CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

Proceedings of
RSEEC 2016
Innovation for efficient and effective management, solutions for power systems of the future!

Organized by:

Transelectrica®
Societate Administrată în Sistem Dualist

UNIVERSITATEA POLITEHNICA DIN BUCUREŞTI 1818

Romanian National Committee "CIGRE"
33, Gen. Gh. Magheru Blvd., postal code RO-010325, Bucharest 1
Correspondence Address: Str. Olteni, Nr. 2 - 4, RO-030786, Bucharest, Romania
Registration no. with the National Trade Register - 173/2007 – fiscal code: 20769417
Phone: +4 021 303 59 56; Fax: +4 021 303 58 30; www.cigre.org.ro

ISSN 2392 – 716X

CONTENTS

CIGRE Regional South-East European Conference

RSEEC 2016 (3rd edition)

October 10th - 12th 2016
University "Politehnica" of Bucharest, Romania

FOREWORD

On behalf of the Romanian National Committee of CIGRE, it is our great pleasure to welcome our distinguished guests of the third edition of CIGRE Regional South-East European Conference (RSEEC 2016), taking place in Bucharest, Romania, during October 10^{th} – 12^{th}, 2016.

RSEEC 2016 is organized by the CIGRE's Romanian National Committee, as organizer, CNTEE Transelectrica (*the Romanian TSO*) and University "Politehnica" of Bucharest, as co-organizers - with kind support of CIGRE Paris.

At its third edition, it is a major biennial event in power systems that provides an exceptional venue to CIGRE members and interested parties for presenting: ***Innovation for efficient and effective management, solutions for power systems of the future!***

The conference brings together power systems engineers, decision makers, economists, academics and others with interest in the domain. The conference also promotes CIGRE as a strong technical organization, capable of contributing to the technical expertise and know-how through its study committees, conference proceedings and the technical documents.

Main Topics include: ***1) State of the Technology for electrical networks of the future; 2) Electricity – key factor for society development; 3) Challenges in education of power system workforce.***

We would like to give again a warm welcome to all RSEEC 2016 conference participants and to wish a successful and enjoyable meeting. We hope that everyone will find the RSEEC 2016, both technically interesting and with stimulating subjects and that your journey in Bucharest, Romania will be an unforgettable and pleasant time.

The Romanian National Committee of CIGRE,

Dr. Ciprian Diaconu Chairman	Dr. Constantin Moldoveanu Vice-Chairman	Dr. Dorin Ioan Haţegan Secretary

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

Papers of
RSEEC 2016
Innovation for efficient and effective management, solutions for power systems of the future!

Bucharest, Romania
October, 2016

Organized by:

RO cigré

Transelectrica®
Societate Administrată în Sistem Dualist

POLITEHNICA UNIVERSITATEA DIN BUCUREȘTI 1818

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#51

Criteria for oil selection suitable for use as insulating liquid in high voltage Instrument Transformers

Dr. B. PAHLAVANPOUR*, Mr. J. NUNES and Mr. C. WOLMARANS
NYNAS AB
UK / Brazil / Sweden

SUMMARY

The use of ultra-high voltage electrical equipment in modern day transmission systems is increasingly being used in many countries, the main drivers being safety, reliability and ease of transport of electricity with minimum loss. This equipment is expensive and needs to be reliable and available at all times. Insulating liquid is used for insulation and cooling in this equipment and this liquid plays an important role in the safe operation of these units. Insulating oil used in UHV transmission is constantly subjected to high electrical and thermal stress, which could lead to oil and paper deterioration. If an insulating oil continues to degrade, it starts to become less of an insulator evidenced by an increase in Dielectric Dissipation Factor (DDF). If an oil with a low resistance to ageing is used and there is progressive production of ageing by-products, consequently, insulation deterioration accelerates. International experience indicates that sealed CT and VTs may fail catastrophically once DDF of the oil reaches 0.5. Further, the limits for DDF in CTs and VTs in the IEC maintenance guide IEC 60422 DDF are more stringent than for any other equipment. Baring this in mind, oil selection for high voltage instrument transformers is an important factor and oil with high resistance to deterioration, good electrical properties and high cooling efficiency should be used. It is also important that such oil is able to sustain these properties during service life of these units. There are oils available in the market being beyond the severe requirements of IEC 60296, special applications. Such oils are used for UHV and are usually referred to as Super Grade Oil. To produce such oil, selection of correct crude oil, refining technique and knowledge of proper use of distillates for production of Super Grade Oil is vital. Over and above the superior ageing behaviour of these oils; the viscosity index and high solvent power are also beneficial. Pour Point is also complemented to the above factors and can influence performance of the oil over the life of the equipment.

KEYWORDS

Insulating Oil, High-Voltage, Super-Grade

INTRODUCTION

Mineral insulating oil is used for cooling and insulation in transformers since over hundred years ago. Specifications for supply of unused oil are published and used as a standard by both buyers and suppliers to define their mutual obligations. When selecting a liquid for electrical insulation purposes, information related to most of the characteristics should be obtained so that the potential user may see the scope for possible application. Certain characteristics and property values are inherent to the type of fluid and these should therefore only be applied to those fluids. In some cases, prescribing a limit for a certain property is not applicable although using typical reference values for

* bruce.pahlavanpour@nynas.com

the type and grade of the liquid in question may be necessary for design purposes. Other characteristics are useful for identifying a material and again typical values should be quoted. The important characteristics from a specification point of view are those which effect the fluid's life and performance. These parameters must have limits set at specification stage in order to achieve a situation where the lifetime of the fluid within the equipment is sufficiently long. Therefore, a standard can be divided into various sections to cover physical, chemical and electrical properties of the oil. These properties can be classified as:

Functional: properties of oil, which have impact on its function as an insulating and cooling liquid.

Refining and stability: properties of oil that are influenced by quality and type of refining and additives.

Performance: properties that are related to long-term behaviour of oil in service and/or its reaction to high electrical stress, temperature and oxidation.

Health, safety and environment: oil properties related to safe handling and environment protection naturally, there may be an overlap between these sections.

International Electro Commission (IEC) standard IEC60296 [1] is one the most widely used standards for supply of oil in the electrical industry. In general, this specification defines two types of oils as one for general purpose and second one for special application. However recent development of ultra-high voltage systems may require super grade oil, over and above requirement of oil for special application, which is not addressed in that specification.

REQUIREMENTS OF INSULATING OIL

The three main functional requirements of insulating oil are:

To meet the **insulation function**, the oil must have high dielectric strength and low dielectric dissipation factor to withstand the electric stresses imposed in service.

To meet the **heat transfer and cooling function**, the oil must have viscosity and pour point that are sufficiently low to ensure that oil circulation is maximal at high temperatures and is not impaired, even at the most extreme low temperature conditions for the equipment.

To meet the **arc quenching function**, the oil requires a combination of high dielectric strength, low viscosity and high flash point to provide sufficient insulation and cooling to ensure the arcing is extinguished.

THE GENERAL REQUIREMENTS

The more general requirements are, in many cases, related to and inter dependant with the three main functional requirements, and the oil needs to have the following general properties:

- The oil must have: low **acidity** (**neutralization value)** to eliminate the risks of sludge formation and corrosion.
- **Anti-oxidant additives** (inhibitors) such as 2,6-di-tert-butyl-p-cresol (DBPC) slows down the oxidation of oil. The content of antioxidant in oil depletes during service life of the oil and is therefore important to monitor. Oils are grouped into three classes depending on the antioxidant content as uninhibited, trace inhibited and inhibited
- The **breakdown voltage** needs to be sufficiently high to provide dielectric strength to prevent breakdown of the oil under electrical stress.
- The oil must not contain levels of **contamination** by any individual **metal**.
- The **density** of the oil has to be low enough to ensure that ice cannot float on the oil surface at very low temperatures and cause internal flashover.
- The **Dielectric Dissipation Factor** (the tangent of the loss angle and commonly referred to as tan delta) has to be sufficiently low to ensure that the dielectric losses are small and that the oil thus provides satisfactory insulating properties.
- The **flash point** needs to be sufficiently high to eliminate the risks of ignition of vapours above the oil during maintenance or in service.

- The unused oil must have a low **furan** content, otherwise the effectiveness of condition monitoring by trend assessment of furan content is impaired.
- The oil must have a high value of **Interfacial Tension (IFT)** to ensure absence of polar compounds in the oil and suitability of the oil for use as insulating material.
- **Mix-ability**: unused mineral insulating oils of the same class, the same group are considered to be mixable and compatible with each other.
- The **moisture content** of the oil must be low, otherwise the electrical strength of the oil will be impaired and moisture will be absorbed into any paper insulation, reducing insulation life and increasing the risk of dielectric breakdown.
- The **oxidation stability** of the oil must be high to reduce oxidation processes in service, which degrade the oil, producing acids and sludge. These can reduce the effectiveness of cooling and cause general internal deterioration and eventual failure
- The oil must have a low **particle size and count** and a low fiber content as the presence of such contaminants, especially in the presence of moisture, can considerably reduce the electrical strength.
- The oil must have undetectable **polychlorinated biphenyl (PCB)** content to meet the requirements of environmental legislation.
- The oil must have a low **polycyclic aromatic (PCA)** carbon content to meet the requirements of health & safety legislation.
- The **pour point** is related to viscosity and needs to be low enough to ensure that the oil flows satisfactorily under low temperature conditions.
- The oil must have low **sulphur content** and contain no corrosive sulphur.
- The viscosity of the oil needs to be low enough to ensure that the oil flows well under all (as well as low) temperature conditions thus providing the necessary cooling and, where appropriate, arc quenching properties.

Of the various insulating fluid options, available to the user, mineral insulating oil has for the vast majority of situation proven to be the most cost effective choice and meets the above functional requirements.

SPECIAL APPLICATION OIL

Insulating oil in transformers with high load and operating at high temperatures is subjected to thermal stress resulting in rapid oxidation of the oil, sludge and acid formation. This will reduce life of the unit possibly leading to premature failure. Clearly there is a requirement for highly refined oil with high resistance to oxidation. Oil for special application is suggested in IEC60296 to fulfil requirement of such units. The limits for oxidation stability are much lower (more stringent) than general specification and sulphur content limit is used to ensure a high degree of refining of the oil. Use of such oil in electrical equipment may extend life of the unit and have a resulting lower total cost of ownership for the user. It may also increase reliability and availability of the unit resulting in reducing operation and investment costs. Use of such oil will lead to reduction in the cost of changing the oil, preventing unscheduled outage and therefore, from the life cycle point of view, has economical and technical advantage.

REQUIREMENT OF SUPER GRADE OIL

Super grade oil can be used for ultra high voltage transformers (UHV). Although there is no such definition or classification for UHV in IEC, but it can be classified as voltage over 400 kV and up to 1200 kV. In instrument transformers especially considering the lower volume used it may be sensible to use super grade for lower voltages as well. In addition to general requirement, super grade oil should have the properties described in the below sections.

Viscosity and viscosity index

The lower the viscosity, the easier the oil circulates naturally, leading to improved heat transfer and thermal distribution. This is especially important in an instrument transformer with no forced cooling. Viscosity influences heat transfer and therefore the temperature rise of the equipment. This is particularly important at low temperature and cold start. High viscosity at low temperature may lead to possible localised overheating. The lower viscosity is also advantageous with regards to faster and better impregnation of paper and therefore lower risk of voids in the solid insulation.

The viscosity at the lowest cold start energising temperature (LCSET) in the revised standard is less than 1 800 mm^2/s. The LCSET for transformer oils is defined in IEC60296 as being –30°C (this is 5K lower than indicated in IEC 60076-2).

Viscosity index plays an important role as oil with high viscosity index will have higher viscosity at given operating temperature than oil with lower viscosity index. This will lead to operation of transformer at higher temperature and lower cooling efficiency as shown in figure 1.

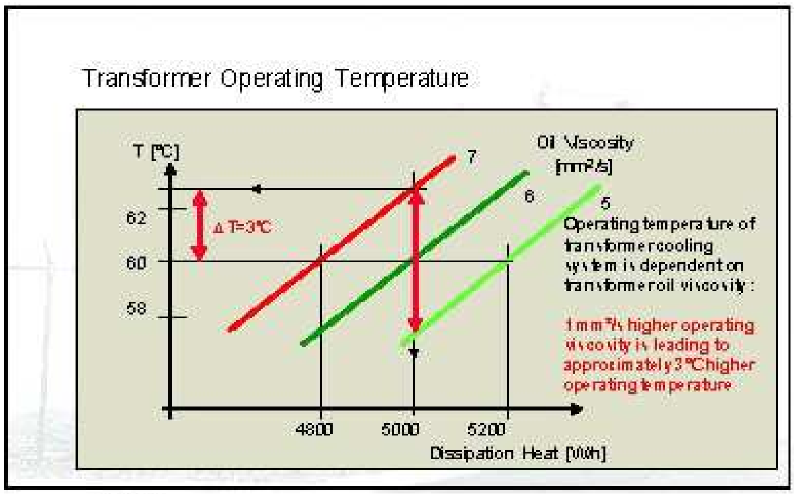


Figure 1: Effect of viscosity on operating temperature

Dielectric dissipation factor (DDF)

The method for measuring DDF content of the oil is IEC60427 (2) or IEC61620 (3). Both methods measure DDF at 90°C. If DDF is measured at any other temperature, then the temperature of measurement shall be stated in the report. Oil should have low DDF and is low figure should remain low during service of the oil. For this reason, oil with high oxidation stability is required.

Interfacial tension (IFT)

This is an important test to make sure supplied oil is free from chemical contamination. It is also can be used as an indication of oil deterioration once it is in service. High IFT (equal or better than 48mN/m) is desirable for super grade oil.

Antioxidant additive content

Antioxidant additive (inhibitor) slows down the oxidation of oil and therefore the formation of oil sludge and acidity. Presences of antioxidant in the oil will effects oxidation stability test results. This is particularly important when it is added to low quality oil, which without adding inhibitor may not pass oxidation stability. To avoid this problem, three limits for inhibitor content of the oil were introduced.

Uninhibited oil should have no detectable inhibitor. Trace inhibited oil may have up to 0.08% inhibitor and inhibited oil is restricted to containing 0.08 to 0.4% inhibitor. Response to inhibitor is very important issue for service life of oil and super grade oil shall have good response to inhibitor as shown in figure 2. To achieve this base oil must be well refined and free from any constraints.

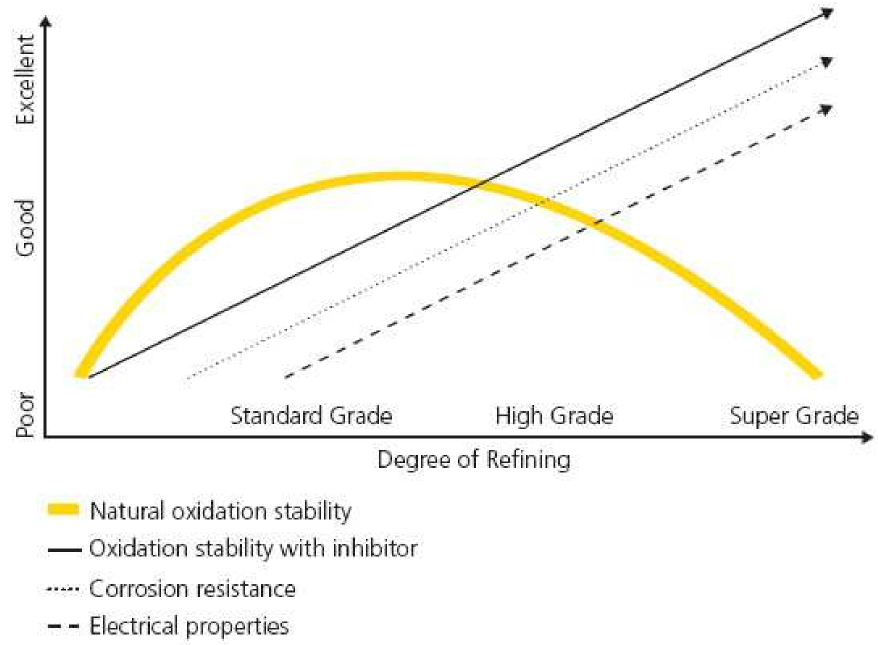


Figure 2: Response to inhibitor and degree of refining

Sulphur Content

Sulphur content of the oil can be used as an indication of degree of refining of the oil and there is no general requirement for standard grade oil but for special application a limit of maximum 0.05% is suggested by IEC60296. However, for super grade oil this figure is usually much lower.

Corrosive sulphur

Super grade oil shall be free from any corrosive and potentially corrosive sulphur.

Oxidation stability

Oxidation of oil gives rise to acidity and sludge formation. This effect can be minimised as a result of high oxidation stability leading to longer service life of the oil. Oxidation stability is measured in accordance with method C of IEC 61125, which is conducted at 120°C. Duration of the test is dependent on level of inhibitor detected in the oil. For uninhibited oil it is 164 hrs, for trace inhibited 332 hrs and for inhibited oil 500 hrs. Test limits for acidity, sludge and DDF for all three these categories are the same. For super grade oil limits for acidity, sludge and DDF are usually better than suggested figures for special application in IEC60296.

Polycyclic aromatics (PCA)

Some PCAs are classified to be carcinogens and therefore need to be controlled to an acceptable level in mineral insulating oil. PCAs are defined so as to be detectable by extraction with DMSO.

(Dimethyl-sulfoxide) under the conditions of BS 2000 Part 346. A limit of maximum 3% DMSO extractable compounds is introduced in this standard. PCAs are also have negative effect on impulse strength of insulting oil as shown in figure 3. Super grade oil is low in PCA as shown in table 1 and figure 3.

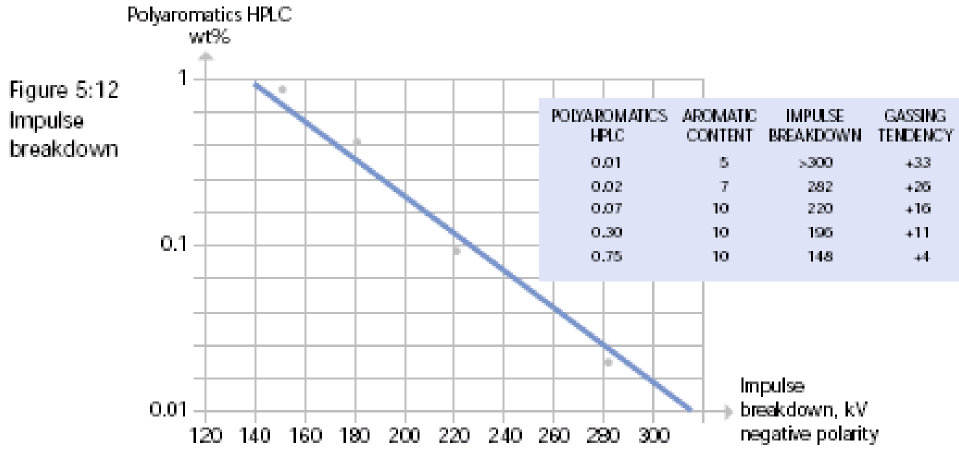


Figure 3: PCA content and impulse strength of the oil.

Table 1: PCA content and impulse strength of the oil

Polyaromatics wt% (PAC) HPLC method (In house)	Aromatic content % IEC 60590	Impulse breakdown kV ASTM D3300 negative polarity	Gassing tendency µl/min ASTM D2300B
0.01	5	> 300	+33
0.02	7	282	+26
0.07	10	220	+16
0.30	10	196	+11
0.75	10	148	+4

High solvent power

Oil with high solvent power are preferred option as this will help to keep oxidation products (if they produced or if present after a retro-fill procedure) soluble in the oil and avoid precipitation and absorption of these material by insulating paper. To achieve this oil with lower aniline point are preferred.

BENEFITS OF SUPER GRADE OIL TO THE USER

Super grade oil has low viscosity and low viscosity index this will give economic advantages to the user for operating the unit at higher temperature and have longer life of the oil and more importantly, their asset. Superior resistance to oxidation of this oil will protect insulating paper and also keep all required parameters oil in an acceptable level for long period. High solvent power of this oil is also protecting insulating paper by avoiding precipitation of oxidation product on paper surface and absorption of these by product by insulating paper. Use of super grade oil will reduce maintenance cost during service life of the unit as this oil has high resistance to oxidation. Since Super grade oil is well refined it is low in PCA consequently this oil has high impulse strength.

Further, in an instrument transformer as the stressed volume compared to the total volume is very high (when compared to a power transformer) – this combined with the fact it is a sealed unit if any localised discharges start this will lead to thermal runaway and/or progressive discharges leading to breakdown/arcing in oil and possibly an explosion. This is why the limits for DDF in service are much lower for instrument transformers – as any sign of quasi conductive and/or polar by-products of ageing increase the probability of dielectric failure substantially. The use of Super Grade oil, which will dramatically reduce the chance of such ageing products is thus a sensible choice in instrument transformers.

In recent years many instrument transformers are also of the SF6-filled gas insulated type and have very good performance however they require gas related maintenance and if any leaks develop the utility can face serious penalties [4] - due to this gas being a "super" green-house gas. Therefore, the technology trend of migrating oil type to SF6 type instrument transformers is likely to reverse. The use of Super Grade oil will then be the sensible choice for OEMs going back to (or increasing production of) oil type Instrument Transformers as it reduces the risk of ageing related failures.

CONCLUSION

For equipment under thermal stress and special application, high -grade oil with high oxidation stability is introduced by IEC60296. This standard does not address super grade oil. Since use of ultra high voltage system is increasing, demand for such oil will increase. Consequently, there is need to have specification for supply of such oil. Implementation of such specification to the electrical industry may lead to more reliable operation and longer life for oil filled electrical equipment. To fulfil requirement of UHV units for insulation and cooling supper grade oil shall have low viscosity, low viscosity index, high solvent power and the base oil shall be well refined.

BIBLIOGRAPHY

[1] IEC 60296 Fluids for electrical application- Unused mineral insulating oils for transformers and switchgears, 2012.

[2] IEC 60247, Measurement of relative permittivity, dielectric dissipation factor and d.c. resistivity of insulating liquids.

[3] IEC 61620, Insulating liquids – Determination of the dielectric dissipation factor by measurement of the conductance and capacitance – Test method.

[4] http://www.echonews.co.uk/news/local_news/14402938.Company_ordered_to_payeasing_ harmful_greenhouse_gas_at_port/21_000_for_rel

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#53

Live Operating and Efficiency of Equipment's Management

Ioan RODEAN*, Daniel MORAR, Vasile BALAN, Catalin BOGUS, Virgil ORLANDEA, Marius SIMBOTIN, Septimiu SOVERESAN**
CNTEE "Transelectrica" SA
Romania

SUMMARY

The paper presents the methods used in recent years in the national power grid to operate more efficiently as high voltage equipment. It includes shares of minor maintenance and operation undertaken by our company for management installations. It also briefly describes the results of applying new technologies and the technical analysis performed using such technical data. As part of asset management technologies have been applied without withdrawal from service of installations, allowing transmission of electricity at full capacity. In applied technologies for minor maintenance remember inspections multispectral spectra in visual, infrared, ultraviolet and laser and live working technologies. Within the operation of equipment were used more management applications databases, which were subsequently used in technical analysis. Also in the operation were used methods of online analysis for operational behavior of equipment. It presents the results of a comparative analysis of the costs of the technologies for minor and corrective maintenance without redraw from service of equipment and exploitation of modern equipment versus traditional technologies. Some conclusions are presented at the end, much like their own recommendations for more efficient operating of equipment.

KEYWORDS

Live operating, efficiency, education.

MAINTENANCE AND OPERATION OF HIGH VOLTAGE NETWORKS

A problem occurred lately is changing electricity transmission networks and distribution as mixed networks with multiple roles: drain power from power plants, electricity transmission and distribution of electricity to large and small consumers. This requires a new National and EU Strategy for Power Grids.

Making maintenance of high voltage installations in the Transmission Grid requires a new approach, namely achieving technical and organizational measures for the application of live working technologies and new technologies other than classical. This will become inevitable.

In this context, stage by stage to every project, project managers and operations personnel are more involved in organizing of those works. In terms of project beneficiary organization of works with classic technologies involves scheduling, execution permissions request and reception. For live operating technologies, organization of the work in terms of project beneficiary is achieved by programming, considering technical criteria and climate, correlating those works with other technologies, getting as many technical data online, request permissions execution and reception. In

* ioan.rodean@transelectrica.ro
** daniel.morar@transelectrica.ro,

addition, all installations from the design stage and then modernization stage need to be made to allow the application of live technologies. So increasing organizational complexity these involve high quality management of project the need to increase efficiency, in terms of the beneficiary.

Such projects require a more efficient organization that leads to changes within the organization: the organization must adopt a management structure of the modern type, advanced with the use of technical personnel trained and authorized.

In our company, it was promoted a project concerning the professional training of specialized operators for: electric lines, transformation units, operations, exploitation of primary equipment, exploitation of secondary equipment. It has thus been set up the "Center of Excellency in Energetics" C.E.E., which includes subunits for training and development of electric operators and training, test and authorization for live working technologies, called the "Center for Research and Development of Live Working Technologies and Rapid Intervention in National Power Grid".

In this center will carry out studies for the implementation of new technologies, technical analysis of the behavior of the equipment into service, technical analysis to efficiency application of new technologies and training of human operators for both the exploitation activity, as well as for the maintenance activity.

Having regard to the experience of other countries as well as the possibilities and technological for more advanced features that can be implemented at the level of the company, such as development of this center by creation a team of rapid intervention in power grid, which will achieve increasing the effectiveness of actions for the elimination of faults from installations, avoid serious damage and take corrective action in installations, both from the point of view of the maintenance and the operative activity (in close connection with the Centers of Remote Control and Surveillance of Installations – C.T.S.I.).

In this Center will hold the theoretical courses of training and professional improvement for human operators. To complete operators training, this Center has possibilities to hold the practical courses in Polygons for: 220-400kV OHTL for all type of tower from NPG, 110kV OHL with several types of towers, 110-220-400kV bays complete equipped – primary and secondary equipment for several significant types of equipment – and medium voltage posts.

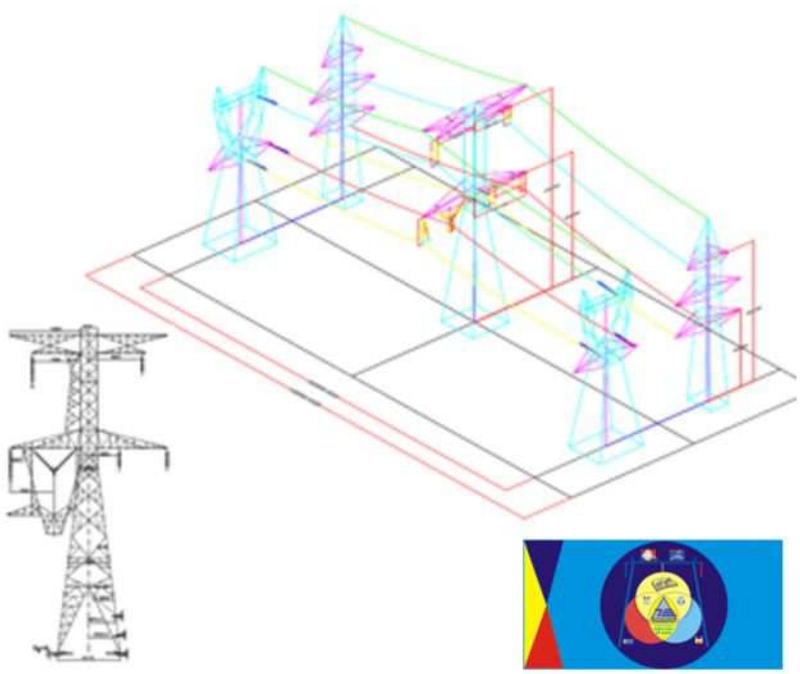


Figure 1. OHTL polygons structure of C.E.E. Center for Research and Development of Live Working Technologies and Rapid Intervention in National Power Grid

EFFICIENCY OF LIVE OPERATION AND LIVE MAINTENANCE

In C.E.E. we have made the technical-economic analysis for live working in our power grid in order to determine on the basis of the perspective plan for maintenance of equipment: the modernization of the equipment, refurbishing of installations, predictive maintenance based on reliability and better organization for corrective maintenance – for quickly answered and accurately.

Economic calculation was performed for each criterion presented previously. Such, from Q1 to Q8 criterion, each technical requirement was "translated" into economic values [1].

Operating criteria (Q1) envisages that non-programming of equipment for withdrawal from service due to safety conditionings of Power System Transmission Grid or area power grid in requested time interval. Congestion that might occur in case of withdrawal from service of electrical equipment will lead to additional costs for the Company. Also power losses will appear in grid. In the Company exist a program for calculating the electrical losses, but currently does not detail Joules-Lenz losses and corona losses. In developing this program, which is ongoing, these details will be available. Following an analysis [2] found that the corona loss calculation for areas of Transmission Grid is recommended to use the method provided by IEEE 738-1993 and Électricité de France, completed study method VNIIE Russia and forecast of meteorological data. Data obtained from the calculation are then compared with data obtained from on-line metrology systems.

The following table shows the values of power losses related to power network operating in case of withdrawal of an OHTL:

Table 1. Calculation of power losses [2]

No.	Element	Losses estimate [MWh]	Losses from metering system [MWh]	Costs [lei]
1	OHTL Bradu-Braşov	2,408	2,167	433,4
2	OHTL Mintia-Sibiu Sud	2,062	1,748	349,6
3	OHTL Iernut-Sibiu Sud	3,698	2,618	523,6
4	Ungheni Autotransformer	0,319	0,308	61,6

Data for calculation of losses corona are collected through monitoring systems parameters of OHTL, weather systems, whose data are provided by the National Institute of Meteorology, measurements made in initially inspection and other databases (on characteristics of the conductor or emissivity and solar absorption).

Climate criterion (Q2), if case of application of LW technologies, is needed to respect the limits imposed on personnel safety. The final decision is taken to carry out operations at the place of execution.

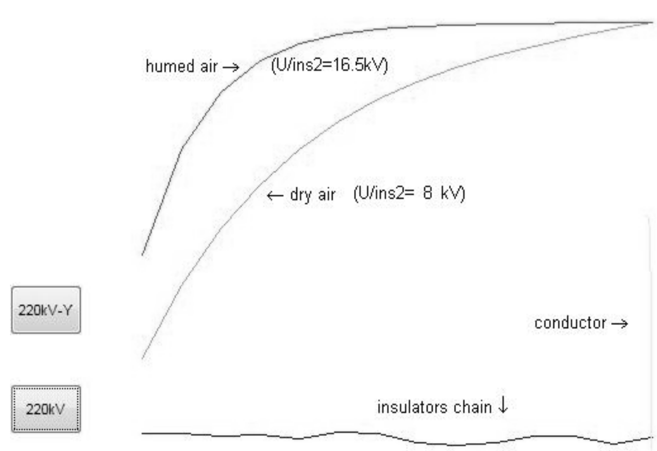


Figure 2. Distribution of voltage on a chain of cape-type insulating glass at a pole type Y, in the climate variation condition

The graph was obtained by simulation using analytical methods of calculation taking into account the longitudinal capabilities of insulators, stray capacitances of insulators to earth and stray capacitances of insulators to conductor [3].

The cost in this case varies: in case of evacuation of wind power plants there is a minimum interval of climatic parameters that allow both energy production and live an intervention to ensure continuity; in contrast to this network, in other networks, live operating cannot be performed at all due to climatic conditions or can be carried with ease, but sometimes withdrawal from service of equipment is more effective.

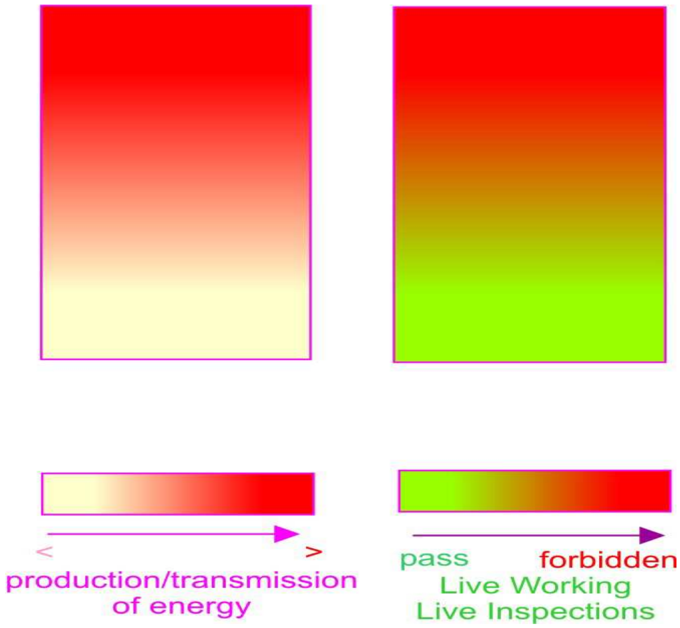


Figure 3. Application of live technologies when variation climate conditions

Technological criterion (Q3) depends on the level of technical and facilities of work according to the technical characteristics of the electrical installation (access to tower, access to the element from the chain insulators, access to at the equipment terminals, etc.). Technical characteristics of the electrical installation in the area determines the necessary of specific equipment (tools and machinery) like pole insulation, insulated arms of raised platform, insulated ladder, cart, helicopter with special platform, etc.

Figure 4. Spacer changing by helicopter with special platform (SC SMART SA line operator)

Organizational criterion (Q4). If case of LW technologies, the access tower is easier than other technologies, being able to choose to apply using helicopter with special platform technologies, to avoid damaging of crops or protected natural areas. Working to high voltage equipment also depends on the overall operation of operation activities of the organization. Such as, before maintenance with LW technologies in OHTL or substations, we archive multispectral inspections in laser spectrum, in audio spectrum, visual spectrum, ultraviolet spectrum and infrared spectrum. Also inspections of equipment can be carried out with robots and scanners. Following technical data from these inspections have been able to identify exactly which components of the equipment needed to apply them remedial operations. By using technical database of equipment with defective components we can get adequate and efficient preparation of the maintenance with LW technologies.

In terms of project beneficiary, organization of works with classic technologies involves a lower level of organization. To work with live technologies, organization of works in terms of beneficiary’s project becomes more complex depending on several technical criteria and climate, correlating those works with other technologies, execution and reception request permissions, and more.

Such projects require a more efficient organization of the recipient by project teams and teams of technical consulting, which leads to changes in the organization. In this context the organization should adopt a management structure advanced / modern. Costs of organization to apply those technologies grow only when switching from inadequate organizational structure, but simplistic, to a complex organizational structure. But once implemented the new structure can speak of greater efficiency of work / organization's activities and therefore operating costs (operating or organization of maintenance) become much lower.

For live working applications need specific measures, specific parameterization of the relays terminals, to ensure all conditions for execution and continuity in the operation of equipment: speed, selectivity, sensitivity and safety.

The architecture of a secondary system of command, control, protection and automation can enable a greater or lesser extent the performance of works under voltage primary equipment, as will become apparent in the following examples.

Preparatory work operations are under tension in specific technologies, although many of these can be common. Those are for live working such as:

- Replacing the voltage transformer
- Replacement or maintenance for breakers
- Replacement or maintenance for line separator
- Replacement or maintenance for busbar separator
- Replacing the cell elements - conductors
- Busbars major maintenance
- Major maintenance for transformers units
- Power lines terminal elements maintenance

Technical criterion (Q5) is closely related to other criteria such as technical equipment of execution unit (Q3), the organization of work (Q4), climatic conditions (Q2) and the safety conditions (Q7). For optimal application of more efficient technologies, be they classical or live, more data are needed, which can be found in electronic databases, such as “Transelectrica-GIS” or “InfoLEA / InfoStaţii / InfoDoc = InfoTehnic”.

Economic criterion (Q9) refers to the efficiency of the work with the chosen technology or all technologies together chosen to be applied on equipment.

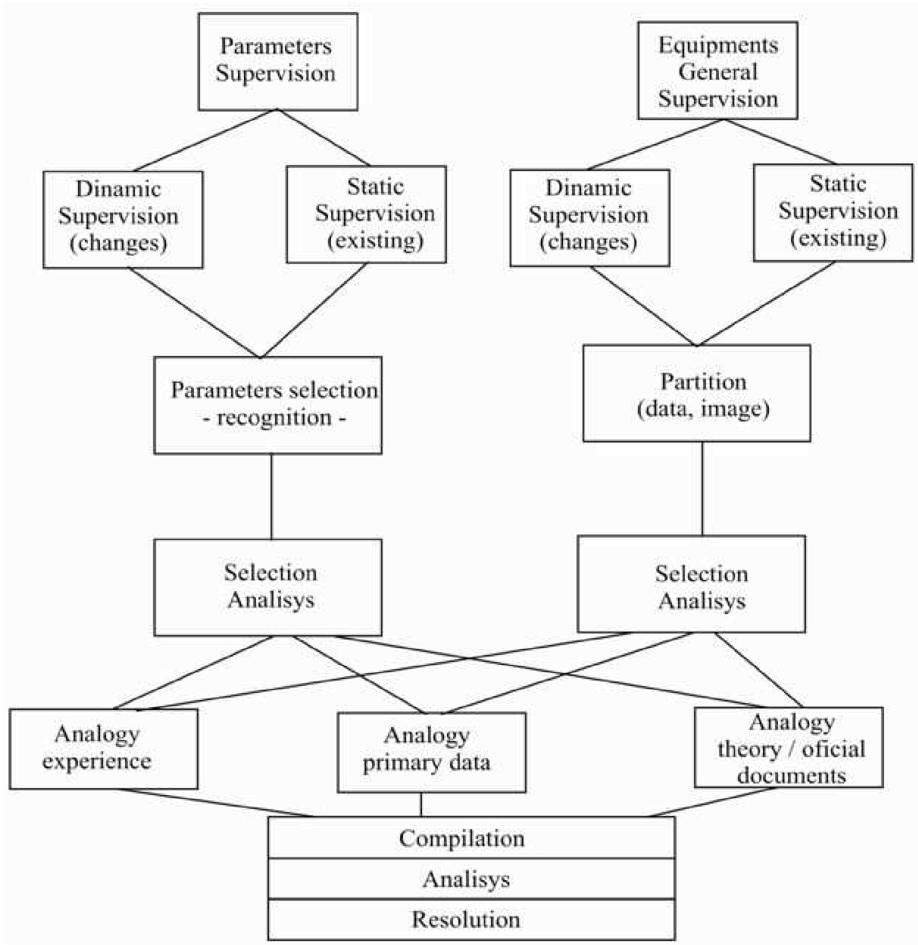


Figure 5. Diagram analysis for application of technologies

Live technologies have been applied for more equipment, such as:

400kV OHTL Tantareni-Turceni G1-2+3-4, 400kV OHTL Tantareni-Turceni G5-6+7-8, 400kV OHTL Urechesti-Rovinari G3+4, 400kV OHTL Urechesti-Rovinari G5+6, and more LW technologies operations being performed:

- Installation aerial nameplates on pillar tip
- Dumpers position adjustment or replacement on conductors
- Replacing spacers
- Replacing parts connecting of the chain insulators (like nuts, eyelets suspension, etc.)
- Replacing protection fittings on suspension tower
- Replacing broken glass insulators from the suspension chains
- Replacement suspension clips of the active conductors
- Preparation work and painting of corroded elements of the crest of tower
- Replacing anchor the tower

Barehands methods for LW applied to the works mentioned above were:

- Ergonomic seat method
- Insulating ladder method from the console
- Insulating ladder method from ground
- Raising arm with insulating platform method

Efficiency of live works resulted from calculations made to table 3.

Table 2. Efficiency of live works

Operation	Efficiency
Corective Maintenance	
Replace an element from insulators chain on suspension tower	20%
Replace clips	15%
Replace anchores	8%
Removal objects from tower	3%
Removal objects from conductors	5%
Replace daylight beacon with helicopter	11%
Replace daylight beacon with ladder	12%
Replace dumpers	19%
Replace a element from insulators chain on strech tower	23%
Painting the crown's tower	25%
Preventive Maintenance	
Multispectral inspections (UV, IR, visible)	12%
Minor maintenance on OHTL	18%
Minor maintenance on substation equipments	2%
Control and inspection with lidar	5%
Control at crown of OHTL tower	3%
Major Maintenance	
Major Maintenace on OHTL (medium value)	9%
400kV OHTL Mintia - Sibiu Sud	
400kV OHTL Ţânţăreni - Turceni	
400kV OHTL Urecheşti - Rovinari	
220kV OHTL Stejaru – Gheorgheni	
220kV OHTL Iernut - Ungheni	

CONCLUSIONS

Application of technologies should occur only after a technical and economic analysis appropriate to achieve greatest effectiveness.

Application of technologies depends on several criteria, but this is reversible, being impetuous necessary to create technical and economic conditions appropriate (development of new technologies, purchasing new technologies or creating operating conditions for their application), that will result in benefits financial and technical.

Live technologies in recent years are used complementary by combining the results and in this way is obtained the greater efficiency of the works. Following the studies result that completion of the major maintenance by applying live working, or only partially, become absolutely necessary for increasing the efficiency and lowering costs of company.

Perhaps because new technologies, compare with traditional technologies, have been applied much less (ratio up to 1/10) or maybe classical technologies are training less time (otherwise traditional technologies being based for training of new technologies) than the new ones, it appears when used live technologies that quality of operations performed and the work as a whole is much greater than the classic ones.

In C.E.E. will training and teach operators to apply the best technology: economic efficiency, highest safety application, best technological and more.

BIBLIOGRAPHY

[1] D. Morar, I. Rodean, M. Oltean, L. Brabete, ISPE “Criteria for Applying of Live Working Technologies in Romanian Transmission Power Grid”, ICOLIM Budapest, 2014.

[2] Transelectrica, ISPE “Studiu multianual al postcalculului CPT şi al bilanţului energetic în RET”.

[3] V. Titihăzan, M. Titihăzan, M. Oltean, I. Sevastre “Simulări numerice privind repartiţia tensiunii în lungul unor structuri electroizolante”, EPC Timisoara, 2009.

[4] M. Oltean, T. Făgărăşan, L. Brabete, I. Sevastre, S. Gal “Live Maintenance on High Voltage Equipments in Substations”, Conference CMDM RoCigre, Bucharest 2011.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#54

Voltage regulation by grid-connected PV systems effects on distribution network operation

M. IONESCU*[1], G. PRESADA (IORDACHE)[2]
[1]University "Politehnica" of Bucharest, [2]CNTEE Transelectrica SA
[1]Romania

SUMMARY

The paper provides a study regarding the benefits and challenges of voltage regulation contribution of distributed photovoltaic generation systems by reactive power flow control. Simulations are performed using the Neplan software on real secondary distribution networks from Ialomita and Calarasi regions, characterized by an important number of grid-connected photovoltaic power plants.

KEYWORDS

Photovoltaic power plant, voltage regulation, reactive power flow control, distribution network.

I. INTRODUCTION

Voltage regulation represents a major concern for distribution networks characterized by a high penetration level of grid-connected photovoltaic power plants. Events such as contingency of network elements or fast solar irradiance variations may have important consequences on power quality and network voltage profile. Furthermore, in the frequent case of the absence of directional load compensation for the on load tap changer voltage controllers, the reversed power flow through distribution power transformers may lead to uncontrolled voltage rise.[2]

On the other hand, regulatory agencies manifest a permanent increasing pressure on distribution network operators performance and quality standards. These requirements have direct impact on photovoltaic power plants grid connection conditions. For example, in present, all grid-connected photovoltaic power plants with installed power higher than 5 MW are considered dispatchable and have the obligation to be capable of reactive power flow control in the common connection point according to power factor values between 0.9 inductive and 0.9 capacitive. Furthermore, these generation units have to ensure zero reactive power exchange with the utility grid during zero generation periods. [3] It is expected that future standards and regulations may extend the previously detailed requirements for photovoltaic power plants with rated power higher than 1 MW.

Voltage regulation contribution of grid-connected photovoltaic power plants involves a series of challenges. From the distribution network operator point of view, even if stationary operation regime registers certain improvements, as reverse power flow consequences on voltage profile become less severe, sudden unavailability of some power plants may lead to inacceptable voltage variations. [2] From the plant owner point of view, reactive power flow control requirements imply the necessity of additional investments in more expensive slightly oversized Volt/VAr capable pulse width modulated inverters and, in some cases, in reactive power compensation equipments.

* mihaiandrei.ionescu@gmail.com

The paper proposes to highlight the main impact directions of grid-connected voltage regulation contribution on distributed network operation. There are taken into account several aspects, such as voltage profile, fast voltage variations, network power losses and on load tap changers voltage regulator interactions. The simulations were made using Neplan software.

II. VOLTAGE SUPPORT FROM PHOTOVOLTAIC POWER PLANTS

The most frequent case of a photovoltaic power plant distribution level connected is represented by the radial medium voltage distribution feeder. As the substation distribution transformer on load tap changer voltage regulator operates autonomously the main interest is represented by voltage regulation in the point of common connection.

In normal conditions, the distribution network operator has the option of setting fixed reactive power or fixed power factor operation for the photovoltaic power plant.[1] On the other hand, there can be taken into account the option of variable reactive power operation, providing a voltage setup in the common point of connection. In this case, voltage control loop is presented in Figure 1. The desired reactive power output is determined by the inverter controller using a droop function $q(V_{meas},Q_{max})$.

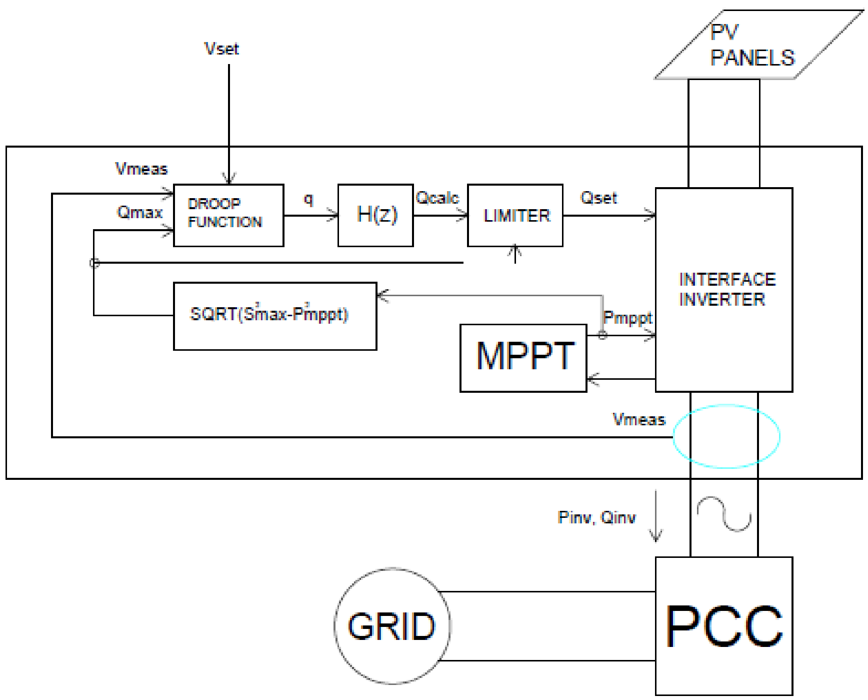


Figure 1. Block diagram of PV inverter with voltage controller

In this case, the point of common connection becomes a *P-U* node, considering a series of limitations, described by equations (1) and (2).

$$P_{PV} = P_{MPPT} \qquad (1)$$

$$\sqrt{P_{PV}^2 + Q_{PV}^2} \leq S_{INV} \qquad (2)$$

where:

P_{PV} is the output real power of the photovoltaic power plant;

P_{MPPT} is the output power provided by the maximum power point regulator;

Q_{PV} is the output reactive power of the photovoltaic power plant;
S_{INV} represents the rated apparent power of the inverter.

The maximum power point tracking regulator determines the real output power desired at each period. By economical considerations, it is desirable that the photovoltaic power plant to operate to its maximum available output power. The restriction described by equation (2) is given by the inverter rated apparent power. The capability diagram shown in Figure 2 provides the real and reactive power output possible to be obtained from a photovoltaic power plant. In order to operate at nominal power output for specific requested power factor, a certain oversize of the grid interface inverter may be mandatory.

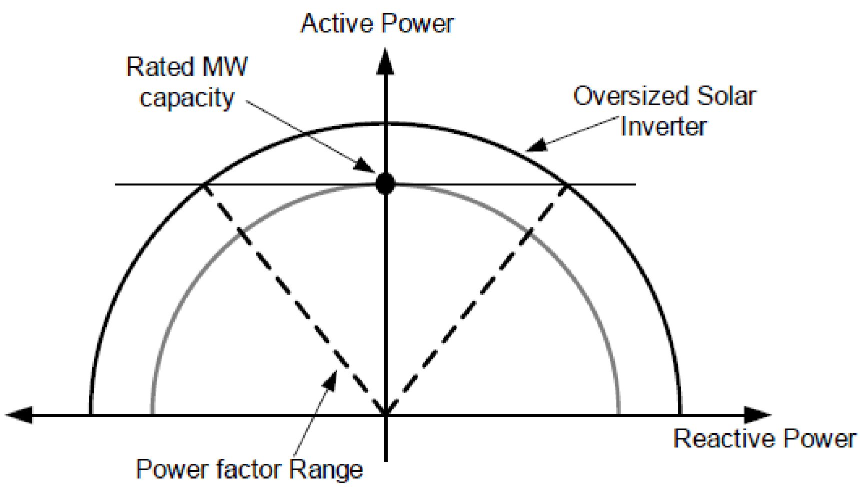


Figure 2. Solar generation P-Q diagram [1]

III. LOAD COMPENSATED ON LOAD TAP CHANGER VOLTAGE REGULATOR

As previously mentioned, the substation busbar on load tap changer voltage regulator operates autonomously. In distribution networks characterized by long medium voltage radial feeders the load compensation principle of operation was applied, considering the fact that for customers connected close to the end of the feeder the voltage level may become inacceptable low. The load compensation takes into account the maximum feeder voltage drop and the output current of the power transformer. The principle of operation is illustrated in Figure 3 and described by equations (3)-(5).

$$V_{busbar} = V_0 + K_{comp} \cdot I_T \qquad (3)$$

$$V_{max} = V_0 + K_{comp} \cdot I_{comp} \qquad (4)$$

$$K_{comp} = \frac{V_{max} - V_0}{I_{comp}} \qquad (5)$$

where:
V_0 is the busbar voltage setup corresponding to zero load operation;
V_{max} represents the maximum busbar voltage setup;
I_{comp} is the maximum value of the compensated current, generally set as 80% of the rated current of the power transformer;
K_{comp} represents the load compensation constant [Ohm].

Distributed generation units manifest a significant impact on load compensated on load tap changer voltage regulators, as shown in Figure 4. The most severe conditions can be observed for high compensation constant voltage regulators and long radial medium voltage feeders with distributed generation units connected close to the medium voltage busbar.

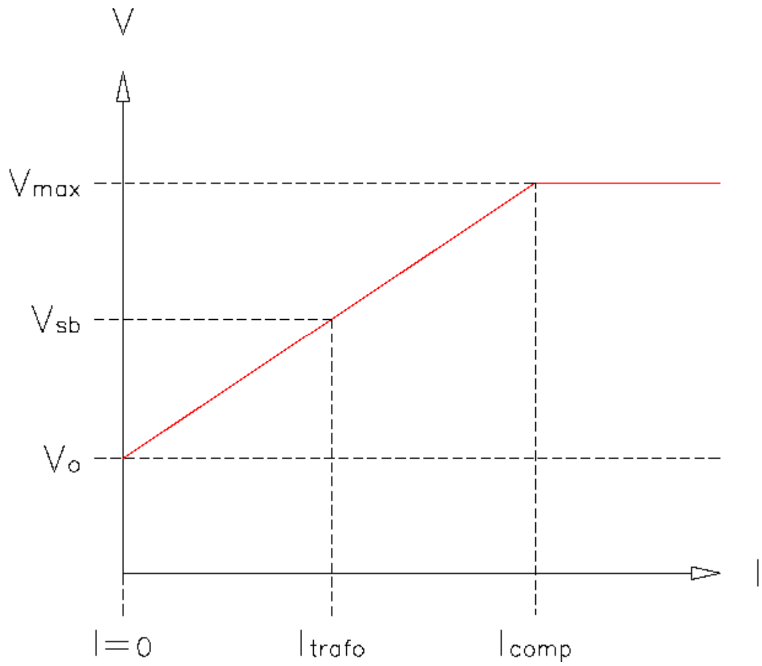


Figure 3 - Load compensation principle of operation [2]

The worst case scenario regarding the distribution network voltage profiles is represented by undetected transformer reverse power flow conditions, as voltage rise will be proportional to busbar voltage setup deviation. In this case, the voltage regulator load compensation should be blocked for a fixed voltage reference equal to V_0.

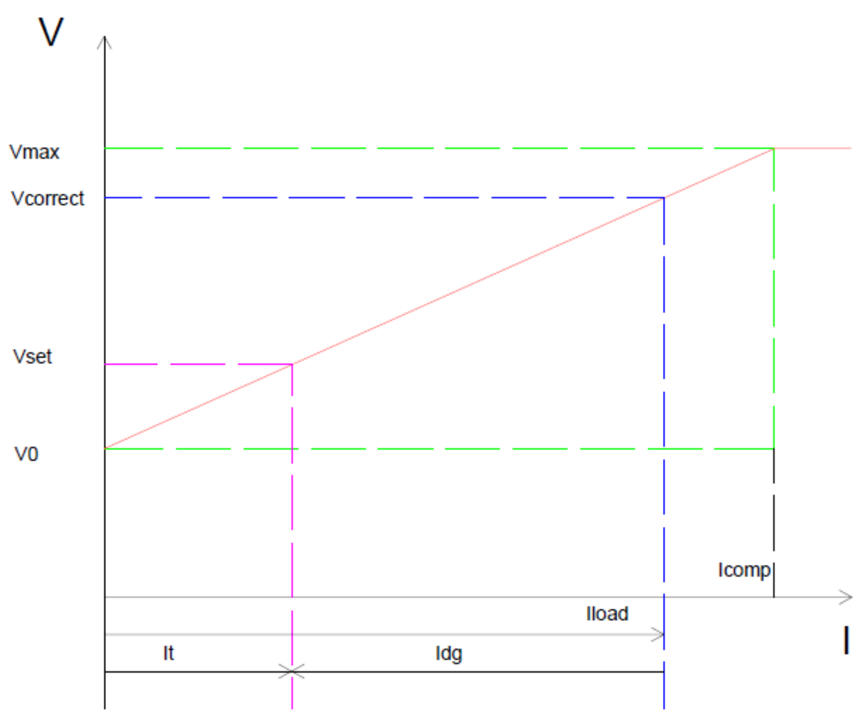


Figure 4 - Distributed generation effects on load compensated voltage regulators

IV. CASE STUDIES AND RESULT ANALYSIS

In this section it is studied the impact of voltage regulation by grid-connected photovoltaic power plants on distribution network, by comparative analysis. The object of the study involves two secondary distribution network areas representing two different situations.

The first situation considered is represented by a long radial 20 kV feeder supplied from 110/20kV Oltenita Sud substation, situated in Calarasi county. A 2.7 MW photovoltaic power plant is connected in the main axis of this feeder by an input-output configuration. The feeder model involves 56 nodes, including the 20 kV busbar of Oltenita Sud substation. For the studies, it is considered that the feeder load corresponds to morning winter peak load, higher than the photovoltaic power plant rated power. As there was no available data about load repartition on step-down substations connected to this feeder, it was considered a weighted average dependent on the step-down transformers rated power. The study involves a comparative analysis regarding network voltage profile, power losses, fast node voltage variations and slow node voltage variations. The analyzed situations are represented on one hand, by unit power factor operation of the photovoltaic power plant and, on the other hand, by voltage regulation operation considering reactive power capabilities corresponding to a power factor between 0.9 inductive up to 0.9 capacitive and a voltage setup in the point of common connection identical to the substation busbar voltage regulator setup.

The voltage network profile obtained by load flow calculation in both of the described situations is represented in Figure 5. The maximum voltage drop was significantly reduced by photovoltaic power plant reactive power flow control.

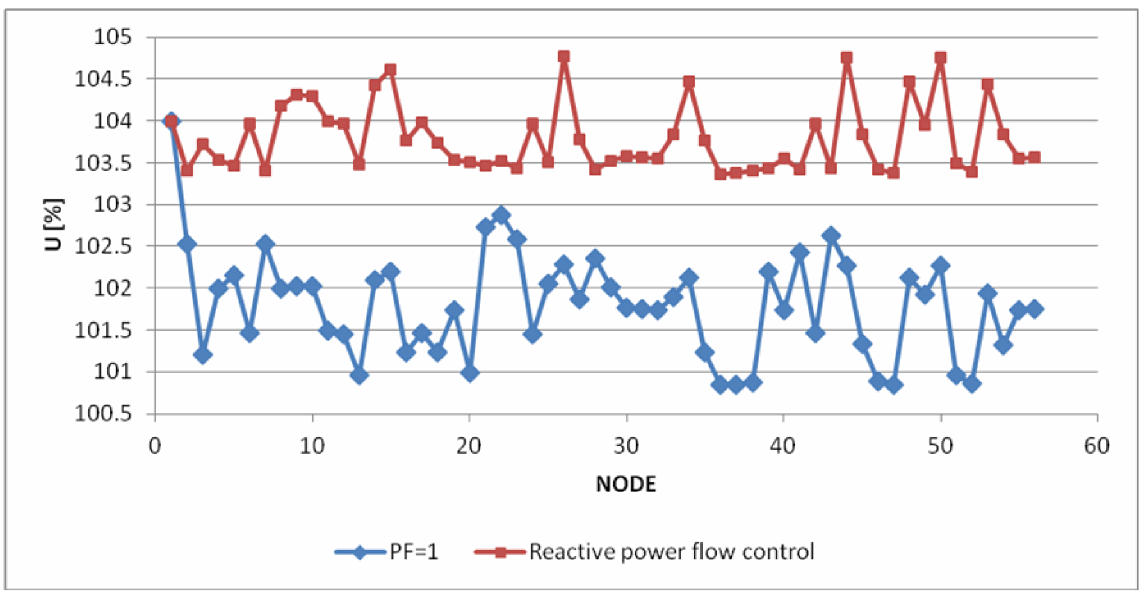


Figure 5 - Network voltage profile comparative analysis

Figure 6 illustrates the comparative analysis of network element loading for the considered situations. It was concluded that by using the photovoltaic power plant voltage control function, network power losses decreased by 44%.

For fast voltage variations calculations was considered a fast solar irradiance drop that lowers the photovoltaic power plant generation to 50%. Figure 7 illustrates the comparative analysis between unit power factor operation and voltage control operation. As operating for an optimized steady state regime in the voltage control case, it can be concluded that fast voltage variations are higher in this situation.

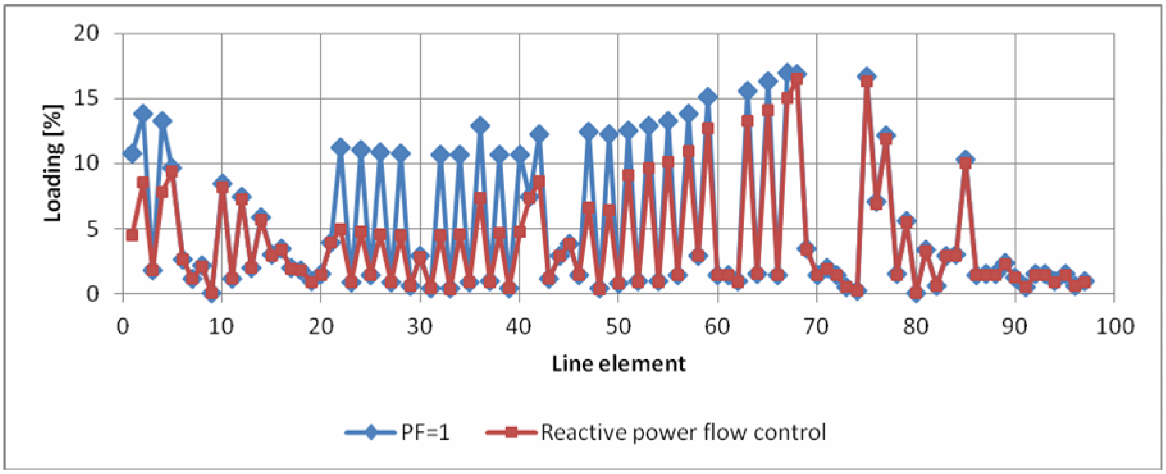


Figure 6 - Network power losses comparative analysis

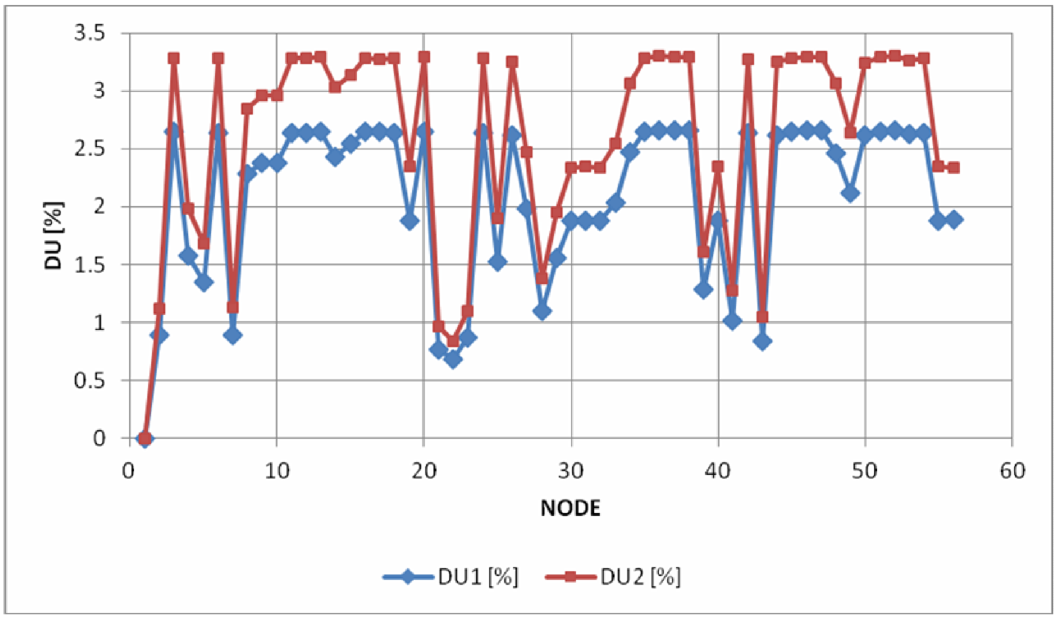


Figure 7 - Fast voltage variations comparative analysis

For slow voltage variations calculation it was considered the intervention of load compensated on load tap changer voltage regulator in case the photovoltaic power plant becomes unavailable. The load compensation settings of the voltage regulator correspond to a 25 MVA 110/20 kV transformer and are detailed in Table I.

Table I - Load compensation settings for Oltenita Sud substation

V_0 [kV]	20.4
V_{max} [kV]	21.8
I_{comp} [A]	524
K_{comp} [Ω]	2.67

Voltage variations are calculated considering the previously described photovoltaic power plant operation modes. The results are shown in Figure 8.

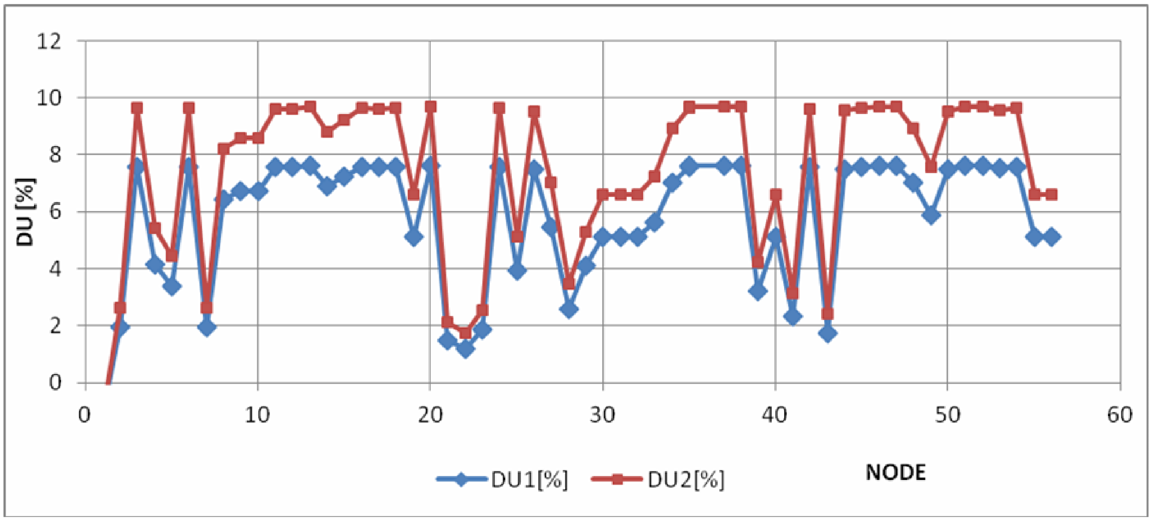


Figure 8 - Slow voltage variations comparative analysis

The second considered case study involves a Neplan model for an entire 20 kV busbar and secondary distribution network supplied from 110/20 kV Barbulesti substation, situated in Ialomita county. In the studied area there are connected four photovoltaic power plants, as it follows: a 9.6 MW photovoltaic power plant and a 2.5 MW photovoltaic power plant connected directly to the substation busbar by separate feeder bays and two photovoltaic power plants 2.5 MW each connected to the same medium voltage feeder. This situation corresponds to a reversed power flow regime. Considering the load compensation settings for the substation voltage regulator similar to the previous case, slow voltage variations are computed considering the presence or absence of the reversed power voltage regulator block. The third considered situation is represented by voltage regulation operation for all photovoltaic power plants considering an active reverse power flow voltage regulator blocking. The results are centralized in Figure 9.

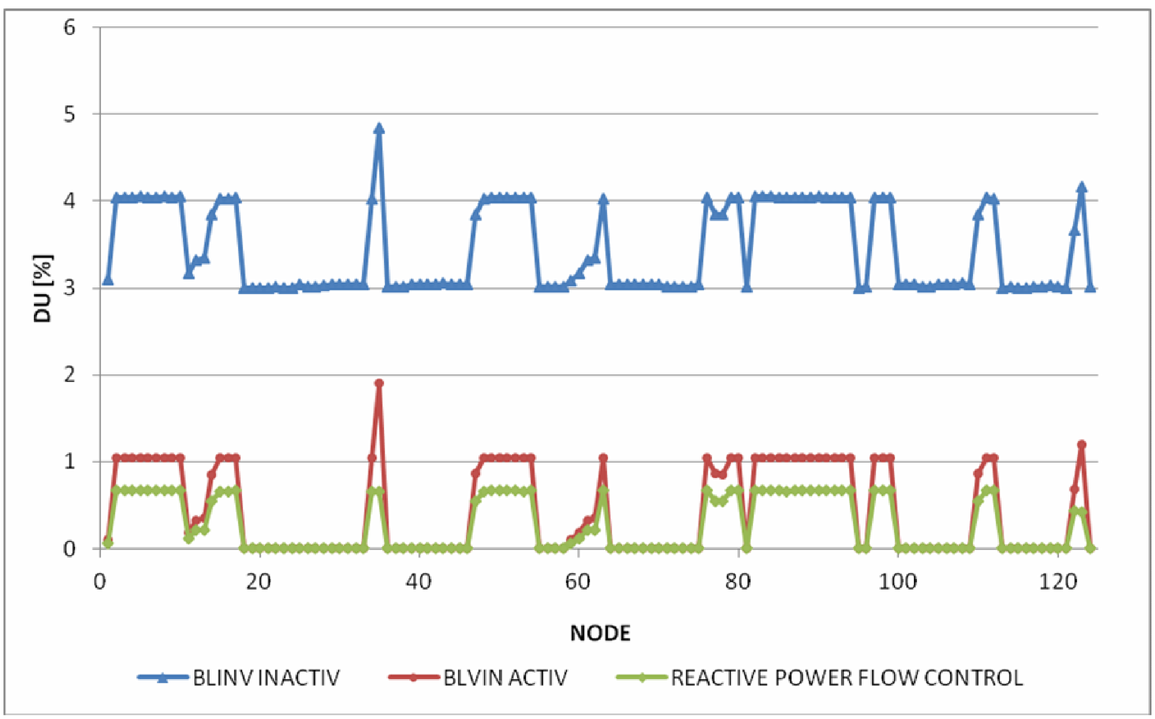


Figure 9 - Slow voltage variations in reversed power flow regime comparative analysis

V. CONCLUSIONS

This paper presented a study regarding the effects of voltage regulation by photovoltaic power plants on secondary distribution network. Comparative analysis revealed significant voltage level improvement and power losses decrease in case of photovoltaic power plants voltage regulation operation. On the other hand, fast voltage variations occurring as a consequence to solar irradiance variations are higher in case of voltage regulation operation. The same situation was concluded for slow voltage variations obtained by sudden photovoltaic power plant unavailability and load compensated substation voltage regulator operation.

It was also concluded that during reversed power flow operation, the on load tap changer voltage regulator should be blocked, in order to avoid uncontrollable voltage rise in the network nodes. Also, in case of reversed power flow regime, fast and slow voltage variations register lower values if photovoltaic power plants operate in voltage regulation mode.

Voltage regulation by grid-connected photovoltaic power plants setup is limited by power quality standards, providing maximum values for slow and fast voltage variations calculated for the most severe conditions.

BIBLIOGRAPHY

[1] Y. P. Agalgaonkar, B. C. Pal, R. A. Jabr, *Distribution Voltage Control Considering the Impact of PV Generation on Tap Changers and Autonomous Regulators, IEEE Transactions on Power Systems, Vol.29, no. 1,* pp.182-192, September 2013;

[2] ICP03 RO, *Instrucţiuni pentru racordarea instalaţiilor de producere în reţeaua electrică de medie tensiune*, Ed.01/19.12.2012, Enel Distributie Romania;

[3] *Ordinul ANRE nr.74/2013 pentru aprobarea Procedurii privind punerea sub tensiune pentru perioada de probe şi certificarea conformităţii tehnice a centralelor electrice eoliene şi fotovoltaice;*

[4] F. Vatră., C. A. Vatră, P. Postolache, A. Poida, *Integrarea şi funcţionarea centralelor eoliene şi a instalaţiilor fotovoltaice în sistemele electroenergetice,* Editura SIER, 2012;

[5] S. St. Iliescu, *Teoria reglării automate,* Editura PROXIMA, 2006;

[6] A. Maknouninejad, N. Kutkut, I. Batarseh, *Analysis and Control of PV Inverters Operating in VAR Mode at Night, Innovative Smart Grid Technologies 2011,* pp.1-5, 17-19 January 2011.

