Techno-economic analysis of the Local System Operator concept in a multi-dwelling unit in Sweden

A parametric sizing and optimization of a PV-battery system with EVs equipped with vehicle-to-home application

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Abstract

The climate change of the environment raises concerns about the increasing greenhouse gas (GHG) emissions where the energy sector is a large contributor to the emission problems. As the electricity demand rises, due to increased population, urbanisation, and improved lifestyle, expanding the renewable generation can solve the problem of covering the increased electricity demand while decreasing the GHG emissions. However, the intermittency of renewable energy put a lot of stress on the electricity distribution system where a decentralised approach of the electricity generation could reduce the stress from renewable energy sources (RES).

This techno-economic study investigates the decentralisation of electricity generation through the Local System Operator (LSO) concept by creating a perfect prediction model where the LSO operates a local energy system in a multi-dwelling unit in Örebro, Sweden which is owned by the housing company ÖrebroBostäder (ÖBO). The local energy system will consist of one or more of the technical components; photovoltaic (PV) system for electricity generation, a battery energy storage system (BESS) to store and supply electricity to the facility, but also to increase the self-consumption and self-sufficiency and electrical vehicles (EV) which will be able to store and supply the building with electricity through Vehicle-to-home (V2H) application charging stations. The cost-benefit analysis of the energy system is made by parametric optimization of the sizes of the different components to maximize the Net Present Value (NPV) of the system after 25 years, and also by creating control and operation strategies of the BESS and the EVs in order to reduce the electricity consumption peaks of the facility load. A degradation model is used to mimic the capacity fade the batteries in the BESS and the EVs experience as time elapses, and different availabilities of EVs during the day is used in the case study to see the effect the driver’s habits and vehicle patterns have on the result.

The result of the case study shows that a 92.4 kWp PV system (yearly production of 710 kWh/kWp) without a BESS or any EVs will provide the highest NPV after 25 years which amounts to 145 420 SEK. Also, shown by the results, is that the BESS and EVs is not economically viable due to high costs, but combining a BESS with a PV system will make the energy system profitable up to 41 kWh BESS, if combined with the PV system size resulting in highest NPV. Whereas a system consisting of EVs will never be profitable no matter what sizes and what components are used in the system. The sensitivity analysis shows that decreasing the cost of the BESS and the EV charging stations for V2H application by 10 % will still not make the components profitable by themselves. However, it will make the BESS profitable for larger sizes when combined with a PV system, while only make the EV charging stations with the V2H services become a little less economically unfavourable.

The results also suggest that the charging and control strategy applied in the study is successful in its task of decreasing the electricity bill, but the investments are too high compared to the savings. Availability of the EVs has a large impact on the use of the V2H on the facility loads profile, where a high availability during the day will increase the usefulness of the EVs on the modelled multi-dwelling unit. Finally, the LSO concept might be viable in the future since it is profitable for a housing company to invest in flexible assets as BESS up to a certain size and if the LSO can aggregate enough of the housing company’s building portfolio it can help transforming the energy system from a traditional top-down approach to a bottom-up approach.
Sammanfattning

Klimatförändringarna väcker oro med ökande växthusgaser, där energisektorn är den största orsaken till utsläppsproblemen. Medan elanvändningsbehovet ökar på grund av ökande population, urbanisering och högre levnadsstandarder, kan en utökning av förnybar elproduktion lösa en del av problemen med att täcka det ökande elanvändningsbehovet och samtidigt minska växthusgasutsläppen. Däremot skapar faktumet att många förnybara energikällor är intermittenta höga belastningar på elnätet, och där ett decentraliserat tillvägagångssätt av elgenereringen skulle kunna minska belastning från förnybara energiresurser.

Denna tekn-oekonomiska studie undersöker decentraliseringen av elgenerering med hjälp av lokal systemoperator- (LSO) -konceptet genom att skapa en perfekt prognos-modell där LSO:n opererar ett lokalt energisystem i ett flerbostadshus i Örebro, Sverige, som ägs av fastighetsägaren ÖrebroBostäder (ÖBO). Det lokala energisystemet består av en eller fler av de tekniska komponenterna; solcellssystem (PV) för elgenerering, ett batterienergiallagringssystem (BESS) för att lagra och tillhandahålla el till fastigheten men även för att öka självanvändningen och självförsörjandet, samt elbilar (EV) som kan lagra och tillhandahålla el till byggnaden genom fordon-till-hem (V2H) funktion på laddningsstationer. Lönsamhetsanalysen av energisystemet är utförd genom en parametrisk optimering av de olika komponenternas storlekar med syfte att maximera nuvärden (NPV) på systemet efter 25 år, och även genom att skapa kontroll- och laddningsstrategier av BESS och EV:s för att minimera toppanvändningen av el från byggnadens fastighetslaster. En degraderingsmodell används för att imitera kapacitetsminskningen batterierna har i BESS och EV:s medan tiden fortlöper, och olika tillgänglighetsnivåer på EVs under dagen används för att se vilken effekt olika användningsbeteenden har på resultatet.

Resultatet på studien visar att ett 92,4 kWp PV system (med årlig produktion på 710 kWh/kWp) utan ett BESS eller några EV:s ger det högsta NPV efter 25 år, vilket är 145 420 SEK. Resultatet visar också att ett BESS och EV:s inte är ekonomiskt hållbart på grund av för höga kostnader, men att kombinera ett BESS med ett PV system gör energisystemet lönsamt upp till 41 kWh BESS, om det kombineras med det PV system som ger högst NPV. Däremot kommer ett system som består av EVs aldrig att vara lönsamt oberoende av vilka komponenter eller storlekar som används i systemet. Känslighetsanalysen visar att en minskning av kostnaderna för BESS och EV-laddningsstationer med V2H-funktion med 10 % kommer fortfarande inte att göra komponenterna lönsamma själva. Det kommer däremot göra BESS lönsamma för större storlekar när det kombineras med PV system, medan det endast gör EV-laddningsstationer med V2H-funktion lite mindre icke-lönsamma.

Resultatet visar också att laddnings- och kontrollstrategin som används i studien är framgångsrik i sin uppgift att minska elräkningen på ett effektivt sätt, men investeringskostnaden är fortfarande för hög i jämförelse med besparingen som kan göras. Tillgängligheten på EV:s har en stor påverkan på användningen av V2H-funktionen på fastighetslasten, där en hög tillgänglighet under dagen ökar nyttigheten av EV:s på det modellerade flerbostadshuset. Slutligen, LSO-konceptet kan komma att bli hållbart i framtiden eftersom det är lönsamt för en fastighetsägare att investera i flexibla resurser som BESS upp till en viss storlek och om en LSO kan aggregera tillräckligt av fastighetsägarens byggnader kan det hjälpa att förvandla energisektorn från ett traditionellt toppstyrtytt tillvägagångssätt till ett tillvägagångssätt nedifrån och upp.
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Abbreviations

AC Alternating Current
BESS Battery Energy Storage System
BMS Battery Management System
CAES Compressed Air Energy Storage
CMS Charger Management System
CO₂ Carbon Dioxide
CPV Concentrated Photovoltaic
DC Direct Current
DNI Direct Normal Irradiation
DoD Depth of Discharge
DSO Distribution System Operator
ESS Energy Storage System
EV Electrical Vehicle
GHG Greenhouse Gas
GHI Global Horizontal Irradiation
HDI Horizontal Diffuse Irradiation
ICT Information and Communication Technology
kWp Kilowatt Peak Power
LCOE Levelised Cost of Energy
LIB Lithium-Ion Battery
LSO Local System Operator
MPP Maximum Power Point
MPPT Maximum Power Point Tracking
Mono-Si Mono-Crystalline
Multi-Si Multi-Crystalline
NP Nord Pool Spot
NPV Net Present Value
OM Operation and Maintenance
PHS Pumped Hydroelectric Storage
PV Photovoltaic
RCM Rainflow-Counting Method
REC Renewable Energy Certificate
RES Renewable Energy Sources
SEI Solid Electrolyte Interface
SEK Swedish Enkronor
SoC State of Charge
SSR Self-Sufficiency Ratio
SvK Svenska Kraftnät
TEP Transactive Energy Platform
TSO Transmission System Operator
VAT Value Added Tax
V2G Vehicle-to-Grid
V2H Vehicle-to-Home
ÖBO ÖrebroBostäder
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1 Introduction

The world stands in front of major challenges as global warming is a recurring concern that threatens the sustainable future of the earth and calls for radical action to be made in order to reduce the carbon dioxide (CO$_2$) emission levels. Several climate change agreements have already been signed and set in motion around the world, with the Paris Agreement entering force in November 2016 in the European Union (EU), being the most significant one [1]. The Paris Agreement states that the goal is to keep the increase of the global average temperature under 2 °C above pre-industrial levels and aims to keep the increase of the global average temperature to maximum 1.5 °C above pre-industrial levels [2].

The earth still relies on fossil fuels to be the major resource for electricity production in spite of the share of renewable energy sources increasing over the years. Fossil powered electricity generation is one of the main sources of greenhouse gas (GHG) emissions [3] and with the increase of population and social development of the society, this is a problem. The electricity demand around the world will increase as a result of improved lifestyle, growing economy, and increased access to electricity for households [4]. Another sector that is a large contributor to the GHG emissions is the transport sector which releases roughly 20% of the total carbon dioxide CO$_2$ emission in Europe [5]. One solution to reduce the historical increase of emissions, and to reach the set-out goals to decrease the level of CO$_2$, is to increase the penetration of electrical vehicles (EVs) which would reduce and eventually eliminate the dependency of fossil fuels for vehicles. However, an increased penetration of EVs would lead to an increased electricity demand.

One way to cover the future demand and to decrease the GHG emissions is to expand the renewable electricity generation, with solar and wind being the most feasible current sources. However, the EV charging and the intermittency of solar and wind power, causes a great deal of stress on the electricity distribution system and the distribution system operators (DSO) face major challenges to stabilize frequency and voltage fluctuations in the grid transmission lines [6][7]. Instead of large investments for the upgrade of distribution grid, a relatively new method of electricity production can be used. Instead of a traditional top-down generation with large-scale solar and wind power plants, a bottom-up approach of electricity generation can be adopted and solve the problems of intermittent renewable sources without heavy investments. The bottom-up approach leads to a decentralisation of the electricity generation by allowing the buildings to generate electricity for self-consumption by installing renewable energy generators [8]. This method can be implemented by a new actor, a local system operator (LSO) that will focus on local, sustainable and renewable solutions at the end-user site.

1.1 The LSO concept

The theory of the concept is that the LSO creates and operates a local energy system that consist of small-scale power plant buildings that will transition the electricity generation from the traditional top-down energy management approach to a digital and sustainable bottom-up approach. The LSO concept is based on a three-step model, which includes:

1. Reduce: The first step of the LSO concept is to reduce the energy consumption of the building by optimizing the technical setup which can decrease the energy related cost. By integrating cloud connected information and communication technology (ICT) such as energy meters, sensors and control systems into the building, the LSO will be able to monitor and fully manage the energy consumption. The real time, around the clock demand side management of the LSO could create more cost and energy efficient buildings where the energy savings covers the investment costs.

2. Produce: The second step of the LSO concept, is to transform the buildings to a more self-reliant energy producer and consumer, a prosumer. Installation of a small-scale PV system for self-consumed generation reduces the amount of electricity drawn from the grid which hopefully can lower the electricity bill. An energy storage system (ESS) combined with a charger management system (CMS) is installed together with the PV system for a more efficient utilization of the intermittent power sources. The CMS is used to control the charging of the ESS, control demand
side peak shaving, and for load levelling based in market spot price. The DSO could also benefit from an ESS as the ancillary services that can be provided stabilizes the distribution grid. As the last action in step 2, the integration of electrical vehicles (EV) may be made smoother by supplying the customer with a CMS for EVs that will control the charging of the vehicles in order to decrease charging costs and optimize battery performance according to usage behaviour.

3. Share: The third and final step is to create a transactive energy platform (TEP) which is a real-time marketplace where the customer is monitored and managed by the LSO, where they can be a part of sharing and trading of surplus electricity with neighbouring customer in the local area, a so-called peer-to-peer energy trading which occurs within the LSO customers. The TEP could create benefit for both sides of the trade, as one side can sell their unused surplus energy to a higher price than the market spot price it usually is sold for \[9][10][11][12], while the other side can buy electricity cheaper than the retailer price.

The concept hopes to reduce the costs for the customers, but also lower the energy demand of buildings, which for the future can be a very valuable action to stop global warming. The LSO concept is a relatively rare method for implementation of renewable energy, but could have great potential to be a more worldwide adopted method which hopefully creates a more environmental friendly and sustainable energy generation around the world.

The LSO concept could have a large impact of introducing a new business model together with renewable energy sources, energy storage and EVs to multi-family building and make the integration as easy as possible. This study will investigate the economic feasibility of step two of the LSO concept on a multi-family building in Örebro owned by the housing company ÖBO. ÖBO is a large housing company in Örebro, Sweden and rents out 22,610 apartments to around 43,000 tenants and is very eager to invest in innovative technology and business models in order to decrease the energy related costs, but also to increase the property value of their buildings. They have already begun to invest a green initiative which includes investment for energy efficiency that saves them around 25 to 30 million SEK per year, but plans to continue the investments as their previous energy efficiency investments has directly increased the property value by around 700 million SEK [13][14].
2 Objective and scope

The future will see challenges in supplying enough renewable electricity to consumers and prosumers with increasing electricity demand coming from increasing usage behaviour and the introduction of more EVs, while still trying to maintain a balance in the electricity grid’s transmission lines to prevent overloads. If a local system where its buildings have its own electricity generation, energy storage (both from stationary batteries and EVs) and control and charging strategies would be implemented, as step two in the LSO concept, this may be a solution to the challenges.

Therefore, the main objective of this study is to find the optimum combination of given sizes for a system which consists of a PV system, a BESS and a different number of EVs with different availability curves in order to maximize the NPV for the system after 25 years. The study will be performed on a real location, which consists of multi-dwelling units owned by ÖBO and therefore the study objective may lead to valuable insights for them and other actors when it comes to decision-making related to electricity generation and storage systems in the future.

Furthermore, other objectives will be developing a PV, BESS, EV, and a price and cost model that is able to simulate the real-life behaviour of such systems over the simulation period. Another objective will also be to develop a smart and cost-effective control and charging strategy for the given facility loads of the multi-dwelling units. A last objective will be to get the knowledge of how uncertainties in the EV usage behaviour may affect the profitability of the system.

The objectives of the study can be fulfilled by answering the following research questions:

- What is the optimum combination of sizes for a PV system, a BESS and number of EVs, with different EV availability curves in order to maximize the NPV of the entire system after 25 years?
- What is a smart and cost-effective control and charging strategy for the given facility load of the multi-dwelling unit?
- How are the EV availability curves affecting the profitability of the system?
3 Study Methodology

The objective is addressed with the study methodology presented in this section and uses the following steps.

1. A literature review is conducted to present PV and battery systems, inverters, EVs, the electricity market, subsidies and incentives and previously done studies on the topic.

2. Data is collected through a variety of software programs, contacts and previously done studies. The data includes location data, facility loads, weather data, specifications and costs for PV and battery systems, inverters, EVs and charging stations. It also includes electricity prices and cost.

3. Based on the literature review and collected data different control and charging strategy models, degradation models and a solar model is created. These models are used to build up four sub-models; PV model, BESS model, EV model and price and cost model, which in turn is used to build up the overall model and system configuration which is designed to meet the objective. More details of the system configuration and the different models and their methodologies is described in the Modelling Approach section.

4. With the overall model a techno-economic parametrisation optimization, using Matlab, is performed with 1. PV system size, 2. Battery size, 3. Number of EVs and 4. EV availability curve, as the changing parameters, in order to find the best combination of those four parameters to maximize the NPV of the system after 25 years.

5. The results are evaluated and discussed and a sensitivity analysis is carried out to handle the uncertainties of the cost input data and to see if better profitability can be achieved in the future.

6. Final conclusions of the study are made along with suggestions on future work that can be done.

3.1 Simulation tools and data collection programs

The simulations tools and data collection programs that is used in the study is briefly described in this section along with the application for which it has been used.

3.1.1 Matlab

Matlab is the main program that has been used in this study. It is used to calculate all parameters with an hourly resolution and to create algorithms for all the different models.

3.1.2 Excel

Excel has been used to create load profiles and box plots for facility loads and electricity prices.

3.1.3 Meteonorm

Meteonorm [15] is a software that has a large database of weather data. It uses a method to calculate the data for an average year, which means that the data is not exact values for a specific year, but how a typical year would look. In this study, version 7.2 has been used for collection of solar irradiation and ambient temperature for Örebro a typical year.

3.2 Limitations

The study is limited to only investigate the facility load for the address Höglundagatan 21 in Örebro. Therefore, the control and charging strategies and models are designed only considering the data from this specific site. If another building would have been investigated with apartment load instead of facility load, the charging strategy applied in this study would probably not be optimal.
The weather data used in the case study is not taken from the exact location of the facility, but from a site nearby, and therefore the irradiation on the facility site may differ to some extent.

Only the last three years Swedish SE3 hourly based Nord pool Spot electricity price data is used to calculate the fluctuations of the electricity price in the case study.

All yearly data used in the study (weather data, facility load data, electricity price data) are limited to a time step of one hour, therefore, several calculations will be made with a one hour time step. All yearly data is reused and remains constant for each year during the test period, where the facility load data and electricity price data is averaged based on a time period of three years. The reuse of the data can affect the result to some extent and may not reflect the real-life result.

All load data have an hourly time step, where the energy is a result of the average power during each hour. Therefore, all loads used in the calculations are assumed to be constant throughout the hour, which helps reduce the time step in certain calculations, but will not illustrate the real live power of the facility electricity consumption, which may affect the result.

The study is also limited to consider specific components for the photovoltaic (PV) model, battery energy storage system (BESS) model and the electrical vehicle (EV) model. The PV modules used in the case study are considered as standard modules with an assumed general average efficiency, a lithium-ion battery (LIB) is used in the BESS, string inverters are used for the PV system whereas a bi-directional inverter is used for the BESS, where both have an assumed general average efficiency. The Nissan Leaf with a 24-kWh battery capacity is chosen for the case study and uses a bi-directional inverter/charging station for the V2H application. All components have been chosen based on their typical applications or based on the interest of the component usage in the future. This does not mean that there could not be other components or technologies better suited for the case study. However, no other component or technology will be evaluated in this study.
4 Literature Review

A literature review was carried out in order to get knowledge about the technologies, the economics and usage behaviours. Knowledge that was needed to be able to model the system in a realistic way. The different parts in the literature review is presented in the following section.

4.1 Photovoltaic (PV)

One of the most promising applications for electricity generation from solar resources is photovoltaics (PVs). This is mostly due to the fact that prices have decreased in recent years along with increasing efficiencies, which have made the installed PV systems to increase worldwide. Figure 1 and Figure 2 shows the reason behind the increasing commercialisation by showing the increasing installed PV capacity and decreasing PV module prices [16].

![Figure 1. Global cumulative installed PV capacity [16].](image1)

![Figure 2. Price learning curve for all commercially available PV technologies [16].](image2)
PVs are normally divided into its three generations. The first generation have cells made out of silicon in a crystalline structure. The second generation is based on thin film technology and the cells can be made out of several materials. A commonality for all thin film technologies are thin layers of semiconductor material applied to a solid backing material [17]. The third generation consist of a wide range of different research technologies, where the focus mostly lies in either prioritizing efficiency or cost. Examples of third generation technologies are: concentrated photovoltaics (CPV), Organic cells, carbon nanotubes and quantum dots. Each generation have a number of different subtypes and sub-technologies [18]. This report will only focus further of the most developed and commercialised technologies which are the silicon based mono-crystalline (Mono-Si) and multi-crystalline (Multi-Si) and the thin film technology. These technologies and their share of the global market over the past years is shown in Figure 3 [16].

![Figure 3. PV production by technology in percentage of global annual production [16].](image)

### 4.1.1 Technical Overview

This section contains the technical overview which are common for all PVs, irrespective of which generation they come from. The principle is that they all work on the principle of the photoelectric effect, which is the process when light in the form of photons is converted directly into electricity in the form of voltage, hence the name (photovoltaic). This works by having a semiconducting material, with a positive charged side and negative charged side forming a p-n junction, sandwiched between conducting layers. When photons (light) strike the PV with enough energy it will knock electrons out of their bonds making them free to move, but only in one direction due to the p-n junction. Metal fingers direct the electrons between the conducting layers and creates a current, in order words electricity [17]. The working principle of a PV cell with silicon as its semiconducting material is illustrated in Figure 4 below [19].

![Figure 4. Working principle of a PV cell](image)
As mentioned, Figure 4 illustrates the working principle of a PV cell alone. Several PV cells are then connected together to form a PV module and several PV modules can also be connected together to form an array of PVs which can generate enough electricity to power a building.

Another technical aspect that is important to understand is the way the capacity of the PV system is given. It is usually given as how much kilowatt peak power (kWp) the system has. This is a measure of the output power a system has under standard test conditions (STC), where the standard test condition uses an irradiance of 1000 W/m², a cell temperature of 25 °C and an air mass (AM) of 1.5. Important to notice is that the peak power is a measurement of the performance under these specific conditions and only occur when sun is at some specific positions and the season is the right. So during most times of the year the power output will be lower and to see the actual electricity that have been generated over the year, it can be better presented in the normalized way as kWh/kWp and year [21].

4.1.2 Silicon Crystalline
Silicon crystalline solar cells are from the first generation of solar cells. They all have in common that they use silicon as semiconducting material, which is the second most abundant material on earth, and the silicon is built in a crystalline structure. There are two different types of silicon crystalline solar cells that will be further evaluated in this study and those are monocrystalline and multicrystalline. These are also the ones most commercialised, mainly due to their high efficiencies for a relatively low cost [18]. The commercialised modules have efficiencies in the range between 14-22.8 % [22].

Mono-crystalline (Mono-Si)
Mono-Si solar cells and modules have the highest efficiency of the commercialised PVs on the market, mainly since they are made of a high-purity silicon. The commercialised cell efficiency ranges from 16-25 % [22]. They are also space-efficient, which means that they have a higher-power output for the same module area if they were compared to for example multicrystalline. Continuing, the life time of the modules are high compared to other solar technologies and they also perform well at low-light conditions. The cells are manufactured by cutting four sides out of cylindrical shaped silicon ingots to make silicon wafers. This process means that a significant amount of silicon is wasted and therefore Mono-Si modules are the most expensive of the commercialised PVs. Another disadvantage is that the efficiency decreases with increasing temperature, i.e. high temperature coefficient [18] [23].

Multi-crystalline (Multi-Si)
Multi-Si solar cells and modules have lower efficiency than Mono-Si, mainly due to their lower silicon purity and that the grain boundaries in the crystal impedes electron flow. Their commercialised cell efficiency normally ranges from 14-18 % [22]. They also have a lower space-efficiency and slightly lower heat tolerance than Mono-Si. However, a different manufacturing method is used to make the Multi-Si cells. The method is to melt raw silicon and pour it in a square mould, which later is cooled and cut into perfectly squared wafers. This method is simpler, cost less and the amount if silicon waste is less compared to the manufacturing process for Mono-Si, therefore the Multi-Si modules also cost less [18][23].

4.1.3 Thin Film
Thin film solar cells are from the second generation of solar cells. They all have in common that they are made out of one or several thin layers of a semiconducting material which is deposited onto substrate made out of glass, plastic or metal. This makes the thin film solar cells very thin (hence the name) and flexible, allowing a number of different applications. The different types of thin film solar cells that exists is categorized by which semiconducting material that is deposited onto the substrate. Cadmium telluride (CdTe) is the one that has been the most cost-effective and it also stands for a large share of the thin films on the market [18][23]. Therefore, the CdTe thin film technology is the one that is going to be further evaluated in this study.

