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Expansion of photovoltaics in Stockholm

Consequences on local power balance and on Fortum Värmes production planning

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Abstract

Expansion of photovoltaics in Stockholm - Consequences on local power balance and on Fortum Värmes production planning

Olof Ivarsson

The focus of this study is to determine what consequences a hypothetical large photovoltaic system in Stockholm could have on how Fortum Värme plans the production of heating, cooling and electricity. A literature study about the technical possibilities to combine the production from photovoltaics with the production in a district heating system is done. By analysing the potential for photovoltaics in Stockholm, calculating the possible production of electricity from a larger photovoltaic system and comparing it to the load in the electrical grid, the possibilities to use Fortum Värmes production of electricity as balancing power to the photovoltaic system are determined. An electricity market model is used to create price profiles of the price of electricity, which changes with larger amounts of electricity from photovoltaics in the energy system, during certain periods of time. A linear optimisation model is created to optimise the production costs of a simplified system containing Fortum Värme's production units. The production costs are optimised using the price profiles from the electricity market model, in order to understand if and how the planning of Fortum Värme's production of heating, cooling and electricity changes when large amounts of photovoltaics are introduced in the energy system.

The results given in the analysis in this thesis makes it reasonable to assume that there is no reason for companies running large district heating systems to offer balancing of large scale photovoltaic systems. The balancing service would increase the costs, lower the profits, cause additional wear on the production units and demand excessive production planning. However, the effects on the price caused when large scale PV system are introduced in the energy system does not affect the production cost significantly.

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Populärvetenskaplig sammanfattning

Det är ett politiskt mål att bebyggelsen i framtiden ska försörjas i större utsträckning med förnybar energi. Lokal produktion av el från solceller ses som en möjlighet att åstadkomma detta. Det är troligt att produktionen av solel inom Stockholm kommer att öka kraftigt i framtiden, bland annat har Stockholms stad ambitionen att öka produktionen av solel på stadens egna byggnader.

En ökad produktion från solceller och andra intermittenta kraftkällor kan dock få konsekvenser för effektbalansering och drift av distributionsnät. Fortum värme, som är Stockholm största tillverkare och distributör av fjärrvärme och fjärrkyla, och som också tillverkar och säljer elektricitet har genom sin varierade produktionspark stora möjligheter att reglera nettoproduktionen av el i Stockholm. I kraftvärmeanläggningar produceras samtidigt el och värme, i värmepumpar används el för att producera värme. Därför undersöks i denna rapport vilka konsekvenser en större utbyggnad av solceller skulle ha på hur Fortum värme väljer att planera sin produktion av värme, kyla och el.

I Stockholm finns idag ungefär 2 MW solceller, men potentialstudier visar att uppemot 200 MW installerad effekt är möjligt i framtiden. Med den installerade effekten skulle solcellerna leverera ungefär 195 GWh el under ett år.

De teoretiska möjligheterna att använda ett fjärrvärmesystem för att balansera intermittent elproduktion är relativt stora. Eftersom många större fjärrvärmesystem kan både producera och konsumera el kan produktionen ställas om för att anpassas efter lasten på elnätet. Den tekniska möjligheten att variera produktionen i en ångturbin är dock begränsad. Att göra större justeringar i produktionen under kortare tid sliter på utrustningen och ökar driftskostnaderna. Värmepumpar och elpannor däremot är mer flexibla och kan startas och stoppas snabbare och oftare.

Om lasten i elnätet i Stockholm jämförs med elproduktionen från solceller och kraftvärme blir det tydligt att det är stora storleksskillnader. Till exempel klockan 14.00 första januari, var lasten 1160 MW medan Fortum värme producerade 137 MW och solcellerna levererade 1 MW. Det finns alltså ingen rimlig möjlighet att kombinera solceller och kraftvärme för att balansera lasten på nätet, och inte heller något incitament att balansera produktionen från solceller med produktion från kraftvärme.

Elpriset kommer att förändras om större mängder intermittenta kraftkällor finns i systemet. En elmarknadsmodell visar att elpriset under dagarna, när solcellerna producerar el, ofta skulle vara lägre än de historiska elpriserna om 10 % av den totala tillförseln av elektricitet i Sverige kom från solceller. Dessa förändrade priser skulle kunna påverka produktionsplaneringen hos Fortum värme, varför detta analyserades med en för ändamålet konstruerad linjäroptimeringsmodell. Värme- och kylabehov, elpris och anläggningsdata från Fortum värme används som indata för att planera en produktion under 48 angivna timmar i april, juni, augusti respektive oktober. Produktionskostnaderna jämfördes mellan scenarion med dagens mängd solceller i energisystemet och med 10 % solceller i energisystemet. Analyserna visade att den totala produktionskostnaden skulle sjunka i samtliga scenarion, förutom i oktober. Att kostnaderna sjunker i april, juni och augusti beror på att elpriserna är så pass låga att kostnaden för att producera värme med elektricitet hålls nere, men inte så låga att vinsten från att producera och sälja el blir för liten. I oktober däremot gjorde de minskade intäkterna från elförsäljning på grund av lägre elpris att det blev dyrare att producera den nödvändiga mängden värme med en stor mängd solceller i systemet än vid historisk mängd solceller.

För att undersöka hur produktionskostnaderna skulle förändras om det tillkom villkor för att upprätthålla balansen på elnätet. Det scenario som analyserades antog att ett krav på hur mycket el som skulle konsumeras tillkommit. Fortum värme skulle alltså bli tvingade att konsumera el för att begränsa mängden el ut på elnätet. Istället för att använda kraftvärme för att producera värme måste elektricitet användas för att producera värme. Detta innebar att den billiga kraftvärmen och intäkterna från elförsäljning försvann och ersattes med ökade kostnader för produktion med värmepumpar. Totalkostnaderna för att producera nödvändig mängd värme under de analyserade 48 timmarna steg med 80 % när konsumtionsvillkoret infördes.

Slutsatserna som kan dras från arbetet är att elpriserna kommer att förändras vid införandet av större mängder intermittenta kraftkällor, och detta kommer att påverka produktionskostnaderna, men inte tillräckligt för att förändra produktionsplaneringen. Detta innebär att sättet som dagens produktion sker på är relativt okänsligt för prisfluktuationer. Vidare kan fastslås att även om det är tekniskt möjligt är det inte ekonomiskt försvarbart att låta produktionen från fjärrvärmesystemet balansera produktionen från solceller i någon större utsträckning.

Executive summary

A political goal is to increase the amount of renewable energy in Sweden’s energy system. To do so, the city of Stockholm plans to increase the amount of photovoltaics (PV) on their own buildings. Fortum Värme is the single largest producer and distributor of district heating and cooling, as well as electricity in Stockholm. One idea is to create a virtual power plant consisting of Forum Värmes production units and the newly installed PV. This study aims at finding out what problems and possibilities such a system could create.

Recent studies show that the potential for PV in Stockholm is 100-200 MW installed power. If 100 MW PV would be installed in Stockholm. On sunny summer days, the system would produce around 80 MW and around 5-20 MW during the few sunny hours in the winter. Fortum Värmes system typically produces around 200-300 MW during winter time and 0-50 MW during summer time. The load in the electrical grid in the area of Stockholm is 1000-1600 MW during the most intense hours in the coldest months and 600-1000 MW during the rest of the year. The difference in size of the production compared to the load are too big to make it reasonable to create a system where the PV and the electricity production from Fortum Värme are used to keep the load in the grid down.

When larger amounts of PV are introduced in the system, it affects the price of electricity. Assumed that 10 % of the total produced electricity in Sweden comes from 10 % the price will decrease during some hours of the day. This could affect the production cost of the heat and cooling that Fortum Värme produces. When production planning is analysed, it shows that a lower price of electricity indeed lowers the production cost in most scenarios. In some cases the total production cost for heating, cooling and electricity increases with lower price of electricity, because of the lower profit from selling electricity. Fortum Värmes system is rather insensitive to price changes since it is optimised to produce the demanded products to as low a price as possible.

The conclusion drawn from this study is that there is no reason to create a virtual power plant from the PV system and Fortum Värmes system, since it would only increase the cost and make the production planning more difficult and time consuming.

List of abbreviations

CHP	Combined heat and power
DH	District heating
EB	Electric boiler
FV	Fortum värme
HP	Heat pump
LCOE	Levelised cost of electricity
PV	Photovoltaics
VPP	Virtual power plant

Contents

1 Introduction

1.1 Scope

It is a political goal to increase the amount of renewable energy in the energy system. Locally produced electricity from photovoltaic cells (PV) is seen as a possibility to achieve this. Because of this, it is reasonable to believe that the amount of PV modules in Stockholm will increase rapidly in the future. For example, the city of Stockholm has the ambition to extend their existing PV system by adding more modules on the roofs of municipally owned buildings.

An increased amount of PV modules and other intermittent sources of renewable electricity may have consequences on the power balance and the load on the grid. Fortum Värme (FV) is a district heating (DH) company that owns the majority of the DH system in Stockholm. FV produces around 75 % of the heat delivered in Stockholm, but they also deliver cooling and electricity. Through the variety of production units, FV has the possibility to regulate the net production of electricity in Stockholm. The combined heat and power plants produces heat and electricity, and heat pumps and electrical boilers use electricity to produce heat.

This master thesis will be a part in the international project GrowSmarter, which aims at demonstrating and evaluating new energy and resource efficient solutions for city regions. Stockholm takes part in the project together with Barcelona and Cologne. Fortum Värme carries out a number of activities as industrial partner, and one of these activities is to find a concept on how the expansion of the PV system in Stockholm can be optimised.

One idea that is to be evaluated is that Fortum Värmes production facilities would be used as a Virtual Power Plant (VPP) together with the PV system in the city, i.e. when there is an excess of electricity from PV, Fortum Värme uses it to produce heat, and when the production of electricity from PV is low, Fortum Värme will produce electricity in their combined heat and power plants.

The main scope is to investigate how Fortum Värme’s combined heat and power-system (CHP) can be used to balance the production of electricity from recent and future PV-systems in the city of Stockholm. Part of the scope is to investigate if the CHP-system and the PV-system can be combined into a VPP. This is done by

- Analysing the potential for electricity from PV in Stockholm by researching reports on potential and investigate the existing plans on expanding the PV system in Stockholm
- Analysing what effects the increased amount of PV would have on the energy system and the price of electricity
- Analysing what possibilities and disadvantages there is to use a DH system as balancing power to PV by studying the existing DH system and researching reports on the subject
- Creating a linear optimisation model to simulate the production in the DH system to analyse scenarios with different production modes

The results will be divided into three parts:

- Scenarios for PV system
  To analyse the potential of power balancing it is important to know what size a future PV system could have, and how much it can produce. This is done by analysing potential studies and collect data over historical production from PV in Stockholm.

- Analysis of power balance
  The purpose of the analysis of power balance is to provide a picture of the scale of the production of electricity in the PV system, the production of electricity from the DH system and the load in the grid. Given data of FV's production and the load in Stockholm is compared to simulated data of electricity from PV. What makes this analysis needed is the fact that the grid surrounding Stockholm, a grid called Stockholmsringen, creates a capacity limit in the transfer of electricity into Stockholm. The maximum load in Stockholmsringen is 1525 MW (Zetterqvist, 2016), and to keep the load from exceeding this, FV has to guarantee a production of electricity at any given hour. If the load in Stockholmsringen rises, FV has to keep it down by providing more power into the grid. It would be interesting to see if the PV system could be used to help FV keeping this power guarantee.

- Analysis of production cost
  The purpose of the analysis is to examine how the total cost of production of heat, cooling and electricity changes when a large scale PV-system is incorporated in the existing district heating system. The PV-system may change the price of electricity depending on how much electricity it is producing, and since the heat pumps run on electricity and the CHPs produce electricity, the changed price of electricity may affect how the production should be planned. The electricity needed to balance the PV-system gives an electricity demand that needs to be met. To investigate how the cost changes with changing electricity price and a demand for electricity an optimisation model is used to minimize the cost of production for each hour over a given 48 hour period of time. The result of the optimisation is the cost of production to meet all demands for a given hour.

