The Impact of Time Series-based Interruption Cost on Online Risk Assessment in Distribution Networks

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***Abstract*— Recent transformations in design, planning and operation of distribution system represent the needed evolutionary step toward a modern integrated infrastructure where new risk-based operations balance economic and reliability criteria. Risk assessment tools are useful for monitoring and supervisory control because they provide operators with the capability to quantify the tradeoff between reliability and economic performance. One part of the risk assessment is the determination of financial impact that can be expressed through the total cost of energy supply interruption. The calculation of interruption cost is typically associated with planning assessment where several parameters essential to network operation are neglected. The proposed mathematical model incorporates time-dependent interruption events, and integrates the spatio temporal risk data using a GIS platform.**

Keywords*— cost function, electricity supply industry, geographic information systems, power distribution, risk analysis;

I. Introduction

The distribution system operation role is to ensure reliability of customer energy supply and guarantee efficiency. Regulatory authorities are increasingly adopting the performance-based rules that discourage distribution utilities from sacrificing service reliability. Thus, the demand for balancing the tradeoff between high reliability and cost effectiveness has increased since the new framework was introduced [1]. An established method for managing this tradeoff is to use risk analysis. Risk is often defined as a function of probability of an event occurrence and related consequence. Evaluating the impacts of outages and the risk reducing investments is thus valuable.

Recent power system risk analysis approaches are using data mining methods and geographical information system (GIS) framework. In [2], the probability-based wind pattern models are built by mining 160-year historical database, then outage records are employed to characterize weather-dependent component models. Additional to the wind data, vegetation and power system data is employed in a predictive method for outage management (OM) in [3]. Different weather-related geospatial data are integrated and processed in GIS platform to predict areas with high risk of outages [4].

Fig. 1 shows the basic formulation of the risk where the assessment is expressed by the correlation between the likelihood and impact, i.e. the risk is assess as the likelihood that

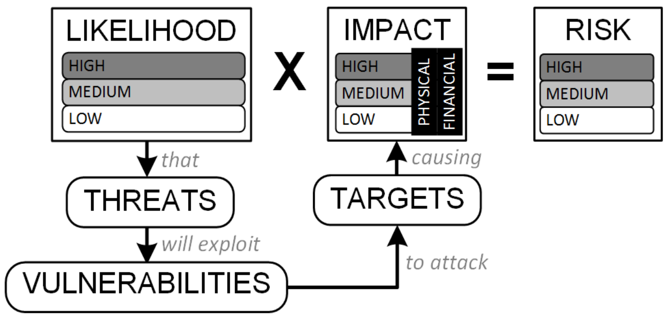

Fig. 1. Risk assessment framework.

threats will exploit vulnerabilities to cause impact on given target [5]. In this framework, the impacts can be different: life threat, financial loss, reputation damage or productivity reduction. The financial impact is most evident for distribution system and it is obtained by calculating energy supply interruption cost.

The calculation of interruption cost is typically associated with cost-benefit analysis where the optimal reliability level is the basis for a feasible economic investment. For example, problems of optimal sectionalizing switch placement [6]-[8], and reallocation [9], consider costs of the energy loss and capital investment in the switch device installation/reallocation. These optimization formulations include curtailed load, the type of involved customers, and the duration of the experienced outage, which all go into the formulation of the interruption cost. The energy consumption profile, time of day and feeder geographic location must also have an influence on the calculation of the interruption cost. Total feeder outage costs due to the time of occurrence and the duration of outage are investigated in [10].

In our work, the interruption cost is investigated focusing on the online risk assessment [3], [4]. The time series based interruption cost formulation supports time varying energy consumption profiles whereas the use of georeferenced network data identifies the event location.

The paper is organized as follows. Section II formulates the calculation of the total interruption cost through the description of the perceptions by utility company, regulatory authority and customers. Section III evaluates the proposed formulation under three study cases. Section IV presents new smart grid

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technologies that affect the power interruption cost and are used in the risk mitigation. Section V is dedicated for conclusions. References are given at the end.