Cadmium Telluride (CdTe)
In common for all types of thin film solar cells, including CdTe, they have historically had lower efficiencies than the silicon crystalline solar cells, but efficiencies are increasing. Efficiencies for cells on the market is approximately around 17 % [22]. They also have lower space-efficiencies and tend to degrade faster.
However, since the manufacturing process is simple it can make mass-production cheaper than for silicon crystalline solar cells. Also, the thin film solar cells are more heat tolerant and can handle much higher temperatures without having as much decrease in efficiency. One disadvantage with the CdTe specifically is that it contains the toxic material cadmium, which is harmless as long as the modules don’t break, but then the disposal or recycling of the modules can be both costly and environmentally dangerous [18][23].

4.1.4 Factors that affect PV system power output
There are a number of different factors apart from the manufacturer’s specifications that can affect the performance of a PV system. The ones most significant are presented in this section.

Module type
Since modules can have different efficiencies, i.e. can transform different percentage of the incoming solar radiation into DC electricity, the module type that is chosen affects the power output. The different module types and their efficiencies have been shown earlier.

Orientation and inclination angle
The sun approximately rises in the east and sets in the west, with variations to the north and south depending on time of the year. That along with the biasing of the sun in the sky towards the equator makes a PV facing the equator the best option to convert the most amount of incoming solar radiation into electricity. Since the incoming solar radiation also strikes the surface of the earth with an angle and the PV converts most radiation into electricity if that angle is the same as the inclination angle of the PV (i.e. striking the surface of the PV directly with no angle), the PV requires an inclination angle to perform better. The optimal inclination angle normally lies around 41°-48° in Sweden and can be obtained either by already having a pitched roof or by installing a tilted mounting system [24].

Shading
The incoming radiation can be blocked by chimneys, trees, tall buildings, clouds or even by closely lying PV modules, which causes shading on the PV modules and arrays. This decreases the power output directly since less radiation strikes the modules. However, unshaded modules can also be affected by shading if the modules of the array are connected in series in a string. The reason for this can be due to the fact that the current output of a partly shaded module is lower and can change the operating point of all modules in the string. If the partly shaded module instead is bypassed, that module will produce no power but the other modules in the array can operate as normal. However there comes a point when several modules are shaded that leads to a lower string voltage than the inverter’s minimum operating point, which causes the entire string to produce no power. More about inverters can be read in section 0. Annually the energy loss from partial shading are estimated to 5-25% depending on the location [25][26].

Dirt and dust
Dirt and dust may accumulate on the surfaces of PV modules, which decreases the power output since it decreases the amount of irradiation that reaches modules. Apart from blocking the irradiation dust also changes the dependence on the angle of incident of the irradiation, i.e. dust can largely affect the chosen inclination angle of the PV modules. A study performed in Malaga, Spain showed that the average daily energy loss a year caused by dust is around 4.4% and during dry periods the daily loss can be higher than 20% [27]. The easiest way to prevent losses from dust is by continuously cleaning the modules. Rain falling down from the sky is normally enough to have the modules back to its initial performance.

Temperature
The cell temperature of PVs affects the efficiency. As the cell temperature increases the power output from the module decreases. This is mainly due to the fact that a higher temperature in a semiconducting material leads to higher resistance in the material which slows down the electrical current. Depending on the cell material from which the PVs are made, the efficiency is decreased at different rates with an increasing cell temperature. Crystalline silicon PVs can have a loss in efficiency of about 0.5% per increased °C, while a thin film PV have a loss in efficiency between 0.02-0.41% per increased °C. Lower ambient temperature, air cooling from wind and high humidity decreases the cell temperature and thereby also the losses [28][29].
**Lifetime degradation**
All PVs will degrade over time, making them less efficient for every year they are used. The reason for this is mainly due to a slow deterioration of the laminate material over time, which leads to a small performance deterioration of the PV modules over time. Normally this deterioration result in a 0.5 % degradation rate per year for crystalline silicon modules and slightly higher degradation for thin film modules. This low degradation rate makes it possible for manufacturers to normally deliver a 25 year power warranty on their modules, since they can assure less than 20% electricity output decrease after 25 years [29][30].

**Mismatch between modules within an array**
If the maximum output power of each module in an array is summed, the maximum power output for the array will always be lower than that value. This is due to slightly different performances between the modules, leading to a mismatch which normally results in 2 % less power output for the array compared to the sum of all individual modules. One factor that can increase the mismatch between modules is shading [31].

**Wiring**
There are a lot of wires in the system to transfer the electricity in the module, between modules, into inverter and to the residents. These wires all have a resistance which result in an overall power loss for the system which normally lies around 3 % [31].

**DC to AC conversion**
Before the electricity can be used by electrical appliances in households it needs to be converted from DC to AC electricity in an inverter. This conversion process results in a small loss. Today the peak efficiency for inverters can be up to 98 % [31].

### 4.1.5 PV System Costs
A PV System includes PV modules, inverters and all installation and control components for modules and inverters. Normally the system is categorized by its size and if it’s a residential or commercial system. As with the module prices earlier mentioned, the system prices have also decreased over the last years, but the decrease have slowed down in the most recent years and started to stabilize. The average prices for turnkey PV systems from Swedish installations companies over the most recent years, excluding VAT, is presented in Figure 5.

![Figure 5. Differences in turnkey PV system prices between Swedish installation companies, excluding VAT, for different systems over the most recent years][32].
For this study, the most interesting systems to investigate further is the roof-mounted commercial systems both above and below 20 kWp. Therefore, a cost breakdown of such a system is shown in Table 1 below. The cost breakdown is done for a roof mounted commercial system with a PV size between 40-60 kWp and based on five different Swedish installation companies. The low and high columns is what the companies expect that can be their absolute maximum or minimum costs [32].

Table 1. Cost breakdown based on 5 Swedish installation companies for a commercial PV system with a size between 40-60 kWp [32].

<table>
<thead>
<tr>
<th>Cost category</th>
<th>Average [SEK/Wp]</th>
<th>Low [SEK/Wp]</th>
<th>High [SEK/Wp]</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Hardware</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Module</td>
<td>5.98</td>
<td>4.89</td>
<td>9.10</td>
</tr>
<tr>
<td>Inverter</td>
<td>0.94</td>
<td>0.44</td>
<td>2.00</td>
</tr>
<tr>
<td>Mounting material</td>
<td>1.28</td>
<td>0.65</td>
<td>2.90</td>
</tr>
<tr>
<td>Other electronics (cables etc.)</td>
<td>0.74</td>
<td>0.10</td>
<td>2.00</td>
</tr>
<tr>
<td><strong>Subtotal Hardware</strong></td>
<td>8.94</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Soft costs</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Planning work</td>
<td>0.21</td>
<td>0.10</td>
<td>1.00</td>
</tr>
<tr>
<td>Installation work</td>
<td>1.52</td>
<td>0.85</td>
<td>2.30</td>
</tr>
<tr>
<td>Shipping and travel expenses to costumers</td>
<td>0.26</td>
<td>0.10</td>
<td>0.50</td>
</tr>
<tr>
<td>Permits and commissioning (i.e. cost for</td>
<td>0.53</td>
<td>0.15</td>
<td>1.00</td>
</tr>
<tr>
<td>electrician, etc.)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other costs</td>
<td>0.07</td>
<td>0.00</td>
<td>0.11</td>
</tr>
<tr>
<td>Profit margin</td>
<td>1.17</td>
<td>0.10</td>
<td>2.05</td>
</tr>
<tr>
<td><strong>Subtotal sub costs</strong></td>
<td>3.76</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Total costs</strong></td>
<td>12.70</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

From the table, it can be seen that the total system price is most dependent on the price of the module. Therefore, the module type that is chosen affects the total price greatly.

The operation and maintenance (OM) costs for a PV system is usually low, a typical value that can be used for the OM costs of a PV system can be 50 SEK/kWp [24].

4.2 Battery

For the LSO to take full advantage of the electricity generation from the intermittent renewable energy sources such as wind and solar PV and increase the self-consumption and self-sufficiency of the building, an ESS is desired to store the generated electricity for later use as the peak power production more than often does not occur during the peak power demand [33]. The ESS could also be used for other applications such as peak shaving, load levelling and, frequency and voltage control of the grid [34].

Peak shaving is a power management process at the demand side which controls and reduces the amount of electricity purchased from the grid during hours of day when the electricity demand is high. The ESS stores energy during off-peak hours and which is later used at the demand side the during peak hours. Peak shaving decreases the fluctuations of the load demand in the grid where the left graph in Figure 6 illustrates how an ESS could affect the load curve [35].
Similar to peak shaving, load levelling is also a method to decrease the fluctuations in the power grid, however, instead of only reducing the peaks, load levelling levels the overall fluctuation of a load curve. As seen in the right graph in Figure 6, the ESS stores energy during the night when the demand is low and discharges during peak hours to achieve a levelled base load curve [37].

The ESS can be useful for frequency and voltage control regulation as the intermittent nature of renewable sources delivers an irregular output which causes fluctuation of the frequency and voltage of the grid. During power output peaks, the ESS will absorb the electricity while supply the grid with electricity during power output drops, which helps to maintain the frequency and voltage levels [38].

There are multiple types of ESS technologies such as flywheels, batteries, compressed air energy storage (CAES), pumped hydroelectric storage (PHS), etc. [39] all having different capacities and discharge period, which give them a diverse application usage [40]. To achieve a decentralised power generation at household level with intermittent renewable energy sources, the battery energy storage system (BESS) is one of the best storage technologies suited to store the intermittent energy, mainly due to space and economic reasons. A BESS combined with solar PV or wind turbines will decrease the dependency of the electrical grid for the household [41][42][43].

A monitoring system that controls the charge and discharge pattern of the battery is very important in order to maximise the performance of the battery [44]. Figure 7 illustrates the difference between an uncontrolled BESS combined with a PV system, versus a controlled BESS. In Figure 7a the battery is charged immediately as the PV system generates electricity, and when fully charged during peak solar power, the electricity is fed out to the grid which leads to excess of energy supply in relation to demand in the grid. Charging the BESS during peak solar power, as in Figure 7b, will result in a more levelled energy supply into the grid [33].
It is important to consider different aspects of a battery in order to select the most suitable battery for the application. Some of the more important aspects are [33] [45]:

- Performance requirements (specific power and energy, power density and energy density)
- Calendar and cycle lifetime
- Round-trip efficiency
- Battery cell and module cost
- Depth of discharge
- Space limitations
- Safety

### 4.2.1 Technical Overview

A battery is made up by one or multiple electrochemical cells where each cell is comprised of a positive (cathode) and a negative (anode) electrode, which can be seen in Figure 8. The electrodes are placed in a closed container which is filled with an either liquid, solid or a paste state electrolyte [46]. The cell can convert electrical energy to chemical energy and is also able to reverse the cycle and able to supply electricity with desired voltage.
The batteries are divided into different categories depending on the combination of material used for the electrodes [47][36][34][48][39].

There are multiple factors that will affect the battery’s degradation, cycle life, calendar life and performance [49]:

- **Depth of discharge, DOD:** The depth of discharge indicates the level of how deeply the battery has been discharged. A fully charged battery has a DoD level of 0% and a fully discharged battery has a DoD level of 100% [50][51][33].
- **Stage of charge, SOC:** The state of charge indicates the level of the total capacity the battery has been charged with, where a high SoC level increases the degradation rate [52][53][54]. The SoC level the battery is stored with when the battery is not used also affects the degradation rate[55]
- **Ambient/cell temperature:** A decreased or increased ambient temperature level will accelerate the degradation of the battery cell and optimum range of operation temperature for a battery is around 25°C – 35°C for lower degradation rate [56][57][58].
- **Charge/discharge voltage and rate:** High power charge and discharge will affect the performance of the battery due to accelerated ageing since they involve high current rates and temperatures [59][60][61][62]

The main investment cost in a household solar PV combined with an ESS is the storage system and the most conventional storage system for a household is a battery. The high cost of the battery has prevented it to reach its full potential as a household ESS but with decreasing prices, which are projected to continue to decrease [63], the BESS will be more attractive to the customer. Figure 9 illustrates the historical and forecasted price of batteries for flow batteries, advanced lead-acid batteries and LIB, which are the most common chemistries used for residential use [64][65]. The figure illustrates that the LIB cost is projected to reduce the most out of the three which could make it more economic viable in the future.
Other papers and reports [66][67][63] also show projections of decreasing battery costs, however, these reports evaluate utility-scale batteries which may vary from residential scale batteries.

4.2.2 Previous Residential BESS Study

A previous residential BESS study has been made by a master thesis student in collaboration with InnoEnergy [68]. The study is a techno-economic analysis for a PV-BESS system in a residential building in order to find the most economic viable size of the battery combined with a 20-kW installed PV system. Four battery technologies are evaluated (lithium-ion, lead-acid, sulphur-sodium, vanadium redox flow battery) by their levelised cost of energy (LCOE) and NPV after 25 years. The evaluation is performed with a Monte Carlo simulation with varying battery inputs which results showing that the LIB being most likely to be profitable. The study shows that the LIB has the lowest LCOE range of 1.99-3.40 SEK/kWh compared to the sulphur-sodium battery which has 2.03-4.57 SEK/kWh which has the second lowest range. The LIB also results in having the lowest total cost (SEK) range, cycle cost (SEK/cycle) range and the highest NPV range of all the battery technologies.

4.2.3 Lithium ion

The lithium-ion battery (LIB) is one of the most common used battery and one of the technologies that is increasing the most in market share the past years [33] due to its high energy-to-weight ratio and efficiency, and large number charge and discharge cycles. However, the li-ion battery still has some obstacles to overcome when it comes to large-scale energy storage, one of them being the high cost per kWh. Even though price per kWh has decreased with up to 65% between 2009 and 2013 [33], it is still a relatively high cost compared to other batteries such as lead acid and Sodium sulphur batteries. Another concern of the LIB is the safety of it. Due to the thermal instability of most metal oxide electrons and the fact they can decompose at increased temperatures, the risk of thermal runaway which leads to the cell overheating and catching fire is not negligible. This is mainly caused by overcharging, over-discharging and high current charging [69]. To avoid these problems, battery management system (BMS) is used to monitor and control the charging and discharging of the battery to assure safety, maximum performance and to increase the battery cycle life [44].
4.2.4 Lithium-Ion Battery Specification

The specification of the LIB is presented in Table 2 and presents the different characteristics with different values that are available in the market.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy density (Wh/L)</td>
<td>500 [70] 220-235 [71]</td>
</tr>
<tr>
<td>Power density (W/L)</td>
<td>170 -300 [48] 400 [73]</td>
</tr>
<tr>
<td>Specific energy (Wh/kg)</td>
<td>90-190 [47] 75 – 125 [48] 75-200 [36] 120-200 [34] 90-180 [71]</td>
</tr>
<tr>
<td>Specific power (W/kg)</td>
<td>500-2000 [39] 760 [71]</td>
</tr>
<tr>
<td>Power rating (MW)</td>
<td>0-0.1 [34] 0.0015-50 [48] 0-0.1 [72] 0.005-50 [72]</td>
</tr>
<tr>
<td>Roundtrip efficiency [%]</td>
<td>85-89 [34] ≈ 99 [47] 90-97 [72]</td>
</tr>
<tr>
<td>Self-discharge [%]</td>
<td>0.1-0.3 % per day [36] Max 5% per month [39] 1% per month [47]</td>
</tr>
<tr>
<td>Discharge time at power rating</td>
<td>Minutes – Hours [34][36]</td>
</tr>
<tr>
<td>Charging duration</td>
<td>Minutes – Hours [74]</td>
</tr>
<tr>
<td>Operating temperature</td>
<td>-30 – 60 °C [47]</td>
</tr>
</tbody>
</table>

The different value ranges of the LIB economic characteristics available in the market is presented in Table 3. One of the important attributes of the LIB is the energy capital cost which determines the cost of the battery’s capacity where the LIB is one of the more expensive type [46].

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Lithium-ion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital cost per cycle [¢/kWh]</td>
<td>15-100 [34][36]</td>
</tr>
<tr>
<td>Fixed O&amp;M cost [€/kW/yr]</td>
<td>6.9 [76]</td>
</tr>
<tr>
<td>Variable O&amp;M cost [€/MWh]</td>
<td>2.1 [76]</td>
</tr>
</tbody>
</table>
4.3 Inverter

Inverters are used to convert DC loads into an AC, or vice versa, in order to connect two electrical components with different electrical current flows in their respective circuit. Inverters are commonly used between grid-connected PV systems, that generate with DC, and the utility grid or other commercial appliances that use standard AC [77]. These inverters are called grid-tied inverters and are classified into four different topologies, central inverters, string inverters, multi-string inverters and micro inverters [78] and can be seen in Figure 10.

![Figure 10. System configuration of different inverter topologies; (a) Central inverter, (b) String inverter, (c) Multi-string inverter, (d) Micro inverter. Source: [78]](image)

The inverter includes a Maximum Power Point Tracking (MPPT) control which is used to increase the efficiency and maximize the power output of the PV module or array [79]. By changing the current or voltage of the system, the power output will remain at the maximum power output point when solar radiation fluctuates [80]. Figure 11 illustrates a typical MPPT graph where MPP indicates the Maximum Power Point and I_M and V_M indicates the current and voltage respectively where the maximum power output occurs. The type of grid-tied inverter used in a system is based on system configuration and the size of the load converted between AC/DC.

![Figure 11. Maximum Power Point Tracking graph with solar power output curve, and current and voltage curve of the module [81].](image)

The inverters mentioned above are used for PV systems where the power is only converted from DC to AC. However, in a BESS, the power must be able to be converted from the grid to the battery (AC to DC) during charging as well as from battery back to an AC source (DC to AC).
4.4 Electrical Vehicle (EV)

The EV market is expected to grow [82] [83] and it is important that the development of the infrastructure improves in the same rate to ensure availability and reliability. However, the increased penetration of EVs could cause problems for the utilities and the grid in the future as the grid peak load will increase, and the need for development of generation and transmission capacity is required [84]. The extra electricity demand creates an increase in the demand profile during peak hours and amplifies the fluctuation of the load, where the size and length of the amplitude is dependent on driven distance, battery size and charging rate [85][84]. A study about travelling habits of vehicle owners made in Stockholm [86] shows that the last trip home peak occurs between 17:00 and 19:00 which will create large demand peaks if all EVs are plugged-in for charging upon arrival.

A solution to this problem is to control the charging of the EVs meaning the start of the charging will be determined and controlled by an intelligent EV-charging management system (CMS), and not started as the EVs are connected upon arrival. This will eliminate the uncontrolled and random charging pattern of the EVs that could lead to distribution losses, reduction in power quality and voltage deviation [87] [88][89] due to phantom loading, voltage imbalance, harmonic currents and DC offset.

System instability can also occur due to overloading which will shorten the lifetime of the transformers and power lines [89] [90]. Several studies show that controlled charging compared to uncontrolled charging has a significant impact in reduction of demand peaks on a demand profile [91][92][93][94], which can be seen in Figure 12. The figure illustrates the difference in controlled and uncontrolled, and how controlled charging can decrease the daily consumption peak. The electricity consumption of a normalised household can decrease the consumption peak by controlling the charging of the EV where a charging upon arrival at the evening is replaced by charging during night time.

![Figure 12. Illustration of uncontrolled and controlled charging on a household electricity consumption [95].](image)

Smart charging, which indicates scheduled and controlled EV charging, can be based on various parameters such as electricity price, load curve, SoC of the EV, etc. The smart charging is managed by an EV-CMS which will take into consideration the parameters in order to lower the charging related cost and to level the load curve [96]. Input data to create a smart charging schedule can be; battery capacity of the EV, minimum battery capacity for daily driving, charger type and power, the hourly high and lows of the electricity price, and the high and lows of the energy demand of the distribution network.

As the EVs use battery technology to power the vehicle, they can have the same application for the grid as the BESS when it comes to integrating the intermittent energy sources [97]. The stress to the grid caused by charging could be reduced by charging the EV with small-scale wind and solar power, with solar more viable.
due to small-scale wind turbines being more location sensitive, and often are not economic feasible in urban areas [98][99][100][101].

A new technology and application of the plug-in EV called vehicle-to-grid (V2G) and vehicle-to-home (V2H) is emerging where the EVs are used as a mobile external energy storage that can supply the grid or the households with electricity [102][103]. In order for this technology to be applied, a bi-directional power converter that allows the electricity to flow back and from the EV to the household or grid is needed [103]. The technology is not fully commercialised today, however, these systems began to be implemented in Japan in 2011 since the Fukushima accident to secure the power supply to the grid in case of another disaster [104][105]. The V2H and V2G technology have a potential to play an important role in the development of the future smart-house/city implementation and Nissan is one of the few car companies to implement this technology into a car, the Nissan LEAF [106][107][108][109]. The V2G and V2H can help with peak shaving, frequency regulation, voltage control, ancillary services, etc. which can increase the power quality and system stability of the distribution grid [110][111][112][113][114]. Figure 13 illustrates how the EVs can help with peak shaving where the EVs discharge during peak hours and charge during off-peak hours.

![Figure 13. Electricity energy demand with and without EV peak shaving [115].](image)

One of the problems with the V2G and V2H application is the accelerated degradation of the battery. The degradation of the battery in the EV will increase as the EVs are used for more than just driving which will decrease the lifetime of the battery. The additional degradation of the battery is one of the more important aspects to take into consideration in the V2G and V2H application [102][116]. The EV reaches the end of life (EOL) limit when the battery capacity reaches between 70 % - 80 % of the initial capacity due to degradation. However, some studies show that the EOL limit could, instead of being a set value, be whenever the battery capacity of the EV can no longer meet the daily travel needed [117][118][119].

### 4.5 Electricity Market Structure

The Swedish electricity market is part of the larger electricity exchange market called Nord Pool Spot was established in 1996 and is owned by the TSOs of Sweden, Norway, Finland and Denmark. All the countries in the Nordic electricity exchange market have deregulated their electricity market in order to create a market which opens competition of electricity production and trading of electricity as a commodity between the producers and retailers, but also between neighbouring countries. The deregulation of the electricity market also improves the exploitation of electricity resources and congestion management process, as well as yield benefits from the enhanced operation efficiency in the networks[120][121][122].

The graphical layout of the exchange market is presented in Figure 14 and shows that Sweden is divided into four electricity areas, SE1 to SE4, while Norway, Denmark and Finland are divided in to five, two and one area(s) respectively.
4.5.1 Key players
The Nordic electricity market has several similarities to a retail-/wholesale market with producers, retailers and end-users, however, the trading platform of Nord Pool Spot becomes more complex as it includes more key players than in a regular retail-/wholesale market. The commercial key players in the electricity market are [120][123]:

- producer: generate and produces the electricity
- broker: intermediary between two electricity trading parties, similar to a realtor. Do not own any electricity,
- trader: buys electricity from one party, and sell to another
- retailer: buys electricity in large and sells it to their customers, the end-user
- end-user: consumer of the final electricity

According to the website Elskling.se [124], there are more than 134 retailers in Sweden which give customers a wide variety of companies to choose from which, as a large benefit for the customers, increases the market competition and drives the price down.

