Aalto University
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Master’s programme in Engineering Physics

Commercial system-level solar photovoltaic test facilities in Nordic conditions

Current status and suggestions for future

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Title Commercial system-level solar photovoltaic test facilities in Nordic conditions — Current status and suggestions for future

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Abstract

The share of renewable energy in the global energy production profile has been increasing rapidly thanks to global effort to decrease greenhouse gas emissions. Solar photovoltaics (PV) represents a rather small portion of the renewable energy mix. However, due to the constantly decreasing solar cell prices and improvements in technology, the share of PV is expected to increase quickly in the near future. As the solar PV becomes feasible in new locations, it is crucial to minimize the uncertainty related to the energy yield assessments of these projects. By having more accurate information about the energy yield of new PV technologies, more accurate investment decisions are possible to be made.

The objective of this thesis is to determine the current status of solar PV test facilities in the Nordics and formulate a suggestion for a PV test facility that would bring added value to a commercial company acting in the energy sector. The research is performed in three stages. The initial stage is to conduct a literature review of the current best practices and existing approaches. The second stage is to conduct a benchmark study about the existing solar PV test facilities, with a focus on Nordic assets. The third stage of the research is an interview round with professionals from the industry about pressing issues and open questions related to solar PV projects. Finally, a suggestion for potential test facility is formulated based on the previous stages.

Based on the literature review and benchmark study, two levels of solar PV testing are determined, module-level and system-level. The module-level testing is more relevant to research organizations and module manufacturers while the system-level testing is typically related to energy yield measurements and in general more beneficial for energy producers. In the benchmark study and the interview round, 13 potential test topics are recognized and evaluated. Topics related to bifacial PV modules and artificial increase of the ground albedo are evaluated thoroughly. A suggestion for test facility is formulated for these two topics.

Keywords Solar PV, Outdoors testing, Energy yield assessment, Test facility

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Tiivistelmä

Uusiutuvan energian osuus globaalista energiantuotantoprofiilista on kasvanut nopeasti maailmanlaajuisen ponnistelun takia pyrkiä vähentämään kasvihuonekaasupäästöjä. Aurinkosähkövoima edustaan vielä pientä osuutta kaikista uusiutuvista energiantuotannon muodoista. Jatkuvasti halpenevien aurinkokennojen sekä teknologian kehittymisen ansiosta aurinkosähkön oletetaan yleistyvän runsaasti lähivuosina. Kun aurinkosähköstä tulee kaupallisesti käyttökelpoista uusilla alueilla, on tärkeä minimoida epävarmuudet liittyen energiatuotantoarviointeihin kyseisissä projekteissa. Tarkempien energiatuotantoarvioiden avulla pystytään tekemään valistuneempia investointipäätöksiä.

Tämän diplomityön tavoitteena on määrittää testiaurinkosähkövoimaloiden nykytila pohjoismaissa sekä muodostaa suositus testiaurinkosähkövoimalasta, joka toisi lisäarvoa kaupalliselle yritykselle, joka toimii energiasektorilla. Tämän työn tutkimus toteutetaan kolmessa vaiheessa. Ensimmäinen vaihe kattaa kirjallisuuskatsauksen, jossa käydään läpi nykyiset parhaat käytännöt ja olemassa olevat lähestymistavat. Toisessa vaiheessa suoritetaan vertailututkimus olemassa olevista testiaurinkovoimaloista keskittyen pohjoismaisiin voimaloihin. Työn kolmas vaihe koostuu energiasektorin ammattilaisten haastatteluista liittyen aurinkosähkön ongelmiin ja avoimiin kysymyksiin.

Kirjallisuuskatsauksen ja vertailututkimuksen perusteella määritettiin kaksi testaamisen tasoa, moduuli- ja systeemitason testaaminen. Moduulitason testaaminen on olennaisempi tutkimuslaitoksille ja moduulien valmistajille, kun taas systeemitason testaaminen tyypillisesti liittyy energiantuotanto arviointeihin ja on olennaisempaa energiantuottajille. Vertailututkimuksesta ja haastatteluista ilmeni 13 potentiaalista testiaihetta. Testiaiheet liittyen kaksipuoleisiin aurinkokennoihin sekä maan heijastavuuden keinotekoiseen parantamiseen valittiin tarkasteluun. Tarkemassa tarkastelussa näille kahdelle aiheelle muotoiltiin tutkimussuunnitelmat.

Avainsanat Aurinkosähkövoima, Ulkotestaaminen, Energiatuotonarviointi, Testilaitos

Preface

I want to thank my instructors Dr Eero Vartiainen, Mr Jari Majamäki and Mr Jan Loikkanen and my supervisor Dr Solveig Roschier for their constant and dedicated support and guidance throughout my thesis. I also want to thank Professor Peter Lund and my thesis supervisor Dr Janne Halme for their support throughout my studies in the university.

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Espoo, 31st of July 2024

Magnus Markkanen

Contents

Symbols and abbreviations

Symbols

T	Temperature
E_G	Bandgap energy
α	Empiric coefficient, Wind sheer coefficient
β	Empiric coefficient, Tilt angle
E_C	Conduction band energy
E_V	Valence band energy
E_F	Fermi-level
e^-	Electron charge
e^+	Proton charge
E	Energy
I_L	Light generated current
I	Electrical current
V	Voltage
I_0	Dark saturation current
q	Elementary charge
R_s	Series resistance
n	Ideality factor, day number
k_B	Boltzmann constant
R_sh	Shunt resistance
I_{sc}	Short circuit current
V_{oc}	Open circuit voltage
J_{sc}	Short circuit current density
P	Power
P_{MPP}	Maximum power point power
I_{MPP}	Maximum power point current
V_{MPP}	Maximum power point voltage
FF	Fill factor
η	Energy conversion efficiency
P_I	Incident or received power
E_e	Irradiance on a surface
A	Area
θ_i	Angle of incidence
θ_z	Zenith angle of the sun
γ	Azimuth angle of surface
γ_s	Azimuth angle of the sun
ϕ	Latitude
δ	Declination angle of the sun
ω	Hour angle
G	Global irradiance
G_b	Beam (direct) irradiance
G_d	Diffused irradiance
G_r	Reflected irradiance

$G_{b,H}$	Horizontal beam irradiance
$G_{d,h}$	Horizontal diffused irradiance
$G_{b,T}$	Tilted beam irradiance
$G_{d,T}$	Tilted diffused irradiance
$G_{r,T}$	Tilted reflected irradiance
ρ_g	Ground albedo
AL	Angle of incidence losses
α_r	Empirical coefficient
F_b	Beam irradiance angular loss factor
F_d	Diffused irradiance angular loss factor
F_r	Reflected irradiance angular loss factor
c_1	Empirical coefficient
c_2	Empirical coefficient
$G_{g,T}$	Global tilted irradiance
G_{eff}	Effective irradiance
S_r	Spectral response
R	Spectrum
R_{STC}	STC spectrum
T_{amb}	Ambient temperature
T_{mod}	Module temperature
W_{mod}	Wind speed at module height
U_0	Empirical coefficient
U_1	Empirical coefficient
d_{mod}	Module installation height
d_{ane}	Anemometer installation height
W_{ane}	Anemometer wind speed
G'	Auxiliary irradiance
T'	Auxiliary temperature
G_{STC}	Irradiance at standard test conditions
T_{STC}	Module temperature at standard test conditions
P_{STC}	Rated power at standard test conditions
$k_{1...6}$	Empirical coefficients
PR	Performance ratio
E_a	Annual energy output
H_a	Average annual plane-of-array irradiance
T_c	Solar cell temperature
T_{BS}	back sheet temperature
ΔT_{CBS}	Temperature difference between solar cell and back sheet with STC irradiance
CP	Capture price
hR	Hourly revenue
hP	Hourly production
hSP	Hourly spot price

LER	Land equivalent ration
$\text{Yield}_i(\text{multi})$	Yield of multi-production of product i
$\text{Yield}_i(\text{mono})$	Yield of mono-production of product i
LL	Land losses
$BiFi$	Bifaciality
BG	Bifacial gain
η_{rear}	Rear side energy conversion efficiency
η_{front}	Front-side energy conversion efficiency
BG_{opt}	Optical bifacial gain
BG_{mod}	Module bifacial gain
BG_{sys}	System bifacial gain
G_{rear}	Rear side irradiance
G_{front}	Front-side irradiance
E_{bi}	Bifacial energy output
E_{mono}	Monofacial energy output
ρ	Albedo
$G^{\uparrow}$	Irradiance from the sky
$G^{\downarrow}$	Irradiance from the ground
ρ_{eff}	Effective albedo
NPV	Net present value
IRR	Internal rate of return
ROI	Return on investment
r	Discount rate
Inv	Initial investment

Abbreviations

PV	photovoltaic
LCOE	levelized cost of electricity
BESS	battery energy storage system
VAR	variable renewable energy
CAPEX	capital expenditure
c-Si	Crystalline silicon
STC	Standard test conditions
AM	Air mass
MPP	Maximum power point
UV	Ultraviolet
EVA	Ethylene vinyl acetate
POE	Polyolefin
AOI	Angle of incidence
IEC	International Electrotechnical Commission
BoS	Balance of system
OEM	Original equipment manufacturer
DC	Direct current
AC	Alternating current
MPPT	Maximum power point tracking
EYA	Energy yield assessment
IEA	International Energy Agency
PVPS	Photovoltaic Power Systems Program
POA	Plane of array
RTD	Resistance temperature detector
IR	Infrared
RTM	Radiative transfer model
TUNI	Tampere University of Technology
TUAS	Turku University of Applied Science
PERC	Passivated Emitter and Rear Contact
BIPV	Building integrated photovoltaic
O&M	Operation and maintenance
BoP	Balance of plant
R&D	Research and development
OPEX	Operating expenses
WACC	Weighted average cost of capital
PVGIS	Photovoltaic Geographical Information System

1 Introduction

1.1 Background

As many countries across the globe are endeavoring to reach carbon neutrality, the importance of renewable energy is evermore increasing. By signing the European Climate Law [1], The European Union is committing to transform Europe into the first climate-neutral continent by 2050. Additionally, part of the European Green Deal is to reduce net greenhouse gas emissions at least 55% by the year 2030 compared to the reference of 1990 level of emissions.[2] Combining these carbon neutrality objectives with the continuously decreasing prices of photovoltaic (PV) modules [3, 4, 5], concurrently decreasing the levelized cost of electricity (LCOE), will lead into new geographical locations becoming financially feasible for utility-scale solar power plants. This can be seen for example in the installed capacity of solar power in the Nordic countries. In 2013 the solar power capacity in Denmark and Sweden were 563 MW and 43 MW respectively, while Finland did not have any significant amount of installed solar power capacity. [6] In 2023 Denmark, Sweden and Finland reached 4900 MM, 4100 MW and 1000 MW solar power capacity respectively. [7, 8]

Photovoltaic modules are already a mature technology and they saw their first commercial utility-scale use in the 1980's [9], however photovoltaics have still substantial potential to improve and advance. Introduction of new technologies and component designs will unavoidably also bring more uncertainties to the solar power plant feasibility assessments. These new technologies must of course be tested, and they must fulfill all required standards before they can be commercialized, but uncertainties beyond these standards have become a more prominent concern. More or less the only way to get definitive proof of concept for new technologies is to test them in real operation conditions in test facilities and sites. These sites can also be utilized to test the performance of the new products during the prototype phase of the product development.

Outdoor test sites are typically utilized by research centers and universities to either characterize commercial products for the producers or to conduct academic research. Even though the appeal of solar PV test facilities might be focused more for academic purposes, also commercial companies can find these extremely useful. The test facilities should bring some added value to the company in order for it to be a justified investment. Since the alternative for commercial companies is to consult a third party that could perform these experiments, it is important to determine what kind of information is valuable to the company. Besides the information that test facilities provide, another gain that is harder to give monetary value is the first-hand experience of working with these new technologies.

Since solar PV has become financially viable in the Nordic countries, new Nordic-specific issues have also become relevant. Nordics represent a minority of the global solar PV markets and naturally much of the outdoor PV testing has been done in conditions that differ significantly to the Nordics. This causes issues for example when evaluating the degradation and energy yield of solar PV in these regions. Both of these aspects can be approximated in laboratory environments, but in order to verify the acquired results, proper outdoor testing will be required. Typically, the outdoor testing done by research institutes and universities is in smaller scale and effects that arise only in utility-scale PV power plants cannot be fully investigated. Therefore, it is important to get real life data from utility-scale test sites and pilot projects to gain the necessary expertise and confirmation about how solar PV, especially new technologies like bifacial modules, will behave in Nordics conditions.

Besides new PV related technologies, other technologies that could be operated in parallel with solar PV can and should also be tested in real life conditions. Battery energy storage systems (BESS) have also become financially viable and as the share of variable renewable energy (VAR) increases, the variability of energy supply will also increase, subsequently causing the electricity price to fluctuate drastically. The variability of electricity supply causes imbalance to the power grid since the frequency of the grid must be controlled constantly by ancillary services. Traditionally the stability of the grid has been secured by fast reactive power capacity that can be turned on and off in short notice. Additionally, the steam turbines from combustion-based electricity generation facilities have natural inertia in the rotating turbines that are generating the electricity. Unfortunately, VAR lacks this kind of natural inertia. However, artificial inertia can be introduce by BESS with grid forming capabilities. Additionally, BESS can be used to provide both fast active and reactive power capacity. Therefore, integrating BESS into the solar PV facilities will bring the required inertia and flexibility to the power grid and decrease the total (PV + BESS) capital expenditure (CAPEX) of the project since both PV and BESS can share some of the components of the facility, main grid connection for example. Naturally it is reasonable to first gain experience and insight of such hybrid PV+BESS systems before building a full-scale facility and a test facility would be ideal for this purpose.

One important aspect when designing a commercial solar PV test facility that needs to be determined is what kind of tests are to be done in the facility and how the facility reflects these tests. As mentioned above, utility-scale test facilities will give accurate insight on how full-scale facility would operate but how this "utility-scale" test site is realized is an open question. The test site can act more as a pilot project for the new technology meaning that the test site will have these new components that are not planned to be replaced while they work, however differing from normal site, these components would be monitored more closely. Another alternative is to design the site in a "modular" way that would allow the components to be changed when new interesting technologies come to the market. Choosing the end usage of the site and designing it accordingly is utmost important for the test facility project to be financially viable.

1.2 Scope of the thesis

The objective of this thesis is to find the current best practices and existing approaches of solar PV test facilities and formulate a guideline and suggestion for a commercial solar PV test facility. The current best practices and existing approaches researched from the literature as well as through a benchmark study. The literature review focuses on reports and suggestions formulated by respectable research organizations and industry standards. The benchmark study provides reference about how well the suggestions found from the literature are followed in reality. Additionally, the benchmark study will provide information about the current status of solar PV test facilities. In order to formulate a suggestion for a commercial solar PV test facility, relevant test topics must be discovered. The relevant and beneficial topics for a commercial electricity producer are investigated through interviews with professionals from the renewable energy industry. Finally, a suggestion for a commercial solar PV test facility is presented.

Research questions that this thesis aims to answer:

- What are the best practices and existing approaches for solar PV test facilities?
- What is the current status of solar PV test facilities with a focus on the Nordics?
- What kind of topics are relevant and beneficial for commercial electricity producer?
- How a solar PV test facility should be realized in the Nordics?

2 Theory

Photovoltaic cells, more commonly called solar cells, are energy conversion devices that convert the energy of electromagnetic radiation (photons) into electricity and heat. The operating principle of solar cells is governed by the photovoltaic effect. In simple terms, the photovoltaic effect is the formation of potential difference between two media, caused by electron-hole pair generation due to incident photons. These electron-hole pairs are then collected, and the collected electrons traverse through external circuit, thus generating electrical current before returning back to the solar cell and recombining with the generated hole.

In this chapter the basic operating principle and theory of photovoltaic cells are explained. The focus of the thesis is on outdoor solar modules and thus the effect of outdoor environment and the variable parameters in these conditions are examined more thoroughly. This is done in order to highlight the relation between the external parameters and performance of the PV modules. Understanding the relation between the external parameters and performance of a PV module is paramount when designing experiments for outdoors solar PV systems. Additionally, the typical design and operation of photovoltaic modules are explained.

2.1 Semiconductor materials in solar cells

As mentioned above, the photovoltaic effect governs the operating principle of solar cells. In order to understand how the photovoltaic effect works in solar cells, let us have a look into the structure of typical solar cells. Currently the most common solar cells are based on crystalline silicon (c-Si) and therefore c-Si solar cells are used as an example in this theory section.

Silicon is a semiconductor material, meaning that its electrical conductivity is somewhere between a conductor and an insulator. The insulator like behavior of semiconductor can be explained using the band structure of these materials. Typical band structure of an intrinsic semiconductor is shown in figure 1. Intrinsic semiconductor means that the material only contains semiconductor materials, in this case pure silicon. Semiconductor materials have a conduction band and a valence band that are separated by a forbidden region called the bandgap. Electrons can only have energies in the conduction or valence and thus the energies within the bandgap are called forbidden. Electrons in the valence band are tightly bonded to the lattice and they cannot participate in conduction unlike the electrons in the conduction band that are not bonded to the lattice and can move freely and participate in conduction. The size of the bandgap is a property of the material that is dependent on the material temperature. The Varshni's model [10] gives an estimation for the temperature dependency of the bandgap as

$$E_G(T) = E_G(0) - \frac{\alpha T^2}{T+\beta}, \tag{1}$$

where T is the material temperature, $E_G(0)$ is the material-specific bandgap at absolute zero (extrapolated from measurable values) and α and β are material-specific constants.

The material-specific constants α and β can have both negative and positive values, but the general trend for semiconductor materials is that the second term in equation 1 is positive and the bandgap is inversely proportional to temperature. [11] The energy required to excite an electron from the valence band to the conduction band is equal to the bandgap $E_G = E_C - E_V$, where E_C is lowest allowed energy of the conduction band and E_V is the highest allowed energy of the valence band. For conductor the conduction band overlaps the valence band and conductors always have free electrons that can participate in conduction. Conversely, insulators have extremely large bandgap and electrons would need large amount of energy to excite from the valence band to the conduction band. Important property for semiconductors used in solar cells is that they are required to have bandgap small enough so that the photons of solar irradiance have enough energy to excite electrons to the conduction band. The importance of the bandgap energy is discussed further in section 2.2.1.

Another interesting property of semiconductors is that their electrical conductivity can be easily engineered by introducing impurities to the intrinsic semiconductor material. Si atoms have four valence electrons and in intrinsic Si lattice all of the Si atoms have formed four covalent bonds with the neighboring Si atoms. By substituting some of the Si atoms with elements that have three or five valence electrons, like boron (B) and phosphorus (P), one can introduce electron vacancies or additional electrons to the lattice. Boron with three valence electrons is called an acceptor in this context since it will "accept" one electron from a Si atom close by. Similarly, phosphorus is called a donor since it will "donate" one free electron to the lattice. In reality one of the valence electrons from P atom that does not participate in the octet will break free from the P atom leaving the P atom positively charged. The valence electron is loosely bonded to the P atom and energy from thermal motion is enough for the electron to break free and thus a donor atom will introduce a free electron to the lattice. B atoms on the other hand are able to capture electrons from the close by Si atoms leaving vacancies to the Si atoms and the B atom will become negatively charged. The vacancies that are left behind by the B atoms have effective positive charge and they can be considered as positive charge carriers similarly to the free electrons that are negative charge carriers. The introduction of donors and acceptors to the semiconductor material is called doping and these donors and acceptors are generally called dopants. Doping the semiconductor with donor atoms will produce N-type semiconductor and doping with acceptor atoms will produce P-type semiconductor. A large selection of dopants exist, and elements with two and six valence electrons can even be used. For example, a viable and popular alternative for boron is gallium due to decreased light and elevated temperature induced degradation. [12, 13]

Due to the introduction of additional charge carriers to the lattice, dopants will change the Fermi-level (E_F) of the doped semiconductor material. Fermi-level represents the average energy of electrons within the semiconductor lattice and thus by increasing the number of electrons in the conduction band or holes in the valence band, the Fermi-level of the system will be altered. In figure 1 typical energy band structure of an intrinsic, N-type and P-type semiconductors are shown. In the intrinsic material the free electrons and holes are due to thermal excitation of electrons from valence band to conduction band and therefore the concentration of both charge carrier

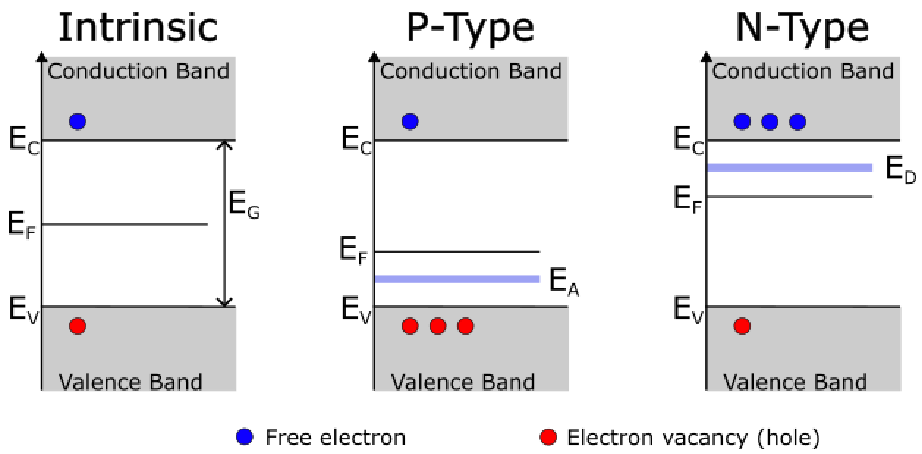

Figure 1: Sketches of typical semiconductor energy band diagrams for intrinsic, P-type and N-type semiconductors.

is equal. Besides increasing the amount of charge carriers, the dopants will introduce new discrete energy states within the forbidden bandgap thus further contributing to the change of the Fermi-level. Additionally, the increase of free charge carriers, electrons or holes depending on the type of dopant, means that also more charge carriers are available for conduction.