[7] O. Masato, T. Kenichi, *Optimal voltage control in distribution systems using PV generators,* International Journal of Electrical Power and Energy Systems, Vol. 33, no. 3, pp.485-492, March 2011;

[8] H. Yu, J. Pan, An. Xiang, *A multi-function grid connected PV system with reactive power compensation for the grid, Solar Energy, vol. 79, no. 1,* pp. 101-106, July. 2005.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#57

Continental European ENTSO-E power system extension by synchronous interconnection with Ukrainian and Moldovan power systems

Daniela BOLBORICI*, Ciprian Gheorghe DIACONU, Oana ZACHIA
CNTEE Transelectrica SA
Romania

SUMMARY

This paper presents the main steps for the Continental European ENTSO-E power system extension and the recently accomplished feasibility study for synchronous interconnection of Ukrainian and Moldovan power systems.

In March 2006, UKRENERGO and MOLDELECTRICA, the transmission system operators (“TSOs”) of Ukraine and of the Republic of Moldova, formally applied for synchronous interconnection to the system of the Union for the Coordination of Transmission of Electricity (“UCTE”), now ENTSO-E. CNTEE Transelectrica SA is the Transmission System Operator acting as a supporting party for this synchronous interconnection process at ENTSO-E.

The first step in this process was the feasibility study. The overall objective of this study was to identify the main elements needed to make possible the synchronous interconnection and to recommend the main measures to be taken in order to overcome the main technical, organizational and legal possible obstacles.

KEYWORDS

Synchronous Interconnection, Inter-area Stability, Frequency Regulation, Real-time Operation

1. STEPS TOWARDS SYNCHONOUS INTERCONNECTION [1]

The steps and measures towards the synchronous interconnection of other power systems with the power system of Continental Europe are established by ENTSO-E internal regulations.

First, the requesting TSO(s) choose one or several neighboring TSO(s) from Continental Europe to be its supporting party/parties at ENTSO-E.

The chosen TSO (the “supporting party”) submits a preliminary application to ENTSO-E for system extension. The preliminary application has to mention the identity of the TSO(s) who request(s) the synchronous interconnection and has to describe, among others, the geographic borderlines involved, the electrical equipment at the borderlines, the estimated loads and generation capacity involved, etc.

ENTSO-E, through one of its working groups, examines the preliminary application and makes the preparations for Terms of references for a feasibility study.

Based on the results of the feasibility study and on other necessary analyses ENTSO-E decides about the continuation of the procedure for the extension. In case the decision is positive, a contract (Connection Agreement) has to be entered into between:

- the supporting party,
- the requesting TSO(s), and
- at least two TSOs from Continental Europe, different from the supporting party.

* daniela.bolborici@transelectrica.ro

The Connection Agreement specifies the rights and obligations of the parties with respect to the next steps in the extension process. It has to contain at least:

- the ENTSO-E rules to be complied with, especially those related to the secure operation and the frequency control;
- the geographic and electrical delimitation of the extension;
- the methods to be used for checking the compliance;
- the detailed technical conditions for the extension (the “Catalogue of Measures”) to be implemented by the requesting TSO(s) to ensure that the extension contributes to the quality and security of operation of the interconnected transmission system in the Continental Europe synchronous area. The Catalogue of Measures must be defined, in accordance with the Operation Handbook and technical recommendations of ENTSO-E.

The Connection Agreement must contain the commitment of the requesting TSO(s) to comply with the Operation Handbook and the relevant network codes and guidelines and to implement the measures written in the Catalogue.

After the Connection Agreement is signed the requesting TSO(s) (in our case Ukrenergo and Moldelectrica) has to implement the measures in the Catalogue and ENTSO-E through one project group, supervises and guides them in this process, as stated in the Contractual Agreement.

After all the measures are implemented, tests in isolated operation and interconnection tests must be prepared and performed. After the assessment of the tests results it is decided about the trial interconnected operation of the transmission system of the requesting TSO(s) with the interconnected transmission system of the Continental Europe synchronous area. The synchronous trial operation is monitored and the compliance with the conditions set out in the Connection Agreement is verified.

Before taking the decision on permanent synchronous operation a final feasibility assessment is performed, the main part of which represents checking whether the requesting TSO(s) are in a satisfactory way compliant with the standards of the Operation Handbook, the relevant network codes and guidelines, and in particular whether all critical non-compliances have been removed.

In this moment the feasibility study for synchronous interconnection of Ukrainian and Moldovan power systems to the Continental European ENTSO-E power system is accomplished and the two requesting TSO(s) analyzed the results and confirmed they want to continue the process.

2. FEASIBILITY STUDY – INTRODUCTION [2]

The feasibility study for synchronous interconnection of Ukrainian and Moldovan power systems to the Continental European ENTSO-E power system was made by a consortium of TSOs from Continental Europe: EMS (Serbia), PSE (Poland), MAVIR (Hungary), ESO EAD (Bulgaria) and Transelectrica was the consortium leader. For leagal and regulatory issues Bernard Energy Advocay (BEA) from Belgium joined the consortium.

The study was funded by The Joint Operational Programme Romania-Ukraine-Republic of Moldova 2007-2013 which is financed by the European Union through the European Neighbourhood and Partnership Instrument and co-financed by the participating countries in the programme.

The beneficiaries are The Ministry of Economy of Republic of Moldova and its partners: The Ministry of Energy and Coal Industry from Ukraine and The Ministry of Economy, Trade and the Business Environment of Romania.

The study was done in good cooperation with experts from Ukrenergo and Moldelectrica who delivered necessary input data and information and who provided clarifications and feedback to the consortium members.

Some of the Consortium tasks were supported by a couple of external experts from EKC (Serbia), Instytut Energetyki and Energopomiar (Poland), companies subcontracted by EMS and PSE.

The study was made in very short time, from November 2014 to January 2016.

The Terms of Reference were established by ENTSO-E and the activity was organized on four working groups: Steady state analyses, Dynamic analyses, Operational issues and Legal and regulatory issues.

The main objectives of the Study are:

- to investigate the possibility of Ukrainian and Moldovan power systems to be operated in parallel with the Continental European synchronous area respecting its technical operational standards;
- to investigate the degree of implementation of ENTSO-E's technical operational standards in the Ukrainian and Moldovan power systems;
- to analyze the difference in relevant legislation in the field of energy between Ukraine and Moldova and the European Union ("EU") countries.

The essential precondition for any extension of the Continental European synchronous area is to keep its reliability at least at the present level. Based on several available reports and analysis, including as delivered by the participating parties from Moldova and Ukraine, the Study makes various recommendations from technical, regulatory and operational point of view for the possible future integration of the Ukrainian and Moldovan power system; it being understood that the Consortium can only suggest recommendations and that it will be later up to the various appropriate bodies, including ENTSO-E, to decide and agree on the needed measures. The Study is to be considered as a preliminary step to be followed by others such as an official assessment by ENTSO-E, a cost-benefit analysis and/or socio-economic analysis, political or State positions, various agreements including but not limited to relevant connection agreement with the Ukrainian and/or Moldovan TSOs and the relevant ENTSO-E TSOs, etc.

3. STATIC STUDIES (LOAD FLOW STUDIES) [2]

This study analyzed with a complete AC modelling, the synchronous operation of interconnected power systems of Ukraine and Moldova with continental part of ENTSO-E interconnection.

Between ENTSO-E Continental European power system and Ukrainian and Moldovan power systems there are the following tie-lines (tie-lines in interface area):

- tie-line between Poland and Ukraine (750 kV line Rzeszow-Khmelnytska)
- tie-lines between Romania and Moldova (400 kV lines Isaccea – Vulkanesti and Succeava – Balti).

One part of Ukrainian power system (Burshtin Island) is disconnected from the rest of Ukrainian power system and synchronously connected to the main ENTSO-E grid. The connection between Burshtin Island and the rest of the Ukrainian power system can be made through:

- 220 kV lines Stryi – Rozdyl – Lviv;
- bus bar couplers in Zakhidnoukrainska (750 kV and 330 kV) and Burshtin (330 kV) stations.

Power flows, voltage profile and power margins have been analyzed in detail verifying the N-1 criterion.

Studies have been based on models and data for the year 2020 considering two cases (Winter Peak load – WP, and Summer off Peak load – SoP).

Sensitivity analyses have been made to determine maximum power exchange in the following directions:

UA+MD → SEE + IT (via new HVDC IT-ME)
UA+MD → SI + AT + IT (without new HVDC IT-ME)
UA+MD → Eastern DE (TSO 50Hz)
Eastern DE (TSO 50Hz) → UA+MD
UA+MD → PL + SK + HU + RO + CZ
PL + SK + HU + RO + CZ → UA+MD
UA+MD → PL + SK
UA+MD → SK + HU
UA+MD → HU + RO

For purpose of this study it was necessary to create proper models with satisfied accuracy. Special attention had to be paid to power systems in the area of interest: Ukraine and Moldova, border countries between Ukraine, Moldova and the rest of ENTSO-E (HU, PL, RO, SK) and countries which were on transit paths for analyzed exchange scenarios (AT, CZ and SEE countries without Turkey). Modeled area consists of interconnection of ENTSO-E Continental Europe and Ukraine and Moldova.

Models from the following sources were used: ENTSO-E provided the Ten Years Network Development Plan model for Continental Europe, SECI project (South East Cooperative Initiative supported by USAID) provided updated models of SEE (AL, BA, BG, HR, GR, ME, MK, RO, RS, SI) and model of Turkey; TSOs from Hungary, Poland, Slovakia, Czech Republic, Ukraine and Republic of Moldova gave updated national models.

Synchronous operation of Ukraine and Moldova with continental grid of ENTSO-E, in case without any additional exchange excepting the present one with Burshtin Island, will result with significant loop flows. Total loop flow is around 790 MW (in Winter Peak 2020) or 455 MW (in Summer Off-Peak 2020). The greatest amount of loop flow is assigned to grid of UA. Roughly it is expected that total value of loop flow in UA divides into three main parts:

- 20-25% flows through RO and then back to UA via MD
- 25-30% flows through PL and back to UA via SK
- Around 50% flows through PL and spreads through CEE and SEE countries and flows back to UA (8-10% flows back to UA from HU and around 40% flows back to UA through RO and MD). These loop flows have influence on branch loadings. In case of PL, DE and MD average loadings are increased, while in the rest of the area of interest (including UA) average loadings are decreased. We have to mention that these changes are not critical (don't introduce any risk).

Synchronous operation of Ukraine and Moldova with continental grid of ENTSO-E slightly increases voltage profile of the interconnection. The most significant changes appear in networks of border countries (HU, RO, SK) as well as in BA, BG, HR, RS, SK and SI. Increase of voltages in 220 kV network is not as great as in 400 kV network, but still should be mentioned.

This general increase of voltages as well as decreased branch loadings in significant part or area of interest leads to decrease of losses in system. Total decrease of active power losses is more than 0.50%. Losses of reactive power are decreased by around 0.40%. However, in some countries there is increase of losses (as result of significant loop flows which result with increased level of branch loadings), such as MD (more than 27.08%) and PL (around 0.30% in Winter Peak 2020).

Calculated maximum secured total exchange from Ukraine and Moldova to ENTSO-E is 1,000 –2,350 MW, depending on regime and direction of exchange. Calculated maximum secured total exchange from ENTSO-E to Ukraine and Moldova is 1,400 – 2,000 MW, depending on regime and direction of exchange.

Results from short-circuit calculations have shown that there is no critical influence of connection of UA/MD to the Continental Europe power system to the level of SC currents. However, there is significant influence to the level of short-circuit currents in nodes close to connection point, so detailed analysis with checking calculated values against typical breaking capabilities is highly recommended.

4. STABILITY STUDIES [2]

The stability studies were divided into two major groups:

- Transient stability analysis
- Steady state analysis

The transient stability analyses are split into two parts, i.e. regional and wide area stability analyses. The regional analyses covered the interface area (Ukraine, Moldova, Romania, Slovakia, Hungary and Poland). Time domain simulations were performed to verify the regional transient stability behavior of the interconnected system. In this scope Critical Fault Clearing Times for most important elements for the area of networks under consideration were calculated. The longest clearing time for which the generator will remain in synchronism is referred to as the critical clearing time. The study included the analysis of the transient stability during and after three phase short circuits, this being the most severe case, concerning the capability to maintain synchronism of the parallel operation. The relevant scenarios regarding power exchange, schedule of power production, network topology were determined in cooperation with UA/MD expert team. The scenarios used in this analysis were based on power flows elaborated in frame of static studies.

As global transient stability we understand dynamic phenomena in a power system occurring after disturbances which may have effect on a large part or entire system performance.

The investigations performed during the Study of global transient stability for the interconnected systems have concerned three types of disturbances:

- Tripping of large generators in various part of the system.
- Faults on the inter-tie lines between ENTSO-E Continental Europe system and UA/MD system.
- Switching on and off the inter-tie lines.

The steady state analysis covered the entire interconnected power system i.e. ENTSO-E Continental Europe connected with UA/MD. Calculation of eigenvalues, eigenvectors and mode participation factors is realized by means of modal analysis tools. The small signal analysis focuses on inter-area oscillations as well as on significant modes which are local to the interface area. The analysis results show influence of UA/MD connection on existing ENTSO-E CE low frequency inter-area modes. Influence of large power transfers, even far from the interface, are also considered. For stability risks resulting from connection of UA/MD power systems discovered, appropriate countermeasures are also considered as part of this study.

The models for dynamic analyses were prepared for the 2020 winter-peak load and summer off-peak load flows. Data used for building the models had different accuracy. Due to the Study time constraints the entire Western Europe including Italy is modelled using uniform default models of generations according to guidelines elaborated by ENTSO-E (System Protection & Dynamics Subgroup). The input data for Eastern Europe, Balkans and Turkey have the typical accuracy of models used by TSOs in planning dynamic studies. Models of individual generators as well as country or area models were verified and validated before connecting them into the entire ENTSO-E CE model. PMU frequency measurements after sudden loss of 1000 MW generation in Spain were used for tuning and validation of the winter-peak dynamic model.

Inter-area small signal stability of the ENTSO-E CE winter peak dynamic model was validated by comparing its low frequency modes with the inter-area modes obtained in the Study performed for Turkish power system interconnection. It has been found that the frequency and the geographical distribution of the inter-area modes are similar with the mode maps in this Study.

Finally it has been concluded that the prepared models enable credible analysis of frequency and geographical distribution of inter-area modes however in case of damping it is rather the trend (improvement or deterioration) and information obtained from comparison with other already known modes that matters.

Data for Ukraine and Moldova were obtained in form of PSS/E and Power Factory models. Majority of Ukrainian large generators are equipped with nonstandard exciters which have to be modelled by means of user defined models. The elaborated model of Ukraine and Moldova power systems was stable operating as an island. Further deeper validation could not be performed due to lack of any test measurements during island operation.

The transient dynamic study involved all large power plants located in the interconnection neighborhood. Critical fault clearing time (CFCT) was calculated in each country and compared with values of CFCT determined in the model before the interconnection. No risks were identified for safe operation of the investigated power plants on the both sides of the interconnection.

The connection of Ukraine and Moldova changes pattern of low frequency inter-area modes in ENTSO-E CE substantially. Two new low frequency modes with frequencies 0.3 Hz and 0.4 Hz emerge. The modes have relatively poor damping in the winter peak model. In the summer off-peak model mode 0.3 Hz becomes unstable. The connection also negatively influences the already known west-east mode 0.22 Hz decreasing slightly its frequency and damping but the changes are not critical. The already known lowest frequency Turkey mode 0.15 Hz remains undisturbed. Large generators from the Ukrainian nuclear plants participate predominantly in the new modes; they also have visible participation in the west-east mode.

Poor inter-area stability in the winter peak base case are influenced by the results of analyses of exchange scenarios and outages of interconnection lines. The damping further decreases if Ukraine and Moldova export more power to the West. N-1 states of the interconnection cause also deterioration of damping. Disconnection of the Rzeszow – Khmelnytska 750 kV line is critical for the inter-area stability of the interconnected systems.

The results of modal calculations show insufficient inter-area stability of the interconnected systems. In such circumstances the synchronous interconnection is not feasible and countermeasures significantly improving damping of the new inter-area modes are necessary.

Inacceptable damping of the new inter-area oscillations has influenced the results of global transient analysis involving simulations of faults on the interface and loss of large generation. The poorly damped or undamped oscillations of Ukrainian generators against rest of the interconnected systems emerged after disturbances, confirm unsatisfactory level of damping of the new inter-area oscillations.

It has been found that the poor damping performance is the result of lack of damping from large Ukrainian generators which are all equipped with inefficient non-standard exciters. It was proved that changing the settings of exciters for generators in nuclear power plants or using separate standard power system stabilizers could significantly improve the situation.

It must be clearly stated that due to lack of engineering information regarding above exciters, technical possibility to adopt any of the proposed solutions remains an open question.

The analysis of damping performance of the Ukraine and Moldova exciters has shown importance of availability of on-site tests in process of verification and validation of the models. At the same time it is essential to have access to system measurements (PMU) which could confirm damping performance of system stabilizers or damping feedbacks of excitation systems also for frequencies lower than local oscillations.

The next aspect associated with low frequency inter-area modes is relatively high variability of their damping depending on many various features of system operation what at least partially we have tried to show in the Study. A mode having generally quite satisfactory damping may go unstable in certain conditions. The reason of the variability is very complex nature of low frequency modes involving not only thousands of generators and turbines, their controls and loads but also network topology, size and direction of power transfers on very large area. Considering this complexity the results of inter-area stability should be taken with proper caution - one cannot say that damping of the new modes after applying countermeasures will ensure stable operation of the interconnection. The new modes have similar damping as the existing modes and there are operational experiences with unstable oscillations associated with these existing low frequency inter-area modes.

Within the project investigations of countermeasures were focused on most effective and economically justified solution (modification/tuning existing control systems). If adoption of proposed measures will be problematic or not sufficient and there will be still a need for further damping enhancement, then a feasible solution can be FACTS devices with SVC technology which are very efficient also for very low frequencies. Recent example of using FACTS devices (SVC, STATCOMs) to improve inter-area stability come from Turkey and its goal is to increase damping of the Turkish mode.

5. OPERATIONAL ISSUES [2]

The objective was to analyze the reports on the Ukrainian and Moldovan power systems and the differences between their operational rules and ENTSO-E Operation Handbook (OH). In particular the dispatching organization, operational procedures, WAMS, congestion management (N-1, outage scheduling, DACF, capacity assessment), system control dynamics concerning the required level of primary and secondary reserve and required load matching based on load forecast and availability and dynamic performance of generators, protection systems, defense and restoration plans, delimitation conditions were analyzed. Finally recommendations in order to overcome and/ or minimize the differences between UA/MD operational practices and ENTSO-E rules are made.

Analyses were made, based on the data provided by the Ukrainian and Moldovan transmission system operator (Ukrenergo and Moldelectrica). Within the frame of the project a database of the generating facilities was prepared showing its capability to participate in primary and secondary control.

Framework program for on-site tests of generators for verification of the said capability to participate in real-time control was prepared also. That allowed detailed testing programs preparation by Ukrainian representatives.

The power system of Ukraine is partially prepared for synchronous operation with ENTSO-E Continental Europe Synchronous Area. The most important deficiency is absence of deployment of primary reserve due to market rules. Besides, this control is not properly tested, so this is to be considered as a severe non-compliance which cannot be easily removed in short terms. It is stated by Ukrainian representatives that Automatic Generation Control (AGC) system has been tested in modes flat tie-line control and tie-line bias control. Now it works in mode flat tie-line control (only the power exchanges are controlled). AGC system has not been tested in the mode flat frequency control, because the Ukrainian system works synchronously with IPS/UPS.

Based on the present information for power units outages, at the present stage the level and quality of secondary control is satisfactory regarding the exchange power flows control.

Severe non compliances to Operational handbook were detected also for Moldelectrica regarding primary/secondary control. The most important reason is lack of deployment of primary control and absence of secondary controller (AGC). Besides implementation of AGC, Moldova will have to modify the market rules aiming to allow Moldelectrica to purchase primary, secondary and tertiary reserve, as well as to exchange/purchase this reserve with adjacent TSOs, which is relevant for Ukraine too. Moldelectrica will have to invest in order to provide reliable data exchange with adjacent TSOs with requested accuracy and protocols. Also, Moldelectrica could be constituted as a control area and join a Control Block. In that case, some relieves toward Moldelectrica are possible, depending on their agreement on secondary control organization in the Control Block.

As for the real-time operation, the most severe detected non-compliance is lack of real-time calculations of network security.

List of the most critical non-compliances to ENTSO-E Operational Handbook is provided in the study. The main issues that have to be covered in order to reach the expected level of compliance are connected to frequency regulation, real-time operation and special protection systems.

6. LEGAL AND REGULATORY ISSUES [2]

The main objective was to analyze the applicable legal systems in Moldova and the Ukraine and to identify the legal existing differences (between UA/MD and ENTSO-E countries) and make proposal to solve them. In particular it covered the following topics: market organization; ownership infrastructure; TSOs' liability; TSOs' specific tasks and obligations; planning constraints; dissemination of information to the market; compensation for cross-border exchanges of electricity; management of interconnections; capacity allocation mechanisms.

Analyses were made, based on the information provided by the Ukrainian and Moldovan transmission system operator (Ukrenergo and Moldelectrica).

Besides the compatibility of legislation, one of the key aspects that may have important legal consequences when considering the synchronous interconnection of electricity systems is how to address the consequences of incidents/accidents/negligence and the resulting liability. Such aspects are typically addressed in contracts such as the former Multilateral Agreement (MLA) originally signed by the UCTE TSOs and later transferred into ENTSO-E, which MLA allows the streamlining of the legal risks and consequences in terms of liability in case of an incident. To the best of experts' knowledge, such agreement does not currently have an equivalent in the Ukraine and/or Moldova.

The possible consequences of the current lack of full implementation in the Ukraine and/or Moldova of the European energy legal system, in particular the Third Energy Package, are another important outstanding point identified. Such consequences may require additional contractual or legal documents, presumably at a high political level, and may involve an international treaty or similar agreement that will certainly be addressed in due time by the relevant political organizations such as the European Institutions and the respective Governments involved. Issues relating to competition law will also have to be addressed in such context.

7. CONCLUSIONS [2]

In this moment the feasibility study for synchronous interconnection of Ukrainian and Moldovan power systems to the Continental European ENTSO-E power system is accomplished and the two requesting TSO(s) analyzed the results and confirmed they want to continue the process jointly.

From static analyses point of view, synchronous connection of Ukrainian and Moldovan power systems to continental part of ENTSO-E is feasible, with infrastructure (existing and planned) expected in 2020.

From dynamic analyses point of view, the interconnection is not feasible without applying proper countermeasures due to the inter-area instability risks identified in the interconnected model. The source of the instability is insufficient damping for low frequency oscillations at large generators in Ukraine.

The inter-area stability can be improved if one of the proposed countermeasures is applied. The adopted solution have to be verified by manufacturers of existing control systems in power plants in Ukraine and Moldova, especially it refers to the nuclear power plants.

Only after such revision of proposed measures and on-site testing of selected exciters and governors, the final evaluation of efficiency of countermeasures and their influence on small signal inter-area stability of the interconnected systems can be done.

Regarding operational issues, according to the data received and analysis prepared, the Power Systems of Ukraine and Republic of Moldova are partially prepared for synchronous operation with Continental Europe System under OH of ENTSO-E rules. The most severe incompliances can be removed with the fulfillment of the recommendations, as depicted in the study. This will speed up and ease the process of reaching full compliance towards achievement of synchronous interconnection with ENTSO-E Continental Europe System. The main issues that have to be covered in order to reach the expected level of compliance are connected to frequency regulation, real-time operation and special protection systems.

The European energy legal system, in particular the Third Energy Package, should be fully implemented in Ukraine and Republic of Moldova. Information received from UA/MD revealed that, regarding energy, the systems in place in Moldova and the Ukraine are currently not fully compliant with the system applicable in the ENTSO-E countries, although both systems are evolving in the right direction.

The next step in the synchronous interconnection process is to establish the detailed list of technical conditions for the extension (the “Catalogue of Measures”) to be implemented by Ukrenergo and Moldelectrica to ensure that the extension contributes to the quality and security of operation of the interconnected transmission system in the Continental Europe synchronous area. The Catalogue of Measures must be defined, in accordance with the Operation Handbook and technical recommendations of ENTSO-E.

BIBLIOGRAPHY

[1] ENTSO-E –Terms of Reference of Regional Group Continental Europe.
[2] *Feasibility study for synchronous interconnection of Ukrainian and Moldovan power systems to the Continental European ENTSO-E power system* - February 2016 – written by a consortium composed of CNTEE Transelectrica SA (RO), JP "Elektromreža Srbije" - EMS (RS), MAVIR Hungarian Independent Transmission Operator Company Ltd. (HU), Polskie Sieci Elektroenergetyczne S.A. (PL), Elektroenergien Sistemen Operator ESO-EAD (BG), and Bernard Energy Advocacy – BEA (BE).

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#58

Benefits of modern AIS substation design using DCB and NCIT

[1]M. MAGNUSSON*, [1]T. ROININEN, [2]A. FRANK
[1]ABB AB, [2]ABB AG
[1]Sweden, [2]Switzerland

SUMMARY

Historically substation design has been based on conventional Air Insulated Switchgear (AIS) and instrument transformers. Today the most common approach in High Voltage (HV) AIS substation design are using gas type circuit breakers, open air disconnectors and oil- or gas-filled instrument transformers.

Over the last 16 years new AIS technologies have entered the market for HV AIS substation which provides a new set of tools for modern substation design. One fundamental technology step is the Disconnecting Circuit Breaker (DCB) solution, which is combining the functions of traditional circuit breaker and disconnector switch in a single unit. Hence enabling more compact substation design with higher availability. With the recent development of Non-Conventional Instrument Transformers (NCITs) new opportunities has emerged. The DCB can be equipped with integrated optical current transformers making separate current transformers unnecessary. The solution makes it possible to even further decrease the size of a substation and at the same time reduce the amount of needed material.

KEYWORDS

Substation design, Disconnecting Circuit Breaker (DCB), Non-Conventional Instrument Transformers (NCITs), Digital substation.

INTRODUCTION

A Disconnecting Circuit Breaker (DCB) combines the function of a traditional circuit breaker and adjacent Disconnectors (DS). The idea was formed in the end of the 90's and the reason was that disconnectors had the highest grade of maintenance. The circuit breakers had improved, and had longer maintenance intervals than disconnectors. Therefore, the need for disconnectors to isolate circuit breakers for maintenance, to increase circuit and busbar availability, was no longer valid. There are also recent development of the Non-Conventional Instrument Transformers (NCITs) provides the possibility to also integrate the current measurement into the DCB. This can be achieved with an optical current transformer integrated in the DCB, hence enabling switching, isolation and current measurement into one single unit. This enables air insulated switch (AIS) yards to be built in a more efficient way with regards to performance, space and environmental impact. With the NCIT technology digital communication according to IEC 61850 has been introduced, which opens up even further possibilities for refinement of substation design and functionality. This paper will look further into substation design and make an evaluation of an installation of DCB with integrated Current Transformers (CTs).

* martin.magnusson@se.abb.com

DISCONNECTING CIRTUIT BREAKER STANDRADS AND TESTING

The disconnecting circuit breaker has emerges from the gas type circuit breaker using Sulphur hexafluoride (SF_6) as insulation and arc-extinguishing medium. The official International Electrotechnical Commission (IEC) standard for the DCB was introduced in 2005 [1], only five year after the commercial products was adopted by the Swedish Transmission system owner; Svenska Kraftnät.

Due to its origin the DCB standard; IEC 62271-108 [1], utilizes most of the material from both the high voltage circuit breakers, IEC 62271-100 [2], and high voltage disconnectors and earthing switches standards, IEC 62271-102 [3], that already existed. There are however some very important additional requirements on the equipment introduce the DCB standard compared to a circuit breaker. Since the DCB are used as an isolation device in the substation the requirement on the internal and external insulation needs to be secured both when the equipment is new and also after aging and years of field operation.

The moving arcing contacts inside the breaking chamber DCB design for internal insulation needs to take into account both the mechanical and electrical wear. As an additional type test of the equipment in the IEC DCB standard it is required to do two combined function tests to demonstrate the isolation distance. There are both a mechanical and a short circuit combined function test. The mechanical test first requires a mechanical operation test as per class M1 or M2 then dielectric test across the isolation distance. The short circuit combined test demands a T100s test then followed by dielectric tests across the isolation distance. There is also an additional mechanical locking function/device on each DCB, one type can be seen in Figure 4.

The external insulation is equally important and here special attention is needed when the insulations are used in hash or polluted environments. Best practice is to use polymeric insulators with silicone rubber sheds due to its excellent hydrophobicity, self-cleanings properties and low leakage current [4] [5].

OPPORTUNITIES WITH DIGITAL COMMUNICATIONS AND NCITs

The DCB solutions with integrated disconnector function can be seen as one of the first steps of modernization of AIS substations, the next step comes with the emerging NCIT technologies and digital communication.

NCITs can be based on different technologies some examples are Rogowski coil electronic CTs and fully optical CTs based on the Faraday effect. The mentioned type of NCITs have the compact size in common and are ideal for integration into other equipment. Rogowski coil solutions are present on the market for Gas Insulated Switchgear (GIS) solutions and CTs based on the Faraday effect can be found as both freestanding CT configurations and as integrated into live tank circuit breakers/DCBs. The possibility to integrate these modern type of sensors into other equipment makes it possible to build compact substations with a substantial reduction in need of material.

A traditional substation relies on point to point copper cabling between the different building blocks of the substation, most of the cabling are duplicated to achieve redundancy of critical substation functions. The implementation of digital communication between primary equipment and substation control replaces copper cables with optical fiber communication and introduces bus configurations for process equipment and Intelligent Electronic Devices (IEDs). As a result much less copper cabling will be needed and cable trenches can in a large extent be replaced with more simple solutions such as piping in the ground.

Substations with DCBs and NCITs have substantial saving in material need in comparison to a traditional AIS substation design. As an example a general three phase oil insulated CT for 400 kV has a total mass off 7500 kg, (of which 750 kg is insulation oil). For a substation with 10 CTs the total mass of 75 000 kg of steel, copper, aluminum, insulation material and oil can be eliminated. The ***Table 1*** below summarizes the potential savings with utilization of DCBs with integrated NCITs.

Table 1: *Summary of savings with DCB, NCIT and Digital communication.*

Apparatus/technology	Direct savings	Indirect savings
DCB	Separate disconnectors not needed	Land accusation and preparation
	Structures and foundations for disconnectors not needed	Fence, gravel, roads, cables trenches, earthing, lightning protection
		Longer maintenance intervals
		Transportation cost
CT integrated into CB/DCB	Structures and foundations for separate CTs not needed	Land accusation and preparation
		Fence, gravel, roads, cables trenches, earthing, lightning protection
		Transportation cost
Digital communication	Reduction of copper cabling	Time for cabling verification during –pre- commissioning
	Simplified cable trenches	Land preparation

Apart from the savings listed above other benefits with NCITs and digital communication can also be found;

The use of optical current sensors eliminates the hazards associated with high voltage secondary circuits of traditional CTs.

Digital communication and simplified connections between IEDs and HV equipment opens up the possibility to speed up commissioning of substations since pre-test can be utilized in a larger extent.

Self-supervision/monitoring integrated into NCIT merging units and other parts of the digital substation.

CASE STUDY COMPARSION SUBSTATION LAYOUT

One of the main benefits with integration of several functions into the same physical apparatus is the possibility to build more compact substations. The following examples show the impact on a breaker-and-a-half (BAAH) substation diameter configuration with respect to substation layout and size for different degree of apparatus integration. A breaker-and-a-half configuration is often used for larger transmission and primary distribution substations. Availability and reliability are high as each object is normally fed from two directions and at the same time the configuration is more cost efficient than the double breaker double busbar configuration [6].

Substation design and projects normally includes multiple discipline and a wide scope. Transmission substations normally have a minimum of two voltage levels with transformers in between, a control building for SCADA and IEDs etc. Connected to this there are design, financing, procurement, civil work, erection, commission, project management etc. for each project.

In this case study the options around the breaker-and-a-half configurations are evaluated with respect to savings in space and material for the high voltage equipment yard at 420kV. The three configurations are:

Option 1: BAAH with live tank circuit breaker (CB), disconnectors (DS) and conventional current transformers (CTs), see Figure 1

Option 2: BAAH with live tank disconnecting circuit breaker (DCB) and conventional current transformers (CTs), see Figure 2

Option 3: BAAH with live thank disconnecting circuit breaker (DCB) and optical current transformers (NCITs), see 3

Considered are the steel structures and foundations for the primary HV equipment within the 420 kV diameter and also the weight of the disconnector and oil filled current transformers. From a practical point of view the reduction on total weight needed to be handle is very interesting as an environmental baseline looking at the reduction in carbon dioxide-equivalent (CO_2-eq.) can also be used.

Going from option 1 (see Figure 1) to option 2 (see Figure 2) there is a space saving of 35% or 1200 m^2 on the HV diameter sizing. Since the conventional disconnectors are removed an additional saving of six disconnecting switches and one complete gantry tower. For the given diameter this is over 32 000 kg of equipment material that is not needed anymore. Furthermore the amount of foundation concreate have been reduced by 20 000 kg CO_2-eq. or 25%.

The next step is to use the optical current transformer mentioned in the previous section. By going from option 2 (see Figure 2) to option 3 (see 3) there both an additional space saving but also the benefit of better measuring and fully enabling the digital communication using the IEC 61850-9-2 LE protocol. An additional saving in space of 190 m^2 or a total of 41% compared to option 1. There is also the need for 22 500 kg less CT equipment of which 2 250 kg less oil in each substation diameter. The amount of foundation needed is again reduced and another 10 000 kg CO_2-eq. are removed or a total improvement of 35% in CO_2-eq. reduction compared to option 1.

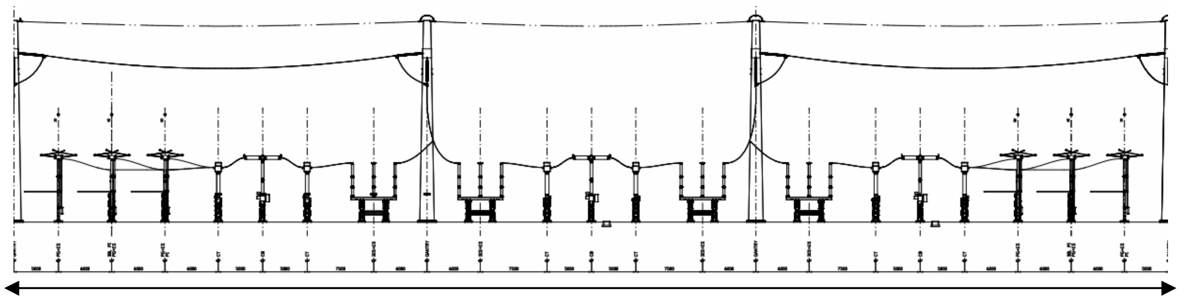


Figure 1: Option 1 with BAAH configuration and conventional circuit breaker, disconnectors and current transformers. The bay width is considered to be 21 m and the length is 160 m, which provides and area of 3360 m^2.

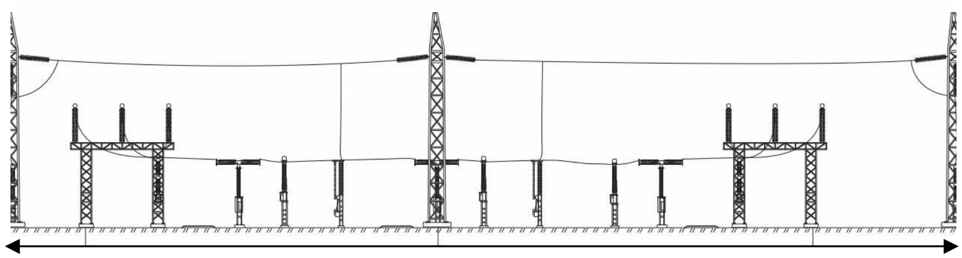


Figure 2: Option 2 with BAAH configuration and DCB and conventional oil filled current transformers. The bay width is considered to be 21 m and the length is 103 m, which provides and area of 2163 m^2.

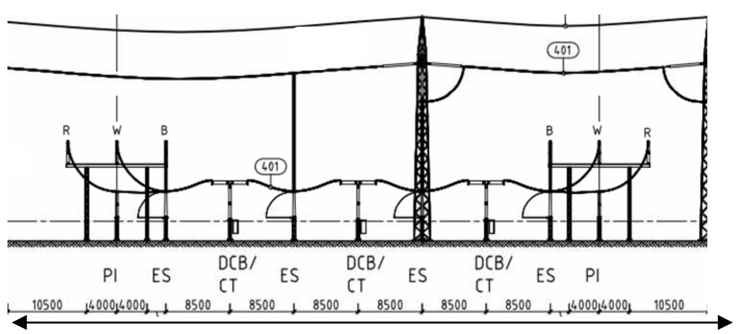


Figure 3: Option 3 with BAAH configuration with DCB and integrated NCIT's for current measurement. The bay width is considered to be 21 m and the length is 94 m, which provides and area of 1974 m^2.

FIELD EXPERIENCE OF DCB WITH INTEGRATED NCIT

The following case study is based on DCB with integrated optical current sensors installed in the Swedish power grid in 2010, see Figure 4.

The DCB is installed in a line with conventional current and voltage instrument transformers. The redundant fiber optic current sensor system installed in each phase of the DCB reads the current on the line and sends the information in sampled values, IEC 61850-9-2LE, format to the protection and control IEDs. The IEDs gathers current readings from the conventional current transformer and compares the analogue values with the data stream from the NCITs, see Figure 5.

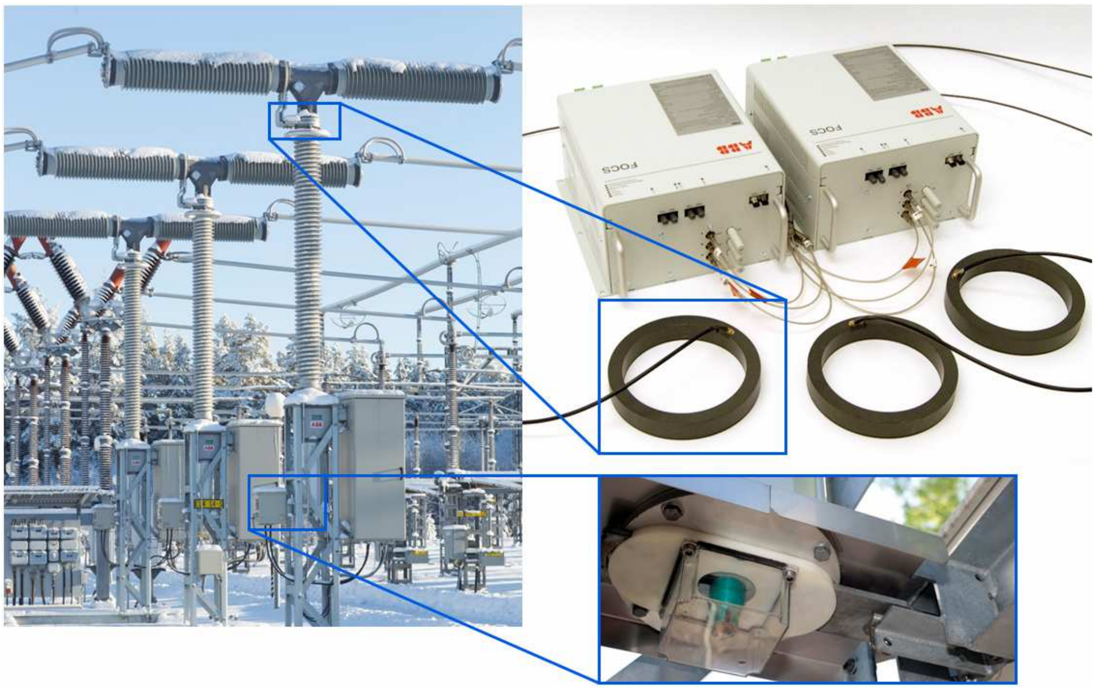


Figure 4: (Left) Pilot installation of a combined unit DCB with NCIT's of fiber optical current sensor (FOCS) type. (Right above) three phase FOCS-kit with three sensor heads and two opto-electric modules for redundancy. (Right below) One type of mechanical locking system for DCB as required by the IEC 62271-108 standard.

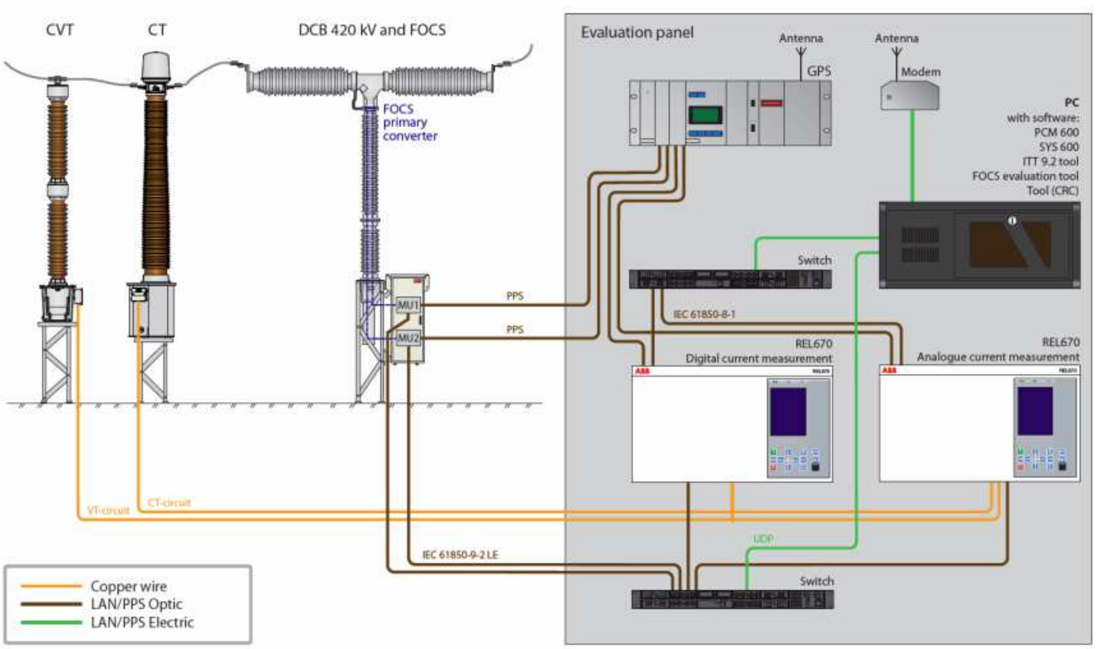


Figure 5: Schematical set up of the reference installation.

Since the installation the DCB/NCIT has seen normal load variations between 500-1500 A and temperature variations between -25 up to 35ºC. The graph, see Figure 6, below shows a comparison between the current reading for one phase from the conventional CT and the optical CT.

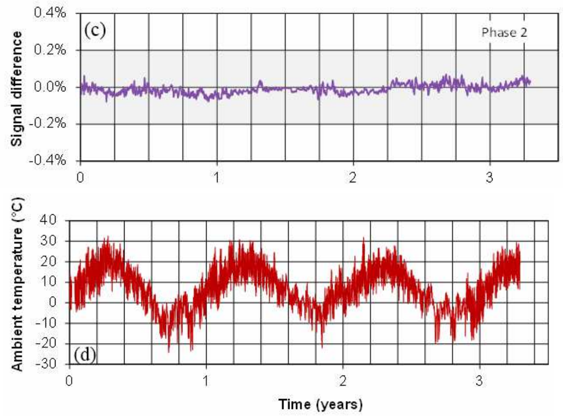


Figure 6: Comparison of phase 2 current readings from CT/NCIT

Comprehensive analysis of the behavior of the system has been made, [7]. During the service time the measurements has been very stable and do not seem to be degraded by temperature variations, age or vibrations from operations of the DCB.

CONCLUSION

The use of disconnecting circuit breakers and NCITs with digital communication can substantially reduce the footprint of a substation with up to 41 % less space needed. The need of steel, copper, insulating materials and oil can be drastically reduced and thereby providing a more eco-efficient substation solution. Hence making an overall reduction of more than 30 000 kg CO_2-eq. per HV diameter in the substation on only the foundations.

BIBLIOGRAPHY

[1] IEC, "High-voltage switchgear and controlgear – Part 108: High-voltage alternating current disconnecting circuit-breakers for rated voltages of 72,5 kV and above," International Electrotechnical Commission (IEC), 2005.

[2] IEC, "High-voltage switchgear and controlgear – Part 100: Alternating-current circuit-breakers," International Electrotechnical Commission (IEC), 2008.

[3] IEC, "High-voltage switchgear and controlgear – Part 102: Alternating current disconnectors and earthing switches," International Electrotechnical Commission (IEC), 2013.

[4] T. Laitinen and T. Lindquist, "Disconnecting circuit breakers in 400 kV substation renovations," in 2015 Cigre SC, Nagoya, 2015.

[5] I. Gutman, L. Stenström, D. Gustavsson, D. Windmar and W. L. Vosloo, "Optimized use of HV composite apparatus insulators: field experience from coastal and inland test stations," in Cigre, 2004.

[6] K. Kutlev, M. Magnusson and U. Andersson, "Reliable and Cost Effective Solutions for HVDC Switchyards," in CIGRE ‑ IEC Colloquium on EHV and UHV (AC & DC), Montréal, 2016.

[7] K. Bohnert, A. Frank, T. Roininen, B. Gülenaltin, P. Gabus and A. Vujanic, "FIBER-OPTIC CURRENT AND VOLTAGE SENSORS AS MODERN ALTERNATIVES TO CONVENTIONAL INSTRUMENTS TRANSFORMERS," in TECH-IT, New Delhi, 2014.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#59

Considerations on Ranking Threats to Power System Security

S. L. VORONCA*
CN Transelectrica SA
Romania

SUMMARY

Contemporary critical infrastructures, power system especially, are facing multiple threats ranging from traditional to emerging, from natural and accidental to intentional. To allocate limited resources to protect them, identifying the most imminent threats is the first and foremost step to achieve efficient and effective protection strategies.

As the majority of traditional risk management methods is not suitable for considering threats of different natures with various features at the same scale, this paper developed a framework for qualitative assessment of threats, allowing ranking them with multiple criteria from a broader dimension like a group decision.

A questionnaire was designed to collect the experts' perceptions on different features of possible threats in their power grids. The analytic network process (ANP) was employed to produce the final threats ranking by considering it as a multi-criteria decision making issue.

The proposed framework was then applied to rank threats from the perspective of a single transmission system operator (TSO) and a wider region of several EU TSOs. The ranking results shows the most imminent threats are still customary ones, such as the meteorological and accidental.

The paper is based on R&D project SESAME Securing the European Electricity Supply Against Malicious and Accidental Threats, one of the projects co- financed by the European Commission under the FP7 Programme, in which CNTEE Traselectrica SA was acting as member in the project consortium and as leader of TSO trial application workpackage.

KEYWORDS

Power system, security, threats, risks

OVERVIEW

Severe failures in critical energy infrastructures operation dramatically impact the human kind and generate large-range undesired impacts. After power system blackout occurrence [1, 2], appreciable economic losses are directly and indirectly striking the society. Various collateral damaging consequences as other infrastructures are interfering with the power system (i.e. sanitary services, drinkable water systems, communications, transports etc.), are significant, too. Different threats are the contemporary critical energy infrastructures exposing to. Several have a common denominator: the human factor. Accidental failures of aging equipment due to the lack of investment might appear most commonly as result of inappropriate action. But last decade continuous growth of malicious actions indubitably represents the result of the human factor aggressive and voluntary intervention. Other threats are the natural ones, which are closely associated with geologic phenomena [3]. Disasters of this kind are random, approximate information about their appearance frequencies coming from the statistical

* simona.voronca@transelectrica.ro

interpretation of related historical records [3]. To prepare the critical infrastructures against this last category of possible threats, namely the natural ones, the identification of the most important ones becomes the first and foremost step to launch effective and efficient actions with limited resources that can be used to decrease the exposure at those threats [4]. Given the characteristics already mentioned with regard to natural threats and for this present paper elaboration purposes, a relevant selection of them, authors have retained as a ranking threats method exemplification.

2. THREATS CLASSIFICATION

Given the large exposure to the outside environment such as wide geographic expansion, unprotected equipment in the fields, excessively relying on digital communication systems, etc., the power system is vulnerable to many potential threats. In general, threats against the security of power system operation can be classified into the following categories (Table 1) [5, 6]:

Table 1- Threats Classification

CAT.	NAT.	THREAT	DEFINITION
Conventional	Non-intentional	Natural threats	*Natural events not strictly controlled by humans that, if they occur, may impact the power system operation causing damages* (geomagnetic storms, earthquakes, forest fires, tsunamis, hurricane, flood, lightening, hail, animal, etc.).
		Accidental threats	*Possible failure of network devices and wrong human decisions that may threat power system operation* (operational fault, system equipment failure, accident owing to poor management, etc.).
Emerging	Intentional	Malicious threats	*Possible intentional actions against power systems facilities and operation, which are undertaken by different agents* (terrorist, criminal group, cyber attackers, copper theft, vandal, psychotic, malware writer, etc.) by various means (explosives, high power rifles, malware, etc.) with the intent to cause damage and get political or economical benefits.
	Non-intent.	Systemic threats	Potential failures brought by the evolution of power systems and new technologies (high penetration of renewable energy sources, bidirectional power flows from prosumers, etc.)

Threats from different catalogues have totally different features. For example natural threats happen unintentionally with huge impacts on a large area and are humanly impossible to prevent; while malicious threats happen with great intention and human efforts can strategically prevent them from happening or diminish their consequences. In addition, each threat has more than one interesting aspect to consider when ranking them. For example, natural disasters like earthquakes happen with tremendous damage; however, they might not occur very often. In contrast, accidental threats like insulation failure happen comparatively often yet with limited damages. Heterogeneous natures and multiple characteristics of these threats make it difficult to compare them on the same scale with multiple considerations through conventional risk assessment measures. Therefore, new framework and tool are needed to rank them not only according to a single aspect but to the most important considerations together.

In this paper we developed a framework to find the most imminent threats against the security of power system operation by ranking them, considering different aspects and their relationships among one another. The complicated ranking problem then can be treated as a multiple criteria decision-making problem. In further development, the Analytic Network Process (ANP) is employed to handle dependence and feedback in this complex decision process [7].

3. ANALYTIC NETWORK PROCESS

As a mathematical theory, the ANP was firstly introduced by Thomas L. Saaty in 1996 [7] to systematically handle dependence and feedback in a complex and conflict decision. The primary reason for introducing the ANP is to overcome the shortcoming of its precedent procedure AHP (Analytic hierarchy process), which is based on the functional independence of the upper parts from all their lower parts in the hierarchy, and from the criteria at each level [8]. However, not all problems can be expressed in a pure hierarchical fashion due to the interactions of various factors which may modify the importance of weights on a global scale [9]. Therefore, Saaty suggested using AHP and ANP in different conditions. More specifically, when the alternatives or criteria are independent, AHP is highly recommended; while ANP can be used to solve the problem of dependence among alternatives or criteria [9].

The reason for ANP's success is that it provides a process to derive from qualitative judgments and quantitative measurements to ratio scale priorities for the influence among factors and groups of factors [10, 11].

ANP has been applied to many practical cases [12], mainly in economics and conflict resolutions, as well as in many engineering applications. Reference [13] employed ANP to determine the faulty behaviour risk in work system safety. Reference [14] combined group ANP, quadratic programming and interval preference information to develop a multi-criteria decision support system to improve civil defence and emergency management.

ANP is structured using a series of pairwise comparisons to determine both the relative weights of each decision criterion and the rating of candidates (called alternatives/options) for each criterion. An analytic network model of a problem composes a set of clusters (i.e. groups of nodes), nodes (any aspect of the problem, e.g. alternatives, criteria etc.), and links (relationship and relative importance weights of different clusters and nodes inside).

Using ANP to solve a multi-criteria decision-making problem involves the following 4 steps:

Problem structuring and model construction,

Pair-wise comparison matrices and priority vectors,

Supermatrix formation and

Ranking or selection of the alternatives;

In the next section we are going to discuss the ANP application to threats ranking in power systems and give an example of threats ranking.

4. TRANSMISSION SYSTEM OPERATORS' PERSPECTIVE ON THREATS

To build a panorama of perceived threats on power system security in a specific region and of the transmission system operators' (TSOs) preparedness to respond to materialized threats, a questionnaire was designed to gather the experts' feelings towards the threats in their own power system. The answers to the questionnaire are intended to be used in ranking all the threats using the Analytic network process (ANP) method.

In designing the questionnaire, as a considerable number of threats would be evaluated and the questionnaire survey is a "one-time-only" shot, we considered the wording for each item to be compact, accurate, easy to understand, and most importantly, short.

questionnarie

The power system is constantly threatened by different threats. In the case of materialization of some threats on power systems, consequences will follow in different gravity. However, with the increase of the preparedness for them, the caused damage can be diminished to some degree. We would like to learn from your expertise and experience on your opinion toward these threats as an expert.

Please kindly to help us fill in the following questionnaire according to your insightful perspective. The answer does not need to necessarily reflect a precise analysis or your institutional official views, but rather express *your estimation* as an expert.

Instructions

For the evaluation of the likelihood, an 11-scaled mark is given from "0-Never happened" to "10-Frequently"; however, these terms are on a comparative term since the most frequent incidents happen in power systems are rear in common standards. The assessment of the impact for each threat is likewise based on an 11-scaled mark system, it should be evaluated in terms of their ability to cause blackouts. For those threats with '0-Never happend' do not necessarily suggest the impacts would also be '0-No impact at all', in such case, please give its impacts imagining it would happen in your grids.

Your Name:
Name of your company:

Questionnaire - Please evaluate the listed threats by choosing from the drop-off list

THREATS			Likelihood in your network	The impact gravity	Preparedness to respond
Accidental threats	operational faults	design error	4	3	7- Deploy countermeasures in progress
		wrong decision	8	9	8- Already deployed
		maintenance accident	9	7	8- Already deployed
	equipments failures	technical failure	8	7	8- Already deployed
		animal interference	7	3	8- Already deployed
		defective maintenance or maintenance e	8	6	8- Already deployed
	fire threats	fire & explosions	6	8	8- Already deployed
	nuclear threats	nuclear disasters	0- Never happened	10- Extremely Severe	6- About to deploy countermeasures
	human threats	outsider threats	7	6	8- Already deployed
		social threats	1-remotely maybe	4	4- About to analyze it
Malicious threats	physical threats	terrorist attack	0- Never happened	9	7- Deploy countermeasures in progress
		war act	0- Never happened	10- Extremely Severe	7- Deploy countermeasures in progress
		random sabotage	1-remotely maybe	3	7- Deploy countermeasures in progress
	human threats	insider threats	1-remotely maybe	6	7- Deploy countermeasures in progress
	cyber threats	malware	4	4	8- Already deployed
		cyber-warfare and terrorists hacking	0- Never happened	4	7- Deploy countermeasures in progress
Natural Threats	geological disasters	avalanches	0- Never happened	0- No impact at all	0 - Never heard
		earthquakes	5	10- Extremely Severe	8- Already deployed
		volcanic eruptions	0- Never happened	0- No impact at all	0 - Never heard
		landslides	5	1	5- Already analyzed it
	hydrological disasters	floods	9	7	8- Already deployed
		limnic eruptions (lake overturns)	0- Never happened	0- No impact at all	0 - Never heard
		tsunamis	0- Never happened	0- No impact at all	0 - Never heard
	meteorological disasters	blizzards	10 - Frequently	8	8- Already deployed
		ice/hoar storm	9	7	8- Already deployed
		cold wave	6	6	8- Already deployed
		cyclonic storms	1-remotely maybe	5	6- About to deploy countermeasures
		droughts	8	5	8- Already deployed
		hailstorms	10 - Frequently	4	8- Already deployed
		heat waves	9	7	8- Already deployed
		tornadoes	1-remotely maybe	5	8- Already deployed
		lightning	10 - Frequently	3	8- Already deployed
		thunderstorm (electrical storm)	7	3	8- Already deployed
		rainstorm	10 - Frequently	6	8- Already deployed
	fires	wild fires	3	3	8- Already deployed
	health disasters	epidemics	0- Never happened	9	4- About to analyze it
		pandemics	0- Never happened	9	4- About to analyze it
		famines	0- Never happened	0- No impact at all	0 - Never heard
	space disasters	impact events	0- Never happened	10- Extremely Severe	0 - Never heard
		solar flares/solar winds/magnetic storms	0- Never happened	2	2- Not aware
	contamination	chemical & biochemical contamination	3	2	1- Heard of
		radioactive contamination	0- Never happened	5	5- Already analyzed it

Fig. 1- Questionnaire for TSO's perspective on threats (example)

When considering the features of a threat, the most important ones are the severity of the impacts and the frequency of its occurrence. These two factors would be essential for calculating its risk. For example, the power system is constantly at risk of becoming endangered by different threats, and in case of threats materialization consequences with different gravity will follow [15]. Common studies will take the frequencies of a threat times its damage for its risk. However, with the increase of preparedness, the caused damage can be diminished to some degree. Therefore, according to this consideration, we selected three most important features to describe a threat:

"likelihood to happen",
"impact gravity", and
"preparedness to respond";

For each of these features, we will ask transmission system operators' experts to score them on different scales by their personal judgment (Fig. 1).

More specifically, for the "*likelihood to happen*" of a threat, experts needed to mark it by an 11-scaled range from:

"0- never happened/won't happen",
"1- remotely maybe" all the way to
"10 – frequent / extremely likely";

Similarly, experts will be asked to give their intuitive assessment on the "*impact gravity*" from
"0 - no impact at all" to
"10 - extremely severe";

Unlike the first two features, the choices for answers to *"preparedness to respond"* were more specific, namely:

"0- Never heard of",
"1- Heard of",
"2- Not aware",
"3- Aware",
"4- About to analyze it",
"5- Already analyzed it",
"6- About to deploy countermeasures",
"7- Deploy countermeasures in progress",
"8- Already deployed";

The questionnaires in the example were filled in by an expert working with a TSO, about the perceived threats on power system security for trial purpose (not necessarily reflect his/her true opinion on the results).

Based on the trial answers given by the expert, we extended the scores to a pair-wise comparison required by the ANP. Weight vectors, supermatrix and limit matrix were calculated to get the ranking of each threat according to a single criterion (Fig. 2) and the final ranking of the threats considering all aspects. Due to the sensitivities of the study, the final results are not given in this paper.

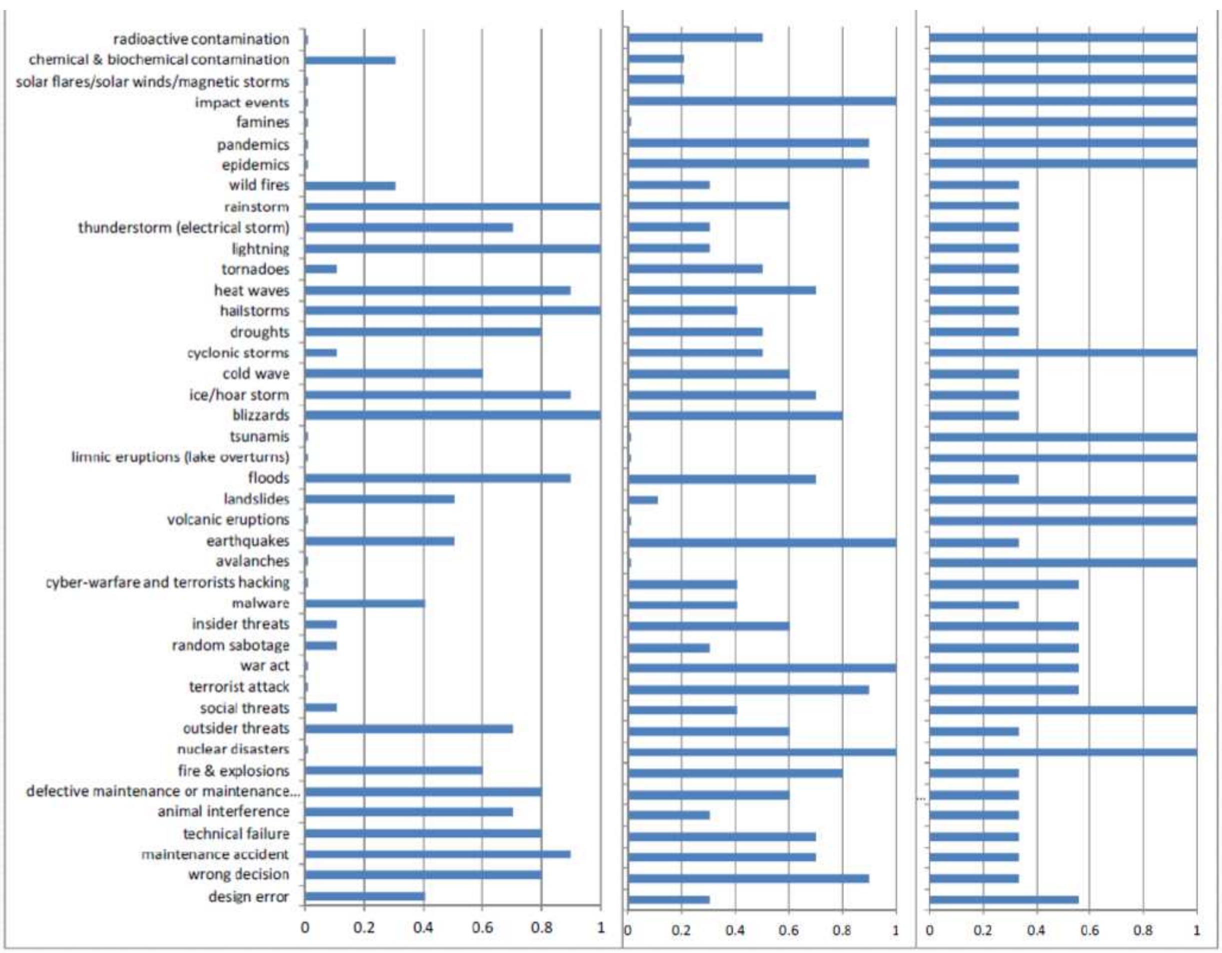


Fig. 2 Input evaluation for "likelihood", "gravity", "unpreparedness" (example)

5. CONCLUSIONS

Providing a panorama of all threats with different nature is quite a challenging task, especially when considering different features to outline them. Since the majority of traditional risk management methods are not suitable for considering threats with different natures at the same scale, further efforts are needed to develop a framework for the qualitative and quantitative assessment of threats, allowing their ranking with multiple criteria from a broader dimension like a group decision.In this paper, we designed a framework to gather the input for threats ranking and made a pilot trial by the approach. The results show that ANP is a suitable method for this purpose, and further extension seems to be promising to refine the results.

ACKNOWLEDGMENTS

This paper has been produced with the financial assistance of the SESAME project (a FP7-security project supported by the European Commission, aiming at providing a contribution to the development of tools and a regulation framework for the security of the European power grid against natural, accidental and malicious attacks. https://www.sesame-project.eu/). The views expressed herein are those of the author and can therefore in no way be taken to reflect the official position of the European Commission.

BIBLIOGRAPHY

[1] T. Huang, Simona-Louise Voronca, A. A. Purcărea, Y.J. Wu, *A framework to rank threats against power systems security*, 5th EEEC Int. Symp., Buletinul AGIR, **4**, Editura AGIR, 2013.

[2] * * *, *Deliverable D1.1 Analysis of historic outages, Version: 2.0,* SESAME - Securing the European Electricity Supply Against Malicious and accidental threats Project, Sept. 2011.

[3] T.L. Saaty, *The Analytic Hierarchy Process: Planning, Priority Setting, Resource Allocation*, McGraw-Hill International Book Co., New York, 1980.

[4] T.L. Saaty, *Multicriteria Decision Making: The Analytic Hierarchy Process*, RWS Publications, Pittsburg, 1990.

[5] SESAME Project - Securing the European Electricity Supply Against Malicious and accidental thrEats, *Deliverable D1.2 Vulnerability and Threat Knowledge Base*, Version: 1.0, May 2012.

[6] E. Bompard, T. Huang, Y. Wu, *Classification and Trend Analysis of Threats Origins to the Security of Power Systems*, International Journal of Electrical Power & Energy Systems, 2013.

[7] Thomas L. Saaty, *Decision Making with Dependence and Feedback: The Analytic Network Process*, 4922 Ellsworth Avenue, Pittsburgh, PA: RWS Publications, 1996.

[8] J.W. Lee, S.H. Kim, *Using analytic network process and goal programming for interdependent information system project selection.* Computers & Operations Research, 2000. 27(4).

[9] Thomas L. Saaty, The analytic network process. Decision Making with the Analytic Network Process, 2006: p. 1-26.

[10] Thomas L. Saaty, Lect9-ANP. ppt T*he Essentials of the Analytic Network Process with Seven Examples.* Retrieved February, 2004. 10: p. 2008.

[11] Thomas L. Saaty, *Theory and Applications of analytic network process.* Vol. 4922. 2005: RWS publications Pittsburgh, PA.

[12] R. Whitaker, *Validation examples of the analytic hierarchy process and analytic network process.* Mathematical and Computer Modelling, 2007. 46(7-8): p. 840-859.

[13] M. Dagdeviren, I. Yüksel, and M. Kurt, *A fuzzy analytic network process (ANP) model to identify faulty behaviour risk (FBR) in work system.* Safety Science, 2008. 46(5): p. 771-783.

[14] J.K. Levy and K. Taji, *Group decision support for hazards planning and emergency management: A Group Analytic Network Process approach.* Mathematical and Computer Modelling, 2007. 46(7-8).

[15] T. Huang, A. A. Purcărea, S. L. Voronca, M. Cremenescu, Y. Wu, *General overview on the societal and technical impacts of blackouts,* Acta Electrotehnica Special Issue Proceedings of the 5th International Conference of Modern Power Systems MPS 2013.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#61

Development of electricity infrastructure in Europe e-Highway2050 project results

C. DIACONU[*], S. SOARE, V. ZAHARIA, M. MARCOLT
CNTEE Transelectrica SA
Romania

SUMMARY

The e-Highway2050 project aims at providing efficient and consistent grid solutions for Europe for 2050 under the new challenges for the European power grid that result from the European Union ambitions in decarbonisation and promotion of renewable energy sources (RES). The project was finalized at the end of 2015, after 40 months of a collective work under the coordination of RTE and the support of the European Commission with significant outcomes to tackle such challenges. Key findings of e-Highway2050 include:

- New methodologies for the development of the European transmission grid have been developed, enabling to address long term horizons, cover the whole Europe, cope with the European low carbon objectives, translated at national, and local levels, while building global grid architectures.
- An invariant set of transmission requirements has been identified in consistency, and in continuity with the Ten-Year Network Development Plan conducted by ENTSO-E. Their benefits for the European system, resulting from the optimal use of energy sources, largely exceed their costs.
- The proposed architectures integrate the present Pan-European – Transmission - Grid, without needing a new separate 'layer' within this existing transmission network.

This paper summarises the following key results:

- the five scenarios to reach long term EU decarbonisation targets which have been created to frame the whole research and development project;
- the critical issues for the transmission grid under these scenarios identified thanks to advanced numerical simulations;
- the major "electricity highways" which have been identified to support any of the above scenarios when deployed at pan-European level;
- the power grid infrastructure suited for a low carbon economy by 2050;
- the key technological, regulatory, governance and operational challenges raised.

KEYWORDS

Electricity - Infrastructure, Pan-European – Transmission - Grid, Long-term – Planning

1. IMPACTS OF THE CLIMATE AND ENERGY UNION POLICY ON THE PAN-EUROPEAN – TRANSMISSION - GRIDS

On March 27th 2013, the Green Paper published by the European Commission (EC) framed an upgraded policy environment within which Europe ought to design its whole energy system from

[*] ciprian.diaconu@Transelectrica.ro

2020 up to the middle of the twenty-first century (2050). Such a long-term perspective had already been laid out in 2011, and then continued through the Energy Roadmap 2050 and the Transport White Paper. Moreover, each of these key policy papers had witnessed a parent European Parliament Resolution, aimed to converge on a “low carbon” vision for the European economy by 2050.

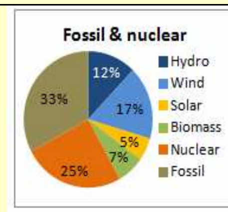
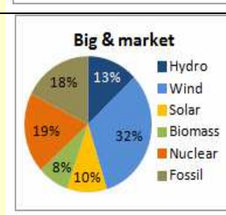
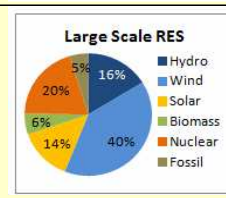
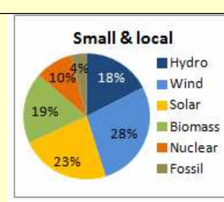
The 2030 and 2050 targets set by the Member States have a direct impact on European energy infrastructures, and more specifically on the pan-European electrical power system. The Ten-Year Network Development Plan (TYNDP) prepared by the European Network of Transmission System Operators for Electricity (ENTSO-E) addresses the development of the pan-European electricity transmission network from now until 2030.

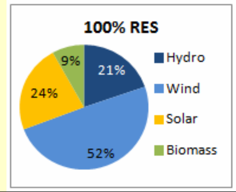
2. DECARBONISED SCENARIOS FROM TODAY TO 2050

The scenarios presented hereafter are the outcome of a sorting process selecting the most challenging cases to be dealt with by power system operators: these are asymptotic cases under which the Transmission System Operators (TSOs) may have to operate the pan-European power system by 2050. They have to explore all the plausible and predictable challenges to the power system. These challenges are driven by changes in generation, demand, storage and electricity markets (i.e. power exchanges within the ENTSO-E or beyond its borders). Overall, the scenario building process is a filtering technique implementing a worst-case approach, i.e. “extreme but still realistic” operational scenarios in line with the EC decarbonisation targets. Such scenarios shape an envelope of all possible future evolutions of the pan-European power system until 2050.

