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Evaluation of the economic impact of investments for resilience improvement in the distribution system

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List of Nomenclature

AEEGSI	Autorità per l'Energia Elettrica, il Gas Naturale e il Sistema Idrico
AFTER	A Framework for electrical power sysTems vulnerability identification, dEfense and Restoration
ARERA	Autorità di Regolazione per Energia Reti e Ambiente
CAPEX	Capital expenditure
CBA	Cost Benefits Analysis
CDF	Cumulative distribution function
DS	Distribution system
DSO	Distribution System Operator
ENTSO-E	European Network of Transmission System Operators
EPRI	Electric Power Research Institute
GWP	Global Warming Potential
OFGEM	Office of Gas and Electricity Markets
OPEX	Operating expenditure
OSCE	Organization for Security and Co-operation in Europe
RAV	Regulatory Asset Value
RIIO	Setting Revenue using Incentives to deliver Innovation and Outputs
RSE	Ricerca sul Sistema Energetico
TOTEX	Total Expenditure
TSO	Transmission System Operators
UK	United Kingdom
WACC	Weighted-average cost of capital
WEC	World Energy Council

List of Symbols

δ_{max}		Coefficient to measure hosting capacity
$\zeta_h^{(N)}$		Harmonic Summation Ratio, for the presence of N inverters and for each harmonic h
λ		Failure rate
λ_c		Rate of permanent fault per length
λ_x		Rate of extreme event
μ		Penalty factor settled by regulation for not attending CIF or CID
$\mu_{CO_2}^{(F)}$	g/kWh_e	Equivalent emission factor
μ_{xx}	$kgCO_2/kgfuel$	Equivalent emission factor of a fuel
$\mu_{CO_2}^{(X,SP)}$	g/kWh_e	Equivalent emission factor for energy vectors x
$\mu_{CO_2eq,p}^{(X,SP)}$	g/kWh_e	Equivalent emission factor for a generic GHG
$\mu_p^{(X)}$	g/kWh_e	Emission factor of an energy vector x
ρ		Stiffness ratio
ρ_{Pk}		Coefficient proportional to the losses
τ		Coefficient proportional to the time
υ		Penalty factor settled by regulation for not attending SAIFI or SAIDI
$a_{ecom,p}$	kBq	Activity of substance p emitted to compartment comp
b		Branches
$c_D(t_1)$	€/kWh	TOU demand rate during time slot t_1
$c_p(t_e)$	kW	Consumption power
$\boldsymbol{c}^{(b)}$		Vector containing the b^{th} column of the node-to-branch incidence matrix
$class_{k,t,q}$		Percentage of customer sector q at node k for each stage t
c		Component
d		Capitalization rate
d_{SYS}	kW	Power demand of the system
e	kWh	Consumption allocation and development
e_i	kWh	Consumption load
ecom		Type of compartment (e.g. air, fresh water, seawater)
f_y	€	Cash flow at y^{th} years
h		Indices of harmonic
i		Indices
$\boldsymbol{i}^{*T}$	A	Vector containing the node currents
$\boldsymbol{i}_k^T$		Auxillary vector with dimension 1xN whose elements are unitary values

$\boldsymbol{i_K}$		Auxiliary vector with dimension 1xN whose elements are unitary values
k		System node
lt		Useful lifetime of the investment
l		Ceiling integer number of the time slot
l_i		Number of load
$m_{CO_2}^{(F,SP)}$	g	Mass of CO_2 emitted from separate production
$m_{CO_2}^{(F)}$	g	Mass of CO_2 emitted from polygeneration systems
m_p	g	Emission mass of substance p
$m_{xxconsumed}$	kg	Fuel consumed
$m_{ecom,p}$	kg	Emission of substance p to medium ecom
$molew_p$		Mole weight of the resource p
n		Indices of inverters
p		Index of substance
q		Index of customer sector
r		Rate of return
t		Year indicator
t_m	s	Time of manual operation
t_{pg}	s	Time to carry the portable generator to the specific nodes
t_r	s	Duration time of automatic switches
t_{rr}	s	Time to repair fault
ts		Stage indicator
t_1	minute	Time Slot
t_e	hour	Time index
x		Event indicator
y	year	Years index
z		Interruption type
Λ_c		Rate of permanent fault
$\beta_{c,n,h}$		Variable indicated for each step h of the service recovery procedure of the component c if the node n is supplied or not
Δ_{max}	kV	Absolute voltage margin
$\boldsymbol{\prod_{LL}}$		Index set of load levels
$\boldsymbol{\Omega_{L,B,t}}$		Index set of load nodes in each stage t
A_h		Individual harmonic
AcP	kg SO_2	Acidification Potential
A_p	$kgCO_2/kg$	Acidification Potential for substance p emitted to the air
AD	kg antimony eq.	Abiotic Depletion

ADP_p	kg antimony eq./kg	Abiotic Depletion Potential of substance *p*
ADP_{fossil}	kg antimony eq./ MJ fossil energy	Abiotic Depletion Potential of fossil energy
ASAI	s	Average System Availability
$\boldsymbol{B_k}$	€	Set containing the nodes supplied from branch *b*
B	€	Number of branches
$B^{(rel,eme)}$	€	Benefit related to the decrease of the cost of the emergency actions in case of ordinary faults
$B^{(rel,int)}$	€	Benefit related to the decrease of ordinary interruptions
$B^{(res,int)}$	€	Benefits related to the decrease of the interruptions in case of extreme climate events
$B^{(res,eme)}$	€	Benefit related to the reduction of the cost of emergency actions in case of extreme climate event
$B^{(res,sea)}$	€	Benefits related to the emergency action in case of extreme climate events
$B_t^{(DNO,afcap)}$	€	Total net DNO benefits
$B_t^{(DNO,tot)}$	€	Total company benefit before the capitalisation
$B_t^{(O\&M)}$	€	Benefit related to the operational and maintenance cost
$B_t^{(rel,sea)}$	€	Benefit related to the costs of emergency actions in case of ordinary fault
$\mathbb{C}$		Total network components
CAAD	kWh	Consumption allocation and development
$CC_{q,z}$	€	Cost of an interruption *z* associated with customer sector *q*
CIC	€	Customer interruption costs
$CIF_{k,t}$		Customer Interruption Frequency
CIF_p		Customer interruption frequency target
CIFC	€	Cost of Costumer Interruptions Frequency
$CID_{k,t}$	s	Customer Interruptions Duration index for node k at stage t
CID_p	s	Customer interruption duration target
CIDC	€	Cost of Costumer Interruptions Duration
C_{LL}^{SS}	€	Cost of energy supplied by substations at load level LL
CCR		Customers complain rate
CD	kWh	Demand Response

C_{DT}	€/kWh	TOU demand rate
CR_i	€	Repair cost of a single component of the network
C_{NR}	€	Cost of energy not supplied for non-residential customers.
C_R	€	Cost of energy not supplied for residential customers.
$C_c^{(eme)}$	€	Cost of emergency actions in case of fault of the component $c \in \mathbb{C}$
C_{cbl}	€	Costs of cable lines
$C_{comp}^{(cap)}$	€	Costs of compensatory works
$C_{cos}^{(cap)}$	€	Capitalized costs related to the construction of the new asset
C_{cs}	€	Cost of changing substation
C_{flt}	€	Cost of fault location team
C_{inr}	€	Cost of interruption costs for non-residential customers
$C_{inv,ann}$	€	Annualised investment
C_{ir}	€	Cost of interruption costs for residential customers
C_{pg}	€	Cost for renting portable generator
C_{rol}	€	Cost of removing overhead lines
C_{rp}	€	Cost removing poles
C_{rpa}	€	Cost of removing previous assets
C_{rsp}	€	Cost of removing a single pole
C_{tot}	€	Total costs of investment
C_{fpg}	€	Cost to rent the portable generator
CoC_t		Cost of capital
C_{ofl}	€	Cost of the fault location team
C_{ons}	€	Costs of energy not supplied
C_{ort}	€	Cost of the fault repair team
C_{rm}	€	Costs of removing previous assets
$C_x^{(eme)}$	€	Costs of emergency action related to the extreme event $x \in \mathbb{X}$ and
Dep_t		Depreciation
$\boldsymbol{D}_{\boldsymbol{dip}}^{(X)}$		Dip-markers matrix for an assigned threshold X
D_{LL}	h	Duration in hours of each load level
$Dint_z$	s	Duration of interruption type z
$DamageFactor_{ecom,p}$	yr·kBq^{-1}	Characterisation factor substance p emitted to ecom
$DEM_{k,t,LL}$	kW	Power demand at node k at each load level LL of the stage t
DR_{fossil}	MJ·yr^{-1}	De-accumulation or fossil energy production

$DR_{antimony}$	$kg \cdot yr^{-1}$	De-accumulation of antimony, the reference resource
$D_{c,n,h}$	s	Expected duration of the phase h which produces the power failure of node n
$D_{x,s}^{(NR)}$	s	Duration of power outages for non-residential customers
$D_{x,s}^{(R)}$	s	Duration of power outages for residential customers
E		Market value of the company's equity
$ENS^{(NR)}$	kWh	Energy not supplied for non-residential customers
$ENS^{(R)}$	kWh	Energy not supplied for residential customers
E_c	kWh	Total consumption
Ex_p	kJ/mol	Exergy content of one mole of resource p
ECO_2	kg_{CO_2}	Emissions of CO_2
EGWP		Emissions of Global Warming Potential
EENS	kWh	Expected Energy Not Supply
EENSC	€	Cost at each stage of the Expected Energy Not Supplied
EIOR		Energy Index Of Reliability
EP_p	$kg \cdot PO_4^{3-}$ /kg	Eutrophication Potential for substance p emitted to air, water or soil
EU		Energy use
EUT	$kg \cdot PO_4^{3-}$	Eutrophication
F	kWh_t	Input fuel energy
$Factor_p$	$MJ \cdot kg^{-1}$	Characterisation factor for abiotic depletion of resource p
F_{oss}		Oxidation factor
$FWAE$	kg dichlorobenzene eq.	Fresh water aquatic ecotoxicity
$FAETP_{ecom,p}$	kg dichlorobenzene eq /kg	Fresh water aquatic ecotoxicity potential
GWP_p	gCO_2/g	Global warning potential
G		Set of GHG (greenhouse gases)
G_{gh}		RMS value of the harmonic group order associated with harmonic order h
G_{g1}		RMS value of the harmonic group order associated with fundamental harmonic
$G_{s\,gh}$		RMS value of the harmonic subgroup order associated with harmonic order h
$G_{s\,g1}$		RMS value of the harmonic subgroup order associated with fundamental harmonic
$\mathbb{H}$		Set of the step include in the service recovery procedure

H		Highest harmonic taken into consideration
HT	kg dichlorobenzene eq.	Human Toxicity
$HTP_{ecom,p}$	kg dichlorobenzene eq /kg	Human toxicity potential for substance p emitted to compartment ecom
HD		Hour Distribution
$\bar{I}_k^*$	A	Node current injected into node k
$\bar{I}^{(b)}(t_e)$	A	Current of the branch b at the time t_e [A]
$I_1^{(h)}$	A	Current waveform of one of the PV inverters in the frequency domain
$I_N^{(h)}$	A	Current of all inverters seen from the (PCC) in the frequency domain
$\bar{I}_a^{(h)}, \bar{I}_b^{(h)}, \bar{I}_c^{(h)}$	A	Three-phase current at h harmonic order
$\bar{I}_{T1}^{(h)}, \bar{I}_{T2}^{(h)}, \bar{I}_{T3}^{(h)}$	A	Positive, negative and omopolar current at harmonic h
$\boldsymbol{I_K}$		Matric containing the short-circuit current of the network in sequence component
I_y	€	Investment at y^{th} years
IRR		Internal rate of return
IR	yr	Ionising Radiation
$Inv^{(e)}$	€	investment to be expensed
$Inv_t^{(cap)}$	€	capitalized DNO benefits
Inv	€	Cost of investment
K		Number of nodes
L_b	m	Length of branch
L_{tot}	m	Total length of the network
$L, L^{(0)}$	W	Total losses, uperscript (0) is the present configuration
L_k	W	Losses allocated to the node k
$LE_{hour,i}$		Load power demand in a specific hour of the day
$Load_{hour,i}$		Daily i load, from 1 to l_i , consumption in a specific hour
LDC		Load Duration Curve
LL		Load Level index
LOLE		Loss of load expectation
LOLP		Probability of load loss in a single day
MLC		Marginal loss coefficient
MAE	kg dichlorobenzene eq.	Marine aquatic ecotoxicity
$MAETP_{ecom,p}$	kg dichlorobenzene eq /kg	Marine aquatic ecotoxicity potential for a substance p
$\mathbb{N}$		Set of the network nodes

N		Number of inverters
$\boldsymbol{N_{dip}^{(X)}}$		Number of dips
$Nint_{k,t,z}$		Total number of customers in node k
$Nq_{k,t}$		Total number of customers in node k at stage t
N_c		Number of component of the network
NCR	€	Network repair cost
NPQ_V		Power quality variation indices in DG
NPV	€	Net present value
$N^{(NR)}$		Number of non-residential customers not supplied
$N^{(R)}$		Number of residential customers not supplied
N_f		Number of fault branch
N_{pgo}		Number of portable generators owned by the network company
N_{pgr}		Number of portable generators that can be rented
N_{poles}		Number of removing poles
$O\&M$	€	Costs of operation and maintenance
OTG		Outages
OUC	€	Outage costs
OD	kg CFC-11 eq.	Stratospheric Ozone Depletion
ODP_p	kg CFC-11 eq./kg	Ozone Depletion Potential for a substance p
$P^{(NR,int)}$	kW	power of each non-residential customer
$P^{(R,int)}$	kW	power of each residential customer
P_{cnsr}, P_{cnsnr}	kW	total power not supplied
P_{pg}	kW	power of portable generator
P_{max}	kW	Maximum power
PCC		Point of common coupling
$PCDER$		Polygeneration Carbon Dioxide Emission Reduction
$PGHGER$		Polygeneration Greenhouse Gasses Emission Reduction
$PTRG(h)$		Peak demand Ratio Global index
$PTRMAX$		Peak demand Ratio Local Index
P_{DG}	kW	Power of DG
$P_{Rk}(t_e)$	kW	Rated power in node k in the hour t_e
$P_{d,k}$	kW	Demand Power in node k
$P_{g,k}$	kW	Generated Power in node k
$P_l(X_c)$	kW	Power losses in the network for the configuration Xc
$P_k(t_e)$	kW	Power in node k in the hour t_e

$P_{rINV,AC}^{(1)}$	kW	Rated power of the individual inverter
$P_{rINV,AC}^{(i)}$	kW	Rated power of the inverters $i = 1, \dots, N$
$\Delta P_k^{(post)}$, $\Delta P_k^{(pre)}$	kW	Power variation, generated power less demand power, before and after power variation at node k
POF	kg ethylene eq.	Photo-oxidant formation
$POCP_p$	kg ethylene eq./kg	Photochemical Ozone Creation Potential for substance p
Q		Index set of customer sector
R	Ω	Resistance of a wire
R_b	Ω	Resistance of branch b
R_{fossil}	MJ	Ultimate reserve of fossil fuels
$R_{antimony}$	kg	Ultimate reserve of antimony
RD		Cost of Debt
RE		Cost of Equity
$\mathbb{S}$		Set of components that failure because of the event
S_{lv}	€	Revenues from sales of the old infrastructure
S_{sc}	kVA	Short circuit power
SAIFI		System Average Interruption Frequency Index
$SAIFI_p$		System average interruption frequency index target
SAIDI	s	System Average Interruption Duration Index
$SAIDI_p$	s	System average interruption duration index target
$SAIC$	€	Cost of not attending SAIFI or SAIDI
T	years	Time horizon
Ta		Tax Rate
T_l	hours	Limit of time
THD		Total harmonic distortion factor
THDG		Group total harmonic distortion
THDS		Subgroup total harmonic distortion
TED		Total Energy Demanded
TPU		Total Phase Unbalance
TPD		Total Phase Distortion
TO		Total outages
TE	kg dichlorobenzene eq.	Terrestrial ecotoxicity
$TETP_{ecom,p}$	kg dichlorobenzene eq /kg	Terrestrial ecotoxicity potential of a substance p
U	kV	Voltage
UO		Unplanned outages

$\mathbb{X}$		Set of extreme climate events
X		Threshold
X		Set of energy vectors $X\epsilon\boldsymbol{X}$
X_1		RMS value of the fundamental component
X_c		Configuration index
X_h		RMS value of harmonic component of order h
X_V		Power quality variation indices
$X_{(10n+i)\Delta f}$		RMS value of the spectral components at $(10n + i)\Delta f$ frequency
Y	Hour	Duration in years
Y_{new}		Value after the new operation
Y_{old}		Value of index before the an operation
Z		Set of interruption type

Abstract

The aim of this thesis is to understand if an investment for improving the resilience of a distribution network, can provide a monetary benefit. The heavy snowfall has been considered as specific extreme event. The procedure investigated in this thesis can be extended to any other extreme climate events, even if different initial databases of the weather conditions should be considered.

The resilience of the electricity system is a relative new topic, which is gaining a main role due to the increasing number of extreme weather events affecting the correct operation of infrastructures. The resilience is the capability of a system to face extreme events and successfully overcome the consequence of them. The consequence of extreme climate events can be the interruption of the services, or in extreme case, the black—out of portions of the network. If one of these consequences happens, the goal is to reduce as much as possible the out-of-service time with some investments.

The case study is a distribution network, composed of 17 nodes. The consequence of an extreme event is the fall of the overhead lines. In this network the number of overhead lines is five. This is the only type of fault considered. For this reason, for improving the resilience of the network, the investment considered will be the substitution of the overhead lines with cable lines, which means no consequences for the new network in case the heavy snowfall will happen again in the future

The first step of this thesis is the fault analysis. Two different types of fault analysis have been made, one related to the resilience of the network, and the other related to ordinary fault. Both types of fault analysis have been made for the network before and after the investment.

In the resilience fault analysis, the changes of the network after an extreme event have been studied. The aim was the calculation of the emergency cost related to the event and the energy not supplied in the network. These indices have been calculated after any automatic or manual operation, that compose the procedure to isolate the fault and supply all the nodes with alternative paths, if existing, or with portable generators.

The second type of fault analysis is related to the ordinary faults (i.e., studied in the reliability framework) of the network in case of permanent fault. In this case, as in the first type of fault analysis, the objective is to calculate the energy not supply in the network, but in this case only alternative paths can be used for supplying the network nodes.

In the second part of the thesis, the benefits will be calculated with two different type of Cost Benefits Analysis (CBA). The first one has been introduced in Italy by the "Autorità di Regolazione per Energia Reti e Ambiente", ARERA, whereas the second one is essentially based on RIIO (setting Revenue using Incentives to deliver Innovation and Outputs), which is the CBA, created by the UK electricity Authority "Office of Gas and Electricity Markets", OFGEM, for the United Kingdom network. The benefits calculated can be divided in: customer benefits, company benefits and social benefits. In the RIIO a new approach is described, the TOTEX approach.

The Italian Authority divided the total expenditure in two different parts, CAPEX, that includes the investments for developing the system, and OPEX, that includes all the costs for running the system. These two types of costs can obtain different incentives.

Conversely, with the TOTEX approach the total expenditure is used to obtain the incentives. Avoiding different incentives for CAPEX and OPEX, all the investments that can be done in the network, can be obtain the same return in monetary terms. The aim of the RIIO is to increase the number of investments to improve the efficiency of the network, also introducing incentives related to innovation.

The time horizon of both CBAs has been fixed at 25 years. The differences in terms of monetary costs for the two CBAs have been calculated and compared using two different approaches.

I. Definition of Resilience

This thesis is focused on the investment act to improve the resilience of the network. The resilience of the electricity systems is a relative new topic.

The definition of resilience changes depending on the fields of research it is used in. Thus, it is difficult to find a definition suitable for all of them. Indeed, the first definition of resilience was introduced for the ecological systems in 1973, by C.S.Holling[1]. He stated that the "resilience determines the persistence of relationships within a system and is a measure of the ability of these systems to absorb changes of state variables, driving variable, and parameters, and still persist". In general, the definition was focused on the existence of internal relationships (which has to persist in the time) when there are changes on important variables of the system.

A broader definition was recently introduced by "Stockholm Resilience Centre" [2]: "Resilience is the capacity of a system, be it an individual, a forest, a city or an economy, to deal with change and continue to develop. It is about how humans and nature can use shocks and disturbances, like a financial crisis or climate change, to spur renewal and innovative thinking." In this definition the system is described as individual, forest, city or economy, so very different subjects.

Some other definition was made by international organization such as:

- **United Nations Office For Disaster Risk Reduction** [3]: "The ability of a system, community or society exposed to hazards to resist, absorb, accommodate, adapt to, transform and recover from the effects of a hazard in a timely and efficient manner, including through the preservation and restoration of its essential basic structures and functions through risk management".

- **Word Bank Group Experience** [4]: "The ability of a system and its component parts to anticipate, absorb, accommodate or recover from the effects of a hazardous event in a timely and efficient manner, including through ensuring the preservation, restoration or improvement of its essential basic structures and functions."

- **European Commission** [5]: "Resilience is the ability of an individual, a community or a country to cope, adapt and quickly recover from stress and shocks caused by a disaster, violence or conflict."

- **Rockefeller Foundation** [6]: "Helping cities, organisations, and communities better prepare for, respond to, and transform from disruption."

- **100 Resilient Cities** [7]: "Urban resilience is the capacity of individuals, communities, institutions, businesses, and systems within a city to survive, adapt, and grow no matter what kinds of chronic stresses and acute shocks they experience."

- **NJ Resiliency Network** [8]: "Municipal resilience is the ability of a community to adapt and thrive in the face of extreme events and stresses. Municipal resilience is achieved by anticipating risk, planning to limit impacts, and implementing adaptation strategies that integrate all community systems – civic, environmental, social and economic – to support recovery and growth."

- **Department for International Development (DFID)** [9]: "Disaster resilience is the ability of countries, communities and households to manage change, by maintaining or transforming living standards in the face of shocks or stresses – such as earthquakes, drought or violent conflict – without compromising their long-term prospects."

- **Hyogo Framework of Action** [10]**:** "Disaster resilience is the capacity of a system, community or society potentially exposed to hazards to adapt, by resisting or changing in order to reach and maintain an acceptable level of functioning and structure."

Even the government of United State of America made its own definition [11]: "Resilience is the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. … [It] includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents".

Using all these definitions above, we can summarise the most important features of a resilient system:

- the consequences/effects of a hazard on the system, which means that the hazard occurs and has an effect which has to be quantified;

- a resilient system has to resist/withstand the effect of the hazard occurrence;

- the resilient system has to absorb/cope the stresses due to hazard occurrence;

- for being resilience, a system has to adapt to/transform to changing conditions, due to the hazard occurrences;

- assurance the quick recovery/restoration/preservation of the functionality of the system;

- only definitions include high impact/low probability events, and human-related hazard (as deliberate attack, conflict and so on).

- only one definition reports the capability to anticipate

Definition for power system

All the definitions above are related to general system. In this section some definitions related to the power system are reported.

European Network of Transmission System Operators (Entso-E) [12], represents some electricity Transmission System Operators (TSOs) from Europe, and give its definition of resilience: "Technical resilience/system safety is the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies)."

Entso-E considers the resilience and the system safety as a unique benefit, which contributes to the criterion of "interoperability and secure system operation" (set out in Article 4 Annex IV [13]) and to the criterion of "system resilience" (criterion 6b in Annex V [13]).

For providing a complete overview, the security of the system is considered by ENTSO-E in the benefit "improved security of supply", defined as "the ability of a power system to provide an adequate and secure supply of electricity under ordinary conditions".

It is worth to note that ENTSO-E specifies that "Making provision for resilience while planning transmission systems, contributes to system security during contingencies and extreme scenarios" (i.e., it is considered that the improvement of the resilience makes an improvement also for guaranteeing the supply of the demand in N-1 condition).

The Organization for Security and Co-operation in Europe (OSCE) gives for resilience the following definition [14]: "In general, resilience is the ability of a system to react and recover from unanticipated disturbances and events. In particular, the resilience is the ability of a system or a "system-of-systems" to resist/absorb the adverse effects of a disruptive force and the speed at which it is able to return to an appropriate functionality".

The same document [14] highlights some disruptive forces to be investigated dividing them in:

- natural (e.g., metereological, geological, fire, etc.)
- technical (e.g., random failure, accidental fire, etc.),
- human unintentional (e.g. cyber-attack)
- management, organizational and operational activities (e.g., lack of safety culture)
- market reason (excessive economic pressure)

By considering the natural threads, the document reports cases of loss of supply due to:

- brush fire
- storm and hurricanes
- earthquakes
- heat- waves
- ice-storms and snow
- land-slides
- geo-magnetic storm.

These natural threats are extreme climate events and are discuss in the next Chapter. For some of them, the most significant parameters to characterized them were reported as well, such as earthquake (ground motion, i.e. peak acceleration or peak velocity of the surface, duration of shaking), floods (height, duration, streaming velocity of the inundation) and storm (wind velocity).

Furthermore, OSCE analysed the climate impacts on electricity transmission and distribution system, providing a relationship between natural hazard and consequences (Table 1):

Table 1 Climate impacts and risks for electricity transmission and distribution [14]

Type	**Natural hazard**	**Risk**
Direct impact on transmission and distribution systems	Extremely high temperatures	Decreased network capacity
	Snow, icing storms	Increased chances of damages to energy networks and blackouts
	Heavy precipitations	Mass movements (landslides, mud and debris flows) causing damages

Due to the fact that the electricity infrastructure is exposed to the natural hazard, there is a connection between resilience and vulnerability of the system.

The vulnerability is defined from OSCE [14] as "the probable damage at risk, given a level of intensity of an adverse event". From this definition, it is possible to see that the concept of the vulnerability is related to the damage: the higher is the vulnerability of the system, the higher is the damage on the system (for a given intensity of the adverse event).

For clearness, the definitions of resilience and vulnerability are reported in Table 2 and compared.

Table 2 Comparison between the definitions of resilience and vulnerability

Resilience	**Vulnerability**
Ability of a system to react and recover from unanticipated disturbances and events. In particular, the resilience is the ability of a system or a "system-of-systems" to resist/absorb the adverse effects of a disruptive force and the speed at which it is able to return to an appropriate functionality	Probable damage at risk, given a level of intensity of an adverse event

The two concepts are linked: in fact, the resilience definition consist also of the "speed of return to an appropriate functionality", whereas vulnerability consider the damage. That is, the higher (in magnitude) the damage, the lower the speed at which the system can recover. Or, to put it in terms of the resilience, the higher the vulnerability of the system, the lower the resilience of the system.

The World Energy Council (WEC), defined the resilience as [15]: "Resilience for energy infrastructure refers to its robustness and ability to recover operations to minimise interruptions to service. Resilience also implies the ability to withstand extraordinary events, secure the safety of equipment and people, and ensure continue and reliable energy production"

Electric Power Research Institute (EPRI) defines the resilience as [16]: "The resilience of the distribution system is based on three elements: prevention, recovery, and survivability. Damage prevention refers to the application of engineering designs and advanced technologies that harden the distribution system to limit damage. System recovery refers to the use of tools and techniques to quickly restore service to as many affected customers as practical. Survivability refers to the use of innovative technologies to aid consumers, communities, and institutions in continuing some level of normal function without complete access to the grid. Improving the distribution system's resiliency requires advances in all three aspects. The most cost-effective approach will combine all three."

In their document [16], the extreme weather events and other natural disasters, threating energy infrastructures' vulnerability, are categorized as:

- Geophysical (earthquake, tsunami, volcanic activity)
- Meteorological (storm)
- Hydrological (flood, mass movement)
- Climatological (temperature extremes, drought, wildfire)

Definition by Italian Network Companies

The main Italian Distribution System Operator (main Italian DSO), e-distribuzione, defines the resilience [17] as: "The system resilience is its capability to resist to heavy external stresses, and to restore, as fast as it can, its normal operation."

The Italian TSO, Terna, defines the resilience [18] as: "Resilience of the electrical network has to take into account two aspects, i.e, the Functional security and the restoration. The resilience indicates the ability of the TSO of withstanding and react to severe weather events, which can lead to reduce the functionality of the network, by restoring as fast as possible the initial status of the system. Its value depends on "how much is the intrinsic security of the system" (reduction of the power peak of the unsupplied customers) and on the "density" of restoration (higher density means shorter time for restoring the services)."

II. Resilience and Extreme Weather Event

A resilient system, as reported in the Chapter I, is able to react to some extreme events, for example climate event or cyber-attack. The increasing number of extreme climate events and their high impact on the network contribute to promote resilience as a main player in the electric sector.

The occurrence of extreme weather events can lead to conditions in which the electricity system cannot operate as usual, creating the premises for the interruption of the services. This extreme outcome should be avoided, but in case the Black-Out of portions of the network is unavoidable, the goal is to reduce as much as it is possible the out-of-service time. The system has to be able to fast and fully recover the normal operation conditions.

The first extreme weather event that focus the attention on the resilience of the electrical network in Italy was the Black-Out in Cortina in December 2013 [19]. The extreme climate event was the heavy snowfall that caused the ice-sleeve in the overhead lines. A second problem related to this event was the fall of several trees on the lines. In this case 60,000 customers were not supply for almost two days. The use of portable generators helped to re-supply some of the customers. However, due to road obstacles, it was difficult to deliver the portable generators. The total power loss, at the end of the extreme event, was 3,000 kW.

A second extreme climate event that focus the attention to the resilience of the electrical system was the heavy snow-fall in Emilia Romagna e Lombardia, in 2015 [19]. In this case, as in the previous one, the icing of the overhead was the cause of the disruptions. The energy not supply in this case was around the 20% of the total energy not supply in 2015. After this event the Italian Authority, at the time Autorità per l'Energia Elettrica, il Gas Naturale e il Sistema Idrico (AEEGSI), made an investigation act to find the causes of the disruption in detail. The result of this investigation was published in a resolution [20] and after that the AEEGSI established the Working Table, act to improving the resilience of the electrical system.

Figure 1 [19] shows the evolution of the number of customers not supply for the Black-Out in Emilia Romagna e Lombardia, for each hour.

