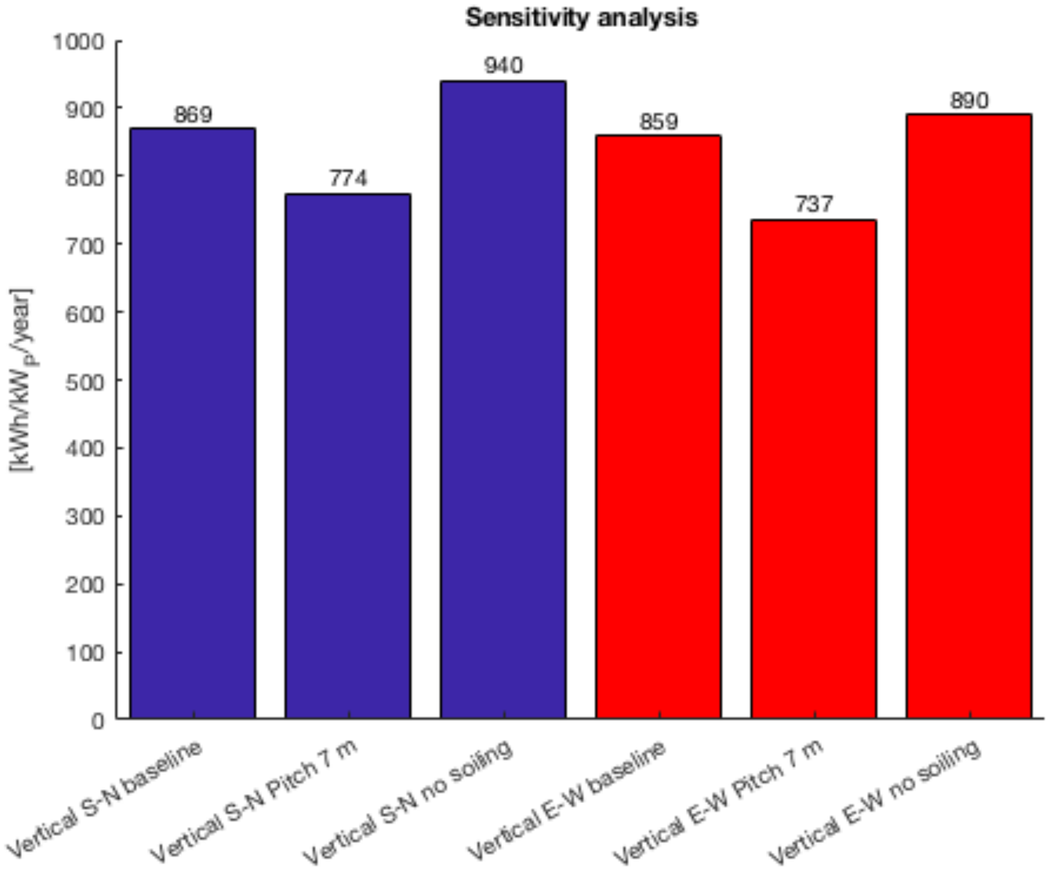

Figure 28. Sensitivity for the two bifacial vertical systems. S-N and E-W represent the system facing North-South and East-West respectively. Pitch has been changed from 10 m to 7 m and zero soiling values has been applied instead of the vertical soiling values.

5.4.2 LCOE

The most important parameter in LCOE calculations is the discount rate. Real WACC has been used as discount rate in this paper as it is common for companies to use this when investigating new projects. Figure 29 show how real WACC affects the LCOE for the two financial set ups. It is clear that set up 1, which is without loans, is more affected by real WACC than set up 2. The future electricity price predictions have been added in the figure for comparison purposes.

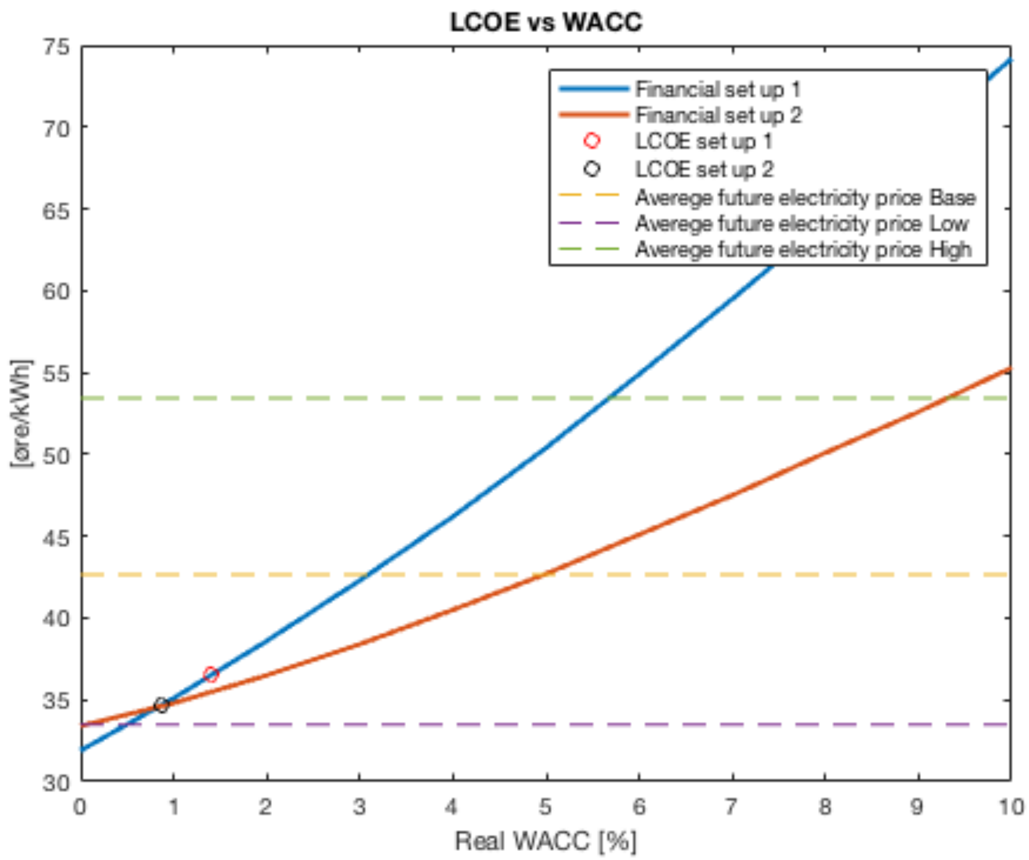

Figure 29. LCOE for the two financial set ups as a function of real WACC. The rings represent the LCOE for set up 1 and 2 and is based on the real WACC used in the economic calculations which is 1.39 % and 0.85 % respectively. The average future electricity prices for the NVE price scenarios Base, Low and High are also shown.

The real WACC used in the six Swedish projects varied from -1.23 % to 4.41 % and Rodríguez-Gallegos *et al.* (2018) uses a DR of 4.88 % in their calculation of PV in Norway. A real WACC of 6 % would equal a LCOE of 55 NOK-øre/kWh and 45 NOK-øre/kWh for set up 1 and 2 respectively. The averaged projected future electricity price in the baseline scenario is 43 NOK-øre/kWh which means that the projects are non-profitable with a real WACC of 6 %. A real WACC of 3.1 % or less would make set up 1 profitable and real WACC of less than 5.0 % would make set up 2 profitable.

6 CARBON FOOTPRINT

A goal of the overall report is to do a holistic evaluation of utility scale solar power in a location close to Skibotn. One part of this is looking at the carbon intensity of the electricity that such a system would produce. It is common to use a life cycle analysis when estimating green house gases (GHGs) connected to power production. It is therefore needed to conduct a LCA of solar power in Skibotn in order to be able to compare the carbon intensity of this electricity with other types of electricity production. A LCA study include all environmental impact that can be tied to the studied product during its entire life cycle, all the way from mining of the raw materials and manufacturing of intermediate products to use and disposal.

The LCA starts with the goal and scope of the study. It includes functional unit, system boundaries as well as the data used and its quality. This is followed by the life cycle inventory (LCI) where the data is gathered and recalculated to fit the study. The life cycle impact assessment (LCIA) explains how the results from the LCI translate into equivalents in the environmental impact categories. This is then followed by result, discussion and lastly conclusion.

6.1 GOAL AND SCOPE

This chapter will describe the goal, scope and system boundary of the study. The data sources will also be presented and their validity examined.

6.1.1 GOAL OF THE STUDY

The goal of this study is to assess the life cycle environmental impacts of the baseline scenario which is a 1 MW bifacial system with 45 degrees tilt and facing true south. This will be done for three cases. The first case is for module production in China since this is where 71 % of all modules were produced in 2019 (Masson and Kaizuka, 2020). The second and third case will investigate modules produced in a region with low carbon intense electricity, namely the EU and Norway. The goal is to investigate the different carbon footprint of the electricity produced for the different cases. A carbon comparison with other types of electricity production as well as the energy payback time of the system is also an end goal.

6.1.2 SCOPE OF THE STUDY

A full scale LCA-analysis is beyond the scope of this master thesis. Instead, an Environmental Product Declaration (EPD) for a module will be used and modified to fit the goal of this study.

This study includes extraction and processing of raw materials, production of intermediate products such as silicon wafers and chemicals as well as the production of the PV cells and modules. Transport of raw material and PV modules in China are included as well as transport from China to Skibotn in Norway. Construction, installation, operation and maintenance (including replacement of inverters) and end-of-life in Norway is included. The study is thus a cradle to grave study. A schematic illustration of the system boundaries is shown in figure 30.