The five challenging scenarios resulting from this filtering process are summarised in Table 1 below, covering a low to maximum RES generation contribution.

Table I: The five challenging scenarios of e-Highway2050: short scenario description (left) and presentation of the corresponding European mix resulting from the quantification process.

Scenario short description	Generation mix at European level
Fossil & nuclear In this scenario, decarbonisation is achieved mainly through **nuclear and carbon capture storage**. RES plays a less significant role and centralised projects are preferred. GDP growth is high. Electrification of transport and heating is significant and energy efficiency is low.	
Big & market In this scenario, the electricity sector is assumed to be **market-driven**. A preference is thus given to centralised projects (renewable and non-renewable) and no source of energy is excluded. **Carbon Capture Storage** is assumed to be mature. GDP growth is high. Electrification of transport and heating is significant but energy efficiency is limited.	
Large-scale RES The scenario focuses on the deployment of **Large-scale Renewable Energy Sources** such as projects in the North Sea and North Africa. GDP growth is high and electrification of transport and heating is very significant. The public attitude is passive resulting in low energy efficiency and limited demand-side management. Thus, the **electricity demand is very high**.	
Small & local The *Small & local* scenario focuses on local solutions dealing with **de-centralised generation and storage**. GDP and population growth are low. Electrification of transport and heating is limited but energy efficiency is significant, resulting in a **low electricity demand**.	

100% RES This scenario relies only on **Renewable Energy Sources**, thus nuclear and fossil energy generation are excluded. High GDP, high electrification and high energy efficiency are assumed. **Storage technologies and demand side management** are widespread.	

Each scenario has a different context in terms of the:
Economy (GDP, population growth, fuel costs);
Technology (maturity, i.e. CCS);
Policies (incentives towards RES, energy efficiency, national/European energy independency);
Social behaviour (nuclear acceptance, preference towards decentralised generation).

These various contexts result in significantly different assumptions for generation, electricity demand, storage, and power exchanges. The major differences between the five scenarios are presented qualitatively in Figure 1.

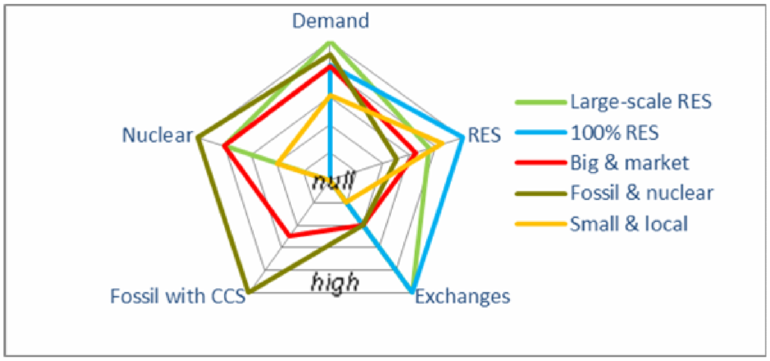


Figure 1: Major differences between the scenarios

The share of Renewable Energy Sources ranges from 40% to 100% in the different scenarios. Wind generation is significantly high in the scenarios *Large-scale RES* and *100% RES* with 40-50% of the generation mix. Solar generation plays a major role in the scenarios *100% RES* and *Small & local* with about 25% of the total generation mix. Nuclear generation ranges from 19 to 25% of the generation mix in three of the five scenarios (*Large-scale RES*, *Big & market* and *Fossil & nuclear*). Indeed, nuclear helps achieve the 2050 EU decarbonisation target. The *100% RES* scenario is nuclear generation free. Fossil energy sources remain significantly high in the scenarios *Big & market* and *Fossil & nuclear* with 20% and 30% of the generation mix, respectively, since for such scenario, the Carbon Capture Storage (CCS) technology is assumed to be mature. The share of fossil generation in the other scenarios stands below 5%.

3. THE POWER GRID INFRASTRUCTURE SUITED FOR A LOW CARBON ECONOMY BY 2050

3.1. Initial conditions: the starting grid

The scope of the project covers the period 2030-2050, thus the starting grid, which represents the initial conditions in the grid architecture, has been set with the following hypotheses:

- the transmission network existing today will still be in operation in 2050, i.e. the existing overhead lines and cable links will have the same topology and characteristics in 2050, even if they have been refurbished;
- the transmission network developments for 2030, foreseen by the TYNDP 2014, which include, for example, major North-South HVDC corridors in Germany, will all be completed.

Based on a detailed model of this transmission network (made of more than 8000 nodes), i.e. the probable transmission network topology in 2030, an equivalent grid model of a hundred clusters has been built to best match the flows occurring on the real grid. For each line of this simplified model, an equivalent impedance and a Grid Transfer Capacity (GTC) is estimated. This equivalent model is the grid initial conditions, i.e. the starting grid, for the simulations. The detailed model and the starting grid are shown in Figure 2.

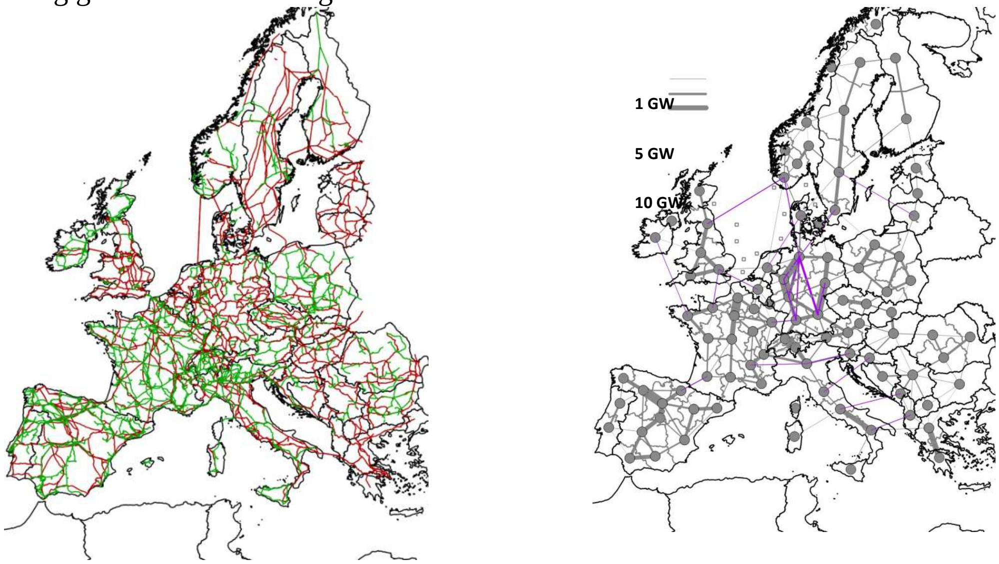


Figure 2: Starting grid of the e-Highway2050 project. Existing grid (left) and starting grid (right, the grey lines represent the existing lines and the purple ones represent the projects to be realised by 2030).

3.2. Grid architectures for 2050

Thanks to the system simulations, different transmission grid can be compared to assess their techno-economic profitability. The purpose of the grid development process is to find an optimal solution between these two extreme situations:

No further reinforcements are implemented after 2030. The grid investments are then minimal but the operating costs of the power system are high because grid congestion can prevent the use of the cheapest generation units.

Infinite capacities are built between all the clusters of the starting grid (the so-called “copper plate” assumption). The grid investment is then virtually infinite, but the operating costs of the power system are minimal because the cheapest generation can always be used wherever its location.

Great Britain and Ireland to Spain through France

In all scenarios, the need to connect the UK to continental Europe appears with a minimum of 6 additional GW (*Small & local*) and up to 31 GW (*Big & market*). In parallel, another 1 to 6 GW more are needed between Ireland and France: such interconnections are extended by a corridor crossing France down to Spain with a size of between 4 and 15 GW. The French-Spain interconnection is then reinforced between 8 GW (*Small & local*) and 20 GW (*Big & market, Fossil & nuclear*). This corridor is also extended to include Scotland via internal British reinforcements. The three main drivers identified for this major corridor are:

- Wind generation in the UK, Ireland and the North Sea. In all scenarios, the total wind capacity in these areas increases between 51 GW (Small & local) and 223 GW (100% RES). This generation can exceed the local demand: it can then be exported to France and Spain.
- Nuclear in the UK and France. In the scenarios Big & market and Fossil & nuclear, the nuclear capacities are increased in the UK by more than 10 GW. In the Fossil & nuclear scenario,

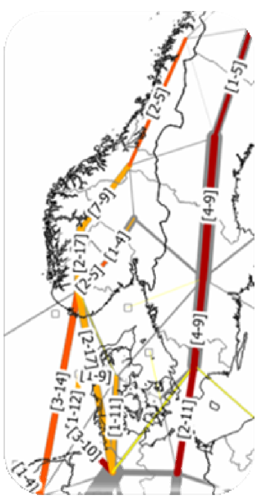
the nuclear capacity is also increased in France when compared to 2012. As a result, such scenarios require the highest capacities for the corridor, since it can be used to export nuclear generation to Spain in addition to wind generation.

- Solar in Spain and Portugal. The solar generation in Spain and Portugal increases between 40 GW (Fossil & nuclear) and 110 GW (100% RES). It creates an opportunity for this peninsula to export solar generation to northern Europe.

Greece to Italy and the Italian backbone

The Greece–Italy interconnection is reinforced in all scenarios between 2 (Big & market, Fossil & nuclear) and 9 GW (100% RES), while reinforcements Italy–Sardinia and Italy–Siciliy are also foreseen in all scenarios. The Italian corridor is reinforced in all scenarios, except for the Big & market one with a maximal value of 11 GW in the Large-scale RES scenario. The main drivers for such reinforcements are:

- Wind generation in Greece. Wind capacity in Greece is increased between 6 GW (Fossil & nuclear) and 24 GW (Large-scale RES, 100% RES). This generation can exceed the local demand and be exported towards Italy.
- Solar generation in Italy. The solar generation in Italy increases between 15 GW (Fossil & nuclear) and 96 GW (Small & local). Although it is mainly located in the North of the country close to the demand centres, significant volumes still need to be transported from the South to the North of the country.
- Connection to North Africa. In the scenarios Large-scale RES and 100% RES, significant connections from Algeria, Tunisia and Libya to Sardinia and Sicily are assumed (40 GW in Large-scale RES and 10 GW in 100% RES). The solar generation coming from these countries need to cross Italy to reach demand centres.

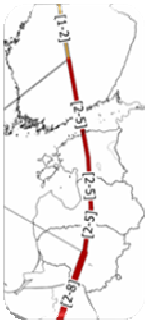


Norway and Sweden to Continental Europe and the UK

In all scenarios, a strong need to further connect Norway and Sweden with the rest of Europe is shown. The additional interconnections between Sweden and Continental Europe range from 6 GW (Big & market) to 15 GW (100% RES): they are extended by a 4 to 9 GW corridor across Sweden. From Norway to Continental Europe and the UK, the additional capacity is between 1 GW (Fossil & nuclear) and 19 GW (Large-scale RES). It is extended by significant internal Norwegian reinforcements. These corridors are connected to the German North-South DC corridors which enable a further transport of this energy within continental Europe. The main drivers for these reinforcements are:

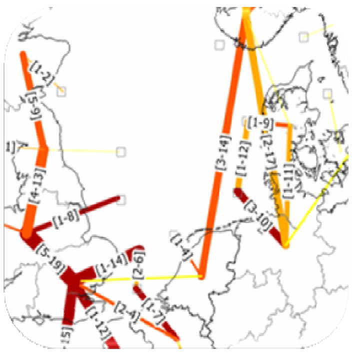
- Hydro power in Norway and Sweden. Hydro power in these two countries is currently around 50 GW. In the scenarios, an increase of between 11 GW (Big & market) and 50 GW (100% RES) is assumed. The resulting generation can exceed local needs and be exported to the rest of Europe. Moreover, hydro power is crucial for the whole European system as it brings significant flexibility. As a result, the interconnections should be sufficient to allow high peaks of exports during critical periods.
- Wind in Norway and Sweden. Wind capacity in Norway and Sweden is assumed to increase between 5 GW (Fossil & nuclear) and 45 GW (Large-scale RES). The resulting generation can exceed local needs and be exported to the rest of Europe.
- Nuclear decommissioning in the UK and France. Connections from Norway to the UK appear only in the scenarios 100% RES and Small & local. In those scenarios, almost

all of the nuclear generation is decommissioned in France and the UK (-47 GW and -73 GW, respectively). As a result, the western part of Europe needs support.



Finland to Poland through the Baltic States

A 2 GW (*Fossil & nuclear*) to 5 GW (*Large-scale RES*) corridor connects Finland to Poland through the Baltic States. The main driver for this corridor is the development of wind generation in the area. For Finland, it increases between 2 GW (*Small & local*) to 37 GW (*Large-scale RES*). For Latvia, Lithuania and Estonia, it stands between 8 GW (*Small & local*) and 36 GW (*Large-scale RES*, *100% RES*).



The North Sea area

In the initial grid, the capacities of the radial links are only around half of the installed offshore wind capacities. Further reinforcements have been assessed within the study. The main conclusion is that by 2050 some offshore clusters with huge volumes of wind power are not close to clusters exhibiting energy deficits. For instance, the offshore cluster near western Denmark is interesting for providing energy to northern Continental Europe rather than to Denmark which does not need all of it. In this case, there are several possible routes to go from an offshore cluster to a cluster with deficit in energy (Germany for instance):

- either through Denmark (radial connection to Denmark and extra capacity between Denmark and Germany);
- and/or through a circular meshing between the offshore North Sea clusters (offshore cluster close to Denmark, towards the offshore cluster close to Germany and the cluster located in North Germany).
- Another example deals with an offshore cluster close to the southern UK: a huge part of its wind power is useful for northern Continental Europe through Belgium. The path could then be:
- either through the UK;
- or through a circular meshing between the offshore North Sea clusters (offshore cluster close to the UK towards the offshore cluster close to Belgium and then Belgium);
- or directly to Belgium.

4. CONCLUSIONS AND RELEVANT IMPLICATIONS

The e-highway2050 project has developed a top-down methodology allowing the power system stakeholders and policy makers to anticipate the future transmission network development needs in line with the long term decarbonisation goals set at European level.

This methodology gives an initial indication of the main challenges that transmission system operators could face if the suggested new lines reinforcements were not implemented.

The results of the studies exhibit the following trends:

An invariant set of transmission requirements has been found: major “North – South” corridors appear in all scenarios with several reinforcements that connect the North of the pan-European electricity system (North Sea, Scandinavia, UK, Ireland), and southern countries (Spain and Italy), to the central continental area (northern Germany, Poland, Netherlands, Belgium and France);

The network extension rate is driven by the increase of generation capacities, especially renewable energy sources.

The proposed architectures could be integrated in the present grid, without introducing a separated 'layer' of transmission grid.

The costs of investment in grid expansion depend on the scenarios. They lie between 100 and 400 billion €. However, the study demonstrates that the benefit for the European economy, resulting from an optimal use of energy sources, would largely exceed these costs in all cases. Indeed, up to 500 TWh of RES curtailment and 200 mega tons of CO_2 emissions would be avoided annually.

How to operate the resulting grid architecture

System operation will be challenged in the future by the major changes expected in the European electrical system. Three main sources of change are identified, each having a potential impact on the different operating issues:

The increasing penetration of renewable energy sources: RES behave radically differently than traditional plants (small power electronics device vs. large synchronous generator). In four of the five e-Highway2050 scenarios, during some hours, they are the only generating units connected to the grid, supplying entirely the European load.

The increasing power exchanges: All the e-Highway2050 scenarios show significant European power flows on the transmission grid.

The increasing number of connections realized with HVDC: HVDC behaves very differently than AC lines. Today, a few DC lines exist in the European system to connect non-synchronous areas and only one DC link is implemented in parallel to AC lines. In e-Highway2050 scenarios, at least 50 GW of more HVDC are foreseen in addition to the 2030 projects of the TYNDP.

Power flows control

In comparison to flows on AC lines, which are determined by Kirchhoff's laws and the topology of the system, HVDC lines are connected via power electronics (PE) and can be actively set by TSOs. The advantage is a better control and a greater flexibility. The drawback is that HVDC are not responding "naturally" to the variations or contingencies affecting the power system and thus efficient coordinated control rules have to be implemented by TSOs.

Within the project, load flows simulations of the full transmission network of the continental synchronous area were performed for each scenario for two snapshots: winter peak and summer offpeak. The model was built from ENTSO-E 2030 grid with the inclusion of the 2050 inter-cluster reinforcements. For terrestrial reinforcements, two strategies were compared: AC and DC. A security study, comparing "N-1" and "N" situation, was then performed. In the simulations performed with AC reinforcements, the architectures are robust but with DC reinforcements, overloads appeared when fixed setting points were assumed. It highlights the need for smarter control rules of HVDC.

Voltage control

TSOs have to operate the system within secure voltage limits. The drastic change in the power system expected by 2050 will probably need adaptations in the reactive power compensation means. To assess these issues, AC load flows were tested within the project. For the two most extreme scenarios, Large Scale RES and 100 % RES, no convergence could be found. The reason is that existing methodologies and tools are inadequate to easily study such different network configurations. In parallel, in the R & D part of the project, an innovative algorithm has been developed to tackle these problems by automatically adapting the reactive power compensations. It could be applied in future studies.

Today, traditional plants are the main contributors to voltage control and their modeling in simulation tools are mature and quite realistic. This is not the case for wind and solar generators which are not systematically taking part to reactive power control and voltage support although it is technically feasible. Without this participation, the situation will no longer be manageable with more RES. This has to be anticipated in network codes and simulation tools should be adapted. HVDC converters also offer new possibilities for voltage control.

Dynamic stability and protection schemes

Traditional plants are synchronous generators; their behavior is well known by TSOs. On the contrary, HVDC, wind turbines and solar panels are connected to the AC grid via power electronics. Their dynamic behavior is completely different. Preliminary studies were conducted within the project but research is still needed to fully assess the impact of their increasing penetration. The "Migrate" research project funded by the EC will start working on this topic in 2016.

BIBLIOGRAPHY

[1] "Energy Roadmap 2050 Impact assessment and scenario analysis", European Commission

[2] G.Oettinger, EU Commissioner for Energy, "A pan-European grid for 2020 and beyond"

[3] "Guidelines for trans-European energy infrastructure", European Commission, October 2011

[4] Thomas Anderski, Amprion et alia, deliverable D2.3 System simulations analysis and overlay-grid development – Digest

[5] http://www.e-highway2050.eu

[6] Thomas Anderski, *Amprion et alia, deliverable D2.4 Contingency Analyses of Grid Architectures and Corrective Measurements*, to be published end of 2015

[7] ENTSO-E, "Ten-Year Network Development Plan (TYNDP)", www.entsoe.eu/major-projects/ten-year-network-development-plan/, 2014

[8] G. Sanchis, RTE et alia, "A methodology for the development of the pan-European Electricity Highways System for 2050", CIGRE Paris, August 2014

[9] B. H. Bakken, M. Paun, R. Pestana, G. Sanchis, "e-Highway2050: A Modular Development Plan on Pan- European Electricity Highways System for 2050", Cigre Lisbon, April 2013

[10] C. Pache, P. Panciatici, RTE; S. Lumbreras, F. Echavarren, L. Sigris, Comillas. Deliverable D8.7. of e-Highway2050 project: Recommendations about critical aspects in long-term planning methodologies, December 2015.

.

CIGRE Regional South -East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#62

Direct measurement of rotors temperatures of power electric machines

C. BULAI*[1], P. CURIAC[2]
[1]**BLACK SEA TECHNOCHIM CO,** [2]**NOVA INDUSTRIAL SA**
[1, 2]**Romania**

SUMMARY

The continuous development of OHL Dynamic Temperature Rating imposes the flexibility also for some basic, old power generation sources, e.g. for turbo-generators In these circumstances, in order to examine their availability, the knowledge of thermal reserve of the older machines imposes also the direct measurement of rotor heating. The present paper intend to offer an overview on the rotor heating of an older turbo-generator operating in different regimes, in function of the facilities offered by the test stand.

KEYWORDS

Turbo-generator, tests, rotor heating, heating measurement

1. INTRODUCTION

The rapid growth of renewable energy (wind power and photo voltaic) results in highly fluctuating grid demands due to changing weather conditions. The operation of conventional thermal power plants shifts from base load to medium and peak load to act as a flexible back-up generation capacity needed to maintain system stability and actual consumption needs. The new flexible operation regime of generators moves to extreme peak load operation with a high number of start-stop cycles and high load ramps. For turbo-generators, this means higher stresses and an accelerated aging with an increased possibility of damages to the generator main components like stator and rotor windings. Sudden shut down and long unplanned outages would be the consequences.

An integrated online monitoring system with different monitoring modules can help to avoid unexpected trips and optimize outages, by identifying issues in advance. This can help to facilitate the timely availability of parts and personnel to address those issues.

The relevant specifications for behavior of the power generation units connected to the grid are especially defined in the *Network Code "Requirements for Grid Connection applicable to all Generators"* [1] and are further explained in a corresponding application guideline [2].

In a recent article [3], the authors summarized the additional stresses supported by end windings of the turbogenerators due to the new network code. Thus, it has been compared the severeness of additional stresses, which are generated by the new flexible grid demands, for two different types of generators (indirectly vs. directly cooled generators). In Table 1 we extracted only additional stresses for rotors.

* paul.curiac@novaindustrialsa.ro

Table 1: Effects of new grid demands on generator rotor

Increased requirements of new grid code ⇨	Physical ⇨ consequences for components	Severeness of additional stresses *)		
		Affected rotor components	Indirect air-cooled	Direct water-cooled
Over-voltage in parallel with low frequency 1,15 U_N at 47, 5 Hz	High exciter current I_e High magnetic flux density B	***Rotor winding***	High	Mid
High load ramp of 24 % of rated active power per min. (0,24 P_N /min)	Fast and high increase of current I in copper conductor	***Complete rotor winding***	High	Low
High amount of very fast load ramps and large active or reactive power changes Peak load condition	Permanent change of dynamic-mechanical stresses and high thermo-mechanical tension at windings	***Rotor winding, especially end-windings covered by retaining rings***	High	Mid

*) Results based on qualitative analysis

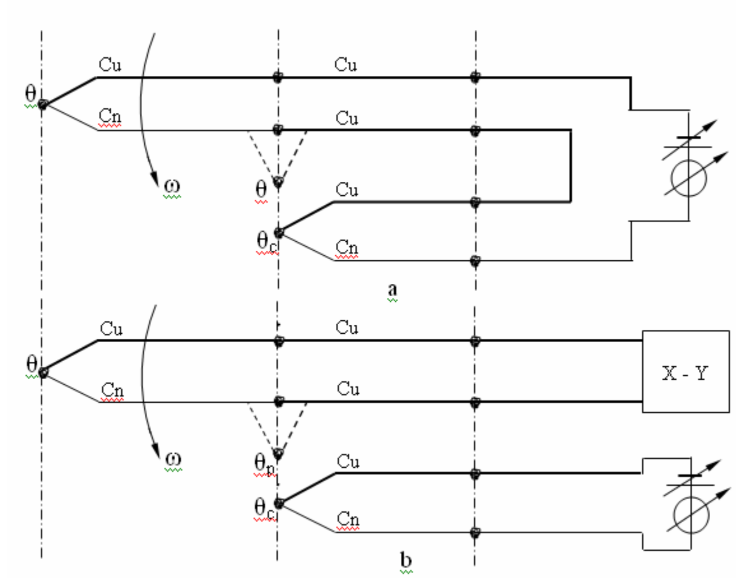
As an example, these are an elevated frequency range (47.5 Hz - 51.5 Hz) and an elevated voltage range (85% - 115%). This increases the risk of extremely high stator magnetization (high flux densities for high voltages – 115% U_N - at low speed – 47.5 Hz -), resulting in the formation of hot spots. The rotor must provide this induction, which results in elevated rotor currents. Thus, considering only the effects on the rotor, the elevated rotor currents can lead to thermal deformation of copper conductors and overheating of the turn insulation on rotor end winding [3].

Through the presented work it has been obtained experimentally the heating of the critical points, identified for the rotor of a turbo-generator of 12 MW, 10.6 kV, cos φ = 0.8 at 3000 rpm which is cooled symmetrically, axial-radial, with air, in a closed circuit.

First, the heating of the rotor's copper has been determined, for a no-load steady-state, a three phase short-circuit regime and a compensation regime (where the rotor current and the voltage are close to their rated values). Second, several tests were conducted, both for steady-state and transient operation, to determine the iron heating of the rotor surface in a case of two-phase short-circuit; this, the more so as attempts to calculate by FEM the temperature distribution on the rotor body surface in case of machine operating in non- symmetric regime, did not full satisfy.

2. MEASURING PRINCIPLE

The main scheme used to measure the temperature of a point on the rotor, in a steady-state operation of the tested turbo-generator, is shown in Figure 1-a: the copper-constantan wires of the thermocouple, starting from the measure junction, passing through the reference junction (with constant temperature) it reach, by means of a special, sliding-contact brush-ring, to a channel of a self-compensation multichannel temperature recorder [4]. The constantan-copper contact from the area of reference junction creates a *parasite thermocouple* (θ_p) whose thermo-electric voltage is canceled with the help of the thermocouple (θ_c), mounted nearby.



	Rotor		Stator
Measure junction	Reference junction	Sliding contact brush-ring	Recorder apparatus

Fig. 1 Schematic diagram for measuring over-temperatures:
a-in steady-state regime; b-in transient regime

The circuit shown in Figure 1b was used to measure the machine rotor heating during transient operation. Since the findings have shown that in the unexcited, steady state operation, the measurement junction temperature is the same as the reference junction temperature, the measurement thermocouple being, thus, compensated by its proper parasite thermocouple formed at this junction, it can be obtained directly, by means of a X-Y mill voltmeter recorder, the time variation over temperature value of the measuring point; for the temperature registration of the reference junction in rotation, it has been used a measuring circuit realized from a nearby mounted thermocouple and connected, by a compensation cable, to a self-compensated multichannel temperature registrator.

It should be noted that, for the temperature measuring were used thermocouples made of two conductors of copper, respectively constantan, each having a diameter of 0.5 mm, and welded together by immersion in a mercury bath. The thermocouples were then calibrated, aged and finally sorted.

In general, it has been preferred analog measurement instruments.

3. THERMOCOUPLES IMPLEMENTATION

Given the important peripheral speed and large radius of the rotor, a special attention is required at location and fixation of the thermocouples and of their circuits. The temperature values of the measured points have been obtained by 73 thermocouples mounted on the turbo- generator rotor, 54 of which were onto the excitation (field) copper, and the rest of 19 thermocouples being distributed as follows [2]:

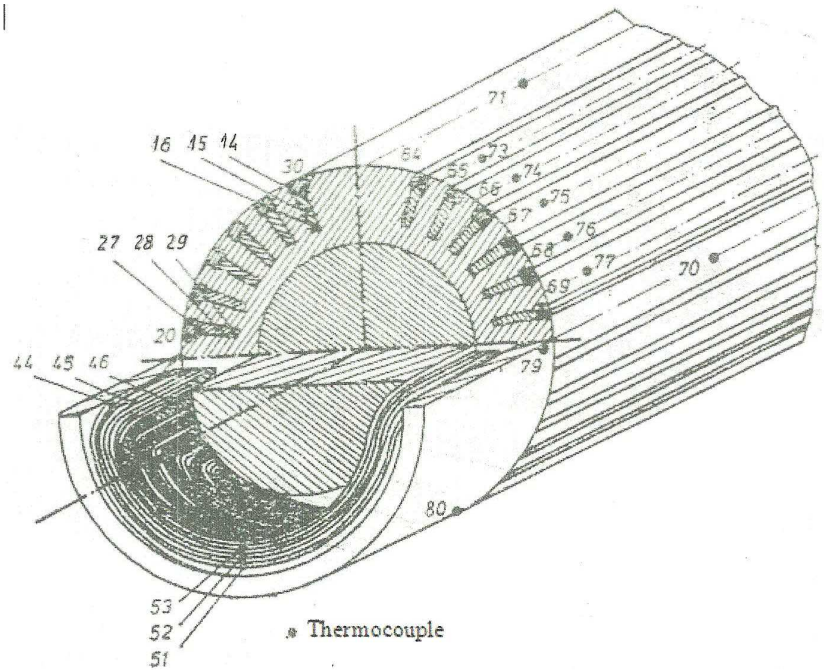


Fig. 2 The location of the thermocouples on rotor

- 54 thermocouples belongs to the field winding copper (TC1-TC9, TC11-TC19, TC21-TC29, TC31-TC39, TC41-TC49, TC51-TC59);
- 6 thermocouples at the closing wedges TC64-TC69);
- 4 thermocouples at wedge-tooth interfaces (TC10, TC20, TC30, TC40);
- 2 thermocouples on the axis of poles (TC70, TC72);
- 1 thermocouple on the axis of poles (TC71);
- 1 thermocouple on the retaining ring (TC80).

The locations of the thermocouples on the rotor are indicated in Figure 2.

The fixing of the thermocouple junctions in measuring points was made by gluing, using epoxy putty; the coils were previously isolated with varnish to prevent the possibility that some parts of the measurement system from being energized. The extraction of the connections from the mounting location of the measurement junctions to the end of the rotor, was carried out under the locking wedges of the slots, by two radial channels made under the front ends of the coils, and then through the hollow shaft.

The special transmission device of the thermo mill volts from thermocouples placed on rotor to the registration instrumentation had more than 100 sliding contacts type brush (Silver-graphite) - ring (Copper-silver alloy) [5].

4. HEATING MEASUREMENT

The heating measurements have been done first by indirect method. The normal cooling being ensured, the machine is subjected to successive heating due to different types of losses during normal operation; based on the results from a no-load test without-excitation (GN), a no-load test at rating voltage (G), and a 3 phase short-circuit test at rated current (Sc), the heating in normal operation can be pre-determined. Second, a direct heating test has been done in a compensation regime (C), with value close to the rated rotor voltage & current. Thus, by having access to an additional synchronous machine with nominal values close to those of the tested machine, the principle scheme presented in Figure 3 was implemented: then, simultaneously, the excitation of the tested machine (MI) was increased and the excitation of the additional machine (MS) was reduced down to the required values [6].

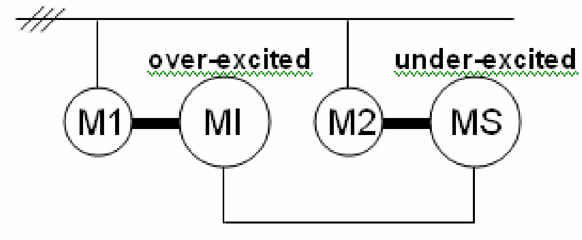


Fig. 3 Test stand setup

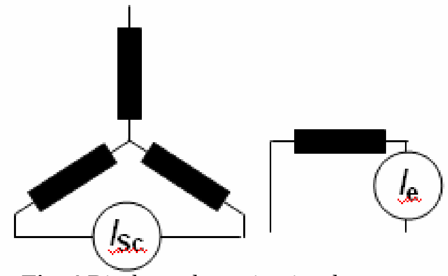


Fig. 4 Bi-phase short-circuit scheme

To determine the rotor surface heating, additional heating tests were conducted for permanent two-phase short-circuit state; to avoid the risk of excessive overheating for the end-windings due to dispersion inverse fields, the short-circuit currents were limited to not exceed 30% of the rated current.

Table 2 Data necessary to achieve the short-circuit between 2 phases (transient regime)

	$0.8\ I_N$	$0.9\ I_N$	$1.0\ I_N$	$1.1\ I_N$	$1.2\ I_N$	$1.3\ I_N$	$1.4\ I_N$
I_{2c} [A]	1100	1235	1375	1515	1655	1785	1785
I_{2m} [A]	1080	1260	1400	1540	1648	1840	1860
I_{ex} [A]	154.0	173.5	192.5	212.5	232.0	251.0	251.0
t [s]	15.5	12.5	10.0	8.5	7.0	6.0	10.0
$(I_{2m}/I_N)^2 \cdot t$ [s]	9.548	10.488	10.360	10.662	10.055	10.745	18.300

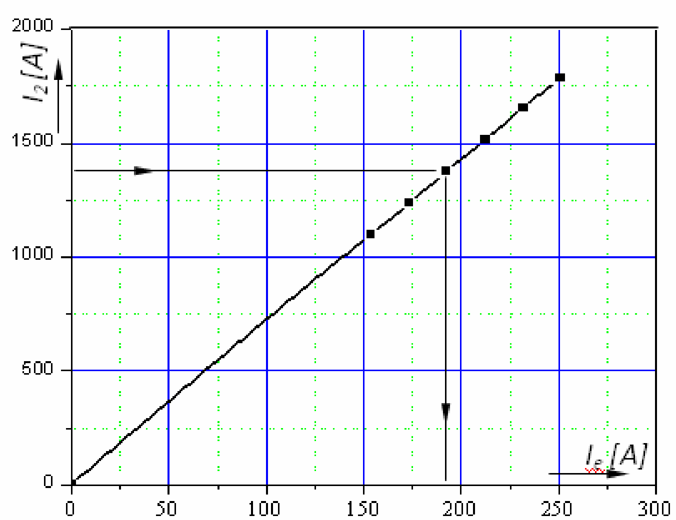


Fig. 5 The characteristic of bi-phase short-circuit

The variations of the rotor surface heating in the circumstances of the two-phase short-circuit in transient regime, have been obtained in the conditions of the application of a raised initial excitation voltage, for time reduction at touch the short-circuit current [7].Using the scheme from Fig.4, the necessary data for realizing of this transient regime (Table 2) have been obtained on basis of the bi-phase short-circuit characteristic, built in advance (Fig. 5) the testing duration for every selected value of current, correspond to time t from the energetic relation [8], [9], [10]:

$$(I_2 / I_N)^2 \cdot t = 10$$

were I_2 represent the value of the two-phase short-circuit current, and I_N the rated current.

5. TEST RESULTS

The results have shown finally a heating field image of the rotor copper bar, e.g. as that from Figure 6. A first finding regarding the proper course of the heating tests performed on rotor, is offered by the fact that the points that give the copper heating variation, depends on the square of the excitation current for all tested permanent regimes, are described, practically, by a right line (Figure 7).

The temperature rise was measured with the thermocouples placed on the surface of the rotor iron, and built in different operating regimes, including the permanent two-phase short-circuit regime at 0.3 $\boldsymbol{I}_{\mathbf{N}}$**.** These measurements are summarized in Figure 8 [11].

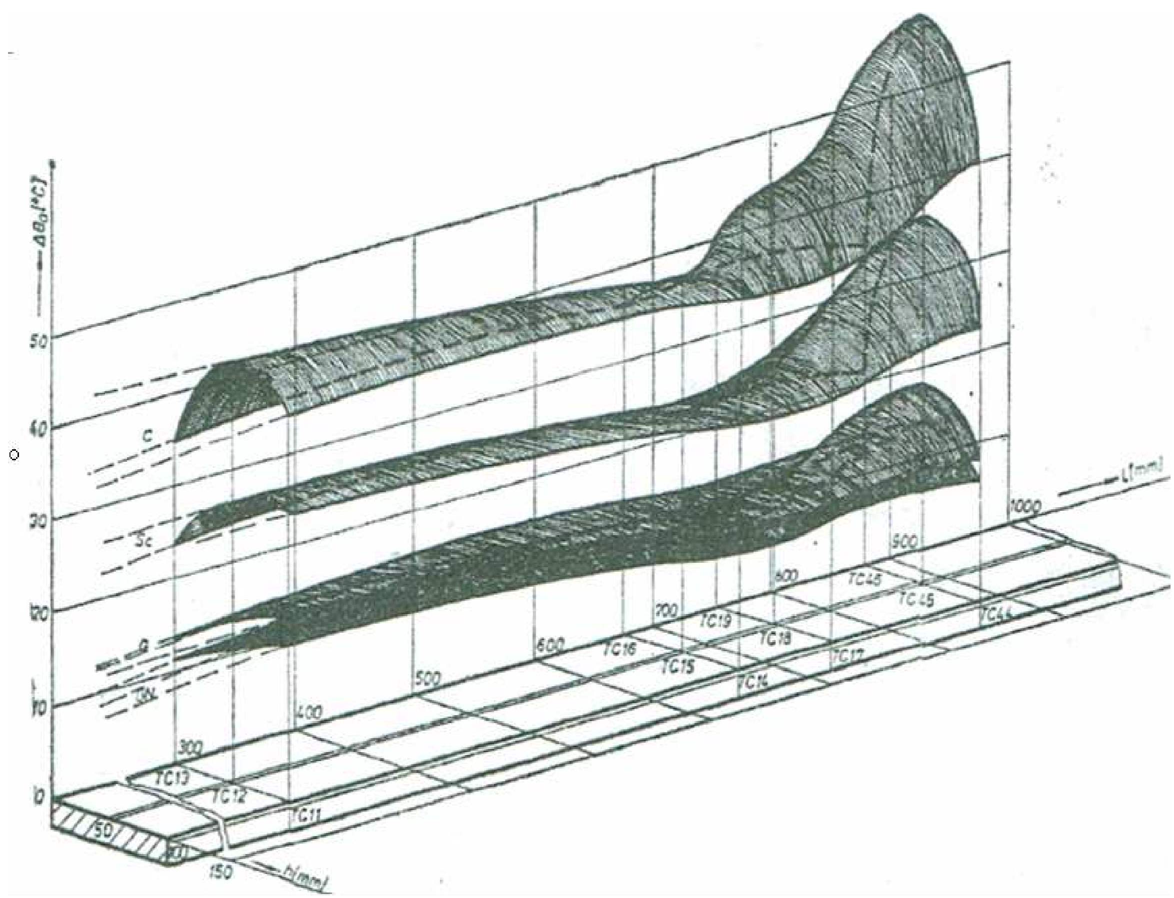


Fig. 6 The thermal field of the rotor bar in different test regimes:
GN-no load, cold run; G-no load, heat run; Sc-3 phase short-circuit; C-compensation

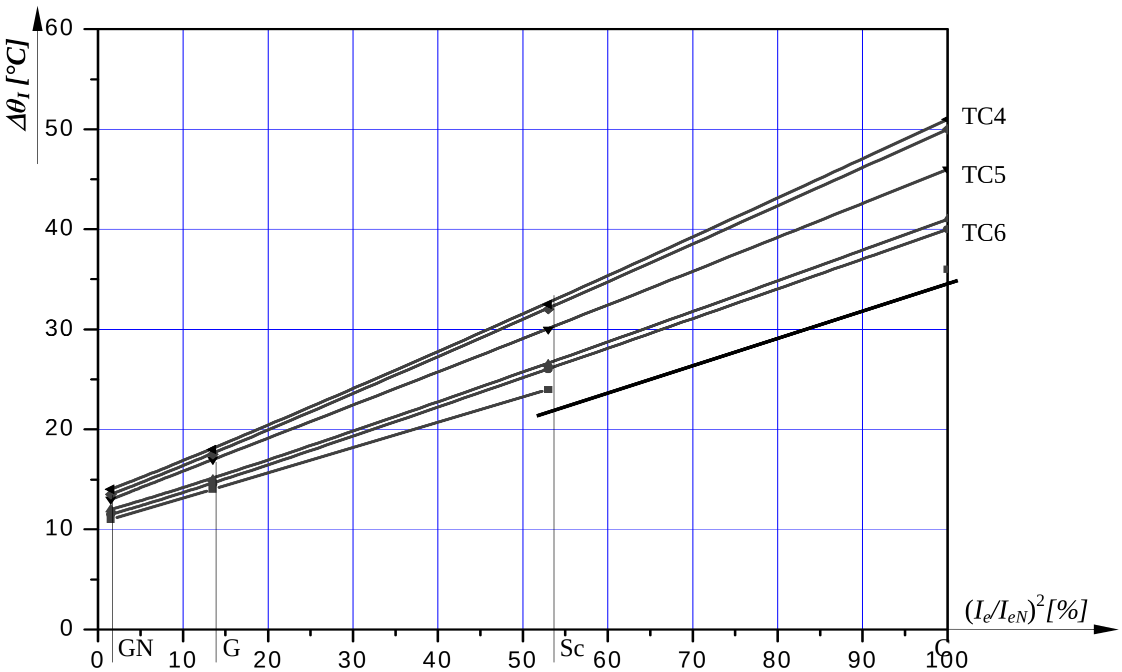


Fig. 7 The copper heating variation with the square of excitation current

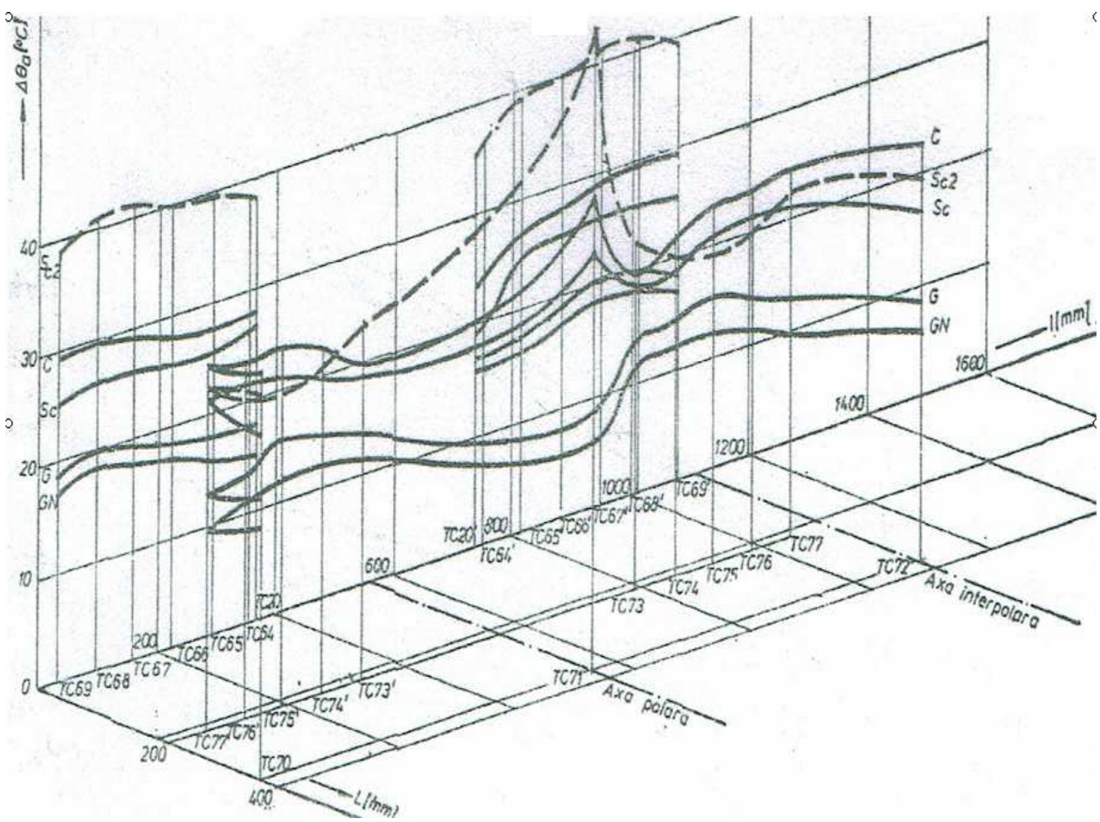


Fig. 8 Rotor iron heating variation in different running regimes

In transient two-phase short circuit regime was registered the variation in time of the heating in different points on the surface of the rotor's iron; thus, the variation in time of the heating on the polar axis is shown in Figure 9.

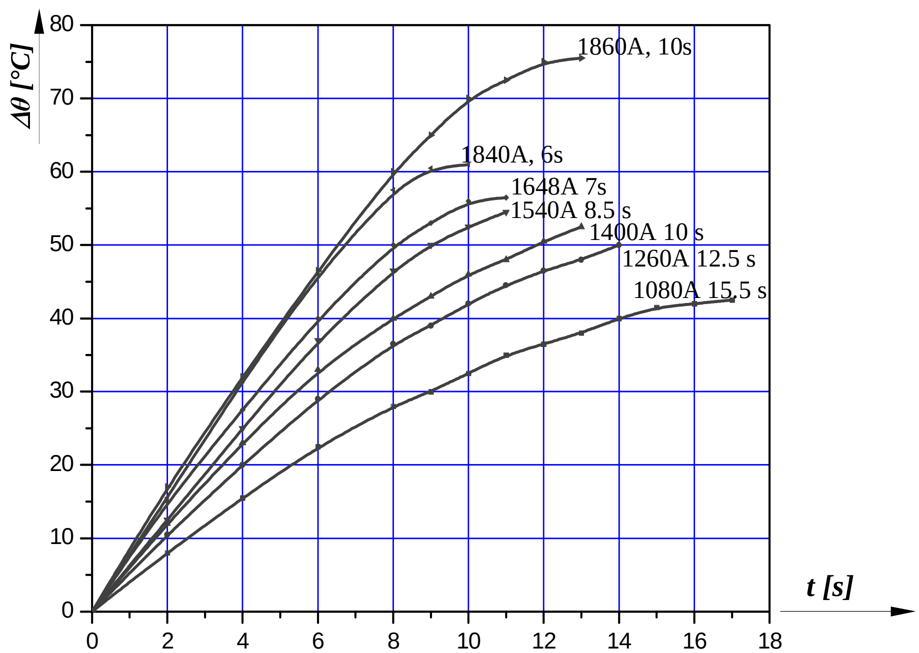


Fig. 9 Iron heating variation in the polar axis in a transient regime of biphasic short-circuit

For the thermocouples placed on the surface of the rotor iron, it has been possible to check the linear character and limit until which is maintained, of the temperature increases, for different values of the energetic coefficient (Fig. 10).

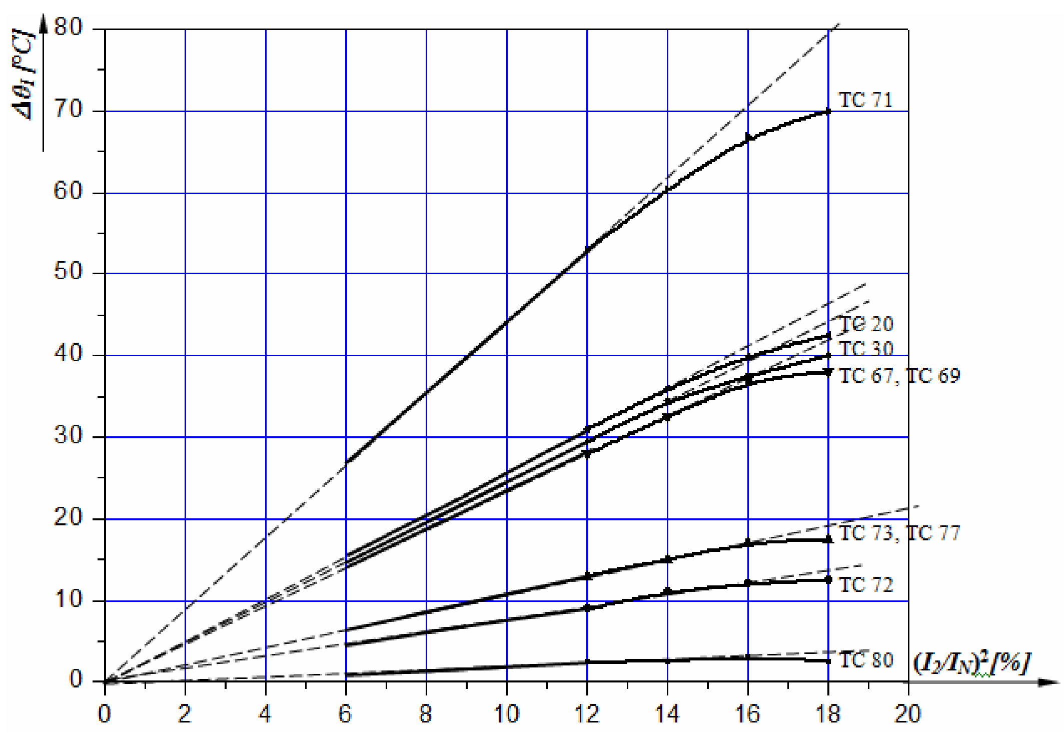


Fig. 10 The iron surface heating variation with the square of the bi-phase transient short-circuits current.

6. CONCLUSIONS

The resulting conclusions for the construction type of the tested turbo generator are:

- For the excitation winding it is observed, especially in a closer regime to the rated one, the maximum heating occurs at the mid height of the bar, where ventilation possibilities are smaller; along the rotor body, the over temperatures grows to the center of the machine;

- Maximum temperature gradient is obtained in zone of the end-coil where, due to larger free spaces, cool air directing may be not well controlled;

- The heating of the end-bars is different from one coil to another due to unbalanced ventilation conditions;

- The most heated point of the rotor winding was recorded at the middle of end of the outer coil;

- By a comparative study of the most heated point and of the average heating of the rotor winding, in function of the square of excitation current and considering the rotor insulation class, it can be determined by extrapolation the excitation current limit and thus, it can be establish more accurate the machine reserves;

- The heating due to eddy currents induced by the inverse field, recorded on the rotor iron surface at the permanent two-phase short-circuit tests are grouped into four temperature domains: the hottest points are in the polar areas, followed by the wedge-tooth interfaces, the teeth of rotor, including the inter-poles axis, and the lowest heating was measured on the rotor retaining ring;

- Maximum dispersion of the values has been recorded in measurement points located on the wedge-tooth interfaces, this being mainly due to mounting technology;

- The heating recorded in the transient bi -phase short-circuit regime, maintains the same grouping of values as in the case of similar permanent regime;

- The maximum value of heating for the thermocouple from polar axis indicates that, during the machine operation, the temperature values would not jeopardize the properties of the rotor's iron.

BIBLIOGRAPHY

[1] *ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators, published by ENTSO-E AISBL*, Brussels March 2013, Belgium.

[2] Implementation Guideline for Network Code “Requirements for Grid Connection Applicable to all Generators”, published by ENTSO-E AISBL, Brussels October 2013, Belgium.

[3] Ana Joswig, Hendrik Steins, Jürgen R. Weidner, “Impact of New Flexible Load Operation and Grid Codes on Turbine Generators with a Focus on End Windings”, Power Gen Europe 2015, June 9-11, 2015, Amsterdam, the Netherlands.

[4] ASTM-STP 470 A – Manual of the use of Thermocouples in Temperature Measurement.

[5] http://www.fabricast.com/

[6] IEC 60034-2-1: 2007 Rotating electrical machines- Part 2 Metods of tests- Section 1 Standard Methods for Determining Losses and Efficiency from Tests (Excluding Machines for Traction Vehicles).

[7] Barret, Ph., Heuillard, J. F., Coustere, A., *Stressess on turboalternators under unbalanced conditions*, CIGRE 11-11, 1970 Sesion.

[8] Blaylock, A. R., Hindmarsh, R., Foster, K. A., *Some critical aspects of generator capability under unbalanced operating conditions*, IEEE Trans, Power App. And Sys., vol PAS-96, No. 5, Sept./Oct., 1977.

[9] Williamson, A. C., *Measurement of rotor temperatures of a 500 MW turbine-generator with unbalanced loading*, Proc. IEE, vol 123, No. 8, Aug, 1976.

[10] D.Popescu, P.Curiac, "Rotors Heating Measurement of Large Motors Starting by Direct Coupling to the Network". In: *E.E.A. Electrotehnica* 33, no 5, Jul.1985, pp. 197-201 (in Romanian).

.

CIGRE Regional South -East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#63

Energizing of Large PM Rotors of Wind Turbine-Generators

P. CURIAC
NOVA INDUSTRIAL SA
Romania

SUMMARY

The high coercive force of today's hard magnetic materials not only makes possible improved permanent magnets (PMs), but also creates problems in magnetizing these materials. With increasing the power of wind generators having rotors equipped with PMs of high energy, became imperative necessary the energizing of PMs only after the rotor complete assembly.

The paper presents two different cases: A - a magnetizing inductor dedicated to magnetize, at once, a pair of poles and then, successively, the rest of pairs of rotor poles for a wind turbine generator of 1.7 MVA, 20 rpm, and B - an 1 MW - class, low-speed, axial flux machine having a disk rotor with PMs between two stators, which are wound in a tooth-coil technology, facilitating thus the magnetizing inductor function of its own armature.

KEYWORDS

PMSG, rare-earth PMs, surface mounted PMs rotors, magnetizing inductors

1. INTRODUCTION

The continuous refinement of hard magnetic materials of high-energy has led to a wide host of their uses in various applications due to their high basic magnetic parameters (remnant flux density, coercive field intensity and maximum energy product). Thus, the application of rare-earth PMs (e.g. NdFeB, SmCo) in the construction of electromechanical converters increased exponentially. In general, it becomes more difficult to magnetize a device which contains such permanent magnets and especially rotors of large PM synchronous machines, e.g. wind turbine-generators.

Although there may be various stages during the manufacturing of a PMSM when the magnetization can be undertaken, the post-assembly magnetization is preferred since it eliminates the difficulties associated with handling of pre-magnetized components. Practically, surface-mounted rare-earth PMs on rotors of large synchronous machines must be magnetized as a whole unit or, if not possible, pole by pole or a pair of poles by a pair of poles, by using appropriate equipment.

Thus, pulsed field approaches become more attractive: the pulsed excitation current typically lasts only a few milliseconds and the cost of the system power supply is much lower. In such a system, the excitation field is generated by discharging a large capacitor bank into an iron core coil (magnetizing inductor).

A fully magnetized magnet is considered to be fully saturated. To ensure saturation, it is necessary to apply an external-magnetizing field of sufficient strength to fully align the magnetic domains, which exhibits the highest coercivity; the magnet's weaker domains will follow.

The magnetizing inductor transforms the output of the magnetizer into the magnetic field used to magnetize the PM's rotor as a whole. Inductors are available in many forms depending on the magnet being processed and other factors. Certain applications may require that cooling provisions be provided in the fixture to maintain a safe operating temperature.

2. SPECIFIC PROPERTIES OF THE USED PMs

2.1 Review

In comparison with metallic PMs, the rare-earth PMs (especially NdFeB type)—recently available from the cost point of view—are offering more advantages (see also Fig. 1):

• Greater power density which leads to the reduction of the dimensions and weight;

• The intrinsic coercive magnetic field intensity of the magnetic polarization is greater than the coercive field of the magnetic flux density which means that these magnets may resist more intensive fields than the metallic ones;

• The small intrinsic recoil permeability of the rare-earth PMs makes the stable operation possible in dynamic conditions;

• The linearity of the demagnetization curve simplifies the calculus of needed devices.

2.2 Magnetizing Requirements for the PM's Material

In general, the rare-earth PMs -including NdFeB- require about 2500 kA/m for magnetization (see also Table 1), [1]; the corresponding magnetic flux density within the magnets rises up to typically 3 to 5 T peak value, yielding a highly saturated iron circuit during the magnetization process.

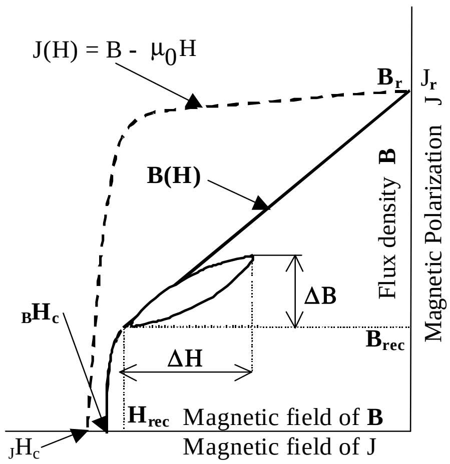


Fig. 1. The demagnetization curve and the recoil loop of PMs

Table 1. Actual magnetic materials

Material	Coercivity H_c [A/m]	Required magnetizing field H [A/m]
AlNiCo	46000 – 130000	200000 – 640000
Ceramic	150000 – 240000	800000 – 960000
SmCo	360000 – 960000	1600000 – 8000000
NdFeB	280000 -- 1000000	1600000 - 3600000

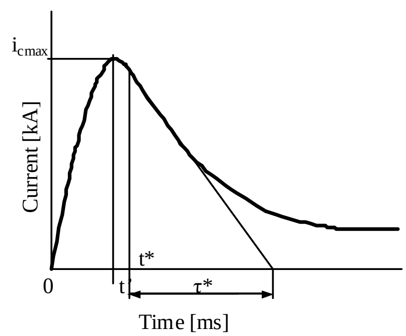


Fig. 2 The typical shape of the magnetizing current

By properly saturating the magnet, the flux levels and resistance to demagnetization indicative of the particular magnet material will occur. By not providing proper saturation, the magnet will be more susceptible to demagnetization from both internal and external influences. If a magnet is to be used at a level less than saturation, it must be fully magnetized and then subjected to a secondary process of controlled demagnetization: the PM is artificially demagnetized up to a value which is slightly higher than the highest possible demagnetization field during the operation (conditioning of the PMs).

2.3 Magnetization by Pulse Currents

The electric circuit for magnetization is presented in Fig. 3. This LRC circuit consists in principle of the loading unit for the capacitor bank (with adjustable loading voltage U_C up to 10 kV) and the discharge unit with the thyristor Th, the freewheeling diode D, and the magnetizing inductor, MI (with parameters R_C, L_C), [2]. When the thyristor is fired, a condenser discharge is started, loading the magnetizing inductor with a pulse current. A choke (with parameters R_{Ch}, L_{Ch}) in series with the thyristor Th, ensures the current limitation in case of a short-circuit of the magnetizing inductor.

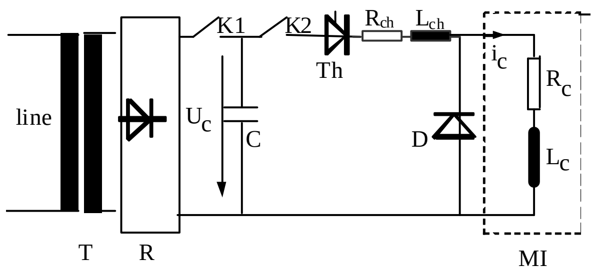


Fig. 3 Condenser bank discharge magnetizer: T-trafo; R-rectifier; K1-loading switch; K2–discharging switch; C – capacitor bank; Th - thyristor; D – flywheel diode; MI–magnetizing inductor; Rc, Lc – MI parameters; R_{ch}, L_{ch} – choke parameters.
parameters

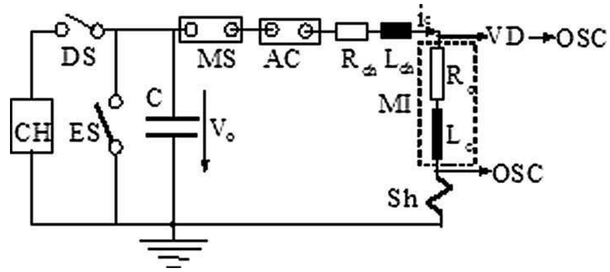


Fig. 4 DS - disconnect. switch; MS - making switch; AC-aux. breaker; CH- charging unit; ES-connecting to earth switch; C - cap. bank; MI – magnet. inductor; VD - voltage divider; Sh - shunt; OSC - oscilloscope; R_{ch} and L_{ch}- Choke's parameters

With the circuit arrangement according to Fig. 3, the main part of the whole electric energy W_{el} is dissipated as heat in the resistance R_C and R_{Ch}. Apart from this "exponential pulse current," other discharging circuits are used producing "sine wave pulse currents," whereas the rest of the energy, remaining to the end of the positive half of the current sin-wave, is dissipated within an external resistance outside of the magnetizer's inductor. The iron yoke is highly saturated, when 10% of the peak current is surpassed. Therefore, the magnetizer inductor inductance changes a little with rising current, when it is saturated. Thus, in a first approximation, is considered constant and saturated.

The following equations describe the exponential pulse current (Fig. 3) up to the aperiodic limit ($4L > CR^2$) [2]:

$$i_c(t) = \frac{U_c}{\omega L}\exp(-\frac{t}{\tau})\sin(\omega t), \quad 0 \le t \le t^* \tag{1}$$

$$i_c(t) = i_c(t^*)\exp\left(-\frac{t-t^*}{t^*}\right), \quad t^* < t \le \infty) \tag{2}$$

$$\tau = \frac{2L}{R} \quad \tau^* = \frac{L_c}{R_c} \quad \omega = \sqrt{\frac{1}{LC} - \frac{1}{\tau^2}} \tag{3}$$

$$R = R_c + R, \qquad L = L_c + L_{ch} \tag{4}$$

$$t^* = (\pi - arctg\,(\omega\tau))\frac{1}{\omega} \quad t' = \frac{arctg\,(\omega\tau)}{\omega} < t^* \tag{5}$$

$$i_{c\max} = i_c(t') = \frac{U_c}{\omega L}\exp(-\frac{t'}{\tau})\frac{\omega\tau}{\sqrt{1+(\omega\tau)^2}} \tag{6}$$

The typical shape of the magnetizing current is presented in Fig. 2. Fig 4 shows the actual industrial circuit used for magnetization.

3. MAGNETIZING INDUCTOR FOR A RADIAL PMSG

3.1. Architecture & Design of the Magnetizing Inductor Configuration

Electromagnetically, a large rotor consists of the laminated iron yoke and the salient permanent magnet poles mounted on the periphery and a number of magnets are placed side by side to make up the pole structure. Normally, the magnets are fixed to the rotor yoke by sticking, using an epoxy resin-based adhesive [3].

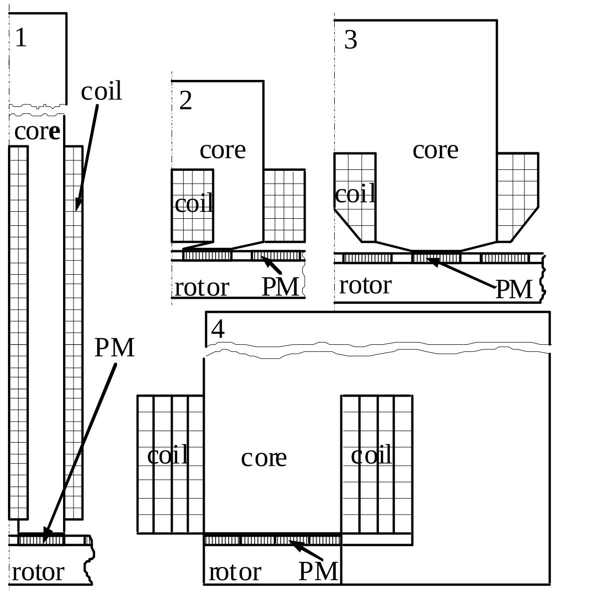


Fig. 5 Design variants for the magnetizing inductor: 1, 2 – two adjacent poles radial flux model; 3 – idem for two spaced poles (both drawings shows a half pole pitch only); 4 – one pole transversal flux model

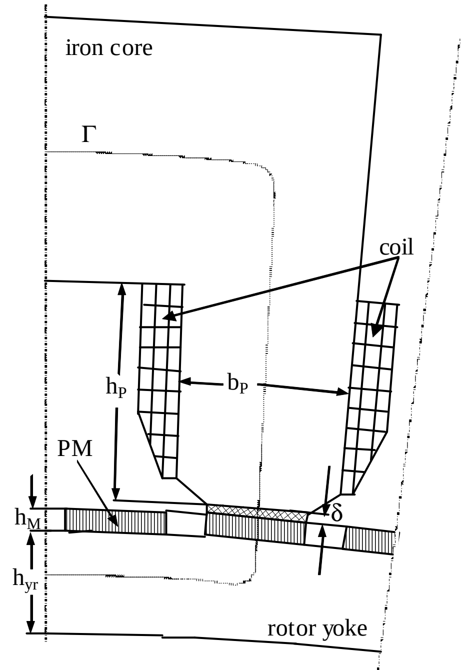


Fig. 6 Rotor & inductor arrangement for magnetizing system configuration

The construction of the wind generator under consideration is summarized in Table 2 [4].

Table 2. Default parameters of the rotor

Rated torque	820 [kNm]
Rated speed	20 [rpm]
Rated Voltage	500 [V]
Number of poles/ phases	160/ 3
External diameter	2560 [mm]
Armature height [mm]	30 [mm]
Armature length [mm]	490 [mm]
Airgas length [mm]	4.5 [mm]
Magnet height [mm]	7 [mm]
Magnet material	Nd Fe B
Remanence at 90° [T]	1.07 [T]

It has to be noted, in the same time, that it is needed to avoid a wrong magnetization of the adjacent pole structures by “springing” over the next pair of poles (see also Fig. 7 and Fig. 8). Thus, we have to first magnetize the pole number n = 1 together with the pole number n + 3 = 4 (n = 1, 3, 5,…), then the pole No. 3 together with the pole No. 6, and so on. Of course, there is more room for a 2D or 3D geometric optimization of the system, [5]. We used the variant presented in Fig. 5.

Calculation of the Magnetic Circuit

For a certain maximum value of the magnetic flux density within the magnets along the pole-axis, it is possible to find the necessary ampere-turns in the same way as an electrical machine calculation.

Table 3 Electric discharge circuit parameters

$V_0 = 5 \times 10^3$ V	$L_c = 1.400 \times 10^{-3}$ H	l_{Fe} = 490 mm
$C = 30 \times 10^{-3}$ F	$L_{c\sigma} = 0.613 \times 10^{-3}$ H	h_s = 67 mm
$W_{el} = 375 \times 10^3$ J	R_c = 0.0929 Ω	N_p= 42 turns

With the parameters of the electric discharge circuit and inductor (see also Table 3) it has been obtained the results presented in Table 4.

3.3 *Power Impulse Magnetizing Simulation*

The two-dimensional magnetic flux distribution - inclusively within the permanent magnets - for the peak value of the impulse current has to be determinate by FEM analysis and coupled circuit.

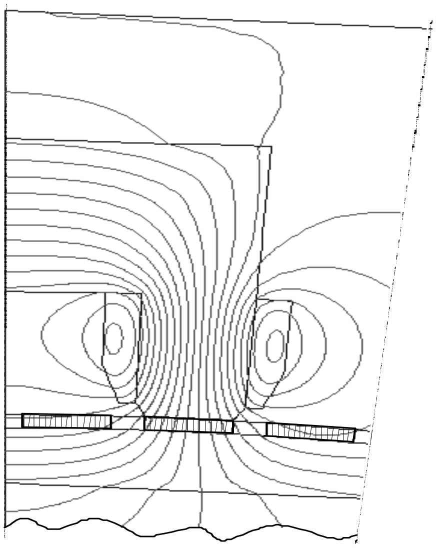


Fig. 7 The magnetic flux lines for the peak of impulse current (partial view)

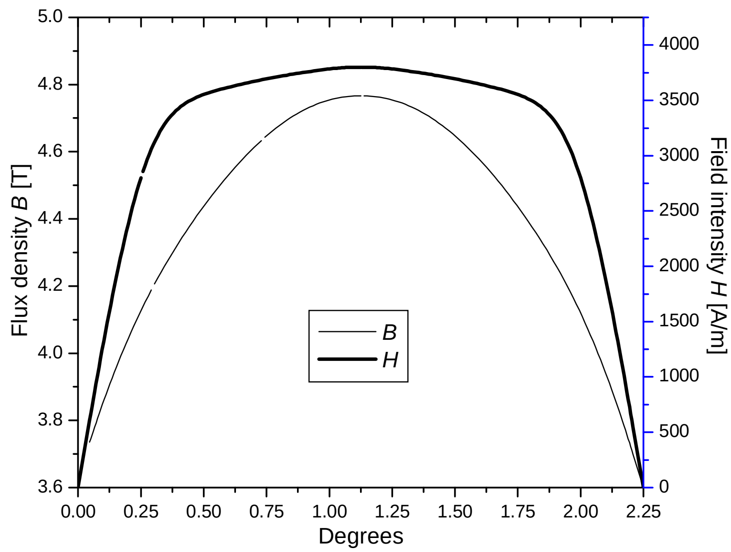


Fig. 8 Radial magnetic flux density & field intensity on the bottom surface of the magnet

Thus, Fig. 7 shows a partial view of the flux lines plot of the two poles magnetizing inductor with yoke geometry as presented in Fig. 6. The variation of the magnetic flux density, respective of the magnetic field intensity along the bottom surface of the PMs is presented in Fig. 8.

Table 4 comparatively presents the analytically obtained results vs. FEM simulation & electrical circuit for the before presented rotor magnetizing.

Table 4 Results of the analytical calculus vs. FEM & electrical circuit analysis

Units	kV	kA	ms	T
Analytical calculation	5	14.20	8.00	5.00
FEM & circuit simulation	5	14.32	8.01	4.90

Thus, the recommended value of 2500 kA/m is surpassed practically along the entire polar pitch, meaning that it is surely possible to magnetize in good condition the whole PMs poles. With the magnetic field intensity $H_M \geq 2500$ kA/m (see also Fig. 8) the remanence magnetic flux density, B_r = 1.2 T, must be already reached, [6].

4. MAGNETIZING INDUCTOR FOR AN AXIAL PMSM

4.1 Structure of the Machine

The defaults of the construction of the machine under consideration are summarized in Table 5 [1]. It consists of two stators and a disk-type rotor, as shown in Fig. 9 [2]–[5]. Each toroidal stator core is wounded from an electrotechnical laminated silicon steel tape; each stator core ring structure has opened slots on one side (or on both sides for stators of a multidisc machine).

The two stators are wound in a tooth-coil technology (i.e., a concentrate winding with a 21/20/3 number of slots/pole/phase) [1], [6]. One can argue that, in certain conditions, each pair of the PMs' rotor poles (which are located between four tooth coils) could be magnetized *in situ*, one by one, by independently energizing only the coils involved in this process.

Table 5 Default parameters for the axial PMSM

Rated torque	65 [kNm]
Rated speed	160 [rpm]
Rated Voltage	1250 [V]
Number of poles/ phases	20/ 3
External diameter	1700 [mm]
Armature height	60 [mm]
Armature length	316 [mm]
Airgap length	6 x 2 [mm]
Magnet height	8 [mm]
Magnet material	Nd Fe B
Remanence at 908	1.05[T]

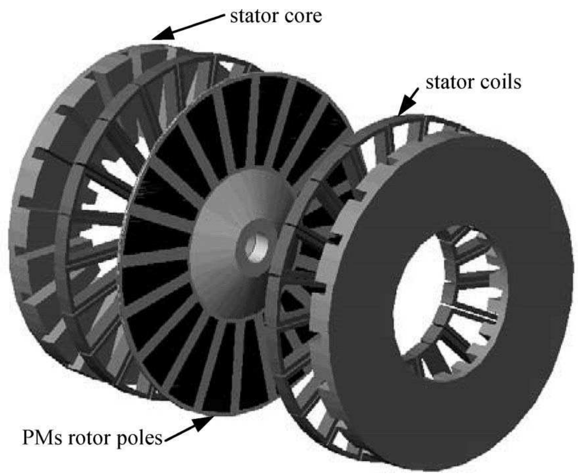


Fig. 9 Scheme of the axial flux machine.

