Residential Demand Response Coordination for Distribution Network Reliability Enhancement

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***Abstract*— This paper establishes a centralized model to activate residential demand response in order to improve distribution network reliability. The model aims at minimizing the damage cost imposed by load curtailments following occurrence of unexpected events. In this model, distribution system operator (DSO) and responsive customers have already signed a contract authorizing the DSO alters the operation of responsive appliances whenever system reliability is jeopardized. The model addresses consumers' preferences and guarantees that the operation of appliances is displaced within the bounds defined by the owners. Once an unexpected event occurs, the DSO commits responsive appliances to avoid likely violations in the network operational limits and costly load curtailments. The proposed model is mathematically formulated in the form of mixed integer linear programming (MILP) and its capability is depicted via applying to a real-world distribution network with some residential consumers. The comparison of service reliability indices after and before utilizing demand response potentials illustrates the effectiveness of the model.**

***Index Terms*— Centralized model, demand response, distribution system operator, reliability, responsive appliances.**

1. Introduction

In modern societies, reliability of electricity infrastructures has a key role in driving forces towards prosperity of the society. However, electricity networks are susceptible to a broad range of faults. The faults followed by unexpected service interruptions may paralyze the industry, agriculture, and even residential sector thereby imposing huge damage costs to the society [1]. These costs have always been a great motivation for the area experts, engineers, and researchers to find solutions to enhance electricity service reliability. In power systems, faults in distribution networks account for almost 80% of reliability issues. This implies the fact that distribution networks which traditionally got the least attention are the best choices if reliability enhancement is the goal.

So far, plenty of solutions have been proposed to enhance service reliability in distribution networks such as regular maintenance activities [2], local generation [3], and demand response (DR) [4] to name just a few. In this paper, the focus is on the third solution which uses demand flexibility to improve service reliability. In 2012, envisioned reliability advantages of DR persuaded the North American Electric Reliability Corporation (NERC) to establish a system for regular data collection and a semi-annual report to announce and measure the contribution of DR to service reliability issues [5]. However, in spite of its importance, few studies have quantified DR benefits to service reliability and attempted to develop models for achieving them. A large producer of aluminum products and its DR capability in serving reliability services have been studied in [6]. The study, though it is valuable, concentrated on a single customer with specific characteristics and the results cannot be expanded to other consumers. The work reported in [7] has approximated the least load reduction potential that is necessary to avoid voltage collapse. Taking into account the flexibility of demand side, [8] has estimated customer interruption cost due to unexpected service interruptions. The obtained results demonstrated that DR can be effective in reducing interruption costs specifically in short duration interruptions. System load profile has been modified according to wholesale market prices in [9] where a few reliability indices were calculated and compared before and after the modification. The provided results demonstrated the significant role that DR can play in reliability enhancement. In [10], impacts of DR on distribution network reliability have been qualitatively studied. The study suffers from the shortage of a quantitative analysis which is a prerequisite to justify drawn conclusions. This shortage has been addressed in [11] wherein a quantitative study, along with sensitivity analyses, has been provided showing the great benefits of DR to distribution network reliability. Furthermore, authors in [12] have investigated the role of commercial DR in the reliability of a technical virtual power plant.

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The mentioned literatures mainly focus on the effect of DR on the network reliability. On the other side, it has been shown that the coordination of responses from residential customers is necessary to achieve the greatest envisioned benefits. It has been shown that the autonomous response of residential consumers may result in severe peak rebounds which in turn can lead to violations in distribution network constraints [13]. Therefore, system-wide frameworks are needed to coordinate responses from different consumers such that overall system efficiency and reliability are improved. In [14]-[15], time-varying prices were designed such that likely negative impacts are avoided. In [16]-[20], algorithms were introduced to coordinate consumers' DR activities. These algorithms, though provided valuable algorithms, did not focus on service reliability benefits from activating residential DR potentials.

According to the above discussions, the literature lacks a model that coordinates residential consumers' response for the purpose of network reliability improvement. In order to fill up this gap, this paper presents a centralized model to shape consumers' load profile following unexpected events. The model aims at minimizing load curtailment costs that an event can impose to the distribution company. In this scheme, it is assumed that the DSO and customers already signed a contract authorizing the DSO to modify the operation of customers' responsive appliances as far as their preferences and comforts are not sacrificed. In the model, customers who signed the contract provide the DSO with information on their responsive loads and preferences. By gathering customers' information, the DSO takes distribution network constraints into account and commits responsive loads in the manner to fulfill violated network operating limits. It is worthwhile mentioning that load curtailment is the last resort in the proposed model. The model is mathematically formulated in the form of mixed integer linear programming (MILP) and guarantees obtaining the global optimum solution. In summary, the main contributions of the paper are listed as follows:

1- This paper introduces the model that coordinates residential consumers' response for the purpose of network reliability improvement by considering responsive appliances and plugged-in hybrid electric vehicle (PHEVs).
2- To coordinate residential DR potentials, a centralized framework is utilized to shape consumers' load profiles to minimize load curtailment costs following unexpected events. The model guarantees that consumers' preferences and comforts are not sacrificed.
3- The model is mathematically formulated in the form of MILP that can be efficiently solved using off-the-shelf commercial solvers and the capability of the model is examined through its implementation on a real-world network with real information.

The rest of the paper is organized as follows. The system model is introduced in Section 2. Mathematical formulation of the model is presented in Section 3 where DR scheme, distribution network, and responsive load models are proposed. Case studies, simulation results, and discussions are provided in Section 4. Finally, Section 5 concludes the paper.

2. System Model and Problem Description

In the considered smart distribution system, DSO and multiple residential customers are the agents. As illustrated in Fig. 1, a two way communication infrastructure enables signal exchanging between DSO and active customers. It is assumed that the DSO signed a contract with some customers (called responsive or active customers) to directly control their responsive appliances under customers' constraints. Customers who signed the contract provide the DSO with data about their responsive loads as well as constraints related to their preferences and comforts. By receiving these data, DSO considers the operational constraints of distribution network as well. DSO optimizes the utilization of responsive customers for minimizing imposed costs under emergency situations.

The objective is to minimize the total interruption cost imposed to the DSO following an unexpected event. DSO commits the responsive appliances of active consumers and plans the charging and discharging cycles of customers' PHEVs in the manner to fulfill the objective. The responsive appliances of each active customer include washing machine, dishwasher, and clothes dryer. Furthermore, the charging and discharging cycles of customers' PHEVs are controlled in the proposed model. Once the optimization problem is solved and the optimum operating periods with the amount of load shedding are determined, the DSO sends control signals to customers' smart meters through communication infrastructures. The smart meters embedded in customers' houses control individual responsive appliances based on the received signals. Fig. 2 shows a typical home area network. As can be seen, the Zigbee-based network shown in the figure enables the smart meter to switch on/off all responsive appliances such as washing machine and dish washer and control the charging and discharging cycles of PHEVs.

3. Mathematical Formulation

As described in Section 2, DSO intends to minimize the imposed costs due to unexpected events. In this section, mathematical formulation of the DSO's optimization problem is presented. The proposed optimization model is solved for each probable contingency and each day under study in order to optimally utilize residential DR resources to minimize the interruption costs following the occurrence of each contingency. The method of evaluating network reliability and obtaining associated reliability indices is then presented in Section 3.5. The input of the model contains two sets of data. The first set includes the data associated with customers' responsive appliances and their comfort limits. The data of underlying distribution network and its operational constraints build the second set of data. By considering the constraints, output of the model would be the optimum load curtailed from passive and active customers demand as well as operating status of responsive appliances and charging/discharging rates and the associated periods of PHEVs.