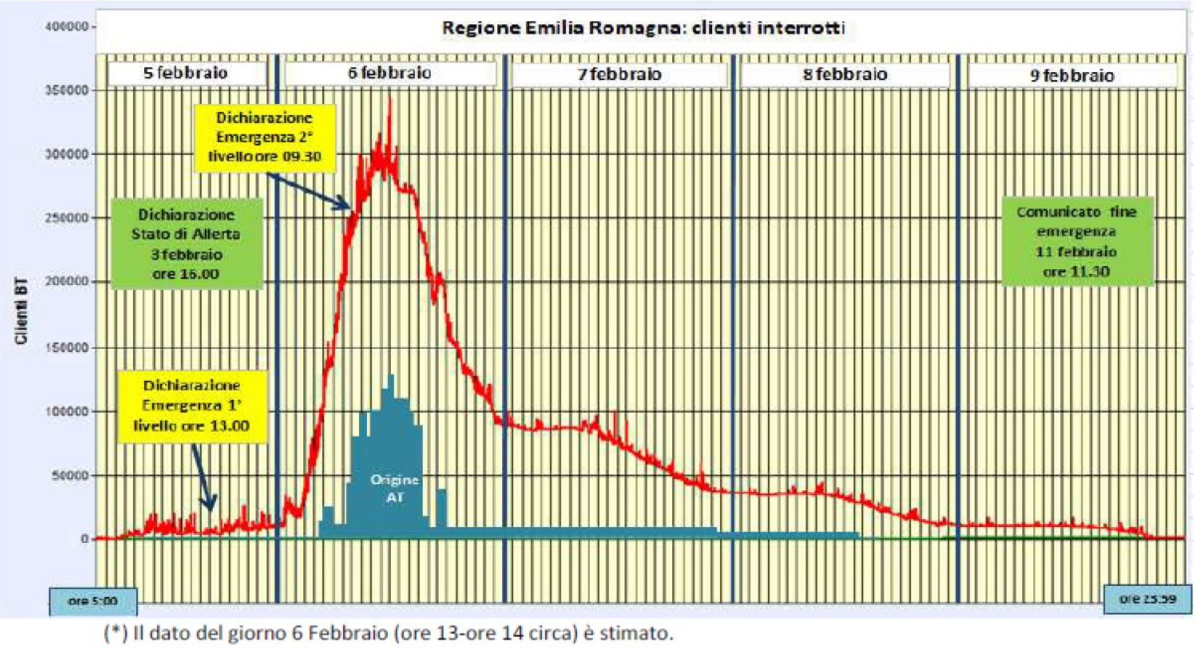

Figure 1 Number of customers not supply per day during the Black-Out in Emilia Romagna e Lombardia [19]

Other extreme climate events that can generate disruption in the electric system are:

- Ice storms and snow
- Heat waves
- Saline Pollution
- Storm
- Flood and heavy rain
- Heart quake
- Terrorism or cyber attacks

In Italy each extreme climate event is concentrated in small areas, for example, the saline pollution is a problem that occurs in Sicily and Sardinia, the heavy snow-fall in the north of Italy. The aim of this thesis is to study the monetary return of an investment act to improve the resilience of a distribution network in case of heavy snowfall.

Another important reason of the growing importance of resilience is related to climate changes. In the last years the number of extreme climate events grow up, as shown in Figure 2 [21] and Figure 3 [21], and is destined to grow up even in the next years due to the climate changes [21]. The Figure 4 [22] shows the major extreme climate events worldwide in 2017 [22].

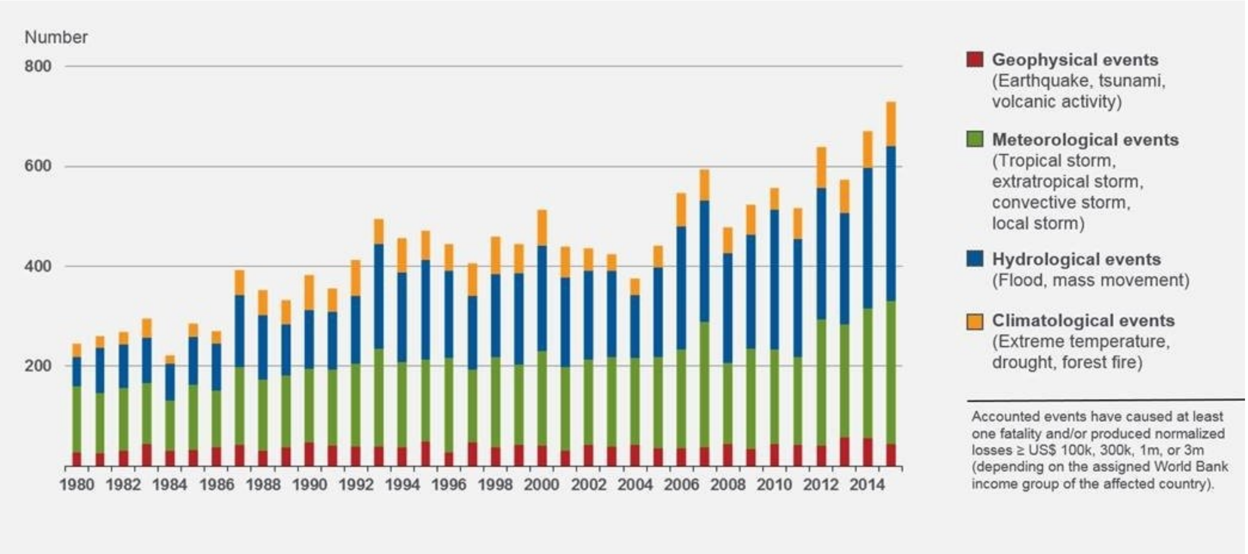

Figure 2 Number of extreme climate events [21]

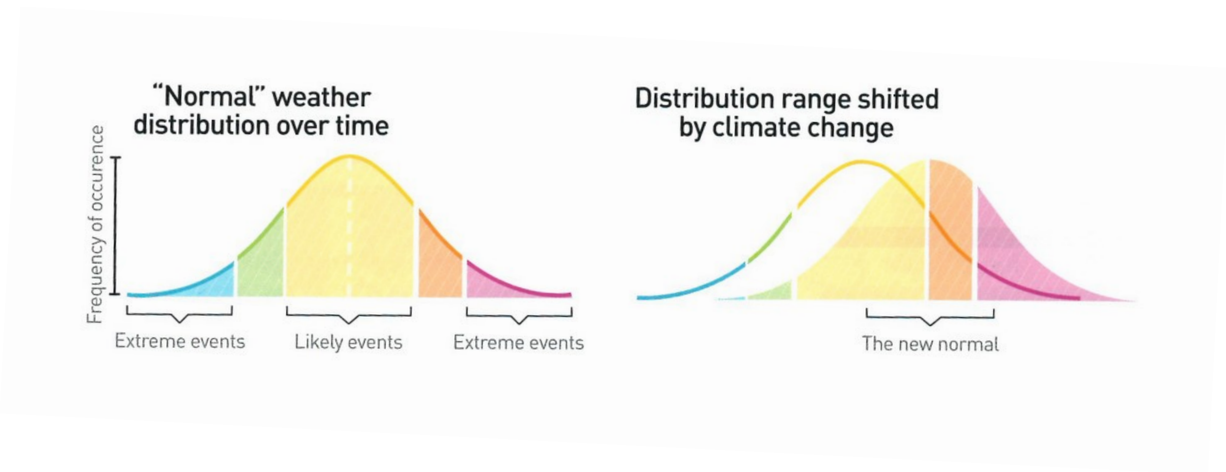

Figure 3 Frequency of occurrence of climate event [21]

Figure 4 Extreme events worldwide in 2017 [22]

The resilience of an electrical system is hard to calculate. There are no formulas that can associate a numerical value to the resilience of a network. To quantify it [19], a resilience curve associated with an event can be used, Figure 5 [19]. The value of R in the axis y is a suitable metric associated to the resilience level of the system. The value R_o is a sufficient value of resilience of the network. After the extreme climate event the value associated to resilience is R_{pe}, and it is significantly compromised. The system needs to adapt to the evolving conditions, the faster it adapts the more the effect of the catastrophic event is minimized. Then the recovery phase starts, and the resilience reaches the value of R_{pr}. This level may or may not be as high as R_O, the pre-event resilience level. For example, the infrastructure recovery may need a longer time to fully recover [panteli 2015]. It is important to notice how some investments that improve the operational resilience can reduce the infrastructure resilience, and vice versa. Moreover to increase the resilience in case of a specific extreme event can lead to decrease the reliability in case of other extreme event. For example, to substitute overhead lines with cable lines increases the resilience of the network in case of heavy snow-fall, but in case the cable lines are damaged, for example due to flood, the time needed to repair the fault will be higher than before the investment. So, from these examples, it is clear that the resilience of a network is related to the extreme event under analysis.

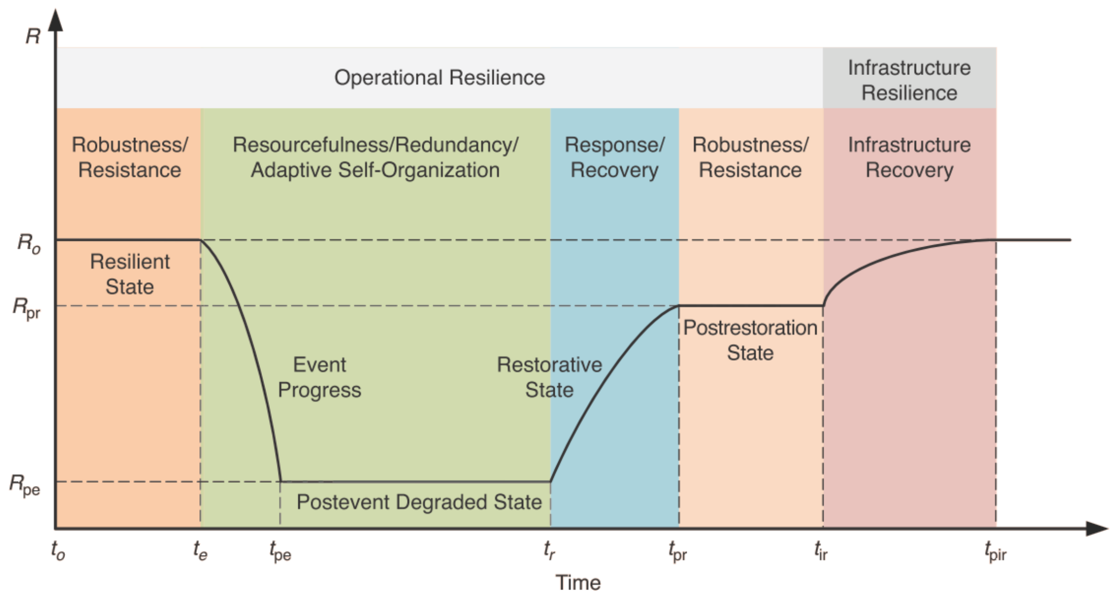

Figure 5 Resilience curve associated with an event [19]

So, it is difficult to measure the resilience of a network. Several resilience metrics exist but usually only the subset that better suit the situation are calculated. The indices used to measure the resilience are related to the reliability.

The indices, from the point of view of customers, were related to *ex-post* analysis. The most common indices are:

- Energy Not Supply (*ENS*)
- System Average Interruption Frequency Index (*SAIFI*)
- System Average Interruption Duration Index (*SAIDI*)

The value of *ENS* is important to value the service quality on a yearly basis [MWh/year]. The value of *ENS* calculated for a single event could be used to measure the value of the resilience of the network for that specific event.

SAIFI is the mean value of interruption of customers. As the *ENS,* this index is calculated on a yearly basis, and can indicate the propriety of a network to absorb events.

SAIDI is the mean duration of interruption for customer. This index is calculated in time on a yearly basis and linked to the propriety of a network to absorb and recovery from an event.

The indices related to the point of view of the network companies, can be divided in two cases:

- Indexes related to the absorption of the inconvenience
- Indexes related to the recovery of the network after an extreme event

The indices related to the recovery of the network after an extreme event indicate for example:

- Number of lines and other components out of service in case of extreme event
- Types and number of substation component damaged
- Number of substations damaged
- Number of cabin and substations of which have lost monitoring and remote control

The indices related to the absorption of the inconvenience indicate for example:

- Repair time of each faulted lines
- Total repair time of all faulted component of the network
- Time to create emergency solution (portable generators, etc …)
- Time to repair monitoring and remote control of the cabin and substations.

From those indices is hard to divide the operational and the infrastructure resilience, distinction that can be helpful to understand how improve the resilience of the network. A complete assessment of the resilience should be quantified:

- The number of customers subjected to the fault. The customers should be sorted in terms of importance, and this has to come from a political agreement (is more important acting to restore the supply for residential customers or for industrial customers?)
- The duration of the interruption. This indication allows to study strategies for reducing as much as possible the time of unsupply.
- The spatial-temporal variation of the extreme event
- The variation of the failure rate of the components, due to the extreme event
- The consideration that the restoration program is made in abnormal conditions, due to the effect of the extreme weather event occurrence

The Ricerca sul Sistema Energetico (RSE), an Italian company specializing in research into the field of electrical energy, is developing a project called “A Framework for electrical power sysTems vulnerability identification, dEfense and Restoration” (AFTER), focus on the development a set of methodology and instruments act to measure and contain risks related to the multiple faults caused by extreme events.

Figure 6 [21] shows how the causes are related to the consequences.

Figure 6 Multiple faults [19]

The consequence of multiple faults caused by the extreme events is the Black-Out. Black-Out are the out-of-service of portion of the network. If a Black-Out happen in the distribution network the problems can be affect a small geographic area. The restore of the network can be obtained with the repair of the faulted components. If the Black-Out happens in a transmission network the geographic area interested can be region or nation or in the worst case, continent. Restoring the network might require multiple days [21].

The possible causes of a blackout can be:

- extreme climate events
- failure of components

The 10% of the causes of Black-Out are unknown in Europe [21].

Figure 7 [21] shows how a single failure of component can lead to a Black-Out. In case of extreme events the initial event is the failure of several components.

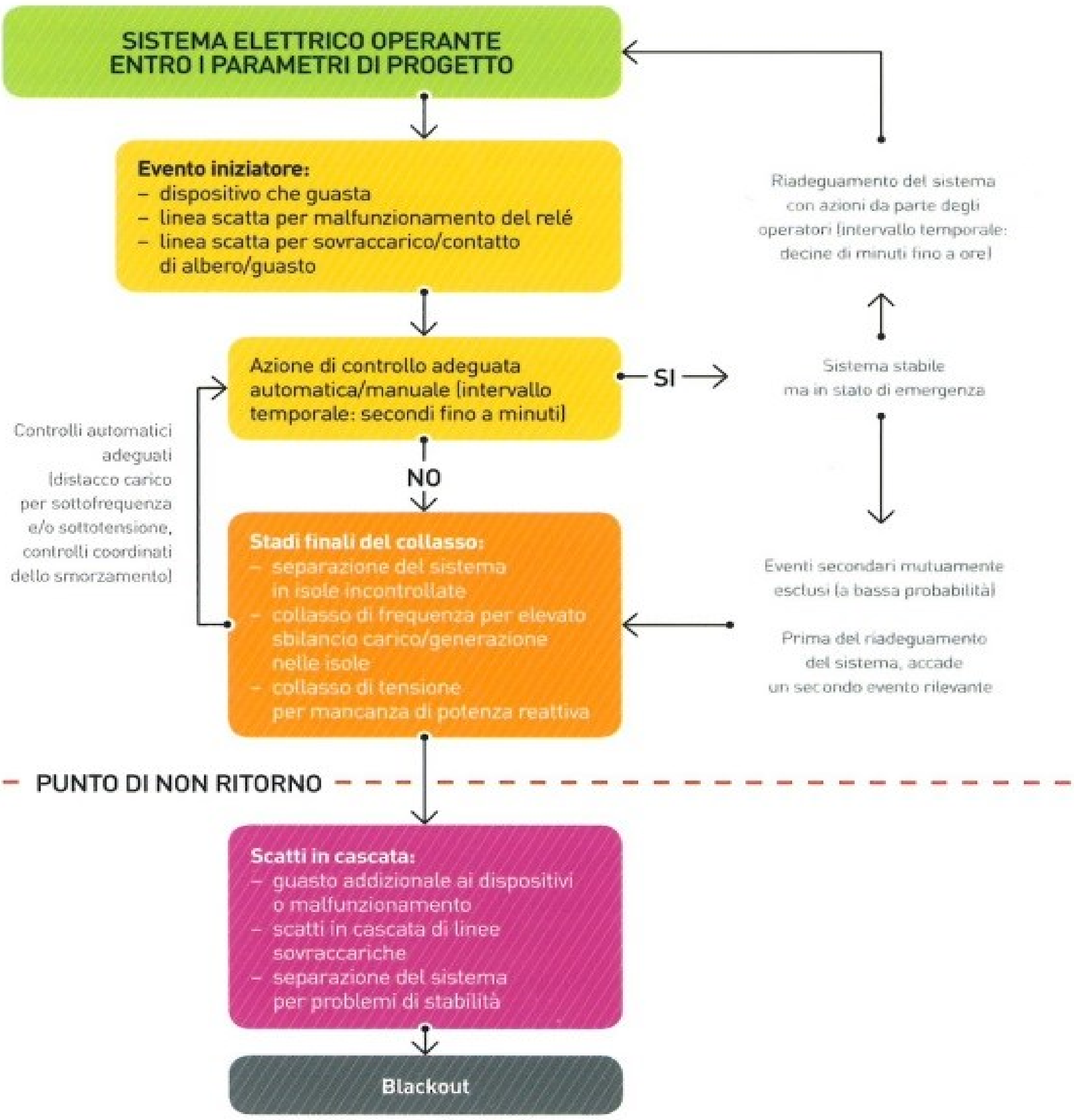

Figure 7 Step of Black-Out[19]

Before the resilience was established as key factor in the electricity system, the development of the network was based on the increasing of the reliability of the system. Reliability is the collection of all aspects of supply interruption [24].

To increase the system reliability the aim of the investment was to create a more robust and elastic network. Create this type of system leads to the $N-1$ security, where N is the number of components of the system. An electric network that can be performed the normal function after a fault is called $N-1$ secure. The problem of the resilience is that the $N-1$ security is not enough. An extreme event causes multiple faults so the $N-1$ security need to improve to reach the $N-k$ security, where k is the number of faults generate by an extreme event.

Most of reliability indices are average values of a particular reliability characteristic for a system. Some of those indices are the same used to calculate the network resilience as:

- System Average Interruption Frequency Index (*SAIFI*)
- System Average Interruption Duration Index (*SAIDI*)
- Customer Average Interruption Duration Index (*CAIDI*)
- Average Service Availability Index (*ASAI*)

Table 3 Reliability versus Resilience

Reliability	Resilience
Static	Adaptive, ongoing, short and long term
Evaluates the power system states	Evaluated the power system states and transition times between states
Concerned with customer interruption time	Concerned with customers interruption time and infrastructure recovery time
Reliability refers to the system ability to consistently supply an adequate level of electricity services to consumers [Billinton, 1970]	The ability of a power system to prepare adequately for, respond comprehensively to, and recover rapidly from major disruption due to extreme events
It measures system performances in case of low-impact/highly-probable events (e.g., *N*-1 contingencies)	It measures the system performances in case of high-impact/low-probability events (*N*-*k* contingencies)
It can be evaluated by considering the *system properties*, without the need to specify the threads considered	It needs the specification of the threads, because becoming more resilient to one threads can lead to be less resilient w.r.t. other ones (e.g., snow vs heat wave)
It is measured by the frequency and the duration of power outages experienced by the customers	It needs knowledge about the operation before, during and after the occurrence of an extreme events, because is focused on the *changes* of the system performances

Even if reliability and resilience have the same indices, they are not the same. The differences are shown in Table 3. [25] [26].

The investment act to improve the reliability of the network do not result in also the increase of the resilience. Thus, a new way to use the investments is needed. For example, the redundant path of overhead line increases the reliability but not the resilience of the network, because in the case under study, all the overhead lines fall down due to the extreme climate event.

A problem related to the extreme climate events are the small number of data about these events. As a result, accurate fragility curves cannot be calculated. These curves are important to associate measurable variables that are characteristic of an extreme event (for example, in case of wind, the wind speed [m/s]) with the failure probability of a network component. These fragility curves can be derived from [27]:

- empirically
- experimentally
- analytically using a structural simulation model
- through a combination of these methods.

The Figure 8 [27] shown an example of fragility curves.

In the scope of this thesis, the faulted components were defined by previous data of comparable events.

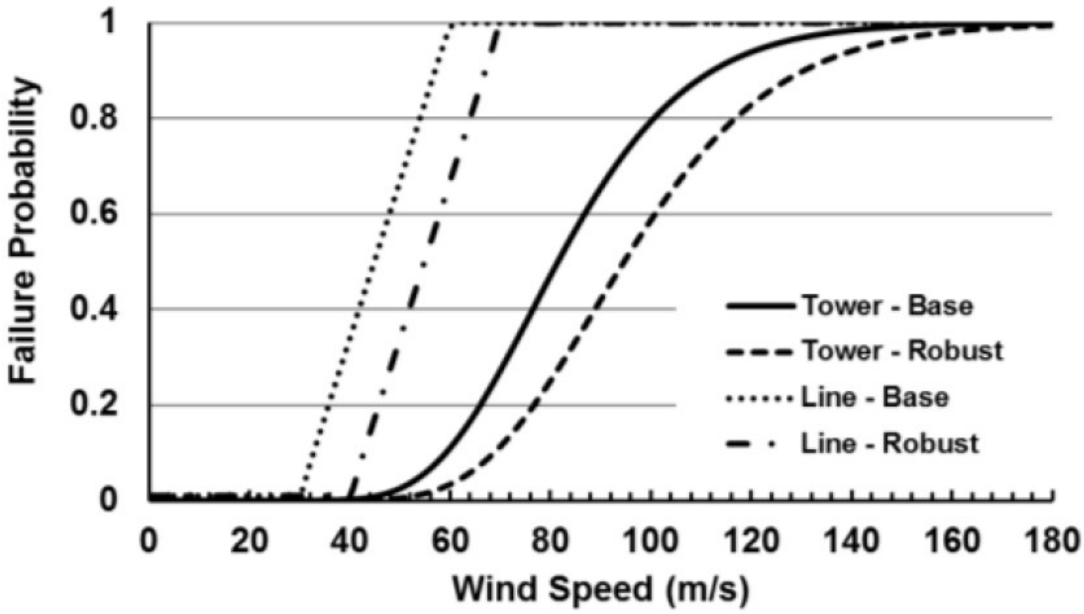

Figure 8 Fragility curves [27]

To avoid the problem generates by the paucity of data companies related to the electric sector are working towards the development and implementation of grid resilience improvement measures [28].

The Table 4 shows the short-term resilience measures. These are the traditional preventive actions in case of Black-Out but also measures related to the weather that can be helpful to prepare next extreme events. Accurate forecast of the extreme event can allow to configurate the network to minimize the impact of that event. Another important benefit related to the forecast of extreme event is the repositioning of the fault location and the repair team to allow faster recover of the network [29].

Table 4 shows also the long-term resilience measures that can be done to mitigate the effects of extreme climate events and to increase the system adaptability. Many studies were made to verify the increase of the resilience thanks to these measures. The Energy storage seems to be the best option to highly increase the resilience of the network [30]. They can be useful to resilience in two ways, with long-duration or short-duration applications. The long duration applications are for example the supply of an isolated part of the network or the reducing of network flow congestions are two examples of long duration applications. Conversely, a possible short-duration application is for example the regulation control.

To avoid the problem generated by the paucity of data, companies developing electric sector are working on modelling the weather effects in power system components, the independent and common cause failures, the countermeasures, and a general framework for evaluating the weather impact on system resilience [28].

To measure the effect on power system components both analytical approach and Monte-Carlo approach can be used. An example of analytical approach is a two-state model (i.e., normal weather conditions and extreme weather conditions) leading to two constants: restoration and failure rates, one for each state [31]. Another approach can be based on the application of Bayesian networks [32], in particular OR-gate model [33], where the outages on the component can be independent failure (direct consequence of the cause) or common cause failure (caused by cascading effect).

Monte-Carlo Approaches have been used both for modelling the effect of traversing events [34] and of non-traversing events [35]. The weather conditions can affect both the restoration time, and the failure rates. Furthermore, it is highlighted that the failure rate can sharply increase during the extreme weather phenomenon, and the possibility to have overlapping component failures increases.

The study of the resilience has to consider *N-k* contingencies, because it is possible that multiple failures happen due to the duration of the extreme weather condition. So, both common cause and independent cause failure should be considered.

The countermeasures are divided in short and long-term. Some of them are reported in Table 4.

Table 4 List of possible countermeasures [26]

Short term	
Before the event	Estimation of weather location and severity
	Coordination with adjacent network
	Reconfiguration to obtain a more resilient state
	Demand side management
During the event	Monitoring
	Ensure communication functionality
	Coordination with repair and recovery crew
	Substation reconfiguration
After the event	Disaster assessment and priority setting
	Restoration damaged component
	Resynchronization of the area
Long term	
Operational procedures	Risk assessment and management
	Improve emergency plan
	Tree trimming/vegetation management
Structural intervention	Undergrounding lines
	Upgrading poles and structure, by using more robust material
	Elevating facilities
Innovative approach	Energy storage
	Distributed generation
	Microgrids

The general framework for evaluating the resilience of the system should be based on three models: weather, component and system. Weather model can be based on observation. The component models use the weather profile as input and should provide the variation of the properties of the components according to the weather conditions, but also according to the loading conditions. Lastly, the system model is based on time series simulation techniques, by taking into account time and spatial domains.

The effects of extreme weather are acquired by the past events and for some extreme weather events are:

- *Flooding*, whose worst problem is the water in the substations.
- *Windstorms*, leading to the destruction of the power grid.
- *Hurricanes*
- *Heat waves*, which creates overload of several components of the power system.

The solutions act to increase the resilience of the network can be divided in two cases:

- active solution
- passive solution

The passive solutions are investment act to decrease the number of fault in case of extreme climate events. For example, the use of devices for avoiding the torsion of the overhead conductors, anti-icing and de-icing devise. WEC [15] recommends some passive solution that can be categorized as combination of soft and hard measures. Hard resilience measures are required to strengthen energy infrastructure, while soft resilience measures may reduce the cost of adaptation, by allowing a more flexible system.

In this thesis the investment considered are a passive solution, the replacement of the cable lines with overhead lines, as reported in Chapter 3.

The active solution is solution act to forecast the extreme climate events. In Italy the Ricerca sul Sistema Energetico (RSE) is developing a tool act to forecast the creation of "ice sleeve" in case of wet snow and wind, the Project Wolf [36]. This tool can be made because the creation of ice sleeve happens only in specific case of wet snow and wind. The creation step of ice sleeve is shown in Figure 9 [19].

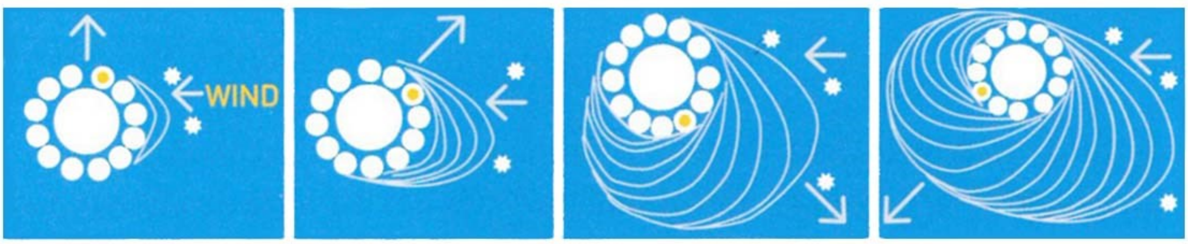

Figure 9 Step of creation of ice sleeve [19]

Another active solution could be reducing the causes of extreme weather events as to reduce the greenhouse gas emissions of extreme weather events as quick as possible. Possible solutions include the change of the energy supply mix, the use of all low-carbon technologies, the implementation of demand management strategies, and the improvement energy efficiency in supply and demand [15].

A third option, that can be useful in case of extreme event, are the Smart Grid. In this case the term "smart" is referred to operational actions act to improve the observability, controllability and operational flexibility of a power system, in particular in case of extreme events. Some of these actions can be [28]:

- Microgrids
- Adaptive Wide-Area Protection and Control Schemes
- Advanced Visualization and Situation Awareness Systems
- Disaster Response and Risk Management

The disaster response is the set of action made after an extreme event. The smart grid can improve the emergency and preparation procedures include in disaster response and risk management.

In this thesis the extreme event studied is the heavy snow-fall with the creation of ice-sleeve in the overhead lines. To simulate the effects of the extreme event the data of previous real heavy snow-fall is used. From the real data another input has been extrapolated, the rate of the extreme events. In this case, for the small area considered, the extreme event happens every 14 years.

Distribution Network

In this thesis the network used is a distribution system (DS), a part of the electrical system which deals to deliver a limited amount of energy and power. The DS is the part in which the power transferred is the lowest, up to 10 MVA, and the distribution networks is small, up to dozens of km. The DS is managed by a distribution system operator (DSO) in each local area [37].

The voltage level of DS typically is low voltage (LV) and medium voltage (MV). The definition of low and medium voltage is not normed. The difference in the rated voltage of electrical system are define in four categories [37]:

Table 5 categories of voltage [37]

Categories	rated voltage V for Alternating Current (AC) system	Rated voltage V for Direct Current (DC) system
category 0	$V \leq 50V$	$V \leq 120V$
category I	$50V < V \leq 1000V$	$120V < V \leq 1500V$
category II	$1000V < V \leq 30kV$	$1500V < V \leq 30kV$
category III	$V > 30kV$	$V > 30kV$

Typically, the category 0 and I are denoted as LV, instead the category II denoted as MV.

Structure

To represent the electrical network a graph is used. A graph is composed by:

- Nodes: the point of input and output of power
- Branches: the interconnection between to nodes (e.g. electrical lines and transformers)

Normally there are three typical network structures [37]:

- Meshed network
- Radial network
- Network with weakly meshed structure but radial operation

Meshed network: used in high voltage (HV).

Radial network: used in LV. The graph is a tree, in which there is no closed loop. Each node has only one path to arrive to another one.