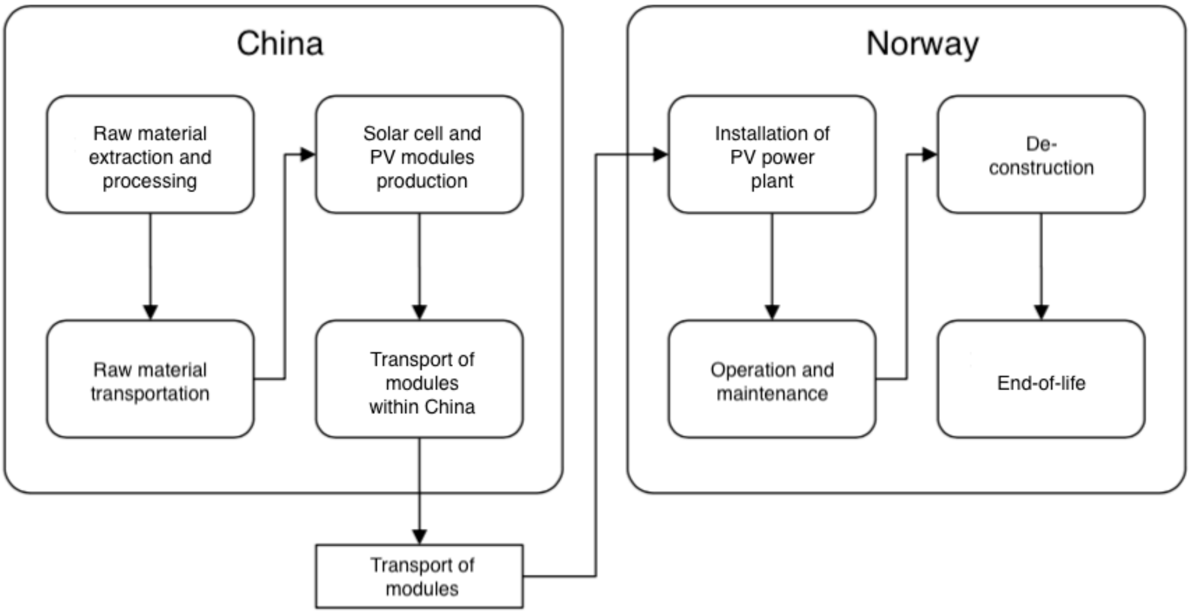

Figure 30. System boundary of the baseline case of this study where the modules are produced in China and placed in Norway. It includes production of PV modules in China and transport to, as well as use and end-of-life, in Norway. Source: (Self-produced figure, 2021)

The contribution to the impact categories climate change and energy use are included in this study.

6.1.3 Functional unit

The functional unit used in this study is *1 kWh of AC electricity supplied to the grid*. This is consistent with the functional unit of the EPD that is the main data source. Also this is what the International Energy Agency (IEA) recommends when comparing electricity-generating technologies, which this study aims to do (IEA, 2016).

6.1.4 System boundary

The International Energy Agency states that the following should be included in a LCA-analysis of PV modules (according to EN 15804 2013) (IEA, 2016):

- Raw material extraction
- Production of modules and all auxiliary products needed
- Transports
- Operation and maintenance (including repair and replacements)
- Deconstruction, recycling and disposal

The scope of this study has been chosen to match these guidelines, se figure 30 above. The system of this analysis is divided into three stages: Upstream, Core and Downstream. Figure 31 show which processes that are included in each stage. For clarification it can be noted that process A:5 in figure 31 include construction of foundation, structures and fences as well as installation of the modules together with auxiliary components such as inverters and cabling. The Upstream stage is located in China while the Core and Downstream stage takes place in Norway. This study also includes transportation between China and Norway between the Upstream and Core stages.

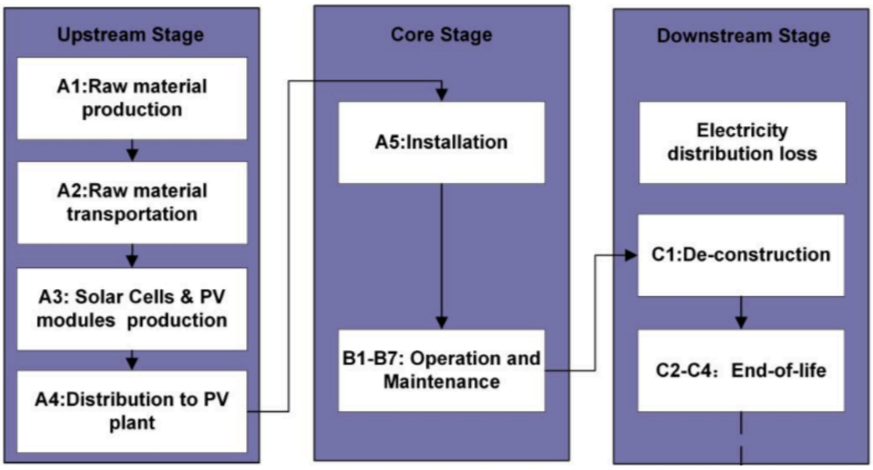

Figure 31. A schematic illustration of the three stages of the study: Upstream, Core and Downstream. The environmental impact is stated for each of these stages. The Upstream processes takes place in China while the Core and Downstream processes takes place in Norway. Source: (EPD International AB, 2021).

6.1.5 Data Sources and Modelling

An EPD from Risen Energy Co., Ltd supplies data for all these stages which is then modified to fit the system in this study. The PV module in the EPD is a bifacial dual-glass monocrystalline silicon module with nominal power of 450W$_p$ (EPD International AB, 2021). The production takes place in Risen Energy's factory located in Changzhou (Jiangsu province) in China. The EPD is the main data source in this study and publicly available on the EPD-database Environdec.com. The EPD is for a 100MW power plant located in China where it is thought to be made up by the above mentioned modules. The energy yield is simulated in PVSyst while the environmental impact for the Core stage is gathered from an actual 100MW power plant in China. This data were gathered in 2020. Their generic data, including material, energy and waste disposal are gathered from the LCI-database EcoInvent 3.4. Energy and material mix data is coming from adapted Chinese local LCI data. Risen Energy has performed their own inventory over material use and energy fluxes and the LCA-tool SimaPro 9.1 has been used to calculate the environmental impacts. The cut-off criteria was set to 1 % of mass flow. Allocation has been carried out by mass for multi-input and -output processes and there are no by-products that need to be allocated. For a detailed process description, see EPD International AB, (2021). Every EPD is controlled by an authorized third party and thus this data is validated that way.

The LCA-database Ecoinvent 3.8 was used to gather data over grid mixes and other types of electricity production. EPDs on Environdec's website were also used to get additional data on other types of electricity production. Both of these platforms provide reliable and controlled data. However, the temporal, geographical and technical validity need to be up to date as the field of energy production is under constant development, especially for the newer technologies such as wind and solar. All data that is gathered from Ecoinvent is allocated at the point of substitution.

No up to date LCA-data could be found for the Chinese grid mix or for module production in a region with a low-carbon grid mix, so a couple of articles have been used as sources of data instead. The Chinese grid mix data is gathered from the article *China's electricity emission* *intensity in 2020 – an analysis at provincial level* which was published in *Energy Procedia* in 2017. It is not an LCA-analysis but rather an article that uses LCA-data to do predictions on the environmental impact of the Chinese electricity production in the future (Li et al., 2017). The other article that is used to simulate production of modules in a country with low-carbon electricity is *A comparative life cycle assessment of silicon PV modules: Impact of module design, manufacturing location and inventory* which was published in *Solar Energy Materials and Solar Cells* in 2021. It is a comparative LCA-analysis which strives to use the most up to date inventory data (Müller et al., 2021).

The PVSyst simulation in chapter 3 is used to estimate the yield when the modules are located in Skibotn. The online tool NTMCalc Basic 4.0 is used to calculate environmental impact during the transport stage. A detailed description of transport follows in chapter 6.2.3.

6.1.6 Geographical, Temporal and Technical Validity

In order to make any conclusion from an LCA-analysis it is important that the ingoing data is of good quality and coverage. The criteria used are often geographical, temporal and technical and all of these should be fulfilled. China has been selected as the country of production to fulfil geographical validity as this is where the majority of the worlds module production takes place. All of the geographical whereabouts of the module has been covered through transport and usage in Norway. Corresponding electricity mixes have always been used.
As for the temporal validity it is a little more complicated as it is difficult to find up to date data of electricity mixes. Data from an article has been used instead of applying 10 year old LCA-data for the Chinese electricity mix. No data is older than 10 years, where most data is less than five years old, and the age of the data is clearly communicated in text and figures. The technical validity is difficult to conclude. Since all data, apart from the two articles used, are from Ecoinvent and Environdec it can be assumed that the technical standard is okay. Especially since no data is more than 10 years.

6.2 Life Cycle Inventory (LCI)

This chapter will treat the inventory of the solar modules life cycle and how these have been calculated. The model used in the simulation in this paper is RSM144-6-420-BMDG which is a 420 W_p bifacial perc monocrystalline solar module from Risen Energy. There are no available LCA-data for this product, instead data from RSM144-7-XXX-BMDG will be used since there is an available EPD for this model. This product is the succeeding model from the same manufacturer and has the same specifications apart from slightly higher W_p, 435-455 W_p instead of 395-420 W_p. It is also slightly heavier and larger, see figure A1 and A2 in Appendix for details. Temperature and maximum ratings are identical, see figure A3 in Appendix. The efficiency of the previous 420 W_p model is 20.6 % while its 20.2 % for the later 450 W_p model. The conclusion is that the environmental impacts from these models can be assumed equal.

This chapter will start by deciding the carbon intensity of the grid mixes for the different regions. These will be used when recalculating the emissions when the modules are installed, used and disposed of in Skibotn instead of China. This will be done for the three stages: Upstream, Core and Downstream. Then a detailed description of transport will follow. The chapter is ended by examining how module production in Europe and Norway would affect the emissions as well as listing other electricity production types used in the comparative analysis.

6.2.1 Electricity carbon intensity

The electricity mix in Norway emits 0.0216 kg CO2-Eq/kWh for medium voltage production according to Ecoinvent 3.8. This data is from the year 2017 but has been extrapolated to 2021. The most up to date data in Ecoinvent for Chinese grid mix is from 2012, where the average value is 1.023 kg CO2-eq./kWh (Müller et al., 2021). An un-dated document in Ecoinvent states that the production mix in the province Xinjiang emits 1.13 kg CO2-eq./kWh, it is in this province that the modules are produced. This is for high voltage production however, not medium voltage. More recent numbers can be found in Li, Chalvatzis and Pappas (2017) LCA-study where they estimate the carbon intensity for each province in China by 2020. They estimated the carbon intensity of the electricity mix in Xinjang to be 0.92 – 1.0 kg CO2-eq./kWh. A common practice in LCA methodology is to never underestimate the environmental impact of the studied product. Hence the lowest value of 0.92 kg CO2- eq./kWh will be used in the calculations. This might seem contradictory but the lowest value here will render the highest carbon footprint for the module in Norway, as will be clear in chapter 6.2.2 below. The carbon intensity is thus 43 times higher in Xinjiang compared to the average Norwegian grid mix. The European grid mix emits 0.388 kg CO2- eq./kWh according to Ecoinvent 3.8. This is excluding Switzerland and the data is from 2015 but extrapolated to 2021. The carbon intensity of the grid mixes are presented in table 12.

Table 12. The carbon intensity of the grid mixes used in this paper.