The rotor core is fabricated with nonmagnetic stainless steel in a disk form and fixed to the shaft between the two stators, carrying axially magnetized NdFeB magnets forming the poles. The poles are inserted into holes opened in the rotor core disk; the disk and the PM poles have the same width and both are covered by a nonmagnetic plate (which is also a part of the magnetic air gap).

4.2. Magnetizing Inductor Function of the Stator

The first magnetizing inductor built in order to magnetize *in situ*, at once, all the magnetic poles of an axial PMSM (with a disk rotor between two stators) has been presented in [2]. This first approach suggested the idea of using even the machine armature as a magnetizing inductor, when the machine has an equal number

Of PM poles and stator teeth approximately (the rotor being locked by inserting nonmagnetic solid plates between the rotor and the stators). In this case, one can magnetize only a pair of poles by a pair of poles.

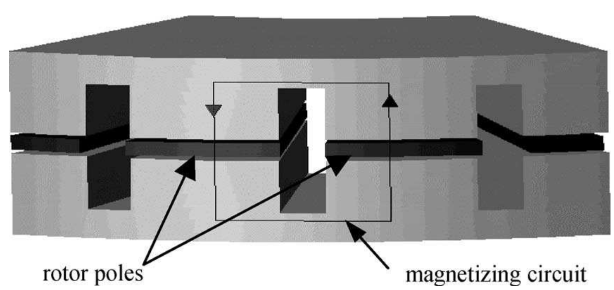


Fig. 10 Two consecutive rotor poles between four teeth,

As we stated before, the number of teeth exceeds the number of poles by only one unit. Thus, a relative position can be obtained just from the design phase, where two consecutive PM rotor poles are practically located between four correspondent tooth-coils (a couple of coils for each stator). This facilitates a direct magnetization of PM rotor poles by energizing only the involved coils (see also Fig. 10). In order to preserve the quality of the armature windings, every pair of the stator tooth-coils has to be used only for the corresponding poles' magnetization, consecutively.

Since the small winding overhangs as well as the simple winding and insulating technique, it is recommended that the concentrated winding be also designed as a "magnetizing inductor" of the axial PMSM rotor. An adequate insulation and fixing system has to be considered against transient forces related to the pulse power magnetizing process.

4.3 Applied Magnetizing Process

The magnetizing circuit consists of two consecutive rotor poles between four teeth (Fig. 10).

Fig. 4 shows the part of the actual simplified synthetic testing circuit used for magnetization, consisting mainly of the charging unit with a dc-adjustable loading voltage CH, the capacitor bank C, the discharging unit with the making switch MS, the auxiliary circuit breaker AC, and the magnetizing inductor MI.

The magnetizing procedure is detailed in [7], [8].

Table 6 Magnetizing inductor (stator coils) & circuit parameters

$V_0 = 5\text{x}10^3$ V	$R_c = 38.300\text{x}10^{-3}\Omega$	N = 20 turns
C $= 30\text{x}10^{-3}$ F	$L_c = 1.558\text{x}10^{-3}$ H	$l_{end} = 162\text{x}10^{-3}$mm

For this system, the LRC circuit and its second-order linear differential equation, with the underdamped solution, is considered. Thus, for the circuit equation

$L\dfrac{d^2 i}{dt^2} + R\dfrac{di}{dt} + \dfrac{1}{C} i = 0$, the first approx. current peak $i_{\max} \approx \dfrac{V_0}{\omega_d L} e^{-\frac{\alpha\pi}{2\omega_d}}$ occurs at $t \approx \dfrac{\alpha\pi}{2\omega_d}$

were:

$$\alpha = R/(2L), \quad \omega_0 = \sqrt{1/(LC)}, \quad \omega_d = \sqrt{\omega_0^2 - \alpha^2}$$

Actually, the magnetizing magnetic circuit of the axial PMSM is highly saturated. Therefore, the tooth-coil inductance L_c changes insignificantly with the rising current. Thus, for convenience, L_c is considered constant and saturated for calculating the discharge current [9].

4.4 Magnetization Analysis of the Axial Rotor

A magnetizer is modeled where a high current is applied to a coil, which causes a magnetic field to be distributed through the material that is to be magnetized. The region to be magnetized is assumed to be made of a nonmagnetic material. Permeability very close to that of air is assigned to that region.

The FEM calculation was done by considering the parameters of the actual magnetizing inductor (i.e., the tooth-coils involved in the two-poles magnetizing operation are connected in series) and of the electric discharge circuit, shown in Table 6.

The 2-D magnetic flux distribution within the PMs' rotor poles has to be determined by using a transient FEM and circuit simulation of the *in situ* magnetizing process of one pair of PMs'rotor poles (see also Fig. 11) [2], [9].

Fig. 12 shows the magnetizing pulse current obtained by discharging the capacitors bank directly on the magnetizing inductor.

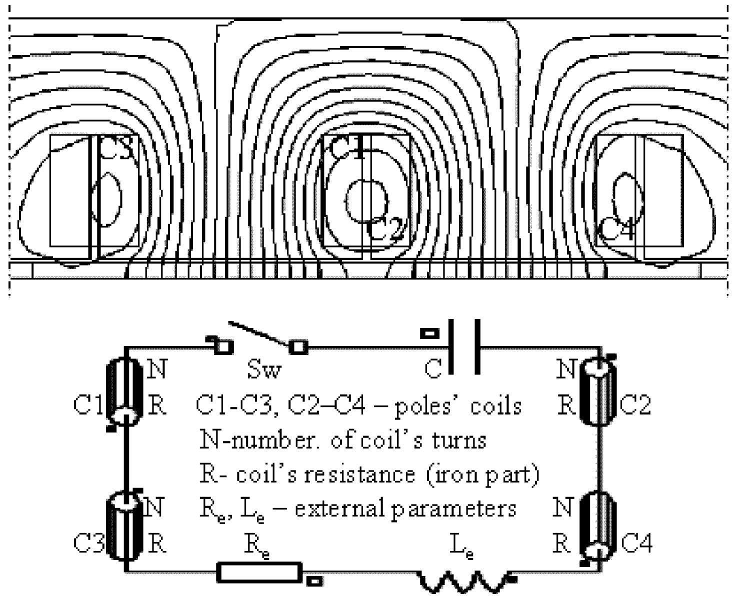


Fig. 11 2-D FEM field half model of the magnetizing inductor and of the external and discharge circuit of the magnetizer system.

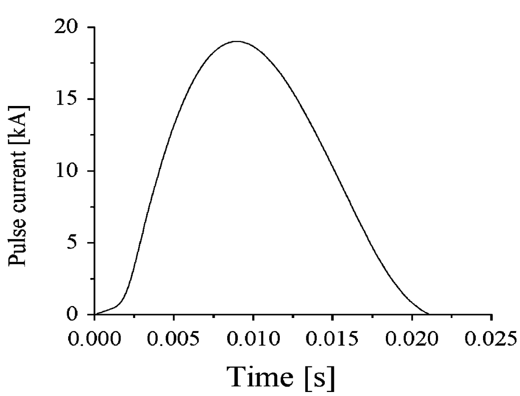


Fig. 12. Simulated magnetizing pulse current.

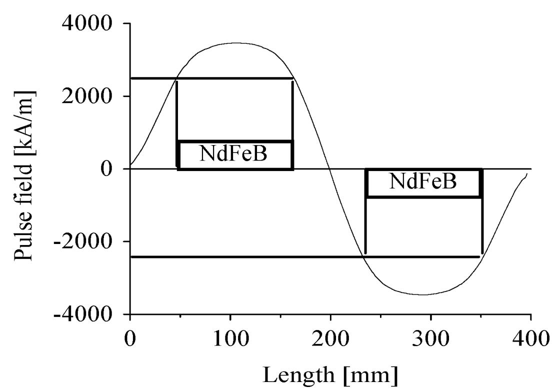


Fig. 13. Variation of the radial magnetic field along the polar pass in the middle plane of the PMs' rotor poles.

The magnetizing flux distribution (for half of the model) of the two-pole arrangement of the axial flux PMSM, discussed before, is shown in Fig. 11. The corresponding magnetic field variation in the middle plane of the PMs' rotor poles height at the average diameter is shown in Fig. 13.

5. CONCLUSIONS

Firstly, it has been presented a magnetizing inductor for magnetization at once a pair of poles and then, successively, the rest of pairs of poles for a radial flux, wind turbine generator of 1.7 MVA, 20 rpm, (to magnetize the big rotor at once, much more energy is needed). Thus, an analytical calculation method for designing the specific magnetizing inductor was performed in order to save magnetizing energy; a computer program containing the analytical formulas was sufficient in order to obtain, in the same way as an electrical machine, the inductor parameters for a certain rotor diameter and a chosen iron yoke shape calculation.

The simulation by FEM coupled to the electrical circuit revealed, finally, the intricacy of the whole problem. So, it has to be noticed here that it is needed to realize an optimum rotor and magnetizing inductor arrangement for magnetizing system configuration in order to protect the neighboring poles from magnetizing with a strong, wrong polarity.

Once the details of the rotor and inductor arrangement are established, they may be regarded as fixed features of the magnetizing inductor design. Then, with the presented methods, the design of a whole family of magnetizing inductors for different rotor dimensions may be done with a short calculation time.

In conclusion, the results confirm the possibility for a successful magnetization, pair by pair, of all rotor poles of a large PM synchronous machine.

Secondly, has been presented the case of a concentrated winding with a sub unitary number of slots per pole and phase, offering small winding overhangs as well as simple windings and insulating techniques, which facilitate the construction of an axial flux PMSM, which does not require a special magnetization inductor. The tooth-coils of the stator are used, also, as independent coils for the magnetizing inductor.

The large effective air gap allows avoiding the parasitic effect of a wide spectrum of tooth-coil winding fields. Therefore, the proposed axial flux PMSG has a linear behavior between torque and current up to a maximum of 200% rated current (4 min) due to the fact that the PMs' thickness is part of the magnetic air gap.

On the other hand, in comparison with a machine having distributed windings, the increased leakage inductance results in higher winding losses and a need for higher inverter rating but with lower field weakening current in the constant power operation region.

BIBLIOGRAPHY

[1] P. Bretchco and R. Ludwig, "Open—loop pulsed hysteresis graph system for the magnetization of rare-earth magnets," *IEEE Trans. Magn.*, vol. 36, pp. 2042–2051, July 2000.

[2] Magnet processing—selecting the right equipment, in Advancing the Science of Magnetics, Walker Scientific, Worchester, MA.

[3] A. Binder, "Design of coils for magnetizing rotors surface rare earth permanent magnets," *Elec. Eng.*, vol. 78, pp. 449–454, 1995.

[4] J. F. Gieras and M. Wing, *Permanent Magnet Motor Technology*. New York: Marcel Dekker, 1997.

[5] C.Ch. Schaetzer, W. Muller, and A. Binder, "Vector optimization of two-dimensional numerical field problems applied to the design of a wind turbine generator," in *Proc. 8th Int. IGTE Symp.*, Gratz, Sept. 1998, pp. 1–6.

[4] F. Magnussen and C. Sadarangani. „Winding factors and Joule losses of permanent magnet machines with concentrated windings". Royal Inst. Technol.. Stockholm, Sweden, (2003) [Online]. Available:
http://_www.ekc.kth.se/eme/publ/

[5] G. Huth, "Optimized winding-systems of permanent-magnet a.c. servomotors," *Electr. Eng.*, vol. 81, pp. 375–383, 1999.

[6] D. H. Kang, P. Curiac, Y. H. Jeong, and S. J. Jung, "Prospects for magnetization of large PM rotors: Conclusions from a development case study," *IEEE Trans. Energy Convers.*, vol. 18, no. 3, pp. 409–416, Sep. 2003.

[7] D. H. Kang, P. Curiac, Y. H. Jeong, and S. J. Jung. (2007). "Field pulse magnetization of PMSM rotors" [Online]. Available: http://www.sprigerlink.com

[8] D. H. Kang, P. Curiac, and J. Lee, "An axial flux interior PM synchronous machine," presented at the Int. Conf. Electr. Mach., Espoo, Finland, Aug. 2000.

[9] R. Mayer, "Dauermagneterregte axialfeldsynchronmaschinen mit hohem drehmoment," Dr.-Ing. dissertation, Tech. Univ. Braunschweig. Braunschweig, Germany, 1987.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#64

Big Storage Systems

[1]Augustin AMET[*], [2]Traian CHIULAN[**]
[1]Tema Energy, [2]CNTEE Transelectrica SA
[1, 2]Romania

SUMMARY
The paper presents solutions for development of medium and large power networks using big batteries storage systems.

KEYWORDS
Energy Storage, Peak Shaving, Battery, Future Grid

1. INTRODUCTION

According to general definition [1] grid energy storage is a collection of methods used to store electrical energy on a large scale within an electrical power grid. Electrical energy is stored during times when production (especially from intermittent power plants such as renewable electricity sources such as wind power, tidal power, solar power) exceeds consumption, and returned to the grid when production falls below consumption.

Any electrical power grid must adapt energy production to energy consumption, both of which vary drastically over time. According to [1] any combination of energy storage and demand response has these advantages:

- fuel-based power plants (i.e. coal, oil, gas, nuclear) can be more efficiently and easily operated at constant production levels
- electricity generated by (or with the potential to be generated by) intermittent sources can be stored and used later, whereas it would otherwise have to be transmitted for sale elsewhere, or simply wasted
- peak generating or transmission capacity can be reduced by the total potential of all storage plus deferrable loads (see demand side management), saving expense of this capacity
- more stable pricing: the cost of the storage and/or demand management is included in pricing so there is less variance in power rates charged to customers or alternatively (if rates are kept stable by law) less loss to the utility from expensive on-peak wholesale power rates when peak demand must be met by imported wholesale power
- emergency preparedness—vital needs can be met reliably even with no transmission or generation going on while non-essential needs are deferred

Energy derived from photovoltaic and wind sources inherently varies – the amount of electrical energy produced varies with time, day of the week, season, and random factors such as the weather. Thus, renewables present special challenges to electric utilities. While hooking up many

[*] augustin.amet@tema-energy.ro
[**] traian.chiulan@transelectrica.ro

wind sources can reduce the variability, solar is reliably not available at night except when stored in molten salt, and tidal power shifts with the moon so is never reliably available on peak demand.

In an electrical power grid without energy storage, energy producers must be tuned to energy production from intermittent energy sources. While some of the producers like oil and gas plants can be scaled up when wind power plants shuts down quickly, others like coal and nuclear plants take considerable time to adapt.

Energy can be stored in various forms: compressed air, batteries flywheel, hydrogen, and superconducting magnetic energy. Among the mentioned technologies batteries are most common.

2. THE STORAGE AND THE GRID

Despite the novel network designs of the electrical grid, its power delivery infrastructures become aged. Figure 1 a) show the basic network diagram where the energy flows directly from producers to consumers.

As the technology progresses, the electric utility seeks to take advantage of novel approaches to meet growing energy demand [2]. Utilities are under pressure to evolve their classic topologies to accommodate distributed generation. As generation becomes more common from rooftop solar and wind generators, the differences between distribution and transmission grids will continue to blur. Figure 1 b) show a schematic of a such distributed network.

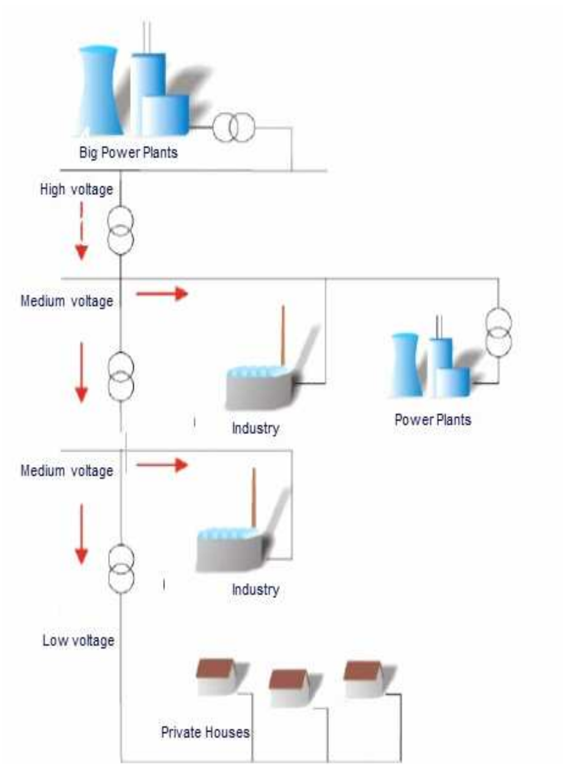


Fig 1. a) – Standard grid topology

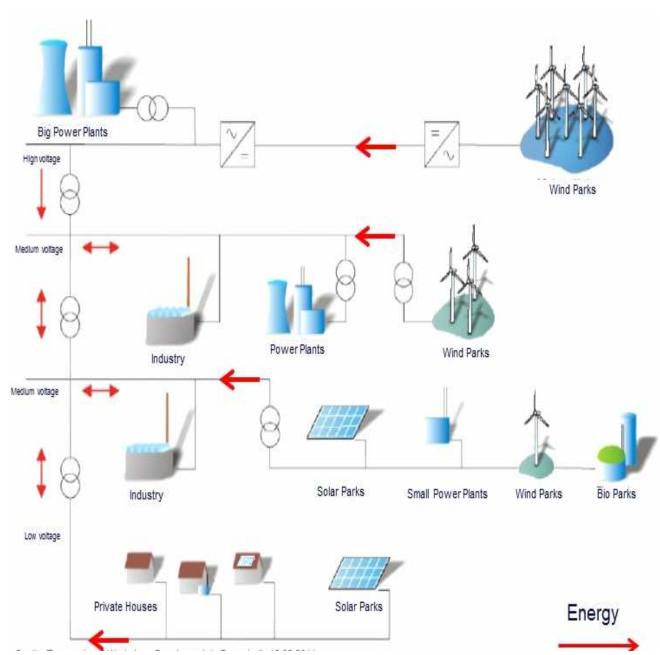


Fig. 1 b) – Enhanced grid topology

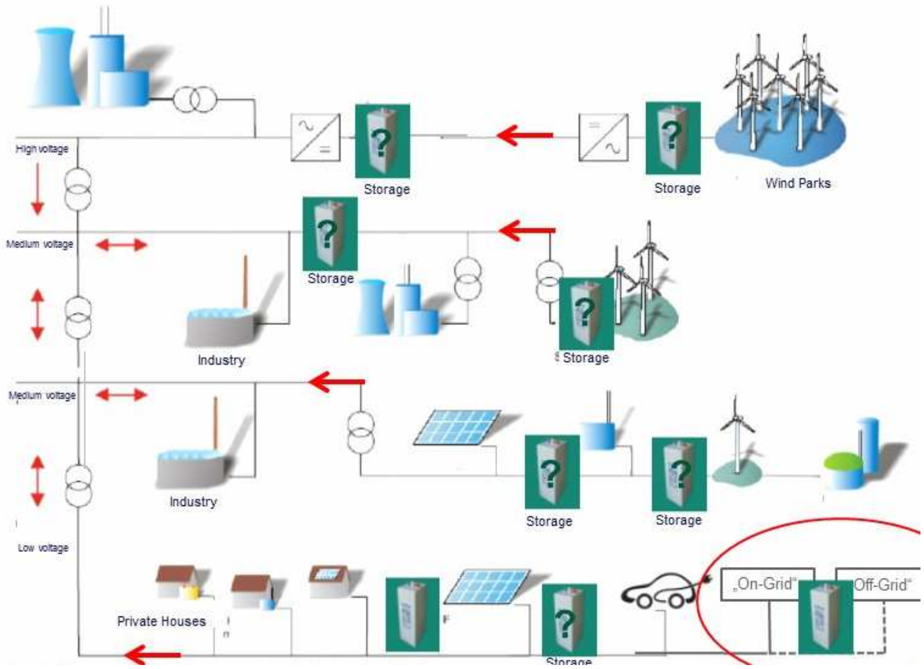


Fig.1 c) – Future grid topology

At present the electrical grid is expected to evolve into the smart grid. This grid uses two-way flows of electricity and information to create an automated and distributed advanced energy delivery network [2], Fig.1 c).

A **smart grid** would allow the utilities to control parts of the system in real time and the customers to obtain cheaper, greener and higher quality power.

3. BIG BATTERY STORAGE SYSTEMS

3.1. Frequency Regulation / Peak energy shaving / Energy Storage for big solar or wind farm

Power balancing in the high or medium voltage grids becomes problematic due to the increasing impact of renewable energy in the existing power grid, thus the frequency is sometimes not stable enough, therefore a portion of „backup energy“ is requested.

Research and development departments of major manufacturers developed systems for „energy backup”. There are some projects implementing such systems into the existing grid in order to stabilize the frequency. Energy can be stored into batteries and when needed, can be given back to the grid. The main technologies involved are lead-acid and Li-Ion batteries.

In Fig. 2 there is a schematic of the standard system and in Fig. 3 there is a schematic of a redundant system.

In the redundant system each battery bank has its own bidirectional inverter. In case one inverter fails the entire system is not compromised, compared to the standard system. The redundant system is also equipped with a diesel generator as a backup power source.

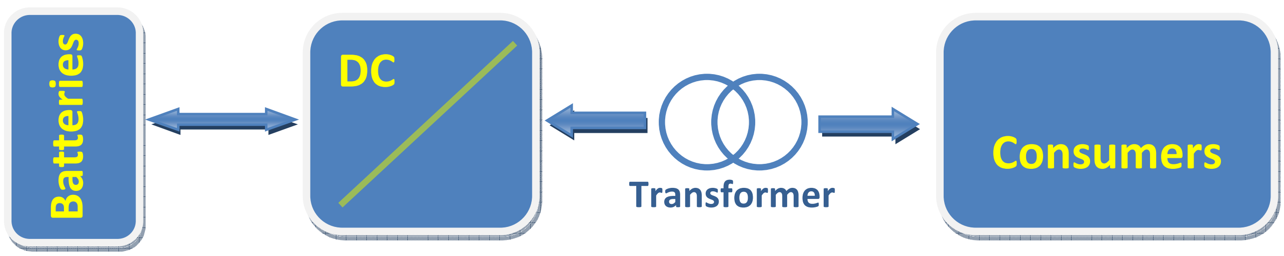


Fig. 2 – Standard battery storage system used for frequency regulation or peak energy shaving

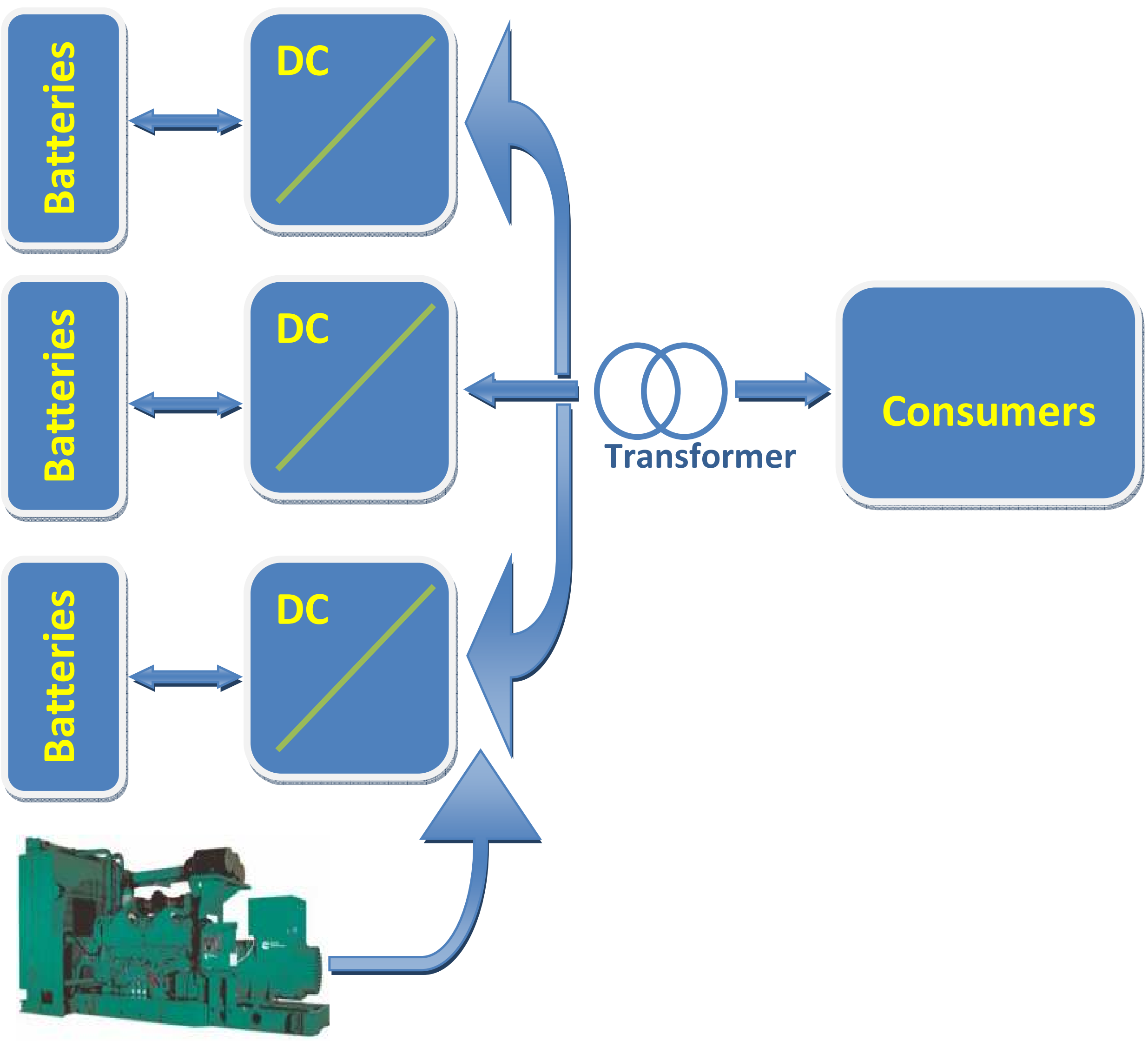


Fig. 3 – High redundant battery storage system used for frequency regulation or peak energy shaving

3.2. The next step in grid development – Smart Operator

Nowadays the energy flow is bidirectional. More and more households become also producers. The growing proportion of distributed generation from renewable sources requires a renovation and expansion of existing networks. The grid must be flexible in order to remain stable because the renewable energy is not continuous and cannot be predicted with high accuracy. For better integration of renewable energies in the intelligent network solutions the concept of "smart operator" was introduced. A “smart operator” is a black box that detects the current condition of the network and optimizes automatically the energy flow. It communicates with the grid controller and with the consumer. The consumer’s’ "smart appliances” are controlled by the “smart operator” in order to prioritize the use of electricity from renewable sources. Figure 4 presents a basic diagram of such a concept.

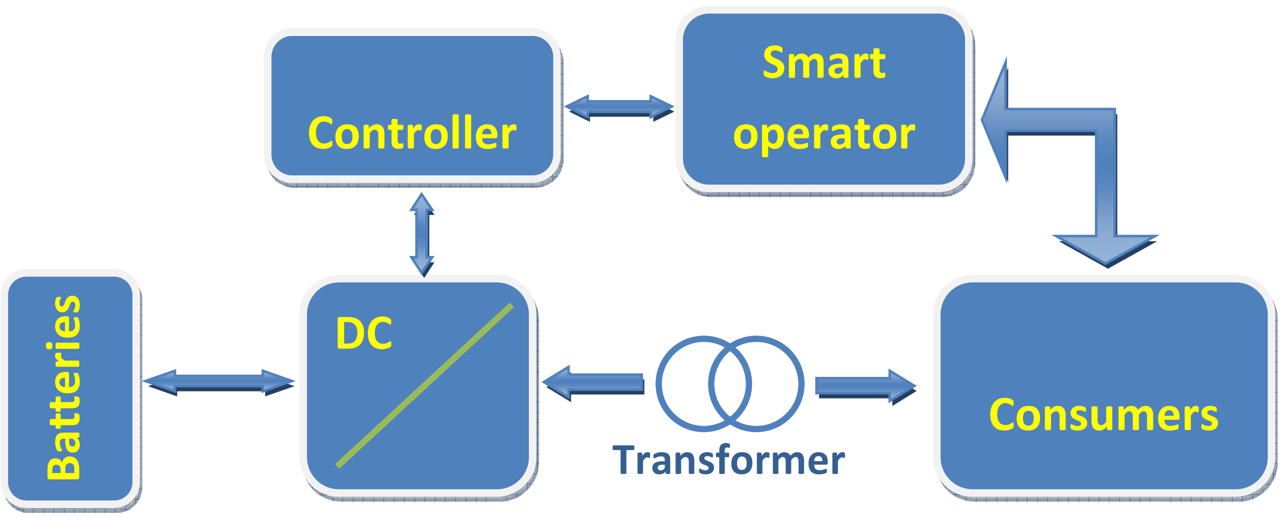


Fig. 4 – Smart operator

4. CONCLUSIONS

The rapid growth in renewable energy is accelerating the efforts to develop a new electricity system. With high levels of penetration, renewable energy increases the need for resources that contribute to system flexibility such as energy storage, which can help ensure system stability by matching supply and demand of electricity. Energy storage can be deployed throughout electricity networks in order to facilitate the use of renewable energy, while producing numerous other benefits, such as a better load management and increased power quality. The future development of energy networks must also implement bidirectional communication between consumer and the distributed producers.

BIBLIOGRAPHY

[1] https://en.wikipedia.org/wiki/Grid_energy_storage
[2] https://en.wikipedia.org/wiki/Electrical_grid
[3] http://www.rwe.com/web/cms/de/1943232/rwe-deutschland/energiewende/intelligente-netze/smart-operator/
[4] AECOM – Energy Storage Study, 13.07.2015

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#65

The risk assessment for the refurbished TSO's substations

V. ZAHARESCU*, C. STANESCU, R. MATIU, D. MORAR
CNTEE Transelectrica SA
Romania

SUMMARY

The paper presents aspects related to technological and also occupational safety and health (OSH) risk assessment, using an evaluation of consequences in conjunction with the assessment of the possibility for the risk occurrence, in the refurbished substations belonging to ST Sibiu.

After the introduction in the first part, the paper presents in the second part the aspects, according with the geographical location of the power transformation substations belonging to the Transelectrica Sibiu Subsidiary and their ranking in the National Power Grid.

Technological risk assessment is presented in third part of the paper, emphasizing the risk exposures in the refurbished substation Brasov and the non-retrofitted substation Dârste. As a case study the paper analyzes the technological risk exposure in Dârste power substation, considering the prospect of its refurbishment and the implementation of mobile team strategy.

Considering that all power substations belonging to ST Sibiu are going to be refurbished, in the fourth part of the paper presents the occupational safety and health risk assessment aspects, in conjunction with dedicated studies.

The final part of the paper contains the conclusions of the authors on the addressed issues.

KEYWORDS

Technological risk, occupational safety and health risk, power substations, refurbishment, transmission grid.

INTRODUCTION

Sibiu Subsidiary (ST Sibiu) is one of the eight subsidiaries of Transelectrica SA, and ensures the operation and maintenance of facilities for power transmission consisting in eight power power substations and 987 km overhead lines (OHL) at a voltage level of 220kV and 400kV. As a special characteristic, over 50% of the total length of 220kV and 400kV overhead lines managed by ST Sibiu are located in mountainous areas with difficult access, operating in difficult weather conditions, and having high requirements in terms of operation and maintenance. These OHL are used to evacuate the power produced in large power plants: hydroelectric power plant Lotru, and thermoelectric power plants Mintia and Iernut.

Inside CNTEE Transelectrica SA, risk management, including the technological aspects, is conducted based on a specific operational procedure, which establishes a general framework of risk identification, analysis and management at the company structure levels. This provides the employees and management with tools that facilitate specific risk management activities in a controlled and efficient way that helps fulfilling predetermined goals. In order to prevent the occurrence of risks and to reduce the impact and probability of their occurrence Transelectrica SA established and implemented the necessary actions, measures and control tools [1].

* valentin.zaharescu@transelectrica.ro

Since Transelectrica was founded in 2000, 5 of the 8 power substations managed by ST Sibiu have gone through a process of refurbishment and also have been the object of a reduction of operational staff. Through SCADA, the information necessary for the remote control and for operational supervision of the power transmission grid are directed inclusively to the center of remote control, surveillance and intervention (CTSI) located in Sibiu South Power substation. CTSI has the permanent staff needed for the surveillance, coordination and performing the maneuvers.

CNTEE Transelectrica SA established a perspective plan for the transmission grid (RET) for 2012-2021 and a RET development plan for 2014-2023 setting a rapid pace for refurbishing the installations. Exposure to risk, seen as a combination between probability and impact represents the consequences related to the established objectives Transelectrica has to address, in the case of risk occurrence. In this context, this paper presents aspects of risk assessment within the context of power substations refurbishment, reaching aspects of operation strategy of refurbished power substations with no operational staff on site.

Law for Occupational Safety and Health no. 319/2006 and Romanian Standards SR EN 12100-1/2004 contain the principles of risk assessment at the workplace. According to their, the employer has obligation to achieve and to be in possession of a risk evaluation to the occupational safety and health, including for those sensitive risk groups. Also, the employer has to decide over the protective measures to be taken and, where appropriate, over the protective equipment which mandatory to be used.

THE IMPORTANCE OF ST SIBIU POWER SUBSTATIONS IN THE NATIONAL POWER GRID

ST Sibiu manages through three operational centers (CE) Brasov, Mures and Sibiu, the following eight power substations, geographically situated in five counties, see figure 1:

Power Substation 220/110/20 kV Alba Iulia– non refurbished;
Power Substation 400/110 kV Braşov – refurbished;
Power Substation 400/110 kV Dârste – non-refurbished;
Power Substation 220/110/20 kV Fântânele – refurbished;
Power Substation 220/110/20 kV Gheorgheni – refurbished;
Power Substation 400/220/110/6 kV Iernut – refurbished;
Power Substation 400/220/110/20 kV Sibiu Sud – refurbished;
Power Substation 220/110/20 kV Ungheni – non-refurbished.

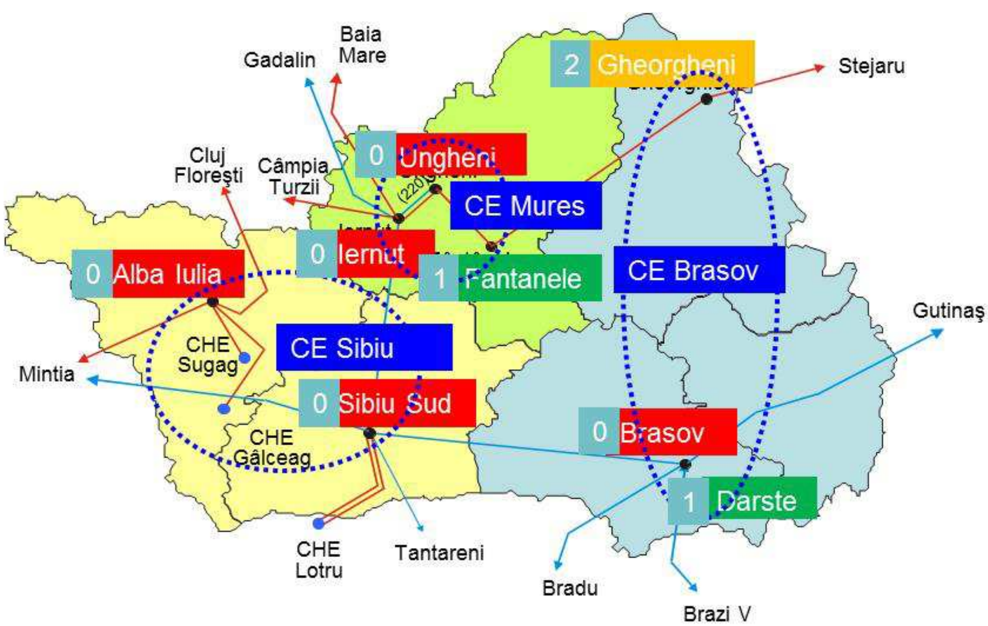


Figure 1. The importance of ST Sibiu power substation in the National Power Grid

In 2008, Transelectrica signed a contract with The Irish Electricity Board Supply International, to elaborate a feasibility study on "The organization and operation of remote control system installations in the Power Transmission Grid". This study also analyzed the strategies related to waiving operational staff from refurbished power substations and setting up mobile teams to service them. In this context the incident response time for each power substation has been established in conjunction with the [3].

According to the Statute for preventive maintenance on equipment and installation from RET, Annex 2c mentions the importance of the substation belonging to ST Sibiu, as presented in Figure 1 [2]. It is noted that from the eight power substations, five have maximum importance degree '0', two have high importance degree '1' and only one has medium importance degree '2'. The maximum level of importance requires according to the study [3], a 10 minutes incident response time. The only way to achieve this is through the existence of five mobile teams based in the Sibiu Sud, Brasov, Iernut, Alba Iulia and Ungheni substations.

THE TECHNOLOGICAL RISK ASSESSMENT

The technological risk assessment as the evaluation of the impact of the risk occurrence combined with the evaluation of the likelihood of occurrence was performed in comparison between a refurbished power substation and a non-refurbished one. The probability of risk occurrence means the possibility or eventuality for a risk to occur and the impact represents the consequences, and the results on the objectives, if the risk would occur. The combination between the two estimations on a bi-dimensional scale, the risk matrix, Exposure = Probability x Impact are the indicator used to establish the attitudes towards each problem identified as a risk, on a scale with 3 steps (low, medium and high), the chances of occurrence for the identified problems, and the extent of the consequences.

The Technological risk factors identified are:

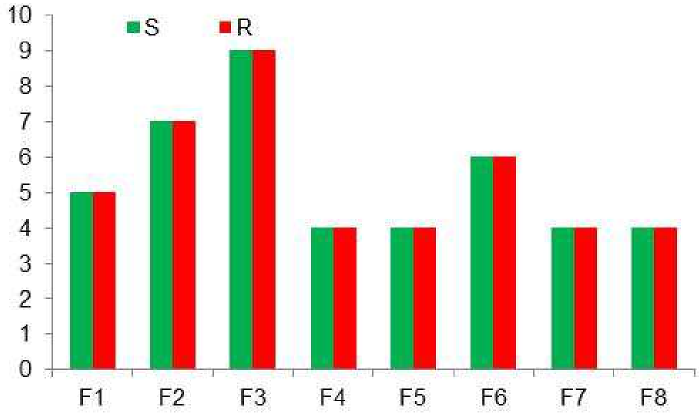
1. Malfunction / disturbance / unavailability of 220kV and 400kV OHL;
2. Malfunction / disturbance / unavailability of substation’s primary switchgear;
3. Malfunction / disturbance / unavailability of transformer units and / or compensation coils;
4. Malfunction / disturbance / unavailability of protection and automation systems;
5. Malfunction / disturbance / unavailability of the command-control-monitoring systems;
6. Malfunction / disturbance / unavailability of internal service facilities ac or dc;
7. Malfunction / disturbance / unavailability of the prevention and fire extinction facilities;
8. Malfunction / disturbance / unavailability of communications, telecommunications and telemetry systems.

We will present a case study for CE Brasov, within ST Sibiu, consisting in the refurbished Braşov power substation, having the maximum priority level and non-refurbished Dârste power substation, with a high level of priority. Considering that the power Dârste power substation will be refurbished and a mobile team based in Brasov power substation already exists, this team will service both power substations [5].

3.1. Refurbished 400/110/6kV Brașov power substation

In the process of refurbishing the ST Sibiu substations, in order to reach the objective "Ensuring safety in operation for the managed facilities in compliance with the conditions set by the RET Technical Code " risks and the circumstances of their occurrence were identified and taking into account including the strategy involving mobile teams existence.

The technological risk assessment for Braşov power substation, according to Figure 2 emphasizes that most of the circumstances were identified as risk factor F3. "Damage / failure / unavailability of transformer units and/or compensation coils".



Inherent Risk		
probability	impact	exposure
S	**R**	**SxR**

The inherent risk has a low probability and a high impact

Figure 2. Technological risk exposure in Brasov power substation

Figure 2 reveals the low level (S-green) of risk occurrence probability, if the risk is treated by refurbishing the equipment (equipment with high reliability), the probability of risk occurrence is maintained at a low level (S-green).

The power substation is refurbished and remote controlled from CTSI and there is always a staff member present in the power substation and a staff member present at the CTSI but the mobile team strategy is not currently implemented. Scheduled maneuvers require a two persons team due to the fact that staff presence is necessary in the exterior power substation because information from SCADA do not provide sufficient confirmation (visual and acoustic) and handling primary switching equipment without verification on the spot can lead to extensive damage [4].

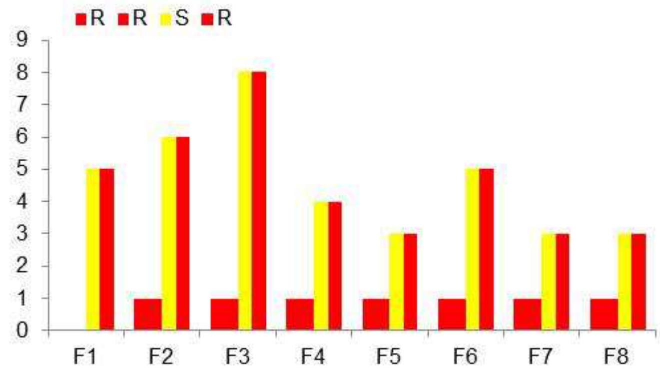
We emphasize that events occurred in remote controlled power substations leading to the impossibility of remote maneuvers and in the absence of operative staff in the power substation, this would have turned into major damage. Also, has been noticed that without the presence of the staff that operates the facilities the data and information needed to assess the equipment status, would have been insufficient.

We consider necessary to have a member of the operative staff, eventually the person who ensures the reception of works, a person trained and authorized to perform at any times shift services. Also, besides the presence of operative staff in the power substation, it is necessary to have operative staff at the CTSI in order to conduct maneuvers and coordinate the power substation staff [5].

3.2. Non-refurbished 400/110/6kV Dârste power substation

The technological risk assessment for Dârste power substation identified a high probability for 7 risk factors F2 ÷ F8, "Equipment exceeding their normal lifespan kept in service, without the investments necessary to replace them". Figure 4 that most of the circumstances were identified as risk factor F3 "Damage/failure/unavailability of transformer units and/or compensation coils". The inherent risk has a medium probability and high impact.

Figure 3 also reveals the high level (R-red) of risk occurrence probability, consisting principally on “equipment with low reliability” the risk needs to be treated by refurbishing the equipment (equipment with high reliability), and this will reduce the risk level by reducing at a low level (S-green), the probability of risk occurrence.



The inherent risk has a high probability

Inherent risk		
probability	impact	exposure
R	**R**	**RxR**

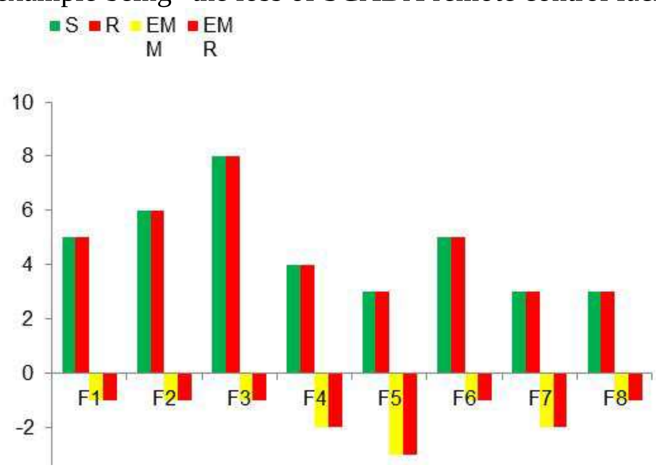
and a high impact

Inherent risk		
probability	impact	exposure
M	**R**	**MxR**

The inherent risk has a medium probability and a high impact

Figure 3. Technological risk exposure in Dârste power substation without the mobile team

In the evaluation the residual risks were analyzed in context of refurbishment, and for the majority of them the risk occurrence probability has been reduced from a medium level (M-yellow) to the low one (S-green). However there are circumstances in which risk occurrence probability remains medium (M-yellow) even in the F5. These can be caused by other circumstances, an example being" the loss of SCADA remote control facilities" [5].



Inherent risk		
probability	impact	exposure
S	**R**	**SxR**

The inherent risk has a low probability and a high impact.

Inherent risk		
probability	impact	exposure
M	**R**	**MxR**

The inherent risk has a medium probability and a high impact

Figure 4. Technological risk exposure in Dârste power substation with the mobile team

THE OCCUPATIONAL SAFETY AND HEALTH RISK ASSESSMENT

4.1. The methodology for risk assesment

The evaluation method follow the evaluation principals related to 7 article from 319/2016 law, according to which regulations, the risk assessment involves identifying all risk factors of accidents and professional diseases and determine the level of risk, based on the combination of severity and probability of maximum foreseeable consequence.

Workplace was assessed as a complex system, structured on the following elements that interact: the means of production, work environment, work task, operator. The evaluation starts from identifying of risk factors for each element of the work system, specifically for the assessed workplace, level of risk on workplace after determining the partial risk levels are set for each risk factor individually.

1. A work accident can be caused due to several risk factors involved in the causal chain. The evaluation takes into account the risk factor which is the last link in the causal chain.

2. Assignment to grades of severity is based on medical criteria for assessing incapacity for work, issued by the Ministry of Health and Ministry of Labor, Social Solidarity and Family.

Table I. Grades of severity and probability classification

GRAVITY			PROBABILITY	
Severity class	Consecuancies	Severity of consecuancies	Probability Class	Accident frequency
1	NEGLIGIBLE	Incapacity predictable for calendar three days	1	once on 10 years
2	SMALL	Work incapacity 3-45 days	2	once on 5 – 10 years
3	MEDIUM	Work incapacity 45-180 days	3	once on 2 – 5 years
4	BIG	INV. III deg.	4	once on 1 – 2 years
5	GRAVE	INV. II deg.	5	once on 1 year – once on 1 month
6	VERY GRAVE	INV. I deg.	6	under once on month
7	MAXIMUM	DECEASE		

3. Classification the probability classes had as source CEN 812/1985, currently being established following ranges:

- The probability that it can produce an undesired event (accident at work or occupational disease);
- The seriousness of its consequences, namely the expected and probable of maximum severity.

Risk = Probability x Severity

4. Evaluation form of employment place is the document summarizing all of the assessment and includes:

- Identification of the workplace;
- Identification of assessors;
- Nomination of the identified risk factors and presenting concrete form of manifestation thereof;
- Maximum foreseeable consequence for each risk factor individually;
- Class of severity and probability for each risk factor individually;
- Partial risk level, based on the combination of severity and probability of each risk factor;
- Risk level job as a weighted average of partial risk levels; for weighting is used the rank the risk factor which is equal to the level of risk.

The overall risk level of the system is calculated as a weighted average of estimated risk levels for each job or each activity; for weighting is used to rank job or activity that is equal in value to the risk level of workplace (activities).

Given studies [6, 7] for evaluation of the level of risk of injury and occupational disease were obtained for ST Sibiu substations before and after retrofitting, the risk levels represented in figure 5.

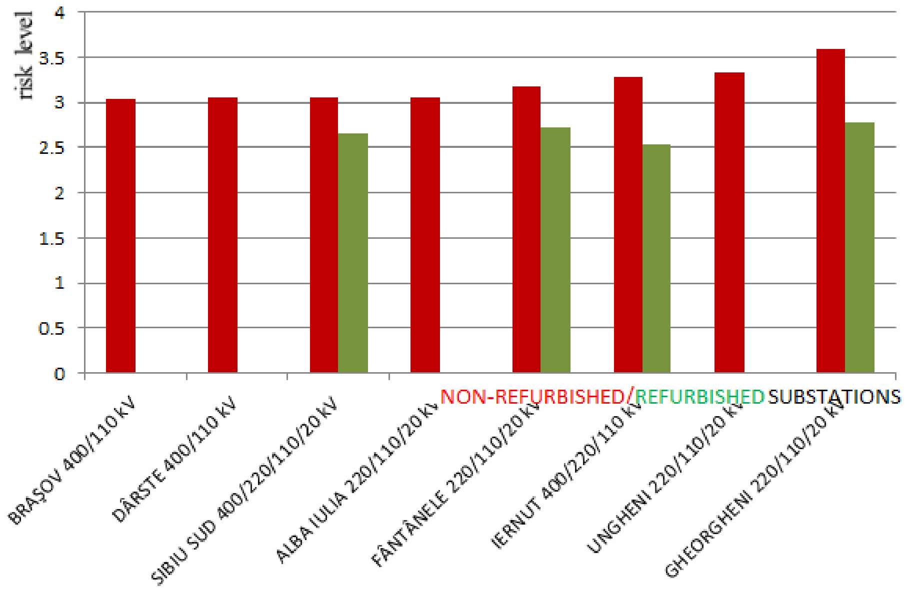


Figure 5. OSH risk level for substations

$$N_g = \frac{\sum\limits_{p=1} r_p * N_{rp}}{\sum\limits_{p=1} r_p} = \frac{\sum\limits_{i=1} N_{rp}^2 * n_p}{\sum\limits_{i=1} N_{rp} * n_p}$$

The overall risk level before refurbishment is 3.23 anf after refurbishment is 2.92, decreasing by 10%, like in figure 6.

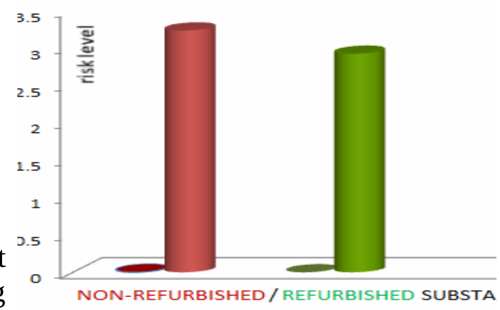


Figure 6. OSH risk level for Sibiu subsidiary

4.2. Refurbished 220/110/20kV Gheorgheni power substation

The overall risk level calculated for this workplace for operational personnel is 2.78, risk level low to very small, well below their acceptable level of risk (3.5), like in figure 7[7].

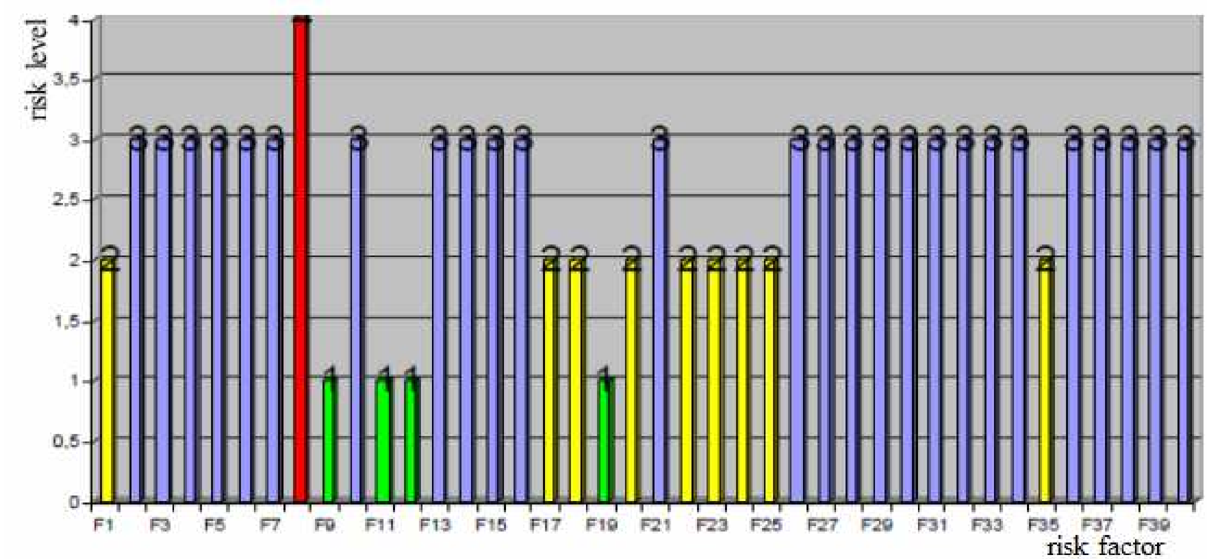


Figure 7. OSH risk exposure in Gheorgheni power substation

The result is supported by "Assessment forms", which is observed risk level, included all 40 risk factors, namely:

-1 risk factor of level 4: 2,5%
-26 risk factors of level 3: 65,0%
-9 risk factor of level 2: 22,5%
-4 risk factor of level 1: 10,0%,
like in figure 8. [7]

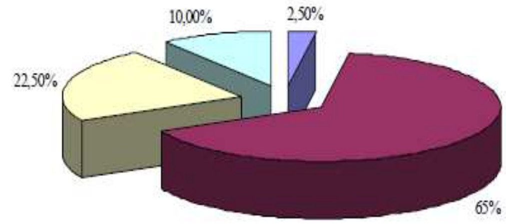


Figure 8. OSH risk factor according with the level

From "Assessment forms" is obtain the risk factors on generic components of work system, namely:

-16 risk factors specific for means of production 40%
-6 risk factors specific for work environment 15%
-4 risk factors specific for work task 10%
-14 risk factors specific for operators 35%
like in figure 9. [7]

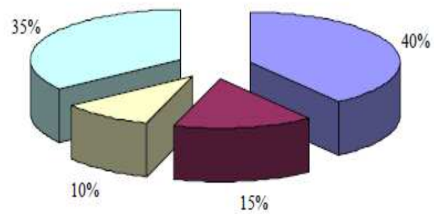


Figure 9. OSH risk factor according with the components of work system

From "Assessment forms" is obtain the risk factors depending on the severity of the consequences, namely:

-26 risk factors of level have maximal possible consequences "DEATH" 65%
- 10 risk factors of level have maximal possible consequences " Work incapacity 3-45 days " 25%
- 4 risk factors of level have maximal possible consequences "NEGLIGIBLE" 10% like in figure 10. [7]

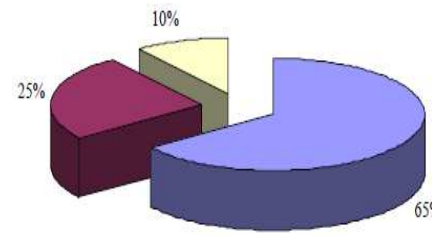


Figure 10. OSH risk factor according with the severity of the consequences

CONCLUSIONS

Technological risk management is a process that involves the entire company staff and is managed by the company administration. Risks that may affect the company and the activities are being identified and assessed. The identified risks must be controlled and maintained within acceptable limits by monitoring them, reviewing them and reporting them continuous in order to achieve the company objectives.

As a result of the refurbishment of 62.5% of transformation substations within CNTEE Transelectrica SA, ST Sibiu, exposure to technological risk has decreased, confirming the necessity and effectiveness of an accelerated pace of refurbishing . In our evaluation the residual risks decreased in the context of refurbishing together with the reduction of the risk occurrence probability for most of the risks from the medium voltage level to the low voltage level. However there are circumstances, in which the risk occurrence probability is still at a medium level, even considering the implementation of mobile team strategy.

The importance each power substation has in National Power Grid determines the way to allocate operative staff is allocated in a refurbished substation. Within the ST Sibiu 62.5% of the substations have the highest level of priority, and this requires the presence of permanent staff in the substation. Considering the analyzed scenarios referring to the implementation of mobile teams for interventions in the substations within ST Sibiu, long-term perspective requires a reassessment in terms of the implications of human and material resources after the refurbishment of the three substations and reevaluation of the priority level of those substations within National Power Grid.

Detailed analysis of the four components of the work system: the means of production, the tasks of work, the operator and the work environment; which conclude the non-expression of OSH (occupational safety and health) risk factors. This is due both professionalism of operators and those who manage the business, of covering content of tasks work, experience gained in tackling all problems.

BIBLIOGRAPHY

[1] CNTEE Transelectrica SA, Operational Procedure, „Risk management", no. PO-TEL–10.00, www.transelectrica.ro;

[2] CNTEE Transelectrica SA, „Rules for preventive maintenance to equipments of the power grid", no NTI-TEL-R-001-2007-03, revizia 3, 2014, www.transelectrica.ro;

[3] CNTEE Transelectrica SA, Studiu de fezabilitate 'The organization and operation of power grid remote control system" year 2008, issued by The Electricity Suply Bord International;

[4] CNTEE Transelectrica SA, Operational Procedure, „Remonte control system for the refurbished power substations", no. PO TEL 07.25, www.transelectrica.ro;

[5] FOREN 2016, paper DS 2.3.3 "Technological risk assessment for the refurbished substations of Transelectrica Sibiu Subsidiary", Valentin Zaharescu, Carmen Stănescu, Matiu Raul, Daniel Morar;

[6] Contract no. 43/20.08.2008, between Transelectrica Sibiu Subsidiary and S.C. LACON EXPERT S.R.L. Bucharest „The study for occupational safety and health assesment in Sibiu Sud substation, Iernut substation, and Sibiu Subsidiary after refurbished";

[7] Contract no 14/ between Transelectrica Sibiu Subsidiary and SC PROT CONSULTING EXPERT CRAIOVA, s-au realizat „The study for occupational safety and health assesment in in 20kV Sibiu Sud substation and 220/110/20kV Gheorgheni substation".

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#68

Numerical evaluation of the effects of phase impedance asymmetry at an untransposed overhead transmission line

A. PANA[1*], AL. BALOI[1], F. MOLNAR-MATEI[1], N. CHIOSA[2]
[1]Politehnica University of Timișoara, Electrical Power Engineering Department,
[2]National Power Grid Company Transelectrica S.A. - Timisoara Branch,
[1, 2]Romania

SUMMARY

Transposition of phase conductors of overhead transmission lines in order to reduce asymmetries produced to the sets of three-phase voltages and currents in normal operating regimes, usually applies to lines with lengths greater than the values imposed by regulations. The solution is relatively rare in electrical transmission networks, due to relatively small lengths of power lines, which is why transposed lines remain sources of impedance mismatch. These asymmetries sometimes have consequences that can seem paradoxical, one of which is shown in this article. It is the effect of active power transfer between the phases of a three phase lines, produced due to the inductive and capacitive coupling between them, present in the electric fields respectively the magnetic fields formed around the three phase conductors. If these couplings, which are associated, by modeling, with inductive mutual impedances, respectively capacitive impedances, are asymmetrical, active power transfer between phases also become unbalanced, resulting additional active power flow on phase conductors, but with different values and senses. This article highlights the effect of the asymmetrical capacitive coupling between the phases of power transmission lines, considering for this the no load stationary operating conditions. Being an unbalanced regime, it was studied by power flow calculation using phase amounts. In this regard it was first determined the equivalent primitive impedances matrices, applying the modified Carson's equations. By using the method of Kron's reduction, the equivalent primitive matrices impedances were then reduced to the equivalent impedance phase matrices. In order to minimize modeling errors, the line is represented by a chain of six octopoles, which correspond to sections of equal length. Numerical analysis of stationary no load operating conditions, demonstrates that on two of the phases the overhead line takes active power from the network, that delivers back to the network on the third phase. On the whole three phases the sum of the active powers at the beginning of the line results of a value much smaller than the phase active power being actually consumed power (absorbed), corresponding to line losses, determined by the no load currents flow. This can be only positive (consumed). In practice they were encountered situations where, in such a regime, the measurement system installed at the beginning of the line indicates that the line generates (produces debit) active power (energy). For such a phenomenon that it is not possible, the indication was attributed to the measurement system errors. But the error is not indicating of a negative active power, when it is positive, but a negative indication of the amount of active power redistributed by the line between the network phases, value determined by the asymmetry of the measurement errors of the elements installed on different phases.

* adrian.pana@upt.ro

KEYWORDS

Transmission overhead lines, Phase series impedances asymmetry, Phase shunt admittances asymmetry, No-load steady-state regime, Power losses.

1. INTRODUCTION

Load unbalances and / or power system elements equivalent impedances asymmetry resulting from their structural asymmetries, causes voltage unbalances in consuming buses of the networks.

The most important f equivalent phase impedances asymmetries are produced by overhead lines, being as greater as the lengths of the lines are higher. Phase transposition of these lines is performed only if the values of their length exceed the limit established by norms. This operation reduces the unbalance in steady-state operating conditions but not the transients or nonsinusoidal steady-state.

Most high voltage overhead power lines are not so long as to require phase's transposition, so that for normal operating regimes, they remain important sources of unbalance. For numerical determination of the effect of unbalance impedance is necessary to use a modeling phase.

2. THREE-PHASE MODELLING OF ELECTRICAL OVERHEAD LINES

Three-phase modelling of overhead transmission lines is based on the determination of the phase series impedance matrix, respectively phase shunt admittances matrix. The unbalanced power-flow results accuracy depends on the impedance and admittance phase power flow calculation accuracy [1-3]. The correct establishing of the expressions for the series or shunt, self or mutual, equivalent parameters is difficult because each conductor lies in both its electric and magnetic fields and electric and magnetic fields of the other conductors, the full set of conductors being close to the ground, whose potential is zero.

The mathematical model used in the case study presented in this article is based on the relations of self and mutual primitive impedances calculation and o respectively self and mutual admittance calculation established by Carson. Then, for the calculation of power flow on a three-phase unbalanced power line having asymmetric load equivalent parameters, primitive impedance and admittance are transformed in phase impedances and admittances, by using the Krohn's transformation method [6]. The entire mathematical model is detailed in the appendix.

Because most high-voltage lines have lengths smaller than the quarter wavelength of the electromagnetic wave that propagates along them, modeling them by equivalent nominal electrical circuit with concentrated parameters is sufficiently precise. However, to minimize calculation errors in the presented application, modeling the line was made by considering six equal sections, which allows calculation of both the untransposed line and the phase transposition in two versions, with or without phases return at the end of the line on the positions from its beginning.

3. CASE STUDY

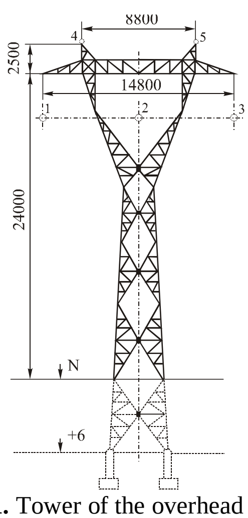


Fig. 1. Tower of the overhead line studied.

For the numerical evaluation of the effects of phase impedance and admittances (susceptances) matrix asymmetries on the steady state operating condition of a high voltage overhead line, a concrete case of an untransposed line having 220 kV rated voltage is considered. The line is a single circuit, built with steel reinforced concrete towers, having triangular phase arrangement. The energized conductors are ACSR type, with 450/75 mm^2 section and the steel protective conductor is bounded having 95 mm^2 cross section (Fig.1). The line has a total length of 120 km and for calculating the normal operation conditions, equivalent three-phase circuit was used, realized as a chain of six equivalent octopoles, corresponding to three equal length segments modeled with concentrated parameters (Fig. 2). In order to calculate the geometric characteristics and the phase impedances matrix, respectively the phase admittances matrix, MathCAD was used.

Using for the used amounts the same notation as in the mathematical model presented above, results the following values, in international system of measurement units:

$$zp = \begin{pmatrix} 0.113+0.708i & 0.049+0.304i & 0.049+0.26i & 0.049+0.319i & 0.049+0.27i \\ 0.049+0.304i & 0.113+0.708i & 0.049+0.304i & 0.049+0.307i & 0.049+0.307i \\ 0.049+0.26i & 0.049+0.304i & 0.113+0.708i & 0.049+0.27i & 0.049+0.319i \\ 0.049+0.319i & 0.049+0.307i & 0.049+0.27i & 2.087+0.759i & 0.049+0.293i \\ 0.049+0.27i & 0.049+0.307i & 0.049+0.319i & 0.049+0.293i & 2.087+0.759i \end{pmatrix} \ \Omega/\text{km} \qquad z_{abc} = \begin{pmatrix} 0.1666+0.65499i & 0.10459+0.24885i & 0.1015+0.20725i \\ 0.10459+0.24885i & 0.17125+0.65141i & 0.10459+0.24885i \\ 0.1015+0.20725i & 0.10459+0.24885i & 0.1666+0.65499i \end{pmatrix} \ \Omega/\text{km}$$

$$pp = \begin{pmatrix} 134.66632 & 23.30416 & 12.65957 & 30.4227 & 17.58124 \\ 23.30416 & 134.66632 & 23.30416 & 27.11827 & 27.11827 \\ 12.65957 & 23.30416 & 134.66632 & 17.58124 & 30.4227 \\ 30.4227 & 27.11827 & 17.58124 & 157.57325 & 26.32782 \\ 17.58124 & 27.11827 & 30.4227 & 26.32782 & 157.57325 \end{pmatrix} \ \text{km}/\mu\text{F} \qquad p_{abc} = \begin{pmatrix} 127.77283 & 16.22545 & 7.02253 \\ 16.22545 & 126.66853 & 16.22545 \\ 7.02253 & 16.22545 & 127.77283 \end{pmatrix} \ \text{km}/\mu\text{F}$$

$$c_{abc} := p_{abc}^{-1} = \begin{pmatrix} 0.00797 & -0.00098 & -0.00031 \\ -0.00098 & 0.00815 & -0.00098 \\ -0.00031 & -0.00098 & 0.00797 \end{pmatrix} \ \mu\text{F/km} \qquad y_{abc} = \begin{pmatrix} 2.503i\times10^{-6} & -3.08i\times10^{-7} & -9.846i\times10^{-8} \\ -3.08i\times10^{-7} & 2.559i\times10^{-6} & -3.08i\times10^{-7} \\ -9.846i\times10^{-8} & -3.08i\times10^{-7} & 2.503i\times10^{-6} \end{pmatrix} \ \mu\text{S/km}$$

For each section of the line, the values of the equivalents concentrated parameters are equal to one sixth of nomminale values to be determined by the equations:

$$\left[\underline{Z}_{abc}\right] = L\cdot\left[\underline{z}_{abc}\right], \quad \left[\underline{Y}_{abc}\right] = L\cdot\left[\underline{y}_{abc}\right] \tag{20}$$

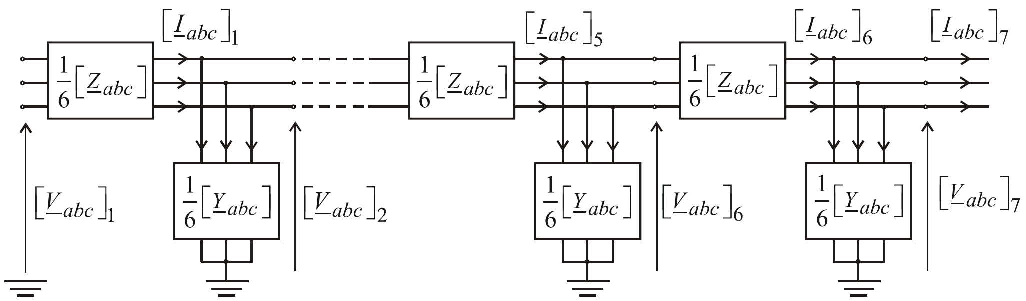


Fig. 2. Three-phase equivalent circuit of the studied line, obtained by concatenation of six identical octopoles.

For the considered no load operating condition it can be first highlighted the effect of equivalent capacities (admittances) unbalance. For the calculation of currents and voltages in the sevent nodes (sections) that delimitates the six segments, voltages and currents in the node $m=7$ (the end of the line, Fig. 4) have been assumed to be known. The equations (19) and (6) were then successively applied, making the calculation by backward power flow calculation:

$$\left[\underline{I}_{abc}\right]_{m-1} = \left[\underline{I}_{abc}\right]_m + \frac{1}{3}\left[\underline{Y}_{abc}\right]\cdot\left[\underline{V}_{abc}\right]_m \qquad m = 7..1 \tag{21}$$

$$\left[\underline{V}_{abc}\right]_{m-1} = \left[\underline{V}_{abc}\right]_m + \frac{1}{3}\left[\underline{Z}_{abc}\right]\cdot\left[\underline{I}_{abc}\right]_{m-1} \qquad m = 7..1 \tag{22}$$

At the beginning node of the line especially interesting are the active and reactive powers per phase and on the three-phase on whole, for whose calculation the known equations are applied:

$$\underline{S}_{i1} = \underline{V}_{i1}\cdot\overline{\underline{I}}_{i1} = P_{i1} + jQ_{i1} \qquad i = a,b,c \tag{23}$$

$$P_{i1} = \mathrm{Re}\left(\underline{V}_{i1}\cdot\overline{\underline{I}}_{i1}\right), \; Q_{i1} = \mathrm{Im}\left(\underline{V}_{i1}\cdot\overline{\underline{I}}_{i1}\right) \qquad i = a,b,c \tag{24}$$

The main obtained results are presented below.

$$Vabc_7 = \begin{pmatrix} 128.172 \\ 128.172 \\ 128.172 \end{pmatrix} \text{kV} \quad Vabc_6 = \begin{pmatrix} 128.111 \\ 128.115 \\ 128.113 \end{pmatrix} \text{kV} \quad Vabc_5 = \begin{pmatrix} 127.989 \\ 128 \\ 127.995 \end{pmatrix} \text{kV} \quad Vabc_4 = \begin{pmatrix} 127.807 \\ 127.829 \\ 127.818 \end{pmatrix} \text{kV} \quad Vabc_3 = \begin{pmatrix} 127.564 \\ 127.6 \\ 127.582 \end{pmatrix} \text{kV} \quad Vabc_2 = \begin{pmatrix} 127.261 \\ 127.315 \\ 127.288 \end{pmatrix} \text{kV} \quad Vabc_1 = \begin{pmatrix} 126.897 \\ 126.972 \\ 126.935 \end{pmatrix} \text{kV}$$

$$Iabc_7 = \begin{pmatrix} 0 \\ 0 \\ 0 \end{pmatrix} \text{A} \quad Iabc_6 = \begin{pmatrix} 6.954 \\ 7.35 \\ 6.954 \end{pmatrix} \text{A} \quad Iabc_5 = \begin{pmatrix} 13.904 \\ 14.696 \\ 13.904 \end{pmatrix} \text{A} \quad Iabc_4 = \begin{pmatrix} 20.848 \\ 22.036 \\ 20.848 \end{pmatrix} \text{A} \quad Iabc_3 = \begin{pmatrix} 27.781 \\ 29.366 \\ 27.782 \end{pmatrix} \text{A} \quad Iabc_2 = \begin{pmatrix} 34.702 \\ 36.682 \\ 34.704 \end{pmatrix} \text{A}$$

$$Iabc_1 = \begin{pmatrix} 41.606 \\ 43.983 \\ 41.61 \end{pmatrix} \text{A}$$

The rms values of the voltages increase toward the end of the line, which was expected due to the no load operating condition, characterized by Ferrantti effect. Currents on the phase conductors have pronounced capacitive character, and their rms values increase towards the beginning of the line which was also expected.