II. Interruption Cost in Distribution Networks

In an energy supply interruption, customers can be subject to the direct economic impacts measured through the loss of yield, raw material, worked hours and stock value [11]-[12]. The power interruption can also cause indirect impacts that are characterized by the loss of leisure, security and opportunity cost [13]. The estimation of costs associated with the interruption is a difficult task that requires considerable data on the individual customers and on the distribution system.

In the calculation of interruption cost, there are three important viewpoints: utility company, regulatory authority and customer [14]. The utility company has income and cost that are related to electric energy sales and capital investments in their distribution network, in addition to the operation and maintenance cost. The regulatory authority balances the consumer prices according to the established rate-case rules, while maximizing the benefits to the society. Customers' interests are affected by both energy purchase price and financial loss during the energy failure [15].

$$C^{TOTAL} = C^{O\&M} + C^{ENS} + C^{PEN} + C^{IC} \tag{1}$$

where

C^{TOTAL}	total cost of the power interruption ($);
$C^{O\&M}$	operation and maintenance cost ($);
C^{ENS}	cost of energy not supplied ($);
C^{PEN}	cost of penalty ($);
C^{IC}	customer interruption cost ($).

In (1), the total cost of the power interruption is obtained by the sum of cost elements perceived by various agents of the energy market.

A. Utility Company Perception

After an interruption event, the utility must restore the energy supply service as quickly as possible. The operation and maintenance cost are associated with this restoration procedure involving the logistic of workforce assignment and equipment location, as well as the replacement of damaged apparatus and implementation of switching maneuvers to reconfigure distribution network. In general, this cost has a fixed value; however, the failure location influences this value since costs of logistic and circuit switching depend on geographical location of the damaged device.

The operation and maintenance cost can be defined as

$$C^{O\&M} = c^{fixed} + c^{route}\Delta d \tag{2}$$

where

c^{fixed}	fixed cost of corrective maintenance ($);
c^{route}	route cost per kilometer ($/km);
Δd	route traveled by the field crew (km).

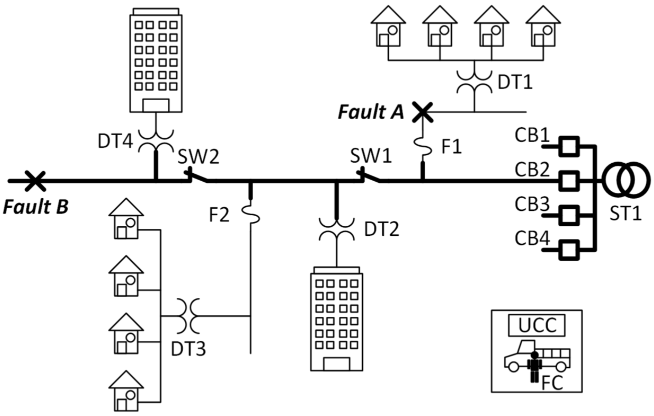


Fig. 2. Distribution system infrastructure with fault events.

The operation and maintenance cost in (2) also depends on the distribution network topology and type of triggered protection device as well as the calculation of the energy not supplied that determines the billing loss due to the power interruption [16]. Fig. 2 presents one-line diagram of a distribution network topology and protection devices that are involved in the fault management. In the first case (Fault A), the failure event happens in a lateral circuit protected by a fuse (F1) that melts and isolates the faulted network section. The energy flow through the distribution transformer (DT1) is interrupted and trouble calls from affected customers to the utility control center (UCC) indicate the network status. A field crew (FC) is then dispatched to replace the fuse and restore the isolated sections. In the second case (Fault B), the failure event happens in the main circuit protected by a circuit-breaker (CB2) at the substation that is triggered by the protection of the substation transformer (ST1). The whole feeder is affected by the fault and energy supply is interrupted for all customers. A field crew is then sent to check the fault point along the feeder and to manually operate the sectionalizing switches (SW1 and SW2), in order to isolate the faulted section and restore the healthy sections. In general, the route traveled by the field crew during the fault point inspection can be calculated by (3).

