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Flexible energy management and solar-related business opportunities for households in Finland

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Abstract

The global cumulative solar power generation capacity based on photovoltaic (PV) technology has grown between 2003 and 2013 from 2,82 GW to nearly 137 GW. This equals a stunning, circa fiftyfold, growth in a mere decade. At the same time, the demand for power companies' electricity sales is expected to be reduced by 14–18 % during the next five years due to the growth of self-generated solar power, while the need for grid balancing services is increasing.

This study aims to increase the understanding of the flexible energy management related business models and opportunities for households in Finland, at the same time implementing solar power generation into the equation. The primary focus will be on the hourly consumption, demand response capabilities, and solar production analysis of households in Finland, but other Southern European countries are also covered for comparison. Fundamentals of different models are studied, after which investment and sensitivity analysis are conducted with a selection of realistic scenarios.

Business opportunities for households do exist in Finland, however, not yet with attractive returns. Base case analysis showed internal rates of return between -3,0 % and -1,6 % without demand response benefits, and internal rates of return between -0,8 % and 0,3 % with them. Thus, demand response had a significant positive impact on the returns of an investment through regulation trading activities and solar production self-consumption maximization.

However, sensitivity analysis showed that high solar system prices coupled with low electricity prices in Finland have a huge impact on the profitability of all scenarios studied. For mature solar markets, Germany and Italy for instance, the returns for similar setups result in internal rates of return between 5,9 % and 11,7 %, which represent attractive returns compared to any other options available for household investments. In fact, a possible best case scenario for Finland also returned an appealing annual return rate of 8,6 %.

In future research, actual pilot programs should be conducted and some of the models and results presented in this study should be tested for verification. Additionally, an evaluation for both technical and psychological aspects of the demand response activities should be performed.

Keywords Finland, Nordic countries, photovoltaic, solar power, flexible energy management, virtual power plant, demand response, investment analysis

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Tiivistelmä

Maailmanlaajuinen aurinkosähkön kumulatiivinen määrä on kasvanut vuosien 2003 ja 2013 välillä 2,82 GW:sta lähes 137 GW:iin. Tämä vastaa lähes viisikymmenkertaista kasvua ainoastaan vuosikymmenen aikana. Samanaikaisesti voimayhtiöiden sähkönkysynnän odotetaan laskevan 14–18 % seuraavan viiden vuoden aikana ja verkon balansointitarpeen kasvavan, pääasiassa laajamittaisen ja kasvavan aurinkosähkön itsetuotannon vuoksi.

Tämän tutkimuksen tavoitteena on kasvattaa suomalaisten kotitalouksien joustavaan energianhallintaan ja aurinkoenergiaan liittyvien liiketoimintamahdollisuuksien ymmärrystä. Olennaisimmat tutkimuskohteet ovat suomalaisten kotitalouksien tunnittaisen kulutuksen, kulutusjoustopotentiaalin, sekä aurinkosähkön tuotannon analysointi, mutta myös joitakin eteläisen Euroopan maita käsitellään vertailun vuoksi. Eri mallien pohjana oleva tutkimusdata käsitellään tässä työssä, minkä jälkeen suoritetaan monelle eri realistiselle skenaariolle sekä investointi- että herkkyysanalyysi.

Tutkimuksessa löytyi suomalaisille kotitalouksille liiketoimintamahdollisuuksia, jotka eivät kuitenkaan vielä nykyisillä muuttujilla tuota tyydyttäviä voittoja. Perusskenaariot tuottivat -3,0 % ja -1,6 % välillä olevia sisäisiä korkoja investoinneille ilman kulutusjoustoa, sekä välillä -0,8 % ja 0,3 % kulutusjouston kanssa. Näin ollen kulutusjoustolla on merkittävä vaikutus investoinnin houkuttelevuuteen suomalaiselle kotitaloudelle lähinnä säätösähkömarkkinoilla toimimisen ja aurinkoenergian itsekulutuksen maksimoinnin tuottamien hyötyjen vuoksi.

Herkkyysanalyysi osoitti, että Suomen korkeilla aurinkosysteemihinnoilla ja alhaisilla sähkön hinnoilla on hyvin suuri vaikutus laskettujen skenaarioiden tuottoihin. Esimerkiksi Saksan ja Italian kehittyneillä aurinkomarkkinoilla, samankaltaiset skenaariot tuottivat 5,9–11,7 % tuottoa investoinnille. Herkkyysanalyysin kaikki positiiviset elementit yhdistävä skenaario tuotti Suomessa parhaimmillaan 8,6 % sisäisen koron investoinnille.

Tulevaisuuden tutkimuksissa tulisi toteuttaa käytännön pilottiohjelmia tässä tutkimuksessa esitettyjen mallien ja tuloksien vahvistamiseksi. Lisäksi tulisi arvioida ja todentaa kulutusjoustoon liittyviä sekä teknisiä että psykologisia haasteita ja ratkaisuja.

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After starting my career at Fortum in June of 2012 for Solar Business Development Team, my view of the future of the electricity generation and consumption has been totally transformed. Sustainable technologies and their challenges represent incredible opportunities for individuals and companies around the world, even though usually these challenges are not seen as much as an opportunity, rather as a barrier. I encourage everyone to take the time to familiarize themselves with the fundamentals of renewable electricity generation, since I personally expect this field to change our lives the most since the discovery of the black gold, oil. Not only the supply side will see a paradigm shift, but also the demand side with automated demand response and smart home systems. I am extremely happy that this thesis became a great starting point for me to holistically understand the topic, and I hope that you, the reader, will also find this study useful.

Thank you solar team (Mika Sappinen, Kaarle Mäkinen, Heikki Siniharju, Eero Vartiainen, Eveliina Dahl, and especially Petra Lundström) for your support, you are amazing professionals, and I hope and believe that you get all the recognition you deserve. Special thanks to my instructor, Dr. Vartiainen, who has shown me the right path with this study, helping with every turn along the way. Warm thanks to my supervisor, professor Sanna Syri, for constructive and supportive feedback. Tuomas Harju, thank you for inspirational lunches and your patience with proofreading my thesis.

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I am forever grateful to have you all in my life. Thank you for helping me to move on to the next chapter in my life. It is going to be legendary.

Espoo, 30 April 2014

Heikki Keskiväli

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List of Abbreviations

AC	alternating current
BRP	balance responsible party
CHP	combined heat and power
DC	direct current
DR	demand response
DSM	demand side management
DSO	distribution system operator
EEX	European Energy Exchange
ENTSO	European Network of Transmission System Operators
EPIA	European Photovoltaic Industry Association
GHG	greenhouse gas
GW	gigawatt, 10^9 watts
IEA	The International Energy Agency
IRR	internal rate of return
JV	joint venture
kW	kilowatt, 10^3 watts
LCOE	levelized cost of electricity
MAE	mean absolute error
MW	megawatt, 10^6 watts
NMAE	normalized mean absolute error
NPV	net present value

NREL	National Renewable Energy Laboratory
NRV	Netzregelverbund
NWP	numerical weather prediction
PV	photovoltaics
reBAP	Regelzonenuebergreifender einheitlicher Bilanzausgleichs-energiepreis
RMSE	root mean square error
TEM	Työ- ja Elinkeinoministeriö
TSO	transmission system operator
TW	terawatt, 10^{12} watts
VAT	value added tax
VHP	virtual heat and power
VPP	virtual power plant
VRE	variable renewable energy

1 Introduction

1.1 Background and motivation

The beginning of this millennia in Europe was filled with over-optimistic energy investments to power generation capacity from fossil fuels. The electricity demand did not evolve as projected and the financial crisis of 2008 led actually to a reduction in the demand of electricity, resulting in European utilities to lose over half of their total market capitalization of earlier one trillion euros (The Economist, 2013). We are at the crossroads of changing electricity generation business. We have the old energy system with huge amounts of base load infrastructure, and the up and coming variable renewable energy sources that need to adapt to the existing business conditions.

Only a decade ago in 2003, the global cumulative solar power generation capacity based on photovoltaic (PV) technology was 2,82 GW. Only nine years later in 2012, the global capacity had reached over 102 GW, and at the end of 2013 the cumulative PV capacity reached nearly 137 GW (EPIA, 2014). This equals nearly a stunning fiftyfold growth in a mere decade, mostly due to generous governmental subsidies, but also due to drastically declined module and solar system selling prices (Fraunhofer, 2014). In 2012, the rooftops alone around Europe increased solar power capacity by nearly 14 GW, and additions of nearly 10,5 GW, 10,4 GW and 11,7 GW for 2013, 2014 and 2015 are expected[1], respectively. (EPIA, 2013a)

In fact, in 2012 and in 2013, PV technology added the most power generation capacity of any other forms of energy in EU-27[2] and EU-28[3] countries, as shown in Figure 1. This kind of large-scale advancement in distributed energy generation does not come alone. At the same time, the demand of electricity sales is expected to be reduced by 14–18 % during the next five years due to the increase in self-generated solar power (IRENA, 2013). All the aforementioned factors represent a change in the current market and product offering design. For utilities, there is no going back to the old-fashioned centralized electricity generation with stable profits and revenues.

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[1] Expected capacity addition is the average of *business-as-usual* and *policy driven* scenarios. (EPIA, 2013a)

[2] EU-27 consists of Austria, Belgium, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom. (Eurostat, 2014c)

[3] Added 28th country to the EU was Croatia. (Eurostat, 2014c)

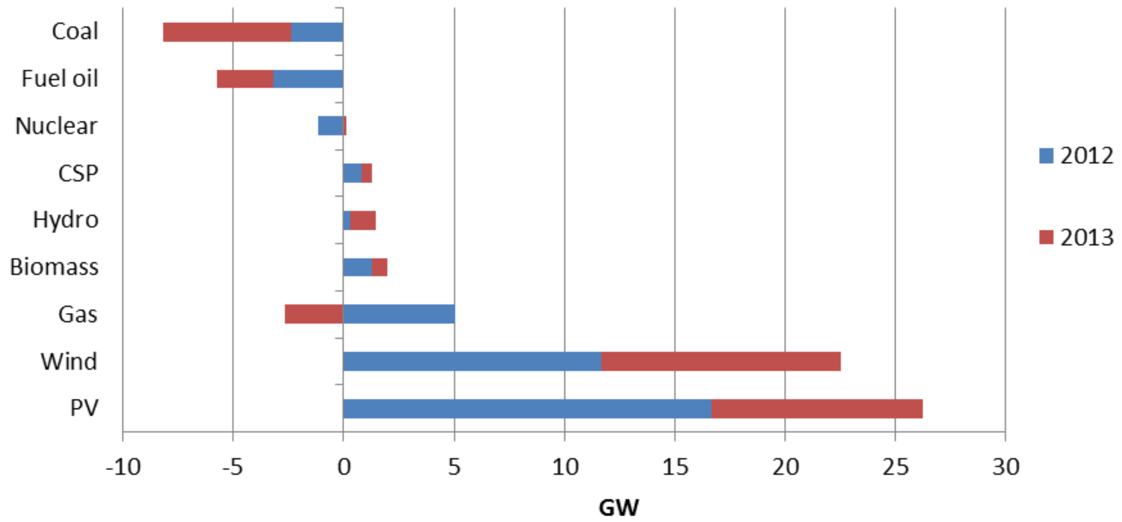

Figure 1. Major power generation capacities' net changes in 2012 for EU-27 and in 2013 for EU-28 countries. Different power generation approaches are listed in ascending order of net change in 2012–2013 from top to bottom. Negative values indicate decommissioned power generation capacity and positive values indicate installed capacity. (EPIA, 2013a; EPIA, 2014)

Variable energy sources do fluctuate, but so does demand, and it all has to match every second of every hour, all the time. Adjustments are needed whatever approach chosen. Nowadays, we have adapted to the situation by constructing fleets of peak load power plants that mostly stand idle. The times are changing, and as the demand for flexible production and consumption increases, its value will most likely increase in the progress. The increasing demand of flexibility can be seen from Figure 2 as rising volatility between adjacent days. According to a Brattle Group consultant Fox-Penner (Asmus, 2010), one possible future for utilities is a scenario, where utilities as "smart energy integrators" do not own power plants or sell power into the grid but provide energy network services and delivery, while keeping the grid stabilized and enabling customers to shift their demand. These smart grid services could be the future profit driver. Opportunity to capture value from the current situation cannot be ignored by utilities in the pursuit of future revenues, margins, and above all, profits.

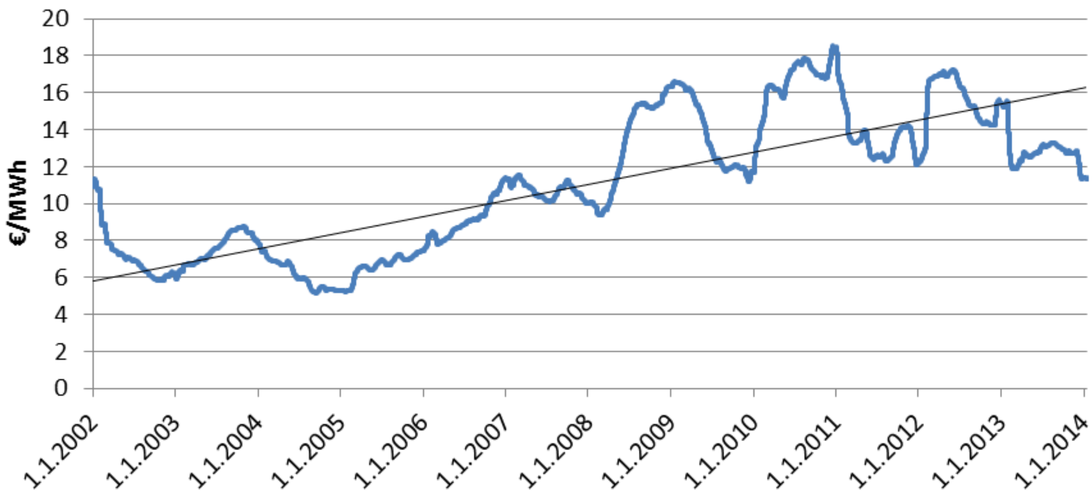

Figure 2. Volatility in electricity system prices in Nord Pool as one year moving averages, including linear trend line. Volatility for this graph represents the difference between minimum and maximum hourly system prices in a 24 hour timespan. (Nord Pool Spot, 2013)

The first section of this paper introduces the reader to the topic and presents most important guidelines for this study. In the second section, the existing and available data relevant to this topic is described so that the reader would have essential knowledge in hand to evaluate this study. Model overview, the third section, opens up the logic behind the main models used. Fourth section provides knowledge of the material and data used, as fifth section presents all results and findings in this study. Impact of some variables to the main findings are studied in the sixth section, sensitivity analysis. In the seventh section, results are discussed and evaluated in holistic manner. Eighth section concludes the thesis and ninth section describes the main limitations regarding the execution of this study. Tenth section proposes opportunities for future research, based on the findings and insight of the author.

1.2 Objective of the study

This thesis aims to increase understanding of the flexible energy management related business models and opportunities for households, at the same time implementing solar power generation into the equation. The primary focus will be on the Nordic countries, but since most data for the study was found from Finland and it can represent with decent accuracy other Nordic countries, Finland is used as main reference country in this study. The development of solar power generation and high availability of electricity market data from Germany is used to create a roadmap of fundamentals that can be applied to other countries with certain limitations and modifications.

Taking into account the findings from German electricity market analysis and simulations, this study reaches for a solution to create flexible energy management business models and identify opportunities in the Nordic countries. However, the objective of this study is not to limit the findings to the Nordic countries but to present possible opportunities in other promising countries and identify the differentiating factors between market areas.

1.3 Scope of the study

In geographical terms, this analysis includes Germany as the starting point for conclusions as the high availability of data and the relatively mature solar market provide informative grounds for further analysis. In addition to Germany, the focus is on Finland but some points are carried out from other promising solar countries as well.

Regarding the methods of evaluation, this thesis consists of economic and technical viewpoints. Firstly, the economic analysis tries to identify the hidden value and potential enabled by flexible energy management related business models. This type of analysis is on the spotlight in this study since the economic factors are the determining side of capitalistic approach. Secondly, some technological aspects are studied to recognize the timing of possible breakthrough approaches and to evaluate the difficulties of potential implementations. Some psychological aspects are also considered: the consumer behavior in both residential and commercial businesses is essential to acknowledge, study, and leverage, however, these are not vastly addressed in this thesis.

In this study, the importance and potential value of distributed energy generation, demand response, demand side management, energy storage, solar energy output forecasting, electricity bundling, and trading are also evaluated.

All the aforementioned measures are used to simulate the best possible approach with the market fundamentals provided by selected countries. Despite the extensive scope of this study, there will be many opportunities and details that are not accounted for, which represent great opportunities for future research.

2 Description of existing knowledge

2.1 Definitions

Since some different interpretations can be found of the following concepts, and in order to prevent misunderstandings and to deliver the results of this study as straightforward and clear as possible, it is necessary to define some essential terminology related to this study. When used in this study, the terminology refers to the definitions explained in this section.

Virtual power plant (VPP):

Despite different views on the concept of virtual power plant, it can be concluded that VPP is an orchestra of energy agents, working together in order to tap the potential with aggregation that could not be tapped individually. An illustration of a possible setup of a VPP is presented in my illustration, Figure 3.

Figure 3. A possible setup of a virtual power plant.

VPP is an aggregated entity of energy production (Ruthe, et al., 2012) that can virtually imitate the energy output of an individual power plant (Zurborg, 2010); is not restricted to a single location[4]; may or may not contain demand response and energy storage capabilities, allowing it to adjust the total energy output through both consumption and production while reacting dynamically to changing conditions (Asmus, 2010); leverages recent advancements in technology[5] (DNV KEMA, 2011); can be monitored and controlled from a single location; delivers value to all parties; is grid-tied; and reduces uncertainty of energy production forecasts and fines for unbalancing (Nikonowicz & Milewski, 2012).

Demand response (DR):

Demand response describes any program that encourages consumers to shift electricity load from one time to another. Both parties, that is supplier and consumer, agree on their involvement and the terms and incentives may differ between cases. The participation of electricity end-users is supported by incentive pricing and tariff schemes. The responsiveness of end-users may rely on either active behavioral changes or passive responses, made possible by automation and remote control. (ENA & Energy UK, 2012)

The aim of DR is to mitigate balance costs, increase grid flexibility and utilization rate, generate value to all parties involved and result into a more dynamic electricity market model.

Some sources use the term *demand side management (DSM)* to describe the same concept than demand response.

Ancillary services:

The measures identified as essential for the transfer of electricity between selling and buying parties are called ancillary services. The costs caused by ancillary services are included in an open access transmission tariff. (UCTE, 2004)

Transmission system operator (TSO):

A responsible party for operating, maintaining and developing the transmission system for its control area and interconnections is called a transmission system operator. (UCTE, 2004)

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[4] Moreover, VPP can be highly distributed.

[5] Mentioned technologies include smart metering, smart grids, active electricity trading and constant data handling, and exchange with the help of commercial wireless technologies, such as WiFi and Bluetooth.

Primary reserve:

As the name indicates, primary reserve is the first measure to prevent outages in the electricity network. Primary reserve reacts automatically to changes in the grid frequency that results in a phase shift between grid frequency and spinning turbines, initiating needed energy adjustments. Therefore, primary reserves are also called spinning reserves. Primary reserves must operate in a pre-determined range since needed adjustments may fluctuate constantly upwards and downwards, resulting spinning reserves to be very limited and expensive. If this pre-determined range of grid frequency is breached, secondary reserve tries to offset the load change and bring primary reserves back to operation. Primary reserves are compensated entirely with capacity payments since net energy delivered in the process is zero on average. (Möller, 2010)

Secondary reserve:

In order to compensate unforeseen events in the grid network, secondary reserve is used. Parties providing secondary reserves respond to either up or down regulation within minutes, when selected frequency limitations have been reached. Within this timespan, most power plants are not capable to shut down or start up, meaning that mostly underutilized production or consumption capacity is adjusted according to the need at given time. Secondary reserve has prices for both capacity reserved for the service and for the amount of electricity exchanged. (Möller, 2010)

Tertiary reserve:

Tertiary reserve is used to cover big, unexpected, and long-lasting energy outages such as sudden nuclear shutdowns, when secondary reserve is not sufficient. Tertiary reserve is in many ways similar to secondary reserve but there are differences in demanded response times. Because tertiary reserve is used to restore an adequate amount of secondary reserve at the right time, reaction time is one of the most critical characteristics (UCTE, 2004). Like secondary reserves, tertiary reserves receive both payments for the capacity reserved and for the energy exchanged at the time of need. (Möller, 2010)

2.2 Methodology

To forecast solar generation, many metrics and measures have been proposed to quantify the accuracy of PV forecasts. When model is designed to forecast production, the data used to train the model should be excluded from test dataset and then test the reliability of the model with other datasets. The need to forecast PV production depends on how the knowledge is meant to be used. For example, utilities and system operators have interest to forecast production output for all hours of the day, both day-ahead and intraday.

To enable benchmarking for different approaches, standardization of measures and metrics is needed. Standardization will also improve the competitive landscape between forecast suppliers as the forecasting business raises more interest. Common metrics used to benchmark forecasts are *root mean square error* (RMSE) and *mean absolute error* (MAE). MAE describes the average magnitude of errors, and is calculated with equation

$$\boldsymbol{MAE = \frac{1}{N}\sum_{i=1}^{N}|e_i|}, \qquad (1)$$

where N is the amount of samples used and e_i the difference between forecast and observation values, or $y_{i,\,forecast} - y_{i,\,observed}$ (Inman, et al., 2013). RMSE is more effected by larger errors, giving them more weight in the calculation

$$\boldsymbol{RMSE = \sqrt{(\frac{1}{N}\sum_{i=1}^{N}e_i^2)}}, \qquad (2)$$

where N is the amount of samples used and e_i the difference between forecast and observation values, or $y_{i,\,forecast} - y_{i,\,observed}$ (Inman, et al., 2013). This is mainly why RMSE is used to evaluate solar forecasts since largest errors in forecasting cause significantly higher balancing costs than smaller errors. Usually these metrics are being normalized with and quoted as percentages of nominal installed PV power to enable comparison. (IEA, 2013b)

2.3 Virtual power plant cases

Virtual power plant concept has been piloted in different forms by various companies. However, the results and studies regarding real-life results from these ventures are yet hard to find as the business models and the level of execution are at a rather early stage. Virtual power plant business case relies heavily on communication protocol and flexibility of the system as a whole. There is not yet a general concept of operating a VPP and all electricity markets are different, making it hard for VPP models to penetrate electricity markets. Currently, at least RWE, Vattenfall Europe, DONG Energy and Deutsche Telekom have been involved in VPP related commercial solutions (MIT Technology Review, 2012).

Already in 2007, several renewable energy companies, including wind turbine and solar companies Enercon and SolarWorld, with Kassel University tested a pilot of a virtual power plant concept with 28 wind turbines, solar systems, biogas-fired generating stations and hydropower plants around Germany. The case study proved that even with significant amounts of variable energy production, overall power supply was evened out with the help of hydro and bio-based power. (MIT Technology Review, 2012)

In February of 2012, RWE started operating its first commercial virtual power plant, which maximum capacity reaches 80 megawatts (MIT Technology Review, 2012). RWE is able to monitor distributed renewable energy sources, aggregate their production and sell the generation with computer assistance to European Energy Exchange in Leipzig. RWE is additionally providing TSO with dispatchable loads and minute-reserves that improve the overall grid stability. (RWE, 2012)

In March of 2012, Vattenfall Europe announced its plans to establish virtual power plant operations (MIT Technology Review, 2012). The company also presented virtual heat and power, or $\text{VHP}_{\text{READY}}$, standard for controllable energy plant units already in April 2011. This standard[6] allows manufacturers to offer customers with plug-and-play products that require no additional installation work. However, the standard does not cover solar energy but more traditional technologies such as heat pumps, batteries, and block-type CHP plants. At the end of 2011, Vattenfall had 100 000 housing units under VPP control. (Vattenfall, 2012b)

DONG Energy Power has been providing power auctions for its 600 MW virtual power plant capacity as of early as 2008. The VPP capacity works as an alternative for any power exchange participant as the fixed price supply, and is offered at four auctions each year. There is also a limitation of 50 % for one buyer of the total available VPP capacity. (DONG Energy, 2014)

Virtual power plant concept has not attracted only utilities to search for business opportunities. In spring of 2012, phone company Deutsche Telekom started selling small gas-fired boiler generators to residential customers. These units could be connected via internet to utilities that allows connection and controlling for virtual power plant purposes. (MIT Technology Review, 2012)

[6] Technical Requirements Specifications can be found from (Vattenfall, 2012a)

In January 2014, Japanese consumer electronics Panasonic set up a joint venture (JV) with energy management firm EPCO to sell aggregated electricity from residential solar in Japan. The total investment to the JV amounted to 2,9 million dollars. Even though the concept of *virtual power plant* was not mentioned, fundamentally this kind of business model would enable operations similar to VPP. The Japanese electricity retail market is expected to be liberalized in 2016. (PV-Tech, 2014)

Virtual power plant concept is not currently subsidized, but instead, virtual power plant operators are incentivized in Germany to feed all produced variable renewable electricity directly to the market (Siemens, 2012). Since the German TSOs are forced by Renewable Energy Law to take responsibility in imbalance costs of solar and wind power, it is more profitable for renewable energy operators to feed produced electricity into the grid without balancing (van der Veen & Hakvoort, 2009). This has actually slowed down the progress made with VPP concept as one of its biggest benefits is the variable renewable energy aggregation and balancing its output, but currently it is not extensively used for such purposes. Renewable Energy Law reform was approved by German cabinet in April of 2014 but there has been no indication of imbalance cost inclusion for solar and wind power (PV-Magazine, 2014).

2.4 The general principles of electricity market

Electricity is a tricky form of energy since it cannot be stored as it is. Electricity usually needs to be transported over long distances, which is relatively ineffective and expensive in terms of both infrastructure and operation. Therefore, the current market is designed mostly for localized markets. When analyzing several market areas, all selected markets and their specifications must be evaluated individually due to the possible fundamental differences in market design. (Möller, 2010)

Wherever there is demand, there is supply. In an isolated electricity system, power supply and demand must be in balance at every instant, which requires constant maintenance. If the equilibrium between supply and demand cannot be maintained, a blackout needs to be conducted in order to protect the network and all loads connected to it from damage. Blackout is basically a static zero equilibrium between supply and demand. In order to avoid wide blackouts, primary, secondary, and tertiary reserves are used (see *2.1 Definitions*). Demand and supply are connected with electricity network that serves two basic needs. Firstly, the electricity needs to be transmitted to distribution systems and eventually to individual customers. The electricity itself is mediated by electro-magnetic fields with a speed of light, which provides for the second need that is to work as a buffer against network fluctuation. Due to a feature of electro-magnetism, electricity networks are able to store energy that converts back to electricity in case of fluctuation in the grid. That is why vast grids are capable to work as a buffer themselves. (Möller, 2010)

Electricity demand follows everyday life with the same cycles than modern life, including day-time, night-time, weekdays and holidays. Usually night-time, weekdays and holidays appear as lowered demand compared to average. Additionally, there are differences between seasons. In locations of low average temperature, winters present the peak demands due to required heating, and in contrast, high average temperature locations experience peak demands during summers due to air-conditioning. There are also differences between intraday peaks as some locations have peaks during evenings, some locations during midday. The demand of consumers can be divided into active and passive demand. Active demand, such as cooking or televisions, is initiated by consumer, as passive demand, such as floor heating, is the background consumption not directly nor actively controlled by consumer. In either case, usually consumers do not give a second thought to their usage time of electricity and even if they would, in most cases consumers would not greatly benefit from it due to long-term electricity contracts. This leads to a situation where the supply-side is primarily responsible for the state of equilibrium. For example, during the World Cup 1990 football final, the electricity demand suddenly rose by 2,8 GW in the United Kingdom between the extra time and penalty kicks. The reason was said to be tea kettles that were switched on (EPIA, 2012a). As can be learnt from the case, the demand side may as well experience significant unpredictable events that need to be taken care of by flexible electricity supply. Luckily, many energy intensive processes, such as large commercial freezers and metal industry electrolysis, can alter their demand at the time of high demand. (Gils, 2014; Möller, 2010)

Supply is usually divided into three categories: base load, mid load and peak load. Base load is characterized by high fixed costs but low variable costs, which is why these facilities are meant to generate as cheap electricity as possible during as many operating hours as possible. Because base load plants are generally big in power output capacity, they basically do not have the flexibility to respond to demand fluctuation. In contrast, peak load units have low fixed costs but high variable costs, and they are small in size. Smaller size results in flexibility in production that can be leveraged during temporarily elevated electricity prices. Due to the expensiveness of the generated electricity by peak load units, the price of electricity rises significantly during peak load hours. Lastly, mid load units are built to counter the cyclical changes between days and nights, filling the gap between base load and peak load. (Möller, 2010)

When all available generation units are put in order by their variable costs, it is called the *merit order curve*. A perfectly working electricity market matches the price for electricity with the value of merit order in demand of a given time period. (Möller, 2010)

2.5 The evolution of European electricity markets

The dynamics of electricity market have recently and fundamentally changed the field of utility business. Earlier, electricity markets were, and still are in many countries, a centralized business for companies with a monopoly status. These highly vertically integrated companies have had no competition and the business has been fairly straightforward and, above all, profitable. However, some electricity markets have lately been liberalized for all companies to compete in, leading to a situation where traditional power companies were laid open to dynamic market conditions and inner market risks. (Möller, 2010)

European electricity market privatization began in the United Kingdom in 1989–1990 by splitting the Central Electricity Generation Board, owner of all electricity generation and transmission in England and Wales, to several companies, and by setting up the Electricity Pool (Newbery, 2006). The UK privatization process was completed in 1996 (Mannila, et al., 2000). Simultaneously, Nordic countries were liberating their electricity markets as reform took place in Norway 1991, in Sweden 1996, in Finland 1998 and in Denmark 2011. The reform culminated in the establishment of Nord Pool electricity exchange platform, enabling cross-border trade of power (Amundsen & Bergman, 2006; Amundsen & Bergman, 2007). The progress made in Nordic countries raised the attention of European Commission. The European Union (EU) started to push forwards the liberalization in the European electricity market by entering EU-wide Electricity Directive (96/92/EC) into force in February 1997 and set rules and timetables for the opening of electricity markets in the member nations (The European Parliament and of the Council, 1997). Later the EU decided that every consumer should be able to choose their electricity supplier in 2007, at the latest. (Green, 2006)

The advanced electricity exchange establishments in the UK and Nordic countries were one of the first steps towards integrated and internal European electricity market. After this, the EU has entered a set of directives into force that have been driving integrated European electricity market even further. However, applying common legislation for nations of EU has arisen challenges and tensions over sovereignty of as critical supply as energy (Newbery, 2002). Selected directives for European electricity market integration are presented in Table 1.

Table 1. Relevant European electricity market integration directives with summaries, implementation dates and source data, after (The European Union, 2014).

Directive	Summary	Entry into force	Official Journal
2003/54/EC	This directive established EU-wide, common rules for the generation, distribution, and transmission of electricity. It also sets rules for the organization and functioning of the electricity sector. Internal accounts for transmission and distribution activities were set to be separated.	4.8.2003	OJ L 176 of 15.7.2003
2003/87/EC	This directive's target was to significantly reduce greenhouse gas (GHG) emissions. The directive additionally proposed allowances for GHG that eventually led to the EU emission trading system.	25.10.2003	OJ L 275 of 25.10.2003
1364/2006/EC	This directive was set to push forwards trans-European energy networks and to introduce the concept of "project of European interest". These projects are allowed to get funding from the European Community.	12.10.2006	OJ L 262 of 22.9.2006
2008/92/EC	This directive was set to improve the transparency of gas and electricity prices charged to consumers. Price information is gathered to Eurostat platform, in which the price of energy supply, taxes and levies, VAT, and other recoverable taxes can be identified.	27.11.2008	OJ L 298 of 7.11.2008
2009/28/EC	This directive was in line with the EU's 20-20-20 objectives that established framework for the production and promotion of renewable energy within the EU.	25.6.2009	OJ L 140 of 5.6.2009
2009/72/EC	This directive introduced EU-wide common rules for electricity generation, transmission, distribution and supply. It additionally identified universal service obligation and consumer rights.	3.9.2009	OJ L 211 of 14.8.2009
714/2009/EC	This regulation established rules for cross-border electricity exchange to improve competition and harmonization. Provided also further guidelines and objectives for European Network of Transmission System Operators (ENTSO) to facilitate market integration.	3.9.2009	OJ L 211 of 14.8.2009

2.6 Marketplaces for electricity

Depending on the market area, electricity can be either sold with fixed price or traded transparently at various marketplaces, as can be seen in my illustration, Figure 4.

