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Cost and benefit analysis in the SuSTAINABLE demos

Lead Beneficiary:

COMILLAS

AUTHORS:

Authors	Organization	Email
Luis González Sotres	COMILLAS	Luis.Gonzalez@iit.upcomillas.es
Pablo Frías	COMILLAS	Pablo.frias@upcomillas.es
Carlos Mateo	COMILLAS	Carlos.Mateo@iit.upcomillas.es
João Filipe Nunes	EDPD	JoaoFilipe.Nunes@edp.pt
Diogo Alves Lopes	EDPD	Diogo.lemos@edp.pt

Reviewers	Organization	Email
Despina Koraki	TU-BERLIN	despoina.koraki@tu-berlin.de
Konstantinos Kaousias	HEDNO	K.Kaousias@deddie.gr
Themistoklis Xygkis	HEDNO Partner	
Rui Gonçalves	EDPD	Ruimiguel.goncalves@edp.pt
Pedro Matos	EDPD	Pedro.godinhomatos@edp.pt

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Executive Summary

Motivation

Smart grid research projects are necessary to further develop new technologies and systems, which are expected to improve the planning and operation of the electric system. This will be one of the keys to mature technologies and get them at an affordable cost. Nevertheless, the evaluation of the cost benefit ratio is necessary to assess up to what extent the application of such techniques makes already sense nowadays. It must be taken into account that even if the cost benefit analyses were currently negative, the improvement of the technologies, and their introduction into the system at a larger scale, could decrease their cost further, making them a reasonable option in the near future.

Approach

This report describes the Cost-Benefit Analysis (CBA) methodology defined for the assessment of the functionalities involved in the SuSTAINABLE concept. The methodology for the cost benefit analysis is based on the guidelines defined by the European Commission (EC) and the Joint Research Centre (JRC) for conducting CBA in Smart Grid projects. It is based on the evaluation of a set of KPIs to take into account all the relevant variables that can affect the cost benefit evaluation. In particular, this document investigates three demos, trying to quantify costs and benefits related to:

1) The impact of Prediction Tools on the generation system.

The generation system is modelled and analysed in Greece and Portugal. A 16% prediction error is modelled regarding the baseline scenario and a 10% prediction error is modelled regarding the project scenario. Costs and benefits are assessed at the 2030 horizon, taking into account references with regards to years 2014 and 2020. In Portugal, conservative scenarios for demand and distributed generation (DG) penetration are assumed, whereas in Greece a very high wind penetration is modelled. This enables one to observe differences not only among countries, but also depending on DG penetration. In practice, it is difficult to evaluate the benefits of forecasting tools, and therefore simulation tools are required for this purpose. In this project, the ROM model developed at IIT-COMILLAS, and widely used in European projects, is used to determine the technical and economic impact of intermittent generation. The model takes into account the electricity market, including load and generation profiles, economic and technical data of generation units, and ancillary services requirements. The main benefits assessed are the reduction of thermal costs and reserve costs, as well as the reduction of CO_2 emissions. Meanwhile, costs are related to the implementation of prediction tools, including among others home energy manager devices, power measuring devices, software tools and communication equipment.

2) The impact of automation on the distribution grids with a view to improving continuity of supply.

In this case, sensitivities to the automation degree are obtained, aiming at identifying the optimal automation degree that maximizes net benefits. An IIT-COMILLAS simulation model is used for this purpose. The model simulates the process of distribution systems operators trying to locate the faults and restore the service. For each fault, the model first determines the affected buses. Next, it tries to apply smart grid solutions such as remotely controlled switches. Then, if required, maintenance crews are sent in order to locate the fault by inspecting visually the power lines and using manual devices. Finally, the fault is repaired. Using this model, this report shows sensitivities to automation degrees in Évora and Rhodes distribution networks. Besides, in Portugal the impact of failure rates is investigated. Finally, the impact of the threshold that determines whether faults are taken into account or not on the evaluation of the continuity of supply indexes is assessed.

3) Coordinated voltage control in distribution grids.

The costs and benefits of coordinated voltage control are assessed in a low voltage network, and in two medium voltage networks corresponding to Évora and Rhodes. The costs assessed are related to smart devices and communication systems, required to implement the coordinated voltage control. Meanwhile, the benefits assessed are related to the reduction of curtailment, voltage deviations costs and energy losses. In particular, the impact of prediction tools, communication systems and DG penetration is gauged. With regards to prediction tools, costs and benefits are assessed given that they are dependent on the prediction error, and in two scenarios which correspond to the two most extreme situations, a) DG underestimation and demand overestimation, and b) DG overestimation and demand underestimation. As for the communication system, it is assessed how the determination intervals in which set-points are transmitted influences the cost benefit analysis. In this way, the availability of sufficient bandwidth in the communication system is modelled, to be able to send set-point signals, for example, every five minutes. Finally, the impact of DG penetration on voltage control in a selected distribution network is evaluated.

Results

The impact of RES forecasting tools on the market highlight that the main benefits are obtained from the reduction of the ancillary services cost, where a reduction of 38% in the forecasting error implies a reduction of 34% of this cost. On the other hand, the impact of thermal costs and CO_2 emissions is very small (lower than 1%), meaning that most changes are associated to generation operation rather than to the market structure. This functionality provides higher benefits for large RES generation, implying that the more renewable energy sources into the system, the higher the necessity of this functionality.

In Portugal, as the increase of demand cannot be only covered by the increase of RES penetration, all costs increase. On the contrary, in Greece, with an aggressive RES penetration scenario, the ancillary service costs experience a huge increase, which can be effectively mitigated thanks to forecasting tools, as shown in the analysis.

Regarding automation degrees, high benefits can be achieved for low automation degrees until an optimal level. In particular, a 7% automation degree is identified as optimal in Évora, while in Rhodes the optimum is 3%. In the later case, the type of network, larger and more rural, as well as the lower demand in Rhodes network, make the cost benefit analysis only positive for very low automation degrees. On the contrary, in Portugal, even up to 40% automation degrees lead to a positive cost benefit analysis, with respect to the baseline scenario.

The sensitivities analysis show that the impact of failure rates on the continuity of supply indexes[1] is linear, identifying the slopes which relate the failure rate decrease with the continuity of supply index improvement. The regulatory threshold used to set which faults are computed when evaluating the continuity of supply indexes has an effect on in the frequency of interruptions, but does affect neither the duration of interruptions, nor the cost benefit analysis.

Regarding coordinated voltage control, prediction tools are shown to have an impact on the improvement of voltage control. In particular, the impact of underestimating or overestimating DG is similar, although the drivers for these costs can be rather different. Communication systems are also identified as relevant to reduce systems costs further, highlighting the value of controlling every minute. With the employment of prediction tools and communication systems, there is usually a trade-off between voltage deviation costs and curtailment. However, concerning DG penetration, all benefits decrease for high DG penetration; meaning that the more DG into the system, the more costly that coordinated voltage control will be.

Conclusions

The three areas investigated show that smart grid solutions can have a positive cost benefit analysis depending on their specific conditions of implementation. As for the impact of the prediction tools in the electricity market, the benefits of reducing the prediction error up to 7% are identified. When setting DG penetration level targets, it should be taken into account that they can affect the cost benefit analysis of functionalities such as the ones studied in this report. In particular, DG penetration levels are expected to have a strong impact on the ancillary services.

Regarding automation degrees, high benefits can be achieved for low automation degrees until an optimal level. While automation degrees of up to 40% could make sense, the optimum is 7% and 3%, respectively in Évora and Rhodes. This highlights the necessity of continuing to implement automation in distribution networks. In the future, with a possible decrease in the cost of automation devices, higher automation degrees could also be favourable. However, a 100% automation degree is not expected to be optimal in distribution networks, at least in the near future.

[1] Continuity of supply indexes measure the duration and frequency of interruptions.

Regarding centralized voltage control, research and development resources should be allocated to improve prediction tools, as well as to improve communication technologies. In case of prediction tools, an overestimation or an underestimation of the DG profile would increase total costs, although the drivers for this total cost increase is different in these two cases. From a communication system point of view, frequent set-points signals transmission would improve the quality of voltage control.

The cost-benefit analysis carried out show that smart grid solutions may lead to a reduction of total net costs, depending on their particular implementation. In the cases investigated, the selection of the adequate prediction error and automation degree targets is critical to be able to integrate renewable energy sources in a cost efficient way. Overall, this points out the necessity of very carefully analysing smart grid solutions and technical characteristics of each distribution network to identify the best opportunities.

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List of Abbreviations

CBA	Cost-benefit analysis
CO2	Carbon dioxide
DG	Distributed generation
DSO	Distribution System Operator
DTC	Distribution Transformer Controller
EB	Energy Box
EC	European Commission
FDIR	Fault Detection, Isolation and Service Restoration
GPRS	General Packet Radio Service
IIT	Institute for Research in Technology
JRC	Joint Research Centre
KPI	Key performance indicator
LV	Low voltage
MV	Medium voltage
NOx	Nitrogen oxide
OLTC	On-load tap changer
OPF	Optimal power flow
PV	Photovoltaics
RES	Renewable energy sources
ROM	Reliability and Operation Model for Renewable Energy Sources
R/X ratio	Resistance to reactance ratio
SAIFI	System Average Interruption Frequency Index.
SAIDI	System Average Interruption Duration Index.
SOx	Sulfur oxide
SSC	Smart Substation Controller
VOS	Value of Service
VOQ	Value of Quality

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1 Introduction

This report describes the Cost-Benefit Analysis (CBA) methodology defined for the assessment of the functionalities involved in the SuSTAINABLE concept. The methodology is based on the guidelines defined by the European Commission (EC) and the Joint Research Centre (JRC) for conducting CBA in Smart Grid projects [1] and is supported by the demos deployed in the project.

In the beginning of the project, a set of KPIs was defined to quantify the performance of the developed functionalities, which are shown in Table 1. A more detailed description of each KPI and their assessment methodology can be found in Deliverable 2.4.

KPI ID	Description
KPI1	Deferred T&D Capacity Investment
KPI2	Reduction of Technical Losses
KPI3	DER Hosting
KPI4	Share of RES
KPI5	Power Quality
KPI6	Reduction of Carbon Emissions
KPI7	Reduction in DER cut-off due to congestion
KPI8	Optimized use of Assets

Table 1 List of KPIs defined in the SUSTAINABLE project

These KPIs are deployed to measure the impact of the SuSTAINABLE concept from a technical point of view, whereas the focus of this report is to assess the economic impact. For this task, the JRC has defined a list of benefits that can be assessed in a smart grid project, which is shown in Table 2, as well as the required formulas to compute them. Table 2 also includes the relationship between these KPIs and the ones defined in the project for the technical assessment, which are used to support the analysis.

KPI ID	Category	Description	Supporting KPI
JRC1	Economic	Optimised Generator Operation	KPI3
JRC2	Economic	Deferred Generation Capacity Investments	
JRC3	Economic	Reduced Ancillary Service Cost	
JRC4	Economic	Reduced Congestion Cost	KPI7
JRC5	Economic	Deferred Transmission Capacity Investments	KPI1
JRC6	Economic	Deferred Distribution Capacity Investments	KPI1
JRC7	Economic	Reduced Equipment Failures	KPI8
JRC8	Economic	Reduced Distribution Equipment Maintenance Cost	
JRC9	Economic	Reduced Distribution Operation Cost	
JRC10	Economic	Reduced Meter Reading Cost	
JRC11	Economic	Reduced Electricity Theft	
JRC12	Economic	Reduced Electricity Losses	KPI2
JRC13	Economic	Reduced Electricity Cost	KPI4

JRC14	Reliability	Reduced Sustained Outages	
JRC15	Reliability	Reduced Major Outages	
JRC16	Reliability	Reduced Restoration Cost	
JRC17	Reliability	Reduced Momentary Outages	
JRC18	Reliability	Reduced Sags and Swells	KPI5
JRC19	Environmental	Reduced CO2 Emissions	KPI6
JRC20	Environmental	Reduced SOx, NOx, and PM-10 Emissions	
JRC21	Security	Reduced Oil Usage	
JRC22	Security	Reduced Wide-scale Blackouts	

Table 2 List of KPIs defined in the JRC cost benefit analysis methodology and their mapping with the project KPIs

In the subsequent sections, the methodology applied to perform the CBA of the functionalities of Advanced Forecasting Tools, Advanced Monitoring and State Estimation, and Coordinated Voltage Control is explained in detail.

2 CBA of RES Forecasting in Market Operation

2.1 Objectives

The RES forecasting tools developed in the SUSTAINABLE project has an impact in market operation that has to be quantified in order to perform a proper cost benefit analysis. Therefore, this chapter analyses the impacts of the forecasting tools focusing on the market operation related costs and benefits. The costs and benefits of RES forecasting related to local problems of the distribution networks are instead analysed in chapter 4.

The main objective of the advanced forecasting tools is to make reliable predictions of controllable and no controllable loads, as well as DG units (wind and PV) connected at the MV and LV levels.

In general, two different perspectives can be considered to assess the benefits of forecasting tools. From a market operation point of view, more accurate forecasts may reduce the requirements of ancillary services and provide a more efficient generator operation, whereas from a network perspective the results of the forecasting tools can be used as inputs for control algorithms to improve their decision-making processes. Table 3 shows the economic KPIs that may be affected by this functionality.

KPI ID	Category	Description	Impact
JRC1	Economic	Optimised Generator Operation	X
JRC2	Economic	Deferred Generation Capacity Investments	
JRC3	Economic	Reduced Ancillary Service Cost	X
JRC4	Economic	Reduced Congestion Cost	
JRC5	Economic	Deferred Transmission Capacity Investments	
JRC6	Economic	Deferred Distribution Capacity Investments	
JRC7	Economic	Reduced Equipment Failures	

JRC8	Economic	Reduced Distribution Equipment Maintenance Cost	
JRC9	Economic	Reduced Distribution Operation Cost	
JRC10	Economic	Reduced Meter Reading Cost	
JRC11	Economic	Reduced Electricity Theft	
JRC12	Economic	Reduced Electricity Losses	X
JRC13	Economic	Reduced Electricity Cost	
JRC14	Reliability	Reduced Sustained Outages	
JRC15	Reliability	Reduced Major Outages	
JRC16	Reliability	Reduced Restoration Cost	
JRC17	Reliability	Reduced Momentary Outages	
JRC18	Reliability	Reduced Sags and Swells	X
JRC19	Environmental	Reduced CO2 Emissions	X
JRC20	Environmental	Reduced SOx, NOx, and PM-10 Emissions	X
JRC21	Security	Reduced Oil Usage	
JRC22	Security	Reduced Wide-scale Blackouts	

Table 3 Impact of Advanced Forecasting Tools in the economic KPIs

The impact of the forecasting tools on network operation has to be necessarily assessed together with additional functionalities that drive effects in the system. Additionally, at the present time the direct impact of forecasting tools on network operation may be very low, since the controllability of the MV and LV grids is not very high and the added value provided by the forecasts may not be exploited with the current automation degree.

For all these reasons, at this point the impact of these tools is investigated considering only the market perspective. The impacts in the distribution network will instead be analysed in chapter 4. Hence, thanks to a better integration of renewable energy in the energy markets the following benefits may be assessed based on the formulae defined in the JRC methodology:

Optimised Generator Operation:

Value (€) = [Annual Generation Cost (€)]Baseline - [Annual Generation Cost (€)]Project

Reduced Ancillary Service Cost:

Value (€) = [Price of Ancillary Service (€/MW) * Purchases (MW)]Baseline - [Price of Ancillary Service (€/MW) * Purchases (MW)]Project

Reduced CO2 emissions:

Value (€) = [CO2 Emissions (tons) * Value of CO2 (€/ton)]Baseline - [CO2 Emissions (tons) * Value of CO2 (€/ton)] Project

2.2 Methodology

In practice, the benefits obtained by forecasting tools are difficult to be assessed, so simulation tools are required to obtain a fair estimation. The ROM model developed at IIT-Comillas has been largely applied in several European projects such as MERGE or TWENTIES to determine the technical and economic impact of intermittent generation and other types of emerging technologies (active demand response, electric vehicles, concentrated solar power, and solar photovoltaic) on the medium-term system operation including reliability assessment [2], [3]. Appendix A provides further information of the tool. In this case, the effect of enhanced forecasting of renewable generation is studied with this tool.

The ROM model receives the characteristics of the electricity market to be analysed as input data and allows simulating the market operation for the required timeframe. This information includes:

- Load and generation profiles (forecasted and actual)
- Economic and technical data of generation units
- Ancillary services requirements

The ROM model allows determining two different horizons for intermittent generation forecasting, the first one at 14h of the day-ahead operation and the second at 24h, allowing the correction of forecasting error thanks to information closer to the operation time.

The main parameters considered by the ROM model to characterize each thermal generation unit are presented in Table 4. For the case of renewable units and consumers, hourly generation and demand profiles are included.

