Advanced Architectures and Control Concepts for

MORE MICROGRIDS

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Annex H3.A to Deliverable DH3

Multi-criteria Assessment of Business Cases for Microgrids

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2. Introduction

Electric utilities have traditionally satisfied customer demand by generating electricity centrally and distributing it through transmission and distribution networks. When demand increases beyond a certain level, however, the capacity of the generation, transmission and distribution systems can become constrained and the traditional utility response to these constraints is to expand or reinforce existing circuits. Recent researches have indicated the potential of micro-generation (μG) technologies in offering an alternative approach to utilities to satisfy demand locally and incrementally. Indeed, μG may bring about various benefits such as a positive capacity margin, and, if properly allocated, may allow transmission and distribution capacity deferral, losses reduction, energy savings, flattening of the peak, voltage control, ancillary services, higher power quality and lowering the loss of load probability [1]–[7].

The μG impacts on the networks will however depend on several parameters, such as: size, type and location of the new connections; the pattern and timing of output; the density of installations, rural/urban setting and proximity to the load; the state of the network and the overall amount of capacity, etc. [8]–[10]. To enable μG to act as an option for the Distribution System Operators (DSO), the operational strategies which can be used when exploiting μG and Demand Side Management (DSM) need to be considered in the planning exercise.

Furthermore, it is to be recognized that with increased levels of μG penetration, the LV distribution network can no longer be considered as a passive appendage to the transmission network. On the contrary, the impact of μG at LV levels on power balance and grid frequency may become much more significant. As a result, these μG resources inevitably need to cooperate with central generators to keep the balance between supplied and consumed power.

Therefore, an adequate control and management architecture is required in order to facilitate full integration of μG and active load management into the system.

A better way to realize the emerging potential of μG is to take a system approach which views generation and associated loads as a subsystem or a

Microgrid (MG) [11]. Moreover, adequate control and management of set of such subsystems or Multi Micro-grid (MMG) should account for all the benefits expected to be seen at all voltage levels of the distribution network. Therefore, different hierarchical control strategies need to be adopted at different network levels.

The economic benefits of installed μG under the MG and MMG concepts to the utility come from deferred generation and distribution investments, net the costs associated with installing, operating, maintaining, administering, coordinating, scheduling, and dispatching μG units [12], [13]. Utilities, that are not μG owners, may offer capacity payments for units that can be dispatched during times of system need in order to ensure availability and to address their interests in performance guarantees.

The impact that large scale μG operated under coordinated and controlled scheme using the MG and MMG may have on the distribution network may lead to different regulatory approaches by creating incentive mechanisms for the Distribution System Operators (DSO), μG owners and loads to accept the MMG concept and define adequate remuneration schemes. Therefore, identification and evaluation of significant, quantifiable economic, technical and environmental benefits and *costs* attributed to the MG and MMG concepts deployment is a prerequisite for building a comprehensive regulatory framework in favour of easier integration and deployment of these concepts.

Multi Criteria Decision Aid (MCDA) techniques are used to evaluate the MG and MMG impact on LV and MV distribution network trying to capture different preference structures of the Decision Maker (DM) and to help in the evaluation of the cost-benefit relation resulting from the deployment of these concepts.

3. Problem formulation

Potential cost-benefit approach is central to the MMG impact evaluation by addressing the real benefits (and costs) that μG in form of MMG can bring to the distribution networks in order to find out the right incentives to encourage the Distribution System Operator (DSO), μG owners and consumers to be involved in the MMG concept deployment.

Therefore, the MMG impact assessment will be modelled as multi-attribute decision making problem assigned to the DSO where the decision is about choosing the amount of controllable load/µG generation, actively managed within the MMG, among several efficient alternatives (options), to account for the technical problem resolution in terms of high congestion level or high voltage drops.

The distribution network is assumed to be operating in two operating modes:

- Normal operating mode referring to a situation when the network technical constraints, in terms of congestion levels and voltages are not violated;
- Stressed operating mode followed by violation of any technical constraint.

Moreover, periods of high electricity market prices in normal operating mode, will account for indirect benefits for the DSO, in terms of:

- LV and MV active losses reduction;
- Emissions' reduction caused by active losses reduction;
- Emission's reduction due to displacement of central thermal units by µG production with less emissions;
- Network investment deferral (in years),

due to price responsiveness of the controllable µG sources and controllable load within each MG.

Besides the benefits passed to the DSO, minimization of the operational cost of each MG leads to lower energy price for the MG consumers in respect to the upstream market prices, power quality improvement, local reliability enhancement, emissions' reduction due to upstream network units displacement and energy production from the µG units within each MG. These benefits should be separately treated and include further on in the analysis (out of the scope of this report), since both, the DSO and the MMG consumers are profiting from the MG and MMG concepts [14].

Hierarchical control and management architecture assuming three control levels has been assumed for MMG operation, described in details in Deliverable DG3, within WPG.

Furthermore, in periods of low electricity market price, the local μG production is not economically attractive and thus, no μG is expected to be dispatched at MG level under Micro-Grid Central Controller (MGCC) control level. Moreover, consideration of a certain load growth will lead to potentially high congestion levels and/or voltage drops resulting in network reinforcement (network investment). Traditionally, the electric utilities have satisfied customer demand by generating electricity centrally and distributing it through transmission and distribution networks. When demand increases beyond a certain level, however, the capacity of the generation, transmission and distribution systems can become constrained and the traditional utility response to these constraints is to expand or reinforce existing circuits.

An alternative option to the network reinforcement is introduced by solving a global optimization procedure of MMG system operation in so called stressed operating condition, under Central Autonomous Management Controller (CAMC) control level, presented within DG3, which at each time interval of technical constraint violation calculates the amount of available controllable μG (not being dispatched locally, within each MG under MGCC) to be produced and/or controllable load to be curtailed, subject to predefined curtailment contracts. The benefits, coming out of the MMG optimization procedure, performed at CAMC level due to the activation of curtailment contracts and μG dispatch in stressed operating conditions for each hour of technical constraint violation, are assigned as direct benefits attributed to the DSO.

Potential benefits and costs coming out of the MG and MMG concepts deployment are assessed using Multi Criteria Decision Aid (MCDA) techniques. The strategy of the MMG impact assessment is first to identify and evaluate the potential criteria/attributes using different MCDA techniques and furthermore, define potential scenarios in order to deal with uncertainties.

3.1 Multi attribute impact assessment

Since the impact that large scale μG operated and managed under MMG concept will be modelled as multi-attribute decision making problem, the attributes should be externally assessed using the optimization procedures performed at MGCC and CAMC level, described in Deliverable DG3. Moreover, Deliverable DG3 presents and describes only the attributes in terms of potential benefits reported due to MMG concept deployment. What is more, the objective of this report is identification and evaluation of potential MMG costs as well, and therefore MMG cost-benefit assessment using different MCDA techniques for capturing different complexity levels of the Decision Maker's (DSO) preference structure.

3.1.1 MMG installation and operational cost attribute

The MMG installation cost, i.e. the cost of putting in place the MMG taken as an a priori cost, annualized, should be considered together with the MMG operational cost, subjected to careful examination in order to avoid duplication of costs or benefits. The cost of putting in place the MMG in terms of MMG communication and control infrastructure will be considered marginal compared to the MMG installation cost and fuel costs for the μG units within the MMG and therefore will be neglected in our analysis.