2 Background

2.1 Virtual Power Plants

Virtual Power Plants describes systems of several power sources, controlled as one single power plant. This is done to prevent instability in the electric grid, but also because of the benefits of a large-scale production. Intermittent power sources may cause problems in the grid because of the varying production of electricity, but if the intermittent power source is combined with a continuously producing unit, it is possible to control and balance the production so that the power distributed to the grid is more stable. A VPP does not need to contain different kinds of power sources, but can also be a system of several smaller unit of the same type, controlled together to function as one unit.

A VPP can be local, but it can also be stretched over entire countries, as it can be a system gaining benefits from the geographical differences of intermittent power sources, like the probability that it is always windy in some part of the country or that the sun always shines somewhere during the day. For example, a research team in Germany has done studies on how a VPP can be used to make sure that the demand of electricity in the country is met with 100 % renewable power sources. By using wind power, solar power and some CHP using renewable fuel, they could create a VPP that on any given time could meet the demand of electricity (Rohrig, 2013). As another project, they studied if it is possible to maintain the stability in the grid by using only renewable power sources. By combining the intermittent power sources with production units capable of fast changes in production, and the possibility to store energy in for example pump hydro plants, they could keep the frequency stable in the matter of seconds, despite the fact that 90 % of the system was intermittent power sources (GREA, 2013).

An example of a VPP system containing several smaller units of the same type is the system of Ökoström Schweiz. It contains 100 small biogas plants spread across the country, controlled as one unit. This makes it possible to keep a stable production, and it is also makes the sensitivity of lost production and increasing demand smaller, since some units can be used as back up units, storing gas to be used when needed, and some units without the possibility to store gas can be run continuously. The system can be controlled and the production can be changed on hourly basis, making it a very flexible system that maximises the use of each unit. (Mutzner, 2012).

2.2 General challenges with large scale PV systems

2.2.1 Technical challenges

North European Power Perspective, NEPP, (2016) presents four direct challenges with energy systems containing a large amount of intermittent sources of electricity. The challenges are:

- Mechanical inertia mass
  PV systems does not use synchronous machines to generate electricity, which makes the amount of mechanical inertia mass in the system smaller when PV becomes a bigger part of the system. The mechanical inertia mass is needed to control the grid frequency.
- Balance regulation
  The amount of electricity produced from PV changes every second and is needed to be balanced in order to maintain grid stability. This makes the need for short time balancing power greater and with that lager flexibility in the producing units. The regulation on longer time scales is also important, with need of for example seasonal storage.
- Times of excess
  Sometimes the PV system produces a lot of electricity at the same time as conventional power sources produces. This makes for an excess amount of electricity, which strains the grid. The excess must be taken care of somehow.
- Grid capacity
  The grid must be able to transfer the needed energy, and to cope with the transients from the PV system.

The challenges that mostly affects district heating systems are the balance regulation and the excess production of electricity, since most of the large district heating systems has the ability to both produce and consume electricity. The grid capacity is mainly a challenge for companies owning and maintaining grids. On local level this is often done by the DH companies, but this is not the case in Stockholm, where FV do not own the electric grid.

2.2.2 Effects on price

When PV is introduced in the energy system, the price of electricity will become more volatile because of the intermittency in the production of electricity. The production of electricity from PV is hard to predict and because of that, the prediction of prices is difficult. What could be assumed is that there will be more hours with low prices (Sköldberg et al, 2015). To simulate electricity prices used in this thesis, an electricity market model was used. The model is further described in chapter 3.2.4.

3 Method

3.1 District heating systems as a VPP combined with PV

3.1.1 Startup times and varying production of electricity

To know how good a DH system is at balancing a PV system, it is important to know how fast the production of electricity in the DH system can be changed. The production of electricity from PV changes within minutes, and to keep a good power balance it is needed to changes the production in the DH system at the same rate as the PV. Small changes can often be made in the heat and electricity production system that is running, but if a larger amount, more than a couple of MW, of power is needed to be balanced, it may be necessary to start another production unit to meet the demand. Table 1 shows the time needed from zero to full capacity in some of FV's production units. This is the minimum time needed without causing unnecessary wear on the turbines.

Table 1. Table of startup times for some of FV's production units. KVV1, KVV6 and KVV8 are CHPs and G1, G2 and G8 are steam turbines in these CHPs (Mellström, 2016).

Production unit	Time from zero to full capacity from cold	Time from zero to full capacity from warm (boiler at 400°C)
KVV1 G1	15-16 hours	7-8 hours
KVV6 G2	13-14 hours	11-12 hours
KVV8 G8	15 hours	6 hours
Heat pumps	2-3 hours	-

Table 1 shows that the CHPs needs to be started about one day before it is supposed to be used. This means that it is not possible to start a turbine to meet power demands on hourly basis, but that the production must be planned ahead. The heat pumps however, are faster and can be started and stopped several times a day. What should be noticed is that when a turbine or a heat pump (HP) is running, it is possible to vary the production in small steps at faster rates than stated in Table 1. From Table 1 it is possible to draw the conclusion that it the electricity consuming system is faster than the electricity producing system. An already running HP can produce at maximum capacity within 15 minutes, and assuming that most production units does not produce at maximum capacity, it means that it is possible to change the consumption of electricity at a rather fast rate (Backteman, 2016).

When studying the production of electricity during 2015, it is noticeable that during some months, the production of electricity changes drastically from night to day. As seen in Figure 1, the production is low at nights and rather high during the days. There are two possible explanations to this. The first being that it is profitable to produce electricity during the day and that FV wants to produce as much as possible. The second explanation is that the heat demand during the day is much lower than during the nights, and since the boiler is running and steam is produced, it is not possible to just stop the boiler. The steam is lead to the turbine to produce electricity, instead of just dumping it in the air. When nighttime comes and the heat demand rises, the steam is used to produce heat instead of electricity (Backteman, 2016).

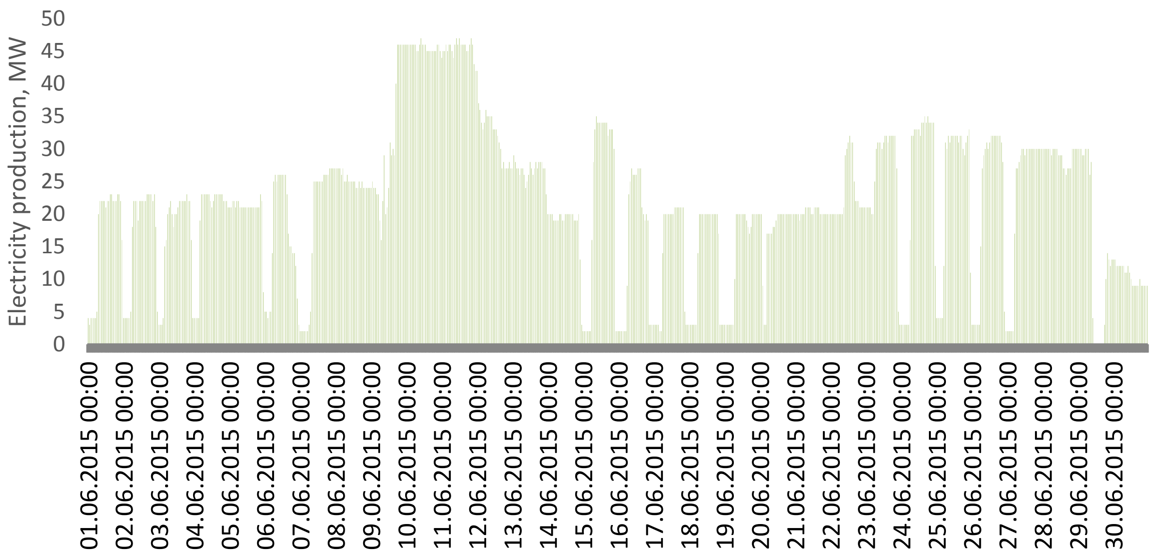

Figure 1. FV's production of electricity from CHP June 2015.

3.1.2 Technical possibilities

Most of the larger district heating systems are based on production units that both can produce and consume electricity. In times with need of electricity is it possible to increase the production of electricity, and when there is an excess of electricity, it could be consumed in HP and electric boiler (EB). This makes them interesting to use as balancing systems in energy systems containing large amounts of intermittent power sources. This may sound good in theory, but in practise, there are some limitations to take into consideration. To easier understand how a DH system can be used to balance a PV system, Table 2 shows different demands of electricity and heating and how the production in the DH system can be controlled.

Table 2. Shows how different demands can be met by changing the production of heat and electricity

High demand of electricity High demand of heat	Increase production of electricity and heat in CHP
High demand of electricity Low demand of heat	Increase production of electricity in CHP Decrease production of heat in CHP
Low demand of electricity High demand of heat	Decrease production of electricity in CHP Increase production of heat in CHP Increase production of heat in HP
Low demand of electricity Low demand of heat	Decrease production of electricity and heat in CHP

3.1.3 Technical limitations

The potential to use CHP alone to balance the production from PV systems is rather low, according to (NEPP, 2016). This is because the lacking possibilities of controlling a scenario where the production of electricity is higher than the demand. A CHP cannot consume electricity, in greater quantities that is, which is needed when there is an excess of electricity. If a CHP is combined with electricity consuming production units, as in a district heating system, the potential rises. If the base production of electricity comes from CHP and the rest from HP and electric boilers, the system is capable of both producing and consuming electricity. One thing that could be problematic with this setup is the cost of using electricity to produce heat. It could be assumed that hours with high electricity production and low demand occurs during times when the heat demand is low, i.e. during the warmer part of the year. During parts of the year with low heat demand, the major production of heat is done through waste incineration at low costs (Fortum Värme, 2016).

The cost of using electricity to produce heat is most often higher than CHP using waste incineration, even if the price of electricity is close to zero, because of the costs of taxes and Tradeable Green Certificates. If the electricity price was negative and the cost for waste incineration was higher, there could be times when HP and EB are cheaper, but that is unlikely today (Fortum Värme, 2016).

HP are cheaper per produced MWh heat than electrical boilers, but since HP are so efficient, a COP around 3 is not unusual, the amount of heat produced per consumed MWh of electricity is larger than the production from an EB. That means that less electricity is needed in a HP to produce the same amount of heat as in an EB. In situations where both the demand for electricity and the demand for heat are low, there might be a disadvantage to use HP, because of the high efficiency.

The costs are not only important when consuming electricity, but also when producing electricity. The main goal with DH systems is to cover the heating demand. When doing so, and using a CHP, co-production of heat and electricity is possible. When more electricity is produced, less heat can be produced. Assuming a scenario where both the heat demand and the electricity load is high, the production of heat to meet the heat demand is priority. If the DH company has several production units it might be possible to meet the heating demand and to produce electricity to keep the load under control by turning on other units, but since the production is planned to be as cheap as possible, the production with the new unit probably will be more expensive per produced MWh than the one already in use. This could make the DH companies think twice before locking themselves to produce electricity when the load is high.

For example, if a DH company has a waste incineration plant running on full capacity, producing 200 MW of heat and 30 MW of electricity at a cost of 50 SEK/MWh, and the heat demand increases so that the plant must produce 220 MW of heat, the production must be changed. The plant can produce 220 MW heat by decreasing the electricity production to 10 MW and without increasing the cost of heat production. If the company running the plant has an obligation to the grid owner that they, when needed, will produce electricity to keep down the load on the grid, and both the heat and electricity demand increases, so that the company needs to produce 220 MW heat and 30 MW electricity, the company must start another production unit. They keep the CHP running on maximum capacity and producing 200 MW heat and 30 MW electricity. Whatever unit they chose to start to produce the remaining 20 MW of heat will be more expensive than using the CHP to produce all the heat, and no electricity.

