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Smart energy for people

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Abstract:

This document presents the results of Task 2.3 of NOBEL GRID. The main purpose is to propose innovative business models for individual actors and evaluate the attractiveness of each one when these are combined into value networks for dealing with a challenge or an opportunity that exists in the context of the NOBEL GRID pilot sites. This is important in order to understand the market potential of the NOBEL GRID technologies and the resulting interactions among the market players, namely DSOs, ESCOs/Aggregators, Retailers and Consumers/Prosumers.

Keywords:

Business models, Value Networks, Business Plans, DSO, Aggregator, Retailer, Prosumer, Incentive Mechanisms.

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EXECUTIVE SUMMARY

This document presents the results of Task 2.3 of NOBEL GRID. The main purpose of the document is to **propose innovative business models for individual actors and evaluate the attractiveness of each one when these are combined into value networks for dealing with a challenge or an opportunity that exists in the context of the NOBEL GRID pilot sites**. This is important in order to understand the market potential of the NOBEL GRID technologies and the resulting interactions among the market players, namely Distribution System Operators (DSOs), Energy Service Companies (ESCOs)/Aggregators, Retailers and Consumers/Prosumers.

In particular we focus on the following innovative, as well as, more straightforward business models:

- Consumers as **Prosumer**: individual consumers (such as home owners, Small-medium enterprises or cooperatives) producing renewable energy locally and deciding how much to consume or export to the grid.
- ESCOs as **Independent Aggregator**: In this business model ESCOs (Energy Service Companies) steer their (potentially large) group of members on their consumption and production decisions and offer this flexibility to other market players such as DSOs and TSOs.
- DSOs evolved into **SmartGrid-enabled DSOs**: Under this business model DSOs perform advanced network management by using tools and processes that treat Demand-Side Management techniques on par with traditional ones when performing their tasks, e.g. maintaining the power quality by minimizing Reverse Power Flows or reducing congestion issues that can lead to power outages.
- Retailers as **Cooperative Virtual Power Plant**: In this business model Retailers, who may also own generation assets and thus act as “Gentailers”, adopt the business model of an Aggregator and take advantage of their customers’ production capacity as well as demand flexibility in order to optimize the way own production is used. In particular, such a (cooperative) retailer can lower electricity bills of its clients and thus increase its market share, by reducing the cost of energy procured in wholesale markets when prices are exceptionally high either by offering dynamic pricing plans or by organizing DR campaigns. In addition, it can provide flexibility services to other market actors (such as balancing services to Transmission System Operators - TSOs) and create an additional revenue stream for the participants.

In addition, this study can be considered as a major step towards identifying the key technical and socio-economic factors that will determine the adoption of NOBEL GRID products by providers, as well as, consumers’ engagement due to the increasing importance of Demand-Response schemes and collective participation through virtual cooperatives. In order to do so and, in absence of statistically significant real data from the demonstration activities that was a deviation from initial plans, a set of simulators have been prepared and used for obtaining values for key technoeconomic metrics, such as:

- **how much flexibility would a DSO ask, 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 and what is the effect of technology (such as Electric Vehicles and smart controllers) and rewards?**

Answers to these questions were obtained for several scenarios that we defined along the following two dimensions:

- The **Electric Vehicle (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 **Photovoltaic (PV) penetration rate** i.e., the percentage of prosumers in an area, which greatly affects the reverse power flows and the quality at the Low Voltage/ Medium Voltage (LV/MV) network.

For the default scenario <Moderate EV penetration rate, Moderate PV penetration rate> we got the following results, which provide the Internal Rate of Return (IRR[1]) for the main roles considered in our analysis when these collaborate in 11 new service offerings as well as the business-as-usual one (rows of table) taking into account the local conditions of the five (5) NOBEL GRID pilot sites. The color coding of the contents is compatible with a widely used rule of thumb that IRR greater (or equal) than 30% are considered to be very attractive (marked with deep green), while negative values are alarming (light red color). White background means that the particular role (column) is not active in a value network (row).

	Terni					Manchester				
	DSO	Aggregator	Retailer	ProsumerA	Prosumer	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.84%	-2.43%	15.69%	-100.00%	-20.70%	0.37%	-4.26%	5.06%	-100.00%	-100.00%
GreenEnergyMax	0.16%	105.63%	15.47%	-100.00%	-20.89%	1.49%	62.13%	5.86%	-100.00%	-100.00%
ProsumerMax	0.16%	131.31%	15.46%	-100.00%	-19.59%	1.49%	83.72%	5.85%	-100.00%	-100.00%
ElectricHeatAutomation	0.16%	92.73%	15.47%	-100.00%	-20.89%	1.49%	51.00%	5.86%	-100.00%	-100.00%
GridAssetsMaintenance	2.77%	#N/A	15.47%	-100.00%	-17.94%	3.27%	#N/A	5.86%	-100.00%	-100.00%
GridQuality&Control	2.82%	#N/A	15.47%	-100.00%	-17.94%	3.30%	#N/A	5.86%	-100.00%	-100.00%
IncidentManagement	2.82%	#N/A	15.47%	-100.00%	-17.94%	3.30%	#N/A	5.86%	-100.00%	-100.00%
IncreasedPowerQuality	2.57%	#N/A	15.47%	-100.00%	-17.94%	2.84%	#N/A	5.86%	-100.00%	-100.00%
CoopPowerPlant	2.57%	18.93%	14.95%	-100.00%	-17.72%	2.84%	7.39%	6.23%	-100.00%	-100.00%
ReduceRPFtoTSO	2.71%	7.63%	15.45%	-100.00%	-17.94%	2.92%	-3.24%	5.82%	-100.00%	-100.00%
CongestionAvoidance	4.01%	24.08%	15.45%	-100.00%	-17.69%	3.71%	16.33%	5.82%	-100.00%	-100.00%
PowerFactorManagement	3.09%	#N/A	15.45%	-100.00%	-18.01%	3.13%	#N/A	5.82%	-100.00%	-100.00%

Figure 1: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Terni and Greater Manchester

	Valencia					Flanders				
	DSO	Aggregator	Retailer	ProsumerA	Prosumer	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.73%	-100.00%	8.41%	-8.01%	-100.00%	6.76%	-100.00%	13.32%	3.38%	-9.93%
GreenEnergyMax	2.10%	-100.00%	9.29%	-8.77%	-100.00%	19.82%	-100.00%	13.68%	2.88%	-9.97%
ProsumerMax	2.10%	-100.00%	9.28%	-8.30%	-100.00%	19.82%	-100.00%	13.67%	3.17%	-9.67%
ElectricHeatAutomation	2.10%	-100.00%	9.29%	-8.31%	-100.00%	19.82%	-100.00%	13.68%	3.10%	-9.97%
GridAssetsMaintenance	5.34%	#N/A	9.29%	-7.60%	-100.00%	20.73%	#N/A	13.68%	3.71%	-9.25%
GridQuality&Control	5.39%	#N/A	9.29%	-7.60%	-100.00%	20.79%	#N/A	13.68%	3.71%	-9.25%
IncidentManagement	5.39%	#N/A	9.29%	-7.60%	-100.00%	20.79%	#N/A	13.68%	3.71%	-9.25%
IncreasedPowerQuality	3.98%	#N/A	9.29%	-7.60%	-100.00%	20.26%	#N/A	13.68%	3.71%	-9.25%
CoopPowerPlant	3.98%	-100.00%	8.57%	-7.82%	-100.00%	20.26%	-100.00%	13.33%	3.35%	-9.19%
ReduceRPFtoTSO	4.57%	-100.00%	9.25%	-8.25%	-100.00%	20.48%	-100.00%	13.65%	3.13%	-9.25%
CongestionAvoidance	4.78%	-100.00%	9.25%	-5.68%	-100.00%	26.07%	-15.38%	13.65%	4.52%	-9.18%
PowerFactorManagement	5.83%	#N/A	9.25%	-7.69%	-100.00%	21.08%	#N/A	13.65%	3.58%	-9.34%

Figure 2: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Valencia and (part of) Flanders

[1] IRR is the interest rate at which the net present value of all the future cash flows (i.e., negative during the first year(s) and hopefully positive in most of the following years) equal zero.

	Meltemi				
	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.99%	-100.00%	3.06%	-4.31%	-9.54%
GreenEnergyMax	4.08%	-100.00%	4.64%	-4.84%	-9.57%
ProsumerMax	4.08%	-100.00%	4.62%	-4.47%	-9.30%
ElectricHeatAutomation	4.08%	-100.00%	4.64%	-4.52%	-9.57%
GridAssetsMaintenance	6.86%	#N/A	4.64%	-4.02%	-8.98%
GridQuality&Control	7.04%	#N/A	4.64%	-4.02%	-8.98%
IncidentManagement	7.04%	#N/A	4.64%	-4.02%	-8.98%
IncreasedPowerQuality	5.82%	#N/A	4.64%	-4.02%	-8.98%
CoopPowerPlant	5.82%	-100.00%	4.40%	-4.16%	-8.92%
ReduceRPFtoTSO	6.56%	-100.00%	4.59%	-4.47%	-8.98%
CongestionAvoidance	7.19%	-100.00%	4.59%	-2.55%	-8.91%
PowerFactorManagement	7.02%	#N/A	4.59%	-4.12%	-9.06%

Figure 3: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Rafina (which includes Meltemi eco-village (the original NOBEL GRID pilot site)

The figures above show:

- That DSOs are allowed to have a low, but positive, IRR in the Business as Usual (BaU) scenario which is increased in most of the cases with NOBEL GRID technologies. This positive effect of NOBEL GRID can reduce the electricity bills of the end-users.
- That Gentailers (Retailers owning distributed generation units) are found to be profitable in all scenarios and all areas considered, while their economic performance is improved on the vast majority of those that are enabled by NOBEL GRID technologies.
- That the business model of an ESCO becoming an Aggregator is not profitable in any of the areas examined in absence of NOBEL GRID technologies due to the need to install additional smart meters (behind the official meter that was assumed to be a low-cost one) in order to have access to fine-grained data and realise advanced methods for meeting requests for flexibility. When considering candidate value networks that are enabled by NOBEL GRID products, mainly smart meters (SLAM and/or SMX), G3M, DRFM and EMA app, duplicated infrastructure is avoided and the profitability largely depends on size of the user portfolio (pool size) the importance of large customer base for aggregators to be profitable and (as appears in Terni and Manchester). Nevertheless, aggregators' capital expenditures are less sensitive to the size/population of the area they are operating and thus they can increase their pool size by expanding to other geographical areas. The following table presents the cumulative cash flows, in other words profits or losses at the end of the evaluation period (at 20th year), of an Aggregator participating in each value network supported by NOBEL GRID and for each pilot site. We observe that NOBEL GRID can hep Aggregators achieve operating profits of up to € 7,375,033 (compared to 70,030 initially achieved in Terni).

Table 1: The effect of NOBEL GRID on the operating profits/losses (in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Terni	Valencia	Manchester	Attica	Flanders
BaU	70,030	-23,546,382	-1,195,073	-19,058,573	-9,328,681
GreenEnergyMax	5,729,343	-23,952,969	5,251,236	-19,007,159	-5,922,509
ProsumerMax	7,168,012	-23,819,853	6,903,353	-18,809,914	-4,957,494
ElectricHeatAutomation	4,595,054	-24,057,137	3,929,054	-19,160,356	-6,683,355
GridAssetsMaintenance	N/A	N/A	N/A	N/A	N/A
GridQuality&Control	N/A	N/A	N/A	N/A	N/A
IncidentManagement	N/A	N/A	N/A	N/A	N/A
IncreasedPowerQuality	N/A	N/A	N/A	N/A	N/A

CoopPowerPlant	2,545,591	-24,246,318	1,564,289	-19,440,015	-8,058,072
ReduceRPFtoTSO	1,002,697	-24,388,739	-215,973	-19,650,550	-9,092,998
CongestionAvoidance	**7,375,033**	-23,800,523	7,136,722	-18,781,014	-4,818,631
PowerFactorManagement	N/A	N/A	N/A	N/A	N/A

- That the financial viability of the prosumer business model heavily depends on three main aspects:
    i. the existence of generous governmental support schemes, since the only area from those analysed where prosumage can flourish is Flanders (net metering regime is in place);
    ii. the presence of high controllable loads (such as EVs) as Prosumers with no support for Automated Demand Repsonse - ADR (those named ProsumerMDR or ProsumerM) are not profitable even when net metering is enabled
    iii. the demand for flexibility by established market players (such as DSOs, TSOs and Retailers) and their willingness to pay, as the IRR of prosumers increases in those value networks where Demand Repsonse (DR) campaigns are frequent and the alternative action is costly (for increasing the reward obtained from Aggregators per kWh offered).
- That even if the cost savings and new revenues from each High-Level Use-Case (HLUC) are not combined/stacked there are many cases where all participants have the incentive to collaborate in service offering. This can be seen by checking whether all participating roles have attractive (light green) or very attractive IRR. Note that even though 2 types of prosumers are shown, it is sufficient one of them to be profitable for a value network to be economically feasible on an end-to-end basis.

Furthermore, we showed that Consumers, either those owning an EV (named ConsumerADR/ConsumerA) or standard ones who can only participate in manual Demand Response campaigns, can see significant reduction on their electricity bills. Based on the table below, we observe that residential[2] users belonging to the ConsumerADR category can see a reduction of up to € 1324 over the 20-year evaluation period.

Table 2 The effect of NOBEL GRID on the total electricity cost for consumers with EV (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Terni	Valencia	Manchester	Attica	Flanders
BaU	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
GreenEnergyMax	-176.77 €	-149.40 €	-223.71 €	-110.28 €	-114.20 €
ProsumerMax	180.72 €	140.46 €	249.73 €	82.96 €	88.71 €
ElectricHeatAutomation	**999.75 €**	**810.61 €**	**1,324.00 €**	540.41 €	567.43 €
GridAssetsMaintenance	94.03 €	141.01 €	66.70 €	189.93 €	176.21 €
GridQuality&Control	94.03 €	141.01 €	66.70 €	189.93 €	176.21 €
IncidentManagement	94.03 €	141.01 €	66.70 €	189.93 €	176.21 €
IncreasedPowerQuality	15.60 €	42.97 €	-31.34 €	82.09 €	78.17 €
CoopPowerPlant	373.09 €	332.83 €	442.10 €	275.33 €	281.08 €
ReduceRPFtoTSO	15.60 €	42.97 €	-31.34 €	82.09 €	78.17 €
CongestionAvoidance	910.90 €	768.90 €	1,154.34 €	**566.03 €**	**586.32 €**
PowerFactorManagement	94.03 €	141.01 €	66.70 €	189.93 €	176.21 €

At the same time instances of the residential ConsumerMDR type can reduce their cost for electricity by up to €392, as evidenced in Flanders for the Congestion Avoidance value network.

[2] Commercial and industrial ones will enjoy even higher cost savings.

Table 3 The effect of NOBEL GRID on the total electricity cost for standard consumers (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Terni	Valencia	Manchester	Attica	Flanders
BaU	0.00 €	0.00 €	0.00 €	0.00 €	0.00 €
GreenEnergyMax	-40.87 €	-39.17 €	-43.70 €	-36.83 €	188.72 €
ProsumerMax	N/A	N/A	N/A	-36.83 €	188.72 €
ElectricHeatAutomation	N/A	N/A	N/A	-4.77 €	220.78 €
GridAssetsMaintenance	151.50 €	153.20 €	148.67 €	155.54 €	381.09 €
GridQuality&Control	151.50 €	153.20 €	148.67 €	155.54 €	381.09 €
IncidentManagement	151.50 €	153.20 €	148.67 €	155.54 €	381.09 €
IncreasedPowerQuality	151.50 €	153.20 €	148.67 €	155.54 €	381.09 €
CoopPowerPlant	159.70 €	162.52 €	149.14 €	155.94 €	368.78 €
ReduceRPFtoTSO	151.50 €	153.20 €	148.67 €	155.54 €	381.09 €
CongestionAvoidance	**171.21 €**	**169.11 €**	**174.72 €**	**166.21 €**	**392.31 €**
PowerFactorManagement	151.50 €	153.20 €	148.67 €	155.54 €	381.09 €

As mentioned earlier, the regulatory authority may set lower regulated rates as a response to cost savings achieved in maintaining and operating the LV/MV grid. The next two tables attempt to quantify how these cost savings can be passed to residential end-users. Table 4 and Table 5 show that the cost savings for residential ConsumerADR members can be up to € 1586 (in case of Greater Manchester that is further reduction of €262 compared to the case where the regulatory authority would allocate the cost savings to other recipients), while a residential ConsumerMDR would achieve reductions on the electricity bill of up to €657 (in case of Flanders that is an additional reduction of €265).

Table 4 The effect of NOBEL GRID on the total electricity cost for consumers with an EV when regulated charge for using the distribution network is a adjusted (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Terni	Valencia	Manchester	Attica	Flanders
BaU	NA	N/A	N/A	N/A	N/A
GreenEnergyMax	-176.77 €	157.61 €	39.00 €	186.53 €	150.47 €
ProsumerMax	400.61 €	447.47 €	512.44 €	379.77 €	353.37 €
ElectricHeatAutomation	**1,703.69 €**	**1,117.62 €**	**1,586.70 €**	837.22 €	832.09 €
GridAssetsMaintenance	94.03 €	448.02 €	329.41 €	486.74 €	440.88 €
GridQuality&Control	94.03 €	448.02 €	329.41 €	486.74 €	440.88 €
IncidentManagement	94.03 €	448.02 €	329.41 €	486.74 €	440.88 €
IncreasedPowerQuality	15.60 €	349.98 €	231.37 €	378.90 €	342.84 €
CoopPowerPlant	592.98 €	639.84 €	704.81 €	572.14 €	545.74 €
ReduceRPFtoTSO	15.60 €	349.98 €	231.37 €	378.90 €	342.84 €
CongestionAvoidance	1,461.58 €	1,075.90 €	1,417.04 €	**862.84 €**	**850.98 €**
PowerFactorManagement	94.03 €	448.02 €	329.41 €	486.74 €	440.88 €

Table 5 The effect of NOBEL GRID on the total electricity cost for standard consumers when regulated charge for using the distribution network is a adjusted (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Terni	Valencia	Manchester	Attica	Flanders
BaU	N/A	N/A	N/A	N/A	N/A

GreenEnergyMax	-40.87 €	267.83 €	219.00 €	259.98 €	453.39 €
ProsumerMax	-8.81 €	267.83 €	219.00 €	259.98 €	453.39 €
ElectricHeatAutomation	151.50 €	299.90 €	251.07 €	292.04 €	485.45 €
GridAssetsMaintenance	151.50 €	460.20 €	411.37 €	452.35 €	645.76 €
GridQuality&Control	151.50 €	460.20 €	411.37 €	452.35 €	645.76 €
IncidentManagement	151.50 €	460.20 €	411.37 €	452.35 €	645.76 €
IncreasedPowerQuality	159.70 €	460.20 €	411.37 €	452.35 €	645.76 €
CoopPowerPlant	151.50 €	469.53 €	411.84 €	452.76 €	633.44 €
ReduceRPFtoTSO	171.21 €	460.20 €	411.37 €	452.35 €	645.76 €
CongestionAvoidance	151.50 €	**476.12 €**	**437.42 €**	**463.02 €**	**656.97 €**
PowerFactorManagement	-40.87 €	460.20 €	411.37 €	452.35 €	645.76 €

1 INTRODUCTION

1.1 INTRODUCTION

This document presents the results of Task 2.3 of NOBEL GRID. The main purpose of the document is to propose innovative business models for individual actors and evaluate the attractiveness of each one when these are combined into value networks for dealing with a challenge or an opportunity that exists in the context of the NOBEL GRID pilot sites. This is important in order to understand the market potential of the NOBEL GRID technologies and the resulting interactions among the market players, namely DSOs, ESCOs/Aggregators, Retailers and Consumers/Prosumers.

In addition, this study can be considered as a major step towards identifying the key technical and socio-economic factors that will determine the adoption of NOBEL GRID products by providers, as well as, consumers' engagement due to the increasing importance of Demand-Response schemes and collective participation through virtual cooperatives.

1.2 SCOPE OF THE DOCUMENT

In this deliverable we perform an assessment of the economic viability of candidate business models for the main NOBEL GRID actors, namely DSOs, ESCOs, Retailers and Consumers. Our starting point is a "standard" business model for each actor and for each of the 5 pilot sites: Valencia (ES), Flanders (BE), Manchester (UK), Terni (IT) and Rafina[3] (GR). Then, we combine the services offered by each actor into value networks by taking into account the 11 NOBEL GRID High-Level Use-Cases (HLUCs) that were defined in D1.3 (1). Note that not all market players are actively involved in the realization of a certain HLUC.

Performing a cost-benefit analysis of the proposed value networks for the whole society of a certain pilot site is out of this report's scope, but is the main focus of D19.2.

1.3 STRUCTURE OF THE DOCUMENT

We start, in Section 2, with an overview of the state of the art on business models for the Smart Grid and challenges and opportunities that were identified in the literature for the market players. In Section 3, we propose a generic value network for smart grids and describe our overall methodology for analyzing candidate NOBEL GRID business models. Then, in Section 4, we introduce the NOBEL GRID Business Model Evaluation tool that implements the methodology, while in Section section 5, we use the Business Modelling Canvas methodology to describe the proposed business model for each key NOBEL GRID actor involved in each High-Level Use-Case. Then, in Section 6 we perform a technoeconomic analysis of key aspects of the proposed business models, while in Section 7, we identify the economically viable High-Level Use-Cases for each key NOBEL GRID actor and pilot site by performing a business plan analysis. Finally, we conclude in Section 8.

[3] Rafina is part of Attica which includes Meltemi eco-village (the original pilot site of NOBEL GRID)

2 BUSINESS MODELS FOR THE SMART GRID

2.1 STATE OF THE ART

The transition from traditional to smart power grids has come to be materialised and catalysed by the high renewable energy penetration and the imperative need for power supply reliability and economic viability. The IBM Institute for Business Value points out that long-standing electric utility business models are rapidly becoming outdated in light of new technologies, policy changes and more demanding consumers. Roles along the value chain are shifting, with traditional buyers gaining a foothold as value providers. To succeed in this new environment, there is a critical need to develop fresh business models, addressing not only traditional energy generation and delivery (updated to benefit from new technologies), but also emerging products and services enabled by new technologies (2). Table 1 describes significant changes that are expected with the widespread use of the smart grid.

Table 6: Comparison between features with and without the smart grid (3)

Environment	Without Smart Grid	With Smart Grid
Data	Offline, scarce data One-way stream	Online, abundant data (big data) Two-way interchange
Energy	Focus on fossil-based Centralized energy production	Prosumers Dynamic business model, Decentralised and dispersed energy production
Information and communication technologies	Some reactive systems in place/Weak preventive mechanisms Little use of Information and Communication technologies Infrastructure with scarce intelligence	Strong preventive mechanisms, complex and dynamic diagnostics and proactive management systems. Widespread use of information and communication technologies Information inference and Decision making features
Agents	Reduced amount of participating agents	Potentially huge amount of participating agents, introduction of ‘virtual’ agents enabled by information and communication technologies.

In this emerging energy landscape there are several new services that can be provided and that will constitute the basis for expanding business models.

To better exploit the SOTA of business models applied to the smart grid and discuss on emerging ones it is advisable to briefly describe which entities compose traditional value chain and how does it differ from the smart grid value chain. As shown in Figure 1 the value chain will extend further and become more complex involving a variety of new participants. The consumer will became an active, empowered value chain participant requiring integration in the smart grid. The information and the power will flow in multiple directions, while the exponential increase in information flow will add tremendous value to the system. The distributed resources (e.g., distributed generation, storage, electric vehicles) will also play an increasingly vital role in operations of both transmission and distribution network and in value creation.

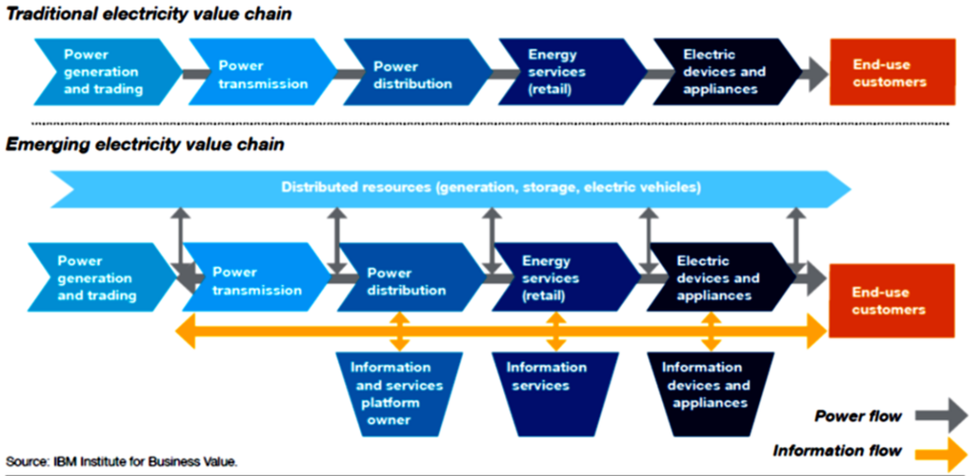

Figure 4: Traditional and emerging electricity value chain (2)

DSO

The authors in (4) argue that DSOs have to change their business focus in order to keep their business lucrative. By developing new business activities, thereby diversifying the business model, and by transforming operational philosophies from passive into active network management, DSOs can overcome the threats that arise from the increasing penetration of DG, incentive regulation, regulated connection charges, and unbundling. Towards this direction an adapted business model for the DSO is proposed based on the development of new business activities (see Figure 2). The latter will enable the transition from active to passive network management by developing new services for the electricity market, creating new revenue drivers for the DSO. The new services include the incorporation of advanced information exchange between generation and consumption, the provision of ancillary services at the distributed level, management of the network to provide network reliability and controllability, and improve customer benefits and cost-effectiveness.

The authors in (5) extend the business model proposed above in the one depicted in Figure 3 which illustrates the existing and new services, flow of revenue, costs, and interaction of key players (i.e. interaction with different consumer categories, transmission system operator (TSO), distributed energy operators and retail suppliers) in an extended business model of DSO. More precisely DSO will contribute to national load balancing and will be compensated for that by the TSO. Moreover, many commercial and industrial users need premium reliability as their production process is sensitive to the electricity input. DSOs will be reimbursed by those industries for providing highly reliable connections. Furthermore, with the use of information and communication technologies, valuable system data will be available that can be shared with DG operators and retail suppliers for efficient planning and operation in return for a payoff. Finally, an important part of the extended business model is the possibility to integrate distributed resources, also including demand response, as alternatives to grid capacity enhancement.

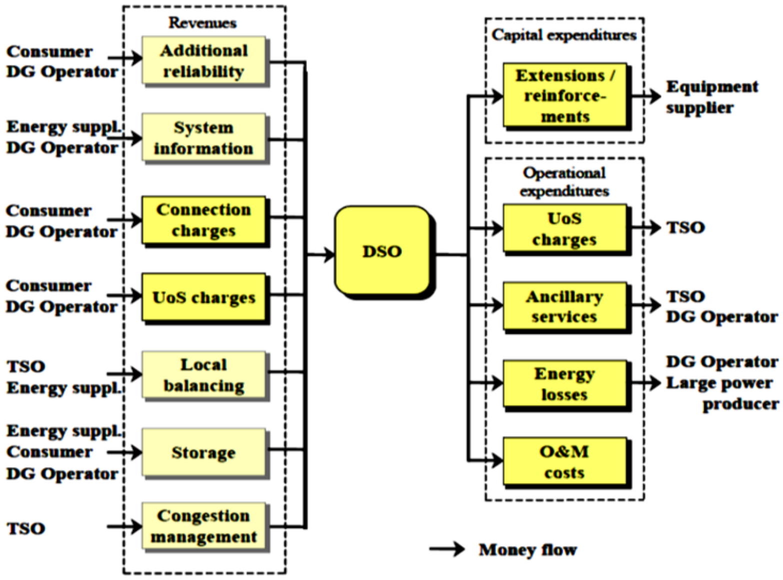

Figure 5: Example of an adapted business model of a DSO.

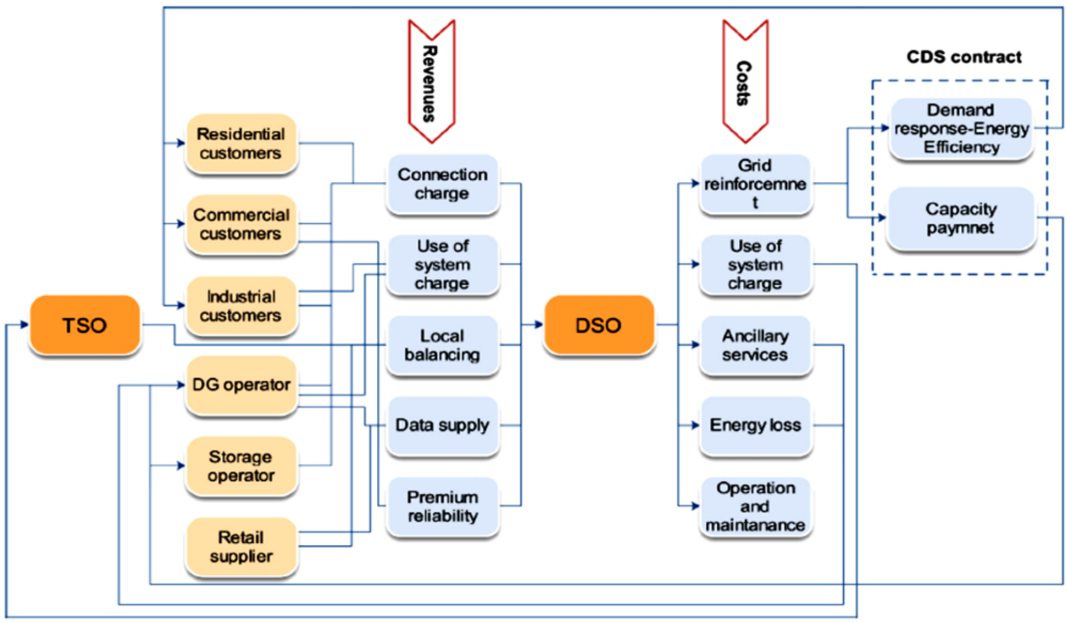

Figure 6: The extended business model for DSO (5).

Aggregator

The authors in (6) describe in general the operations that an aggregator performs. More precisely what kind of tasks the aggregator should take care of and what added value he brings to the power system. Initially, the aggregator collects customer demand flexibility and provides access to the market. The aggregator's job is to enable the demand response and bring it to the wholesale market. To achieve that the aggregator studies which customers can provide profitable demand response, promotes the demand response service to customers, installs control and communication devices at customer's premises and provides financial incentives to the customers to provide demand response. In addition, the aggregator actively offers the distributed energy resources to the disposal of other power system participants either through on one-to-one basis (bilateral contracts) or through organized markets by submitting offers to these markets. The DR Service is purchased form regulated participants such as TSO and DSO, and deregulated participants such as retailers, generators, traders and BRP. Among other the aggregator facilitates market participation since the benefit for an individual (small-scale) customer from trading on organized markets would probably be too low compared to the costs. Currently the market operators have also set rules about the minimum bids and offers, probably to limit their transaction costs. The Aggregator should also try to anticipate the requests and make forecasts about them, which is difficult for a single customer. The aggregator also makes sure that the load control decisions do not cause problems for the electrical network. He can do this validation by consulting system operators (DSO's and TSO). He sends his planned schedules for load control to concerned DSO's. Within NOBEL GRID the aggregator also can offer non-flexibility based services to DSOs, like voltage control and harmonics filtering.

Then, the authors of the report (6) discuss the business opportunities of the DER aggregator in the Finnish electricity market. DER aggregator's relationship with other power system participants as well as end customers was discussed. The authors argue that the relationship with customers is crucial to the aggregator, and more important than the relationship with buyers of the aggregator's service. Taking into account that electricity is a commodity, and asserts that the aggregator does not have to make efforts to sell it to the buyers (e.g. TSO and DSO) as long as his service meets quality requirements (such as short enough activation time) and is cheap enough. On the other hand, joining a demand response program brings the consumer relatively small benefits compared to his total electricity bill while load control requires interfering with the customers' production processes or living comfort. Thus, the aggregator needs to build a personalized relationship with consumers and motivate them appropriately. In addition, the requirements placed on the existing business of the aggregator, i.e. what kind of companies can assume the aggregator role is presented in Figure 4.

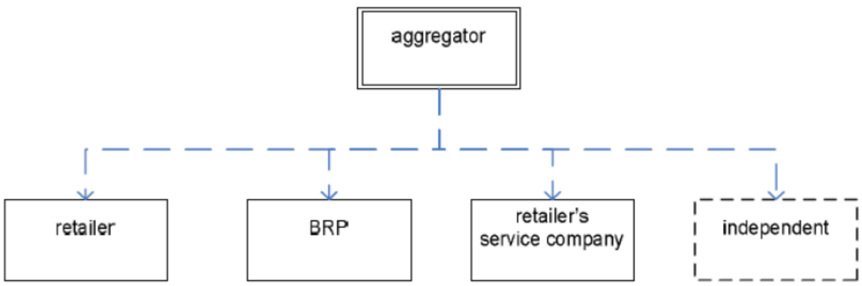

Figure 7: Aggregator business models classified according to the aggregator's identity (7).

The simplest case is if the aggregator himself is a retailer that aggregates the DER which his retail customers can offer. This is the business model which has been studied in e.g. EU-DEEP project task force 1.

Another possibility is that the aggregator acts as a service company to the retailer and has no independent position on the electricity market. In this case he performs activities such as forecasting, scheduling optimization and load control as normal but the effect of load control is summed into the consumption balances of the respective retailers. The retailers can then sell this power forward, based on the Aggregator's advice. In that case the Aggregator secured his income by making a service contract with the retailer. The benefit of this model compared to the retailer model is that the aggregator is not limited to a certain group of customers, with whom he has a retail contract. However, the disadvantage is that he has to first come into agreement with several retailers to take advantage of this fact. Third possibility is that the balance responsible party acts as aggregator for customers whose retailers belong to his balance portfolio. The load changes are then automatically included in his consumption balance. Finally, the Aggregator can act as an independent company, which has made no agreement about income sharing or service provision with retailers. Instead his balance account would be directly credited by load reduction or charged by load increase, caused by the control actions which he has exerted on the customers.

Also, a number of international projects have paid attention to the role and business opportunities of the aggregator company. For example, the overall goal of EU-DEEP (Distributed energy partnership, FP6/2004–2009) was to produce innovative business solutions for enhanced DER (demand response, energy storages and distributed generation) deployment in Europe. Figure 5 below shows some of the money flows between the aggregator, his customers and buyers of aggregated services. The idea in this model was to

balance intermittent generation with the use of DER. Besides balancing, the resources can also be used on the spot market and offered as reserves to the TSO.
In addition, ADDRESS's (Active distribution networks with full integration of demand and distributed energy resources, FP7/2007-2013) main objective was to enable the "active demand" in the context of the smart grids of the future, or in other words, active participation of domestic and small commercial consumers in the power system markets and service provision to the power system participants. Figure 6 presents the simplified representation of ADDRESS's architecture form which various business opportunities can be extracted. In this architecture, the aggregators are a central concept. The aggregators are the key mediators between the consumers on one side and the markets and the other power system participants on the other side. More precisely the aggregators collect the requests and signals for AD-based services coming from the markets and the different power system participants. They gather the "flexibilities" and the contributions provided by consumers to form AD-based services and they offer them to the different power system participants through various markets.

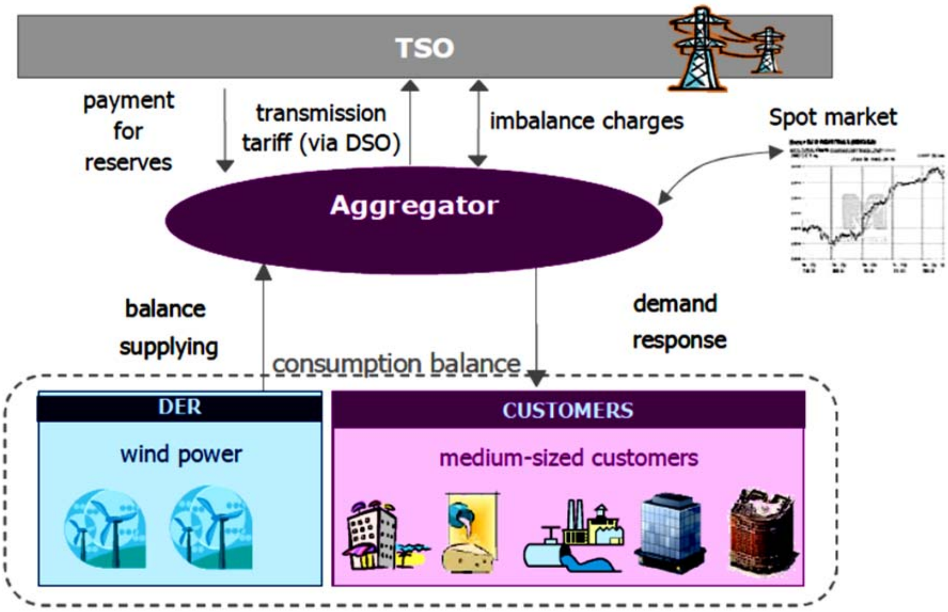

Figure 8: Money flows in the EU-DEEP first BM (8).

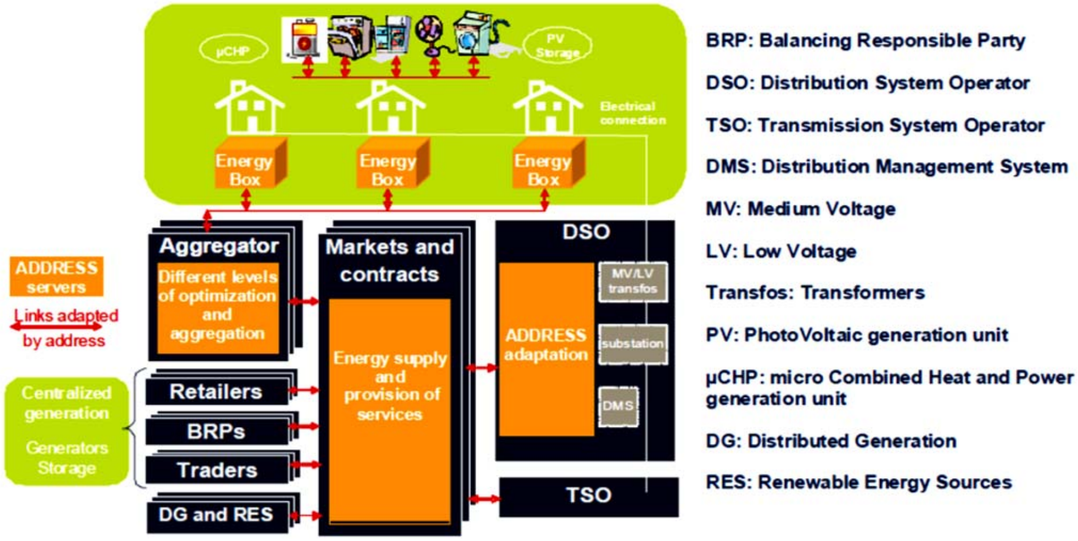

Figure 9: According to the ADDRESS project, the aggregator communicates with customers via "energy boxes", which perform load control and measurement, and with regulated and deregulated market participants through markets (9).