3.1. Objective

By executing residential DR program, DSO aims to minimize the total costs imposed under occurrence of unexpected events, as expressed in (1). The imposed cost is composed of two terms in general. The first term is the sum of interruption costs due to load curtailments. Furthermore, sum of bills that should be paid for purchasing electricity from wholesale market, the incomes from selling energy to customers and the money paid to the responsive customers for utilizing their responsive loads should be accounted as the second term of DSO's costs. It is worthwhile mentioning that when a contingency occurs in the network, the first term dominating the second one because of the high amount of value of lost load (VOLL); hence, the second term is not considered in the objective function. The following equation formulates the objective function, where $PC_{NR}^{b,t}$ and $PC_{R}^{n,t}$ are curtailed loads from non-responsive and responsive loads, respectively. To curtail each unit of either responsive or non-responsive loads, a significant penalty (i.e., VOLL) should be paid to the consumers.

$$TIC = \sum_{b \in B} \sum_{t \in T} \left(PC_{NR}^{b,t} + \sum_{n \in NB} PC_{R}^{n,t} \right) \times VOLL_b \tag{1}$$

The objective is to minimize the total cost by considering the following constraints. It should be noted that the presented models in Sections 3.2 and 3.3 will be linked to the objective function through the constraints presented in Section 3.4.

3.2. Responsive Appliances

Constraints over the operation of responsive appliances should be considered to ensure their complete operation and customers' convenience. In this paper, instead of assuming the uniform power consumption for appliances, the real consumption pattern based on energy consumption profile (ECP) of appliances is taken into account. A sample ECP for a washing machine is depicted in Fig. 3 [21]. For each appliance, the required energy for complete operation should be provided. The total required energy of each appliance is equal to the surface under its ECP. The set of expressions (2) ensures satisfying this requirement. These expressions also guarantee the continuous operation of each appliance. In other words, each appliance after startup consumes its required power at each time interval based on its associated ECP.

$$P_a^{n,t} = \sum_{i=1}^{k_a} z_a^{n,t-k_a+i} . p_a^{k_a-i+1}, \qquad \forall n \in N, \forall a \in A, \forall t \in T \tag{2}$$

In (2), $z_a^{n,t}$ is the binary variable denoting startup status of appliance *a* of customer *n* at time step *t*. $z_a^{n,t}$ is equal to 1 if the appliance is started up at the associated time step and otherwise it is equal to 0. Nominal power of appliance *a* at time step *k* in the ECP is obtained from the related ECP which is denoted by p_a^k. For washing machine, p_a^k at the second time step is equal to 2000 W. Moreover, it should be noticed that k_a is the number of required time steps for the complete operation of appliance *a*, which is equal to 8 for washing machine. The above equation state that by starting an appliance a at time step *t*, the consumption profile of appliance between time interval [t, $t + k_a$ **-** 1] is compatible with the associated ECP. To illustrate this, assume that *z* in t = 12 is equal to 1 for washing machine. For t = 12, when *i* in equation (2) is equal to 8 then z = 1 (it should be noted that k_a = 8), hence $P_a^{n,t}$ at t = 12 is equal to p_a^1. It means that the consumption power of washing machine at t = 12 is equal to the power of the first interval of ECP. In addition, at t = 15 (i.e. the forth interval after startup) *z* is equal to 1 for *i* = *5*. Hence, $P_a^{n,t}$ at t = 15 is equal to p_a^4.

Each customer who participates in the DR program delivers allowed start and ending times of its responsive appliances. Responsive appliances must operate just during this time interval, i.e. during interval $\left[\alpha_a^n, \beta_a^n\right]$. The following set of constraints guarantees this rule. It represents that appliances cannot be started during the undesired intervals of customers. In other words, each appliance *a* of customer *n* only can be started between α_a^n and $\beta_a^n - k_a + 1$. $\beta_a^n - k_a + 1$ in equation (3) ensures that appliance has enough time after startup to continuously consume the required energy for doing its job. Furthermore, equation (4) ensures that for a typical day each appliance only can operate just once. The usage of responsive appliances by customers in a typical day is determined based on statistical data [21]. It should be noted that these hard constraints guarantee adhering customers' comfort.

$$z_a^{n,t} = 0, \qquad \forall n \in N, \forall a \in A, \forall t \in T - \left[\alpha_a^n, \beta_a^n - k_a + 1\right] \tag{3}$$

$$\sum_{t \in T} z_a^{n,t} = 1, \qquad \forall n \in N, \forall a \in A \tag{4}$$

Finally the consumed reactive power of responsive appliances is calculated by (5).

$$P_a^{n,t} = Q_a^{n,t} \times PQR_R^{n,t}, \qquad \forall n \in N, \forall a \in A, \forall t \in T \tag{5}$$

3.3. Plugged-in Hybrid Electric Vehicle

Recently, penetration level of plugged-in hybrid electric vehicles (PHEVs) is increased in different countries. In addition, DR strategies and incentive mechanism are introduced to encourage the owners to participate in DR program. They utilize rechargeable batteries that can be charged by connecting their plug to network. PHEVs are usually connected to grid as soon as arriving home. This period of time, however, is usually coincident to peak interval of residential loads, so controlling the charging time of PHEVs by the DR program not only fulfill the objective but also can avoid their disadvantages.

For modeling PHEVs, some constrains should be satisfied. In this paper, charging/discharging cycles of the PHEVs are controlled to fulfill the objective. It is worth noting that because of the positive impact of utilizing discharge power of PHEVs through vehicle to grid (V2G) infrastructures, controlling both charging and discharging power of PHEVs is considered in this paper [22], [23]. Here, the model of utilizing PHEVs' batteries by considering the travel pattern of their owners is presented. The PHEV's battery cannot be charged or discharged at the same time. Hence, constraint (6) is considered. It should be noted that constraint (6) is considered for interval of at home. In the out of home period both $x_{ch\_p}^{n,t}$ and $x_{disch\_p}^{n,t}$ should be equal to zero because the PHEVs cannot be charged or discharged at home by the customer.

$$x_{ch\_p}^{n,t} + x_{dch\_p}^{n,t} \le 1, \qquad \forall n \in NP, \forall t \in \left[\alpha_{PHEV}^n, \beta_{PHEV}^n\right] \tag{6}$$

The arrival and departure times of PHEVs are important factors and designated by α_{PHEV}^n and β_{PHEV}^n, respectively. The arrival and departure times of vehicles to/from home are generated based on historical data presented by NHTS [24]. Numerous historical data of PHEVs arrival and departure are taken from NHTS. Then, the data are classified and based on the attained probability distribution functions, by using Monte-Carlo approach different arrival/departure time are assigned to each customer for each day under study. During the journey interval when a PHEV is out of home, its battery cannot be charged or discharged, so the set of expressions (7) and (8) should be met.

$$x_{ch\_p}^{n,t} = 0, \qquad \forall n \in NP, \forall t \in T - \left[\alpha_{PHEV}^n, \beta_{PHEV}^n\right] \tag{7}$$

$$x_{dch\_p}^{n,t} = 0, \qquad \forall n \in NP, \forall t \in T - \left[\alpha_{PHEV}^n, \beta_{PHEV}^n\right] \tag{8}$$

The charging and discharging rates of PHEV's battery should be mounted between minimum and maximum allowable ranges which is preserved through the set of constraints (9) and (10). The product of binary variables $x_{ch\_p}^{n,t}$ and $x_{dch\_p}^{n,t}$ to the sides of relations (9) and (10) forces the charging and discharging energies of battery into zero when charge or discharge decisions are not taken.

$$\underline{E}_{ch\_p}^n . x_{ch\_p}^{n,t} \le E_{ch\_p}^{n,t} \le \overline{E}_{ch\_p}^n . x_{ch\_p}^{n,t}, \qquad \forall n \in NP, \forall t \in T \tag{9}$$

$$\underline{E}_{dch\_p}^n . x_{dch\_p}^{n,t} \le E_{dch\_p}^{n,t} \le \overline{E}_{dch\_p}^n . x_{dch\_p}^{n,t}, \qquad \forall n \in NP, \forall t \in T \tag{10}$$

The important factor of the PHEVs' batteries is their state of charge (SoC) at each time step. PHEV's battery SoC is attained by equations (11) and (12), where E_{0p}^n is the SoC of battery at the time of arrival which also called initial SoC.