The P- and N-type semiconductors by themselves are not that useful as solar cells, but when they are electrically connected, the end product will have interesting new properties. As discussed above, doping changes the carrier concentration of the semiconductor and determines which carriers (electrons or holes) are the majority charge carriers in the material. In the intrinsic semiconductor the carrier concentrations are balanced and neither of the carriers are a majority charge carrier. When P- and N-type semiconductors are connected electrically, the electrons and holes are free to diffuse from their original side to the other side. Once a free electron and a hole are brought to contact, they will recombine. In this recombination process, the free electron will "drop" to the hole and they will annihilate each other. Energy equal to the bandgap will be emitted as a photon from the semiconductor as a result of recombination. The aforementioned recombination is called radiative recombination and in reality, there exist other kind of recombination methods as well, namely Auger recombination and defect-assisted recombination. Initially both P- and N-type semiconductors have externally neutral charge, but as the free charge carriers are recombining, the ionized dopant cores are left to their respective sides of the combined semiconductor since they are tightly bonded to the lattice. This will cause the accumulation of negative charge in the P-side and positive charge in the N-side. As a result, an electric field will be induced between these two sides of the semiconductor. Such a junction of two materials is called a P/N-junction. Due to the induced electric field between the two sides, the charge carriers at the region close to the junction will drift towards their majority side and the region at the junction will be depleted from charge carriers. This is conveniently called the depletion region. The mentioned diffusion (due to difference in carrier concentration) and drift (due to induced electric field) of charge carriers will induce currents across the P/N-junction, called diffusion and drift currents. Once enough of the charge carriers have diffused across the depletion region, the diffusion and drift currents are equal and the net current across the junction is zero. Thus, the P/N-junction is at equilibrium. These diffusion and drift currents of charge carriers are essential to the operation of a solar cell. The formation of a P/N-junction is shown in figure 2.

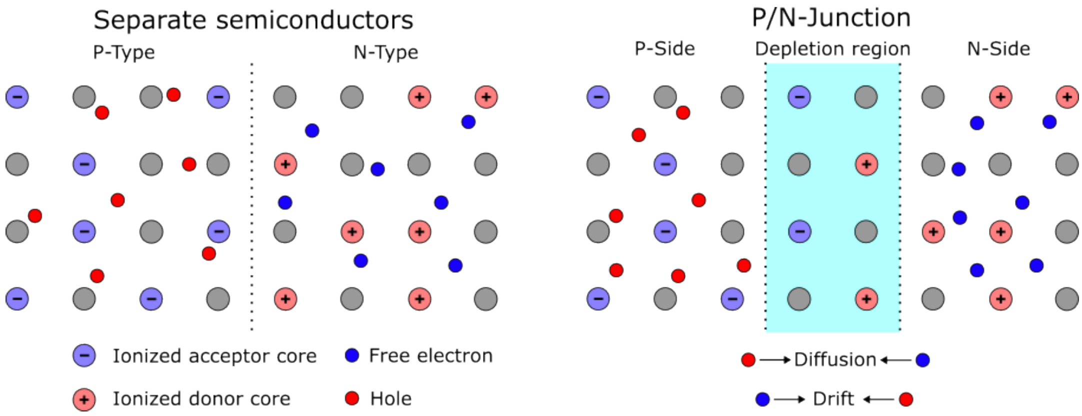

Figure 2: Formation of P/N-junction. In thermal equilibrium the diffusion and drift currents are equal and the net current across the junction is zero.

In order to get a more holistic understanding of solar cell operation, let us have a look at the energy band diagrams of a P/N-junction structure. As discussed above, the Fermi-levels of P- and N-type semiconductors are not at the same level. However, by definition, the Fermi-level of the material describes the average energy of the electrons within the lattice, and therefore is should be constant for the whole lattice. When P- and N-type semiconductors are connected together to form a P/N-junction, the free charge carriers diffuse from their majority side to their respective minority side, they will also set the Fermi-levels of each side to the same level. However, the distance from the Fermi-level to the electron bands remains constant across this process, causing bending of the electron bands. This bending of the bands will indicate that an electric field has been induced between the two sides. The process of band bending is depicted in figure 3. This property of setting the Fermi-level to the same level across the semiconductor is essential for solar cell operation and engineering.

2.2 Solar cells and photovoltaic modules

Solar cells are electrical devices that are capable of converting electromagnetic radiation into electricity. Typically, these cells are rather small and brittle, and they do not produce much electricity alone. Therefore, it is a good idea to combine multiple of these solar cells into one larger device that is capable of producing more electricity and able to better withstand its operating environment. These larger devices are commonly called photovoltaic modules or PV modules. Thus, the naming convention has slight inconsistency mixing the terms solar and photovoltaic, especially since these two

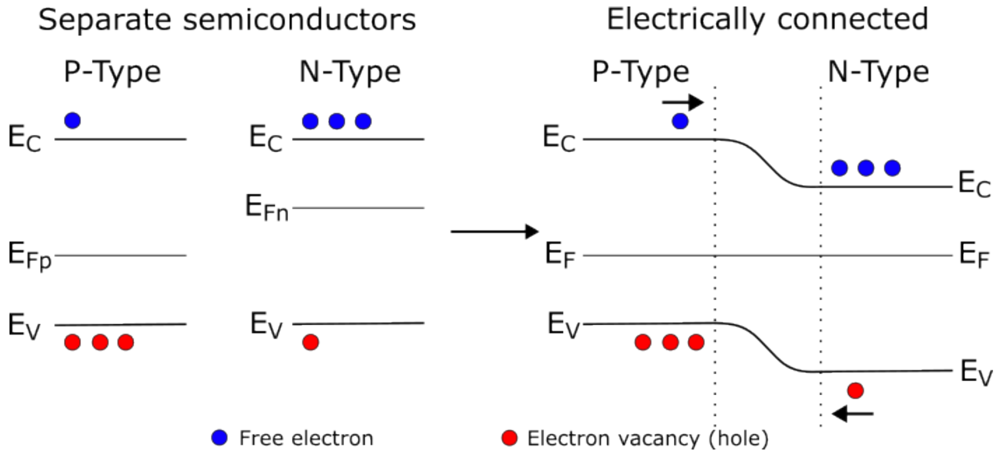

Figure 3: Illustration of the electron band structure of P- and N-type semiconductors when they are brought to electrical contact and a P/N-junction is formed.

terms do not technically mean the same thing. In this thesis the devices are referred to as solar cells and photovoltaic modules according to the common naming convention.

In this section the operating principle of solar cells is covered. Additionally, the characterization parameters used for solar cells are also discussed. After examining the operation and characterization of solar cells, we will go through how solar cells are used to make PV modules. Typical structure of a PV module is presented and the operation of PV modules in outdoors conditions is discussed.

2.2.1 Operating principle of solar cells

The operation of a solar cell is fairly simple, the solar cell is illuminated, and the energy of the light is converted into electricity. How this works at the micro level and what other phenomena affect this process are far more complicated questions. In micro level, the energy of the incident photon is absorbed by an electron (e^-) in the valence band and the electron is excited to the conduction band where it is able to participate in conduction. As the electron is excited from the valence band to the conduction band, a hole is left to the valence band that acts as effective positive charge (e^+). This process is called electron-hole pair generation. If we consider the energy band diagram of a semiconductor illustrated in figure 1, the conduction and valence bands are separated by the bandgap that does not contain any allowed states for the electron. Thus, a requisite for the electron-hole pair generation is that the incident photon must have enough energy to excite the electron all the way from the valence band to the conduction band. This energy is equal to the bandgap energy E_G. This implicates that only photons with energy higher than the bandgap energy are able to generate electron-hole pairs. For example, silicon has bandgap energy of 1.12 eV. Photons with this energy are in the near-infrared region and all photons with this energy or more are able to generate electron-hole pairs. However, even though electrons with more energy are able to generate electron-hole pair, this does not mean that they will generate more usable energy. Photons that have more energy than the bandgap energy

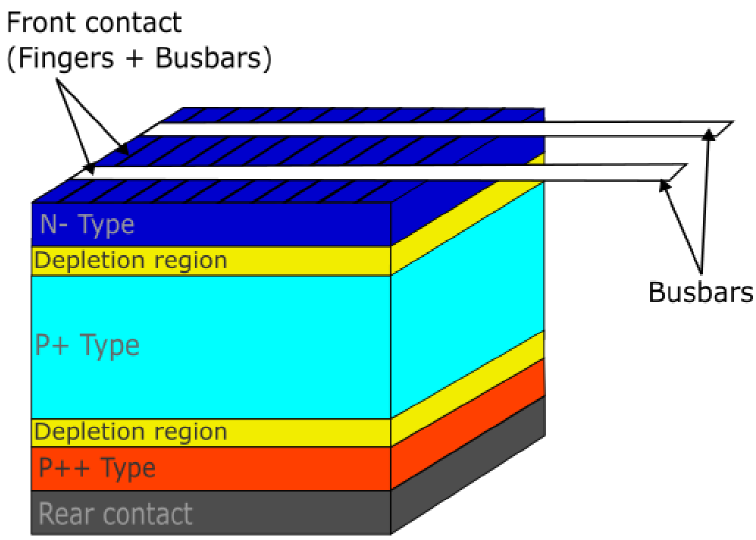

Figure 4: Illustration of typical monofacial c-Si solar cell structure. In order to complete the circuit, the busbars would be connected to the rear contact with external load.

will excite electrons to higher states of the conduction band. Due to the principle of minimum energy, the electrons will emit their "extra" energy to the lattice as phonons, i.e., as heat, in a process called thermalization. This means that the usable energy that a solar cell can convert per photon is equal to the bandgap energy.

Let us then have a look at the typical structure of a solar cell and how the photovoltaic effect occurs in the cell. In figure 4 the typical structure of a monofacial c-Si solar cell is presented. The most common solar cell structure consists of three semiconductor layers with different kind of dopants and dopant concentrations. These three layers are lightly acceptor doped (P+), heavily acceptor doped (P++) and donor doped (N-). The idea behind the three-layer design is that the light is absorbed in the middle P+ layer. The generated electron-hole pairs are then separated to their respective sides of the cell. It is important to note that a depletion region is also formed between two P-type semiconductors if their dopant concentrations are different. This can be demonstrated with figure 3. As we discussed in section 2.1, the Fermi-levels across the whole semiconductor must be in the same level in thermal equilibrium. If the two P-type semiconductors have different dopant concentrations and thus different Fermi-levels, an electric field will also be induced across such junction. In this kind of cell design the P+ layer acts as the absorber layer for the incident light while the P++ and N- layers act as membranes that allow only their respective majority charge carriers to travel across the depletion region.

The energy of the incident light is converted to electrical form in the following manner. Photon with enough energy ($E \geq E_G$) is absorbed in the P+ layer where the electron-hole pair is generated. The charge carriers are then separated into their respective depletion region by diffusion where the induced electric field will cause drift current of the majority charge carriers. Free electrons will be separated to the N-layer where they are collected by the front contact. The front contact consists of fingers that mainly collect the free electrons and busbars that connect the fingers to external load. The electrons will then travel through the external load producing electricity after which they will reach the rear contact of the solar cell. The generated holes have diffused and drifted to the P++ layer of the cell where they can get into contact with the rear contact. When the electrons reach the rear contact they will recombine with holes, thus completing the energy conversion process. The current that follows from this process is called the light generated current I_L.

The separation of the charge carriers to their respective majority sides is important to avoid recombination of the electron-hole pairs before the free electrons have generated electricity. If a free electron finds a hole in the absorber layer, they will recombine, and no electricity will be produced by it. Recombination can occur through several methods, but in all of these methods the energy absorbed from the photon will be lost. Thus, recombinations represent a significant form of losses in solar cells.

2.2.2 Characterization of solar cells

In section 2.2.1 we discussed how solar cells convert the energy of electromagnetic radiation into electricity. In this section let us look into what kind of parameters are related to this phenomenon. Solar cells have several parameters that are critical to its operation. These are called characterization parameters of the solar cell.

Many of the characterization parameters of a solar cell can be determined from an IV-curve. As the name implies, the IV-curve is an electrical current (I) measurement of the solar cell as a function of cell voltage (V). When a solar cell is characterized, it is illuminated with a light source that emits a standardized spectrum of electromagnetic radiation. The importance of the standardized characterization conditions comes from the fact that the light generated current, and thus the results of the characterization, is dependent on the intensity and spectrum of the incident light. Intensity of the incident light determines what is the flux of photons to the solar cell and the spectrum determines the energy distribution of these photons. Besides determining how many photons have enough energy to generate an electron-hole pair, the photon energy also affects how likely and in what depth the photon is absorbed by the semiconductor. The absorption coefficient of the semiconductor is a material-specific parameter. Therefore, in order to get comparable characterization measurement results, these measurements must be done in standard conditions. Technically these measurement conditions can be arbitrarily chosen as long as they are accurate and reported. However, it is convenient to use conditions that are close to real operating conditions. Thus, standard test conditions (STC) are used for solar cells, irradiance of 1000 W/m^2 at cell temperature of 25°C and AM1.5G (*Air Mass 1.5 Global*) spectrum. AM1.5G standard specifies that characterization is done with spectrum that corresponds to extraterrestrial solar radiation that has passed 1.5 atmospheres (air masses). The incident light rays will travel through 1.5 atmospheres when they come from solar zenith angle of 48.19°. [14] The global part of the name refers to global horizontal irradiance spectrum that consists of the direct and diffused irradiance (see section 2.2.4).

Now that we know what kind of conditions are typically used for these characterization measurements, let us go through the characterization parameters themselves and discuss what these parameters tell us about the solar cell. The formation of a P/N-junction turns the solar cell into a diode and naturally current-voltage relation is according to the diode equation. However, since illuminating the solar cell generates current, the diode equation turns into form.

$$I = I_L - I_0 \left(e^{\frac{q(V+IR_s)}{nk_BT}} - 1 \right) - \frac{V + IR_s}{R_{sh}}, \tag{2}$$

where I_0 is the dark saturation current, q is elementary charge, V is the cell voltage, R_s is series resistance of the circuit, R_{sh} is shunt resistance of the cell, n is the ideality factor of the solar cell, k_B is the Boltzmann constant and T is the cell temperature. The dark saturation current I_0 is an important parameter of a solar cell and it measures the recombination rate in the solar cell and thus it describes how much efficiency is lost due to recombination. Increasing the operating temperature T also increases the recombination rate and thus I_0. The ideality factor n is also closely related to the performance of the solar cell through the quality of the cell. The ideality factor describes how well the solar cell acts like an ideal diode. Situation $n = 1$ corresponds to an ideal diode. A plot from a typical IV-measurement is illustrated in figure 5.

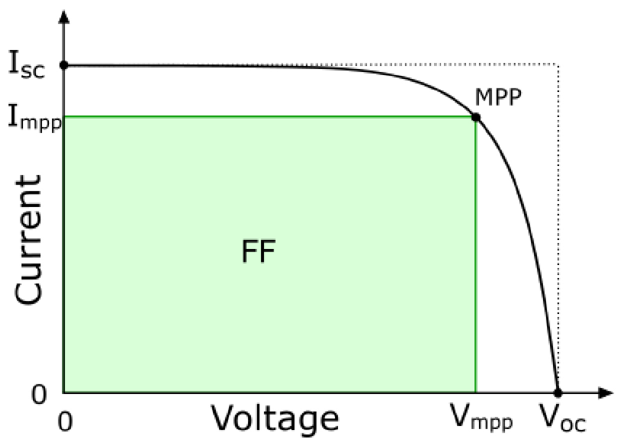

Figure 5: Sketch of a typical IV-curve measurement with some common characterization parameters. Commonly IV-curve would imply that the cell voltage is plotted as a function of current, however the typical convention is to plot the current as a function of cell voltage.

Two important characterization parameters that can be determined from the IV-curve are short circuit current I_{sc} and open circuit voltage V_{oc}. The short circuit current I_{sc} of a solar cell is the maximum current that can be drawn from the solar cell. This occurs when we apply zero voltage over the cell, i.e., when it is short circuited. For a good solar cell, the short circuit current is close to the light-generated current I_L and therefore I_{sc} is proportional to the number of electron-hole pairs generated and therefore it is proportional to the irradiance and cell surface area. Due to this proportionality, the short circuit current is usually reported as the short circuit current density J_{sc}, since this parameter is not proportional to the surface area. The short circuit current also has a slight temperature dependency. According to the Varshni's model (Eq.1) the bandgap energy decreases as a function of temperature. This means that if the spectrum of the incident light is kept constant, the number of photons that have enough energy to generate electron-hole pairs also increase as a function of temperature. Thus, the I_{sc} is proportional to the cell temperature. However, it is important to mention that the dependency is not strong and typically other mechanisms dominate the performance.

The open circuit voltage V_{oc} on the other hand corresponds to the cell voltage when the solar cell is not connected to an external load ($I = 0$), i.e., V_{oc} is the maximum voltage available from the cell during normal operation. Unlike the short circuit current, the open circuit voltage is not proportional to the size of solar cell since it is more related to physical properties of the semiconductor material in question. In order to understand the physical meaning of the open circuit voltage, let us consider an illuminated P/N-junction in open circuit condition. The incident photons generate electron-hole pairs and due to the P/N-junction these charge carriers are separated to their respective majority sides of the junction. As these charge carriers with different polarities accumulate to the different side of the junction, a potential will be induced between them that is opposing to the potential induced by ionized dopant cores. Eventually the potential induced by the charge carriers is equal to the potential induced by the junction and an equilibrium is found. The potential required to find this equilibrium is equal to the open circuit voltage V_{oc}. Thus, the open circuit voltage is dependent on the P/N-junction of the solar cell. Additionally, V_{oc} is proportional to the bandgap energy of the semiconductor. Therefore, V_{oc} is inversely proportional to the cell temperature. In addition, V_{oc} is also proportional to the irradiance. If we solve the diode equation (eq. 2) for open circuit voltage V_{oc} with the assumption that the shunt resistance R_{sh} is large ($R_{sh} \to \infty$), we get

$$V_{oc} = \frac{nk_BT}{q} \ln\left(\frac{I_L}{I_0} + 1\right). \tag{3}$$

From equation 3 we can see that the open circuit voltage has logarithmic dependency on the light generated current I_L that in return is proportional to the electron-hole pairs generated and thus the incident irradiance. Equation 3 shows linear dependency between open circuit voltage and cell temperature. However, the dark saturation current I_0 has also strong dependency to cell temperature and thus the rapid increase of I_0 causes the open circuit voltage to be inversely proportional to the cell temperature.

Let us then discuss about some important characterization parameters that are derived from the IV-curve and I_{sc} and V_{oc}. The usable work that we can get out of a solar cell comes in the voltage region $[0 - V_{oc}]$. One can calculate the power output of the solar cell in this voltage region simply as

$$P = I \cdot V, \tag{4}$$

where I is electrical current and V is cell voltage. The power of the solar cell can be calculated for the whole usable voltage region and a maximum power is achieved in so called maximum power point (MPP). The maximum power at MPP is denoted as

$$P_{MPP} = I_{MPP} \cdot V_{MPP}, \tag{5}$$

where I_{MPP} is the maximum power point current and V_{MPP} is the maximum power point voltage. Since the maximum power is heavily dependent on the shape of the IV-curve (see figure 5), it is also dependent on the cell temperature. The maximum power point parameters I_{MPP} and V_{MPP} are proportional to the maximum values, I_{sc} and V_{oc}, and therefore they have similar dependencies to temperature. As discussed above, I_{sc} increases and V_{oc} decreases as a function of cell temperature. Typically, the decrease in V_{oc} is the more dominant one and thus the maximum power is inversely proportional to the cell temperature. However, due to these dependencies, the maximum power is also proportional to the irradiance due to the proportional dependency of I_{sc} on irradiance.

Now that we have gone through the basic parameters of a solar cell (I_{sc}, V_{oc}, P_{MPP}), let us discuss about parameters that describe the performance of the solar cell more directly. First of these parameters is called fill factor FF. The fill factor is calculated as

$$FF = \frac{P_{MPP}}{I_{sc}V_{oc}} = \frac{I_{MPP}V_{MPP}}{I_{sc}V_{oc}}. \tag{6}$$

From equation 6 we can see that fill factor is the ratio between the achievable maximum power and the theoretical power with I_{sc} and V_{oc}. This can also be illustrated as ratio between the green rectangle and a rectangle formed by the dashed lines in figure 5. The fill factor describes the shape of the IV-curve and thus fill factor gives insight into how much recombinations take place in the solar cell, i.e., how good is the solar cell performance. In simple terms, low fill factors indicate high amount of recombinations and poor performance. It is important to note that the fill factor by itself does not tell what kind of recombinations take place in the cell.

The second important performance parameter and probably the most important single parameter of a solar cell is the energy conversion efficiency η. Solar cell efficiency is calculated as

$$\eta = \frac{P_{MPP}}{P_I} = \frac{I_{MPP}V_{MPP}}{P_I} = \frac{I_{sc}V_{oc}FF}{P_I}, \tag{7}$$

where P_I is the power of the incident light. The power of the incident light is calculated as

$$P_I = E_e \cdot A, \tag{8}$$

where E_e is the irradiance received by the solar cell and A is the surface area of the solar cell. For the standard test conditions the irradiance is $E_e = 1000\ \mathrm{W/m^2}$. The power conversion efficiency naturally tells us how large fraction of the energy of the incident light the solar cell is able to convert into electrical energy. As one can see from equation 7, the power conversion efficiency is related to all of the previously mentioned characterization parameters. Thus, the temperature dependency of the conversion efficiency is also dependent on the temperature effect of these parameters. Yet again the temperature effect on the open circuit voltage is dominant one and therefore the conversion efficiency is inversely proportional to the cell temperature. It is important to note that the conversion efficiency is normalized with respect to the irradiance with the incident power term in equation 7 and thus it does not have direct

Table 1: Summary of the characterization parameters of solar cells and their crude dependency on environmental parameters. Fill factor is not presented in this table due to strong dependency on other cell parameters like series and shunt resistance.

Parameter	Temperature dependency	Irradiance dependency	Spectrum dependency
I_{sc}	Proportional	Proportional	Dependency
V_{oc}	Inversely proportional	Proportional	Dependency
P_{MPP}	Inversely proportional	Proportional	Dependency
η	Inversely proportional	Proportional	Dependency

irradiance dependency. The hinted indirect irradiance dependency stems from the relation between cell voltage and the incident irradiance (see equation 3). Additionally, the energy conversion efficiency is also dependent on the spectrum of the incident light through spectral response. The spectral response is in concept similar to the quantum efficiency of the solar cell. The spectral response of the solar cell is the ratio between generated current and power incident on the solar cell as a function of wavelength. Due to the spectral response, also the spectrum of the incident light is an important external parameter that must be considered when characterizing solar cells. In order to get comparable results from solar cell characterization measurements, the spectrum of the incident light must be known accurately, and the results must be corrected with spectral mismatch correction to represent measurements done in the standard test conditions.