Network with weakly meshed structure but radial operation: normally used in MV. It is used in radial operation, redundant branches are opened, to simplify the protection schemes. To choose the branch to open different criteria is used [37]:

- Loss minimization
- Operation cost minimization
- Optimization of specific reliability indicators

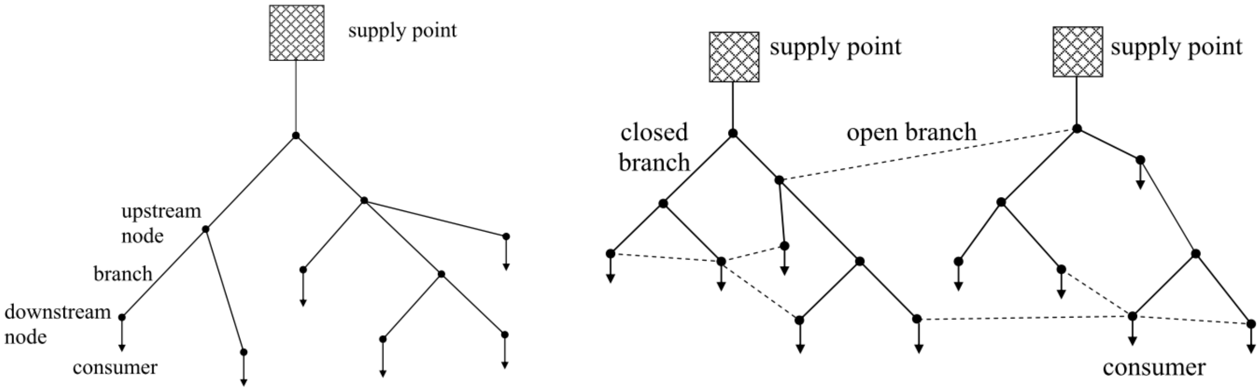

Figure 10 Structure of the Network [37]

III. Description of CBA and Network

The aim of this thesis is to understand if an investment for improving the resilience of a network, can give a monetary benefit. This study aims to improve the resilience of the network in case of specific extreme climate events, the ice sleeves created by heavy snowfall.

The benefits are calculated with two different types of cost benefits analysis (CBA), one introduced in Italy by the "Autorità di Regolazione per Energia Reti e Ambiente", ARERA, and the second one is essentially based on CBA, created by the UK electricity Authority "Office of Gas and Electricity Markets", OFGEM, for the United Kingdom network, described in "RIIO", setting Revenue using Incentives to deliver Innovation and Outputs.

In United Kingdom RIIO is considered the improvement of the price cap regulation, an ex-ante regulation used in UK until the development of RIIO. The type of incentive regulation can be of two types, *ex-ante* regulation, that keep in consideration the costs of investments only after one regulatory period, and the opposite is the *ex-post* regulation, where the incentives are related to the real costs of the investments. A typical ex-ante regulation is the price-cap regulation, as said above, a typical ex-post regulation is the rate-of-return. In RIIO the ex-ante and ex-post regulation are mixed, because the incentives are modified in base of the ex-ante analysis and the real costs of the investments ex-post.

CBA Italian Authority

The Italian Authority CBA was made following the instruction given by ARERA, the Italian Authority [38]. This type of CBA is related to the regulatory plan in force in Italy, where the costs are divided in:

- Operating Expenditure, OPEX;
- Capital Expenditure, CAPEX.

OPEX includes all the costs for running the system, whereas CAPEX includes the investments for developing the system. These two types of costs can obtain different incentives, one used for OPEX and another one for CAPEX, as written in the regulatory plan.

In general, the CBA allows to compare the total costs and the expected benefits.

Calculation of total costs

The Italian Authority defined the total costs as:

$$C_{tot} = \sum_t Inv + \sum_t O\&M \tag{3.1}$$

where: t is the year in which the costs are calculated.

The $O\&M$ are the costs of operation and maintenance during the entire useful time of the investment. This is a net cost, calculated in Equation (3.3), and it is the difference between the O&M costs of new assets minus the O&M of previous assets. The Inv is the cost of the investment and is the sum of multiple costs considering the cost of implementation of the intervention. These multiple costs are:

- the capitalized costs related to the construction of the new asset $C_{cos}^{(cap)}$;
- costs of compensatory works, $C_{comp}^{(cap)}$;
- costs of removing previous assets C_{rm}.

At these costs must be subtracted any recovery obtained from the sale of the old infrastructure S_{lv}. The Equation to calculate the total costs is the following:

$$Inv = C_{cos}^{(cap)} + C_{comp}^{(cap)} + C_{rm} - S_{lv} \qquad (3.2)$$

$$O\&M = (L_{tot} \cdot O\&M)_{pre} - (L_{tot} \cdot O\&M)_{post} \qquad (3.3)$$

where L_{tot} is the total length of the network.

Parameters for expected benefits

The benefits of the investment can be divided in: *customers* benefit, *company* benefit and *social* benefits. For each area several parameters can be calculated, but in this thesis only few of them are kept in consideration[1].

Residential Benefits

The customers benefit is composed of different terms. The first term, $B^{(res,int)}$, is related to the decrease of the interruptions in case of extreme climate events thanks to the investment considered. This benefit is related to the increase of the resilience of the network. The Equation used is shown in (3.4):

[1] To increase the number of this parameters can be used the key variable indices (KPIs), that can be found in the Appendix A.

$$B^{(res,int)} = \sum_{x\in\mathbb{X}}\sum_{s\in\mathbb{S}}\left[\begin{array}{c}\left(\lambda_x \cdot \lambda_{x,s} \cdot \left(ENS_{x,s}^{(R)} \cdot C_R + ENS_{x,s}^{(NR)} \cdot C_{NR}\right)\right)_{pre} + \\ -\left(\lambda_x \cdot \lambda_{x,s} \cdot \left(ENS_{x,s}^{(R)} \cdot C_R + ENS_{x,s}^{(NR)} \cdot C_{NR}\right)\right)_{post}\end{array}\right] \quad (3.4)$$

where $\mathbb{X}$ is the set of extreme climate events considered, $\mathbb{S}$ is the set of components that failure because of the event $x \in \mathbb{X}$, λ_x is the number of extreme event in one year, $\lambda_{x,s}$ is the failure rate of the component because of the extreme climate event $x \in \mathbb{X}$, $ENS_{x,s}^{(R)}$ ($ENS_{x,s}^{(NR)}$) is the energy not supplied for residential (non-residential) customers; C_R (C_{NR}) is the cost of energy not supplied for residential (non-residential) customers.

The value of the $ENS_{x,s}^{(R)}$ ($ENS_{x,s}^{(NR)}$) can be calculated:

$$ENS_{x,s}^{(R)} = D_{x,s}^{(R)} \cdot N_{x,s}^{(R)} \cdot P^{(R,int)} \quad (3.5)$$

$$ENS_{x,s}^{(NR)} = D_{x,s}^{(NR)} \cdot N_{x,s}^{(NR)} \cdot P^{(NR,int)} \quad (3.6)$$

where $D_{x,s}^{(R)}$ ($D_{x,s}^{(NR)}$) is the duration of power outages for residential (non-residential) customers because of the extreme event $x \in \mathbb{X}$ that caused the failure of the set of component $s \in \mathbb{S}$, $N_{x,s}^{(R)}(N_{x,s}^{(NR)})$ is the number of residential (non-residential) customers not supplied and $P^{(R,int)}$ ($P^{(NR,int)}$) is the power of each residential (non-residential) customer.

The second customer benefit, $B^{(rel,int)}$, is related to the decrease of ordinary interruptions thanks to the investments. This benefit is related to the increase of reliability of the network and can be calculated as:

$$B^{(rel,int)} = \sum_{c\in\mathbb{C}}\left[\left(\lambda_c \cdot \left(ENS_c^{(R)} \cdot C_R + ENS_c^{(NR)} \cdot C_{NR}\right)\right)_{pre} - \left(\lambda_c \cdot \left(ENS_c^{(R)} \cdot C_R + ENS_c^{(NR)} \cdot C_{NR}\right)\right)_{post}\right] \quad (3.7)$$

where: $\mathbb{C}$ is the total network components; λ_c is the fault rate of the component $c \in \mathbb{C}$ in case of permanent fault, $ENS_c^{(R)}(ENS_c^{(NR)})$ is the energy not supplied for residential (non-residential) customers due to the fault of the component $c \in \mathbb{C}$.

In particular $ENS_c^{(R)}(ENS_c^{(NR)})$ can be calculated as:

$$ENS_c^{(R)} = \sum_{n\in\mathbb{N}}\sum_{h\in\mathbb{H}} \beta_{c,n,h} \cdot D_{c,n,h} \cdot N_n^{(R)} \cdot P^{(R,int)} \quad (3.8)$$

$$ENS_c^{(NR)} = \sum_{n\in\mathbb{N}}\sum_{h\in\mathbb{H}} \beta_{c,n,h} \cdot D_{c,n,h} \cdot N_n^{(NR)} \cdot P^{(NR,int)} \quad (3.9)$$

where :$\mathbb{N}$ is the set of the network nodes; $\mathbb{H}$ is the set of the step include in the service recovery procedure; $\beta_{c,n,h}$ is a variable that can be 0 or 1 that indicated for each step h of the service recovery procedure of the component c if the node n is supplied ($\beta_{c,n,h} = 0$) or not ($\beta_{c,n,h} = 1$); $D_{c,n,h}$ is the is the expected duration of the phase h which produces the power failure of node n; and $N_n^{(R)}$ ($N_n^{(NR)}$) is the number of residential (non-residential) customers of the node n.

Company Benefits

The first company benefit, $B^{(res,eme)}$, is related to the reduction of the cost of emergency actions thanks to the investments made for managing the consequence of extreme weather events. The Equation is reported in (3.10):

$$B^{(res,eme)} = \sum_{x\in\mathbb{X}} \sum_{s\in\mathbb{S}} \left(\lambda_x^{res} \cdot \lambda_{x,s} \cdot C_x^{(eme)}\right)_{pre} - \left(\lambda_x^{(res)} \cdot \lambda_{x,s} \cdot C_x^{(eme)}\right)_{post} \tag{3.10}$$

where $C_x^{(eme)}$ is the costs of emergency action related to the extreme event $x \in \mathbb{X}$ and component $s \in \mathbb{S}$; the other parameters have been already explained above.

The last benefit considered, $B^{(rel,eme)}$, is related to the decrease of the cost of the emergency actions in case of ordinary faults. The Equation to calculate this benefit is shown in (3.11).

$$B^{(rel,eme)} = \sum_{c\in\mathbb{C}} \left(\lambda_c \cdot C_c^{(eme)}\right)_{pre} - \left(\lambda_c \cdot C_c^{(eme)}\right)_{post} \tag{3.11}$$

where $C_c^{(eme)}$ is the cost of emergency actions in case of fault of the component $c \in \mathbb{C}$.

CBA “RIIO model”

RIIO model has been created in UK by Ofgem, the English authority of electricity. RIIO is a new regulatory plan, and with a new type of approach, the TOTEX approach, tries to focus on multiple concepts. These are [39]:

- **sustainable energy sector**: looking for incentive investments that focus on creating a more sustainable delivery of electricity or another type of environmental objective.
- **sustainable network services**: “providing network services that are safe, reliable and available”. Trying to incentive all the investments that minimising the environmental impact of network services.
- **play a full role**: the network companies need to take a leading role in delivery electricity focused on sustainable option and need to be open minded to find alternatives to provide

services in the best sustainable way. The network companies must focus on the future needs of the consumers and find new path to manage the uncertainty of the future.

- **long-term value of money:** looking to deliver sustainable network services at low costs, searching the best possible value for money.
- **long-term cost:** the network companies need to be focus on minimise the long-term cost. This is the total costs of delivering output, so the companies need to make careful choices about capital (infrastructure) and non-capital solution, on the basis of reduce costs in the long term. Long term means in some case the eight-year price control period, in other case the useful life time of the assets.
- **consumers**: the network companies need to be focus on the satisfaction of consumers, including a broad spectrum of network users.
- **stakeholders**: the network companies need to provide report for the authority and for stakeholders also.

These concepts of RIIO model are related to the multiple sector, and for the distribution system can be find more specific concepts [39]:

- **customers satisfaction:** with measurement of customer satisfaction reflecting the experience of consumers and network users.
- **environmental impact**: looking to reach the low carbon generation and low carbon delivery. Search to decrease all the emissions of the electricity network system.
- **social obligation**: having a special regard for vulnerable clients.
- **reliability and availability:** reduce the customer interruptions (CI) and customer minute lost (CML) or energy not supplied (ENS).

The overview of the objectives and components of the RIIO model are in the Figure 11 [39], and the summarise of the output in the Figure 12 [39].

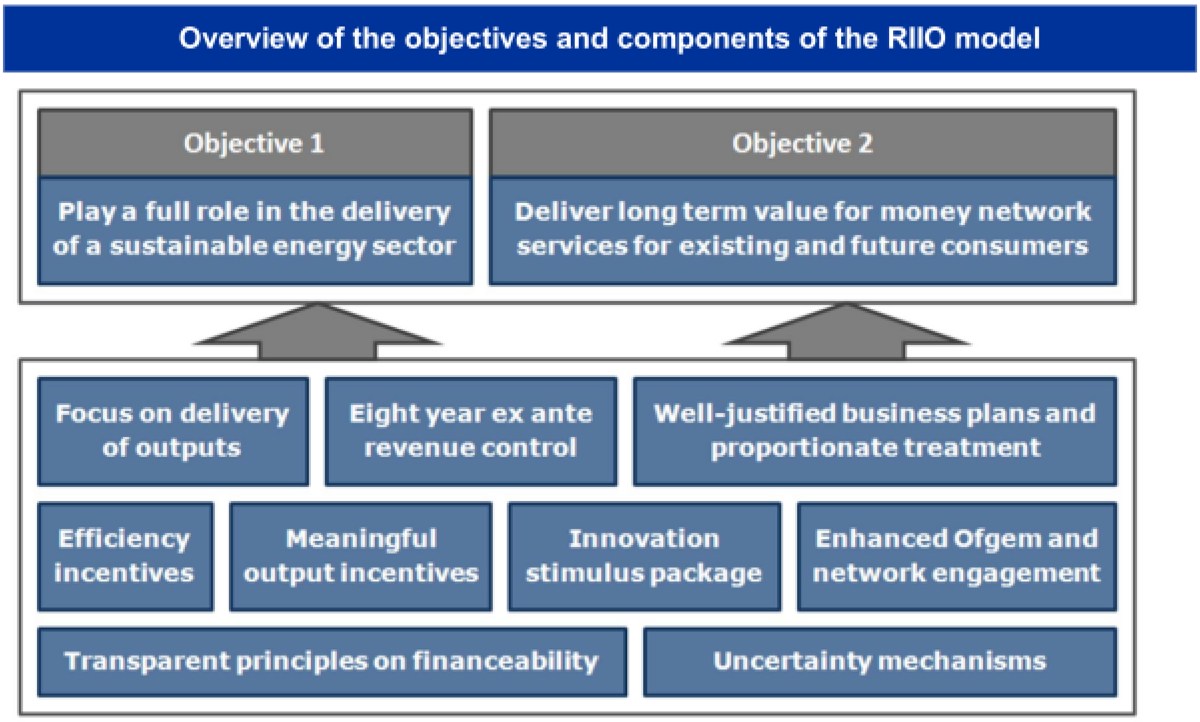

Figure 11 Objective and components of the RIIO[39]

RIIO Outputs

Output categories	Primary outputs	Secondary deliverables
Customer satisfaction Reliability and availability Safe network services Connection terms Environmental impact Social obligations	• Reflect 'service' that customers of network services experience • Priorities and level informed by stakeholder engagement • Limited number in each category • Rewards and penalties related to delivery performance • Ofgem set sectoral level, with potential variation by company • Common industry metrics developed at price control review (where feasible) • Companies expected to deliver over long term	• Deliverables that companies can be 'held to account on' that relate to (a) management of network risk and hence long-term delivery of primary outputs; and (b) anticipation of future needs • Company-specific levels, tied to costs in business plan • Monitored on ongoing basis • Ofgem consider whether and how to take action if and when concerns with delivery arise • Signal in price control proposals what action might be taken and under what circumstances

Figure 12 RIIO output [39]

The three elements considered in the RIIO framework are [39]:

- an upfront (ex-ante) price control that sets both the outputs that network companies have to deliver and the revenue that they are able to earn for delivering these outputs efficiently;

- the option of providing licensed third parties with a greater role in delivery by giving them responsibility for delivering key projects following a competitive process;
- a time-limited innovation stimulus for electricity networks, open to network companies and non-network parties.

The total key elements of the RIIO model can be summarised in the Figure 13 [39]

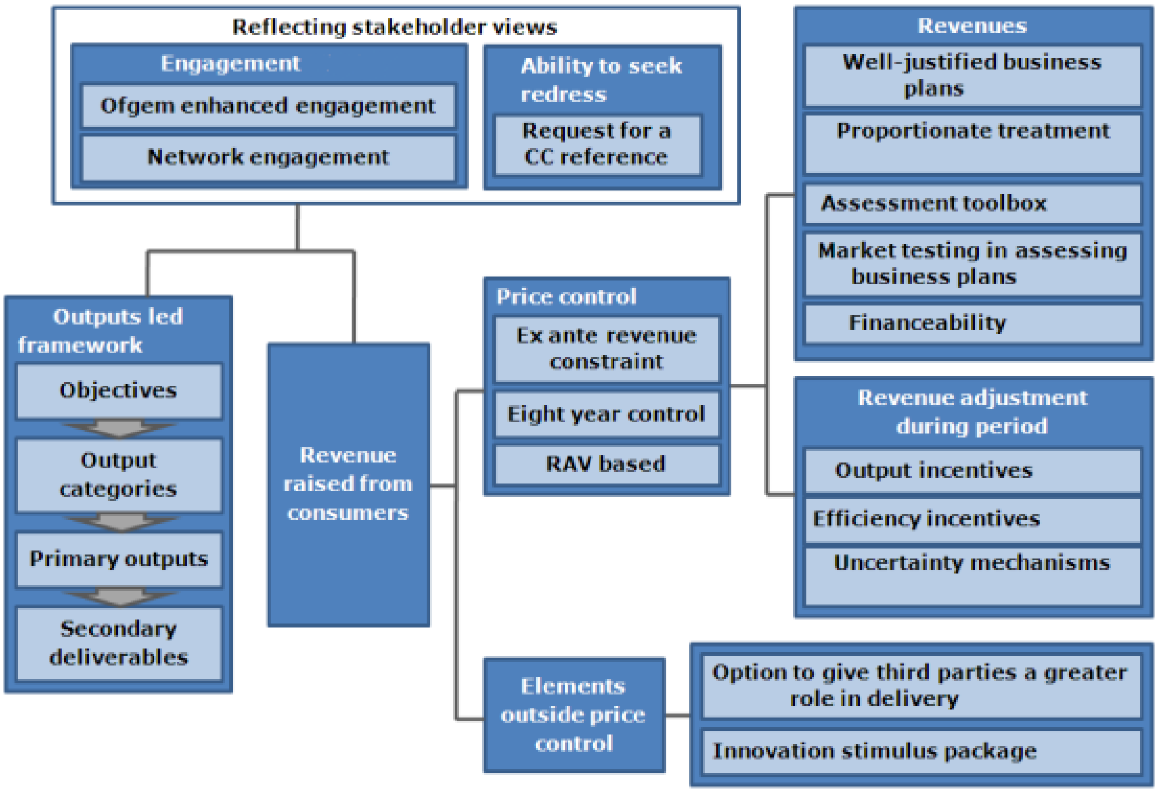

Figure 13 Key elements of RIIO [39]

In this thesis we will analyse the TOTEX index defined by RIIO and on the calculation of the CBA. How to increase the importance of the stakeholders and the calculation of the revenue with the incentives are beyond the scope of this thesis. With the TOTEX index, the OPEX and CAPEX indexes substituted by a single parameter: the total expenditure. This choice aims to improve productivity of business, considering all the factors related to the system.

The TOTEX approach considered a split of the total expenditure in two parts [39]. The first one is the *fast money* that is a part of the expenditure that is financed during the first year of the expenditure. This is similar to OPEX. The second part of expenditure is the *slow money,* similar to CAPEX, and it's financed through all the years of the investments. Shifting from TOTEX to fast and slow money a capitalisation rate is needed. This capitalisation rate determines the portion of TOTEX added to opening *Regulatory Asset Value,* RAV. This index is used by Ofgem to provide a reasonable return to investors. To calculate the value of RAV the Equations (3.26) and (3.27) are used, and it's important to calculate the opening base revenue. This new type of remuneration can be summarized in the Figure 14 [39]

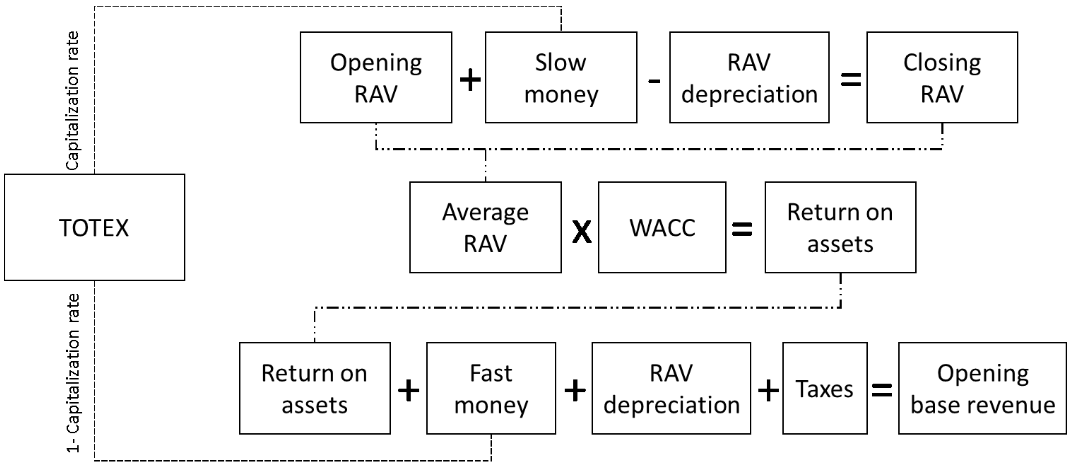

Figure 14 Totex approach [39]

The TOTEX approach leads to a new way to define the return on assets: the weighted-average cost of capital, WACC [39]. This is calculated from the cost of debt and cost of equity of the business. The calculation of WACC is the Equation below:

$$WACC = \frac{E}{E+D} \cdot RE + \frac{D}{E+D} \cdot RD \cdot (1 - Ta) \qquad (3.12)$$

where E is the market value of the company's equity, D is the Market value of the company's debt, RE is the Cost of Equity, RD is the Cost of Debt, and Ta is the Tax Rate.

Being "*forward* looking" is another important feature of the TOTEX approach. [39] This helps the companies to make more informed choices and to produce electricity efficiently through better output. RIIO added a new way to evaluate the investments. For each of them the company needs a "*business plan*" reviewed by the regulator. This *business plan* reports the evaluation about the performance of the system, in term of quantity and quality. Thus, it gives a clear view about the company's objectives and the best way to achieve them. This *business plan* needs to be compared to a business plan made by the Authority to assess the accuracy of the forecast made by the companies.

In UK the experience proved that in many cases the company's expenditure was lower than the expenditure forecast made by Ofgem, so to use the *TOTEX* approach the regulator need an improvement in the evaluation of the company's investments. This problem of asymmetry between the real and the forecast expenditure has been mitigated with the use of the "*matrix*

IQI" [39] (Information, Quality, Incentive), that is a new way of incentive. This matrix combines efficiency incentive with incentives to formulate forecasts closer and closer to reality. The correct calibration of this matrix is one of the most important aspect of the TOTEX approach.

At the end the revenue from the RIIO framework can be summarized as in Figure 15 [39]

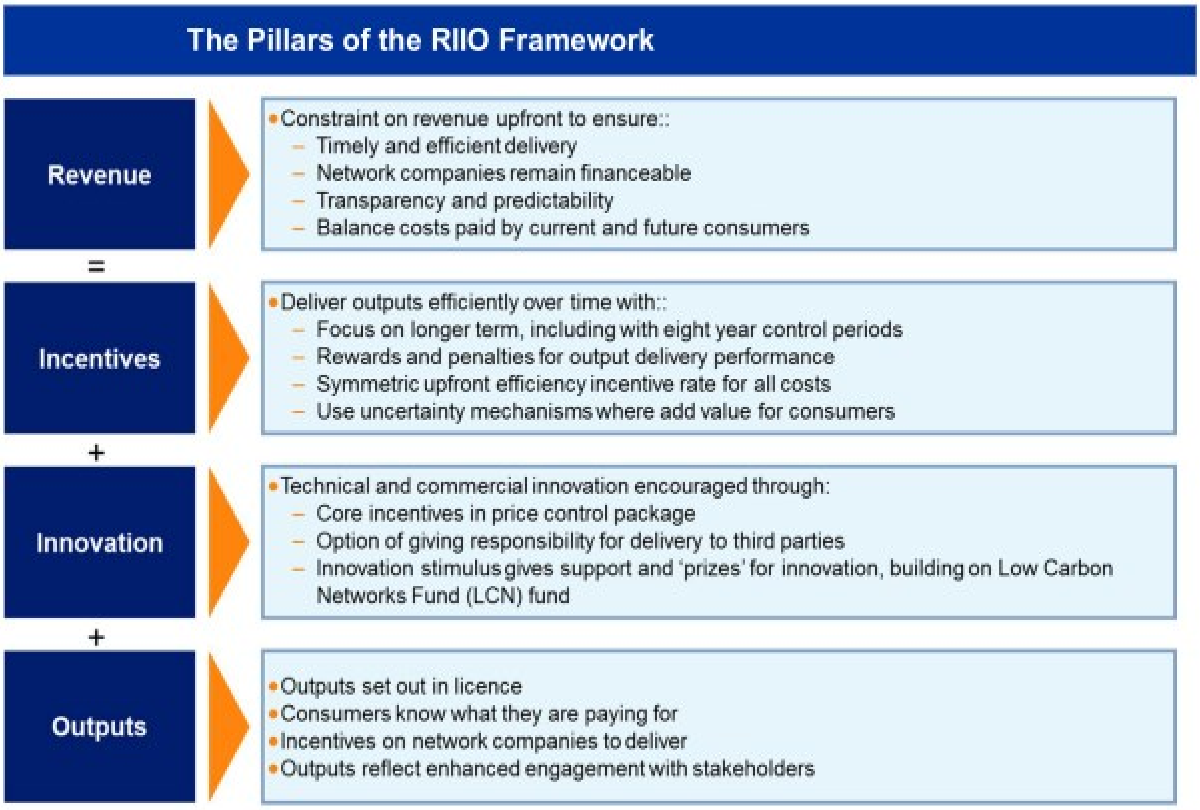

Figure 15 RIIO Framework

Calculation about total cost

The use of TOTEX approach needs the evaluation of some costs. These costs are the same of the Authority CBA and they are:

- Inv, the costs of the investment;
- Crm, costs for removing previous assets;
- Slv, salvage cost of the investment;
- $O\&M$, the cost of operation and maintenance during the entire useful time of the investment

The sum of the first three terms is the TOTEX as shown in Equation (3.13):

$$TOTEX = Inv + C_{rm} + S_{lv} \tag{3.13}$$

If the useful lifetime of the investments is higher than the time horizon of CBA, T, the Equation written above cannot be used. The new Equation of TOTEX must keep in consideration only the value of the investments from year 0 to year T, and then annualise it. The value of the annualised investment is shown in Equation (3.14)

$$Inv_{ann} = \frac{Inv \cdot d}{1-(1+d)^{-lt}} \cdot \frac{1}{1+d} \cdot \left(1 - \frac{1}{(1+d)^T}\right) \cdot \frac{1}{1-\left(\frac{1}{1+d}\right)} \tag{3.14}$$

where lt is the useful lifetime of the investment, and d is the discount rate. The new Equation of the TOTEX becomes:

$$Totex = Inv_{ann} + C_{rm} - S_{lv} \tag{3.15}$$

Parameters for expected benefits

This section focuses on the expected benefit of the investment. As in authority CBA, benefits are divided in *company* benefits and *social* benefits.

Company Benefits

There are three types of benefits for the network companies. The first is the benefits related to the emergency action in case of extreme climate events, $B_t^{(res,sea)}$. With the investment, the resilience of the network increases, so the emergency actions in case of extreme climate events are less expensive. These emergency actions can be, for example, the costs of rent portable generator, or the faulted team, as explained later. The Equation to calculate this benefit is shown in Equation (3.16):

$$B_t^{(res,sea)} = \left(\left(C_{fpg} + C_{ort} + C_{ofl}\right)_t\right)_{pre} - \left(\left(C_{fpg} + C_{ort} + C_{ofl}\right)_t\right)_{post} \tag{3.16}$$

The subscripts *pre* and *post* indicate if these costs are calculated before or after the investment. C_{fpg}, is the cost to rent the portable generator; C_{ort} is the cost of the fault repair team; C_{ofl}, is the cost of the fault location team.

The second benefit is related to the costs of emergency actions in case of ordinary fault. This benefit is linked to the reliability of the network. The emergency actions are the same of the ones described for the resilience. The Equation is reported in (3.17).

$$B_t^{(rel,sea)} = \left(\left(C_{ort} + C_{ofl}\right)_t\right)_{pre} - \left(\left(C_{ort} + C_{ofl}\right)_t\right)_{post} \tag{3.17}$$

The last DNO benefit is related to the different between the operational and maintenance cost before and after the investments, $B_t^{(O\&M)}$. In the case under study this is a positive benefit, but it can be also negative if the operational and maintenance costs after the investment are higher than before. The Equation to calculate this benefit is shown in (3.18)

$$B_t^{(O\&M)} = (L_{tot} \cdot O\&M)_{pre} + (L_{tot} \cdot O\&M)_{post} \tag{3.18}$$

where $O\&M$ is a cost for unit of length of the lines. This value must be multiple for the length of the lines, L_{tot}.

Once the benefits have been found, the next step is the calculation of the total company benefit before the capitalisation, $B_t^{(DNO,tot)}$, reported in Equation (3.19).

$$B_t^{(DNO,tot)} = Totex + B_t^{(res,sea)} + B_t^{(O\&M)} + B_t^{(rel,sea)} \tag{3.19}$$

At this point the total DNO benefit is capitalized through the capitalisation rate, Cap_{rate}. This is the part of the costs called *slow money*. The Equation of the capitalized DNO benefits, $Inv_t^{(cap)}$, is:

$$Inv_t^{(cap)} = B_t^{(DNO,tot)} \cdot Cap_{rate} \tag{3.20}$$

The other part of the costs is the *fast money,* that is called also investment to be expensed, $Inv^{(e)}$, and the Equation is:

$$Inv_t^{(e)} = B_t^{(DNO,tot)} \cdot (1 - Cap_{rate}) \tag{3.21}$$

Then, the calculation of the total net DNO benefits, $B_t^{(DNO,afcap)}$,is made as explained in Equation (3.22).

$$B_t^{(DNO,afcap)} = Inv^{(e)} + Dep_t + CoC_t \tag{3.22}$$

In the CBA the value of depreciation, Dep_t ,is calculated as shown in Equation (3.23)

$$Dep^{(ftte)} = \frac{Inv_t^{cap}}{T} \tag{3.23}$$

$$Dep_t = \sum_{x=2}^{t} Dep_x^{(ftte)} \quad (3.24)$$

where Dep_t is the depreciation, T is the time horizon of the CBA.

