INCREASING THE PENETRATION OF RENEWABLE ENERGY SOURCES IN THE DISTRIBUTION GRID BY DEVELOPING CONTROL STRATEGIES AND USING ANCILLARY SERVICES

D.5.3

Enabling frameworks for INCREASE solutions

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Authors	Andreas Tuerk (JR), Andrej Gubina (UL), Tomi Medved (UL), Jernej Zupančič (UL), Veronika Kulmer (JR)
Contributors	
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Contents

List of figures

List of tables

Glossary

ADR	Automatic Demand Response
aFRR	Automatic Frequency Replacement Reserve
AMI	Advanced Metering Infrastructure
AS	Ancillary Service
DR	Demand Response
DRES	Distributed Renewable Energy Source
DSM	Demand Side Management
DSO	Distribution System Operator
EG	Elektro Gorenjska (Slovenian DSO)
FCR	Frequency Containment Reserve
FEP	Flexible Energy Product
FIT	Feed-in Tariff
FIP	Feed-in Premium
FRR	Frequency Replacement Reserve
GEP	Green Energy Premium
IL	Interruptible Loads
LC	Local Control
LV	Low Voltage
MAS	Multi-Agent System
mFRR	Manual Frequency Replacement Reserve
PV	Photovoltaic
RR	Restoration Reserve
SiC	Simple Control
TLS	Traffic Light Service
TSO	Transmission System Operator
TTS	Tendering System
VAT	Value Analysis Tool

Executive Summary

The results of this report come timely as the energy market is undergoing a dramatic change. The new electricity market design being developed will allow innovative companies with new business models to emerge and compete on the market. Already now we see the emergence of new market players, such as aggregators and industrial companies starting to offer secondary or tertiary reserves via demand response measures. In most European countries however consumers are not enabled to offer their flexibility. This report will contribute to this discussion putting the INCREASE solution in a broader context of needed regulatory, economic or market preconditions.

This report investigates the viability of the INCREASE solutions and key INCREASE Ancillary Services (AS) within the current framework conditions in the INCREASE partner countries. While the low voltage (LV) grid of the Slovenian Distribution System Operator (DSO) Elektro Gorenjska (EG) was the basis for previous assessments in the INCREASE Report D5.2, an assessment for a representative European grid is the basis for overall policy conclusions. We find cases with positive revenues for the aggregator implementing INCREASE solutions in scenarios with lower level of photovoltaic (PV) generation integration, but a large amount of demand response (DR) units (up to 10,000) are needed to compensate the aggregators costs. Factors such as higher market prices that we find for example on the reserve markets would promote profits for the aggregators. Other enabling factors are changing regulatory frameworks in several EU countries and the upcoming new EU electricity market directive. These developments will better enable aggregators to provide services on the markets. Regarding our cost assumptions, we have assumed that the aggregator incurs the start-up costs for his business. If we consider that the established companies such as energy retailers start to include aggregation in their business portfolio, the costs may be much lower and also smaller DR pools may become profitable. Overall the EU grid is more profitable than the EG grid, even when assuming lower personal costs for Slovenia than for the EU average. Also for small pool sizes in the investigations we were able to shore up sufficient flexible energy quantities from DR to reach 1 MW, the minimum bid size in many reserve markets. However also smaller DR-based flexible energy quantities may lead to business cases and therefore the market provisions should not be prohibitive.

The energy market of the future will be characterized by a multitude of market actors with different business portfolios and cost structures. Only an inclusive approach will lead to the needed transition of the EU energy systems.

1 Introduction

In the INCREASE project, we have developed innovative solutions for control of distributed renewable energy sources (DRES) and of demand response (DR) units. They include advanced inverters for small-scale photovoltaic (PV) generation, as well as the hierarchical multi-agent system (MAS) for their control. The supervisory control level, the scheduling control, is in charge of the flexible energy portfolio optimization, where demand response units' flexible energy is optimized to maximize the value of the ancillary services (AS) provided in the electricity markets and prevent grid conflicts of interest.

The outcome of the control of flexible energy sources is highly dependent on the rules and boundary conditions within which the system operates. These rules encompassing the technical, economic, market, and regulatory provisions define the framework that characterize each country in which the solutions are deployed.

The report D5.3 will investigate the viability of the INCREASE solutions and key INCREASE AS within the current framework conditions in the INCREASE partner countries. Similarities and differences between the partner countries are analyzed. The low voltage (LV) grid of the Slovenian Distribution System Operator (DSO) Elektro Gorenjska, was the basis for previous assessments in the INCREASE Report D5.2, here we carried out our assessments for a representative European grid as basis for overall policy conclusions. This approach should help to generalize our findings. With purpose of application of INCREASE solutions within wider, EU region, data was gathered from several DSOs in central, southern and northern region. A representative grid was created using this information comprising typical amount of feeder per transformer station, size of loads connected per feeder, and typical loading of the transformer and lines in the network. In the representative grid, the impact of INCREASE technologies implementation was analyzed using the scenario approach. Sensitivity of those results to key drivers was also analyzed

The results of this report come timely as the energy market is undergoing a dramatic change. The European Commission is preparing an ambitious legislative proposal to redesign the electricity market (the Winter Package). The idea of the new legislative proposal is to increase security of supply and ensure that the electricity market will be better adapted to the energy transition. The transition will bring in the market a multitude of new producers, in particular of renewable energy sources, as well as enable full participation of consumers in the market notably through demand response. The new electricity market design being developed will allow innovative companies with new business models to emerge and compete on the market. Already now we see the emergence of new market players, such as aggregators or industrial companies starting to offer secondary or tertiary reserves via smart control of demand response measures. In most European countries however the consumers are not enabled to offer their flexibility. This report will contribute to this discussion putting the INCREASE solution in a broader context of needed regulatory, economic or market preconditions.

The report builds on the INCREASE reports D5.1 and D5.2. In the latter, the INCREASE Value Analysis Methodology designed in the project is described, based on a technical analysis where MAS control strategy operation is simulated in a typical distribution network, using Evaluation Scenarios. These scenarios cover the problem space in which MAS control operates, reflecting different operating stages of LV networks, e.g. with different penetrations rates of DRES and Demand Response or different seasons. The simulated outcomes of the MAS control strategies provide operating schedules of DRES- and DR-units and thus the physical properties of the four key INCREASE AS.

Based on the technical analysis an economic, environmental and operation security assessment is made for different business cases that enables a broader view on possible benefits to the society than classical cost-benefit assessment. These assessments are made with the Value Analysis Tool (VAT), a MATLAB based computing tool, created in INCREASE using Value Analysis scenarios defined in the project. These scenarios comprise a series of parameters that describe the assumptions used in our Value Analysis.

Several of these assumptions were specific to the Slovenian LV grid, whereas in case of other assumptions, e.g. profit sharing, typical market values were used. The analysis in the present report will present the results of the calculation of the break-even point for various actors and the associated business models that connect them. Sensitivity analysis will be used to investigate the impact of various assumed values in order to enable the implementation of the proposed INCREASE solutions in selected EU countries.

2 Flexibility provision in an evolving electricity system

Due to the growing share of variable renewable non-dispatchable generation in Europe (replacing traditional generation) flexibility is becoming more important. Flexibility on the demand side could be used by suppliers to optimise their portfolio, network operators to delay or avoid network reinforcement, and by system operators for balancing and constraints management purposes. This chapter gives a brief overview of possible flexibility options and providers and the upcoming EU framework in which they may operate.

2.1 The role of flexibility providers

There is a range of possible providers of flexibility, Table 2.1. These include industrial and commercial consumers, energy storage providers, distributed generation aggregators and domestic consumers.

Table 2.1 The providers of flexibility considered in INCREASE

	Industrial and commercial consumers	Energy storage providers	Distributed generation	Aggregators	Domestic consumers
Considered in INCREASE			**X**	**X**	

Industrial and commercial consumers
In some EU countries, e.g. Germany or Austria, Industrial and Commercial consumers have started to provide flexibility to be used for provision of services, such as tertiary reserves. This includes e.g. demand response activities in cement production (Germany) or refineries (Austria).

Energy storage providers
While storage has been providing flexibility in other countries, and pumped hydro storage has historically played a strong role in several EU countries, the potential of battery and other forms of storage to smooth intermittent generation or contribute to local/national balancing has not yet been fully realized in many EU countries. In Belgium the Transmission system operator (TSO) Elia plans to enable storage options to provide primary reserve. And in all EU countries storage is playing a growing role in pilot projects, however storage has to compete with dispatch of renewables (in particular downward reserve provision).

Distributed generation (DG)
The volume of DG on the system has increased in recent years. While this can pose challenges, creating greater need for flexibility, DG can also provide flexibility, creating opportunities to

supply locally and provide other services to market actors. This way major benefits can be obtained at almost no extra hardware investments.

Aggregators

The main function of aggregation is to identify and gather ("aggregate") the flexibilities of consumers and other flexible resources. Aggregators create agreements with industrial, commercial, institutional and residential electricity consumers to aggregate their capability to adjust energy and/or shift loads on short notice [SEDC, 2015]. Their goal is to build up sufficient capacity of flexible resources in their portfolio to provide flexible energy products as services to the markets. They can aggregate generation, flexibility from demand response or both, provide resources that can be sold on different markets. We observe the establishment of aggregators in several EU countries, such as Belgium, Germany, Slovenia or Austria. The regulatory frameworks however are not always supportive for demand side management or participation of distributed renewable generation. This related for example to minimum bid sizes or scheduling periods [ECofys, 2014]. PV, for example, can only bid into the market at certain hours a day. The maximum flexibility depends on the weather. Consumption patterns allow shifting of demand also only for certain timeframes (Ecofys, 2014]. Industrial and commercial consumers have in some EU countries, e.g. Germany or Austria, started to provide flexibility such as tertiary reserves. This includes for example demand response activities in cement production (Germany) or refineries (Austria). There is insufficient experience so far to aggregate flexibility from the residential sectors.

Domestic consumers

While few consumers already provide flexibility, the majority could play an active role in providing flexibility, such as demand response, once smart meters (and other supporting technologies) are in place to enable it [Ofgem, 2015]. The inclusion of consumer into markets will however again need aggregators. Such aggregation could also be a role of the independent aggregators, as such a market role may conflict with the DSO's public obligation to serve.

2.2 The upcoming new EU regulatory frameworks

Already in the past 20 years, the European electricity market has constantly been changing and today's market differs fundamentally from the market only five years ago [EC, 2015a]. From the 1990s up to around 2005, changes were substantially characterized by regulatory intervention to promote competition in the power industry, while today a great challenge is the integration of renewable energy sources (RES) into the system. Today, the European Union has energy rules set at the European level, but in practice it has 28 national regulatory frameworks (the differences across member states can be seen in chapter 3 of this report).

To address these challenges, the European Commission is preparing an ambitious legislative proposal to redesign the electricity market (the Winter Package). This initiative follows the publication of a consultation on wholesale market, a communication on retail markets [EC, 2015b] and the staff working document on self-consumption [EC, 2015c]. Some of the aims of the new legislation are echoed by EU Energy Union strategy [EC, 2015d]. The idea of the new legislative proposal is to increase security of supply and ensure that the electricity market will be better adapted to the energy transition which may bring in a multitude of new producers, in particular of renewable energy sources, as well as enable full participation of consumers in the market notably through demand response. The new electricity market design being developed will allow innovative companies, such as aggregators, with new business models to emerge and compete on the market. Also, new enabling technologies such as smart grids, smart metering, smart homes, self-generation and storage equipment are empowering citizens to take ownership of the energy transition, to reduce costs and allow them to participate actively in the market [EC,2015a].

The Commission's vision for the new electricity market design aims to deliver a new deal for energy consumers, including by better linking wholesale and retail markets. Taking advantage of new technology, new and innovative energy service companies should enable all consumers to fully participate in the energy transition, managing their consumption to deliver energy efficient solutions which save them money and contribute to overall reduction of energy consumption. This EU new framework will trigger changes to the national regulatory frameworks where the access of new players to the market is moving only slowly.

Support for Demand Response is already reflected in the Third Energy Package, which requires network operators to take the potential of Demand Response and energy efficiency into account when planning system upgrades. Demand response of households however may combine with their own local generation and storage opportunities to enable self-supply and further provide new flexibilities to the aggregators and the markets.

3 Framework Matrix

Ancillary services provided by INCREASE solutions can create value for the stakeholders. The operation of the MAS control strategy with the models of DR and of advanced inverters will be simulated in a typical distribution network. The Ancillary Services as described by the simulated outcomes of the MAS control strategies for a series of operating states will be appraised using several defined Evaluation Scenarios. The focus is on the chosen four key AS in INCREASE.

The value that the results of the MAS Evaluation Scenarios provide to the stakeholders will be assessed with the help of the *Value Analysis Tool (VAT)* using *AS Value Analysis scenarios*. These scenarios consist of a series of parameters that describe the technical, market, economic and regulatory boundary conditions of the value analysis. In the value analysis, they are modified according to the situation in the country that is the focus of the simulation.

The fundamental data structure that contains the key parameters of the Value Analysis Scenarios is the *Framework Matrix*. The parameters in the Framework Matrix are classified as *enabling/limiting* and *modifying*. While a range of values of the enabling/limiting parameters can prevent the INCREASE solutions to be implemented, the modifying parameters merely influence the value provided by INCREASE AS to the stakeholders. For example, the availability of measurements of DRES generation is classified as a technical enabling parameter, since without it, some of the INCREASE solutions cannot be implemented. Similarly, an example of a modifying technical parameter are the voltage limits, since their setting defines the performance of the INCREASE solutions: if the local control starts to curtail at V_{init} = 1.06 p.u., the KPIs will show a different performance than when the curtailment limit is set to V_{init} = 1.08 p.u.

The framework matrix is an important basis for policy conclusions as it allows sensitivity analyzes of the VAT scenarios to understand which assumptions or boundary conditions need to be changed in order to allow the implementation of the INCREASE solutions. An initial Framework Matrix definition is presented in Table 3.1.

Table 3.1: Framework Matrix definition

Parameters	Enabling/limiting	Modifying
Technical	Availability of measurements of: DRES generation, DR status, PQ violations	Voltage limits: under/overvoltage
	Frequency of the recording and collection of measurements	Response certainty and response time
	Existing AMI for DR	
Market	DR reserve market participation rules	Market time step resolution
	Market operation schedules	Penalties for reserve non-delivery
	Do TSO need to make monthly tenders for DR?	Bid structure in various markets (minimum bid, bid increments, bidding period)
		Existing markets for AS
		Tendered products
		Active power reserve market rules
		Remuneration: power/energy, pay as bid/marginal price
		Award procedure (price merit order/energy price)
Regulatory	Procurement method for AS: mandatory/free, mandatory/paid, tendering, open market	Can DSOs prescribe control mechanisms integrated in the DRES generation unit?
	Measurement responsibility: DSO?	Existence of VUM measures in operation
	DRES preferential dispatch: does the DSO need to buy all energy regardless	Is stepwise DRES curtailment allowed?
	Is DRES curtailment allowed at all?	Time-of-Use charging of the network costs for small DN-connected consumers (Tariffs enabling DR)
Economic		Economic support for PV: FIT, grid parity?
	How many hours per year is the opportunity to earn the money (4D) Is it a self-destroying opportunity as more cheaper players coming into the market	Energy price

Apart from the technical parameter the other framework conditions will be discussed in the following chapters.

4 Regulatory frameworks for reserve markets in selected EU countries

Regulatory frameworks for energy markets have already been discussed in report D5.2. This chapter will go into more details regarding reserve markets. The regulatory frameworks are different in all EU member states. This chapter will include most of the INCREASE partner countries (Austria, Slovenia, Netherlands, Belgium) and a couple of other interesting examples.

4.1 Austria

The Austrian TSO APG is acting as control area manager and responsible for the required power plant capacity in the APG control area, which covers all of Austria. The procurement of frequency containment reserves (FCR), frequency restoration reserves (FRR) and replacement reserves (RR) takes place in an organized market by regular tenders. Today there is no Demand Response participation in the spot markets in Austria. In regard to the balancing market, the relevant requirements do not explicitly take into consideration aggregated Demand Response. To gain accreditation as a supplier of reserves first a technical prequalification and second a framework agreement is required. In 2014 the technical prequalification documents were revised to facilitate plant pooling, decrease the minimum plant size of one technical unit and enable the participation of consumers besides generators. In the RR market the minimum pool-size was decreased from 10 MW to 5 MW for tertiary reserve making it easier for smaller aggregators to participate in the market. Furthermore, the duration of the activation was reduced from 16 to 4 hours, enabling participation for a range of demand resources. Currently between 5 and 10 aggregators are active on the Austrian market, some of them providing tertiary reserve form industrial processes. Table 4.1 summarizes the requirements for participation in Austrian Control Energy Market, (APG 2016).

Table 4.1: Tendering conditions for participation in Austrian Control Energy Market

	FCR	FRR	RR
Bid	min. 2 MW	min. 5 MW	5 – 50 MW
Bid increments	1 MW	5 MW	1 MW
Bidding period	Weekly	Weekly	Market maker: weekly Day ahead: daily
Tendered products	1 week (Monday – Sunday 00:00 – 24:00)	Peak week (12-hour-blocks), off-peak week, weekend (48-hour-block)	4-hour-blocks
Reimbursement	Power price (“pay as bid”)	Power price & energy price (“pay as bid”)	Market maker: Power price & energy price

			Day ahead: energy price
Award procedure	Power price merit order		

The legal basis for the Austrian reserve market are

- The Electricity Industry and Organisation Act (“Elektrizitätswirtschafts- und –organisationsgesetz – ElWOG”) [ElWOG, 2015]
- Regulations on system utilization tariffs can be found in the respectively valid System Utilization Tariff Directive (“Regelungen über Systemnutzungsentgelte finden Sie in der jeweils gültigen Systemnutzungsentgelte-Verordnung – SNT-VO“) [SNT-VO, 2016]

Organisational and technical framework

The most important documents are:

- **Operation Handbook of ENTSO-E RG CE (Regional Group Continental Europe)**
  The Operation Handbook (OH) is an updated collection of principles and rules for the operation of the Continental Europe Synchronous Area.
- **General grid conditions**
  General grid conditions, together with the mandatory legal and regulatory requirements, govern the legal position of APG with regard to the grid connection and grid utilisation.
- **Technical and organizational rules for grid operator’s (“Technische und Organisatorische Regeln für Betreiber und Benutzer von Netzen – TOR”)**
  TOR is a multi-part and comprehensive national technical system of rules and standards, developed by Energie-Control GmbH in co-operation with grid operators. The contents of this work are intended equally for all power and distribution grid operators and all grid users.

Conditions for participation in tenders for control energy

Suppliers undergo a technical prequalification to examine whether they meet the technical criteria required to guarantee the necessary quality of the primary, secondary and tertiary control. The prequalification procedure must be carried out separately for each type of control energy. The framework conditions are laid down in the Operation Handbook der ENTSO-E, Policy 1.

