Delft University of Technology

MSc. Sustainable Energy Technology
Photovoltaic Materials and Devices

Thesis Report

Cost sensitivity study of thin film solar PV module systems for different case studies

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Author:
Federico van Eijnatten

Supervisors:
Prof.dr.ir. A Smets
dr.ir. T. de Vrijer
ir. K. Saleh

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Abstract

This study analyzed the profitability and cost constraints of thin film solar PV modules for commercial sized lightweight roofs by using the reversed LCOE method. The focus will be on a particular technology of solar PV, namely, thin film solar PV module technology. Thin film solar PV modules are able to serve the niche market of commercial scale lightweight roofs, without competition with the highly matured traditional solar PV market. As such, the objective of this study is to derive actionable insights into the cost constraints of thin-film solar PV modules for these applications. Using the reversed LCOE method, figures show that there is a high variability in conditions that influences the performance and the profitability of thin film solar PV modules in a commercial scale lightweight roof project. This study shows that both profitable and unprofitable scenarios are possible and provides an analysis on how various conditions influence the project's profitability.

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1 Introduction

Cutting emissions by decreasing the use of fossil fuels has been a driving trend in western societies. Yet, energy consumption, and especially electricity has increased over the past and is expected to increase in the future (IEA, 2021). This puts pressure on new forms of energy resources and the electricity infrastructure. One of which is solar energy.
Solar energy presents great opportunities as substitute for traditional energy resources due to several reasons. Essentially, solar energy accounts for no emissions during operation, making it an environmentally friendly option. Furthermore, solar energy is highly scalability due to its modularity. In recent years, the solar energy market has experiences substantial growth. By 2023, the total installed solar capacity was estimated to be around 1,600 GW (IEA-PVPS, 2024), with an added installed solar capacity of more than 400 GW in 2023 alone. In the coming years, (IEA, 2024) the installed solar capacity is expected to continue growing at a similar rate as last year.
However, there are some drawbacks. First, solar energy entails high capital expenditure, which pose a significant barrier for many potential customers with limited available funds or uncertain financial projections. This financial barrier can slow down the adoption rate, particularly among small businesses and residential customers. Second, the intermittency of solar energy poses another challenge. Solar modules generate electricity only when the sun is shining, which means energy production can be unpredictable and does not always align with the energy demand. As a results, not all energy produced by solar modules can be used immediately, leading to the necessity of selling excess energy back to the grid or investing in costly energy storage solutions. Third, the global supply chain for solar modules is heavily dominated by a small concentrated group of manufacturers. This reliance on a limited number of manufacturers presents risk related to supply chain disruptions, trade disputes, geopolitical tension and limited competition & innovation in the industry.

1.1 Literature and method

For new solar module manufacturers to enter the market, it is crucial to understand the specific conditions under which their modules are most suitable. Factors such as local climate, energy consumption profiles, and financial incentives play an important role in determining the viability and attractiveness of solar investments. By tailoring solutions to meet the diverse needs, solar PV producers can help accelerate the transition to clean energy and stimulate further market growth.

Traditionally, investments in renewable energy resources have been assessed using the Levelised Cost Of Electricity (LCOE). The LCOE calculation is a well-established standard for financially comparing different renewable energy resources and serves as a benchmark criterion for judging most renewable energy projects. Though, it disregards the business perspective of solar PV manufacturers, it only provides insights in the profitability from the customer perspective. The following figure, shows the LCOE of solar compared to wind, gas peaking and nuclear (Research, 2024).

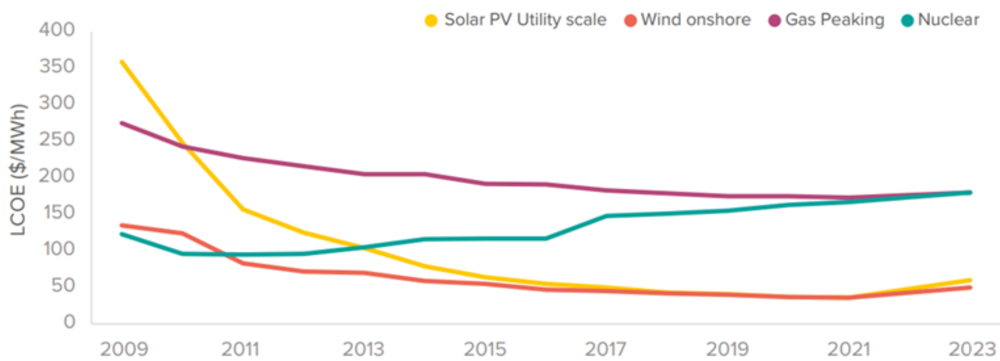

Figure 1: Depiction of the LCOE of utility scale solar PV compared to wind, gas peaking and nuclear energy generation.

From figure 1 it becomes clear that utility scale solar PV is much cheaper than traditional energy generation from gas peaking and nuclear. Furthermore, solar PV currently has reached grid parity in large parts of the world

(Muhammad Kamran et al., 2019), meaning using solar PV as energy resource is cheaper over its entire lifetime compared to electricity from the grid. This means that for customers, it is financially more attractive to consume generated energy from solar PV rather than consuming electricity from the grid. For solar PV consumers, that is beneficial, since the they save more money on their electricity bill. For solar PV manufacturers however, the LCOE lacks insights into the effects of the solar PV module cost on the solar PV project profitability.

Past research has thoroughly studied the effects influencing the LCOE of solar PV for fixed crystalline silicon glass panels under varying circumstances. A paper from 2011 in the Renewable and Sustainable Energy Reviews (Wang, Kurdgelashvili, Byrne, & Barnett, 2011) has covered the effects of module efficiency and module costs on the LCOE. More recently, papers have been published looking into the same effects for thin film technologies like perovskite. This paper (Michele De Bastiani & Grancini, 2022) studied the sensitivity of perovskite module efficiency and cost on the LCOE. Information on the cost and efficiency of solar PV modules are often used as inputs and obtained from respected large research institutes like the German Fraunhofer with a recent report from 2024 (Philipps & Warmuth, 2024) or from the American National Renewable Energy Laboratory (NREL) with a renowned report from 2022 (NREL, 2022)Nevertheless, the papers all lack in providing insights into the cost constraints of solar PV modules. A better understanding in the cost constraints for different evolutions of modules is particularly interesting for new technologies, like thin film solar PV modules. Since these products have not reached full production scale, and are still being innovated and developed, future market prices are hard to predict. Therefore, understanding the value these products can provide is vital in understanding the business feasibility of these products. This understanding is needed for thin film solar PV manufacturers to understand their position in the market. This research aims to provide a better understanding of the cost constraints of thin film solar PV modules under varying circumstances. Therefore, an updated study on the sensitivity of the module efficiency and module cost is needed.

To study this research gap, a different approach to the LCOE is needed and will be combined with reverse engineering. Reverse engineering studies are useful for understanding the limits under which products are feasible, from a manufacturer. In this context, the reversed LCOE method combines LCOE with reverse engineering to determine cost constraints from the manufacturer perspective. More specifically, determining the capital cost constraints for PV modules in a solar PV system under varying circumstances. This method keeps the flexibility of the LCOE method in using various case studies and to study the sensitivity of parameters on the results. This is particularity useful for the assessment of business models using new technologies in solar PV modules and it helps speciality solar PV module manufacturers better understand their product market fit. In literature, this method was used to assess the cost constraint for wave energy in this paper (de Andres, Medina-Lopez, Crooks, Roberts, & Jeffrey, 2017) . However, in this study this approach aims to establish the maximum allowable expenditures for thin film solar PV module costs across different solar PV technologies and conditions, providing manufacturers with critical insights to optimize their offerings.

In conclusion, this method is used because it has the flexibility, like the standard LCOE, to study different scenario's and perform a sensitivity study of the results, while also being able to obtain tangible results for solar PV module manufacturers.

1.2 Current status solar PV

When looking into the solar PV module profitability, one can look into the solar PV module prices. The following image shows the solar PV module prices of the last twelve months, from June 2023 till June 2024.

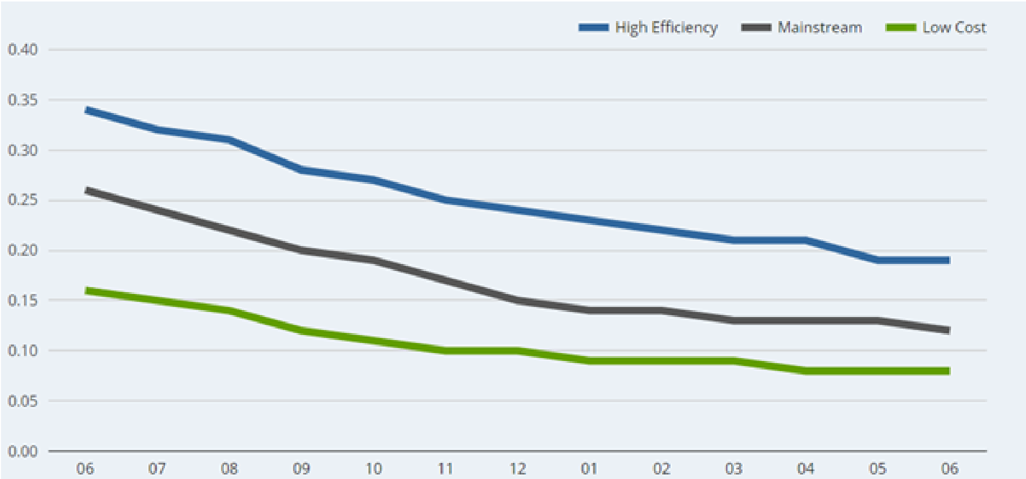

Figure 2: Solar PV modules prices of the last twelve months, from Juni 2023 until Jun 2024, expressed in €/Wp, for high efficiency, mainstream and factory second modules.

From figure 2, solar PV manufacturers show decreasing prices over the last twelve months (PVXchange, 2024). Prices are dependant on the quality of the solar panels and the efficiency. In general, the prices of solar modules in in the range of 0.10- 0.20 €/Wp. This is largely due to economies of scale. As already mentioned, the market of solar PV is in a rise and economies of scale enable manufacturers of solar panels to produce at larger scales. The following figure shows the economies of scale for solar PV manufacturers.

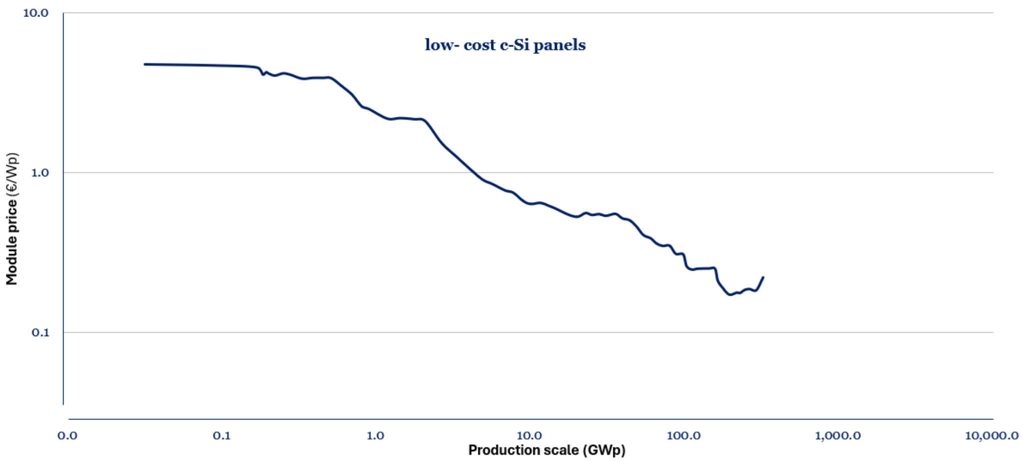

Figure 3: Solar PV module cost in €/Wp on production scale in GWp for CdTe and c-Si panels.

From figure 3, it becomes clear that as the market is approaching production scales of 100- 1000 GW, panel prices in the range of 0.10- 0.20 €/Wp become profitable. Figure 3 and figure 2 also show the market is highly competitive. This is good news for solar PV consumers, obtaining low priced solar PV panels. Nevertheless, the low costs due to economies of scale are a barrier for new market entrants in producing solar PV modules at a competitive price.

1.3 Scope

In this study, the focus will be on a particular technology of solar PV, namely, thin film technology. Thin film solar PV is able to serve the niche market of lightweight roofs, without competition of the highly matured traditional solar PV market. As such, the goal of this study is to provide better insights into the profitability of solar PV manufacturers of thin film modules.

1.3.1 Thin film technology

Thin film solar modules are a type of solar modules processed, using deposition of a photovoltaic material onto a substrate. These substrate are typically only a few μm thick, allowing for more flexibility and lightweight. Whilst traditional solar modules are made using wafers.

Traditionally, solar panels have predominantly been constructed using crystalline silicon (c-Si) photovoltaic cells. The production process begins with high-purity silicon, which is used to grow ingots through the Czochralski method. These cylindrical silicon ingots are subsequently thinly sliced into wafers with a thickness ranging between 100 to 300 μm. This slicing process is one of the limiting factors in reducing the thickness of the active material of solar cells. After being cut in thin discs, the wafers undergo a doping process with either boron or phosphorus to enhance electron and hole concentrations, respectively. These doped wafers form the fundamental structure of a solar cell.

The manufacturing of a complete solar panel involves several steps: applying aluminum finger contacts, laser scribing, adding a transparent conductive oxide (TCO) layer, integrating back contacts, and encasing the assembly. This meticulous process enables crystalline silicon cells to achieve standard efficiencies well above 20%. Ongoing research and development efforts are continuously pushing the boundaries of efficiency, making c-Si cells a reliable and highly efficient option in the solar market.

Conversely, thin-film cell construction needs a substrate on which it is realised. The substrate can be either a transparent insulator or a metal like aluminum. The active material can be made from Cadmium Telluride (CdTe), Copper Indium Gallium Selenide (CIGS) and amorphous silicon (a-Si).

CdTe technology is made from the deposition of a cadmium sulfide (CdS) buffer layer onto a substrate, followed by a CdTe absorber layer. This can be achieved through techniques such as vapor transport deposition or close-spaced sublimation. CdTe modules can achieve high efficiencies, up to 22.3%, but contain cadmium, a toxic element, requiring special precautions to be taken during manufacture, installation, and disposal (Buonomenna, 2023).