Parameter	Description
EFOR	Percentage of hours in a year that the corresponding unit fails [p.u.]
MaintDur	Duration of the maintenance works for the corresponding unit [h]
MinThermOut	Minimum output of the corresponding unit (rated value) [MW]
MaxThermOut	Maximum output of the corresponding unit (rated value) [MW]
ThrRampUp	Maximum ramp up rate [MW/h]
ThrRampDown	Maximum ramp down rate [MW/h]
VarHeatRate	Heat rate of the unit [Mcal/MWh]
NoLoadHeatRate	Heat rate, regardless of the output of the unit [Mcal/h]
FuelCost	Unit cost of the fuel burned by the unit [$/Mcal]
SpecCO2Emiss	Specific CO2 emissions [t CO2/MWh]
OMVarCost	Variable operation and maintenance costs of the unit [$/MWh]
StrtUpCons	Amount of calorific energy to be started up [Mcal/str]
StrtUpHrs	Number of hours before operation required to start up a unit [h]

Table 4 Parameters description for the characterization of thermal units

The two scenarios that will be compared are the following:

- Baseline scenario: RES forecasting with baseline forecasting error according to current average performance.
- Project scenario: RES forecasting (reducing the baseline forecasting error) through the advanced forecasting tools.

The scope of this methodology is applicable at a country level. However, the impact of improving the forecasting tools can be assessed at a local level considering the specific contribution of a certain region, for instance in terms of renewable installed capacity in the target area. This approach has been considered to quantify the benefits in the regions where the demos of the project have been deployed. In case of the costs, the devices required to be installed at the renewable generation units have been considered.

2.3 Case studies

2.3.1 Portugal

2.3.1.1 Implementation details

The energy mix that has been considered for Portugal is shown in Figure 1 and the average values for each thermal technology are summarized in Table 5. The demand profile for 2014 in Portugal has been obtained from ENTSOE [4] and the wind, PV generation and hydro inflows have been modelled with contributions from the project partners and data obtained from REN [5], the Portuguese TSO.

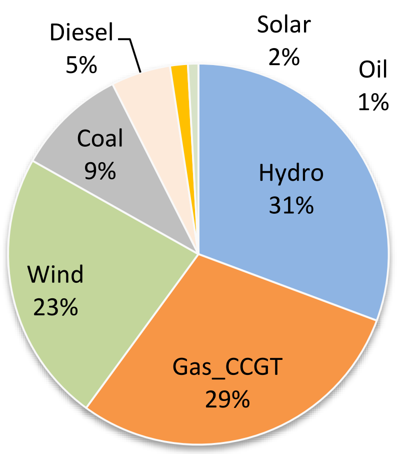

Figure 1 Generation mix of Portugal for the reference year

Parameter	Coal	Diesel	Gas_CCGT	Oil
EFOR [p.u.]	0.06	0.06	0.05	0.06
MaintDur [h]	72.00	96.00	48.00	96.00
MinThermOut [MW]	135.31	173.30	96.71	49.34
MaxThermOut [MW]	292.67	236.50	392.07	165.00
ThrRampUp [MW/h]	78.68	63.20	295.36	115.66
ThrRampDown [MW/h]	78.68	63.20	295.36	115.66
VarHeatRate [Mcal/MWh]	1,257.40	1,422.65	570.34	1,391.03
NoLoadHeatRate [Mcal/h]	59,481.25	37,042.72	265,192.36	98,277.70
FuelCost [€/Mcal]	0.02	0.04	0.03	0.03
SpecCO2Emiss [t CO2/MWh]	0.51	0.46	0.13	0.33
OMVarCost [€/MWh]	0.04	0.03	0.06	0.03
StrtUpCons [Mcal/str]	1,332,371.67	994,931.03	370,033.21	394,705.88
StrtUpHrs [h]	23.04	15.00	7.00	15.00

Table 5 Average values of the parameters of thermal units in Portugal case study

The average forecasting errors considered in the analysis are 16% for the baseline scenario and 10% for the project scenario, in the day-ahead timeframe. The upward reserve requirements have been adjusted taking into account three aspects: cope with approximately 90% of the forecasting error, 5% of demand variation and the failure of the largest thermal unit, whereas the downward reserves only consider the 5% of demand deviation. To perform the economic assessment, the prices of the Iberian electricity market for 2014 have been considered as reference, which presented an average marginal electricity price of 44.33 €/MWh. The average cost of the tertiary reserve for that period was 62.51 €/MWh for the upward and 27.5 €/MWh for the downward case. This information has been obtained from OMIE and REE, the Iberian market and system operators [6], [7].

The CBA has been performed for the 2030 horizon, where two reference years have been simulated: 2014 and 2020. The intermediate years have been interpolated and extrapolated from the results obtained for these years. The demand, wind and PV considered for each reference year are presented in Table 6, where conservative scenarios for demand and RES growth have been defined. Finally, a price of 25 €/tCO2 has been considered for the whole period based on [8], and the other economic parameters have been also considered invariant.

	GWh 2014	GWh 2020
Demand	47,837	50,739
Wind	11,751	12,44
PV	443	1,072

Table 6 Demand and RES production in Portugal case study

2.3.1.2 Costs assessment

The costs included in the implementation of the forecasting tools in the Évora site are summarized in Table 7. In 2014, the installed RES capacity at the network under study is 50.93 kW. For 2020, installed total capacity of 300 kW has been assumed. This increase has been used to assess the increase in costs, where an efficiency gain of 30% has been assumed between both scenarios, based on expected cost reduction and the installation of facilities with larger capacity.

	Unitary cost	Duration (years)	Number of units 2014	Cost 2014 (€)	Cost 2020 (€)
Home energy manager device	63	10	40	2,520	10,391
Power measuring device	47	10	40	1,880	7,752
Router 3G	70	10	40	2,800	11,545
SIM card	30	10	40	1,200	4,948
Installation costs	13	10	40	520	2,144
TOTAL				**8,920**	**36,780**

Table 7 Costs of implementing the RES forecasting tools in Portugal case study

2.3.1.3 Benefits assessment

Table 8 summarizes the results of the benefits obtained by the forecasting tools with the described methodology for the year 2014.

KPI	Baseline (k€)	Project (k€)	Difference (k€)	Difference (%)
Thermal cost	928,593	927,946	647	0.07%
Upward reserve cost	42,957	27,924	15,033	35.00%
Downward reserve cost	18,036	12,005	6,030	33.43%
CO2 emissions cost	161,711	161,469	242	0.15%

Table 8 Benefits of implementing the RES forecasting tools in Portugal case study for 2014

It can be seen that the maximum variation is achieved in the upward reserve cost, followed by the downward reserves. These results seem to be reasonable since the improvement in the forecasting tools allows reducing the use of reserves, and the upward reserve requirements are approximately three times higher than the downward reserves, which is more or less the same relation than the benefit obtained between both of them. This is related to the actual tertiary reserve prices. Upward reserve (more production) is usually over the marginal price in the spot market and downward reserve (less production) below. The variation in CO_2 emissions and thermal cost are barely affected. In Table 9 the results for the three KPIs per MW installed of RES capacity are presented.

Benefits	Value per MW installed (€)
Optimised Generator Operation	139
Reduced Ancillary Service Cost	4,540
Reduced CO2 emissions	52

Table 9 Benefits per MW installed of RES capacity in Portugal case study for 2014

The same approach has been performed for a 2020 scenario. Table 10 presents the results for this case.

KPI	Baseline (k€)	Project (k€)	Difference (k€)	Difference (%)
Thermal cost	987,485	986,368	1,117	0.11%
Upward reserve cost	49,836	32,134	17,703	35.52%
Downward reserve cost	20,757	13,745	7,012	33.78%
CO2 emissions cost	165,290	165,178	112	0.07%

Table 10 Benefits of implementing the RES forecasting tools in Portugal case study for 2020

Regarding the benefits for the 2020 scenario, it can be seen that almost the same results appear when they are compared to the first case. In Table 11, results for the three economic benefits per MW installed of 2020 RES capacity are presented.

Benefits	Value per MW installed (€)
Optimised Generator Operation	211
Reduced Ancillary Service Cost	4,699
Reduced CO2 emissions	21

Table 11 Benefits per MW installed of RES capacity in Portugal case study for 2020

2.3.1.4 Comparison of costs and benefits

The costs and benefits for each year are compared in Figure 2. A linear increase of RES capacity has been assumed between the two reference years. For this analysis the expected lifetime of each equipment has been considered, which is equal to 10 years. Thus, after this period new equipment is installed assuming the same initial costs. It can be seen that in the first stage, the benefits do not compensate the initial investment. This is because the higher benefits are obtained when a substantial amount of RES is deployed.

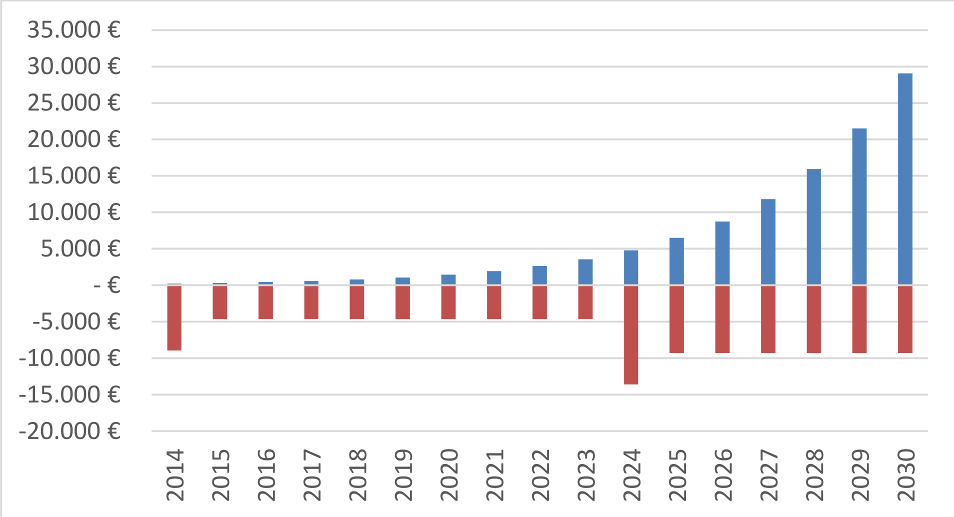

Figure 2 Annual costs and benefits in Portugal case study

2.3.1.5 Sensitivity Analysis

A sensitivity analysis to the forecasting error has been performed, considering a 7% and a 13% value, respectively, where the net accumulated benefit for each case is shown in Figure 3.

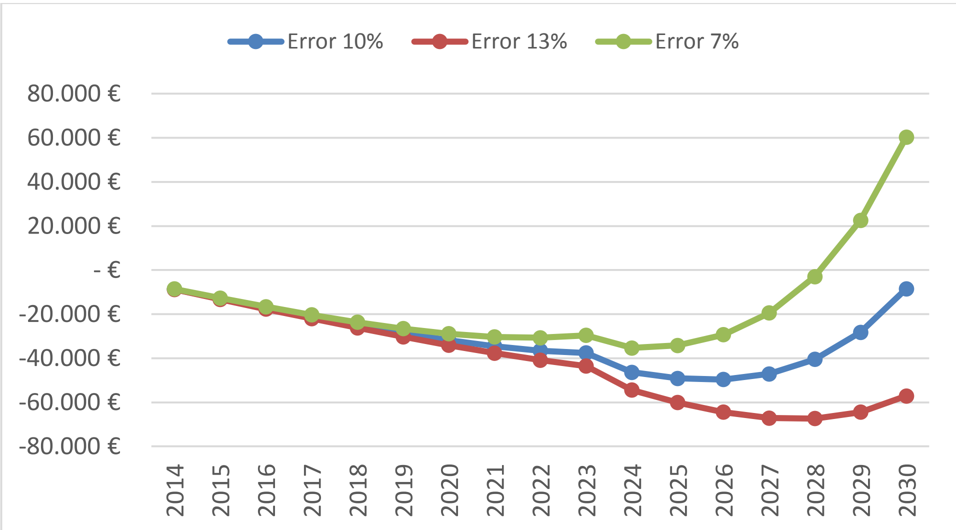

Figure 3 Sensitivity of the net accumulated benefit to the forecasting error in Portugal case study

The variation of the forecasting error has an important impact on the benefits, where it can be seen that reducing the error from 10% to 7% provides higher benefits than the reduction from 13% to 10%, which encourages a further improvement of the forecasting tools.

2.3.2 Greece

The energy mix that has been considered for Greece is shown in Figure 4 and the average values for each thermal technology are summarized in Table 12. The demand profile for 2014 in Greece has been obtained from ENTSOE and the wind, PV generation and hydro inflows has been modelled with contributions from the project partners and public sources like ADMIE, the Greek TSO [9].

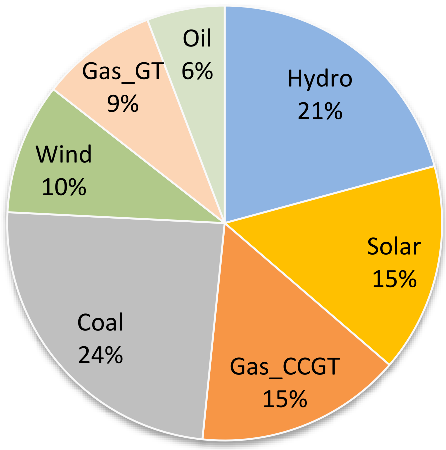

Figure 4 Generation mix of Greece for the reference year

Parameter	Coal	Gas_CCGT	Gas_GT	Oil
EFOR [p.u.]	0.12	0.06	0.00	0.00
MaintDur [h]	1,260.00	627.79	672.00	672.00
MinThermOut [MW]	146.60	63.00	220.29	220.29
MaxThermOut [MW]	313.68	125.66	450.00	450.00
ThrRampUp [MW/h]	173.43	62.64	229.71	229.71
ThrRampDown [MW/h]	173.43	62.64	229.71	229.71
VarHeatRate [Mcal/MWh]	2,550.80	2,628.54	2,305.19	2,305.19
NoLoadHeatRate [Mcal/h]	30,075.96	47,942.43	177,817.09	177,817.09
FuelCost [€/Mcal]	0.02	0.03	0.03	0.03
SpecCO2Emiss [t CO2/MWh]	1.81	0.82	0.70	0.70
OMVarCost [€/MWh]	0.04	0.05	0.06	0.06
StrtUpCons [Mcal/str]	1,465,808.00	391,368.42	380,000.00	380,000.00
StrtUpHrs [h]	15	7	7	7

Table 12 Average values of the parameters of thermal units in Greece case study

The average forecasting errors considered in the analysis are 16% for the baseline scenario and 10% for the project scenario, in the day-ahead timeframe. The upward reserve requirements have been adjusted taking into account three aspects: cope with approximately 90% of the forecasting error, 5% of demand variation and the failure of the largest thermal unit, whereas the downward reserves only consider the 5% of demand deviation. To perform the economic assessment, the market prices and reserve costs from Portugal case study have been used, so the effect of different generation mixes can be compared considering the same economic boundary conditions.

As in the case of Portugal, the CBA has been performed for the 2030 horizon, where two reference years have been simulated: 2014 and 2020. The intermediate years have been interpolated and extrapolated from the results obtained for these years. The demand, wind and PV considered for each reference year are presented in Table 6, where more aggressive scenarios for demand and RES growth have been defined. Finally, the same price of 25 €/tCO2 has been considered for the whole period, and the other economic parameters have been also considered invariant.

	GWh 2014	GWh 2020
Demand	49,258	61,023
Wind	2,982	19,853
PV	3,819	4,965

Table 13 Demand and RES production in Greece case study

2.3.2.1 Cost assessment

The costs for Greece case study are presented in Table 14 and have been derived from the Évora demo, but extrapolated for the RES generation in Rhodes in the reference years considering the same efficiency gain of 30% than in Portugal case study. However, in this case it has been applied not only for 2020 but also in 2014, since the Rhodes network already considers larger RES generation units than Évora. In 2014, the installed RES capacity in the network under study is 70.9 MW. For 2020, an installed capacity of 186.1 MW has been assumed.

	Unitary cost	Duration (years)	Number of units 2014	Cost 2014 (€)	Cost 2020 (€)
Home energy manager device	63	10	38,979	2,456	5,832
Power measuring device	47	10	38,979	1,832	4,351
Router 3G	70	10	38,979	2,729	6,480
SIM card	30	10	38,979	1,169	2,777
Installation costs	13	10		507	1,203
TOTAL				**8,692**	**20,644**

Table 14 Costs of implementing the RES forecasting tools in Greece case study

2.3.2.2 Benefits assessment

Table 15 summarizes the results of the benefits obtained by the forecasting tools with the described methodology for year 2014.