1. **Framework Agreement**
   The second step in gaining accreditation as a supplier involves the conclusion of a Framework Agreement. This agreement, which contains details relating to the legal relationship between the supplier and the control area manager, is identical for all suppliers. A separate framework agreement must be signed for each type of control energy.
2. **Access to the tendering system (TTS) of APG**
   In order to participate in the tenders of APG, an access to the TTS is required. For this purpose, first the company must be approved for a tender of APG and recorded by means of Company Masterfile Form in TTS.

4.2 Slovenia

In Slovenia automatic FCR provision by synchronous generators is mandatory. On the other hand, FRR and RR are procured by the TSO via annual tenders. The contract awarded can be an annual- or a multi-year contract. The current regulatory framework prohibits DRES. The rigid tariff system does not enable the Time-of-Use charging of the network costs for small distribution-connected consumers. Network costs for the invoice are calculated based on the peak connection power and measured energy consumption per consumer per hour. Since the tariffs are fixed to the same hours for all consumers, this stimulates consumers to adapt their consumption to a predetermined pattern. This pattern is not tailored to any needs of the DSOs, it is an average-fit-all approach. The tariffs do not reflect the loading situations in different feeders (e.g. congestions, voltage problems). The DSO can only charge the same amount from all the consumers, regardless of their point of connection.

The "Energy Act (Official Gazette of the Republic of Slovenia, No 17/2014)" is the main act in the energy sector establishing common rules for organization and function. It lays down the principles of energy policy, principles and measures in order to ensure security of supply, as well as it regulates the area of energy infrastructure and heat distribution [Energy Agency 2016]. The Slovenian Energy Agency (Agencija za energijo, http://www.agen-rs.si/web/en/home) is established as the national energy regulation authority and responsible for preparation and compliance of energy related rules. The Energy Agency acts under public authorization and shall carry out the administrative and other tasks specified in the Energy Act as well as EU regulations, which determine the competences of the national energy regulators.

4.2.1 Overview on Rules and Decrees [ALPStore, 2013]

Transmission System Operator (TSO)

The "Decree on the method for implementing public service obligation relating to the activity of transmission system operator in the field of electricity (Official Gazette of the Republic of Slovenia, No. 114/2004)" lays down the rights and obligations of the provider of the public service of transmission system operator (TSO), the organization of the public service, the manner and conditions of providing required services, the rights and obligations of the customers and means of financing.

The "System Operation Instructions for the Electricity Transmission Network (Official Gazette of the Republic of Slovenia, No. 49/07)" lay down the instructions for the transmission network operation and conditions for electrical energy transmission from producers to customers. Minimum requirements for operation of interconnected networks set by UCTE and ETSO are also enclosed. These Instructions incorporate rules for customer connection to the transmission network and do not directly address distributed generation.

Distribution System Operator (DSO)

The “Rules on the system operation of electricity distribution network (Official Gazette of the Republic of Slovenia, No. 123/2003)” stipulate technical and other requirements for safe operation of distribution networks with the aim to provide reliable and quality energy supply. These Rules lay down the rules for systematic operation of the electricity distribution network, the duties of the distribution network operator, the terms and conditions for customer connection to the distribution network and define ancillary services of the distribution network.

4.2.2 Primary Reserve, Secondary Reserve, Tertiary Reserve

The power reserve market in Slovenia is regulated as follows [Gubina, A. et al., 2015]:

- FCR (Primary Reserve): TSO (ELES) is responsible to secure the power needed for regulation of frequency. Automatic FCR provision by synchronous generators is mandatory.
- FRR (Secondary Reserve) and RR (tertiary Reserve) are procured by TSO (ELES) via annual tenders in 2 phases:
    - 1st phase: Determination of technical capability of the participants. Technical requirements are part of the tender and can vary among the tenders.
    - 2nd phase: TSO chooses in live auction the cheapest offers available. The selected providers are reimbursed for reservation of the unit and for energy provided for RR.

For 2014 ELES used for lease of ancillary services (FRR and RR) two types of procedures [Energy Agency, 2015]:

- Secondary Reserve: Direct negotiations with potential bidders.
- Tertiary Reserve: The tenders for the provision of the RR were selected on auctions. For the selection of providers of tertiary reserve, ELES foresaw four different products in relation to its quality, the duration of supply and energy source, Table 4.2. The first product was a long-term product, covering the period from 2014 to 2018 (Product 14-18). The next two (A + B) were intended to cover the needs for tertiary control only in 2014, but they differed in terms of the required quality of ensuring the ancillary service. The fourth product was also intended only for 2014; its special feature was the fact that it must be provided by dispersed production sources, and consumers who can provide demand response (Product DSM). Table 4.2 summarizes the requirements for participation in Slovenian Control Energy Market.

4.3 Germany

In Germany for all control reserve types the prequalification is conducted exclusively by the TSO in whose control area the relevant technical units fall. This includes generation facilities and controllable consumer loads, that are connected to the grid, independently of the voltage level. To gain accreditation as a supplier of reserves first a technical prequalification and second a framework agreement is required. The technical prequalification includes technical minimum

criteria to guarantee the necessary quality for FCR, FRR, RR and IR. For providing interruptible loads (see below for details) plant pooling is allowed to reach the minimum lot size by 50 MW.
In Germany the procurement of balancing power takes place in an organized market by regular tenders [50Hertz 2016] for the following products, Table 4.3.

- Primary control reserve (FCR)
- Secondary control reserve (FRR)
- Minute reserve (RR)
- Interruptible loads (IL)
  - SOL: automatically frequency-controlled within the second when the level drops below a predefined grid frequency and remotely controlled without delay by the transmission system operator (immediately interruptible loads)
  - SNL: remotely controlled within 15 minutes by the transmission system operator

German TSOs exclusively conduct the prequalification for all control reserve types for all relevant technical units connected to the grid in their control area, including generation facilities and controllable consumer loads, regardless of the voltage level. To gain accreditation as a supplier of reserves a signed framework agreement is required in addition to a technical prequalification. The latter includes technical minimum criteria to guarantee the necessary quality for FCR, FRR, RR and interruptible load service (SOL and SNL) [TC2007-D2; TC2007-D3; TC2003-D1; AbLast, 2012]. For providing interruptible load service plant pooling is allowed to reach the minimum lot size of 50 MW.

Table 4.2: Requirements for participation in Slovenian Control Energy Market (tertiary reserve)

	mFRR
Bid	min. 1 MW all together (134 MW) 15 MW reserved for DSM
Bid increments	1 MW
Bidding period	yearly
Activation	Min 15 min ahead
Tendered products	4-hour-blocks For DSM – Max 2 activation per day “non activation period after finished activation” – 30 min
Reimbursement	Power price & energy price (“pay as bid”)
Award procedure	Power price merit order

A first step towards demand side flexibility was made in Germany with the ordinance for interruptible loads (IL) introduced in 2012 and taking place in an organized market by regular tenders. Pursuant to the ordinance, large electricity consumers shall shed loads in cases of bottlenecks, thus stabilizing the grid. In return they shall receive a compensation that is passed on to electricity consumers. In terms of this regulation, interruptible loads are major consumption units connected to the medium and high and transmission grid (at least 110kV voltage level). Those units are characterized by drawing large amount of electricity at any time and can quickly reduce their consumption of power according to the actual frequency or remote controlled for a certain period of time.

Table 4.3: Tendering conditions for participation in German Control Energy Market

	FCR	FRR	RR	IL
Bid	min. 1 MW	min. 5 MW	5 – 25 MW	50 -200 MW
Bid increments	1 MW	1 MW	1 MW	1 MW
Bidding period	Weekly	Weekly	Daily	Monthly
Tendered products	1 week (Monday – Sunday 00:00 – 24:00)	Peak Mo - Fr (12-hour-blocks) off-peak (rest days)	4-hour-blocks	15 minutes, 4 hours, 8 hours at any given time
Reimbursement	Power price ("pay as bid")	Power price & energy price ("pay as bid")		Power price & energy price
Award procedure	Power price merit order			Energy price

Germany is currently revising its regulatory framework with a new framework for the secondary and tertiary reserve to be adopted in 2016. It aims to allow additional actors providing flexibility from renewables, Demand side management providers and storage providers easier accede to the reserve markets. A tender on each working day for the secondary reserve will enable actors with small renewable parks, or actors that provide flexibility from production processes a better market access. They could for example better forecast the capacities they could offer. Also the German government plans to keep the current minimum size of 5 MW for the secondary reserve but to allow offers below 5MW for one offer per secondary reserve product.

4.4 Belgium

Aggregated Demand Response in Belgium does not participate in the spot market primarily because of the requirement. In regard to the Primary reserve (R1), the Belgian TSO Elia has developed a combination of a symmetric and symmetric FCR products in order to allow demand side participation, [ELIA 2016]. Furthermore, R1 requires 30 seconds for the entire volume to be delivered, unlike, for example, the Nordic markets that allow only 5 seconds to reach the entire volume.

R3DP (tertiary reserve dynamic profile) is a product of Elia for balancing purposes on the transmission grid. Until 2015 this product was tendered yearly, but since 2016 there is also a monthly tendering, in order to follow the European trend to move towards short term sourcing to increase liquidity in the balancing market. Elia also has plans to move toward a weekly tendering. For 2016, the yearly volume is 700 MW and the monthly volume is 70 MW, with full competition between the products “R3 Production (R3PROD)” and “R3 Dynamic Profile (R3DP)”.

Only prequalified access points will be allowed to provide these yearly and monthly volumes. The requirements for access points can be found in Synergrid code C8-1 (see further).
The number of activations / month in R3DP product design:

- Max. activation duration of 2 hours with at least 12 hours between 2 consecutive activations
- Max. 40 activations per year + max. 8 activations per month

According to Synergrid code C8-01, [ELIA 2016], only connection points that meet the following 5 criteria are qualified for the products DSR 2015-2016 and R3DP 2016:

- There must be a connection agreement between the DSO and the grid user;
- It is a grid connection with a voltage ≥ 1 kV;
- The grid user must have a supply contract with an energy supplier who has a access contract with the DSO;
- The contractual connection power must be 100 kVA at least;

The measurement data are collected by measurement of load curve and AMR (automatic meter reading) as shown in Table 4.4.

Table 4.4: Tendering conditions for participation in Belgium Control Energy Market

	FCR	FRR	RR
Bid	min. 1 MW	min. 5 MW	min 10 MW
Bid increments	1 MW	1 MW	1 MW
Bidding period	Weekly	Weekly	Monthly
Tendered products			R3DP
Reimbursement			
Award procedure			

4.5 Netherlands

The TSO TenneT is in the Netherlands responsible (and part of Germany) for acquiring FCR, aFRR, mFRR and RR which is in practice almost never used, only for re-dispatching purposes. FCR is in the Netherlands mandatory for all the generators with an installed power bigger than 60 MW. They must provide 1 % of their installed capacity for FCR. Generators with a size between 5 and 60 MW may provide up to 3 % of their capacity on a voluntary basis, but this does not happen in practice as no generators are paid for their contribution. TenneT procures only one product that is a symmetrical regulation band.

In 2015, a variation of Emergency Power program, called “Omgekeerd Noodvermogen”, started to operate. This allows upward and downward regulation, also accessible by loads. Changes in the Dutch System Code per 13 January 2014 include:

- Obligation to supply primary reserve stops.
- TenneT has to procure in a market oriented way, at least once per week.
- Minimum bid size 1 MW (symmetrical upward and downward).
- Production units of 60 MW and up must still have a primary regulator (for units 5 and 60 MW this obligation stops).
- Units smaller than 60 MW can join the tender.

Practically it was also decided to join the existing German internet platform [50Hertz 2016] where already a weekly auction of primary reserves is executed.

4.6 Other EU countries

In **Italy,** wholesale market operators can act as demand aggregators (dispatching user). However, there are no independent Demand Response aggregators in Italy today. In regard to the balancing market, the regulatory framework for aggregated Demand Response participation is not yet in place.

Aggregation is not legal in **Spain** and there is only one scheme allowing Demand Response. Proposals to open balancing services to Demand Response are currently under consultation. It is planned to reduce the minimum sum of bids to 5 MW from currently 10 MW. From the approval of these amendments on, renewable energy operators willing to offer ancillary services for balancing would have to pass a technical test, which is currently being defined and discussed by regulators and the TSO, to qualify to provide the service.

France has a history of Demand Response programs lead by EDF prior to market liberalization. The balancing mechanism (tertiary reserve) in France operated by the French TSO, RTE, takes the form of permanent and transparent calls for tenders. It is in principle open to everyone (competitive generators and certain loads) and provides real-time reserve of power that can be used for upward and downward balancing. Renewable energy plant operators are not entitled to offer these services and they do not participate in the wholesale market for energy like conventional generators. The French regulator is now working to develop mechanisms to open up the market to third party entrants and additional tender regulations, which will enable the aggregated participation of demand side resources.

5 Economic and policy framework conditions in INCREASE countries

5.1 Current economic framework conditions

The profitability of aggregators depends also on the economic and policy framework conditions. Economic framework conditions for example include the electricity prices, Table 5.1, that determine the revenue for aggregators but also the financial support framework for renewables in the form of Feed-in Tariff (FIT) that determine the revenues for PV plants. The balancing energy prices are also important when delivering reserves. Table 5.1 gives an overview of current electricity prices and FITs in the EU.

Table 5.1: Electricity prices and FIT/FIP in various countries

	Electricity price (€/MWh)	FIT/FIP for PV
Austria	25	100 €/MWh
Slovenia	35	150 €/MWh
Netherlands	33	70-147 €/MWh in a premium scheme
Belgium	32	Quota system
Germany	32	109,5 €/MWh

INCREASE solutions however can also be provided on the reserve markets. Here the prices are much higher. For Slovenia for example the tertiary reserve price was up to 240 €/MWh in 2015.

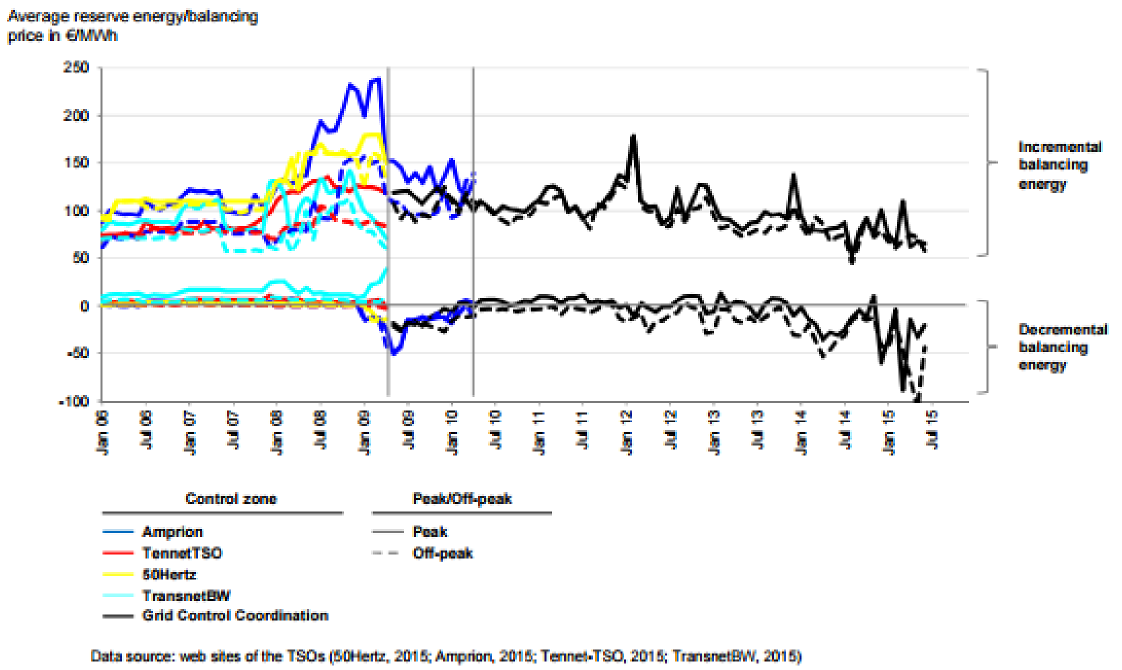
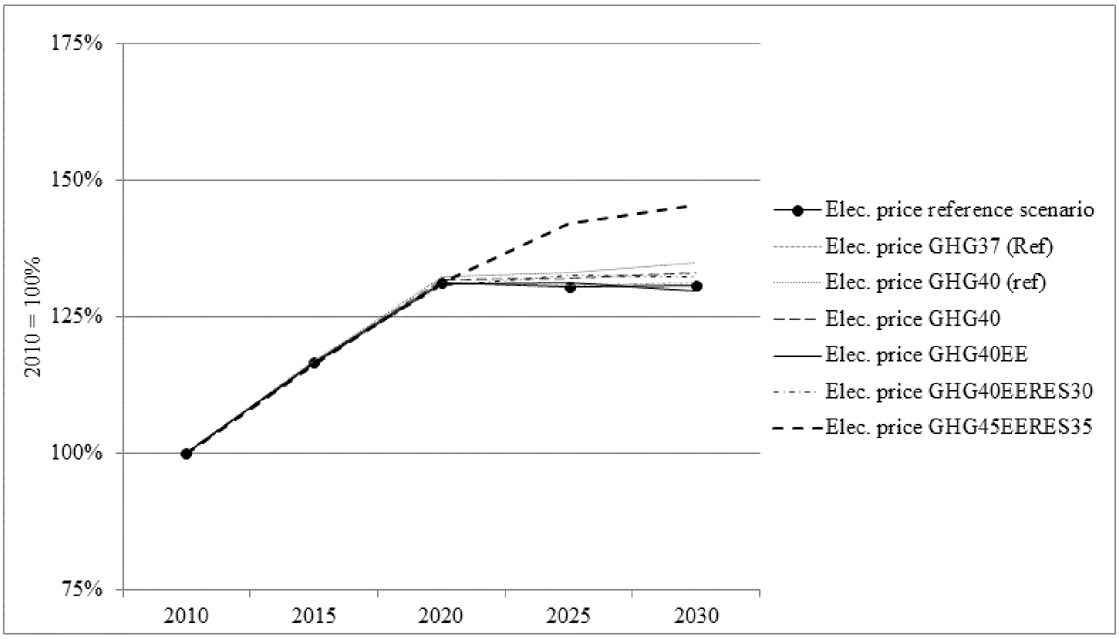


Figure 5.1: Balancing prices 2004-2015

Figure 5.1 summarizes the overall evolution of the yearly average balancing prices from 2004 to 2015, [50Hertz 2016]. The prices for incremental balancing energy increased until 2008 by approximately 50 % and remained largely stable afterwards with a further price drop after 2012.