The MMG installation cost includes the cost of the MGCC in each of the MGs, the cost of the MC for each type of source considered within each MG, as well as the LC for each of the consumers within each MG being part of the MMG.

On the current pace of this study, we assume simple MMG installation sharing mechanism by equally distributed installation cost between the DSO and the MMG consumers due to the fact that both sides share the benefits from the MG deployment. However, by closer identification of the benefits passed to the consumers due to MMG concept deployment, higher participation of the consumers in the MMG installation cost may take place, leading to different final conclusions.

The cost for putting in place the MGCC is covered by the DNO. Indicative values for the cost of each local controller were used, namely 300€ for each micro wind generator and PVs local controller, 500€ for each local controller of each controllable unit within the MMG and 100€ for each LV load local controller. The cost of the MGCC is assumed to be 500€, whereas the cost of the CAMC functionality related to the MMG optimization procedure, described in DG3, is assumed to be 100 000€ [15].

The MMG operational cost consists of the fuel cost of the controllable μG units being dispatched at MMG level within each MG as well as the cost of the non-critical (controllable) load being curtailed with activation of curtailment contracts under CAMC control level, in stressed MV operating conditions (described in DG3 within WPG). The total operational cost, assigned as negative benefit, which account for the number of years of network investment deferral, needs to be discounted to the initial year when network investment due to load growth needs to take place. The average interest rate used is assumed to be 7% [16].

4. Definition of set of alternatives (options)

Seven (7) alternatives are presented to the Decision Maker, where the DSO may decide to do nothing or to take some actions exploiting the control and management infrastructure of the MMG concept in respect to a reference option of 20 % non-controllable μG installed capacity. This reference value was defined due to the Portuguese legislation, allowing 25% of μG installed capacity regarding a respective MV/LV transformer's peak load to be installed causing no technical problems in terms of overvoltages and reverse power flows. Being on the safe side, 20 % of micro-generation will be taken as a reference option in this study work. The alternatives selection has been done due to exploitation of the controllability and management of the MMG concept through active μG/load management in respect to already existing non-controllable μG (20% in respect to a corresponding MV/LV transformer's peak load).

A. No active network management (20% non-controllable μG installed capacity (coming from RES);
B. 20% non-controllable μG together with 10% controllable μG and 10% controllable load within each MG of the MMG;
C. 20% non-controllable μG together with 20% controllable μG and 20% controllable load within each MG of the MMG;

D. 30% non-controllable μG together with 10% controllable μG and 10% controllable load within each MG of the MMG;

E. 30% non-controllable μG together with 20% controllable μG and 20% controllable load within each MG of the MMG;

F. 40% non-controllable μG together with 10% controllable μG and 10% controllable load within each MG of the MMG;

G. 40% non-controllable μG together with 20% controllable μG and 20% controllable load within each MG of the MMG.

5. Dealing with uncertainties – Definition of scenarios

The uncertainties regarding the electricity market prices and load growth levels are captured through definition of scenarios. Moreover, LV and MV load and RES generation profiles are taken into account by consideration of additional scenarios regarding two principal seasons.

I. Typical day of low electricity market prices and 2% load growth during winter;

II. Typical day of low electricity market prices and 2% load growth during summer;

III. Typical day of high electricity market prices and 2% load growth during winter;

IV. Typical day of high electricity market prices and 2% load growth during summer;

V. Typical day of low electricity market prices and 3% load growth during winter;

VI. Typical day of low electricity market prices and 3% load growth during summer;

VII. Typical day of high electricity market prices and 3% load growth during winter;

VIII. Typical day of high electricity market prices and 3% load growth during summer.

Typical days of low and high electricity market prices using OMEL data have been identified. Since the analysis are performed on annual basis, the benefits in terms of active losses reduction and μG generation are multiplied by the number of days with low and high electricity market prices during each season for each scenario of load growth during the year of study. Stressed operating conditions will include also the number of years of investment deferral due to activation of curtailment contracts and/or controllable μG dispatch under CAMC control level (described in DG3).

In line with the load growth, 2% and 3% annual growth of RES is considered in the scenarios of 2% and 3% load growth, respectively.

6. Definition of study cases

The impact assessment is performed at LV and MV distribution voltage level in typical Portuguese distribution networks through the different management and control strategies described in DG3, assumed to be developed in real market environment.

Several data are needed for performing the analysis, provided by the Portuguese utility (EDP):

- Identification of typical distribution urban and rural networks;
- Typical LV and MV load profiles for summer and winter;
- RES production curves for summer and winter;
- Identification of typical day of low and typical day of high market prices (using OMEL data).

Real LV and MV networks have been used in this analysis. Two independent study cases have been considered due to different potential technical constraint violation in each of the network. Namely, in rural networks due to the wires length, what is expected to take place is significant voltage drop considering certain annual load growth, whereas in typical urban network, high congestion levels are assumed as a common technical issue.

Figure 1 and 2 present typical Portuguese LV urban and rural networks used in the analysis. Figures 3 and 4 show typical MV urban and rural network, respectively with several MGs placed as shown below. The ten worst nodes regarding the voltage drop are designated in black in Figure 3, whereas the ten most congested lines in Figure 4 are shown in bold.

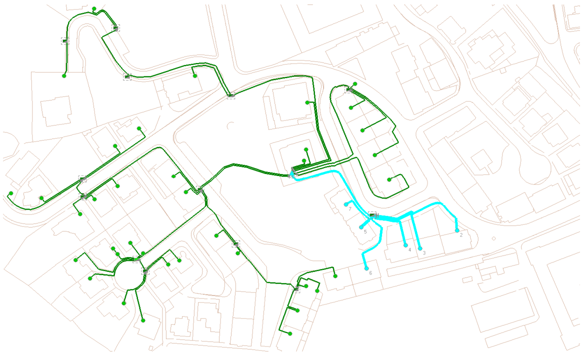

Figure1. Typical LV urban network

Figure2. Typical LV rural network

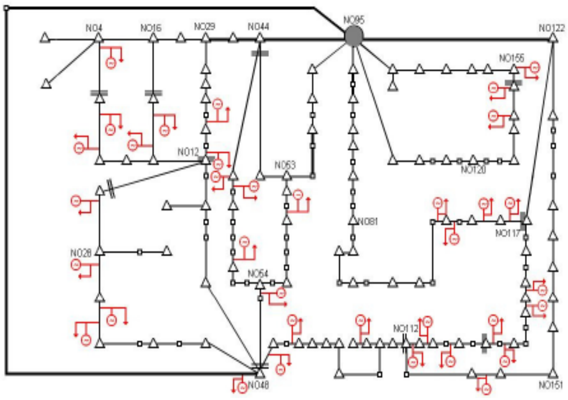

Figure3. Typical MV urban network

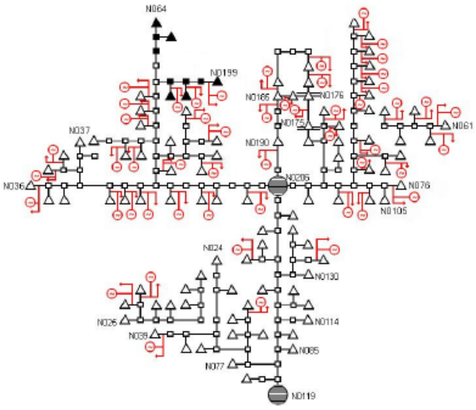

Figure4. Typical MV rural network

Starting at a single MG level, in different scenarios, different μG production level is expected to take place, due to electricity market price responsiveness, which would decrease the MV load profile at the MMG level for the hours of μG production under MGCC. Therefore, since the reduction of MV hourly load profile depends on the amount of μG produced locally and the μG installed capacity is a certain percentage of respective MV/LV substation or particular MG peak demand, the same percentage reduction in the 24-hours load profile is applied to each LV/MV node where MG is placed. Thus, our analyses are based on the real demand at each MV/LV substation level where a MG is placed. Figure 5 and Figure 6 present typical LV and MV load profiles for Portuguese distribution networks. Figures 7 and 8 depict the typical PV and wind profile for Portugal [15]. Figure 9 illustrates the electricity market prices used in the analysis [17].