Now the cost of capital CoC_t is calculated as reported in Equation (3.25).

$$CoC_t = WACC \cdot avg(RAV_t^{(opening)}, RAV_t^{(closing)}) \quad (3.25)$$

where $WACC$ is explained above; avg is the average value; Rav_t can be calculated with the Equations (3.26) and (3.27).

$$RAV_t^{(opening)} = RAV_{t-1}^{(closing)} \quad (3.26)$$

$$RAV_t^{(closing)} = Inv_t^{(cap)} + RAV_t^{(opening)} - Dep_t \quad (3.27)$$

The initial value of $RAV_t^{(closing)}$ is zero.

Parameters for social benefits

Now the social benefits must be calculated. The depreciation and capitalization are not applied for these benefits. The social benefits considered in this thesis are the avoided costs of interruption in two cases, for extreme climate event and in case of ordinary fault, related to the reliability of the network.

In case of extreme climate event the benefit $B_t^{(res,int)}$ is calculated as shown in Equation (3.28).

$$B_t^{(res,int)} = \left(\left(C_R \cdot P^{(R,ns)}\right)_t\right)_{pre} - \left(\left(C_{NR} \cdot P^{(NR,ns)}\right)\right)_{post} \quad (3.28)$$

C_R (C_{NR}) is the interruption costs for residential (non-residential) customers; $P^{(R,ns)}$ ($P^{(NR,ns)}$) is the power of residential (non-residential) customers not supplied.

The same benefit in the case of reliability $B_t^{(rel,int)}$ can be calculated as:

$$B_t^{(rel,int)} = \left(\left(C_R \cdot ENS^{(R)}\right) + \left(C_{NR} \cdot ENS^{(NR)}\right)\right)_{pre} - \left(\left(C_R \cdot ENS^{(R)}\right) + \left(C_{NR} \cdot ENS^{(NR)}\right)\right)_{post} \quad (3.29)$$

where $ENS^{(R)}$ and $ENS^{(NR)}$ are the value of energy not supply for residential and non-residential customers in case of permanent fault.

CBA: Common and Different

After the description of the two CBAs, can be interesting to summarize the common and the different parts. To create a CBA three main steps must be followed, and are in common in both type of analysis:

- Definition of boundary conditions (demand growth forecast, discount rate, local grid characteristics) and implementation choices (roll out time, chosen functionalities);
- Identification of costs and benefits (investment, benefits: reduced congestion cost, reduced operational and maintenance costs, higher capacity utilisation);
- Sensitivity analysis of the CBA outcome to variations in key variables/parameters.

The steps are the same in the two types of CBA, but some of the values entered are different. For example, in the first step the condition considered are:

- The probability of the extreme climate events, supposed 1 event every 14 years. This value is chosen thanks to data of previous years, and is equal for the two CBA;
- Time horizon of the CBA. The AEEGSI set this value at 25 years, but in RIIO the time horizon is 45 years. In this thesis, to compare the results of the CBA, the time horizon will be set at 25 years;
- Cost of interruption for residential and non-residential customers, chosen with the help of one of the most important electricity company in Italy. The value is the same for the two CBA;
- Discount Rate, 4%, set by the AEGGSI, this value is used only for the authority CBA;
- WACC, value used only for the RIIO CBA.
- Length and type of each line of the network under study;
- The probability of component failure due to extreme events;

The last two points are explained better later with the case study and are the same for the two CBA.

The second step to create the CBA includes the costs, that are the same for the two CBA. They are described better in the final part of this chapter, but here there is a list of them:

- The investment of the new assets, *Inv;*

- The cost of removing previous assets due to investment options, C_{rm} ;
- Salvage cost of previous assets, S_{lv}. This is a benefit that can be derived from, for example, the sale of previous assets;
- Net annual operation and maintenance cost, *O&M*.

The benefits considered in the CBA are related to the number of interruptions, that decrease after investment, and the lower cost of the emergency action that can be done in case of extreme climate events. These benefits are the same for the two CBAs for allowing the comparison of the two CBA. The benefits considered are:

- Saving of interruption cost;
- Saving of emergency actions' costs.

The main different between the two CBAs are the approach used to define the total costs, the TOTEX approach. AEEGSI are looking to include in the Italian regulatory plan this new type of approach to improve the regulatory plan itself. The main reason of this change is the advantage to use a single parameter, the TOTEX, to consider the costs. Using OPEX and CAPEX divided, the incentives of these two costs are divided. That means, an investment related to one of these costs can be more advantageous than one related to the other cost due to the incentives, even if the network benefits from these investments are the same. Considering the TOTEX, this problem decades. Related to this, the new approach remains neutral in terms of technological choices, so new solution can be profitable as the traditional one. This is an important step that aims to improve the efficiency of the network with new investments.

Another difference between the two CBA is the length of the regulatory period, that is extended from 5 years, of the AEEGSI CBA, to 8 years of the RIIO CBA. The extension of the regulatory period should reduce the regulatory risk but exposes the company to risk and uncertainty derived from the change of the environment's condition, as number of client, climate change etc… To solve this problem in UK the "*uncertainty mechanism*" are used. This mechanism allocates the risk between clients and the owners of the network.

In Italy, for a future use of the RIIO model, the value of WACC is set by the authority because the value is similar to the value of the cost of capital, as reported in the "Poyry" report [40]. The "Poyry" report, is a documentation made by "Poyry" that provides an overview of RIIO framework and compare them with the actual regulatory plan of Italy. The Authority set an objective output level and cost of services, if a company reach or overcome these objectives it can be obtain incentive higher than WACC.

At the end the *AEGGSI* determined to base the future incentives with the TOTEX approach to pursue the following objectives [41]:

- increase the total productivity of the regulatory services in the electric sector;
- delete the unbalance choice between solutions with high value of OPEX and CAPEX, and nullify behaviours that exploit the different type of incentive;
- encourage infrastructural development;
- encourage uses of new technologies.

Network under study

The network under study is a distribution network with 17 nodes, Figure 16.

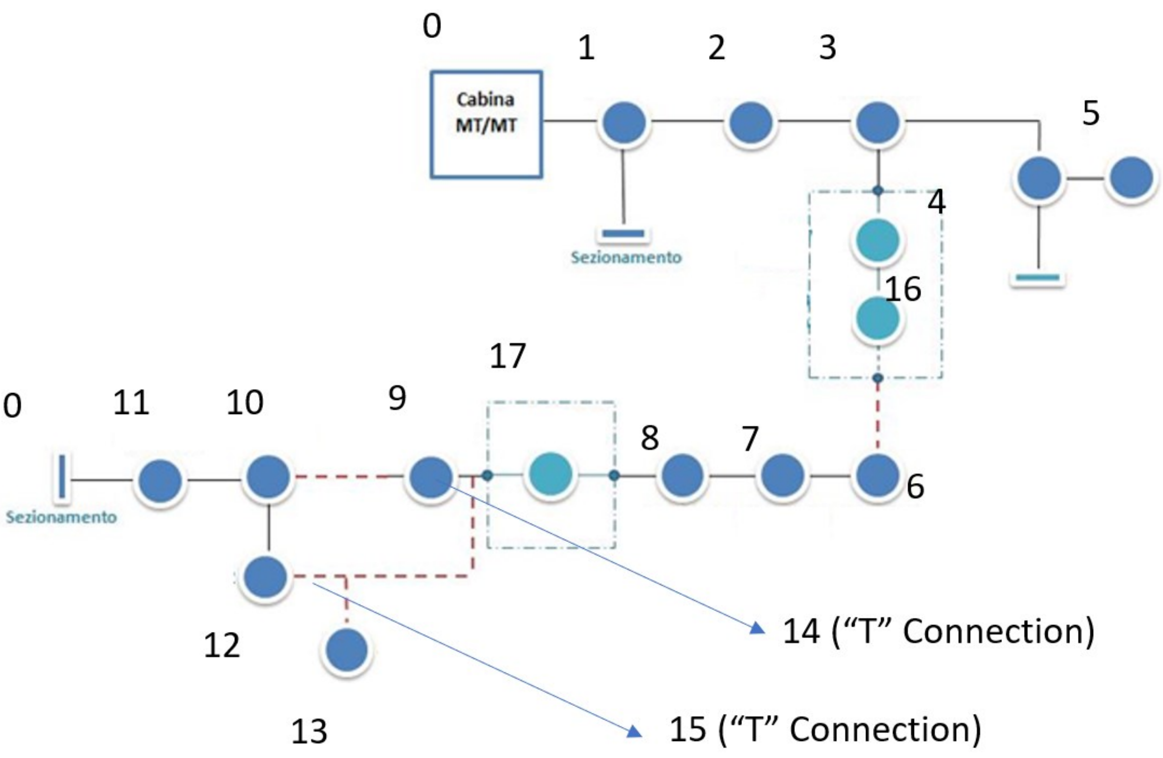

Figure 16 Standard condition of the network

This is a real 15 kV medium voltage network. Each node is a substation but not all are owned by the network company, in particular: nodes 16 and 17. These nodes cannot be reached by the company employees, and this is important for fault analysis, as specified in the next chapter. The number of customers, residential and non-residential, and the power in each node are described in Table 6:

Table 6 Nodes

# Nodes	***BT Customers***	***Residential Customers***	***Non Residential Customers***	***P_{TOT} [kW]***	***Residential Power***		***Non-Residential Power***	
					%P	***P [kW]***	***%P***	***P [kW]***
1	18	13	5	67.50	93%	62.775	7%	4.725
2	235	196	39	4.50	33%	1.485	67%	3.015
3	242	196	46	882.00	91%	802.62	9%	79.38
4	0	0	0	-	-		-	
5	61	49	12	301.00	96%	288.96	4%	12.04
6	4	3	1	130.50	10%	13.05	90%	117.45
7	70	65	5	280.50	77%	215.985	23%	64.515
8	42	6	36	529.30	30%	158.79	70%	370.51
9	63	53	10	505.00	61%	308.05	39%	196.95
10	27	24	3	95.50	94%	89.77	6%	5.73
11	83	70	13	406.50	62%	252.03	38%	154.47
12	57	50	7	221.00	84%	185.64	16%	35.36
13	0	0	0	-	-		-	
TOT	***902***	***725***	***177***	***3423.3***		***2379.155***		***1044.145***

Only some nodes have a remote switch, which means that those nodes can be open and close with a remote control in a short time. The list of nodes that have the remote switch is the following, Table 7:

Table 7 Automatic Switches

# Nodes	Automatic switches
1	no
2	no
3	no
4	no
5	no
6	no
7	no
8	yes
9	no
10	no
11	no
12	no
13	no
14	yes
15	yes

In the Figure 16 the continuous lines represent cable lines, instead the dotted lines are overhead lines. The overhead lines have the characteristics shown in Table 8 . The parameters of the cables are separated in Table 9

Table 8 Overhead lines

Length	817	m
Mateial	Cu	
Section	25	mm2
Type of Lines	overhead	

Table 9 Cable lines

Length	3270	m
Mateial	Al	
Section	150	mm2
Type of Lines	cable lines	

All the nodes indicated with zero are potential supply nodes, but at the beginning only the secondary substation is connected to the network, all of other supply points are disconnected. The branch open is the branch that connects the node 0 to node 11 and the node 9 to node 10. The branch that links the nodes 9 and 10 are open in 10 but close in 9. The nodes 14 and 15 are "T" connection, so they are not substation.

The only type of fault considered in this thesis is the fall of all overhead lines, due to the extreme climate event. In this case an island in the network is creating as in Figure 17 and the costumers of the isolated node are not supply.

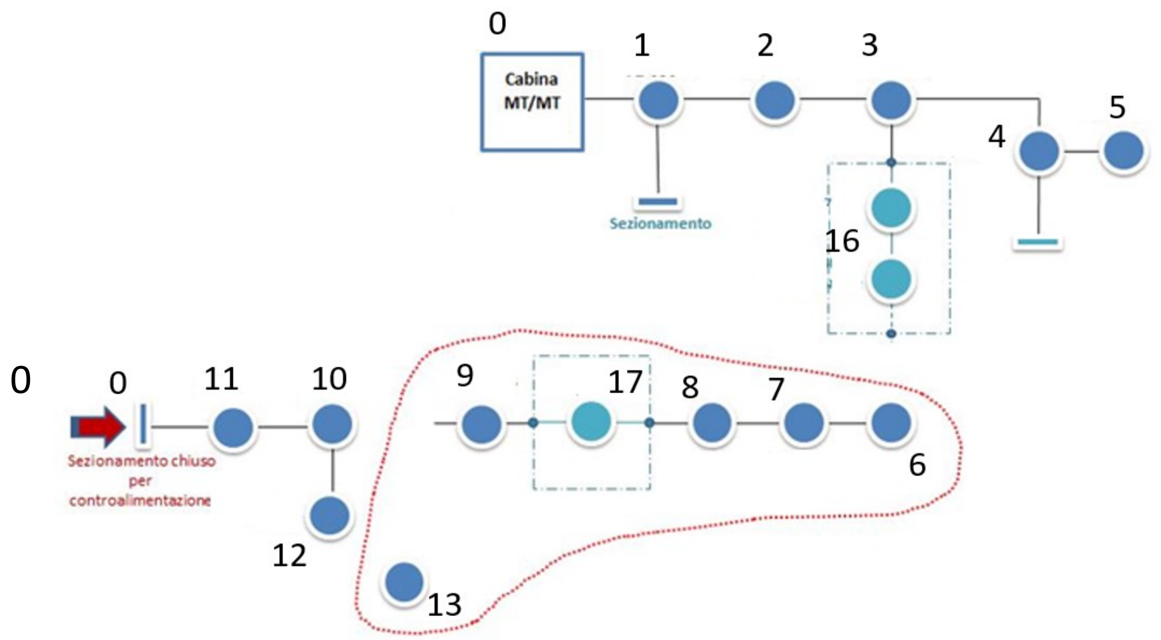

Figure 17 Network after extreme climate event

For the reason above, the investment under study considers the substitution of the overhead lines with cable lines. The cost of the investment is calculated as the sum of multiple costs. First of them is the costs of removing previous assets C_{rpa} that is the sum of two costs, one related to the removing the overhead lines C_{rol} and the second related to the removing the poles C_{rp}. To find the cost of removing poles two inputs are needed: the number of removing poles and the cost for removing a single pole. The Equation used are:

$$C_{rpa}, = C_{rol} + C_{rp} \quad (3.30)$$

$$C_{rp} = N_{poles} \cdot C_{rsp} \tag{3.31}$$

In this thesis the number of poles has been assumed to be 80, and the cost for removing a single pole has been assumed to be 500 €. The cost for removing all the overhead lines has been assumed to be 10 000 €.

Table 10 Cost for removing poles

Number of poles	80
Cost for removing a single pole	500 €

The costs for removing previous assets are:

Table 11 Costs of removing previous assets

Type of cost	***Value [€]***
Cost of removing overhead lines	10000
Cost for removing poles	40000
Cost for removing previous assets	50000

Another two costs are taken into account for the total costs of the investment. The cost of the cable lines C_{cbl}, that is the cost to bury a cable, and the cost of changing some substation C_{cs} that need to be update for the cable lines. There are 5 substations to change and the new one cost 35000€, so the costs of changing substation can be calculated as:

$$C_{cs} = 5 \ \cdot 35000 = 175000 \text{ €} \tag{3.32}$$

The costs of the investment are summarized in the Table 12:

Table 12 Cost of the investment

Type of cost	***Value [€]***
Cost for removing previous assets	50 000
Cost of new substation	175 000
Cost of cable line	327 000
Cost of investment (total costs)	552 000

After the investment the normal operational condition remain the same, and no new automatic switches are added, the only change is the new five lines, and the new network is shown in Figure 18

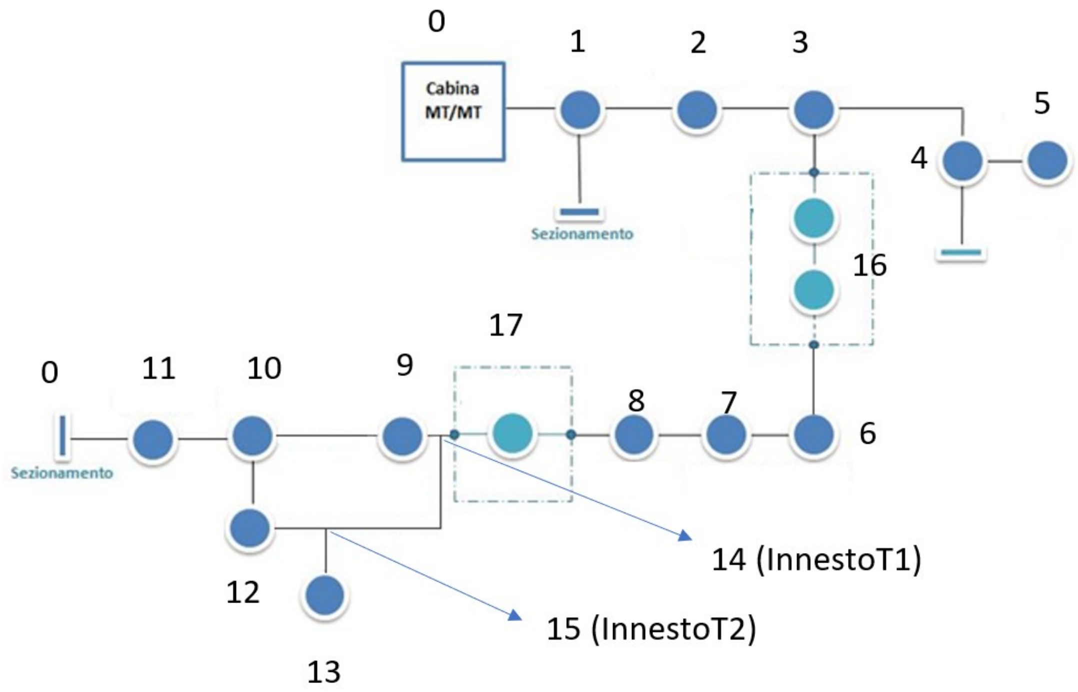

Figure 18 Standard condition of the network after investment

For the CBA studies, the fault analysis will be run with the network before the investment, to see the number of costumers and the power not supplied, then the fault analysis is made another time after the investment. The fault analysis, before and after investment, are run two times, one to study the resilience of the network, and another type to study the reliability of the network. Both type of studies needs to have a better CBA analysis.

IV. Fault Analysis

This chapter aims to explain the procedures implemented for the two-different fault analysis, namely the former one for the resilience calculation and latter one related to the reliability of the network.

Resilience Fault Analysis

The first fault analysis explained is the one related to the resilience. The starting input is the configuration of the network, graphically obtained thanks to the Matlab function "graph" are used. Table shows the different broads reporting also the starting and ending nodes for every branch.

Table 13 Branches, with starting and ending nodes

# Branches	*Starting nodes*	*Ending nodes*
1	0	1
2	1	2
3	2	3
4	3	4
5	4	5
6	16	6
7	6	7
8	7	8
9	14	9
10	10	11
11	10	12
12	15	13
13	17	14
14	14	15
15	3	16
16	8	17
17	15	12

The result of the "graph" is Figure 19. The dotted lines represent the closed branches that in case of extreme climate event fault.

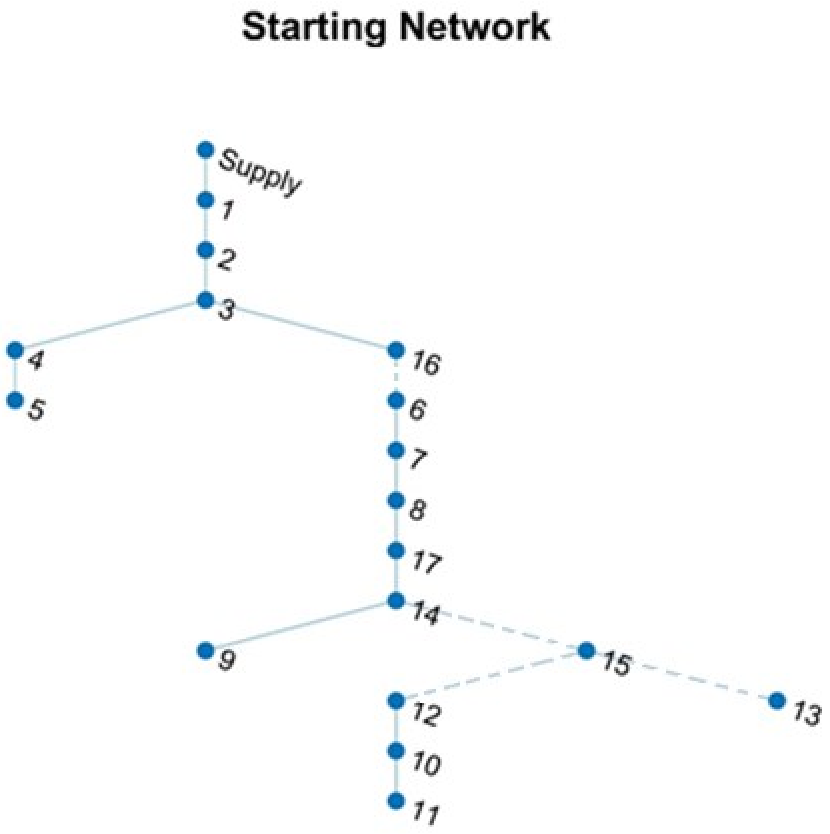

Figure 19 Network in standard condition

This is the initial network configuration and the same structure will be maintained also after the investment. Two structures, one related to the nodes of the network, and the other one related to the branch of the system are introduced in Table 14 and Table 15 respectively. The two tables contain both the variable name and its meaning.

Table 14 Structure Node

Name and Meaning
Node.Number: Number of the nodes
Node.NumberResCust: Number of residential customers
Node.NumberNonResCust: Number of non-residential customers
Node.TotCust: Number of total customers
Node.PowerResCust: Power of residential customers for each node
Node.PowerNonResCust: Power of non-residential customers for each node
Node.RemoteControlled: Binary parameter to indicate the remote-controlled nodes (1 if is remote controlled, 0 otherwise)
Node.Belongingnode: Binary parameter to indicate if the nodes is own by the network companies (1 if yes, 0 otherwise)

Table 15 Structure Branch

Name and Meaning
Branch.StartNode: Starting node of the branch
Branch.EndNode: Ending node of the branch
Branch.lambda_perm: Fault rate for permanent fault (fault/year/km)
Branch.Status: Binary index if the branch is close ,1, or open ,0.
Branch.Length_km: Length of the lines(km)
Branch.ConnectedToTheSupply: Binary index that indicate if a branch is connected to the supply (1) or not (0)

The first fault analysis considers the network before the investment. In this case after the extreme climate event, the five overhead lines fall down. These lines connected the node:

- 16 to 6
- 14 to 15
- 15 to 13
- 15 to 12
- 10 to 9

The rate of fault of the overhead lines was equal to 1, certainty failure, and the rate of fault of the cable lines was equal to 0, certanty unfailure. If the rate of fault of the overhead lines wasn't equal to 1, a Monte-Carlo method would be used to check what lines fell down. Due to the fault, the supply point opens his switch, so in the first step all the nodes are not supplied. The duration of this step continues until the automatic proceedings starts. This duration time is an input of the Matlab file and in this thesis the value of this variable is set to 10 minutes, a mean value of all the automatic operations.

Table 16 Duration time of automatic operation

t_r	10 minutes

So, for this period the Energy Not Supplied, ENS, and the costs related to the energy not supplied, C_{ons}, are calculated as follow:

$$ENS = (P^{(R)} \quad + P^{(NR)}) \ \cdot t_r \tag{4.1}$$

$$C_{ons} = [(C_{ir} \cdot P_{cnsr}) + (C_{inr} \cdot P_{cnsnr})] \cdot t_r \quad (4.2)$$

where: $P^{(R)}$ ($P^{(NR)}$) are the power of residential (non-residential) customers for each node; C_{ir} (C_{inr}) are the cost of interruption costs for residential (non-residential) customers; t_r is the duration time of automatic switches, set to 10 minutes. The number and the power of customers for each node are reported in the Table 6, the costs are shown in the Table 17.

Table 17 Cost of interruption

C_{ir}	12 €/kWh
C_{inr}	54 €/kWh

At this point the second step can be study. After the automatic operations, the manual operation starts. The duration time of a single manual operation is an input of the Matlab files. The manual operations are made by a fault team that checks if a branch is faultes, and in that case, opens that branch. There is a cost of this fault location team, C_{oflt}, that increases at each manual operation. The number of manual operation is found in automatic way through a "while" loop, that ends when the number of open branch is equal to the number of faults in the network, that are, in this thesis, five. When all the faulted lines are opened the "while" loop ends. Another important input is the order in which the lines are checked. The network companies choose an order for checking the branches because not all the branch have the same probability of failure in case of particular events. The know how and the experience of the network company helps the company itself to create this order, for example for this type of extreme climate events the branch that are in the top as priority are the overhead lines. The cable lines are not in the priority order because the rate of fault of these lines are 0, so they are not affect in case of extreme climate event. The input for this step are written in Table 18:

Table 18 Input step 2

C_{flt}	250 €/h
t_m	1 hour
$Number\ of\ fault$	5

The priority order of the checking node is shown in Table 19.

Table 19 Priority checking nodes

Priority order	***Starting node***	***Ending nodes***
1°	16	6
2°	9	10

The other overhead lines are not checked because the nodes 14 and 15 are remote controlled. The cable lines are not checked because could not fault for the event under study. After each manual operation, a power test is made, to check if some nodes can be connected to the supply point. In addition to this, a check of the network is made to find isolated nodes of the network that can be supplied trough power generator. The power generator needs to supply isolated part of the network that cannot be supplied in other way. These generators remain connected to the node until the fault has been repaired. To consider the power generator, some inputs are needed. The first of them is where the portable generator are connected. As input of the Matlab file, a binary variable called $typeofpg$ was created. If this index is 1, the portable generator can be connected to every node of the network, if it's zero, the only node in which the portable generator can be connected is nodes with a substation MV/LV. Other input related to the portable generator are:

- the time that a specific team needs to carry the portable generator to the specific node (t_{pg});
- the power of the portable generator (P_{pg})
- the number of portable generators owned by the network company (N_{pgo})
- the number of portable generators that can be rented (N_{pgr})
- the cost for renting portable generator (C_{pg}). This cost includes also the cost of a team that carry the portable generator to node to connect.

Table 20 Input related to the portable generators

Input Index	***Value***
t_{pg}	2 hours
N_{pgo}	3
C_{pg}	1160 €/day
P_{pg}	500 kW
N_{pgr}	10

The time to carry the portable generator to a node is equal for each generator, independently from the portable generator is rented or not. This hypothesis can be made because the extreme climate events can be predicted few days in advance, so the portable generator rented are already carried to the warehouse with the portable generators owned by the network company, so all depart from the same place. The last input is the criterion for choosing which isolated part of the network need to be supplied. There are two possible ways, one related to the number of costumers of each node isolated, and the other one that is related to the power of the isolated nodes. For this reason, a binary variable, “$checkwithpower$”, has been added. If this variable is equal to 1, the power of the isolated nodes is more important than the number of costumers, 0 otherwise. In this thesis this variable is set to 0.

Table 21 Choice of the connection criterion for portable generators

$checkwithpower$	0

After each manual operation the update of the value of ENS and $Cons$ are made. The last step of procedures considers the time that is needed for completely repairing all the faults in the network. This time is an input time (t_{rr}). By using this time, the value of ENS and $Cons$ are again updated.

Table 22 Time to repair the network

t_{rr}	16 hours

Figure 20 shows the scheme related to the fault analysis.

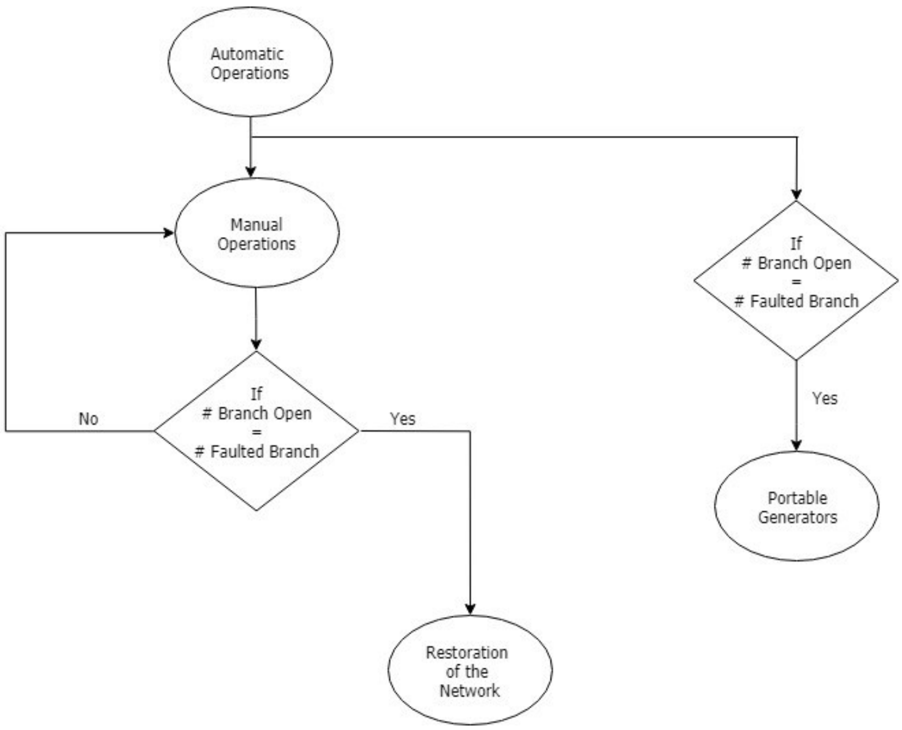

Figure 20 Steps of resilience fault analysis

Step 1: Automatic operation

Now the steps of the fault analysis are explained in detail. The first step is the automatic operation, made by the remote control. In this case the network opens the supply point, the substation MV/MV, after the fault. The other automatic switches are in the nodes 14, 15 and 8. The branch starting from the node 8 is not faulted so the switch in this node did not open. The nodes 14 and 15 are connected to faulted branches so the switches in the nodes open three branches, that connected the node:

- 14 to 15
- 14 to 13
- 15 to 12.