Now that we have covered the major characterization parameters of solar cells, let us quickly summarize these and see how the environmental parameters affect them. The characterization parameters of solar cells are presented in table 1 with their dependencies to environmental parameters. In this context the environmental parameters are considered to be cell temperature, irradiance and spectrum of the incident light. Technically the cell temperature is not an environmental parameter, unlike ambient temperature, but cell temperature is strongly dependent on the ambient temperature. Considering that the cell temperature is dependent on many other parameters as well like wind speed and direction and irradiance, it makes more sense in the context of characterization parameters to state the performance dependency on the cell temperature rather than the ambient temperature. From table 1 we can see that majority of the performance parameters are inversely proportional to the cell temperature, I_{sc} being the only parameter with proportional dependency. Therefore, solar cell works better in low temperatures. All of the characterization parameters presented in table 1 have dependency on the incident spectrum and all of these parameters also have proportional dependency on the incident irradiance. In general, the irradiance dependency comes from the fact that with increased irradiance, the number of electron-hole pairs generated also increases. The spectrum dependency stems from the fact that spectrum of the incident light determines the fraction of incident photons that are able to generate electron-hole pairs. However, it is important to note that the cell temperature is dependent on the irradiance and the spectrum and thus irradiance and spectrum can indirectly affect the other characterization parameters through cell temperature. Studying the cell temperature dependency on all the relevant environmental parameters generates a rather dynamic system that is out of scope of this thesis.

2.2.3 Photovoltaic modules

As mentioned in the beginning of chapter 2.2, typically solar cells are combined into one larger electrical device called photovoltaic module in order to enhance the performance of the solar cells in real life conditions. The properties of a PV module can be roughly separated into two categories, electrical performance, and durability.

Two key electrical parameters of a solar cell are short circuit current I_{sc} and open circuit voltage V_{oc}. These are the maximum current and voltage that can be drawn from the solar cell, and they directly affect the maximum power P_{MPP} of the solar cell (see section 2.2.2). Both short circuit current and open circuit voltage are dependent on the number of electron-hole pairs generated and collected. However, the open circuit voltage is limited by the bandgap of the semiconductor material in question. Therefore, in STC, I_{sc} is dependent on the active surface area of the cell and V_{oc} is dependent on the semiconductor material used. Typically, the solar cells used in utility-scale PV systems are around 18.2×18.2 cm^2 or 21.0×21.0 cm^2 and they have short circuit current of $I_{sc} \approx 9 - 15$ A, depending on the size and efficiency of the solar cell. [15, 16] The open circuit voltage of a c-Si solar cell is around $V_{oc} \approx 0,6$ V. The current of the solar cells is adequate, but the voltage is rather low and therefore solar cells are connected in series within the PV module to increase the total voltage of the module. When the solar cells are connected in series, they will face new problems that a singular cell is able to avoid, like partial shading. Shading will cause losses to a singular solar cell as well but when the solar cells are connected in series and some of the solar cells are shaded, the shaded cells will limit the current of the whole string. In other words, the shaded cells will dissipate the current produced by the illuminated cells and the majority of the dissipated energy will convert into heat, thus increasing the module temperature. In extreme this can lead to hot spots that can severely damage the PV module. In order to avoid such conditions, bypass diodes are installed in the modules. However, since these bypass diodes are rather expensive, typically three are installed per module. Thus, shading and partial shading remains a significant issue that must be considered when designing a PV system. An illustration of a typical electrical circuit for a PV module is presented in figure 6 (a).

Besides the electrical performance of the solar cells, the PV module must also protect the solar cells from external harm like moisture and mechanical damage. Additionally, the PV module must be safe to handle, and electrical insulation is of utmost importance. Typical structure of a monofacial and bifacial PV module is shown in figure 6 (b) and 6 (c). Bifacial PV modules are able to collect light from both sides of the panel unlike monofacial modules that have opaque back sheets. As we can see from figure 6, in a PV module the solar cells are encapsulated between a glass sheet and a back sheet or two glass sheets. Therefore, these three layers are responsible for the durability of the module. Besides these layers the module

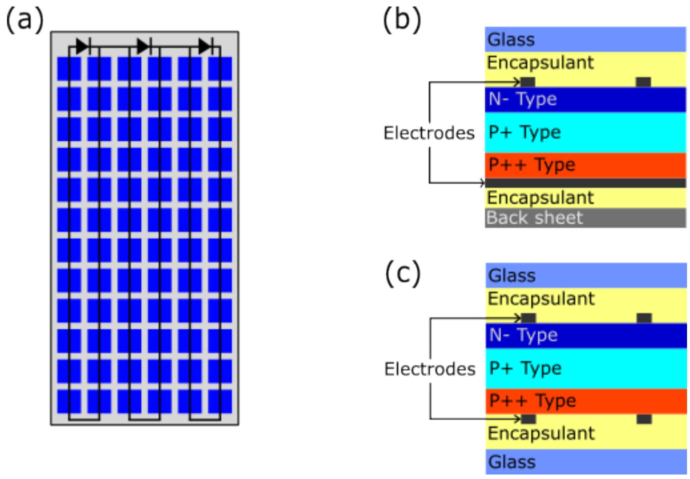

Figure 6: Structure of typical solar modules. (a) Illustration of the electrical circuit of a typical PV module. (b) Structure of a typical monofacial PV module. (c) Structure of a typical bifacial PV module.

is surrounded by a metal frame (typically made out of aluminum) that reinforces the module and prevents the module from twisting. After the solar cell, by far the most important layer of the module is the encapsulant. The encapsulant has strict requirements for light transmittance, thermal expansion coefficient, electrical, thermal and moisture resistance, UV-durability, and adhesion to name a few. Due to the large list of requirements, the cost of the encapsulant can be a significant share of the total module cost, especially when the price of the solar cells is decreasing rapidly. Currently the most common encapsulants are ethylene vinyl acetate (EVA) based. In the near future alternative materials for the encapsulant are expected to arise, like polyolefins (POE). [17, 18]

2.2.4 External parameters effecting PV module performance

Since solar PV power plants are located outdoors, the environmental parameters have a significant effect on the performance of PV modules. As discussed in the previous sections, the cell temperature, irradiance and incident spectrum are the main parameters directly affecting the solar cell operation. Understanding how external parameters like ambient temperature, wind speed and angle of incidence (AOI) affect these parameters is important when the expected power output of a PV modules is being calculated.

Let us first consider how AOI effects the operation of a PV module. Some of the incident solar radiation is reflected when it reaches the glass cover (or any other interface) of the PV module and the share of radiation reflected is dependent on the angle of incidence. In order to get a more holistic understanding about how the AOI effects the reflection losses, let us first determine how the AOI is defined. The angle of incidence θ_i can be expressed as a function of several solar angle parameters

$$\cos\theta_i = \sin\beta\sin\theta_z\cos(\gamma - \gamma_s) + \cos\beta\cos\theta_z, \tag{9}$$

where β is the tilt angle of the module, θ_z is the zenith angle of the sun, γ is the azimuth angle of the module and γ_s is the azimuth angle of the sun. Besides the AOI, the zenith angle of the sun θ_z is also important solar angle and it is defined as

$$\cos\theta_z = \sin\phi\sin\delta + \cos\delta\cos\omega\cos\phi, \tag{10}$$

where ϕ is the latitude, δ is the sun's declination angle and ω is the hour angle. The declination angle is defined as

$$\delta = 23.45^\circ \sin\left(360\frac{284+n}{365}\right), \tag{11}$$

where n is the day number, e.g., $n = 1$ is the 1st of January. The hour angle is defined as

$$\omega = (t - 12\mathrm{h})\frac{15^\circ}{\mathrm{h}}, \tag{12}$$

where t is the time in hours [h]. The sun's azimuth angle is defined as

$$\sin\gamma_s = \frac{\cos\delta\sin\omega}{\sin\theta_z}. \tag{13}$$

Now with equation 9, one can determine the AOI for any arbitrary surface for any time of the year.

The irradiance G that a PV module receives is composed of three solar components, beam (direct) G_b, diffused G_d and reflected G_r. Typically, in a PV system, the horizontal beam $G_{b,H}$ and diffused $G_{d,H}$ irradiance are measured using pyranometers and the irradiance on a tilted surface can be calculated from these measured values. For a horizontal surface the reflected irradiance is assumed to be zero since a horizontal surface does not have a line of sight to the ground. The solar components of the irradiance on a tilted surface can be calculated as

$$G_{b,T} = \frac{\cos\theta_i}{\cos\theta_z}G_{b,H}, \tag{14}$$

$$G_{d,T} = \frac{1+\cos\beta}{2}G_{d,H}, \tag{15}$$

$$G_{r,T} = \rho_g(G_{b,H} + G_{d,H})\frac{1-\cos\beta}{2}, \tag{16}$$

where ρ_g is the albedo of the ground. The downfall of equations 15 and 16 is that they both assume that the diffused and reflected irradiance are uniformly distributed from the sky and ground (isotropic model). This is known not to be the case, for example due to cloud enhancement phenomena [19] and the non-uniform albedo of the surroundings. More accurate models have been presented especially for the diffused solar component like the Muneer model [20] and Perez model [21]. However, both of these models require additional parameters and thus the isotropic model is simpler. The isotropic model is used in the context of the AOI effects part of this thesis. Comparison between the isotropic, Muneer and Perez models are provided in [22, 23].

Now that we have covered the angle of incidence and the solar components on a tilted surface, we can determine what is the effect of AOI on the PV module performance. A widely adapted analytical model [24] for PV module angular losses has been presented by Martin and Ruiz in [25]. In the analytical model the angular losses of the incident radiation as a function of angle of incidence θ_i is defined as

$$AL(\theta_i) = 1 - \left(\frac{1 - e^{-\cos\theta_i/\alpha_r}}{1 - e^{-1/\alpha_r}} \right), \tag{17}$$

where α_r is an empirical coefficient that characterizes the dependency of the angular losses on the spectral reflectance of the surface. The equation 17 gives the fraction of angular losses as a function of AOI and one material-specific coefficient α_r. In order to understand the effect on the module performance, the angular losses of each solar component must be considered. The angular loss factors for beam F_b, diffused F_d and reflected F_r irradiance can be determined as [25]

$$F_b(\theta_i) = \frac{e^{-\cos\theta_i/\alpha_r} - e^{-1/\alpha_r}}{1 - e^{-1/\alpha_r}}, \tag{18}$$

$$F_d(\beta) \approx e^{-\frac{1}{\alpha_r}\left(c_1\left(\sin\beta + \frac{\beta - \sin\beta}{1-\cos\beta}\right) + c_2\left(\sin\beta + \frac{\beta-\sin\beta}{1-\cos\beta}\right)^2\right)}, \tag{19}$$

$$F_r(\beta) \approx e^{-\frac{1}{\alpha_r}\left(c_1\left(\sin\beta + \frac{\pi-\beta-\sin\beta}{1+\cos\beta}\right) + c_2\left(\sin\beta + \frac{\pi-\beta-\sin\beta}{1+\cos\beta}\right)^2\right)}, \tag{20}$$

where $c_1 = 4/3\pi$ and c_2 is an empirical coefficient that is dependent on the angular loss coefficient α_r. Since the angular losses for the diffused and reflected irradiance are determined with fitting parameters c_1 and c_2, these loss factors are approximations that based on [25] approximate the angular losses accurately. Now after the solar component specific angular losses the irradiance that reaches (global tilted irradiance) the solar cell is

$$G_{g,T} = (1 - F_b)G_{b,T} + (1 - F_d)G_{d,T} + (1 - F_r)G_{r,T}. \tag{21}$$

Besides the AOI effects, also the spectral response of the solar cells and the spectrum of the incident light effect the power output of the PV module. Since different solar cells have different kind of spectral response (absorption profile) and the spectrum of the incident light changes with latitude and time of day, both of these effects must be taken into account when defining the effective irradiance G_{eff}. The effective irradiance is defined as [26]

$$G_{\text{eff}} = G \frac{\int S_r(\lambda)R(\lambda)\,\mathrm{d}\lambda}{\int S_r(\lambda)R_{STC}(\lambda)\,\mathrm{d}\lambda}, \tag{22}$$

where G is the global horizontal irradiance, S_r is the spectral response of the solar cell as a function of wavelength, R is the spectrum of the incident sunlight and R_{STC} is the STC spectrum according to the AM1.5 standard. It is important to note that the real irradiance does not change even though we apply the effective irradiance. The incident radiation remains the same but, the effective irradiance describes how the irradiance effects the power output of the PV module. As one can expect, accurate estimation of the effective irradiance is extremely challenging, and the model presented in equation 22 is rather simple and it used in this thesis to give an easy-to-understand relation between the spectral effects and module performance. More sophisticated model is presented for example in [27].

Alongside the irradiance and spectrum of the radiation, the solar cell temperature is one of the major parameters that affect the performance of a PV module. Since the solar cells are in the middle of the PV module, it is impractical to measure the cell temperature and therefore typically the PV module temperature is considered in the analytical models. In the Faiman module temperature model [28] the module temperature is expressed as a function of irradiance G, ambient temperature T_{amb} and wind speed at the module height W_{mod}

$$T_{\text{mod}} = T_{\text{amb}} + \frac{G}{U_0 + U_1 W_{\text{mod}}}, \tag{23}$$

where U_0 and U_1 are empirical coefficients that are specific to the module type in question and can be determined from measurements. Coefficient U_0 describes the effect of the irradiance to the module temperature while U_1 describes the effect of the wind. The coefficients U_0 and U_1 vary only slightly for same solar cell technology and mounting types and measured values can be found in the literature [28, 29]. It is important to note that the irradiance G used in equation 23 must take into account the angular losses but not the spectral response of the cells. Typically, the wind speed is not measured right at the PV module level and the anemometer can be located several meters higher compared to the modules. The wind speed at the module level can be calculated using the wind profile power law

$$W_{\text{mod}} = \left(\frac{d_{\text{mod}}}{d_{\text{ane}}}\right)^{\alpha} W_{\text{ane}}, \tag{24}$$

where d_{mod} is the installation height of the PV module, d_{ane} is the height of the anemometer, α is a dimensionless coefficient that describes the wind shear and W_{ane} is the wind speed measured by the anemometer. For a usual PV system environment (open field) the coefficient α has values around $\alpha \approx 0.2$. [30]

Now that we have gone through the major external parameters that affect the performance of a PV module, let us have a look at how the performance can be estimated. The outdoors performance of a PV module can be estimated using a variant of King's model [31, 32]

$$P(G', T') = G' P_{STC} \left[1 + k_1 \ln(G') + k_2(\ln(G'))^2 + k_3 T' + k_4 T' \ln(G') + k_5 T'(\ln(G'))^2 + k_6 T'^2\right], \tag{25}$$

where P_{STC} is the maximum power produced by the module in STC and $k_i, i \in [1, 6]$ are empirical coefficients that must be determined by fitting to measured values. The values for k_i coefficients should be PV technology specific and the coefficient values for common technologies can be found in the literature. [32] G' and T' are auxiliary variables that are defined as

$$G' = \frac{G_{\text{eff}}}{G_{STC}} = \frac{G_{\text{eff}}}{1000\ \text{W/m}^2}, \tag{26}$$

$$T' = T_{\text{mod}} - T_{STC} = T_{\text{mod}} - 25°\text{C}. \tag{27}$$

Note that the effective irradiance G_{eff} is used in equation 26 and thus also in equation 25. The effective irradiance should not be used in equation 27 to determine the module temperature T_{mod}.

Equation 25 gives the estimation of the instantaneous power of a PV module. This power value will vary constantly due to changes in temperature and irradiance. Therefore, the instantaneous power does not describe how well the PV module operates in general. A more suitable parameter to describe the performance of a PV module is the performance ratio (PR). Annual average PR is defined as

$$PR = \frac{G_{STC} \cdot E_a}{P_{STC} \cdot H_a}, \tag{28}$$

where E_a is the annual energy output of the PV module and H_a is the average annual plane-of-array irradiance. The performance ratio is defined in standard IEC 61724-1. [33]

2.3 Solar PV power plant components and structure

In this chapter, we will go through the required components in a solar PV power plant and a typical structure of such a power plant. The design or structure of a PV power plant from the point of view of solar PV testing can be separated into three categories, electrical devices and monitoring devices and other components. More traditional categorization would be to separate the power plant into PV modules, inverters and balance of system (BoS). However, the first categories are used in this section since the main objectives of this thesis are related to solar PV testing. Designing a solar PV power plant requires many more steps like finding the optimal layout and sizing for the given site, however these steps are not covered in this section and we will focus on the components of solar PV system.

Let us first have a quick look at the electrical devices and components of a typical grid-connected PV installation. Quite obviously the PV modules are one of the most common electrical devices in a solar PV power plant. Because a utility-scale PV system has an immense amount of PV modules, their price and performance are two of the key factors when selecting the PV technology and original equipment manufacturer (OEM). Besides price and performance, environmental and social issues have become more important for major players in the energy sectors and the OEMs must pass these requirements. Additionally, the site in question also affects what kind of PV modules should be installed. Typically, the biggest difference is whether the site has monofacial or bifacial modules.

Since the electricity produced by PV modules is direct current (DC), it must be converted into alternating current (AC) before it can be supplied to the grid. Besides converting the current from DC to AC, the PV inverters are typically also responsible for performing maximum power point tracking (MPPT) for the PV module and setting the module voltage to V_{MPP}. In general, three different types of inverters are used with PV modules, string inverters, central inverters and microinverters. PV modules are connected to a series of modules to form a string and the string is then connected to a string or central inverter. Both of these inverter types have their advantages and disadvantages. The separation between a string and a central inverter especially for utility-scale applications is rather vague currently due to new innovations and designs like the virtual central inverter for example. [34, 35] However, the biggest difference between these two inverter types is the number of string connected to the inverter. Central inverters typically have far more strings connected to a single inverter compared to string inverters. [36, 37] This means that central inverters are able to handle more power and thus less inverters are needed. This naturally causes other issues; central inverters are larger and thus heavier. Having more string inverters across the site also increases security against component failure since one inverter or string accounts for a smaller portion of the total site. Another typical difference between string and central inverters is the number of MPP trackers connected to a single inverter. Typically, central inverters can have multiple MPP trackers while string inverters have only a single MPP tracker. As mentioned above, the difference between string and central inverters is vague and this also applies to the number of MPP trackers per inverter. Microinverters are typically connected to a single PV module, and they are not as efficient as string or central inverters. Therefore, microinverters are typically used in residential applications.

The rest of the electrical devices, or at least the majority of them, are located in the substation of the power plant. A Substation is a building and/or location that has typically the monitoring and controlling systems of the power plant as well as transformers that step up the voltage to be suitable to be injected to the main grid. In utility-scale PV systems medium voltage step up transformers are placed before high voltage transformers. The main grid connection point is typically not connected at the PV power plant, but the voltage is stepped up at the substation and then transported through high voltage (110 kV) cabling to the grid connection point. Simple schematic of a PV power plant is presented in figure 7.

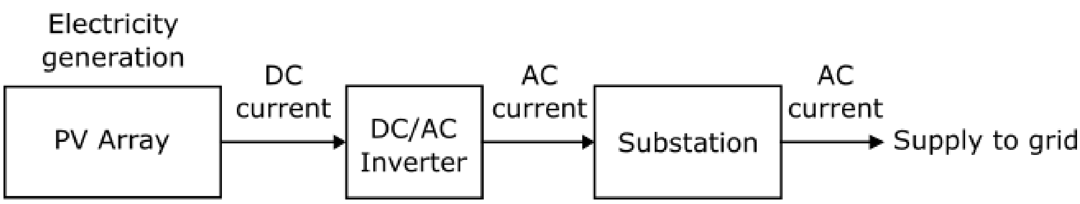

Figure 7: Simple schematic of the energy conversation process in a solar PV power plant.

Typically, utility-scale solar PV power plants have some kind of monitoring devices to validate the operating conditions of the PV modules and to ensure that the site is operating appropriately. Usually, PV power plants have a weather station at the site that is able to perform all the required measurements. The most common parameters measured in a solar PV power plant are irradiance, wind speed and direction, ambient temperature and relative air humidity. Pre-designed solutions for the weather station exist in the market in abundance. [38, 39]

Finally, we get to the other components and aspects of the PV power plant. Two extremely important components of a solar PV power plant are the mounting structures and foundations, and both of these topics are closely related to each other. Generally, the ground mounting structures used in a utility-scale PV power plant can be set into two categories, fixed and 1-axis tracking. 2-axis tracking mounting structures also exist, but these are not typically used for large commercial applications. Within the fixed and 1-axis tracking mounting categories there exist multiple different variations of the type. However, the advantages and disadvantages remain the same within each category. The biggest difference between the variants is their compatibility with different foundation types. The foundation type must be chosen based on the soil and weather conditions in the site in question.

One aspect or topic that is not a component but is starting to get more attention when designing a PV power plant is the biodiversity and sustainability of the site. Currently many of the solar PV sites are old farmlands and their biodiversity has been extremely monotone. Since the land area is not being actively used for anything, letting the vegetation return to a more natural state would improve the biodiversity of the local area. Some of these biodiversity sustainability improving measures could be extremely cost effective and worth considering when designing a PV power plant.

3 PV system monitoring

Before the investment decision of a utility-scale PV system, a feasibility study of the site in question is conducted. In the feasibility study an energy yield assessment (EYA) is conducted where the potential production of the designed PV system is estimated. This estimation is then used to determine the potential profitability of the PV system project. As the EYA only estimates the production and thus gives an estimation for the profitability, it is important to monitor the operating conditions of the PV system and cross reference the conditions with the output production. This way the true performance of the PV system can be determined and compared to the estimated performance. This can help to find failure modes within the PV system or errors in the EYA process.

As the EYAs should be as accurate as possible, a great deal of work has been done to provide tools for accurate estimations. Additionally, the International Energy Agency (IEA) has a Photovoltaic Power Systems Program (PVPS) that is actively working on many PV system-related topics including PV technology development and policy recommendations and strategies for PV technologies and systems. PVPS publishes an annual report about the different PVPS tasks and the individual task groups publish more detailed reports about their specific task related topics. [40] The PVPS Task 13 focuses on reliability and performance of photovoltaic systems and many of their reports have been used as basis for this thesis. [41] Besides the PVPS Task 13 report, many other guidelines and recommendations for PV system monitoring exist, for example IEC standards.

In the context of this thesis, the required monitoring and measurements in a system-level solar PV test facility had to be determined. In this chapter the current best practices and existing approaches for PV system monitoring and energy yield measurements are summarized from relevant reports, guidelines and standards.

