DSOs Using Demand-Side Management Techniques For Reducing Congestion Issues: The Case of ASM Terni

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Abstract[1]

In this paper we focus on the effects of the renewables and electric vehicles on the LV/MV network and assess the potential of Demand Side Management techniques in dealing with the associated technical issues, namely Congestion on MV/LV feeders due to Reverse Power Flows (RPF) or High Loads. We follow a simulation-based approach to identify the market conditions that render Demand Side Management services for reducing congestion issues both attractive and commercially viable for buyers and providers of flexibility respectively.

1. Introduction

The majority of the electricity system or "grid" all over the world was built when the cost of energy was reasonably low. Over the years, this aging power grid had to cope with new challenges imposed by higher demands and increasing nonlinear loads; thus, placing new reliability concerns. Even as demand has skyrocketed, there has been a continuing underinvestment in transmission and distribution, thus limiting even further the grid's efficiency and reliability. In order to keep up with this

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ever-increasing demand, the energy providers, from their side, are dictated vastly to activating peak load generators that are both monetary and environmentally cost inefficient. This results in prices significantly rising, not necessarily - and in most cases this is the case - as a linear function of the demand, which is in turn translated to high energy charges for the consumers. The move to a smarter grid is not only essential but – one could say – inevitable, as it promises to change the entire business model and its relationship with all stakeholders and all consumers of electric power [DOE], thus transforming the grid into a more efficient, reliable, communication-enabled system.

In essence, smart power grid is a host of solutions that is aimed to realize all the aforementioned goals by "empowering consumers, improving the capacity of the transmission lines and distribution systems, providing information and real-time pricing between the provider and consumers, and higher levels of utilization for renewable energy sources" [HMA+13].

Furthermore, as climate changes accelerate, there is an apparent need to identify and employ ways of using energy more effectively as well as generating electricity with less emissions. The effective management and reduction of loads and wasted energy (losses) crave detailed information knowledge, while the use of large amounts of renewable generation requires the integration of the load in the operation of the power system in order to help in balancing supply and demand [HMA+13]. Therefore, the adoption of the smart grid aims to enhance every aspect of the power system, including generation, transmission, distribution and consumption.

Smart grid technologies, including communication networks, advanced sensors and monitoring devices, form the foundation of new ways for the energy providers to generate and deliver power and for the consumers to understand and control their energy consumption. They could also contribute to greenhouse gas emission reductions by increasing efficiency and conservation, facilitating renewable energy integration and enabling Plug in Hybrid Electric Vehicles (PHEVs).

Distributed Energy Resources (DERs), including renewables (RE) are at the centre of this thrilling landscape being essential components towards a sustainable energy future. Nevertheless, the expected deep penetration and integration of renewables including storage and electric vehicles (EVs) poses a number of technical and economic challenges but at the same time portrays myriad of opportunities for both consumers as well as energy companies.

From the perspective of the utilities, Demand Side Management (DSM) and demand flexibility forecast will become even more complex. Current systems are built to meet peak demands in a techno-economic environment where the value exhibits geographical and temporal variations. The integration of renewable intermittent generation will substantially increase the need for ancillary services i.e. for resources to handle supply/demand imbalances at various time-scales, maintain power quality, and assure reliable power delivery under contingencies.

On the other side is the perspective of the consumers where we can see a rise of empowerment. Prosumers (consumers with generation capabilities), either stand-alone or in groups represented by entities like aggregators that pool their resources, exhibit now sufficient power to make market impact. For example, even limited within their comfort range, orchestrated modifications in flexible loads of a larger set of consumers (like adapting temperature settings for thermostats, or changing charging or discharging times of EVs) can deliver enough capacity (load curtailment) for effective demand side management towards a more stable, less congested smart grid. However, and to exploit this potential and help them make the right choices in terms of efficacy and cost efficiency, consumers need to be provided with the proper tools and incentives in terms of technologies and interfaces, price signals, policies, and regulations.

This new type of active consumers and the deep integration of the DERs unleashes the potential for leveraging Demand Response (DR) in new ways to reduce energy loads and alleviate stress on the grid during peak conditions. Nonetheless, two key reports by the EC's JRC [BER+16] and the SECD [COA15] outlining and evaluating the status of DR in EU member states have both identified a slow penetration of DR services in Europe and listed a number of barriers and challenges for unlocking the DR potential, the most critical of which, are:

- Aggregation services for consumers not fully enabled;
- Inadequate and/or non-standardised baselines;
- Market design not enabling the participation of DR;
- Consumers not able to fully leverage the capabilities of demand side resources;
- Lack of standardised processes between Balance Responsible Parties and aggregators.

Furthermore, taking the existence of renewables as granted, the use of storage raises flexibility. This can restrict the number of cases where DR is necessary, and/or the load to be curtailed by means of DR. This can render DR and Automated DR (ADR) contracts more attractive to users, reduce the risk of consumer fatigue, while lead to savings on total DR incentives offered by the provider. Thus, by making DR more targeted, it will also become more effective. Furthermore, more storage implies more flexibility yet at a higher cost. As also highlighted in MIT's "Utility of the Future" study [MIT16] "DER technologies may compete to provide the same electricity services. The profitability of one technology (e.g., storage) strongly depends on the deployment of others (e.g., DR)". However, the trade-off between more storage and more DR and how the provider can strike the right balance is yet undetermined.

Congestion issues can occur either for the Distributed Generation (DG) either for a high EV penetration in the Distribution Network (DN). Recent trends in terms of share of EV circulating is arising problems to the DSO that needs to dramatically improve the DN to host the proper number of EV charging points, and, as final instance, new transformer installations are required, as preliminarily estimated in [CGG+12] . On the other hand, congestion issues related to DG are generally associated to Reverse Power Flow (RPF) at the primary substations, as in [MCC+18]. In addition, RPF widely implies not only overcurrent on the feeders but also overvoltages and miscoordination of the protections, as in [M02], [HAS+15] and [HAK09]. In this respect, penalties can be also applied in some countries (e.g., in Japan) since RPF from the DSO to the TSO is not allowed, as in [HAK09].

The main driver for congestion events considered is the adoption of Electric Vehicles by residential/commercial and industrial consumers. As mentioned in the previous case, the number of EVs present (the EV penetration rate) determines the percentage of EVs compared to all vehicles in that area and thus the potential controllable load. Even though the adoption of EVs in European countries is low nowadays, this is expected to change soon as the manufacturers move away from conventional vehicles and costs go down, or authorities provide the appropriate incentives. Furthermore, we focus on individual LV feeders and in upper class neighbourhoods, or in touristic places with EV fleets high adoption rates will be achieved significantly sooner.

2. State of the Art

2.1. Congestion issues, effects and traditional countermeasures

One of the main goals of a DSO is to provide power supply, ensuring power quality in terms of continuity of service and stability of electrical parameters, namely voltage and frequency within the limit. In a distribution network, a congestion is generally referred to an overcurrent occurring on equipment of the network (e.g., cable, overhead line, transformer), its definition can be actually extended to the general abnormal conditions produced by an overload in terms of both production and generation, [NWL+17]. In this respect, a congestion corresponds to an increasing/decreasing voltage over the limit in case of high production or consumption, respectively; these voltage benchmarks are defined by international standards, normally ±10% of the rated voltage is allowed in the networks at all voltage levels.

From the DSO point of view, the overcurrent and abnormal voltages cause an opening of the switch, as a final instance, to protect its infrastructure and the customer's equipment, the protection thresholds can vary among countries and voltage levels (e.g., overcurrent can be interrupted either by a time reverse response or by a fix step as well as abnormal voltages can be allowed with different tolerances). To reduce interruptions, that are subject to penalties, DSO design its network to avoid congestions and its development plans are implemented to remove bottlenecks, to increasing the meshing degree of the network and to adapt the exiting infrastructures to the increasing customers' capability (i.e., higher demand from EVs and higher injection from RES), as in [RBT12].

Apart from the network design, authors in [HWL+14] collect the most important remedial actions that can be implemented to solve a congestion in case of distribution networks with high penetration of DERs. In this context, two groups can be identified; on the one hand congestions can be managed by active control methods on the infrastructure and power flows, on the other hand, market methods can support the congestion management. With respect to the traditional countermeasures, adopted to prevent and manage congestion during real-time operation, the most common methods for implementing direct control are network reconfiguration, as in [SH12] and [BW89], reactive power control, as in [VK08], and active power control, as in [ZB07].

Reconfiguration in distribution networks implies a change of the grid topology by means of closing the switches, that are normally open, whilst the switches, normally close, are opened in order to get a more efficient or suitable for delivering the power to the customers, maintaining the same radial structure, which is widely applied in case of the distribution. This solution can be applied both at LV and MV level, in case those have already a meshed part or some rings; the status of the switches has to be remotely controlled in order to have an effective and prompt react to the congestion, [HWL+14].

Reactive power can be provided by flexible AC transmission system (FACTS) devices (e.g. Static VAR compensator (SVC)) and inverters properly configured to manage voltage during real-time operations, especially in networks having long feeders, where voltage problems are more critical than overload of the line, [HWL+14].

Finally, the active power control method is linked with costs or customers' comfort, [HWL+14]. Assuming that the congestion is only caused by the DG or flexible demands; the active power control method can avoid congestions effectively; the main issue is the cost minimization and dissatisfaction.

2.2. Demand Response campaigns

DR and demand side management are part of an inevitable step towards a flexible and truly sustainable energy system that incorporates the so-called smart grid. Demand side management has traditionally been used as a broad term involving the management of electricity demand through various means. The latter include activities affecting the load shaping (shedding load, shifting load or activating on-site generation) and various energy efficiency measures, whose purpose is to steadily reduce the load level. Demand response is usually defined as the ability to modify the electric consumption pattern of the consumers. Therefore, it is referred to a wide variety of demand shifting and/or reduction techniques that are applicable in several DR concepts and initiative types. The common characteristic of all these techniques is the temporary alteration of the demand variation of the demand profile.