KPI	Baseline (k€)	Project (k€)	Difference (k€)	Difference (%)
Thermal cost	2,814,690	2,814,039	651	0.02%
Upward reserve cost	32,178	20,986	11,192	34.78%
Downward reserve cost	5,156	3,436	1,720	33.36%
CO2 emissions cost	1,337,257	1,337,321	-64	0.00%

Table 15 Benefits of implementing the RES forecasting tools in Greece case study for 2014

The maximum variation is again the reserve cost which implies a reduction in upward and downward reserve of almost 35% for both; the thermal operation cost is also reduced. However, the CO_2 emissions cost experienced a small increase due to the higher presence of coal-based power plants in the unit commitment, as the required reserves are lower for the project scenario. In Table 16 the results for the three economic benefits per MW installed of RES capacity are presented.

Benefits	Value per MW installed (€)
Optimised Generator Operation	166
Reduced Ancillary Service Cost	3,286
Reduced CO2 emissions	-16

Table 16 Benefits per MW installed of RES capacity in Greece case study for 2014

Then, the benefits obtained from the 2020 scenario are presented in Table 17, where this scenario supposed a much larger deployment of RES generation.

KPI	Baseline (k€)	Project (k€)	Difference (k€)	Difference (%)
Thermal cost	2,386,784	2,380,833	5,952	0.25%
Upward reserve cost	122,073	79,555	42,518	34.83%
Downward reserve cost	18,312	12,776	5,536	30.23%
CO2 emissions cost	1,113,922	1,108,066	5,856	0.53%

Table 17 Benefits of implementing the RES forecasting tools in Greece case study for 2020

It can be seen that the forecasting improvement has a higher impact in the 2020 scenario. This demonstrates again that the higher deployment of RES generation within the system is, the higher the benefits for an improvement in the forecasting tool are. The results for the three economic benefits per MW installed of RES capacity are presented in Table 18.

Benefits	Value per MW installed (€)
Optimised Generator Operation	626 €
Reduced Ancillary Service Cost	5,058 €
Reduced CO2 emissions	616 €

Table 18 Benefits per MW installed of RES capacity in Greece case study for 2020

2.3.2.3 Comparison of costs and benefits

The costs and benefits for each year are compared in Figure 5. A linear increase of RES capacity has been assumed between the two reference years. For this analysis the expected lifetime of each equipment has been considered, which is equal to 10 years.

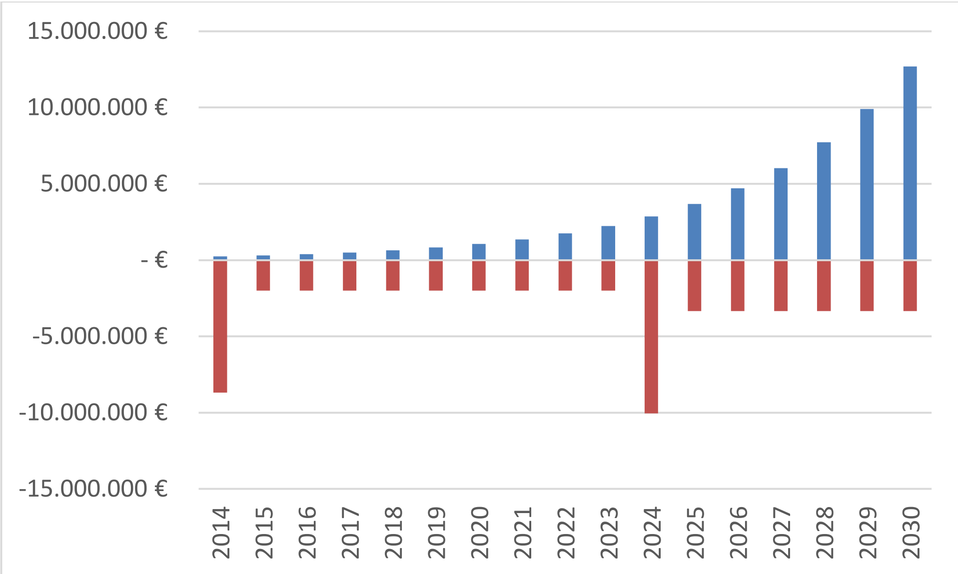

Figure 5 Annual costs and benefits in Greece case study

2.3.2.4 Sensitivity Analysis

A sensitivity analysis to the forecasting error has been performed, considering a 7% and a 13% is presented in Figure 6.

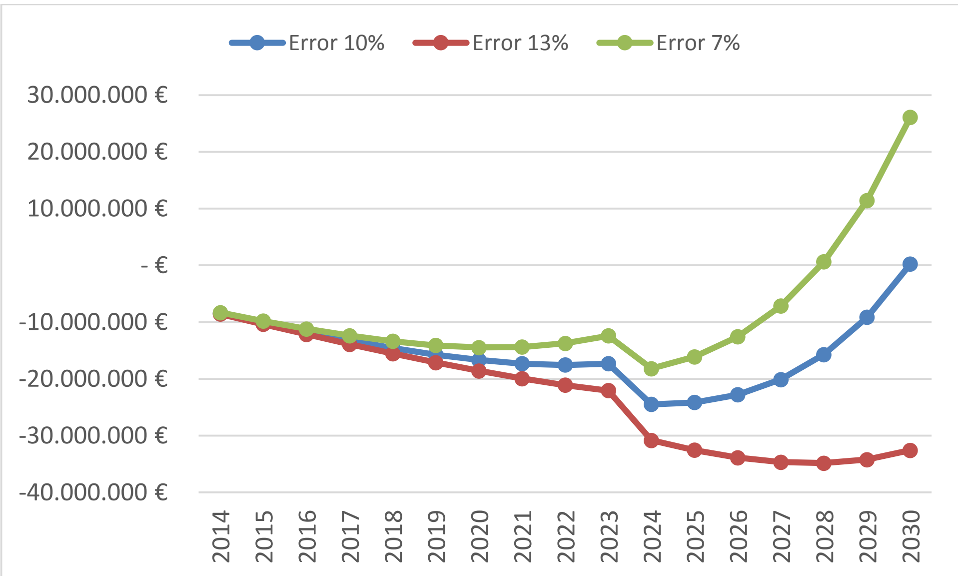

Figure 6 Sensitivity of the net accumulated benefit to the forecasting error in Greece case study

It can be observed that in contrast to Portugal case study, reducing the error from 10% to 7% provides lower benefits than the reduction from 13% to 10%, which makes the initial developments of the forecasting tools more attractive.

2.4 Conclusions

In this chapter, the impact of the RES forecasting tools has been assessed from a market perspective, since this functionality is an enabler for other functionalities that can be used by the DSO. In the two case studies for Portugal and Greece, similar effects have been observed from the reduction of the forecasting error. The main benefits are obtained from the reduction of the ancillary services cost, where a reduction of 38% in the forecasting error obtained approximately 34% of reduction of this cost. Thus, it can be concluded that, in the analysed cases, an improvement in the forecasting tools in a specific ratio can provide practically the same reduction in the ancillary service cost. Conversely, the impact on the thermal costs and CO2 emissions is very small (lower than 1%), which means that the avoided cost is more related to the economics of the market structure than to a substantial change in the generation operation.

Comparing the costs to the benefits of this functionality, it can be noticed that the costs to implement this functionality are really important, but the leverage of these costs among other functionalities that potentially use the same devices may help the overall cost benefit ratio. Additionally, it has been observed that this functionality provides higher benefits for larger amounts of RES generation.

Comparing the results for the two reference years of each case study, it can be seen that in the case of Portugal, where a conservative increase of RES was assumed, all the KPIs presented an increase in the costs, since the increase of demand might not be covered by the increase of RES capacity. On the contrary, in Greece case study where a larger amount of RES penetration was considered in 2020, the thermal costs and CO2 emissions were reduced approximately a 20%, but the ancillary service cost experienced a huge increase (approximately four times more). However, it has been shown that thanks to the forecasting tools this large increase can be mitigated effectively.

Finally, a sensitivity analysis with regards to the forecasting error has been carried out, where it has been observed that the benefits also increase in case of lower forecasting error, but the impact may be different according to the baseline. According to the results of the simulations, in systems with moderate RES generation, the reduction of forecasting error provides higher benefits when the baseline is lower, whereas in systems with very high RES penetration, the higher benefits are obtained for the initial error reductions, which encourage even more the use of this functionality for this scenario.

3 CBA of Smart Monitoring and Control in Continuity of Supply

3.1 Objectives

The main objective of the smart monitoring and state estimation functionality is to make the network fully observable and guarantee an adequate degree of redundancy through real-time information and pseudo-measurements, which provides quicker detection of anomalies as well as reduced operational and maintenance costs. Moreover, the combination of this information with control actions allows mitigating the occurrence of some constraints and reducing restoration time when faults occur.

In this case, the impact of smart monitoring together with the automation of secondary substation on the improvement of the quality of supply is studied. With this aim in view, the economic benefit of the reduction of sustained outages will be computed based on the following equation:

Reduced Sustained Outages:

Value (€) = [Outage Time (h) * Load Not Served (kW estimated) * VOS (€/kWh)]Baseline - [Outage Time (h) * Load Not Served (kW estimated) * VOS (€/kWh)]Project

3.2 Methodology

The reduced outages must be obtained through real experience in the field, which requires studying large periods of time with information of the state of the network. However, a first estimation may be obtained through simulations [10]. Hence, the assessment of this benefit will be performed by using a tool developed at IIT-COMILLAS that simulates the behaviour of a crew in the fault location process taking into account the following parameters. Appendix B provides further information of this tool.

- Network configuration
- Failure rate
- Location time
- Value of Service (VOS) = Lost Load

Outage management is usually performed as an iterative process that operates the switches of the secondary substations and /or overhead lines to isolate the outage, restoring the service for the other segments until the faulty segment is repaired, when service is restored to all consumers. The switches in conventional MV/LV substations must be operated manually, while smart secondary substations and overhead lines may be remotely controlled through circuit breakers with positive impacts in location and operation times.

The following two scenarios are compared:

- **Baseline scenario:** No secondary substation automation
- **Project scenario:** Different levels of secondary substation automation. Currently, remote control is possible in 4 of the secondary substations in Évora.

3.3 Implementation details

In brief, the time to restore service in a feeder is comprised from some of all of the following elements for each load:

$$t = tresp + nsteps_j \times toper_j + t1 + \sum_i (t2_i + t3_i) + t4 + t5$$

where:

$tresp$	is a fixed term to account for the response time of the operator in the control centre (min)
$nsteps_j$	is the number of switching actions performed by the operator in the control centre to isolate the faulty segment among two remote controlled elements
$toper_j$	is a fixed term to account for the time required for each switching action performed by the operator in the control centre (min)
$t1$	is a fixed term to account for the time required for fault detection and sending a maintenance crew (min)
$t2_i$	is a fixed time period for each step of the dichotomic search process, which determines whether the fault is located upstream or downstream (it comprises operation of the switches, getting into the car, ...) (min)
$t3_i$	is a variable time period proportional to distance to travel in step i, considering a certain speed s3 (min)
$t4$	is a variable time period for fault localization along a segment, proportional to distance to cover, considering a certain speed s4 (min)
$t5$	is a fixed time period to repair a fault in a branch of the feeder (min)

Table 19 shows the parameters used in the simulations to obtain SAIDI[2] and SAIFI[3].

Simulation step	Parameter	Value
Regulatory threshold to consider long-duration interruptions of supply	$t_{max,reg}$ (min)	1 ; 3
Response of the control centre for Fault Detection, Isolation and Service Restoration (FDIR) with smart grid solution	$t_{operator}$ (min)	0 ; 0.5
	$t_{operator,j}$ (min)	0 ; 0.2
Response of maintenance crew	t_1 (min)	10
Operation of load break switches in underground networks with secondary	t_2 (min)	8

[2] SAIDI is the System Average Interruption Duration Index. It measures the duration of the interruptions.
[3] SAIFI is the System Average Interruption Frequency Index. It measures the frequency of the interruptions.

substations connected in input-output	s_3 (km/h)	45
Visual inspection of overhead lines	s_4 (km/h)	10
Fault reparation	t_5 (min)	120

Table 19 Parameters of the reliability simulations

3.4 Case studies

3.4.1 Évora MV feeder

3.4.1.1 Costs assessment

It is assumed an investment cost of 7,200 € per smart MV/LV substation. This cost takes into account only the equipment required to improve reliability, not including other equipment such as MV/LV transformers, which are necessary in the substation even if there is no automation. The idea behind this approach is that transformers are already installed in the substations and the question is whether substations are automated. 100% automation degree corresponds to installing remote controlled devices in 28 MV/LV substations, which would have a cost of 201,600 €.

3.4.1.2 Benefits assessment

First, SAIFI and SAIDI are computed for each automation degree. They are shown in the following figures. There is a significant decrease both in SAIFI and SAIDI for low incremental automation levels respect the case of no automation. As the automation degree goes on increasing, SAIFI and SAIDI continue decreasing, but with lower rates.

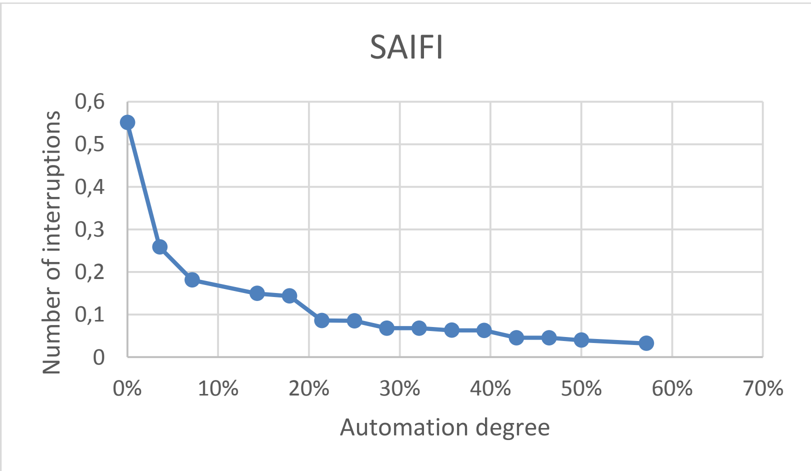

Figure 7 SAIFI for each automation degree in Évora MV network.

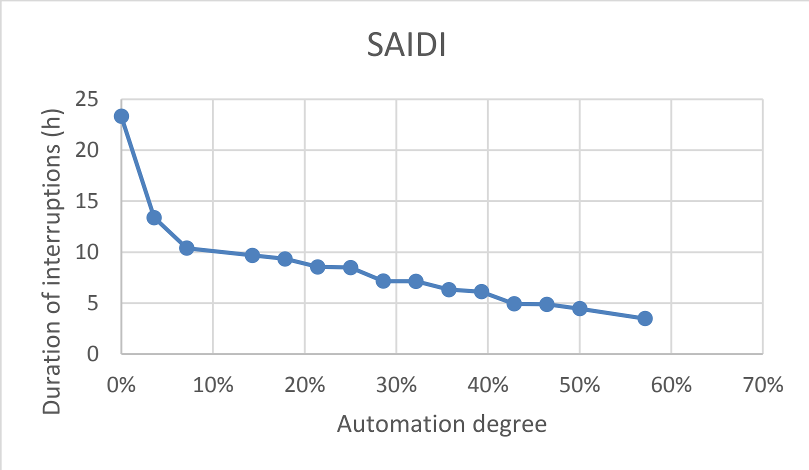

Figure 8 SAIDI for each automation degree in Évora MV network.

The amount of the energy not supplied is evaluated taking into account the duration of interruptions. For this purpose, given that the total installed power in the network is 18.9 MW, a simultaneity factor of 0.9 and a load factor of 0.6 are considered. This leads to an annual consumption of 10.2 MWh that together with the information of the duration of interruptions, results in a certain annual interruption cost for each automation degree. Finally, the benefits of a given automation degree are assessed by computing the cost difference respect to the baseline scenario of no automation (see the Reduced Sustained Outages formula in section 3.1).

3.4.1.3 Comparison of costs and benefits

In order to compare costs and benefits, the annual cost derived from interruptions is used to compute a net present value, assuming a discount rate of 5% and a period of 15 years. Figure 9 compares costs and benefits. The option with the maximum net benefit corresponds to an automation degree of 7%, with a net benefit of 38,675 €. Automation degrees of up to 40% lead to net benefits, however the economic optimum is only 7%.

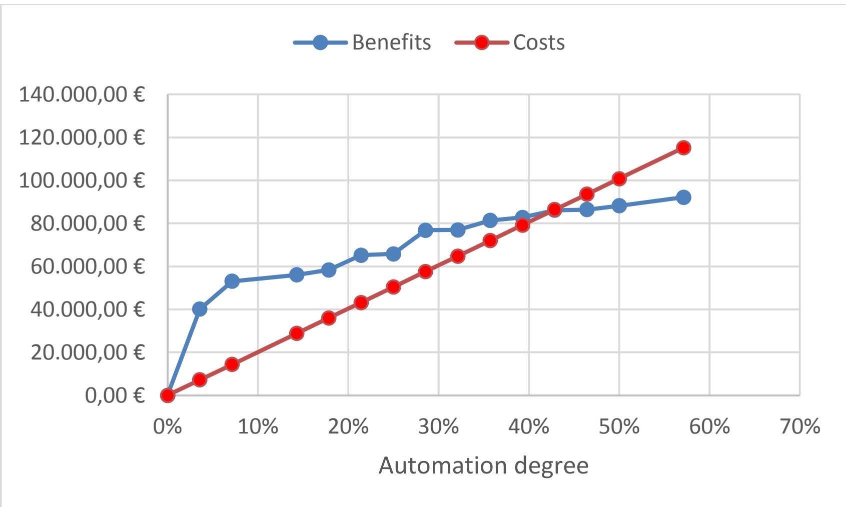

Figure 9 Costs and benefits in Évora MV network.

