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THE POTENTIAL OF PEER-TO-PEER TRADING AND BLOCKCHAIN TECHNOLOGY IN A DECENTRALISED ENERGY NETWORK

A VALUE-BASED ANALYSIS

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Abstract

In this dissertation we analysed the current state of the Belgian electricity market and trends that will shape its future organisation. From this analysis we conclude that Belgium will face some significant challenges at the supply side, mainly due to the expected closure of its nuclear capacity. At the same time, this stresses the importance of an effective integration of renewable energy sources (RES) that are mostly decentrally located in the form of distributed generation (DG). However, the intermittent and unpredictable nature of these sources poses extra stress on the existing energy system. At the same time, untransparent and rigid pricing methods inhibit the unlocking of flexibility positioned at the consumer and prosumer level. With the goal of both integrating prosumers and at the same time increasing the efficiency of RES, we propose a peer-to-peer (PTP) set-up that enables participants in a microgrid to trade locally generated electricity. Our value-based analysis shows that such a set-up financially benefits those participants. Furthermore this set-up induces other demand side flexibility methods such as demand response (DR). Finally, we discuss the fitness of blockchain technology to fulfill the aggregator role in the proposed PTP network. We found that blockchain technology is not an exclusive solution in the previously defined market set-up. Depending on who takes on the aggregator role, blockchains could add more value than a traditional database system.

Woord vooraf

Deze thesis samenwerking was niet tot stand gekomen indien we niet op een avond onze fascinatie voor de energiemarkt en blockchain technologie deelden en besloten onze toenmalige thesissen te annuleren en samen te gaan schrijven. Een gesprek met Georges Lieben, CEO van June Energy, inspireerde ons om bij te dragen aan een betere integratie van duurzame energiebronnen. In combinatie met onze gemeenschappelijke interesse voor nieuwe technologieën hoopten we hierover een thesis te kunnen schrijven. Daarom willen we graag Prof. dr. Poels bedanken om ons de kans te geven dit onderwerp te onderzoeken. Tijdens het schrijven hebben wij alvast voldoening gevonden in het ontdekken van deze vrij complexe, en tegelijk uiterst interessante markt.

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Dankwoord Hannes *Dankuwel aan mijn ouders die mij vijf jaar ondersteund hebben tijdens het afwerken van deze studie — en dit nog een extra jaar zien zitten. En tenslotte, bedankt aan Jorn om met mij dit onderwerp te willen schrijven.*

Hannes en Jorn

Contents

Glossary

APS auction-based pricing strategy. 33, 34, 62, XI

ARP access responsible party. 6, 17, 18, 21, 22, 26, 32, 36, 38, 41, 48, 51, 90, 91, 97, 98, 100, 103, 104, 106, 109, 111, 115–117, IX, XII

BS bill sharing. 33, 62, XI

DG distributed generation. 1, 2, 10–12, 17, 18, 22, 26, 29, 37, 38, 40, 44, 47, 48, 53, 90, 109, 112, III, VII

DR demand response. 14, 22, 23, 31, 35, 36, 76, 90–93, 112, III, VIII

DSO distribution system operator. 6, 7, 18, 23, 26, 41, 42, 48, 51–53, 90, 110–112, 119

EMTS energy management trading system. 35, 64, VIII

ET export tariff. 2, 3, 34, 40, 42–44, 47–59, 61, 69, 76, 78–80, 83, 87–89, 93–95, 110, 120, VIII, XIII

EU European Union. 5–10

EV electric vehicle. 10, 37

FIT feed-in tariff. 40, 43, 44

GEC green energy certificates. 9, 10, 40, 43

IRR internal rate of return. 83–87, XII, XIII

MMR mid-market rate. 33, 34, 62, 70, 71, 97

NM net metering. 2, 3, 40, 43, 44, 47–59, 61, 69, 76, 78–80, 83, 87–90, 93–95, 111, 120, VIII, XII, XIII

PTP peer-to-peer. 2, 14, 27, 29, 34, 37–40, 44, 45, 51, 59–71, 76–83, 85, 87–94, 96–98, 100, 103, 106, 109–113, 120, III, VIII, XII, XIII

PV photo voltaic. 9–12, 17, 19, 20, 29–31, 37, 40–44, 52, 59, 61, 64, 69, 76, 78–83, 87, 93, 95, 96, 110, 111, 119, 120, XI

RES renewable energy sources. 1, 2, 8, 10–12, 14, 17–20, 22, 26, 29–32, 37–40, 44, 45, 109, 110, III, VII, XI

ROI return on investment. 44

SLP synthetic load profile. 23–25, 40, 69, 76, 77, 119, 120, XI

TSO transmission system operator. 6, 7, 16–18, 21, 22, 26, 36, 41, 48, 51, 90, 91, 97, 109–112, 115, 117, IX

WT wind turbine. 11, 12, 17, 19, 20

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Chapter 0

Introduction

0.1 Context

Management of the energy market in Belgium anno 2018 is a hot topic. In March 2018, the federal and regional governments have agreed upon a energy pact that will determine the strategic decision making in the energy market in the short to the long term. The agreement includes a closure of the nuclear power plants by the year 2025 and a transition towards more RES. The focus of this agreement and a significant portion of the literature is mainly on how the supply of energy must be organized in order to meet an exogenous demand. This paradigm mainly stems from the traditional organization of the energy market in which centralized power plants supply the energy market in a top down approach.

0.2 Problem statement

Energy systems of the future will be highly carbonized, distributed, democratized and digital. With a rise in ecological awareness came a rise in DG, forcing established market players to rethink the centralized and top-down approach. The intermittent character of DG sources results in increasingly difficult balancing responsibilities for grid operators. Meanwhile, there is little transparency at the demand side of the market, making it impossible to employ its flexibility for balancing purposes. Currently no efficient way - that reflects market dynamics - of integrating an increasingly amount of household solar photo voltaic installations into the grid has been found, retaining the need for a large base load capacity to secure the supply.

0.3 Research questions

The possibility of influencing consumer and prosumer behaviour with price signal that reflects local scarcity on the electricity market could increase the efficiency of the energy supply sources and decreases the overall need of energy generation which in turn results into a more efficient utilization of RES and ultimately lowered system costs. In this dissertation we investigate whether an energy market with integrated DG can potentially benefit from market- and pricing mechanisms that are as well decentral, located near the end-consumer. We analyse if a so called PTP energy trading network within a virtual micro grid results in both economical advantages for the total electricity grid, as well as financial incentives for participants in such a network.

1. How can PTP trading of electricity support a decentralized electricity network?
2. What is the value-based impact of PTP trading on the electricity market?
   (a) What is the value for consumers and prosumers?
   (b) What is the value for the supply side?
   (c) Is there a need for new market players?
3. Can blockchain serve as a medium to enable PTP trading of electricity?

0.4 Methodology

In order to find answers to the above defined research questions we start with a broad literature study to gain insight in the energy market organization, trends and challenges with a key focus the Belgian electricity market. After this broad study we form a clear problem statement and and perform a literature study investigating key technologies that have a high potential of tackling the found energy market challenges, focusing on the demand side. These technologies are micro grids, PTP trading, energy storage and demand response. The goal is to evaluate potential solutions and find a blueprint for a to-be decentralized energy market. Sufficient knowledge about these technologies allow us to model the value streams of the to-be PTP market. As a basis for comparing we use the NM, currently applied in Belgium and the expected to be implemented ET method. Supported by value-based modelling techniques all relevant value streams within these three different market set-ups are modelled. The models are then compared in a qualitative as well as in a quantitative manner by populating the models with parameters relevant to the Belgian electricity market. We define a set of participants and run multiple simulations to quantify the differences between the three given market set-ups in term of energy cost and profitability. The effect a changing market set-up on the revenue of the supply side is evaluated. For a more elaborate explanation of the calculation method we refer to chapter 5, section 1.2. Finally, based on this value-based analysis, we list the key requirements that need to be fulfilled in such a PTP network and based on literature and pilot projects evaluate if blockchain technology can or is required to facilitate such a market set-up.

0.5 Chapter overview

In chapter 1 we analyse the current state of the energy market. We discuss historic events that have led to the today's energy market, key trends and challenges that define tomorrow's energy market. This broad approach is essential to discover the dynamics that shape the energy market of the future. Chapter 2 is an introduction to micro grids and peer-to-peer trading, both having the potential of tackling the challenges that were mentioned in the previous chapter and make a decentralized market a reality. In chapter 3 we map the value streams that define the energy market as-is (NM) and expected to-be (ET). Chapter 4 introduces a blueprint of the to-be energy market building on the topics covered in chapter 2, the value streams of this blueprint are mapped. Chapter 5 quantifies the value streams that were defined in chapter 3 and 4, this allows for comparison between current and future market set-ups. The changing value for market participants is evaluated. Chapter 6 discusses the role blockchain could take in the design introduced in chapter 4. In chapter 7 we come back to the research questions and recommend future research.

Chapter 1

Analysis of the current energy market state

1.1 Energy transition in Belgium

The energy market has long been a very monolithic and centralised industry based on a top-down approach: Centralised electricity generation plants supplying consumers through transmission and distribution, while abiding to strict regulation imposed by the government and/or owned by the aforementioned. At the end of the 20th century and the beginning of the 21st, the European and Belgian energy market has undergone a significant transformation. The energy market has mainly taken on its current shape as an outcome of the white paper: *"An energy policy for the European Union"*, published by the (European Commission, 1995). From this date on the European Union (EU) translated this white paper into more and more binding directives leaving the EU member states no real room for interpretation and setting the stage for how the energy market is organised today. The directives were built around three pillars:

1. Liberalised, competitive and integrated European energy market.
2. Security of energy supply.
3. Preservation of the environment.

These three pillars are in line with the so called *energy trilemma* as defined by the World Energy Council, this trilemma encompasses respectively: energy equity, energy security and energy sustainability and are linked to the three previously mentioned pillars. It provides a framework on which countries can be evaluated when it comes to their energy policy choices and implementation. The Energy Union Strategy launched in February 2015 further builds upon the above defined pillars. In the following paragraphs an overview is given on how the Belgian market is currently organised as an outcome of historic events (European Commission, n.d.-a).

1.1.1 Liberalisation of the energy market

In the 20th century the Belgian energy market was characterized by a high degree of consolidation leading to a situation in which most of the activities in the energy sector were mainly in the hands of a small amount of market players. Because of this monopolistic positioning the European Commission feared that the drive for efficiency and innovation was affected. This situation also did not correspond with one of its key objectives: making electricity affordable for every consumer. The previously highly regulated and mostly state-owned phases of production and supply of energy was therefore liberalised by converting EU directives into federal laws with aim of increasing competition, ultimately ensuring affordable prices. This ultimately led to a complete liberalization of the energy generation and supply activities in 2004 (Flanders) and 2007 (Brussels and Wallonia). For the exact process of the translation of EU directives into federal laws that ultimately led to the current energy market we point to more elaborate publications (Vinck & Schoors, 2008).

To understand the dynamics of the market we dig deeper into the value creating activities and the different market players that perform these activities. Figure 1.1 displays the market parties. Physical flows are shown in blue, administrative flows are shown in red. There are four key activities in the energy market, namely generation, transmission, distribution and supply. Generation and supply are liberalised markets since 2004 (Flanders) and 2007 (Brussels and the Walloon region). Producers and suppliers interact on the wholesale market through ARPs to trade electricity. These actors are responsible for balancing a perimeter with one or multiple access points. To safeguard network quality and high service level transmission and distribution, performed by the TSO and distribution system operator (DSO) respectively, remain regulated markets. The Belgian TSO Elia is responsible for grid demand forecasting and balancing of the high-voltage grid. It outsources this responsibility partly to ARPs that are connected to the high-voltage grid and distribute electricity over the low-voltage grid to the consumer. They forecast the demand and balance the low-voltage grid. DSOs deliver the electricity to the consumer over the low-voltage grid. DSO companies are regulated and mostly owned by inter-communal, municipal and state-owned companies. Suppliers are the face of the electricity market for the consumer. They buy electricity on the wholesale market and invoice the consumer for electricity, transmission, distribution, grid management and taxes. Suppliers have a balance obligation, for which they rely on ARPs (cf. Appendix A). Throughout this dissertation we refer to these market parties as roles, these can be performed by distinct entities but even so it is possible for a single entity to perform multiple roles (Elia, n.d.; Hijgenaar et al., 2017; Next Kraftwerke Belgium, n.d.-b).

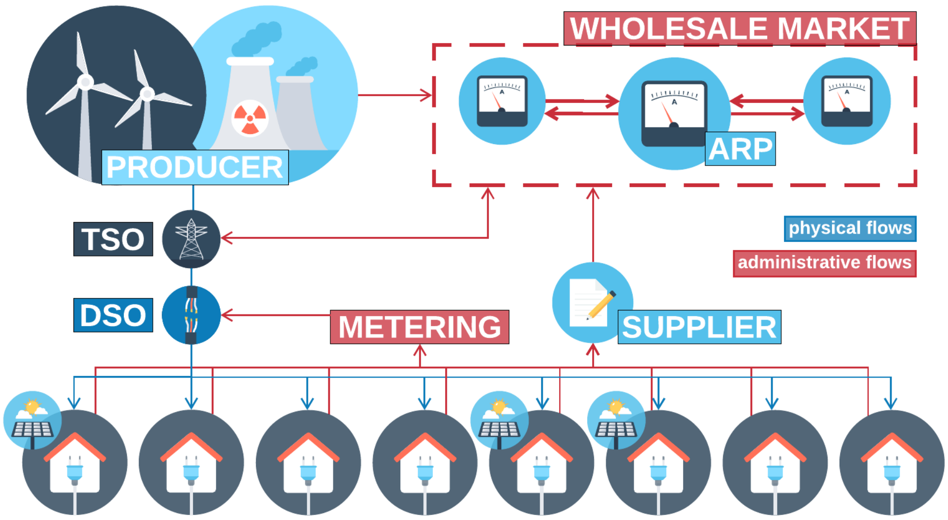

Figure 1.1: Roles on the energy market. Physical flows are shown in blue, administrative flows are shown in red. There are four key activities in the energy market, namely generation, transmission, distribution and supply.

Up until the liberalisation of the energy markets it was not unusual that a single entity had the responsibility of both generation and transmission of energy (Wikipedia, 2018a). A main pillar of the European energy directives was to ascertain vertical disintegration, meaning that one single entity cannot be a responsible party for generation and/or supply on the one hand and transmission and/or distribution on the other hand.
The goal of this directive was to increase competitiveness, resulting in lower energy prices. Cross-border trading had lowered the market prices in Belgium (cf. supra) (Brown, Wang, Sovacool, & DAgostino, 2014). As the costs associated with the transmission, distribution and taxes rise (cf. supra), resulting in a higher total energy bill for the consumer, one could argue against the natural monopoly of TSO and DSOs. Hijgenaar et al. (2017) points out that a vertical integrated market is cheap and effective, but not an incentive for system efficiency.

1.1.2 Security of energy supply

According to European Commission (n.d.-b) the EU imports more than half of all the energy it consumes. Its import dependency is particularly high for crude oil (90%) and natural gas (69%). The total import bill amounts to more than 1 billion EUR per day. In addition many countries rely heavily on a single supplier. This dependency results in a high vulnerability to political and commercial disputes or infrastructure failures. To ensure a reliable energy supply in the future the EU has issued numerous directives, including an Energy Security Strategy in May 2014.

Energy security can either relate to dependency on primary[1] and secondary energy. Because Belgium's energy market is limited by the scarcity of natural resources (primary energy), the country has imported 100% of its primary energy between 1993 (when the last coal mine was closed) and 2010 (Brown et al., 2014). This primary energy constraint creates an opportunity to stimulate production from domestic renewable sources since that would be the only form of primary energy Belgium could harvest itself, lowering the dependency on the import of primary energy (CREG, CAWP, Brugel, & VREG, 2016; European Commission, 2017a).

Today's domestic electricity market is highly liberalised (cf. infra). This liberalisation manifests itself externally as Belgium trades electricity with neighbouring countries. Although this limits[2] the secondary energy independency, cross-border cooperation results in lower electricity prices in Belgium since both France and the Netherlands have relatively lower electricity retail prices (Brown et al., 2014). Projects of common interest are on their way to increase the interconnectivity with the UK (project Nemo) and Germany (project ALEGrO), this will lead to a further convergence of European energy prices (European Commission, 2017a).

A high degree of liberalisation does not necessarily mean a high degree of competitiveness. A case in point is the domestic electricity market and natural gas import market, both dominated by the Suez Group (Brown et al., 2014). Besides, the composition of Belgium's regulatory environment adds an extra layer of complexity to the energy security challenge (cf. supra).

Domestic factors, the competitiveness of neighbouring markets, a monopolistic domestic market and the regulatory environment have prevented Belgium from further increasing its independence on energy imports. Increased consumption from RES could improve our energy independency.

1.1.3 Preservation of the environment

The EU climate targets for 2020, 2030 and 2050 are focused around three areas: greenhouse gas emission cut, increased share of renewables and improvement of energy efficiency. The 2020 targets are enforced by binding legislation. In 2015, the share of renewables in Belgium amounted for 6,9% of Gross Inland Consumption (European Commission, 2017a; FEBEG, 2017).

The Kyoto Protocol (signed 1997, into force since 2005, extended until 2020) (Wikipedia,

[1]Primary energy is energy available in nature like oil, natural gas, solid fuels (coal a.o.) and nuclear fuel (uranium). Renewable sources like solar and wind energy are also considered primary energy sources. Secondary energy is primary energy converted into consumable forms of energy like electricity and fuel oil (Wikipedia, 2018d).

[2]Assuming that foreign competition decreases (investment in) domestic generation.

2018b) and the more recent Paris Agreement (signed 2012, into force from 2020) aim at reducing greenhouse gas emission in response to the global climate change threat (cf. supra). Belgium has committed to both agreements. Hereafter we aim to explain actions that were taken by the Belgian government to preserve the environment and meet the requirements of the above agreements (Wikipedia, 2018c).

The change in fuel portfolio for electricity generation serves as the major driver for Belgium's better-than-average performance on reducing CO2 emission in the period from 1970 until 2010. Brown et al. (2014) praise Belgium for effectively lowering carbon emission and successfully implementing EU directives during the 1970-2010 period. The case below shows that not all government actions have led to effective incentives.

In the period from 2007 to 2015 the Flemish government actively subsidized the installation of domestic solar panels using green energy certificates (GEC). Although clearly reaching the objective to stimulate PV adoption, this policy had some major drawbacks. De Groote (2016) argues against this policy, they point out the Mattheus effect, a positive relationship between income and subsidized solar adoption. The commitment to buy[3] back GEC at a predetermined price, significantly indebted the government. With the aim of filling up the gap that these GEC left behind the new government imposed the infamous 'Turteltaks', costs are now being borne by the entire population.

1.2 Market and consumer trends

Energy systems of the future will be highly decarbonized, distributed, democratized and digital (Siemens, 2017). Looking at the historic events that shaped today's energy market we see that these four trends are a logical extension. This segment aims to dig deeper into the trends and the correlation with the past.

1.2.1 Decarbonized

The decarbonization trend has come a long way. Starting even before the Kyoto Protocol to more recent actions like the Paris Agreement, where at the time of writing 195 countries have committed to keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1,5 degrees Celsius (Wikipedia, 2018c). Besides decarbonization has since long been on EU's agenda (cf. infra).

These agreements are considered key drivers for clean electricity and energy efficiency initiatives. On the generation side this means finding a new energy mix. The federal minister together with the three regional ministers of energy have committed to finding a low carbon

[3]GEC could also be traded on an open market, however the equilibrium prices on this open exchange where lower than the committed buy-back prices by the government.

energy mix, where renewables must take on the role of the major source of energy in the medium to long term. The share of RES in 2016, which can in general serve as a benchmark year (i.e. with normal nuclear availability), amounted to a production of 14,2 TWh or 15,7% of the total electricity production in Belgium. In line with the international agreements and EU policies mentioned earlier, the goal is to increase this share still further. PwC (2016) estimates that by 2030 44,3% of energy production will be renewable and up to 67,4% in 2050.

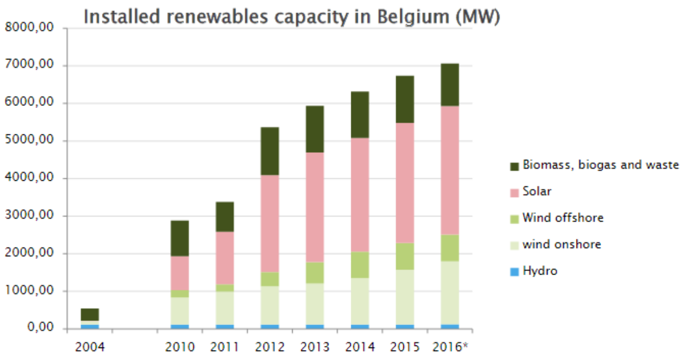

Figure 1.2: Installed capacities of renewables from 2010 to 2016, by energy source and expressed as MW/year. 2004 is displayed for reference (FEBEG, 2017).

Renewables have the advantage of being less carbon intensive and in that way have the potential to contributing towards the decrease of greenhouse gas emissions as put forward by the Kyoto and Paris Agreements. However, the bulk of these sources (wind and solar) differ fundamentally from traditionally used energy generating sources for which the grid was originally designed. Therefore, the rise in RES comes with great challenges (cf. supra).

The rise of electric vehicle (EV) fits into this decarbonizing trend. As a whole industry is moving from fossil fuel to electricity, the changing load curves create an extra challenge for energy supply and grid balancing. This also brings a lot of potential, as Hijgenaar et al. (2017) pointed out that a vehicle-to-grid connection can benefit more energy efficient grid balancing (cf. 2.2.6).

1.2.2 Distributed

The decarbonization trend is fuelled by the rise of DG from RES, cheap PV panels and government incentives (GEC, cf. infra) have led to an increasing amount of prosumers. A prosumer is a consumer with generation capacity, consequently both consuming and producing energy. This has a lot of obvious benefits, an increasing PV adoption rate contributes to an increased share of renewables production. On the other hand, this also creates a grid with increased complexity, with resulting balancing challenges. The inability to measure behind-the-meter[4] consumption and generation has led to increasing grid balancing efforts (De Tijd, 2018).

Closely interrelated with the rise in RES is the rise in DG. DG can be loosely defined as *"small-scale electricity generation"* (Pepermans, Driesen, Haeseldonckx, Belmans, & D'haeseleer, 2005) or according to Ackermann, Andersson, and Söder (2001): *"DG is an electric power source connected directly to the distribution network or on the customer side of the meter."* A third definition by Dulau, Abrudean, and Bica (2014) indicates *"production of electricity near the consumption place".* Although no clear consensus on a definition has yet been established, Key recurring words are: small-scale, close to the place of consumption and not connected to transmission lines. Traditionally, a limited amount of electricity generators would supply the entire market in a top down approach, neatly and sequentially following the steps of production, transmission, distribution and finally, consumption. DG transforms this paradigm into a more complex, bidirectional model in which the boundaries between the value-creating activities within the electricity market become blurred. It is mainly the customer who is at the core of this evolution, as every year more prosumers both deliver and take from the grid. In fact DG is not a new phenomena at all. As pointed out by Pepermans et al. (2005), in the early years of the existence of electricity, DG was basically the only existing source of energy. Given that it was technically not possible to transport electricity over large distances at that time, it meant that electricity had to be generated close to the place of consumption. It was only when alternating current was invented and in that way electricity could be transported across longer distances through high-voltage lines (i.e. transmission) that the advantages of centralised generation were completely recognised (Wikipedia, 2018e). This centralization trend in the 20th century came with great advantages. A higher degree of interconnection assured an increase in the security of supply due to the possibility of backups of shortages at one point in the grid by surpluses in other parts, which smoothed balancing services. Due to economies of scale it had also benefited the overall affordability of electricity at that point in time.

The centralization trend stopped in the late 20th and early 21st century. In relation to the third pillar of the energy trilemma, namely the rise of ecological awareness and the objective of decarbonization came a change on the highest strategic level in decision making. The liberalisation (cf. infra) of the energy markets in Europe together with a push for more carbon-free electricity generating sources created an environment in which DG became more attractive again. New technological improvements in the efficiency of wind turbines (WTs),

[4] A behind-the-meter system is a renewable energy generating facility (in this case, a solar PV system) that produces power intended for on-site use. The location of the solar PV system is literally *behind the meter*, on the owner's property, not on the side of the electric grid/utility.

PV and batteries further facilitated this shift (Pepermans et al., 2005). El-Khattam, Hegazy, and Salama (2005) divide DG into traditional and non-traditional generators. It is important to note that the current decentralisation trend is mainly due to an increase in non-traditional generators and with emphasis on the increase in renewable devices, being PV and WTs. The rise in RES and DG are therefore highly correlated, especially because a large part of these new RES are of small sizes, located at/near customers.

In Belgium most DG originates from small-scale ($<$ 10 kWp) solar installations, therefore in the further analysis when mentioning DG, this mostly refers to decentralised solar installations. International Energy Agency (2017) stated in their annual report *"Renewables 2017"* that global PV installations increased with 50% in the year 2017. As was mentioned earlier, the regional governments and especially the Flemish government actively subsidized solar installations in the 2007-2015 period (cf. section 1.3), which clearly correlates with the rapid growth in installations to be witnessed in Figure 1.3 (APERe, 2018).

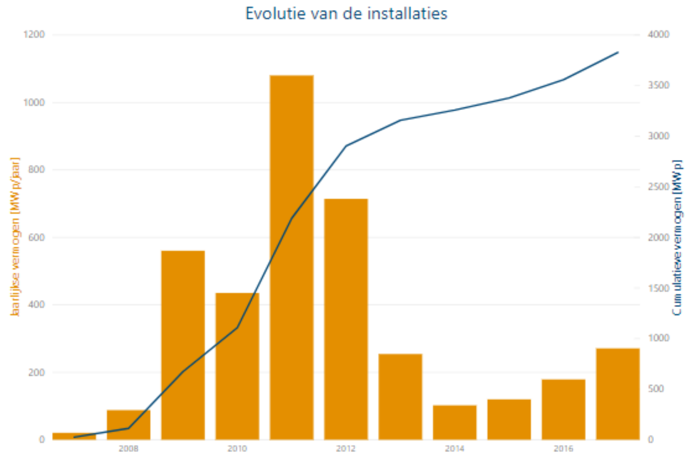

Figure 1.3: Evolution solar installations between 2007 and 2017 expressed as MWp/year. The y axis on the right hand side displays the cumulative power (MWp) (APERe, 2018).

In relation to the reduction in support by government, a similar drop in annual installations was to be witnessed from the year 2012 on. However, the most recent years saw a comeback in solar installations as prices dropped, making them able to independently compete with other electricity sources and providing ever increasing return on investment for prosumers and companies (Sanders, 2017). Ultimately there is now an installed capacity of 3.828 MWp in Belgium of which 75% in Flanders. Important to note is that of this number 84% are small installations ($<$ 10 kWp) which clearly indicates the relation between RES adaptation and DG (APERe, 2018).

1.2.3 Democratized

The rise of prosumers relates to a further liberalisation of the energy market. The annual reports by VREG about the state of the electricity market indicate a trend in which every year more consumers are switching supplier. *"Within Europe, the Flemish energy market is one of the most active, with a high number of supplier changes."* - VRT (2018b) Figure 1.4 shows the percentage of Flemish household access points that switched supplier compared to the total number of household access points, displayed for January 2009 until April 2018. A clear rise is notable in 2012 onwards. This relates to the severance payment for switching being abolished in September 2012. From 2012 onwards the yearly average switching has always been higher than pre-2012 levels. In 2016, driven by the newly implemented *Turteltaks* (cf. infra) a record number of households (19,06%) seeked economization. In 2017, a total of 18,67% of Flemish households switched supplier. January 2018 recorded the highest monthly switching rate of this decade (4,09%).

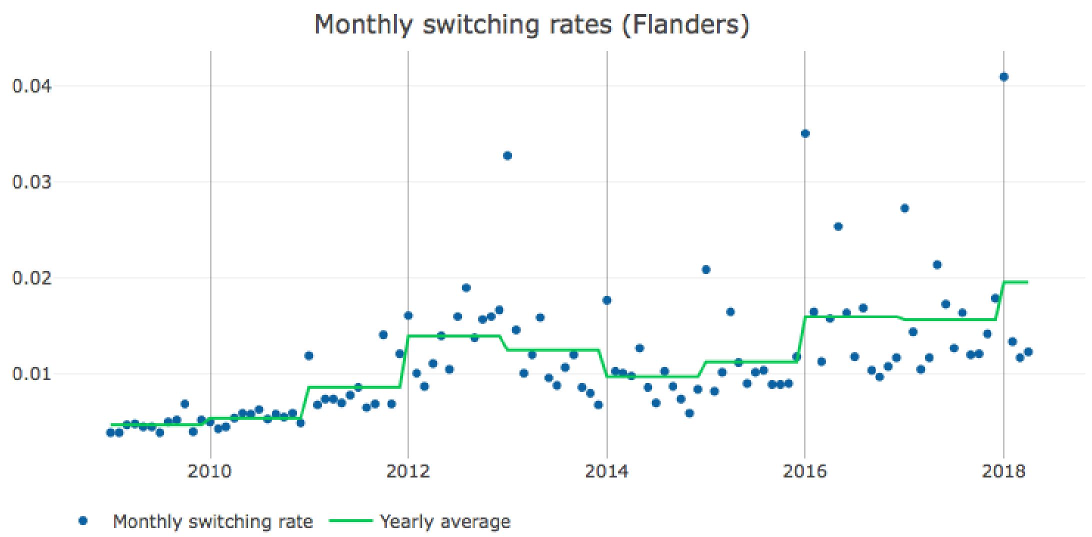

Figure 1.4: The percentage of Flemish household access points that switched supplier compared to the total number of household access points, displayed for January 2009 until April 2018. The blue dots display the monthly switching rates, the green curve represents the yearly averages (VREG, 2009, 2010, 2012, 2013, 2014, 2015, 2016, 2017, 2018a, 2018b).

Consumers are playing an increasingly active role in the energy market, from generation to distribution. Today's consumer wants to manage its own consumption but lacks the tools to do so, furthermore the expectation when it comes to customer service are higher than ever. This has created opportunities for utility companies to evolve to more consumer centric business models, provide energy management tools and integrate with new sectors like emobility and battery storage (Pinson et al., n.d.). As distributed production is increasing, so is behind-the-meter consumption, resulting in a decreasing paid consumption. Therefore, enabling energy transactions could become more important than owning assets. In relation to the sharing economy the interest in so called PTP trading of excess generated electricity has also increased in recent years as prosumers became aware that they have become a market player owning a valuable asset (Hamari, Sjöklint, & Ukkonen, 2016).

1.2.4 Digital

As digital technologies have found their way into most industries, the energy sector is no exception. On the demand side, internet connected home thermostat control applications integrate with other connected devices and appliances. On the supply side, advanced forecasting methods predict the energy demand to the minute (Elia, n.d.). Enhanced connectivity brings the opportunity of more energy efficiency through better forecasting and energy trading. Still a big part of the value chain from generation to consumption is not digitised, nor vertically integrated with other activities. In order to prepare for a future with PTP trading, DR and smart grids, a minimal condition has to be fulfilled, that is smart metering. VREG (n.d.) states a smart meter to be an essential part of smart grids, to facilitate *"the integration of (locally generated) renewable energy and the associated two-way traffic of electricity."* This would result in more efficient use of the infrastructure in place. The goal is to bring intelligence to both the supply and demand side, in this way increasing energy efficiency on the grid and in consumer's homes. As part of the energy pact, the Flemish government decided to roll out a smart meter program between 2019 and 2039 (Vlaamse overheid, n.d.).

1.3 Main challenges of the Belgian energy market

As was pointed out in the previous paragraphs, we are currently facing a significant transition in all the aspects of the energy market. In this paragraph we present the most prevalent challenges that the energy market in Belgium will face in the short to long term, resulting from the current state and trends mentioned previously.

1.3.1 Finding the right energy mix in a post-nuclear era

Today's energy production capacity is mostly nuclear (40,35%)[5] and natural gas (33,21% in 2017), excluding household solar capacity (Elia, 2018). As the government has committed to a low carbon future with a high degree of RES, it is yet unsure how we will be able to fill the void left by nuclear and fossil fuel generation.

The Belgian government decided in the beginning of the century that nuclear energy gener-

[5]Note that due to the high load factor of nuclear compared to other energy sources the share of production amounts to 50% on average.

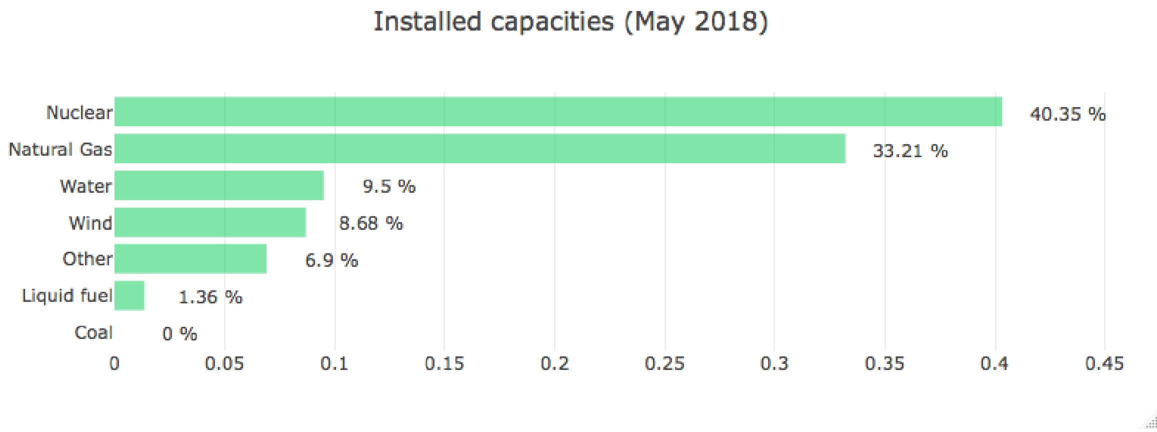

Figure 1.5: The installed capacities of centralised producers in May 2018, shown per energy source by percentage of total installed production capacity.

ation will not be a part of the long term energy mix. Although it has already altered the original decision of 2003 three times in 2009, 2013 and 2015 by evermore extending the phase-out with several years, there is currently no single party in Belgium that explicitly advocates a nuclear future (VRT, 2018a). In March 2018 the energy pact was agreed upon, finalising the closure of all nuclear plants in the year 2025[6].