$$SoC_p^{n,t} = E_{0p}^n + \left(\eta_{ch\_p}^n . E_{ch\_p}^{n,t} - \frac{1}{\eta_{dch\_p}^n} . E_{dch\_p}^{n,t}\right), \qquad \forall n \in NP, \forall t = \alpha_{PHEV}^n \tag{11}$$

$$SoC_p^{n,t} = SoC_p^{n,t-1} + \left(\eta_{ch\_p}^n . E_{ch\_p}^{n,t} - \frac{1}{\eta_{dch\_p}^n} . E_{dch\_p}^{n,t}\right), \qquad \forall n \in NP, \forall t \in (\alpha_{PHEV}^n, \beta_{PHEV}^n] \tag{12}$$

The state of charge of all PHEVs' batteries at any time interval *t* should be positive. On the other hand, it should be lower than battery capacity. These conditions are stated in set of constraints (13). The constraint of positive SoC in (13) can be stated in form of (14) which means that the discharging energy at each time interval cannot be more than the SoC at the previous time step.

$$0 \le SoC_p^{n,t} \le \overline{E}_p^n, \qquad \forall n \in NP, \forall t \in T \tag{13}$$

$$\frac{1}{\eta_{dch\_p}^n} . E_{dch\_p}^{n,t} \le SoC_p^{n,t-1}, \qquad \forall n \in NP, \forall t \in T \tag{14}$$

Before leaving home, the SoC of PHEV's battery should be sufficient for the next journey as follows. It is worthwhile mentioning that PHEVs can decrease the curtailed load by deferring their charging, but if a PHEV's battery is not charged until the required level, the interruption cost is paid to the PHEV owner. It should be noted that constraints (7), (8), and (15) guarantee adhering customers' comfort in using their PHEVs.

$$SoC_p^{n,t} \geq E_p^n, \qquad \forall n \in NP, \forall t = \beta_{PHEV}^n \tag{15}$$

The average amount of charging/discharging powers are calculated and considered at each time interval based on the charging/discharging energies. The relations between average charging/discharging powers and charging/discharging energies are described in (16) and (17) respectively. It should be noted that the duration of each time interval (Δt) is equal to 0.25 hours. Based on the characteristics of battery charger, the amount of consumed reactive powers during charging and discharging periods are obtained by (18) and (19).

$$E_{ch\_p}^{n,t} = P_{ch\_p}^{n,t} \times \Delta t \qquad \forall n \in NP, \forall t \in T \tag{16}$$

$$E_{dch\_p}^{n,t} = P_{dch\_p}^{n,t} \times \Delta t \qquad \forall n \in NP, \forall t \in T \tag{17}$$

$$P_{ch\_p}^{n,t} = Q_{ch\_p}^{n,t} \times PQR_{PHEV}^{n,t}, \qquad \forall n \in NP, \forall t \in T \tag{18}$$

$$P_{dch\_p}^{n,t} = Q_{dch\_p}^{n,t} \times PQR_{PHEV}^{n,t}, \qquad \forall n \in NP, \forall t \in T \tag{19}$$

3.4. Distribution Network Constraints

Households are hosted by the distribution network which makes it necessary to consider power flow and network operational constraints. If the effect of distribution network is ignored and just the balance of supply and demand is considered, the output of the problem may be unrealistic and lead to violations in network operational limits. As the result, the constraints imposed by distribution network are included in the proposed model.

The following two sets of constraints ensure the bus-level active and reactive powers balance.

$$P_{NR}^{b,t} + \sum_{n \in NB}\left(P_{Fixed}^{n,t} + P_{ch\_p}^{n,t} - P_{dch\_p}^{n,t} + \sum_{a \in A} P_a^{n,t}\right) + \sum_{b' \in B} PF_{b,b'}^{t} = PC_{NR}^{b,t} + \sum_{n \in NB} PC_R^{n,t}, \qquad \forall b \in B, \forall t \in T \tag{20}$$

$$Q_{NR}^{b,t} + \sum_{n \in NB}\left(Q_{Fixed}^{n,t} + Q_{ch\_p}^{n,t} - Q_{dch\_p}^{n,t} + \sum_{a \in A} Q_a^{n,t}\right) + \sum_{b' \in B} QF_{b,b'}^{t} = QC_{NR}^{b,t} + \sum_{n \in NB} QC_R^{n,t}, \qquad \forall b \in B, \forall t \in T \tag{21}$$

In order to calculate active and reactive power flows through lines, the following linear equations are used.

$$PF_{b,b'}^{t} = L_{b,b'}^{t} \times \left[-\frac{1}{2} G_{b,b'} (V_{b,t}^2 - V_{b',t}^2) + B_{b,b'} (\delta_{b,t} - \delta_{b',t})\right], \qquad \forall (b,b') \in L, \forall t \in T \tag{22}$$

$$QF_{b,b'}^{t} = L_{b,b'}^{t} \times \left[\frac{1}{2} B_{b,b'} (V_{b,t}^2 - V_{b',t}^2) + G_{b,b'} (\delta_{b,t} - \delta_{b',t})\right], \qquad \forall (b,b') \in L, \forall t \in T \tag{23}$$

For deriving the above equations, active and reactive losses of distribution network are neglected. The resulted equations are linear with respect to square of voltage amplitudes. For detailed information about calculating the above two equations, inspired readers are referred to [25].

Amplitude of bus voltages should be mounted between lower and upper limits which is adhered by (24). Furthermore, the angle of bus voltages should satisfy constraint (25). It should be explained that relations (22) and (23) are linear in respect to the square of voltage amplitude. Therefore, in order to preserve the linearity of the model, in (24) the square of voltage magnitude is considered to be between the square of allowable lower and upper bounds.

$$\underline{V}^2 \leq V_{b,t}^2 \leq \overline{V}^2, \qquad \forall b \in B, \forall t \in T \tag{24}$$

$$-\pi \leq \delta_{b,t} \leq \pi, \qquad \forall b \in B, \forall t \in T \tag{25}$$

Line active power flow limits are taken into account as follows:

$$-PF_{sys}^{t} \times \overline{S}_{b,b'} \leq PF_{b,b'}^{t} \leq PF_{sys}^{t} \times \overline{S}_{b,b'}, \qquad \forall (b,b') \in L, \forall t \in T \tag{26}$$

To ensure that the power factor remains constant by shedding the load, the following two sets of constraints are incorporated.

$$PC_{NR}^{b,t} = QC_{NR}^{b,t} \times PQR_{NR}^{b,t}, \qquad \forall b \in B, \forall t \in T \tag{27}$$

$$PC_R^{n,t} = QC_R^{n,t} \times PQR_R^{n,t}, \qquad \forall n \in N, \forall t \in T \tag{28}$$

The minimum and maximum capabilities of load curtailments associated with passive and active customers are declared as follows:

$$0 \leq PC_{NR}^{b,t} \leq P_{NR}^{b,t}, \qquad \forall b \in B, \forall t \in T \tag{29}$$

$$0 \leq PC_R^{n,t} \leq P_{fixed}^{n,t} + P_{ch\_p}^{n,t} + \sum_{a \in A} P_a^{n,t}, \qquad \forall n \in N, \forall t \in T \tag{30}$$

3.5. Reliability evaluation of the network

As clarified in the previous sections, the proposed model is considered for each contingency. In other words, following the occurrence of each contingency, the proposed model minimizes the interruptions costs through optimal utilization of residential

DR resources. In this section, the method of assessing the distribution network reliability and calculating the associated reliability indices is presented and the associated flowchart is depicted in Fig. 4. In order to perform reliability analysis, three main steps are taken into account.

1) *Gathering probable scenarios*: In this paper, by using state enumeration technique, all N - 1 contingencies associated with occurring active failures in the network branches are regarded as probable contingencies. It is worthwhile mentioning that, the probability of occurring two simultaneous outages is too small and the N-1 criterion is very common in distribution networks. By considering the occurrence of active failure in the branches, the protective switches are opened to stop feeding power to fault location. Then the switching actions are done to energize the interrupted customers as much as possible. It is assumed that the switching action of circuit breakers is through automatic remote control, however isolating faulted branches takes long equal to switching time (1 hour in this paper). By occurring a contingency, the status of network branches (i.e. in service or out of service) at each time interval (i.e. during switching and repair times) is determined and is considered in the proposed model by defining $L^{t}_{b,b'}$. If the branches between two nodes b and b' be out of service then the $L^{t}_{b,b'}$ in equations (22) and (23) is set to 0 to demonstrate the network topology after fault occurrence.