Region	Norway	EU (excl. Switzerland)	China (Xinjiang)
g CO2- eq./kWh	21.6	388	920

6.2.2 Upstream, Core and Downstream stage

This chapter will explain in detail how the emissions from the EPD are recalculated to fit the system of this study. In short, this is done by scaling the different stages with the difference in energy yield and carbon content of the electricity mixes for Norway and China.

The carbon emissions in the EPD are calculated for module production in China and the results are presented in figure 32. It is clear that the Upstream stage is responsible for a majority of the carbon emission as it is attributed 80 % of the total emission.

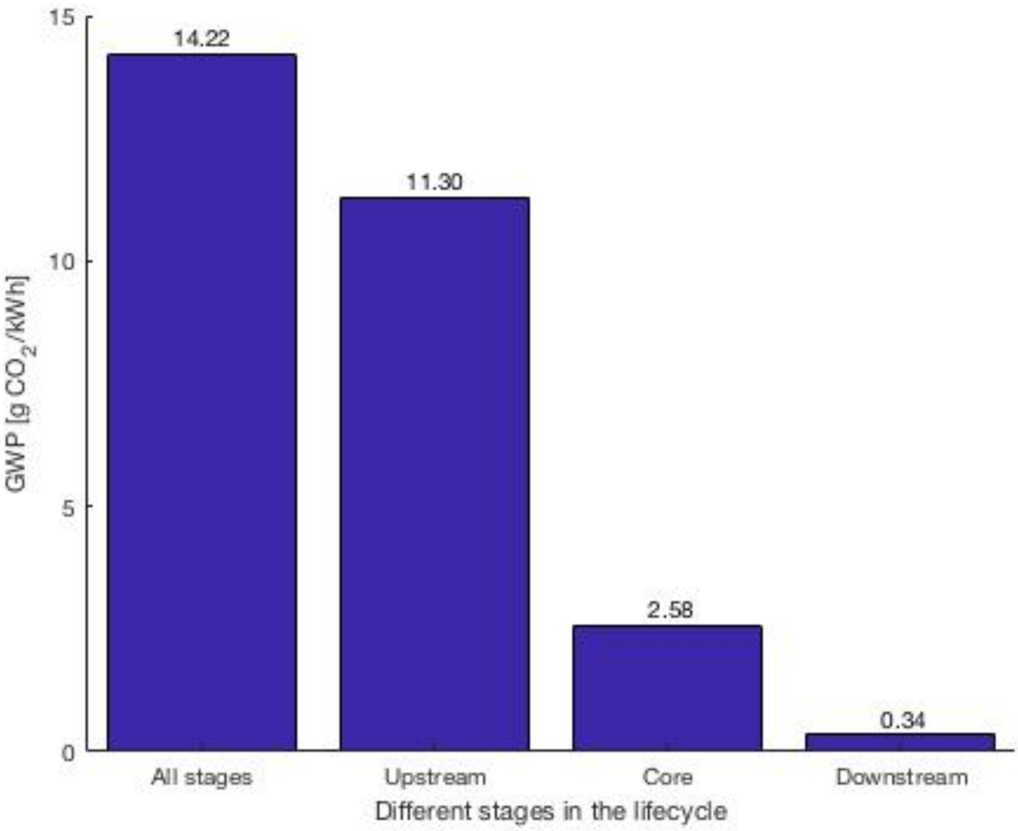

Figure 32. Emission tied to the three different stages in the modules life cycle. The data is gathered directly from the module EPD and is valid for the Chinese PV-plant in the EPD. Source: (EPD International AB, 2021)

The carbon emission in the EPD is given in CO_2-eq./kWh in the EPD. If the modules are produced in China but installed in Norway, then there is a need to scale the environmental impact up since the modules will produce less kWh in Skibotn compared to China but still emit the same amount of CO_2-eq during production. The scale factor is 0.48 and calculated as the ratio of produced energy in Skibotn compared to the Chinese PV power plant. These number are taken from the PVSyst simulation result in chapter 5.2 and EPD respectively. The scaling applies to energy use for all three stages following the same reasoning.

The conditions in Norway also differ from the ones in China regarding the carbon intensity of the electricity grid mix. This affects the Core and Downstream stage as they take place in Norway. The Core stage is made up of the construction, installation and O&M of the power plant. The installation and O&M consume mainly electricity according to the EPD, no information regarding the construction phase is given. It is therefore assumed that 50 % of the GWP from this stage stems from electricity use and this half is scaled with the ratio of carbon intensity from the electricity mixes. The ratio is 43 as explained in chapter 6.2.1. If a higher value of the carbon content of the Chinese grid mix would have been used then the ratio would have been greater. That is why the lower value is chosen, as not to scale the emission too much. The same scaling is applied to the Downstream stage where 50 % of the GWP from this stage is assumed to stem from electricity use. The EPD states that the deconstruction and demolition is powered by electricity but that this stage also includes a 100km transport from the PV site to the waste treatment site as well as disposal of used modules. The uncertainty of these assumptions will be delt with in the discussion. This scaling applies to GWP but also energy use since it is assumed that energy use is connected to burning of fossil fuels in the electricity production.

6.2.3 TRANSPORT

The EPD includes a transport of 100km out of the factory in the Upstream stage, denoted A4 in figure 31. The distance between the factory and the Beijing harbour is 185 km but the emission of the extra 85 km is seen as negligible in this study. The modules are transported by container cargo ship from the harbour to Amsterdam in the Netherlands. The route is assumed to go through the Suez channel since this is the most common way for cargo ships between China and Europe. The transport from Amsterdam to Skibotn is carried out on a truck with a trailer of 28-34 tonne. The calculations are carried out with NTMCalc Basic 4.0 where only module weight, not shipment size, is used as a parameter (*NTMCalc 4.0*, 2022). This is consistent with the modelling approach in Ecoinvent (Müller et al., 2021). The program allocates environmental impact by weight according to:

$$allocation\ factor = \frac{product\ weight}{cargo\ carrier\ capacity * cargo\ capacity\ factor} \tag{8}$$

If the product is of low density then the allocation can be too low using the above allocation factor. The modules have a density of 433 kg/m^3 which is assumed to be a relatively high density compared to other products on the cargo ship. The allocation by mass is thus considered not to attribute the modules with too little environmental impact. The same allocation method is applied in the transport with truck. The distances and corresponding environmental impact is shown in table 13.

Table 13. Environmental impact from transportation per module. Calculated with NTMCalc Basic v4.0.

	Route	**Transportation type**	**Distance (km)**	**Emission (kg CO2-eq)**	**Total energy (MJ)**
	Beijing - Amsterdam	Container ship	21495	18.75	240.3
	Amsterdam - Skibotn	Truck with trailer 28-34 tonne	3006	7.20	105.8
Total				25.95	346.1
Total per kWh				2.33E-03	3.11E-02

6.2.4 MODULE PRODUCTION IN EUROPE OR NORWAY

This chapter explains in detail how the environmental impact of module production in Europe and Norway is estimated using electricity mixes and the emission data from the EPD.

There is no available LCA-data on the Environdec or Ecoinvent databases for modules produced in a country with a low-carbon grid mix. No usable LCA-data could be found using google, google scholar or LUB Search either. However, using the LCA-study made by Müller *et al.* (2021) it is possible to make a rough estimation. They found that 52-69 % of the GHG emissions from module production in China stem from the electricity use. These numbers include production, transport and EoL of the module but exclude BOS, installation and operation. BOS are all the auxiliary products needed to produce electricity such as structures, inverters and cabling. No data of how much of GHGs that is attributed to BOS could be found. Instead it is assumed that 80 % of the emission in the Upstream stage is attributed to production of the module, the rest in attributed production of BOS. This is not including structures however, as this is included in the Core stage in the EPD. This is a rough assumption which brings uncertainty into the result. From the interval proposed by Müller *et al.* (2021) it is assumed that 60 % of the GHGs from the production of modules stems from electricity use. If the production would be placed in Europe or Norway it is possible to use the carbon intensity of these electricity mixes to estimate the change in overall GWP. It is assumed that BOS would be responsible for the same amount of GWP even though the production of modules takes place outside of China. The transport is set from China to Skibotn even though the production takes place in Europe or Norway as the raw material is likely to be produced in China. The method of re-calculating emissions through region specific electricity mixes is nothing new but rather a common practice in LCA-applications. It is used by Itten *et al.* (2015) and Müller *et al.* (2021) amongst others.

6.2.5 Other types of electricity production

In order to put the results of this study into perspective it is needed to find comparable data. These should be of cradle-to-grave type since this is what is performed in this study. Two sources were used to find reliable data, Ecoinvent and Environdec, and the result is presented in table 14. Both of these sources provide reliable and controlled cradle-to-grave data.

Table 14. GWP for different electricity production types. All are cradle-to-grave type with 1 *kWh supplied to the grid* as functional unit. Sources: Ecoinvent 3.8 and Environdec.

Type	**GWP [g CO_2/kWh]**	**Year**	**Location**	**Source**
Hydro reservoir	6.29	2012	Norway	Ecoinvent
Wind onshore <1 MW	13.9	2012	Norway	Ecoinvent
Wind onshore >3 MW	23.9	2012	Norway	Ecoinvent
Wind onshore 4.5MW	7.3	2019	Europe	Environdec (EPD)
Wind mixed	15.6	2022	Northern Europe	Environdec (EPD)

6.3 Life Cycle Impact Assessment (LCIA)

The impact categories chosen are based on the goal of the study. The aim is not to evaluate all present environmental impact but rather to evaluate carbon intensity and energy payback time. Categories such as acidification and toxic substances will thus be left out of this study.

The following impact categories are evaluated in this study:

- Climate change
- Energy use

The following indicators are used:

- Greenhouse gas emissions (kg CO_2-eq.) are assessed using their 100 year global warming potentials (GWP). This indicator aggregates greenhouse gases emitted and express them in CO_2-eq. based on their contribution to the greenhouse effect. Since the LCI-results are given in GWP there is no need to convert these result.
- The total energy payback time (EPBT) can be defined as the time it takes for a renewable energy system to produce the same amount of energy that was put into the production of the system itself. This includes both renewable and non-renewable energy sources and refers to primary energy or kWh-eq. (Zhang & Yang, 2019).