5.2 Future economic framework conditions in the EU

As shown in Figure 5.2, the electricity price increases in a 2030 perspective are projected to be similar to those under the reference scenario, but somewhat lower in the scenario combining ambitious energy efficiency measures with a 40 % GHG target [EC, 2014]. Projected price increases in 2030 are the most pronounced in the scenario combining a 45 % GHG target, a 35 % renewables target and ambitious energy efficiency policies. Among the scenarios resulting in 40 % GHG reductions in 2030, the one based on a sole GHG target with moderate renewables and energy efficiency policies is projected to result in a small price increase of less than 2 % compared to the Reference scenario in a 2030 perspective [EC, 2014]. Implementing ambitious efficiency policies is expected to reduce electricity prices in 2030, but by very little in relative terms. The scenario including a RES target of 40 % sees an increase of around 1 % compared to the Reference scenario, if met in the context of ambitious energy efficiency policies [EC, 2014].



Source: PRIMES 2013 (used in the Impact Assessment of the EU 2030 Energy and Climate Package)

Figure 5.2: Average price of electricity in final demand sectors

5.3 Future policy framework conditions in the EU

Regarding policy frameworks for renewables the European Commission has decided on comprehensive rules for the assessment of state aid in the energy sector. The text adopted in

2014 creates the framework for the ability of MS to grant state aid in this sector until 2020. The new state aid rules foresee the gradual introduction of competitive bidding processes for allocating public support, while offering MS flexibility to take account of national circumstances. The guidelines also foresee the gradual replacement of feed in tariffs (FITs) by feed in premia (FIPs) and on the longer term to auctioning systems, both exposing RES to market signals. The reform of the policy frameworks can mean less support for renewables and are another argument for designing new business models to deploy them [Fruhmann, 2014]. Member states are in the process of setting out the arrangements by which they will harmonize their balancing arrangements to complete the Single Energy Market across the EU. The primary means of achieving this in the electricity market is the “European Target Model” which will result in a series of European Regulations that make binding obligations on Member States to change their national market rules.

6 Economic sensitivities of INCREASE results

6.1 Chosen scenarios and cases

In the sensitivity analysis several services were investigated from report D5.2. Ancillary services, which were included in mentioned report, provided Voltage Control, Current congestion mitigation, Voltage unbalance mitigation and Reserve provision. Ancillary services, that provide those functions were defined as Basic service, Scheduling service, Balancing service and TLS service. Sensitivity analysis, performed in D5.3, was carried out for the basic service to determine the impact on PV production sales and for scheduling and balancing service, where different optimization criteria was used in scheduling control for the aggregator's business. The INCREASE controls, referred to in this chapter, are presented in Chapter 7.

Scenario 1 investigated Basic service implementation in the network. A comparison of INCREASE inverter Local control and Simple control was performed. Prices were varied to determine the setting, where switching from Simple control to Local control is economically feasible for the PV owners which sell their produced energy on the wholesale market or under the FIT remuneration scheme. In addition, the impact of inverter curtailment voltage in the Basic service was investigated. Profits gained from PV production were calculated for different curtailment voltage levels.

Scenario 2 investigates Aggregator's perspective in the INCREASE MAS control, in the Balancing service and Scheduling service. The Aggregator sells PV produced energy on the market as well as flexible energy products, which are offered by DR units in his portfolio. Comparison between the economic optimization (the standard case) and energy based optimization (where he provides as much as green energy as possible), used in scheduling control process of DR units is presented here. The energy optimization is the best option from a governmental view as it helps to meet targets.

In both scenarios energy prices were varied as well as the shares of each actor in the division of the revenues in the MAS scheme and costs, related to the operation of aggregator.

Aggregator's business was analyzed for **two cases of aggregation**. In the first case, the aggregator has PV units and DR units in his business portfolio, while in second case, aggregators business portfolio consists only of DR unit. Both cases can be observed in the market.

The profitability of the aggregator's business was calculated on specific grid level of operation, where costs, revenues and profits per kW were used. Absolute profitability of aggregator's yearly business operation was also calculated for the entire aggregators pool of DR units and PV. The impact of different aggregator's unit pool sizes and level of utilization of particular pool is further described in following chapter of Assumptions for value analysis.

6.2 Chosen business model

Based on results of initial economic calculation, a new business model was selected, with the focus on improving the aggregators' conditions and profits. PV owners are aggregated in the aggregators PV portfolio and their produced energy is sold on the wholesale market. The PV unit owners pay to the aggregator a contractual share $\boldsymbol{\varphi_{PV}}$ of their market revenue for its service as a broker to provide them the access to the wholesale electricity markets. This share represents the cost of service of the Aggregator as it gives the PV market access and assumes all the market risks associated with selling of PV energy. PV owner's costs consists of upgrades of the inverter control which allows them to actively participate in Voltage control schemes and increase their energy production.

The profit of the i-th PV unit under the Market scheme $PS_{PV\text{-}M}$ is calculated as a sum of all energy produced by the PV unit $W^{a}_{PV\text{-}M}$ where a = EC denotes economic and a = EN energy based SC optimization, multiplied by the appropriate market price S_M. The fixed PV unit costs C_{PV} are subtracted, which represents annual maintenance and inverter upgrade cost.

$$PS^{a}_{PV-M} = \sum_{i=1}^{N}\left(\left(1-\varphi_{PVi}\right)\sum_{k=1}^{T} W^{a}_{PV-Mik}\cdot S_{Mk} - C_{PVi}\right),\ a \in \{EN, EC\}$$

For the DR units in the aggregators' portfolio, the aggregator has to cover the costs of acquiring DR unit flexibility capability C_{DRe}. They include installation, operation and maintenance of the Advanced Metering Infrastructure (AMI, ADR box and the required communication equipment) and the availability fee payment to the DR unit owners. In addition to DR costs, the aggregator covers his own cost C_{SCA}, which represent his cost of software purchase and updates together with personnel and overhead costs. The revenue of the Aggregator also includes the income $R_{A\text{-}DR}$ stems from successful sales of Flexible Energy Products (FEP) on the wholesale electricity markets. The FEP are composed of the DR units' energy changes ΔW_{DR} in a given time interval, and we assume that they are sold at the same market price S_M in both directions (increase and decrease of consumption).

$$PS^{a}_{SCA} = \varphi_{DR}\cdot\sum_{k=1}^{T} S_{Mk}\sum_{i=1}^{N}\left|\Delta W_{DRik}\right| + \varphi_{PV}\cdot\sum_{k=1}^{T} W^{a}_{PV-Mik}\cdot S_{Mk} - \sum_{i=1}^{N} C_{DRe\,i} - C_{SCA}$$

Income from offering the flexible energy products on the market, which are gained via different DR schedule optimization are split between aggregator and DR unit owners. The DR unit owner revenues are determined as share of entire revenues, gained with trading the flexible energy product on the market and availability cost.

$$PS^{a}_{DR} = \left(1-\varphi_{DR}\right)\cdot\sum_{k=1}^{T} S_{Mk}\sum_{i=1}^{N}\left|\Delta W_{DRik}\right| + C_{availability}$$

Availability payment $C_{availability}$ is defined for each of the DR units as an access fee, paid from the aggregators side, as a fixed yearly amount for using the DR flexibility. It also serves as a compensation tool in case of negative revenues from selling DR energy products on market, where aggregator has to cover the losses of DR unit in order to keep them in his business portfolio. For the economic evaluation some of the assumptions were updated with latest values we received from market actors, and are described in following chapter of Value analysis assumptions.

Relative and absolute profitability of the aggregator was determined for both cases of operation: joint PV and DR unit portfolio and DR unit aggregation only. Initial set of results for value analysis showed, that implementation of availability fee paid by aggregator to DR unit owners, set the DR unit in positive orientation of the profits, but the aggregators expenses exceeds his income from selling DR FEP on wholesale market. Due to the fact that the difference between high rate and the low rate of electricity price is relatively low, his income from selling DR energy products on wholesale is too low. This conforms to the market reality as the aggregator usually offers his services on reserve or balancing market, where prices are higher.

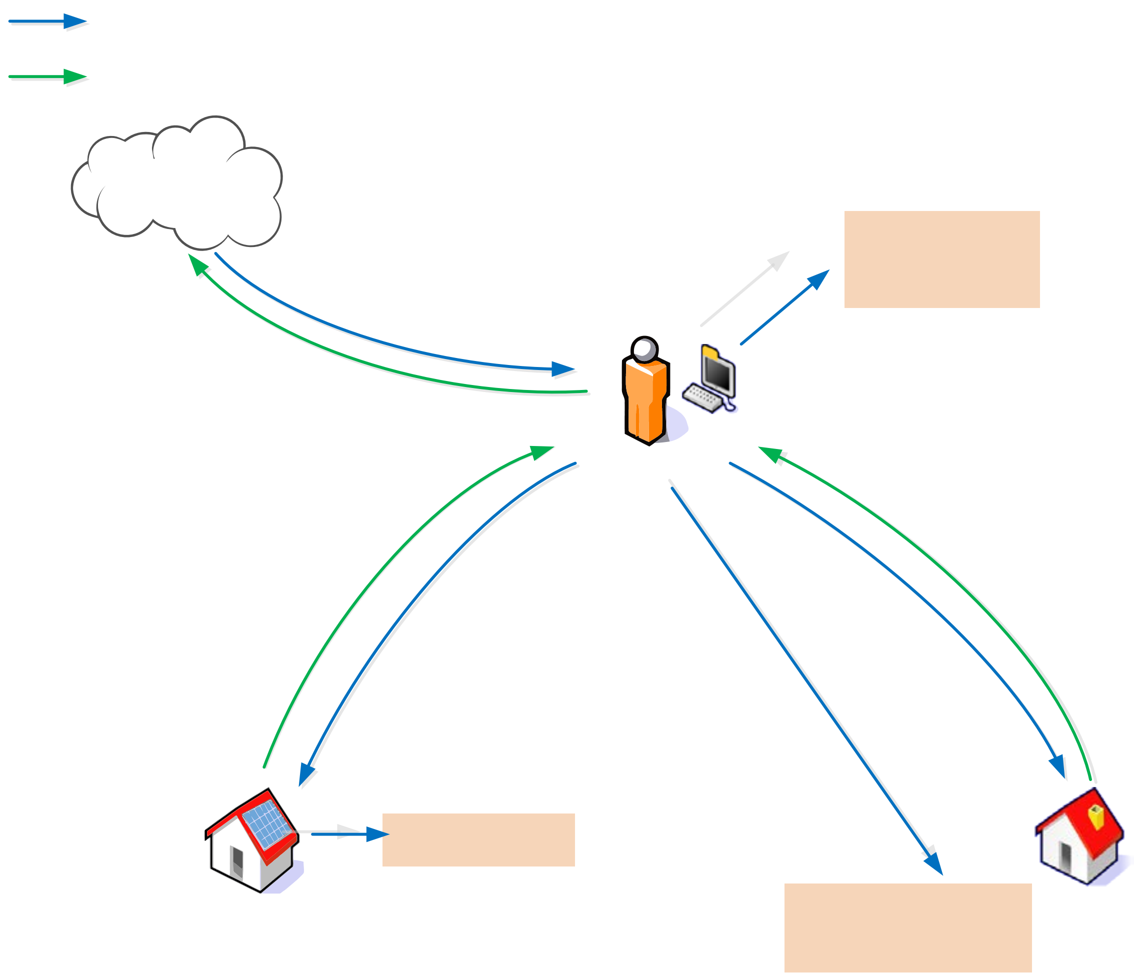


Figure 6.1: The aggregator business model

6.3 Assumptions for value analysis

In this chapter a list of assumptions for the cost of PV inverter upgrades, DR unit equipment and cost related to aggregators business are listed. The cost of upgrading the inverter to enable INCREASE local control are given in Table 6.1. While INCREASE Deliverable D5.2, Chapter 7: Assumptions for value analysis describes several scenarios for upgrade of inverter cost, we only consider software upgrade of existing inverters for calculations in this task.

Table 6.1: PV owner costs

Type of cost	Expense
Cost of inverters SW upgrade [per 7kW inverter]	150 €
Installation fee for the upgrade per PV plant	500 €
Yearly maintenance cost	3 €

For the PV inverters and DR equipment, 25 years' technical lifetime was defined, and annuity was defined with yearly interest rates of 2.5 %. Cost which are present for the integration of the DR units to the MAS scheme of operation are given in Table 6.2.

Table 6.2: DR unit equipment costs

Type of cost	Expense
DR unit communication cost	500 €
Installation fee for the upgrade of DR unit	200 €
Yearly maintenance cost	1 €
Availability fee	600 €

In Table 6.3 aggregator's costs are presented, related to his operation. He has to buy software in order to operate, which is annually updated, and depending on the unit pool size of aggregation, several employees together with overhead costs are also taken into consideration.

Table 6.3: Aggregator's costs

Type of cost	Expense	
Aggregator's software cost	100,000 €	
Cost of SW update per year	200 €	
Technical lifetime of software	25 years	
	Slovenian grid	**EU grid**
Personnel cost per year	30,000 €	50,000 €
Overhead cost per year (50 % of personnel cost)	15,000 €	25,000 €

The number of personnel, which is employed by the aggregator, varies with the size of the aggregators pool and the level of penetration (scenario) for that pool.

Table 6.4: Number of employed personnel for different scenarios and pool size, with amount of aggregated units

Scenario / utilization	100 unit pool size			1000 unit pool size			10000 unit pool size		
	Number of personnel	Aggregated DR units	PV units	Number of personnel	Aggregated DR units	PV units	Number of personnel	Aggregated DR units	PV units
1 (20 %)	1	20	40	1	200	400	3	2000	4000
2 (40 %)	1	40	80	1	400	800	3	4000	8000
3 (60 %)	1	60	120	2	600	1200	3	6000	12000
4 (80 %)	1	80	160	2	800	1600	4	8000	16000
5 (100 %)	1	100	200	2	1000	2000	4	10000	20000

For PV the number of units reach up to 20,000 in the biggest pool size for DR. 7,5 kW DR units were used in simulations, along with 20 kWp PV installations.

The chosen cost structure is of high importance from the subsequent assessments, we assume that the aggregator start is business based on INCREASE solutions, with corresponding personnel or overhead cost. If an establish company such as an energy trader starts with aggregation as part of a broad portfolio of business activities the coots may be lower.

6.4 Parameters for the value analysis

In sensitivity analysis, which was implemented in value analysis specific parameters were varied in order to determine their impact on the business of the actors involved in business model. Impact of variation for aggregators software cost, cost of his personnel and availability fees was investigated along with changes on electricity price on the wholesale electricity market. Parameters, which are defined in business model, and determine the profit sharing between the actors, were also looked into together with the size of aggregation pool in aggregators business. Parameters and their variations are given in Table 6.5, where values in bold represent initial value of parameter, which was used for calculations in variations of other parameters.

Table 6.5: Sensitivity analysis parameters

Parameter	Variation of default values
Energy price	**-200 %, -100 %, +100 %**, +200 %, +300 %
Agg. share from PV sales	10 %, **20 %** to 90 % (in 10 % steps)
Agg. share from DR sales	75 %, **50 %**, 25 %
Agg. SW cost	**100 000**, to 10,000 (in steps of 10,000)
Agg. DR pool size	100, 1000, **10000**
Availability fee per DR unit	300 €, **600 €**, 900 €

With acquisition of 3 set of values for each parameter, a linear factor was determined, and further extrapolation of the results was possible if greater range of variation was required.

7 INCREASE technical control solutions

In the selected business model with several actors, multiple INCREASE solutions were used. PV owners, DR units, DSO and Aggregator are part of proposed Multi Agent Scheme, which has defined hierarchal order of actions and position of the individual party.

For the PV owners, two controls of inverters were compared from the economic point of view. Existing control, **Simple Control** (SiC), represents a control of the inverters in the network before the implementation of the INCREASE solutions. The inverters are programmed to shut down the production of the PV unit if the voltage level in the point of connection rises above upper threshold of 1.1 p.u.

Through software upgrade of the inverter control, **Local Control** (LC) of the inverter can be implemented to PV plants. LC features droop control of production curve, which is triggered accordingly to the voltage levels of the local node or point of connection. Inverters starts gradually curtailing output of the PV plant at lower limit (1.06 p.u. was used as default value), which activates the control process and in case of reaching the upper limit (1.1 p.u.), the PV unit is shut down entirely. Local control provides a partial curtailment option, which allows higher level integration of PV production and lowers the occurrence of PQ violations in the network.

PV and DR units are aggregated within Scheduling Control into the Aggregators' portfolio, where he manages the sales of PV produced energy and flexible energy products, offered by DR units. Scheduling control allows the aggregator to schedule the operation of DR units accordingly to an economic or a system oriented scheduling approach. After the schedules for units in his portfolio are prepared, the DSO evaluates the impact of DR operation on the network conditions. With a traffic light system mechanism (TLS) DSO performs a suitability check of the proposed schedules, and decides whether schedules are acceptable or they interfere with security of operation in the network. In this report we only use the simple TLS, in the previous report we have different TLS systems.

Scheduling control, and the MAS control strategy is furthermore described in deliverable report 3.4 together with the different optimisation methods of scheduling control. The technical results of INCREASE controls are presented and evaluated in INCREASE Deliverables D5.1 and D5.2.

8 Impact range of the business economic performance of INCREASE scenarios

We analyze the range of impacts on the profits of aggregator, DR unit and PV owner by varying initial assumptions such as prices, cost assumptions, revenue shares, technological specifications, etc. In particular, we are interested to learn how the results are affected in terms of magnitude and directions of business economic performance in different service scenarios: Basic service of PV operation and comparison of economic and energy based optimisation of scheduling DR units.

The selections of parameters as well as their variation (direction and magnitude) are reported in Table 6.5. By means of this sensitivity analysis we aim to study the range of possible impacts of the business economic performance (i.e. revenues) and the relative importance of assumptions and parameters.

8.1 PV owner's profits under the Basic Service

The owner of the PV unit has to be incentivized to implement INCREASE control strategies. In other words, the PV unit owners experience losses compared to the Simple control case (SiC) and have to be remunerated accordingly. In this context we aim to analyze how changing energy prices impact the profits of the PV unit owner. Thereby we study the impacts of changing market conditions under the following specifications associated with Local control strategy as representative solution strategy. The rationale is that we find hardly any differences in direction and magnitude of impacts on the PV unit owner's profits regarding the different INCREASE control strategies.

The analysis is done for the summer and winter period. As a starting point, Figure 8.1 illustrates the change in PV unit owner's profits when switching from simple to local control. We find that the impacts are significantly stronger in winter than in summer. Furthermore, with increasing installed capacity, the impact also rises.

In Figure 8.1 an effect can be observed a shift in the impact between the scenarios SC4 and SC5 in summer where in winter the reaction is "constant". This is the results of the difference between the inverter controls. In lower penetration scenarios, where voltage rise is between 1.06 and 1.1 p.u. local control is only partially curtailing. But from scenario SC4 and higher with higher penetration levels, the earlier partial curtailment of local control yields higher infeed of PV energy compared to simple control. This represents the turning point for the network, where using local control becomes preferred mode, more effective than existing simple control.