The study was done in order to evaluate the effects of phase impedances and admitances asymmetry on the power flow in steady state operating conditions. It can be seen that in terms of rms values of voltages and currents, the unbalance is minor. The asymmetry of the currents phase shift related to the corresponding voltages is however more pronounced and is reflected in pronounced unbalance of active powers on the three phases of the line. For the beginning of the line results:

$$Pabc_{1_1} := \mathrm{Re}\left(Vabc_{1_1} \cdot \overline{Iabc_{1_1}}\right) \cdot 10^{-3} = -347.721 \quad \text{kW} \qquad Qabc_{1_1} := \mathrm{Im}\left(Vabc_{1_1} \cdot \overline{Iabc_{1_1}}\right) \cdot 10^{-3} = -5268.288 \quad \text{kVAr}$$

$$Pabc_{1_2} := \mathrm{Re}\left(Vabc_{1_2} \cdot \overline{Iabc_{1_2}}\right) \cdot 10^{-3} = 5.933 \quad \text{kW} \qquad Qabc_{1_2} := \mathrm{Im}\left(Vabc_{1_2} \cdot \overline{Iabc_{1_2}}\right) \cdot 10^{-3} = -5584.574 \quad \text{kVAr}$$

$$Pabc_{1_3} := \mathrm{Re}\left(Vabc_{1_3} \cdot \overline{Iabc_{1_3}}\right) \cdot 10^{-3} = 359.427 \quad \text{kW} \qquad Qabc_{1_3} := \mathrm{Im}\left(Vabc_{1_3} \cdot \overline{Iabc_{1_3}}\right) \cdot 10^{-3} = -5269.464 \quad \text{kVAr}$$

$$Pabc_{1_1} + Pabc_{1_2} + Pabc_{1_3} = 17.639 \quad \text{kW} \qquad Qabc_{1_1} + Qabc_{1_2} + Qabc_{1_3} = -16122.325 \quad \text{kVAr}$$

Reactive power unbalance does not seem unusual, but that of the active powers seem downright strange. Thus, it appears that on the phases *b(2)* and *c(3)* the active powers are positive (incoming, taken by the line from the network) and on the phase *a(1)* the active power is negative (outgoing, delivered by the line to the network) . This effect is the consequence of the phase mutual inductance unbalance and especially mutual capacity between the phase conductors (mutual capacitive susceptances). It's a confirmation of a known fact according to which a three-phase load consisting of only capacitors of different values of capacities in delta connection, leads to active power redistribution between the network phases. Thus, on two of the phases this receiver receives (takes) active power from the network, which it delivers back to the network on the third phase [7], without affecting the active power balance on the three phases on whole.

In the case of the studied line, the active power at the beginning of the line on the three-phases on whole has a value much smaller than on the phases ($P_1 = P_{a_1} + P_{b_1} + P_{c_1} = 17,639$ kW). This power has the physically sense of a consumed power (lost power) and corresponds to the sum of Joule-Lenz losses produced on the energized conductors of the line operating in no load conditions.

In practice, it can happen that the measuring system installed in the substation at the beginning of the line, although very accurate in other operating conditions may indicate a negative power (energy) in no load operating conditions. This does not mean that the line generates active power (energy), but the sum of the powers (energies) redistributed between network phases is negative, due to the asymmetry of the measurement errors of the system components installed on different phases. Of these elements, the most likely are the current transformers, known that at low values of the currents have large measurement errors for both rms and angle.

The problem disappears if the conductors are transposed. The values of active and reactive powers at the beginning of the line for the two cases of transposition (with or without come back) are shown below.

$$Pabc_{1_1} := \mathrm{Re}\left(Vabc_{1_1} \cdot \overline{Iabc_{1_1}}\right) \cdot 10^{-3} = 5.51 \quad \text{kW} \qquad Qabc_{1_1} := \mathrm{Im}\left(Vabc_{1_1} \cdot \overline{Iabc_{1_1}}\right) \cdot 10^{-3} = -5373.529 \quad \text{kVAr}$$

$$Pabc_{1_2} := \mathrm{Re}\left(Vabc_{1_2} \cdot \overline{Iabc_{1_2}}\right) \cdot 10^{-3} = 7.722 \quad \text{kW} \qquad Qabc_{1_2} := \mathrm{Im}\left(Vabc_{1_2} \cdot \overline{Iabc_{1_2}}\right) \cdot 10^{-3} = -5373.833 \quad \text{kVAr}$$

$$Pabc_{1_3} := \mathrm{Re}\left(Vabc_{1_3} \cdot \overline{Iabc_{1_3}}\right) \cdot 10^{-3} = 4.361 \quad \text{kW} \qquad Qabc_{1_3} := \mathrm{Im}\left(Vabc_{1_3} \cdot \overline{Iabc_{1_3}}\right) \cdot 10^{-3} = -5374.136 \quad \text{kVAr}$$

$$Pabc_{1_1} + Pabc_{1_2} + Pabc_{1_3} = 17.593 \quad \text{kW} \qquad Qabc_{1_1} + Qabc_{1_2} + Qabc_{1_3} = -16121.498 \quad \text{kVAr}$$

$$Pabc_{1_1} := \mathrm{Re}\left(Vabc_{1_1}\cdot\overline{Iabc_{1_1}}\right)\cdot 10^{-3} = 2.167 \quad \mathrm{kW} \qquad Qabc_{1_1} := \mathrm{Im}\left(Vabc_{1_1}\cdot\overline{Iabc_{1_1}}\right)\cdot 10^{-3} = -5373.478 \quad \mathrm{kVAr}$$

$$Pabc_{1_2} := \mathrm{Re}\left(Vabc_{1_2}\cdot\overline{Iabc_{1_2}}\right)\cdot 10^{-3} = 8.088 \quad \mathrm{kW} \qquad Qabc_{1_2} := \mathrm{Im}\left(Vabc_{1_2}\cdot\overline{Iabc_{1_2}}\right)\cdot 10^{-3} = -5373.533 \quad \mathrm{kVAr}$$

$$Pabc_{1_3} := \mathrm{Re}\left(Vabc_{1_3}\cdot\overline{Iabc_{1_3}}\right)\cdot 10^{-3} = 7.347 \quad \mathrm{kW} \qquad Qabc_{1_3} := \mathrm{Im}\left(Vabc_{1_3}\cdot\overline{Iabc_{1_3}}\right)\cdot 10^{-3} = -5374.552 \quad \mathrm{kVAr}$$

$$Pabc_{1_1} + Pabc_{1_2} + Pabc_{1_3} = 17.601 \quad \mathrm{kW} \qquad Qabc_{1_1} + Qabc_{1_2} + Qabc_{1_3} = -16121.563 \quad \mathrm{kVAr}$$

4. CONCLUSIONS

In order to evaluate the effects of equivalent phase impedances asymmetry and equivalent phase admitances of an overhead transmission line, its more accurate three-phase modeling is needed. In the case study analyzed in this paper is numerically demonstrated, by using a mathematical modeling widely accepted, that an overhead line not transposed operating in no load condition causes a pronounced unbalance in active power on phases. The capacitive susceptances asymmetry between the line phases leads to a redistribution of powers between the phases of network. On two of the phases the line receives active power from the network, which delivers back to the network. Such unbalance should not change the power balance on the three phases on whole, but in such a situation if in the metering system of powers (energies) there is an asymmetry of measurement errors of the elements installed on different phases, the unnatural effect of metering the active power delivered by the line operating in no load conditions may occur. The elements the most likely to produce these measurement errors are the current transformers known to have large measurement errors, for both rms values and phase in the case of low and very low currents compared with their rated current.

APPENDIX

The modified Carson relations applied to an overhead electrical line. The Krohn's reduction method.

A. Primitive impedance matrix and phase impedance matrix for overhead lines

The calculation of self and mutual primitive impedances for an overhead line having any number of conductors is done taking into account that each conductor is placed in its own variable magnetic field and in the variable magnetic fields of the other conductors. The Carson's equations are often used in practice [1-4], [6]. These were deducted based on a technique based on the conductor images, using the simplifying assumptions that the ground is a solid uniform, infinite size, with a uniform surface perfectly flat on the outside and whose electrical resistivity is constant. Also the end effect which is introduced by grounding the neutral conductor is reduced for the frequencies that are found in the network and can therefore be neglected. Some additional mathematical simplifications led to modified Carson's equations, which proved to be sufficiently accurate and is therefore widely used in the modeling of both the overhead and underground lines [4], [6].

The modified Carson's equations for self and mutual primitive impedance calculation for overhead lines are:

$$\underline{z}_{ii}^{p} = r_i + k_1 \cdot f + j \cdot k_2 \cdot f \left(\ln \frac{1}{GMR_i} + k_3 + \frac{1}{2} \ln \frac{\rho}{f} \right) \tag{1}$$

$$\underline{z}_{ij}^{p} = k_1 \cdot f + j \cdot k_2 \cdot f \left(\ln \frac{1}{D_{ij}} + k_3 + \frac{1}{2} \ln \frac{\rho}{f} \right) \tag{2}$$

where $\underline{z}_{ii}^{p}$ is the self-impedance of conductor *i* in ohm/mile, $\underline{z}_{ij}^{p}$ - mutual impedance between conductors *i* and *j* in ohm/mile, r_i - resistance of conductor *i* in ohm/mile, f - frequency in hertz, D_{ij} - distance between conductor *i* and conductor *n* in feet, GMR_i - geometric mean radius of conductor *i* in feet, ρ - resistivity of earth in ohm·m, k_1, k_2, k_3 - constants, having the values: $k_1 = 1.58836 \cdot 10^{-3}$, $k_2 = 2.02237 \cdot 10^{-3}$, $k_3 = 7.6786$.

In Fig. A1 is presented a section of unit of length of a three phase overhead line, with three phase conductors (denoted *a, b, c)* and two grounded (*g*) neutral conductors (n_1 și n_2). Self and mutual primitive impedances are presented on the figure.

Applying Kirchhoff's voltage law for the circuit in Fig.1, one can write the equation matrix (3):

$$\begin{bmatrix} \underline{V}_{ag} \\ \underline{V}_{bg} \\ \underline{V}_{cg} \\ \underline{V}_{n_1g} \\ \underline{V}_{n_2g} \end{bmatrix} = \begin{bmatrix} \underline{V}'_{ag} \\ \underline{V}'_{bg} \\ \underline{V}'_{cg} \\ \underline{V}'_{n_1g} \\ \underline{V}'_{n_2g} \end{bmatrix} + \left[\begin{array}{ccc|cc} \underline{z}^p_{aa} & \underline{z}^p_{ab} & \underline{z}^p_{ac} & \underline{z}^p_{an_1} & \underline{z}^p_{an_2} \\ \underline{z}^p_{ba} & \underline{z}^p_{bb} & \underline{z}^p_{bc} & \underline{z}^p_{bn_1} & \underline{z}^p_{bn_2} \\ \underline{z}^p_{ca} & \underline{z}^p_{cb} & \underline{z}^p_{cc} & \underline{z}^p_{cn_1} & \underline{z}^p_{cn_2} \\ \hline \underline{z}^p_{n_1a} & \underline{z}^p_{n_1b} & \underline{z}^p_{n_1c} & \underline{z}^p_{n_1n_1} & \underline{z}^p_{n_1n_2} \\ \underline{z}^p_{n_2a} & \underline{z}^p_{n_2b} & \underline{z}^p_{n_2c} & \underline{z}^p_{n_2n_1} & \underline{z}^p_{n_2n_2} \end{array}\right] \cdot \begin{bmatrix} \underline{I}_a \\ \underline{I}_b \\ \underline{I}_c \\ \underline{I}_{n_1} \\ \underline{I}_{n_2} \end{bmatrix} \tag{3}$$

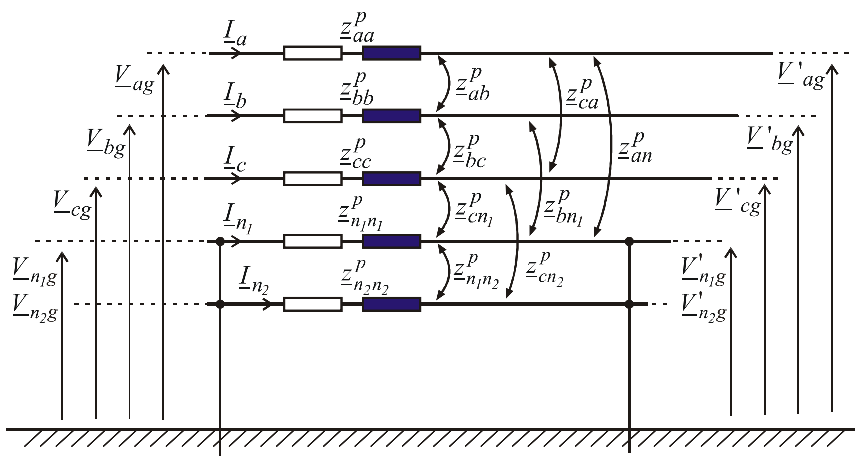


Fig. A1. Section of a three phase overhead line and primitive impedances.

The matrix from equation (3) can be written by partitionning:

$$\begin{bmatrix} [\underline{V}_{abc}] \\ [\underline{V}_{ng}] \end{bmatrix} = \begin{bmatrix} [\underline{V}'_{abc}] \\ [\underline{V}'_{ng}] \end{bmatrix} + \begin{bmatrix} [\underline{z}^p_{ij}] & [\underline{z}^p_{in}] \\ [\underline{z}^p_{nj}] & [\underline{z}^p_{nn}] \end{bmatrix} \cdot \begin{bmatrix} [\underline{I}_{abc}] \\ [\underline{I}_{ng}] \end{bmatrix} \tag{4}$$

thus it can be written the self and mutual primitive impedance matrix:

$$\left[\underline{z}^p\right] = \begin{bmatrix} [\underline{z}^p_{ij}] & [\underline{z}^p_{in}] \\ [\underline{z}^p_{nj}] & [\underline{z}^p_{nn}] \end{bmatrix} \tag{5}$$

For most applications, however, it is necessary the phase impedance matrix. Primitive impedance matrix transformation into a phase impedances matrix can be done by applying Kron's reduction method [5]. It can be applied when the neutral conductor (or protective conductor) is connected to ground so that the voltages between the two points are zero at both ends of the considered section:

$$\left[\underline{V}_{ng}\right] = 0 \quad \text{and} \quad \left[\underline{V}'_{ng}\right] = 0$$

Thus, equatin (4) can be reduced to:

$$\left[\underline{V}_{abc}\right] = \left[\underline{V}'_{abc}\right] + \left[\underline{z}_{abc}\right] \cdot \left[\underline{I}_{abc}\right] \tag{6}$$

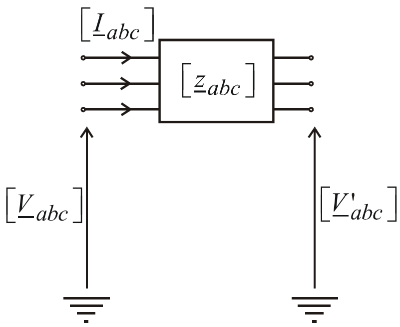


Fig. A2. Simplified three-phase electrical equivalent circuit associated to the phase impedances matrix .

In the equivalent electrical circuit for three-phase unit of length of the line (Fig. A2), the phase impedance matrix allows computing the voltage drop and hence the network buses voltages, by applying (6).

In expression (6) is identified the phase impedance matrix that can be determined by an expression that uses elements of the primitive impedance matrix [5]:

$$\left[\underline{z}_{abc}\right]=\left[\underline{z}_{ij}^{p}\right]-\left[\underline{z}_{in}^{p}\right]\cdot\left[\underline{z}_{nn}^{p}\right]^{-1}\cdot\left[\underline{z}_{nj}^{p}\right] \tag{7}$$

The phase impedance matrix is a square matrix of size 3 x 3:

$$\left[\underline{z}_{abc}\right]=\begin{bmatrix}\underline{z}_{aa} & \underline{z}_{ab} & \underline{z}_{ac}\\ \underline{z}_{ba} & \underline{z}_{bb} & \underline{z}_{bc}\\ \underline{z}_{ca} & \underline{z}_{cb} & \underline{z}_{cc}\end{bmatrix} \tag{8}$$

B. Primitive potential coefficient matrix and phase capacitance matrix for overhead lines

In order to determine the phase shunt admittance matrix is needed the determination of the potential of a conductor belonging to an overhead line, which is placed in the own electric field and in the electric fields caused by the other conductors. By applying the method of the images to ground surface of the electric charges of conductors of the line, one can determine the expression of the voltage drop between conductor and ground [6]. For each conductor, its potential relative to the ground is influenced by electrical charges of all conductors through the self and mutual potential coefficients. For a three-phase line with three phase conductors and two neutral conductors (or ground conductors), we can write the equation:

$$\begin{bmatrix}V_{ag}\\ V_{bg}\\ V_{cg}\\ V_{n_1g}\\ V_{n_2g}\end{bmatrix}=\left[\begin{array}{ccc:cc}p_{aa}^{p} & p_{ab}^{p} & p_{ac}^{p} & p_{an_1}^{p} & p_{an_2}^{p}\\ p_{ba}^{p} & p_{bb}^{p} & p_{bc}^{p} & p_{bn_1}^{p} & p_{bn_2}^{p}\\ p_{ca}^{p} & p_{cb}^{p} & p_{cc}^{p} & p_{cn_1}^{p} & p_{cn_2}^{p}\\ \hdashline p_{n_1a}^{p} & p_{n_1b}^{p} & p_{n_1c}^{p} & p_{n_1n_1}^{p} & p_{n_1n_2}^{p}\\ p_{n_2a}^{p} & p_{n_2b}^{p} & p_{n_2c}^{p} & p_{n_2n_1}^{p} & p_{n_2n_2}^{p}\end{array}\right]\cdot\begin{bmatrix}q_a\\ q_b\\ q_c\\ q_{n_1}\\ q_{n_2}\end{bmatrix} \tag{9}$$

Appropriate partitioning the matrices in equation (9), we can write in a compacted form:

$$\begin{bmatrix}[V_{abc}]\\ [V_{ng}]\end{bmatrix}=\begin{bmatrix}\left[p_{ij}^{p}\right] & \left[p_{in}^{p}\right]\\ \left[p_{nj}^{p}\right] & \left[p_{nn}^{p}\right]\end{bmatrix}\cdot\begin{bmatrix}[q_{abc}]\\ [q_n]\end{bmatrix} \tag{10}$$

The primitive potential coefficients matrix is square one, size 5 x 5:

$$\left[p^{p}\right]=\begin{bmatrix}\left[p_{ij}^{p}\right] & \left[p_{in}^{p}\right]\\ \left[p_{nj}^{p}\right] & \left[p_{nn}^{p}\right]\end{bmatrix} \tag{11}$$

The primitive potential coefficients expressions are deducted based on the same concept of Carson, using the conductors' images [6]:

$$p_{ii}^{p}=k_p\cdot\ln\frac{S_{ii}}{RD_i} \tag{12}$$

$$p_{ij}^{p}=k_p\cdot\ln\frac{S_{ij}}{D_{ij}} \tag{13}$$

where p_{ii}^p is the self potential coefficient, în mile/microfarad, p_{ij}^p - mutual potential coefficient, în mile/ microfarad, S_{ii} - distance from conductor *i* and its image, in feet, S_{ij} - distance from conductor *i* and the image of conductor *j*, in feet, RD_i - radius of conductor *i*, in feet, D_{ij} - distance from conductor *i* to conductor *j*, in feet, k_p = 11.17689 - constant resulting from consideration of air relative permittivity to the amount of: ε_{air} = 1.424 10^2 μF/mile.

The neutral conductor is grounded, $\left[V_{ng}\right]=0$ so the primitive potential coefficients matrix can be reduced, using Kron's reduction method [6], to the phase potential coefficients matrix, by applying the equation:

$$[p_{abc}]=\left[p_{ij}^p\right]-\left[p_{in}^p\right]\cdot\left[p_{nn}^p\right]^{-1}\cdot\left[p_{nj}^p\right] \tag{14}$$

Relația (9) se poate acum reduce la (15)

$$[V_{abc}]=[p_{abc}]\cdot[q_{abc}] \tag{15}$$

Is obtained immediately the phase capacities matrix, expressed in μF/mile, being the inverse of the phase potential coefficients matrix:

$$[c_{abc}]=[p_{abc}]^{-1} \tag{16}$$

$$[c_{abc}]=\begin{bmatrix} c_{aa} & c_{ab} & c_{ac} \\ c_{ba} & c_{bb} & c_{bc} \\ c_{ca} & c_{cb} & c_{cc} \end{bmatrix} \tag{17}$$

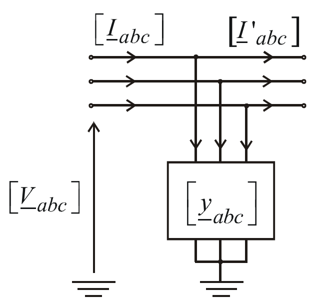


Fig. A3. Simplified three-phase electrical equivalent circuit associated to the phase admittances matrix..

According to a widely accepted practice, most often the shunt conductance of an overhead transmission line can be neglected, so that for the phase shunt admittances matrix expressed in μS/mile, results the equations:

In the electrical equivalent circuit for the unit of length of the line, the phase admittance matrix determines the capacitive currents and their contribution to the current values on the phase conductors. According to the notations in Fig. A3, we can write:

$$[\underline{I}_{abc}]=[\underline{I}'_{abc}]+\left[\underline{y}_{abc}\right]\cdot[\underline{V}_{abc}] \tag{19}$$

$$\left[\underline{y}_{abc}\right]=0+j\cdot\omega\cdot[c_{abc}] \tag{18}$$

BIBLIOGRAPHY

[1] H. Keshtkar, S. Khushalani Solanki, J.M. Solanki, „Improving the Accuracy of Impedance Calculation for Distribution Power System” (IEEE Transactions on Power Delivery, vol. 29, Aug. 2013, pp. 570 - 579)

[2] W.H. Kersting, R.K. Green, „The application of Carson's equation to the steady-state analysis of distribution feeders” (Power Systems Conference and Exposition (PSCE), 2011 IEEE/PES, 20-23 March 2011, Phoenix, AZ, USA, pp. 1-6)

[3] T.F.R.D. Martins, A.C.S. Lima and S. Carneiro Jr., "Effect of approximate impedance formulae on the accuracy of transmission line modeling" (IET Gen. Transm. Distrib., vol. 1, no. 4, 2007, pp. 534 -539)

[4] J. R. Carson, “Wave propagation in overhead wires with ground return” (Bell System Technical Journal, vol. 5, New York, 1926)

[5] G. Kron, “Tensorial analysis of integrated transmission systems, Part I, the six basic reference frames”, (AIEE Trans., vol. 71, 1952)
[6] W.H. Kersting, “Distribution System Modeling and Analysis” (CRC Press, Boca Raton, USA, 2002)
[7] A. Pană, „Active Load Balancing in a Three-Phase Network by Reactive Power Compensation”, Chapter 11 in "Power Quality Monitoring, Analysis and Enhancement", edited by A. Zobaa, M.M. Canteli and R. Bansal (InTech Europa, open access publisher, Rijeka, Croatia, 2011).

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#69

Switching requirements for disconnectors and earthing switches

Ioan Dorin HATEGAN*, Emilia STOICESCU**
CNTEE Transelectrica SA
Romania

SUMMARY

The paper tells about disconnecting switch bus transfer and bus charging currents at the rated voltages of 220 and 400 kV. CIGRE Study Committee A3 made an International survey on switching requirements for Bus-transfer switching of Disconnecting Switch, Bus-charging switching of Disconnecting Switch, Induced current switching of Earthing Switch, at the rated voltages of 72.5-362 kV and Romania participated of it. The survey wants to know the difference between practice and standard value for switching requirements.

We will present the switching condition for Romania and the conclusion of the CIGRE survey. Even though DS Bus-charging currents at 420 kV AIS exceeds the existing standard value in one country, most of the currents at the rated voltages from 123 kV to 550 kV, especially for GIS applications, are covered by the standard values. The transmission lines are designed to carry twice capacity corresponding to the capacity under double circuits condition, when a single circuit is suspended due to a fault.

Both Electromagnetically (EM) & Electrostatically (ES) Induced currents by Earthing switch (ES) significantly exceeds the standard values, especially for the cases of higher nominal current. CIGRE will investigate the filed experience whether such ES have any reliability problems on the requirements. [1]

KEYWORDS

Disconnecting Switch, Earthing Switch, Bus charging current

1. BUS-TRANSFER CURRENT SWITCHING BY DISCONNECTING SWICH

For disconnecting switch the capability to having a breaking depending of the magnitude of the load transferred, the size of the loop between the location of the bus coupling and the disconnector switch to be operated. [1]

When is designed a station is need to know the switching requirements for DS used to transfer load currents from one bus system to another. Also the disconnectors shall comply with the bus transfer requirements of IEC 62271 – 102 Annex B. [2]

* ioan.hategan@ transelectrica.ro
** emilia.stoicescu@transelectrica.ro

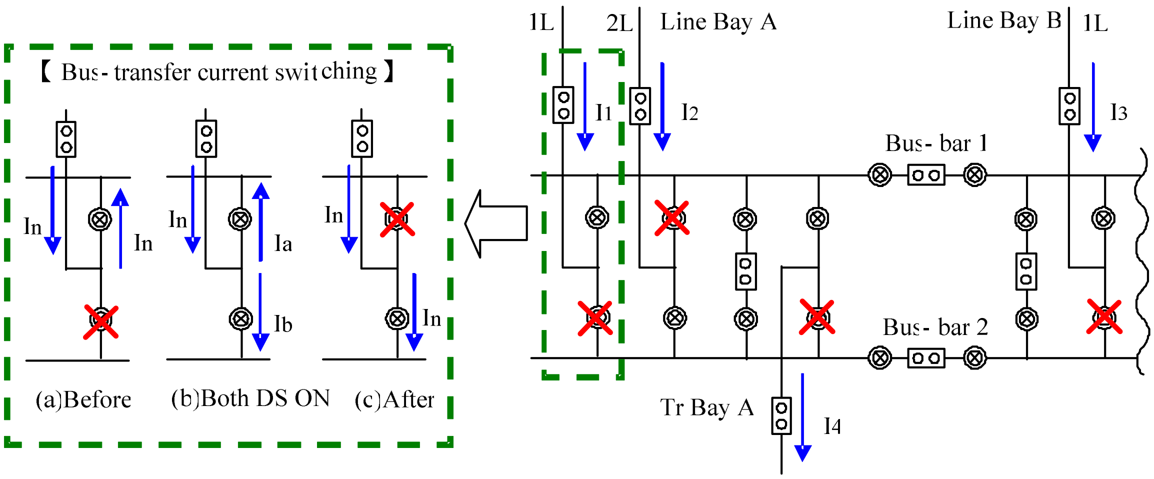


Fig.1.1 Bus transfer current switching [1]

For Romania the usually bus transfer parameters and requirements for a 220 kV systems is presented in Table 1.1 and for a 110 kV systems is presented in table 1.2.

Table 1.1: Bus-transfer parameters and requirements 220 kV [1]

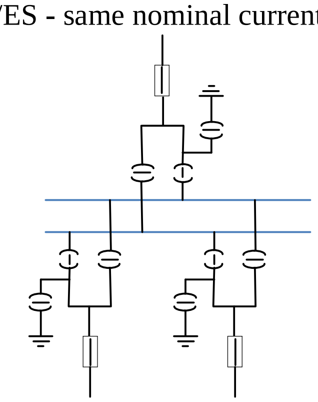
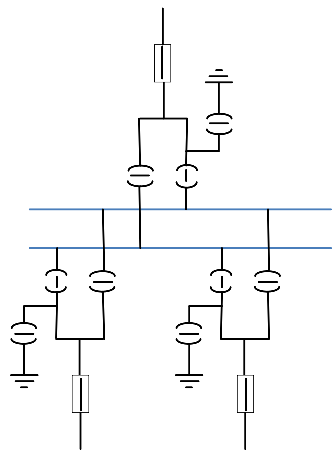
Voltage level	**220 kV**	
Design / Country	**Romania**	
Busbar arrangement / scheme	**Double busbar arrangement**	
Single line diagram * typical or maximum values of nominal currents through the CBs and DSs	For all CB/DS/ES - same nominal current.(1600 A or 2000A) 	
Rated voltage	**220**	kV
Rated current	**1600 or 2000**	A
Rated frequency	**50**	Hz
Specified bus-transfer voltage	**220**	kV
Rated voltage of DS	**245**	kV
Rated current of DS	**1600 or 2000**	A

Table 1.2: Bus-transfer parameters and requirements 110 kV [1]

Voltage level	**110 kV**	
Design / Country	**Romania**	
Busbar arrangement / scheme	**Double busbar arrangement**	
Single line diagram * typical or maximum values of nominal currents through the CBs and DSs	For all CB/DS/ES - same nominal current. (1600 A or 2000A) 	
Rated voltage	**110**	kV
Rated current	**1600 or 2000**	A
Rated frequency	**50**	Hz
Rated voltage of DS	**123**	kV
Rated current of DS	**1600 or 2000**	A

2. BUS-CHARGING CURRENT SWITCHING BY DISCONNECTING SWITCH (DS)

It's important to know the current interruption capability of DS when de-energizing long busbars or other energized parts, for example short length of cables, etc.

For Romania the usually bus charging current and related value for 220 kV and 110 kV systems is presented in Table 2.1.

Table 2.1 Bus-charging current and related value [3]

Voltage level	**220 kV**	**110 kV**
Country	Romania	Romania
Rated voltage(kV)	220	110
Rated current(A)	1600 or 2000	1600 or 2000
Rated frequency(Hz)	50	50
Bus-charging current(A)	1600 or 2000	1600 or 2000

3. INDUCED CURRENT SWITCHING BY EARTHING SWITCH (ES)

In the case of multiple configurations of overhead transmission lines, current may circulate in de-energized and earthed lines as a result of capacitive and inductive coupling with adjacent energized lines [1].

ES applied to earth these lines shall therefore be capable of assuring the following service conditions [1]:

– making and breaking of a capacitive current when the earth connection is open at one termination and ES is performed at the other termination;

– making and breaking of an inductive current when the line is earthed at one termination and ES is performed at the other termination;

– carrying continuously the capacitive and inductive currents.

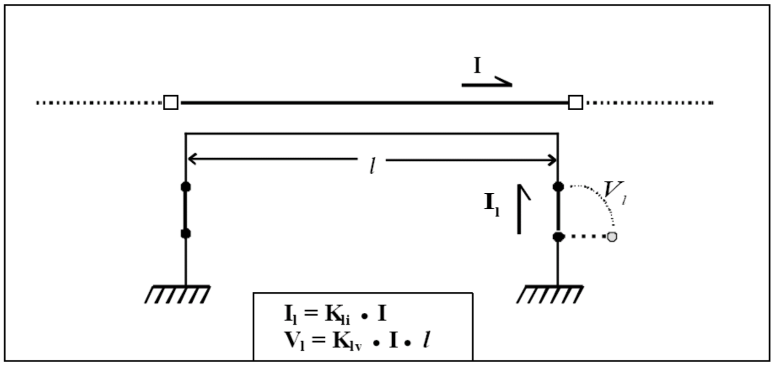


Fig 3.1 Electromagnetic Induction (Inductive current) from parallel lines

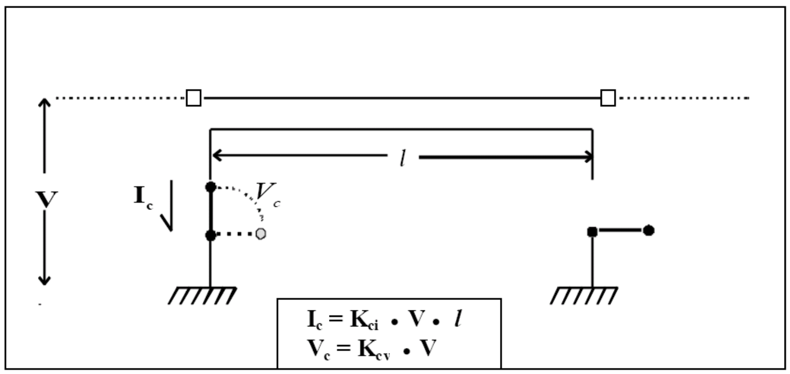
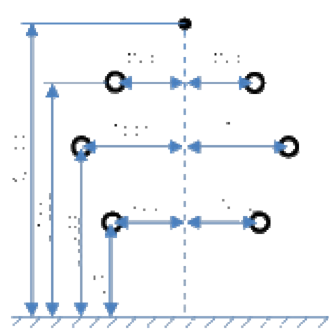
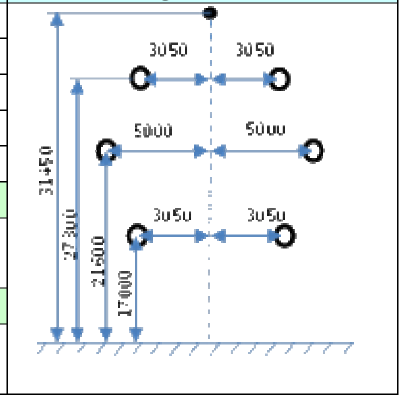


Fig 3.2 Electrostatic Induction (Capacitive current) from parallel lines

For Romania the usually induced current parameters and requirements for 220 kV and 110 kV systems is presented in Table 3.1.

Table 3.1 Induced current parameters and requirements

Voltage level	**220**	kV	Tower design
Country	**ROMANIA**		
Arrangement	**Double circuit**		
Rated voltage	**220**	kV	
Rated current	**1600 or 2000**	A	
Rated frequency	**50**	Hz	
Maximum length of double circuit line	**116**	km	
Electromagnetically*			
Induced current and voltage evaluation	**80/2000**	A / V	
Electrostatically*			
Induced current and voltage evaluation	**2/6000**	A / V	

Voltage level	**110**	kV	Tower design
Country	**ROMANIA**		
Arrangement	**Double circuit**		
Rated voltage	**110**	kV	
Rated current	**1600 or 2000**	A	
Rated frequency	**50**	Hz	
Electromagnetically*			
Induced current and voltage evaluation	**80 / 2000**	A / V	
Electrostatically*			
Induced current and voltage evaluation	**2 / 6000**	A / V	

CONCLUSION

Regarding CIGRE international surveys on switching requirements for Bus-transfer switching of Disconnecting Switch, Bus-charging switching of Disconnecting Switch, Induced current switching of Earthing Switch even though DS Bus-charging currents at 420 kV AIS exceeds the existing standard value in one country, most of the currents at the rated voltages from 123 kV to 550 kV, especially for GIS applications, are covered by the standard values. The transmission lines are designed to carry twice capacity corresponding to the capacity under double circuits condition, when a single circuit is suspended due to a fault. [1]

Both Electromagnetically (EM) & Electrostatically (ES) Induced currents by Earthing switch (ES) significantly exceeds the standard values, especially for the cases of higher nominal current. CIGRE will investigate the filed experience whether such ES have any reliability problems on the requirements. [1]

In Romania the requirements for disconnectors comply the bus transfer requirements of IEC 62271 – 102 Annex B and the earthing switches comply the induced current switching requirements of IEC 62271-102 Annex C.

If an earth switch is combined with a disconnector as a single unit, the rated short – time withstand current of the earth switch shall be at least equal to that of the disconnector.

BIBLIOGRAPHY

[1] Hiroki Ito Chairman, CIGRE Study Committee A3 “International surveys on switching requirements for Bus-transfer switching of Disconnecting Switch, Bus-charging switching of Disconnecting Switch, Induced current switching of Earthing Switch, at the related voltages of 72.5-362 kV”

[2] IEC 62271-102 – High- Voltage switchgear and controlgear – Part 102 High Voltage alternating current disconnectors and earthing switches.

[3] Working Group A3.28 – CIGRE Brochure 570 - Switching Phenomena for EHV and UHV.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#72

Considerations on indicators for assessing the level of competition in the balancing and ancillary services markets

Pavel ATANASOAE[*], Radu PENTIUC, Crenguta BOBRIC, Eugen HOPULELE
University "Stefan cel Mare" of Suceava
Romania

SUMMARY

Assessing the level of competition and transparency in the electricity market requires continuous monitoring and evaluation of the behavior of market participants. Market surveillance can prevent the abuse of dominance or market power. Electricity market consists of the regulated market and the competitive market and energy transactions are wholesale or retail. Opening the electricity market is achieved by progressively increasing the competitive market share. The paper presents in a synthetic manner, components of the competitive market for electricity and evolution the main indicators for assessing the level of competition on the balancing and ancillary services markets.

KEYWORDS

Competitive electricity market, market concentration indices, ancillary services market, balancing market.

1. INTRODUCTION

Ancillary services are some operational reserved services procured by the Transmission System Operator (TSO) for keeping a balance between supply and demand, stabilizing the transmission system and maintaining the power quality on an economical basis in any competitive electricity market environment. The term ancillary services are used to refer to a variety of operations beyond generation and transmission that are required to maintain grid stability and security. These services generally include, frequency control, spinning reserves and operating reserves [1], [2], [3].

The electric power system has two unique requirements which must be continuously and exactly satisfied in order to maintain overall system stability and reliability. Energy and capacity are the basic products customers really use. But energy and capacity alone are not sufficient to reliably operate the power system. A series of ancillary services are required that provide the system operator with the resources needed to maintain the instantaneous and continuous balance between generation and load, to manage transmission line flows. These services are required under normal conditions and when contingencies happen. Ancillary services also provide the resources needed to restart the power system if the system operator is unable to maintain the generation/load balance and the system collapses. Restructuring and the introduction of competitive generation markets has required that these services be clearly defined and monetized. Markets have been created for several ancillary services in order to minimize the cost of maintaining reliability [4].

To maintain a stable operating state of the transmission system, the following actions are needed: to control the frequency of the system; to control the voltage of the system; to control the

[*] atanasoae@eed.usv.ro

stability of the system; to control the load of the network; to restart the system in certain circumstances.

These system needs could be satisfied using the following ancillary services (the control of network load is handled by other means than ancillary services) [5]:

1. Maintaining frequency: frequency control; spinning reserve; remote automatic generation control; emergency control actions;
2. Maintaining voltage: voltage control;
3. Maintaining stability: frequency control; spinning reserve; emergency control actions;
4. Restarting system: black start capacity.

System frequency is a fundamental indicator of power system health. It can be observed everywhere on the power system and provides an immediate indication of the balance between generation and load.

Control of voltage is tightly connected to reactive power control. Voltage can be controlled through voltage control, reactive power control, power factor control or by a combination of two of these, so they are often referred to as voltage/reactive power control. The need for reactive power varies as demand varies and as the sources of generation vary. As reactive power is not viable to be transmitted over long distances in transmission network, its production is distributed across the system, usually closer to the locations where it is needed. Voltage stability is the ability of a power system to maintain steady acceptable voltages at all network nodes in the system under normal operating conditions and after being subjected to a disturbance.

The Balancing Market (BM) covers the differences between notified production and forecasted consumption. Thus, the balance between demand and electricity production is determined on a commercial basis, in real time. For imbalances, participants assume financial responsibility.

The Ancillary Services Market (ASM) operates on types of reserves, secondary, fast tertiary and slow tertiary. Ancillary services market is the market where contracts are concluded between producers qualified to provide every type of ancillary service and the Transmission System Operator (TSO), aiming at providing the National Power System (NPS), against payment, with production capacities that can be mobilized at the request of the national dispatcher, under conditions determined by the technical capabilities of those production units (according to the types of ancillary services for which they were qualified).

2. INDICATORS OF MARKET CONCENTRATION

The competitive level in the electricity market can be assessed by a set of transparent and relevant indicators:

a) rate of market concentration;
b) the Herfindahl-Hirschman Index (HHI);
c) Pivotal Supplier Index (PSI) or Residual Supplier Index (RSI)

The market concentration is determined by the number of existing market participants and their market shares. The rate of market concentration is reflected in the market share of the largest market participant (C_1) or the sum of the market shares of the first three participants (C_3). According to practices and documents elaborated at the European Union level, values of C_1 can be interpreted as:

- values higher than 20% may be concern for competition;
- a value higher than 40% may suggest the existence of a dominant position;
- a value higher than 50% indicates a dominant market position.

Values C_3 can be interpreted as:

- C_3 tends to 0%, perfect competition;
- $40\% < C_3 < 70\%$, moderately concentrated market;
- $70\% < C_3 < 100\%$,excessively concentrated market.

For each market, the Herfindahl-Hirschman Index is calculated by summing the squares of participants' market shares:

$$HHI(i) = \sum_{j=1}^{N} \left[Q_j(i) \right]^2 \quad (1)$$

where $Q_j(i)$ is the market share of the j participant, in the i time period.

The *HHI* is interpreted as:

- HHI tends to 0, perfect competition;
- HHI<1000, unconcentrated market;
- 1000<HHI<1800, moderately concentrated market;
- HHI>1800, high market concentration;
- HHI=10000, monopoly.

The Pivotal Supplier Index at system level is defined for each producer/market participant, with the formula:

$$r_j(i) = \frac{CAP_{tot}(i) - CAP_j(i)}{CERERE(i)} \quad (2)$$

where:

$CAP_{tot}(i)$ – total capacity available in the system in hour i;

$CAP_j(i)$ – available power of producer/market participant j in hour i;

$CERERE(i)$ – total system load in time interval i.

The RSI is a form of PSI, calculated for the largest producer (seller) of each period. To customize different markets, PSI/RSI can be determined based on the quantities offered/sold hourly by market participants, according to the formula:

$$r_j / RSI_j(i) = \frac{\sum_{k=1}^{N} Q_k(i) - Q_j(i)}{\sum_{k=1}^{N} V_k(i)} \quad (3)$$

where:

$Q_{k/j}(i)$ – quantity offered by the producer/ participant k/j to market in hour i;

$V_k(i)$ – quantity sold by the producer/participant k to market in hour i.

3. THE EVOLUTION OF THE CONCENTRATION INDEXES ON THE BALANCING AND ANCILLARY SERVICES MARKETS

The current structure of the power generation sector reflects the successive reorganizations that took place in recent years and led to a reduced concentration on the wholesale electricity market. Figure 1 shows market shares of producers with dispatchable units according to the delivered energy in the year 20015.

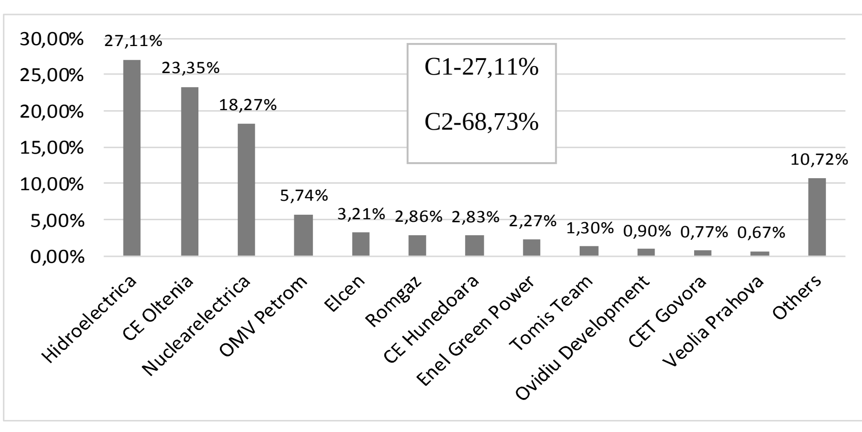


Fig. 1. The market shares of producers with dispatchable units in 2015 (source: ANRE)

The C1 indicator has value of 27.11%, the C3 indicator has value of 68.73% and HHI has value of 1680. These values can be interpreted as worrisome for competition respectively correspond to a moderately concentrated markets. The market structure at generation level it provides against a baseline on the degree of competition existing in the power market.

On ***the Balancing Market*** is traded balancing power corresponding to the following types of control:

- secondary regulation (automatically activated in maximum of 15 minutes);
- fast tertiary (manually activated in maximum of 15 minutes);
- slow tertiary control (start time and load takeover in 7 hours).

Figure 2-9 shows comparative the annual values of the concentration indicators for the 2009-2015 period determined on the energy actually delivered by producers on the balancing market for each type of regulation and direction. The values of the concentration indicators show a prevailing participant and an excessive concentration of the balancing market for all types of regulation.

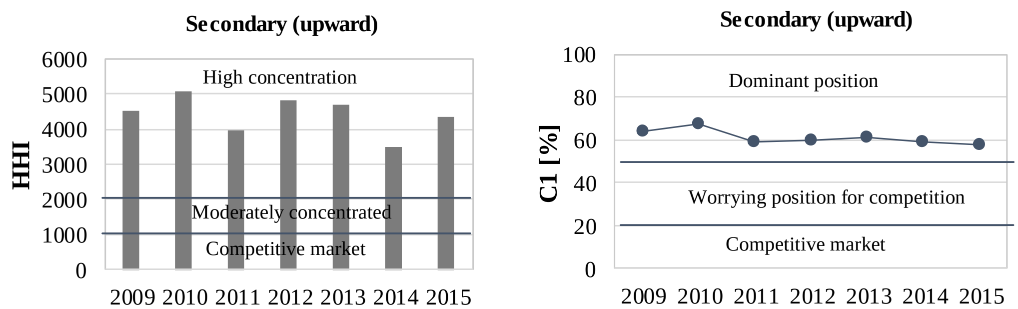


Fig. 2. The evolution of the concentration indexes on Balancing Market (Secondary regulation - upward) (processing data from website: http://www.anre.ro)

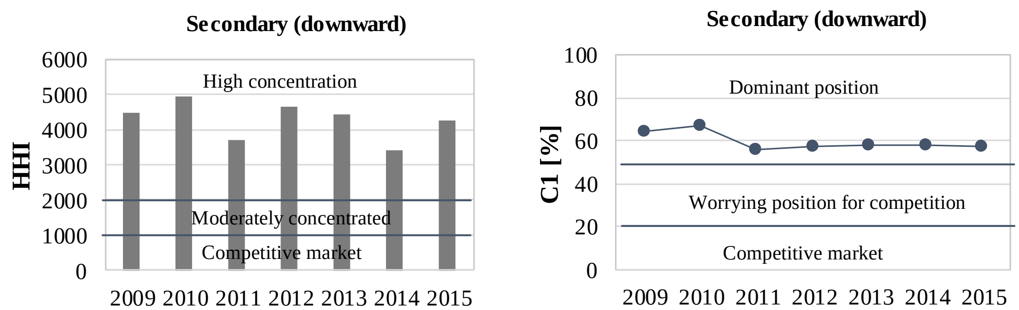


Fig. 3. The evolution of the concentration indexes on Balancing Market (Secondary regulation - downward) (processing data from website: http://www.anre.ro)

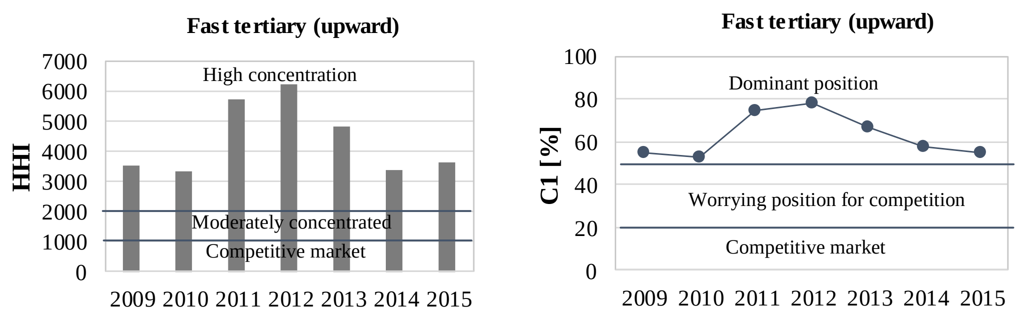


Fig. 4. The evolution of the concentration indexes on Balancing Market (Fast tertiary - upward) (processing data from website: http://www.anre.ro)

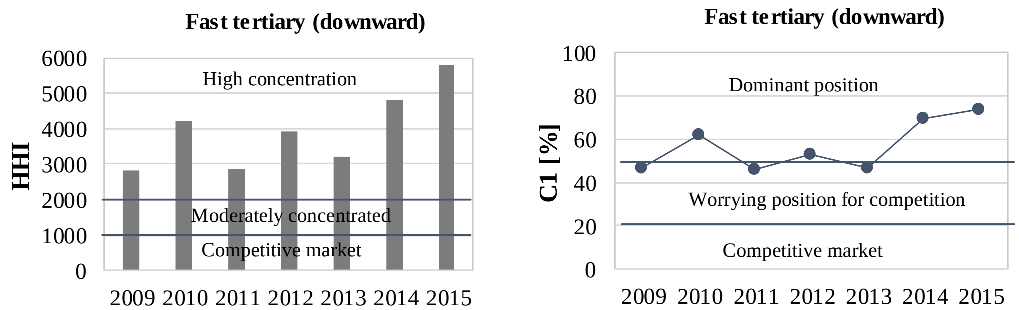


Fig. 5. The evolution of the concentration indexes on Balancing Market (Fast tertiary - downward) (processing data from website: http://www.anre.ro)

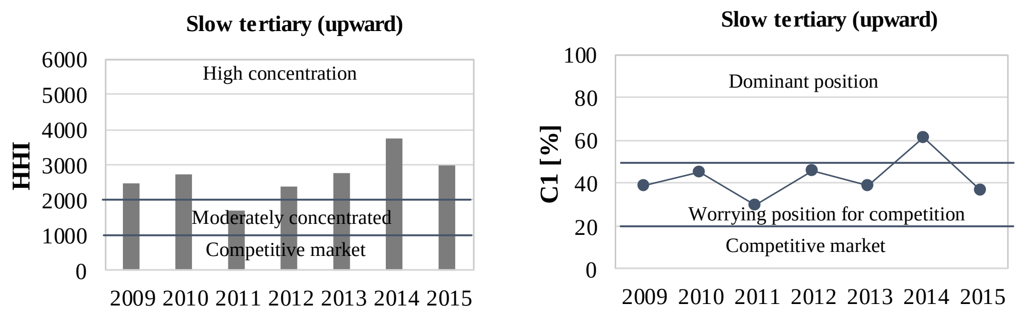


Fig. 6. The evolution of the concentration indexes on Balancing Market (Slow tertiary - upward) (processing data from website: http://www.anre.ro)

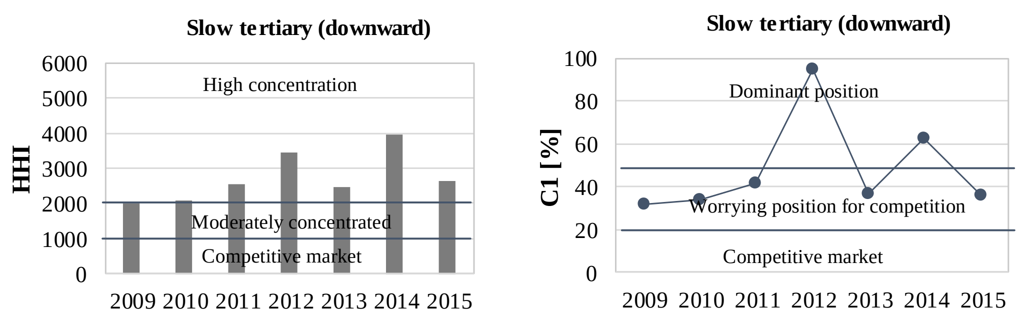


Fig. 7. The evolution of the concentration indexes on Balancing Market (Slow tertiary - downward) (processing data from website: http://www.anre.ro)

The Ancillary Services Market is the market where contracts are concluded between producers qualified to provide every type of ancillary service and the Transmission System Operator (TSO), aiming at providing the National Power System (NPS), against payment, with production capacities that can be mobilized at the request of the national dispatcher, under conditions determined by the technical capabilities of those production units (according to the types of ancillary services for which they were qualified); contracts require offering the capacities on the balancing market, and the possible amounts of energy produced/reduced are subject to settlement on the balancing market.

The ancillary services market operates on types of reserves secondary, fast tertiary and slow tertiary that the TSO is contracting on regulated or competitive (based on auctions) from generators that are qualified for this type of services. As the concentration on the ancillary services market is constantly high (the hydro producer is able to provide most of these services at a higher quality), the reserve is primarily ensured through regulated contracts concluded between producers and the

Transmission System Operator. In the table 1 is presents the annual concentration indicators for the Ancillary Services Market in the period 2009-2015.

Table 1. The annual concentration indicators for the Ancillary Services Market

Year/Component		Secondary reserve regulation	Fast tertiary reserve regulation	Low tertiary reserve regulation
2009				
Regulated component	C1 [%]	62.2	80.2	71.7
	C3 [%]	88.7	90.4	100
Competitive component	C1 [%]	-	-	42.1
	C3 [%]	-	-	82.7
	HHI	-	-	2869
2010				
Regulated component	C1 [%]	71.3	83.0	44.2
	C3 [%]	92.5	90.0	90.2
Competitive component	C1 [%]	-	-	-
	C3 [%]	-	-	-
	HHI	-	-	-
2011				
Regulated component	C1 [%]	56.1	80.2	40.2
	C3 [%]	83.5	88.3	84.7
Competitive component	C1 [%]	-	77.0	63.4
	C3 [%]	-	93.3	96.5
	HHI	-	6089	4815
2012				
Regulated component	C1 [%]	53.0	82.5	46.5
	C3 [%]	98.9	93.2	89.3
Competitive component	C1 [%]	93.9	98.4	51.6
	C3 [%]	100	100	88.0
	HHI	8858	9679	3500
2013				
Regulated component	C1 [%]	52.0	81.0	53.4
	C3 [%]	99.0	92.6	100
Competitive component	C1 [%]	98.8	-	40.8
	C3 [%]	100	-	83.3
	HHI	9759	-	2772
2014				
Regulated component	C1 [%]	76.5	75	51.4
	C3 [%]	100	100	100
Competitive component	C1 [%]	88.2	86.3	-
	C3 [%]	97.0	95.7	-
	HHI	7822	7497	-
2015				
Regulated component	C1 [%]	77.2	63.6	63.9
	C3 [%]	100	100	77.3
Competitive component	C1 [%]	73.5	89.7	74.2
	C3 [%]	94.8	94.0	94.1
	HHI	5728	8070	5756

Source: ANRE

To cover differences between the planned values of consumption and production respectively and their values occurring in real time, TSO operating the balancing market, buy or sell energy in the order determined prices by offerings of the dispatchable producers. The participants who causes imbalances pay for energy shortage the price resulting from the increase in accepted offers on the balancing market and receive for excess energy the price resulting from in accepted offers to drop on the balancing market.

Figure 8 shows the monthly average prices for imbalance settlement recorded by the balance responsible parties (surplus price and deficit price) for July 2005 - December 2015, compared to the market closing price on the day ahead market.

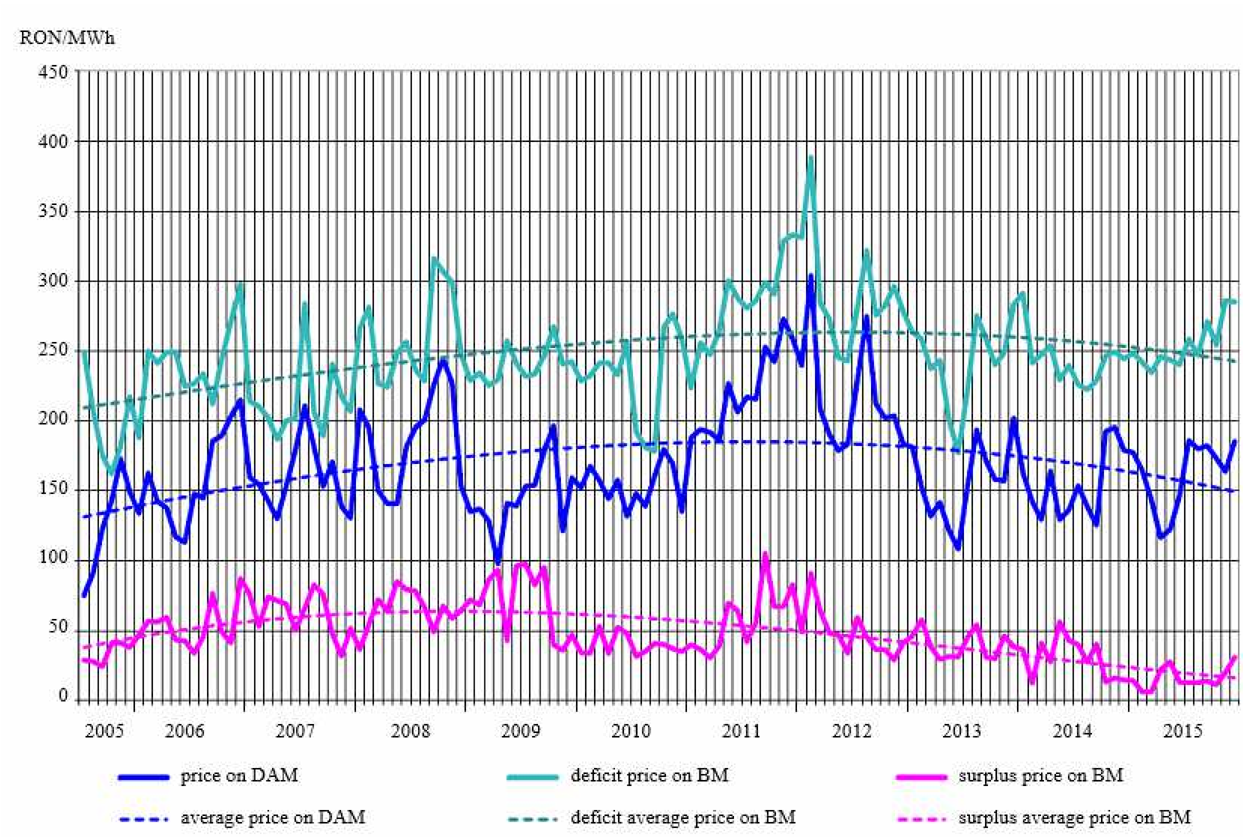


Fig.8. The monthly average prices on BM (surplus price and deficit price) and DAM (source: ANRE)

Guaranteed access to the network is ensured for the electricity contracted and sold on the electricity market that is benefiting from the support system for renewable energy sources. Priority access to the network is ensured for electricity contracted and sold at regulated price (generated in power plants with an installed capacity of less or equal 1 MW per plant or in the case of high efficiency cogeneration from biomass, 2 MW per plant).

The transmission system operator and/or distribution operators ensure the transmission, distribution, as well as priority dispatching of the electricity generated from renewable sources for all renewable energy sources generators, regardless of capacity, on the basis of transparent and non-discriminatory criteria, with the possibility of amending the notifications within the business day, according to the ANRE approved methodology. The limitation or interruption of electricity production from renewable energy sources shall be applied only in exceptional cases where this is necessary for ensuring the stability and security of the National Power System.

Production units using dispatchable renewable sources are responsible for payment of the imbalances created.

The monitoring reports submitted by TSO show that there were intervals trading they were ordered power cuts wind power plants and photovoltaic power plants recorded as dispatchable units to the balancing market. The reason was always getting the balance between production and consumption and framing the balance amount scheduled.

4. CONCLUSIONS

The values of the concentration indicators show a prevailing participant and an excessive concentration of the balancing market for all types of regulation.

In order to maintain the level of safety for in the NPS operation, in the conditions the significant increase the number of power plants from renewable sources, the ancillary system services are achieved both through market mechanisms as well as through regulated contracts.

For the ancillary services market is distinguished the high concentration level for all three types of reserves, both on the regulated component and on the auction. It is noted that most of the quantities purchased for secondary and fast tertiary regulation reserves on the competitive component have been made available by the hydro producer.

There are frequent situations in which to cover the deficit of the system power and achieving a sufficient reserves of fast tertiary regulation at peak times starts were ordered or keep operating dispatchable thermal units. These situations have led the occurrence of intervals dispatching with excess power or increase thereof. Thereby have resulted for these hourly intervals both selections growth as well as the reduction of power, generating costs on the balancing market.

Also, it was found that the production of electricity of the wind power it was poor in relation with the values notified in most hourly intervals. This has resulted a large amount of energy selected on the balancing market. Thereby, the energy traded on the balancing market in the year 2015 it had a market share of 8.25% of the total generation energy.

BIBLIOGRAPHY

[1] H. Holttinen, N. A. Cutululis, A. Gubina, A., A. Keane, F. Van Hulle, Ancillary services: technical specifications, system needs and costs. REserviceS, Deliverable D 2.2., 2012.

[2] A. Mehdipour Pirbazari, Ancillary services definitions, markets and practices in the world, in Proc. 2010 Transmission and Distribution Conference and Exposition: Latin America (T&D-LA), 2010 IEEE/PES, pg.32-36.

[3] CIGRE, Ancillary Services: an overview of International Practices, CIGRE Working Group C5.06, October 2010.

[4] B. Kirby, Ancillary Services: Technical and Commercial Insights. Wärtsilä, July 2007.

[5] EURELECTRIC, Ancillary Services. Unbundling Electricity Products – an Emerging Market. Union of the Electricity Industry, EURELECTRIC, Thermal Working Group, February 2004.

[6] D. Newbery, R. Green, K. Neuhoff, P. Twomey, A Review of the Monitoring of Market Power. European Electricity Transmission System Operators, 2004.

[7] Romanian Power Market Operator: http://www.opcom.ro

[8] Transelectrica Romanian Power Grid Company: http://www.transelectrica.ro

[9] Romanian Energy Regulatory Authority: http://www.anre.ro

.

CIGRE Regional South -East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#73

Advanced Techniques for inspecting Power Energy Equipment using Augmented Reality

[1]Octavian GHITA, [1]Cosmin BANICA, [2]Luca IACOBICI, [3]Ioan Dorin HATEGAN
[1]Politehnica University of Bucharest Electrical Eng. Faculty, [2]CNTEE Transelectrica SA,
[3]DTDR CNTEE Transelectrica SA
Romania

SUMMARY

The advance in the field of augmented reality (AR) allows newer approaches to traditional activities, such as service, maintenance or intervention in various field operations. The idea of this paper is to present the design for an innovative AR platform which is currently under development and is designed to be used in Electrical Power Stations. Field data from sensors and additional information stored in QR tags placed on equipments are transmitted to a server and from here to the AR equipments carried by the intervention personnel. In this case, real time data can be displayed, enhancing the perception of team members and providing additional info that can help them to fulfill their mission.

KEYWORDS

Augmented reality, wireless sensors, monitoring platform.

I. INTRODUCTION

Augmented Reality used for inspection, service and maintenance of Electrical Power Stations equipments is an innovative solution that is not yet found on the Romanian market. However, certain services are used for industrial inspection and service, at least internationally, in different industrial or military applications.

Augmented Reality (AR) is a concept that involves enrichment of perception of an observer on the environment by superimposing in real-time of a static or dynamic digital content over a particular subject. The added content can be in the form of text, sound, images, video, static or animated 3D models, etc. Unlike virtual reality, augmented reality does not create a simulation of the environment. Instead, using a real object or space and incorporating technology, supplements the context given, in order to improve the cognitive process of the user. Most often, to access and explore the augmented reality are used mobile devices such as smart glasses, tablets, smart phones, document chambers or PCs equipped with a video camera.

Car manufacturers, such as BMW or Mercedes Benz, or aircraft manufacturers, such as Rockwell and Boeing, use augmented reality systems for inspection and service, but not for commercial purposes, as they are not intended for sale[1]-[4].

There are other areas offering applicability to augmented reality solutions: tourism, architecture, archaeology, medicine, military or navigation, but they are partial solutions that employ mainly visual information. Developments of products such as Vuzix Glass are available for purchase, both as standard and improved versions, Head-up-Display, manufactured by Laster Technologies, Atari, Epson, Microvision etc. All these products must operate using hardware and software platforms, the cost of which is not public, being still under development by various research consortiums and projects.

The use of AR in critical infrastructure allows team members, such fire workers, medical or rescue personnel to enhance their perceptions and to have more info about the intervention they perform. One should consider that most of the time, such interventions take place in unknown areas where is harder to perform exercises for training purposes, due to the complex nature of Electrical Power Stations.

II. DESCRIPTION OF THE SOLUTION

Such an innovative product aims to develop a technology for distribution of additional visual information to maintenance or intervention teams, through individual AR glasses, allowing members of the maintenance teams better plant operation, faster visualization of hazards in interventions, and improved response times compared to normal operation. The platform has several features that give it a character of innovation on the Romanian market, as it can be seen in the figure 1.

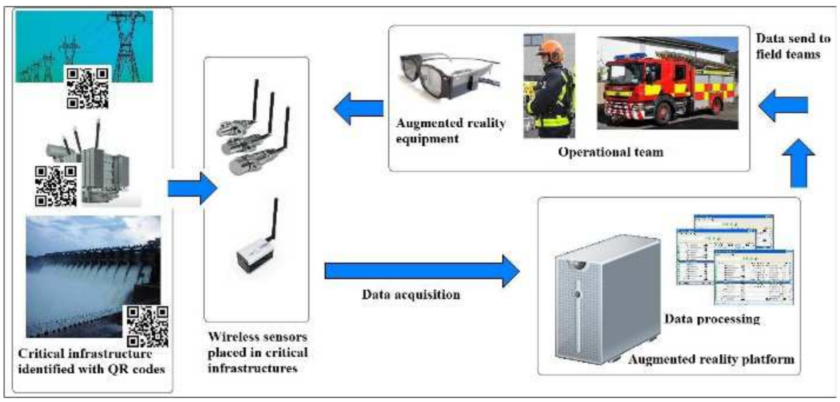


Figure 1. General structure of the monitoring platform

The components of the platform are:

- a measurement sub-system, consisting in several types of wireless sensors for temperature, mechanical effort, displacement, current, vibrations, etc;
- a communication sub-system, allowing bi-directional exchange of data between sensors and platform and between platform and AR equipments;
- a server, responsible for data processing operations and for database storage of events;
- AR equipments, such as: VUZIX glasses or immersion tablets, to allow reception of data directly to intervention teams on the field [5],[6].

Electrical Power Stations and their equipments will be identified through Quick Response (QR) codes to allow additional viewing of additional features: running, temperature, explosion or fire hazard, crack or slip hazard, vibrations, corrosion, etc. In addition, in the area, wireless temperature sensors, mechanical strength sensors, presence sensors, smoke detectors, etc. will be installed, which would enable field acquisition of additional information for the maintenance or intervention teams.

All this stream of data would be managed by a server, the augmented reality platform, where data will be stored and processed. From here, through AR glasses, text information will be sent to maintenance teams, which in turn would send to the server their own information, as messages.

Such technical solution allows the field operator to know a lot of additional information during missions, facilitates his/her training process, and maintenance becomes much easier. Moreover, any dangerous situations could be easily avoided, especially for intervention staff, fire fighters, SMURD, gendarmes, who are to act in a relatively unknown area.

An analysis of the other products of the same type, in the automotive or military industry, shows some technical specifications and characteristics that the market requires from such products:

By using the augmented reality, staff can perform tasks in a more efficient, faster and safe manner. The innovative advantage offered by the use of augmented reality applications consists in the provision of technology support for training solutions, employing 3D e-learning with "zero" risk in case of operating errors, and to offer the possibility of repeating the drill until the trainees learn the necessary skills and competences, by understanding the operations, techniques and procedures to be applied at a different level.

Some clear advantages can be obtained from here, regarding the training of various intervention teams, maintenance or even operative actions in Electrical Power Stations.

Creation of scenarios of operation, service and maintenance of installations involves various types of display solutions (hardware and software). AR display solutions available on the market today are multiple, providing users with different experiences. Most suitable for this project as:

Using a series of infrared emitters, state-of-art video projectors, active or passive stereoscopic glasses and position trackers, the result obtained is a complete immersion of the user in the virtual world in which objects levitate in space. 6DOF electromagnetic trackers are implemented to monitor the position and orientation of the user, and are used to calculate a stereoscopic perspective that allows the user to move free around the objects levitating in space. Peripherals, such as, for example, the Force Feedback devices and virtual gloves are integrated as an option within the system.

Figure 2. Augmented reality in monitoring equipment

III. FEATURES OF THE TRANSMISSION NETWORK

One important part of the AR platform is the communication sub-system. The design of WIMAX architecture seems to be the most feasible solution available because of low power consumption and readiness to use without sophisticated configuration procedures [7],[8].

To achieve the project objectives, it is essential for the telecommunication system to meet the following requirements:

a. Performance: the network should allow simultaneous transfer of all data streams without the risk of congestion. Moreover, in applications for data collection from sensors for critical infrastructure, it is essential that information propagation times to be minimal, in order to avoid a delayed response. Not least, it is essential that transmissions are correct and complete – any loss of information or submission of incoherent information is unacceptable in the monitoring systems of critical infrastructure.

b. Flexibility: there are many types of sensors from which data must be collected and the transmission network must be adaptable to any of them. Similarly, there are several applications and interfaces that need to take, interpret and display the data collected - and similarly, the network must provide the necessary communications for them

c. Scalability: communications system must allow connection of any number of sensory systems without modification of the main infrastructure or architecture. Adding a network element must mean just connection of the element to the network core through the relevant circuit, without requiring substantial changes.

d. Increased availability: it is obvious that for monitoring Electrical Power Stations, the network should ensure maximum availability. Such resiliency and redundancy systems should be available and implemented throughout the network.

e. Seamlessness: the network must be easily built, configured, expanded, managed and monitored. Thus, at least at the level of modules or levels, it is necessary that the equipment and technologies used to integrate seamlessly and to simplify network complexity.

f. Fast installation and commissioning of sensor systems.

g. Installation in any situation, environmental conditions, relief, of monitoring sensors of any type of objective within critical infrastructure.

IV. DRAWBACKS

There are several problems that need to be clarified when implementing an AR platform. One of the problems that occur testing the functionality of the AR platform is the distance at which the VUZIX glasses are able to operate. Several tests have been made, placing a QR code generating the description of an electrical engine, having larger printed surfaces applied on the engine: first a normal QR code of 2.5 cm^2, then a larger one at 10 cm^2 and finally an even larger one, at 20 cm^2 (see table 1).