Another thing that is important to take into account when analysing an energy system, both with a lot of electricity from PV and systems with mostly conventional power, is the need for frequency control. In Sweden the grid frequency is 50 Hz. To keep the frequency stable, the consumption and production must be balanced. If the load increases without more production, the frequency will decrease, and if the production increases without increasing load, the frequency will increase. The frequency is stabilised by changing the production in specific production units, depending on the changing load. A system with high mechanical inertia mass is less sensitive for frequency changes, but the problem is that a CHP does not always contribute with high mechanical inertia. The mechanical inertia mass comes from rotating machines and a CHP varies the amount of produced electricity, and therefore changes the amount of mechanical inertia mass. When the turbines are shut down, no mechanical inertia is available (Sköldberg et al., 2015).

The general conclusion of the theoretical possibilities and limitations of the use of DH system to balance a large PV system is that it the pre-requisites are met, but it depends on how the DH system is constructed and the size of the PV system if it is practically and economically possible to produce the power needed for balancing.

3.2 Scenarios of solar electricity production

3.2.1 Existing PV-systems

In the end of 2015 the PV-systems managed by the city of Stockholm had an installed power of around 2 MW (Heyum, 2015). Most of these modules were installed on buildings in Stockholm owned by companies run by the city of Stockholm, as part of the project Sustainable Järva, which was a project to make the suburban area around Järvafältet in Stockholm more environmentally sustainable (Stockholm stad, 2015). The city of Stockholm also has a larger PV module in Frihamnen, which has an installed power of 200 kW. The modules around Järvafältet are smaller with an average installed power of 30 kW. Figure 2 shows the location of the modules.

Figure 2: The location of the PV modules in Stockholm. A blue dot represents one module.

The modules send production and module data to a database, and those modules that produced electricity during the entire year 2015 are used in this project to create a production profile. That means that modules installed during 2015, or module that does not produce the entire year are subtracted from the production profile. This is done to make sure that the production data is reliable and shows true values. The installed power of the modules used to create the production profile is 0,8 MW. The production of electricity from these PV modules is given in Figure 3.

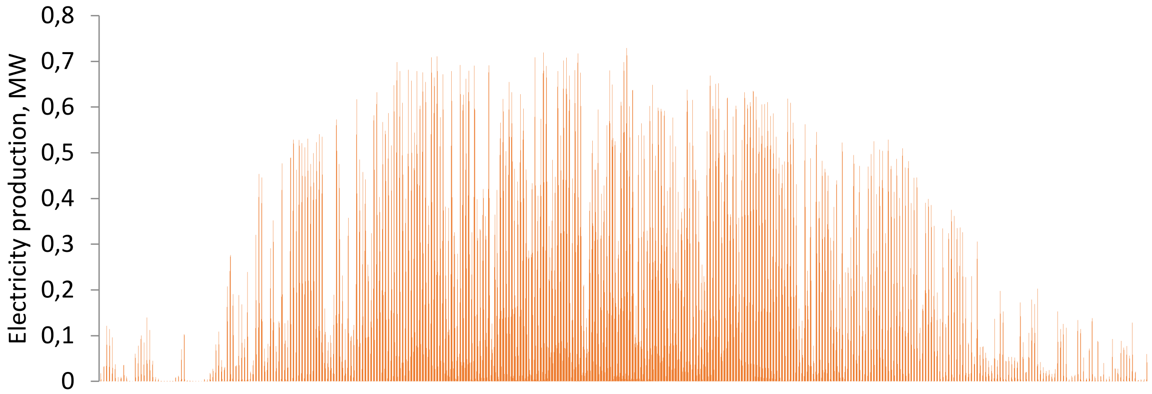

Figure 3. The production of electricity from the existing PV system during 2015. The total production during the year was 195 GWh of electricity (Stockholm Stad, 2016).

3.2.2 Future growth in PV capacity

To increase the amount of PV modules the plan from the city of Stockholm is to install another 1MW, an increase of 50 %, until 2020 (Heyum, 2015).

Previous studies show that the potential for PV in Stockholm is rather large. A study from 2013 concludes that using the roofs of buildings owned by the city of Stockholm, an installed effect of almost 250 MW is possible to achieve (Stockholms stad, 2013). A more recent study analyses the same buildings as in the previous study, but excludes roofs that are not suitable. The roofs can be unsuitable because they are too small, they are valuable in a cultural aspect or has too many chimneys or other objects that makes the installation harder or may cast shadows over the PV modules. The study shows that it is possible to install PV modules with a total installed power of around 100 MW (Wiksell, 2015). This means that even with a though selection of appropriate rooftops, the potential is still a lot bigger than what is currently planned to be installed.

The European Photovoltaics Technology Platform (PVTP) has studied levelised cost of PV electricity (LCOE) between 2014 and 2030, which shows that the LCOE will decrease by around 45 % until 2030. This is due to lower production costs for PV modules, higher module efficiency and lower cost for equipment used to balance the system, i.e. inverters, cables and infrastructure. The cost is believed to decrease further until 2050 (PVTP, 2015).

3.2.3 Simulated future system

The size of the PV-system used for analysis in this report is based on the potential studies and how the price may change in the future. The large potential and the possible lower price for PV-systems makes the assumption of 200 MW reasonable. To simulate this PV-system, the data from the existing PV-system is used and scaled up to 200 MW. The existing system includes smaller and larger modules, placed in different locations and in different angles, which means that the data gives realistic, usable values. (Widén, 2016). The data from Figure 3 is scaled in order to match a system with an installed power of 200 MW.

The production from the PV-system used for analysis is given in Figure 4

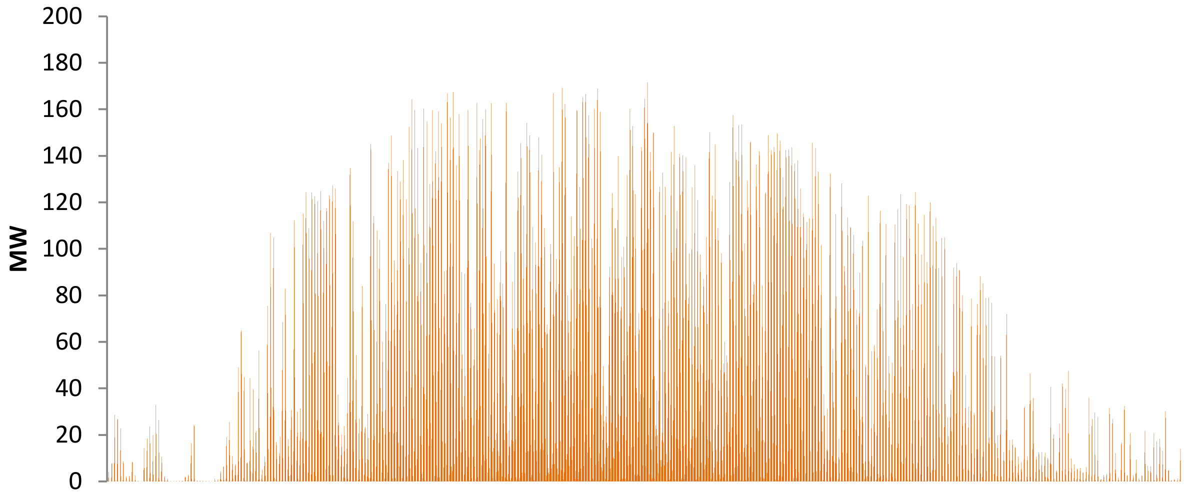

Figure 4. The production of electricity during 2015 in the simulated large PV system.

The existing PV-system at Järvafälten needs about 7 m^2/kW (Wiksell, 2015). This gives that those PV modules used as reference in this report takes up just above 5000 m^2, and that the 200MW-system used for calculations would need 1 400 000 m^2. In the earlier potential study, the area available was estimated to 1 800 000 m^2 (Stockholm stad, 2013). The efficiency of the PV modules used at Järvafälten is 15,2 % (Wiksell, 2015), and the past decade, the efficiency of new modules has increased 0,4 percentage points on average each year (PVTP, 2015). If this continues, the efficiency of a Si-PV module would be 20% in 12 years' time. That means the efficiency would increase by 25 % in 12 year, which decreases the needed area for a given installed power, which means that a 200 MW system probably needs less than 1 400 000 m^2 of roof area.

3.2.4 Electricity market model

To generate the price profiles used in the project, an electricity market model, developed in the research group BEESG at Uppsala University, was used. The model is based on how the Nord Pool spot market functions, with some simplifications. It uses non-linear optimization to minimize the total system operational costs, subject to constraints involving supplier capacities, supply and demand balances in price areas, and import and export capacities between areas. Linear supply functions are modelled for each power supply type (hydropower, nuclear power, gas turbines, etc.) separately, based on assumed bid ranges. The latter are the main parameters that are adjusted to fine-tune the model to reproduce the current spot market behavior. Since the model is constructed to generate short-term variable price profiles in the range of days to weeks, no physical hydropower model is included, but the varying reservoir levels and resulting water values are represented by a varying supply curve for hydropower.

Data for the model were collected from NordPool spot and the Nordic TSOs. The whole Nordic power market was modelled; the four Swedish price areas SE1-SE4 modelled separately, and the other areas aggregated into one Norwegian, one Danish and one Finnish area. Actual consumption data from the respective price areas were used, as well as average actual export capacities between areas. Actual wind power data were also used, while future solar power generation was generated using a scenario model also developed in the research group (Lingfors & Widén).

When generating data for the project, the supply curve parameters, mainly for hydropower, were adjusted to fit the model output to the actual market prices during each of the four weeks studied, using today's solar power generation. After a satisfactory model fit was obtained, the model was re-run with increased solar power generation but all other model parameters unchanged. Therefore, the generated price profiles reflect the possible price variations resulting from an increased PV power generation alone.

3.3 Production cost

3.3.1 Delimitations and assumptions

The system analysed is limited to include the CHP-units normally at use in FV's southern and central system at a given time of the year. Figure 5 shows the geographical location of the south and central system. Also included are heat pumps and accumulation tanks. The reason to the fact that just the south and central are used, instead of FV's whole district heating system, is to limit the complexity of the analysed system. Only the south and central system is used as it contains those production units necessary to perform an analysis and the heating and cooling demands represents 80 % of FV's customers.

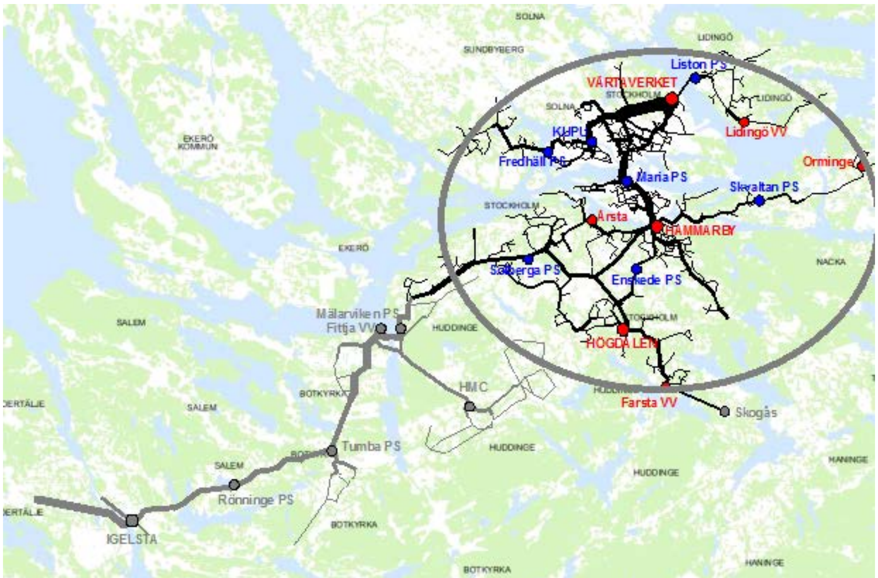

Figure 5. The south and central system is shown inside the grey circle.