The EPBT can be calculated in the follow way (Zhang & Yang, 2019):

$$EPBT = \frac{E_{mat}+E_{manuf}+E_{trans}+E_{inst}+E_{EoL}}{E_{annual}-E_{O\&M}} \qquad (9)$$

Where E_{mat} is the primary energy used to produce all materials, E_{manuf} is the primary energy used in manufacturing, E_{trans} is the primary energy used in transportation, E_{inst} is the primary energy used during installation, E_{EoL} is the primary energy used during End-of-Life, and $E_{O\&M}$is the annual energy demand used during operation and maintenance. All of these are given in *MJ* of primary energy. E_{annual} is the annual electricity production in kWh, this needs to be adjusted by the primary energy to electricity conversion efficiency for the grid where the PV system is installed. This is 3.91 MJ_p/kWh in Norway (Louwen et al., 2017).

6.4 RESULT

This short chapter presents the results. First is GWP presented for module production in China, Europe and Norway respectively. The GWP for comparable energy sources will also be included. This is followed by the result for the energy use.

6.4.1 LIFE CYCLE GHG EMISSIONS

All results are presented for solar power production placed in Skibotn, it is only the production location of modules that is changed. The GWP is for modules produced in China is shown in figure 33. The Upstream stage stands for 81 % of the total emissions, the Core stage for 9 % and transport for 8 %, the rest that is attributed the downstream stage is negligible but non-zero.

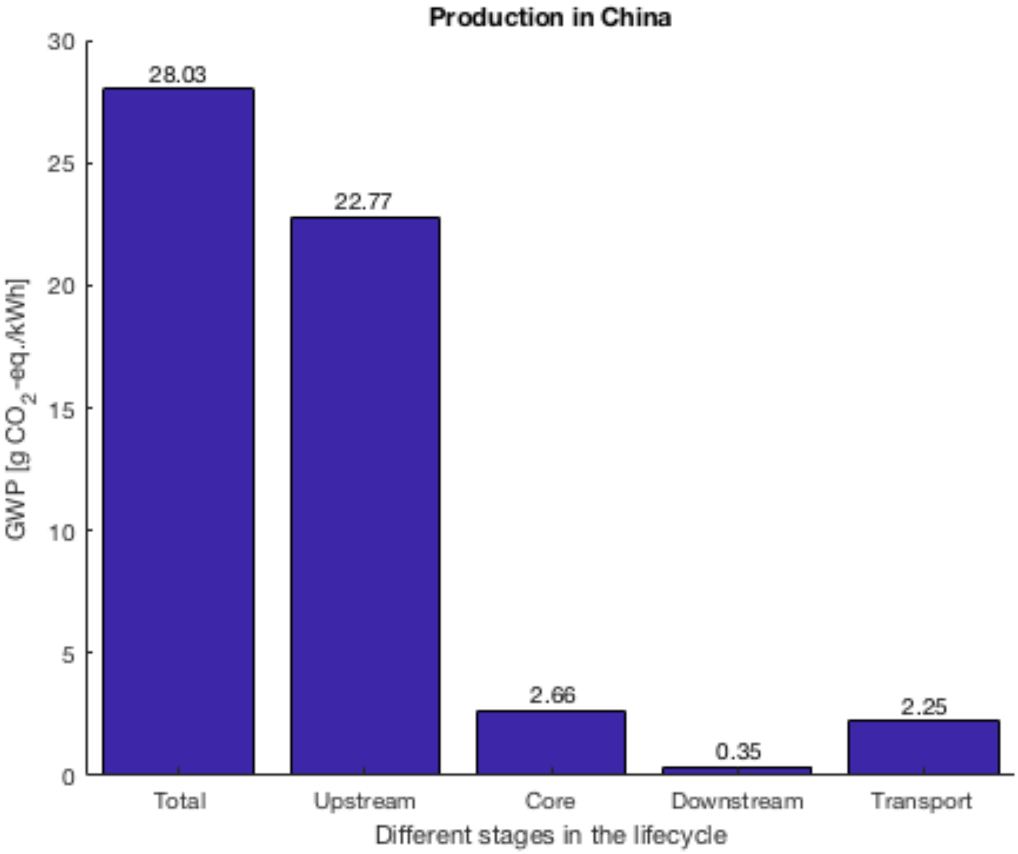

Figure 33. Global warming potential tied to transport and the three different life cycle stages: Upstream, Core and Downstream. The Upstream stage takes place in China and the Core and Downstream stages takes place in Norway where the modules are installed. The data is gathered from the EPD and are recalculated to fit this study.

Figure 34 display the GWP for module production in China, Europe and Norway respectively. European module production yields a GWP of 22g CO_2-eq./kWh and Norwegian production 17g CO_2-eq./kWh, a reduction of 22 % and 38 % respectively. It is clear that the total GWP follows the carbon intensity of each country's electricity mix and that the difference is substantial if production is placed in Europe or Norway compared to China. The relative contribution from the Core and transport stages are increased as the overall GWP decreases for the European and Norwegian cases. The contribution from the Core stage is 12 % and 15 % while transport stands for 10 % and 13 % for Europe and Norway respectively. Corresponding figures to 33 but shown for Norwegian and European module production can be found in Appendix figure A4 and A5.

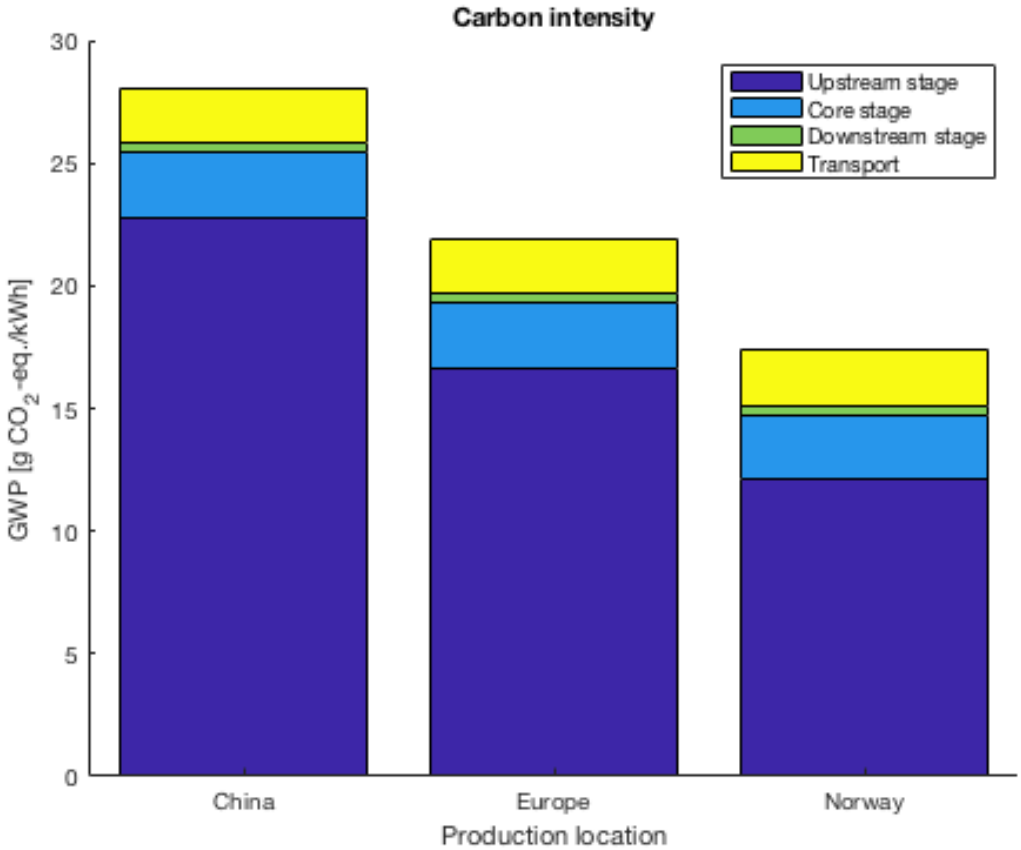

Figure 34. GWP for three different module production locations. LCA-data from a Chinese power plant have been scaled with electricity mixes to estimate production in Europe and Norway. Installation, use and disposal takes place in Norway in all three cases.

A goal of this study is to compare the carbon intensity of solar power with other sources of energy production. This comparison is presented in figure 35. Solar power in Skibotn has the highest GWP of all energy types, roughly 6 g CO_2-eq./kWh higher than the Norwegian grid mix. However, if the module production would be based in Europe then the GWP is similar to that of the grid mix. If the production is placed in Norway then the GWP is in the same size as that of mixed wind power. It is difficult to estimate the exact GWP of wind power as the different sources show a big spread in their results. Something that also can be seen in other LCA review studies (Bhandari et al., 2020). However, it can very roughly be said that solar power has a GWP twice that of wind power, considering the baseline scenario with Chinese module production. A clear trend of lower GWP for wind power in the newer LCA-studies, compared to the old ones from 2012, is visible. It is strange that the Norwegian wind power show higher GWP for the larger turbine size. An opposite correlation is shown by Bhandari et al. (2020).

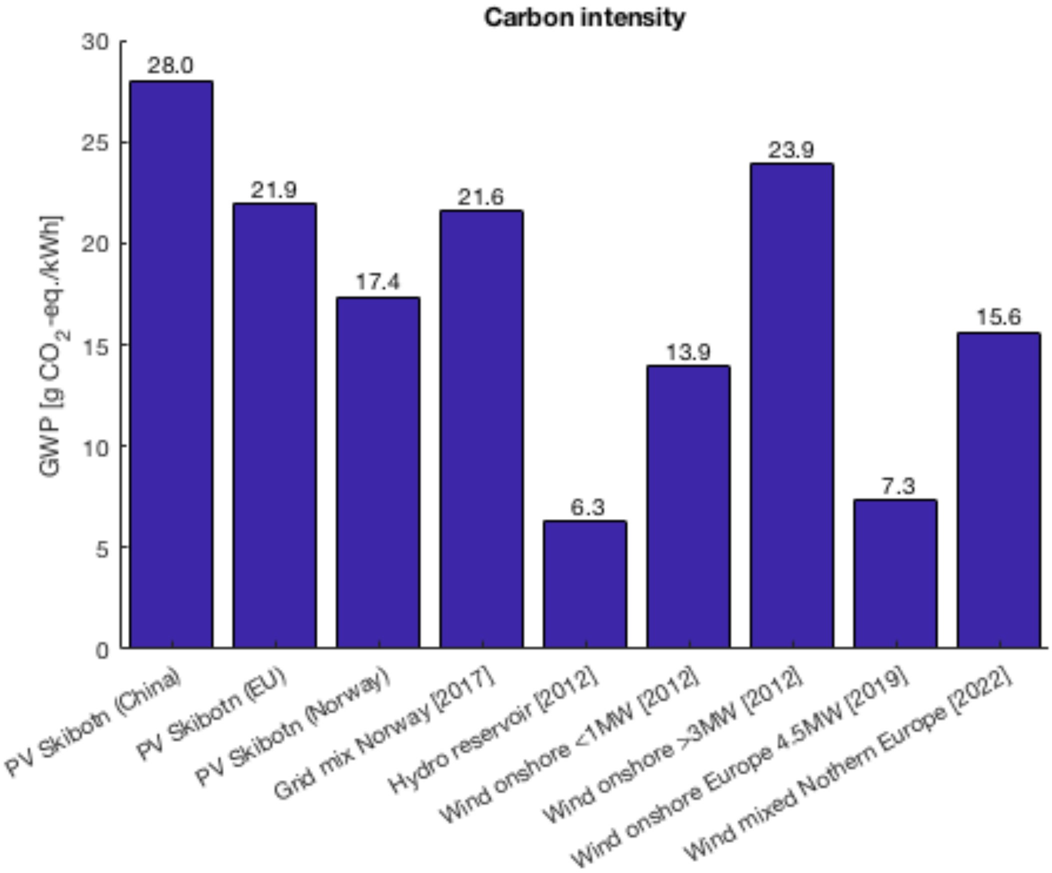

Figure 35. Carbon intensity for different types of electricity production together with the result of this study. PV Skibotn refers to this study where the different module production locations are denoted in the parathesis. The other production types can be found in table 14 in chapter 6.2.5 Hard brackets denotes the year when the study was performed. All data from 2012 is for Norway.