In contrast to the aforementioned projects the FENIX project (Flexible electricity networks to integrate the expected energy evolution, FP6) deals with distributed generation. FENIX project use the concept of virtual power plant (VPP), which includes a flexible portfolio of DER (flexible distributed generation, power storage facilities, flexible loads) remotely monitored and operated as a single entity. An aggregator acting as a commercial VPP (CVPP) applies FENIX concepts on behalf of DER to enable optimal participation of DER in electricity-related markets. More precisely this project considered CVPP applications under conditions prevailing in UK and Spain. More precisely, the following cases, constituting business opportunities for DER where evaluated: (i) optimized wholesale market participation, where the operating schedule of DER was optimized by a CVPP, (ii) commercial aggregation where the CVPP bundles the wholesale market transactions of DG operators to capitalize on the portfolio effect and to reduce administrative costs (iii) balancing services to the TSO, (iii) intra-day adjustment upward or downward services to the Supplier (Retailer), (iv) tertiary reserve services to the TSO, (v) active internal balancing where the CVPP arranges operational adjustments to minimize aggregate imbalance positions of DG under his control.

In the same context in 2008, RWE Energy and Siemens Power Transmission and Distribution started a pilot project to develop and pilot business models and technical concepts for the creation of a VPP consisting of 9 small hydro units (8.6 MW). In a VPP, the operation of distributed installations is scheduled and optimised by an "aggregator", either for the purpose of energy trading in the wholesale market or to provide ancillary services to the grid operator. Siemens proposes the two following business models shown in Figures 7 and 8.

Figure 10 depicts the business model enabled by direct marketing of power with market and management premium. The revenues derive from direct marketing e.g. at EEX (energy exchange). Also, the VVP Aggregator receives a market premium for compensation of difference between the EEG (Renewable Energy Act) feed-in tariff and monthly average spot market energy price. The management premium covers the costs for admission to energy exchange, connection to trading system, market clearing, etc. In addition, revenues occur from aggregation and marketing of distributed renewable generators (previously uncontrolled in-feed). More accurately it includes market operation (energy marketing, administration of contracts with plant operators etc.), operation of distributed generators, and contracts with generation operators and VPP System incl. SW, HW & Integration.

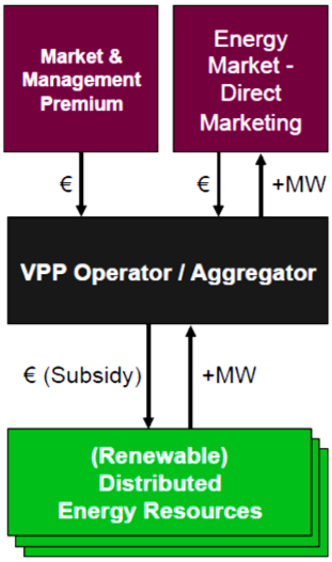

Figure 10: Business model enabled by direct marketing of power with market and management premium (10).

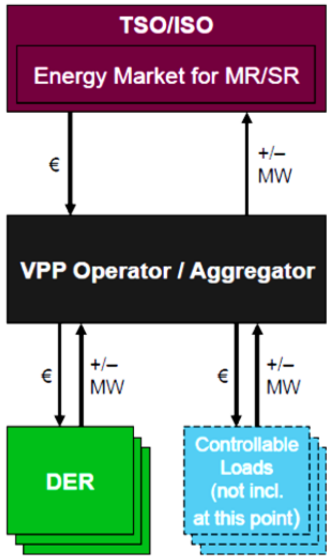

Figure 11: Business model to sell Tertiary/Minute Reserve in the TSO Reserve Market (10).

Figure 11 depicts Business model to sell Tertiary/Minute Reserve in the TSO Reserve Market. In that case the revenues come from providing capacity to Minute Reserve or Secondary Reserve and for making capacity available and particularly the aggregator receive a reward (price) for providing energy after call and for providing positive and negative reserve power.

Prosumer-oriented business model

The ever-increasing development of smart grid technologies allows prosumers to be economically active/motivated entities that:

- Consume, produce and store electricity;
- Take part in economic and technological optimization in electricity consumption;
- Get actively involved in the creation of value for electricity services.

The author in (11) has conducted a review of literature regarding business models for renewable energy production. The review showed that two basic choices exist: (i) utility-side renewable energy business models and (ii) customer-side renewable energy business models. With the term utilities the authors in (11) refers to the classical centralized energy utilities. In utility-side business model the renewable energy systems are on and off shore wind farms, large scale photovoltaic projects, etc. and range from one to some hundred megawatts. The value proposition in this business model is bulk generation of electricity fed into the grid. On the other hand in customer-side business models the renewable energy systems are located at customers' premises. Possible technologies are small photovoltaic, solar thermal water, micro turbines etc. Customer-side business models, or else, prosumer business models are directly in line with NOBEL GRID context and thus, we will focus on them in the sequel.
The growing penetration of renewable energy resources at distribution level which are installed at residential premises and commercial buildings leads to the change that energy is not only consumed behind the meter but also produced. In this setting consumers are evolving into a more active part by being energy producers themselves, i.e. they are becoming prosumers. In (11) the authors review the current challenges of utilities to build new prosumer-oriented business models. As already mentioned the classical

centralized utility's value proposition was comprised and in several cases still comprises production and delivery of service at a fixed price. However, among other the authors in (12), (13) and (14) dealing with business models for energy utilities expect have pointed out that the increasing share of renewable energy resources, energy efficiency techniques and smart energy applications the classical value proposition was no longer a foundation for further growth of electric utilities. From this side the authors conclude that there was an intense need for utility companies to develop new value proposition to remain competitive in the rapidly changing energy landscape. Thus, in this context it is often argued that electric utilities need to develop from simple commodities to comprehensive energy solution providers offering services such as consulting installation, financing, operation maintenance etc. (12), (15) and (16). The review concludes that these value propositions require significantly higher effort with the individual customer and leads to higher transaction costs per customer. Thus, the necessity to create packages of services since individual services are not profitable enough is pointed out.

As far as revenue streams are concerned in the context of utility's electricity sales increasing its business opportunities. Firstly, decoupling sales volume and revenues is proposed. More precisely this means separating the utilities fixed cost recovery from the amount of electricity sold. By breaking the link between sales volume and revenues, the utility shall be motivated to focus on its customers' energy service requirements and not just on increasing sales volume. Then, dynamic pricing is proposed meaning a flexible price which is orientated at the wholesale price of electricity. The extreme form is real-time pricing and a moderate one is Time of Use pricing with peak and off-peak rates. The price signals would motivate consumers to reduce consumption or shift consumption to lower-cost time-slots. The benefit for the utilities is a reduce in peak load which leads to lower back up capacity requirements and lower grid capacity requirements at peak times.

The authors in (17) propose seven new value proposals for prosumers. Then based on them they propose four prosumer-oriented business models.

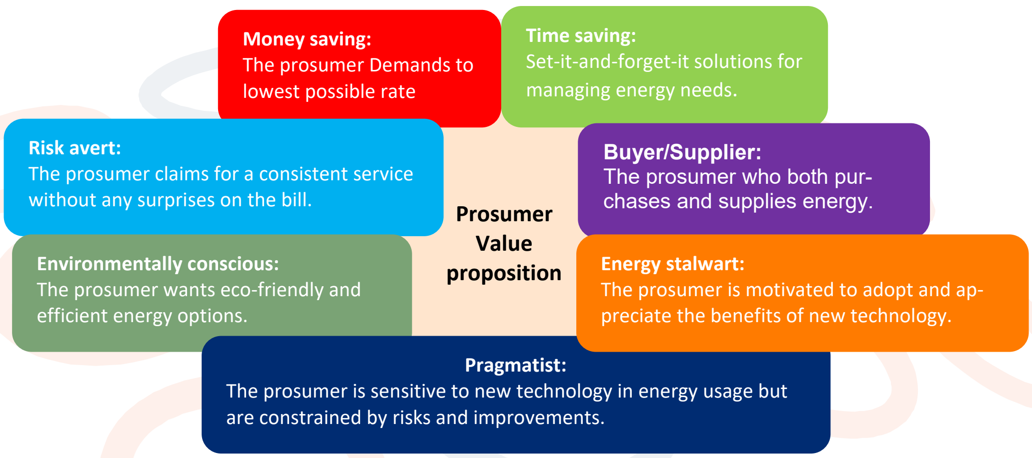

Figure 12: New prosumer value propositions (17).

They propose that ESCOs are capable of offering services for prosumers for management of electricity actively which correspond to the following value propositions: "money saving", "pragmatist users", "environmentally conscious", and "energy stalwarts" and propose the following ESCO prosumer-oriented business model (Table 2).

Table 7: ESCO prosumer-oriented business model characteristics (17)

Value Proposition	Prosumer Interface
Improved energy efficiency Reduced energy costs Energy performance contraction	Prosumer interactions management Prosumer segmentation Real-time media- or web-based communications
Infrastructure	**Revenue model**
Smart grid data management Grid monitoring	Energy savings Energy efficiency enhancements Charge for performance/service level offered

The authors in (18) consider how prosumers interact with DSOs in order to optimize the resources generated in a distributed manner. It is claimed by them that by using a distributed market-based control that sends adaptive signals to prosumers, the latter will become aligned with the concerns of the regulator/DSO, and both stakeholders will be satisfied. These basic elements introduced are applied to a DSO prosumer-oriented business model, i.e. suitable for users that produce, store and consume electricity by the authors in (17) have been further developed in Table 3.

Table 8: DSO prosumer-oriented business model characteristics (17)

Value Proposition	Costumer Interface
Security of supply and quality of service Choice of energy source System flexibility services Market facilitation	Active demand program Real-time media- or web-based communications In-home displays
Infrastructure	**Revenue Model**
Grid connection Smart metering systems Local network services	Energy selling Static pricing Provision of connection services Transmission/distribution fees

Challenges

There is a high need to review the main challenges regarding new prosumer-oriented business models taking into account the latest developments in the smart grid are and the role of the prosumer in the energy market value chain. Since there is a certain degree of disparity among the studied business proposals and their introduced business models, they have been summarized in Table 3 with all their most prominent features, specifically considering the role of the prosumers in the reviewed related works.
According to the research that has been done (17), there are several common challenges that must be overcome for the presented models:

- Infancy of smart grid businesses: Although the technology is already present and in fact has been regarded as consolidated in several cases, the manufacturers and vendors still struggle to make it visible. What is more, the smart grid has still a low impact and is often mistaken for the advanced metering infrastructure, rather than all of the systems behind it.
- Lack of interconnectivity: The different manufacturers that develop goods and services for the smart grid are unlikely to cover all of its various aspects, so the final system will be prone to incorporate devices from different vendors. It is not clear how they are going to interact with each other with ease; nowadays, there are several different standards covering information and communication technologies and power separately, but these remain poorly merged as a common effort.

- Unknown response for established business partners: The entrance of new SMEs, competitors and users in the electricity trade may be received with hostility from the already well-established DSOs and TSOs. Legislation must be created to prevent that from happening.

2.2 PROPOSED BUSINESS MODELS

In this section we will give an overview of the proposed business models that will be evaluated in the context of NOBEL GRID:

- Consumers as **Prosumer**: individual consumers (such as home owners, Small-medium enterprises or cooperatives) producing renewable energy locally and deciding how much to consume or export to the grid.
- ESCOs as **Independent Aggregator**: In this business model ESCOs (Energy Service Companies) steer their (potentially large) group of members on their consumption and production decisions and offer this flexibility to other market players such as DSOs and TSOs.
- DSOs evolved into **SmartGrid-enabled DSOs**: Under this business model DSOs perform advanced network management by using tools and processes that treat Demand-Side Management techniques on the same par with traditional ones when performing their tasks, e.g. maintaining the power quality by minimizing Reverse Power Flows or reducing congestion issues that can lead to power outages.
- Retailers as **Cooperative Virtual Power Plant**: In this business model Retailers, who may also own generation assets and thus act as “Gentailers”, adopt the business model of an Aggregator and take advantage of their customers’ production capacity as well as demand flexibility in order to optimize the way own production is used. In particular, such a (cooperative) retailer can lower electricity bills of its clients and thus increase its market share, by reducing the cost of energy procured in wholesale markets when prices are exceptionally high either by offering dynamic pricing plans or by organizing DR campaigns. In addition, it can provide flexibility services to other market actors (such as balancing services to TSOs) and create an additional revenue stream for the participants.

3 THE METHODOLOGY FOR EVALUATING NOBEL GRID BUSINESS MODELS

The following figure 10 describes the overall methodology for analyzing candidate NOBEL GRID business models and their socio-economic impact on the individual actors and the overall society.

- Step 1: Create a generic value network for Smart Grids
- Step 2: Create a value network for each High-Level Use-Case, based on the generic value network for Smart Grids and examine whether there is a valid business case behind each High-Level Use-Case (HLUC) by
    - o Identifying key actors and NOBEL GRID products involved.
    - o Identifying the value each entity perceives for being actively involved.
- Step 3: Describe the business model of the High-Level Use-Case for each key NOBEL GRID actor involved, using the Business Modelling Canvas methodology (19).
- Step 4: Identify the High-Level Use-Cases for each key NOBEL GRID actor and pilot site that are expected to be economically viable by performing a business plan analysis.

An additional step is to perform a cost-benefit analysis for the whole society of a certain pilot site, by understanding what are potential cost savings from the business models of individual actors. Note that even though this step is out of this report's scope it is a vital process for evaluating business models in a holistic way.

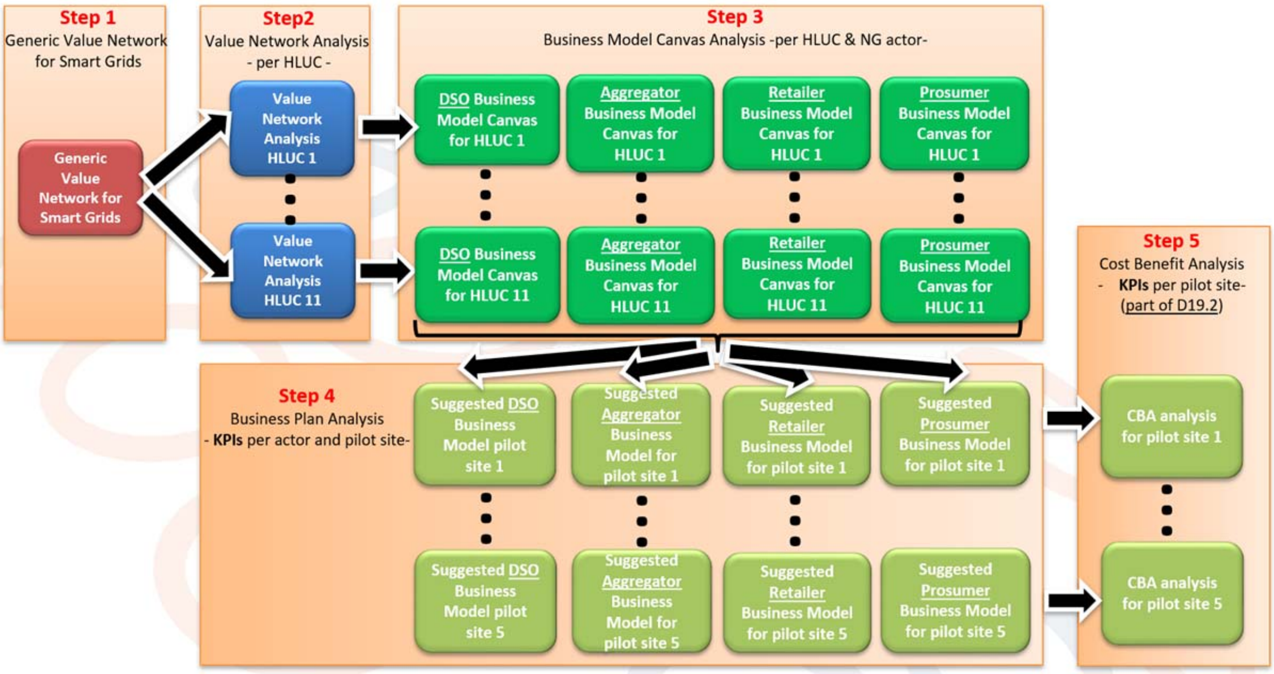

Figure 13: The overall methodology for analysing NOBEL GRID business models

The starting point of our work is to describe the main steps to be taken (by one or multiple business actors) for a certain product/service to be delivered to its current and prospective customers. It originates from the Porter's well-known value chain concept (20), widely used in the business literature to describe the value creation system among organizations. More specifically, a service offered should be depicted as a system, made up of subsystems each with inputs, transformation processes and outputs, involving the acquisition and consumption of resources (money, labour, materials, equipment, buildings, land, administration and management).

The value chain model is a linear view of a business, more in the sense of an industrial production line, where money is exchanged for a particular input service/product. However, this is not sufficient to reflect the complexity and the inherent network character of the entities in the Smart Grid. For example, a DSO could offer an information service to end customers (e.g., when green energy is highly available) but the latter pay a membership fee to the aggregator with whom they have a direct business relationship. Finally, the aggregator will either share the fee with the DSO immediately or wait until all bilateral transactions are cleared. This is analogous to "freemium" services in the Internet; an end-user may not pay for a smartphone application but this is done by advertisers who want access to end-users' personal data.

Another reason for adopting the value network analysis methodology (21) is its focus on information flows, not only on physical outputs and money. Obviously information flows are key elements of Smart Grids and cannot be ignored. Note that NOBEL GRID report D3.1 (22), which focuses on mapping business goals of several actors to particular system architecture details, follows a complementary approach based on SGAM (Smart Grid Architecture Model) framework.

In Deliverable D2.1 we had identified the following 7 main steps:

1. Power Production that is responsible for secure power generation (e.g., using fossil fuels, renewable sources, etc.). Note that this step can be performed by traditional, large power generators or even individuals (e.g., homeowners, entrepreneurs). This means that we focus on the core aspects of power production, which are not affected by size or technology.
2. Power Transmission by TSOs, which includes the High-Voltage transmission grid and the necessary actions to operate, ensure the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity.
3. Power Distribution by DSOs, who provide customers with Low (or Medium) Voltage power and is responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long-term ability of the system to meet reasonable demands for the distribution of electricity.
4. Power Retailing that includes forecasting as accurate as possible the demand of end-users and customer relationships management (e.g., billing). In principle, this step can be performed by any service provider and thus can be highly competitive.
5. Power Consumption that includes all appliances that rely on electricity to operate or store energy for future use. These appliances can belong to both residential and commercial end-users. An interesting case is a company that operates a set of batteries for storing low-priced energy and selling it back to a DSO later. Such a company would perform both the roles of consumption and production, even though it does not generate new energy.
6. Wholesale Market Operation that is responsible for collecting cost information and expected demand in order to compute wholesale prices and production levels, as well as, for performing market clearing.
7. Energy-related aggregator services provided by Aggregators and ESCOs to the rest key participants of the smart grid (i.e. consumers/prosumers, DG, DSOs, retailers).

We should highlight again the distinction between roles and actors. One role (e.g., power production) can be performed by several actors (companies or prosumers), even if they have significant differences in terms of size, core market, etc. Furthermore, one actor can be involved in one or more roles; for example a retailer could also act as an aggregator.

Then, we defined a “standard” business model for each key NOBEL GRID actor and considered a set of 11 candidate extensions, called NOBEL GRID High-Level Use-Cases (HLUC). The importance of the Aggregator’s role in smart grids can be evidenced in the generic value network by looking at the exchanged information and money flows.

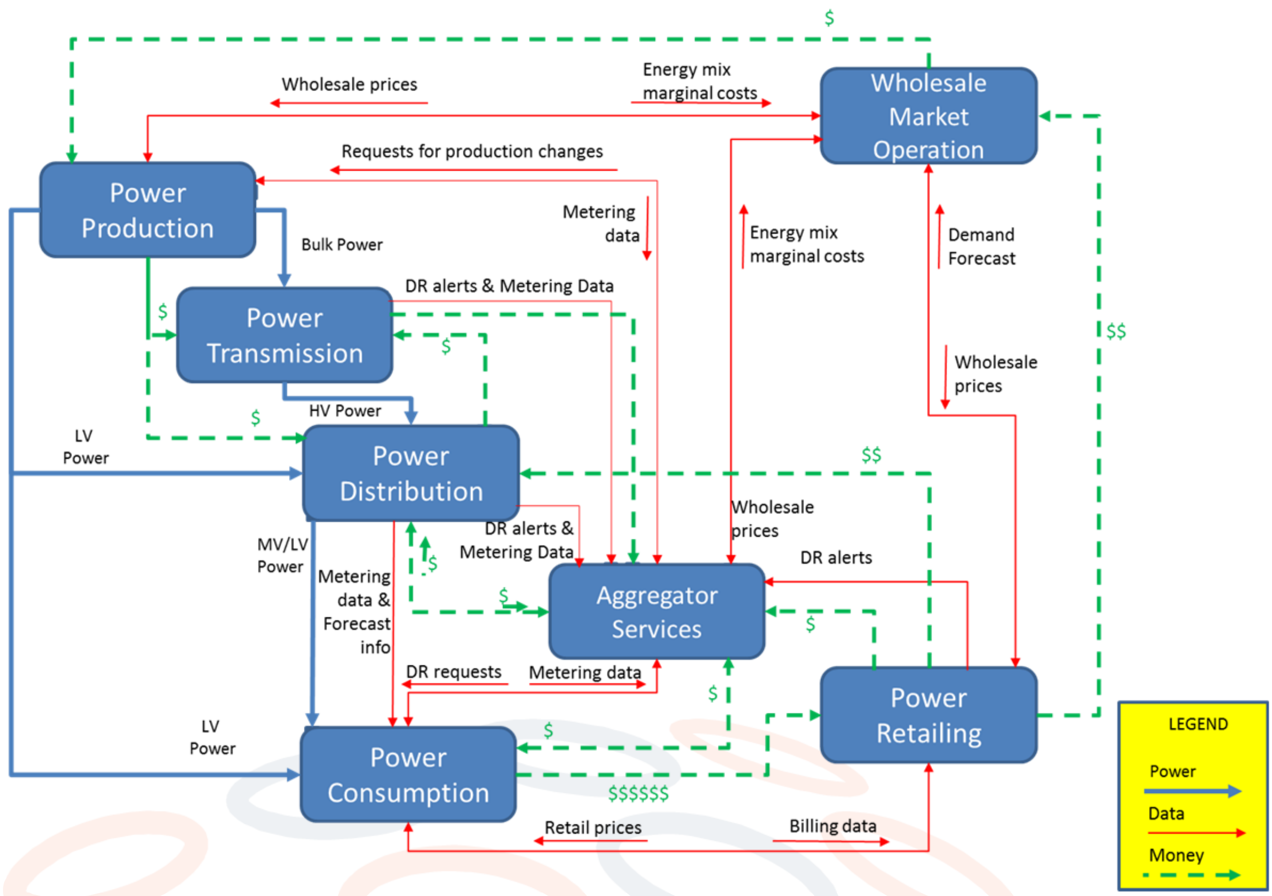

Figure 14: The generic value network for smart grids

The figure 11 describes a generic value network for smart grids. In wholesale electricity market competing generators offer their electricity output to retailers. Wholesale transactions (bids and offers) in electricity are typically cleared and settled by the market operator. Then, Electricity retailers provide fixed prices for electricity to their customers and manage the risk involved in purchasing electricity wholesale electricity prices. Retail bills paid by end-users usually cover the costs of wholesale energy, transport through transmission and distribution networks, and retail services.

Power generation from large scale power plants is transmitted through transmission network and distribution network to the end-users. Distributed generation (DG), connected at distribution network level is increasing its share in the energy generation mix. Also , proactive consumers (“prosumers”), adopting distributing generation systems play a significant role in the smart grid market and alter the traditional business models.

Aggregators and ESCOs provide energy-related support services to key participants of the smart grid, i.e. consumers, prosumers, DG, DSO and retailers. The most important aspect of the aggregator’s role is acting as Demand Response service provider and manage the negotiation between demand and energy sourcing stakeholders dispatching appropriate signals to aggregated consumers to provide demand flexibility to support grid operation after receiving an emergency signal from DSO or following retailers request, e.g. in particular timeslots when high wholesale prices are expected due to peak demand. An ESCO is a company that develops, installs and arranges financing for projects designed to improve the energy efficiency and maintenance costs for facilities over a time period. In the sequel Aggregators and ESCOs are merged in one actor called Aggregator.

In most European Member States, DSOs are responsible for metering as an integrated part of the grid whereas customers are always the owners of their data.

We believe that the selected steps/roles are key to analysing contemporary and future developments in Smart Grids. We could add additional supporting steps/roles but this would have a detrimental effect on the readability of the value network. Such omitted steps include, but are not limited to, the following:

- Information providers, such as those regarding weather forecast.
- Ancillary maintenance services, such as subcontractors for grid maintenance.
- Communications providers, such as Internet Service Providers.
- Financial institutions, such as banks and credit card issuers.

The next step is to perform a value network analysis for the set of 11 High-Level Use-Cases that were selected for demonstrating the NOBEL GRID concepts and tools, and whose business aspects were laid out in D1.3.

In order to improve the readability of the present report, we will omit those steps and redirect the interested reader to D2.3, where a comprehensive analysis is provided.

The third step is to describe the main value proposition, infrastructure used, customers, and finances among others for each HLUC/service and for each one of the 4 key NOBEL GRID actors. The large number of combinations requires a methodology supporting quick message delivery and efficient comparison. For this purpose, the business modelling canvas methodology has been selected which was extended to consider social (innovation, sustainability, social costs, benefits etc.) aspects, as well.

The following table gives an overview of a business model canvas.

Table 9: The business model canvas table and key information expected

Key Partners	**Key Activities**	**Value Propositions**	**Customer Relationships**	**Customer Segments**
The set of entities providing inputs (raw material or data) necessary for the service to be delivered.	The most critical tasks, i.e. those business processes whose details must be kept secret from rivals.	The set of products / services and their properties (e.g., low-cost, high quality) an entity offers to meet the needs of its	Automated & personalised relationships via the EMA app (e.g., forecast) and gamification techniques.	The exact market that the business entity is focusing at. It can be a niche market (e.g., eco-friendly home owners) or a very broad one (such as

<table>
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<td>These partners can be upstream suppliers only, as well as, peers that occasionally become downstream providers.</td>
<td>Key Resources

The most important inputs for a product/ service to be realized.</td>
<td colspan="2">customers.</td>
<td>Channels

The ways used for the value propositions to be delivered to customers. These can be privately owned or from third parties.</td>
<td>Low-Voltage households and businesses).</td>
</tr>
<tr>
<td colspan="3">Cost Structure

The cost items that can be lump sum (such as the distribution network), repetitive but mostly fixed (for example personnel salaries), or repetitive and highly variable (like wholesale power bought).</td>
<td colspan="3">Revenue Streams

The sources of revenue for the entity that can be either lump sum (e.g., connection fee), repetitive but fixed (such as monthly “all you can eat” prices) and repetitive but variable (like commission from sales of power).</td>
</tr>
<tr>
<td colspan="3">Societal Costs

The negative effects of the product/service to the society (e.g., carbon emissions).</td>
<td colspan="3">Societal Benefits

The positive effects of the product/service to the society (e.g., increased collaboration between society members).</td>
</tr>
</table>

The fourth step is to perform a business plan analysis for assessing whether a certain product/service as part of a broader ecosystem (High-Level Use-Case or value network) provides the desired return on investment. In other words, whether the expected revenues in a certain time period will not only cover the projected costs during the same period, but also allow a profit to be made that will secure the long-term viability of that entity. In order to do so we used the NOBEL GRID Business Model Evaluation tool, which is described in the next section. The attractiveness is evaluated by utilising the Internal Rate of Return (IRR), which is the interest rate at which the net present value of all the cash flows (both positive and negative) equal zero. A widely used rule of thumb is that IRR greater (or equal) than 30% are considered to be attractive. The time window used for evaluation has been set to 20 years. For compatibility reasons the costs and revenues are limited to those in the area under investigation, even though some roles (notably retailers and aggregators) could have a national scope.

After estimating the attractiveness of atomic products/services we need to identify any bottlenecks in offering the end-to-end service in a certain location. This means that all involved roles should have a positive net benefit (at least) for the service to be offered. Suppose, for example, that all roles but one (consumers) have a big interest in realizing Demand Response services. Then an incentive mechanism may exist that will make every participant happy (for example by slightly reducing the profitability of aggregators).

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 combinations of:

- Low EV penetration rate
- Moderate EV penetration rate
- High EV penetration rate

as well as:

- Low PV penetration rate
- Moderate PV penetration rate
- High PV penetration rate.

Figure 15 and Figure 16 give a graphical representation of those candidate future evolution paths for EV and PV respectively. These charts refer to Terni, Italy, where the present number of EVs is 5 and the number of PVs is 4420. Assuming that the number of delivery points in Terni is 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.

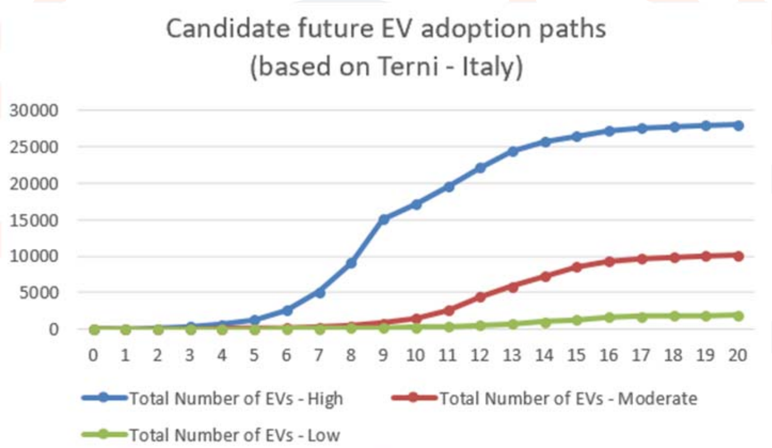


Figure 15: Candidate future EV evolution paths for a 20-year period applied to Terni - Italy

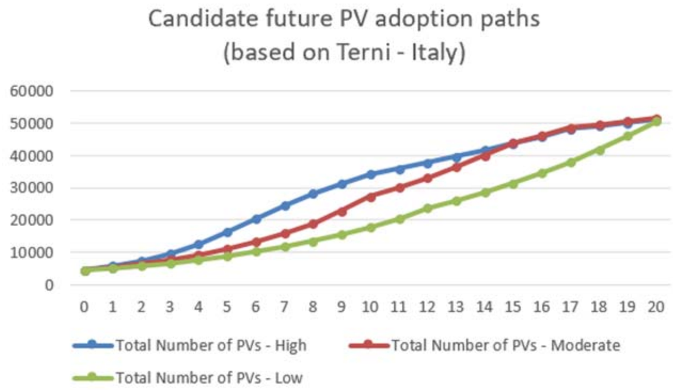


Figure 16: Candidate future PV adoption paths for a 20-year period applied to Terni - Italy

In absence of statistically significant real data from the demonstration activities, inputs from experts inside the consortium were sought regarding costs and revenues. Furthermore, custom simulators were prepared and used 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 THE NOBEL GRID BUSINESS MODELS EVALUATION TOOL

The Nobel Grid Business Model Evaluation tool is a "what-if" scenario tool for the techno-economic evaluation of innovative smart grid technologies. Performing a techno-economic evaluation of innovative technologies is a complicated task due to the uncertainty that even experts face in estimating future costs and revenues, as well as the difficulty in choosing the appropriate set of modeling assumptions. This is particularly true in the smart grid context, which is attributed to the large number of roles and stakeholders and the nature of the electricity grid.

The Nobel Grid Business Model Evaluation tool allows the user to model value networks of multiple roles/actors, aiming at:

- Evaluating business models enabled by innovative smart grid technologies (e.g., those by H2020 EU-funded projects);
- Evaluating the replication & upscaling of technologies, such as those empowered by H2020 EU-funded projects, and
- Evaluating the Cost-Benefit of technologies, such as those empowered by H2020 EU-funded projects (but not limited to those).

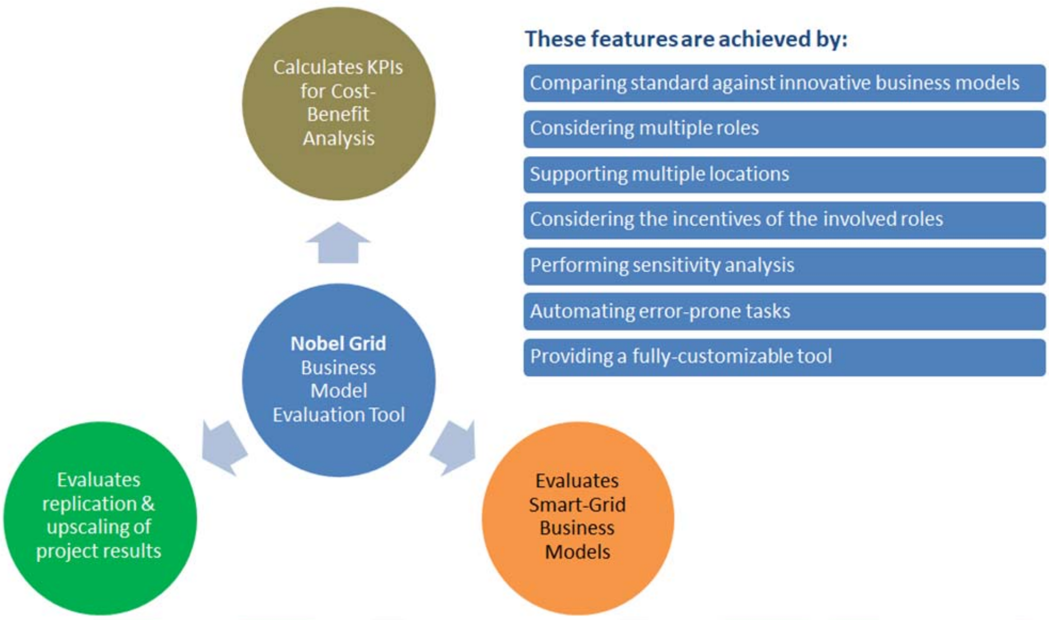


Figure 17: The main features of the Nobel Grid Business Model Evaluation tool

This techno-economic evaluation is done by:

- Comparing standard/existing against new innovative business models using several financial metrics based on data inputs supplied by the user (future versions will be integrated with smart grid simulation modules for reducing the inputs required);
- Considering multiple roles organized into value networks in any context where multiple roles/business actors interact, including technology providers (thus not restricted to smart grid markets);
- Supporting multiple locations simultaneously, such as pilot sites, regions or countries;
- Considering the incentives of the roles when deciding how money flows within the value network (e.g., how revenues should be split, how services should be charged, etc.);

- Performing sensitivity analysis for cost items and revenue streams whose magnitude is not known a-priori;
- Automating error-prone tasks;
- Providing a fully-customizable, transparent and flexible tool based on Microsoft Excel (e.g., the user can see under the hood, add features and update formulas);

Inputs to the Nobel Grid Business Model Evaluation tool were supplied by market experts and by using a set of simulators. 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, price elasticity or willingness to join Demand-Response campaigns.

The simulator works on quarter-hour time-scales for a complete year is powerful and extensible. 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).

In order to run the prosumer simulator, we used data inputs on solar production, load curves and retail prices for each European country, namely Belgium, Greece, Germany, Italy, Spain and UK from publicly-available data sources (in most cases the ENTSO-E Transparency Platform). 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. The prosumer simulator outputs, such as annual self-consumption, injected energy, imported energy, flexibility provided, etc. were fed into the Nobel Grid Business Model evaluation tool for studying under what circumstances the grid-connected prosumer business model is financially attractive, or additional support from other business entities (such as RESCOs/Aggregators) is required.

A secondary simulator was used for estimating the loads for charging the EVs when their owners make all decisions autonomously.

3 types of EVs are considered: domestic, commercial and industrial. Each EV type:

- Has an average battery capacity (kWh)
- Uses a charger type with a certain average charging rate (kW)
- Has a charging window (e.g., during the night)

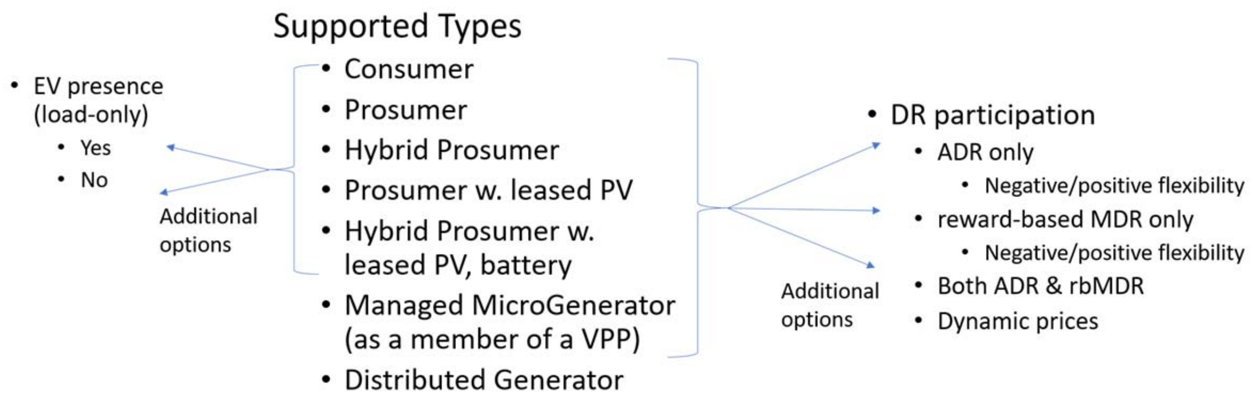


Figure 18 The types of grid-connected users that are supported by the simulator

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)

The approach is the following:

For each EV type (domestic, commercial and industrial) and MV feeder we run a separate simulation to determine the total power required for EV charging in any 15-min slot. Then we add the power requirements of all EVs in the area according to the feeder topology.