CIGS technology, on the other hand, employs a complex absorber layer consisting of copper, indium, gallium, and selenium. The CIGS thin films are typically deposited on a flexible substrate through processes such as co-evaporation or sputtering. A key advantage of CIGS technology is its high efficiency potential, which has reached over 22% in laboratory settings (Benda, 2020).

However, this study will focus on a-Si thin film solar technology. a-Si is a type of thin film solar technology that offers unique advantages for specific applications due to its distinct material properties and manufacturing processes. Unlike crystalline silicon (c-Si), a-Si has a different atomic structure, which results in different electrical and optical characteristics.

The production of a-Si thin film solar cells begins with the deposition of silicon in its amorphous form onto a substrate, which can be glass, metal, or plastic. At HyET Solar in Arnhem, this is achieved using plasma-enhanced chemical vapor deposition (PECVD) of silane gas (SiH4) onto an aluminum substrate. PECVD is a key technique because it allows for the deposition of thin layers of a-Si at relatively low temperatures, making it compatible with flexible substrates. Once the a-Si layer is deposited, several additional processing steps are performed to complete the solar cell. These include the application of doped layers to form p-i-n (positive-intrinsic-negative) junctions, which are essential for creating the electric field that separates charge carriers generated by light absorption. A transparent conductive oxide (TCO) layer is also applied to the front of the cell to facilitate the collection of generated current, while maintaining high transparency to incoming sunlight.

One of the primary benefits of a-Si technology is its potential for low-cost production. The thin layers require less material usage, and the deposition processes can be conducted at lower temperatures compared to c-Si. Moreover, a-Si cells exhibit a higher degree of flexibility and lightweight properties, making them ideal for applications where traditional rigid and heavy panels are unsuitable. However, a-Si solar cells typically have lower efficiencies compared to c-Si and other thin film technologies like CdTe and CIGS. Efficiencies for a-Si modules generally range below 10%, though continuous advancements aim to improve the efficiency. Moreover, a-Si cells have better performance in low-light conditions and high-temperature environments, which can be beneficial in certain climatic conditions.

In this study, thin film amorphous silicon solar PV modules produced by HyET Solar in Arnhem will be studied. Currently, they focus on three types of modules. The first module consists of a single junction hydrogenated amorphous silicon (a-Si:H) layer that could yield an efficiency of 8%. The second module consists of a double junction between the same a-Si:H layer and hydrogenated nanocrystalline silicon that could yield an efficiency of 12%. The third, and last evolution is a double junction between the same a-Si:H and perovskite that could yield an efficiency of 16%. These three types of modules will be studied in this research. All three modules will have comparable weight. Since the largest portion of the weight is encapsulant and lubricant, the active layer does not play a significant role in the total weight. All three modules are considered to weight 2 kg/ m^2.

1.3.2 Customer profile

The technology of a-Si thin film solar modules is particularly well-suited for niche market segments, such as lightweight roofs. Up until now, glass panels have been dominant in the PV market. However, these glass panels require strong roofs capable of sustaining loads up to 25 kg/m2. Specifically, c-Si panels weight approximately 13.2 kg/m2 (Philippe Stolz, 2017) and CdTe PV modules can weight up to 16.5 kg/m2. When including balance of system components, the total weight often exceeds 20 kg/m2. This substantial weight is due to the PV cells being encased in large aluminum frames, which are then mounted onto additional structural frames on the roofs. These extra materials not only increase environmental impact but also raise the product cost and installation expenses. The high weight of glass PV panels restricts their implementation to areas that can support the load. A study conducted by Systemiq in the Netherlands (Systemiq, 2021a) revealed that many roofs can't support such heavy panels without reinforcement. The study estimates that 25% of industrial roofs and roofs on distribution centers are severely limited in their capacity to carry such solar panels, without structural reinforcement. This reinforcement involves significant investment in building infrastructure, temporary disruptions to building operations, and increased emissions.

As a result, thin film solar PV strategically positions itself to seize opportunities within the niche market of lightweight roofing solutions. Thin film PV modules are characterized by their slim and lightweight design. Among various options, this study focuses on polymer-encapsulated thin film PV modules with bottom adhesives, developed by HyET Solar. This design make the panels easier to install, lowers material usage, thus makes them more accessible during operation for maintenance. Further advantages are the anti-fouling top layer, reducing soiling losses, the lower environmental footprint, local supply chain of materials, no use of harming materials and the ability to be bended for more complex roof designs.

Lastly, this study focuses on commercial scale roofs, meaning about 1 MWp of installed capacity. For a-Si thin film PV modules, this equates a roof area of about 10,000m^2.

1.3.3 Study cases

To be able to understand the effects of different environments on the business case of a thin film PV project, four different study cases are chosen. The performance of solar PV is very dependent on the solar irradiation. In dessert land and near earth's equator, the average daily solar irradiation can be as high as 6 kWh/m^2. Whilst in locations further away from the equator, the solar irradiation can be as low as 3 kWh/ m^2. This means highly irradiated areas receive twice the amount of energy. This has a huge difference on the solar yield of a project, and also on the business profitability. Therefore, this study will cover both dessert area as well as a lower irradiated area.

Apart from the technical performance of the PV modules, economic environment also plays a large role. To finance a solar PV project, securing funds through debt is often the most cost-effective option.The cost of debt depends on the risk perceived by the lending bank and the economic conditions in the specific country. For example, stable regions like Northwest Europe typically have lower debt rates, whereas less developed regions, such as Southeast Asia, tend to have higher debt rates. In this study, we will select one location with relatively high and another with relatively low debt costs for comparison.

Lastly, a key factor that significantly impacts business profitability is the value of energy, specifically, the price at which a kilowatt-hour of energy can be sold. In some energy markets, prices are determined by the state, whilst most energy markets have auctions to determine the energy prices. On one hand, state set energy prices are easy for future prognosis and give stability to the energy market. On the other hand, it results in little transparency on the market dynamics and is dependent on government policy. In this study, two locations are chosen with a fixed energy price and two locations are chosen with a market dependent energy price.

These three key factors namely, solar irradiation, cost of debt and value of energy, were used to determine four distinct case studies. The first case study is in UAE, Dubai. This location has a very high irradiance, relatively low cost of debt and a moderately low but stable energy price. The second case study is in the Netherlands, Zuid-Holland. This location has a low irradiance, a relatively low cost of debt and a high and uncertain energy price. The third case study is in Indonesia, Java. This locations has a moderate irradiance, a high cost of debt and a moderate but stable energy price. The fourth, and last case study is in the USA, Colorado. This location has a high irradiance, a low cost of debt and a moderate energy price.

These four locations will be used to compare, and understand the business profitability of thin film solar PV modules.

1.4 Objective and outline

The objective of this study is to derive actionable insights into the cost constraints of thin-film solar PV modules with a specific focus on their application in commercial-scale lightweight roof projects. The focus is on understanding the economic feasibility and profitability of deploying these modules in commercial-scale solar PV projects by identifying and analyzing the cost constraints.

In this study, thin-film solar PV modules will be examined, produced by HyET Solar, evaluating three different technological evolutions with efficiencies of 8%, 12%, and 16%. These technologies are particularly suited for application on lightweight roofs of large buildings, where the load-bearing capacity is limited to a maximum of 2 kg/m^2, including the modules and associated cabling. The area under consideration for each case study is a 10,000 m^2 flat roof without any tilt.

The research encompasses four distinct geographical locations: the UAE, the Netherlands, Colorado, and Indonesia. Each location presents unique environmental. financial and market conditions, which will influence the performance and economic viability of the solar PV installations. The study aims to assess the profitability of solar PV installations in each of these locations, under the constraint of lightweight roofs, by analyzing the economic performance using the reversed LCOE method. This method, detailed in Chapter 2, is critical for understanding the cost threshold at which these thin-film PV modules can be profitably deployed in each specific context. The calculations are shown and discussed in chapter 3. Following the application of this method to the case studies, the findings on cost constraints will be discussed in Chapter 4. This discussion will include a comparative analysis of the results across different locations and efficiency levels, as well as a sensitivity analysis to identify key factors influencing profitability. Ultimately, the study aims to provide tangible, data-driven conclusions on the profitability and cost constraints of thin-film solar PV technology, offering valuable insights for both manufacturers and project developers considering these technologies for commercial-scale applications. The final conclusions and implications of these findings will be elaborated in Chapter 5.

2 Methodology

This section outlines the method and the data used in this study. First, the levelized cost of energy concept will be discussed, including its inputs and its use. Then, the LCOE concept is applied and rewritten to obtain a formula to describe the financial constraints of such a project. This enables manufacturers and project developers to better understand capital cost constraints of PV modules with respect to the entire project. Thereafter, the individual variables in the formula are discussed like the energy yield calculation, the weighted average cost of capital (WACC), the electricity prices, the operational expenditures (Opex) and the capital expenditure (capex) of the balance of systems, as inputs for the cost constraints. For all the study cases, the area of the roof where the modules will be installed is 10,000 m^2 and the modules have an operational lifetime of 16 years.

2.1 LCOE

To assess the economic viability of a PV system, the levelized cost of energy (LCOE) formula is used as renowned method. The LCOE is a metric in the energy sector, representing the average cost per unit of electricity generated, typically per kilowatt-hour. This metric provides a comprehensive means of comparing different energy technologies on a consistent basis, allowing for informed decision-making regarding investments and policy development.

importance of LCOE By providing a standardized metric, the LCOE allows for comparing different energy generation technologies such as solar PV, wind, nuclear and fossil fuels under varying economic and technical conditions. It is particularly useful in identifying trends in the cost of renewable energy technologies over time and understanding the impacts of technological advancements and economies of scale. From a business development perspective, the LCOE is instrumental in shaping investment strategies in the energy sector. Investors and companies use the LCOE to assess the financial viability of PV project compared to other energy technologies. LCOE is also an important indicator for policy development. Policymakers rely on the LCOE to design and implement regulations and incentives that promote the deployment of cost-effective renewable energy technologies. Feed-in tariffs, tax credits, and renewable energy certificates are examples of policy mechanisms informed by LCOE analysis. These policies help create a favorable economic environment for sustainable energy innovation and deployment, driving further reductions in its LCOE and supporting the transition to a sustainable energy future.

Energy yield To determine the LCOE, energy yield estimation plays a crucial role. Energy yield refers to the total electrical energy output generated by a PV system over as specific period, typically measure in kilowatt-hours (kWh).
Solar irradiance, representing the solar energy received per unit area, forms the basis of energy yield calculations. Solar irradiance data, often expressed in kilowatt-hours per square meter per year ($kWh/m^2/year$), is collected and analyzed to predict the potential energy production of a PV system. Site-specific factors such as geographical location, climate conditions, and seasonal variations are taken into account to provide accurate estimates of solar irradiance.
Technical and empirical data about the performance of PV modules are crucial inputs for determining the energy yield. This data provides insights into the efficiency and capabilities of the PV system, influenced by factors like orientation, tilt angle can affect the performance. Combining the solar irradiance and the expected efficiency, the expected yearly energy yield can be calculated.
When considering the energy generation over the entire useful lifetime of a PV module, the yearly degradation rate should be accounted for as well. The degradation rate refers to the annual decrease in the energy output of a PV system due to the gradual decline in the performance of the solar modules. This rate is typically expressed as a percentage per year. Over time, the efficiency of PV modules diminishes, reducing the overall energy yield. Accurately estimating the degradation rate is essential for long-term projections of energy production and for determining the LCOE, as it impacts the total amount of usable energy generated over the system's lifespan. By incorporating the degradation rate into energy yield calculations, more realistic and reliable predictions of the PV system's performance and economic viability can be achieved.

Capital and operational expenditures Aside of the energy generation, the LCOE also includes all costs associated with the generation of electricity over the lifetime of the system, providing a thorough economic assessment. These costs include capital expenditures (capex) of both the PV modules as well as other materials like wiring, mounting structures, inverters and other essential hardware, also known as balance of system. These

costs are initial investments required to install the PV system. Additionally, it includes costs related to site preparation, labour installation and connection to a meter or to the grid, which can vary significantly based on the project's location and scale.
Operational expenditures (opex) are also a critical component of the LCOE, addressing the ongoing costs of operating and maintaining the PV system throughout its operating life. Opex includes regular operation and maintenance (O&M) activities such as performance monitoring, cleaning the solar modules to ensure optimal performance, conducting routine inspections and performing necessary repairs. Insurance costs fall under Opex as well, providing financial protection against potential damages and losses due to unforeseen events. These recurring costs ensure the system's reliability and longevity, contributing to the overall economic evaluation captured by the LCOE.

Exclusions Importantly, the LCOE calculations excludes potential costs associated with grid integration, such as costs related to upgrades to transmission and distribution infrastructure or ancillary services needed to support grid stability. Especially for offshore wind, these costs play a important role in properly defining the LCOE as shown in a study from Gu Choi in 2015 (Gu Choi, Yong Park, Park, & Chul Hong, 2015). For solar PV, it plays a smaller role, and due to time constraints, it is not included in this study.
Additionally, the LCOE does not account for residual value of the system at the end of its operational life. In some cases, components of the system may retain value through resale, recycling, or repurposing, which could potentially offset some of the initial costs. However, excluding residual value simplifies the calculation and provides a conservative estimate of the cost of energy.

Financing principles Furthermore, the LCOE incorporates the cost of financing the PV system, an essential element that reflects the time value for money. This financial component includes several key element, such as the interest paid on loans used to finance the initial Capex, and the return on equity expected by investors. These financing costs are critical because they directly impact the overall economic feasibility of the project.
When a PV system is financed through debt, the interest paid on loans constitutes a significant portion of the ongoing costs (Eero Vartiainen, 2019). The terms of the loan, including the interest rate and the repayment schedule, influence the magnitude of these costs. Higher interest rates and longer repayment periods increase the financial burden on the project, thereby raising the LCOE. Conversely, favorable loan conditions with lower interest rates and shorter repayment periods can reduce the overall cost, making the PV system more economically attractive.
In addition to debt financing, equity financing plays a vital role in the overall financial structure of PV projects. Equity investors, same as lenders, expect a return on their capital. The expected return on equity varies based on factors such as market conditions, perceived risk, and alternative investment opportunities. A higher expected return on equity, increases the LCOE, reflecting the need to generate sufficient revenue to meet investor expectations. Conversely, lower expected equity return reduces the LCOE, enhancing the project's financial appeal.
The LCOE calculation incorporates these financing costs by discounting future cash flows to present value terms. This discounting process is essential because it acknowledges the time value of money, the principle that a euro is worth more today than in the future due to its potential earning capacity. The process of discounting is applied by using a discount rate. A value by which money is discounted over time to represent its true value. By applying a discount rate, the LCOE captures the present value of all future costs and revenues associated with the PV system. This approach ensures that the financial analysis accurately represents the true cost of generating electricity over the system's lifetime.
This discount rate used in the LCOE calculation is typically determined by the weighted average cost of capital (WACC), which reflects the overall cost of financing, considering both debt and equity. The WACC is a critical factor in the LCOE as it balances the cost of debt and the required return on equity, providing a comprehensive measure of the project's financing costs. A higher WACC indicates higher overall financing costs, leading to a higher LCOE, while a lower WACC suggests more favorable financing conditions and a lower LCOE.