Moreover, it is relevant to mention that the RES generation mix share depends on the type of network:

- Urban distribution network comprises 100% PV in the mix of RES generation installed;
- 20% wind and 80% PV in the generation mix of RES installed in rural distribution network.

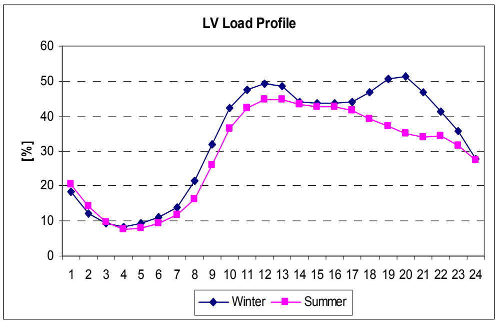

Figure5. Typical aggregated daily LV load profile

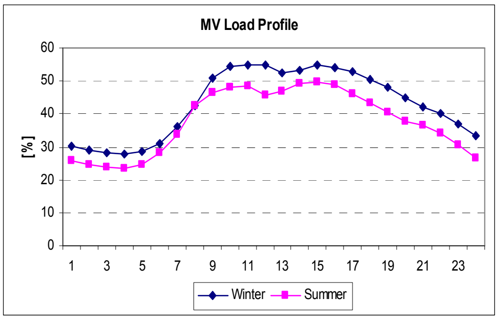

Figure6. Typical aggregated daily MV load profile

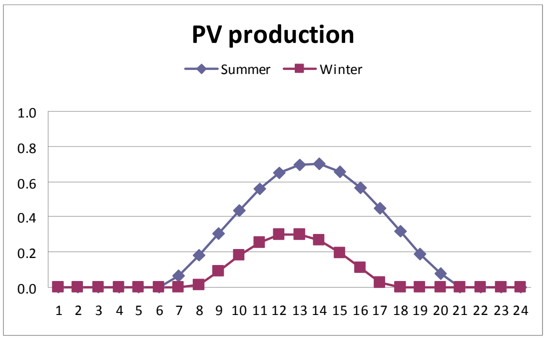

Figure7. PV production profile

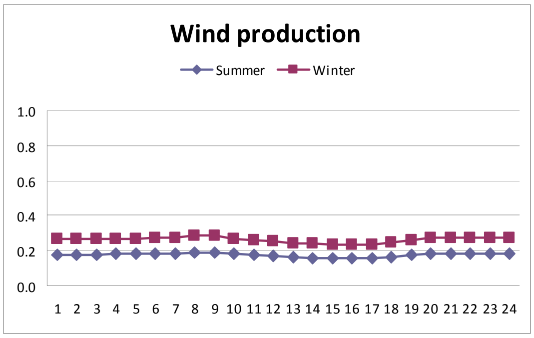

Figure8. Wind production profile

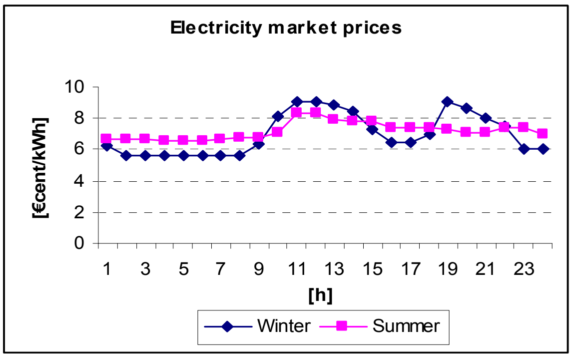

Figure9. OMEL electricity market prices

7. Multi-criteria framework

As forehead mentioned, cost-benefit identification and evaluation is central to the MMG impact evaluation by addressing the real benefits and costs that μG in form of MMG can bring to the distribution networks. Therefore, the MMG impact is modelled as multi-attribute problem by identification of costs and benefits due to a coordinated control and management of large scale μG at different distribution network control levels, described in Deliverable DG3. Furthermore, several MCDA techniques are presented in this section for evaluation of the cost-benefit relation of the MMG concept from DSO perspective. Evaluation of the MMG impact implies two sources of complexity in the decision making: multiple criteria evaluation and multiple scenarios to describe uncertainty. The methodology used for identification and evaluation of the attributes of the multiple criteria has been illustrated in Deliverable DG3, within WPG. Moreover, the attributes related with the technical, economical and environmental benefits are assessed within the same deliverable for different modes of operation at different control levels. The attribute related with the cost of MMG concept deployment will be subject of study this report as well as cost-benefit assessment using different Decision Aid (DA) techniques.

Finally, a comparative approach using data envelopment analysis will be presented.

7.1 Multi attribute assessment of the MMG impact deployment

The analysis that follows presents the case of typical LV and MV urban distribution network. Similar analysis can be performed for the rural network case.

Since the problem is modeled as multi-criteria, the attributes are explicitly defined performing optimization procedure at MGCC and CAMC level. Moreover, the criteria of the problem are defined through the attributes, recognizing four main criteria in our case: total annualized cost for putting in place MMG (consisted of annualized installation and operating cost), investment deferral, LV and MV active losses reduction and CO_2 emission reduction due to displacement of upstream network units from the μG (controllable or not) and activation of curtailment contracts for the controllable load under CAMC. Moreover, the benefit of CO_2 reduction due to LV and MV active losses reduction will not be considered in the multi-attribute assessment due to avoiding duplication of criteria/attributes and satisfying the preferential independence condition, assuming that these benefits are captured within the active losses reduction criteria/attribute.

Table I presents the attributes of the first evaluation criteria considered.