$$\Delta d = d_{UCC,SW_1} + \sum_{i=2}^{N} d_{SW_i,SW_{i+1}} + d_{SW_{N+1},SW_N} \tag{3}$$

where

d_{UCC,SW_1}	traveled route between the UCC and SW_1 (km);
$d_{SW_i,SW_{i+1}}$	traveled route between the SW_i and its upstream adjacent switch SW_{i+1} (km);
N	switch number of the faulted section.

All distances involved in the calculation of the traveled route are obtained using the GIS platform with the georeferenced position of distribution network components. In addition to space, the time is important in the calculation of the energy not supplied. Time intervals for fault management are described as follows:

- Outage Report Time (Δt^{OR}): time interval between the fault occurrence and the dispatch of field crews;

- Maneuver Time (Δt^{M}): it consists of the field crew travel time, feeder inspection and manual switching time of isolating the faulted section, and time of restoring the healthy feeder sections;

- Repair Time (Δt^{R}): time interval that is required to repair the damaged equipment and to restore the energy supply service.

Time intervals, Δt^{OR} and Δt^{R}, can be determined using Weibull-3P and generalized Gamma probability distributions, respectively [17]. On the other hand, the Δt^{M} interval is significantly dependent on the fault point location and network topology thus it's calculated as in (4).

$$\Delta t^{M} = \Delta d \big/ V^{AV} + N \Delta t^{SW} \tag{4}$$

where

V^{AV}	average speed of field crew vehicle (km/h);
Δt^{SW}	time interval for operating manually one sectionalizing switch (h).

When the fault occurs in the main circuit, the energy supply is interrupted in the whole feeder during the outage report time and maneuver time, whereas customers at faulted section remain without electricity. Hence, the billing loss is the worth of energy in kWh that could be sold to customers during the interruption, given by the cost of energy not supplied.

$$C^{ENS} = \sum_{i \in \Omega} \sum_{j \in \Phi} c_{i,j}^{ens} x_{i,j} \tag{5}$$

$$c_{i,j}^{ens} = c_j^{e} L_j \sum_{m \in \Theta} \sum_{n \in \mathrm{T}} f_{i,m,n}^{dem} y_{j,m,n} \tag{6}$$

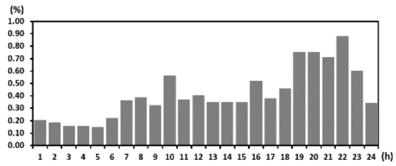
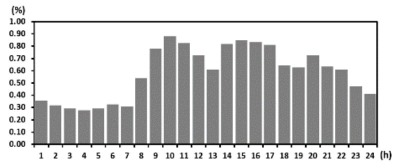
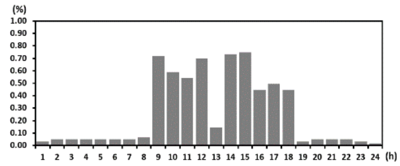
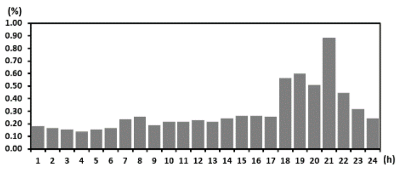
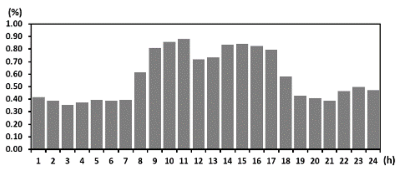
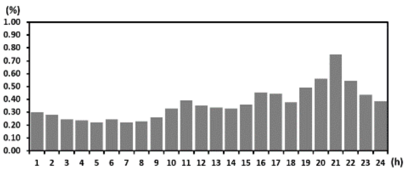
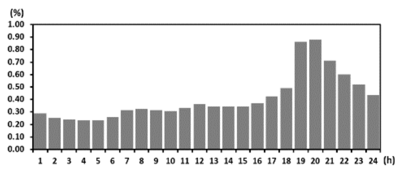
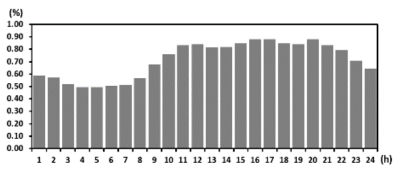
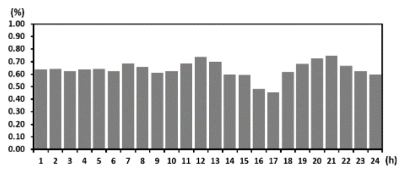
where