On average, the nuclear power plants deliver 50% of the energy in Belgium, which indicates the current importance of nuclear energy in the energy mix. As this subject proved to be highly controversial and politically charged, several independent studies were ordered by the Belgian government in the last years in order to evaluate the outcome of such a phase-out scenario. Out of these studies we discuss the main conclusions.

1.3.1.1 Impact on security of supply

As was mentioned previously, the nuclear plants deliver on average 50% of the energy in Belgium. According to CREG et al. (2016) this was even 60% in 2016. However, the nuclear plants faced some major issues in the years 2012-2015. Due to these issues several of the plants were either put manually or automatically out of work which led to fears of an electricity shortage in the end of 2014. Ultimately a real shortage was avoided. Yet, this partial closure of the nuclear plants already indicate the dependency of Belgium on nuclear energy. With the definite closure of the nuclear plants together with several older gas-fuelled plants in 2025 it is yet uncertain if sufficient backup capacity will be up and running at that point in time.

[6]It has to be noted that several conditions were included in the final text that might potentially extend the lifetime of some nuclear plants in the case of a great risk of security of supply.

The TSO of Belgium, Elia (2017)[7] concluded in their study that the supply of energy can be fulfilled, on the condition that the construction of new gas plants is undertaken in the near future. Elia (2017) argues that at least 3,6 GW (compared to a current 6 GW of installed nuclear capacity) of extra thermal capacity will be needed in order to manage the shock of the nuclear phase-out in 2025. If no decision is made however, Elia (2017) points out that the nuclear extension of 4 GW (67% of current nuclear capacity) is unavoidable to assure security of supply. Albrecht, Hamels, and Thomass (2017) also point out that extra investments in renewable energy sources and more importantly gas plants will be indispensable to assure the security of energy supply in the future, however, he states that a clear governmental investment strategy is currently lacking and the focus has been predominantly on short term decisions such as the subsequent extension of the lifetime of the nuclear plants.

A study by PwC (2016) in which three scenarios with a different degree of nuclear phase-out were studied also pointed out that Belgium would become a strong net-importer of electricity. Paradoxically, Belgium would need to import a fair share of energy from France of which the share of nuclear in its total energy generation amounts to 75%. Even if Belgium would manage to replace the current nuclear capacity with gas-fuelled power plants it would still be dependent on external countries for supplying primary source of this energy: natural gas.

1.3.1.2 Financial consequences

Elia (2017) points out that numerous new investments in renewable and gas-fuelled power plants are necessary in order to facilitate the nuclear exit in 2025: at least a capacity of 3,6 GW is needed, compared to the current 6 GW capacity of nuclear. However, they calculate that the current wholesale price for electricity is insufficient to repay the costs of these investments. This non-rentability of new gas-fuelled plants results in the probability that governments will have to at least carry a part of the burden, because private investors are not incentivized at current prices. PwC (2016) quantifies the increase in the production cost of electricity from 95 EUR/MWh at the current capacity of 6 GWh nuclear generation to 111 EUR/MWh in the scenario of a complete nuclear phase-out, forecasted for the year 2030. Albrecht et al. (2017) calculates a electricity price increase between 40% to 100% for consumers.

All three studies argue that a nuclear phase-out does not necessarily have to result in a significant risk of power shortages in the future due to insufficient supply. However, this conclusion

[7] CREG, the controlling body of the electricity and gas market in Belgium raised concerns in accordance to the study delivered by Elia, the TSO of Belgium. CREG indicates that Elia based its results on wrong assumptions and data. They indicate that Elia bases its forecasted scenarios too much on historical data and does not take into account the potential of the possible significant impact of technology when it comes to energy efficiency. CREG points out that Elia itself, as the TSO, is one of the most important market players in the energy market and therefore not suited to conduct such a study (CREG, 2017a; VRT, 2017).

is based on the condition that government takes action now and invests in gas-fuelled power plants in the short term and renewables in the longer term combined with investments in extra interconnections with neighbouring countries. At the same time these traditional gas plants are ever more unprofitable due to the increased availability of cheaper RES. A clear vision and action plan is therefore indispensable in order to support this transition period.

1.3.2 The impact of distributed generation and renewable energy sources on grid balancing

Following supportive governmental policies the adoption in RES has seen a sharp increase in the last ten years. Especially the adoption of domestically owned solar PV installations and larger scale WT both on- and off shore. Although they contribute to the third pillar of the energy trilemma in the form of environmental preservation, their intermittent and unpredictable behaviour poses extra stress on parties responsible for keeping the grid balanced. To explain this we first give a brief introduction on how and by which parties the grid balancing is currently organised, after which we discuss the challenging interaction between RES and balancing.

1.3.2.1 The balancing process

With a time period between production and consumption tending to zero, electricity is unlike most other commodities. Therefore, in the energy sector, basic operational and supply chain managerial related concepts when it comes to production, transportation and delivery mostly do not hold. Especially the concept of inventory or storage is nearly non-applicable. Progress is being made on this issue with a focus on ever more performing storage techniques being developed (cf. supra). However, at this point in time large-scale storage is not yet living up to its expectations. As a consequence the main challenge and task of the TSO lies in its responsibility of assuring balance between demand and supply on the high-voltage grid in real-time by analysing and forecasting all the in- and outputs on its grid. The control of demand is only a last resort option in the case all other balancing capacities have been depleted[8]. Given this demand of electricity (i.e. the total load on the grid), Belgian TSO, Elia, has the end responsibility of finding matching supply capacity, taking into account the availability and capacity of the generators at its disposal (Elia, n.d.). However, Elia outsources this responsibility to ARPs.

Finding a long-term electricity mix that will match the expected overall demand is a strategi-

[8]Elia has a portfolio of industrial demand flexibility within its third reserve (RP3) which it could potentially activate in the case of imbalances still exist after the activation of its primary and secondary reserve. In the case all reserves to fulfil demand are depleted, Elia will, as a last resort, activate a so called 'disconnection plan' which shuts of parts of the grid in order to avoid a grid-wide blackout.

cal governmental decision (cf. infra). In the medium to short term it is Elia's responsibility to employ this given generating capacity in a way that demand is met in the most efficient and effective way. The performance by which this task is executed ultimately has a major impact on different factors. Firstly, repeated imbalances damage the grid and causes power outages that threaten the security of supply. Secondly, inefficient balancing practices lead to elevated system costs across the electricity value chain which ultimately affects the total affordability for end-consumers (Elia, n.d.; Open Energi, 2017). For a more in-depth overview of Elia's responsibilities (i.e. balancing and ancillary services) and how it interacts with ARPs we refer to Appendix A.

1.3.2.2 Distributed generation and renewable energy sources

DG has some clear advantages from a consumer point of view: such as a reduced transmission and distribution needs, a relative low investment cost and increased independence of the prosumer and the effective implementation of RES (Abu-Sharkh et al., 2006; Lopes, Hatziargyriou, Mutale, Djapic, & Jenkins, 2007). In high level the International Energy Agency (2002) outlines 5 factors that drive the usage of DG: developments in DG technologies, constraints on the construction of new transmission lines, increased customer demand for highly reliable electricity, the electricity market liberalisation and concerns about climate change. On the other hand a shift to more decentralization in a system that was developed to secure the top-down flow from centralised units to consumers comes with great challenges, the bulk of which are technical and linked to the distribution network. Power quality issues such as variations in voltages and frequencies (Lopes et al., 2007) increase the pressure on DSOs and leads to the need for ARPs and ultimately the TSO to deliver ancillary services in compensating these variations (Pepermans et al., 2005). Where as the normal sequence is from high to low voltage such as transmission-distribution, DG results in bidirectional flows (Dondi, Bayoumi, Haederli, Julian, & Suter, 2002). These connection issues can result in grid distortions. When, the DG source is located near/at the consumer the centralised utilities loses control over a share of the generating potential on its grid, increasing the need for effective management of its - reduced - remaining sources (Pepermans et al., 2005).

However it are mainly distributed RES that pose a significant challenge due to their intermittent and unpredictable behaviour, especially when it comes to grid balancing.

Intermittency

Traditional energy generating sources such as nuclear or thermal sources are usually relatively controllable when it comes to the time of production and the amount of electricity produced. For wind and solar, electricity is only generated when weather conditions are favourable. A definition by (U.S. Energy Information Administration, n.d.): *"an electric generating plant* *with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements."* Currently 15,6% of electricity production comes from RES, of this share 55% is intermittent. By 2030 (PwC, 2016) expects this to increase to 44,3%, of which 76% intermittent and to 67,4%, of which 80% intermittent by 2050. This forecasted increase in both the share of RES and the relative share of intermittence is due to an expected increase in PV installations and both on- and offshore WT. At the same time, biomass-fueled power plants, that can generate electricity at constant rates comparable to traditional sources recently saw a cutback in subsidy policy by the Flemish government, as politicians indicated not to consider biomass as an electricity source of the future in Belgium (Het Laatste Nieuws, 2017). The conditions in Belgium result in that solar PV installations have an average load factor of 10% while WT onshore of 20% and WT offshore of 40%, in comparison nuclear plants run on a 80-90% load capacity.

This intermittent character induces several implications; first of all, while on average they do not produce half of the peak capacity, the interconnections have to be designed in a way that they allow the flow of peak capacity which elevates costs (Cappelle et al., 2011; Rycroft, 2017). Furthermore, the higher degree of intermittent RES, the higher will be the variation in generation in both extrema. Conversely, what is needed is a higher amount of generating sources that can either be turned on- and off in a flexible manner. Examples of these are gas (peaker) plants that have the flexible potential required to compensate near-instantaneous variations in intermittent sources.

Another option is to import/export deficits and excesses with neighbouring countries. However, as the intermittence is mostly related to climatological variables and weather tends to be similar in neighbouring countries this implies that periods of over- and underproduction will mostly be similar, reducing its compensating potential (Lemeire, 2017). On summer or spring days with bright skies and a decent amount of wind it might happen that PV and WT are producing near peak capacity. This combined power injection has as one consequence that distribution grids get congested resulting in over voltages (Rycroft, 2017). If these variations in voltages are to elevated, the PV converters will detect this and automatically turn off the PV installation (Cappelle et al., 2011). In the case that the grid is able to manage this elevated injection, the grid operators will still have to manage balance within their perimeter. As control over wind and solar is mostly distributed it will mostly have to shut down flexible traditional sources such as gas plants or in the extreme case nuclear plants. Electricity wholesale markets are based on the merit order principle (European Commission, 2014) which prioritizes energy sources based on their marginal costs of the electricity source. As RES such as wind and solar have marginal costs tending to zero they outplace traditional electricity sources such as gas plants (Van Isterdael, Albrecht, & Laleman, 2014). Ultimately this leads to an underutilization of traditional sources, which threatens the rentability of these sources (Denholm, O'Connell, Brinkman, & Jorgenson, 2015). In line with this conclusion is the observation that producers are shutting down more and more gas-fuelled plants, the capacity of which decreased with 10% in the last 10 years (VRT, 2018c). Another option is to curtail centralised WT or PV resulting in the same rentability issues for these sources together with a loss of potential green electricity.

Ultimately, the higher the share of intermittent RES the higher will need to be the overall installed capacity of flexible generating sources as variations in instantaneous generation will be more and more extreme. Yet, on average the underutilization of these sources will increase as sufficient capacity will need to available to be available to react on frequency and voltage variations, while at the same time they will become less profitable (Open Energi, 2017). In Figure 1.6 below Pöyry (2011) estimated the hourly variations in intermittent RES generation throughout the year, clearly indicating a sharp increase in variation of periods with more or less generation in the case of a higher share of RES. Pöyry (2011) also point out that this volatility on its turn will impact the volatility of wholesale prices of electricity.

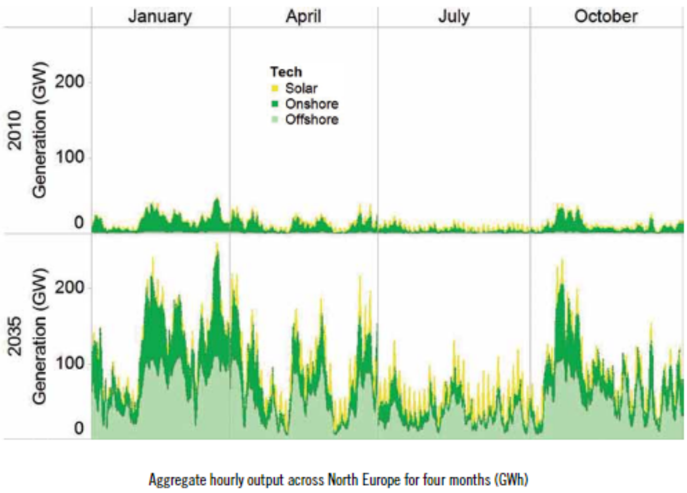

Figure 1.6: Estimated hourly variations in intermittent RES generation throughout the year (Pöyry, 2011).

Mismatch of demand and supply: the Duck Curve

The main installed RES capacity in Belgium consists of PV installations. And although it's intermittence and unpredictability are great challenges, the key issue with solar production is that periods of peak production do not correspond with periods of peak consumption and on the other hand; the time of peak consumption is on average accompanied by a period of minimal or zero solar production.

First of all, in a seasonal perspective electricity consumption peaks during the cold winter months. Due to elevated heating and lighting requirements the demand for electricity is significantly higher than during the summer periods. Another and more important mismatch is the one during a single day. Figure 1.7 (top figure) shows the total load on the TSO's grid a traditional spring day in Belgium. Figure 1.7 (bottom figure) plots the solar generation for that same day. It can be seen that solar on average reaches its peak at a period when the load tends to be lower. This phenomena is also known as the Duck Curve (St. John, 2016). On spring or summer afternoons it might happen that solar delivers up to 30% of all electricity on to the grid alternated with 0% at night. This means that in order to assure balance some other sources will have to be turned down according to this 30%, which again puts extra pressure on the ARPs and the TSO.

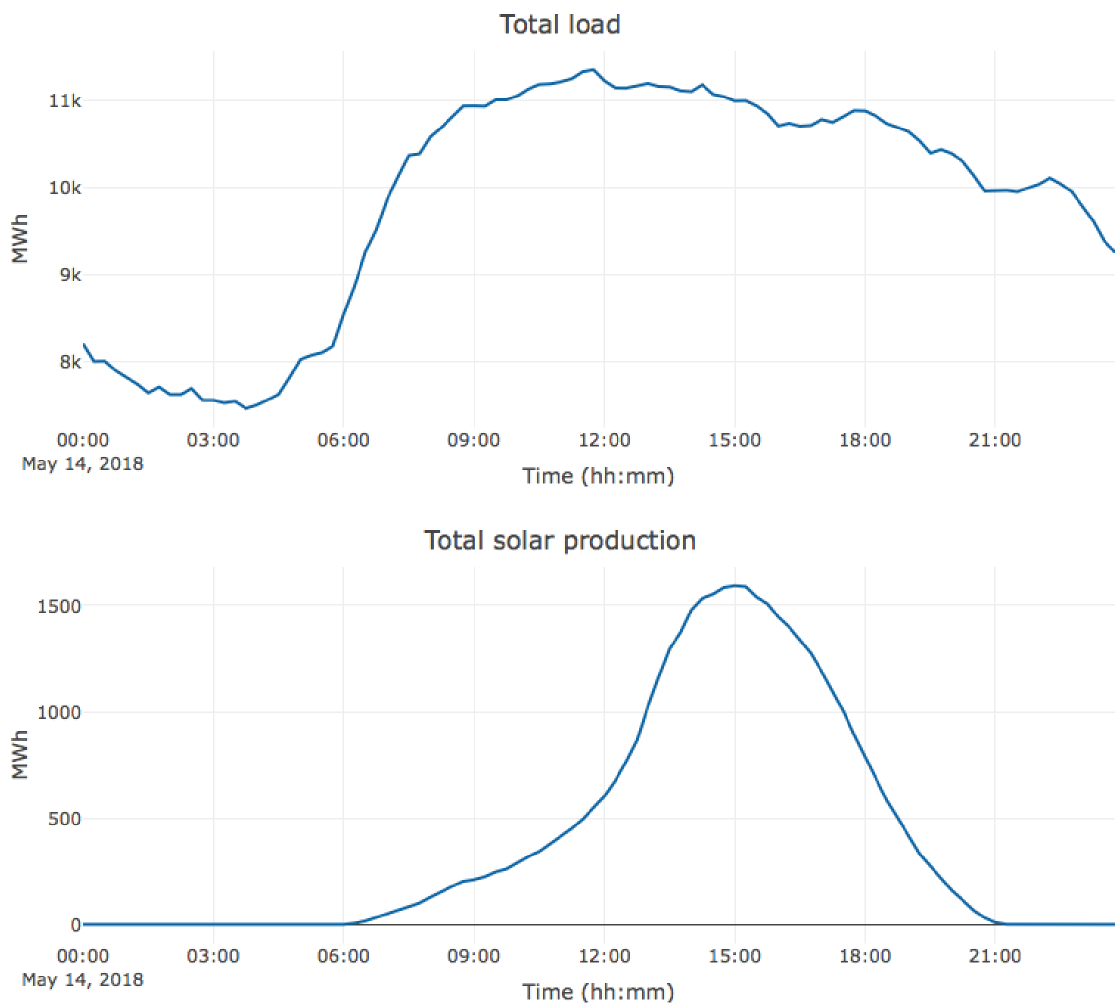

Figure 1.7: Total load (above) and solar production (below) in Belgium on 14 May 2018 (Elia, 2018).

Unpredictability

The ARPs and Elia as TSO use sophisticated forecasting methods in order to estimate the expected loads on their responsible part of the grid and ensure balance by contracting the needed electricity generating sources. In a traditional centralised electricity network the main challenge was to accurately forecast the load at the demand side, as the capacity of traditional electricity sources at the supply side is more or less deterministic. With rise in DG and RES and the intermittence and loss of control that comes with it, this relative deterministic supply side is now also more and more subject to uncertainty (Pepermans et al., 2005). This puts extra stress on the forecasting performance resulting in more imbalances and higher costs that come with it (cf. supra). It is also important to note that on the day-ahead markets (cf. infra) suppliers acquire electricity of generators based on the forecasts that were made of the their generation. However, as a share of this generation consists of RES related to weather forecasts, it is not unlikely that these forecasts are not completely accurate. The resulting deviations in forecasted and actual generation leads to shortcomings of generators to fulfil the orders of suppliers. Ultimately these suppliers or ARPs are then forced to compensate the shortcomings on the more expensive intra-day markets or in the ultimate case the TSO will ascertain balance through the delivery of ancillary services by activating its reserve capacities. Ultimately this results in the outcome that the share of electricity generation is coming more and more from balancing capacities, however these were not designed to deliver these capacities systematically to the grid (Merz, 2016). This was also witnessed in Germany where the volume on the intra-day markets increased by 40% from 2014 to 2015, linked to the the chosen path for renewables there (Kotte, 2016).

1.3.3 Non-integrated demand side

When we analyse the previous paragraphs it is clear to see that a transition towards more decentralised energy sources will lead to more uncertainty and variability at the supply side in combination with the already existent and increasing uncertainty at the demand side. Grid operators and ARPs will therefore face an ever more challenging task in keeping the grid balanced. Although the rise in DG and RES causes a lot of challenges, it also comes with a great stabilizing potential in the form of flexible resources such as DR and energy storage capable of shifting balancing activities from grid-operators towards the end-consumers. As we will explain in the next chapter, important pre-conditions to unlock this flexible potential at residential or industrials households is the - financial - incentivization of customer behaviour to effectively shift or adjust consuming behaviour in a way that it benefits the overarching grid. Literature and pilot projects have indicated that forms of dynamic pricing such as real-time pricing, critical-peak pricing and time-of-use pricing can potentially unlock this flexible potential (Networks, 2014; River, 2005; Van Isterdael et al., 2014; Widergren, Marinovici, Berliner, & Graves, 2012). In Belgium about 55% of consumers do have a twofold metering device that separates between day- and night consumption (CREG, 2016), which can be considered as a form of time-of-use pricing (Energy Exchange, n.d.). Most suppliers do offer variable contracts with varying average prices per month. However, other forms of dynamic pricing are not to be witnessed in the Belgian electricity market. The lack of advanced metering infrastructure also known as smart metering results in that suppliers are at this point in time not able to individualize consuming patterns into designated periods. Instead they have to resort to SLP (cf. infra). This leads to the constatation that there is currently no transparent nor effective way in which grid-operators and suppliers can translate and assign variations in their costs due to variable energy wholesale prices or increased system costs into the billing of end-consumers who are causing these variations. Ultimately this leads to a near non-existing usage of the residential DR potential in Belgium.

1.3.3.1 The billing of consumers

In Belgium, a consumer usually pays a monthly sum that is based on its -estimated- net consumption. This is due to the fact that in Belgium the great majority of households still have traditional meters that are not connected to electricity suppliers. Which means that meter values have to be manually checked once or twice a year by the responsible DSO, based on which the supplier will bill their customer. As meters are only checked once or twice a year this implies that for monthly billing the supplier will estimate the consumption of their customer based on previous metering amounts. In fact the monthly (or two-/three monthly) payments serve as a deposit, at the end of the year the customer will then settle the total bill by either paying extra or receiving money back (VREG, 2018).

1.3.3.2 Synthetic load profiles

As traditional meters do not have the capability of providing suppliers with continuous data this implies that suppliers have no clear image about how much a particular consumer consumes during a particular period ranging between months, weeks, days or even on a quarterly-hour basis. A supplier simply obtains the total net consumption of a household at the end of the year. The fair share of these suppliers have variable contracts with their customers in which they are free to let the energy component of the total price vary per month based on market conditions such as the price they pay to producers. As the supplier only has info about the consumption for the total year, the regulating bodies have developed six so called SLPs to assign consumption to time-periods. Each load point is placed within a certain SLP based on relevant variables concerning this consumer load point. These SLPs provide a statistical distribution for a consumer over the year, providing an estimate of the quarterly-hour consumption based on their total annual consumption. Ultimately the supplier will bill the customer based on this estimated consumption per month, but it will also obtain totals for consumption during peak or off-peak periods and day/night[9] periods, that is if the contract includes variable pricing schemes (VREG, 2018d, 2018).

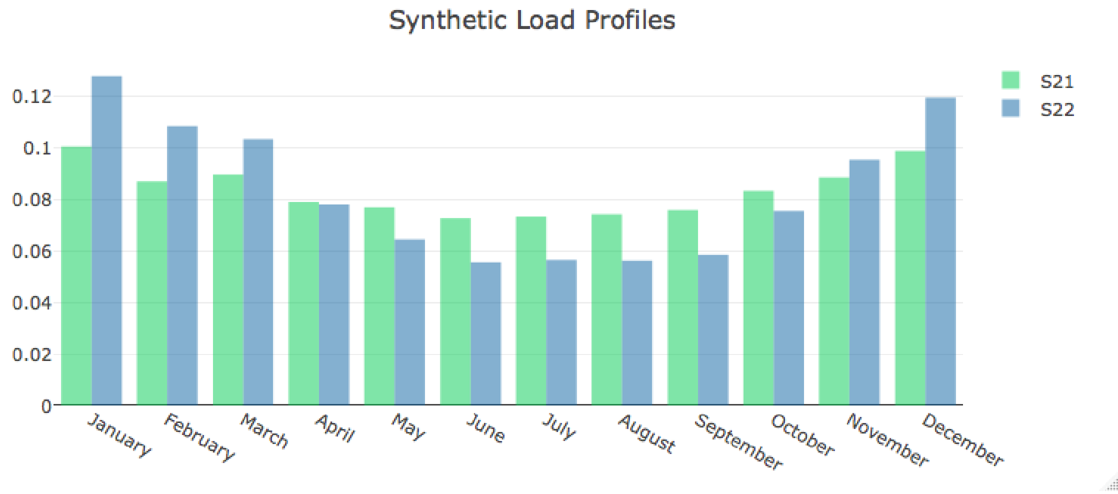

Figure 1.8: Monthly totals of the two household SLPs.

On Figure 1.8 the monthly totals of the two household SLPs are plotted. Household consumers are categorized into one of two SLPs, being S21 and S22[10]. SLP S22 consumes the bigger part of its total consumption at night, at least more than 56,6%. According to Van Isterdael et al. (2014) 18,45% of Belgian household consumers are categorized in SLP S22. Figure 1.9 displays both consumption patterns throughout a day in November.

Clearly, a consumer only has an impact on its total consumption, the decision when to consume is irrelevant, as the distribution is fixed according to the SLP in which they belong. This implies that even if a consumer effectively shifts its consumption towards periods with cheaper electricity rates - keeping the total consumption equal - this will not be reflected in the energy bill of this consumer. About 55% of consumers in Belgium have a twofold meter that separately tracks day and night (including weekend) consumption. In these cases there does exist an incentive to shift consumption towards the more beneficial night period. This shortcoming has also been identified by the Nationale Bank Van België (2010). The NBB raises questions in relation to the variable contracts offered by suppliers, adding that they

[9]A consumer also has the option of choosing for a twofold meter which separately tracks day and night consumption. In that way a supplier is not dependent on the SLP to estimate night consumption. It will however still has to use the SLPs to estimate the quarterly-hour consumption.

[10]S21 has a night/day consumption ratio smaller than 1,3 or is a consumer without a separate night meter in case no historical records are available. S22 has a night/day consumption ratio larger than or equal to 1,3 or is a consumer with a separate night meter in case no historical records are available.

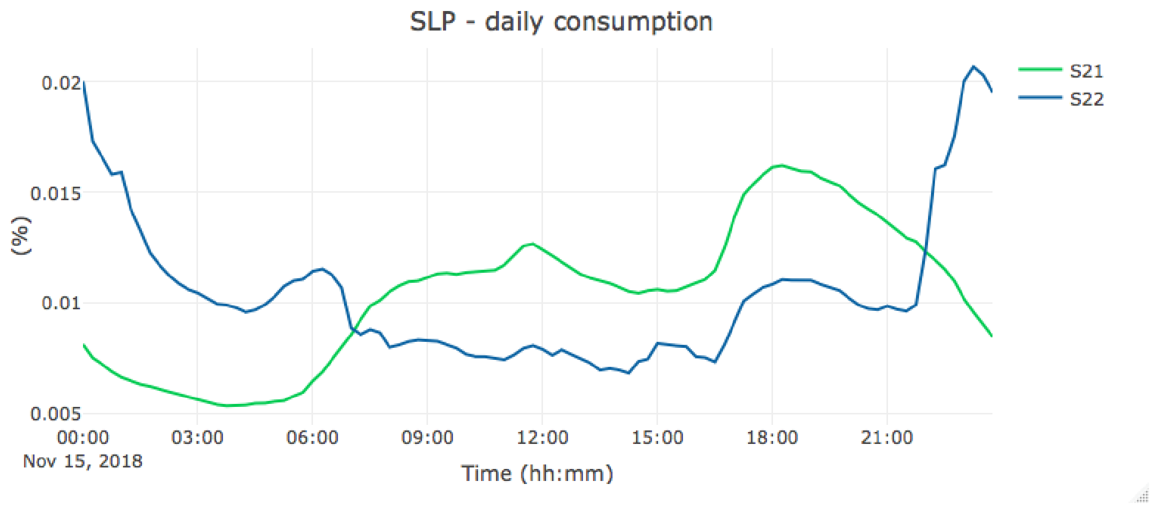

Figure 1.9: Consumption patterns of SLP S21 and SLP S22 throughout the day, averaged over all days of November. Source:*Elia*, cf. Chapter 5.

would be non-transparent towards consumers as fluctuations are only communicated ex-post on their annual or monthly bills and consumers do not have a clear image as to which SLP they belong.

1.3.4 The need for consumer centric models

As was mentioned in previous paragraphs it becomes clear that consumers are becoming a more and more important market player within the energy market in line with the trend of decentralization and democratization. At the same time, their producing and flexible capacity is currently not being directed towards a contribution to the overarching grid. Grijalva and Tariq (2011) indicate that prosumers need to be equipped with technology and intelligence that allows them to achieve their own objectives.

The model of long distance transmission followed by distribution also causes energy losses in the range of 8%-15% (International Electrotechnical Commission, 2007). Therefore systems that enable local generation, transportation and consumption could reduce these losses. As energy bills include on average 65% of non-energy component related costs (cf. supra) there clearly exists an incentive for consumers to surpass the need for costly transmission transport and distribution. Local trade through the usage of microgrids, where generation and consumption are closely linked could in relation to this serve as a solution. This possibility will be introduced in the next chapter and thoroughly examined in the chapters thereafter.

1.4 Problem statement

This chapter presented a current state and some key evolutions that will likely impact the future state of the electricity market. Out of this analysis we defined the key challenges Belgium's electricity market will face in the short to long term, these are:

- The energy market in Belgium has partly been liberalized since the beginning of the century. Together with a push for more environmentally friendly sources of energy this created an environment in which a lot of consumers evolved to prosumers. With the rise in RES also came the rise in DG, resulting in an increasingly decentralised energy system. However, anno 2018 the energy market is still organised in a top-down centralised approach, with balancing and grid responsibilities still controlled by the TSO, DSOs and ARPs.

- The rise in RES and DG, such as wind and solar increases the variability and unpredictability at both the supply and demand side due to their intermittent character. This results in more complicated forecasting issues, technical challenges and increased variability in supply. The task of the TSO, DSOs and ARPs in balancing, forecasting and delivering ancillary services are being put more and more to the test.

- A decentralised energy system requires an efficiently integrated demand side of the market in order to respond in a flexible way to the aforementioned variations in the supply of electricity. However, the lack of advanced metering infrastructure and dynamic pricing methods results in non-existing incentives for consumers to shift or lower consumption in a way that it benefits the overarching grid. Yet, prosumers are playing a more and more prominent role and are willing to become a real market player in the spirit of the democratization trend.

- The rise in RES increases the need for sources that are capable of delivering base load capacity. However, Belgium is facing a nuclear phase-out in the year 2025, losing 6 GW of its generating capacity. Investments in new thermal gas plants are therefore necessary, yet, at current electricity wholesale prices they are not profitable and the rise in RES tends to push them even more out of the market. With this increasing risk at the supply side it becomes even more important to manage the demand side of the market in an efficient and effective manner as this could eventually lower the total need for generating capacity at the supply side.

In order to facilitate a true transition into a smarter decentralized system it is necessary that the control mechanisms shift from top-down to bottom-up, similar to what is happening when it comes to generation. At this point in time the flexible potential at the consumer level is not being used. Untapping this potential could serve the overarching grid while incentivizing consumers and prosumers in a manner that is in line with the market dynamics. In the remainder of this work we analyse the impact of new technologies that could potentially shift the market design into a more decentralised organisation. Particularly we will investigate whether a new market approach, i.e. the PTP trading of electricity within microgrids, potentially supports this objective.

Chapter 2

Towards a decentralized market

2.1 Introduction

"The market rules established before the large expansion of variable RES now need to be adjusted. The energy market alone does not provide price signals which are sufficiently strong and effective for long-term planning and security of supply." - World Energy Council (2016). The World Energy Council (2016) considers nodal pricing and pooling as effective market redesign practices. The nodal price represents the local value of energy, consisting of the actual cost of energy plus the cost to deliver the energy. This incentivizes appropriate RES location. A reduction in overall variability can be achieved by pooling bids of different RES, resulting in a smaller forecast error and thus lower balancing costs. Both applications are in line with a microgrid that allows for local PTP trading.

2.2 Microgrids

2.2.1 Definition

The increasing degree of decentralisation on the generation side has led to a need to accommodate a large number of small-scale RES. The volatility that comes with these kinds of energy sources poses challenges for integration with the current system (Mengelkamp et al., 2018). This increased DG capacity is located on the load side, behind the meter, whereby the excess electricity flows to the grid. Microgrids, which are defined as *small power distribution systems consisting of loads, DG, and energy storage devices*, are considered an efficient way to utilize RES (Wang, Wang, Zhou, & Chi, 2017). The energy sources are located in close proximity of each other. DG energy resources can be of different types: RES such as solar panels and wind turbines or natural gas generators a.o.. These are owned by local prosumers, small businesses or small power companies that are connected to supply the local area (LO3 Energy, 2018). The rise of DG in Belgium is fuelled by solar PV adoption, therefore we will

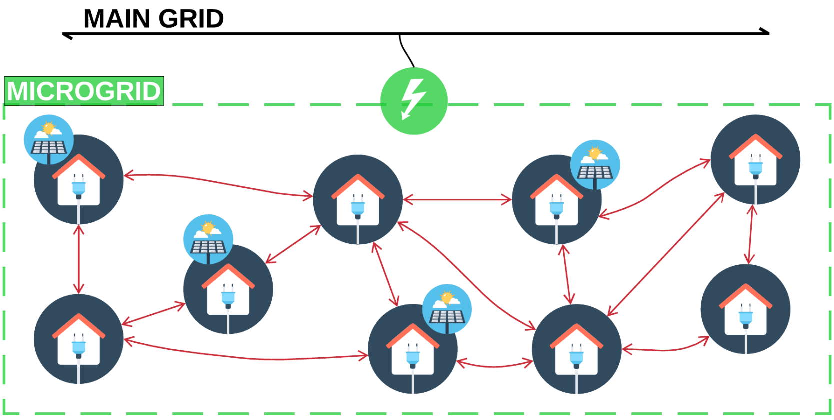

Figure 2.1: Schematic representation of a microgrid.

be focussing on integrating PV in microgrids. The key difference from a conventional power utility is that the power generators are of similar size as the loads within the microgrids and located close to the end users (Abu-Sharkh et al., 2006).

2.2.2 Advantages

Microgrids provide a number of benefits to the local level as well as to the overarching grid, in terms of increased efficiency, reliability, economic and environmental advantages (Interesting Engineering, 2015). Microgrids are environmentally friendly. RES are the most cost effective and convenient energy sources to install at small scale, allowing consumers to become prosumers and produce and consume locally. Consuming locally reduces the loads on the transmission net, possibly leading to lower transmission fees and ultimately contributing to a lower energy bill. Abu-Sharkh et al. (2006) reason that local consumption increases energy efficiency. In addition, local generation from PV installations has zero emissions. Efficiency losses due to through-the-wire losses incurred by transmission over long distances are minimised when trading locally. By virtue of good match between generation and load, the impact on the distribution network could also be minimised (Abu-Sharkh et al., 2006). Differentiating the generation across multiple small scale plants increases the security of supply. As In microgrids consumers are less dependent on a handful of central power plants and transmission that is subject to failure. Case in point, the expected blackout in Belgium in 2015. After the temporary closure of one nuclear plant lead to a shortage of 545 MW in Elia's strategic reserve (VRT, 2015). In the end a blackout was prevented. Hurricane Sandy coming ashore had a more dramatic outcome: in 2012, 8,5 million people were left without power, of which 1,3 million were still not reconnected one week later. Six months after the disaster the number of microgrid projects had dramatically increased (LO3 Energy, 2018).