In electricity grids, DR is similar to dynamic demand mechanisms, which attempt to manage consumer participation of electricity in response to supply conditions. The difference is that DR mechanisms respond to explicit requests to shut off when stress in the grid is sensed, whereas dynamic demand devices passively shut off. Demand response is as concept relatively simple. The energy providers incentivize their electricity consumers to reduce on demand their consumption at critical, called "peak" times. It can also enable curtailment of power used or inception of site generation, which may or may not be connected in parallel with the grid. Contracts, made in advance, specifically determine both how and when the energy provider or another third-party intermediary can reduce a consumer's load. As is concluded, DR is a component of smart energy grid, which also includes energy efficiency , home and building energy management, distributed renewable resources and electric vehicle charging.

Globally, the IEA estimates that about 3900 TWh of current electricity consumption is technically available today for demand response, and it is expected to almost double by 2040 to about 6 900 TWh, or nearly 20% of electricity consumption worldwide. The potential for demand response varies by region and sector, but in all regions, most of the current and future technical potential at lower cost lies in the buildings sector, especially in space and water heating and cooling. Electricity demand for space heating and cooling can be shifted over a certain number of hours, the extent depending on the thermal inertia. Most of the remaining potential in buildings is related to electricity used for large appliances, such as washing machines, refrigerators, dishwashers and clothes dryers. EVs are expected to become participants in demand response programmes over time [IEA16]. The benefits of increased demand response are enormous. In the IEA Central Scenario, the implementation of the full technical potential of demand response (6900 TWh) results in about 185 GW of additional flexibility for the electricity system globally in 2040 – roughly equivalent to the currently installed electricity supply capacity of Italy and Australia combined. This amount of flexibility would avoid a cumulative USD 270 billion (in 2016 dollars) of investment in new electricity infrastructure (new power-generation capacity and transmission and distribution). As the bulk of demand response potential is in the buildings sector, almost 1 billion households and 11 billion connected appliances participate in demand response programmes by 2040 under the Central Scenario (Figure 1). Large commercial buildings, such as supermarkets, hotels and offices, industry and EVs can also play a significant role [IEA17].

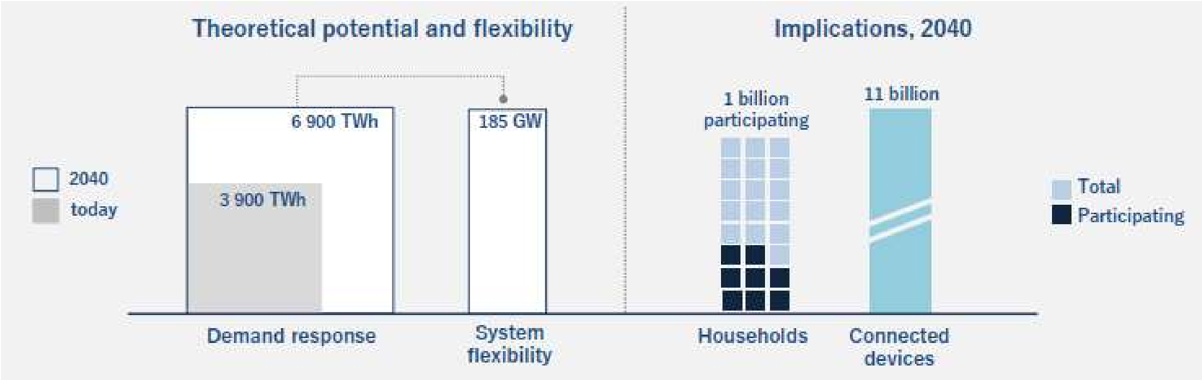

Figure 1. Global potential of demand response and its implications [Source: IEA17]

Initially, DR schemes were implemented with larger users of energy- C&I users, as well as some residential users, often through the use of dedicated control systems to shed loads in response to a request by an energy provider or market price conditions. With the advancement of smart grid communications and technology, more residential users have the option to enroll in DR programs, giving DR the capability to cover a larger portion of the overall system. In fact, many industry observers have expressed that any true vision of a comprehensive smart grid is incomplete without a DR program included. As a result, DR consists a win-win solution for both the energy providers and the consumers at times of peak energy demand, i.e. DR is a cheaper, faster, cleaner and more reliable solution than adding a peaking power plant, given the willingness of participation from both sides. Specifically, the user response to an eventual rise of the electricity price could imply the adoption of measures that aim to reduce momentarily the load level. DR enables both the provider and consumers to save money, which is and will continue to be the key driver in the mass adoption of DR programs. For example, Figure 2 illustrates the achievable potential of DR for U.S. for peak demand reduction by sector and program type; they seem to be promising.

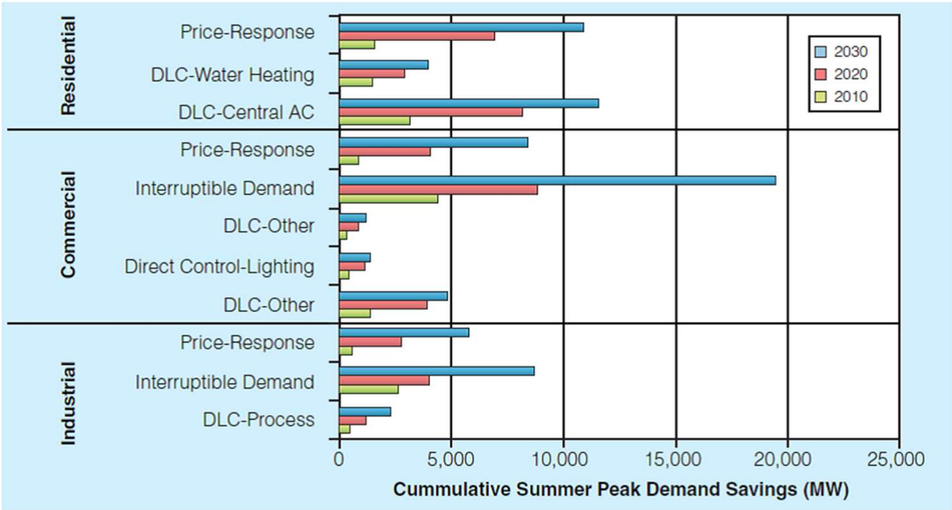

Figure 2. The realistic achievable potential for U.S. from DR

Moreover, In the EU, variable renewables are playing a pivotal role in decarbonising the power sector. Under the 450 Scenario , over 570 GW of wind and solar PV installations will need to come online by 2040 (IEA, 2016). In this scenario, renewables make up more than 60% of total electricity generation, reaching almost 2100 TWh in 2040, more than twice today's level. Wind and solar PV account for almost 60% (1 250 TWh) of the overall renewable generation, making the European Union one of the regions with the largest combined share of wind and solar PV in total power generation. Flexibility measures are needed as soon as the share of variable renewables in the generation mix increases beyond 27%, on average, across the continent. These are required to avoid periodic curtailment of solar PV and wind power generation at times when total supply from those sources exceeds demand. In the absence of additional flexibility measures, total curtailment would exceed 85 TWh in 2040, which is equivalent to nearly 7% of the combined generation from wind and solar PV. The introduction of measures to prevent curtailment will be critical to increased deployment of wind and solar PV. The IEA projects that in 2040 digitally enabled demand response measures can reduce curtailment by some 22 TWh, and a further 45 TWh can be saved through additional energy storage, a substantial share of which would be digitally enabled battery storage, limiting curtailment to 1.6% of total wind and solar PV generation. This allows the system to accommodate 67 TWh of additional generation from variable renewables and to avoid about 30 Mt of CO2 emissions (Figure 3) [IEA17].

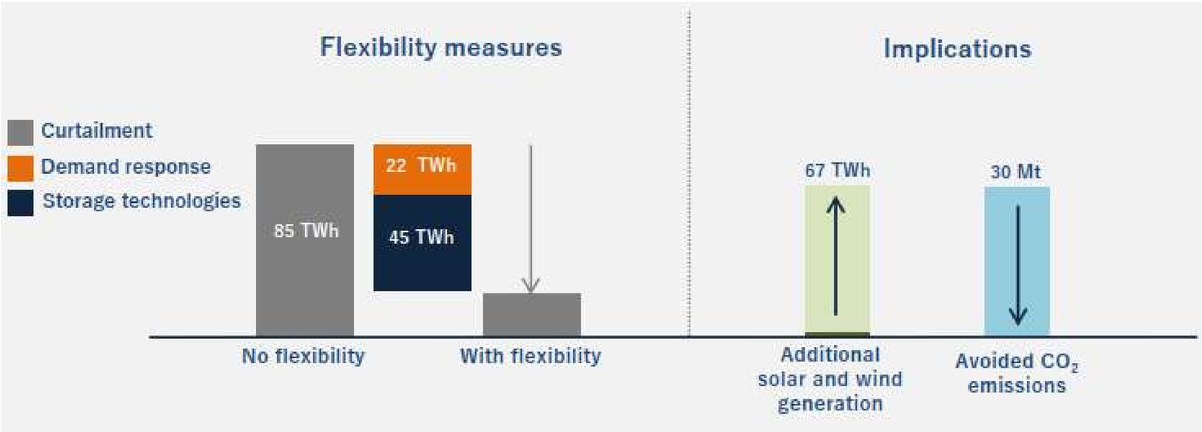

Figure 3. Flexibility measures and their implications in the European Union in 2040 [Source: IEA17]

There are many ways of classifying the DR programs according to various criteria, indicatively naming the purpose, the trigger factor, origin and type of signal, motivation method, control, system/market structure, promotion and financing, targeted consumers, automation of response, etc. [CL12], [HP08]. Although there are several classifications available in the literature, the most commonly accepted entail three main categories as defined in [S14]:

1. Rate-based or price DR programs: different energy tariffs are contractually appointed in deregulated markets according to which price varies over time as a motivational rule for consumers to alter their consumption patterns. The prices can be pre-set or may vary dynamically and even skyrocket at peak times, resulting in consumers paying high charges. The prices can also be established a day in advance, on a daily or hourly basis, or in real-time and the consumer would react to its fluctuations. Examples of this type of programs are available in Table 1.