4.5.2 Nord Pool Spot Electricity Trading
The trading of electricity can take place in two different market places at Nord Pool Spot, the day-ahead market called Elspot, or the intraday market called Elbas [125]. The day-ahead market is the core market place for electricity traders where the buyer of electricity estimates how much electricity they will need for every hour for their customers and set a price they are willing to pay for the electricity hour by hour. At the same time, the producer assesses how much electricity they are able to produce for each hour and at what price. When the deadline for bids have past, the price for the electricity is decided based on where the demand and supply price is met, which can be seen in Figure 15, for all the 24 hour of the next day [126].
Figure 15. Day-ahead supply and demand price graph [126].

The intraday market is used as a supplement to the day-ahead market as most of the electricity is traded in the same day, up until one hour before the hour of consumption. It is made to create a balance between production and consumption whenever the outcome of consumption or production from one of the parties in the day-ahead trading has not gone as planned. It can happen that a producer’s plant is experiencing an unexpected failure or increase in production and electricity can be traded near real time in order to restore the balance in the system [127].

4.5.3 Transmission System Operator, TSO, and Distribution System Operator, DSO
The TSO is the non-commercial player that is the owner and is responsible for management and operation of the high and very high-voltage grid, where in Sweden the TSO is called Svenska kraftnät (SvK). SvK is responsible for the electrical supply of the Sweden, and the maintenance of the power lines between the producers and the high to medium voltage lines. SvK is also responsible to balance the frequency of the power grid and keep it at 50 Hz which is made by making sure that production does not exceed consumption or the other way around. This balancing service is called up or down regulation and performed by large-scale electricity producers or users, also known as balancing responsible partners (BRP) [128][129].

The medium and low-voltage distribution grid is located between the high-voltage grid and the end-users, and is managed and controlled by the DSO. The DSO is responsible for maintenance of the power lines, for distribution of electricity from the higher voltage power lines to the end users, but also to gather and distribute data to all the other players the market. There are more than 160 different DSOs in Sweden where each DSO owns a part of the power grid which creates a natural monopoly where end-users cannot change DSO as there in no other to change to. The DSO charges the end-users a grid fee for providing the transmissions lines to the end-user where the grid fee is used for maintenance and upgrade of the grid and vary depending on where the end-user is located geographically as the DSO decides the price [128][129].

4.5.4 Electricity Price
The customers of the retailers can have different types of electricity subscription such as, fixed price, varying price, mixed price and hourly where the price differ from type and retailer. The retailers offer the customer a fixed price every month in order to secure the customer from increased prices, a varied price with a different fixed price every month that follows the increases and decreases of the market. The mixed price represents the best sides of fixed and varied price together while the hourly price adjust according to the Nord Pool Spot price hourly [130].

The mandatory grid fee paid to the DSO every month is based on amount electricity transferred and the geographical location of the end-user, but also on what kind of electricity transfer contract the end-user has with the DSO. Residential buildings can either have a fuse subscription which is based on fuse box size
installed in the building, or a power transfer contract which is based on maximum consumption peaks of the building [131].

The price is broken-down into different parts and illustrated in Figure 16 where it can be seen that the end-users’ electricity price consists of the NP-spot price, energy tax, the renewable energy certificates (RECs) which is described in detail in next chapter, a consumption fee to SvK and a retailer marginal which varies from subscription contract and retailer. The end users also have to pay VAT on 25 % of the aggregated electricity price, however, companies do not have to pay VAT on the energy tax. [132][133][134]

![Fees for Transferred Electricity](image)

*Figure 16. The included fees for transferred electricity*

### 4.6 Subsidies and Incentives

In order to increase the renewable share and decrease the dependency of the conventional power grid, Sweden has introduced several actions that includes economic support and tax reduction to make PV systems and energy storage system more affordable and more economical viable for both private persons and registered companies.

#### 4.6.1 PV Systems

The government of Sweden hands out economic support for PV system in where private persons and companies will be able receive support for 20 % and 30 % respectively of the total investment cost. The support is based in the total installation cost of the grid connected system, where the maximum support for a system amounts to 1.2 million SEK and maximum 37 000 SEK/kWp including VAT [135] [136].

A tax reduction for selling surplus electricity is given for producers that sells and feeds in solar electricity into the conventional power grid. The producer receives a tax reduction of 0.60 SEK per kWh sold electricity if the amount of sold electricity exceeds the consumed, with a maximum annual amount of 18 000 SEK which corresponds to maximum 30 000 kWh sold electricity. No VAT is paid for the sold electricity as long the sold electricity does not exceed 30 000 SEK, then the producers are obligated to pay a VAT of 25 % of the selling price. As sold electricity is considered as an income, the producers have to pay income tax for the sold electricity, however, the producers are allowed to sell electricity for 40 000 SEK per building and system annually without paying income tax [137][138].

All PV solar systems that exceed an installed power of 255 kWp (or 18 000 m² of solar panels) are obligated to pay a 32.5 öre/kWh energy tax on all the produced electricity. If a system is smaller than 255 kWp, and the owner does not own any other systems, no energy tax is paid. A new legislation that went into action the 1st of July 2017 says that a producer that owns multiple systems, each smaller than 255 kWp, but with an
aggregated power of 255 kWp or more, do not have to pay full energy tax for the produced electricity but instead pays a reduced tax of 0.5 öre/kWh produced [139][140].

A way for producers to gain income is to sell Renewable Energy Certificates (REC) that is handed out by the government to electricity producers with renewable energy sources such as solar, wind, hydro etc. The producers receive an electronic REC for every MWh of electricity produced and can sell the REC at to open market. The buyers, who are retailers or in some cases electricity users, are subject to quotas and therefore are required to possess a certain number of RECs relative to their sold or consumed electricity in order to see how much renewable electricity that was sold or consumed, compared to non-renewable electricity. The average price for a REC in 2016 was 158 SEK/MWh or 0.158 SEK/kWh. The retailer then adds the cost of the RECs to the customers’ electricity bill, which means that all the end users in Sweden help with paying for the expansion of renewable electricity [141][142][143].

4.6.2 Battery Subsidies
Sweden hands out a support for energy storage system as of 2016 and in order to be able to receive the support, the storage system must; be connected to a source that produces renewable electricity, be grid connected, contribute to load, and the storage system must lead to an increased annual usage of electricity from a renewable source. The support is given for a maximum 60 % of the total investment cost up to 50 000 SEK. However, this support is only given to private persons which means that companies, including housing companies, are not allowed to apply for the support [144][145].

4.7 Previously done studies on the topic
There have been multiple studies conducted of a system configuration consisting of PVs and BESS, both theoretical and real-life studies, however, studies also including EVs and V2H/V2G are relatively limited, especially real-life studies. The studies presented below shows V2H impact, optimal sizing of PV systems and BESSs, charging control strategies, etc.

A study made by Alirezai et al. [114], which includes all relevant components, investigates the V2H technology performance in fulfilling the energy demand of an energy efficient building together with a PV system and a stationary BESS in order to satisfy the requirements of a net zero energy building. The study includes a modelled building is a single-family house in Orlando, US where a PV system generates electricity to power the house and excess electricity is stored during off-peak hours in the EV, when connected, and in the BESS and later used in during peak hours. The results from the study shows that the EV and V2H together with PV and BESS where able to reduce the electricity consumption to a degree where the electricity demand from the grid is reduced to zero for certain months of the year. The system not only result in a monetary reduction of the electricity related costs, but also results in a revenue to recoup the installation cost of the system.

A study made by Ozan Erdinc [146] investigates the economic impacts of a PV system, BESS, EVs with V2H and a home energy management system, which control all home appliances based on electricity price, under different operation strategies. The system component sizes and the operation strategies are design to decrease the daily electricity cost in order to reduce the electricity bill. Five different operation strategies are used in the case study where different use and sizes of PV, BESS and home energy management system are applied and V2H is available in all the cases. The results from the case study show that all cases but one, where no BESS and no home energy management system where used, decreased the daily electricity costs.

The study made by Zhang el al. [147] model a grid-connected PV-battery system in a case study on a typical residential building in Sweden where an optimal BESS size is defined with consideration of three different rule-based operation strategies; a conventional operation strategy, a dynamic price load shifting strategy and a hybrid operation strategy. The strategies are designed to maximize the systems Self Sufficiency Ratio (SSR) and the Net Present Value, and consist of parameters such as battery capacity, electricity price, PV size, etc. The results of the case study show that a conventional operation strategy, nor the dynamic price load shifting strategy of the PV-battery system, is not economic viable, but increase the SSR. Both the strategies result in a similar performance due to the difference of the highs and lows of the electricity price is too small. The
hybrid operation strategy however shows positive economic results where the NPV and SSR increases together, up until a certain battery size where there is a trade-off between NPV and SSR.

A case study made by Dufo-López [148] investigates the optimal sizing and control strategy of a privately-owned BESS based on different time sensitive electricity pricing in the Spanish electricity market, in order to reduce the electricity bill. The model in the techno-economic analysis is performed to find the optimal storage size with a charge/discharge strategy under a real-time pricing, in order to minimize the net present cost of the system. The case study considers the hourly electricity prices of Spain in 2013 and near future cycle cost of batteries, and they conclude that a system will not be economic viable in the Spanish electric market in order to recoup the capital cost plus the O&M and replacement costs. The results indicate that the cycle cost of the battery have to be much lower, or the difference of high and low electric prices must be significantly larger in order for the system to be profitable.

Other interesting studies related to the subject of this study:

- Cost-benefit analysis of the impact of V2H from light plug-in EVs for the Canary Islands, Spain where V2H is used for load levelling and peak shaving with consideration of hourly variation of the electricity price [149].
- Model-based study which investigates the use of a BESS in order to maximize the self-consumption and self-sufficiency of a PV system for several single-family house in Sweden where the multiple combination of different PV and BESS sizes are tested [150].
- Techno-economic analysis which develops a model in order to optimize the self-consumption and self-sufficiency of a PV-battery system for commercial use in Germany for current use and future use [151].
- Study investigates the integration and use of EVs and V2H/G and contributes with a conceptional framework of different applications the EVs can provide from an industry point of view and analyse the benefits, the hurdles and opportunities of the EVs in the energy sector [152].
5 Modelling Approach

This section contains the model description. The first parts describe the system configuration and the model methodology, first the overall methodology and later the methodology for all sub-models. After that follows an in-detail description of the different models and their strategies and finally all the model inputs that have been used in the study is presented.

5.1 System Configuration

The system configuration can be described as the PV is connected via a string inverter to the facility load, the battery, the EVs and the grid. The electricity produced from the PV can go directly to the facility load and the grid since it is converted into AC through the string inverter and since the grid is outside the system boundaries and only is considered as the electricity is being sold to it. However, the electricity that goes to the battery has to be converted through a bi-directional inverter since the battery store the electricity in DC and the electricity needs to be able to go both directions. The same thing applies to the EVs and that is why the electricity needs to go through the charging station first. The overall physical structure of the model is presented in Figure 17 below.

![Figure 17. Possible system configuration consisting of PV System, BESS and EV with V2H application](image)

5.2 Model Descriptions

The overall model methodology starts with a set of PV data inputs that is sent to the PV model. The PV model handles the input data and gives out an electricity production curve that is used to reduce the facility load profile and create a new facility load after the PV. That new facility load is sent to the BESS model along with a set of BESS data inputs. The BESS model handles the inputs and gives a new facility load after the BESS model. That new facility load is sent to the EV model along with a set of EV data inputs. The EV model handles the inputs and gives a new facility curve after the EV model. That new facility load, that is the last facility load, is sent to the price and cost model along with a set of price and cost data inputs and also the original facility load profile. The output of the price and cost model is the total NPV for the entire system for one year. This is repeated for 25 years and the NPV after 25 years is saved. All which have been described so far is for one size of PV and battery, one number of EV for one EV availability curve. How the different models handle the input data is described in more detail in the four following sub-sections.

When the first NPV has been saved the number of EVs is changed and the model restarts and saves a new NPV for the new number of EVs, but still with same PV and battery size and with the same EV availability curve. This is repeated until all number of EVs have been tested and the model then continues to repeat the same procedure for all battery and PV sizes. When all sizes have been tested, plots can be created to show the result of the NPV after 25 years for all different combination of sizes with a constant EV availability
curve. After that the EV availability curved is changed and the process is repeated until all EV availability curves have been tested and then the model ends. The line showing that the EV availability curve changes is only blue to be able to differentiate it from the other lines. Results have to be plotted for each number of EVs and with one availability curve at a time is because two parameters need to be fixed in order to be able to show the results for the four different parameters. All which have been described is shown in Figure 18 below.

Figure 18. Overall Model Description.
The different sizes, number of EVs and EV availability curves that have been used in the model is shown in Table 4 below.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>PV system sizes [kWp]</td>
<td>28</td>
</tr>
<tr>
<td></td>
<td>56</td>
</tr>
<tr>
<td></td>
<td>112</td>
</tr>
<tr>
<td></td>
<td>168</td>
</tr>
<tr>
<td>Battery sizes [kWh]</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>25</td>
</tr>
<tr>
<td></td>
<td>50</td>
</tr>
<tr>
<td></td>
<td>75</td>
</tr>
<tr>
<td></td>
<td>100</td>
</tr>
<tr>
<td>Number of EVs [-]</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>8</td>
</tr>
<tr>
<td>EV availability curves [% of EVs available at mid-day]</td>
<td>0</td>
</tr>
</tbody>
</table>

More about the EV availability curves is described in section 5.6.6.

5.2.1 PV Model Description

The first sub-model of the main model is the PV model. It uses the PV data inputs to calculate the electricity production curve for one year by using the ASHRAE solar model. This is shown in Figure 19, PV Model below. For more information about the PV data inputs and ASHRAE solar model see section 5.6.3 and 5.5 respectively.

![PV Model Description Diagram](image)
5.2.2 BESS Model Description

The second sub-model of the main model is the BESS model. It uses the BESS data inputs and the facility load after being reduced by the PV as inputs in all the different steps in the model. The first step of the model is a perfect prediction model that uses the inputs to decide the monthly peaks that should be lowered and at which hours there will be surplus. This information is sent to the BESS control and charging model which then is able to simulate the battery behaviour for one year and calculate the SOC for the battery every hour that year. That information is then sent to the BESS degradation model which, with help of the SOC and the other inputs, calculates the degradation for the battery with hourly resolution. The same BESS degradation model is than used once more, but this time with the calculated degradation, to be able to simulate the behaviour of the battery as it is being degraded at the same time. Before finishing the model, it is tested if the total battery degradation exceeds 20%. If it does, the battery will be replaced with a new battery without any degradation the next year when the BESS model is used. Lastly the BESS Model creates a new facility load after the BESS Model which it sends out as output from the model. This is all shown in Figure 20 below.

Figure 20. BESS Model Description.
5.2.3 EV Model Description

The third sub-model of the main model is the EV model. No deeper explanation will be given of the model methodology since it is almost identical to the BESS model methodology. The only differences are that it uses different data inputs and the facility load after the BESS as input, along with that is uses 25% as the limit for degradation to decide whether the EV battery should be replaced or not. It also creates a different facility load after the EV model as output as can be seen in Figure 21 below.

![EV Model Description Diagram](image)

Figure 21. EV Model Description.
5.2.4 Price and Cost Model Description

The final sub-model of the main model is the price and cost model. As can be seen in Figure 22 below it uses a lot of different price and cost data inputs along with the original facility load and the facility load after the EV model as inputs. It then calculates the investment cost, the revenue, the OM cost and replacement cost for one year before calculating the NPV for that year and give that as an output.

More information about the price and cost data inputs can be seen in section 5.6.7.

As can be seen in, after all the sub models have calculated the new facility loads and sent their costs and specifications, the NPV can be calculated for that year. The NPV is calculated by

\[
NPV = -C_{\text{invest tot}} + \sum_{y} \frac{\text{Revenue}_{y} - C_{\text{OM tot } y} - C_{\text{replace tot } y}}{(1+i)^y}
\]  

(1)

Where \(C_{\text{invest tot}}\) is the total investment cost, \(\text{Revenue}_{y}\) is the revenue of the year \(y\), \(C_{\text{OM tot } y}\) is the total OM cost of the year \(y\), \(C_{\text{replace tot } y}\) is the total replacement cost of the year \(y\) and \(i\) is the discount rate set as 4%. All the parameters in the equation to calculate the NPV is calculated according to the following equations.

\[
C_{\text{invest tot}} = C_{\text{invest PV}} + C_{\text{invest BESS}} + C_{\text{invest EV charging station}}
\]  

(2)

Where \(C_{\text{invest PV}}\) is the investment cost for the PV system, \(C_{\text{invest BESS}}\) is the investment cost for the BESS and \(C_{\text{invest EV charging station}}\) is the investment cost for the EV systems charging stations. The reason why only the EV system’s charging stations are taken into account in the cost calculations is since the costs are calculated as if they were made by ÖBO and the EVs themselves are assumed to be owned and paid by the tenants.

\[
\text{Revenue} = C_{\text{el before}} - C_{\text{el after}}
\]  

(3)
Where \( C_{\text{defter}} \) is the electricity cost for the multi-dwelling units before, without any system installed and \( C_{\text{defter}} \) is the electricity cost for the multi-dwelling units after the systems have been installed. Apart from the decreased electricity cost due to lower electricity consumption, \( C_{\text{defter}} \) also takes into account RECs and grid benefit reimbursement if PV generated electricity surplus is sold to the grid.

\[
C_{\text{OM, tot}} = C_{\text{OM, PV}} + C_{\text{OM, LCOE, BESS}} + C_{\text{OM, EV, charging station}}
\]

(4)

Where \( C_{\text{OM, PV}} \) is the OM costs for the PV system, \( C_{\text{OM, LCOE, BESS}} \) is the OM costs for the battery system and \( C_{\text{OM, EV, charging station}} \) is the OM costs for the EV system’s charging stations.

\[
C_{\text{replace, tot}} = C_{\text{replace, PV}} + C_{\text{replace, BESS}} + C_{\text{replace, EV, charging station}}
\]

(5)

Where \( C_{\text{replace, PV}} \) is the replacement cost for the PV system, \( C_{\text{replace, BESS}} \) is the replacement cost for the battery system and \( C_{\text{replace, EV, charging station}} \) is the replacement cost for the EV system’s charging station. Note that these costs only come in place for when the end of the lifetime for some of the component is reached, the rest of the times these costs are set to zero. More details and the separate cost for all the different components are presented in section 5.6.8.

5.3 Control and Charging Strategy Models

The case study focuses on maximizing the NPV value after 25 years, in order to do this, the costs need to be as low as possible while having as large as possible revenue. The costs are mostly dependent on the sizes of the PV system and battery and number of EVs, but also on the usage of the stationary battery and the EV battery, since a higher usage leads to higher degradation and therefore higher replacement costs. The revenue is mostly depending on how much the electricity bill can be lowered, which is directly correlated to how much the electricity consumption can be lowered and how much of the solar surplus that is being taken care of by the storage assets. Therefore, a strategy which can lower the electricity bills as much possible, absorb as much solar surplus as possible, while using the battery and EV as little as possible is obtained.

The control and charging strategy in the case study focuses on peak shaving, rather than load shifting, as using the electricity from the battery during high Nord Pool spot price and charge during low price will not provide a significant monetary advantage. The electricity price is relatively similar throughout the hours of the day with occasional price peaks some hours of the year which leads to load shifting, due to price of electricity, will not result in significant profit spread out over a year when the cycle cost of the battery also included. Therefore, this model is focused on decreasing the consumption peaks of the facility. With this charge and discharge method, the battery will not be discharged and charged every day which could lead to a longer battery life. The battery charge and discharge model is also designed to increase the self-consumption of solar power \([153][148]\).

5.3.1 Perfect Prediction Model and Priority Order

To be able to perform the control and charging strategy a perfect prediction model is designed to find the facility consumption peaks of each month in order to reduce the electricity related cost, but also to find if surplus is available at any given time of the year, and if so, at which hours it occurs.

The surplus availability and the occurrence is found by subtraction of each hourly facility consumption with corresponding hourly PV production where a higher PV power compared to the facility consumption results in a surplus as the surplus power is calculated as

\[
P_{\text{surplus}}(h_i) = P_{\text{facility}}(h_i) - P_{\text{PV}}(h_i),
\]

(6)

where \( P_{\text{PV}}(h) \) is the hourly PV power. The ability to know the amount of surplus and occurrence of it allow the model to forecast and plan the available battery capacity of the BESS and the EVs in order to absorb as much as surplus for later use and increase the PV self-consumption of the facility. The PV model and structure is described in detailed later in the study.
To be able to reduce the consumption peaks, the model uses the output facility load data from the PV model where all the hourly consumption power, $P_{\text{facility}}(h)$, of the year is divided into the month the hours belong to and locate the maximum consumption peak of each month which is denoted as $P_{\text{facility, max}}(month)$. The maximum consumption peak of each month is measured and reduced with the maximum discharge power, $P_{\text{discharge,max,BESS}}$, to a new maximum consumption peak denoted as $P_{\text{facility,new, max}}(month)$, where $P_{\text{facility,new, max}}(month)$ is given by

$$P_{\text{facility,new, max}}(month) = P_{\text{facility, max}}(month) - P_{\text{discharge,max,BESS}} \quad (7)$$

The new value is used as an input into the BESS charge/discharge strategy and/or EV charge/discharge strategy which reduces all consumption power peaks to that are higher than $P_{\text{facility, max}}(month)$ and creates a new facility load profile with a lower facility consumption. The new load profile is run through the perfect prediction model once again in order to find the new consumption peaks that is used into the EV charge/discharge strategy. A small but significant difference in the model for the EVs is that the discharge power of the EVs is dependent on the availability of EVs connected to the facility at the occurrence of the maximum consumption peak for each month. The BESS charge/discharge strategy, the availability and discharge power of the EVs is described in depth in the following sections.

The electricity priority order of the facility is illustrated in Figure 23 which describes the electricity flow of all components in the system. As can be seen in the figure, all the PV production is always directly used by the facility to lower the electricity consumption. If the PV production exceeds the facility consumption, the surplus electricity will be directed and begin to charge the BESS until the battery is fully charged. If surplus is still available after the battery has been fully charged or $P_{\text{PV}}(h)$ exceeds the maximum charging power of the BESS, $P_{\text{charge,max,BESS}}$, the remaining part of the PV production will charge the EVs until they are fully charged. When the BESS and the EVs are charged to maximum or the PV generation of electricity exceeds the maximum charging power of both the BESS and EV, the excess electricity will be sold to the grid and the retailer of ÖBO.

As the scheme below shows, the electricity produced by the PV that exceeds the facility consumption is prioritized by the battery first, later EVs and lastly sold to the grid. This order of prioritizing is decided since the battery is a certain source that will always be in place, which the EVs are not, so to handle uncertainties in the behaviour of the EV drivers it is prioritized in this way. It is also prioritized in this way since the EVs themselves will be owned by the tenants and not by ÖBO and therefore the EVs are charged last.
Figure 23. Prioritising scheme of PV-generated electricity.
5.3.2 BESS Control and Charging Model

The charging and discharging scheme of the battery used in this case study is designed to reduce the peak power consumption in every month in order to decrease the electricity bill, as the part of the bill that can be affected is based on the highest amount of electricity transferred during one hour. The charge and discharge scheme is illustrated in Figure 24 and used in the same way for the BESS whether the whole system includes a PV system and EVs, only a PV system, only EVs or none of them. The scheme is also designed to increase self-consumption of solar electricity when a PV system and surplus is available. The algorithm uses the maximum facility power consumption for each month derived from the perfect prediction model as an input to the scheme, together with the facility load profile after the PV production, in order to compare \( P_{\text{facility}}(h) \) with \( P_{\text{facility,new,\text{max}}}(\text{month}) \) and reduce the consumption if needed.

