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Cost/worth assessment of reliability improvement in distribution networks by means of artificial intelligence

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ABSTRACT

A major challenge for the power utilities today is to ensure a high level of reliability of supply to customers. Two main factors determine the feasibility of a project that improves the reliability of supply: the project cost (investment and operational) and the benefits that result from the implementation of the project. This paper examines the implementation of an Artificial Intelligence System in an urban distribution network, capable to locate and isolate short circuit faults in the feeder, thus accomplishing immediate restoration of electric supply to the customers. The paper describes the benefits of the project, which are supply reliability improvement and distribution network loss reduction through network reconfigurations. By comparison of the project benefits and costs the economic feasibility of such a project for an underground distribution feeder in Greece is demonstrated.

1. Introduction

Distribution system protection and restoration along with loss reduction are some of the most important topics concerning contemporary power engineering research. Two main parameters lead power utilities nowadays to redefine their policies regarding investments on power networks. The first parameter is the demand for increased reliability considering the fact that the way of living today (both at personal and professional level) tends to become fully dependent on electricity. On the other hand the energy problem and its consequences to the environmental pollution render the need for energy saving more imperative than ever. It is estimated that the largest proportion of losses in power networks corresponds to distribution networks; for a typical system in a developing country, distribution losses account for approximately 8% of the total electrical energy produced [1]. Considerable research has been accomplished so far for systems and methods that contribute in loss reduction across distribution networks and reliability improvement.

Automation has been applied to the distribution network in order to achieve significant service reliability improvement for electricity customers [2–4]. Other approaches investigate reliability improvement and interruption cost minimization based on appropriate switch location or relocation across a distribution feeder [5,6]. Finally, significant research has been conducted on loss reduction in distribution systems via network reconfiguration. These applications are based on the development of algorithms for switching operations utilizing heuristic, fuzzy logic and other approaches [7–9].

The undertaking of investments in such novel systems from the utility's perspective constitutes a complex procedure which depends on many factors. The investment decisions are based on project economic feasibility studies through which the most beneficial investment alternative is determined. For an investment to be economically viable, utility's cost to improve reliability should be less that the customer's cost.

In this paper, the implementation of a Multiagent System (MAS) [10–12] in urban distribution networks is examined as an investment proposal. The MAS is capable of locating and isolating sustained faults to the shortest possible segment of the feeder, and of achieving restoration of supply to the maximum possible number of consumers (within approximately 0.5 min). Additionally, the system deals with the loss reduction problem by transferring loads to adjacent buses.

The problem of fault detection and power restoration is a multiobjective dynamic combinatorial problem with topology constraints [13]. In practice considering that the complexity of the problem has been classified as NP-complete it becomes obvious that for real time fault restoration the problem cannot be solved exactly. The proposed MAS on the other hand implements heuristic approaches in order to deal with the problem, thus it becomes suitable for online implementation. Modifying the implementation approach of the proposed MAS, either a centralized management of the network or local supervision and control of adjacent topologies, the required time for optimal or near-optimal solution could also be improved. Furthermore, once the ontology of the software

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agents is constructed, additional functionalities for the MAS, such as network reconfiguration for loss reduction or real time management of distributed generators during peak demand periods, only require upgrade of the MASs software. Considering that most of the aforementioned functionalities are based on heuristic approaches, since such algorithms seem to be more suitable for real applications, upgrading MASs software would demand disproportional effort.

A case study is presented, in which two investment alternatives for the MAS implementation on a specific feeder are examined and the benefits during the lifetime of the investment are analyzed. Useful conclusions are derived about conditions under which the project is profitable. Finally, the effects on reliability improvement are discussed and an approach concerning real time loss reduction is demonstrated.

2. System implementation

2.1. Network and feeder description

Distribution systems in Greece consist of groups of interconnected radial circuits, as shown in Fig. 1. Both underground cables and overhead lines are used. Network reconfiguration may be accomplished by switching operations aiming to transfer loads among feeders. However, the infrastructure of these networks does not allow frequent switching operations. Basic prerequisite for this is the existence of remote controlled switches that permit centralized management of the distribution system. Distribution automation depends greatly on remote control capability concerning the switches, and power utilities today invest ever more often toward this direction.