After a time (t_r), a re-feeding test is made. In this test also the second supply point closed. The nodes 10,11 and 12 are disconnected from the branches faulted, because the line that connects the node 10 to 9 is open in 10. These nodes can be supply by the second supply point. The rest of the network cannot be supplied because the branch that connects the nodes 16 to 6 is faulted and do not open yet. The nodes 13 and 15 are completely isolated, but there is no need to portable generator because neither has connected clients. The network after this step is shown in Figure 21:

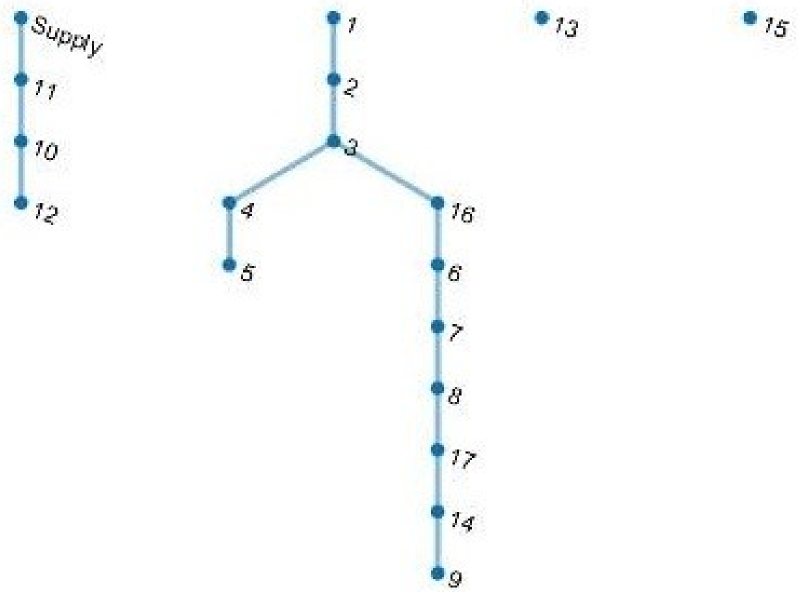

Figure 21 Network after remote control

The calculation of ENS and C_{ons} is made. Considering all the automatic operation made, for ten minutes no nodes was supplied. So, to calculate these indices all nodes are needed to be kept in consideration. From Equation (5.1) and (5.2), with the parameters of Table 16 and Table 17, it is possible to calculate ENS and C_{ons} with the Equation (4.3) and (4.4) respectively.

$$ENS = (P_{cnsr} + P_{cnsnr}) \cdot t_r \tag{4.3}$$

$$C_{ons} = [(C_{ir} \cdot P_{cnsr}) + (C_{inr} \cdot P_{cnsnr})] \cdot t_r \tag{4.4}$$

The value of P_{cnsr}, and P_{cnsnr}, are the sum of the total power not supplied for each node as described in the Table 23. Table 24 shows the value of ENS and C_{ons}.

Table 23 Power not supply for each node step 1

Node	$\boldsymbol{P_{cnsr}}$ *[kW]*	$\boldsymbol{P_{cnsnr}}$ *[kW]*
1	62.775	4.7250
2	1.485	3.0150
3	802.620	79.380
4	0	0
5	288.960	12.040
6	13.050	117,.450
7	215.985	64.515
8	158.790	370.510
9	308.050	196.950
10	89.770	5.73000
11	252.030	154.470
12	185.640	35.360
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	2379.2	1044.1

Table 24 ENS and C_{ons} Step 1

Node	***ENS*** *[kWh]*	$\boldsymbol{C_{ons}}$ *[€]*
1	11.2500	168.075
2	0.7500	30.105
3	147.0000	2319.660
4	0	0
5	50.1667	686.280
6	21.7500	1083.150
7	46.7500	1012.605
8	88.2167	3652.170
9	84.1667	2388.650
10	15.9167	231.110
11	67.7500	1894.290
12	36.8333	689.520
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	570.550	14156

Step 2: Manual Operation

The second step of the resilience fault analysis is related to the manual operations. A team searches the faulted lines and opens the branch faulted following the order created by the network company (Table 19). An important input related to the fault location team is its cost. Normally this is a cost for hour. Each manual operation, by hypothesis, takes a determinate time, that it's an input, t_m. In this case the value of t_m is 1 hour. The number of manual operation is related to the number of fault branch close, N_f, that need to be open. This step in the Matlab file is automatic, by a "while loop" that ends when all the faulted branches are open. In this case, five lines are faulted, but only 2 manual operations are needed, because the other three are open with a remote control, as result of the step 1 of fault analysis. In case the rate of fault is not 1, certainly fault, or 0, certainly operating, a Monte-Carlo can be made to check which branch is faulted. The input for this step are shown in Table 25.

Table 25 Parameters Step 2 calculation

C_{flt}	250 €/h
t_m	1 hour
N_f	5

The first manual operation is made to check the branch that connects the node 16 to 6, following the priority order made by the network company. This is a faulted branch, so the fault location team opens it. If the branch checked was not faulted, the fault location team did not open it. After the action of the fault location team, a re-feeding test is made. In this case all the nodes downstream the node number 6 can be supplied by portable generators because there are not faulted branches connected. The new configuration of the network is shown in Figure 22.

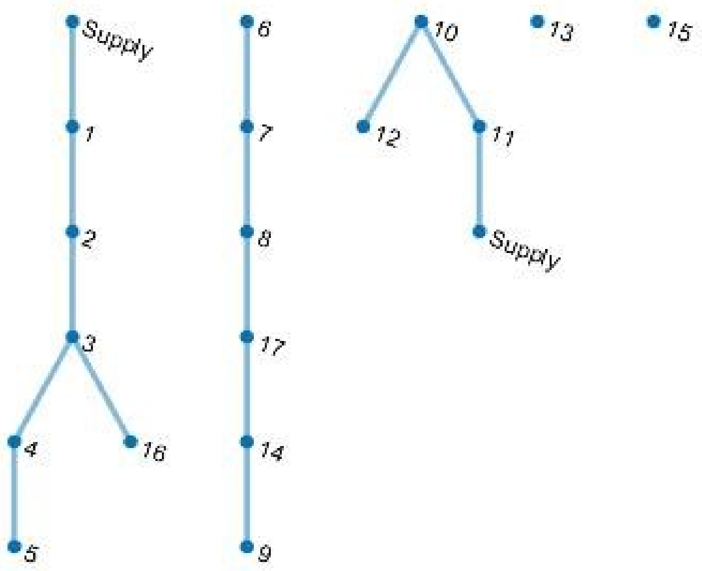

Figure 22 Network after the first manual operation

In the network configuration an island can be seen. This part of the network cannot be supplied yet because the node 9 are connected to a faulted branch. At this point, the indices are calculated. The calculation is the same as in the step 1.

Table 26 shows P_{cnsr} and P_{cnsnr}. Table 27 shows ENS and C_{ons}.

Table 26 Power not supply first manual operation

Node	$\boldsymbol{P_{cnsr}}$ *[kW]*	$\boldsymbol{P_{cnsnr}}$ *[kW]*
1	62.775	4.725
2	1.485	3.015
3	02.620	79.380
4	0	0
5	288.960	12.040
6	13.050	117.450
7	15.985	64.515
8	58.790	370.510
9	08.050	196.950
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	1851.7	848.5850

Table 27 ENS and C_{ons} first manual operation

Node	***ENS*** *[kWh]*	$\boldsymbol{C_{ons}}$ *[€]*
1	67.500	1008
2	4.500	181
3	882.000	13918
4	0	0
5	301.000	4118
6	130.500	6499
7	280.500	6076
8	529.300	21913
9	505.000	14332
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	2700.3	68044

At this point the second manual operation can be done. The second branch to check is the one that connected the node 9 to 10. This branch is open in the node 10 but close in the node 9. The fault location team, after ascertaining that the branch is faulted, opens the node 9. After this operation, network has a new configuration, shown in Figure 23.

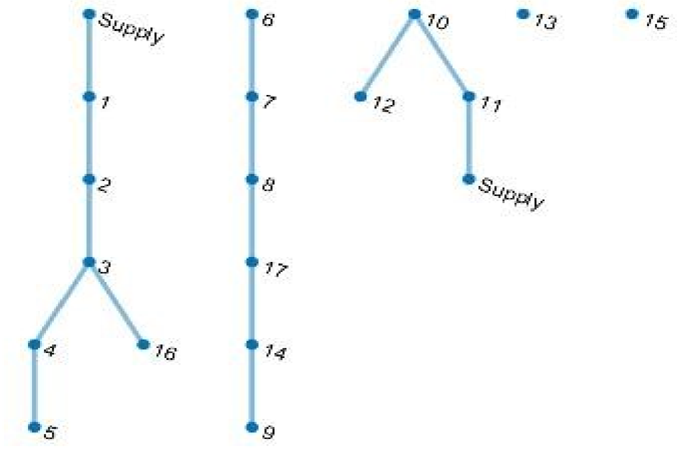

Figure 23 Network after the second manual operation

As can be seen in the Figure 23, the network can be divided in three parts. Two of them are supply with supply points, the substation MV/MV and a second supply point, whereas the third is an isolated part of the network, not supply, but that is potentially supplied with portable generator. At the end of the step the value of $P_{cnsr}$and $P_{cnsnr}$are calculated, shown in Table 28, and the value of ENS and C_{ons} are shown in Table 29.

Table 28 Power not supply second manual operation

$\boldsymbol{Node}$	$\boldsymbol{P_{cnsr}}$ $[kW]$	$\boldsymbol{P_{cnsnr}}$ $[kW]$
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	13.050	117.450
7	215.985	64.515
8	158.790	370.510
9	308.050	196.950
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	695.8750	749.4250

Table 29 ENS and C_{ons} second manual operation

$\boldsymbol{Node}$	$\boldsymbol{ENS}$ $[kWh]$	$\boldsymbol{C_{ons}}$ $[€]$
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	130.500	6499
7	280.500	6076
8	529.300	21913
9	505.000	14332
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	1445.3	48819

The time lying between the falling of the lines and the end of the step related to the manual operations is two hours and ten minutes (10 minutes for the automatic switches, and 2 hours for the two manuals operation). In the network there is an island that can be supplied with portable generators. So, the next operation is carry the portable generators to the nodes to connect. For the hypothesis made, the portable generators can be connected in every node, and the number of customers is more important than the power of the nodes. In this case the number of portable generator available is enough to supply all the node isolated, so after having discovered the isolated part of the network, the portable generators are carry to the node 6 to supply that part of the network. The total portable generators needed to supply the isolated part of the network are calculated in the Table 30.

Table 30 Power of isolated nodes of the network

Node	***Power*** *[kW]*
6	130.50
7	280.50
8	529.30
9	505.00
14	0
17	0
Tot	1445.3
Power Portable Generator [kW]	500
Number of Portable Generator	3

To carry the portable generator to the node 6, the specialized team takes 1 hour. It has been hypothesized that the road system does not takes any damage from the extreme climate events, or the maintenance workers remove the obstacle in the street that connect the deposit of the portable generator and the node to connect. This is an acceptable hypothesis, because the network companies work in collaboration with city Authorities to have the streets, that connect important point of the network, clean from obstacle. The new configuration of the network is shown in Figure 24.

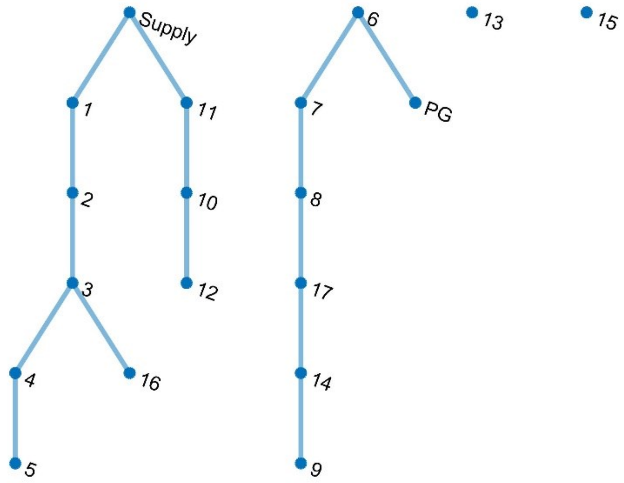

Figure 24 Network with Portable Generator

From the time of the last manual operation and the time in which the portable generators are connected passes 1 hour, so a calculation of the ENS and C_{ons} are needed. The results are the same as the last manual operation because the time and the node not supply are the same.

Table 31 ENS and C_{ons} before Portable Generators installation

Node	***ENS*** *[kWh]*	C_{ons} *[€]*
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	130.500	6499
7	280.500	6076
8	529.300	21913
9	505.000	14332
10	0	0
11	0	0
12	0	0
13	0	0
14	0	0
15	0	0
16	0	0
17	0	0
TOT	1445.3	48819

The last cost to calculate for this step is the cost to rent the portable generators. As written above the portable generators to rent are three, but the network companies own 3 portable generators so there is no additional cost.

Even changing the input $typeofpg$ and $checkwithpower$ the results of ENS and C_{ons} , in this case study, did not change because the number of portable generators are in an appropriate number to supply all the not supply nodes.

Step 3: Restoration of the network

The last step considers the time that a repair team needs to repair all the faults in the network. The hypothesis made in this thesis is that for every fault there is one dedicated repair team. The costs of these team and the time are inputs of the Matlab file, shown in Table 32.

Table 32 Time and cost to restore the network

t_{rr}	16 hours
C_{rt}	95 €/h

After having connected the portable generators, no nodes with customers are not supply, so in the time remaining for the restore of the network the ENS and C_{ons} are zero.

The time of restoration of the network starts when all the faulted branches are discovered (in this case after the second manual operation). The total time starts when the extreme climate event happens and ends when the network is completely repaired, after 18 hours and 10 minutes.

Calculation about costs

To conclude the fault analysis in case of extreme climate events a summary of costs is made. The first cost to calculate is the cost of fault location team. The team that checking the network has a cost calculated as shown in Equation (4.5)

$$Ctot_{flt} = C_{flt} * Number\ of\ manual\ operation * t_m \tag{4.5}$$

In this case the manual operations were 2, and the cost of fault location team is 250 €/h. The results are reported in Table 33.

Table 33 Cost of fault location team

C_{flt}	250 €/h
$Number\ of\ manual\ operation$	2
t_m	1 hour
$Ctot_{flt}$	500 €

The cost related to the portable generators are zero, as explained in the Step 2. Now the cost related to the repair team can be calculated with the Equation (4.6)

$$Ctot_{rt} = C_{rt} * Number\ of\ faulted\ branch * t_{rr} \qquad (4.6)$$

In the case under study the value to calculate the $Ctot_{rt}$ are shown in Table 34.

Table 34 Cost of restoration team

C_{rt}	95 €/h
$Number\ of\ faulted\ branch$	5
t_{rr}	16 hours
$Ctot_{fltrt}$	7600 €

At the end the cost of ENS and C_{ons} can be calculated as the sum of the cost of the single operations, as shown in Table 35.

Table 35 Value of ENS and C_{ons} for each step

Operation	$ENS\ [kWh]$	$C_{ons}\ [€]$
1° automatic operation	570.550	14156
1° manual operation	2700.3	68044
2° manual operation	1445.3	48819
waiting of portable generator	1445.3	48819
Time to restore the network	0	0
TOT	6161.45	179838

Fault analysis after the investment

After the investment the resilience fault analysis are useless, because all the branch will be cables, so the rate of fault is 0. In case of extreme climate event the network remains in his standard condition.

Reliability Fault Analysis

The second fault analysis needed for the CBA is the reliability fault analysis. The aim of this fault analysis is to calculate the Energy Not Supplied for the network after permanent fault. Contemporary failures are not considered in this analysis, so one fault at time is studied. Fault analysis keeps in consideration a re-feeding by closing the second supply point normally open. For this analysis the nodes 16 and 17, has been hypothesized never faulted because are nodes not owned by the network company.

The inputs of this fault analysis are the same of the resilience fault analysis (shown in Table 14 Table 15 and Table 17). The time duration of both the automatic operations and the manual operations is the same as in the resilience fault analysis, but the time needed for repair the fault is 10 hours instead of 16.

Table 36 Reliability input

t_r	10 minutes
t_m	1 hour
t_{rrl}	10 hours

To calculate the number of operation that are needed to restore the normal operation of the network some standard situations have to be studied.

1) The node upstream of the faulted node is remote controlled. If yes, all the nodes of the network are subjected to one automatic operation after the fault. The slack can supply the node from itself to the remote controlled upstream node. The node downstream the faulted node need 1 extra manual operation to be supplied. This operation need to open the node downstream the faulted node.

2) There are a downstream remote-controlled node and an upstream remote-controlled node, the number of manual operation will be the number of nodes between the upstream remote-controlled nodes and the upstream node closer to the fault node plus the number of nodes between the downstream remote-controlled nodes and the downstream node closer to the fault node. There is always an automatic operation after the fault. If there is an alternative supply node the upstream nodes can be supplied, if not they can be supplied only after the repair of the faulted node.

3) The last case is that no remote controlled downstream node of the faulted node. After the first manual operation, the number of manual operation needed to isolate the node is the number of node from the upstream remote-controlled node and the upstream node closer

to the faulted node. The upstream node of the faulted node can be connected to an alternative supply point only after an extra manual operation that open the upstream node. If there isn't an alternative supply point, the upstream nodes remain not supply.

For the network under study, if the branch that connected the nodes 9 and 10 is considered open, the number of manual operation that are needed in case of fault can be check in the Table 37.

Table 37 Number of manual operation for reliability

		Number of faulted branch																
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**
Nodes	**1**	0	1	2	3	4	4	4	5	0	0	0	0	0	0	3	0	0
	2	0	2	2	3	4	4	4	5	0	0	0	0	0	0	3	0	0
	3	0	2	3	3	4	4	4	5	0	0	0	0	0	0	3	0	0
	4	0	2	3	3	4	4	4	5	0	0	0	0	0	0	3	0	0
	5	0	2	3	3	4	4	4	5	0	0	0	0	0	0	3	0	0
	6	0	2	3	3	4	4	4	5	0	0	0	0	0	0	4	0	0
	7	0	2	3	3	4	4	5	5	0	0	0	0	0	0	4	0	0
	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	10	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0
	11	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0	0	0
	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	0	2	3	3	4	4	4	5	0	0	0	0	0	0	4	0	0
	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0

The nodes that remain not supply because there is not an alternative supple are reported in

Table 38.

Table 38 Nodes not supply because no alternative supply exist

		Number of faulted branch																
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**
Nodes	**1**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	4	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
	5	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0
	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	9	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0
	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	13	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

At this point, the ENS for residential and non-residential customers are calculate, for each node, as:

$$ENS = (P_{cnsr} + P_{cnsnr}) \cdot t_{tot} \tag{4.7}$$

where t_{tot} is the sum of the duration time of all the operations (automatic and manual) that need to supply that node; P_{cnsr} (P_{cnsnr}) is the residential (non-residential) power of the node under study.

The value of ENS for every node and for every fault branch are shown in Table 39 and Table 40 for residential customers, and in Table 41 and Table 42 for non-residential customers. With this value of ENS the cost for the energy not supply can be calculated as:

$$C_{ons} = (ENS^{R} \cdot C^{R}) + (ENS^{NR} \cdot C^{NR}) \tag{4.8}$$

The C^{R} (C^{NR}) is the cost of interruption for residential (non-residential) customers, and are the same used in resilience fault analysis (Table 17).

Table 39 ENS [kWh] reliability, part 1, residential customers

Faulted Branch \ Nodes	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	10.4625	0.2475	133.77	0	48.16	2.175	35.9975	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
2	73.2375	3.2175	1739.01	0	626.08	28.275	467.9675	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
3	136.0125	3.2175	2541.63	0	915.04	41.325	683.9525	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
4	198.7875	4.7025	2541.63	0	3804.64	41.325	683.9525	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
5	261.5625	6.1875	3344.25	0	4093.6	54.375	899.9375	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
6	198.7875	4.7025	2541.63	0	915.04	54.375	899.9375	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
7	261.5625	6.1875	3344.25	0	1204	54.375	899.9375	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
8	261.5625	6.1875	3344.25	0	1204	54.375	1115.923	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0
9	324.3375	7.6725	4146.87	0	1492.96	67.425	1115.923	26.465	51.34167	14.96167	42.005	30.94	0	0	0	0	0

Table 40 ENS [kWh] reliability, part 2, residential customers

Nodes	Faulted Branch 17	16	15	14	13	12	11	10
1	10.4625	10.4625	10.4625	10.4625	10.4625	10.4625	10.4625	10.4625
2	0.2475	0.2475	0.2475	0.2475	0.2475	0.2475	0.2475	0.2475
3	133.77	133.77	133.77	133.77	133.77	133.77	133.77	133.77
4	0	0	0	0	0	0	0	0
5	48.16	48.16	48.16	48.16	48.16	48.16	48.16	48.16
6	2.175	2.175	2.175	2.175	2.175	2.175	2.175	2.175
7	35.9975	35.9975	35.9975	35.9975	35.9975	35.9975	35.9975	35.9975
8	26.465	26.465	26.465	26.465	26.465	26.465	26.465	26.465
9	51.34167	51.34167	51.34167	51.34167	51.34167	3131.842	51.34167	51.34166667
10	104.7317	14.96167	14.96167	14.96167	104.7317	14.96167	14.96167	14.96166667
11	294.035	42.005	42.005	42.005	546.065	42.005	42.005	42.005
12	30.94	30.94	30.94	30.94	30.94	30.94	30.94	30.94
13	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0

Table 41 ENS [kWh] reliability, part 1, non-residential customers

Nodes	Faulted Branch 1	2	3	4	5	6	7	8	9
1	0.7875	5.5125	10.2375	14.9625	19.6875	14.9625	19.6875	19.6875	24.4125
2	0.5025	6.5325	6.5325	9.5475	12.5625	9.5475	12.5625	12.5625	15.5775
3	13.23	171.99	251.37	251.37	330.75	251.37	330.75	330.75	410.13
4	0	0	0	0	0	0	0	0	0
5	2.006667	26.08667	38.12667	158.5267	170.5667	38.12667	50.16667	50.16667	62.20667
6	19.575	254.475	371.925	371.925	489.375	489.375	489.375	489.375	606.825
7	10.7525	139.7825	204.2975	204.2975	268.8125	268.8125	268.8125	333.3275	333.3275
8	61.75167	61.75167	61.75167	61.75167	61.75167	61.75167	61.75167	61.75167	61.75167
9	32.825	32.825	32.825	32.825	32.825	32.825	32.825	32.825	32.825
10	0.955	0.955	0.955	0.955	0.955	0.955	0.955	0.955	0.955
11	25.745	25.745	25.745	25.745	25.745	25.745	25.745	25.745	25.745
12	5.893333	5.893333	5.893333	5.893333	5.893333	5.893333	5.893333	5.893333	5.893333
13	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0

Table 42 ENS [kWh] reliability, part 2, non-residential customers

Faulted Branch	Nodes 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
10	0.7875	0.5025	13.23	0	2.00667	19.575	10.7525	61.75167	32.825	0.955	25.745	5.89333	0	0	0	0	0
11	0.7875	0.5025	13.23	0	2.0067	19.575	10.7525	61.75167	32.825	0.955	25.745	5.89333	0	0	0	0	0
12	0.7875	0.5025	13.23	0	2.00667	19.575	10.7525	61.75167	2002.325	0.955	25.745	5.89333	0	0	0	0	0
13	0.7875	0.5025	13.23	0	2.0067	19.575	10.7525	61.75167	32.825	6.685	334.685	5.89333	0	0	0	0	0
14	0.7875	0.5025	13.23	0	2.0067	19.575	10.7525	61.75167	32.825	0.955	25.745	5.89333	0	0	0	0	0
15	0.7875	0.5025	13.23	0	2.0067	19.575	10.7525	61.75167	32.825	0.955	25.745	5.89333	0	0	0	0	0
16	0.7875	0.5025	13.23	0	2.0067	19.575	10.7525	61.75167	32.825	0.955	25.745	5.89333	0	0	0	0	0
17	0.7875	0.5025	13.23	0	2.0067	19.575	10.7525	61.75167	32.825	6.685	180.215	5.89333	0	0	0	0	0

V. Calculation of CBA

This chapter focuses on the explanation of the CBA. The time horizon of the CBA in RIIO framework is 45 years, whereas the Italian Authority set as 25 years as time horizon. This thesis considered for both CBA as time horizon in order to compare them 25 years.

Before starting the calculation of the CBA, the number of climate events and the number of faults in the time horizon is calculated thanks to a computerized mathematical technique, the Monte-Carlo method. To calculate the number of extreme climate events the rate of extreme event, shown in Table 43Table 45, is needed. To find the number of faults in the time horizon the rate of permanent faults, Λ_c , calculated with the Equation (6.1), is needed.

$$\Lambda_c = L_b \cdot \lambda_c \cdot T \qquad (6.1)$$

L_b is the length of each branch, shown in Table 44, T is the time horizon of the CBA, shown in Table 45, λ_c is the failure rate per length.

Table 43 Input of Monte-Carlo method

T	$25\ years$
λ_x	$\frac{1}{14}$

The number of faults for each branch every year of the CBA was determined by mean of the Monte-Carlo method. The distribution of faults follows a Poisson Distribution. The inputs of this method are shown in Table 44. The results of the Monte-Carlo method are the number of faults in the time horizon of the CBA for every year. With the same method the number of extreme events was calculated.

Table 44 Input for failure rate

L_b	827	m
λ_c^{ol}	0.0578	fault/km/y
λ_c^{cl}	0.0465	fault/km/y
$(\Lambda_c^{ol})_{pre}$	1.19	fault/branch
$(\Lambda_c^{cl})_{pre}$	0.9614	fault/branch
$(\Lambda_c^{cl})_{post}$	0.9614	fault/branch

The input rate is the same for every year because the faults are independent one to each other, so if one event happens the probability of happening of the next event does not change. The last input needed for this method is the seed of the random numbers, shown in Table 45. This is important to create a repeatability of the results.

Table 45 Seed of Poisson Distribution

$seed$	0

The number of extreme events is the same before and after the investment. The rate of permanent fault changes after the investment, so the Monte-Carlo method has to be repeated for getting the faults before and after the investment.

For statistically representing the reality, this Monte-Carlo method has to be run multiple times with the Monte-Carlo method (in this thesis 1000 times). Some results of the Monte-Carlo method are shown in Figure 25 to Figure 27. The Figure 25 shows the number of extreme events in 25 years for one iteration, the Figure 26 and Figure 27 show the permanent fault of each branch in 25 years, before and after the investment.

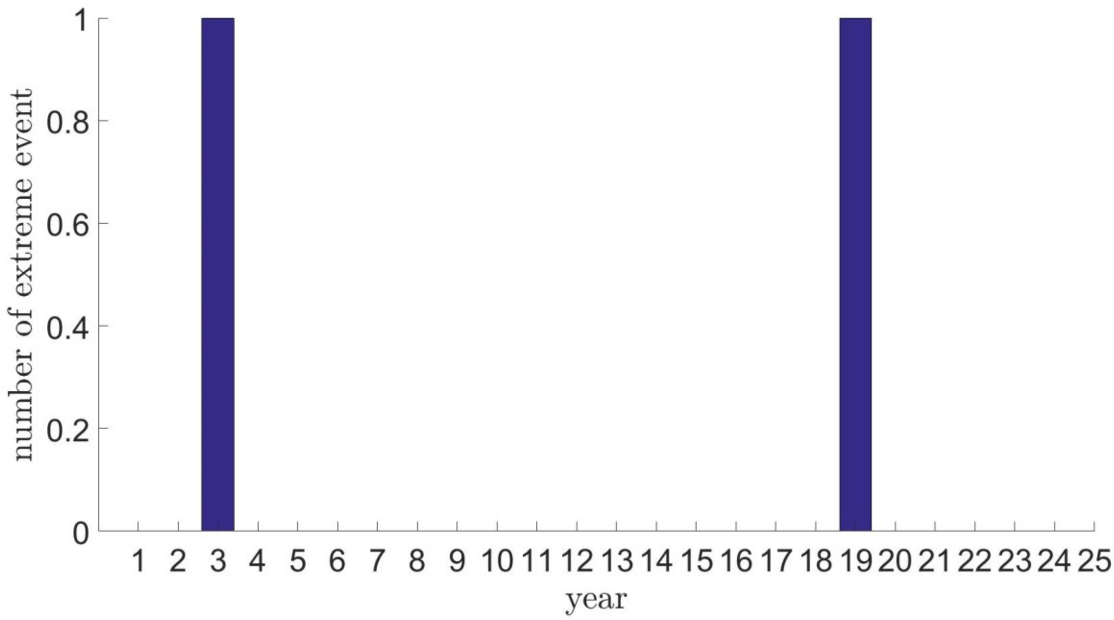

Figure 25 Number of extreme events

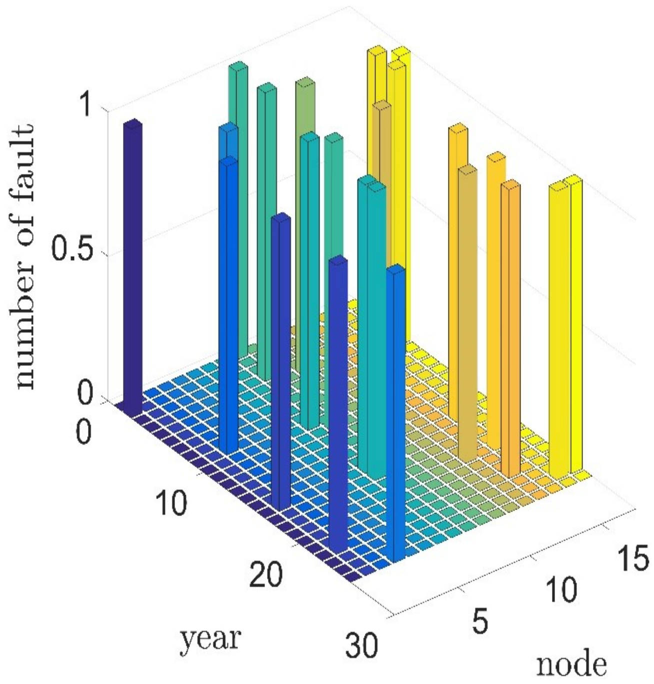

Figure 26 Number of faults before investment

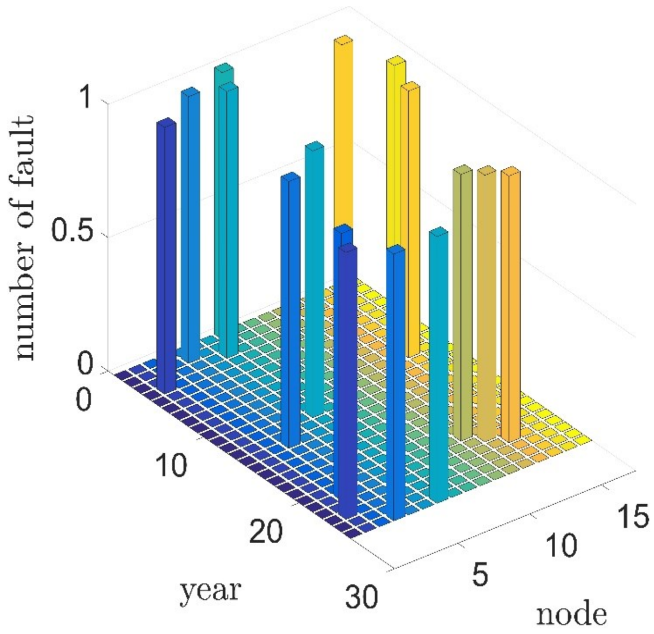

Figure 27 Number of faults after investment

RIIO CBA

Following the steps described in the Chapter 3, the RIIO CBA can be done. The first step is to calculate the cost of the investment, keeping in consideration the life time of the investment (30 years) and the time horizon of the CBA (25 years). In this case, the life time of the investment is longer than the time horizon of the CBA, so the cost of the investment is calculated with the Equation (5.3)

$$Inv_{ann} = \frac{Inv \cdot d}{1-(1+d)^{-lt}} \cdot \frac{1}{1+d} \cdot \left(1 - \frac{1}{(1+d)^T}\right) \cdot \frac{1}{1-\left(\frac{1}{1+d}\right)} \tag{5.3}$$

where lt is the lifetime of the investment, Inv is the total cost of the investment, T is the time horizon and d is the is the discount rate. The results are shown in Table 46

Table 46 Inputs of RIIO CBA

Inv	502,000	€
lt	30	$years$
d	0.04	
T	25	$years$
Inv_{ann}	453,520	€
Cap_{rate}	0.85	

Now the TOTEX can be calculated with the Equation (5.4)

$$Totex = Inv_{ann} + C_{rm} - S_{lv} \tag{5.4}$$

where C_{rm} is the costs for removing previous assets and S_{lv} is the salvage cost of the investment. All costs are shown in the Table 47

Table 47 Costs

Crm	50,000€
Slv	0€
$Totex$	532,550€

As written in Chapter 3 the subscripts *pre* and *post* indicate if these costs are calculated before or after the investment. The first *company* benefit calculated is related to the decrease of the operational and maintenance costs as shown in Equation (5.5).

$$B_t^{(O\&M)} = (L_{tot} \cdot O\&M)_{pre} + (L_{tot} \cdot O\&M)_{post} \quad (5.5)$$

where $O\&M$ is a cost for unit of length of the lines and multiples for the length of the lines, L_{tot}. All the values and the results of this benefit is shown in Table 48.