As the monthly part of the electricity bill which can be affected is based on the highest mean consumption during one hour, every hourly consumption of the month is passed through the scheme in Figure 24 and compared to \( P_{\text{facility,new,\text{max}}}(\text{month}) \). The battery charging and discharging scheme will not only take into consideration the maximum consumption peak, but also forecasting of surplus produced by the PV system in day, \( d \), or the next coming day, \( d+1 \).

If \( P_{\text{facility}}(h) \) is larger than \( P_{\text{facility,new,\text{max}}}(\text{month}) \), the battery will discharge with \( P_{\text{BESS,\text{discharge}}} \) until

\[
P_{\text{facility}}(h) = P_{\text{facility,new,\text{max}}}(\text{month})
\]

is given. As there is no monetary gain to decrease the load under \( P_{\text{facility,new,\text{max}}}(\text{month}) \), all consumption peaks higher than \( P_{\text{facility,new,\text{max}}}(\text{month}) \) will be decreased to this value, and in this way the DoD for each cycle is reduced, the C-rate of the battery lowered and capacity for later use. This will lead to a reduced stress on the battery, but also make it possible for the battery to decrease more than four consumption peaks for one day, if that were to occur.

If \( P_{\text{facility}}(h) \) is lower than \( P_{\text{facility,new,\text{max}}}(\text{month}) \) and there is no surplus during day \( d \), or next day, \( d+1 \), the battery will be charged normally with \( P_{\text{charge,BESS}} \) between 00-06 and 22-00. However, if it were to be any aggregated surplus in \( d+1 \) and no surplus on day \( d \), the battery will be either charged or discharge in the night between 22:00-00:00, to the level where the available capacity in the battery combined with the surplus \( P_{\text{surplus}}(d+1) \) the coming day will fill up the battery to \( SoC_{\text{max,BESS}} \). In this way, the battery is able to take fully use of the surplus and have a fully charged battery for the coming day.

When there is a surplus in day \( d \), the battery will charge or discharge between 00-06 in the same way as described before in order to fully use of the surplus. If the momentary surplus \( P_{\text{surplus}}(h) \) between 06 and 22 would to exceed \( P_{\text{charge,max,BESS}} \), the battery will be charged with the highest charging power and the remaining surplus power, \( P_{\text{surplus,new}}(h) \), will be either charging the EVs or sold to the grid. However, if the surplus power is lower than the maximum charging power, \( P_{\text{charge,max,BESS}} \), the charge power of the battery will be equal to \( P_{\text{surplus}}(h) \). After charging with the surplus power and there is surplus in the next day \( d+1 \), the battery will either charge or discharge between 22-00, depending on the available capacity, to make room for the surplus the next coming day as described previously.
Figure 24. BESS charge and discharge scheme.
State of Charge Estimation BESS

The SoC level of the BESS is estimated for each time step where the initial SoC of the LIB is given by

$$SoC_{BESS}(t) = \frac{\text{available battery capacity}(t)}{\text{maximum initial battery capacity}}$$  \hspace{1cm} (9)

and is a measurement of how many percent of the maximum initial battery capacity is available at time \(t\). Estimation of the SoC at time \(t\) uses the previous state of charge of the battery at time \(t-1\) with the added SoC which the battery gains with the charge/discharge power during the elapsed time \(t\) and is given by

$$SoC_{BESS}(t+1) = \begin{cases} 
SoC_{BESS}(t) + \frac{P_{\text{charge BESS}} \cdot t}{\text{maximum initial battery capacity}} & \text{during charge} \\
SoC_{BESS}(t) - \frac{P_{\text{discharge BESS}} \cdot t}{\text{maximum initial battery capacity}} & \text{during discharge}
\end{cases}$$  \hspace{1cm} (10)

Charge and Discharge Power BESS

During solar surplus/facility consumption peaks, the BESS is charged/discharged with a higher power than during discharging or charging at night time as mentioned above. \(P_{\text{discharge max BESS}}\) and \(P_{\text{charge max BESS}}\) is decided by the minimum number of hours a full charge or discharge cycle should require. The higher charge power enables the BESS to reduce four peaks during one day with the maximum reduction, but also to increase the amount of surplus the system can receive during one hour. In this case study the BESS should be able to charge/discharge the maximum usable battery capacity between the SoC limits in four hours. Figure 25 illustrates how the hours of capacity of the battery is divided.

The maximum charge power \(P_{\text{charge max BESS}}\) and \(P_{\text{discharge max BESS}}\) is given by

$$P_{\text{charge max BESS}} = P_{\text{discharge max BESS}} = \frac{\text{maximum usable capacity}}{\text{minimum charge/discharge length}}$$  \hspace{1cm} (11)

and will vary depending on the size of the battery. A lower charge/discharge power is used between the hours of 22:00-00:00 where a full charge or discharge cycle will take eight hours in order to reduce the risk of creating consumption peaks during charging and gain a more levelled load profile during discharge. Another reason for a lower power during night time is because lower power decreases the temperature of
the battery during charging/discharging, and a decreased temperature reduced the degradation rate of the battery [154]. The lower charge/discharged power is given by

\[ P_{\text{charge,BESS}} = P_{\text{discharge,BESS}} = \frac{\text{maximum usable capacity}}{\text{charge/discharge length}}. \]  

(12)

The charge and discharge rate of the BESS is also called the C-rate [155], where C-rate is defined as the elapsed time for a full charge or discharge of the battery, meaning a battery with a C-rate of 1 C will fully charge/discharge the battery capacity in one hour [156]. The C-rate is dependent on the charge/discharge power where the high and low rate, \( C_{\text{rate,max,BESS}} \) and \( C_{\text{rate,BESS}} \), is given by

\[ C_{\text{rate,max,BESS}} = \frac{P_{\text{charge,max,BESS}}}{\text{maximal initial battery capacity}} \]  

(13)

and

\[ C_{\text{rate,BESS}} = \frac{P_{\text{charge,BESS}}}{\text{maximal initial battery capacity}} \]  

(14)

As the power from and to the battery are same during charge or discharge on the DC side of the inverter, whether it is the higher or lower C-rate, the load the facility consumption will be affected by will vary as the electricity passed through the inverter of the BESS. The load the facility will be affected by is therefore given by

\[ P_{\text{charge,load,BESS}} = \begin{cases} P_{\text{charge,BESS}} & \text{during charge} \\ \eta_{\text{inv}} P_{\text{discharge,BESS}} & \text{during discharge} \end{cases} \]  

(15)

where \( P_{\text{charge,load,BESS}} \) is the added power to the facility consumption during charging of the BESS and \( P_{\text{discharge,load,BESS}} \) is the power the facility consumption will be reduced by during discharge.

5.3.3 EV Control and Charging Model

The EV control and charging model in the case study is used similar to the BESS where the stored energy of the EVs are used to lower and reduce the power consumptions of the facility by using V2H during consumption peaks. The main difference between the EV as a battery resource and a stationary BESS is that the EV may not be available at all hours of the day as these are privately owned and is often not available during the day. The case study will test the effect different availabilities of EVs throughout the day will have on the facility consumption on an economic level. The EVs will be used in the same way in all cases whether the systems include a PV system and a BESS, one of them, or none of them.

The EV charging and discharge scheme, seen in Figure 26, uses the hourly facility consumption output after the PV and the BESS is used as an input into the EV scheme. The differences between the EV scheme and the BESS charge/discharge scheme is the change of availability and change of battery capacity of the vehicles as the EVs are not stationary and are more fluctuant, compared to the BESS.

The new monthly maximum consumption peak is calculated in the perfect prediction model and given by

\[ P_{\text{facility,new,max}}(\text{month}) = P_{\text{facility,max}}(\text{month}) - P_{\text{discharge,max,EV}}(h), \]  

(16)

where the maximum EV discharge power \( P_{\text{discharge,max,EV}}(h) \) is varying depending on the availability of the EVs and is given by the maximum discharge power of one EV multiplied with the number of EVs available at the hour of occurrence of \( P_{\text{facility,new,max}}(\text{month}) \).
Every hourly facility load $P_{\text{facility}}(h)$ is ran through the scheme, as for the battery scheme and compared to $P_{\text{facility,new, max}}(\text{month})$, whereas, if larger, is discharged with $P_{\text{discharge, EV}}$ until $P_{\text{facility,new}}(\text{month})$ is equal to $P_{\text{facility,new, max}}(\text{month})$.

During days where no aggregated solar surplus is available and no surplus is available the next coming day, the EVs will be charged between the hours of 00:00-06:00 and 22:00-00:00 until they are fully charged, unless the SoC of the EV is less than $SoC_{\text{drive, EV}}$. Then the EV will be charged instantaneous until $SoC_{\text{EV}}(t)$ is equal to $SoC_{\text{drive, EV}}$ is reached, no matter what hour of the day it is. $SoC_{\text{drive, EV}}$ is the minimum SoC required for the owners of the EV to be able to make the average daily travel, which is described in detail in section 5.6.6.

Days where equation where no surplus is available but surplus is available in the next coming day, the EV will be charged to $SoC_{\text{max, EV}}$ between hours 00:00-06:00 for the owners to be able to drive during the day and later charged or discharged between 22:00-00:00 in order to completely fit the next day’s PV surplus and reach a fully charged EV battery.

The EV will be charged or discharged between 00:00-06:00, on the days with surplus, in order to reach $SoC_{\text{max, EV}}$. During the hours of 06:00 and 22:00 when the PV surplus is available, the EV will be charged either with $P_{\text{charge, EV}}$ or $P_{\text{charge, max, EV}}$ depending on the rate of the surplus. If the surplus power from the PV is larger than the maximum charge rate of the EV, the EV will be charged with the maximum charging rate and the remaining electricity will be sold to the grid. If no surplus is available in the next coming day, the EV will be charged to $SoC_{\text{max, EV}}$, while if it were to be surplus the next day, the EV will be discharged in order to reach a fully charged battery with the capacity of the surplus.
Figure 26. EV charge and discharge scheme.
State of Charge Estimation EV

The SoC level estimation of the EVs are made in a similar way where $\text{SoC}_{\text{EV}}$, which is the SoC level of the EVs are determined by

$$\text{SoC}_{\text{EV}}(t) = \frac{\text{available battery capacity}(t)}{\text{maximum initial battery capacity}}$$

(17)

and is a measurement of how many percent of the maximum initial battery capacity is available at time $t$. In the same way as the BESS, the estimation of $\text{SoC}_{\text{EV}}$ at time $t+1$ uses the previous state of charge of the battery at time $t$ with the added SoC which the battery gains with the charge/discharge power during the elapsed time $t$ and is given by

$$\text{SoC}_{\text{EV}}(t+1) = \begin{cases} 
\text{SoC}_{\text{EV}}(t) + \frac{P_{\text{charge,EV}} \cdot t}{\text{maximum initial battery capacity}} & \text{during charge} \\
\text{SoC}_{\text{EV}}(t) - \frac{P_{\text{discharge,EV}} \cdot t}{\text{maximum initial battery capacity}} & \text{during discharge}
\end{cases}$$

(18)

Charge and Discharge Power EV

The charge/discharge powers of the EVs differs slightly to the BESS charge power and is dependent on the scenario of the EV. As mentioned before, during night time (22:00-00:00) and early morning (00:00-06:00) the EVs are either charged or discharged, depending on SoC and surplus availability, with the rated power of the charging stations and is denoted as $P_{\text{charge,EV}}$ and $P_{\text{discharge,EV}}$.

The charge power of the EVs during surplus is dependent on the available excess power from the PV system. As it is desired to store as much of the surplus electricity as possible in the available EVs, the charge power $P_{\text{charge,EV}}$ will be equal to the rate of the surplus $P_{\text{surplus}}(t)$, however, in order to avoid failure during charging, the maximum charge power, $P_{\text{charge,max,EV}}$, is decided by the maximum power rate allowed from the charging station, even if the surplus rate exceeds $P_{\text{charge,max,EV}}$.

During consumption peaks, the discharge power of the EVs is dependent on how much the EVs, with a specific availability, can lower the highest peak of the month to, and at the same time, not lowering the peak to a lower value than any other value of the month can be lowered to by the EVs. This means that when the EVs have a low availability the discharge power is low since only a small amount can be discharged without lowering the peaks to a lower value than any other peaks. And if the EVs have a high availability the discharge power is high since a lot of peaks can be lowered. In this way the optimal number of peaks will be lowered every month and the discharge power will vary between 0 and $P_{\text{discharge,max,EV}}$, where the maximum discharge power is decided by the charging station.

In the same way, as for the BESS, the regular charge/discharge power is lower than the maximum charging power and is used between the hours of 22:00-00:00 where a full charge/discharge cycle of the EVs will take eight hours. The maximum charge/discharge power is not used in order to reduce the risk of creating consumption peaks during charging, or creating valleys during discharge. The EV will also gain the benefits of a lower charge temperature as the BESS gains with a lower power, which reduces the degradation rate [154]. The charge/discharge power of the EVs during night time and early morning is given by

$$P_{\text{charge,EV}} = P_{\text{discharge,EV}} = \frac{\text{maximum usable capacity}}{\text{charge/discharge length}}$$

(19)
The C-rate and the maximum C-rate of the EVs \(C_{rate,EV} \) and \(C_{rate,max,EV} \) is dependent on the charge and discharge power, but also the maximal initial battery capacity of the EV, and is given by

\[
C_{rate,EV} = \frac{P_{charge,EV}}{\text{maximal initial battery capacity}}
\]

and

\[
C_{rate,max,EV} = \frac{P_{charge,max,EV}}{\text{maximal initial battery capacity}}
\]

The power of the EVs is measured at the DC side of the charging station where the power that is charged/discharge to/from the EVs, will differ from the power that the facility consumption will affected with as it passes through the inverter of the charging station. Therefore, the power that will either increase or decrease the facility consumption is given by

\[
P_{\text{charge,load,EV}} = \begin{cases} 
P_{\text{charge,EV}} & \text{during charge} \\
\eta_{inv} P_{\text{charge,EV}} & \text{during discharge}
\end{cases}
\]

where \(P_{\text{charge,load,EV}}\) is the added power to the facility consumption during charging of the BESS and \(P_{\text{discharge,load,EV}}\) is the power the facility consumption will be reduced by during discharge.

5.4 Degradation Models

This section describes the degradation models in more detail, which are used both in the BESS and EV model. The degradation model is used to estimate the lifetime of the LIBs in the BESS and in the Nissan Leaf. The model is taken from [157] which is used to estimate the capacity fading of a BESS with deterministic and stochastic power profiles similar to the power profile used in the case study. The degradation model is a revised and modified version of the degradation models used in [158] and [159] which originates from model used in [160].

5.4.1 BESS Degradation Model

The degradation model is for the LIB where the usable capacity of the battery is denoted as \(L\) in the model and is stated as a percentage of the original battery capacity. \(L\) is calculated as

\[
L = (1 - p_{SEI})e^{-t f_d} + p_{SEI}e^{-t r_{SEI} f_d}
\]

where \(p_{SEI}\) is solid electrolyte interface (SEI) formation portion coefficient and represents the portion of lithium that is consumed during early parts of the battery lifetime during SEI film formation at the start of cycling, \(r_{SEI}\) is the SEI formation rate ratio coefficient, \(t\) is the time duration of the degradation model and \(f_d\) is the linearized degradation function. The linearized degradation function which represent the effect of cycling and calendar aging which is assumed to be completely independent of each other. The cycling affects the degradation during usage of the battery while calendar aging affects the degradation when the battery is not in use. The linearized degradation function is given by

\[
f_d = f_{cyc}(SOC, DOD, T, C, n) + f_{cal}(SOC_{avg}, T_{avg}, t)
\]

where \(f_{cyc}\) represent the cycling aging effect on the model, \(f_{cal}\) represents the calendar aging effect, \(T\) is the temperature, \(C\) is the charging rate and \(n\) represent a full cycle \((n = 1)\) or a half cycle \((n = 1)\). In the calendar aging function, \(SOC_{avg}\) and \(T_{avg}\) represent the average state of charge and temperature of the battery as a function of time \(t\).
The cycling aging function is given by

$$ f_{\text{cyc}} = \sum_{i=1}^{N} f_{\text{DoD},i}(\text{DoD}_i) \cdot f_{\text{SoC},i}(\text{SoC}_i) \cdot f_{\text{C},i}(C_i) \cdot f_{\text{T},i}(T_i) \cdot n_i $$

(25)

where $f_{\text{DoD}}, f_{\text{SoC}}, f_{\text{C}}$ and $f_{\text{T}}$ are the stress function that is dependent on $\text{DoD}$, $\text{SoC}$, the charging rate $C$ and the temperature $T$. As seen from the equation above, the cycling aging effect is completely independent from the time elapsed. The $\text{DoD}$ stress function is calculated as

$$ f_{\text{DoD},i} = \frac{1}{k_1 \cdot \text{DoD}_i^2 + k_3} $$

(26)

where $\text{DoD}_i$ is the depth of discharge for each individual cycle and $k_1$, $k_2$ and $K_3$ are the $\text{DoD}$ stress model coefficients. $\text{DoD}_i$ is given by the cycle amplitude, which is described further down in the text, times two.

This degradation model indicates that the degradation rate of the battery increases with high $\text{SoC}$ levels during a cycle and the rate is decreased with lower $\text{SoC}$ levels. The $\text{SoC}$ stress function in this model is given by

$$ f_{\text{SoC},i} = e^{\left(\frac{\text{SoC}_i - \text{SoC}_{\text{ref}}}{k_{\text{SoC}}}\right) \frac{\text{SoC}_{\text{ref}}}{\text{SoC}_i}} $$

(27)

where $\text{SoC}_i$ is the average level of state of charge for the individual cycle, $\text{SoC}_{\text{ref}}$ is the reference level of $\text{SoC}$ and is set to 0.5 and $k_{\text{SoC}}$ is the $\text{SoC}$ stress function coefficient.

As mentioned before, the C-rate of the battery affects the degradation rate of the battery and the C-rate stress function is given by

$$ f_{\text{C},i} = e^{k_{\text{C}}(C_i - C_{\text{ref}})} $$

(28)

where $k_{\text{C}}$ is the C-rate model coefficient, $C_i$ is the C-rate of the battery during each individual cycle and $C_{\text{ref}}$ is the reference C-rate which is set as 1. The C-rate affecting the aging in the degradation model is not the same as the one charging or discharging the battery. In the degradation model, the C-rate $C_i$ is calculated as

$$ C_i = \frac{\text{DoD}_i \cdot 2n_i}{t_{\text{end}} - t_{\text{start}}} $$

(29)

where $t_{\text{start}}$ and $t_{\text{end}}$ is the occurrence of the cycle start and the cycle end respectively in respect to the time elapsed.

The operation temperature of each cycle affects the degradation rate and the temperature stress function is a result of Arrhenius equation which is commonly used for measuring the aging effect the temperature has [53][161][162]. The temperature stress function is calculated as

$$ f_{\text{T},i} = e^{k_{\text{T}}(T_i - T_{\text{ref}})} $$

(30)

where $k_{\text{T}}$ is the temperature stress model, $T_i$ is the battery cell temperature of each cycle and $T_{\text{ref}}$ is the reference temperature if most degradation experiments are performed in and is set to 293 K or 25 °C. As the degradation model is only tested theoretical and not empirical, the temperature $T_i$ is set constant to 30 °C as it is in the middle of the optimal range mentioned in section 4.2.1.
The calendar aging effect is independent from cycling, thus, no aging effect from DoD and C-rate, and SoC, and T will be constant during the periods between the cycles. The calendar aging function is given by

\[ f_{cal} = k_t \cdot f_{SoC}(SoC_{avg}) \cdot f_T(T_{avg}) \]

where \( k_t \) is the time stress coefficient, \( f_{SoC}(SoC_{avg}) \) and \( f_T(T_{avg}) \) are the average SoC level and temperature stress function respectively. They are calculated in a similar way as the SoC and temperature stress functions in equation (27) and equation (30) with the difference being the SoC and temperature used in the equation. Instead of \( SoC_i \) and \( T_i \) given for the individual cycle, the average SoC level \( SoC_{avg} \) and average temperature \( T_{avg} \) is used. \( SoC_{avg} \) and \( T_{avg} \) is given by

\[ SoC_{avg} = \frac{\sum_{i=1}^{N} SoC_i}{N} \]

and

\[ T_{avg} = \frac{\sum_{i=1}^{N} T_i}{N} \]

respectively where \( N \) is the number of cycles passed during the elapsed time.

As the BESs charging and discharging model in this case study is developed in a way that the BES will not be used at the same hours during a cycle and day, and also not be used every day of the year, the BES will have an irregular cycle schedule which is dependent on the electricity consumption of the facility, the power generation of the PV system to some extent the hours of the year. In order to count the number of irregular cycles, the Rainflow-counting method (RCM) is used in several lifetime stress studies [146][147]. The RCM was developed by Tatsuo Endo in 1967 [165] and is used analyse fatigue data in a randomly fluctuating load profiles [149][150]. A MATLAB algorithm [168] of the RCM is slightly modified and used in this study to count the cycles of the BES. The RCM algorithm is developed according to the ASTM standard of cycle counting in a fatigue analysis and works in a way that it reads the data and find the extrema or so called turning point of the load where an example can be seen in Figure 27. The load profile data, SoC in this example, fluctuates over the time elapsed where the RCM algorithm locates the turning points and then calculates the cycles.

![Figure 27. SoC profile with turning points marked out.](image)
With this algorithm, five outputs are given for each cycle:

1. Cycle amplitude
2. Cycle mean value
3. Cycle stress (0.5 or 1)
4. Cycle start time (at which \( t \) the cycle starts)
5. Cycle end time (at which \( t \) the cycle ends)

where the cycle mean value is used as \( SoC \) in equation (27) and equation (32), the cycle stress indicates if the cycle has a full or half stress effect on the cycle which denotes \( n \) in equation (25) and equation (29), and the cycle start time, \( t_{\text{start}} \) is used as the time elapsed and what time the cycle occurs and is denoted as \( t \) in equation (31). \( t_{\text{start}} \) is also used together with cycle end time, \( t_{\text{end}} \), in equation (29).

### 5.4.2 EV Degradation Model

The EVs will use the same degradation model as for the BESS in order to estimate the lifetime of the battery when the EVs are connected into the buildings and used for V2H, as both of them consist of LIBs that will have irregular charge/discharge cycles. However, as the EVs are not stationary, and have a driving pattern during the time away from the facility that is not taken into account in the degradation model, additional degradation needs to be integrated that solely accounts for degradation from the travelling of the EVs. The additional degradation model is dependent on an estimated lifetime of a Nissan Leaf and the daily driving distance assumed for the owners. The capacity fade of the LIB in the EV will be added annually and linearly to the capacity fade from the degradation model and is denoted as \( CF_{\text{annual,Orebro,EV}} \) and given in \%/year and calculated as

\[
CF_{\text{annual,Orebro,EV}} = \frac{100 - L_{\text{end,EV}}}{S_{\text{proj,life,EV}}} \cdot S_{\text{daily,Orebro,car}} \cdot 365
\]  

(34)

where \( L_{\text{end,EV}} \) is the capacity fade limit of an EV where it is considered as the EOL and given in \%, \( S_{\text{proj,life,EV}} \) is the projected distance a Nissan Leaf amount before the EOL and given in km, \( S_{\text{daily,Orebro,car}} \) is the average daily driving distance of a car in Orebro and given in km/day. The annual capacity fade due to driving is added to the annual capacity fade from the degradation model.

### 5.5 ASHRAE Solar Model

There are many different solar models available. In this study the ASHRAE model has been used and all the following equations and assumptions is based on that model [169][170]. The ASHRAE solar model comes to use in the PV model and is used to calculate the solar angles and irradiation that strikes the PV, which is later used to calculate the electricity production curve.

