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Final Report

DYNAMIC NETWORK TARIFFS - AN OPPORTUNITY FOR THE ENERGY TRANSITION

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List of abbreviations

EV	Electric Vehicle
DNT	Dynamic Network Tariff
DER	Distributed Energy Resource
LRMC	Long Run Marginal Cost
SRMC	Short-Run Marginal Cost
DSO	Distribution System Operator
IBT	Inclining Based Tariff
ToU	Time of Use
GU	Grid User
IREG	Intermittent Renewable Generation
TSO	Transmission System Operator
TNO	Transmission Network Operator
DNO	Distribution Network Operator
ICT	Computer and Information Technology
ES	Expected Shortfall
PVPC	Voluntary Price for the Small Consumer

Note:

Figures presented in this report have been collected from the referenced documents.

1 INTRODUCTION

1.1 BACKGROUND

A significant transformation in the energy sector is taking place due to power industry restructuring, ever-increasing employment of intermittent renewable generation, environmental constraints, and emergent prosumers such as electric vehicles (EVs). These factors impose the necessity of redesigning distribution network tariffs to promote renewable energy generation accommodation and incentivise customers to promote energy efficiency. Power generated requires the transmission and/or distribution network to reach the end user, which is associated with the capital cost, reinforcement cost, maintenance cost, network loss cost, etc. The fee allocated to the customers for consuming electricity has different terminology, such as tariffs, charges, and rates. Tariffs are a group of charges consisting of distribution network charges, transmission network charges, energy prices, and regulated taxes.

Also, the ever-increasing use of smart meters paves the way to the clean energy transition. Smart metering devices are the cornerstone for tariff designs that serve the power grid. Public smart charging and its role in integrating electric vehicles into the electricity network could also contribute to innovative tariff designs. Current network tariffs often send mixed signals to market participants, not always reflecting the needs of today's energy system. Beyond this, taxes are typically rigid-blunting relevant network market or network price signals. There is no specific tariff design that could satisfy all customers or achieve all objectives at the same time. After all, a specific tariff is designed in response to questions that governments, regulators, and network operators need to answer.

Dynamic network tariff (DNT) is very well associated with the power flow pattern in the network. It does not necessarily represent the load consumption of any individual customer, but the aggregated consumption of end users directly demonstrates the variation of power flow in the network. Furthermore, it can account for the intermittent power generation changesin the grid due to renewable energy resources. Consumers are free to decide how and when to react to price signals of energy and network tariffs and to adjust consumption during specific time intervals. Consumers' higher responsiveness to price signals can benefit the whole power system and consumers themselves.

1.2 OBJECTIVES

The 2020-02 dynamic tariff workgroup focus on the current practices, experiences and challenges in implementing dynamic tariff in Europe. The work's scope includes academic research and industrial experiences on dynamic network tariffs. Smart meters enable better communication and data collection. The work group investigates the design of a suitable network tariff structure, underlining the key tariff principles maximising benefits for all parties involved.

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2 SURVEY

Electricity transmission and distribution are paid for by costs collected by transmission system operators (TSOs) and distribution system operators (DSOs) respectively [4]. At least in part, the distribution network's peak loads decide the power grid's investment cost. With the ever-increasing penetration of IREG and emerging prosumers like electric vehicles, the fixed network tariff may not function well for the power system due to the growing gap between highest and lowest loads and challenges associated with their accurate forecasting. In other words, if the network pricing scheme is not updated, there is a risk of rising peak loads and irrecoverable investment, which means that extra costs won't be passed along to the customers who drive the investment [5]. Therefore, more sophisticated network tariff planning techniques are required.

Terminologies used to describe the fees charged to users for using energy include tariffs, charges, and rates. Tariffs are a collection of fees that include energy prices, transmission network fees, distribution network fees, and controlled taxes [6]. Taxes come in many forms, including those that promote energy efficiency, nuclear power, combined heat and power (CHP), renewable energy sources (RES), and CHP. Table 1 [7] contains a comprehensive classification of electricity tariffs. The electricity price structure will impact the interests of stakeholders and consumers, so certain principles or factors like system sustainability, economic efficiency, implementability, reliability, and operability are frequently used as fundamental standards for developing electricity prices [8, 9].

Table 1 Components, subcomponents, and elements of electricity price

Components	Subcomponents	Elements
Taxes & Levies	• RES support • CHP support • Nuclear support • Energy efficiency support • Social tariffs • System operation • Market operation • Security of supply • Environmental taxes • Excise taxes • Value-Added Tax (VAT) • Other	• Individual taxes finance the general state budget • Ear-marked levies financing policies
Network	• Transmission • Distribution	• Transmission costs of investment and operation • Distribution costs of investment and operation • Metering • Network company's margin
Energy	• Energy	• Wholesale energy cost • Supplier's margin

The DSO must charge network tariffs to cover the network's capital and operating expenses as part of the energy price structure [10, 11]. Capital expenses are incurred due to equipment purchases required to provide network services. These typically include overhead and underground cables, substations, control centres, information and communications technologies (ICT), metering systems, and other equipment. System service fees, maintenance fees, metering service fees, and other user service fees are all included in operational expenses. It is important to research how to choose a scientifically sound network tariff to achieve cost reflectiveness and economic efficiency without risking rising energy efficiency and demand response.

In the current situation, dynamic network tariff—a concept that envisions quick price changes to accommodate fluctuating network demand and shifting network conditions like grid bottlenecks, congestion, or DSO cost recovery—is a viable option. Dynamic tariffs come in various forms and can be chosen depending on the circumstances and goals of the application scenarios. Table 2 [13] lists the objectives and characteristics of various dynamic tariff categories.

- **Super peak time of use (ToU) scheme**: In this static scheme, there is a specific period during which consumers are subjected to a high price signal to cut back on consumption. A peak era may coexist with this one.
- **Real-Time Pricing (RTP):** Rates fluctuate hourly and are typically correlated with the wholesale energy market.
- **Critical Peak Pricing (CPP)** is the predetermination of higher prices to be applied during peak times, which may be due to an increase in the cost of energy or an increase in the demand for network bandwidth. Critical periods can last up to 8 hours; notification is typically given 1 to 2 days in preparation.
- **Critical Peak Rebates (CPR):** This program resembles the CPP in some ways. However, this system discounts consumers who reduce consumption rather than charging more during peak hours.

Table 2 Goal and attributes of different dynamic tariff types

	TOU	RTP	CPP	CPR
Goal	Change routine behaviour of end users to improve base load (e.g. to increase RES uptake)	Adapt consumption to external variables (e.g. excess RES output, grid overload)	Reduce critical peak demand (e.g. in case of grid overload)	Increase demand when electricity is abundant (e.g. in case of excess RES output)
Rationale	Time of use	Time of use	Time of use	Time of use
Cost driver	Energy	Energy	Energy	Energy
Time blocks per day	Limited (3-6)	Hourly, Quarter-hourly (24, 96)	–	–
Price update frequency	Reflect average energy costs (weekly, monthly, seasonally, ...)	Reflect system costs (daily)	–	–
Type	–	–	Peak price	Rebate

Duration	—	—	Short	Short
Occurrence	—	—	A few times per year	A few times per year
Often combined with	CPP & CPR	—	TOU	TOU

DSOs now have a new tool to manage the electricity grid that considers the changing value of distribution network resources: dynamic network tariffs. Dynamic tariffs enable DSOs to send a stronger price signal after alerting the customer, particularly when used with load forecasting tools. This is especially true for the few peak hours per year. Dynamic price signals are sent to consumers based on real-time data given by smart metering technology, which will aid in developing a more cost-reflective system. The desired outcomes are either decreased peak demand, where lower network upgrade costs will help all parties, or increased revenue which may be directed at network reinforcement. Additionally, dynamic network tariffs can significantly increase the accommodation capacity for IREG and improve the system's security, economics, and predictability [7] by encouraging network use in power systems with a high percentage of intermittent generators. Market participants who learn the date and place of system congestion from the pricing signal can respond rapidly, considering network congestion relief.

In conclusion, the dynamic network tariff mechanism is viewed as a time-varying price signal reflecting network usage in near real-time, motivating customers to act socially responsibly, and playing a significant role in demand-side responses, network congestion management, cost recovery, etc. Given this context, this paper aims to present the current state of study in this field while providing a systematic overview of the real-world applications of dynamic network tariffs in different nations.

2.1 CURRENT PRACTICES IN VARIOUS COUNTRIES

In most nations, network tariffs typically consist of three parts: fixed costs, volumetric (energy-based) tariffs, and capacity (power-based) tariffs. Additionally, some countries also include corrections factors agreed with the regulator to account for forecast error. According to the terms of the contract between the retailer and the customer, the DSO collects fixed fees from customers either monthly or yearly, regardless of the capacity or volume utilised [14, 15]. A volumetric or energy-based tariff is charged according to the quantity of energy utilised in an hour, typically measured in currency/kWh. The contracted grid capacity or the power consumed, which usually depends on meter rating, is the basis for paying a capacity or power-based tariff [16]. The following introduces the current dynamic network tariff practices in different nations.

2.1.1 Portugal

In Portugal, one national DSO runs on HV, MV, and LV, ten DSOs only run on LV for the mainlands, and two additional DSOs are allocated for the archipelagos [6]. The voltage levels correlating to typical households, small businesses, small industrial customers, and large industrial customers are used to categorise tariffs into standard low, special low, medium, and high categories [17]. Network tariffs for all customers include capacity and volume, but for households rather than for big industries, volume is weighted much more heavily [18]. Volume and capacity components are both continuous.

Static ToU tariffs have been used in Portugal for a while, with varying periods designated for various consumer types. There are two-period (peak and off-peak) and three-period ToU for families (peak, off-peak, and super off-peak). With variations between two seasonal periods, industrial customers are charged on at least four periods (peak, half-peak, off-peak, and super-off-peak) or more if asked [18].

To maximise the benefits of demand-side flexibility and encourage effective use of the power network, Portuguese regulators required the three major Portuguese DSOs to plan to implement dynamic network tariff schemes targeting customers of different voltage levels in December 2014. In 2016, the pilot project was started with willing industrial customers, and two tariff schemes, including dynamic ToU and Critical Peak Pricing, were tried [12]. The Portuguese regulatory authorities hope this phased, gradual strategy will prevent negative consequences for specific consumer groups that cannot react to price signals.

2.1.2 Finland

Finnish customers are free to select their preferred network tariff on their own. The primary components of Finnish household electricity network tariffs are fixed and volume fees. The volume fees are typically constant (time-invariant) [19], but they can also be time-based, meaning that various rates apply during the day and at night [20]. Large users, such as industrial and commercial ones, have network tariffs that are more closely linked to the usage time, so their network fees are governed by their patterns of electricity consumption and demand charges [21]. Network tariffs account for about one-third of the overall electricity bill for the average Finnish household, which consumes 18,000 kWh of electricity annually [22].

In Finland, DSOs are free to create their network rates. National regulators are more concerned with monitoring the DSO's overall income than with the pricing of specific distribution grid tariffs, giving DSOs enough latitude to set grid tariffs specific to the needs of various user groups. As a test for dynamic network tariffs, four DSOs in Finland have started providing households with on-demand charging choices. Users can select from the network price list, including demand fees [23]. Geographic discrimination is not permitted, however, as one of the regulatory principles requires that within a DSO's distribution region, the network price be the same for the same kind of customers. Demand-based charges are presently modest, and DSOs that charge households on demand do so gradually. Even though few DSOs have changed their pricing, the industry is interested in implementing "dynamic" distribution network tariffs for consumers [22].

2.1.3 Spain

Spain has a deregulated electricity market with liberalised production and delivery. The management of the reserve market and power balance, as well as the transmission of energy from generators to consumers, are all tasks that fall under the purview of the power system operator Red Eléctrica de Espana, which also operates the high-voltage transmission network [24]. The Precio Voluntario para el Pequeno Consumidor (PVPC) tariff comprises volumetric charges and contracted capacity and is used to settle claims for a limited number of consumers. While contracted capacity, also referred to as the access tariff and, including network costs, generation capacity costs, payments to the regulatory Agency and system operator, among other things, is dependent on hourly energy prices determined by Red Eléctrica de Espana. After the day-ahead electricity exchange has closed, the PVPC is released [6].

When determining how much to charge consumers, the voltage level is considered. Network tariffs for customers connected above 1 kV include seasonal differentiation and a ToU structure with 6 periods; network tariffs for customers connected below 1 kV with contracted power over 15 kW include seasonal differentiation and a ToU structure with 3 periods; and network tariffs do not include seasonal differentiation for customers connected below 1 kV with contracted power under 15 kW.

2.1.4 Sweden

Similar to most countries, in Sweden, the DSO that distributes energy remains a regulated monopoly. Dynamic network tariffs only comprise a tiny portion of all dynamic tariffs, which are widely used [27]. The Swedish Energy Market Inspectorate attempts to create more dynamic network components by designing network prices. To move toward even more cost-reflective tariffs, which promote the effective use of the electricity network, the present strategy aims to enhance price signals derived from network tariffs [28].

A strong proponent of smart meters, which serve as a prerequisite for the adoption of dynamic network tariffs, Sweden has also been another. 91% of meters could remotely capture hourly values as early as May 2010 [27]. Since then, new amendment legislation has been proposed, allowing all energy users to request hourly metering at no additional cost.

2.1.5 Norway

The 131 DSOs in Norway are given great latitude in creating network tariffs, with the national regulator imposing income limits [18]. 94% of the transmission system is owned and operated by Statnett FS, with the remaining 6% by regional grid owners. The consumer's voltage level determines the tariff variety. The volume fee makes up two-thirds of the network price for the average household consumer, with the fixed charge making up the final third. Consumers with yearly usage above 100,000 kWh are subject to cost-reflective tariffs, in which the fixed and capacity components represent the remaining fixed costs. In contrast, the volumetric component covers the marginal cost of power supply [29]. The current electricity price structure is challenged by problems with cost allocation and a lack of incentives to reduce power usage.

A switch to a subscribed capacity model was suggested in 2017 by the Norwegian Energy Regulatory Authority (NVE-RME). Stakeholders contend that it may be difficult to put such a model into reality and that it may be too complex for customers to comprehend. In February 2020, NVE-RME unveiled a fresh plan distinguishing fixed and variable costs [30]. The marginal cost of network loss accounts for about 1/6 of the short-term variability in the cost of the electricity distribution system; the remaining 5/6 of the cost is fixed. The DSO will employ the ToU concept to raise the volumetric charges when it is anticipated that capacity will be constrained to encourage consumption reduction. However, in theory, this expense shouldn't be higher than the long-term marginal cost of network expansion.

2.1.6 Estonia

Elering AS is the monopoly-operated transmission network in Estonia, while Elektrilevi OÜ holds the bulk of the market share (86.2%) for the distribution system [31]. The cost of the entire network is broken down into several parts: the cost of the transmission network (37%), the investment (23%), the running cost (24%), the output (10%), and the loss (6%). The current price range covers exchange, equivalent, and fixed rates. Prices for exchange packages vary hourly depending on a variety of variables. When prices are low, consumers can take advantage of cheap electricity while shifting their consumption when prices are high [32]. The volume charge covers most network expenses for residential users.

2.1.7 Italy

While there are 151 DSOs in Italy, ENEL Distribuzione manages most of the distribution system, and the regulator sets the distribution price structure [18]. Before determining voltage levels, tariff types are first decided by customer types, such as households and businesses. The network tariff bill for the client is broken down into four categories: fixed, volume, capacity, and tax. There is no distinction between residential users' energy transmission and distribution rates, nor are there different rates depending on the area.

The prior tariff structure was an inclining block tariff (IBT) based structure, where 6 distinct blocks and unit costs established limits increased per consumption levels [18]. Now, a non-progressive structure with an extra capacity-based component has occurred. The capacity and fixed fees are the primary sources of funding for the distribution expense, making up about 12% of the total electricity bill. The majority comes from the capacity fee; metering and marketing expenses are calculated from fixed expenses [33, 34].

2.1.8 Australia

To distribute energy, the east Australian continent is divided into seven regions: Victoria, New South Wales, Queensland, South Australia, Australian Capital Territory, Tasmania, and Northern Territory [35]. Consumers are divided into several categories based on their voltage level and energy usage [22].

The National Electricity Rules mandate that distributors transition single rate usage tariffs to reflect various peak and off-peak times to progressively improve how their tariffs reflect service costs [36]. The current reform seeks to make volumetric components lighter by replacing them with fixed and capacity-based components. Another approach is based on a transitional demand tariff consisting of a fixed charge, a constant volumetric component, and a seasonal demand charge. The fixed charge and the ToU volumetric tariff component impact some older customers. Non-residential consumers are liable to IBT-based flat charges and other components, like low-voltage residential consumers. Large or commercial customers use more than 160 MWh and are liable to transitional demand fees [23].

2.1.9 The United States of America

Various practices are used in the USA regarding dynamic ToU prices [12, 18, 37]. The "Energy Select" program, which features static ToU and CPP tariffs, is operated by Gulf Power. Four energy prices (ranging from low to crucial) are included in the CPP plan, and the customer is aware of the application deadline. The critical period, when energy costs are more than ten times higher than during the off-peak period, can be announced by utility hours in advance. These periods usually last one to two hours and correspond to hot summer afternoons or chilly winter mornings.

In Northern California, the dominant energy provider PG&E has unveiled a new IBT design. By peak hours, PG&E provides three ToU tariff plans. Seasonal price variations make eight winter months less costly than four summer months. Households can save even more money by reducing total volume utilisation and moving usage to off-peak times. Additionally, PG&E offers "add-ons" that customers can select to supplement their fundamental programs. With the SmartRate add-on, households can get the lowest price if they cut their energy use by 15% on hot days (called SmartDays; 96°F) for up to 15 days each year. This addition addresses capacity-related capacity peaks in hot conditions. The day before SmartDay, registered families will receive notice, allowing them to make arrangements to use less energy. Families, according to PG&E, can cut their summer bills by up to 20% through the initiative.

A CPR program is administered by Southern California Edison and is called "Save Power Days". The critical times on the following day, which will last no longer than 15 hours throughout the year and less than 4 hours each, are announced to customers via text message or email. According to the program's findings, consumer demand for energy is now lower than average over the previous five days.

Table 3 compares various nations' tax components and distinguishing characteristics. The majority of nations have already begun dynamic network tariff pilot programs.

Table 3. Comparison of tariff components and key features among different countries

Countries	Tariff Components			Key Features
	Fixed	Capacity	Volumetric	
Portugal	√	√	√	Volume has a much higher weight in household tariffs than for large industries. Static ToU tariffs have been used for a long time, and different periods are divided for different consumers. There has been a pilot project to implement dynamic network tariff schemes targeting customers of various voltage levels.
Finland	√		√	Electricity consumers can choose the volume fee options with the attribute of usage time. A few DSOs that charge households on demand are using a gradual approach.
Spain		√	√	PVPC tariff consisting of volumetric charges and contracted capacity is a settlement method for a few consumers. The voltage level is considered when allocating costs to the consumers.
Sweden	√	√	√	Dynamic network tariffs occupy only a small fraction. But the high-coverage installation of smart meters creates the prerequisites for implementing dynamic network tariffs.
Norway	√	√	√	The tariff class is determined by the voltage level the consumer is connected to. For a typical household customer, the volume charge

Countries	Tariff Components			Key Features
	Fixed	Capacity	Volumetric	
				(2/3) and the fixed charge (1/3) make up the network electricity bill. Consumers with annual consumption above 100,000 kWh are associated with cost-reflective tariffs.
Estonia	√	√	√	Three pricing schemes are implemented: fixed, equivalent, and exchange packages. The volume fee covers most of the network costs for most residential users.
Italy	√	√	√	The customer's network tariff bill consists of four parts, fixed, volume, capacity, and tax. A non-progressive structure of tariff that incorporates an additional component based on capacity replaces the IBT structure.
Australia	√	√	√	The reform that aims to change the proportion of network tariff components is being implemented to gradually make their tariffs more accurately reflect the costs of serving their customers.
The United States	√	√	√	Some programs are considered US attempts at dynamic ToU tariffs, such as the "Energy Select" program, a new IBT design of PG&E, and the "Save Power Days" program.

3 Smart Metering and Aspects on the Tariff Structures

3.1 Smart metering

Smart metering can play an essential role in enabling flexibility of the consumption side, e.g. dynamic demand response actions of customers' loads. Smart metering comprises residential smart meters and metering systems for collecting and analysing energy use and other measurements. The regulatory drivers are partly country-specific, and the details of metering functionality may vary in different countries.

The primary role of a smart metering system is to provide hourly energy consumption data for billing purposes. Making use of smart meter data and measures in various business functions may increase the cost-effectiveness of smart meter investments. A smart metering system combined with the related ICT systems and business processes forms a larger entity, creating added value for customers, DSOs, energy retailers and service providers. Smart metering is an essential enabler for improving competition in the electricity market by enhancing greater differentiation between energy retailers. However, smart metering could provide real-time energy consumption data to the utility and offer several ways to improve electricity distribution and retail energy businesses. Smart metering offers a huge amount of data for developing new functions for Smart Grids. The possibilities of using smart metering include, for example, real-time energy information, customer service, demand side management, disconnection and reconnection of electricity supply, determination of load profiles for network calculations, network planning and secondary transformer condition monitoring, more accurate interruption statistics, more sophisticated power quality monitoring facilities, and the management of low voltage (LV) distribution networks. From the LV network management point of view smart metering system can also be seen as an extension of SCADA (Supervisory Control and Data Acquisition) and Distribution Management system (DMS) for controlling and monitoring the last parts of the network (i.e. LV network) between the medium voltage network and LV-connected customers. (Järventausta, 2015)

On a national level, smart metering data makes it possible to achieve balance settlement based on measured values instead of estimated values for all customers. Therefore, the impact of residential demand response will become visible to retailers and balance responsible parties, and the imbalance costs will be shared among market stakeholders more fairly. To implement a smart metering system, the whole meter chain from the customer site to the business systems has to be improved.

More accurate and customer-specific load models can be created using hourly measurements to support load estimation and forecasting (Mutanen, 2018). Household level loads now in Time-of-Use control can also be dynamically controlled by electricity retailers via smart metering systems. Hourly measurements enable new kinds of dynamic tariffs which support energy-efficient targets and the operation of the electricity market (Lummi, 2019).

3.1.1 Smart metering in the EU context

The European Commission considers the smart metering system an excellent tool for transparency and competition in retail markets for electricity: this has been enabled through energy market liberalisation and the single European market regulations (European Commission, 2019). Since first addressed in the 2006/32/EC directive, smart metering issues have been dealt with in many ways. Article 19 of Directive 2019/944, as part of the 'Clean Energy Package', requires that consideration is given to:

- Smart metering deployment decisions need to be taken based on cost-benefit analyses, which should follow the Commission recommendation 2012/148/EU;
- Member States need to publish the minimum technical and functional requirements for smart metering;
- Member States need to make sure smart metering systems are interoperable and capable of delivering output for energy management systems;
- End-users need to contribute to the costs of deploying smart metering systems, taking into consideration the long-term benefits for the entire value chain;
- Should the cost-benefit analysis (CBA) result in a negative assessment, the Member State should repeat the CBA after four years;

- A smart metering system must comply with relevant EU data protection laws

3.2 ASPECTS OF THE DEVELOPMENT OF TARIFF STRUCTURES

The Distribution System Operators (DSO) face the changing operational environment of the future, e.g., increased demand response, distributed generation, electric vehicles and storage at the customer site, which set new challenges to the pricing of electricity distribution. DSOs collect their revenues mainly by fixed basic charges (€/month) and energy-based consumption charges (cent/kWh). Strongly energy-based (with or without time-of-use) distribution tariffs are not necessarily cost reflective, as the costs of DSOs related to energy form only a small proportion of their total costs. However, the network is built and operated to accommodate customers' peak power needs, causing more fixed costs. During recent years, the discussion concerning power-based distribution tariffs has increased. They are seen to include a great potential in activating and enabling the customers in the electricity market and to be fairer and cost-reflective. The tariffs might have various incentives included in the tariff structure, with the objective that the customer is incentivised to reduce the distribution use of system costs.

On the other hand, DSOs should be enablers of the efficient operation of the electricity market by providing an infrastructure, Advanced Metering Infrastructure (AMI) and a platform, through which data collected by smart meters are accessible to the grid users, for a well-functioning electricity market. (Rautiainen 2017) Smart metering with established remotely reading enables the DSOs to collect more detailed information about electricity use than before, e.g. the energy used during an hour or 15 minutes. Among other benefits achieved through smart metering, the DSOs can now develop their pricing, especially for household users, by applying tariffs that are more cost-reflective than previously, encouraging users toward efficient use of electricity from the grid viewpoint. (Repo 2021)

The increase in energy efficiency and customers-grid users' small-scale, behind the meter" electricity production result in decrease of their electricity consumption from the grid, measuring the amount of energy on a monthly or yearly level. These small scale, behind the meter production units, does not match perfect with the real time grid users consumption (working days, PVs produce maximum, the user is away e.g. at his working place), Thus, the billing is in some cases set to a yearly level, to offer best economics for the user, but as avolumetric-kWh consumption charge (in cent/kWh),actually does not cover the grid costs and as net metering, it decreases the DSO+s revenues.. In contrast, the costs of DSOs remain almost the same. Often the regulator (national level Energy Agency, EU level is ACER) sets allowed revenues, which are passed through the tariffs according with an expectation of the demand (and production, if charged for network access). If the DSO's revenue is different from the allowed revenue, the regulator will rectify in the following period. One option is to increase the price level of the volumetric energy charge, but this would lead to problems in terms of customer equality to high cross-subsidies between the customers. Some customers would have to pay very high distribution fees and others much lower, even when their peak loads (e.g. in winter) could remain almost the same. In case of small scale, behind the meter production units and regulated net usage tariffs dynamic oriented pricing would bring more sustainable and cost effective network. The increasing demand response activity brings another change in the operational environment, the use of electricity storage systems, increasing amounts of electric vehicles and other new large electricity loads. High demand response activity, especially if electricity storage systems are used and a high amount of new electric loads like electric vehicles, might lead to increasing peak loads in the distribution networks. Wholesale spot price-based contracts induce the same hourly prices to the customers. This means that all such customers are incentivised to consume energy during cheap hours, which might increase peak loads in the distribution networks and increase reinforcement investment needs. All this means that without reforming the distribution pricing, there is a risk of decreased energy consumption taken from the grid and increased peak loads and investment needs, so the additional costs cannot be targeted to the customers causing the investment needs. Thus, more advanced cost-causation-based network tariff design methods are called for. (Rautiainen 2017) In recent years, researchers, DSOs, regulators, and other stakeholders in many countries have been discussing options to develop distribution network pricing to respond to the upcoming challenges (CEER 2017; Eurelectric 2013; Eurelectric 2016; Energy Networks Association 2014; Electricity Networks Association 2016; Chitkara 2016).

Due to the monopoly positions of DSOs, distribution network business is subject to regulation and the pricing of network services is typically steered by general principles to ensure that the pricing is, e.g., non-discriminatory, fair between different users, cost-reflective, enables the DSOs to recover their costs of operation fully, and intelligible and practical from the user viewpoint (Eurelectric 2013; Honkapuro 2017b). In practical implementation, these principles often conflict with each other. The applied distribution network service charges resulting from a compromise between the realisation of different principles. There is no universal one-size-fits-all solution for pricing electricity distribution services, i.e., grid tariffs. (Repo 2021) Table 1 presents the criteria for assessing network tariffs (Honkapuro 2017a).

The distribution network business is driven mainly by its high capital costs from investments in various network assets (i.e., underground cables, overhead lines, transformers, etc.). In the short term, most of the costs are fixed, but in the long term, costs also depend on the maximum demand of the distribution network. From a smart grid perspective, it is important that the pricing of network services reflect the actual operation costs also in the case of small electricity users. From different proposed pricing schemes, power-based grid tariffs, which account for the maximum demand of the user in different ways, have been actively studied because of their strong potential as alternatives for becoming future tariffs of household users. Demand charges (€/kW) have been applied to commercial and industrial users for decades, but today, their use could be extended to larger household user groups through smart metering. (Repo 2021) The motivation for developing grid tariffs is multiform. For instance, using power-based grid tariffs might enable realising the following benefits (Repo 2021):

- Enhancing the overall cost-reflectivity of the pricing of grid tariffs;
- Offering better chances for the users to actively impact the magnitudes of their distribution fees better than today;
- Providing an essential tool for the DSO to offer a neutral and cost-based platform for other market participants to develop novel services.

Table 4. Criteria for assessment of network tariffs (Honkapuro 2017a)

Criteria	Definition
Additivity	The distribution tariff does not conflict with the electricity suppliers' and other operators' present and foreseeable pricing structure.