2. Incentive or event-based DR programs: in this category consumers are rewarded for being activated by reducing their loads upon request or for granting the provider the permission to take over the control of some or all of the equipment in consumers' premises. A set of DR signals (either for voluntary demand reduction or mandatory demand reduction by means of external control) is sent by

the DR event issuer to the participating consumers. Examples of such programs [BLR+10], [P02], [HP08], [FHN+07] are shown in Table 1.

3. Demand reduction bids: here consumers initiate and send demand reduction bids to the provider (or the aggregator if exists) [MSW+10], which consist of the available demand reduction capacity and the requested price. This type of programs is mainly oriented to large consumers, i.e. they can deliver load reductions at prices for which they are willing to be curtailed, or they can recognize and determine the load quantity they would be willing to curtail at the announced price [HP08]. Within these broad categories of DR programs there are several different program types [CL12] as shown in Table 1.

DR programs often use mechanisms to induce consumers to reduce demand in order to limit the peak demand; however, they may also support the demand increase during periods of high production and low demand. It is worth noting that, since DR may limit the consumers' comfort, these would desire limiting the time during which they may be exposed to such discomfort. Automation, monitoring and control technologies are, therefore, fundamental to manage energy-use process, making DR less hindering for the user [S14].

Table 1. Common types of DR programs [S14] [MPW+07]

Price options	Incentive- or event-based options	Demand reduction bids
TOU (time of use rates): rates with fixed price blocks that differ by time of day CPP (critical peak pricing): rates that include a pre-specified, extra-high rate that is triggered by the utility and is in effect for a limited number of hours RTP (real-time pricing): rates that vary continually (typically hourly) in response to wholesale market prices	Direct load control: customers receive incentive payments for allowing the utility a degree of control over certain equipment Emergency demand response programs: customers receive incentive payments for load reductions when needed to ensure reliability Capacity market programs: customers receive incentive payments for providing load reductions as substitutes for system capacity Interruptible/curtailable: customers receive a discounted rate for agreeing to reduce load on request Ancillary services market programs: customers receive payments from a grid operator for committing to curtail load when needed to support operation of the electric grid (i.e., ancillary services)	Demand bidding/buyback programs: Customers offer bids to curtail load when wholesale market prices are high

A wide range of DR programs and tariffs are already offered by energy providers that have been settled to use the available energy more efficiently and to encourage consumer response and competitive energy retailers [M04], [OT08], [N10], [MKX11], [MWJ+10], [RCQ09], [CJH05], [OH08], [H07], [TV09],

[C10], [A09], [QS06], [AGK+09], [ML10], [S14]. An overview of DR programs that are available in the US market are summarized in [RI10] together with the associated rules for participating in such programs, while [PD11] points out some of the demonstration projects available in this domain. From the research perspective, the literature on DR is already extensive. The vast majority of the current research work is closely related to different variations of classical optimization, such as job scheduling and load balancing [HG10], [BPK+11], [S14], [KT11]. To the same direction, examples include the lowering of peak customer demand [BMI+12] by shifting the consumption towards the periods of high renewable energy production [S08], [JBB16]. A detailed review of the theoretical models on DR optimisation is presented in [BPK+11], where the works included are categorized into general concept papers and papers on DR models applicable to the wholesale or retail markets.

To set the scene for the application of all these models, the active participation of users is critical as they are the recipients of any changes required in the context of DR. However, consumers are often discouraged from participating in DR, mainly due to the uncertainty of price response programs, the undefined quantity of load that might be available for reduction during an event, the economic viability of participating in a DR program and the willingness to maintain occupant comfort during a DR event. The energy providers can tackle with most of these concerns by designing and offering DR programs that would motivate users to enrol in DR. A critical element of expanding DR participation and impacts is coming up with incentives or dynamic pricing alternatives. In this way, consumers will be able to realise the benefits deriving from DR and thus enhance their willingness to enrol in a DR program utilising control technology such as smart thermostat and energy information. Nevertheless, how much consumers must be paid, in order to entice them to participate in the programs, is not apparent as it depends on the operational costs and power objectives of the energy provider, as well as the interpretation to the consumers, namely the incentive rate. If programs are designed well and power is assigned an appropriate value, DR programs will be cost-effective.

3. Congestion issues in ASM Terni #ASM Terni#

3.1. ASM Terni topology, load profiles and EV & PV shares

ASM TERNI S.p.A. is an Italian multi utility company, providing in water, gas, electricity and environmental services at the city of Terni and the surrounding area. It owns and operates the local power distribution network, covering a surface of 211 km2 and delivering energy to 65,500 customers annually, corresponding to Terni municipality. The ASM distribution network acquires electricity at High Voltage (HV) through 3 primary substations and supplies electricity to residential and business customers through 60 Medium Voltage (MV) lines (10kV to 20kV) and about 700 secondary substations. The peak power is about 70 MW and the total length of the power lines in the grid is about 2,400 km (600 km at Medium Voltage, MV and 1,800 km at Low Voltage, LV).

In 2018 the energy consumption reached 390 GWh, while the Distributed Generation (DG) connected to the MV / LV network generated 184 GWh. Thus, about 50% of the total consumption was covered by RES, notably, 1289 power generation plants are actually connected. In 2018, the DG consists of 1278 PV arrays (31.5 MWp), 7 hydro plants (10 MWp) and 4 biomass/waste (20.9 MWp), which produced 32 GWh, 71 GWh and 81 GWh respectively. Figure 1 provides more details about energy mix, whilst Figure 2 reports the evolution over the last decade of the DG connected at the Low Voltage (LV) network; both figures show that the local DG is growing over the time as well as they point out that a new incentive policy would enable additional installations, as in the period 2011 – 2015.

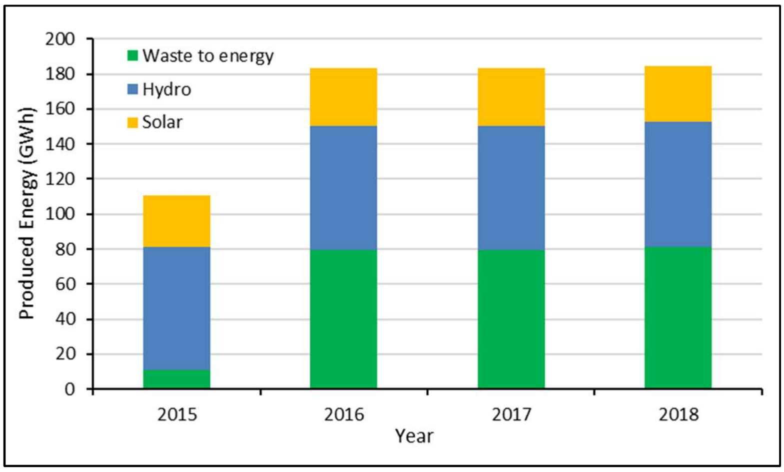

Figure 1: Energy mix in ASM distribution network

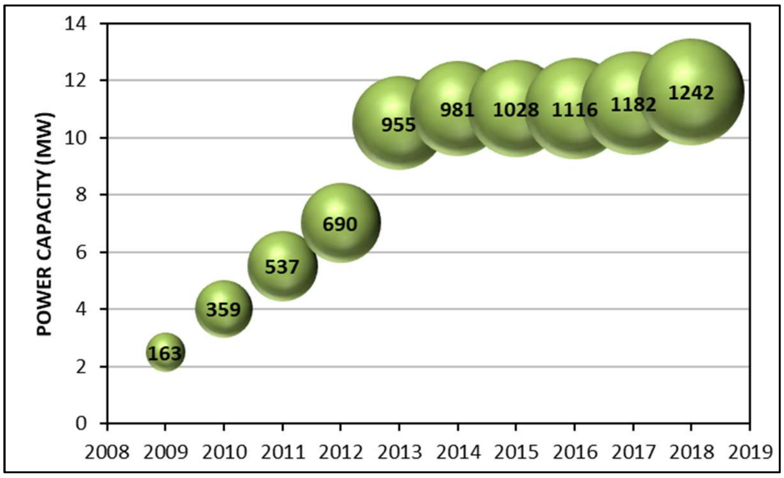

Figure 2: Number and size of LV PV plants in ASM distribution network

A notable amount of produced energy is not consumed locally but it produces RPF, notably about 22 GWh were injected in the TSO network in 2017. In order to get a more detailed view on RPF profile in ASM network, is worth outlining that RPF was measured in five T/D connection points (i.e., the buses of the Primary Substation). In this work, each bus was considered independent for fiscal and technical reasons, since the TSO can arrange different topology. As a consequence, every calculation of energy transition were performed in each bus considering only the load and the production effectively connected to the bus bar, since every bus distributes and receives electric power from a specific part of the distribution network.

Table 1 shows the total absorbed energy, the reverse energy, the absorption power peak and the reverse power peak measured in each bus in 2017. Moreover, Nq,RPF and Nq,RPF>AE are evaluated; representing the percentages of quarter hours per year in which either RPF is detected (Nq,RPF) or energy from RPF is higher than energy from TG in that period (Nq,RPF>AE). Data reported in Table I clearly shows that RPF occurs in 1, 2 and 4.