Table 48 Benefit O&M

$O\&M_{pre}$	3	$€/m/year$
$O\&M_{post}$	0	$€/m/year$
$(L_{tot})_{pre}$	4135	m
$(L_{tot})_{post}$	3270	m
$B^{(O\&M)}$	12,405	€

To calculate the benefit related to the savings of emergency action cost due to resilience improvement, the inputs needed are:

- the cost for rent portable generator, C_{fpg};
- the cost of fault location team, C_{ofl};
- the cost of repair team, C_{ort}.

These costs are the results of the resilience fault analysis. After the investment, in case of extreme climate event, these costs are zero because no fault happens. The Equation (5.6) is used to calculate this benefit. The Table 49 shows the costs and the benefits calculated.

$$B_t^{(res,sea)} = \left(C_{fpg} + C_{ort} + C_{ofl}\right)_{pre} - \left(C_{fpg} + C_{ort} + C_{ofl}\right)_{post} \quad (5.6)$$

Table 49 Benefit related to resilience emergency action

$\left(C_{fpg}\right)_{pre}$	0	€
$(C_{ort})_{pre}$	7,600	€
$\left(C_{ofl}\right)_{pre}$	500	€
$\left(C_{fpg}\right)_{post}$	0	€
$(C_{ort})_{post}$	0	€
$\left(C_{ofl}\right)_{post}$	0	€
$B_t^{(res,sea)}$	8,100	€

In this case the cost to rent the portable generator C_{fpg} is zero, because the network company owns the number of portable generator needed to supply the isolated part of the network as explain in Chapter 4.

The value of $B_t^{(res,sea)}$ shown in Table 49 is correct only when an extreme event occurs. In the remaining years of the CBA time horizon, this value will be zero. For example, the Figure 26 shown the years in which an extreme event occurs, so, only in the years 2 and 19 the $B_t^{(res,sea)}$ will be different from zero. The cost of emergency action in case of extreme event after investment are zero because no branch faulted.

The Figure 28 shows the Cumulative Distribution Function (CDF) made by the value of this benefit in each iteration. For the almost 20% of the time this benefit is zero because the extreme climate event happen every 14 year.

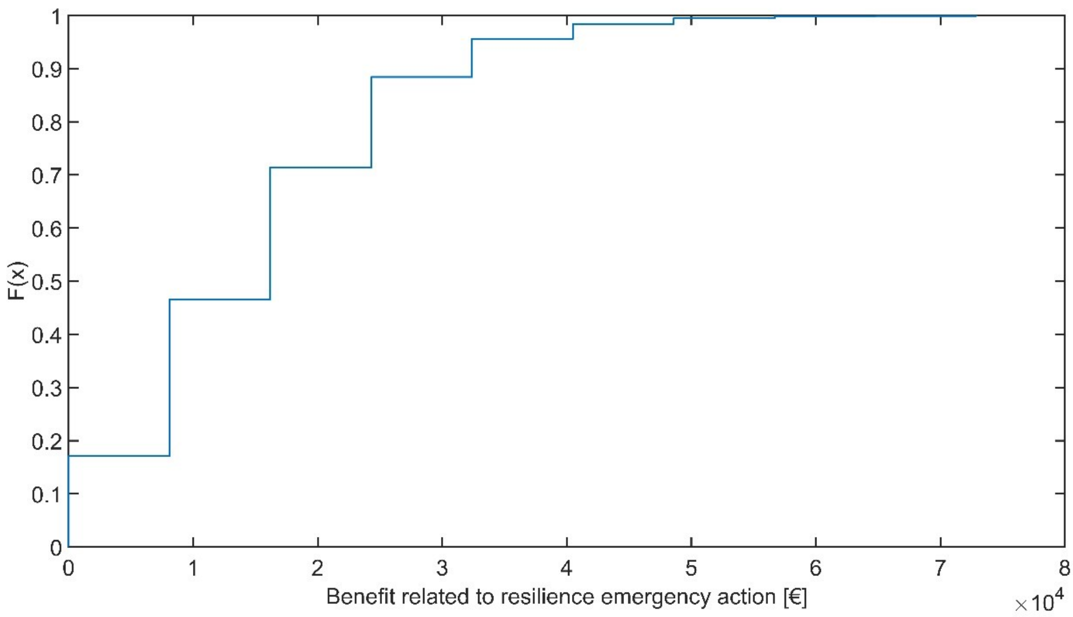

Figure 28 CDF of the benefit related to the resilience emergency action

The benefit related to the savings of emergency action cost due to reliability improvement can be calculated, in case of ordinary fault, with the Equation (5.7).

$$B_t^{(rel,sea)} = \left(C_{ort} + C_{ofl}\right)_{pre} - \left(C_{ort} + C_{ofl}\right)_{post} \tag{5.7}$$

The Figure 29 shows the CDF of the final value of this benefit for 1000 iterations.

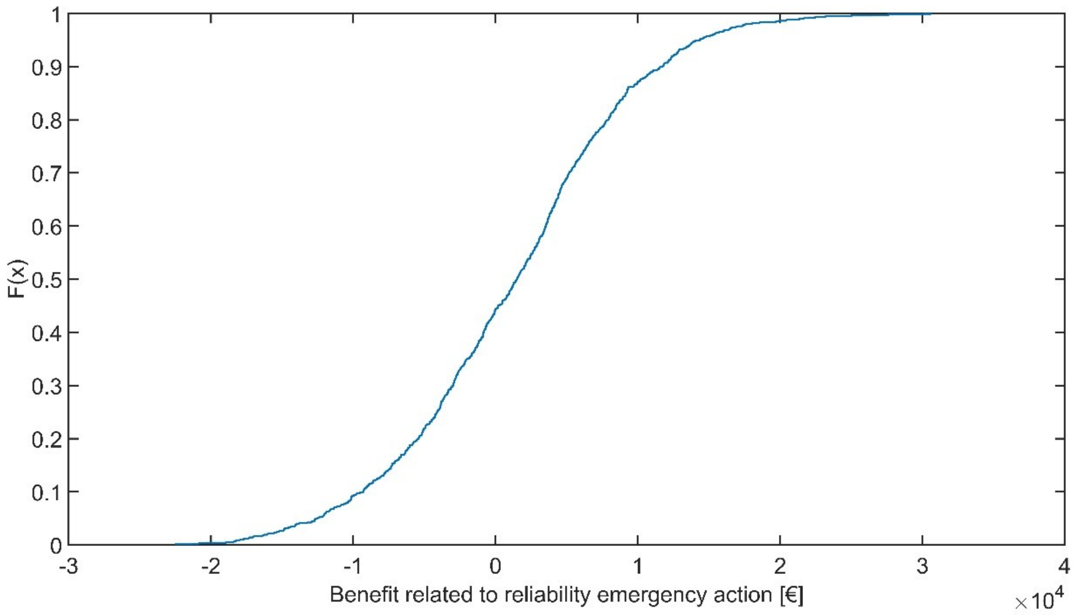

Figure 29 CDF of the benefit related to the reliability emergency action

From Figure 28 it is possible to notice that the value of the benefit related to the resilience is always positive, or at least zero. Conversely, Figure 29 shows that the value of the benefit related to the reliability can be both negative and positive. The explanation is that for the resilience, the number of extreme events is the same before and after the investment, because the investment does not affect the rate of extreme weather event. In the second case (i.e, the one related to the reliability), the investment changes the rate of fault of the components of the network, so the Monte-Carlo method has to be run both before and after the investment. When the benefit has a negative value, means that the number of faults is higher after the investment than before the investment. Running the Monte-Carlo method multiple times solves this problem, indeed the mean values of the two benefits are shown in Table 50 and are both positive.

Table 50 Mean Value of Benefits related to emergency action

Mean Value of benefit related to the reliability emergency action [€]	1,187.3
Mean Value of benefit related to the resilience emergency action [€]	14,855

In this thesis the possibility of using portable generators in case of permanent fault was not taken into consideration. The number of remote and manual operations needed to supply the network after a fault depends on the faulted branch, so for each fault, a different value of C_{ort} and C_{ofl} can be calculated. Table 51 shows the sum of C_{ort} and C_{ofl} in case only one faulted branch.

Table 51 C_{ort} + C_{ofl} for faulted branch

Faulted Branch	$C_{ort} + C_{ofl}$ [€]
1	950
2	1450
3	1700
4	1700
5	1950
6	1950
7	1950
8	2200
9	2200
10	1200
11	950
12	950
13	1450
14	950
15	950
16	950
17	1200

During one year more than one branch can be faulted and some of these even multiple times, so the value of the $C_{ort} + C_{ofl}$ is calculated with the Equation (5.8).

$$C_{ort} + C_{ofl} = \sum_{t=1}^{T} \left(\sum_{b=1}^{17} \left(N_{fault}\right)_b \cdot \left(C_{ort} + C_{ofl}\right)_b \right)_t \tag{5.8}$$

where N_{fault} is the number of fault of the branch b in the year t.

The rate of extreme event does not change before and after the investment, so the extreme event happens always in the same year, whereas the rate of permanent fault changes before and after the investment and thus also the number of faulted branches in each year.

At this point the total company benefit before the capitalisation, $B_t^{(DNO,tot)}$, can be calculated with the Equation (5.9)

$$B_t^{(DNO,tot)} = Totex + B_t^{(res,sea)} + B_t^{(O\&M)} + B_t^{(rel,sea)} \tag{5.9}$$

The slow money can be calculated with the Equation (5.10) and the fast money with the Equation (5.11)

$$Inv_t^{(cap)} = B_t^{(DNO,tot)} \cdot Cap_{rate} \tag{5.10}$$

$$Inv^{(e)} = B_t^{(DNO,tot)} - Inv_t^{(cap)} = B_t^{(DNO,tot)} \cdot (1 - Cap_{rate}) \tag{5.11}$$

The value of the Cap_{rate} is shown Table 46.

The following steps, related to the depreciation, are described in Chapter 3, Equations from (3.22) to (3.27).

Now the benefit related to the avoided cost of interruption in case of extreme event is calculated with the Equation (5.12), where the value of C_{ons} before the investment is calculated in the fault analysis and shown in Table 52. The value of C_{ons} after investment is zero, because no branch faults. The final value of the benefit, $B_t^{(res,int)}$, in the year in which the event occurs, is shown in Table 52. If the extreme event does not occur, the value of $B_t^{(res,int)}$ is zero.

$$B_t^{(res,int)} = (C_{ons})_{pre} - (C_{ons})_{post} \tag{5.12}$$

Table 52 C_{ons} for each step

Operation	***Cons*** *[€]*
1° automatic operation	14156
1° manual operation	68044
2° manual operation	48819
waiting of portable generator	48819
Time to restore the network	0

Table 53 C_{ons}

$\boldsymbol{Cons_{pre}}$ [€]	179838
$\boldsymbol{Cons_{post}}$ [€]	0
$\boldsymbol{B_t^{(res,int)}}$ [€]	179838

The Figure 30 shows the CDF made using the results of the final value of the 1000 iteration of $B^{(res,int)}$.

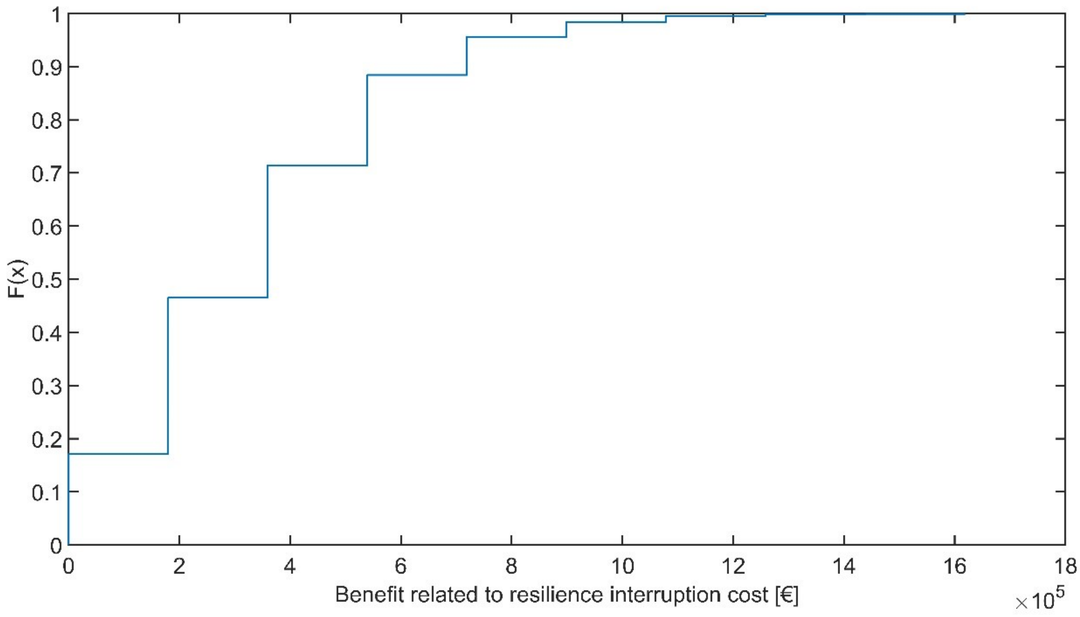

Figure 30 CDF of the benefit related to the resilience interruption cost

The benefit related to the interruption cost due to permanent fault is calculated with the Equation (5.13).

$$B_t^{(res,int)} = \left(\left(C_R \cdot P^{(R,ns)}\right)_t\right)_{pre} - \left(\left(C_{NR} \cdot P^{(NR,ns)}\right)\right)_{post} \tag{5.13}$$

where the value of $P^{(R,ns)}$ ($P^{(NR,ns)}$) is the energy not supplied for residential (non-residential) customers, result of the reliability fault analysis. The value of $\left(C_R \cdot P^{(R,ns)}\right) + \left(C_{NR} \cdot P^{(NR,ns)}\right)$ can be calculated with the Equation (5.14).

$$\left(C_R \cdot P^{(R,ns)}\right) + \left(C_{NR} \cdot P^{(NR,ns)}\right) = \sum_{t=1}^{T} \left(\sum_{b=1}^{17} \left(N_{fault}\right)_b \cdot \left((C_R \cdot RENS_R) + (C_{NR} \cdot NRENS_R)\right)_b\right)_t \tag{5.14}$$

The CDF made with the 1000 value of this benefit is shown in Figure 31. The observations that can be made for the Figure 30 and Figure 31 are the same made for the Figure 28 and Figure 29. The mean values of the last two benefits calculated are in Table 54.

Table 54 Mean values of benefits related to the interruption costs

Mean Value of benefit related to the reliability interruption costs [€]	329,820
Mean Value of benefit related to the resilience interruption costs [€]	54,209

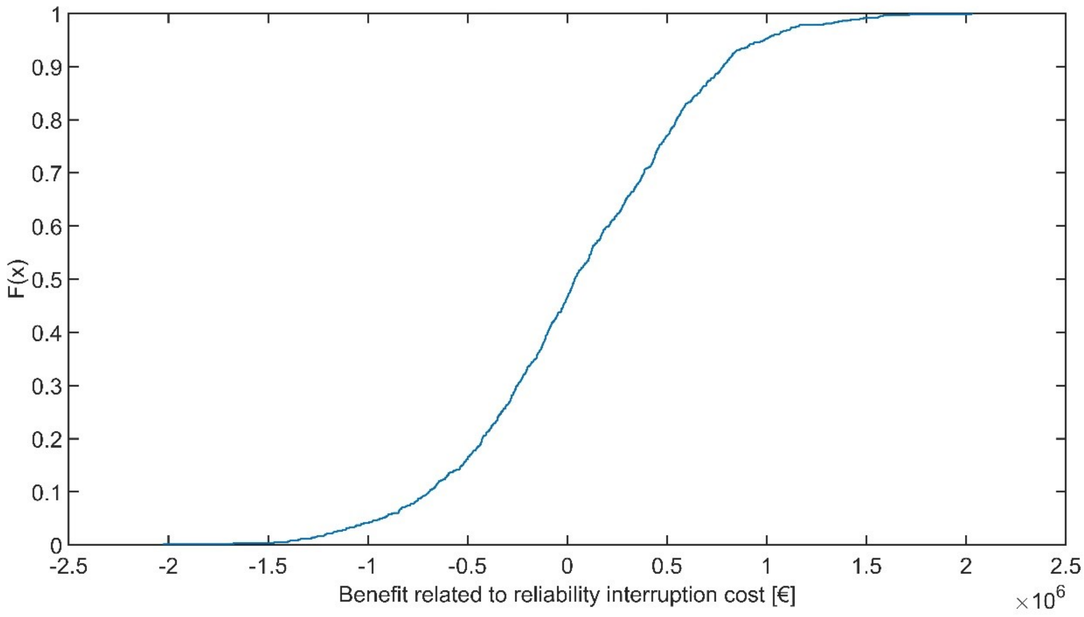

Figure 31 CDF of the benefit related to the reliability interruption cost

The sum of the last two benefit is the total social net benefit, B_t^{social}.

$$B_t^{(social)} = B_t^{(rel,int)} + B_t^{(res,int)} \tag{5.15}$$

The net benefit, $B_t^{(net)}$, can be calculated with the Equation (5.16).

$$B_t^{(net)} = B_t^{(DNO,afcap)} + B_t^{(social)} \tag{5.16}$$

$B_t^{(DNO,afcap)}$ is the total net DNO benefit calculated with the Equation (3.22) in the Chapter 3.

The last step of this CBA is to calculate the Net Present Value NPV with the Equation (5.17)

$$NPV = \sum_{t=1}^{T} B_t^{dnet} \tag{5.17}$$

where $B^{(dnet)}$is the discount net benefit, calculated with $B_t^{(net)}$ and the discount factor D_f,show in Equation (5.18) and (5.19) respectively.

$$B_t^{(dnet)} = B_t^{(net)} \cdot D_f \tag{5.18}$$

$$D_f = \frac{1}{(1+d)^t} \tag{5.19}$$

This CBA has been run 1000 times and the final value is the mean of all value of NPV at the 25 years. The result is shown in Table 55. The first result is the value of NPV if the reliability is not considered, the second otherwise.

Table 55 NPV CBA RIIO

NPV without considering reliability	$-163{,}200€$
NPV considering reliability	$-114{,}100€$

The Figure 32 shows the mean value of NPV calculated in the 1000 iterations.

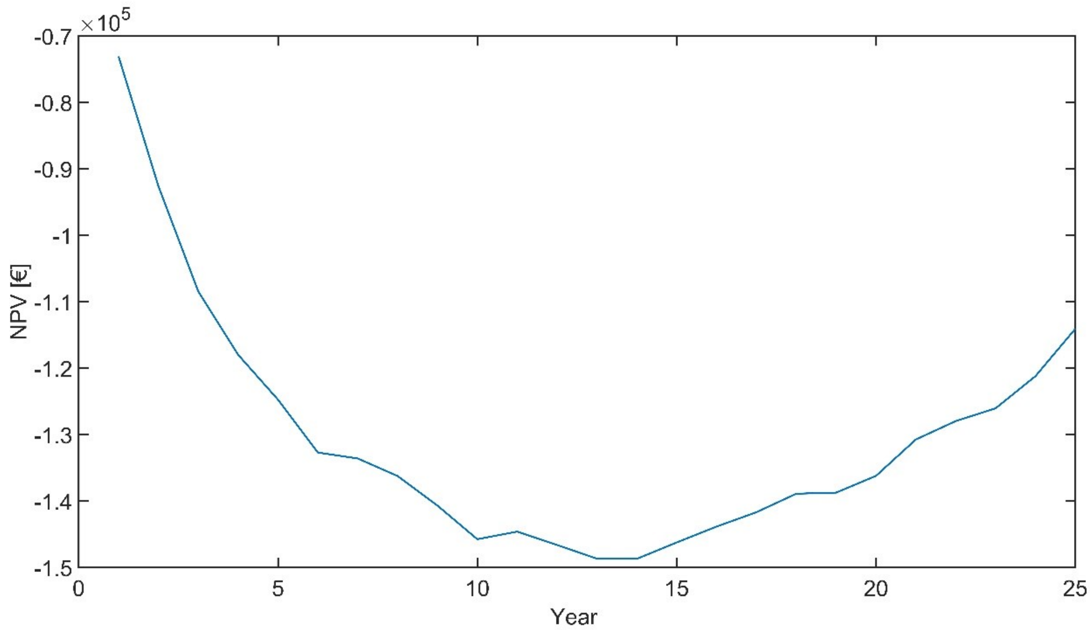

Figure 32 Trend of NPV for year

Italian Authority CBA

Next step is the execution of the Italian Authority CBA. The cost of the investment needs to be annualized with the Equation (5.20)

$$C_{inv,ann} = \frac{d \cdot Inv}{1-(1+d)^{lt}} \tag{5.20}$$

Then the Net Present Cost (NPC) can be calculated. Two formulas can be used, the first one, show in Equation (5.21), if the life time of the investment is less or equal to the time horizon of the CBA, the second one, (5.22), otherwise.

$$NPC = Inv + C_{rm} - S_{lv} + B_t^{(O\&M)} \cdot \left(\frac{1}{1+d}\right) \cdot \left(1 - \frac{1}{(1+d)^T}\right) \cdot \left(\frac{1}{1-\frac{1}{1+d}}\right) \quad (5.21)$$

$$NPC = C_{inv,ann} + C_{rm} - S_{lv} + \left(Inv_{ann} + B_t^{(O\&M)}\right) \cdot \left(\frac{1}{1+d}\right) \cdot \left(1 - \frac{1}{(1+d)^T}\right) \cdot \left(\frac{1}{1-\frac{1}{1+d}}\right) \quad (5.22)$$

In this thesis the life time of the investment is higher than the CBA time horizon so the Equation (5.22) are used. The value of $B_t^{(O\&M)}$ is calculated with the Equation (5.5) and shown in Table 48. The results are shown in Table 56.

Table 56 Investment Italian Authority CBA

Inv	502000	€
$C_{inv,ann}$	29031	€
C_{rm}	50000	€
S_{lv}	0	€
NPC	338760	€

The next step is the evaluation of the company and social benefits. The benefit related to the avoided cost of interruption in case of extreme event is calculated with the Equation (5.23).

$$B^{(res,int)} = \sum_{t=1}^{T} \frac{\left((C_{ons})_{pre} - (C_{ons})_{post}\right)}{(1+d)^t} \quad (5.23)$$

where $(C_{ons})_{pre}$ and $(C_{ons})_{post}$ are shown in Table 52. The Figure 33 shown the CDF of this benefit calculated in the 1000 iteration.

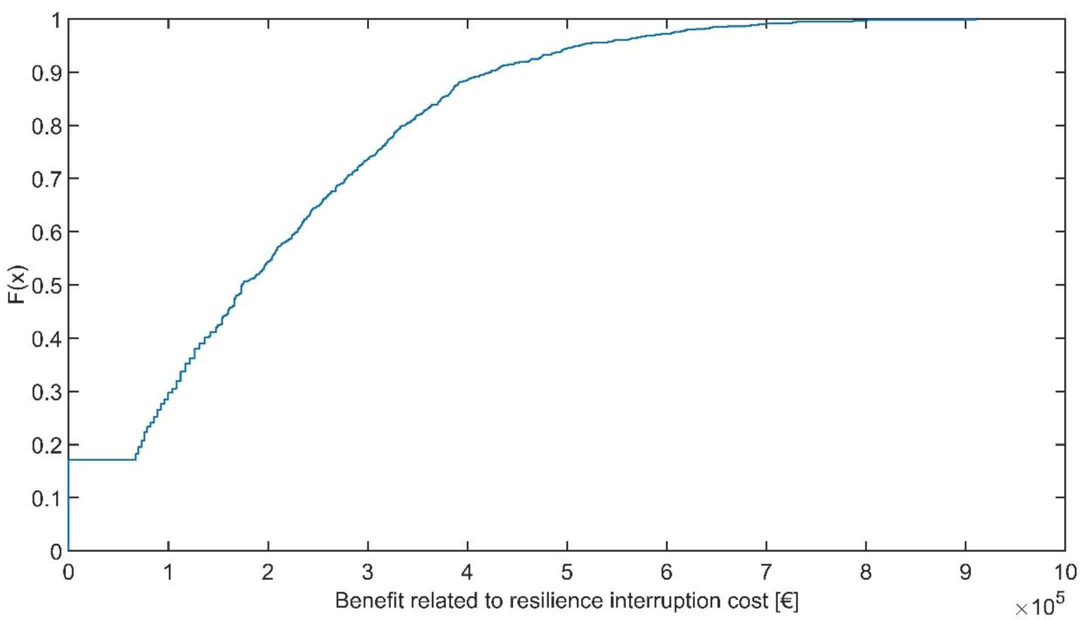

Figure 33 CDF of the benefit related to the resilience interruption cost

The benefit related to the savings of interruption cost due to the reliability improvement can be calculated with the Equation (5.24).

$$B^{(rel,int)} = \sum_{t=1}^{T} \frac{\left(\left(ENS_{x,s}^{(R)} \cdot C_R + ENS_{x,s}^{(NR)} \cdot C_{NR}\right)_t\right)_{pre} - \left(\left(ENS_{x,s}^{(R)} \cdot C_R + ENS_{x,s}^{(NR)} \cdot C_{NR}\right)_t\right)_{post}}{(1+d)^t} \quad (5.24)$$

The Figure 34 shown the CDF of this benefit calculated in the 1000 iteration.

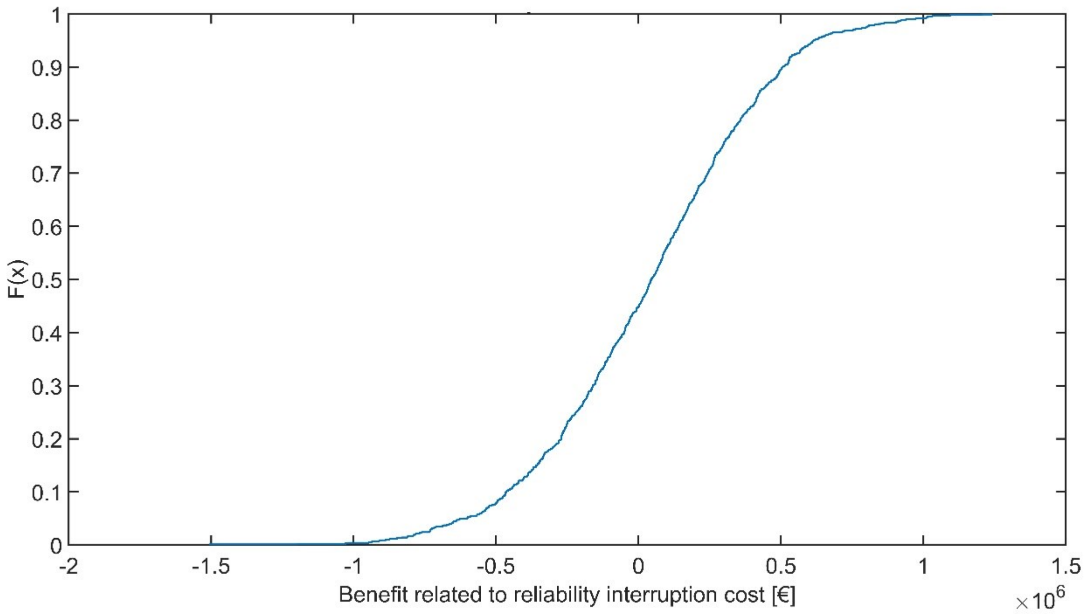

Figure 34 CDF of the benefit related to the reliability interruption cost

The last two benefits needed are related to the saving of emergency action in case of extreme event, calculated with the Equation (5.25), or in case of permanent fault, calculated with the Equation (5.26).

$$B^{(res,sea)} = \sum_{t=1}^{T} \frac{\left(\left(C_{fpg} + C_{ort} + C_{ofl}\right)_t\right)_{pre} - \left(\left(C_{fpg} + C_{ort} + C_{ofl}\right)_t\right)_{post}}{(1+d)^t} \quad (5.25)$$

$$B^{(rel,sea)} = \sum_{t=1}^{T} \frac{\left(\left(C_{ort} + C_{ofl}\right)_t\right)_{pre} - \left(\left(C_{ort} + C_{ofl}\right)_t\right)_{post}}{(1+d)^t} \quad (5.26)$$

The values used for C_{fpg}, C_{ort} and C_{ofl} as the same used for the RIIO CBA, shown in Table 49. The CDF of these benefits calculated in the 1000 iteration are shown in the Figure 35 and Figure 36.