- Apart from EV loads, flexibility requested by a DSO will depend on the additional aggregate power of the following users
  - Consumers (actual data from Terni were used)
  - Prosumers (simulated based on actual data regarding the number of prosumers and their average peak capacity)

For each EV (actually for each group of EVs e.g.,10 for tractability) we simulate the charging process by:

- Randomly choosing the SoC (state-of-charge) when arriving at the charging station (since distances travelled per day may differ)
- Randomly choosing the 15-min slot when charging starts (replicating the fact that not all users arrive at the charging station simultaneously)
- Setting the charging duration and power 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

Known limitations are the following:

- No charging losses are considered, nor smart charging (i.e., battery is charged to 100% not up to 90% for longer life) but their effect is balanced out
- We assume that a charger will always be available (i.e., we don't evaluate the business model of a charging station operator)
- Each EV is charged once (single charge/discharge cycle per day, including weekends/holidays)

5 THE NOBEL GRID VALUE NETWORKS AND ASSOCIATED BUSINESS MODELS

In this section we will define efficient business models for each one of the core NOBEL GRID actors. As described in Section 3, we follow the Business Modeling Canvas methodology adapted in order to include social (innovation, sustainability, social costs, benefits etc.) aspects, as well.

5.1 HLUC – GREEN ENERGY MAX

The main objective of this HLUC is to allow the consumer to reduce energy usage at times when the grid is at its most carbon intensive, by shifting usage to periods when renewable generation is at its greatest. Shifting is enabled by the provision of appropriate information that directs end users' actions and is further facilitated via device automation towards achieving consumer's goal of reducing personal carbon emissions.

In this section we will describe the business models of the Aggregator and the Prosumer that are relevant to the Green Energy Max HLUC (the rest main actors are not involved).

5.1.1 Business model of the DSO

DSO is not involved.

5.1.2 Business model of the Aggregator

The DRFM engine allows the Aggregator to perform user-oriented DR campaigns focused on fostering renewable energy use. The software module capabilities achieve savings in reducing wasted time collecting information about customers joined the program, in making energy-saving calculations and in obtaining external information.

Table 10: The Business Model Canvas of HLUC1 for Aggregator

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Prosumers who provide real-time information about production levels	Recruiting householders Aggregating flexibility from householders Running campaigns, offering incentives to prosumers Selling flexibility to DSOs Managing a co-operative i.e. encouraging engagement and participation	Real-time metering data for prosumers High quality forecasting tool in form of DFRM Ability to shift demand usage patterns to match supply Ability to aggregate flexibility	Prosumers – mediated via EMA App Prosumers: face-to-face communication via co-operative meetings and events etc.	Residential consumers environmentally motivated and living in a similar geographical location i.e., a city or city region

	Key Resources		Channels	
	DRFM cockpit EMA app Users' consent to access smart meters data Membership network		Virtual channels via web, email, mobile etc. As part of wider co-operative membership offer At events and conferences Via Third Parties (such as satisfied customers using social networks)	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: license to use DFRM cockpit, EMA App, Servers Repetitive (static): licencing fee to use smart meter data (where applicable), Personnel salaries, Internet subscription Repetitive (variable): incentives paid to prosumers for flexibility	Fixed (static): Membership fee from consumers Fixed (variable): payment from DSO for flexibility and demand shifting; Non-fixed (variable): sales of additional energy services, e.g., heating installations

5.1.3 Business model of the Retailer

Retailer is not involved.

Commercial & Residential end-users who buy the energy produced (and especially those who do it on purpose)

5.1.4 Business model of the Prosumer

The new service offered by the Aggregator will enable users to maximize their green electricity use. This is a need that has been documented by members of non-profit cooperatives such as Carbon Co-op. More specifically, this service will provide **information** to the prosumers regarding the **renewable energy mix**, the **real-time energy consumption** and the **most suitable time for allocating energy consumption in terms**

of high renewable energy production. In some cases, joining the service could be an ethical choice instead of driven by financial incentives.

Table 11: The Business Model Canvas of HLUC1 for Prosumer

<table>
<tr>
<td rowspan="2">Key Partners

Other Prosumers belonging to the same community</td>
<td>Key Activities

Responding to campaigns initiated by the aggregator

Engaging in a householder co-operative, sharing learning experiences etc.</td>
<td rowspan="2">Value Propositions

Providing demand flexibility to an aggregator</td>
<td>Customer Relationships

With aggregator via EMA App; and

Via face-to-face communication via co-operative meetings and events etc.</td>
<td rowspan="2">Customer Segments

Residential consumers environmentally motivated and living in a similar geographical location i.e., a city or city region

Retailers who buy the energy produced</td>
</tr>
<tr>
<td>Key Resources

EMA app

Smart meters data

Smart home equipment

Solar panels

Battery storage</td>
<td>Channels

Via an Aggregator’s platform</td>
</tr>
<tr>
<td colspan="3">Cost Structure

Sunk: smart home equipment when purchased outright, solar panels, inverter

Repetitive (static): membership fee to Aggregator, repayments for smart home equipment when purchased from an ESCO</td>
<td colspan="2">Revenue Streams/ Cost reductions

Fixed (variable): incentive for flexibility and demand shifting from aggregator; solar FIT payments, savings made in energy usage</td>
</tr>
</table>

5.2 HLUC – PROSUMER MAX

In this section we will describe the business models of a DSO, an Aggregator and a Prosumer that are relevant to the prosumer Max HLUC (the Retailers are not involved).

The Aggregator provides services to prosumers that enable them to better match energy consumption with green energy production, as well as, to DSOs by finding a set of consumers who are willing to conform to DR requests to meet certain targets (e.g., excessive green energy is consumed). The main objective of this HLUC is to enable the prosumers to maximize the usage of the power they generate, reducing costs, carbon emissions and reverse power flows. Also, by providing a mix of information and automation (e.g. activating their appliances when their PVs are producing) the Aggregator ensures that prosumers get the best value from their investment in renewable technologies (self-produced energy consumption) and DSOs postpone investments for infrastructure upgrades.

5.2.1 Business model of the DSO

Table 12: The Business Model Canvas of HLUC2 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs Aggregators Prosumers who are part of an Aggregator and willing to use green energy	Transform, manage and distribute power to end-users Finding aggregators that could bring flexibility to the network Aggregating flexibility from the aggregators Offer incentives for aggregators	Secure and high-quality MV/LV power to end-users Real-time metering consumption and generation information availability High quality forecasting tool in form of DRFM	EMA App as the main tool for communication and exchange of information Data availability to feed the new services created by aggregators to be offered to end consumers	Commercial & Residential end-users who need high quality and stable energy

<table>
<tr>
<td></td>
<td>Key Resources

DRFM cockpit

EMA app

Smart meters (except from UK) & data for distribution network</td>
<td>Visibility and knowledge of network situation and therefore the DR needs</td>
<td>Channels

Virtual channels via web, email, mobile etc.

At events and conferences

Via Third Parties</td>
<td></td>
</tr>
<tr>
<td colspan="3">Cost Structure

Sunk: Smart meters (except from UK), licenses for G3M, DFRM cockpit, EMA App

Repetitive (static): Personnel salaries, Network maintenance, servers

Repetitive (variable): Wholesale price * kWh, Power losses * penalty, DR requests * Aggregator's price</td>
<td colspan="2">Revenue Streams/ Cost reductions

Fixed (variable): 1xConnection fee

Repetitive (variable): Commission for power distribution, Reduced economic penalties for RPF (imbalances).</td>
</tr>
</table>

5.2.2 Business model of the Aggregator

Table 13: The Business Model Canvas of HLUC2 for Aggregator

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Prosumers who provide real-time information about production levels	Recruiting householders Aggregating flexibility from householders Running campaigns, offering incentives to prosumers Selling flexibility to DSOs Managing a co-operative i.e. encouraging engagement and participation	Real-time metering data for prosumers High quality forecasting tool in form of DFRM Ability to shift demand usage patterns to match supply Ability to aggregate flexibility	Prosumers – mediated via EMA App Prosumers: face-to-face communication via co-operative meetings and events etc. DSOs: long term relationships (due to monopoly)	Residential, homeowners, environmentally motivated, living in a similar geographical location i.e. a city or city region DSOs: virtual monopoly so dependent on local situation
	Key Resources DRFM cockpit EMA app Smart meters & data Membership network		**Channels** Virtual channels via web, email, mobile etc. As part of wider co-operative membership offer At events and conferences Via Third Parties	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: DFRM cockpit, EMA App, Servers Repetitive (static): licencing fee to use smart meter data (where applicable), Personnel salaries, Internet subscription Repetitive (variable): incentives paid to prosumers for flexibility	Fixed (static): Membership fee Fixed (variable): payment from DSO for flexibility and demand shifting; Non-fixed (variable): sales of additional energy services, e.g., heating, energy efficiency etc.

5.2.3 Business model of the Retailer

Retailer is not involved.

5.2.4 Business model of the Prosumer

Table 14: The Business Model Canvas of HLUC2 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Other Prosumers members of the community	Responding to campaigns initiated by the aggregator Engaging in a householder co-operative, sharing learning experiences etc.	Providing demand flexibility to an aggregator Generating income via sales of energy and/or reducing costs through increased energy	With aggregator via EMA App; and Via face-to-face communication via co-operative meetings and events etc.	Commercial & Residential end-users who prefer to use green energy Retailers who buy the energy produced The local DSO

	Key Resources EMA app Smart meters & data Smart home equipment Solar panels Battery storage	efficiency	**Channels** As part of wider co-operative membership offer At events and conferences	

Cost Structure Sunk: smart home equipment when purchased outright Repetitive (static): membership fee to Aggregator Fixed: repayments for smart home equipment when purchased from an ESCO	**Revenue Streams/ Cost reductions** Fixed (variable): incentive for flexibility and demand shifting from aggregator; solar FIT payments, savings made in energy usage

5.3 HLUC – SOCIAL HOUSING – ELECTRIC HEAT AUTOMATION

The purpose of this HLUC is automating electric heating systems to reduce consumer cost and increase grid stability. The Aggregator provides services both to the DSO (grid balancing) and the consumer by advising cost-effective energy consumption schedules. The main objective of this HLUC is to demonstrate the potential of large scale electric heating installations, to play a role in grid balancing and provide opportunities for energy aggregators to enter the market.

In this section we will describe the business models of a DSO, an Aggregator and a Prosumer that are relevant to the Electric Heat Automation HLUC (the Retailers are not directly involved).

5.3.1 Business model of the DSO

Table 15: The Business Model Canvas of HLUC3 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs Aggregators Prosumers (i.e. landlords) who are willing to participate in DR schemes	Manage and distribute power to end-users Analyse metering data to predict supply of renewable energy and demand	Secure and high-quality MV/LV power to end-users Reinforce grid stability Real-time metering data to Retailers, Aggregators	Automated relationships via the G3M, DRFM and EMA app (e.g., forecast)	Commercial & Residential end-users who need high quality and stable energy
	Key Resources		**Channels**	
	G3M DRFM EMA app Smart meters (except from UK) & data for distribution network Distribution network Monopoly rights		Retailers, who are responsible for managing end-user relationships (e.g., membership fee paid via energy bill) Aggregators, who increase efficiency of operations by relying on DR techniques	
Cost Structure			**Revenue Streams/ Cost reductions**	
Sunk: G3M, Smart meters (apart from UK), licenses for G3M, DFRM cockpit, EMA App Repetitive (static): Personnel salaries, Network maintenance, investment fee Repetitive (variable): Wholesale price * kWh, Power			Fixed (variable): 1xConnection fee Repetitive (variable): Commission for power distribution, Reduced economic penalties for imbalances.	

losses * penalty, DR requests * Aggregator's price	

5.3.2 Business model of the Aggregator

Table 16: The Business Model Canvas of HLUC3 for Aggregator

<table>
<tr>
<td rowspan="2">Key Partners

Prosumers who provide real-time information about production levels</td>
<td>Key Activities

Recruiting householders/building managers

Aggregating flexibility from householders

Running automated campaigns, offering incentives to prosumers

Selling flexibility to DSOs</td>
<td rowspan="2">Value Propositions

Real-time metering data

High quality forecasting tool in form of DFRM

Ability to automate, shifting demand usage patterns to match supply

Ability to aggregate flexibility</td>
<td>Customer Relationships

With prosumers – mediated via EMA App.

Contact with landlords/building managers via virtual methods</td>
<td rowspan="2">Customer Segments

Building managers/ landlords living in a shared development or building

DSOs</td>
</tr>
<tr>
<td>Key Resources

DRFM cockpit

EMA app

Smart meters & data

Smart Heating systems</td>
<td>Channels

Virtual channels via web, email, mobile etc.

At events and conferences

Via Third Parties</td>
</tr>
</table>

Cost Structure	Revenue Streams/ Cost reductions
Sunk: DFRM cockpit, EMA App, Servers Repetitive (static): licencing fee to use smart meter data (where applicable), Personnel salaries, Internet subscription Repetitive (variable): incentives paid to prosumers/landlords for flexibility	Fixed (static): Fee from landlord/building manager Fixed (variable): payment from DSO for flexibility and demand shifting; Non-fixed (variable): sales of additional energy services, e.g. heating, energy efficiency etc.

5.3.3 Business model of the Retailer

Retailer is not involved.

5.3.4 Business model of the Prosumer

Table 17: The Business Model Canvas of HLUC3 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Other Prosumers (Building managers/landlords) via a co-operative	Responding to campaigns initiated by the aggregator Engaging in a householder co-operative, sharing learning experiences etc.	Providing demand flexibility to an aggregator Generating income via sales of energy and/or reducing costs through increased energy	With aggregator via EMA App; and Via face-to-face communication via co-operative meetings and events etc.	Retailers who buy the energy produced Commercial & Residential end-users who prefer to use green energy The local DSO who want DR services

	Key Resources EMA app Smart meters & data Smart home equipment Smart Heating systems Solar panels Battery storage	efficiency	**Channels** As part of wider co-operative membership offer At events and conferences	
Cost Structure Sunk: smart home equipment when purchased outright Repetitive (static): co-op membership fee Fixed: repayments for smart home equipment when purchased from an ESCO			**Revenue Streams/ Cost reductions** Fixed (variable): incentive for flexibility and demand shifting from aggregator; solar FIT payments, savings made in energy usage	

5.4 HLUC - MAINTAINING GRID ASSETS

The main objective of this HLUC is to provide the DSO with the necessary tools to perform a better and more efficient monitoring and maintenance of the MV/LV grid assets. Through the monitoring and prognosis tools provided by NOBEL GRID the DSO will be able to forecast potential problems in the network and perform appropriate preventive actions. In this section we will describe the business model of a DSO only, as the Aggregators, Prosumers and Retailers follow the Business-as-Usual.

5.4.1 Business model of the DSO

Table 18: The Business Model Canvas of HLUC4 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs	Manage and distribute power to end-users Power quality monitoring. Analyse network data to better planning of the maintenance tasks	Secure and high-quality MV/LV power to end-users Reinforce grid security and stability with a better monitoring of the network assets	Automated relationships via the G3M.	Commercial & Residential end-users who need high quality and stable energy
	Key Resources		**Channels**	
	G3M Smart meters & data Distribution network		Automatic data gathering	
Cost Structure			**Revenue Streams/ Cost reductions**	
Sunk: Distribution network, Smart meters			Fixed (variable): 1xConnection fee Repetitive (variable): Commission for power distribution, Reduced maintenance costs and troubleshooting tasks, Reduced asset management costs, Reduced penalties for potential black outs and failure avoidance	

5.4.2 Business model of the Aggregator

Aggregator is not involved.

5.4.3 Business model of the Retailer

Retailer is not involved.

5.4.4 Business model of the Prosumer

Prosumer is not involved.

5.5 HLUC – CONTROLLING THE GRIDS FOR POWER QUALITY & SECURITY

The main objective of this HLUC is to ensure the power quality and security of the network by providing the DSO with the necessary tools to perform a continuous and online power quality monitoring that will point out abnormal power levels in the network in a more efficient manner, drastically reducing the response time to power quality failures and the maintenance costs.

In this section we will describe the business model of a DSO that is relevant to the "Controlling the grids for power quality & security" HLUC (similarly to Section 5.4 the Aggregators, Prosumers and Retailers are not involved).

5.5.1 Business model of the DSO

Table 19: The Business Model Canvas of HLUC5 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs	Manage and distribute power to end-users Ensure the power quality and security of the network Power quality monitoring. Analyse network data to better planning of the maintenance tasks	Secure and high-quality MV/LV power to end-users Reinforce grid security and stability	Automated relationships via the G3M.	Commercial & Residential end-users who need high quality and stable energy

	Key Resources G3M Smart meters & data Distribution network		**Channels** Automatic data gathering	
Cost Structure Sunk: Distribution network, Smart meters			**Revenue Streams/ Cost reductions** Fixed (variable): 1xConnection fee Repetitive (variable): Commission for power distribution, Reduced maintenance costs and troubleshooting tasks, Reduced penalties for potential network instability reduction	

5.5.2 Business model of the Aggregator

Aggregator is not involved.

5.5.3 Business model of the Retailer

Retailer is not involved.

5.5.4 Business model of the Prosumer

Prosumer is not involved.

5.6 HLUC – BLACKOUT AND INCIDENT MANAGEMENT

This high-level use-case focuses on monitoring the incidents of the network and managing them in an efficient and time-responsive way. This is a key issue for the DSO to avoid potential bigger derived problems. The services offered by this use case offer cost savings to DSOs in terms of maintenance, operation and asset life, rather than through direct revenue streams. In particular, DSOs will be able to better plan the resources needed for maintenance tasks, as well as, reduce its maintenance costs and the related response-time.

In this section we will describe the business model of a DSO that is relevant to the “Blackout and incident management” HLUC (the Aggregators, Prosumers and Retailers are not involved).

5.6.1 Business model of the DSO

Table 20: The Business Model Canvas of HLUC6 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs	Ensure the power quality and security of the network Power quality monitoring. Analyse network data to better planning of the maintenance tasks Incident monitoring	Secure and high-quality MV/LV power to end-users Reinforce grid security and stability Direct incident monitoring	Automated relationships via the G3M.	Commercial & Residential end-users who need high quality and stable energy
	Key Resources G3M Smart meters & data Distribution network		**Channels** Automatic data gathering	
Cost Structure Sunk: Distribution network, Smart meters			**Revenue Streams/ Cost reductions** Fixed (variable): 1xConnection fee Repetitive (variable): Commission for power distribution, Reduced penalties for potential black out situations	

5.6.2 Business model of the Aggregator

Aggregator is not involved.

5.6.3 Business model of the Retailer

Retailer is not involved.

5.6.4 Business model of the Prosumer

Prosumer is not involved.

5.7 HLUC- INCREASE IN POWER QUALITY

The main reason for DSOs to follow this business model is **reducing the penalties they must pay if there were outages or blackouts at the network due to lack of reliability and quality** in their service, and also the reduction of the **maintenance costs**, due to the work performed to solve the aforementioned incidents.

In this section we will describe the business models of a DSO, an Aggregator and a Prosumer that are relevant (Retailers are not directly affected nor are asked to update their business processes).

5.7.1 Business model of the DSO

Table 21: The Business Model Canvas of HLUC7 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs Aggregators Consumers who are willing to participate in DR schemes	Grid reconfiguration and management to distribute high power quality to end-users Analyse metering data for predicting supply of renewable energy and demand, incidents, emergencies etc.	Secure and high-quality MV/LV power to end-users Forecast data to end-users regarding weather, network congestion, black outs notice etc. Real-time metering data to Retailers, Aggregators	Automated relationships via the G3M, DRFM and EMA app	Commercial & Residential end-users who need high quality and stable energy
	Key Resources		**Channels**	
	G3M DRFM EMA app Smart meters & data Distribution network Monopoly rights		Retailers, who are responsible for managing end-user relationships (e.g., membership fee paid via energy bill) Aggregators, who	

			increase efficiency of operations	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: Distribution network, G3M, Smart meters Repetitive (static): investment fee Repetitive (variable): Wholesale price * quantity, Power quality deterioration penalty, DR requests * Aggregator's price	Fixed (variable): 1xConnection fee, Repetitive (variable): Commission for power distribution, Reduced maintenance costs and troubleshooting tasks, Reduced penalties for potential black outs and failure avoidance

5.7.2 Business model of the Aggregator

Aggregator is not involved.

5.7.3 Business model of the Retailer

Retailer is not involved.

5.7.4 Business model of the Prosumer

Table 22: The Business Model Canvas of HLUC7 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Other Prosumers via a co-operative	Engaging in a householder co-operative, sharing learning experiences etc.	Generating income via sales of energy and/or reducing costs through increased energy	Via face-to-face communication via co-operative meetings and events etc.	Commercial & Residential end-users who prefer to use green energy Retailers who buy the energy produced

<table>
<tr>
<td></td>
<td>Key Resources

EMA app

Smart meters & data

Smart home equipment

Solar panels

Battery storage</td>
<td>efficiency</td>
<td>Channels

As part of wider co-operative membership offer

At events and conferences</td>
<td>

The local DSO</td>
</tr>
<tr>
<td colspan="3">Cost Structure

Sunk: smart home equipment when purchased outright

Repetitive (static): co-op membership fee

Fixed: repayments for smart home equipment when purchased from an ESCO</td>
<td colspan="2">Revenue Streams/ Cost reductions

Fixed (variable): solar FIT payments, savings made in energy usage</td>
</tr>
</table>

5.8 HLUC – THE CO-OPERATIVE POWER PLANT

Retailers, who also own generation assets and thus act as "Gentailers", take advantage of their customers' production capacity as well as demand flexibility to optimize the way own production is used. In particular, such a (cooperative) retailer can lower electricity bills of its clients and thus increase its market share, by reducing the cost of energy procured in wholesale markets when prices are exceptionally high. This is done either by offering dynamic pricing plans or by organizing DR campaigns (by adopting the role of an Aggregator or collaborating with an independent one). In addition, it can provide flexibility services to other market actors (such as balancing services to TSOs) and create an additional revenue stream for the participants.

In this section we will describe the business models of all main NOBEL GRID actors that need to cooperate in this HLUC.

5.8.1 Business model of the DSO

DSOs are not required to update their business model for the cooperative power plant to be realized.

5.8.2 Business model of the Aggregator

Table 23: The Business Model Canvas of HLUC8 for Aggregator

<table>
<tr>
<td rowspan="2">Key Partners

Prosumers who produce energy and provide real-time information about production levels</td>
<td>Key Activities

Recruiting householders/building managers

Aggregating flexibility from householders

Running automated campaigns, offering incentives to prosumers

Selling flexibility to DSOs and power retailers</td>
<td rowspan="2">Value Propositions

Real-time metering data

High quality forecasting tool in form of DFRM

Ability to shift demand usage patterns to match supply

Ability to aggregate flexibility

Ability to save prosumers money</td>
<td>Customer Relationships

Prosumers –via EMA App

Prosumers: face-to-face communication via co-operative meetings and events etc.

DSOs: long term relationships (due to monopoly)</td>
<td rowspan="2">Customer Segments

Residential, living in a shared development or building

DSOs: virtual monopoly so dependent on local situation

Power Retailing</td>
</tr>
<tr>
<td>Key Resources

DRFM cockpit

EMA app

Smart meters & data

Membership network (customer base)</td>
<td>Channels

Virtual channels via web, email, mobile etc.

At events and conferences

Via Third Parties

As part of wider co-operative membership offer</td>
</tr>
</table>

Cost Structure	Revenue Streams/ Cost reductions
Sunk: DFRM cockpit, EMA App, Servers Repetitive (static): licencing fee to use smart meter data (where applicable), Personnel salaries, Internet subscription Repetitive (variable): incentives paid to prosumers for flexibility	Fixed (static): Membership fee Non-fixed (variable): payment from DSO for flexibility and demand shifting, sales of portfolio to BRP, sales of additional energy services, e.g., heating, energy efficiency etc.

5.8.3 Business model of the Retailer

Table 24: The Business Model Canvas of HLUC8 for Retailer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Prosumers DSOs BRP	Optimize production/consumption portfolio on the wholesale market	Better prices for production sold to the BRP Lower cost of balanced energy for sale to customers	Better prices for prosumers	Commercial & Residential end-users
	Key Resources DRFM cockpit Aggregator's DR portfolio EMA app Smart meters & data		**Channels** Wholesale market through BRP	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: Smart meters Repetitive (static): static fee for services of Aggregator Repetitive (variable): variable fee for services of Aggregator	Repetitive (variable): lower energy price of production/consumption portfolio

5.8.4 Business model of the Prosumer

Table 25: The Business Model Canvas of HLUC8 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Other Prosumers via a co-operative	Join the CoPP and provide necessary services according to SLA Indirectly through Aggregator Participate in the energy market	Lower energy cost Financial reward for cooperation in CoPP	Automated relationships via the EMA app (e.g., forecast) and feedback to aggregator	The local DSO Commercial & Residential end-users who prefer to use green energy Retailers who buy the energy produced
	Key Resources		**Channels**	
	EMA app Smart meters & data		Directly with Aggregator or indirectly through e.g., a retailer who is linked to the aggregator	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: Smart meter (SMX or SLAM), SHID for automated DR Repetitive (static): maintenance Repetitive (variable): comfort losses	Repetitive (variable): Commission for joining CoPP and lower energy price because of better insight and time shifting of consumption

5.9 HLUC – IMBALANCE REDUCTION THANKS TO THE SMART CITIZENS INVOLVEMENT IN DR

Reverse Power Flows (RPF) can create congestion issues at MV feeders in case of high PV penetration rates, which can lead to higher maintenance costs, power outages, higher penalties and customer dissatisfaction. In such a scenario, RPF could reach feeder capacity limits whenever RES production is significantly higher than demand.

In this case we focus only on the consequences of congestion caused by high reverse power flows. In other words, 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 (as will be described in HLUC11) 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.

In this section we will describe the business models of a DSO, an Aggregator and a Prosumer that are relevant to the Electric Heat Automation HLUC (again, the Retailers are not involved).

5.9.1 Business model of the DSO

Table 26: The Business Model Canvas of HLUC9 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs Aggregators Consumers who are willing to participate in DR schemes	Transform, manage and distribute power to end-users Analyse metering data for predicting supply of renewable energy and demand	Secure and high-quality MV/LV power to end-users Forecast data to end-users regarding availability of green energy Real-time metering	Automated relationships via the G3M, DRFM and EMA app (e.g., forecast) and gamification techniques	Commercial & Residential end-users who need high quality and stable energy

	Key Resources G3M DRFM EMA app Smart meters & data Distribution network Monopoly rights	data to Retailers, Aggregators	**Channels** Retailers, who are responsible for managing end-user relationships (e.g., membership fee paid via energy bill) Aggregators, who increase efficiency of operations by relying on DR techniques	
Cost Structure Sunk: Distribution network, G3M, Smart meters Repetitive (static): Personnel salaries, Network maintenance Repetitive (variable): Wholesale price * quantity, Power losses * penalty, DR requests * Aggregator's price			**Revenue Streams/ Cost reductions** Fixed (variable): 1xConnection fee Repetitive (variable): Commission for power distribution, Reduced economic penalties for RPF (imbalances).	

5.9.2 Business model of the Aggregator

Table 27: The Business Model Canvas of HLUC9 for Aggregator

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Commercial & Residential end-users	Find a set of end-users who are willing to conform to DR	DR services to reduce power	Two-Sided Platform where DSOs & retailers	DSOs who want to reduce costs by reducing reverse flows and power

who would like to know in real time info about outages and would like to gain money reward for providing flexibility	requests so that a certain target is met (e.g., excessive green energy is consumed) Send DR requests to end-users (or to their equipment directly)	losses Increased green energy consumption Reduced energy bills	eventually find end-users who are willing to conform to DR requests	losses and/or create an eco-friendly brand Retailers who want to reduce costs by minimizing demand when wholesale prices are high Prosumers/consumers who want to consume green energy.
	Key Resources DRFM EMA app Profiles of eco-friendly end-users		**Channels** Own channel (web-based)	
Cost Structure Sunk: Software, Servers Repetitive (static): licencing fee to use smart meter data (where applicable), Personnel salaries, Internet subscription			**Revenue Streams/ Cost reductions** Repetitive (variable): DR requests * price	

5.9.3 Business model of the Retailer

Retailer is not involved.

5.9.4 Business model of the prosumer

Table 28: The Business Model Canvas of HLUC1 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Other Prosumers belonging to	Responding to campaigns initiated by the aggregator	Providing	With aggregator via EMA App;	DSOs who want to reduce costs by reducing reverse

<table>
<tr>
<td rowspan="2">the same community</td>
<td>Engaging in a householder co-operative, sharing learning experiences etc.</td>
<td rowspan="2">demand flexibility to an aggregator</td>
<td>and

Via face-to-face communication via co-operative meetings and events etc.</td>
<td rowspan="2">flows and power losses and/or create an eco-friendly brand

Commercial & Residential end-users who buy the energy produced (and especially those who do it on purpose)</td>
</tr>
<tr>
<td>Key Resources

EMA app

Smart meters data

Smart home equipment

Solar panels

Battery storage</td>
<td>Channels

As part of wider co-operative membership offer

At events and conferences</td>
</tr>
<tr>
<td colspan="3">Cost Structure

Sunk: smart home equipment when purchased outright, solar panels, inverter

Repetitive (static): membership fee to Aggregator, repayments for smart home equipment when purchased from an ESCO</td>
<td colspan="2">Revenue Streams/ Cost reductions

Fixed (variable): incentive for flexibility and demand shifting from aggregator; solar FIT payments, savings made in energy usage</td>
</tr>
</table>

5.10 HLUC – DSO: EFFICIENT RECOVERY FROM POWER OUTAGE

In this section we will describe the business models of a DSO, an Aggregator and a Prosumer that are relevant to the “DSO: Efficient Recovery from Power Outage” HLUC (again, the Retailers are not involved).

5.10.1 Business model of the DSO

Table 29: The Business Model Canvas of HLUC10 for DSO

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
TSOs Aggregators Consumers who are willing to participate in DR schemes	Transform, manage and distribute power from the producer plant to the end-user Increase resilience in Smart Grid Analyse metering data for predicting supply of flexibility needed	Social reward in providing flexibility Enhance stability of the grid	Automated relationships via the G3M, DRFM and smart meter, EMA APP	Commercial & Residential end-users who need high quality and stable energy
	Key Resources G3M DRFM EMA APP Smart meters & data Distribution network Monopoly rights		**Channels** Directly by an agreement / by an Aggregator EMA APP, smart meter	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: Distribution network, G3M, EMA APP, DRFM, Smart meters Repetitive (static): Personnel salaries, Network	Fixed (variable): 1xConnection fee Repetitive (variable): Commission for power distribution, Penalty reduction for potential black outs, Benefit from Energy

maintenance Repetitive (variable): Wholesale price * quantity, Power losses * penalty	Authority due to failure avoidance, Reduced maintenance costs and troubleshooting tasks

5.10.2 Business model of the Aggregator

Table 30: The Business Model Canvas of HLUC10 for Aggregator

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Commercial & Residential end-users who would like to know in real time info about outages and would like to gain money reward for providing flexibility	Find a set of end-users who are willing to conform to DR requests so that a certain target is met (e.g., excessive green energy is consumed, enhance resilience of the smart grid) Send DR requests to end-users (or to their equipment directly)	Reward for flexibility provided	Automated relationships via EMA APP	DSOs who need DR flexibility in order to recover from power outage
	Key Resources DRFM EMA app Profiled end-users		**Channels** Own channel (web-based)	

Cost Structure	Revenue Streams/ Cost reductions
Sunk: Software, Servers Repetitive (static): licencing fee to use smart meter data (where applicable), Personnel salaries, Internet subscription	Repetitive (fix): Payment from stakeholder

5.10.3 Business model of the Retailer

Retailer is not involved.

5.10.4 Business model of the prosumer

Table 31: The Business Model Canvas of HLUC10 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
Aggregator	Plan production Manage orders Serve customers	Supply products using stable grid	Personal Assistance	DSOs who need DR flexibility in order to recover from power outage Commercial & Residential end-users who buy the energy produced (and especially those who do it on purpose)
	Key Resources Plant Service provided		**Channels** Own production channel	
Cost Structure		**Revenue Streams/ Cost reductions**		
Repetitive (static): retail electricity price, DR membership, Internet subscription		Rewards/incentives directly from DSO or through the Aggregator for their demand flexibility.		

5.11 HLUC – POWER LOSSES REDUCTION THANKS TO POWER FACTOR MANAGEMENT

In this section we will describe the business models of a DSO, an Aggregator and a Prosumer that are relevant to the "Power losses reduction thanks to Power Factor management" HLUC (the Aggregators and Retailers are not involved).

5.11.1 Business model of the DSO

Table 32: The Business Model Canvas of HLUC11 for DSO

<table>
<tr>
<td rowspan="2">Key Partners

TSOs

Producer who accept the power factor to be managed in real time</td>
<td>Key Activities

Transform, manage and distribute power from the producer plant to the end-user

Power losses reduction in the grid

Analyse metering data for predicting supply of renewable energy and demand</td>
<td rowspan="2">Value Propositions

Secure and high-quality MV/LV power to end-users

Real-time power factor management of producer plant</td>
<td>Customer Relationships

Automated relationships via the G3M, DRFM and smart meter</td>
<td rowspan="2">Customer Segments

Commercial & Residential end-users who need high quality and stable energy</td>
</tr>
<tr>
<td>Key Resources

G3M

DRFM

Smart meters & data

Distribution network

Monopoly rights</td>
<td>Channels

Directly by an agreement</td>
</tr>
<tr>
<td colspan="3">Cost Structure

Sunk: Distribution network, G3M, DRFM, Smart meters

Repetitive (static): Personnel salaries, Network maintenance

Repetitive (variable): Wholesale price * quantity, Power losses * penalty</td>
<td colspan="2">Revenue Streams/ Cost reductions

Fixed (variable): 1xConnection fee

Repetitive (variable): Commission for power distribution, Reduced maintenance costs and troubleshooting tasks and reduced penalties for power losses</td>
</tr>
</table>

5.11.2 Business model of the Aggregator

Aggregator is not involved.

5.11.3 Business model of the Retailer

Retailer is not involved.

5.11.4 Business model of the prosumer

Table 33: The Business Model Canvas of HLUC11 for Prosumer

Key Partners	Key Activities	Value Propositions	Customer Relationships	Customer Segments
DSO who supplies connection to the grid	Plan production Losses reduction	Maximize power production	Contract	The local DSO Commercial & Residential end-users who prefer to use green energy Retailers who buy the energy produced
	Key Resources		**Channels**	
	Availability of primary energy to be transformed in electrical energy		The grid	
Cost Structure			**Revenue Streams/ Cost reductions**	
Repetitive (static): retail electricity price, losses, Internet subscription, devices for the power factor management			Reduced power losses	

6 TECHNOECONOMIC ANALYSIS OF PROPOSED BUSINESS MODELS

6.1 DSO USING DEMAND-SIDE MANAGEMENT TECHNIQUES FOR MINIMIZING REVERSE POWER FLOWS AND REDUCING CONGESTION ISSUES THAT CAN LEAD TO POWER OUTAGES

In this business model we assume that a DSO asks for flexibility from an Aggregator in order to deal with technical issues; in particular Reverse Power Flows (RPF) and congestion on LV/MV network.

6.1.1 Minimizing Reverse Power Flows

Minimizing Reverse Power Flows is related to HLUC9 and HLUC11.

In the case of HLUC 11 we are interested on the following effects of high PV penetration in rural areas:

- Increased (technical) network losses
- Increased voltage at the end of rural lines and thus PV, as well as, smart meter disconnection

However, the simulator does not consider voltages or network losses, thus the business model evaluation task for HLUC11 will be based on ASM Terni estimations regarding the costs involved. This means that the following simulations will focus only on the congestion issues due to RPF and the implications of RPF to the financial relationship with the TSO. In particular, we have identified the following effects:

- 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:

$$\max((energy\_received - energy\_injected * 1.023) * rate, 0)$$

Note that according to the current regime the energy injected is increased by 2.3% and thus cost savings are further magnified. Moreover, in the extreme scenario where more energy was injected than delivered during a period, the TSO does not pay ASM Terni.

- On the other hand, we conjecture that RPF can create congestion issues at MV feeders in case of high PV penetration rates, which can lead to higher maintenance costs, power outages, higher penalties and customer dissatisfaction. In such a scenario, RPF could reach feeder capacity limits whenever RES production is significantly higher than demand. Here we assume that capacitors are already installed (or reactive power management has taken place) and thus the far away PV plants in rural areas (connected to secondary by means of long LV lines) will not be disconnected because voltage along the line does not overcome maximum limit, before overload issues occur. Furthermore, such outages lead to higher maintenance costs (both planned and reactive ones), higher replacement costs due to shorter life span of equipment and increased personnel.

Thus, there is a trade-off between reduced transmission costs (i.e., a benefit) and costs due to high RPF.

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 are the PV 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 controllable loads such as Electric Vehicles, remuneration asked etc.).

6.1.1.1 Simulation setup description

The details of the simulations performed are the following:

1. We focused on a certain LV/MV loop that is serviced by the Terni Ovest (TO) primary substation, where as described in D16.1 significant reverse power flows exist. More specifically we simulated the feeders fed by a bus of TO (Green Bus) TO_GB LUZI and TO_GB SALIT where 1000 points of delivery 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. This is a rather conservative decision as outages are harder to take place compared to a tree-like topology. The reason is that customers will likely be served even if a technical failure takes place along one of the lines. Eventually, in Section YYY, 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.
2. 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.
3. The effective bottleneck capacity of each line (after considering the technical losses involved) is 5.518313873 MW.
4. 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 as we will describe next). 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, or
    c. the total surplus production (or demand) exceeds the combined capacity of the feeders
5. We assume that whenever the (perfectly forecasted) load exceeds a threshold (set at the 90% of the effective line capacity) a DR campaign will be triggered, where the flexibility asked is given by the formula

$$\max(\mathit{surplus\ production} - \mathit{capacity\ threshold}, 0)$$

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.