For each essay, the camera sensitivity was tested, to obtain certain information decoding the seen QR code on the electrical engine. As one can observe, the camera has clear distance limitations, when it reach the maximum range at which QR code can be correctly interpreted.

For the first QR code surface of 2.5 cm^2, a distance of 5 m is the maximum distance at which correct info about engine was displayed, for the second QR surface of 10 cm^2, almost 6 m are obtained and for the last one, a QR code surface of 20 cm^2, maximum distance was increased to almost 8 m, as presented in figure 3. The tests were performed on daylight, at a perpendicular direction to the applied QR code.

This result is not the best expected by users, because such distances are being considered small ones in Electrical Power Stations. Also, the distance can be drastically reduced if smoke or bad lighting is present in fire situations or if QR code printing area is deteriorated. Also, there are other drawbacks that can be taken into account: for example, if the entrance of team members in the area covered by a specific QR code is not perpendicular to the code printed surface, the AR equipment can't read the QR code. The same is valid also if the team member is moving too fast and the camera mounted on AR equipment is not focusing on the QR code.

Table 1. Behavior of system sensitivity

	QR surf. 2.5 cm2	QR surf. 10 cm2	QR surf. 25 cm2
Distance [m]	Sensitivity 2.5 cm2 [%]	Sensitivity 10 cm2 [%]	Sensitivity 25 cm2 [%]
0,50	100,00	100,00	100,00
1,00	99,00	99,00	100,00
1,50	98,00	99,00	100,00
2,00	97,00	99,00	100,00
2,50	96,00	98,00	100,00
3,00	95,00	98,00	100,00
3,50	90,00	97,00	99,00
4,00	84,00	95,00	98,00
4,50	78,00	94,00	97,00
5,00	65,00	90,00	96,00
5,50	40,00	80,00	95,00
6,00	20,00	60,00	92,00
6,50	10,00	40,00	85,00
7,00	5,00	30,00	70,00
7,50	0,00	20,00	60,00
8,00	0,00	5,00	40,00

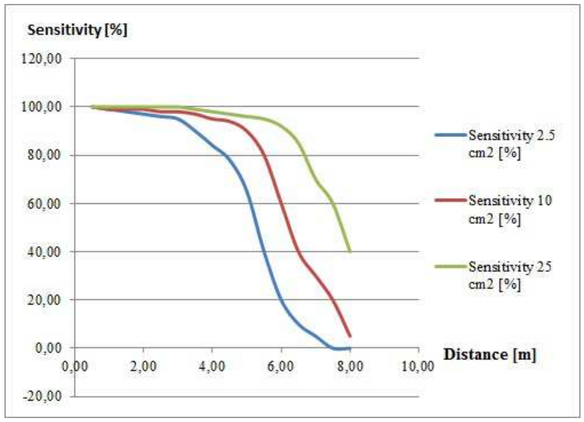


Figure 3. Variation of AR equipment sensitivity in function of distance and QR area

A certain success however was obtained when info from sensors retransmitted to the server was displayed on the VUZIX glasses lenses. The system was tested only for temperature sensors, but current temperature was displayed as a text pulsating on the lenses surface.

Also, a certain delay can be mentioned in showing information from the platform. Depending of the nature of information and of communication system problems in certain areas, a delay between 5 and 15 s was obtained. There were significant differences if the text message was coming directly from the AR platform or it was acquired from sensors, transmitted to platform, processed there then retransmitted to the VUZIX AR sub-system. This answering time should be taken into account when dynamic regimes occur, especially in hazardous interventions.

V. CONCLUSIONS

The design of an AR platform for inspection, maintenance and intervention in Electrical Power Stations should verify some strict conditions, in order to become a successful example. First of all, the architecture of the system should be kept as simple as possible, using integrated sensors, that send data automatically to the platform, in order to allow higher flexibility in implementation. On the platform, the format of data must be indexed, to allow a fast transfer to the AR sub-system.

Although AR equipments can substantially enhance team information in certain intervention scenarios, until now the platform is far more suitable for inspection or maintenance operations, when parameters in the environment vary slowly or remain constant and the moving speed of team members is reduced, allowing QR code readings by cameras of AR equipments.

In laboratory tests, all sub-systems proved well, bi-directional info was exchanged from sensors to platform and from platform to AR equipments, but with a certain delay in answering time, going up to 15 s, when dynamic regimes involving temperature sensors were simulated. This drawback can be critical in dangerous situations, but research team is currently working to improve this parameter.

Also, even if QR codes applied to sensitive parts of equipment in Electrical Power Stations can be correctly read by VUZIX AR glasses, the distance at which the system works is reduced, under 8 m, regardless of QR effective area. In real intervention situations of smoke, gas or steam vapors, this distance can be reduced even further.

A test that was giving good results was the transmission of sensors signals to platform and from here to AR equipments.

At this moment, the research team of the project is working to ensure portability of information to other AR equipments, such as tablets or laptops, to increase the flexibility of the system and to allow a certain ease in control of maintenance or intervention scenarios.

Taking into account all these facts, one can affirm that use of AR equipments for inspecting Electrical Power Stations has a significant potential and can give a considerable advantage in dangerous interventions, but further tests must be conducted and improvements are needed in order to obtain a viable system.

BIBLIOGRAPHY

[1] Graham, M., Zook, M., and Boulton, “A. Augmented reality in urban places: contested content and the duplicity of code”, Transactions of the Institute of British Geographers, DOI: 10.1111/j.1475-5661.2012.00539.x 2012.

[2] Karissa Bell, “BMW steps into augmented reality with AR driving glasses for Mini”, April 2015.

[3] Olivia Jung, “Google Glass Integration Has Been Tested by Mercedes-Benz”, August 2013.

[4] R. Behringer, S. Chen, V. Sundareswaran, K. Wang, M. Vassiliou, “A Distributed Device Diagnostics System Utilizing Augmented Reality and 3D Audio”, Virtual Environments ’99, Eurographics 1999, pp 105-114.

[5] “Introducing Virtual Environments”, National Center for Supercomputing Applications, University of Illinois.

[6] http://www.vuzix.com/augmented-reality/products_star1200xld/

[7] Roger Marks (June 29, 2006). "IEEE 802.16 WirelessMAN Standard: Myths and Facts" (PDF). Presentation at 2006 Wireless Communications Conference. Washington, DC: ieee802.org. Retrieved August 26, 2011.

[8] "IEEE Xplore - Comparison of power consumption of mobile WiMAX, HSPA and LTE access networks". Ieeexplore.ieee.org. doi:10.1109/CTTE.2010.5557715. Retrieved October 30, 2012.

.

CIGRE Regional South -East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#74

Intelligent System for Monitoring Energy Installations using self piloted Drones

[1]Octavian GHITA, [1]Cosmin BANICA, [2]Luca IACOBICI, [3]Ioan Dorin HATEGAN
[1]Politehnica University of Bucharest Electrical Eng. Faculty, [2]CNTEE Transelectrica SA,
[3]DTDR CNTEE Transelectrica SA
Romania

SUMMARY

The monitoring solutions of Energy Installations that are today implemented in the field are based either on human inspection of each equipment or are conducted from a central point where information from the network is gathered. Both solutions have long term availability and are used with success, but some future issues could affect their efficiency. Costs and resources are more and more implied to fulfill this task so an innovative solution based on self piloted drones can become a viable alternative, especially in wide areas or in difficult terrain conditions. Monitoring and integrating the information in an intelligent platform can provide better understanding of problems in electrical networks or faster answering times if an unexpected event occur.

KEYWORDS

Drones, electrical rechargeable system, high stability video cameras, flight plan.

I. INTRODUCTION

Energy production, transport and distribution equipments are subject to many depreciation factors and their status must be well known at all times. Thus, different monitoring methods should be implemented and put into practice. One particular monitoring method is to use self piloted drones, with highly stabilized high resolution video cameras and supported software capable to process acquired data.

Such a system should be able to obtain information about transformers status, about insulations and electrical line status or about Corona effect by filming the equipments from short range, with or without the presence of a human operator of the drone. Then the images are stored into a server where additional image processing can be performed, in order to obtain more information about the phenomena. Similar systems are beginning to be used in Canada, U.S. Austria or Germany, providing economy in manpower and resources for electrical companies and customers alike and replacing the experienced personnel needed elsewhere. [1]-[4]

II. DESCRIPTION OF THE SOLUTION

The monitoring solution can be used in two different versions of the drone system. It can be done either using a rapid inspection of the equipment, through a direct flight to the area of interest, followed by a complete high resolution 360° movie, either an advanced monitoring flight that implies use of drone stabilizer system in order to obtain good images of the equipment. Each case will mean a fleet of ready-to-go drones, a transporting system and a base station for flight, taking into account that an electrical drone can fly for about 30-40 minutes, depending of atmospheric conditions and load.

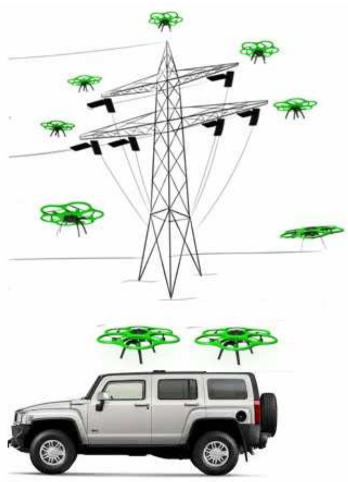


Fig. 1. Rapid inspection drone „Light" fleet

Rapid inspection of Energy Installations:

- UAV (Unmanned Aerial Vehicle) multi-copter/ fleet with transporter and base station for 24/7 monitoring solutions with a pay load of max 1 kg
- Vertical take-off or transporter/charger system and base station
- Multi sensorial inspection (Video, ultrasounds detection, audio detection, IR camera)
- GPS positioning system
- Automated or semi automated flight plan
- Ground control station
- Data process block
- Homing navigation system
- Recharging Kit

Fig. 2 Advanced monitoring „Heavy" drone

Advanced Monitoring of Energy Installations:

- UAV (Unmanned Aerial Vehicle) multi-copter/ fleet with transporter and base station for 24/7 monitoring solutions with a payload of max 3 kg
- Vertical take-off or transporter/charger system and base
- Multi sensorial inspection (Video, ultrasounds detection, audio detection, IR camera, UV camera)
- GPS positioning system
- Automated or semi automated flight plan
- Ground control station and communication features

- Data process block
- Homing navigation system and human navigation control
- Recharging Kit, including wireless rechargeable solutions

III. FEATURES OF THE MONITORING SOLUTION

In function of the flight solution chosen, the charging type of drone should allow a flexibility of fly missions through increasing fly time, decreasing in recharge time, even through rapid recharge, where infrastructure allow this.

The technical solutions for electrical recharge can go to different types, such as:

Battery re-charge at base station or at the transporter platform, either changing the depleted battery with a fully charged one, either using wire recharge;

Electrical re-charge using electromagnetic induction, wireless type, providing the base station with a circular recharging circuit, able to develop an electromagnetic field strong enough;

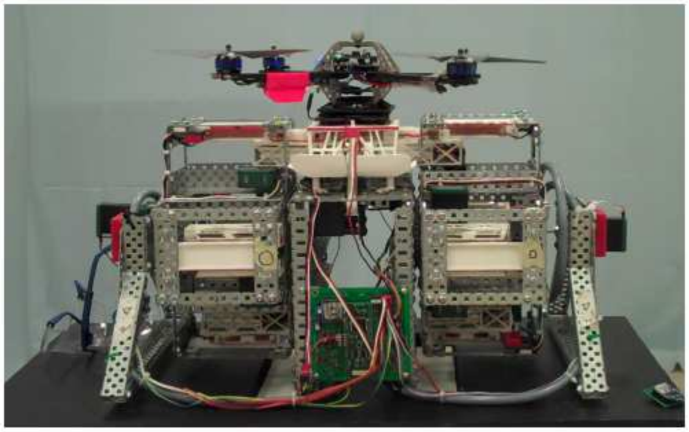


Fig. 3 Fast recharging system for light drone

The charging systems must also take into account supplementary consumption of high performance video cameras and stability systems, needed to achieve good resolution images.

IV. FLIGHT PLAN

There is another aspect also important that need to be taken into account in such situations, the so called flight plan. In the launching moment of a drone, it must save in the internal memory the GPS coordinates of the destination, where the monitored equipment is stored and the GPS coordinates of the base station, for a safe return of the drone. An average drone is capable of cruising at 25 km/h for 30 - 40 minutes, so effective range is between 15 to 20 km. Wind, air currents, air temperature and atmospheric conditions affect this range and a careful design of the flight plan is required. If the monitored problem persist, another drone should be ready to operate and will be launched when the first one has used more than 50% of battery energy. Thus, a permanent aerial monitoring system will be able to send images or to store them for further analysis.

V. CONCLUSIONS

The use of automated drones for monitoring electrical installation is at first steps elsewhere around the globe, due to the fact that better cameras and drones become available each day. The most important aspect is to have a good flight plan, balanced with a certain fleet of drones, both light for fast inspection and heavy for advanced monitoring activities. The recharging systems used by electrical drones can provide a certain flexibility, while remaining eco-friendly, especially if surveyed equipments are located in lived zones or restricted areas.

BIBLIOGRAPHY

[1] http://www.theverge.com/2013/2/1/3940898/darpa-gigapixel-drone-surveillance-camera-revealed
[2] http://www.zdnet.com/blog/robotics/
[3] Dempsey, Martin E. (9 April 2010). "Eyes of the Army—U.S. Army Roadmap for Unmanned Aircraft Systems 2010–2035"(PDF). U.S. Army. Retrieved 6 March 2011.
[4] Pasztor, Andy; Emshwiller, John (21 April 2012). "Drone Use Takes Off on the Home Front". The Wall Street Journal.

.

CIGRE Regional South-East European Conference RSEEC 2016 (3rd edition)
October 10th - 12th 2016 University "Politehnica" of Bucharest, Romania

#75

Integrated monitoring and control system for real-time estimation of operational state over the entire electrical networks' assembly

C. MOLDOVEANU, A. VASILE, M. AVRAMESCU, A. TAVA, I. IONITA, G. IOSIF
NOVA INDUSTRIAL S.A.
Romania

SUMMARY

The paper describes the necessity of on-line monitoring of power systems and the specifications that a complete integrated monitoring system must meet. These findings are exemplified by SIMCEC system, Romanian integrated monitoring system for the entire power grid assembly (with the features and advantages that it presents), its utility and the results of several tests carried out on the monitoring system itself. The final part contains conclusions and recommendations to support and improve network monitoring and maintenance.

KEYWORDS

Integrated Monitoring System, Smart Grids, Metrology.

1. INTRODUCTION

High voltage primary equipment from power substations (e.g. *power transformers, shunt reactors, circuit breakers, switchgears, current transformers, voltage transformers, surge arresters*) and high voltage overhead power lines have a major role in the power system and are vital for the operational safety of the system.

The major purpose of the monitoring systems is to detect any modification of the technical condition of the equipment and electrical installations in operation, with direct results in the prevention of catastrophic defects, maintenance optimization, extending the equipment's' life time, better usage of power facilities, increasing reliability and operational safety of substations and high voltage power lines, increase of the physical lifetime, reducing the likelihood of unexpected incidents leading to electricity transfer / distribution discontinuation.

The main solution that meets the needs mentioned above is the use of intelligent systems for on and off-line monitoring for power substations (for the primary electrical equipment in substations, namely: *power transformers, shunt reactors, circuit breakers, disconnectors, current transformers, voltage transformers, surge arresters and high voltage power lines*).

2. REQUIREMENTS FOR AN INTEGRATED MONITORING SYSTEM IN SIMCEC

The SIMCEC Romanian system **was designed as an integrated software system dedicated to monitoring the momentary technical condition of the National Power System**, allowing:

- real-time monitoring of network status parameters (received from dedicated sensor networks), e.g.: the operating parameters of primary electrical equipment in substations (power transformers, shunt reactors, circuit breakers, disconnectors, current transformers, surge arresters) and the high voltage overhead power lines, etc.
- monitoring systems' integration at substation, regional branches or company (system operator) level;

- storing data locally or centrally (regional center / branch / company) in a dedicated database;
- automatic data processing and analysis;
- diagnosing of the momentary technical condition through dedicated software;
- alerting system operator for special preset situations;
- systems dynamic mapping providing momentary or historical information about the main components' technical momentary condition of the power system (primary equipment and high voltage power lines), etc.

The SIMCEC system is a complex software system that provides:

- **online data (through the EMCSIT sensor array & sensor networks) regarding status and operating parameters of the assets of high voltage national power system** *(high-voltage transformers, shunt reactors, circuit breakers, disconnectors, current transformers, voltage transformers, surge arresters and overhead lines rated at 110 kV, 220 kV, 400 kV, 750 kV)*
- **analysis of the online data, together with offline data for momentary technical condition diagnosis on the monitored assets (for operational management decisions, etc.),**
- **an unique data base on the monitored operating assets** (database that may serve to statistical analysis, forecasting the development of short, medium and / or long term management decisions, etc.),
- **alerting operation personnel** for abnormal operating situations (preset for alarms) or failure events.

The software system ensures real-time information on the current status of the electrical networks' assembly, enables operating risk assessment, helps establishing urgency, nature and hierarchy of maintenance works.

The software system ensures the completeness and correctness of operation's verification from a technical point of view, rapid assessment of the equipment' and installations' momentary technical condition, data storage (historical data) in a SINGLE database, modern, flexible and operational nationwide.

The system is designed and built to run exclusively as a web application.

This makes it portable to any platform regardless of operating system used.

Users can access and use the expert system from anywhere on the local network with a compatible **web browser** using access rights received at their first registration on the system.

The system has a client-server architecture with a web server, a central database and clients based in different geographical regions.

Both central servers and client servers belong to the same local network. This architecture was chosen taking into account the following elements:

- experience from similar projects;
- lower infrastructure costs;
- high performance in system utilization;
- reliability;
- the easiness of implementing future software upgrades.

Using the **WEB technology built system** is simple, the user having access to an intuitive graphical interface, friendly and easy to use. To access the system, the user is required to use only a compatible Web browser (*Google Chrome v.32 / v.9 Internet Explorer / Mozilla Firefox V.26*).

In order to have a complete picture of the monitored equipment condition, **SIMCEC system accesses data measured on-line** (via existing monitoring equipment type EMCSIT / OHLM) and **off-line** (via prophylactic measurements for equipment diagnosis - obtained from existing expert systems), bringing them to the same denominator, **centralized in a single point but available anywhere within the network.**

SIMCEC system achieves its objectives by pursuing the two following directions:

- **Porting / rebuilding from scratch existing specific applications** *(for (auto) power transformers and shunt reactors, circuit breakers, current and / or voltage transformers, surge arresters and high voltage power lines)*, **by bringing them to the same level and by using web technologies (which offer more in terms of portability, upgradability and software maintenance);**
- **Centralizing all monitoring systems with the same interface and under a single database, thus creating a dynamic map of the system as a whole.**

The SIMCEC system is built using web technologies (*ASP, Ajax, JavaScript, JQuery and HTML*) that make all the monitoring systems in operation available to the user.

The relational database model used in the SIMCEC was implemented with the help of the ORACLE database management system.

This work was carried out through the program: Partnerships in priority areas - PN II, developed with the support of MEN (Ministry of National Education) - UEFISCDI (the Executive Agency for Higher Education, Research, Development and Innovation), project no. 33/2014. "

3. SIMCEC SYSTEM FUNCTIONS

SIMCEC software main window includes (as shown in Figure 1): an expandable-tree-type menu offering details about the *company, branches, centers, stations and installations*of the power system, and a map of the geographical region which will highlight the selected item in the tree menu.

The launch of the software is accomplished by entering the appropriate address in a web browser, from a terminal locatedin the Ethernet network that hosts the SIMCEC system.

The following figure shows the representation of the tree menu expanded to the substation level and the selected substation automatically located on the map. This page has zoom in, zoom out and pan facilities or can be reset using the top right "zoom out" button.

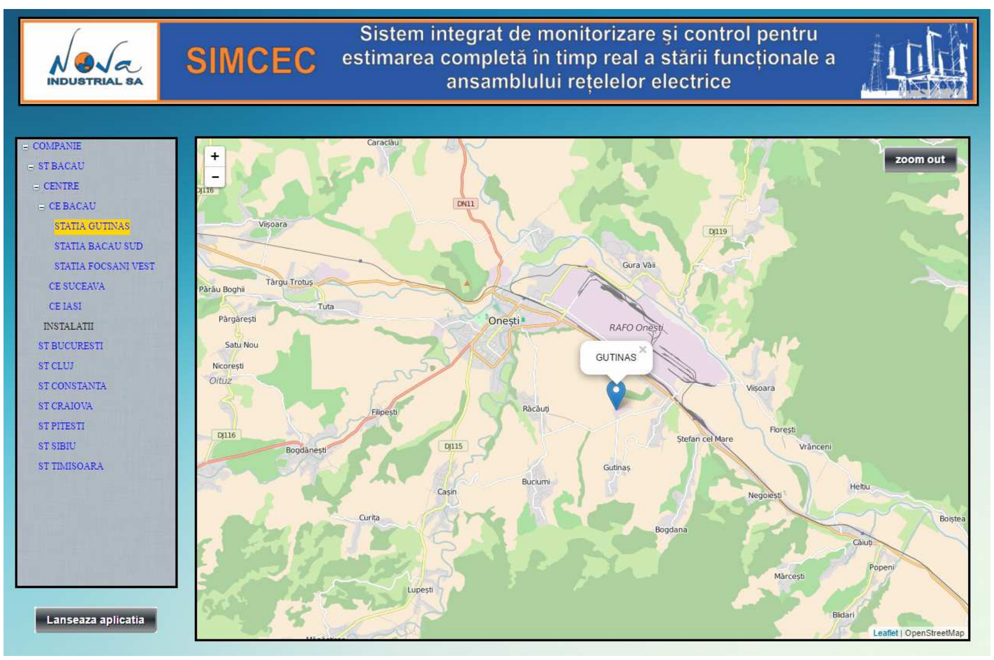


Figure 1. Automatic location of the selected items on the map

The "Launch client" button takes the user to a login / authorization screen, that allows access for viewing or interacting with the web monitoring system defined for the selected substation

(SIMCEC Substation), that is loaded in the web browser window after the security checks have been cleared.

4. SIMCEC - SUBSTATION MONITORING

SIMCEC Substation starts with the dynamic schema of the monitored substation. The challenge was to draw dynamically the circuits of the station's single-line diagram and interacting with them, all with web technologies.

The result of implementing single-line diagram of a station using ASP, JavaScript, JQuery and Ajax can be seen in the next figure. The diagram follows accurately the single-line diagram of Gradiste substation, Romania and consists of elements representing: breakers, disconnectors, transformers, surge arresters, grounding knives, lines, bars and links to the ground.

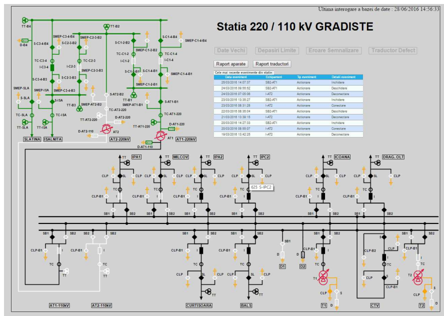


Figure 2. Dynamic Single-line substation diagram

The dynamic part of the data structure attached to each element was made to include both electrical and graphics properties and links to other items.

With elements structured this way (and considering the neighbors of each element)it was possible to create an oriented graph, that can be navigated starting from voltage transformers that indicate the presence of voltage on the line and considering the open or closed state of the switchgear, thus creating energized dynamically colored areas.

This is exemplified in the above figure, the color used for the energized area being black (the color can be replaced with any other color or colors attached to different voltage levels: 400kV, 220kV, 110kV).

5. SIMCEC – PRIMARY EQUIPMENT MONITORING

This section refers to an universal software for all individual device types: *breakers, disconnectors, current / voltage transformers, surge arresters*- SIMCEC EMCSIT (data are retrieved from different EMCSIT online monitoring equipment).

The software has a **unique standardized structure**, the differences being given by the types of the measured parameters and the specific operation of each type of primary equipment.

In order to build the web pages for the primary equipment, the specifications of EMCSIT on-line monitoring devices were taken into account, keeping astandardized visual aspect for all types of primary equipment.

The main window contains an area with information related to device and location, a generic drawing of the monitored device, a section of the monitored values, a section of monitored contact states, the position (*open/closed, connected/disconnected*), a list of events and a label with the monitored equipment's general technological state, a menu that provides access to historical data or other settings.

For example, in the case of the circuit breaker the following are monitored:

- the line currents;
- the currents through the tripping and closing coils;
- the level of supply voltage;
- number of operations from the installation or from the last technical revision;

- SF6 gas alarm;
- circuit breaker state opened/closed.

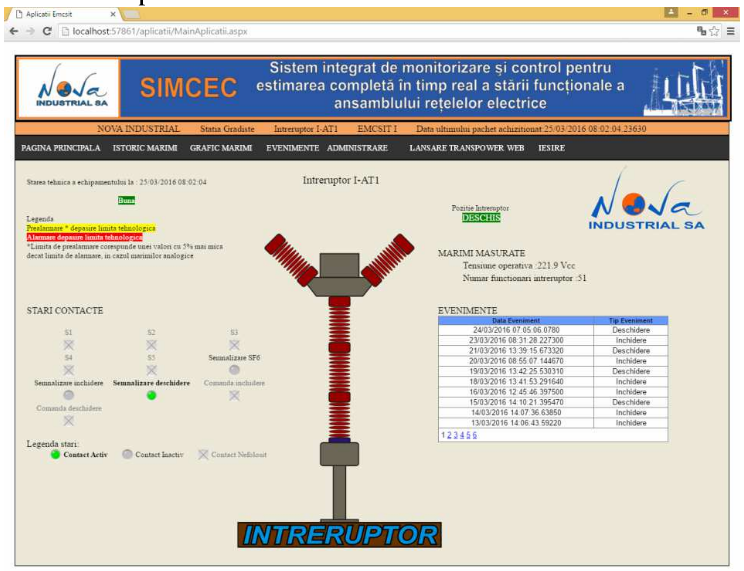


Figure 3. SIMCEC EMCSIT main page - circuit breakers' case

In order to help the user to have a detailed analysis of the device, the web page provides a history of the measured data. Historical data may be filtered by date (start date / end date), through two "date-time picker" elements. The software also has a section where it may be drawn a chart, for a total of 1 up to 5 parameters simultaneously on the same chart.

The system also records every so-called "event" for each monitored device. This "event" represents:

- *complete recordings with a high sampling rate*, for circuit breakers, disconnectors, current and/or voltage transformers,
- *circuit opening/closing operations* for the circuit breakers and disconnectors,
- *over currents and over voltages* for the current and/or voltage transformers.

Such an "event" can be seen in the next screen capture, web page created with JQuery and HTML Canvas technologies. The web page has a drop-down list from which the events can be selected for viewing, it also has the possibility to save the charts in "png" format or the data in "csv" format, a plain text formatted file type, accepted by most of the spreadsheet editors..

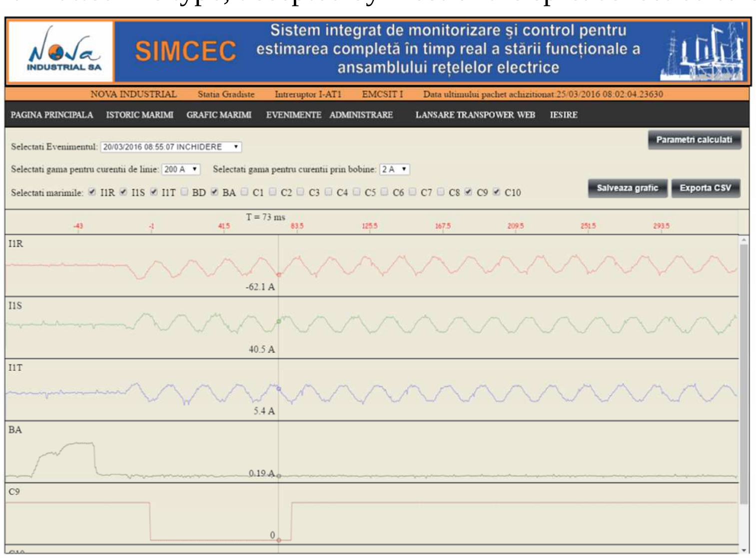


Figure 4. Events - EMCSIT I – circuit breaker closing under load

Each monitored equipment has stored in the database a set of limits for each monitored parameter. They define normal operation, pre-alarm threshold and alarm threshold for the selected parameters.

At every query addressed to the monitoring equipment, the system compares the measured values with preset limits and decides whether or not to alarm the user, that the system exceeded the alarm thresholdand exited the normal operation state.

The next figure presents an alarm case for a circuit breaker for which the monitoring system notifies the user that the supply voltage has significantly decreased, its value being in the alarm zone.

Figure 5. Analysis of the monitored parameters - alarm for the operative voltage for a circuit breaker

6. SIMCEC – TRANSFORMER MONITORING

This section refers to the application for (auto) transformers and shunt reactors (TRAFOMON 5 Web - SIMCEC component).

TRAFOMON 5 – Web, component of SIMCEC system, is the software interface designed for the on-line monitoring of power transformers and high voltage shunt reactors, ensuring on-line data acquisition regarding:

a) Operating condition: transformer meets / does not meet the standards of operation; it is connected / disconnected to / from grid;

b) Operating parameters: currents, overloads, voltages, voltage increase, frequency, power factor; powers: active, reactive, apparent ; temperatures, winding temperatures, oil temperature, hot spot temperature, power quality, etc.;

c) Operating condition for the active part (core + windings + inner connections);

d) The moisture level of insulation by: on-line measurement of water-in-oil content and determination of the water content in the solid insulation;

e) Operating condition of the cooling system,

f) The insulation condition of high voltage bushings equipped with tap for measuring the power / dissipation factor;

g) The operating condition of the on-load tap changer (OLTC); etc.

TRAFOMON 5 – Web, component of SIMCEC system collects data from Trafomon 5 on-line monitoring equipment.

This web software module is designed in a similar way to those dedicated to the other primary equipment from a substation (see cap.5), with a generic drawing of the device, the main parameters values placed intuitively around the transformer tank to symbolize the different sensor positions and the technical states of monitored components.

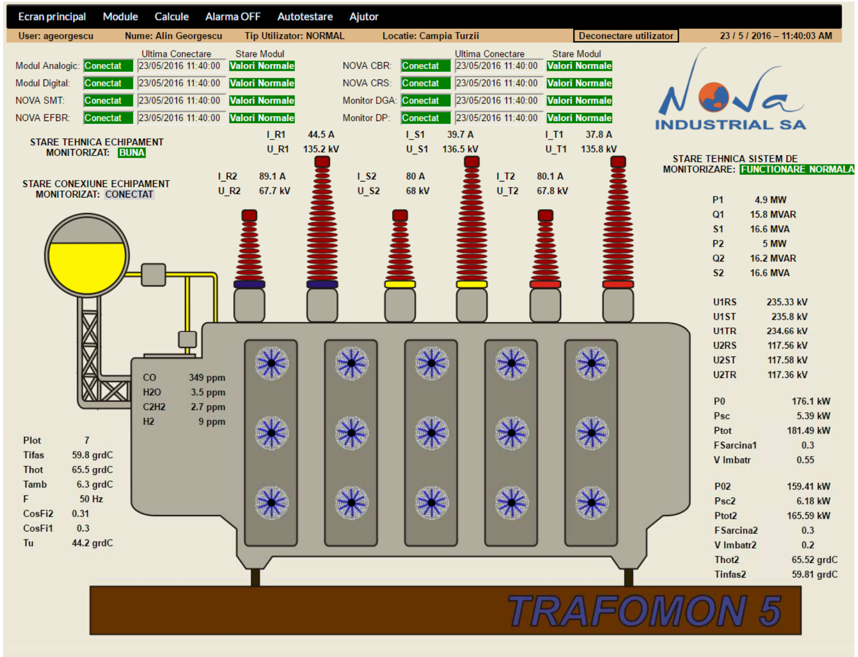


Figure 6. SIMCEC TRAFOMON Main Screen

The main difference is that the transformer monitoring subsystem consists of several smaller modules that can be added or removed from the initial configuration. Each module has its own momentary state placed on the upper part of the main screen and associated web pages for momentary data, historical data and events.

The modules included in the Trafomon subsystem are:

- Analog module, responsible with voltage, current, power and frequency acquisition;
- Digital module, responsible for the digital (1 or 0) states of monitored contacts as well as the alarm relays that go off when certain limits are reached;
- SMT module, responsible with bushing monitoring;
- EFBR module that monitors the temperatures of the transformer unit evaluating at the same time the efficiency of the cooling units;
- CBR module that starts the cooling units automatically when the oil reaches a certain temperature and switches between the cooling units in order to achieve a uniform operation time of all the cooling units;
- CRS module that monitors the on-line tap changer’s operation and record the motor’s current and voltage curve for every tap change;
- DGA module that analyzes the gases dissolved in oil and its water content;
- PD module that “listens” for partial discharges inside the transformer unit’s tank through an acoustic method;
- Disturbance module that records the harmonic distortions as well as the fast rise or fall phenomena in voltages and currents;
- Video module that provides transformer unit visible spectrum surveillance.

The SIMCEC System also includes an overhead line monitoring system - SIMCEC LEA. This subsystem focuses on monitoring the parameters of the overhead power lines as well as the integrity and safety of the towers supporting them.

7. CONCLUSIONS

An integrated monitoring and control system for real-time estimation of operational state (as the one presented in current paper) offers a unitary and complete vision over the whole power system providing teh system is entirely on-line monitored.

The web-based system is user friendly, the user having access to an intuitive and easy to exploit graphical interface.

The software system guarantees real-time availability of necessary information regarding the momentary state of the power system and allows the operating risk assessment and determining the urgency, the nature and the hierarchy of maintenance works.

The system checks the operation completeness and correctness from a technical standpoint, assures a fast evaluation of equipment and installations' momentary technical condition, stores the data regarding the operation in a unique, modern, flexible and nationwide operational database.

BIBLIOGRAPHY

[1] "PE 029/97 Designing norm for the power equipment dispatcher-controlled information systems in the National Power System";

[2] Tender documents: "Service delivery and product supply for on-line monitoring of the primary power equipment in the 220/110 kV substations Gradiste and Mostistea˝, on December 22nd 2011;

[3] "Obtaining Value from On ‑ Line Substation Condition Monitoring", CIGRE Paris, brochure no. 462, June 2011;

[4] Modern Techniques for Protecting and Monitoring of Transmission Lines" CIGRE Paris brochure no. 462, June 2011;

.

CIGRE Regional South-East European Conference RSEEC 2016 (3rd edition)
October 10th - 12th 2016 University "Politehnica" of Bucharest, Romania

#76

Intelligent equipment for monitoring power transformers disturbances in the transmission and distribution power systems

C. MOLDOVEANU*, V. BREZOIANU, M. AVRAMESCU, A. VASILE, S. ZAHARESCU, A. TAVA, I. IONITA, G. IOSIF
NOVA INDUSTRIAL S.A.
Romania

SUMMARY

Power systems can have many hidden faults and even if a problem is discovered, the cause that created the disturbance can be very hard to find. Monitoring power transformers disturbances is an important aspect in solving this type of electrical problems because it can provide real time analysis and automatic identification of faults. The intelligent equipment for monitoring power transformers disturbances in the transmission and distribution power systems - NOVA P01 was created to address the type of problems mentioned before, to provide, on request, data about the sequence of events, dynamic faults and disturbances and to set specific limits, to ensure that they can be used in analyzing events. Equipment includes/and is not limited to oscillograph, digital fault recorder, protection relays and transient recorder.

KEYWORDS

Energy, power quality, Smart Grid, online monitoring, power transformer disturbances.

1. INTRODUCTION

In transport and power distribution systems often appear disturbances and faults for various reasons such as:

- atmospheric conditions (lightning surges that can cause the insulation piercing at electrical components of the power transmission or distribution grid),
- events caused by changes in the technical condition of the equipment or high voltage power lines,
- a line conductor breakage due to overload (thermal, mechanical, etc.) or aging, which causes the fall to the ground of the conductor (therefore mono-phased short-circuits) or short circuiting of conductors on different phases (three-phased short-circuits);
- failure of primary equipment (power transformer, circuit breaker, etc.) from a substation which may cause changing parameters of the power in transit and / or operating system configuration change;
- disturbances in power source characterized by changing the parameters of voltage and current produced (RMS values, peak frequency, harmonics, etc.);
- etc.

Nova P01 equipment aims to detect, store and analyze the evolution in time of wave currents and voltages of high power transformers.

* cmoldoveanu@novaindustrialsa.ro

This paper refers to the an intelligent equipment for monitoring power transformers disturbances in the transmission and distribution power systems, in particular to a device that enables detection, analysis, recording and transmission of information on current and voltage perturbations or power quality at some point of the system (line or substation) to a central monitoring and control, operational dispatch center and / or the control room of a power station.

The device is designed to be integrated into the SMART GRIDS monitoring and online management system of disturbances and quality of power (in transport and distribution systems), in order to improve / increase the power security and the quality of transmission and distribution electricity.

Also the equipment can be integrated into SCADA Operating systems and SCADA Monitoring systems, respectively.

2. NOVA P01 – POWER QUALITY MONITORING AND ENERGY CONSUMPTION CONTROL AND MANAGEMENT

2.1 Motivation

In transport and power distribution systems, by disturbances or faults is understood any kind (or nature) of abnormality in AC or in the generation, transmission and distribution of power electricity.

- Voltage dips, interruptions and increases are also considered voltage disturbances (of short time) in AC systems.
- Voltage dips are short reductions of voltage, lasting from milliseconds to seconds.
- Voltage increases are small increases in voltage, lasting from milliseconds to seconds.
- Voltage interruptions are more severe declines in the amount of tension. The threshold for voltage interruptions is usually less than 10% of rated voltage.

Disturbances and malfunctions can generate significant costs and repairs. Every year, significant funds are lost because of disturbances.

For example, increasing voltage can cause the insulation piercing of some components of the power supply, the effect being gradual, cumulative. Power outages are more severe declines in power voltage supply, that can cause inoperative of equipment or can damage the equipment, due to overstressing at reinstatement / starting up.

In particular, power substations also have their specific problems. Among them we may mention lack of integration of the data collected directly, or from transducers regarding waves of current and voltage through the power transformer windings, also lack of data transmission to the operation management center of transmission or distribution of electricity. These problems were solved through an automated process for acquisition, processing, display and storage of the data, creating reports and establishing a communication protocol for transmitting data to any type of operation management center.

2.2 Features

In order to remove the disadvantages presented above, an **intelligent device for monitoring power transformers disturbances** in power transportation and distribution systems was needed. The solution is an equipment that required the following characteristics:

- acquire and processes the automatic current wave forms and voltage on the three phases of the transformer windings, by sampling sinusoidal voltage or current signals, synchronized with a high-speed sampling, namely 512/256/128 samples / a time sinusoidal signal;
- analyze any transient fault and disturbance affecting power transformer;
- collect fault records and specify their parameters;
- provide data on the sequence of recorded events, faults and disturbances dynamic functioning of protection systems (post incident analyzes, post failure);

- monitor power quality parameters at the input terminals and output transformer respectively;
- ensure the possibility of measured data synchronization with time reference data management center / information related to the transmission or distribution of electricity;
- determines and monitors their online losses of the transformer, thereby streamlining own technological consumption in the transport system or distribution of electricity;
- store in its memory equipment, sinusoidal wave forms of current and voltage signals monitored online;
- provide automatic identification of faults characterized by voltage dips, voltage increases, power failure, the time of the duration of the event;
- real-time data transmission to management center measured data / information related to the transmission or distribution of electricity or final consumers.

Fig. 1. NOVA P01 equipment

NOVA P01 is an intelligent electronic device, SMART GRID compatible, which provides simultaneous detection, description of disturbances in the functioning of power transformers and shunt reactors in transport systems and / or distribution of electricity:

- monitoring in synchronized real time, waves of current and voltage transiting a power transformer (by sampling at different speeds, preset to minimize the amount of data required to be processed according to the purpose of analysis)
- data analysis that helps define the nature and characteristics of dynamic disturbances and/or faults inside the transformer or in the system. This is accomplished:
  - by analyzing power quality parameters
  - by storing sequential digital information.

The device enables the analysis of events requiring data capture with high resolution and of events requiring data capture with lower resolution.

Events with high resolution (such as spikes in time) are made with a relatively high sampling rate (512 samples / a period sine wave), while events of low resolution (such as those characterized by slow changes over time, type sag and swell) are made with a lower sampling rate (256 or 128 samples / a sine wave period). Events such low resolution can be captured and stored for a longer period of time.

The preset speed of sampling data is optimized to minimize the amount of data used for the processing and storing of data for a specific equipment.

Conventional architectures do not ensure the capture of the waveform with multiple sample rates (functioning as a data-logger on acquisition and archiving the data), due to the operations required for both processing and management of data (performance limitations), and for waveform data storage (memory limitation on bandwidth and capacity respectively).

Moreover, NOVA P01 displays all the values in real time. In the graphics section, the channels can be selected in any combination and each type of channel has its own axis. All these features are also available in a remote location in the same local area network, after installing the NOVA P01 client application.

The device, works as **a logger of defects, data logger, oscillograph, power quality monitor, all of them combined into a Dynamic Disturbance Recorder (DDR).** The device can monitor:

• RMS values for:
- phase voltages compared to neutral phase: minimum 12 inputs;
- phase currents compared to neutral phase: at least 9 inputs;
- a residual current or neutral: minimum 3 inputs

• frequency;
• active power, reactive power and deforming power on all three phases and total power;
• power quality parameters;
• THD and harmonics up to 49 harmonics;

The device may aggregate RMS values measured at 512, 256 or 128 points per period and store them at a minimum rate of 50 measurements per second.

The Time stamp recorded for the defect (Failure Registration - FR) has an accuracy of ± 10 microseconds UTC; If a defect occurs, the equipment can record at least 10 records up to 50 periods each.

• The machine can store recorded data for a period of 10-30 days, and power quality parameters (128 samples / period each channel).

This work was carried out through the program: Partnerships in priority areas - PN II, developed with the support of MEN (Ministry of National Education) - UEFISCDI (the Executive Agency for Higher Education, Research, Development and Innovation), project no. 33/2014.

3. RESULTS

3.1 Displaying processed data

The NOVA P01 software application has three distinct sections:

- Measurement section – shows if a measurement is in progress, and when it started; from here a user can start a measurement or can stop it
- Graphic area – shows all the voltages and currents that are monitored
- Real time data section – contains all the data acquired from the hardware in real time

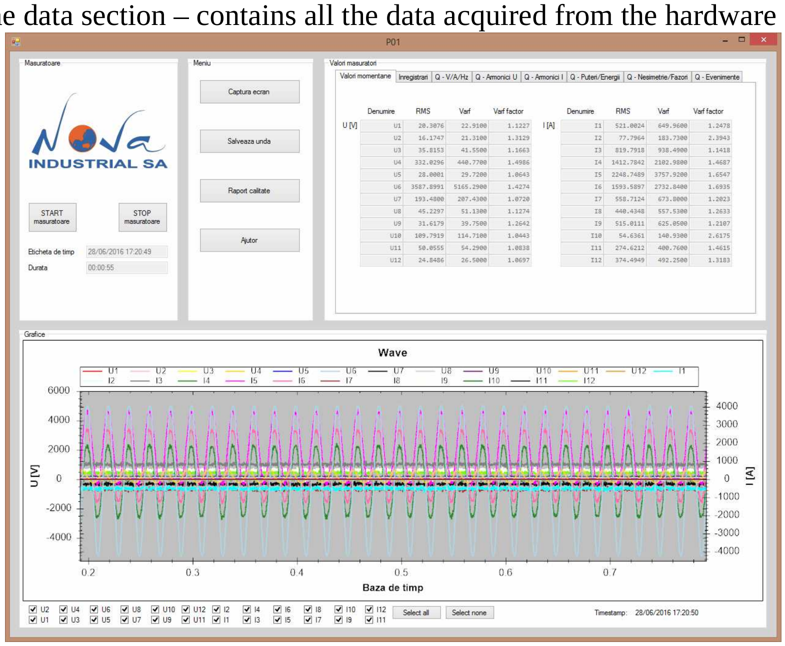


Fig. 2. NOVA P01 software application

The “real time section” also contains processed information about power quality.

Power quality monitoring is done on 6 channels, three voltages and three currents.

Information categories were chosen by measurements acquired or calculated. In this structure was implemented with tabs for each category of information in the field of power quality, as follows:

- V / A / Hz (Root Mean Square (RMS) values, peak, crest factor, both for voltage and current, and for each phase, etc.);
- Harmonics - (Total Harmonic Distortion THD- along with harmonics for voltages and currents for each phase separately)
- Power / Energy - (active power (W), apparent power (VA), reactive power (VAR) power factor (power factor), Cos Φ and energy types respectively)
- Unbalance / Phasors (unbalance and phasor diagram for each phase separately)
- Power quality events (dips, swells, interrupts)

All the real time values are represented as shown below.

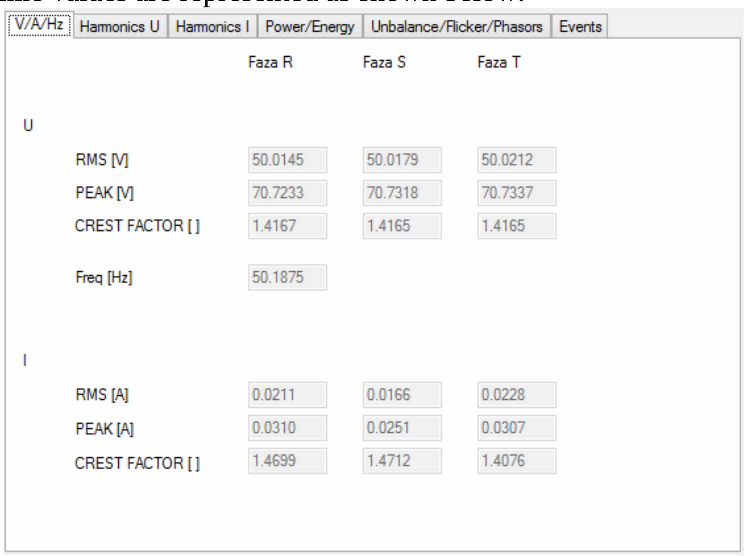


Fig. 3. Example of real time values display

Regarding storage, there is an organized storage structure on the equipment hard drive, that is based on measurements folders and type of aggregation, channels and time information. Thus, when it receives a notice of exceeding the trigger limit from the analysis module, a predefined number of values recorded before the notice of appearance, a so-called pre-trigger and a number predefined of values after the time of the event occurrence (the limit exceeding), are extracted from the buffer.

These values are saved with the timestamp of the event (GSM time).

In the figure below is presented a section of a recording for 24 channels.

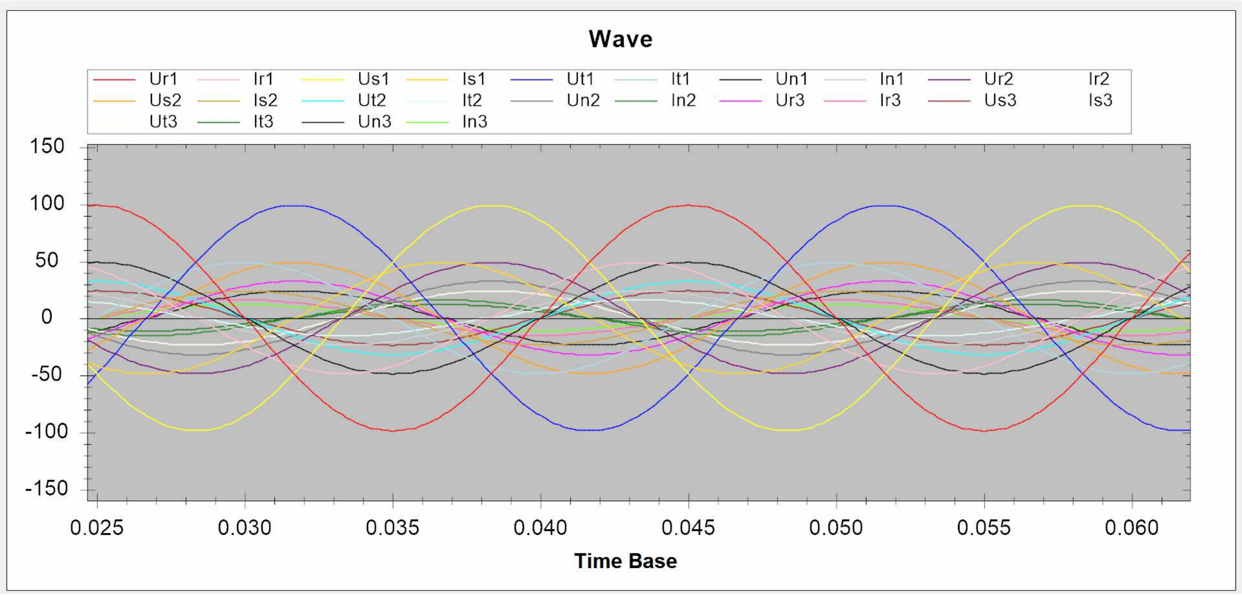


Fig. 4. Waveform graphic

3.2 Advantages and usability

An advantage of the equipment is the fact that it provides possibility for upgrading and integration into SCADA monitoring and control systems for power transmission and distribution, regardless of their complexity.

Also the equipment is highly user oriented, through the following actions:

- creating a database on the disturbances in power transformers or power quality transformer terminals and update it with new records;
- presenting the evolution of the monitored measurements, for the selected time interval;
- possibility to select how many waveforms are represented simultaneously on the chart;
- possibility to set alarms when each of the predetermined variation thresholds are exceeded for every monitored channel;
- creating a log of alerts and events.

If a measurement is running, screenshots can be made from the software application and there is the possibility to store the selected waveform.

Also, historical analysis of the data is available (in table format and chart format).

Another advantage of NOVA P01 is that it can be accessed from a remote location. A client application can be used from anywhere in same network with the equipment (and implicit with the server application).

This way, a user can see in real time what is happening in substation from a remote location. Moreover, several clients can access the data from the server at the same time and even transfer files on client local hard disk.

4. CONCLUSIONS

NOVA P01 provides bidirectional communication, remote data center management and/or remote end user access, thereby enabling:

- monitoring transport and power distribution systems from a remote location;
- eliminating operational personnel travel for daily operational activities;
- synchronization of the time reference for several measurement systems monitored by the data management center;
- updating parameters of the software module on energy efficiency.
- the equipment provides local and remote reading of online monitored data.

The device ensures a high capacity data storage for measured and processed data, including waveforms for a minimum period of 30 days, allowing analysis and extraction of data in storage memory.

Multiple equipments NOVA P01 installed in different points in the electrical grid can be used to compare fluctuations of various inputs or processed data.

BIBLIOGRAPHY

[1] "PE 029/97 Normativ de proiectare a sistemelor informatice pentru conducerea prin dispecer a instalatiilor energetic din Sistemul Energetic National";

[2] NTI-TEL-S-009-2010-01 Detalii şi specificatii de echipamente pentru realizarea unui sistem de comandă, control protectie şi automatizare la nivel de statie electrică;

[3] "NTE 011/12 vol II: Norma tehnica pentru proiectarea sistemelor de circuite secundare ale statiilor electrice. Sisteme de conducere si teleconducere";

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#77

3D CAD/CAE Modeling software for the computation of Electromagnetic Field Distribution in HV Substations and Investigation of Human Exposure

C. MUNTEANU[*], M. PURCAR
Department of Electrotechnics and Measurements, Technical University of Cluj-Napoca, Romania

SUMMARY

The numerical simulation software and procedure of the electromagnetic field distribution in high voltage (HV) substations and analysis of the human exposure is presented in this paper. The authors developed a computer aided design software (CAE) which is able to retrieve the 3D coordinates of the substation constitutive components and function on the specific loads, computes the spatial distribution of the electromagnetic field. The specific elements of the HV substation (e.g. towers, breakers, circuit conductors, bus bars, transformers, etc.) were built-up by the authors as three dimensional (3D) CAD models and stored in a data base under the SolidWorks environment. The examples of both 3D CAD and CAE approaches are demonstrated on the 3D models of 110kV Cluj-Sud substations and cell 2 of 400kV Gădălin substations. The simulated electromagnetic field distributions are represented over the 3D models of the substations in order to visualize and spot the high concentration zones with the electromagnetic field and make comparisons with the professional human exposure limits. A comparison between the measurements performed in situ and simulated electric field is made.

KEYWORDS

CAD/CAE modeling, high voltage substations, electromagnetic field, human exposure.

1. INTRODUCTION

The electromagnetic field interferences (EMI) represent unknown factors to both human health and malfunction of the electrical devices. In order to fulfill both health regulations and standards, e.g. [1] and [2] an EMI map becomes a very important instrument. Such a map would require instrumentation, measurements methodologies and advanced computational models for numerical simulation. From all presented means, the numerical simulation has several advantages for the electromagnetic field distribution study produced by the HV substations because it does not require investment in measurement devices and operative personnel and can easily analyze complex working scenarios covering both substation yard and its neighborhoods.

The majority of the simulation software used for the computation of the electromagnetic field distribution produced by the high voltage substations are based on the chard simulation method (CSM) in combination with Finite Difference Method (FDM), Finite Element Method (FEM), Boundary Element Method (BEM) or combinations of these methods (FDM-CSM, FEM-CSM, BEM-CSM) for the computation of the electric field [3-10] or a semi analytical method as described in [11-14] for the computation of the magnetic field.

[*] calin.munteanu@ethm.utcluj.ro

This paper presents an advanced CAD-CAE computation software and methodology for the electromagnetic field computation produced by HV substations and power lines. Regarding the previous works [12-14], the methodology introduced in this paper has the advantage that the input of 3D coordinates of substation constitutive components (e.g. terminals and conductors) is made via a graphic user interface, customizable for two CAD environments - SolidWorks and AutoCAD. An integrated solver of the electromagnetic field spatial distribution was implemented in the new CAE software. The computation approach used in this paper allows representation of the electric field distribution on horizontal and transversal slices directly on the 3D CAD model. Hence, it is easy to highlight the high intensity field zones and discuss the human exposure with respect to the actual legislation.

The substation constitutive components were built-up by the authors as 3D CAD models and stored in a data base under the SolidWorks CAD environment. Cluj-Sud 110kV and 400kV Gădălin substations 3D model were built up in order to demonstrate the computation methodology. The results are compared with in situ measurements. Finally, the electric and magnetic field results are compared with standard human exposure limits.

2. COMPUTATIONAL MODEL

The electromagnetic field computation approach integrated in the CAE software requires the approximation of the complete substation structure by straight finite conductor segments. Hence in a first step, the 3D coordinates and gauge of the substation electrical equipment and power lines need to be collected. The simulation algorithm structure is presented in Figure 1.

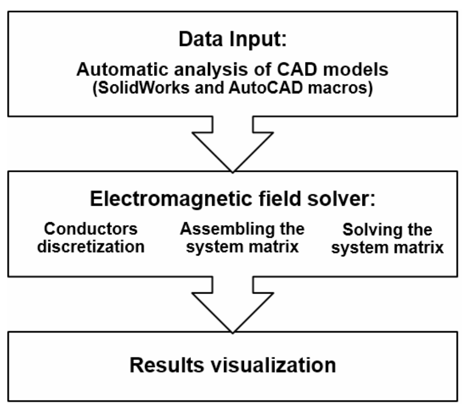


Figure 1: The structure of the computational algorithm.

2.1. Data Input

The 3D substation model is analyzed in order to retrieve the (x, y, z) coordinates of the electrical terminals and conductors.

The coordinates of the equipment terminals and conductors are collected via a CAD/CAE customized interfaces, see Figure 2 (a) and (b). The interfaces were developed under two CAD environments -SoildWorks and AutoCAD. They are designed based on specific CAD system features used for the substation design. The interfaces allow setting the number of discretization segments of each a conductor direction, the diameter of segments, sag, voltage, current and phase of each circuit.

a) **b)** **c)**

Figure 2: (a), (b) CAD/CAE interfaces for collecting the coordinates of the substation constitutive elements; (c) previsualization of the conductor direction superposed over the 3D CAD model.

In order to check the correctitude of the collected data it is possible to preview the retrieved data in terms of conductor direction and/or position of the equipment terminals superposed over the 3D CAD model of the substation, see Figure 2 (c).

2.2. Electromagnetic Field Solver

The electromagnetic field solver discretizes the substation conductors using finite straight segments (see Figure 3), assembles the system matrix with the contribution of each conductor segment and solves the matrix.

Both the electric and magnetic field distribution were validated in [12-14] a brief description of the computation procedure will be briefly presented in the following.

The electric field is finally computed from the charge density contribution of each discretization conductor element, according to the conductor phase angle. The same principle is used for the computation of the magnetic field but using the currents through each conductor instead of charge density. The advantage of the magnetic field to the electric field computational algorithm is that the current is constant through a complete conductor length while the charge density distributes on each discretization segment along a complete conductor length. The disadvantage of the magnetic field to the electric field computational algorithm is that the current through the conductors may vary in time (amplitude and phase) function of the power line loads while the voltage is always maintained constant. Hence, in order to compute the magnetic field distribution electricity distribution company should provide the exact power line loads.

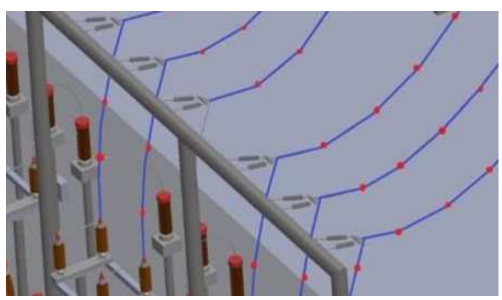


Figure 3: Discretization of the conductors in straight finite conductor segments.

2.3. Results Visualization

The simulated components of the electromagnetic field are superposed over the 3D CAD model in order to visualize and identify the areas with the dangerous electromagnetic field levels inside the substation, see Figure 4.

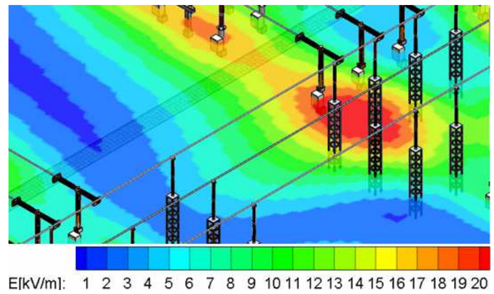


Figure 4: Example of electric field visualization in a slice parallel to the ground.

3. 3D CAD MODELS LIBRARY

Based on the specific technical descriptions a 3D model library (e.g. bypass bus bars, breakers, transformers) was build up fully parametrized in the SolidWorks CAD software environment [5], see Figure 5. Even from the design phase, parameters instead of fixed dimensions were used for the definition of the 3D CAD model library components. The parameters list allows a fast modification and reconfiguration of the models. Being standardized and parameterized, the 3D CAD library components can be used for the virtual construction of any substation type.

110kV High voltage breaker picture

3D model of a high voltage breaker

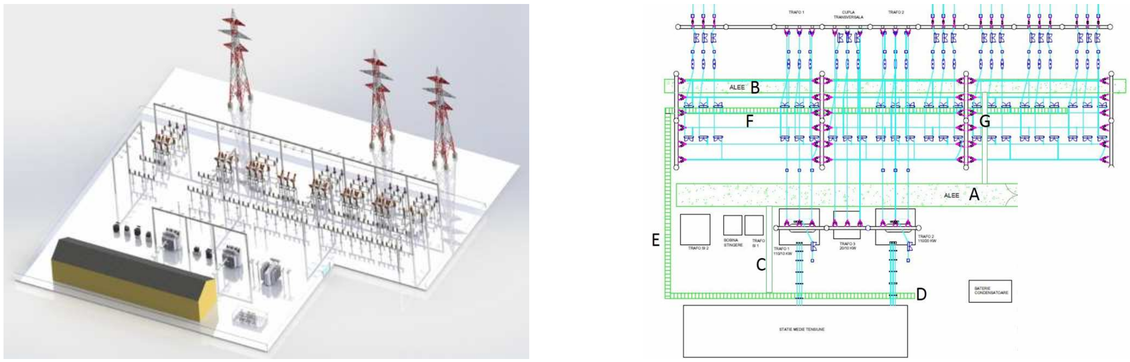
400kV High voltage separator picture

3D model of a high voltage separator

Figure 5: 3D CAD model library components built in SolidWorks

4. STUDY CASE 1 - COMPUTATION OF THE ELECTRIC FIELD DISTRIBUTION BASED ON THE 3D CAD MODEL OF 110 KV CLUJ-SUD SUBSTATION

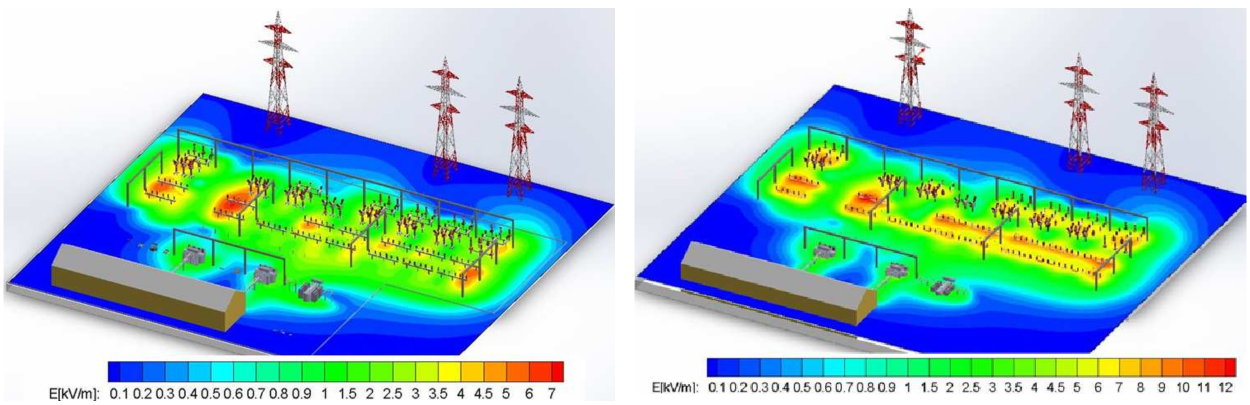
Cluj-Sud 110 kV high voltage substation represents an important hub for the Cluj-Napoca city area. A complete overview of the 3D SolidWorks model of the Cluj-Sud 110 kV high voltage substation is shown in Figure 16 (a) [12]. In Figure 16 (b). is presented the schematic overview of the electrical circuits used to build the computational model. On the same figure the access personnel lanes are marked with letters from A to F.



(a) **(b)**

Figure 6: (a) 3D SolidWorks model of the 110kV Cluj-Sud high voltage substation; (b) the schematic overview of the electrical circuits and the access personnel lanes A to F.

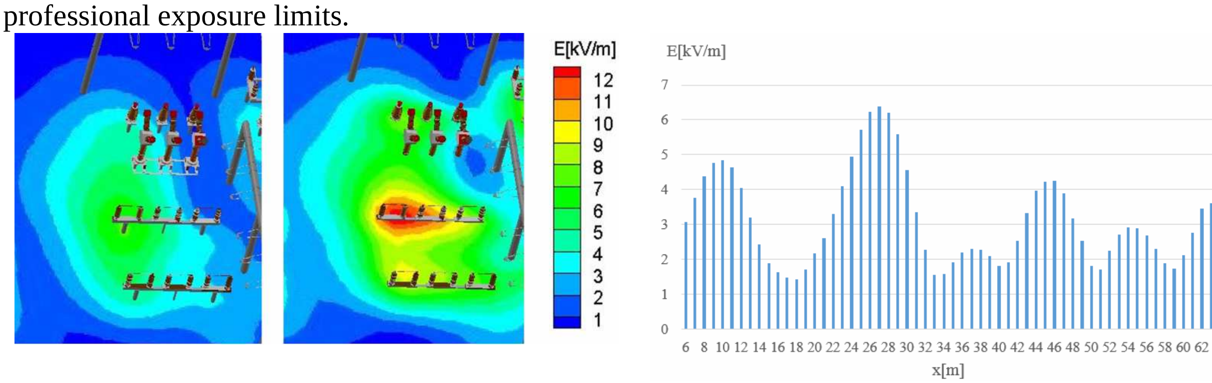
The exposure limits to electromagnetic fields are quantified by two EU documents [1] and [2]. Both above mentioned documents have been transposed in the Romanian legislation resulting two governmental documents [16] and [17]. According to these documents, the occupational exposure limit to the electric field is 10 kV/m at 50Hz. This limit was particularly checked during the performed analyses. In Figure 7 (a) is represented the strength of the electric field at 1.7 m and (b) 3 m above the ground (bottom). The highest field values were found in the neighborhood of the line bays, bus-bars circuit breakers and disconnectors, see Figure 8 (a) and (b). It can be noticed that there are large areas inside substation where the occupational exposure limit is exceeded but only starting from 3 m above the ground.



(a) **(b)**

Figure 7: Electric field distribution: (a) 1.7 m above the ground and (b) 3 m above the ground.

The highest value of the electric field strength is noticed along the lane B and is 6.5 kV/m, see Figure 6 (c). It occurs in the neighborhood of the interrupters, but it still does not exceed the professional exposure limits.



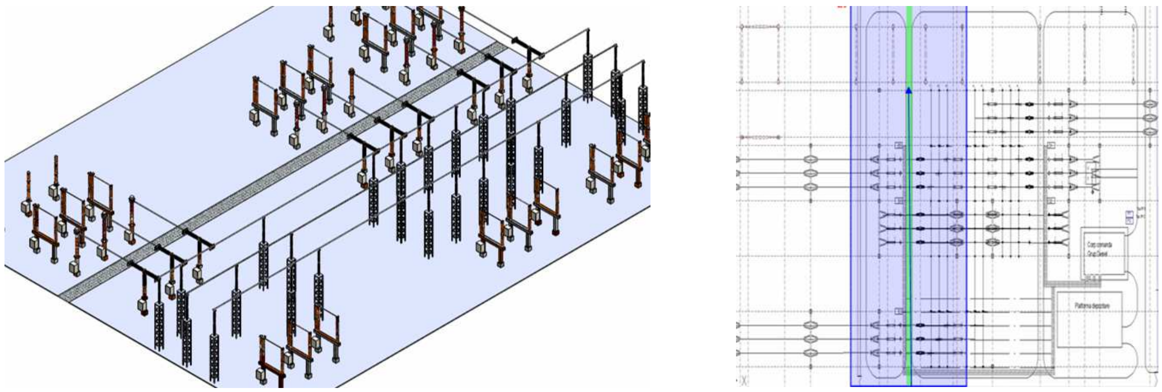
(a) **(b)** **(c)**

Figure 8: Detail of the electric field distribution around the bus-bars circuit breakers: (a) 1.8m and (b) 3m above the ground; (c) Electric field distribution at 1.7m along the lane B.

5. STUDY CASE 1 - COMPUTATION OF THE ELECTROMAGNETIC FIELD DISTRIBUTION BASED ON THE 3D CAD MODEL OF 400 KV GĂDĂLIN SUBSTATION

The 400 kV Gădălin substation represents an important energy hub of the Romanian energetic system providing interconnection between three important Transylvanian substations: Iernut, Cluj East and Roșiori. Munteanu *et. al.* computed and analyzed in [11] the electric field generated by the Roșiori substation.

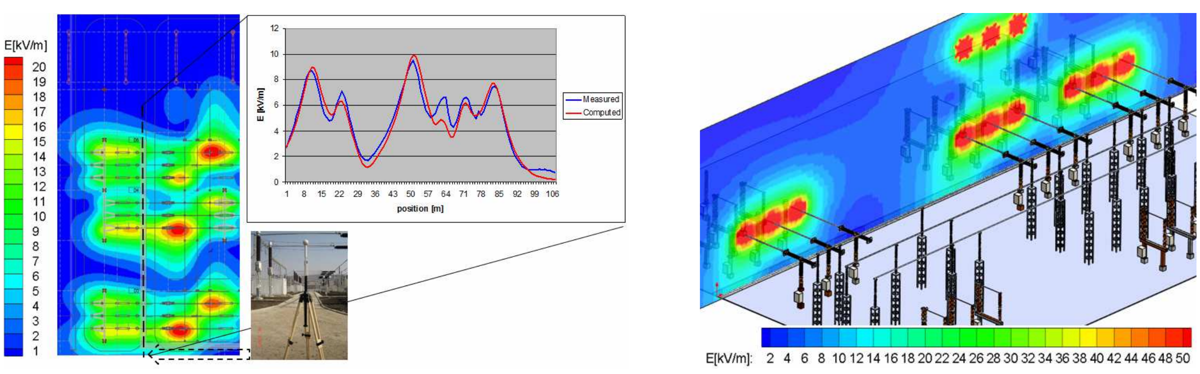
After substation retrofitting and upgrading the electric field measurements were performed along the main ally of cell 2. The 3D SolidWorks model and 2D schematic view of the electrical circuits that describe cell 2 are presented in Figure 9: (a) and (b).



(a) **(b)**

Figure 9: (a) The 3D SolidWorks CAD model of cell 2 (the lane where the electric field measurements were performed is marked in dark grey) (b) the electrical circuits of cell 2, with the main alley marked by an arrow.

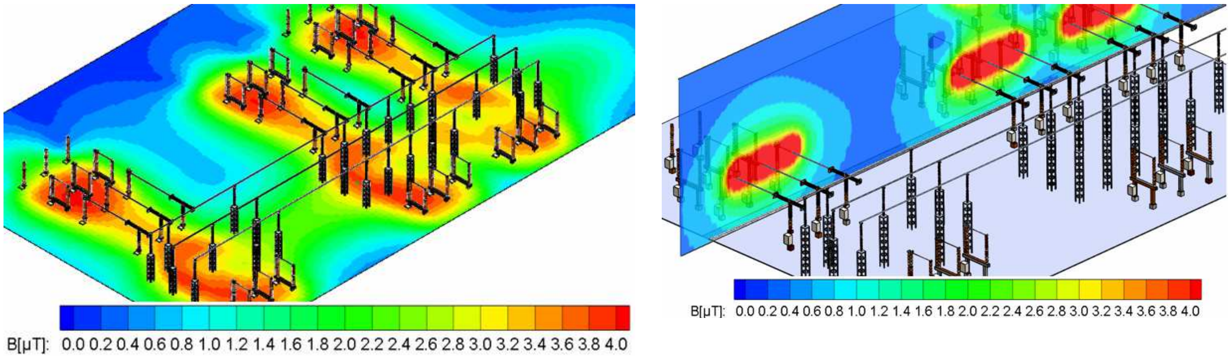
The electric field measurements have been performed with a field meter device HI 3604 ELF with the measuring loop set horizontally. All measurements were taken at 1.7 m height from the soil surface being considered the most critical human exposure zone [1, 2] to the power frequency electromagnetic field. A good agreement between the simulated electric field intensity and measurements can be noticed in Figure 10 (b). The highest deviation is less than 15%. The highest value of the electric field does not exceed 10 kV which is the highest limit for the professional exposure at 50Hz in controlled environment. The simulation results are shown in Figure 10 (a) through a cross-section along the central alley in Figure 10 (b).