In summary, the Levelized Cost of Energy (LCOE) is an essential metric for evaluating the economic viability of energy systems, particularly PV technology. By accounting for all factors associated with electricity generation, including capital expenditures (capex), operational expenditures (opex), and energy yield, the LCOE provides a comprehensive measure of the true cost of energy. Furthermore, by accounting for the time value of money through discounting future cash flows, the LCOE ensures an accurate and realistic financial assessment. This holistic approach enables investors, policymakers, and other stakeholders to make informed decisions, supporting the strategic development and deployment of renewable energy technologies.

The formula, expressed in €/kWh is expressed as follows:

$$\text{LCOE} = \frac{\text{C}_{\text{capex}} + \sum_{t=0}^{N} \frac{\text{C}_{\text{opex}}}{(1+\text{WACC})^t}}{\sum_{t=0}^{N} \frac{\text{E}_{\text{yield}} \times (\text{1-DR})^t}{(1+\text{WACC})^t}} \tag{1}$$

LCOE : Value of energy (€/kWh)
$\mathbf{C}_{\text{capex}}$: Capital expenditures (€)
$\mathbf{C}_{\text{opex}}$: Operational expenditure (€/year)
N : Useful life of the system (years)
WACC : Weighted average cost of capital per year (%/year)
$\mathbf{E}_{\text{yield}}$: Production yield (kWh)
DR : Degradation rate (%/year)

Using the variables listed, the LCOE can be calculated. The LCOE functions as the minimum selling price for PV project owners, representing the lowest price at which they can sell the generated electricity while covering all costs and achieving the desired return on investment.

2.2 Grid parity

Crystalline PV panels have been leading the charge towards grid parity. A notable milestone was achieved in 2012 when Germany witnessed the historic convergence of solar LCOE and grid prices, making a pivotal moment in the global transition towards sustainable energy sources (Wirth, 2014). Since then, the trajectory towards grid parity has accelerated, having reached grid parity in multiple countries and market segments around the world (Muhammad Kamran et al., 2019). However, for thin film PV systems, the journey towards grid parity presents a distinct set of challenges. Unlike their crystalline counterparts, thin film technologies face hurdles such as lower efficiencies, higher degradation rates, and shorter lifespans, which pose significant obstacles o achieving cost competitiveness. Despite technical advancements aimed at enhancing thin film technology, literature on its grid parity of thin film PV systems remains sparse, highlighting the early development stage and the challenges in evaluating its economic viability on a large scale.
In light of these challenges, this study explores the cost constraints of PV systems at grid parity by assuming grid parity as a foundational premise. To achieve this, the LCOE formula will be reversed, enabling a comprehensive analysis of cost dynamics. This approach utilizes a reversed LCOE framework, similar to methodologies employed in previous research on the cost constraints of wave energy production (de Andres et al., 2017). Through this investigative lens, we seek to identify the key cost constraints and underlying factors that govern the economic feasibility of thin film PV systems. By examining the nuances of technology innovation, performance optimization, and market dynamics, we aim to uncover the limiting factors and key influences. This understanding will be crucial for achieving grid parity and enhancing the competitiveness of thin film PV systems in the renewable energy market.
In summary, the aim of the reversed LCOE study serves as a critical exploration into the challenges and opportunities surrounding thin film PV technology, offering valuable insights for policymakers, industry stakeholders, and researchers alike. Through a holistic examination of cost drivers and performance metrics, we aspire to catalyze the advancement of thin film PV systems towards grid parity, thus contributing to the realization of a sustainable and resilient energy future.
Using the same variables as used in formula 1, the formula is rewritten with capital expenditure as unknown and LCOE as variable input. Since, LCOE is assumed to be the electricity price, this yields the following formula:

$$\text{C}_{\text{capex}} = \sum_{t=0}^{N} \frac{\text{E}_{\text{yield}} \times (\text{1-DR})^t \times \text{LCOE} - \text{C}_{\text{opex}}}{(1+\text{WACC})^t} \tag{2}$$

Using the reversed LCOE formula, we can determine the capital expenditure (Capex) constraints for a PV project. This approach involves calculating the net present value (NPV) by considering the generated energy,

multiplying it by the value of the energy, and then discounting this product over the project's lifetime. From this amount, we subtract the operational expenses incurred during the project lifespan.
The resulting NPV indicates the point at which the project neither gains nor loses money, meaning that at a Capex equal to the NPV, the project will break even. In other words, all lenders and investors will receive their capital with the expected returns paid over the project's duration. Thus, the reversed LCOE formula provides a clear representation of the capex limitations, making it a valuable tool for project developers when assessing the financial viability of PV projects.

It is essential to recognize that the target LCOE, e.g. the electricity price, varies significantly across different scenarios. Additionally, the WACC and energy yield are not consistent in all situations, making it imperative to account for these variations when conducting an economic feasibility analysis. To address these differences, this study will focus on four distinct locations: the United Arab Emirates (UAE), the Netherlands, Indonesia, and the United States (Colorado). These locations have been selected to represent a diverse range of climatic, economic, and regulatory environments, providing a comprehensive understanding of the factors influencing PV system viability.
For each of these case studies, specific values for the LCOE, WACC, and energy yield will be determined and analyzed in the following chapters. The electricity price, in particular, will be evaluated under two scenarios for each country: own use and selling to the grid. This distinction is crucial as it reflects the different economic contexts, regulatory frameworks, and incentive structures that impact the profitability of PV projects. Similarly, the WACC will be examined under two scenarios per location, reflecting variations in the expected return on equity. These scenarios will account for different financing conditions and investor expectations, providing a nuanced understanding of how financial factors influence project viability.

This analysis offers crucial insights for thin film PV module manufacturers, as it helps to establish a maximum price for their products, ensuring competitiveness and economic feasibility within the renewable energy market.

2.3 Energy yield calculations

To obtain realistic values for the energy generated on a specific location in the world, the Solar Atlas database is used. Solar Atlas provides information on solar resource and photovoltaic power potential globally by making use of the SolarGIS model. It is a well known and renowned method within the solar industry to obtain reliable data for a typical meteorological year.

Solargis Solar Radiation Methodology Solargis calculates the GHI using Typical Meteorological Years (TMY). TMY is a set of weather data for a specific location. This dataset is designed to represent a year with average weather conditions based on historical data. This data set is visualised in figure 4 for locations around the world.

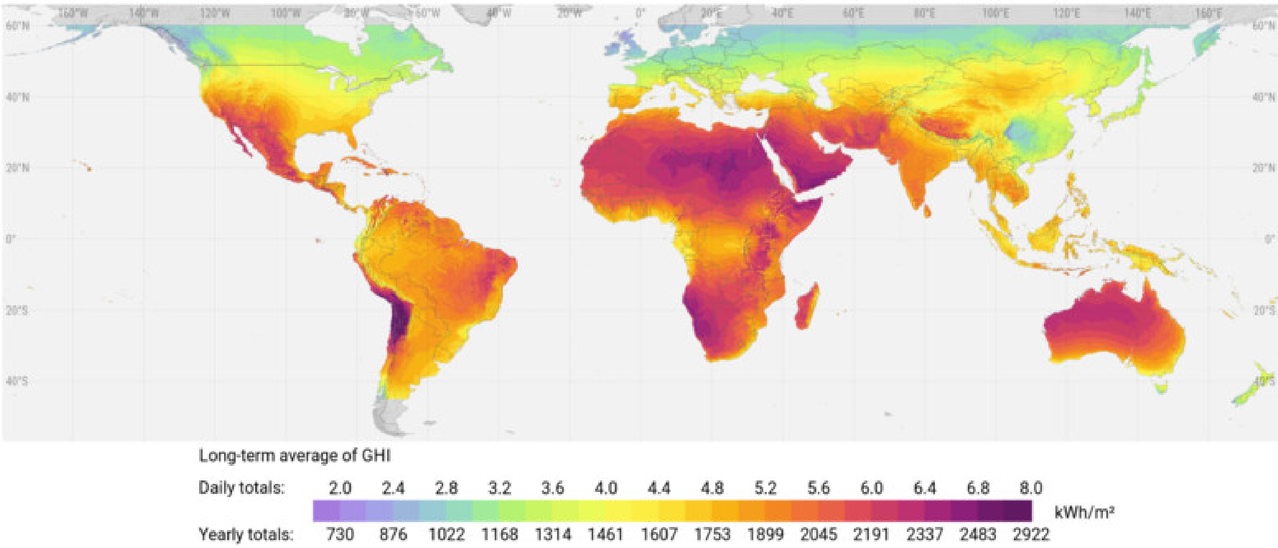

Figure 4: Solar Atlas GHI data

To determine the Global Horizontal Irradiance (GHI) from TMY data, the average values of both Direct Normal Irradiance (DNI) and Diffuse Horizontal Irradiance (DHI) are measured. The GHI can be calculated using the following formula:

$$\mathrm{GHI} = \mathrm{DHI} + \mathrm{DNI} \cdot \cos(\theta) \tag{3}$$

Where θ represents the solar zenith angle, which is the angle of the sun's irradiance relative to the Earth's surface. This angle varies continuously over time between 0° and 90°. SolarGIS has calculated all the solar zenith angles during a TMY with time steps of 15 minutes. In this study, the SolarGIS data for the four locations will be used.
Furthermore, tilt angle of the panels is 0°. In such situation, no albedo effect takes place. Also, the Sky-View Factor (SVF) is assumed to be 1, meaning a clear with no obstruction of buildings. With 0° tilt angle, the GHI is equal to the total irradiation on the panel. Using the Solargis data, the following data is gathered and used as GHI:

Country	Irradiance (Wh/Wp/year)
UAE	2,212
NL	1,048
Indonesia	1,683
Colorado	1,770

2.3.1 Performance losses

Though, not all irradiation can be converted to electricity. The total irradiated energy undergoes losses like system losses, degradation losses, temperature losses and losses due to soiling. From SolarGIS, average performance losses historically range between 15%-20%. These performance losses were calculated for crystalline silicon glass panels.
Thin film solar PV modules have different spectral mismatch losses and electrical losses within the module. Though, cable losses and inverter losses are the same, since those a not dependent on the modules.
The studied modules from HyET Solar have not been studied comprehensively during operations to assess the performance losses properly over its lifetime. Therefore, the traditional performance losses for a general PV system are used to determine the performance losses of the study cases. For this study, a performance ratio of 85% is assumed. This means that of all irradiated energy, on average of its entire lifetime, 85% is converted by the PV system into useful energy. In section 4.3 a sensitivity study is conducted on the performance ratio to understand the implications of a lower and a higher performance ratio on the cost constraints of the modules and the overall profitability of the project.

The energy output per year can be calculated by multiplying the specific yield by the performance loss for every location. This results in the following values:

Country	Irradiance (Wh/Wp/year)	Performance ratio (%)	Average Solar yield (Wh/Wp/year)
UAE	2,212	85	1,880
NL	1,048	85	891
Indonesia	1,683	85	1,431
Colorado	1,770	85	1,083

Over its entire lifetime, the solar modules degrades thus yield a lower performance. HyET has conducted experiments on the degradation rate, confirmed by the NREL, and showed a degradation rate of about 0.5% per year. This means, that every consecutive year, from the first year onwards, the modules convert 0.5% less energy compared to the year before.
This will be implemented in the net present value (NPV) of the project. Therefore, the values will not be implemented in the solar yield, but rather within the discounting of the annual revenues, combined with the value of energy discussed in section 2.5.

2.3.2 Installed capacity

In this section, the total installed capacity of the three different technologies is shown. As discussed before, 8%, 12% and 16% efficiency modules are used in the study cases. Since the roof area in the study is constant, the installed capacity varies. The following installed capacities are assumed in the study cases for the three different evolutions of technologies:

Country	Coverage (%)	8% module (MWp)	12 % module (MWp)	16% module (MWp)
UAE	90	0.72	1.08	1.44
NL	90	0.72	1.08	1.44
Indonesia	90	0.72	1.08	1.44
Colorado	90	0.72	1.08	1.44

Table 1: Installed capacity of the three evolutions of thin film solar PV module system for 10,000m2 roof area.

Note, due to the use of three different technologies, spectral mismatch may vary. From a study by Dupré in 2018, a maximum of 2.1% difference in spectral mismatch is found when comparing two terminal tandems cells with single junction cells (Dupré, Niesen, De Wolf, & Ballif, 2018). This difference is neglected in the study for simplicity and a marginal expected effect on the study cases.

2.4 Financing cost

To obtain cost constraints, more values have to be determined. First, the weighted average cost of capital (WACC). It is a crucial parameter affecting the PV system's LCOE, and appeared to be one of the largest influencing factors according to (Langer et al., 2023) for a comparable techno-economical study of PV systems. The WACC is the weighted average between the cost of debt and the cost of equity financing. The share between debt and equity financing is dependent on the lender's conditions. The formula of the WACC can be calculated as follows:

$$\text{WACC} = \frac{D \cdot k_D \cdot (1 - \text{CT}) + E \cdot k_E}{D + E} \tag{4}$$

where:

- D is debt financing
- k_D is the interest rate of debt financing
- CT is the corporate tax rate
- E is equity financing
- k_E is the interest of equity financing

The WACC is calculated using the interest rates of debt (k_d) and equity (k_E), share of debt (D) and equity (E) on the total investment and the corporate tax rate (CT). The corporate tax rate is included for the debt financing since no tax has to be paid for if the company would have made a profit elseways. The interest rate of debt financing is dependent on the lender's conditions. In this study, it is different for every case study. The debt ratio is equal for all project. Both in (Gautam, 2023) and in (Langer et al., 2023) the debt ratio was 70% and the equity ratio 30%. In this study, the same figures will be used for debt and equity ratios.