The start-up times and other operational delays are assumed not to affect the system, as it would need a more complicated model.

The values for heating and cooling demands and the price of electricity in the reference scenario are based on historical values from 2015. This is done to better match the values from the PV-system, which also is based on values from 2015.

The fact that the electrical grid around the city of Stockholm is limited in its transmitting capacity and that FV has a responsibility to produce electricity so that the load on the grid is not exceeding the capacity limit is not taken into consideration. The fact that the PV-system combined with the electricity produced by FV may affect the electrical grid is not taken into account, as this would need a more complicated model.

The complexity of the district heating system, such as how the distribution system is designed and how it affects the production and distribution, the limits in which unit can deliver to a which part of the system and such, is not taken into account. It is assumed that there are no transfer capacity limitations in the system and that every production unit can deliver heating/cooling to every customer needing it.

The scenarios analysed are based on the assumption that a specific demand for heating and cooling must be met at a given hour by a given set up of production units. The production units are CHPs, HPs and cooling machines. A production unit has a cost per produced heat and/or electricity and cannot produce over their capacity. The electricity produced is sold at a given price every hour. The production cost includes for example costs for fuel, taxes and fees, and are calculated separately for every production unit. By looking at a specific period of time, 48 hours, assuming that the production units historically used during those 48 hours are available, and using historical values of heating and cooling demands, the model can optimise how the production should be planned to minimise costs.

The periods of time used to extract historical data are 48 hours in April, 48 hours in June, 48 hours in August and 48 hours in October, all during the year 2015, to get representation from every season of the year. April and October share the same available production units. June and August share the same production units. The production units available are given in Table 3.

Table 3. Table of the available production units in each month.

Month	Available production units – type of unit
April and October	HDV – CHP KVV6 – CHP KVV8 – CHP VV2 – Heatboiler HBV - HP ROP1-2 – HP ROP3 – HP ROP3 – Free cooling NIM – HP
June and August	HDV – CHP (Not all boiler because of maintenance work) HBV – HP ROP1-2 – HP ROP3 – HP ROP3 – Free cooling NIM – HP

3.4 Description of calculations

The optimisation problem is a linear problem (LP), and is therefore solved with a Simplex LP algorithm. Dotzauer (2002) was used to create the model, which was created in MS Excel.

The goal function used in the optimisation model is given as

$$min \sum_{k=1}^{K} (c_{h,k} q_k + c_{c,k} r_k - \beta p_k) \qquad (1)$$

with the constraints

$$\sum_{k=1}^{K} (q_k) = q_D \qquad (2)$$

$$\sum_{k=1}^{K} (r_k) = r_D \qquad (3)$$

$$\sum_{k=1}^{K} p_k = p_D \qquad (4)$$

$$\underline{q}_k \leq q_k \leq \overline{q}_k$$
$$\underline{r}_k \leq r_k \leq \overline{r}_k$$
$$\underline{p}_k \leq p_k \leq \overline{p}_k$$

where
$c_{h,k}$: cost per produced MWh heat in production unit k, $[SEK/MW]$
$c_{c,k}$: cost per produced MWh cooling in production unit k, $[SEK/MW]$
q_k: production of heat in production unit k, $[MW]$
r_k: production of cooling in production unit k, $[MW]$
β: income for produced electricity, $[SEK/MW]$
p_k: production of electricity in production unit k, $[MW]$
q_D: heating demand, $[MW]$
r_D: cooling demand, $[MW]$
p_D: electricity demand, $[MW]$
$\underline{q}_k, \underline{r}_k, \underline{p}_k$: lower production limit for production unit k, $[MW]$
$\overline{q}_k, \overline{r}_k, \overline{p}_k$: upper production limit for production unit k, $[MW]$

Since the production of heat and electricity in a CHP plant is dependent on the α-value, the total production in a CHP is given as

$$s = q_{MT} + q_{DV} + p \qquad (5)$$

where
s: produced steam $[MW]$
q_{MT}: heat from back-pressure turbine $[MW]$
q_{DV}: direct heat $[MW]$
p: produced electricity $[MW]$

The produced amount of steam cannot be larger than the capacity of the boiling pan, and thus a constraint is needed, namely

$$\underline{s} \leq s \leq \overline{s}$$

where
$\underline{s}$: lower steam production limit, $[MW]$
$\overline{s}$: upper steam production limit, $[MW]$

The electricity produced is given as

$$p = \alpha q_{MT} \tag{6}$$

where
α: the quota between production of electricity and heat

The optimisation is done in one step for each hour. The function minimises the total cost for production of heat, cooling and electricity for each production unit. Note that there is no unit that produces all three products at the same time, which means that q_k, r_k and/or p_k are zero for at least one unit, depending on its type. For example, a heat pump may produce heat and cooling, but no electricity, hence $p_k = 0$.

The constraints are given to make the optimisation behave in a certain way. The demands for heating, cooling and electricity must be met, but a unit cannot produce more than its capacity. The upper limit of production for a unit is given by its maximum capacity and, for CHP units, the alpha value which shows how the co-production of heat and electricity is allocated. The lower limit is dependent on what kind of unit it is and how fast it is possible to regulate it. For CHP units the alpha value is variable between zero and its maximum, to simulate the possibility to vary the flow through the turbine.

3.5 Data

The heating and cooling demand is based on historical values from 2015. The electrical demand is based on what power is necessary to produce in order to regulate the PV-system as planned. Table 4 show the data for each production unit.

Table 4. Table showing the data for each included production unit (Fortum Värme, 2016).

Production units	α-value	COP	P_{max} (winter/summer)	q_{max} (winter/summer)	r_{max}
HDV – CHP	0,3		90/45 MW	300/150 MW	
KVV6 – CHP	0,45		68 MW	150 MW	
KVV8 – CHP	0,4		138 MW	345 MW	
VV2 – HB				150 MW	
HBV – HP		3,35		128 MW	90 MW
NIM – HP		2,86		36 MW	23 MW
ROP1-2 – HP		3,27		150 MW	
ROP3 – HP		3,23		150 MW	40 MW
ROP3 – Free cooling					15 MW

3.6 Costs

The production cost for a unit depends on what type it is and what fuel it uses. The production cost of a CHP unit, c_{CHP}, is calculated by

$$c_{CHP} = \frac{c_{fuel} + t_{CO_2}}{\eta} + c_{O\&M} + c_{NO_x} \tag{7}$$

where

c_{fuel}: cost of fuel, including emissions allowances [SEK/MWh]
t_{CO_2}: cost of CO_2-taxes [SEK/MWh]
η: efficency oft the production unit
$c_{O\&M}$: cost of maintenance and operation [SEK/MWh]
c_{NO_x}: cost of NO_x-fees [SEK/MWh]

The production cost for a heat pump, c_{HP}, is calculated by

$$c_{HP} = \frac{c_{electricity} + c_{transit} + c_{TGC} + t_{electricity}}{COP} + c_{M\&O} \tag{8}$$

where

$c_{electricity}$: cost of electricity [SEK/MWh]
$c_{transit}$: transit cost of electricity [SEK/MWh]
c_{TGC}: cost of Tradeable Green Certificates, including quota obligation [SEK/MWh]
$t_{electricity}$: cost of taxes for using electricity [SEK/MWh]
COP: Coefficient Of Performance of the heat pump
$c_{O\&M}$: cost of maintenance and operation [SEK/MWh]

The profit from selling electricity, β, is calculated by

$$\beta = c_{electricity} + c_{transit} \tag{9}$$

where

$c_{electricity}$: cost of electricity [SEK/MWh]
$c_{transit}$: transit cost of electricity [SEK/MWh]

4 Results

4.1 Analysis of power balance

When the load in Stockholmsringen is compared to the production of electricity from the PV-system and the electricity produced in FV's system, it becomes clear that the load is several times bigger than the production. The maximum electricity production from the PV-system is about 170 MW and the peak production of electricity from CHP was just under 300 MW during 2015. The maximum values where achieved during different times of the year, where the PV produces its maximum during June and the CHP during January, but assuming that they happen at the same time, the total combined peak power would be 470 MW. The load is equal to or lower than 470 MW during less than 200 hours a year, which means that the combination of CHP and PV could keep Stockholm self-sufficient during a total of about a week, assuming that the PV-system could produce its maximum continuously. Figure 6 shows the comparison of gross load and electricity production.

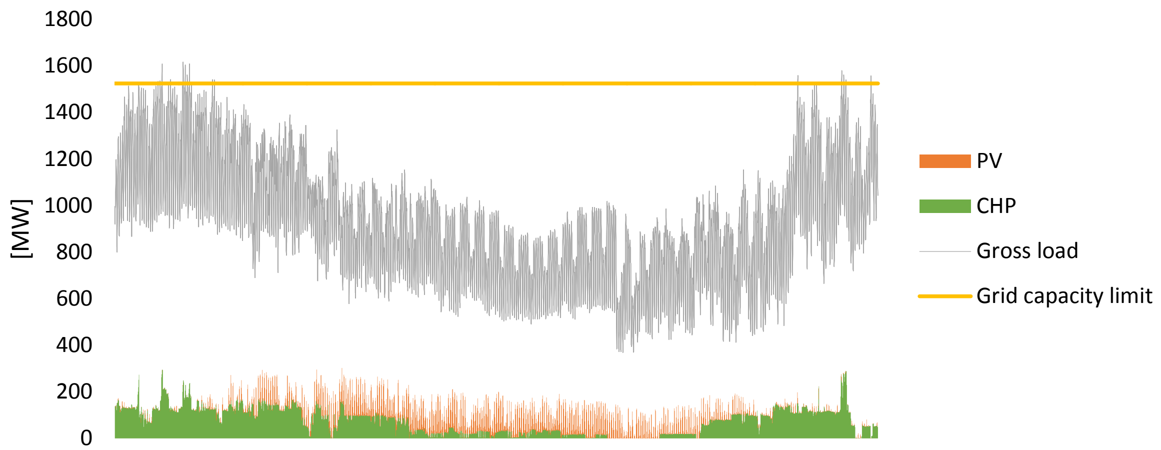

Figure 6: Gross load, grid capacity limit and production of electricity from CHP during 2015, combined with assumed production of electricity from a 200 MW PV system.

Figure 6 also shows the grid capacity limit in Stockholmsringen. This limit is reached at a gross load of 1525 MW, which means that more than 1525 MW cannot be transferred into Stockholm. The production inside of Stockholmsringen subtracted from the gross load in Stockholm must be lower than 1525 MW to avoid issues. Since FV has the responsibility to make sure that the limit is not reached, they have to pay a fee each time the load in the grid exceeds 1525 MW for more than three hours. The scenario where the load is 1525 MW or higher and FV does not produce enough electricity to not exceed the limit is rather rare. These high loads appear in the cold period of the year, but that is also when the production of electricity from CHP is highest. Only at times where the production in the CHPs for some reason is lower than planned is it likely to exceed the capacity limit. Figure 7 shows the net load, i.e. the production from CHP and PV is subtracted from the gross load. As seen, the electricity from FV's system keeps the load well under the limit almost the whole year.