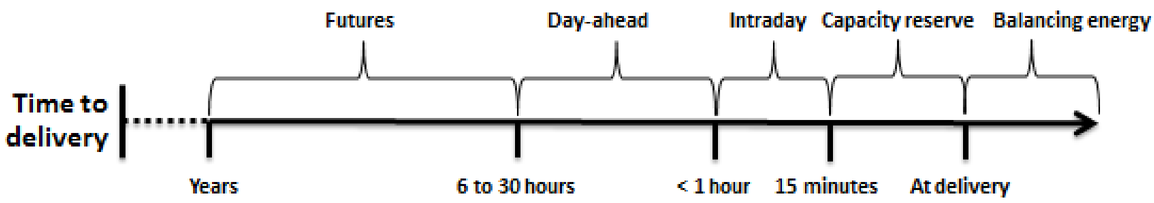

Figure 4. An illustration of the chronologic occurrence of different electricity marketplaces.

Futures and intraday trading are not taken into account in the analysis of this study but understanding of electricity trading as a whole is an essential tool in forming the big picture provided by this paper.

2.6.1 Futures market

The longest running products of electricity trading are futures. The delivery time for futures may vary from one week to several years. Future contracts usually bind participants to buy or sell constant power delivery through the decided time period. Since electricity supply and demand vary seasonally, base load and peak load futures are sold separately so that realistic guidelines for both production and consumption profiles can be provided to market participants. This data of future electricity pricing is essential for long-term planning of, for example, power plant investments or energy intensive production line cost analysis and execution. Futures may be used also in hedging purposes. (Möller, 2010)

2.6.2 Day-ahead market

As the delivery time for electricity futures draws closer, the market participants usually have better view on their supply and demand profiles. For TSOs operating on the market, it is essential that most of the imbalances are cleared on the day-ahead, or so called spot market, that in Nordic countries is called Nord Pool Spot. The spot market is the best opportunity for market participants to balance their positions as the liquidity is regularly sufficient. Depending on the market area, prices are set for the next 24 hours following the merit order curve on half-hour or hourly basis. On some occasions, as the inelastic demand matches delivery restrictions on the supply side, radical price increases can be experienced. (Möller, 2010)

2.6.3 Intraday market

In some occasions, supply and demand may fluctuate after the day-ahead trading has ended. However, after the closing, if needed, intraday trading can be executed[7]. Therefore this marketplace has higher importance for market participants with a production or consumption portfolio that may experience unexpected fluctuations between the day-ahead market and the time of gate-closure[8], for instance renewable energy portfolio with wind and solar power generation. This buffer created by gate-closure is intended for TSOs to aggregate all the traded electricity and evaluate the possibility of operational constraints. (Möller, 2010)

2.6.4 Capacity reserve market

Since even the best predictions of electricity flows do not always match the realized flows, and constant match between consumption and production must be sustained, there is a need for capacity reserves. These reserves are paid by a capacity premium in addition to net energy flow compensation because the amount of required energy is unknown beforehand. These reserves usually receive high compensation for their services compared to day-ahead electricity prices, thus motivating market participants to mitigate possible imbalances. The TSOs of the market area allocate these capacity reserves long before the actual energy delivery, like the electricity futures, but in practice the service is delivered between intraday and balancing energy market. (Möller, 2010)

2.7 Nordic electricity market

The Nordic countries have one of the most advanced and transparent electricity markets in the world, Nord Pool Spot. In 2012, 432 TWh worth electricity valued at 11,7 billion euros, or 77 % of all traded power in the Nordic countries, was traded through Nord Pool Spot, making it the world's largest market for buying and selling power. The market liquidity is secured by vast participation of 370 trading members. (Nord Pool Spot, 2013)

Elspot is the marketplace for day-ahead electricity sales. It works as an auction where the price is calculated at 12.00 Central European Time for the electricity to be delivered the

[7] The intraday market in the Nordic countries is referred as Elbas. (Nord Pool Spot, 2013)
[8] Gate-closure is the time when intraday market is closed, usually 15 minutes before the start of delivery.

next day. The price is derived from the merit order curve, where the demand-side bids and supply-side bids cross. (Nord Pool Spot, 2013)

Despite the high functionality of Elspot market, there is need for some intraday trading for power due to unforeseen events that affect the net balance. This marketplace is called Elbas, where buyers and sellers may trade power closer to the delivery hour, thus having the opportunity to reduce the amount of unknown imbalance costs. In 2012, 3,2 TWh of power was traded on Elbas by 118 participants. (Nord Pool Spot, 2013)

The balancing energy market in Nordic countries consists of balancing power, frequency controlled reserves and imbalance power. All these marketplaces are valued differently, as presented in Table 2. In brief, frequency controlled disturbance reserves are the last resort to protect the grid from damages and blackouts. Stabilizing power, such as Elbas and balancing power, are proactive measures to stabilize the grid and avoid the usage of more expensive frequency controlled capacity. Frequency controlled operation reserves are used to fine-adjust the grid frequency. (Fingrid, 2014)

Table 2. Electricity marketplaces on Nord Pool Spot with prices and technical requirements, after (Fingrid, 2013a).

Market place	Type of contract	Minimum size	Activation time	Activation interval	Price level 2013	Potential for VPP concept	Used in this study
Frequency controlled normal operation reserve	Yearly and hourly markets	0,1 MW	3 minutes	Constantly	14,36 €/MW,h + price of electricity	Yes	No
Frequency controlled disturbance reserve	Yearly and hourly markets	1,0 MW	5s/50%, 30s/100%, when *f*[9] under 49,9 Hz	Several times per day	3,36 €/MW,h	Yes	No
On-off frequency controlled disturbance reserve	Long-term	10 MW	Instantly, when *f* under 49,5 Hz	About once a year	~0,5 €/MW,h + 580 €/MWh +activation fee 580 €/MW	Yes	No
Balancing power market	Hourly market	10 MW	15 minutes	According to the bids, several times per day	Market price	Yes	Yes
Fast disturbance reserve	Long-term	10 MW	15 minutes	About once a year	~0,5 €/MW,h + 580 €/MWh	Yes	No
Elspot	Hourly market	0,1 MW	12 hours	-	Market price	Yes	Yes
Elbas	Hourly market	0,1 MW	1 hours	-	Market price	Yes	No
Strategic reserves	Long-term	10 MW	15 minutes	Rarely	.	Yes	No

The TSOs operating on the Nord Pool Spot are Energinet, Svenska Kraftnät, Fingrid, Litgrid, Elering, Statnett, and Augstsprieguma tikls. (Nord Pool Spot, 2013)

2.8 German electricity market

This analysis is not fully focused on the German market model but as some results and conclusions from the German electricity market are proposed as a part of this thesis, it is essential to understand the basic characteristics of the marketplace.

There are in total four transmission system operators (TSOs) operating on the German electricity market: TransnetBW, Amprion, 50Hertz, and TenneT (ENTSO-E, 2013c). To balance the net deviations of different balancing groups in the electricity generation market of Germany, the TSOs use compensation energy. The system control platform

[9] *f* stands for frequency.

“Netzregelverbund” (NRV) that handles compensation energy, was expanded in May 2010 to cover all four transmission areas. To facilitate the usage of such balancing, the TSOs introduced a standardized cost for balance energy, or Regelzonenuebergreifender einheitlicher Bilanzausgleichs-energiepreis (reBAP). (Amprion, 2013)

ReBAP is primarily calculated by summing up the total costs of utilized balance energy and dividing that figure with the total amount of utilized balance energy[10]. These prices are applied for each 15 minutes[11] of a given day, thus reflecting the cost of balancing in the market area. Energy shortfall in the control area corresponds to a positive balance energy value, meaning that additional energy is purchased from the market at a certain price level. The need to sell surplus energy leads to a negative balance energy. (Amprion, 2013)

In Germany, despite the high costs related to balancing energy, the solar and wind producers are in 2013 exempted from the responsibility of balancing (Borggrefe & Neuhoff, 2011). The four TSOs in Germany are responsible for these fluctuations and according to the German market model, these costs are translated through reBAP to those parties that cannot meet their quotas for electricity delivery, thus increasing the cost of electricity.

The value of balancing energy market relies heavily on the balance responsible parties (BRP) and the success of their electricity deliveries. On some occasions, it is financially beneficial for BRP to deviate contrary from the net deviation in the balancing area, which has negative effect on the stability of the grid due to its speculative nature[12]. Germany has single-pricing model for their off-balance penalties, which enables this type of speculation. Excessive speculation and abuse of the system is prohibited by the threat of penalties, however, manipulation within certain limits is allowed. Other European countries, such as Finland, have dual-price model for buying and selling balancing electricity production that prevents most of this kind of speculative operations. (Möller, 2010)

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[10] More information on the calculation of compensation energy prices can be obtained from (50Hertz, 2013).
[11] For this analysis, these quarter-hour values have been combined to hourly weighted average values to enable comparison with other relevant data that is reported in hourly intervals.
[12] If the expectations of the net deviation appear to be wrong, manipulative BRP’s amplify negative effects, possibly resulting in blackouts.

2.9 Relevant previous studies

There are several papers discussing many of the aspects relevant for this thesis, but none thoroughly analyzes the VPP related business opportunities in Nordic countries. Key topics include household electricity consumption, solar power forecasting, balancing costs of solar, and distributed power generation aggregation. All the aforementioned subjects are indeed essential for the viability of VPP business models but none of the studies alone deliver sufficient results on the matter. The findings in these papers are taken into account, analyzed and applied for this thesis in order to achieve thorough view for further conclusions.

2.9.1 Household electricity consumption

The Ministry of Trade and Industry of Finland, *Työ- ja elinkeinoministeriö* (TEM), conducts a study of Finnish household electricity consumption every five years. The latest report, *Kotitalouksien sähkönkäyttö 2011*, was earlier published in 2006. The study was conducted with the help of inquiry material from 4 666 households across Finland, systematic gathering and analysis of material from field, and supportive literature. However, field studies were not executed for the study of 2011 but findings from the field studies of 2006 were applied by adjusting the results with correlations found from earlier research. One of the main points of the study is to gather sufficient data for the needs of TEM with reasonable costs, which is reflected in the limited amount of field studies executed. (TEM, 2013)

The study reveals some encouraging points for the development of VPP business opportunities amongst other relevant trends. The study[13] notes that electricity consumption increased between 2006 and 2011 by 2 TWh that was fully traceable to increase in heating end-usage[14]. Of this, 60 % was from heating and ventilation-related, increasing annually by 4 %. Significant rise was seen in heat pump and floor heating consumption as the energy used for these more than doubled in five years. The increasing demand for heat pumps has continued as the total amount of pumps in Finland has increased from under 500 000 units to over 600 000 during 2012 and 2013 (Suomen Lämpöpumppuyhdistys ry, 2014). Even though heat pumps are characterized by high coefficiency of performance, thus decreasing

[13] Apartment types of block of flats, terraced and detached houses were taken into account in the study.

[14] When evaluating the results of this paper, one should keep in mind that figures presented were not temperature corrected as 2006 was colder than 2011. This has an impact on the heating figures presented, and in this case it emphasizes the increase in electricity consumption for heating.

the total amount of energy required for heating, the consumption of electricity increases as heat pumps usually replace either oil or wood usage. From total electricity usage, 59 % was used for heating[15] and the remaining 41 % for household appliances. (TEM, 2013)

The total consumption of appliances and lighting has not increased, mostly thanks to energy efficiency directives that have driven forward less consuming products to the market. In fact, in just five years the consumption of lighting and televisions has dropped drastically by 40 %. At the same time the electricity consumption of information technology has doubled due to the increase in computer density and time of use. Same kind of trend was seen in car related heating. (TEM, 2013)

According to the study, the focus group for this thesis, detached house[16] residents, account for 41 % of all residents, equivalent of 1 035 524 households in 2011 with an average of 2,59 residents per household. Of all these households, 44 % were electrically heated. In total, detached houses consumed 14,2 TWh of electricity in 2011. (TEM, 2013)

All in all, the findings in the paper predict further increase in Finnish electricity usage for electricity based heating, including heat pumps and floor heating, is replacing combustion based solutions, including burning oil, wood and pellets. This creates more adjustable load for flexible energy management related business models in the future.

2.9.2 Solar forecasting

A report by IEA Photovoltaic Power Systems Program (IEA-PVPS), *Photovoltaic and Solar Forecasting – State of the Art (2013),* describes approaches and results of different forecasting methods. The paper concludes that regional forecasts for PV power are needed when 1–2 % of yearly electricity demand is generated with solar power. An inquiry of forecasting results around the world was conducted for the study and the results imply RMSEs between 15 % and 64 % for 24–48 hour ahead forecasts. However, the locations and timing of the forecast periods vary, thus having an effect on the results and comparability. Overall, the best results were accomplished not by individual forecasting methods rather than combining several different forecast methods and iterating the results with post-processing procedures.

[15] Including water, car, and indoor heating.
[16] Detached houses in this study include both single and duplex houses.

It is also worth mentioning, that the paper highlights the immaturity of the solar forecasting business and that the results presented are just the first benchmarks for the industry. Predicting solar power ramp rates and collaboration with smart grid capabilities and electricity load controls are also seen as the next big developments forwards.

2.9.2.1 Factors affecting forecast accuracy

The study points out that there are four main factors affecting the results of forecasts: local weather conditions, area size covered by the forecast, selection of time horizon, and the accuracy measures selected. (IEA, 2013b)

Firstly, local climate types and weather conditions characterize different locations. It can be summarized from the paper that sunny locations experience, on average, lower forecasting errors than cloudy and rainy locations. The positions of clouds are especially challenging to predict over 6 hours ahead due to the chaotic nature of the cloud systems. (IEA, 2013b)

Secondly, the number of sites and the size of the area covered by the forecast is shown to have significant impact. It has been studied that PV forecasting improves significantly as the size of geographical area increases. For an area size of Germany, a reduction in RMSE of 64 % was seen compared to a single location. For several locations, occurring errors partially cancel each other out, resulting in reduced total error compared to a single location, in which this kind of balancing does not realize. (IEA, 2013b)

Thirdly, forecasting horizon has a clear correlation on the results received: as the forecast horizon increases, typically the forecasting accuracy decreases. The change is more radical for methods that rely solely on past data. Very short term forecasts of 0–6 hours benefit most from measured data, and forecasts beyond 6 hours require numerical weather prediction (NWP) models. Usually the best results are achieved via approaches that make use of data both from past and the future. (IEA, 2013b)

Lastly, as forecasting results are being benchmarked and standardized, it is of high importance that all values are indeed comparable. Attention must be paid on the accuracy measure selected and on the dataset used. Some datasets include only daylight hours while some datasets include every hour of the day, resulting in better results due to the effortless forecasting of solar irradiation during the night. (IEA, 2013b)

2.9.2.2 Intraday forecasting

When referred to intraday forecasting, it is usually translated to predictions of 0–6 hours ahead. In (IEA, 2013b) it is stated that intraday forecasts are of smaller economic value than day-ahead forecasts since most of the electricity is traded on day-ahead market. However, as the solar penetration increases, the importance of intraday forecasting is set to grow, resulting in new business opportunities. As tools for prediction, intraday forecasts utilize total sky imagery, satellite imaging, and stochastic learning techniques, such as persistence[17]. All the aforementioned techniques are described in Table 3.

Table 3. Different solar power forecasting techniques and their characteristics, after (IEA, 2013b).

Technique	Sampling rate	Spatial resolution	Maximum forecast horizon	Application
Persistence	High	One point	Minutes	Baseline
Total sky imagery	30 seconds	10–100 meters	Tens of minutes	Ramps, regulation
Satellite imagery	15 minutes	1 km	5 hours	Load following
Numerical weather prediction (NWP)	1 hour	2–50 km	10 days	Regional power prediction

Total sky imagery tracks the cloudiness of an area and tries to predict their movements from real time up to 10–30 minutes ahead. Since solar irradiance is highly dependable on cloud cover, irradiance can be predicted from the current cloud cover and predicted with the help of cloud velocity, direction and opacity. First, sky imaging equipment acquires an image with a 360 degree view of the sky above that is then flattened from the fisheye perspective, and analyzed to identify clouds. Then consecutive images are used to generate cloud motion vectors that can be used to form deterministic or probabilistic model of cloud cover, providing sufficient data to predict irradiance and power output of a PV plant. The problem with sky imagery is multiple cloud layers since only the lowest layer and its movements appear in the sensors, leaving possible upper layers excluded from the vector analysis. When using satellite imagery, same kind of approach is used than with sky imaging, but in reverse manner. The amount of reflected light transmitted from clouds is measured with satellite sensors and the light reaching ground can be calculated. Due to the image processing and download time of data from the satellite, the satellite imaging data cannot be updated very frequently. However, much larger areas are covered by satellites and can be monitored and analyzed continuously. This leads to capability to provide more

[17] Persistence describes an approach, in which forecasts are made based on the preceding samples.

accurate forecasts for longer time periods. Satellite imaging is shown to outperform numerical weather prediction models for short-term forecasts, and provide significant improvements for up to 5 hours forecasts. Stochastic learning techniques are based on patterns in data or even images. Basically, this method uses historical patterns to predict the future. One approach in the field of stochastic learning is to measure current or recent PV power output that is extrapolated and adjusted to the changing sun angles accordingly. (IEA, 2013b)

2.9.2.3 Day-ahead forecasting

To successfully trade large volumes of electricity on the market, it is essential to have a reliable prediction of the total amount of electricity produced so that costly balancing energy is not needed. Therefore, day-ahead forecasting is of extreme importance for utilities that need accurate power output forecasts for their electricity supply. Usually the needed forecasts extend from 12 hours to 36 hours, depending on the electricity market model. For intraday forecasts, past observation has great value but with day-ahead forecasts the focus is on the numerical weather prediction. (IEA, 2013b)

Numerical weather prediction (NWP) relies on three-dimensional modeling that is highly complex process. Due to the dependence on powerful computational ability, only 14 global models are in use worldwide. The model usually runs from two to four times per day, taking input from satellites, radars, radiosondes and ground station measurements (global horizontal irradiance, relative humidity, temperature, vapor pressure, sunshine duration, wind speed and direction) into account. (IEA, 2013b)

2.9.3 Grid integration costs of solar power

Future grid issues, expansion and integration costs in the EU context are widely studied, as in (Egerer, et al., 2013), but to estimate the cost of high penetration of renewable energy resources, especially solar power, more specific evaluations are needed with up-to-date assumptions.

To evaluate the total costs of solar power, an expert team from Imperial College of London conducted a study and published a report *Grid Integration Cost of Photovoltaic Power Generation* in September 2013 that quantifies the costs for 11 key European markets: Austria, Belgium, Czech Republic, France, Denmark, Greece, Italy, Netherlands, Portugal, Spain and the United Kingdom. The report focuses on the feasibility of installing up to

480 GW of PV by 2030 which equals more than 10 % of projected total European electricity demand at that time. Even though the report does not take Nordic countries into account, it gives comprehensive insight on the matter and especially guidelines for the vastly discussed topic of solar integration costs on a large scale. (PV Parity, 2013)

The cost of photovoltaics in the paper is defined as the sum of both levelized cost of electricity (LCOE) and system cost included. More detailed description is illustrated in Figure 5. The study quantifies the costs for following grid integration measures: additional capacity cost of PV, transmission costs, reserve generation costs, costs of distribution network capacity and losses, and effects of applied demand response. (PV Parity, 2013)

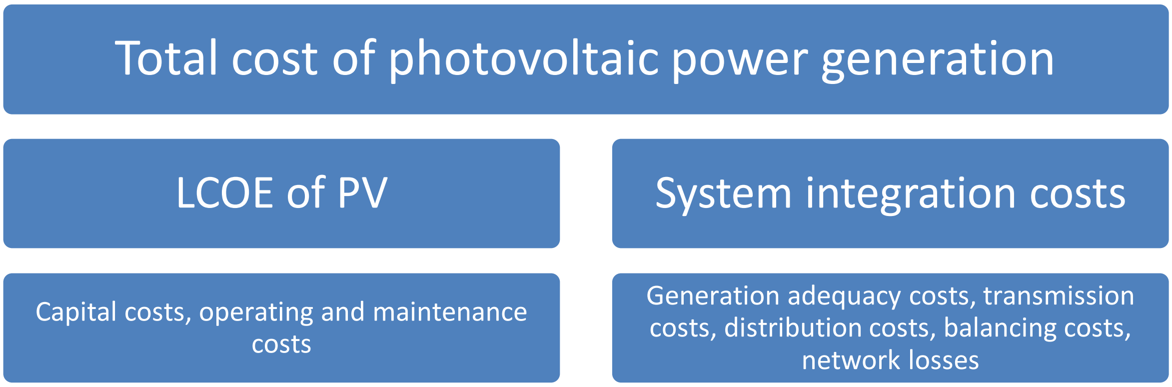


Figure 5. The total costs of photovoltaic power generation, after (PV Parity, 2013).

Additional capacity costs refer to the existing power generation capacity that can be displaced by PV. The method used to quantify the cost was calculated by formula

$$\Delta C_{PV} = \left(1 - \frac{D^C}{D^E}\right) * C^{I_o}, \qquad (3)$$

where C_{PV} is additional capacity cost of PV, D^C the percentage displaced capacity of incumbent generation due to PV penetration, D^E the percentage displaced energy of incumbent generation due to PV penetration, and C^{Io} the per-unit capacity cost of incumbent technology. The study points out that for Northern European countries, the effect of PV is basically zero since the consumption profile does not match PV production profile and peak demand occurs during cold and dark winter months. Therefore, even though PV can replace some of the net energy of current power generation facilities, PV cannot totally replace these facilities. The situation in Southern European countries is the opposite as the peak demand matches perfectly the PV production profile, resulting in negative costs, or in other words, benefit. It is found that additional generation capacity is a major component of total integration costs. For Northern Europe, the cost for additional generation capacity varies from 14 to 16 €/MWh, while in Southern Europe (Greece) the benefit for PV may reach over 20 €/MWh due to the high match of peak load and PV peak production. (PV Parity, 2013)

The European wide grid costs were found by the study to be relatively low. To reach the PV penetration level of over 10 % by 2030, a strong interconnected system within Europe is needed so that fluctuations in production can be reduced and solar power could be generated there where it makes the most economical sense. By 2030, the grid costs were said to amount to 2,8 €/MWh. (PV Parity, 2013)

Increasing PV penetration will increase the need to balance the errors in PV output forecasts by additional frequency response and operating reserves. This is set to be covered by part loading conventional power plant, which increases operating costs. However, if interconnected European grid is achieved, the geographical distribution will partially even out the forecasting errors[18]. The paper indicates that the balancing costs required by PV increase along with the penetration rate, amounting to 1,04 €/MWh by 2030. (PV Parity, 2013)

Adding PV capacity into the electricity infrastructure has somewhat reducing effect on distribution network losses due to increased local production and consumption of electricity, and the reduced need to transmit electricity long distances. However, the PV Parity study reveals that after 8 to 10 % PV penetration rate, the overall losses start to increase due to increased reverse power flows in the system. If cost for losses is assumed at 50 €/MWh, and the PV penetration at 2 %, the savings received in reduced losses total between 2,5 €/MWh and 5,5 €/MWh. (PV Parity, 2013)

Regarding all the aforementioned costs, the report summarizes that 18 % PV penetration rate is technically feasible and its costs are relatively modest. At 2 % penetration rate, the total impact varies between countries from a benefit of 50 €/MWh to a cost of 13 €/MWh. At 18 % penetration rate, the upper limit for cost was reported to total 26 €/MWh. The role of demand response was also evaluated, which has the strongest link to the topic of this study. Shifting the load from peak hours to time periods of lower demand results in increased self-consumption rates, leading to savings in transmission losses, network costs,

[18] This effect is further discussed in the next section *2.9.4 Distributed generation aggregation.*

and balancing reserves. In total, demand response was calculated to bring down the highest cost at 2 % penetration rate from 13 €/MWh to 9 €/MWh and at 18 % penetration rate from 26 €/MWh to 21,5 €/MWh, equaling overall cost reduction of over 15 % in both cases. The paper also highlights that the benefits of demand response, as overall costs of grid integration, are higher in Northern Europe than in Southern Europe. As a conclusion, the total grid integration costs were not seen to have a significant impact on the competitiveness of PV technology in the long run, but further developments of various cost mitigation resources[19] were encouraged.

Another paper by Schaber et al. (2012) studied the costs related to grid extension costs triggered by increased share of variable renewable energy (VRE). The paper provides an overview with different shares of PV and wind capacities in addition to large range of varying scenarios in Europe. The system model takes into account the total system costs, including VRE, transmission grid, backup power, storage capacity, operation, maintenance, fuel and carbon related costs. The model was conducted with hourly resolution[20] over the area of Europe that was split into 83 different regions. The study found that grid extensions, in general, reduced overproduction in addition to the capacity of needed VRE and backup capacity. Having coal and gas combined cycle power plants as backup technologies[21] and carbon price at 20 €/t, the range for average European costs of electricity was 80–170 €/MWh with grid extensions and over 207 €/MWh without the extension. In total, increased shares of VRE require six times the high voltage grid capacity that is currently available, resulting in total grid investment costs of 250 billion euros that translates into 20–25 % of investment costs for VRE. The price impact for consumers was seen at most at 6 €/MWh with assumptions of 7 % capital cost and 40-year lifetime for the grid. (Schaber, et al., 2012)

The study of Schaber et al. (2012) additionally found that a 60 % VRE scenario for 2050 is feasible. As solar power complements well day-time demand, it cannot provide electricity during the night. The study found that with optimal grid, the penetration rates for wind power would be 51 % and solar power 9 %, which resulted in minimal overproduction for given VRE share of energy mix. With low VRE cost scenario, the average European cost

[19] such as demand response, energy storage, and smart grid technologies.
[20] Short-term variability of under one hour resolution was not included in the study.
[21] With assumed carbon price of 20 €/t, costs for coal power plant were in the study at 55 €/MWh and for gas turbines at 110 €/MWh. With carbon price of 100 €/t, the costs were at 115 €/MWh and 155€/MWh, respectively. (Egerer, et al., 2013)

of electricity was found to be 80 €/MWh and additional grid integration costs 3 €/MWh. This grid integration cost is much in line with the study by PV Parity (2013), however, grid costs of 2,8 €/MWh were found to occur already in 2030 with solar power penetration rate of 10 %. Without grid extensions, the low VRE cost scenario would result in 90 €/MWh cost of electricity with no additional grid-related costs. Without grid extension, the optimal penetration rate for wind would be at 39 % and for solar 21 %. (Schaber, et al., 2012)

A study by Fürsch et al. (2013) evaluated the costs of electricity system with 80 % VRE penetration and 80 % reduction in CO_2, compared to 1990, in Europe until 2050. Two scenarios were used, scenario A and B. Scenario A assumed cost-optimal deployment of generation and grid capacities from a perspective of integrated system. Interconnector capacities were only moderately expanded in scenario B by limiting extensions to grid projects that already have reached planning phase. (Fürsch, et al., 2013)

The study found that in both scenarios, A and B, significant amounts of grid transmission lines had to be built to Europe. A total of 111 000 km for scenario B, and 228 000 km for scenario A of transmission lines had to be added as extensions, representing an increase for today's total of transmission lines of 37 % and 76 %, respectively[22]. Therefore both scenarios showed also major increase in the share of fixed costs in the average system cost until 2050. According to the study, variable costs were 75 billion euros and fixed costs 65 billion euros in 2010, resulting in an average system cost of 47,1 €/MWh. However, due to increased share of solar and wind power, which have low variable costs and high capital expenditure, fixed costs account more than 90 % in both scenarios of the total expenditure in 2050. Fixed costs were in line with (Schaber, et al., 2012) at 256 and 264 billion euros, variable costs were 28 and 30 billion euros, and average costs 65,6 and 67,9 €/MWh, for scenarios A and B in 2050, respectively. These findings indicate somewhat lower total electricity costs in 2050 than in Schaber et al. (2012), even with higher VRE penetration rate of 80 % compared to Schraber's study's 60 %. Even though grid investment costs roughly match between these studies, differences in production technology investment costs easily create variations in total electricity cost results. (Fürsch, et al., 2013)

In general, the solar power grid integration cost evaluations depend highly on the long-term scenarios, which have very high uncertainties. Additionally, due to the complexity of

[22] It was not specified in the study, what would be the total amount for high voltage transmission lines.

EU-wide electricity grids, different scenarios are often used, which make the benchmarking of separate studies difficult. Especially the distribution between wind and solar power within the VRE capacity do differ between studies. However, these studies can be used as the guidance for the size of magnitude of possible costs related to grid integration. It can be learnt from the aforementioned studies that the costs related to high penetration of renewable energy sources, and especially solar power, are not unappealing, rather quite feasible.

2.9.4 Distributed generation aggregation

The effects of spatial distribution of solar power generation units have been largely studied. Three different papers were especially relevant for this thesis: IEA's *"Photovoltaic and Solar Forecasting: State of the Art"*; Wiemken et al.'s (2001) *"Power characteristics of PV ensembles: Experiences from the combined power production of 100 grid connected PV systems distributed over the area of Germany"*; and Suri et al.'s (2014) *"Cloud cover impact on photovoltaic power production in South Africa"*. All of the papers show a major link between forecasting capability and distributed aggregation of individual generation units.

Wiemken et al. (2001) studied effects of combined PV power generation compared to individual solar systems. For the study, data from 100 individual PV systems in 'German 1000 Roofs Programme' in 1995 was gathered. The systems included amounted to a capacity of 243 kWp, of which system sizes were mainly between 1 kWp and 5 kWp, covering an area of 600 x 750 km. The availability of system data was high during the research as 98 % of the time data in time resolution of 5 minutes was available. The emphasis was in the time window of 90 minutes around noon during the summer months. For comparison purposes, the PV system power output *P* was normalized with formula

$$P = \frac{\sum_n P_n}{\sum_n P_{installed,n}}, \qquad (4)$$

where P_n is the power output of single power plant and $P_{installed,n}$ the nominal power capacity of single power plant. (Wiemken, et al., 2001)

The study revealed significant differences between individual and aggregated systems. It was found that power fluctuations of more than 5 % of the ensemble of 100 systems were non-existent in the given time resolution. This is clearly visible in Figure 6.

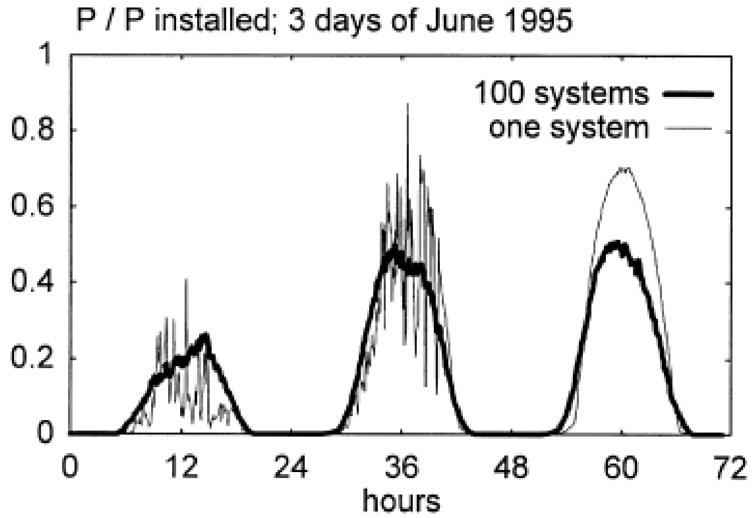


Figure 6. Balancing effect of PV ensemble compared to individual solar systems, after (Wiemken, et al., 2001).

The same phenomenon was studied for South Africa in more recent paper by Suri et al. (2014), conducted in partnership with Eskom, the South African electricity utility, and GeoModel Solar, the solar resource consultant and operator of SolarGIS database. This study analyzed eight years' worth, between 2005 and 2012, of high-resolution SolarGIS solar and meteorological data to produce PV output simulation[23] with different setups. Four levels of aggregation were simulated for different area sizes, which specifications and results are presented in Figure 7 and Table 4. The results showed that by aggregation, overall share of minimum power output increases, maximum power output decreases[24], and the magnitude and steepness of 15-minute power fluctuations decreases. In brief, spatially distributed aggregation results in smoother daily power production profiles, which are characterized by more stable and less fluctuating power output.