(a) **(b)**

Figure 10: (a) Comparison between the simulated electric field strength at 1.7m above the ground along the central lane and measurements; (b) the electric field map through a cross-section along the central lane.

The currents through the substation buss bars were unknown. Hence, the computation of the magnetic field was performed considering a hypothetical situation e.g. a constant current i=100A through each buss bar. The simulation results of the magnetic field distribution is presented in Figure 11 (a) at 1.7m above the ground and Figure 11 (b) through a cross-section along the central lane.



(a) **(b)**

Figure 11: The magnetic field map in cross-sections: (a) at 1.7 m above the ground and (b) through a cross-section along the central lane.

No measurements were available for the magnetic field density. The maximum magnetic field density resulted from simulation is 4µT. The limits (e.g. 500 µT) [1-2] for the professional exposure in the magnetic field are not exceeded.

CONCLUSIONS

A 3D CAD/CAE Modeling software and methodology for the computation of the Electromagnetic Field Distribution in HV Substations was presented. The CAE environment developed in this paper interacts with the 3D CAD model of the substation, retrieves (x, y, z) coordinates of the electrical terminals and conductors, allows setting the specific loads and computes the electromagnetic field spatial distribution. A fully parameterized and reconfigurable 3D CAD model library with the specific substation constitutive components was built-up under the SolidWorks CAD environment. The 3D SolidWorks substation components allow fast design and configuration of the substation computational models. Both 3D CAD and CAE approaches were outlined on the 3D CAD models of 110kV Cluj-Sud substation and cell 2, of 400kV Gădălin substation. The comparisons between the simulated electric field and measurements along the central lane of cell 2 of 400kV Gădălin substation are in a very good agreement. The simulated electromagnetic field values do not exceed the professional human exposure limits in controlled environment.

BIBLIOGRAPHY

[1] Council Recommendation of 12 July 1999 on the limitation of exposure of the general public to electromagnetic fields (0 Hz to 300 GHz).

[2] Directive 2013/35/EU on the minimum health and safety requirements regarding the exposure of workers to the risks arising from physical agents (electromagnetic fields).

[3] N. P. Herbert, Introductory Electromagnetics, Wiley, 1971.

[4] H. Singer, H. Steinbigler and P. Weiss, "A charge simulation method for the calculation of high voltage fields." IEEE Trans Power Apparatus Syst, vol. 93, no. 5, pp. 1660-1668, 1974.

[5] B. Lee and et al, "An effective modelling method to analyze the electric field around transmission lines and substations using a generalized finite line charge," IEEETrans Power Delivery, vol. 12, no. 3, p. 1143–1150, 1997.

[6] A. Rankovic and M. S. Savic, "Generalized charge simulation method for the calculation of the electric field in high voltage substations," Springer-Verlag Electr Eng, vol. 92, pp. 69-77, 2010.

[7] Mazen Abdel-Salam, M.T.El-Mohandes, "Combined method based on finite differences and charge simulation for calculating electric fields", IEE Transactions on Industry Applications, vol. 25, No. 6, pp.1060-1066, 1989.

[8] J.N. Hoffmann, P. Pulino, “New developments on the combined application of charge simulation and numerical methods for the computation of electric fields”, IEEE Transactions on Power Delivery, vol. 10, No. 2, pp. 1105-1111, 1995.
[9] Bo Zhang, Jinliang He, Xiang Cui, Shejiao Han, Jun Zou, “Electric field calculation for HV insulators on the head of transmission tower by coupling CSM with BEM”, IEE Transactions on Magnetics, vol. 42, No. 4, pp. 543-546, 2006.
[10] S. Schmidt, G. Zech, W. Otto, “Fast and precise computation of electrostatic fields with a charge simulation method using modern programming techniques”, IEEE Transactions on Magnetics, vol.32, No. 3, pp. 1457-1460, 1996.
[11] W. Krajewski, "Numerical evaluation of the magnetic field exposure near the transition tower of an overhead-underground hv line," Progress In Electromagnetics Research M, Vol. 14, 247-261, doi:10.2528/PIERM10101102, 2010.
[12] C. Munteanu, M. Purcar, D. Bursasiu, E. Merdan, V. Farcas, "CAD/CAE modeling of the human exposure to electric field inside a high voltage substation", in EPE 2014 - Proceedings of the 2014 International Conference and Exposition on Electrical and Power Engineering, pp. 476-479, 2014.
[13] C. Munteanu, G. Vișan, T. I. Pop, V. Țopa, E. Merdan, A. Răcășan, „Electric and Magnetic Field Distribution inside High and Very High Voltage Substations,” în Proc. 20th International Zurich Symposium on Electromagnetic Compatibility, Zürich 2009.
[14] C. Munteanu, V. Topa, M. Purcar, L. Grindei, A. Racasan "Study of the electric field generated by the high voltage substations" MMACTEE'10 Proceedings of the 12th WSEAS international conference on Mathematical methods and computational techniques in electrical engineering, pp. 74-77, 2010.
[15] SolidWorks, "www.solidworks.com," [Online].
[16] “HG 1136/30.08.2006”, Official Romanian Gazette, no. 769/11.09.2006.
[17] “OMSF 1193/29.09.2006”, Official Romanian Gazette, no. 895/03.11.2006.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#78

AC Interference Modeling, a Tool for Personnel Safety Investigation

M. PURCAR*, C. MUNTEANU
Department of Electrotechnics and Measurements, Technical University of Cluj-Napoca
Romania

SUMMARY

The numerical simulation procedure for the evaluation and mitigation of the electromagnetic field interferences generated by the high voltage alternating current power lines (HVAC) on the buried metallic structures (e.g. pipelines networks) is presented. The benefits of the software tool in investigation of the personnel safety will be highlighted with the example of safety elements design.

KEYWORDS

High voltage alternating current power lines, underground metallic pipeline networks, electromagnetic field interference, simulation software, personnel safety.

1. INTRODUCTION

Simulation technologies represent nowadays common tools for the optimal processes design. An important application of the simulation technologies is the investigation of the hidden phenomena created by the electromagnetic field interferences (EMI) between the HVAC and the underground metallic pipeline networks that may affect both human health and good functioning of the related equipment.

Besides the well-known DC or AC corrosion phenomena of the buried metallic structures [1]-[6] (which can lead in time to important damages) a very serious effect of the stray induced currents is represented by the shock hazard for the personnel [7], [8].

The stray induced currents are basically generated by the HVAC in the neighborhood metallic structures via three mechanisms:

Capacitive or electrostatic coupling, when the HVAC and victim metallic structure behaves like the capacitor armatures; this coupling holds only for the metallic structures above the ground;

Inductive interference, when the HVAC and victim metallic structure behaves like the transformer primary and secondary coils respectively;

Resistive or conductive interference related to the AC fault currents (e.g. phase to ground) that flow towards the metallic underground pipelines or structures.

The simulation technology applied in this paper uses the simulation software tools developed in [9]. The software suite for the AC interference prediction and solution techniques to mitigate the unwanted effects allows modeling complex HVAC and metallic pipeline networks with no restrictions on geometry and electrical connections. The software has been presented in [7]-[11].

2. COMPUTATIONAL MODEL

The computational approach can handle both conductive and inductive coupling mechanisms.

* marius.purcar@ethm.utcluj.ro

2.1. Resistive coupling

The pipelines buried in the ground can be seen as large electrodes surrounded by an immense electrolyte. Assuming, for simplification, that there are no concentration gradients, Ohm's law holds and electrochemical cells can be described by the Laplace equation with non-linear boundary conditions governed by the electrochemical reactions at the electrodes (pipe surfaces) [12].

The model is applied in solving the conductive component during the fault to earth (e.g. phase to ground). It considers the complete ground half-space where the earth surface is modeled as an insulator. The inhomogeneity of the soil is modeled using a two layer soil approach [13], see Figure 1.

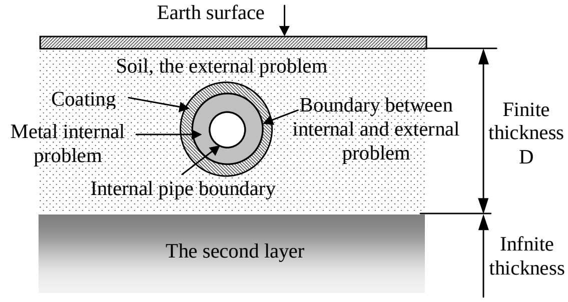


Figure 1: Pipe cross section: internal and external domain coupled through coating [7], [10].

2.2. Inductive coupling

The model computes the induced electromotive forces E (EMF) along the arbitrary closed contour Γ, see Figure 2 left, formed by the HVAC's and pipeline networks according to Maxwell's second equation [11].

Based on the EMF formulation (7), the induced voltages and currents are later calculated by assembling and solving the well-known transmission line model (TLM) from each element l_i, see Figure 2 right,

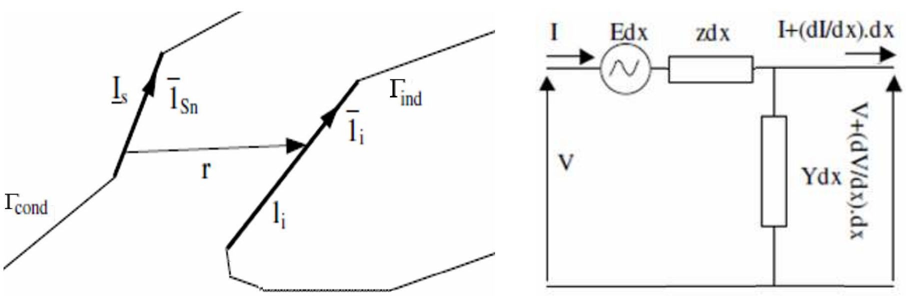


Figure 2: Division of source and victim wire in piecewise linear segments (left); TLM for the pipeline-earth electrical circuit (right).

The numerical approach requires the pipeline section parameters (e.g. diameter, coating, soil resistivity, etc.) and HVAC parameters (voltage, current, phase transposition, sag, tower geometries etc.). More details on the numerical implementation, specific boundary conditions, modeling of fault and inductive interference can be found in [7], [10] and [11].

3. STUDY CASE - AC INTERFERENCE BETWEEN THE HVACs AND PIPELINES IN THE SAME CORRIDOR

This example has been in detailed presented in [8]. This study will highlight the specific mitigation procedure regarding the phase to ground in the neighbourhood of the pipeline at a valve station.

The pipeline under consideration has a diameter of 42 inch, is polyethylene coated and about 90 km long. The pipeline is influenced by 4 different power lines: L_1, L_2, L_3 and L_4 with voltages of 110, 220 to 380 kV, see Figure 3.

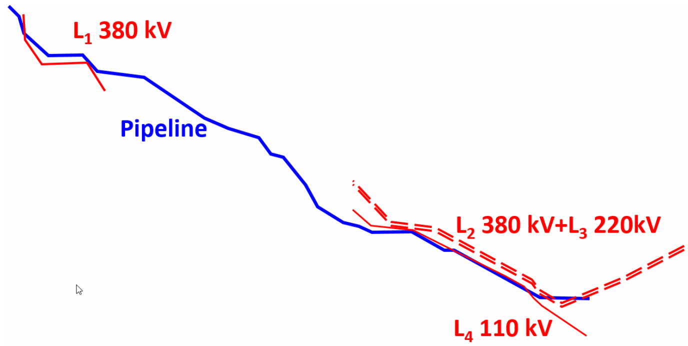


Figure 3: Studied configuration: blue = pipeline, red = HVAC.

The power lines 2 and 3 have common towers. The steady state and fault current parameters of the HVAC's are presented in Tables 1 and 2.

Table 1: Steady-State full and average load parameters

HVAC	**V [kV]**	**Circuits**	**Max load [A]**	**Average load [A]**
L_1	380	2	4000	1200 (30%)
L_2	380	2	4000	1200 (30%)
L_3	220	2	2000	600 (30%)
L_4	110	1	500	250 (50%)

Table 2: Fault parameters

HVAC	**I_1 [kA]**	**I_{21} [kA]**	**I_2 [kA]**	**I_{12} [kA]**	**Fault Duration**
L_1	46	5	47	3	5
L_2	56	0	47	11	5
L_3	35	4	30	7	5
L_4	14	3	10	2.5	5

In Table 3 are summarized the results of the 8 working scenarios and compared with the maximum allowed AC voltage during steady-state (which is 15V) and faults interference (coating stress limit which is 2000V) with respect to the impact on the personnel exposure and safety [1].

According to the results presented in Table 3 the following conclusions can be drawn:

All steady state scenarios (average and full load) exceed the 15V maximum allowable limit; the highest induced voltage is 96 V (when the contribution of all HVAC's during full load are considered);

During single phase to ground fault of circuit 2 of the power line L1 the maximum allowable coating stress voltage is exceeded;

Table 3: Results for the ss and fault scenarious

Scenario	**Power Line**	**Load**	**V allowed**	**V max**	**Allowed?**
1	All	Average	15	30	No
2	All	Full	15	96	No
3	L1	Full circuit 2	15	81	No
4	L2	Full circuit 1	15	41	No
5	L3	Full circuit 1	15	29	No
6	L1	Fault circuit	2000	2215	No
7	L2	Fault circuit	2000	186	Yes
8	L3	Fault circuit	2000	1110	Yes

The AC induced voltage along the pipeline for the full load of the power transmission lines is represented in Fig. 4.

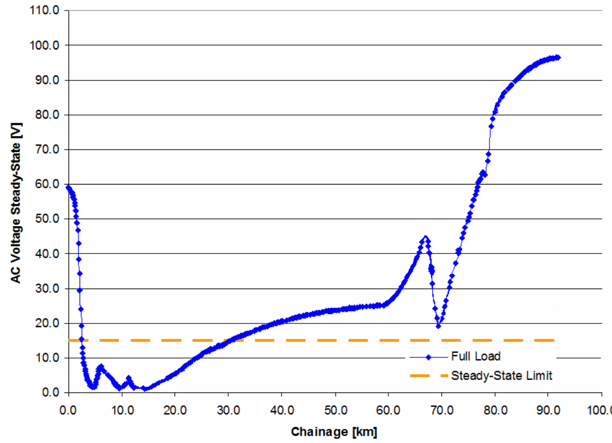


Figure 4: AC induced voltage along the pipeline versus the 15V safe limit during steady-state for all power lines at full load.

The highest induced voltage in the pipeline (as a sum of resistive and inductive components) occurs during the fault (phase to ground) of circuit 2 of power line, L_1, see Figure 5.

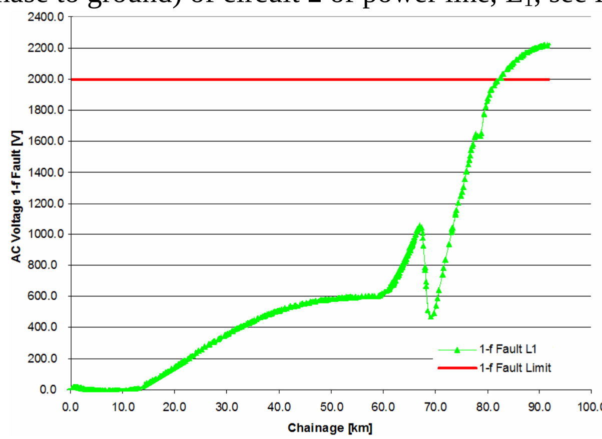


Figure 5: Pipeline voltages during fault of circuit 2 of power line L_1.

The highest touch potential is 460V and occurs at the valve station in Figure 6 left. The touch potential exceed the 367V safe limit which is calculated for zero soil resistivity and a fault duration of maximum 5 cycles (50 Hz each). The earth potential rise around the tower poles and pipeline is presented in Figure 6 right.

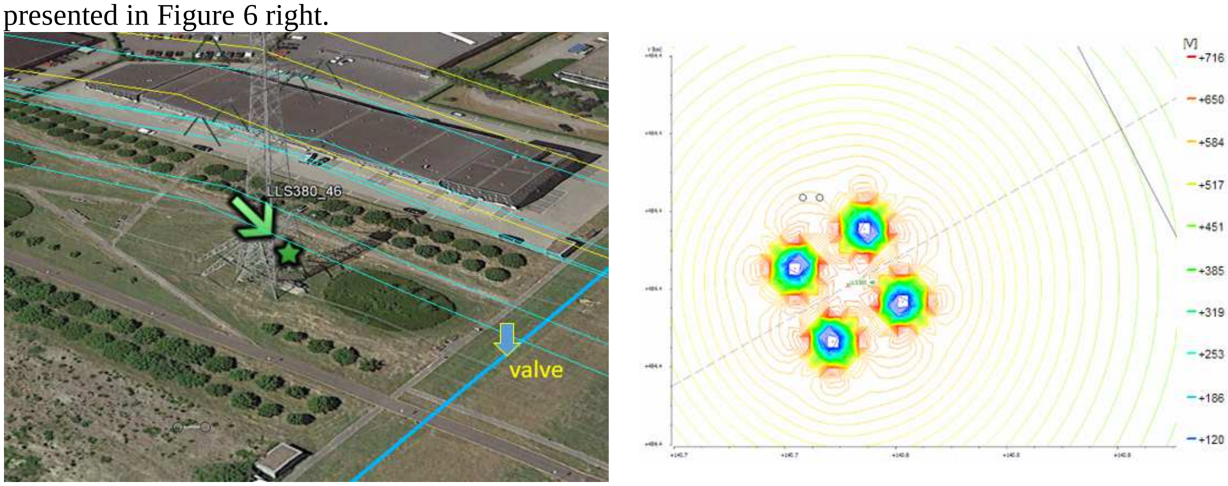


Figure 6: Detail of the faulted tower and location of the valve station where the touch potential exceeds the safe limit (left); earth potential rise around the tower poles towards the pipeline (right).

In order to reduce the touch potential below the safe limits a gradient control mat (2x2m) is foreseen at the valve, see Figure 7 (left).

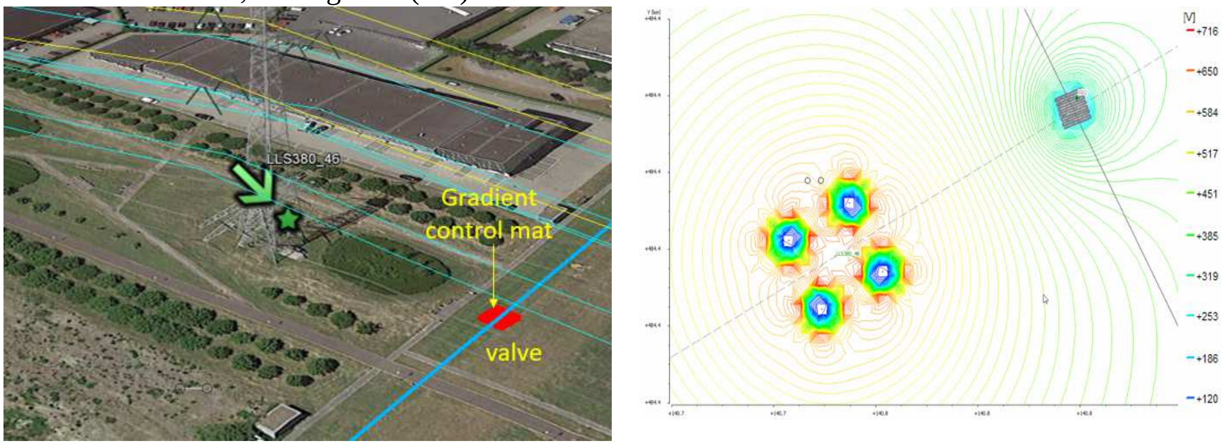


Figure 7: Detail of the faulted and gradient control mat at a valve station (left); earth potential rise around the tower poles towards the pipeline (right).

The gradient control mat distorts the earth potential rise and reduce it up to 120V at the valve station. The earth potential rise around the tower poles and pipeline is presented in Figure 7.

CONCLUSIONS

In this paper a software technology for the electromagnetic field interference prediction has been presented. The computational technology is able to model both resistive and inductive coupling mechanisms, between multiple HVAC's and pipeline networks. Both steady-state and fault scenarios of all power lines are simulated and assessed with respect to the impact on the working personnel safety. It could be noticed that during the average and full load working conditions the highest induced voltage is 96 V, hence, exceeding the 15V safety limit. In case of the single phase fault scenarios only if the fault occurs in circuit 2 of power line L1 the maximum allowable stress voltage 2000V is exceeded. A gradient control mat is required at the valve station in order to mitigate the touch potential below the safe limits.

BIBLIOGRAPHY

[1] "Guide on the Influence of High Voltage AC Power Systems on Metallic Pipelines", CIGRE, Working Group 36.02, 1995.
[2] SP0177-2007, "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control", 2007.
[3] International, Corrosion Supervisory Committee PRC, "AC Predictive and Mitigation Techniques – Final Report," 1999.
[4] EPRI Project 1902-07, BIRL Final Report, EPRI, "TL WorkstationTM Code: Version 2.3, Volume 3: CORRIDOR Manual," Palo Alto CA, 1992.
[5] F. Dawalibi, "Power Line Fault Current Coupling to Nearby Natural Gas Pipelines, Volume 2: User's Guide for ECCAPP Computer Program, Final Report, EPRI Project RP 742-4, A.G.A. Project PR 176-510," Safe Engineering Services & Technologies Ltd, Montreal, 1987.
[6] C. Munteanu, G. Mates, M. Purcar, V. Topa, I.T. Pop, L. Grindei, A. Racasan, "Electromagnetic field model for the numerical computation of voltages induced on buried pipelines by high voltage overhead power lines", The European Physical Journal, Applied Physics, DOI: 10.1051/epjap/2012110462, 2012.
[7] L. Bortels, C. Baeté and J.-M. Dewilde, "Accurate modeling and troubleshooting of ac interference problems on pipelines," in NACE International CORROSION 2012, Salt Lake City, 2012.

[8] Purcar M., Munteanu, C., Bortels, L., Baete, C., “AC interference assessment and impact on personnel safety”, in EPE 2014 - Proceedings of the 2014 International Conference and Exposition on Electrical and Power Engineering, pp. 457-461, 2014.
[9] E. NV, "www.elsyca.com," Elsyca NV. [Online].
[10] L. Bortels, J. Parlongue, W. Fieltsch and S. Segall, "Manage Pipeline Integrity by Predicting and Mitigating HVAC Interference," in NACE Store, Houston, 2010.
[11] L. Bortles, J. Deconinck, C. Munteanu and V. Topa, "A General Applicable Model for AC Predictive and Mitigation Techniques for Pipeline Networks In," IEEE Transactions on Power Delivery, vol. 21, no. 1, pp. 210-217, 2006.
[12] Brichau, F., Deconinck, J., ‘A Numerical Model for Cathodic Protection of Buried Pipes’, Corrosion-vol 50, No. 1, Nace International, 1994.
[13] Purcar, M., Deconinck, J., Bortels, L., Nelisen, G., “Two Layer Model for Cathodic Protection of Buried Pipes”, Proceedings of the Advances in Numerical Computation Methods in Electromagnetism Symposium, ANCME 2000, Gent, Belgium, 8 - 9 June 2000.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#80

Cornerstone in European Connection Codes implementation in Romanian technical legislation

Dr.ing. D. ILIŞIU*
CN Transelectrica – DEN
Romania

SUMMARY

The analysis of the new pan-European code highlights some new requirements which must be reflected, in the shortest time from approval, in the Grid Code and secondary legislation in Romania.

The paper presents analysis of the main aspects of the paneuropean connection codes, highlighting them backbone and the newest concept and requirements. The requirements of this Regulation shall apply from three years after publication time necessary to adapt national legislation for no exhaustive requirements.

KEYWORDS

Grid code, power control, ancillary services, active power control, reactive power control, voltage control, power factor, low voltage ride through, requirements for generation, demand requirements.

I. INTRODUCTION

The need of developing a common European Code connection derives both from the European Council decisions 714/2009 and especially from the need of having common technical requirements in Europe. Ensuring the same level of technical requirements for all producers and consumers of electricity is a beneficial process for equipment manufacturers and network operators / system with the obvious intention of ensuring constant quality of the product “electricity” in a single market. A single European electricity market can become viable only if there are some single European requirements whose compliance can be guaranteed only by the entities (producers and consumers) using equipment that complies with standards and technical requirements of common connection.

The development of codes of connection and operation with the European regulatory nature such as Pan-European Grid Code ultimately contribute to achieving a degree of reliability and a high power quality in the entire European network and an equal treatment of consumers.

At this time, in Europe is working five synchronous systems (Continental Europe, Nordel, England, Ireland and the Baltic States) with different requirements for users’ connection (producers, distributors and consumers) and power-frequency control rules. Consequently, the performance provided by each synchronous system is different. The differences between operating rules of those five European power systems are based on natural differences of size, development, interconnection with other systems, types of block control that form them.

* doina.ilisiu@transelectrica.ro

1.1. The law basis

The Directive 2009/72/CE of European Parliament and Council of 13 July 2009 with regarding of common rules for internal electricity market points the need for enhanced cooperation and coordination between transmission system operators in the ENTSO-E space to create common network codes. These Pan-European Codes should provide an effective and transparent access to cross-border transport networks to ensure coordinated planning and future-oriented technological development of the transport system, including interconnection capacity building and environmental protection.

The Transmission system operators (TSOs) are, in accordance with Article 12 of Directive 2009/72/EC, responsible for high and very high network operation for long distance, with transport and supply of electricity including the consumers directly connected and for distributors. In addition to the transport task, TSO responsibility is to ensure the security, to a high level of reliability and quality.

By developing the Code of generating sources connection, ENTSO-E aims to establish some clear and objective requirements for connection of generators to the grid, in order to achieve a competition based on the same technical requirements imposed on equipment suppliers. In this way, are created the premises of the efficient functioning of the internal electricity market in terms of safe operation of the system even if the renewable energy production is increasing.

1.2. Mandatory of Pan-European Codes

Pan-European codes, including that for generators and consumers / dealers connection, have European regulatory nature. Thus, Code connection will come into force on the twentieth day following its publication in the Official Journal of the European Union. No later than ten years after entry into force of this grid Code, all existing units must comply with all provisions of the network code or to receive a derogation decision from the network operator about the provisions for which they do not comply. Exemptions are issued and managed by the network operator so that within five years all generating units that do not comply with a requirement, to resolve nonconformities from Code or by an exemption or by an improving performance.

The application forms for the analysis of non-conformities will be submitted for each network operator no later than six months after entry into force of the Network Code. Network operator must notify the applicant the decision granting the exemption and should have a record of all exemptions granted.

The request for exemption, submitted in writing to the network operator, will include the following information: identification of the requesting applicant, describing the reason why he wants to change the provision / Network Code parameter for which is seeking the exemption. The network operator must keep a register of all derogations granted and provide to ENTSO-E the records updated at least every 6 months.

II. THE STRUCTURE OF GENERATORS CODE CONNECTION

The code is designed so that each type of generator is rated by output power, the requirements thus classified in terms of management system (knowledge of technical data and provide the monitoring of production sources), the requirements for active power control and behaviour at frequency variations, the requirements related to voltage stability (voltage control at the point of connection, reactive power control) and group behaviour requirements for emergency / restoration, this category including also the requirements for "robustness" in operation, given by the behaviour in defects case.

2.1. Classification of generating units

Classification of generating unit is based on voltage level from the point of connection and unit capacity [MW]. The generating units, in the scope of this Code connection, are classified in four groups A, B, C and D as follows:

(a) connection point below 110 kV and maximum capacity of 0,8 kW or more (type A);

(b) connection point below 110 kV and maximum capacity at or above a threshold proposed by each relevant TSO in accordance with the procedure laid out in paragraph 3 (type B). This threshold shall not be above the limits for type B power-generating modules contained in Table 1;

(c) connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO in accordance with paragraph 3 (type C). This threshold shall not be above the limits for type C power-generating modules contained in Table 1;

(d) connection point at 110 kV or above (type D). A power-generating module is also of type D if its connection point is below 110 kV and its maximum capacity is at or above a threshold specified which shall not be above the limit for type D power-generating modules contained in Table 1.

Synchronous areas	Limit for maximum capacity threshold from which a power-generating module is of type B	Limit for maximum capacity threshold from which a power-generating module is of type C	Limit for maximum capacity threshold from which a power-generating module is of type D
Continental Europe	1 MW	50 MW	75 MW

Table 1 Limits for thresholds for type B, C and D power-generating modules

The connection requirements are presented starting with type A units being developed to type D units. This structure and the idea of developing requirements for small groups, defined as non-dispatchable units to the grid code are new and require special technical rules necessary for distributed generation. In this sense the Grid code must be adapted for each TSO.

2.2. Specific requirements

2.2.1. Behaviour on the frequency variations

The main novelty is imposing some specific requirements and responsibilities to small units (class A), requirements that doesn’t exist in most of network codes. Of these the most important are related to the requirement of remaining in operation over a wide range of frequency: 47.5 Hz -51.5 Hz and on frequency variation equal with 2Hz/s.

Another novelty is the assessment for units type A, and B is the requirement of imitated reaction to the frequency deviation. That means that those units must react only to high frequency deviation (greater than 50 Hz) or for frequencies smaller than 50 Hz. From C class is required a complete reaction to the frequency deviation during all domains as in Figure 1 and Table 2:

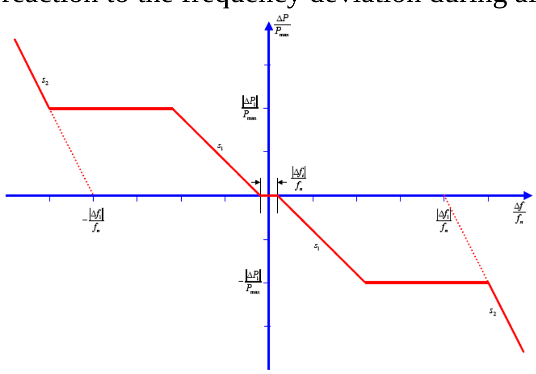


Figure 1. Frequency-active power response for generators type C

Parametrii	Intervalele [mHz]	Intervalele [%]
Puterea activa raportata la capacitatea maxima	-	2-10 %
Abaterea relativa de frecventa	10-500 mHz	0.02-1.0 %
Domeniul de insensibilitate la frecventa	20-30 mHz	0.04-0.06 %
Statism S1	-	2-20 %
Statism S2	-	2-12 %

Table 2. Values for parameters from Figure no.1

In terms of control schemes and their settings, the protection schemes and their settings are read as follows:

- Schemes and generated power control device settings (RAV and power regulators) must be coordinated and agreed between the network operator and the operator of the unit, especially on one of these situations: isolated operation and depreciation of local and inter area oscillations.

- Beginning with type C generating units, the active power of the unit must be controllable. In this respect, the unit control system must be able to receive a reference value (setpoint), implemented either manually or automatically by remote-controlled equipment by the system operator.

- The system operator is entitled to require to the unit to produce any power in the range of minimum and maximum set.

Each generating unit must be able to activate the entire power reserve according to the above figure and table parameters specified by the TSO.

TSO sets: the droop values, insensitivity bands, death bands in frequency response and frequency inflection points. Accuracy of frequency response measurements of active power must be greater than 10 mHz.

Each generating unit must be able to provide all active power reserve for a period specified by the TSO of each synchronous area between 15 min and 30 min.

Requirements regarding the operation in voltage-frequency domain for units connected to a voltage level higher than 110 kV.

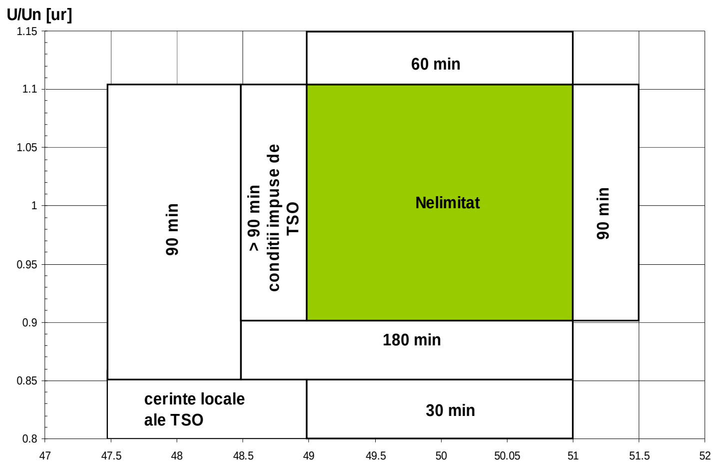


Figure 2. Requirements regarding the operation in voltage-frequency domain for units connected to a voltage level higher than 110 kV

2.2.2. Requirements for system protection and automation

In terms of protection and automation system, begining with type B generators is provided explicit the coordination of the setting with network operator. Also, the line connecting the generator protection must meet the network operator. Also, the line connecting of the generator protection must respect the requirements of the network operator. Network operator is entitled to request automatic like RAR-M type for radial connection schemes, and RAR-M or RAR-T for loop connection schemes.

Responsibility for the application of torsion, transitional arrangements which requires up to 50% maximum torque capacity, are considered normal and should not result in dangerous applications. For such requests occurred during mono, three-phase shortcircuits the generator producer takes the necessary measures.

III. PARTICIPATION TO SYSTEM RESTORATION

The restoration capacity in terms of starting the system without power source is not required, but TSO has the right to require this capability for some units.

A unit with ability of restoration must start in a time range specified by TSO and can synchronize with another system in the frequency set. The generator unit must be able to control automatically the voltage and to operate in the same time with other generating units when the network is isolated or during the system restoration. A generator unit must pass from interconnected system to isolated system without using any switching signal to identify an isolated network.

The isolated on their own services of generating units operation is required from type C units.

Generating units whose start time is greater than 30 minutes must be able to isolate on their services when the connection with the network is lost, from any point of operation of the PQ diagram without using additional signal. The minimum isolated run time is set by the TSO.

IV. THE REQUIREMENTS OF SYNCHRONOUS GENERATING UNITS REGARDING THE VOLTAGE STABILITY

Each synchronous generating unit must be equipped with an automatic control in order to provide a constant voltage across the generator. The excitation system of the generating unit must contain a device for preventing / damping power oscillation (PSS). The output signal from the PSS should be limited to less than ± 10% of the output voltage signal of the generating unit at the AVR entrance and PSS operation must not lead to instability. PSS must go out of service when the generating unit operates at less than 10% of Pmax.

Reactive power and voltage control is achieved in the synchronous generating units-type D according with the diagram:

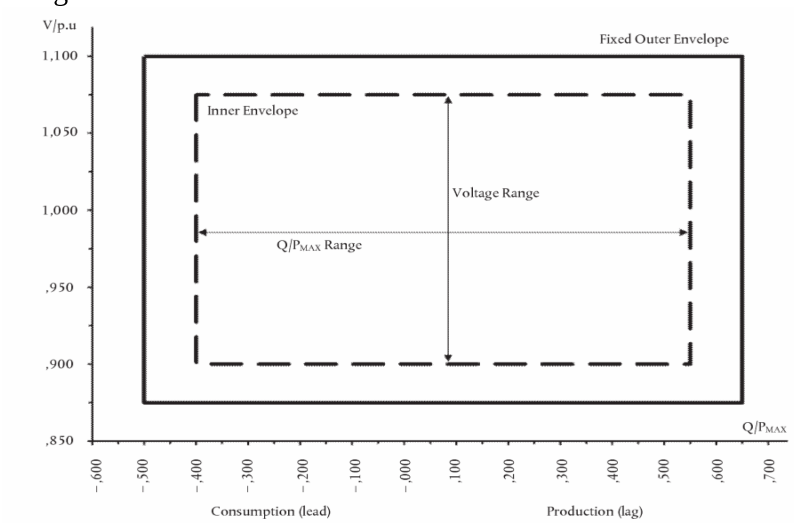


Figure 3. U-Q/Pmax profile of a synchronous generating unit

And for a wind power plant type D according to the following diagram (which highlights the need for the zero reactive power exchange with the system at zero active power delivered to the system):

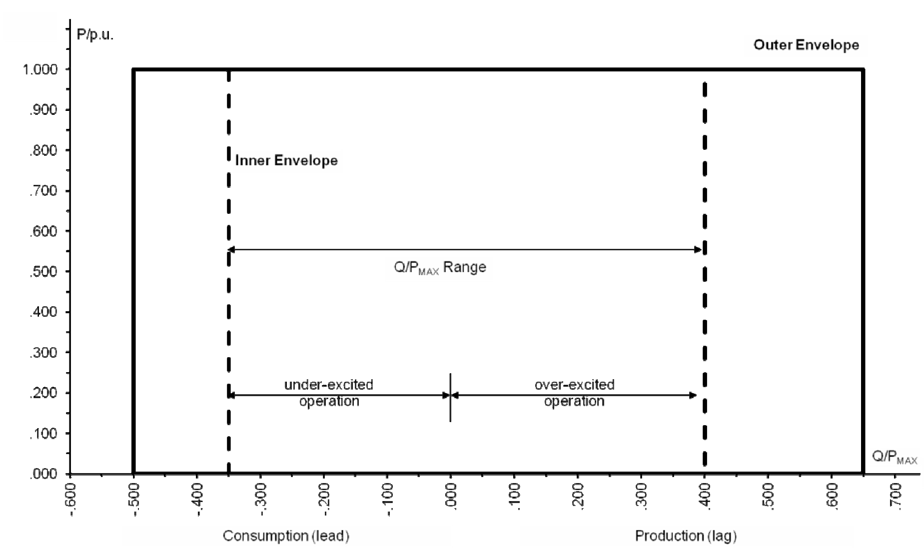


Figure 4. U-Q/Pmax profile of a wind power plant

4.1. Requirements for reactive power control on wind power plants

Wind power plant type C and D should be able to control the voltage at the point of common connection with the reactive power exchange with a reference value of voltage between 0.95 pu and 1.05 pu in steps of 0.01 or less p.u. with a slope of 2% to 7% in steps less than or equal to 0.5%. The setpoint can be operated with or without a deadband in the range of ± 10% of nominal voltage of the network in steps less than 0.5%.

4.2. Robustness of generators

A novelty brought by this code is the requirement of fault ride through begining with units from class B. The minimum requirement imposed to synchronous units is represented in Figure 5 with the range of values from table 3.

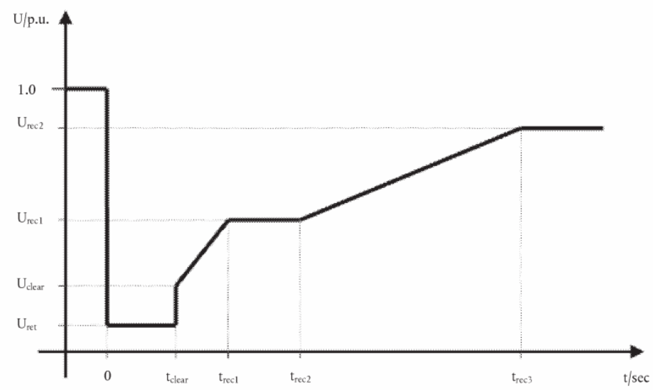


Figure 5. Fault-ride-through profile of a power-generating module

The diagram represents the lower limit of a voltage-against-time profile of the voltage at the connection point, expressed as the ratio of its actual value and its reference 1 pu value before, during and after a fault. Uret is the retained voltage at the connection point during a fault, tclear is the instant when the fault has been cleared. Urec1, Urec2, trec1, trec2 and trec3 specify certain points of lower limits of voltage recovery after fault clearance.

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}:	0,05-0,3	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	0,7-0,9	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}-0,7
U_{rec2}:	0,85-0,9 and ≥ U_{clear}	t_{rec3}:	t_{rec2}-1,5

Table 3. Parameters for Figure 5 for fault-ride-through capability of synchronous power-generationg modules

The requirement refers to the fact that synchronous generating units must remain connected to the network for short-term deeps and interruption (symmetric or asymmetric faults) like those in Figure 5, with range of values in table 3.

The same requirement also applies to wind generating units, but with the parameters from Table no. 4

Voltage parameters (pu)		Time parameters (seconds)	
U_{ret}:	0,05-0,15	t_{clear}:	0,14-0,15 (or 0,14-0,25 if system protection and secure operation so require)
U_{clear}:	U_{ret}-0,15	t_{rec1}:	t_{clear}
U_{rec1}:	U_{clear}	t_{rec2}:	t_{rec1}
U_{rec2}:	0,85	t_{rec3}:	1,5-3,0

Table 4. Parameters for Figure 5 for fault-ride-through capability of power park modules

V. EXCHANGE OF INFORMATIONS

This chapter comes to regulate exchange data flux as online and off line exchange between the TSO a generating unit. These requests are present from class B. Most important rules are:

- TSO and network operator defines exactly the list of data to be transmitted on line and offline;
- Generator unit will be equipped in accordance with standards approved by TSO or network operator to transmit information in real time or post event, for a certain period.
- Real-time information is necessary to monitor the unit, exchange of information including:
- signal condition of primary control operating unit;
- scheduled active power (power saw);
- measured active power;
- droop value;
- available power including wind and solar power plants, if they operate in limitation.
- generating unit must be equipment to record the following parameters: voltage, active power, reactive power, frequency and harmonics. The settings of recording equipment, including criteria for release and registration period shall be determined by the operating system and TSO.

Changes/upgrades/replacements to unit equipment, which would have a significant impact on network and interconnection between systems such as: turbines, generators, converters, high voltage equipment, protection or control (hardware and software) will be notified to the network operator, for it to set before the PIF, the required settings.

VI. MATHEMATICAL MODELS AND SIMULATIONS

Each system operator is entitled to request simulation models. These should be provided in the format required by the system operator, highlighting the behaviour of generating unit in steady state and dynamic behaviour (short-term and long-term transitional) in the common point of connection. In order to dynamic simulation the model must contain the following sub-models: speed and active power control, voltage control, including PSS, excitation system and the limitations, models for the generator and converter protection. System Operator may require additional requirements for models for dynamic and static systems, studies of group operator to demonstrate the dynamic and static performance.

VII. TESTING COMPLIANCE WITH CODE REQUIREMENTS

System Operator has the right to require tests of compliance with network code requirements or national legislation.

The group operator is responsible for testing, in accordance with the conditions of the network code, being responsible for personnel and plant safety during tests. Costs with tests will be borne by the group operator. Decision regarding participation of the system operator to the tests and how this participation will be, is at the sole discretion of the transmission system operator.

Generating unit must prove the technical ability to continuously vary of the active power in order to contribute to frequency control and must check the tuning parameters such as insensitivity, droop, dead band, control bandwidth, and dynamic parameters, including response to frequency variations. Tests are performed by applying frequency steps in order to activate at least 10% of the maximum active power exchange, taking into account the dead band and droop settings. Simulated frequency deviation signals are injected simultaneously on both speed and power regulators, if those exist. Tests are considered good if they meet the following requirements: test results for both dynamic parameters and for the steady state are in accordance with the requirements of the Code and there are no unredeemed oscillations after shifting step response.

VIII. CONCLUSIONS

After the enter in force (at 17.05.2016) of the network code on requirements for grid connection of generators, as Regulation 613/2016, Transelectrica starts the developing of a Technical Norm for establish the no exhaustive requirements specified in the Code and the local requirements. Those norms will include, at least:

1. Classification of generating units in four classes A, B, C and D.
2. Introduction of fault ride through requirement not only for RES (as it was in NT 30 and NT 51) but also for classic units (synchronous) with low power (Class B and C, between 0.8 kW and 10 MW).
3. Introducing of the requirements for voltage control by imposing areas like U-Q/Pmax adjustment, for both RES power plants and classic units.
4. Data exchange between the generating unit and TSO is established both for online and offline information including the obligation to provide the TSO of the mathematical model of the unit.
5. Settlement of the obligation to perform tests with simulated signals to prove compliance of the unit / wind power plant with code requirements.

BIBLIOGRAPHY

[1]. "UCTE Operation Handbook", Version 2.5E, Union for the Coordination of Transmission of Electricity (UCTE), Brussels, Belgium, 20 July 2004.

[2] "Manual Time Error Correction Standards", Standard # WEQBPS-004- 000, Version 0, Draft 3, NAESB, 15 January 2005.

[3] "The Grid Code", Issue 3, Revision 29, National Grid Electricity Transmission, Warwick, U.K., 1 September 2008.

[4] "Active power control în the UCPTE system. Inventory", Version 2.5E, Union for the Co-ordination of Production and Transmission of Electricity (UCPTE), 1991.

[5] "Final Report - System Disturbance on 4 November 2006", Union for the Co-ordination of Transmission of Electricity (UCTE), Brussels, Belgium, January 2007.

[6] “Five Good Reasons to Abandon Synchronous Time Control”, Yann G. Rebours, Member, IEEE, Julien Pestourie, and Etienne J. Monnot Powertech

[7] “Monitoring of generating units’ contribution to Frequency and Voltage Control”, P. Juston, F. Guy, S. Henry, P. Bertolini Powertech

[8] Roşca P. – Electronic measurements, sensors and transducers, Ed. Alma-Mater, 2002;

[9] Industrial energy - 1451 b - 9 - Creţu Nicu Cătălin.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#81

Voltage control in substations with many generation units injection

[1]D. ILISIU*, [2]D. FIRICA
[1]CNTEE Transelectrica S.A. – NDC Bucharest, [2]University “Politehnica of Bucharest”
[1, 2]Romania

SUMMARY

Large Wind parks connected in a same connection point as Fantanele Est, Fantanele Vest and Cogealac (600 MW) connected in S 400/110 kV Tariverde, Verbund and Land Power (225+84 MW) connected in 400/110 kV Rahman and Crucea Nord+ Targusor+N.B. Targusor (108+119.6+59.8 MW) in Substation 400/110 kV Stupina, offer a voltage control in them connection point at 400 kV level. Paper deals with stability and control issues of those wind farms. All wind farms provide three types of control: active power control in relationship with the balancing market, the voltage control at 400 kV level and, in some cases, reactive power control at level of each feeder connected into 110kV. The paper deals with the voltage control at 400 kV level. Detailed dynamic model of the wind farm an equivalent of the transmission system are presented, the test results and the behavior in normal operation. Paper used wind turbine models (with variable speed and pitch control) and generators models (generators with full power converters), voltage/reactive power controller models and tap changers.

KEYWORDS

Wind power plant, Conformity tests, Voltage and reactive power control, voltage controller model

INTRODUCTION

Paper deals with control issues of large wind farms, typically behaviour from voltage and reactive power control point of view.

Wind farms Fantanele and Cogealac are presented as well as Wind farms from Stupina due to different type of tyrbines and voltage controllers. The paper describes principles of voltage and reactive power control in both substations. The requirements for wind farm grid connection regarding reactive power supply are also described.

Results of conformity tests and real operation are presented in last Section.

CEE Fantanele and cogealac example

The 400 kV Tariverde substation is designed to be a power substation for the wind power plants (WPP) in the area, WPP Fantanele East has an installed capacity of 85 MW (34 turbines of 2.5 MW), WPP Fantanele West 260 MW (104 turbines of 2.5 MW) and WPP Cogealac 255 MW (102 turbines of 2.5 MW). One – line diagram is shown in Fig. 1.

* doina.ilisiu@transelectrica.ro

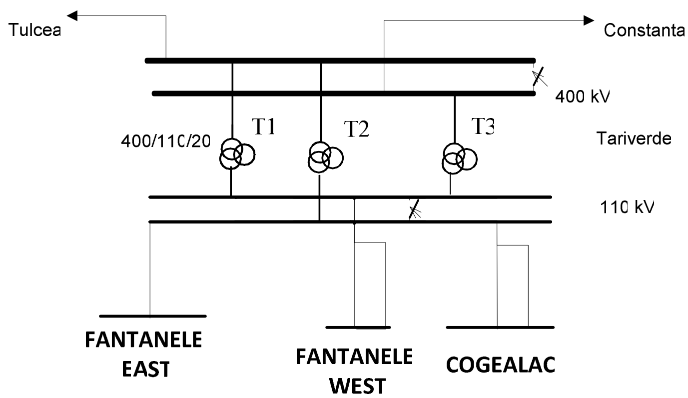


Fig. 1. Simplified one line diagram of 400/110 kV Tariverde

The specificity of this WPP is the intermediate connection point in 110 kV which cannot be considered as a public connection point because all three WPPs have the same owner. In this case the connection point was considered the 400 kV where the all three WPPs must fulfill the connection requirements. As regards the voltage and reactive power control, the main requirements should ensure:

- less than 0.95 capacitive/inductive power factor for maximum active power,
- zero reactive power interchange with the system in case of no active power produced and,
- the reactive power and the voltage control for a sending set point automatically recived from National Dispatch Center [1].

The fulfilling of connection requirements starts with the reactive study which provides the V/Q capacity control of WPPs.

The type of wind turbines (WT) is GE 2.5xl from the General Electric manufacturer and it is the largest wind park of GE on shore from Europe (600 MW). The general P-Q curve is represented in Fig. 2 where WindFREE of WT can provide ±1.2 MVAr from P=0 to Pmax, and all others WTs provide 0.9 cap. <cosφ< 0.9 ind. capacity (red lines). In order to fulfill the Requirement of Romanian Code of Wind Farm connection to the grid: “zero reactive power in connection point in case of zero active power produced”. WPP Fantanele East is equipped with 6 WindFREE WT, WPP Fantanele West is equipped with 36 WindFREE WT and WPP Cogealac is equipped with 38 WindFREE WT. The condition of Q=0 at P=0 must be reached by each feeder (Fantanele Est, West and Cogealac) at level of 100kV connection.

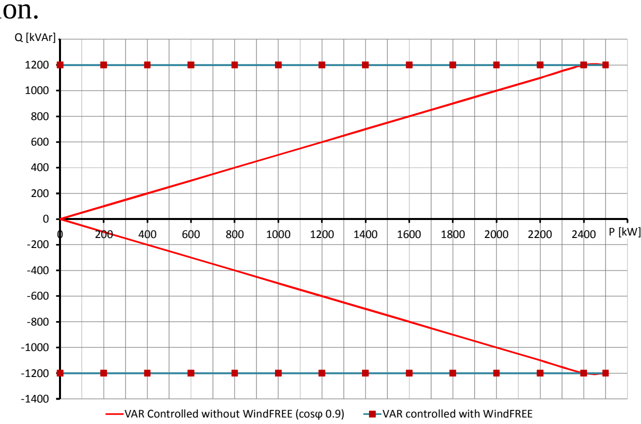


Fig. 2. P-Q capability of WT General Electric

All this reactive power capacity must be provided during the voltage or reactive power control.

The reactive capacity relative to 400 kV connection point must be carried out both for WPP Fantanele and Cogealac. The theoretical P-Q diagrams for WPP Fantanele East and WF Fantanele West is seen Fig. 3.

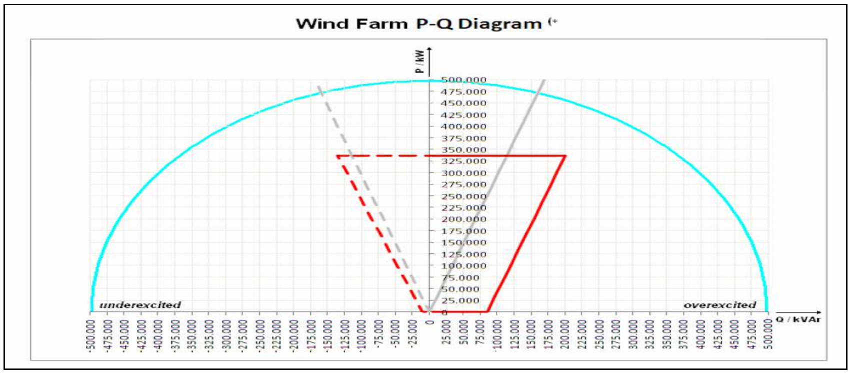


Fig. 3. P-Q diagram for WPP Fantanele East and West in 400 kV connection point

The GE controller (WFMS - wind farm management system) was designed to control both voltage and reactive power of each wind park at a voltage level of 110 kV. It controls the reactive power produced by each WT. Tap changing on the transformers 110/33 kV are solved by means of autonomous automatics. These controls are not sufficient for 400 kV voltage control, therefore the control of the tap changer of the three 400/110 kV transformers is also necessary. The complete voltage regulation is realized by a superior automation named ASRU.

The WFMS of the each WPP are supervised by one voltage controller called ASRU (EGU provider). The principal ASRU schema is presented in the Fig. 4.

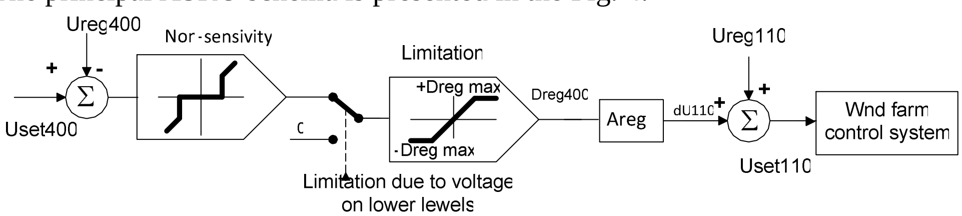


Fig. 4. Schema of the voltage regulation in the 400 kV Tariverde substation

The ASRU is the first level of hierarchical voltage control. Its task is to track, with closed loop, voltage set point sent from NDC (National Dispatch Centre) on the level of 400 kV. The elements controlled by the ASRU are:

- Reactive power controllers of each wind farms as setpoint for WFMS of each WF;
- The tap control of 110/33 kV transformers which belong to each wind farm respectively;
- The tap control of 400/110 kV transformers.

The tap control of 110/33 kV transformers can be integrated either into the ASRU control loop command or into the reactive power control of the wind turbines (WFMS), or by individual controller according dispatcher decision.

The general admitted insensitivity in the 400 kV voltage control is ±0.5 kV and it is the sum of all insensitivities in slave control loops.

The control hierarchy is: the WFMS of all WPPs act first, the taps of 110/33 kV transformers are controlled afterwards and the tap positions of 400/110 kV transformers are controlled finally (all three 400/110 kV transformers are operated in parallel on one 110 kV bus bar).

In the taps control ASRU considers some insensitivity related to the U_{nom}=110 kV voltage: dead band 5%, band of reaction without delay 9% and maximum reaction delay 180s.

Above mentioned principle of the ASRU was slightly changed. Proportional regulator is replaced by PI controller, which distribute reactive power demand (based on relationship reactive power-voltage/coefficient) among particular WFMS. The amount of required reactive power set point is calculated in accordance with wind condition and available active and reactive power of each WF. If reactive power is not available, the required control action is not possible and the control action is stopped.

Take in consideration that this wind farm composed of three WPPs and total installed power of 600 MW represents the largest onshore wind farm with GE wind turbines, the voltage and reactive power control represent the largest voltage control for a wind farm controlling a total reactive power in the range of -300 to +450 MVAr. After the commissioning tests, the voltage control of this connection point operates continuously.

CEE Crucea and Targusor example

The 400/110 kV Stupina substation is designed to be a power substation for the wind power plants (WPPs) in the area, WPP Crucea Nord has an installed capacity of 108 MW (36 turbines of 3 MW), WPP Targusor 119.6 MW (52 turbines of 2.3 MW) and WPP Nicolae-Balcescu Targusor 59.8 MW (26 turbines of 2.3 MW). One – line diagram is shown in Fig. 1.

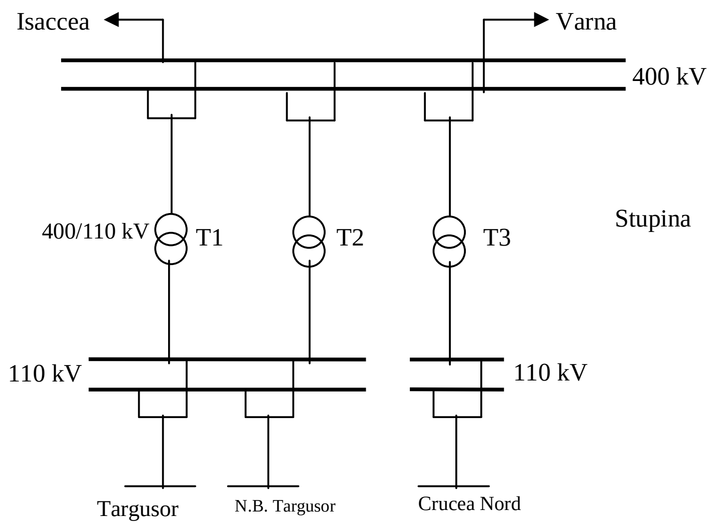


Fig. 5. Simplified one line diagram of Substation 400/110 kV Stupina

All this reactive power capacity must be provided during the voltage or reactive power control.

The reactive capacity relative to 400 kV connection point must be carried out both for WPP Targusor and WPP Crucea Nord. The theoretical P-Q diagrams for WPP connected in Substation Stupina are seen in Fig. 3.

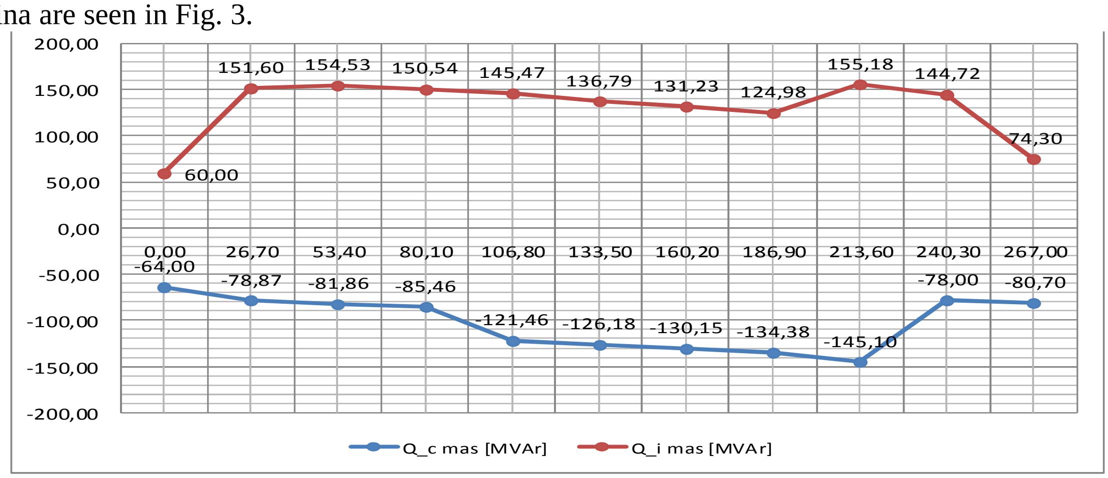


Fig. 6. P-Q diagram for WPP Targusor, N.B. Targusor and Crucea Nord in 400 kV connection point

The wind power plant will be brought out into the transmission system of Transelectrica on the voltage level of 400 kV in the substation 400/121 kV Stupina. The substation Stupina 400/121 kV actually consists of:

- Two bus bars 400 kV
- Two main transformers 400/121 kV (250 MVAr) T1, T2 equipped with tap controllers
- Two bus bars 121 kV – System 12

CEE Crucea Nord is connected directly in 400 kV. Each wind power plant will have in its area its own substation and transformer 121/30 kV with tap changer regulation under load. Usually, tap changers (121/30kV) are in automatic mode controlled by a local rely and monitored by Joint controller (JC) provided by Siemens.

Joint Control (JC) controls only main transformer tap changer of S400/121 kV Stupina. Joint control is a first level of hierarchical control of voltage and reactive power at 400kV bus bar. JC operate at:

1) Level of 121kV bus bar and send to each WPP required Q set point (Q1, Q2).

2) Level of 400kV (WPP Crucea Nord) and send to the system required Q set point (Q3) for CEE Crucea.

JC manages reactive power injected to bus bar from each main transformer and tap changer position. Reactive control makes the distribution of reactive power for each wind farm according to each WF maximum capability from PQ diagram.

When JC is in remote mode, receive set point from DEN of TSO; in local mode receive setpoint from local Joint control operator.

Schema of the JC controller is shown in Fig. 7.

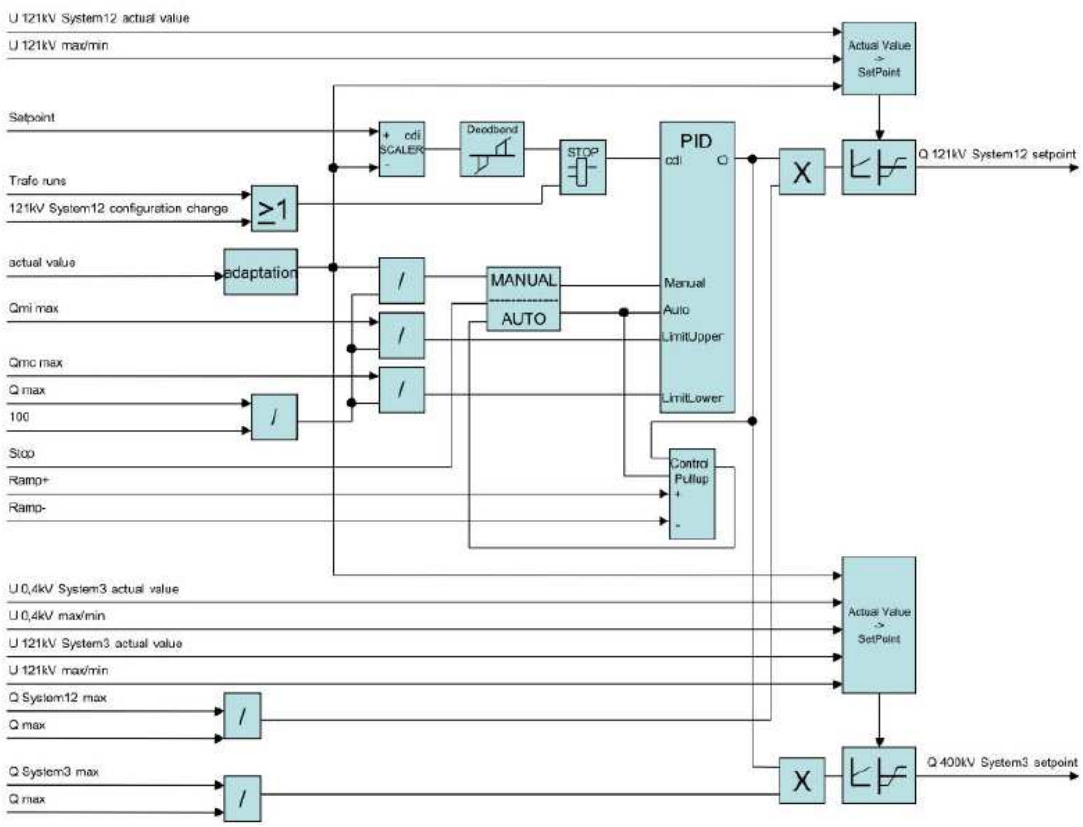


Fig.7. Schema of the voltage regulation in the 400 kV Stupina substation

Compliance test results

Tests of voltage control have been performed on the bus bars BB1-400 kV – Substation Stupina 400/110 kV.

The tests have been performed for the following situations:

All the 3 WPP under JC control and the voltage regulation was performed with command of the JC from DET Bucuresti and Local Dispatch Center (DLC EGPR). Another test was performed as WPP Crucea Nord being under JC control, and WPP Targusor and WPP N.B. Targusor working independently with reactive power control; the voltage control has been verified with Local JC command (Figure 8);

All the 3 WPP under Local JC control; the reactive power has been equally distributed between the 3 WPP. The parameters have been recorded in the following locations: - In the Station Stupina, on the 400 kV bus bar, trafo T3 (Figure 9), In the Substation Crucea Nord on the 110 kV bus bars. The ramp rates of the reactive power: 6 MVAr/min, 18 MVAr/min and 36 MVAr/min.

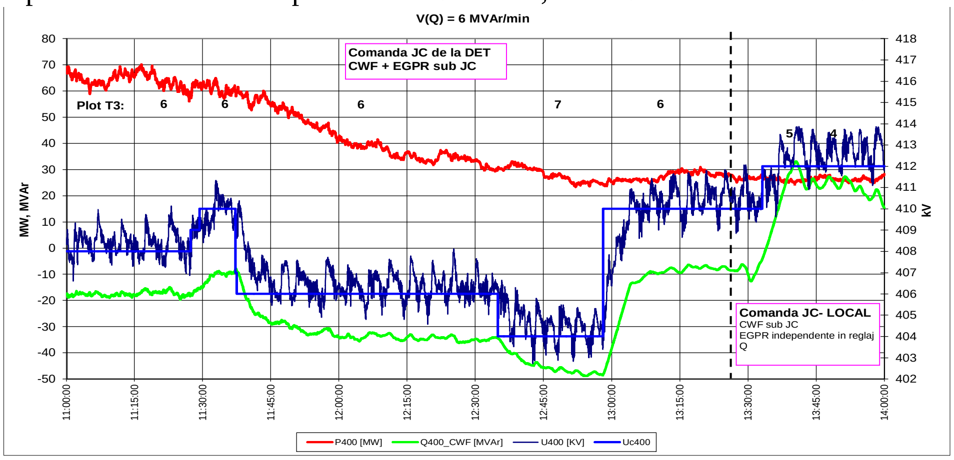


Fig. 8. Test for voltage control in CP

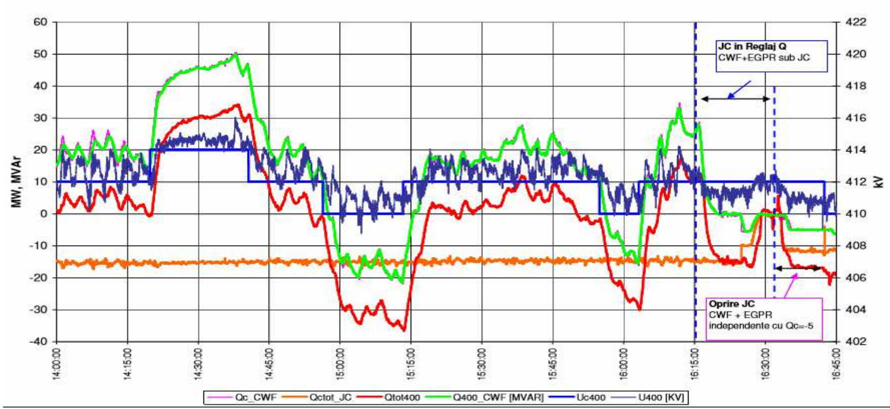


Fig. 9. Tests of voltage control in Stupina Substation 400/110 kV

The following conclusions resulted from the performed tests:

- WPP Crucea Nord being under JC is able to assure, alone or together with the other 2 WPP, the voltage regulation on the 400 kV bus bars, according to the voltage set point

- WPP Crucea Nord being under JC is able to assure, alone or together with the other 2 WPP, the reactive power regulation on the 400 kV bus bars, according to the reactive power set point

- JC divides proportionally with installed power the reactive power set points between the 3 WPP.

Normal operation records

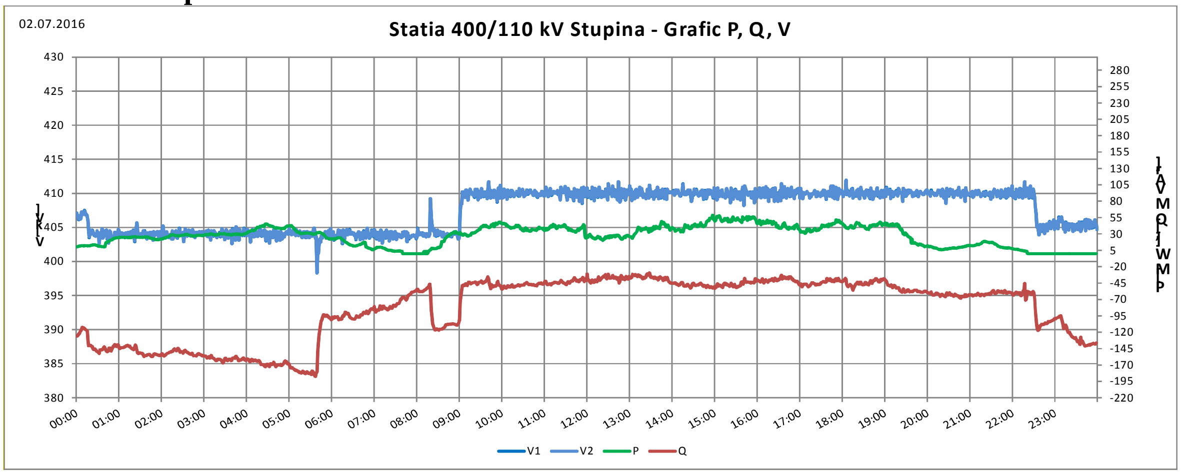


Fig.10. This figure highlights the controllability of the 3 WPP in the CP to almost zero active power. The reactive power absorbed by the three power plants is between 45 and 195 MVAr. It finds the influence of connection /disconnection of 200 MVAr inductor on voltage control of 400/110 kV Substation Varna.