Cost-reflectivity	Tariff reflects the distribution system's costs within the spot pricing limits. Tariff ensures the viability of the electricity distribution business.
Feasibility of practical implementation	Practical implementation of the tariff is cost-efficient and realisable with present and foreseeable technology (i.e. metering and ICT systems). In addition, customer communication issues are not a barrier to implementation.
Incentives for efficient use of electricity	Distribution tariffs, electricity supply prices, and taxes give customers incentives for resource-efficient electricity use. Customers have genuine possibilities to affect their distribution bills through their actions.
Intelligibility	The customer understands how the total price of the electricity distribution is formed and how they can affect the total fee.
Neutrality for the third party	Tariff does not constrain the operation and business of third parties (e.g. in the case of the demand response services) whenever such operation follows the technical limits of the distribution system.

In addition to power-based grid tariffs, other development options regarding pricing have also been discussed in the literature, such as volumetric or demand related time-of-use pricing, critical peak pricing, and real-time pricing (Eurelectric 2016). Compared to power-based grid tariffs, different dynamic pricing schemes, which could take place between the DSOs and aggregators in the form of ancillary services, have been discussed as potential tools, e.g., for congestion management (Huang 2019).

4 Determination of the Updating Period of Dynamic Network Tariffs

Dynamic network tariff (DNT) is very well associated with the power flow pattern in the network. It does not necessarily represent the load consumption of any individual customer, but the aggregated consumption of end-users directly demonstrates the variation of power flow in the network. Consumers are free to decide how and when to react to price signals of energy and network tariffs and to adjust consumption during specific time intervals. Consumers' higher responsiveness to price signals can benefit the whole power system and consumers themselves. Demand response has the potential to become one of the most cost-effective flexibility sources in a power system, key to enabling the integration of a high share of renewable energy generation (REG). These resources are normally available near load centres. DNT scheme can shift demand towards the periods when renewable energy generation is abundant and decrease consumption when there are generation constraints.

By reducing peak demand, network-upgrad investments can also be reduced, resulting in lower final tariffs. Also, by providing information about grid conditions through location-based pricing, market participants know the time and location of system congestion and can react quickly based on the prices. By optimising the distributed energy resource (DER) participation in the local grid – incentivising a prosumer to supply a specific demand to decongest a line – or by simply reducing demand in a specific location, the investments in the grid may be reduced.

The time of use (ToU) tariff can substantially reduce the curtailment of REG and improve the system's reliability and predictability. With real-time pricing, even shorter-term variations in renewable energy output can be balanced with demand. Automation processes using smart appliances based on pre-set criteria according to consumers' preferences can increase the responsiveness of consumers to price signals. This can improve the flexibility and reliability of demand response. In the case of dynamic ToU tariffs, automation is key to enabling consumers to react to price changes on short notice and reap such a mechanism's benefits. Consumers can use energy storage systems integrated with smart meters to charge and discharge EVs automatically, depending on price variations. For example, by applying dynamic prices in combination with smart EV charging, EVs could alter their charging patterns to flatten the peak demand, fill the load valleys and support the real-time balancing of the grids.

4.1 Considerations for Dynamic Pricing Design

End users are charged for network usage directly based on the usage of the network or indirectly on the energy price. Like energy pricing, network tariffs can be designed. As discussed below, various considerations must be taken while designing dynamic network pricing.

- *Begin with a limited program*: A limited release of a program is known as a soft launch, essentially a feedback process. It reviews the outcome and pre-validation of assumptions before going for a full-fledged program. It enhances the probability of success of the program. A typical soft launch may be about 10 to 15 per cent of the target program.
- *Define the end-user and align it to maximise the validity*: The end user should be defined as the one that would benefit most from the program design. The validation ensures that the program results can be extrapolated from the target to larger groups.
- *Establish an internal group to suggest the next action:* An internal group should always monitor and analyse the dynamic network pricing options. This group will determine the impact of dynamic network pricing on the end users. The design and evaluation will be more useful if the dynamic network pricing scheme is not combined with any other scheme.
- *Analyse ex-ante and post-facto schemes:* The scheme must be analysed with good examples for ex-ante and comprehensive post-facto data to make the outcome meaningful. Statistical calculations can be used for economical and societal impacts. The length of the evaluation period is also optimally considered.
- *Plan an assessment period for long-term impacts:* Short-term programs may not adequately reflect the long-term impacts. Also, the response may be initially slow due to the learning and acceptability curve.
- *Combine various data sources to improve understanding of impacts:* Provision should be made to collect additional data that may impact energy consumption, the usage profile, the paying capability level, etc.

4.2 Reasons for Low Acceptability of Dynamic Network Tariffs

The end users are not enthusiastic about accepting the dynamic network tariffs in many European countries. There are several reasons for this:

- *General lack of interest in managing electricity consumption:* Most end users view electricity as something they use when needed, not when it will be cheaper. Also, a few appliances can be shifted to other times for use.
- *Poor Incentives Scheme:* The price signals might not be worth convincing the end users. Historically, the prices have not been high or volatile enough for end users to save very much by switching from high-peak to off-peak price hours. Moreover, the average retail consumer's bill comprises fixed, regulated network costs and taxes, limiting the scope to pass on energy savings.
- *Low Saving:* Most participants in a pilot study in Germany expected that by doing their washing and drying in off-peak periods with cheaper energy tariffs, they would make annual savings of 12%-30%. Such savings are unlikely to be achieved. A recent pilot project concluded that the expected savings would not even cover the cost of investing in the smart meters required for many households. If more power is consumed off-peak, the greater the savings, but only certain consumers may have the flexibility to make large shifts in consumption.
- *Limited penetration of smart meters:* For a company to charge a particular price for a particular hour, smart meters must be installed to accurately record the power flow in real time and transmit the information to the suppliers. Unfortunately, the roll-out of smart meters has been significantly delayed in many countries, preventing the full value of dynamic network tariffs from being realised.

Given these limitations, many customers remain on relatively simple, static tariffs. In the Scandinavian countries, even where smart meters have been distributed, the predominant price structure that has emerged is one of the variable tariffs that change monthly and can send price signals that induce seasonal (instead of intraday) consumption shifts. Seasonal fluctuations in electricity generation due to relative water scarcity in winter and high dependency on hydro generation mean a monthly price signal has been sufficient.

4.3 Ways to Speed Up the Adoption of Dynamic Network Tariffs

There are two ways to increase the adoption of dynamic tariffs: one regulatory and one market driven.

- *Regulatory Option:* Where the roll-out of smart meters is sufficiently advanced, regulators can spur the use of dynamic TOU tariffs by requiring suppliers to offer them to all customers. This could be made the default or mandatory option. Customers need to opt out of the tariff rather than opt into it. Many Spanish consumers pay for their electricity according to dynamic TOU tariffs. Ontario became the first jurisdiction in North America to introduce TOU tariffs as the default option in 2012. Within four years, the enrolment rate was 89%. By contrast, according to one estimate, a successful TOU opt-in offering may have attracted only 20% of customers.
- *Market-driven Option*. Household technological development can offer an alternative to the regulatory approach and make dynamic TOU tariffs more attractive to the end-users. An automated management system will help monitor and respond to changes in tariffs. While the high upfront costs of these devices can be a deterrent, some suppliers have already started investigating this possibility.

"Bundling" electricity with other goods and services may also speed the adoption of new technologies. For example, energy suppliers are partnering with technology providers to offer discounts on everything from smart thermostats to control electric heating systems to battery storage and home charging units for electric vehicles**.** Other examples of bundling include combining EV leasing with discounts at EV charging stations in Sweden when signing a TOU tariff contract with the respective supplier.

4.4 Estimation of Block-Wise Dynamic Tariff

Although the deployment of the smart meters for efficient distribution grid operation is being achieved by enabling two-way communication allowing system operators to send tariff signals at defined time intervals, the complexity in shifting system loading due to changes in pricing signal is less advantageous in the real-time dynamic network pricing (RT-DNT), if adopted. The drawback of implementing RT-DNT associated with the end user corresponds to insufficient time intervals for manipulating their consumption. Also, the consumers are grouped based on their total consumption. This will result in more complications as enforcing consumption change by sending tariff signals for each consumer class in such a short duration may not be possible. Although day-ahead pricing is applied based on the predicted load, actual loading patterns are known only during power delivery. It may be effective if the block dynamic tariff is to be planed and announced in advance.

Fig. 1 illustrates a loading profile on a substation. Suppose the utility decided to plan for N blocks of tariff calculation. In that case, the optimal duration and the tariff should be such that it provides the best economic signal to the participants.

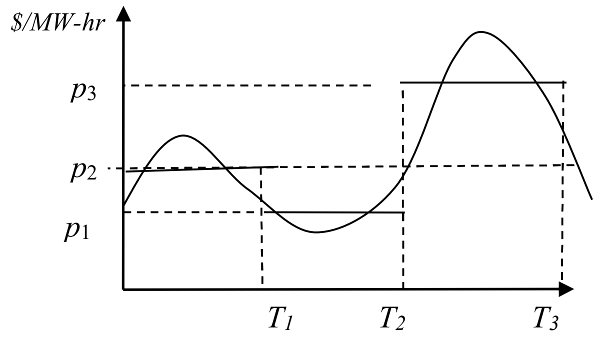


Fig. 1: Non-linear electricity price curve approximated by block-wise cost

Equation (1) shows that the area under the price (obtained from the day-ahead) curve between any segment/block equals the area under the block price curve. The price of block-*k, p_k,* should be such that

$$\int_{T_i}^{T_{i+1}} f(t)\,dt = p_k(T_{i+1} - T_i) \tag{1}$$

If the number of block segments is large, the approximated block tariff will be very close to the real-time tariff. If the block size is one, the tariff is flat (or fixed), i.e., the price remains unaltered irrespective of system loading.

If there are *N* block segments, we can write the total error function as follows

$$J = \sum_{k=1}^{N}\left(\int_{T_i}^{T_{i+1}}(f(t) - p_k)dt\right) \quad (2)$$

Or

$$J = \sum_{k=1}^{N}\left(\sum_{T_i}^{T_{i+1}}(f(t) - p_k)\Delta t\right) \quad (3)$$

The error function *J* can be minimised separately for each segment (24 hours) using conventional or non-conventional optimisation techniques to find the optimal block prices. Due to the complexity of the problem, conventional optimisation techniques may fail due to discontinuities at the due to behaviour of the signal and therefore, we must use some methods that do not require the gradients, such as genetic algorithms (GA), Tabu search (TS), evolutionary programming (EP), simulated annealing (SA), particle swarm optimisation (PSO), etc.

The mismatch between the block area and actual curve at the edges of the block reflects l errors due to sudden change in the price, which does not give the economic signal. It is better to reduce this error while deciding the optimal block size. The difference between the actual price and the block price may be more at the edges of the block prices. Therefore, block size and the number of blocks can be easily decided for the known value of maximum errors in the difference region between block curve and actual signal. For N equal blocks, the error (ε_k^s) At the starting edge of blocks will be:

$$\varepsilon_k^s = \frac{(f(T_i) - p_k)}{p_k} \ \forall\, i \in N \quad (4)$$

where, f(t1) is the tariff at time t1. ε_k^s In (3) is a predefined error value that guarantees the errors at the starting edge blocks remain within the prescribed limit. The error may occur at any edge of the block (starting or ending). To take care of the error at the ending edge of the block, the following constraint, along with (3), is to be enforced.

$$\varepsilon_k^e = \frac{(f(T_i) - p_k)}{f(T_i)} \ \forall\, i \in N \quad (5)$$

This is an optimisation where objective function J subject constraints are mentioned in (3) and (4). Following constrains should also be required to get the optimal solution.

$$T_{i+1} \geq T_i \quad \forall i \in N \quad (6)$$

Since starting block may be part of the end one, the following constraints (6) will be imposed to take care of this.

If $(p_N > p_1)$ then $T_1^B = (T_2 - T_1) + 24 - T_{N+1}$

For other blocks,

$$T_k^B = (T_{k+1} - T_k) \quad k = 2, .. N \quad (7)$$

Therefore, the following constraint must be satisfied.

$$\sum_{k=1}^{N} T_k^B = 24 \quad (8)$$

Equation (2) represents the objective function to be optimised for a given number of blocks for obtaining the tariff for each block and the optimal block sizes to satisfy the constraints. The number of blocks is increased if the optimal solution is not achieved.

5 Regulatory Issues to be Addressed

A main challenge posed by the energy transition is to develop a pricing structure providing the right economic signals to all uses of electricity under a scenario where network use has become more uncertain due to intermittent production or new consumption patterns.

Dynamic network tariffs promote more efficient network use where technological solutions enable demand response. Being dynamic, the price signals can be sent closer to real-time, increasing the cost-reflectiveness of network tariffs, which should result in a more cost-efficient system, benefitting all network users and the energy transition.

Their effectiveness relies on a proper framework in terms of smart-metering, access to data, predictability and the price signals passed on to network users.

The efficient use of these tariffs requires a high level of automation. The corresponding cost-benefit analysis must precede their implementation to account for the monitoring and communication requirements and the cost savings obtained.

However, some important regulatory issues must be addressed regarding the effectiveness of the price signals passed on to network users[1]: the interaction between dynamic network tariffs and retail prices and between dynamic network tariffs and flexibility procurement.

Interaction between dynamic network tariffs and retail prices

When a dynamic network tariff applies, the corresponding dynamic end-user price aggregates three main components: (1) the dynamic network tariff, an energy component, and their corresponding (3) taxes, fees, levies and charges within the electricity bill. The sum of all components would enable the consumer to decide how much to consume for a given price. When the energy price component is also dynamic, it results in a fully dynamic retail price.

Thus, the dynamic network tariff effectiveness relies mainly on the alignment between the network and the energy price signals and non-distorting taxation.

However, the energy and the network components may not always be aligned due to a dynamic energy component measures scarcity in the wholesale market; meanwhile, a dynamic network tariff measures scarcity on the network at a local level. Thus, the resulting change in a customer's consumption in each hour or period may be higher or lower than the network used needed because of the energy price signal.

The evolution of the Spanish spot prices and the hourly demand on the working days of July 2021 helps to show this misalignment between energy and network components for a fully dynamic retail price. It should be considered that, on the one hand, July is one of the months in which there is the greatest demand in the year[2] and solar photovoltaic production. Conversely, wholesale market prices were conditioned by high natural gas and CO_2 prices.

[1] CEER Paper on Electricity Distribution Tariffs Supporting the Energy Transition Distribution (Ref: C19-DS-55-04 - 20 April 2020)
[2] High season for the annual distribution of peak and peak-off network tariff hours

The following graph shows the average hourly demand of the Spanish mainland system and the spot prices for each hour of the day on the working days of July 2021. The graph shows that the highest hourly spot prices did not occur during the highest demand hours. In addition, average high spot prices occurred in several off-peak hours[3].

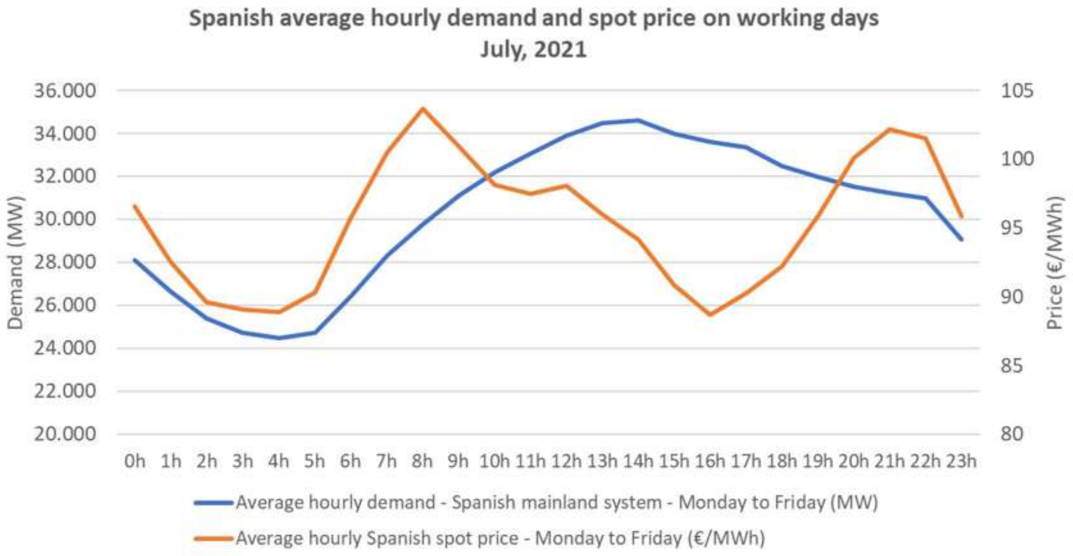


Fig. 2 Spanish average hourly demand and spot price on working daysJuly, 2021

As the following graph shows, the aggregation of the corresponding hourly energy component and the variable component of the time of use network tariffs for each hour for a customer connected in medium voltage results in a misalignment between the hours with higher retail hourly prices and hours with higher demand.

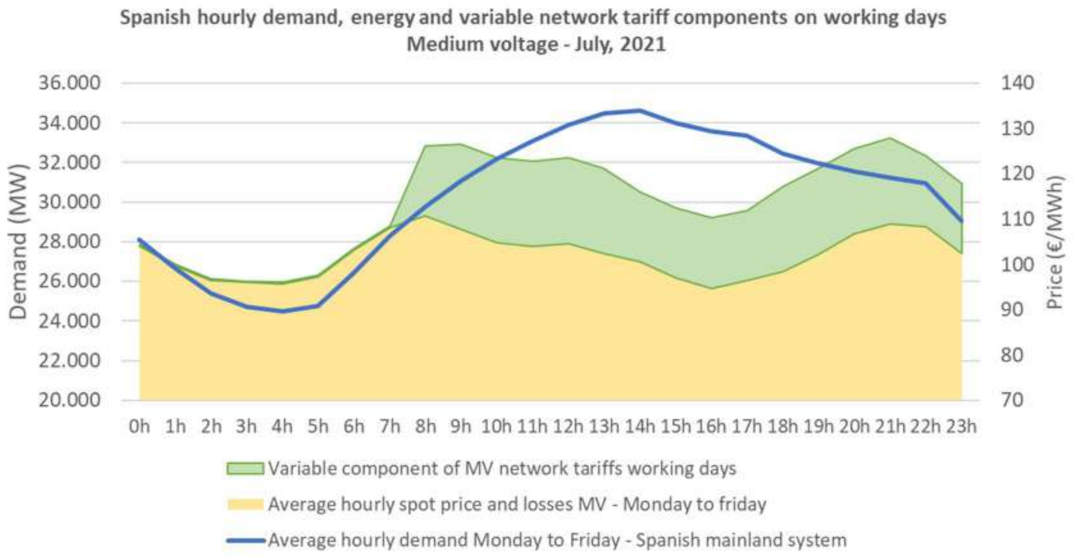


Fig.3 Spanish hourly demand,energy and variable network tariff components on working days Medium voltage July, 2021

[3] From 0h to 8h on working days in the mainland system.

This misalignment could increase strongly in the future with the expected increase of intermittent distributed generation in local areas due to the decrease of the market price in hours of greater solar production and the increase of price volatility.

In addition, unregulated retail prices are usually set by the market. Thus, the retail price structure and its time differentiation (e.g. peak and peak-off periods) may not match the corresponding regulated network tariff structure for all customers.

However, some customers cannot react to demand response incentives, and the existence of different retail products promotes innovation that could contribute to those consumers reacting to demand response. Regulators must balance between the applied design principles in their dynamic tariff approach, such as simplicity, economic efficiency, and equity, deciding, among other aspects, whether dynamic tariffs are voluntary for customers and how costs are distributed between dynamic and static tariff users.

On another hand, the energy and network price signals may be affected by the distorting effect of high taxes and levies. High taxes may amplify or dilute the corresponding final price signal, affecting the customer's decision about how much to consume for a given price at each moment.

For instance, the following graph shows the average hourly retail price for each hour on working days of July 2021 for a Spanish customer connected in medium voltage with an energy component indexed to the spot prices. The weight of system charges to finance public policy costs (as renewable support, tariff deficit annuities, etc.) and non-recoverable taxes in the hourly retail price is higher than the weight of the time of use static network tariffs, affecting the effectiveness of any dynamic network price signal.

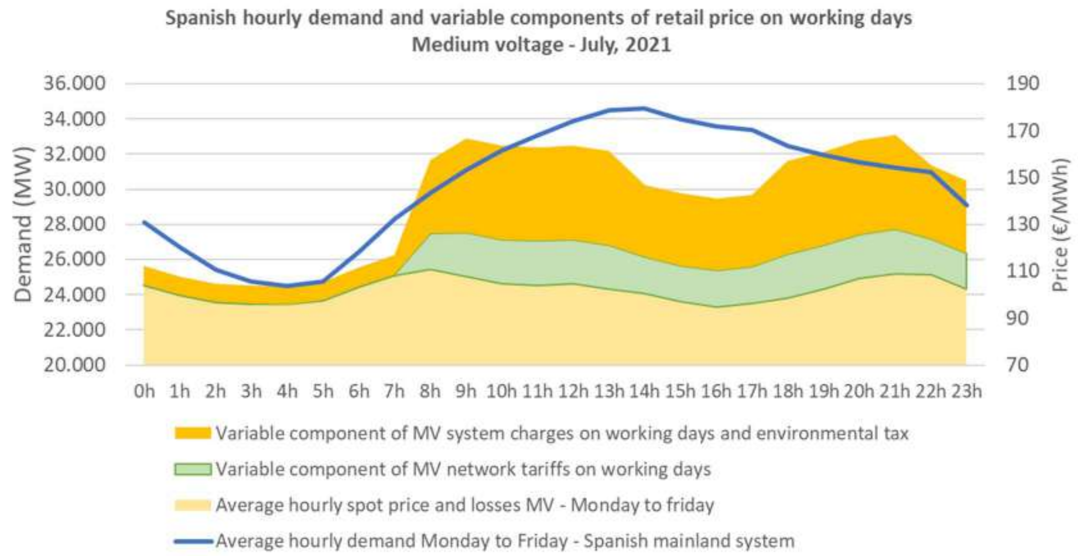


Fig.4 Spanish hourly demand and variable components of retail price on working daysMedium voltage - July 2021

Interaction between dynamic network tariffs and flexibility procurement

The energy transition to higher decentralised and intermittent renewables shares requires increased flexibility. To ensure efficient operation and planning of their network, grid operators need to combine, together with network reinforcement, solutions for local congestion management and other flexibility services, such as voltage control.

Dynamic network tariffs and flexibility procurement are different instruments for changing network use. Although they may be similarly effective in some cases, combining both would not necessarily lead to an increase in realising their shared objectives.

Firstly, a customer's flexibility can be used to respond to dynamic network tariffs and offer flexibility services in a procurement (individually or in aggregation). The interaction between both instruments needs to be considered.

Secondly, the effectiveness of dynamic network tariffs depends on customer flexibility and the interaction between the network tariff signals and other behaviour-influencing factors.

As it depends on the potential for flexible behaviour. For small customers, such as private households and small businesses mostly connected to the low voltage level, it might be questionable whether there are currently available sufficient (technological) possibilities for providing flexibility.

In contrast, the explicit procurement of flexibility through contracts creates more certainty for grid operators and allows customers willing to provide flexibility to be adequately remunerated.

Thirdly, advanced differentiation in time and location is needed to solve local congestion when applying dynamic network tariffs. As the same network prices apply to all customers within the same distribution area, but congestions may be local or limited to several connections, the dynamic price signal could be counterproductive if it is set for an area that is larger than the congested zone, e.g. by incentivising a response from customers where it is not needed. Again, regulators should balance economic efficiency and equity between customers when the corresponding pricing zones are defined.

In addition, there is a risk of incorrect cost allocation due to the complexity of dynamic tariff calculations. Calculating dynamic tariffs can be complex as they must properly reflect a network's congestion. If they fail to do so, this will lead to unjustified charges for the affected network users because they would have to pay different prices for network usage without any potential congestion to justify it.

The complexity of dynamic tariff calculation is also important when discussing the potential effects of dynamic tariffs and flexibility procurement being applied simultaneously. Realising the benefits of dynamic network tariffs is even more complex when explicit flexibility is applied because the interaction between both instruments makes the effects of any behaviour change in response to tariffs harder to predict. Under a system of continuously changing tariffs and network load situations, it won't be easy to allocate and (subsequently) apply explicit flexibility effectively.

But this situation is not just limited to load management to solve congestion. Voltage and reactive power control become more complex with increasing penetration of distributed energy resources. Voltage is a locational issue, but it also has to be managed by grid operators to not contribute to voltage instability in the neighbouring and the upper distribution and transmission grids. In addition, the characteristics of flexibility needs may be different for distribution and transmission operators. Demand-responsive customers can play an essential role in voltage stability, which must align between the reactive power signal prices of network tariffs applied to active customers and flexibility procurement.

Again, the complexity of dynamic tariff calculation and the locational nature of voltage control are important factors when discussing the potential effects of dynamic tariffs and voltage control procurement being performed simultaneously by active customers.

Combining higher explicit procurement with static tariffs may be simpler for grid operators and consumers than for lower explicit procurement with dynamic tariffs. The trade-off between these two options should be further analysed, testing the ability of dynamic tariffs to promote a more efficient system through pilot projects, regulatory sandboxes or pilot regulations.

6 RESEARCH WORK BY MEMBERS OF THIS CIRED WORKGROUP

6.1 PILOT EVALUATION OF A LOCAL PEER-TO-PEER MARKET WITH DYNAMIC NETWORK TARIFFS – THE INTERRFACE HORIZON 2020 PROJECT DEMONSTRATIONS

6.1.1 Background

In the framework of the H2020 INTERRFACE project, a local market platform is being developed and demonstrated that includes a dynamic tariff concept. The trading and settlement rules are designed primarily for low and medium voltage (LV and MV) networks; they build upon the radial structure of the topology [3]. The project uses peer-to-peer (P2P) local market concept to provide new opportunities for electricity market participation and thus engage consumers into the INTERRFACE proposed market structures that are designed to exploit Distributed Energy Resources (DERs) and empowers customers to become active market participants [1]. Beside the local trading opportunity, the project develops a dynamic network usage tariff (DNUT) to give reflective indication of the grid effects of the flows. The DNUT helps to raise awareness on the limitation of the network infrastructure and incentivizes customers to reduce losses and relieve overloaded elements.
The project published the underlying network modelling concept and validation [2], the principles of the DNUT [3], the P2P market operation and conceptual framework [4]as well as the initial results from demonstrations in separate publications [5]. This chapter summarizes the key parts of those references to introduce a novel approach for dynamic network tariffs.

6.1.2 The dynamic network usage tariff concept

The concept of dynamic tariff based on forecasting the constraints by network calculation is not widely implemented in practice [5]. In the INTERRFACE project complementary (in parallel with the conventional retail option for customers) trading platform is targeted to facilitate P2P energy transactions between small users and to use DNUT to motivate market players to carry out network-advantageous transactions [3]. End-user retail tariff consists of energy price and network usage tariff [3]. Tax and additional elements also occur in practice, but this does not change the developed concept in general, therefore neglected through the demonstrations. The total transactional price on the local market is quite similar. It consists of the energy price determined by the bidders (supply and demand match) and the DNUT calculated by the platform. The local DNUT is presumably lower than the general network tariff, since the local transactions do not use high voltage networks (nor the MV grid in the case of an LV market). Therefore, DNUT is a measurable incentive for local users to trade locally. This could lead to local balancing capabilities and avoided cost in the system level network infrastructure [3].
The DNUT is used to introduce the physical constraints posed by the distribution system to the trading platform. When a transaction between participants is considered, the DNUT is also added to (or subtracted from) the

energy price, thus representing the effects of the transaction on the grid infrastructure. This serves as an incentive to hit orders that are advantageous from the grid perspective or hinder other orders that would move the network towards a congested state [4].
DNUT calculation is an innovative method, which relies on load-flow approximations, as follows. A base-case for load and generation is forecasted for every 15-minute interval. It models under the assumption that users have a default consumption and production, independently from the local market prices, even in the absence of a local market. Secondly, using the base-case flows, voltage, current, and loss sensitivity factors are calculated by load-flow simulations. The effect of trades on the system state (nodal voltages, branch currents, total loss) are estimated using these sensitivity factors [5].
These values are used to calculate the DNUT through weighting and fulfilling (one or more) predefined criteria according to the schedule of the demo [5]:

1. Nodal voltages should be in a tolerance range.
2. Network loss should be minimized.
3. Branch currents are limited by thermal constraints.

The reason to avoid load-flow for network condition calculations is because it is computationally intensive. Thus, it would be time-consuming for continuous market operation, especially when considering numerous orders and more than a hundred prosumers, as for each submitted order, one load flow would calculate the DNUT for only one node. Moreover, DNUTs must be recalculated after each trade concluded. The presented DNUT method can consider the following aspects (directly or indirectly) [5]:

1. network loss,
2. nodal voltage,
3. asymmetry level (through voltages and loss),
4. congestion of network elements (branch currents),
5. distance of partners (through voltages and loss),
6. time of network use (present in the market through volume and price of orders, but additional DNUT element can be designed based on the system operator's need).