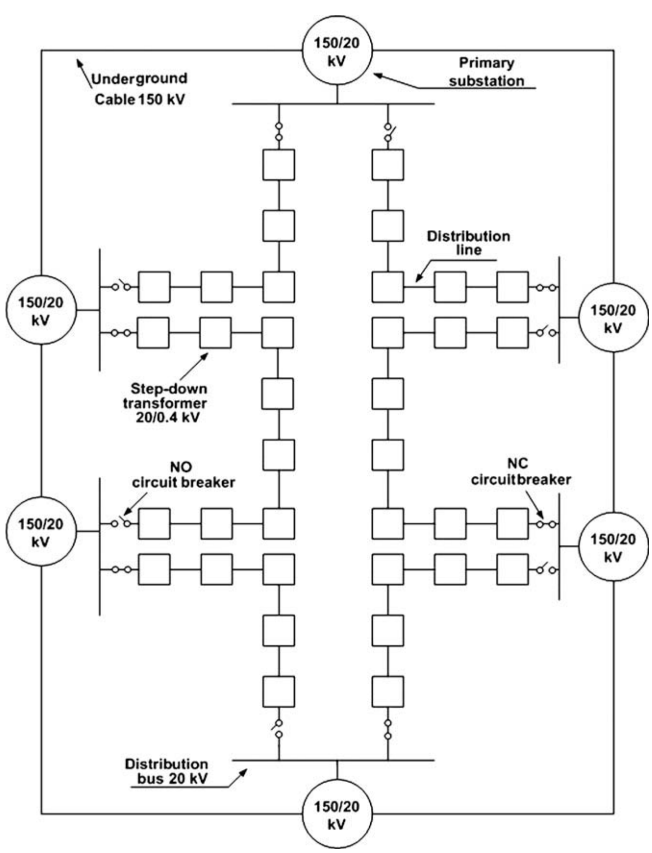

Fig. 1. Typical topology of distribution networks.

The analysis in this paper focuses on a distribution feeder that consists of an underground cable protected by a circuit breaker (CB) at the sending end of the High Voltage (HV 150 kV)/Medium Voltage (MV 20 kV) substation. A second path for alternative feeding is also considered at the end of the feeder from an adjacent bus (20 kV).

For the analysis 18 load points, shown in (Fig. 2), are assumed across an urban distribution feeder (part of distribution network in Fig. 1); each one supplied by a step-down transformer 1MVA, 20/0.4 kV.

A line fault will cause the tripping of the NC 20 kV circuit breaker, and as a result the entire line will undergo a power outage. Control engineers hereupon have to perform a search over the line, in cooperation with the technical support crew. The crew, under the guidance of the control center, manually operates the load switches of the line locally, while the control center is trying to locate the fault by operating the breaker and deciding by its behavior. This procedure may last up to several hours. Based on information provided by the Public Power Company (PPC) the average time needed for this procedure is 2 h, as the crew has to move sequentially among a number of substations, often during rush hours.

The MAS architecture proposed in [10–12] implements similar groups of collaborating software agents which are expected to join decisions and actions to achieve a common goal. The goal is to autonomously perform effective fault management on MV power distribution lines. The system is capable of locating and isolating simultaneous or even cascading line faults.

Two basic states describe the system's operation; the steady-state and the fault isolating state. The MAS will not change to fault isolation state unless it realizes fault detection followed by total voltage and current loss across all phases.

As soon as the CB tripped to clear the fault, the MAS will change to a new state. The adjacent MAS installations, hosted in adjacent substations, exchange messages containing their corresponding fault detection status. The result is that the MAS installations of substations adjacent to the fault will realize that a fault occurred between them. Thereafter, these systems proceed to fault isolation by opening the load switches located at both sides of the fault. Finally power restoration is achieved by closing the circuit breakers at the terminals of the line.

2.2. MAS hardware requirements

A set of required apparatus must be installed on each step-down transformer for the proposed MAS implementation. This set consists of the following devices:

– One embedded computer, powered by Uninterruptible Power Supply (UPS), for hosting and implementing the agent's ontology.
– Two motor driven MV (20 kV) load switches. The local agent (hosted in the embedded computer) is responsible for the operation of these switches. The open–close operations are executed via an appropriate signal between the computer and the motor of the switch.

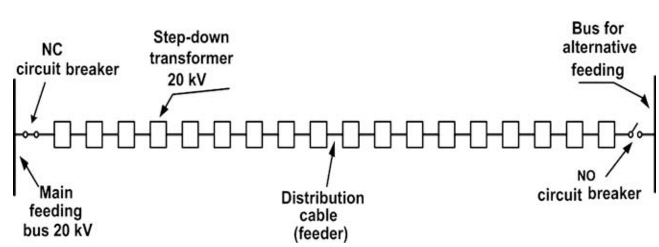

Fig. 2. Typical layout of urban distribution feeder.

- Inductive and/or capacitive couplers along with MV modems to enable Power Line Communications (PLC). Couplers must be installed in such a way that the communication between the agents is ensured even if the load switches are opened.
- Current and voltage transformers for the measurement of the voltage and the current of every phase of the feeder.
- IEDs (Intelligent Electronic Devices) for real time metering of the current, voltage, power factor, active and reactive power at the transformer. The IEDs' role should be restricted to recording the electrical parameters of the substation, and to indicating local fault detection.
- In this study it is assumed that initially, i.e. before the MAS installation, the only available data for the feeder's condition are given by an existing SCADA system and only the two CBs at the terminals of the feeder are remotely controlled. The total installation cost of the additional above set of devices is estimated to be about 30,000 €, based on prices that were provided by some of the largest power companies.