Ω	set of time series comprised in the interruption time interval;
Φ	set of customers on the feeder;
$c_{i,j}^{ens}$	cost of energy not supplied for j^{th} customer in the i^{th} time step ($);
$x_{i,j}$	binary variable that indicates the status of the j^{th} customer. If equal to 1, the energy supply is interrupted;
c_j^{e}	electricity rates on the j^{th} customer ($/kWh);
L_j	installed power in the j^{th} customer (kW);
Θ	set of customer types such as residential, commercial and industrial;
T	set of consumption profiles;
$f_{i,m,n}^{dem}$	function of load demand that represents fluctuations in the energy consumption along a day;
$y_{j,m,n}$	binary variable that indicates the type and consumption profile of the j^{th} customer.

In (5), the size of Ω is equal to summation of Δt^{OR}, Δt^{M} and Δt^{R} divided by the time step (Δt). Thus, electricity rate is given in $/kWh for a time step of one hour; in case the time step is given in minutes, electricity rates must be multiplied by the quotient of $\Delta t / 60$. In addition, each customer status, $x_{i,j}$, during the interruption time interval should be obtained by solving an optimization problem that minimizes both the amount of energy not supplied and number of switching maneuvers subject to operational restraints of the distribution system [18].

In (6), the $f_{i,m,n}^{dem}$ function provides the load percentage demand hour-by-hour. Table I presents different average load behavior where columns are customer types and rows are consumption profiles. These characteristics are associated with each j^{th} customer using the binary variable, $y_{j,m,n}$. For example,

TABLE I. LOAD DEMAND TO DIFFERENT CUSTOMER TYPES AND CONSUMPTION PROFILES.

$f_{i,m,n}^{dem}$		Customer Type (m)		
		Residential (m=0)	***Commercial (m=1)***	***Industrial (m=2)***
Consumption Profile (n)	***Low (n=0)***			
	Medium (n=1)			
	High (n=2)			

a customer of commercial type with high consumption profile has $y_{j,1,2} = 1$. Since each customer has just one behavior, other binary values are equal to 0, or in mathematical terms: $\sum_{m\in\Theta}\sum_{n\in\mathrm{T}} y_{j,m,n} = 1$.

B. Regulatory Authority Perception

The distribution system remains regulated ensuring reliable energy supply and efficient distribution system operations [1]. Regulatory authorities have introduced the rules for customer compensation for long outages [19]. According to these rules, utility companies are penalized with the customer compensation whenever the outage duration is larger than the established limit.

Equation (5) can also be employed in the calculation of the cost of penalty, C^{PEN}, where the individual customer compensation is given as in (7).

$$c_{i,j}^{pen} = \left(\frac{\alpha c_j^e L_j}{1 + e^{\frac{(\Delta t^{\max} - i\Delta t)\pi}{\sigma\sqrt{3}}}} \right) \sum_{m\in\Theta}\sum_{n\in\mathrm{T}} f_{i,m,n}^{dem} y_{j,m,n} \tag{7}$$

where

$c_{i,j}^{pen}$	individual customer compensation or cost of penalty for j^{th} customer in the i^{th} time step (\$);
α	factor of penalty;
$\Delta t^{\max}$	maximum outage duration defined by the regulatory authority (h);
σ	average standard deviation of outage report and repair time (h);

Equation (7) reflects the compensation rule where utility companies are penalized whenever the interruption duration exceeds an established limit, i.e. when the product of $i\Delta t$ is less than $\Delta t^{\max}$, the cost of penalty is zero; otherwise the cost of penalty is the cost of energy not supplied multiplied by a factor of penalty, α.