As a consequence of dynamic network tariff, the settlement price on each connection point might differ. However, this does not mean that nodal pricing is used, since prices are not strictly connected to the nodes, rather to the transaction and the two partners in the transaction. There are different options regarding the payment of the DNUT [5]:

1. The buyer (that hits the order) is charged the full amount of network tariff.
2. The trade partners share the costs 50-50%.
3. The market participant placing the order is charged a fixed price as DNUT. The full cost is evaluated at order hitting, and the remainder is paid by the aggressor [5].

The designed DNUT is composed of three main components: current charges, voltage charges, and loss charges. A detailed description of each component is given in the following subsections. Every transaction induces flows on the local network, which can be categorized either as burdening flows, meaning that the flows cause even greater load on lines, or relieving flows, in which case the flows reduce pressure on the grid. The dynamic network usage tariff (DNUT – €/MWh), is a tool of incentivization in the local market, which is either added to or subtracted from the energy price of a given order. On the one hand, the tariff can be consistently lower than standard network charges, because the transmission network is not used, thus increasing the number of local market participants. On the other hand, it serves congestion management purposes and ensures adequate voltage values through incentivizing such transactions (or submission of orders) that are advantageous from the perspective of the grid operator. This tariff consists of three main elements that allocate charges to the deviation in nodal voltages, branch flows, and overall network loss. For every pair of participants, and both flow directions, a DNUT value is calculated with the usage of a representative measure of energy transaction (i.e. fixed transaction volume), thus creating a DNUT matrix by the size of the number of prosumers. Trading between identical nodes (two prosumers on the same network node) has minimal effects on the grid, which are neglected. Therefore, the diagonal of the aforementioned DNUT matrix is set to zero. The calculations of the other elements in the matrix use the charges mentioned above and the estimated state of the system as a result of the fixed transaction. The charges consist of limiting and linear components. Nodal voltages are constrained to be in the nominal ±10% interval in order to ensure sufficient quality of service, while branch currents are constrained in order not to surpass the rated currents of the given lines of the grid (rated current can be determined by the IACMS module). The linear components account for the physical effects of energy transactions. A cost is calculated for every node based on how much the voltage amplitude is changed, and for every line based on how much the amplitude of the phase current is changed. Costs are also assigned to the deviation in network losses (estimated by line losses using calculations from line resistances and currents). The resulting DNUT can either be positive or negative, based on how the network is affected by the transacted energy. In the case of accepted transactions, both participants (seller and buyer) pay 50% of the calculated DNUT[2].

6.1.3 Example of the DNUT and P2P market framework

Let us assume a base network state for a given delivery period. It consists of the planned topology of the network and the forecasted energy flows between the local participants and the main grid. These mean base-case flows and are denoted with blue arrows in 5 Figure. Photovoltaic (PV) generation and household (HH) consumption. Each bid contains information about the energy price: how much the supplier would like to receive, or how much the demanding household would like to pay for the energy. The clearing price is then modified by the DNUT. DNUT depends on who is hitting the bid. 6. Figure shows a case where PV#1 sells half of the generated power to HH#1. The transaction is not simply added to the base-case flows. In fact, the base case is decomposed to the assumed transaction (denoted with green), and the remaining flow (still denoted with blue), as in Fig. 6. The loss cost of the assumed transaction is calculated from the difference of the two cases: the total loss cost of the base case (blue, Fig. 5), and the total loss cost when the transaction is subtracted from the base case (blue, Fig. 6) [3].

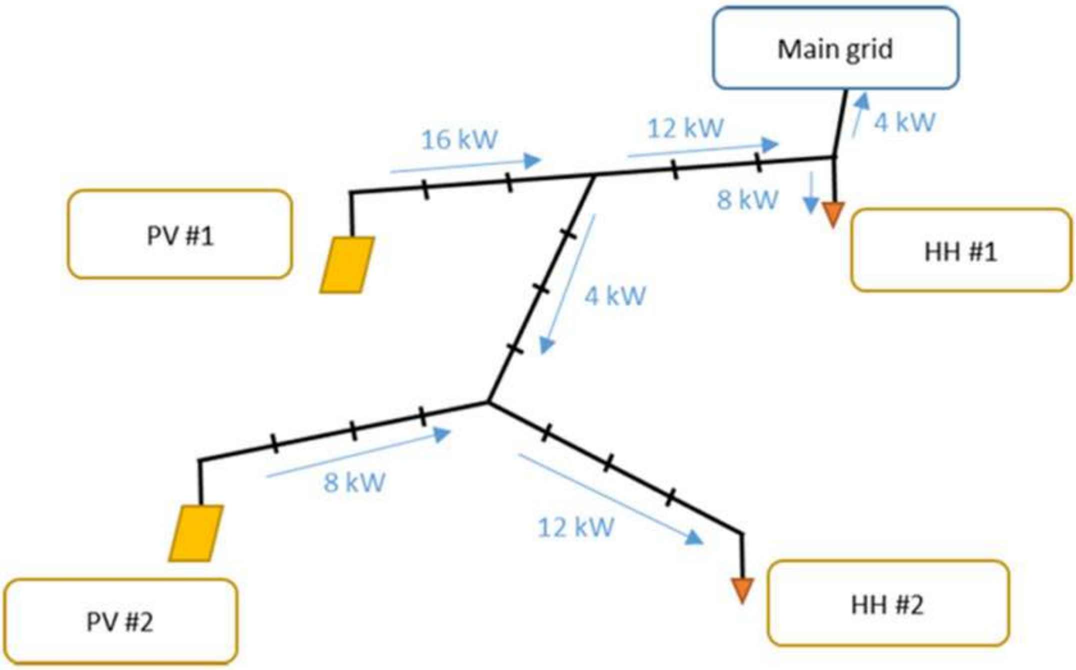
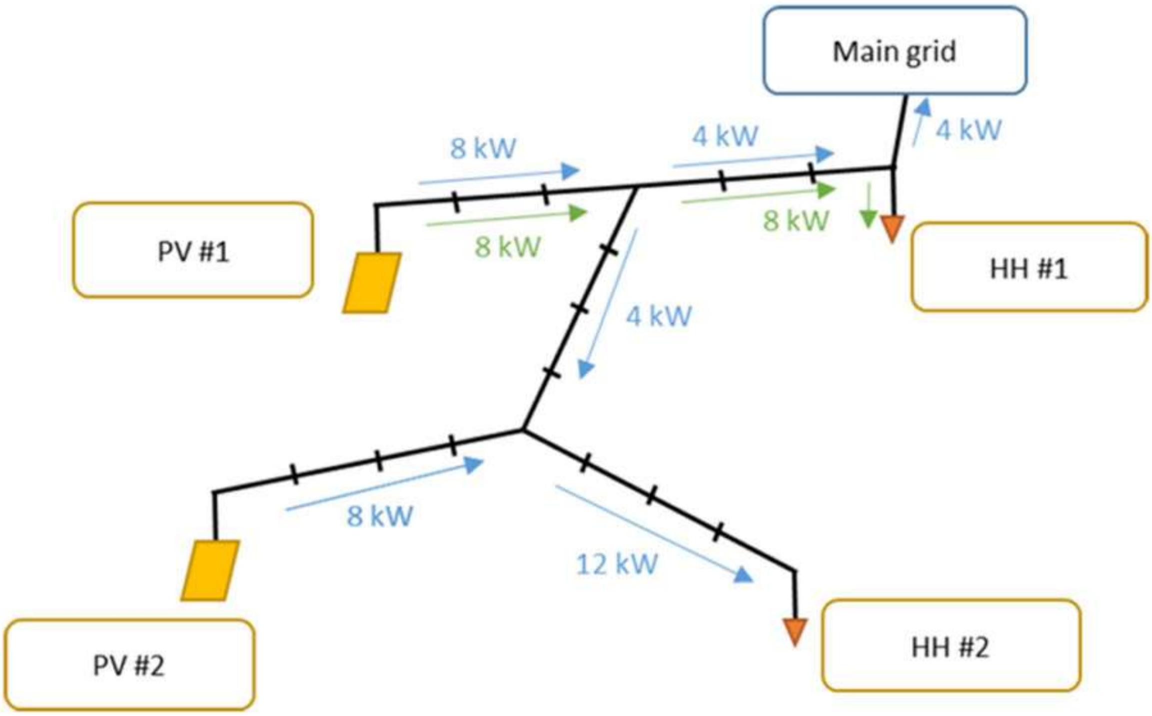


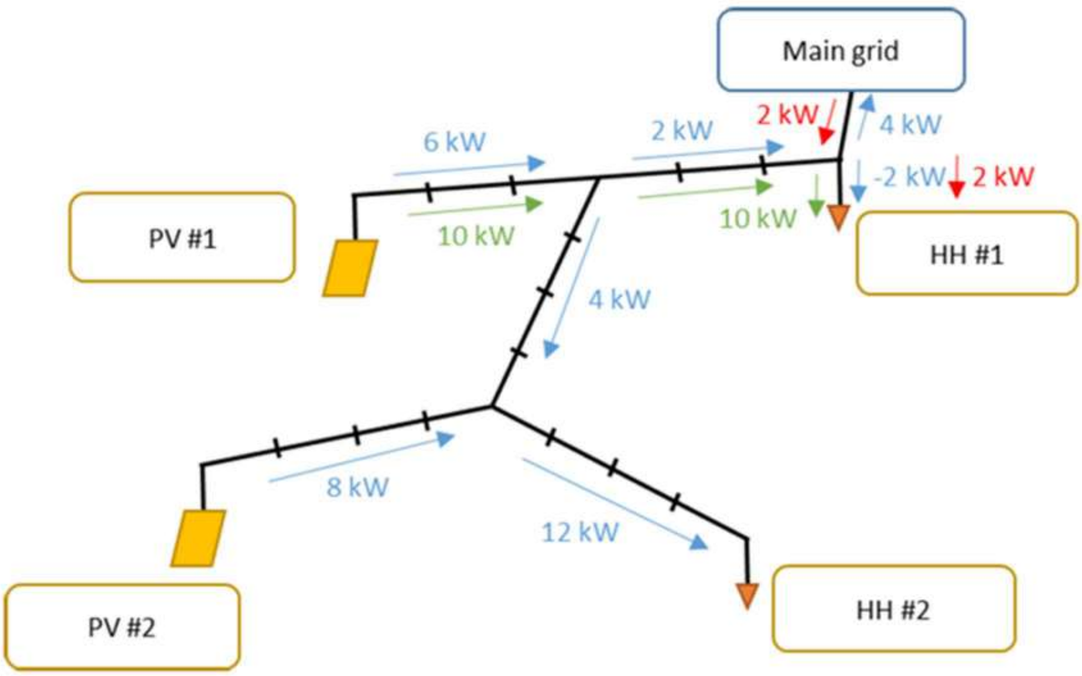
Figure 5 : example of a base case flow [3]



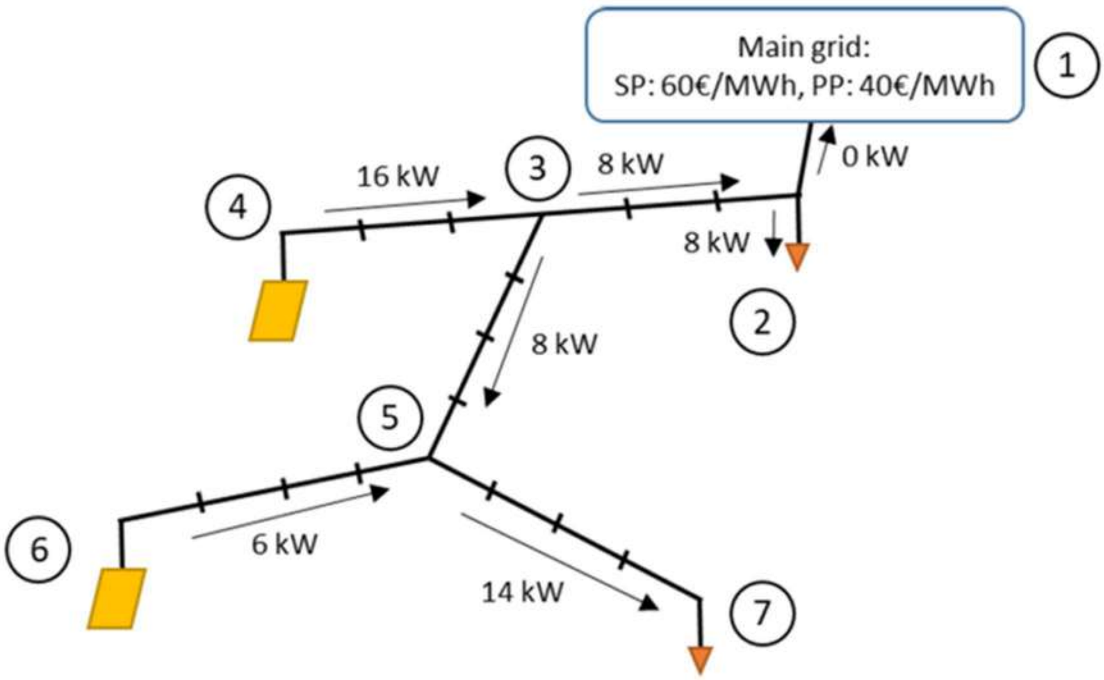
6. Figure: DNUT calculation if a 8 kW sale order of PV#1 was hit by HH#1 [3]

A local-market energy transaction may exceed the base-case flows, hence resulting in an overflow (denoted with light blue in Fig. 7). The overflow is always modelled between the main grid and the market participant whose forecast was wrong. Base-case flows are modified properly if such a transaction is executed. After the modification, the procedure of DNUT calculation is the same as in the first case. The main grid has a different sale price (SP) and purchase price (PP) as marked in Fig. 8. In this example, the aggressor pays the whole amount of network tariff. Although it might look unfair, this way both partners pay and get the price that is shown on the platform [3].

However, HH#1 is forecasted only to consume 8 kW; therefore, base-case flows have to be extended with 2 kW from the main grid to HH#1. Then DNUT is calculated from the difference between the network cost with blue, green, red and network cost in case of only blue and green flows. After delivery, the real flows can be determined from the meter data (black in Fig. 8). Furthermore, these can be used when forecasting the base-case flows for the next day [3].



7. Figure: 10 kW sale order of PV#1 was hit by HH#1 [3]



8. Figure: Metered physical flows [3]

6.1.4 Demonstration sites

There are 4 distinct areas in 3 DSO areas where INTERRFACE evaluates the operation of the P2P market with the DNUT. 2 Hungarian DSOs – namely MVM and E.ON – have 1 site each and the Slovenian Elektro Ljubljana (ELJ) have 2 demonstration areas. The aim of the pilot sites is to test a P2P market concept in different countries with distinct regulatory specifications and differences in the technical state of the art for existing solutions. Furthermore, the localization in different DSO areas will ensure the applicability in different DSO systems.

General aspects have been taken into account in the site selection of all DSOs; one of them is to find a site where any typical distribution system issues caused by the increasing distributed PV penetration can be handled. Further aspects were the better data provision (preferably time series remotely read metering) as well as flexibility potential (potentially controllable assets such as boilers, batteries or EVs) [1].
Voltage levels differ at the three demonstration sites: the MVM site includes only LV area focusing on households, while the E.ON site consists of a MV line and one of its LV transformer district in detail thus more concentrating on industrial and commercial users and MV connected power plants while the ELJ site is again a village area with households but some sensors (IMOTOL and LISA) are only applied there to enhance congestion management[1].

6.2 ASSET ENABLED LOCAL MARKETS (T6.1) – SUMMARY OF DEMONSTRATIONS

During the demonstration of asset-enabled local markets, along with the necessary market design and algorithm development, a framework, an IT platform solution was developed, which provides an environment for important development tasks such as functional testing, sensitivity and use case analysis. The demonstrations were carried out on 4 sites from 3 DSOs:
Elektro Ljubjana (ELJ) – Gradisce and Besnica;
MVM DÉMÁSZ (NKM/MVM) – Zsombó;
E.ON Dél-dunántúli Áramhálózati Zrt. – Bóly.
The 3 partners had quite different data inputs for the demonstration. The project developed a common modelling method and interfaced the different datasets from the DSOs. Then the data sources were interfaced in the framework. The integration with the IEGSA platform provides possibilities to extension of this solution. This section summarizes the key developments, results and offers a discussion on the applicability as well. Section 2.1. overviews the elements of the architecture, Section 2.2. shows the validation procedure for the grid models, then Section 2.3 evaluation and results and 2.4 covers results from the demonstrations in Slovenia and Hungary.

A local market platform from was introduced, on which peer-to-peer transactions can be executed. The platform is basically a marketplace, where both supply and demand orders can be placed and hit by prosumers of the network. The bidding/hitting mechanism can be manual or automatic, depending on the preferences of a prosumer. The traditional retail market can operate in parallel with this platform, thus allowing voluntary participation . However, trading on the local market obliges the participants to consume or produce the transacted energy.
The operation of the local market is similar to the intraday wholesale electricity market: energy (min. 1 Wh) can be traded in a continuous manner for 15-minute periods of a day, starting from the previous day until gate closure, which precedes physical delivery by 1 hour. The settlement is carried out after energy delivery, taking market data and measurements into consideration.

6.2.1 Demonstration framework

The framework was created in a way to a fully operating structure where the infrastructure is modeled properly, participants can make bids, and the effects of the transactions can be included in the dynamic network usage tariff calculation.

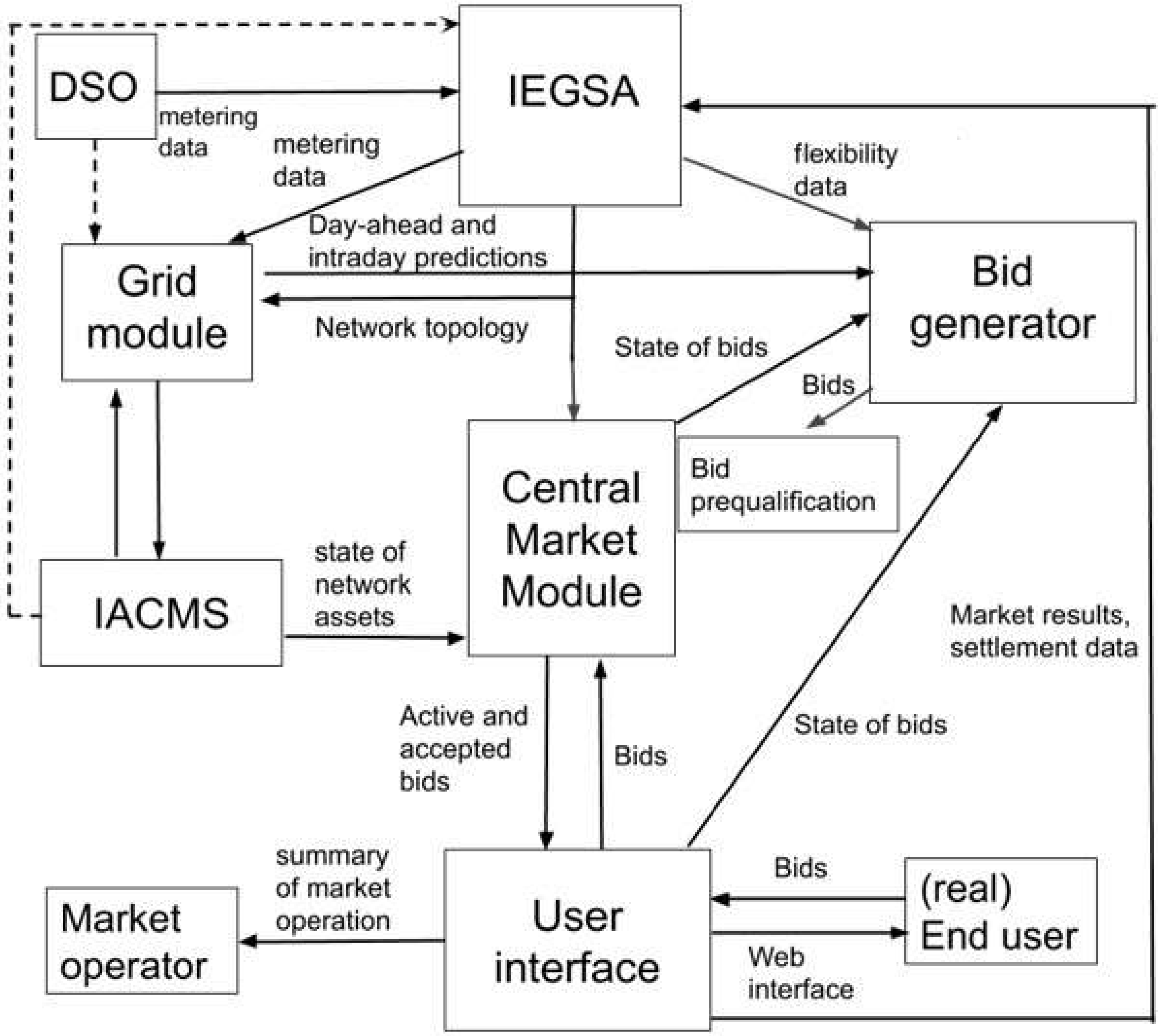


Figure 9:

Modular architecture of the implementation

The modular structure of the proposed local market scheme is summarized, where the modules of the system and the information flow is depicted. The grid module, the market module, and the bid generator are discussed in detail in the following subsection. The Interoperable pan-European Grid Services Architecture (IEGSA) is a common platform developed in INTERRFACE project. In the specific use case for asset-enabled local market IEGSA stores the grid data, and the metering data necessary for base-case power flow calculations and receives the market results from the Central Market Module. It serves the purpose of interoperability as well, therefore it also shares data to the market module and receives data of the user activity as well. Active users may submit their bids through the User Interface of the system, while for passive participants, the bid generator simulates the bidding behaviour. The Integrated Asset Condition Management System (IACMS), which continuously monitors the system components (e.g. lines and transformers) in order to provide up-to-date loadability data for the market transactions (the operational details of IEGSA, IACMS and the process of bidding are not the subject of this study, but presented in Deliverable 6.1 - "Technical requirements and setting of microgrid local electricity markets demo – IACMS technical specification" and in D3.3 "INTERRFACE System Reference Architecture"). The dashed lines in Figure 2 (between the DSO – grid module and IACMS – IEGSA) represent a one-time data share (initialization of attributes) between the functional elements.

6.2.2 Principles of dynamic network usage tariff (DNUT)

Every transaction induces flows on the local network, which can be categorized either as burdening flows, meaning that the flows cause even greater load on lines, or relieving flows, in which case the flows reduce pressure on the grid.

The dynamic network usage tariff (DNUT – €/MWh), is a tool of incentivization in the local market, which is either added to or subtracted from the total energy clearing price of a given order, observed by the corresponding bidder. On the one hand, the tariff can be consistently lower than standard network charges, because the transmission network is not used, thus increasing the number of local market participants. On the other hand, it serves congestion management purposes and ensures adequate voltage values through incentivizing such transactions (or submission of orders) that are advantageous from the perspective of the grid operator.

This tariff consists of three main elements:

- deviation in nodal voltages;
- branch flows;
- and overall network loss.

For every pair of participants, and both flow directions, a DNUT value is calculated with the usage of a representative measure of energy transaction (i.e. fixed transaction volume), thus creating a DNUT matrix by the size of the number of prosumers. Trading between identical nodes (two prosumers on the same network node) has minimal effects on the grid, which are neglected. Therefore, the diagonal of the aforementioned DNUT matrix is set to zero. The calculations of the other elements in the matrix use the charges mentioned above and the estimated state of the system as a result of the fixed transaction. The charges consist of limiting and linear components. Nodal voltages are constrained to be in the nominal ±10% interval in order to ensure sufficient quality of service, while branch currents are constrained in order not to surpass the rated currents of the given lines of the grid (rated current has been determined by the IACMS module).

The linear components account for the physical effects of energy transactions. A cost is calculated for every node based on how much the voltage amplitude is changed, and for every line based on how much the amplitude of the phase current is changed. Costs are also assigned to the deviation in network losses (estimated by line losses using calculations from line resistances and currents).

The resulting DNUT can either be positive or negative, based on how the network is affected by the transacted energy. In the case of accepted transactions, both participants (seller and buyer) pay 50% of the calculated DNUT.

6.2.3 Definition of flow types

In the framework, there are three ways to handle the power flow resulting from a transaction, which are described based on Fig. 3. The applied methods should be selected depending on the activity of prosumers.

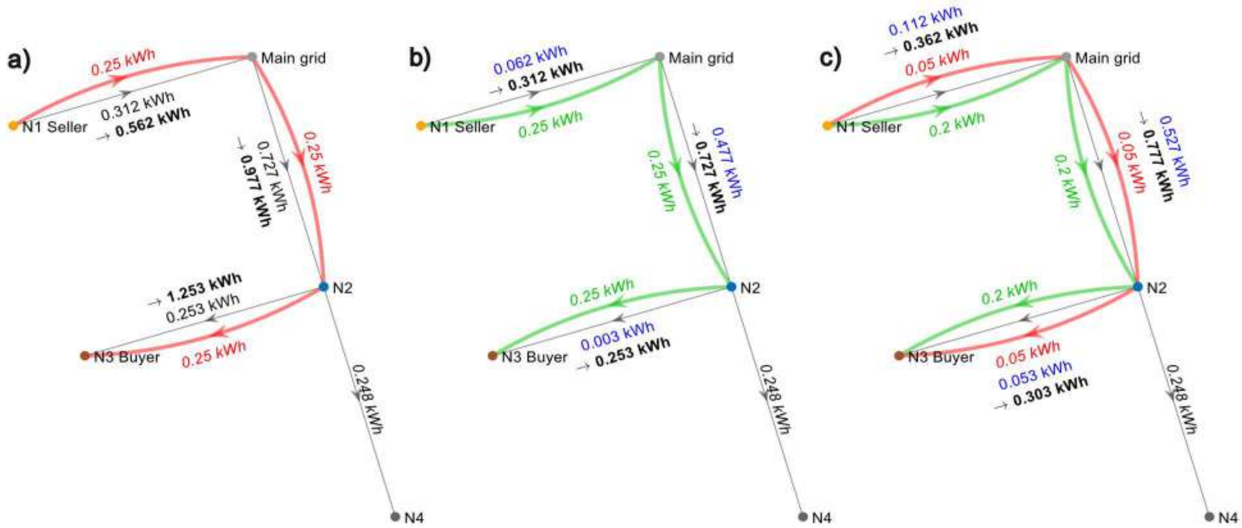


Figure 10: Excessive (red), nominated (green), unnominated (blue), and resulting physical (bold) flows in the model

In Fig. 10 a) the transaction is treated as an excessive flow (in red), which is added to the forecasted base case. This approach assumes active consumers who react to price signals on the platform (e.g. cheap energy generates more demand) resulting in a new energy flow. Each trade creates a new system state, which will be the reference for further transactions. The DNUT matrix must be recalculated accordingly. The state-of-the-art local market models use this approach to estimate the physical effects of transactions. This is referenced as zero base case (ZBC) market throughout this document.

The method in Fig. 10 b) considers the transaction flow to be a part of the estimated base case, thus creating a nominated (green), and a remaining, unnominated (blue) flow. In this case, it is assumed that the market participants trade only their forecasted energy consumption/generation on the market platform to gain surplus. Each trade leaves the system state unchanged, and the initial DNUT matrix should not be updated. However, if a transaction exceeds the estimated base case, excessive flows are introduced similarly to Fig. 10 a).

A combination of these two options is applied in Fig. 10 c), which is assumed to consider prosumer behaviour more precisely. The ratio of nominated and excessive flows can be altered through a defined overflow ratio. In this example, the value of this ratio is 0.2, which means that 80% of the transaction is nominated from the base case, while the remaining part is added to the network flows.

6.2.4 Market framework validation in simulations

In this section, the operation of the local market is briefly presented and validated through market simulations for one specific quarter hour (QH). The aim of these simulations is to show the attributes of the local market framework. The ZBC market approach is used as a benchmark to our method.

Before the implementation for the national demonstration sites, the local market concept was tested on the IEEE European LV test feeder, which also contains the neutral line. 55 loads are present in the system, each of them connecting to one of the three phases, which introduces asymmetry in the simulations. An earthing resistance of 30 Ω is considered at prosumers. The network topology and consumption/production data are shown in Figures. 11 and 12.