With respect to scenario related to DG, T/D connection point 4 is the most notable since only PV plants are connected at this bus. Figure 3 reports the variation of RPF in April, when RPF is maximum since high production does not correspond to high consumption, otherwise, during Summer, the RPF is less since great production from PV corresponds to notable local consumption, notably because of Air Conditioning. For Figure 3, tick marks are referred to the midnight of the related day, and then RPF always arises to the daily maximum at noon, notably, in the middle of the day, the absorbed power rapidly decreases (i.e., from 6 MW to 0 MW). With respect to the variation over the week, RPF is high on Sunday (16/04 and 23/04) and on public holidays (17/04). Finally, this Figure shows that a future increasing of DG penetration will arise issues about congestions because of a lack of local consumption.

Table 1: RPF at T/D connection points (2017)

	T/D connection point					Network
	EX-SIT	VVV	VVR	TOV	TOR	Total
Imported energy (GWh)	27.0	2.8	99.1	32.4	69.5	230.1
RPF energy (GWh)	5.2	18.4	0	0.4	0	24.0
Imported power peak (MW)	20.4	17.0	22.2	11.9	7.9	59.5
RPF peak (MW)	11.1	7.5	0	4.1	0	22.4
$N_{q,\ RPF}$ (%)	35.0	82.9	0	6.8	0	85.3
$N_{q,\ RPF>AE}$ (%)	27.8	82.0	0	5.8	0	0.6

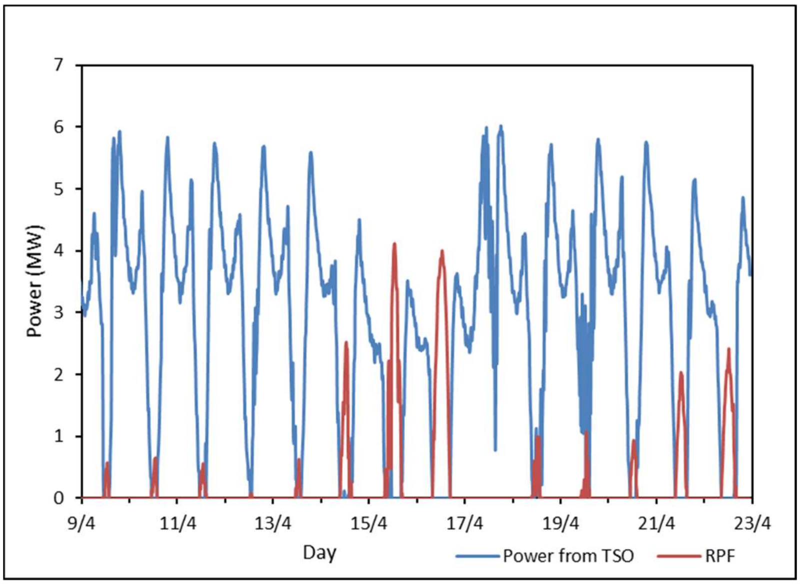

Figure 3: Power profile for Terni OVest (TOV) primary substation from 09/04/2017 to 23/04/2017

3.2. Congestion issues

With respect to the congestion issues in Terni distribution network, it is worth pointing out that LV network has radial topology whilst MV network is partially meshed (i.e., some antenna links and simple rings are still present in the grid), during the exercise, radial topology is implemented for both levels. In addition, a Supervisory Control And Data Acquisition (SCADA) system is deployed for the MV network, meaning that for a notable part of the secondary substations a Remote Terminal Units (RTUs) are installed, able to send data as well as they enable switch control from a remote control room. If a congestion is near to occur in a meshed part of the network, RTU functionality will allow operator preventing abnormal condition and properly changing network topology to reduce the overload. Then, in the actual status of the network, DSO can only leverage on this functionality (i.e., network reconfiguration) to solve a congestion since it cannot leverage on control of reactive and active power of the customers, as in [HWL+14]. Considering the LV part of the network, there are not available actions to manage a congestion during real time operation because that part of the grid is fully radial; therefore, the DSO prevent abnormal conditions by means of a proper design, essentially replacing cables when new consumers or producers are going to be connected.

Then, with respect to the DG and EV penetration, two additional challenges are actually addressed by the DSO, namely, a wide and prompt replacing of the infrastructure and new criteria design compliant with the new type of load profile. In this respect, it is worth recalling that the demand factor and coincidence factor of EV and PV are dramatically different from those of the normal passive consumer, as preliminarily evaluated in [CGG+12] and [CGG+11], and then lines and equipment for EV and PV installations are bigger (i.e., more expensive) than those for a normal customer, having the same contractual power. In order to evaluate the adequacy of its development plan, as reported in [BCC+19], ASM Terni has also carried out a tool to evaluate the effect of the lack of an asset in terms of user disconnected and congestion occurring; moreover, as reported in the present work, it aims to identify how DR campaigns can enable investment deferring on the infrastructure. With respect to the interruptions, the most common KPI are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). In particular, for the LV users of the DSO, the reached KPI in 2017 are: for SAIDI 28.963 minutes/user/year in high density area and 60.844 minutes/user/year in rural area, respectively (considering only interruptions longer than 180 s), while for SAIFI 1.477 number of outages/user/year in high density area and 3.976 number of outages/user/year in rural area, respectively (short interruptions are also considered, i.e. longer than 1 s). The simulations, that the next section are going to present, consider high density area.

4. Simulation setup

Given that we are interested in understanding the effect of future adoption EV and PV technologies on DSOs and the market in general, a custom simulator was developed and utilised for obtaining values for key technoeconomic metrics, such as:

- how much flexibility would a DSO ask during the next 20 years, how frequently and what is its willingness to pay for such services?
- what is the expected flexibility offered by different types of participants to Demand-Response campaigns during the next 20 years and what is the effect of technology (such as Electric Vehicles and smart controllers) and rewards?
- What is the annual self-consumption, injected energy, imported energy of a consumer with several types of technologies (PV, EV, battery, smart home controller, etc.).

4.1. Overview

The main simulator models a (hypothetical) prosumer's decisions regarding energy production, consumption, battery charge/ discharge and import/injection that considers several factors, which include, but are not limited to:

- locality, especially for determining generation capacity, load patterns and considering the financial regime (fixed/dynamic retail prices, injection prices, net metering presence, etc.);
- agreements with other market actors like DSOs, RESCOs/Aggregators;

• technology (such as batteries and smart controllers for participating in Automated Demand-Response campaigns),

• residents' habits in terms of absence hours, EV charging window (e.g., during the night), price elasticity or willingness to join Demand-Response campaigns.

A key feature of the simulator is a repository of (currently) 62 separate prosumer states, which depend on the local production level, consumption, battery state-of-charge, arbitrage between retail prices, peak/off-peak period and presence of DR campaigns, etc. At any point in time the prosumer will be in one of those states based on the policy to be followed (e.g., if retail prices are currently higher than injection prices then prioritise local consumption, use excess production for charging battery and inject any remaining production to the system). Furthermore, the simulator works on quarter-hour time-scales for a complete year, which allows further demand and supply aspects to be modelled. In fact, new states can be introduced on the simulator, based on the policies available to decision makers.

Based on the decisions of the consumers (that can be residential, commercial or industrial) and simplified information about the topology of the LV/MV network (feeders form a tree or loops, effective capacity of feeders by incorporating the effect of network losses, etc.) we are able to simulate simple network events such as congestions. Furthermore, we defined a set of random variables for mimicking a wide range of events, such as hardware failures resulting in topology reconfiguration or even outages to be resolved using DR campaigns, the acceptance of a prosumer to shift some load to other time slots, inverter availability, etc.

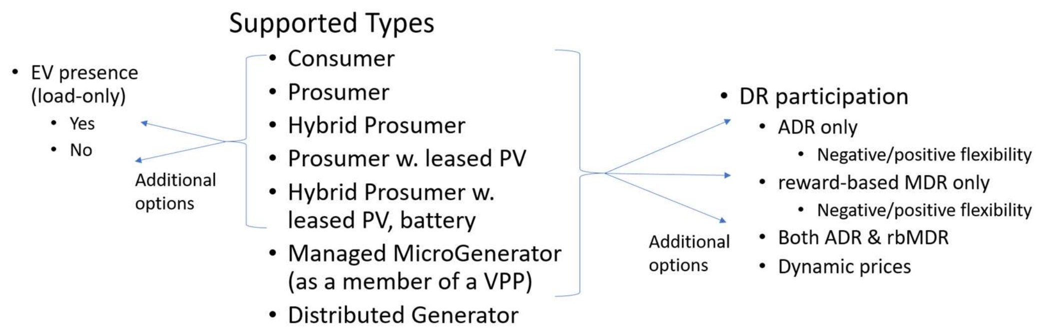

Figure 3 The types of grid-connected users that are supported by the simulator

4.2. Simulation details

We focused on a certain LV/MV loop that is serviced by the Terni Ovest (TO) primary substation, where as described in Section 3.1 significant reverse power flows exist. Being a loop, there is the possibility to change the length of the feeder, reducing one and increasing the other, by switching the status of some disconnectors, which are remotely controllable. Thus, each of the 1000 customers belonging to that loop feeder will likely be served even if a technical failure takes place along one of the lines. This is a rather conservative decision as outages are harder to take place compared to a tree-like topology. Eventually, in Section 6, in order to scale up results to the rest ASM Terni network, we will assume that increased PV penetration is expected in up to 10-12 similar feeders.

The probability of a technical failure occurring on any feeder is a random variable following the Bernoulli distribution with p=0.5%. Thus about 160 failure/maintenance events happen per year on each feeder.