C. Customer Perception

The customer interruption cost is the most significant part of the total cost of the power interruption, but its calculation is a difficult and subjective task. Customer interruption cost comprises economic losses experienced by different types of customers as a result of power supply failures. Examples of the factors that contribute to such cost are: wages paid to idle workers, loss of sales, overtime costs, damage to equipment, spoilage of perishables, cost of running back-up generators, and cost of any special business procedures [20]. Residential customers may also be affected by the endangered well-being , spoiled food and damaged appliance.

Customer interruption cost has been investigated by many utility companies around the world and the results are obtained using both analytical and simulation techniques. The most popular and direct formulation to assess the impact of power interruption is the customer damage function that expresses the cost associated with outage as a function of outage duration. Customers connected to the feeder can be classified according to their economic activities in order to produce a customer sector damage function [10]. Table II shows an example of customer damage function values that are employed in the calculation of interruption cost of the j^{th} customer as in (8).

TABLE II. FEEDER SECTOR CUSTOMER DAMAGE FUNCTION [10].

Customer Type (m)	Interruption Duration ($\Delta t^{OR} + \Delta t^{M} + \Delta t^{R}$)				
	1min	*20min*	*1 hour*	*4 hours*	*8 hours*
Residential	0.0000	0.0278	0.1626	1.8126	4.0006
Commercial	0.9797	11.8537	35.1409	166.2123	305.2044
Industrial	1.8808	4.7237	12.2565	46.3678	88.5821

$$c_{i,j}^{ic} = L_j \sum_{m\in\Theta}\sum_{n\in\mathrm{T}} \left(c_{i,m}^{CDF} - c_{i-1,m}^{CDF} \right) f_{i,m,n}^{dem} y_{j,m,n} \tag{8}$$

where

$c_{i,j}^{ic}$	customer interruption cost for j^{th} customer in the i^{th} time step (\$);
$c_{i,m}^{CDF}$	customer damage cost (\$/kWh);

Equations (5) and (8) are jointly employed in the calculation of customer interruption cost, C^{IC}, where time series of $c_{i,j}^{CDF}$ are interpolations for table values of customer damage function.

III. TOTAL INTERRUPTION COST EVALUATION

The proposed method for calculating the total cost of energy supply interruption in distribution network supports both failure events in lateral circuits and main circuit. Due to the high impact of failure events in main circuit, study cases for evaluating the interruption cost only consider faults on the main circuit; moreover, the assumption of faults on lateral circuits depends upon likelihood, such as failure rate, that is not the focus of this specific work. Hence, each feeder section is limited by at least two sectionalizing switches.

In this evaluation procedure, the total interruption cost is calculated for each feeder section. The test distribution network is a real feeder with nine sections limited by ten sectionalizing switches that has its data available in [21]. Values of $f_{i,m,n}^{dem}$ and $c_{i,m}^{CDF}$ functions are obtained using data from tables I and II, respectively. Furthermore, other parameters used in the study cases are given as follows: $c^{fixed} = 30\,\$$; $c^{route} = 0.22\,\$/km$; $\Delta t^{OR} = 0.25\,h$; $\Delta t^{R} = 4\,h$; $V^{AV} = 40\,km/h$; $\Delta t^{SW} = 0.05\,h$; $c_j^e = 0.1157\,\$/kWh$, if residential; $c_j^e = 0.1038\,\$/kWh$, if commercial; $c_j^e = 0.0749\,\$/kWh$, if industrial customer; $\alpha = 15$; $\Delta t^{\max} = 4\,h$ and $\sigma = 1\,min$. Calculations are performed using a programming language of general purpose (C++) and integrated with a distribution network simulation platform [22] that provides support for the use of georeferenced data.