2) *Contingency analysis*: In this step, the proposed optimization problem (relations (1) – (30)) is solved for each contingency and the outcome related to the occurrence of the associated contingency is determined. In other words, once a fault occurs in the network, by determining new network topology (as described in Step 1), the optimal amount of curtailed load at each load point as well as the optimal utilization of responsive resources are obtained in order to prevent network violations. In the optimization problem, as the main contribution, the effect of DR is investigated. In other words, in emergency situations, at first, the DR capability of responsive loads is utilized. Then, if it is required, the last resort is the load curtailment. Therefore, using DR potential of responsive loads helps to postpone electricity usage in emergency conditions, resulting in reducing curtailed loads. In summary, the utilization of DR for enhancing network reliability based on proposed model is addressed in this step.

3) *Calculating reliability indices*: The service reliability indices evaluated in this paper include expected energy not served (EENS), system average interruption frequency index (SAIFI), system average interruption duration index (SAIDI), and expected interruption cost (EIC). Mathematical formula of the above mentioned indices are given through (31) – (34) in the following, respectively [26].

$$EENS=\sum_{c\in C}\sum_{b\in B}\sum_{t\in T}\lambda_c\times\left(PC^{b,t,c}_{NR}+\sum_{n\in NB}PC^{n,t,c}_{R}\right)\Delta t \quad (31)$$

$$SAIFI=\frac{\sum_{b\in B}\lambda_b .NC_b}{\sum_{b\in B}NC_b} \quad (32)$$

$$SAIDI=\frac{\sum_{b\in B}U_b .NC_b}{\sum_{b\in B}NC_b} \quad (33)$$

$$EIC=\sum_{c\in C}P_c .TIC_c \quad (34)$$

where λ_c, P_c, and TIC_c are the failure rate, probability and total interruption cost of contingency *c*, respectively. In addition, NC_b, λ_b, and U_b represent the number of customers, equivalent failure rate, and equivalent repair time at bus *b*, respectively. The above indices are formulated for one typical day. It should be explained that, the information about the time of failure or its associated probability is not available. On the other hand, because of the varying load of the network and varying flexibility of responsive loads during the 24 hours of a day, the effect of time of fault occurrence should be considered in the model. To calculate the reliability indices, occurrence of contingencies at different hours of a day are considered and finally the average of indices over 24 hours is considered.

In order to calculate the reliability indices over the year, the proposed model is solved for 8 days. In this regard for each season 2 days are considered, one for weekdays and another for weekends. Theses 8 days are representative for all 365 days in the year and the results obtained for these 8 days are extended to obtain the indices over the year. For each of the 8 mentioned days, the indices are calculated by using relations (31) – (34). To calculate indices for each day, the indices are averaged over 24 hours by considering the occurrence of contingencies at different hours of a day. After obtaining indices for 8 studied days, to compute the indices over the year, they are multiplied by the number of days that they are representative for them. For example the indices obtained for a weekday of summer are multiplied by 68. Finally, the weighted indices of 8 studied days are summed with each other.

4. Numerical Results

In this section, the proposed centralized DR scheme is applied to a Finnish distribution network with total 200 customers. The distribution network under study is illustrated in Fig. 5. As depicted, this network feeds 61 load points through 2 radial feeders with a normally open tie line between them. The input data of the model including load and customers' data, reliability parameter and technical data of the network is presented in Appendix.

Two major case studies designated as base case and DR enabled case are conducted and the associated results are compared. In the base case, all of the customers are passive and their load profile is correspondent with their usual consumption pattern, whereas in the DR enabled case, a portion of customers at each bus is responsive and their responsive loads can be scheduled by DSO in order to fulfill the objective. In this case, responsive customers receive incentive to change their load profile based on the received signals from DSO in order to increase distribution system reliability. In proceeding, performance of the proposed model during a few likely contingencies is evaluated. In this regard, for evaluating the impact of DR on the reliability indices of customers, it is assumed that all of 200 customers are actively participated in DR program. Then, system oriented reliability indices are reported. As the last study, a sensitivity analysis on the penetration level of active customers is performed and the effect of customers' position in the network on the system reliability indices is evaluated. It is worthwhile mentioning that proposed MILP model is solved using CPLEX 12.0 solver [27].

4.1. Evaluating Four Likely Contingencies

In this section, the effect of executing the proposed model is evaluated when a number of likely contingencies are happened. In each case, some important parameters are compared with the base case. It should be mentioned that the four contingencies illustrate faults occurred at different parts of the network and different times of a typical day.

Contingency 1: In this case, a fault is occurred on section 40-41 at 18:00. By occurring this fault the upstream circuit breaker isolate load points 40 to 61. After switching time (here is assumed to be 1 hour) by isolating the faulted section and closing upstream circuit breaker, load points 40 and 49-61 are restored, while load points 41-48 remain isolated until the end of repair time (here is assumed to be 6 hours). During switching time, the operation of responsive appliances of active customers situated in load points 40 and 49-61 can be delayed to reduce the amount of energy not served and the associated interruption costs. On the other hand, DR cannot be effective on the number of affected customers and interruption duration of load points 41-48. It is because allowable deferring time of responsive appliances is shorter than the repair time. Table I compares the reliability indices of the mentioned contingency for the two case studies. As can be concluded, the energy not served and the associated interruption costs are reduced by 30.8% and 31.1%, respectively after enabling DR. The number of affected customers and average interruption duration remain unchanged.

Contingency 2: A fault is occurred on branch 8-9 at 20:00, causes the upstream beaker to operate. Load points 8-32 are isolated after the operation of circuit breaker. During the switching time, the mentioned load points remain interrupted. By isolating the faulted section and closing the tie switch, right side feeder must supply customers situated in load points 9-32. In the base case, where no responsive customer exists, for the reason of limited capacity of tie line and voltage amplitude limit of buses, only few isolated customers can be energized during repair time. By enabling residential DR potentials, it is possible to solve the overload problem and feed more customers during repair time. Furthermore, during switching time, amount of load curtailed is reduced in this case. Comparison of the reliability indices for this contingency is given in Table II. As it is shown, average interruption duration, energy not served, and the associated damage costs are reduced considerably while the number of affected customers is the same in both case studies. The energy not served and damage costs indices reduce by 63.7% and 59.6%, respectively.

Contingency 3: In this case, Section 1-2 is faced to a fault at 14:00. The upstream circuit breaker is opened and load points 1-32 are isolated. By appropriate switching actions, customers connected to load points 8-32 are transferred to the neighboring feeder. Following the fault, in both the base case and DR enabled case, customers connected to load points 1-7 remain interrupted during the switching time. In order to restore the customers hosted by load points 8-32, the circuit breaker laid in section 7-8 is opened and the tie switch is closed. By doing so, a portion of the customers are energized through the neighboring feeder and just experience a momentary interruption. It is worth mentioning that all of the customers are not restored because of overload and under voltage condition in the neighboring feeder. It should be mentioned that in the DR enabled case, it is possible to energize more customers by the switching action since the overload condition is partly mitigated via load management. The reliability indices of the base case and DR enabled case during the contingency are compared in Table III. As can be seen, the number of affected customers is significantly reduced in the DR enabled case. Also, other reliability indices are improved in the DR enabled case. In this case, energy not served and interruption costs are improved by 47.8% and 41.0%, respectively.