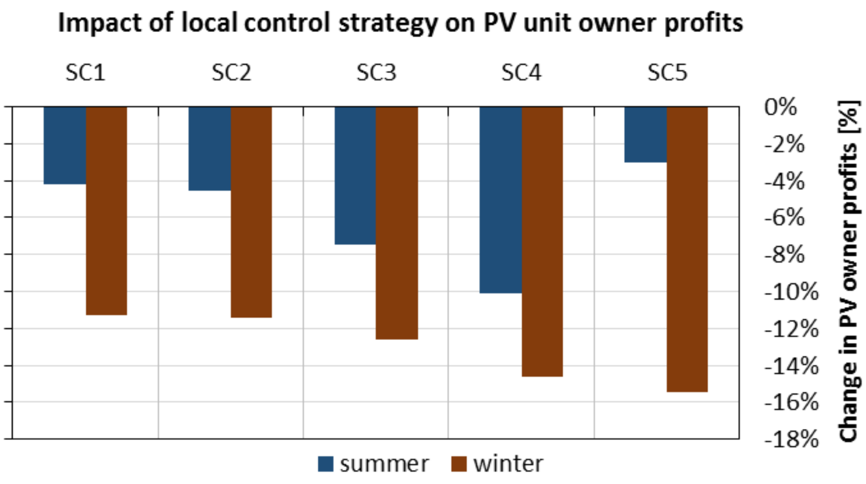


Figure 8.1: Change in PV unit owner profits in case of local control strategies compared to the simple control case

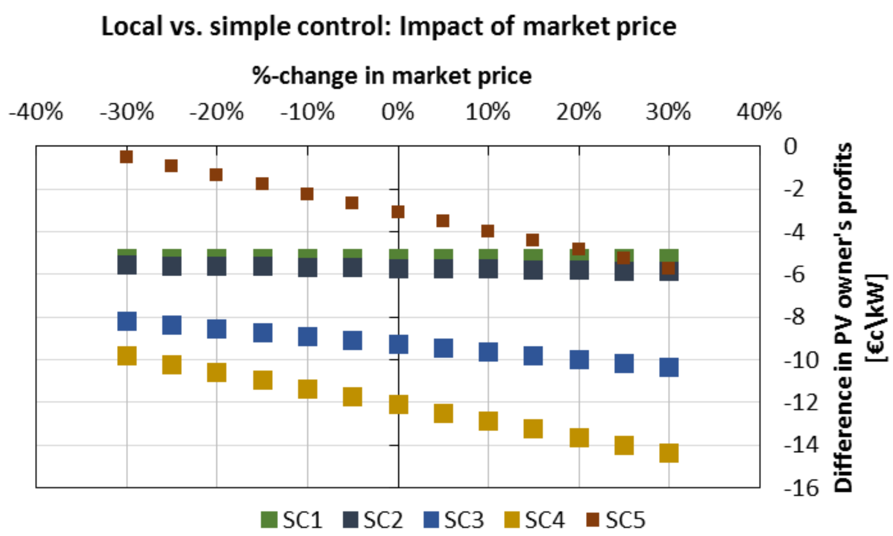


Figure 8.2: Impact of market price on change in PV unit owner profits (summer period)

In a next step we vary the market price in order to gain insights on the range of impacts and derive implications on the importance of the market conditions. We find that in the summer period the PV unit owner is not able to reach the break-even point compared to the SiC case. Generally, the costs (e.g. personal costs, etc.) are too high and hence the increase in the market price is not able to overcome the cost disadvantage compared to SiC. For winter, the direction of results is similar, but the potential increase in prices has to be much higher in order imply positive profits (as already illustrated in Figure 8.1 impacts in winter are higher than in summer).

8.2 Changes in the "curtailment voltage"

Subsequent to analyze changing market conditions, in this section we study the impacts of changing technological specifications. More specifically, we change the curtailment voltage from 1.06 to 1.08 and investigate the impact thereof on PV unit owner's profits. Overall our findings show that a higher number of PV units increase the rise in the profits (following the assumption of economics of scale). In SC1, the smallest PV penetration scenario (12 units) PV unit owner's profits are affected negligible (around 0.32 %). In a next step we are interested in the market price which represents the break-even point for the Basic Service assuming a curtailment voltage of 1.08 and thus results in positive revenues compared to the LC case with initial curtailment voltage. Results show that the extent of the impact is independent from the size of the network (i.e. number of PV units) and that an increase in the market price has slightly stronger effects on the profits in case of a higher curtailment voltage. For instance, an increase in the electricity price of 30 % results for SC5 in a gain in additional profits of 10 % compared to the lower curtailment voltage. Of course the gain in additional profits is modest. Measured in absolute terms (€ cent per kW), as expected in higher penetration scenarios price changes have a higher impact on the increase in PV owner's profits due to the change in the curtailment voltage.

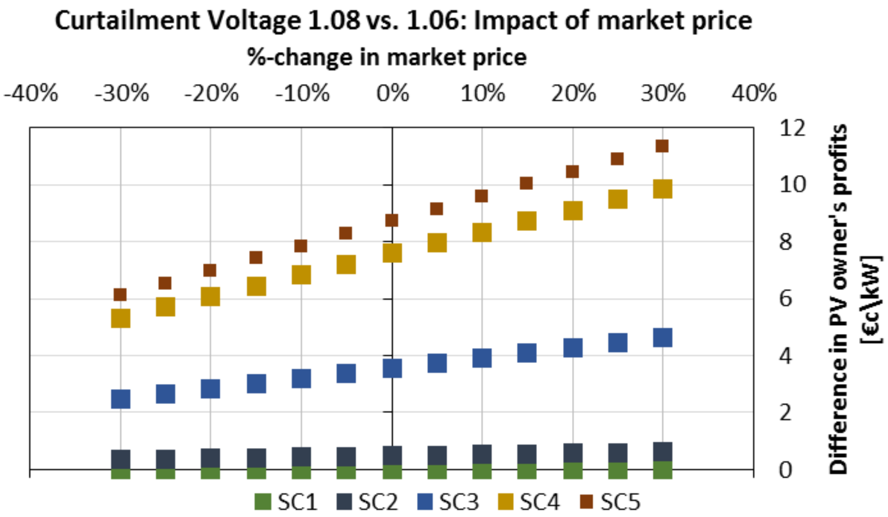


Figure 8.3: Difference in PV unit owner profits due to a change in the curtailment voltage under varying electricity prices

8.3 Aggregator's profits under economic optimization of PV and DR- EU grid

In this section we focus on the aggregator and how different market and business assumptions influence its economic performance. More specifically we analyze the following questions:

- Where is the break-even point of the aggregator?
- Under which market price, aggregator costs, number of DR units as well as further market specifications is the aggregator able to gain positive revenues?

We carry out the analysis for the winter period (results in summer are similar in direction and magnitude of impacts) and for TLS1 scheme, since we find no striking differences between the different TLS schemes. The analysis is done for all five PV penetration scenarios. We vary the following parameters, Table 8.1.

Table 8.1 The assumptions for aggregator's profit calculation, economic optimization

Specification	Default	Impact range
Electricity price		Ranges between -150 % and + 200 %
aggregators share from DR unit revenues	φ_{DR}: 50 %	25 % - 75 %
Aggregator's revenues from PV owners	φ_{PV}: 20	10 % - 90 % in 10 %-steps
Availability fee payment to the DR unit owners	600 €	300€ and 900€

Aggregator's DR pool size 10,000 and 1,000

By analyzing the impacts of changing market conditions and cost specifications on aggregator's profits we find that market prices have the strongest impact on aggregator's profits. For instance, in the default pool size of 10,000 units a doubling of electricity prices triples aggregator's profits. Other parameters which correspond to costs specifications of the aggregator have a much higher impact.

Figure 8.4 shows a range of impacts on the aggregator's profit outcomes under varying assumptions of electricity prices for different pool sizes 10,000 units (upper left), 1,000 units (upper right) and 100 units (lower right) and aggregator's profit under varying pool sizes (lower left); for all five PV penetration scenarios, economic optimization, EU grid

Figure 8.4: Range of impacts on the aggregator's profit under varying assumptions of electricity prices

In addition to analyze profits per kW, we are also interested in the total profits per year for the aggregator. We investigate the total amount of profits for the aggregator for different pool sizes, different penetration scenarios and electricity prices. Figure 8.5 shows the impacts of pool size with different numbers of DR units on total aggregator's profit per year for all penetration scenarios– Case of economic optimization. Findings show that as expected the highest profits per year are generated with the largest pool size and in the penetration scenario with the largest installed capacity. Figure 8.5 shows that in case of a pool size of 10,000 units total profits per year increase significantly with increasing number of PV units installed. Assuming the smallest pool size, we find total losses in every penetration scenario. With 1,000 DR units in a pool, profits range between 8,000 € and nearly 300,000 € per year, depending on the number of PV units.

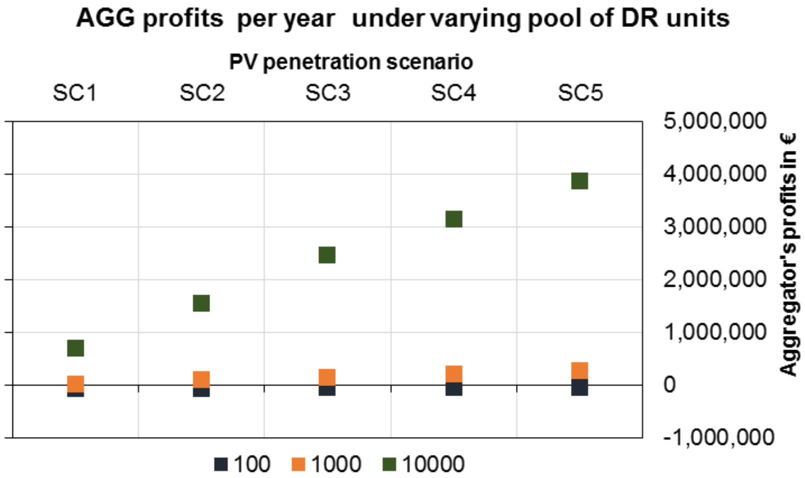


Figure 8.5: Impacts of pool size on total aggregator's profit, economic optimization

As already illustrated a doubling of the electricity price triples the profit per kW in the default case. In total this implies, as shown in Figure 8.6, that instead of a total profit of over 700 k€ per year in case of SC1, the aggregator gains nearly 1.8 million € profit. With a tripling of the market price (throughout the year), total profits in case of SC5 would amount to 14 million € per year.

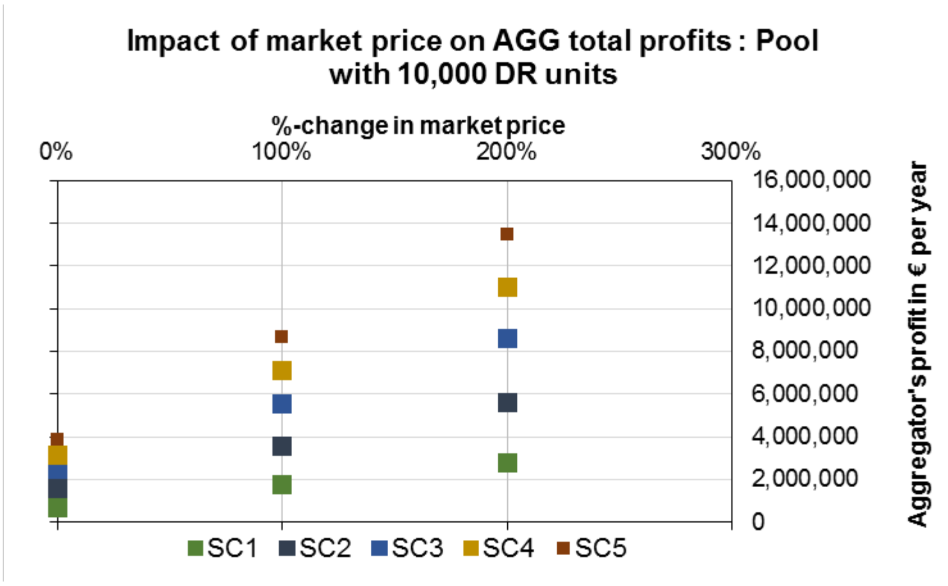


Figure 8.6: Impacts of electricity prices on total aggregator's profit, economic optimization

In the second step we turn to the influence of the share of DR unit profits and find that the variation of the payment to DR unit (initially 50 %) has a modest impact on aggregator's profits. The higher the share from DR unit revenues the higher are the profits. As illustrated in Figure 8.7, this pattern is observable for all PV penetration scenarios. In the default case, with 10,000 DR units in aggregator's pool, profits are always positive and hence a higher share of DR revenues boosts aggregator's profits. Further analysis shows however that in cases of losses (e.g. as in SC1 with 1,000 units, or more generally under a pool of only 100 units) higher shares of DR revenues are not able to reverse or offset them. 100 DR units combined with 200 units of PV represent 4.75 MW of aggregated power.

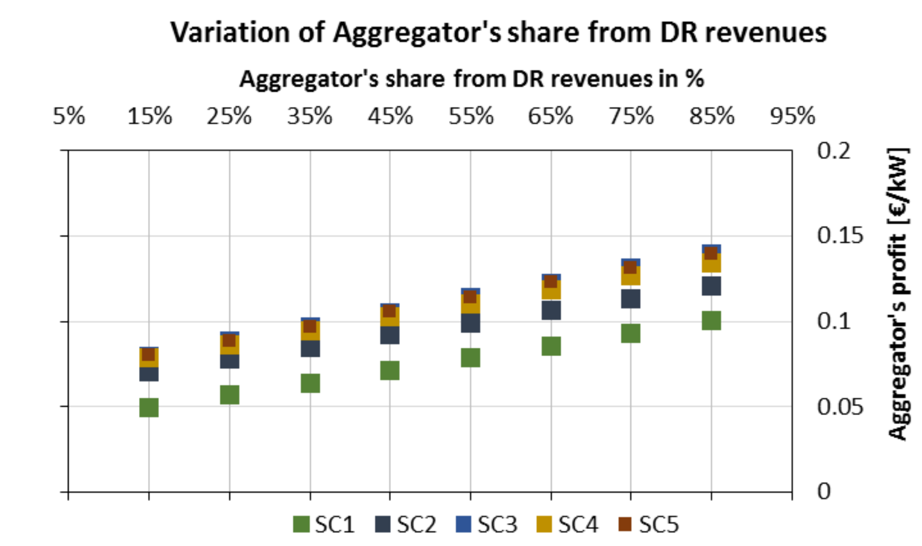


Figure 8.7: Range of impacts on the aggregator's profit under varying assumptions of share from DR unit revenues for all five PV penetration scenarios – Case of economic optimization, 10,000 DR units

Third, the alteration of the PV owner’s share of revenues also affects aggregator’s profits significantly. As illustrated in Figure 8.8, the higher the aggregator’s share of PV owner’s profits, the smaller is the aggregator’s loss. In terms of magnitude, the impact of the share of PV unit owner’s profits is much stronger than that of DR revenues shares. The reason is straightforward, since the profits of the PV unit owner are much higher than the profits of the DR unit.

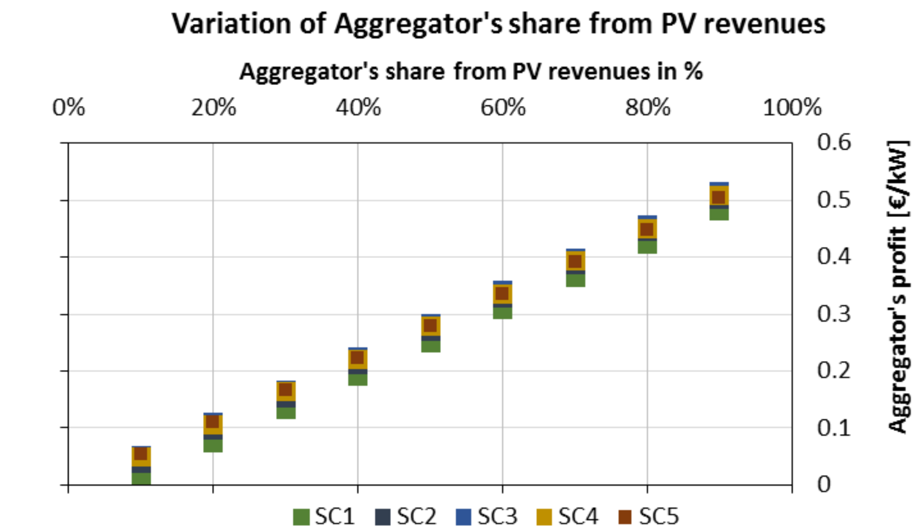


Figure 8.8: Range of impacts on the aggregator’s profit under varying assumptions of the aggregator’s profit share from PV unit owner for all six PV penetration scenarios – Case of Balancing Service

Fourth, in contrast to the relatively strong impact of electricity price and the profit share from PV unit owner, a reduction in aggregator’ software costs hardly affects the profits. Finally results also show that the variation of the availability fee, which is paid from the aggregators’ side as a fixed yearly amount for using the DR flexibility, has a rather modest impact on aggregators’ profits. As illustrated in Figure 8.9, an increase in the fee paid to the DR unit of 300€, reduces the profits [per kW] by 3 %.

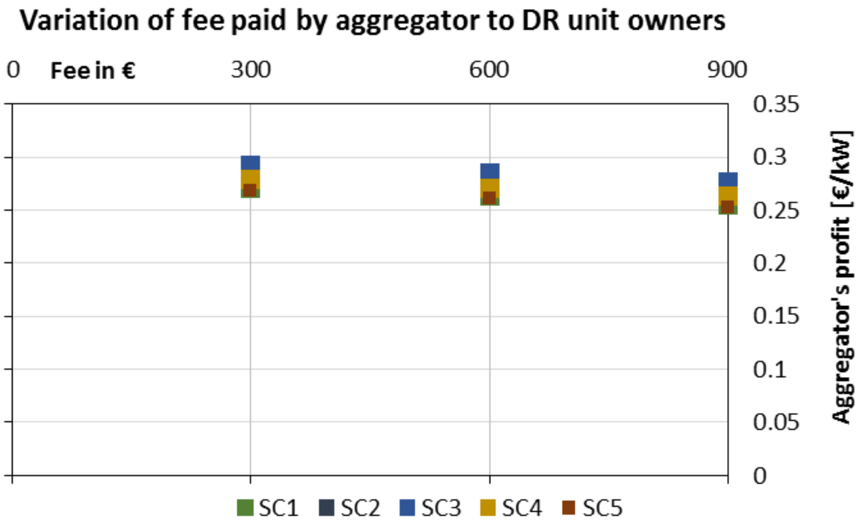


Figure 8.9: Range of impacts on the aggregator's profit under varying assumptions of the availability fee paid to the DR unit for all six PV penetration scenarios – Case of Balancing Service

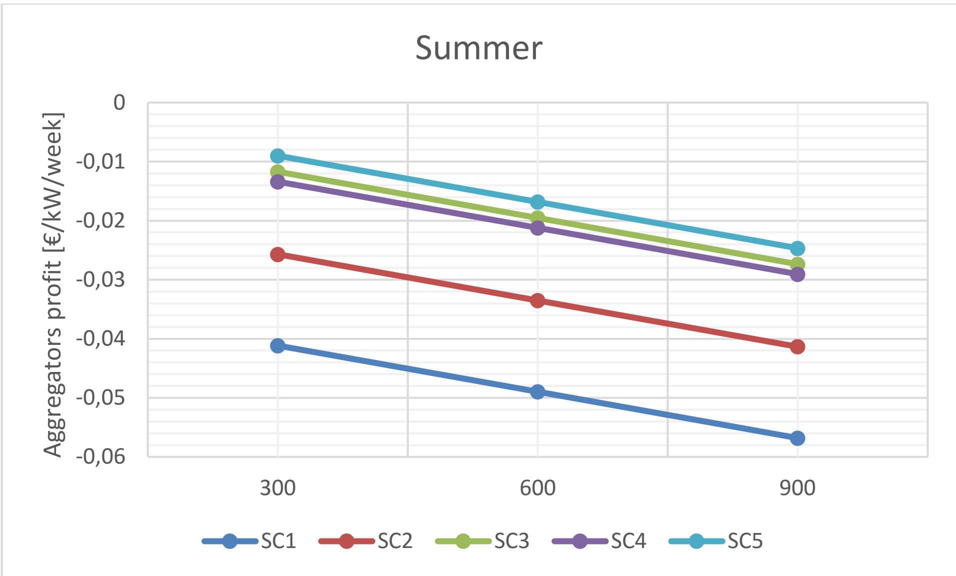


Figure 8.10: Aggregator availability fee payment - summer

Availability fee for DR units is paid by the aggregator to DR units to offset the negative financial outcome for DR units, as described in Chapter 6.2. Figure 8.10 shows the impact of the aggregator availability fee payment in summer, and Figure 8.11 the impact of this fee in winter. It can be seen that when reducing or increasing the fee by a third aggregators' profits change by 20 %.