The first study case evaluates the influence of the time step (Δt) in the calculation of power interruption cost. The base case is obtained using $\Delta t = 1\,min$ because time intervals involved in interruption cost calculation has accuracy by hundredths of hour. Fig. 3 shows the percentage error in the calculation of

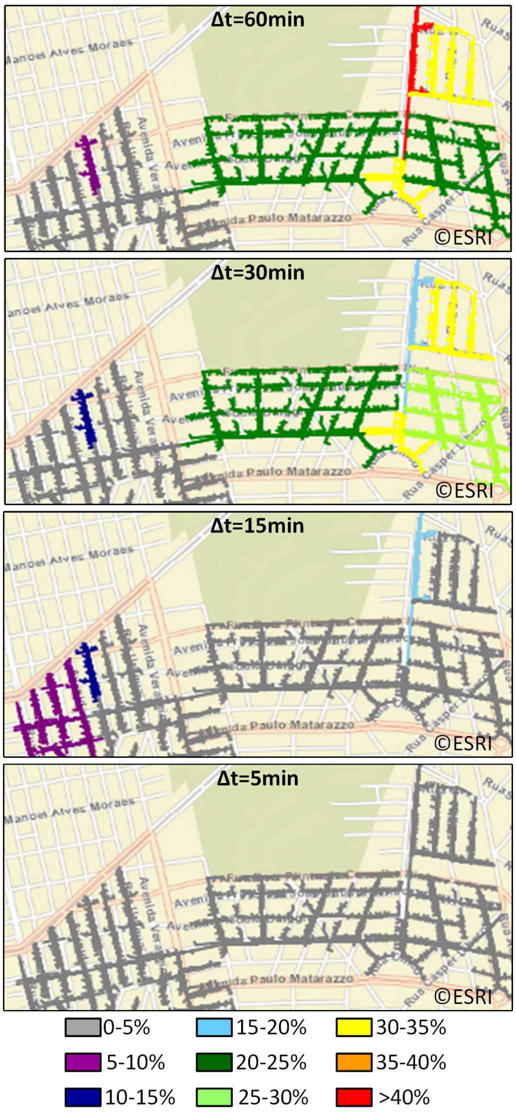


Fig. 3. Percentage error in the power interruption cost for different choices of time step.

interruption cost for $\Delta t = 60, 30$ and $15\,min$. The percentage error decreases according to the reduction of time step. For example, the error percentage is in the range of 0-5% to $\Delta t = 5\ min$ while the error is larger than 40%, in one feeder section, to $\Delta t = 60\ min$. This effect results of the inadequacy of large time steps that are not able to precisely reproduce all of the operating stages involved in a fault management. Hence, the choice of short time steps should be more suitable in the calculation of power interruption cost.

The second study case assesses the influence of the geographical location of UCC in the total interruption cost for each feeder section. Fig 4 presents distances from two locations (L1 and L2) to the geometric center of feeder sections. The total interruption cost decreases one range of \$ 4,000.00 for some feeder sections when the UCC changes its location from L1 to L2. Since the location L2 is near to the geometric center of feeder sections, the route traveled by field crew is shorter and, consequently, the route cost as well as maneuver time interval