3.4.1.4 Sensitivity analysis

A sensitivity analysis is carried out to the failure rate of power lines. This sensitivity is obtained in the case of no automation. Both indexes show a linear increase depending on the failure rate of the power lines. The slopes of these lines indicate the relative improvement in SAIFI and SAIDI associated to a change in the failure rates of the power lines.

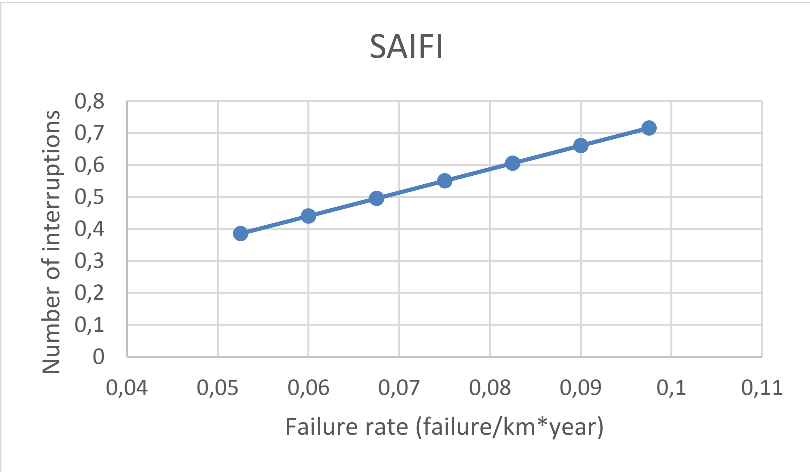

Figure 10 SAIFI in Évora MV network for several power line failure rates.

Figure 11 SAIDI in Évora MV network for several power line failure rates.

A sensitivity analysis is also carried out regarding the threshold that is considered to determine that a consumer interruption is taken into account for computing SAIFI and SAIDI. This sensitivity aims at assessing the impact of more restrictive future regulations, as the automation degree increases. Thresholds of 1min and 3min are modelled.

The figures show that with a 1min. threshold, SAIFI is significantly higher than for a 3min. threshold, but only for high automation degrees. This means, that only when the network is highly automated, the times for restoring a fault can be low enough so that the threshold can make a difference in the number of interruptions being computed.

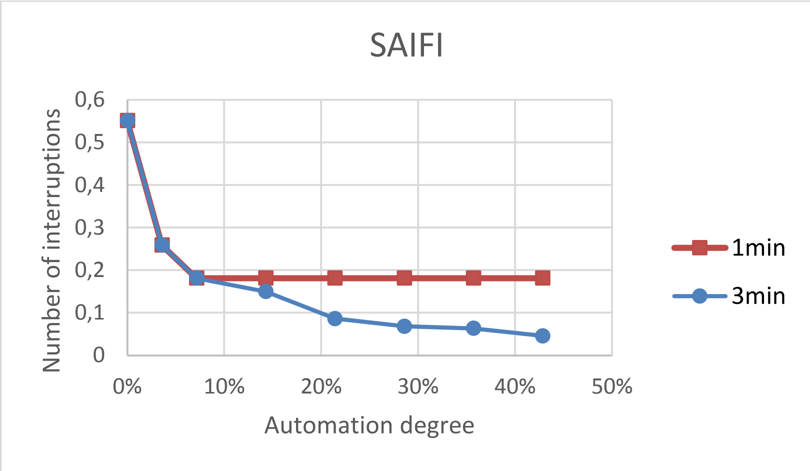

Figure 12 SAIFI in Évora MV network for several minimum interruption time threshold.

On the contrary Figure 13 shows that SAIDI remains almost equal independently of the minimum interruption time threshold. The reason for this result is that the faults which are computed or not for SAIDI and SAIFI depending on the threshold are very short. Therefore, these faults can influence SAIFI, but they have a very small effect on SAIDI. As the cost and benefit is based on the duration of interruptions, this regulatory policy would not have a significant impact on the cost benefit analysis. Therefore, the optimal automation degree is still 7%.

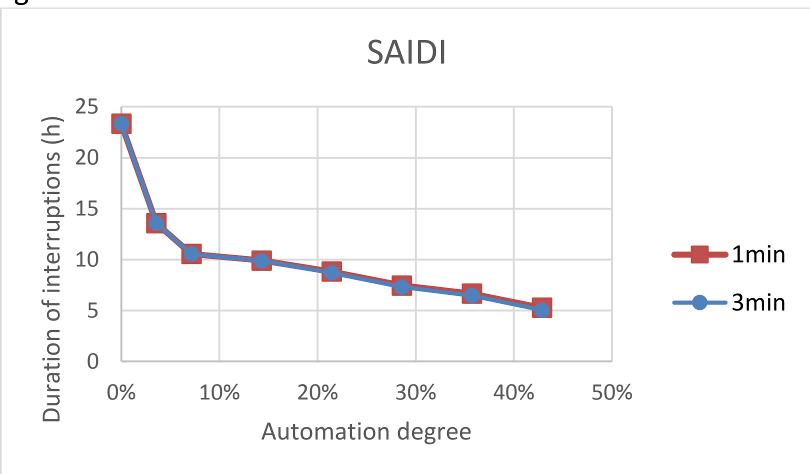

Figure 13 SAIDI in Évora MV network for several minimum interruption time threshold.

3.4.2 Rhodes MV feeder (R-220)

3.4.2.1 Costs assessment

The costs are computed assuming the same unitary cost per smart MV/LV substation than in Évora MV network. As the number of substations is higher, the cost associated to a certain automation degree is also higher. In this network, 100% automation degree corresponds to automating 120 MV/LV substations, which would have a cost of 864,000€, significantly higher than in Évora MV network.

3.4.2.2 Benefits assessment

SAIFI and SAIDI are computed to assess the benefits of an increased automation degree. In both indexes there is a significant improvement for low automation degrees, and results stabilize starting at 3% automation degree for SAIFI, and 15% for SAIDI. This saturation of the curves is due to the fact that the network is rural, having the feeders less options to be reconfigured in order to restore the service after faults occur. This implies that only low automation degrees can make sense in this network, as higher automation degrees have almost no effect on the continuity of supply indexes.

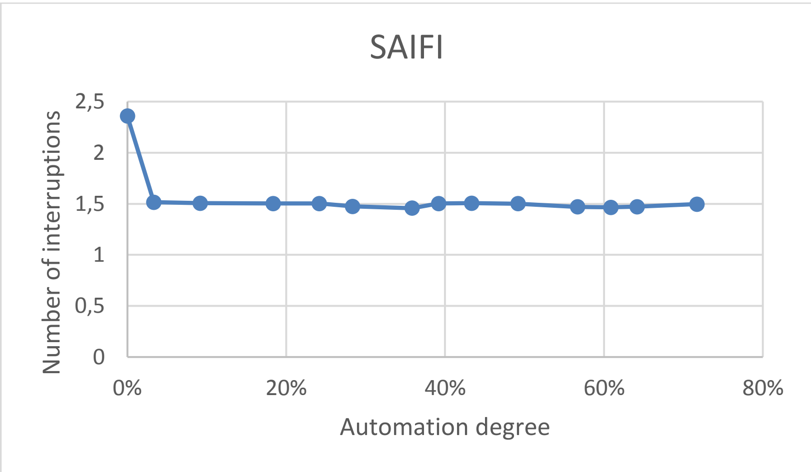

Figure 14 SAIFI for each automation degree in Rhodes MV network.

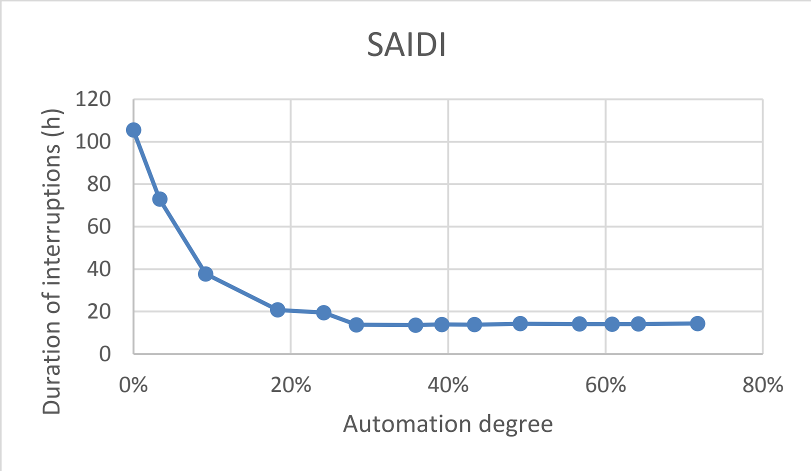

Figure 15 SAIDI for each automation degree in Rhodes MV network.

As in Évora network, a 0.9 simultaneity factor, and a 0.6 load factor are assumed to compute a total consumption of 2.4MWh, significantly lower than in Évora. Therefore, even though the SAIDI associated to no automation is higher than in Évora (105h instead of 23h), the benefits associated to the automation degree do not increase that much, as the lower consumption is limiting the amount of energy that is not supplied.

3.4.2.3 Comparison of costs and benefits

The following figure compares costs and benefits in the Rhodes MV network. Even, though the SAIDI reduction for low automation degrees is higher than in Évora, the benefits do not increase that much due to the reduced consumption. Besides, costs are also higher because this network is larger and this means that it is necessary to automate more MV/LV substations to achieve the same percentage (120 consumption buses in Rhodes opposed to 28 consumption buses in Évora). Only 3% and 9% automation degrees lead to a net benefit. In this network the economic optimal is 3%, with a net benefit of 12,218.39€.

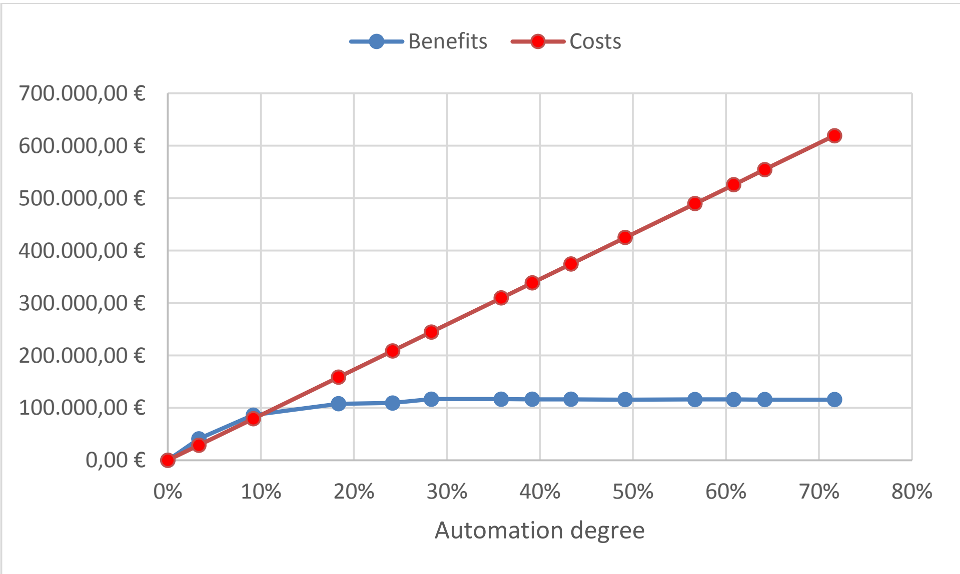

Figure 16 Costs and benefits in Rhodes MV network.

3.5 Conclusions

Results show that an increased automation degree has benefits in terms of SAIDI and SAIFI. However, in rural networks there is a saturation effect, meaning that very high automation degrees do not provide additional benefits, due to the lack of additional alternative feeders for reconfiguring the network and restoring the service after faults.

In Évora network the optimal automation degree is 7%. Considering the current cost of interruptions and the additional cost of making a MV/LV substation smart, only low automation degrees are currently economically justified in this network. In the future, as the technology is improved and the cost of smart substations decrease, higher automation degrees could be justified. Also changes in regulation affecting the unitary cost of interruptions would affect this cost benefit analysis. On the other hand, a modification of the minimum time threshold used to determine which faults are taken into account in SAIFI and SAIDI, could affect SAIFI, but would have impact neither in SAIDI nor in the cost benefit analysis.

In Rhodes network, which is characterized by a larger grid and lower consumption level, even though the SAIDI reduction is larger, the benefits of automating the network do not usually compensate the costs of the smart MV/LV substations, meaning that nowadays the optimal is only 3%. However, it has to be taken into account, that with the degree of automation we are referring only to remote controlled devices. Manual switches and breakers were not the focus of the analysis, and they will also be required in the distribution grids, and probably with higher penetration levels.

4 CBA of Voltage Control in Quality of Supply

4.1 Objectives

The main objective of the coordinated voltage control is to maximize the production of renewable generation while keeping voltage profiles within an admissible range. To do so, different control strategies are implemented and tested in the project. These technical solutions can be evaluated both in field tests and through simulations. In this report, Matlab/Matpower has been used to model and simulate the voltage control and evaluate the power flows, in order to assess the benefits derived from this functionality. The direct benefit is the increasing amount of renewable energy production, but there are two other benefits that are expected to be significantly affected by this functionality. They are all assessed with the following equations:

Congestion cost

Value (€) = [Curtailment (kWh) * Curtailment unitary cost (€/kWh)]

Electricity losses

Value (€) = [Losses (kWh) * Price of energy losses (€/kWh)]

Sags and swells (Quality of Supply)

Value (€) = [Deviation Time (h) * Load Poorly Served (kW estimated) * VOQ (€/kWh)]

The main objective of the analysis is to assess the value of controlling voltage by using OLTC and reactive power control, as well as curtailing distributed generation, in LV and MV networks.

In particular, the following sub-objectives are identified:

1) Quantifying the value of having a good prediction to guide decisions
2) Quantifying the value of controlling voltages every minute versus controlling voltages every hour or even in longer periods.
3) Quantifying how the existence of PV fluctuations influences the value of controlling voltage.
4) Identifying the best strategy to set curtailment set-points of distributed generation.

4.2 Methodology

As a first estimation, power flow analysis tools can be used to assess these benefits and for this study Matlab/Matpower is used to model representative networks and simulate the voltage control with different control means. To perform this analysis, the following data is required:

- Load and generation profiles (forecasted and actual)
- Technical data of lines and transformers
- Characteristics and location of control means
- Value of Quality (VOQ)

The project scenario is the following:

- **Project scenario:** OLTC, reactive power regulation, curtailment

The OLTC is modelled by means of controlling the reference of the slack bus. Simulations also investigate how inverters of PV generators contribute to voltage control by regulating reactive power. The current active power production is determined according to the daily profile of PV generation. Taken into account the limitation of the apparent power, the constraints of the reactive power consumed or generated are established. When no other control variables are available, the model uses curtailment to comply with the voltage limits.

The main steps of the methodology can be summarized as follows. Appendix C provides further information.

First, LV and MV networks are modelled using Matlab/Matpower. Demand and generation are increased relative to the reported values, in order to investigate cases in which voltage control is necessary. The modelling includes OLTC, residential consumers, PV generation and reactive power control. Daily profiles with an 1 minute resolution are identified and taken into account for consumers and PV generation.

Set-points are determined for the production of distributed generation and for the reactive power control. The process of deciding the value of the set-points and quantifying the impact of each scenario is composed of three steps.

1) First, an optimal power flow (OPF) for each minute is evaluated. In this OPF the slack bus produces energy using a daily cost curve of energy of about 40€/MWh. The PV generation is dispatched at a 0 €/MWh cost. Therefore PV generation is only curtailed when voltage problems occur. Initially voltages are constrained to 0.95 p.u. – 1.05 p.u in Portuguese case[4]. If the OPF doesn't converge (i.e. voltage limits cannot be satisfied even curtailing PV), then voltage limits are relaxed by 0.01p.u. Voltage limits are relaxed till the OPF converges. This initial OPF is modelling how the DSO might decide the curtailment decisions, curtailing energy only when voltage limits are not satisfied. These decisions are taken based on predictions. Therefore, in case of modelling a prediction error, the profiles used in the OPF include a prediction error. Prediction error can affect both load estimation and PV estimation. The two extreme situations are considered, a) load overestimation and generation underestimation; and b) load underestimation and generation overestimation.
2) Second, the set-points are determined. When the control decisions are taken every minute, the set-points are directly set to the values obtained by the OPF. Instead, when decisions are taken in longer periods, the curtailment set-points are set, a) using the median of the set-points of every minute, and b) using the minimum of the set-points of every minute, with a view to minimizing voltage problems. Reactive power set-points are always set using the median.
3) Finally, the evaluation of the scenario is assessed running another OPF every minute, in which PV generation and reactive power control variables are set to the

[4] In Greek case, the limits are 0.9p.u. and 1.1 p.u.

set-points identified in step 2, with the slack bus being located in the substation the only control variable. Using the results of these OPF a) curtailment cost, b) voltage cost; and c) energy losses cost, are quantified. The reductions of these costs are the benefits associated to each type of control.