[23] The simulation assumed installations to be large-scale ground-mounted crystalline-silicon PV power plants with 27° North mounting and high-efficiency central inverters (Suri, et al., 2014).
[24] Spatial distribution increases the odds that cloud cover occurs somewhere over the aggregated area, therefore the maximum output decreases (Suri, et al., 2014).

Table 4. Aggregation levels' characteristics and main findings showing smoother overall power output and improved production certainties, after (Suri, et al., 2014).

Aggregation level	Square size	Number of power plants	Range of maximum 15-minute changes as nominal DC power percentages	Percentiles[25] as % of nominal DC power		
				P99	P50	P1
0	5 km x 5 km	1	±15 to ±40	2–15	60–80	78–92
1	50 km x 50 km	9	±8 to ±24	4–21	60–79	77–91
2	250 km x 250 km	49	±3 to ±10	9–28	61–78	78–89
3	500 km x 500 km	225	±2 to ±6	12–32	61–77	79–87

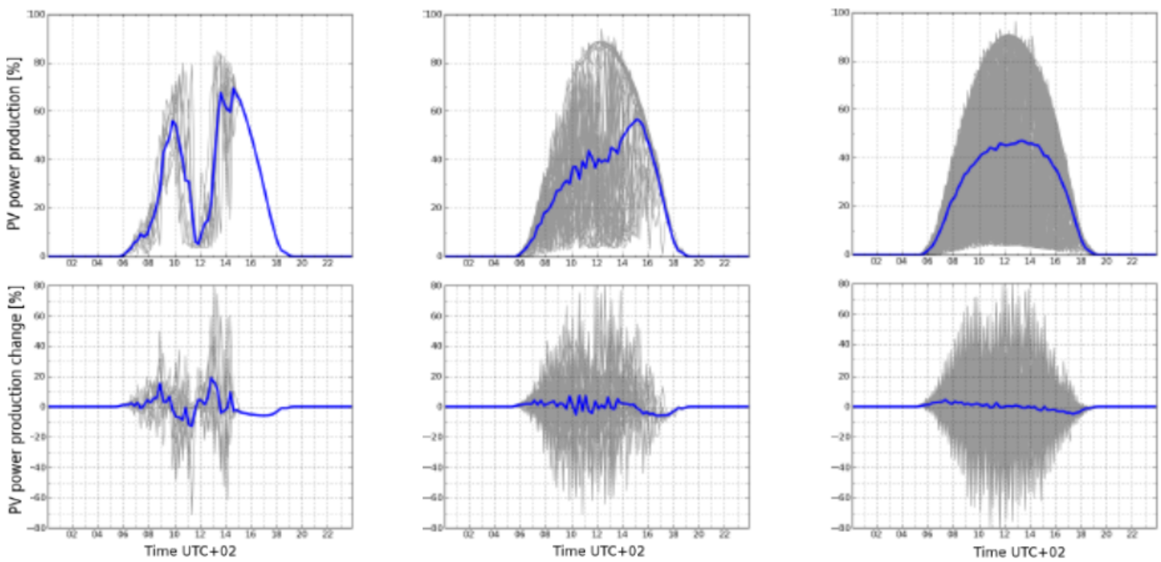
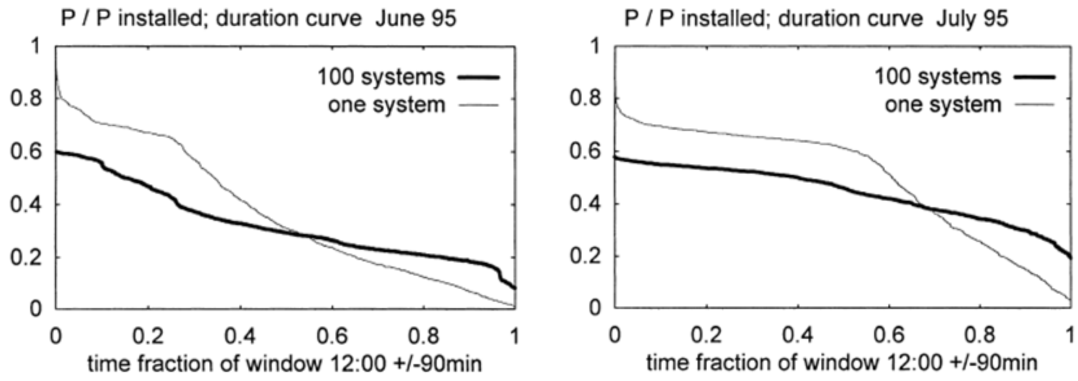


Figure 7. Daily PV power production profiles (top row) and 15-minute variability (bottom row) in Upington, South Africa, on 1 January 2012. Blue line illustrates the aggregated profile as grey lines represent individual power plant data. Aggregation level 1 on the left, level 2 in the middle, and level 3 on the right, after (Suri, et al., 2014).

Wiemken et al. (2001) studied an ensemble of 40 individual solar systems and found that the power output profiles were mainly influenced by the spatial distribution of the systems, not the total number systems. Therefore, increasing the number of total system amount to over 100 was not expected to improve overall results significantly. An analysis of power curves produced in June and July 1995 for the time window around noon showed that for every day a production of approximately 10 % could have been guaranteed for June and

[25] Results for percentiles gathered between 11:00 and 13:00 local South African time. P99 represents a value, on top of which 99 % of the data occurs, P50 the same with 50 %, and P1 the same with 1 %.

about 20 % for July. Simultaneously, the maximum power output was limited to approximately 60 %, illustrated in Figure 8, which is remarkably below the maximum output of an individual PV system, from 80 % to 90 %. (Wiemken, et al., 2001)



a) **b)**

Figure 8. Power curves of both individual and ensemble PV systems for a) June 1995, and b) July 1995, as presented in (Wiemken, et al., 2001). This comparison highlights the leveling effect of PV ensembles as the maximum power output is lower but the minimum power output is higher.

One of the main contributors mentioned in the study was the distance between PV systems. An independent long-term dataset of 10 years studied six different sites in Germany. The interstation distances in the study were from 200 km to 680 km. It was found that the cross-correlation between the interstations followed an exponential curve. It showed a reduced cross-correlation as the distances increased, cross-correlation efficiency being decreased from a high of 1,0 to a low of under 0,1 as distance increased from 0 km to 680 km. These findings result in less fluctuating overall power output for spatially distributed systems. (Wiemken, et al., 2001)

The study concluded that power fluctuations, standard deviations, and amplitudes of power changes in the given time resolution improved with the PV system ensemble. Power fluctuations of more than 5 % disappeared in the time resolution of 5 minutes and peak power production was limited to 65 % of nominal power capacity. The maximum power did not reach the levels of individual systems but more balanced production profile was achieved. This profile could additionally be improved by self-consumption by households. All in all, PV ensembles could enable certainty over an estimated percentage of production during some time windows, for example, for day-ahead electricity sales purposes. (Wiemken, et al., 2001)

IEA's *"Photovoltaic and Solar Forecasting: State of the Art"* presents similar findings on the impact of error reduction for area forecasts in technical literature. It was found, as in (Wiemken, et al., 2001), that solar forecasting errors decreased radically as the distance between observed locations increased. Many case studies studying spatial distribution of solar power installations were presented for Germany, Canada, U.S., and Japan. Compared to single location forecasts, RMSE in Germany reduced by 64 % as RMSE for an area in Canada and U.S. reduced by 67 % with only 10 ground stations. In Japan, a study for an area of 100 km x 60 km resulted in mean absolute error reduction of 22 % as for whole of Japan resulted in error reduction of around 70 %. The latter case and its findings are illustrated in Figure 9 that shows clear correlation between the amount and distance of locations and relative errors measured.

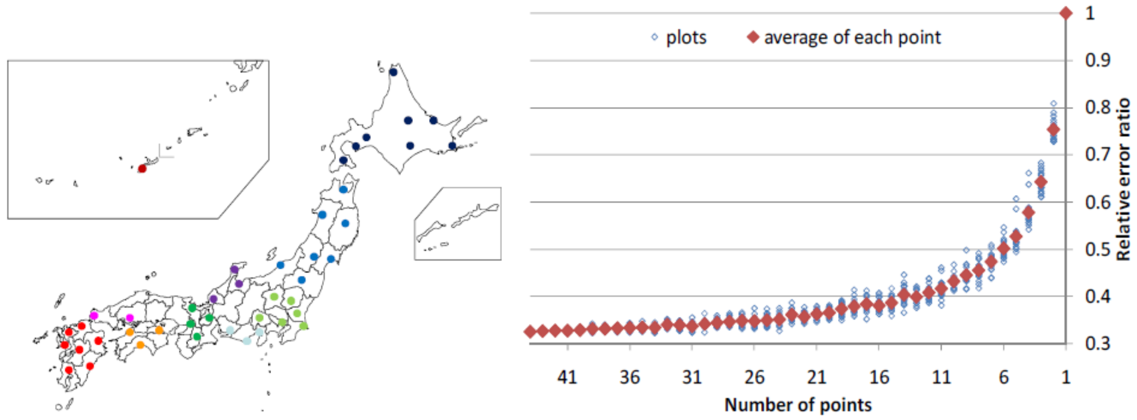


Figure 9. Correlation between distance and relative error in Japan for spatially distributed solar systems, as presented in (IEA, 2013b).

2.9.5 Distributed consumption aggregation

As important the aggregation of power production is, so are the benefits gained from the aggregation of consumption. Different aspects of this topic are discussed in EURELECTRIC's discussion paper from August 2013 called *"Pooling Flexibility: Technical Aspects of Aggregation"*.

The study introduces a platform to be established for flexibility services. Aggregation of consumption would enable the participation of smaller customers to balancing market as nowadays only large industrial customers are participating to such services. Smaller residential and commercial customers have very high barriers of entry due to bureaucracy, the simple impossibility of participation due to local legislation or low volumes, or the lack of smart metering and monitoring capabilities. (EURELECTRIC, 2013)

The flexibility in dynamic consumption could provide benefits for three different causes:

1. Optimization of energy portfolio
2. Balancing market after gate-closure time
3. Constraint management in transmission and distribution network

At the moment, these value adding services are now accessible for only large commercial customers but the paper suggests that European network code should enable participation for all flexibility providers. Aggregators could have increased importance as the role of balancing responsible party if a transparent platform that could increase liquidity and ease exchange of data between relevant parties, would exist. This would mean having fundamentally different approach to the current system. Nowadays, the electricity system provides services for all of its customers but in the future, customers would be able to provide services for the system and reduce their energy bills in the process. Since both power generation and consumption are needed to be constantly in equilibrium, it would be logical for both parties to participate in the flexibility services as well. Paper finds that TSOs, as the operators of bigger volumes, are logical partners to large industrial consumers that are ready for demand response, but DSOs could aggregate smaller consumers. The communication between both TSOs and DSOs would be vital for this kind of arrangement to be successful. (EURELECTRIC, 2013)

Additionally, the constraint management and balancing services should be divided as the causes are fundamentally different, according to the research paper. Compensation for constraint management should be received from grid operators as constraint fees are paid as network fees. Balancing fees should be received from the ones responsible for being out of balance. (EURELECTRIC, 2013)

2.9.6 Battery efficiency

Realistic analysis requires adding battery charge and discharge efficiencies to the analysis. In this study, batteries are used to store the surplus energy from household rooftop solar systems. Understanding battery efficiencies is important since underestimating efficiency results in too large of solar system design as overestimating efficiency results in undersized system.

According to Stevens and Corey (1996), lead acid battery charge efficiencies are higher at low states of charge that non-linearly decreases closer to full charge. Their findings indicate that charging the battery from 0 % to 84 % results in average charging efficiency of 91 % as incremental charge from 79 % state-of-charge to 84 % resulted only in average of 55 % efficiency (Stevens & Corey, 1996). However, the performance of batteries has developed significantly during the last 18 years so further results are needed.

To study battery chemistries, capacities and schedules for energy storage units under time-of-use pricing, Barnes et al. (2011) studied round-trip efficiencies of several different battery technologies. The paper found lead acid to reach 80 %, NiCd 70 %, NiMH 80 %, Li-ion 92 %, and NaS 80 % round-trip efficiency. (Barnes, et al., 2011)

To implement realistic and conservative values for battery efficiency to the analysis, efficiencies for both charging and discharging were decided to be 90 %, resulting in round-trip efficiency of 81 %. This efficiency is reached by many different battery technologies according to Barnes et al. (2011) so results of the analysis are not limited to just one technology. To preserve relatively simplistic approach in the analysis, the battery system is assumed to preserve its state-of-charge without losses over time.

3 Model overviews

The problem covered in this study is extremely complicated. Various different variables, some of which are predictable, some of which are not, affect each other in ways that are in many cases basically impossible to analyze without experimental research. Therefore, this study and its analysis are intended to get close enough to the reality with decent accuracy and complexity. Too complex analysis is harder and more expensive to pilot in real life, and the achieved benefit from complex analysis in this case is questionable as the accuracy and predictability of the results cannot be verified without real life research. Further research could and should be carried after demonstrations on the field.

3.1 Solar balancing costs in Germany

Since the market model in Germany is somewhat distorted due to the balancing exemptions for solar power generation, the hypothetical balancing costs for solar power were analyzed. The hourly spot and intraday electricity pricing, the expected and actual solar power production were acquired from European Energy Exhange Transparency Platform (EEX, 2014) and reBAP pricing[26] was downloaded from TENNET website (TENNET, 2013).

The analysis reflects every hour of the year 2012. The actual and estimated solar power production from all four TSO areas were included and the forecast errors can be compensated in the analysis in either intraday or reBAP market. Being efficient at the intraday market requires sophisticated forecasting and electricity trading capabilities, as reBAP is an alternative that does not require forecasting iteration since all errors in forecasts are paid after the actual production. Firstly, the analysis compensates certain percentage of total error with intraday electricity and the total cost impact reflects the difference between given spot and intraday price. Since pricing of intraday is based on executed deals, the average price was used. However, if the amount of required balancing power exceeded the intraday availability, highest price for the hour was used instead of average price. The remaining need of balance was then executed through reBAP. It was expected in the analysis that balance energy was always available at the given cost, despite the fact that this would not always be the real situation. However, to illustrate the big

[26] reBAP is priced for every 15 minutes, therefore this simulation was conducted with volume weighted price averages for full hours.

picture of balancing costs related, this kind of approach was estimated to be sufficiently accurate as simulating fluctuations in the reBAP prices would make the analysis unnecessarily complicated.

3.2 Determining demand-shift capability

To fully understand the opportunities with virtual power plant related models, the hourly consumption of households that can be shifted on-demand must be determined. The basis of the analysis was the hourly mapping of detached house electricity consumption in Finland in 2012[27] that is compiled from the data of Fortum and TEM. Even though TEM provided the total annual consumption of detached houses for several categories[28], only categories of car heating, water heating, shiftable space heating[29], and cooling were considered for demand-shift. All the selected loads benefit from the thermal storage characteristics of water, air and thermic mass. As the load is shifted, the changes for the consumers are not instantly observable, if at all. However, this psychological aspect of demand-shifting has to be thoroughly investigated to return maximal results with minimal loss in comfort.

Therefore, the hourly household consumption was divided into shiftable and non-shiftable load. The behavior of shiftable loads is presented in Table 5. To heat cars during winter months, most people time their heaters to turn on before they leave for work. Therefore it was estimated that 85 % of the total energy is allocated between 5.00 and 8.00 o'clock, reflecting the outdoor temperature, on top of the base load of 15 % that is running constantly during sub-zero temperatures. Same approach with different hours was used for water heating. Heating water for domestic use does not correlate significantly with temperature, as discovered in (Gils, 2014), and most people time their water heaters for cheaper prices of night hours. The majority of heating, in this case referred as *shiftable space heating,* correlates heavily with outdoor temperature. An average of hourly temperatures in Helsinki and Tampere was used to analyze the allocation of heat load. Degree hours were calculated with a limit of 12 °C, meaning that heat load is activated

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[27] The year 2012 was used due to the consistency of the material available.

[28] Categories included cooking, dishwashers, laundry machines, cold appliances, televisions, computers, car heating, indoor and outdoor lighting, water heating, space heating, cooling, and other consumption. Other consumption includes extraordinary loads, such as hair driers, hoovers, water beds, aquariums, terrariums.

[29] Only 45% of the total amount of allocated space heating was considered as shiftable load. This provides the simulation a buffer against too optimistic results. The share of 45 % also eliminated unrealistic hourly results of negative shiftable and non-shiftable loads in the calculation.

every time temperature drops below that. For lower temperatures the load naturally increases. Same approach was used for cooling load but with a limit of 20 °C and cooling is activated when that outdoor temperature is exceeded.

Table 5. Parameters used in the hourly analysis for determining demand-shift loads.

Load category	Time correlation	Temperature correlation
Car heating	15 % allocated evenly to all hours of sub-zero temperatures. Remaining 85 % allocated to hours between 5.00 and 8.00.	85 % allocated reflecting cold degree hours.[30]
Water heating	15 % allocated evenly to all hours. Remaining 85 % allocated to hours between 20.00 and 6.00.	No temperature correlation was used for this load.
Shiftable space heating	No time correlation was used for this load.	Shiftable space heating activated when outdoor temperature drops under 12 °C
Cooling	No time correlation was used for this load.	Cooling activated when outdoor temperature rises over 20 °C

It is noteworthy that total annual energy values for different loads were obtained from a TEM report for 2011 (TEM, 2013) but temperatures used to model heat loads were from 2012. This mismatch does represent errors for the model but for the "big picture" approach of this study, the magnitude of the error was considered small. Additionally, year 2011 was extraordinarily warm in comparison (Ilmatieteen laitos, 2014), providing conservative values for heat loads instead of overestimating them.

3.3 Economic analysis of VPP capacity on regulation electricity market

As the minimum regulation electricity capacity to be provided is 10 MW (Fingrid, 2013a), our base profile analysis results in having a portfolio of 55 000 base profile households in order to achieve 10 MW of shiftable VPP capacity every hour of the year of 2012. To evaluate the economics of regulation electricity trading, some parameters need to be studied as every bid placed on the market can be priced by the bidder, but the delivery of the regulation electricity bid depends on the current price level. Therefore the pricing of the bid needs to be predetermined. In this analysis, a price benefit, or price premium, compared to the spot price was used. This means that the analysis places the regulation electricity bid as a function of the current spot price, based on a pre-determined price

[30] Cold degree hours in this case allocate power correlating negative temperatures. This approach realistically reflects car heating as more cars are simulated to be heated when temperature decreases and vice versa.

premium. In the case of load shifting due to regulation electricity, the buyback electricity was assumed to cost the same amount than during the hour of adjustment.

The more realistic approach of reducing actual energy consumption by participating and reacting to upward electricity trading by reducing consumption was conducted without the electricity buyback feature. For every hour of the year, a minimum fixed compensation required for shutting down loads was determined. For activated hours, the traded regulation volume was compared with the available flexible load provided by households so that the market liquidity for upward regulation capped the volumes traded. Total benefit for households was achieved by summing up all traded hours and their received benefit, which was then divided by the total amount of households participated in the analysis.

3.4 Investment analysis

To calculate the internal rates of return (IRR) for different setups for households, an investment calculator was used. The tool is available in full in *Appendix 4. Investment analysis calculator.*

To understand the nature of IRR, the concept of net present value (NPV) has to be understood. Both IRR and NPV values are used as the basis for investment appraisal techniques that indicate for investor the attractiveness of the given project. NPV is defined with an equation

$$\boldsymbol{NPV = -l_0 + \int_1^n \frac{c_i}{(1+r)^i}}, \tag{5}$$

where l_0 is the initial investment, thus it is a negative value. In the equation, c_i represents the cash flows in the time period from $i = 1$ to n, which might include either positive or negative values. Lastly, r represents the cost of capital and n is the number of periods. The internal rate of return is the cost of capital, r, that brings the present value of the returns into equality with the initial investment, hence NPV = 0. Positive IRR means that investment grows interest over time, negative signaling the opposite. The IRR received from the calculations is comparable to any returns households are able to receive in different forms of investments, such as stocks or bank deposits. (Osborne, 2010)

By using given parameters, the calculator generates an annual free cash flow for the investment's lifetime that is used to provide the given IRR. Most of the assumptions vary between setups chosen but some parameters remain unchanged. The inflation factor was chosen to be 2,0 %, which is also the target for European Central Bank (European Central Bank, 2014). Annual degradation rate for PV modules has been estimated at 0,2–1,0 % in a study from 2009 (Ndiaye, et al., 2013) but the technology of the modules has improved significantly during the last years, and extensive study of 2 000 degradation rates by National Renewable Energy Laboratory (NREL, 2012) resulted in a median degradation rate of 0,5 %, which was supported by another study (Pulver, et al., 2010), and thus chosen for this analysis. The lifetime of the solar system[31] was assumed to be 25 years, which is supported by module manufacturer warranties (Kyocera, 2013; SunPower, 2012; Yingli Solar, 2011) and several studies (EPIA, 2011; Ndiaye, et al., 2013). Maintenance costs of the system in the investment analysis are assumed at 25 € per year.

The electricity price used in the analysis was calculated by using the pricing data of Fortum's electricity and distribution contracts, Fortum Takuu and Fortum Yleissiirto, respectively (Fortum, 2014b). Calculations were conducted for all used individual profiles: low, base, and high profile. Fixed costs cannot be avoided by partial solar power replacement. Total electricity prices were 0,112 €/kWh, 0,117 €/kWh, and 0,110 €/kWh for base, low, and high profiles, respectively. Variable cost for all profiles was found to be 0,106 €/kWh that is also the cost related to electricity, which can be avoided by self-generating solar power. All breakdowns are available in *Appendix 5. Electricity price breakdowns*.

[31] The inverter cost is assumed in the total system cost. The lifetime of inverter is assumed at 25 years so no replacement inverters are not simulated in this analysis. However, in real life situation a replacement inverter could be required.

4 Material and data used

To carry out all the analysis for this paper, significant amounts of data from different sources was used and combined. Therefore the reasoning behind the selection of the data used is important to understand for the reader to form a picture of the validity of this study.

For the analysis, mostly data from the years of 2011, 2012, and 2013 was used. The data for these whole years was available during the research part of this study, and therefore was the most recent tool to be used for the analysis. If other years are used in the analysis, it is mentioned separately.

4.1 Fortum's database

4.1.1 Household consumption

Different household consumption profiles used in the analysis were composed of material received from Fortum's database. This database has information on individual points of consumption that are mostly residential locations across Finland. To have as relevant information for this study as possible, Finnish city called Lahti was chosen as the representative location for the individual household profiles as it is relatively close[32] to Hauho, which is the weighted center for Finnish population to live in (Helsingin Sanomat, 2012). Additionally, sufficient 2012 data for households in Lahti was available to conduct required analysis.

Hundreds of data series were available across Finland but only the most consistent series over time period of 1.1.–31.12.2012 for Lahti were chosen for the base, high and low profiles. Additionally, only data series sums of over 5 000 kWh were accepted since figures less than that did not represent the target group of customers that can be identified from Table 6. For the average profile, households from Kajaani, Lahti, and Jyväskylä were chosen to compile an aggregated profile of 146 households. (TEM, 2013)

[32] Distance between Lahti and Hauho is approximately 60 kilometers.

Table 6. Average annual electricity consumption by given household categories (TEM, 2013).

Form of living	Additional information	Annual energy consumption [kWh]	Target group for this study
Block of flats	1 resident, regular amenities	1 400	No
	1 resident, high level of amenities[33]	3 000	No
	3 residents, regular amenities	2 400	No
Terraced house	2 residents, regular amenities	3 300	No
	3 residents, regular amenities	4 000	No
Detached house	2 residents, district heating	5 500	Yes
	4 residents, district heating	7 300	Yes
	2 residents, electric heating	17 400	Yes
	4 residents, electric heating	19 600	Yes

The information received from Fortum's database results in an average hourly consumption of 1 460 W, equaling an annual consumption[34] of 12 821 kWh. Results are illustrated in Figure 10. As can be seen from Table 6, the annual consumption matches the one of larger detached houses, being in between district and electric heated households with more than one resident. Therefore, the data is suitable to be used for this study as largest consumers represent the biggest benefit for demand-shift opportunities. In addition to aggregated consumption profile, three different profiles were generated for more accurate analysis: base, low, and high profiles.[35]

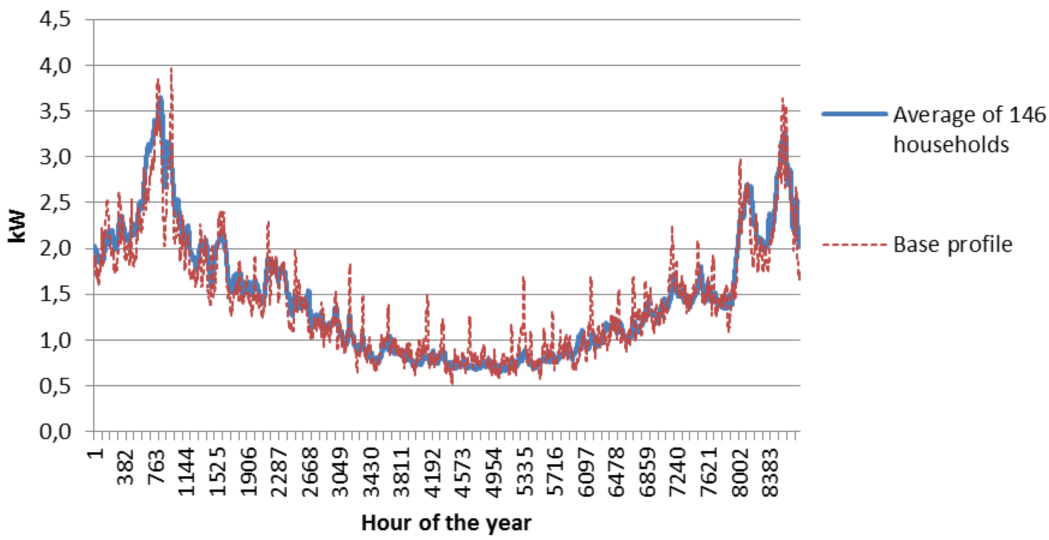

Figure 10. Moving averages of 24 hours of electricity consumption for an average household profile and base profile in 2012 in Lahti, representing the weighted average location of population in Finland.

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[33] If 10% of all households have the same appliances, it is regarded as high level of amenities. (TEM, 2013)
[34] Year 2012 had a total of 8 784 hours.
[35] Two additional consumption profiles, high and low, are used in sensitivity analysis.

The base profile is an individual household with annual consumption of 12 715 kWh that nearly matches the average consumption of 12 821 kWh. Since individual households experience more fluctuations in hourly consumption, base profile provides more realistic figures than average of 146 households. Large quantities of samples level out the consumption fluctuations that is demonstrated by the average profile.

As can be seen from Figure 10, the 24 hour moving average of base profile consumption matches very well the average household profile throughout the year, justifying the use of base profile as the real life consumption profile as a stand-in for the averaged one.

4.1.2 ZEMA

Most of the information used in this study was gathered through a market data program called ZEMA. This platform gathers together selected information across databases and selected data series can be exported in intervals of 15 minutes, hours, days or months, depending on the availability and the need of the data. For this thesis, several different data series, that are listed in Table 7, were exported to be used in the analysis.

Table 7. Data exported from ZEMA database for the analysis in this thesis.

Data type	Market area	Data interval
Outdoor temperature	Finland	1 hour
Electricity spot prices	Germany, Finland, Sweden	1 hour
Intraday electricity price and volume	Germany, Finland	1 hour
Regulating electricity price and volume	Finland	1 hour
Solar production, actual	Germany	15 minutes, 1 hour
Solar production, day-ahead estimate[36]	Germany	15 minutes, 1 hour

One of the most important parts of this study, household related analysis, relied on the temperature data from 2012, which was the latest full year of available data while this study was conducted. Since the representative location for Finland was selected to be Hauho, the available temperature data for Helsinki-Vantaa airport and Tampere-Pirkkala airport were used to form an average to represent hourly temperatures. The same temperature was selected to provide for the aggregated consumption profile of Lahti, Jyväskylä, and Kajaani households as well.

[36] The forecasts for wind and solar production are provided on behalf of German TSOs by external service companies that deliver their predictions daily for the next day at 18.00 at the latest. This equals forecast time horizon of 6 to 30 hours ahead. (EEX, 2013)

4.2 ENTSO-e

European network of transmission system operators for electricity (ENTSO-e) provides country-specific load data through their transparency platform. The data portal was used to obtain hourly load values for Germany and Italy for the year of 2012 for further analysis. (ENTSO-e, 2014)

4.3 Nord Pool

The website of Nord Pool electricity exchange provides historic market data in a resolution of one hour for various products. Datasets for spot and regulation electricity prices and volumes were exported in a resolution of one hour for the use of this paper. The data is available for all the countries and their transmission networks participating at the Nord Pool exchange but due to the scope of this study, only the data for Finland was used. (Nord Pool Spot, 2013)

4.4 NREL

National Renewable Energy Laboratory (NREL) has recently launched a beta version of their online tool for everyone to utilize. The tool provides measured hourly solar irradiation data for selected locations around Europe and the United States. User is able to determine various parameters such as performance ratio, tilt angle for the solar installation, and the size of the system. Despite the usefulness of the database, some data was not exactly matching data from other databases, such as (SolarGIS, 2014), but for the needs of this study and after some preliminary comparisons, the results from the database were considered satisfyingly accurate. (NREL, 2013)

To generate hourly solar irradiation dataset, historical data of both solar irradiation and meteorological data has been collected over multiple years. PVWatts generates a typical year data by compiling single year's worth of hourly data in monthly blocks from different years in the data collection period. Therefore, months' hourly data for solar irradiation is represented by months of different years, thus resulting in lower correlation between locations than would be the case with single year measured data for all locations. Most typical months of the long-term observations are selected for this typical year data, which provides both lossless information in month's resolution and combines the long-term knowledge into one useful dataset. (NREL, 2013)

This data was used in this paper to study the impact of aggregation of solar systems and to provide household solar system production in a resolution of one hour for the VPP analysis. System tilt angle of 30° and performance ratio[37] of 0,82 were used for the data of Sweden and Finland. Production numbers for available Finnish data for Helsinki and Tampere are illustrated in Figure 11. However, for the household solar production analysis, the solar irradiation data for Tampere was used instead of Helsinki as its inland characteristics are closer to the representative location, Lahti. Both datasets are included in the analysis for aggregated solar production.

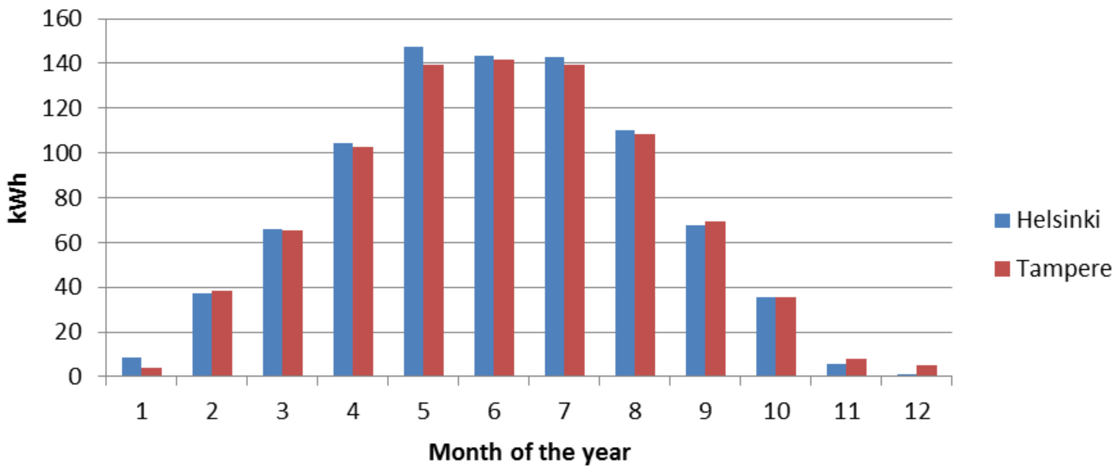

Figure 11. Monthly production distribution for 1 kW solar system in Helsinki and Tampere, with annual peak load hours of 871 kWh_p and 858 kWh_p, respectively. Data generated after PVWatts (NREL, 2013).