To acquire the amount of irradiation that is received by the PV modules the position of the sun relative to the earth first has to be decided for the chosen location for every hour of the year. Starting with the declination angle of the earth, \( \delta \). It can be decided by

\[
\delta = \arcsin(0.39795 \cdot \cos(2 \pi \frac{n - 173}{365})) ,
\]  

(35)

where \( n \) is the number of the day ranging from 1 to 365. The hour angle of the earth relative to the sun, \( \omega \), is decided by

\[
\omega = \frac{\pi}{12} (t_s - 12) ,
\]  

(36)

where \( t_s \) is the solar time and is defined as

\[
t_s = t_{\text{clk}} + \frac{\psi_{\text{sid}} + \psi_{\text{loc}}}{15^\circ} + \frac{\Delta t_{\text{EOT}}}{60} + \Delta t_{\text{DST}}
\]  

(37)
where \( t_{cl} \) is the clock time, \( \psi_{std} \) is the time zone meridian (set as -15° for Sweden), \( \psi_{loc} \) is the local longitude, \( \Delta t_{EOT} \) is the equation of time and \( \Delta t_{DST} \) is the daylight-saving time set as -1 between day 87 to 304 (i.e 27th of March to 30th of October). The clock time is set with hourly resolution in the middle of the interval of the irradiation data, i.e 24 different values from hour 0.5 to 23.5 for every day. This is to better represent the average angles that occur during that hour. The equation of time can be calculated as

\[
\Delta t_{EOT} = A \cdot \cos\left(2\pi \frac{n-1}{365}\right) + B \cdot \sin\left(2\pi \frac{n-1}{365}\right) + C \cdot \cos\left(4\pi \frac{n-1}{365}\right) + D \cdot \cos\left(4\pi \frac{n-1}{365}\right),
\]

where \( A, B, C \) and \( D \) are constants given as \( A=0.258, B=-7.416, C=-3.648 \) and \( D=-9.228 \).

The previously mentioned angles and parameters is then used to decide the solar position through the solar zenith angle, \( \theta_z \), calculated as

\[
\theta_z = \arccos(\cos \phi \cdot \cos \delta \cdot \cos \omega + \sin \phi \cdot \sin \delta),
\]

where \( \phi \) is the latitude for the location, and the solar azimuth angle, \( \gamma_s \), calculated as

\[
\gamma_s = \text{sgn}(\omega) \cdot \arccos\left(\frac{\cos \theta_z \cdot \sin \phi - \sin \theta_z \cdot \cos \phi}{\sin \theta_z \cdot \cos \phi}\right),
\]

Where \( \text{sgn} \) is a function which returns -1 if the value of \( \omega \) is negative and +1 if the value of \( \omega \) is positive.

With the position of the sun, the slope angle of the PV, \( \beta_{PV} \), and the azimuth angle of the PV, \( \gamma_{PV} \), known, the incidence angle that the sun strikes the PV with, \( \theta \), is

\[
\theta = \arccos(\cos \beta_{PV} \cdot \cos \theta_z + \sin \beta_{PV} \cdot \sin \theta_z \cdot \cos(\gamma_{s} - \gamma_{PV})).
\]

The cosine effectiveness, \( \varepsilon_{cos} \), is then simply the cosinus of the incidence angle as seen in equation below.

\[
\varepsilon_{cos} = \cos \theta
\]

When the cosine effectiveness has been calculated, the total amount of irradiation that strikes the PV modules, \( I_{tot} \), can be calculated as

\[
I_{tot} = I_{DNI} \cdot \varepsilon_{cos} + I_{diff \_tilt} + I_{ref}
\]

where \( I_{DNI} \) is the direct normal irradiation from the sun \( I_{diff \_tilt} \) is the diffuse irradiation that strikes the tilted PV and \( I_{ref} \) is the reflected irradiation that strikes the PV. \( I_{diff \_tilt} \) is calculated by

\[
I_{diff \_tilt} = I_{diff} \cdot \frac{1 + \cos \beta_{PV}}{2}
\]

where \( I_{diff} \) is the horizontal diffuse irradiation and \( \frac{1 + \cos \beta_{PV}}{2} \) is the PV-sky view factor. \( I_{ref} \) is calculated by

\[
I_{ref} = I_{gh} \cdot \text{albedo} \cdot \frac{1 - \cos \beta_{PV}}{2}
\]

where \( I_{gh} \) is global horizontal irradiation, \( \frac{1 - \cos \beta_{PV}}{2} \) is the PV-ground view factor and \( \text{albedo} \) is the reflectance of earth set as 0.7 January to February and 0.2 rest of the year [171].
5.6 Model inputs
The following section describes all the inputs that have been used in the study for the already mentioned sub-models.

5.6.1 Location
The location used for the study is Höglundagatan 21 in Örebro, which have the coordinates N 59° 17' 11.40", E 15° 13' 49.35". It has been chosen due to the fact that it has several rooftops with large area available for PVs, hence have large PV potential. There are seven buildings with roofs that can be used for PV production and the roofs with appurtenant letters can be seen in Figure 28 below, where up is the north direction.

![Arial view of the buildings in case study.](image)

Roof A, D and F have been chosen not to be evaluated since not all the roof area is needed to get enough electricity production and all of those roofs have some disadvantages. Roof A is neglected since the slope of the roof is against northwest and hence have the lowest overall incoming solar irradiation. Roof D and F are neglected since they are situated lower than the surrounding buildings and therefore have a lot of shading which would lead to high shading losses over the year. However, all the other roofs have been evaluated by measuring their blueprints, which can be seen in appendices Blueprints Höglundagatan 21, and their usable roof areas along with their orientations and roof tilt angle is presented in Table 5 below. All the roofs have two different orientations since the slope of the roof face different directions. The orientation is given from 0° to 360° where 0° is facing due north and the usable roof area is the area that seems possible to set up PVs on, but it can include some obstacles. That is why 80% of the usable roof area is assumed to be the total module area as will be later described in the PV model.
### Table 5. Roof area parameters.

<table>
<thead>
<tr>
<th>Roof</th>
<th>Orientation [°]</th>
<th>Roof tilt angle [°]</th>
<th>Usable roof area [m²]</th>
</tr>
</thead>
<tbody>
<tr>
<td>B</td>
<td>NE 77°</td>
<td>14</td>
<td>140</td>
</tr>
<tr>
<td>B</td>
<td>WSW 257°</td>
<td>14</td>
<td>100</td>
</tr>
<tr>
<td>C</td>
<td>NE 77°</td>
<td>14</td>
<td>140</td>
</tr>
<tr>
<td>C</td>
<td>WSW 257°</td>
<td>14</td>
<td>180</td>
</tr>
<tr>
<td>E</td>
<td>NE 77°</td>
<td>14</td>
<td>130</td>
</tr>
<tr>
<td>E</td>
<td>WSW 257°</td>
<td>14</td>
<td>130</td>
</tr>
<tr>
<td>G</td>
<td>NE 77°</td>
<td>14</td>
<td>250</td>
</tr>
<tr>
<td>G</td>
<td>WSW 257°</td>
<td>14</td>
<td>250</td>
</tr>
<tr>
<td>Total:</td>
<td>NE 77°</td>
<td>14</td>
<td>660</td>
</tr>
<tr>
<td>Total:</td>
<td>WSW 257°</td>
<td>14</td>
<td>660</td>
</tr>
</tbody>
</table>

#### 5.6.2 Facility Load Profile

The electricity consumed and metered at Höglundagatan 21 is used solely for the facility loads and powers lighting in public spaces such as stairwells and cellar, fans in the ventilation system, pumps in the heating system, laundry room, etc. The hourly average electricity consumption for years 2014 to 2016 of the facility loads can be seen in Figure 29 and it mainly illustrates that the maximum electricity consumption is evenly distributed throughout the year. Which means that no significant difference in electricity consumption is seen between summer and winter.

![Hourly Average Electricity Consumption for Högludagatan 21 (2014-2016)](image)

However, as it’s difficult to accurately define the exact value and to which hour the consumption corresponds to in the just shown graph, a boxplot for every hour of the day is made where an hour includes the electricity consumption for the same hour of all the days of an average year and can be seen in Figure 30. Using an average year means that a typical year is formed by taking the average consumption load from 2014 to 2016. This boxplot shows that the base load of the facility is around 35 kWh/h and consumption ranges up to 90 kWh/h with some expectations exceeding 90 kWh/h and also that the consumption peaks fall between hour 8 and 15.
Figure 30. Boxplot presenting the hourly distribution of the average electricity consumption for year 2014 to 2016 of Höglundagatan 21

An illustration of the electricity consumption, as presented in Figure 30, eases the visualization of the electricity consumption for a day. The diagram shows the minimum, maximum and median value of the consumption in kWh of each hour, but also the first and third quartile of all the hours. This method is a simple way to distinguish when the consumption peaks is most likely to occur during the day.

5.6.3 PV Model Inputs

The following section contains and presents the inputs used in the PV model in order to calculate the electricity generated from the PV system.

System size and module parameters

The PV modules are assumed to lay in arrays flat on the roofs presented in section 5.6.1, therefore they have the same tilt angle as the roofs and will not be affected by shading from nearby modules. It is also assumed that 80% of the usable area will be the total module area. This is to account for the small obstacles that are on some of the roofs and for the space that needs to be between modules and arrays. In other words, the total module area, \( A_{\text{module\_tot}} \), can be calculated as:

\[
A_{\text{module\_tot}} = A_{\text{usable}} \cdot 0.8, \tag{46}
\]

Where \( A_{\text{usable}} \) is the usable roof areas presented in section 5.6.1. With the known area for one module, \( A_{\text{module}} \), the number of modules, \( N_{\text{module}} \), round down to the nearest integer then can be calculated as:

\[
N_{\text{module}} = \frac{A_{\text{module\_tot}}}{A_{\text{module}}} \tag{47}
\]

The approach to calculate the number of modules is a simplified method but still reasonable, as not the entire roof area is considered as the usable, but only the area of the roofs that seems usable. Furthermore, none of the PV sizes uses the entire usable roof area, so if more roof area is needed in reality, there will be space left.
The total system size of the PV system then can be calculated as

$$\text{PV}_{\text{system size}} = N_{\text{module}} \cdot P_{\text{module}}$$

(48)

Where $P_{\text{module}}$ is the maximum rated power for a module at STC.

By deciding a total usable area, the total system size can be calculated with the three equations above and with the module parameters presented in Table 6 below.

**Table 6. PV module input parameters.**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\eta_{\text{module}}$</td>
<td>17 %</td>
</tr>
<tr>
<td>$A_{\text{module}}$</td>
<td>1.6 m²</td>
</tr>
<tr>
<td>$P_{\text{module}}$</td>
<td>280 W</td>
</tr>
</tbody>
</table>

All module parameters have been chosen after typical values from manufacturers, i.e. no specific module type have been chosen, and $\eta_{\text{module}}$ is the efficiency of the module itself.

With the chosen module parameters, the total PV system sizes chosen for the study can be shown. That with the corresponding usable area from the roofs, i.e. the total roof area that is needed to obtain the corresponding PV system size when taking into account that extra space is needed to fit the arrays, is presented in Table 7 below.

**Table 7. PV system size in area and installed peak capacity.**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$A_{\text{usable}}$ [m²]</td>
<td>0  200  400  800  1200</td>
</tr>
<tr>
<td>$\text{PV}_{\text{system size}}$ [kWp]</td>
<td>0  28  56  112  168</td>
</tr>
</tbody>
</table>

As can be seen from the table, the usable roof area is above 660 m², which is the total available roof area for one orientation, for some system sizes. For those system sizes the roofs facing south west will be prioritized first since they have a higher incoming solar irradiation for the presented tilt angles over a year and the roofs facing north west will be used to cover the remaining usable area.

**Irradiation and temperature data**

All the weather data comes from Meteonorm, which gives data based on the past to represent how a typical year would look. The weather data used in this study is direct normal irradiation (DNI), global horizontal irradiation (GHI), horizontal diffuse irradiation (HDI) and ambient temperature. All data is with hourly resolution, which means that the solar data is the irradiation received during one hour and the temperature data is the average value during one hour. The data is used to calculate the electricity output from the PV model.

Figure 31, Figure 32 and Figure 33 shows the data of all the solar irradiations that has been used as input in the model from Meteonorm data.
It can be seen in the previously three figures that the DNI has slightly higher values than the GHI and the HDI has lowest values. It can also be seen that the irradiation in general is higher in the middle of the graphs, i.e. during the summer.
Figure 34 shows the ambient temperature that has been used as input in the model from Meteonorm data.

It can be seen from the previously figure that the ambient temperature is varying from day to day and that the temperature is highest during the summer and lowest during the winter.

**Losses**

The real PV system will not perform perfectly over the entire year since losses will occur caused by a number of different things (see section 4.1.4). Therefore, losses are used in the model and all inputs are show in Table 8 below.

<table>
<thead>
<tr>
<th>Type of loss</th>
<th>Loss value [%/year]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reflection</td>
<td>3</td>
</tr>
<tr>
<td>Shading</td>
<td>5</td>
</tr>
<tr>
<td>Dirt</td>
<td>4</td>
</tr>
<tr>
<td>Mismatch between modules</td>
<td>2</td>
</tr>
<tr>
<td>Wiring</td>
<td>3</td>
</tr>
<tr>
<td>Temperature</td>
<td>Varying over the year</td>
</tr>
<tr>
<td>Degradation</td>
<td>0.5</td>
</tr>
</tbody>
</table>

The degradation loss is set to increase linearly with 0.5 %/year, which is a conservative assumed value.

The temperature loss is varying over the year since the cell temperature, $T_{cell}$, of the PV module varies over the year according to

$$ T_{cell} = T_{amb} + \frac{(NOCT - 20)}{800} \cdot I_{tot} $$

(49)

where $T_{amb}$ is the ambient temperature for every hour, $I_{tot}$ is the total incoming irradiation every hour and NOCT is the nominal operating cell temperature, measured under open circuit conditions in a nominal terrestrial environment (NTE). I.e. irradiance of 800 W/m$^2$, spectrum AM 1.5, ambient temperature of 20 °C and wind speed of 1 m/s. The losses caused by the cell temperature then becomes

$$ Loss_{temp} = \beta_{ref} \cdot (T_{cell} - T_{ref}) $$

(50)

where $\beta_{ref}$ is the temperature coefficient having different values for different types of PV modules and $T_{ref}$ is the reference temperature.
All the inputs to calculate the varying cell temperature every hour can be seen in Table 9 below [172][28].

Table 9. Temperature inputs for PV cell temperature calculations.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$T_{amb}$</td>
<td>Varying according to Meteonorm data</td>
</tr>
<tr>
<td>$T_{ref}$</td>
<td>25 °C</td>
</tr>
<tr>
<td>NOCT</td>
<td>45 °C</td>
</tr>
<tr>
<td>$\beta_{ref}$</td>
<td>0.004 °C$^{-1}$</td>
</tr>
</tbody>
</table>

When adding all different losses together the effect they have on the total system efficiency can be seen varying over the year. This is shown as an example for the first year in Figure 35 below. It should be mentioned that this is the effect that other losses apart from the module efficiency have on the total system efficiency. Which means that if the efficiency in this graph is 100 %, the PV system will convert 17 % of the incoming solar radiation into electricity since that is the efficiency of the PV modules.

![Effect from losses on total efficiency](image)

*Figure 35. Annual effect from losses on total system efficiency*

As can be seen in the figure above, the losses increase, hence lead to a lower efficiency, during the summer when the ambient temperature and irradiation is high. However it can also be seen that during the winter periods the total losses is decreasing as a result of that the cell temperature gets lower than the reference temperature according to equation (50).

5.6.4 BESS Model Inputs

The inputs for the BESS model is presented in this section and the five BESS sizes chosen for the case study are between 0-100 kWh and presented in Table 10.

Table 10. BESS sizes chosen for the case study.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Battery size [kWh]</th>
</tr>
</thead>
<tbody>
<tr>
<td>BESS size</td>
<td>0  25  50  75  100</td>
</tr>
</tbody>
</table>

As mentioned in 4.2.1, the degradation rate of the battery is affected by a number of parameters where the SoC limits being one of them. As seen in in Figure 36, when the SoC of the battery is approaching the upper levels during charging or lower levels during discharging, the voltage of the battery increases or decreases respectively. When the voltage alters, the current alters with it where high or low voltages increases the degradation rate. Therefore, the SoC limits, $SoC_{max,BESS}$ and $SoC_{min,BESS}$, where the battery stops to charge during charging and stops to discharge during discharging is set to 90 % and 20 % respectively [173].
The C-rate of the BESS are constant as the ratio between $P_{\text{charge,BESS}}$ and the maximum initial battery capacity will not change and by using equation (13) and (14), the maximum $C_{\text{rate,max,BESS}}$ and $C_{\text{rate,BESS}}$ is calculated to $C/5.7$ and $C/11.2$ respectively.

All the input parameters in the battery model are listed in Table 11.

### Table 11. Battery model input parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\text{SOC}_{\text{max,BESS}}$ [%]</td>
<td>90</td>
</tr>
<tr>
<td>$\text{SOC}_{\text{min,BESS}}$ [%]</td>
<td>20</td>
</tr>
<tr>
<td>$C_{\text{rate,BESS}}$ [C]</td>
<td>0.0875</td>
</tr>
<tr>
<td>$C_{\text{rate,max,BESS}}$ [C]</td>
<td>0.175</td>
</tr>
</tbody>
</table>

#### 5.6.5 Inverter Inputs

The PV system is assumed to have a DC-AC string inverter while the BESS will include a bi-directional inverter. As the inverters is not a main part of this case study, both the inverters efficiencies will be set to 95 % [175][176][177]. As seen in Figure 37, the inverters are assumed to have a power ratio of one, which means the maximum power the inverters are able to convert is the same maximum power the PV system can produce and the maximum charge/discharge of the battery, and still be able to have a 95 % efficiency. In the cases where the system includes a PV system and a BESS, the PV power is first converted from DC to AC through the grid-tied inverter then later converted back to DC by the battery inverter. The lifetime of both inverters is assumed to be 10 years [178][179][180]. Depreciation of the remaining value of the inverter is taken into account in the calculations if the lifetime of the inverter exceeds the simulation period.
The input parameters used in the case study are presented in Table 12.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inverter efficiency [%]</td>
<td>95</td>
</tr>
<tr>
<td>Inverter lifetime [years]</td>
<td>10</td>
</tr>
</tbody>
</table>

### 5.6.6 EV Model Inputs

This section consists of all EV model related parameters used in the case study.

#### Availability and travelling habits of EVs

The case study includes four different availabilities (0%, 25%, 50%, and 75%) of the EVs during the day as a percentage of total EVs that is registered to tenants of the ÖBO building. In order to design the availability curve of the EVs, departures and arrivals of the EVs are taken from a study of travelling habits in Stockholm county [86] which includes all kind of fuel powered cars, and it is assumed that the EVs in the case study have the same patterns as in the study. As seen from Figure 38, which is taken from the travelling habit study and the availability curve in the case study is based on, most of the departures from home during a weekday starts between 07:00 and 08:00 in the morning and the arrival home starts between 16:00 and 18:00.
An example of different availability curves for eight registered EVs is presented in Figure 39, where it can be seen that it is assumed that the drivers of Örebro have the same travelling habits as the drivers of Stockholm, where most of the departures and arrivals occurs between 07:00-08:00 and 18:00-19:00 respectively. It is also assumed that all the days in the case study is treated as a weekday.

![Availability curves for 8 EVs](image)

Figure 39. Example of the availability curves for 8 EV’s used in case study.

In order to estimate the energy consumption of the EVs when being driven after departure, in order to calculate the new battery capacity and SoC of the EVs upon arrival back, the driving distance and fuel consumption of the EV needs to be calculated. According to a travelling habit study in Örebro Municipality [181], the average driving distance of a trip is 7.9 km and the average number of daily trips of a car is 1.4 trips per day. However, in the case study it is assumed that each EV will make two trips per day and return home after leaving home. A daily average number of trips of two will give an average daily distance of 15.8 km. All data is taken for weekdays only as it is assumed that all days in the case study is assumed to be weekdays. The Nissan Leaf 24 kWh battery EV used in the case study has an efficiency of 0.24 kWh/km according to the Nissan Leaf webpage [182] calculated with a distance of 100 km on a fully charged battery. The efficiency and daily driving distance results in a daily electricity consumption of 3.792 kWh/day according to the equation below:

\[
Ec_{daily,EV} = S_{trip,Örebro,car} \cdot N_{trip} \cdot Ec_{km,EV},
\]

(51)

where \( S_{trip,Örebro,car} \) is the average driving distance of a car in Örebro per trip, \( N_{trip} \) is the average number of daily trips for an EV in the case study and \( Ec_{km,EV} \) is the electricity consumption of an EV in the case study given in kWh/km. Table 13 present the driving habit and fuel consumption parameters used in the case study.

<table>
<thead>
<tr>
<th>Attribute</th>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average distance/trip</td>
<td>( S_{trip,Örebro,car} ) (average distance/trip)</td>
<td>7.9 km/trip</td>
</tr>
<tr>
<td>Average number of trips/day</td>
<td>( N_{trip} )</td>
<td>2</td>
</tr>
<tr>
<td>Average daily driving distance</td>
<td>( S_{daily,Örebro,car} )</td>
<td>15.8 km/day</td>
</tr>
<tr>
<td>Electricity consumption/km</td>
<td>( Ec_{km,EV} )</td>
<td>0.24 kWh/km</td>
</tr>
<tr>
<td>Electricity consumption/day</td>
<td>( Ec_{daily,EV} )</td>
<td>3.792 kWh/day</td>
</tr>
</tbody>
</table>

Table 13. Driving habits and fuel consumption parameters.

EV Battery Capacity

The battery capacity of the EVs are not considered as individual capacities where each EV have their own SoC, battery capacity and degradation, but instead as one big aggregated battery capacity connected to the
facility. This leads to the aggregated battery capacity decreases or increases when an EV leaves or arrives to the facility and that the SoC of the aggregated EV battery is an average of all EVs. It is however taken into consideration that the EVs that leave at one specific hour will return with the same capacity, minus the decrease in capacity from the driving distance, at one specific hour independently of the capacity the EVs had when they left the facility. The EVs also take into consideration the solar surplus that will be produced during the day and the EVs that stay will have a lower capacity than the EVs that leave in order for them to be able to charge the surplus. But as mentioned an aggregated battery capacity leads to one degradation rate for all EVs which would not be the case in real life, but used in the case study for simplicity.

State of Charge Parameters, EV
The EVs will not be able to use the total battery capacity for driving, but instead have similar SoC limit as the BESS in order to reduce the degradation effect on the EV battery. The EVs have a $SoC_{\text{max, EV}}$ and a $SoC_{\text{min, EV}}$ on 90% and 20% respectively that the battery cannot exceed. However, as the EVs are privately owned by the tenants, the vehicles always have to have a minimum battery capacity over the $SoC_{\text{drive, EV}}$ in order for the drivers to be able to drive the average daily driving distance at any time of the day. This limit is called $SoC_{\text{drive, EV}}$ and will be the lowest level the EVs will be able to reach during V2H and is based on the fuel consumption and driving habits of the EV owners. As the electricity consumption per day is calculated to 3.792 kWh/day which is the minimum required energy each EV need in order to reach the average driving distance, $SoC_{\text{drive, EV}}$ is given by

$$SoC_{\text{drive, EV}} = SoC_{\text{min, EV}} + \frac{E_{\text{daily, EV}}}{\text{initial EV battery capacity}}$$

and calculated to 35.8%. The EV SoC related parameters used in the EV model is presented in Table 14.