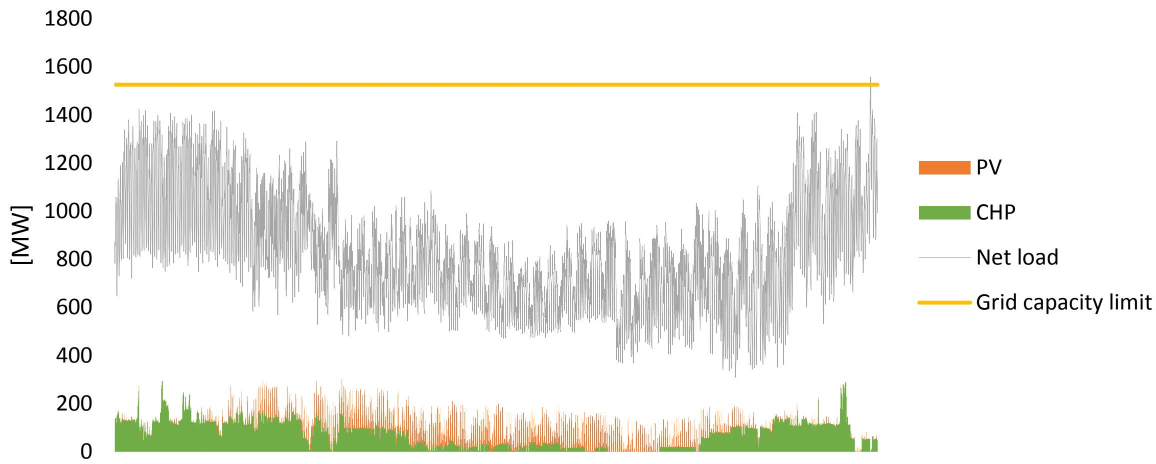

Figure 7: Net load, grid capacity limit and production of electricity during 2015.

During the winter season, the electricity production from the PV-system is at its lowest. This means that the PV-system cannot be used alone to keep the load under the limit. Apart from the low production, another problem is that the load peaks appear in the afternoon, when it is getting darker and colder. The PV-modules produce electricity when the sun is up, and stops producing in the afternoon. This causes a slight offset in production compared to when the demand is as highest. Even if the PV-system could produce enough to keep the load under the limit, it would be produced at the wrong time. An example of this offset is shown in Figure 8.

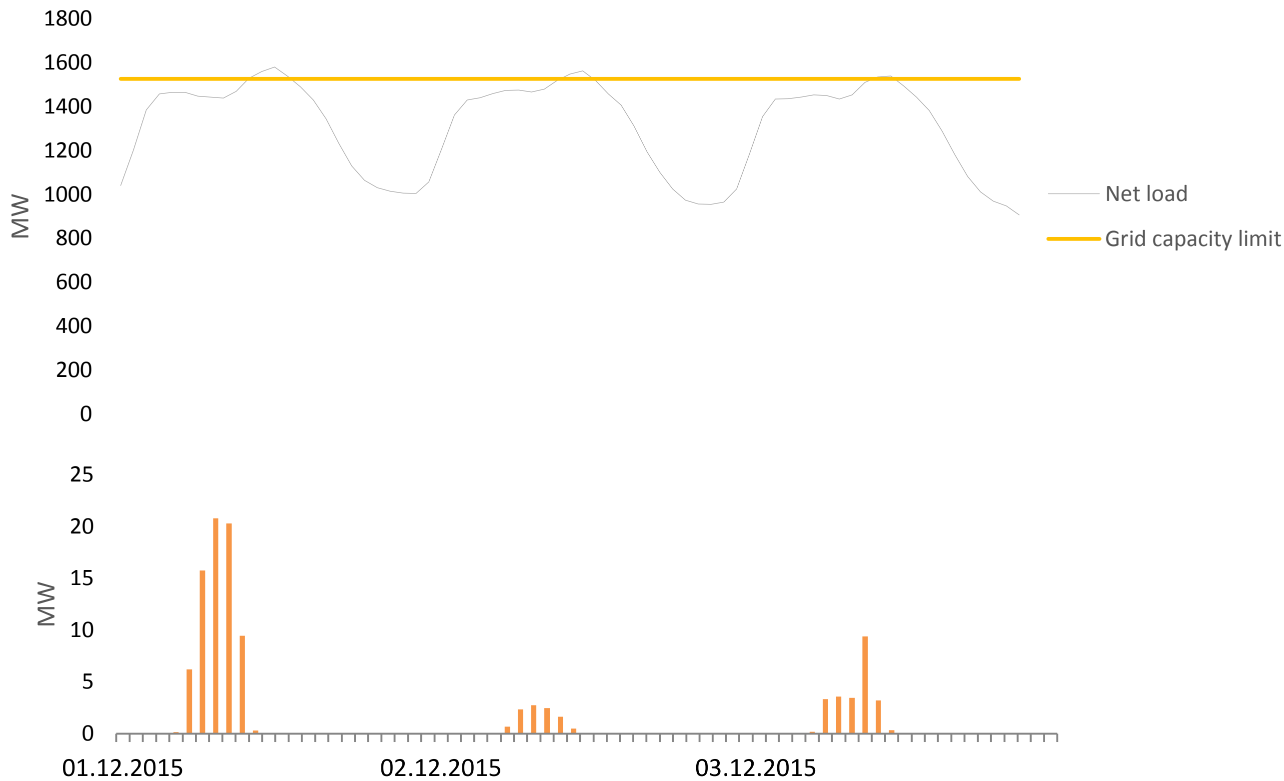

Figure 8: The top graph shows the grid net load and the grid capacity limit during 1/12 to 3/12 2015. The bottom graph shows the production of electricity from PV during the same dates.

The PV-system does affect the load, especially during the summer when the production of electricity is high. The load during the summer is rather low and there is no risk of exceeding the limit. As seen in Figure 9, the combination of CHP and PV reduces the load during the days. The PV-system produces most electricity during the day, which makes the net load drop during the middle of the day.

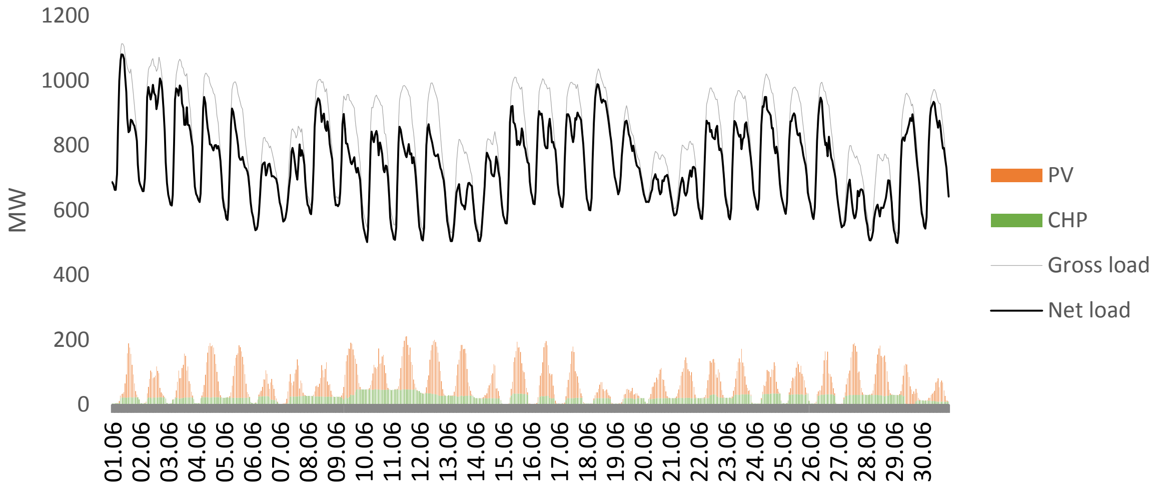

Figure 9: Comparison between gross and net load in June 2015.

The difference in size between the load and the production, the low production from PV during the times with high loads and the offset in production makes it difficult to find a reason to use FV's system as power balance for the PV-system.

4.2 Analysis of production costs

The results will be presented as different scenarios. An overview of these scenarios is shown in Table 5.

Scenario	Month	Description
April	April	Comparison between historical and simulated electricity prices
June	June	Comparison between historical and simulated electricity prices
August	August	Comparison between historical and simulated electricity prices
October	October	Comparison between historical and simulated electricity prices
Consumption demand	April	Comparison between simulated electricity prices in April, with and without a demand for maximum power output to the grid

Table 5. The different scenarios analysed, what month they are based on and a despriction of the scenario.

In each scenario different set-ups of production units are used, depending on which month is analysed. April and October has the same set up and June and August has the same set up. If a different set-up is used in a scenario, this is stated before the result is presented.

In the scenarios for the months, the given month is analysed and a comparison between costs and production planning is made between the case with historical electricity prices and the case with electricity prices simulated with the assumption that 10% of Sweden's production of electricity comes from PV. This assumption is based on the Swedish Energy Agency's proposal on how to increase the amount of PV in Sweden's energy system, which says that in 2014 it is possible that 7-10 % of the electricity used in Sweden comes from PV (Energimyndigheten, 2016).

4.2.1 April

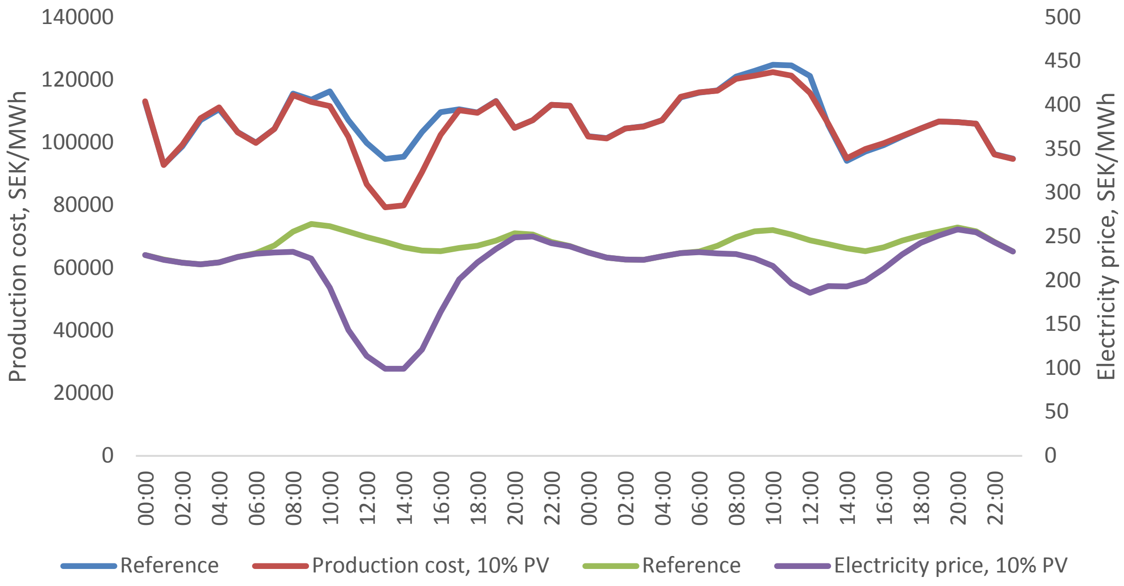

Figure 10. Showing the production cost for the 48 analysed hours in April, and the electricity price for the same period of time. Notice the different scale on the axis.

The price profiles used in the analysis and the production cost in April can be seen in Figure 10. When compared to the price profile, it shows that during the hours with very low electricity prices the production cost decreases. Figure 11 shows the electricity production. There are more hours of electricity production in the reference scenario, because of the higher electricity price, which makes it more profitable to produce electricity.