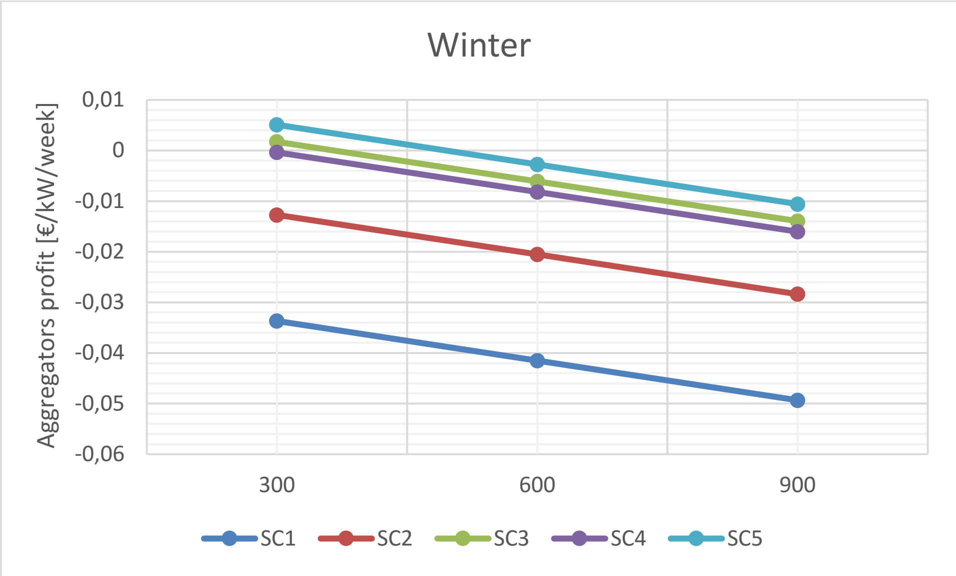


Figure 8.11: Aggregator availability fee payment - winter

8.4 Aggregators profits from DR units under economic optimization

In this subsection we study a different business model, which assumes that the aggregator only receives profits from the DR unit. This implies that the aggregator does not receive revenues from the PV units.

In order to analyze the sensitivity of aggregator's profits from DR units we focus on the most crucial impact parameters: electricity market prices and pool size of DR units. Our analysis is carried out for winter in order to ensure comparison with the previous subsection, as aforementioned results for the summer period show in terms of direction and trend of impacts high similarities.

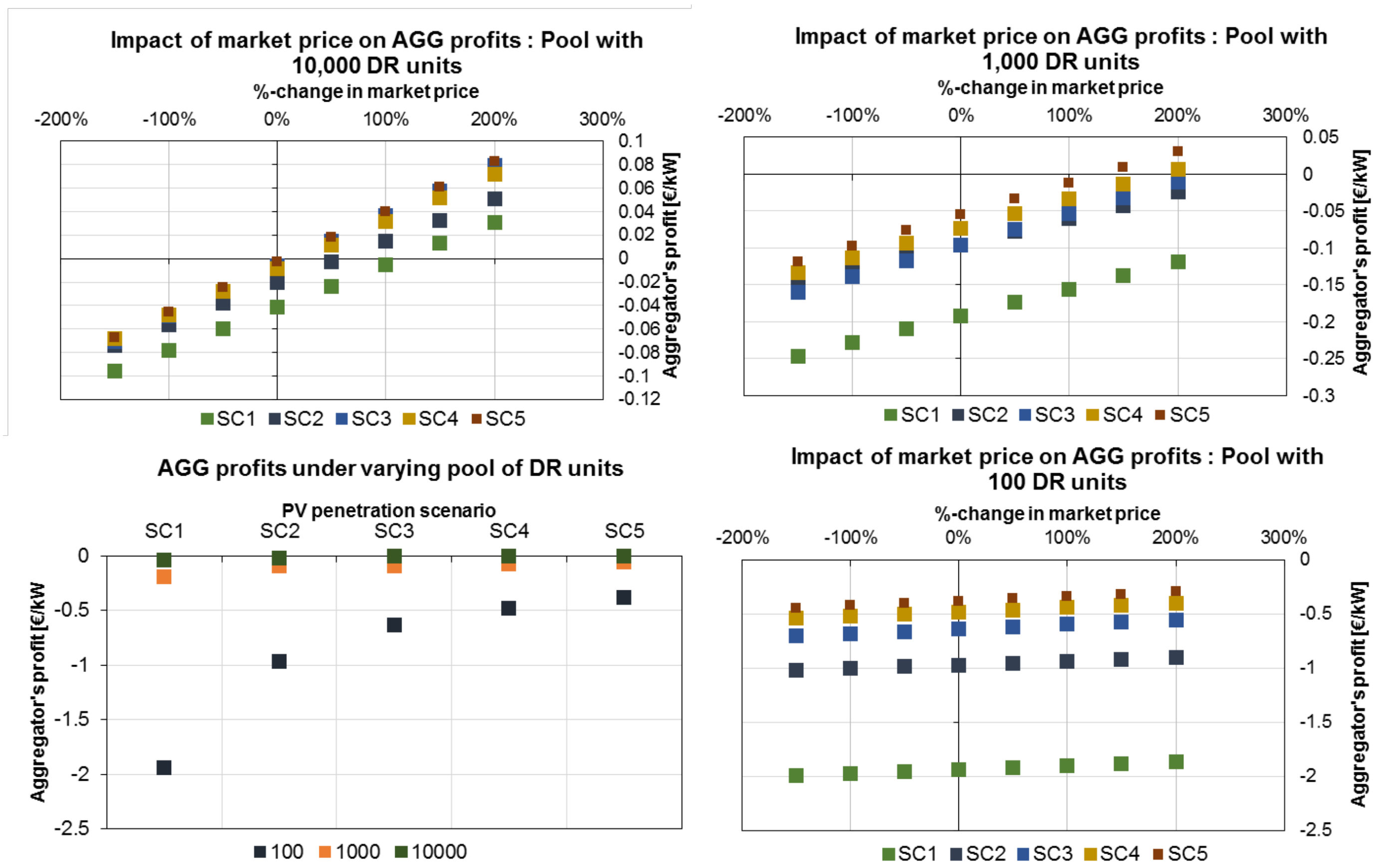


Figure 8.12 illustrates the results and we find that in the default case (no change in electricity price and 10,000 DR units in the pool) aggregator's profits from the DR unit are slightly negative. In comparison to the case where the aggregator receives revenues from DR and PV unit, the profits are substantially lower. This implies that the profits of the aggregator laid out in the previous section are mainly driven by the PV unit owner revenues. This finding

supports the results illustrated in

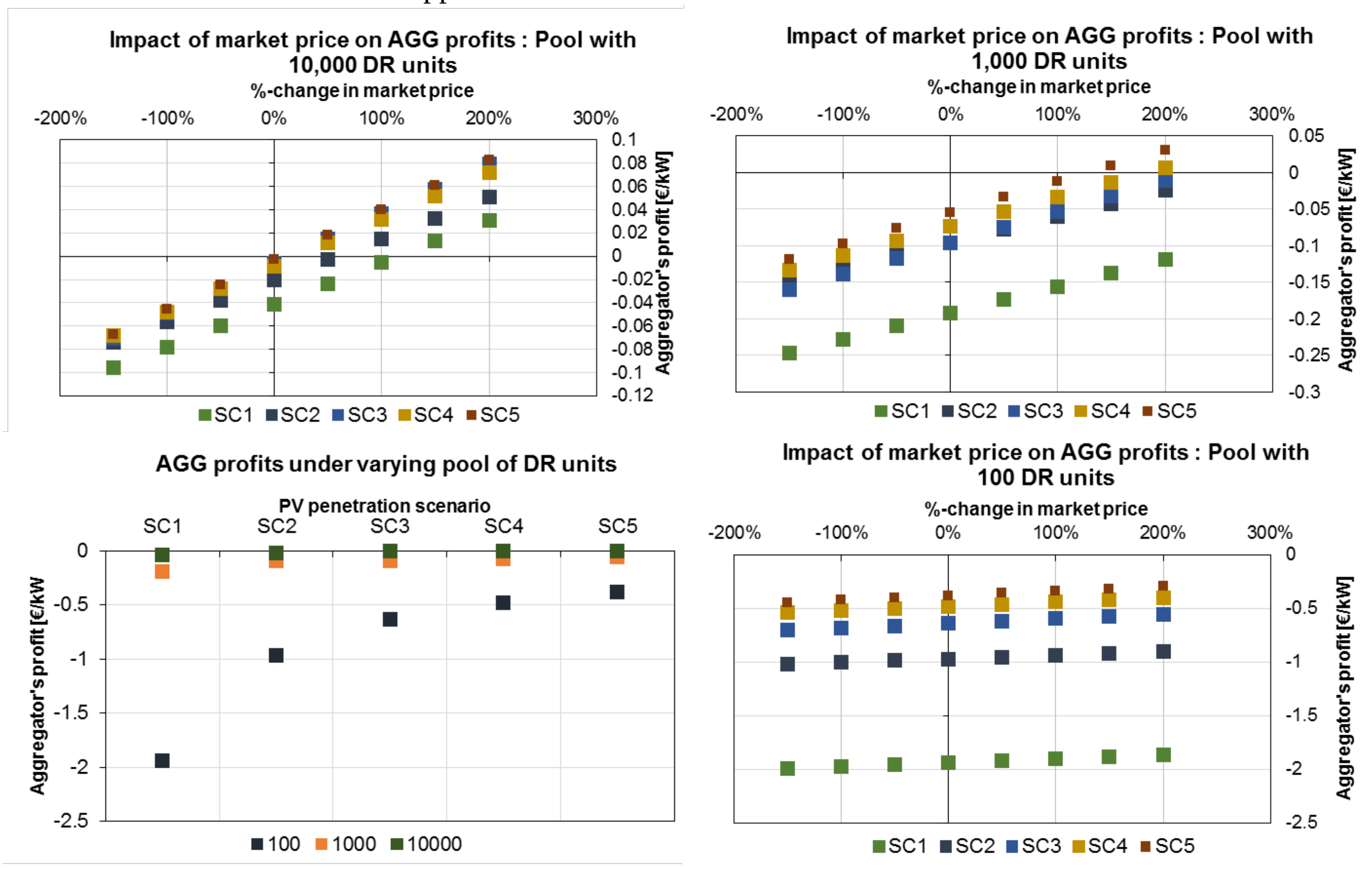
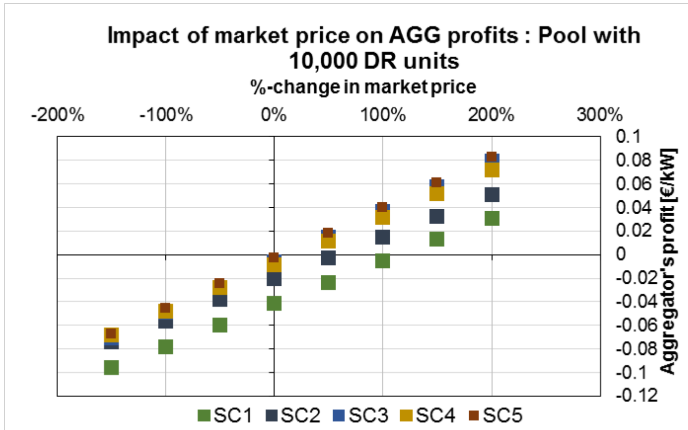
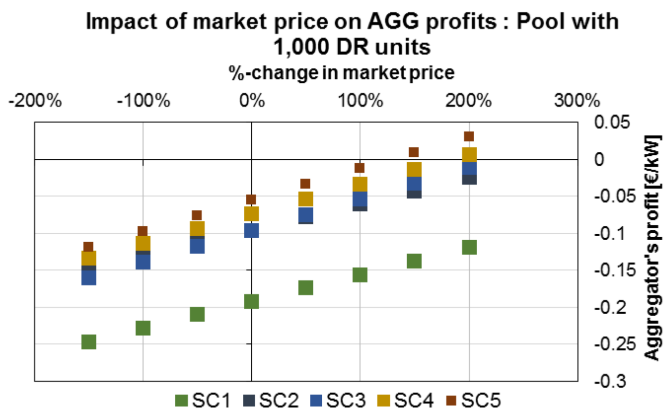
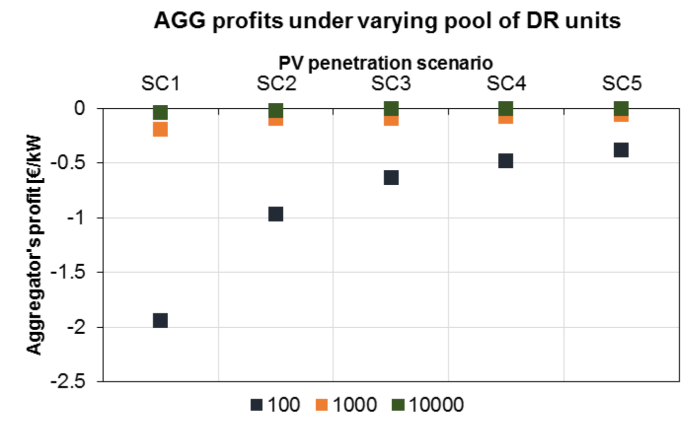


Figure 8.12, which shows that the share of PV unit owner revenues strongly affects the profits.

Besides the substantially lower level of profits in this business model, the direction and trend of the impact of changing electricity prices is similar to the one before. We find that in case of the default pool size of 10,000 units a doubling of electricity prices more than triples aggregator's profits. In case of the smaller pool size of 1,000 DR unit's aggregator's profits solely from DR units hardly reach the break-even point. A tripling of the electricity price is required in order to ensure profitability for the majority of penetration scenarios. For the smallest pool of DR units, 100, a price change of over 700 % would be required to tackle the break-even point (from a current point of view this rather drastic increase in electricity prices is either plausible nor realistic).


Impact of market price on AGG profits : Pool with 10,000 DR units
%-change in market price
-200%
-100%
0%
100%
200%
300%
0.1
0.08
0.06
0.04
0.02
0
-0.02
-0.04
-0.06
-0.08
-0.1
-0.12
Aggregator's profit [€/kW]
SC1 SC2 SC3 SC4 SC5


Impact of market price on AGG profits : Pool with 1,000 DR units
%-change in market price
-200%
-100%
0%
100%
200%
300%
0.05
0
-0.05
-0.1
-0.15
-0.2
-0.25
-0.3
Aggregator's profit [€/kW]
SC1 SC2 SC3 SC4 SC5


AGG profits under varying pool of DR units
PV penetration scenario
SC1
SC2
SC3
SC4
SC5
0
-0.5
-1
-1.5
-2
-2.5
Aggregator's profit [€/kW
100 1000 10000

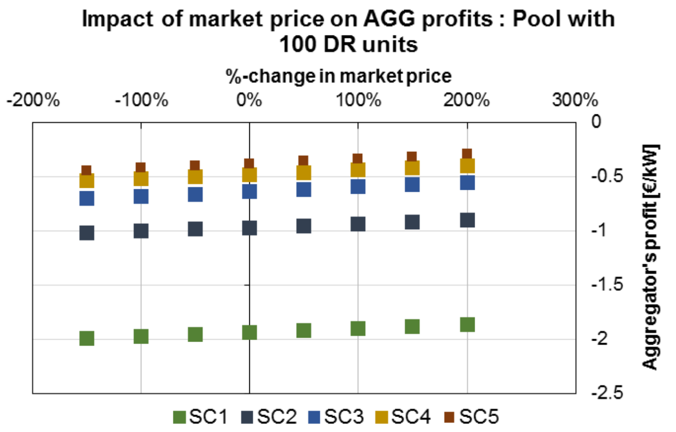

Impact of market price on AGG profits : Pool with 100 DR units
%-change in market price
-200%
-100%
0%
100%
200%
300%
0
-0.5
-1
-1.5
-2
-2.5
Aggregator's profit [€/kW]
SC1 SC2 SC3 SC4 SC5

Figure 8.12 shows the range of impacts on the aggregator's profit from DR unit under varying assumptions of electricity prices for different pool sizes 10,000 units (upper left), 1,000 units (upper right) and 100 units (lower right) and aggregator's profit under varying pool sizes (lower left); for all five PV penetration scenarios, economic optimization, EU grid.

Figure 8.12: Range of impacts on the aggregator's profit from DR unit under varying assumptions of electricity prices for different pool sizes

8.5 Aggregator’s profits under Economic optimization for PV and DR- EG grid

In addition to the detailed investigation of sensitivities in the EU grid we also study the impacts on a smaller grid. In this case we draw our attention to the INCREASE example grid of Elektro Gorenjska in Slovenia (from here on EG grid). The default business assumptions follow the ones of the EU grid. Again, in order to study the profitability of an aggregator in a small grid, we focus on the most crucial impact parameters: electricity market prices and pool size of DR units. Our analysis is carried out for winter in order to ensure comparison with the previous subsection (again results for the summer period show in terms of direction and trend of impacts high similarities).

Compared to the EU grid however, although direction and trend of results are similar, the profits are in absolute terms much lower in the EG grid: 0.05 EUR per kW in the EU grid compared to 0.1 EUR kW in the EU grid (under default assumptions). As illustrated in Figure 8.13, in total yearly profits in the largest penetration scenario (SC6) range between 4 Million (no changes in prices) and 14 Million Euros (tripled electricity prices throughout the whole year).