Beside the financial, environmental and reliability incentives, Mengelkamp et al. (2018) indicate the existence of socio-economic incentives for the integration and expansion of locally produced renewable energy. Like keeping the profits from energy trading in the community or incentivizing investments in RES and local balancing and in that way helping counter climate change. Mengelkamp et al. (2018) argue that *'especially community incentives may lead to consumers' increased willingness to pay higher prices for local energy."*

"Microgrids can be smart and put power in the hands of the consumer. Connecting up local resources and operating them through metering systems is the basic form of the modern microgrid. The next step is [..] the smart, transactive microgrid." - LO3 Energy (2018). Increased device connectivity allow energy usage to be measured real-time. Linking this data to the microgrid network using smart meters, creates the potential to incentivize consumption in real-time through price-driven triggers (LO3 Energy, 2018). This is called DR (cf. supra).

2.2.3 Limitations

Today's energy market only allows consumers to trade with RES producers indirectly through retailers (i.e. suppliers). In the current reimbursement system (net metering, cf. supra) prosumers - consumers that generate energy, mostly from PV - have no incentive to actually consume their proper generated energy or to trade locally. Meaning there is room for improvement in the allocation of household generated electricity. This can be considered as a constraint of the optimal microgrid design that fully exploits all advantages that come with a microgrid, described above. Wang et al. (2017) name the trust issue between microgrid participants and security information risks as possible challenges when implementing a microgrid. According to Abu-Sharkh et al. (2006) the primary issue to consider is how accurate the energy supply within the microgrid can satisfy the local loads. Two factors that contribute to independency from the overarching grid are precise energy and power balance within the microgrid and seasonal match between generation and load. Energy storage and DR (cf. supra) can be effective to achieve energy balance at the daily time scale. To ensure balance over longer time scales sufficient energy capacity must be available, especially when using intermittent energy sources.

2.2.4 Design

Mengelkamp et al. (2018) have derived a framework for building efficient microgrid energy markets that includes seven market components. Based on these seven components we discuss the microgrid design.

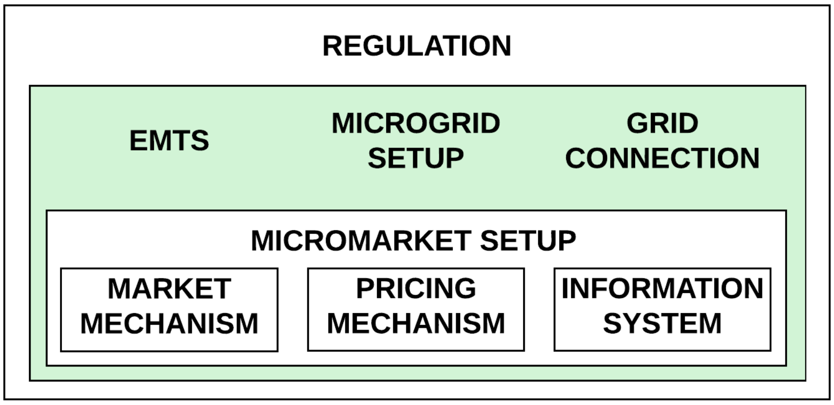

Figure 2.2: Seven microgrid components (Mengelkamp et al., 2018).

2.2.4.1 Microgrid set-up

In the microgrid set-up a clear objective is defined. For instance, this can be securing supply or integrating local RES. This objective is also apparent in the pricing mechanism (cf. supra) to ensure effective incentive to attain this objective. The microgrid participants and the form of energy traded and the used energy grid are also defined. To successfully run a microgrid a sufficient number of market participants is needed of which a subgroup should also produce energy (Mengelkamp et al., 2018). When pooling participants that balance each others consumption and generation patterns through trading, the need for balancing on the level of the main grid reduces. The number of pooled participants reduces the overall variance, resulting in smaller forecasting errors for the ARP and ultimately better balancing.

2.2.4.2 Grid connection

A virtual microgrid simply couples households over a information system. As all microgrid participants are linked to the superordinate grid, being the distribution grid that is in use today, a physical decoupling is not possible. A physical microgrid allows for decoupling by disconnecting a limited number of connection points (Mengelkamp et al., 2018).

2.2.4.3 Information system

To connect all market participants an efficient and reliable information system that monitors the market operations and provides a platform and equal access for all participants, is needed (Mengelkamp et al., 2018; Schleicher-Tappeser, 2012). In chapter 6 we investigate whether blockchain checks all the boxes.

2.2.4.4 Market mechanism

The market mechanism ensures efficient allocation of traded energy quantities by matching buy and sell orders. This mechanism should be implemented into the information system and comprises the market's allocation and payment rules, and bidding format (Mengelkamp et al., 2018). Long et al. (2017) distinguish three possible market mechanisms in a microgrid: BS, APS and mid-market rate (MMR).

Bill sharing method
The first one, BS, will group together all consumers and prosumers within a microgrid and record their total exchange of electricity between the micro- and main grid. Ultimately This results in a shared total electricity BS for all members of the microgrid. The costs and potential revenues from exports are then appropriated to the right consumers based on their individual consumption and generation. This means that all internal transactions between members of the microgrid are not billed. In this case the entire microgrid can achieve significant savings if it manages to increase the local matching of generation and demand.

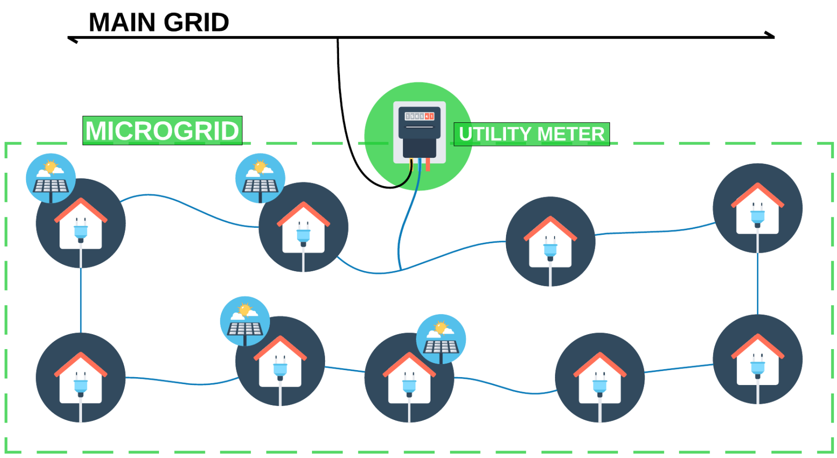

Figure 2.3: BS market mechanism, schematic drawing.

Auction-based pricing strategy
In this market model the participants are rational actors that place buy and sell orders for the excess generation available in the microgrid on a continuous basis. The market aggregator ensures that bids are matched every closing period. (i.e. 15 min). Crucial in this method is that consumers and prosumers can accurately forecast their generation and/or consumption as bids are generally placed on a day-ahead basis. Every deviation in the actual versus the forecasted quantities will impact the profitability of this actor as the deviations will have to

be compensated on the retail market (Lee, Xiang, Schober, & Wong, 2014; Wang et al., 2017; Zhang, 2017). Furthermore this set-up requires a high degree of information availability and consumer participation.

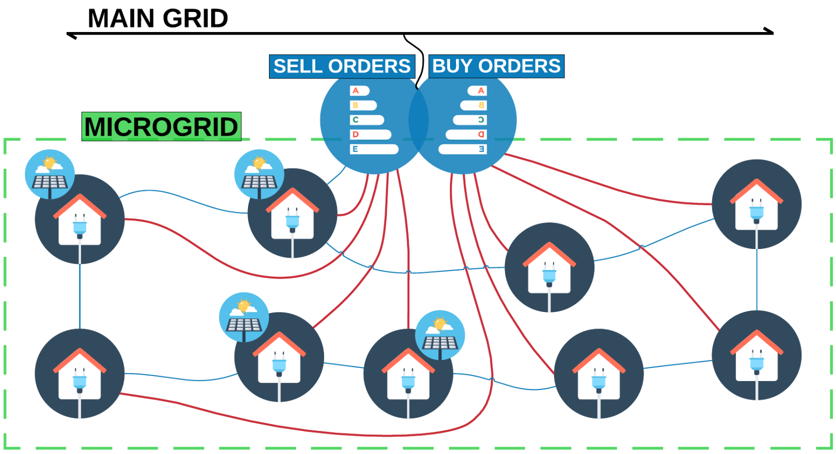

Figure 2.4: APS market mechanism, schematic drawing.

Mid-market rate

In this method the price on the PTP market will not be determined by matching buy- and sell orders, rather the PTP price resembles the mid-value in the range of the price obtained by the prosumer for selling excess electricity to the grid (i.e. the ET) and the price paid by a consumer for buying electricity from the grid (i.e. the retail price), this incentivizes both parties to partake in the PTP market (Long et al., 2017). The ultimate price received/paid by a prosumer or consumer for every unit of electricity will be dependent on the relative volumes traded on either the PTP or retail market within a specific time period (cf. 4.2.4).

2.2.4.5 Pricing mechanism

The pricing mechanism is implemented via the market mechanism, it provides efficient allocation of energy (Mengelkamp et al., 2018). Assuming that microgrid participants are rational and cooperate with each other, they will react to a varying electricity price such that their respective revenues are maximized. In this assumption, it is more plausible to use a market-driven price for direct trading than a price determined solely by the electricity suppliers or system operators (Lee et al., 2014). Using a market-driven price signals can takes into account scarcity; an oversupply of local energy should drive down the market price, while a supply shortage within the microgrid raises the market price. As long as the average microgrid price is lower than the external grid price, local markets are economically beneficial to their participants. Taking into account socio-economic reasons (cf. infra) the microgrid price can even surpass the external grid price (Mengelkamp et al., 2018).

2.2.4.6 Energy management trading system

The energy management trading system (EMTS) automatically secures energy supply on the microgrid. Therefore access to real-time demand and supply data is needed, based on this data a forecast of consumption and generation is made. The forecasted quantities are traded and the remaining shortage or excess quantities are imported or exported respectively. The goal of an EMTS is to decrease the burden of energy trading(Mengelkamp et al., 2018). Different strategies can be implemented in this EMTS. One strategy can be to minimize energy spend, or socio-economic incentives, like maximizing local energy consumption, could also determine the strategy.

2.2.4.7 Regulation

The optimal microgrid design is constrained or enforced by regulation. The distribution of fees and taxes, the integration into the market in place and the allowed market design are determined by legislative rules (Mengelkamp et al., 2018).

2.2.5 Demand response

DR is one way of coping with the variation in electricity demand. Historically, the balancing of supply and demand was done by varying the output of power plants. As this requires large investments to ensure sufficient generating capacity, utilities were looking for ways to increase flexibility on the demand side. This is done by shifting or reducing peak energy demand, making expensive energy imports and capacity investments no longer necessary (Hurley, Peterson, & Whited, 2013). Numerous advantages can explain the popularity of DR as a demand side resource of flexibility. For starters, the effect of DR on the electricity bill. Under tight electricity supply and demand conditions DR can significantly reduce the cost of generating electricity. DR has the potential of reducing the need for expensive new generation, transmission, and distribution facilities to meet these peaks in demand. DR initiatives require little investment and the payback time is relatively short. However, DR does not imply a decrease in energy consumption on the long term. Note that DR programs contribute to a more efficient allocation of generated power and in that way indirectly contribute to sustainability. In Figure 2.5, shown below, we see that consumption is reduced when prices peak (during hours 11, 14 and 17) (Rowles, 2017). In case smart meters have a large installed customer base, smart metering can make it possible to aggregate consumers on a large scale so they can provide dispatchable services to aggregators (Hurley et al., 2013). Van Isterdael et al. (2014) has quantified the potential flexibility households can offer on the Belgian electricity market through DR. Although the positive effects on balancing the grid and - when widely

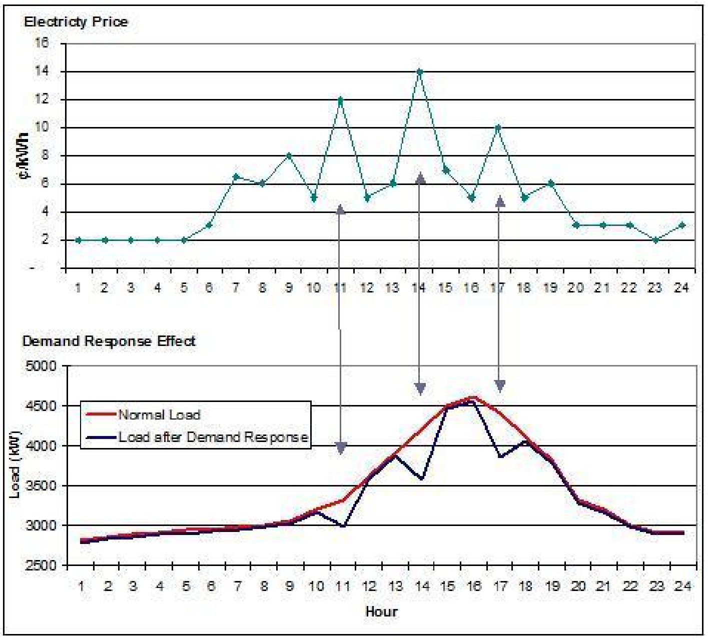

Figure 2.5: Demand response effect (Rowles, 2017).

adopted - possibly lowering the required generation capacity, are significantly smaller for households compared to industrial and commercial consumers, they are not to be neglected. However, the financial benefit per household to participate in balancing activities remains low[1], not taking into account the required investment to perform DR. In this study, the assumption that a flexible pool of households can be offered as a balancing resource via an aggregator is made, for which Van Isterdael et al. (2014) emphasizes the importance of smart meters. In the previous chapter we argued that at this point incentivized DR through dynamic pricing methods are not prevalent in the Belgian energy market. However, large industrial consumers and aggregators of smaller consumers are already enabled to provide ancillary services to Elia in the form of flexible demand programs. These DR programs involve a relatively high minimum required amount of load reduction compared to other programs, and require advanced metering infrastructure, more specifically real-time meters, which limits the number of suitable participants (Abu-Sharkh et al., 2006).

[1]The maximum revenue the aggregator can get from a ARP for offering the flexibility of one household is estimated at 23,5 EUR for a whole year. In case the flexibility of the aggregated pool of households is offered to Elia (TSO) as ancillary service, the aggregator receives only 1,59 EUR per household per year. For this calculation it is assumed that an aggregator can offer 6,205 MWh of flexibility in one year by pooling 13,178 households.

2.2.6 Battery storage

Conventional power generation is organised on the principle that power is generated when it is needed (Wang et al., 2017). This obviously does not apply to RES, as was pointed out in the previous chapter, the intermittent and unpredictable character creates a need for storage systems to optimise the allocation of these kinds of sources. *"Batteries can mitigate the intermittency of PV solar panels and thereby improve the utilization of renewables, and can improve adequacy of the system by decreasing necessary peak load."* - Van Isterdael et al. (2014). Efficiency gains can be achieved by coupling batteries of electric vehicles to the grid. However, not only will plug-in hybrid EVs significantly increase the total loads of households (Shireen & Patel, 2010) , it will mostly coincide with the already existing residential evening peak, ultimately putting more stress on distribution grids (Kavousi-Fard, Abunasri, Zare, & Hoseinzadeh, 2014; Kennel, Gorges, & Liu, 2013). In contrast, home batteries have the potential to deliver the same kind of flexibility without burdening the grid to a higher extent. As these are located behind the meter and directly connected to the power source these can tackle the intermittency problem at the source (Van Isterdael et al., 2014). At the downside, Larcher and Tarascon (2015) consider the recycling, environmentally questionable extraction methods, the toxic character and the limited supply of battery resources as limitations. Furthermore, the technology has not developed sufficiently resulting in that costs still outweigh the potential financial benefit for investors (Quoilin, Kavvadias, Mercier, Pappone, & Zucker, 2016).

2.3 Peer-to-peer trading of energy

2.3.1 Introduction

PTP trading of energy is a rather new paradigm that emerged in recent years. Especially since the liberalization trend, that has taken place in Europe and all across the world in the early 2000's, the concept has widely emerged. This can in a sense be explained by the constatation that in this more and more decentralizing industry even the smaller market players - such as prosumers - are taking on active rolls themselves. Therefore it feels intuitive that these new players can participate fully by organizing their own supply and demand of energy with established market participants or amongst themselves, excluding the traditional mediators (i.e. PTP), while assuring their own profitability. Park and Yong (2017) indicate two main reasons for why PTP trading of energy is gaining more and more interest. First of all there is the rise in DG and prosumers (cf. 1.2.2) in which consumers now own their own small-scale electricity generators. Second, with the arrival of the sharing economy and rise in popularity of services such as Airbnb and Uber, prosumers are becoming aware that now also their privately owned electricity can signify a source of value by trading amongst peers, without having to rely on established players (Parag & Sovacool, 2016).

2.3.2 Definition

Before defining PTP trading, the concept of PTP needs to be understood. Giotitsas, Pazaitis, and Kostakis (2015) define a PTP network as *"[a network in which] each peer is both a provider and receiver of resources and can directly communicate with the rest without the mediation of an intermediary node, thus enabling the network to continue operations if one or more peers seize to function."* Applying this notion on the energy market gives: A definition by Roy, Bruce, and MacGill (2016): *"PTP trading would result in an energy value payment by the distributed consumer to the distributed generator."* The definition by Zhang (2017) is similar: *"It refers to the direct energy trading among consumers and prosumers in distribution networks, which is developed based on the "P2P economy" concept."* Theoretically one could also classify suppliers and ARPs as peers in the electricity network. For these players markets already exist on which they can trade energy amongst themselves (i.e. wholesale markets). Per the previous definitions, PTP trading of energy extends this notion and considers an extra market between end-consumers, on the lowest level of the energy market hierarchy. In the literature, PTP trading is commonly associated with microgrids, at the distribution level as it seeks to balance locally generated electricity, often within the same distribution grid. To conclude, PTP trading of electricity includes the virtual direct transfer from prosumer to consumer of electricity, the subject of which is the excess generated electricity injected into the grid by the prosumer. Note that the word virtual is necessary as the physical flow of electricity is not necessarily from prosumer to consumer, it is rather a flow of information and certification that certifies the origin to be sourced from a certain prosumer. Building on the framework for microgrids as proposed by (Mengelkamp et al., 2018) we can place PTP trading within the market and pricing components of a microgrid.

2.3.3 Advantages

PTP trading of energy has found a lot of attention in recent years and the term is mostly coinciding with the rise of attention for RES, DG and microgrids. This is not a coincidence because several studies indicate that PTP trading helps in supporting a large penetration and effective usage of RES in the grid (Lee et al., 2014; Zhang, 2017; Zhang, Wu, Cheng, Zhou, & Long, 2016). The main reasons that explain this lies in the fact that grids with decentralised generation units could potentially benefit from a market approach that is as well decentralised. In a traditional set-up the suppliers and ARPs would estimate the load of their access points to the grid and contract the needed generating capacities of producers on centralised wholesale markets. From this wholesale market electricity is then transported through transmission and distribution to the the access points. On the other hand, consumers and prosumers trade on the retail market with suppliers, but not amongst themselves. This results in that prosumers will only optimise their own electricity usage without taking into account consumption or generation patterns of other consumers (Morstyn, Teytelboym, & McCulloch, 2018). Because no incentive exists to consume local generated electricity, the connection with the transmission grid is essential to balance generation and demand at the distribution grids. PTP trading on the other hand has the the capability of connecting generation and load points that are in physical proximity. An effective PTP market of electricity can connect both producers and consumers directly, without having to go through an intermediate supplier (Lee et al., 2014). Ultimately this contributes to a better balance in local generation and demand (Mihaylov et al., 2014; Zhang et al., 2016) as local consumers and prosumers will base their consumption more on time-related pricing signals that relate to the local availability of electricity (Nieße et al., 2012; Roy et al., 2016). Balancing at the consumer or distribution level reduces the need for the exchange between the distribution and transmission grid (Zhang, 2017), in turn this leads to reduced congestion of the transmission and distribution lines and avoided transmission line losses resulting in reduced overall transportation costs (Ekanayake, Jenkins, Liyanage, Wu, & Yokoyama, 2012; Lee et al., 2014). The reduction of dependence on the mostly 'grey' energy coming from the transmission system increases the usage of local and green energy and leads to a more effective utilization of RES (Mihaylov et al., 2014). In conclusion, PTP trading could facilitate the coordination of generation and demand on distribution grid-level, hereby lowering overall system costs, increasing system reliability and reducing the need for investments in upstream generation and transmission infrastructure (Morstyn, Farrell, Darby, & McCulloch, 2018; Morstyn, Teytelboym, & McCulloch, 2018).

2.3.4 Economic value and financial incentives

Although the previously indicated technical value for the overall system and reduced system costs, the real opportunity from PTP trading should come from the alignment of consumer, prosumer and grid operator interests. This is achieved by creating financial incentives for consumers when partaking in PTP trading over traditional retail market trading with suppliers (Lee et al., 2014; Morstyn, Teytelboym, & McCulloch, 2018). As indicated by Park and Yong (2017) this implies that PTP trading of energy will only be viable as long as the business model behind it can assure added value in the form of profitability of both prosumers who sell electricity from RES and consumers that purchase electricity from the prosumers. Therefore a PTP network model should deliver additional value over a more traditional model in which consumers trade electricity through their retailers. It also has to be noted that such new business models might negatively affect already existing market players such as suppliers. If a PTP electricity trading model succeeds in delivering additional value to prosumers it also serves as an extra incentive for the investment in RES. Currently there exist many ways in which excess generation by prosumers is reimbursed. In Belgium prosumers currently benefit from the NM method, however, with the arrival of smart metering it is expected that this scheme will be replaced by a feed-in tariff (FIT) or more precisely an ET.

2.3.4.1 Current reimbursement schemes for prosumers

The most common methods in Europe are the usage of NM and a so called FIT or ET (European Commission, 2017b). In Belgium, the NM method is still being used in both Flanders and Wallonia. The method of GEC (which was obtained for every kWh produced) has been abolished in 2014. In Flanders the responsible Minister of Energy, Tommelein is planning to let solar owners install smart meters in 2019. With properties such as bidirectional metering it is expected that the NM method will be replaced by a FIT or ET, similar decisions are expected to be taken in both Wallonia and Brussels, although the time frame is yet unclear. Prosumers who are currently profiting from the NM method will continue to do so for 20 more years, including all prosumers who installed a PV installation before January 2021 (Vlaamse Overheid, 2018a).

NM - uneven distribution of costs

Consumers with DG sources such as solar PV installations are currently (2018) billed in the same way as a normal consumer, namely based on its total net yearly consumption that is then allocated to quarter-hourly periods according to their corresponding SLP (cf. 1.3.4). However, it can be argued that prosumers make use of the services of grid-operators while not fully paying for them. At the same time prosumers who inject more than they consume lose a part of its saving potential. We can demonstrate this by two examples:

<u>Example 1: net-consuming prosumer</u>

Household A owns a residential PV installation with 3 kWp capacity. According to figures of (Vlaamse Overheid, 2018c) this would potentially deliver about 2400 kWh on a yearly-basis. While an average a Belgian household consumes 3500 kWh of electricity. The average retail price of electricity is 0,25 EUR/kWh[2]. This gives a yearly electricity bill of:

$(3500\text{kWh} - 2400\text{kWh}) = 1100\text{kWh}$ net consumption at a price of 200 EUR

or a saving of $2400 * 0,25 = 600$ EUR due to the usage of solar PV.

Traditional meters do not separate production from consumption, instead a reversing meter is used which will display the net consumption over the period. This means that if prosumers manage to completely balance their aggregated consumption and production over the billing

[2]In the assumption of a fixed supplier contract. (i.e. no separation in day-/night tariff nor monthly variation)

period, they will not pay for the services provided by grid operators as the total bill falls to zero. However, an aggregated net consumption that equals zero does not necessarily mean that a prosumer has never consumed from the (Wood & Borlick, 2013). In real-time there is almost never an exact match of supply and demand by an individual household (illustrated in Figure 2.6), resulting in that a prosumer will still need services provided by the grid operators. In fact prosumers use the grid as a form of storage mechanism; it stores its excesses on the grid and discharges in the case of a shortage. This means that ARPs and grid operators take on the task of balancing, frequency and voltage control and assure the prosumers' supply of electricity (Wood & Borlick, 2013).

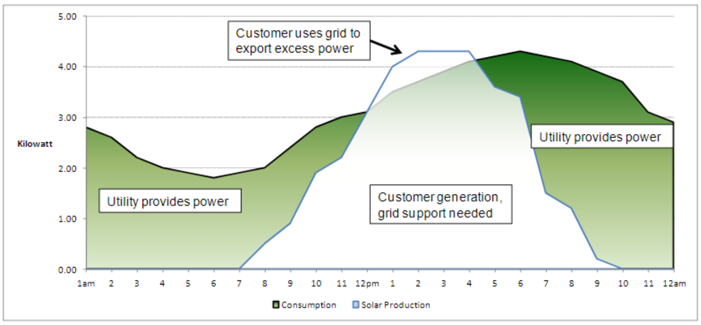

Figure 2.6: Supply and demand curve of an individual household (Wood & Borlick, 2013).

These prosumers also put even more stress on the infrastructure provided by the DSOs and TSO due to the induced bidirectional flow, the technical requirements and the need for better management systems (cf. 1.3.3), which in turn increases the costs for these grid operators. Yet, the savings on their electricity bill does not only include the energy share but also the share that goes to transmission, distribution and taxes. As illustrated in Figure 2.7, the electricity component only amounts to 19% (Flanders), 23% (Wallonia) and 33% (Brussels) and grid-related costs amount to 45% on average (FEBEG, 2017). In the current set-up consumers also save on this 45%, including taxes this amounts to 60% to 65%. DSOs are obliged to pass on these extra costs on their customers in the form of extra transportation costs, paradoxically it are the consumers without PV installations that mostly bear these costs instead of PV owners who are causing it.

The governments of Belgium acknowledged this imbalance and tried to obtain a better allocation by installing a so called prosumer tariff. This was installed in Flanders in 2015 (Vlaamse Overheid, 2018b) and to be installed in the Walloon region in 2020, in Brussels they plan to effectuate a roll-out of bidirectional meters (cf. 1.2.4) (Eneco, 2017). The aim of which is to let the DSOs translate these costs directly to the PV owners for their usage of the grid. The tax is linked to the installed capacity of the PV installation and not to the actual production.

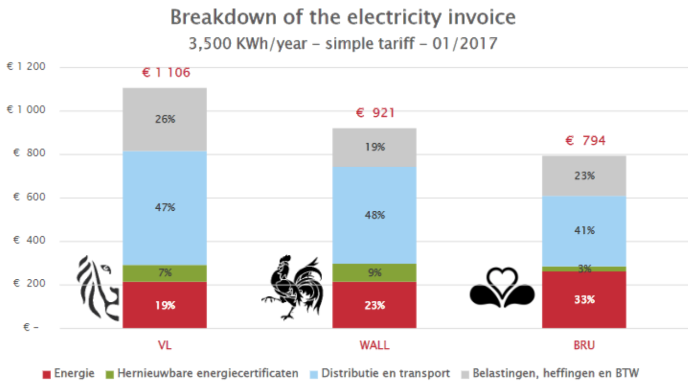

Figure 2.7: Breakdown of the electricity invoice (FEBEG, 2017).

In the previous example this would increase the electricity bill for household A with about 300 EUR.[3]

Example 2: net-producing prosumer

Household B owns a residential PV installation with 5 kWp capacity. This would potentially deliver about 4000 kWh on a yearly basis. This gives:

$4000\text{kWh} - 3500\text{kWh} = 500\text{kWh}$ net production.

At the end of the year, the meter of household B will read 0 kWh and not -500 kWh. Therefore the maximum saving a PV owner can obtain is equal to its total consumption. In this case $3500 * 0,25 = 875$ EUR. This also implies that household B did not obtain 250 EUR $(= 1000 * 0,25)$ of savings due to the excess production. The consequence is that a prosumer is never incentivized to become a net-producing entity and will aim for a net-consumption of zero. Although the grid could potentially benefit from this additional supply of green electricity. If we take into account the prosumer tariff the situation in which a prosumer manages to generate more than he consumes on a yearly basis will result in a evermore increasing electricity bill proportional to the PV installation, as the tariff is based on the size of the PV installation. In Figure 2.8 we see that the most value is created when the prosumer manages to balance his entire generation and consumption. From that point the retail component will reach zero (and does not go negative) and increased PV size will only increase the prosumer tariff leading to an increased overall electricity bill.

Roll-out smart metering 2019: Implementation of an ET?

The European Union committed itself to achieving an 80% adoption rate of smart meters across Europe in 2020. The Flemish minister of Energy, Bart Tommelein plans to roll-out smart metering devices (cf. 1.2.4). With clear advantages such as continuous metering which could allow dynamic pricing methods and reduced administrative burden for DSOs,

[3]Based on the average prosumer tariff over all DSOs in Flanders.

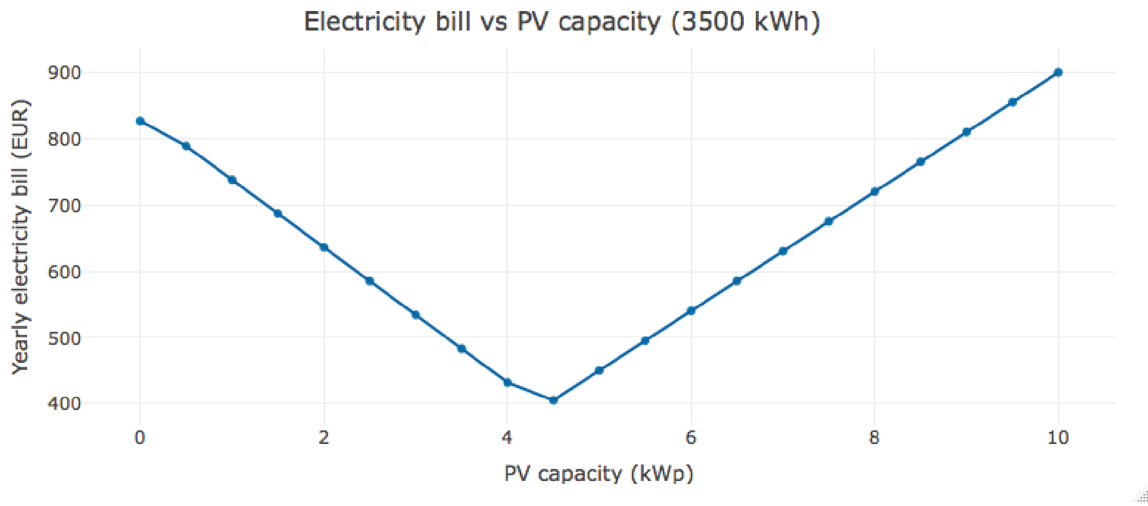

Figure 2.8: Electricity bill in function of PV installed peak capacity, based on a yearly consumption of 3500kWh.

they also allow to track the separate production and consumption of a household through bidirectional metering. This would allow the suppliers to bill their consumers based on their total consumption instead of their net-consumption in the NM method. On the other hand, prosumers would now be reimbursed for the amount they inject into the grid in the form of a FIT or ET.

Export tariff

The Flemish government likely plans to install such an ET method with the arrival of the smart data system "Atrias" in combination with the roll-out of smart meters (VREG, 2018). Per definition a FIT is an amount of money obtained for every amount of energy a prosumer generates by itself, regardless if it consumes or exports this generation (Tariff, n.d.). The method of GEC certificates can in this way be considered as a form of a FIT, as it reimbursed every kWh of electricity produced. However, with the expected arrival of smart metering in Belgium it will now become possible to distinguish between self-consumed generation (i.e. behind-the-meter consumption) and generation that was fed back into the grid. Therefore a lot of countries do not use a FIT but rather a so called ET, as the reimbursement is based only on that part of the generation that is fed back into the grid, the excess generation. These tariffs can be fixed or variable, no standard is currently being used in Europe. However, Minister Tommelein vaguely indicated that the reimbursement would probably be linked to the electricity wholesale prices at the time of export to the grid. As this would make the tariff is subject to market principles it can be expected that prosumers will not obtain a great price for their delivered electricity as moments of injection will be accompanied by the injection of other PV owners resulting in an over-abundance of solar generated electricity. With increasing penetration rates of PV owners a decrease of these FITs is expected (Long et al., 2017). On the upside, as prosumers do pay for their consumed electricity of the grid - including grid costs - this means that a prosumer tax would disappear.