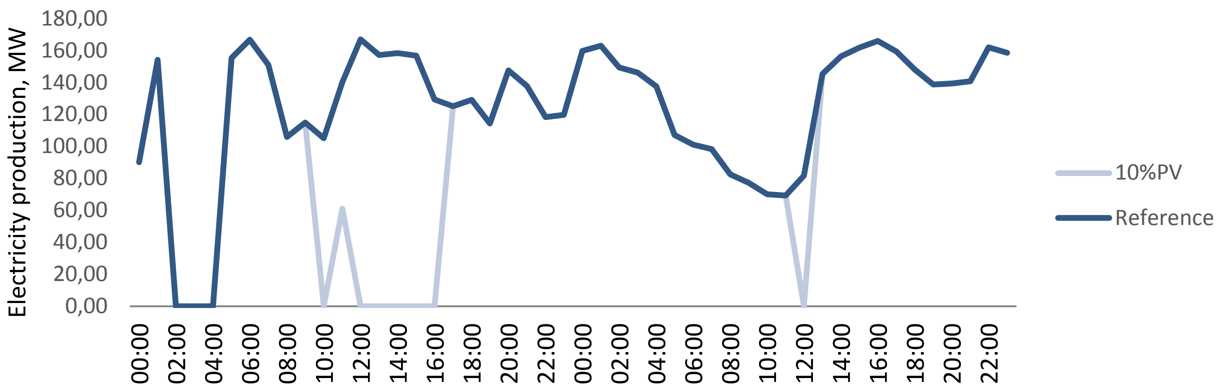

Figure 11. Production of electricity in April

Figure 12 shows how the production cost per type of production unit. The cost of production from HP includes both heat and cooling, since the cooling is a bi product from heat production. What is noticeable is that the cost for using HP and the profit from selling electricity is lower. This is due to lower electricity prices, which make the HP cheaper, but also the sold electricity cheaper. The production cost from CHP and free cooling are the same in both scenarios.

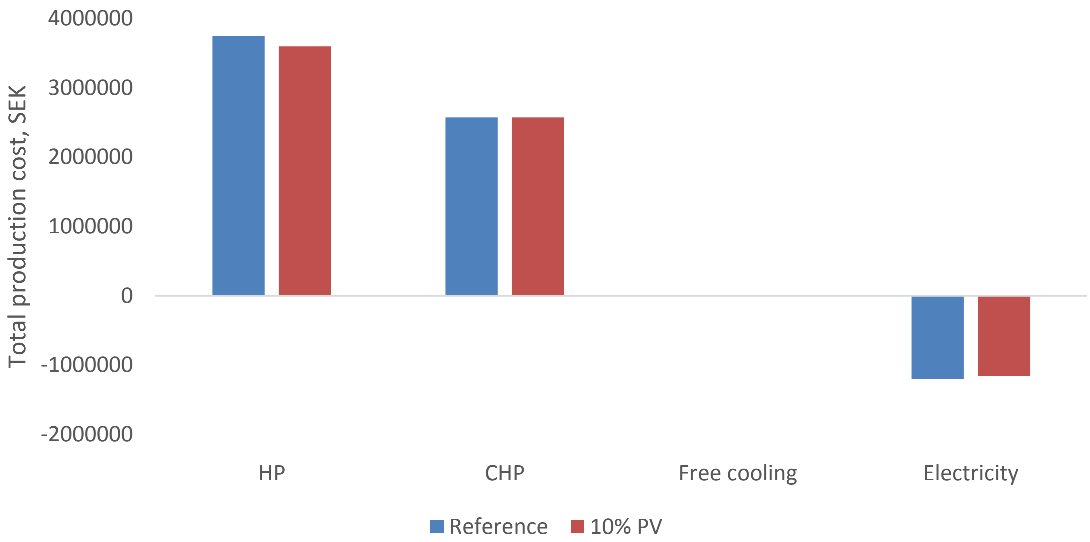

Figure 12. The total production cost per type of production unit when analysed in the reference and the 10% PV scenario.

The cost of the total production the 48 analysed hours in April is 105000 SEK or 2 % lower with 10 % PV than in the reference scenario. This means that the total price per produced MW of heat, including the cost of production and the profit from selling electricity, decreases with about 2 SEK/MWh.

4.2.2 June

The price profile used in the analysis and the production cost in June is shown in Figure 13. When comparing the production cost to the price profile, it shows that during the hours with very low electricity prices the production cost decreases. The production is done in the same way in both scenarios. The production cost increases drastically at around hour 21 because of a larger heat demand and a higher price of electricity, which makes for more expensive heat production.

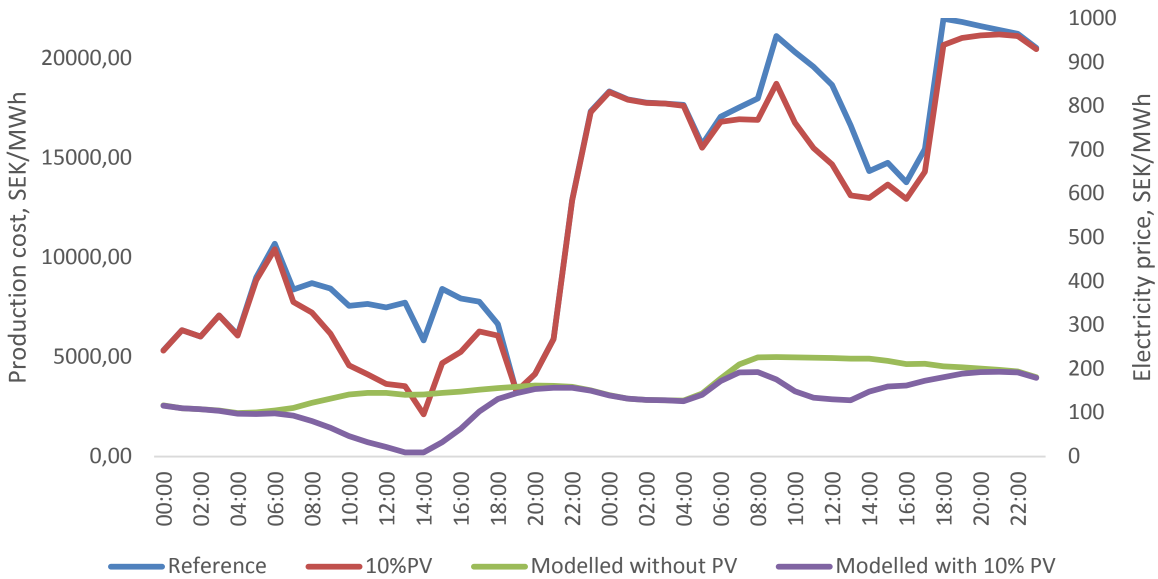

Figure 13. Showing the production cost for the 48 analysed hours in June, and the electricity price for the same period of time. Notice the different scales on the axis.

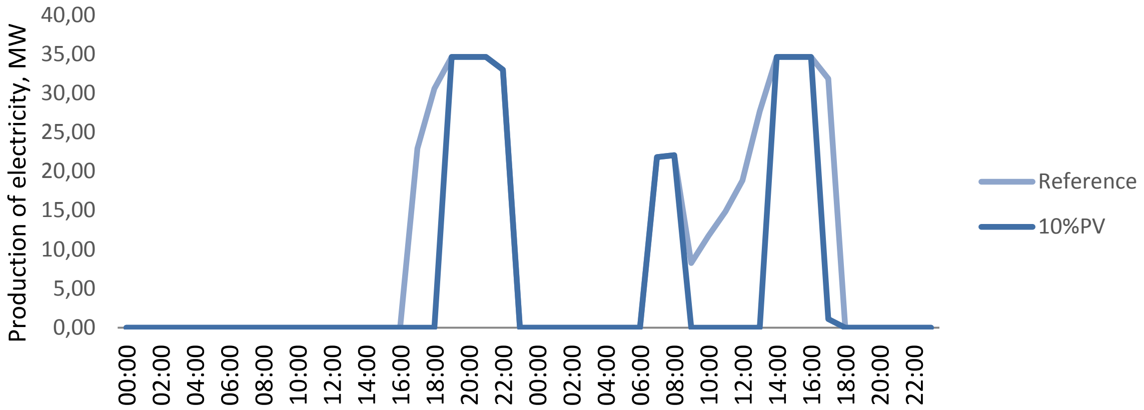

Figure 14. Production of electricity in June.

Figure 14 shows the production of electricity in June. Since the electricity price is higher in the reference scenario, the production is more profitable and therefore more electricity is produced in the reference scenario than in the 10 % PV scenario.

Figure 15 shows the cost of production per production unit. As seen in the figure, the cost of the production from HP is lower in the 10 % PV scenario, which depends on the lower price of electricity. The low price of electricity makes the production of electricity less profitable, which also is visible in the figure. What is interesting is the fact that the cost of production in CHP is negative. This is because the only CHP in use during the summer is the waste incineration plant in Högdalen, and since companies receiving waste to use as fuel are paid to do so, the cost per produced unit of heat is negative.

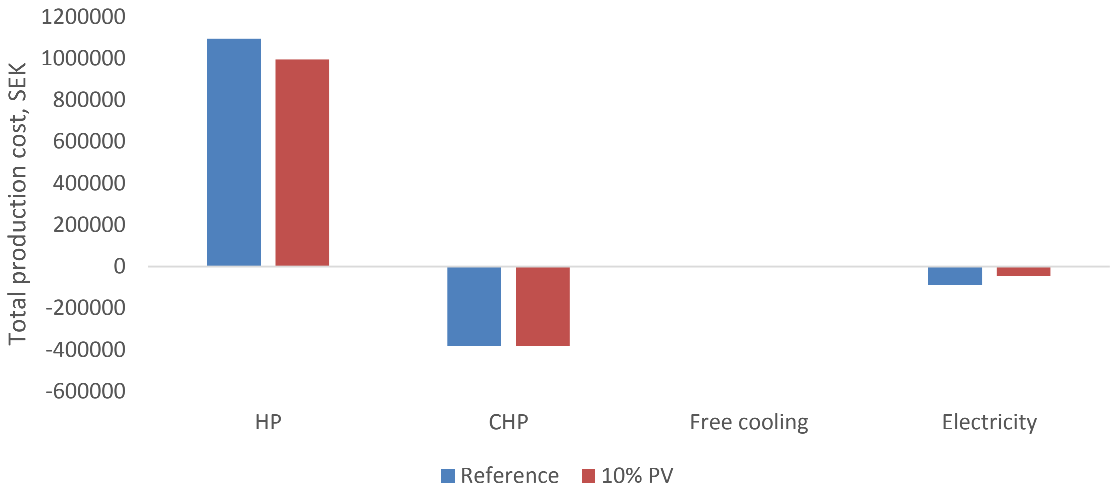

Figure 15. The total production cost per type of production unit when analysed in the reference and the 10% PV scenario.

The cost of the total production the 48 analysed hours in June is 59000 SEK or 9 % lower with 10 % PV than with the historical amount of installed PV. This means that the total price per produced MW of heat, including the cost of production and the profit from selling electricity, decreases with about 4 SEK/MWh.

4.2.3 August

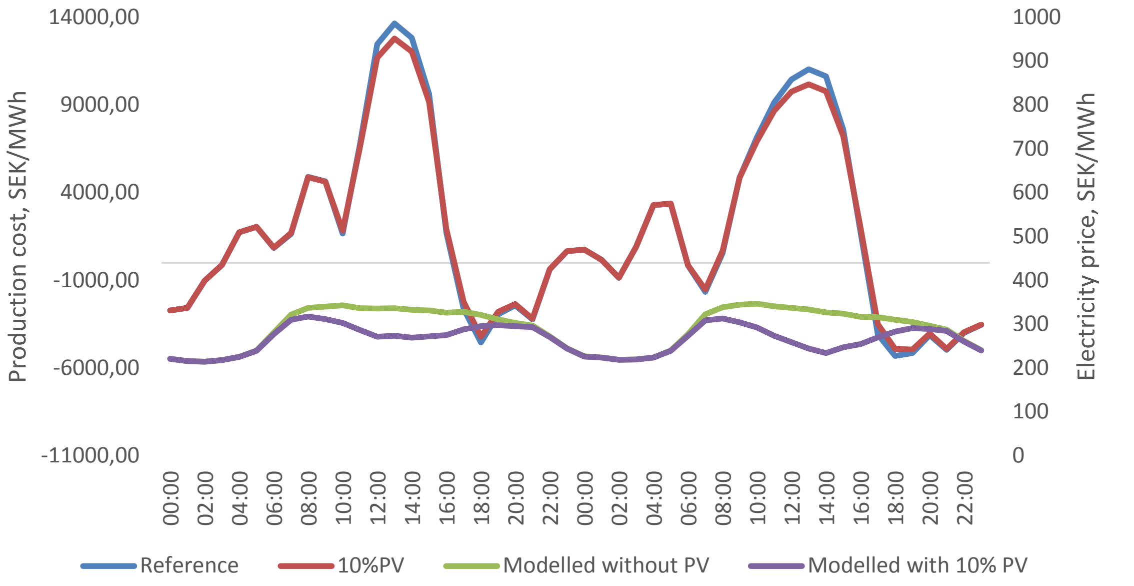

Figure 16. Showing the production cost for the 48 analysed hours in August, and the electricity price for the same period of time. Notice the different scales on the axis.