<table>
<thead>
<tr>
<th>EV State of Charge parameter</th>
<th>Value [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>$SoC_{\text{min, EV}}$</td>
<td>20</td>
</tr>
<tr>
<td>$SoC_{\text{max, EV}}$</td>
<td>90</td>
</tr>
<tr>
<td>$SoC_{\text{drive, EV}}$</td>
<td>35.8</td>
</tr>
</tbody>
</table>

Charging Station and Power, EV
As the EVs are to be used as external BESS during V2H, the system in this case study need special bi-directional charging stations compared to the typical one-directional station that is commonly used for charging. Nissan offers bi-directional charging station developed by a company called Nichion [183] on their Japanese website [184]. The rated charge and discharge power of the station is set to 3 kW (200 V, 15 A) but can reach maximum power of 6 kW for a limited time [184][185] which according to the Swedish Energy Agency categorises as a normal charging station [186] and is therefore is classified for the subsidy from Swedish Environmental Protection Agency [187]. The EVs will normally be charged and discharged with the rated 3 kW which is denoted as $P_{\text{charge, rated, EV}}$ and $P_{\text{discharge, rated, EV}}$ respectively, unless during power consumption peaks where the EVs will be discharged with a varying power between 0 and the maximum discharge power, $P_{\text{discharge, max, EV}}$, dependent on number of peaks lowered and desired level of the peaks. $P_{\text{charge, EV}}$ will be equal to the surplus power with a maximum power of 6 kW during days where PV production exceeds the facility load. The lifespan of the charging station is assumed to be 10 years [188].

All the EV charging related parameters are presented in Table 15.

<table>
<thead>
<tr>
<th>EV charging station parameters</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{\text{charge, rated, EV}}/P_{\text{discharge, rated, EV}}$ [kW]</td>
<td>3</td>
</tr>
<tr>
<td>$P_{\text{charge, max, EV}}/P_{\text{discharge, max, EV}}$ [kW]</td>
<td>6</td>
</tr>
<tr>
<td>Lifespan charge station [years]</td>
<td>10</td>
</tr>
</tbody>
</table>
5.6.7 Degradation Model Inputs

The degradation model inputs are used to estimate the capacity fade of the LIB in the BESS and in the EVs where the remaining total capacity out of the initial total capacity of the BESS and EV is denoted as $L_{\text{BESS}}$ and $L_{\text{EV}}$ respectively. The components reach their EOL when $L_{\text{EOL,BESS}}$ and $L_{\text{EOL, EV}}$ reach limit of 80 % and 75 % respectively.

The inputs of all coefficients used in the degradation model is presented in Table 16.

<table>
<thead>
<tr>
<th>Coefficient</th>
<th>Value</th>
<th>Coefficient</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>$p_{\text{SEI}}$</td>
<td>0.0296</td>
<td>$k_C$</td>
<td>0.2374</td>
</tr>
<tr>
<td>$t_{\text{SEI}}$</td>
<td>150.24</td>
<td>$C_{\text{ref}}$</td>
<td>1</td>
</tr>
<tr>
<td>$K_1$</td>
<td>16215</td>
<td>$k_T$</td>
<td>0.0693</td>
</tr>
<tr>
<td>$K_2$</td>
<td>$-1.722$</td>
<td>$T_{\text{ref}}$</td>
<td>25 °C</td>
</tr>
<tr>
<td>$K_3$</td>
<td>8650</td>
<td>$T_i$</td>
<td>30</td>
</tr>
<tr>
<td>$k_{\text{SoC}}$</td>
<td>0.5345</td>
<td>$K_2$</td>
<td>$3.4 \cdot 10^{-10}$</td>
</tr>
<tr>
<td>SoC$^{\text{ref}}$</td>
<td>0.5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

End of Life limits | Value [%] |
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$L_{\text{EOL,BESS}}$</td>
<td>80</td>
</tr>
<tr>
<td>$L_{\text{EOL, EV}}$</td>
<td>75</td>
</tr>
</tbody>
</table>

Additional EV Degradation Model Inputs
The additional capacity fade is calculated by using equation (34) and according to data from [189] and [190], the Nissan leaf drivers have an average daily driving distance on 15 610 km/year and not the average 19 312 km/year as conventional ICE cars have. As lifetime mileage data is not available, [191] uses the data from [192] to extrapolate and project the lifetime mileage with the result that the Nissan leaf will reach the EOL limit after 217 261 km where a 25 % capacity fade the distance gives a $1.151 \cdot 10^4$ % capacity fade per km. With an average daily driving distance of 15.8 km in Örebro, the capacity fade from driving will amount to 16.18 % during the test period of 25 years. The calculated distances and degradation from driving is presented in Table 17. The calculated degradation is added to the degradation model linearly on a yearly basis in order to use a realistic degradation of the battery in the case study.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average annual driving distance per car</td>
<td>15 610.6 km</td>
</tr>
<tr>
<td>$S_{\text{proj.life, EV}}$</td>
<td>217 261 km</td>
</tr>
<tr>
<td>Capacity fade per distance</td>
<td>$1.15 \cdot 10^4$ %/km</td>
</tr>
<tr>
<td>$S_{\text{daily,Orebro,car}}$</td>
<td>15.8 km</td>
</tr>
<tr>
<td>Average daily capacity fade due to driving per EV [%/day]</td>
<td>$1.82 \cdot 10^{-3}$</td>
</tr>
<tr>
<td>$CF_{\text{annual,Orebro, EV}}$</td>
<td>0.647</td>
</tr>
<tr>
<td>Capacity fade of a Nissan Leaf due to driving after 25 years</td>
<td>16.18 %</td>
</tr>
</tbody>
</table>

5.6.8 Price and Cost Model Inputs
This section describes all the price and cost model inputs that have been used in the price and cost model.

Electricity Prices and Costs Inputs
ÖBO has as two electricity subscriptions, one power dependent DSO subscription from EON, and one varying electricity transfer from the retailer Bixia but will under autumn of 2017 switch to an hourly price electricity transfer subscription. Which retailer that will receive ÖBO as a customer is still under negotiation and therefore is Bixia chosen as the retailer in the case study.
The hourly price is varying according to the NordPool day-ahead spot price \[193\] and to minimize the effect of yearly fluctuation of the electricity price, an hourly average electricity price is used. Average hour prices are taken from the years 2014 to 2016 is used in the case study and is given by

\[
C_{NP\text{spot \_price \_avg}}(h_i) = \frac{C_{NP\text{spot \_price \_2014}}(h_i) + C_{NP\text{spot \_price \_2015}}(h_i) + C_{NP\text{spot \_price \_2016}}(h_i)}{3}
\]

(53)

The hourly distribution of the average Nord Pool spot price is illustrated Figure 40.

**Hourly Distribution of the Average Nord Pool Spot Price for years 2014-2016**

![Hourly Distribution of Average Nord Pool Spot Price for years 2014-2016](image)

**Figure 40. Hourly distribution of the average Nord Pool Spot price for years 2014-2016.**

All the fees that the electricity bill consist, both to the retailer and the DSO, are presented in Table 18.

**Table 18. All electricity price related costs [133][141][193][194][195][196]**

<table>
<thead>
<tr>
<th>Description</th>
<th>Unit</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Retailer transfer fees</td>
<td>SEK/kWh</td>
<td>0.036</td>
</tr>
<tr>
<td>RECs cost</td>
<td></td>
<td>0.036</td>
</tr>
<tr>
<td>Governmental fee</td>
<td></td>
<td>0.004</td>
</tr>
<tr>
<td>Retailer margin</td>
<td></td>
<td>0.021</td>
</tr>
<tr>
<td>Energy tax</td>
<td></td>
<td>0.325</td>
</tr>
<tr>
<td>NordPool spot price</td>
<td></td>
<td>Varying/hour</td>
</tr>
<tr>
<td>DSO transfer fees for power tariff subscription</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Grid fee [SEK/kWh]</td>
<td></td>
<td>0.063</td>
</tr>
<tr>
<td>Monthly consumption fee [SEK/kW per month]</td>
<td></td>
<td>95.20</td>
</tr>
<tr>
<td>Subscription fee [SEK/month]</td>
<td></td>
<td>600</td>
</tr>
</tbody>
</table>

The monthly consumption fee paid to the DSO is decided by the highest hourly peak consumption during the month and then multiplied with 95.20 according to the table above.
The average electricity price used in the case study is illustrated as an hourly distribution in Figure 41.

**Hourly Distribution of the Average Electricity Price for years 2014-2016**

As of now, ÖBO have 38 kWp of solar panels installed which means they do not classify for the obligated energy tax that has to be paid when a company or private person exceed the 255 kWp installed tax limit for one PV system or a total aggregated total system. However, their already installed PV system leads to the system planned in this case study has a smaller installed PV capacity than 216 kWp in order to avoid the tax limit.

When the PV production exceeds the facility consumption and the BESS and/or the EVs is not able to take up the excesses electricity, the surplus is sold back to the retailer where the reimbursement the retailer Bixia pays the producer follows the Nord Pool spot price \([197]\). The reimbursement in the case study is given by

\[
C_{\text{reimburse}}(h_i) = C_{\text{NPspot.price.avg}} \cdot P_{\text{surplus}}(h_i)
\]  

(54)

The retailer Bixia also buys the RECs from the producers which they receive for each MWh of electricity produced. The average price for a REC in 2016 paid by the retailer was 158 SEK/MWh \([141]\). The producer also receives a reimbursement for the grid benefit gained from selling electricity to the grid and is paid out by the DSO and is given per kWh during the winter months (January-March and November-December). The grid benefit reimbursement is 0.0292 SEK/kWh, however, as the ÖBO has a power based subscription at the DSO, ÖBO classifies as an electricity producer and must pay a subscription fee of 152 SEK/month in order to be able to sell electricity to the grid \([198]\).

The electricity price is projected to increase by 22% in 2030 compared to the electricity price in 2017 which \([199]\) becomes a 1.7% increase electricity price every year that is put into the model. This is an assumed value taking into account what would happen with the bought electricity if the price would increase with 1.7% per year and no further analysis have been done to justify the assumption due to the large scope of the study.
The average yearly cost of electricity, \( C_{\text{elprice,avg}} \), that is used to calculate the EV owners fee for access to charging at the facility is given by averaging each hourly electricity price and varies yearly as the electricity price changes hourly and yearly. The average yearly cost of electricity is given by

\[
C_{\text{elprice,avg}} = \frac{\sum_{i=1}^{8760} C_{\text{NPspot,price,avg}}(h_i)}{8760}.
\] (55)

The electricity producer related cost and reimbursement parameters are presented in Table 19.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sold RECs [SEK/MWh]</td>
<td>158</td>
</tr>
<tr>
<td>Grid benefit reimbursement [SEK/kWh]</td>
<td>0.0292</td>
</tr>
<tr>
<td>Electricity Producer subscription fee [SEK/month]</td>
<td>152</td>
</tr>
<tr>
<td>Yearly electricity price increase [%]</td>
<td>1.7</td>
</tr>
</tbody>
</table>

**PV Costs Inputs**

The PV costs are based on that the total PV system size is above 20 kW\(_p\) for a grid-connected, roof mounted commercial system, which is within the range for all of the PV sizes that is used in the model. The total cost of the PV system then changes with the total system size according to the cost presented in Table 20 below.

<table>
<thead>
<tr>
<th>Cost parameter</th>
<th>Cost [SEK/W(_p)]</th>
</tr>
</thead>
<tbody>
<tr>
<td>( C_{\text{inverter, PV}} )</td>
<td>0.94</td>
</tr>
<tr>
<td>( C_{\text{OM, PV}} )</td>
<td>0.02</td>
</tr>
<tr>
<td>( C_{\text{inverter, PV (excluding VAT)}} )</td>
<td>11.8</td>
</tr>
</tbody>
</table>

Except for the OM cost for the PV system, the only ongoing cost will be the replacement cost of the PV system’s inverter every 10 year, which means that \( C_{\text{replace, PV}} \) is equal to \( C_{\text{inverter, PV}} \) every 10 year.

Apart from the cost, the model also takes into account that a company get 30 % in subsidies for the installation cost of a PV system up to a maximum of 1.2 MSEK.

**BESS Costs Inputs**

The battery procurement cost of the LIB is set accordingly to Tesla’s price for their Powerwall which results in a price of 3 796 SEK/kWh including BMS, and excluding VAT and inverter cost [200]. The installation cost of the BESS, which includes installation cost of the inverter is set to 7 485 SEK and is a onetime cost. Replacement of the LIB will be executed when the LIB have reached the EOL and the cost for procurement of a new LIB will be equal to the original battery procurement cost and denoted as \( C_{\text{replace,LIB,BESS}} \). Inverter cost is dependent on the maximum charge/discharge power of the LIB and set to 3.98 SEK/W excluding VAT [75].

The total investment cost of the BESS is given by

\[
C_{\text{invest, BESS}} = C_{\text{procurement LIB, BESS}} \cdot \text{battery size} + C_{\text{inverter, BESS}} \cdot \text{inverter size} + C_{\text{installation, BESS}}
\] (56)

The operation and maintenance cost (O&M) of the BESS, \( C_{\text{OM,BESS}} \) which is given in SEK/kW-yr and consist of two parameters, one fixed and one varying and calculated as

\[
C_{\text{OM, BESS}} = C_{\text{FOM, BESS}} + C_{\text{VOM, BESS}} \cdot N_{\text{BESS}} \cdot h_{\text{op}},
\] (57)

where \( C_{\text{FOM,BESS}} \) is the fixed parameter and is set to 67.2 SEK/kW-yr, \( C_{\text{VOM,BESS}} \) is the varying parameter and set to 20.5 SEK/MWh, \( N_{\text{BESS}} \) is the annual number of cycles of the BESS and \( h_{\text{op}} \) is the number of
annual operational hours of the BESS. The levelized cost of energy (LOCE) of the O&M costs of the battery, \( C_{OM.LCOE.BESS} \), is given in SEK/kWh and calculated as [76]

\[
C_{OM.LCOE.BESS} = \frac{C_{OM.BESS}}{N_{BESS} \cdot h_{op}}
\]  

(58)

All the BESS related cost inputs are presented in Table 21.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>( C_{procurement,LIB,BESS} ) [SEK/kWh]</td>
<td>3.796</td>
</tr>
<tr>
<td>( C_{replace,LIB,BESS} ) [SEK/kWh]</td>
<td>3.796</td>
</tr>
<tr>
<td>( C_{inverter,BESS} ) [SEK/W]</td>
<td>3.98</td>
</tr>
<tr>
<td>( C_{install,BESS} ) [SEK]</td>
<td>7485</td>
</tr>
<tr>
<td>( C_{FOM,BESS} ) [SEK/kW-yr]</td>
<td>67.2</td>
</tr>
<tr>
<td>( C_{VOM,BESS} ) [SEK/MWh]</td>
<td>20.5</td>
</tr>
</tbody>
</table>

**EV Costs Inputs**

The charging stations used for V2H is, according to Nissans website [184], purchased for 691 200 yen each, while Nichions product sheet has a price of 580 000 yen for the cheapest available [185]. The cheapest alternative is chosen in this study as the extra features will not be needed. With the currency conversion of today (13/07/17) [201] from yen to SEK, the charging stations price is 42 990 SEK per station. However, as the stations will be bought from Japan, there is need to take into account customs and additional VAT when imported. According to [202], the customs fee is 10% of the stations cost which results in the cost of one charging station after customs is calculated as

\[
C_{station,customs,EV} = C_{station,EV} (1 + customs_{fc})
\]  

(59)

where the listed station cost is denoted as \( C_{station,EV} \). No shipping cost is taken into account.

The website www.emobility.se, which is recommended by the Swedish Energy Agency [203], states that the installation cost that installation cost of a charging station is very dependent on the level of charging (fast, semi-fast or normal) and the extent of ground work that needs to be done [204][205]. An overall total cost for a normal level charging station is between 25 000 – 50 000 SEK where the station cost of 15 000 SEK included. This means that the total installation cost for a normal level charging station is between 10 00 – 35 000 SEK, and therefore installation cost \( C_{installation,EV} \) is set to 22 500 SEK.

An incentive in Sweden called ‘Klimatklivet’ [206] was taken into action in 2015 [207] which gives financial support for climate smart actions that will reduce the CO\(_2\) emissions on a local level. The financial support is given for all types of legal entities such as municipalities, county councils, housing companies and other organisations. The financial support is given for charging stations and poles. The organisation will receive a financial support of 50% of the total investment cost but no more than 20 000 SEK per station/pole [187]. The financial support of charging stations/poles is denoted as \( C_{support,EV} \).

The total cost of a charging stations including installation cost and financial support is represented as \( C_{invest,EV} \) and calculated as

\[
C_{invest,EV} = C_{station,customs,EV} + C_{installation,EV} - C_{support,EV}
\]  

(60)

The cost of replacing the charging station after the lifetime is denoted as \( C_{replace,EV} \) and is equal to the investment cost of the original EV charging station.
The yearly O&M cost of a charging station is, according to [208], 10% of the material cost which in this study is set to 10% the cost of the station before customs plus the installation cost to include all the material needed for the station. The yearly O&M cost of the one charging station, $C_{OM, EV}$, is given by

$$C_{OM, EV} = (C_{invest, EV} + C_{installation, EV}) \cdot 0.10,$$

and results in 6 549 SEK/year, which is a feasible result compared to the assumed O&M cost of 5 000 SEK/year for a charging station in [209]. The O&M cost will include costs for repair and service costs, software update and subscriptions, station cleaning, etc.

As ÖBO is a housing company, they are not allowed to sell or charge the owner of the EVs for the electricity used for charging of the EV [210]. Therefore, a yearly access-to-charging fee combined with parking space fee will be charged to the owner together with their rent, where the fee is dependent on the yearly electricity consumption and average electricity price. The EV owner’s yearly fee is given by

$$C_{charging, fee, EV} = F_{EV, daily} \cdot C_{elprice, avg} \cdot 365 \cdot \frac{\text{days}}{\text{year}}.$$

All the EV related cost parameters used for NPV calculations is given in Table 22.

Table 22. EV charging related costs used in the case study.

<table>
<thead>
<tr>
<th>Cost parameter</th>
<th>Value [SEK]</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{station, EV}$</td>
<td>42 990</td>
</tr>
<tr>
<td>customs%</td>
<td>10 [%]</td>
</tr>
<tr>
<td>$C_{station, customs, EV}$</td>
<td>47 289</td>
</tr>
<tr>
<td>$C_{EV, installation}$</td>
<td>22 500</td>
</tr>
<tr>
<td>$C_{EV, support}$</td>
<td>20 000</td>
</tr>
<tr>
<td>$C_{invest, EV}$</td>
<td>49 789</td>
</tr>
<tr>
<td>$C_{OM, EV}$</td>
<td>6 549 [SEK/year]</td>
</tr>
</tbody>
</table>
Results and Discussion

The results of the techno-economic analysis are presented in the following sections. First, the overall electricity consumption results are presented and described in section 6.1. Next, the economic analysis results of the different combination of components in the system configuration are presented and discussed in section 6.2. Afterward, result of a more detailed economic analysis of different sizes of PV system and BESS that yields a positive NPV are presented in section 6.3. Continuing, the degradation results for both the stationary battery and the EV battery are presented in section 6.4. Lastly a discussion of all the results is presented in section 6.5.

6.1 Overall Facility Electricity Consumption Results

Different variation of components and sizes are tested with the various models that have been described. To get a better understanding of how the results for the different combination of sizes looks like, the result for the electricity consumption and charging control of a specific combination of sizes is first shown in this section. Other sizes will have different values and the availability of the EVs can affect the result, but the principle will be the same for any combination of sizes.

Figure 42 below illustrates the example of charge and discharge control of the BESS and the EVs, and shows how a system configuration consisting of a 112 kWp PV system, a 50 kWh BESS and 4 EVs with 50% availability is used. The figure shows how the electricity consumption of the facilities for day 125, i.e 5th of May, would look without any components, with only a PV system, a combined PV and BESS and a combination of all three. The top graph shows how the facility load is affected by the components where the green curve is the original electricity consumption and the blue curve is the reduced consumption from the grid after the PV generation is used instantaneously to power the facilities. As seen by the red curve, the 5th of May is a day with a consumption peak between the hours of 10:00 and 11:00 which is lowered by discharging the BESS. The BESS start charging at 22:00 in the evening which increase the electricity consumption relative the original consumption which is seen in the figure. The middle graph in the figure shows the SoC of the BESS which is lowered during the discharged and increased when charged during the night. The turquoise electricity consumption curve shows the effect of the discharge power from the EVs where consumption peaks are lowered between 08:00-09:00 and 10:00-11:00 where the aggregated SoC of the EVs is presented in the bottom graph. As seen in the SoC graph of the EVs, the SoC decreases during the discharge and increased during charging after 22:00, but is also increased between 17:00-19:00 due to the other 50% of the EVs are returning home. As the EVs returning has a higher battery capacity than the EVs connected to the facility throughout the day, the average connected battery capacity is increased, and the aggregated EV SoC is increased.

Figure 42. Example of the charge and discharge control. Top graph: Electricity consumption for different system configurations; Middle graph: BESS SoC graph; Bottom graph: Aggregated EV SoC graph
Figure 43 is another example of how the charge and discharge control works and the figure illustrates how the control is optimized in order to absorb the surplus electricity generated from the PV system that exceeds the hourly facility consumption. The blue curve in the top graph shows the consumption with only a PV system which generate surplus electricity, and without a BESS or EVs, the surplus will be sold back to the grid. However, with a BESS and EVs, the electricity will be stored as seen by the red and the turquoise curve which reduces the electricity sold to the grid. As seen in the graph, the BESS and EVs are discharged early in the morning to be able to fit the surplus electricity generated during the day by the PV system. Noticeable in the middle graph is how the BESS is discharged from maximum SoC at 22:00 to prepare for the surplus electricity generated next day.

**Electricity Consumption From Grid June 28th**

- **112 kWp PV, 50 kWh BESS, 4 EVs, 50% Availability**

![Electricity Consumption From Grid June 28th](image)

**Battery charging scheme SOC**

- **SOC**

**Aggregated EV charging scheme SOC**

- **SOC**

*Figure 43. Example of the charge and discharge control at a day with surplus electricity. Top graph: Electricity consumption for different system configurations; Middle graph: BESS SoC graph; Bottom graph: Aggregated EV SoC graph.*

An illustrative result of the charge and discharge control of a system with PV, BESS and EVs can be seen by comparing the electricity consumption from the grid during the entire year. This comparison is illustrated in Figure 44 and Figure 45. Figure 44 presents the facility load without any components and it can be seen that a few peaks occur every month. Since a power tariff subscription is used the electricity bill can be reduced just by lowering these peaks without having to reduce the total yearly electricity consumption. It can also be seen that the peaks have close to the same value irrespective of the season.

**Electricity Consumption From the Grid**

![Electricity Consumption From the Grid](image)

*Figure 44. Facility load without a PV system, a BESS and without EVs.*

As seen in Figure 45, when using a PV system, BESS and EVs the peaks are reduced and levelled for each month. The peaks during the winter month has been reduced from around 100 kWh to 80 kWh per hour, with the exception of November which is only reduced to around 85 kWh as November has the highest hourly peak of the year. The most noticeable in the graph is the baseload which is lowered during the
summer month where the electricity from the PV system at some hours of the day removes the dependency of the electricity from the grid. The PV system also reduces the peaks during the summer months which will have a great impact on the electricity bill. To give some context, the savings from lowering the highest peaks of the month with 20 kWh/h each month would be about 23 kSEK/year and this is without decreasing the total consumption at all. In the example, the peaks are decreased between 15-35 kWh/h depending on the month. Moreover, a PV system is used in the example which decreases the total consumption and therefore decrease the cost even further since less electricity is bought from the electricity retailer and DSO.