Cost of debt and cost of equity

The cost of debt for solar projects depends on various factors. The interest rate by banks, the additional risk of the project and the expected profit from the lender are included. The Climate Policy Initiative has conducted a research on the interest rate of debt in various countries (Gautam, 2023). The analysis is conducted using the Capital Asset Pricing Model (CAPM), a popular method often used to determine cost of debt and equity. The formula for CAPM is as follows:

$$\text{Required Rate of Return} = \text{Risk Free Rate} + \beta \times (\text{Required Market Returns} - \text{Risk Free Rate}) \tag{5}$$

This traditional method includes for multiple factors. The risk free rate is a rate, independent of a niche or sector, and represent the minimal required return rate in a certain country or region and serves as a benchmark for alternative investments. It is a value, dependent on the credit rating, assigned by a credit rating agency like Moody's, Standard & Poor's or FitchRatings. The second factor is the project dependent risk. The β indicates the volatility, or systematic risk, relative to the benchmark. This value, together with the required market returns, are evaluated by financial agencies. As such, the Climate Policy Initiative studied the financial risk, and thus the required return rate for debts in the solar industry. Additionally, the Climate Policiy Initiative added an extra variable called the Climate investment Risk Premium(CIRP) to incorporate the additional risk of climate investments. The CIRP is determined using a Climate Investment Risk Score (CIRS). The CIRS incorporates the national government credit risk (SR), off-taker risk (OR) and political risk (PR). The CIRP is included and serves as the quantitative representation of additional investment risk due to an investment in the field of solar energy generation. Incorporating climate investment risk in the CAPM formula yields the following:

$$\text{Required Rate of Return} = \text{Risk Free Rate} + \beta \times (\text{Required Market Returns} - \text{Risk Free Rate}) + \text{CIRP} \tag{6}$$

In this study, figures from January 2023 will be used for the estimation of the cost of debt and the required rate of equity return for climate projects per country.
According to a study from Jannis Langer, there is a difference in Indonesia between local financing and external financing (Langer et al., 2023). For local debt financing, the interest rate was 9.5% in his study, and up to

11.9% for certain sites. While for external debt financing, the interest rate was 6.8% and in a certain case even as low as 5.8%. For simplicity, this study will focus only on local debt financing.

In the table below, the values for the cost of debt and the required rate of equity return, or the cost of equity, are represented for the case studies used.

Location	Cost of Debt	Required Rate of Equity Return
UAE	4.5 %	12.6 %
The Netherlands	4.8 %	9.4 %
Indonesia	9.1 %	14.7 %
Colorado	4.3 %	10.3 %

Table 2: Cost of capital including the clean investment risk for different countries

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2.4.1 WACC

Finally, the WACC can be determined for a project. Using the formula explained before, the WACC will be calculated. Initially, the nominal WACC will be calculated, used for the net present value of the operational expenses during the system lifetime. Since the WACC is determined at initiation of the project, it can be assumed to be fixed for the entire project lifetime. The WACC calculation inputs are as follows:

Location	D (%)	k_D (%)	CT (%)	E (%)	k_E(%)
UAE	70	4.5	25.0	30	12.6
The Netherlands	70	4.8	25.8	30	9.4
Indonesia	70	9.1	22.0	30	14.7
Colorado	70	4.3	25.0	30	10.3

Table 3: Inputs for the formula 4 to calculate the WACC for all case studies.

Using these values, the WACC for every situation can be calculated and yields the following:

Location	WACC (%)
UAE	6.14
The Netherlands	5.31
Indonesia	9.38
Colorado	5.35

Table 4: Weighted average cost of capital for every case study.

This aligns well with number of the IEA (IEA, 2023), assuming a WACC for solar projects in EMDE countries to be between 9% and 12% and for advanced economies between 4% and 6%.

2.5 Value of energy targets

For the reverse LCOE, a value of energy target has to be set to determine the cost constraints. The value of energy target is the electricity price customers would else have payed for their electricity. In this study, the value of energy is set equal to the incumbent electricity price of the customers.

The United Arab Emirates have set ambitious goals for clean energy production by 2030 and 2050. In 2014, a net metering scheme got implemented by the Crown Prince of Dubai (DEWA, 2023) to boost the implementation of solar energy in the emirate. Due to the net metering scheme, the time value of electricity is equalized and does not play a role anymore. To determine the value of energy, the electricity price in Dubai is set as benchmark. The electricity price in the emirate of Dubai is set by the Dubai Electricity and Water Authority (DEWA). The prices vary from 23 fils/kWh for residential customers up to 38 fils/kWh for industrial customers. This equates 58 €/MWh (2024 conversion rates) and 95 €/MWh. On top 6 fils/kWh, or about 15 €/MWh, is charged on electricity as fuel surcharge (DEWA, 2023). This totals 29 fils/ MWh for residents and 44 fils/ MWh for industrial customers. In this study, only the industry customers will be interesting due to their high energy demand. Therefore, the benchmark for a target LCOE is the electricity price of 110 €/MWh.

For The Netherlands, there will be made a distinction between own use and selling of electricity. For own use, the value of energy is equal to the value of energy one would pay for electricity from the grid. For selling parties, the value of energy is equal to the selling price of the energy, minus the transport costs and the taxes payed. Last few years, the electricity price has fluctuated a lot, but over the lifetime of a PV project, the wholesale electricity price is used and is assumed to be around 75 €/MWh, with a sensitivity to be as low as 40 €/MWh according to S&P Global (SPGlobal, 2023). This is the value of energy for selling parties. For own use, extra expenses like taxes, levies and transport cost are added. This yields a total of 130 €/MWh, with 10 €/MWh for transport, 20 €/MWh for balancing and hourly differences, about 20 €/MWh for VAT and only a few euro's of levies for large consumers.

In Indonesia, all electricity prices have been set by the government (Kompas, 2023). Electricity prices are updated every three months based on Indonesia crude prices, inflation and coal reference prices (Antara, 2023). The business tariff for the months July-September 2024 is Rp1,444.70. 2024 Juli exchange rate 81.93 €/MWh (PLN, 2024). It is assumed the price will stay constant over the lifetime of the project. Additionally, there is a 5% tax rate on electricity. This total the electricity price for business consumer on 86.46 €/MWh.

In Colorado, the US, Xcel Energy serves as the regulated electric utility provider, where electricity tariffs vary based on customer classification, seasonal fluctuations, and specific charges. This study focuses on tariffs applicable to small commercial customers. As of 2024, the tariff structure includes several components: General Rate Schedule Adjustment, Purchase Capacity Cost Adjustment, Demand Side Management Cost Adjustment, Electric Commodity Adjustment, Transmission Cost Adjustment, Extraordinary Gas Cost Recovery Rider, Transportation Electrification Programs, Revenue Decoupling Adjustment Pilot, and a 2% Renewable Energy Standard Adjustment (Energy, 2024b). For the winter season, the tariff stands at 53.1 $/MWh, while during summer it rises to 88.52$/MWh. When factoring in all charges mentioned, the comprehensive rates amount to 111.45$/MWh in winter and 147.53$/MWh in summer. To simplify the analysis, the average tariff rate across seasons is considered. Accordingly, the average tariff for consumption (own use) amounts to 129.49$/MWh, whereas for electricity sold back to the grid, it stands at 70.83$/MWh. Converted to euros, these rates approximate 119 €/MWh and 65 €/MWh, respectively.

It is important to note that while electricity prices have shown a slight increase over the past decade, the potential fluctuation of electricity tariffs is not accounted for in the analysis specific to Colorado (Energy, 2024a).

This results in the following values of energy:

Location	**Own use value of energy (€/MWh)**	**Selling price of energy (€/MWh)**
UAE	110	74
The Netherlands	130	75
Indonesia	86	82
Colorado	120	65

Table 5: Value of Energy for two scenarios for the case studies

Value limitations: unaccounted influencing factors Important to note is that the value of energy for different customers does not take opportunity loss into account. This plays a very big role for a certain customer type. Since it is hard to quantify, it will not be taken into account. But it is important to note that this does make the business proposition better for customers. Also, price cannibalization is not considered in this study, Though study found that it can play a major role and lower profits by 33% (L. Reichenberg, 2023). It is still unclear on how this influences the specific customers, since the price benchmark is related to long term energy contracts. Lastly, the effect of green certificates are unaccounted for in this study. Green certificates are introduced in the US and the EU to give more incentive to produce energy using renewable energy resources. Nevertheless, the effect is still less than 1 €/MWh currently, and it is unclear how this market-based policy instrument will change in the future. Therefore, it will not be included in this study.

2.6 Opex

This section discusses all the running cost associated to the project. These costs include insurance, performance monitoring, visual inspections, spare parts, and cleaning. Effective management of these expenses is crucial for the financial viability and operational efficiency of PV projects.
According to literature, the operational costs for a 20 MWp utility-scale PV project in the U.S. range between 8-20 \$/kWp/year (Seth B. Darling & Velosae, 2011). Recent data from the National Renewable Energy Laboratory (NREL) indicate that OM costs for commercial rooftop PV panels were approximately 18 \$/kWp/year in 2022 (NREL, 2022). These values are based on 2021 USD (and should be adjusted 5% higher for 2022 estimates, applicable to systems larger than 100 kWp but less than 5 MWp.)
The International Renewable Energy Agency (IRENA) reported OM costs for OECD member countries, including both the Netherlands and the U.S., to be 17.8 \$/kWp/year in 2022 (IRENA, 2022). In 2021, it reported a cost of 18.2 \$/kWp/year for OECD countries, indicating a stable cost structure within these developed economies.
In Indonesia, operational cost estimates for utility-scale PV projects vary between 8-32 \$/kWp/year in 2021. A benchmark in a recent study used an initial value of 23 \$/kWp/year (Langer et al., 2023). This range reflects the higher variability in operational conditions and maintenance requirements in the region.
UAE currently assumed same as Indonesia, probably higher due to cleaning to prevent soiling. Using 2022 exchange rate conversion from USD to EUR, a average conversion rate over the entire year of 0.951 \$ / € is used.
Based on the literature, the following values for operational expenses will be used in this study:

Country	**Opex €/kWp**
UAE	21.87
NL	17.12
Indonesia	21.87
Colorado	17.12

Table 6: Yearly operational expenses solar projects per region.

2.7 Capex

For a thin-film PV project,, the capital investment beyond the cost of the modules can be divided into two primary categories: Electrical Balance of Systems (EBOS) and inverter costs. The innovative installation technique of thin-film PV involves attaching the modules using a glue layer on the underside, eliminating the need for structural framing and thereby reducing overall costs.
According to NREL, the minimal sustainable price for electrical balance of systems is reported to be 174 \$/kWp in 2022 for community size PV, 3 MWp, systems and 0.208 kWp/m^2 panels (NREL, 2022). This translates to 36.19 \$/m^2. This value is applicable to thin-film PV systems as well, given that labor and cable costs are proportional to the area covered, regardless of the panel efficiency.
For inverter costs, the assumption is 36\$/kWp in 2022 for community-scale PV system with a capacity of 3 MWp. Given an module efficiency of 80 Wp/m^2, the inverter cost is calculated to be 2.88 \$/m^2. For a module efficiency of 120 Wp/m^2, the inverter cost would be 4.32\$/m^2 and for 160 Wp/m^2 it would result in a cost of 5.76\$/m^2. Therefore, the total cost excluding the modules comprises 36.19 \$/m^2 for EBOS and 2.88 \$/m^2, 4.32\$/m^2 and 5.76\$/m^2 for 80, 120 and 160 Wp/m^2 respectively. Since the source data provided is from 2022, exchange rates of 2022 will be used and translates to the following capex for EBOS and inverter:

Efficiency	**EBOS €/m^2**	**Inverter €/m^2**	**Total capex €/m^2**
8%	34.42	2.74	37.16
12%	34.42	4.11	38.53
16%	34.42	5.48	39.90

Table 7: Yearly operational expenses solar projects per region.

3 Calculations

In this section, the Calculation of the reversed LCOE approached will be shown. For this, four distinct case studies are used, namely UAE, NL, Indonesia and US (Colorado). All data used for the calculations is discussed in chapter 2. Using these specific values for each case, the cost constraints in €/Wp and in €/m^2 for a thin-film PV system at commercial scale on a lightweight roof can be determined. The following formula is applied:

$$C_{\text{capex}} = \sum_{t=0}^{N} \frac{E_{\text{yield}} \times (1\text{-DR})^t \times \text{LCOE} - C_{\text{opex}}}{(1 + \text{WACC})^t} \tag{7}$$

E_{yield} : Production yield (kWh)
DR : Degradation rate (%/year)
t : Useful life of the system (years)
LCOE : Value of energy (€/kWh)
C_{opex} : Operational expenditure (€/year)
WACC : Weighted average cost of capital per year (%/year)
C_{capex} : Capital expenditures (€)

3.1 Total energy yield calculation

To determine the module cost constraint, the energy yield is calculated. Determining the energy yield is critical in understanding the project's profits. First, the energy yield is calculated on a yearly basis. This is accomplished by determining the location-dependent yearly irradiance per case study using Solar GIS data. This data shows the total solar radiation on the earth's surface over an entire, typical meteorological year. For the four study cases used, it leads to the following figures:

Country	**Irradiance (kWh/m^2/year)**
UAE	2,212
NL	1,048
Indonesia	1,683
Colorado	1,770

Table 8: The yearly median irradiance per region in kWh/m^2/year

Since, not all solar irradiation can be converted into energy, the module efficiency has to be taken into account. The module efficiency is dependent on the technology used, and in this study the following figures are used:

	SJ a-Si:H (€)	**DJ a-Si:H with nc-Si:H (€)**	**DJ as-Si:H with perovskite (€)**
Efficiency (%)	8%	12%	16%

Table 9: Efficiency (%) of the three studied technologies.