The price profile used in the analysis of August and the production cost per hour is shown in Figure 16. The electricity price is generally higher in August than in the previous month, and there is not a big difference between the reference scenario and the 10 % PV scenario. This makes for rather high production costs during daytime in both scenarios, since the cooling demand is high during the hot months. During night time the production cost becomes negative since the demand for cooling and heating are low, but the waste incineration plant is still running because of the profit from burning waste.

The cost of the total production the 48 analysed hours in August is 3000 SEK or 4 % lower with 10 % PV than with the historical amount of installed PV. This means that the total price per produced MW of heat, including the cost of production and the profit from selling electricity, decreases with about 0,3 SEK/MWh.

Figure 17 shows the cost of production per production unit. The production does not differ between the two scenarios, and the cost differs only in the cost for HP, which is lower in the 10 % PV scenario because of lower electricity prices. The profit from selling electricity, which differs slightly, also depends on the lower electricity prices in the 10 % PV scenario.

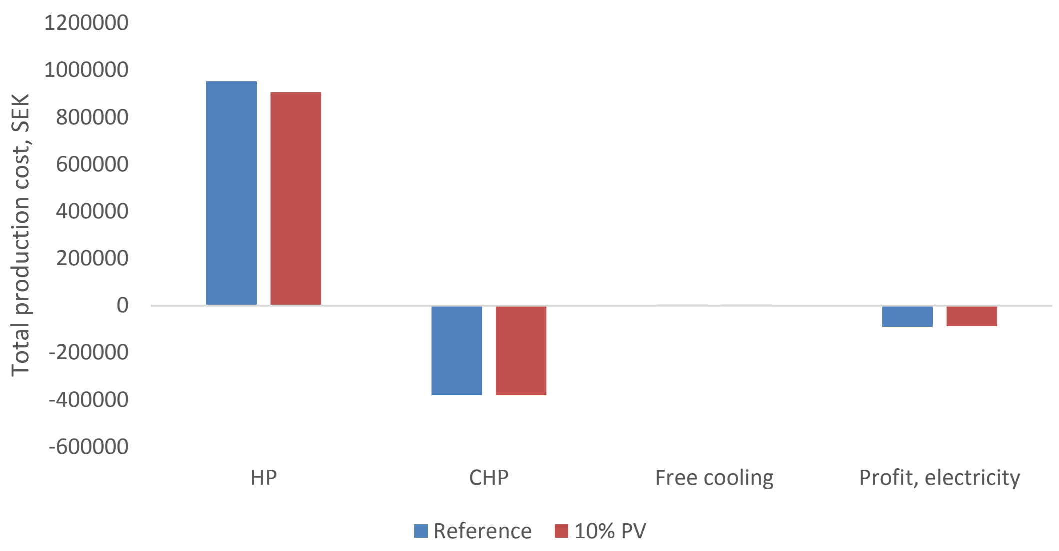

Figure 17. The total production cost per type of production unit when analysed in the reference and the 10% PV scenario.

The cost of the total production the 48 analysed hours in August is 3000 SEK or 4 % lower with 10 % PV than with the historical amount of installed PV. This means that the total price per produced MW of heat, including the cost of production and the profit from selling electricity, decreases with about 0,3 SEK/MWh.

4.2.4 October

The price profile used in the analysis of October and the production cost per hour is shown in Figure 18. Note that the cost during the days is actually higher in the 10 % PV scenario than in the reference scenario. The figure also shows that the difference in price of electricity is rather small between the two scenarios. The production is done in the same way in both scenarios, but the cost of HP and the profit from electricity differs, which can be seen in Figure 19, with less profit from selling the electricity due to lower price of electricity. This explains the higher cost in the 10 % PV scenario, since the cost per hour during daytime is lowered in the reference scenario by the higher income from selling electricity.

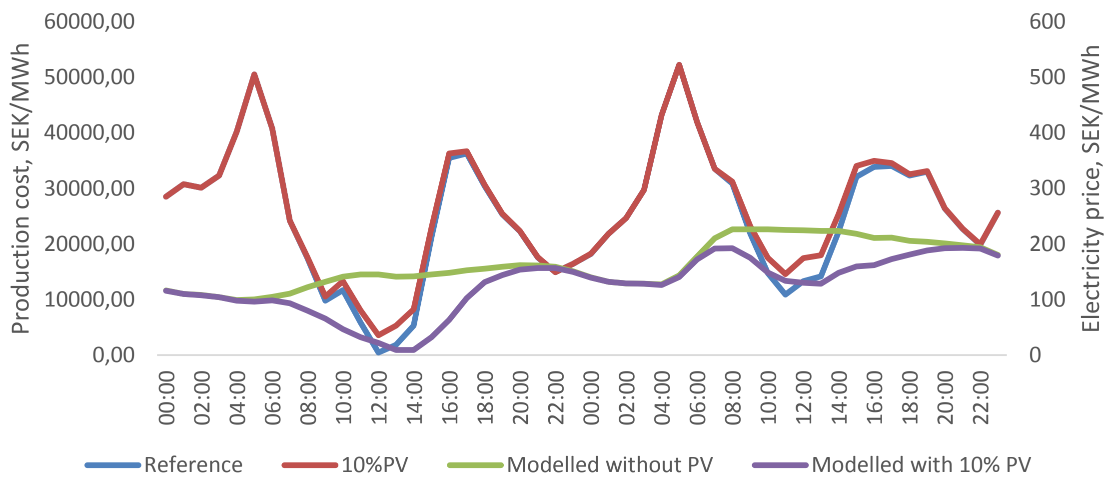

Figure 18. Showing the production cost for the 48 analysed hours in October, and the electricity price for the same period of time. Notice the different scales on the axis.

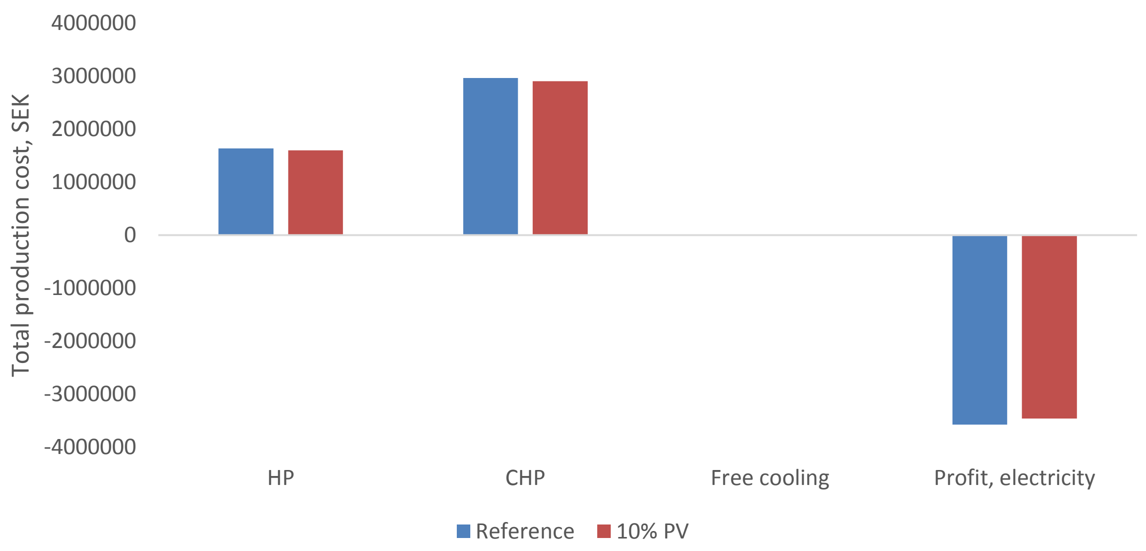

Figure 19. The total production cost per type of production unit when analysed in the reference and the 10% PV scenario.

The cost of the total production the 48 analysed hours in October is 15000 SEK or 1 % higher with 10 % PV than with the historical amount of installed PV. This means that the total price per produced MW of heat, including the cost of production and the profit from selling electricity, increases with about 0,5 SEK/MWh.

4.2.5 Regional electricity self-consumption requirement

In this scenario a hypothetical production requirement in the form of a consumption requirement is introduced. This is done to show the effects of running the DH system as part of a VPP. It is assumed that no more than 100 MW of electricity can be delivered from a VPP that consists of the PV system and the DH system. In this scenario, the month of August is used and both price profiles are based on 10 % PV. Figure 20, Figure 21 and Figure 22 shows the total production, the total consumption and the net production of electricity during the 48 hours in June analysed in this scenario.

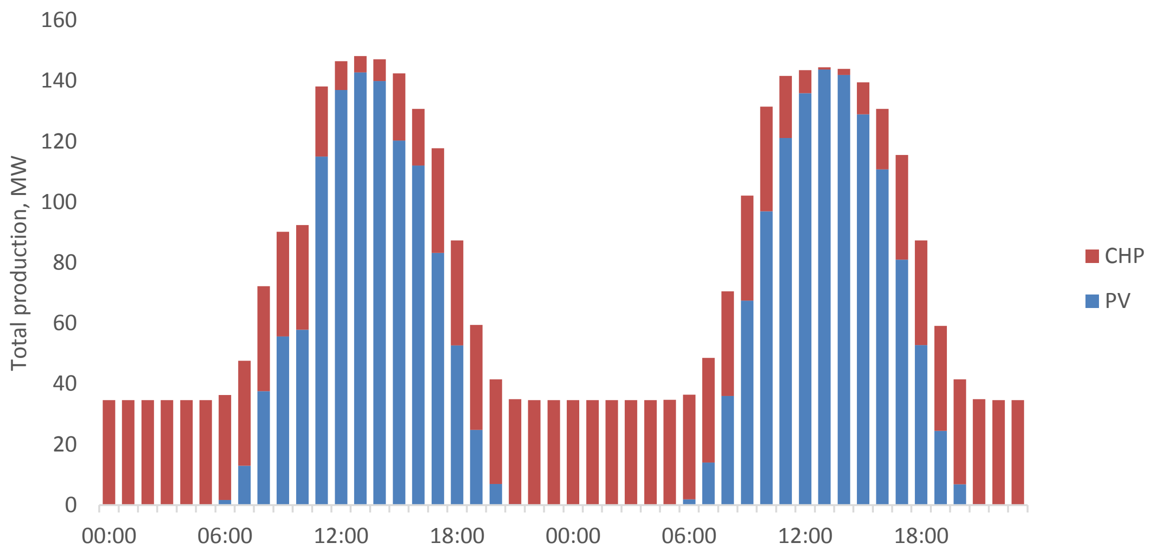

Figure 20. The total production of electricity, from CHP and PV, during the analysed 48 hours.