As mentioned before, it is assumed that the circuit breakers C1-C4 and the tie line switch can be controlled remotely in coordination with each other. Furthermore, it is assumed that the branch isolators (like isolators of branches between nodes 8 and 9) are manually controlled which their position change takes long equal to switching time (1 hour in this paper). In contingency 3, after branch 1-2 faced to a fault, circuit breaker C1 is opened and after that circuit breaker C3 is opened. In this condition the faulted section is isolated form the network under C3 and load points 8-32 are energized by closing the Tie-line switch. These switching actions are assumed that be handled through automatic remote control infrastructure and hence load points 8 to 32 experience momentary interruption. It should be explained that in Contingency 2, after fault occurs in branch 8-9, circuit breaker C3 is opened to stop feeding the fault location. The isolation of branch 8-9 is done by crew team which takes long equal to switching time (1 hour) and after that the tie-line switch is closed to energize load points 9 to 32. It should be noted that the tie-line switch cannot be closed before isolating the fault location. Hence, load points 9 to 32 remain unenergized for 1 hour. In general speaking, if the fault occurs between the circuit breakers C1 and C3 or between circuit breakers C2 and C4, the load points under C3 and C4 experience momentary interruption, and can be rapidly transferred to a neighboring feeder by automatic switching operation. In this case utilizing proposed DR framework can feed more customers after remote switching which leads to improvement in SAIFI.

Contingency 4: An unexpected event occurs in Section 60-61 at 17:00. Following this fault, the upstream circuit breaker operates and isolates load points 40-61. The customers fed from these load points remain interrupted during switching time. By opening the faulted section and closing the tie line, all customers are restored. During repair time, load points 40-60 are fed through the right side feeder and load point 61 is fed by the neighboring feeder. In both base case and DR enabled case, all of the load points are energized after switching time because of no overload issue. However, in the DR enabled case, by utilizing the flexibility of responsive loads, the amount of load shedding and its associated costs are decreased during switching time. Table IV compares the reliability indices for the two study cases following occurrence of the mentioned contingency. The number of affected customers and interruption duration remain the same in both cases. It is because all of the customers fed through load points 40-61 are isolated during switching time and at least their non-responsive loads are curtailed. The amount of energy not served and the associated damage costs are reduced by 36.1% in case of utilizing DR potentials of residential customers.

4.2. General Results

In the previous sub-sections, the impacts of activating residential DR on the system reliability during four individual contingencies were demonstrated. This section evaluates the impact of executing the proposed DR program on the overall distribution system reliability. For assessing distribution network reliability, as explained in Section 3.5, all credible contingencies during the days understudy are considered and the obtained results are combined to investigate the system oriented reliability indices during the year. Table V compares the system oriented reliability indices in both base case and DR enabled case. The results presented show the significant impacts of the proposed method on distribution network reliability. It is worthwhile to mention that this amount of improvement is obtained by just using the flexibility of three responsive appliances and PHEVs of customers without scarifying their preferences. Responsive appliances of each customer include washing machine, dishwasher, and clothes dryer while the charging/discharging cycles of customers' PHEVs are also controlled. The energy consumption of the mentioned responsive appliances is about 30% of the total energy consumption of each customer. The obtained results in this section demonstrate that the flexibility in residential responsive loads can reduce the expected interruption cost around 28%. In addition, executing the DR program improves reliability indices as well. The studies confirm the significant impact of DR on the reliability of the network.

As mentioned before, this improvement in network reliability is obtained by deferring responsive appliances of active customers. In an ideal network, deferring loads is not a desirable action. Table VI presents invoked DR potentials in the DR enabled case. In this table, "EPE" represents the expected postponed energy of responsive customers. "EIF_a" and "EIF_c", respectively introduce expected interruption frequency of responsive appliances and customers. In addition, "EID_a" and "EID_c" represent expected interruption duration of responsive appliances and customers, respectively. As can be seen, this significant improvement in system reliability is obtained by just deferring responsive loads (including PHEVs) about 30 minutes in 0.26 times a year. For getting such an improvement responsive customers are deferred less than 2 hours in 0.38 times a year. On the other hand, for achieving this level of improvement in system reliability, we need to defer responsive loads only for a few minutes a year.

4.3. Sensitivity Analysis

Penetration level of active customers in the network is an important and effective factor on DR capability and consequent reliability improvements. In the previous section the studies are done by assuming 100% penetration level of active customers in distribution network. It means that, in the DR enabled case, all customers are actively participating in DR program. It is an unreal assumption in a real-world distribution network. It is because there are limited numbers of customers which may sign a contract with DSO. Because of this reason, in this section, the effect of penetration level of active customers on the system reliability indices and invoked DR potential indices is evaluated. It should be noted that penetration level of responsive customers at each bus of the network is assumed to be the same. System reliability indices of the distribution network for different penetration levels of customers are demonstrated in Table VII. It can be seen that the reliability indices are improved as the penetration level of active customers increases.

Invoked DR potential indices for different penetration levels of active customers are compared in table VIII. It can be seen that by increasing the penetration level of active customers, frequency and duration of load deferring is decreased.

4.4. Position of Active Customers Analysis

One of the challenges of DSO in designing a DR program is the fact of fairness in contracts. In other words, DSO is interested to make a contract with and pay to customers who are able to improve system reliability effectively. On the other hand, customers supplied with high level of reliability should pay more to the DSO. In this section, two different studies are conducted. In the first study, the effect of executing designated DR program on the reliability indices of customers at different parts of the network is evaluated. The second study focuses on the effectiveness of enabling DR potentials of customers connected at different parts of the network.

In the first study, it is assumed that all of the customers actively change their responsive loads. The improvement in reliability indices of the customers hosted in the main feeder, laterals, lower half, and upper half of the network is presented in Table IX. As can be seen, the customers who are hosted in the main feeders experience more significant improvements in their reliability indices compared to those hosted in the laterals. In addition, by comparing the customers who are hosted in the upper half and lower half of the network, it can be seen that the improvement of reliability indices in the lower half of the network is more significant.

In the second study, DR potential of customers at different parts of the network is enabled and reliability indices are calculated. Fig. 6 depicts improvements in system reliability indices when DR potential of customers connected to either main feeder or laterals is activated. As can be seen, enabling DR potential of customers hosted by laterals is more effective in improving system reliability indices.

Fig. 7 compares improvements in system reliability indices when customers at either upper half or lower half of the network are participated in the DR program. As can be seen, DR from customers connected to the ending part of the network is more effective in improving system reliability indices.

5. Conclusion

This paper presented a centralized scheme to coordinate residential DR potentials in order to improve distribution system reliability. The model uses the flexibility in the operation of responsive appliances and PHEVs to fulfill violations in network operational constraints and avoid costly load curtailments. The proposed model adheres customers preferences since the operation of responsive loads is adjusted within the bounds and limits defined by the owners. The model was applied to a real-world distribution network with several customers. The conducted studies demonstrate the effectiveness of the model in enhancing all service reliability indices. It is shown that the improvement is achieved just by negligible adjustments in the operation of responsive loads. It is determined that customers connected to the main feeders and lower half of the network experience more significant benefit from the DR program. Also, it is demonstrated that DR potential of customers connected to the laterals and lower half of the network is more effective in improving system reliability.

6. Appendix

In this section the input data of the model are presented. Three main categories of input data including load and customers' data, network data, and the reliability data are presented in this section.

There are 61 load points and total 200 residential customers in the network under study. The peak load and number of the customers at each load point are summarized in Table A1. The customers' load data are related to the Finnish network which is available for weekdays and weekends through 4 seasons of the year. For reproducibility purposes, disaggregated load data which show the electric appliances consumed power at each time step can be downloaded from [28].The load data are related to a typical customer and the fix load of a typical customer is extracted by considering the consumed power of non-responsive appliances; In addition, the fix loads of 200 customers in the network are generated considering the typical load profile and using Monte-Carlo simulation by adopting normal probability distribution function with standard deviation of 10%. A sample load profile for a weekday at summer is depicted in Fig. A1.

The consumption patterns of responsive appliances are taken from [28] and [21]. The starting time and end time of each appliance's operation is achieved based on the responsive load profiles in Finland and allowable delay that each customer is ready to apply in its utilization plan. Based on the data presented in [28] the preferred start time of each responsive appliance is obtained and using Monte-Carlo simulation, the preferred starting time of each responsive appliance is generated for each responsive customer. The average delay in utilization of each appliance is obtained using statistical data presented in [21]. For example the applied delay in using washing machine is presented in Fig. A2. The data related to Finland are used to estimate the allowable delay time.