6. A complete year is simulated in quarter-hourly (15min) slots.
7. Loads for consumers depend on the location and are those for a typical residential family, based on synthetic load profiles. These customers are assumed to be charged with a (country-specific) fixed rate.
8. Similarly, production is location-specific and is based on profiles generated using the PVsol commercial software for a rooftop PV system of 3.6 kWp. The exact production is then scaled up/down according to the average peak capacity installed in that area by residential, commercial or industrial prosumers (no generator-only entities have been considered). More specifically, the average peak capacity for:
    a. residential prosumers is 4.29 kWp
    b. commercial prosumers is 23.351 kWp
    c. industrial prosumers is 41.9 kWp

where considered according to input from ASM Terni.

9. 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.
10. 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 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:
    a. 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;
    b. 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.

11. 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 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).
12. 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 neighborhoods, or in touristic places with EV fleets high adoption rates will be achieved significantly sooner.
13. Furthermore, we assumed that there are three types of EVs, each one with a certain battery capacity and associated charger type. In particular:
    a. "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.
    b. "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.
    c. "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.
14. 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).

15. Furthermore, we assumed that the population of EV owners is evenly split between "night chargers" and "day chargers".
16. The DSO asks flexibility from an Aggregator before a severe congestion issue. This means that either flexibility needs are perfectly known, which means 100% accurate production and demand forecasting, or that DSOs have systems with advanced monitoring capabilities.
17. The Aggregator pool size is set to 30%. The rest 70% (700 in this case) 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 Demad 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).
18. 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' behavior is governed by the following parameters
    a. 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).
    b. 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).
19. 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

$p = \min(\exp\left(-\frac{0.1}{c}\right), 1)$. This probability tends to 0 when $c = 0$. Since the probability can be also expressed as $p = target/(\mathrm{N} * \mathrm{x})$, 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.

20. 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:
    a. The flexibility asked is increased by 10% (or any other value) in order to account for uncertainty in user behavior.

b. The maximum expected flexibility provided from EVs is calculated first (by considering the flexibility reserved for on-going campaigns).

c. 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.

21. 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.
22. Technical losses are not considered.
23. An outage is assumed to last 10 slots, while the duration of the last slot is normally distributed. Thus, the maximum duration of an outage is 150 mins.
24. No battery systems are installed, which can reduce RES production surpluses.

We will explore two candidate options for ASM Terni avoiding sustained outages:

- Option1 (Business-as-Usual scenario): upgrade network by installing a new line and assume that congestion issues are definitely avoided. However, it takes 1-2 years until the new line is fully operational.
- Option2 (HLUC9): ask flexibility from Aggregator (assuming that flexibility needs are perfectly known, which means 100% accurate production and demand forecasting).

Figure 19: 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.

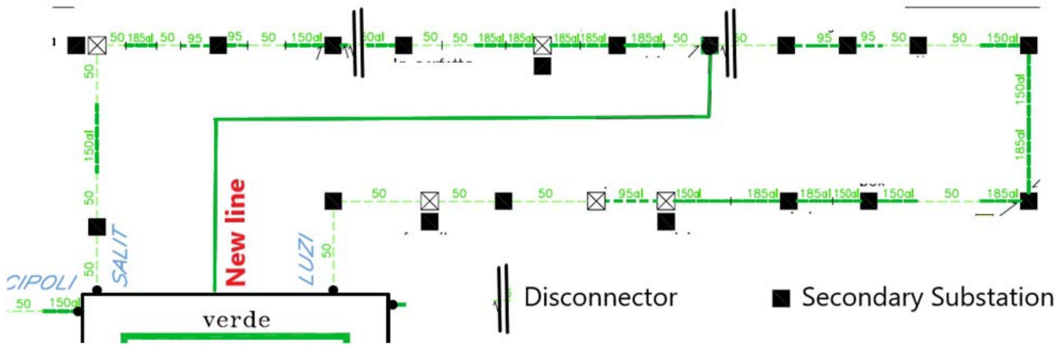


Figure 20: The new topology of the benchmark MV feeder loop in Terni following the traditional approach of upgrading capacity by adding a new feeder

6.1.1.2 Simulation results

The next plot gives us the number of outages per year that are expected, for the parameter values explained above, to be caused by Reverse Power Flows in the Business-as-Usual scenario, when the PV penetration rate varies from 10% to 80% (horizontal axis) and for different EV penetration rates (curves blue, red, green and purple). We observe that regardless of the EV penetration rate, which affects the surplus production to be injected, outages start taking place when more than half of the endpoints become prosumers. In particular, 8 outages were found to be happening every year due to high surplus production if PV penetration reaches 70%, growing to 17 when 80% of endpoints are prosumers.

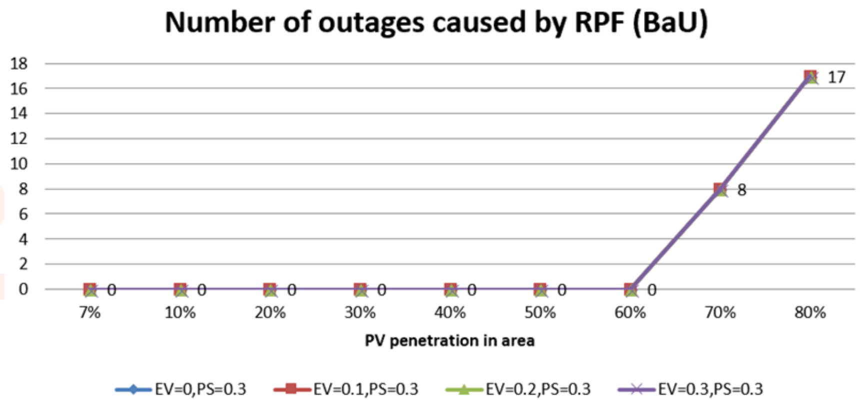


Figure 21: The expected number of outages caused annually by Reverse Power Flows in Business-as-Usual scenario for the benchmark feeder loop in Terni

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. We see that 1 outage on average will be taking place every year on top of those attributed to high local RES production. 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.

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.

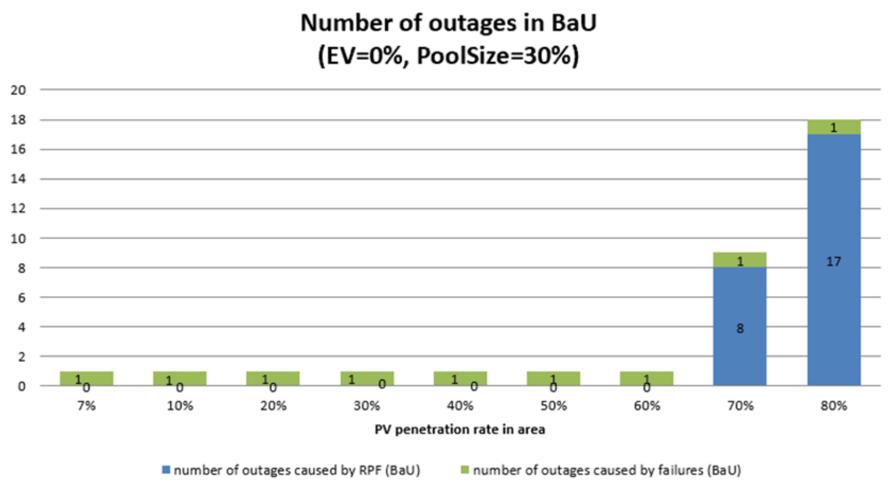


Figure 22 : The total expected annual number of outages (RPF and technical aspects) in Business-as-Usual scenario for the benchmark feeder loop in Terni

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%.

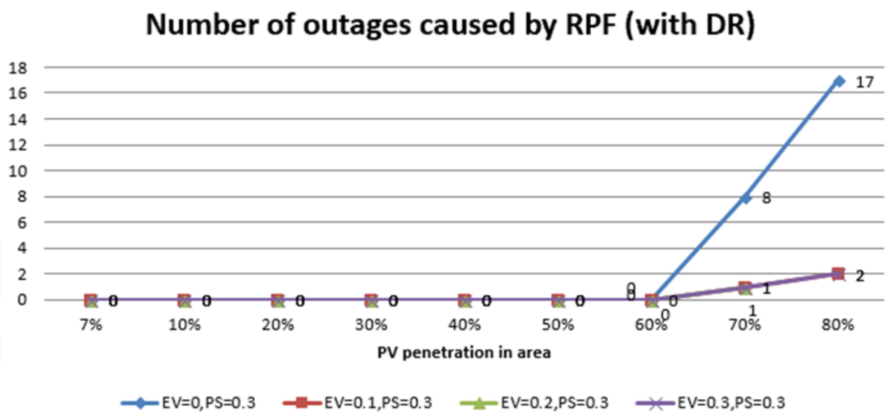


Figure 23: The expected number of outages caused annually by Reverse Power Flows in the NOBEL GRID-enabled scenario (with DR) for the benchmark feeder loop in Terni

A breakdown of the flexibility obtained per member type (EV, rest ADR, MDR) is shown in the figure below. We observe that EVs contribute the highest share of flexibility in all combinations of PV and EV penetration rates.

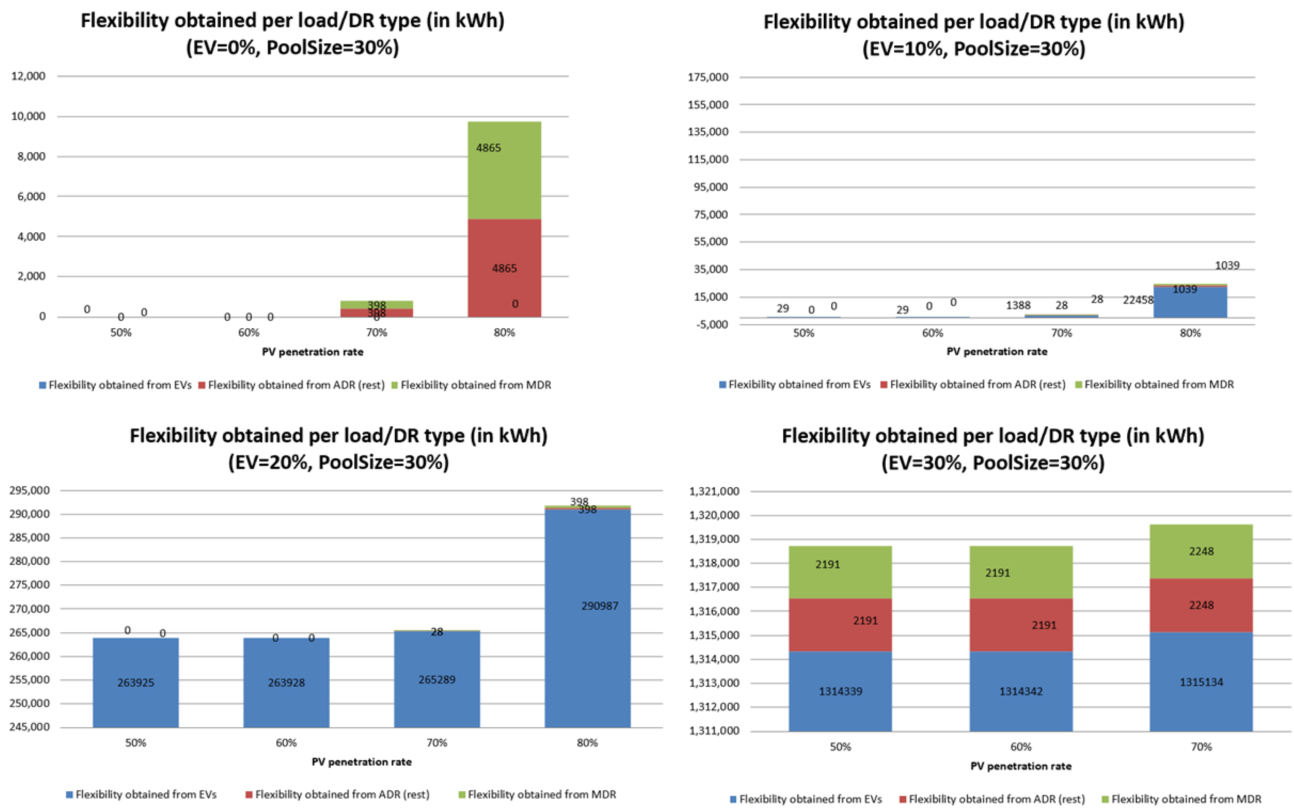


Figure 24: A breakdown of the flexibility obtained per member type for different combinations of PV and EV penetration rates for the benchmark feeder loop in Terni (low PV penetration rates have been omitted for better readability)

The following figure compares the estimated minutes of annual outages in the Business-as-Usual and NOBEL GRID-enabled scenarios for 20% EV penetration and varying PV penetration levels. Given the assumption (23) these minutes are analogous to Figure 21 and Figure 23, while these may slightly differ as the duration of the last outage slot is a random variable (e.g., outputs for 20% and 30% PV penetration rates differ by 4 minutes). Similar figures are obtained for 10%vand 30% EV penetration and thus are omitted.

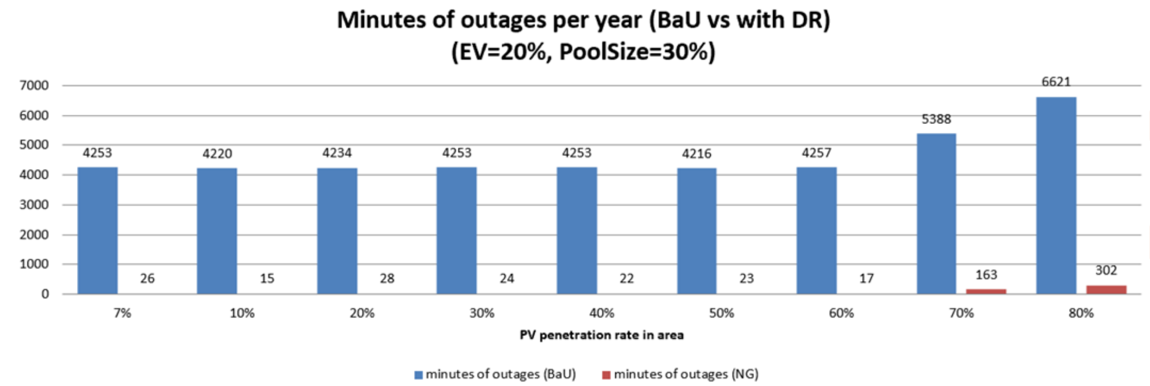


Figure 25: Comparing the estimated minutes of annual outages due to Reverse Power Flows in the Business-as-Usual and NOBEL GRID-enabled scenarios for EV penetration rate 20% for the benchmark feeder loop in Terni

The following tables provide a summary of the key technoeconomic metrics that will be used as input in the business model evaluation task. The first one refers to the case where EV penetration is 0%, while the second for EV penetration equal to 10%.

Table 34 Useful technoeconomic metrics regarding congestion issues for EV penetration rate 0% and varying PV penetration rates

EV=0,PS=0.3	PV penetration									
	7%	10%	20%	30%	40%	50%	60%	70%	80%	90%
number of outages caused by RPF (BaU)	0	0	0	0	0	0	0	8	17	
number of outages caused by Loads (BaU)	0	0	0	0	0	0	0	0	0	
number of outages caused by failures (BaU)	1	1	1	1	1	1	1	1	1	
number of outages caused by RPF (NG)	0	0	0	0	0	0	0	8	17	
number of outages caused by Loads (NG)	0	0	0	0	0	0	0	0	0	
number of outages caused by failures (NG)	1	1	1	1	1	1	1	1	1	
minutes of outages (BaU)	21	25	25	21	25	22	26	1157	2441	
minutes of outages (NG)	21	25	25	21	25	22	26	1157	2441	
DR requests due to RPF	0	0	0	0	0	0	0	28	350	
DR requests due to Loads	0	0	0	0	0	0	0	0	0	
TO_GB total energy (from TSO)	13,570,284	13,074,023	11,528,310	10502269	9864042	9435622	9121684	8878655	8686202	
TO_GB total energy (to TSO)	-	-	96,131	711933	1715549	2928972	4256878	5560191	6884581	
lost energy consumed due to outages	703	703	703	703	703	703	703	1126	1053	
lost excess energy produced due to outages	-	-	-	0	0	0	0	27704	70309	
Flexibility obtained from EVs	-	-	-	0	0	0	0	0	0	
Flexibility obtained from ADR (rest)	-	-	-	0	0	0	0	398	4865	
Flexibility obtained from MDR	-	-	-	0	0	0	0	398	4865	
flexibility from Evs that was not effective	0	0	0	0	0	0	0	0	0	
flexibility from non-EVs that was not effective	0	0	0	0	0	0	0	201	484	
% of flexibility from Evs that was not effective	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	
% of flexibility from non-EVs that was not effective	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	0	0	
flexibility cost per kwh from EVs	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	
flexibility cost per kwh from ADR	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.383292	0.307320	
flexibility cost per kwh from MDR	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.383292	0.307320	
MAX TO_GB power (from TSO)	4095	4043	3904	3894	3894	3894	3894	3894	3894	
MAX TO_GB power (to TSO)	0	0	975	2085	3194	4303	5412	6521	7631	
DR events for avoiding congestion	0	0	0	0	0	0	0	19	332	
DR events for avoiding outages	0	0	0	0	0	0	0	9	18	
lost energy consumed due to outages (NG)	703	703	703	703	703	703	703	1,126	1052.577258	
lost excess energy produced due to outages (NG)	-	-	-	-	-	-	-	27,491	68581.20295	

Table 35 Useful technoeconomic metrics regarding congestion issues for EV penetration rate 10% and varying PV penetration rates

EV=0.1,PS=0.3	PV penetration								
	7%	10%	20%	30%	40%	50%	60%	70%	80%
number of outages caused by RPF (BaU)	0	0	0	0	0	0	0	8	17
number of outages caused by Loads (BaU)	1	1	1	1	1	1	1	1	1
number of outages caused by failures (BaU)	1	1	1	1	1	1	1	1	1
number of outages caused by RPF (NG)	0	0	0	0	0	0	0	1	2
number of outages caused by Loads (NG)	0	0	0	0	0	0	0	0	0
number of outages caused by failures (NG)	1	1	1	1	1	1	1	1	1
minutes of outages (BaU)	154	167	169	160	165	163	162	1308	2584
minutes of outages (NG)	17	29	25	19	27	21	21	166	308
DR requests due to RPF	0	0	0	0	0	0	0	28	350
DR requests due to Loads	0	0	0	1	0	0	0	0	0
TO_GB total energy (from TSO)	16,313,090	15,816,832	14,271,120	13244647	12602507	12169173	11853263	11607031	11409009
TO_GB total energy (to TSO)	-	-	96,131	711501	1711205	2919714	4245647	5545758	6864957
lost energy consumed due to outages	8,948	8,944	8,944	8944	8944	8944	8944	9367	9452
lost excess energy produced due to outages	-	-	-	0	0	0	0	27704	70089
Flexibility obtained from EVs	29.4	29.1	29.1	29	29	29	29	1388	22458
Flexibility obtained from ADR (rest)	-	-	-	0	0	0	0	28	1039
Flexibility obtained from MDR	-	-	-	0	0	0	0	28	1039
flexibility from Evs that was not effective	0	0	0	0	0	0	0	0	0
flexibility from non-EVs that was not effective	0	0	0	0	0	0	0	28	57
% of flexibility from Evs that was not effective	0	0	0	0	0	0	0	0	0
% of flexibility from non-EVs that was not effective	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1	0
flexibility cost per kwh from EVs	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000
flexibility cost per kwh from ADR	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.161802	0.334874
flexibility cost per kwh from MDR	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.161802	0.334874
MAX TO_GB power (from TSO)	6348	6347	6347	6347	6347	6347	6347	6347	6347
MAX TO_GB power (to TSO)	0	0	975	2085	3194	4303	5412	6521	7631
DR events for avoiding congestion	0	0	0	0	0	0	0	27	348
DR events for avoiding outages	0	0	0	1	0	0	0	1	2
lost energy consumed due to outages (NG)	1,101	1,100	1,100	1,100	1,100	1,100	1,100	1,100	1099.852007
lost excess energy produced due to outages (NG)	-	-	-	-	-	-	-	3,970	8331.539509

The third one refers to the case where EV penetration is 20%, while the forth for EV penetration equal to 40%. Notice that these two tables include the combined effect of reverse power flows and high loads on congestion issues, which in some cases turn into outages. This is evident, for example, in the grey-colored rows for PV penetration higher than 70%.

Table 36 Useful technoeconomic metrics regarding congestion issues for EV penetration rate 20% and varying PV penetration rates

EV=0.2,PS=0.3	PV penetration								
	7%	10%	20%	30%	40%	50%	60%	70%	80%
number of outages caused by RPF (BaU)	0	0	0	0	0	0	0	8	17
number of outages caused by Loads (BaU)	30	30	30	30	30	30	30	30	30
number of outages caused by failures (BaU)	1	1	1	1	1	1	1	1	1
number of outages caused by RPF (NG)	0	0	0	0	0	0	0	1	2
number of outages caused by Loads (NG)	0	0	0	0	0	0	0	0	0
number of outages caused by failures (NG)	1	1	1	1	1	1	1	1	1
minutes of outages (BaU)	4253	4220	4234	4253	4253	4216	4257	5388	6621
minutes of outages (NG)	26	15	28	24	22	23	17	163	302
DR requests due to RPF	0	0	0	0	0	0	0	28	350
DR requests due to Loads	1361	1361	1361	1362	1361	1361	1361	1361	1361
TO_GB total energy (from TSO)	18,766,251	18,270,108	16,724,395	15697878	15053576	14616328	14297706	14050383	13850370
TO_GB total energy (to TSO)	-	-	96,131	711457	1708999	2913593	4236815	5535835	6853077
lost energy consumed due to outages	297,815	297,697	297,697	297697	297697	297697	297697	298121	298276
lost excess energy produced due to outages	-	-	-	0	0	0	0	27704	70125
Flexibility obtained from EVs	263,925.4	263,914.2	263,916.9	263920	263922	263925	263928	265289	290987
Flexibility obtained from ADR (rest)	-	-	-	0	0	0	0	28	398
Flexibility obtained from MDR	-	-	-	0	0	0	0	28	398
flexibility from Evs that was not effective	0	0	0	0	0	0	0	0	0
flexibility from non-EVs that was not effective	0	0	0	0	0	0	0	28	57
% of flexibility from Evs that was not effective	0	0	0	0	0	0	0	0	0
% of flexibility from non-EVs that was not effective	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	1	0
flexibility cost per kwh from EVs	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000
flexibility cost per kwh from ADR	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.161802	0.243276
flexibility cost per kwh from MDR	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.161802	0.243276
MAX TO_GB power (from TSO)	10970	10968	10968	10968	10968	10968	10968	10968	10968
MAX TO_GB power (to TSO)	0	0	975	2085	3194	4303	5412	6521	7631
DR events for avoiding congestion	1361	1361	1361	1361	1361	1361	1361	1388	1709
DR events for avoiding outages	0	0	0	1	0	0	0	1	2
lost energy consumed due to outages (NG)	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1,160	1159.667156
lost excess energy produced due to outages (NG)	-	-	-	-	-	-	-	3,970	8331.539509

Table 37 Useful technoeconomic metrics regarding congestion issues for EV penetration rate 30% and varying PV penetration rates

EV=0.3,PS=0.3	PV penetration								
	7%	10%	20%	30%	40%	50%	60%	70%	80%
number of outages caused by RPF (BaU)	0	0	0	0	0	0	0	8	17
number of outages caused by Loads (BaU)	654	652	652	652	652	652	653	653	653
number of outages caused by failures (BaU)	1	1	1	1	1	1	1	1	1
number of outages caused by RPF (NG)	0	0	0	0	0	0	0	1	2
number of outages caused by Loads (NG)	35	35	35	35	35	35	35	35	42
number of outages caused by failures (NG)	1	1	1	1	1	1	1	1	1
minutes of outages (BaU)	42586	42460	42591	42632	42566	42556	42599	43758	45005
minutes of outages (NG)	3615	3593	3631	3643	3582	3627	3630	3742	4503
DR requests due to RPF	0	0	0	0	0	0	0	28	350
DR requests due to Loads	2582	2582	2582	2583	2582	2582	2582	2582	2582
TO_GB total energy (from TSO)	17,249,988	16,757,414	15,211,700	14185005	13539189	13098107	12773355	12523489	12322180
TO_GB total energy (to TSO)	-	-	96,131	711281	1707310	2908074	4227650	5524128	6841095
lost energy consumed due to outages	4,531,918	4,528,230	4,528,232	4528234	4528236	4528238	4530723	4531148	4531858
lost excess energy produced due to outages	-	-	-	0	0	0	0	27704	69660
Flexibility obtained from EVs	1,314,339.7	1,314,329.5	1,314,331.9	1314334	1314337	1314339	1314342	1315134	1334252
Flexibility obtained from ADR (rest)	2,190.9	2,190.9	2,190.9	2191	2191	2191	2191	2248	2860
Flexibility obtained from MDR	2,190.9	2,190.9	2,190.9	2191	2191	2191	2191	2248	2860
flexibility from Evs that was not effective	13971	13973	13972	13972	13972	13972	13971	13745	16532
flexibility from non-EVs that was not effective	996	996	996	996	996	996	996	1024	1252
% of flexibility from Evs that was not effective	0	0	0	0	0	0	0	0	0
% of flexibility from non-EVs that was not effective	0	0	0	0	0	0	0	0	0
flexibility cost per kwh from EVs	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000	0.100000
flexibility cost per kwh from ADR	0.310540	0.310609	0.310841	0.311080	0.311328	0.311583	0.311847	0.296410	0.292612
flexibility cost per kwh from MDR	0.310540	0.310609	0.310841	0.311080	0.311328	0.311583	0.311847	0.296410	0.292612
MAX TO_GB power (from TSO)	16772	16770	16770	16770	16770	16770	16770	16770	16770
MAX TO_GB power (to TSO)	0	0	975	2085	3194	4303	5412	6521	7631
DR events for avoiding congestion	2547	2547	2547	2547	2547	2547	2547	2574	2888
DR events for avoiding outages	35	35	35	36	35	35	35	36	44
lost energy consumed due to outages (NG)	303,347	303,228	303,228	303,228	303,228	303,228	303,228	303,228	360,129
lost excess energy produced due to outages (NG)	-	-	-	-	-	-	-	3,970	8,332

6.1.2 Minimizing congestion issues due to high loads

In this subsection we will focus on congestion issues as a result of high demand, instead of high production. Such cases can occur after power outage restoration happens, as demand is increased, and this can pose significant grid challenges. To make things worse, local PV production is disconnected due to security reasons and thus along a feeder there is no more internal balance between production and consumption because all the consumptions are supplied by the network; so that the starting branch of the feeder could supply all the loads during their maximum absorption although they are normally supplied by DER. This branch would be a bottleneck and its overload could be not allowed by the breaker and another outage would occur, if this occurs the technician will reduce the number of secondary substation (i.e. the number of users) connected before restarting power by means of remote control.

Furthermore, this is true especially in case of high EV penetration where several customers could start the charging process simultaneously. Here we will focus on the latter case, to take advantage of the complementarities with other cases (e.g., similar simulation setup with the minimising RPF scenario analysed before).

Congestion issues due to high loads 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.

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 are 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 details of the simulations performed are the same as in the minimising RPF scenario, except from the following:

1. 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 neighborhoods, or in touristic places with EV fleets high adoption rates will be achieved significantly sooner.
2. 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 demand, or
    c. the total demand exceeds the combined capacity of the feeders even when no technical anomaly is present.
3. We assume that whenever the (perfectly forecasted) load exceeds a threshold (set at the 90% of the effective line capacity) a DR campaign will be triggered, where the flexibility asked is given by the formula

$$\max(load - capacity\ threshold, 0)$$

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.

4. 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. Again, the only form of "efficiency" is the lost load during an outage.
5. In contrast to the previous case, the number of prosumers in the area considered is not important. This is mainly due to the assumption that no rebound effects exist after an outage. Nevertheless, to verify this claim simulations with various PV penetration rates were performed.

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 (HLUC9): ask flexibility from Aggregator.

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%.

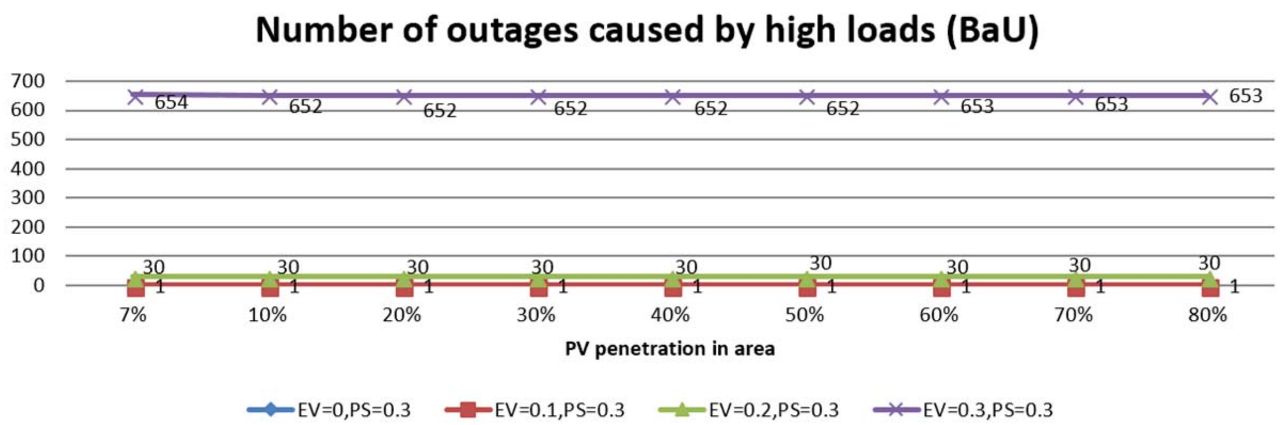


Figure 26: The expected number of outages caused annually by high loads in Business-as-Usual scenario for the benchmark feeder loop in Terni

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.

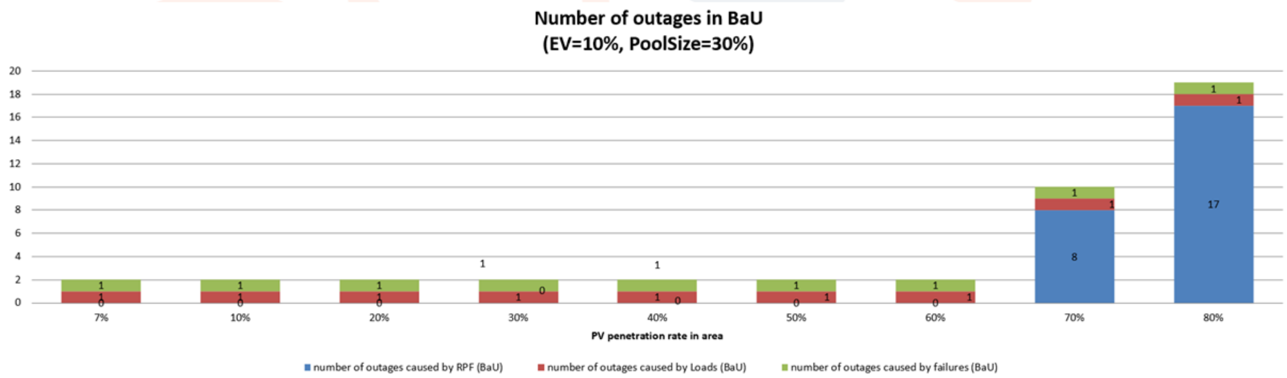


Figure 27: The total expected annual number of outages (high loads and technical aspects) in Business-as-Usual scenario for the benchmark feeder loop in Terni

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.

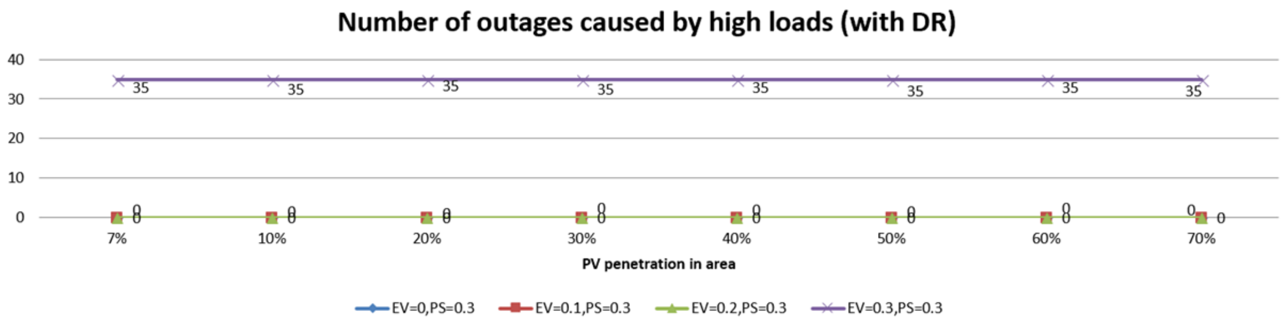


Figure 28: The expected number of outages caused annually by increased loads in the NOBEL GRID-enabled scenario (with DR) for the benchmark feeder loop in Terni

6.2 COOPERATIVE VIRTUAL POWER PLANT

6.2.1 kWmax

In this subsection we will study whether Ecopower should adopt the business model of an Aggregator who provides balancing services to TSO, such as mFRR. More specifically, Ecopower will be relying upon the flexibility offered by its customers/members in order to bid offers to the TSO, who is responsible for making sure that the energy produced by generators at any time equals the users' demand. It is expected that Ecopower members will be asked to offer their flexibility in up to 20 times.

Ecopower should offer this service if it is profitable, i.e., her expected revenues>expected costs. Obviously, the imbalance price (e.g., per kWh) which serves as the Aggregator revenues needs to be higher than the total cost of flexibility per kWh to such an extent that it will allow the Aggregator to have an attractive return on its investments. In doing so one should have a good estimate of the performance of the elements involved and especially those that are not under the direct control of Ecopower. This is of great importance for an Aggregator to manage its portfolio effectively. In other words, in order for Ecopower to bid offers to the balancing markets, like the frequency reserve, it is important to have accurate flexibility profiles of its members and how their flexibility is affected by the remuneration offered to them. These are the questions we will be trying to answer via simulations.

<u>Simulation setup</u>

- A TSO is facing a system imbalance even and is assumed to ask flexibility from Aggregators in order to deal with the issue in the most cost-effective way. We used ex-post data on imbalance prices for 2016 in order to identify the 20 events that would involve Aggregators. In particular we assumed that Aggregators, such as Ecopower, will be asked to contribute during the events with the highest imbalance prices, as we expect that other, more traditional, balance providers will be able to offer lower bids.
- A user who expressed interest in joining MDR campaigns is asked to shift [20%-80%] of its baseline consumption to an "off-peak" period whenever a smart grid actor (e.g., a TSO, DSO, retailer, BRP, etc.) asks a certain level of flexibility for dealing with technical issues. If such an (hourly) MDR campaign starts, then a member participates in the MDR campaign with a probability [20%-80%].
- Similarly, a user who has smartgrid ready devices that can be remotely controlled can participate in ADR campaigns. If an (hourly) ADR campaign starts, then Aggregator shifts loads accounting for [20%-80%] of user's baseline consumption to an "off-peak" period.
- In both cases:
    - TSO pays the imbalance price of that slot for the flexibility obtained
    - Aggregator transfers a significant part of revenues (e.g., 60%) to participants

The following figure presents the expected annual flexibility from each MDR member in kWh as a function of:

- the requested flexibility that is expressed as a percentage of the baseline load
- the participation probability, which defines whether a certain member will accept a DR activation signal.

Colour coding has been used for better readability of the performance in terms of flexibility only; it is not meant to suggest economic attractiveness.

FLEXIBILITY per MDR member		participation probability 20%	40%	60%	80%
flexibility as % of baseline	20%	0.7	0.8	1.2	1.7
	40%	0.9	1.4	2.2	3.1
	60%	1.2	2.3	2.7	3.8
	80%	1.6	2.1	4.9	7.1

Figure 29: The annual expected flexibility in kWh from each MDR kWmax member as a function of the flexibility asked by the Aggregator and participation probability during any slot

A first attempt to understand the economic attractiveness of MDR flexibility is shown in the following figure. It gives an overview of the total cost (in €/kWh) to a TSO, assuming that the Aggregator includes a 40% markup on the participants' reward. Note that the costs below are the outputs of a single simulation. Given the stochastic nature of the simulator, running a series of simulations and getting the average (for each combination of flexibility asked and participation probability) would remove any oscillations.

COST OF FLEXIBILITY TO TSO (€/kwh)		participation probability 20%	40%	60%	80%
flexibility as % of baseline	20%	0.30	0.26	0.25	0.26
	40%	0.26	0.49	0.41	0.36
	60%	0.29	0.44	0.41	0.27
	80%	0.25	0.51	0.40	0.26

Figure 30: The cost of MDR flexibility for a TSO as a function of the flexibility asked by the Aggregator and participation probability during any slot

Similarly, the following figure presents the expected annual flexibility from each ADR member as a function of:

- the requested flexibility, again expressed as a percentage of the baseline load, and
- the override probability, which defines whether a certain member will feel uncomfortable with the action performed by the Aggregator. In this simulation setup we have excluded this aspect.

FLEXIBILITY per ADR member		override probability 0%
flexibility as % of baseline	20%	2.1
	40%	4.2
	40%	6.3
	40%	8.4

Figure 31: The annual expected flexibility in kWh from each ADR kWmax member as a function of the flexibility asked by the Aggregator and override probability during any slot

Finally, the cost of ADR flexibility to TSO is shown in the next figure, which includes the remuneration of both the consumer and the Aggregator (no colour coding was used as resulting costs were almost identical, i.e., a mantissa of at least 4 digits would have to be used for any differences to be visible).

COST OF FLEXIBILITY TO TSO (€/kwh)		override probability 0%
flexibility as % of baseline	20%	0.33
	40%	0.33
	60%	0.33
	80%	0.33

Figure 32 The cost of ADR flexibility for a TSO as a function of the flexibility asked by the Aggregator and override probability during any slot

The highest cost of flexibility observed, €0.51/kWh (or €510/MWh) is lower than the published imbalances of 2016 in Belgium for 23 events and 84 events in 2017. This indicates the following:

- Flexibility services can compete with the traditional balance providers having the highest cost and
- The members requiring a high reward in order to offer their flexibility would be activated in about up to 20 events per year. The frequency of activation requests to the rest members will depend on the Aggregator's portfolio management strategy.