3.1 Current best practices and existing approaches for solar PV test facilities

PVPS Task 13 group has published reports about analyzing and monitoring system-level solar PV installations [42, 43, 44, 45] as well as module-level energy yield measurements [46]. System monitoring in this context means measuring certain performance related parameters of the PV system while analyzing refers to the analysis done based on the measured data. Currently there exists no guideline or best practices for system-level solar PV testing. Differing from monitoring that is typically done for every larger PV system, PV testing refers to testing of a certain aspect or aspects of the PV system, like new PV modules or mounting structures for example. It is recognized in [46] that system and module-level testing and monitoring differ from each other in some ways, but as long as the secondary uncertainties would be minimized, a system-level test facility could be used for performance and reliability studies. The secondary uncertainties are related to the system configuration, e.g., inverter performance, mismatch losses etc. Therefore, by combining the findings and practices from these reports and guidelines and from IEC 61724-1 standard [33], one can formulate a general guideline for system-level solar PV test facility monitoring. Topic-specific test facility setups are explored in section 6. Since the topic of this thesis is system-level PV test facilities, the practicalities specific to module-level test facilities are mainly omitted. The reason for this is that the PV modules in a system-level test facility are expected to operate in typical utility-scale PV system conditions in order to yield realistic results.

3.1.1 Structural recommendations

The best practices for a PV system can be separated into the design or structure of the facility and monitoring measurements. The design and structure of the test facility includes topics such as mounting rack layout, PV module installation, PV module shading, albedo of the ground and sensor positioning. The most prominent issue related to mounting rack layout is misalignment of the PV modules and especially misalignment of the irradiance sensor, e.g., pyranometer or reference cell. The error in measured irradiance is proportional to the AOI and especially in the Nordics where the sun's zenith angle θ_z changes drastically over the year, the measurement error due to misalignment can be significant. Misalignment of $< 0.5\%$ is recommended in [46]. However, with AOI of $> 50°$ the measured error will be $> 1\%$. Misalignment of $< 0.5\%$ is rather small error margin when considering a system-level test facility that might contain up to several MWs of PV modules and it is unreasonable to expect such precision for this scale of a PV system. On the other hand, the installation angle of the irradiance sensors should be measured accurately since a smaller number of the sensor are installed to the site.

Besides the incident irradiation to the PV modules, also the module temperature will effect the operation of the PV module and in a PV system environment the PV modules typically will experience temperature gradient from the bottom to the top of the module. In [46] it is recommended to measure the temperature of the PV modules at irradiance > 800 W/m^2 with an infrared camera to discover possible non-uniformities in the module temperature profile. Review of infrared imaging for PV field applications is provided in [47]. As PV modules mounted on a tilted rack experience commonly temperature gradients, it is recommended to install the PV modules 1 m above ground and at least 10 cm away from other objects to assure proper air circulation around the PV modules. [46] Additionally the PV modules at the edges of the site have typically lower operating temperature compared to the rest of the modules. For module-level testing dummy modules are recommended to be installed at the edges of the site. A similar approach should be used for system-level testing where the PV modules installed at the edges are not considered in the energy yield measurements. This however would require unusual string configuration where the edge modules are not connected in the same string as the central modules. Typically PV modules are connected into strings based on the rows and not columns. Additionally, the effect of the lower temperature edge modules in a utility-scale PV system would be omitted from the energy yield measurements. This will be further discussed in section 6.

The PV module shading is an issue for module-level testing, but for system-level testing that is done in utility-scale like environment, the module shading and data point rejection due to shading are less common obstacles. However, the non-uniformity of irradiance across the system-level PV installation may prove to be a significant source of error for the energy yield measurements. Therefore, installing several irradiance sensors within the test facility is recommended for larger PV systems.

Surroundings and especially the albedo of the surroundings plays a critical role in the total irradiance that a PV module receives. This is even more crucial for bifacial modules which are further discussed later in this thesis (see sections 5.1.1 and 6). Therefore, the albedo of the ground around the PV system should be measured before and preferably also after the PV system construction. PVPS Task 13 has formulated best practices in order to minimize the measurement error. [46] According to these recommendations,

- The ground albedo should be as uniform as possible.
- Installation height of the PV modules should be > 1 m.
- Distance between module rows should be large enough to avoid different irradiance conditions on the front and rear of the mounting rack.
- High reflective surfaces should be removed, covered or painted from the surroundings.

Additionally, if bifacial modules are used, the rear-side irradiance should also be measured from multiple locations since one location that would represent the total rear irradiance is hard to find. [46]

The final topic of the structural recommendations is sensor positioning. The installation positions of meteorological and module temperature sensors are given in standards IEC 61724-1 [33] and IEC 61853-2 [48]. The general recommendation is that the sensor should be positioned in such locations that represent correct operating conditions of the PV modules without intervening in the operation of the monitored PV modules.

3.1.2 Measurement recommendations

Recommended or required measurements for PV system monitoring are defined by the classification of the PV system. In standard IEC 61724-1 [33] these classifications are defined as Class A and Class B. Class A is intended for larger utility-scale PV systems while the Class B is intended for smaller installations such as rooftop systems or medium size commercial installations. The standard states that the user of the standard may determine which class suits their application the best and thus there is some grey area between these classifications. In the context of this thesis, we cover only Class A. Class also determines the recommended maximum sampling interval, which is 5 s for irradiance, temperature, wind and electrical output measurements. The maximum recording interval is 5 min; however, a 1 min interval is recommended. Sampling frequency refers to the frequency of measured data points, however, these data points

Table 2: The required meteorological and temperature measurements according to the standard IEC 61724-1 for Class A PV system. In the minimum number of sensors column, the symbol x refers to multipliers for different PV system sizes presented in table 3.

Parameter	Minimum number of sensors
Plane of array irradiance (POA)	$1x$
Global horizontal irradiance	$1x$
Horizontal albedo	$1x$
Plane of array rear-side irradiance	$1x$
Diffuse horizontal irradiance	$1x$
Direct normal irradiance	$1x$
PV module temperature	$3x$
Ambient air temperature	$1x$
Wind speed	$1x$
Wind direction	$1x$
Soiling ratio	$1x$
Rainfall	$1x$
Snow	$1x$

Table 3: Sensor multipliers for different PV system sizes. [33]

System size (AC) [MW]	Multiplier
< 40	2
≥ 40 to < 100	3
≥ 100 to < 300	4
≥ 300 to < 500	5
≥ 500 to < 700	6
≥ 700	7 + 1 for each additional 200 MW

are typically not stored permanently. Recording interval refers to the time between stored data points. The stored data points are typically acquired from the average of the measured data points. Other methods also exist for determining the stored data point, for example maximum or minimum value during the recording interval. The required meteorological and temperature measurements according to the standard IEC 61724-1 for Class A PV system are presented in table 2. Sensor multipliers depending on the PV system size are presented in table 3.

The meteorological and temperature measurements listed in table 2 can be generalized as the environmental measurements. The irradiance received by the PV modules is the most important environmental parameter in terms of the power output of the PV system and therefore it is typically measured with great precision. As mentioned in section 3.1.1, irradiance is measured either with a pyranometer or a reference cell. A high quality (according to ISO-9080 standard [49]) pyranometer is recommended to measure the broadband irradiance since thermopile pyranometers are not spectral-selective. Thermopile pyranometers measure the temperature of the thermistor and determine the incident irradiance. Alternatively, spectral-selective reference cells can also be used to estimate the global irradiance as a function of short-circuit current. Since the reference cells are spectral-selective, the selected reference cells should have similar spectral response to the solar cells that are being monitored in order to avoid large error margins in the irradiance measurements. As mentioned, pyranometer is the recommended sensor, however it is recommended to used reference cell in addition to the pyranometers to measure the plane of array irradiance. The advantage of reference cells is that if they are selected properly, their results reflect the true conditions that the monitored PV modules are experiencing, like angular and spectral response. Therefore, the reference cells give better understanding of the low-light performance and degradation of the solar cell. [46] If only reference cells are decided to be used, it must be kept in mind that the irradiance given by the reference cells is just an estimation that must be temperature-corrected. The temperature correction is required even if a pyranometer is used alongside the reference cells and therefore the reference cells must have a way to measure the cell temperature. Another major difference between a pyranometer and a reference cell is that the pyranometer is much slower to respond to changes in irradiance and it typically takes 3-5 s for the pyranometer to reach 95% of the value of sudden variation in irradiance while the reference cell will respond almost instantaneously. The slower response time of the pyranometer does not cause significant error in the measurements when the data is integrated over time. On the other hand, the fast-responding reference cell must have higher sampling frequency compared to the pyranometer in order to get as accurate data when integrated over time. Thus, the recommended sampling frequency is 1 Hz for the reference cells. [46] In addition to the global irradiance, also the direct and horizontal diffuse irradiance should be measured in a solar PV test facility. The direct irradiance should be measured with a pyrheliometer while the horizontal diffuse irradiance should be measured with a pyranometer utilizing a shading ball. It is not recommended to calculate the diffused irradiance as $G_d = G - G_b$. [46] Additional recommendations for irradiance measurements are presented in Appendix A.

The second most important environmental parameter for PV modules is the operating temperature. The temperature of the solar cells can be measured in three different ways, contact measurement method, non-contact method or via modelled relationship using proxy measurements. In the contact measurement method, the temperature of the module back surface is measured typically with a thermocouple or a resistance temperature detector (RTD). RTD sensors are recommended since they have less uncertainty compared to thermocouples, but RTDs are also more expensive. Since in the contact method the measured temperature is the module back sheet temperature, a temperature correction must be applied to get the cell temperature. A widely accepted correction model for the cell temperature T_c is provided in [50]

$$T_c = T_{BS} + \Delta T_{CBS} \frac{G}{G_{STC}}, \tag{29}$$

where T_{BS} is the measured back sheet temperature, ΔT_{CBS} is the temperature difference between cell and back sheet in STC irradiance conditions and G is the broadband irradiance. One downside of the contact measurement method is the requirement for a physical contact with the back surface of the PV module. For monofacial modules this is not an issue, however, for bifacial modules this can cause partial shading at the rear-side and thus increase the uncertainty of the energy yield measurements. The non-contact method could provide a solution to this particular problem. The most common non-contact method is to use infrared (IR) camera to measure the module temperature. The additional benefit of using an IR camera would be that the temperature gradient could also be determined with the same measurement. However, the quality of the IR camera determines how accurate results it will provide and typically IR camera require well trained person to operate it properly. Therefore, IR cameras might be too problematic for this purpose, at least for now. The third method for determining the cell temperature is to use the modelled relationship and a proxy measurement. Typically, the used proxy method is to measure open circuit voltage V_{oc} of the module and determine the cell temperature from the relations ship between V_{oc} and T_c. The downside of the V_{oc}-method is that the determined temperature is the average temperature of all the solar cells connected in series within the module. Additionally, this method would require periodic IV-measurements to determine V_{oc}.

One environmental measurement that is not mentioned in table 2 is the spectral irradiance. The spectrum of the incoming irradiance will affect the power output of the PV modules due to the spectral response of the solar cell within the module. However, the effect of the spectral response is far less significant compared to the irradiance and cell temperature, yet still not negligible. Measuring the spectral irradiance with spectroradiometers is not as simple as the other measurements due to the long measurement duration. Additionally, the measurements have typically multiple sources of noise that complicate the measurement process. Therefore, simulated spectral data is used in many cases. The solar spectrum can be simulated using radiative transfer models (RTM). [46]

The environmental measurements give the relevant parameters about the operating conditions. However, in order to measure the real-life performance of the PV modules, some electrical measurements must also be done. Unsurprisingly the most common electrical parameters measured from a PV module are current and voltage. The output power of the module will be calculated as the product of current and voltage. A more interesting aspect of the electrical measurements is how often the IV-curve measurement is done if it is measured and in what condition the PV module is kept outside of the IV-curve measurement. In general, there are three different methods for the current-voltage measurements, only MPPT, only IV-curve or MPPT+IV-curve. In the MPPT method the PV modules are kept constantly at the MPP, and no other parts of the IV-curve are measured like I_{sc} or V_{oc}. Thus, with the MPPT method one cannot determine the average cell temperature from V_{oc}. The MPPT method is how commercial PV systems operate and therefore the power production of such a system would simulate a real commercial PV system well. In the IV-curve method the IV-curve of the string is measured in regular intervals and then the module is set to a certain voltage. Typical voltage values are $V(I_{sc}) = 0$, V_{mpp} and V_{oc}. V_{mpp} in the context of IV-curve method refers to the maximum power point determined in the previous IV-curve measurement. The third alternative is to combine these two methods and measure the IV-curve periodically and utilize MPPT on other times. The MPPT+IV method is most useful since it benefits from both of the measurement schemes. Fortunately, the majority of modern string inverters have the capability to perform an IV-measurement in order to detect defects and faults in the system.

The required accuracy of the electrical measurements for stand-alone PV modules are stated in standard IEC 60904-1 [51]. According to the standard the voltage and current must be measured using instrument with accuracy of ±0.2% of V_{oc} and I_{sc}. The Class A from standard IEC 61724-1 [33] requires that the measured uncertainty must be within ±2.0% for inverter level measurements. Additionally, the electrical and environmental measurements should be synchronized in order to produce data that can be used in benchmarking. More detailed recommendations for the electrical measurements are provided in appendix B.

4 Benchmark study of outdoor solar PV test facilities

The purpose of the benchmark study was to learn what kind of outdoor PV testing is currently done globally with a specific focus on the Nordic and especially Finland. The benchmark study was planned to serve two purposes, determine what kind of testing is currently done in the Nordics by commercial and academic parties and learn the typical structure and design of different kind of test facilities. Additional attention was given to finding out how a commercial company would benefit from outdoor PV testing, i.e., what kind of testing should be conducted, and how the testing should be conducted. The benchmark study was done in the form of interviews and three visits to test facilities located in Finland and Sweden. The interviewed parties represent various kinds of organizations with different needs and interest when it comes to testing PV technologies. The interviewed parties include research teams from Finnish universities, international research centers and commercial companies that produce solar power in Finland. Additionally, one energy company producing solar electricity in India was interviewed about their PV pilot projects.

In total 8 interviews were conducted and based on the interviews, three categories of testing were determined: module-level testing, system-level testing and non-disclosed (commercial companies). The non-disclosed category contains two commercial companies that did not have significant module or system-level testing, or they did not want to disclose what kind of testing they are conducting. Nonetheless, all of these categories provide valuable insight into the current status of solar PV testing. The interviewed parties were also separated into three groups, commercial companies, universities and research centers. The number of interviewed parties per group are shown in figure 8.

In the interviews with parties that are conducting outdoor PV testing, the focus was placed on what they are testing and why and what kind of test setup they have. Important parameters that were discussed with these parties were what kind of measurement instruments they are using and how these instruments were set up in the site. All of the interviewed parties were asked what kind of testing they would see beneficial for a commercial company, considering that conducting basic research is not a commercial company's top priority. It is common for commercial companies to participate in joint research projects, but conducting such research by themselves is not in the business area of a typical energy company.

The interviewed parties were chosen based on what kind of player they represent in terms of performing PV testing. Two of the interviewed parties were university research groups both located in Finland (Tampere University of Technology (TUNI) and Turku University of Applied Science (TUAS)), three of them were international research centers, located in Switzerland, Italy and Sweden, and three of them were commercial companies that produce and sell solar electricity. It is important for the benchmark study to interview parties representing different categories to gain holistic understanding of the state of the art of outdoor PV testing.

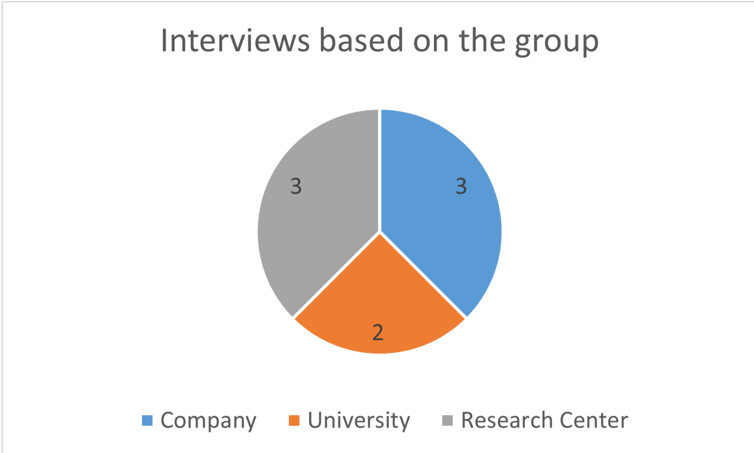

Figure 8: Chart of the interviewed parties based on group.

4.1 Module-level testing

In the context of this thesis, module-level testing is defined as testing where the operation or characteristics of the PV modules is studied. Such a test facility does not provide information about the technology as a part of a utility-scale installation. Typically, this kind of testing is done by universities and research centers, and it requires expensive measurement equipment for only relatively few modules. The expensive measurement instruments are required for accurate measurements and more complex measurement protocols compared to energy yield measurements typically done for PV installations. This kind of testing is closely related to basic research and typically it is not done extensively for commercially mature technology and products. Module-level testing can however provide valuable information about how the specific modules would behave in specific environments or when combined with some other components that are being investigated, like different kind of inverters or string configurations for example.

The main benefit of module-level test sites is that the deployed modules and other components like the inverters can be changed easily when a need to test some other product arises. In such case the expensive measurement instruments can be readily used for multiple tests and thus the cost of each new test will decrease. The testing conditions can also be more easily controlled and monitored when compared to larger installations. The testing conditions can change drastically even in short distances inside the site due to different shading and wind conditions that are caused by the surrounding environment and fast-moving clouds. This can potentially introduce large error margins to the measured data. To some extent the errors will level out the longer the testing is conducted, however, some errors will inevitably remain. Some of the errors could be counteracted by installing more weather and other measurement instruments but this again would increase the cost of the test facility.

4.2 System-level testing

System-level testing means testing that is done in larger PV installation that gives insight into how the whole PV installation operates at the system-level. The main difference between system-level and module-level testing is that system-level test facility should resemble a utility-scale PV system. These kinds of test sites can be considered as pilot project and in practice they can even be proper solar PV sites that utilize some kind of new technology. Typically, system-level test sites do not have as broad selection of measurement instruments since the conditions across the site will change and multiple copies of each measurement instrument would have to be installed to gain accurate information about the conditions across the whole site. This kind of sites might have the same measurement instruments as module-level test sites, for example pyranometers and pyrheliometers and even spectroradiometers, but the data received from these measurements does not represent accurately the conditions across the whole site. The data can be used to gain general understanding of the conditions and to make less accurate predictions and conclusions.

Undoubtedly the benefits of system-level testing are more valuable to commercial companies compared to module-level test sites. The most apparent benefit of system-level testing is that it provides data about how the technology in question works as part of a real solar PV installation. This is extremely important, for example when the energy yield and mechanical stability of the modules are estimated. Another benefit is that the test site will produce electricity that can be sold to the grid, thus decreasing the total cost of the test site. Also, when considering commercial companies that develop and construct their own solar PV power plants, the experience gained from actually constructing the site can prove to be valuable for the future projects that could potentially use some of the tested technologies.

Naturally system-level test sites will have more disadvantages due to their size. Generally, the CAPEX of such installations is higher, and they require a larger land area. Therefore, they should be built as part of a larger solar PV power plant or as a large pilot project that is estimated to be financially beneficial. Even then the new technologies deployed at the site impose additional risk to the project. Another disadvantage is that the PV modules cannot be easily replaced by some new modules. Technically the modules are easy to replace but it is not financially reasonable to replace the PV modules before they are degraded to a certain point. Taking into account that modern PV modules have 30+ years lifetime, it means that it would not be reasonable to replace the PV modules before these modules have degraded at least 30 years. Otherwise, potential profits from these modules would be lost. Therefore, these system-level test sites would only provide data from the initial modules, at least until replacing these modules can be financially justified.

4.3 Findings from the interviews and site visits

The desired results from the interviews and site visits were to find out the current status of solar PV testing in the Nordics and gain insight on what a commercial company in the energy sector could test in an outdoor PV test facility. Even though only eight parties were interviewed, a rather clear image of the current status was received. The other meaningful result from the interviews was to gain a benchmark for what kind of measurement instruments are typically included in a solar PV test site.

4.3.1 Test site designs

Based on the interviews, Finland does not currently have proper system-level solar PV test facilities. Some commercial companies in the energy sector might have smaller pilot projects that are not truly system-level and information about these projects is not publicly available. No relevant information was received about these test sites during the interviews with the commercial companies. However, such system-level sites exist in other parts of Europe, like the interviewed research center in Sweden. A great deal can be learned from these projects. When considering Finland as a location for a solar PV test facility, one of the biggest differences for example to a Central European country is the fact that Finland and Nordic countries in general can get heavy snow fall that causes unique challenges to the solar PV facilities. Therefore, the system-level test facility in Sweden provides excellent benchmark for a solar test facility in the Nordics. Of course, snow is not unique to the Nordic countries, but in general the Nordic countries will receive more snow compared to other countries in Europe, especially in regions where solar power is financially more profitable. Even though the commercial companies operating in the Nordics did not have proper test sites, they mentioned to do occasionally testing for some components of solar PV site. Especially different and new inverters were interesting components for the companies. Inverters are rather easy and cheap to change and test and due to different inverters having different user interfaces, testing the inverters gives valuable information and experience about the products that are currently in the market for a relatively small investment and effort.

The two interviewed university research groups represented very different kind of experimental methods and interests. Tampere university of technology (TUNI) has one rooftop installation with monofacial modules and several different sized strings that can be easily modified into any desired configuration. Some of the modules can even be measured individually. This rooftop installation is mainly designed to study the shading effects of the surrounding buildings and clouds and in the context of this thesis it can be classified as a module-level test site. This test site has been used in several academic research publications [52, 53, 54, 55, 56]. Since the shading response of the modules is in the focus of the experiments, the PV modules are not connected to inverters and the IV-curve is measured typically with 1 Hz frequency. This means that the energy yield of the PV modules is not measured. Such a test site is ideal when the response of the modules is being researched. It is worth mentioning that the PV modules can be connected to inverters for energy yield measurements, however this is not the usual function of the test site.

Turku university of applied science (TUAS) on the other hand had a very large variety of experiments and test locations. One of the test sites of TUAS was located on the rooftop of the campus building and it has well equipped test table for several PV modules. Also, many of the campus building rooftops had monofacial PV modules that can provide energy yield data. It is important to note that the conditions of these modules were not monitored closely. TUAS also has at least two test locations with bifacial modules. One of the test locations is a rooftop installation with a few vertically installed bifacial modules and the other is a project where bifacial modules were used as roofs of canopies. It is possible to alter the string configuration of the canopy roof modules to provide data about how shading and rear-side illumination affect the optimal string configuration. Both of these projects can provide interesting data about how bifacial PV modules could be integrated into built environments and what kind of energy yield should be expected from such installations.