The following scenarios and sensibilities are studied. Although they have been simulated in all the networks, only the most representative cases are selected to be presented in this report.

1) Test case 1: Sensitivity to prediction error.
   - The following values of prediction errors are modelled: 0%, 10%, 20%, 30% and 40%. The two extreme situations regarding network operation are simulated.
     a) Underestimating PV generation and overestimating demand.
     b) Overestimating PV generation and underestimating demand.
   - This case assumes that set-points are controlled every minute, because the sample interval is assumed to be the same for evaluating OPFs and for fixing set-points. It also assumes 100% DG penetration.
2) Test case 2: Sensitivity to signal interval.
   - The signal interval defines the length of the period in which the set-points are transmitted, with a view of investigating how communication constraints relate to bandwidth availability. The signal interval values assessed are 1min, 5min, 15min, 30min, 1h, 2h, 4h, 8h, and 24h.
   - The sensitivity is studied in the case of a perfect prediction, as well as in the presence of prediction error. In this case a curve is used to obtain the prediction error, given the instant of the prediction. Sunny days versus days with fluctuations are also compared.
   - Set-points are defined for the distributed generation and for the reactive power control. Two types of set-points are considered, which are described next concerning the case of curtailment signals.
     a) Percentage set-points. In this case the production of the PV installations is limited to a percentage of the real maximum production.

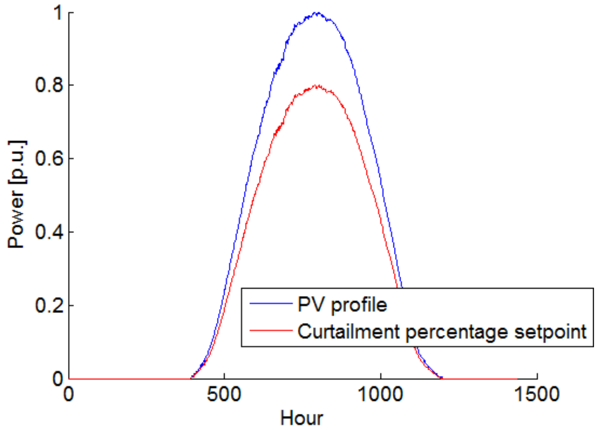

Figure 17 Percentage set-points.

b) Absolute set-points. In this case the production of the PV installations is limited to a maximum production in kW. The restriction only applies when the real PV profile is higher than the set-point. If no curtailment is expected to be required the set-point is set to infinite, meaning that PV will produce as much as possible.

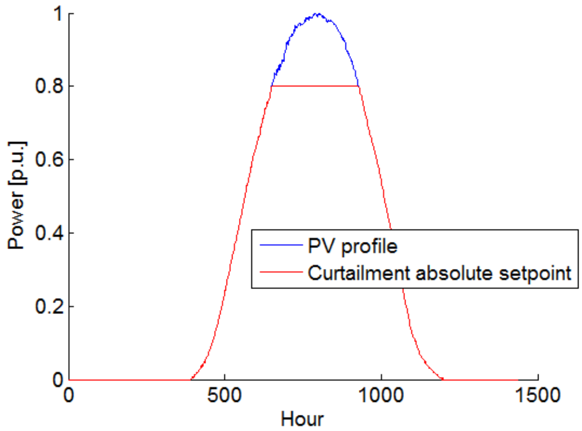

Figure 18 Absolute set-points.

- Two types of methods for obtaining the set-points, based on the information of the OPFs, are studied:

  a) Median of the set-points of the OPFs during a given interval, with the aim of using some kind of average value, but more robust to outliers.

  b) Minimum of the set-points of the OPFs during a given interval, with the aim of maximizing curtailment and minimizing voltage problems.
- The impact of the reactive power control is assessed. Cases with only OLTC and curtailment versus cases with OLCT, curtailment and reactive power control are simulated and directly compared.
- These cases assume 100% DG penetration. The base case studied for all the networks is perfect prediction, regarding a day with fluctuations, while controlling with the median of the absolute set-points.

3) Test case 3: Sensitivity to DG penetration.
    - This case assumes that set-points are controlled every minute, since in this case the sample interval is the same for evaluating OPFs and for fixing set-points. No prediction error is assumed.

4.3 Case studies

4.3.1 Évora LV feeder

4.3.1.1 Implementation details

Évora LV feeder is modelled using Matlab/Matpower. A ±5% voltage limit is taken into account in the simulations, corresponding to the limits in Portugal.

4.3.1.2 Costs assessment

Table 20 shows the equipment considered and its cost. A net present value with a discount rate of 5% and a period of 15 years is evaluated. The cost of the communication system is 1€ and 10€ for controlling every 24 hours and 1 minute, respectively. In the case of intermediate signal intervals, a linear cost decrease is assumed.

Asset	Unitary cost (€)	Duration (years)	Unitary NPV 15 years (€)	Number of units	TOTAL NPV 15 years (€)
DTC prototype	1,178.00	15	1,178.00	1	1,178.00
Single-phase EB GPRS 2nd Generation	85.00	15	85.00	3	255.00
Three-phase EB GPRS 2nd Generation	115.00	15	115.00	9	1,035.00
Outdoor electricity box	1,000.00	20	879.74	12	10,556.88
Grid mapping	300.00	20	263.92	1	263.92
EBs installation	13.00	15	13.00	12	156.00
DTC installation	300.00	15	300.00	1	300.00
Mobile communications	1-10	1/12	130.68-1,306.87	12	1568.24-15,682.44
Total					15,313.04-29,427.24

Table 20 Equipment cost in Évora LV feeder

4.3.1.3 Benefits assessment

The main benefit investigated is the reduction of curtailment. Curtailment cost depends on the cost of energy, which is assessed taking into account the following hourly prices of the wholesale market.

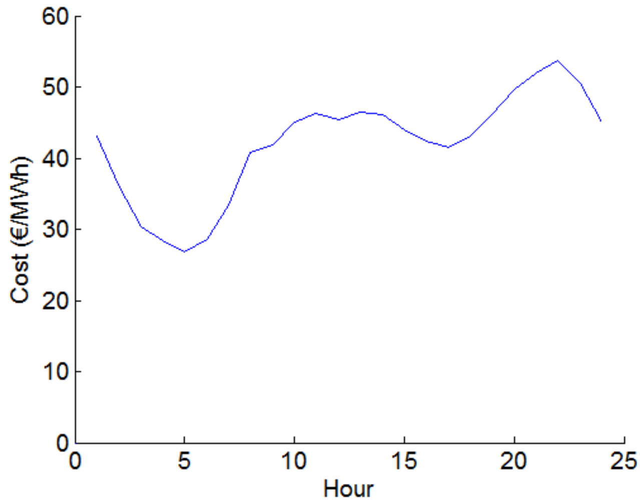

Figure 19 Hourly energy cost.

Two additional benefits are computed. First, benefits derive from the necessity of compliance with the voltage limits. These benefits are assessed using the following voltage cost function. This function assumes zero cost when voltages are within the specified limits, 3€/kWh associated to an interruption cost for very low or high voltages, and a linear interpolation in the intervals 0.8—0.95p.u. and 1.05-1.2 p.u.

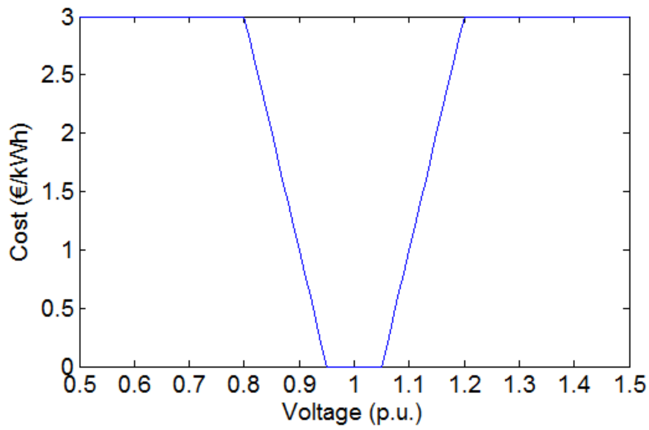

Figure 20 Voltage cost as a function of voltage in per unit.

The last benefit is the reduction of energy losses. These losses are economically assessed using the same hourly prices as for curtailment, which is shown in Figure 19. The net present values of all these costs are calculated with a discount rate of 5% and a period of 15 years. In case that losses are to be evaluated using the price of the regulator, this cost is 101.3€/MWh, which would lead to 2.41 times the cost taken into account in this section, related to the wholesale market.

4.3.1.4 Comparison of costs and benefits

4.3.1.4.1 Test case 1: Sensitivity to prediction error

Figure 21 shows the cost and benefits of the prediction error during one day with fluctuations, in case of underestimating distributed generation and overestimating demand. In this LV network, the voltage cost is higher than the curtailment cost, so total cost is mostly influenced by the improvement of voltage cost. On the one hand, when underestimating distributed generation, the higher the prediction error, the higher the voltage cost is. This results in an increase of total cost as the prediction error grows. On the other hand, when overestimating distributed generation, curtailment increases while voltage cost remains constant. This also leads to an increase of total cost. The order of magnitude is also similar in that case.

Costs and benefits are significantly lower in this LV network than in the subsequent sections, which model MV networks. The reason for this is that in the LV network, power and energy are lower than in the MV network, and therefore this leads to lower costs.

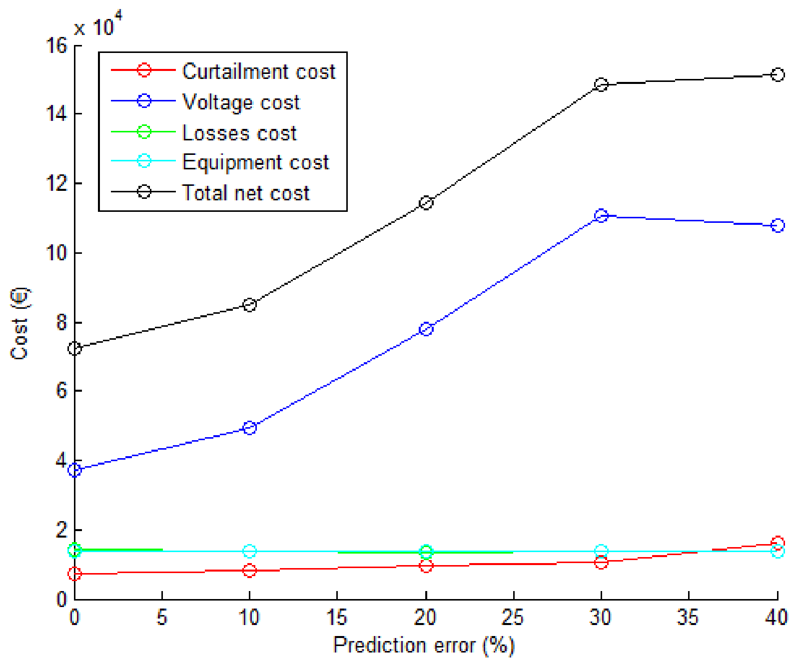

Figure 21 Sensitivity to prediction error, in the case of underestimating distributed generation and overestimating demand, by controlling every minute using the absolute set-points in a day with fluctuations.

4.3.1.4.2 Test case 2: Sensitivity to signal interval

Figure 22 shows the costs and benefits considering the sensitivity to the signal interval, that is, the length of the period in which set-points are fixed. The higher the signal interval, the higher the total cost is. The exception is for long signal intervals, as in this case the equipment cost decreases, because the communication cost reduces. In case that the prediction is not perfect, the results are similar to the perfect prediction case. In case of a sunny day, results are also very similar to results in days with fluctuations, meaning that controlling voltage in short intervals has a value in both types of days, independently on the existence of fluctuations. It was also checked that the effect of reactive power control is negligible in the LV network; as it is usually the case in this voltage level due to the high R/X ratio of conductors.

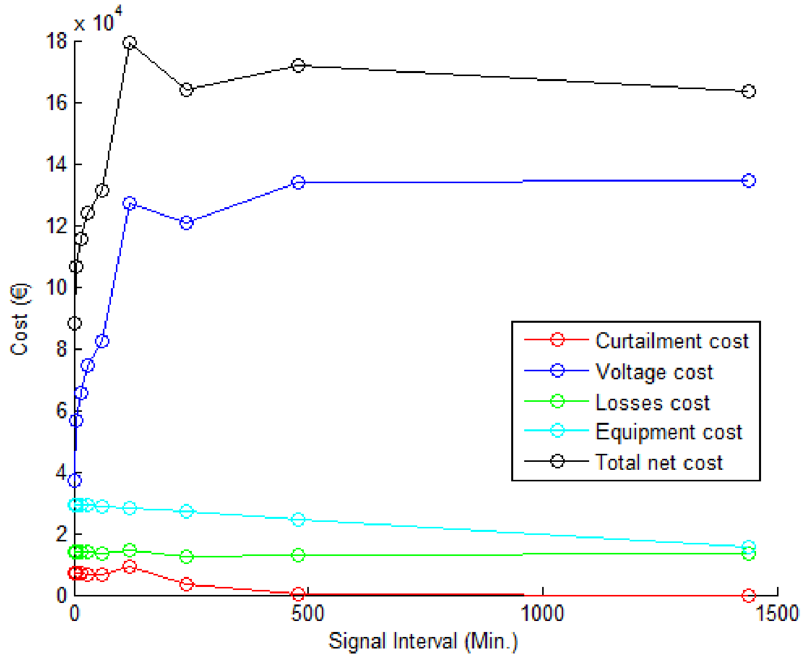

Figure 22 Sensitivity to signal interval in the case of perfect prediction in a day with fluctuations, by controlling using the median of the absolute set-points.

4.3.2 Évora MV feeder

4.3.2.1 Implementation details

Évora MV feeder is modelled using Matlab/Matpower. A ±5% voltage limit is taken into account in the simulations, corresponding to the limits in Portugal.

4.3.2.2 Costs assessment

Table 21 shows the equipment considered and its cost. The net present value is calculated using a discount rate of 5% and a period of 15 years.

Asset	Unitary cost (€)	Duration (years)	Unitary NPV 15 years (€)	Number of units	TOTAL NPV 15 years (€)
SSC prototype	11780	15	11,780.00	1	11,780.00

DTC prototype	1,178.00	15	1,178.00	35	41,230.00
Three-phase EB GPRS 2nd Generation	115.00	15	115.00	14	1,610.00
Outdoor electricity box	1,000.00	20	879.74	14	12,316.36
Grid mapping	300.00	20	263.92	1	263.92
EBs installation	13.00	15	13.00	14	182.00
SSC installation	3000	15	3,000.00	1	3,000.00
DTC installation	300.00	15	300.00	35	10,500.00
Mobile communications	1-10	1/12	130.68-1,306.87	49	6,403.66-64,036.63
Total					87,285.94-144,918.91

Table 21 Equipment cost in Évora MV network

4.3.2.3 Benefits assessment

Benefits are assessed taking into account the reduction of curtailment, voltage deviation cost and energy losses. As in the LV network, the main benefit considered is the reduction of curtailment. In particular, the same hourly prices as in the LV network are applied, which are shown in Figure 19. Voltage problems are computed using the voltage cost function shown in Figure 20. Energy losses are computed using the hourly prices shown in Figure 19. These costs are presented together with the equipment costs in section 4.3.2.4. Costs are represented using the net present values calculated with a discount rate of 5% and a period of 15 years.

As in this network the energy generated is greater than in the LV network, curtailment costs increases. As the power and energy of electrical buses is also higher in the MV network than in the LV network, this leads to more costly voltage problems and to more energy losses. Therefore, the benefits associated with these concepts are also higher.

4.3.2.4 Comparison of costs and benefits

4.3.2.4.1 Test case 1: Sensitivity to prediction error

Figure 23 shows the sensitivity to the prediction error in case of underestimating distributed generation and overestimating demand. As distributed generation is underestimated, the higher the prediction error is, the lower the curtailment is. This results in voltage deterioration increasing the total cost.