2.3.4.2 PTP trading as financial incentive of RES

With the rise in DG and the resulting excess generation injected into the grid, suppliers are experiencing more and more periods with an over-abundance of electricity coming from DG. In many countries the FIT and ET have in relation to this decreased significantly, with decreasing profitability for prosumers as a consequence. On the contrary, PTP trading transforms prosumers from price-takers towards price-makers (Long et al., 2017). Roy et al. (2016) indicate that NM and FIT methods do not account for the locational and temporal variation in the value of energy exports and the potential avoided network augmentation. FIT en NM methods do only account for the load and generation of individual prosumers, however, the impact on the grid is highly interrelated with the load and generation patterns of other consumers and prosumers, therefore these methods do not facilitate in coordinating effective electricity usage of a group of consumers. Rather will these consumers optimize their own financial position, which is not always aligned with the grid operator interests (Morstyn, Teytelboym, & McCulloch, 2018). PTP trading on the other hand induces local trade during time periods that are either more favourable for prosumers or consumers. The time-related pricing signals on the PTP market incentivizes consumer and prosumer behaviour to better align their generation and consumption. A minimal condition for PTP trading to be successful is that the prices on the PTP market are located in the range of the retail price consumers pay to suppliers and the price that prosumers obtain for injecting their excess electricity into the grid (Lee et al., 2014). At that point, consumers and prosumers will financially be incentivized to participate in the PTP market instead of on the retail market. As most distributed renewables in Belgium consist of PV installations, PTP trading is not yet sufficient to fulfil the total demand during an entire day; therefore the role of suppliers remains vital to deliver the electricity that was not matched on the PTP market. Yet, the higher the penetration rate of RES, the more electricity supply will shift from the retailer to PTP market, and less revenue is generated at the suppliers side. A possible reaction to this could be for suppliers to elevate their FIT in order to compete with the PTP market, which in turn profits prosumers. Wang et al. (2017) and Lee et al. (2014) indicate that prosumers as well as consumers can gain significantly from participating in a PTP market over a retail market, increasing the return on investment (ROI) in RES. Roy et al. (2016) simulated such a PTP market for the Australian electricity market and concluded that a PTP market results in monetary benefits for prosumers over traditional retail trading, but for consumers there is no significant saving potential from a PTP set-up. Yet, a high volume of consumers is needed to facilitate a liquid PTP market. However, apart from pure financial incentives, PTP trading also induces more societal related advantages. The fact that electricity is being bought locally from RES are qualitative factors that likely influences the behaviour of consumers and might increase participation in a PTP market even though prices are similar or even premium to a traditional retail market (Hasse et al., 2016; Mengelkamp et al., 2018).

Chapter 3

E3-value modelling of as-is (net metering) and to-be (export tariff) energy market

3.1 Introduction

Historically the energy market was highly vertically integrated and centralised producers provided consumers in a top-down, sequential approach. The past liberalisation and present decentralisation trend increase the complexity of the value chain in the energy market. Moving from a sequential flow of value activities to a more and more interconnected network of value transfers. In this section we use the E3-value modelling technique introduced by (Gordijn, Akkermans, & Van Vliet, 2001) in order to map all the value streams of this increasingly complex energy market. We start with a high level overview of the organisation of the energy market, after which the focus will be on how prosumers are currently integrated in this market. We compare two different methods in the way prosumers are reimbursed for their DG; the current NM method and the widely used and expected to be implemented ET method.

3.2 High level model of the electricity market

In chapter 1 we gave a brief overview of the organisation of the current energy market. E3-value modelling provides a useful framework for visualising the value-adding activities and exchanges between the market participants in this network. To reduce the complexity of the model we distinguish between one model including the generation and supply network (Figure 3.1) and another model including the activities and exchanges related to balancing (Figure 3.2).

3.2.1 Generation and supply of electricity

The sequence within the electricity market is initiated by a *consumer* wanting to consume electricity. We consider a prosumer to be treated as a regular consumer by other actors, that also happens to consume or inject its generated electricity, i.e. it has the value activity *Electricity Generation*. Starting from the origin of this electricity to be consumed, the *centralised producers* generate consumable energy (in this case, electricity) from primary resources. From this point on we make a distinction between the physical flow of electricity denoted by 'electricity' and the administrative flow of electricity denoted by 'electricity*'.[1]

In the first case the producers deliver physical electricity to the transmission net. The TSO manages the transmission of electricity to the distribution net and maintains the infrastructure. The *DSO* manages the distribution net and transports electricity on lower voltage levels to end-consumers. DSOs are also responsible for metering the consumption, which allows suppliers to charge consumers accordingly.[2] On the other hand *suppliers* are responsible for supplying the desired amount of electricity to their consumers. They do this by forecasting the expected offtakes by the consumers within their perimeter, they either perform this activity as an *ARP* or outsource this to an ARP, which is explained in the next model. Suppliers purchase electricity* from the centralised producers a rato the wholesale price and handle the billing of consumers at a retail price based on their net consumption over the year period. Together with this administrative flow, the supplier is dependent on the TSO and DSO for delivering the physical electricity. A supplier repartitions the amount paid by the consumer to all relevant parties involved: a transmission fee to the TSO, a distribution fee (including prosumer tariff for prosumers) to the DSO and taxes and levies to the *regulator*. The resulting difference between all incoming payments from consumers and the outgoing repartitioning fees constitutes the margin for the supplier which it uses to pay its internal costs and potentially generate a profit. The prosumer is compensated indirectly via a reversing meter (i.e. NM), in return a prosumer tariff is paid to the DSO for grid usage (through the supplier). Note that the metering activity performed by DSOs is included in the distribution activity.

3.2.2 Balancing

As DG is posing an extra challenge on balancing in the electricity market, we explicitly included these activities in the second model. The *TSO* is responsible for balancing the overall grid and outsources this activity to *ARPs* who ensure balance within their perimeter. An

[1] For the remainder of this work we will use the asterisk to indicate administrative electricity quantities instead of physical quantities.

[2] Note that we did not explicitly include the metering activity as it would only add to the complexity of the model.

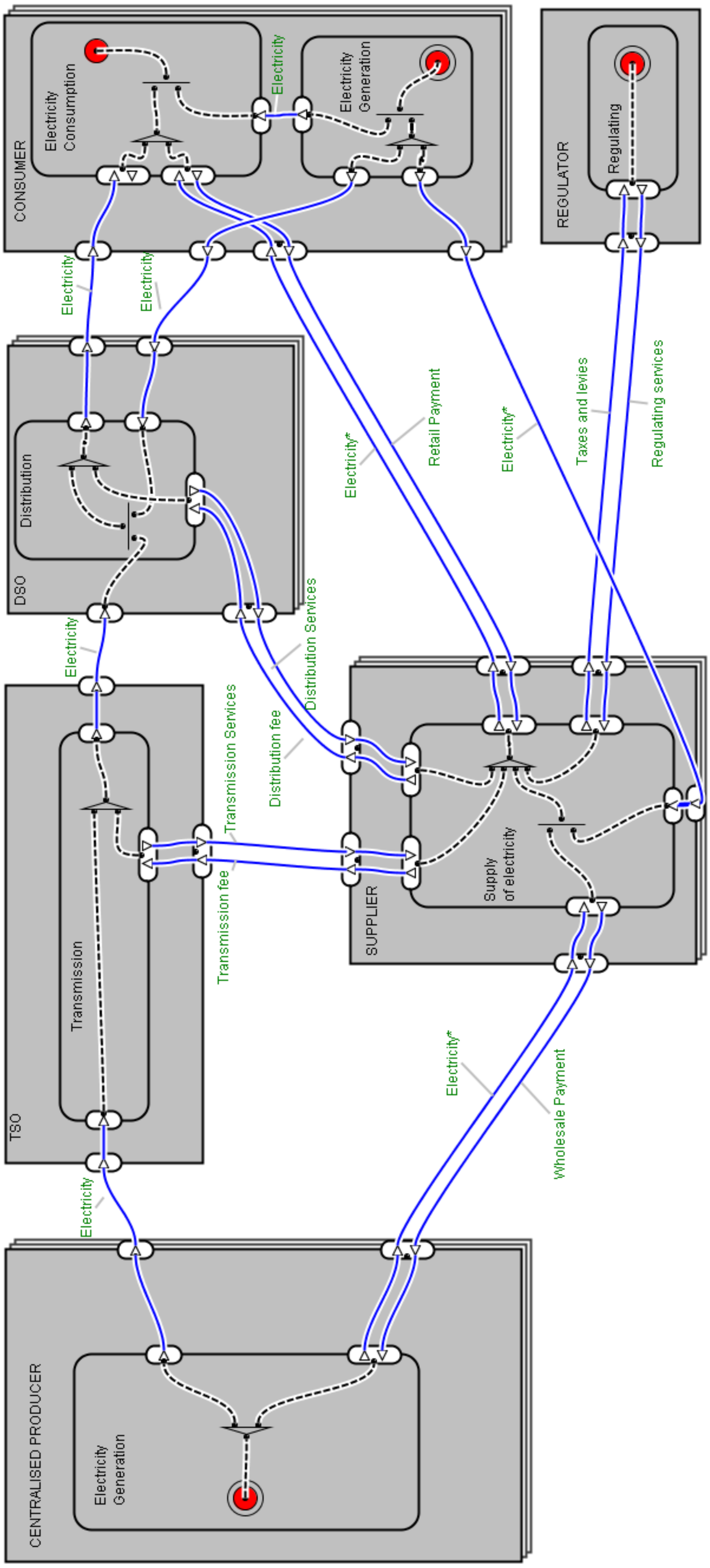

Figure 3.1: E3-value model: generation and supply.

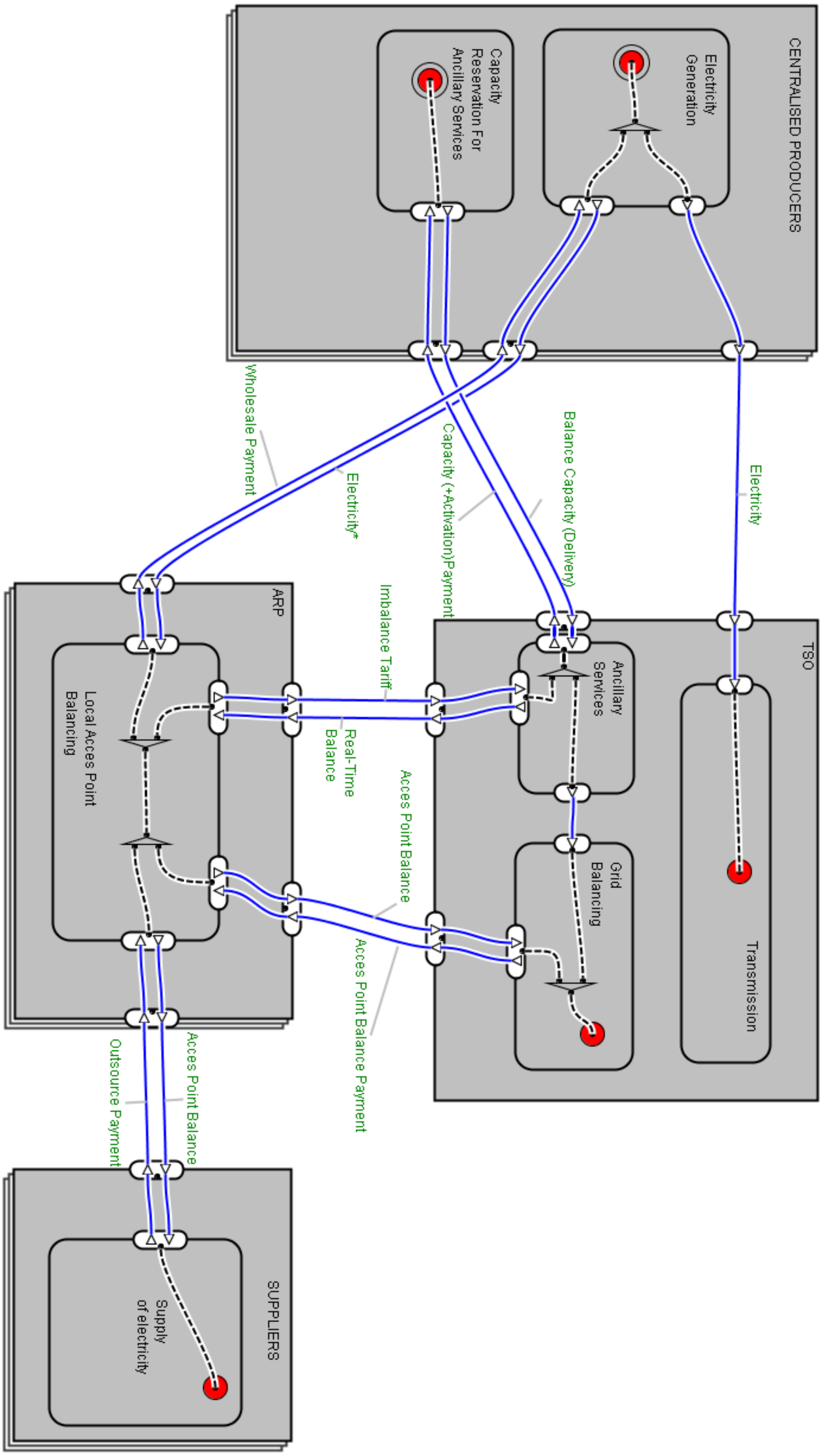

Figure 3.2: E3-value model: balancing.

ARP is a role that can be fulfilled either by a *producer*, a *supplier*[3] or a large *consumer*. In case of the latter, no supplier is involved and electricity is purchased directly from the producers. Every supplier should either perform the ARP role itself or be connected to an ARP[4]. ARPs place buy orders for the desired amounts of electricity and are matched with the sell orders of centralised producers through the wholesale markets[5] and trade electricity amongst each other[6] in order to balance the grid within their perimeter on a quarter-hourly basis. When an imbalance in the perimeter of an ARP does occur in real-time, ancillary services of the TSO are invoked (cf. Appendix A). The TSO has reserved capacity of producers which it can activate in case of a real-time imbalance. It pays producers a fixed reservation payment and a potential activation payment. The TSO will then charge the ARP in case with an imbalance tariff. A balanced grid is achieved by the combination of local access point balanced parts of the grid performed by ARPs and residual balancing through ancillary services by the TSO, that also restores the local access point balance.

3.3 Model assumptions and parameters

Having analysed the general value adding activities and exchanges in the current electricity market we now focus on the value for consumers, prosumers and suppliers under two different prosumer reimbursement schemes: NM and ET and - in the next chapter PTP trading - using the E3-value modelling technique. Based on the mapping of these value streams within each market set-up we will then give a comparative quantitative analysis by analysing the profitability for each participant under each scenario (cf. chapter 5). As the basis for the analysis we consider a single distribution grid (i.e. one DSO) and all participants are connected to the same supplier. Note that we merely focus on the interaction between consumers/prosumers and suppliers, the interaction between supplier and other market players (such as bill repartitioning) has been abstracted. To reduce complexity we will incorporate the task of an ARP into the role of the supplier. In reality both roles can be performed by two single entities when a supplier subcontracts an ARP to perform balancing at one of the access points the supplier serves. However the supplier will always bear the balancing responsibility, no matter if it performs the balancing activity itself. Hereafter we use the term 'participant' as an overarching term for prosumers and consumers.

[3]In that case the ARP role and supplier role coincide completely and form one entity in the model.

[4]Note that in some cases the supplier and aggregator role coincide and would form one entity in the model. In that case suppliers interact with consumers as well as with the wholesale market.

[5]These include the year-ahead, day-ahead and intraday market as explained in Appendix A

[6]Note that we did not explicitly include the trade between ARPs as this would only add to the complexity of the model. This trade is implicitly included in the value activity *Local Access Point Balancing* and occurs on the intraday market autoref Appendix A.

3.3.1 Model parameters

We first list all relevant general parameters in Table 3.1. If needed extra parameters are included per method. All electricity quantities are in kWh.

Table 3.1: Model parameters. All electricity quantities are in kWh.

parameter	description
$Q_i(t)$	total consumption of participant i in time period t
$Q_{e,i}(t)$	excess consumption of participant i in time period t
$Q_{rt,i}$	total yearly electricity purchased from supplier by participant i
$G_i(t)$	total generation of participant i in time period t
$G_{e,i}(t)$	excess generation of participant i in time period t
$G_{rt,i}(t)$	self-generated consumption of participant i in time period t
$Q_{wh}(t)$	Purchased electricity at wholesale market by supplier in time period t
$MG_{out}(t)$	total electricity outflow from distribution to transmission in time period t
$MG_{in}(t)$	total electricity inflow from transmission to distribution in time period t
$P_{rt}(t)$	per unit electricity retail price ($\frac{EUR}{kWh}$)
$P_{wh}(t)$	per unit electricity wholesale price in time period t ($\frac{EUR}{kWh}$)
B_i	yearly electricity bill of participant i (EUR)

3.4 As-is model: net metering

At the time of writing (May, 2018) prosumers are not directly compensated for the electricity they inject into the grid. The current metering process does not allow to measure the excess generated electricity within small time periods as the majority of the meters are analogue. This implies that at the end of the year the DSO obtains one[7] meter total and prosumers are indirectly compensated as they are only charged for their net consumption (total consumption minus generated electricity *over the total year*), as was explained in the previous chapter.

3.4.1 Additional assumptions and requirements

In the first model we will not treat prosumers and consumers as separate actors as their interactions with other actors in the value model do not significantly differ in terms of value exchange. The only difference is that consumers do not perform the value activity *electricity generation*. Prosumers also pay a prosumer tariff T_i that is related to the size of its PV installation (See Table 3.2). We also make the assumption that all prosumers in NM pay a

[7]In the case a prosumer chooses for a day- and night tariff he will have two meter readings: one for day and one for night.

single retail tariff, i.e. no separation between day and night.[8]

Table 3.2: Extra model parameter: prosumer tariff.

parameter	description
T_i	yearly prosumer tariff based on PV capacity of participant i

3.4.2 Qualitative description

If the consumer has DG it will first satisfy a part of its total consumption with $G_{ci}(t)$ (i.e. behind the meter consumption). In the case that $G_i(t) > Q_i(t)$, the excess generated electricity $G_{e,i}(t)$ will be injected back into the grid. Divided in a physical flow to the DSO and an administrative flow to the supplier. Note that there is no returning flow from supplier to prosumer for the $G_{e,i}(t)$ it obtains. In NM the supplier does not explicitly pay for the electricity generated by the prosumer. This is explained by the fact that a supplier cannot assign the injected electricity to an individual prosumer due to the lack of smart metering. However, as excess generation results in a reversing meter at the prosumer it lowers its net consumption. Therefore the supplier implicitly pays for this excess generation in the form of a lowered electricity bill for the prosumer at the end of the year. The interesting fact is that in NM the total quantity the prosumer purchases from the retailer at the end of the year $Q_{rt,i}$, does not necessarily equal the total amount it consumed from the grid, the sum of $Q_{e,i}(t)$. This is because excess generation from a certain period can compensate excess consumption in other periods. Note that all individual and time period related parameters are not prevalent to the DSO and suppliers. Only the participant‘s year total $Q_{rt,i}$ is prevalent to the supplier through the physical check of their meter. Based on which it will charge the consumer.
The ultimate electricity bill B_i for a particpant i in NM amounts to:

$$B_i = \left(\sum_{t=1}^{T} Q_{rti} P_{rt} \right) + T_i \tag{3.1}$$

With:

$$Q_{rti} = \sum_{t=1}^{T} (Q_i(t) - G_i(t)) \tag{3.2}$$

A consumer (i.e. no value activity *electricity generation*) only has the option to purchase its total consumption $Q(t)$ from its retailer at a price P_{rt}, in this case: $Q_i(t) = Q_{e,i}(t) = Q_{irt}(t)$, such that

[8] Based on the assumption of rational prosumers: in NM excess generation during the day can compensate for consumption in night periods which increases profitability.

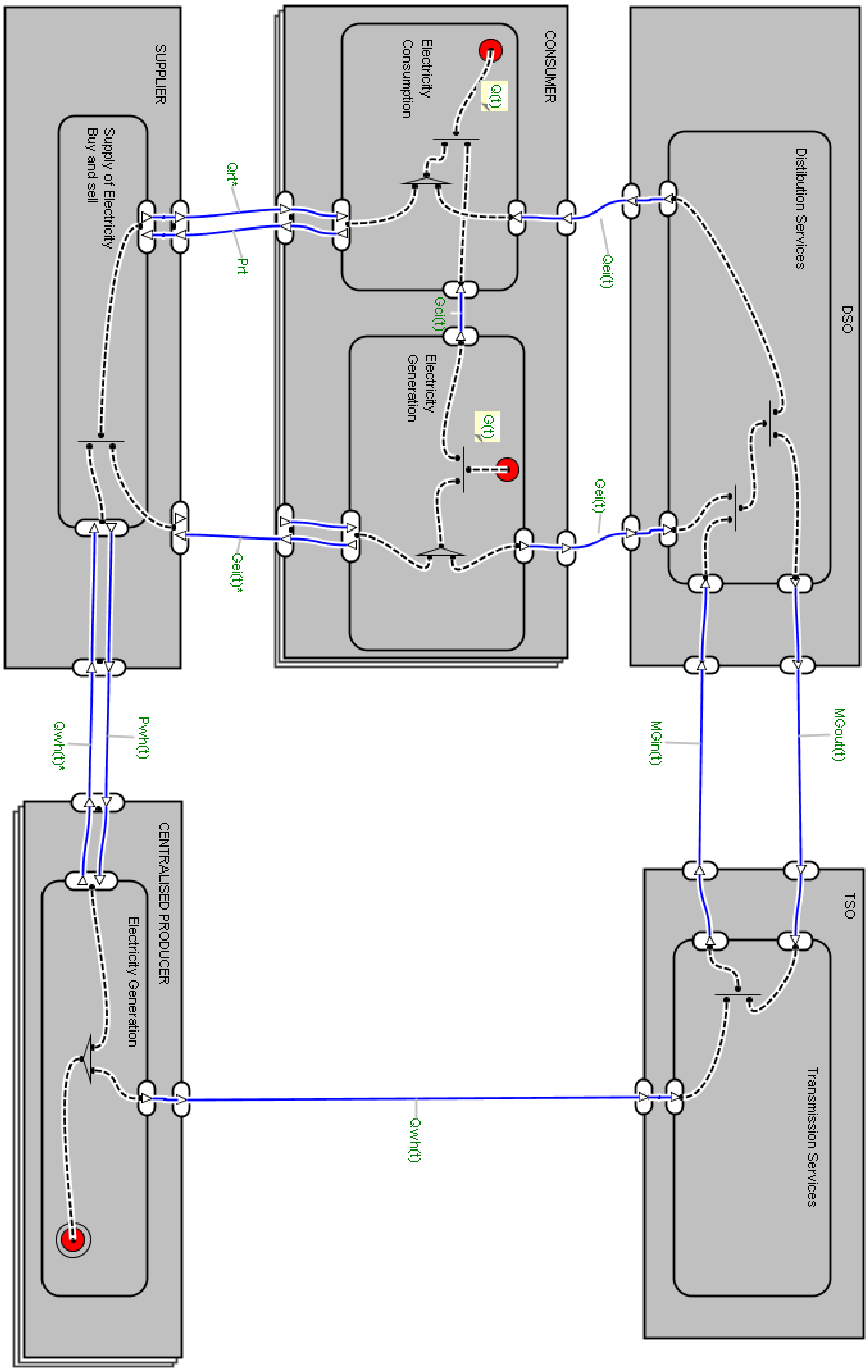

Figure 3.3: E3-value model: net metering method.

$$\sum_{t=1}^{T} Q_i(t) = Q_{rti} \text{ and } G_i(t) = 0 \tag{3.3}$$

3.5 To-be model: export tariff

As was stated in the previous chapter, the regional ministers of energy are planning the roll-out of smart metering in the coming years. The expectation is that this roll-out will be accompanied with a phase-out in using the NM method that allows no transparency into the gross consumption and production within a specific time period, towards an ET where a prosumer is compensated for the number of kWh it injects into the grid and pays the total it consumes from the grid. Anticipating this phase-out, we analyse the value exchanges in such a market set-up.

3.5.1 Additional assumptions and requirements

Note that a bidirectional meter with near continuous metering is required for the implementation of ET. In order to distinguish between generation and consumption within a certain time period t. In this way the supplier and grid operators gain knowledge about the quantities consumed or generated by a participant, within a specific quarter-hourly time period. An extra parameter is introduced: a fixed ET P_{et} which is obtained for every kWh injected into the grid.

3.5.2 Qualitative analysis

As the metering for electricity injection by prosumers is now separated, the prosumer can now be compensated directly by the supplier for the amount of excess electricity that is injected into the grid as indicated by $G^*_{e,i}(t)$.

Compared to the NM model there is only a subtle difference. In general all streams related to the physical stream of electricity remain the same. However the singular value exchange between prosumer and supplier for the excess generation $G_{e,i}(t)$ in NM is now replaced by a bidirectional exchange as the prosumer will be reimbursed for its total excess generation a rato of P_{et}. The changes compared to NM are indicated in red in Figure 3.4.

In practice, by dividing the year into smaller periods of 15 minutes allows to estimate the total excess generated electricity per time period. Taking the sum of $G_{e,i}(t)$ over all time period then results in the total excess generated electricity over the year. The calculation of Q^*_{rt}, i.e. the yearly electricity purchased from the supplier is no longer the difference between total consumption and generation over the year period, rather Q_{rt} is now the sum of all excess consumption in time period t, $Q^*_{rt}(t)$. The ultimate electricity bill for a prosumer in

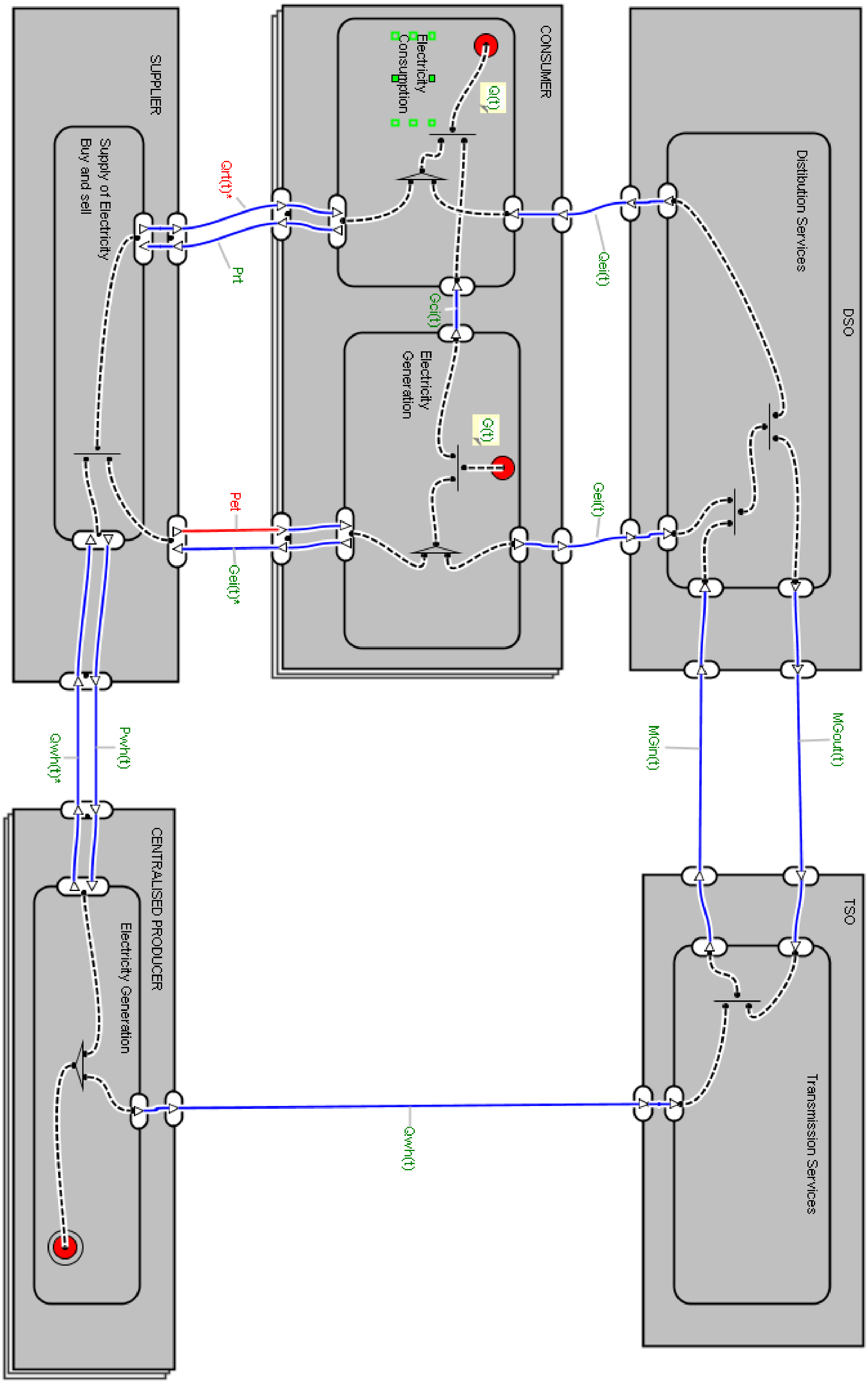

Figure 3.4: E3-value model: export tariff method.

ET amounts to[9]:

$$B_i = \sum_{t=1}^{T} (Q_{e,i}(t)P_{rt} - G_{e,i}(t)P_{et}) \tag{3.4}$$

In the extreme case that $t \rightarrow 0$, i.e. perfect assignment of generation and consumption, every administrative flow of electricity $Q^*_{rt}(t)$ and $G^*_{e,i}(t)$ equals the physical quantities of $Q_{e,i}(t)$ and $G^*_{e,i}(t)$, such that all externally purchased electricity from the supplier equals the consumed physical electricity from the grid.

[9]The electricity bill for a consumer will not change compared to NM

Chapter 4

E3-value modelling of peer-to-peer electricity trading networks

4.1 Introduction

Having modelled the current (NM) and potential future (ET) method of reimbursing excess PV generation and taking into account that these methods do not provide accurate price signals that benefit the coordination of prosumer and consumer behaviour, as well that these methods do no fully support the alignment of consumption with the availability of local generated electricity (cf. 2.3.4). In this chapter we investigate how a new market paradigm; a PTP market of electricity can potentially be organised. Building on the E3-value modelling technique we propose a market set-up that integrates local PTP trading of electricity within a microgrid. In this chapter we give a qualitative overview of the relevant roles, value activities and value streams required in this network.

4.2 Microgrid design, assumptions and requirements

Enabling PTP transactions requires a set of conditions to be fulfilled and a new energy network design. Using the framework introduced by Mengelkamp et al. (2018) we propose a microgrid design with the capability of facilitating PTP trading of electricity. Based on this design the corresponding PTP electricity trading network is modelled in Figure 4.2. Changes compared to the ET model are indicated in red. The following extra parameters and variables compared to the previous chapter are defined in Table 4.1 and Table 4.2, respectively.

Table 4.1: Microgrid parameters. All electricity quantities are in kWh.

parameter	description	formula
$G_{tot}(t)$	total sold generated in time period t	$G_{tot}(t) = G_{ptp}(t) + G_{rt}(t)$
$Q_{tot}(t)$	total electricity quantity purchased in time period t	$Q_{tot}(t) = Q_{ptp}(t) + Q_{rt}(t)$
$G_{rt}(t)$	total generated electricity quantity sold on retail market in time period t	$\max\left\{\sum_{i=1}^{I}\left(G_{e,i}(t) - Q_{e,i}(t)\right), 0\right\}$
$Q_{rt}(t)$	total electricity quantity purchased on retail market in time period t	$\max\left\{\sum_{i=1}^{I}\left(Q_{e,i}(t) - R_{e,i}(t)\right), 0\right\}$
$G_{ptp}(t)$	total generated electricity quantity sold on PTP market in time period t	$\min\left\{\sum_{i=1}^{I} G_{e,i}(t), \sum_{i=1}^{I} Q_{e,i}(t)\right\}$
$Q_{ptp}(t)$	total electricity quantity purchased on PTP market in time period t	$\min\left\{\sum_{i=1}^{I} G_{e,i}(t), \sum_{i=1}^{I} Q_{e,i}(t)\right\}$

Table 4.2: Microgrid Variables. All prices are in EUR.

variable	description
$P_{co}(t)$	per unit price of consumed electricity in time period t
$P_{ex}(t)$	per unit price of sold generated electricity in time period t

4.2.1 Microgrid set-up

The microgrid considered includes a set of participants in the PTP network. These consist of prosumers with a privately owned PV installation and consumers. The subject of the PTP market within this microgrid includes the certification of consumption of excess electricity generated by the prosumers for which the consumers pay a certain per unit price. The purpose of the trading network is to facilitate an increase in consumption of locally generated electricity. A key assumption is that we consider participants in this network as rational actors, i.e. they will always choose to obtain or pay the best price for electricity available at that moment in time.

4.2.2 Grid connection

The microgrid considered in this chapter can be defined as a virtual microgrid. We basically use the same distribution grid as in the previous chapter with NM and ET. However, the participants are now virtually connected through an extra market player: the aggregator (cf. chapter 6). The physical connection with the overarching transmission grid is still necessary in order to compensate the imbalances that occur within the microgrid. It is important to note that even if a consumer purchases a relative share of electricity from the PTP market, it does not necessarily mean that this share was physically delivered from another prosumer within the microgrid. However, inducing better matching within the microgrid lowers the need for interaction with the transmission grid. Although we make the assumption that the participants are all part of the same distribution grid, this does not necessarily have to be the case within a virtual microgrid (Nosratabadi, Hooshmand, & Gholipour, 2017).

4.2.3 Market mechanism

The choice of the market mechanism is key for a well-functioning PTP market. A liquid and competitive market ensures that the price on the PTP market constitutes a profitable alternative over the retail market. It is important to note that the subject of the PTP transaction includes the excess electricity generation of prosumers. This means that a prosumer has the ability to sell all the electricity that he does not consume himself during a particular time period a rato of $P_{ex}(t)$, either on the PTP market or to the suppliers through the retail market. In the literature, three main market paradigms have been designed that determine how consumers and prosumers trade excess electricity within a microgrid (cf. chapter 2). We conclude that an MMR set-up is an ideal transition market mechanism coming from the as-is situation to the to-be PTP market paradigm.

Drawbacks of bill sharing and auction-based pricing strategy

The *BS method* has the potential of reducing the consumers electricity bill, but time-based signals are not fully translated into the individual electricity bill, rather will it impact the total costs of the microgrid and thus a consumer will not be directly incentivized to shift consumption behaviour (Long et al., 2017). BS also requires holistic participants who put the overall microgrid profitability before their individual profitability, which is unfortunately not always to be reconciled with the notion of rational acting participants.

In an *APS market* the pricing is determined by the local availability of electricity and therefore consumers will be incentivized to shift their consumption towards cheaper periods or, reversely, prosumers will shift their generation towards periods of scarcity on the PTP market (Long et al., 2017). In theory APS systems could induce effective price-setting on the PTP market as it has a comparable design as the traditional wholesale market of electricity (Izakian, Abraham, & Ladani, 2010). However, it is rather unrealistic to assume that consumers and prosumers do inherit the same amount of rationality and degree of participation as respectively suppliers and centralised producers. Placing the responsibility of forecasting and bidding completely at the consumer side might potentially result in imperfect competitive PTP markets with sub optimal pricing and value allocation.