2.3. Investment cases examined

Two investment cases have been examined regarding the implementation of the proposed MAS. The first one requires installation of agents on all step-down transformers. Every agent must be accompanied by the aforementioned set of devices, in order to permit communication among them and supply of the data needed (voltage, current, fault reading etc.). Based on simulation results it is estimated that the whole procedure until the restoration of supply is carried out in a time period close to 0.5 min [10–12]. In this investment case the cost for the system implementation across the feeder is estimated to be 540,000 € (i.e. 18 load points $*$ 30,000 € each).

The second investment case investigates an alternative "selective" approach of the implementation and it is shown in Fig. 3. Agents are again installed in the two transformers in the middle of the feeder (transformers #9 and #10) but only in an arbitrary number of the remainder transformers (transformers #1, #2, #3, #4, #5, #9, #10, #14, #15, #16, #17 and #18 were chosen). Using this approach, the MAS is capable of detecting in which half segment of the feeder any occurring fault is located, with respect to the side of the Normally Closed (NC) circuit breaker which supplies the feeder or to the side of the Normally Open (NO) circuit breaker that allows alternative feeding. The healthy feeder segments can be resupplied as soon as possible. This may be achieved by opening the load switch located nearest to the faulty feeder segment and in turn by closing the appropriate circuit breaker.

Using this "selective" approach, among the possible 19 feeder segments, where a fault might occur, only to 8 of them utility's crew will have to be sent to locate and isolate the fault manually, restoring supply to the faulty feeder segment. The respective time needed may be estimated to be approximately equal to 30 min, since the maximum possible manual interventions are only 2. Whenever a fault occurs at the feeder only in eight segments the fault will not be detected immediately, and these segments correspond to step-down transformers without MAS installed (Fig. 3). Therefore, if a fault occurs at any of these segments utility's crew should be sent to isolate the fault and restore power supply. Since the candidate faulty segments are 4, the 2 MASs at the middle of the feeder have already detected at which half of the feeder the fault occurred, the maximum manual operations of load switches are 2.

The importance of the second investment case is the reduced investment cost of the system implementation. Using an analysis similar to the one concerning the first investment case, the initial estimation for that cost is 360,000 € (12 load points $*$ 30,000 €), i.e. a cost almost 67% of the cost of the first case. Its disadvantage however is that half of the customers will suffer an outage of up to 30 min.

2.4. Business cases examined

Three business cases about possible outages in the feeder were examined in this paper. The variation among them concerns different levels regarding the feeders' and each transformer's loading. All expected outages are assumed to occur during noon, e.g. between 12am–14pm of a typical week day. In the first business case (A), the feeder's load is assumed to be approximately 89% of its nominal power (18 MVA) and each transformer's average load equals to 800 kW. In the second business case (B) the corresponding values are 44% and 400 kW. Finally, the third business case (C) considers 70% of nominal power for the feeder's loading and random levels of loading for each step-down transformer. These levels vary between 300 and 860 kW. Each one of the business cases was applied sequentially to each one of the above mentioned investment cases. Therefore, the combination of all cases provided six basic scenarios (A_C, A_S, B_C, B_S, C_C, C_S) that were finally examined. Additionally, two more sub cases (C_{1S} and C_{2S}) refer to scenario C_C. Indices 1 and 2 denote the location of the expected fault across the feeder, whereas index 1 refers to a fault at the first half of the feeder and index 2 at the second accordingly. The subscript "C" or "S" denotes the investment alternative selected: "C" for complete (one agent with the set of required apparatus is installed on every transformer), and "S" for selective (agents are installed on selected transformers). In Table 1 the examined scenarios along with the considered levels for feeder and transformers loading are presented.

3. Reliability improvement

3.1. Reliability improvement

The assumption about the time needed for a fault to be located and isolated without the proposed MAS relies on an estimation arising from the personnel's experience. In Greece the average time for the whole procedure is approximately 2 h. Statistical data indicate that underground lines usually sustain permanent outages, while overhead lines usually undergo temporary ones. Underground networks are affected by bad weather conditions (floods, etc.). Moreover, ductworks in water supply, natural gas or telecommunication networks may cause accidental faults in power networks.