The penetration level of PHEVs is assumed to be 15%. Based on [29] and [30], charging/discharging rate limits of PHEV's battery are assumed to be 3 kWh. In addition the charging/discharging efficiencies are assumed to be 0.9. The capacity of PHEVs' batteries is randomly selected based on PNNL report [31]. The arrival and departure time of vehicles to/from home are generated based on historical data presented by NHTS [24] using stochastic method.

The distribution network under study is a real-world network located in Finland which is depicted in Fig. 5. As depicted, this network feeds 61 load points through 2 radial feeders with a normally open tie line between them. The tie-line switch and four circuit breakers C1-C4 enables reconfiguring the network topology following fault occurrence in the network. The technical data of the network are summarized in Table A1 and Table A2. The nominal voltage of the network is 20 kV and allowable bound of nodes' voltage magnitude is [0.95 – 1.05] p.u.

The data required for reliability assessment is another set of input data. The VOLL of load points as well as peak load and number of customers are presented in Table A1. The availability of network branches is presented in Table A2. The repair time of the branches and switching time are respectively assumed to be equal to 6 hours and 1 hour. The branches' failure rates are obtained by the availability and repair time data. In order to calculate the reliability indices the proposed model is run for 8 days (for each season 2 days are considered, one for weekdays and another for weekends). The time set for each day is equal to {1, 2, 3, …, 96} and the duration of each time interval is equal to 0.25 hours.

Acknowledgment

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Nomenclature

Indices (Sets)

n (N)	Index (set) of responsive customers.
t (T)	Index (set) of time intervals.
$k(K)$	Index (set) of time intervals of appliance's energy consumption profile (ECP).
a (A)	Index (set) of responsive appliances.
$b,b^{'}(B)$	Indices (set) of network buses.
$c\,(C)$	Index (set) of contingencies.
NB	Set of responsive loads at each bus of the network.
NP	Set of customers with plugged-in hybrid electric vehicle (PHEV).

Constants and Parameters

$P_{fixed}^{n,t}, Q_{fixed}^{n,t}$	Non-responsive part of active and reactive powers associated with responsive customer *n* at time step *t*.
k_a	Number of required time steps for complete operation of appliance *a*.

p_a^k	Active power demand of appliance *a* at time step *k* of its ECP.
α_a^n, β_a^n	Beginning/end of allowable period for the operation of appliance *a* of customer *n*.
$\alpha_{PHEV}^n, \beta_{PHEV}^n$	Arrival/departure times of the *nth* customer's PHEV.
E_{0p}^n	Primary charging level of the *nth* customer's PHEV at the arrival time.
E_p^n	The *nth* customer's PHEV energy consumption during out of home period.
$\overline{E}_p^n$	Battery capacity of the customer's PHEV.
$\overline{E}_{ch\_p}^n, \underline{E}_{ch\_p}^n$	Maximum/minimum charging rate of PHEV's battery.
$\overline{E}_{dch\_p}^n, \underline{E}_{dch\_p}^n$	Maximum/minimum discharging rate of PHEV's battery.
$P_{NR}^{b,t}, Q_{NR}^{b,t}$	Active/reactive power demands of non-responsive loads at bus *b* and time step *t*.
$PQR_R^{n,t}$	Active to reactive powers ratio of responsive customers.
$PQR_{NR}^{b,t}$	Active to reactive powers ratio of non-responsive customers.
$PQR_{PHEV}^{n,t}$	Active to reactive powers ratio of PHEV's battery charger.
PF_{sys}^t	Power factor of distribution network at time step *t*.
$\overline{V}, \underline{V}$	Upper/lower allowed voltage amplitude.
$G_{b,b'}, B_{b,b'}$	Real/imaginary parts of the respective element in the admittance matrix.
$\overline{S}_{b,b'}$	Capacity of the line from bus *b* to b'.
$L_{b,b'}^t$	Binary variable indicating up or down state of line from bus *b* to b' at time step *t*.
$VOLL_b$	Value of lost load (VOLL) at bus *b*.
$\eta_{ch\_p}^n, \eta_{dch\_p}^n$	Charging and discharging efficiencies of *nth* PHEV's battery.

Functions and Variables

TIC	Total interruption cost associated with load curtailments.
$P_a^{n,t}, Q_a^{n,t}$	Active/reactive Power demands of the *nth* customer's appliance *a* at time *t*.
$z_a^{n,t}$	Binary variable indicating startup status of the *nth* customer's appliance *a* at time step *t*; 1 if the appliance is started up, 0 otherwise.
$x_{ch\_p}^{n,t}, x_{dch\_p}^{n,t}$	Charging/discharging binary indicators of the *nth* customer's PHEV at time step *t*.
$P_{ch\_p}^{n,t}, Q_{ch\_p}^{n,t}$	Active/reactive charging rates of the *nth* customer's PHEV battery at time step *t*.
$P_{dch\_p}^{n,t}, Q_{dch\_p}^{n,t}$	Active/reactive discharging rates of the *nth* customer's PHEV battery at time step *t*.
$E_{ch\_p}^{n,t}, E_{dch\_p}^{n,t}$	Charging/discharging energies of the *nth* customer's PHEV at time step *t*.
$PF_{b,b'}^t, QF_{b,b'}^t$	Active/reactive power flows of line between bus *b* to b' at time step *t*.
$PC_{NR}^{b,t}, QC_{NR}^{b,t}$	Active/reactive loads curtailed from non-responsive loads at bus *b* and time step *t*.
$PC_R^{n,t}, QC_R^{n,t}$	Active/reactive loads curtailed from the *nth* customer's responsive load at time step *t*.
$V_{b,t}, \delta_{b,t}$	Amplitude and phase angle of voltage at bus b and time step t.

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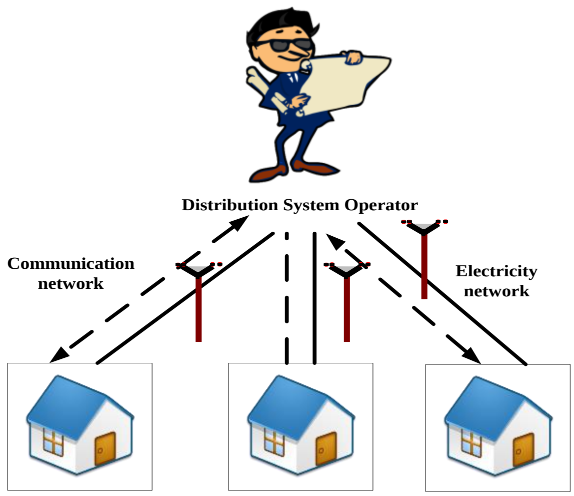

Fig. 1. A typical smart distribution system.

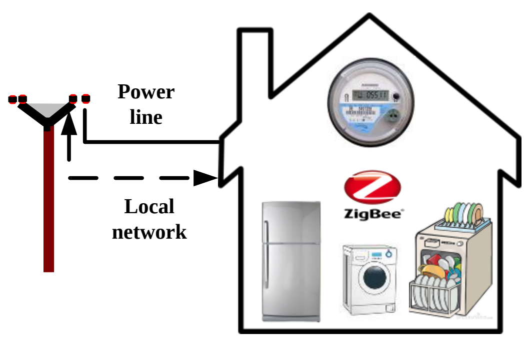

Fig. 2. A typical smart home equipped with a home area network.