Table I

Calculated attributes for the first evaluation criteria

Scenario	Alternative	Ann.Inv. Cost [mil.€]	Operating Cost [mil.€]	Total Cost (C_1) [mil.€]
Scenario I	A	0.16	0	0.16
	B	0.169	0.002	0.171
	C	0.179	0.007	0.186
	D	0.17	0.001	0.171
	E	0.18	0.011	0.191
	F	0.172	0.002	0.174
	G	0.181	0.007	0.188
Scenario II	A	0.16	0	0.16
	B	0.169	0	0.169
	C	0.179	0.007	0.186
	D	0.17	0.001	0.171
	E	0.18	0.008	0.188
	F	0.172	0.001	0.173
	G	0.181	0.004	0.185
Scenario III	A	0.16	0	0.16
	B	0.169	0	0.169
	C	0.179	0.006	0.185
	D	0.17	0.001	0.171
	E	0.18	0.004	0.184
	F	0.172	0.001	0.173
	G	0.181	0.004	0.185
Scenario IV	A	0.16	0	0.16
	B	0.169	0.009	0.178
	C	0.179	0.004	0.183
	D	0.17	0	0.17
	E	0.18	0.005	0.185
	F	0.172	0	0.172
	G	0.181	0.001	0.182
	A	0.16	0	0.16
	B	0.169	0.002	0.171

Scenario V	C	0.179	0.007	0.186
	D	0.17	0.001	0.171
	E	0.18	0.011	0.191
	F	0.172	0.002	0.174
	G	0.181	0.007	0.188
Scenario VI	A	0.16	0	0.16
	B	0.169	0	0.169
	C	0.179	0.007	0.186
	D	0.17	0.001	0.171
	E	0.18	0.008	0.188
	F	0.172	0.001	0.173
	G	0.181	0.004	0.185
Scenario VII	A	0.16	0	0.16
	B	0.169	0	0.169
	C	0.179	0.006	0.185
	D	0.17	0.001	0.171
	E	0.18	0.004	0.184
	F	0.172	0.001	0.173
	G	0.181	0.004	0.185
Scenario VIII	A	0.16	0	0.16
	B	0.169	0.009	0.178
	C	0.179	0.004	0.183
	D	0.17	0	0.17
	E	0.18	0.005	0.185
	F	0.172	0	0.172
	G	0.181	0.001	0.182

Table II displays the attributes for the four evaluation criteria: total MMG cost (C_1), investment deferral (C_2), LV and MV active losses reduction (C_3) and CO_2 emissions reduction (C_4) for every scenario defined.

Table II

Evaluation criteria for the multi-attribute problem

Scenario	Alternative	Evaluation Criteria			
		Cost (C_1) [mil.€]	Inv.Deferral (C_2) [years]	Losses red. (C_3) [MWh]	CO_2 reduction (C_4) [t]
Scenario I	A	0.16	0	0	0
	B	0.171	2	15.1	110.5
	C	0.186	3	31.0	186.1
	D	0.171	2	32.5	321.9
	E	0.191	4	64.5	540.2
	F	0.174	3	61.0	647.1
	G	0.188	4	77.4	741.7
	A	0.16	0	0	0
	B	0.169	1	3.7	52.7

Scenario II	C	0.186	3	21.4	183.5
	D	0.171	3	74.4	1128.6
	E	0.188	5	93.9	1413.3
	F	0.173	5	146.6	2422.8
	G	0.185	6	157.3	2642.6
Scenario III	A	0.16	0	0	0
	B	0.169	2	43.5	235.6
	C	0.185	4	103.0	620.3
	D	0.171	3	72.1	548.5
	E	0.184	4	119.9	869.7
	F	0.173	3	89.3	788.2
	G	0.185	4	137.1	1123.1
Scenario IV	A	0.16	0	0	0
	B	0.178	2	41.9	317.5
	C	0.183	4	84.8	721.6
	D	0.17	3	116.0	1563.9
	E	0.185	6	168.4	2180.4
	F	0.172	5	193.6	3089.2
	G	0.182	7	236.0	3691.0
Scenario V	A	0.16	0	0	0
	B	0.171	1	12.2	64.7
	C	0.186	2	33.4	201.6
	D	0.171	1	22.3	249.0
	E	0.191	3	70.6	596.7
	F	0.174	2	59.9	628.1
	G	0.188	3	83.3	790.8
Scenario VI	A	0.16	0	0	0
	B	0.169	1	8.7	69.0
	C	0.186	2	22.2	185.3
	D	0.171	2	72.2	1090.9
	E	0.188	3	84.1	1213.4
	F	0.173	3	135.4	2260.2
	G	0.185	4	147.4	2413.7
Scenario VII	A	0.16	0	0	0
	B	0.169	1	36.8	202.6
	C	0.185	2	87.7	502.0
	D	0.171	2	68.4	528.1
	E	0.184	3	120.3	864.0
	F	0.173	2	86.0	759.5
	G	0.185	3	137.1	1113.4
Scenario VIII	A	0.16	0	0	0
	B	0.178	1	34.6	248.2
	C	0.183	2	70.2	567.9
	D	0.17	2	112.1	1512.3
	E	0.185	3	144.7	1865.9
	F	0.172	3	179.4	2880.5
	G	0.182	5	223.8	3493.4

As it can be seen from Table II, alternative A prevails against the other alternatives in the cost criterion, whereas, alternative G wins over the rest of the alternatives in the investment deferral criterion, the active losses reduction and the CO_2 reduction.

The assessment described in Table II shows two sources of complexity in the decision making: multiple criteria of evaluation (C_1, C_2, C_3, C_4) and multiple scenarios to describe uncertainty (8 scenarios). Our strategy will be first to deal with the multi-criteria problem by conducting the evaluation through trade-off analysis and value function, and then capture the uncertainty issue through robustness analysis and analysis of regret.

7.2 Decision Aid

7.2.1 Trade off analysis

The methodology behind the multi-criteria framework used in this research considers first trade-off analysis as Decision Aid technique, by defining trade-offs, chosen by the DM after careful examination of the situation. Each trade-off reflects the ratio of improvement in one criterion (for instance, investment deferral) over degradation in another (MMG total cost). Three trade-offs are defined, namely α_1[€/year], the trade-off between the cost and investment deferral, which defines the amount of money that DSO is willing to invest in order to have the network upgrade deferred by one year, the second trade-off α_2 [€/MWh] presenting the amount of money required for having the total active losses decreased by 1MWh and the third one α_3 [€/t] defining the negative benefit (cost) associated with 1ton of CO_2 emissions' reduction for each alternative and scenario developed.

Starting with reference value for the cost/investment deferral trade-off of α_1 = 5000 [€/year], for the cost/losses reduction α_2 = 100 [€/MWh], and for the cost/CO_2 reduction α_3 = 10 [€/t], the equivalent cost is calculated, using (1).

$$Eq.\cos t = C_1 - \alpha_1 \cdot C_2 - \alpha_2 \cdot C_3 - \alpha_3 \cdot C_4 \qquad (1)$$

where C_1, C_2, C_3 and C_4 are the values of the attributes for the four criteria considered. The minus sign before each trade off indicates that the criteria C_2, C_3 and C_4 are designated as benefits.

Table III shows the equivalent cost for each alternative in each scenario, calculated as in (1), after considering the attributes presented in Table II.