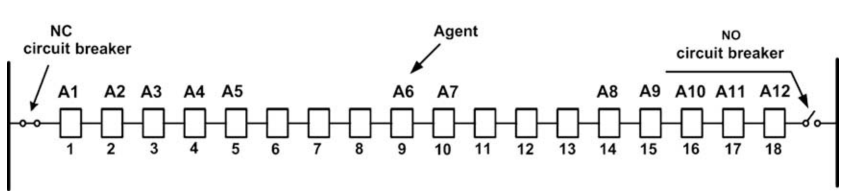

Fig. 3. Selective system implementation for scenario 2.

Table 1
Scenarios examined and loading levels.

Scenario	Feeder loading (% of nominal power)	Each transformer average loading (kW)
A_C	89	800
A_S	89	800
B_C	44	400

Utilities commonly use measurement indices in order to quantify the quality of service in a factual manner [14]:

– The 'SAIDI' (System Average Interruption Duration Index) defined as: (Σ Customer Interruption Durations)/(Total Number of Customers Served).
– The 'EENS' (expected energy not supplied).
– The 'CAIDI' (Customer Average Interruption Duration Index) defined as: (Σ Customer Interruption Duration)/(Total Number of Customers Interrupted).
– The 'ASIDI' (Average System Interruption Duration Index) defined as: (Σ Connected kVA Duration of Load Interrupted)/(Total Connected kVA Served).

The proposed MAS improves only the proportion of the 'SAIDI', 'CAIDI' and 'ASIDI' indices attributed to permanent feeder faults. Several other kinds of faults (i.e. faults at 20/0.4 kV transformers or at Low Voltage lines-0.4 kV) may be responsible for an outage from the customer's perspective, but the proposed system does not deal with all of them. Nevertheless, the improvement accomplished is not negligible, since the majority of the faults at underground feeders is not "self-clearing" and usually lead to an outage. The improvement regarding the 'SAIDI' index may for example reach to a level of 20% or more.

The SAIDI index was measured in the '90s [15] and was found to vary from 16 min (Germany) up to 11 h 30 min (Brazil). In Italy, [16] from 1999 to 2003 the SAIDI index value was between 153.8 and 72.1 min/customer/year. According to an IEEE trial-use guide [14], 90 min may be considered to be an average value for the SAIDI index. This value is adopted in this study in order to illustrate possible reliability improvement results. Moreover, the fault frequency in the examined feeder (taken from [22]) is considered to be 8 faults in a time period of 30 years, for a 6 km feeder. Based on the consideration that every fault causes at least a 2 h outage to all consumers, it results that the outage duration for every customer from this kind of faults is 32.5 min/customer/year. This value of course only corresponds to permanent feeder faults, the kind of faults the proposed system deals with, and represents therefore the maximum improvement that can be achieved to the aforementioned SAIDI index of 90 min (approximately 36%). Furthermore, the EENS for every occurred fault across the feeder is given from:

$$\mathrm{EENS} = \sum_{j=1}^{18} \mathrm{TL}_j \cdot t_j \quad (1)$$

where

EENS: expected energy not supplied (kWh),
TL_j: loading for this time period of transformer j (kW), $j = 1,\ldots,18$,
t_j = outage duration of transformer j.

Table 2 presents the EENS for each of the examined scenarios. The second column refers to the EENS at the feeder for 1 fault and the third column refers to the EENS across the feeder for a time period of 30 years. After the MAS implementation, the EENS caused by sustained faults at the underground feeder may be completely avoided.

Table 2
EENS across the feeder.

Scenario	EENS (kWh) for 1 fault	EENS (kWh) in 30 years
A_C	28,800	230,400
B_C	14,400	115,200
C_C	11,435	91,480
A_S	25,600	204,800
B_S	12,800	102,400
C_S^1	20,345	162,760
C_S^2	20,230	161,840

3.2. Value of Lost Load (VLL)

Considerable work has been done around the world on the determination of customer costs associated with electric energy supply interruptions. The CIGRE TF 38.06.01 report [17] illustrates this work and the methodologies developed to assess customer interruption costs and to utilize these data in a wide range of applications.

The Value of Lost Load (VLL) is defined as the value an average customer places on an unsupplied MWh of energy. Some researchers refer to the same concept as the Interrupted Energy Assessment Rate (IEAR) [18]. VLL depends on many factors. Hence, it is often difficult to estimate a single value for it. These factors include:

– the activities affected by the curtailment and therefore the time of day and mix of customers,
– the overall number of interruptions,
– availability of advance warning,
– weather conditions, and
– interruption duration.

Determination of VLL generally demands intensive research. A rather rough estimate can be found by dividing the Gross Domestic Product (GDP) over a year by the total energy consumed within this year [18]. This assumption banks on the acceptance that every generated kWh contributes equally to the GDP. In Greece these values are approximately 228 billion € and 57,000 GWh, respectively, resulting in a VLL estimation of 4 €/kWh. This estimation provides a low bound for further considerations, since it does not account for many factors such as additional damages due to the unexpected nature of electricity outages or the different cost associated with different customer types.