6.2.2 FlexPrice

In this section we will evaluate the attractiveness of a particular dynamic pricing scheme to several customer types and its potential to steer their consumption from peak to off-peak periods.

More specifically the FlexPrice dynamic pricing scheme is a two-part tariff composed of:

- a fixed annual charge set, for instance, at €30 and
- the variable part that correspond to the day-ahead (Belpex) prices (thus no markup is added). Note that the final price paid will include Distribution costs, Transport costs, Taxes and VAT.

In order to lower the adopters' risk caused by unnoticed extraordinary high prices, Ecopower sets a critical peak price level. When day-ahead prices are published, and the DRFM identifies that a certain price threshold will be exceeded, then users are notified in order to schedule their loads.

After prices are announced, users that are present at the building will decide how much to consume during a particular slot. At any slot consumers decide whether they should reduce or increase load.

6.2.2.1 Simulation setup

Consumers' decisions regarding load reduction are characterized by a set of parameters. The simulator was configured so that different consumers are modelled in terms of the following parameters:

- **consumer availability hours**, which determine when a consumer uses electrical appliances and thus can adjust loads. We defined 2 user types;
  - o "Allday" who leave the building at 8:00 am every day and return at noon.
  - o "Evening" who leave the building at 8:00 am every day and return at 17:00.

Both user types go to bed at 00:00 and wake up at 7:00 am.

- **High-price threshold**, which is defined as a percentage (e.g., 140%) of the average day-ahead price witnessed during the previous year.

- **Low-price threshold**, which again is defined as a percentage (e.g., 110%) of the average day-ahead price witnessed during the previous year
- **Response probability**, which defines how likely it is that an available user will reduce demand whenever:
    - the Belpex price is higher than the High-price threshold
    - the Belpex price is not lower than the Low-price threshold (these slots are named “Other”).

A user can reduce load with different probabilities when in any of the two states mentioned above.

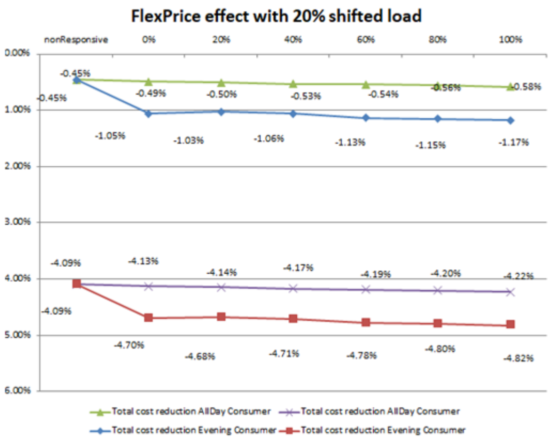
- **Magnitude of reduced load**, which defines what percentage of the baseline load will be shifted to other slots.

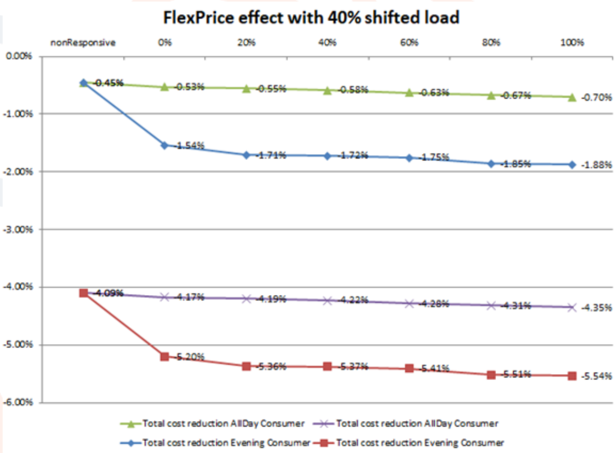
If any shifted load exists so far (or is planned to take place during the same day) and the consumer is available/present, then she decides whether increase load or not. This decision is also governed by the parameters above. More specifically, if the price during a slot is lower than, either the High-price threshold or the low-price threshold, then a certain share of the total daily shifted loads is included in that slot. Eventually all loads will be shifted so that the baseline daily load equals the adjusted daily load, i.e., no efficiency takes place.

6.2.2.2 Simulation results

The following figures present the effect of FlexPrice scheme on the average retail price (before VAT) and the total cost with respect to the fixed plan. We observe the following:

1) All consumers adopting this pricing scheme enjoy a small but consistent bill saving, ranging from 0.5% up to almost 6%. Those shifting a larger part of their slot load to another period see a slightly greater benefit.
2) Interestingly, the “Evening” Consumers have a greater reduction on their electricity bill of about 1.5%. This means that while they have fewer choices regarding when their load should be shifted, the day-ahead prices during those slots are lower.
3) The FlexPrice scheme is beneficial even for consumers that are insensitive to prices. Their benefit, however, is lower than those willing to move some load to “shoulder” periods.





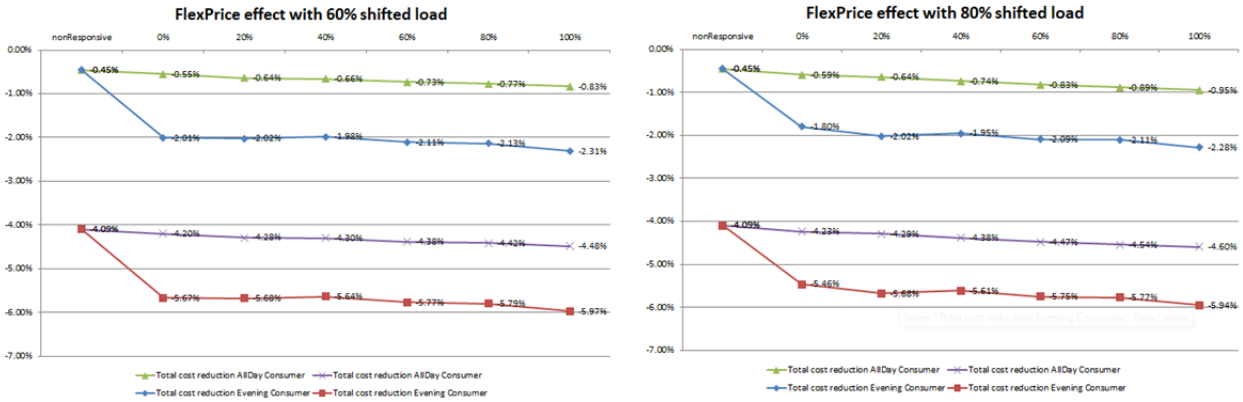


Figure 33: The effect of FlexPrice scheme on the average retail price (before VAT) and total cost of 2 consumer types; “Allday” and “Evening”

In the following chart we see that periods of High prices contribute to a rather small degree on the annual cost of a consumer (in particular an “Allday” one who whenever she decides to save money shifts 80% of her demand during that slot to another one). Thus, there is a limited potential for cost savings. Similar contributions of each cost category to the total electricity cost of a consumer were witnessed for other consumer types as well.

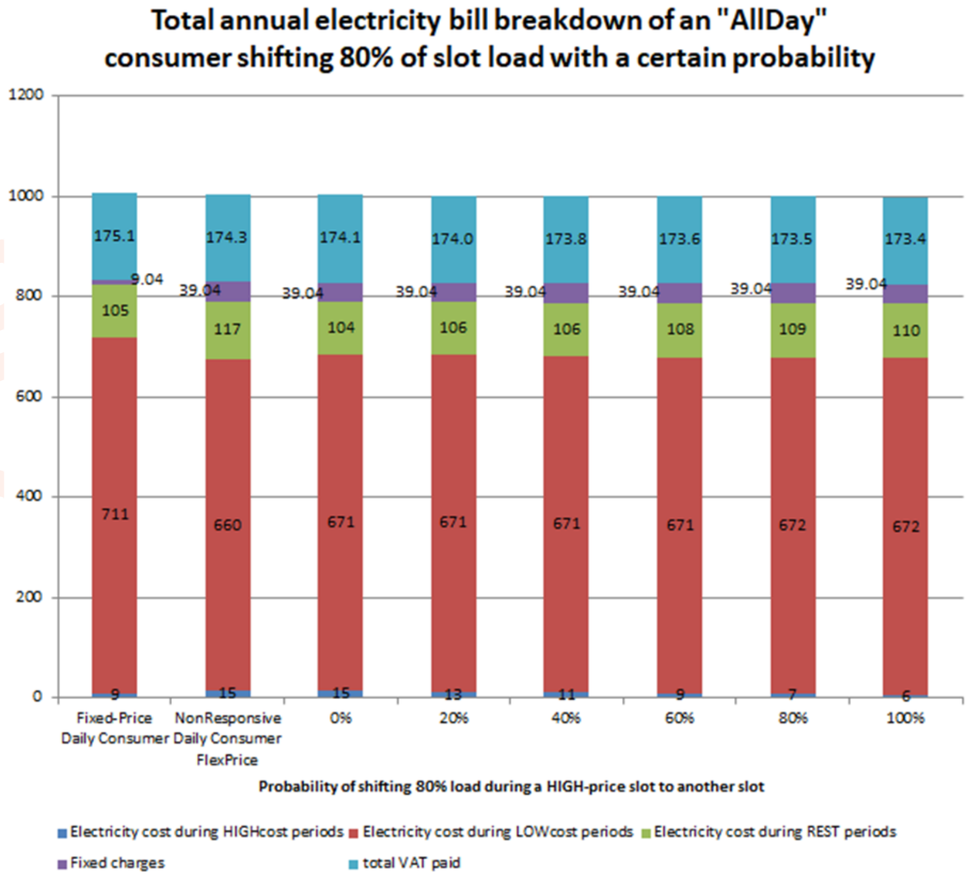


Figure 34: The breakdown of the annual electricity cost of an exemplary consumer

The following tables present key techno-economic metrics for the user type depicted on Figure 34 and a similar one, who shifts 40% with varying probabilities. Both user types are compared to a consumer under a fixed contract and a consumer who, even though is part of the FlexPrice portfolio, she never shifts any load.

Table 38 Useful technoeconomic metrics regarding the effect of FlexPrice service offering to a consumer that shifts most of its load (80%) to a less costly period

	Static Price Consumer	Insensitive FlexPrice cosnumer	FlexPrice consumer shifting 80% of load during a HighPrice period to rest periods with 20% probaability	FlexPrice consumer shifting 80% of load during a HighPrice period to rest periods with 40% probaability	FlexPrice consumer shifting 80% of load during a HighPrice period to rest periods with 60% probaability	FlexPrice consumer shifting 80% of load during a HighPrice period to rest periods with 80% probaability
self-consumption	0	0	0	0	0	0
energy bought	3842	3842	3842	3842	3842	3842
total NET energy exported	0	0	0	0	0	0
flexibility offered	0	0.00	34.97	69.64	100.71	136.54
revenues (feed-in tariff)	0	0	0	0	0	0
costs (served from grid)	824.74328	790.9747667	790.0831083	789.1645773	788.3282324	787.3273824
Electricity cost during HIGHcost periods	8.6529735	14.57234676	12.72779001	11.09121367	9.216786266	7.130510007
Electricity cost during LOWcost periods	711.40314	659.7250737	662.7873768	666.3696704	668.8674344	671.5314258
Electricity cost during REST periods	104.68716	116.6773463	114.5679414	111.7036933	110.2440117	108.6654466
average retail price	0.2146651	0.205875143	0.20563994	0.205404627	0.205185463	0.204919828
variable VAT paid	173.19609	166.104701	165.9174527	165.7245612	165.5489288	165.3387503
Fixed charges	9.04	39.04	39.04	39.04	39.04	39.04
fixed VAT paid	1.8984	8.1984	8.1984	8.1984	8.1984	8.1984
total VAT paid	175.09449	174.303101	174.1158527	173.9229612	173.7473288	173.5371503
TOTAL COST	1008.8778	1004.317868	1003.238961	1002.127539	1001.115561	999.9045327
Total cost reduction Evening Consumer		-0.45%	-0.56%	-0.67%	-0.77%	-0.89%
retail price reduction Evening Consumer		-4.09%	-4.20%	-4.31%	-4.42%	-4.54%

Table 39 Useful technoeconomic metrics regarding the effect of FlexPrice service offering to a consumer that shifts almost half of its load (40%) to a less costly period

	Static Price Consumer	Insensitive FlexPrice cosnumer	FlexPrice consumer shifting 40% of load during a HighPrice period to rest periods with 20% probaability	FlexPrice consumer shifting 40% of load during a HighPrice period to rest periods with 40% probaability	FlexPrice consumer shifting 40% of load during a HighPrice period to rest periods with 60% probaability	FlexPrice consumer shifting 40% of load during a HighPrice period to rest periods with 80% probaability
self-consumption	0	0	0	0	0	0
energy bought	3842	3842	3842	3842	3842	3842
total NET energy exported	0	0	0	0	0	0
flexibility offered	0	0.00	30.61	60.13	88.77	119.09
revenues (feed-in tariff)	0	0	0	0	0	0
costs (served from grid)	824.74328	790.9747667	790.6883728	790.3639143	790.124991	789.8194525
Electricity cost during HIGHcost periods	8.6529735	14.57234676	14.57234676	14.57234676	14.57234676	14.57234676
Electricity cost during LOWcost periods	711.40314	659.7250737	662.4870467	665.4013307	668.2409879	670.7784334
Electricity cost during REST periods	104.68716	116.6773463	113.6289794	110.3902368	107.3116563	104.4686723
average retail price	0.2146651	0.205875143	0.20580115	0.205715855	0.205653956	0.205574437
variable VAT paid	173.19609	166.104701	166.0445583	165.976422	165.9262481	165.862085
Fixed charges	9.04	39.04	39.04	39.04	39.04	39.04
fixed VAT paid	1.8984	8.1984	8.1984	8.1984	8.1984	8.1984
total VAT paid	175.09449	174.303101	174.2429583	174.174822	174.1246481	174.060485
TOTAL COST	1008.8778	1004.317868	1003.971331	1003.578736	1003.289639	1002.919938
Total cost reduction Evening Consumer		-0.45%	-0.49%	-0.53%	-0.55%	-0.59%
retail price reduction Evening Consumer		-4.09%	-4.13%	-4.17%	-4.20%	-4.23%

We see that the average retail price of both user types is about 1 eurocent lower than the fixed price one (before applying VAT). Considering the fixed annual charge and VAT, a consumer would end up paying 95.5% of its current bill on average.

In the following figure we see the effect of FlexPrice scheme on the average retail price (before VAT) and the total cost with respect to the fixed plan when a 10% discount is applied on the day-ahead wholesale price before announcing the dynamic price. The cost savings in this case are significantly higher and thus the FlexPrice scheme could attract a considerable share of customers. Ecopower, in order to do so, will have to buy energy in the over-the-counter market (via bilateral agreements with other generators) whenever its production cannot meet the baseload.

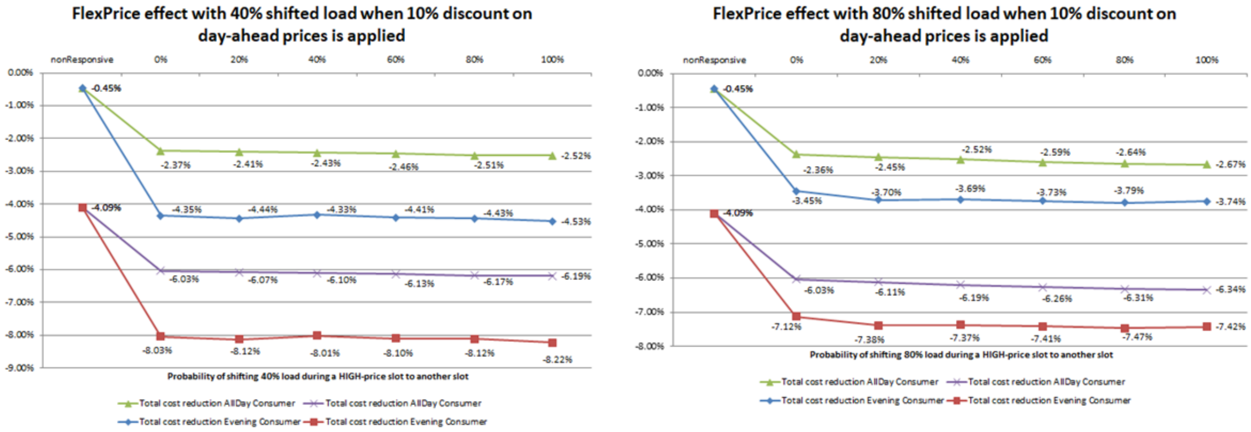


Figure 35: The effect of FlexPrice scheme when a 10% discount is applied on the day-ahead wholesale price before announcing the dynamic price.

Note that so far, the High price was set to 140% of the average day-ahead price in Belgium during 2016, while the Low price was set to 110%. In the following figure we see the effect of the proposed pricing scheme when High-price periods are determined as 180% of average day-ahead price during 2016 and a 10% discount on day-ahead (i.e., Belpex) prices are announced. This is done for 2 types of customers; those that shift 40% and 80% of a high-priced period's load to other slots. We observe that for the former user type (on the left hand side of the figure) such a change leads to a negligible reduction on cost savings. On the other hand, users that shift a high share of their slot load to other off-peak times see an additional 1% cost reduction.

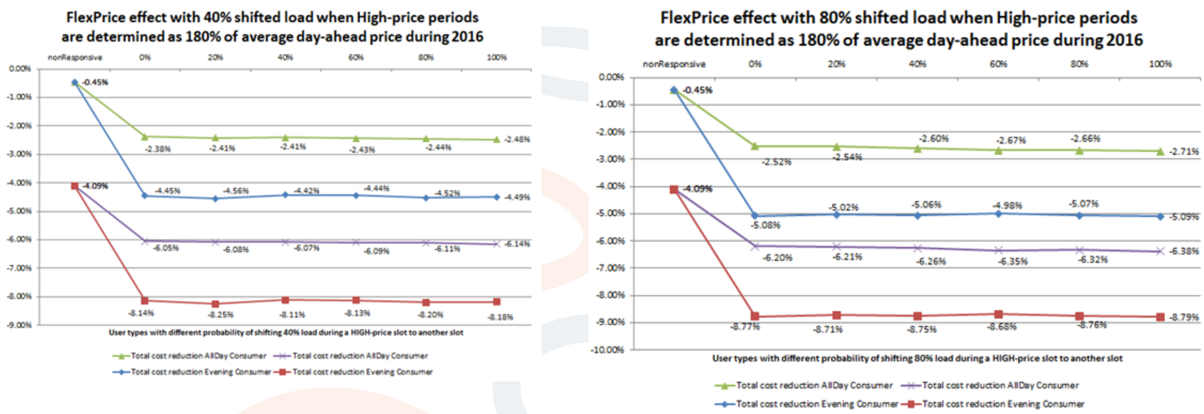


Figure 36: the effect of FlexPrice scheme when a 10% discount is applied on the day-ahead wholesale price and a higher HighPrice threshold is set

Thus, FlexPrice has the potential to slightly lower the bill of the prosumers, compared to the fixed price. It is expected that if a customer does not act, she will have the same price on average with those having selected a static price. On the other hand, it was found that if a customer follows the notifications and pricing trends regularly and shifts a large share of the baseline load, then they should have cheaper electricity. Furthermore, we noticed that FlexPrice is probably more convenient for customers that spend most of the day away from their premises, as day-ahead prices tend to be lower late at the evening.

6.2.3 CoopBalance

Ecopower members have expressed their interest in reducing net peak loads, which are manifested as an imbalance between production and consumption during a particular timeslot (e.g., of 15 minutes). Their motivation is primarily attributed to social factors, such as reduced ecological footprint, rather than economic ones like bill savings.

In order to better match consumption with production Ecopower can request flexibility from an Aggregator so that its members:

- Reduce their consumption when negative peak loads exist (production is very low compared to consumption) and
- Increase their consumption when negative peak loads exist (production is very high compared to consumption).

6.2.3.1 Simulation setup

In this section we want to estimate the expected effect of DR campaigns, as supported by NOBEL GRID technologies, on **Ecopower** net peak loads based on assumptions on the following aspects:

- Hours during the day that an Ecopower member is available at the premises for participating in an MDR campaign. This affects the flexibility that can be obtained during the day and night. We assume that there are two user types:
  - users (such as pensioners, home-office workers, etc) who are available from 08:00 AM until 23:59 PM (named ereafter AllDay or pensioners);
  - workers who are available from 18:00 PM until 23:59 PM
- Probability of each user accepting to participate on a particular DR campaign, under the condition that she is available at that time (see aspect above). Thus, users choose whether, or not, to participate in MDR campaigns, where no monetary reward is promised. Their only economic benefit will be a long-term one as any Ecopower cost savings will be transferred to these users, e.g., in the form of discount coupons.
- The flexibility asked from each member as a percentage (%) of the baseline load during the DR campaign period.
- The percentage of Ecopower's customer base that is part of an Aggregator's portfolio (hereafter referred as "Aggregator's pool size").
- Frequency of DR events which depends on the following thresholds
  - Negative imbalance threshold (here defined as a percentage (%) of the lowest net load observed quarter hourly during the year 2016) and
  - Positive imbalance threshold (here defined as a percentage (%) of the highest net load observed quarter hourly during the year 2016)
- Number of EVs, expressed as a percentage of Ecopower's customer base, whose charging schedules can be defined by an Aggregator in a way that will rarely cause inconvenience to their owners. Thus, EVs contribute to flexibility that is obtained from ADR campaigns. We assume that no other controllable loads (such as cooling, heating, lighting, etc.) contribute to ADR flexibility. The effect of such controllable loads will be studied in the future.

The following diagram sketches the methodology used for calculating the total net load of Ecopower at any 15min slot using data for 2016 in the Business-as-Usual scenario (the light green box on the top the figure) and the CoopBalance case as supported by NOBEL GRID (the green box on the bottom the figure).

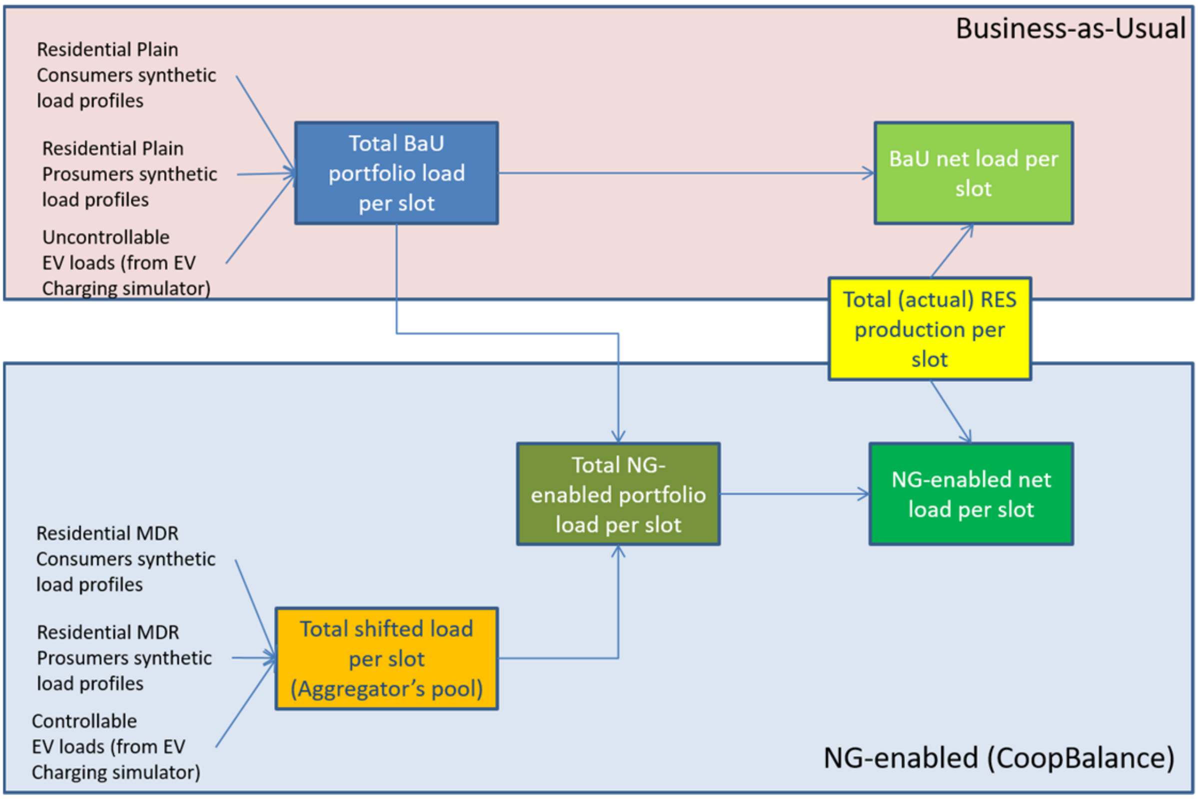


Figure 37: A graphical illustration of the approach used for calculating the total net load of Ecopower at any slot for the CoopBalance case (caseA: external BRP entity)

To calculate the number of plain consumers, plain prosumers, MDR consumers, MDR consumers and EV owners we consider the following:

- current share of prosumers (44%) as a percentage of the total Ecopower customer base (43600)
- EV penetration rate (treated as a free variable)
- Aggregator's pool size (treated as a free variable)

Furthermore, we want <u>to estimate the expected financial benefits of the CoopBalance scheme</u> in the form of:

a) increased revenues from surplus own production
b) cost savings from more balanced own production and consumption (e.g., what is the offtake total cost per kWh that customers would pay)

Currently Ecopower relies upon an external BRP for

- Selling any surplus production to wholesale markets (for a certain price P_injection)
- Energy bought for a certain price P_offtake (= Price_Endex * 108%)
- Being balanced

Since P_offtake >P_injection Ecopower has the incentive to "self-consume" as much as possible, which affects both financial benefits above.

We also want to <u>estimate the additional revenues (or even costs) from imbalance markets as a function of the load forecasting error</u>. This revenue stream (or cost if own imbalances frequently contribute to system imbalances and imbalance prices are high) can only be realized when Ecopower adopts the role of the BRP (on top of the Generator and Retailer). Thus, the attractiveness of Ecopower becoming a BRP for serving her own needs (thus not being balance responsible for other entities) depends on the accuracy of the profile.

The following diagram sketches the methodology used for calculating the total net load of Ecopower when not relying on an external BRP. As before, we have two net load estimates, one for the Business-as-Usual scenario and the other for CoopBalance case as supported by NOBEL GRID.

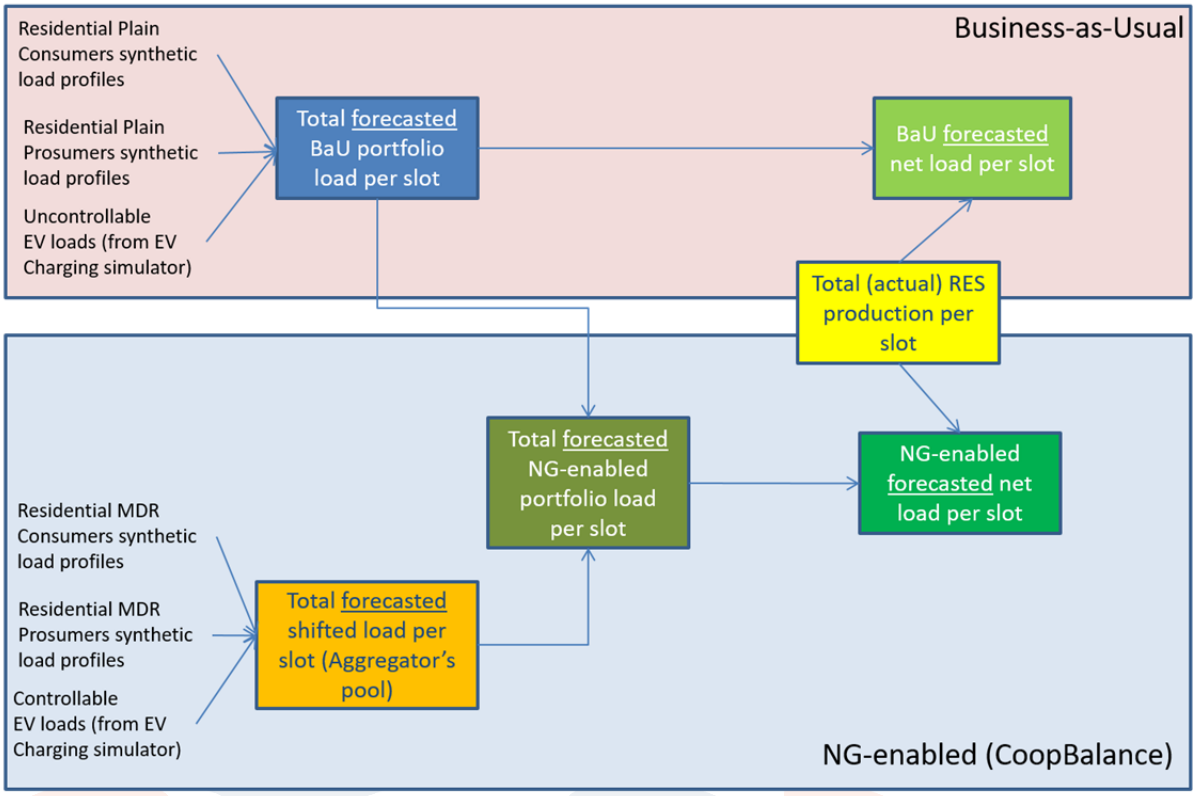


Figure 38: A graphical illustration of the approach used for calculating the total net load of Ecopower at any slot for the CoopBalance case (caseB: internal BRP entity)

However in the "internal BRP" case, we assume that Ecopower performs the load estimation twice; one for procuring any capacity for meeting the expected demand from the day-ahead market and at the real-time market (e.g., up to 15 minutes before closure) for buying any additional capacity. As shown in the next diagram, the load forecast error will affect the imbalances caused (even though local imbalances will result in revenues whenever Ecopower helps the system operator to achieve balance).

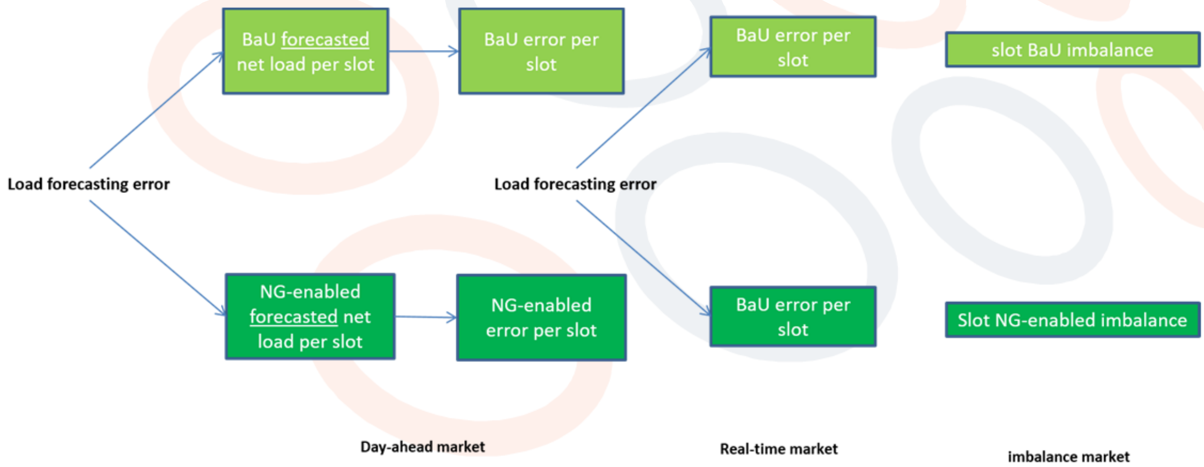


Figure 39: Forecast error and energy bought from wholesale markets in the CoopBalance case

In particular, we assume that all 15min slot loads apart from production are uniformly distributed and the lower and upper range are determined by applying the load forecast error on the actual load data for 2016. Furthermore, we assume that the updated forecast for the real-time market will also be based on the same load forecast error. This means that it will be uniformly distributed, but the range will be a quadratic form of the load forecast error and thus significantly reduced (compared to the day ahead error range).

The following figure presents a high-level overview of the scenarios that were simulated for both the external BRP scenario and the internal one. These scenarios are placed on the two-dimensional space where each of the 4 quadrants refer to a set of parameters.

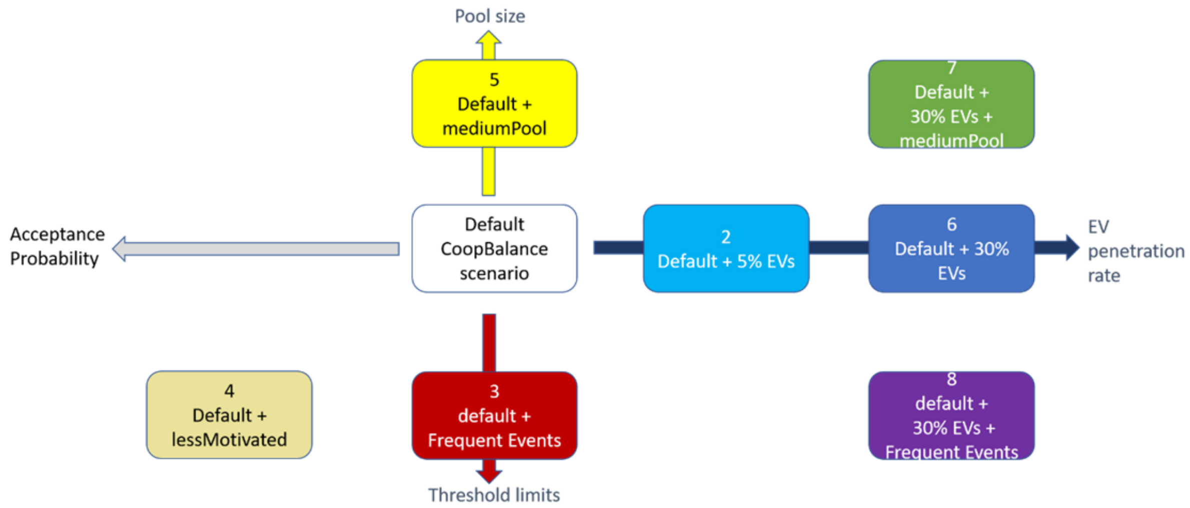


Figure 40: A high-level overview of the simulated scenarios for the CoopBalance case

A more detailed view of the selected parameter values for each scenario appear on the following table.

Table 40: Parameter values for each CoopBalance scenario simulated

	Scenario							
Parameter	1	2	3	4	5	6	7	8
MDR user type	Pensioner	Pensioner	Pensioner	Pensioner	Pensioner	Pensioner	Pensioner	Pensioner
MDR accept. prob.	80%	80%	80%	**40%**	80%	80%	80%	80%
% of baseline asked	60%	60%	60%	60%	60%	60%	60%	60%
Pool size	75%	75%	75%	75%	**50%**	75%	**50%**	75%
EV penet. rate	0%	**5%**	0%	0%	0%	**30%**	**30%**	**30%**
Negative imbal. limit as % of MIN	7.5%	7.5%	**12.5%**	**12.5%**	7.5%	7.5%	7.5%	**12.5%**
Positive imbal. limit	7.5%	7.5%	**12.5%**	**12.5%**	7.5%	7.5%	7.5%	**12.5%**

as % of MAX								

6.2.3.2 Simulation results

6.2.3.2.1 Default case

The following figure presents the net load per 15min slot in ascending order for the “Business As Usual”. The minimum peak is -8909 kWh while the threshold for starting DR campaigns in order to reduce consumption is set to -8241 kWh (7.5% of minimum). Similarly, the maximum is 14685 kWh while the threshold for asking flexibility is set to 13583 kWh (7.5% of maximum).

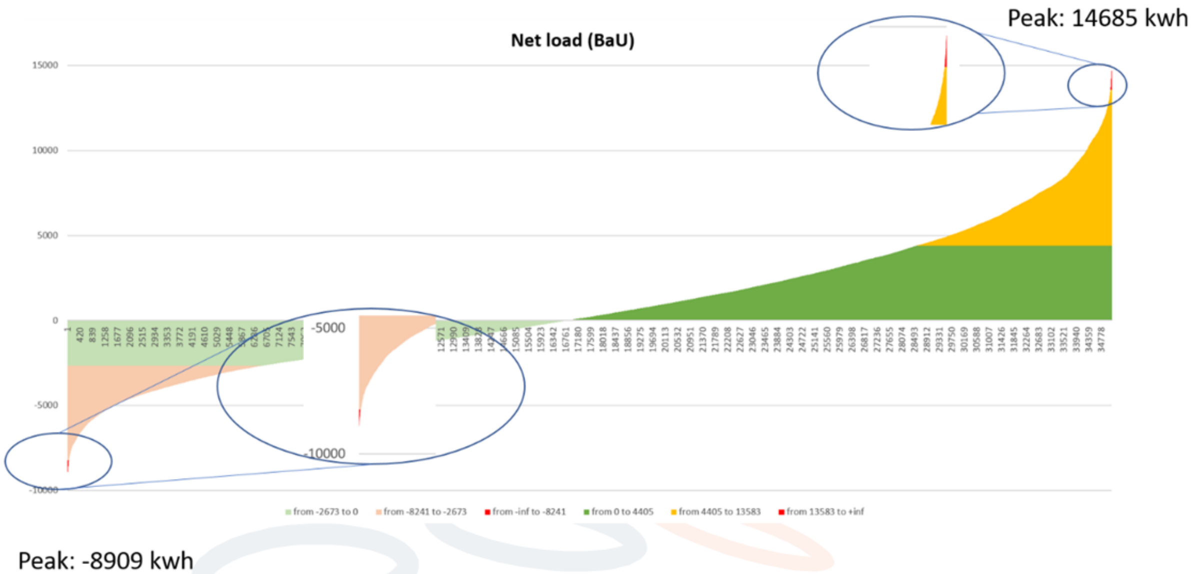


Figure 41: The net load of Ecopower per 15min slot in ascending order for the “Business As Usual” scenario (default case)

A similar chart appears for the CoopBalance scenario, where the minimum peak is estimated at -8614 kWh (reduced by -3.93%) and the maximum peak at 14489 kWh (reduced by -1.77%). Comparing the two figures we see that the flexibility obtained mostly from EV charging eliminated negative spikes, while MDR campaigns reduced the positive spikes.