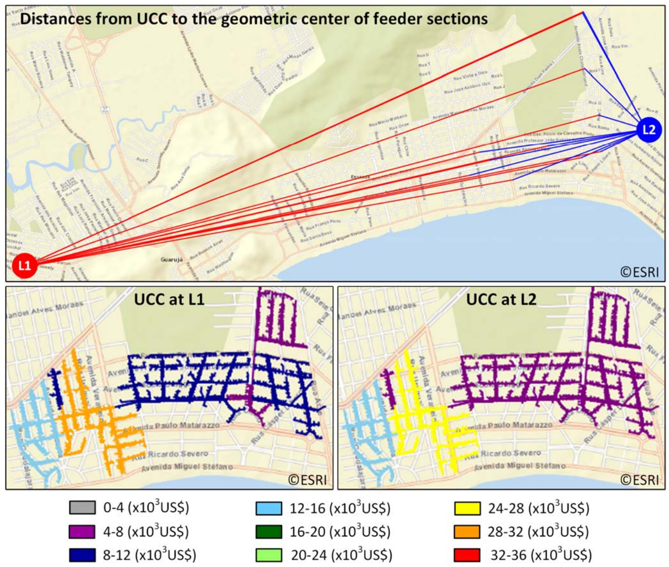


Fig. 4. The total interruption cost by feeder section to two locations of UCC.

decreases, which contributes mainly to the reduction of customer interruption cost. In this example, the route lengths are obtained through the sum of perpendicular distances, but the accuracy of the method can be improved using tools that build routes according to street limits.

In addition to the spatial data, the interruption cost also depends on time. In this way, *the third study case* evaluates the influence of the failure occurrence time. Fig. 5 shows the total interruption cost by feeder section calculated at two different times, at 02:00 and at 17:00. When failure event occurs at 17:00 the financial impact is greater than an event at 02:00 because load demand is greater, too. Consequently, total interruption cost is greatest at 17:00 when there is a feeder section that has an

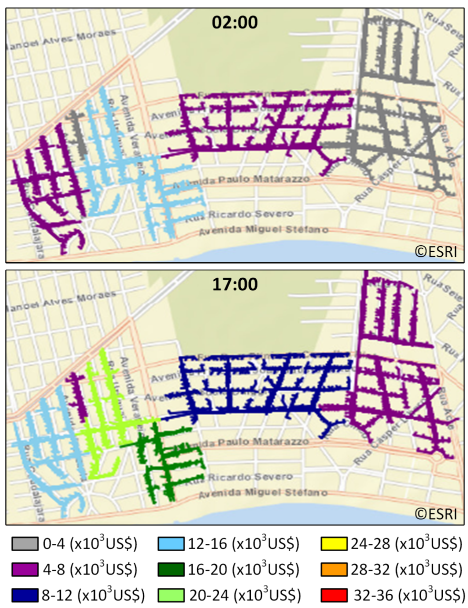


Fig. 5. The total interruption cost by feeder section in two failure occurrence time.

increase around $ 8,000.00 in comparison to failure event at 02:00.

The use of time series for calculating the power interruption cost seems to be an efficient way to determine the financial impact of failure events in distribution network because this method incorporates both the operating stages of the fault management and customer behavior. In this way, two important attributes of smart grids, that is, self-healing from power disturbance events and active participation by customers in demand response [23], should be easily incorporated in the risk assessment framework.

Self-healing strategies are conduced via distribution automation solutions, specifically through smart protective and switching devices that minimize the number of interrupted customer during failure events [24] and reduce the interruption time by eliminating the outage report time as well as isolation time [25]. Active customer equipped with smart meter establishes bi-directional interaction with utility company, by receiving electricity price data and responding with the monitoring and control of responsive appliances. Responsive loads may contribute to a reduction in customer interruption cost but these loads become non-responsive when the interruption duration exceeds the maximal acceptance delay time [26].

IV. Conclusion

The study has made the following contributions:

- The novel formulation of power interruption cost based on time series is used to represent the financial impact in a risk assessment framework.
- The use of time series improves the calculation accuracy by enabling the incorporation of all time-dependent events in the cost formulation, such as operation stages involved in a fault management and customer load patterns.
- The results demonstrate that the integration of spatio-temporal data via a GIS platform has a significant impact on the calculation of the total worth of the power interruption cost.
- The cost-impact formulation supports the inclusion of self-healing strategies and response demand behavior required in the risk mitigation.

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