An outage occurs if a) both feeders experience a technical problem, or b) there is topology reconfiguration and the effective capacity of the only feeder in use cannot cope with the production (or demand)[2], or c) the total surplus production (or demand) exceeds the combined capacity of the feeders. An outage is assumed to last 10 slots, while the duration of the last slot is normally distributed. Since the simulator works on quarter-hourly (15min) slots, the maximum duration of an outage is 150 mins.

We assume that whenever the (perfectly forecasted) load exceeds a DR campaign will be triggered. The effective bottleneck capacity of each line (after considering the technical losses involved) is 5.52

[2] In respect of this, the worst case is that a single feeder has to feed all the secondary substations in case of maximum production/consumption

MW, while the threshold is set at the 90%. The flexibility asked, in case of RPF and high loads respectively, is given by the following formula:

$$\begin{cases} max(surplus\ production - capacity\ threshold, 0) \\ \max(load - capacity\ threshold, 0) \end{cases}$$

This applies to the case where a topology reconfiguration has taken place due to a technical failure, or maintenance, on the other feeder. When both feeders are unexpectedly off, all served endpoints get disconnected and no flexibility can be procured.

We used data inputs on solar production, load curves and retail prices for Italy from publicly-available data sources (in most cases the ENTSO-E Transparency Platform[3]). Loads for consumers depend on the location and are those for a typical residential family, based on synthetic load profiles. Similarly, production is based on profiles generated using the PV*SOL[4] commercial software for a rooftop PV system of 3.6 kWp in Terni, Italy. The exact production is then scaled up/down according to the average peak capacity installed in that area by residential, commercial or industrial prosumers. More specifically, the average peak capacity for residential, commercial and industrial prosumers in Terni is 4.29 kWp, 23.351 kWp and 41.9 kWp, respectively. The number of prosumers depends on the PV penetration rate, i.e., the percentage of prosumers in that area. As explained this is one of the core simulation parameters in the sense that it determines the maximum production that can be injected.

In the case of high reverse power flows we assume that voltage along the line does not overcome maximum limit, before overload issues occur. This means that capacitors are already installed, or reactive power management has taken place and thus outages due to disconnection of the far away PV plants in rural areas (connected to secondary by means of long LV lines) are avoided.

An additional load that can greatly affect the capability of Aggregators (and its members eventually) to deliver the promised flexibility is EV charging. We assume that the EV owner has a charger that can

[3] https://transparency.entsoe.eu/
[4] http://pvsol-online.valentin-software.com

be remotely controlled by the Aggregator of its choice; a form of Automated DR campaign. EV charging depends on the travel patterns of its owner. We defined two EV owner types:

1. those that charge it in the afternoon (e.g., when returning home after work or after the driver's shift in case of a company fleet) in order to use it next morning. This user type is named "night chargers" hereafter;
2. the ones that charge it around noon (e.g., when shopping or commute has finished) called "day chargers".

This is an important assumption because it allows Aggregators to manage their portfolio of EV owners so that they can offer both negative (peak shaving) and positive (valley filling) flexibility to DSOs. Thus, EV charging can be delayed or expedited compared to the slot that its owner would start the process if left alone.

In order to model the charging process and the associated loads at any slot we grouped the owners of each type into at least two bins (the actual number depends on the population of EV owners with minimum 2 and maximum 30). Users belonging to the same bin are assumed to have a random SoC (state-of-charge) level since distances travelled per day may differ. Furthermore, members of the same bin start and stop the charging simultaneously. The exact delay of each bin is a random variable that is normally distributed. In that way we introduced randomness into the charging process, which is important for cases of congestion caused by high loads (see next subsection). Obviously, the worst-case scenario for a grid operator would be all owners to start charging the EV batteries at the same time (i.e., having a single bin). The charging duration and power is carefully selected (for each bin) so that the EV is either fully charged (in case the duration and power are high enough) or charged at the highest rate supported by the charger. Furthermore, each EV is charged once per day (single charge/discharge cycle), including weekends/holidays.

Similarly, to PV penetration rate, the number of EVs present (the EV penetration rate), is the second key parameter for our analysis. It determines the percentage of EVs compared to all vehicles in that area and thus the potential controllable load. Even though the adoption of EVs in European countries is low nowadays, this is expected to change soon as the manufacturers move away from conventional vehicles and costs go down, or authorities provide the appropriate incentives. Furthermore, we focus on individual LV feeders and in upper class neighbourhoods, or in touristic places with EV fleets high adoption rates will be achieved significantly sooner. Their number depends on the:

- Number of users of each type in each area (based on actual data from Terni)
- Assumptions about EV penetration rate, which affect all consumer types (based on the scenario under investigation)

Figure 4 and Figure 5 give a graphical representation of those candidate future evolution paths for EV and PV respectively in Terni, where the number of EVs at the end of 2016 is 5 and the number of PVs is 4420. Assuming that the number of delivery points in Terni will remain fixed to 65000, then at Y20 the EV penetration will be 43% (High EV increase rate), 15% (Moderate EV increase rate) and 3% (Low EV increase rate), while the PV penetration rate is 79% in all three cases and their only difference is on the increase path.

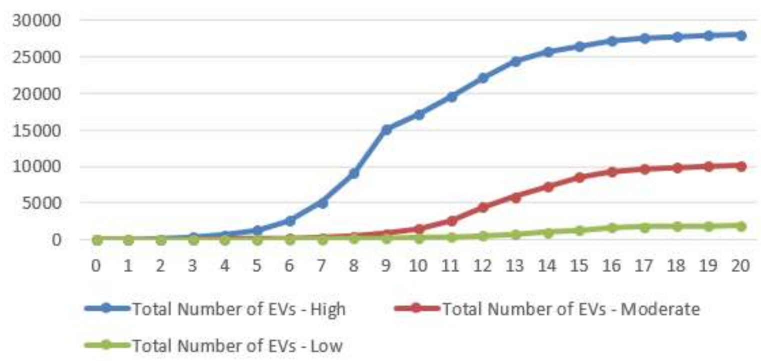

Figure 4: Candidate future EV evolution paths for a 20-year period in Terni – Italy

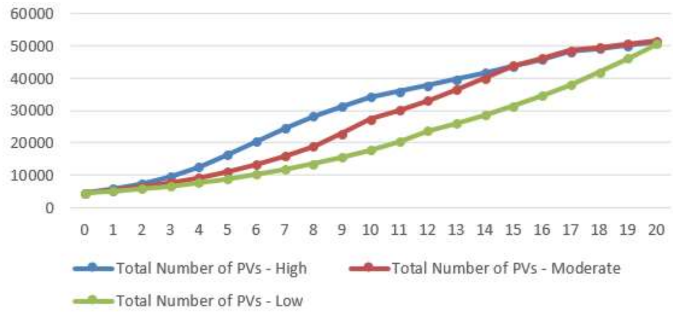

Figure 5: Candidate future PV adoption paths for a 20-year period in Terni - Italy

Furthermore, we assumed that there are three types of EVs, each one with a certain battery capacity and associated charger type. In particular:

- "Small EVs" that are owned by residential users and equipped with a 30kWh battery, which is charged using a level-2 charger of 20kW maximum rate. We assume that each residential end point owns a single "Small EV" with a probability equal to EV penetration rate.
- "Medium EVs", owned by commercial users and equipped with a 50kWh battery, which is charged using a level-3 charger of 50kW maximum rate. We assume that each commercial end point owns four (4) "Medium EV" with a probability equal to EV penetration rate.
- "Large EVs", owned by industrial users and equipped with a 80kWh battery, which is charged using a level-3 charger of 50kW maximum rate. We assume that each commercial end point owns four (4) "Large EV" with a probability equal to EV penetration rate.

The average EV battery daily charging load of each EV type is assumed to be 20% of the battery capacity; a rather conservative assumption (which was nevertheless determined by simulating the charging process as mentioned above). No other battery systems are assumed to be present. Furthermore, we assumed that the population of EV owners is evenly split between "night chargers" and "day chargers".

The DSO relies upon its systems with advanced monitoring capabilities in order to predict a severe congestion issue and asks flexibility from an Aggregator in order to avoid its negative consequences.

The Aggregator pool size is set to 30%. The rest 70% (700 in this feeder) are assumed not to provide flexibility of any form. On the other hand, the EV penetration rate is also used for defining the share of 300 users that participate in Automated Demand Response (ADR) campaigns, where flexibility offered comes from cooling, heating, lighting, etc. The rest users (1000*30%*70%=210 in this case) participate in Manual Demand Response (MDR) campaigns. Furthermore, no users with dynamic pricing schemes are in place. It is important to note the importance of locality when addressing congestion issues; no aggregator members from other parts of the distribution network can offer their flexibility. Thus, locality is an important criterion for Aggregators when managing their portfolio (together with load types and usage patterns).

Electric Vehicle (EV) owners are assumed not to override/disturb the charging plan as set by the Aggregator. On the other hand, the aggregator's members providing MDR and (non-EV) ADR flexibility do this in a best-effort way. This means that there are no contracts for guaranteeing that the asked flexibility will be delivered upon request, or otherwise a penalty will be paid. More specifically, participants' behaviour is governed by the following parameters

- Availability, which refers to the probability that a certain user type will be at its premises (during the day) or awake (during the night). This affects the (non-EV) ADR flexibility as being away is assumed to restrict the controllable load (thus no preheating/precooling takes place).
- Willingness to participate, which refers to the probability that a user (who is available) will accept the DR activation signal. This probability is linked to the monetary reward for each kWh of flexibility delivered. In case of (non-EV) ADR it refers to the case where a user overrides the Aggregator's control action (e.g., temperature set point).