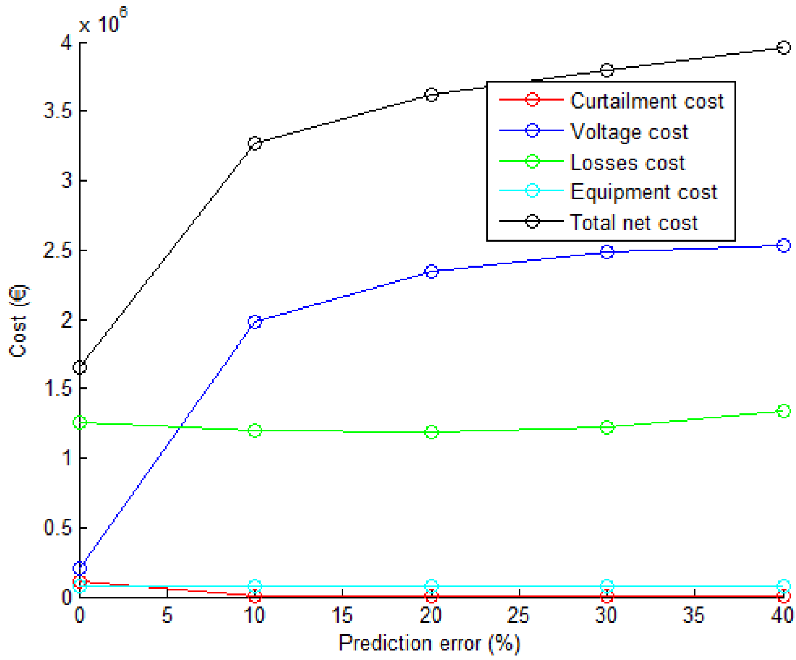

Figure 23 Sensitivity to prediction error In the case of underestimating distributed generation and overestimating demand, by controlling every minute using the absolute set-points in a day with fluctuations.

Figure 24 shows the sensitivity to prediction error, in case of overestimated distributed generation and underestimated demand. In this case, due to the overestimation of distributed generation, curtailment increases, while the voltage problems remain low. This is the opposite effect compared to what was observed when distributed generation was underestimated. Despite in one case the driver for total cost is voltage cost and in the other case it is curtailment cost, the order of magnitude of total cost is very similar. It reaches a maximum of about 350,000€-400,000€ in the day considered.

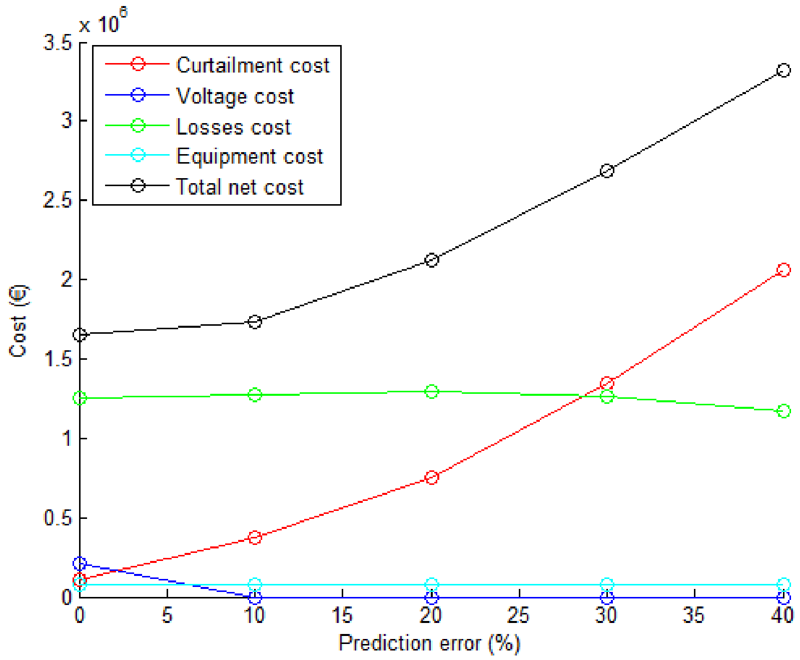

Figure 24 Sensitivity to prediction error In the case of overestimating distributed generation and underestimating demand, by controlling every minute using the absolute set-points in a day with fluctuations.

4.3.2.4.2 Test case 2: Sensitivity to signal interval

Figure 25 shows the sensitivity to the signal interval, that is, the length of the period in which set-points are fixed. The higher the signal interval is, the higher the total cost is. Cost increases as a result of the increase in the voltage cost, as the signal interval increases. The sensitivity to the signal interval is shown in Figure 25, where controlling with the median of the absolute set-points is applied. Total cost saturates starting at a signal interval of 2h. As in the LV network, the increase is mainly due to the voltage cost.

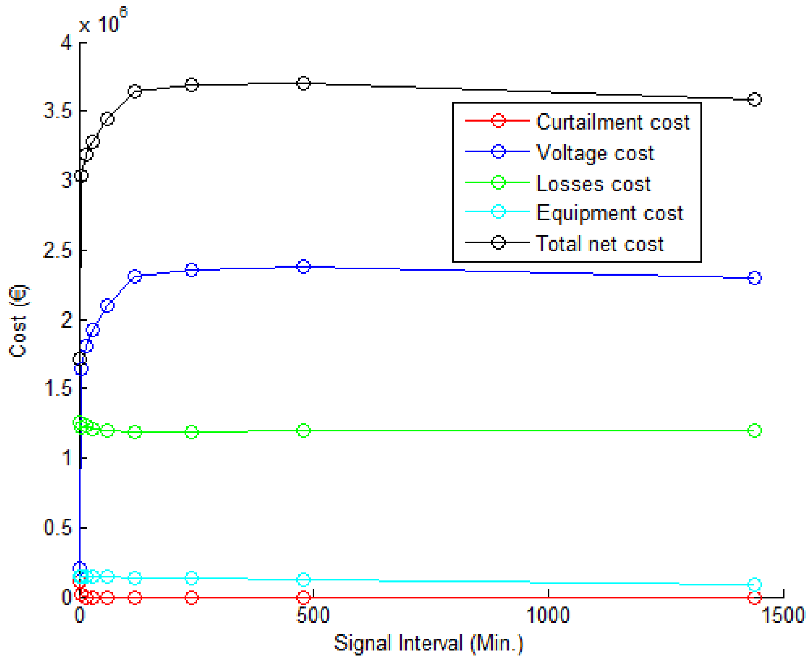

Figure 25 Sensitivity to signal interval in the case of perfect prediction, by controlling using the median of the absolute set-points in a day with fluctuations.

Figure 26 shows the zoom in during 1 hour, showing that in this network controlling every minute is beneficial for the grid, but total cost is very similar in the interval 5min-1hour. This means that, in this network, the best cost-benefit ratio could be obtained for 1 min control interval.

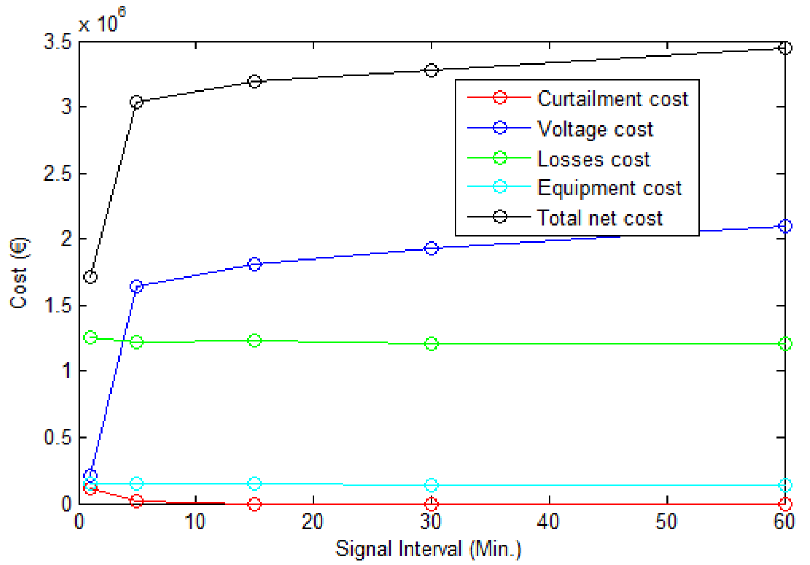

Figure 26 Sensitivity to signal interval in the case of perfect prediction, by controlling using the median of the absolute set-points in a day with fluctuations (zoom in, 1 hour).

Figure 27 shows the impact in a sunny day with no fluctuations. Controlling with signal periods of 2h is less beneficial for the grid than in the day with fluctuations. However, the magnitude order of total cost and its general tendency are similar, which confirms the fact that controlling with smaller periods is beneficial for the grid, both in days with fluctuations and in days without fluctuations. In this day however the highest cost is obtained controlling every 4h, while in the other day the highest total cost was already obtained controlling every 2h.

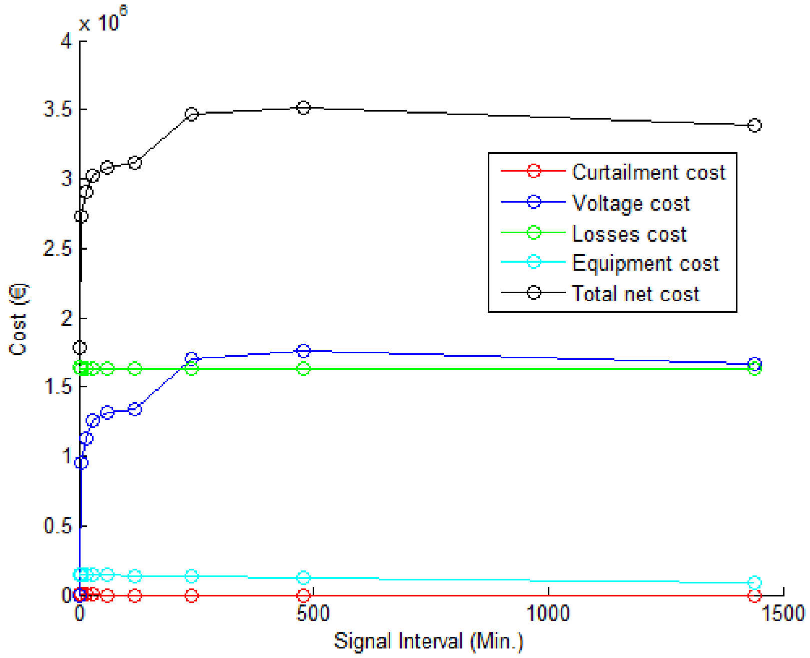

Figure 27 Sensitivity to signal interval in the case of perfect prediction, by controlling using the median of the absolute set-points in a regular day.

Figure 28 shows the sensitivity to the signal interval in case of reactive power not being used for voltage control. Small differences are observed compared to the case of reactive power control as well, shown in Figure 25. In case of 1 min interval control, the cost is lower in Figure 25 than in Figure 28. This means that reactive power control contributes to system cost reduction. However, in case of 5 min interval control, the costs are slightly lower without reactive power control. This means that, in this particular case, sending the median set-points every 5 min does not provide adequate signals to control reactive power.

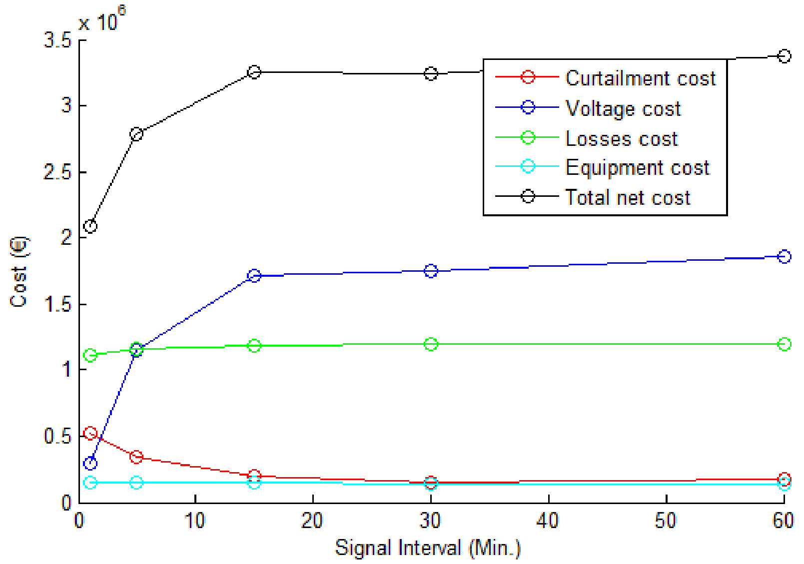

Figure 28 Sensitivity to signal interval in the case of perfect prediction, by controlling using the median of the absolute set-points in a day with fluctuations, without using reactive power control.

4.3.2.4.3 Test case 3: Sensitivity to DG penetration

Figure 29 shows the sensitivity to DG penetration. Although in the other sensitivities studies there is generally some kind of a trade-off between curtailment and voltage cost, in case of DG penetration, all indicators get worse as DG penetration increases. This means that for an increased level of DG penetration, total cost increases as a result of curtailment cost, voltage cost and energy cost. This confirms that higher DG penetration levels lead to more challenges for the distribution network operators, rendering the use of smart solutions necessary, provided that network reinforcements are to be avoided.

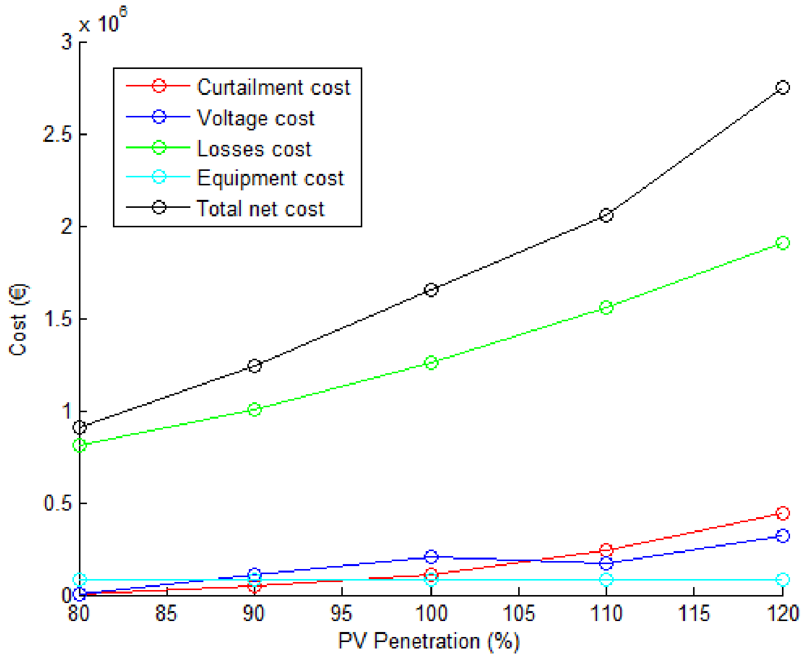

Figure 29 Sensitivity to DG penetration in the case of perfect prediction, by controlling using the median of the absolute set-points in a day with fluctuations.

4.3.3 Rhodes MV feeder (R-260)

4.3.3.1 Implementation details

Rhodes MV feeder is modelled using Matlab/Matpower. A ±10% voltage limit is taken into account in the simulations, corresponding to the limits in Greece.

4.3.3.2 Costs assessment

Table 22 shows the equipment considered and its cost. The net present value with a 5% discount rate and a period of 15 years is calculated.

Asset	Unitary cost (€)	Duration (years)	Unitary NPV 15 years (€)	Number of units	TOTAL NPV 15 years (€)
SSC prototype	11,780	15	11,780.00	1	11,780.00
DTC prototype	1,178.00	15	1,178.00	84	98,952.00
Three-phase EB GPRS 2nd Generation	115.00	15	115.00	35	4,025.00
Outdoor electricity box	1,000.00	20	879.74	35	30,790.90
Grid mapping	300.00	20	263.92	1	263.92
EBs installation	13.00	15	13.00	35	455.00
SSC installation	3000	15	3,000.00	1	3,000.00
DTC installation	300.00	15	300.00	84	25,200.00
Mobile communications	1-10	1/12	130.68-1,306.87	119	15,551.75-155,517,53
Total					190,018.57-329,984.35

Table 22 Equipment cost in Rhodes MV network

4.3.3.3 Benefits assessment

Benefits are assessed taking into account the reduction of curtailment, voltage problems and energy losses. As in the LV network, the main benefit is the reduction of curtailment. In particular, the same hourly prices as in the LV network are applied, which are shown in Figure 19. Voltage problems are computed using a similar voltage cost function to the one shown in Figure 20, but with voltage cost being zero in the interval between 0.9 and 1.1 p.u., as the voltage limits in Greece are ±10%. Energy losses are computed using the hourly prices shown in Figure 19. The net present values of these costs are presented together with the net present value of equipment cost in section 4.3.3.4.