Mid-market rate

To overcome the issue of forecasting and the required degree of participation in APS, we put forward the *MMR pricing method* as introduced by (Long et al., 2017). Additionally, MMR has the potential to align individual behaviour with the entire microgrid interest, as opposed to BS. The PTP price P_{ptp} resembles the mid-value in the range of the price obtained by the prosumer for selling excess electricity to the grid P_{et} and the price paid by a consumer for buying electricity from the grid P_{rt}. As savings through PTP trading are now shared equally amongst prosumers and consumers, this incentivizes both parties to partake in the PTP market (Long et al., 2017). The ultimate price received/paid by a prosumer or consumer for every unit of electricity will be dependent on the relative volumes traded on either the PTP or retail market within a specific time period.

4.2.4 Pricing mechanism[1]

The MMR takes the excess generation on the PTP market as the priority to fulfil consumption within the microgrid. We define one extra relevant pricing parameter: the PTP market price

[1](Long et al., 2017)

$P_{ptp}(t)$ will be the mid-value of the two previous prices, i.e:

$$P_{ptp}(t) = \frac{P_{rt}(t) - P_{et}}{2}$$

The ultimate price will depend on the quantities traded on the PTP market and the retail market, therefore the total amount of generation and consumption within the microgrid in a certain period of time will impact the price. We define $Q_{ptp}(t)$, $Q_{rt}(t)$ and $Q_{tot}(t)$, $G_{ptp}(t)$, $G_{rt}(t)$ and $G_{tot}(t)$ as the electricity quantity sold, respectively purchased on the PTP market, retail market and the total of both during time period t. Ultimately for each period t a weighted average price for excess generation is obtained: $P_{ex}(t)$ and a price for consumption: $P_{co}(t)$. There exist three possibilities on how generation and demand can relate to each other within the microgrid in a certain time interval t:

Excess generation = Demand

$$\sum_i (G_{e,i}(t) - Q_{e,i}(t)) = 0$$

In this case there is a perfect match within the PTP market and no compensation through the retail market is required. Therefore, consumers will pay the P_{ptp} to prosumers:

$$P_{co}(t) = P_{ptp}(t)$$
$$P_{ex}(t) = P_{ptp}(t).$$

Excess generation > Demand

$$\sum_i (G_{e,i}(t) - Q_{e,i}(t)) \geq 0$$

In this case there is an over-abundance of local generated electricity, demand will be fulfilled entirely from the PTP market. The remainder of excess generation will be sold to the retailers at the export tariff. Therefore, P_{ex} is determined by the weighted average on both markets:

$$P_{co}(t) = P_{ptp}(t)$$
$$P_{ex}(t) = \frac{G_{ptp}(t)}{G_{tot}(t)} P_{ptp}(t) + \frac{G_{rt}(t)}{G_{tot}(t)} P_{et}.$$

Excess generation < Demand

$$\sum_i (G_{e,i}(t) - Q_{e,i}(t)) \leq 0$$

In this case the PTP market within the microgrid is not sufficient to fulfil the total demand. This shortage needs to be compensated by electricity from the main grid, provided by the retailers. P_{co} will be determined by the weighted average on both markets:

$$P_{co}(t) = \frac{Q_{ptp}(t)}{Q_{tot}(t)} P_{ptp}(t) + \frac{Q_{rt}(t)}{Q_{tot}(t)} P_{rt}(t)$$
$$P_{ex}(t) = P_{ptp}(t).$$

Every time interval t can be placed in one of these three situations, and therefore every period will be characterised with a certain value for $P_{co}(t)$ and $P_{ex}(t)$ applicable for every participant in the PTP market.

Total electricity bill The resulting electricity bill for a prosumer B_i with $Q_{co}(t)^2$, $Q_{ex}(t)$ the quantity consumed and generated in period t respectively will result in:

$$B_i = \sum_{t=1}^{T} (Q_{e,i}(t)P_{co}(t) - G_{e,i}(t)P_{ex}(t))$$

The resulting electricity bill for a consumer B_i:

$$B_i = \sum_{t=1}^{T} Q_{e,i}(t)P_{co}(t)$$

4.2.5 Information and energy management trading system

When analysing this set-up it becomes clear that the aggregator in such a microgrid requires a smart energy management trading and information system. First of all, the meters positioned at the participants need to broadcast accurate metering data from their meters to the aggregator in every time period as this aggregate of the generation and consumption data will influence the ultimate consumption and export price for the given time period. In that way it also enables to record the amount of electricity that is imported or exported from/to the supplier. Another requirement is that participants are actively and continuously informed about prices and volumes valid on the PTP market within each time period. A high degree of information helps to assure that the participant makes rational decisions. For example, increasing the PV capacity in an already saturated PTP market might not be a value-creating investment (cf. chapter 5). The exact requirements and potential solutions are elaborated on in chapter 6.

4.3 To-be model: peer-to-peer

In the PTP model we assume that participants do not have contracts with suppliers anymore but that the administrative interaction between for the supply of energy is through a new

[2] Note that, for prosumers, $Q_{co}(t)$ equals the net consumption, i.e. adjusted for the generation within that time period. For consumers $Q_{co}(t)$ equals the total consumption within that period as their generation equals zero.

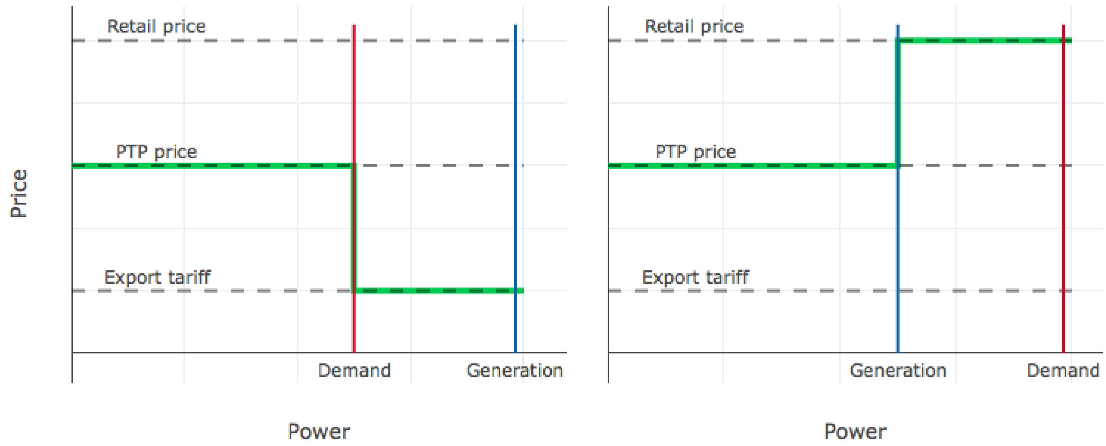

Figure 4.1: Left: consumption and export prices when microgrid PV generation exceeds consumption. Right: consumption and export prices when microgrid consumption exceeds generation.

market player: the aggregator. In practice the aggregator will first aggregate all incoming excess generation and consumption and match both, for which the $P_{ptp}(t)$ is applicable, i.e. the PTP market. A shortage in this local PTP market will activate the aggregator to purchase electricity from the supplier at a rate of $P_{rt}(t)$. A surplus in the local market will activate the aggregator to sell the excess at P_{et} to the supplier. The ultimate price for a participant will then include the PTP price and the residual retail price. It is important to note that such a market set-up does not necessarily alter the physical flow of electricity. However, this mechanism assures the administrative certification of local generated and consumed electricity.

When implementing a PTP model that allows prosumers and consumers to trade energy, we no longer treat these actors as a single party in order to model the differences in both. The key observation to be made is that a prosumer and consumer do not transact directly with a supplier anymore. All administrative services are now provided through the aggregator. This includes metering and storage of consumption and generation data and the billing of consumers as well as ensuring *ex-post* balance on the PTP market by purchasing and selling electricity to the supplier. For a prosumer, who generates an amount of electricity $G_i(t)$ in time period t will first use a share for its proper consumption $G_{e,i}(t)$ (i.e. behind the meter consumption), the excess of which $G_{e,i}(t)$ is offered to the aggregator. On the consumption side - this can either be the excess consumption by the prosumer or the consumption by a consumer - the aggregator will firstly match consumption with available excess generation

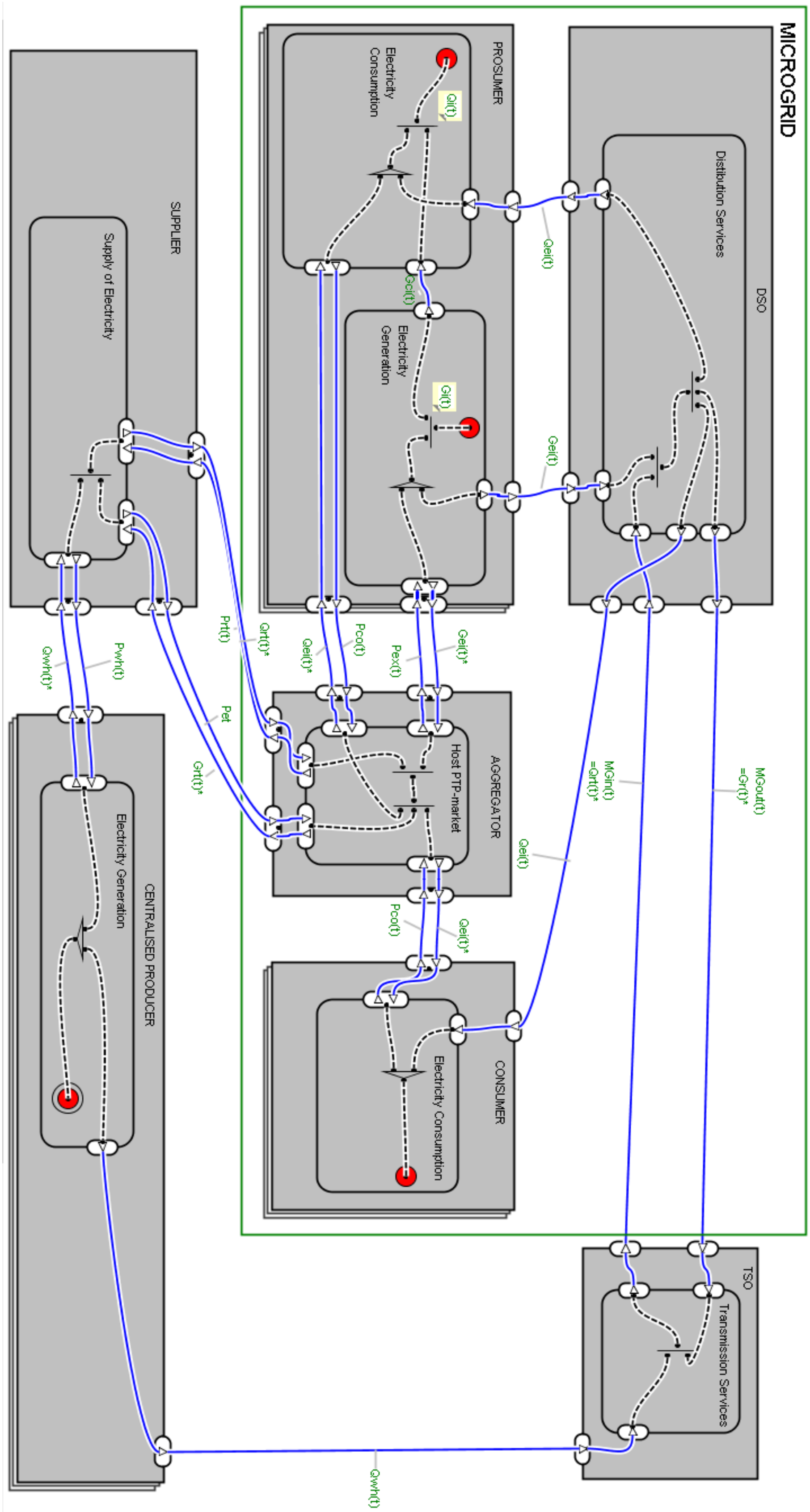

Figure 4.2: E3-value model: microgrid with PTP trading of electricity.

at the price $P_{ptp}(t)$[3]. In case excess generation surpasses consumption in a time period the excess generation $G_{rt}(t)$ is exported to the main grid and purchased by the supplier at $P_{et}(t)$. In the other case when excess generation falls short of consumption, this shortage $Q_{rt}(t)$ is compensated through the import of electricity from the main grid at $P_{rt}(t)$. Note that these administrative flows are matched with the physical flows indicated by $MG_{out}(t)$ and $MG_{in}(t)$ respectively. As explained earlier the previously mentioned quantities will then determine the ultimate price paid/received for a participant in that particular time period. Such that for every participant and time period only two possibilities exist; either a participant has excess electricity consumption within that period and pays the price $P_{co}(t)$ or it sells its excess generation at a price $P_{ex}(t)$. Note that it is not needed for a participant to forecast or place bids for its consumption and/or generation as the pricing happens *ex-post*. The supplier obtains electricity either through the wholesale market from centralised producers ($Q_{wh}(t)$ at $P_{wh}(t)$) or through the excesses on the PTP market provided by the aggregator ($Q_{rt}(t)$ at $P_{rt}(t)$). Note that the supplier can then deliver this electricity to other microgrids with which it is connected through another aggregator[4].

Note that the activities *Supply of Electricity* and *Host PTP market* overlap to a certain extent as the original role of the supplier has changed. We will come back to this in chapter 6, where we perform a more in-depth analysis of the tasks and requirements for the role of aggregator. Furthermore, we provide an analysis on which parties are suited to take on this role.

[3] Note that $P_{ptp}(t)$ is only implicitly present in the model through $P_{ex}(t)$ and $P_{co}(t)$.

[4] Not included in the model.

Chapter 5

Quantitative analysis

5.1 Approach

In this chapter we will use the same set of consumers and prosumers to evaluate the differences between NM, ET and PTP. We drew 30 numbers from a normally distributed sample with a mean of 3700 and a standard deviation of 900, representing the yearly consumptions of 30 market participants. The resulting distribution is shown in Figure 5.1. The sample of 30 participants has a mean yearly consumption of 3978,82 kWh. For 12 of these participants we drew another sample to determine a PV capacity distinct from zero (the prosumers), we assumed the other 18 participants to have no PV capacity (the consumers). PV capacity is drawn from a range[1] between 65% and 125% of the yearly consumption, assuming that the size of the PV installation is chosen so that it covers the larger part of the consumption on a yearly basis in case of NM. The SLP[2] is randomly attributed to consumers. Because having a single meter is currently most profitable for prosumers, we assume all prosumers to be SLP S21. For an elaborate description of the data and used calculations in this chapter, we refer to Appendix B.

[1] Percentage that would cover the yearly consumption, assuming an efficiency of 80%

[2] S21 has a night/day consumption $< 1{,}3$ or is a consumer without a separate night meter in case no historical records are available. S22 has a night/day consumption $\geq 1{,}3$ or is a consumer with a separate night meter in case no historical records are available. (cf. 1.3.4)

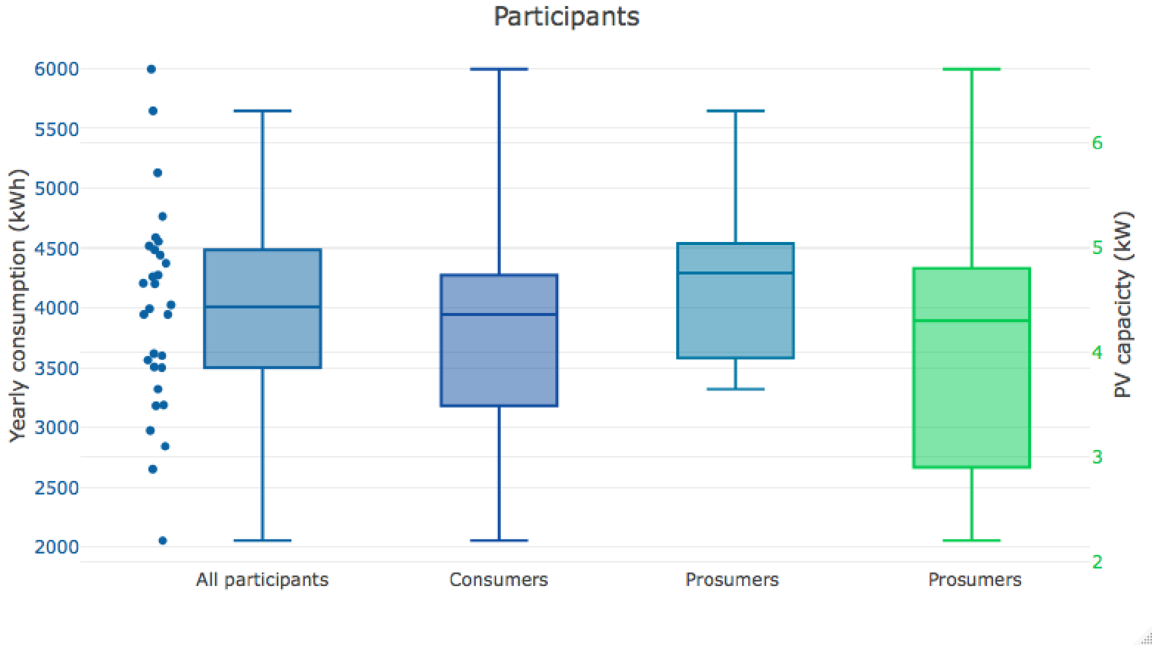

Figure 5.1: Set of participants

5.2 Peer-to-peer results

In this section we display the generation and consumption patterns that are prevalent on the PTP market as a whole, including the resulting pricing schemes. We discuss the average of four months, each representing one season.

January

Figure 5.2 displays the aggregate consumption, generation and resulting net consumption throughout a day[3] in January. Figure 5.3 shows the resulting prices throughout that day, implementing a MMR pricing scheme (cf. 4.2.3). During the whole month of January, the excess generation is nearly zero throughout the whole day, resulting in a net consumption that is identical to the consumption and a consumption price $P_{co}(t)$ that is identical to the retail price $P_{rt}(t)$. All consumption is then satisfied by the import of electricity from the main grid, instead of the small portion of generation with which prosumers satisfy a share of their own consumption. The export price $P_{ex}(t)$ equals $P_{ptp}(t)$, however, as no prosumer has excess generation this price has no impact on the eventual electricity bill for the prosumer.

May

Figure 5.4 displays the aggregate consumption, generation and resulting net consumption

[3]Calculated as the average over all days in January

throughout a day[4] in May. Figure 5.5 shows the resulting prices throughout that day, implementing a MMR pricing scheme (cf. 4.2.3). In May, the excess generation between seven in the morning and eight in the evening results in a significant drop in the net consumption, in turn leading to a price drop on the PTP market as the relative share of local traded electricity increases at the cheaper rate $P_{ptp}(t)$. Both export and consumption prices ($P_{ex}(t)$ and $P_{co}(t)$) are significantly lower during daylight. Between 9 am and 6 pm the net consumption is negative, meaning the microgrid as a whole generates more electricity than it consumes. This results in a minimum $P_{co}(t)$ and a lowered $P_{ex}(t)$, because the PTP market is saturated. It also results in a net flow of electricity from the microgrid to the the main grid. Note that the export price $P_{ex}(t)$ will never reach $P_{et}(t)$ as there will always be local demand within the microgrid. Such that the relative weight of $P_{ptp}(t)$ will never reach zero.

July

Figure 5.6 displays the aggregate consumption, generation and resulting net consumption throughout a day[5] in July. Figure 5.7 shows the resulting prices throughout that day, implementing a MMR pricing scheme (cf. 4.2.3). For July similar conclusions as for May can be found, however, as summer days have a longer periods of sunlight this will result in an increased availability of excess generation available on the PTP market. Ultimately this results in more time periods with lowered consumption and export prices ($P_{co}(t)$ and $P_{ex}(t)$).

October

Figure 5.8 displays the aggregate consumption, generation and resulting net consumption throughout a day[6] in October. Figure 5.9 shows the resulting prices throughout that day, implementing a MMR pricing scheme (cf. 4.2.3). During October, the increased consumption in the morning and evening in combination with decreased generated volume, results in that the main share of electricity is provided by the suppliers through the main grid, resulting in only a short price drop for consumption during day time. The total excess generation will never exceed the consumption within a certain time period, resulting in that prosumers can always sell their excess electricity at $P_{ptp}(t)$. As there is in every time period a net flow of electricity from the main grid to the microgrid through the supplier, the consumption price $P_{co}(t)$ will never reach its lower bound $P_{ptp}(t)$.

[4] Calculated as the average over all days in May

[5] Calculated as the average over all days in July

[6] Calculated as the average over all days in October

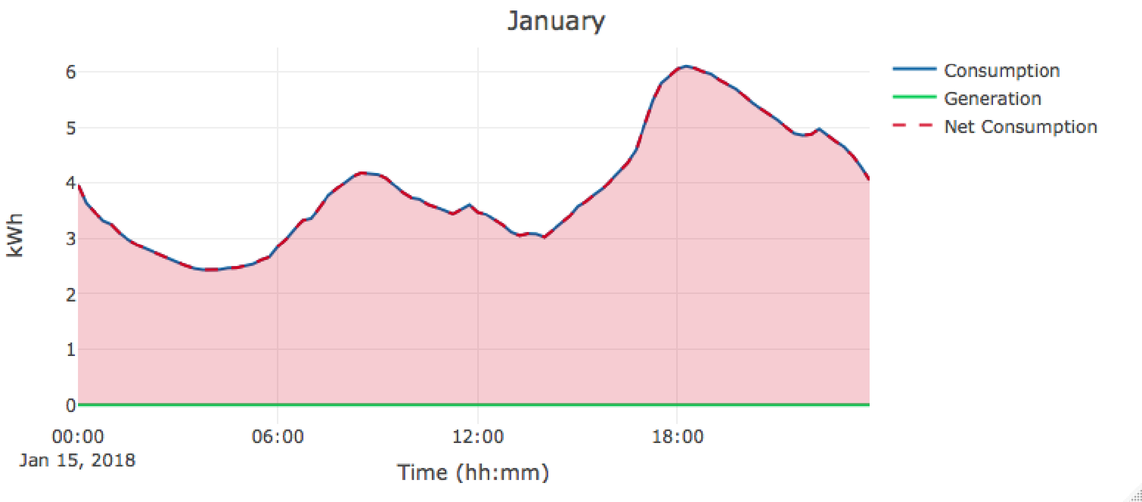

Figure 5.2: Aggregate consumption, generation and resulting net consumption throughout a day in January.

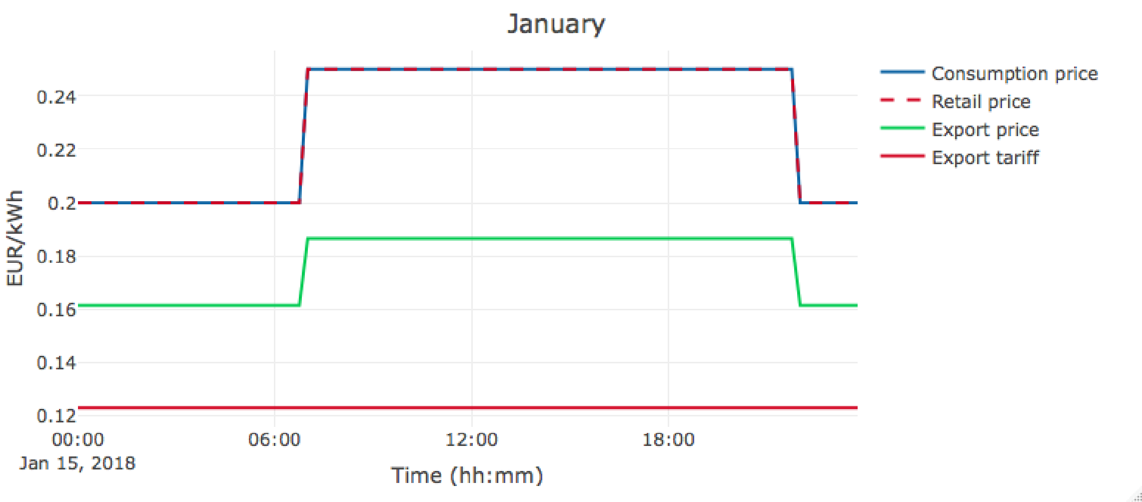

Figure 5.3: The resulting prices throughout a day in January. Consumption price, Retail price, Export price and Export tariff represent $P_{co}(t)$, $P_{rt}(t)$, $P_{ex}(t)$ and P_{et} respectively.

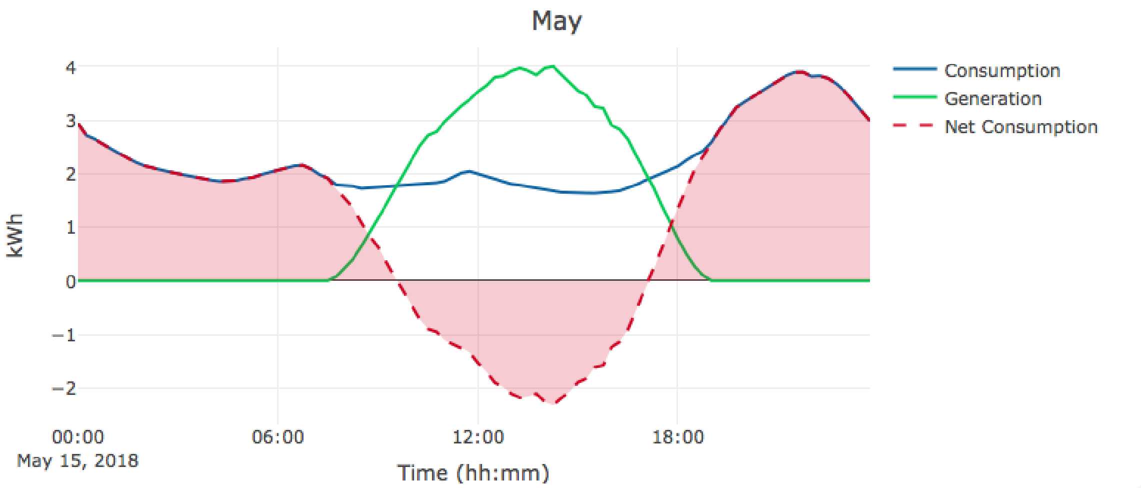

Figure 5.4: Aggregate consumption, generation and resulting net consumption throughout a day in May.

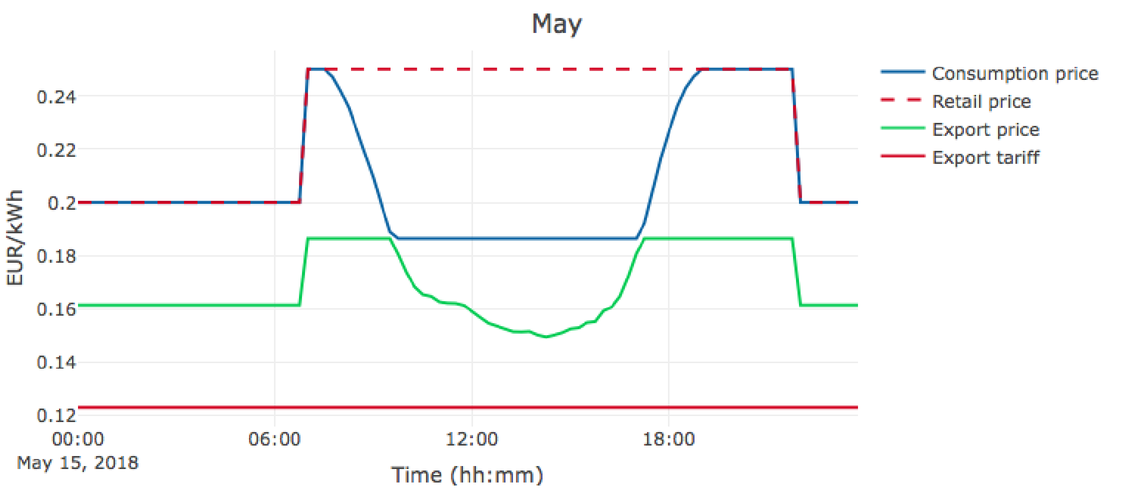

Figure 5.5: The resulting prices throughout a day in May.

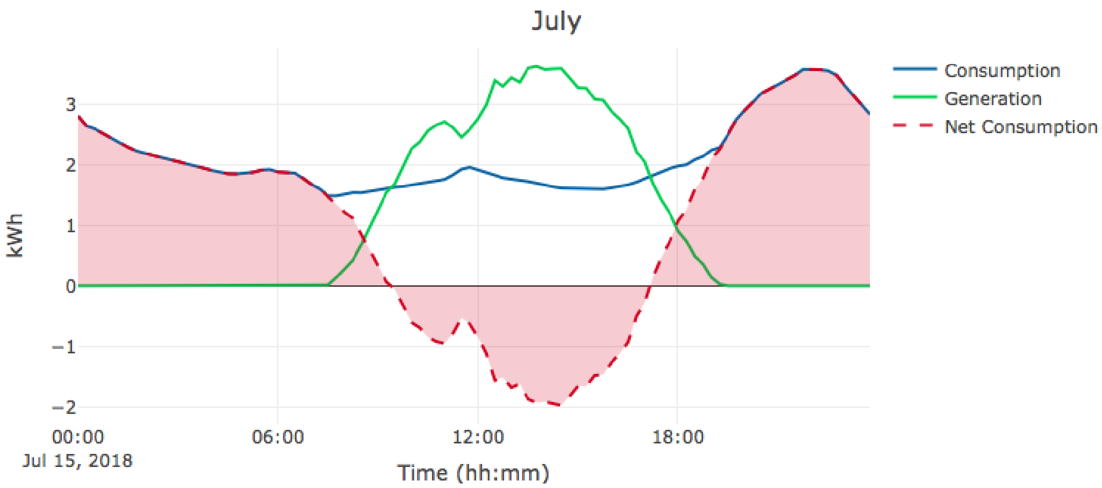

Figure 5.6: Aggregate consumption, generation and resulting net consumption throughout a day in July.

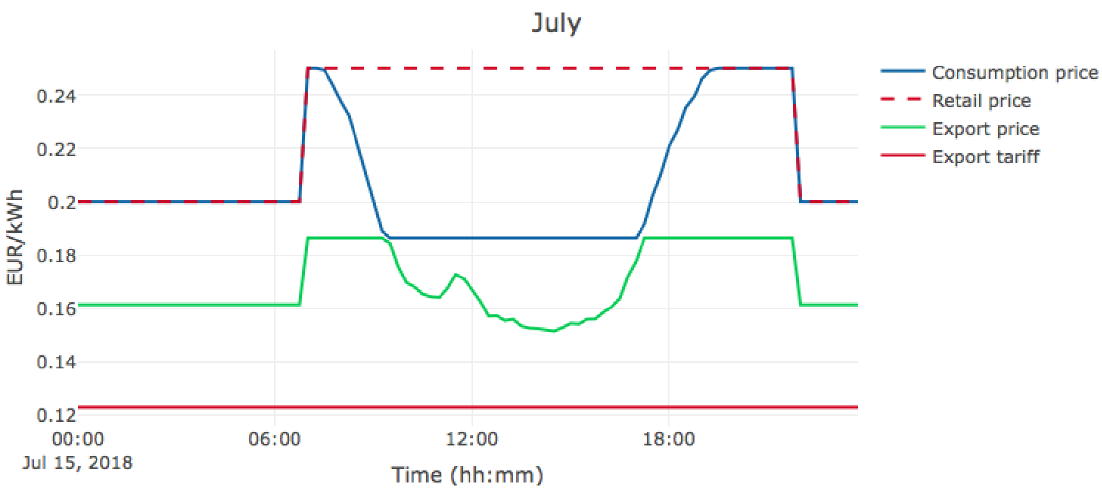

Figure 5.7: The resulting prices throughout a day in July.

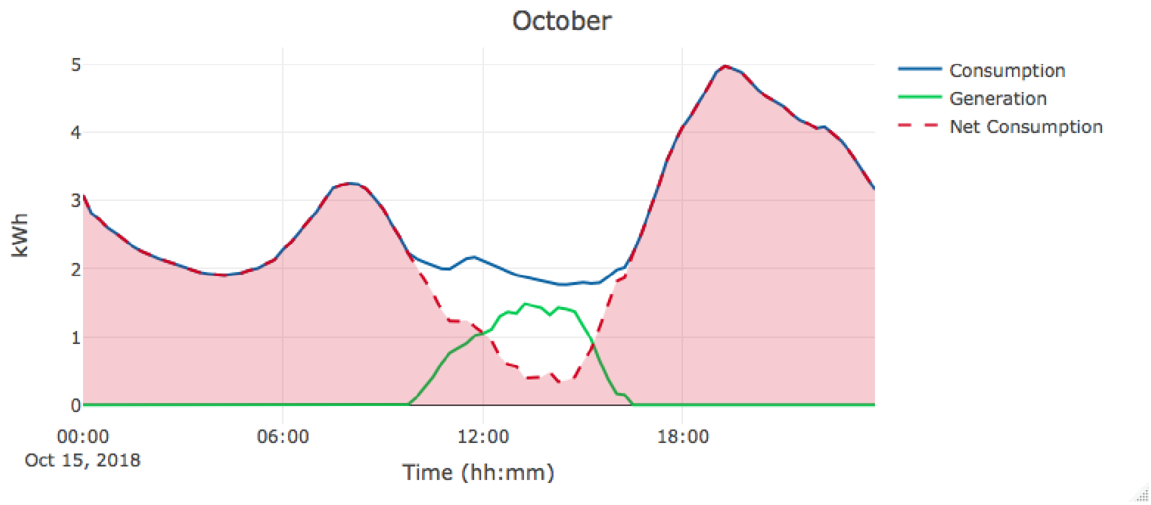

Figure 5.8: Aggregate consumption, generation and resulting net consumption throughout a day in October.