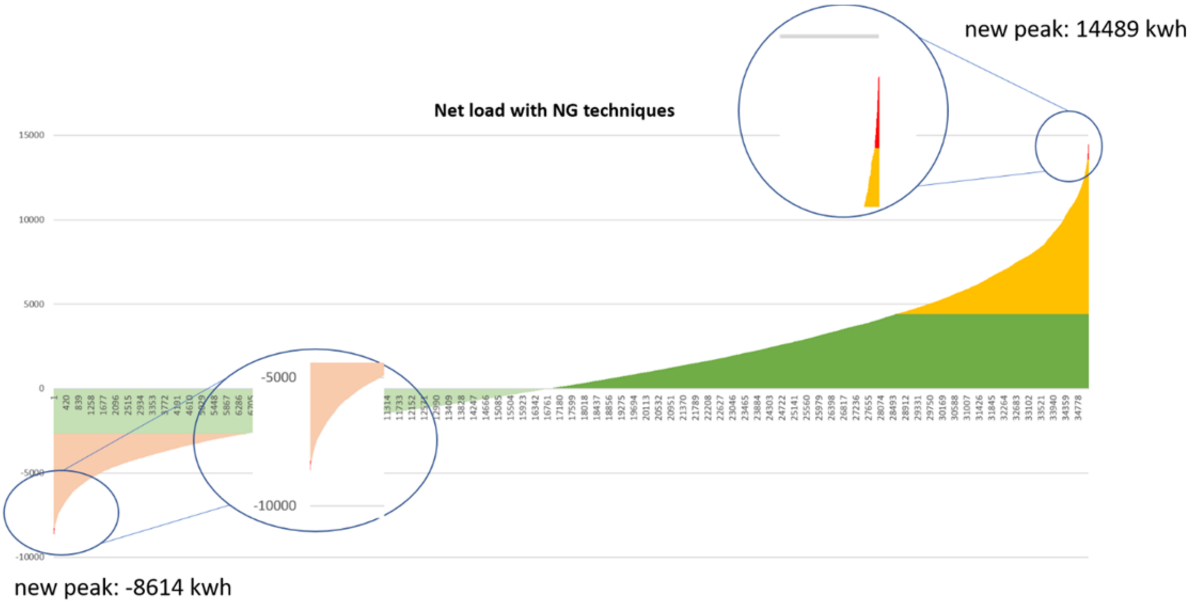


Figure 42: The effect of CoopBalance service offering to the net load of Ecopower per 15min slot (default case)

6.2.3.2.2 Case6: 30% EV penetration rate

The following figure presents the net load per 15min slot in ascending order for the "Business As Usual". The minimum peak is -27984 kWh while the threshold for starting DR campaigns in order to reduce consumption is set to -25885 kWh (7.5% of minimum). Similarly, the maximum is 14684 kWh while the threshold for asking flexibility is set to 13583 kWh (7.5% of maximum).

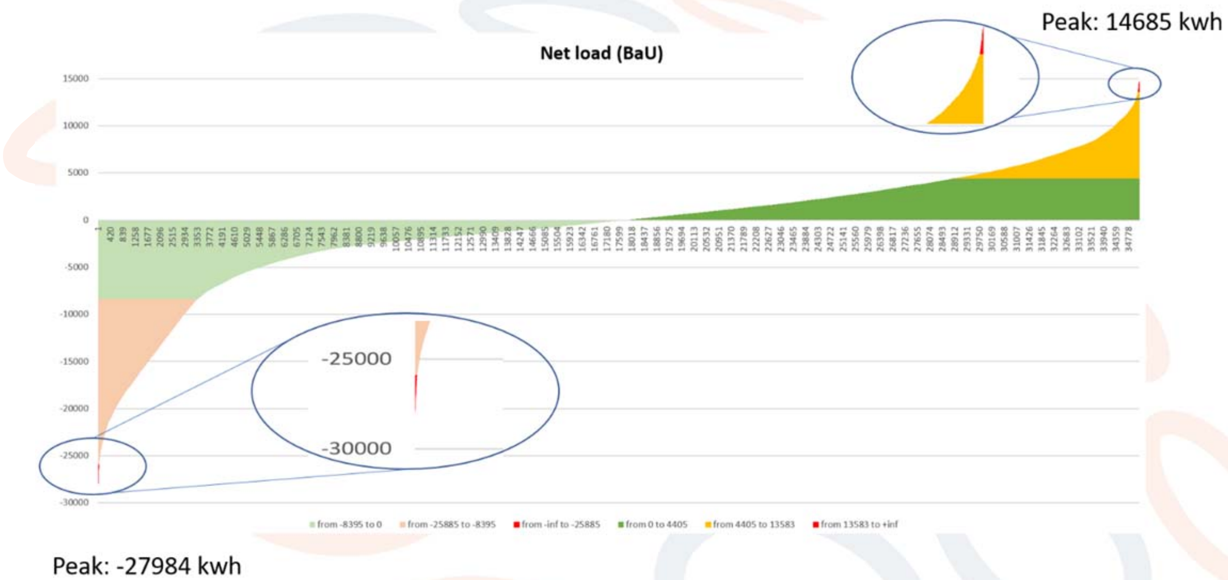


Figure 43: The net load of Ecopower per 15min slot in ascending order for the "Business As Usual" scenario (case with 30% EV penetration rate)

A similar chart appears for the CoopBalance scenario, where the minimum peak is estimated at -25884 kWh and the maximum peak at 14444 kWh. Comparing the two figures we see that the flexibility obtained mostly from EV charging eliminated negative spikes, while MDR campaigns reduced the positive spikes.

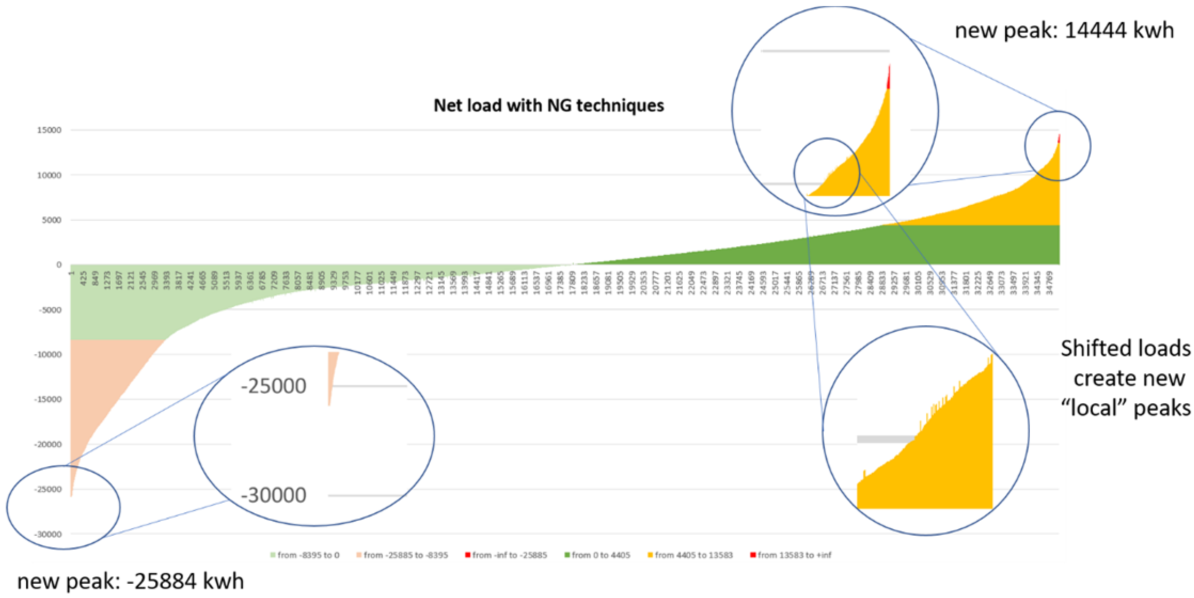


Figure 44: The effect of CoopBalance service offering to the net load of Ecopower per 15min slot (30% EV penetration rate case)

The next figure provides a different view of the peak shaving achieved with NOBEL GRID techniques. We observe that no slot during the simulated year of 2016 exceeded the threshold of -25885 (this is why bin “<=-25885” is omitted from the lower histogram. On the other hand, the size of bin “[-25885,-23885]” has been increased by 26 (the number of slots in the BaU scenario exceeding the threshold).

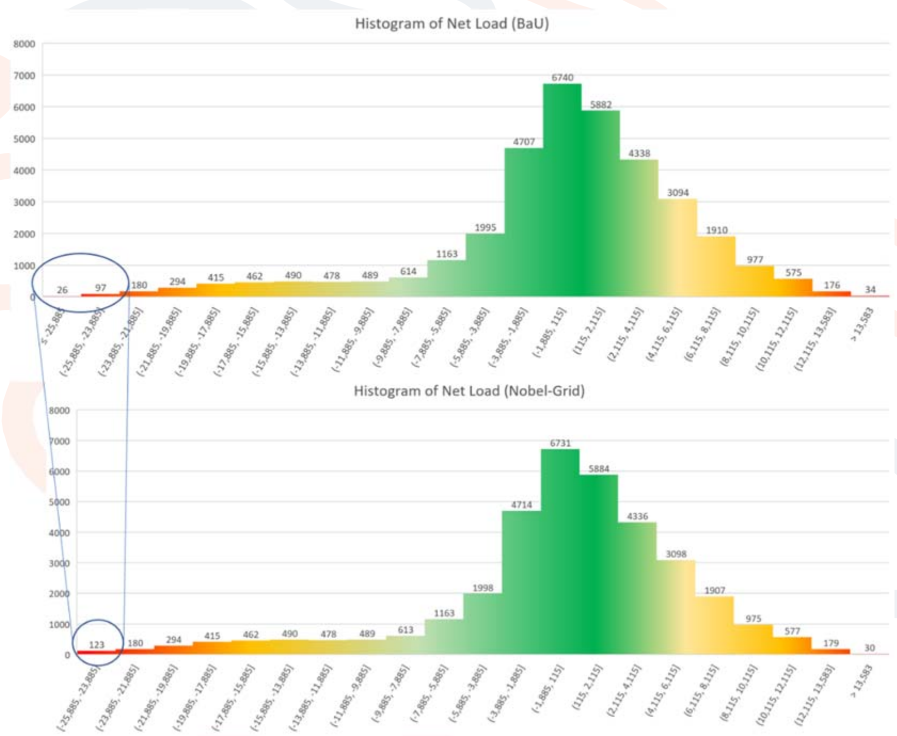


Figure 45: Histograms of net load before (top) and after the CoopBalance service (bottom) offering (30% EV penetration rate case)

6.2.3.2.3 Case8: 30% EV penetration rate and frequent events

The following figure presents the net load per 15min slot in ascending order for the "Business As Usual". As in Case6 the minimum peak is -27984 kWh while the maximum is 14684 kWh. The only difference is that the threshold for starting DR campaigns in order to reduce/increase consumption is set to 12.5% (translated into -25885 kWh and 13583 kWh respectively).

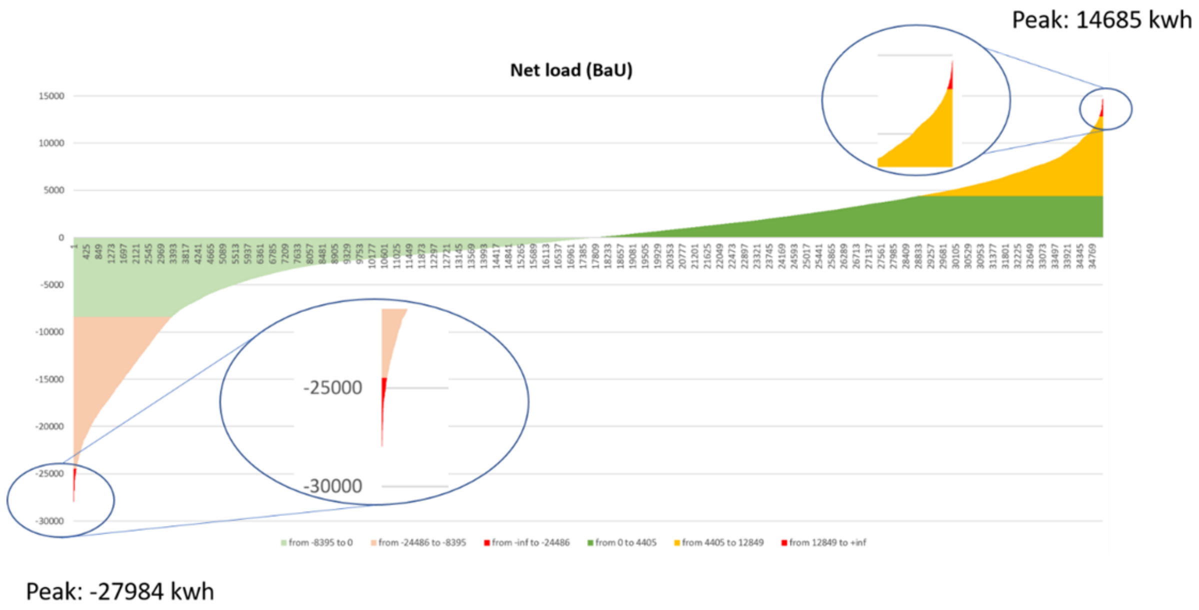


Figure 46: The net load of Ecopower per 15min slot in ascending order for the "Business As Usual" scenario (case with 30% EV penetration rate and frequent DR events)

The following figure presents the net load per 15min slot in ascending order for the CoopBalance scenario, where the minimum peak is estimated at -25884 kWh and the maximum peak at 14520 kWh. Note that in Case6 the minimum peak is -24485 kWh and the maximum 14444 kWh.

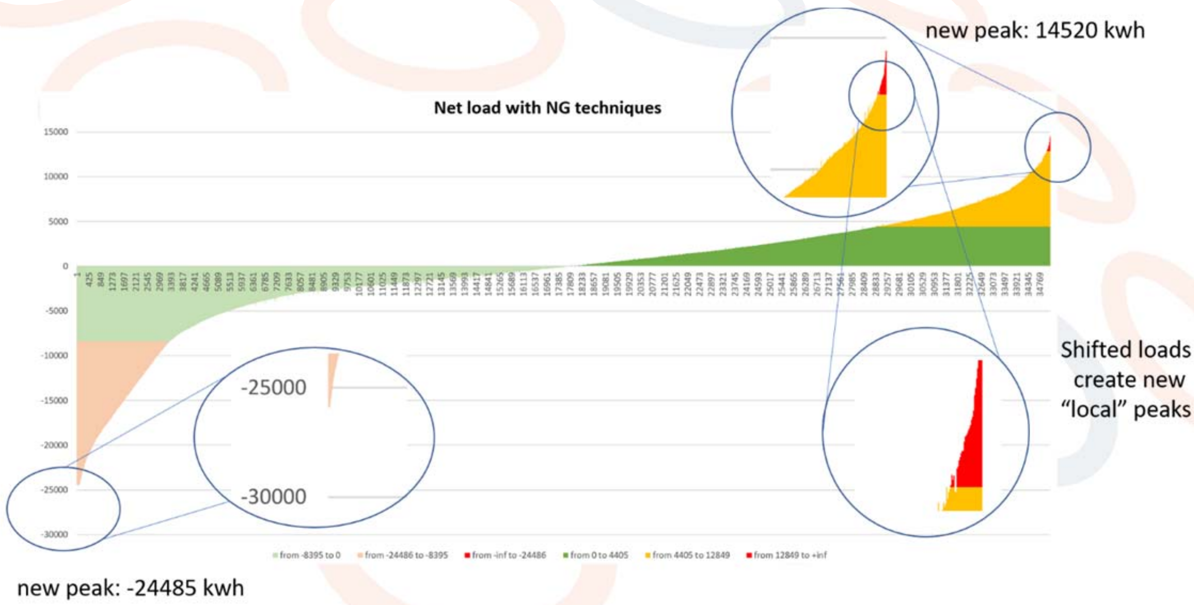


Figure 47: The effect of CoopBalance service offering to the net load of Ecopower per 15min slot (30% EV penetration rate case and frequent DR events)

As in Case6, the flexibility obtained mostly from EV charging eliminated negative spikes, while MDR campaigns reduced the positive spikes. In particular, the following figure provides the effect of CoopBalance on reducing net load spikes in kWh.

Figure 48: The reduction on net load spikes of CoopBalance service (30% EV penetration rate case and frequent DR events)

The following table presents key metrics for each simulated case.

Table 41: Key technoeconomic metrics for each simulated case of CoopBalance service offering

	1: Default	2:Default + 5% EVs	3:Default + freqEvents	4:Default + lessMotivated	5:Default + mediumPool	6:Default + 30% EVs	7:Default + 30% Evs + mediumPool	8:Default + 30% Evs + FreqEvents
MIN (BaU)	-8909.18	-8909.18367	-8909.18	-8909.18	-8909.18	-27983.6	-20249.3	-27983.5597
MAX (BaU)	14684.79	14684.91785	14684.79	14684.79	14684.79	14684.79	14684.79	14684.7932
MIN (NG)	-8558.96	-8692.91282	-8323.73	-8634.41	-8566.92	-25884.5	-18730.4	-24485.3625
MAX (NG)	14424.94	14506.82177	14445.71	14629.53	14476.31	14524.91	14634.12	14519.7319
MIN (NG effect %)	-0.03931	-0.02427504	-0.06571	-0.03084	-0.03842	-0.07501	-0.07501	-0.12500901
MAX (NG effect %)	-0.0177	-0.01212782	-0.01628	-0.00376	-0.0142	-0.01089	-0.00345	-0.01124029
MIN (abs NG effect)	-350.222	-216.270851	-585.459	-274.777	-342.265	-2099.03	-1518.86	-3498.19723
MAX (abs NG effect)	-259.854	-178.096073	-239.083	-55.268	-208.482	-159.886	-50.6766	-165.061335
Annual Balance (BaU)	28118777	26688368.61	28118777	28118777	28118777	-2.3E+07	-5836068	-22813490.6
Annual Balance (NG)	28118940	26688368.61	28107095	28118777	28118777	-2.3E+07	-5836068	-22808167.9

Annual Benefit per member from CoopBalance (€)	0.00649	0.006118318	-0.00319	0.003688	0.004417	0.009656	0.001156	0.00571778
Average Annual Flexibility from each MDR consumer	0.682322	0.41989071	2.099454	0.99724	0.839781	0.209945	0.314918	0.6823224
Average Annual Flexibility from each MDR prosumer	0.99724	0.629836066	2.466858	0.970997	0.682322	0.262432	0.209945	0.52486339
total neg flex from EV	0	1084.763359	0	0	0	26708.94	20894.39	101299.924
total neg flex from nonEVs	8959.203	7874.440963	35515.03	29869.04	8959.203	0	0	0
total pos flex from EV	0	729	0	0	0	3358.256	2629.256	10587.5999
total pos flex from nonEVs	8798.923	8069.993471	26387.6	14632.81	8798.923	5994.584	6723.584	21432.2918
Average BRPadjusted endex (€/kWh)	0	0.038220962	0.038221	0.038221	0.038221	0.038221	0.038221	0.03822096
Average BELPEX (day-ahead market)	0	0.036633048	0.036633	0.036633	0.036633	0.036633	0.036633	0.03663305
Average BELPEX (day-ahead market) (% DIFF)	0	-0.04154564	-0.04155	-0.04155	-0.04155	-0.04155	-0.04155	-0.04154564
Average imbalance prices 2016 (per kWh)	0	0.035314928	0.035315	0.035315	0.035315	0.035315	0.035315	0.03531493
imbalance prices 2016 (PAID only)	0	0.047099973	0.044026	0.041303	0.046474	0.210111	0.11627	0.22009506
Injected Energy	0	0	0	0	0	66802150	66970167	66617419.7

It is interesting that in all cases examined the reduction of the net load maximum peak is below 2%, which explains why the thresholds defined (7.5% and 12.5%) were sometimes exceeded; though less frequently compared to the BaU scenario. We should note that in all cases we have assumed that the Aggregator's pool for MDR campaigns is composed of members that are present during the day ("pensioners" user type) which offsets the absence of controllable loads apart from EV batteries (such as for heating, cooling, lighting, etc). On the other hand, the target reduction for the minimum (negative) net load was reached in cases 6, 7 and 8 only, which involved a significant number of EVs (accounting for 30% of all vehicles owned by Ecopower members). The effect of CoopBalance on minimum and maximum net loads appears in the following chart.

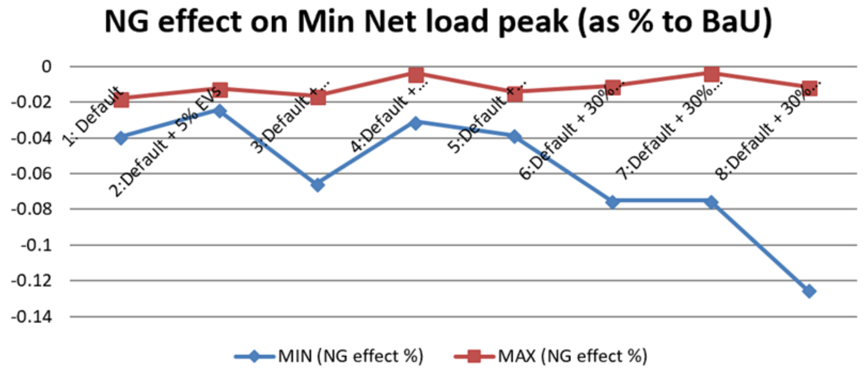


Figure 49: The effect of CoopBalance on minimum and maximum net loads for each of the 8 cases simulated

The following two figures present the estimated flexibility obtained in each case from MDR and ADR (EVs) users. We should highlight that EVs contribute to both positive and negative flexibility (load increase and reduction respectively) depending on the availability (or not) of Ecopower surplus production. Especially for the case of negative flexibility, EVs were able to meet the requested flexibility (so that the threshold was not violated) and thus no MDR campaigns were run. This justifies the absence of flexibility from nonEVs for cases 6, 7 and 8.

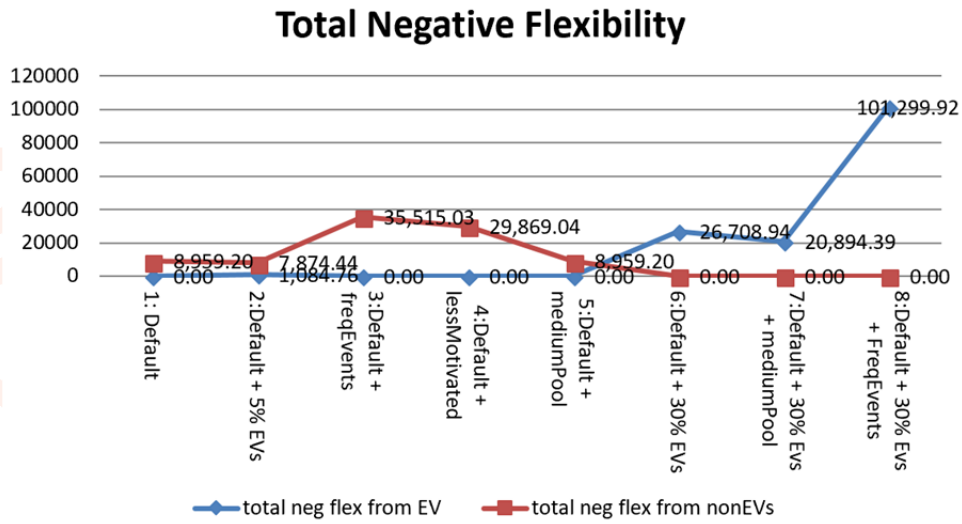


Figure 50: The estimated negative flexibility obtained in each of the 8 simulated cases from MDR and ADR (EVs) users.

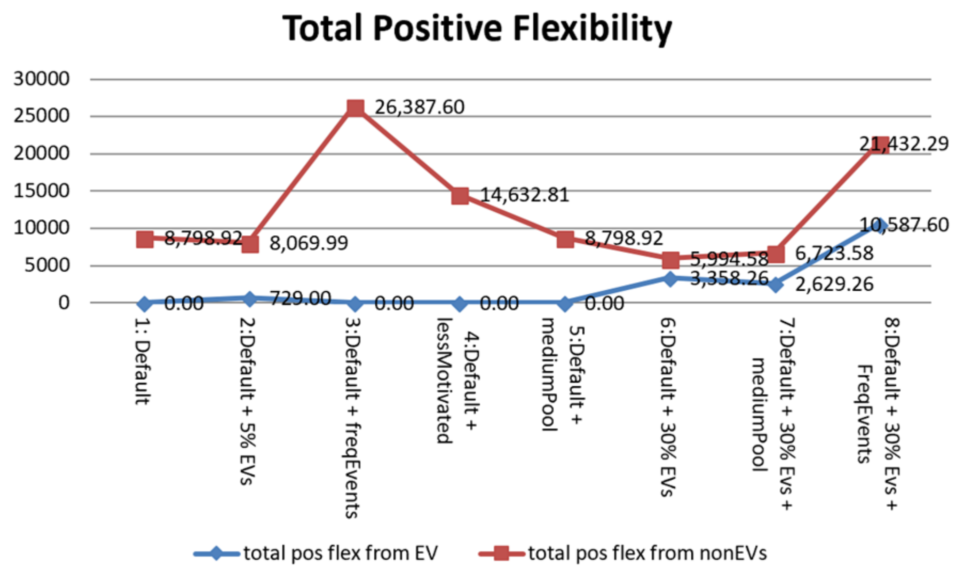


Figure 51: The estimated positive flexibility obtained in each of the 8 simulated cases from MDR and ADR (EVs) users.

Taking a closer look at the flexibility from EVs, we see that in the cases with high EV penetration rate (namely 6, 7 and 8) the needs for positive flexibility are significantly less compared to the needs for negative flexibility. This is justified by the following figure, where the effect of CoopBalance scheme on annual Ecopower balance

$$(\sum \text{total production on each15 min slot} - \text{ total consumption on each 15min slot})$$

is shown. We see that while the current Ecopower installed capacity results in a slight positive annual balance for cases 1-5, the significant loads required for charging the EVs results in negative balance for cases 6-8. Since production surplus happens less often in the slots of cases 6-8, there is less need for (positive) flexibility from EVs. Note that the annual balance for the BaU and CoopBalance case are equal as we assume that flexibility results in loads to be shifted, instead of efficiency gains. Furthermore, when calculating the loads needed for recharging the EV battery we assumed that at the end of the day the state of charge will be about 80%; resulting in quite moderate load needs.

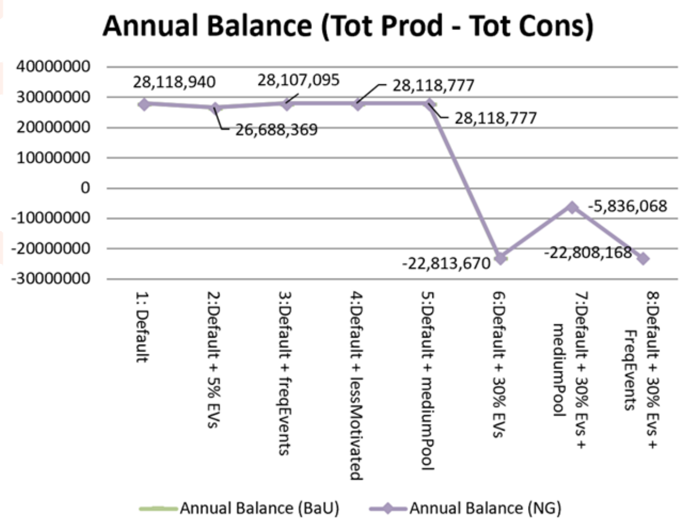


Figure 52: The effect of CoopBalance scheme on annual Ecopower balance for each of the 8 cases simulated

With respect to the expected financial benefits of the CoopBalance scheme, which includes the revenues from surplus own production sold for 0.03 €/kWh to the external BRP and the cost savings from more balanced own production and consumption (e.g., what is the offtake total cost per kWh that customers would pay), these were found to be quite low as shown in the figure below.

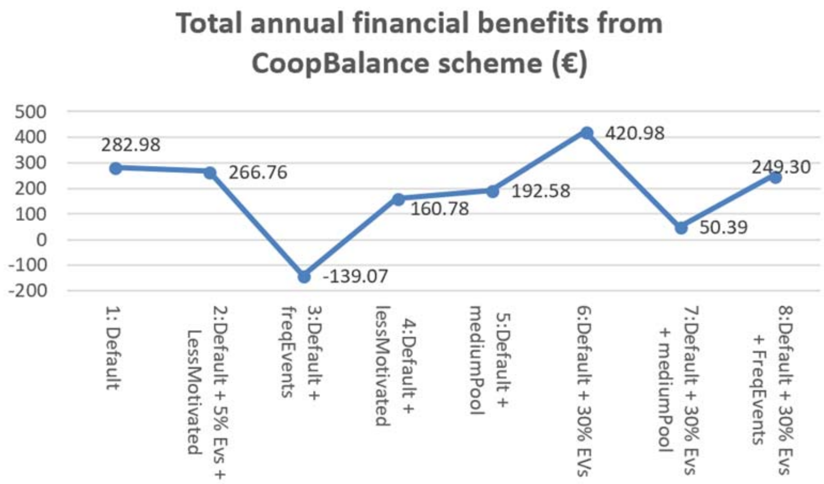


Figure 53: The financial annual benefits of CoopBalance scheme to Ecopower for each of the 8 cases simulated

Assuming that no extra costs are involved (e.g., capital expenditures for equipment, operational expenditures for personnel that orchestrate the DR campaigns, etc.) and that the benefits are equally shared amongst all 43600 Ecopower members, the following figure presents the negligible dividend per member. These preliminary results render this service not attractive. This could change if coopBalance members were willing to pay a small annual fee to Ecopower.

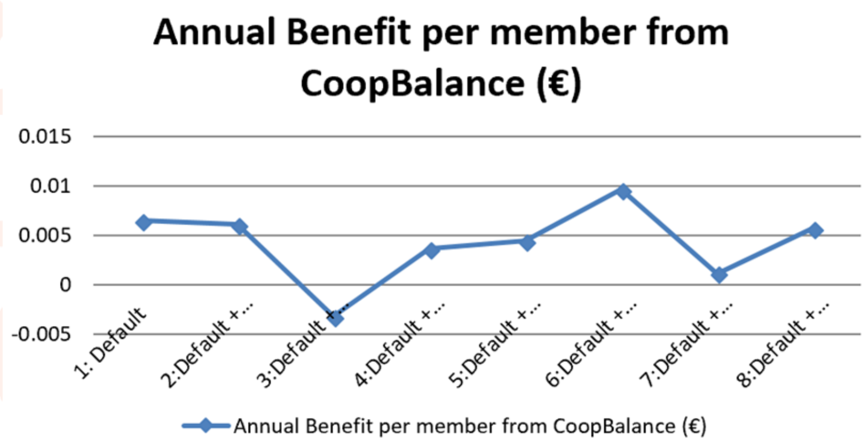


Figure 54: The financial annual benefits of CoopBalance scheme to individual Ecopower members for each of the 8 cases simulated

6.3 INDEPENDENT AGGREGATOR

In this section we will evaluate the attractiveness of the ProsumerMax service to several customer types and its potential to maximise self-consumption and thus reduce the electricity bill of the prosumers. The purpose of the simuation is to understand how much self-consumption will be increased and the resulting effect on cost paid. In order to do, the independent aggregator (Carbon Coop in our case) uses a traffic-light system informing eligible prosumers whether they should consume at that moment, or not.

6.3.1.1 Simulation setup

As before, prosumers' decisions regarding load reduction are characterized by a set of parameters. The simulator was configured so that different prosumers are modelled in terms of the following parameters:

- **availability hours**, which determine when a customer uses electrical appliances and thus can adjust loads. We defined 2 user types;
  - "Allday" who leave the building at 8:00 am every day and return at noon.
  - "Evening" who leave the building at 8:00 am every day and return at 17:00.
- **Magnitude of reduced load**, which defines what percentage of the baseline load prosumers will shift to other slots every time they react to a signal.

Again, if user responded to at least one signal then this will not affect the daily load, i.e., no efficiency takes place.

6.3.1.2 Simulation results

The following tables describe the estimated self consumption achieved by a prosumer in Manchester for various combinations response probabilities (columns) and magnitude of reduced load (rows). The first one refers to an "Allday" prosumer while the second to an "Evening" type.

Table 42: The estimated self consumption achieved by an "Allday" prosumer in Manchester

response probability for "Allday" prosumer

	plain prosumer (0%)	Prosumer Max 20%	Prosumer Max 40%	Prosumer Max 60%	Prosumer Max 80%
20%	1171	1192	1212	1228	1246
40%	1171	1214	1256	1284	1321
60%	1171	1235	1295	1346	1396
80%	1171	1256	1335	1406	1474

Table 43: The estimated self consumption achieved by an "Evening" prosumer in Manchester

response probability for "Allday" prosumer

	plain prosumer (0%)	Prosumer Max 20%	Prosumer Max 40%	Prosumer Max 60%	Prosumer Max 80%
20%	1171	1174	1177	1179	1179
40%	1171	1178	1184	1188	1189
60%	1171	1181	1190	1196	1201
80%	1171	1185	1196	1205	1210

We observe that a plain prosumer in Manchester (one that does participate in ProsumerMax service) self consumes 34.4% (1171 kWh out of 3401 kWh per year), while an "allday" subscriber to ProsumerMax can achieve increase self-consumption up to 43.3% (1474 kWh per year). Similarly, an "Evening" subscriber can achieve self consumption up to 1210 kWh per year (or 35.6%).

Assuming that energy not self-consumed is injected to the grid following a FeedInTariff the maximum price for the ProsumerMax service would be approximated by:

$$Self - consumption\ increase\ * (retail\ price\ after\ VAT - feed\ in\ tariff)$$

For example, a prosumerMax belonging to the “Allday” type with 60% response rate and 60% shifted load and a margin of 0.08 €/kWh between retail and feed-in-tariff would be willing to pay up to 1346-1171 * 0.08=14 per year.

Finally, the following figures provide an overview of the effect of ProsumerMax on the electricity bill (for retail price before VAT = 0.19, fixed charges 82.11 per year and 14.3 % VAT). We observe that bill reduction can range from 0.46% up to 9.84%).

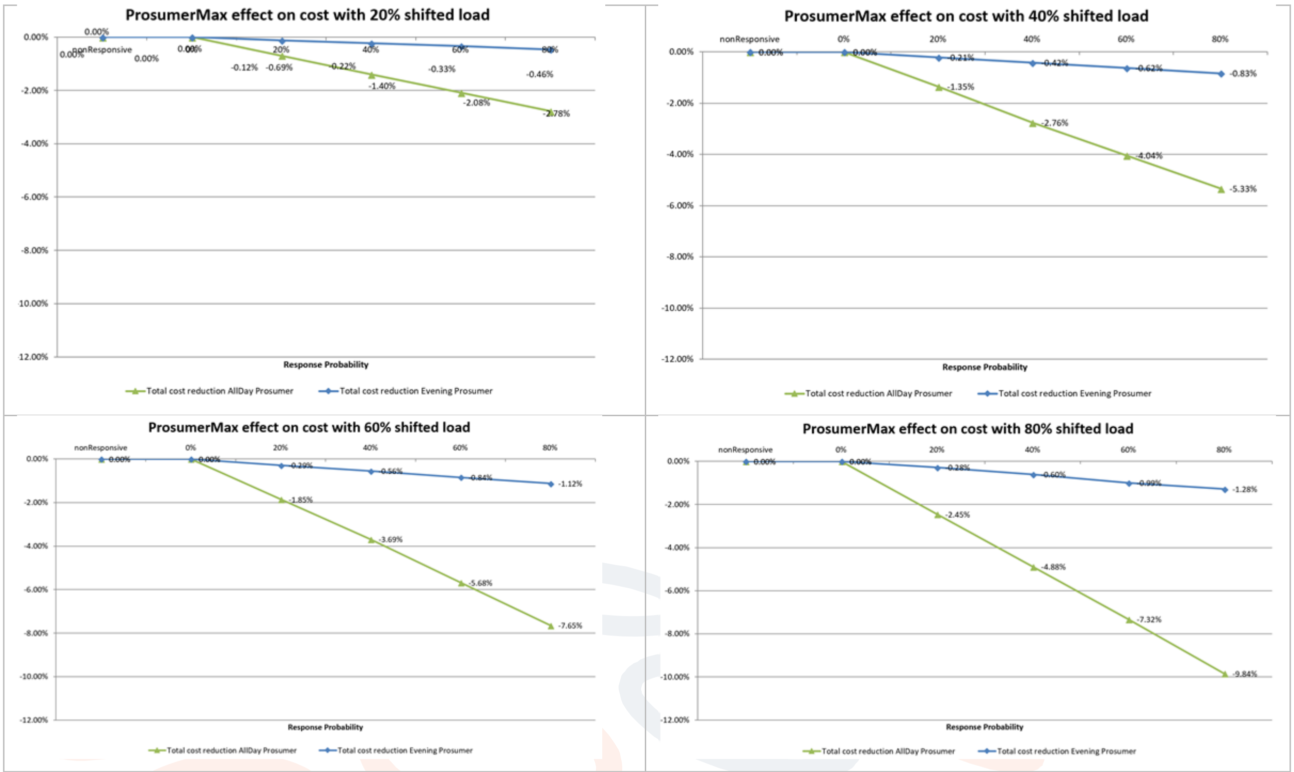


Figure 55: Effect of ProsumerMax on the electricity bill of prosumers for different response rates to recommendations

7 DISCUSSION ON PROPOSED BUSINESS MODELS FOR THE NOBEL GRID PILOT SITES

This section will investigate the expected profitability of the business models, as defined in section 5, the technoeconomic metrics produced from the simulators and according to the assumptions taken for costs and revenues, for each one of the NOBEL GRID PILOT sites. As no data from real-world experiments were used, the purpose is not to screen the unprofitable business models but to raise awareness of possible socioeconomic issues so that the necessary adjustments are made and shed some light on the key factors that will drive adoption of NOBEL GRID products.

This has been accomplished by preparing, for each main role (DSO, Aggregator, Retailer, and Prosumer), a set of business plans and then consider which ones should be adopted based on their profitability on a 20-year period on each pilot site:

- Terni in Italy, where 65000 delivery points are serviced by the local DSO (ASM Terni)
- Valencia in Spain, where 6000 delivery points are serviced by the local DSO (Alginet)
- Greater Manchester in UK (United Kingdom), where 1.2 million delivery points are serviced by a "virtual" local DSO[4].
- Rafina in Greece, where 8870 delivery points are serviced by a "virtual" local DSO (as in the previous case a small part of the Greek DSO; HEDNO)

Flanders in Belgium, where the 43000 customers of the local Gentailer Ecopower (a member of NOBEL GRID consortium) are serviced by a "virtual" DSO.