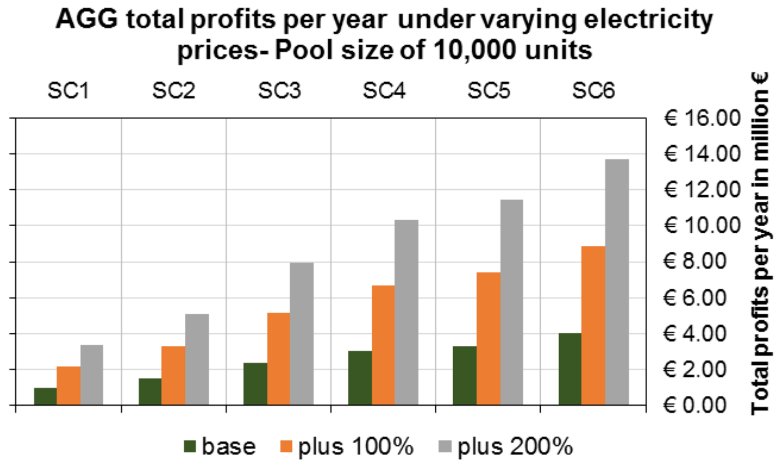
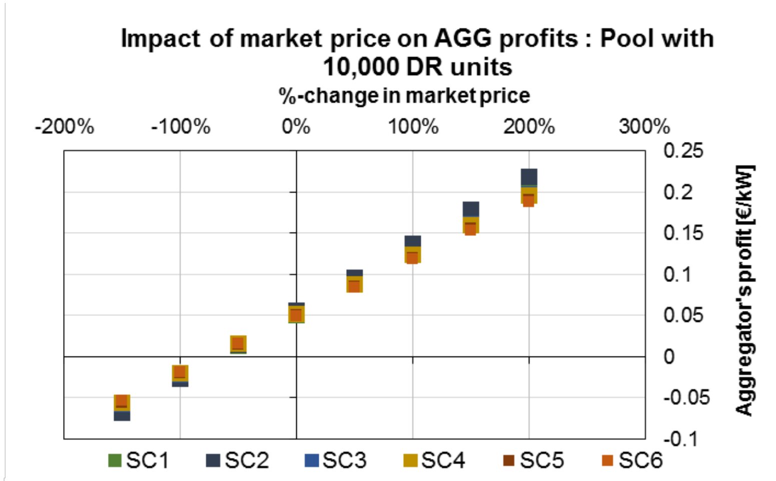
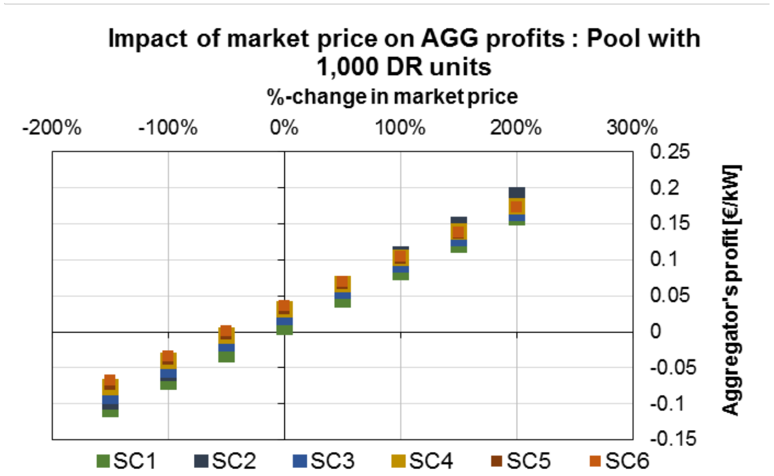
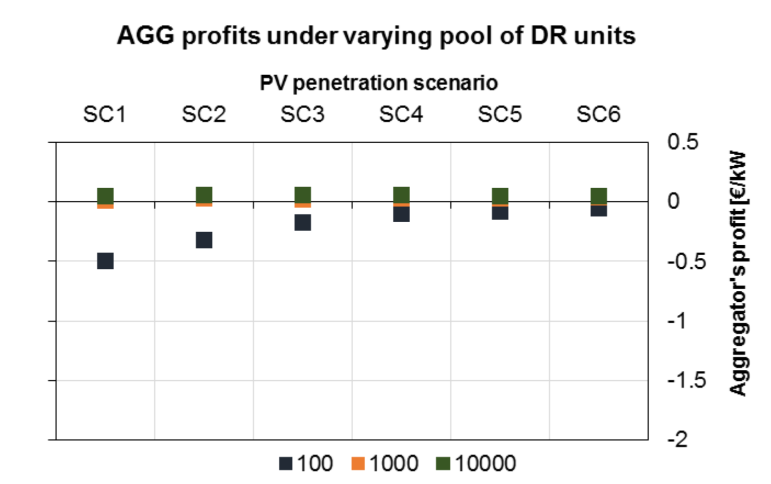


Figure 8.13: Aggregators total profits per year under different electricity prices – 10,000 DR units, EG grid, economic optimization


Impact of market price on AGG profits : Pool with 10,000 DR units
%-change in market price
-200%
-100%
0%
100%
200%
300%
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
Aggregator's profit [€/kW]
SC1
SC2
SC3
SC4
SC5
SC6


Impact of market price on AGG profits : Pool with 1,000 DR units
%-change in market price
-200%
-100%
0%
100%
200%
300%
0.25
0.2
0.15
0.1
0.05
0
-0.05
-0.1
-0.15
Aggregator's profit [€/kW]
SC1
SC2
SC3
SC4
SC5
SC6


AGG profits under varying pool of DR units
PV penetration scenario
SC1
SC2
SC3
SC4
SC5
SC6
0.5
0
-0.5
-1
-1.5
-2
Aggregator's profit [€/kW
100
1000
10000

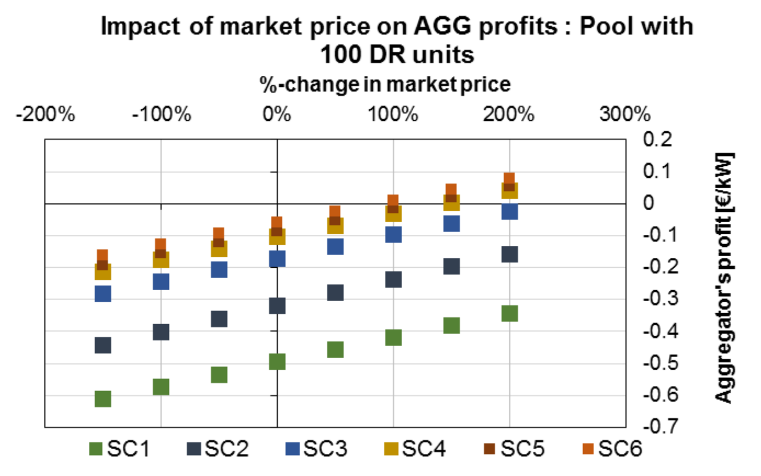

Impact of market price on AGG profits : Pool with 100 DR units
%-change in market price
-200%
-100%
0%
100%
200%
300%
0.2
0.1
0
-0.1
-0.2
-0.3
-0.4
-0.5
-0.6
-0.7
Aggregator's profit [€/kW]
SC1
SC2
SC3
SC4
SC5
SC6

Figure 8.14 illustrates the results and we find that also in the smaller grid, as expected market prices have a strong impact on the profitability. As before, in the default pool size of 10,000 units a doubling of electricity prices triples aggregator's profits. In this smaller grid the aggregator already receives positive profits in case of a size of 1,000 units (with no additional price increase). The by far smallest pool of DR units (100) becomes hardy profitable. Only in case of the highest penetration scenario a tripling of electricity prices leads to profits.

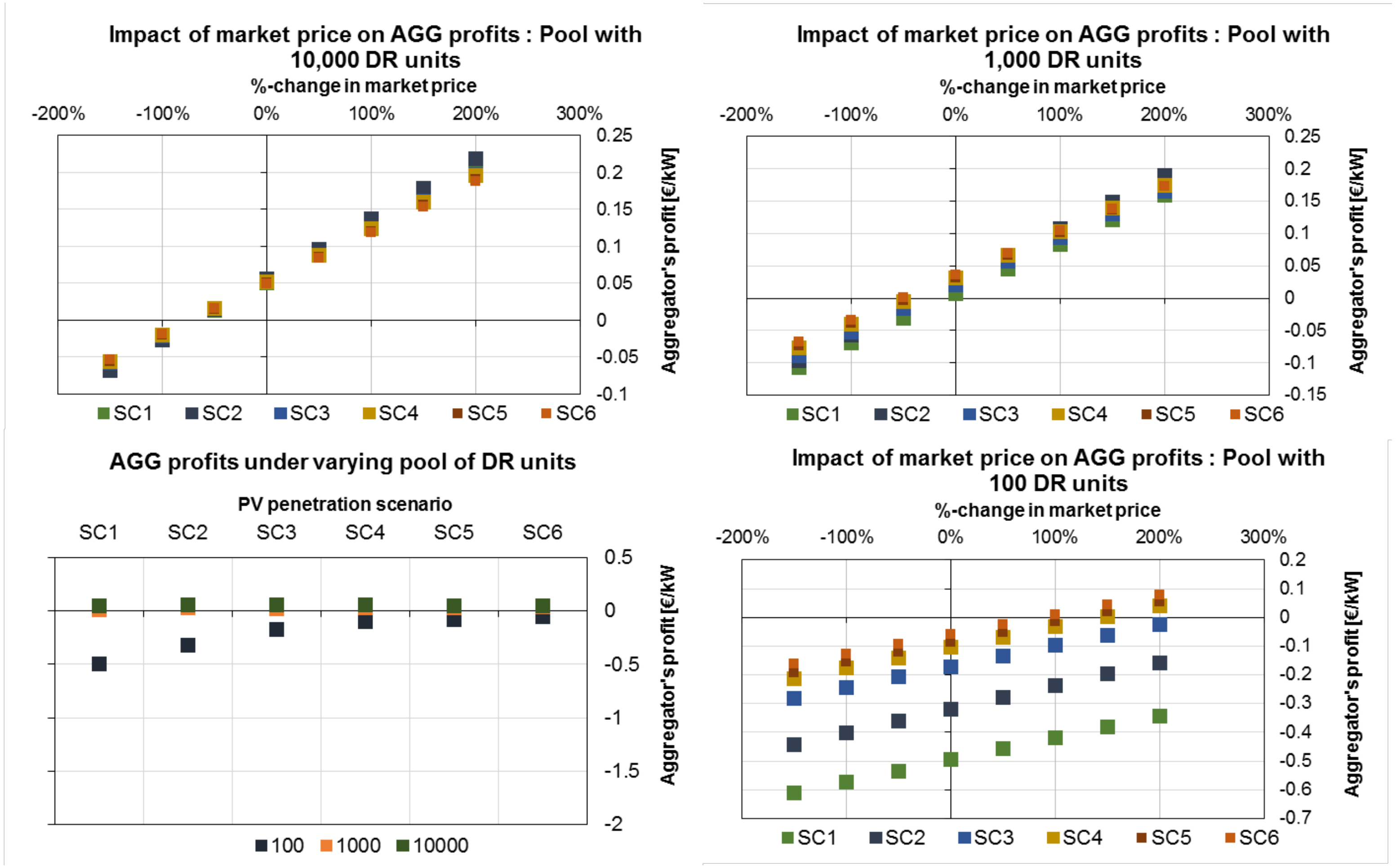


Figure 8.14: Range of impacts on the aggregator's profit under varying assumptions of electricity prices for different pool sizes 10,000 units (upper left), 1,000 units (upper right) and 100 units (lower right) and aggregator's profit under varying pool sizes (lower left); for all five PV penetration scenarios, economic optimization, EG grid.

8.6 Aggregator's profits under Energy optimization for PV and DR- EG grid

As in case of economic optimization, we are interested in the impacts of changing market conditions and business assumptions on aggregator's profits under energy optimization. Thus, as before we analyze the following questions:

- Where is the break-even point of the aggregator?
- Under which market price, aggregator costs as well as further market specifications is the aggregator able to gain positive revenues?

We carry out the analysis for the winter period (results in summer are similar in direction and magnitude of impacts) and for TLS1 scheme. We also find no striking differences between the different TLS schemes. The analysis is carried for all five PV penetration scenarios. We vary the following parameters, Table 8.1:

Table 8.2 The assumptions for aggregator's profit calculation, Energy optimization

Specification	Default	Impact range
Electricity price		Ranges between -150 % and + 200 %
Aggregator share on DR unit revenues	φ_{DR}: 50 %	25 % -75 %
Aggregator's revenues from PV owners	φ_{PV}: 20	20 % - 90 % in 10 %-steps
Aggregator's DR pool size	10,000	100 and 1,000

Analogous to the case of economic optimization we find that the impacts of altering profit shares from PV and DR units are quite similar. Regarding the PV owner's share of profits Figure 8.15 shows the higher the aggregator's share of PV owner's profits, the smaller is the aggregator's loss. Also in this case the impacts of the PV unit profit share are much stronger than the one of the DR profit share. Thus, a rise in the profit share from the DR hardly affects aggregator's profits (see Figure 8.16). Even if the aggregator receives all revenues from the DR unit, under the default assumptions, the increase in profits still is negligible. The reason is that the profits of the DR unit are rather small (on average the DR profits amount to 0.08 € per kW) compared to the profits of the PV unit owner (on average profits amount to 0.4€ per kW).

The smallest impact is again observed for changing software costs. Assuming software costs of 1,000 € instead of 100,000 € profits only increase by 0.4 % (see Section 8.3). In contrast to the minor importance of software costs electricity prices and the pool size of DR units have a crucial impact on profits. Figure 8.17 illustrates the impact of changing electricity market prices for different pool sizes. In case of the default pool size of 10,000 units a doubling of electricity prices triples aggregator's profits. The extent of the impact of electricity prices on profits falls with decreasing pool size. For a smaller pool with 1,000 DR units a doubling of the electricity price doubles the profits. In case of the smallest pool with only 100 DR units, we find that prices have to be at least tripled in order to imply profits in the largest penetration scenario. By studying the total profits per year we find that as expected the highest total profits per year are generated with the largest pool size and in the penetration scenario with the largest installed capacity. Figure 8.17 shows that in case of a pool size of 10,000 units total profits per year increase significantly with increasing number of PV units installed. Assuming the smallest pool size, we find total losses in every penetration scenario. With 1,000 DR units in a pool, profits range between 7,000 € and nearly 300,000 € per year, depending on the number of PV units.

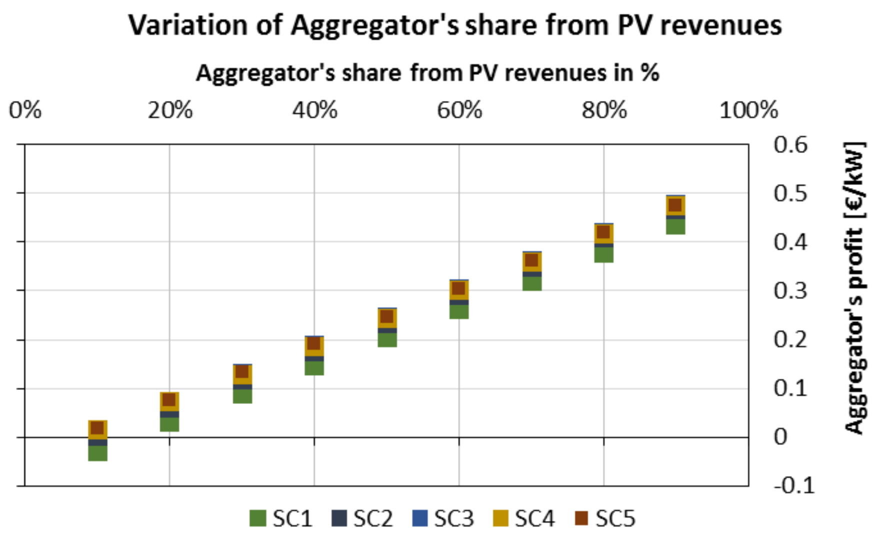


Figure 8.15: Range of impacts on the aggregator’s profit under varying assumptions of the aggregator’s profit share from PV unit owner for all five PV penetration scenarios – Case of Balancing Service, EU grid

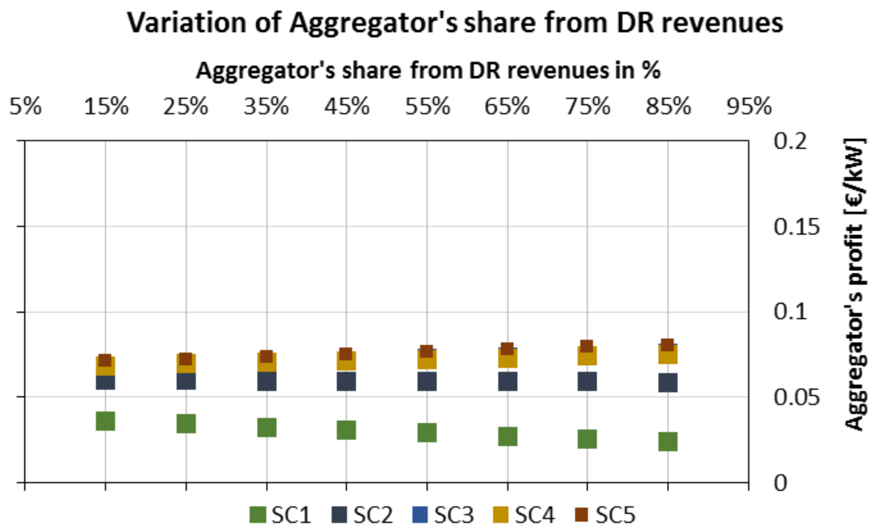


Figure 8.16: Range of impacts on aggregator’s profit under varying assumptions of the aggregator’s profit share from DR unit for all five PV penetration scenarios – Case of Balancing Service, EU grid

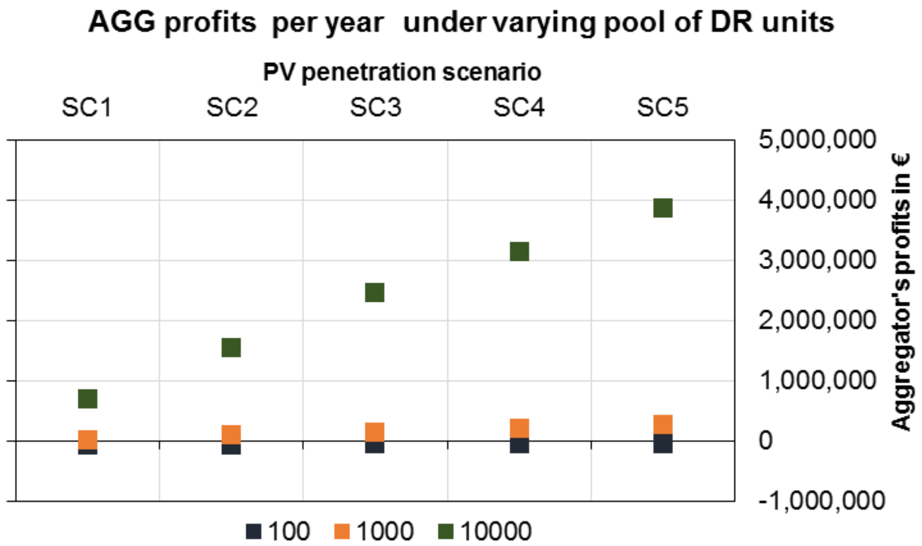


Figure 8.17: Impacts of pool size with different numbers of DR units on total aggregator's profit per year for all penetration scenarios– Case of energy optimization

As already illustrated a doubling of the electricity price triples the profit per kW in the default case. In total this implies, as shown in Figure 8.18, that instead of a total profit of over 700 k€ per year in case of SC1, the aggregator gains nearly 1.8 million € profit. With a tripling of the electricity price (throughout the year), total profits in case of SC5 would amount to 12 million € per year.