[37] In the tool, the performance ratio includes losses in PV module nameplate ratings, inverters and transformers, module mismatches, diodes and connections, DC and AC wiring, array soiling, system availability, array shading and tracker misalignment (NREL, 2013).

5 Results

This section is divided into two different parts, which both aim to provide for the findings of this study, but from different fronts.

Results derived from the German electricity market are based on actual data, instead of modeling or analysis. The findings aim to quantify some fundamental statements that are very often discussed, when solar power production is addressed. These topics include: *Can solar power production be predicted?*; *How much does the balancing of the variable solar power production cost?*; *If solar power production reaches high levels in the energy mix, how does the price of electricity react to this abundance of day-time energy supply?* The findings aim to support the solar-related analysis conducted with the Finnish households.

Results from Nordic countries provide mostly household, demand-shift, and solar power production related analysis. The match between household consumption and solar conditions is emphasized, and the role of battery storage and demand-shift are studied to quantify the economic potential for households. Additionally, the impact of aggregated solar power production and electricity consumption is analyzed.

5.1 Germany

5.1.1 Solar forecasting

Since German TSOs publish their solar production estimates for every hour (EEX, 2013), it was possible to study the forecasting errors occurred in Germany in 2012. These results can be compared with figures from literature sources. For example, large European utility Enel is one of the pioneers in renewable energy production forecasting. According to the company's presentation slides, the company is able to forecast PV with a day-ahead error of as low as 2–5 % as normalized mean absolute error, or NMAE (Gigliucci, 2013). However, the method how this value is calculated was not presented. NMAE could be calculated with all hours of the day or with just the hours when sunshine is available. Naturally, NMAE decreases if all hours of the day are used. Nevertheless, Enel's results are good for a single site production forecasting. For reference, forecasting results for whole Germany's solar power production are presented below in Figure 12. For this modeling, solar power production forecasts and actual production of all four German TSOs were combined.

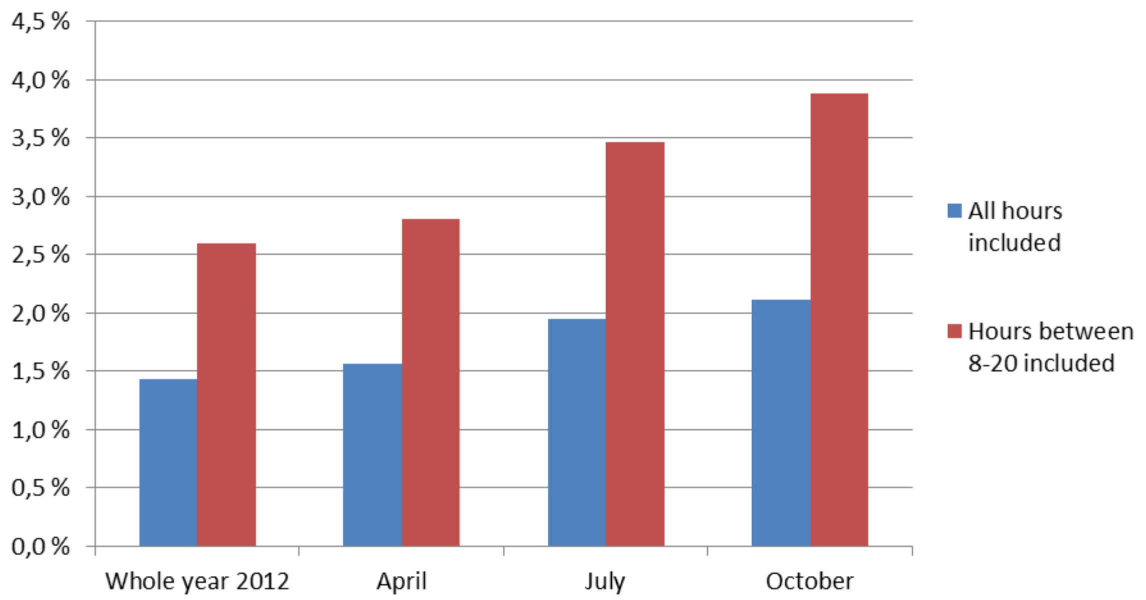

Figure 12. Normalized mean absolute error (NMAE) values for solar power production forecasts in four German TSO areas in 2012. Expected and actual output values were combined for all areas for every hour.

As it was assumed, NMAE is lower for forecasts covering all hours compared to hours of sunlight, in this case between 8.00 and 20.00. The differences in NMAE between months of April, July and October are probably caused by differences in frequencies of cloud coverage and rainfalls. Even though the technology and methods used for solar power production forecasting form still a relatively new business segment, the results are already satisfying, even though there is a lot room for improvement. The balancing impact of spatial distribution generation contributes significantly in a scale of a whole country, which makes Enel's claim on their single location NMAE of 2–5 % even more significant for further progress.

Analysis of the same data of 2012 produced also values for root mean square error (RMSE). For the hours between 8.00 and 20.00, the value for RMSE was 1 247,4 MW, equaling as normalized 4,34 % of nominal PV capacity. For all hours of the day, 919,6 MW and 3,20 % were gotten for absolute and normalized RMSE, respectively. These figures are in line with literature findings in *Photovoltaic and Solar Forecasting:*

State of the Art (IEA, 2013b) that present results of 3,9 % and 4,6 % for intra-day and day-ahead forecasts, respectively[38].

If the error values are reflected to the average power output of the solar fleet, the amount of inaccuracy increases. For 2012, the average power generated between hours of 8.00 and 20.00 was 5 738 MW and the average error in forecast was 745 MW, resulting in an average of 13 %.

Some hypothetical economic effects of solar forecasting in Germany for 2012 are presented in the next section.

5.1.2 Balancing costs of solar power

One of the main challenges with large scale solar power production is its variability. Since solar power is used for power generation amongst the first power sources as it has negligible variable costs and therefore is at the front of the merit order curve, other sources for electricity need to adapt to the variations caused by weather changes. Assessing the balancing costs for solar power is important so that true cost of solar power is revealed.

Despite the high costs related to balancing energy, in Germany, the solar and wind producers are in 2013 exempted from the responsibility of balancing (Borggrefe & Neuhoff, 2011). The four TSOs in Germany are responsible for these fluctuations and according to the German market model, these costs are translated through reBAP to those parties that cannot meet their quotas for electricity delivery, thus increasing the cost of electricity. However, successful intraday trading based on improved forecasts could reduce the need for expensive balancing energy.

In general, the price of balancing is cheaper at intraday than reBAP market. The hypothetical balancing costs for solar power are presented in Table 8 and Figure 13.

[38] The results were from two balancing areas in German electricity grid over one year, including night-time hours.

Table 8. Hypothetical[39] balancing costs for German solar power production in 2012 with different error reduction and balancing market scenarios. Units in €/MWh$_{produced}$.

Reduction achieved from 2012 total error	The ratio of day-ahead error compensation in intraday/reBAP market										
	100/0	90/10	80/20	70/30	60/40	50/50	40/60	30/70	20/80	10/90	0/100
0 %	0,55	0,97	1,41	1,85	2,30	2,75	3,19	3,64	4,09	4,53	4,98
10 %	0,50	0,87	1,26	1,68	2,08	2,48	2,87	3,27	3,68	4,08	4,49
20 %	0,44	0,77	1,14	1,49	1,85	2,20	2,55	2,91	3,27	3,63	3,99
30 %	0,38	0,69	0,99	1,31	1,61	1,92	2,23	2,55	2,86	3,17	3,49
40 %	0,34	0,59	0,86	1,11	1,38	1,65	1,91	2,18	2,45	2,72	2,99
50 %	0,28	0,49	0,71	0,93	1,15	1,37	1,59	1,81	2,04	2,27	2,49
60 %	0,22	0,39	0,57	0,74	0,92	1,10	1,28	1,45	1,63	1,81	1,99
70 %	0,17	0,29	0,42	0,56	0,69	0,82	0,95	1,09	1,23	1,36	1,50
80 %	0,11	0,19	0,28	0,37	0,46	0,55	0,64	0,73	0,82	0,91	1,00
90 %	0,05	0,09	0,14	0,18	0,23	0,27	0,32	0,36	0,41	0,45	0,50
100 %	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00

On the x-axis of Table 8 can be found the ratio that describes the share of intraday and reBAP market balancing used to compensate the errors in solar power production. The y-axis proposes a scenario, in which a certain percentage of actual error can be mitigated even before the day-ahead market. In other words, if forecasting methods would improve in the near future, the day-ahead forecast errors could be decreased by 50 % in total, meaning the balancing costs could be found on the row of 50 %.

As can be expected, the total costs for balancing decrease linearly with the reduction in the total error, all the way to 0 €/MWh$_{produced}$ if there would be no errors in the day-ahead forecasts. The interesting finding, however, is the radical increase in balancing costs as the reBAP share increases. The biggest costs of 4,98 €/MWh$_{produced}$ occur when all of the forecast error is compensated with reBAP and none at intraday market. As the share of intraday increases, the total cost decreases approximately 0,45 €/MWh $_{produced}$ per 10 % step towards intraday trading. This trend is clearly visible in Figure 13 that represents the scenario of 0 % error reduction.

[39] Currently, renewable energy is not required to balance their power output in Germany, therefore calculations in Table 8 represent a hypothetical scenario.

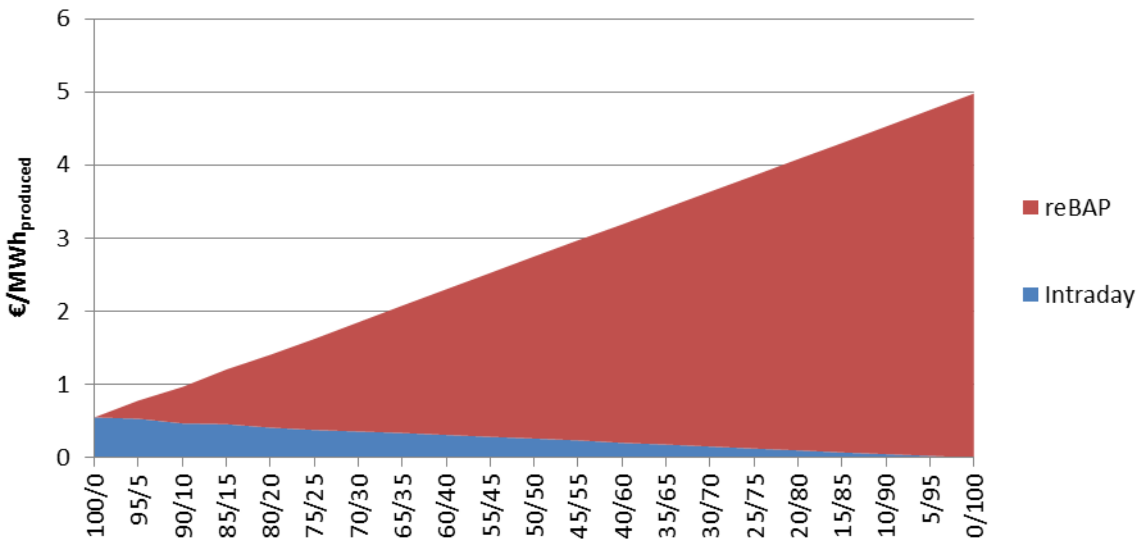

Figure 13. Hypothetical balancing costs for German solar power production in 2012 as a function of ratio of error compensated in reBAP and intraday markets.

By being able to forecast accurately solar power output on intraday basis, the producer could reduce balancing costs all the way to 0,55 €/MWh$_{produced}$. Additionally, if the producer would be able to improve the day-ahead forecast by 50 %, the costs would go down to 0,28 €/MWh$_{produced}$.

These results show that not only the significance of forecasting is huge for grid stability, there is also a huge economic incentive for producers to predict their power output accurately. Of course market models differ between countries and there are fluctuations between years but the main message can be clearly identified from these results.

5.1.3 Solar premium

When considering a vast integration of solar power to the existing energy mix, the problems related to the oversupply of solar electricity occur. It is a valid concern as oversupply tends to decrease prices and for solar power the hours of generation cannot be, or should not be, limited. To address this concern, further analysis was conducted using the German market as a real life reference.

For Figure 14, the impact of increasing solar share in energy mix was studied by using data exported from ZEMA database. For comparison, the data for July was used for years of 2011, 2012 and 2013. Firstly, the average electricity price for every time period was calculated, after which the average selling price for generated solar power was analyzed using the hourly, aggregated data from German electricity market. This produced the so called solar premium that reflects the difference between generating and selling electricity on a constant rate, compared to generating and selling electricity from a solar power plant. This calculated data was combined with the share of solar power in the total energy mix in the country during the given time period.

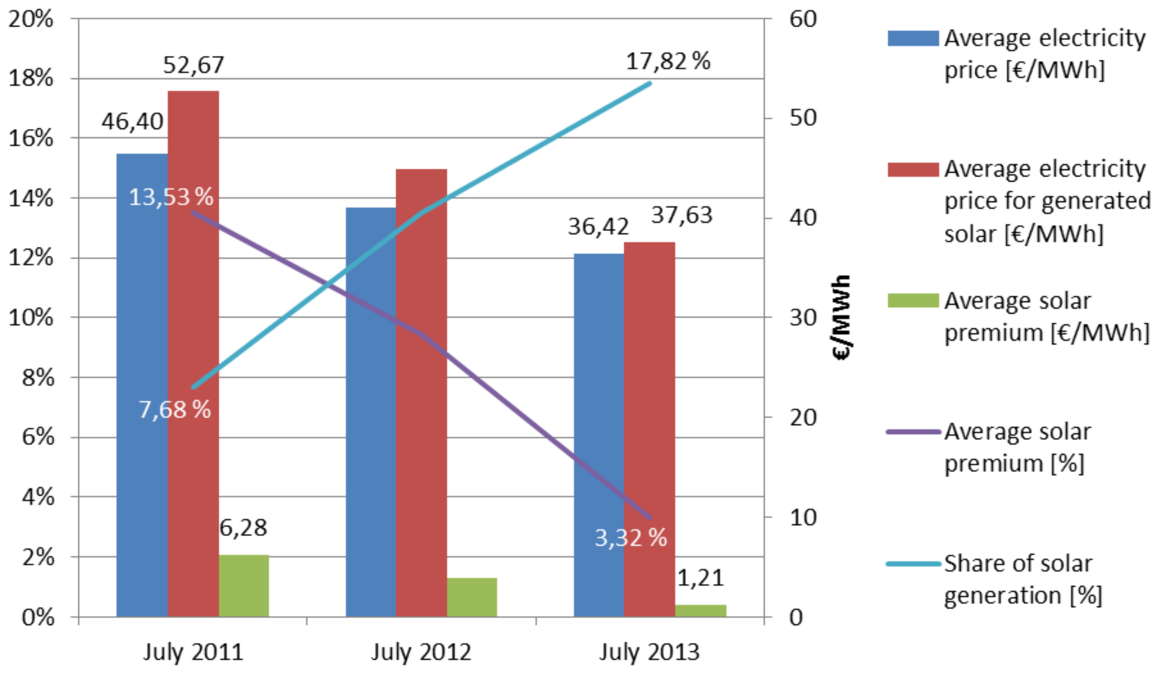

Figure 14. The impact of increasing solar share in energy mix to electricity price premium experienced by solar power generation in Germany.

The results show that the premium for solar electricity naturally erodes when the share of solar energy in the energy mix increases for the supply for the midday hours increases without significant changes in demand. The average premium decreases from 13,53 % to 3,32 %, while the solar share in the electricity mix increases from 7,68 % to 17,82 %. However, solar is able to receive rather satisfying premium for its electricity even though the share of solar soars to almost 20 % of the total energy produced. These results remove some doubt from the claim that the increase in solar power would make electricity price plummet during daytime, thus cannibalizing the economics of solar power generation. Germany is the pioneer of solar power installations and it may represent the future of many other countries regarding the development in electricity prices. Some results can be derived from the electricity market of Germany, but energy pricing is generally rather complicated entirety as energy mix, market dynamics, politics and environmental issues all affect the matter.

5.2 Nordic countries

5.2.1 Electricity marketplaces

To find the best approach for demand-shift capable capacity, different business opportunities were evaluated. Even though Nordic electricity market forms one big entity, only market area of Finland was studied. Values for 2013 in Finland from ZEMA and Nord Pool databases were used for this analysis. A constant load of 10 MW at spot market was used as the reference level, resulting in a total cost of roughly 3,61 million euros for 2013. To evaluate different marketplaces, as illustrated in Figure 15, the benefit from the demand-shift capability with different approaches was calculated. The total hours of activation describe the effort related to the benefit[40]. Every time the demand-shift capacity was used to gain additional economic benefit in this analysis, the hour was considered as an *activated hour of operation*.

For spot market based approach, the 12 lowest cost hours of each day were used to deliver the same amount of electricity in 2013, which would be the case with a constant 10 MW load. Therefore, each of these 12 hours consisted a load of 20 MW, and the process was terminated during the more expensive hours of operation. The benefit with this approach was calculated at 446 788 € with 4 380 hours of shifted capacity. For Elbas market, a price premium was assumed at 25 % in order to activate either buying or a selling bid. This price premium was set to demonstrate attractive amount of compensation coupled with low level of total effort. A maximum of 20 MW and a minimum of 0 MW were considered as the possible range. This resulted in 426 hours of activation with a benefit of 66 855 €. For regulation electricity market, a price premium was assumed, for the same reasons than for Elbas, at 50 % in order to activate either upward or downward regulation operations. A maximum of 20 MW and a minimum of 0 MW were considered as the possible range. This resulted in 494 hours of activation with a benefit of 278 222 €. For frequency controlled operative reserve, a constant ability to adjust load between 0–20 MW was assumed. In general, the net consumption will not change in the process. This provides an ±10 MW adjustable load with a total benefit of 1 257 936 € over 8 689 hours of activation. For frequency controlled disturbance reserve, a constant ability to reduce load by 10 MW

[40] For Elbas, regulation electricity, frequency controlled operative and disturbance reserves, it was assumed that the replacement electricity could be purchased back with the same price. Yearly contract terms were used for frequency controlled reserves.

was assumed. This setup provided a total benefit of 294 336 € over 6 358 hours of activation. All findings are presented in Figure 15.

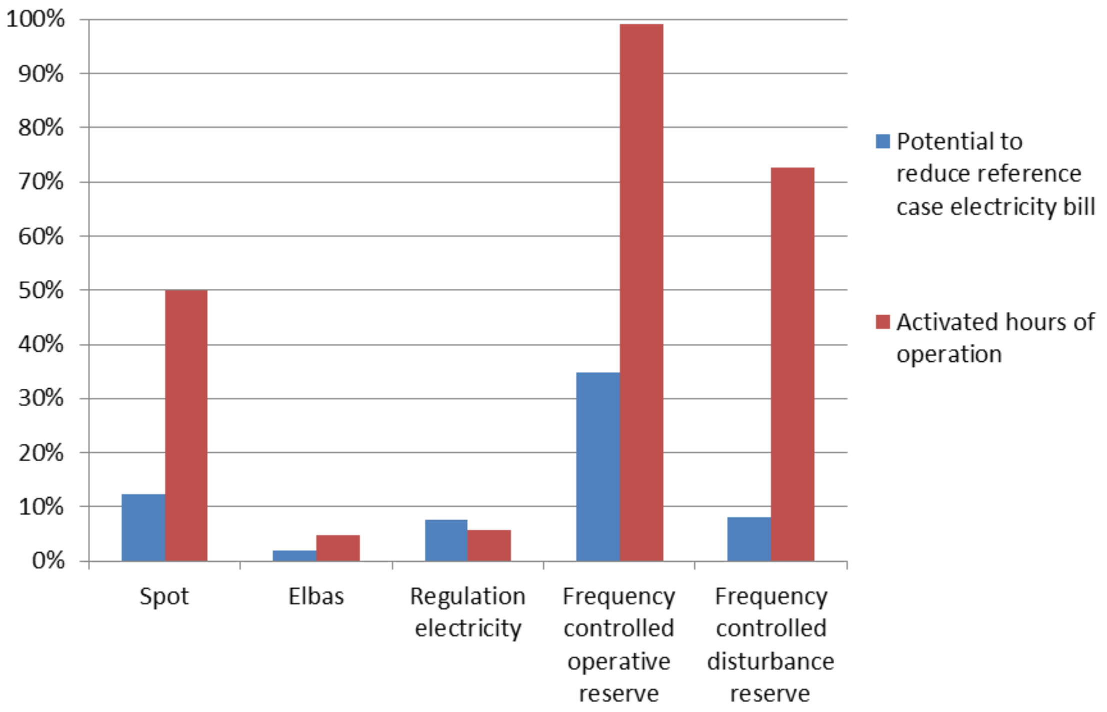

Figure 15. Benefit achieved from different marketplaces with various demand-shift setups compared to having constant 10 MW load on spot market in Finland, 2013. Red column indicates effort, or activation hours, as blue column indicates economic benefit received compared to reference case. Every time the demand-shift capacity was used to gain additional economic benefit in this analysis by moving demand to another time, the hour was considered an *activated hour of operation*.

These results reveal major differences between marketplaces, both in terms of technical execution and compensation for the flexibility. Further characteristics of different marketplaces and possibilities to apply them into business models are presented in Table 9.

Table 9. Characteristics and compensation levels for a flexible load of 10 MW in different electricity marketplaces in Finland. These results quantify Figure 15.

Marketplace	Trigger for demand response	Total benefit achieved	Total hours of activation[41]	Benefits	Challenges
Spot	12 lowest cost hours for electricity	446 788 €, or 102 €/h_{act}	4 380	+Prices set day-ahead +Simple to execute +No binding contracts	-No large compensation to be tapped
Elbas	A price benefit of 25 % compared to spot price	66 855 €, or 157 €/h_{act}	426	+Level of participation freely chosen +No binding contracts	-Low liquidity -Low annual market value
Regulation electricity	A price benefit of 50 % compared to spot price	278 222 €, or 563 €/h_{act}	494	+High compensation +Good liquidity +No binding contracts +On/Off adjustments	-Requires large volumes -Requires sophisticated trading system
Frequency controlled operative reserve	Changes in frequency between 49,9 and 50,1 Hz	1 257 936 €, or 145 €/h_{act}	8 689	+Very high compensation	-Technically challenging -Sudden/constant load adjustments
Frequency controlled disturbance reserve	Frequency drops below 49,9 Hz	294 336 €, or 46 €/h_{act}	6 358	+High compensation +Fairly simple to execute +On/Off adjustments	-Technically challenging -Sudden/constant load adjustments

For households, the best match is minimal loss in living comfort, minimal level of participation combined with highest compensation. Based on the preliminary calculations, it can be found that regulation electricity market matches these requirements the best for residential segment for low participation levels generate high compensation. Technically, participation in on/off adjustments is generally easier approach for household electricity consumption than constant linear adjustments. Additionally, regulation electricity does not bind consumers to long-term contracts and every hour of participation can be freely chosen. However, participation requires active trading, remote load control and 10 MW minimum volume, which means large quantities of households should be aggregated and demand response infrastructure should be established for households to be able to participate.

Discussions with the Finnish TSO Fingrid revealed that it would be technically possible for household consumers participate to high value frequency controlled normal operating

[41] The hours of activation, or €/h_{act}, includes hours when on/off action is activated by given trigger. The amount of hours that are needed to possibly cover the imbalance in net energy consumption is not included.

reserve. Despite being adjusted multiple times per minute, having aggregated capacity of small operators could successfully imitate the characteristics of a more fit capacity for such use, for example water power generators that are capable to adjust production somewhat linearly. However, there are some limitations related to this subject. Participation to frequency controlled normal operating reserve makes the connected load to switch on and off possibly significantly more frequently than the load is designed for, causing wear and breakage if the load equipment is not durable enough. This is indeed an opportunity for further research to map and design durable equipment that could participate the frequency controlled reserves and harvest the fees provided for participants. (Fingrid, 2013b)

After taking all aspects into account, regulation electricity was chosen to be the demand-shift solution for further analysis in order to harness the biggest economic benefit for households with minimal impact on comfort.

5.2.2 Household consumption profile

To recognize the importance of households in the electricity market of Finland is essential for this study. The households in this analysis include detached houses that have relatively much higher consumption rates than other forms of residency. The relation between the total consumption in Finland and the households is illustrated in Figure 16.

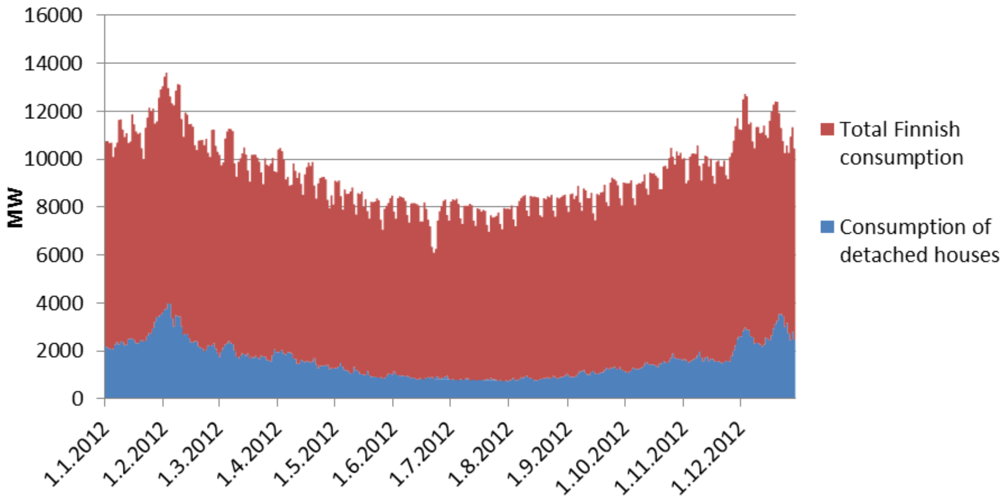

Figure 16. Total Finnish electricity consumption and the simulated share of detached houses' electricity consumption[42] as 24 hour moving averages for 2012.

[42] The consumption of detached houses is derived from the hourly simulation analysis based on total consumption by TEM report combined with real life hourly data from aggregated consumption data of 146 households in Lahti, Jyväskylä, and Kajaani in Finland.

The results based on hourly consumption analysis conducted reveals that, on average, detached houses consumed 17,1 % of all electricity in Finland in 2012. However, these households contribute significantly to variations that are problematic for the whole electricity system in terms of pricing and delivery. As the minimum hourly share of specified households was only 5,2 % in 2012, the maximum ratio was found at as high as 39,5 %. To be specific, the time of this highest share of electricity consumption occurred 23.12.2012 between 23.00 and 24.00. At this time, traditionally households are cooking their Christmas hams by using electric ovens, surely providing most of the consumption.

When assessing the demand-shift or virtual power plant business models, it is important to gain knowledge of the consumption profiles in the consumer interface. Studies of the household consumption in detached houses reveal the social aspect of electricity consumption[43], illustrated in Figure 17.

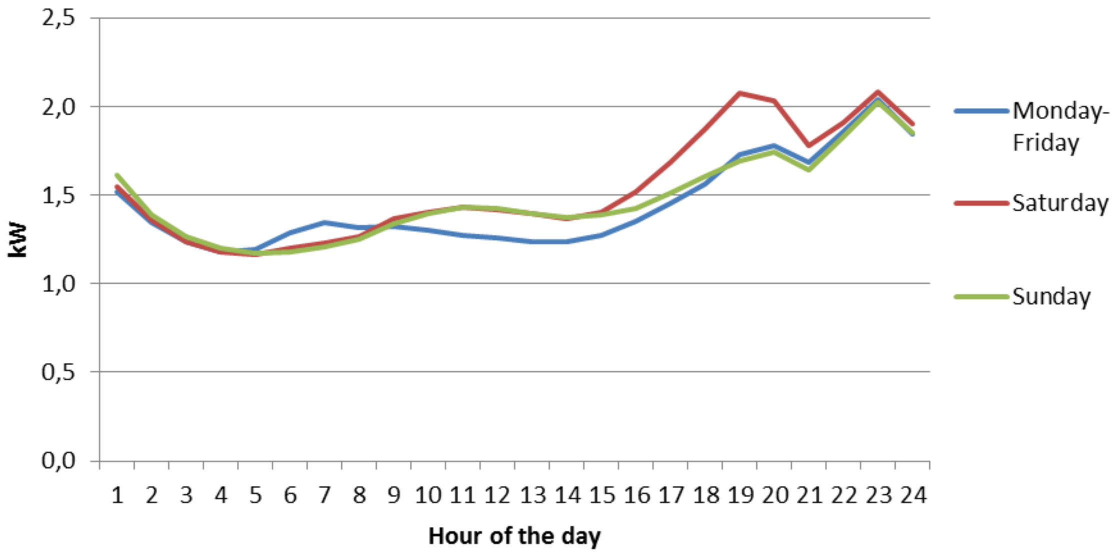

Figure 17. Average household consumption for different weekdays and hours in Finland in 2012, derived from aggregated detached house profile of 146 households in Lahti, Kajaani, and Jyväskylä.

As the baseline is rather similar between weekdays, a delay of couple of hours in the slightly elevated consumption of morning is clearly visible during weekends. Additionally, Saturday nights experience systematically higher consumption. Since the load profile differs from other days between 15.00 and 22.00, it is probable that the tradition of sauna

[43] The data was obtained from Fortum's database and compiled from 146 different unidentified consumers.

bathing provides significantly for this peak. In general, during the usual working hours between 9.00 and 16.00, the consumption is slightly lower during weekdays since consumers are not home using their domestic appliances.

Given the status and characteristics of sauna bathing, it is not applicable to demand-shift or VPP execution since the loss in comfort is hard to justify with the possible gain achievable. However, the increase in electricity could be compensated by other load reductions, such as water, car, and indoor heating. These loads were simulated for every hour of the year 2012 to map the potential related to demand-shift capacity, illustrated in Figure 18.

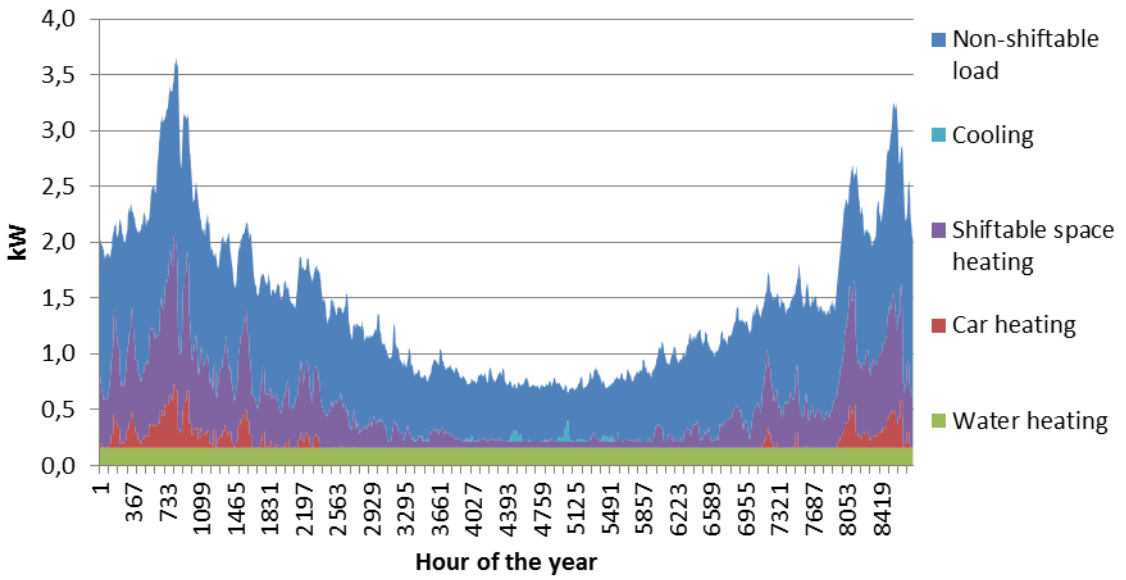

Figure 18. Simulated average detached household electricity consumption breakdown of 12 821 kWh for 2012 as moving average of 24 hours. Moving average is used for illustrative purposes.