The research center located in Switzerland has a system-level test site that is built next to a solar PV system that uses monofacial PERC (Passivated Emitter and Rear Contact) modules. The PERC module PV system is used as a benchmark for the system-level test site. The test site consists of two smaller test areas, both having bifacial PV modules that are installed into the same orientation as the benchmark modules. The difference between these two test areas is that the ground in one of the areas is covered with white rocks while the other area is a grassy field similar to the benchmark section of the site. Besides the two system-level test areas, the test site also contains a smaller module-level test area where smaller batches of different PV modules can be tested. In this module-level test area also vertically installed bifacial PV modules are tested. The PV modules at all of the test sites are kept at the MPP to measure the true energy yield of each site.

The interviewed research center located in Italy does not have a system-level testing area, but it has several smaller module-level test areas. The speciality of these test areas is that they have large amount of measurement instruments compared to the other sites included in this benchmark study. The measurement instruments are covered with more details in section 4.3.2. Due to the extra attention to the measurement instruments, these test sites give extremely accurate information on the operating conditions and energy yield of the PV modules. One of the test sites measures only AC power, but more accurate IV-measurements are done in the other test sites. Such a site design is ideal when multiple different technologies are being tested. Due to the smaller size of each test site, the amount of measurement instruments required to get accurate operating condition measurements is less compared to a system-level test site. The obvious downside of this is that the benefits discussed in section 4.2 are not gained.

The visited research center in Sweden had a large test area that contained several PV setups. Many of the setups are demonstrations or proofs-of-concept, like building-integrated photovoltaics (BIPV), 2-axis tracker, solar tents and road railing mounted modules, just to name few. Besides these demonstrations and proofs-of-concept, the test site has also four ground-mounted PV test beds with different kind of monofacial modules. The modules on these test beds are kept at MPP and we can consider that these form a system-level test setup. These tests were built between 2009-2012 and they only have monofacial PV modules. Even though the test facility contains multiple experiment setups, data analysis of the energy yield has not been conducted actively. Therefore, the test facility has not been used to study system-level phenomena. The test site also has some standalone/off-grid installations as demonstrations. The test site is used in training courses, like PV module installer training, and therefore it contains even more different smaller installation that are not mentioned in this benchmark study.

All of the interviewed parties were asked about hybrid PV+BESS sites and the test site in Sweden had a battery system test bed integrated as part of the site. The Swedish research center was also planning to increase the amount of batteries and inverters to study the operation of a PV+BESS hybrid site. All of the other parties stated that this is an interesting and topical matter. During the interviews it was discussed that such a hybrid site would not directly provide new information or insight about PV technologies, but including BESS in conjunction with a PV site would again yield valuable experience on how this kind of site should be designed, built and operated.

4.3.2 Test site measurement instruments

The variety and placement of the measurement instruments greatly defines what kind of data can be received from a test site. Typically, the instrument setup is designed once the desired results of the test site are decided. One purpose of the interviews was to inquire what kind of measurement setup each outdoor test facility has. The typical measured parameters by each interviewed party with their test sites are shown in table 4. Besides these typical parameters, some other measurements are also commonly done in such test sites, like indirect irradiance measurements with reference cell that measure short-circuit current of the cell. As mentioned in the theory section (see section 2.2.2), the irradiance in directly proportional to the short-circuit current of a solar cell and thus it can be used as a close approximation of the irradiance level. A major issue with reference cells is that they have certain spectral response. If the spectrum of the incident light changes drastically, the irradiance approximation will have some error. This error can be corrected if the spectrum of the incident light is measured with a spectroradiometer and the spectral response of the reference cell is known. In practice this is a hard and tedious process since the reference cells will degrade over time and they would have to be calibrated regularly. One could argue that this is also the case with pyranometers, and this is correct, pyranometers are calibrated typically every two years. [57] However, the pyranometers are usually sent to a third party for calibration and thus it is generally seen as a more pleasant process. Also, sites typically have only few pyranometers when they could have tens or even hundreds of reference cells, rendering the calibration process of the reference cells even more tedious.

Table 4: Different interviewed parties and the measurement instruments that they use in their outdoor test facility.

Interviewed party	Irradiance	Module temperature	Wind	Relative humidity	Spectrum	Rain detector
TUNI	Global and diffused	Yes	Speed and direction	Yes	No	No
TUAS	Global, direct and diffused	Yes	Speed and direction	Yes	Yes	Yes
Research center (Switzerland)	Global, direct and diffused	No	Speed and direction	Yes	No	No
Research center (Italy)	Global, direct and diffused	Yes	Speed and direction	Yes	Yes	Yes
Research center (Sweden)	Global, direct and diffused	No	Speed and direction	Yes	No	Yes

As we can see from table 4, all of the test sites have at least two pyranometers, one measuring the global irradiance and one measuring diffused irradiance. Four out of five interviewed test sites used sun tracker with shade disk to measure the diffused irradiance. One test site used a shadow-ring for diffused irradiance measurements. Additionally, three of the sites had pyranometers tilted in the same angle as the PV modules to measure global irradiance at the plane of array. Also, all of the test sites that had energy yield measurement had pyrheliometers to measure the direct irradiance. The extensive irradiance measurements are unsurprising since irradiance is one of the key parameters that determine the power output of a solar cell.

Typically, all solar PV power plants have at least one weather station to monitor the weather conditions at the site and this was also the case in all of the sites included in the benchmark study. That is the reason why all of the sites have wind speed and direction and relative air humidity measurement instrument, as these are typically included in the weather station. The wind conditions and relative air humidity are relevant parameters when considering the temperature of the PV modules. Rainfall sensor is also a rather common instrument in a weather station, but the information gathered from the rainfall does not typically give much insight on the power output of the PV modules. It might seem to be rather useless to measure the rainfall but considering that the weather stations are relatively cheap instruments compared to the rest of the equipment, investing in a weather station with rainfall sensor is not an irresponsible decision. Additionally, the cleaning effect of rain could be investigated with a rainfall sensor. However, having a dedicated rainfall sensor for this might be unnecessary since moderately accurate rainfall data can be received from local weather stations.

As mentioned in the theory section (see section 2.2), temperature is one of the parameters that directly affect the performance of a solar cell and therefore it is important to measure this parameter in a test environment. Getting accurate value for the cell temperature is difficult since a PV module has multiple layers, and the solar cell is in the middle. Measuring the surface temperature of module has been good enough approximation for the cell temperature (see section 3.1.2) and with monofacial modules measuring this temperature is not difficult by placing a thermocouple at the rear of the module. However, with bifacial modules the challenge arises from the fact that the thermocouple would cause shading on the rear-side of the module and thus disturbing the experiment. Therefore, the module temperature of bifacial modules would have to be determined by some other means. The average temperature of the module string can be calculated from the IV-curve, but depending on how many modules are in one string, the temperature might not be accurate enough. Interestingly two of the interviewed researcher centers did not measure the module temperature at all. In the case of the Swiss research center this was due to the aforementioned difficulties related to measuring the temperature of bifacial modules. The other interviewed party that did not measure the module temperature was the Swedish research center. Surprisingly both of these research centers were the only ones that were considered to have system-level test sites. The rest of the interviewed parties that had bifacial modules measured the module temperature either with a reference cell or by placing a thermocouple at the rear-side of the module, thus causing partial shading.

Since different solar cells have different spectral responses, the spectrum of incident light will also affect the power output of a PV module. Therefore, measuring the spectrum of the incident radiation will give better insight on the performance of the PV modules. Typically, the spectra of direct and diffused light are rather constant, but the biggest difference in the spectrum can be seen in the reflected light. Albedo is defined as the fraction of reflected light with respect to the incident light in the sense of intensity and it can get values between $0.0 - 1.0$ and thus it does not take into account the spectrum of the reflected light. Especially when considering bifacial PV modules, omitting the spectrum of the reflected light can cause noticeable error when trying to estimate the energy yield of bifacial modules. However, getting accurate and up to date data of the spectrum is difficult since the incident irradiance might change rapidly, due to clouds for example, and measuring the spectrum is not a fast process since only one or few wavelengths can be measured at a time. Change in the irradiance over the long measurement period will skew the measured spectrum. Two of the interviewed parties measured the spectrum of the incident light. In both of these cases the interviewed party stated that the spectroradiometer data does not provide useful insight about the performance of the modules, but it can be used to calibrate other instruments.

Some of the test sites included in this benchmark study also had some more specialized ways of measuring certain parameters. The research center located in Italy had a pyranometer installed for the rear-side of the bifacial modules in the plane of array. This is rather expensive way of measuring the global rear-side irradiance considering that the conditions will change drastically in the rear-side of module across the site due to majority of the incident light being diffused or reflected and the infrastructure not being symmetrical. However, this will give more accurate information about the rear-side irradiance compared to a reference cell. Speaking of rear-side reference cells, at least in TUAS's canopy site the rear-side irradiance is measured in this way. Using rear-side reference cells is much cheaper method of gaining an approximation of the irradiance level and due to the cheaper price, multiple of these cells can be installed thus gaining better understanding how the irradiance changes across the whole installation. Having both rear-side pyranometer and reference cells could possibly give even better understanding of the rear-side irradiance. Also, another more specialized measurement instrument that few of the interviewed parties had was a soiling sensor. A soiling sensor does not give direct information about the condition of the PV modules, but it gives general information about how bad the soiling of the modules is, e.g., when the modules must and should be cleaned and how large reduction in power output could be expected due to soiling. Therefore, at least some sort of soiling sensor is probably included in every site, commercial or academic.

One important topic discussed during the interviews related to measuring was the sampling frequency of different parameters. Generally, the test sites included in the benchmark study had the same sampling rates. Weather measurements had a sampling rate of 10 Hz and the IV-curve measurements were measured every 5 minutes. These sampling frequencies are in line with the best practices published by IEA PVPS Task 13. [46] Two exception to this were the rooftop installation at TUNI and the research center in Sweden. In the TUNI test site the IV-curves of modules the modules were measured with frequency of 1 Hz while the weather measurements were done with frequency of 10 Hz. In the Swedish research center the weather measurements were done every 6 seconds.

4.3.3 Common points of interest

As part of the interviews, the different parties were asked what they are currently testing and what they would see as potential topics to test in the future. During this part of the interviews additional attention was given to testing that would be beneficial for commercial companies to do. One topic that came up in almost all of the interviews was the market penetration of bifacial modules and the inaccuracy of energy yield estimation done for them. All of the interviewed companies already use bifacial modules in their utility-scale PV systems and all of the test sites that conducted energy yield measurements also had bifacial modules except the Swedish research center. It is clear that in many cases bifacial modules are currently the default technology for utility-scale sites and during this benchmark study we were unable to find any system-level test site that would have bifacial modules in the Nordics. Having a system-level PV test site with bifacial modules in Finland for example poses interesting opportunity to gain advantage in estimating the energy yield of the bifacial modules. The research group at TUAS is already doing modeling work with bifacial modules, but their data comes from the smaller canopy installation. During the interviews also the topic of 1-axis tracking for bifacial modules in Finland came up. 1-axis tracking is not common in Finland and therefore combining 1-axis tracking and bifacial modules could also provide advantage for a commercial company in the industry. This would also grant experience with 1-axis tracking installation and information about their operation and stability during winter conditions. The idea of testing vertically installed bifacial modules in a system-level site also came up in several interviews.

Another topic that was discussed in several interviews was snow losses and how they should be tackled. This topic is not directly related to new technologies or components, but as the amount of solar power increases in the Nordics, having optimal method of minimizing the snow losses becomes more important. Creating a solution for the snow losses is more related to the experience of designing and operating a PV system and therefore almost any test site could be used to study the phenomena. Additionally, more or less any PV system in the Nordics can be retrofitted to study snow losses. However, certain sites might be more interesting to study snow losses, like sites with 1-axis tracked bifacial modules.

Topics related to the stability and durability of the modules and the installations also came up during the interviews. Some of the interviewed parties stated that the current trend of PV modules is to grow in size while the thickness of the front and rear glass plates is reduced. Naturally the larger modules will experience larger stress due to wind and snow cover. Combining this with the thinner design, the mechanical stability of the modules will be compromised. One of the interviewed parties was planning to implement dynamic mountings for vertically installed bifacial modules to reduce stress caused by the wind. The effect of snow cover on the larger and thinner cells can be tested in a controlled environment, but the effect of wind in a utility-scale PV system must be tested in proper environment, i.e., in a system-level PV installation. This is especially important since the location, shape and size of the site affects the wind conditions across the site. Also, the natural non-uniform accumulation of snow cover on top of the module is an important factor when considering the mechanical stability of PV modules.

Also, the topic of foundation stability was raised during the interviews. Many of the PV system sites especially in Finland and Sweden have rather swamp-like ground and floods during spring are likely in many of these locations. Even though the providers of the foundations are to an extent responsible for the stability, gaining experience with different kind of foundation options and being sure that they will withstand the harsh conditions many of the potential PV system sites might have is extremely important when considering the risks of a PV system investment decision.

4.4 Conclusions of the benchmark study

In total 8 independent parties representing a wide variety of players in the industry were interviewed. Also, three outdoor PV test sites were visited. From these interviews and site visits we are able to gain insight into the state of outdoor PV testing in Finland and collect list of necessary measurement instruments and methods for a well-functioning solar PV test facility. Also, the interviews provided information about what kind of technologies and components are currently interesting to experiment with.

No system-level PV test facilities were found in Finland during the benchmark study. This, however, does not mean that such facilities do not exist. If such a system-level test facility is owned by a commercial party, they would most likely not want to share their results and experiences from the test facility. Smaller solar PV installation does already exist in Finland that could be categorized to be part of system-level testing, but due to the lack of required measurement instruments, these installations could be considered more as pilot projects rather than test sites or facilities. Several universities have some sort of smaller scale outdoor PV test sites, but these typically have only a few PV modules of the same type, thus these sites cannot be used to gain insight about how these modules would behave in utility-scale environment. During several interviews it was discussed that the modules would have to be experimented within a utility-scale environment, i.e., system-level testing, since the installation itself will affect the conditions that the modules must withstand.

Based on the interviews and the site visits, we were able to collect a list of common measurement instruments that are required for a test site in order to gain meaningful data out of the site. A weather station was included in all of the sites included in this benchmark study and typically the weather station was measuring temperature, relative humidity and wind speed and direction. Typically, even commercial solar PV sites have one of these weather stations to measure the weather conditions at the site. [33] However, depending on how accurate information is required and the size of the site, a test site could possible require multiple weather stations or even separate measurement units for some of these parameters. Temperature and wind conditions are typically such parameters that should be as close to the modules as possible. Global, direct and diffused irradiance was also measured in all of the sites that had energy yield measurements. Using solar tracked shade disk to measure the diffuse irradiance was seen as the industry standard. Again, depending on how accurate information is required and on the size of the site, multiple irradiance measurement units might be required (see section 3). Also, in order to get more accurate irradiance conditions, the pyranometers measuring global and diffused irradiance should be installed on the plane of the array. Some sites included both horizontal and plane of array measurements for these irradiances. Depending on the module technology, the module temperature was also measured. Typically, the module temperature was not measured when the site had bifacial modules.

Besides common parameters like ambient temperature, wind conditions and irradiance, also some less useful or more complex parameters were measured in the sites. One of the more complex parameters measured in two of the sites was the spectrum of the incident light. However, the spectroradiometer measurements did not provide much insight on the performance of the modules and inclusion of a spectroradiometer in a test site should be considered with extreme caution. One parameter that was measured in the same sites as the spectrum of the incident light was precipitation. More high-end weather stations typically include a rainfall sensor, and this is most likely the reason why these sites measure the precipitation. Based on the interviews the precipitation data was not used or analyzed actively. Several of the sites also had soiling sensors.

Currently bifacial PV modules are the most common modules in new solar PV ground-mounted installations. Naturally one of the most experimented commercial modules are also bifacial. When considering a solar PV test site that is operated by a commercial company, it is not reasonable to include a large amount of experimental modules to the site, since this would increase the risk of the project. What many of the interviewed parties mentioned was testing commercially available products to gain more experience with them, like the bifacial modules currently. Besides the bifacial modules, also larger and thinner modules were seen as an interesting topic to experiment with in a solar PV test site. This was mainly due to concerns about the mechanical durability of these modules. 1-axis tracking was also a topic that was seen interesting to experiment with and especially 1-axis tracking for bifacial modules was seen as a technology that should first be tested in a system-level PV test site.

5 Potential experiment topics

Besides the benchmark study (section 4), an additional round of interviews was held to find out what kind of topics would be interesting and meaningful to test and experiment with from the standpoint of a commercial company. The participants of this interview round were professionals of the energy sector working with PV technology in the Nordics. The interviews were conducted as one-to-one interviews and two workshops with multiple participants. In total 12 participants were interviewed during these different events. The interviewed participants represent different professionals that are required during a utility-scale PV project, from project development to engineering and construction. Besides these areas of a PV system project, also the interests of operation and maintenance (O&M) were considered during these interviews.

An additional interview round was organized in order to find potential test or experiment topics. Based on these interviews, the different topics were then evaluated. In the evaluation process the added value of the topic to a commercial company was considered. Additionally in this phase the basic properties of the test topic were also determined. These properties bundle important information about the test topic such as,

- How the experiment could be realized?
- What is used as benchmark for the experiment?
- Do we receive quantitative data from the experiment?
- What kind of results and/or data we are expecting from the experiment?
- What are the requirements of the experiment? (in the sense of measurement instruments and facilities)
- What is the timetable of the experiment?

In this chapter the most relevant experiment topics from the interviews are discussed and a brief overview of the evaluation is provided.

5.1 Common topics with benchmark study

Many of the topics that came up during the second interview round were also discussed during the benchmark study (see sections 4.3.3 and 4.4). Such common topics are bifacial modules, increased ground albedo, 1-axis tracking, vertical modules, snow losses and foundation and mounting structure durability.

5.1.1 Bifacial modules

Bifacial PV modules are PV modules that are able to produce electricity from incident light from both sides of the module. In theory this just increases the total power output of the modules. In reality, however, this causes the system to be far more complex especially from the energy yield estimation point of view. The front-side energy yield can be estimated rather accurately, but the true energy yield of the rear-side is more challenging to estimate. In typical installation the rear-side of a bifacial module receives mainly diffused and reflected irradiance and therefore the surroundings of the module play a greater role in the energy production profile. The diffused and reflected irradiance can be simulated but currently the accuracy of these simulations is questionable. Having accurate energy yield assessment of the PV system is paramount when considering the investment decision of a commercial PV power plant.

Since the bifacial modules are more or less the default modules for new utility-scale PV systems [17], information and experience with this kind of modules is practically unavoidable in the future. This fact places bifacial modules into a rather special position from the standpoint of commercial testing. If bifacial modules were installed to a test site environment, i.e. to a site with more accurate environmental measurements, the test site would give some initial results after the first summer and more general results after a full year. Since each year can have rather radical differences in the weather conditions, accurate and reliable results would be received only after several years of testing. Now considering that majority of the new utility-scale PV systems are going to have bifacial modules, one would receive very similar data from these standard or non-test sites where bifacial modules are installed, at least in the sense of energy yield data. This invokes the question that is this kind of testing necessary or would we gain accurate enough data from these regular PV systems. The information would undoubtedly be useful today but if it takes several years to gain this information from a test site then it would most likely come too late for a commercial company. Thus, testing bifacial modules in a more controlled environment might not be reasonable and financially justified.

5.1.2 Increased ground albedo

The reflectivity or albedo of the ground at the solar PV installation is an important parameter, since the bifacial modules can generate electricity from light collected by both sides of the panel. By increasing the albedo of the ground, we would in theory at least increase the amount of light that will reach the rear-side of the bifacial module. This in return would increase the energy yield of the module.

Several methods have been proposed to increase the albedo of the ground, like covering the ground with white plastic or gravel. The theoretical increase of albedo can be calculated from the properties of these material, but in order to gain more reliable data about how these materials increase the productivity of the PV modules, these materials would have to be tested in real PV system conditions. Covering the ground with these materials also has some additional concerns related to them. The durability of these materials is something that needs to be considered and determined. In this case durability will also include coloring of the material. Typically, white plastic or plastic in general will turn yellow when exposed to UV light and harsh conditions for long duration.[58, 59] Also their stability in Nordic weather conditions would have to be determined. The second concern related to covering the ground has to do with the biodiversity of the location. In utility-scale PV systems located in the Nordics, typically the biodiversity of the area can be preserved to an extent since the ground will remain as a grass field. More generally this means that the area will return to its natural state. If this ground would be covered with plastic or gravel, the biodiversity of the PV system area would be compromised. The third issues that might arise from these high albedo ground covering materials is visual nuisance. PV installations are commonly criticized for damaging the scenic view of countryside and the addition of these bright materials could be seen as causing further nuisance and harm to the local area.

One solution for this that came up during the interviews was to plant white clovers at the PV site. The idea itself does not require white clovers, but by planting some flowers at the PV site, the albedo could potentially be increased while the biodiversity of the local area is improved. White clover is perennial plant, meaning that it survives multiple years, and it would not have to be replanted each year, thus not increasing significantly O&M costs. The possible increase in albedo would most likely be minimal but this solution would cover also other aspects that a utility-scale PV system requires, like considering biodiversity. Biodiversity improving related matters are further discussed in section 5.2.6.

5.1.3 1-axis tracking

1-axis tracked modules are partially in similar position to the bifacial modules. Gaining accurate enough data to perform proper energy yield estimation for 1-axis tracked modules would take several years. Similar, although not as holistic, data would be received from a regular site that utilizes 1-axis tracking. The major difference for 1-axis tracking compared to bifacial modules is the fact that we lack experience with 1-axis tracking in the Nordic conditions. One of the major benefits that a solar PV power plant has had historically is the fact that there are no moving parts in the power plant. Naturally moving parts will introduce additional wear and tear to the system and especially in Nordic conditions snow and ice will cause additional issues. Therefore, 1-axis tracking is not expected to be so widely used in utility-scale PV systems in the near future. Thus, there is still some time to conduct commercial experiments with 1-axis trackers and gain valuable information about the true energy production of 1-axis tracking PV systems. This in return will bring added value to a commercial company through more accurate energy yield assessments and lower risk related to future projects. Also combining 1-axis trackers with bifacial modules will provide valuable information and experience.

5.1.4 Snow cover losses

When building a PV system in the Nordics, one cannot avoid snow cover losses, and this naturally raises concerns. Besides shading the modules, snow cover also causes additional load on the PV module that can damage the panel. Both of these aspects affect the business case of PV system in regions that are prone to snowing. Therefore, it is important to understand how severe snow cover losses each site is expected to experience and what kind of snow cleaning protocol would be optimal to the specific site. The issues related to snow cover losses can thus be separated into two smaller topics, finding a way to estimate what is the expected snow cover losses in the site and formulating the optimal snow cleaning protocol based on the expected snow cover losses. Results from both of these topics could be verified in a real-life PV system. This would not require a proper solar test site, however, conducting the initial verification at a test site where the conditions are closely monitored could be beneficial and make the whole process easier.