Now the solar irradiance and the module efficiency are know, the yearly energy yield depends on the actual performance of the solar modules. This is expressed in the performance ratio, and listed below for all cases:

Having these three figures, the solar irradiance, the module efficiency and the performance ratio, the yearly yield can be calculated per square meter. Though, the area used is larger. Therefore, the total area of the solar projects is to be calculated. The are used in all situations is 10,000m^2, with a coverage ratio of 90%, meaning only 90% of the roof will effectively be covered with solar modules.

Country	Performance Ratio
UAE	85%
NL	85%
Indonesia	85%
Colorado	85%

Table 10: Performance ratio (%) per situation

Consequently, the yearly energy yield can be calculated in MWh/year. This is done by multiplying the solar irradiance in kWh/$\mathbf{m^2}$/year by the module efficiency in %, the performance ratio in %, and the module surface area in m^2 and dividing by 1,000. As follows:

$$E_{\text{yearly}}(\text{MWh/year}) = \frac{\text{Irradiance (kWh/m}^2\text{/year)} \times \text{Module Efficiency (\%)} \times \text{Performance Ratio (\%)} \times \text{Module Area (m}^2\text{)}}{1000}$$

(8)

Using this equation, the following yearly energy yields are determined:

	Energy Yield (MWh/year)		
Country	η = **8%**	η = **12%**	η = **16%**
UAE	1,354	2,031	2,707
Netherlands	641	962	1,283
Indonesia	1,030	1,545	2,060
Colorado	1,083	1,625	2,166

Table 11: Yearly energy yield per region in MWh/year

Finally, the total energy yield of the entire project can be calculated. A system lifetime of 16 years is determined, with a yearly degradation rate of 0.5%. This leads to the following figures:

	Energy Yield (MWh)		
Country	η = **8%**	η = **12%**	η = **16%**
UAE	20,870	31,305	41,740
NL	9,888	14,832	19,776
Indonesia	15,879	23,819	31,758
Colorado	16,700	25,050	33,400

Table 12: Total energy yield per region and technology in MWh

3.2 Total project profit

Now that the total energy yield of the project is calculated, the value of energy is to be determined. The value of energy is dependent on energy market, country and period, but not on technology used . As discussed in chapter 2, two distinct values of energies are used, the value of energy for own use of energy, and the value of energy for selling energy. This leads to the following initial values of energy:

Location	**Own use value of energy (€/MWh)**	**Selling price of energy (€/MWh)**
UAE	110	74
The Netherlands	130	75
Indonesia	86	82
Colorado	120	65

Table 13: Value of Energy for two scenarios for the case studies

Important to note that these initial values of energy are to be discounted for future energy production years. This is necessary to repay debt and make the profit aimed for by equity owners. Therefore, the WACC is determined and used to discount the value of energy over the lifetime of the project. As described in chapter 2, the following figures are used:

Location	**WACC(%)**
UAE	6.14
The Netherlands	5.31
Indonesia	9.38
Colorado	5.35

Table 14: Weighted average cost of capital

Using the values of energy, the WACC, the yearly energy yields and the degradation rate, the total revenue of the project can be calculated. This is calculated as follows:

$$\text{Total Revenue (€)} = \sum_{t=1}^{n} \frac{E_{\text{yearly}} \times \text{Value of Energy}}{(1 + \text{WACC} + \text{Degradation rate})^t}$$

(9)

So the total revenue of a project is calculated by multiplying the yearly energy yield by the value of energy, and dividing that by the the degradation rate and the WACC, dependent on the time in years. This yields to the revenues of all cases used, for four countries, three technologies and two values of energy.

	η =8%		η =12%		η =16%	
Country	Selling	Consuming	Selling	Consuming	Selling	Consuming
UAE	1,031,866	1,533,854	1,547,798	2,300,781	2,063,731	3,067,708
NL	520,324	901,894	780,485	1,352,842	1,040,647	1,803,789
Indonesia	729,556	765,144	1,094,334	1,147,716	1,459,112	1,530,288
US	759,797	1,402,702	1,139,695	2,104,053	1,519,594	2,805,404

Table 15: Total revenue in € for a thin-film project on a 10,000 m^2 lightweight roof for four different locations, three different technologies, and two different values of energy.

3.3 Include Capex and Opex

Now, opex and capex apart from module costs will be subtracted. This includes installation costs, balance of systems and inverter cost. To finally come to the production cost constraint of the solar panel itself. These costs account for 37 €/m^2. Leading to the following values:

The opex is given below and is discounted over its lifetime with the same WACC as the value of energy is discounted with.

Country	**Opex (€/year)**
UAE	40,941
NL	32,049
Indonesia	40,941
Colorado	32,049

Table 16: Yearly operational expenses solar projects per region.

Efficiency	**Total capex €**
8%	334,440
12%	346,770
16%	359,100

Table 17: Yearly operational expenses solar projects per region.

These Capex values account for installation cost, electrical balance of systems and inverter cost. The values vary due to the increase in scale of the inverter by increasing installed capacity. This equates 0.46 €/Wp, 0.32 €/Wp and 0.20 €/Wp for 8%, 12% and 16% efficiency, respectively.

Now, including the total net profit from the project, including the discounted opex and capex, the NPV, this the total cost for modules can be estimated. Also, the cost per area and cost per capacity can be calculated. Here follows the total cost for modules available:

	η =**8%**		η =**12%**		η =**16%**	
Country	Selling	Consuming	Selling	Consuming	Selling	Consuming
UAE	€ 262,471	€ 764,460	€ 766,074	€ 1,519,057	€ 1,269,677	€ 2,273,654
NL	€ -171,957	€ 209,614	€ 75,875	€ 648,231	€ 323,707	€ 1,086,848
Indonesia	€ 31,440	€ 67,028	€ 383,888	€ 437,270	€ 736,336	€ 807,512
US	€ 68,386	€ 711,291	€ 435,955	€ 1,400,312	€ 803,523	€ 2,089,333

Table 18: Total module cost constraints in €for a thin-film project on a 10,000 m^2 lightweight roof for four different locations, three different technologies, and two different values of energy.

4 Results & Discussion

In this section, the results that follow from applying the method described in chapter 2 and applied in chapter 3 will be shown and discussed. First, the cost constraints in both €/Wp and €/m^2 will be discussed. Then, the results will be discussed more in detail by looking into the breakdown of costs. Thereafter, the sensitivity of parameters is discussed. Lastly, the limitations and opportunities of the study are discussed.

4.1 Results

In chapter 3, the reversed LCOE method served as a tool for thin film PV module manufacturers to determine the net present value of a solar PV project. Since the WACC incorporates the expected return of investment, a net present value of zero will suffice a break even scenario and the resulting added value of the project may be allocated towards the procurement of the modules. Thus, to analyze the module cost constraints per installed capacity of such projects, the cost per capacity is derived by dividing the net present values presented in Figure 18 by the system's specific capacity. This leads to the following figures.

	η = **8%**		η = **12%**		η = **16%**	
Country	Selling	Consuming	Selling	Consuming	Selling	Consuming
UAE	26 €/m^2	76 €/m^2	77 €/m^2	152 €/m^2	127 €/m^2	227 €/m^2
NL	-17 €/m^2	21 €/m^2	8 €/m^2	65 €/m^2	32 €/m^2	109 €/m^2
Indonesia	3 €/m^2	7 €/m^2	38 €/m^2	44 €/m^2	74 €/m^2	81 €/m^2
US	7 €/m^2	71 €/m^2	44 €/m^2	140 €/m^2	80 €/m^2	209 €/m^2

Table 19: Module cost constraints per area in €/m^2 for a thin-film project on a 10,000 m^2 lightweight roof for four different locations, three different technologies, and two different values of energy.

This table shows the maximal prices that customers ought to be willing to pay for solar PV modules. Maximal prices, since under the assumed conditions, these prices will yield a break even scenario for the entire solar PV project. Each case study is designed to reflect different financial and operational scenarios in different environments, providing a comprehensive understanding of the economic feasibility of photovoltaic (PV) projects.
Notably, the scenario of selling the electricity produced by 8% efficiency modules in the Netherlands, results in a negative price. This means the business is not profitable for lightweight roof consumers with a roof of 10,000m^2 that want to sell the electricity produced. This is mainly due to the high costs associated to operations and the installation. This will be discussed more in detail in the next chapter.
Looking at the highest value from the table shows a maximal price of 227 €/m^2 for 16% efficiency in UAE for own use of electricity. This shows high profitability of the solar PV project and might need to me adjusted since this may compete with roof reinforcement for the installation of traditional solar PV panels. This will be discussed later in more detail.

The data from table 19 can be used in a figure, for better visualization. To do so, upper and lower bounds within a case study will be used by setting the selling case as lower bound for the module cost constraint per case study, and the consuming case as upper bound for the module cost constraints per case study. For the consumption scenario, consumer grid prices are used. This customer profile represent a scenario where the customer, pays the commercial electricity price and want to use all energy produced. This is the most optimistic scenario.
In contrast, the selling scenario utilizes the selling prices for electricity. This customer profile is a commercial project developer and aims to sell the generated electricity at wholesale price. Consequently, the cost constraints for this scenario are much lower compared to the consumption scenario. The selling scenario represents a more realistic scenario, with less risk involved for project developers.
These two scenarios effectively illustrate the boundaries of a solar PV project's profitability within each region. By analyzing these boundary cases, we can better understand the range of economic outcomes for different investment strategies and customer priorities.
Using these upper and lower boundaries per region, the data from the table can be visualized as follows.

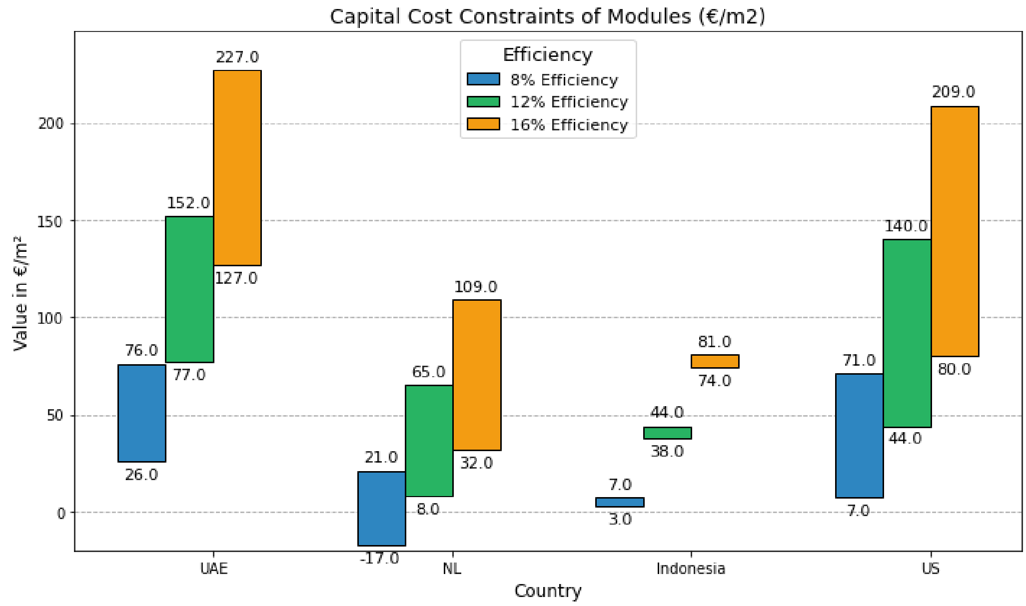

Figure 5: Module cost constraints per area in €/m^2 for a thin-film project on a 10,000 m^2 lightweight roof for four different locations and three different technologies, with upper and lower bounds based on the value of energy.

This figure visualized the module cost constraints. It shows UAE and US have the highest module cost constraints. This means those countries are the most profitable thus more capital can be allocated to the procurement of modules. Notably, the spread between the lower and upper bound in Indonesia is rather small due to small difference between selling and consumption prices. Nevertheless, it shows comparable results as in the Netherlands. These two countries are less profitable compared to UAE and US.

To better benchmark the module cost constraints with existing literature, the module cost constraints per project will be calculated per installed capacity, in €/Wp. This yields the following:

	η = **8%**		η = **12%**		η = **16%**	
Country	Selling	Consuming	Selling	Consuming	Selling	Consuming
UAE	0.36 €/Wp	1.06 €/Wp	0.71 €/Wp	1.41 €/Wp	0.88 €/Wp	1.58 €/Wp
NL	-0.24 €/Wp	0.29 €/Wp	0.07 €/Wp	0.60 €/Wp	0.22 €/Wp	0.75 €/Wp
Indonesia	0.04 €/Wp	0.09 €/Wp	0.36 €/Wp	0.40 €/Wp	0.51 €/Wp	0.56 €/Wp
US	0.09 €/Wp	0.99 €/Wp	0.40 €/Wp	1.30 €/Wp	0.56 €/Wp	1.45 €/Wp

Table 20: Module cost constraints per installed capacity in €/Wp for a thin-film project on a 10,000 m^2 lightweight roof for four different locations, three different technologies, and two different values of energy.

Equal to 19, it shows a negative value for selling energy in the Netherlands with 8% module efficiency modules. The rest of the values show a comparable cost profile as in table 19.
Same as with table 19, the data from table 20 can be used to make a figure with upper and lower bounds for every region. This yields the following figure.

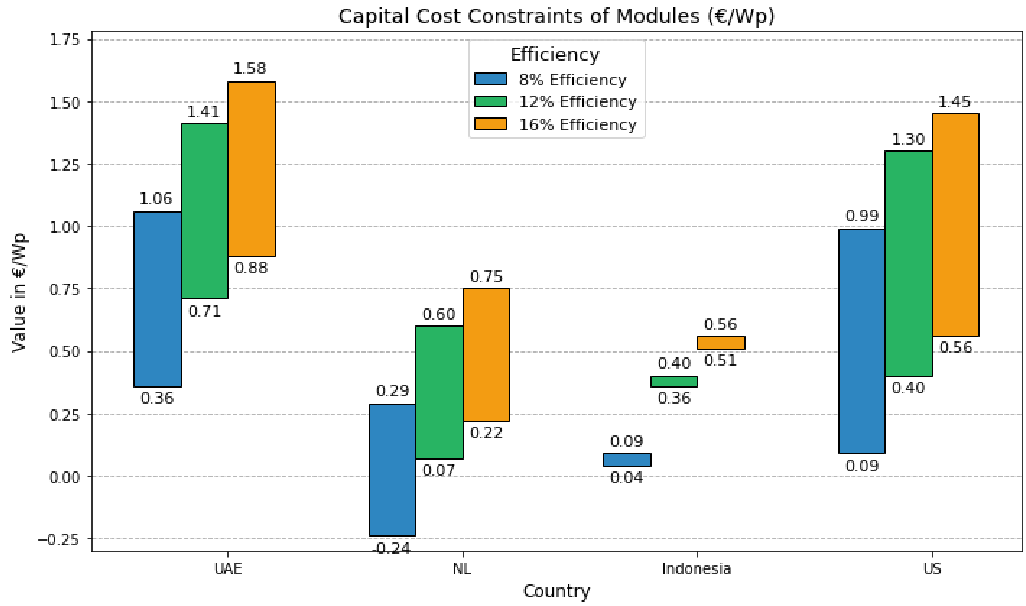

Figure 6: Module cost constraints per installed capacity in €/Wp for a thin-film project on a 10,000 m^2 lightweight roof for four different locations and three different technologies, with upper and lower bounds based on the value of energy.