6.4.2 ENERGY USE

The following result is for the baseline scenario where the modules are produces in China and installed in Skibotn. The Upstream stage is also dominating when looking at energy as it stands for 84 % of the total energy use during the modules life cycle, see figure 36. The Core stage is attributed 9 % and transport 7 %. The contribution from the Downstream stage is negligible. The EPBT is 1.4 years.

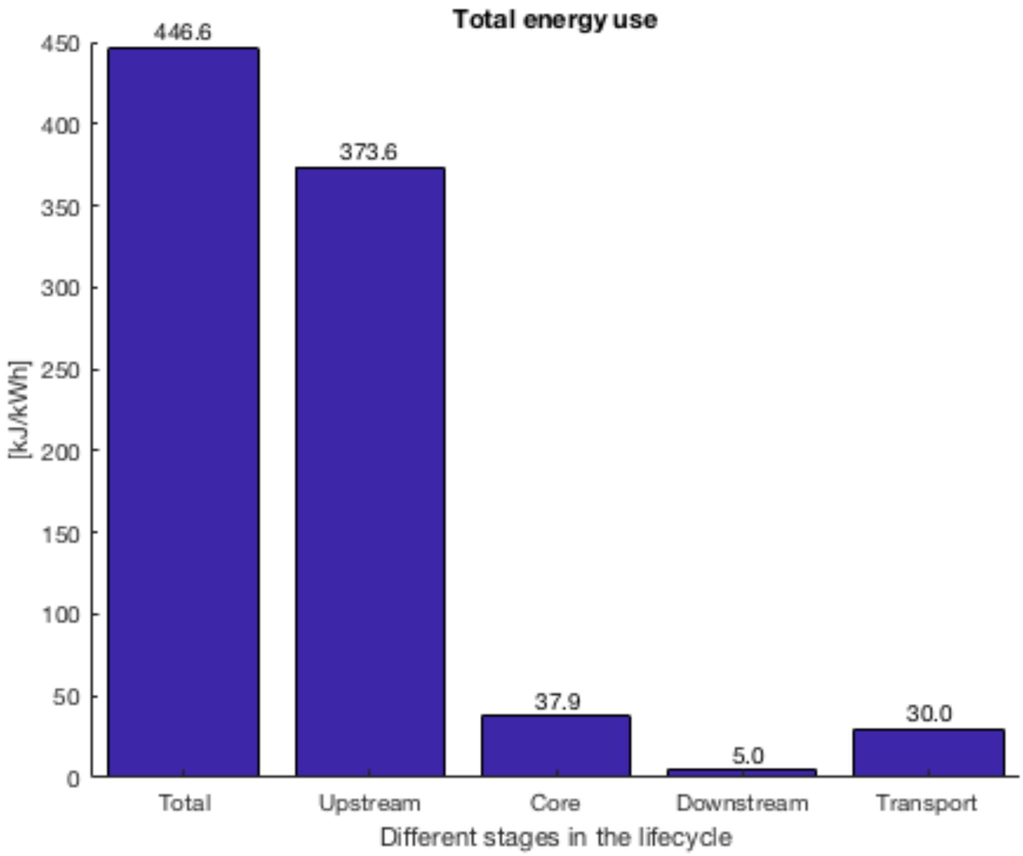

Figure 36. Primary energy use for transport and the three stages of the modules life cycle. This includes both renewable and non-renewable energy.

6.5 DISCUSSION REGARDING CARBON FOOTPRINT ANALYSIS

The results and assumptions will be discussed below. However, the implication of the result will be discussed in the overall report discussion in chapter 7.4. It is clear that the upstream stage, which includes mining and production, is dominating the GWP and energy use. The contribution from the Downstream stage is negligible for both GWP and energy use while the Core stage makes up 9 % of the total GWP. Other studies have found the Core stage to be small or close to zero and explains this with the minimal operation and maintenance requirements of a PV-power plant (Hsu et al., 2012). It is unclear if these studies include construction in their Core stage.

GWP for PV power production would be 22 % less if the modules were produced in Europe instead of China. This is in line with Müller *et al.* (2021) who found that modules produced in Europe emit 44 % less GHG compared with Chinese production. This is only for module production however, not including BOS, installation and O&M. It is thus reasonable that the GWP reduction in this study is less since the emission from BOS and installation is assumed the same disregarding the module production country. If the module would be produced in Norway then the GWP would be 38 % less compared with production in China. This is a result of the great differences in carbon intensity of the grid mix in the two countries. It should be noted that these calculations are based upon findings from mainly one paper and that it includes a rough assumption that the module is attributed 80 % of the Upstream emissions in the EPD, the rest is attributed BOS. This assumption is not based on literature as no such information could be found. If BOS was also assumed to be produced in Norway then the emission reduction would be even larger. It is clear that the electricity used in module production plays a fundamental role for the overall GHG emission tied to solar power. This makes it important to use up to date electricity data in studies like this one.

Figure 35 compares the GWP of solar power in Skibotn with other production types. The production in Skibotn performs the worst when considering the baseline scenario. It emits roughly two times as much GHG compared to the two newer studies carried out on wind power. This study only compares the GWP but there are also other factors to consider. One example is the turbines used in wind power that are known to be hard to recycle (Andersen et al., 2014). Solar power emits around 6 g CO_2-eq./kWh more than the average grid mix in Norway. The great difference in GWP of the grid mix and hydro is surprising considering that the Norwegian electricity production is made up of 90 % hydro (Energifakta Norge, 2021). NVE states that the carbon intensity of the grid mix was 17 g CO_2-eq./kWh in 2019 which eliminates the suspicion of bad Norwegian grid mix data from Ecoinvent. Perhaps the answer is in the transformation and transport of electricity as Ecoinvent states that the production mix of high voltage electricity emits 7.7g CO_2-eq./kWh in Norway in 2017. If the modules would be produced in Europe then the PV electricity would have a carbon intensity at the same level of the grid mix. In the scenario of Norwegian module production then the carbon intensity would be substantially lower, in the same range as mixed wind produced electricity. No detailed conclusions can be drawn from the scenarios of module production in Europe or Norway due to uncertainty in the underlying assumptions. Nevertheless, they provide an indication of the substantially lower GHG-emissions if modules are produced in a country with a low carbon intensity grid mix.

6.5.1 Completeness, sensitivity and consistency

The study is regarded as complete seen as the goal was not to conduct a full LCA analysis but rather a simplified study. However, there are a few assumptions that are not backed by literature. These are the assumptions that module stand for 80 % of the emissions in the Upstream stage and that half of the emissions in the Core and Downstream stages stem from electricity use. Also, one can argue that the cases for module production in Europe and Norway are non-complete as these are only recalculated from the Chinese production case and not based on real production in these regions. However, this simplified method is considered in line with the goal of the study.

The baseline scenario with module production in China and use and end-of-life in Skibotn is seen as robust. The uncertainty lies within the scale factor when recalculating the Core and Downstream stages. From figure 33 and 36 it is clear that the exact value of this scale factor is not of any great importance since the Upstream stage would be dominating both the GWP and Energy use even if the scale factor would be significantly different. Since this is not a hot spot it is not included in the sensitivity analysis. However, the result regarding production in Europe and Norway is not seen as robust and should be interpretated carefully.

6.5.2 Sensitivity analysis

The life time of the PV system can be longer than the 30 years used in the baseline scenario. Part of this is because the Nordic conditions favour less degradation, see chapter 2.4. If a life time of 40 years is applied then the GWP in the baseline scenario is 21.3 g CO_2-eq./kWh, a 24 % decrease.

One weakness in the report is the lack of validated up to date grid mix data for China. This data is something that also Müller *et al.* (2021) struggled to come across. If the carbon intensity used in the scaling where 20 % less, equalling 0.736 kg CO_2-eq./kWh, then the GWP would be 28.05 g CO_2-eq./kWh, almost identical to the base line scenario. This is because only the Core and Downstream stages are scaled with the electricity mixes and their relative contribution is small. Thus the lack of up to date grid mix data does not constitute a great uncertainty in this analysis. However, if 20 % decarbonization is applied to the electricity used for module production in China, then the GWP would be 24 g CO_2-eq./kWh, a 14 % decrease.

6.5.3 Conclusion

Solar power in Skibotn has a GWP of 28g CO_2-eq./kWh which is relatively high compared to wind which has a GWP of around 7-16 g CO_2-eq./kWh. It is very high compared to hydro at 6g CO_2-eq./kWh. However, if the modules would be produced in Europe or Norway then the GWP would be significantly less at 22g CO_2-eq./kWh and 17g CO_2-eq./kWh respectively. Then solar in Skibotn would be comparable with the grid mix of Norway. However, it should be noted that the result for European and Norwegian module production contains great uncertainties due to significant assumptions.

7 DISCUSSION

The discussion is divided in five subchapters. The first chapter treats the results from the simulation, the second deals with the economic feasibility, the third uses the result from this study to see how well solar power fits in the future energy system, the fourth looks into the carbon footprint of solar power in Skibotn and compares this result with other types of electricity production and the last chapter is an outlook which identifies knowledge gaps and proposes further research topics.