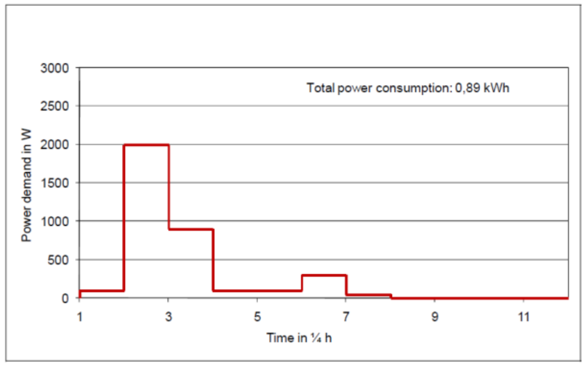

Fig. 3. ECP of washing machine [21]

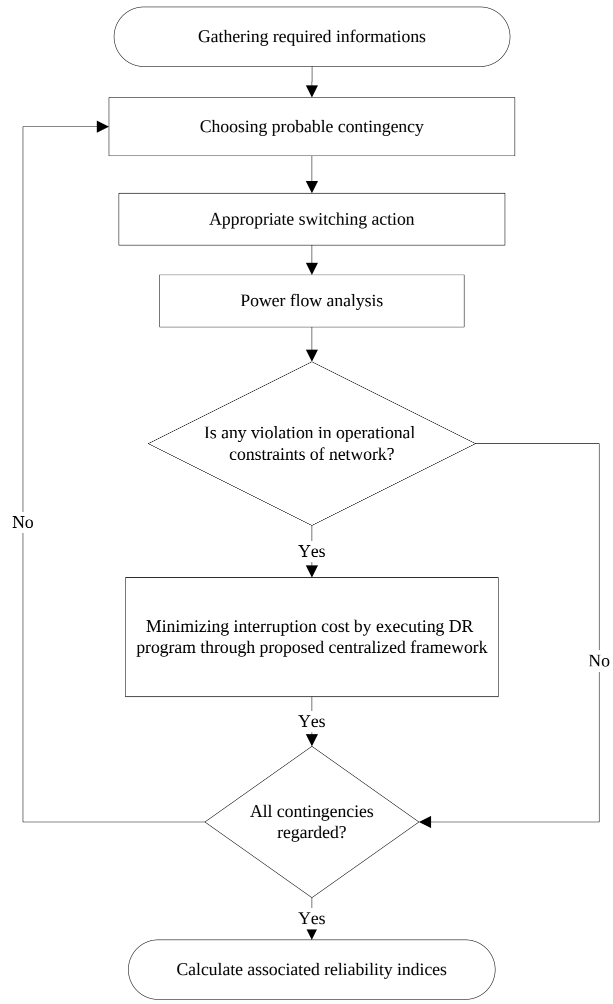

Fig. 4. Procedure of reliability analysis considering DR program

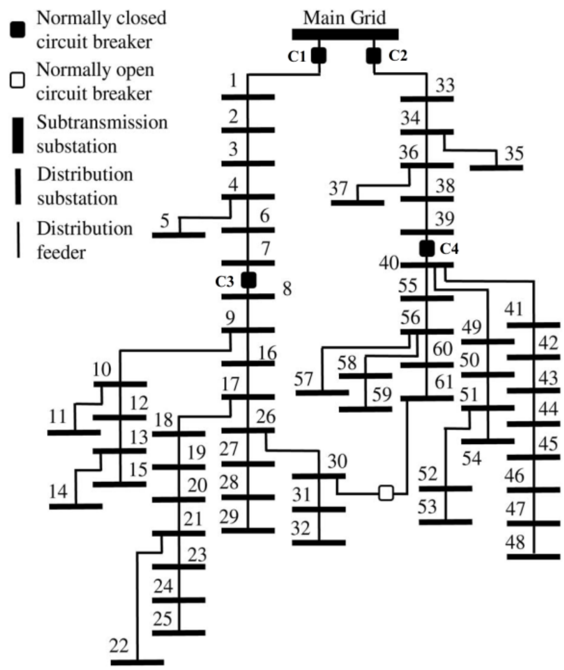

Fig. 5. Single line diagram of Finnish distribution network under study

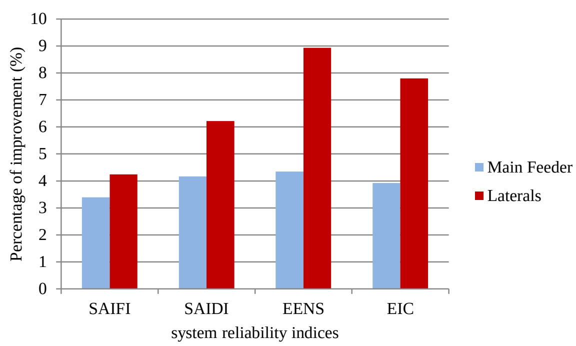

Fig. 6. Comparison of System reliability improvement for customers placed at the main feeders and laterals

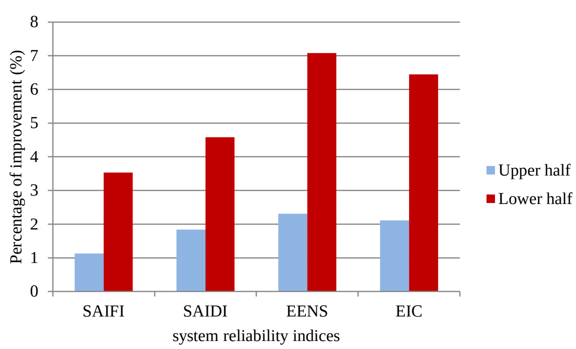

Fig. 7. Comparison of System reliability improvement for customers placed at the beginning and ending part of feeder

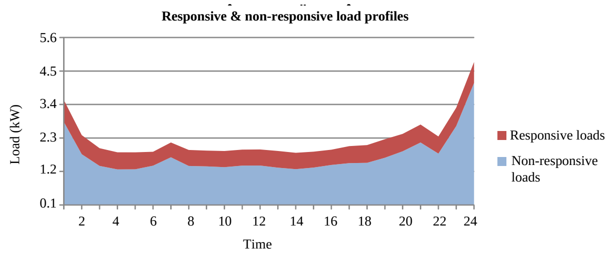

Fig. A1. Typical load profile of a customer in a weekday at summer

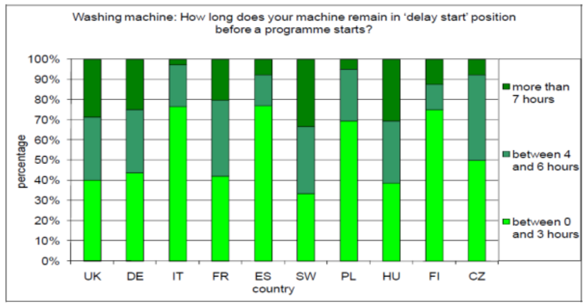

Fig. A2. Applied delay in using washing machine by customers [21]

Table I. Comparison of service reliability indices in contingency 1

Index	Base Case	DR Enabled
Number of affected customers	68	68
Average interruption duration (h)	2.8182	2.8182
ENS (kWh)	288.9	198.7
Interruption Cost (€)	7615.6	5232.8

Table II. Comparison of service reliability indices in contingency 2

Index	Base Case	DR Enabled
Number of affected customers	88	88
Average interruption duration (h)	1.50	1.05
ENS (kWh)	215.7	78.4
Interruption Cost (€)	4044.4	1634.2

Table III. Comparison of service reliability indices in contingency 3

Index	Base Case	DR Enabled
Number of affected customers	62	21
Average interruption duration (h)	1.2	1.00
ENS (kWh)	125.0	65.2
Interruption Cost (€)	2579.6	1521.8

Table IV. Comparison of service reliability indices in contingency 4

Index	Base Case	DR Enabled
Number of affected customers	68	68
Average interruption duration (h)	1.00	1.00

ENS (kWh)	77.0	49.1
Interruption Cost (€)	1881.9	1201.9

Table V. System oriented reliability indices

Index	**SAIFI** (occ/cust.yr)	**SAIDI** (hrs/cust.yr)	**EENS** (kWh)	**EIC** (€)
Base case	0.0708	0.1464	57.3548	1319.6
DR enabled	0.0631	0.1264	39.2241	942.8
Improvement (%)	10.88	13.66	31.61	28.55

Table VI. Indices of invoked DR potentials in DR enabled case

EPE (kWh)	**EIF_a** (occ/appl.yr)	**EIF_c** (occ/cust.yr)	**EID_a** (hrs/occ.app)	**EID_c** (hrs/occ.cust)
19.0421	0.2589	0.3793	0.5687	1.7060