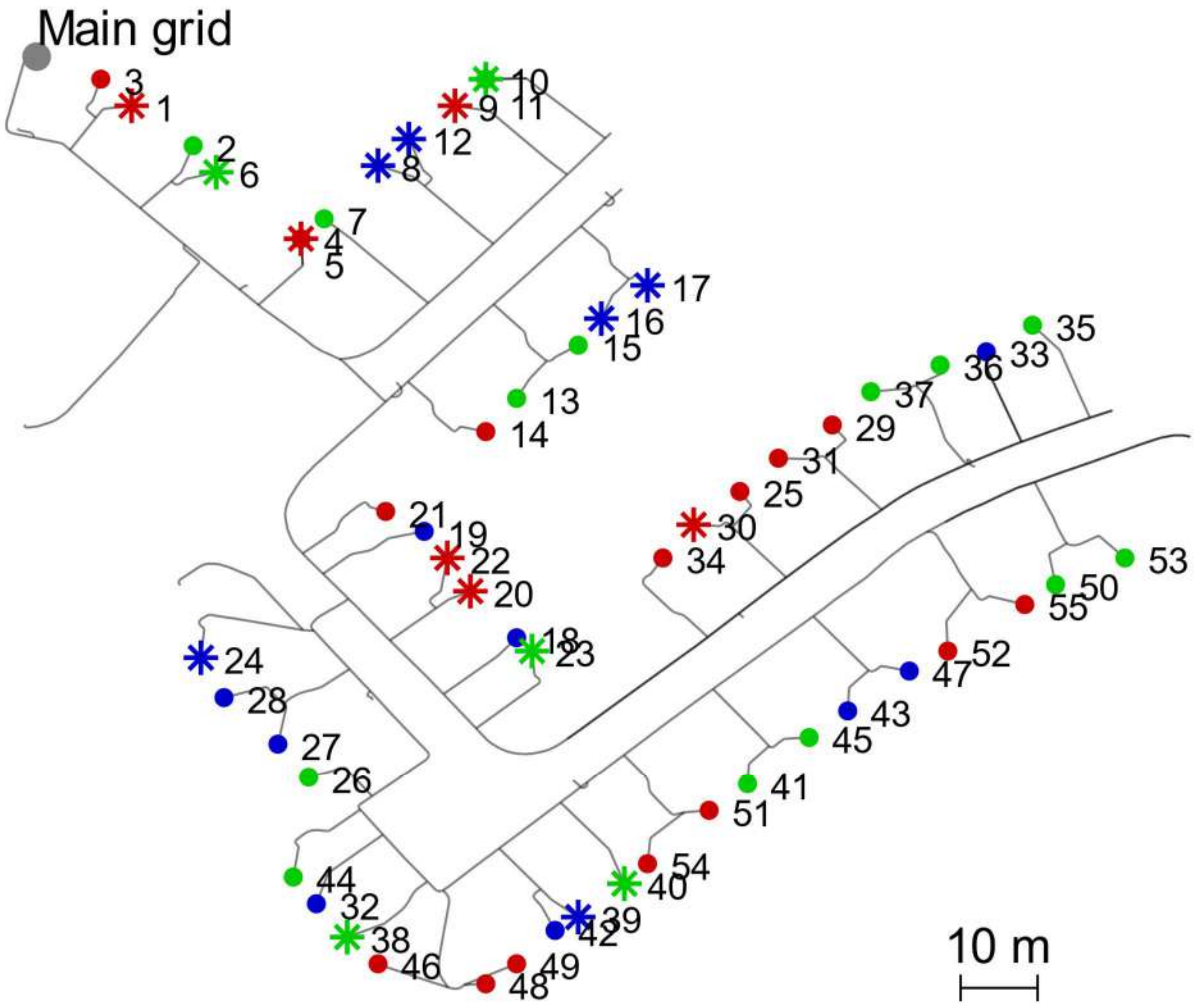


Figure 11: Network model with single-phase prosumers (red – phase a, green – phase b, blue – phase c, producers are marked by asterisks)

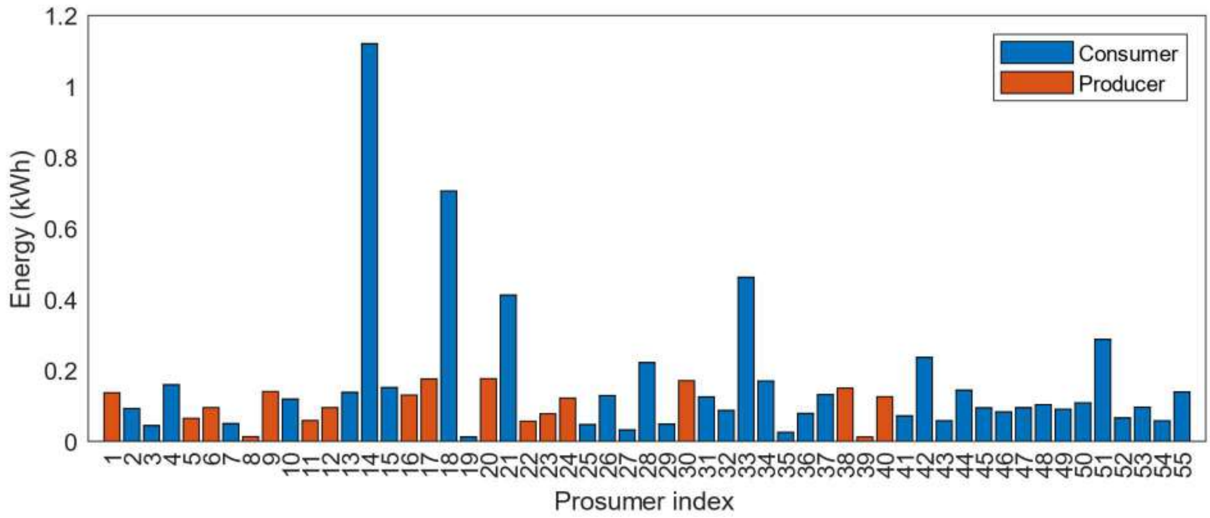


Figure 12: Base case produced (red) and consumed (blue) energy by prosumers in the given QH

The effect of growing prosumer participation ratio (PPR – the ratio of prosumers trading on the local market to all prosumers in the network) is evaluated through a Monte Carlo simulation for both the ZBC approach and the local market framework. A single market simulation is carried out 100 times, using a different set of orders. The participating prosumers submit exactly one order in each iteration. The change of the surplus relative to the number of participating prosumers over the course of the simulation is depicted in Fig. 13.

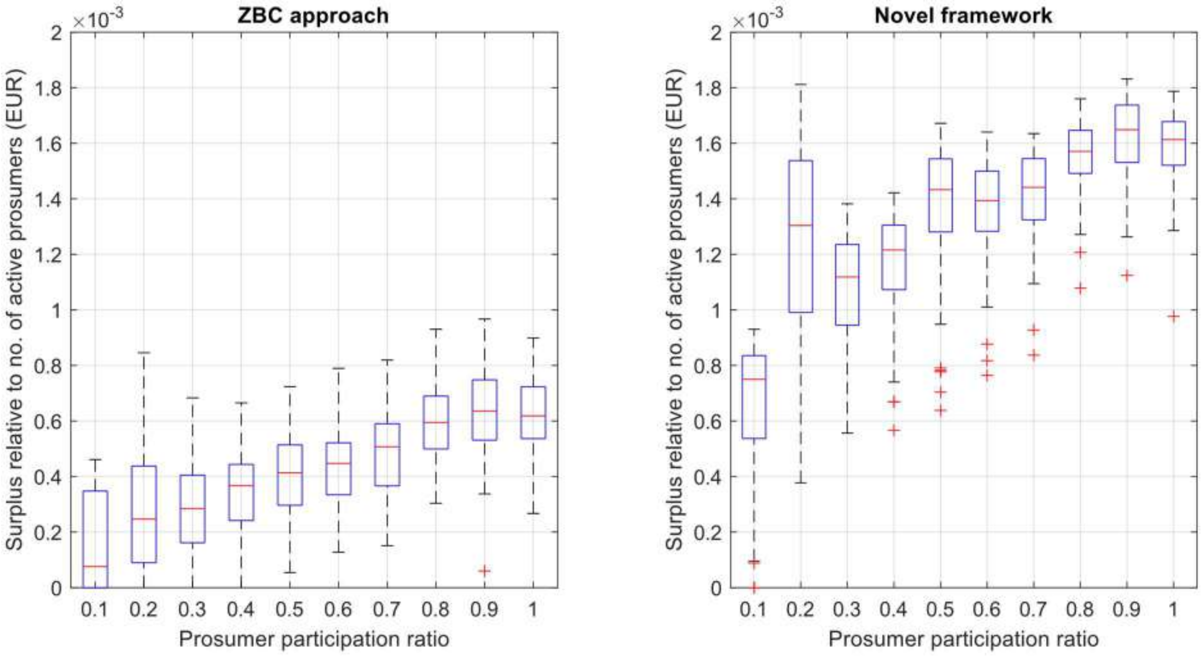


Figure 13: The change of surplus in the system as a result of increasing PPR in Monte Carlo simulation

In general, the surplus increases with growing participation ratio, which translates into increasing relative surplus curves in both cases. The rate at which the relative surplus is growing is not constant due to several factors that are altered randomly during the simulations. This rate is influenced by the ever-changing ratio of active producers to active consumers, and the order in which trade orders are submitted and thus matched.

Because of the good (estimated) state of the network (considering all prosumers), on average a 2.6 times higher relative social welfare value can be reached through considering the base case energy injections compared to the ZBC approach. This is also shown in Fig. 14, where the average of the sum traded volumes on the markets are depicted.

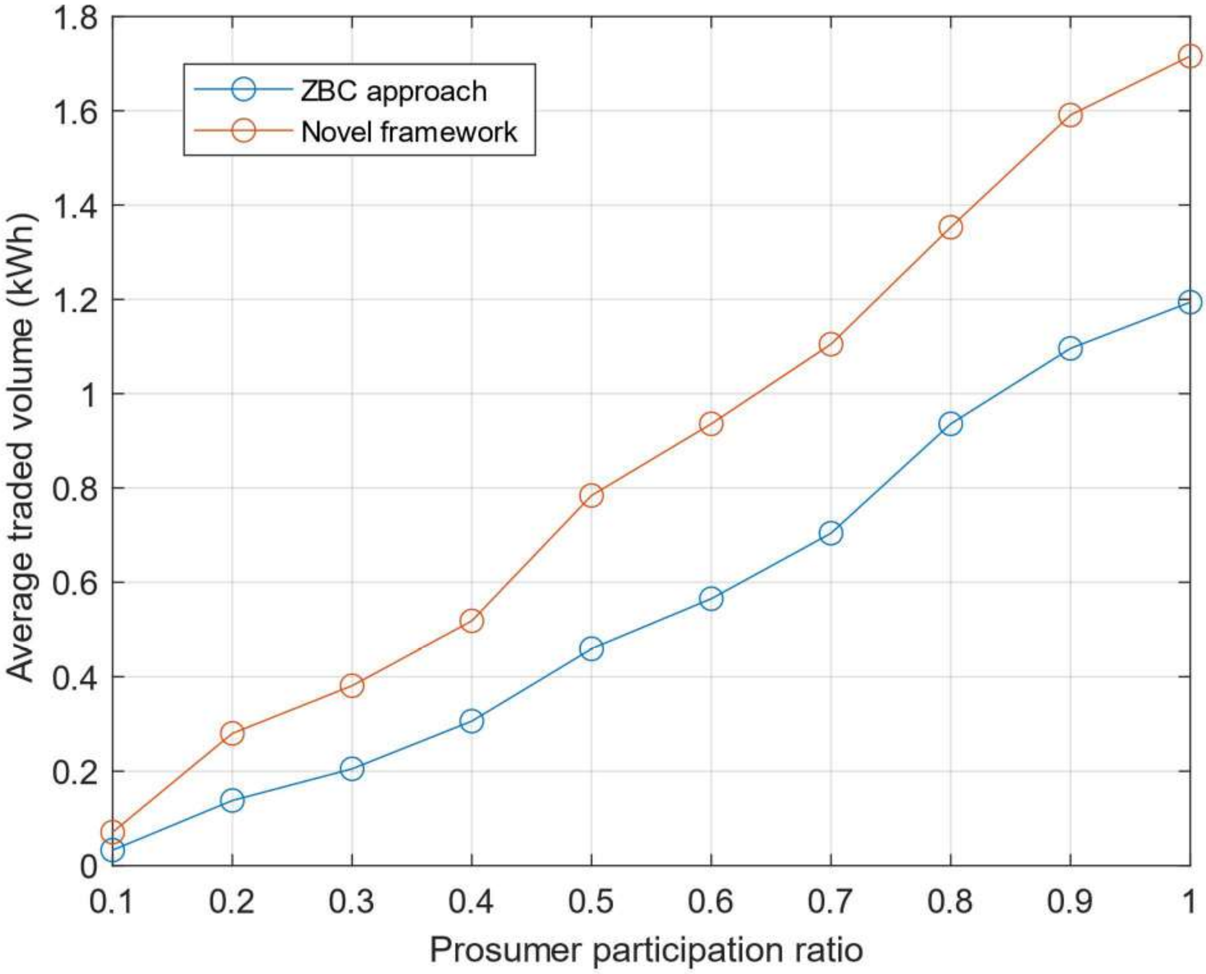


Figure 14: Mean sum traded volumes considering the two market approaches

The results show that the DNUTs influence the market transactions in such a way that is beneficial from the network perspective, while local generation (in a consumption-heavy area) has been incentivized. It can be also concluded from the simulations that the initial state of the system has a vast influence on DNUTs, and thus local trades.

Regarding the novelty of this concept, results proved the ability and viability of the proposed market structure to fulfil the following contributions:

- The LV market platform is proved to be operable parallel to a working traditional retail system.
- The proposed DNUT structure fully considers the network state and energy flows resulting from the transactions on the local market and the estimated base case of the

retail market. Furthermore, through DNUTs the platform is able to handle potential changes in the behaviour of prosumers (e.g. transitioning a part of their power consumption from retail to the local market platform).

- Instead of blocking unfavourable transactions or punishing participants for burdening trades during the settlement process, the platform incentivizes participants before entering the transaction. The market is not only competitive per se, but the DNUTs also promote network-friendly transactions for a prosumer by being lower for bids placed at favourable (e.g. neighbouring) nodes.

6.2.5 Grid model validation

The grid module is designed to generate a unified grid representation, which helps to convert raw grid topology information into a pre-defined data structure. The model output is standardized, the numbering of the elements is used uniformly by the other modules of the framework. This transformation guarantees that the local market framework is independent of the network size and topology and minimizes the malfunctions of parametrization. The grid module requires standardized input datasets as follows:

- network topology data (graph representation);
- parameter table of line types (impedance calculation);
- attribute table of prosumers (load/generation constraints).

Due to the different types of input data received from demonstration partners, the mentioned data structures are filled with data manually, since not every demonstrator store their data in a Common Information Model format yet. When the preliminary tasks are accomplished, the execution of the grid module starts with the build-up of the network graph representation. This representation is a definite connection structure of the line elements with a corresponding length parameter and line type. The grid module reads the parameter table of the line types and links the corresponding physical parameters to the graph representation of the line. Consequently, the data used for the topology representation include line attributes (impedance per length, length, type definition), transformer electrical data, switching & protection devices, voltage, and current measurements. The developed model is a 4-wire representation which considers asymmetry, as it is an important factor for low voltage networks.

Then in the next step, the program places the prosumers on the graph according to the original topology information. Data sources include consumer smart metering data, synthetic load profiles (where 15-minute resolution measurements are not available), distributed generation measurements. This is provided by two pieces of information stored in the attribute table of the prosumers: (i) linked graph number, and (ii) the distance of the designated entity from the start node of the graph (each line element has a start and end node). At the end of this step, the physical parametrization of the network is terminated, and the full grid representation can be created. For this reason, the grid module is able to compute the admittance matrix of the network, which is essential for further simulations. The results are stored in separate variables. The phase assignment of the loads is based on measurements and can be refined with further data available in the system.

Local trading of the prosumers is only feasible if the grid infrastructure can handle the market requirements. Therefore, to calculate the base of the grid factors that are constraining the market actions, reliable models are needed. The discussed Slovenian demonstration site is located in Gradišče. The spatial expanse of the grid is noticeable with 8 separate circuits and 154 consumers covering the whole LV side of a transformer with 160 kVA rated power. Due to the highland environment, each circuit is relatively long with a moderate number of junctions. In all consumer connection points, metering devices provide active power and voltage measurements in the 3 phases, respectively. The graph representation of the case study grid is shown in Fig. 2.

The result of the grid calculation process is twofold: it defines the physical representation of the demo sites and provides an estimation for the day-ahead flows. The latter method is based on historical data (statistical approach), and there is a possibility to use stochastic parameters and a higher number of simulations to increase the visibility of possible customer behavior. It is important to note that estimating the day-ahead profile of consumers or prosumers is a difficult task per se, but with around 50 connection points per LV circuit, the power flow calculations could be seen as representative.

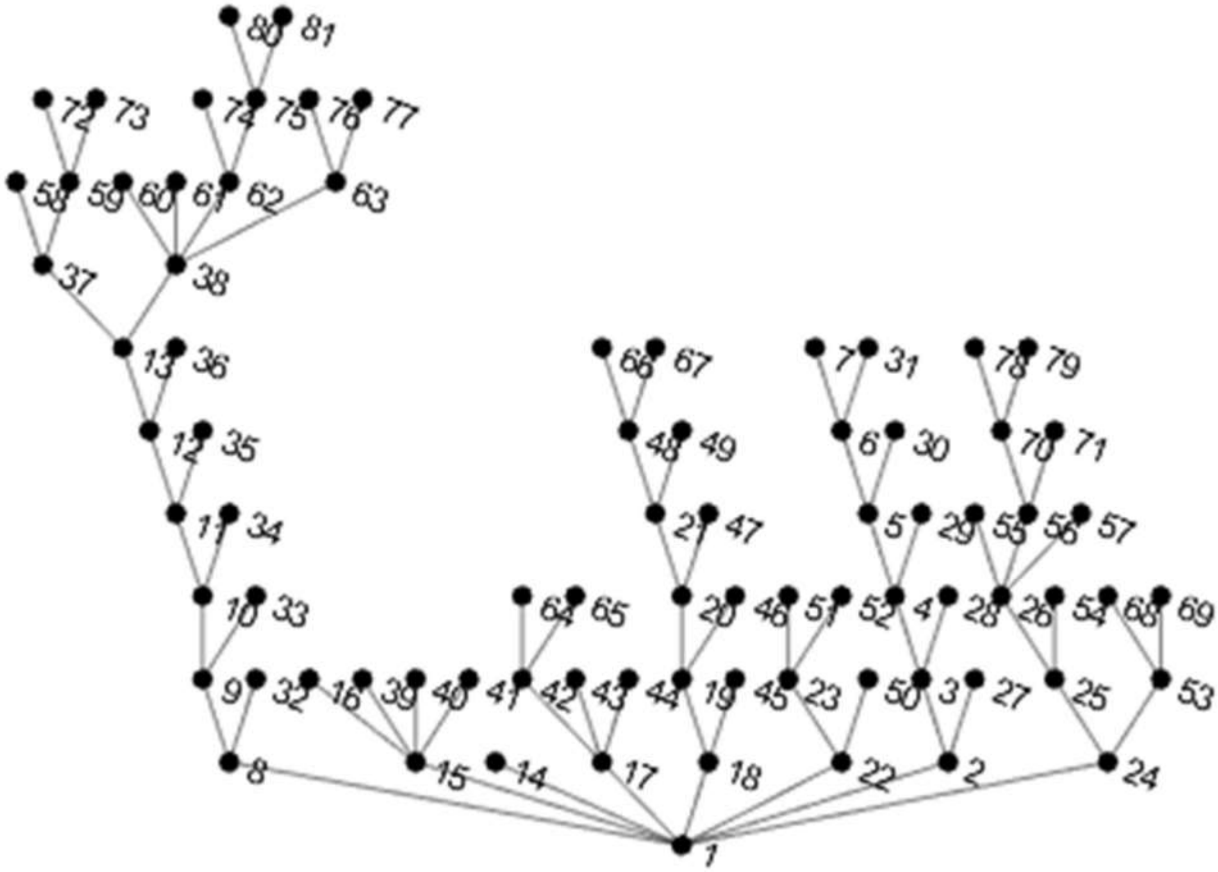


Figure 15: Node connection diagram of Gradisce location

The modelling phase was investigated under some simplifying assumptions. Reactive power data is only available for some industrial/commercial customers; therefore, in other cases it must be estimated. At this stage, the model neglects reactive power flows. Protection devices are neglected (static numbers are available; therefore, separated validation and marking of possible supply interruptions is feasible from the data); transformer LV-side voltages are 1.04 per unit, similarly to the practical settings (based on measurements). Unbalanced calculations are considered with a 4-wire line representation and 3-phase transformer model based on the vector group and impedance data.

The proposed P2P local market concept requires an accurate mapping technique of the real-time grid states. The grid module uses power measurements recorded in consumer connection points and a graph-based representation of the real grid to estimate the actual state (and electrical parameters) of the grid. For validation purposes, the load-flow voltage results and the real voltage measurements are compared. Despite the extensive availability of power measurements, a limited set of voltage values were accessible. Naturally, single-phase consumers provided only one time series, and 34 pieces of 3-phase measurements are missing. This means that more than 75% of consumers are taken into the validation, which is significant in the context that an LV site is investigated. While voltage time series have a 10 min resolution, the power meters record data every 15 minutes.

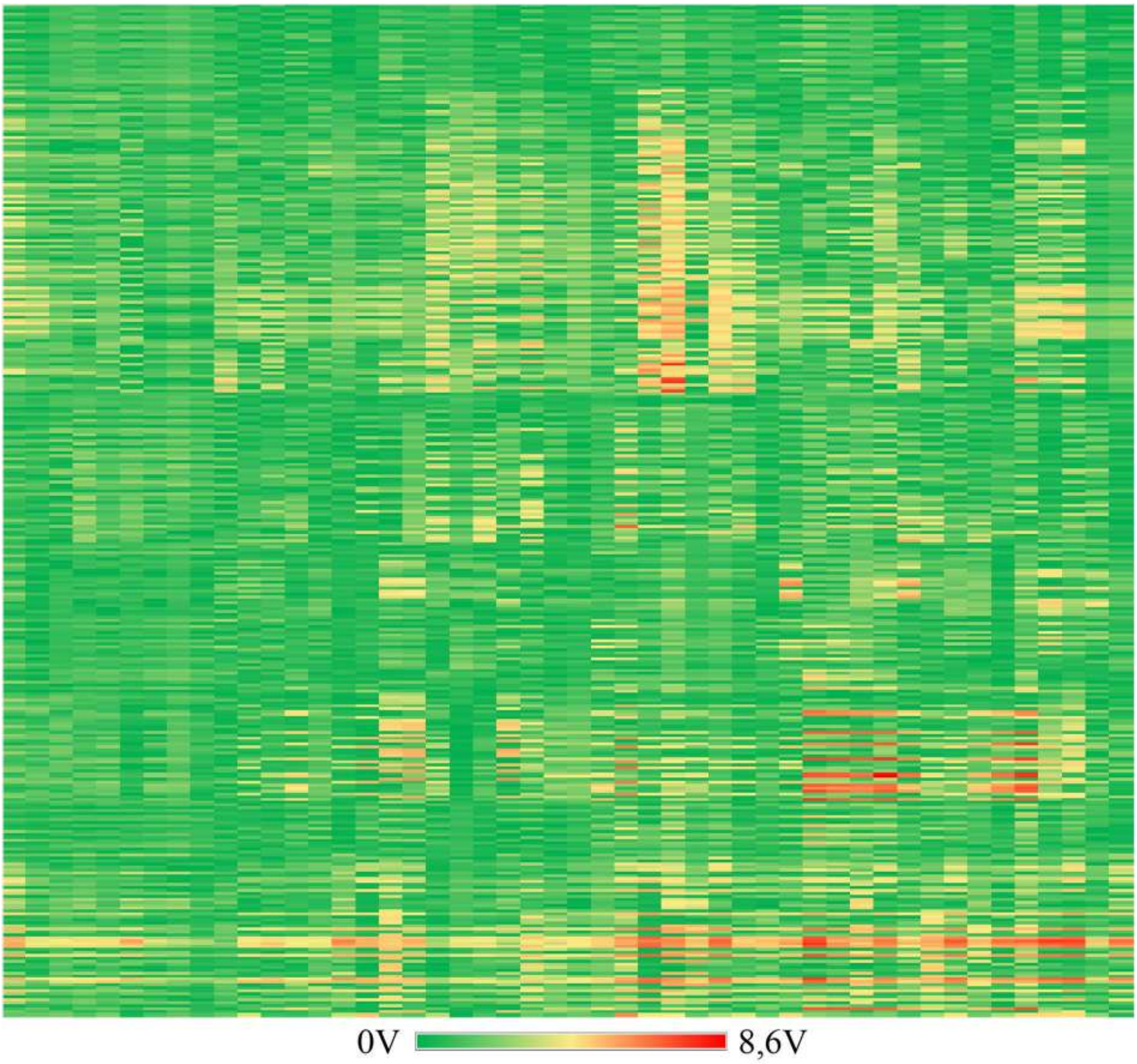


Figure 16: Heatmap of deviation between simulation and real voltage dataset; each row shows one metering point (node) and each column represents one period from 00:00 to 23:30 with 30 min resolution

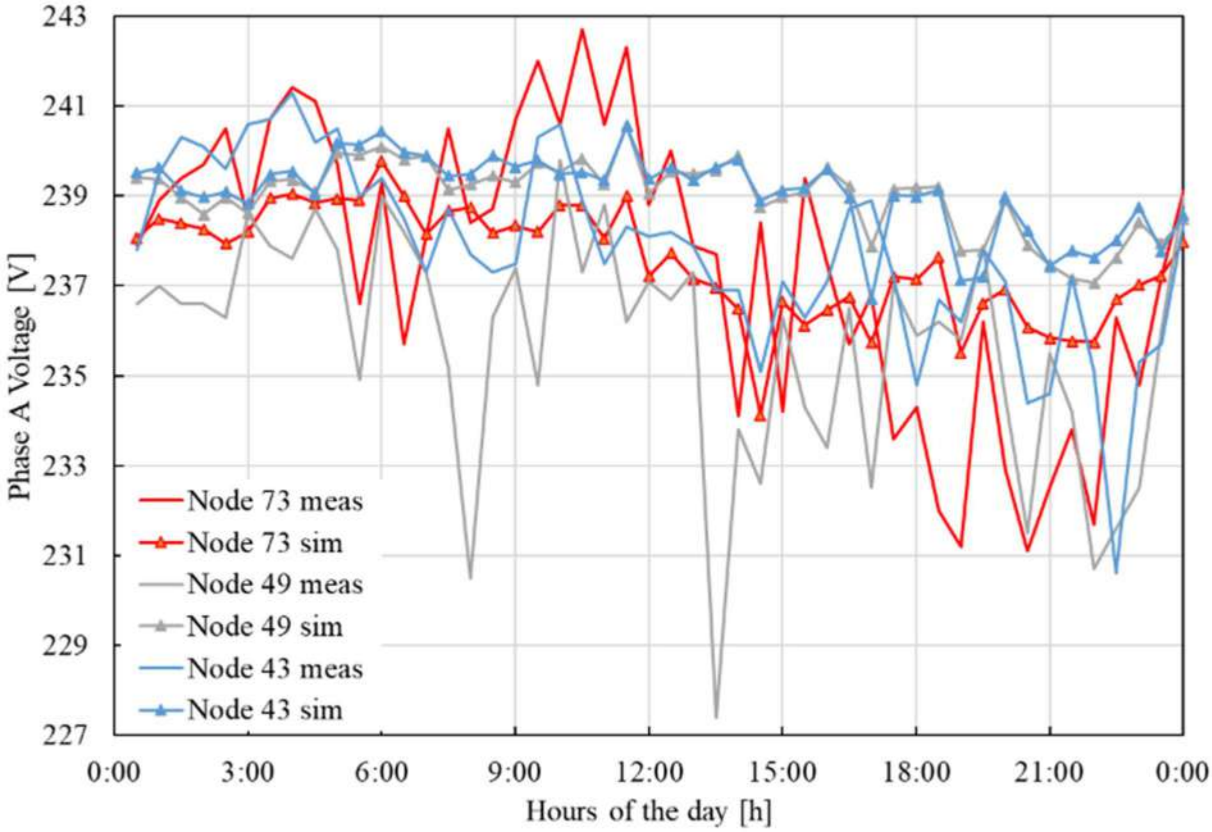


Figure 1: Metered (solid lines) and simulated (triangle markers) end node voltages in case of three circuits; the node numeration is denoted above

Since the proposed local market uses 15-minute timesteps, the validation process included 96 comparable moments in 24 hours,. The grid model accuracy compared with real-time measurement set was validated on data corresponding to the 13th of August. The deviation between real-time and simulation records are demonstrated via a heatmap in Figure . The rows of the heatmap represent every measurement time series. The 48 columns show the simulation accuracy at a moment with a colour gradient from 0% deviation (green) to 8,6% (red), respectively. An optimistic 1% assumed sampling error means approx. 2,3 V deviation between real and metered data. Figure shows that in most cases the deviation between simulation and on-site measurements is under this threshold. The performance of the grid module simulation is significant and verifies that the model maps the real grid features well. The root cause for larger deviations in the metering data is unknown, it should be considered a significant load element switch, which is hard to predict in the case of low number of LV customers.