7.1 SIMULATION

The measurements from the pyranometer show that the irradiation is highest during May and June which is then followed by July and then April. The yield is highest during May which is then followed by April and then June. The discrepancy between irradiation and yield is attributed higher albedo and lower temperatures during April than in June and July. These effects result in higher yield in April even though the irradiation is less and that the soiling value is 25 % during April and 2 % during June and July. The pyranometer measurements also show that Gálggojávri receives 11% less GHI than Oslo and 13 % less GHI than Stockholm. However, it should be noted that this way of measuring discriminates high latitude areas. This is because the measurement is on a horizontal surface and that the optimum angle of modules increases with latitude. The optimum angle is thus further from the horizontal plane in Gálggojávri compared to Oslo or Stockholm. This discrimination can be overcome by measuring irradiance in the plane of array, i.e. with the same tilt as the modules.

The system that has the highest energy output is the bifacial system facing true south with tilt 45°, it produces 955 kWh/kW$_p$/year. This equals a bifacial gain of 14 % compared to the monofacial system with the same tilt and azimuth. The bifacial gain is 17 % when the systems are tilted 60°, however the energy yield is less than for tilt 45°. This is in the same range as the experimental bachelor study performed on modules installed on the roof the university in Tromsø (Børsheim, 2021). This study found BG's of around 10 % for 40° tilt and 16 % for 60° tilt.

The simulation also show that vertical modules produce less electricity compared to modules mounted at 45°. This is confirmed by an experimental study in Sweden at 65°N which found that vertical modules produce less than modules of tilt 45° (Granlund et al., 2019). Vertical modules facing South-North and East-West produces 9 % and 10 % less electricity respectively. The vertical modules have been simulated with snow soiling values estimated from a Swedish study. The area around Skibotn is also subjected to a lot of snow drift which Frimannslund *et al.* (2021) argue could be a stronger contributor to snow soiling than snowfall. It is clear that more research needs to be performed on this topic in order to better estimate snow soiling on vertical modules. The vertical modules facing East-West have a different production curve than modules facing south, as shown in figure 23. These modules are facing the morning and evening sun which makes their output profile less in midday but more pronounced in the morning and evenings. This pattern is a better match for the energy system as the energy use usually contains two peaks at morning and early evening. This is when most people wake up or come home from work and use home appliances, charge their car and take showers. The morning peak is also attributed to the industry as this is when all the machinery and lighting are switched on. So even though this vertical system produces less electricity it might be a better fit to the electricity use and hence produce electricity when the electricity price is higher. Which system that is most profitable is not investigated further in this paper but something that future studies could look into. It is also possible to combine two systems to achieve a smoother daily production profile. The Vertical East-West system together with the south facing system with 45° tilt would give a smooth profile but still with high yield. The vertical system facing South-North show higher yield during February and March compared to the other systems. This is likely because the vertical setup facing south is beneficial when the solar angle is low in late winter.

The energy densities are between 50-60 kWh/(m^2*year) for the different systems. Bolinger & Bolinger (2022) investigated over 90 % of the utility scale solar power systems in USA and found the average value to be 110 kWh/m^2. This is roughly twice the energy density in this study but coherent considering the higher solar irradiation in USA. The energy density rises up to 80 kWh/(m^2*year) when the pitch is lowered to 7 m. The overall yield does however go down with decreased pitch. The decrease is -7 %, -11 % and -14 % for the bifacial system facing south with tilt 45°, the vertical system facing South-North and the vertical system facing East-West respectively. This shows how cost of land has to be weighted against the extra yield when determining pitch for a PV-systems.

Simulation of bifacial modules are rather new and there is not many validation studies of utility scale in the literature, as explained in chapter 2.8. However, the studies that exist indicate good agreement. One thing that became obvious during bifacial simulation in PVSyst is that there is no possibility of having the backside producing electricity even though the front side is covered by snow or frost. Instead the soiling value is defined as a monthly percent that is applied on the total irradiance that month.

The albedo has been pointed out in literature as an important parameter that is difficult to estimate. However, the sensitivity analysis showed that the energy yield on a yearly basis only changes with +1.9 and – 2.0 % when the albedo is changed with +20 % and -20 % respectively. Large uncertainties in energy yield due to bad estimations of albedo can thus be disregarded. The soiling value is the parameter with greatest uncertainty and the sensitivity analysis shows that by adjusting the values to the tabulated Tromsø values, shown in table 3, the energy yield changes with +4.3 %. Soiling values are further discussed in chapter 7.5. The temperature dependence of solar cells is discussed in chapter 2.3 where it is shown that the cells benefit from low temperatures. Since the systems have such long life times they could be affected by future temperature increase due to for example climate change. The sensitivity analysis included a temperature increase by 2°C which resulted in a decrease in yield by -0.7 %. This shows that the PV-system is not highly affected by the temperature increases that climate change could bring.

7.2 Economic feasibility

There will not be any utility scale solar power installed this far north if there is no economic feasibility in such projects. Northern Norway is likely to be one of the last markets for solar power because of the low electricity prices caused by the great availability of hydropower. The economic evaluation shows that both financial set ups are profitable if the future electricity price is at NVE's baseline scenario. However, this is with the low discount rates stated in chapter 4. They might seem suspiciously low but this is the most applicable values that could be found in literature as these are actual values used in Swedish projects recently. Similar WACCs have also been reported in Germany as stated in chapter 2.9.1. One contributing factor could be that the risk is considered low in Sweden and Germany which would lower the cost of equity and debt. The sensitivity analysis shows how important real WACC is for the profitability of a PV-project. Figure 29 illustrates the relevance of real WACC and it also shows that a real WACC higher than 5.0 % would mean that neither of the set ups would be profitable. The above reasoning is for a life time of 30 years, however Solgrid uses a life time of 40 years in their concession application. The longer life time is highly possible and will further reduce the LCOE by 4-5 NOK-øre/kWh. In addition, Swedish industry leaders predict CAPEX to go down by 40 % within ten years. CAPEX makes up a great deal of the total costs as solar power doesn't have any fuel costs and low O&M costs. Therefore, this would have great impact on the LCOE for solar power. This is in-line with IRENA that predicts LCOE to go down with 58 % on average between 2019-2030 in the G20 countries (IRENA, 2020a). With a cost reduction of 40 % in CAPEX, and a life time of 30 years, then the LCOE is 25 NOK-øre/kWh with the financial set up 2. This is lower than the lowest predicted future electricity price by NVE, as shown in figure 34. If such a price reduction becomes reality then the far north is very likely to see its first utility scale solar power system. Again, this is with a low WACC but still a clear indication that solar power is on the rise even in these high latitude areas.

The financial set up 2 results in lower LCOE than set up 1 and figure 29 show that set up 2 is less effected by real WACC. One explanation can be that cost of debt is lower than the cost of equity. Also, part of the cost of debt is deductible through the corporate tax as shown in equation 3. The financial set up becomes more important for higher WACCs as shown in figure 29. The difference in LCOE is 10 NOK-øre/kWh for the two set ups investigated with a real WACC of 6 % which makes a huge difference in profitability. However, recent real WACC values reported in Sweden have been around 1-2 % which makes the financial set up less important.

If all GOs are sold then the projects would be roughly 200 000 NOK more profitable. It can be argued that not all of these is likely to be sold as only 14 % of all the GOs issued in 2018 were sold. 14 % of 200 000 NOK equals 28 000 NOK which is neglectable considering other costs and revenues of a solar power project of 1 MW scale. Nevertheless, if all GOs are sold then it can have a significant effect on the profitability. The near future will tell if this subsidy system will stay in Norway or get removed through the political platform Hurdalsplattformen.

This study does not match the production profile of solar power with monthly spot prices, instead yearly average values are used. Summer usually means lower electricity prices since there is less need for heating and lighting. This could make solar power less profitable than what is shown in this study as solar power mainly produces electricity during these months. However, it is not certain that the future electricity use will look the same as the historical use. A changed energy landscape, with the development of electricity intense industry, could affect this price difference between summer and winter. Electricity intense industry will decrease the relative contribution of heating and lightning and can schedule production to times with low electricity price and thus level out price differences. Also, wind power is increasing, especially in Sweden, and it produces more in winter than in summer. The green steel projects in Sweden are planning to build large amount of wind power to power the electrolysis of hydrogen. This is estimated to amount to 55 TWh if the industry fully commits on hydrogen (LKAB, 2021) . The idea is to build wind power that supplies the electrolysis for hydrogen production with electricity. The hydrogen storage is dimensioned to facilitate hydrogen for two weeks of production. Hence, the electrolysis will run when the wind power is producing enough or when the grid electricity price is low. This could reduce the very low electricity price that has been seen sometimes during summer historically. The price areas SE1, where such installations would be placed, and NO4 are tightly connected and such installations are likely to affect the electricity prices in NO4.

The same reasoning can be applied to the daily pattern of electricity use. The electricity use is highest in the morning and evenings as explained in chapter 7.1. This might not be true in the future if electricity intense industry schedules its production to times of low electricity price. Nevertheless, this is the situation of today and this pattern is a perfect match to the production profile of the vertical bifacial system facing East-West. Electricity is bought and sold by the hour and higher demand means higher price. So although the bifacial system facing south with 45° tilt gives a higher yield it might not be certain that this system is more profitable than the vertical East-West system.

7.3 SOLAR POWER IN THE FUTURE ELECTRICITY SYSTEM

The future electricity need is highly affected by new electricity intense industry as explained in chapter 2.1 and 7.2. These industries are often placed in the northern parts of Norway and Sweden since the electricity price is much lower here compared to the southern parts. Such projects include the steel industry in Sweden which plans to electrify parts of their processes which will demand huge amounts of electricity. A massive battery factory recently went into production in northern Sweden as well. The petroleum industry in Norway have plans on electrifying some of their platforms and hydrogen production through electrolysis could also become a reality in Northern Norway. It is hard to predict the outcome of all these projects but NVE states that the electricity need could be around 200 TWh by 2040 if many of these plans become an reality. NVE predicts the electricity production to be 186 TWh by 2040 in their baseline scenario which means there could become a deficit of 14 TWh. Hence additional power production, above the baseline scenario, might be necessary. Hydro power will not be able to account for all of these 14 TWh of additional power, therefore new solar- or wind power needs to be installed. The economic analysis show that solar power very well could be profitable as of today and if the CAPEX continues to go down as the Swedish industry leaders predicts then it most certainly will be profitable within the next ten years. This means that solar power could take a place in the power system also in the very north.