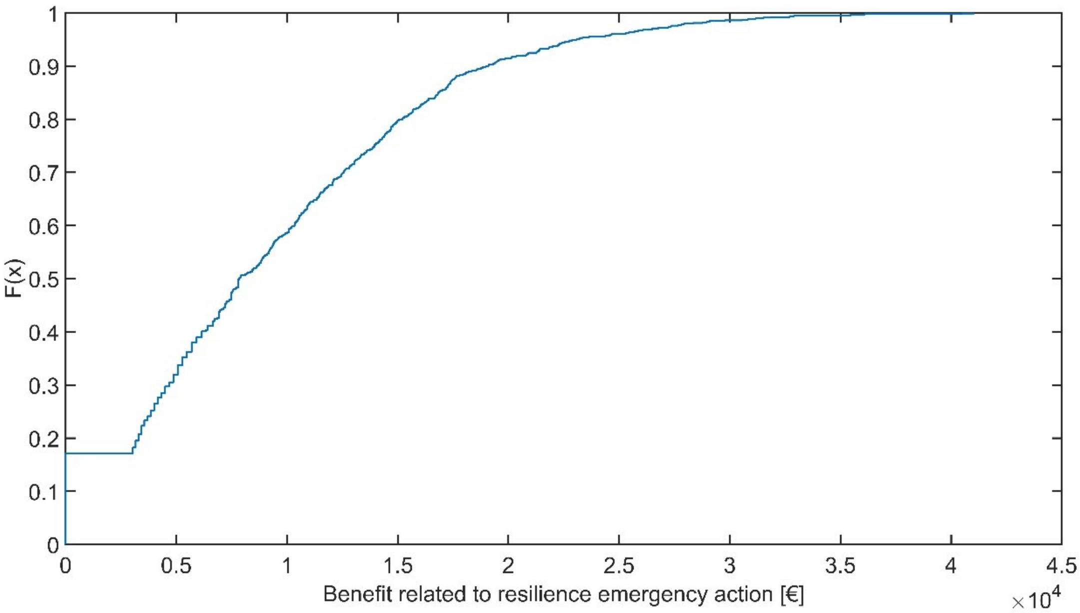

Figure 35 CDF of the benefit related to the resilience emergency action

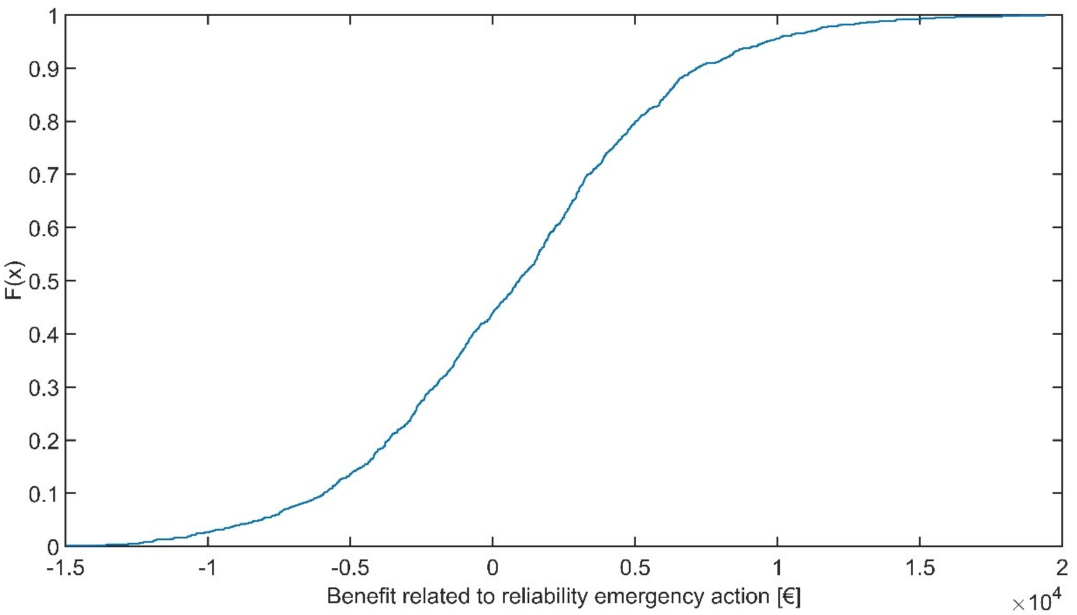

Figure 36 CDF of the benefit related to the reliability emergency action

The mean value of the benefits calculated in the Italian Authority CBA are shown in Table 57.

Table 57 Mean values of benefits of the Italian Authority CBA

Mean Value of benefit related to the reliability emergency action [€]	768.3134
Mean Value of benefit related to the resilience emergency action [€]	9,327.3
Mean Value of benefit related to the reliability interruption costs [€]	35,569
Mean Value of benefit related to the resilience interruption costs [€]	207,090

Obtained the value of all the benefits, the Net Present value of total Savings (NPS) can be calculated.

$$NPS = B^{(res,int)} + B^{(rel,int)} + B^{(res,sea)} + B^{(rel,sea)} \tag{5.27}$$

Now the NPV can be calculated with the Equation (5.28).

$$NPV = NPS - NPC \tag{5.28}$$

As for the previous CBA these calculations have been repeated 1000 times, and the value of the final NPV is the mean value of all NPV calculated. The final value is shown in Table 58.

Table 58 NPV Italian Authority CBA

NPV without considering reliability	$-135{,}400$€
NPV considering reliability	$-86{,}000$€

VI. Conclusion

The results from the two CBAs give negative NPV, indicating losses in monetary terms for the network company who made the investment. The NPV values, without considering reliability, are shown in Table 59.

Table 59 NPV value without considering reliability

RIIO CBA: NPV without considering reliability [€]	$-163{,}200$
Italian Authority CBA: NPV without considering reliability [€]	$-135{,}400$

The NPV value derived from the RIIO CBA is more negative than the NPV value derived from Italian Authority CBA. Even considering the reliability, the results of NPV stay negative in both cases, as shown in Table 60.

Table 60 NPV value considering reliability

RIIO CBA: NPV considering reliability [€]	$-114{,}100$
Italian Authority CBA: NPV considering reliability [€]	$-86{,}000$

Due to the paucity of extreme climate events, network companies are reluctant to bear the cost of investments to improve resilience. In monetary terms, is more convenient to restore a network than prevent its disruption.

The different values of NPV are influenced by how the NPV is related to the investment. In the RIIO CBA the investment is divided in two parts, the *slow* money and the *fast* money, calculated with the Equation (3.20) and (3.21), respectively. The *fast* money represent for every year the portion of net benefit used for calculating the discounted net benefit, shown in Equation (3.22), of the year, whereas the *slow* money represents the portion of the net benefit used for the calculation of the depreciation, shown in the Equation (3.23), of the all the following years. With the capitalisation rate used in this thesis, shown in Table 46, the value of fast money is low, and the benefits related are small. If the capitalisation rate is set to 0.15, the value of fast money increases and the NPV value at the end of the CBA are less negative than the NPV calculated with the Italian Authority CBA. Table 61 shows the new NPV of the RIIO CBA. It is worth to note that the in the Italian Authority CBA this distinction between *slow* and *fast* money does not exist.

Table 61 New NPV

Cap_{rate}	0.15
RIIO CBA: new NPV value [€]	$-74{,}100$

The goal of the Italian Authority is to reduce the number of disruptions in case of extreme climate events. The results shown above emphasise the need for investments towards the network companies to help them improve network resilience by sharing the costs.

The method explained in this thesis can be used to evaluate the investment act to improve the resilience of the network due to different extreme climate events with a change of the faulted components and rate of fault of them.

This work may be the first steps for understanding how the legislative framework should move for making acceptable the resilience-based design by all the operators, by calibrating the needed incentives allowing the implementation of new fault clearing strategies and network components.

Appendix A

Environmental KPIs

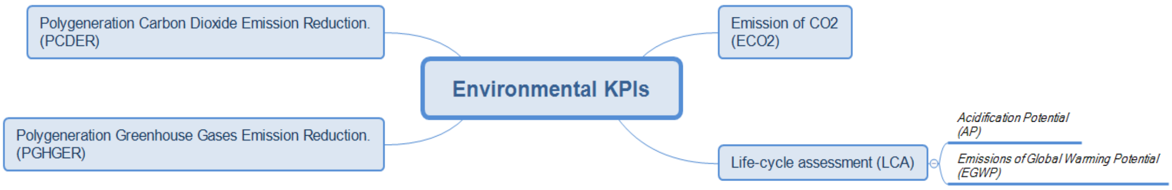

Figure 37 Environmental KPIs

CO2 emissions

This KPI is used to estimate the emissions of CO_2. The emissions of CO_2 (ECO_2) can be calculated as [42](2):

$$ECO_2 = \mu_{xx} \cdot m_{xxconsumed} \cdot F_{oss} \tag{1}$$

Where: μ_{xx} is the emission factor of the fuel used, $m_{xxconsumed}$ is the fuel consumed, F_{oss} is the oxidation factor of the fuel.

In case of multi-generation system connected to a distribution network, the evaluation of the emissions is based on the comparison between the mass of CO_2 emitted from the multi-generation system, and the mass which of CO_2would be emitted by considering the separate production of the same useful outputs. The KIPs are:

Polygeneration Carbon Dioxide Emission Reduction ($PCDER$) [43]:

$$PCDER = \frac{m_{CO_2}^{(F,SP)} - m_{CO_2}^{(F)}}{m_{CO_2}^{(F,SP)}} = 1 - \frac{\mu_{CO_2}^{(F)}.F}{\sum_{X\in \boldsymbol{X}} \mu_{CO_2}^{(X,SP)} \cdot F} \tag{2}$$

Where $m_{CO_2}^{(F,SP)}$: mass of CO_2 emitted from separate production; $m_{CO_2}^{(F)}$:mass of CO_2 emitted from multi-.generation systems, F: input fuel energy, $\mu_{CO_2}^{(F)}$.: equivalent emission factor, $\boldsymbol{X}$: set of energy vectors $X\epsilon\boldsymbol{X}$, $\mu_{CO_2}^{(X,SP)}$: equivalent emission factor for energy vectors X.

Poligeneration Greenhouse Gases Emission Reduction ($PGHER$) [43]

[2] In case of generation from different sources, this formula can be extended as summation of the emission of CO_2 from each source.

$$PGHGER = 1 - \frac{\sum_{p\in\mathbf{G}} \mu^{(F)}_{CO_2eq,p} . F}{\sum_{p\in\mathbf{G}} \sum_{X\in\boldsymbol{X}} (\mu^{(X,SP)}_{CO_2eq,p} \cdot X)} \tag{3}$$

Where: $\boldsymbol{G}$: is a set of GHG; p is a generic GHG;

$$\mu^{(X,SP)}_{CO_2eq,p} = GWP_p \cdot \mu^{(X)}_p \tag{4}$$

is the equivalent emission factor for a generic GHG (greenhouse gases), and the rest of terms is the same explain above.

Life cycle assessment (LCA)

Life-cycle assessment (LCA) is an objective way to determine potential environmental impacts of a product or service.

Four phase to complete a LCA analysis can be defined [44]:

- Goal and scope definition, in which the aim of the study, the functional unit and the system boundaries are described.
- Inventory analysis, which include a life cycle inventory (LCI) of system input/output data was made
- Life cycle impact assessment (LCIA), where system is studied to better understand their environmental impact
- Interpretation, where the results are studied.

To measure the environmental impact different indicators were used [45]:

Acidification (AP)

This indicator measures the impact of different acidifying pollutants:

$$AP = \sum_p A_p \cdot m_p \tag{5}$$

Where: A_p is the acidification potential for substance p emitted to the air; m_p is the emission of substance p to the air.

Emissions of Global Warming Potential (EGWP)

This indicator measures the mission of CO_2 thanks to the Global Warming Potential (GWP):

$$EGWP = \sum_{p} GWP_p \cdot m_p \tag{6}$$

Where: m_p is the emission of substance p to the air; GWP_p is the Global Warming Potential for substance p, integrated over a years.

Abiotic Depletion (AD)

This KPI measure depletion of nonrenewable resources [45]:

$$AD = \sum_{p} ADP_p \times m_p \tag{7}$$

With: ADP is the Abiotic Depletion Potential:

$$ADP_{fossilenergy} = \frac{DR_{fossil}}{(R_{fossil})^2} \times \frac{(R_{antimony})^2}{DR_{antimony}} \tag{8}$$

Where: ADP is the Abiotic Depletion Potential of fossil energy measured in kg antimony eq./ MJ fossil energy; $DR_{fossilenergy}$ is the de-accumulation, or fossil energy production, in MJ yr^{-1}; $R_{fossilenergy}$ is the ultimate reserve of fossil fuels in MJ; $R_{antimony}$ is the ultimate reserve of antimony, the reference resource, in kg; $DR_{antimony}$ is the de-accumulation of antimony, the reference resource, in kg yr^{-1}.

In case of complex substances, ADP_p can be measured as [45]:

$$AD = \sum_{p} Factor_p \times m_p = \sum_{p} \frac{Ex_p}{molew_p} \times m_p \tag{9}$$

Where: $Factor_p$ si the characterization factor for abiotic depletion of resource p based on the enxergy content; Ex_p is the exergy content of one mole of resource p and $molew_p$ is the mole weight of resource p.

Stratospheric Ozone Depletion (OD)

OD measure the emission of CFC-11 eq. for a substance i. [45]:

$$OD = \sum_{p} ODP_p \times m_p \tag{10}$$

With: ODP_p is the Ozone Depletion Potential for a substance p.

Human Toxicity (HT)

This KPI measure the toxicity of a substance p emitted to an emission compartment [45]:

$$HT = \sum_{p} \sum_{ecom} HTP_{ecom,p} \times m_{ecom,p} \tag{11}$$

Where: $HTP_{ecom,p}$ is the Human Toxicity Potential for substance p emitted to compartment $ecom$ (e.g. air, fresh water, seawater), $m_{ecom,p}$ is the emission of substance p to medium $ecom$.

Ecotoxicity

To measure the Ecotoxicity multiple KPIs are need, based of the emission compartment in study [45]:

$$FWAE = \sum_{p} \sum_{ecom} FAETP_{ecom,p} \times m_{ecom,p} \tag{12}$$

$$MAE = \sum_{p} \sum_{ecom} MAETP_{ecom,p} \times m_{ecom,p} \tag{13}$$

$$TE = \sum_{p} \sum_{ecom} TETP_{ecom,p} \times m_{ecom,p} \tag{14}$$

Where: $FWAE$ is the fresh water aquatic ecotoxicity, $FAETP_{ecom,p}$ is the fresh water aquatic ecotoxicity potential. MAE is the marine aquatic ecotoxicity; $MAETP_{ecom,p}$ is the marine aquatic ecotoxicity potential. TE is the terrestrial ecotoxicity; $TETP_{ecom,p}$ is the terrestrial ecotoxicity potential.

Eutrophication (EUT)

This KPI measure the Eutrophication of a substance [45]:

$$EUT = \sum_{p} EP_p \times m_p \tag{15}$$

Where: EP_p is the Eutrophicantion Potential for substance p emitted to air, water or soil.

Photo-oxidant formation (POF)

This KPI measures the oxidant formation [45]:

$$POF = \sum_{p} POCP_p \times m_p \tag{16}$$

Where: $POCP_p$ is the Photochemical Ozone Creation Potential for substance p.

Ionising Radiation (IR)

This KPI measure the damage created by radioactive releases [45].

$$IR = \sum_{ecom} \sum_{p} DamageFactor_{ecom,p} \times a_{ecom,p} \tag{17}$$

Where: $a_{ecom,p}$ is the activity of substance p emitted to compartment $ecom$; $DamageFactor_{ecom,p}$ is the characterisation factor for substance p emitted to $ecom$, measure in yr·kBq^{-1}.Year was used instead of DALYs to have all units as mentioned in SI

Technical KPIs

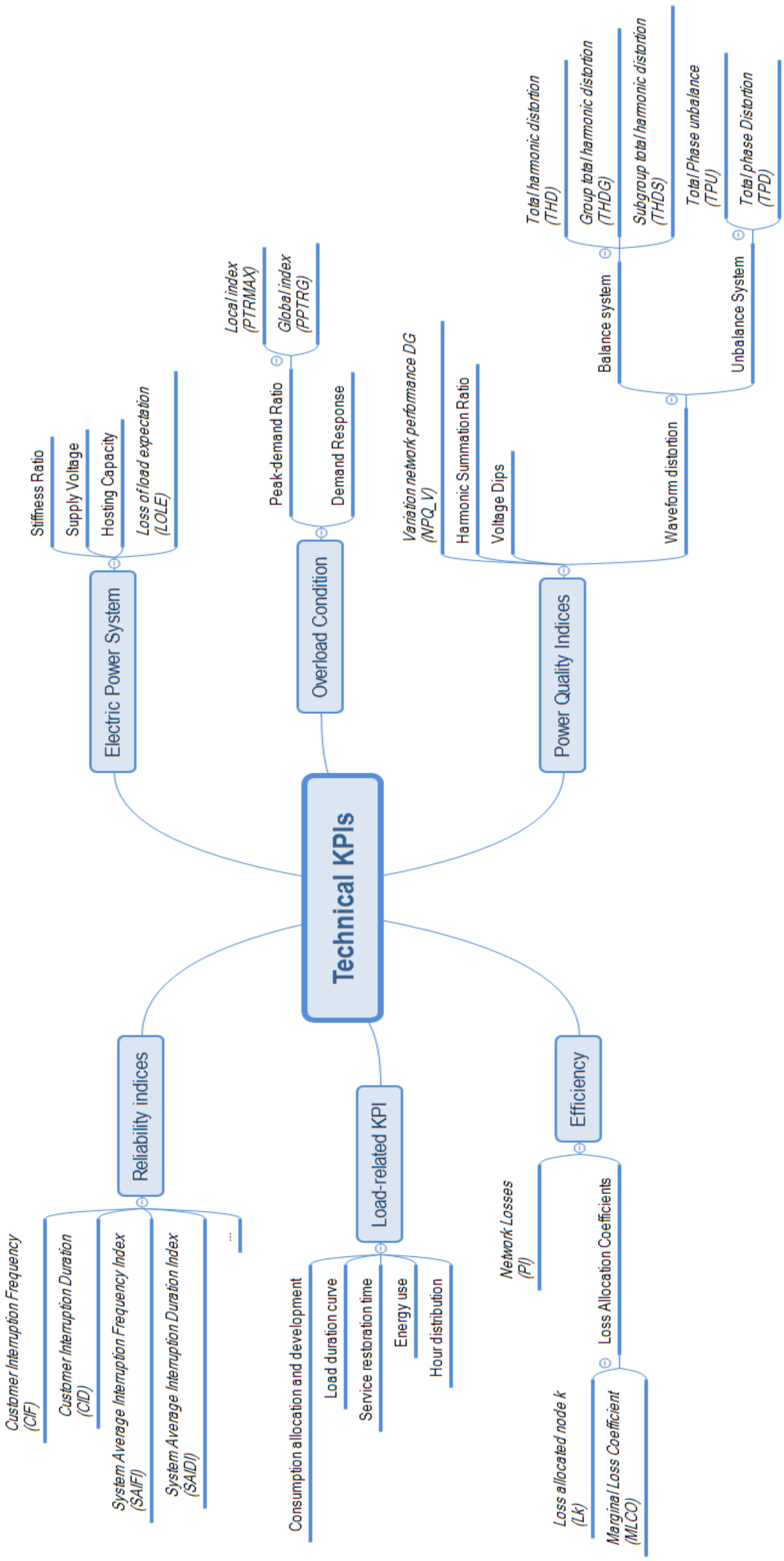

Figure 38 Technical KPIs

Overload Condition

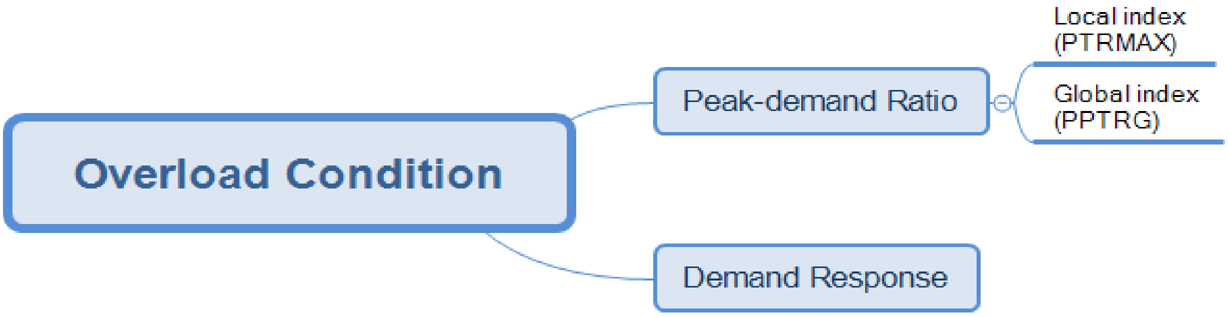

Figure 39 Overload Condition KPIs

Peak-Demand Ratio

This indicator gives an information about the substation transformers to prevent overloading conditions. It is possible to use a priori information thanks to contract power and energy consumption of the customers supplied by each substation. Considering each hour *te*=1,2,....,24 for the day and each node *k*= 1,2,....,*k*, the KPIs can be either *local* or *global*:

- *Local* index: ratio between the hourly power during the day and the rated power of the transformers [43].

$$PTRMAX = \max_{te}\left(\frac{P_k(te)}{P_{Rk}(te)}\right) \tag{18}$$

- *Global* index: ratio between the maximum loading of the substation transformers at a given hour *te* and the rated power of the transformers [43]

$$PTRG(h) = \max_{k}\left(\frac{P_k(te)}{P_{Rk}(te)}\right) \tag{19}$$

Demand Response

Peak-demand ratio KPI can be extended to customers. In that case maximum consumption is the variable measured during the period of reporting. The consumption can be measured for a single customer or for all costumers. In the last years Demand Response (DR) has developed to have a new impact of the network. Customers participating in the DR will be paid to change their electricity demand when peak demand is too high.

$$CD = Max\ (e_i) \tag{20}$$

Where CD is the Demand of the Customers, e_i is the consumption load.

Different rates been developed over time as:

- Time-Of-Use (TOU), the price change during the time but with coefficients fixed for a year.
- Real-Time Pricing (RTP), the price changes every hour and coefficients also.
- Spot Pricing (SP), price is defined right before the consumption

In case of TOU the cost of the power demand during the planning horizon is [46]:

$$c_{DT} = \max_{te} \frac{\sum_{t_1=te}^{te+l-1} d_{SYS}(t_1) \cdot c_D(t_1)}{l} \tag{21}$$

Where $c_D(t_1)$ is the TOU demand rate during time slot t_1; d_{SYS} is the power demand of the system during time slot t_1; l is the ceiling integer number of the time slots in any 15-minute interval.

Efficiency KPIs

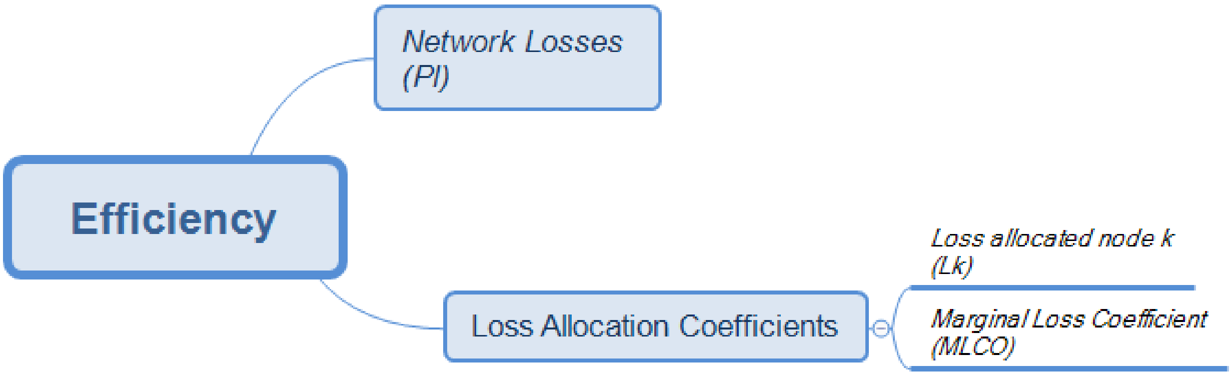

Figure 40 Efficiency KPIs

The KPIs about efficiency are of two types:

- Network losses, that is the losses in all distribution network
- Loss allocation coefficients, that refer the losses to every node (generations or load)

Network Losses

Network losses can be calculated as [43]:

$$P_l(X_c) = \tau \cdot \sum_{t_e=1}^{T_e} \sum_{b \in B} R_b \cdot \left| \bar{I}^{(b)}(t_e) \right|^2 \tag{22}$$

Where: $t_e = 1,2,\dots,T_e$ is time steps, $b = 1,2,\dots,B$ is the branch of the network configuration X_c; τ is:

$$\tau = \frac{h}{60} \tag{23}$$

In which t_e is expressed in minutes

Loss allocation coefficients

In distribution system to determinate the loss allocation we need to consider the slack node is the higher voltage system, therefore the slack node is not included in loss allocation.

For *radial system*, the Branch Current Decomposition Method can be used. The Equation to estimate the losses allocated to the node k is [43]:

$$L_k = Re\left(\bar{I}_k^{*} \sum_{b \in \boldsymbol{B_k}} R^{(b)} \cdot \bar{I}^{(b)}\right) \tag{24}$$

Where: $\bar{I}_k^{\,*}$ is the node current injected into node k; $R^{(b)}$ is the resistance of the series impedance of the π model of branch b=1,…,B; $\bar{I}^{(b)}$ is the current flowing into the series of resistance $R^{(b)}$; $\boldsymbol{B_k}$ is the set containing the nodes supplied from branch b.

To find the total losses of the system is sufficient to sum the allocated losses.

For *weakly-meshed distribution system,* a different method must be used, i.e. the modified bus admittance matrix method. The losses are allocated to the load node k = 1,…,K-1 because the slack node must be not considered [43].

$$L_k = Re\left(\bar{I}_k^{*} \sum_{b=1}^{B} \boldsymbol{i}^{*T}\left(\boldsymbol{c}^{(b)^{*}T} \cdot R^{(b)} \cdot \boldsymbol{c}^{(b)}\right)\right) \tag{25}$$

With: $R^{(b)}$ is the resistance of the branch b =1,…,B-1; $\boldsymbol{c}^{(b)}$ is the vector containing the b^{th} column of the node-to-branch incidence matrix; $\boldsymbol{i}^{*T}$ is the vector containing the node currents.

L_k can be interpreted as *marginal loss coefficient*. Marginal loss coefficient (*MLC*) is used to measure the marginal losses in a given instant. In each node where *MLC* is measured small increase in the active or reactive generation (or load) leads to an increase or a reduction of the total system losses. This variation depends on the net node power. If L represents the total losses (i.e. the sum of all L_k for k = 1,…,K) , the superscript (0) is the present configuration and P_k is the power at node k [47]:

$$MLC = L - L^{(0)} = \rho_{Pk} \left(P_k - P_k^{(0)} \right) \tag{26}$$

Where: ρ_{Pk} is a coefficient proportional to the losses derivative before and after the variation of the configuration.

Benefits and penalties can be obtained with variation of generators or load. Benefits for load reduction are then obtained with:

- Net power increases and $\rho_{Pk} < 0$
- Net power decreases and $\rho_{Pk} > 0$

To see the difference between before (pre) and after (post) the power variation at node k, this Equation can be used [43]:

$$\Delta P_k^{(post)} - \Delta P_k^{(pre)} \cong L_k \cdot \left(P_{g,k}^{(post)} - P_{g,k}^{(pre)} - P_{d,k}^{(post)} + P_{d,k}^{(pre)} \right) \tag{27}$$

If the left-hand side is negative, then the total power losses were reduced.

Power quality variation indices KPIs

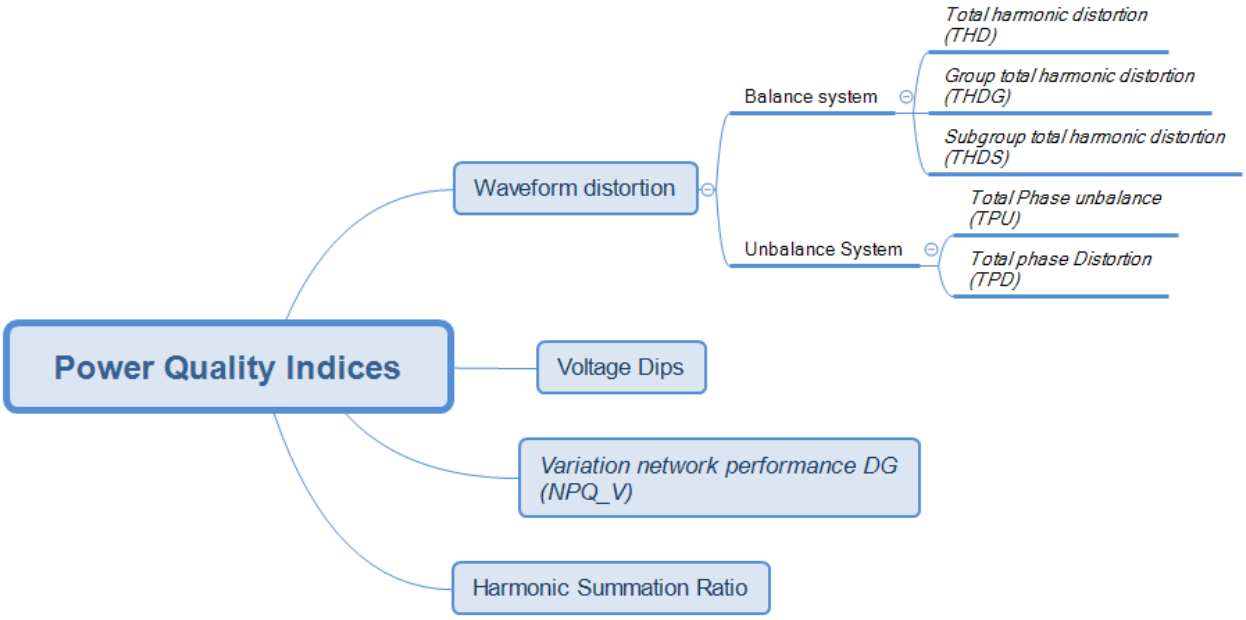

Figure 41 Power Quality Variation Indices KPIs

Called X a value of a single or global index, power quality variation indices describe effects about an operation in the network [48]:

$$X\_V = \frac{Y_{old} - Y_{new}}{Y_{old}} \cdot 100 \tag{28}$$

Where: Y_{new} is value after the new operation; Y_{old} is the value of index before the new operation.