The Aggregator defines the monetary reward in such a way that a certain percentage of contacted members and being available will accept the invitation. In particular, if c is the user compensation then a probability density function for the willingness to participate is given by $p = min(exp(-0.1/c),1)$. This probability tends to 0 when $c = 0$. Since the probability can be also expressed as $p =$

$target/(N * x)$, then the aggregator can select the compensation by using the following formula $c = -a/ln(p)$, where target is the total flexibility asked by the DSO (in kWh), N is the number of users to be invited (e.g., the complete portfolio or a specially selected subgroup) and x is the individual flexibility asked, which is assumed to be the average hourly load of a residential/commercial/industrial consumer. In our case we have used p=0.9, so that the compensation (and consequently the cost to DSO) is not extremely high. Obviously, these parameter values will determine whether the total flexibility asked can be achieved or not. In the latter case, we assume that the DSO accepts the flexibility that can be offered in order to minimize the consequences of RPF. Thus, a simple negotiation phase exists between the DSO and the Aggregator.

When a request for flexibility arrives from the DSO, the Aggregator is assumed to determine how much to ask from each member type in the following way:

- The flexibility asked is increased by 10% (or any other value) in order to account for uncertainty in user behaviour.
- The maximum expected flexibility provided from EVs is calculated first (by considering the flexibility reserved for on-going campaigns).
- If the flexibility from EVs alone cannot meet the target set in step a), then rest ADR member and MDR ones are involved on an equal basis. The possibility for aggregating the missing flexibility by splitting in halves the contribution from rest ADR loads and MDR members is investigated. This is done by following the approach described in (19) for MDR members and asking the same amount of flexibility from rest (non EV) ADR . If this is not technically feasible (e.g., their number is low), or the maximum amount per kWh that a DSO is willing to pay has been exceeded then they agree on the maximum flexibility that can be achieved.

Flexibility provided is load that is shifted in advance or delayed and affects not only the offtake energy, but also surplus production injected to the grid. Furthermore, the load to be shifted is evenly shared amongst a number of slots, which are randomly selected from those slots where the user is available.

Note, however, that loads supposed to take place during an outage are not shifted. This is the only form of "efficiency" achieved. In case of high loads, Aggregator's members provide negative flexibility, i.e., load that is delayed and thus affects mostly the offtake energy after the campaign period. This is the most important difference compared to the previous case where positive flexibility was sought.

5. The effect of DR on congestion issues

In this subsection we will focus on the ability of DR campaigns to avoid congestion issues on a single feeder loop for several combinations of EV and PV penetration rates. Whenever high demand cause congestion, we assume that these are attributed to high number of EVs and that several customers have start the charging process simultaneously. On the other hand, when extremely high production surpluses occur, the reason is the high number of PV owners in that area.

Regardless of the reason for congestion, such issues result in higher maintenance costs (both planned and reactive ones), higher replacement costs due to shorter life span of equipment, increased personnel, lost revenues due to power outages, higher penalties and customer dissatisfaction for the DSO in question.

The total number of outages, that is including those originating from unexpected hardware failures, human error or proactive maintenance, is shown in the figure below. We see that 1 outage on average will be taking place every year on top of those attributed to high local RES production[5]. Since we assumed that the probability of a technical problem is independent of the EV penetration rate, similar graphs were witnessed for the rest cases regarding EV acceptance.

The DSO has several options; to rely on Demand Response campaigns, upgrade the lines affected at the most convenient time, or the Business-as-Usual (BaU) approach which is translated into ignoring the congestion issues and paying the penalties imposed from regulatory authority.

[5] Thus less than 1% of all hardware failures will eventually result in power outage

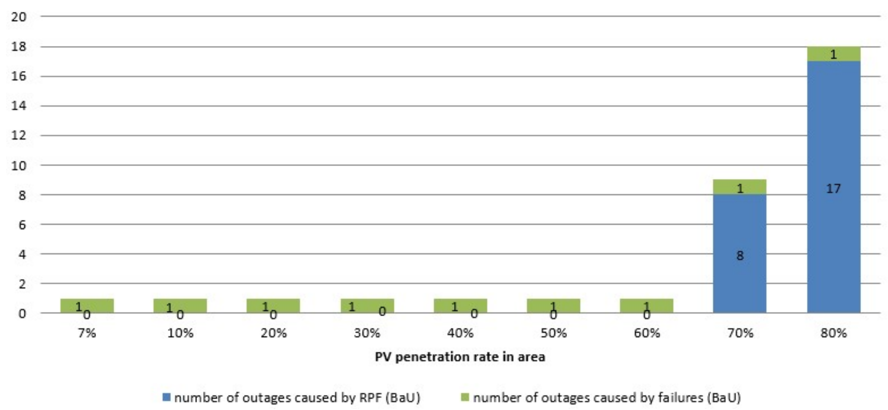

Figure 22 : The total expected annual number of outages (RPF and technical aspects) in Business-as-Usual scenario for the benchmark feeder loop in Terni

One of the main reasons for performing the simulation study is to see what the effect of Demand Response campaigns would be on the number of outages caused by RPF (excluding those appearing for technical reasons). This is shown in the figure below. We observe that for the particular assumptions made and parameter values selected Demand Side management techniques can greatly reduce power interruptions.

For example, at 70% PV penetration the number of outages were found to be reduced by 87% (1 instead of 8 events) for EV penetration 10% or more. Thus, the potential of controlled EV charging on dealing with congestion issues is clear. When prosumers reach 80% the outages can be reduced by 62% (2 events instead of 17 in the BaU) for EV market share higher than 10%.

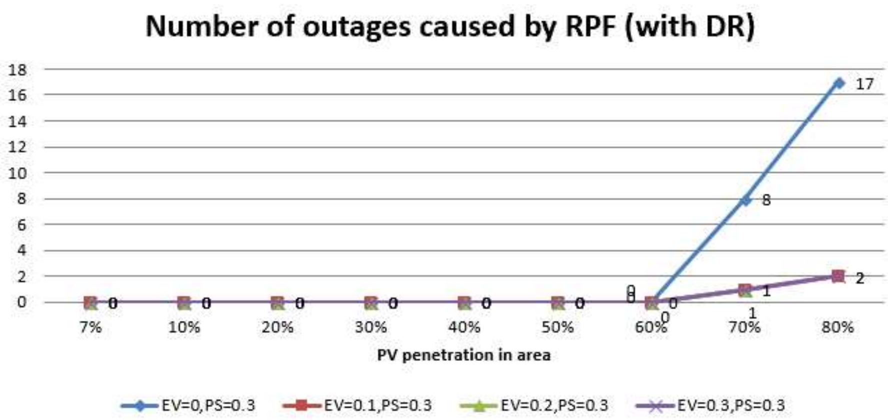

Figure 23: The expected number of outages caused annually by Reverse Power Flows when DR is used for the benchmark feeder loop in Terni

A breakdown of the flexibility obtained per member type (EV, rest ADR, MDR) is shown in the figure below. We observe that the flexibility obtained is increasing as EV penetration increases. Furthermore, EVs contribute the highest share of flexibility in all combinations of PV and EV penetration rates due to the Aggregator's policy in portfolio management.

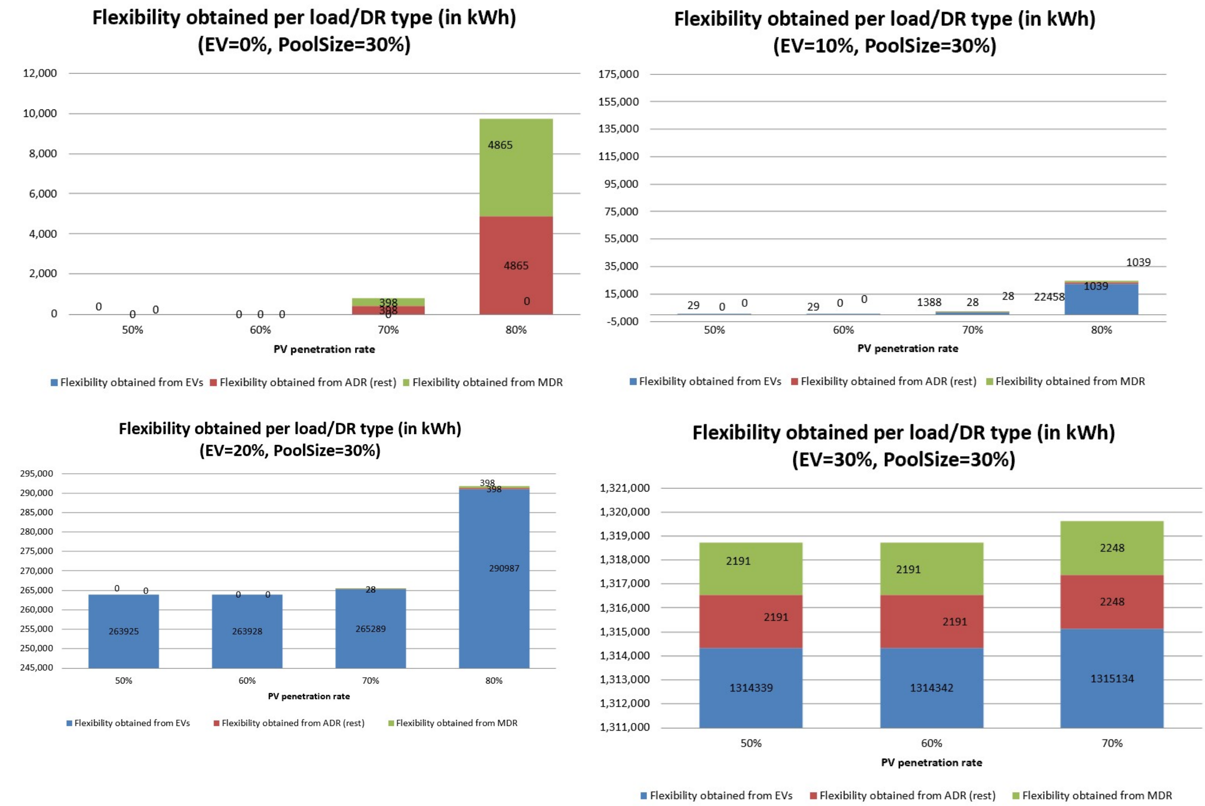

Figure 24: A breakdown of the flexibility obtained per member type for different combinations of PV and EV penetration rates for the benchmark feeder loop in Terni (low PV penetration rates have been omitted for better readability)

The next figure presents the expected number of outages per year in the Business-as-Usual scenario due to high loads. We observe that the outages are insensitive to PV penetration rate (horizontal axis) for both EV penetration rates (red, green curves). Furthermore, outages due to high loads start taking place when 10% of the endpoints buy EVs. In particular, 1 outage was found to be happening every year due to high loads if EV penetration reaches 10%.