Wind power produces more electricity during winter and solar power produces more during summer as shown in figure 25. It becomes clear that the production profile of the two production types are a good match as they produce electricity in different times during the year. Hydro power makes up the absolute majority of power production in NO4. Figure 37 shows how the water level in the water basins changes over the year. It shows that the lowest water levels usually are found around mid-may which is when solar power produces at maximum. Thus, solar power could assist the hydro power when the water basins are running low and when wind power has relatively low output.

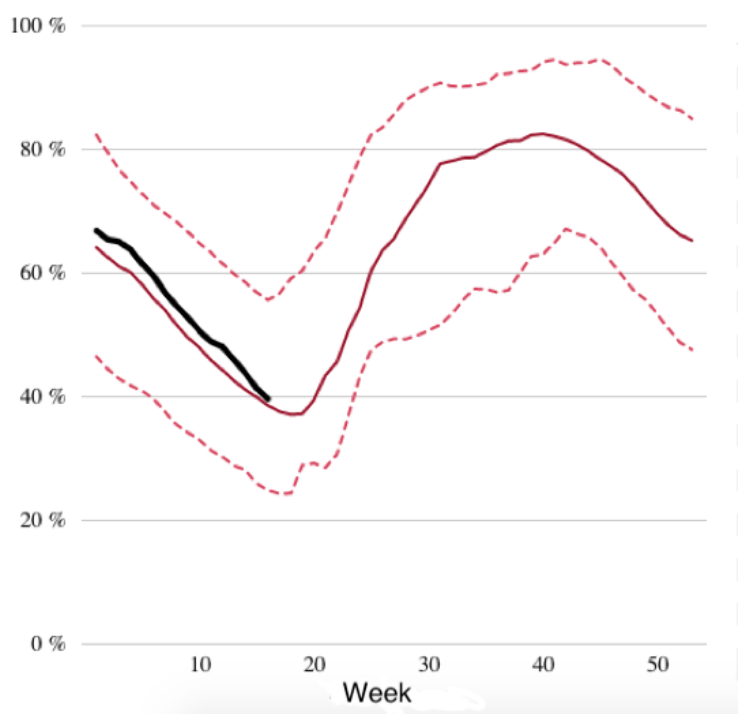

Figure 37. The degree of filling in the basins of hydro power in NO4. Dotted lines represent max and min values while the full red line represent the mean value. The black line is the values of 2022. The degree of filling is usually at its lowest around week 20 which is in the middle of May. These are mean values calculated over the last 20 years. Source: (*Magasinstatistikk - NVE*, 2022)

NVE predicts that there will be 6 TWh of new installed land based wind by 2040, see chapter 2.1. Solar power is predicted to increase by 6 TWh and hydro power by 11 TWh. By combining solar- and wind power one gets a smoother production curve over the year. Solar power is yet only installed in low numbers in Norway but NVE predicts the market to expand quickly in the years to come. An idea would be to investigate the possibility to install solar power in connection to wind power. Such areas are already made available to power production and additional solar power would not lay claim to any new land. Also, infrastructure such as roads and grid connection is also already in place and the overlapping production profiles would increase the capacity factors in the power lines. The lines unlikely need to be upgraded as they are dimensioned to handle the production peaks in winter time for the wind power on site. Solar power would merely use the available capacity in summer. These intermittent power types would then be balanced by the highly available hydro power which would make a robust system.

7.4 CARBON FOOTPRINT

All electricity production releases GHGs, also solar power. The emissions are minimal during its operation as no fuel and very little maintenance is required in the electricity production. The majority of emissions is instead tied to the production of the modules as shown in chapter 6.4.1. It is in the upstream processes, such as mining and production, that the greatest improvement in emissions can be achieved. The production of modules is electricity intense and decarbonization of the grid mix has profound impact on the emissions. Chapter 6.5.2 showed that a 20 % decarbonization of the electricity used in production in China resulted in 14 % less emissions from the electricity produced by the modules. China has a very carbon-heavy grid mix which leaves great room for improvements, this may not be done very quickly however. Another way to reduce the emissions in the near future would be to move electricity intense production of precursors to regions with low-carbon electricity mix. This particularly applies to the production of silicon products, such polysilicon and Cz-silicon, which are the most energy intense precursor (Müller et al., 2021). The contribution from transport is small in comparison to the possible gains as shown in chapter 6.4.1. A third option would be to move the entire production to a region with low-carbon grid mix as investigated in chapter 6.4.1. Production in Norway and EU results in 22 % and 38 % less GWP respectively. A fourth aspect that is investigated in chapter 6.5.2 is longer life time of the solar power system. The GWP decrease with 24 % by increasing the life time from 30 years to 40 years. This is because the emissions mainly takes place in the upstream processes. To reduce the emissions further one have to look into the emissions tied to mining of materials as well as production of BOS.

The greatest climate gain from solar power is obtained if the system is produced in a region with low-carbon grid mix and placed in a region with high-carbon grid mix. The very opposite is true for production in China and use in Norway as the grid mix in Norway mainly consists of hydro power. The Norwegian grid mix has a lower GWP than the investigated solar power and the analysis also show that solar power emits roughly twice as much GHGs as wind power. If the climate gain is the only goal then it would be best to fully develop the 23 TWh of available hydro power in Norway and then to install wind power. However, other aspects such as a smooth production profile over the year, easier and faster installations, better land use or the recyclability of power systems can be arguments for the development of solar power in the north.

7.5 OUTLOOK

A few knowledge gaps were identified during the literature study. The most prominent were snow soiling values as well as validation studies of simulation with bifacial modules. The greatest uncertainty in the simulation stems from the soiling values. The literature claims that this is the most important parameter for Nordic conditions, yet it is difficult to find guiding values, see chapter 2.7. The sensitivity analysis shows that the yield is affected by +4.3 % when changing the values from the modified values to the tabulated Tromsø values stated in chapter 3.4.2. The greatest improvement in the simulation would be to further investigate the snow soiling values. The most reliable model to predict snow soiling is the Marion model, see chapter 2.7. It was proposed in 2013 and has been validated numerous times, also in Norway. The model requires site specific data of accumulated snow, temperature and irradiance and then calculates how much of the modules that are covered in each calculation point. The difficulty is to convert this partially snow coverage into soiling values that can be applied in the simulation program. This difficulty is why the model has not been applied in this study. It can be assumed that this topic will gain more research as solar power becomes increasingly implemented in snowy areas. The bifacial technology is rather new which means that the 2-D view factor model has not been validated extensively with these modules. However, the first studies show good agreement. A downside of 2-D view factor model is the user-defined values, such as the shed transparent factor that decides how much light that passes through the rows of modules and reflects on the ground. Such parameters increase the complexity of the simulation since validated values are not available in literature. Future research in the topic, and in the best case guiding values, would make these choices easier. Also, there is no way to include electricity production from the backside of the modules even if the frontside is covered by snow or frost. Another aspect of solar power that is little researched is the end-of-life stage. This is simply because very few systems have reached the end of their life time. Hence little is written about the recyclability of the system. Also, the life time used can vary substantially between projects. The life time varied between 30 and 45 years for five recent projects in Sweden (Lindahl et al., 2021). The sensitivity analysis show that a life time of 40 years reduces the LCOE with 5 NOK-øre/kWh compared to 30 years which equals a 14 % cost reduction. There is not much cost-data to be found for solar power in Norway. The most recent data, and the only one bifacial, is from the concession application from Solgrid. This data is also the basis in the LCOE calculations in this paper. The lack of data is also something that NVE is struggling with in their online LCOE-tool as they are currently using estimates rather than real data. This knowledge gap is partly narrowed with this study. However, more research and data from actual systems are required to make correct estimations of the cost of solar power in Norway.

This study shows that solar power is economically feasible in the north. However, there are still challenges that need to be solved before solar power gets implemented at scale. Especially land use is something that could become problematic. The land use for wind power is already a hot topic in Norway. There were a lot of new wind power installed in 2018 and 2019 which made many people weary of new projects (Amundsen, 2021). This has led to many projects now being stopped and is why NVE predicts very little new wind power before 2030, as explained in chapter 2.1. Solar power also demands large areas and it is wise to learn from the development of wind power as to not end up in the same situation where many projects get a red light. NVE states that it is not only costs or profitability but also a question regarding land use that will limit the development of solar power in the future (Haukeli et al., 2021). Future research should therefore investigate how the deployment of utility scale solar power can be achieved with the acceptance of the public. One interesting solution could be to install new solar power in conjunction with already existing wind power. This will also lead to other benefits as explained in chapter 7.3. Another form of co-use of land is where solar power is installed on grazing land (Haukeli et al., 2021). Such projects are currently being planned in Gjøvik in Norway (Kessel et al., 2021). Both wind and solar power installations affects the local environment and therefore often meet local resistance. This problem have been named NIMBY (not in my back yard). One way to address this would be to work out compensation models for the local communities. Another practical aspect that is interesting to further look into is manual snow removal. This could be particularly interesting in spring time when the snow cover can be thick and the irradiance high. There could be significant savings in manually removing the snow instead of letting it slide of, or even worse thaw.

8 CONCLUSION

The PV-system that gives the highest yield in this Arctic location is a bifacial system with 45° tilt and facing south. This system has an output of 955 kWh/kW$_p$/year. The bifacial system with 60° tilt produces 936 kWh/kW$_p$/year which is very similar. The vertical bifacial systems facing South-North produces only slightly less and with a similar production profile. The vertical bifacial system facing East-West produces as much as the vertical South-North system but with a significantly different daily production profile. This is the only system with two distinct production peaks during mornings and evenings which matches the electricity use that has the same pattern. All monofacial systems produce substantially less than the bifacial systems. The bifacial gain is 14 % and 17 % respectively for the systems of 45° and 60° tilt facing south.

The economic feasibility of solar power relies heavily on the discount rate tied to the project. The project in this study turn unprofitable for real WACC values above 5.0 %. This is a higher real WACC than what has been reported in recent Swedish PV-projects, thus solar power in Skibotn is profitable already today. With a real WACC of 1.39 %, which is the average of recent Swedish projects, the LCOE is 36 NOK-øre/kWh. If the life time is set to 40 years, which is very reasonable in this Nordic location, it is 32 NOK-øre/kWh. Both of these are lower than the predicted future electricity price in NO4 which is 43 NOK-øre/kWh if averaged over 30 years.