Table III

Trade off analysis and equivalent cost for α_1 = 5000 [€/year], α_2 = 100 [€/MWh] and α_3 = 10 [€/t]

Scenario	Alternative	C_1 [€]	$\alpha_1 \cdot C_2$ [€]	$\alpha_2 \cdot C_3$ [€]	$\alpha_3 \cdot C_4$ [€]	Eq.cost [€]	Eq.cost Ranking
Scenario I	A	159700	0	0	0	159700	6
	B	170530.4	10000	1510.6	1104.7	157915.1	5
	C	181416.7	15000	3102.3	1861.4	161453	7
	D	170996.1	10000	3253.5	3219.2	154523.5	4
	E	183130.4	20000	6448.2	5402.1	151280	3
	F	172806.1	15000	6098.1	6470.8	145237.2	1
	G	183521.4	20000	7738.3	7417.1	148366.1	2
Scenario II	A	159700	0	0	0	159700	5
	B	169588.1	5000	369.7	526.6	163691.8	7
	C	181320.9	15000	2142.6	1834.7	162343.6	6
	D	170542.5	15000	7442.6	11286.0	136813.9	4
	E	181816.4	25000	9385.3	14133.2	133297.8	3
	F	172137.3	25000	14662.3	24228.2	108246.8	1
	G	182227.9	30000	15728.3	26426.5	110073.2	2
Scenario III	A	159700	0	0	0	159700	7
	B	169389.6	10000	4346.2	2355.6	152687.8	6
	C	180379.5	20000	10300.6	6203.1	143875.8	5
	D	170828.3	15000	7207.0	5484.9	143136.3	4
	E	181124	20000	11987.4	8697.4	140439.2	3
	F	172185.8	15000	8928.3	7882.0	140375.5	2
	G	182498.9	20000	13710.5	11231.4	137557	1
Scenario IV	A	159700	0	0	0	159700	7
	B	174189.8	10000	4190.3	3175.4	156824.2	6
	C	179925	20000	8475.6	7215.9	144233.4	5
	D	170325	15000	11600.7	15639.1	128085.2	4
	E	180796.5	30000	16841.5	21804.0	112151	3
	F	171900	25000	19358.4	30892.1	96649.5	2
	G	181598.8	35000	23601.9	36910.3	86086.6	1
Scenario V	A	159700	0	0	0	159700	4
	B	170213.9	5000	1220.7	647.3	163346	6
	C	181627.6	10000	3344.0	2015.5	166268	7
	D	170325	5000	2229.8	2489.7	160605.5	5
	E	183882	15000	7062.2	5966.8	155853	3
	F	172854.7	10000	5994.7	6280.6	150579.4	1

	G	184287.5	15000	8326.2	7907.6	153053.6	2
Scenario VI	A	159700	0	0	0	159700	5
	B	170197.3	5000	870.9	689.9	163636.5	6
	C	181385.3	10000	2218.8	1853.5	167313.1	7
	D	170561.1	10000	7216.1	10908.5	142436.4	3
	E	181167.9	15000	8409.9	12134.0	145624.1	4
	F	172028.8	15000	13535.1	22601.9	120891.8	1
	G	182180.5	20000	14736.4	24137.0	123307.1	2
Scenario VII	A	159700	0	0	0	159700	7
	B	169200	5000	3676.4	2026.5	158497.2	6
	C	179532.5	10000	8767.9	5020.4	155744.3	5
	D	170806.9	10000	6837.9	5281.3	148687.6	4
	E	181415.4	15000	12031.3	8640.1	145743.9	2
	F	172145	10000	8595.7	7595.4	145953.9	3
	G	182777	15000	13705.4	11133.9	142937.7	1
Scenario VIII	A	159700	0	0	0	159700	7
	B	169200	5000	3457.8	2482.4	158259.7	6
	C	178857.2	10000	7023.2	5679.2	156154.8	5
	D	170325	10000	11209.3	15123.3	133992.4	4
	E	179825	15000	14473.7	18659.4	131692	3
	F	171900	15000	17942.4	28805.4	110152.2	2
	G	181732.8	25000	22382.9	34934.0	99415.9	1

As it can be noticed from Table III, alternative F wins in the scenarios of low market prices (Scenario I, II, V and VI), whereas in periods of high electricity market prices (Scenario III, IV, VII and VIII), alternative G gains over the other alternatives.

Now, if a different DM values the investment deferral more than the previous one, this attitude is translated into a higher trade-off α_1. For instance, table IV shows the equivalent cost, considering α_1 = 30000 [€/year], α_2 = 100 [€/MWh] and α_3 = 10 [€/t].

Table IV

Trade off analysis and equivalent cost for α_1 = 30000 [€/year], α_2 = 100 [€/MWh] and α_3 = 10 [€/t]

Scenario	Alternative	C_1 [€]	$\alpha_1 \cdot C_2$ [€]	$\alpha_2 \cdot C_3$ [€]	$\alpha_3 \cdot C_4$ [€]	Eq.cost [€]	Eq.cost Ranking
Scenario I	A	159700	0	0	0	159700	7
	B	170530.4	60000	1510.6	1104.7	107915.1	6
	C	181416.7	90000	3102.3	1861.4	86453	4
	D	170996.1	60000	3253.5	3219.2	104523.5	5
	E	183130.4	120000	6448.2	5402.1	51280	2
	F	172806.1	90000	6098.1	6470.8	70237.2	3

	G	183521.4	120000	7738.3	7417.1	48366.1	1
Scenario II	A	159700	0	0	0	159700	7
	B	169588.1	30000	369.7	526.6	138691.8	6
	C	181320.9	90000	2142.6	1834.7	87343.6	5
	D	170542.5	90000	7442.6	11286.0	61813.9	4
	E	181816.4	150000	9385.3	14133.2	8297.8	3
	F	172137.3	150000	14662.3	24228.2	-16753.2	2
	G	182227.9	180000	15728.3	26426.5	-39926.8	1
Scenario III	A	159700	0	0	0	159700	7
	B	169389.6	60000	4346.2	2355.6	102687.8	6
	C	180379.5	120000	10300.6	6203.1	43875.8	3
	D	170828.3	90000	7207.0	5484.9	68136.3	5
	E	181124	120000	11987.4	8697.4	40439.2	2
	F	172185.8	90000	8928.3	7882.0	65375.5	4
	G	182498.9	120000	13710.5	11231.4	37557	1
Scenario IV	A	159700	0	0	0	159700	7
	B	174189.8	60000	4190.3	3175.4	106824.2	6
	C	179925	120000	8475.6	7215.9	44233.4	4
	D	170325	90000	11600.7	15639.1	53085.2	5
	E	180796.5	180000	16841.5	21804.0	-37849	2
	F	171900	150000	19358.4	30892.1	-28350.5	3
	G	181598.8	210000	23601.9	36910.3	-88913.4	1
Scenario V	A	159700	0	0	0	159700	7
	B	170213.9	30000	1220.7	647.3	138346	6
	C	181627.6	60000	3344.0	2015.5	116268	4
	D	170325	30000	2229.8	2489.7	135605.5	5
	E	183882	90000	7062.2	5966.8	80853	2
	F	172854.7	60000	5994.7	6280.6	100579.4	3
	G	184287.5	90000	8326.2	7907.6	78053.6	1
Scenario VI	A	159700	0	0	0	159700	7
	B	170197.3	30000	870.9	689.9	138636.5	6
	C	181385.3	60000	2218.8	1853.5	117313.1	5
	D	170561.1	60000	7216.1	10908.5	92436.4	4
	E	181167.9	90000	8409.9	12134.0	70624.1	3
	F	172028.8	90000	13535.1	22601.9	45891.8	2
	G	182180.5	120000	14736.4	24137.0	23307.1	1
Scenario VII	A	159700	0	0	0	159700	7
	B	169200	30000	3676.4	2026.5	133497.2	6
	C	179532.5	60000	8767.9	5020.4	105744.3	5
	D	170806.9	60000	6837.9	5281.3	98687.6	4
	E	181415.4	90000	12031.3	8640.1	70743.9	2
	F	172145	60000	8595.7	7595.4	95953.9	3
	G	182777	90000	13705.4	11133.9	67937.7	1
Scenario VIII	A	159700	0	0	0	159700	7
	B	169200	30000	3457.8	2482.4	133259.7	6
	C	178857.2	60000	7023.2	5679.2	106154.8	5
	D	170325	60000	11209.3	15123.3	83992.4	4
	E	179825	90000	14473.7	18659.4	56692	3
	F	171900	90000	17942.4	28805.4	35152.2	2