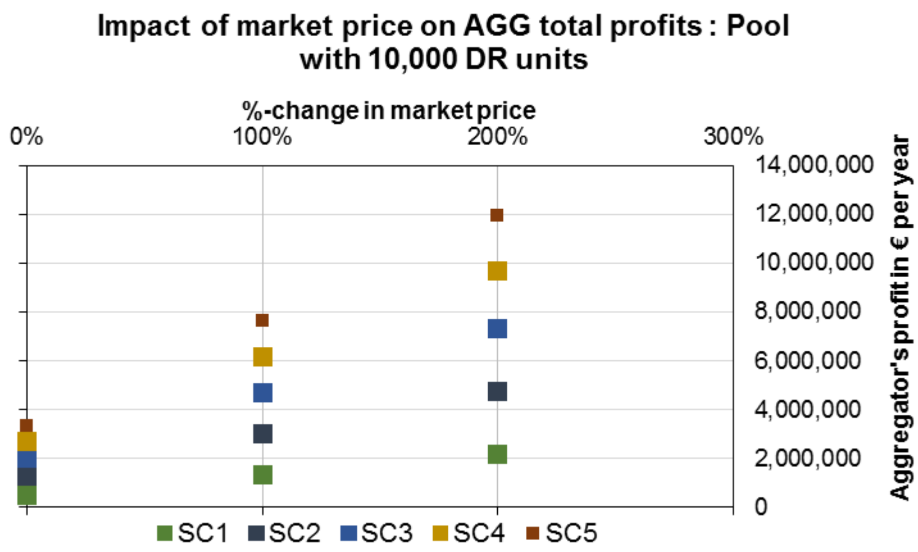


Figure 8.18: Impacts of increasing electricity prices on total aggregator's profit per year for all penetration scenarios– Case of energy optimization, 10,000 DR units

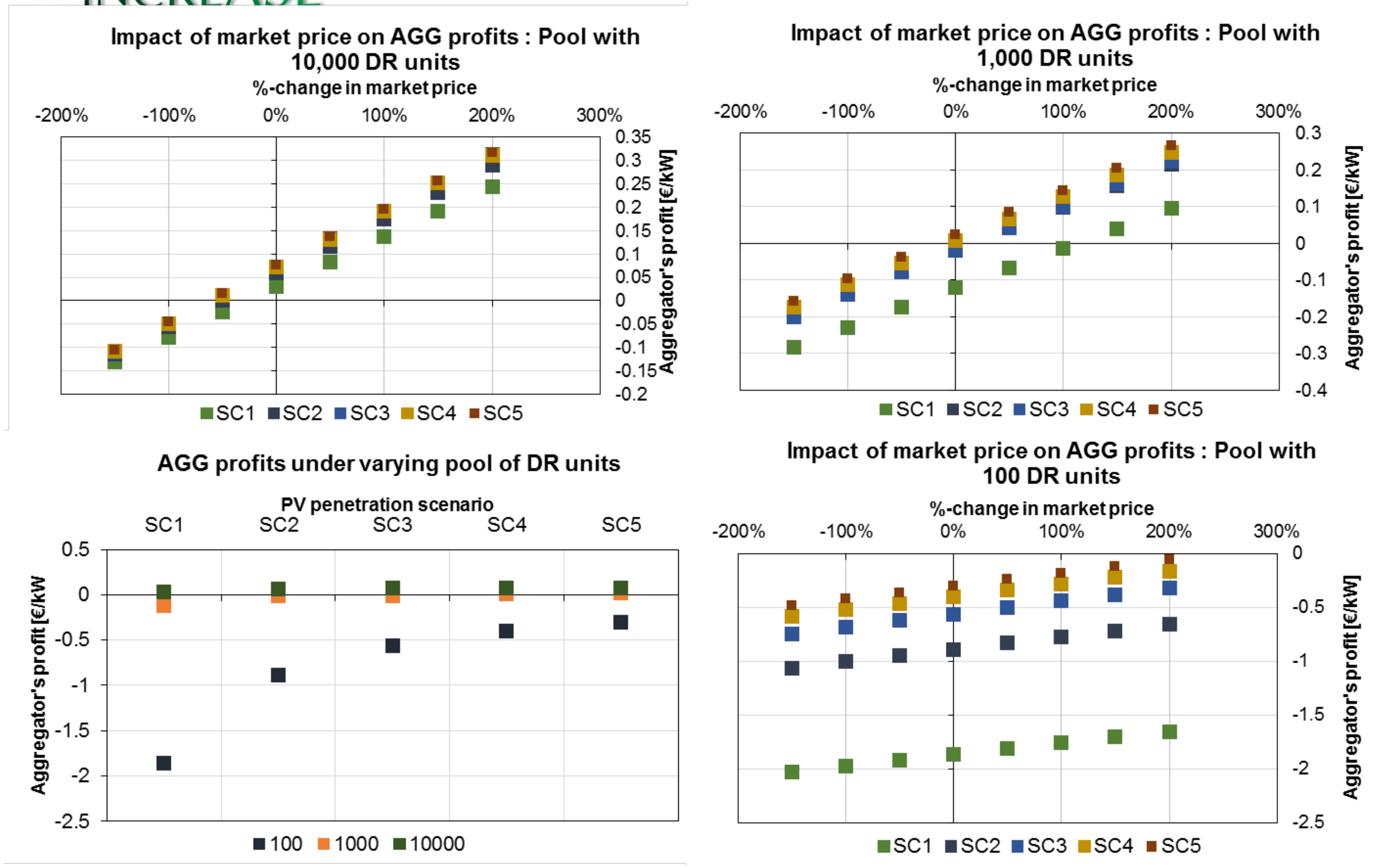


Figure 8.19: Range of impacts on the aggregator's profit under varying assumptions of electricity prices for different pool sizes 10,000 units (upper left), 1,000 units (upper right) and 100 units (lower right) and aggregator's profit under varying pool sizes (lower left); for all five PV penetration scenarios, energy optimization, EU grid

8.7 Aggregators profits from DR units under Energy optimization- EG grid

Analogous to the analysis of impacts under economic optimization we study the effects of a different business model, which assumes that the aggregator only receives profits from the DR unit. This implies that the aggregator does not receive revenues from the PV units.

In order to analyze the sensitivity of aggregator's profits from DR units we focus on the most crucial impact parameters: electricity market prices and pool size of DR units. Our analysis is carried out for winter in order to ensure comparison with the previous subsection (anyhow, as aforementioned results for the summer period show in terms of direction and trend of impacts high similarities). First as illustrated in Figure 8.20 we find that compared to the business case where the aggregator receives revenues from the DR and PV unit, the aggregator experiences a loss. This is already observable in the default case with the largest pool size of 10,000 units. There the economic losses are however quite small. Second the results reveal that magnitude and direction of impacts depend on the penetration scenarios. In the default case of 10,000 DR units, losses in SC1 (the smallest PV penetration scenario) rise with increasing electricity prices, while for SC3 to SC5 losses fall with increasing prices. Figure 8.21 also shows that SC2 is hardly affected by any changes in prices (even by a tripling of the electricity price).

These rather surprising results trace back to the development of the DR unit profits. As shown in Figure 8.20, DR unit profits in the lower penetration scenarios SC1 and SC2, fall with increasing prices. Moreover, in case of SC1 with increasing prices DR unit incur losses. This effect occurs because of the energy optimization process. In SC1 the units operate as they are scheduled and the positive profit for DR units was achieved with availability fee payment from the aggregator. Losses (negative profits) would otherwise occur since the units are scheduled to improve the network condition and not the market situation. With the availability fee the aggregator covers DR units' losses, but with increase of energy price, the losses become higher and scenario 1 becomes negative. In higher penetration scenarios, where PQ violations starts occurring, Simple Traffic light mechanism rejects the schedules of the DR units in some time instances and outcome is economically better, and with increased prices it yields more profits.

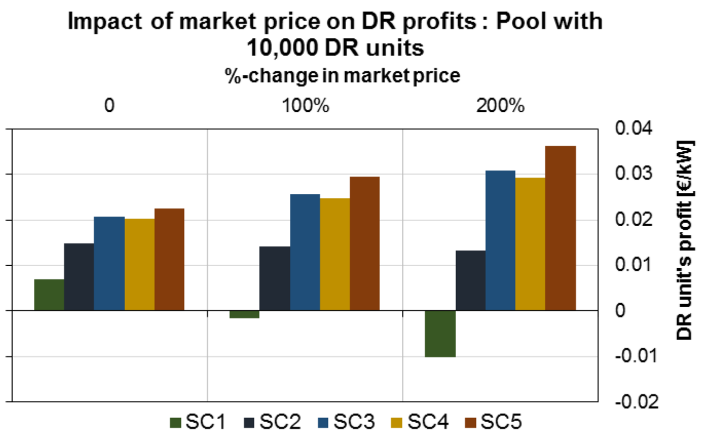


Figure 8.20: Range of impacts on the DR unit profits under varying assumptions of electricity prices; Case of energy optimization, 10,000 DR units

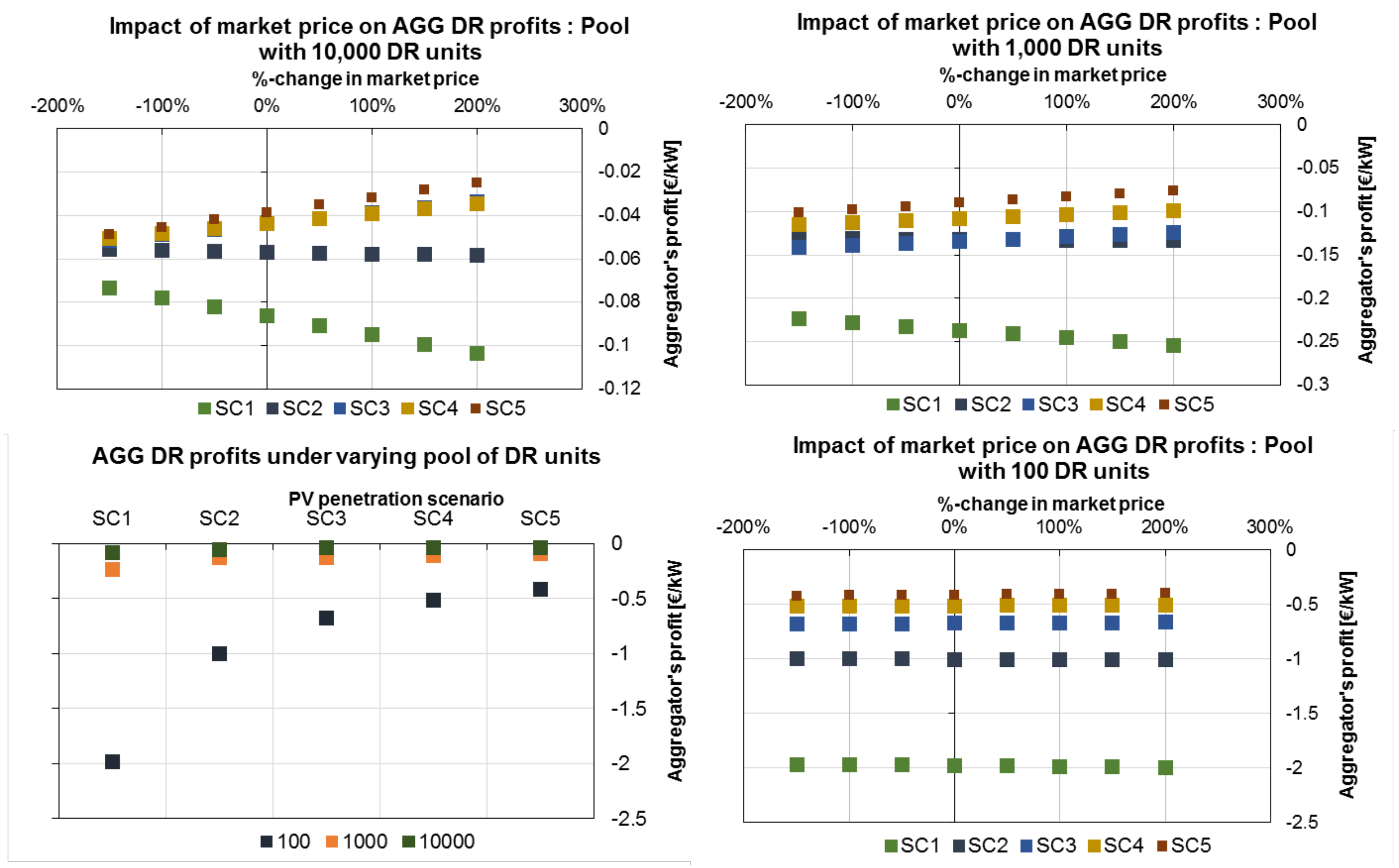


Figure 8.21: Range of impacts on the aggregator's profit from DR unit under varying assumptions of electricity prices for different pool sizes 10,000 units (upper left), 1,000 units (upper right) and 100 units (lower right) and aggregator's profit under varying pool sizes (lower left); for all five PV penetration scenarios, energy optimization, EU grid

8.8 The green energy premium (GEP)

Finally, we compare aggregator's profits between the two optimization procedures, economic and energy optimization in order to analyze the influence of market conditions and business assumptions on the Green energy premium (GEP). The premium is calculated as the difference between the aggregators profit under scheduling service and balancing service. The previous findings show that market prices, pool size and share of PV unit owner's revenues have by far the strongest impact on profits. Therefore, we analyze how these parameters affect the level of GEP.

8.8.1 GEP based on Aggregators profits from DR and PV

We start with altering electricity market prices (all other assumptions are on default). Results depicted in Figure 8.22 show that with rising energy prices the level of GEP increases strongly. For instance, for SC1 in the default case with no changes in electricity prices GEP amounts to 4 €c/kW, while a tripling in the electricity price implies a GEP of 14 €c/kW (hence the GEP is more than tripled). The reason is that higher electricity prices boost the profits of the aggregator stronger under economic optimization. Taking a look on the total amount of GEP required per year we find that under default electricity prices it ranges between 200 k€ and 500 k€. If electricity prices are tripled throughout the year GEP amounts to 1.5 million in case of SC5 or in case of smaller penetration scenarios to 600 k€ (see Figure 8.23).

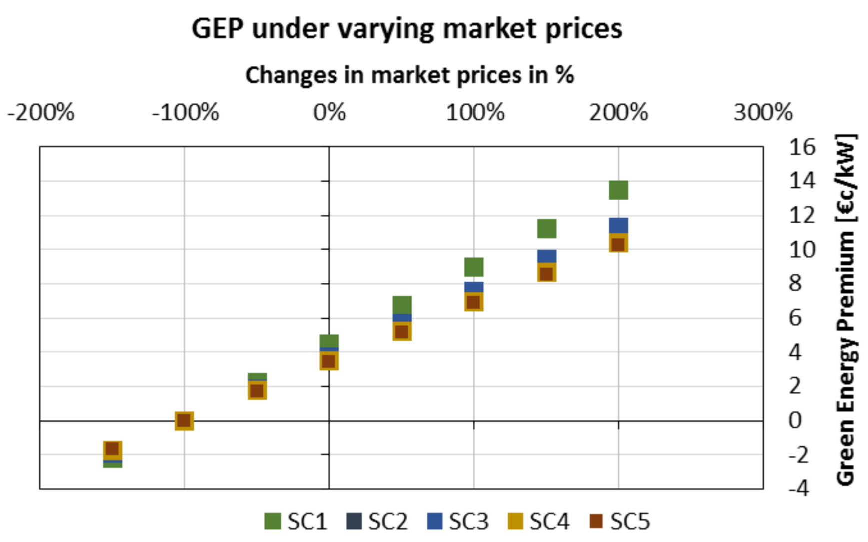


Figure 8.22: Impacts of altering electricity prices on the Green Energy Premium for all penetration scenarios

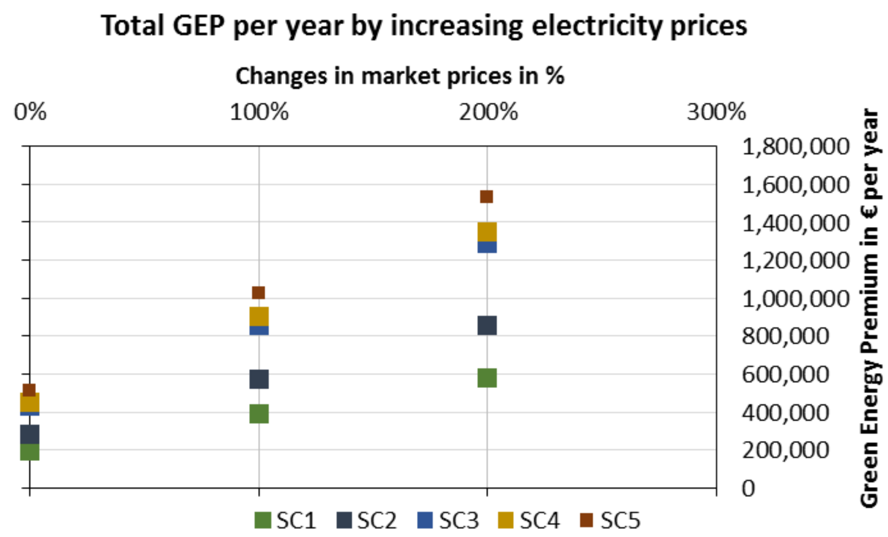


Figure 8.23: Total GEP per year in € under increasing electricity prices

We find a completely different picture by analyzing the impacts of the share of PV unit owner profits on aggregator's profits (see Figure 8.24). A higher share of PV unit owner profits reduces the GEP. Hence, the share of PV unit owner profits has a stronger effect on aggregator's profits under energy optimization. For instance, in case with no share of PV revenues the GEP amounts to 3.8 €c/kW for SC5, while in a case where the aggregator receives all revenues from the PV unit the GEP is about 2.6 €c/kW.