A more accurate value for customer interruption cost assessment, in regard to customer types, is adopted by a complete and detailed interruption cost analysis based on a customer survey approach that was implemented in Greece in 2001 [19] concerning three types of customers:

– industrial,
– commercial (Business),
– commercial (Organizations).

The survey provides two types of interruption costs, the average cost per interruption ($/int) and the Cost Normalized by Annual Peak Demand (CNAPD) ($/kW). These values are known as 'aggregated averages'. The aggregated average interruption cost is calculated as the ratio of the sum of interruption costs to the sum of the respective peak demand for all customers. The respondents were asked to calculate their costs for an interruption (Expected Customer Interruption Cost-ECOST) and for a 2 h scenario the results obtained are shown in Table 3.

Since in this project all costs and economic values are expressed in €, a conversion of CNAPD from $/kW to €/kW is implemented based on two considerations. The first is the exchange rate between the two currencies in 2001 and the second is the readjustment of CNAPD to present values. Converting 2001 $ to 2008 € (with a 2001 exchange rate of 0.8832 $ for 1 € and a CNAPD inflation rate of 3.5%) CNAPD becomes for these customer types as shown in Table 4.

It must be noted that the value for average cost per interruption for residential customers was taken by [20], since the interruption cost analysis conducted in Greece could not provide such data.

The time period for the financial benefits of the MAS depends on economic criteria regarding the lifetime of the components that constitute the investment project. In this project the basic parameter defining this period is the lifetime of the MV load switches [21]. This approach relies on the importance of these components to the functionality and efficiency of the MAS with regard to their initial cost. Therefore, a rational value used in this project for this lifetime is 30 years. Respectively the time period of cost-worth assessment for the MAS is also 30 years.

The value of the annual fault frequency shown in Table 5 is taken from [22] and indicates that during the period of 30 years, 8 faults at least are expected to occur at the feeder. That period is divided to 8 time zones assuming equal duration for each, and one fault is assumed to occur at the end of each of these time zones. Respectively CNAPD is assumed to be increased by 3.5% per year and the values shown in Table 6 correspond to the expected ones for CNAPD, for industrial customers. This way it is ensured that the financial benefits will come up to the worst possible time horizon. Accordingly, the above procedure is applied also to the other three customer types, in order to obtain the corresponding CNAPD values for the 8 time zones.

3.3. Customer and Load Data

A detailed analysis of the feeder involves the determination of the actual customers located at each load point [23]. This includes the customer type and the load demand for each customer. Each customer has a unique load profile. These data, however, are usually not available, as metering is energy based. For the examined feeder in this paper the individual customer load profiles for the feeder were not available. Therefore, customer types loading levels were modeled using representative percentages of feeders' nominal power. Table 7 shows the percentage of feeders' loading applied to each customer type.

3.4. Reliability Benefits of the Proposed System

The approach adopted in this paper regarding the benefits resulting by the MAS implementation is focused on the evaluation of the MAS contribution in interruption costs reduction. Whenever an outage occurs at the feeder, all customers will eventually suffer an interruption cost which in turn depends on two parameters: the CNAPD for each customer type and the corresponding power that the specific customer type consumes during the considered 2 h outage. Each one of the six scenarios in this paper assumes a different amount of unsupplied power for each customer type. The unsupplied power for each customer type is computed from:

$$\mathrm{UNP}_i = \sum_{j=1}^{18} \mathrm{TL}_j \cdot p_i \tag{2}$$

where

UNP: unsupplied power (kW),
TL_j: loading for this time period of transformer j (kW), $j = 1,\ldots,18$,
i: customer type, $i = 1,\ldots,4$ and,
p_i: percentage of feeders' loading applied for customer type i, as shown in Table 7.

Results of these six basic scenarios are shown in Tables 8 and 9.
In Table 9 the unsupplied power for the scenarios A_S, B_S, and C_S is presented. As aforementioned in this paper, adopting investment case "S", results to a time period of 0.5 h, which means that almost half customers at the feeder will suffer a 30 min outage. In order to evaluate the benefit by the aforementioned selective approach, the unsupplied power that will be saved should be assumed for 1.5 h, due to the initial scenario of a 2 h outage. For the other half seg-

Table 3
ECOST and CNAPD for electrical power customers in Greece.

Customer type	ECOST ($)	CNAPD ($/kW)
Industrial	10,937	13.66
Commercial (Business)	909	4.09
Commercial (Organizations)	2000	11.09
Residential	2.5	1.0

Table 4
CNAPD for electrical power customers in Greece (2008).