More details about our methodology and related tool can be found in Section 3 and 4.

7.1 VALENCIA (SPAIN)

The following table provides an overview of the attractiveness of each individual value network to the roles involved for the default evaluation scenario <Moderate EV penetration rate, Moderate PV penetration rate> in Valencia.

Table 44: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Valencia

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.73%	-100.00%	8.15%	-8.78%	-100.00%
GreenEnergyMax	2.10%	-100.00%	9.28%	-9.59%	-100.00%
ProsumerMax	2.10%	-100.00%	9.27%	-9.08%	-100.00%
ElectricHeatAutomation	2.10%	-100.00%	9.28%	-9.09%	-100.00%
GridAssetsMaintenance	5.34%	#N/A	9.28%	-8.34%	-100.00%
GridQuality&Control	5.39%	#N/A	9.28%	-8.34%	-100.00%
IncidentManagement	5.39%	#N/A	9.28%	-8.34%	-100.00%
IncreasedPowerQuality	3.98%	#N/A	9.28%	-8.34%	-100.00%
CoopPowerPlant	3.98%	-100.00%	9.37%	-8.55%	-100.00%
ReduceRPFtoTSO	4.57%	-100.00%	9.25%	-9.02%	-100.00%
CongestionAvoidance	4.78%	-100.00%	9.25%	-6.27%	-100.00%
PowerFactorManagement	5.83%	#N/A	9.25%	-8.43%	-100.00%

[4] The area of Greater Manchester is part of a broader area where the distribution network is operated by Electricity NorthWest. We focus on the area Greater Manchester only, where the NOBEL GRID consortium member CarbonCoop is acting as an ESCO (Energy Services Company).

We observe that the DSO in question and the Retailer are positively affected by the High-level use-cases supported by NOBEL GRID tools and business processes. In fact, the IRR of the DSO increases from 0.73% in the business as usual scenario to up to 5.83% in the case of Power Factor Management. It is noteworthy that the DSO enjoys benefits from Nobel Grid technologies even in those HLUCs that do not require any change in its business processes, such as GreenEnergyMax, ProsumerMax and ElectricHeatAutomation. In those cases the benefits come from the reduced costs for active grid management system (i.e., the G3M) and special equipment for acquiring data from transformation centers, where SMX devices with 3G connectivity are used[5]. In the CoopPowerPlant case, additional cost savings were recognised which are related to penalties (e.g., due to outages) and lower technical network losses. The reason is that end-users that are charged according to a dynamic pricing scheme or respond to DR signals are expected to have a positive impact on the LV/MV grid as well. In the rest High-level use-cases, where the DSO is actively involved, the cost savigns are further increased and include reduced non-technical losses (bad debt) and maintenance savings.

The IRR of the Gentailer is slightly increased from 8.15% to 9.37% in the case of CoopPowerPlant due to its ability to negotiate better contract terms with its BRP, as a result of lower net load peaks (imbalances).

On the other hand, we see that an ESCO acting as an Aggregator would not be viable in Valencia due to the limited number of end-users. This is evidenced also from the fact that even when acting as an ESCO only, the IRR cannot be computed (appears as -100%). Note that the Aggregator is not active at all in HLUCs GridAssetsMaintenance, GridQuality&Control, IncidentManagement and IncreasedPowerQuality and thus the IRR computation was not attempted. Nevertheless, the population limitation is not expected to be a hard constraint as Aggregators do not have to be limited to a single area.

Consumers would not find interest in installing a rooftop PV of 3.6kWp and become prosumers in Valencia even if a feed-in-tariff of 15 €c/kWh was effective. Nevertheless, combining an Electric Vehicle with a PV and a smart home controller (a combination that we name ProsumersADR) would help those prosumers in being almost indifferent from a purely financial point of view. Of course, if one was considering social aspects or the cost savings in terms of fuel compared to a conventional car, then it is very likely that becoming a prosumerADR will be attractive.

Table 45: The effect of NOBEL GRID on the total electricity cost for consumers in Valencia (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	total electricity cost for consumers (present value in € over a 20-year period)		Cost savings on total electricity cost of NOBEL GRID HLUC compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-14,109.54 €	-7,664.81 €	0.00 €	0.00 €
GreenEnergyMax	-14,258.93 €	-7,703.98 €	-149.40 €	-39.17 €
ProsumerMax	-13,969.07 €	-7,703.98 €	140.46 €	N/A
ElectricHeatAutomation	-13,298.93 €	-7,671.92 €	**810.61 €**	N/A
GridAssetsMaintenance	-13,968.53 €	-7,511.61 €	141.01 €	153.20 €
GridQuality&Control	-13,968.53 €	-7,511.61 €	141.01 €	153.20 €
IncidentManagement	-13,968.53 €	-7,511.61 €	141.01 €	153.20 €
IncreasedPowerQuality	-14,066.56 €	-7,511.61 €	42.97 €	153.20 €
CoopPowerPlant	-13,776.70 €	-7,502.29 €	332.83 €	162.52 €
ReduceRPFtoTSO	-14,066.56 €	-7,511.61 €	42.97 €	153.20 €

[5] We have assumed that WiFi smart meters are deployed at customer premises and thus the entity responsible for operating the advanced metering infrastructure do not have to pay the significant costs for connecting the smart meters to the Internet.

CongestionAvoidance	-13,340.64 €	-7,495.70 €	768.90 €	**169.11 €**
PowerFactorManagement	-13,968.53 €	-7,511.61 €	141.01 €	153.20 €

In the table above, we see the total cost of ownership (in present values) for the two types of consumers[6], those with an EV (termed ConsumerADR) and plain consumers (named ConsumerMDR). We see that the costs are reduced in all cases but Green Energy Max (where members are willing to spend some money for receiving recommendations on more sustainable electricity consumption and thus cost savings are less important for them). **Cost savings (inclusive of any revenues from Demand Response campaigns) can be as high as € 810 during the 20-year evaluation period for Consumers with EV (a 6.2% reduction in the case of Electric Heat Automation) and close to € 170 for classic consumers (a 2.4% reduction in the case of Congestion Avoidance).** Note that the ConsumerADR (as well as the ProsumerADR) see increased charges due to the higher loads attributed to EV charging. We should note that a DSO, as a regulated monopoly, would be mandated to either reduce the rates that end-users pay, or return (most of) the profits to the regulatory authority. In the former case, the costs above would be reduced even further.

In order to estimate the actual effect of NOBEL GRID on the consumers we adjusted the energy component of the regulated charge for using distribution network for retail energy by residential consumers (€/kwh) from 0.0169134 (as holds in the BaU scenario) to a new one so that the IRR of the PowerFactorManagement (having the highest IRR amongst the ones enabled by NOBEL GRID) for the DSO will be close to the BaU scenario. Following a trial and error we found that the new regulated rate should be 0.07029 €/kwh. In this case, and as shown in the table below, **the total benefit of consumers with EV from NOBEL GRID becomes €1117 (a reduction of 8.4% compared to the BaU), and €476 for plain consumers (resulting in 3.5% lower electricity bill)**.

Table 46: The effect of NOBEL GRID on the total electricity cost for consumers in Valencia with an adjusted regulated charge for using the distribution network (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	total electricity cost for consumers with adjusted regulated rate (present value in € over a 20-year period)		Cost savings on total electricity cost of NOBEL GRID HLUC compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-13,802.53 €	-7,357.80 €	N/A	N/A
GreenEnergyMax	-13,951.93 €	-7,396.98 €	157.61 €	267.83 €
ProsumerMax	-13,662.07 €	-7,396.98 €	447.47 €	267.83 €
ElectricHeatAutomation	-12,991.92 €	-7,364.91 €	**1,117.62 €**	299.90 €
GridAssetsMaintenance	-13,661.52 €	-7,204.61 €	448.02 €	460.20 €
GridQuality&Control	-13,661.52 €	-7,204.61 €	448.02 €	460.20 €
IncidentManagement	-13,661.52 €	-7,204.61 €	448.02 €	460.20 €
IncreasedPowerQuality	-13,759.56 €	-7,204.61 €	349.98 €	460.20 €
CoopPowerPlant	-13,469.70 €	-7,195.28 €	639.84 €	469.53 €
ReduceRPFtoTSO	-13,759.56 €	-7,204.61 €	349.98 €	460.20 €
CongestionAvoidance	-13,033.63 €	-7,188.69 €	1,075.90 €	**476.12 €**
PowerFactorManagement	-13,661.52 €	-7,204.61 €	448.02 €	460.20 €

In the following set of figures, we see the cumulative cash flow for a DSO in Valencia, deploying a smart grid with the basic functionalities (on the left) and with NOBEL GRID technologies on the right. In the first case

[6] Either residential, commercial or industrial ones

the cumulative cash flow is about 1.2 million Euros, while in the NOBEL GRID case and especially for the incident management High-level Use-case more than 2.1 million Euros are obtained.

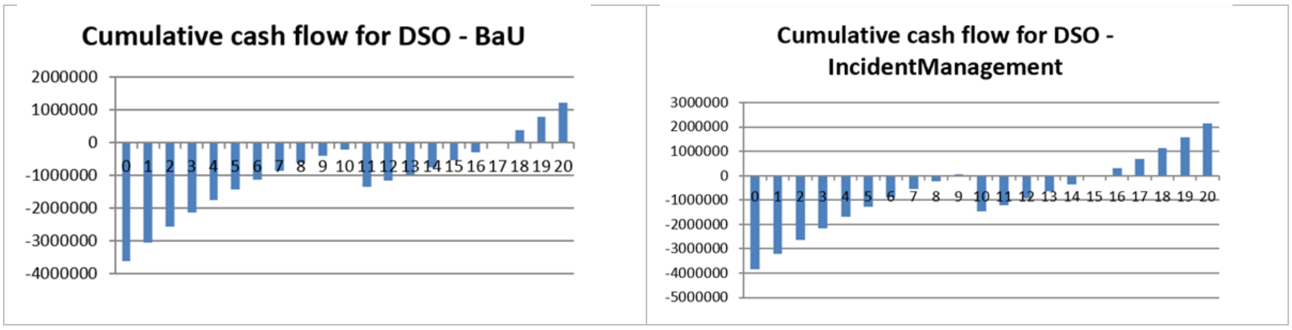


Figure 56: The evolution of cumulative cash flows for a DSO in Valencia (left: Business-as-Usual scenario, right: with NOBEL GRID technologies avoiding outages via Demand Response campaigns)

Furthermore, the payback period for a DSO and a retailer appear in the charts below.

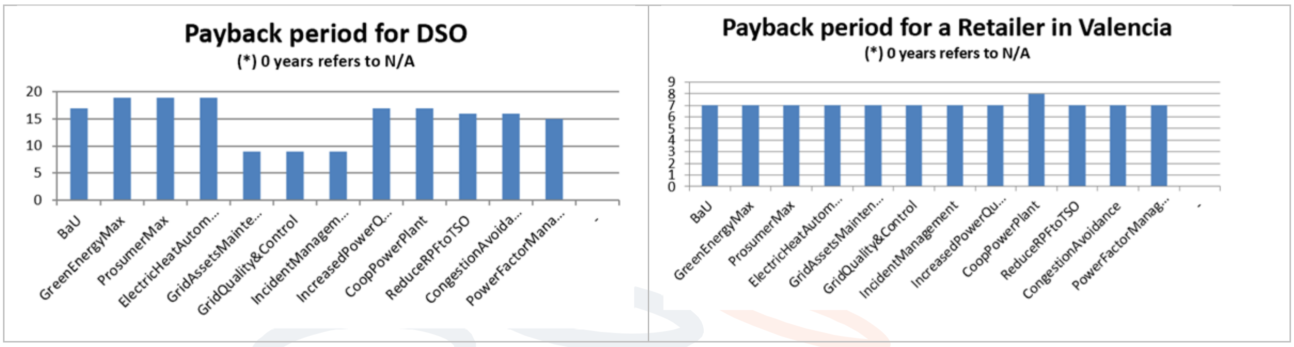


Figure 57: The payback period for a DSO and a retailer in Valencia for different value networks

The following figure presents the cumulative cash flows, in other words operating profits or losses before deduction of any interest and taxes, at the end of the evaluation period (at 20th year) of a Retailer participating in each value network supported by NOBEL GRID in the area of Valencia only. **Such a retailer would increase its operating profits by more than €700,000 in the case of Cooperative Power Plant compared to the Business-as-Usual scenario.**

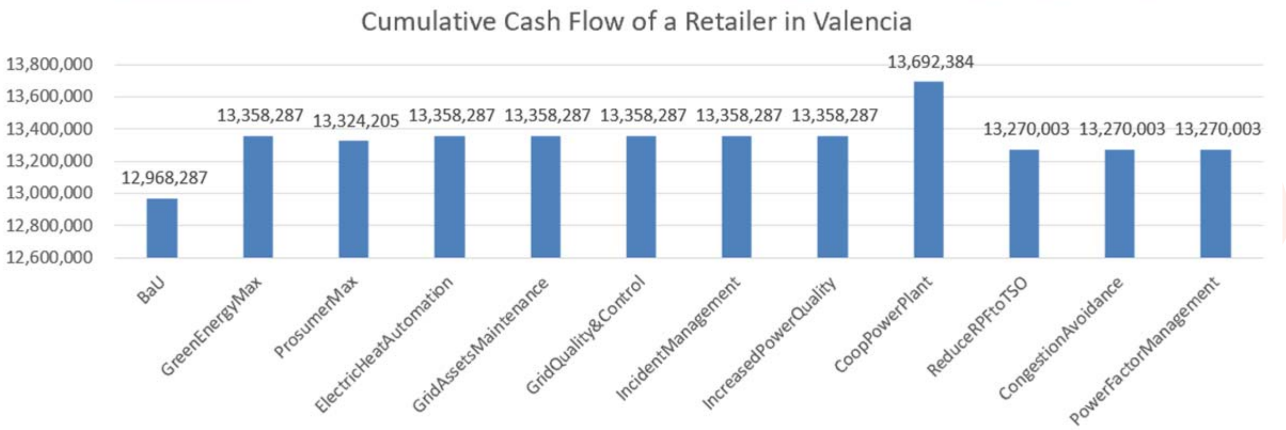


Figure 58: The cumulative cash flow for a Retailer in Valencia in the Business-as-Usual scenario and for the 11 value networks proposed by NOBEL GRID

In the case of a scenario <Moderate EV penetration rate, Low PV penetration rate > similar results are obtained; the main difference being that DSO and Retailer have more revenues as less prosumers means that more energy is bought.

Table 47: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Valencia (Moderate EV penetration rate and Low PV penetration rate case)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	1.20%	-100.00%	8.32%	-8.78%	-100.00%
GreenEnergyMax	2.62%	-100.00%	9.44%	-9.59%	-100.00%
ProsumerMax	2.62%	-100.00%	9.43%	-9.08%	-100.00%
ElectricHeatAutomation	2.62%	-100.00%	9.44%	-9.09%	-100.00%
GridAssetsMaintenance	5.79%	#N/A	9.44%	-8.34%	-100.00%
GridQuality&Control	5.84%	#N/A	9.44%	-8.34%	-100.00%
IncidentManagement	5.84%	#N/A	9.44%	-8.34%	-100.00%
IncreasedPowerQuality	4.45%	#N/A	9.44%	-8.34%	-100.00%
CoopPowerPlant	4.45%	-100.00%	9.51%	-8.55%	-100.00%
ReduceRPFtoTSO	5.03%	-100.00%	9.41%	-9.02%	-100.00%
CongestionAvoidance	5.29%	-100.00%	9.41%	-6.27%	-100.00%
PowerFactorManagement	6.26%	#N/A	9.41%	-8.43%	-100.00%

A more interesting scenario is when High EV penetration rate is combined with Low PV penetration rate. The large number of EVs means high demand for energy, but also that congestion events happen more frequently. In the Congestion Avoidance HLUC, each prosumerADR obtains high rewards for allowing an Aggregator to control the EV charging process without causing any discomfort to the user.

Table 48: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Valencia (High EV penetration rate and Low PV penetration rate case)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	12.03%	-100.00%	11.15%	-8.01%	-100.00%
GreenEnergyMax	14.00%	-100.00%	11.77%	-8.77%	-100.00%
ProsumerMax	14.00%	-100.00%	11.76%	-8.30%	-100.00%
ElectricHeatAutomation	14.00%	-100.00%	11.77%	-8.31%	-100.00%
GridAssetsMaintenance	15.71%	#N/A	11.77%	-7.60%	-100.00%
GridQuality&Control	15.73%	#N/A	11.77%	-7.60%	-100.00%
IncidentManagement	15.73%	#N/A	11.77%	-7.60%	-100.00%
IncreasedPowerQuality	14.92%	#N/A	11.77%	-7.60%	-100.00%
CoopPowerPlant	14.92%	-100.00%	11.07%	-7.82%	-100.00%
ReduceRPFtoTSO	15.23%	-100.00%	11.74%	-8.25%	-100.00%
CongestionAvoidance	4.92%	-100.00%	11.74%	15.57%	-100.00%
PowerFactorManagement	15.95%	-100.00%	11.74%	-7.69%	-100.00%

The Aggregator, however who is assumed to keep 25% of the cost for the flexibility that a DSO pays, is still not profitable. It was found that even when the Aggregator keeps the lion's share, e.g. ,85% of what the DSO pays, this business model would not be profitable for small user portfolios. Furthermore, when a prosumerADR gets 15% of the reward (that is about 226 euros per year) it is no longer profitable. However, there are cases (for example in Flanders with 43600 members) that all participants are profitable.

We should also note that the IRR for the DSO in this case is significantly reduced (4.92% instead of over 12% in the BaU). This means that the DSO (and the society in general) would be probably[7] more efficient if it had invested in new lines whenever EV penetration exceeds 10% (as described in section 6.1).

7.2 TERNI (ITALY)

The following table provides an overview of the attractiveness of each individual value network to the roles involved for the default evaluation scenario <Moderate EV penetration rate, Moderate PV penetration rate> in Terni.

Table 49: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Terni (Italy)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.84%	-2.43%	15.69%	-100.00%	-20.70%
GreenEnergyMax	0.16%	105.63%	15.47%	-100.00%	-20.89%
ProsumerMax	0.16%	131.31%	15.46%	-100.00%	-19.59%
ElectricHeatAutomation	0.16%	92.73%	15.47%	-100.00%	-20.89%
GridAssetsMaintenance	2.77%	#N/A	15.47%	-100.00%	-17.94%
GridQuality&Control	2.82%	#N/A	15.47%	-100.00%	-17.94%
IncidentManagement	2.82%	#N/A	15.47%	-100.00%	-17.94%
IncreasedPowerQuality	2.57%	#N/A	15.47%	-100.00%	-17.94%
CoopPowerPlant	2.57%	18.93%	14.95%	-100.00%	-17.72%
ReduceRPFtoTSO	2.71%	7.63%	15.45%	-100.00%	-17.94%
CongestionAvoidance	4.01%	24.08%	15.45%	-100.00%	-17.69%
PowerFactorManagement	3.09%	#N/A	15.45%	-100.00%	-18.01%

We observe that the DSO in Terni who serves 65000 customers (compared to 6000 in Valencia) will see not only improved technical performance, but also higher economic results in most of the Nobel Grid High-level Use-cases. The only exceptions are the GreenEnergyMax, ProsumerMax and ElectricHeatAutomation value networks where economic performance in terms of IRR is slightly reduced.

Furthermore, the Retailer obtains slightly lower IRR compared to the BaU case, since the number of consumers turning into prosumers grows faster compared to Valencia as the number of prosumers during the first year is higher.

On the other hand, the Aggregator appears to be profitable in most HLUCs, and especially in the GreenEnergyMax, ProsumerMax and ElectricHeatAutomation where IRR exceeds by far 30%. These high profits would encourage more aggregators to appear. But, as soon as a competitor emerges then, assuming that their market shares will converge, both will become unprofitable as the next table suggests.

Table 50: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Terni (Italy) when 2 Aggregators exist

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.84%	-100.00%	15.69%	-100.00%	-20.70%
GreenEnergyMax	0.16%	-100.00%	15.47%	-100.00%	-20.89%
ProsumerMax	0.16%	-100.00%	15.46%	-100.00%	-19.59%
ElectricHeatAutomation	0.16%	-100.00%	15.47%	-100.00%	-20.89%

[7] Remember that we treat each HLUC as a separate business model and thus the benefits are isolated and at the same time most CAPEX are borne.

GridAssetsMaintenance	2.77%	#N/A	15.47%	-100.00%	-17.94%
GridQuality&Control	2.82%	#N/A	15.47%	-100.00%	-17.94%
IncidentManagement	2.82%	#N/A	15.47%	-100.00%	-17.94%
IncreasedPowerQuality	2.57%	#N/A	15.47%	-100.00%	-17.94%
CoopPowerPlant	2.57%	-100.00%	14.95%	-100.00%	-17.72%
ReduceRPFtoTSO	2.71%	-100.00%	15.45%	-100.00%	-17.94%
CongestionAvoidance	4.01%	-100.00%	15.45%	-100.00%	-17.69%
PowerFactorManagement	3.09%	-100.00%	15.45%	-100.00%	-18.01%

With respect to prosumer the outlook is not promising, but we see a different trend compared to Valencia. In Terni, the IRR cannot be computed for the ProsumerADR type while it remains negative for the rest prosumers. The reason for this difference appears to be twofold:

- the slightly higher retail prices in Terni for electricity which render EVs costlier to operate (compare the table below for consumers in Terni to the ones in Valencia) and
- the lower prices for the photovoltaic panel in Terni that render prosumer more attractive.

In the table below, we see the total cost of ownership (in present values) for the two types of consumers, those with an EV (termed ConsumerADR) and ConsumerMDR. As in the case of Valencia, the costs are reduced in all cases but Green Energy Max (where members are willing to spend some money for receiving recommendations on more sustainable electricity consumption and thus cost savings are less important for them). **Cost savings (inclusive of any revenues from Demand Response campaigns) can be as high as € 1000 during the 20-year evaluation period for Consumers with EV (a 7.2% reduction in the case of Electric Heat Automation) and over € 170 for classic consumers (a 2.1% reduction in the case of Congestion Avoidance).** Again a ConsumerADR sees increased charges due to the higher loads attributed to EV charging, while these cost savings will be higher if regulated prices were reduced as a direct effect of improved DSO cost effectiveness.

Table 51: The effect of NOBEL GRID on the total electricity cost for consumers in Terni (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Total electricity cost for consumers (present value in € over a 20-year period)		Effect of NOBEL GRID HLUC on total electricity cost compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-14,762.81 €	-8,308.49 €	0.00 €	0.00 €
GreenEnergyMax	-14,939.59 €	-8,349.36 €	-176.77 €	-40.87 €
ProsumerMax	-14,582.09 €	-8,349.36 €	180.72 €	N/A
ElectricHeatAutomation	-13,763.06 €	-8,317.30 €	**999.75 €**	N/A
GridAssetsMaintenance	-14,668.79 €	-8,156.99 €	94.03 €	151.50 €
GridQuality&Control	-14,668.79 €	-8,156.99 €	94.03 €	151.50 €
IncidentManagement	-14,668.79 €	-8,156.99 €	94.03 €	151.50 €
IncreasedPowerQuality	-14,747.22 €	-8,156.99 €	15.60 €	151.50 €
CoopPowerPlant	-14,389.72 €	-8,148.79 €	373.09 €	159.70 €
ReduceRPFtoTSO	-14,747.22 €	-8,156.99 €	15.60 €	151.50 €
CongestionAvoidance	-13,851.91 €	-8,137.27 €	910.90 €	**171.21 €**
PowerFactorManagement	-14,668.79 €	-8,156.99 €	94.03 €	151.50 €

In the following set of figures, we see the cumulative cash flow for a DSO in Terni, deploying a smart grid with the basic functionalities (on the left) and with NOBEL GRID technologies on the right. In the first case the cumulative cash flow at the end of the evaluation period is just below 10 million Euros, while in the NOBEL GRID case and especially for the incident management High-level Use-case that more than 12 million Euros are obtained.

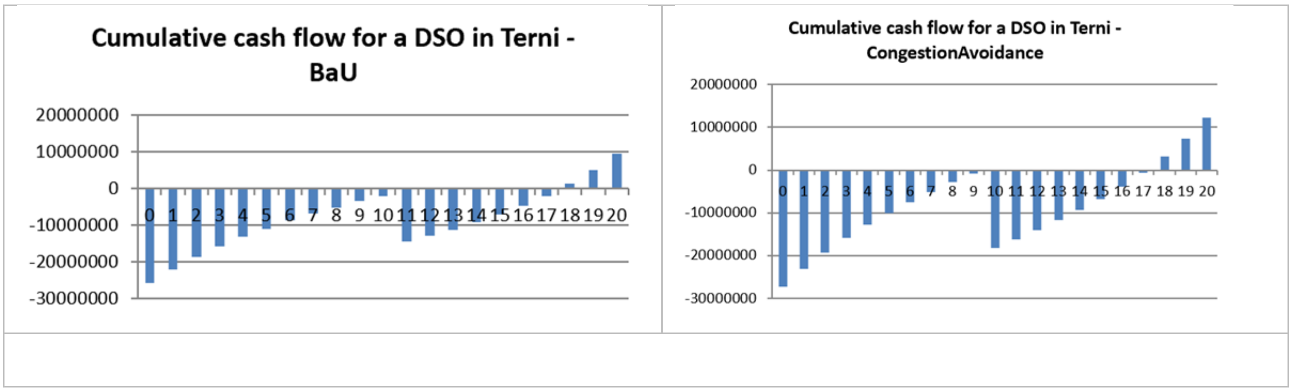


Figure 59: The evolution of cumulative cash flows for a DSO in Terni (left: Business-as-Usual scenario, right: with NOBEL GRID)

Furthermore, the payback period for a DSO and an aggregator appear in the charts below.

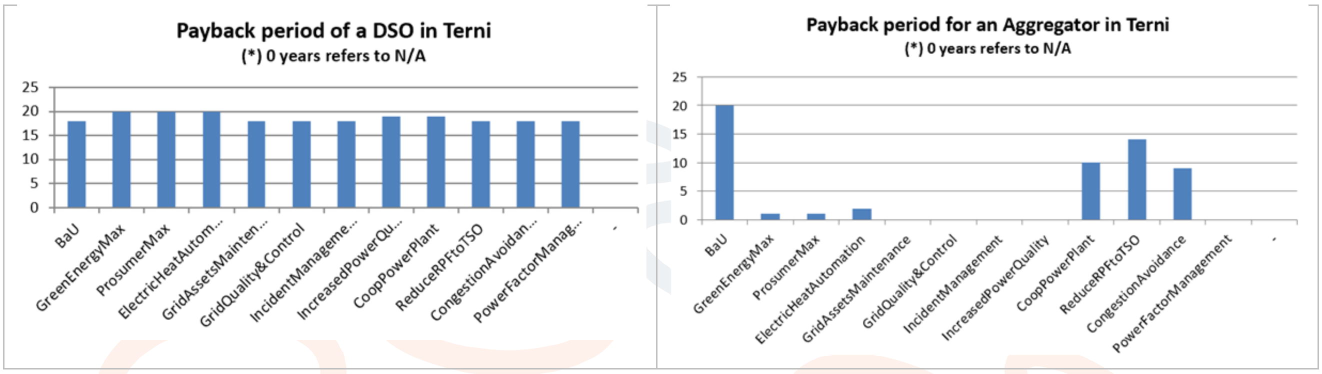


Figure 60: The payback period for a DSO and an Aggregator in Terni for different value networks

The following figure presents the cumulative cash flows, in other words operating profits or losses before deduction of any interest and taxes, at the end of the evaluation period (at 20th year) of an Aggregator participating in each value network supported by NOBEL GRID in the area of Terni only. As expected from the preceding analysis such an Aggregator is marginally profitable in the Business-as-Usual scenario, with operating profits reaching €70,000. On the other hand, being part of NOBEL GRID-enabled value networks brings significant operating profits reaching € 7,375,000 in the case of Congestion Avoidance. The main reason for this x100 increase in operating profits is that the Aggregator can offer its advanced services without having to duplicate the smart metering infrastructure.

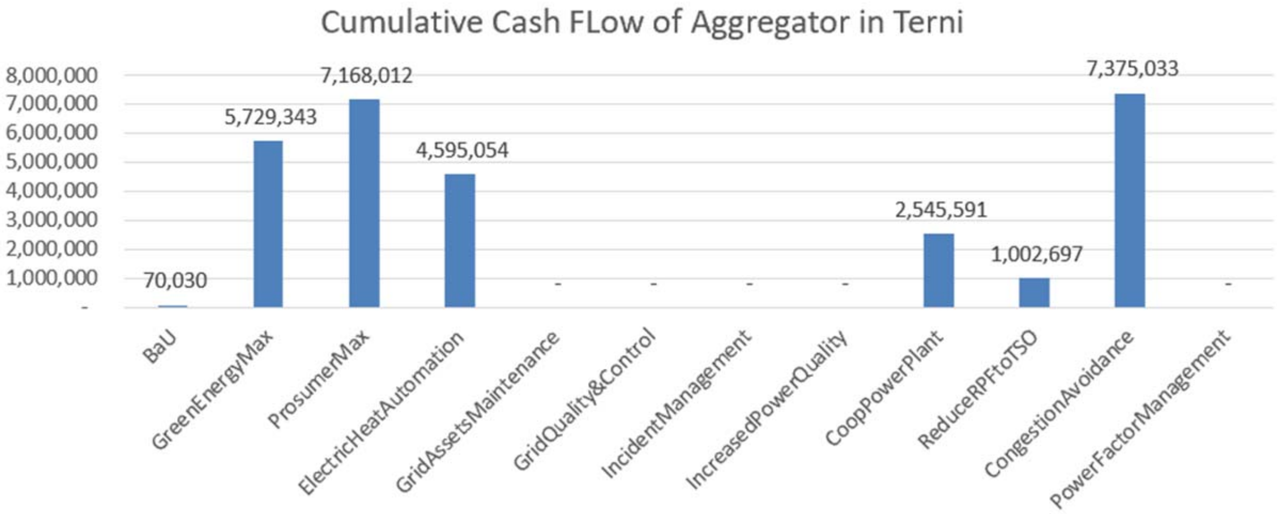


Figure 61: The cumulative cash flow for an Aggregator in Terni in the Business-as-Usual scenario and for the 11 value networks proposed by NOBEL GRID

A similar figure with the cumulative cash flows of a Retailer appears in the figure below. We see that such a Retailer in Terni would be more profitable with NOBEL GRID technologies by at least € 400,000 compared to the Business-as-Usual scenario.

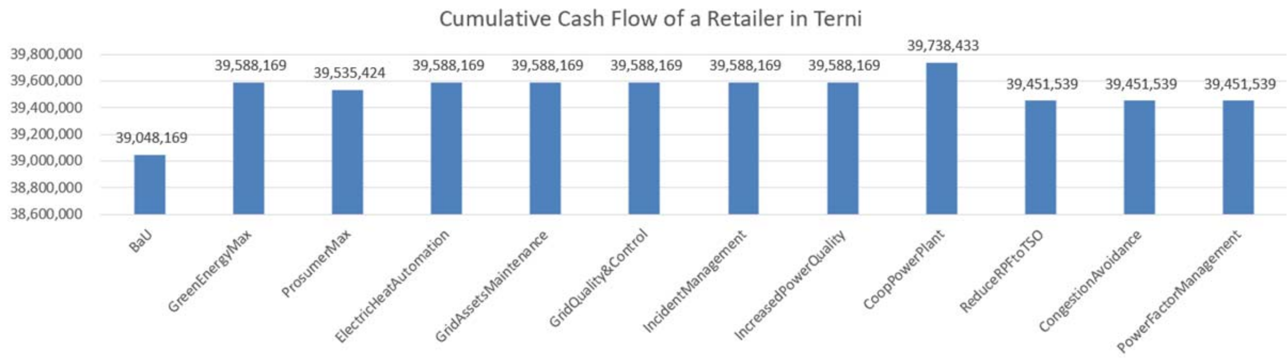


Figure 62: The cumulative cash flow for a Retailer in Terni in the Business-as-Usual scenario and for the 11 value networks proposed by NOBEL GRID

In the case of a scenario <High EV penetration rate, Low PV penetration rate> we see that ProsumerADR are also profitable in case of Congestion Avoidance HLUC. Keep in mind that this behavior appeared in Valencia as well.

Table 52: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Terni (Italy) (High EV penetration rate and Low PV penetration rate case)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	11.44%	-1.54%	17.25%	-100.00%	-20.70%
GreenEnergyMax	11.54%	107.61%	17.13%	-100.00%	-20.89%
ProsumerMax	11.54%	267.78%	17.12%	-100.00%	-19.59%
ElectricHeatAutomation	11.54%	6.00%	17.13%	-100.00%	-20.89%
GridAssetsMaintenance	12.97%	#N/A	17.13%	-100.00%	-17.94%
GridQuality&Control	12.99%	#N/A	17.13%	-100.00%	-17.94%
IncidentManagement	12.99%	#N/A	17.13%	-100.00%	-17.94%

IncreasedPowerQuality	12.80%	#N/A	17.13%	-100.00%	-17.94%
CoopPowerPlant	12.80%	113.02%	17.01%	-100.00%	-17.72%
ReduceRPFtoTSO	12.88%	7.63%	17.10%	-100.00%	-17.94%
CongestionAvoidance	**13.06%**	99.56%	17.10%	11.64%	-17.69%
PowerFactorManagement	13.14%	#N/A	17.10%	-100.00%	-18.01%

However, the Aggregator is found to be profitable in all value networks suported by NOBEL GRID. This is in contrast to Valencia where the population size is significantly less (65000 in Terni compared to 6000 in Valencia). Furthermore, and most importantly, the Congestion avoidance is an all-win situation, as the DSO has incentive to delay the investment in a new line with a capacity that will almost eliminate congestion events and thus outages due to high demand. So far, when computing the IRR in the BaU scenario we had assumed that the line upgrade takes place at Year 0. **If the capacity upgrade takes place at Y20 and the inflation rate was 2% then the IRR of that DSO will be 12.54% (instead of 11.44%[8]), which is still lower than the 13.06% IRR obtained with NOBEL GRID technologies. Thus, the capacity upgrade would be avoided at all.**

7.3 MANCHESTER (UK)

The following table provides an overview of the attractiveness of each individual value network to the roles involved for the default evaluation scenario <Moderate EV penetration rate, Moderate PV penetration rate> in Manchester.

We observe that all entities, apart from consumers that examine the financial attractiveness of becoming prosumers, see improved economic performance with NOBEL GRID-enabled HLUCs. We should highlight the fact that Retailers in UK are responsible for deploying the smart meters, not the DSOs. Furthermore, about 90 retailers were found to be serving 1.2 million customers in greater Manchester area (compared to 7 in Terni, 5 in Flanders and 1 in the rest places).

Table 53: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Manchester (UK)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.37%	-4.26%	5.06%	-100.00%	-100.00%
GreenEnergyMax	1.49%	62.13%	5.86%	-100.00%	-100.00%
ProsumerMax	1.49%	83.72%	5.85%	-100.00%	-100.00%
ElectricHeatAutomation	1.49%	51.00%	5.86%	-100.00%	-100.00%
GridAssetsMaintenance	3.27%	#N/A	5.86%	-100.00%	-100.00%
GridQuality&Control	3.30%	#N/A	5.86%	-100.00%	-100.00%
IncidentManagement	3.30%	#N/A	5.86%	-100.00%	-100.00%
IncreasedPowerQuality	2.84%	#N/A	5.86%	-100.00%	-100.00%
CoopPowerPlant	2.84%	7.39%	6.23%	-100.00%	-100.00%
ReduceRPFtoTSO	2.92%	-3.24%	5.82%	-100.00%	-100.00%
CongestionAvoidance	3.71%	16.33%	5.82%	-100.00%	-100.00%
PowerFactorManagement	3.13%	#N/A	5.82%	-100.00%	-100.00%

[8] IRR takes into account the present value of all cash flows, thus a non-negative inflation rate (in this case 2%) results in delayed capacity upgrades being more favourable.

In the table below, we see the total cost of ownership (in present values) for the two types of consumers, those with an EV (termed ConsumerADR) and ConsumerMDR. The costs are reduced in most cases except from Green Energy Max (where members are willing to spend some money for receiving recommendations on more sustainable electricity consumption and thus cost savings are less important for them), IncreasedPowerQuality and ReduceRPFtoTSO. **Cost savings (inclusive of any revenues from Demand Response campaigns) can be more than € 1300 during the 20-year evaluation period for Consumers with EV (a 9.7% reduction in the case of Electric Heat Automation) and over € 170 for classic consumers (a 2.3% reduction in the case of Congestion Avoidance).** Again a ConsumerADR is faced with a higher electricity compared to the plain comuser as a direct consequence of owning an EV, while these cost savings will be even higher if regulated prices were reduced (due to improved DSO cost effectiveness from using NOBEL GRID outputs).

Table 54: The effect of NOBEL GRID on the total electricity cost for consumers in Manchester (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	total electricity cost for consumers (present value in € over a 20-year period)		Effect of NOBEL GRID HLUC on total electricity cost compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-13,597.01 €	-7,528.56 €	0.00 €	0.00 €
GreenEnergyMax	-13,820.72 €	-7,572.26 €	-223.71 €	-43.70 €
ProsumerMax	-13,347.28 €	-7,572.26 €	249.73 €	N/A
ElectricHeatAutomation	-12,273.01 €	-7,540.20 €	**1,324.00 €**	N/A
GridAssetsMaintenance	-13,530.31 €	-7,379.89 €	66.70 €	148.67 €
GridQuality&Control	-13,530.31 €	-7,379.89 €	66.70 €	148.67 €
IncidentManagement	-13,530.31 €	-7,379.89 €	66.70 €	148.67 €
IncreasedPowerQuality	-13,628.35 €	-7,379.89 €	-31.34 €	148.67 €
CoopPowerPlant	-13,154.91 €	-7,379.42 €	442.10 €	149.14 €
ReduceRPFtoTSO	-13,628.35 €	-7,379.89 €	-31.34 €	148.67 €
CongestionAvoidance	-12,442.68 €	-7,353.84 €	1,154.34 €	**174.72 €**
PowerFactorManagement	-13,530.31 €	-7,379.89 €	66.70 €	148.67 €

In order to estimate the actual effect of NOBEL GRID on the consumers we adjusted the energy component of the regulated charge for using distribution network for retail energy by residential consumers (€/kwh) from 0.0319 (as holds in the BaU scenario) to a new one so that the IRR of the Congestion Avoidance (having the highest IRR amongst the ones enabled by NOBEL GRID) for the DSO will be close to the BaU scenario. Following a trial and error we found that the new regulated rate should be 0.026 €/kwh. In this case, and as shown in the table below, **the total benefit of consumers with EV from NOBEL GRID becomes €1586 (a reduction of 11.6% compared to the BaU), and €437 for plain consumers (resulting in 5.9% lower electricity bill)**.