5.2.3 Household consumption match with solar production

Since assigning direct load control capacities for regulation electricity market is just one approach, the possibilities to utilize this demand-shift regarding solar power should be assessed as well. The main idea of the approach is to maximize the size of household solar systems that are installed on their rooftops. Usually the solar systems are measured to produce the amount of electricity that could be self-consumed by the households. This way there would be no need to feed electricity into the grid[44] and the electricity bill would be minimized as the cost for both electricity and network would decrease.

By utilizing the online service of PVWatts (NREL, 2013) for Tampere, Southern Finland, and combining the data with consumption profiles of selected Finnish households in Lahti, we can conclude a couple of determining aspects. Figure 19 shows the problem with winter months that for this illustration were decided to be from October until March. The consumption is much higher on average than the production of the installed solar system. It is noteworthy that the solar irradiation platform does not take into account snow cover, which leads in this case to slightly higher irradiation levels for the solar production than in real life. Additionally, the reason for low solar production is not the size of solar system as 5 kW system is too big of a system, in fact, as can be seen from the amount of surplus in Figure 20.

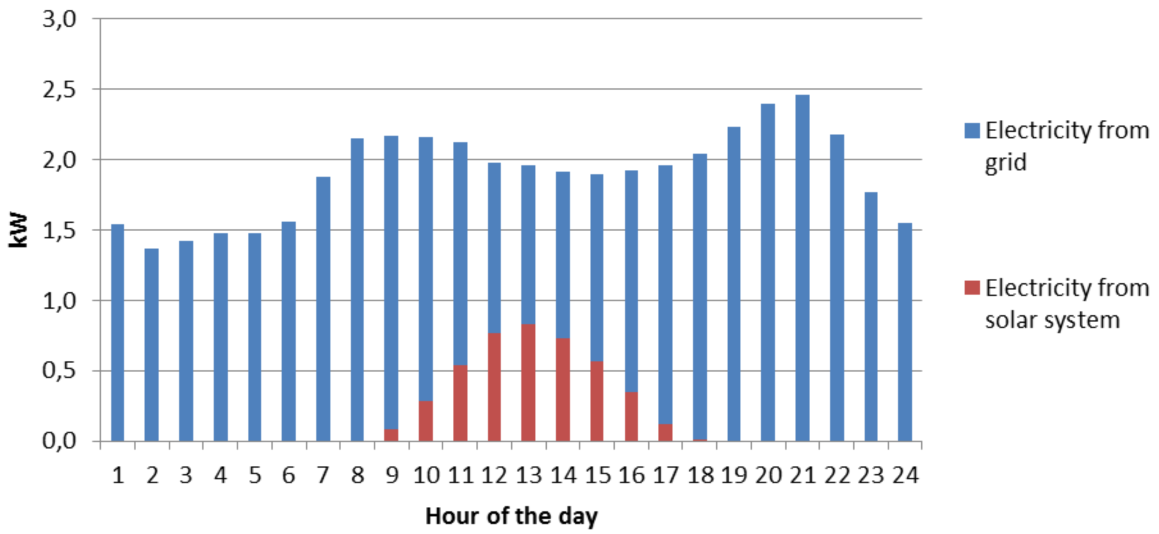

Figure 19. The average consumption and solar production[45] of base profile in Lahti, Finland with a 5 kW solar system between winter months of October and March. Total peak load hours in the simulation were 858 kWh/kW$_p$ and annual consumption 12 821 kWh.

Figure 20 shows the opposite side of the problem that is the characteristics of summer months. As the average consumption of Finnish detached houses decreases nearly 50 % for the summer, the average production from the 5 kW solar system increases drastically. To address this problem, there are three different approaches: build a smaller solar system,

[44] Feeding electricity back to the grid presents a variety of problems for at some point reverse currents could occur, and it would be increasingly difficult for TSOs to manage their infrastructure and its operations.
[45] Since PVWatts did not provide solar irradiation data for Lahti, data from another inland city, Tampere, was used for hourly analysis. Tampere is located approximately 120 km northwest from Lahti.

store the solar system surplus to battery storage, or shift load taken from the grid to the hours of highest solar production.

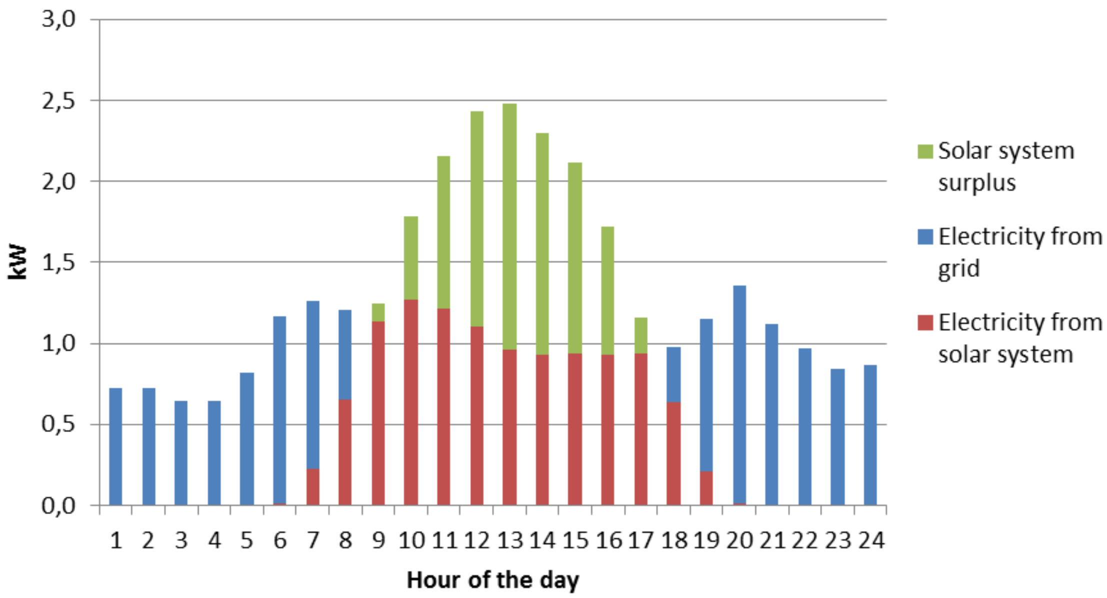

Figure 20. The average consumption and solar production for base profile in Lahti, Finland with a 5 kW solar system between summer months of April and September. Total peak load hours in the simulation were 858 kWh/kW$_p$ and annual consumption 12 821 kWh.

Due to the unattractive match between solar power production and consumption profile in the Nordic countries, it is necessary to study the potential in shifting the consumer load. This measure aims to improve the match during high solar power production hours so that load from the nightly hours are shifted to midday. The benefit with this measure is in the margin between the night hour consumption and producing the electricity itself with solar system. As can be seen from Figure 21, a 5 kW solar system on a roof of an base profile detached house would produce notable surplus between 8.00 and 18.00, on average. This indicates that there is value in shifting load from 18.00 to 8.00 to these hours of surplus so that all produced solar power would be self-consumed instead of being dumped or fed into the grid with little or no benefit.

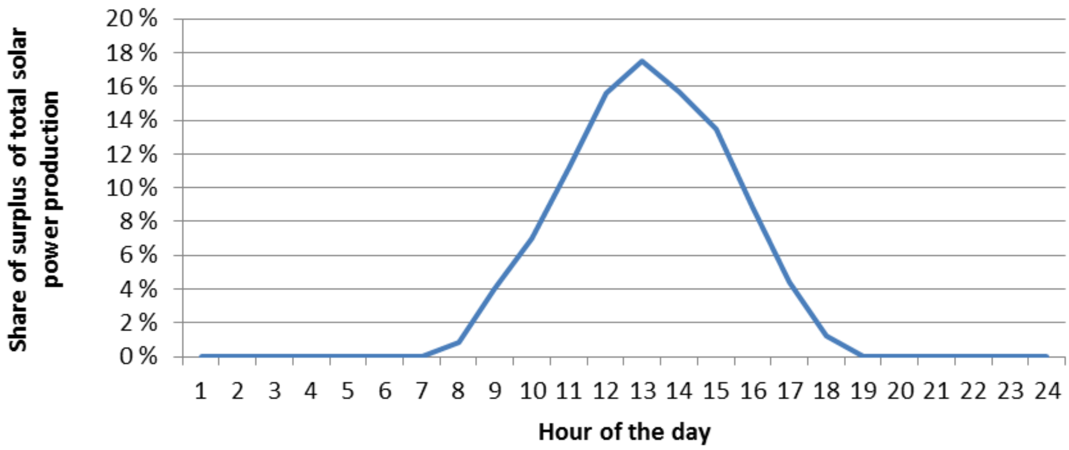

Figure 21. The average distribution of solar production surplus on different hours of the day for base profile in Tampere, Finland with a 5 kW solar system in 2012. Total peak load hours in the simulation were 858 kWh/kW$_p$.

5.2.4 The benefits of spatially distributed generation

As the literature showed in *2.9.4 Distributed generation aggregation,* the spatial distribution has significant effects on the predictability of solar power production. By using the online service of PVWatts (NREL, 2013), the benefits of spatial distributed aggregation were studied. Figure 22 shows the results for six different locations in both Finland and Sweden both as separate and as aggregated. The aggregated generation results in approximately 859 peak load hours, which is in line with results of SolarGIS service. Aggregated solar profile is the average of following locations, from southernmost to northernmost: Göteborg, Sweden (57° 42’ N, 898 kWh$_p$); Karlstad, Sweden (59° 22’ N, 957 kWh$_p$); Helsinki, Finland (60° 10’ N, 871 kWh$_p$); Tampere, Finland (61° 29’ N, 858 kWh$_p$); Östersund, Sweden (63° 10’ N, 856 kWh$_p$); and Kiruna, Sweden (67° 51’ N, 717 kWh$_p$) (World Atlas, 2014).[46]

[46] Due to the nature of PVWatts service and its approach to generate solar irradiation data, the solar profiles are not as cross-correlated as they would be in real life situation.

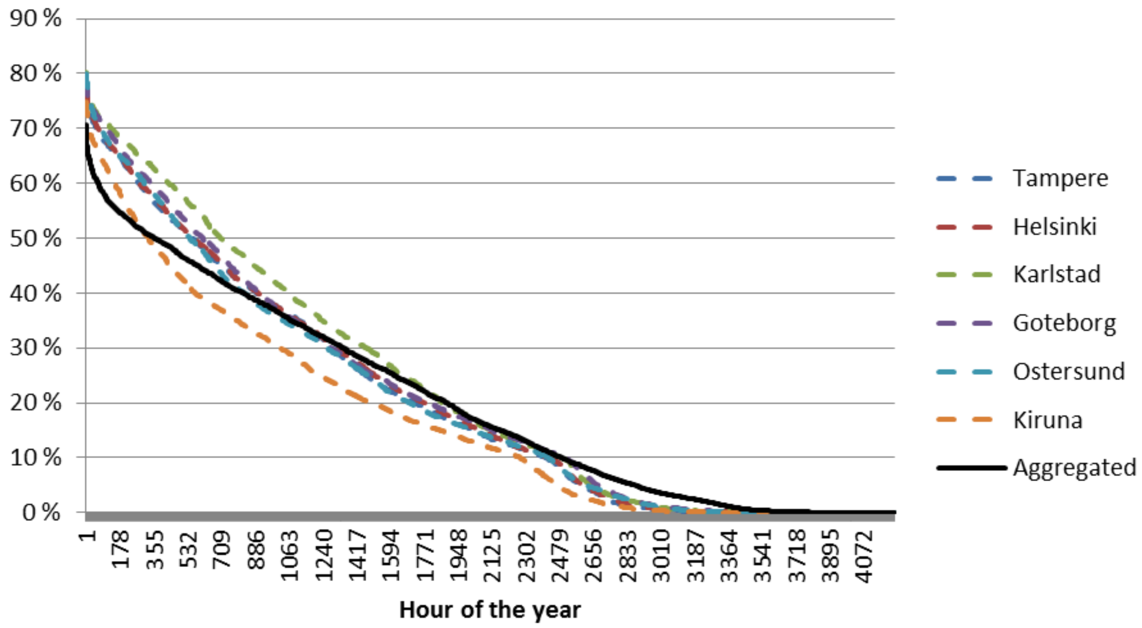

Figure 22. Nordic solar irradiation data from six Nordic locations, after PVWatts (NREL, 2013). The PVWatts data used in this simulation was not gathered from the months of the same year, which leads to non-correlating data points that produce better results than in real life. However, the impact of aggregated solar generation can be clearly seen from the illustration.

All the hourly results have been sorted from hour of most irradiation to the least. This way an illustrative curve is generated for every location. The steeper the decline, the bigger production variations can be found in general. Radical intraday fluctuations can be extremely difficult to handle in large scale and their forecasting is not as accurate as forecasting more balanced changes. The area the curve covers represents total solar power generated over the time period of one year.

As can be seen from Figure 22, the results from PVWatts support the literature conclusion that spatial distribution evens out production, causing more predictable outcome and more steady production profiles. The peak production for aggregated solar profile was found to be at 70,7 % of the maximum power, while the range for single locations stood between 74,9 % and 80,2 %. The same kind of peak production performance was found in the cases of real life Germany data and literature research on German solar installations. Additionally, the aggregated approach produced power for 3 824 hours as the range for single locations varied between 3 288 and 3 548 hours. These results indicate a decrease of approximately 10 % in peak production power and an increase of approximately 10 % in total production hours for an aggregated profile of just six individual locations. Further distribution would, according to literature research, further improve these metrics. Spatial distribution is a good demonstration of what would happen if large portfolios would be managed as one source of energy. Evening out extremes and enhancing the capability to forecast production are essential characteristics in the future if solar power is intended to be a major part of countries' energy mixes around the world.

5.2.5 Individual solar systems with battery storage

For grid-connected households[47], the most beneficial situation with solar system installations would be a system, which production could be fully self-consumed[48]. By increasing self-consumption of electricity, consumer avoids electricity taxes on the self-produced portion, as well the variable network costs and value added tax. In some cases, other extra costs can be related to purchasing electricity from the grid.

In general, the solar production and household consumption profiles for Nordic countries do not match, resulting in smaller solar systems to be installed. For example, peak load in Nordic countries occur in the morning around 8.00 and 9.00 and in the evening around 19.00 and 21.00. Additionally, annual peak loads occur during cold winter months, when solar power is not sufficiently available. On the other hand, some countries with high countrywide cooling capacity experience annual peak loads during highest solar production, resulting in very good match between these two determining factors. This match is important because greater match leads to opportunity to make an economic decision to install larger solar system, for with the volume, usually the unit price decreases significantly.

By using the base profile household consumption data and solar profile data from PVWatts, the match between consumption and solar power production was studied. The simulation shows that a detached house in Finland could have a solar system of 530 W with surplus of under 0,1 %. A system of this size would produce solar power worth 3,6 % of the household's annual electricity consumption of 12 715 kWh. With solar system sizes of 1,5 kW and 3 kW, total electricity consumption of 9,4 % and 15,2 % would be covered, respectively. For a 1,5 kW solar system, surplus of solar electricity was still relatively low at 7,1 %, but rose to 25,1 % with 3 kW solar system. More detailed information with various parameters can be found from Figure 23.

[47] In this section, when referred to 'household', it is represented by base profile.
[48] This topic is extensively covered in EPIA report "Connecting the Sun" (EPIA, 2012a)

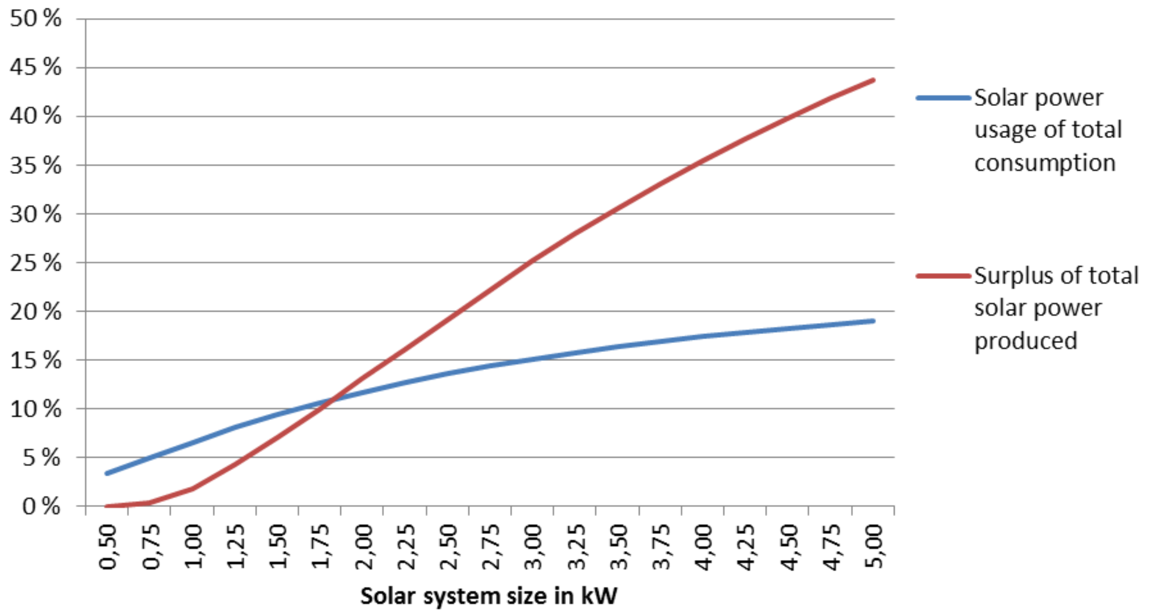

Figure 23. The correlation between solar system size, solar power share and surplus for base profile in 2012 in Lahti, Finland. The consumption data was combined with solar power output data from PVWatts for Tampere (NREL, 2013).

It can be seen from Figure 23 that the share of surplus steeply increases when solar system size surpasses 1 kW, and the self-consumption rate steadily levels off with the increase in solar system size. This is logical outcome as more and more of the solar electricity output is produced as surplus, the increase in self-consumption slowly erodes.

The problem of solar energy surplus could be solved with household battery storage[49]. For example, if a 3 kW solar system were coupled with a robust 12 kWh battery storage, there would be no surplus and the solar system would produce 19,3 % of the household's consumption with total battery losses of 4,8 %. The situation is illustrated in Figure 24. Rolling maximum values of 24 hours were chosen for illustrative purposes.

[49] Battery charging efficiencies of 90 % for both charging and discharging was used, resulting in round-trip efficiency of 81 %.

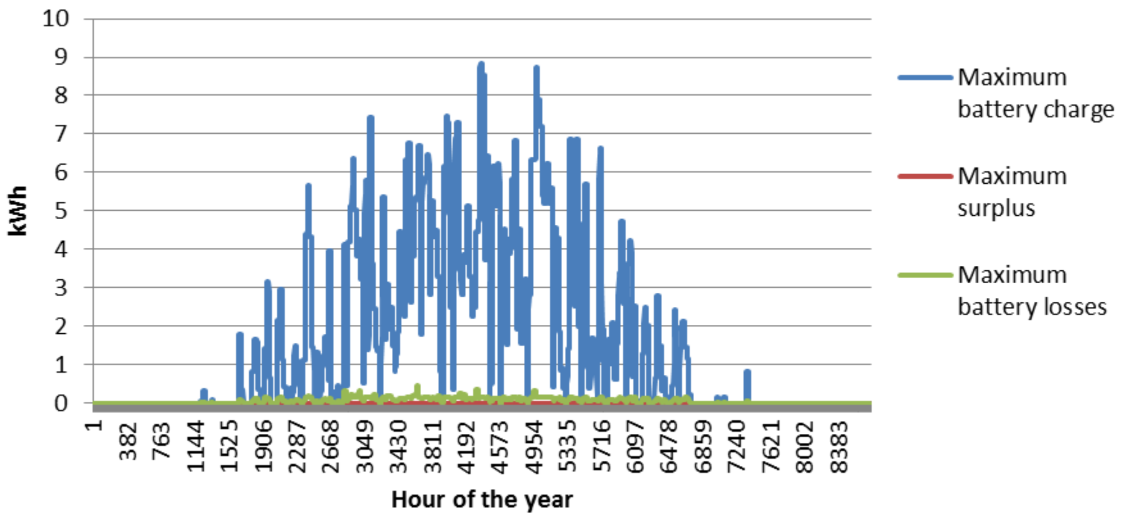

Figure 24. Rolling 24 hour maximum values for 12 kWh battery storage coupled with a 3 kW solar system and base profile in Finland, 2012.

It can be stated that the battery storage for this case is definitely too large for the maximum benefit in relation to costs. The maximum battery charge falls short on the limit of 12 kWh and even though the battery size would be significantly reduced, the surplus rate would not change drastically as only individual peaks reach high levels of battery charge. Another scenario with a 5 kWh battery is illustrated in Figure 25.

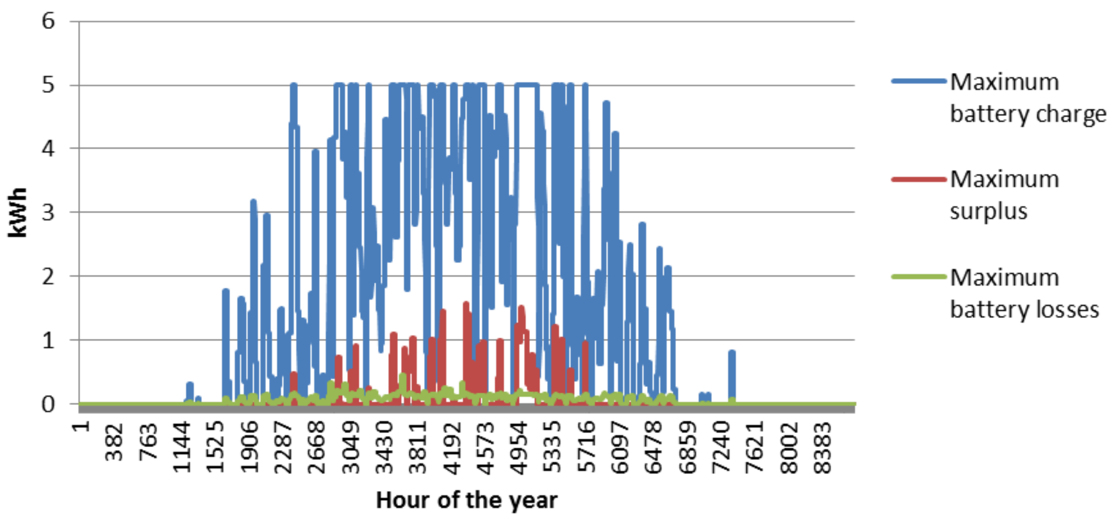

Figure 25. Rolling 24 hour maximum values for 5 kWh solar energy battery storage coupled with a 3 kW solar system and base profile consumption in Finland, 2012.

In this case, it is clear that there is now a limitation for battery charge at 5 kWh. As the upper limit of battery energy stored is reached, some of the solar energy is surplus. Despite this capping of solar energy usage, only 2,4 % of the total solar energy produced cannot be used, while 4,3 % of total production is lost with battery inefficiency. What is worth noting is the fact that 18,9 % of the household's total consumption is being covered by solar power, which is very close to the share of 19,3 % with the oversized battery of 12 kWh.

The relationship between sizes of solar system and battery storage is worth studying in order to find the optimal combination. Small sized batteries might not provide sufficient benefits and oversized batteries cause additional expenses and do not provide linearly increasing value. However, as the size of the battery increases, its unit price decreases. To further analyze this multifaceted problem from purely technical point of view, the relation of solar system size, battery size, and total losses were studied. Results are illustrated in Figure 26.

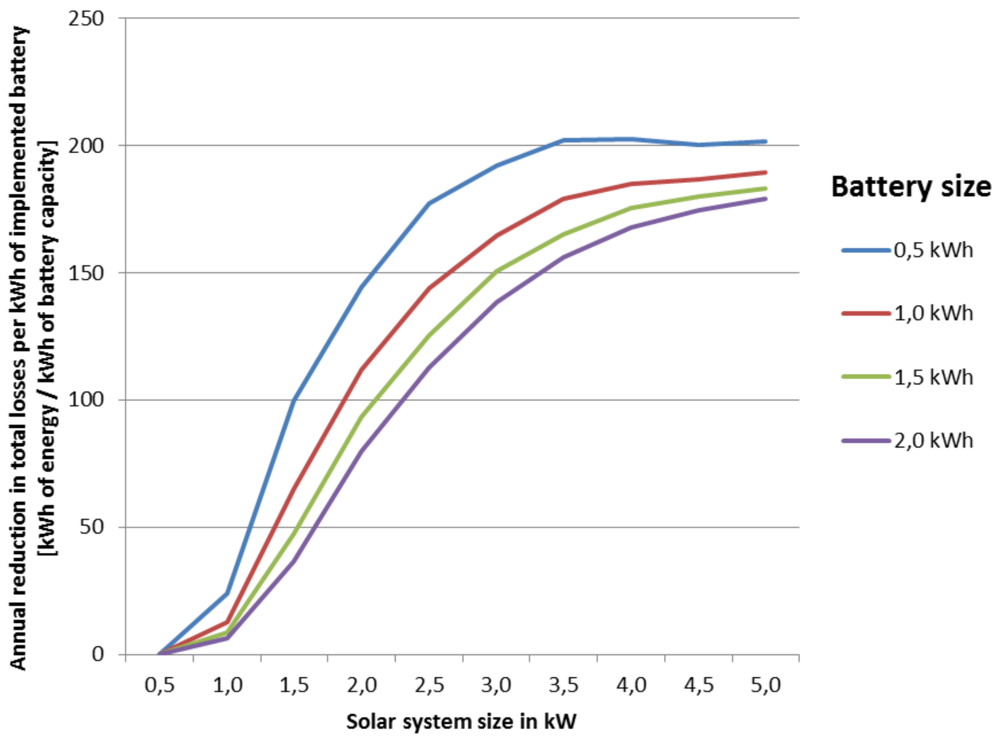

Figure 26. Reduction in rooftop solar system total losses as the function of battery storage size and solar system size. Total losses represent the amount of energy that is lost due to battery energy flow inefficiencies and surplus solar power that cannot be fed into the battery. Losses presented in the graph are normalized with the battery capacity to enable comparison between setups. Solar data of Tampere and consumption data of base profile in Lahti were used in the analysis.

The economic justification for smaller batteries is clearly visible in Figure 26. It seems that the biggest improvements in loss reduction is received in the solar system size range of 1–2 kW, smaller batteries resulting in biggest loss reductions per implemented kWh. As the self-consumption is able to consume significant share of solar power output from solar systems under 1 kW, the loss reductions clearly increase for systems over 1 kW as self-consumption is not able to reduce the amount of surplus. For solar systems over 2 kW, the amount of generated surplus is at the levels, where the battery capacity is the bottleneck, thus providing limited loss reductions. This can be seen as the leveling of loss reduction for largest solar systems with all battery systems.

Despite the bigger benefits received by smaller battery sizes, if cost reduction in unit price decreases sufficiently along with the battery size increase, economies of scale could support larger storage installations. Battery size optimization is further studied in (Weniger, et al., 2014), *Sizing of residential PV battery systems.*

5.2.6 Aggregated solar systems with battery storage

Studying the case for individual households is relevant as fluctuations in solar power production and electricity consumption are close to real life situations, thus much greater and harder to predict than larger volumes of households. As pointed out earlier in this paper, aggregation of both electricity consumption and solar power production result in significantly more predictable outcome, depending of the total number of locations and their cross-correlation, which is highly affected by distance.

The same situations were studied for aggregated systems as for individual base profile household. Results can be found from Table 10. Aggregated consumption is the average of 146 individual household electricity consumption and aggregated solar profile from (NREL, 2013) is the average of six Nordic locations from southernmost to northernmost: Göteborg, Sweden (57° 42' N, 898 kWh_p); Karlstad, Sweden (59° 22' N, 957 kWh_p); Helsinki, Finland (60° 10' N, 871 kWh_p);Tampere, Finland (61° 29' N, 858 kWh_p); Östersund, Sweden (63° 10' N, 856 kWh_p); and Kiruna, Sweden (67° 51' N, 717 kWh_p) (World Atlas, 2014).[50] Aggregated solar profile resulted in total of 859 peak load hours.

[50] Due to the nature of PVWatts service and its approach to generate solar irradiation data, the solar profiles are not as cross-correlated as they would be in real life situation.

Table 10. Comparison between single location and aggregated consumption and production scenarios. Base consumption profile from Lahti was combined with solar data from Tampere for aggregated consumption profile, which includes households from Lahti, Kajaani, and Jyväskylä. Aggregated consumption profile was combined with aggregated solar data from six Nordic cities in Finland and Sweden.

Setup	Base profile	Aggregated profile
Maximum solar system with <0,1% surplus; no battery	530 W	1 030 W
Total losses[51] with 1,5 kW solar system; no battery	7,1 %	3,3 %
Total losses with 2 kW solar system; no battery	13,1 %	10,9 %
Total losses with 2 kW solar system; 0,5 kWh battery	8,9 %	7,8 %
Total losses with 3 kW solar system; no battery	25,1 %	25,2 %
Total losses with 3 kW solar system; 0,5 kWh battery	21,4 %	22,2 %
Total losses with 3 kW solar system; 1 kWh battery	18,7 %	19,6 %

A quick comparison between the two options of having individual system or aggregated portfolio of systems reveals the benefits of the latter, for smaller systems. Usage of aggregated portfolio allows installation of larger solar systems and results, to some extent, in smaller surplus of total solar electricity production. For example, a household with 1,5 kW solar system participating in aggregated portfolio produces 3,8 %-points less surplus of total solar production than individual households. It seems that the benefits of aggregated portfolio diminish as the solar systems grow larger. Since the two scenarios match quite well each other[52], only differences are in the volatility of both consumption and solar production. As it can be seen in Table 10, mismatches with smaller systems are clearly at lower level for aggregated scenario. Due to equal overall consumption and solar power outputs between scenarios, this benefit erodes when moved to larger solar installations.

5.2.7 Contribution of demand-shift model to solar surplus

As the demand-shift capacity can be used for balancing market purposes, the capacity could be used for in-house purposes as well. Since the match between consumption and

[51] Total losses include both battery losses and solar production surplus.
[52] Base profile consumption is 12 715 kWh as aggregated is 12 821 kWh. Solar data for Tampere results in 858 peak load hours and 859 peak load hours for aggregated profile.

solar production for households is far from optimal in Nordic countries, the situation could be optimized with the available demand-shift capacity.

The model used for this analysis calculates the demand-shift available consumption for full following day on hourly basis and compares that to the expected solar power production[53]. The demand-shift available consumption included water heating, car heating, cooling, and shiftable space heating. If there is surplus production from the solar system, the demand-shift available capacity is shifted to match the hours of surplus, thus leading to lower shares of overall surplus. For example, if for the hours between 11.00 and 14.00 forecast predicts solar production surplus, demand-shift available load could be utilized during these hours instead of night hours. In this simulation, demand-shift available load after 18.00 and before 10.00 can be shifted for hours 10.00–18.00 to cover the potential surplus production. This process is illustrated in Figure 27.