	G	181732.8	150000	22382.9	34934.0	-25584.1	1

In this case, the final ranking leads to different conclusions. Namely, alternative G wins in all the scenarios due to the higher valuation of the investment deferral criterion making the MMG concept with higher percentage of μG and controllable load, more favourable solution. Moreover, in periods of lack of sun radiation (scenario I and scenario III), when the PV profile is significantly lower in comparison with the other two scenarios, the management and control of the controllable μG units and loads under CAMC control level gains higher importance. Furthermore, valuing the investment deferral criterion higher, brings the MMG concept favourable solution if there is a significant percentage of installed capacity (RES or not) and controllable load.

7.2.2 Value function approach

The next step is building a value function, representing the Decision Maker's preference structure. For a given value function *v*, any two points x' and x'' such that $v(x') = v(x'')$ must be indifferent to each other and must lie on the same indifference curve.

We will restrict the approach to additive value functions [18], but more complex functions could be used.

The approach consists in building an individual normalized value function for each criterion, and then assessing weights to build the multi-attribute value function. Note that, if the individual value functions are all linear, the problem reduces to the one discussed in the previous section.

A possible multi-attribute value function for the present problem would be:

$$v(c_1,c_2,c_3,c_4)=k_1v_1(c_1)+k_2v_2(c_2)+k_3v_3(c_3)+k_4v_4(c_4) \quad (2)$$

where c_1, c_2, c_3 and c_4 stand for the attributes of the four criteria considered and $v_1(c_1)$, $v_2(c_2)$, $v_3(c_3)$ and $v_4(c_4)$ are the individual value functions for each of the criteria.

As a first attempt, the following Individual Value Functions (IVF) were considered:

$$v_1(c_1) = \frac{200000 - c_1}{200000 - 159700} \qquad v_3(c_3) = \frac{c_3}{400} \qquad v_4(c_4) = \frac{c_4}{5000} \tag{3}$$

$$v_2(c_2) = \frac{c_2}{10} \tag{4}$$

In order to build the Multi-Attribute Value Function (MAVF), as indicated in (2), its parameters or weights need to be assessed (k_1, k_2 and k_3 and k_4 for the total MMG cost, investment deferral active losses and environmental criterion, respectively). When using predefined functions, n-1 judgment of indifference is sufficient to calculate these parameters, where n is the number of criteria. Then, using (2) and considering additionally that the sum of the parameters is the unity, determination of k_1, k_2, k_3 and k_4 is immediate.

Taking into consideration the trade-offs from table III, it is possible to define three pairs of points, each point on the same indifference curve, which are valued the same by the DM, assuming that the attributes of losses reduction and CO_2 reduction in (5) is the same at P' (C_1, C_2, C_3, C_4) and Q' (C_1, C_2, C_3, C_4), C_1 and C_4 are assumed to be the same in P'' and Q'' (6), as well as the C_1 and C_3 in (7) and therefore they are excluded respectively:

P'(150000, 0, -, -) ~ Q'(200000, 10, -, -) (5)

P''(160000, -, 0, -) ~ Q''(200000, -, 400, -) (6)

P'''(150000, -, -, 0) ~ Q'''(200000, -, -, 5000) (7)

Table V presents the weights of each criteria considered.

Table V

Evaluation criteria weights

Weights for each evaluation criteria			
k1	k2	k3	k4
0.224	0.277	0.222	0.277

Due to the consideration of linear individual value functions, equivalent results to the one from table III can be obtained using (2) and the calculated weights from table V.

The shape of the individual value functions reflects the way the DM values the variation of the corresponding attribute. The individual value function of the cost is usually linear, because the increase in DM satisfaction is independent of the attribute level. On the other hand, we may see different attitudes regarding some criteria, for instance, some DMs are very favourable to increase the number of years of MV network investment deferred when they do not have any network investment deferred, and therefore they are willing to pay more, but not so favourable when some years of investment deferred is reached. It is relevant to note that neither of the attitudes captured by the individual value functions can be classified as correct or incorrect – they simply correspond to different managing styles and external constraints.

Therefore, in order to capture different Decision Maker's attitudes, the investment deferral individual value function can be modelled as quadratic function of type (8), whereas the individual value functions of the other three criteria remain the same, as in (3):

$$v_2'(c_2) = 2 \cdot \left(\frac{c_2}{10}\right) - \left(\frac{c_2}{10}\right)^2 \tag{8}$$

Consequently, the MAVF becomes non-linear, but still additive. In this case, the weights remain the same, which is not a general case. Table VI demonstrates the both linear and quadratic MAVF, whereas Figure 10 shows graphical representation of (8) used for the investment deferral.

Table VI

Comparison between the linear and quadratic MAVF

Scenario	Alternative	Linear IVF				Linear MAVF	Quadr. MAVF
		C_1	C_2	C_3	C_4		
Scenario I	A	1	0	0	0	0.224	0.224
	B	0.731	0.2	0.038	0.022	0.233	0.278
	C	0.461	0.3	0.078	0.037	0.214	0.272
	D	0.720	0.2	0.081	0.064	0.252	0.297
	E	0.419	0.4	0.161	0.108	0.270	0.337
	F	0.675	0.3	0.152	0.129	0.304	0.362