While Figure introduces a general picture about the performance of the grid module, Figure 1 shows a comparison of 3 circuit endpoint node voltages. This reveals the voltage patterns of both simulated (triangle marked) and real measurements (solid lines). It is seen that the simulation and measured time series have a similar fluctuation, respectively.

6.2.6 Description of the IACMS algorithm

The Integrated Asset Condition Management System aims at the highest utilisation of physical network assets with the aim to eliminate network constraints that would hinder the operation of, and the free access to, the market. At the same time, the system avoids unnecessary risks associated with outages caused by aging equipment. These goals are achieved by the consideration of various information about the assets and then informing the market about their availability and loadability.

The underlying theoretical consideration is that the nominal power or ampacity of the equipment are calculated based on worst case scenarios. Accordingly, if the weather is considered, a much more accurate seasonal ampacity can be calculated. Standardized calculations, at the same time, do not take into consideration the aging of the equipment, which would lessen their loadability.

The IACMS module is considering the differences of data stored and condition information collected by the operators of the demo sites and is therefore prepared for lack of data.

The system consists of the following modules for all types of equipment:

- Thermal behaviour model applying statistical environmental data
- Asset condition module limiting excessive ageing by adjusting the thermal limits

6.2.7 Transformers

The algorithm calculates the upper loadability limit for the given time interval in case of a given forecasted ambient temperature value. The initial load ratio (K_0) is set to 500% of the nominal load value so that the iterative solution approaches the final K_i value from above, using the interval halving method. The output is the permissible transferred power for the given time interval, which is 15 mins.

The inputs of the IACMS for transformers are as follows, source are the DSOs:

- Basic (nameplate) data: type, nominal voltages and currents, nominal power, no-load loss, short-circuit loss, weight, oil weight, location
- Operational history information: time in operation or installation date
- Condition information: visual checks, oil tests, insulation resistance tests, other diagnostic measurements

6.2.8 Overhead lines

For medium voltage power lines, the ambient adjusted line rating (AA-LR) gives an optimal solution by considering the required input data and the achievable surplus transmission capacity. For this purpose, the ambient temperature and solar radiation should be known along the power line route in real time, while the wind parameters (speed and direction) are taken into consideration as constant values. Accordingly, a surplus 10% transmission capacity in average can be achieved by the application of AA-LR calculation methodology. The output of the calculation is the real time ampacity of the OHL. This value is calculated every 15 mins.

The inputs of the IACMS for overhead lines from the DSO-s are as follows:

- Basic (nameplate) data: type, nominal voltage and current, type and data of conductor, location
- Operational history information: time in operation or installation date, planned height above ground
- Condition information: visual checks

The inputs of the IACMS for overhead lines from C&G sensors are as follows:

- LISA sensor detecting the damage of the conductor by electric field measurement
- IMOTOL sensor detecting the deformation of poles by residual strain measurement

6.2.9 Cables

In case of cables, the algorithm creates a detailed thermal model for the cable structure considering losses and thermal properties of the different layers. Using this model, plus taking into account the environmental conditions, the permissible load can be calculated for a given time interval. The output of the algorithm will be the maximum permissible rating for the day that is safe for the integrity of the cable structure.

The inputs of the IACMS for cables are as follows, source are the DSO-s:

- Basic (nameplate) data: type, nominal voltage and current, material and cross-section of conductor, resistance of conductor
- Operational history information: time in operation or installation date, installation mode/laying depth, soil type if buried
- Condition information: insulation resistance measurements, diagnostic measurements

6.2.10 Summary of IACMS results

The following table contains the total excess energy allowance throughout the demonstration periods where IACMS was active, which means a total of 7 weeks. The values equal the transmissible energy above the static limits that were made possible by the IACMS calculation, per asset type and per demonstration site. The values were calculated by the following method: the total transmissible energy based on the static load was subtracted from the total transmissible energy based on the dynamically calculated load, considering a full load, nominal voltage and a power factor of unity in both cases. At Zsombó, there were no cables in the LV demonstration area.

Table 5: Excess energy allowance (total values for 7 weeks)

	Besnica	**Zsombó**	**Bóly**
Cables	11.55 MWh	NA	40.59 MWh
Overhead lines	35.22 MWh	135.25 MWh	69.99 MWh
Transformers	8.47 MWh	67.37 MWh	66.72 MWh

6.2.11 Scenarios in the demonstration

In this demonstration, the operation of the market was simulated using artificial bids. Each bid was described by the following parameters:

- type of the bid (supply or demand);
- index of the trading period, for which the bid is relevant;
- volume of the bid;

- submission price of the bid.

For every considered participant, bids were generated based on the historical consumption/production data provided by the demonstrators. It is assumed that every participant submits bids to the market in two steps: First, day-ahead bids are submitted on the day before the trading period (D-1); and second, intra-day bids are submitted on the day of trading. In the case of intra-day bids, it was assumed that the prediction of consumption/production regarding the trading period is more precise than in the case of day-ahead bids.

The demonstration was performed for different scenarios, listed in Table 1. DSOs uploaded the data for the analysis, then the BC was calculated, and the bid generator provided the p2p activity. 19 different scenarios were analysed during a year timespan. Scenario 1, 17 and 18 are the so-called base scenarios for seasons of winter, spring-autumn and summer respectively. These scenarios provide a reference for the analysis of different considerations, which can be grouped:

- Data availability – metering and synthetic load profiles are always available, while feeder metering (Sum-meter) is only available in Scenario 2;
- DNUT elements – loss, load ability (with or without IACMS) and voltage regulation;
- Share of DNUT (Scenario 3 and 4 considers different options);
- Scenario 15 considers symmetric conditions in the modelling;
- Order types (metering based / flexibility);
- Scenario 13 and 14 analysed a local energy storage system (only available at Zsombó site).

Table 6: Scenario schedule

Number	Start date	End date	Name (DNUT change / data availability change)
1	2021.01.04	2021.01.24	Base case for winter
2	2021.07.12	2021.07.25	Grid measurements included in the estimation
3	2021.04.26	2021.05.16	Shared DNUT
4	2021.05.17	2021.06.06	Fix DNUT for bidder, remaining for aggressor
5	2021.06.07	2021.06.20	Congestion management limit
6	2021.06.21	2021.07.11	Congestion management limit + punishment

7	2021.01.25	2021.02.21	Voltage limit in the DNUT
8	2021.02.22	2021.03.14	Voltage limit with DNUT punishment
9	2021.07.26	2021.08.15	Losses + congestion management
10	2021.03.15	2021.04.04	Losses + voltage limit
11	2021.09.06	2021.09.26	Losses + congestion management + voltage limit
12	2021.09.27	2021.10.17	Extra flexibility offers added
13	2021.10.28	2021.11.07	DSO storage use case 1
14	2021.11.08	2021.11.21	DSO storage use case 2
15	2021.11.22	2021.12.05	Asymmetry consideration test
16	2021.12.06	2021.12.19	Non-anonym bids, without automatic pairing
17	2021.04.05	2021.04.25	Base case for spring/autumn
18	2021.08.16	2021.09.05	Base case for summer
21	2022.01.03	2022.01.24	DSO congestion forecast test with increased base case flow

The following table summarizes the parameter settings for the simulations. The parameters were tuned by preliminary tests to provide practical and realistic scenarios. However, the sensitivity analysis for these opens up further possibilities for this implementation.

Table 7: Parameter settings for the simulations

Parameter name	**Value**	**Dimension**	**Description**
Voltage limit cost	1000	EUR/pu	The price for exceeding voltage limits, a component of DNUT, is practically unlimited and excludes orders that surpass these limits.
Current limit cost	1000	EUR/pu	The price for exceeding line loading limits, a component of DNUT, is practically unlimited and excludes orders that surpass these limits.
Transformer limit cost	1000	EUR/pu	The price for exceeding transformer limits, a component of DNUT, is practically unlimited and excludes orders that surpass these limits.

DNUT trading volume	20	pu	The unit of power transmission, for which DNUT is calculated, is equal to 2 kW.
Per unit power	100	W	Per unit of power used.
Voltage limit	0.15	pu	Voltage limit that applies in both directions and is around 35V. Going over this limit results in additional DNUT fees.
Transformer limit	5	%	Transformer loading limit. Going over this limit results in additional DNUT fees.
Overflow ratio	0.2	-	Ratio of energy transmission in the system, that is not part of the BC, but covered by local market activity.
Voltage linear cost	0.0037	EUR/pu	The cost for deviation from the reference voltage; is applicable in both directions and is assessed for voltages within the range of the reference voltage and the voltage limit.
Current linear cost	7.36E-05	EUR/pu	The cost for deviating from the BC current; is applicable in both directions and is assessed for all lines.
Loss cost	0.02	EUR/pu	Cost of total system loss caused by the transmission.
Transformer linear cost	7.36E-06	EUR/pu	The cost for deviating from the maximum transformer loading.
Retailer purchase price	0.0156	EUR/pu	Price on which the retailer purchases a unit of energy.
Retailer selling price	0.0338	Eur/pu	Price on which the retailer sells a unit of energy.
Battery scenario parameters			
Voltage deviation interval (lower bound)	1	%	Exceeding this voltage limit at the battery connection point will turn on the battery in discharge mode.

Voltage deviation interval (higher bound)	4	%	Surpassing the voltage limit at the battery connection point will activate the battery in charging mode.
Maximum battery power	160	kW	Nominal maximum power of the battery.

Table 8 summarizes the statistical attributes which were used to evaluate the different scenarios. Since the framework gives all the relevant market and grid data as an output, more descriptive attributes were created to help the participants in the analysis.

Table 8: List of the most relevant output variables

Unit of measure	Variable name
[%]	Maximum of line load in BC over all lines and periods
[%]	Maximum of line load in OLM over all lines and periods
[%]	Maximum of line load in ALM over all lines and periods
[%]	Expected shortfall (5%) of all line loads in BC (over all periods and lines)
[%]	Expected shortfall (5%) of all line loads in OLM (over all periods and lines)
[%]	Expected shortfall (5%) of all line loads in ALM (over all periods and lines)
[%]	Expected shortfall (5%) of worst case line loads (worst case over periods) in BC
[%]	Expected shortfall (5%) of worst case line loads (worst case over periods) in OLM
[%]	Expected shortfall (5%) of worst case line loads (worst case over periods) in ALM
[%]	Maximal loss per traded volume ratio (LpTVr) in BC (over trading periods)
[%]	Maximal loss per traded volume ratio (LpTVr) in OLM (over trading periods where OLM is active)
[%]	Maximal loss per traded volume ratio (LpTVr) in ALM (over trading periods)
[%]	Minimal LpTVr in BC (over trading periods)
[%]	Minimal LpTVr in OLM (over trading periods where OLM is active)
[%]	Minimal LpTVr in ALM (over trading periods)
[%]	Maximal change in LpTVr in ALM compared to BC
[%]	Minimal change in LpTVr in ALM compared to BC
[V]	Maximal voltage deviation (VD) in BC (over all prosumers and periods)
[V]	Maximal VD in OLM (over all prosumers and periods)
[V]	Maximal VD in ALM (over all prosumers and periods)

[V]	Minimal voltage deviation (VD) in BC [V] (over all prosumers and periods)
[V]	Minimal VD in ALM [V] (over all prosumers and periods)
[V]	Average voltage deviation (VD) in BC (over all prosumers and periods)
[V]	Average VD in OLM (over all prosumers and periods when LM is active)
[V]	Average VD in ALM (over all prosumers and periods)
[V]	Expected shortfall (5%) of voltage deviation (VD) in BC (over all prosumers and periods)
[V]	Expected shortfall (5%) of VD in OLM (over all prosumers and periods when LM is active)
[V]	Expected shortfall (5%) of VD in ALM (over all prosumers and periods)
[V]	Average change in VD in ALM compared to BC (over all prosumers and periods when LM is active)
[%]	Exchanged flexible power relative to maximal transmissible power

6.2.12 Evaluation of the complete set of demonstrations

The 4 demonstration sites provided a validation environment for the developed market and grid modelling methods. Figure 2 provides the average ratios of OLM and BC traded volumes for all 3 base cases (winter, spring and summer), and all 4 demonstration sites.

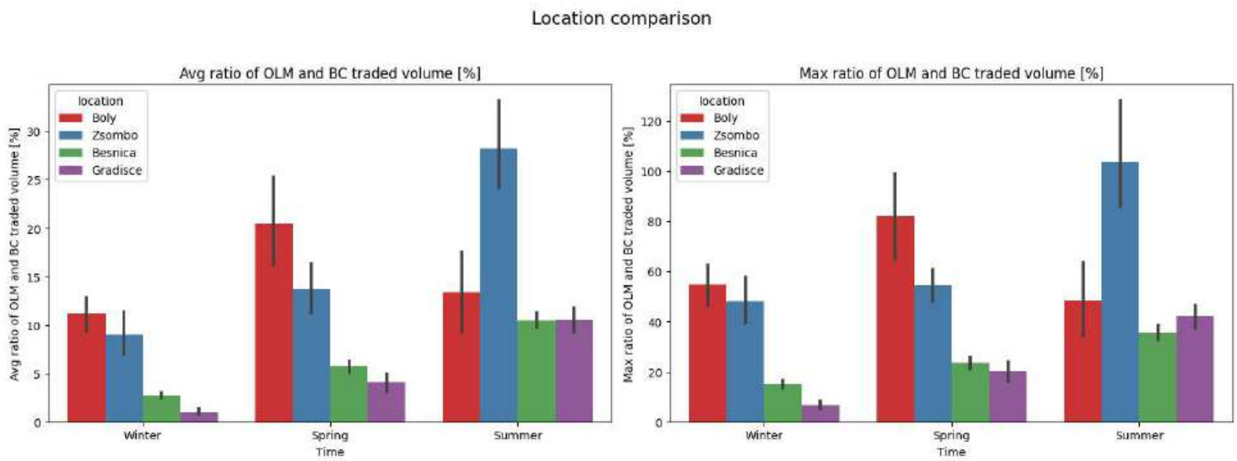


Figure 2: Average ratio of ALM and BC traded volumes in the whole demonstration – base cases

Due to the fact that the producers on the local markets are PVs, the seasonality clearly had a great effect, as in the summer the traded volume change is significantly larger. Site Bóly (marked with red) had the most local generation (this was the only site with MV model and a MV PV power plant), however in the summertime there were less OLM activity due to the high DNUT, because losses increased on the site greatly. Regarding the Slovenian demonstration sites, the lack of production and therefore the lack of supply bids clearly constrained the p2p trading. The traded volumes basically confirmed the viability of the p2p markets in general, and with increasing volatility, the market activities were expanded. The results clearly show that the availability of local generation is an entry barrier. The consumption also has seasonality, which also adds to the processes.

One of the most important aspects of the introduction of the DNUT is the concept of payments. 3 different approaches were analysed through the demonstrations. The basic concept was that the aggressor pays the DNUT (Scenario 1), while another solution could be a 50-50% share (Scenario 3), and the DNUT can be fixed for the bidder, and the remaining part is paid by the aggressor, the dataset is still the whole demonstration period for these scenarios (Figure). The trading intensifies in the summer, especially when the aggressor pays the DNUT – this means, that the available local generation is a tempting option for the local users. The fixing of the DNUT leads to the reduction of the traded volumes, which indicates further activity from p2p point of view – this means that fixing the bidder's DNUT is a possible tool for market enhancement. This predictability might encourage prosumers to access the local market.

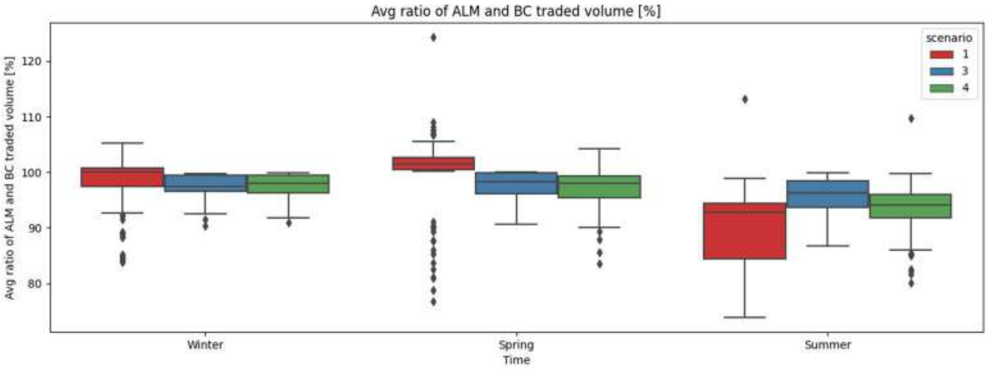


Figure 19: Different concepts for the DNUT share

Figure 3 shows the different bid acceptances throughout the demonstration of the voltage regulation options. 4 scenarios were important from this point of view:

- Scenario 1 – BC
- Scenario 7 – Voltage limit – if a transaction would lead to violation, it is not allowed
- Scenario 8 – Voltage limit with punishment fees near the limit
- Scenario 10 – Voltage limits and losses define the DNUT

The demonstration sites are generally voltage constrained, so this element has actual effects on the trading (contrary to the CM, which is described later). E.g. for the average ratio of accepted demand bids for Scenario 1 and 8, there is a clear limitation spring. However, since these results are aggregated values for the 4 locations, the location attributes cannot be considered. At different site analysis some further aspects are discussed in this report below. Another key conclusion is that the trading activities are larger in the summer, and for most of the time, the networks were not constrained by the limits.

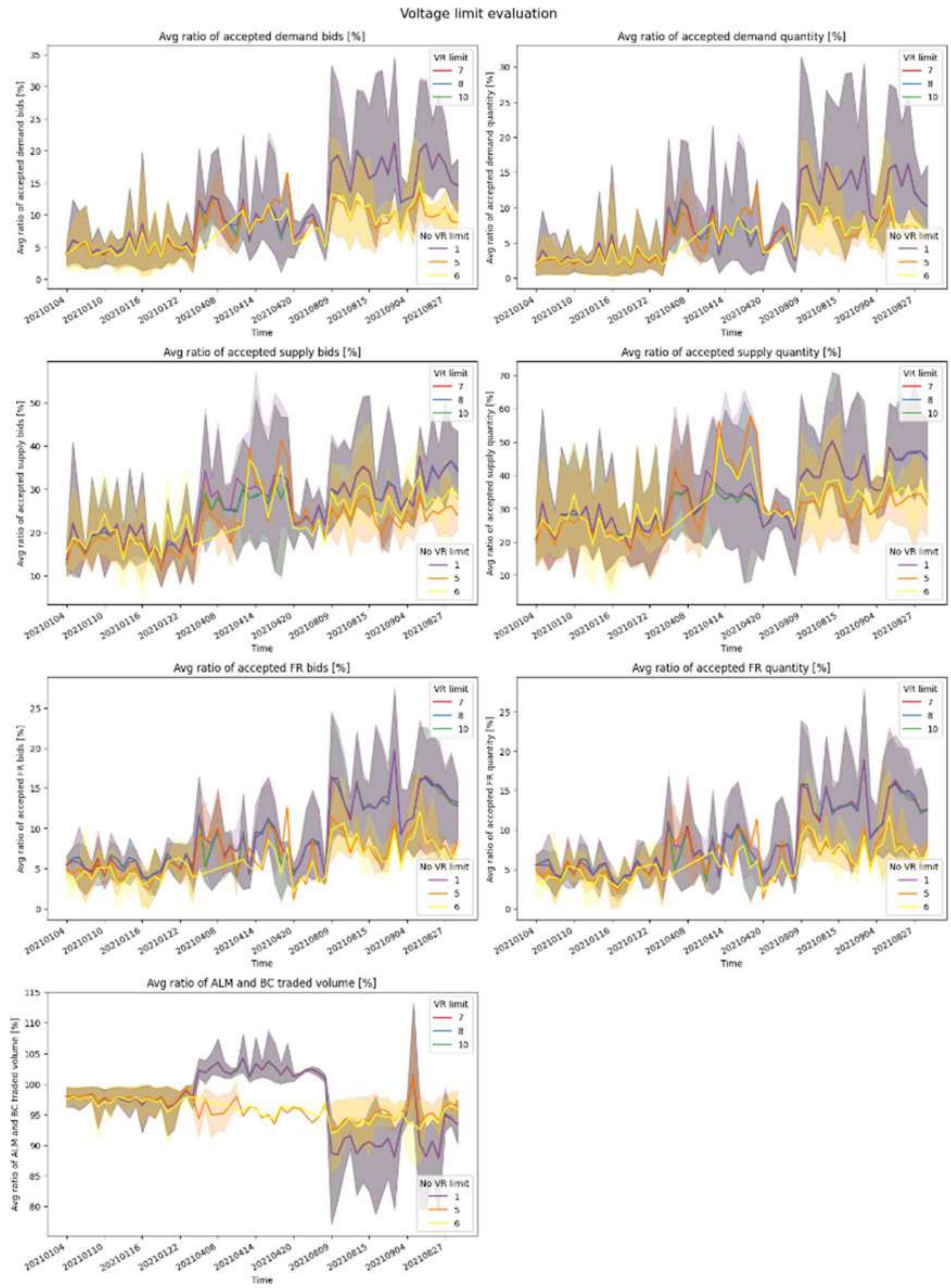


Figure 3: Voltage regulation aspects in the DNUT – effects on the bid acceptance

The next discussed parameter is the CM option. Since the static loadability of the network branches are larger than the flows, there's very few congestion periods – however some were present. In the future with more and more renewables, higher loadings are expected, which will underline this capability of the developed framework. These LV demonstration sites are mainly comprised of overhead lines; cable LV networks are often involved with higher load densities and results may be different. Testing the framework at such sites would add further conclusions to these scenarios. In the case of Bóly, where MV level is also considered, the situation is different, and CM have a limiting effect.

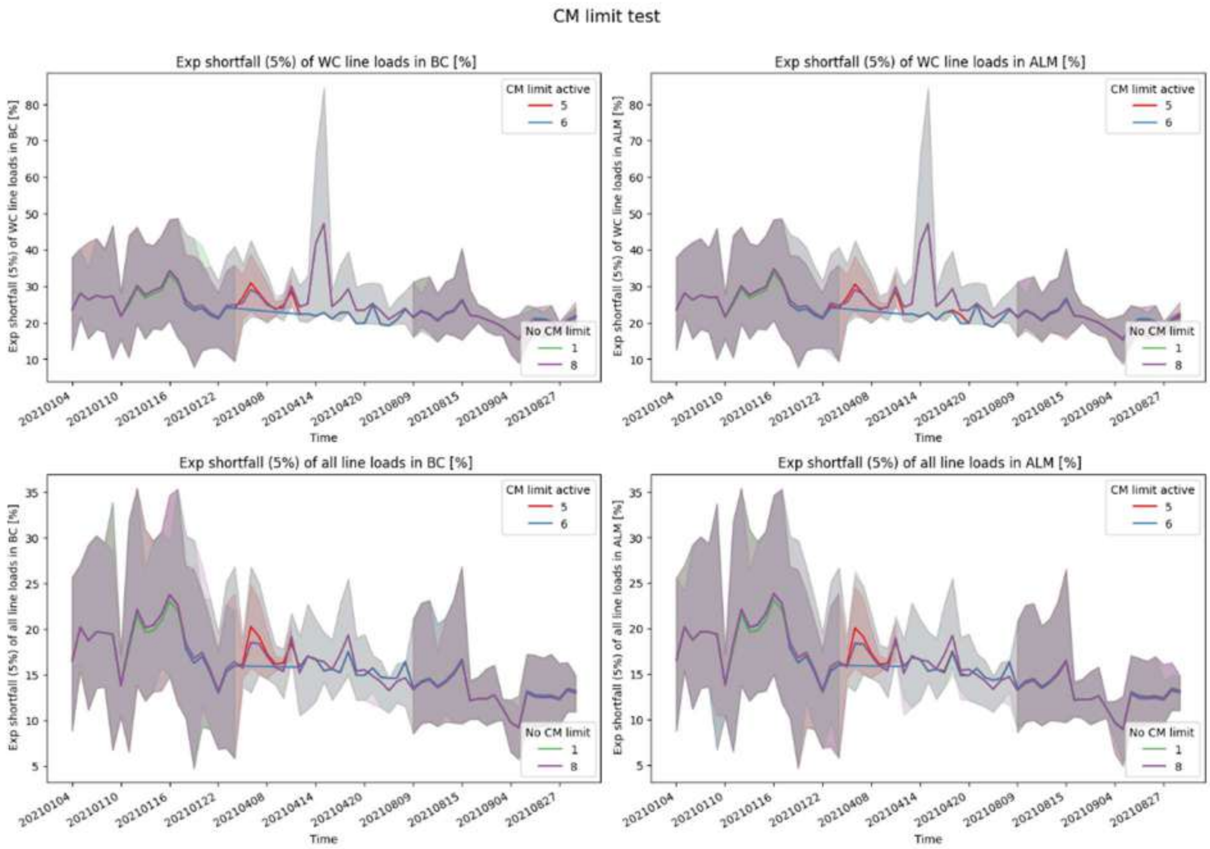


Figure 21: ES in CM scenarios

In Scenario 15, a symmetric grid representation was used, which resulted in restricted market activity. However, the phase assignment of element is not known at the DSO sites, which makes asymmetry tough to handle. The difference in the modelling approach is clear, however a practically usable asset enabled framework must be aligned with the DSO data availability. There is a clear potential in handling asymmetry properly as Figure describes.

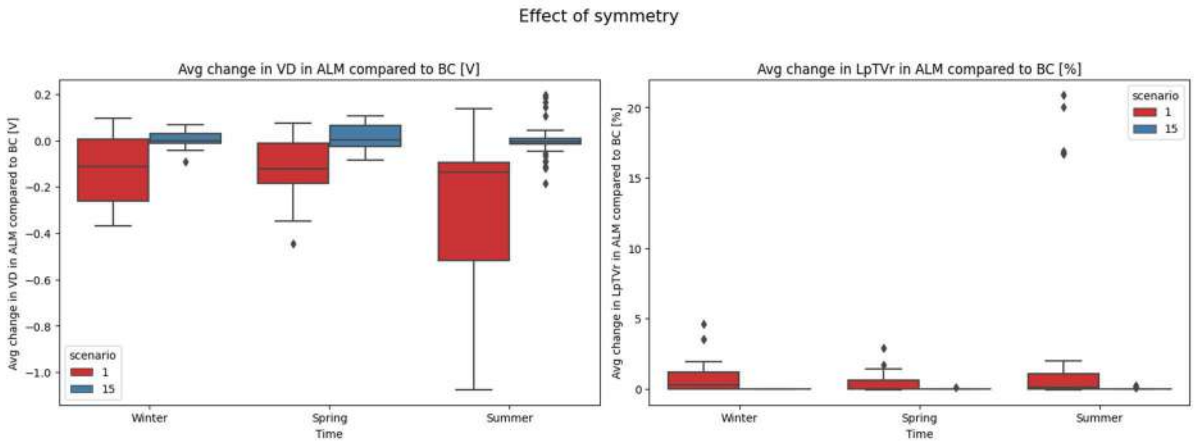


Figure 22: Symmetry – asymmetry considerations

6.2.13 Slovenian demonstrations

Basic requirement for running the simulations from the DSO perspective were input data. BME as the developer of the algorithms and programs in MATLAB (licence was arranged by Elektro Ljubljana), specified which data would be needed, in what format and how and where should the data be available. Elektro Ljubljana agreed to provide all necessary data for both LV pilot sites, which comprise grid topology and the technical parameters of lines and assets.

After having a clear picture about the grid, BME also integrated the smart meters data. This included Sum-meter data: Voltage, current, power factor, active and reactive energy (bidirectional) in 10-minute resolution measured at the MV/LV transformer station.. For calculations of the load flows and voltage levels among grid branches (lines, cables) and nodes, Elektro Ljubljana provided data from all LV smart meters, measuring the consumption and production of the grid users- customers- market active participants. Both selected LV grid have a common feature, that all grid user's connection points are equipped with smart meters. 15 min data of active power and energy have been collected, for more than two years. Simulations were using real smart meters data. Every Monday, for the past 7 days, 15 min smart meters data were collected and stored on server where authorized participants had access to perform analysis.