Customer type	CNAPD €/kW
Industrial	19.72
Commercial (Business)	5.89
Commercial (Organizations)	16
Residential	1.27

Table 5
Feeder data for the examined case study.

Feeder nominal power (kVA)	18,000
Number of step-down transformers (20/0.4 kV)	18
Total feeder length (km)	6
Feeder resistance (Ω/km)	0.245
Feeder reactance (Ω/km)	0.116
Fault frequency (1/km/a)	0.045

Table 6
CNAPD estimation for industrial customers.

Time period (years)	Fault at the end of this period'	CNAPD at the end of period (€/kW)
0–3.7	1	22.4
3.7–7.4	1	25.44
7.4–11.1	1	28.9
11.1–14.8	1	32.8
14.8–18.5	1	37.3
18.5–22.2	1	42.3
22.2–25.9	1	48
25.9–29.6	1	54.6

Table 7
Loading levels for customer types.

Customer type	Percentage of feeders' loading applied to the customer type (%)
Industrial[1]	10
Commercial (Business)[2]	30
Commercial (Organizations)[3]	15
Residential[4]	45

Table 8
Unsupplied power for examined scenarios complete invest.

Scenario	Transformer loading (TL) (kW)	Unsupplied power (UNP) (kW)
A_C	800	14,400
B_C	400	7200
C_C	Random	11,435

ment of the feeder the unsupplied power that will be saved must be assumed for 2 h since the power restoration by the MAS is assumed to be almost instantaneous. Finally, in order to evaluate the benefit for the 1.5 h outage that the MAS could prevent from occurring, the according CNAPD should be considered.

The benefit (in present value) that arises from the system implementation for every one of the above scenarios results as follows:

$$\mathrm{BM}_{(\mathrm{PV})} = \left\{ \begin{matrix} \sum_{g=1}^{8} \frac{\mathrm{CNAPD}_{g,m_i} \times \mathrm{UNP}_m \times p_i}{(1+a)^g} \\ \sum_{g=1}^{8} \frac{\mathrm{CNAPD}_{g,k_i} \times \mathrm{UNP}_k \times p_i}{(1+a)^g} \end{matrix} \right\} \tag{3}$$

where

- BM(PV): Benefit in Money (present value) (€),
- CNAPD: cost normalized by Annual Peak Demand, for every $g = 1,\ldots,8$ the corresponding CNAPD for every customer type and for examined outage case is adopted,
- a: nominal discount rate 8%,
- g: 8 equal time period representing the time point within the 30 years time zone for a fault to occur, each time period has duration equal approximately to 3.7 years,
- m: refers to 2 h outage,
- k: refers to 1.5 outage, and
- i: refers to customer type, $i = 1,\ldots,4$.

The results for each one of the above scenarios are given in Table 10.

4. Loss reduction

A simple proposition for the loss reduction problem is illustrated in this paper. Of course it has to be mentioned that this is not an optimum management of the possible switching operations at the feeder. The basic intention is to estimate a reasonable order of magnitude of loss reduction and use it accordingly, in order to calculate the benefit obtained by such a reduction.

Five time zones are considered during a day. For each time zone an average loading for every transformer is assumed. The magnitude of the average loading is used for the load flow calculations on the feeder and finally for the losses computation across it. It is worth mentioning that after the installation of the MAS, loss reduction and load balancing issues may be treated in real time. This allows the network operator to deal with basic topics of system reliability in a more straightforward and fast way.

In order to achieve an estimation of the magnitude of the loss reduction it is assumed that at the beginning of each time zone the system transfers some of the endmost loads of the feeder (transformers) to the adjacent bus. For every time zone five load flow calculations were implemented. Each one includes load transfer starting at first by transferring the endmost five transformers and ending up with the simple case where the last transformer is transferred to alternative feeding. This approach is adopted since the number of transformers that could be transferred to the adjacent bus depends on the available capacity of the bus. The analysis considers the average value of losses of these five cases as new feeder losses. Finally, an amount of losses is estimated for each time zone. The simulations regarding load flow analysis at the feeder were implemented using Neplan© software [24].

The above approach justifies the choice made previously for selective installation of agents, implemented in scenarios A_S, B_S and C_S. Potential change of feeding direction for the feeder would have as a result the endmost loads of the line to be considered as first and vice versa. With the specific choice in scenarios A_S, B_S and C_S, the described operation of the system is not violated.

The proposed MAS, along with its metering devices, permits continuous and real time recording of many operational feeder data. Such an ability may allow network management to perform network reconfiguration in a centralized level (i.e. one agent responsible for every switching operation at the feeder where it is installed), or in a distributed level (i.e. every agent proposes a solution in a local level). Even so, in the second case a head agent may examine all the local propositions and eventually decide the optimum one. It is also important to clarify that having the complete topology of the distribution network available introduces the possibility of optimum determination of the number of agents and their installation points. That means that for some feeders agent installation may prove profitable for every transformer whereas for others this may be done selectively.