A topic that came up in the second interview round closely related to snow cover losses was losses caused by pollen cover. Soiling losses are nothing new to PV systems but considering that the forested areas in Nordics can experience extreme pollen covers during spring and summer, it is important to tackle this issue as well. Similar to the snow cover, the pollen cover will have large variation from year to year and an optimal cleaning strategy could be formulated similarly to the snow clearing. However, the pollen cleaning strategy will most likely differ from the snow clearing strategy since pollen does not apply any significant load on the modules and rain will more easily clean the modules. Nevertheless, a proper and well-planned practice for pollen and soil cleaning should be formulated.

5.1.5 Vertical PV modules

Vertical modules were also something that was brought up in both of the interview rounds. The vertical modules considered in the context of this thesis are bifacial modules that are installed in a mounting structure vertically. Building integrated PV (BIPV) modules that are placed vertically against the facade can also be referred to as vertical PV modules. BIPV modules are not covered in this thesis. The vertically installed modules have rather interesting properties that render this kind of mounting solution useful in certain applications. Typically, bifacial vertical modules are installed in the east-west orientation, i.e. the faces of the module are facing east and west, in order to capture the morning and evening irradiance. Such installation method has both positive and negative aspects.

PV module in vertical position will cover minimal ground area and the ground can be used for something else, like farming. This then invokes the question of agrivoltaics, i.e. having agricultural activity at the solar PV site, and combining vertical modules with agricultural activity. This possibility will be discussed in section 5.2.7. Also due to the unique production profile of vertical modules, they can be used to even out the daily production of solar power. Additionally, since the vertical modules do not have horizontal active area, they do not suffer from snow cover losses. Some snow and especially soil and pollen might stick to the surface of the module, but there is no possibility for large snow pile to accumulate on top of the module for example. Combining this "anti-snow cover" property with the increased albedo of the snow on the ground and vertical modules might have a rather noticeable winter production profile.

The negative aspect of vertical modules is the fact that in the utility-scale, the vertical module rows would have to be installed further apart from each other to avoid shading. This in turn would decrease the maximum energy yield of the PV installation in terms of used land area. Naturally when the modules are installed vertically, their vertical area is maximized. This in return will cause increased wind stress on the modules, mounting structures and foundations. Gaining experience and information about how vertically installed modules will endure Nordic conditions is important and real-life testing might be required to gain confirmation for this.

5.1.6 Foundation and mounting structure durability

Foundation and mounting structure durability is a rather complicated topic to test in a PV system environment where the modules are expected to produce electricity as well. The durability of foundations and mounting structures in extreme conditions can be tested by artificially applying these conditions upon the structures, however, such testing is not in the core business area of a mainly electricity producing commercial company. If the durability of foundations and mounting structures is meant to be tested in a typical solar PV system environment, then the experiment would be extremely time consuming and yet again such testing is not in the core business area of an electricity related commercial company.

The issue and concern related to foundation and mounting structure durability also extents to many of the other testing topics like 1-axis tracking, vertical modules and optimal bifacial module installation height (see sections 5.1.3, 5.1.5, 5.2.2). Thus, the foundation and mounting structure durability would be "tested", or at least information and verification about the durability would be received as by-product from these other tests. The other angle that this can be looked at is that the durability testing should be conducted before performing the other experiments in order to minimize the risks of the other experiments. The added value of these angles needs to be estimated before choosing the most suitable approach to the matter.

5.2 New experiment topics

In this section new experiment topics that came up during the second interview round are covered. This section will focus on topics that were evaluated to be relevant to a commercial company. Great value is placed for experiment topics that will produce quantitative results that have a clear benchmark. Additionally, topics that will introduce some important aspect about new utility-scale solar projects in Nordics are covered. The popularity of bifacial PV modules has evoked new questions and uncertainties related to solar power. Thus, many of the topics introduced in this section will be closely related to bifacial modules.

5.2.1 Optimal tilt angle for Nordic conditions

Simulating the optimal tilt angle for the PV arrays is typically done with dedicated software, however quite often the data used by the software is not accurate for high latitudes that one might face in Nordic PV system projects. In order to find the true optimal tilt angle for modules and especially bifacial modules in the Nordics, a series of bifacial PV module rows could be installed in different tilt angles, for example in

10° increments from 10° to 60°. This would yield real life data about how the angle affects the operation of the PV modules. It is important to note here that this kind of testing would not provide information only about the energy yield of the modules, but also about the installation costs, snow cover losses and degradation related to the different tilt angles. Thus, this would provide a more holistic picture of what is the optimal tilt angle for PV modules in the Nordics. For the tilt angles between the measured angles the values could be interpolated to get an estimation.

Due to the large amount of PV modules and land area required to do such an experiment, this would end up being a rather costly project. The costs of the experiment can be reduced by decreasing the number of tilt angles tested and the number of modules installed. This naturally would decrease the accuracy of the results. Also, something to point out is that the optimal tilt angle would not be found directly through this method, but the interval where the optimal tilt angle is located. Therefore, the resolution of the tilt angles would be rather high to gain any meaningful results. This then again invokes the question, is this kind of testing viable for a commercial company.

5.2.2 Optimal bifacial module installation height

Similar to the optimal tilt angle (section 5.2.1), the optimal installation height for bifacial modules should be considered when designing a PV system. Compared to monofacial PV modules, bifacial modules have additional parameters that affect the performance and thus the optimal installation height needs to be calculated differently.

In the case of the module installation height, the optimal solution is found as a trade-off between benefits and costs. The higher the PV modules are installed from the ground, the closer the module temperature is to the ambient temperature. Also added benefit for bifacial modules is that the rear-side of the module will receive more irradiance since it will "see" more of the surroundings and thus more diffused and reflected irradiance is able to reach the rear-side of the module. The negative effect of increasing the installation height is the added costs and decreased stability of the installation.

The optimal installation height can be calculated and simulated. However, if the optimal height differs significantly from the current standard installation height, it would be reasonable to conduct an experiment where the optimal height is verified.

5.2.3 Hybrid PV park

The concept of hybrid park utilizing PV and a battery energy storage system (BESS) is not new by any means, but such hybrid solutions have not been financially feasible historically. With the decreasing prices of lithium-ion batteries, lithium-ion based stationary energy storages are also beginning to have feasible business cases in the near future. [60, 61] In order to realize such potential project in the future, experience about the construction and operation of a PV+BESS hybrid park would be valuable.

Since the utility-scale battery systems are expensive, it would be cost-effective to test the operation of a BESS in smaller scale before committing to a full-scale project.

Even though the small-scale system would not be able to generate significant revenue, practical experience about the operation of such a system could be achieved. Also, such smaller scale battery system would be ideal for testing different kind of power plant controllers. Power plant controllers are also something where added experience before utility-scale project would be highly valued.

One benefit of building smaller test hybrid park is to get better understanding of the CAPEX breakdown of such project. Many of the balance of plant (BoP) components can be fully or partially shared by the PV and BESS sides of the park. Gaining proper experience of the synergy between these systems is important when examining future business cases. Also, the optimal dimensioning of the BESS could be tested first on a smaller scale. However, the extent of these benefits and whether they can be realized with smaller scale testing is an open question. Most likely a utility-scale project would be required to get proper information about these matters and again this evokes the question is this kind of testing necessary and financially beneficial.

5.2.4 Capture price maximization with east oriented modules

One aspect of renewable projects that must be determined is the capture price of the project. Capture price is the average electricity price of the electricity produced by the assets that are included in the project. Therefore, capture price is an important parameter when considering the profitability of the given project. Capture price (CP) is calculated as a function of hourly revenue (hR) and hourly production (hP)

$$CP = \frac{\sum_i hR_i}{\sum_i hP_i} = \frac{\sum_i hP_i \cdot hSP_i}{\sum_i hP_i}, \tag{30}$$

where hSP is the hourly spot price of electricity. [62] The subindex i indicates a specific hour in the lifetime of the project. From equation 30 we can see that the capture price is dependent on the hourly production and spot market price. Maximizing the capture price for solar power is rather difficult since typically the hourly spot market price and hourly production have negative correlation. Therefore, prioritizing production during hours when the spot market price is high, one could increase the capture price of the project.

Finland's geographical location provides an interesting opportunity to prioritize production during more valuable hours. Finland, and especially eastern Finland is located in the eastern corner of the Europe and therefore the solar power production in the morning begins before many other European countries like Germany for example. By prioritizing the morning solar power production in eastern Finland, one could utilize the lack of solar power production during these hours in the central and western Europe and increase the capture price.

By default, the PV modules are oriented to face south in the northern hemisphere in utility-scale PV system projects. Since the irradiance received by a solar module is dependent on the angle of incidence, by facing the modules towards east, the morning production of PV modules could be increased, i.e. prioritized. To an extent the theoretical increase in the capture price can be simulated. However, considering that the production of bifacial modules is still uncertain, it would be less risky to test this theory about increased capture price in smaller scale and in real life conditions.

5.2.5 Optimal string configuration and optimizers

As the amount of solar power in the Nordics and the size of the projects increases, inevitably more PV power plants will be located in areas where parts of the installation will experience partial shading. This partial shading can be caused by trees in the nearby forest or built infrastructure that casts shadows. No matter what causes the shading, mainly the edges of the PV system will be shaded. This partial shading of the edge modules can cause rather extensive decreases in solar power production depending on how the string configuration is designed for the PV module rows. Therefore, finding optimal string configuration for each PV system is crucial.

One way to optimize the string configuration is to minimize the shading losses by placing the shaded PV modules that are located at the edge of the site behind the same inverter string. In theory this would increase the energy yield of the PV system since the shaded PV modules at the edge of the site would not dissipate the energy produced by the other modules. A similar solution could be realized by installing optimizers to the modules that are located at the edge of the site. Optimizers are electrical devices that are able to perform maximum power point tracking (MPPT) for individual PV modules.[63] This means that each PV module that would have an optimizer would operate at its MPP, and it would not affect the other modules since the modules with optimizers are not connected to a centralized inverter string that controls the operating voltage. It is important to note that the modules with optimizers would be connected to a centralized DC/AC inverter, but the MPPT would be performed by the optimizer, unlike with typical string configurations where the MPPT is done for the whole string. In some cases, it could be cheaper to utilize optimizers at the edge of the PV installation compared to installing new string for these edge modules as the number edge modules in the same string could be rather small.

Contrary to the aforementioned issues of partial shading at the edge of the site, the optimal string configuration or optimizers could also be utilized when the edge modules produce more electricity than the middle modules of the site. This might happen especially with bifacial modules. Typically, the modules at the edge of the site have lower module temperature and the rear-side of the module can receive more diffused and reflected irradiance, since other modules do not shade the surrounding ground as much compared to the modules in the center of the PV system.

One can determine accurately the partial shading experienced by the edge modules, but determining the increased electricity produced by the edge modules and the whole site due to the string configuration can prove to be difficult. Thus, in order to estimate the added value of the new string configuration and to verify that the new string configuration actually can provide added value, testing this kind of string configuration and/or optimizers in small-scale real-life conditions is necessary.

Another way to counter the negative effect of the partial shading caused by nearby forests is to build the first PV modules further away from the forest. This however comes with the disadvantage of losing land area that could be used for solar power and in many cases this land area would have to be leased either way to secure the solar project. This causes an optimization problem where the optimal distance from the forest (or shading object) would have to be calculated so that we maximize the energy yield versus costs. The solution of this optimization problem could then be compared to the estimated added value gained from the new optimal string configuration. However, this is very extensive problem and solving it is out of scope of this thesis.

5.2.6 Improved biodiversity

One aspect of any construction project that has become more important in recent years is how the project affects the biodiversity of the local area. Naturally PV installations will raise concerns since they are typically large projects that cover vast land areas. In the case of replacing farmland with a PV system, the biodiversity of the local area is typically seen to be improved just by letting the vegetation grow at the area. However, if the area has been forest or some other biome with healthy biodiversity to begin with, constructing a PV system in such location will damage the local biodiversity. By implementing methods that improve or preserve some of the biodiversity, new solar PV project can be seen as more environmentally friendly and local acceptance towards these projects could improve. Since many of these methods to improve the local biodiversity are new, gaining real life experience with them and seeing that they actually work is crucial.

The methods to improve biodiversity and their effectiveness are tied to the site location. Therefore, there does not exist one solution that would fit every site. Some of these methods are, for example ecological corridors and planting biodiversity improving plants to the area. The flora planted into the site could be chosen in a way that the growth of the grass would be hindered. This way the O&M costs of the site could be decreased. The possibility of planting white clovers for example was already discussed in section 5.1.2. Biodiversity related experiments are more qualitative in nature and therefore quantifying the added value of these actions is difficult. At this stage these biodiversity related experiments could be considered as experience and knowledge increasing topics rather than value adding. However, this might not be the case for long as the amount of required acts towards biodiversity and sustainability increases.

5.2.7 Agrivoltaics

One concept that would be interesting to explore further is agrivoltaics. The idea of an agrivoltaic site is to have agricultural activity at the same site with a PV system, thus co-locating these two production forms and gaining additional yield from the same land area. The idea for agrivoltaics originates from the underlying reason that solar PV and agriculture prefer similar kind of conditions, plenty of sunlight and flat land. Due to this reason, PV installations and agricultural farms will naturally compete for the land area and the trend has been to convert farm area into PV power plants. This in return will decrease food production that in general is an important field of industry to any country. Therefore, pairing solar PV and agriculture is an interesting potential solution to find balance between energy and food production. Because of this agrivoltaics has received interest from multiple parties like research institutions and governments. [64, 65] It is important to note that when the land area is used for multiple purposes, PV and agriculture in this case, the combined land usage must be considered. Land equivalent ratio (LER) is defined as the relative land area required for mono-production in order to achieve the yield of dual land use

$$LER = \sum_i \left(\frac{\text{Yield}_i(\text{multi})}{\text{Yield}_i(\text{mono})} \right) - LL, \tag{31}$$

where $\text{Yield}_i(\text{multi})$ is the multi-production of product i, $\text{Yield}_i(\text{mono})$ is the mono-production of product i and LL is land losses due to co-location of multiple production forms. Equation 31 can be used for any number of products that are produced at the same land area. Using LER one can quantify the added value of agrivoltaics from the standpoint of land usage and co-location. [44]

The added benefits and yield of agrivoltaics depend on what kind of agricultural activity is planned and how the solar PV installation is designed. In theory the agricultural activity can be crop production, grazing or beekeeping for example. All of these different forms of agriculture would also require different kind of implementation and the optimal solar installation would also be different. Many of these different solutions contain uncertainties about how well they will work together and especially in the Nordic environment. Therefore, forming a potential combination of agricultural method and solar PV installation and then testing this is utmost important before launching utility-scale projects. The concept of agrivoltaics in the Nordics is a worthy topic for its own thesis and we will not dwell into the detail in this thesis.

5.3 Summary of the topics

Utility-scale solar has become financially feasible in the Nordics only recently, especially in Finland, and it can be seen from the wide range of test topics presented in this chapter. It must be stressed that not all of the topics were presented in this chapter, only the most relevant topics were presented. In total 22 topics were recognized and 13 of these were presented. Some of these topics had overlapping themes and some of them had multiple topics built into one larger topic. Although many of the topics presented in this chapter were not directly related to each other, many of them had common factor in the bifacial PV modules. Even though many of the topics do not assume bifacial modules, majority of them would gain an additional angle to the experiment if bifacial modules would be utilized.

One important aspect of the different experiment topics is the timetable, i.e., how fast results could be expected from the experiment. It is important to realize when the experiment will yield results in order to design accordingly these experiments and especially projects that will use the result from these experiments. Due to the varying nature of solar power production that is dependent on the weather and season, the timetables of these experiments can be seen to have several stages. Many effects and phenomena can be noticed within a single year, however, to get accurate knowledge, data from several years would be required to diminish the error caused by the variance in each year. In the context of this thesis, the timetable refers to the initial results of the experiment and not the accurate results, unless stated otherwise. Also, many of the topics covered in this chapter have concern related to long term stability. These kinds of aspects will get clarification only after several years of exposure to the nature. Many of these aspects, like plastic coloring for example, can be tested in an accelerated environment. The materials and technologies used in the experiments should be chosen based on these accelerated tests conducted by the manufacturers, providers and/or research institutes. Doing this kind of testing is not in the core business area of a commercial company.

When considering commercial research and development (R&D) activities, the added value of these activities should be known or at least estimated before the investment decision. In the case of solar PV testing, having quantitative data that is initially estimated and/or simulated will help estimating the possible added value. Once the experiment actually produces the data, the initial estimates and the actual data can be compared, and the true profitability of the R&D project can be determined. Therefore, it is important to know what kind of quantitative data can be assumed from the specific experiment.

The information about timetables, is the experiment assumed to utilize bifacial modules and does the experiment produce quantitative data are shown in table 5 for each topic covered in this chapter. The entries in the timetable column refer to the expected initial results from the experiment. One season in this context means the typical solar power production period in the Nordics that is from spring to early or mid-autumn. Some of the topics have several years as the timetable. In these occasions the main result from the experiment is expected to be noticeable after long exposure to the nature, i.e., degradation, or the effect of the experiment will be noticed only after several seasons, like in the case of biodiversity changes. It must be stressed that the timetable is the time it takes to receive the initial results from the completion of the project. This time does not take into account the development, pre-engineering and construction of the project. This is especially important for the hybrid PV park topic, where the initial result after the construction is to learn about the operation of the hybrid system.

The initial timetables of the test topics are shown in figure 9. The majority of the projects have an initial timetable of one season or one year. The reason for this is that many of these experiments require data from the whole annual cycle. In some cases, the relevant part of the annual cycle is only during the solar power production season as discussed above. After the first annual cycle the future data can be estimated. However, estimating the future data based on a single annual cycle can contain a significant amount of error from the expected average annual cycle. Thus, many of the experiments that have one year or one season as their timetable will receive more accurate data for estimation after several years. Because many of these topics have in practice multiple timetables, it is difficult to assess the added value of these topics accurately. In order to make well educated investment decisions about what topics to pursue, a clear definition of which aspects of the topic are included when assessing the added value of these experiments.

Table 5: Summary of the potential test topics with relevant information about their timetables and expected results. In the "Bifacial modules"-column mark x indicates that the experiment is assumed to utilize bifacial modules and mark o indicates that bifacial modules would provide additional and valuable information but is not necessary for the topic to be studied.

Topic	Timetable	Bifacial modules	Quantitative data
Bifacial modules	1 year	x	x
Increased albedo	1 season	x	x
1-axis tracking	1 year	o	x
Snow cover losses	1 winter	o	x
Vertical modules	1 year	x	x
Foundation and mountings	1 year	o	
Optimal tilt angle	Several years	o	x
Optimal module height	1 year	x	x
Hybrid PV park	Few months		
Maximized capture price	1 season	o	x
Optimal string config.	1 season	o	x
Improved biodiversity	Several years	o	x
Agrivoltaics	1 season	o	x
TOTAL	N/A	x=4 o=8	x=11

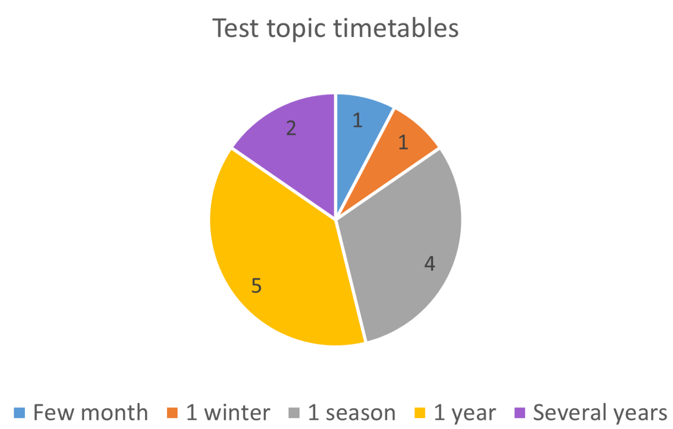

Figure 9: Initial timetables of the presented test topics.

In this chapter the potential experiment topics were presented and a preliminary overview about the evaluation process was provided. In chapter 6 few topics that are seen as the most relevant are selected for more thorough study about how these kinds of experiments should be realized. More detailed evaluation of these topics is also presented in chapter 6 as well as a rudimentary method with results to evaluate the potential added value of these experiments to a commercial company.

6 Results

The ultimate goal of this thesis was to provide a guideline and suggestions for commercial system-level solar PV test facility. The best practices and current approaches were determined through a literature review of handbooks, reports and standard as well as a benchmark study of European solar PV test facilities. The guideline was formed from these materials and the suggestions for potential test topics were collected from professionals of the solar electricity industry. In this section the guideline for the test facility is presented and a more detailed evaluation of few test topics covered in section 5 is depicted. Additionally, the importance of the chosen site location is explored.

6.1 Site location selection

When planning a commercial solar PV test setup, alongside the technology or components that are under investigation, the site where the experiments are designed to be conducted has paramount importance. Additionally, how the site and PV system are designed has a significant effect on the resulting data from the experiment and the cost of the project.

When considering the location of a solar PV test facility several factors must be taken into account. In general, a solar PV test facility can be built as a purely testing facility or it can be built together with a larger PV installation. These two are extremes and many other alternatives how to design the test facility exist between them. Some of these alternatives are for example to build a site where one or several sections are dedicated for more closely monitored testing and experimenting and one or several sections are dedicated for larger scale piloting. Alternatively, the experiments could be done in collaboration with universities or a research center using their already existing facilities. All of these options have their pros and cons, and some relevant options for commercial research and development (R&D) projects are explored in this section. The directional options for different sites that are covered in this section are shown in table 6.

Table 6: Directional options for solar PV test facility sites.