Table 55: The effect of NOBEL GRID on the total electricity cost for consumers in Manchester with an adjusted regulated charge for using the distribution network (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Total electricity cost for consumers with adjusted regulated rate (present value in € over a 20-year period)		Cost savings on total electricity cost of NOBEL GRID HLUC with adjusted regulated rate compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-13,334.31 €	-7,265.85 €	N/A	N/A
GreenEnergyMax	-13,558.01 €	-7,309.55 €	39.00 €	219.00 €

ProsumerMax	-13,084.57 €	-7,309.55 €	512.44 €	219.00 €
ElectricHeatAutomation	-12,010.31 €	-7,277.49 €	**1,586.70 €**	251.07 €
GridAssetsMaintenance	-13,267.61 €	-7,117.18 €	329.41 €	411.37 €
GridQuality&Control	-13,267.61 €	-7,117.18 €	329.41 €	411.37 €
IncidentManagement	-13,267.61 €	-7,117.18 €	329.41 €	411.37 €
IncreasedPowerQuality	-13,365.64 €	-7,117.18 €	231.37 €	411.37 €
CoopPowerPlant	-12,892.20 €	-7,116.71 €	704.81 €	411.84 €
ReduceRPFtoTSO	-13,365.64 €	-7,117.18 €	231.37 €	411.37 €
CongestionAvoidance	-12,179.97 €	-7,091.14 €	1,417.04 €	**437.42 €**
PowerFactorManagement	-13,267.61 €	-7,117.18 €	329.41 €	411.37 €

The following figure presents the cumulative cash flows, in other words operating profits or losses before deduction of any interest and taxes, at the end of the evaluation period (at 20th year) of an Aggregator participating in each value network supported by NOBEL GRID in the area of Greater Manchester only. **We see that such an Aggregator is generating losses in the Business-as-Usual scenario, while on the other hand, being part of NOBEL GRID-enabled value networks brings significant operating profits reaching € 7,136,000 in the case of Congestion Avoidance.** As in the case of Terni, the main reason for this change is that the Aggregator can offer its advanced services without having to duplicate the smart metering infrastructure.

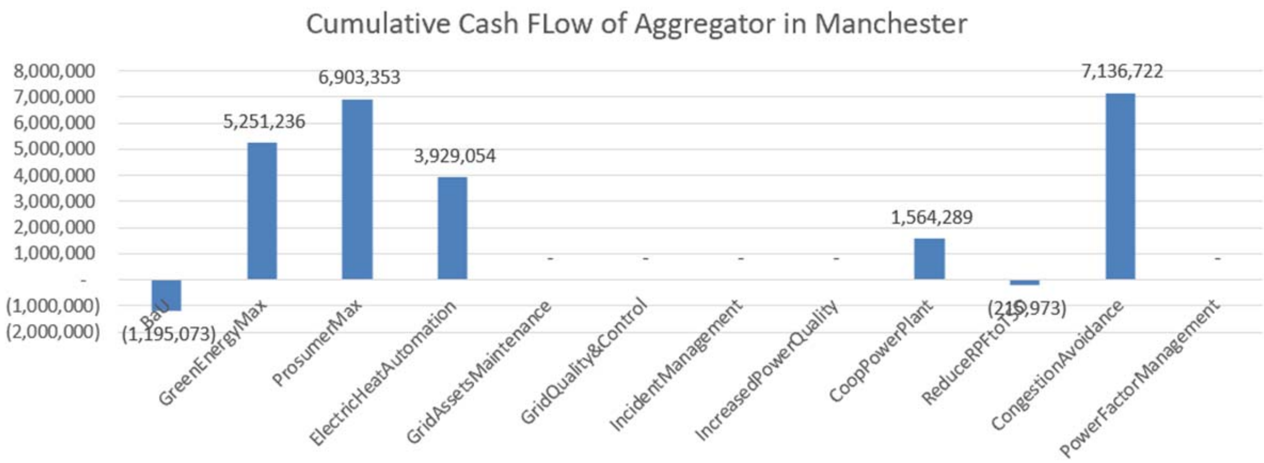


Figure 63: The cumulative cash flow for an Aggregator in Greater Manchester area in the Business-as-Usual scenario and for the 11 value networks proposed by NOBEL GRID

The following table compares the cumulative cash flows of a Retailer in Manchester following the Business-As-Usual scenario and the Cooperative Power Plant scenario using NOBEL GRID. **We see that, at the end of the evaluation period, each one of those Retailers in Manchester would be more profitable with NOBEL GRID technologies by as much as € 450,000 compared to the Business-as-Usual scenario.**

Table 56: A comparison of the cumulative cash flows of a Retailer in Manchester following the Business-As-Usual scenario and the Cooperative Power Plant scenario using NOBEL GRID

BaU	22,254,453
CoopPowerPlant	22,702,534

A graphical representation of those effects of NOBEL GRID on retailers appears in the figures below.

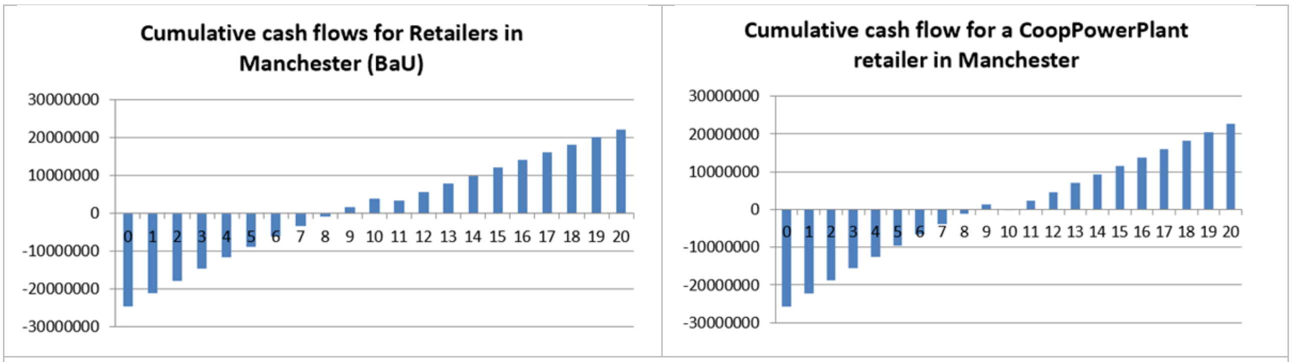


Figure 64: The evolution of cumulative cash flows for a Retailer in Manchester (left: Business-as-Usual scenario, right: with NOBEL GRID)

However, the most important effects of NOBEL GRID are across the entire value chain[9]. Perhaps the most interesting finding is that Aggregators are now profitable in all service offerings, as suggested by the respective HLUCs, but ReduceReversePowerFlowsToTSO that as was described in section 6.1 would require extremely high PV market share. This is of high importance as the BaU scenario was found not to be attractive due to the need for Aggregators to install additional smart meters at the premises of their members only (not all delivery points) to be able to support DR campaigns. This effect is shown in the figures below. On the left hand side, we see that the cumulative cash flow of an Aggregator in case of traditional smart grid technologies were selected is consistently negative, while, on the right where NOBEL GRID technologies are involved, it turns positive in less than 10 years and then grows fast so that a satisfactory return is achieved.

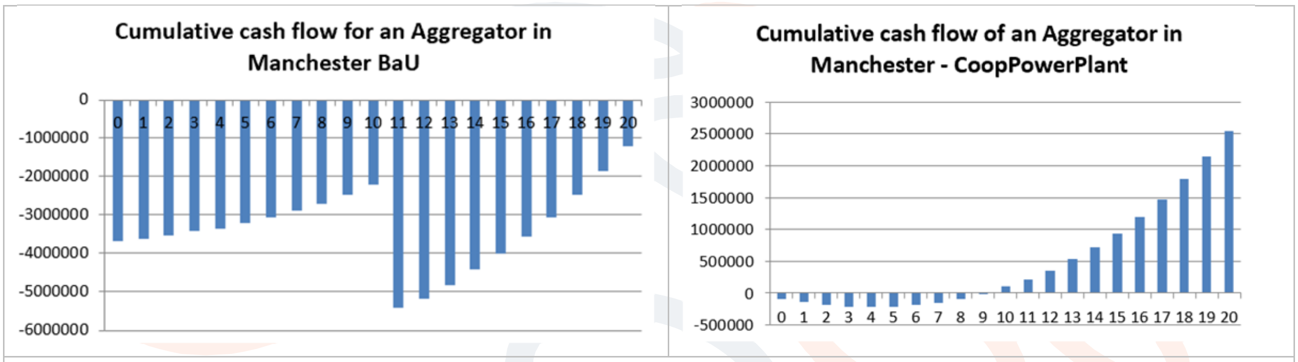


Figure 65: The evolution of cumulative cash flows for an Aggregator in Greater Manchester area (left: Business-as-Usual scenario, right: with NOBEL GRID)

7.4 FLANDERS (BELGIUM)

The following table provides an overview of the attractiveness of each individual value network to the roles involved for the default evaluation scenario <Moderate EV penetration rate, Moderate PV penetration rate> in Flanders. We see that DSOs, Retailers and ProsumersADR are profitable both not only in the BaU scenario, but also with the specific NOBEL GRID-enablens functionalities run by the actors. What is interesting in the case of Flanders is that due to the net metering regime, becoming a ProsumerADR is attractive[10]. This is true despite the non-viability of the Aggregator business model examined, since in

[9] Such aspects are analysed in detail in D19.2

[10] The GreenEnergyMax service is not expected to be popular amongst prosumer anyway, as it targets eco-friendly consumers.

HLUCs GridAssetsMaintenance, GridQuality&Control, IncidentManagement, IncreasedPowerQuality prosumers are not directly involved.

Table 57: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in (part of) Flanders (Belgium)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	6.76%	-100.00%	13.32%	0.48%	-100.00%
GreenEnergyMax	19.82%	-100.00%	13.68%	-0.06%	-100.00%
ProsumerMax	19.82%	-100.00%	13.67%	0.28%	-100.00%
ElectricHeatAutomation	19.82%	-100.00%	13.68%	0.20%	-100.00%
GridAssetsMaintenance	20.73%	#N/A	13.68%	0.83%	-100.00%
GridQuality&Control	20.79%	#N/A	13.68%	0.83%	-100.00%
IncidentManagement	20.79%	#N/A	13.68%	0.83%	-100.00%
IncreasedPowerQuality	20.26%	#N/A	13.68%	0.83%	-100.00%
CoopPowerPlant	20.26%	-100.00%	13.33%	0.49%	-100.00%
ReduceRPFtoTSO	20.48%	-100.00%	13.65%	0.23%	-100.00%
CongestionAvoidance	26.07%	-15.38%	13.65%	1.84%	-100.00%
PowerFactorManagement	21.08%	#N/A	13.65%	0.70%	-100.00%

In the table below, we see the total cost of ownership (in present values) for the two types of consumers, those with an EV (termed ConsumerADR) and ConsumerMDR. The costs are reduced in all cases except from Green Energy Max (where members are willing to spend some money for receiving recommendations on more sustainable electricity consumption and thus cost savings are less important for them). **Cost savings (inclusive of any revenues from Demand Response campaigns) reach € 586 during the 20-year evaluation period for Consumers with EV (a 3.5% reduction in the case of Electric Heat Automation) and over € 392 for classic consumers (a 3% reduction in the case of Congestion Avoidance).**

Table 58: The effect of NOBEL GRID on the total electricity cost for consumers in Flanders (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	total electricity cost for consumers (present value in € over a 20-year period)		Effect of NOBEL GRID HLUC on total electricity cost compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-17,080.33 €	-13,217.52 €	0.00 €	0.00 €
GreenEnergyMax	-17,194.52 €	-13,028.80 €	-114.20 €	188.72 €
ProsumerMax	-16,991.62 €	-13,028.80 €	88.71 €	188.72 €
ElectricHeatAutomation	-16,512.90 €	-12,996.74 €	567.43 €	220.78 €
GridAssetsMaintenance	-16,904.11 €	-12,836.43 €	176.21 €	381.09 €
GridQuality&Control	-16,904.11 €	-12,836.43 €	176.21 €	381.09 €
IncidentManagement	-16,904.11 €	-12,836.43 €	176.21 €	381.09 €
IncreasedPowerQuality	-17,002.15 €	-12,836.43 €	78.17 €	381.09 €
CoopPowerPlant	-16,799.25 €	-12,848.74 €	281.08 €	368.78 €
ReduceRPFtoTSO	-17,002.15 €	-12,836.43 €	78.17 €	381.09 €
CongestionAvoidance	-16,494.01 €	-12,825.22 €	**586.32 €**	**392.31 €**
PowerFactorManagement	-16,904.11 €	-12,836.43 €	176.21 €	381.09 €

Again the cost savings above will be even higher if regulated prices were reduced (due to improved DSO cost effectiveness from using NOBEL GRID outputs). As in the previous cases we adjusted the energy component of the regulated charge for using distribution network for retail energy by residential consumers (€/kwh) from 0.1266 (as holds in the BaU scenario) to a new one so that the IRR of the Congestion Avoidance (having the highest IRR amongst the ones enabled by NOBEL GRID) for the DSO will be close to the BaU scenario. Following a trial and error we found that the new regulated rate should be 0.1206 €/kwh. In this case, and as shown in the table below, **the total benefit of consumers with EV from NOBEL GRID becomes €851 (a reduction of 5.15% compared to the BaU), and €657 for plain consumers (resulting in 5.12% lower electricity bill)**.

Table 59: The effect of NOBEL GRID on the total electricity cost for consumers in Manchester with an adjusted regulated charge for using the distribution network (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Total electricity cost for consumers with adjusted regulated rate (present value in € over a 20-year period)		Cost savings on total electricity cost of NOBEL GRID HLUC with adjusted regulated rate compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-16,815.66 €	-12,952.04 €	N/A	N/A
GreenEnergyMax	-16,929.86 €	-12,764.14 €	150.47 €	453.39 €
ProsumerMax	-16,726.96 €	-12,764.14 €	353.37 €	453.39 €
ElectricHeatAutomation	-16,248.23 €	-12,732.07 €	832.09 €	485.45 €
GridAssetsMaintenance	-16,639.45 €	-12,571.77 €	440.88 €	645.76 €
GridQuality&Control	-16,639.45 €	-12,571.77 €	440.88 €	645.76 €
IncidentManagement	-16,639.45 €	-12,571.77 €	440.88 €	645.76 €
IncreasedPowerQuality	-16,737.49 €	-12,571.77 €	342.84 €	645.76 €
CoopPowerPlant	-16,534.59 €	-12,584.08 €	545.74 €	633.44 €
ReduceRPFtoTSO	-16,737.49 €	-12,571.77 €	342.84 €	645.76 €
CongestionAvoidance	-16,229.34 €	-12,560.55 €	**850.98 €**	**656.97 €**
PowerFactorManagement	-16,639.45 €	-12,571.77 €	440.88 €	645.76 €

The cumulative cash flow for the ProsumerADR type in BaU and the payback period across all cases is shown below, confirming that the investment is recovered before the end of the evaluation period (20 years).

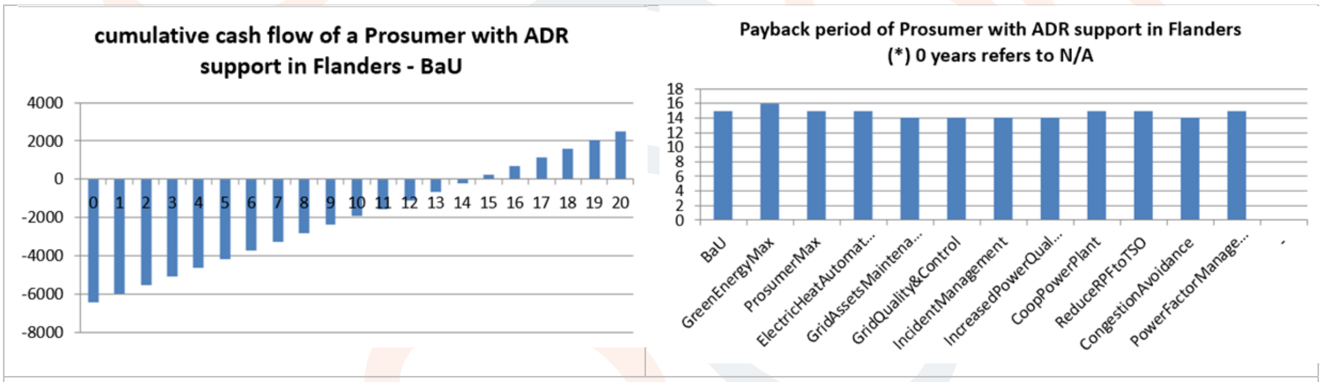


Figure 66: Profitability metrics for Prosumer with ADR support in Flanders (left: the evolution of cumulative cash flows in the Business-as-Usual case, right: the payback period before and after NOBEL GRID)

The following figure presents the operating profits or losses before deduction of any interest and taxes at the end of the evaluation period (at 20th year) of a ProsumerADR in Flanders with an EV, whose charging is remotely controlled by an Aggregator, in each value network supported by NOBEL GRID. **We see that even**

though a Prosumer in Flanders with an EV, whose charging is remotely controlled by an Aggregator, is generating profits in the Business-as-Usual scenario but NOBEL GRID can increase the attractiveness of her investments by up to € 1,000 over a 20-year period in the case of Congestion Avoidance. Furthermore, the net metering regime in Flanders results in an non-attractive ProsumerMax service.

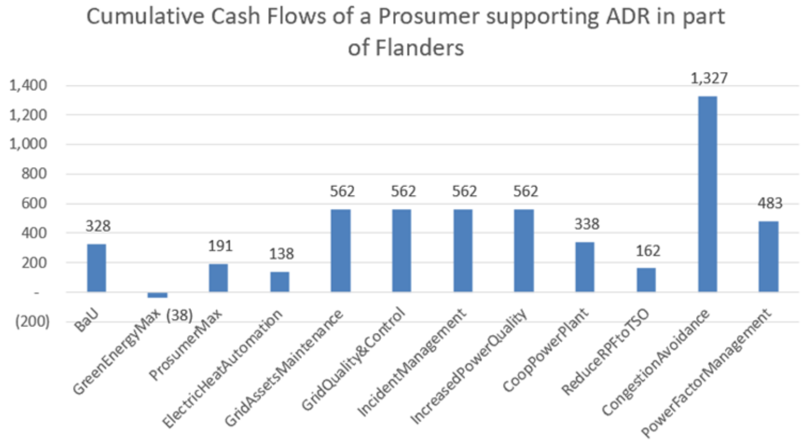


Figure 67: The evolution of cumulative cash flows for a Prosumer in (part of) Flanders in the Business-as-Usual scenario and for the 11 value entworks proposed by NOBEL GRID

The IRR of the roles in Flanders for the <High EV penetration rate, Moderate PV penetration rate> shows that the Aggregator would be profitable by offering flexibility to DSOs for avoiding congestion issues that can lead to outages. Furthermore, all participants have the incentive to participate without any need for side-payments.

Table 60: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in part of Flanders (Belgium) (High EV penetration rate and Moderate PV penetration rate case)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	22.01%	-100.00%	15.30%	0.48%	-100.00%
GreenEnergyMax	28.73%	-100.00%	15.50%	-0.06%	-100.00%
ProsumerMax	28.73%	-3.54%	15.49%	0.28%	-100.00%
ElectricHeatAutomation	28.73%	-100.00%	15.50%	0.20%	-100.00%
GridAssetsMaintenance	29.28%	#N/A	15.50%	0.83%	-100.00%
GridQuality&Control	29.31%	#N/A	15.50%	0.83%	-100.00%
IncidentManagement	29.31%	#N/A	15.50%	0.83%	-100.00%
IncreasedPowerQuality	28.95%	#N/A	15.50%	0.83%	-100.00%
CoopPowerPlant	28.95%	-100.00%	15.13%	0.49%	-100.00%
ReduceRPFtoTSO	29.07%	-100.00%	15.47%	0.23%	-100.00%
CongestionAvoidance	**30.78%**	19.03%	15.47%	21.79%	-100.00%
PowerFactorManagement	29.46%	#N/A	15.47%	0.70%	-100.00%

7.5 RAFINA / MELTEMI (GREECE)

The following table provides an overview of the attractiveness of each individual value network to the roles involved for the default evaluation scenario <Moderate EV penetration rate, Moderate PV penetration

rate> in the broader area of Meltemi, Rafina, where about 8800 delivery points exist. We observe that there are many similarities with Valencia, where 6000 customers exist, and solar irradiation is a little bit lower.

This meant that the DSO in question and the Retailer are positively affected by the High-level use-cases supported by NOBEL GRID tools and business processes, while the Aggregator are negatively affected by the small pool size of members (30% of the delivery points are assumed to be part of the latter's portfolio). We should note that we have assumed a 225% increase on the regulated charges of the DSO compared to existing ones, in order to recover the cost of the smart meter roll-out in all HLUCs. This is justified however as smart meters' deployment for residential customers hasn't started yet. Furthermore, Prosumers under a feed-in-tariff of 0.15 €c/kWh are not profitable on their own, while any additional revenues from flexibility offered (especially in Congestion Avoidance HLUC) was deemed not high enough to have a payback before the end of the 20-year evaluation period.

Table 61: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Rafina (including Meltemi, Greece)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	0.99%	-100.00%	3.06%	-4.31%	-9.54%
GreenEnergyMax	4.08%	-100.00%	4.64%	-4.84%	-9.57%
ProsumerMax	4.08%	-100.00%	4.62%	-4.47%	-9.30%
ElectricHeatAutomation	4.08%	-100.00%	4.64%	-4.52%	-9.57%
GridAssetsMaintenance	6.86%	#N/A	4.64%	-4.02%	-8.98%
GridQuality&Control	7.04%	#N/A	4.64%	-4.02%	-8.98%
IncidentManagement	7.04%	#N/A	4.64%	-4.02%	-8.98%
IncreasedPowerQuality	5.82%	#N/A	4.64%	-4.02%	-8.98%
CoopPowerPlant	5.82%	-100.00%	4.40%	-4.16%	-8.92%
ReduceRPFtoTSO	6.56%	-100.00%	4.59%	-4.47%	-8.98%
CongestionAvoidance	7.19%	-100.00%	4.59%	-2.55%	-8.91%
PowerFactorManagement	7.02%	#N/A	4.59%	-4.12%	-9.06%

The following figure presents the cumulative cash flows, in other words operating profits or losses before deduction of any interest and taxes, at the end of the evaluation period (at 20th year) of a Retailer participating in each value network supported by NOBEL GRID in the area of Rafina (Greece) only. **Such a retailer would increase its operating profits in all cases supported NOBEL GRID compared to the Business-as-Usual scenario, with the positive effect ranging from €300,000 up to €1,500,000 in the case of Cooperative Power Plant.**

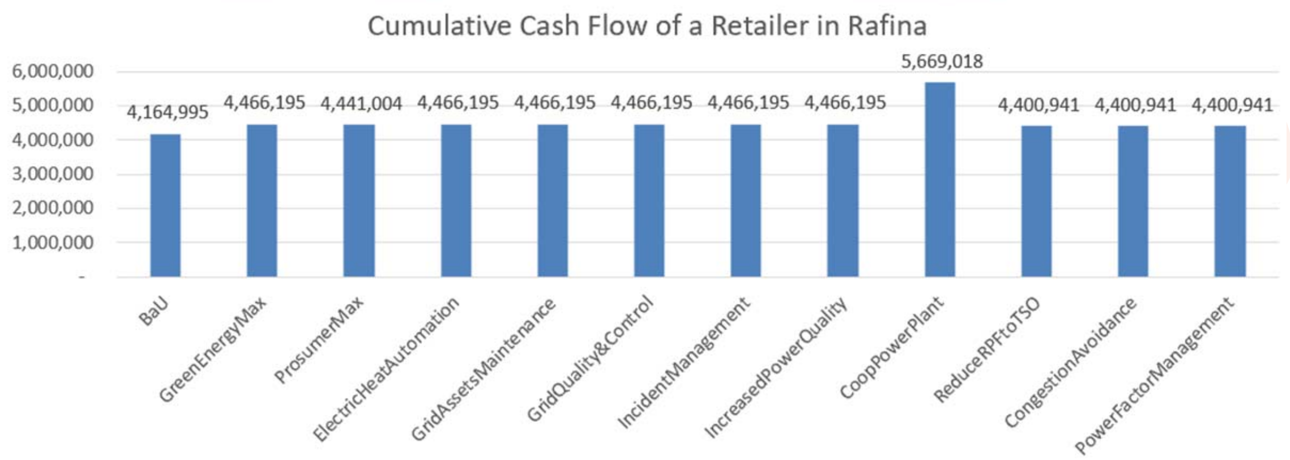


Figure 68: The cumulative cash flow for a Retailer in Rafina (including Meltemi) in the Business-as-Usual scenario and for the 11 value networks proposed by NOBEL GRID

In the table below, we see the total cost of ownership (in present values) for the two types of consumers, those with an EV (termed ConsumerADR) and ConsumerMDR. As in most pilot sites examined the costs are reduced in all cases except from Green Energy Max. At the same time the total electricity cost for a residential consumer in that area is slightly higher than Valencia and Terni, which is attributed to the increased regulated charges. **Cost savings (inclusive of any revenues from Demand Response campaigns) reach € 566 during the 20-year evaluation period for Consumers with EV (a 3.3% reduction in the case of Congestion Avoidance) and over € 166 for classic consumers (a 1.6% reduction in the case of Congestion Avoidance).**

Table 62: The effect of NOBEL GRID on the total electricity cost for consumers in Flanders (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	total electricity cost for consumers (present value in € over a 20-year period)		Effect of NOBEL GRID HLUC on total electricity cost compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-17,700.30 €	-10,533.45 €	0.00 €	0.00 €
GreenEnergyMax	-17,810.58 €	-10,570.28 €	-110.28 €	-36.83 €
ProsumerMax	-17,617.34 €	-10,570.28 €	82.96 €	-36.83 €
ElectricHeatAutomation	-17,159.89 €	-10,538.21 €	540.41 €	-4.77 €
GridAssetsMaintenance	-17,510.37 €	-10,377.91 €	189.93 €	155.54 €
GridQuality&Control	-17,510.37 €	-10,377.91 €	189.93 €	155.54 €
IncidentManagement	-17,510.37 €	-10,377.91 €	189.93 €	155.54 €
IncreasedPowerQuality	-17,618.21 €	-10,377.91 €	82.09 €	155.54 €
CoopPowerPlant	-17,424.97 €	-10,377.50 €	275.33 €	155.94 €
ReduceRPFtoTSO	-17,618.21 €	-10,377.91 €	82.09 €	155.54 €
CongestionAvoidance	-17,134.26 €	-10,367.23 €	**566.03 €**	**166.21 €**
PowerFactorManagement	-17,510.37 €	-10,377.91 €	189.93 €	155.54 €

Again the cost savings above will be even higher if regulated prices were reduced (due to improved DSO cost effectiveness from using NOBEL GRID outputs). As in the previous cases we adjusted the energy component of the regulated charge for using distribution network for retail energy by residential consumers (€/kwh) from 0.1266 (as holds in the BaU scenario) to a new one so that the IRR of the Congestion Avoidance (having the highest IRR amongst the ones enabled by NOBEL GRID) for the DSO will be close to the BaU scenario. Following a trial and error we found that the new regulated rate should be 0.1206 €/kwh. In this case, and as shown in the table below, **the total benefit of consumers with EV from NOBEL GRID becomes €862 (a reduction of 5% compared to the BaU), and €463 for plain consumers (resulting in 4.4% lower electricity bill)**.

Table 63: The effect of NOBEL GRID on the total electricity cost for consumers in Manchester with an adjusted regulated charge for using the distribution network (present value in € over a 20-year period; highlighted values refer to the maximum positive effect)

	Total electricity cost for consumers with adjusted regulated rate (present value in € over a 20-year period)		Cost savings on total electricity cost of NOBEL GRID HLUC with adjusted regulated rate compared to BaU (in € over a 20-year period)	
	ConsumerADR	ConsumerMDR	ConsumerADR	ConsumerMDR
BaU	-17,403.49 €	-10,236.63 €	N/A	N/A

GreenEnergyMax	-17,513.77 €	-10,273.46 €	186.53 €	259.98 €
ProsumerMax	-17,320.53 €	-10,273.46 €	379.77 €	259.98 €
ElectricHeatAutomation	-16,863.08 €	-10,241.40 €	837.22 €	292.04 €
GridAssetsMaintenance	-17,213.56 €	-10,081.09 €	486.74 €	452.35 €
GridQuality&Control	-17,213.56 €	-10,081.09 €	486.74 €	452.35 €
IncidentManagement	-17,213.56 €	-10,081.09 €	486.74 €	452.35 €
IncreasedPowerQuality	-17,321.40 €	-10,081.09 €	378.90 €	452.35 €
CoopPowerPlant	-17,128.16 €	-10,080.69 €	572.14 €	452.76 €
ReduceRPFtoTSO	-17,321.40 €	-10,081.09 €	378.90 €	452.35 €
CongestionAvoidance	-16,837.45 €	-10,070.42 €	**862.84 €**	**463.02 €**
PowerFactorManagement	-17,213.56 €	-10,081.09 €	486.74 €	452.35 €

In the scenario <High EV penetration rate, Moderate PV penetration rate> we observe similar financial performance with Valencia, as the DSO and the society would see improved IRR and thus lower regulated charges in the long-run. Furthermore, the ProsumerADR business model is found to be positively affected by the increased demand for flexibility as a countermeasure for congestion and outage avoidance (IRR of 15% has been obtained in HLUC CongestionAvoidance). As in Valencia, however,

- **The Aggregator is still not profitable even if it keeps 85% of the cost for the flexibility that a DSO pays.**
- **the DSO would probably do better by doing capacity upgrade as soon as EV market share in area is close to 10%, since the IRR in the Business-as-Usual case is higher than the one in CongestionAvoidance HLUC (12.21% compared to 7.16%).**

Table 64: An overview of the economic profitability of market players for each standalone NOBEL GRID value network they are active in Rafina (Greece) (High EV penetration rate and Moderate PV penetration rate case)

	DSO	Aggregator	Retailer	ProsumerA	Prosumer
BaU	12.21%	-100.00%	6.26%	-10.01%	-100.00%
GreenEnergyMax	14.77%	-100.00%	7.60%	-10.87%	-100.00%
ProsumerMax	14.77%	-100.00%	7.59%	-10.19%	-100.00%
ElectricHeatAutomation	14.77%	-100.00%	7.60%	-10.28%	-100.00%
GridAssetsMaintenance	16.23%	#N/A	7.60%	-9.61%	-100.00%
GridQuality&Control	16.30%	#N/A	7.60%	-9.61%	-100.00%
IncidentManagement	16.30%	#N/A	7.60%	-9.61%	-100.00%
IncreasedPowerQuality	15.54%	#N/A	7.60%	-9.61%	-100.00%
CoopPowerPlant	15.54%	-100.00%	8.32%	-9.65%	-100.00%
ReduceRPFtoTSO	15.89%	-100.00%	7.56%	-10.20%	-100.00%
CongestionAvoidance	7.16%	-100.00%	7.56%	15.40%	-100.00%
PowerFactorManagement	16.28%	#N/A	7.56%	-9.69%	-100.00%

Of course, as already mentioned, by stacking the cost savings and new revenues when the HLUCs are combined could lead to a positive outlook for all involved roles, such as the Aggregator. Furthermore, Aggregators' capital expenditures are less sensitive to the size/population of the area they are operating. Thus, if they were expanding to the rest Greece they would have very high chances of being profitable (as the analysis in Terni has revealed).

8 CONCLUSIONS

This document presents the results of Task 2.3 of NOBEL GRID. The main purpose of the document is to **propose innovative business models for individual actors and evaluate the attractiveness of each one when these are combined into value networks for dealing with a challenge or an opportunity that exists in the context of the NOBEL GRID pilot sites**. This is important in order to understand the market potential of the NOBEL GRID technologies and the resulting interactions among the market players, namely DSOs, ESCOs/Aggregators, Retailers and Consumers/Prosumers.

In particular we focus on the following innovative, as well as, more straightforward business models:

- Consumers as **Prosumer**: individual consumers (such as home owners, Small-medium enterprises or cooperatives) producing renewable energy locally and deciding how much to consume or export to the grid. It was found that the financial viability of the prosumer business model heavily depends on three main aspects:
    - the existence of generous governmental support schemes, since the only area from those analysed where prosumage can flourish is Flanders (net metering regime is in place);
    - the presence of high controllable loads (such as EVs) as Prosumers with no support for ADR (those named ProsumerMDR or ProsumerM) are not profitable even when net metering is enabled
    - the demand for flexibility by established market players (such as DSOs, TSOs and Retailers) and their willingness to pay, as the IRR of prosumers increases in those value networks where DR campaigns are frequent and the alternative action is costly (for increasing the reward obtained from Aggregators per kWh offered).
- ESCOs as **Independent Aggregator**: In this business model ESCOs (Energy Service Companies) steer their (potentially large) group of members on their consumption and production decisions and offer this flexibility to other market players such as DSOs and TSOs. It was found that the business model of an ESCO becoming an Aggregator is not profitable in any of the areas examined in absence of NOBEL GRID technologies due to the need to install additional smart meters (behind the official meter that was assumed to be a low-cost one) in order to have access to fine-grained data and realise advanced methods for meeting requests for flexibility. When considering candidate value networks that are enabled by NOBEL GRID products, mainly smart meters (SLAM and/or SMX), G3M, DRFM and EMA app, duplicated infrastructure is avoided and the profitability largely depends on size of the user portfolio (pool size) the importnance of large customer base for aggregators to be profitable and (as appears in Terni and Manchester). Nevertheless, aggregators' capital expenditures are less sensitive to the size/population of the area they are operating and thus they can increase their pool size by expanding to other geographical areas.
- DSOs evolved into **SmartGrid-enabled DSOs**: Under this business model DSOs perform advanced network management by using tools and processes that treat Demand-Side Management techniques on par with traditional ones when performing their tasks, e.g. maintaining the power quality by minimizing Reverse Power Flows or reducing congestion issues that can lead to power outages. It was found that DSOs are allowed to have a low, but positive, IRR in the BaU scenario which is increased in most of the cases with NOBEL GRID technologies. This positive effect of NOBEL GRID can reduce the electricity bills of the end-users.
- Retailers as **Cooperative Virtual Power Plant**: In this business model Retailers, who may also own generation assets and thus act as "Gentailers", adopt the business model of an Aggregator and take advantage of their customers' production capacity as well as demand flexibility in order to optimize the way own production is used. In particular, such a (cooperative) retailer can lower electricity bills of its clients and thus increase its market share, by reducing the cost of energy procured in

wholesale markets when prices are exceptionally high either by offering dynamic pricing plans or by organizing DR campaigns. In addition, it can provide flexibility services to other market actors (such as balancing services to TSOs) and create an additional revenue stream for the participants. It was found that Gentailers (Retailers owning distributed generation units) are found to be profitable in all scenarios and all areas considered, while their economic performance is improved in vast majority of those that are enabled by NOBEL GRID technologies.

An important finding was that even if the cost savings and new revenues from each HLUC are not combined/stacked there are many cases where all participants have the incentive to collaborate in service offering. This can be seen by checking whether all participating roles have attractive (light green) or very attractive IRR. Note that even though 2 types of prosumers are sown, it is sufficient one of them to be attractive for a value network to be attractive on an end-to-end basis.

Furthermore, we showed that Consumers, either those owning an EV (named ConsumerADR/ConsumerA) or standard ones who can only participate in manual Demand Response campaigns, can see significant reduction on their electricity bills. Based on the table below, we observe that residential[11] users belonging to the ConsumerADR category can see a reduction of up to € 1324 over the 20-year evaluation period. These cost savings are further increased if the regulatory authority set lower regulated rates as a response to cost savings achieved in maintaining and operating the LV/MV grid.

[11] Commercial and industrial ones will enjoy even higher cost savings.

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9.2 ACRONYMS

Table 65. Acronyms

Acronyms List	
AD	Active Demand
ADR	Automated Demand Response
BE	Behavioral Economics
BRP	Balance Responsible Party
BM	Business Model
BMS	Building Management System
BYOD	Bring your own Device
CBP	Capacity Bidding Program
CAPEX	Capital Expenditure
CPP	Critical Peak Pricing
CVVP	Commercial Virtual Power Plan
DADRP	Day-Ahead Demand Response Program
DBP	Demand Bidding Program
DER	Distributed Energy Resources
DESSs	Distributed Energy Storage Systems
DG	Distributed Generation
DR	Demand Response
DSO	Distribution System Operator
EDRP	Emergency Demand Response Program
EEX	Energy Exchange
ELRP	Emergency Load Response Program
EV	Electric Vehicle
ESCOs	Energy Service Companies
HV	High Voltage
HLUC	High Level Use Case
HVAC	Heating, Ventilating, and Air Conditioning
HW	Hardware
ICT	Information and Communication Technologies
IRR	Internal Rate of Return
KPIs	Key Performance Indicators
LV	Low Voltage
LSE	Load Serving Entities
MDR	Manual Demand Response

MV	Medium Voltage
NYISO	New York Independent System Operator
OLA	Operational Level Aggreement
PCT	Programmable Controllable Thermostat
PDP	Peak Day Program
PJM	Pennsylvania Jersey Maryland
PV	Photovoltaic
RES	Renewable Energy Sources
RPF	Reverse Power Flows
RTP	Real-Time-Pricing
SCE	Southern California Edison
SGAM	Smart Grid Architecture Model
SLA	Service Level Aggreement
SHIC	Smart Home Intelligent Controller
SW	Software
TOU	Time-Of-Use
TSO	Transmission System Operator
V2G	Vehicle-to-Grid
VPP	Virtual Power Plant
VEN	Virtual End Node