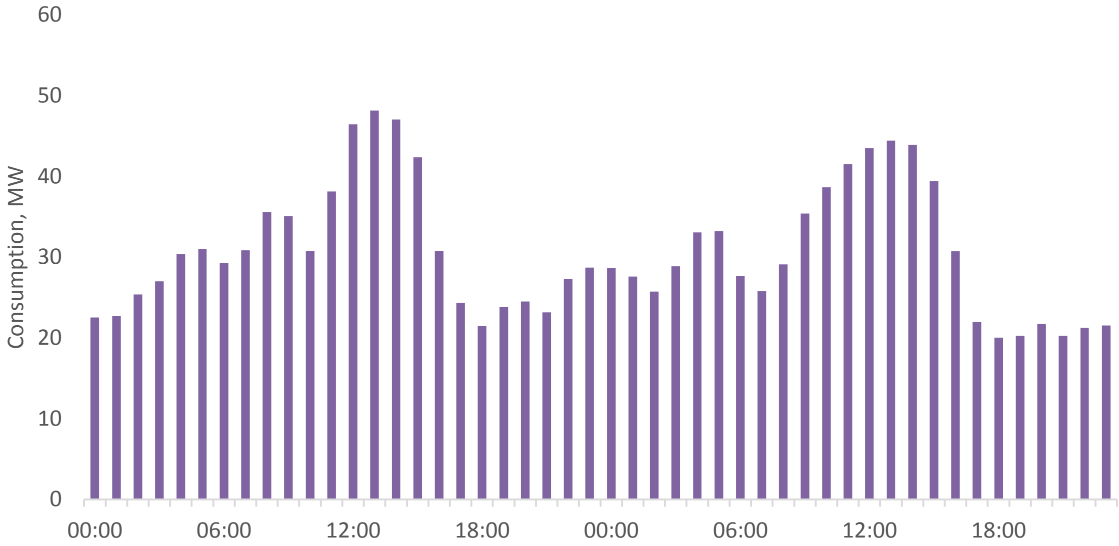

Figure 21. The total consumption of electricity in the DH system during the analysed 48 hours.

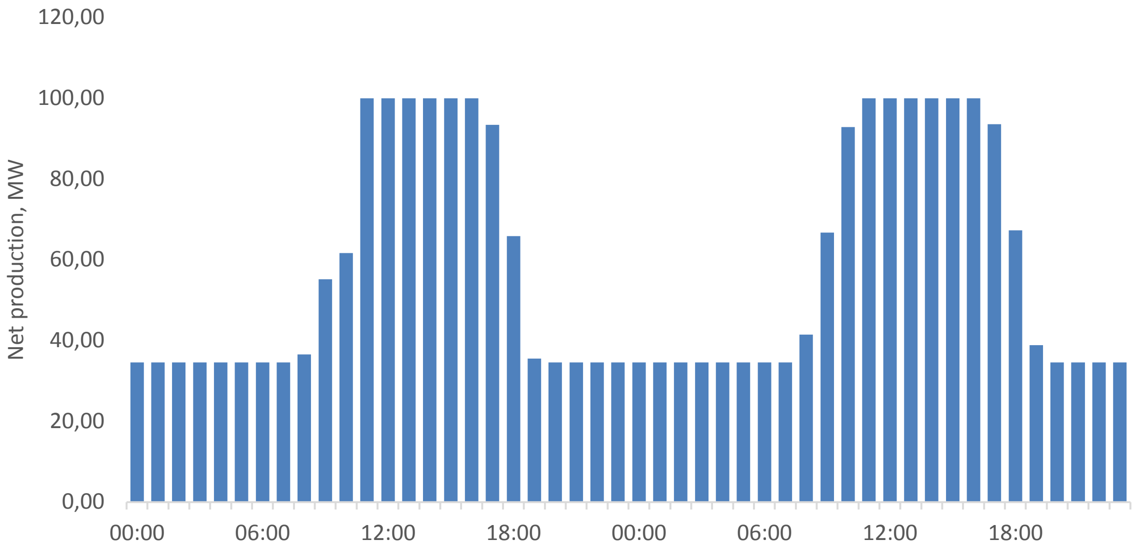

Figure 22. The net production of electricity, when the consumption is subtracted from the electricity produced from PV.

As seen, it is possible to balance the net production of electricity by producing less and consuming more. However, the cost per hour increases when consumption requirements are put on the production.

Figure 23 shows the comparison of costs with and without the consumption requirement. The difference comes from the fact that when electricity needs to be consumed, HPs are used which cost more than the CHPs. The cost per produced MWh of heat is therefore increase. Adding to the increased cost are also the lack income from produced electricity, which comes from the lower production in the CHPs.

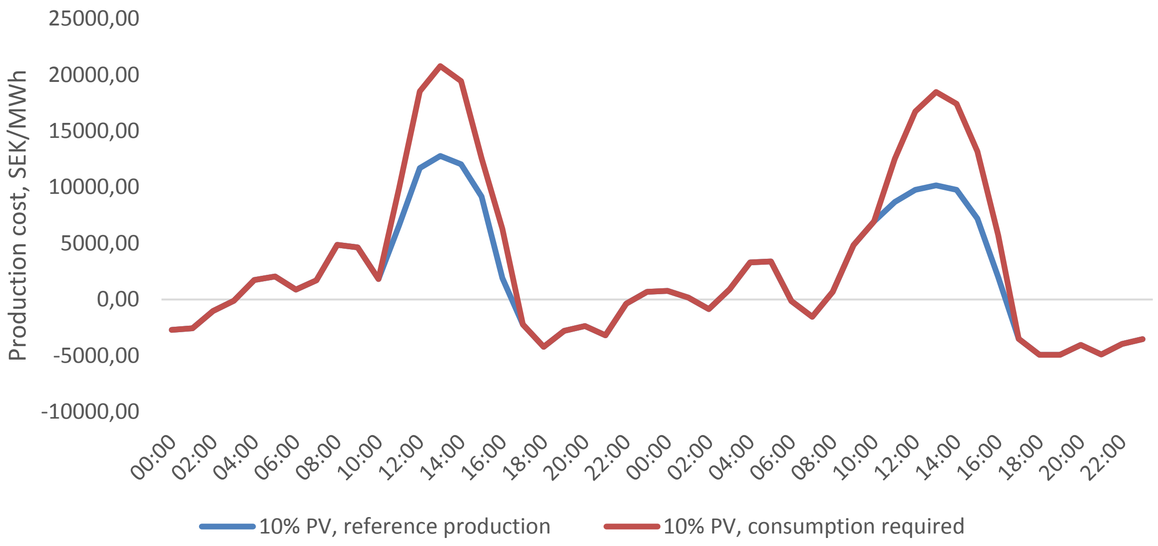

Figure 23. Cost per hour when producing with and without consumption demand.

The cost of the total production the 48 analysed hours in June is 70000 SEK or 80 % higher with 10 % PV and a consumption demand than with 10 % PV and no consumption requirement. This means that the total price per produced MW of heat, including the cost of production and the profit from selling electricity, increases with about 7 SEK/MWh.

4.3 Summary of results

The analysis shows that the most apparent consequence of a large scale PV-system integrated in the existing district heating system is the changes of the price of electricity. In the scenarios where no requirement for specific production to balance the PV-system exist, the only effect on how the production is planned is when electricity is produced. The order in which the CHP's and the HP's are used does not change. This indicates that FV's cost is not very sensitive to the electricity price.

Table 6 shows a summary of the key values from the analysis of production cost. The table shows the difference between the reference scenario and the 10 % PV-scenario for each analysed month, both total production cost and cost per produced MWh.

Table 6. Summary of the changes in cost between reference scenario and analysed scenarios.

Scenario	Change in total production cost	Change in cost per produced MWh
April	-2%	-2 SEK/MWh
June	-9%	-4 SEK/MWh
August	-4%	-0,3 SEK/MWh
October	+1%	+0,5 SEK/MWh
Consumption requirement	+ 80%	+7 SEK/MWh

What is noticeable is that low electricity prices make the total production cost smaller in April, June and August. In October however, the cost increases. This is because the lower income from selling electricity. The cost for running the HPs decreases with the lower price of electricity, but not enough to compensate the lower incomes.

The fact that the total cost of production is the sum of production cost and profits from selling electricity, the cost per produced MWh is not very high. This is important to keep in mind when studying the result.

When an additional restriction for electricity consumption is introduced, it becomes apparent that it makes the production more expensive. That is reasonable, because every constraint added to the base constraint, that the demands should be met, should increase the price. The interesting question is how much it changes the price, and with the consumption demand, the cost was 80% higher than without a regional electricity self-consumption requirement.

5 Discussion

The use of a DH system to balance the electricity from a large PV system is technically possible and theoretically a good idea. If the two systems are combined to a VPP it may be possible to keep a constant power output, which could make it possible to avoid load peaks in the local grid and to keep the price of electricity less volatile. However, the balance of production from a PV system, or any other intermittent source of electrical power, introduces challenges that needs to be dealt with. For example, there is need for both production and consumption of electricity in order to keep the grid stable. A DH system, consisting of CHP and HP, can produce and consume electricity, which makes it interesting from a VPP point of view.

When comparing the production of electricity from the PV system and the DH system with the load in Stockholmsringen, it is clear that the PV system does not contribute with electricity in the times it is needed. During the colder period of the year, the PV system produces less than in the warmer period. During the hours of the day that the load is as highest, i.e. in the afternoon, the production is close to zero. This means that a large scale PV system those not change the production planning during the hours with high loads, and therefore it makes no difference if the PV system exists or not.

Since the production of electricity from PV is zero several hours and may be near peak power just some hours later, it is hard to maintain a stable level of balancing. It is also a rather hard task to decide on what level the balancing should be done. If a constant output of electricity is the goal, much research must be put in finding a level that is economically feasible at the same time as it does not stress the system to much. If the goal is to relief the grid from load peaks, much planning must be done to make sure that the needed headroom exists. Either way, the system cannot be optimised to be run at a low cost. There will be moments where it is needed to produce in a specific, but economically suboptimal way.

The main goal when planning the production today is to make sure demands are met and, if profitable, to produce electricity to decrease the total cost. When other ways of planning the production are introduced, such as balancing for a constant output of electricity, the planning must be done to meet these requirements first, and the cost can be optimised after that. This makes for a higher total cost of production and less profit. Given this, there exists no incentive for DH companies to offer a balancing service. If however there would be some kind of bonus for those who make sure to plan their production in order to balance an intermittent source of electricity, and it would be possible to profit from doing so, it would be more likely that DH companies would try to balance some amount of intermittent electricity. It is important to keep in mind that power balancing stresses the production units, and it may cause more wear than normal when turbines are ramped up and down more often.

Even if it, in a given system, was economically and technically possible to balance an intermittent source of electricity, the question remains how it should be done. As previously stated, a stable output or a more even load in the grid could be two goals to work for, but to decide on a general plan of production would probably take a long time. More research must be done in order to determine how the balancing should be planned.

6 Conclusions

The conclusions that can be drawn from the analyses in this thesis are:

- It is reasonable to believe that the amount of large photovoltaic systems will increase in the future, because of better technology and lower prices
- It is technically possible to balance intermittent sources of electricity by using district heating systems. This means that it also is possible to create a VPP from a photovoltaics system and a district heating system
- There are no general incentives for district heating companies to balance the production from intermittent sources of electricity

- The effects on the price of electricity based on the introduction of large scale photovoltaic systems in the existing energy system does not affect the production planning of Fortum Värmes system significantly.
- The reason for the lack of effects from a more volatile price of electricity is that the system is insensitive for price changes. The production cost changes with changing electricity price, but the order in which the production units are used does not change.
- If other ways of planning the production than just to meet the demands at as low cost as possible are introduced, the production planning changes. This makes for drastically increased costs caused by lack of profit from production of electricity and/or increased cost for production of heat.

- The results given in the analysis in this thesis makes it reasonable to assume that there is no reason for companies running large district heating systems to offer balancing of large scale photovoltaic systems. The balancing service would increase the costs, lower the profits, cause additional wear on the production units and demand excessive production planning. However, the effects on the price caused when large scale PV system are introduced in the energy system does not affect the production cost significantly.

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