As mentioned before this result is for a specific combination of sizes and the combination will have a significant effect on both the electricity bill, cost savings and on the initial investment of the system. The results of the NPV after 25 years for all the different constellation of PV, BESS and EVs will be shown in the sections below. They have been divided in sections of the number of EVs that were used in order to be able to vary the PV system and BESS size within one graph.

### 6.2 Net Present Value Results

This section contains the result and discussion of the economic analysis of the different combination of components in the system configuration.

#### 6.2.1 0 EVs

The result of the NPV after 25 years for a system configuration with 0 EVs, PV system sizes and BESS sizes are shown in Figure 46. Since no EVs are used the results won’t be affected by the EV availability and therefore only one graph is shown.

The graph shows that all the different PV system sizes investigated have their highest NPV without a BESS and have a decreasing trend as the BESS size increases. The installed PV system capacity of 56 kW and 112 kW results in a NPV of around 100 000 SEK with the maximum NPV will be yielded from a PV system
size between 56-112 kW. A PV system of 56 kW is the last capacity that yields a positive NPV combined with an increasing BESS, as long as the BESS is smaller than around 30 kWh

### 6.2.2 2 EVs

The result of the NPV after 25 years for a system configuration with 2 EVs, for varying availabilities, PV system sizes and BESS sizes are shown in Figure 47, Figure 48, Figure 49 and Figure 50.

![Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (0% Availability)](image1)

*Figure 47. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (0% availability).*

![Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (25% Availability)](image2)

*Figure 48. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EV’s (25% availability).*

![Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (50% Availability)](image3)

*Figure 49. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EV’s (50% availability).*
As seen from the figures, all the different availabilities for 2 EVs will result in a negative NPV and have a maximum when the BESS is set to zero, for all PV system sizes, and steadily decreases as the BESS increases. The highest NPV is yielded from a 75% availability and decreases as the availability decreases, as the possibility of decreasing the peaks increases when the availability of the EVs is higher. The maximum NPV for 75% availability is between -50 000 SEK and -150 000 SEK depending on the PV system size, where an installed PV capacity of 56 kW or 112 kW for the different availabilities, and no BESS resulting in the highest NPV for 2 EVs. A system configuration of no installed PV system will almost always be the lowest NPV yielding configuration as the BESS increases, with the exception of a 28 kW PV system combined with a 50 kWh BESS. Also seen in the figures is that the 56 kW PV system and 112 kW system will result in an equal NPV for small and large BESS but will differ significantly in the NPV with BESSs between 25-60 kWh.

It can also be noticed that the NPV is almost the same for 25 % and 50 % EV availability. This is because the number of EVs available at a specific hour is rounded to the closest integer and are therefore either one or two EVs are available when only having a total of two EVs (except for one hour of the day which has zero EVs available for 25 % availability). However, when using 75 % EV availability fewer hours only have one EV available and when using 0 % availability more hours have zero EVs available.

### 6.2.3 4 EVs

The result of the NPV after 25 years for a system configuration with 4 EVs, for varying availabilities, PV system sizes and BESS sizes are shown in Figure 51, Figure 52, Figure 53 and Figure 54.
As seen from the figures, all the different availabilities for 4 EVs will result in a negative NPV and have a maximum when the BESS is set to zero, for all PV system sizes, and steadily decreases as the BESS increases. The highest NPV is yielded from a 75% availability and decreases as the availability decreases, as the possibility of decreasing the peaks is larger when the availability is higher. The maximum NPV for 75% EV availability is between -350 000 SEK and -430 000 SEK depending on the PV system size, where an installed PV capacity of 112 kW and 56 kW with no BESS results in the highest NPV for 4 EVs. A system configuration with a 56 kW PV system or 112 kW for the different availabilities will result in almost exact same NPV with an increasing BESS, with exception of a 25 kWh BESS that results in a significant 50 000 SEK higher NPV for the 56 kW PV system.
6.2.4 8 EVs

The result of the NPV after 25 years for a system configuration with 8 EVs, for varying availabilities, PV system sizes and BESS sizes are shown in Figure 55, Figure 56, Figure 57 and Figure 58.

![Figure 55](image1.png)

*Figure 55. Graph of NPV after 25 years for varying size of PV system and BESS with 8 EVs (0% Availability).*

![Figure 56](image2.png)

*Figure 56. Graph of NPV after 25 years for varying size of PV system and BESS with 8 EVs (25% Availability).*

![Figure 57](image3.png)

*Figure 57. Graph of NPV after 25 years for varying size of PV system and BESS with 8 EVs (50% Availability).*
As seen from the figures, all the different availabilities for 8 EVs will result in a negative NPV and have a maximum when the BESS is set to zero, for all PV system sizes, and steadily decreases as the BESS increases. The highest NPV is yielded from a 75% availability and decreases as the availability decreases, as the possibility of decreasing the peaks is higher when having a high availability. The maximum NPV for 75% is between -920 000 SEK and -1 020 000 SEK depending on the PV system size, where an installed PV capacity of 112 kW and 56 kW with no BESS results in the highest NPV for 8 EVs. A system configuration with a 56 kW PV system or 112 kW will result in almost exact same NPV with an increasing BESS, with exceptions at some BESS where the NPV is slightly higher for a 56 kW PV system.
6.2.5 Summary of NPV Results

The result of the highest NPV yielding system configuration is summarised in Table 23 where the PV system size, BESS sizes and the highest yielded NPV for each number of EVs and availability is presented.

Table 23. Summary of NPV result for different number of EVs and availabilities.

<table>
<thead>
<tr>
<th>EVs [-] / Availability [%]</th>
<th>0</th>
<th>25</th>
<th>50</th>
<th>75</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>56/112 kW_p</td>
<td>56/112 kW_p</td>
<td>56/112 kW_p</td>
<td>56/112 kW_p</td>
</tr>
<tr>
<td>0 kWh BESS 100 000 SEK</td>
<td>0 kWh BESS 100 000 SEK</td>
<td>0 kWh BESS 100 000 SEK</td>
<td>0 kWh BESS 100 000 SEK</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>56 kW_p</td>
<td>56/112 kW_p</td>
<td>56 kW_p</td>
<td>112 kW_p</td>
</tr>
<tr>
<td>0 kWh BESS -250 000 SEK</td>
<td>0 kWh BESS -150 000 SEK</td>
<td>0 kWh BESS -150 000 SEK</td>
<td>0 kWh BESS -50 000 SEK</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>112 kW_p</td>
<td>112 kW_p</td>
<td>112 kW_p</td>
<td>112 kW_p</td>
</tr>
<tr>
<td>0 kWh BESS -550 000 SEK</td>
<td>0 kWh BESS -475 000 SEK</td>
<td>0 kWh BESS -420 000 SEK</td>
<td>0 kWh BESS -350 000 SEK</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>168 kW_p</td>
<td>112 kW_p</td>
<td>112 kW_p</td>
<td>112 kW_p</td>
</tr>
<tr>
<td>0 kWh BESS -1 180 000 SEK</td>
<td>0 kWh BESS -1 050 000 SEK</td>
<td>0 kWh BESS -970 000 SEK</td>
<td>0 kWh BESS -920 000 SEK</td>
<td></td>
</tr>
</tbody>
</table>

As seen from the table, the highest NPV is always yielded without a BESS. It can also be seen that the system configuration can consist of a larger PV capacity when the number of EVs and availability increases as the EVs will be able to store more surplus electricity which is generated from a larger PV capacity. The availability also increases the NPV as the EVs will be able to decrease more consumption peaks as mentioned before. One important point to take from the table is also that the NPV always will be negative when having a system that include EVs.

6.3 Results Yielding a Positive NPV after 25 years

As seen from the results in section 6.2, a system configuration without EVs always result in a higher NPV than with EVs and will only result with a positive NPV for certain PV and BESS sizes. The results for PV and BESS sizes which yields positive NPV after 25 years is presented in this section.

6.3.1 PV system size

Figure 59 below illustrates the calculated NPV after 25 years for several different PV system sizes in order to find the size that yields the highest NPV. The graph shows a drop in NPV at a system size around 90 kW_p which is the system size where the installed system exceeds the area of 660 m^2 and PV modules are then installed on the roofs facing northeast. As the roofs facing north east have a lower solar yield than the roofs facing southwest, the PV system will not generate as much electricity per m^2 and therefore have a lower NPV. As a consequence of this along with that too much surplus is generated, the NPV will decrease when increasing the PV system size above 95 kW.
As seen in the figure above, the installed PV capacity yielding the highest NPV after 25 years is $92.4 \text{ kW}_P$, where the calculated NPV for all years for this PV system size is presented in Figure 60 below.

An installed capacity of 92.4 kW$_P$ will result in a NPV of 145 420 SEK after 25 years and generate 65 438 kWh the first year. With other words the PV system generates about 710 kWh/kW$_P$ installed capacity the first year.

As seen in the figure above the graph is increasing every year with the exception of every tenth year when the NPV dips due to the replacement investments of inverters for the PV system that is made throughout the test period.

6.3.2 BESS size

Figure 61 presents the result of NPV after 25 years for five of the PV system sizes that yields the largest NPV according to Figure 60 together with an increasing BESS.
Figure 61. Graph of NPV after 25 years for varying PV system and BESS sizes with 0 EVs.

The graph shows that a PV capacity of 92.4 kW without a BESS yet again yields the highest NPV of the PV sizes which has been tested. However, all the different PV sizes will still yield a positive NPV up until a certain size of the BESS. A noticeable aspect about the graph is the increase the larger PV sizes makes for certain BESS sizes compared with the smaller PV system sizes. The reason why the increase only occurs for larger PV system is that these systems generate surplus and some specific sizes of BESS can take care of more of the surplus in combination with decreasing the highest peaks of the month more.

Another noticeable fact with the graph is that the curves for the larger capacity with an increasing jump in capacity has a steeper inclination before the ‘jump’ compared to the curves for smaller capacities. The steeper inclination leads to the 92.4 kW PV system, at some sizes of the BESS, not being the size that generates the largest NPV as seen between 6-10 kWh BESS. The reason for the ‘jumps’ is how the facility load curve is affected by the electricity from different PV system sizes and the charge/discharge strategy of the different BESS sizes. At smaller BESS sizes, the monetary gain from reduction of consumption peaks is significant smaller than the cost of the BESS, and the costs of the BESS increases at a higher rate than the monetary gain yielded from an increasing battery size. This is also the reason of why the NPV decreases compared to being constant. However, at a certain BESS size, an ‘optimum’ is found where the number of lowered consumption peaks increases drastically due to the load profile after the PV, and the combination of the surplus electricity generated, the monetary gain will increase significantly. Beyond this size, the number of peaks lowered is not correlated with the increase of BESS and the cost will yet again outgrow the monetary gain. This ‘optimum’ occurs at different BESS sizes for different PV system sizes as the PV sizes all affect the facility load in a different way and the ‘jump’ is only experienced by the PV sizes that generate surplus electricity.

It is also visible to see a large decrease in the NPV when the PV capacity exceeds 92.4 kW due to a decreased solar yield per m² as previously described in section 6.3.1.

6.3.3 Self-Consumption and Self-Sufficiency

As one of the reasons for installing a PV system is to generate and produce your own electricity and become less dependent on the conventional power grid and hopefully gain some monetary advantages from it. One aspect of a PV-BESS-EV system is to maximize the self-consumption of PV generated electricity and also to increase the self-sufficiency, as a higher self-sufficiency means less bought electricity form the grid.

The original electricity consumption of the facility amounts to 415 260 kWh per year and the PV capacity that yields the highest NPV (92.4 kWh) generates 65 438 kWh per year, however, the PV system generates excess electricity at some hours during the day. The surplus electricity amounts to 230.7 kWh per year, which
means the electricity consumption of the facility with the PV system will be 350 053 kWh per year. This gives a self-consumption of 65 207.3 kWh per year and a self-sufficiency ratio of 0.157 or 15.7%. The BESS and EVs are used to store the excess electricity for later use which will increase the self-consumption and the self-sufficiency. Table 24 shows the result of the facility load, the self-consumption and the self-sufficiency ratio after each component in a system contain the highest NPV yielding PV system with a 50 kWh BESS and 4 EVs with 50% availability.

Table 24. Table presenting facility load, self-consumption and self-sufficiency ratio after each component of a system configuration (92.4 kWp PV system, 50 kWh BESS, 4 EV’s with 50% availability)

<table>
<thead>
<tr>
<th>Component</th>
<th>Total facility consumption [kWh]</th>
<th>Self-consumption [kWh]</th>
<th>Self-sufficiency ratio [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Original</td>
<td>415 260</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>After PV system</td>
<td>350 053</td>
<td>65 207</td>
<td>15.700</td>
</tr>
<tr>
<td>After BESS</td>
<td>349 826</td>
<td>65 434</td>
<td>15.757</td>
</tr>
<tr>
<td>After EVs</td>
<td>349 822</td>
<td>65 438</td>
<td>15.758</td>
</tr>
</tbody>
</table>

As seen from the table above, the PV system will increase the self-consumption where 99.7% of the PV generated electricity is self-consumed by the facility. However, as the PV system does not generate a lot of excess electricity, a 50 kWh BESS and/or 4 EVs will not increase the self-consumption, nor the self-sufficiency ratio significantly. Therefore, a BESS and/or EVs will not be useful for the purpose of increase the self-consumption or the self-sufficiency. In order to be able to increase the self-consumption and the self-sufficiency, a large PV system that generates more excess electricity is needed, as seen from the results in section 6.3.1, increasing the PV capacity will yield a lower NPV for the PV system where trade-off occurs. The trade-off will be between NPV or a larger PV capacity that will increase the self-consumption and hopefully decrease the electricity bill related costs, and as seen from the previous results, larger PV capacity will decrease the NPV and will therefore not be more economic viable.

One important point about the self-consumption, self-sufficiency and the results are that the data is taken after the first year of the test period which mean as the time lapse. However, as the lapes and the components begins to degrade, the PV will not generate as much electricity, and the BESS and EVs will not be able to store as much energy as before, which means that the self-consumption and self-sufficiency will decrease over time and be less efficient. So, the result of the table are the highest values that will be reached during the lifetime of the system.

6.4 Degradation Results

The result of the degradation model performance test is presented in Figure 62 and Figure 63 where it can be seen that the BESS will be discharged to 20% every day during the day and later fully charged during the night. As the control strategy of the BESS during the performance test is set to start the discharge when the facility load consumption exceeds 60 kWh and not a specific time, the start and the end hour of discharge varies.

Figure 62. Illustration of SoC of the BESS from the performance test of the battery degradation model.
As seen from the result in Figure 63, the BESS will reach the 80% EOL limit after around 3600 cycles at 80% DoD in about 9.1 years, which compared to the cycle life data in section 4.2.4 seems realistic.

![Battery degradation](image)

**Figure 63. Illustration of battery life indicator of the LIB from the performance test of the degradation model.**

Figure 64 and Figure 65 presents an illustration of the result of the degradation model from the full test where graphs show the life indicator of the LIBs in the BESS and of the aggregated EVs in a system configuration consisting of a 92.4 kWp PV system, a 50 kWh BESS and 4 EVs with 50% availability. The graphs illustrate how the batteries will degrade with the respect of time and number of cycles where the EOL limit is at 80% for the BESS and 75% for the EV. The degradation curve in both the figures do not stop exact at EOL of respective component as the life indicator value is tested before each year start, meaning if the component reaches the EOL in year one, component will remain in use the year out and be replaced in the beginning of year two.

![Battery degradation](image)

**Figure 64. Visual illustration of life indicator of the LIB in a 50 kWh BESS in a system configuration consisting of a BESS, a 92.4 kW PV system and 4 EV's with 50% availability.**

As seen from Figure 64, the degradation rate of the battery is higher in the beginning and slowly levels out as time is elapsed. The battery will reach the EOL limit after 2020 cycles, which compared to the LIB
specifications in section 4.2.4 that present cycles between 1500-3000, show that the result is reasonable. However, the most noticeable in the figure is that the LIB reaches around 219 000 hours since it was first used before reaching the EOL, which translates to a lifetime around 25 years. A lifetime of 25 years is around twice as the calendar life suggested in section 4.2.4 and a LIB will most likely reach this number in a real-life experiment. Compared to the performance test of the degradation model, it seems like the calendar degradation does not affect the LIB as much as would be expected.

The degradation model now shows that the system configuration will manage to function for 25 years without replacing the LIB in the BESS which will affect and increase the NPV result as the battery is one of the more expensive components in the whole system. A lifetime of around 10-15 year would drastically decrease the economic viability of the BESS.

![Figure 65. Visual illustration of life indicator of the aggregated LIB of 4 EV’s with 50 % availability in a system configuration consisting of EV’s, a 92.4 kWp PV system and a 50 kWh BESS.](image)

As seen from the representation of the EV degradation in Figure 65, the EVs will reach the EOL limit at 75% of the initial capacity after around 122 000 hours (around 14 years) and 5830 cycles, and then replaced in year 15 to new EVs which will reach 78% of the initial capacity before the test period is over. If the lifetime of the EVs are 14 years and they are driven the average travel distance of 15.8 km per day, the EVs will reach 80 738 km after 14 years, which is almost three time less than the estimated lifetime distance of 217 261 km mentioned in section 5.6.7. This show that the V2H application of the EVs will have a large impact on the degradation rate and the lifetime of an EV.

The degradation of the EVs are assumed for the aggregated EV battery capacity and therefore, all EVs have to be replaced at the same time, where the owners cost for replacement of EVs is not taken into account in the calculations of NPV.

6.5 Discussion of Results
All the results have been presented and the following section discusses the results in more detail.

6.5.1 PV System
The results show that a PV system size of 92.4 kWp (yearly production of 710 kWh/kWp) without any BESS and/or EVs will generate the highest NPV but not necessarily the highest solar electricity self-consumption ratio. A larger installed capacity would most likely increase the self-consumption ratio and decrease the electricity used from the grid. A larger PV system to increase the self-consumption ratio would most likely work for this building where the generation peaks of the PV occurs at the same hours as the facility load peaks and the electricity from the PV is used instantaneously. A larger PV capacity than 92.4 kWp will lead to a relative large decrease of the NPV as seen in Figure 59, due to a lower kW/m² generation as the
expanded roof top area has an electricity output/m². However, in a situation where the PV system is powering a buildings apartment load instead of facility load as in this case study, a larger PV capacity, an added BESS and/or EVs, would have a very different effect on both the NPV and the self-consumption ratio. As an apartment load differs a lot in peak hours compared to a facility load, a larger PV capacity could lead to a decreased NPV without increasing the self-consumption. A BESS would also most likely be more profitable for an apartment load than for a facility load as more electricity per m² from the PVs could be stored in the BESS for later use.

From the results it can also be seen that a PV system is always needed in order to get a positive NPV after 25 years. This is mainly due to that most of the electricity cost for ÖBO comes from their high total electricity consumption that they must pay for to the electricity retailer. By using a PV-system they can reduce their total consumption and thereby decrease these costs. Using a battery or EV does not decrease the total consumption, just shift it. It should however also be mentioned that the peak costs that can be decreased by using a battery or EV also stand for a large part of the costs and that is where using a battery or EV can bring an economic value. Of ÖBOs total costs from the beginning that can be influenced, not taking fixed costs into consideration, about 4/5 comes from the transfer fee of electricity to the electricity retailer and 1/5 comes from peak costs to the DSO.

Another fact to consider with the PV system is that all PV modules are assumed to lay flat on the roof, i.e. having the same tilt angle as the roof's 14° with the same orientation. The fact that the orientation is facing mostly west is the main reason why the system only produces 710 kWh/kWp installed capacity the first year and not within the range 800-1100 kWh/kWp as could be assumed from typical Swedish values, but the low value also indicates that the assumed losses are slightly over dimensioned. If the modules instead where tilted 30° they would generate slightly more electricity, but the result wouldn't change drastically. However, if the orientation were changed closer to due south the electricity production would increase more and with that the economic value of the PV system. For future studies, it should therefore be considered if the modules could be mounted in a different way to assure more south orientation. This was not considered in this study due to the large scope and that optimizing the PVs angle and orientation were not considered as the most important aspect.

6.5.2 BESS

As seen from the results, a BESS can be used to decrease and control the electricity consumption of the facility, and result in a positive NPV, for certain BESS sizes. However, as seen from the graphs, a BESS can only be economically viable when combined with a PV system due to the high costs of the LIB and inverters. A trade-off between the PV system size and the BESS size occurs as the balance between them is important to take into account when deciding the optimal system configuration. If the system is sized after the highest NPV after 25 years, a PV system without a BESS and without EVs should be used. However, if the system is sized after increasing the self-consumption ratio of solar electricity, the PV system must be large enough to generate surplus and a BESS must be used to absorb the surplus and store it for later use. The larger the PV system and the BESS is, the larger the solar electricity self-consumption ratio gets, but this also leads to increased investment cost and to decreased NPV. So, the customer, in this case ÖBO, will have to decide what is more important, a high profit, or a lower dependency of the electricity grid with increased ability to be flexible in their electricity usage.

A system configuration consisting of only a BESS can, with today's costs of the system, not be economically viable, as all the costs of the BESS in the case study is based on newly fabricated products, and a way to lower the investment costs could be to use second-life batteries. The second-life batteries come from for example EVs and could still be used as a stationary battery even though it is considered as dead for the EVs, and will have a lower investment cost. It could also have been seen from the point of view that the volatility on the Nordic pool spot market is not high enough to make an investment in a battery economic viable.

Another way that could make the BESS economical viable is if ÖBO could get increased profit by delivering services as frequency regulation to the TSO or voltage control and congestion management to the DSO. Basically, meaning that ÖBO increases or decreases the electricity consumption from their buildings in an
aggregated way according to the need of the electricity grid or other actors and gets paid for doing so. As the charge and discharge control strategy is designed in the way that the BESS is only discharged under certain days and certain hours of the month, which make the BESS unused during a large part of the days during a month, the BESS could be used for these kinds of services during the other days. Exact business models of how ÖBO could get revenues from these kinds of services would have to be further investigated, but if additional profit can be added by using a BESS it could be economically viable to invest in a larger BESS system than this study showed when only the electricity costs have been considered. A larger BESS per building also means that the LSO concept gets more viable since less buildings have to be aggregated together to deliver a large capacity in flexible electricity usage.

6.5.3 EV

As seen by the result of the case study, any scenario where EVs are used for V2H will not make any profit after 25 years which make the use of EVs to lower the electricity related costs not economical viable with today’s cost of charging stations. As the technology of V2H is relatively new and unexplored, the bi-directional charging stations used for V2H is not commercialised on a big scale which make the implementation expensive. Compared to the mentioned 15 000 SEK for a normal charging station, the bi-directional station used in this study is around three times more expensive. However, as with most new technology, the costs decrease as the product gets more developed and the business model more commercialised. A decreased cost of V2H charging stations could lead to using EVs to power buildings and homes, economical viable.