In case of new DG, with this index NPQ_V can be obtained. NPQ_V evaluate the variation of the network performance in presence of a DG [48].

$$NPQ\_V = \frac{X\_V}{P_{DG}} = \frac{Y_{old} - Y_{new}}{Y_{old} P_{DG}} \cdot 100 \tag{29}$$

Harmonic Summation Ratio

This index represents the effect of the presence of N inverters connected to the PCC for each harmonic order h=1,….,H [48];

$$\zeta_h^{(N)} = \frac{I_h^{(N)}}{I_h^{(1)}} \frac{P_{rINV,AC}^{(1)}}{\sum_{i=1}^{N_i} P_{rINV,AC}^{(i)}} \tag{30}$$

Where $I_h^{(1)}$ is the current waveform of one of the PV inverters in the frequency domain; $I_h^{(N)}$ is the current of all inverters seen from the PCC in the frequency domain; $P_{rINV,\,AC}^{(1)}$ is the rated power of the individual inverter monitored; $P_{rINV,AC}^{(i)}$ is the rated power of the inverters n=1,...,N_i.

Waveform distortion

Balance system

Numerous indices can be used to describe waveform distortion. Some of them are:

- The individual harmonics (A_h);
- The total harmonic distortion factor (THD);
- The individual interharmonics ($THDG$);
- The total interhharmonic distortion factor ($THDS$).

The first one (A_h) is the ratio between the RMS value of harmonic component of order h, X_h, and the RMS value of the fundamental component, X_1, of the considering waveform [49]:

$$A_h = \frac{X_h}{X_1} \tag{31}$$

The Equation of the total harmonic distortion factor (THD) is [49]:

$$THD = \frac{\sqrt{\sum_{h=2}^{H} X_h^2}}{X_1}\, 100 \tag{32}$$

Where : $\sqrt{\sum_{h=2}^{H} X_h^2}$ is the RMS of the harmonic content, H is the highest harmonic taken into consideration.

To value the interharmonics, grouping or subgrouping are needed. There are two ways to find waveform distortion in case of interhharmonics:

- the group total harmonic distortion ($THDG$) is define as [50]:

$$THDG = \sqrt{\sum_{h=2}^{H} \left(\frac{G_{gh}}{G_{g1}}\right)^2} \tag{33}$$

Where: G_{gh} is the RMS value of the harmonic group order associated with harmonic order h [50]:

$$G_{gh} = \sqrt{\frac{X^2_{(10h-5)\Delta f}}{2} + \sum_{i=-4}^{4} X^2_{(10h+i)\Delta f} + \frac{X^2_{(10h+5)\Delta f}}{2}} \quad (34)$$

With $X_{(10h+i)\Delta f}$ is the RMS value of the spectral components at $(10h + i)\Delta f$ frequency.

- The subgroup total harmonic distortion ($THDS$) [50]:

$$THDS = \sqrt{\sum_{h=2}^{H} \left(\frac{G_{s\,gh}}{G_{s\,g1}}\right)^2} \quad (35)$$

Where $G_{s\,gh}$ is the RMS value of the harmonic subgroup order associated with harmonic order h [50]:

$$G_{s\,gh} = \sqrt{\sum_{i=-1}^{1} X^2_{(10h+i)\Delta f}} \quad (36)$$

Unbalance system

In case of unbalance system, the indicators are different:

- Total Phase Unbalance (*TPU*)
- Total Phase Distortion (*TPD*) that is the *THD* extended to unbalance system

Unbalance system is a three-phase system that has not a perfectly balanced load in all three-phases, so current, voltage and impedances are difference in each phase. To analyze an unbalance system three balanced systems are used. These balanced systems are positive, negative and zero sequence. Generally speaking, all systems can be written as sum of this three system.

Equation of *TPD* is [50]:

$$TPD = \frac{\sqrt{\sum_{h=2}^{H}\left[\left(I_{T1}^{(h)}\right)^2 + \left(I_{T2}^{(h)}\right)^2 + \left(I_{T3}^{(h)}\right)^2\right]}}{\sqrt{(I_{T1}^{1})^2 + (I_{T2}^{1})^2 + (I_{T3}^{1})^2}} \quad (37)$$

Where [50]:

$$\begin{vmatrix} \bar{I}_{T1}^{(h)} \\ \bar{I}_{T2}^{(h)} \\ \bar{I}_{T3}^{(h)} \end{vmatrix} = \frac{1}{3} \begin{vmatrix} 1 & e^{j\frac{2\pi}{3}} & e^{j\frac{4\pi}{3}} \\ 1 & e^{j\frac{4\pi}{3}} & e^{j\frac{2\pi}{3}} \\ 1 & 1 & 1 \end{vmatrix} \begin{vmatrix} \bar{I}_{a}^{(h)} \\ \bar{I}_{b}^{(h)} \\ \bar{I}_{c}^{(h)} \end{vmatrix} \quad (38)$$

With h=1,...,H is the harmonic order, and $\bar{I}_a^h, \bar{I}_b^h, \bar{I}_c^h$ are the three-phase current at h harmonic order.

TPU is [50]:

$$TPU = \frac{\sqrt{\sum_{h=0}^{H}\left[\left(I_{T2}^{3h+1}\right)^2 + \left(I_{T3}^{3h+1}\right)^2 + \left(I_{T1}^{3h+2}\right)^2 + \left(I_{T3}^{3h+2}\right)^2 + \left(I_{T1}^{3h+3}\right)^2 + \left(I_{T2}^{3h+3}\right)^2\right]}}{\sqrt{\sum_{h=0}^{H}\left[\left(I_{T1}^{3h+1}\right)^2 + \left(I_{T2}^{3h+2}\right)^2 + \left(I_{T3}^{3h+3}\right)^2\right]}} \quad (39)$$

Where: H is the maximum harmonic order

Voltage dips

Voltage dips are a short duration reduction in RMS voltage.

To estimate the number of voltage dips in case of short-circuit current, this Equationtion can be used:

- Find the current and voltage of three-phase balanced system in positive, negative and zero sequence, in case of single-phase fault, two-phase fault, three-phase fault.
- Then calculate the dip matrices [51].
- At the end find the number of dips $\left(\boldsymbol{N}_{\boldsymbol{dip}}^{(X)}\right)$ [48]:

$$\boldsymbol{N}_{\boldsymbol{dip}}^{(X)} = \left(\boldsymbol{I}_{\boldsymbol{k}} \otimes \boldsymbol{i}_{\boldsymbol{k}}^{T}\right) \cdot \left(\boldsymbol{D}_{\boldsymbol{dip}}^{(X)} \cdot \boldsymbol{i}_{\boldsymbol{k}}\right) \quad (40)$$

Where: $\boldsymbol{I}_{\boldsymbol{k}}$ is a matric containing the short-circuit current of the network in sequence component, $\boldsymbol{i}_{\boldsymbol{k}}$ is an auxiliary vector with dimension 1xN whose elements are unitary values, $\boldsymbol{D}_{\boldsymbol{dip}}^{(X)}$ is dip-markers matrix for an assigned threshold X.

Electric Power System KPIs

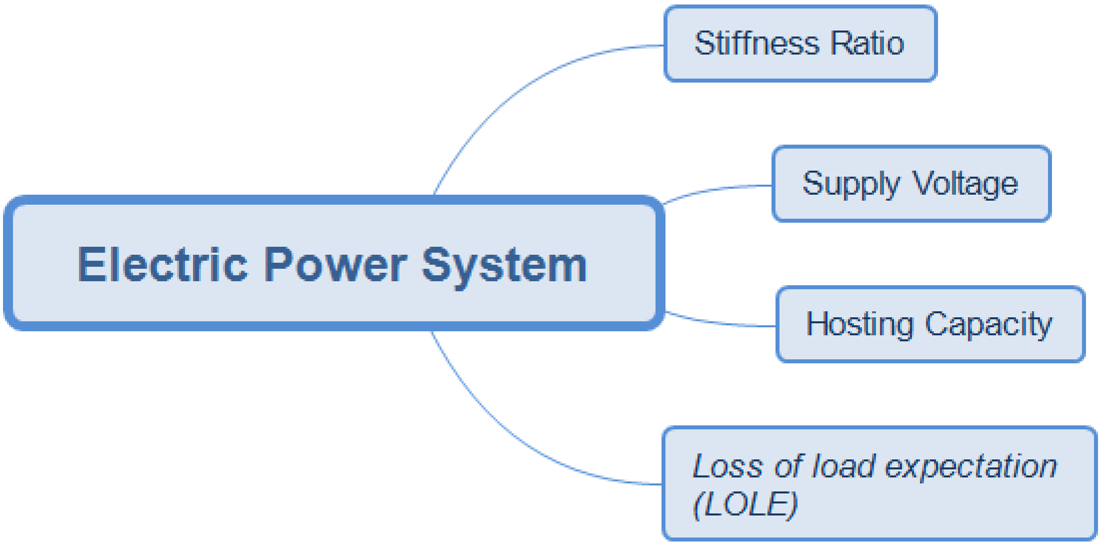

Figure 42 Electric Power System KPIs

LOLE

LOLE is loss of load expectation. It can be calculated [52]:

$$LOLE = LOLP \times 365 \qquad (41)$$

Where LOLP is the probability of load loss in a single day. 365 is the day in a year.

Hosting capacity

The maximum connection of a distributed energy resources (DER) accepted by the energy network system without problem of reliability or power quality is represented by the hosting capacity. To define hosting capacity is needed to calculate the amount of RES (renewable energy sources) generation beyond which the problem is no more acceptable. Indices that can be used are:

- The probability of occurrence of overvoltages (or undervoltages) at the customer level calculated with a Monte-Carlo Simulations.
- The probability of event of overcurrent calculated by load flow.

Considering a new connection of a generator to the distribution system, another method to measure hosting capacity is [53]:

$$P_{max} = \frac{U^2}{R} \times \delta_{max} \qquad (42)$$

Where: U is the nominal voltage, R is the resistance of a wire, and δ_{max} is [53]:

$$\delta_{max} = \frac{\Delta_{max}}{U} 100 \tag{43}$$

And Δ_{max} is the absolute voltage margin, that is the maximum variation of voltage to remain in the voltage magnitude limits (often the 5-8% around the nominal voltage).

Stiffness ratio

The stiffness ratio is an indicator of the strength of the Electric Power System (EPS) in case of distributed energy resources (DER) calculate at the point of common coupling (PCC). The Equation is [43]:

$$\rho = 1 + \frac{S_{sc,EPS}}{S_{sc,DER}} \tag{44}$$

Where S_{sc} is the short circuit power [kVA].

Higher value mean that EPS has a high ability to withstand voltage deviations, therefore high strength of the network.

Supply Voltage

Slow variation

Slow voltage variations of supply voltage are measured, in a single place, in a long period of time to avoid instantaneous errors in the measurement. This can be done for a segment of distribution system with other indices:

- The percentage of sites that exceeds the objectives in a determinate period;
- The average or median value of the site indices;
- The value of the site index not exceeded for a fixed percentage (90,95 or 99%) of sites

The European Norm EN 50160-2011 [54] quantifies slow voltage variations using the 10-min mean RMS value and considering a week as the minimum measurement period; in particular, for the medium voltage networks, the 99th percentile of the 10-min mean RMs value over one week is considered the minimum limit.

Reliability KPIs

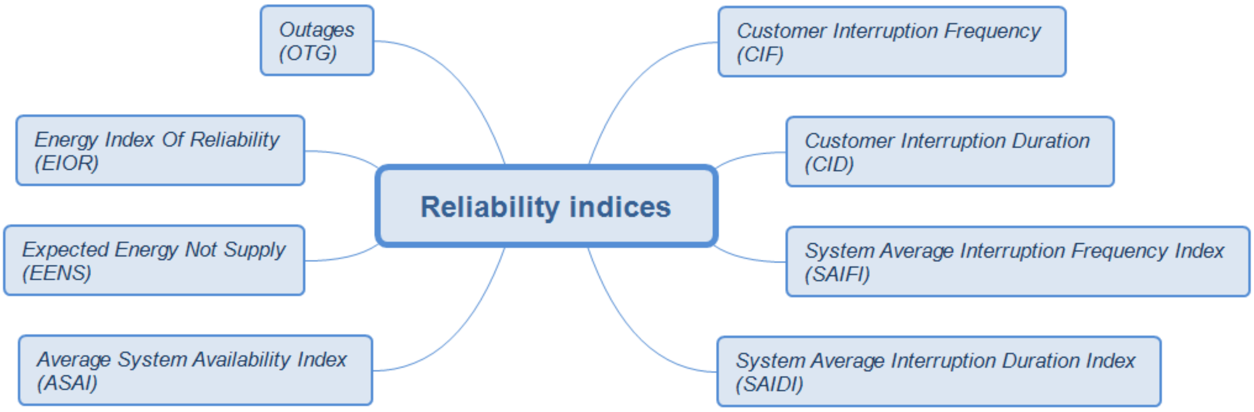

Figure 43 Reliability Indices

The restoration procedure is composed of different stages during which a different number of customer is supplied.

Customer Interruption Frequency (CIF)

At each load node and for each stage Customer Interruption Frequency (*CIF*) can be calculated [48]:

$$CIF_{k,t} = \lambda \sum_{z\epsilon \boldsymbol{Z}} Nint_{k,t_s,z} \tag{45}$$

Where: λ is the average failure rate of the component (i.e. branch); $Nint_{k,t_s,z}$ is the total number of customers in node i at stage t_s; $\boldsymbol{Z}$ is the set of interruption type.

Customer Interruption Duration (CID)

Customer Interruption Duration (*CID*) is measured at each load node and for each stage [48]:

$$CID_{k,t} = \lambda \sum_{z\epsilon \boldsymbol{Z}} Nint_{k,t_s,z} \cdot Dint_z \tag{46}$$

Where: $Dint_z$ is the duration of interruption type *z.*

System Average Interruption Frequency Index (SAIFI)

SAIFI is a measure of how many sustained interruptions an average customer will experience over each stage [44]:

$$SAIFI_t = \frac{\lambda \sum_{k\epsilon \boldsymbol{\Omega}_{k,t}} \sum_{z\epsilon \boldsymbol{Z}} Nint_{k,t_s,z} \cdot Nq_{i,t_s}}{\sum_{k\epsilon \boldsymbol{\Omega}_{L,B,t}} Nq_{i,t_s}} \tag{36}$$

Where: λ is the average failure rate of the component (i.e. branch); $Nint_{i,t_s,z}$ is the total number of customers in node k at stage t_s; $\boldsymbol{Z}$ is the set of interruption type; Nq_{k,t_s} is the Total number of customers in node k at stage t_s; $\boldsymbol{\Omega}_{\boldsymbol{k},t_s}$ is the index set of load nodes in each stage t_s; $Dint_z$ is the duration of interruption type *z.*

System Average Interruption Duration Index (SAIDI)

SAIDI is a measure of how many interruption hours an average customer will experience over each stage [48]:

$$SAIDI_t = \frac{\lambda \sum_{i \epsilon \Omega_{k,t}} \sum_{z \epsilon \boldsymbol{Z}} Nint_{i,t_s,z} \cdot Dint_z \cdot Nq_{i,t_s}}{\sum_{i \epsilon \Omega_{L,B,t}} Nq_{i,t_s}} \tag{37}$$

Where: λ is the average failure rate of the component (i.e. branch); $Nint_{i,t_s,z}$ is the total number of customers in node i at stage t_s; $\boldsymbol{Z}$ is the set of interruption type; Nq_{i,t_s} is the Total number of customers in node i at stage t_s; $\boldsymbol{\Omega}_{\boldsymbol{k},t_s}$ is the index set of load nodes in each stage t_s, $Dint_z$ is the duration of interruption type *z.*

Customer Average Interruption Duration Index (CAIDI)

Customer Average Interruption Duration Index (*CAIDI*) measure the average time that it takes to restore service:

$$CAIDI = \frac{SAIDI}{SAIFI}$$

Average System Availability Index (ASAI)

ASAI is the ratio of total customer hours in which service is available divided by the total customer hours in the time period for which the index is calculated for each stage [48]:

$$ASAI_t = \left[1 - \frac{SAIDI_{t_s}}{8760}\right] 100 \tag{38}$$

Expected Energy Not Supply (EENS)

For each stage *EENS* can be calculated [48]:

$$EENS_t = \sum_{k \epsilon \Omega_{k,t}} \sum_{LL \epsilon \prod_{\boldsymbol{LL}}} CID_{k,t} \cdot \frac{D_{LL}}{24} \cdot DEM_{k,t,LL} \tag{39}$$

Where: CID_{k,t_s} is the customer interruptions duration index for node k at stage t_s; D_{LL} is the duration in hours of each load level LL; LL is the load level index; $DEM_{i,t_s,LL}$ is the power demand at node k at each load level LL of the stage t_s; $\prod_{LL}$ is the index set of load levels; $\boldsymbol{\Omega_{k,t}}$ is the index set of load nodes in each stage t.

Energy Index Of Reliability (EIOR)

EIOR Is the ratio between EENS and the system Total Energy Demanded (*TED*) [52]:

$$EIOR = \frac{EENS}{TED} \tag{40}$$

Outages (OTG)

This KPI is the ratio between unplanned outages (*UO*) and the total outages (*TO*) in the network [55]

$$OTG = \frac{UO}{TO} \tag{41}$$

Load-related KPI

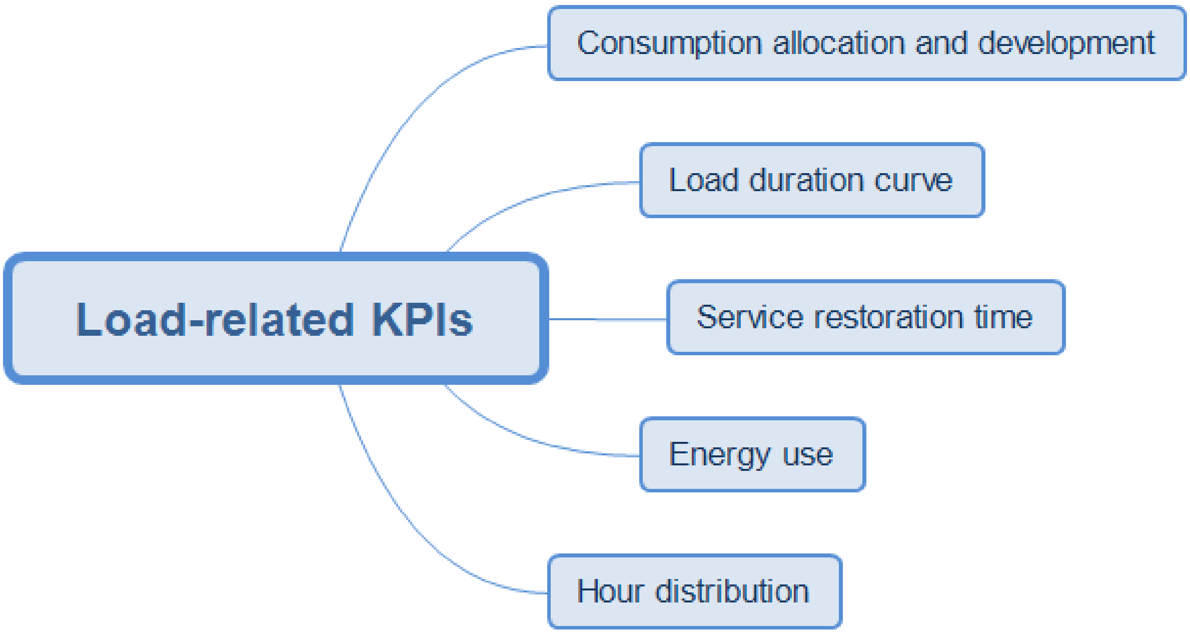

Figure 44 Load-related KPIs

Service restoration time

This is the time elapsed from when a disturbance occurs until service is restored to customers

Energy use

This KPI indicates a graphical representation of daily load energy consumption in a specific area [56]:

$$EnergyUse = [Loadenergy_{hour,i}] \tag{42}$$

Where $Loadenergy_{hour,i}$ is the load power demand in a specific hour of the day, *i* is from *1* to *n* load.

Load duration curve

This KPI gives an overview about the duration of peak demand for each load during a certain period in a specific area [56].

$$Reference_{load_{consumption}} = \{LoadCurve_{hour,i}\} \tag{43}$$

Where $LoadCurve_{hour,i}$ is the reference of the load consumption during each hour, from 1 to *n* load.

Hour distribution

This KPI show the hourly energy distribution of the load [56].

$$HD = \{Load_{hour,i}\} \tag{44}$$

Where $Load_{hour,i}$ is the daily *i* load (from 1 to *n)* consumption in a specific hour.

Consumption allocation and development

This index measure how much every load needs as a power demand during reporting period [56]:

$$CAAD = \int_{ts}^{tf} cp(t_e) \cdot t_e \tag{45}$$

Where: *cp* is the consumption of power measurement values of one load, *t* is the reporting period between *ts=tstart , tf=tfinal*.

With this index the total consumption E_c can be measured [56]:

$$E_c = \sum_{i=1}^{n} CAAD_i \tag{46}$$

Where: $CAAD_i$ is the individual energy consumptions of *1* to *n* loads during the period of reporting.

Other KPI

Number of transformers and number of LV feeders installed per substation.

Number of the connected customers and sensitivity, importance of the area supplied with the MV/LV PDS.

PDS means public distribution substations transformer.

Economic KPIs

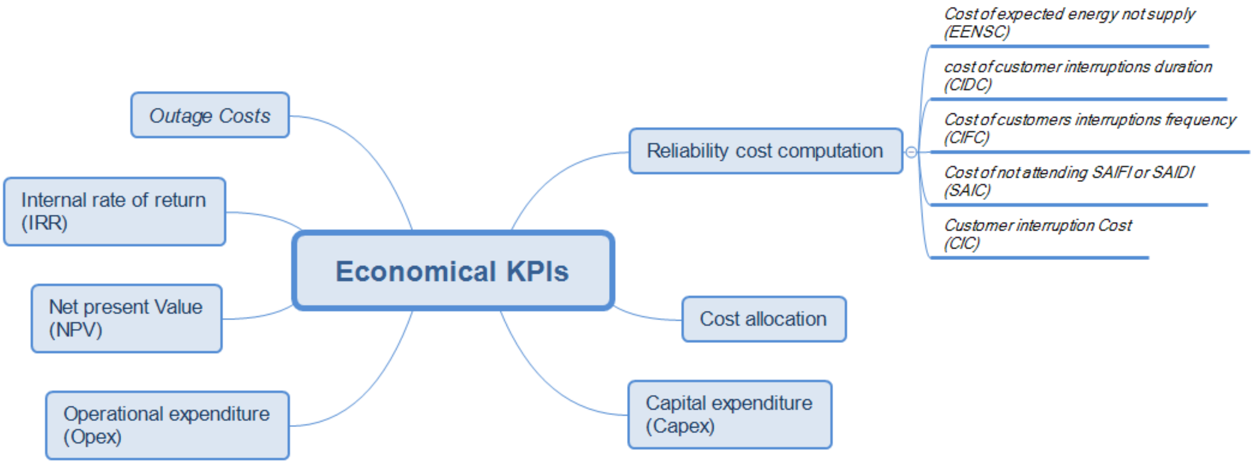

Figure 45 Economical KPIs

Reliability cost computation

The cost of non-supplied energy can be considered either from the distribution companies' viewpoint or from the customers' viewpoint

EENSC

From perspective of distribution companies, the cost at each stage of the Expected Energy Not Supplied (*EENS*) is [48]:

$$EENSC_t = \sum_{k\epsilon\Omega_{k,t}} \sum_{LL\epsilon\prod_{LL}} CID_{k,t} \cdot C_{LL}^{SS} \cdot \frac{D_{LL}}{24} \cdot DEM_{k,t,LL} \tag{47}$$

Where: $CID_{k,t}$ is the customer interruptions duration index for node i at stage t; D_{LL} is the duration in hours of each load level LL; LL is the load level index; $DEM_{k,t,LL}$ is the power demand at node k at each load level LL of the stage t; $\prod_{LL}$ is the index set of load levels; $\boldsymbol{\Omega_{k,t}}$ is the index set of load nodes in each stage t; C_{LL}^{SS} is the cost of energy supplied by substations at load level LL

Cost of costumer interruptions duration (CIDC) & Cost of costumer interruption frequency (CIFC)

The *CID* and *CIF* costs at each stage are [48]:

$$CIDC_t = \mu \sum_{i \epsilon \Omega_{k,t}} \left[\left(CID_{k,t} - CID_p\right) \sum_{LL \epsilon \prod_{LL}} C_{LL}^{SS} \cdot \frac{D_{LL}}{24} \cdot DEM_{i,t_s,LL} \right] if \left(CID_{k,t} > CID_p\right) \quad (48)$$

$$CIFC_t = \mu \sum_{i \epsilon \Omega_{k,t}} \left[\left(CIF_{k,t} - CIF_p\right) \sum_{LL \epsilon \prod_{LL}} C_{LL}^{SS} \cdot \frac{D_{LL}}{24} \cdot DEM_{i,t,LL} \right] if \left(CIF_{k,t} > CIF_p\right) \quad (49)$$

Where: $CID_{k,t}$ is the customer interruptions duration index for node *k* at stage t_s; D_{LL} is the duration in hours of each load level *LL*; *LL* is the load level index; $DEM_{kt_s,LL}$ is the power demand at node *k* at each load level *LL* of the stage t_s; $\prod_{\boldsymbol{LL}}$ is the index set of load levels; $\boldsymbol{\Omega_{k,t}}$ is the index set of load nodes in each stage t_s; C_{LL}^{SS} is the cost of energy supplied by substations at load level *LL;* μ is the penalty factor settled by regulation for not attending *CIF* or *CID*; CID_p is the customer interruption duration target settled by regulation; CIF_p is the customer interruption frequency target settled by regulation.

SAIC

Cost of not attending *SAIFI* or *SAIDI (SAIC)* at each stage is [48]:

$$SAIC_t = \upsilon \sum_{k \epsilon \Omega_{k,t}} \sum_{LL \epsilon \prod_{LL}} 8760 \cdot C_{LL}^{SS} \cdot \frac{D_{LL}}{24} \cdot DEM_{k,t,LL} \quad if \left(SAIFI_t > SAIFI_p\right) or \left(SAIDI_t > SAIDI_p\right) \quad (50)$$

Where: D_{LL} is the duration in hours of each load level *LL*; *LL* is the load level index; $DEM_{k,t,LL}$ is the power demand at node *k* at each load level *LL* of the stage *t*; $\prod_{\boldsymbol{LL}}$ is the index set of load levels; $\boldsymbol{\Omega_{k,t}}$ is the index set of load nodes in each stage *t*; C_{LL}^{SS} is the cost of energy supplied by substations at load level *LL;* υ is the penalty factor settled by regulation for not attending *SAIFI* or *SAIDI*; $SAIFI_p$ is the system average interruption frequency index target settled by regulation; $SAIDI_p$ is the system average interruption duration index target settled by regulation.

CIC

The customer interruption cost (*CIC*) due to outages in year *t* is [48]:

$$CIC_t = \lambda \sum_{k \epsilon \Omega_{k,t}} \sum_{LL \epsilon \prod_{LL}} \sum_{q \epsilon \boldsymbol{Q}} \sum_{z \epsilon \boldsymbol{Z}} Nint_{k,t,z} \cdot Dint_z \cdot CC_{q,z} \cdot class_{k,t,q} \cdot \frac{D_{LL}}{24} \cdot DEM_{k,t,LL} \quad (51)$$

Where: λ is the average failure rate of the component (i.e. branch) ; $Nint_{k,t,z}$ is the total number of customers in node *k* at stage *t*; $\boldsymbol{Z}$ is the set of interruption type; *;* $\boldsymbol{\Omega_{k,t}}$ is the index set of load nodes in each stage t; LL is the load level index; $DEM_{k,t,LL}$ is the power demand at node k at each load level LL of the stage t; $\prod_{LL}$ is the index set of load levels; $\boldsymbol{Q}$ is the index set of customer sector; D_{LL} is the duration in hours of each load level LL; $Nint_{k,t,z}$ is the total number of customers in node k at stage t; ; $Dint_z$ is the duration of interruption type z; $CC_{q,z}$ is the cost of an interruption z associated with customer sector q; $class_{k,t,q}$ is the percentage of customer sector q at node k for each stage t.

Outage Costs

Outage cost (OUC) is composed of customer interruption cost (CIC) and the network repair cost (NCR) [57]:

$$OUC = CIC + NRC(\lambda_i, CR_i)$$

Where: CR_i is the repair cost of a single component, i=1,...,N_c is the N_c component of the network, λ is the average failure rate of the ith component

This KPI evaluates the total cost in a day to how costly is the distribution in terms of energy consumption, and to incite end user to reduce their power demand.

Investment Analysis

NPV

Net Present Value is the balance at t=0 of all the discounted cash flows during the lifetime of an investment [58]:

$$NPV = \sum_{y=1}^{Y} \frac{f_y}{(1+r)^y} - \sum_{y=1}^{Y} \frac{I_y}{(1+r)^y} \tag{52}$$

Where I_y are the investment at y^{th} years; n is the duration in year, cash flows at the y^{th} is f_y.

IRR

If NPV=0 then r=IRR internal rate return [58]:

$$0 = \sum_{y=1}^{Y} \frac{f_y}{(1+IRR)^y} - \sum_{y=1}^{Y} \frac{I_y}{(1+IRR)^y} \tag{53}$$

Social KPIs

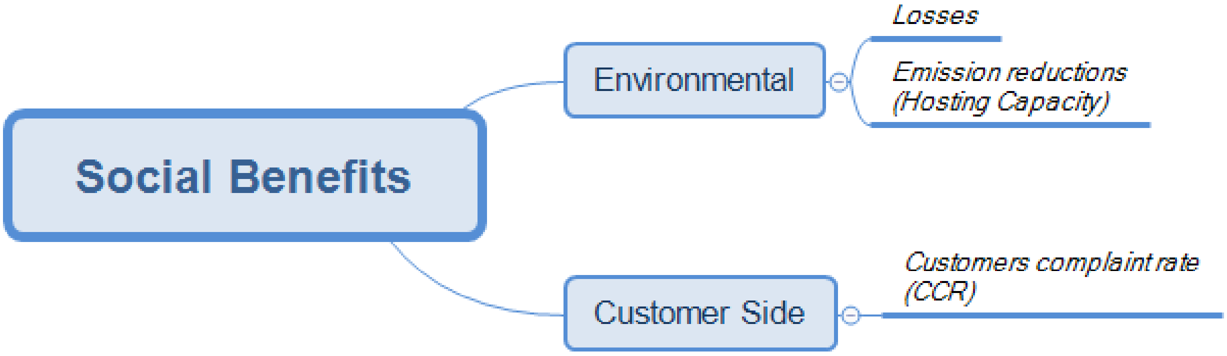

Figure 46 Social Benefits

Customers complaint rate

It is the number of unsatisfied customers [59]:

$$CCR = \frac{Amount\ of\ complained\ customers}{Total\ customers} \cdot 100 \tag{54}$$

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