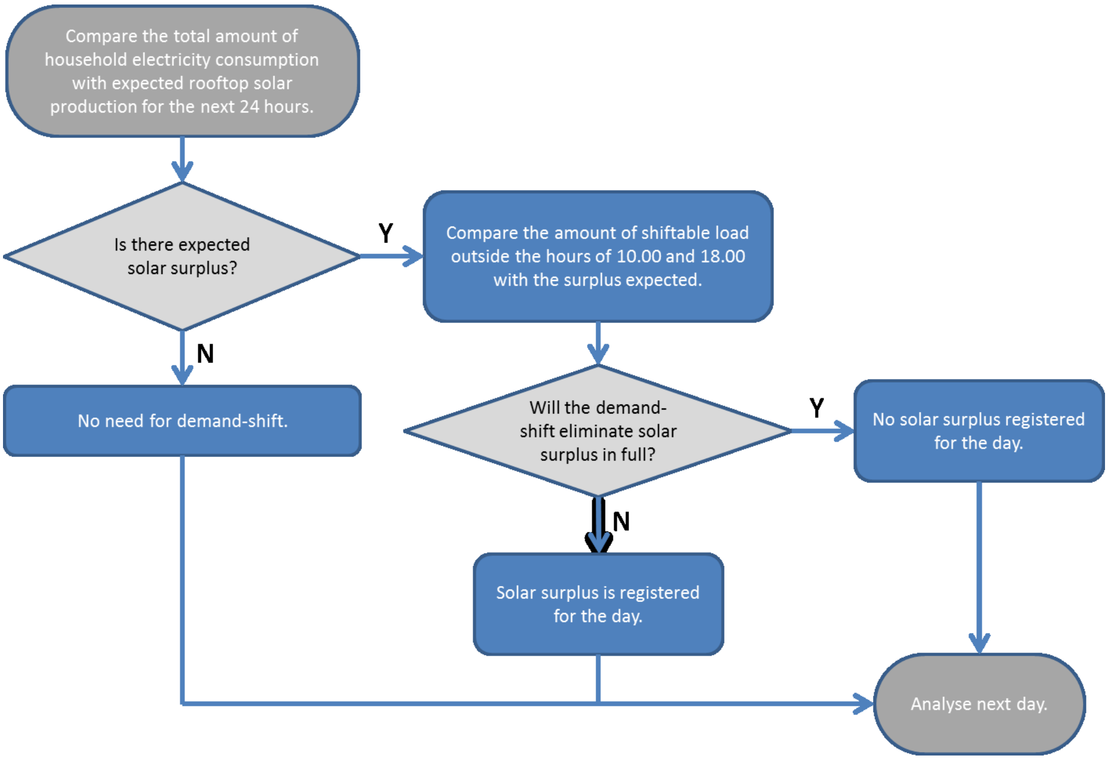

Figure 27. A process flow diagram to model the benefits of using demand-shift to minimize the solar production surplus for a household with a rooftop solar system.

Demand-shift capability increases significantly the amount of consumed solar power with all solar system sizes. Adjusting daily loads allows base profile household to install as large as 2 kW solar system basically without inflicting any production surplus. The impact

[53] In this analysis, it is assumed that the prediction is accurate for the next 24 hours of solar production.

of these results is two-sided. For bigger solar installations, the amount of surplus electricity reduces significantly, and at the same time bigger installations lead to lower unit prices at the time of purchase. This translates directly into more attractive initial capital expenditure per unit.

Technically, demand-shift capacity could replace batteries to some point, and therefore reduce potential capital expenditure with the same benefits achievable. Possibly, the combination of both demand-shift and battery storage could improve total performance even further. To illustrate differences between all setups, battery storage and pure demand-shift scenarios are illustrated in Figure 28.

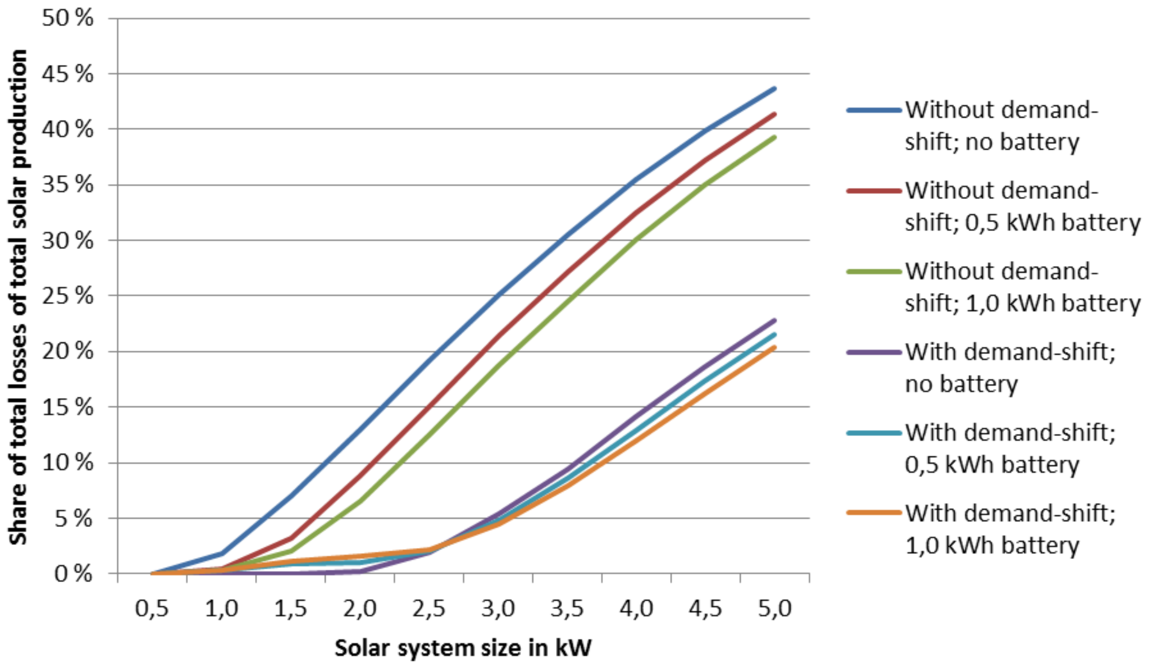

Figure 28. Share of total losses of total solar system output with and without demand-shift and battery storage for base profile with an annual consumption of 12 715 kWh.

These simulations reveal the distinct difference between household with and without demand-shift. For solar system sizes smaller than 2,5 kW, the lowest losses are experienced by demand-shift scenario without battery storage. With larger solar systems the demand-shift without battery suffers from slightly larger surplus. This surprising result can be explained by the priority of the process used in the simulation: as solar production surplus occurs, battery storage is used first and demand-shift second. This leads to some battery losses due to battery inefficiencies[54]. High capital expenditure related with battery

[54] Round-trip battery efficiency is assumed at 81 %.

storages and possible loss in comfort caused by any demand-shift supported the approach to use batteries as much as possible as the primary buffer for solar surplus.

It can be summed up that demand-shift solution alone is the biggest single provider for solar surplus cuts as battery extensions do not significantly improve the performance in comparison. Additionally, demand-shift results in surplus decrease of roughly 15 to 20 percentage points with larger solar systems than 2,5 kW. This difference decreases as solar systems decrease in size.

5.2.8 Economic impact of demand-shift in regulation market

It was earlier studied that the regulation electricity market offers the largest value for the least effort. As demand-shift can be used for solar power surplus mitigation, it could also be used to gain economic benefit from the regulation electricity market, which is quantified in this section. To achieve the sufficient 10 MW regulation electricity volumes for every hour for the year, summer months included, a portfolio of 55 000 aggregated households was required and used in the calculations[55]. This scenario includes strong limitations that are identified in the next section.

On the regulation electricity market, upward regulation means either increasing power production or reducing power consumption as downward regulation means the opposite: either reducing power production or increasing power consumption. If it is assumed that shifted load does not affect the amount of shiftable loads of the following hours, results for the hours of activation indicate that upward regulation provides significantly more opportunities than downward regulation. As the price premium trigger for the placed bid is increased, hours for downward regulation quickly decrease in comparison to upward regulation. At a price premium of 10 €/MWh, upward regulation covered 39 %, or 855 hours, of all activation hours during the year of 2012, but a price premium of 100 €/MWh led to a share of 94 % for upward regulation, equaling a total of 185 activation hours.

In brief, upward regulation electricity provides the opportunity to gain more with less activation hours, as illustrated in Figure 29.

[55] Therefore the aggregated profile was used in this simulation.

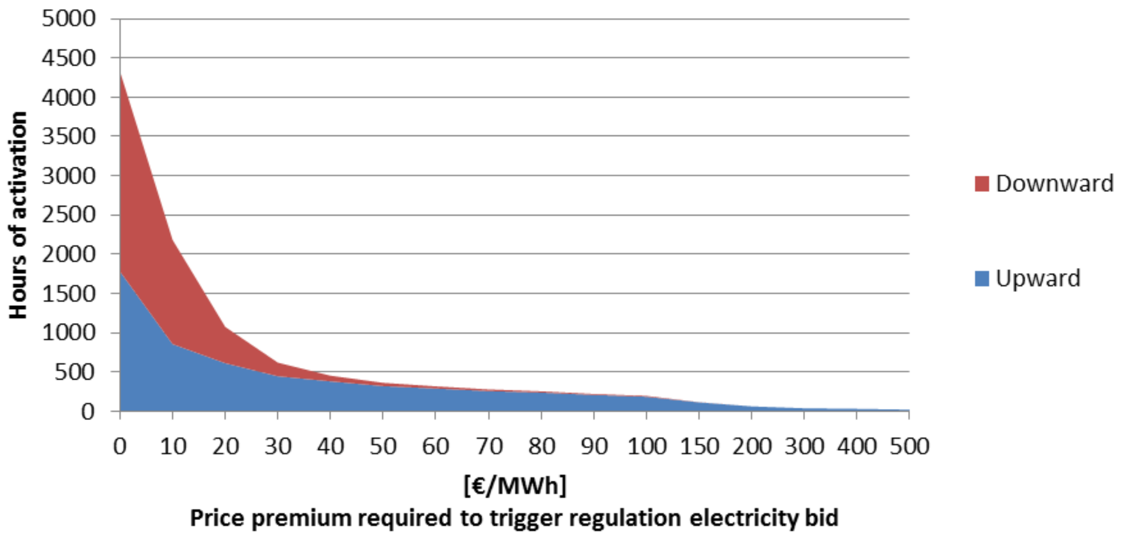

Figure 29. The distribution of regulation electricity activations to downward and upward regulation as a function of set price premium in 2012 for Finnish electricity market. The amount of downward regulation hours, and thus value, reduces quickly as price premium increases but value in upward regulation clearly exists even with higher price premiums.

For households, it is essential to find the balance between compensation and effort. The figure presented above does not provide information of the amount of economic benefit received from regulation electricity, therefore the gained benefit as a function of price premium was studied. If price premium is set low, a total of 4 332 hours leads to activated bid during one year, but the benefit received per activation hour is lowered as well. If price premium is set higher, the activation hours do decrease, but gain more compensation per unit. This phenomenon is presented in Figure 30.

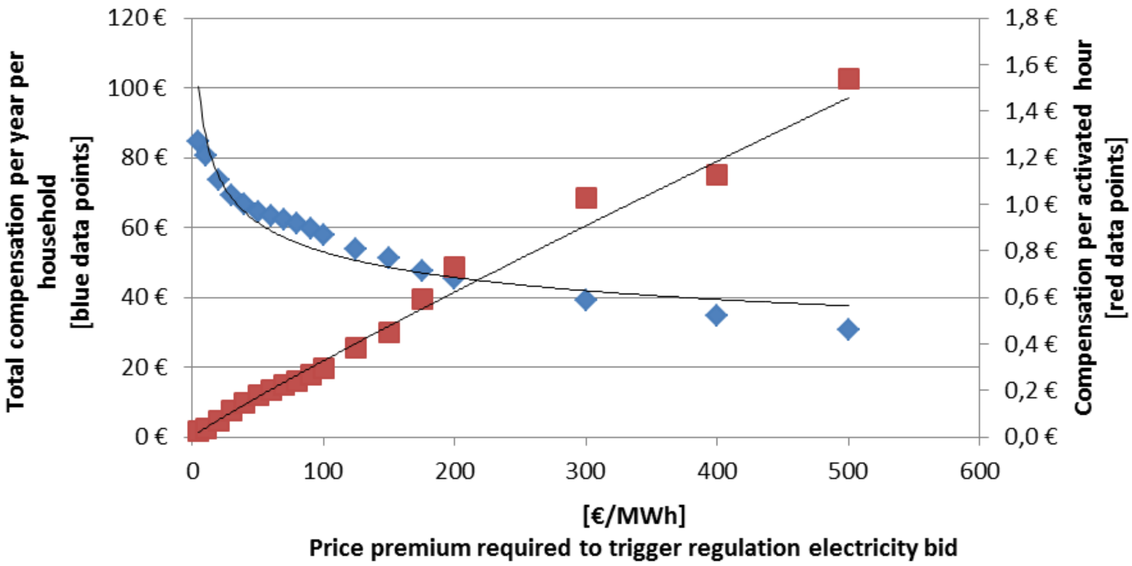

Figure 30. Simulation of the total compensation received by households (blue data points) and compensation by activation hour (red data points) as a function of set price premium. Trend lines added for illustrative purposes. Higher price premiums result in higher compensation by activation hour but to lower total compensation. Thus, high price premium triggers provide somewhat less benefit but with significantly less effort.

It depends on the customers and their range of acceptable comfort, which parameters are being used, but it can be seen from Figure 29 and Figure 30 that possibly the most attractive combination lies at the level of 100 €/MWh price premium that results in total annual compensation of 58 € per household and activates only 196 hours of regulation trading. It depends on the customer's preferences and requirements, which scenario suits the best, but for the further analysis, this level of compensation combined with the annual benefit was assumed to be sufficient value for residential customers to agree upon.

It has to be noted that the assumption used in this simulation is giving optimistic values for the gained benefit, as the households might not be able to shift the given load during adjacent hours. Even with this optimistic simulation, the economic incentive for households might not prove to be sufficient regarding all the installations and modifications this kind of approach might require. However, if the equipment required for demand-shift actions exists, participation for regulation electricity market would provide additional economic incentive. Additionally, the importance of such flexible capacity on grid stability could be embraced by TSOs. For example, an aggregated portfolio of shiftable load in households could react quickly in rare occasions, such as nuclear power plant going suddenly offline.

As the presented results reflect the full year operations, the impact of individual months on the full year results is illustrated in Figure 31.

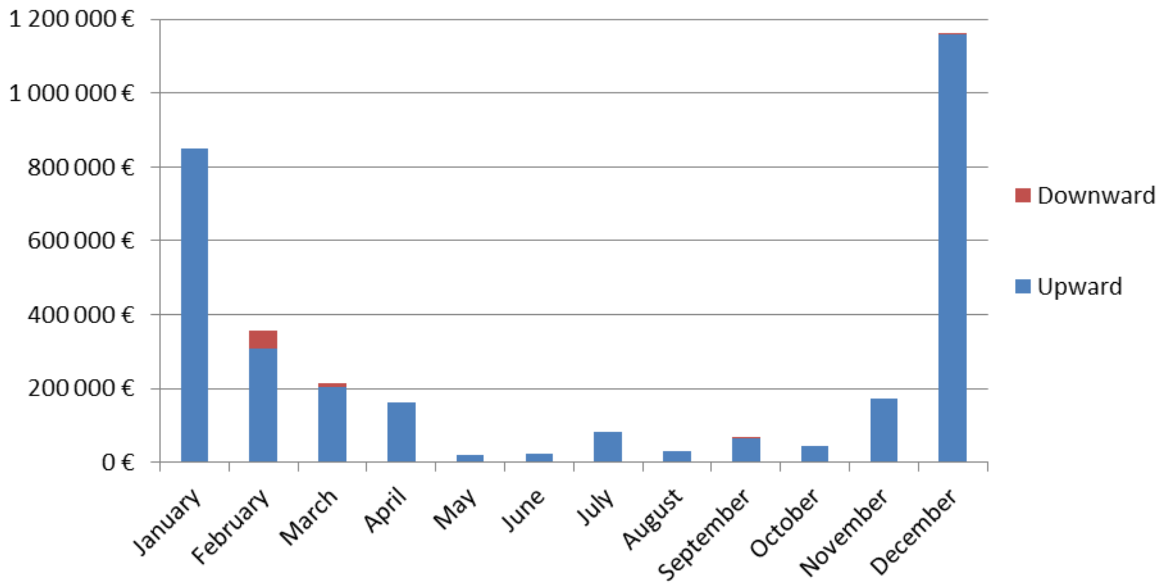

Figure 31. The distribution of downward and upward regulation compensation for an aggregated portfolio of 55 000 households by given month in 2012, by using the selected price premium of 100 €/MWh.

The emphasis of the regulation electricity compensation is clearly on the winter months. December and January represent alone a compensation of 2 008 791 €, or 63 % of the total compensation available with these parameters throughout the year. If we consider half of the year to be supplied with flexible energy capacity by households, months from November to April would be included. During 2012, these months covered 92 % of the available compensation. This translates into a total compensation of 53 € per household per year.

These results support a scenario, in which the flexible load of households would be utilized for regulation electricity trading purposes during winter months and used for solar power surplus mitigation during summer months when the value of regulation electricity is significantly lower. Even though the imbalance electricity trading is not included in this study, the benefits of having a portfolio of flexible load for balance responsible parties could be noteworthy. Imbalance fees occur for balance responsible parties, such as utilities, if they differ from the promised electricity delivery. However, the largest benefits from imbalance market are mainly overlapping time-wise with high value regulation electricity since largest power outages cause simultaneously imbalance fees for the outage responsible, and high regulation electricity prices for others to compensate the imbalance.

5.2.9 Economics of electricity consumption reduction in regulation market

The scenario evaluated in *5.2.8 Economic impact of demand-shift in regulation market* is covered from the end-customer's perspective, therefore the problems of balance responsible parties (BRPs) are not taken into account.

As the demand is shifted from one hour to another due to regulation electricity activation, the energy balance of BRP is affected. Reacting to TSO's need for regulation electricity does not result in imbalance fees for BRP but shifting the demand for the next hour does, as the day-ahead delivery of this given hour goes out of balance. Therefore, more realistic regulation electricity potential for households could be found in absolute reduction of electricity usage. This approach would have an impact on the net energy usage of reacting loads, which would lead to lower average indoor temperatures and reduced usage of heated water for households if applied. The correlation between annual household compensation and required electricity reduction is illustrated in Figure 32.

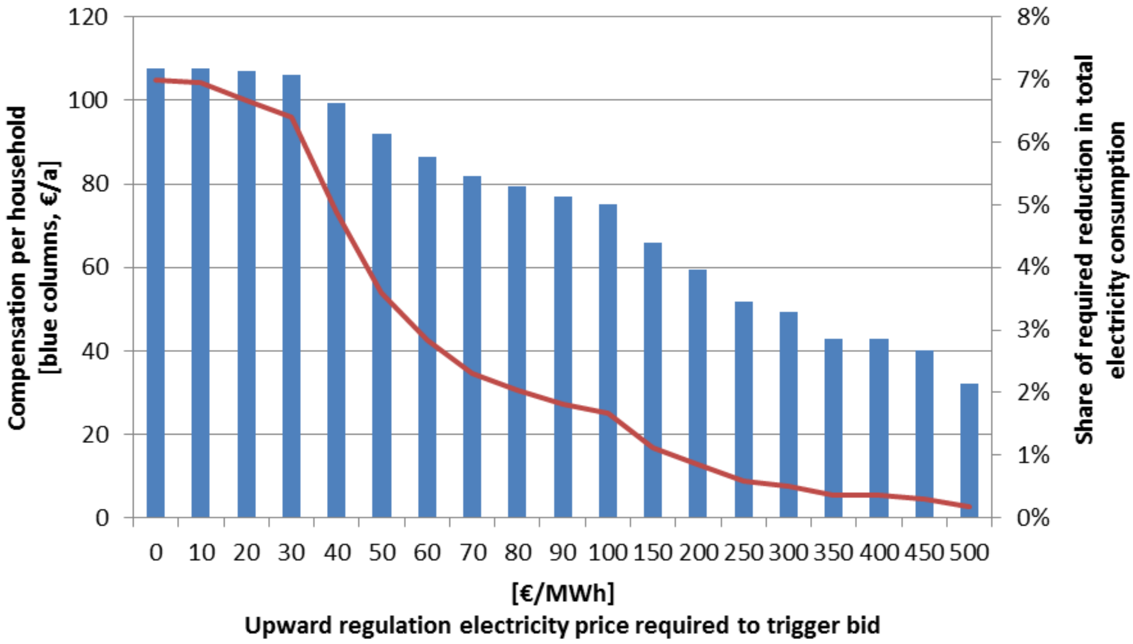

Figure 32. Illustration of the correlation between annual household compensation and required electricity reduction on the upward regulation electricity market. The aggregated portfolio of households in this simulation includes 55 000 households and both benefit and effort are assumed to be distributed evenly for all participants.

The results indicate that the total annual compensation available for households that are willing to reduce their electricity usage is attractive. At low price premium levels, the required reduction of electricity exceeds 800 kWh per year, or 5 %, of annual consumption, while compensation is slightly over 100 € annually. However, higher price premiums provide more value for effort. At 100 €/MWh price level, required electricity reduction is only 215 kWh, or 1,7 %, for an annual compensation of 75 €, while 200 €/MWh requires a reduction of only 109 kWh, or 0,9 %, with a compensation of 59 €. The distribution of the total available profit for all participants by given months in 2012 with a price trigger of 100 €/MWh is illustrated in Figure 33. Profits are shown as the total value available per participating household.

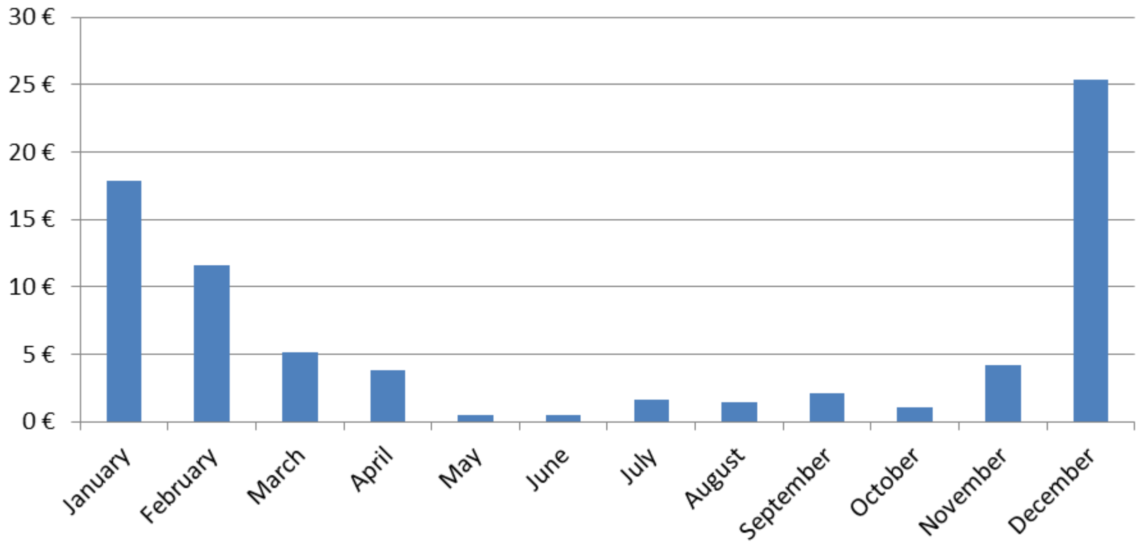

Figure 33. The available total upward regulation electricity compensation distribution by given month for individual households in a portfolio of 55 000 households in 2012. This profit must be shared between the service provider and the customer. The compensation is achieved by participating Finnish upward regulation market with a price trigger of 100 €/MWh.

Despite the total value calculated above, there are at least two parties sharing the possible profits: customer and regulation electricity trader that most likely acts also as the infrastructure provider[56]. Estimating the profit distribution between these parties is purely speculation, but it can be estimated that roughly 60–80 % of the profits could be given to the consumers. At 100 €/MWh regulation electricity price trigger this translates into annual profits of 45–60 € for residential customers.

[56] This infrastructure includes the whole business model, required equipment, active electricity trading, and constant operation and maintenance activities.

The available benefit is clearly concentrated on winter months, when the overall electricity consumption is high in general. Summer months most likely have had sudden power plant shutdowns that have resulted in temporary elevated upward regulation price levels. This supports the suggestion of using flexible energy management during summer for solar power purposes and during winter for regulation electricity purposes, while gaining the maximum benefit from both revenue models.

5.2.10 Investment analysis

To provide concrete results for household business opportunities, internal rate of return was calculated for different scenarios to benchmark the economic attractiveness of studied solutions. IRR was chosen due to its nature of being comparable to other investment options that are available for households. Additionally, using IRR removes the need to use cost of capital as an assumption, which often has very high impact on the final results and thus investment decisions[57].

Usual investment types for households with excess money are individual stocks, houses, government bonds, and bank deposits. In order to obtain an attractive investment status, the return calculated here should beat the returns achieved via other investment instruments, or at least match them. If return is below zero, the value of the investment decreases over time. For reference, bank deposits had rates between 0,00 % and 1,50 % in February of 2014 in Finland (Kauppalehti, 2014) and the average dividend yield for equities in Finnish stock exchange in 2008–2013 was 3,6 % (Balance Consulting, 2014). As the inflation for Europe is on average 2 % (European Central Bank, 2014), if an investment is not successful in returning more than that, the purchasing power of money will erode over time. Therefore it is imperative for households to find investments for their money that at least preserve their current wealth. Any positive returns, however, are better than having extra cash on hand, losing its value due to the running inflation.

To calculate IRR for systems built today, the solar system kit pricing of Fortum was used. Since cumulative PV capacity in Finland was at 1 MW level at the end of 2012 without any significant installation surge in sight (EPIA, 2013a), the pricing for rooftop PV installations in Finland is not globally competitive and value chains are underdeveloped. However, mature and developed residential markets exist in Germany, for example. The

[57] However, price inflation of 2 % is assumed in the calculations. Therefore the maintenance costs of the solar system and electricity price increase 2 % annually in the analysis.

current cumulative residential solar capacity already exceeds 4 GW on the rooftops of Germany, which represents residential PV penetration rate[58] of 1,5 % (ClearSky Advisors, 2013). The PV learning curve[59] driven by large volumes has generated lower prices, which are presented in Table 11.

Table 11. Current pricing of residential rooftop PV systems in Finland and Germany.

Country	Solar system size	Local price per watt without VAT	Finnish VAT[60] adjusted price per watt	Source
Finland	1 470 W	2,76 €/W	3,42 €/W	(Fortum, 2014a)
	4 410 W	2,05 €/W	2,54 €/W	(Fortum, 2014a)
Germany	< 10 000 W	1,70 €/W	2,11 €/W	(BSW-Solar, 2013)

It seems that significantly lower prices can be found from the mature market of Germany. Figure 34 illustrates the breakdown of the German cost of 1,70 €/W for rooftop solar.

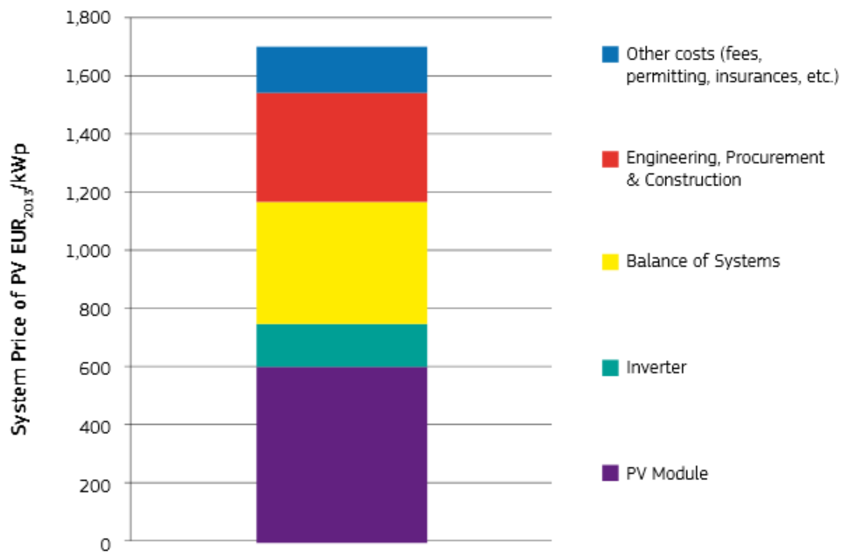

Figure 34. Rooftop solar system cost breakdown in Germany, after *PV Status Report 2013* by (European Commission, 2013).

The prices presented in Table 11 are as both local prices and adjusted to the VAT of 24 % used in Finland. The German residential solar installations are exempted from VAT (Seel, et al., 2013). The differences between Finnish and German prices are not caused by technology but rather by differences in business practises and costs related to bureaucracy.

58 Residential PV penetration rate indicates the share of residential rooftops that are utilized for solar power generation.

59 As the global cumulative PV capacity doubles, the average module selling price declines 21,5 %, on average. (SEMI, 2014)

60 Used VAT for Finland was 24 %. (European Commission, 2014)

Therefore these prices could be used in the investment analysis for the scenario of mature residential solar market for Finland. Pricing in Finland signals that smaller solar systems are roughly 35 % more expensive per watt than larger solar systems. Therefore this price progression is applied also for German pricing[61]. The results for IRR with different price per watt assumptions are represented in Table 12.

Table 12. IRR results from the investment simulation that applied German rooftop PV price level for Finland combined with Finnish consumption data and solar irradiation yields. Price level for smaller German solar systems uses the same progression as in Finland; smaller systems are 35 % more expensive, on per watt basis, than larger systems. IRR calculated for 25 years of solar system operation.

Price reference	Solar system size	Finnish VAT adjusted price per watt	Internal rate of return (IRR)
Finland	1 470 W	3,42 €/W	-2,98 %
	4 410 W	2,54 €/W	-1,56 %
Germany	1 500 W	2,85 €/W	-1,77 %
	5 000 W	2,11 €/W	-0,49 %

It is clear that the current residential PV system pricing leads to unattractive rates of return, especially for Finland but also for mature markets with applied Finnish VAT. However, these results can be further improved by residential smart solutions.

To enable the demand-shift operations to complement both regulation electricity trading and solar surplus mitigation, smart solutions are required for households. These solutions already exist, however, in different forms that might be required for the aforementioned operations. Despite the differences in the hardware, these products provide rough price range for the future products as well. Nest Learning Thermostat costs 181,25 €[62] (Nest, 2014), tado°'s Connector Kit with the Heating App costs 299,00 € (tado°, 2014), and Fortum Fiksu hardware costs 540,00 €[63] (Fortum, 2014a). All these solutions have the ability to be remotely controlled, can react to multiple input signals, and have wireless communication capabilities. The pricing of these products indicate that high-end solutions with several add-ons could reach as high as 1 000 €, but on the low end with high volumes, prices could go as low as 200 €. Taking into account this price range in the analysis, a

[61] Since the average cost for German solar systems below 10 kW was cited, it is assumed that this price applies for rather large, 5 kW solar systems. Smaller systems are assumed to cost 35 % more, as indicated by Finnish pricing progression.
[62] Used exchange rate, 1 USD = 0,728 EUR
[63] Additionally, a service fee of 4,98 € per month and 124 € for installation are applied for the product. (Fortum, 2014a)

reference case solution is assumed to cost 500 €. Any monthly service fees related to the regulation trading services are assumed to be covered in the profit distribution between provider and customer, hence no monthly fees are assumed. All system related investments are assumed to have a lifetime of 25 years. These assumptions are used in the investment analysis of Table 13 and sensitivity analysis. Additionally, the income from regulation electricity trading, studied in section *5.2.9*, is assumed at 50 € per year.

Table 13. IRR results from the investment simulation that applied different current price scenarios for Finland with both demand-shift and regulation trading features. Finnish VAT is applied to all prices used in this calculation. IRR calculated for 25 years of solar system operation.

Price reference	Solar system size	Finnish VAT adjusted price per watt	IRR with demand-shift	IRR with demand-shift and regulation trading
Finland	1 470 W	3,42 €/W	-3,52 %	-0,84 %
	4 410 W	2,54 €/W	-0,72 %	0,31 %
Germany	1 500 W	2,85 €/W	-2,42 %	0,33 %
	5 000 W	2,11 €/W	0,40 %	1,38 %

By implementing demand-shift and regulation trading, the Finnish pricing reaches positive IRR of 0,31 %, however only for larger systems. German price level in Finland would produce IRR of 1,38 % with both demand-shift and regulation trading. This level of IRR could easily compete with bank deposit returns.

In addition to provided returns, implementing demand-shift capability would basically enable a lot of customer value in form of remote security services, automated or on-demand control of loads, and other possible comfort adding products and innovations. Value additions in these extras cannot be integrated to these calculations as they only improve the user experience, and possibly everyday life, but not the economics.

6 Sensitivity analysis

6.1 Consumption profiles

Most of the analysis conducted in this study was executed by using base profile that roughly matched the average consumption of 146 individual households. For an average household, the annual consumption was 12 821 kWh as 12 715 kWh was the consumption used for the base profile. To further understand the differences between households, a low and a high profile were also generated. These profiles were randomly selected households with an approximate difference of ±5 000 kWh from the base profile. Low profile[64] resulted in annual consumption of 7 102 kWh and high profile in consumption of 17 225 kWh. The 24 hour moving averages of these consumption profiles are presented in Figure 35.