Option	Description
Module-level	Site dedicated for module-level testing
System-level	Site dedicated for system-level testing
Co-located	Co-located module and system-level testing
Large co-located	Co-located module and/or system-level testing with a larger PV system
Collaborative	Collaboration site with a third party

Before choosing the most appropriate site location for the testing, the scale and scope of the project must be determined. In sections 4.1 and 4.2 the difference of module and system-level testing are covered. Using these definitions, one can determine the scale of the desired R&D project. Option between module and system-level testing is not mutually exclusive and a test facility can host experiments where both of these are conducted, like in the case of co-located and large co-located options. However, including both module and system-level test facilities will naturally increase the total cost of the project. The two major differences between module and system-level testing from the site's point of view are the required land area and environmental conditions. Many of the module-level test sites included in the benchmark study were built close to a research center or a university for convenience. Many of the measurement instruments required frequent maintenance and inspections, and choosing a location that is easy to access, like the rooftop of a campus building, is more important than the annual irradiance of the location. Therefore, the irradiance conditions might not represent conditions that a typical utility-scale PV system would encounter. On the other hand, module-level test facilities require less land area, and they are more flexible to deploy from the point of view of the location. System-level PV test facilities are typically deployed in locations where the irradiance levels are similar to a utility-scale PV installation and naturally a system-level test facility would require more land area. Additionally, a system-level test facility would require more PV modules for the experiment that in return would increase the cost of the installation. However, module-level testing typically utilizes more expensive measurement hardware to get more accurate data. Therefore, the cost elements of these different levels of testing cannot be directly compared, especially if the system-level PV test installation would produce electricity that could be sold to the grid.

When comparing module and system-level testing with each other, it is important to note some critical factors that set them apart. In theory, system-level test facility could have all the same measurement instruments as a module-level test site with same precision and measurement instrument redundancy to mitigate errors caused by varying conditions. However, from the financial point of view it is optimal to test phenomenon that do not require such high precision in a system-level test facility with less measurement instruments and devices. Therefore, system-level PV test facilities are expected to have by default less measurement instruments compared to module-level test facilities. Excellent example of this are the test facilities in the Swiss and Italian research centers discussed in section 4.

Once the scale and scope of the R&D project has been set, the most suitable option for the site location and configuration can be determined. As mentioned before, all of the options presented in table 6 have their positive and negative aspects. Let us go through these options and highlight the key factors of each one.

6.1.1 Module-level site

In the module-level option the solar PV test facility with module-level testing setup exists as its own entity. Such a site is suitable when a relatively small number of PV modules are being investigated. This kind of setup is typical for research centers and universities as was shown in the benchmark study. The good aspect of this kind of site is that the investigated technologies and components can be more easily changed, inspected, maintained and monitored. It is important to note that module-level testing can be performed without deploying expensive measurement equipment, however, the results would be mainly energy yield related with data from only several modules. Connecting a small number of modules to the main grid would not be necessary.

6.1.2 System-level site

In the system-level option the setup is very similar to the module-level option, but the required land area would be larger and less measurement instruments would be required, i.e., more PV modules per measurement instrument. Such a site would resemble a utility-scale solar PV installation; however, the installation could be much smaller. This kind of site would be suitable for a technology pilot project for example. The site could be small enough that the party conducting the experiment could own it and there would be no need for land lease agreements with the landowners. If the land were leased for the test facility, it would increase the cost of the project. Inspecting and maintaining the PV system would still be relatively easy, but depending on the size of the PV system, it potentially could be connected to the main grid and the main grid connection cost could again increase the costs of the project. Additionally, in Finland all utility-scale PV systems that are connected to the grid require certain permits. [66] The decision to connect the PV system to the grid would have to be made case by case depending on the expected energy yield.

6.1.3 Co-located site

In this option the module and system-level sites are co-located. Technically, these two installations at the same location could be treated as their own entities. The added value of co-locating the sites would come from the ease of inspecting, maintaining and monitoring the installations at the same time. This kind of installation could still be realized in a rather small land area. However, if there is a desire to conduct multiple system-level experiments at the same site, the required land area could become rather significant. The second benefit of this option is that the module and system-level installations could share the same infrastructure like the substation and grid connection point. Technically, co-location does not increase the costs of the project significantly from a system-level site if the module-level testing would be conducted without the more expensive measurement equipment.

6.1.4 Large co-located site

In this option module or system-level testing facility is co-located with a large PV system. Alternatively, both module and system-level test facilities could be included. This option is more oriented towards commercial companies that are building utility-scale PV systems and would like to incorporate a test facility into their PV installation. A large co-located site could also be realized if the party performing the R&D project would collaborate with the owners of the utility-scale PV system. This option has more added benefits for the system-level testing facility compared to the module-level one. Since a system-level test facility would resemble a utility-scale PV installation, all the necessary land lease agreements and permitting for the PV installation would already be done for the utility-scale power plant and therefore the test facility could use the same permits and land lease agreements. Naturally the test facility would have to be designed as part of the utility-scale installation before the permitting phase. An additional benefit of the land area required by the utility-scale PV system is that the system-level test facility would also have more area and more topics could be tested at the same site. One positive aspect of this option that has not been discussed with the other options is the requirement for benchmarking the experiments. The required benchmark depends on the topic that is being investigated, but many topics can use standard PV modules as their benchmark. If the utility-scale PV installation would have default or standard modules, these could be used as the benchmark for the experiment. Especially in the system-level option providing a benchmark that is co-located with the test setup could be expensive. On the other hand, module-level test facility would not have many added benefits in this option besides the benefits discussed in section 6.1.3.

6.1.5 Collaborative site

In the collaborative option the test facility would be realized with a third party. Differing from the large co-located site, in the collaborative site the third party would not have utility-scale PV installation that could be utilized for benchmarking etc. The third parties considered in this option would be research centers or universities that already have experience in solar PV experiments and possibly a PV test facility. In general, this option is more suitable for module-level testing. Since research centers and universities rarely have existing utility-scale or system-level PV installations, the collaboration with a system-level project would be more in line with consulting. Additionally, the concern of sharing the results and data with the third party could compromise the benefit of the R&D project.

6.1.6 Summary of the site selection

When considering the options presented in table 6, two higher level categories can be noticed. The first category is to have a test facility that exists in isolation from other facilities. This means that the site exists purely to conduct research and it has no other major functions. The options with module and system-level site and the co-located site represent this category. Co-locating module and system-level test facilities are not considered as separate functions in this case (co-location option). On the other hand, the large co-located site and collaborative site represent the category where the test facility is co-located with some other facilities. In the collaborative option the test facility could also exist in isolation, but the experiment would be conducted in collaboration with a third party. When co-locating multiple facilities, the experiment setup can have some CAPEX and OPEX synergies with the other facilities.

The first three options in table 6 represent more research focused sites, and therefore these options are more suitable for parties that are conducting more basic research. Other alternative is that the experiment itself could damage or hinder the operation of the other facilities. Such an experiment could be related to the foundation and mounting structure stability and in the case of system failure the integrity of the other facilities could be compromised. The third alternative could be that the other facilities could hinder or disturb the operation of the test facility and thus the test facility is desired to be placed in isolation from other facilities. For example, accurate module-level performance analysis could be this kind of experiment.

The large co-located site and collaborative site represent more general or commercial research. Both of these options represent a very different kind of testing from each other. In the large co-location option the test facility is placed in conjunction with a utility-scale operating PV system that can mask the test facility in the middle of the PV installation. This would give the PV modules under examination realistic utility-scale PV system conditions and the operation of PV modules in these conditions could be studied. Especially with topics involving bifacial PV modules or biodiversity, this kind of conditions would be desired. Thus, large co-location option would be suitable for system-level testing where the conditions of a utility-scale PV installation are required. The collaboration option then represents a completely different kind of research. This option does not specify the scale or site configuration in any way and therefore this option is the most open-ended. However, the main benefit of this option is to gain the knowledge and experience of the third party and utilizing it. Therefore, collaboration option would be the most suitable when the research topic is not well understood, or it requires specialized equipment or skills that are hard and/or expensive to come by.

6.2 System-level test site with bifacial PV modules topics

The primal objective of this thesis was to find out what kind of topics would be beneficial for a commercial company to test in the field of solar PV and how this testing should be conducted. There are two direct ways in which a commercial company can benefit from solar PV testing. First is to decrease uncertainty regarding profitability of a solar PV project and the second is to find and validate ways to increase profitability. In practice the way these methods bring added value comes down to decreasing uncertainty related to energy yield assessments (EYA) and increasing the energy yield. Some other methods for increasing profitability also exist like maximizing asset specific capture price as discussed in section 5.2.4. Additionally, providing other kind of value to the project is also possible like improving the biodiversity and sustainability as discussed in section 5.2.6. By studying the operation and performance of bifacial PV modules, both of these ways to provide added value are possible.

In section 5.1.1 bifacial PV modules as a test topic were criticized due to their expected popularity in the near future [67] and thus not gaining much added value from more controlled monitoring. However, many of the other topics can be used with bifacial modules and some even require the deployment of bifacial modules, like the increased albedo of the ground. Therefore, as a part of a utility-scale PV system with bifacial modules, some of these modules could be monitored with rather small increase to the total CAPEX of the project. This will also provide an excellent benchmark for any other topics related to bifacial modules that are potentially tested on the same site.

Large variety of topics have already been researched with bifacial PV modules like performance between monofacial and bifacial modules [68], temperature coefficient of bifacial modules [69], effect of mounting structure [70], effect of soiling losses [71] and effect of micromismatch losses due to non-uniform rear irradiance [72], just to name few. Additionally, a large amount of research has been conducted on modeling and simulating the performance as well as experimentally determining the performance of bifacial PV modules [73, 74, 75, 76, 77]. However, the majority of the research is done and validated with module-level test setups and thus the results do not fully capture the system-level effects of a bifacial utility-scale PV system.

6.2.1 Bifacial PV modules

Before we discuss the test setup for bifacial PV modules, let us cover some important parameters related to bifacial PV modules. Two important parameters that are used with bifacial PV modules are bifaciality $BiFi$ and bifacial gain BG. Bifaciality is defined as the ratio between the rear efficiency η_{rear} divided by the front efficiency η_{front}

$$BiFi = \frac{\eta_{rear}}{\eta_{front}}. \tag{32}$$

Typically, the different sides of a bifacial solar cell do not have the same efficiency and therefore $BiFi$ is practically always < 1. Since the front-side of the module receives more irradiance by default, the general practice is to treat the more efficient side of the solar cell as the front-side. Otherwise $BiFi$ would get values > 1. The bifacial gain can be determined in three levels; optical bifacial gain BG_{opt}, module bifacial gain BG_{mod} and system bifacial gain BG_{sys}. The optical bifacial gain is the ratio between the average irradiance received by the rear and front-sides of module

$$BG_{opt} = \frac{G_{rear}}{G_{front}} \tag{33}$$

Optical bifacial gain gives the theoretical maximum for the bifacial gain and for many applications it is too simple since it does not include any information about the PV module or system in question. Module bifacial gain includes the bifaciality of the module and it is defined as

$$BG_{mod} = \frac{G_{rear} \cdot BiFi}{G_{front}}. \tag{34}$$

Module bifacial gain can be used for module-level analysis, but for system-level analysis the system bifacial gain should be used

$$BG_{sys} = \frac{E_{rear}}{E_{front}} = \frac{E_{bi} - E_{mono}}{E_{mono}}, \tag{35}$$

where E_{bi} is the electricity output of the bifacial PV module and E_{mono} is the electricity output of a monofacial PV module. It is important to note that the monofacial PV module used to determine E_{mono} should have similar performance to the front-side of the bifacial module.

As discussed in 6.2, the majority of the research done for bifacial modules have been conducted from the standpoint of single or few modules and not the whole system. For stand-alone module test setups bifacial gain values in the range of 9.9% – 15.98% have been reported. [68, 77] However, for a utility-scale PV system with bifacial modules, the bifacial gain is expected to remain below 10%. [78, 79, 80] The major difference between module and system-level setups comes from the amount of ground that the rear-side of module is able to see. In a larger PV installation, the modules will be close to other modules and these will obscure direct line of site from the ground and thus decrease the rear-side irradiance. The decrease in rear-side irradiance and thus bifacial gain is stronger for interior modules that are surrounded by other modules. The modules on the edge of the installation are able receive more reflected irradiance since at the edges of the system there are no modules to obscure the line of site. This phenomenon is referred to as the edge effect. [78] The edge effect can cause significant uncertainty in EYA especially for smaller PV systems with narrow module rows. Depending on the way of simulating the rear-side irradiance, the edge effect reaches from 3 up to 9 modules towards the center of the array in a row. [77, 78] Majority of the edge effect will dissipate at the second row from the edge and marginal amount is left at the third row. A solar bifacial PV array can be separated into 9 unique regions as shown in figure 10. In theory the regions mirrored from the North-South axis are identical, west and east regions for example. However, depending on the specific location these might have significant differences. For example, if towards the west from the PV system there is a road and towards the east there is forest, the rear-side irradiance conditions will be drastically different. Therefore, these regions are expected to be unique, even if their conditions do not differ significantly. Additionally, the rear-side conditions are not identical when mirrored from the West-East axis since the first module row will receive less rear-side irradiance compared to the last module row that have no obstruction behind them.

Determining the magnitude of the bifacial gain due to the edge effect is important to decrease the uncertainty of energy yield assessments. Additionally, if these edge modules that produce more current are connected in series to the interior modules that produce less current, the interior modules will dissipate the additional electricity produced and the full potential of the PV system is not realized. Thus, designing the PV system in a way that takes into account the edge effect can provide increased yield from the power plant. Even though the rear-side irradiance conditions at the center of the array are simulated to be rather uniform, monitoring their conditions and especially energy yield is important to determine the true bifacial gain of modules and provide accurate benchmark for the edge modules. As discussed in section 5.1.4, in theory any PV system can be used to study the snow cover losses at the system-level. At higher latitudes, like in the Nordics, snow cover losses and soiling losses are expected to be one of the major factors related to decreased energy yield of PV systems. [81] Simply by studying the edge effect and bifacial gain in a utility-scale site, much could be learned from snow cover losses using the same site. Additionally, the effect of snow on the albedo and rear-side irradiance could be studied. Thus, deploying such experiments in a utility-scale PV installation that has bifacial modules would provide information about a great variety of topics.

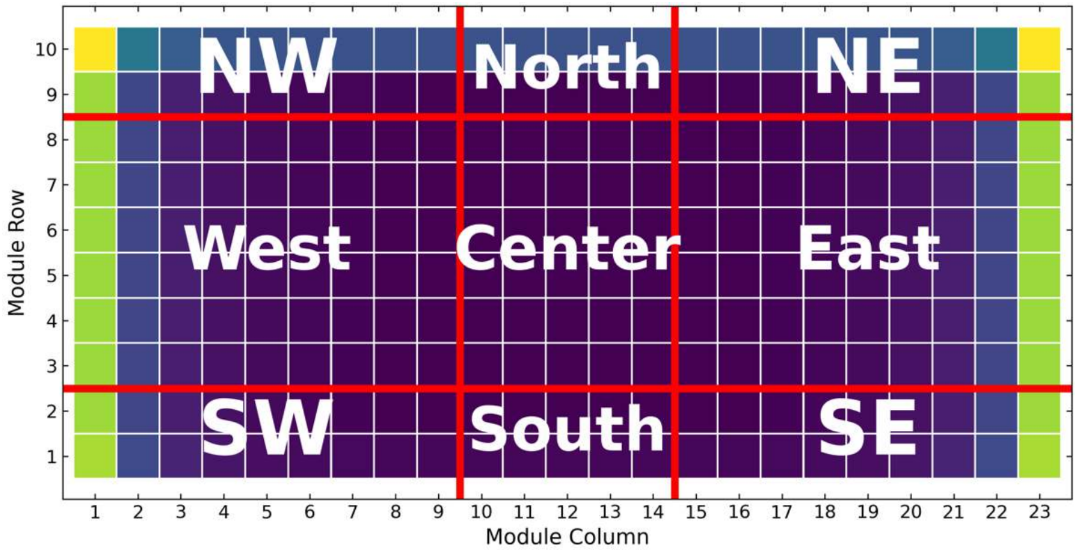

Figure 10: Simulated array of bifacial PV modules with their rear-side irradiance with respect to the rear-side irradiance of the center modules. The PV system is separated into regions that have unique rear-side irradiance conditions. The modules are faced towards south. [78]

In the beginning of section 5, one of the mentioned items that must be evaluated was the benchmark for the topic. As mentioned above, for the edge modules the central modules could be used as benchmarks, but the other topics mentioned in this section do not have benchmark yet. A natural benchmark for the interior modules would be monofacial modules. Another alternative for the benchmark would be to use the rated power of the bifacial modules and reference the expected energy yield with the measured energy yield. This option would require accurate irradiance measurements for both the front and rear-side of the module. Front-side irradiance measurements are not an issue, but finding a location at the rear side of the module that represents the irradiance conditions across the whole module might prove to be challenging. Due to inhomogeneity of the ground albedo and shading from mounting structures, the rear-side irradiance across single module is not uniform. For the edge module up to 50% of variation was reported for the rear-side irradiance in a simulation. [75] Additionally, due to the tilt angle of the module and subsequent difference in clearance height between the bottom and top of the module, central modules are assumed to experience variation in the rear-side irradiance up to 30% across the module. [75] This being said, the benchmarking can be done without monofacial modules, but these sources of uncertainty must considered.

Depending on the required accuracy for the snow cover losses, the benchmarking will change greatly. If only the amount of energy yield lost due to snow cover is determined, simple pyranometer or reference cell that has heating element would suffice. The idea is to be able measure the irradiance after snowfall and referencing the measured irradiance with the energy yield of the modules. However, if the share of panels or active area suffering from snow cover losses must be determined, benchmarking becomes vastly more difficult. In this a case more sophisticated method would have to be formulated. Additional issue for the snow cover losses will cause the bifaciality of the modules (if bifacial modules are used). After snowfall the ground would be covered with snow that has typically a high albedo in the range of 0.55 – 0.98. [82] If the increase in the ground albedo is not taken into account, the snow cover losses will not be as high as they are in reality. In order to determine the bifacial gain due to the increased albedo from the snowfall, the albedo of the ground would have to be monitored. As albedo is the fraction of received irradiance that the ground (or any surface) reflects, the albedo of the ground can be determined with two pyranometers, one measuring global horizontal irradiance towards the sky and the other measuring global horizontal irradiance towards the ground. The albedo can then be determined as

$$\rho = \frac{G^{\uparrow}(0)}{G^{\downarrow}(0)}, \tag{36}$$

where $G^{\uparrow}(0)$ is the irradiance from the sky and $G^{\downarrow}(0)$ is the irradiance from the ground. [83] The (0) refers to the tilt angle of the pyranometers. Commercial measurement devices for albedo measurements called albedometers also exist. In essence, these albedometers are two pyranometers measuring the irradiance from both sides of the devices. Another cheaper alternative for pyranometer in the albedo measurements is to use reference cells. [83] Reference cells are not as accurate as pyranometers and they are not able to measure the irradiance from the whole spectrum. However, this acts also as an advantage for the reference cells. If the reference cell has similar spectral response to the monitored PV modules, the reference cell will automatically filter out all of the wavelengths that do not participate in the electron-hole pair generation and there is no need for spectral mismatch correction.

6.2.2 Ground albedo increase

Many of the studies that look into the bifacial gain, also include some kind of research about how albedo and especially increased albedo effect the bifacial gain. [77, 78, 80] Out of the controllable parameters albedo has the largest effect on the bifacial gain, followed by the tilt angle and the clearance height. [78] The bifacial gain for PV modules in an array with albedo of $\rho = 0.5$, clearance height of 1.5 m and tilt angle of 25° was simulated to be around 27.73% – 31.41%. [77, 80] The increase in the bifacial gain when the albedo is increased from 0.2 to 0.5 is roughly 20%. One major factor that must be considered when the albedo is increased in the simulations is the uniformity of the albedo. Also, typically the albedo is not a constant property of the surface, and it depends on the spectral and angular distribution of the incident light. In addition to the surface material, the surface conditions also affect the albedo. In general, wet surface has lower albedo compared to dry surface, since water has low albedo. Another factor that must be considered is also the roughness of the surface since rough surfaces experience more self-shading compared to smooth surfaces. [78] Besides the material chosen to increase the albedo, the area where this material is applied plays also an important role. In a field test conducted for a single bifacial PV module; by doubling the surface area of the reflective cover, the energy yield of the PV module was increased by 1.6%. [84] The reflective cover was sized in such a way that the cover went 0.5 m outside of the module from the front and 1.0 m from both sides. The area of the reflective cover was increased from the rear of the module, from 2.5 m to 5.0m. The albedo of the reflective cover was around $\rho \approx 0.55$. [84] This indicates that the most crucial region for the reflective material is right under the PV module. One could also from a hypothesis that the covered land area becomes more important as the tilt angle of the modules is increased. However, this also brings partial relief to concerns mentioned in section 5.1.2 about the biodiversity of the PV installation, since only part of the ground would have to be covered with the reflective material.

The added benefits from increasing the ground albedo are rather self-explanatory and through field testing, the magnitude and uncertainty related to the increased bifacial gain could be verified. Additional benefit of having plastic, fabric or gravel under the PV modules is to block vegetation growth under the modules. This would decrease the maintenance cost and make the grass related maintenance easier and faster since there would be no need to go under the module. One other and rather major uncertainty related to the used materials is how the reflective materials will endure the Nordic weather conditions. In general, the Nordics receive large amount of rain and snow annually and especially during springs the melting snow can cause floods. Especially thin layers of reflective material can get dirty very quickly and their cleaning might end up costing more than they bring added revenue. Therefore, for the Nordic conditions, white gravel or something similar could be the optimal reflective material. However, even these materials can degrade and discolor over time and the melting snow can cause the gravel to spread out. In summary, testing reflective materials to increase the ground albedo would provide data and experience about the added energy yield as well as the functionality of these materials in Nordic conditions. Bifacial PV modules without the reflective material underneath them should ideally be used as the benchmark.

6.2.3 Requirements of the test site

Within the scope of this thesis was to formulate a test site plan for a commercial company where they could conduct experiments and tests. The terms test site and experiment are used rather loosely here. In the context of this thesis and especially in this section, test site refers to any kind of outdoors facility where research related to solar PV can be conducted. The test site plan formulated in this section is more of a suggestion that can be followed based on ones needs and resources and it can easily be modified to fit other solar PV testing purposes. However, the general theme in the plan is to conduct the experiments in utility-scale like conditions to capture the system-level effects.