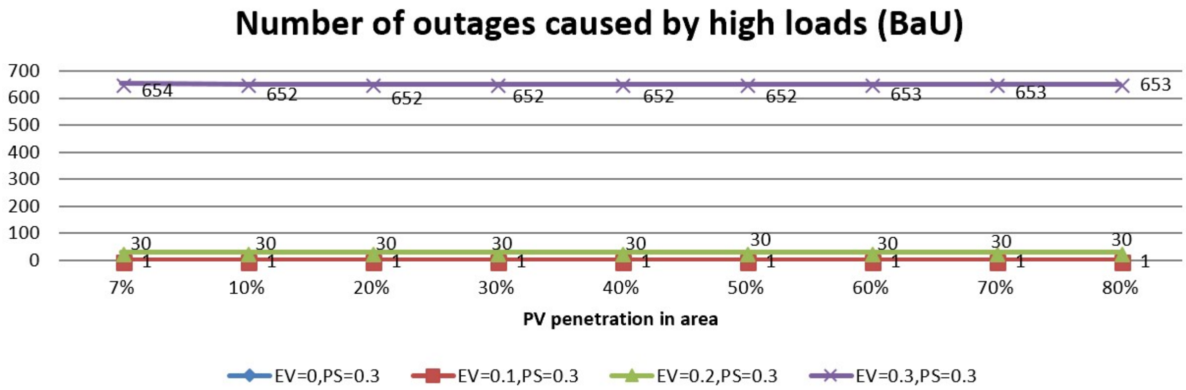

Figure 6: The expected number of outages caused annually by high loads in Business-as-Usual scenario for the benchmark feeder loop in Terni

The total number of outages, that is including those originating from unexpected hardware failures, human error or proactive maintenance, is shown in the figure below. As in the case of Minimise RPF, we see that 1 outage on average will be taking place every year on top of those attributed to high local RES production.

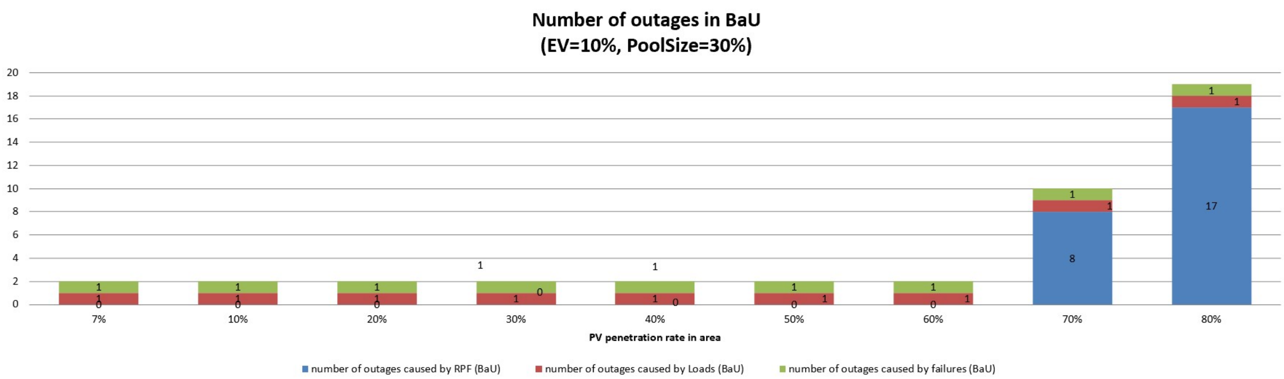

Figure 7: The total expected annual number of outages (high loads and technical aspects) in Business-as-Usual scenario for the benchmark feeder loop in Terni

In the following figure we see that Demand Side Management techniques succeed in eliminating outages caused by high loads alone or as the combined effect on technical issues on one feeder and failure of the remaining one to handle all loads for EV penetration up to 20%, while significantly reducing those events for higher EV shares.

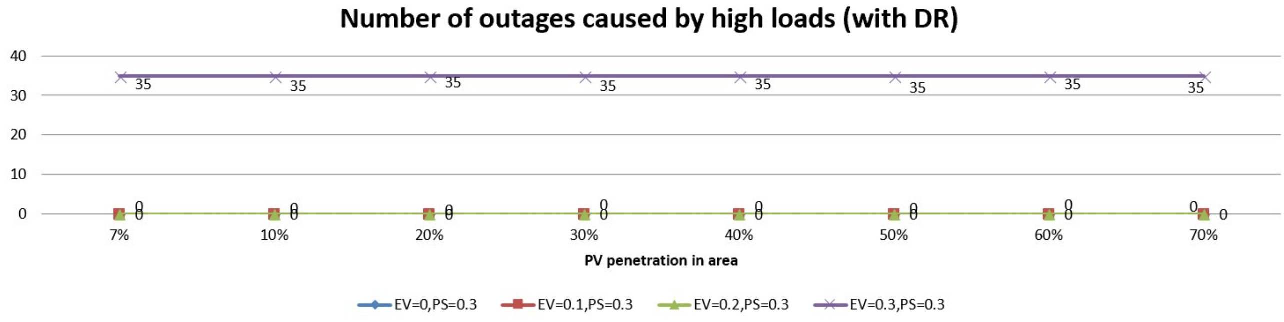

Figure 8: The expected number of outages caused annually due to high loads when DR is used for the benchmark feeder loop in Terni

6. Market conditions for viable DR campaigns

In order to identify the market conditions that render Demand Side Management services attractive to such a DSO we run a set of what-if scenarios (simulations). Such market conditions include the EV penetration rate which affects the frequency of congestion events that could be dealt with DR campaigns, the Aggregator's portfolio size, member's availability for participating and response rate, presence of self-consumption from PV, remuneration asked, etc.

The prosumer simulator outputs, such as annual self-consumption, injected energy, imported energy, flexibility provided, etc. were fed into a state-of-the-art Business Model evaluation tool for studying under what circumstances the DSO should seek support from other business entities (such as RESCOs/Aggregators) in order to deal with congestion issues.

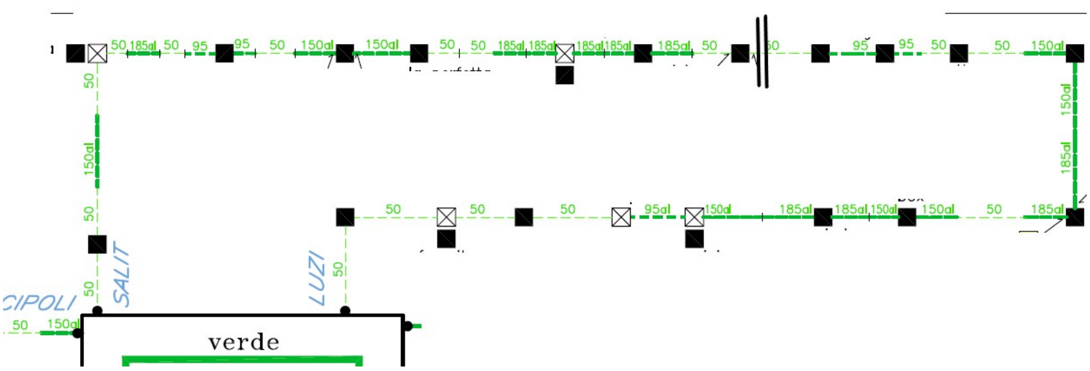

Figure 9: The topology of the benchmark MV feeder loop in Terni as of today

In the figure above we see a diagram of the Terni Ovest LUZI and SALIT loop as of today, while the next one presents the new topology after a new line is introduced.

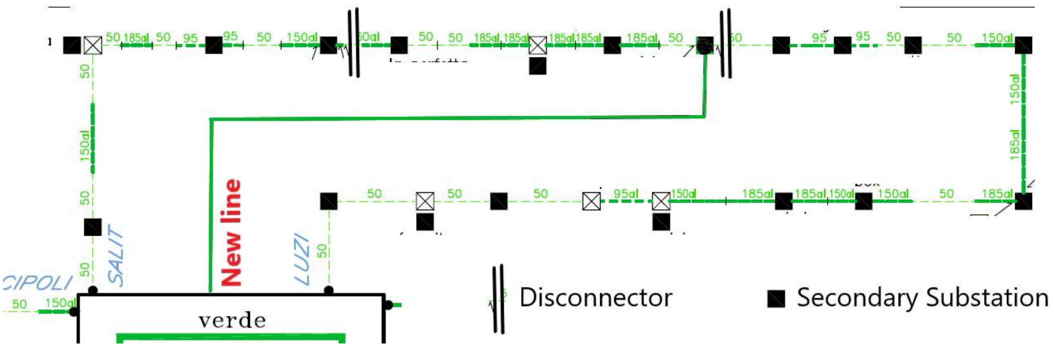

Figure 10: The new topology of the benchmark MV feeder loop in Terni following the traditional approach of upgrading capacity by adding a new feeder

Thus, as in the case of minimising RPF, we will explore two candidate options for a DSO such as ASM Terni in avoiding a new outage:

- Option1 (Business-as-Usual scenario): upgrade network by installing a new line and assume that congestion issues are definitely avoided.
- Option2: ask flexibility from Aggregator.
- Option3: do nothing

In order to evaluate the business models and identify any bottlenecks we need input data that will allow us to estimate the evolution of each cost item and revenue stream. The evolution of costs and revenues can depend on multiple factors, but we focused on a set of scenarios that we defined along the following two dimensions:

- The **EV penetration rate**, which can have a great effect on the network due to the high loads involved and the highly likely attempt of many consumers to charge their car as soon as they return to their premises.