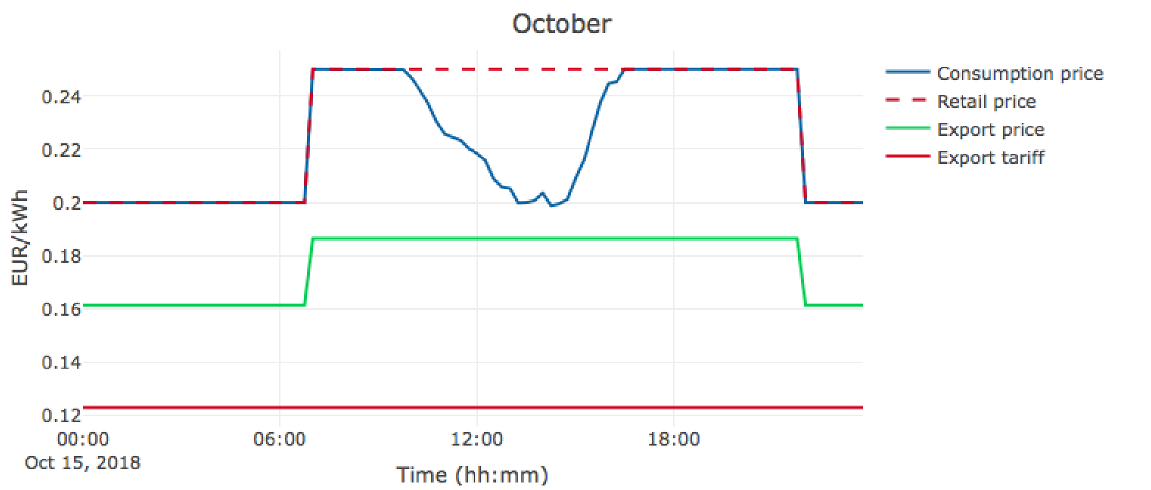

Figure 5.9: The resulting prices throughout a day in October.

Note. $P_{ptp}(t)$ is inversely proportional with the availability of locally generated electricity, creating an incentive to shift consumption to peak generation hours and increasing the benefit PTP has over NM. This can be done through forms of DR (cf. 2.2.5). Likewise prosumers are incentivized to store electricity (cf. 2.2.6) and inject this into the microgrid during off peak generation hours as this increases their revenue. The potential of changed consuming and generating behaviour is evaluated and calculated below (cf. 5.4).

5.3 Peer-to-peer vs net metering vs export tariff

The cost for an individual in case of NM and ET is independent of other market participants. This is not the case in a PTP market. The results apply to the above defined participants in the previously defined PTP market set-up. For a given PTP market set-up, changing the total market PV capacity, the total yearly consumption or consumption patterns influence the cost on the PTP market for each individual. Therefore, when analysing changing PV capacity and consumption, we ran a simulation to take the changing PTP market in regard.

5.3.1 Consumers

When implementing an ET, compared to NM only the reimbursement of excess generation changes. Meaning this does not have any effect on the electricity bill of consumers, therefore we exclude this market set-up for consumers. Looking at the PTP costs for participants without solar capacity we see two distinct values, this relates to SLP. Consumers with SLP S21 obtain a reduction of 5,53% when trading on a PTP market, while consumers with SLP S22 obtain a reduction of 3,58%. As the latter consume a significantly larger part during the night, the volume that they consume from the PTP market is significantly smaller than for consumers with SLP S21. A larger share of consumption during the night reduces one's benefit of PTP trading because there is no local generation pushing down the consumption price $P_{co}(t)$. Assuming all consumers would have consumption pattern S22, PTP trading would still be beneficial. Every consumer benefits from PTP trading as long as the consumption during the hours with available generation is not zero and the overall consumption remains the same. The mean cost reduction when moving to a PTP market is 5,10%. Distribution of electricity costs for the 18 consumers are plotted in Figure 5.10.

In order to quantify the effect of an increasing yearly consumption, we ran a simulation for one specific consumer. Participant 19 has no PV capacity and a yearly consumption of 3505,6 kWh, an approximation of the average household consumer in Belgium. Incrementing the yearly consumption of participant 19 from 0 kWh to 7500 kWh (ceteris paribus) and calculating the resulting PTP cost for the given participant, generated Figure 5.11. For a given consumption pattern, the percentage cost reduction is fixed (5,53% for participant

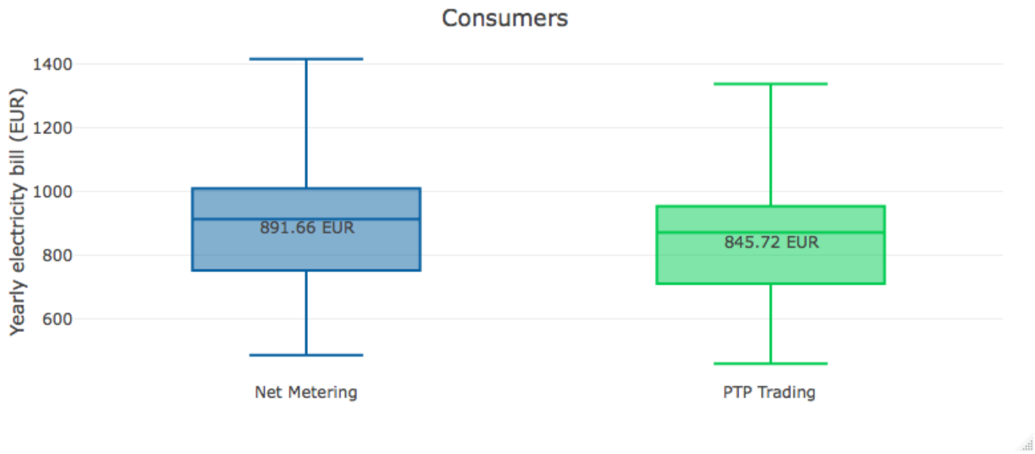

Figure 5.10: Distribution of electricity costs for the 18 consumers.

19 as it is SLP S21). Meaning the absolute cost reduction increases with increasing yearly consumption. Differing consumption patterns, for any participant, would change the overall PTP cost. Although the consumption pattern of an individual can differ from the SLP, we can assume that the SLPs are a fit approximation for the aggregate of the individual consumption patterns. On the level of an individual, increasing the consumption (ceteris paribus) generates a larger cost reduction in absolute terms when consuming of a PTP market as opposed to the retail market. Note that for an individual to change its consumption pattern (ceteris paribus) while consuming of a PTP market could decrease its electricity bill in relative terms. This is the case when a part of the consumption shifts to peak generation hours (cf. supra).

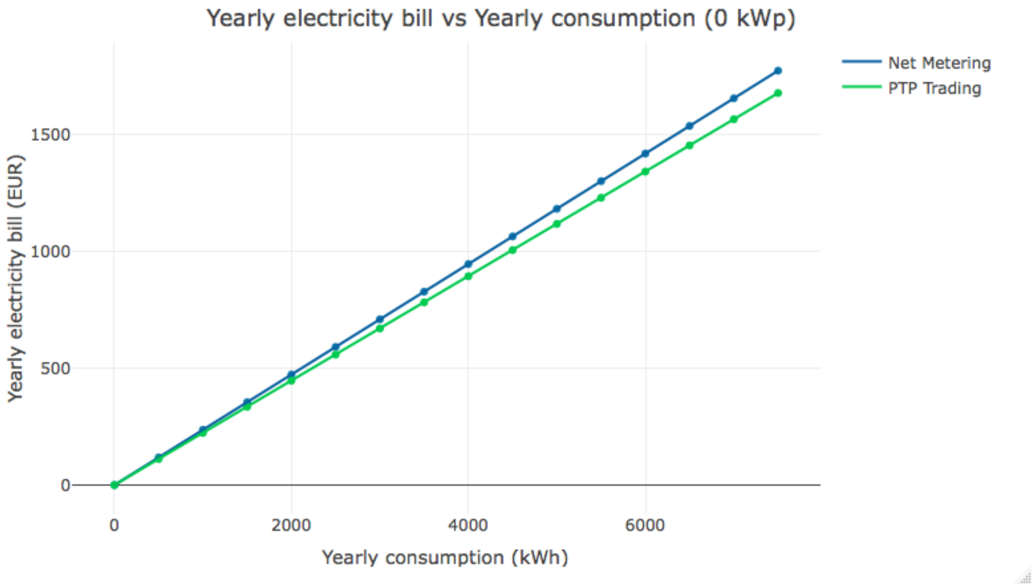

Figure 5.11: Results of simulating an incrementing consumption for a consumer.

5.3.2 Prosumers

The mean cost for prosumers in a NM set-up is 600,65 EUR per year. When changing the reimbursement method for excess generation of prosumers to ET, a mean cost reduction of 35,61% of the electricity bill cost is found. Moving from a NM set-up to a PTP market drives the cost down even further, a mean cost reduction of 49,98% is achieved. Distribution of electricity costs for the 12 prosumers are plotted in Figure 5.12.

In order to quantify the effect of an increasing PV capacity or yearly consumption, we ran a simulation for one specific prosumer. Participant 2 has a yearly consumption of 3500 kWh, an approximation of the average household prosumer. Incrementing the PV capacity of participant 2 from 0 kWp to 10 kWp (ceteris paribus) and calculating its resulting PTP cost, generates Figure 5.13. For a PV capacity ranging from 0 kWp to 10 kWp, participant 2 has the lowest yearly electricity bill at any given PV capacity in a PTP market. The ET case - depending on the capacity - can mean a substantial saving compared to NM. When no PV capacity is installed, the participant is indifferent between NM and ET as both costs are equal. It is clear that having PV capacity never generates revenue for the prosumer in case of NM. Due to the prosumer tariff having a PV capacity that exceeds 4,5 kWp actually increases the electricity bill when expanding past this point - given a yearly consumption of 3500 kWh. This is in stark contrast with the case of ET and PTP trading, where installing a larger PV capacity pays off. In the above defined PTP market set-up, participant 2 would start earning money as from a capacity larger than 5 kWp. As the export price $P_{ex}(t)$ on

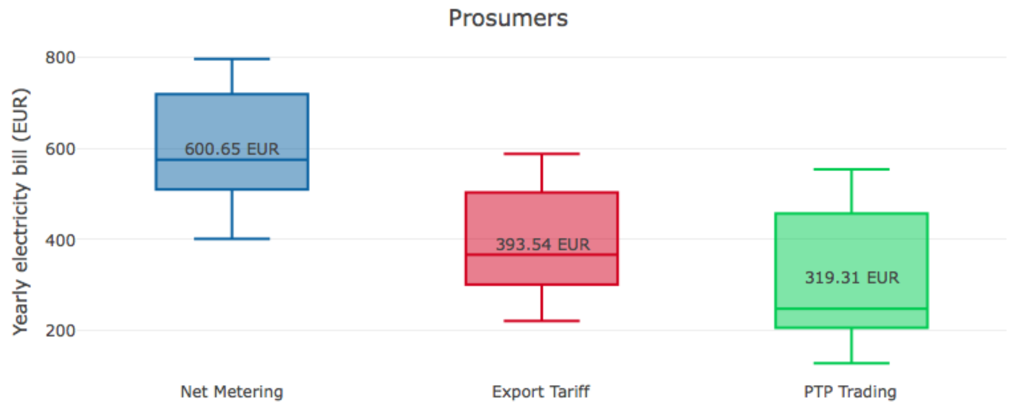

Figure 5.12: Distribution of electricity costs for the 12 prosumers.

the PTP market is always higher than P_{et}, the zero point in case of ET lies at a higher PV capacity. Participant 2 would generate a profit from a capacity of 6,5 kWp.

Implementing an ET or PTP set-up would provide better reimbursement of prosumers with a relatively large capacity, though it is unlikely to have a PV installation larger than 5 kWp while consuming no more than 3500 kWh per year in the current market set-up - NM. Due to the prosumer tariff, the increased profitability of scaling PV capacity is limited. This means that for most prosumers moving to an ET market would mean a decrease of the electricity bill and consequently, increasing return on investment of solar panels. The incentive for consumers to become prosumer increases. And prosumers are incentivized to scale their solar installation as there no longer is a prosumer tariff limiting the profitability for capacities[7] larger than 4,5 kWp. Moving to a PTP market would increases the profitability even further - especially for larger installations - as the electricity bill is lowest for any given PV capacity. Starting from a capacity[8] of 2,5 kWp, PTP becomes increasingly cheaper than ET. As the export price ranges between the PTP price and the P_{et}, by default PTP trading is more profitable than selling to a supplier at the ET. PTP trading and ET diverge because offering bigger quantities to the microgrid (ceteris paribus) relatively increases[9] the prosumers' revenue during certain time periods, while exporting to the supplier is at a fixed ET. Using the NM reimbursement method, a prosumer is reimbursed at the retail price - which is always higher than the export price - for its excess generation. However, including the prosumer tariff still makes NM more expensive than both other methods. As the PTP cost is inversely proportional to the size of an individual's PV installation (ceteris paribus), the incentive to scale is always present.

[7] Assuming a yearly consumption of 3500 kWh.
[8] Assuming a yearly consumption of 3500 kWh.
[9] As long as the total net consumption is not negative.

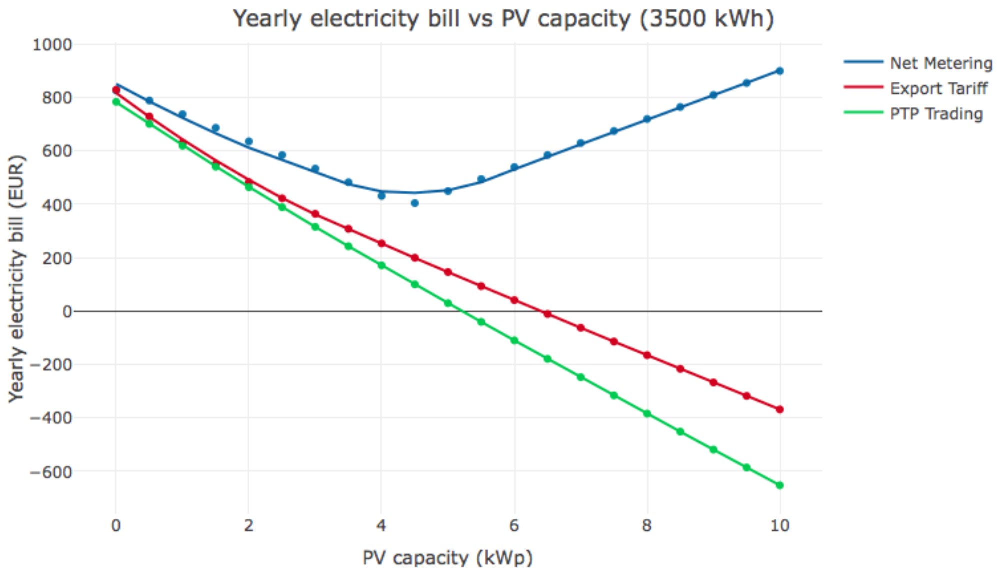

Figure 5.13: Results of simulating an incrementing PV capacity for a prosumer.

This does not hold true regarding the market as a whole (cf. supra).
Incrementing the yearly consumption of participant 2 from 0 kWh to 7500 kWh (ceteris paribus) and calculating the resulting PTP cost for participant 2, generates Figure 5.14. Similar conclusions can be found for Figure 5.13 as for Figure 5.14. For a yearly consumption ranging from 0 kWh to 7500 kWh, it is obvious that participant 2 has the lowest yearly electricity bill in a PTP market. Having a PV installation of 4,3 kWp makes NM more expensive than both other methods. Even though a capacity of 4,3 kWp is a multiple of what is needed for yearly consumptions smaller than 3000 kWh, NM still costs money. Using the reversed meter method, prosumers are not reimbursed for the amount of generation that exceeds their consumption on a yearly basis. Based on the size of the inverter (cf. infra), participant 2 still pays a prosumer tariff. As from 3500 kWh the participant in case no longer has a negative[10] net consumption and consequently a electricity bill different from zero, proportionate to its yearly consumption.
In contrast, ET and PTP trading actually generate a positive cash flow up until slightly less than 2500 kWh and 3000 kWh respectively. Nevertheless, it is unlikely to have such small yearly consumption totals in combination with a PV capacity of 4,3 kWp as long as a prosumer tariff is to be paid.

[10]Measured on a yearly basis.

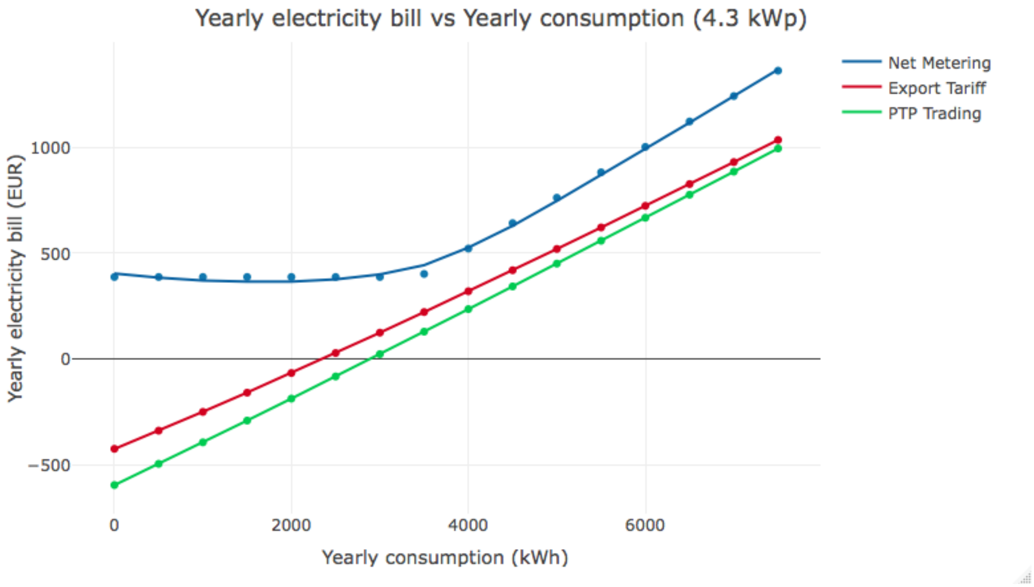

Figure 5.14: Results of simulating an incrementing consumption for a prosumer.

5.3.3 Microgrid dynamics

Figures 5.11, 5.13 and 5.14 show that in a PTP market, prosumers are incentivized to increase[11] their PV capacity for a given yearly consumption or to decrease their consumption for a given PV capacity as they could benefit monetarily. However, as other participants are incentivized in the same way, the marginal benefit decreases when multiple participants act on this incentive. The value for each participant is determined by his share of generation and consumption during each time period relatively to the total market generation and total market consumption respectively. As electricity is a necessary good - there will always be a base consumption - we investigate the effect of an increasing PV market capacity as opposed to a decreasing total market consumption in a PTP market. Even so, both effects are likely to have the same outcome as total net consumption (total consumption minus total generation) drives the PTP price within a time period.

Figure 5.15 shows the simulation of an increasing total microgrid PV capacity, ranging from 4,3 kWp - if participant 2 was the only prosumer - to 210 kWp - if all participants had solar capacity. Participant 2 is considered not to change its PV capacity, while all other participants are installing and scaling solar capacities. The green curve represents the consequential drop of the participant's share of PV capacity. The yearly electricity bill[12] of participant 2 is plotted in red. We see that for participant 2 an increase in the overall PV capacity[13] within

[11]Or for a consumer to install PV capacity or decrease consumption.

[12]Assuming a yearly consumption of 3500 kWh.

[13]This corresponds with increasing the share of prosumers within the microgrid or increasing their individual

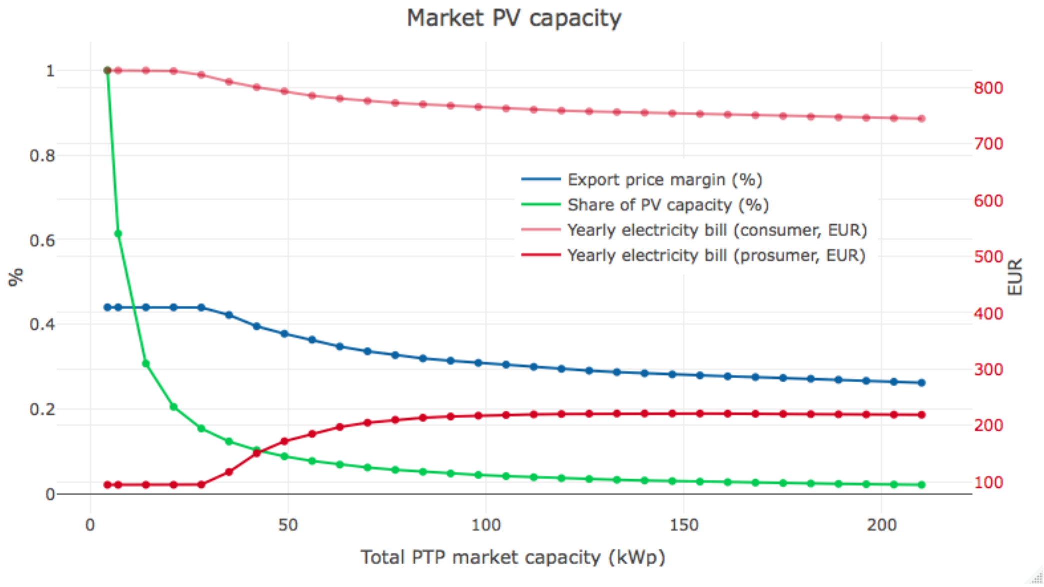

Figure 5.15: Results of simulating an incrementing market PV capacity.

the microgrid (ceteris paribus) increases its electricity bill. In the case of low market capacity, the total generation within a time period will never exceed the total consumption resulting in that all generation can be sold to peers within the microgrid. The prosumer in case manages to sell all of its generation at the highest possible export price, being the PTP price. The margin the export price has over P_{et} is stable around 44% (represented by the blue curve), the yearly electricity bill amounts to a total of 94 EUR. This holds true for all time periods up until a market capacity of 28 kWp. The steep drop in the PV market share of participant 2 does not affect his proper profitability as long as the market is not saturated in certain time periods. Further increasing the market capacity will result in total generation exceeding the total consumption in the microgrid as a whole during certain time periods. Part of the generation will then be sold to the supplier at the export tariff, and part will be sold to peers at the PTP price. The export price will constitute a share of the lower export tariff, with an overall reduction of the export price as a consequence. This is shown by the ever decreasing export price margin. At a market capacity of 200 kWp the margin is valued at slightly more than 26% of the export tariff. As opposed to a prosumer, a consumer actually benefits an ever-growing microgrid PV capacity. Its yearly electricity bill is represented by the decreasing pink curve. However, a consumer's incentive to adopt and become a prosumer is still very large. Even in a saturated microgrid, a cost reduction of more than 500 EUR on the yearly electricity bill can be achieved. The scenario of an ever increasing total market PV capacity is even more plausible as the growth of PV capacity could be fuelled by either consumers

PV capacity.

adopting or prosumers scaling.

While on the level of the individual there is a clear incentive to scale up its PV capacity - or decrease consumption as a matter of fact - given the valid PTP market prices, this does not hold true on the microgrid as a whole. As long as the participant's share grows relative to the total market PV capacity, a benefit can be obtained. But given that every participant has the incentive to scale, this will not be the case for long. The benefit of scaling decreases in relative terms, however it will never be zero as the export price is always higher than the export tariff. The initial purpose of PTP trading within a microgrid, to increase energy efficiency by trading locally and keeping money in the community by bypassing the supplier, vanishes once the microgrid is saturated. It is unlikely a supplier will buy any quantity of excess generation at the given export tariff. Adopting a variable pricing scheme for ET would be an adequate reaction to a substantially growing household solar capacity. A lower export tariff during peak generation hours would limit prosumers' incentive to scale.

5.3.4 Profitability

In order to quantify the effect of a changing market set-up on the profitability of having solar capacity, we compare the payback period and IRR in the three market set-ups for the given set of prosumers. Assuming that an individual prosumer based its investment decision on the added benefit in the current market set-up - NM, we investigate how changing the market set-up influences the payback period and IRR. A lifetime of 20 years and an initial investment cost of 1300 EUR/kWp for PV installations, and a lifetime of 10 years and an initial investment cost of 200 EUR for a smart meter is assumed. To allow comparability IRR is calculated over 20 years in every scenario. The cost a smart meter is only taken into account for ET and PTP as it is not required to participate in a NM set-up. Figure 5.16 shows the distribution of payback periods of the given set of prosumers, using the base case of a NM consumer. A household consumer who decides to invest in solar panels in a NM set-up encounters a significant drop in the payback period of its installation when moving to a ET set-up, and an slightly bigger drop when moving to a PTP set-up. The mean payback period for the given set of prosumers[14] is 13,30 years for NM, 8,97 years for ET and 8,04 years for PTP (representing a drop of 32,6% and 39,5% respectively).

Figure 5.17 displays the IRR, calculated over the assumed lifetime of a PV installation. The potential savings discussed in previous sections (cf. infra) are reflected by the IRR. In an ET and PTP market set-up an mean IRR[15] of 10,54% and 12,53% respectively is found, this is in stark contrast with the IRR of 4,79% in a NM set-up.

[14]Assuming the PV installation is used in the given market set-up during its complete lifetime.

[15]Based on the PV capacities and yearly consumption of the given set of prosumers.

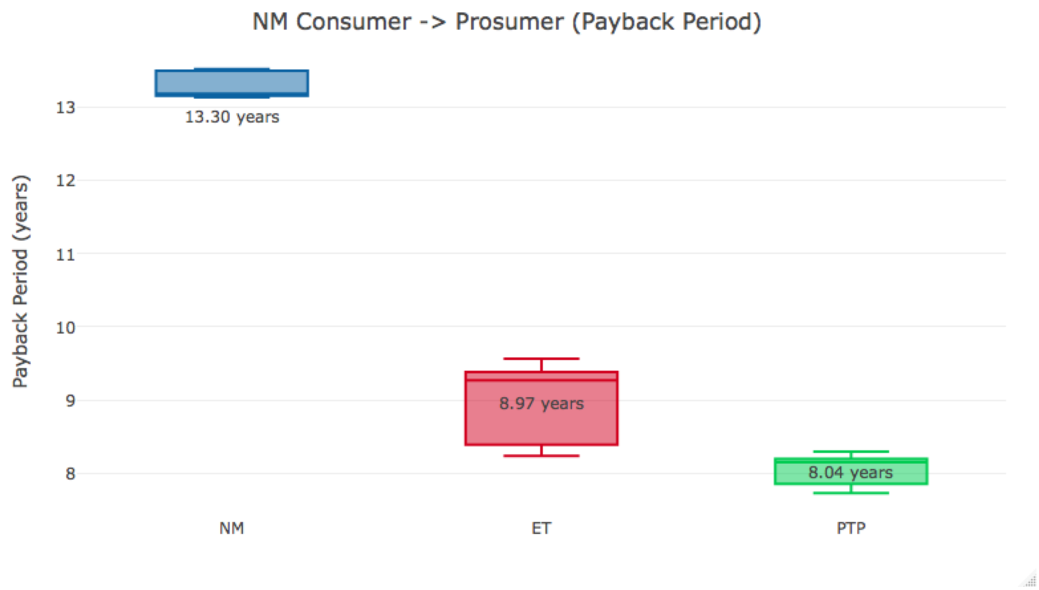

Figure 5.16: Distribution of packback periods for prosumers.

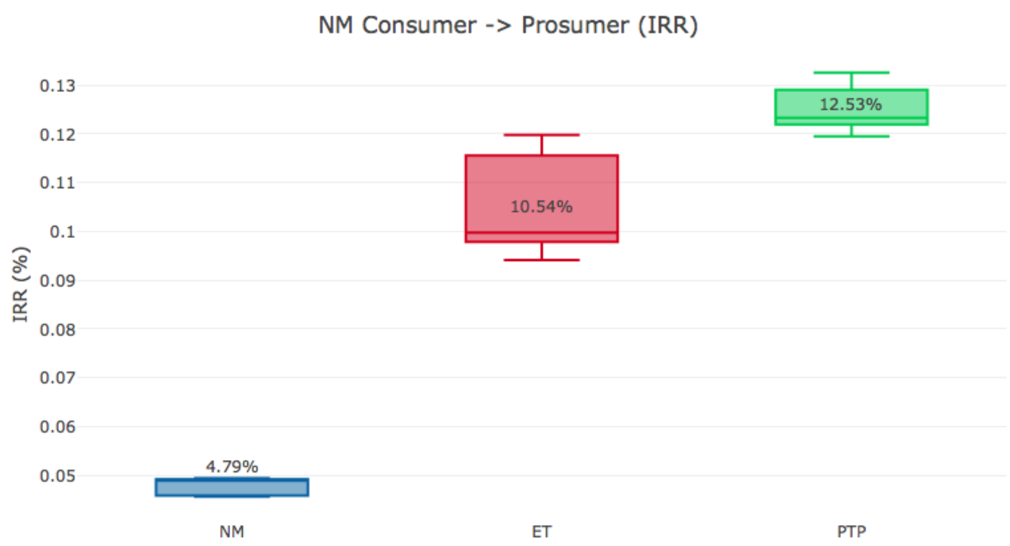

Figure 5.17: Distribution of IRR for prosumers.

The payback period and IRR[16] for the investment of a smart meter - necessary to participate in a PTP set-up - are displayed in Figure 5.18. This scenario addresses the case of a consumer changing to a PTP market, calculated on the given set of consumers. After a period of 4,89 years[17] the investment of the smart meter is earned back, which is less than half of the assumed lifetime. A mean IRR of 26,64% is found, calculated over 20 years. In a period of 20 years the consumer will have invested twice in a smart meter, equivalently the mean IRR calculated over 10 years - the assumed lifetime of a smart meter - also equals 26,64%.
Figure 5.19 plots a scenario[18] where one consumer decides to become a prosumer, given a PTP market and calculated on the given set of consumers. A mean payback period of 8,95 years and a mean IRR of 10,49% is found. This means that given a PTP market, a consumer would benefit from investing in solar (ceteris paribus). This supports previous findings. Note that this incentive holds true on the level of an individual consumer, but not for the microgrid as a whole. Saturation of the microgrid decreases the marginal benefit to scale (cf. infra).

[16]The IRR is calculated over 20 years to allow comparability with prosumers.
[17]The mean payback period for the given set of consumers.
[18]The size of the installed capacity is chosen so it covers 72% of the yearly consumption, assuming an efficiency of 80%.

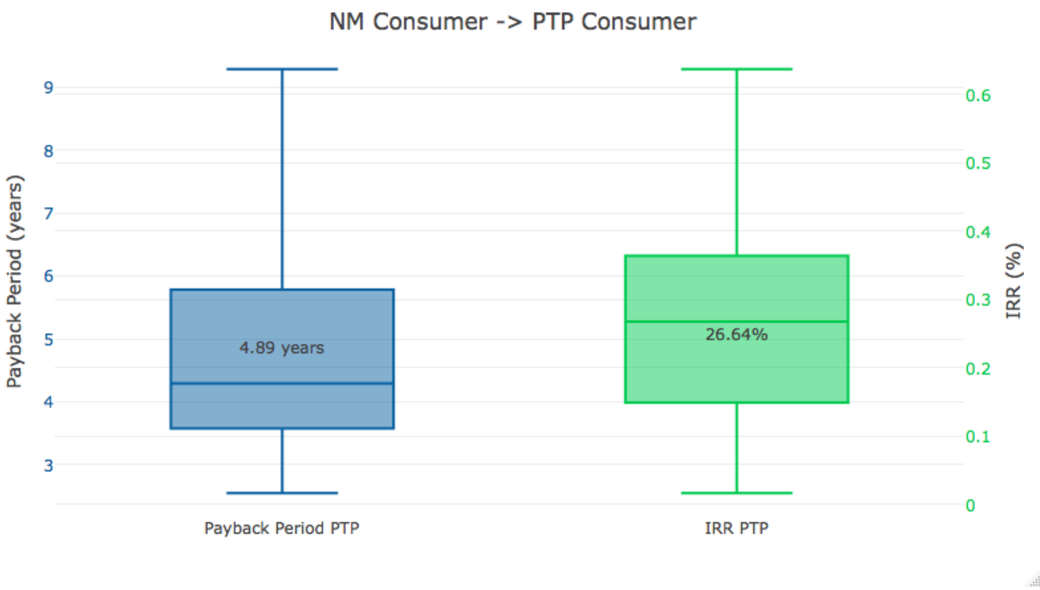

Figure 5.18: Distribution of packback periods for consumers.

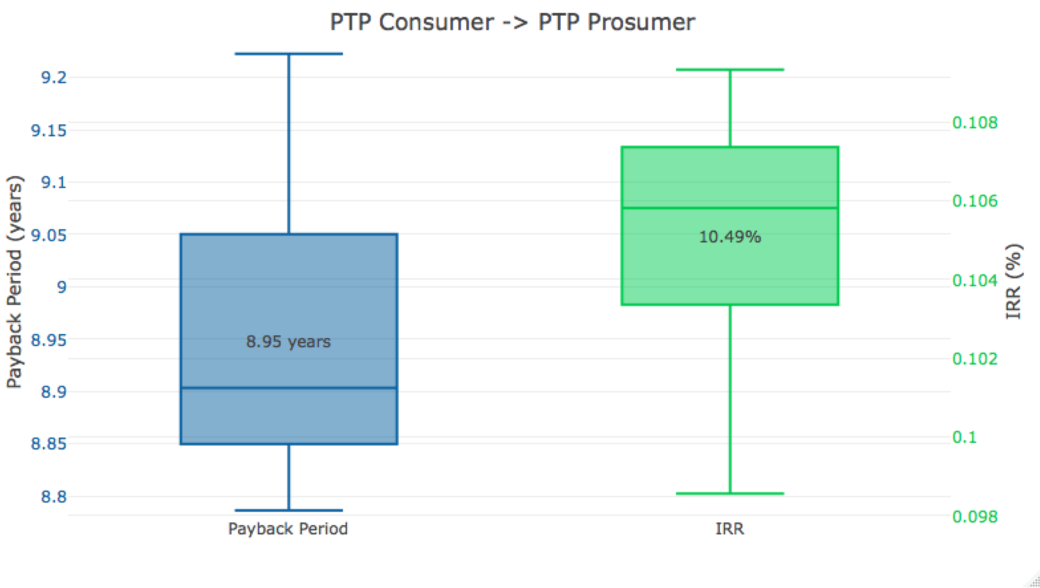

Figure 5.19: Distribution of IRR for consumers.

Table 5.1 summarizes the different scenarios: The value equals the obtained IRR by moving from the base case (row) to the go-to case (column).

Table 5.1: The value equals the obtained IRR by moving from the base case (row) to the go-to case (column)

		consumer	prosumer		
		PTP	NM	ET	PTP
consumer	NM ET	26,64%	3,39	9,00%	10,61%
	PTP				10,49%

The significantly higher profitability for consumers versus prosumers relates to the relatively low investment cost of a smart meter as opposed to the high investment cost of a PV installation and a smart meter. This puts the cost reductions obtained by consumers and prosumers in perspective. Prosumers save a greater[19] total on their yearly electricity bill, but this comes at the cost of greater investment.