Using the metric of €/Wp makes it more comparable with literature since most solar PV modules are compared based on their price per installed capacity. One study focused on the LCOE of utility scale solar PV from 2019 estimates the total solar PV system capex in Europe to be about 0.46 €/Wp (Eero Vartiainen, 2019). According to another study, median installed solar PV project cost in the US in 2022 were estimated to be 1.01 €/Wp (2022 exchange rates) (Mark Bolinger, 2023). Other literature estimates the global average capital costs in 2023 of Solar PV to be 0.876 €/Wp (Manzolini et al., 2024). These figures from literature show that for traditional solar PV projects, typical prices are between 0.40 €/Wp and 1.00 €/Wp. This is in line with UAE and US for all technologies.
Though not competing with traditional solar panels, since this study focuses on lightweight roofs, it shows that the results form this study are comparable with results from literature in regards to the expected module procurement for solar PV projects.

The average cost constraint per area over all the study cases is 71 €/m^2 with an average cost constraint per area for the selling scenario of 42 €/m^2 and an average cost constraint per area for the consuming scenario of 100 €/m^2.
The average cost constraint per installed capacity over all the study cases is 0.60 €/Wp with an average cost constraint per installed capacity for the selling scenario of 0.33 €/Wp and an average cost constraint per installed capacity for the consuming scenario of 0.87 €/Wp.

Notably, the differences between the different technological evolutions of respectively 8%, 12% and 16% within every case study vary much more when comparing per area in figure 5 than comparing per Wp in figure 6. The reason for big differences between the different module types is not only due to the increase in revenue by an increase in energy generation, but also due to the a higher area efficiency of the module. This means that an increase in efficiency plays a very large role in the cost per area thus increases profitability largely when analyzing the cost constraint per area of the module.

4.2 Cost breakdown

To better understand the implications of the module cost constraint, a breakdown of the costs associated to the solar PV system is provided. For this, the average values between selling and consuming are used, to be able to compare the scenarios between different countries better. Also, only the cost breakdown of the 8% module efficiency is shown.

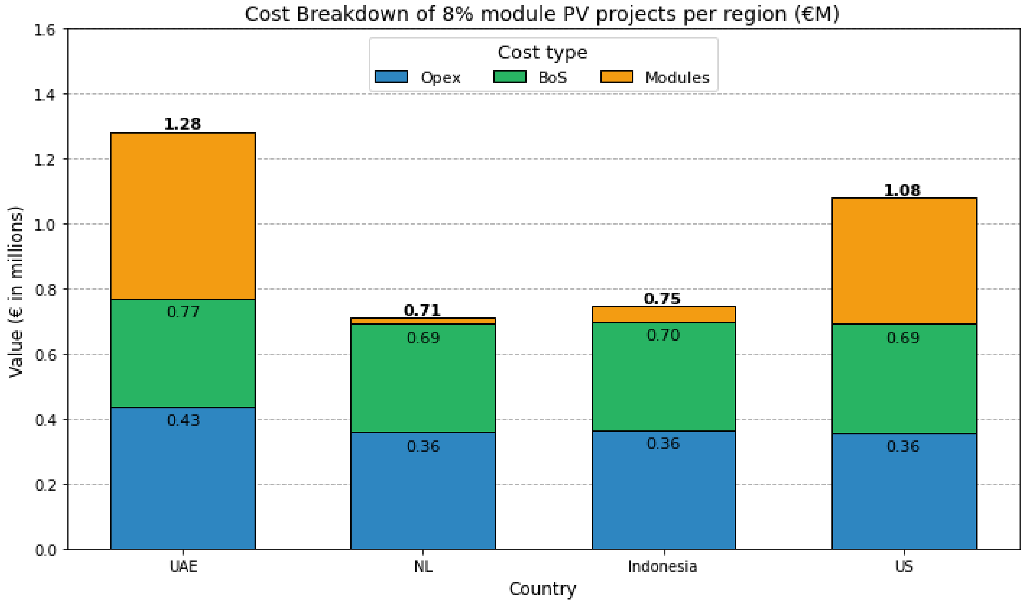

Figure 7: Cost breakdown of 8% modules for all four regions.

The figure clearly shows that Opex and BoS are almost the same everywhere since these costs do not vary largely. The net present value of the Opex differs due to differences in the WACC, that changes the net present value of future costs due to discounting. These differences though, do not account for the large differences in total cost. The large differences in module cost is related to the difference in the Opex and BoS, with respect to the total value of the project. This difference counts for the costs that can be directed towards modules. It is mainly due to a higher solar irradiance, thus more energy production. Since UAE and US generate more value over the project's lifetime, the module costs constraints are much higher. For example, the project's net present value in UAE is 1.28 M€, and for NL it is 0.71 M€. Comparative, UAE has a total net present value of almost twice as high. When subtracting the costs associated to Opex and BoS, the project in UAE is left with 0.51 M€ for modules, while the project in NL is left with 0.02 M€ for modules. This is a factor of 25 difference between these two cases. This shows, that for such a project in the Netherlands, same as in Indonesia, it would result in too high costs associated for Opex and BoS with respect to the total value generated by the project for the procurement of solar PV modules.
The analysis also reveals significant regional variations in the potential for profitable PV investments. Notably, the Netherlands demonstrates unfavorable conditions for PV profitability, largely due to less favorable irradiation levels.
When looking at the costs breakdown of a project using 16% module efficiency solar PV modules. The following results show:

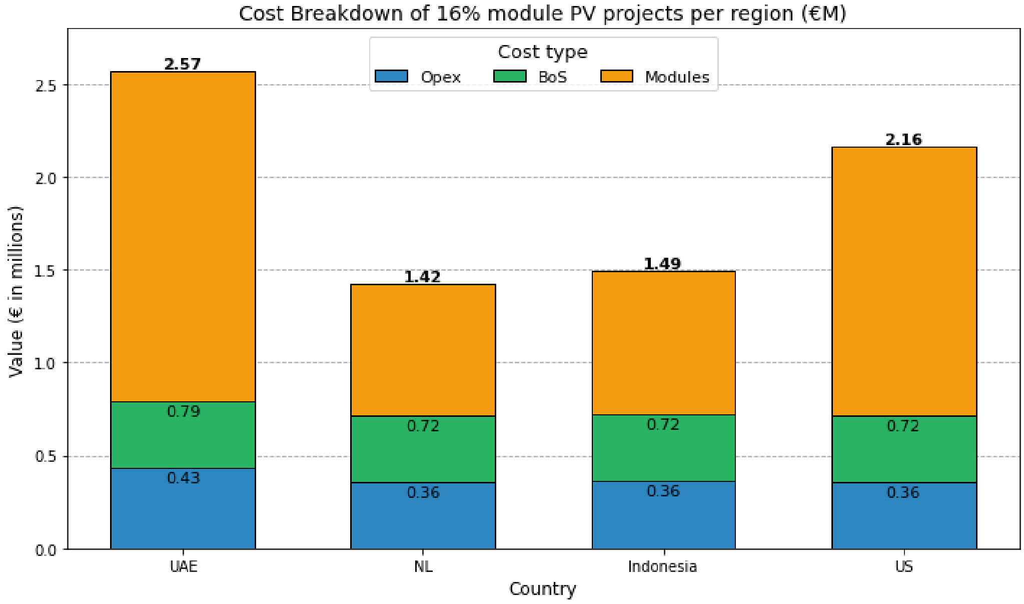

Figure 8: Cost breakdown of 16% modules for all four regions.

Figure 8 shows that the net present values of the projects are much higher compared to figure 7. This allows for higher expenditures for the modules. Even in the Netherlands and Indonesia, over 0.7 M € is available for modules expenditures. In UAE, the available budget for modules is more than 2.7 M€.
This cost breakdown goes to show that for 8% efficiency modules, the profitability of the project largely depends on the regional conditions. While for 16% efficiency modules, the project is very profitable and a good price for solar PV modules can budgeted.

4.3 Sensitivity study of results

Section 4 showed the range of levelized cost constraints per case study. It showed values that ranged between the countries as well as between technology. To better understand the implications of the results, a sensitivity analysis is conducted. The sensitivity analysis is discussed in this section

4.3.1 Sensitivity per case study

The sensitivity analysis of the results will be focused on the four different case studies. Input parameters will be changed by 20% and the change in Net Present Value (NPV) is measured and documented. The study cases of the UAE, the Netherlands, Indonesia and the US will be analyzed based on their sensitivity of the technical and market input parameters.

First, the technical parameters are studied and include the degradation rate, the operational life and the performance loss. The initial yearly degradation rate was 0.5%. Therefore, a 20% change would result in a degradation rate of 0.4% and 0.6%. This is still within the boundaries of appropriate panels since market standards are to be below 1% degradation rate per year. The operational life was set to be 16 years. A +20% and a -20% change would result in a operational life of 19 years and 13 years, respectively. The performance ratio in this study was 80%. Therefore, the performance loss is 20%. A +20% and -20% change would result in 24% and 16% performance loss, respectively. Figure 9 shows what the change in NPV per change of 20% of the technical parameters.

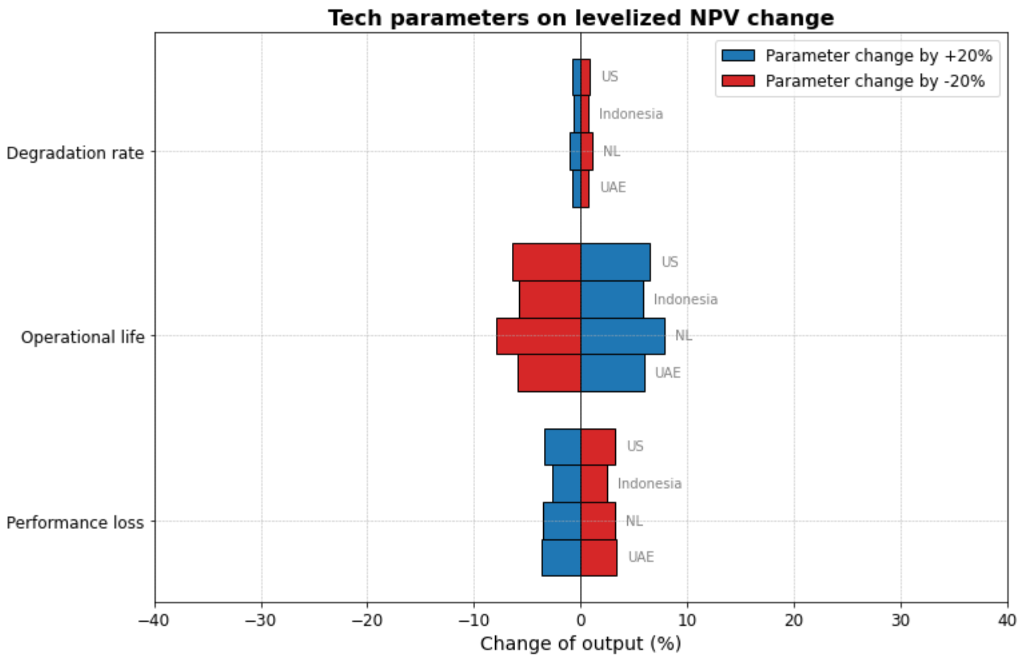

Figure 9: Sensitivity of technical parameters on the NPV change per country

The figure shows that the degradation rate plays a minor role, with an effect of much less than 10%. The other two parameters, operational life and performance loss, also show limited sensitivity with an effect of less than 10% as well.

Second, the market parameters are studied and include the capital expenditure (capex), the operational expenditure (opex), value of energy, cost of debt and cost of equity. The cost of debt and the cost of equity are part of the weighted average cost of capital (WACC) as discussed earlier in section 2.4. The capex is a fixed value for all case studies but changes with the total installed capacity. The Opex is dependent per case study, and has two values, € 32,049 for the Netherlands and the US, and € 40,941 for the UAE and Indonesia. The cost of debt and the cost of equity are all different per case study. The value of energy is also different for all case studies. The average value between the two selling and consuming scenarios is chosen as reference value. Figure 10 shows what the change in NPV per change of 20% of the technical parameters.