The results obtained from the above described loss reduction analysis are shown in Table 11.

Table 9
Unsupplied power for examined scenarios selective invest.

Scenario	Transformer loading (TL) (kW)	Unsupplied power for 2 h (kW)	Unsupplied power for 1.5 h (kW)
A_S	800	8000	6400
B_S	400	4000	3200
C_S^1 (fault at 1st half of feeder)	Random	6385	5050
C_S^2 (fault at 2nd half of feeder)	Random	6150	5285

Table 10
Benefit from power restoration.

Scenario	System implementation cost (€)	Benefit in Money (present value) (€)
A_C	540,000	406,200
A_S	360,000	385,000
B_C	540,000	203,000
B_S	360,000	183,630
C_C	540,000	322,600
C_{1S}	360,000	291,840
C_{2S}	360,000	290,410

4.1. Loss Reduction Benefits

Based on the previous analysis, the benefit in energy saving for every year due to network reconfiguration is equal to 546,812 kWh. For the evaluation of the corresponding money profit, every saved kWh is rated with average wholesale price of electricity. It is mentioned that this price concerns the cost for the power utility for every produced kWh and not the profit arising after power consumers purchase energy from the power utility. A period of 30 years is also considered for the computations. It is assumed that electricity prices follow a general inflation rate equal to 3.5%. Finally the profit from loss reduction for the utility in present value is given as follows:

$$\mathrm{PV} = \sum_{z=1}^{30} \frac{\mathrm{SE} \times c \times (1+b)^z}{(1+a)^z} \tag{4}$$

Table 11
Loss reduction analysis.

Time zone	Average loading [kW–kVar]	Cosφ	Initial losses [kW]	Average value for final losses [kW]	Loss reduction [kW]
00am–8am	250–120	0.9	36.8	22.8	14
8am–12am	625–300	0.9	237.1	145.8	91.3
12am–3pm	800–390	0.9	396.4	242.7	153.7
3pm–8pm	550–265	0.9	182.8	112.6	70.2
8pm–12pm	475–230	0.9	135.8	83.8	52

where

PV: present value (€),
SE: saved energy per year (kWh),
c: cost/kWh for the initial year (0.04 €/kWh),
b: 3.5% increase, equal to the inflation,
a: nominal discount rate 8%, and
z: year of analysis.

The results obtained from the above calculations are shown in Table 12.

4.2. Overall benefit

The overall benefit from the MAS implementation, shown in Table 13 for the different scenarios, may be derived from the contribution of the two individual benefits, the power restoration profit and the loss reduction profit, respectively.

These results illustrate that in all cases the proposed system ensures payback. The best case shown in Table 13 corresponds to scenario A_S, i.e. when the MAS implementation across the feeder is selective and the faults are expected to occur during the peak load demand. Even if two faults occur under these circumstances and the other two during a low demand period of the load curve (i.e. 40% loading of nominal power), the benefit still remains high. On the other hand, only scenario (B_C) does not lead to significant profit but at least it ensures payback.

Regarding the scenarios examined above, 7 payback time points come up for the time period of 30 years. The 7 scenarios in Fig. 4 correspond to scenarios A_C, B_C, C_C, A_S, B_S, C_{1C} and C_{2C}, respectively. The first segment of each bar refers to the needed payback period (colored in black) while, the second one to the time period within which only profit is yielded.

Furthermore, Fig. 5 illustrates the cash flows (in present value) for scenario A_C. Bars refer to annual profit from loss reduction and grey segments to profit from power restoration after fault occurrence. The payback time point shown in the figure marks the beginning of the profitable time period.

Table 12
Savings from loss reduction.

Period of analysis	Saved energy (SE) per year (kWh)	Total saving in present value (PV) (€)
1–30	546,812	362,745

Table 13
Overall benefit from power restoration and loss reduct.

Scenario	System implementation cost (€)	Overall Benefit in Money (present value) (€)
A_C	540,000	768,945
A_S	360,000	747,745
B_C	540,000	565.745
B_S	360,000	546,377
C_C	540,000	685,345
C_S^1	360,000	654,585
C_S^2	360,000	653,155

5. Remarks for further considerations

For the above analysis it was assumed that the automation level in distribution network was almost negligible. This affects in turn the implementation cost of the MAS and in this particular case it maximizes it. Many power utilities already participate in procedures that aim to update distribution networks by implementing new technologies in order to increase automation level. A basic prerequisite to this direction is the installation of load switches and circuit breakers that allow remote management. It may therefore be concluded that a system like the one proposed in this paper may actually cost less than the estimation derived in the previous analysis.