	G	0.409	0.4	0.193	0.148	0.286	0.353
Scenario II	A	1	0	0	0	0.224	0.224
	B	0.755	0.1	0.009	0.011	**0.201**	**0.226**
	C	0.464	0.3	0.054	0.037	0.209	0.267
	D	0.731	0.3	0.186	0.226	0.350	0.409
	E	0.451	0.5	0.235	0.283	**0.370**	**0.439**
	F	0.691	0.5	0.367	0.485	0.509	0.578
	G	0.441	0.6	0.393	0.529	**0.499**	**0.565**
Scenario III	A	1	0	0	0	0.224	0.224
	B	0.760	0.2	0.109	0.047	0.262	0.307
	C	0.487	0.4	0.258	0.124	0.311	0.378
	D	0.724	0.3	0.180	0.110	0.315	0.374
	E	0.468	0.4	0.300	0.174	0.330	0.397
	F	0.690	0.3	0.223	0.158	0.331	0.389
	G	0.434	0.4	0.343	0.225	0.346	0.413
Scenario IV	A	1	0.0	0	0	0.224	0.224
	B	0.640	0.2	0.105	0.064	0.239	0.284
	C	0.498	0.4	0.212	0.144	0.309	0.376
	D	0.736	0.3	0.290	0.313	0.399	0.457
	E	0.477	0.6	0.421	0.436	0.487	0.554
	F	0.697	0.5	0.484	0.618	0.573	0.643
	G	0.457	0.7	0.590	0.738	0.632	0.690
Scenario V	A	1	0.0	0	0	0.224	0.224
	B	0.739	0.1	0.031	0.013	0.203	0.228
	C	0.456	0.2	0.084	0.040	0.187	0.231
	D	0.736	0.1	0.056	0.050	0.218	0.243
	E	0.400	0.3	0.177	0.119	0.245	0.303
	F	0.674	0.2	0.150	0.126	0.274	0.318
	G	0.390	0.3	0.208	0.158	0.260	0.319
Scenario VI	A	1	0.0	0	0	0.224	0.224
	B	0.740	0.1	0.022	0.014	**0.202**	**0.227**
	C	0.462	0.2	0.055	0.037	0.181	0.226
	D	0.730	0.2	0.180	0.218	0.319	0.364
	E	0.467	0.3	0.210	0.243	**0.302**	**0.360**
	F	0.694	0.3	0.338	0.452	0.439	0.497
	G	0.442	0.4	0.368	0.483	**0.425**	**0.492**
Scenario VII	A	1	0.0	0	0	0.224	0.224
	B	0.764	0.1	0.092	0.041	0.230	0.255
	C	0.508	0.2	0.219	0.100	0.245	0.290
	D	0.724	0.2	0.171	0.106	0.285	0.329
	E	0.461	0.3	0.301	0.173	0.301	0.359
	F	0.691	0.2	0.215	0.152	0.300	0.344
	G	0.427	0.3	0.343	0.223	0.316	0.375
Scenario VIII	A	1	0.0	0	0	0.224	0.224
	B	0.764	0.1	0.086	0.050	0.232	0.256
	C	0.525	0.2	0.176	0.114	0.243	0.288
	D	0.736	0.2	0.280	0.302	0.366	0.410
	E	0.501	0.3	0.362	0.373	0.379	0.437
	F	0.697	0.3	0.449	0.576	0.498	0.557

	G	0.453	0.5	0.560	0.699	0.558	0.627

The outcome is much in line with the fact that the MG developer is much concerned at the initial moment when there is a need of network reinforcement rather than after reaching a certain level, when the willingness to pay for extra year of network upgrade deferral, decreases. This can be observed in table VI, where for instance, in scenario II, alternative B gains over alternative C whereas alternative E looses value in comparison with C and D and alternative G in respect to alternative F for the quadratic MAVF in comparison with the linear one. Similar situation can be observed in scenario VI.

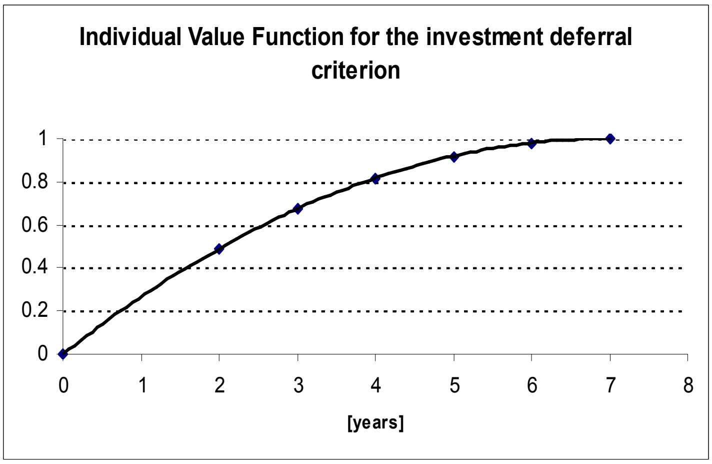

Figure10. Individual Value Function used for the investment deferral criterion

As it can be seen from Figure 10, after reaching a certain level of satisfaction, additional increase of years of investment deferral is less valued in comparison to the same additional increase before the satisfaction limit point.

7.2.3 Dealing with uncertainties – Aggregation of scenarios

The uncertainties in this study are captured with the scenarios defined in Section 5. However, the only existing uncertainty is due to the load growth levels and electricity market prices related with dry or wet summer (or winter) influencing the prices of the electricity market pool. Therefore, four scenarios can be denoted as mutually exclusive scenarios, listed below. The other four (related with winter and summer season) need to be aggregated since they correspond to a period of a year.

I. Typical day of low electricity market prices and 2% load growth;
II. Typical day of high electricity market prices and 2% load growth;
III. Typical day of low electricity market prices and 3% load growth;
IV. Typical day of high electricity market prices and 3% load growth;

Table VII illustrates the aggregated attributes of the four criteria for the four aggregated scenarios. The aggregation of the attributes for the MMG total cost, LV and MV active losses reduction and CO_2 reduction has been done by summing up the attributes' values for winter and summer for the scenarios related with the electricity market prices and load growth levels, whereas the aggregated value of the investment deferral attribute corresponds to the minimum value between the scenarios (situations) of winter and summer for each scenario of electricity market prices and respective load growth level.

Table VII

Multi attribute assessment for the 4 aggregated scenarios and α_1 = 5000 [€/year], α_2 = 100 [€/MWh] and α_3 = 10 [€/t]

Scenario	Alternative	Evaluation Criteria			
		Cost(C1) [mil.€]	Inv.Deferral (C2) [years]	Losses red.(C3) [MWh]	CO_2 red.(C4) [t]
Scenario I	A	0.16	0	0	0
	B	0.172	1	18.8	163.1
	C	0.184	3	52.4	369.6
	D	0.171	2	107.0	1450.5
	E	0.186	4	158.3	1953.5
	F	0.173	3	207.6	3069.9
	G	0.185	4	234.7	3384.4
Scenario II	A	0.16	0	0	0
	B	0.174	2	85.4	553.1
	C	0.182	4	187.8	1341.9
	D	0.171	3	188.1	2112.4
	E	0.182	4	288.3	3050.1
	F	0.172	3	282.9	3877.4
	G	0.183	4	373.1	4814.2
	A	0.16	0	0	0
	B	0.171	1	20.9	133.7
	C	0.184	2	55.6	386.9

Scenario III	D	0.171	1	94.5	1339.8
	E	0.185	3	154.7	1810.1
	F	0.173	2	195.3	2888.3
	G	0.185	3	230.6	3204.5
Scenario IV	A	0.16	0	0	0
	B	0.169	1	71.3	450.9
	C	0.180	2	157.9	1070.0
	D	0.17	2	180.5	2040.5
	E	0.181	3	265.0	2729.9
	F	0.172	2	265.4	3640.1
	G	0.183	3	360.9	4606.8

Two basic concepts have been applied to deal with uncertainty, absolute robust approach and minimax regret approach. The idea of this approach is trying to avoid unpleasant outcomes in adverse scenarios choosing the best alternative in the global ranking.

A. Absolute robust approach

In the absolute robust approach we are dealing with situations when uncertainties come from competitor's decision. The decision rule corresponds to the minimax paradigm or choosing the alternative that in the worst case has the best value, as in (9).

$$\min_{z\in Z}\max_{s\in S} Robustness(z,s) = \min_{z\in Z}\max_{s\in S}(Eq.Cost(z,s)) \tag{9}$$

with Z and S being set of alternatives and set of scenarios, respectively.