The cost reductions when moving to a ET or PTP set-up (cf. infra) are sufficient to cover the investment of smart meter. A positive IRR points out a positive net present value, meaning the gathered savings over the lifetime of the smart meter are larger than the initial investment cost. Even though the mean cost reduction for consumers is only a fraction of the mean cost reduction for prosumers, taking into account the size of the investment, a consumer's incentive to participate in a PTP market is sufficiently large in terms of profitability (a mean IRR of 26,64% was found). The profitability[20] of a prosumer who made his investment decision based on a NM set-up, increases greatly when changing the market set-up (3,39% vs 9,00% vs 10,61%). Also, consumers can still benefit from investing given a changed set-up. A consumer who decides to adopt given the market set-up (ceteris paribus) profits substantially more in an ET and PTP market (3,39% vs 9,00% and 10,49%).

As shown in the previous segment, the profitability on a PTP market is affected by one's share of market capacity (assuming an unchanged yearly consumption), this in turn affects the IRR and payback period. Nonetheless, the profitability will always be better compared to NM because ET serves as a lower bound for the profitability on a PTP market.

5.3.5 Revenue supply side

Substantial cost reductions achieved by microgrid participants do not come out of nowhere. Trading locally affects the amount of electricity that is purchased on the retail market, resulting in a decreasing revenue for the supplier. Figure 5.20 show the yearly costs, revenues and

[19] An average of 49,98% compared to 5,10% for consumers (cf. infra).

[20] Assuming the PV installation is used in the given market set-up during its complete lifetime.

resulting profits of a supplier in different market set-ups. Based on the given set of participants a supplier would earn 20,8 thousand EUR in an ET market. Not taking into account the prosumer tariff, this would result in the highest profit. However, prosumer tariff is to be paid in a NM set-up, a compensation for the generous reimbursement of excess generation - which is valued at the retail price. The reimbursements are represented by the red bars in Figure 5.20. ET compensates for the omitted prosumer tariff by a less generous reimbursement - valued at the export tariff[21]. Given that the ET reimbursement method is driven by volume, rather than by the inverter size in case of NM, it better reflects the scarcity on the market. This results in NM having the highest profit of 21,3 thousand EUR. Looking at the costs and revenues generated in a PTP market, a notable difference from ET can be seen. In spite of the consumption and generation volumes being valued at the same prices in ET and PTP, the profit of a supplier in case of PTP amounts to a total of 19,1 thousand EUR - representing a drop of more than 8%. Taking the traded volumes into account clarifies this difference.

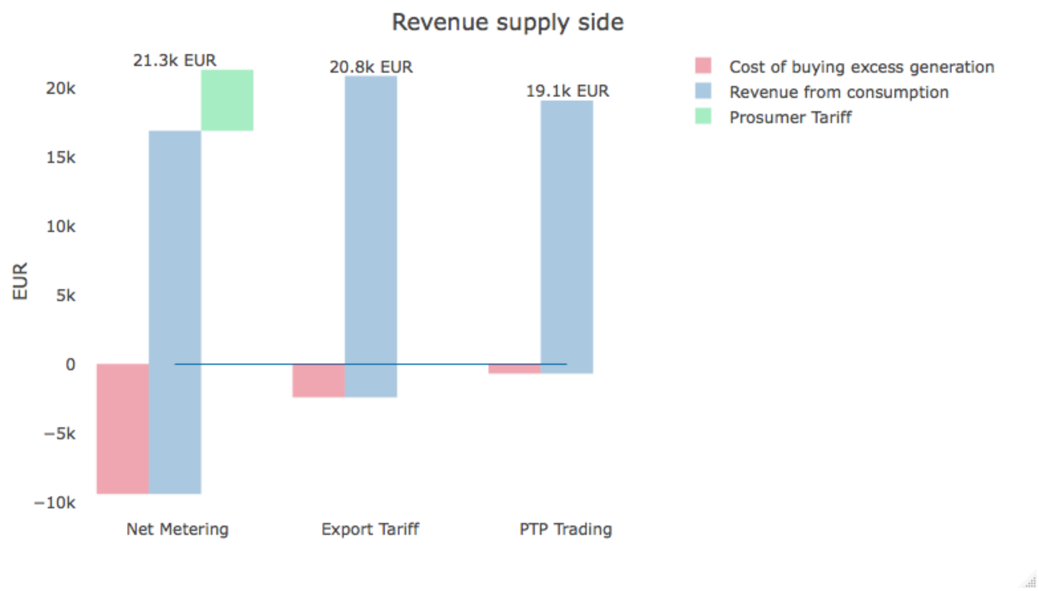

Figure 5.20: Revenue of supply side for given set of participants. Note that the costs of NM are implicit.

Looking at Figure 5.21 and comparing the volumes[22] of May that are traded with the supplier in a PTP market versus in a ET market, we clearly see a smaller volume is sold on the retail market in a PTP market (represented by A and C) as opposed to in an ET market (represented

[21]See Figure 5.5 for a comparison of the retail price $P_{rt}(t)$ and retail tariff P_{et}.

[22]The sold and bought volumes in PTP and ET set-up are priced at the same levels, which allows for comparison.

by the blue area - A, B and C). Yet, this only accounts for the revenue from sold quantities. The supplier also buys excess generated quantities. In an ET[23] set-up the supplier reimburses the prosumer for its excess generation, this volume is represented by the green area (B and D) in Figure 5.21 and priced at the export tariff. In a PTP market the supplier pays the same price for excess generation. This is in contrast with the case of NM, where the supplier reimburses prosumer for their excess generation a rato the retail price. However, the traded volumes are not the same. Part of the generation is traded locally. Generation[24] that is not traded locally due to saturation on the microgrid is sold to the supplier at the export tariff, this volume is represented by area D in Figure 5.21. In short, when moving to a PTP market area B[25] is traded locally and no longer sold to and purchased from the supplier. In a PTP set-up the volume represented by area B is traded from one peer to another in a single transaction. In a NM or ET set-up, this volume virtually passes through a supplier, it is bought from one prosumer and sold to another pro- or consumer, doubling the amount of transactions taking place.

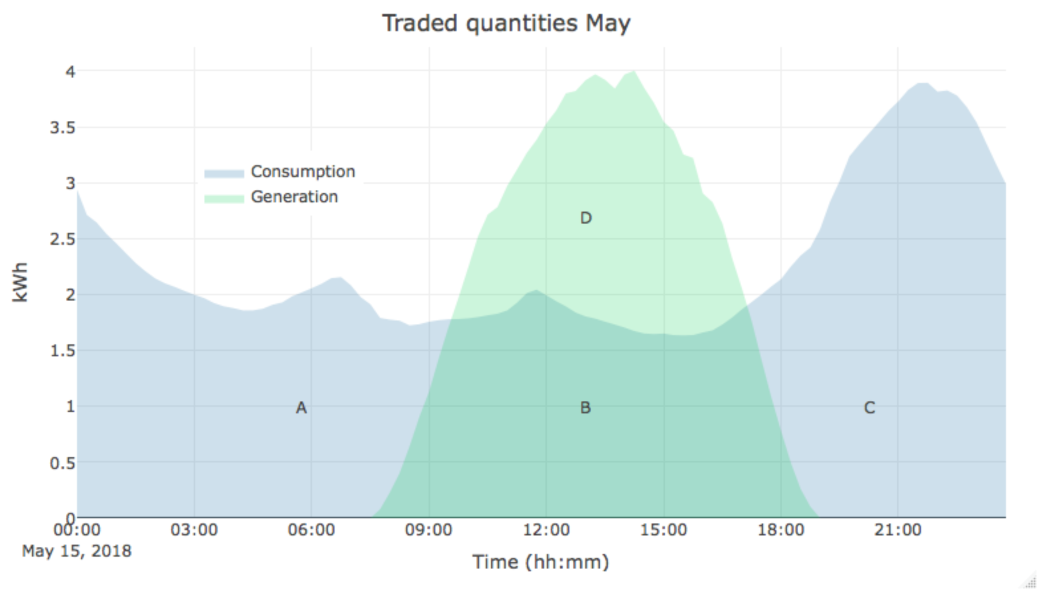

Figure 5.21: Traded volumes.

Note that Figure 5.21 is not representative for all months. When no excess generation is available in a certain time period all microgrid net consumers are supplied through the retail

[23]In a NM set-up the traded quantities are the same as for ET. The reimbursement is done at the retail price, not at the export tariff.

[24]Total generation is defined as the generation amount exceeding the behind the meter consumption in a time period (cf. infra). This does not imply there is no generation.

[25]The surface of B represents the volume that is bought and sold.

market. For example, in January the total generation[26] is zero at any given point in time Figure 5.2. This means there is no local trading. The resulting total net consumption volume (equal to the total consumption) is bought on the retail market at the retail price.
The more consumption is shifted towards periods when local DG is available, the lower the revenue for the supplier will be as the microgrid is less dependent on import from and export to the main grid. A decrease in supplier revenue will also result in lower revenue for the DSO and TSO. However, this decrease in revenue can make sense; due to better matching of local generation and consumption the task of the TSO is simplified. On the other hand, nothing much changes for the DSO, the same quantities of electricity move through the distribution grid, yet this party sees its revenue decrease. Therefore in such a set-up a DSO must find ways to stay viable. A possibility might be that the DSO obtains a commission on the transactions taking place in the PTP market or possibly takes on the role of aggregator as facilitating a PTP market can help in local balancing. Abu-Sharkh et al. (2006) reason that by virtue of good match between generation and load, the impact on the distribution network could also be minimised.

5.4 Effect of demand response and storage

In the previous calculations we assumed that the participants retain their consumption and generation patterns regardless of the market set-up they are faced with. However, in the case of PTP trading it can be seen that during periods of excess generation both the consumption and export prices decrease (Figure 5.22). As this impacts the profitability of consumers and prosumers it is not unlikely that they will react to these price signals. Two possible ways to do so are through DR and storage capacity (cf. 2.2.5). To analyse the impact we simulated the effect of DR and storage capacity in the given PTP set-up.

5.4.1 Demand response

In chapter 2 the potential of DR in a NM set-up is illustrated. As the NM pricing scheme consisting of only day and night tariff does not provide sufficient incentive to shift consumption, the case of providing dispatchable services to either an ARP or the TSO was discussed. Although positive effects on balancing were possible, the financial benefit of providing flexibility for balancing purposes was found to be very limited. Considering the fact that investment in a smart meter is indispensable and deployment on large scale - by grouping households - is required to meet the threshold for participation, opposed to the low financial return, the tendency for a household to participate is disputable. The introduction of a variable pricing scheme, as is the case in a PTP market, increases the incentive to shift consumption. Because

[26]Total generation is defined as the generation amount exceeding the behind the meter consumption in a time period (cf. infra). This does not imply there is no generation.

the consumption price on a PTP market fluctuates between a bigger range throughout the day, the potential to save on the electricity bill by shifting demand is greater. This type of DR is of course driving by the PTP price and not by a request for flexibility from an ARP or TSO for balancing purposes. Note that both drivers are not necessarily aligned.
Figure 5.22 represents the valid prices during the average day in May. In area A P_{co} is dropping from the maximum retail tariff, to the minimum PTP price, in area C the reverse movement takes place. These areas have the highest P_{co} throughout the day due to limited availability of local generation and the valid day tariff on the retail market. The period in between, area B, is characterized by a high availability of solar generation resulting in the lowest P_{co} throughout the day. The consumer in case has a clear incentive to shift consumption from areas A and C to area B to minimize its energy bill.

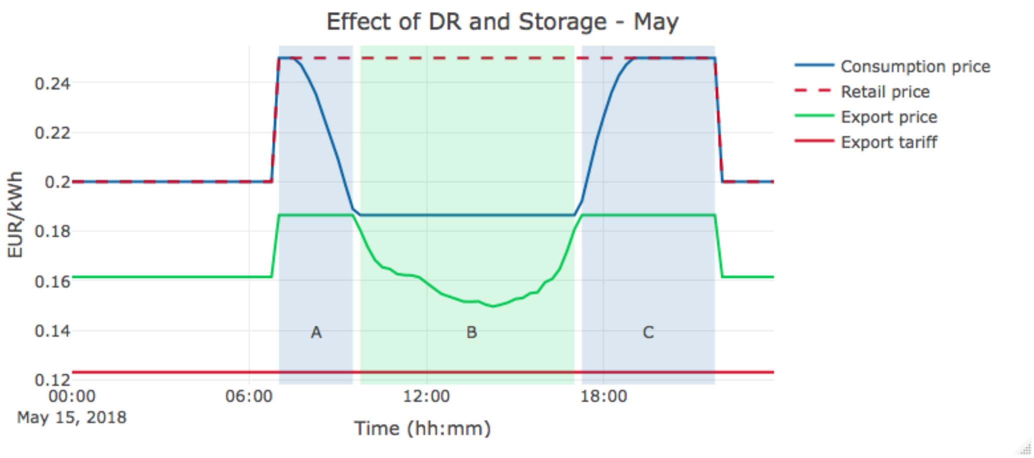

Figure 5.22: Evolution of prices throughout the day.

We simulated a scenario in which a consumer, participant in the given PTP set-up, is willing to shift 10% of its daily consumption. Given that local generation - a major driver for the consumption price - is only available in large quantities during summer months, we assume a consumption shift only during the months May till August. This simulation is calculated over the given set of consumers, assuming the given consumer is the only one shifting demand. A mean cost reduction of 47,14 EUR, representing a mean decrease of 5,48% on the yearly electricity bill. Although the potential of DR is expected to be smaller for the other months, there definitely is room for optimization throughout the whole year.
The necessary investment cost for a smart meter is already justified by the achieved savings from moving to a PTP market (cf. infra), DR makes a smart meter even more affordable. In addition, the savings from DR[27] can only be achieved in a variable pricing scheme. In that

[27]Considering price driven DR. Disregarding DR driven by a request for flexibility from a ARP or TSO for

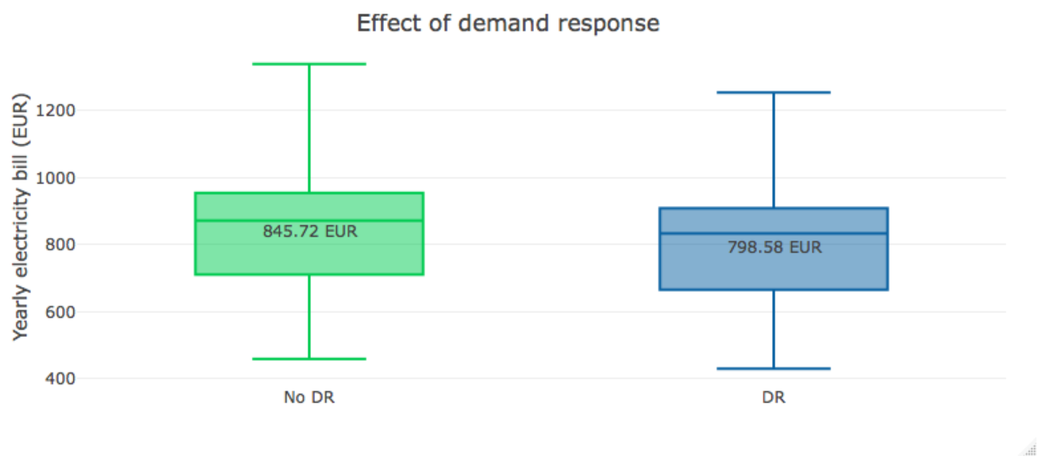

Figure 5.23: Effect of consumption shift on electricity bill for consumers.

way PTP can be seen as a way to lower the entry barrier to DR for households, while DR improves the local balancing. Considering both facts, there is synergy between PTP and DR. Note that DR does not imply an increase or decrease in energy consumption on the long term. When a consumer shifts a share of its consumption from one period to another, the total consumption remains the same. The issue in this PTP market may be that instead of consuming at the same level or shifting consumption to further decrease the electricity bill, consumers might perceive the new set-up as a simple reduction of their electricity bill to which they react with an overall increased electricity consumption, especially during the off-peak periods. Hereby the consumer obtains the advantage of consuming more at the same price, yet, this does not correspond with the the value that PTP trading should deliver to the overarching grid.

5.4.2 Battery storage

Due to little variability in retail prices, storing energy on a battery and discharging later is a rare practice among households. The price difference between the day and night retail rate is insufficiently large - resulting in a small benefit when shifting generation - to justify the investment cost of a battery. As the PTP price is driven by local availability from intermittent energy sources, it is more variable by default. On a PTP market, the same way a consumer is motivated by variable pricing to shift consumption and benefit monetarily, a prosumer is motivated to store generated volume and offer that volume when prices are highest. As the export price is analogous with the consumption price, a prosumer that wants to maximize its revenue from generation will shift generation to off peak periods. Due to the night tariff, high export prices are situated during a subset of the total off peak period, being area A and C in

balancing purposes.

Figure 5.22. We consider the case where a single prosumer stores 60% of its daily generated volume during peak hours (represented by area B in Figure 5.22) and discharges this volume during period A and C. The results of a simulation - considering each individual prosumer to shift (ceteris paribus) - are plotted in Figure 5.24. A mean cost reduction on the yearly electricity bill is found of 22,5 EUR, representing slightly more than 7% of the mean electricity bill without shifting generation. Considering the high investment cost of home batteries, we can assume a mean yearly financial return will not suffice to justify the investment.

5.5 Conclusion

The following conclusions can be drawn:

- ET and PTP increases the financial return for *prosumers* over NM. This is mainly due to the relatively high prosumer tariff in NM. In PTP additional savings are obtained due to the ability to sell a share of excess generation at the higher PTP rate instead of the export tariff.
- In PTP, *consumers* obtain additional savings due to the availability of local generation priced at the lower PTP-rate. Taking into account the required investment in a smart meter this still provides a significant financial return.
- In line with the increased return for participants, the revenue for the *supply side* decreases when moving from NM to ET and PTP. In PTP this can be appropriated to the fact that consumption is first matched with local generation, and suppliers deliver the residual consumption instead of the total consumption (in NM and ET).
- Increasing the PV capacity for an individual results in additional savings in ET and PTP. However, if the overall PV capacity within the microgrid increases prosumers savings are reduced, while consumers savings increase. However, for a consumer, installing PV capacity will still generate positive return in PTP.
- The variable nature of prices in PTP could result in additional savings for participants when consumption is shifted to periods with available local generation in the form of *DR*.
- In the same way, *storage* capacities increase savings for prosumers. However, taking into account the investment cost of a home battery, this likely does not result in a desirable return.

Quantitative results and additional conclusions are listed in Tables 5.2, 5.3, 5.4 and 5.5.

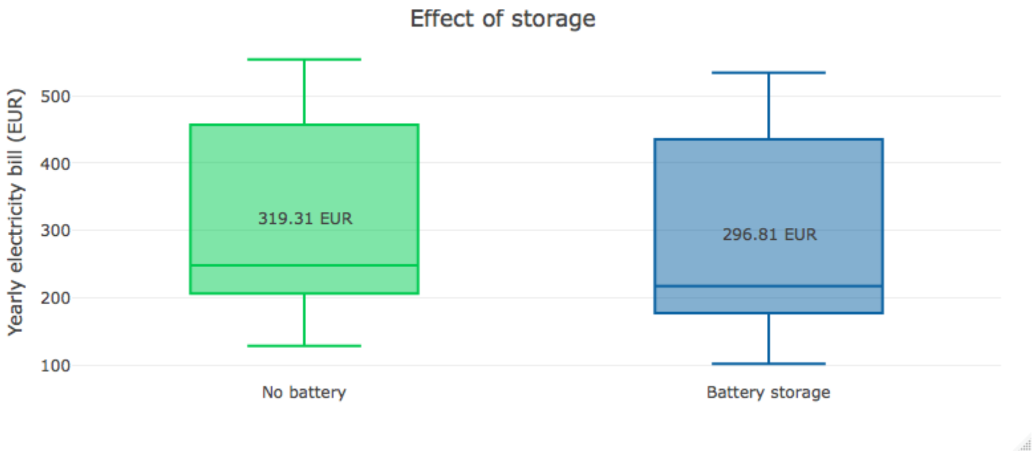

Figure 5.24: Effect of generation shift on electricity bill for prosumers.

Table 5.2: Summary quantitative results

	NM	ET	PTP
Total bill prosumer (EUR)	600,65	393,54	319,31
Total bill consumer (EUR)	891,66	891,66	845,72
IRR (%)	4,79	10,54	12,53
Payback Time (years)	13,3	8,97	8,04
IRR: consumer (%)			26,64
Revenue Supply Side (EUR)	21,3k	20,8k	19,1k
Metering	Analogue	Continuous, Bidirectional	Continuous, Bidirectional
Incentivize DR?	No	No	Yes
Incentivize Storage?	No	No	No (savings are not sufficient)
Metering	Analogue	Continuous, Bidirectional	Continuous, Bidirectional

Table 5.3: Summary conslusions NM

Advantages prosumers	Compensation of consumption with generation in other periods is possible.
Disadvantages prosumers	Increasing PV capacity could result in increased electricity bill. Prosumer tariff is not linked to effective grid usage
Advantages consumers	No investment in smart meter required.
Disadvantages consumers	
General advantages	Prosumer tariff covers grid costs.
General disadvantages	Metering activity is not complex. Prosumer tariff is lump sum and does not resemble effective grid usage. No incentive to consume local generated electricity.

Table 5.4: Summary conslusions ET

Advantages prosumers	No decrease in financial return when expanding PV capacity.
Disadvantages prosumers	Requires smart meter investment.
Advantages consumers	
Disadvantages consumers	
General advantages	Charged based on effective grid-usage and generation.
General disadvantages	item Requires more complex data-keeping and information management. No incentive to consume local generated electricity. Everlasting expansion incentive.

Table 5.5: Summary conclusions PTP

Advantages prosumers	Marginal decrease in return when expanding PV capacity. Extra savings possible when shifting generation.
Disadvantages prosumers	Electricity bill is dependent on external factors. Requires smart meter investment.
Advantages consumers	Savings due to lower priced local consumption. Extra savings possible when shifting consumption (DR).
Disadvantages consumers General advantages	Requires smart meter investment. Incentivizes consumption of local generated electricity. Reduces balancing efforts for grid-operators and exchanges with main grid.
General disadvantages	Requires more complex data-keeping and information management. Less revenue for suppliers and grid operators (however, potential savings on system costs). Requires an extra market role. Everlasting PV expansion incentive (may lead to sub-optimal situation if applied by all participants).

Chapter 6

Clearing the market

The previous chapter has shown the potential of PTP trading using the MMR pricing method. Howbeit, the underlying assumption is that an effective market clearing mechanism is in place that has access to real-time metering data. In our PTP market design we propose the emergence of a new market role: the aggregator (cf. 4.2.6). We discuss the tasks of and requirements for this role and investigate whether blockchain technology might be well-positioned to take on the aggregator role, building on the notion of a truly decentralised PTP microgrid.

6.1 Aggregator role

The aggregator keeps track of every participants proper consumption and generation and accordingly, imports or exports the appropriate quantity to balance the microgrid. Imports in case of local scarcity, exports when the local generation exceeds the local consumption (i.e. local saturation). Using a MMR, a net consumer pays the weighted average of the PTP price and the retail price (i.e. the consumption price, cf. 4.2.4). A net producer receives the weighted average of the PTP price and the export tariff (i.e. the export price, cf. 4.2.4). Depending on the current retail price, export tariff, the resulting PTP price and the consumed, locally generated and imported quantities, these prices are determined for every time period. The resulting prices are communicated in real time to microgrid participants. Based on the set prices and tracked quantities the aggregator bills each participant accordingly.

It is however key to note that, although the aggregator assures a so called 'administrative' balance within the microgrid (i.e. matching generation and supply origins), this does in fact not resemble the same as ensuring physical balance within the microgrid. To import and export quantities an aggregator relies on an ARP. This ARP will have to provide the TSO, *ex-ante*, with its nomination programs related to their perimeter, which includes the forecasted expected load within the microgrid and the contracted quantities from the centralised producers such that matching generation is found Appendix A. Note that PTP trading induces participants in a microgrid to better match consumption and generation, implicitly shifting balancing services to the lowest level of aggregation. As a PTP market provides a high degree of local balancing, the tasks of the ARP are of a lesser extent. In addition, real time metering data is available and already being processed for local balancing purposes. This means data is available on the level of the consumer, this optimal demand side transparency decreases forecasting errors. Both roles, aggregator and ARP, when working in close cooperation form a synergy. The ARP gets access to real time data and benefits a high degree of local balancing. The aggregator needs access to the wholesale market to import and export in case of scarcity and saturation respectively.

To reduce complexity, in chapter 3 we assumed the tasks of ARP to be incorporated into the role of supplier. Note that the activities *Supply of Electricity* and *Host PTP market* have overlapping tasks (cf. 4.3). They both contain billing, pricing and rely on an ARP for balancing. Deducting these tasks from the role of the supplier leaves us with no more than what can be performed by the ARP and an aggregator. In this way in Figure 4.2 the activity of supplier does not represent the activity of supplier in Figure 3.3 to its full extent. Therefore, our proposition includes that the aggregator and ARP roles can interact and secure supply on the microgrid without the need of a third party (i.e. supplier) (represented by scenario A in Figure 6.1).

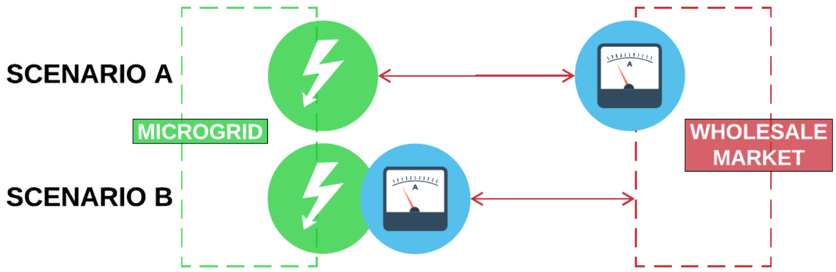

Figure 6.1: Scenarios for the role of aggregator.

Scenario A: Separate entities

Figure 6.2 shows the E3-value model for the aforementioned scenario A. Note that the original supplier role has disappeared, the ARP now fulfils what is left of the traditional supplier role and interacts with a independent aggregator.

Scenario B: Single entity

In a more radical approach the balancing responsibility could be shifted entirely to the aggre-

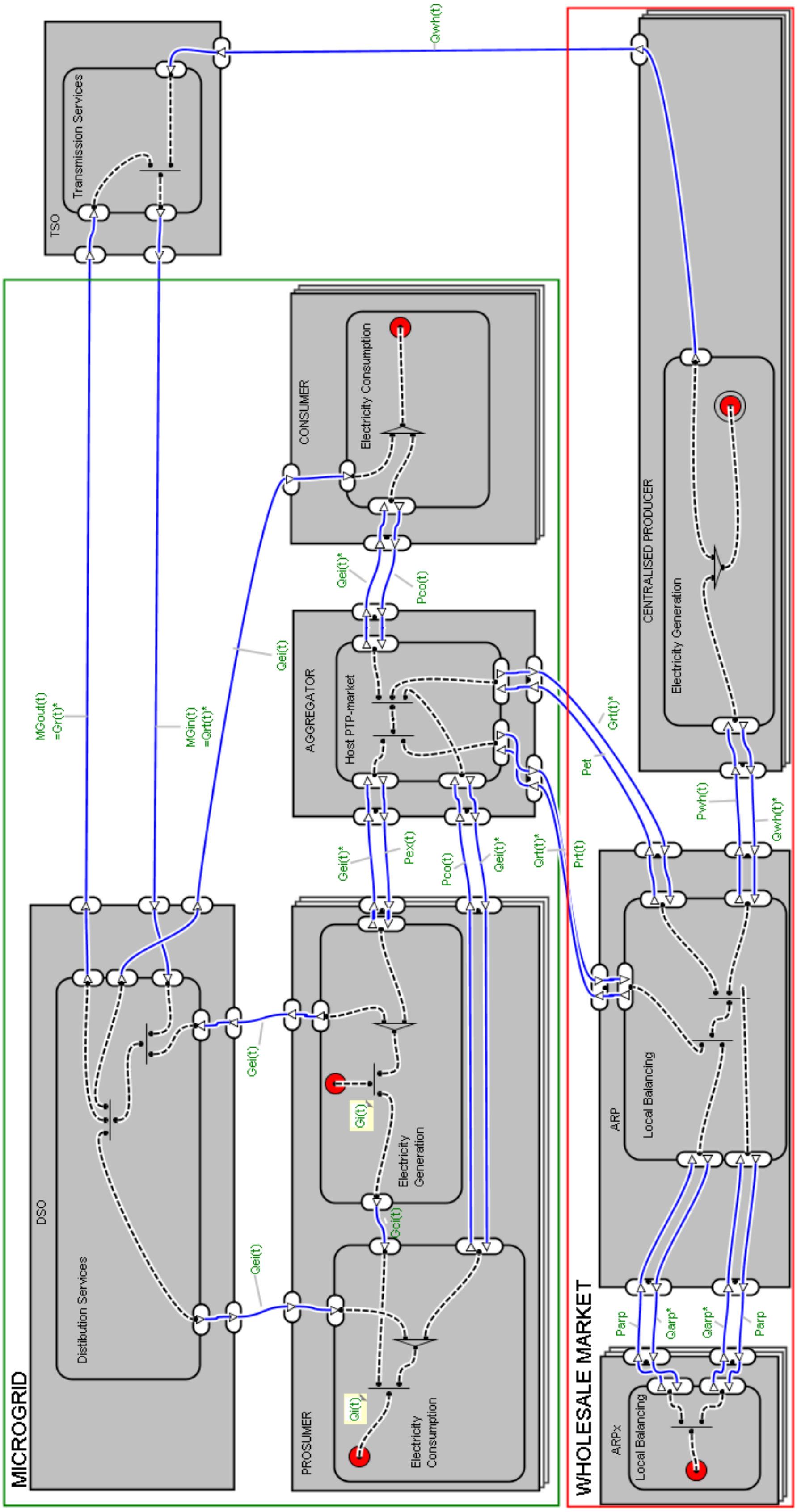

Figure 6.2: E3-value model for scenario A.

gator, shown in Figure 6.3. This means that this entity will now be responsible for the task *Host PTP market*, as well as delivering local access point balancing (indicated by *microgrid balancing*), which was an ARP task originally. In this form the aggregator now directly trades with centralised producers and/or ARPs on the wholesale market. Note that the aggregator is now responsible for the physical streams $MG_{in}(t)$ and $MG_{out}(t)$, indicating the flows that assure the physical balance within the microgrid.
In the end, although receiving the same margins, in a PTP set-up smaller volumes will be traded on the wholesale market as there is more consumption from local generation (cf. 5.3.5). Why would a traditional supplier want to take on the role of aggregator? The Belgian energy market is characterized by an elevated number of competitors. In April 2018, 42 suppliers were active on the Flemish electricity market of which 34 have a market share of less than 1,36%. More than 61% of the market is supplied by the two biggest incumbents (VREG, 2018c). Wallonia has a similar structure, in Brussels the gap between small and big suppliers is even larger (CREG, 2017b). This imperfect competitive market is driven by prices, whereby entering is challenging. Putting the customer first, delivering value through other factors than low pricing, like environmental and socio-economic factors (cf. 2.2.2), may be an edge over incumbents. Implementing a blockchain clearing mechanism could lower costs for the supplier, resulting in a higher margin (CCN, 2018).

6.2 What is blockchain?

PwC (2015) defines blockchain as *"a technology that enables so-called "peer-to-peer" transactions. With this type of transaction, every participant in a network can transact directly with every other network participant without involving a third-party intermediary."* Iansiti and Lakhani (2017) adds that *"the ledger itself can also be programmed to trigger transactions automatically."* The following principles serve as an introduction to the concept of blockchain.

Distributed database. This means that data is not centralized in one database, nor owned and secured by one institution (Iansiti & Lakhani, 2017). Instead the transaction data is distributed, stored locally on all participating computers of the network (PwC, 2015). No central authority controls the data or the information. This also implies that no one can control the blockchain. Every participant has access to the entire database and everyone can verify records.