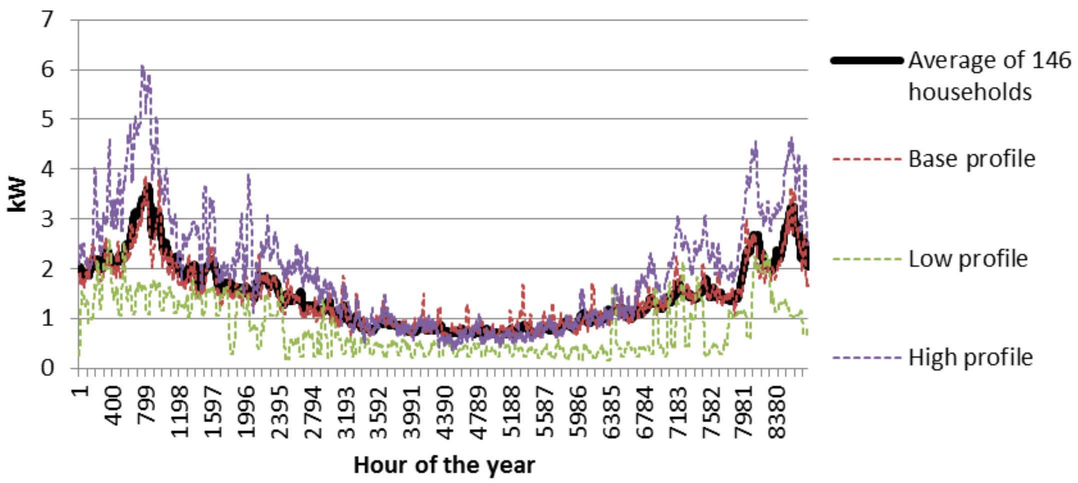

Figure 35. All consumption profiles for 2012 in Finland. Households included in the profiles are located in Lahti, Kajaani, and Jyväskylä, retrieved from Fortum database. 24 hour moving averages were used for illustrative purposes.

To map the demand-shift capacity for all profiles, shiftable space heating and water heating were adjusted. For high profile, both consumption loads were increased +50 % and for low profile -50 %. Since base case profile has a total consumption of 12 715 kWh and water heating accounts for 10,8 %, or 1 373 kWh, and shiftable space heating 55,0 %, or

[64] The simulation model and low profile conflicted during several hours due to radical changes in both temperature and household consumption, which lead to negative power of non-shiftable load. This kind of situation is unrealistic and was forced to fit the model by restricting the minimum for non-shiftable load to zero. This resulted in low profile consumption of 7 112 kWh instead of actual 7102 kWh, and the former was used in the model but was not considered to have significant impact on the results delivered in this study.

6 992 kWh, these adjustments led to a total consumption changes of 4 183 kWh. Rest of the balance between profiles can be justified by the variations in the domestic appliance usage. The biggest differences in consumption occur naturally during the time of highest consumption, but even out rather close to each other during the summer months. This data can be used to determine the magnitude of benefit variations for fundamentally different consumption profiles.

6.2 Assumptions and their effects in the analysis

To study the impact of several different variables, a selection of factors were chosen to identify drivers of both high and low significance. The demand-shift scenarios were chosen since these setups were in the focus of this study. Both the worst case and the best case demand-shift services were evaluated. Another important aspect of the investment analysis is the price of household electricity. To estimate the importance, ±30 % change in the electricity price, on top of price inflation, was studied. For example from the beginning of 2000 until the end of 2013, the electricity price in Finland has increased by 176 % so price fluctuations do exist, especially on the upside (Nord Pool Spot, 2013). As the price of rooftop solar systems has developed drastically during the last few years (European Commission, 2013), it is relevant to include ±30 % solar system price scenarios in the analysis. Since governmental support is important for emerging technologies, scenarios with a VAT of 10 % and 0 % are calculated. These kinds of incentives are additionally very plausible and easy to execute if suitable political climate and determination exists. Lastly, as solar irradiation levels may vary between locations and used data may include some systematic measurement errors, the impact of the variable annual solar irradiation of ±10 % was applied to the sensitivity analysis.

The different scenarios used in the sensitivity analysis and their effect on the profitability calculations are presented in Table 14.

Table 14. Summary of sensitivity analysis assumptions and scenarios carried for different Finnish consumption profiles. IRR calculated for 25 years of solar system operation.

Sensitivity scenario	Description	Changes inflicted	Impact in %-points to IRR
1. Low benefit demand-shift services	Initial service and equipment investment cost of 1 000 € with an annual benefit of 30 €.	Increased self-consumption of solar power and initial investment cost, coupled with gained benefit from regulation trading.	Positive 0,59–1,52 %
2. High benefit demand-shift services	Initial service and equipment investment cost of 200 € with an annual benefit of 70 €.	Increased self-consumption of solar power and initial investment cost, coupled with gained benefit from regulation trading.	Positive 2,22–4,31 %
3. Decreased electricity price	-30 % for all price components.	The amount of avoided electricity purchases decreases.	Negative 2,40–2,83 %
4. Increased electricity price	+30 % for all price components.	The amount of avoided electricity purchases increases.	Positive 1,88–2,09 %
5. Decreased solar system price	-30 % for all price components.	A decrease in initial investment cost.	Positive 2,26–2,53 %
6. Increased solar system price	+30 % for all price components.	An increase in initial investment cost.	Negative 1,54–1,69 %
7. Reduced VAT for solar systems	VAT to 10 % from 24 %.	A decrease in initial investment cost.	Positive 0,77–0,82 %
8. Removed VAT for solar systems	VAT to 0 % from 24 %.	A decrease in initial investment cost.	Positive 1,34–1,49 %
9. Lower solar irradiation	-10 % solar irradiation.	Lower annual solar production with increased amount of purchased electricity from the grid.	Negative 0,53–0,80 %
10. Higher solar irradiation	+10 % solar irradiation.	Higher annual solar production with decreased amount of purchased electricity from the grid.	Positive 0,49–0,71 %

6.3 Results of the sensitivity analysis

Comparing consumption profiles reveals the differences in the usage of generated PV electricity, illustrated in Figure 36. High consumption profile allows very good self-consumption rates for generated PV electricity compared especially to low profile. Additionally, demand response has a visible impact on the total solar surplus, which is fed to the grid with less economic benefit than if it was self-consumed.

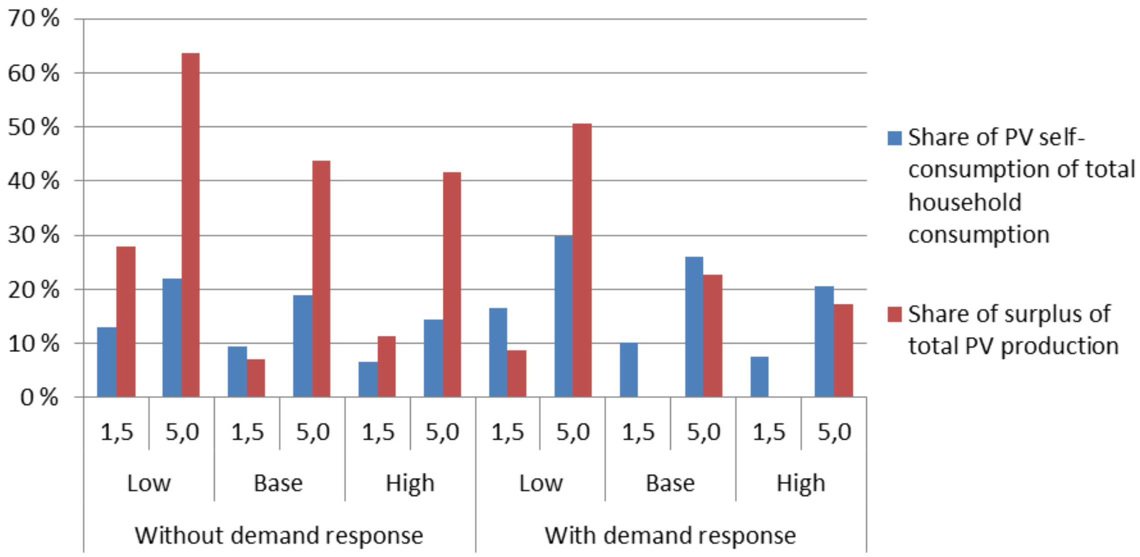

Figure 36. Sensitivity analysis conducted with three different consumption profiles, with and without demand response. Solar system sizes (x-axis) chosen for this analysis were 1,5 kW and 5 kW. Solar irradiation with 857 peak load hours and consumption occur in profile households in Lahti, Finland. Total annual consumptions are 7 102 kWh, 12 715 kWh, and 17 225 kWh for low, base, and high profile, respectively. Total annual solar production for a 1,5 kW system is 1 287 kWh and 4 289 kWh for a 5 kW system.

Even though Figure 36 demonstrates the end-usage of all electricity flows, it provides little practical information from the economic point of view. Therefore, different scenarios' impact on the internal rates of return was studied to find the biggest positive and negative drivers for returns. A total of 10 different scenarios were studied and the rates of returns were compared to the reference levels of each consumption profile with small and large solar system of 1,5 kW and 5 kW. Reference levels for this sensitivity analysis are presented in Table 15 and results from the 10 scenarios in Figure 37.

Table 15. Reference level assumptions and internal rates of return (IRR) for all consumption profiles with small and large solar systems on the household rooftops in Finland. IRR calculated for 25 years of solar system operation.

Consumption profile	Solar system size	Solar system unit price	IRR
Low	1,5 kW	3,42 €/W	-3,99 %
Base			-2,96 %
High			-3,10 %
Low	5,0 kW	2,54 €/W	-3,01 %
Base			-1,76 %
High			-1,64 %

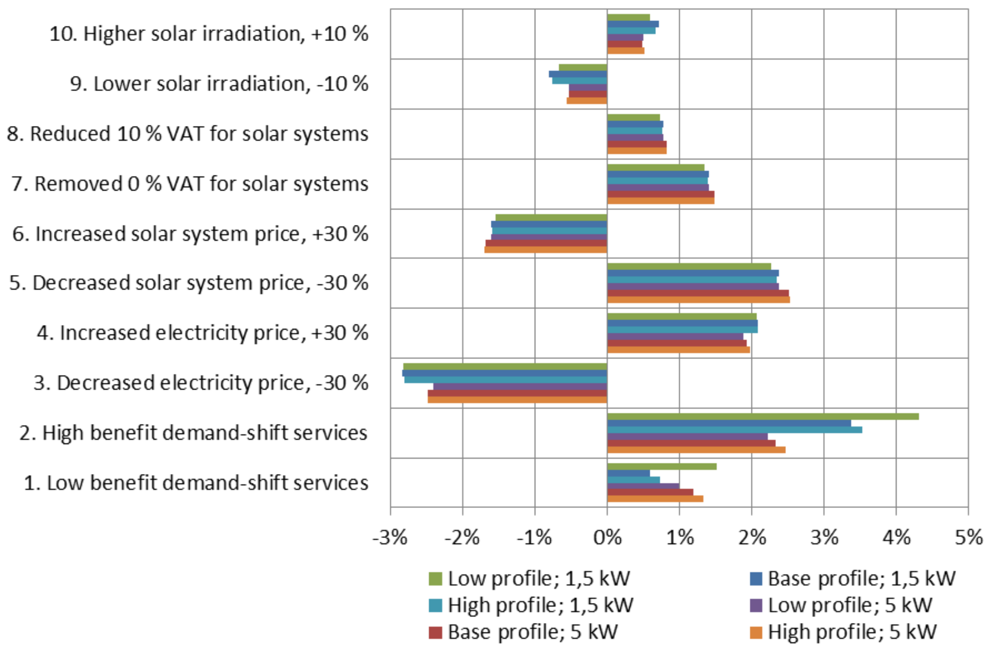

Figure 37. The impact of a given scenario on the IRR as %-point difference from the given reference levels of Table 15. Sensitivity analysis for internal rates of return for 10 different scenarios for all consumption profiles with small (1,5 kW) and large (5 kW) solar system.

IRR differences shown in Figure 37 clearly reveal the biggest opportunities and threats for household solar system returns. It can be concluded from the analysis that low electricity price is the single biggest threat for returns. However, system price decrease of 30 % improves IRR more than electricity price increase of 30 %. As for bigger 5 kW solar systems, -30 % price reduction translates into a unit price of 1,78 €/W that already is reality in the mature market of Germany and therefore could be reached in Finland as well in the near future (BSW-Solar, 2013).

The amount of benefit that could be reached by giving VAT reductions for household solar systems is worth noting. 10 % VAT would improve IRRs by over 0,5 %-points as 0 % VAT could improve IRRs by nearly 1,5 %-points. Reduced VAT is somewhat likely scenario as it is relatively easy to execute and the supportive political climate towards sustainable future exists.

Several of the scenarios studied are relatively unlikely or include high uncertainty. Scenarios 1 and 2 are one of the least likely as regulation trading and its benefits along with demand response activities include high uncertainties in execution and no large-scale solutions yet exist. However, both regulation trading scenarios generate IRR improvements in the range of 0,5–4,5 %-points so high risk comes with relatively high reward. Solar system price increase of 30 %, scenario 6, can be considered as quite unlikely as increasing installation volumes only drive system prices even lower. Only total solar market slowdown could lead to opposite results, which is basically impossible in Finland as only negligible volumes yet exist (EPIA, 2013a).

Additionally the best case scenario was analyzed for Finnish household. The best case scenario includes assumptions of higher solar irradiation levels, 0 % VAT, 30 % decrease in the solar system pricing, high benefit demand-shift services, and 30 % increase in electricity price for a high consumption profile household with a large 5 kW solar system. The following assumptions generated an IRR of 8,64 %, which is an extremely attractive level of return for an investment for a household. That big of returns would generate more than double the value for investors than the average company in Finnish stock exchange as dividends in 2008–2013. The approach used in this best case scenario is very possible in the coming years. Higher solar irradiation levels could be reached in the sunniest regions in Southern Finland, VAT could be excluded from solar systems by politicians due to the sustainable global mindset, and 30 % decrease in solar system prices is just a matter of time[65] and market advancements. Increase of 30 % in electricity price is also possible, as recently as in 2011, the household retail prices were 155,70 €/MWh and 294,20 €/MWh, for Finland and Denmark, respectively (EPIA, 2013b). These prices are actually over 35 % and 160 % higher, respectively, than the average total price[66] of 113,00 €/MWh that was used in the sensitivity analysis. Therefore room for electricity price hikes do exist in Finland. Lastly, the availability of high benefit demand-shift services and the existing profits are in the hands of companies in the energy industry, which is very well recognized by the utilities struggling with profitability in ever challenging market conditions.

In the individual scenario sensitivity analysis, only scenarios 2, 4, and 5 produced some all-the-way positive IRRs. Despite some improvements in other scenarios, they were not sufficient to raise the IRR above zero levels. All actual IRRs are presented in more detail in *Appendix 6. Sensitivity analysis for consumption profiles*.

[65] According to (SEMI, 2014), as cumulative solar installations double, the average module selling price decreases with a learning rate of about 21,5 %.
[66] The price used was based on the retail electricity pricing of Fortum at the beginning of 2014.

6.4 Country comparison

The business case for residential solar power for Nordic countries is not the most optimal in worldwide comparison; the electricity consumption peaks do not match with solar production, and both electricity prices and solar irradiation levels are relatively low. Therefore to illustrate these differences, the same simulation model was conducted for two additional European countries: Germany and Italy.

For hourly solar irradiation data, PVWatts platform was used for Italian data and real life solar power output data for 2012 from ZEMA platform was extracted for Germany[67]. Italian data was collected from Naples[68] with an annual yield of 1 388 kWh/kW$_p$ that matches Massi Pavan & Lughi (2012) values for Central Italy solar yields. Real life solar production data from Germany resulted in an annual yield of 973 kWh/kW$_p$.

The household consumption profile in this simulation was assumed to equal nationwide load profile for 2012, obtained from ENTSO-e transparency platform (ENTSO-e, 2014). Electricity retail prices were assumed at 0,292 €/kWh and 0,229 €/kWh for Germany and Italy, respectively (Eurostat, 2013). The non-avoidable, fixed fees' share of total electricity costs was assumed at 5,25 % for Germany and at 6,75 % for Italy (EPIA, 2013b). This results in avoidable electricity cost of 0,277 €/kWh in Germany and 0,214 €/kWh in Italy. Feeding surplus solar production into the grid is assumed to receive the average spot price for electricity. For Germany, this was in 2013 on average 0,038 €/kWh[69] and 0,063 €/kWh[70] for Italy.

To estimate the annual household electricity consumption in 2012, the total electricity consumption for households (Eurostat, 2014a) was divided by country population (Eurostat, 2014b) to produce an electricity consumption factor for households. This index was then used to estimate the annual household consumption in the given countries, presented in Table 16.

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[67] Actual production data was normalized by total production capacity. This production data is highly distributed across Germany, thus providing more balanced production data than single location.
[68] Performance ratio of 0,75 and tilt angle of 30° was assumed for PVWatts data.
[69] Spot price average for Germany in 2013 was obtained from EEX Transparency Platform (EEX, 2014) through the ZEMA platform.
[70] Spot price average for Italy in 2013 was obtained from (GME, 2014).

Table 16. Household electricity consumption data by given country in 2012 (Eurostat, 2014a; Eurostat, 2014b) used to estimate the annual household consumption for Germany and Italy.

Country	Total electricity consumption [TWh]	Total population	Total electricity consumption per capita [kWh per capita]	Electricity consumption factor	Annual household consumption [kWh]
Finland	22,24	5 401 267	4 117,55	100,00 (reference)	12 715
Germany	137,00	80 327 900	1 705,51	41,42	5 267
Italy	69,46	59 394 207	1 169,47	28,40	3 611

For the investment analysis, investment costs for both Germany and Italy are needed. The residential PV system cost was already determined for Germany, and Tudisca, et al. (2013) suggest that Italian residential PV system costs are 2,5 €/W as Massi Pavan & Lughi (2012) suggest a range of 2,2–2,4 €/W added with reduced VAT of 10 %. For conservative analysis, the higher value of 2,5 €/W plus 10 % VAT was assumed for smaller systems. As was stated before, smaller systems are assumed to be 35 % more expensive than larger systems, due to reduced benefit from economies of scale. Assumptions and results are presented in Table 17.

Table 17. Internal rates of return for residential PV systems in different countries with their given price and solar irradiation levels. Used consumption profiles represent average household consumption rates derived above. IRR calculated for 25 years of solar system operation.

Country	System size	Local investment cost[71]	Annual yield	IRR
Finland (Tampere)	1 470 W	3,42 €/W	858 $\mathrm{kWh/kW_p}$	-2,98 %
	4 410 W	2,54 €/W		-1,56 %
Germany (whole country data)	1 500 W	2,21 €/W	973 $\mathrm{kWh/kW_p}$	11,69 %
	5 000 W	1,70 €/W		8,15 %
Italy (Naples)	1 500 W	2,75 €/W	1 388 $\mathrm{kWh/kW_p}$	7,71 %
	5 000 W	2,04 €/W		5,88 %

The country comparison reveals distinct differences between circumstances; the effects of electricity price and solar irradiation levels appear to have significant impact on the return levels. Even though the annual consumption of households is generally lower in Southern Europe, IRRs of over 10 % for small scale systems in Germany do represent a major business case for any household with regular consumption and rooftop available for a solar system installation. The bigger solar system sizes suffer in comparison of the lower self-

[71] VATs are included for Finland and Italy, 24 % and 10 %, respectively. Large systems are assumed to be, in line with Finnish pricing, 35 % more expensive than smaller systems. The German residential solar installations are exempted from VAT (Seel, et al., 2013).

consumption rate as the most economical approach is to maximize self-consumption. All of the cases calculated represent very good investment opportunities for any households since they protect the wealth of a household from erosive inflation and additionally provide highly attractive returns.

The returns for residential solar power are very high for the calculated cases of Germany and Italy, but in the future, TSOs or governments might introduce additional costs to cover some of the nationwide system costs, which would negatively impact the returns. This has already taken motion in Germany where officials, including Chancellor Merkel, have backed up a plan to charge small renewable energy plant owners for their own use of electricity. Similar plans have been laid out in Spain and several U.S. states. (Bloomberg, 2014)

The scope of this study does not cover the demand-shift capabilities of German or Italian households, but as a learning from earlier sections of this study, these return levels could be further improved by implementing automated and intelligent demand response systems. This is due to the relatively low consumption of the Southern European households, which results in lower self-consumption rates than in Northern Europe. It is worth noting that these return levels do not take into account any subsidies or economic incentives, apart from the VAT exemption in Germany and reduction in Italy. Therefore, the constant development in cost reduction for both modules and installations will very likely drive residential solar system market towards even larger volumes and more attractive business cases.

7 Discussion

The simulation executed for this thesis contains various parameters, which all contain significant amount of uncertainties. Therefore, this study does not intend to be ultimately correct nor precise with its results, but instead give guidelines on how to approach the big picture and included obstacles.

The extensive introduction of solar power to Nordic countries, despite the smart solutions presented in this study, will be a difficult task. Non-attractive solar irradiation levels and underdeveloped solar value chain combined with especially low electricity prices produce a challenging business case for solar. Despite these factors, the returns for smart solar solutions could combine different revenue models and provide all participants attractive investment opportunities. By taking full advantage of sophisticated automation, remote control opportunities, mobile user interfaces and other user experience improving services, the future of smart living and distributed energy generation could be revolutionized.

One of the biggest obstacles for major solar power market penetration is regulated electricity around the world. Artificially low electricity prices can be achieved by government subsidies, which makes solar power less attractive of a business opportunity, as showed in the section 6, *Sensitivity analysis*. According to EPIA report, household electricity post-tax price in 11 European countries without regulated prices[72], was in 2011 on sample average 175,50 €/MWh. At the same time the regulated prices in 12 European countries[73], where over 90 % of all households had regulated prices, the sample average was 143,60 €/MWh. It seems that, on average, the non-regulated electricity is over 20 % more expensive than regulated electricity in Europe. In the *Sensitivity analysis*, it was studied that 30 % more expensive electricity led in Finland to nearly 2 %-points higher IRRs for residential solar systems. Therefore it can be concluded that the price regulation does have significant impact on the overall attractiveness of solar power. (EPIA, 2013b)

One of the biggest benefits from the grid point of view is the distributed nature of rooftop solar power. As current electricity infrastructure relies on relatively large power plants to provide the required electricity, small power plants distributed across the country could

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[72] These 11 countries in 2011 were Austria, Czech Republic, Finland, Germany, the United Kingdom excluding North Ireland, Latvia, Luxembourg, Netherlands, Norway, Slovenia, and Sweden.
[73] These 12 countries in 2011 were Bulgaria, Cyprus, Estonia, France, Greece, Hungary, Lithuania, Malta, Poland, Portugal, Romania, and Slovakia.

provide more secure power supply. A sudden outage from a large power supply usually leads to grid stability issues, or even blackouts, but much more distributed infrastructure could be more flexible and dynamic in such cases. However, the quality of forecasting solar power should still improve significantly, but as pointed out in this study, predictions on large geographical areas can already provide relatively accurate estimates with smaller range of uncertainty.

Considering the amount of high uncertainties in parameters and seasonal variations, it would be justified to apply so called A-B testing for the flexible energy management field testing. In this context, A-B testing could consider more than two subgroups of which every subgroup would have different parameters in use for the application. It would also be highly beneficial to gather information of the consumer feedback on the impacts of the demand side management: did the consumers notice anything, and if they did, what kind of actions led to the notable changes. This way vast amounts of empirical data could be obtained simultaneously, at the same time allowing benchmarking the validity of parameters used. The value proposition should be balanced between supplier and consumer so that both parties would receive an acceptable amount of compensation for their participation.

It was also studied that large share of solar penetration in the electricity mix does not remove the premium solar power receives during day time. Inevitably, the overall electricity price has dropped in Germany due to the subsidized large scale introduction of variable energy sources, such as solar and wind, but the average price for sunshine hours has not plummeted, even with over 17 % share in the electricity mix for some summer months. On the demand side, as cheap electricity is introduced for sunshine hours, it attracts more consumption, which balances the increase on the supply side. Simultaneously, as the electricity price declines for sunshine hours, power plants of highest variable cost structure start running at a loss, which naturally cuts the capacity on the supply side. This means that changes, which large shares of solar power introduce for electricity grids, are balanced on many fronts. Despite the aforementioned balancing, the development in both flexible energy management and storage are required for large-scale adaptation of solar power to help with frequency-related challenges in the grid.

The findings of this study show that there is significant potential within residential segment to have a part in virtual power plant concept as an adjustable aggregated load.

8 Conclusions

8.1 Overview of the results

Flexible energy management and solar-related business opportunities for households in Finland were studied in this thesis, with some background study of the fundamentals supporting the business cases.

As the results from real life material from the mature solar market of Germany and scientific literature indicated, the forecasting of solar power with already existing tools and methods is possible in a given range of uncertainty, especially if the solar power production is distributed geographically over large area. Therefore, demand response aggregation or virtual power solutions might be easier to operate with solar power, than is currently believed by common opinion. Normalized mean absolute error of 2,59 % and root mean square error of 4,34 % for the time period between 8.00 and 20.00 were found for Germany's four transmission areas' solar production in 2012. The spatial distribution of generating units basically eliminates drastic ramp rates and reduces the negative impact on the frequency and stability of the grid. Improving the accuracy of solar forecasting was also studied to have a significant impact on the balancing costs because improved intraday forecasts were calculated to save up to 4,43 €/$MWh_{produced}$ in Germany in 2012. It was also found that despite the high solar penetration in the German electricity mix, which was over 17 % in July of 2013, the electricity price for the hours of sunshine still remained over 3 % higher than the average daily electricity price over the time period.

To increase understanding on the household consumption patterns in Finland, an hourly consumption analysis was conducted. By combining consumption and weather data from various databases, four different consumption profiles were generated: low, base, high, and aggregated. These actual households were located in Finnish cities of Jyväskylä, Kajaani, and Lahti to represent detached houses of different sizes. This consumption data was then broken down into shiftable and non-shiftable loads to determine the available capacity for different business opportunities. It was found that there is a clear mismatch between solar production and household consumption, thus demand response could significantly improve the self-consumption rates in Nordic countries. Battery solutions were not found to be competitive against demand response capability to cost-efficiently increase the amount of self-consumption for households.

Another value adding approach is to include households in demand response programs. To capture the biggest value with the minimal demand response effort, the upward regulation trading was chosen to be the approach for aggregated household portfolio, or the virtual power plant concept. It was calculated that over 100 € per household per year is achievable with upward regulation trading for a portfolio with 55 000 households that equals the minimum demand response capacity of 10 MW for every hour of the year. However, a moderate annual compensation of 50 € was used in the base case analysis.

The economic evaluation of Finnish household solar installations showed that solar alone does not currently represent an attractive business case with IRR range between -1,64 % and -3,99 %, price inflation being assumed at 2,0 %. However, by implementing demand response activities, bigger systems in Finland would be IRR positive. If the pricing level of Germany applied in Finland, it could be possible to reach over 1 % IRR for solar installation with demand response services.

Conducted sensitivity analysis and country comparison showed that electricity and solar system prices have a huge impact on the profitability of the household solar system, both having a positive impact of nearly 2 %-points on the IRR with given realistic scenarios in Finland. Additionally, political support in form of reduced VAT could further improve the economics of solar in range of 0,5–1,0 %-points on the IRR in Finland. Country comparison showed that residential solar is already very attractive in Germany and Italy, which had IRRs of 8,15–11,69 % and 5,88–7,71 %, respectively. These returns represent very good returns for any household as bank deposits gain under 2 % annually. The best case scenario that was found to be plausible for Finnish households in the near future, resulted in an impressive IRR of 8,64 %.

This study proved that viable solar-related business cases currently do exist in Europe without subsidies, just not yet in the Northern Europe. Demand response potential in Northern Europe is attractive, but the same does not apply to residential solar installations. The barriers are however variables, such as solar system and electricity prices, that could easily change the direction towards more positive returns, which coupled with demand response services could provide smart homes of the future very attractive business cases and stable electricity networks for societies.

8.2 Business opportunity proposal

The main incentive for conducting this study was to find an approach to make viable flexible energy management and solar-related business cases for households in Finland, but also in the rest of Europe.

It was concluded in the section *5 Results* that it is possible for households in Finland to reap benefits by combining different revenue models. As no single approach created sufficient business case, a combination of different services should be used. It was found that there is a great match between high value regulation electricity trading and solar power surplus since the former occurs during winter months and the latter during summer months. By combining these models into one product would save costs and maximize the benefits.

Providing sophisticated and automated demand response infrastructure, activities, and services require high technology products, which could also be relatively easily applied for customer experience purposes. Remote control of lighting, indoor temperature, security, or control over other miscellaneous purposes, such as electric vehicle charging in the future, could be implemented in the same offering as the essential equipment required in demand response. The total cost of the offering would supposedly increase very slightly[74] but the added value for household customers could increase dramatically due to extensive synergy benefits. This approach, named Home Unified Services, has also been supported by McKinsey consulting as a one of "twelve companies of tomorrow" in their *Quarterly Report March 2014*, *Are you ready for a resource revolution?* (McKinsey, 2014). This kind of approach would both maximize the attractiveness of the offering for customers and increase sources of revenue, thus profits, for the supplier. Full smart home solutions could be easily first piloted in the Nordic countries, since the transparent electricity market enables such tryouts, and later to be introduced for larger markets.

Instead of just selling a solar system, selling a whole smart home system with services could be the winning end-customer value proposition of the future. In brief, even moderate economic benefit with a high quality user experience generates significant global potential and should be considered by a modern electricity company as a part of future's business models.

[74] Since demand response services already require load control and constant data transfer, only user interface should be added, which is supposedly very moderate cost addition of the total.

9 Limitations

The topics presented in this study have just recently gained public attention, thus these topics are not yet extensively covered by various publications. Therefore many limitations were created by several assumptions applied. Especially the segment chosen, consumption data, solar production data, solar forecasting, and possible grid issues were covered in a very limited manner.

The household segment was chosen for this study due to the availability of relevant material, hourly consumption data. Additionally, households are relatively standardized with basic needs of indoor heating, lighting, domestic water and appliance usage. Despite the availability of the data, this hourly data was broke down using total annual consumption by end-usage points. Therefore, several assumptions had to be made regarding household consumption patterns to create an hourly breakdown from the theoretical total consumption. In the best case, an actual household data in large quantities would be available and the economic potential assessment would be made based on that data instead. It has to be recognized that commercial sector has huge potential[75], but at the same time it introduces challenges with non-standardized and classified processes. These processes could possible equal the economic flexible energy management potential of thousands of households.

The solar industry is still relatively new segment with limited amount of available public data. Luckily, the mature market of Germany provided real life solar production data but for Finnish application, third-party compiled data of NREL had to be used. The most accurate simulations could be conducted with actual production data over several tens of years in several locations, which was unfortunately not available for this study. Even though the fundamentals and challenges for solar production forecasting were introduced, for Finnish solar power production, some actual forecasts and their materialized errors would provide more depth into the analysis. In this study, it was assumed that demand-shift enabling party would have perfect forecasts of the solar irradiation levels for the next day. This data was used for demand-shift capability purposes to mitigate the solar production surplus for households.

[75] The demand response potential, especially in commercial sector, is further studied in (Gils, 2014).

One of the biggest challenges related to variable renewable energy are the grid issues. Some of these issues were introduced in this study, but were not taken into account in any further analysis. Especially aggregation-related services require detailed analysis on the impact to the grid; will there be reverse energy flows, or will the stability of the grid be otherwise endangered. However, this kind of analysis requires deep and detailed understanding of the nature of electricity networks, which was not the starting point for conducting this study.

Flexible energy management and VPP related calculations of this study concentrate on the easiest approaches to retain the biggest gains; the on/off adjustments required by regulation trading at the Nordic electricity market. However, one of the biggest values could be retained by participating to the frequency controlled market. Despite the largest value, it is also the most difficult to execute because the stress on the equipment adjusted is high due to constant load adjustments. Additionally, it has to be tested on the field how accurately a large fleet of small independent load points (households) react in the required time and with the required amount. Despite the lack of this evaluation in the detailed analysis, the range of demand-shift benefits used in the investment analysis has a large buffer so successfully implementing frequency controlled models would make the high benefit scenario a more probable case.