6.2.13.1 Preliminary proof-of-concept simulations for Gradisce

Market simulations are carried out for two scenarios for the same day of operation:

- Scenario A: the original LV network in Gradišče is used, which only contains two prosumers that inject power to the grid throughout the day.
- Scenario B: two additional, randomly selected nodes are replaced by prosumers, while the energy production profiles of existing ones were used.

In both scenarios, a base case (generation and load) is defined based on measurements, which represents the estimated state of the network without the influence of the local market. In this article, we focus on two of the grid-related aspects of the market results, namely phase voltage deviations and changes in network losses. Therefore, prosumer prices, calculated DNUT, social welfare, and other economic measures are not discussed. The sum of network losses in a given quarter-hour is divided by the total traded volume to ensure comparability between the base case, and local market results. The total traded volume is defined as the sum of generation and consumption in the system.

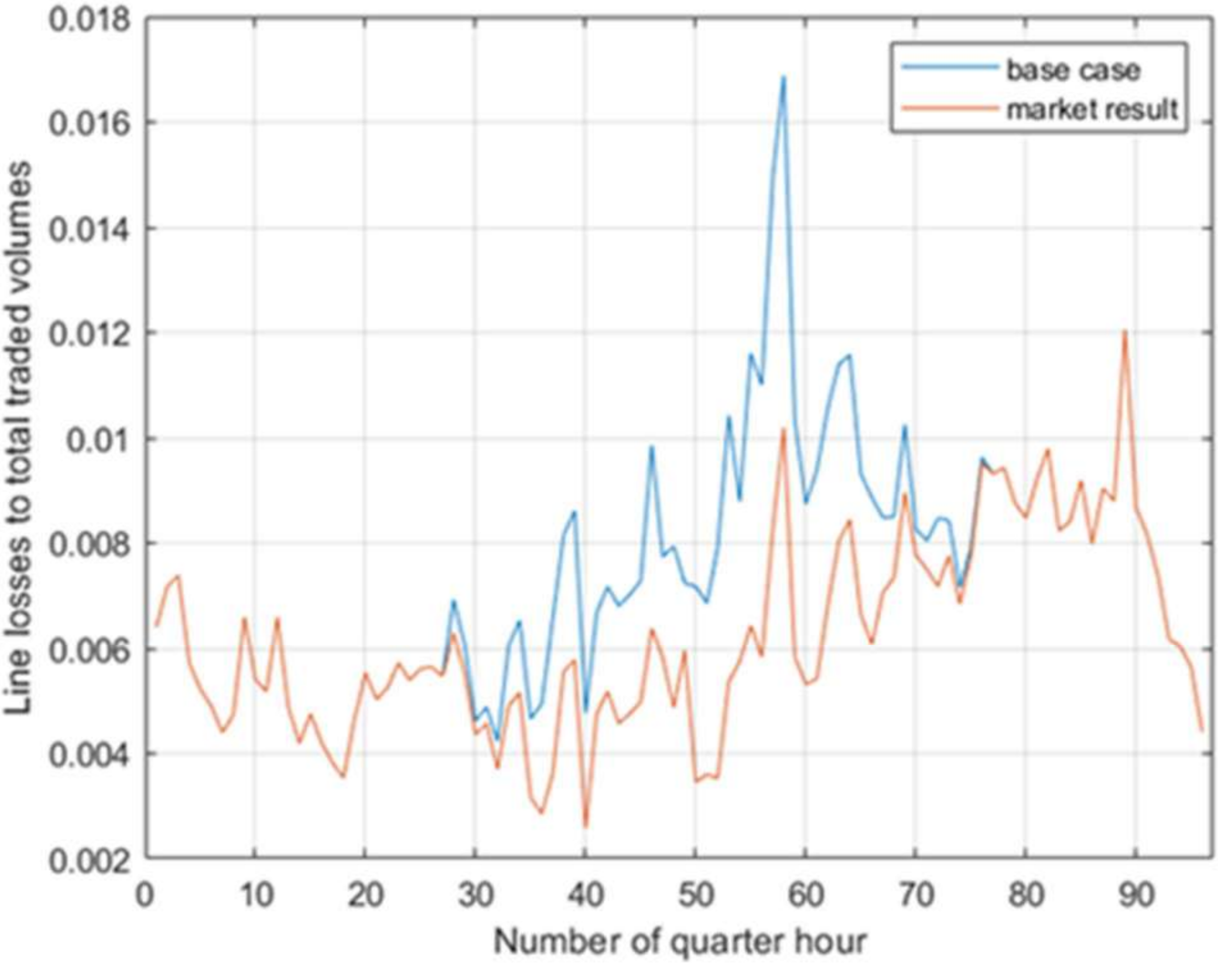


Figure 23: Comparison of relative losses for the base case and local market results in scenario 1

Figure summarizes the relative losses (MWh/MWh) in Scenario A. In this case, the local generation is rather low, most of the consumption is covered by the external grid. Therefore, the loss relative to consumed energy is less favourable, as the flows follow the conventional route from the medium voltage grid through the transformer to the customers. Compared to that, the introduction of the local market provides information on the grid state for participants, thus showing a possibility to bid for the local generation. These added transactions lower the relative losses as the generation is physically closer to the consumption.

Figure depicts the highest and lowest voltage phase RMS values for both the base case and the local market results, calculated in 15 min time steps for the whole day. Despite the additional trading, the voltage values remain in a tight zone. Although the applied dynamic tariff practically forbids voltage limit violations, this result is rather due to the lack of supply bids (which come from only 2 generators). The number of supply orders is raised by connecting two more producers to the network in Scenario B.

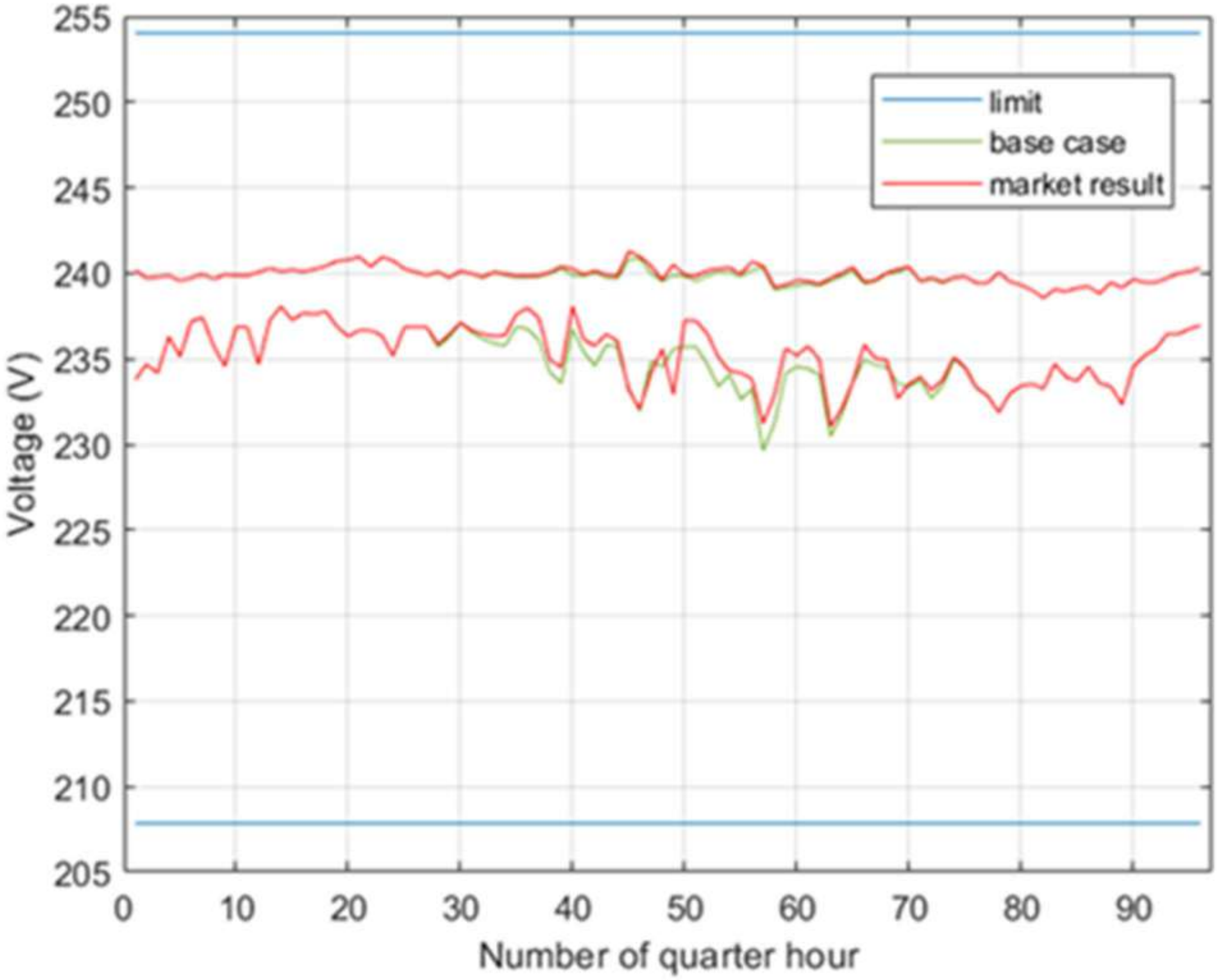


Figure 24: Comparison of minimum and maximum phase voltages for the base case and local market results in Scenario A

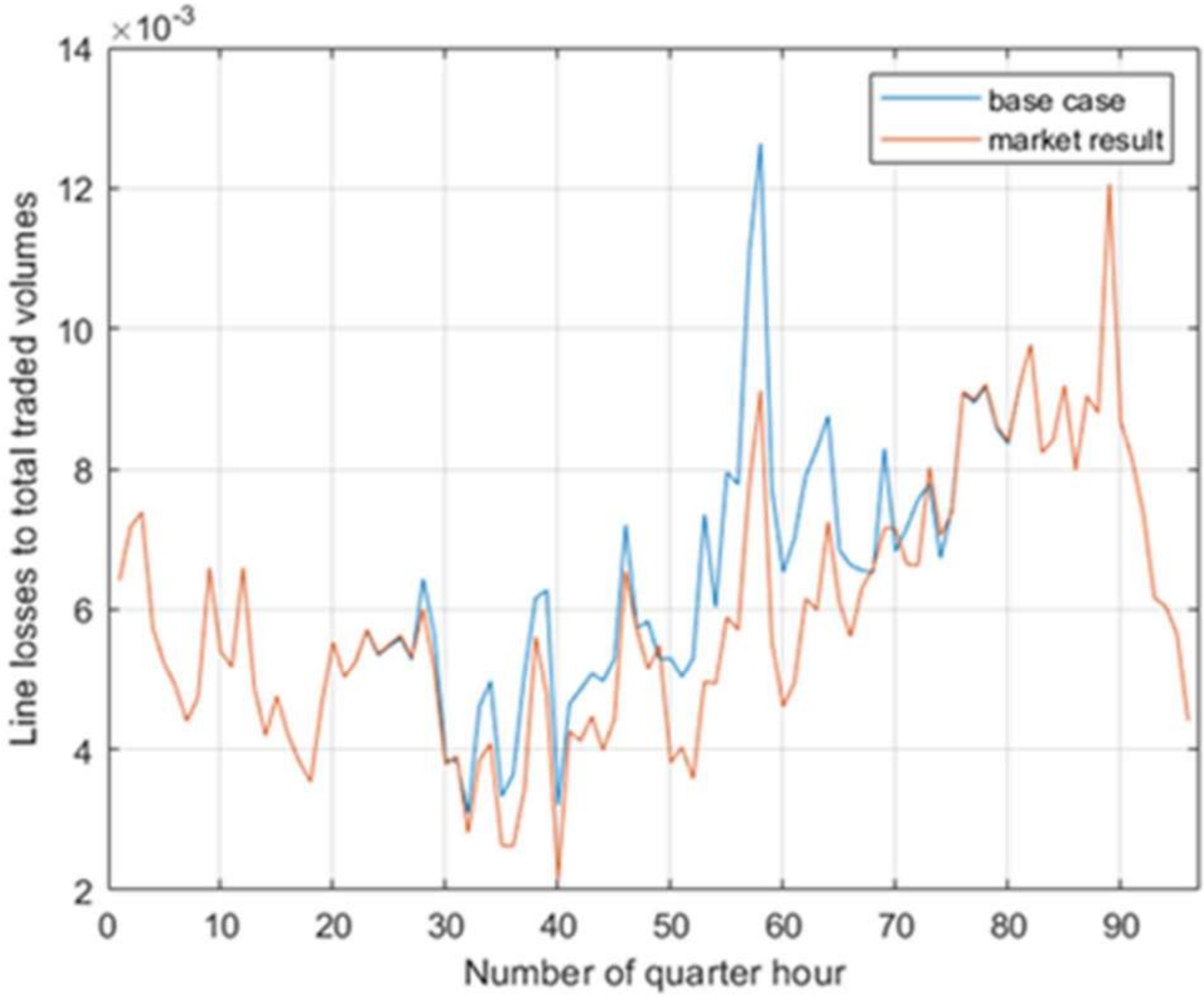


Figure 25: Comparison of relative losses for the base case and local market results in Scenario B

In this scenario the relative losses (Figure) in the base case are already lower compared to Scenario A (Figure 16) due to the increased number of local generators, which have resulted in lower loaded network branches. This loss ratio is further improved by the local market.

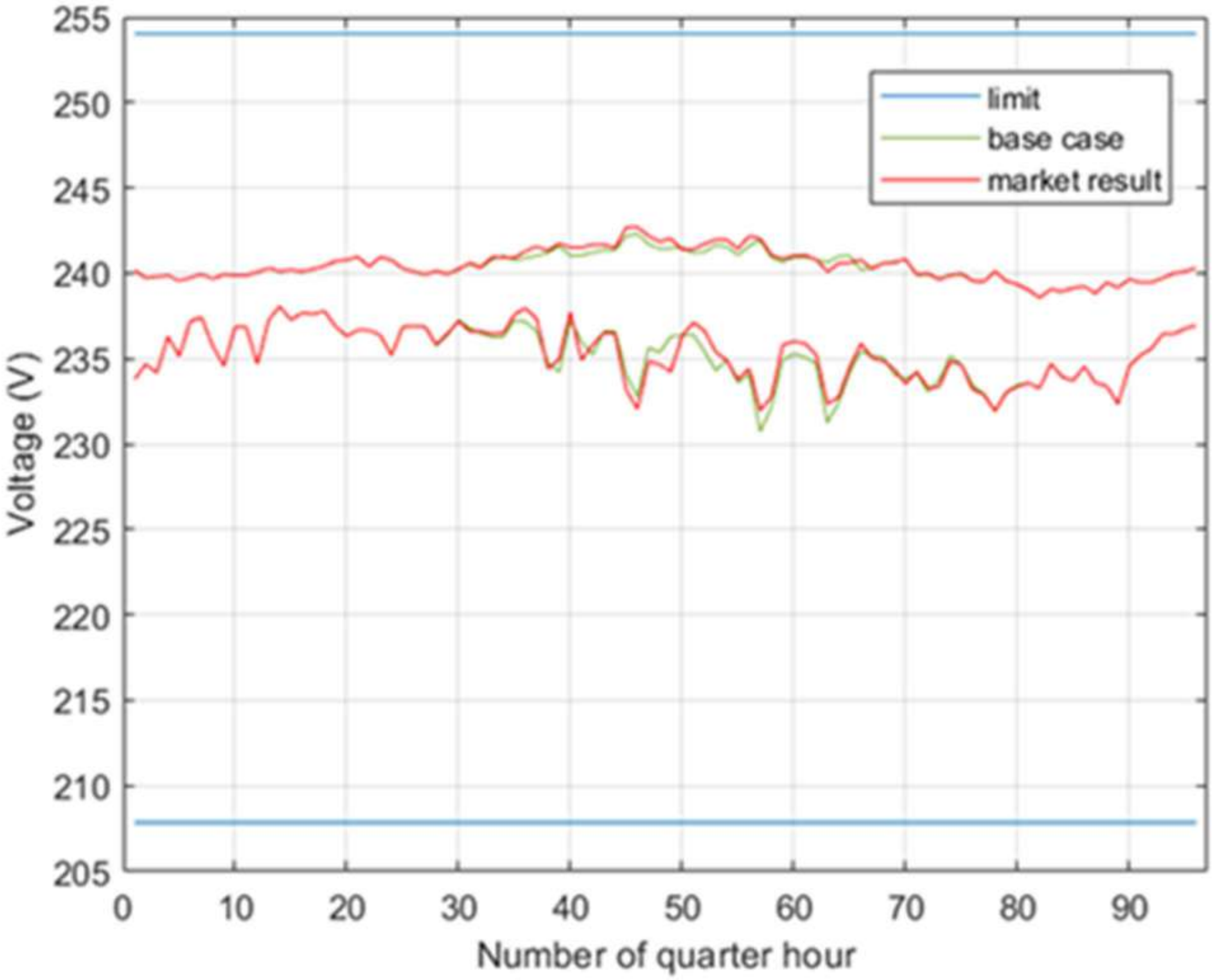


Figure 26: Comparison of minimum and maximum phase voltages for base case and local market results in Scenario B

Figure shows that there is still only a slight rise in voltage RMS values, meaning that the constraints defined by the operation standards are not violated.

6.2.13.2 Demonstration of use cases

Regarding the Slovenian demo sites, if we rely strictly on the original data, no trading emerged in the local market because of the lack of production, no generation was present. To overcome this issue, 3 fictive producers were added to each site (based on historical PV data) to the following nodes: Besnica nodes IDs are 4012546, 4028551, 4029986 and to the following nodes IDs in Gradisce: 4031767, 4023908, 402488

start date	end date	Number of the scenario in D 6.1	Name of the scenario	15min metering+ profiles	15min metering + (feeder-time series metering)	Loss off	Loss on	Loadability (CM)-IACMS off	Loadability (CM)-excluded trades over limit	Loadability (CM)-limit excludes trades + punishment close to limit	Voltage regulation (VR)-off	Voltage regulation (VR)-excluded trades over limit	Voltage regulation (VR)-excluded trades over limit + deadband punishment	Symmetric load distribution	Asymmetric load distribution	Order types-only metering (history) based	Order types-flexibility orders added	Order types-(extra DSO storage usa cases)battery for supply quality improvement	Order types-(extra DSO storage usa cases) battery as market facilitator	DNUT sharing (Who pays the DNUT)-agressor	DNUT sharing (Who pays the DNUT)-50-50% agressor and bidder	DNUT sharing (Who pays the DNUT)-fix cost for bidder + remainder by agressor	Anonymity and automatic matching-anonym with automatic pairing	Anonymity and automatic matching-non-anonym without automatic pairing
2021 01 04	2021 01 24	1	**Simplest case**	x			x	x			x				x	x				x	?		x	
2021 02 22	2021 03 14	8	VR limit + punishment test	x		x		x					x		x	x	?			x			x	
2021 05 17	2021 06 06	4	DNUT fix for bidder, remainder by agressor	x			x			x			x		x		x					x	x	
2021 06 21	2021 07 11	6	CM limit + pusihment test	x		x				x	x				x	x	?			x	?		x	
2021 08 16	2021 09 05	18	BC summer	x			x	x			x				x	x				x				
2021 09 06	2021 9 26	11	**Loss+CM+VR**	x			x			x			x		x	x	?			x	?		x	
2021 09 27	2021 10 17	12	**Extra flexi orders -> expected BC!**	x			x			x			x		x		x			x	?		x	

Table 9 : Scenarios of Slovenian demo

Simulations for different scenarios were run on one week time frame according to the Table where scenarios are listed.

The results were uploaded on a weekly basis (the name of the directory includes the date of the last day of the week), the output files were available in .xlsx and in .mat format (MATLAB) as well.

The system performs a post-processing of the results as well, and calculates indicators, which may be of interest during the evaluation process.

The basic idea of the pre-processing was to provide integrative descriptive values, based on which the whole evaluation may be carried out; single line loads and voltage values are also available in each of the simulation periods.

In the stats out files, the so called 'expected shortfall value'- ES had been calculated, which is a very simple coherent measure of risk: it stands for the expected value of the worst 5%. For example, if we have 100 lines, and the normalized load value (between 0 and 1, where 1 stands for the maximal load) is given, then the ES is calculated this way: we take the ascending (non-descending) ordering of these values and take the average of the last 5.ES may be useful, because traditional statistical values (like the average or the maximum) are not always very representative, the whole distribution is on the other hand a too large data set to analyse.

The Table above shows the list of all planed scenarios. In this document, the visualization of the results is specific, that for each demo site, results had been calculated only for specific time frames and this is evident also from the graphs.

ELJ Slovenia provided topologies for two LV networks, Gradisce and Besnica. These two networks are not geographically close to each other. Slovenian pilot locations also have a different number of loads (mainly households), that is why the results are presented on separate figures. From the DSO perspective, we also observed other results; especially interesting were the results of settlement, for specific scenarios.

In the case of ELJ, the following scenarios were performed:

- Base case, base case summer (Scenario 1, 18)
- DNUT fix for bidder, remainder paid by buyer (Scenario 4)
- Congestion limit + punishment test (Scenario 6)
- Voltage limit + punishment test (Scenario 8)
- DNUT contains loss, congestion and voltage limit values (Scenario 11)
- Extra flexibility orders (Scenario 12)

Results of the simulations were given mainly for months of January, February, rarely for months in Spring and then again for all scenarios, results were available again for the Autumn period, as the scenario schedule describes Table .

6.2.13.3 Congestion management

Figures 20. and 21. demonstrate the effect of the congestion management mechanism built into the DNUT. The plots show the comparison between the line loads with and without the congestion management mechanism in place.

The results suggest that the congestion management mechanism built into the DNUT does not have a significant impact on the line loads in the current demonstration on the LV level. The line loads remain low with only minimal fluctuations throughout the simulation (except for Besnica site where an outlier value can be observed), indicating that the congestion management does not significantly affect the overall loading. This is due to the fact that congestion is extremely rare in such LV networks as line loading rarely approaches the permitted line loading limit. This holds for both demo sites and across all simulation periods. Line loading in the winter period tends to be higher due to the seasonal reduction in solarPV together with higher winter (heating) loads.

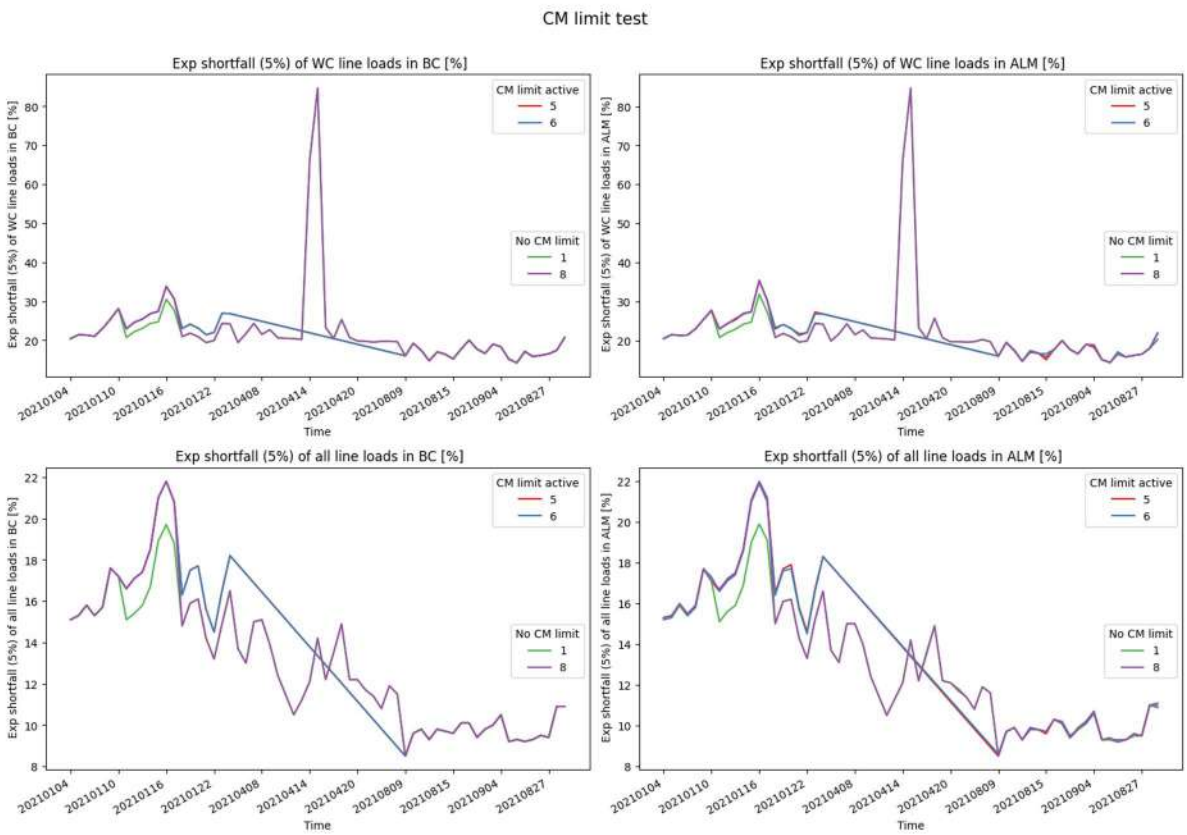


Figure 27: Besnica line loads with and without congestion management built into the DNUT.

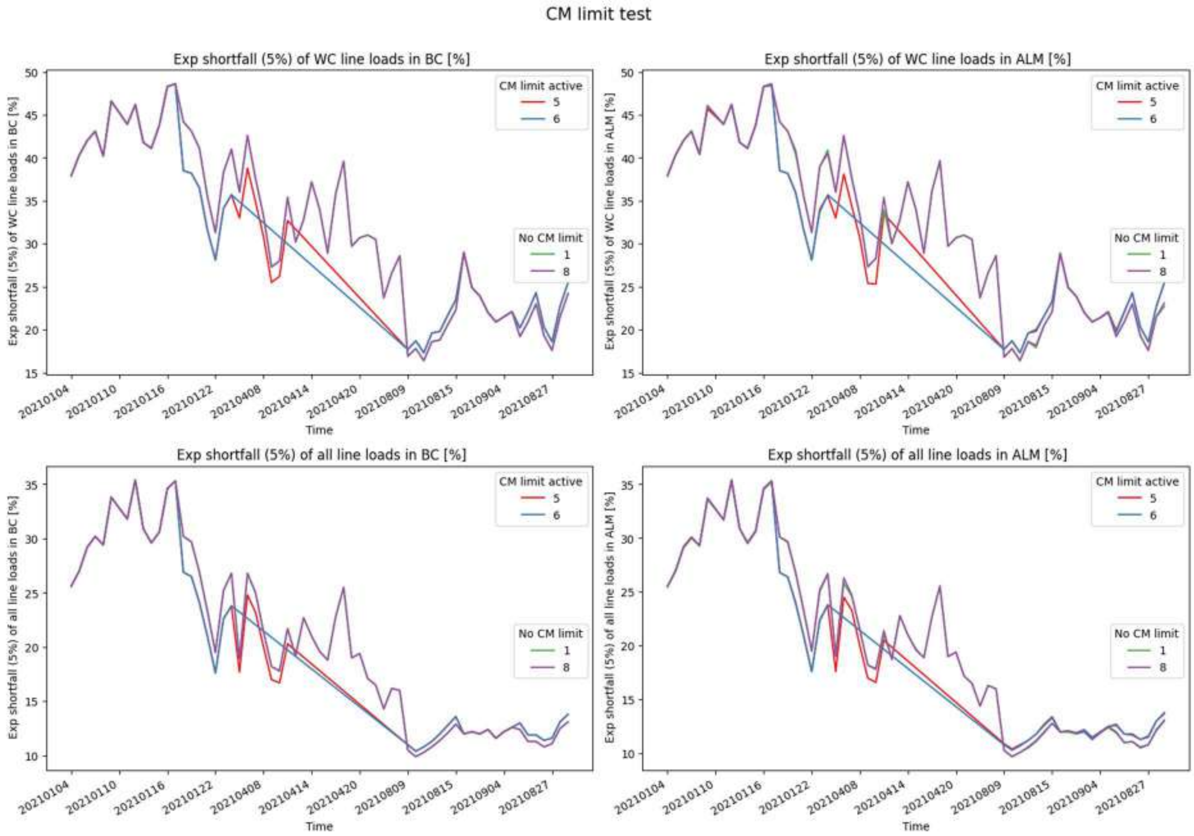


Figure 28: Gradisce line loads with and without congestion management built into the DNUT.

6.2.13.4 Impact of Loss in the DNUT Calculation

Figures 22, 23 show different levels of penalization for loss in the DNUT calculation and the corresponding loss per traded volume (LpTV) values. Scenarios 7, 8 show the LpTV values without considering loss in the DNUT calculation, while scenarios 1, 10 show the LpTV values with loss penalization in the DNUT calculation.