In this plan the topics mentioned in sections 6.2.1 and 6.2.2 are tested in the same site. If the test site or area is integrated into a utility-scale PV system (large co-located site, see section 6.1.4), the test sites can utilize the same weather measurement data measured at the site. At the same time the components that are being experimented with will experience typical utility-scale PV system conditions. This is especially important

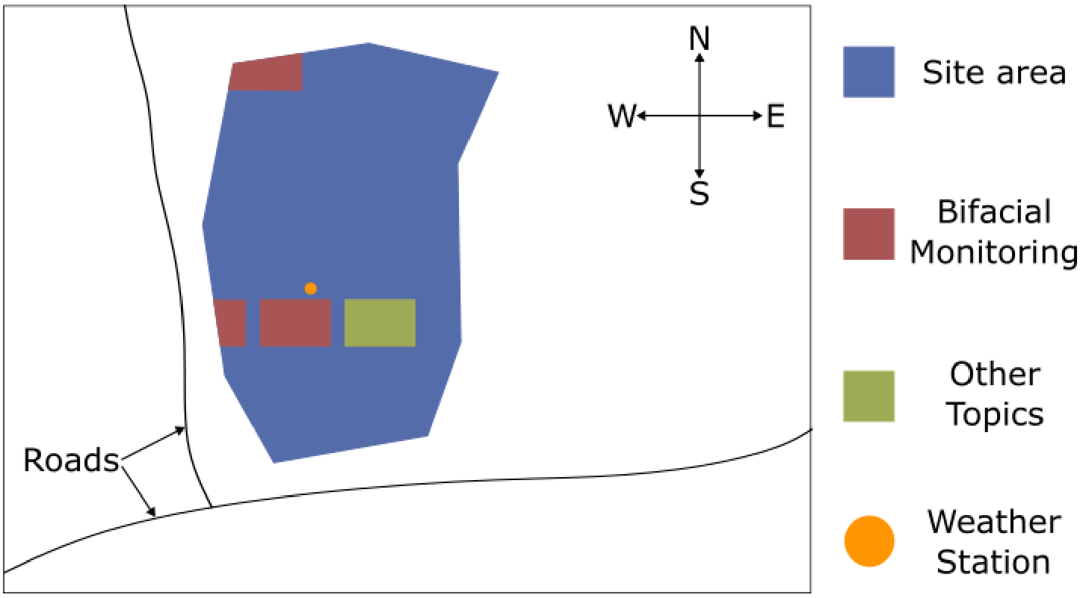

Figure 11: Illustration of a possible solar test site. The bifacial PV modules are monitored in three locations: at the edge, corner and middle of the site. If the edge effect of the site is known, it is sufficient to test other topics only in the middle of the site. The illustration shows only one weather station while in reality several weather stations could be deployed. The test areas are not to scale in the illustration.

for topics related to bifacial modules as discussed in 6.2.1. The required PV monitoring measurements for class A PV system were given in table 2 and the multipliers for sensor redundancy as a function of the PV system capacity were given in table 3. It is important to note that even though these "required" measurements are mentioned in the IEC 61724-1 standard [33], all PV systems do not follow the standard and the classification of the site is up to the owner of the site. However, it is recommended that the utility-scale PV system where the test sites are located would have at least one weather station that has instruments to perform all of the measurements mentioned in table 2. The weather station should be located in close vicinity to the test sites in order to avoid spatial error in the measurements. An illustration of the potential test site design is presented in figure 11. In the design presented in figure 11, the bifacial PV modules are monitored in three locations. In practice these three locations can be combined into one larger region or then the center modules and the edge and corner modules could be monitored in their own regions. Since the edge modules are expected to operate in different MPP conditions, these modules should be connected to optimizers to capture the conditions due to the edge effect. The modules in the center of the array could be connected to the same string since their individual variation is expected to be less significant. Additionally, determining the bifacial gain of string connected PV modules is the objective of the experiment and not to determine the operating conditions of individual modules. For this same reason the PV modules would be kept at the MPP, and no IV-measurements would be conducted. Including large scale IV-measurements in the site would complicate the test setup and bring additional costs to the project. Even though excluding IV-measurements will mean that majority of the characterization parameters will not be measured, the added costs of these measurements most likely overshadow the benefits. This is true since the characterization parameters are not necessary when determining the energy yield of the PV system.

One important aspect of the test sites is the number of modules included in them. The required edge modules can be taken directly from the PVPS Task 13 report. [78] Thus the required area for the corner edge effect is 2 rows and 9 modules. Technically for the west or east side edge effect 1 row with 9 modules is enough to cover the edge effect. However, in order to minimize the uncertainty and error due to micromismatches, two or three rows should be used. A similar number of rows should be used for the interior modules for the same reason. The number of modules per row can be determined for each site individually. A recommendation is to use 9 modules or then the number of modules in one string. For south facing bifacial PV systems, a test site at the southern edge of the site is not required since the edge effect is not as prominent in the "front" edge as it is in the "rear" end. Therefore, an optional test site could be located at the northern edge of the site. This northern test area would require a similar number of modules as the corner test are.

Even though some of the measurements already done in the site can be directly used for the test sites, some measurements must be done specifically for the test area in question. For bifacial modules these measurements are the module temperature and rear-side irradiance. As discussed in the benchmark study (see section 4), measuring the module temperature of a bifacial PV module with a probe is challenging without disturbing the irradiance conditions of the module. Fortunately, many of the reference cells have built-in temperature sensor and the readout of this sensor can be used to approximate the temperature of the bifacial PV module. Additionally, the module temperature can be approximated from the ambient temperature, irradiance and wind speed using equation 23. There exist two options to measure the rear-side irradiance, using a pyranometer or a reference cell. Both of these have their advantages, pyranometer is able to measure irradiance from the whole sunlight spectrum with higher accuracy while the reference cell measures only the relevant part of the spectrum, and it is cheaper. Especially since the rear-side irradiance has stronger variation in the irradiance spectrum due to the high share of reflected irradiance, reference cell might prove to be more convenient options for this end use. However, one issue that neither a pyranometer nor a reference cell can solve is the non-uniformity of the rear-side irradiance. One single spot does not fully represent the irradiance conditions that the rear-side of a PV module will experience and thus measuring the rear-side irradiance required multiple irradiance sensors. Based on the tables 2 and 3, the minimum number of module temperature sensors for a class A PV system is 6. Depending on the size of the test area, more temperature sensors could be required. According to simulations done in [75], the rear-side of the module will receive roughly different irradiance conditions for the top, middle and bottom of the module. Thus, in order to measure the irradiance conditions more accurately the rear-side irradiance should be measured from these three locations. It is sufficient to measure the front-side irradiance with just one reference cell and thus each irradiance measurement location would contain 4 reference cells measuring irradiance and temperature, 1 facing sky and 3 facing ground. Again, to mitigate errors caused by spatial differences, at least two of these irradiance measurement locations should exist for each test site. The measurement locations should be evenly distributed across each test site.

When the albedo of the ground is increased (artificially or naturally), the albedo of the ground must be monitored in order to get correct information about relations ship between the rear-side irradiance, albedo and energy yield. Unfortunately, measuring albedo of a utility-scale PV installation does not make much sense since the PV modules will disturb the albedo measurement. Additionally, if the albedo is measured before the PV system is built, the conditions will typically change after the construction project and the previous results are no longer valid. [83] An alternative for the albedo measurement is to use plane of array irradiance measurements for front and rear-sides and determine the pseudo albedo from these measurements. However, as discussed above, the front and rear-side irradiances are planned to be measured using reference cells that have certain spectral response. This spectral response will introduce error to the albedo values. On the other hand, due to the spectral response the reference cells will filter out all the non-relevant wavelength. In addition to the error caused by the spectral response, also part of the diffused irradiance would be included in the albedo measurement. Therefore, the albedo measured this way could be called effective albedo ρ_{eff} of the module.

6.2.4 Summary of the test site

For the sake of clarity, let us summarize the plant for the test site. The main topics included in the test plan were bifacial PV modules and artificially increased albedo. The controlled monitoring of bifacial modules was chosen because it is an easy and cheap topic to implement. On a PV system that already has bifacial module and basic measurement devices like a weather station, the added cost of this test would come from the reference cells used to monitor the irradiance and temperature conditions and from the optimizers used for the edge modules. The artificially increased albedo was also chosen due to very similar reasons. When testing the reflective material to increase ground albedo, the added costs come from the reference cells and from the reflective material itself. This kind of test site resembles very closely the test facility in the Swiss research center interviewed in the benchmark study in section 4. The research center in Switzerland stated that they do not measure the module temperature directly, but they had reference cells to measure the rear-side irradiance. Thus, their approach is very similar to the one suggested in this section. Besides the data received from the weather stations (irradiance, ambient temperature, wind speed, rainfall, etc.), energy yield data from the inverter strings and the irradiance and temperature data from the reference cells would be utilized. Additionally, the edge modules would gain individual yield data from the optimizers. Additionally, the test setup described for bifacial modules in section 6.2.1 could also be utilized for new PV module technologies. The technology in question naturally affects what kind of setup is required but the setup describe in this thesis cab act as a good basin for more complicated setups, as long as the component being tested is the module and not some other component. This setup might work for other components as well but that would have to be evaluated case by case.

The experiment with the bifacial PV modules without the reflective materials would give information about what kind of bifacial gain values one can expect in the Nordic conditions and thus decrease the uncertainty related to the energy yield of bifacial PV modules. Additionally, the edge effect would be studied and the reach and magnitude of it would be clarified. This will help in the future to find optimal PV system layouts. Also, snow related effects like snow cover losses and albedo increase due to snow could be studied at least partially during winters. Similarly to the first topics, in the albedo increase topic the true bifacial gain of the PV system would be measured. Over the year the durability of the reflective materials would also become clear.

7 Discussion and conclusions

During this thesis we have discussed how solar cell and photovoltaic (PV) modules operate and how the operating environment effects their performance. Additionally, we covered the current best practices and existing approaches for module-level testing as well as the requirements for system-level PV monitoring. As part of the two interview rounds a benchmark study of the currently existing solar PV test facilities was done and commercially potential test topics were investigated. In this final chapter, the results and findings from the study are collected and summarized. Additionally, the limitations of the study and suggestions for future research will be discussed.

7.1 Conclusions

The first objective of this thesis was to collect the best practices and current approaches for system-level solar PV testing. This was done in the form of a literature review and a benchmark study. In the literature review, the lack of system-level testing and especially guidance for system-level testing was noticed. The literature related to system-level installations was typically related to the analysis and operation of the PV system. The majority of the literature about test PV system design and operation was about module-level test sites or stand-alone modules. Some standard related to PV monitoring and measurement of external parameters in system-level were also covered in the literature review. Combining the findings from the literature review, a holistic guideline and recommendations for the measurements was formed.

In the benchmark study, 8 parties were reviewed about solar PV related testing and piloting. The majority of the participant had their own test facilities, but only two participants were conducting research on a larger number of PV modules. The rest of the participants had smaller PV installations that were used to study some specific phenomena or then they conducted module-level testing. The most prominent difference between the system-level and module-level test facilities was that the system-level facilities had far less measurement instruments and sensor compared to the module-level facilities. Additionally, the system-level test facilities kept the modules at the maximum power point (MPP) at all times while the module-level facilities typically performed and IV-measurement for the modules. The majority of the sites also conducted all or most of the measurements required in standard IEC 61724-1.

The second objective of this thesis was to investigate what kind of solar PV related topics would be potential to test from the point of view of a commercial company. This objective of the thesis was covered by the interview portion of the benchmark study and the interview round of industry professionals. In total 12 professionals were interviewed during the second interview round. During the second interview round, 22 potential topics related to solar PV projects were recognized and 13 of these topics were chosen for preliminary evaluation. These 13 topics were chosen for the preliminary evaluation due to their relevance, practicality and due to the frequency, that they came up in different interviews.

The third objective was to formulate a plan for potential solar PV test facility with some relevant test topics. The idea of the test plan was to provide easy-to-follow guideline about how the chosen test topic should be investigated and what kind of results one could expect from the experiment. The two topics that were chosen for more thorough evaluation were bifacial PV modules and artificially increased albedo. Bifacial PV modules had uncertainty related to true bifacial gain in general and due to the edge effect, that causes the modules close to the edge of the array to receive more rear-side irradiance and subsequently produce more power. Determining the magnitude of these effects and thus decreasing the uncertainty related to the energy yield assessments is the key result of this experiment. The second topic was about artificially increasing the albedo of the ground. This experiment had also very similar issues and expected results with the bifacial topic. However, when considering the increased albedo, the reflective material used for this raises many questions. As part of the experiment the applicability and durability of the reflective material would also be studied in parallel with the energy yield-increasing and uncertainty-reducing effect.

As part of the test plan, the most suitable site location from the standpoint of co-locating multiple assets had to also be considered. For the chosen topics, the most suitable test location was evaluated to be as a part of a utility-scale PV system. In such a system, the other modules would provide utility-scale like environment for the test modules and some measurements devices could be shared by the utility-scale PV system and the test system. One of the main devices or instruments that could be shared would be a weather station that contains devices to measure the weather parameters like ambient temperature, wind speed and direction and rainfall, as well as pyranometers and pyrheliometers to measure different components of the solar radiation.

7.2 Limitations of the study

Due to the nature of this study, it contains several limitations, simplifications and assumptions. All of these factors will include error and uncertainty to the results. As one of the main goals of the study was to find efficient ways to reduce uncertainties related to potential test topics, these topics have uncertainty also related to them. This naturally limits the accuracy of any analysis related to these topics.

In the theory section (2), the dependency of the characterization parameters on major external parameters was discussed. The dependency was analyzed at a higher level and the results were given in qualitative fashion. With this kind of analysis, the importance of each parameter can be understood, but knowing the dependency in quantitative level would be necessary for example when calculating the instantaneous power of a PV module or when applying temperature or spectral corrections to some parameters.

The literature review consisted mainly of material published by Photovoltaic Power Systems Program (PVPS) Task 13. The PVPS Task 13 reports use the majority of the relevant material available, but new articles and publications published after these reports could have had more current information. Due to the large number of publications published regarding PV modules and systems, going through all of these would not have been possible during this thesis work.

The benchmark study had several limitations. The number of interviewed parties were rather small, especially since the included parties represented three different categories who all had very different methods and interests. Focusing more on one category would have granted a more holistic view about the current status of solar PV test facilities. Additionally, some of the interviewed parties were located outside of the Nordics and thus they did not directly represent the status in the Nordics. This, however, was also an advantage of the benchmark study, since this way we were able to cover a larger range of topics with relatively few interviews. However, the more holistic approach to the Nordic requirements would have been more beneficial.

During the initial evaluation of the potential test topics, the lack of deep knowledge about these topics caused some limitations during the evaluation process. The background knowledge of some topics caused these topics to be less relevant due to bias for more familiar topics. All of the topics should have received an equal amount of attention for fair evaluation process. Additionally, some of the topics were too large to cover in this thesis and at least partially this was the reason why they were not covered in section 6.

The results section (6) had the most limitations out of all the sections. The options for the test site location had only a few common options that have real life examples. Since the options were mirrored from real life, some more optimal test setup and locations could still exist. The site selection section did not have a thorough method for the process. A more thorough method for the site selection could yield a more optimal site selection scheme. Similar to the literature review, when covering and evaluation the bifacial module and albedo increase topics, as much as possible information was gathered from relevant sources. However, due to time limitations only part of the source material was covered. Especially bifacial PV modules have much new information published about them and keeping up with the new research is extremely time consuming.

7.3 Suggestions for future research

As discussed above, this subject is seeing constant development from all around the globe. As the PV module prices keep decreasing, solar PV power will become financially feasible to even larger share of the Earth. Due to this, some new regional problems will become more relevant. Many of the topics mentioned in 5 are relevant everywhere, but some of the topics had regional requirements, like the snow-related topics. A constant investigation of the research that has been done, especially in these new regions, is important to avoid any unnecessary redundancy in the research.

A test site suggestion for two test topics was presented in this thesis and a natural future research suggestion would be to realize these case studies. Decreasing the uncertainty and providing validation to performance model is extremely important for making accurate investment decisions in the future. Only 2 out of 13 test topics mentioned in this thesis were evaluated thoroughly. Evaluating the rest of the test topics also would give a more holistic view of what is currently needed in the solar PV sector and what is actually possible.

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A Irradiance measurement recommendations

Summarized below are recommendations for irradiance measurements in a solar PV test facility. Recommendations from PVPS Task 13 report [46].

- The pyranometer and reference cell slope/tilt and orientation must match that of the test modules within a small fraction of a degree.
- The tilted instruments should receive roughly the same amount of ground-reflected radiation as the modules. This is usually achieved by mounting them in close proximity and at the same height.
- If there is any risk of dew, frost or snow accumulation and data under those conditions needs to be evaluated, use instruments with ventilators and/or low power heaters. Ventilators can also help reduce any thermal offset which is one of several sources of error and uncertainty.
- Sensors optics must be cleaned and inspected regularly, as appropriate for local conditions and test schedules. In some instruments, the desiccant must also be checked and replaced periodically to prevent condensation inside the instrument.
- Calibrations must be checked regularly. If at all possible, a scheme should be implemented whereby multiple instruments are checked against each other and sent to an external calibration lab on an alternating basis.

B Electrical measurement recommendations

Summarized below are recommendations for current-voltage measurements performed with either maximum power point trackers or IV-curve tracers. The recommendations are directly copied from PVPS Task 13 report, Photovoltaic Module Energy Yield Measurement: Existing Approaches and Best Practice [46].

B.1 General requirements

- The general measurement requirements and accuracy of the equipment have to comply with IEC 60904-1 and IEC 61829.
- IEC 61724-1 2017 covers the main data acquisition requirements for PV systems and should be used as a reference also for PV modules.

B.2 Measurement accuracy

- Uncertainty of current and voltage data acquisition hardware should be below: I_{dc} : 0.05% and V_{dc} : 0.05%.
- Uncertainty of all calibrated shunt resistances should be below 0.1%.

B.3 DC Load

- Choose a DC Load which can control the current and voltage fast with fast settling time.
- Use dedicated, zero current, voltage sensing leads (four wire connections).
- Use the same make and model DC load for PV module comparisons to eliminate any differences introduced by the hardware.
- The DC load should be in a constant temperature environment climate (e.g. air conditioned room) to limit temperature fluctuations and the resulting measurement uncertainties, and to achieve lowest thermal drift (as cabinet temperature can show delta $T = 30$K per day).

B.4 IV scan procedure

- The parameters I_{sc}, R_{sc}, I_{mp}, V_{mp}, R_{oc} and V_{oc} should be derived from the scanned IV-curves to determine if there are any problems with the device or measurement, such as irregular curvature, scatter, or non-monotonic (not continually increasing or decreasing) behaviour.
- The scan speed, direction, settling time and resolution have to be optimized for different technologies, partly to minimize hysteresis effects (that often show up as different IV traces particularly near V_{mp}).
- The scan should take no longer than 1-2 seconds to minimize scatter in the data from variation within clouds.
- The system should be able to measure during cloud enhancement conditions (i.e., reflections off clouds near the sun) that increase the irradiance higher than clear sky values. Irradiances can briefly peak at 1800W/m^2 even in less sunny climates such as Northern Europe.
- Consider appropriate timing so transients between IV scans and MPP tracking do not impact the measurements.
- There should be at least 50 measurement points per IV scan, with a minimum of 10 sampling points per measurement point.
- The distribution of points in the IV curve may be optimized to ensure there are enough near I_{sc}, P_{max}, and V_{oc}. For example fits to I_{sc} will not be very accurate if there are very few points near I_{sc}.
- It is recommended to interpolate between data points before examining residuals. Fitting method: Cubic spline fits e.g. find points where $V < V_{oc}/10$ for I_{sc} : Intercept with $V = 0$ gives I_{sc}, slope gives $-1/R_{sc}$, $V_{mp} \cdot 0.45 < V < V_{mp} \cdot 0.55$ for P_{max}. Maximum $V \cdot I$ gives P_{max}, $I < I_{sc}/10$ for V_{oc}: Intercept with $I = 0$ gives V_{oc}, slope gives $-1/R_{oc}$.

- Stable meteorological conditions are required before starting an IV scan.

B.5 Module bias when not being measured

- Modules should operate at their maximum power point (MPP) at all times except during IV-curve measurements. Leaving the module at I_{sc} or V_{oc} between IV curves can result in higher module temperatures due to extra heat from recombination in the cells.
- Extra care should be taken for thin film devices because module bias may cause damage to the cells and increase their degradation rate.

B.6 Maximum power point tracking

- Maximum power point (MPP) trackers may sometimes operate the module at a local maximum instead of at the MPP, so ensure that the MPP tracking algorithm is fast and accurate.
- The static and dynamic tracking accuracy (tracking efficiency) of the MPPT should be known.
- The tracking algorithms of the MPPT device should be optimized for all technologies independently of the fill factor (FF) to allow a fair comparison of the results.
- Systematic cross-checking of the MPPT data with IV-data is recommended at different environmental conditions and for different module technologies.

B.7 Data sampling and synchronization

- Eliminate or use only high quality multiplexers, many are unreliable.
- Synchronize the IV scans of all PV modules.
- The recommended interval for IV scans is 1 min, but it can change in dependence of the scope of testing.
- The data acquisition rate for environmental parameters should be in the range of 1-10 Hz, with averaging to a target sampling frequency of 1-5min.
- The data acquisition rate for IV scan parameters should be greater than 1000 Hz with averaging to the target sampling frequency of the measurement points in the IV scan.
- The data acquisition rate for the environmental parameters (averaged values) should be synchronized with the IV scans.

- It is best to measure the irradiance before and after an IV trace to ensure irradiance stability during the trace. Examination of the scatter in current from I_{sc} to I_{mp} can indicate irradiance variability, but is a less direct method.

B.8 Shunts

- When external shunts are needed the typical range is 1 mω to 10 mω. They should have calibration certificates and low thermal drift characteristics.
- Calibrated shunt resistance uncertainty can reach 0.01%; the temperature coefficient should be below ±5 ppm/K (20 to 60°C).

B.9 Cables

- Four-wire connections should be made: two wires for the module power and a current measurement and two wires for a zero-current voltage measurement.
- Wires should be at least 6 mm^2 in cross sectional area for distances over 20 m. For distances less than 20 m, 4 mm^2 is sufficient for an insignificant voltage drop.
- If a four-wire connection is not made, cabling lengths should be minimized and the voltage drop should be characterized.

B.10 Connectors

- Must be standard PV module connectors (e.g., MC4) to withstand outdoor conditions and repeated reconnections without significant change in contact resistance.
- Use Y-connectors for splitting the PV module connectors into a 4-wire test configuration.
- Periodically check the connection resistance of your extension cables as it could change over time due to corrosion, dust, etc.

B.11 Fuses and overvoltage protection

- Fuses and overvoltage protection can introduce uncertainty; therefore, for optimum measurement performance, either do not use protection devices or design them so that there is minimal impact on the signals.

B.12 Checks and validation

- Quantify the voltage drop at the short-circuit condition and calculate the difference between the measured and true module I_{sc}.
- Quantify any current flow at the open-circuit condition and calculate the difference between the measured and true module V_{oc}.

B.13 Calibration:

General: regular calibration is needed for reference measurements to avoid any drift or bias.

- Calibrate the measurement equipment according to manufacturer specifications.
- Calibrate at least every two years and track the drift and bias on a quarterly basis.