As the simulations conducted in this study were numerous and somewhat complex, most of the calculations were conducted independently, thus no overlapping effects were studied in most cases. The most realistic results would be achieved by combining different approaches and studying their impact on the overall performance of the approach chosen. However, as long as no detailed real life consumption data or demand-shift experience exist, it is somewhat unnecessary to conduct analysis of high complexity, as much more could be learnt from actual pilots with relatively small expenses.

All energy business is highly affected by country specific regulation and politics. Despite the fact that demand response regulation in Finland was taken into account in this study, it is important to understand the European political climate towards demand response business models. Since this exceeds the scope of this study, more details of the current state, critical points and future developments of demand response at the scale of Europe can be found from *Appendix 7. The political climate in Europe for demand response*.

10 Future research

Due to the vast scope executed for this thesis, many of the aspects researched were not possible to carry out with the highest detail. This study aims to create a roadmap, or guidelines, for future opportunities, thus the results simulated are indeed indicative and hypothetical. This leaves plenty of room for future research, where same aspects would be studied with higher level of detail.

The household consumption model was delivered as an approximate simulation and the need for variables was minimized in order to achieve needed results with reasonable workload in relation to other important topics of this study. Focusing on simply modeling the household consumption would enable the use of several different consumption profiles and increase the amount of variables and their dynamics. This would result in more realistic figures of both the consumption profile and the usage profiles of different appliances.

Alternatively, testing the findings in this study with real life demonstrations for household energy management could prove extremely valuable. Most critical subjects for this kind of demonstration would be verifying the amount of available flexible energy capacity in different households, and verifying the existing economic potential. Also, the reliability of remote and automated demand response, in addition to the whole communication infrastructure, should be extensively verified before any commercial launches.

In addition to technical research, the psychological aspects of such business opportunities should be studied. The range for comfort varies between households, and to gain maximum benefit from the business case, all different customer needs and requirements should be studied and later taken into account when making business with automated flexible energy management. Especially indoor temperature and domestic water consumption are delicate matters for households and may vary significantly between customers. These ranges of comfort should be mapped and business models designed to fit these different needs.

As the whole study concentrated on the flexible energy management for households, it is also very important to expand the scope in the future on the commercial and industrial scale, which potential is extensively studied in for example (Gils, 2014). Bigger companies have larger scale, thus larger potential. Flexible energy management advancements could be thus driven alternatively by the volumes of several segments in the near future.

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APPENDICES

Appendix 1. Linearized nominal PV capacity in Germany 2012

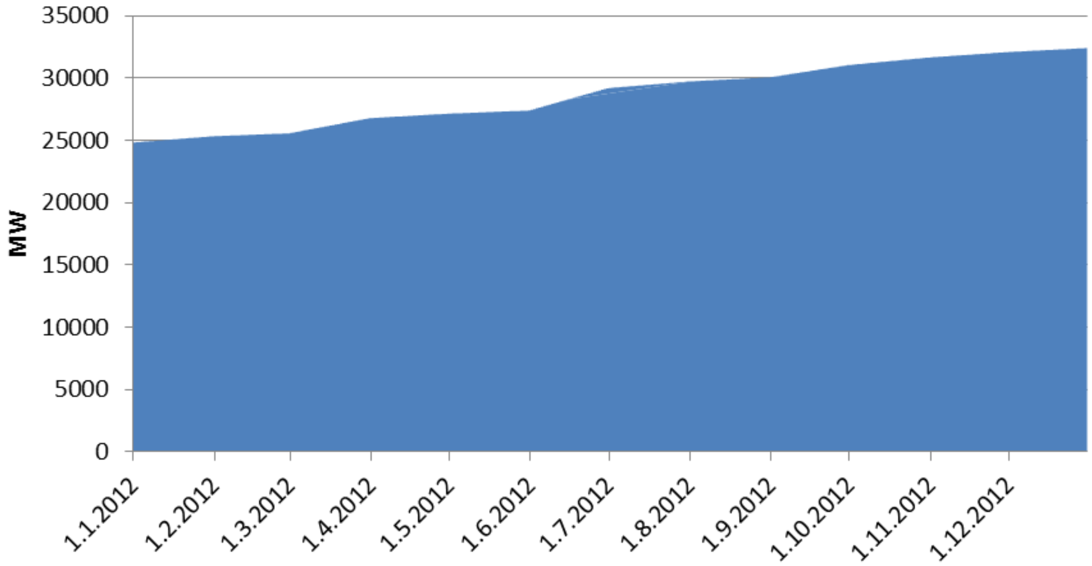


Figure A 1. For normalization purposes, the PV capacity of Germany in 2012 was interpolated for every hour of the year. Data from (Bundesnetzagentur, 2013a), (Bundesnetzagentur, 2013b), (EPIA, 2013a), and (EPIA, 2012b) was combined to form monthly capacity additions from the end of 2009 until July 2013. The data for 2012 was then linearized so that from the beginning of a month until the end of it, the installation rate for PV was constant. This approach was chosen to create as real-life simulation as possible in the case of normalization because no sudden installation additions at the end of every month are involved.

Appendix 2. Household consumption profiles for 2012, Finland

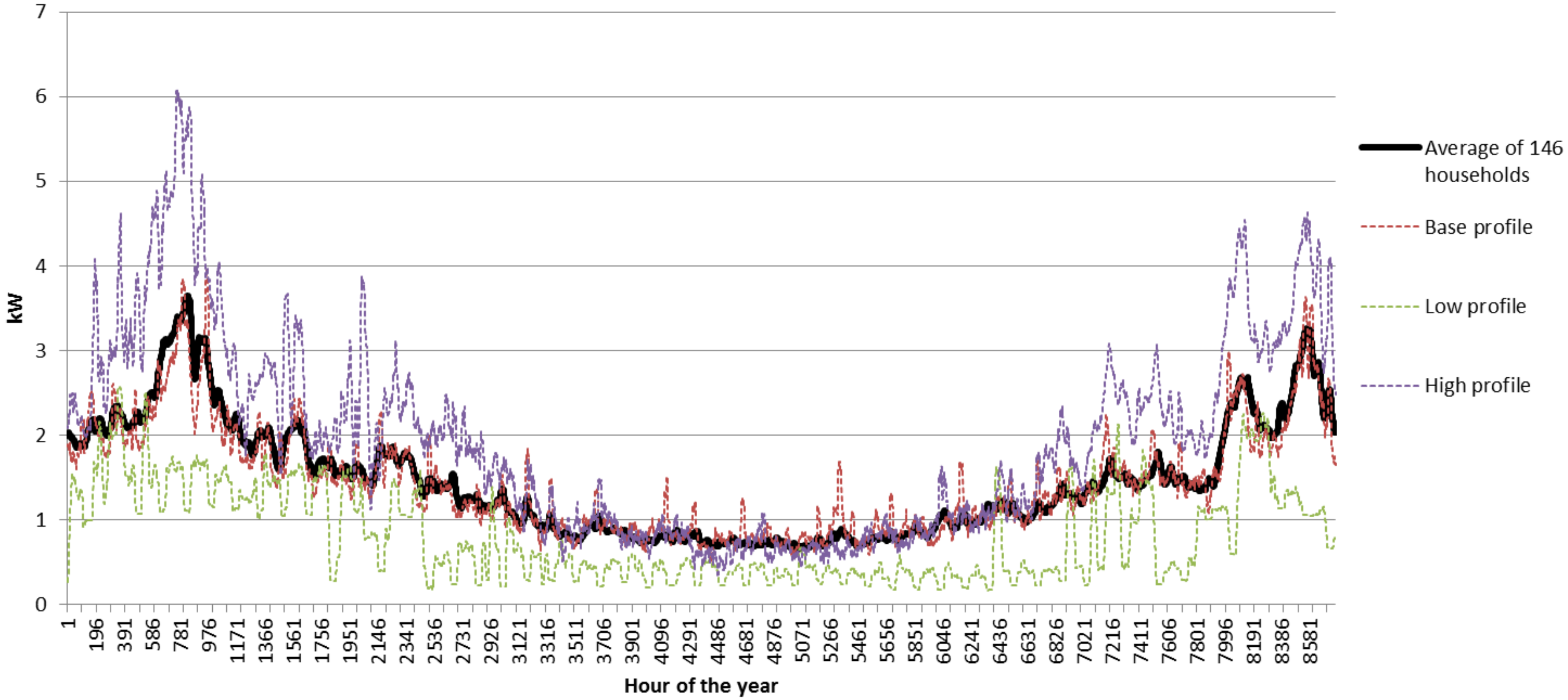


Figure A 2. Individual household consumer profiles were fetched from Fortum database (Fortum, 2013) for Lahti, Finland. For average profile of aggregated households data from Kajaani, Jyväskylä, and Lahti was used. Profiles were selected from a group of 146 households to present low and high profiles. For illustrative purposes, moving averages of 24 hours are used in this figure.

Appendix 3. Simulated household consumption breakdowns

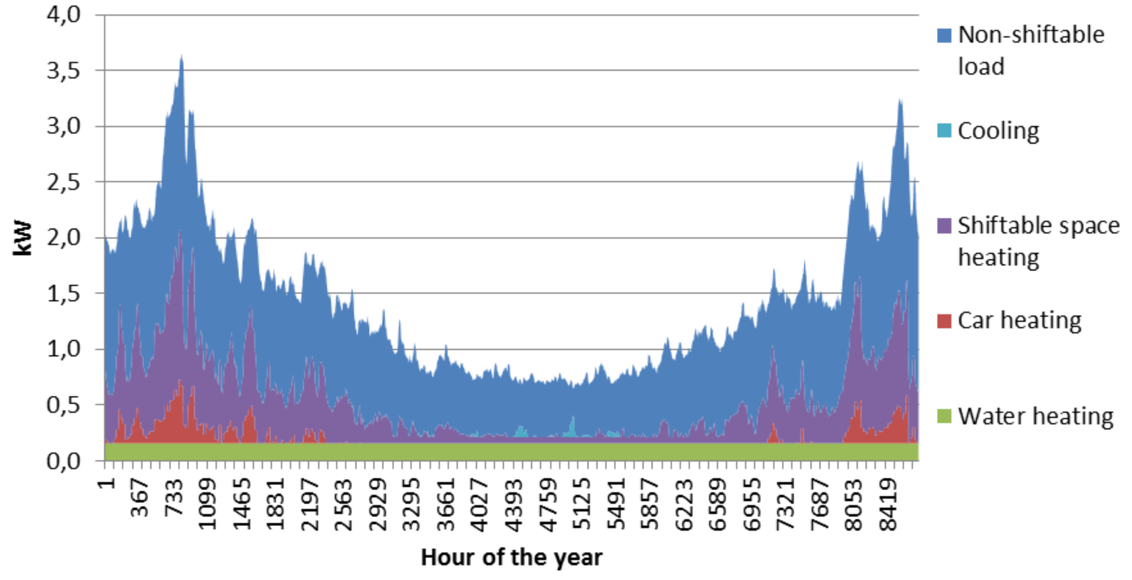


Figure A 3. Simulated electricity consumption breakdown for an average of 146 households as 24 hour moving average. Total annual consumption for the profile is 12 821 kWh.

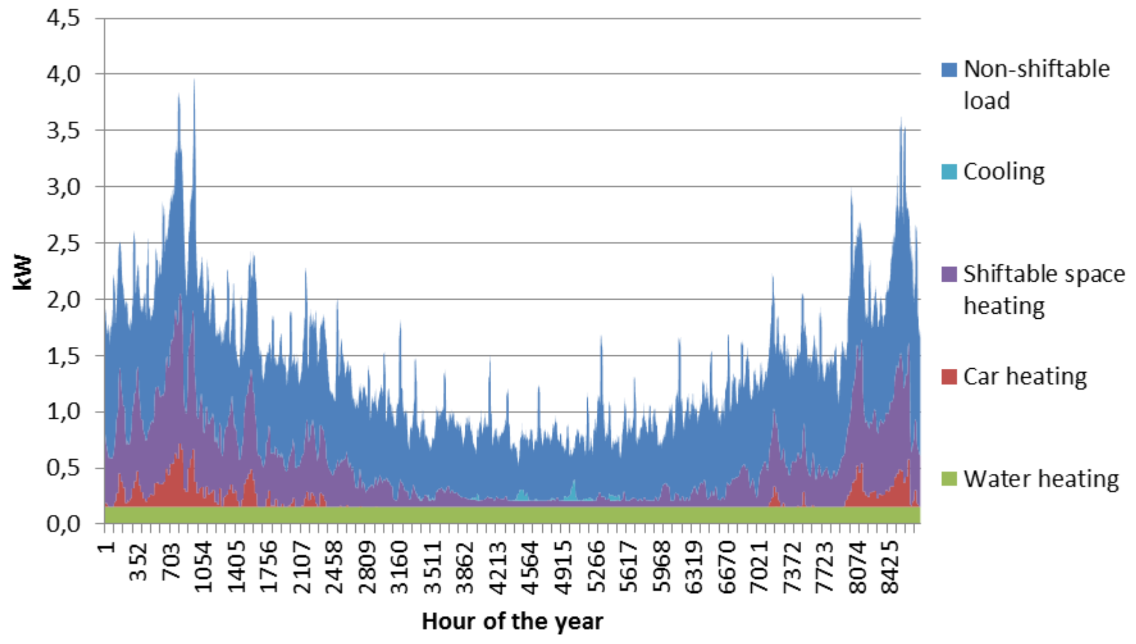


Figure A 4. Simulated electricity consumption breakdown for base profile household as 24 hour moving average. Total annual consumption for the profile is 12 715 kWh.

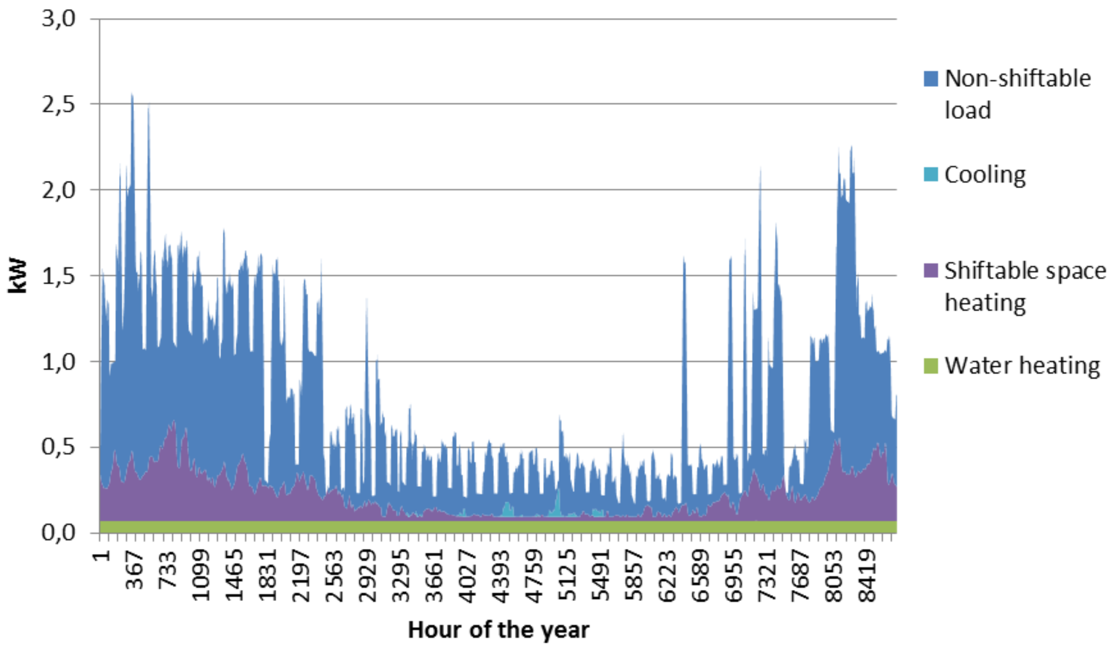


Figure A 5. Simulated electricity consumption breakdown for low profile household as 24 hour moving average. Total annual consumption for the profile is 7 102 kWh.

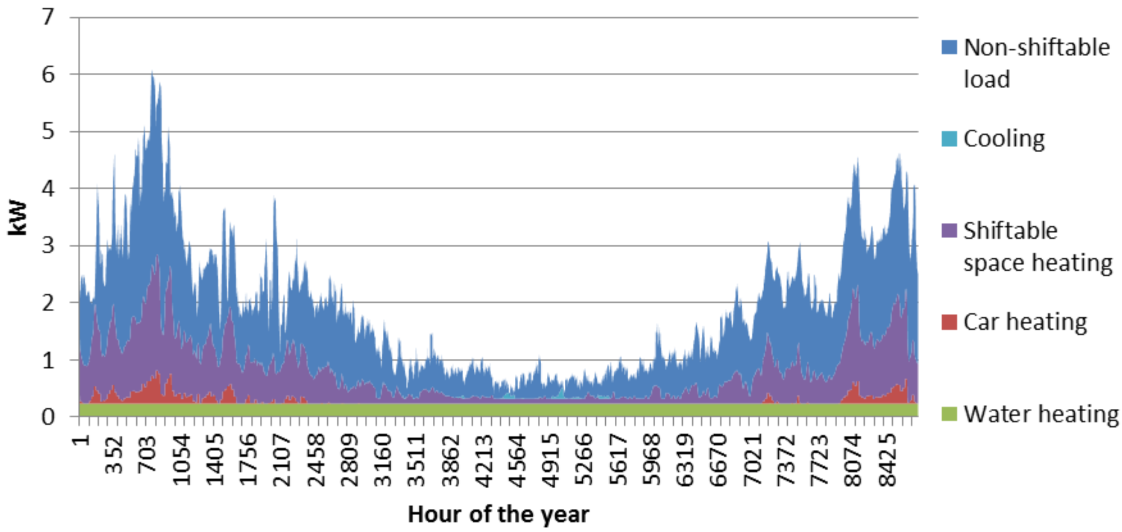


Figure A 6. Simulated electricity consumption breakdown for high profile household as 24 hour moving average. Total annual consumption for the profile is 17 225 kWh.

Appendix 4. Investment analysis calculator

PV system		
System size	1,47	kW
System production	857,743	kWh/kWp/a
CAPEX	3,42	€/W
Annual output	1261	kWh/a
Annual surplus	84,59	kWh/a
Degradation rate	0,5	%
System lifetime	25	years
Investment costs	5027,4	€
Maintenance costs	25	€/a
Demand-shift system		
Investment costs	0	€
Maintenance costs	0	€/a
System lifetime	25	years

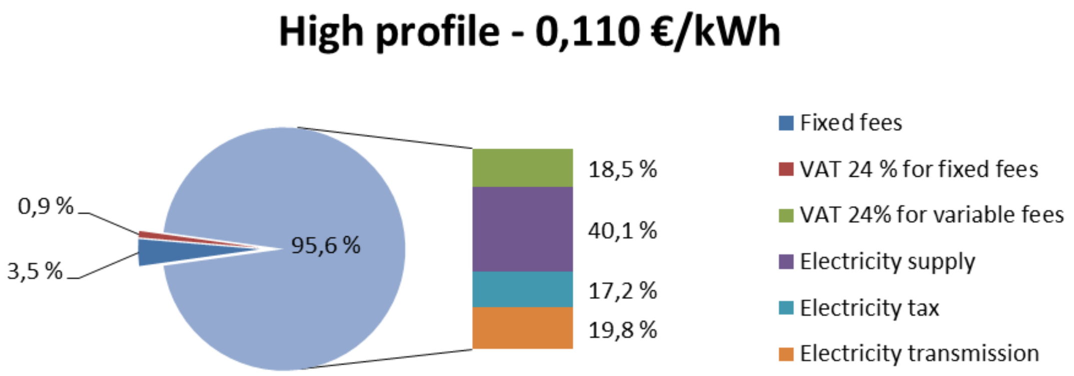
Financial assumptions		
Inflation factor	2,0	%
Customer elec price	0,106	€/kWh
Grid input price	0,042	€/kWh
Consumer data		
Total elec consumption	12715	kWh/a
PV to autoconsumption	1176	kWh/a
Elec purchased from grid	11539	kWh/a
PV to grid	85	kWh/a
Elec purchase included	N	Y/N
Regulation compensation	0	€/a

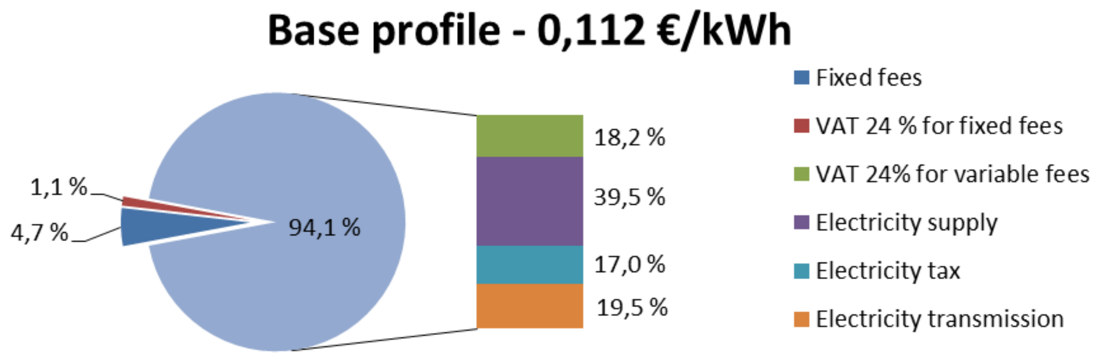
RESULTS	
Sum of cash flow	**-1 795 €**
IRR %	**-2,98 %**

Year		0	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**
Inflation factor		1,00	**1,02**	**1,04**	**1,06**	**1,08**	**1,10**	**1,13**	**1,15**	**1,17**	**1,20**	**1,22**	**1,24**	**1,27**	**1,29**	**1,32**	**1,35**	**1,37**	**1,40**	**1,43**	**1,46**	**1,49**	**1,52**	**1,55**	**1,58**	**1,61**	**1,64**
System degradation factor		1,00	**1,00**	**1,00**	**0,99**	**0,99**	**0,98**	**0,98**	**0,97**	**0,97**	**0,96**	**0,96**	**0,95**	**0,95**	**0,94**	**0,94**	**0,93**	**0,93**	**0,92**	**0,92**	**0,91**	**0,91**	**0,90**	**0,90**	**0,90**	**0,89**	**0,89**
Production																											
PV total production	kWh		1261	1255	1248	1242	1236	1230	1224	1217	1211	1205	1199	1193	1187	1181	1175	1170	1164	1158	1152	1146	1141	1135	1129	1124	1118
PV to autoconsumption	kWh		1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1175	1170	1164	1158	1152	1146	1141	1135	1129	1124	1118
PV to grid	kWh		85	78	72	66	60	53	47	41	35	29	23	17	11	5	0	0	0	0	0	0	0	0	0	0	0
Purchases																											
Electricity purchased	kWh		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Customer electricity price	€/kWh		0,11	0,11	0,11	0,11	0,12	0,12	0,12	0,12	0,13	0,13	0,13	0,13	0,14	0,14	0,14	0,15	0,15	0,15	0,15	0,16	0,16	0,16	0,17	0,17	0,17
Cash flow analysis																											
PV consumption benefit	€		127	130	132	135	138	140	143	146	149	152	155	158	161	165	168	170	173	175	178	181	183	186	189	192	194
Elec sales to grid / regulation	€		4	3	3	3	3	3	2	2	2	1	1	1	1	0	0	0	0	0	0	0	0	0	0	0	0
Maintenance costs	€		-26	-26	-27	-27	-28	-28	-29	-29	-30	-30	-31	-32	-32	-33	-34	-34	-35	-36	-36	-37	-38	-39	-39	-40	-41
Elec purchases	€		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EBITDA			105	107	109	111	113	115	117	119	121	123	125	127	130	132	134	136	138	140	141	143	145	147	149	151	153
Depreciation			-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201	-201
Net income			-96	-94	-92	-90	-88	-86	-84	-82	-80	-78	-76	-74	-72	-69	-67	-65	-63	-62	-60	-58	-56	-54	-52	-50	-48
Initial investment		-5027,4																									
Depreciation			201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201	201
FREE CASH FLOW		-5027,4	105	107	109	111	113	115	117	119	121	123	125	127	130	132	134	136	138	140	141	143	145	147	149	151	153
Cumulative cash flow		-5027,4	-4922	-4815	-4706	-4595	-4482	-4367	-4251	-4132	-4011	-3888	-3763	-3635	-3506	-3374	-3240	-3104	-2966	-2827	-2685	-2542	-2397	-2249	-2100	-1949	-1795

Figure A 7. Investment analysis calculator with assumptions applied for calculations with Finnish price levels for small residential PV systems. Internal rate of return (IRR) can be found from the top right corner that is calculated from the free cash flow over the lifetime of the given system.

Appendix 5. Electricity price breakdowns





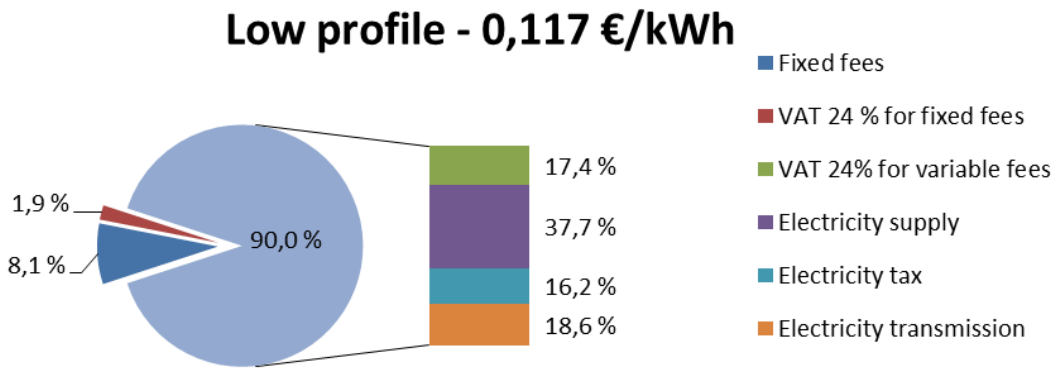


Figure A 8. Finnish household electricity price breakdown with separation into fixed and variable fees for three different consumption profiles: base, low, and high. The column on the right represents total variable fees that can be avoided by residential solar power production. Fixed fees needs to be paid for despite solar power self-consumption since additional electricity still needs to be purchased from the grid. Fixed fees also cause the differences between the electricity prices for different consumption profiles.

Appendix 6. Sensitivity analysis for consumption profiles

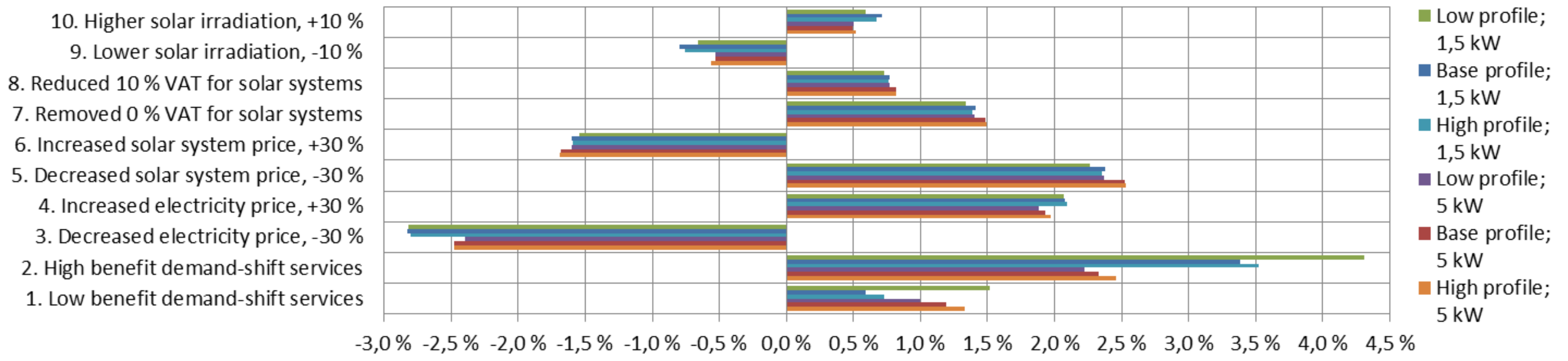


Figure A 9. The impact of a given scenario on the IRR as %-point difference from the given reference levels of Figure A 10. Sensitivity analysis for internal rates of return for 10 different scenarios for all consumption profiles with small (1,5 kW) and large (5 kW) solar system.

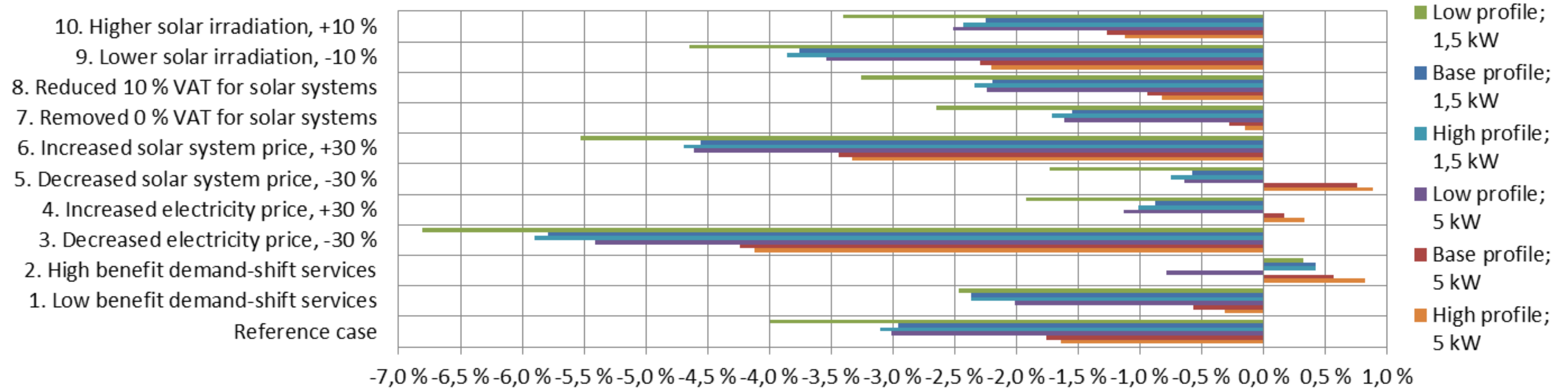


Figure A 10. Sensitivity analysis results for different Finnish household profiles as actual IRR percentages.

Appendix 7. The political climate in Europe for demand response

All energy business is highly affected by country specific regulation and politics. Despite the fact that demand response regulation in Finland was taken into account in this study, it is important to understand the future roadmap and the European political climate towards demand response business models overall.

A brand new report by Smart Energy Demand Coalition (SEDC), *A Map and Analysis of Demand Response in Europe Today* (SEDC, 2014) was published in Brussels, Belgium, during the event *EPIA-SEDC Conference on Consumers Empowerment* on March 19th, 2014. The report mapped regulatory structures in 15 European countries[76] to benchmark countries' efforts to improve access of consumers to demand response activities.

The Energy Efficiency Directive of EU requires TSOs and national regulators to allow consumers to participate demand response activities, enable actions of service providers, such as aggregators, and encourage demand response development. SEDC recognized in its report measurable progress between 2013 and 2014, but only Belgium, Great Britain, Finland, France, Ireland and Switzerland, resulting in 6 out of 15, were considered to be market areas with commercially viable demand response product offering within 2014. In the rest of the European countries, aggregated demand response activities were considered to be either illegal or otherwise impossible to operate due to country regulation. All countries were scored by four criteria: 1) Consumer access to demand response programs, 2) Existing demand response programs, 3) Demand response measurement and verification, and 4) Payments and penalties related with demand response participation.

The summary of the report, The Ten Rules for Successful Demand Response, highlight the importance of: easing demand response participation; increasing pricing transparency and the non-regulated role of aggregators; improving product and service unbundling; providing fair pricing of both penalties and compensations; establishing communication protocols; and legalizing all electricity markets where supply side participates.

Even though major regulatory advancements in some European countries have already been made, European wide and transparent market for demand response activities alone will finally unleash the full potential of cost effective flexible energy management.

[76] Evaluated countries and their overall score for 2014 in the report were Austria (12), Belgium (18), Denmark (7), Finland (14), France (18), Great Britain (14), Germany (8), Ireland (16), Italy (3), Netherlands (10), Norway (12), Poland (7), Spain (2), Sweden (12), and Switzerland (18), after (SEDC, 2014).