While the LpTV values do change slightly when loss is considered in the DNUT calculation, the changes are not significant and the overall pattern of the LpTV values remains the same. The reason for this is that the DNUT calculation without loss penalization already accounts for certain aspects of loss (e.g., scenarios 7 and 8 penalize voltage limit violations that strongly correlate with loss as well), so the additional penalization for loss does not result in a significant change in the overall LpTV values. However, there are small changes in the LpTV values when considering loss in the DNUT calculation, and this effect might be emphasized with more significant penalization of loss.

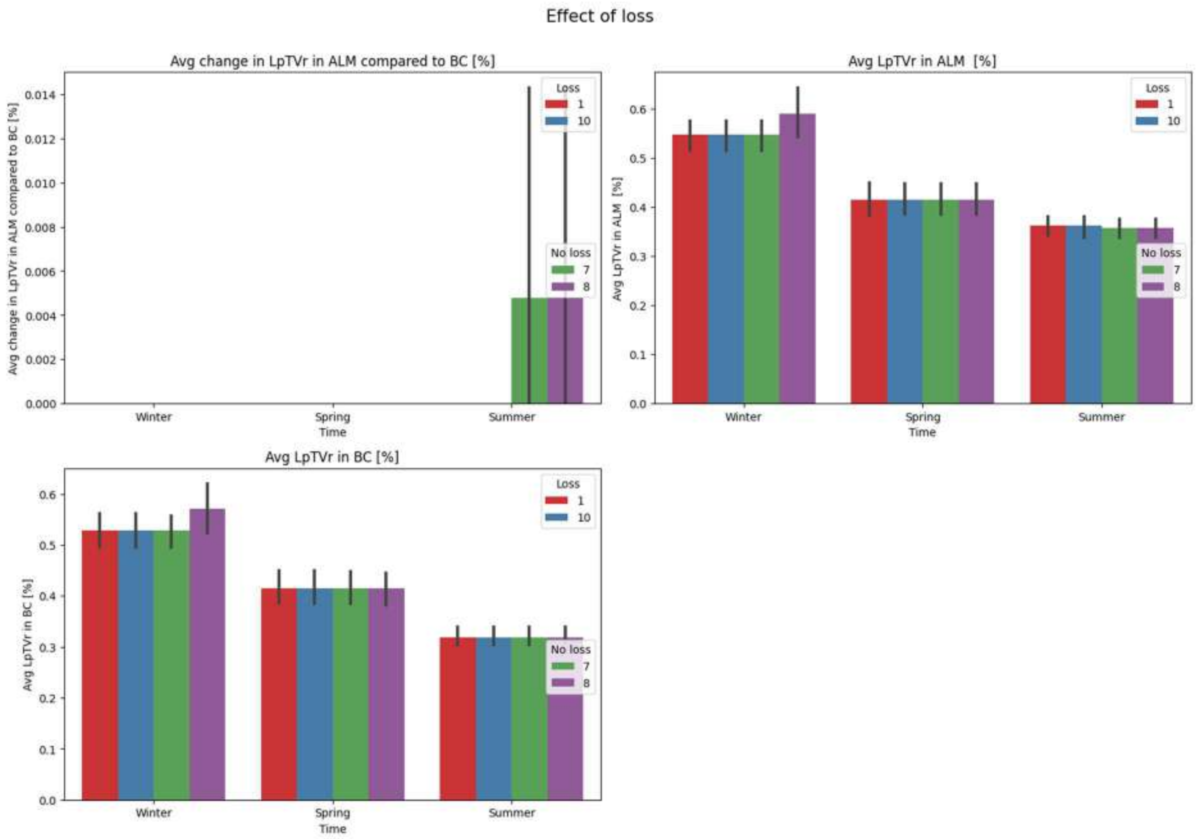


Figure 29: Besnica Loss per Traded Volume (LpTV) values with and without loss built into the DNUT.

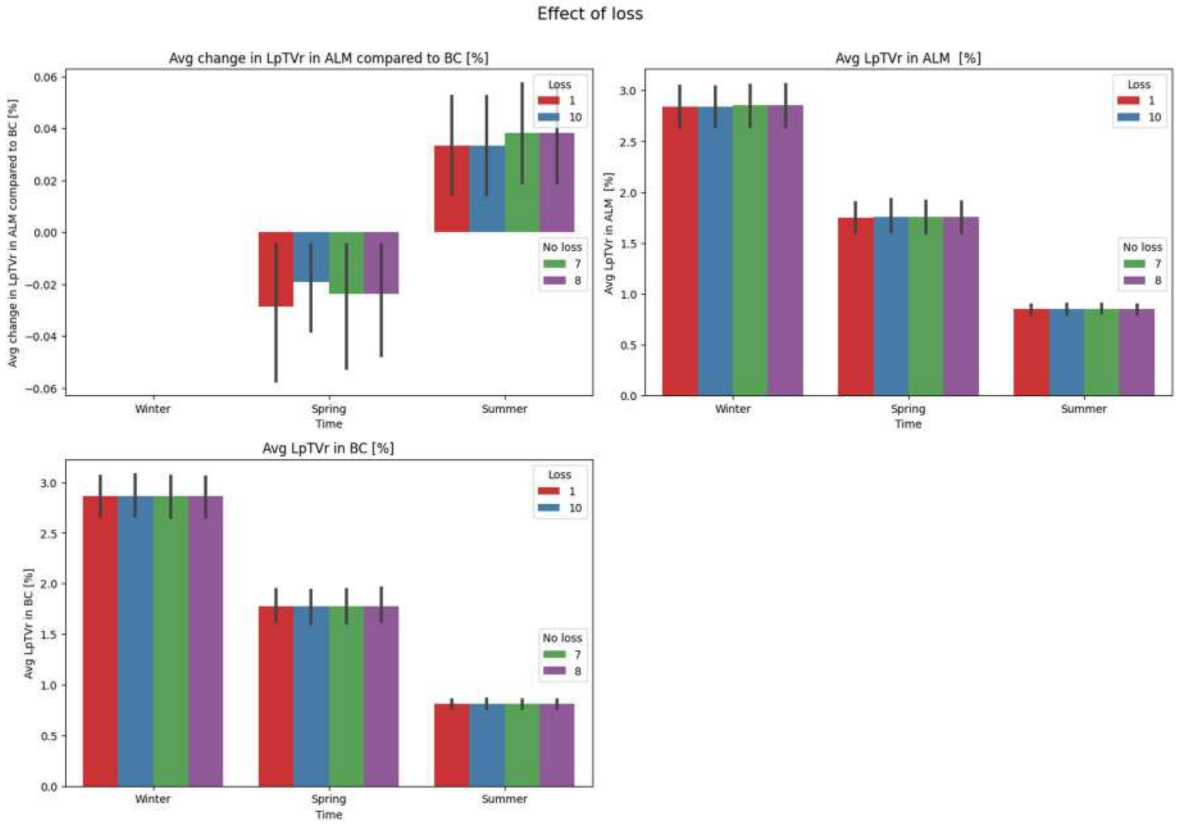


Figure 30: Gradisce Loss per Traded Volume (LpTV) values with and without loss built into the DNUT.

6.2.13.5 Effect of Voltage Regulation in the DNUT on local market activity

Figures 31, 32 show scenarios representing different types of voltage regulation in the DNUT and its effect of local market activity.

The figures demonstrate that when a voltage regulation element is built into the DNUT (scenarios 7, 8, 10), there is no significant impact on local market activity compared to the baseline scenario (scenario 1) or compared to other scenarios without voltage regulation (scenarios 5, 6). However, when congestion management is introduced into the DNUT (scenarios 5 and 6), there is a small but noticeable reduction in local market activity, which is due to the limited variability of orders in terms of congestion management compared to order variability in terms of voltage deviation. These effects are based on the settings of DNUT cost elements, as linear costs for current and voltage changes were introduced.

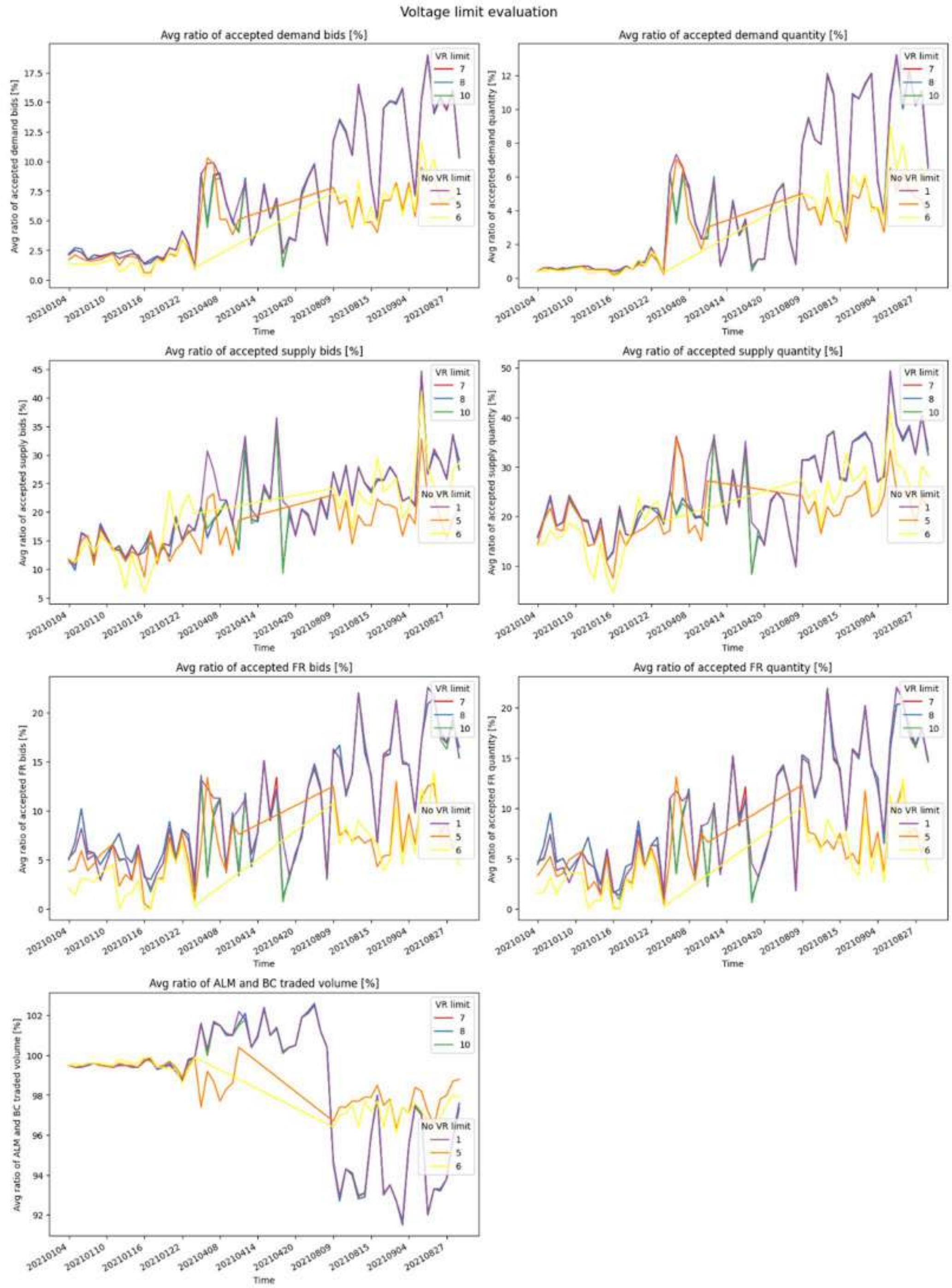


Figure 31: Besnica effect of active voltage regulation element built into the DNUT in terms of local market activity.

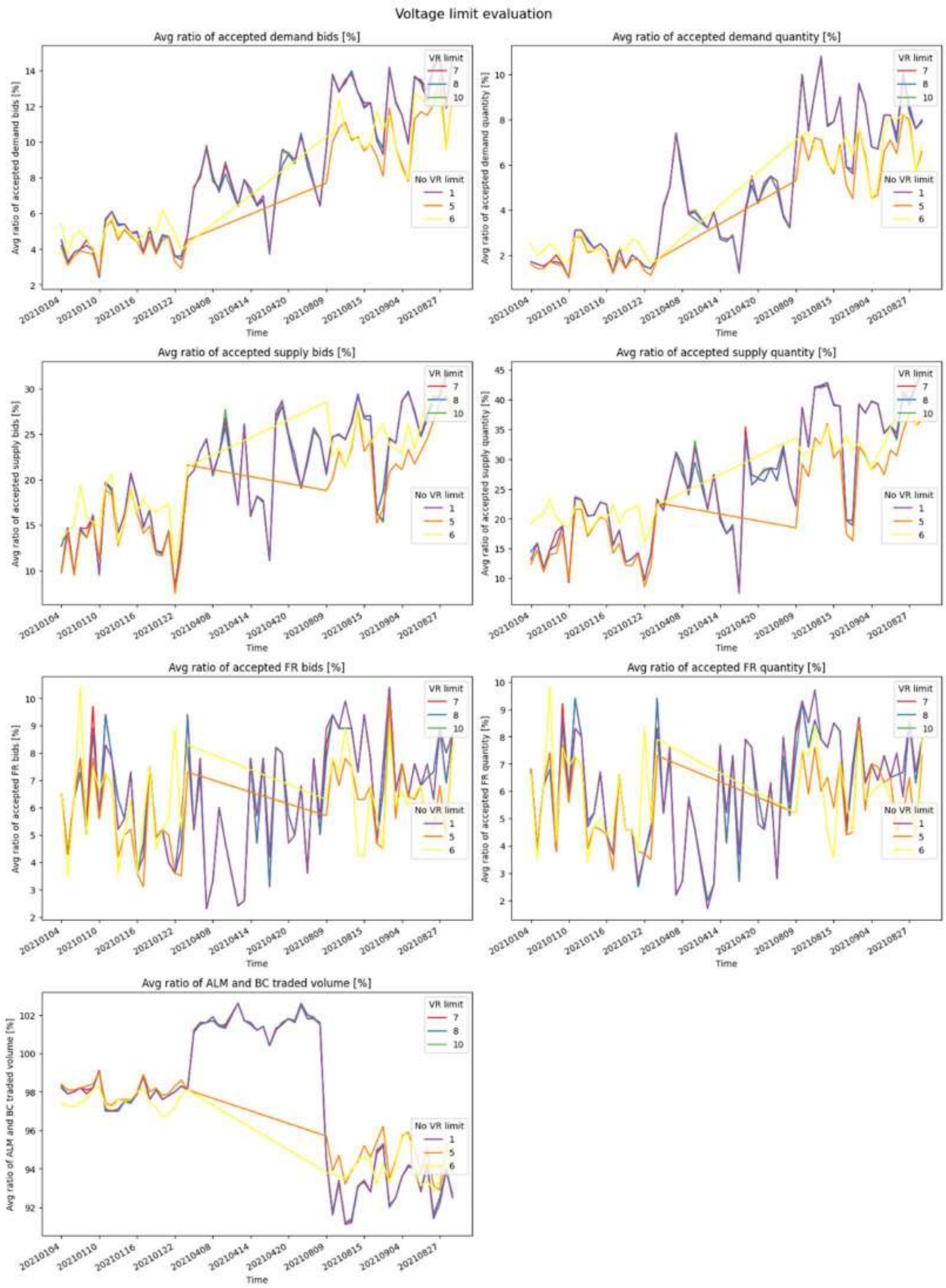


Figure 32: Gradisce: effect of active voltage regulation element built into the DNUT in terms of local market activity.

6.2.13.6 IACMS effect evaluation

The objective of IACMS was to allow increased energy flow through the assets, so as to not limit the operation of the local market.

The below tables summarize the inputs and outputs of IACMS for one demonstration week (4-10 January 2021) in the Besnica demo site.

Table 10 Input weather parameters of the IACMS for the week beginning 4 January 2021

Weather Parameter	Average value for 7 days of the week	Min value for 7 days of the week	Max value for 7 days of the week
Ambient temperature (°C)	1.757	-0.6	4.6
Wind speed (m/s)	0.433	0.11	1.22
Wind direction (degree, most significant)	58.494	-	-
Solar radiation intensity (W/m^2)	150	150	150
Precipitation intensity (mm/h)	0	0	0
Relative humidity (%)	98.077	94.87	100
Rain	0	-	-
Snow	0	-	-

Table 11: Results of IACMS calculation on the transformer

Transformer	Value
Average rated load (kVA)	50
Average permissible load (kVA)	66.3636
Min permissible load (kVA)	65.1
Max permissible load (kVA)	67.4
Total excess energy over static load (kWh)	2749.08

Table 12: Aggregated results of IACMS calculation on cables

Cable	Value
Average rated load (A)	178.25
Average permissible load (A)	185.5553

Total excess energy over static load (kWh)	3401.16

Table 13: Aggregated results of IACMS calculation on overhead lines

OHL	Value
Static line rating (A)	160.5
Ambient adjusted line rating (A)	235.9971
Total excess energy over static load (kWh)	17574.80

Figures 26, 27 compare local market activity in Besnica and Gradisce for scenarios with and without IACMS active.

Figures 26, 27. show that the expected shortfall of line loading decreases in the Slovenian sites when IACMS is active meaning that line loadability in these cases is higher (with some exceptions including scenario 4 that has a very high market activity due to the DNUT sharing protocols). This highlights the benefits of using the IACMS tool, as it helps optimise network utilisation by providing more information about line loading and increasing market activity, making IACMS an essential tool for grid management.

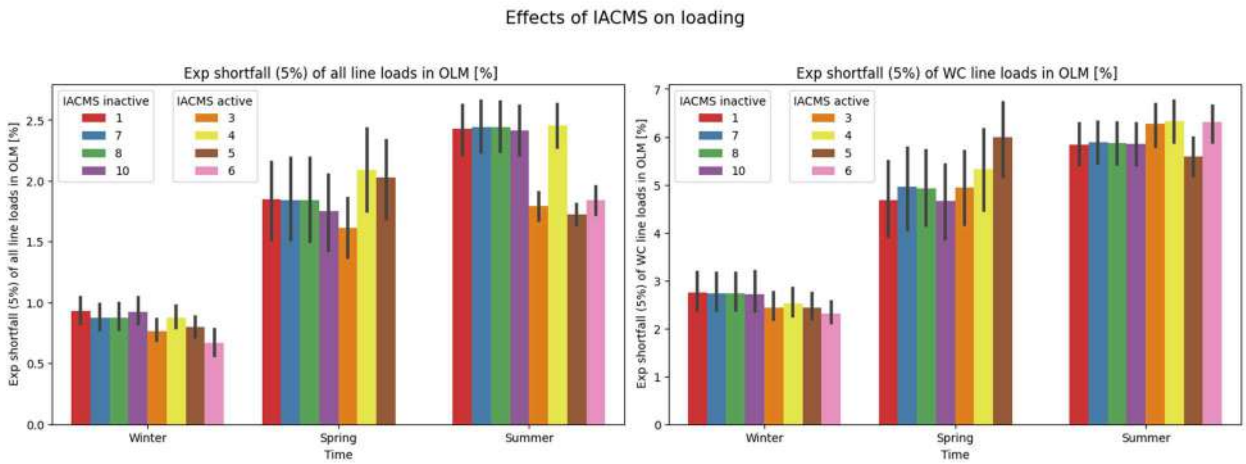


Figure 33: Gradisce: local market activity according to IACMS activity status demonstrated by the expected shortfall of line loading.

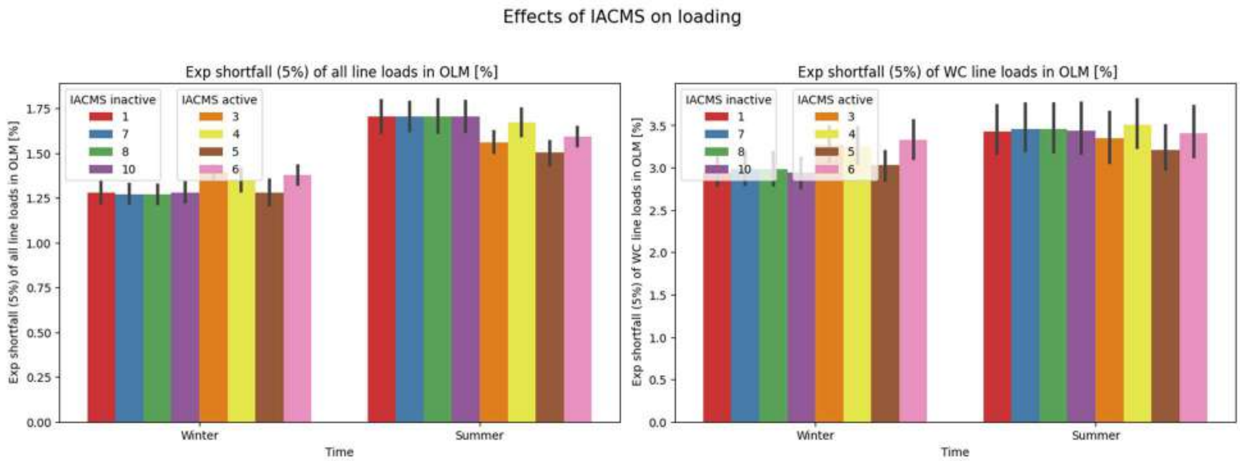


Figure 34: Besnica: local market activity according to IACMS activity status demonstrated by the expected shortfall of line loading.

6.2.14 Summary of the P2P market result, relevant for all pilot sites

The integration challenges of renewable energy transform the entire value chain of the power sector. The future market model can be differentiated on several levels: it could be dependent on the amount of energy, transmission distances, the number of participants, etc., but the decentralization is inevitable. Local energy generation is becoming widespread nowadays, not only for economic reasons, but also as a representation of independency and decent behavior. Peer-to-peer (P2P) markets aim to provide trading opportunities between a large number of market players, even when buyers and sellers are fragmented. Also, auctions on P2P markets are a flexible solution, allowing prices to respond to market conditions. This local market structure is appropriate to enhance the customer's access to new energy-related market activities, which therefore could play a part in the energy transition. The players on this marketplace shall submit their bids (if they are buyers) or offers (if they are sellers). These shall include information on the quantity of electricity and the network connection point where the exchange will take place. Consumers may buy electricity from sources different than their local retailer and can also offer their household generation for sale. The introduction of this market structure is feasible in parallel with the conventional one. There is a possibility to handle services through such P2P markets. If the trading is not done between two consumers, but between a consumer and a DSO, the DSO can create a group of bids and offers, thus creating means of flexibility. Such flexibilities can either be used by the DSO for grid services or aggregated/forwarded to the TSO, depending on the wholesale TSO-DSO coordination scheme. The DSO and the TSO also participate in the market, and they can both behave as bidders: by specifying and pricing their flexibility needs (and the price they are willing to pay for it), they can enhance the utilisation of local sources. This latter aspect is also necessitated by the merging of traditional DSO and TSO operations, which converge previously separated tasks, thus the demonstration could provide a way for testing this aspect as well.

This marketplace is based on the P2P concept and provides the possibility to create local energy transactions by simulating the behaviour of market participants in line with different bidding strategies from previous research. The load and generation datasets are derived from DSO databases to create realistic reference situations. Then the effects of the different bidding strategies can be analysed. The demonstration aims to examine the cooperative use of these two elements of the toolset. 3 DSOs are involved, 2 from Hungary and 1 from Slovenia. The DSOs offered unanimous measurement data about the demonstration locations and provided inputs to create a new dynamic network usage tariff (DNUT). The concept of dynamic tariff based on forecasting the constraints by network calculation is not widely implemented in practice. Integrating such solution with the P2P concept is generating new ideas as frameworks are being developed. In these demonstrations, prosumers can buy and sell electricity either from this local market (P2P context) or from the retailer in the already existing framework. In addition to the P2P context, the project proposed a novel dynamic network usage tariff scheme (DNUT). The grid fees for each transaction are calculated by the actual effect on the infrastructure (losses, voltage limits, overload, asymmetry effects considered). To calculate such, the project developed a modelling approach tailored for medium voltage (MV) and low voltage (LV) networks, which is appropriate for steady-state analysis. Since P2P markets have a large number of expected bids, and the calculation must pair a DNUT (grid effect) to each bid, a sensitivity-factor based simplification is proposed instead of running a large number of load flows. With these tools, end users can behave as “market participants”, dynamic pricing can be used efficiently, and the effects of network asset constraints can also be taken into consideration. Data used for the demonstration will be provided by affected DSOs, while the behaviour of consumers is to be examined by the involvement of consumers in the affected DSO service areas. The demonstration focuses on upscaling the role of customers and creating new services and market rules within the local marketplace. These tools will be part of the Interoperable pan-European Grid Services Architecture (IEGSA); thus, their collaborative operation could be demonstrated, and mutual benefits could be exploited. The IEGSA has to provide an interface for consumer participation, an access for DSOs, and a pool for asset condition data.

Most of the output variables have not shown any sign of change, depending on the characteristics of each scenario, and even those, that did, further investigation would be needed.

- Presented variables give significant information (loss, voltage deviation, etc.) about how the network would respond to each trading scenario, but as it is presented in the previous chapters – a minor of them had shown any signs of changes during the aforementioned scenarios. This leads to a conclusion, that the trading does not have any significant impact on the network, which is possible, because the number of local RES is low.

The results obtained for voltage deviation has a mismatch achieving unexpected values which will be investigated in the future.

6.2.14.1 Transparency in data and communication

During the demonstration the sensor usability was ensured in IACMS module. The IEGSA platform connection via interfaces were effectively developed and implemented. The detailed running results mentioned above proving the business case of the P2P local market concept. This complex and international cooperation seemed to be a success story in spite of difficulties.

6.2.14.2 Scalability

The approach of asset-enabled local market platform is demonstrated to be an effective tool for various, differently designed DSO operational environment, and distribution grid sections. The applied methodology can be thus used in any, non-looped, tree-like distribution network, to solve various grid service requirements. The ease of use, energy product based bidding can deliver benefits for multiple stakeholders, system operators, individual and aggregated grid users, and can further provide an entry point for higher level (system balancing) of local flexibility aggregation. This approach is recommended for further usage as a single solution can be of use for a multitude of scenarios, local specialties, with single aimed, or combined use cases.

6.2.14.3 Use cases for participants

Different use cases were tested, and can be further included, on the basis of energy product biding.

- DSO congestion management – as a distributed marketplace helping congestion alleviation
- Settlement platform for energy communities, with usage tariff markups providing a single channel for multiple incentives
- Providing local balancing
- Peer-to-peer trading with grid tariff incentive
- Incentivizing self-reliance of network areas – moving towards autonomous microgrids

6.2.14.4 Conclusions

This demonstration described a P2P local market concept which is applicable for distribution networks. The opportunities with the proliferation of such local P2P markets were described. The INTERRFACE simulation framework was introduced from the viewpoint of demonstration analysis. The basic concept of the market operation and DNUT was presented. Thanks to the dynamic network usage tariff (DNUT) facilitating transactions which result in desired flows according to the actual state of the distribution grid, several measures describing the efficiency of operation are expected to improve during the simulated operation of the local market. The loss compared to total trading volume is expected to be reduced. Line congestions and near-overload of system components (e.g., transformers) are expected to be alleviated, in an ideal case, the load of the network will be more balanced. Voltage regulation measures are expected to improve (in the case of the corresponding DNUT calculation – the DNUT does not always include elements related to voltage stability). The results showed that the framework is capable of providing data for evaluation of the local P2P market. However, in the first scenarios, there are not large differences due to the bidding strategies. Further analysis with increased activity could show the potential of the developed tool. The proposed local energy market provides an opportunity for participants to translate their flexibility potential to local transactions financially beneficial for them. If a consumer participant is ready to reschedule some of its peak load, and energy is available at the local market at an appropriate price, the peak-shaving of overall consumption patterns may be realized via the result of such transactions.

6.3 Research project introducing novel tariffs based on the predicted highest local power peaks- commercial name "Save money as Active Consumer"

Easing the burden on the distribution network through the use of the Active Customer, or the official name of the project under which it was submitted to the Energy Agency of Slovenia (financing it) was given as "Use of a critical tariff enabled in a regulatory framework to reduce the overburdening of the distribution network".

The proposed project meets the requirements of the legislation because it:

- Will use new equipment, which in the proposed way of use is not yet established in the Republic of Slovenia,

- Will explore a new way of network operation and planning, which will demonstrate positive effects with the aim of deferring the investments in the power network assets.

- Will propose a new business model in relation to active electricity consumers, from which the latter would benefit (increasing energy efficiency and generating positive financial effects).