The modules used in PV-power production is mainly produced in China. The majority of CO_2-emissions tied to solar power stem the from the mining and production of the modules. Little emission take place in the operation and maintenance stage and almost none in the end-of-life stage. Electricity from solar power in Skibotn has a GWP of 28 g CO_2-eq./kWh which is relatively high compared to wind which has a GWP of around 7-16 g CO_2-eq./kWh. It is very high compared to hydro which has a GWP of around 6 g CO_2-eq./kWh. If the life time is set to 40 years, which is very reasonable, then the GWP is substantially lower at 21 g CO_2-eq./kWh. Also, if the modules would be produced in Europe or Norway then the GWP would be 22 g CO_2-eq./kWh and 17 g CO_2-eq./kWh respectively. This would make solar power in Skibotn comparable with the GWP of the grid mix in Norway and mixed wind power. However, it should be noted that the result for module production in Europe and Norway contains great uncertainties due to large assumptions.

Utility scale solar power in the Arctic is profitable already today considering the low real WACCs used in Sweden lately together with the prediction of future electricity prices by NVE. This warrants further research on the topic where a special focus should be on snow soiling as this is difficult to estimate and gives the greatest uncertainty in PV-simulation. The possibility to install solar power in connection to already existing wind power should also be investigated. Such combined installations would give a smooth production profile over the year and lessen the need for new areas for energy production.

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10 APPENDIX

The following currency rates where used to recalculate EUR and USD to NOK:
1 EUR – 9.77 NOK
1 USD – 9.04 NOK

Table A1. Future electricity prices for price area NO4 used in the economic calculations. From NVE's prognosis. Source: (Haukeli et al., 2021)

Year	NOK-øre/kWh	Year	NOK-øre/kWh	Year	NOK-øre/kWh	Year	NOK-øre/kWh	Year	NOK-øre/kWh
2023	39	2031	44	2039	43	2047	43	2055	43
2024	39	2032	44	2040	43	2048	43	2056	43
2025	39	2033	44	2041	43	2049	43	2057	43
2026	40	2034	44	2042	43	2050	43	2058	43
2027	41	2035	44	2043	43	2051	43	2059	43
2028	42	2036	44	2044	43	2052	43	2060	43
2029	43	2037	44	2045	43	2053	43	2061	43
2030	44	2038	43	2046	43	2054	43	2062	43

MECHANICAL DATA

Solar cells	Monocrystalline
Cell configuration	144 cells (6×12+6×12)
Module dimensions	2128×1048×30mm
Weight	29.0kg
Superstrate	High Transmission, Low Iron, Tempered ARC Glass
Substrate	Tempered Glass
Frame	Anodized Aluminium Alloy type 6063T5, Silver Color
J-Box	Potted, IP68, 1500VDC, 3 Schottky bypass diodes
Cables	4.0mm² (12AWG), Positive(+)350mm, Negative(-)350mm (Connector Included)
Connector	Risen Twinsel PV-SY02, IP68

Figure A1. The mechanical data for RSM144-7-XXX-BMDG that are used in the LCA in chapter 6. Source: (EPD International AB, 2021)

MECHANICAL DATA

Solar cells	Monocrystalline
Cell configuration	144 cells (6×12+6×12)
Module dimensions	2034×1000×30mm
Weight	27kg
Superstrate	High Transmission, Low Iron, Tempered ARC Glass
Substrate	Tempered Glass
Frame	Anodized Aluminium Alloy type 6063T5, Silver Color
J-Box	Potted, IP68, 1500VDC, 3 Schottky bypass diodes
Cables	4.0mm² (12AWG), Positive(+)350mm, Negative(-)350mm (Connector Included)
Connector	Risen Twinsel PV-SY02, IP68

Figure A2. The mechanical data for RSM144-6-420-BMDG that are used in the simulations. Source: (Risen Energy, 2020)

TEMPERATURE & MAXIMUM RATINGS

Nominal Module Operating Temperature (NMOT)	44°C±2°C
Temperature Coefficient of Voc	-0.28%/°C
Temperature Coefficient of Isc	0.05%/°C
Temperature Coefficient of Pmax	-0.36%/°C
Operational Temperature	-40°C~+85°C
Maximum System Voltage	1500VDC
Max Series Fuse Rating	25A
Limiting Reverse Current	25A

Figure A3. The temperature and maximum ratings for the two modules RSM144-7-XXX-BMDG and RSM144-6-420-BMDG that are used in the LCA-calculations and simulations respectively. The ratings are identical. Sources: (EPD International AB, 2021)(Risen Energy, 2020)

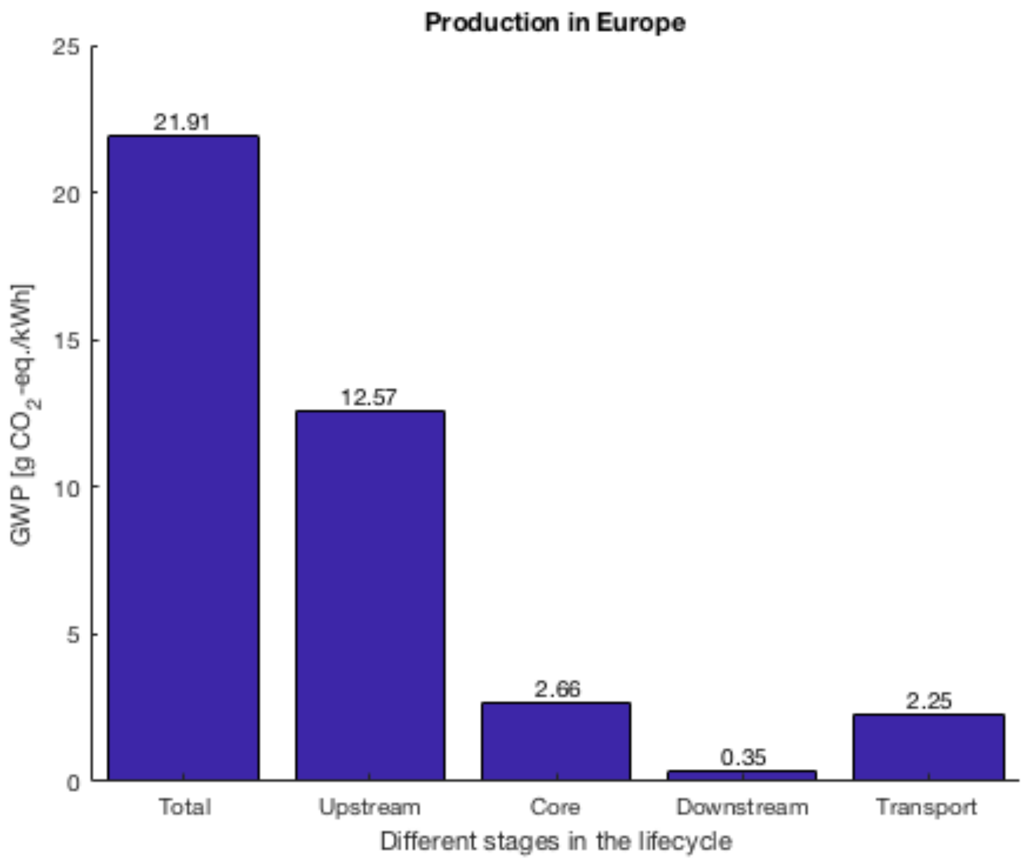

Figure A4. Emission tied to transport and the three different stages in the PV-modules life cycle. Module production in Europe and use and disposal in Norway. The data is recalculated from the EPD of the module to fit the study. Source: (EPD International AB, 2021)

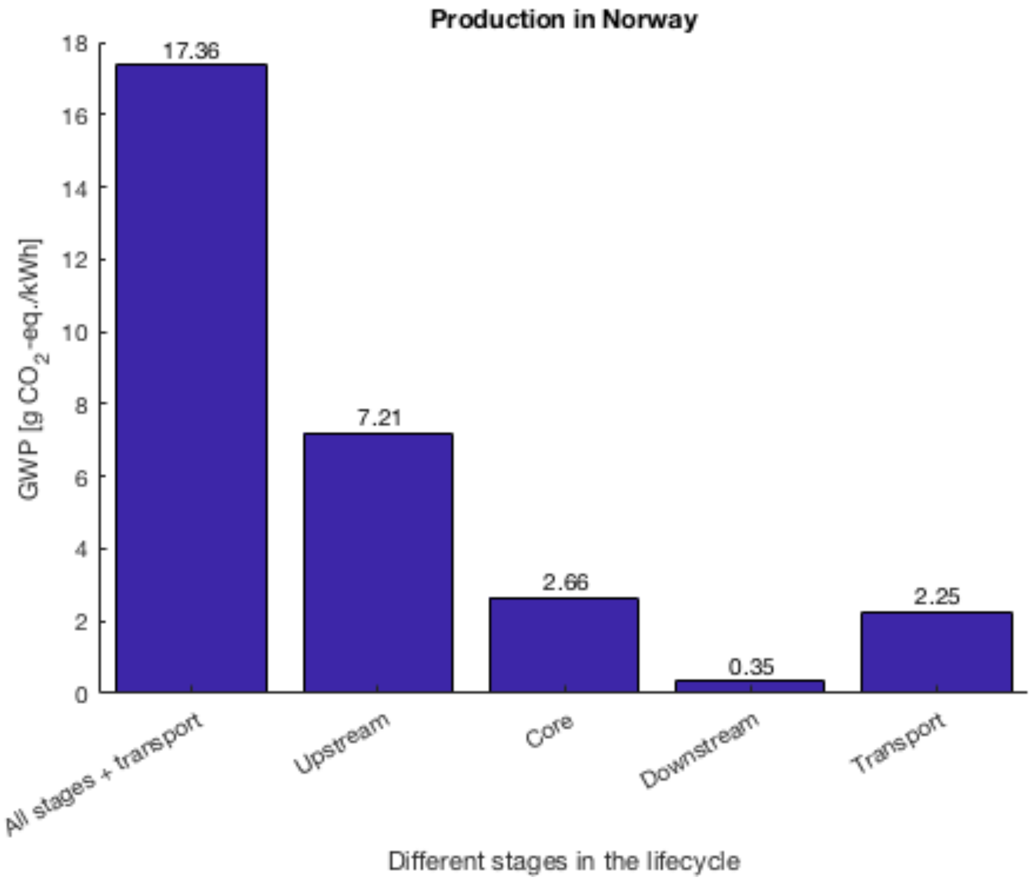

Figure A5. Emission tied to transport and the three different stages in the PV-modules life cycle. Module production, use and disposal in Norway. The data is recalculated from the EPD of the module to fit the study. Source: (EPD International AB, 2021)