4.3.3.4 Comparison of costs and benefits

4.3.3.4.1 Test case 1: Sensitivity to prediction error

Figure 30 shows the costs and benefits due to the prediction error in Rhodes MV Network, in case of underestimating distributed generation and overestimating demand. The result is very similar to the ones obtained in Évora MV network. As distributed generation is underestimated, curtailment remains low or decreases and voltage problems get worse. The opposite effect occurs in case of distributed generation overestimation. In that case, curtailment increases and voltage cost remains low or decreases. Total cost is lower than that in Évora MV network.

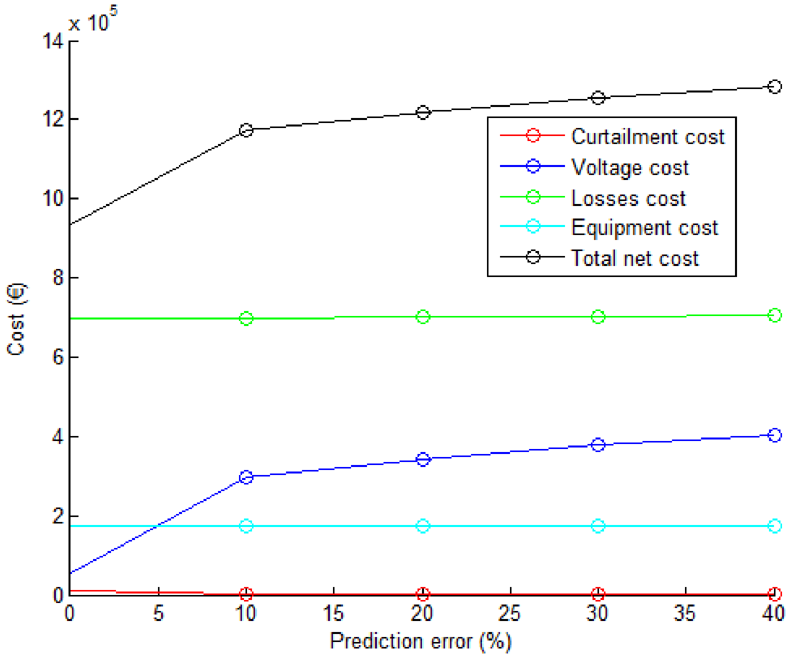

Figure 30 Sensitivity to prediction error in the case of underestimating distributed generation and overestimating demand, by controlling every minute using the absolute set-points in a day with fluctuations..

4.3.3.4.2 Test case 2: Sensitivity to signal interval

Figure 31 shows the costs and benefits as a function of the signal interval for OLTC, curtailment and reactive power control. Similarly to Évora MV network, the higher the signal interval is, the higher voltage costs are. However, this tendency changes regarding the interval between 2h and 24h (120min.-1440min.), yielding a significant decrease. This decrease in total cost is due to the reduction of the communication requirements as the signal interval increases. This means that controlling every 2h has less net benefit with respect to controlling every 24h. On the contrary, the total net cost for 1 min control is much lower than the corresponding for 24h control. This implies that controlling 1 min control is much more effective. The highest costs are observed in case of controlling every 2h. The main driver for total cost increase when controlling using the median of the absolute set-points is voltage cost which increases together with the signal interval up to 2h. Curtailment costs remain very low in any case.

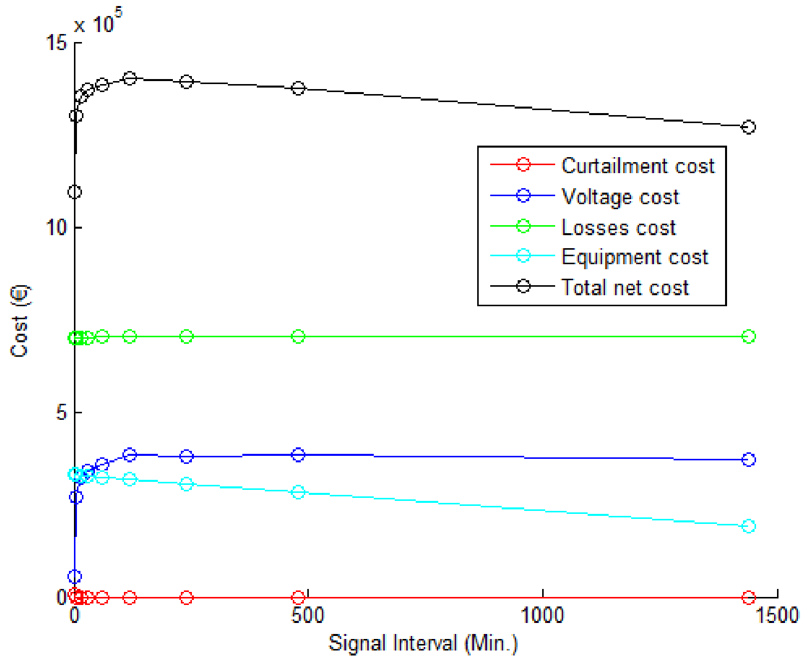

Figure 31 Sensitivity to signal interval In the case of perfect prediction, by controlling using the median of the absolute set-points in a day with fluctuations.

Figure 32 shows the sensitivity to the signal interval in case of control using the minimum of the absolute set-points. In this case, curtailment increases and, thus, total cost increases as well. A plausible explanation is that choosing the minimum of the set-points leads to curtailment maximization. In case of control using the median of set-points, it is the voltage cost which increases, and therefore there is also in an increase in the total cost. This means that there is insufficient curtailment. The final effect (total cost rise) is the same in both cases, although the main driver for the total cost increase is different. Observing the scale of the Y-axis of Figure 32 and Figure 31, it is evident that total costs are higher in case of control using the minimum of the absolute set-points. This is the reason why the median of the set-points is usually employed as the control principle in this work. In general, controlling with the minimum set-points implies using lower set-points, which leads to more curtailment. However as a result of the increased curtailment, there are usually less voltage problems.

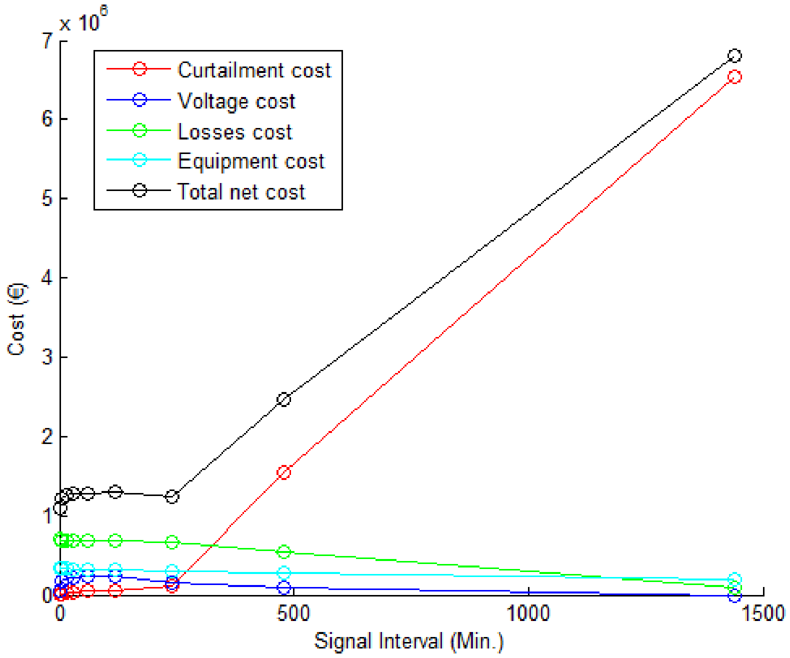

Figure 32 Sensitivity to signal interval in the case of perfect prediction, by controlling using the minimum of the absolute set-points in a day with fluctuations.

Figure 33 shows the sensitivity to the signal interval in case of control using percentage set-points. Results are similar to these emerged from control with the median of the absolute set-points. By means of percentage set-points, curtailment is specified as a percentage of the DG production, and this curtailment takes place even if the final DG production is much lower. This means that control using absolute set-points might work better for defining the DG maximum production, avoiding unnecessary curtailment. However, they can result in voltage cost increase, as it is shown in this particular case.

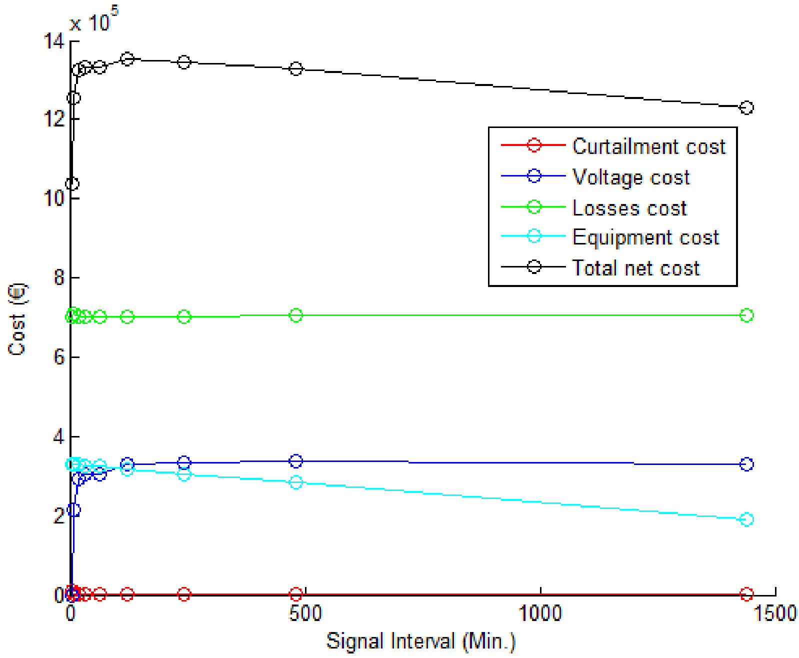

Figure 33 Sensitivity to signal interval, in the case of perfect prediction, by controlling using the median of the percentage set-points in a day with fluctuations.

4.4 Conclusions

In this chapter, it is observed that prediction error and transmission interval of set-points signals are of great interest from a voltage control point of view. The impact of signal interval and prediction error reduction is similar. Therefore, resources should be dedicated to improve both communication systems and prediction tools.

The prediction error leads to voltage cost increase when distributed generation is underestimated. However, when distributed generation is overestimated, curtailment cost increases. Although drivers are different, in both cases this leads to a total cost increase, meaning that, as expected, the lowest cost corresponds to no prediction error, that is, it is preferable to make all related calculations with the actual DG profile. However, it still has to be determined which level of research cost is required to reduce the prediction error.

In this work, the sensitivities to the signal intervals are mainly studied using control by means of the median of the absolute set-points. This technique is advisable to provide a correct signal for curtailment, while obtaining adequate levels of voltage quality. Controlling with absolute set-points is more precise for setting an upper limit of DG production. In case of percentage set-points, some extra curtailment may also be applied when DG production is low, which in some cases can lead to further reduction or voltage costs.

There are some differences in voltage control concerning days with fluctuations versus sunny days with no fluctuations, but the related tendencies are similar. However, in Évora MV network, it is found that the total cost is lower for 2h interval control in sunny days than in days with fluctuations.

Reactive power control shows to have only a negligible impact regarding LV since these networks are characterized by the R/X ratios. In MV networks, in case of 1min interval control, there is a cost reduction associated with the reactive power control. However, in case of 5min interval, such reduction is not observed. This fact points out how necessary proper interval determination is for effective reactive power control. In this particular case, controlling reactive power every 5min. by sending the median of the reactive power set-points does not seem to be effective for reducing voltage problems.

5 Conclusions

The three fields studied show that implementing smart grid solutions can have a positive cost-benefit ratio, depending on their particular implementation. In case of RES forecasting tools, a 10% prediction error is generally within profitability limits. Moreover, benefits are clearly higher than costs for a 7% prediction error. The main benefits are obtained from the reduction of the ancillary service cost. A reduction of the 38% in the forecasting error results in a reduction of the ancillary services cost in a similar portion (34%). On the other hand, in the scenarios analysed, the corresponding impact on the thermal costs and CO2 emissions is very small, meaning that rather there is a modification of generation operation than substantial changes in the market structure.

The two cases studied are representative of two types of situations. In Portugal case study, where a conservative increase of RES is assumed, all costs increase in order to supply the additional demand. On the contrary, in Greece case study, where a larger amount of RES penetration is modelled, ancillary service cost experience a huge increase, that can be mitigated effectively thanks to the forecasting tools. Therefore, tools developed in SUSTAINABLE can have a considerable impact in allowing more renewable energy integration.

In the case of smart monitoring and control, low automation degrees can achieve a significant reduction of the continuity of supply indexes, while the indexes saturate for higher automation degrees. By cross comparing costs and benefits, it is confirmed that low automation degrees are the economic optimum. In particular, in Évora MV network, a 7% is identified as the optimum automation degree, while, in Rhodes MV network, the optimum is 3%. However, in Évora MV network the net benefit is positive up to 40%, meaning that even though the preferred automation degree is 7%, benefits would also be obtained with higher automation degrees. The sensitivity to the time threshold that determines which interruptions are taken into account to compute the continuity of supply indexes shows that an 1min threshold could lead to a higher SAIFI than in the case of a 3min- threshold, but could also have almost no impact in SAIDI or in the cost benefit analysis. Therefore, the optimum would still be 7% in Évora network and 3% in Rhodes network. Overall, this analysis points out the necessity to boost automation implementation in distribution networks.

Regarding voltage control, it is observed that prediction error reduction also serves more benefits for power networks. Therefore, prediction tools could prove beneficial not only to the electricity market, but also to distribution networks (in case of a centralized voltage control system). This is confirmed in both cases of DG production overestimation and in the case of DG production underestimation. In both cases, the order of cost magnitude is similar, although the drivers for the cost is voltage cost and curtailment cost, respectively.

From the communication system point of view, the capability to transmit set-points frequently could improve voltage control effectiveness. The most significant benefits are obtained via 1 min control. The benefits saturation starts approximately between 2h and

4h. Regarding reactive power control, the appropriate selection of the set-points is identified as a critical parameter. If there is no frequent transmission of reactive power set-points, there will not be substantial benefits.

The cost-benefit analysis carried out shows that smart grid solutions bring net benefits dependent on the sensibilities to the prediction error and the automation degree, among others. In this case, the selection of the optimal prediction error and automation degree targets is critical in order to integrate renewable energy sources in a cost efficient way. Overall, this highlights the necessity of carefully assessing smart grid solutions taking into account technical characteristics of each distribution area to identify the best opportunities.

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Appendix A: RES Forecasting in Market Operation

The main objective of the ROM model is to study the impact of intermittent generation on the power system operation. Besides, it permits the estimation of the maximum of intermittent generation that can be integrated into the system with a certain level of reliability. Finally, it identifies the possible actions that allow a higher integration of intermittent generation without compromising system reliability.

The operational model receives as input data the installed capacity previously computed and simulates the system hourly operation during a year. For each day unit commitment and economic dispatch are deterministically optimized. Detailed operation constraints such as minimum load, ramp rate of thermal units and secondary reserve procurement are included into the daily optimization model. Up reserve and down reserves depend on each hour. For instance, the demand and RES generation used for the Portugal and Greece case studies are included in Figure 34 and Figure 35.