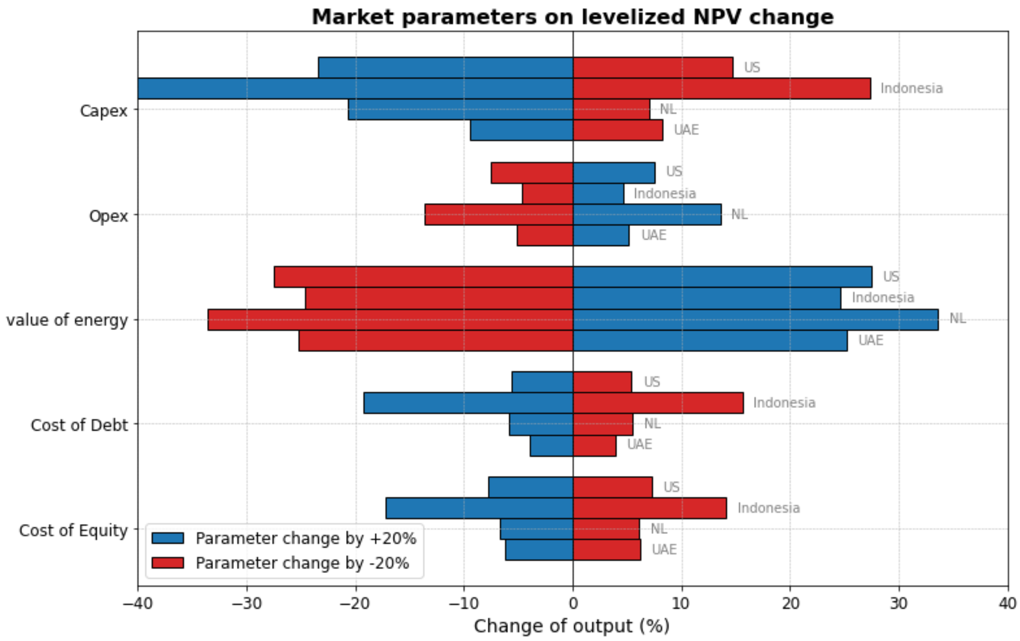

Figure 10: Sensitivity of market parameters on the NPV change per country

From figure 10, two things catch the attention.
First, when comparing the market parameters from figure 10 with the technical parameters from figure 9, it is clear that the market parameters show a much higher sensitivity.
Second, the figure shows a very high sensitivity for the capex and value of energy, and a moderate sensitivity for the other three parameters. The sensitivity of the capex is especially high for Indonesia. This is due to the fact that Indonesia has a very low NPV to begin with and the sensitivity is dominated by the lowest efficiency technology in Indonesia. That results in the fact that the relative sensitivity is much higher compared to other parameters and case studies. In case of a change of +20% of the capex for the Indonesia case study, the NPV changes with +61% and is out of limits within the graph. When looking at the capex parameter of other case studies, it is still clear that this parameters has a high sensitivity.

The sensitivity of parameters has now been discussed based on technical parameters and market parameters on the NPV changes in every case study. Since some values in the case studies have been dominated by lower efficiency technologies, the same sensitivity study will be composed but based on the differences in technologies instead of case studies.

4.3.2 Sensitivity per technology

In this section, the same sensitivity study will be conducted as in the last chapter, but will be applied for the three different technologies, being the 8%, the 12% and the 16% efficiency modules. The data from the different case studies is combined and the average values for every technology is used.
This results in three distinct plots, one for every technology, where both the technical parameters, as well as the market parameters can be combined in one figure.

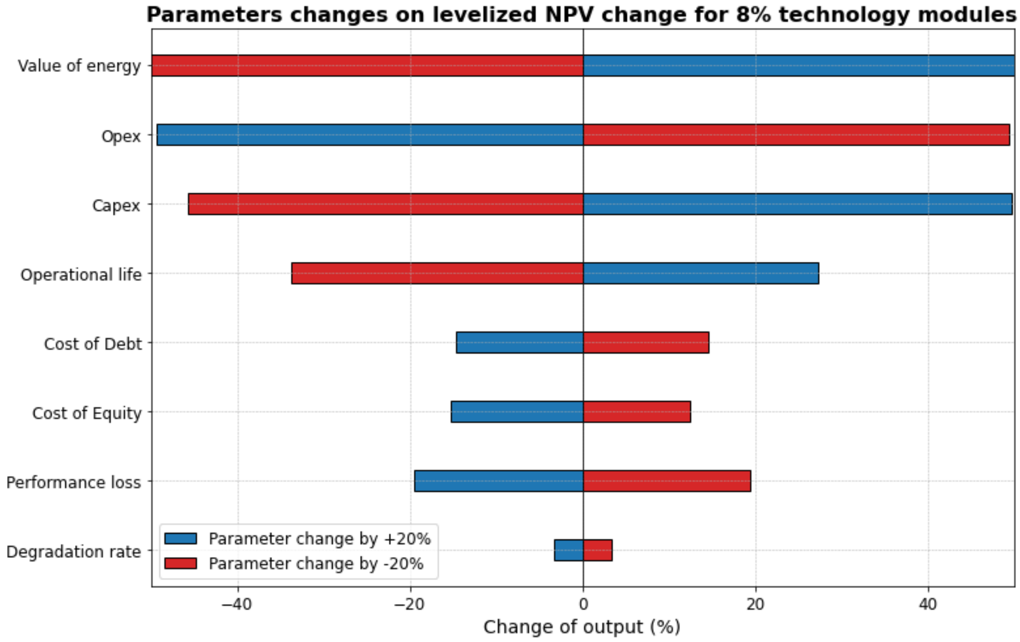

Figure 11: Sensitivity of the parameters on the NPV change for 8% efficiency modules

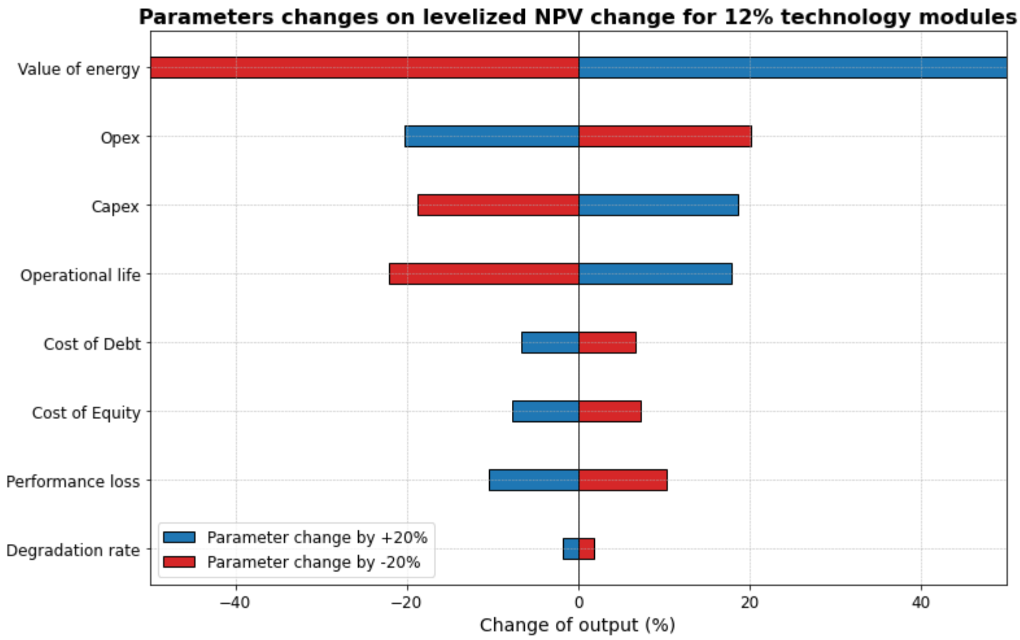

Figure 12: Sensitivity of the parameters on the NPV change for 12% efficiency modules

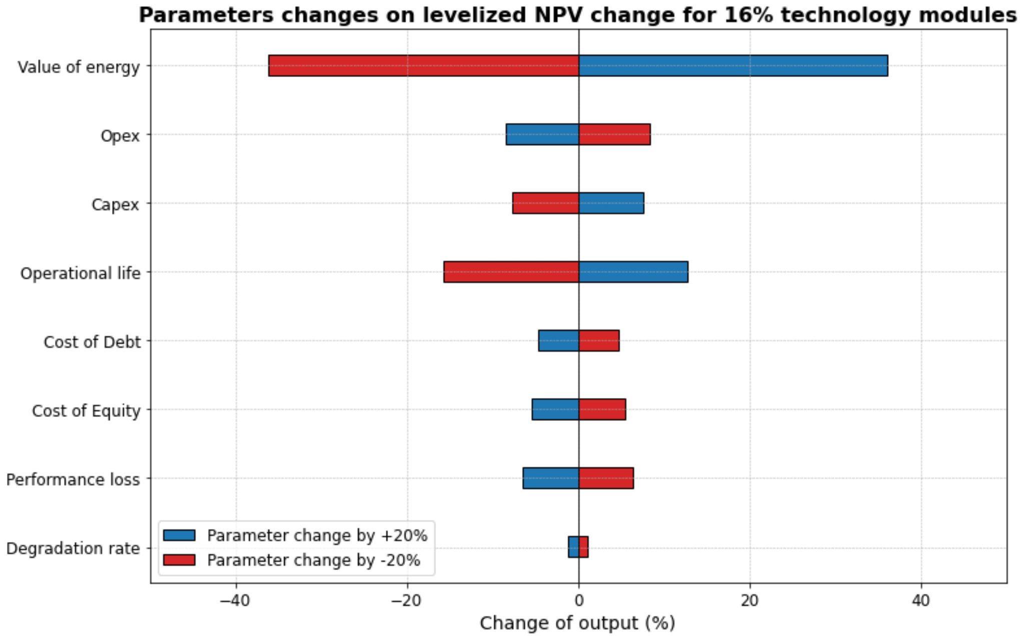

Figure 13: Sensitivity of the parameters on the NPV change for 16% efficiency modules

From these three figures, two things catch the attention.
First, the lower efficiency modules are much more sensitive to the parameter changes than the higher efficiency modules. The sensitivity of all parameters is much higher for the low efficiency modules. The value of energy, the opex, the capex and the operational life all exceed a sensitivity of 20% on the NPV for an input change of 20% and can even exceed 50% on the NPV change for value of energy, capex and opex. This means that the 8% efficiency is highly sensitive to the input parameters and is less reliable than the 12% and the 16% efficiency modules. The 12% efficiency module show lower sensitivities, except for the value of energy parameter. The 16% efficiency shows even lower sensitivities with the same exception for the value of energy parameter. Especially this technical evolution shows high reliability in the results, since almost all parameters have low sensitivity. This means that changes in the input parameters do not influence the result of the NPV of the project much, making the uncertainty of the results low.

Second, the parameter value of energy has the highest sensitivity of all parameters. The sensitivity stays high, even for the 16% efficiency. This means that the uncertainty of the value of energy, is represented in the results as well. For that reason, this study covered two values of energy, a selling and a consuming price, as mentioned in section 2.5. This ensured that both higher and lower values of energy were taken into account in this study. The differences between those values were discussed in the results section 4.1.

4.3.3 Combined sensitivity per parameter

In the past sections, the sensitivity of parameters were discussed based on the module technology used, and based on the case study location. In this section, all situation will be combined, to obtain one single graph that shows the sensitivity of the input parameters, regardless of the specific case study. Figure 14 below show this bar plot.

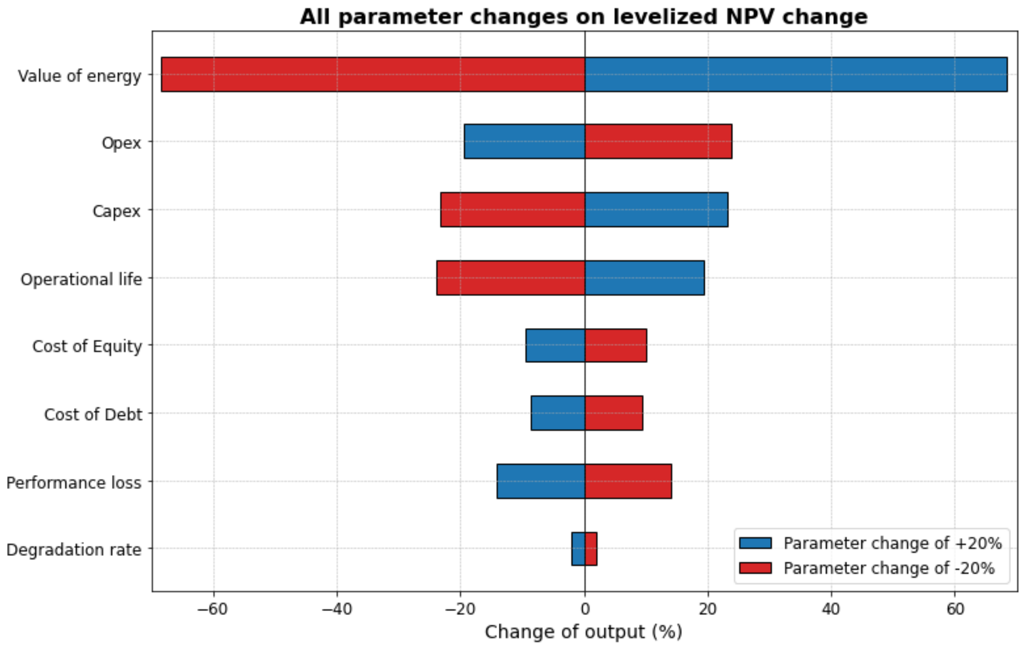

Figure 14: Sensitivity of all parameters on the NPV change.

From the graph, the same sensitivities are noticeable as the graphs before. The highest sensitivity occurs for the value of energy parameter. As mentioned in section 4.3.2, this parameter is studied in more detail in section 4.1. The opex, capex and operational life follow next, with a moderate sensitivity of about 20%. The opex and capex have been studied from literature, but still have an inherent uncertainty due to prices of other manufacturers and local labour wages. The sensitivity of the operational life is also inherently uncertain and hard to determine, this sensitivity is to be taken into account for. The cost of equity, cost of debt and performance loss follow with a lower sensitivity of about 10%. Last is the degradation rate with a marginal effect for a 20% change.

4.4 Limitations: roof reinforcement

Having compared the LCOE of thin-film PV with different electricity prices, it is important to note that there is an alternative way to generate electricity. Lightweight roofs can be reinforced to enable the safe installation of glass panels.

A recent study, delved into the additional cost of PV on lightweight industrial roofs in the Netherlands (Systemiq, 2021b). For this study, 164 construction reports were analysed, 20 interviews were conducted with stakeholders and three partners collaborated in the study, of which a construction engineering firm, a system consultant and the Dutch state department of enterprises (RVO). Together, they assessed the structural roof restrictions based on six parameters. The first one being the materials used for the construction to assess the structural strength of the building. The second parameter is the material of the roof, used to calculate the total weight of the roof and consequently the carrying capacity. The third parameter is the angle of inclination of the roof to determine the effects of wind, snow and water accumulation. The fourth parameter is the roof area. In this study, the roof area was typically between 200 and 15,000 m^2 and was used to determine fatigue on the construction materials. The fifth parameter is the year of construction, typically between 1970 and 2020, used to determine the safety margins necessary. The sixth, and last parameter used, is the 'consequence class', a metric from CC1 to CC3 used to determine what the consequences would be if the construction would fail. This is based on the expected amount of people in the building and has an effect on the safety margin used for the building.
Using these six parameters, four groups of intervention possibilities are determined. These include, lowering the load on the roof, customizing the solar PV system, reinforcing the construction and others. Based on the needed intervention possibilities, the roofs are categorized into three categories. The first category are roofs without structural restrictions for rooftop glass panels. The second category are roofs with minor structural restrictions for rooftop glass panels. The third category are roofs with major structural restrictions for rooftop glass panels.