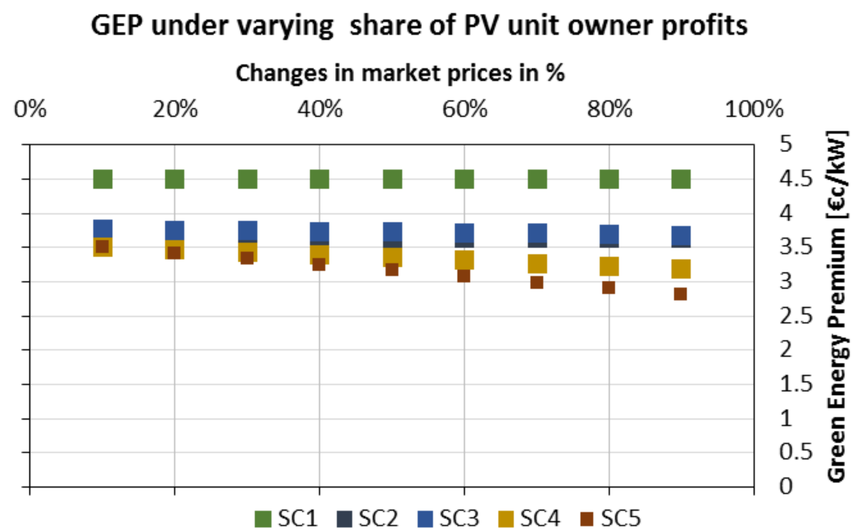


Figure 8.24: Impacts of PV unit owner profit shares on the Green Energy Premium for all penetration scenarios

Finally, we are also interested if GEP differs between different pool sizes of DR units. We find that the impact of the pool size on aggregator's profits amounts to the same extent in both optimization services. More precisely, the extent of the impact of different DR unit pools is the same in both cases energy and economic optimization. In SC1 GEP is always 4.5 €c/kW, independent of the pool size.

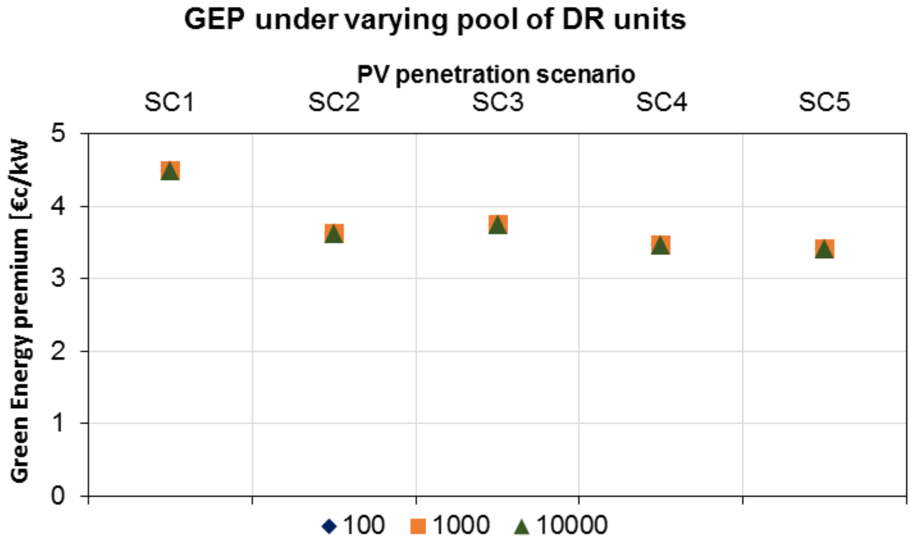


Figure 8.25: Impacts of DR unit pool size on the Green Energy Premium for all penetration scenarios

8.8.2 GEP based on Aggregators profits from DR units only

Also in case of the second business model, where the aggregator receives revenues only from the DR unit (instead of both units, DR and PV), rising energy prices lead to a strong increase in the level of GEP. For instance, as illustrated in Figure 8.24, for SC1 in the default case with no changes in electricity prices GEP amounts to 4.5€c/kW, while a tripling in the electricity price implies a GEP of 14 €c/kW (hence the GEP is more than tripled). The reason is that higher electricity prices boost the profits of aggregator stronger under economic optimization. Generally direction and magnitude of the impact on GEP due to rising electricity prices are extremely similar to the default business case (see Figure 8.26). More specifically for the penetration scenarios SC1, SC2 and SC3 the amount of premium for every level of the electricity price is nearly the same (differences are below 0.05 %). In case of the largest PV penetration scenario the amount of GEP differs by 0.1 EUR cents in the default case with no price increase and rises to 0.4 €cent assuming a tripling of prices.

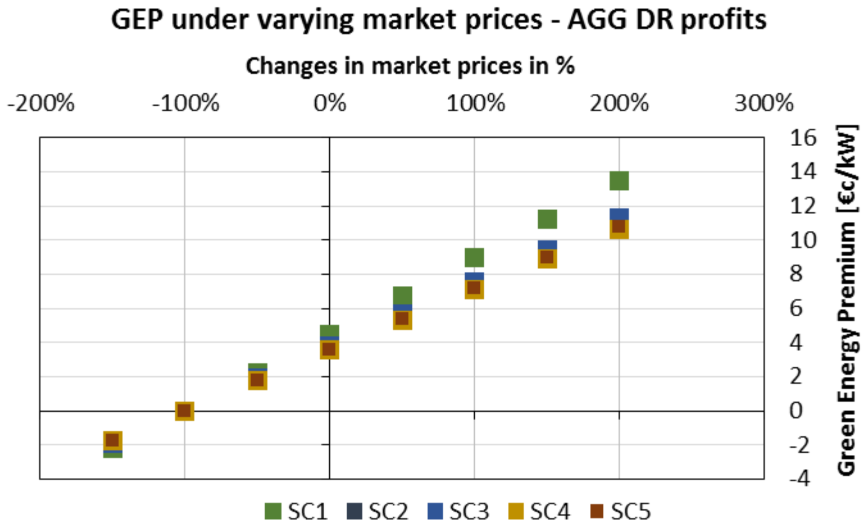


Figure 8.26: Impacts of altering electricity prices on the Green Energy Premium for all penetration scenarios assuming the business case where the aggregator receives revenues only from the DR unit

The results in this chapter show that under the cost assumptions we took, for a small pool of flexibility from DR, it is hardly profitable. DR units need to provide flexibility on reserve market, the availability payments need to be low and the share of profits they get from the aggregator also needs to be low. For PV also smaller pools are profitable. This means for small pools the aggregator should mainly include PV.

Regarding our cost, we have assumed that the aggregator starts up his business. If we consider established companies such as energy retailers that start to include aggregation in their business portfolio the cost may be much lower and also small DR pools may become profitable. Overall the EU grid is more profitable than the EG grid, even as we assume lower personal costs for Slovenia than for the EU average.

9 Conclusions

This report investigated the viability of the INCREASE solutions and key INCREASE AS within the current framework conditions in the INCREASE partner countries. While the low voltage (LV) grid of the Slovenian Distribution System Operator (DSO) Elektro Gorenjska that was the basis for previous assessments in the INCREASE Report D5.2, an assessment for a representative European grid is basis for overall policy conclusions. We find cases with positive revenues for the aggregator implementing INCREASE solutions. The aggregator has a successful business if his costs are distributed among sufficient DR units in his pool. In case of aggregator's pool size of 10 000 aggregated DR units, the costs are spread across enough units to achieve positive profit in the operation. Scenarios with lower level of integration of PV and DR are less profitable, which becomes problematic in smaller aggregator's pool size, where he becomes profitable only with increased energy prices or including the PV units in his business portfolio as well. For all of the pool sizes the higher level of integration presents better cost distribution and more favourable conditions for his operations. Other factors such as higher market prices that we find for example on the reserve markets would promote profits for aggregators. Under the cost assumptions we took, for small pools flexibility from DR is hardly profitable. DR units need to provide flexibility on reserve market, the availability payments need to be low and the share of profits they get from the aggregator also needs to be low. For PV also smaller pools are profitable. This means for small pools the aggregators should mainly include PV in their aggregation.

Regarding our cost assumptions, we assumed that the aggregator starts his business. If we consider established companies such as energy retailers that start to include aggregation in their business portfolio the costs may be much lower and also small DR pools may become profitable. Overall the EU grid is more profitable that the EG grid, even when assuming lower personal costs for Slovenia than for the EU average. Also for small pool sized we are able to secure flexible energy portfolio sizes above 1 MW, the minimum bid size in many reserve markets. However also smaller amounts may lead to business cases and therefore the market provisions should not be prohibitive.

The energy market of the future will be characterized by a multitude of market actors with different business portfolios and costs structures and only an inclusive approach will lead to the needed transition of the EU energy systems.

10 Appendix 1: Specifications of the EU grid

To investigate the impact of renewable production, advanced inverter controls and implementation of DR units in the network, need for additional test grid besides EG network model appeared. The new selected model had to represent general structure of the network, applicable to multiple locations and situations.

To avoid the difficulties with the selection of proper grid model, a different approach was proposed. A questionnaire about typical network settings and parameters was used to collect the information about network properties from several DSO from different European region, to cover the southern, central and northern European geographical aspects. Based on those typical, average values of the network and its elements, representative case was constructed. Parameters, which were collected are shown in Table 10.1.

Table 10.1: Network parameters

Typical parameters	**Grid 1**
Network type	Rural/LV
Voltage level/grid type	
Transformer(s)	
Power rating [kVA, MVA]	
Primary voltage [kV]	
Secondary voltage [kV]	
Average Loading of TR [%]	
Type of feeder (OHL/Cable)	
Line diameter/ intersection [mm,mm2]	
Length - average feeder(m)	
Number of feeders per transformer	
Optional parameters	
Average number of load nodes per feeder	
Short circuit current of a customer	

DSOs and the project partners provided the requested parameters for their typical networks and additional grid information about line properties, loads, etc. With this approach enough data was received to cover all of the required aspects. For the purpose of analysis, the low voltage, rural network was chosen. Rural networks are more receptive to impact of the RES implementation due to the longer feeder lines, weaker network structure, bigger loads, etc.

10.1 Rural network parameters

In rural areas LV networks are operating radially and are supplied through one transformer station. Transformers from 50 kVA up to 800 kVA are used through different regions or countries, Table 10.2.

Table 10.2: Transformer information in LV networks

Country	Rated power [kVA]	Voltage level [kV]	Loading rate [%]
Finland	100	20/0.4	15 - 25
Belgium	160, 250, 400, 800	10/0.4	50 – 60
Slovenia	50 - 630	20/0.4	50 – 60
Spain	50, 100, 160, 250	30-10/0.4	50 – 70
Netherlands	250, 400, 630, 1250	10-20(25)/0.4 (LL)	30 –80

Networks consist of 3 to 10 feeders, in length from 90 up to 800m, which can supply from 5 to 80 load nodes each, Table 10.3

Table 10.3: Feeder information in LV networks

Country	Number of feeders	Average length [m]	Load nodes/feeder
Finland	3	370	5
Belgium	4 - 8	200 – 800	1 – 20
Slovenia	5 - 10	400 - 800	30 – 80
Spain	N/A	90 - 160	N/A
Netherlands	2-12	10 - 350	2-50

10.2 Designed rural network

Based on the inputs, synthetic network was designed with focus on central European region. Typical network configuration was designed and is presented in this chapter.

In comparison to urban LV network, lower load density was used when creating rural network. Two factors contribute to this: longer average feeder length and unstructured branch topology. 6 radial feeders are defined, each supplies from 20 loads. In Table 10.4parameters, used for rural network are listed.

Table 10.4: Rural network parameters

LV rural network parameters	
Number of feeders	6
Number of loads per feeder	20
Feeder length [m] ? avarage	600
Power line properties (Cable/OHL, sections)	OHL, 4x70 CU mm^2 $^{(\text{ nl cable 4*150 AL})}$4x35 CUmm^2
Rated power of MV/LV transformer [kVA]	250 (nl 400kVa)
Loading of MV/LV transformer	55 %

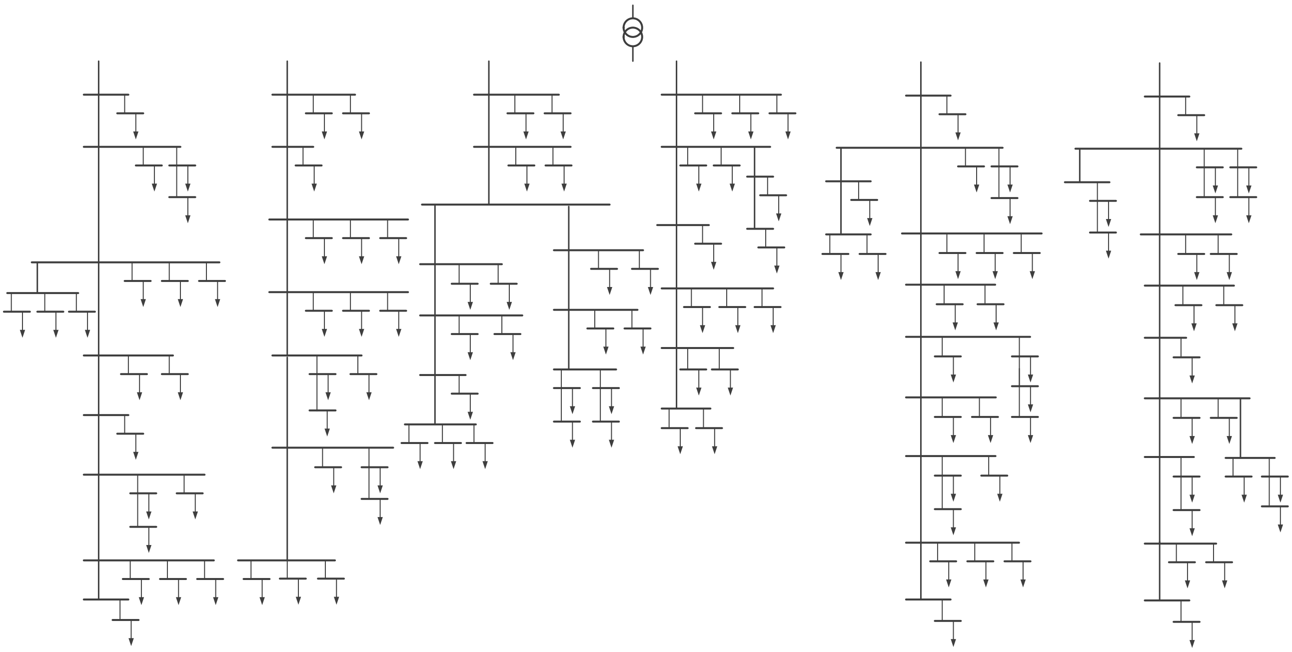


Figure 10.1: Proposed rural LV network

The network consists of 177 nodes, 120 nodes are modelled as households, each with its own load consumption profile. Each of the household is also potential PV location for smaller PV plants of 20 kWp. Rated power of the transformer was used for scaling of the consumption in order to achieve proper average loading of the transformer of 55 %. Due to the later implementation of PV plants, and power peaks of consumption above rated power, transformer was swapped for 400 kVA in order to avoid convergence issues with power flow calculations and possible higher rate of implementation of the PV’s within the network.

Table 10.5: Transformer parameters

Transformer	
Rated power	400 kVA
Voltage levels	21 kV / 0.42 kV
Full load losses	1.011 %
Idle state losses	0.129 %
U_K factor	4 %

10.3 Scenario development

For the sensitivity analysis requirements, additional set of scenarios was defined to investigate the impact of PV and DR unit implementation in the network. Similarly as in EG network, winter and summer conditions were simulated as the most borderline condition settings. Scenarios are described in Table 10.6.

Table 10.6: Implementation of PV units

Scenario	Amount of PV units	Installed PVpower
1	12	240 kWp
2	24	480 kWp
3	36	720 kWp
4	48	960 kWp
5	60	1200 kWp

Since the network represents small area, same orientation, efficiency and style of installation was assumed for all units.
PV units were evenly distributed between the feeders in the network and along the feeder. All of the PV units were 20 kWp power plants they were connected through 3 phase inverter, with symmetrical phase distribution of production and constant factor Cos $\varphi = 1$.

For the second part of analysis, DR implementation scenarios are defined in Table 10.7.

Table 10.7: DR unit implementation scenarios

Scenario	Number of PV units	Amount of DR units	Available DR power
1	12 / 240kw^	6	42 kW
2	24/ 480kw^	12	84 kW
3	36/ 720kw^	18	126 kW
4	48/ 970kw^	24	168 kW
5	60/ 1200kw^	30	210 kW

11 Appendix 2: Energy prices

To make a full economic evaluation, energy prices for different business models and selling schemes were taken into consideration. The following values of these parameters have been assumed in the evaluation:

Table 11.1: Default electricity prices

	Default values	Unit
Market price	BSP-Southpool prices – summer, winter	€/MWh
FIT	150	€/MWh
Premium	50	€/MWh

The BSP[1] hourly DA prices for the following two typical weeks were used, Figure 11.1:

- Summer: 8.6. - 14.6.2015.
- Winter: 11.2. - 17.2.2015.

[1] BSP SouthPool Regional Energy Exchange, Ljubljana, Slovenia

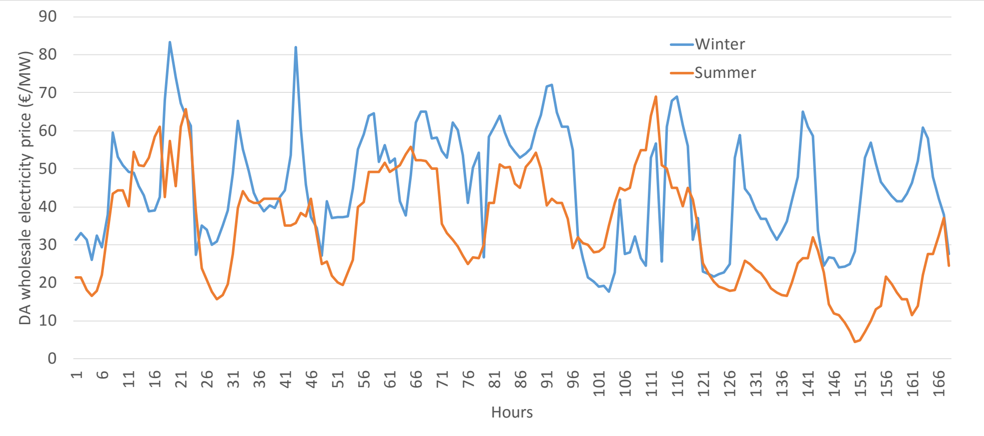


Figure 11.1: The DA wholesale energy market prices used, summer and winter

The value of FIT as well as the value of Premium was taken from the Slovenian national FIT agency Borzen that was valid on 1.6.2015.

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https://www.borzen.si/en/Home	Borzen Slovenian Power Market Operator (Borzen, d.o.o.)
http://www.eles.si/en/index.aspx	ELES Transmission System Operator – TSO (Elektro Slovenija, d.o.o.)
http://www.sodo.si/	SODO Distribution system Operator – DSO (Sistemski operater distribucijskega omrežja z električno energijo)