However, the cost of the charging station is not the only problem of the V2H usage are facing, but also the ownership of the EVs is a major problem here. For some scenarios in the case study, it is assumed that all the EV owners are willing to participate in the V2H but this might not be the case in the real world. As the EVs are privately owned by the tenants and not owned and controlled by ÖBO, it could be possible that the tenants/EV-owners are not willing to participate in V2H as it has a large impact on the lifetime of the EVs, and therefore the vehicle must be replaced earlier compared to not participating in V2H, which is a cost for the EV owners. A reimbursement to the EV owners for letting ÖBO use their vehicle for V2H usage could be an incentive for the owners to be more eager to engage and participate in V2H. The reimbursement must be larger or at least equal to the number of kilometres or kWh used, i.e. LCOE, that the owner misses out on due to the shorten lifetime, which could be converted into a monetary value by calculating the total EV procurement and usage cost throughout the lifetime divided by the expected lifetime distance in km or kWh used. This would give an estimation of how much each km or kWh is worth and the owners would be reimbursed for every km or kWh they miss out on. A detailed reimbursement/price/cost scheme study of V2H for private owners must be done to ensure that every party in the system will make a profit from the new business model as the total reimbursement to the EV owners must be smaller than the profit ÖBO will make each year by using V2H to lower the electricity related costs. As mentioned earlier, there will be no profit from any scenario including EVs and V2H and therefore, no reimbursement will be able to be paid out to the EV owners.

Another difficulty with EVs owned by the tenants is the driving patterns and habits of the owners. It could be seen in the result that the number of EVs that were available when peaks should be lowered or PV surplus charged affected the result greatly. When using 0 % availability almost no peaks were lowered which also is very dependent on the facility load profile which have most of it peaks in the middle of the day when the EVs are not available. If an apartment load would have been used instead more EVs would probably have been available when peaks should be lowered in the morning and in the evening.

In the case study, it is assumed that the patterns and habits of the owners are constant every day of the year in order to find the perfect configuration of components and EV usage. However, it is also assumed that every day of the year is a weekday and uses the same availabilities, patterns, and habits for weekends where they as a matter of fact differ from weekdays. Due to the complexity of the code, the weekend availabilities, patterns and habits were not included in the case study. However, the availabilities, driving patterns and habits of the EVs differ a lot from reality. In real life, the owner does not use the vehicles in the same way every day and the unpredictable usage will affect the availability, and the patterns and habits which in itself
leads larger fluctuations in the load curve as there might not be any EVs available one day which could make the EV discharge all the other days unnecessary when having an effect subscription. The unpredictable driving habits where the EV owners might drive longer distance some days could lead to large loads during night time when charging starts and could possibly create such large load peak that it increases the maximum electricity consumption peak for the month and make all the other discharge days’ supernumerary. This problem also increases as the numbers of EVs in the building increases.

One solution to the problems the private ownership of EVs create could be creating an EV car sharing service for the tenants which is controlled and owned by ÖBO. If ÖBO were to use an EV car sharing service, they would be able to control the availabilities of the EVs during the day by making them unavailable for booking for the tenants, they will be able to plan charging and EV selection as ÖBO will know how much energy the EVs has used. This could also lessen the impact an increased implementation EVs have on the facility load and grid as the charging will be more controlled and scheduled.

Same thing also applies for EVs as did for the stationary batteries regarding if they are used to deliver services as frequency regulation to the TSO or voltage control and congestion management to the DSO. Meaning that if the EVs also are used with these purposes they might become economically viable or at least less unviable, making the ISO concept more viable.

6.5.4 Charge and Discharge Control Strategy

The charge and discharge control strategy of the BESS is not designed after the electricity price throughout the day but instead after consumption peaks and PV generation. As mentioned earlier, this strategy would not generate any monetary profits and would increase the degradation rate of the BESS as it would be charged and discharged every single day. However, this strategy would work in the point of decreasing the consumption peaks as the consumption highs and lows works in harmony with the high and low of the electricity price as it would discharge during mid-day, and charge during night, as that is when the electricity price is high and low respectively. This strategy would however most likely only work for a facility load and not for an apartment load as the highs and lows of the load curve contradicts with the electricity price, which is why a charging control strategy cannot be to general and has to be partially design after specific loads.

In the control strategy used in the case study, the BESS and the EVs starts to charge at 22:00 in the night as the facility consumption is low and the possibility that the increased electricity consumption affect the daily consumption maximum as at its lowest. However, when the BESS increase in size and the EVs increase in numbers, the possibility of the charging of the BESS and EVs will create a new daily or even a new monthly maximum consumption peak if they all start charging at the same time. The larger BESS and the larger number of EVs could help to decrease the monthly maximum consumption peak below the charging peak when all the components starts to charge at the same time. That is why it is important to make sure to spread out the charging throughout the hours to prevent creating maximum peaks during charging. To start charge for instance two of the EVs to maximum and then two new could be a solution to the problem that were not a problem with the number of EVs in the case study, but could be a problem with a greater number of EVs.

One aspect that could help the BESS to become economical viable, is the SoC limits of maximum of 90% and minimum of 20% that is chosen for the case study. As the limits are chosen to increase the lifetime of the battery and not after reducing the consumptions peaks to its maximum, it is possible that expanding the SoC limits of the battery to use 100% of the battery capacity, instead of 70% which is used in the case study, could lead to a positive NPV. When more battery capacity is available, the more the consumption peaks can be lowered, which could lead to a positive NPV as the electricity bill is lowered even more. However, with this strategy, the battery will degrade at a higher rate and the EOL limit will be reached faster, which leads to the LIB being replaced more often during the 25-year test period.

6.5.5 Degradation Model

As seen from the result of the degradation of the BESS and the EVs, the degradation rate of the BESS seems unrealistic as a LIB will most likely not have a lifetime over 25 years, where a shorter lifetime will
affect the economic result and viability of a BESS. The realistic results from the cycle test of the degradation model indicates that the calendar stress factor does not affect the degradation as much as wanted when the BESS is not used every day.

A reason for why the model gives unrealistic results could be that the study made by Karagiannopoulos et al. [157], which the degradation model is based on, conducted experiments on a LIB in order to derive the different constants used in the stress models and this is not made in this case study. The experiment is also done in the study [158] which Karagiannopoulos et al. model is based on, and all the stress constants in the two studies differs from eachother which mean that the constants are not general and real experiments must be done on the LIB that will be used in order to derive the exact constants. However, using the constant from one of the studies should give a well enough estimation of the degradation to receive realistic results. With more realistic results, the LIB in the BESS would most likely be replaced at least one time which would result in a lower NPV than what is given by the result and the BESS would be even less economic viable.

The results of the EV degradation is harder to compare if reasonable due to Nissan Leaf is relatively new and precise lifetime data and studies are not decisive at the moment. However, as both the BESS and the EV use the same degradation model, it is most likely that the degradation of the EVs differs significantly.

### 6.5.6 Subsidies and Taxes

The subsidies in Sweden on different energy sustainable components have a rather significant effect on the results in the case study. As seen from the result, a PV system without any BESS and without any EVs will always yield the highest NPV where the subsidies for PVs help to increase the economic viability of solar electricity. Subsidies are given for PV system and for EV charging station but not for BESS and as seen in the results, a BESS will always result in either a negative or a decreased NPV as the sizes increases. Therefore, subsidies for BESS would increase the possibility of a positive NPV which will lead to an increased willingness to invest in them. An increased willingness to invest in BESS will also increase the size a PV system can have and still be economically viable. This is something that helps increasing the renewable energy sources in a decentralised energy approach.

The subsidies given for PV system in Sweden, both for private persons and companies, increases the economic viability of them which increases the willingness to invest in them. However, the fact that companies and private persons need to pay energy tax on the electricity generated by their PV system if it exceeds 255 kW_{P} contradicts the subsidy in some ways. Private persons will in most cases not be affected of this as a 255 kW_{P} PV system will generate more electricity than needed for a single-family house, the affected ones will be the companies with multiple stores or buildings. As ÖBO is a company with several buildings, installing PV system of them will force them to pay tax for the electricity generated for own use, from their own system. Even though the laws around the taxes for the PV systems were recently changed for the better, where ÖBO only have to pay the low tax if they install several systems where each system does not exceed the capacity limit but the aggregated capacity does, it still will put companies with large installation areas, e.g. large malls, in a spot where they have to pay tax for the electricity they have generated from something they own and uses for themselves.

### 6.5.7 Property Value

An aspect this study does not take into account is the effect of a system configuration consisting of a PV system, a BESS and EVs for V2H can have on property value of the building and for ÖBO. As the innovative technology and business model could increase the property value of the building to the point where a positive NPV is not needed in order to make an overall profit as the increase in property value exceeds the expenditure of the system. This could very much be a possibility for ÖBO as they have made investments which has increased the property value of several buildings before and it is something they highly value.
7 Sensitivity Analysis

As the case study is largely influenced and affected by the costs of the components used in the calculations, it is important to investigate the impact of the different investment parameters in a sensitivity analysis. Most of the cost for different parameters were each taken from one source which might not reflect the market price at the moment of purchase. Therefore, all the most vital cost parameters in the case study is increased and reduced by 10% in order to see the possible outcome of a variation in market price. The vital cost parameters consist of the PV, BESS and EV parameters and is presented in Table 25.

<table>
<thead>
<tr>
<th>Cost parameter</th>
<th>Original Cost</th>
<th>Increased Cost (+10%)</th>
<th>Reduced Cost (-10%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(C_{\text{invest_PV}}) [SEK/Wp]</td>
<td>11.8</td>
<td>12.98</td>
<td>10.62</td>
</tr>
<tr>
<td>(C_{\text{inverter_PV}}) [SEK/Wp]</td>
<td>0.94</td>
<td>1.034</td>
<td>0.846</td>
</tr>
<tr>
<td>(C_{\text{procurement_LIB_BESS}}) [SEK/kWh]</td>
<td>3 796</td>
<td>4 176</td>
<td>3 416</td>
</tr>
<tr>
<td>(C_{\text{inverter_BESS}}) [SEK/W]</td>
<td>3.98</td>
<td>4.38</td>
<td>3.56</td>
</tr>
<tr>
<td>(C_{\text{install_BESS}}) [SEK]</td>
<td>7 485</td>
<td>8 234</td>
<td>6 737</td>
</tr>
<tr>
<td>(C_{\text{station_customs_EV}}) [SEK/charging station]</td>
<td>47 289</td>
<td>52 018</td>
<td>4 2560</td>
</tr>
<tr>
<td>(C_{\text{installation_EV}}) [SEK/charging station]</td>
<td>22 500</td>
<td>24 750</td>
<td>20 250</td>
</tr>
</tbody>
</table>

The costs are changed and presented only for 0% and 75% availability as these results will illustrate the largest differences in NPV as seen in the previous results. In the following sections, the results of the sensitivity analysis are presented in the exactly same way as the original result was, but with different values of the NPV caused by the changed costs.

7.1 Increased Costs +10 %

This section presents the result when all the most vital cost parameters are increased with 10 %.

7.1.1 0 EVs

The result of the NPV after 25 years with 10% increased investment costs for a system configuration with 0 EVs, for varying PV system and BESS sizes are shown in Figure 66 and Figure 67.

![Figure 66. Graph of NPV after 25 years for varying size of PV system and BESS with 0 EVs (0% availability) +10% increased costs.](image)

NPV After 25 Years for Varying Sizes of PV System and BESS with 0 EVs (0% Availability) +10% Increased Costs
NPV After 25 Years for Varying Sizes of PV System and BESS with 0 EVs
(75% Availability) +10% Increased Costs

Figure 67. Graph of NPV after 25 years for varying size of PV system and BESS with 0 EVs (75% availability) and +10% increased costs.

7.1.2 2 EVs

The result of the NPV after 25 years with 10% increased investment costs for a system configuration with 2 EVs, for varying availabilities, PV system size and BESS sizes are shown in Figure 68 and Figure 69.

NPV After 25 Years for Varying Sizes of PV System and BESS with 2 EVs
(0% Availability) +10% Increased Costs

Figure 68. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (0% availability) and +10% increased costs.

NPV After 25 Years for Varying Sizes of PV System and BESS with 2 EVs
(75% Availability) +10% Increased Costs

Figure 69. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (75% availability) and +10% increased costs.

7.1.3 4 EVs

The result of the NPV after 25 years with 10% increased investment costs for a system configuration with 4 EVs, for varying availabilities, PV system size and BESS sizes are shown in Figure 70 and Figure 71.
9.8

Figure 70. Graph of NPV after 25 years for varying size of PV system and BESS with 4 EVs (0% availability) and +10% increased costs.

Figure 71. Graph of NPV after 25 years for varying size of PV system and BESS with 4 EVs (75% availability) and +10% increased costs.

7.1.4 8 EVs
The result of the NPV after 25 years with 10% increased investment costs for a system configuration with 8 EVs, for varying availabilities, PV system size and BESS sizes are shown in Figure 72 and Figure 73.

Figure 72. Graph of NPV after 25 years for varying size of PV system and BESS with 8 EVs (0% availability) and +10% increased costs.
**7.2 Reduced Costs -10 %**

This section presents the result when all the most vital cost parameters are decreased with 10%.

**7.2.1 0 EVs**

The result of the NPV after 25 years with reduced investment costs for a system configuration with 0 EVs, for varying PV system and BESS sizes, are shown in Figure 74 and Figure 75.

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**NPV After 25 Years for Varying Sizes of PV System and BESS with 8 EVs**

(75% Availability) +10% Increased Costs

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**Figure 73.** Graph of NPV after 25 years for varying size of PV system and BESS with 8 EV’s (75% availability) and +10% increased costs.

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**NPV After 25 Years for Varying Sizes of PV System and BESS with 0 EVs**

(0% Availability) -10% Reduced costs

---

**Figure 74.** Graph of NPV after 25 years for varying size of PV system and BESS with 0 EV’s (0% availability) and -10% reduced costs.

---

**NPV After 25 Years for Varying Sizes of PV System and BESS with 0 EVs**

(75% Availability) -10% Reduced Costs

---

**Figure 75.** Graph of NPV after 25 years for varying size of PV system and BESS with 0 EV’s (75% availability) and -10% reduced costs.
7.2.2 2 EVs
The result of the NPV after 25 years with reduced investment costs for a system configuration with 2 EVs, for varying availabilities, PV system size and BESS sizes are shown in Figure 76 and Figure 77.

Figure 76. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (0% availability) and -10% reduced costs.

Figure 77. Graph of NPV after 25 years for varying size of PV system and BESS with 2 EVs (75% availability) and -10% reduced costs.

7.2.3 4 EVs
The result of the NPV after 25 years with reduced investment costs for a system configuration with 4 EVs, for varying availabilities, PV system size and BESS sizes are shown in Figure 78 and Figure 79.

Figure 78. Graph of NPV after 25 years for varying size of PV system and BESS with 4 EVs (0% availability) and -10% reduced costs.
7.2.4 8 EVs
The result of the NPV after 25 years with reduced investment costs for a system configuration with 4 EVs, for varying availabilities, PV system size and BESS sizes are shown in Figure 80 and Figure 81.

7.3 Conclusion of Sensitivity Analysis
The results of the sensitivity analysis show a clear difference between the original, the increased and the reduced costs, not only in that the NPV has increased or decreased, but also which size of PV system is the most economic viable. With increased costs, the highest NPV is lower for each number of EVs and availability, compared to the NPVs for the original costs. However, the most noticeable with the result for increased costs is that the larger PV system sizes becomes less economic viable than not installing a PV system. ÖBO will actually lose more money installing a large PV system compared to not installing a PV system. This also applies for the increasing BESS sizes where a system consisting of only a BESS and no PV will yield a higher NPV than a system with a BESS and a large PV system. Compared with the original cost where a system configuration without a PV system always will, with some few exceptions, yield the
lowest NPV when combined with a BESS. However, for the reduced results, the larger PV system sizes will always yield a higher NPV than a system without a PV system. As seen in the graphs from section 7.2, a PV system of 168 kW\textsubscript{P} yields the highest NPV with only a few exceptions where it is combined with a certain size of BESS.

One interesting point from the sensitivity analysis is that the BESS will generally become a lot more economic viable, for the configurations where a positive NPV is given, when the costs are reduced. For the original costs, the configurations will give a positive NPV for BESS sizes up to around 15 kWh as seen in Figure 46, the increased costs only yields a positive NPV for BESS sizes up to around 10 kWh as seen in Figure 66 and Figure 67. The largest difference is given for the reduced cost where a BESS size of around 50 kWh still will be economic viable for certain PV system sizes as seen in Figure 74 and Figure 75. This shows that cost of the BESS is a significant part of the economic viability of a system that consists of a BESS.

The result of the NPV yielding configuration for increased and reduced PV, BESS and EV related costs are presented in Table 26 and Table 27.

Table 26. Summary of NPV result for 10\% increased PV, BESS and EV costs for different number of EVs and availabilities.

<table>
<thead>
<tr>
<th>EVs [-] / Availability [%]</th>
<th>0</th>
<th>75</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>56 kW\textsubscript{P} 0 kWh BESS 50 000 SEK</td>
<td>56 kW\textsubscript{P} 0 kWh BESS 50 000 SEK</td>
</tr>
<tr>
<td>2</td>
<td>56 kW\textsubscript{P} 0 kWh BESS -325 000 SEK</td>
<td>56 kW\textsubscript{P} 0 kWh BESS -130 000 SEK</td>
</tr>
<tr>
<td>4</td>
<td>56 kW\textsubscript{P} 0 kWh BESS -655 000 SEK</td>
<td>56 kW\textsubscript{P} 0 kWh BESS -420 000 SEK</td>
</tr>
<tr>
<td>8</td>
<td>56 kW\textsubscript{P} 0 kWh BESS -1 350 000 SEK</td>
<td>56 kW\textsubscript{P} 0 kWh BESS -1 070 000 SEK</td>
</tr>
</tbody>
</table>

Table 27. Summary of NPV result for -10\% reduced PV, BESS and EV costs for different number of EVs and availabilities.

<table>
<thead>
<tr>
<th>EVs [-] / Availability [%]</th>
<th>0</th>
<th>75</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>168 kW\textsubscript{P} 0 kWh BESS 240 000 SEK</td>
<td>168 kW\textsubscript{P} 0 kWh BESS 240 000 SEK</td>
</tr>
<tr>
<td>2</td>
<td>168 kW\textsubscript{P} 0 kWh BESS -100 000 SEK</td>
<td>168 kW\textsubscript{P} 0 kWh BESS 100 000 SEK</td>
</tr>
<tr>
<td>4</td>
<td>168 kW\textsubscript{P} 0 kWh BESS -350 000 SEK</td>
<td>168 kW\textsubscript{P} 0 kWh BESS -160 000 SEK</td>
</tr>
<tr>
<td>8</td>
<td>168 kW\textsubscript{P} 0 kWh BESS -930 000 SEK</td>
<td>168 kW\textsubscript{P} 0 kWh BESS -690 000 SEK</td>
</tr>
</tbody>
</table>

As seen from the result presented in the tables above, and compared to the result with the original cost in Table 23, the largest difference is that the largest PV system size always yields the highest NPV for reduced costs and the 56 kW\textsubscript{P} yields the highest NPV for reduced costs. Whereas, the highest NPV is given from the 56 kW\textsubscript{P} PV system for low number of EVs and higher availabilities, and when the number of EVs increases and availabilities decreases, the highest NPV is yielded from the larger PV system sizes.
8 Conclusions and Future Work

From the study made, the main conclusion is that the overall recommendation to ÖBO is that a system consisting of only a 92.4 kWp PV system (same as a yearly production of 710 kWh/kWp) at Höglundagatan 21 is the optimal system configuration based on the maximum yielding NPV. A system consisting of a BESS can be profitable up to 41 kWh if combined with the optimum PV system size but never as profitable as for a PV system alone, and EV charging stations with V2H-application will always result in a non-profitable system with today’s cost of equipment and electricity prices.

The control and charging strategy made for the facility load of the study was successful in peak-shaving only the highest peaks of the month and maximizing the self-consumed solar surplus. In other words, the strategy was successful in decreasing the electricity costs as much as possible, but with today’s costs for BESS and EV charging stations and today’s electricity pricing, the investments will be higher than the savings that can be made from the investment.

EV availability affects the profitability of the system significantly. An increased availability increases the ability to peak-shave the monthly highest peaks and to absorb solar generated surplus electricity drastically, specifically when the load profile has peak hours and surplus hours occurring when EVs are unavailable. An increased ability to absorb solar generated surplus electricity also enables the instalment of a larger PV system which increases the self-consumption and self-sufficiency of the system. With other words, an increased EV availability can increase the electricity related economic savings a lot, but not more than it costs to invest in the charging stations.

Even though a system configuration including a BESS or EV charging stations were not the most profitable solution, there can still be a value of having them installed. Because, for the Local system operator concept to be viable, many buildings need to have flexible energy assets, as BESS or EV charging stations, installed to be able to aggregate enough flexible electricity usage after the needs of the electricity grid or other actors on the energy market. The study has showed that it can be profitable to have a BESS up to a certain size installed in combination with a PV system. This means that it could give an incentive for housing companies as ÖBO to invest in the flexible energy assets needed to make the local system operator concept viable, especially if extra revenues can be added if the aggregated flexibility services are delivered to and paid by actors as the TSO or DSOs.

To model an even more realistic behaviour and to get further value out of the study, future work and further investigation could be done regarding the following:

- The existing control and charging strategy should be tested and optimized according to a different electricity load profile with peaks occurring at other hours. The load profile could for example have the apartment load profiles included.
- The orientation and inclination of the PV modules should be optimized in order to receive as much incoming solar radiation as possible over a year.
- Further investigate the degradation model to simulate the degradation behaviour in a more realistic way and evaluate the degradation of individual EVs and not as an aggregated fleet.
- Investigation on the effect the energy system has on the property value of the buildings. As a non-profitable energy system could end up as profitable if the property value increases enough.
- A price study should be carried out on how the reimbursement should be done to the EV owners. Another alternative to investigate could also be if ÖBO owned the EVs themselves in a car-sharing service.
- Further investigate how the behaviour of EV usage affect the ability to lower peaks or charge solar surplus. Where different types of behaviours should be taken into consideration in combination with different load profiles.
Investigate how electricity pricing can affect the economic viability of the system. For example, if the Nordic pool spot market's volatility increases and make the use of batteries and EVs more profitable.

Investigate what kind of cost reductions that are necessary for batteries and charging stations to make investments economically viable and when in the future that is likely to happen.

Investigate how business models should be built and how much revenue that is necessary from services as frequency regulation, voltage control or congestion management in order to make investments in BESS systems or EVs economically viable.

In conclusion, the usage of a PV system in combination with a BESS and EVs using V2H charging, shows potential in lowering electricity consumption peaks and optimizing the self-consumption of solar surplus from PV generation. However, today’s batteries and especially EV charging infrastructure are not yet cost competitive to make a profit with existing electricity prices and subscriptions. If costs continue to drop, the conclusions in this study is considered and the suggested future work is carried out, this study may suggest different solutions on how a housing company as OBO can make a profit from an investment consisting of a PV system, a BESS and EV charging infrastructure and how they with the help of a local system operator can change the energy system from a traditional top-down approach to a bottom-up approach in the future.
9 References


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Appendices

Blueprints Höglundagatan 21

The blueprints of the buildings used in the case study is presented in the figures below.

Figure 82. Blueprint of the buildings facades
Figure 83. Blueprint of the roof for building G

Figure 84. Blueprint of the roof for building B
Figure 85. Blueprint of the roof for building C

Figure 86. Blueprint of the roof for building E
**Result Electricity Consumed from the Grid**

Illustration of the facility electricity consumption in an example of an energy system consisting of a 112 kWp, a 50 kWh BESS and 4 EVs with 50% availability is presented of the figures below.

*Figure 87. Original electricity consumption profile of Höglundagatan 21.*

*Figure 88. The electricity consumption profile of Höglundagatan 21 after a 112 kWp PV system.*
Figure 89. The electricity consumption profile of Höglundagatan 21 after a 112 kWp PV system and 50 kWh BESS operated after the control strategy.

Figure 90. The electricity consumption profile of Höglundagatan 21 after a 112 kWp PV system and 50 kWh BESS and 4 EVs with a 50% availability, both operating after the control strategy.