6.3.1.1 Background of the pilot project

The commercial name of the project, when communicating with grid users (GU) was "Manage and save". The aim of the project was, to provide GU additional tariffs. This means, that users were offered additional tariffs beside existing two (high and low) tariffs, with prices intended to incentivise them to increase or decrease their consumption. These additional tariff are defined by the legislation as Critical Peak Power Tariffs (KKT). 15 min smart meter data was considered obligatory by the Metering department, so as to ensure month end completion of 15 min values for each GU.

This project focussed on the methodology for determining the regulatory framework and the methodology for calculating network charges for electrical operators, in accordance with Article 135 of the Act.

The additional tariffs, beside the basic high (VT) and low (MT), unit tariff (ET), defined by the Act were:

Prices valid from	Type of consumption	Tariffs	consumed active electrical energy [EUR/kWh]				
		Connection power fee [EUR/kW/month]	PKKT	NKKT	VT	MT	ET
01.01.2021	Households KKT VT	0,72515	0,28917	0,01040	0,03026	0,02326	0,02690
	Households KKT MT	0,72515	0,28786	0,00909	0,03026	0,02326	0,02690

	Households KKT ET	0,72515	0,28873	0,00996	0,03026	0,02326	0,02690

Table 1: Slovenian Energy Agency published prices for the special KKT tariffs, valid in 2021

Prices valid from	Type of consumption	Tariffs	consumed active electrical energy [EUR/kWh]				
		Connection power fee [EUR/kW/month]	PKKT	NKKT	VT	MT	ET
01.01.2022	Households KKT VT	0,77417	0,83937	0,01262	0,03143	0,02417	0,02728
	Households KKT MT	0,77417	0,83806	0,01131	0,03143	0,02417	0,02728
	Households KKT ET	0,77417	0,83893	0,01218	0,03143	0,02417	0,02728

Table 2 Slovenian Energy Agency published prices for the special KKT tariffs, valid in 2022

VT: high tariff	every working day from 6 am to 10 pm
MT: low tariff	every working day from 10 pm to 6 am, all weekends and national holidays
ET: the price of a tariff does not change, for all time slots it is same, unique	

Table 3: Time slots, when the basic/ normal tariffs are valid.

Some clarifications: Monthly fees, which depend on the connection type (households rated capacity is e.g. 7 kW, or 10 kW, or 14 kW up to 41 kW- if a household uses a heat pump) of the user: Power fee (0.74142 EUR/kW/month) and a fee for other fees as e.g. RES fee (renewable sources) and CHP fee (combined heat and power) - monthly fees, comprise the fixed part of the tariff. This part is not relevant for the savings of the GU in case of their active participation in the project.

Due to difference in regular tariffs (GU who did not take part in the project) and the KKT tariffs/rates, customers who participated in the project, saved some money, even without any active change of their load during the times when they were informed about the KKT rates. This is more evident from the next table, where the reader can see, how much were some tariffs are cheaper.

Regular prices for other GU, households:	VT EUR/kWh	MT EUR/kWh	ET EUR/kWh	Difference in prices regular and KKT	VT EUR/kWh	MT EUR/kWh	ET EUR/kWh
Households, valid from 1.1.2021	0,03734	0,0287	0,03444	Direct benefit for GU	-0,00708	-0,00544	-0,00754
Households, valid from 1.1.2022	0,04182	0,03215	0,03858	Direct benefit for GU	-0,01039	-0,00798	-0,01130

Table 4: housholds particpating in the project, got additional lower prices for regular tariff, which meant for them additional direct savings

From these tables we can see, on how the additional tariffs stimulate customers to change their consumption: in case if we provide them the information about the validity of PKKT, very high price, this was for them a signal to reduce the consumption. Opposite, when we informed them about the valid time slots for NKKT, this was for them a signal to increase consumption: load shifting.

Prices valid from	Type of consumption	Tariffs	price difference to stimulate customers	
		Monthly connection power fee [EUR/kW/month]	PKKT	NKKT
01.01.2021	Households KKT VT	0,72515	856%	-66%
	Households KKT MT	0,72515	1138%	-61%
	Households KKT ET	0,72515	973%	-63%

Table 5: Price list of KKT tariffs valid in 2021

We can see below, that in 2022, Agency changed prices in order to encourage more active participation by customers: these rates mean that GU can save more, but can also be penalized more.

Prices valid from	Type of consumption	Tariffs	price difference to stimulate customers	
		Monthly connection power fee [EUR/kW/month]	PKKT	NKKT
01.01.2022	Households KKT VT	0,77417	2571%	-60%
	Households KKT MT	0,77417	3367%	-53%
	Households KKT ET	0,77417	2975%	-55%

Table 6 : Price list of KKT tariffs valid in 2022

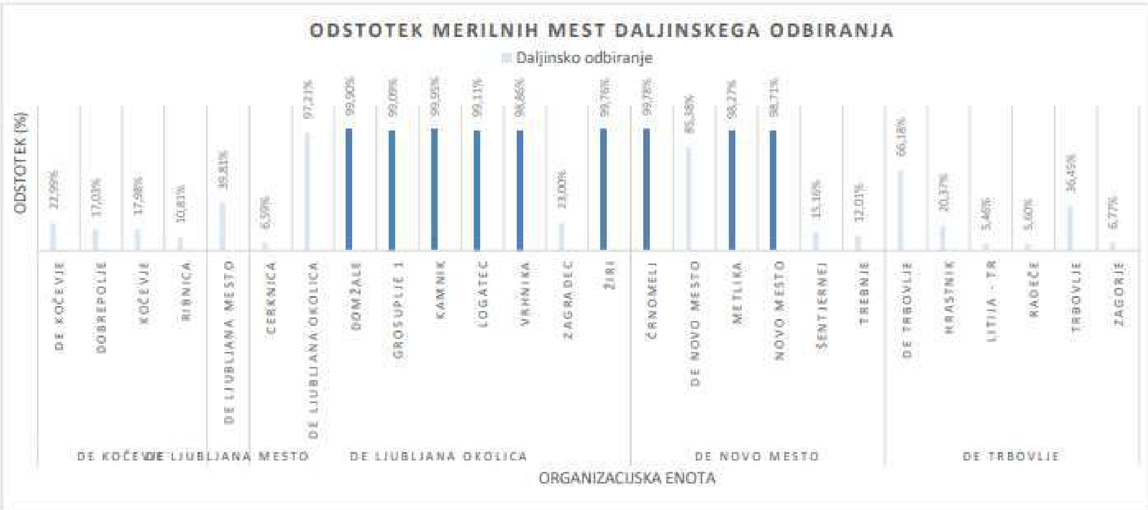
PKKT rates were provided whenever the forecast for a coming week showed values close to or above the transformer rating. Conversely, about the NKKT rate, e.g. applied during working weeks, when load forecasts indicated that consumption will be low. This comprised was a load shifting trial.

6.3.1.2 Selection of the GU:

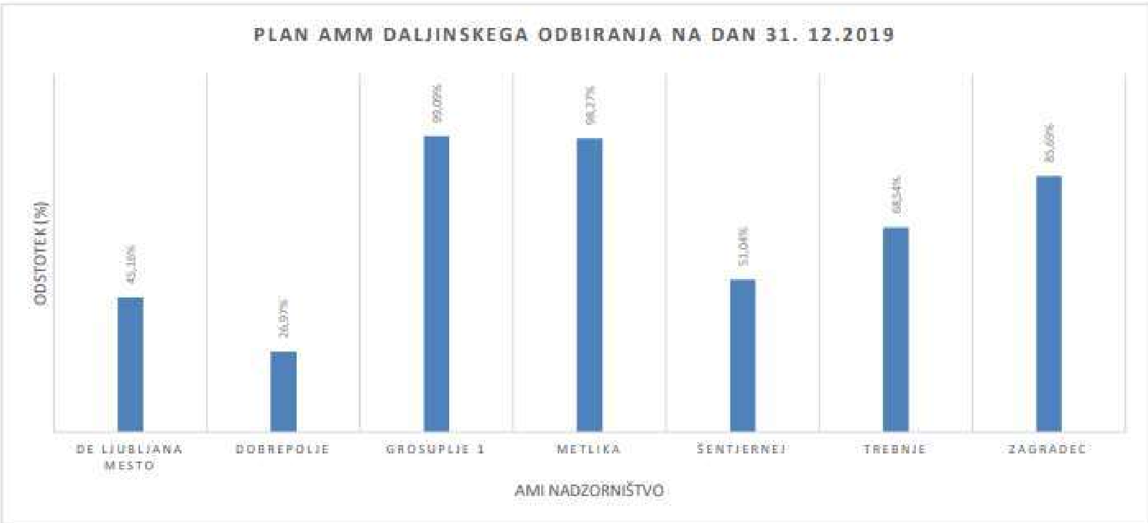
First step in the project was the methodology on how to select the GU, who will be invited to cooperate and are connected at the low voltage (LV). The aim of provision of additional tariffs-KKT was, that GU who would respect the tariffs will with their right consumption/load change help the grid: when the prediction of the MV/LX transformer station would point possible overload, then the customers will be informed about KKT with very high prices and so it is assumed that they would response with decreasing their consumption. Conversely, when the forecast indicates gaps in the load profile, GU will be invited to increase their consumption and thanks to using energy during cheapest time slots, save money.

As mentioned, the project will involve GU from preselected parts of the LV grid, which are facing with MV/LV transformers, operating at upper level of their default operation stage. This was done as a study of the entire Elektro Ljubljana., electric power network, comprising 342,165 active metering points. The study uses various criteria and aspects of measuring, on the basis of which the most optimal area was proposed:

- Ratio of each type of smart meter, so as to ensure highest level of data availability (PLC). Of course all metering points must be equipped with a smart meter, optimised to reduce the number needed to be replaced.



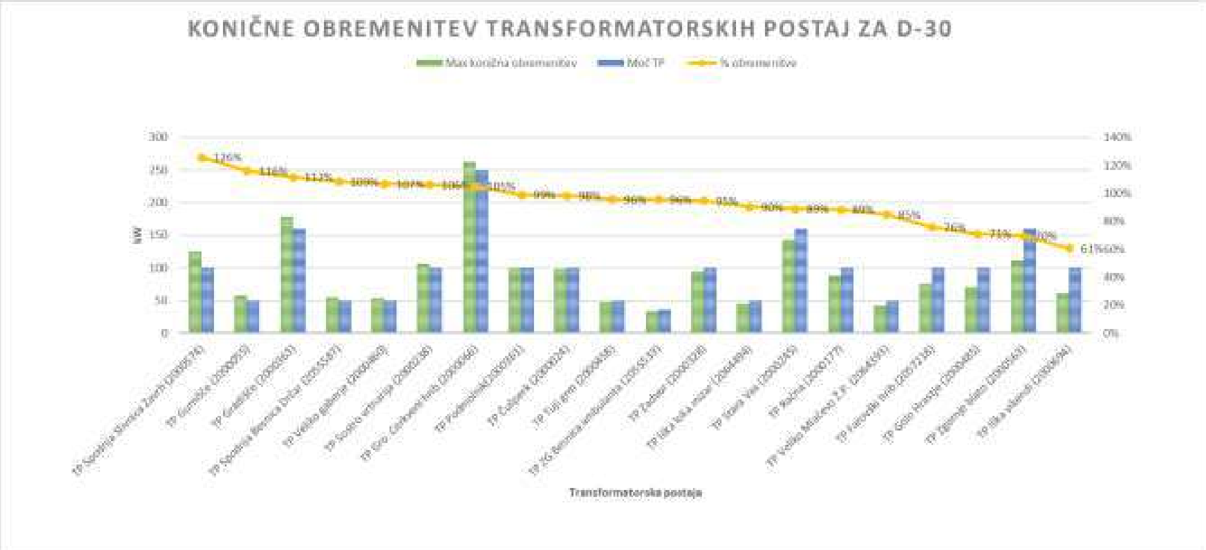
Graf 2: Odstotek merilnih mest daljinskega odbiranja (Vir: eIS, 30.5. 2019)



Graf 3: Plan AMM daljinskega odbiranja na dan 31.12. 2019 (Vir: eIS, 30.5. 2019)

Figure 4: % of all metering points with remote meter reading, second graph is about the plans to establish remote meter reading.

- If transformer station sum meters are installed, measuring the transformer, and LV feeder, loads, will identify which stations are most loaded and for longest time per year,



Graf 2: Konične obremenitve transformatorskih postaj (Vir: Advanced, 9. 07. 2019)

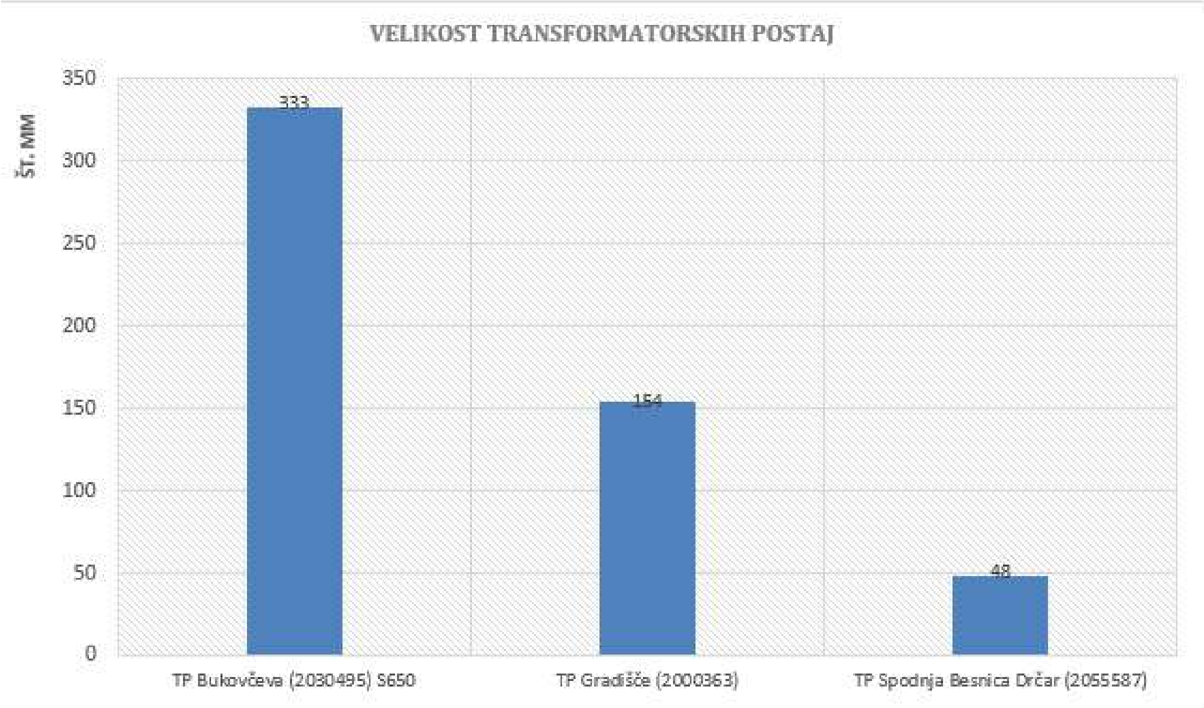
Figure 5 : peak loads of transformer stations, D-30

- Further analyses were also: types of GU, number of RES, who is the supplier (important because of later billing process).

The results of the study were that the pilot as the most optimal area for the involvement of GU, could be either area of city Grosuplje or as a potential area around city of Metlika.

As a result, from this study 3 MV/LV transformer stations were selected:

- “Domžale”, with more than 330 GU,
- Gradišče”, with more than 150 GU,
- Spodnja Besnica Drčar”, with more than 50 GU(2021).



Graf 1: Število merilnih mest po transformatorskih postajah (Vir: eIS, 25.09. 2019)

Figure 6: number of metering points, at the selected transformer stations, which were selected to participate in the project

Direct invitations by post (DSO has limited data of GU, these are name of the owner or payer, address and city).

From all invited GU 24% (128 of 535 GUs) accepted the invitation to participate.

6.3.1.3 Dataset data from smart meters

In the project 3 MV/LV transformer stations were involved (nominal power):

Gradisce Spodnja Besnica Drčar Domžale -Bukovceva

160 kVA 50 kVA 630 kVA

These data set were used for forecasting the load of each transformer. Every Monday, using MATLAB Forecasting Tools, SW provide data set. Based on the analytics (graphical), we prepared the time slots for tariffs. One of the examples of the graphs, forecast was made on hourly time period basis:

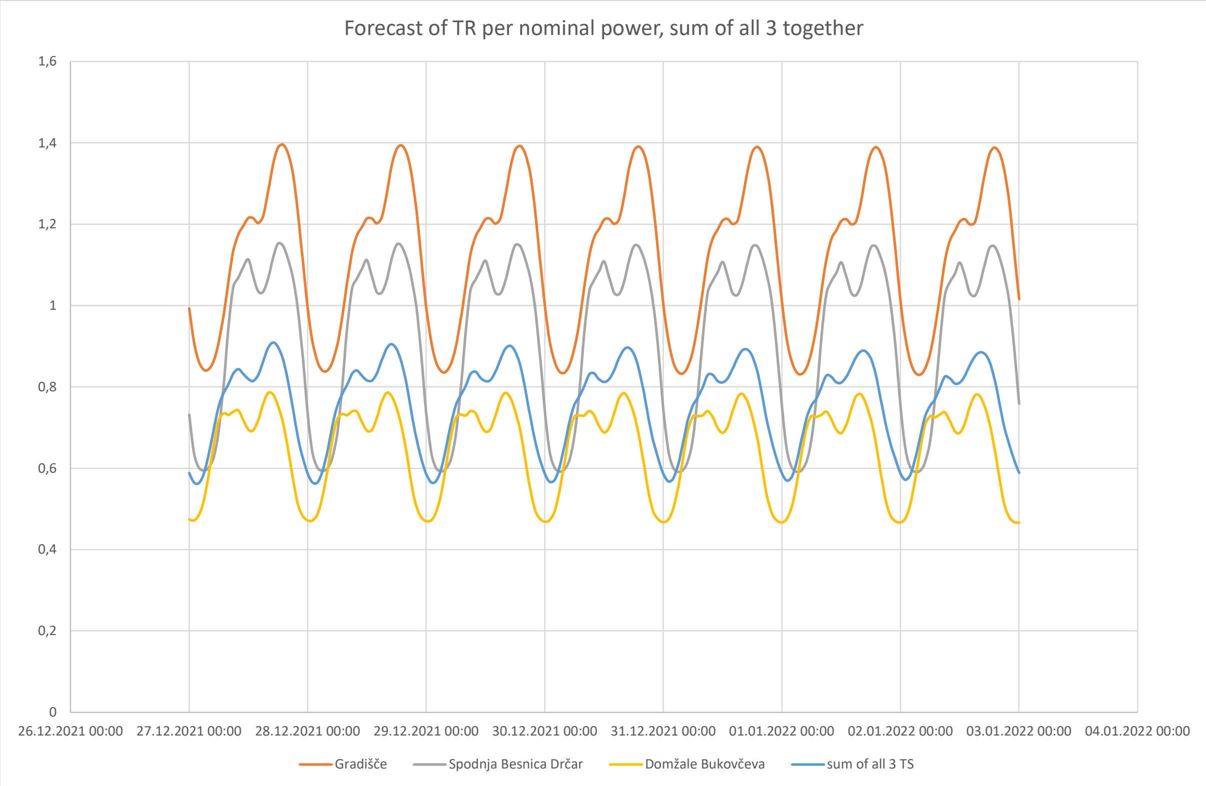


Figure 7: load forecast per transformer station, for one week

In general there was no variety between load curves on a daily basis for one week forecast. So the DSO has to decide on how to exploit the available tariffs to "correct" load line. Usually, we tried to stimulate GU to shift the consumption, which means that we provided NKKT. In time slots, where we identified a potential transformer overload, we informed the GU about PKKT via SMS, to decrease the consumption. Informing GU had been done manually, providing text SMSs, usually 2 days in advance, sometimes we also repeated the notifications.

Supplier role:

At the beginning of the project, one of the biggest Slovenian suppliers also participated, to explore the opportunity of ensuring higher availability and reliability of the data, which the smart meters are able to provide. They were also involved in our campaign of collecting the active GU, but ceased participation after the first year

The dongles are produced by Astron, Connects to Landis & Gyr E450 - I1 port and this device which is implemented just next to the smart meter, is capable to ensure electricity meter data (WEB, REST API) in Real time with secure access.

Main features of these devices:

- Flexible & adjustable data transfer interval
- LTE NB-IoT secure mobile communication
- No external power supply
- Ultra-low power consumption

- Simple upgrade solution for installed & operational electricity meters
- Easy plug & play installation and provisioning
- Tested with Nokia, Ericsson, Huawei cellular LTE NB-IoT networks

Smart meters:

While all meters in the project are smart and connected via PLC to a local data concentrator, some periodic metering data was lost during network disruptions. As a consequence, there were occasions when manual meter reading was required to enable the dynamic tariff billing to be completed.

6.3.1.4 Analysis and discussion on the experiences

1) Question: when providing lower price for net usage, did GU respond and increase their consumption, instead of using electricity in other more expensive or even cheaper time slots?

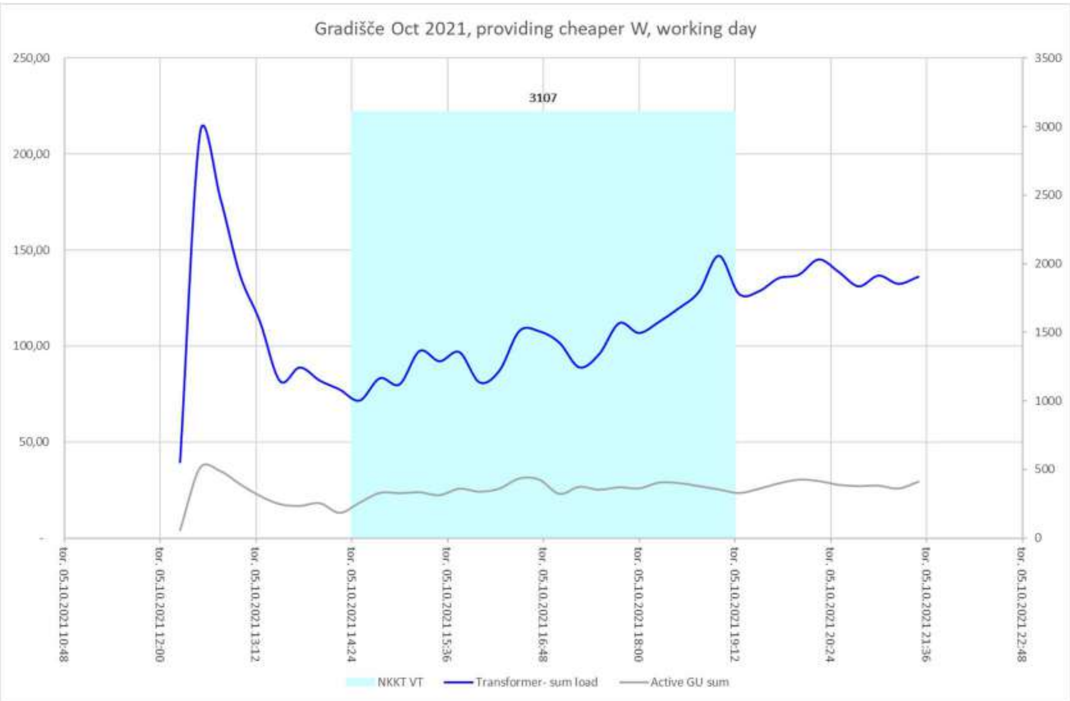
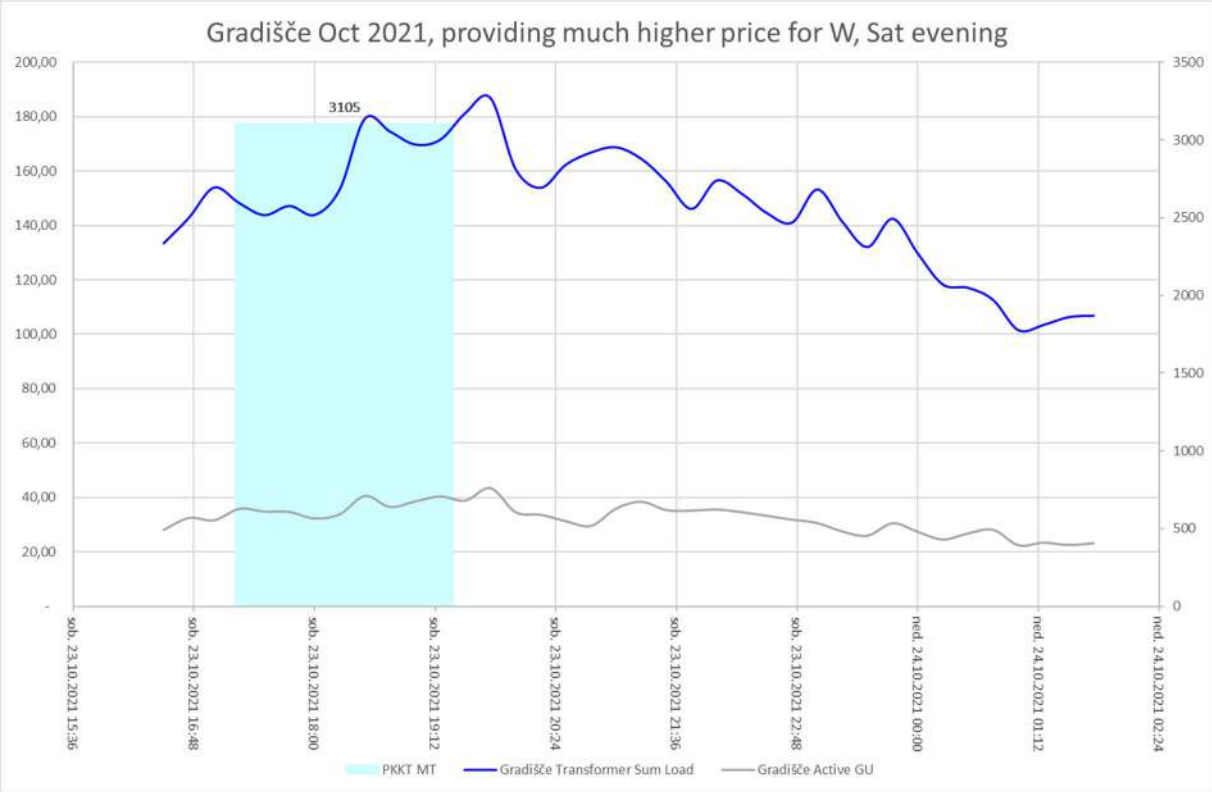


Figure 8 : Afternoon, we provided cheaper tariff, there was an effect

2) Question: when providing highest prices for net usage, with the aim to decrease transformer loading, did active GUs decrease their consumption?



Facts: active grid users represent only ¼ of all GU connected to observed grid areas. Most of them do not have bigger (power and energy) electrical devices, such as heat pumps, with which they could respond. These are two main reasons, why the results are not convincing as expected.

Some conclusions: GU were willing to participate, namely they automatically paid lower prices for grid usage. We believe, that they really collaborate, actively, but because of below 100 % participation, the effect on the transformer loading was minor or sometimes worse. There is still a strong barrier: GU will not change their consumption (inelastic demand) in cases when they decide, to do a specific home task, which is for them un deferrable at a particular moment. Typical time slots, when the GU will neglect even the highest prices for electricity are weekend evening hours.

7 Conclusions and Outlook

In this report, we review the survey, technical feasibility and difficulties for dynamic network tariffs of current practices and existing proposals for dynamic network tariffs in global distribution systems. A detailed discussion is made in determining the updating period of dynamic network tariffs (1 hour, 0.5 hours, 15 minutes, etc.) in various voltage-level distribution systems and methods of designing dynamic network tariffs for various voltage-level distribution systems, and constraints to be respected. It should be noted that the research in this area is not over yet, and we will continue to pay attention to developments in this field.

The use of dynamic network tariffs in various countries is still in its infancy. The scope of the pilot should be further expanded. The participation of all stakeholders – suppliers, consumers and energy services companies – is key to ensuring the pilot is successfully implemented. There should be adequate indicators to assess how dynamic tariffs can change aggregate and peak consumption. Also, the total benefits of these new schemes should not only be seen as DSO or customer benefits: all System gains and costs shall be considered during the pilot. Although some of the expected gains are long-term-related, the pilot should help understand how much this type of tariff will impact customer behaviour and network costs. The ultimate goal of this research is to adjust the power demand by reflecting the cost of power transmission through the dynamic network price. With the active participation of various countries and the continuous addition of various advanced equipment, the perfect and scientific dynamic network tariffs mechanism will not be far away.

8 LIST OF FIGURES

expected shortfall of line loading
Besnica: local market activity according to IACMS activity status demonstrated by the expected shortfall of line loading

9 LIST OF TABLES

10 REFERENCES

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