The minimax regret approach captures situations when the quality of the decision is evaluated ex post. It considers the regret or disappointment of a decision made in respect to a competitor's decision which turns out to be better. Therefore, the best value in each scenario is designated as Eq.Cost* and the regret is calculated, as in (10).

$$\min_{z\in Z}\max_{s\in S} \mathrm{Re}\,gret(z,s) = \min_{z\in Z}\max_{s\in S}(Eq.Cost(z,s) - Eq.Cost^{*}(s)) \tag{10}$$

Tables VII and VIII present the results of the two basic concepts, when it comes about uncertainty, robustness and regret, corresponding to the attribute values of table VII, for the aggregated scenarios illustrated in this section. The paradigm behind both approaches is the minimax, i.e. firstly the worse value of each alternative in each scenario is selected, depicted in bold and then the Decision Maker's preference is made in respect to the best one. Different ranking can be observed for the both approaches, namely in the absolute robust approach, alternative F wins over the other alternatives, having globally the best value from the worst ones in each scenario, whereas alternative G gains over the other alternatives, exploiting the minimum regret in respect to the best value in each of the scenarios. Moreover, alternatives B and C are valued lower for the absolute robust approach, in comparison with alternative A due to having higher equivalent cost in periods of low electricity prices (Scenario I and III) and therefore lower rank.

Table VII

Absolute robust approach analysis

Alternative	Equivalent cost				Robustness Ranking
	Scenario I	Scenario II	Scenario III	Scenario IV	
A	159700	159700	**159700**	159700	5
B	**163482**	150312	162782	152557	6
C	160097	129409	**164881**	143199	7
D	136111	115897	**142908**	122355	4
E	130172	103161	**136652**	112611	3
F	106717	90125	**114629**	99206	1
G	107376	77361	**115188**	86141	2

Table VIII

Minimax regret approach analysis

Alternative	Equivalent cost				Min.regret Ranking
	Scenario I	Scenario II	Scenario III	Scenario IV	
A	52983	**82339**	45071	73559	7
B	56764	**72951**	48153	66416	6
C	53379	52048	50252	**57058**	5
D	29393	**38535**	28278	36214	4
E	23454	25800	22023	**26470**	3
F	0	12764	0	**13065**	2
G	**659**	0	558	0	1

8. Data envelopment analysis

8.1 Methodology

DEA [19], [20] is a non-parametric performance measurement technique based on linear programming and can handle large numbers of variables with different measurement units. Generally, the performance of Decision Making Units (DMU) is evaluated. A DMU is a uniform entity with some decision autonomy, operating a production process that converts a set of inputs into a set of outputs. DEA models use these inputs and outputs to compute efficiency score for a given DMU when this particular DMU is compared with all the other DMU considered. The relative efficiency of a DMU is usually defined as the ratio between the sum of its weighted output levels to the sum of its weighted input levels. The weights are computed by the LP model by maximizing the DMU's efficiency score.

There are three basic DEA models [20]: Constant Return-to-scale (CCR), Variable Return-to-scale (VRS) and an additive model. The CCR model assumes that the output increases by the same proportional change of the inputs. The VRS comprises the case where output increases by less than the proportional change of the inputs (decreasing returns to scale - DRS) and where the output increases by more than the proportional change of the inputs (increasing returns to scale - IRS). The VRS assessment implies that DMU are only compared to others DMU of roughly similar size, and under VRS, input and output oriented analysis will give different measures of efficiency for inefficient DMU.

For this specific problem the following considerations were made:

- DMU: scenario's alternatives
- Inputs: Installation Cost [€], Operational Cost [€]
- Outputs: Investment Deferral [years], losses reduction [MWh] and CO_2 reduction [tons]
- DEA Model: CCR model. The VRS assessment implies that DMU are only compared to others DMU of roughly similar size, however in this case since the network is always the same we may consider that all the

DMU have similar size and the difference in performance is not due to lack of scale efficiency.

It is important to note that in this problem the concept of DMU is not appropriate since it is not a process (that converts input to outputs) where a decision-making can perform actions to improve the system. In this problem, the DMU can only be evaluated as in terms of efficiency and the information provided by the benchmark set in terms of inputs improvement is not useful because physical model will not be target to any transformation. Therefore, the information for the DEA analysis that will be presented in the following section is only the efficient of each alternative.

8.2 Results

The efficiency scores of each alternative computed with the CCR model for each scenario illustrated in 7.2.3, are presented in Table IX.

Table IX: Results from the efficiency analysis of scenarios I-IV

	Scenario I		Scenario II		Scenario III		Scenario IV	
Alternatives	Efficiency (%)	Ranking	Efficiency (%)	Ranking	Efficiency (%)	Ranking	Efficiency (%)	Ranking
A	0	7	0	7	0	7	0	7
B	27.7	6	52.8	6	44.2	6	100	1
C	75.6	5	100	1	67.1	5	77.5	6
D	86.3	4	95.6	5	100	1	93.3	5
E	100	1	100	1	100	1	100	1
F	100	1	100	1	100	1	100	1
G	100	1	100	1	100	1	100	1

The result for DMU A is obvious and with no significance, since the only way to make this solution efficient is to remove the installation cost. Moreover, alternative A does not have a benchmark set because none of the other DMU can be compared to it. Significant percentage of μG makes the alternatives E, F and G efficient solutions in all the scenarios. Moreover, in periods of high electricity market prices (Scenario II and IV assuming 2% and 3% load growth, respectively) alternatives with lower percentage of μG turn out to be efficient as well. As a general remark, in all scenarios the average efficiency is high, as well the number of efficient solutions.

9. Conclusions

This report deals with the evaluation of potential costs and benefits by deployment of the MG and MMG concepts using multi-criteria decision aid methods. Identification of multiple criteria and assessment of their attributes precedes the decision aid process, where different decision aid techniques have been applied for capturing different Decision Maker's preference structures.

Starting with trade-off analysis, we have shown how different trade-offs lead normally to different evaluations/rankings in each scenario. What we may always argue about is a range of trade-offs where the MMG concept deployment turn out to be favourable solution. Further on, different Decision Maker's attitudes have been translated into different value functions and applied in the analysis.

Moreover, the uncertainties coming out from the electricity market prices and load growth levels have been dealt by definition of four mutually exclusive scenarios.

The main idea of the study was to evaluate the MG and MMG concepts deployment as potential solution to deal with normal and stressed distribution network operating modes exploiting the controllability and active management potential of the concept. What can be drawn as conclusion from these studies is that large scale deployment of μG may only be feasible under the MG and MMG concepts, whereas small μG penetration does not require adoption of sophisticated MG and MMG management and control concepts. Therefore, only significant percentage of μG can make the MG and MMG concepts viable and economically interesting solutions.

Furthermore, the analysis made is from the DSO perspective, meaning identification of the cost and benefits attributed to the DSO. There is no doubt that some of these benefits are shared by the MMG consumers as well. Therefore, initially we have assumed an equal share of MMG installation costs, in terms of communication and control infrastructure cost, between the consumers and the DNO. Further identification and evaluation of benefits passed to the MMG consumers may lead to different share of the MMG consumers in the MMG installation cost and potentially to different conclusions, namely in what concerns the thresholds of decision.

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