PTP transactions. All transactions and communication take place directly (literally, peer-to-peer) between the customer and the provider instead of through a central node (Iansiti & Lakhani, 2017). There is no central authority overlooking every transaction, or intermediary needed to verify authenticity of either peer involved in the transaction. The PTP concept

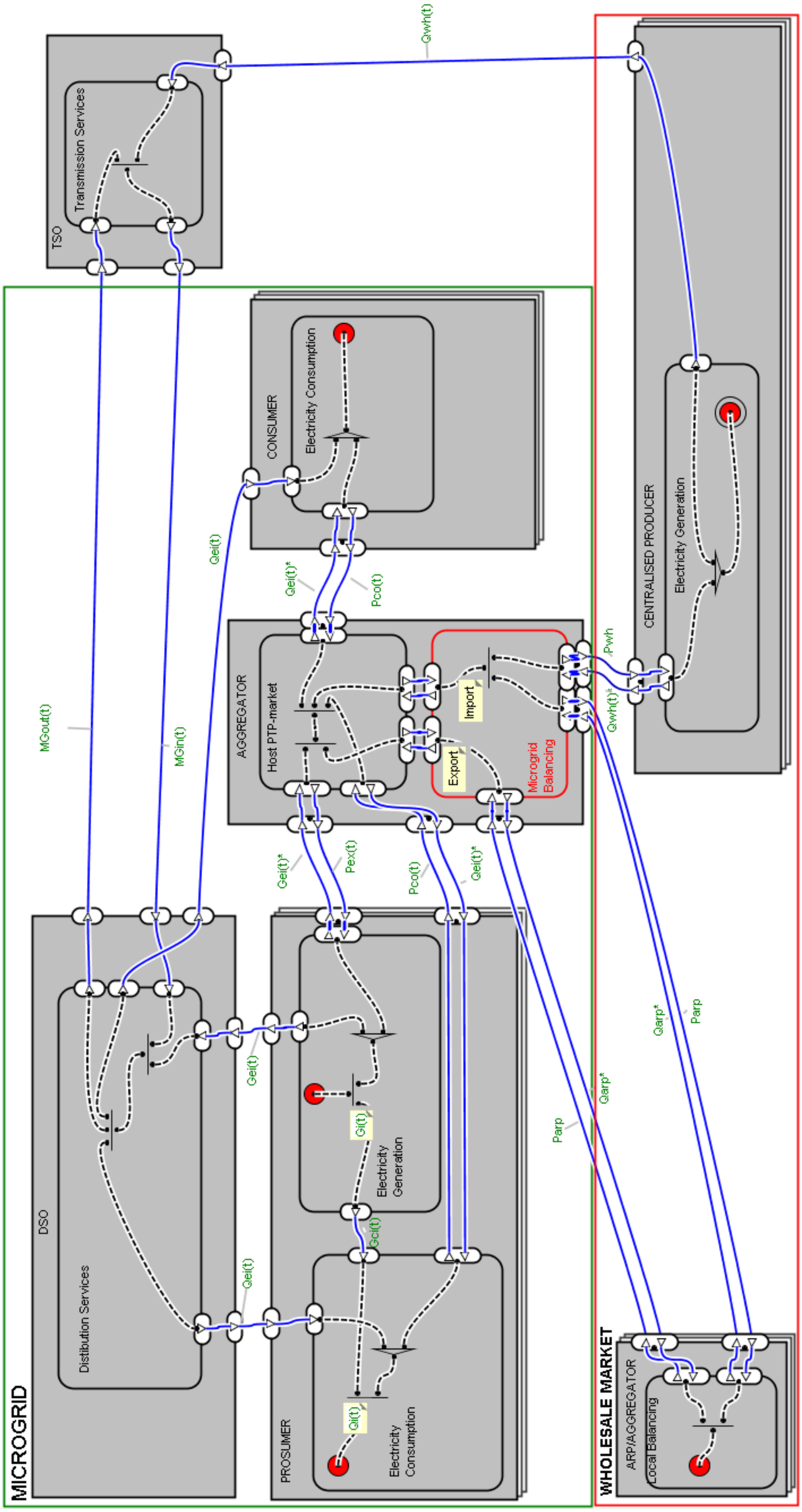

Figure 6.3: E3-value model for scenario B.

relates to the fact that the transaction is stored on a network of computers; the computers of the peers involved in the transaction, as well as the computers of other network participants that act as witnesses to the transaction. In that way other participants can provide confirmation about the transaction (PwC, 2015).

Immutable records. The information of a single transaction is encrypted and combined with the encrypted information about other transactions made during the same time period into a new block of data (PwC, 2015). After validation by other network participants, a block is added to the chain of blocks (Degraeve & Guerreiro, 2016). A block contains three elements: encrypted data, a timestamp and a link to the previous block. In this way, once entered in the database, they cannot be altered (Iansiti & Lakhani, 2017). All blockchain records - this could be a.o. a transaction, a title, a contract, a vote or music - are immutable (Degraeve & Guerreiro, 2016). As Tapscott and Tapscott (2016) put it: "*If you'd wanted to steal a Bitcoin, you'd have to rewrite the entire history of it on the blockchain*[1] *in broad daylight.*" On the other hand Greenspan (2017) nuances the immutability, referring to it as the inability to change *"information which can only be corrupted or changed if a majority of the validating nodes decide to maliciously collude."*, while also pointing out the fact that private chains are more easily rewritable given the small number of participants.

Smart contracts. Network participants can define rules that trigger transactions between peers that are automatically executed (Iansiti & Lakhani, 2017). Contracts as we know them are a set of promises that are legally enforceable, but do not execute automatically. A smart contract automatically executes predefined processes when a set of conditions are fulfilled.

Public, private or permissioned? Differences relate to who is allowed to participate, validate and maintain the shared ledger (Jayachandran, 2017). On a *public blockchain*, participants are identified by blockchain addresses so their identities can remain anonymous. Anyone has access to read and write (Merz, 2016). The anonymity, immutability and transparency come at the cost of efficiency (Noyes, 2016): A vast amount of computer power is required to achieve consensus, resulting in slow transaction speed. In addition, there is little to no privacy regarding the transaction data (Jayachandran, 2017). The shortcomings of a public blockchain can be mitigated by tweaking the structure of the technology (Peck, 2017). Two known variations are private and permissioned blockchains. Consulting a multitude of sources it seems there is no consensus on the exact definition of these types of blockchain. However, generally this holds true: *Permissioned blockchains* are operated by known entities, compared to public blockchains they trade off lower anonymity and transparency for higher efficiency (Noyes, 2016). This type of blockchain is considered to be a hybrid version between

[1] Referring to the Bitcoin blockchain; a public blockchain.

public and private blockchains. *Private blockchains* are operated by a single entity and partly trade off anonymity, transparency and immutability for efficiency (Noyes, 2016).

6.3 Blockchain powered energy markets

"In the last year (i.e. 2017), the roughly 120 energy blockchain start-ups in existence collectively raised a total of 324 million USD. [..] 59% of blockchain energy projects focus on building a peer-to-peer grid network." - Consensys (2018)

In April 2016 the first blockchain PTP transaction of electricity was record on the Brooklyn Microgrid in New York city. This pilot project was launched by LO3 Energy and Consensys. This community energy market enables members to trade self generated energy securely using smart contracts on the Ethereum blockchain (Zhang, Wu, Long, & Cheng, 2017).

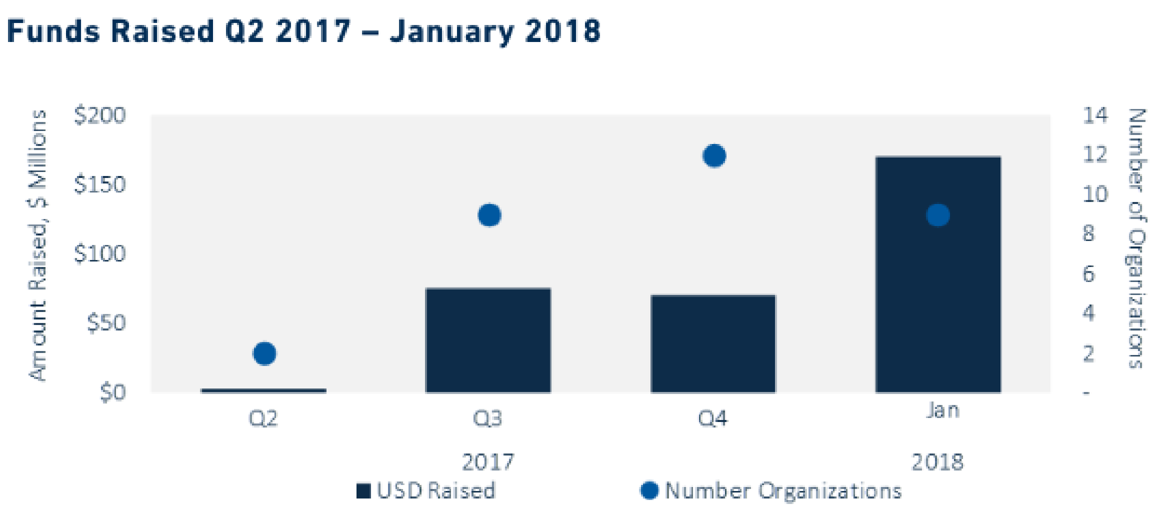

Figure 6.4: Investment in energy blockchain start-ups. (Colleen, 2018)

6.4 Blockchain aggregator

The previous section shows that blockchain has the potential to act as a clearing mechanism on the PTP market. Given the PTP market set-up defined in chapter 4, we discuss the necessity and fitness of blockchain to fulfil the particular role of aggregator.

Scenario B (cf. 6.1) represents the case where an aggregator has the tools and know-how to assure balancing itself, without the need of an ARP as external partner. However, in the current market organisation and regulation a physical third party (i.e. ARP) is still essential for access to the wholesale market (cf. supra). Although efforts are being made to build blockchain applications to connect actors on the wholesale market (Merz, 2016) (Consensys, 2018), it is unlikely that a blockchain application could fill the void between the microgrid participants on the one hand and the wholesale market (producers and other ARPs) on the other hand in the near future. Therefore we will assume blockchain only to take on the role of aggregator within the microgrid, while supporting the ARP (represented by scenario A and Figure 6.2) or an ARP entity taking on both roles, while using blockchain technology to support the aggregator role. Note that this can be represented by Figure 6.3, only the interpretation of who takes on the role of *aggregator + ARP* changes.

6.4.1 Is blockchain needed?

According to Greenspan (2015a) blockchains are *"a technology for shared databases with multiple non-trusting writers [and interacting transactions] to be modified directly."* Based on this definition, we evaluate the added value of blockchain over other database technology.

There is a need for a shared database with multiple writers. There is a clear need for a shared common database. Tracking total excess generation and consumption on a 15 minutes basis at the level of every individual is necessary to determine the correct prices for a time period. All participants should write metering data in real-time by means of a smart meter[2]. Read access is available to all participants to consult the valid prices and their proper consumption and generation levels. Read access is needed for the ARP to consult metering data in order to import or export the necessary quantities and adjust forecasts in real-time.

Writers' interests are not unified. Writers (i.e. microgrid participants) are assumed to be known to each other as they live in the same neighbourhood. However, Wang et al. (2017) name the trust issue between microgrid participants and security information risks as possible challenges when implementing a microgrid. Each participant has the incentive to register a lower than actual consumed volume, or a higher than actual generated volume. Participants want as much volume to be traded locally. The ARP is dependent on local shortages to obtain revenue.

A trusted third party is not desirable. For settlement within the microgrid, a third party is not desirable. As a third party would likely charge a premium per transaction, this would decrease the benefit of trading locally. Hence, the need for a medium where peers can transact *directly*. (Greenspan, 2015a) reasons that lower costs, automatic reconciliation and the inability to find a suiting intermediary a.o. are good reasons to prefer a blockchain-based solution over a trusted third party. Note that given the current regulation, a third party (i.e. ARP) is required for access to the wholesale market - opposed to settlement within the microgrid.

[2] Presumably connected to a blockchain wallet.

Interacting transactions are unlikely. This means that a particular transaction may depend on (the outcome of) another transaction, to which blockchains are a solution (Greenspan, 2015a). As an individual participant - in a particular time period - will either be net consumer or net producer (i.e. exclusively incoming or outgoing flows to one node) it is unlikely interacting transaction will occur in the same settlement period.

Based on the four topics discussed above, (Greenspan, 2015a) argues that blockchain is not essential as other database technologies can cater to the needs of what is required in the given set-up. Merz (2016) however argues that in terms of multilateral interoperability (cf. supra) blockchain can offer numerous advantages solely for communication and data storage purposes.

6.4.2 Is blockchain better?

In the end the choice of (type of) blockchain versus centralised database comes down to a choice of technology. You could build a system that fulfils the needs to a high degree using either technologies. The decision boils down to a trade-off of four factors[3]: robustness, performance, disintermediation and privacy.

Performance. The distributed nature of blockchain makes that executing computational logic is less efficient than on a traditional database since all steps are performed for every node in the network, with identical results (Greenspan, 2015b). In a centralised system the computational effort would only need to be performed once at the central node.

Robustness. Greenspan (2016) also refers to the performance issue stated above as *build-in redundancy*. In case of a blockchain database, just because every transaction is processed at every node makes that no individual node is crucial to the database. Because it is distributed a node that goes down can catch up on the transactions it missed.

Disintermediation. The validation performed by the nodes in a blockchain network ensures a single version of the truth. In case of conflicting transactions only one can be accepted, ensuring all nodes to converge on the same decision. In case of a traditional centralized database the owner has all the power, while in a blockchain set-up the power is distributed across individual nodes. These nodes cannot fake transactions or modify the database in violation of its rules (Greenspan, 2015a).

Data privacy - considered as the combination of anonymity of identity on the one hand and the level of transparency of transaction records on the other hand - varies greatly across the different types of blockchains. Blockchains are sharing more information between the peers

[3]Note that there are ways to increase the abilities of either technologies on all four factors (Greenspan, 2016).

than a centralised databases because everyone sees everything that is happening even though they did not partake in the transaction (Greenspan, 2016). All transaction data (and identity dependent on the type of blockchain) would be visible to all peers in the network. There are techniques to encrypt, but the confidentiality will always be worse than on a centralised database where data is only shared between parties involved in the transaction.

6.4.3 Conclusion

For the relationship between a blockchain - taking on the role of the aggregator - and the ARP, we consider two scenarios:

Scenario A: Community of microgrid participants control the ledger
Represented by scenario A in Figure 6.1. The ARP acts as one of the peers, however it could be governed by different rules. Read access is given to an ARP providing it with real time data needed to take care of imports and exports at predetermined tariffs. The ARP benefits from real time data that allows for better forecasting, resulting in lowered imbalance costs. As the traditional supplier is bypassed, the ARP - that would otherwise be subcontracted by the supplier - earns a bigger margin. Cutting out the middleman while employing a protocol that establishes trust among peers collectively contributing to a single version of the truth that is distributed across the entire network is more eligible in a PTP network, rather than trusting a single entity with its version of the truth. Assuming peers are willing to share transaction data.

Scenario B: ARP controls the ledger
The ARP controls the ledger and gives access to microgrid participants to read and write date (represented by scenario B in Figure 6.1). Algorithms determine consensus, in this way the ARP in case uses blockchain technology to clear the market automatically resulting in cost savings. A private blockchain seems to be most likely to be implemented in the second scenario, keeping all control in the hands of a single entity. PwC (2015) points out that ex-post modification is possible, meaning we are no longer benefiting what may be the biggest benefit of blockchain in a microgrid - a single version of the truth synchronised across all nodes, ensuring balance. Considering the decreased added value of using blockchain, this might as well be managed by other database technologies.

Whether blockchain technology is suited to take on the role aggregator is highly dependent on the specifics of the market set-up. Although scenario A makes a strong case for the implementation, it is less likely to become a reality. Scenario B is closer to reality, but the added value of using blockchain is limited. Therefore traditional database technology might be better suited to fulfil the requirements. We can conclude that either technology (i.e.

centralised database and blockchain) can fulfil the requirements to a high degree but the final choice will depend on the specifics of the market set-up.

Chapter 7

General conclusion

The energy market in the European union has witnessed a high degree of liberalisation since the beginning of the century. Together with this trend and building on the dynamics within the European energy market, the Belgian energy market is evolving into a into a decarbonized, distributed, democratized and digital system. At the same time, the Belgian energy market is facing a major transition at the supply side with the expected closure of its nuclear capacity in the year 2025. This increases the need for replacement capacity, extra interconnections with neighbouring countries and a more efficient and effective integration of the demand side. Moreover, beneficial support mechanisms increased the adoption rate of DG sources in the form of RES. Their intermittent and unpredictable character poses significant challenges for grid operators, especially when it comes to the balancing of generation and consumption.
At this point in time centralised entities such as the TSO and ARPs take on the role of assuring balance of the load points within its perimeter by matching consumption with generation originating from the centralised wholesale markets. The current control mechanisms take electricity demand as exogenous and assure balance in a top-down, reactive manner. Yet, potential benefits can be gained by unlocking flexibility positioned at the demand side of the market. However, current customer billing methods are rather non-transparent and do not translate system costs nor savings into price signals for consumers who lay at their foundation. At the same time, with the rise in DG came a rise in prosumers owning their own small-scale generation facilities. We argue that past and most recent methods of integrating these new market players have been far from effective and do not contribute to aligning their interests with the interest of the overarching energy system.
We argue that an energy market in which generation is more and more decentralising can benefit from market and control mechanisms that are as well decentrally located. In our analysis we propose a set-up which includes microgrids that allow the PTP trading of electricity, and pose our main research question:

How can PTP trading of electricity support a decentralised electricity network?

However, the answer to this question is highly interrelated with the answer to the following:

What is the value-based impact of PTP trading on the electricity market?

In relation to the second question, by applying value-based modelling techniques we found that in this new set-up (i.e. PTP trading) both consumers and prosumers can save significantly on their electricity bill compared to traditional reimbursement methods. Although ET offers a significantly improved reimbursement for prosumers, as the investment of PV is incentivized, consumers are still left out of the equation and local trading is not incentivized. In a PTP market, trading locally between participants excludes a share of the revenue for suppliers, with resulting lowered revenue for the DSO and TSO. Furthermore, the ultimate impact is dependent on the characteristics in which the PTP market is established, including the number of participants and the relative quantities being consumed or generated. To effectively host such a PTP market we propose the emergence of a new entity: the microgrid aggregator responsible for hosting such a PTP market.

In relation the the first question, and building on the the answer to the second question we can expect consumers and participants to participate in a PTP market. Furthermore, the pricing signals that emanate from this market promote the consumption of locally generated electricity. This reduces the need for balancing parties to compensate shortages through the centralised wholesale markets. At the same time, the smart metering infrastructure and availability of relevant data reduces forecasting and balancing errors issues, in this manner these variations propagate in a lesser extend to the the rest of the market. We argue that the PTP approach is well-positioned to enable balance from the bottom-up as it aligns microgrid participants' interests with the interests of grid operators resulting in a positive outcome for both the microgrid and the overarching grid as a whole. In this sense the reduced revenue for grid operators in a PTP market might be offset by additional savings on system costs.

We conclude that a PTP market is effective in integrating prosumers and consumers by delivering them added financial value, simultaneously incentivizing them to consume local available electricity and reducing the dependence of the microgrid on the main grid. Extending the energy market liberalisation up to the point where prosumers are active actors ultimately achieves a reduced need for centralised power capacity and an increased profitability of RES. Contributing to all three pillars of the energy trilemma, we argue that PTP markets has the potential to create suiting financial incentives that support an evermore decentralising energy

system.
Having ascertained the emergence of a new role required to host such a PTP market we then pose the final research question:

Can blockchain serve as a medium to enable PTP trading of electricity?

It could, but the medium blockchain is certainly not the exclusive solution. The question is more about *which technology is best suited* rather than *should I use blockchain.* Depending on the specifics of the market set-up a traditional database system could fulfil the requirements. We found that blockchain technology is not an exclusive solution in the previously defined market set-up. Depending on who takes on the aggregator role, blockchains could add more value than a traditional database system.

7.1 Discussion

Sensitivity analysis. The results of chapter 5 are based on a predefined set of participants with the resulting market outcomes. We have found that not the number of prosumers and consumers influence an individual's electricity bill rather the ratio generation versus consumption in certain time periods affects the PTP cost. To investigate the effect of this changing ratio we have performed sensitivity analysis by running multiple simulations, iterating through incrementing ratios while calculating the changing cost for an individual participant (cf. 5.3.3 and 5.3.4).

Assumption of the rational participant. We assume rational participants who want to minimize their electricity bill and maximize their revenue from PTP trading. In order to do so they have the willingness and ability to install PV panels and to buy a smart meter.

Assumption of the free aggregator. As chapter 5 built upon the blueprint represented in chapter 4 we assumed the aggregator not to be charging any premiums over the supplier's prices. Chapter 6 starts with the re-evaluation of the role of the supplier. Due to overlapping tasks a supplier is no longer required and the aggregator and the ARP can interact directly. The margin of the supplier over the cost of electricity (producer), transmission fee (TSO), distribution fee (DSO) and balancing costs (ARP) are funds that are available for any costs related to the aggregator role (and DSO, cf. supra).

Price risk. Because prices are determined *ex-post* - dependent on the local consumption/-generation and imported/exported amounts - microgrid participants face greater price risk opposed to in a NM market. However, the ultimate consumption price will always be lower because $P_{ptp}(t)$ is the mean of P_{et} and $P_{rt}(t)$. $P_{rt}(t)$ serves as an upper bound for $P_{co}(t)$. The same goes for exporting electricity, P_{et} serves as a lower bound for $P_{ex}(t)$.

Challenges to implement a PTP market. Although offering a high potential of being a means to incorporate DG into the market and support an evermore decentralising energy system, PTP is likely to have a number of challenges for implementation. The majority of Belgian households has no solar capacity, nor a smart meter. As prosumers become more active market players established market players (i.e. suppliers, TSO, producers) will see a decrease in revenue simply due to less needed. It is unlikely these parties will just undergo without reacting to this trend.

Grid usage. The grid usage of local trading is not accounted for. When implementing a PTP market, the same amount of electricity will flow through the distribution net - possibly over shorter distances due to better matching - but the overall revenue of the supply side decreases, which includes the DSO's revenue. Note that due to bypassing the supplier (cf. 6.1) funds are available for any costs related to the aggregator and DSO (cf. infra).

Generalisation across regions. As data was not always available about all three regions (Flanders, Wallonia and Brussels) we were not always able to support our argumentation with concrete numbers. However we did verify on a qualitative basis whether the generalisation across regions held true. The quantitative analysis in chapter 5 is based on data of Belgium entirely.

7.2 Research gap

PTP solutions put forward by other works (Hijgenaar et al. (2017) a.o.) operate under the assumption of system user participation. Hijgenaar et al. (2017) points out that *"a thorough cost-benefit analysis should pinpoint the financial incentives required to activate users into using the system."* This has been our approach to contribute to previous works with our research.

7.3 Future research

In our value-based analysis we quantified the financial impact for consumer, prosumers and the supply side in the proposed PTP market. As we have indicated that revenue for traditional suppliers will likely decrease, the impact on DSO and TSO is more ambiguous as PTP markets might potentially reduce overall system costs. Further research could analyse if PTP markets is in fact value enhancing for the overall energy value chain instead of purely shifting financial benefits to other players.

We indicated that participants can potentially benefit from applying DR within a PTP market. Future research could focus on the exact relationship between the price of local, renew-

able electricity and consumption patterns. Also socio-economic factors should be taken into account; such as the consumers' willingness to pay for for local and renewable electricity.
In our analysis in chapter 5 we concluded that profitability (or costs) for participants in a PTP set-up are dependent on the characteristics of the microgrid. Future research could investigate the optimal microgrid composition, such as the the scale, the energy sources, and the relative share of prosumers and consumers, as well as the optimal combination of consumer profiles - while taking into account technical constraints.

Appendix A

Balancing responsibility and ancillary services

A.1 Electricity balancing responsibility: ARPs

Elia outsources part of its responsibility to balancing responsible parties, which are also called ARPs as these have an amount of access points to the grid under their balancing responsibility. As stated in the *Federal Grid Code (Art. 157(1))* (Elia, 2002): *"The ARP will provide and deploy all reasonable resources in order to maintain on a quarter-hourly basis the balance between total injections and total offtakes within its perimeter."* ARPs can be producers, suppliers, major customers (such as large industrial companies) or traders. These parties sign a contract with the TSO, Elia, which includes their rights and obligations and are commissioned for their balancing services. (Elia, n.d.; Next Kraftwerke Belgium, n.d.-a)

ARPs forecast the expected offtakes within their perimeter and place bids to obtain the desired amount of electricity at a certain price/electricity unit - or produce the electricity themselves. On the supply side electricity producers place sell orders for their forecasted production that exceeds their own consumption needs (note that these producers are ARPs themselves). Bids are then allocated through merit-order, ensuring competitive prices. In general three markets for the exchange of electricity exist, based on its time until physical delivery. The Forward Market or long term market allows ARPs to assure a large share of its supply portfolio up to three years ahead of physical delivery. Secondly, on the Day Ahead Market (DAM) electricity can be traded one day prior to delivery until 14.30. These trades must be included as a so called nomination within an *access program* and delivered to Elia. ARPs must provide Elia with these *access programs* on a daily basis and it displays this ARPs final position. In general an access program includes:

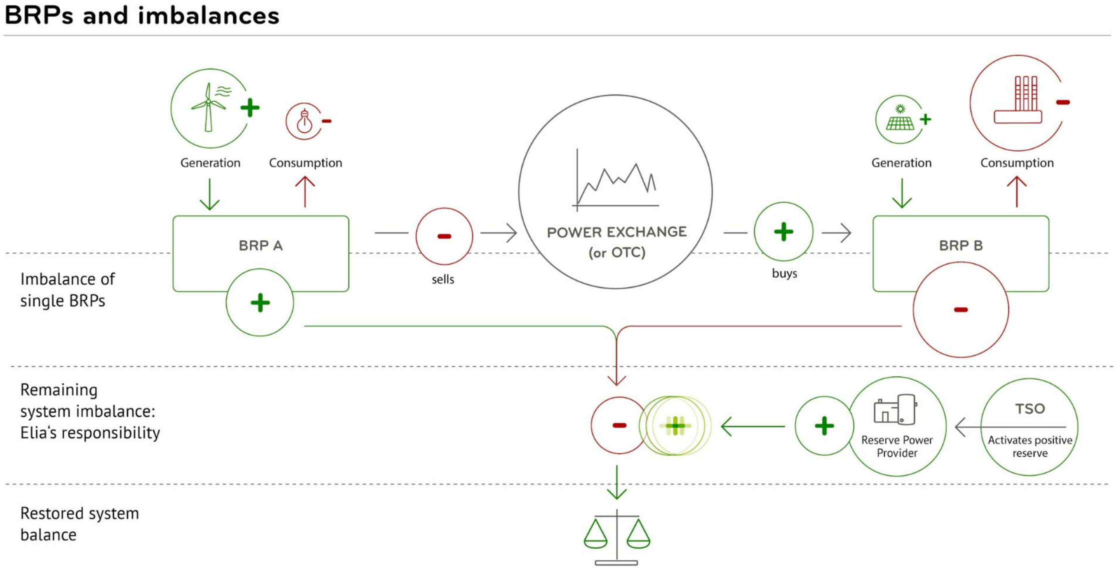

Figure A.1: ARPs and imbalances. (Next Kraftwerke Belgium, n.d.-a)

1. Expected injections and offtakes, which includes possible own production.

2. Nominations for power exchanges between ARPs, on the Forward and Day Ahead Market.

3. Import and export nominations.

These day-ahead nominations allows Elia to then analyse based on its own measuring and data if these programs assure balance on a quarter-hour basis. (Elia, n.d.)
If an imbalance is expected to occur on the same day, for instance due to an unexpected breakdown of a facility, ARPs have two last-resort options. Firstly, ARPs can still obtain nominations on the third Continuous Intraday Market (CIM) or EPEX. Trading on this market is possible up until five minutes before physical delivery. Secondly, ARPs have the possibility of exporting or importing electricity across the border on an intraday basis. These nominations should at least be delivered to Elia one day after the day of the trade. This will then adjust the ARPs final position, based on this ultimate position Elia will charge the ARP if needed. (Elia, n.d.) If Elia still detects an imbalance, meaning that the final total position is imbalanced , this ARP will be charged with an imbalance tariff which can amount up to 4500 EUR/MWh which is about 100 times the normal price. In general prices for electricity ordered by ARPs will increase when coming closer to the physical delivery date and will ultimately be very high in the case of an effective imbalance, due to the mentioned imbalance tariff. This is in order to incentivize qualitative balancing services by ARPs. (Elia, n.d.)

A.2 Ancillary Services: TSO

Ultimately, the TSO, Elia, collects all access programs of all the ARPs active on the national grid, which then allows it to analyse if sufficient supply capacity is available on a macro-economical level. Any residual imbalances that do occur in real-time must be resolved by taking the necessary steps to ensure balance. (Elia, n.d.) The main ancillary service that Elia delivers is frequency control, in which its main objective is to avoid frequency deviations. When electricity generation falls short of the instantaneous consumption, the frequency which should be at 50 Hz will drop. Drops in frequency of already 1% can cause the risk of damaging equipment and infrastructure. Frequency drops lower than 47,5 Hz can ultimately cause a grid-wide blackout. (Schlabbach & Rofalski, 2014) When frequency drops or rises do occur, Elia will deliver so called ancillary services. It can do so by activating its reserves that it has contracted with producers and ARPs. These are classified into:

1. Primary reserves: Contracted production units that can automatically detect frequency fluctuations and adjust up or downwards in a range of 0-30 seconds. This reserve can compensate for the loss of two 1500 MW production units.

2. Secondary reserves: Automated and continuous activated up-downstream regulation with a ramp up in the range of 30 seconds to 15 minutes.

3. Tertiary reserves: This reserve is manually activated by Elia in case of a severe, systemic imbalance in the control area. This includes the request for extra production by contracted producers or the request for decrease in outtakes by contracted consumers.

Elia pays a reservation price to keep these capacities available and will pay an activation price to its contractors when employing these reserves. It will subsequently pass through these costs to the ARPs in the aforementioned imbalance tariffs. ARPs, being actors in the electricity network will consequently pass on these costs onto their consumers. Ultimately the end-consumers electricity bill will partly consist of imbalance costs. In accordance to the affordability of electricity objective it is therefore in societal interest that the balancing takes place in the most efficient and effective way. It is important to note that Elia already pays these parties in exchange for having the needed capacity available. This implies that a higher degree of uncertainty and risk of security of supply will increase the needed capacities and with it the overall system costs. (Elia, n.d.)

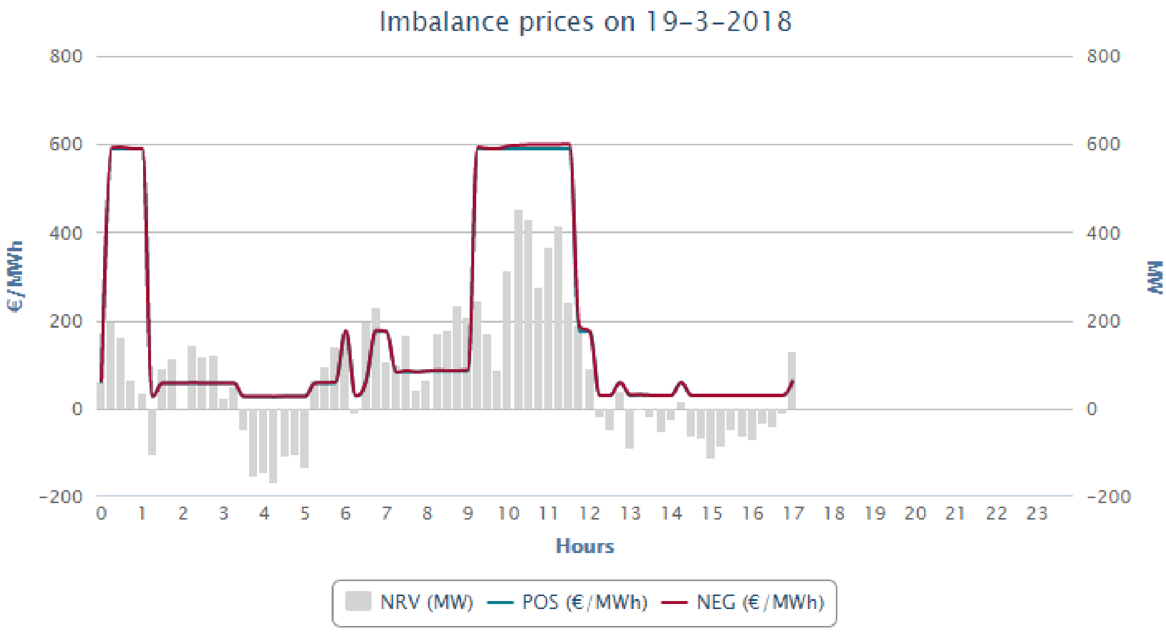

Figure A.2: Imbalance prices, March 19, 2018. (Elia, 2018)

Appendix B

Calculations

Making use of data provided by Elia (2018); Synergrid (2018) we are able to determine the individual generation and consumption levels within a 15 minutes time periods based on a consumer's yearly consumption, SLP and its possible installed PV capacity. Important to note is that we consider all generation and consumption totals and patterns to be independent of the market setup considered, i. e. the consumption Qi(t) and generation Gi(t) during period t of every participant i will be the same in all three models considered. As prosumers are located in physical proximity we assume that all prosumers have the same distribution of PV generation throughout the day. Similarly we do not consider transport losses at the DSO level. All participants in the network are connected with the same retailer and consequently pay the same prices on the retail market. This retail tariff includes all costs related to transmission, distribution, taxes and the energy cost and is repartitioned by the supplier. Based on the actual quarter hourly consumption (Synergrid, 2018) levels of the SLPs we calculate the distribution of consumption throughout the whole year. For the generation we predicate the distribution upon the real time adjusted solar production (Elia, 2018) in Belgium. A consumption and generation distribution is calculated for each month, averaged over each day of that month. These distributions allow us to calculate the quarter hourly generation and consumption of a participant based on the yearly generation[1], yearly consumption and SLP respectively, including the resulting quarter hourly net consumption for each participant. Because excess consumption or generation are the only quantities that interact with the market, behind the meter consumption is excluded from our analysis. For an individual, positive net consumption equals excess consumption, negative net consumption equals excess generation. Next, we combine the net consumption of above defined participants in order to calculate the total consumption, total generation and total net consumption per quarter of

[1] Based on the average PV capacity efficiency in Belgium, resulting in a yearly kWh/kWp ratio of 800.

an hour for the PTP market as a whole. For each time period a participant with a positive net consumption contributes to the total consumption of that period, while a negative net consumption contributes to the total generation of that period. The latter represents excess generation, this is usually present during daytime and evidently limited to prosumers only. Combining the calculated totals gives the quarter-hourly total net consumption for the PTP market. A pricing scheme as described in chapter 4 is implemented and calculated for each time period. In combination with the individual net consumption a cost or revenue per time period is determined for each participant, multiplied by 30,5 days[2] and summed over each month. Prosumers no longer benefit a single meter when moving away from a NM setup, we assume a different retail tariff during day and night for all participants in both the ET and PTP case. Continuing on the previously defined PTP market setup, microgrid participants interact with a supplier only indirectly through an aggregator that is charged with a day and night tariff. The resulting total yearly electricity bill can be compared with the NM electricity bill, which is computed on a yearly basis by default. The revenue from PV generation in case of an ET is calculated in a similar fashion as for PTP trading, by multiplying the individual negative net consumptions by the ET[3]. This revenue is then subtracted from the total yearly consumption cost, in case no NM was performed. Consumers are considered to have a seperate night meter, the NM electricity bill is equal to the yearly net consumption times a weighted[4] average retail tariff. In case of NM, prosumers pay a prosumer tariff[5] based on the capacity of their inverter.

[2]Each month is assumed to have 30,5 days, sums up to 366 days per year.

[3]0,123 EUR/kWh. This is the valid export tariff in Germany (European Commission, 2017c).

[4]Weighted by day and night consumption. This calculation is performed for both SLP S21 and SLP S22 separately due to differing consumption patterns.

[5]The size of the inverter is assumed to be 0,9 times the PV capacity. This is multiplied by a prosumer rate of 100 EUR/kW.

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