Apart from the division of roofs into three categories based on their structural restrictions, the study also shows a division based on four roof types. The first roof type is roofs of distribution centers. The second roof type is roofs of agricultural buildings. The third roof type is roofs of industrial buildings. The fourth roof type is old building roofs. For this study, the first and third, distribution centers and industrial building roofs respectively, are of interest.
Category two accounts for only 4% and 9% of industrial building roofs and distribution center roofs, respectively. The additional roof reinforcement costs for category two are 15 €/m^2. Category three accounts for 26% and 25%, of industrial building roofs and distribution center roofs of the total roofs covered in the study, respectively. The additional roof reinforcement costs for category three are 75 €/m^2. This goes to show that category three roof reinforcement are very expensive and affect large portions of the industrial building roofs distribution center roofs. This limits the implementation of rooftop solar PV due to structural limitations for glass panels. These figures show the importance for lightweight solar PV panel solutions for the industrial and commercial large scale roofs segment.

Before looking into the implications of the reinforcement costs, the components of the reinforcement costs will be discussed. As mentioned, the options consists of four groups, namely lowering the load on the roof, customizing the solar PV system, reinforcing the construction and others. For distribution centers and industrial building roofs with category three, large structural roof limitations, the reinforcement costs are 75 €/m^2. The costs consist of replacing insulation and roofing, reinforcing the purlins, the trusses and reinforcing the columns or adjusting the girders. Especially replacing insulation and roofing is very costly. The costs are estimated to be between 27 €/m^2 and 38 €/m^2depending on the building type.
Though very important, opportunity cost due to a temporal halt of operations in the building are not included as costs. Especially for buildings with operations serving a commercial purpose, the opportunity costs associated due to the reinforcement can be high. Further assumptions were a panel weight of 17.5 kg/m^2 with a total weight, including BoS of 25 kg/m2 for distribution centers roofs and 35 kg/m^2 for industrial roofs and a total installed capacity of 2.5 MWp.

Now having discussed the roof reinforcement for these type of buildings, a new cost comparison for glass panels can be determined using the cost of reinforcement of 75 €/m^2. Since, the roof area in this study is 10,000 m^2, the additional cost for roof reinforcement is 10,000 times 75 €, so 750,000 €.
The roof reinforcement cost of 750,000 € will be compared with the 16% efficiency modules. The cost breakdown figure used in chapter 4.2 is used to show what the result is of the addition of the roof reinforcement cost. Figure 15 shows the comparison of this cost breakdown, together with the additional cost of roof reinforcement. The budgets show that the roof reinforcement cost, as additional cost, would increase the total cost of the project largely, and in some cases, like in the Netherlands and Indonesia, would cut severely into the budget for the modules.

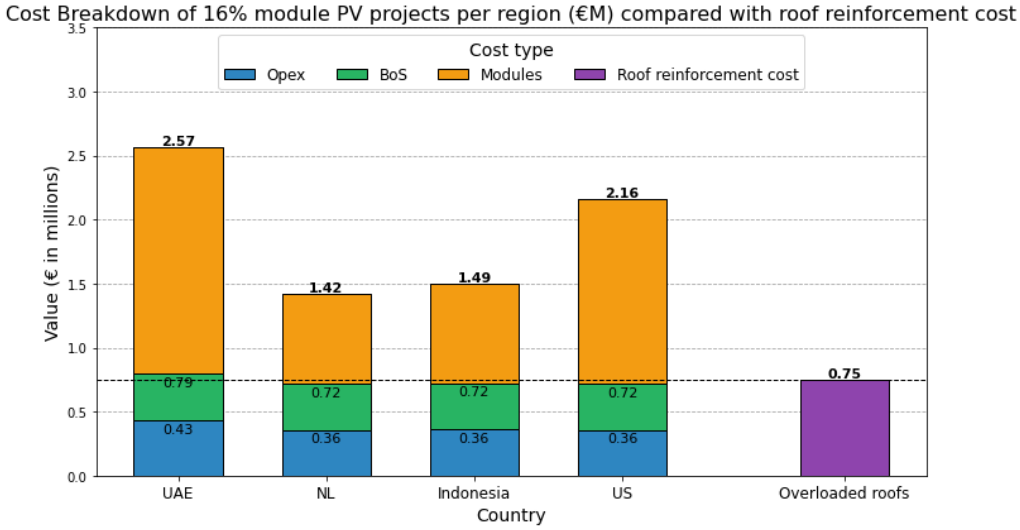

Figure 15: Cost breakdown of 16% modules for all four regions compared with roof reinforcement cost.

Important to note is that traditional glass panels have a higher efficiency, this a higher net present value that could account for a higher expenditure for the solar PV modules. Nevertheless, the roof reinforcement cost addition shows the large impact it makes in the total budget and how it relates to the other costs like Opex and BoS. Actually, the roof reinforcement costs are higher than the Opex and BoS costs combined.
Especially in the Netherlands, the roof reinforcement premium make solar projects financially unattractive. With the rising trend of policy instruments to lower CO_2 emissions and increase own production of clean energy, companies are inclined to implement rooftop solar. Thin-film lightweight solar PV without the need of roof reinforcement could play an important role for the implementation of solar energy for such roofs.

4.5 Market compatibility

This section will discuss the market compatibility of the results of the study cases.
The results from section 4.1showed cost constraints for the solar PV modules between 0 €/Wp and 1.58 €/Wp. Since a cost of 0 €/Wp is unrealistic, the cost constraints will be compared to the market prices discussed in section 1.2 and the roof reinforcement cost from section 4.4. The market prices of normal solar PV modules lies between 0.10 €/Wp and 0.20 €/Wp. These prices indicate that if manufacturers were able to supply these modules at a cost constraint that lies above that range, a profitable project is possible. All projects with values below this range would result in unprofitable projects, thus are not feasible.
On the other hand, section 4.4 discussed a roof reinforcement cost of 75 €/m^2 for heavily weight limited roofs in the Netherlands. This means that, if thin film solar PV module manufacturers were able to supply the modules at a cost lower than 75 €/m^2, this would result in a more profitable business case than using glass panels and reinforcing the roof.

Combining these two limits show a profitable range of projects with a cost constraint above 0.10 €/Wp and a limit of 75 €/m^2. All the value above the 75 €/m^2 would be hard to capitalize on as manufacturer since this opens up competition for traditional glass panel manufacturers. The case studies that would qualify as profitable are the following: Netherlands with self consumption, UAE all cases, US all cases, except selling at 8% efficiency and Indonesia from 12% efficiency onwards.

Apart from the profitability of a project, it is important to consider the market size. Even though this was not part of the study scope, the market size is an important indicator for manufacturers to consider. As the UAE shows high cost constraints, thus highly profitable, the number of lightweight commercials roofs in the region is expected to be very small compared to other locations like the Netherlands and the US. To make a robust business case from the profitability of thin film solar PV modules, the market size is important to consider as manufacturers.

5 Conclusions & Recommendations

This thesis work focused on the economic feasibility and profitability of deploying HyET Solar modules in commercial-scale solar PV projects by identifying and analyzing the cost constraints. The objective was to derive actionable insights into the cost constraints of thin-film solar PV modules with a specific focus on their application in commercial-scale lightweight roof projects. This chapter concludes this report with the most important findings from this thesis work and presents recommendations for future research that can be conducted within the same field of study.

5.1 Conclusion

This techno-economic study analysed the profitability and the cost constraints of three different evolutions of HyET Solar modules under four distinct case studies. All three evolutions of HyET Solar modules are thin-film PV modules, with a weight of 2 kg/ m^2. These PV modules are made in Arnhem, the Netherlands, and vary in efficiency, based on the technology used. In this study, the first evolution consists of a single junction hydrogenated amorphous silicon (a-Si:H) layer that yields an efficiency of 8%. The second evolution consists of a double junction between the same a-Si:H layer and hydrogenated nanocrystalline silicon that can yield an efficiency of 12%. The third, and last evolution is a double junction between the same a-Si:H and perovskite that can yield an efficiency of 16%. Although these three evolutions of thin-film PV modules currently have not yet reached the wholesale market, ongoing research suggests that thin-film PV modules will become commercially available in the future. Therefore, understanding what prices solar manufacturers could charge, while still providing a valuable product to their clients will be crucial as this innovations emerge. In this thesis work, this understanding will be studied by determining the cost constraints of the project.
The cost constraints of these three evolutions of thin-film PV modules are dependent on the type of project. In this thesis work, the reversed LCOE method is used and applied on four distinct case studies to provide a broad understanding of what drives such cost constraints. The reversed levelized cost of energy (LCOE) method is a way to determine the break-even cost of modules under a set of conditions. It uses the traditional way of the levelized cost of energy, but instead of determining what the levelized cost of energy would be under a set of conditions, it determines what the pricing of the PV modules would be under another set of conditions. Since this set of conditions varies per project, four case studies are chosen. The case studies differ in solar irradiation, value of energy and cost of debt. The chosen locations of the case studies are the United Arab Emirates (UAE), the Netherlands, Indonesia and Colorado, the United States (US).
The cost constraints are analyzed using the reversed LCOE method for three evolutions of thin-film PV modules, under four different case studies to provide tangible insights into the business proposition and profitability of the emerging innovative technology.
For the determination of the cost constraints, multiple sources were used to determine the values for the given conditions per case study. Project financing by debt and equity is taken into account to present a realistic discount rate for the project. Furthermore, differences in solar irradiation were accounted for as well to understand the implications of it. Lastly, the value of energy is analyzed per region, both for selling as well as for buying. This means, that using your own electricity would result in not paying the full electricity price on the market, which includes for example network transport cost and taxes. Being able to use your own generated electricity would thus result in a higher value of energy. Conversely, selling the electricity produced, would result in a lower value of energy compared to consuming it since the network transport cost and taxes payed by the buying party, and not directed to the selling party. This distinction between values of energies are implemented in this study as well, to understand the broad picture of the profitability of thin-film PV projects under varying conditions. Further assumption, like the size of the project, the expected cost of other components, and performance ratio can be read in chapter 2.

The results of the reversed LCOE method under these different conditions are provided in chapter4, and are expressed in two metrics, being price per area and price per capacity, for four case studies using three different technologies with two values of energy. This resulted in a total of 24 different scenarios. These are shown in table 19 and table 20. For the 8% efficiency, with a low value of energy in the Netherlands, it shows a negative value, indicating no positive business case is possible. For the 16% efficiency with a high value of energy in the UAE and the US, it results in a price per area of 227 €/m^2 and 209 €/m^2, respectively.
The average cost constraint per area for the modules under all 24 conditions is 71 €/m^2. For the 16% efficiency with a high value of energy in the UAE and the US, it results in a price per capacity of 1.45 €/Wp and 1.58 €/Wp, respectively. The average cost constraint per capacity for the modules under all 24 conditions is 0.60 /€Wp.

From the sensitivity study in section 4.3 it became clear that the higher efficiency modules showed lower sensitivity to the input parameters compared to the lower efficiency modules. It even showed a difference between the location of the case studies with Indonesia standing out with the highest sensitivity. The highest sensitivity from the input parameters was the value of energy. In this research, this sensitivity was taken into account by comparing selling and consumption values of energy as boundary values.
Of the cases studied, UAE yields the best outcome under current conditions, followed closely by the US, Colorado case. The Netherlands and Indonesia show less profitable results.
In the case of 8% efficiency modules, the Netherlands and Indonesia cases show very limited cost constraints. Figure 7 shows these two cases have cost constraints of 0.02 M € and 0.05 € for the Netherlands and Indonesia, respectively, for 1 MWp of solar PV capacity. This results in a levelized cost of 0.02 €/Wp and 0.05 €/Wp for the 8% efficiency panels for the Netherlands and Indonesia, respectively. These cost constraints are so limiting, no profitability from these projects is realistic.
In the case of 16% efficiency modules, the UAE and the US show the most profitable conditions. Figure 8 shows these two cases have cost constraints of 1.78 M € and 1.44 M € for the UAE and the US, respectively, for 1 MWp of solar PV capacity. This results in a levelized cost of 1.78 €/Wp and 1.44 €/Wp, for the UAE and the US, respectively. These figures show sufficient margin for thin film solar PV manufacturers since current cost of thin film solar PV modules are much lower.

These figures show that there is a high variability in conditions that influences the performance and the profitability of thin film solar PV modules in a commercial scale lightweight roof project. This study shows both profitable and unprofitable scenarios are possible and provides an analysis on the impact of conditions on the profitability of such a project.

5.2 Recommendations

This study analyzed the profitability and cost constraints of thin film solar PV modules for commercial sized lightweight roofs by using the reversed LCOE method. In this section, recommendations on future research on this topic are being suggested.
First, this study focused on four distinct locations. For future research, a larger set of study cases could be investigated to identify more profitable locations. A more extensive study on cost constraints and profitability of such projects in other regions could enable solar PV project developers, investors and solar PV module manufacturers to better understand the market and identify the most attractive opportunities.
Second, the current study is contingent upon the specific assumptions that apply today, like value of energy, operational expenses and cost of debt. Though, these assumptions may change in the future. Understanding what influences these assumptions today, helps to better understand the implications of changes in the future. For example, currently, the Netherlands and Indonesia are not considered profitable with 8% efficiency modules under the assumed conditions. Future research could reassess this study under a new set of assumptions and conditions to obtain updated insights, potentially leading to different outcomes.
Third, this study focused merely on the cost constraints and profitability of thin film solar PV projects. Future research could study the implications of the results of this study. Since the profitability varies largely among the study cases, international energy transportation could be studied. With emerging ammonia and hydrogen markets, alongside infrastructure developments and policy initiatives, production of solar energy could be used to produce ammonia or hydrogen. This disentangles the value of energy at a certain location and could result in higher values of energy for the specific project. This enables the possibility for a new business model. Part of this research would be analyzing the transportation cost and the net difference in value of energy. A better understanding of local ammonia or hydrogen production for these kind of solar PV projects could result in new profitable business models.

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