- The **PV penetration rate** i.e., the percentage of prosumers in an area, which greatly affects the reverse power flows and the quality at the LV/MV network.

In particular, we defined three scenarios based on the **EV and PV penetration rates**:

- <Low EV increase rate, Low PV increase rate>
- <Moderate EV increase rate, Moderate PV increase rate>
- <High EV increase rate, High PV increase rate>

The following figures present the cumulative DSO costs, which include those for DR, penalties and lines upgrade, of each option for 3 different scenarios regarding EV and PV penetration rates.

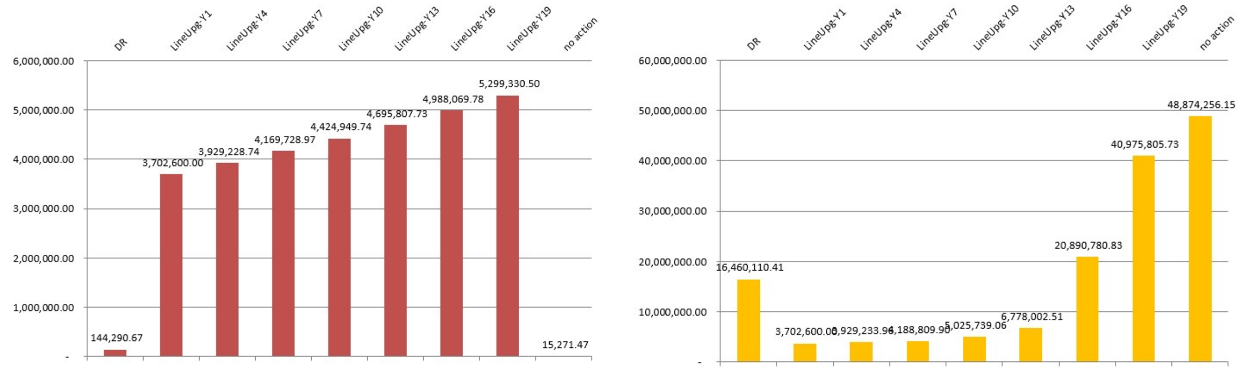

Figure 11: Cumulative DSO costs at Year 20 for LOW (on the left) and HIGH (on the right) EV and PV penetration rates

Note that according to the current regime, RPF reduce the energy-related costs to TSO, because injected energy during a certain period (e.g., a month) is subtracted from the energy absorbed during the same period. These costs are given by the following equation: $\max((energy\_received - energy\_injected * 1.023) * rate, 0)$, i.e., the energy injected is increased by 2.3% and thus cost savings are further magnified. These cost savings are not included in our analysis.

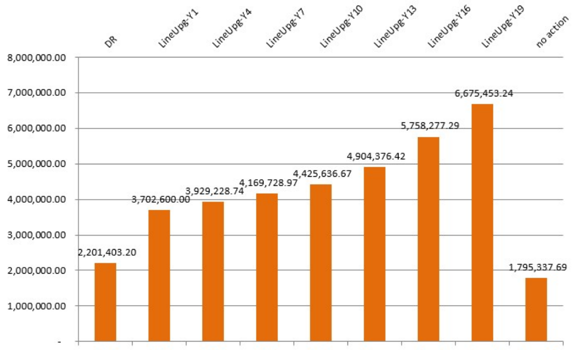

Figure 12: Cumulative DSO costs at Year 20 for MODERATE EV and PV penetration rates

We observe that upgrading the lines is the most cost-effective option in the HIGH scenario and the DSO has no incentive to delay these investments. Thus, upgrading at Y1 minimises the costs for the DSO and the society, who will finance this investment. Ignoring the effects of high EV and PV seems to be preferable in the LOW scenario, where total penalties account to 10.6% of the second-best option (DR campaigns). On the other hand, in the MODERATE scenario, requesting flexibility from an Aggregator costs 81.6% compared to ignoring the congestion. The next figure presents the cumulative DR costs for the three different scenarios.

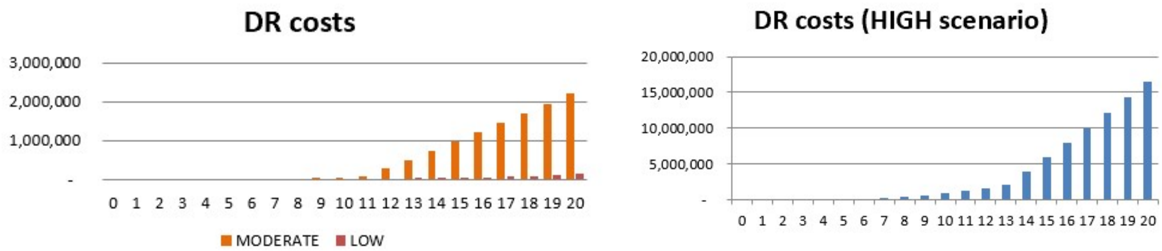

Figure 13: The cumulative DR costs for a DSO in the three different scenarios

Given that “no action” strategy in the MOERATE scenario will have a detrimental effect on the society, we assume that the “DR strategy” is preferable. However, this non-extreme scenario is the only favourable case for the congestion avoidance Aggregators’ service.

Having examined the attractiveness of Demand Response campaigns for the DSO in different scenarios regarding the EV and PV increase rates, in the following we will focus on the viability of the "congestion avoidance" service for different cost scenarios of an Aggregator. These cost scenarios appear on the following table.

Table 1: Aggregator cost scenarios

in € '000	CAPEX	OPEX
LOW		40
MODERATE	10	80
HIGH		120

The following two tables present the cumulative cash flow and Internal Rate of Return (IRR) respectively for an Aggregator in year 20 for different combinations of EV,PV increase rates and Aggregator costs. We observe the following:

1. In the LOW scenario regarding EV, PV penetration, the revenues from DR campaigns do not exceed the costs in any of the 3 cost scenarios.
2. In the MODERATE scenario regarding EV, PV increase rates, the service is marginally sustainable in the case of LOW costs only, resulting in positive cash flow balance and neutral IRR (0%).
3. In the HIGH scenario, the congestion avoidance service is profitable in all cases of costs examined but HIGH.

Table 2: Aggregator's Cumulative Cash Flow (at Y20) for different combinations of EV,PV increase rates and Aggregator costs

		EV, PV increase rates		
		LOW	**MODERATE**	**HIGH**
Aggregator cumulative cash flows	**LOW**	(900,098)	167,402	5,319,059
	MODERATE	(1,871,993)	(804,493)	4,347,164
	HIGH	(3,815,783)	(2,748,283)	(2,748,283)

Table 3: Aggregator's Internal Rate of Return (at Y20) for different combinations of EV,PV increase rates and Aggregator costs

		EV, PV increase rates		
		LOW	**MODERATE**	**HIGH**
Aggregator IRR	**LOW**	#N/A	0%	24%
	MODERATE	#N/A	#N/A	15%
	HIGH	#N/A	#N/A	#N/A

Thus, the congestion avoidance service is expected to be both attractive for DSOs and participants to DR event alike, as well as slightly profitable in the case of MODERATE EV and PV increase rates and only for LOW Aggregator costs. The cumulative cash flow for the aggregator appears in the figure below.

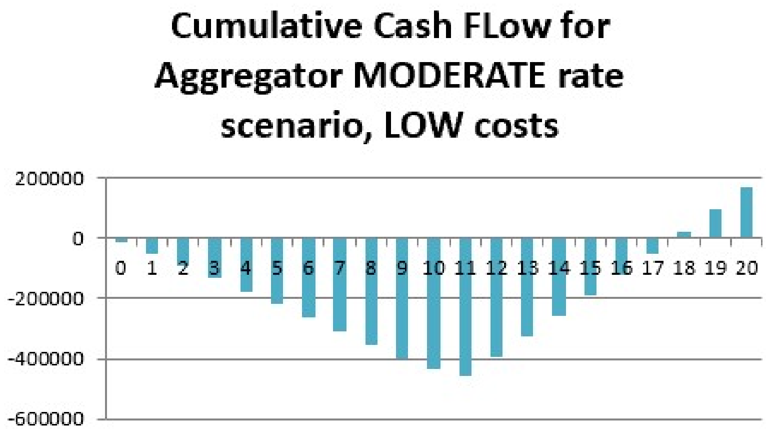

Figure 14: Cumulative Cash Flow for Aggregator MODERATE rate scenario, LOW costs

Conclusions

Based on the simulations performed in this paper we argue that congestion issues due to high loads will be important in the near future as penetration of Electric Vehicles and Renewable sources increases. Nevertheless, reverse power flows are not expected to be a problem in parts of the distribution network where redundancy lines exist (i.e., loops). Furthermore, we observed that Demand Side management techniques, and especially those that are controlled by service providers (ADR) can greatly reduce power interruptions. Apart from the technical aspects, we have shown that

Demand Response is the most cost-effective solution for DSOs when dealing with congestion issues in one of the three scenarios examined, namely the moderate one regarding EV, PV increase rates. However, in order for Demand Response programs to be launched, the Aggregators need to be profitable. It was found that a win-win scenario is obtained in the case of low capital and operational expenditures scenario.

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