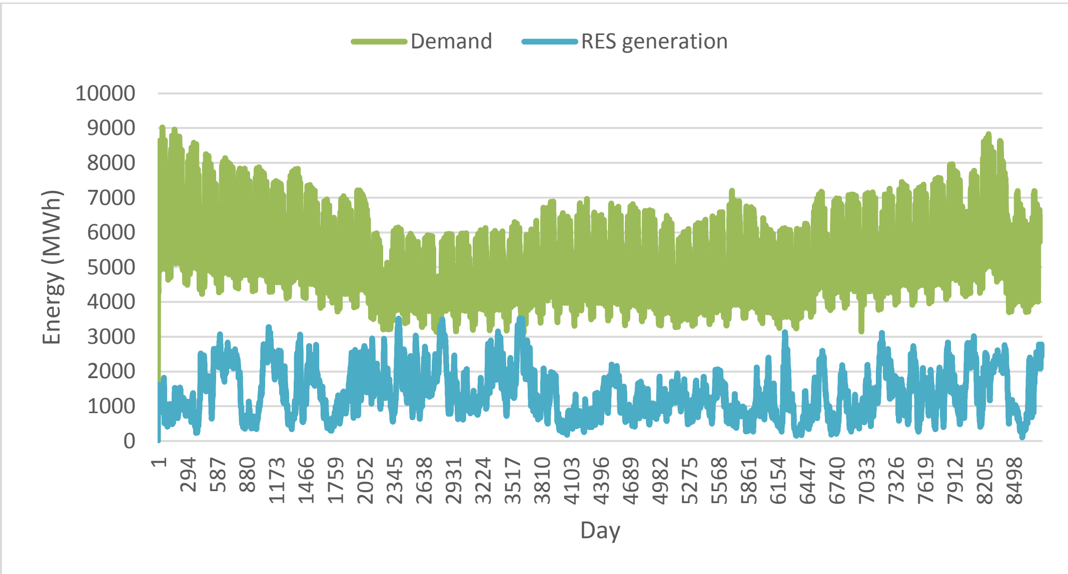

Figure 34 Demand and RES generation profiles used for Portugal case study in 2014

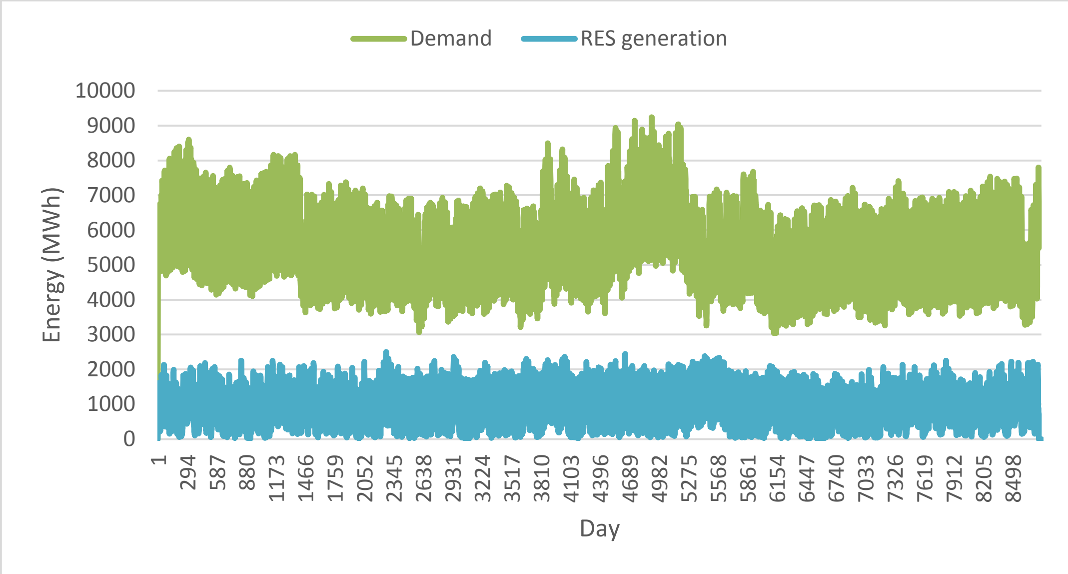

Figure 35 Demand and RES generation profiles used for Greece case study in 2014

Different events are simulated, such as unit failures, RES forecasting errors, and corrective actions are applied, such as use of up and down reserve, use of pumped storage units, commitment of gas turbine units in real time, use of electric vehicles, etc. This process is repeated for the 365 days of the year Figure 36.

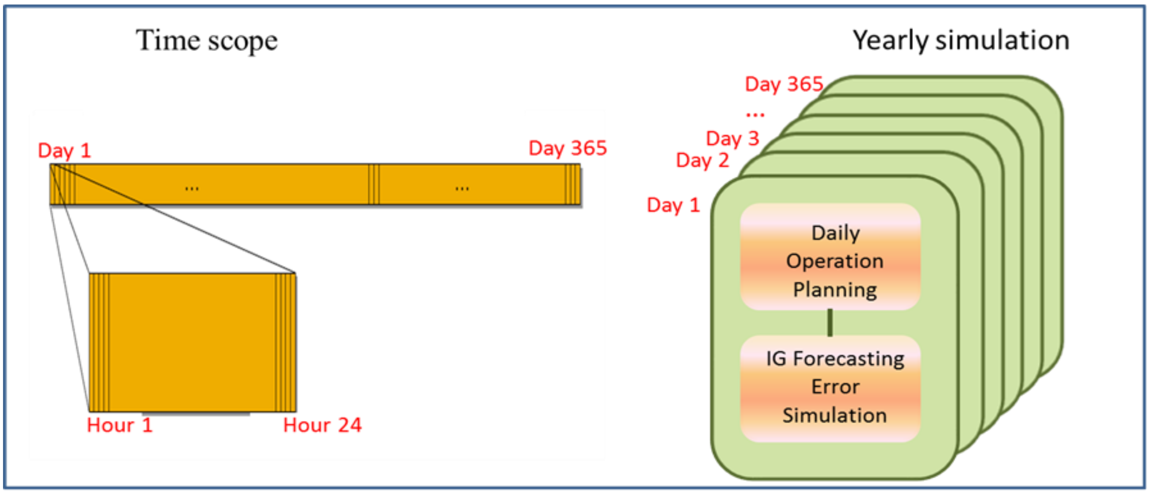

Figure 36 Mid-term operational model

Apart from the characteristics of thermal groups, other input data are hourly demand, intermittent generation, wind forecasting errors, distributed generation profiles and EVs data.

The optimization problem is to meet demand and the requirements of up and down reserve minimizing operation costs, which includes thermal units' variable costs (fuel, operation & maintenance, CO2 emissions and start-up costs), hydro units' variable costs, penalty for shortcoming of up and down reserve and costs of energy not supplied.

The constraints of the model are: i) generation-load balance and assignment of up and down reserve; ii) thermal units: start-up/shutdown and unit commitment; bound on power reserve and power output; up and down ramps; exponential start-up costs; iii) hydro units: bound on pumped storage hydro up and down power reserve; water inventory in hydro storage reservoirs and pumped storage hydro; bound on hydro power output; daily hydro output target; electric vehicles: charge and discharge.

This model allows the analysis of power reserve needs, thermal and hydro generation output, among other resources in the system. The operational analysis is essential in order to determine if the capacity resulting from the expansion model can be safely integrated to the system.

The main outcomes are hourly generation by technology, including pumped storage hydro and electric vehicles generation and consumption, wind curtailment and water spillage, energy not supplied, fuel and CO2 costs and system marginal cost.

Appendix B: Smart Monitoring and Control to improve continuity of supply

An IIT-COMILLAS simulation model has been used to assess the continuity of supply indexes (SAIDI and SAIFI). The objective of the model is to obtain these indexes, which quantify the frequency of interruptions and their duration. To obtain these figures, the model simulates the process of a control centre to locate the faults, repair the faults and restore the service.

The model requires as input:

1) The topology of the distribution network
2) The consumers
3) The failure rate of power lines
4) The existence of automation or monitoring in the distribution network.

The model simulates every possible fault in the network. Then, it assesses which consumers are affected. Finally, it simulates the process of locating the fault, repairing it and restoring the service, in order to determine the duration of the interruptions. Once all the interruptions are parameterized, and their duration is estimated, the model computes SAIDI and SAIFI indexes according to the following formulas:

$$SAIFI = \frac{\sum \lambda_i N_i}{N_T}$$

$$SAIDI = \frac{\sum U_i N_i}{N_T}$$

Where, λ_i is the failure rate, N_i is the number of consumers affected, U_i is the annual outage time, N_T is the total number of consumers served.

The main outputs of the model are SAIFI and SAIDI indexes, as well as some variations of these indexes such as TIEPI[5] and NIEPI[6]. The difference between SAIFI/SAIDI, and NIEPI/TIEPI, is that SAIDI and SAIFI weight interruptions based on number of consumers, while TIEPI/NIEPI weight per installed power. In general, SAIFI and SAIDI are used in this report, as they are more commonly used. However, the calculations of the cost benefit analysis are based on TIEPI.

[5] TIEPI is Installed Capacity Equivalent Interruption Time
[6] NIEPI is Installed Capacity Equivalent Number of Interruptions

Appendix C: Centralized voltage control

Figure 37 shows as example 6 residential consumer profiles. A total of 65 different profiles have been modelled using the Load Profile Generator[7].

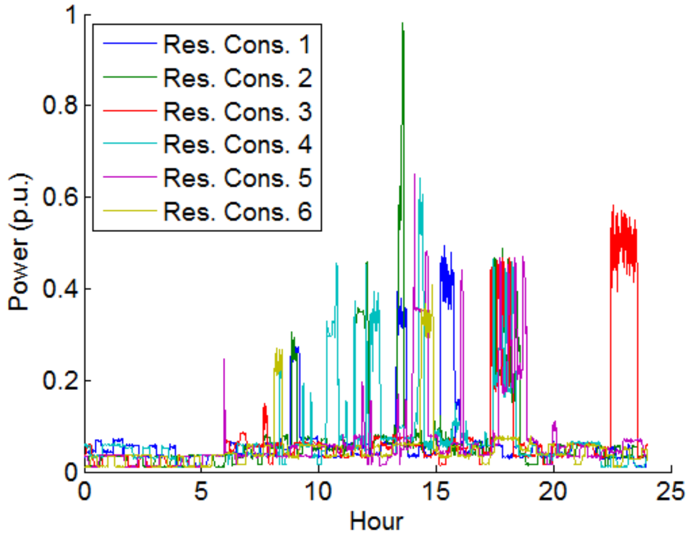

Figure 37 Residential consumer profiles, with a 1min. resolution.

Figure 38 shows the aggregated profile of the consumers in the database. This is the profile that has been used in the MV networks.

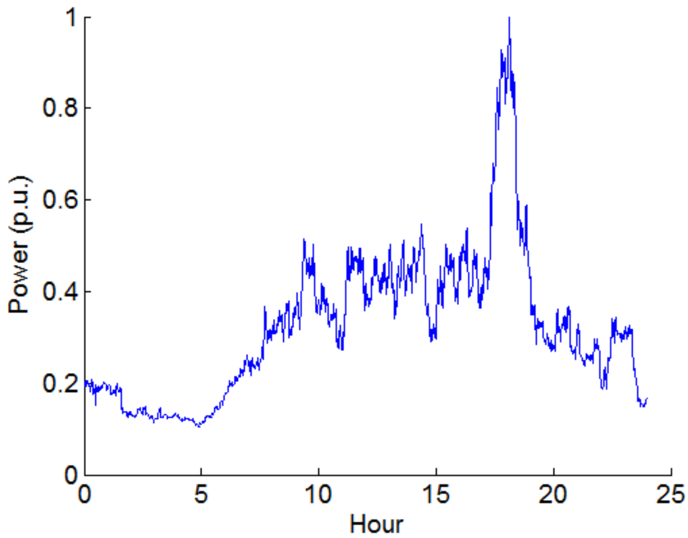

Figure 38 Aggregated consumer profiles, with a 1min. resolution.

[7] http://www.loadprofilegenerator.de/

Figure 39 shows the photovoltaic profiles under study. One case study is a sunny day, and the other case study is a day with many fluctuations.

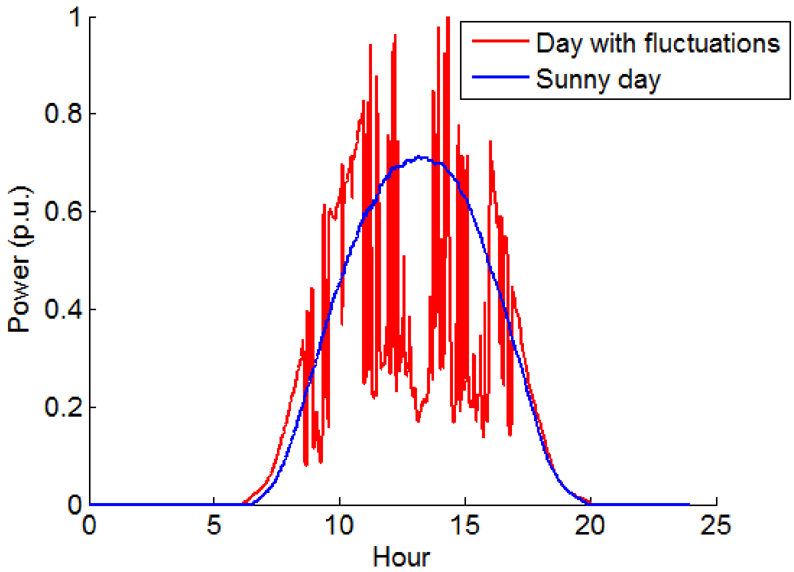

Figure 39 Photovoltaic profiles with a 1min. resolution.

Figure 40 shows the bus voltages in Évora MV network in case of no prediction error and in the case of 40% prediction error. In case of prediction error, some voltages are above 1.05p.u. This graph represents all voltages, and as most voltages are inside limits, it does not adequately represent the cases outside limits (which are only a fraction). Therefore, an alternative way of representation is used next.

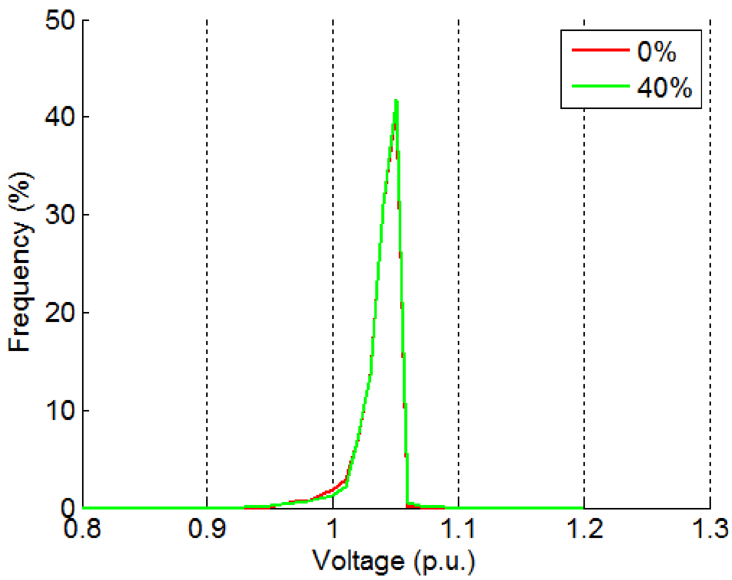

Figure 40 Bus voltages in Évora network depending on the prediction error.

Figure 41 shows the bus voltages in case of no prediction error. Each line is a cumulative distribution function of all the bus voltages in 1 minute. Except for a few voltage values above 1.05p.u., most voltages are in the range from 0.95 to 1.05 p.u.

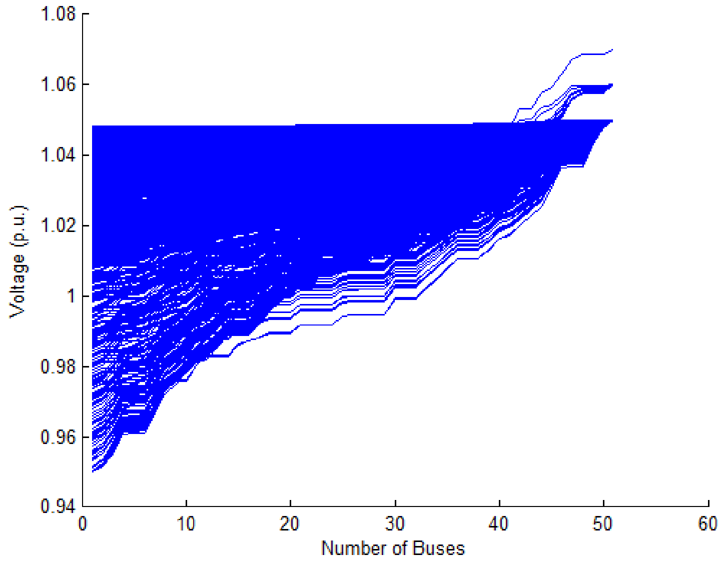

Figure 41 Bus voltages in Évora network. No prediction error

Figure 42 shows the bus voltages in case of a 40% prediction error. In this case, there are voltage values lower than 0.95 p.u., which were the inside limits for 0% prediction error. Besides, some more voltage values are above 1.05p.u.

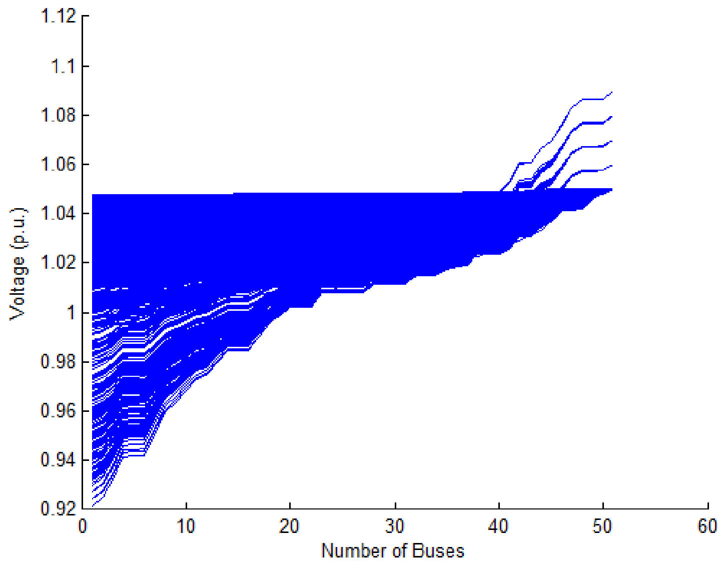

Figure 42 Bus voltages in Évora network. 40% prediction error