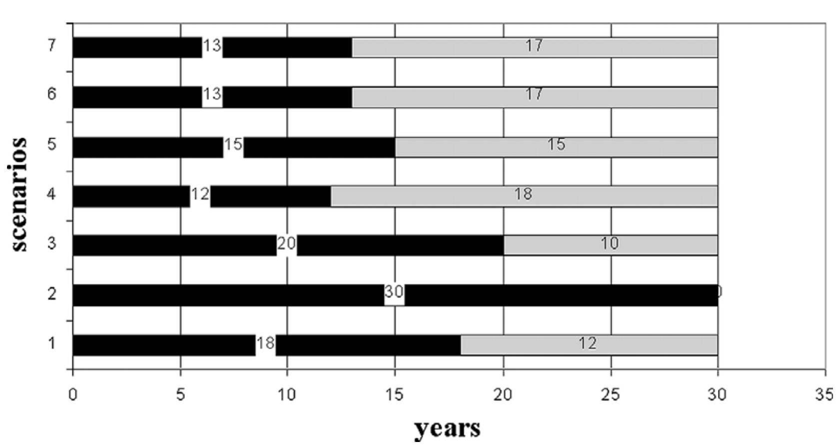

Fig. 4. Payback and profit time periods.

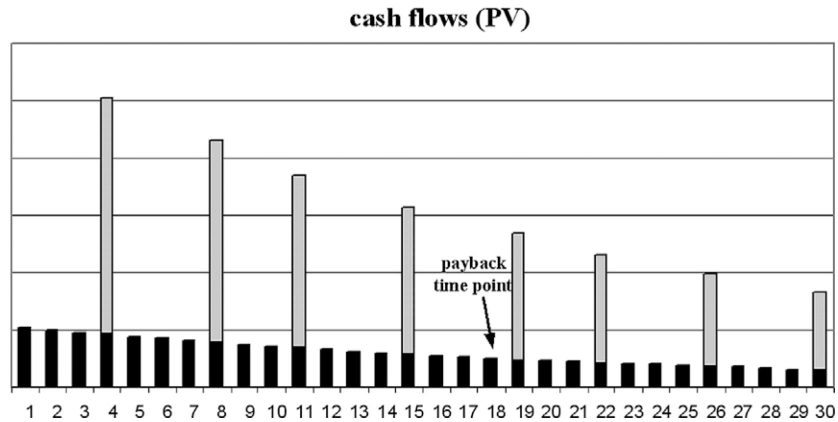

Fig. 5. Cash flows (in present values) for scenario A_C.

Moreover, it has to be clarified that the resulting benefit by reliability improvement depends greatly on the national Distribution Code (DC), which covers the technical aspects relating to the connection and use of the distribution licensee's distribution network. The DC specifies day-to-day procedures that govern the relationship between the distribution licensee and users of its distribution system for planning and operating purposes in normal and emergency circumstances. In [25] a similar feasibility study like the one presented in this paper, is conducted by the Taiwan Power Company. The purpose of this study is to evaluate the benefits for the specific DSO that arise when distribution automation (DA) is applied to the distribution network. It becomes obvious that when such feasibility studies are conducted regulations defined by corresponding DC bust also be considered. By this way it is ensured that in order to estimate the benefit due to the reliability improvement, additional parameters, such as costs for not delivered energy or costs for potential penalties when an outage occurs, would also be taken in account.

The way the MAS is installed at the feeder, using either a complete or a selective installation scenario, depends on the availability and magnitude of the following data:

– fault frequency of the feeder,
– nominal power of the feeder,
– number of step-down transformers (20/0.4 kV),
– Value of Lost Load for the feeder or the distribution networks it belongs,
– feeder losses,
– average feeder or transformer loading during the outage (estimation derives from load curves), and
– adjacent feeders, buses, distribution network topology.

Further research has to be done concerning the optimum installation of MASs in a distribution network, in order to achieve the best possible reliability improvement and at the same time the minimum implementation cost. The benefits in such an approach may be modified in the case where one agent is installed in every transformer, but on the other hand such an approach not only ensures payback but also leads to a significant profit.

6. Conclusions

This paper illustrates how reliability improvement and loss reduction may be achieved to distribution networks by using software agents as the basic means of perception of the real time network condition. In turn, the proposed MAS is responsible for decisions and actions that may be taken, in order to deal with power restoration and loss reduction problems.

Useful conclusions regarding the improvement of reliability indices and limits about the prerequisites ensuring payback for such an investment are depicted. Different scenarios regarding the conditions under which a fault occurs in an urban underground feeder have been examined. It is shown that reliability improvement along with loss reduction and ensured payback may be accomplished at the same time, in all of the examined cases.

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