Table VII. System oriented reliability indices for different penetration levels of active customers

Penetration level of active customers (%)	**SAIFI** (occ/cust.yr)	**SAIDI** (hrs/cust.yr)	**EENS** (kWh)	**EIC** (€)
0 (Base case)	0.0708	0.1464	57.3548	1319.6
25	0.0670	0.1349	49.0024	1152.0
50	0.0660	0.1332	46.1124	1101.1
75	0.0640	0.1279	41.8240	995.9
100	0.0631	0.1264	39.2241	942.8

Table VIII. Indices of DR potential invocation for different penetration levels of active customers

Penetration level (%)	**EPE** (kWh)	**EIF_a** (oc/app.yr)	**EIF_c** (oc/cust.yr)	**EID_a** (h/oc.app)	**EID_c** (h/oc.cu)
25	10.1979	0.2850	0.4026	0.5997	1.7991
50	12.4983	0.2756	0.3964	0.5841	1.7424
75	17.1039	0.2722	0.3930	0.5749	1.7246
100	19.0421	0.2589	0.3793	0.5687	1.7060

Table IX. Percentage of reliability indices improvement for customers hosted in different places of network

Position of Customers	**SAIFI Improv.** (%)	**SAIDI Improv.** (%)	**EENS Improv.** (%)	**EIC Improv.** (%)
Main feeders	12.39	17.24	31.87	31.11
Laterals	9.99	12.54	29.12	26.94
Upper half	10.22	13.22	28.92	27.35
Lower half	10.76	13.41	29.82	27.92

Table A1. Peak demand, number of customers, and VOLL of load points

bus #	Apparent peak load (kVA)	Active peak load (kW)	Number of customers	VOLL ($/kWh)	bus #	Apparent peak load (kVA)	Active peak load (kW)	Number of customers	VOLL ($/kWh)
1	24.2	22.99	1	10.4	32	58.6	55.67	4	17.9
2	11.8	11.21	3	29.9	33	86.3	81.985	4	23.3
3	11.4	10.83	1	24.5	34	89	84.55	7	24.5
4	38	36.1	3	29.9	35	10.2	9.69	1	19.2
5	6.07	5.7665	1	24.5	36	81.4	77.33	5	15.9
6	71.4	67.83	3	26.7	37	102	96.9	6	24.5
7	58.5	55.575	4	24.5	38	38.6	36.67	4	60
8	34.9	33.155	4	24.5	39	0.73	0.6935	0	24.5
9	7.36	6.992	1	24.5	40	95.1	90.345	6	16.1
10	50.3	47.785	2	29.9	41	56.4	53.58	4	33.8
11	124	117.8	7	10.2	42	30.9	29.355	2	29.9
12	29.7	28.215	2	18.1	43	22.7	21.565	1	33.8
13	39.3	37.335	3	29.9	44	6.11	5.8045	2	10.4
14	55.4	52.63	2	29.9	45	49.9	47.405	6	24.5
15	87.8	83.41	5	24.5	46	35.3	33.535	4	29.9
16	53.7	51.015	4	15.1	47	27.6	26.22	3	24.5
17	63.6	60.42	3	27.8	48	31.5	29.925	2	27.9
18	22.3	21.185	1	26.3	49	55.6	52.82	5	19.2
19	50.2	47.69	5	24.1	50	3.31	3.1445	2	28.5
20	15.4	14.63	0	24.5	51	68.6	65.17	3	24.8
21	24.4	23.18	1	15.8	52	24	22.8	1	33.1
22	37.3	35.435	5	24.5	53	143	135.85	7	24.5
23	120	114	4	16	54	83	78.85	3	12.8
24	49.9	47.405	6	29.9	55	32	30.4	1	17.9
25	23.7	22.515	1	7.86	56	78.2	74.29	2	29.9
26	42.2	40.09	4	29.9	57	32.1	30.495	2	14
27	34.4	32.68	4	29.9	58	40	38	4	25.1
28	31.8	30.21	4	31.1	59	38.5	36.575	1	24.5
29	99.4	94.43	5	24.5	60	7.1	6.745	1	29.9
30	43.5	41.325	6	15.3	61	99.1	94.145	6	28.3
31	85.8	81.51	5	29.9					

Table A2. Network line data including technical and availability data

Line #	FB	TB	R(Ω)	X (Ω)	Cap (kVA)	Availability	Line #	FB	TB	R(Ω)	X (Ω)	Cap (kVA)	Availability
1	0	1	0.8463	0.3973	800	0.999997	32	31	32	1.3918	0.4074	200	0.999995
2	1	2	0.4124	0.1936	800	0.999987	33	0	33	0.3749	0.1760	800	0.999996
3	2	3	0.1884	0.0884	800	0.999995	34	33	34	0.3401	0.1597	800	0.999996
4	3	4	0.0100	0.0047	800	0.999996	35	34	35	0.3486	0.1020	200	0.999987
5	4	5	0.7811	0.2286	200	0.999995	36	34	36	0.1048	0.0492	800	0.999996
6	4	6	0.1645	0.0772	800	0.999996	37	36	37	0.3761	0.1101	200	0.999991
7	6	7	0.2699	0.1267	800	0.999995	38	36	38	0.1216	0.0571	800	0.999992
8	7	8	0.2754	0.1293	800	0.999992	39	38	39	0.1860	0.0873	800	0.999994
9	8	9	0.2306	0.1082	800	0.999994	40	39	40	0.2494	0.1171	800	0.999998
10	9	10	0.7365	0.2156	800	0.999991	41	40	41	0.4433	0.1298	200	0.999995
11	10	11	0.5141	0.1505	800	0.999996	42	41	42	1.0350	0.3029	200	0.999996
12	10	12	0.2196	0.0643	200	0.999999	43	42	43	0.5182	0.1517	200	0.999994
13	12	13	0.5881	0.1721	200	0.999994	44	43	44	0.3811	0.1115	200	0.999998
14	13	14	0.2526	0.0739	200	0.999997	45	44	45	0.3847	0.1126	200	0.999993
15	13	15	0.5272	0.1543	200	0.999995	46	45	46	0.4190	0.1226	200	0.999997
16	9	16	0.1420	0.0667	800	0.999998	47	46	47	0.4253	0.1245	200	0.999998
17	16	17	0.1459	0.0685	800	0.999998	48	47	48	0.8524	0.2495	200	0.999996
18	17	18	0.4808	0.1407	200	0.999997	49	40	49	0.5164	0.1511	200	0.999997
19	18	19	0.3076	0.0900	200	0.999993	50	49	50	0.9119	0.2669	200	0.999996
20	19	20	0.3184	0.0932	200	0.999995	51	50	51	0.6314	0.1848	200	0.999998
21	20	21	0.4339	0.1270	200	0.999998	52	51	52	0.6355	0.1860	200	0.999995
22	21	22	0.4943	0.1447	200	0.999997	53	52	53	0.9832	0.2878	200	0.999994
23	21	23	0.4312	0.1262	200	0.999997	54	51	54	0.9588	0.2806	200	0.999994
24	23	24	0.3788	0.1109	200	0.999997	55	40	55	0.4194	0.1228	200	0.999997
25	24	25	0.5132	0.1502	200	0.999996	56	55	56	0.4496	0.1316	200	0.999995
26	17	26	0.5638	0.1650	200	0.999997	57	56	57	0.5380	0.1575	200	0.999997
27	26	27	0.2426	0.0710	200	0.999996	58	56	58	0.4325	0.1266	200	0.999996
28	27	28	0.3342	0.0978	200	0.999995	59	58	59	0.0753	0.0220	200	0.999996
29	28	29	0.4596	0.1345	200	0.999996	60	56	60	0.6386	0.1869	200	0.999997
30	26	30	0.3148	0.0921	200	0.999994	61	60	61	0.6693	0.1959	200	0.999996
31	30	31	0.6120	0.1791	200	0.999991	62	30	61	0.3784	0.1107	200	0.999997