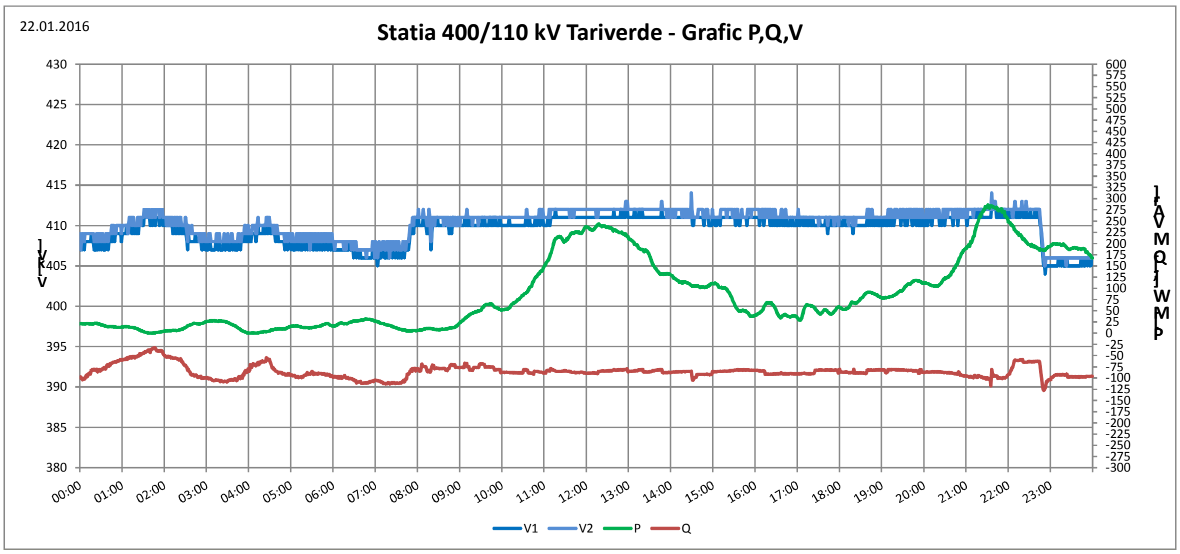


Fig. 11. Highlights the capability to regulate the voltage variations in conditions of big active power variations in WPP Fantanele and Cogealac

CONCLUSIONS

Voltage control represents the normal operation mode of RES connected in high voltage grid. For substations where are connected more than one WPP or PVPP (photovoltaic power plant) is mandatory to create a secondary voltage controller. The paper analyzes two different controllers and substation topology. For both the time real results confirm the correctness and efficiency on voltage variations.

Current practice highlights that only two voltage set points are necessary to be used during the day and those can be scheduled.

The secondary voltage control needs to be improving for main substations being the necessary level for the third voltage control.

BIBLIOGRAPHY

[1] D. Ilisiu, C. Munteanu, *Integration of the Wind Farms into the Romanian Power System*, CIGRE Integration of wide-scale renewable resources into the power delivery system, Calgary 2009

[2] A. Berizzi, M. Merlo, P. Marannino, F. Zanellini, S. Corsi, M.Pozzi, "Dynamic Performances of the Hierarchical Voltage Regulation: the Italian EHV System Case", the 15th Power Systems Computation Conference (2005)

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#83

The use of computing technologies for the effective management of resources of a modern city- Smart City

B. TATU*
Teletrans SA
Romania

SUMMARY

The paper gives a detailed presentation of the cloud-computing model and how it could help to solve the challenges that occur out of the need of creating intelligent cities (SmartCity), intelligent energetic grids (Smart Grids), efficient transportation systems, as well as efficient human interaction and adequate analysis or interpretation of the huge data amount in various fields. Presentation of the CityNext concept.

KEYWORDS

SmartCity, cloud-computing, SmartGrid, IoT (Internet of Things), ICT (Information and communication Technology), DA (Data Analytics)

INTRODUCTION

The Smart City concept is trying to include multiple secure technological solutions in view of a better management of the resources and the needs of a modern city. These technologies can lead to a better crisis management in situations such as natural disasters or arsons, by minimizing the reaction time of all the factors involved, due to the simultaneous access to information. A facile access to certain resources may lead to the accomplishment of this desired goal.

For this purpose, cloud technologies provide complex and secure solutions that could help the exchange of information among different factors involved. A SmartCity model can be designed around public services such as: the energetic sector, various governmental entities, the transportation system, health, schools, buildings and agriculture. Such a model cannot be created without an efficient informatics and communication infrastructure (Information and Communication Technologies – ICT).

Next, we will concentrate on these 2 directions namely, how such an informatics model that would manage the information received from the factors involved could be developed and how these factors can interact using a modern and efficient telecommunication system. At Smart City Expo World Congress 2015 in Barcelona the importance of using digital systems in the main sectors of a city has been underpinned “If you can digitize the analogue, you can digitize the city, and now we are seeing the application of the internet of things (IoT), smart apps and the amazing ability of the cloud to store, manipulate and analyze the massive volumes of data”. [5]

* btatu@teletrans.ro

“Cloud-computing” concept – SmartCity implementation

The National Institute of Standards and Technology gives the following definition of cloud computing:

“Cloud computing is a model for enabling ubiquitous, convenient, on-demand network access to a shared pool of configurable computing resources (e.g., networks, servers, storage, applications, and services) that can be rapidly provisioned and released with minimal management effort or service provider interaction.” [16]

The creation of a unitary platform for smart city using cloud computing technology which would include the information provided by the various factors stated above could be a viable solution. A major benefit of this technology with direct relation to the SmartCity concept would be that the user does not need a very highly-performing computer in order to operate a complex database, even if such operations need such systems. The access to cloud is made very easily and the users in various locations can take advantage of the great power of processing data without investing very much in technology or employee training. Cloud computing involves four technologies, namely: virtualization technologies, security, and programming and data management.

The model of services provision

Cloud computing is implemented in three models: Soft as service (SaaS), Platform as service (PaaS) and Infrastructure as Service (IaaS). [16] Each model offers different calculation services.

- **Saas** – offers business applications used individually or simultaneously by more companies. The best example is the e-mail services relying on the same principle: the provider hosts all the programs and all the data in a certain location and it offers the final user the access to them by means of the internet. In this model the clients do not buy the software but they rent it for use paying only for as much as they use. Usually the service is full, including the hardware, the software and the support. The user has access to the service by any authorized means.
- **Iaas** – offers on-line processing or data storage capacity. This service is ideal for big companies that need a great power of processing or very big storage capacities for a certain project (in testing media- for example). Iaas has the capacity to process and store data, to offer networking and other fundamental calculation resources, allowing the clients to implement and run various types of software which may include operation systems as well.
- **Paas** – Offers a medium of development for application developers. They offer tool packages and standards for development, as well as distribution and payment channels. This allows for the fast programming of software applications and the distribution on several pre-established channels, in order to efficiently attract clients. The development platforms are hosted in cloud and they are accessed by means of a browser.

The implementation model

The cloud computing models are offered to the clients in three forms of implementation: public, private and hybrid.

The private cloud model (internal) is used, for example, by a company. It can represent more departments within the same company. In order to improve the way of using the work stations virtualization, the already existent servers are used. A private cloud also involves the provision and the measurement of components which will allow for the rapid changing of components where necessary.

The public cloud model (external) is based on providing the resources by means of internet, simultaneously for more users, the clients share, in this way, the applications, the processing power, and the storage capacity.

The hybrid cloud model is a combination of the models mentioned above. The companies can run applications in the public cloud, while the data and the private applications are stored in the private cloud.

Advantages/Disadvantages

Avantages	Disadvantages
Cost –the data migration towards the cloud may be a cheaper solution because of the multitude of hardware and licences involved.	**Cost** – Because of the multiple needs a business has, and thus requiring permanent chnge, the cost of cloud implenentation could be higher and higher.
Storage – the traditional solution of owning the hardware could prove more expensive than renting cloud space	**Security** – even if the centers work hard to maintain a high level of security, still, securing the communication paths to the data centers could turn out to be problematic.
Access – the authorised users can access the company data anytime and from anywhere by means of an internet connection.	**Privacy** – many cloud providers keep the data in different cities, states or even continents, where the legislation regarding security and privacy of data differs from the one in the user's country, which can lead to various problems.
Speed– Hardware instalation can cost a company time, while in cloud, everyting is ready to use in minutes.	**Speed –** the upload time may be too big for daily usage, when the company transfers big files.

Interest fields for SmartCity

Energy – Due to the raising concerns regarding energy consumption, it is necessary that the electrig grids models be modernized and adapted to the new necessities. Thus, the concept of Smart Grid appeared, a network which shoud meet the following requirements, starting from the source to the consummer.

- **Real time support for various services** – a real time support service which should be avalabe 24/7, even in case of damage in cerain points. This requiremnet is alredy met by the present cloud technologies, but the problem of delay in the communication paths of the internet providers is still present.
- **Damage tolerance support -** cloud services offer this kind of support by the implemention of sophisticated virtualization, replication and other technologies, in case of multiple damage to servers.
- **Data security** – the data used in a cloud system for SmartGrid need to have the highest level of protection. Unfortunately, the present services do not meet this requirement but , in the future, there will be platforms dedicated to various such fields.
- **Provision of internet routing** – Due to the fact that there are still interruptions in internet connectivity, for a SmartGrid type of network, it is necessary to create a mechanism that would insure safe paths for acessing cloud services.
- **Open Application Programming Interfaces (APIs): -** Necessary in order to interconnect various applications and equipment specific for SmartGrid (metering infrastructure, intelligent counters, programmable Controllers (PLC) wireless networks, portals).

One can notice the fact that around the network that involves the energy providers and the transportation system of high and medium voltage, a very secure communication system must be provided, versatile and tloerant in case of damage, so that the communication should not be jeopardized.

The implementation of cloud computing model for SmartGrid networks is, at the moment, only at the theoretical level, but the interest is raising together with the need of high calculation power, of huge amount of data storage, all of them happening in real time. Due to its scalability ant to its flexibility, as well as its capacity of managing huge data quantities, the cloud computing model may develop and adapt to the necessities of a SmartGrid network, by sloving all the problems that have been identified.

Tourism – another important domain is tourism, from the perspective of attracting as many tourists who will spend as large amounts of money as possible. Thus, a series of applications that offer visitors a great amount of information which helps them find taxis, bars, landmarks, and other attractions as fast as possible, in their area, has been developed. Also there is a series of applications, which process big amounts of data provided by a series of sensors in the city which, along with the information from the audio/video surveillance systems from important objectives, create profiles using artificial intelligence and suggest various itineraries depending on the budget, free time and preferences. Among these applications one can count:

Smart destination – it offers the visitors itinerary suggestions based on a series of information received from the city sensors

Emotion recognition with artificial intelligence – based on algorithms in the field of artificial intelligence and facial/age/sex/ feelings recognition they create dedicated offers for visitors. For the local authorities and for the governmental ones, a series of applications intended to make their work easier, to offer transparency towards the citizens and to offer information for business developers are provided.

Transportation system – An intelligent system meant to make car parking more efficient has been implemented in Barcelona where, with the help of a complex network of sensors, and of some web or smartphone applications, the inhabitants and the tourists may see, in real time, the situation of parking spots available inside a certain area.

Also, in Barcelona, they have implemented an intelligent system of making the public transportation more effective. All the transportation means and the stations are interconnected and offer real time information. Such systems have started to be implemented in our country as well, In Bucharest, Sibiu, Timisoara.

Intelligent roads – many projects that aim for the traffic flow decongestion based on information provided by various sensors are implemented in many cities of the world. Another idea is awaiting for imlpementation, namely, the illumination of roads and highways only when there is trafic. This would certainly lead to energy savings.

Another initiative concerning the intelligent ways has been taken by the Great Britain Government transportation Department, which is developing a pilot project by implementing a Wi-Fi sensor network along A 14 motorway which will render the traffic surveillance, warning systems, speed limitation systems and payment systems more effecient.

Another developing segment is the one of electrical vehicles which automatically involves creating a charging network for these vehicles. Still, due to the limitation of manufacturing technologies for rechargeable batteries, the solutions for this field would still be the hybrid vehicles (electrical energy and fuel).

Public services: -- an innovative system concerning garbage collection has been implemented in Barcelona involving the use of intelligent containers that help collecting garbage more efficiently. The system is based on ultrasonic sensors that identfy the filling degree of containers, regardless of the form or structure of the materials from inside, and send all the information through mobile telecommunication using a SIM card. Thus, the company would use the collecting system more efficiently knowing the degree of container filling.

CityNext

In July 2013, the beginning of a global program was announced that aims to implement a platform for SmartCityes. The idea behind this is using cloud technologies, smartphones and data analysis(DA- data analitycs), social networks for creating thriving cities.

CityNext aims to gather together information from different fields such energy, infrastructure, water provision, tourism, social services, education, as well as local administrations, to manage this information and to provide it to users.

After several years, some solutions to the major problems that the big cities face have been identified.

Here are some important achievements:

Smart Grid Networks
Residual and potable water management
Energertic System Management
Carbon emissions control

Smart Grids in Issy-Les-Moulineaux, France– a consortium formed by more companies in the field of utilities, constructions, sofrware, as well as other fields have launched ***IssyGrid*** – an experiment through which more citizens and buildings owners have been introduced into a system of energy monitoring, an experiment whose result was 10 to 20 % drop in energy consumption.

Intelligent buldings
Public illumination
Waste management
Urbanism

Smart Buildings in Seattle, WA, US **-** IT companies have designed an application to monitor and optimize the energy consumption in the central part of the city aiming to reduce the consumption with up to 25%.

Traffic management
Fleet management
Taxation systems managemeny
Parking systems management
Airports, railways, harbors.

Taxation system and traffic management in Tijuan China – the solution that has been implemented has succeeded in improving and the trafic conditions and the payment of tollways in less than 3 seconds.

Sureveilance systems
Crisis management
Police
Judicial system management

Public safety- Ogden, Utah, US – in a partnership among IT companies, an application has been developed which offers real time information to the police officers on duty.

Mobile Tourism Apps
Library Management Systems
Tourism Portals
Destination Management Systems

Tourism Portal in Luxor, Egipt –application developed by some IT companies for spotting touristic destinations and providing information on landmarks (virtual tours, hotels, restaurants etc)

Electronic communication and messaging services
Managerial education systems
Education management systems
Increasing university education efficacy

Increasing university education efficacy in Bangkog, Thailand – one university in Thailad has implemented an efficient electronic system for student management, for application registration, management of libraries and credits count.

Public health system
Home medical assistance
Wellness
Pandemy management
Primary medical assistance

Public health Hague Sysyem **-** a cloud-based technology has been developed for medical staff useful for knowledge exchange and medical projects management.

Taxes and fees collection systems
Document management
Public services: portals, applications
Open data

Taxes and fees collection system Buenos Aires, Argentina – is an application that reduces the time for acessing and processing various types of forms and that creates a better transparency in the citizen-local authorities relationship.

As mentioned above, such a system can be useful in case of disaster, when it is essential for the various governmental institutions and the citizens to collaborate within a short time frame, or for the easy acess to vital information in certain situations. The applications for smartphones and real time location tracking systems may provide vital information to people in critical situations.

A pilot project is being developed in Barcelona where an application is used that can be installed on the mobile phone providing real time information about population density fluctuation in various areas, about the unemployment rate and available housing, in order to facilitate decisions involving business opportunities and real estate tendencies.

Such partnerships are being developed in other cities such as Auckland, Buenos Aires, Hainan Province, Hamburg, Moscow, NewYork and Philadelphia .

CONCLUSION

According to Forbes, five big cities have managed to implement smart City technologies in various fields [17]:

1. Barcelona –intelligent parking and environment protection systems
2. New York – intelligent illumination and traffic monitoring systems
3. London – technology and data management
4. Nice – environment protection systems and authorities interaction
5. Singapore – intelligent traffic monitoring system

This proves the growing interest that governments have for the SmartCity concept. According to IDC (International Data Corporation) by 2017, at least 20 governments will have created projects and will have allocated budgets for the SmartCity concept.

There is a growing interest for this field as more and more IT companies have been developing solutions for all that concerns IoT, SmartGrid or SmartCity.

Still, despite the various efforts and despite the number of pilot projects in various stages of development, one can notice the lack of a unitary implementation strategy for Smart City technologies which could lead to security risks or to data protection flaws. Also, the lack of common strategies among governmental institutions could cause the creation of duplicate projects resulting in faulty resource management.

Another danger is the huge amount of data that can enter in a SmaryCity system at a given time. This amount if information may come from the governmental institutions or from independent sources. The management, the storage the interpretation of data coming from various sources- sensors, smart phones, GPS - may be difficult and may create faulty forecast. An example of independent application is ***waze*** an application for navigation and traffic with the biggest community that shares traffic information saving time and money for many commuters.

It is estimated that the new approach to the future of cities will contribute to energy efficiency and to environment protection and that it will generate a new economic environment. Also, through the development of the new concepts of intelligent homes, home comfort will rise and the use of electrical or hybrid cars will reduce the negative impact on the environment.

BIBLIOGRAPHY

[1] Antony T. Velte, *Cloud Computing - A Practical Approach*, (McGrow-Hill, 2009)
[2] Barrie Sosinsky, *Cloud Computing Bible,* (2011)
[3] Dan Pritchett, *BASE, an ACID Alternative ACM Queue*. (July. 2008).
[4] enterprise.microsoft.com
[5] eu-smartcities.eu
[6] IT Control Objectives for Cloud Computing: Controls and Assurance in the Cloud, (WITCOC 2011)
[7] Ivanka Menken, *Cloud Computing: The Complete Cornerstone Guide to Cloud Computing Best Practices,* (2008)
[8] Janina Popeanga, *Cloud Computing and Smart Grids* (www.dbjournal.ro/archive/9/9_6)
[9] Mark McGranaghan, Jim Glass, *Vision for Smart Grid Telecommunications Infrastructure – CIRED* 2015 Lyon, France.
[11] Keith Banwaith, *SmartGrid Telecommunications*
[12] Mircea Eremia, Lucian Toma, *Catre orasele inteligente ale viitorului – "Smart Cities"*. (www.agir.ro/buletine/2048)
[13] Sadia Fayyaz, *Handling Security Issues for Smart Grid Applications using Cloud Computing Framework,* (Journal of Emerging Trends in Computing and Information Sciences VOL. 3, NO. 2, February 2012)
[14] Stelian Gal, *SmartCity Sibiu Romanian Energy Centre*
[15] Werner Vogels, *Eventually Consistent.* ACM Queue. (December 2008).
[16] uptothecloud.6dg.co.uk
[17] www.forbes.com
[18] www.idc.com
[19] www.smartcitiesprojects.com
[20] Yogesh Simmhan, Mike Giakkoupis, Baohua Cao, and Viktor Prasanna, *On Using Cloud Platforms in a Software Architecture for Smart Energy* (www-scf.usc.edu)

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#84

Improving Back-up Protection Systems in Power Grid Using Wide Area Synchrophasor Measurements

A. MIRON[*1] M. DRAGOMIR[2] R. PENTIUC[1], C. POPA[1], C.E. BOBRIC[1]
[1]University of Suceava, [2]CNTEE Transelectrica SA
Romania

SUMMARY

Synchronized phasor measuring technology are becoming an important element of wide area measurement systems used in protection, monitoring, and control applications. Phasor measurement units (PMUs) are power system devices that provide synchronized measurements of real-time phasors of voltages and currents.

Current differential protection used today on a large scale to protect power systems is a simple protection, sensitive, acting only to short circuit inside the protected zone, having absolute-selectivity using information from two ends of the protected area.

In the paper a new method is proposed for *back-up protection* of 400 kV transmission networks from East and North-East Area of Romanian Power Grid, based on synchrophasor measurements.

According to the International Electrotechnical Vocabulary, *back-up protection* is intended to operate when a power system fault is not cleared, or an abnormal condition is not detected, in the required time because of failure or inability of other protection to operate or failure of the appropriate circuit breaker to trip. The *back-up protection* is, by definition, slower than *main protection*.

The principle of the proposed protection scheme [1], [2] consist of in comparing inside a system protection center of the positive sequence voltage magnitudes at each bus substation during fault conditions to detect the nearest bus to the fault. Then the absolute differences of positive sequence current angles are compared for all lines connecting to this bus to detect the faulted line. The new technique depends on synchronized phasor measuring technology with high speed communication system and time transfer GPS system.

KEYWORDS: back-up protection, Phasor Measurement Unit (PMU), Global Positioning System (GPS), Phasor Data Concentrator (PDC), synchrophasor.

INTRODUCTION

Every power system is subjected to permanent or transitory disturbances created by random load changes, by faults created by natural causes and sometimes as a result of equipments failure.

When a disturbance in the power system occurs, control and protection system must pick-up to stop the power system degradation, restore the system to the normal state, and minimize the impact of the disturbance [1],[3],[4].

Phasor Measurement Units (PMUs) are the most accurate and advanced synchronization technology devices. They gives information about the current and voltage phasor, frequency and rate

[*] alexandrumiron49@yahoo.com

of change of frequency (ROCOF), these all information are synchronized with a high accuracy to a common reference time provided by Global Positioning System (GPS) [5], [6].

The accuracy of synchronization is better than one microsecond, and the set of measurements provide a real-time snapshot of the state of the power system. The advent of this technology has been made possible by advancements in computer, networks and processing technologies and availability of accurate GPS signals. These all technological growth is opening the gateways of rapidly approaching era where all metering devices will be time synchronized with high precision and accurate time tags as part of any measurement [5], [7].

Synchronized phasor measurements have offered solutions to a number of complex protection problems. These include the protection of series compensated lines, protection of multi-terminal lines, and the inability to satisfactorily set out-of-step relays [8].

Phasor measurements are particularly effective in improving protection functions which have relatively slow response times. For such protection functions, the latency of remote measurements is not a significant issue. For example, back-up protection functions of distance relays and protection functions concerned with managing angular or voltage stability of networks can benefit from remote measurements with propagation delays with latencies of up to several hundred milliseconds [8], [9].

The paper provides a new technique for wide area protection (WAP) using PMU. This paper introduces protection scheme depending on comparing positive sequence voltage magnitudes the bus bar substations and positive sequence current phase difference angles for each interconnected line between two substations of power system. The measurements are processed in a system protection central (SPC). This capability is used to set up a wide area control, protection and optimizing the platform by means of new fast communication system and (GPS) [1], [2].

AN OVERVIEW OF CONVENTIONAL PROTECTIONS

One of the main conditions imposed to electrical installations is the operation safety, i.e. continuous power supplying of consumers. Ensuring uninterrupted operation of the electrical systems is particularly important, because the disturbances in functioning may have very serious consequences and also, the electrical installations are more exposed to faults than other types of installation.

The gravity of the disturbances consequences comes firstly from the fact that a fault occurred in a power system could affect the functioning of the entire system, and secondly, from the fact that it can lead to extremely high destructive effects.

Protective relaying, as a branch of the power system, has the role to detect the phenomena that occur in power systems and which could disturb the normal functioning, proceeding to the isolation of the system parts of the system that are the seat of these phenomena. By isolating these perturbations from the rest of the system, it is allowed to continue system functioning under the previous normal conditions, or in slightly less good conditions, by limiting the disturbing phenomena to a smaller part of the system.

In this regard, the distance protection [10], [11], [12], can meet the above conditions being a universal and complex protection, which can be used in networks of any configuration without transmission channels or a very low number of channels as well.

The distance protection is a protective measure the distance between the jobsite protection and the fault, tripping the circuit breaker with a delay greater as the distance to the fault is greater. Therefore the time of operation of the distance protection is function of the distance between the jobsite protection and fault location. The purpose of any distance relay is to provide the main protection for own line and backup protection for all adjacent elements of power system.

This variation in time by distance is achieved in stages or zones (fig. 1). Zone 1 protection is set to trip with no intentional delay. This zone must under reach the remote end of the line, since it is not possible to distinguish the exact location of fault near the remote bus. Zone 1 is usually set to reach 80% to 90% of line length. Zone -2 relay protect the rest of the line length (delayed with 0.3 to 0.5 sec), and zone – 3 relay provide 100% backup to all adjoining lines.

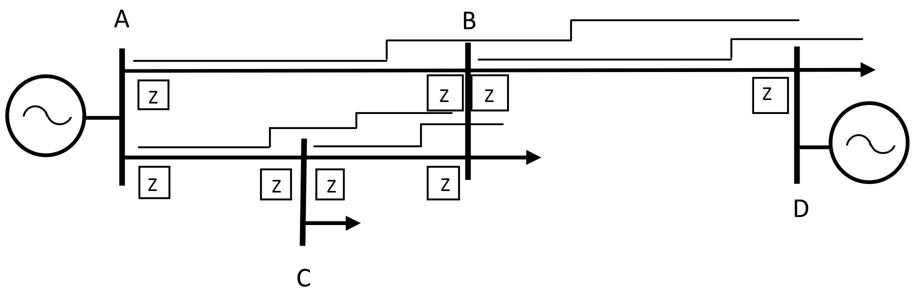


Fig. 1. Three zones of operation for each stand alone relay [1], [4].

The malfunction of protection devices and unwanted trips are considered as the main cause of propagate of major disturbances in the power system. As pointed out above, the backup protections pick-up when the primary protection fails to operate or when the primary protection is temporarily out of service [1].

In this paper is presented a new backup protection system for East and North- East Area of Romanian Power Grid.

For this reason, every substation must be installed PMUs (fig. 2), the communication of data among protection systems being achieved by optic-fiber networks, developed along the 400 kV overhead transmission lines using the OPGW and the OPUG cables [4]

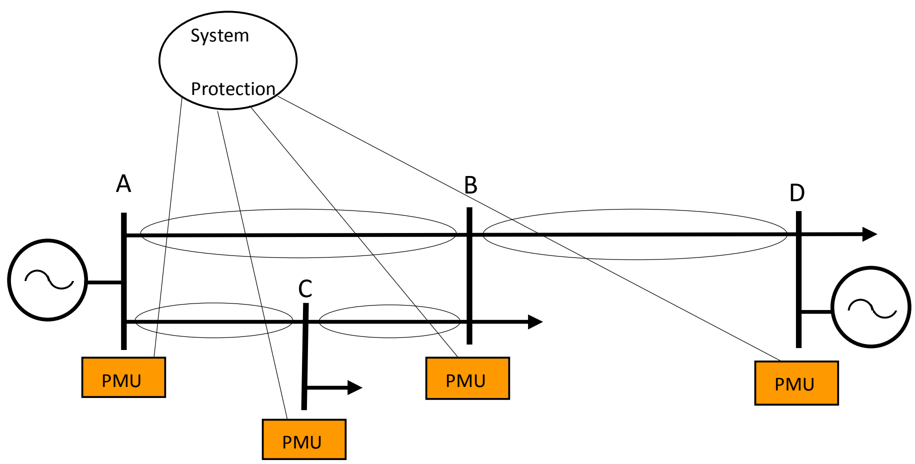


Fig. 2. The new protected zones of the proposed relay [1], [4].

OVERVIEW OF PHASOR MEASUREMENT SYSTEMS

The phasor measurement unit (PMU) is the basis of any synchronous phasor measurements system Understanding its capabilities and limitations is key to understanding the possibilities of wide-area measurement and control. Various characteristics of PMU gives him a multitude of applications in transmission and distribution power systems. Synchrophasors offer the precise time synchronized measurements of different parameters of electrical networks by means of devices called phasor measurement units (PMUs). The phasor is a vector which has magnitude, direction and sense, mathematically represented by a complex number characterized by amplitude and phase, corresponding to the respective quantities of a cosine function. The cosine quantities represented by phasors, in a common diagram, have the same frequency. [3, 9].

An alternative wavelengths can be represented by a mathematical equation (1) [8]:

$$x(t) = X_m \cos(\omega t + \varphi) \tag{1}$$

where: X_m- sinusoidal waveform amplitude,

ω = 2πf - angular velocity that depends on frequency and
φ - original wave angle relative to a reference.

The root mean square (RMS) value of the input signal is ($X_m/\sqrt{2}$). Equation (1) can also be written as

$$x(t) = Re\{X_m e^{j(\omega t+\varphi)}\} = Re[\{e^{j\omega t}\}X_m e^{j\varphi}] \tag{2}$$

Commonly the term $e^{j\omega t}$ is suppressed, understanding that frequency is ω.

The sinusoid of Eq. (1) is represented by a complex number X known as its phasor representation:

$$x(t) \leftrightarrow X = (X_m/\sqrt{2})e^{j\varphi} = (X_m/\sqrt{2})\,[\cos\varphi + j\sin\varphi] \tag{3}$$

A sinusoid and its phasor representation are shown in Fig. 3

In the Figure 1 the reference is a fixed point in time (such as time = 0). The phasor magnitude is related to the amplitude of the sinusoidal signal [8, 13, 14]. Analytical expression of the phasor symbolic form, is typically represented as: $\underline{X} = X_m\angle\varphi$.

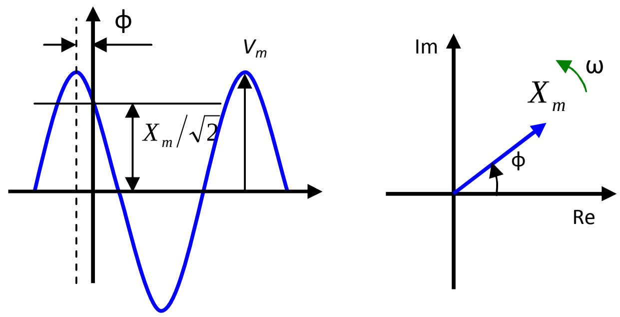


Fig. 3. Phasor representation of a sinusoidal waveform [8, 9, 14].

Theories and achievements of phasor measurement have already been discussed in detail in reference [8, 9, 14, 15].

Connections of PMU to the GPS antenna for receiving accurate time, and to secondary circuit of instrument transformers for measuring the primary system [analog] voltage, V_B, and current, I_L, are shown in fig. 4,[13].

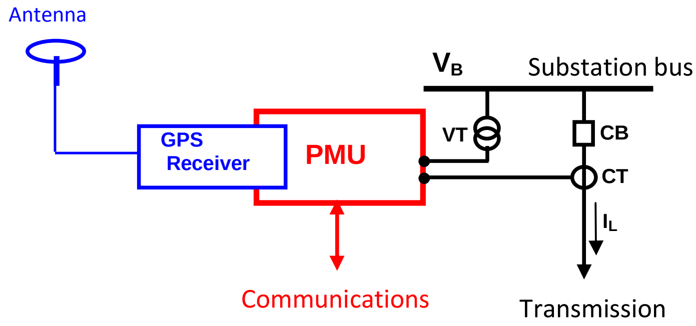


Fig. 4. Phasor measuring unit connections [13]

Each PMU simultaneously measures voltage and/or current phasors (amplitude and angle) that are synchronized with GPS time stamping with 1.0 μs accuracy.

The data from all connected PMUs with identical time-tags are collected, synchronized and archived by the Phasor Data Concentrator (PDC) to other client application for display, analysis and control.

The Standard for Synchrophasors for Power Systems, IEEE C37.118 serves as excellent sources for understanding the fundamentals of the Global Positioning System (GPS) and timing as it relates to synchrophasor measurement [19]. It also addresses other technical issues that must be considered in the implementation of the synchrophasor measurement device often referred to as the Phasor Measurement Unit (PMU).

THE ANALYZED NETWORK

Synchronized Phasor measurement of voltage and current at different nodes of power system is important measurement technique real-time of power systems.

The Phasor Measurement Units (PMUs) installed in important nodes of power system, sent data (bus voltage magnitude, voltage phase angle, frequency, line currents) by dedicated communications channels to a Phasor Data Concentrator (PDC) at the control center [1].

The function of the PDCs is to gather data from all PMUs, reject bad data, align the time–stamps, and create a coherent record of simultaneously recorded data from a wider part of the power system. There are local storage facilities in the PDCs, as well as application functions which need the PMU data available at the PDC. This can be made available by the PDCs to the local applications in real time [8].

Also, the PDC exports these measurements as a data stream as soon as they have been received and correlated, to a System Protection Center (SPC) which make a wide area protection [1], [4], as shown in fig. 5.

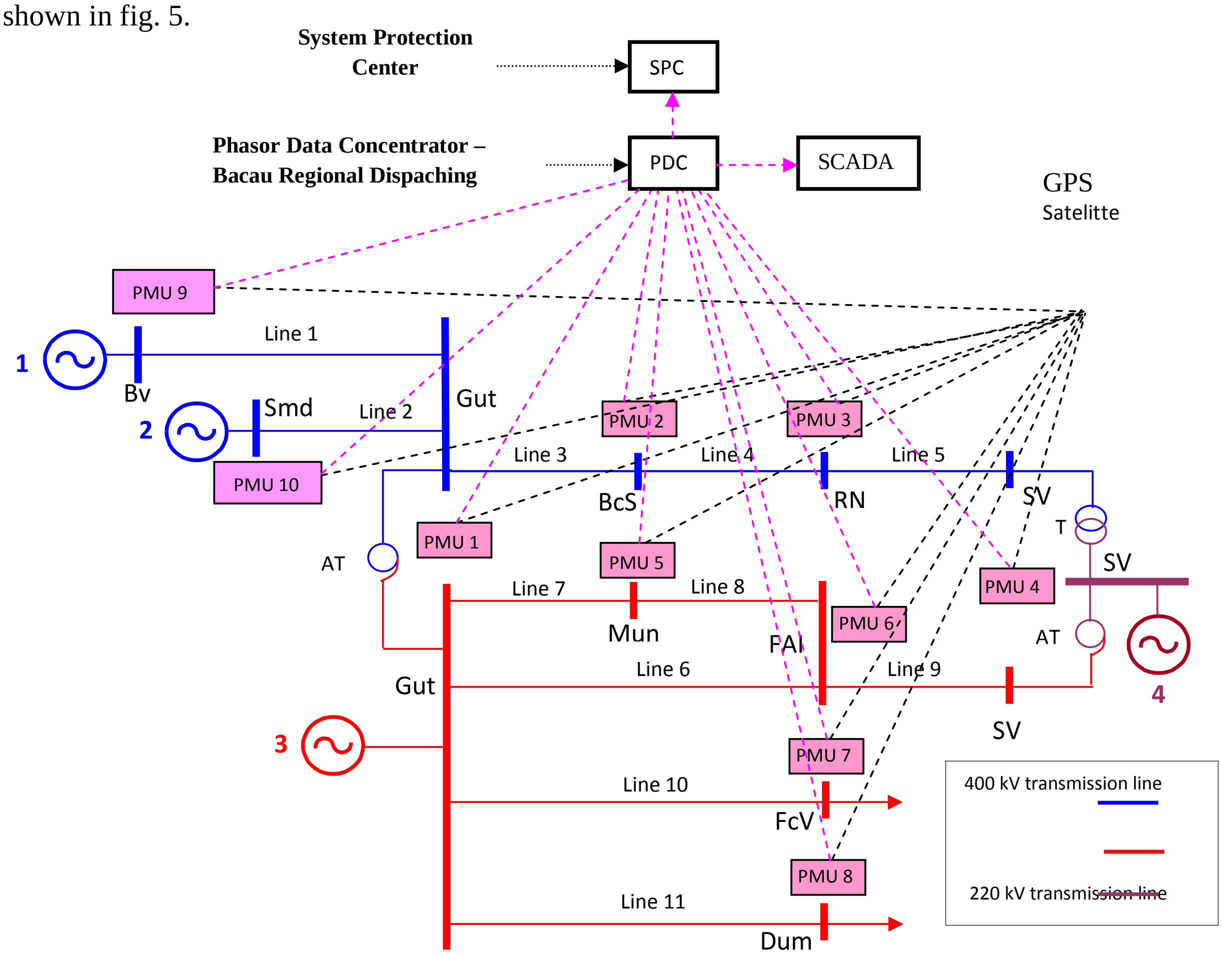


Fig.5. Single line diagram for WAPMC in the East and North-East Area of Romanian power grid [4].

Table 1. The lengths and angles of the lines

Line	Terminals		Length (km)	Voltage (kV)	$\lvert\Delta\varphi\rvert$
1	Gut	Bv	124	400	$\lvert\varphi_{GBv}-\varphi_{BvG}\rvert$
2	Gut	Smd	136	400	$\lvert\varphi_{GS}-\varphi_{SG}\rvert$
3	Gut	BcS	55	400	$\lvert\varphi_{GB}-\varphi_{BG}\rvert$
4	BcS	RN	59	400	$\lvert\varphi_{BR}-\varphi_{RB}\rvert$
5	RN	SV	99	400	$\lvert\varphi_{RS}-\varphi_{SR}\rvert$
6	Gut	FAI	190	220	$\lvert\varphi_{GI}-\varphi_{IG}\rvert$
7	Gut	Mun	117	220	$\lvert\varphi_{GM}-\varphi_{MG}\rvert$
8	Mun	FAI	74	220	$\lvert\varphi_{MI}-\varphi_{IM}\rvert$
9	FAI	SV	116	220	$\lvert\varphi_{IS}-\varphi_{SI}\rvert$
10	Gut	FcV	87	220	$\lvert\varphi_{GF}-\varphi_{FG}\rvert$
11	Gut	Dum	89	220	$\lvert\varphi_{GD}-\varphi_{DG}\rvert$

For analysis of proposed method has been used the 400 and 220 kV transmission network in East and North-East Area of Romanian Power Grid represented by 10 substations and over 1140 km of transmission lines. In table 1 the lengths of the lines are represented in km and $\lvert\Delta\varphi\rvert$ as the absolute difference between the positive sequence current angles measured at the ends of the line [1].

Fig. 6 shows the positive sequence current angles $\angle\varphi_{mn}$ measured at transmission line terminals.

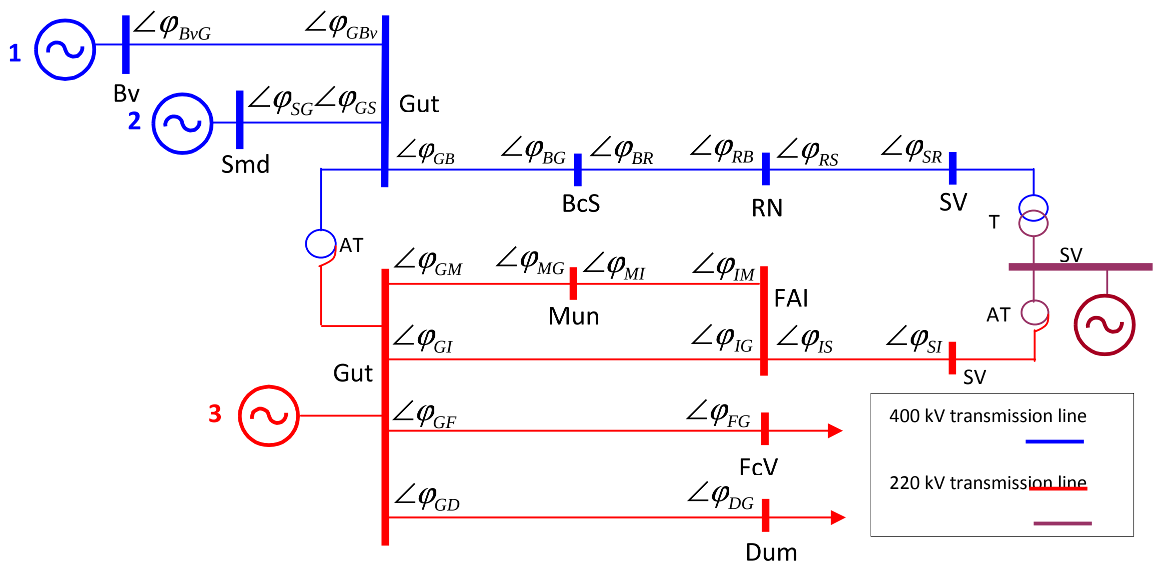


Fig. 6. Positive sequence current angles [4].

THE PROPOSED TECHNIQUE

In [1] and [2], Eissa et al., propose a new technique for backup protection of the transmission lines based mainly on two components to identify the faults on the lines. The first component is the low voltage that occurs due to fault and which is measured on the substation busbars where is connected the line. The second component is the power flow direction on the line after fault occurrence.

When the short-circuit occurs, the circuit impedance suddenly decreases to the *Zsc* value and short circuit currents flowing between the source and location of the fault reach high values. Short circuit currents are out of phase angles φsc to phase voltages, where

$$\varphi_{sc} = tan^{-1}\frac{X_{sc}}{R_{sc}} \tag{4}$$

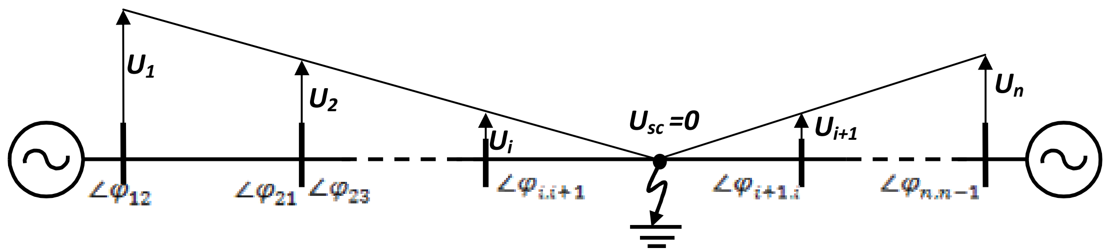


Fig. 7. The variation diagram of the voltage to the short-circuit place

The angle values *φsc* depend on the type and parameters line (for overhead lines, φsc = 20° to 80°). For a metallic three-phase shortcircuit, the phase voltages become zero at the fault site (Usc = 0), and as we approach the source the voltages increase with impedance (fig.7).

Referring to fig. 7, it can be seen that

$$\begin{aligned} &U_i < U_{i-1} < \cdots < U_2 < U_1 \\ &U_{i+1} < U_{i+1} < \cdots < U_{n-1} < U_n \end{aligned} \tag{5}$$

Three-phase short-circuit current is calculated using positive sequence scheme, the reactances of this scheme are equal with positive reactances, e.m.f. of the sources are the positive sequence and the short circuit currents are also the positive sequence currents..

The phase angle is used to determine the direction of fault current with respect to a reference quantity. The voltage is usually used as the reference quantity. To distinguish between a fault occurs in one direction or another, it is necessary to compare the phase angle of current to the reference voltage [1], [16], [17], [18].

The normal power flows in a given direction will result in the phase angle between the voltage and the current varying around its power factor angle ±φ. In the normal operating the line current flows at one end from the busbar to the line and at the other end from the line to the busbar, so that the difference between the phase angle of voltage and current from both ends of the line will be close zero. In the event of a fault on the line, the current from one end of the line changes in the opposite direction (at the end of the current flows from the line to the busbar), and the phase angle becomes (180^0 + φ). In this case, the difference of phase angles at the two ends of the line will be maximum (about 180^0) [1], [18].

The proposed method is to identify the faulty line, this being achieved by comparing amplitudes of positive sequence voltages for each substation on the main busbars. Minimum values of the voltages indicate faulty line that is connected to the two substations. In addition are compared, differences of the absolute phase angle of the positive sequence current on all lines. Maximum angle absolute difference is chosen to identify the faulty line. The line is tripped when the above two conditions are fulfilled [1], [2].

Operating conditions described above, can be described mathematically as [1], [2],

$$Min\{|U_i|, |U_{i+1}|\} \tag{6}$$

where $|U_i|$ and $|U_{i+1}|$ are the amplitudes of the positive sequence voltages measured by PMUs at the substation bus-bars (i) and (i+1) which is connected the faulted line.

The second requirement is to compare the positive sequence current angles absolute differences of lines connected to the substation bus-bars and then selecting the line with the biggest difference angles so,

$$Max\{|\Delta\varphi_{i,1}|, |\Delta\varphi_{1,2}|, \dots, |\Delta\varphi_{i,i+1}|\} \tag{7}$$

where $|\Delta\varphi_{i,i+1}|$ is the absolute difference of the positive sequence current angles from the two ends of the line connected to the substation bus-bars. It can be described mathematically by the relationship,

$$|\Delta\varphi_{i,i+1}| = |\varphi_{i,i+1} - \varphi_{i+1,i}| \tag{8}$$

Relationships (6) and (7) may be logically implemented in fig. 8, [1], [2].

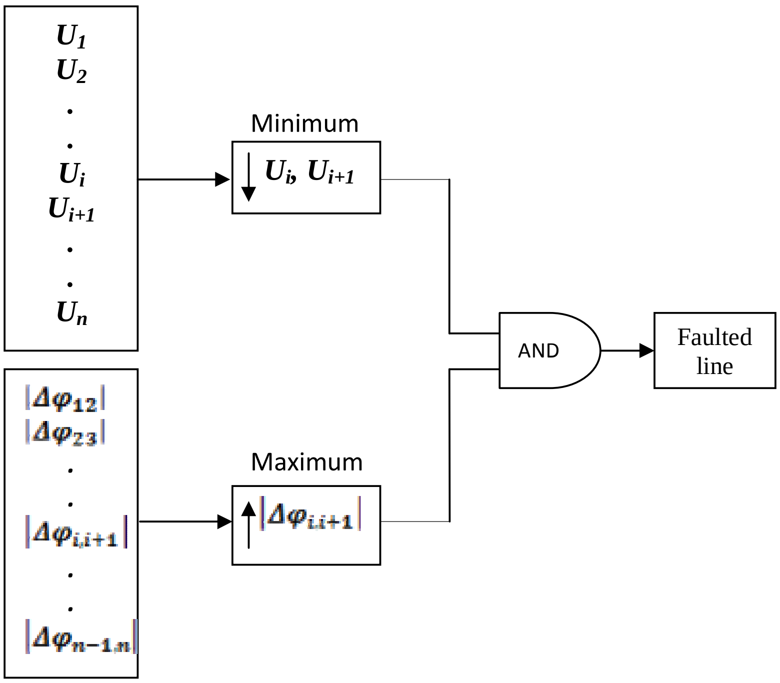


Fig. 8. The logic implementation of the proposed method [1].

SIMULATION RESULTS

To verifying the proposed method, the authors have modeled in Matlab a segment of the 400 kV transmission network from the eastern part of Romania, with 4 equivalent sources and 3 transmission lines of 400 kV, as shown in Fig. 9.

Substation A - Substation Gut 400 kV
Substation B - Substation Bv 400 kV
Substation C - Substation Sm 400 kV
Substation D - Substation BS 400 kV

For the simulation, the paper will only use generic names (Substation A Substation B, etc.)

In each node of 400 kV, it is modeled a equivalent source, as shown in Fig 9.

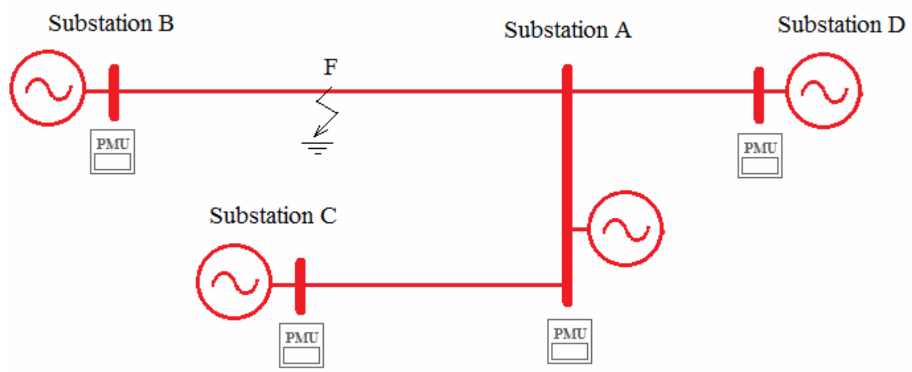


Fig. 9 - The 400 kV modeled grid

The phasor measurement units (PMUs) are placed in substations A, B, C and D and they monitor the voltages at the substation bus-bar levels and the currents which arrive or leave through the substation lines. Each PMU receives analog signals from (CTs) and (VTs) in bay level [1].

• Voltage transformers (VTs) on the main bus (400 kV) of substation. Each PMU receive 3 phase voltage (U_{ABC}).

• Current transformers (CTs) on each line terminal receive 3 phase current (I_{ABC}) to the PMU.

• PMU converts the analog voltage and current signals to digital samples synchronized in time of measuring, the Discrete Fourier Transform method inside PMU calculates the positive sequence voltage and current phasors.

The parameters of the equivalent sources of 400 kV are shown în table 2.

Table 2 – The parameters of the sources

Source	U [kV]	$S_{Short\text{-}circuit}$ [MVA]
A	400	3700
B		4400
C		4200
D		1200

The parameters of the 400 kV overhead lines are shown în table 3

Table 3 – The parameters of the lines

Line	U [kV]	R_1 and R_0 [Ω/km]	X_1 and X_0 [Ω/km]	B_1 and B_0 [S/km]	Length [km]
A-B	400	0,038 and 0,180	0,331 and 1,131	$3{,}4 \cdot 10^{-6}$and $2{,}3 \cdot 10^{-6}$	124,7
A-C					136,3
A-D					55,3

The fault was simulated on the 400 kV line A-B on phase C, at the half distance of the line measured from substation A and it was assumed that the fault resistance was 5 Ω.

The voltages and the currents at the PMU placed on substation A are shown in figure 10 and figure 11 respectively.

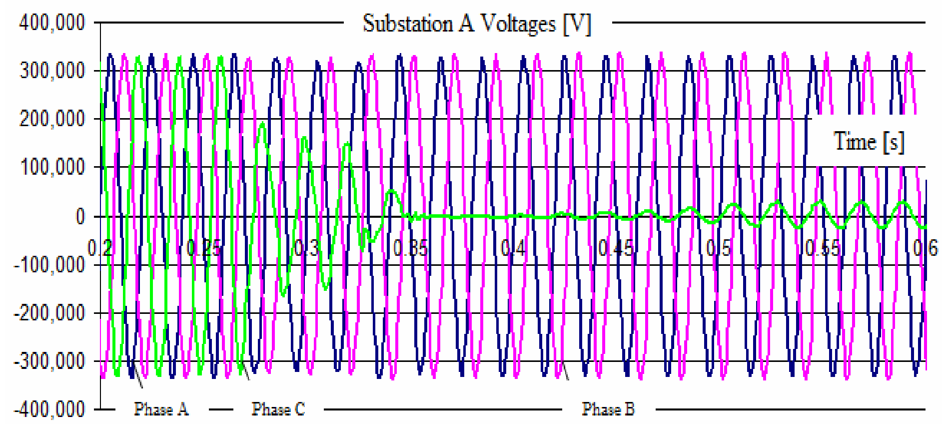


Fig. 10. The voltages at substation A (Gut)

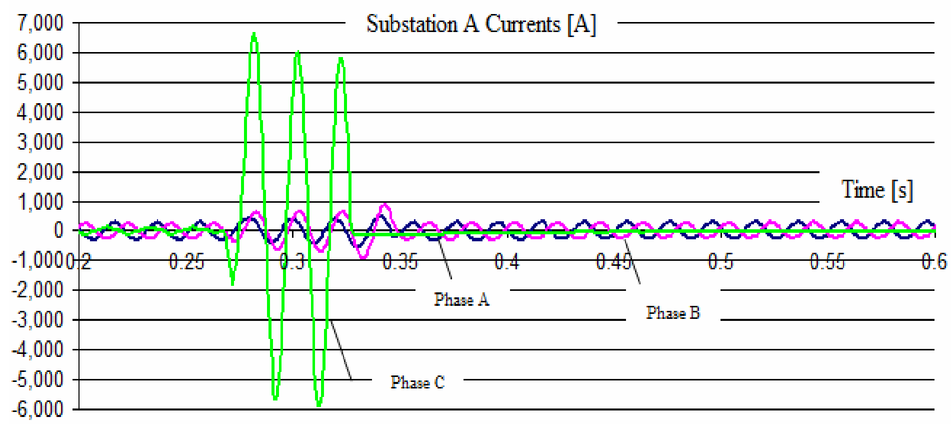


Fig. 11. The currents at the substation A (Gut) on line A-B

The voltages and the currents at the PMU placed on substation are shown in figure 12 and figure 13 respectively.

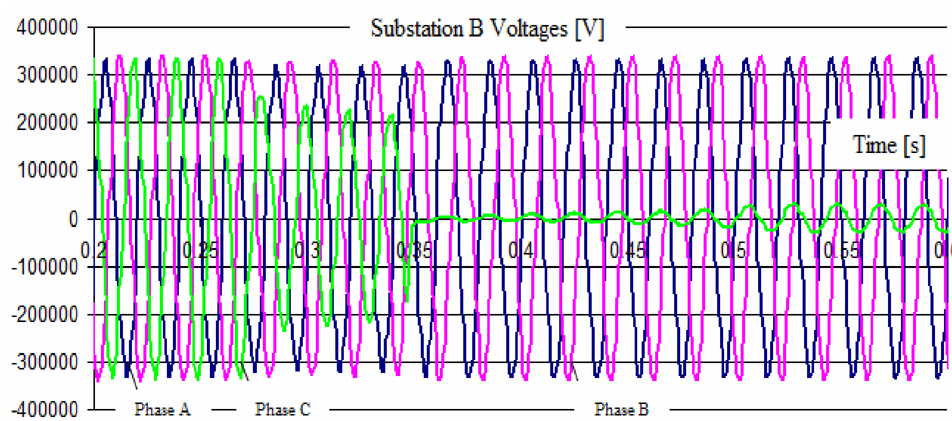


Fig. 12. The voltages at substation B (Bv)

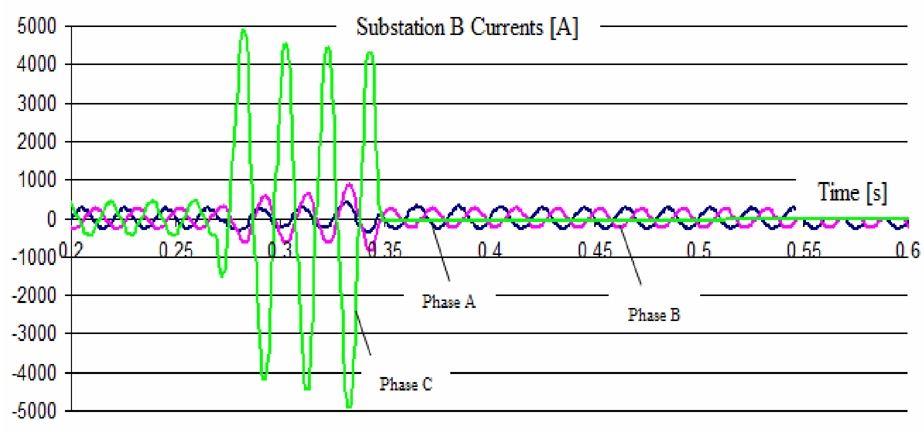


Fig. 13. The currents at the substation B (Bv) on line B-A

In the fig. 14 are shown differences in module between the positive sequence current angles at the ends of the 3 lines. It can be seen that the faulted line (line A-B), the difference is greatest (about 170 degrees). Also in the figure below, we see that at the time of 0.33 seconds, $|\varphi_A - \varphi_B|$ drops to about 95 degrees, because in the A substation the line B is disconnected; in B station the line remains connected until the 0.33 seconds moment, when in the B station the line A is disconnected; after this time, there is not fault current, so $|\varphi_A - \varphi_B|$ drops to 0 degrees.

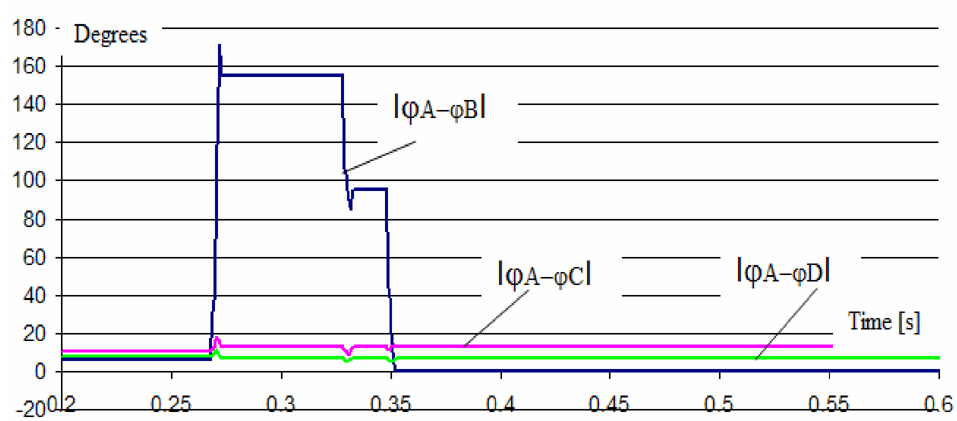


Fig. 14. The positive current argument differences for fault on line 400 kV A-B

CONCLUSIONS

The paper provides a new idea for fault detection using Phasor Measurement Units (PMUs) in a wide area system. This is achieved by [1],[2]:

- comparing amplitudes of the positive sequence voltages measured by PMUs at the substation bus-bars which are connected the line. The minimum voltage value, from two ends of the line indicates the nearest line to the fault.
- in addition, the absolute differences of the positive sequence current angles are calculated for all lines. These absolute angles are compared to each other. The maximum absolute angle difference value is selected to identify the faulted line.

For real-time analysis of protection, control and monitoring of power systems, based on synchronized phasor measurements, has been used the simulation of the 400 kV transmission network from East and North-East Area of Romanian Power Grid, using Matlab modeling.

BIBLIOGRAPHY

[1] M.M.Eissa, M.Elshahat Masoud, M.M.Elanwar, "A Novel Back Up Wide Area Protection Technique for Power Transmission Grids Using Phasor Measurement Unit", *IEEE Trans. Power Delivery*, vol. 25, no. 1, pp. 270-278, January 2010.

[2] M.M.Eissa, M.Elshahat Masoud, „A Novel Wide rea Protection Classification Technique for Interconnected Power Grids Based on MATLAB Simulation", http://www.intechopen.com/download/get/type/pdfs/id/17564

[3] *Wide Area Protection and Emergency Control*, 2002, IEEE Members, Working Group C6.

[4] A.Miron, M.Dragomir, S.Gal, A.Rusu, Gh.Moraru, I.Nedelcu, "Real-Time Monitoring, Control and Protection by Implementation of the PMUs in North- East of Romanian Power Grid", CIGRE, Paris, 2014.

[5] Waheed Ur Rahman, Muhammad Ali, Chaudhry A. Mehmood, Asadullah Khan, "Design and Implementation for Wide Area Power System Monitoring and Protection using Phasor Measuring Units" *WSEAS Transactions on Power Systems*, Issue 2, Volume 8, April 2013.

[6] Mladen Kezunovic, Zheng Ce, "Monitoring Power System Dynamic Performance Using Synchronized Sampling" in *Monitoring of Power System Dynamics Performance* 28-30 April 2008, Saint Petersburg.

[7] R. F. Nuqui and A. G. Phadke, "Phasor measurement unit placement techniques for complete and incomplete observability", *IEEE Trans. Power Delivery, vol. 20*, no. 4, pp. 2381–2388, Oct. 2005.

[8] G. Phadke and J. S. Thorp, *"Synchronized Phasor Measurements and Their Applications"*. New York: Springer, 2008.

[9] J.D.Ree, V. Centeno, J.S.Thorp, and A.G.Phadke, "Synchronized Phasor Measurement Applications in Power Systems", *IEEE Trans. Smart Grid*, vol.1, no.1, pp. 20-27, June, 2010.

[10] G. Ziegler, *Numerical Distance Protection. Principles and Applications,* Publicis Corporate Publishing, Erlangen, Siemens, 2006.

[11] Stanley H. Horowitz, Arun Phadke *"Power System Relaying – 3rd ed."* John Wiley & Sons Ltd. The Atrium, Southern Gate, Chichester, England, 2008.

[12] Y.G. Paithankar, "*Transmission Network Protection. Theory and Practice*", Marcel Dekker, Inc. 270 Madison Avenue, New York, 1998.

[13] Elmo Price, "Practical Considerations for Implementing Wide Area Monitoring, Protection and Control", *59th Annual Conference for Protective Relay Engineers*, 2006.

[14] xxxx, "Phasor Technology and Real-Time Dynamics Monitoring System (RTDMS)" Electric Power Group, Consortium Electric Reliability Techology Solutions.

[15] M. Adamiak, W. Premerlani, B. Kasztenny, "Synchrophasors: Definition, Measurement and Application", *Power Systems 2005 Conference Distributed Generation, Advanced Metering and Communication*, March 8-11, 2005, Madren Center, Clemson University, Clemson, SC, USA

[16] M. M. Eissa, "Development and investigation of a new high-speed directional relay using field data," *IEEE Trans. Power Del.*, vol. 23, no. 3, pp. 1302–1309, Jul. 2008.

[17] M. M. Eissa, "A new digital feed circuit protection using directional element," *IEEE Trans. Power Del.*, vol. 24, no. 2, pp. 531–537, Apr. 2009.

[18] M. M. Eissa, "Evaluation of a new current directional protection technique using field data," *IEEE Trans. Power Del.*, vol. 20, no. 2, pp. 566–572, Jul. 2005.

[19] IEEE Draft Standard PC 37.118, *"IEEE Standard for Synchrophasors for Power systems"*

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#86

T&D Utilities: Implementing a Systemic Asset Investment Planning Strategy

B. JOUFFROY*
The CoSMo Company
France

SUMMARY

Designing and implementing successful maintenance and investment strategies comes with many challenges for utilities. Traditional methods based on extended intuition and know-how supported by simple modeling tools such as spreadsheets cannot cope with the increasing complexity and expectations of today's utilities business environment.

In this context, systemic Asset Investment Planning is being adopted by innovative utilities that want to get a pragmatic and powerful solution to meet their challenges. This new approach enables them to integrate their maintenance and investment strategies and project into a holistic analysis. They can then configure, simulate and compare multiple scenarios in order to better understand and optimize the impact of their decisions on the whole system in the short and long term.

The French electricity Transmission System Operator, RTE, has started implementing this approach, which greatly helps its strategic planners take optimized decisions with already shown significant returns.

KEYWORDS

Strategic capital planning; asset investment planning; systemic optimization; maintenance and investment; transmission and distribution utilities; cost optimization; risk analysis.

1. THE NEW CRITICALITY AND COMPLEXITY OF STRATEGIC CAPITAL PLANNING FOR T&D UTILITIES

Transmission & Distribution (T&D) utilities are responsible for operating, maintaining and investing in their electricity or gas networks. Designing and implementing the right maintenance and investment strategies so as to ensure network performance, reliability and security, as well as low electricity or gas prices is a must do for them. Thus strategic capital planning decisions are key to T&D utilities mission. Nowadays, however, these decisions are becoming even more critical, with new challenges adding more pressure on their quality and justifiability.

First, utilities are facing a wall of investments due to the simultaneous aging of a large part of their assets that were installed in short and successive development phases more than 50 years ago. This massive aging of infrastructure implies potential severe impacts on network and service reliability, and thereby, triggers capital investment requirements. Considering their constrained budget, T&D utilities have to assess and mitigate risk while choosing when and where to invest. What's more, their workforce is also aging, with many capital planning and maintenance experts approaching retirement, which puts utilities under additional pressure to find ways to capture and replace their knowledge.

* baptiste.jouffroy@thecosmocompany.com

Second, the relationship between the T&D's and regulatory bodies are such that more and more requirements are asked from the regulators' side. In particular, regulators demand higher levels of transparency for costs and tariffs, and utilities have to take up the challenge of the wall of investments while striving against limited available funds to meet performance measures in order to gain or maintain credibility with regulators.

Moreover, electricity T&D utilities have to complete the aforementioned tasks on a dynamic network that is undergoing a paradigm shift toward smart grids. Yet smart grids require healthier asset performance and higher operational performance, while their assets are subject to different depreciation curves than traditional equipments. T&D utilities also have to consider the effects of external factors such as climate change on their infrastructure, and make it more resilient to potentially harsh environmental conditions.

Finally, T&D utilities are facing a data tsunami that is complex to leverage. They need to turn this data into actionable investment intelligence in order to support better decision processes.

2. THE LIMITS OF CURRENT ASSET MANAGEMENT PRACTICES

Current asset management practices are not up to these complex challenges. Indeed, the traditional method for planning long-term funding strategy has often been based on extended intuition and know-how, acquired through years of experience by the same experts that are now approaching retirement.

However, intuition has its limits that the simple spreadsheet and home-grown tools (that have been used to support decisions) cannot truly overcome, mainly due to high risk of errors in data entry, poor data availability, and lack of holistic computing capacity.

Moreover, decisions have often been biased by the varying background of employees who take part in decision-making meetings and their oral skills when putting their planning preferences forward.

Finally, the different internal processes have each been aiming to optimize plans independently of each other, which has given rise to operational conflicts and relational tensions.

These practices lead to poor learning from experience, hazardous planning that is difficult to justify to regulators, and sometimes reliability accidents caused by equipment failure, regulated fines due to reliability and performance issues, rejected rate applications and safety incidents.

3. THE EMERGENCE OF ASSET INVESTMENT PLANNING

Current asset management practices are thus inadequate in the face of the growing criticality and complexity of strategic asset planning, and that is why T&D utilities are turning to fact- and process-based methods to help improve reliability and performance and reduce costs and investments. Such methods enable to focus the decision process on data instead of on people, which leads to more rational and explainable decisions. They ease the analysis of the plans and their improvement based on past experience. They also provide a repeatable and auditable process that can ease relations with regulators.

Analytics enable T&D utilities to extract relevant information out of the important amount of available data, discover correlations or patterns to take more informed decisions, react to yet unseen problems, challenge intuition and capture employees' knowledge.

T&D utilities have begun to recognize these multiple benefits and invest in Enterprise Asset Management (EAM) and Asset Performance Management (APM) solutions, which respectively improve asset performance and workforce productivity, and reduce operational costs and risk while improving maintenance planning. These solutions are helpful for short-term planning, however, they are insufficient for strategic long-term capital planning, also called Asset Investment Planning (AIP).

AIP utilizes data from maintenance costs, assets condition, budget, risks and criticality as inputs in order to design capital investment plans on the long term. It enables therefore the simulation of multiple scenarios and assess their impact via relevant key performance indicators, and thereby, compare and select the most appropriate ones.

In such a way, AIP potentially solves most of utilities' growing issues regarding asset management by enabling them to make repeatable and defensible investment decisions, thus gaining trust and approval from regulators.

These decisions ultimately lead to more realistic plans that can be implemented without time or budget excess, and provide better cost and performance optimization while integrating criticality and risk in the decision process. Besides, it enables to capture asset management knowledge and wisdom, gives a better visibility into asset condition, and induces improved data quality.

However, it does not guarantee a holistic approach of utilities' networks which could ideally integrate all the constraints, the relevant processes and couplings that are involved in the decision process.

4. SYSTEMIC AIP

To go beyond these limits, T&D utilities have started to adopt an innovative approach to AIP called *systemic* AIP. This approach takes into account multiple organizational and operational constraints and processes, such as the network (topological) model, human resources, finance, asset management policies, aging, operational planning and risk, and all the couplings and interactions that exist among them. Systemic AIP enables to simulate plans in a most realistic manner and compare them according to all the relevant indicators.

Integration of interconnections in T&D utilities' systems is key to a powerful AIP strategy. Indeed, asset life cycle cost, risk, and performance should not be solely considered at the discrete asset level, since improving the performance of a discrete component does not necessarily lead to better system performance, particularly if that component is not the weakest link in the network or if the latter contains redundancy. A systemic perspective of electricity and gas networks is necessary to better improve overall performance, especially since these networks are particularly complex and are composed of a multitude of components interconnected to each other.

This systemic AIP with a holistic vision of the whole organization of utilities and their constraints, enables users to create globally optimized plans based on information from all the different *silos* involved in the strategy. That can satisfy all of them by finding the best balance among their different objectives and minimizing operational conflicts.

5. CASE STUDY

a) *Introduction and context*

RTE, the French electricity Transmission System Operator, owns and operates the largest electricity grid in Europe:

- 100,000 km of lines from 50 kV to 400 kV,
- 2,600 substations (including 3,900 connected) and their 100,000+ equipment,
- 270,000 towers,
- 1,200 power transformers.

RTE's global annual asset management budget, dedicated to maintenance and renewal, is close to €700 million per year. Their general strategy consists in maximizing asset service life. They have defined 20 technical policies of preventive maintenance, corrective maintenance and enhancement, and renewal. Preventive maintenance aims at delaying the failure and detecting failure risk for preventive intervention. Renewal policies are designed assessing the severity of a potential event according to multiple categories of impact and its frequency.

RTE identified limits in its current approach in the fact that the 20 technical policies were mainly planned independently from each other. Decisions were taken in *silos*, while in reality policies were competing for the same resources. They recognized that the system complexity was beyond human intuitions, with a systemic behaviour mainly determined by dynamic interactions. In order to improve their capital planning strategy, they decided to invest in innovative methods.

RTE chose to call upon The CoSMo Company, who has developed a unique modeling and simulation platform dedicated to *complex systems* and its solution MONA, that has been developed using this platform. MONA is a disruptive systemic AIP solution dedicated to optimizing maintenance and renewal strategies for electric and gas networks. MONA brings a systemic approach to AIP, integrating all operational and organizational constraints (assets, outages and non-delivered energy, human resources and finance) into one single model. Strategic planners can use it to simulate decades of network operations under various scenarios and globally optimize strategies. The first uses of MONA by RTE demonstrate the benefits of using *systemic* AIP for strategic capital decisions.

b) Use case

RTE used MONA to compare three different maintenance and investment scenarios concerning a portion of the French network for three categories of assets: Overhead lines, Circuit breakers and Disconnectors.

- **Scenario 1** is a baseline scenario simulating the global impact of current asset management strategies on the network.
- **Scenario 2** has been designed following the simulation results of Scenario 1. Budgets are reallocated between asset classes and between CAPEX (capital expenditures) and OPEX (operational expenditure). Part of the Overhead Lines CAPEX renewal budget is reallocated to Circuit breakers and Disconnectors CAPEX.
- **Scenario 3** represents a shift in the maintenance strategy for Circuit Breakers and Disconnectors, from a "replace when it fails" strategy to a "replace when it fails for the second time".

Key performance indicators chosen to evaluate the three scenarios are:

- CAPEX and OPEX: cumulated spending (net present value);
- Average quantity of assets failing per year;
- Financial loss due to Non Delivered Energy (NDE)
- Conflicts: number of delayed operations.

c) Results

Simulation results for the three scenarios are detailed in Table 1. Cumulated NDE for the three scenarios is represented in Figure 1.

		Scenario 1	**Scenario 2**	**Scenario 3**
Disconnectors	Failures per year	4	3	3
	NDE (M€)	4,5	1,8	0,8
	CAPEX (M€)	4,1	5,5	5,7
	OPEX (M€)	2	1,4	0,2
Circuit Breakers	Failures per year	5	4	10
	NDE (M€)	12,8	10	78
	CAPEX (M€)	4,9	6,7	6,7
	OPEX (M€)	6,9	4	2,4

Overhead Lines	Failures per year	21	23	23
	NDE (M€)	17,6	22,8	22,5
	CAPEX (M€)	37,2	28,8	28,8
	OPEX (M€)	3,8	3,9	3,8
Total	CAPEX (M€)	46,2	41	41,2
	OPEX (M€)	12,7	9,3	6,4
	NDE (M€)	35	35	101
Total	(M€)	93,9	85,3	148,6
Total conflicts	Nb operations	953	750	733

Table 1. Comparison of scenario results

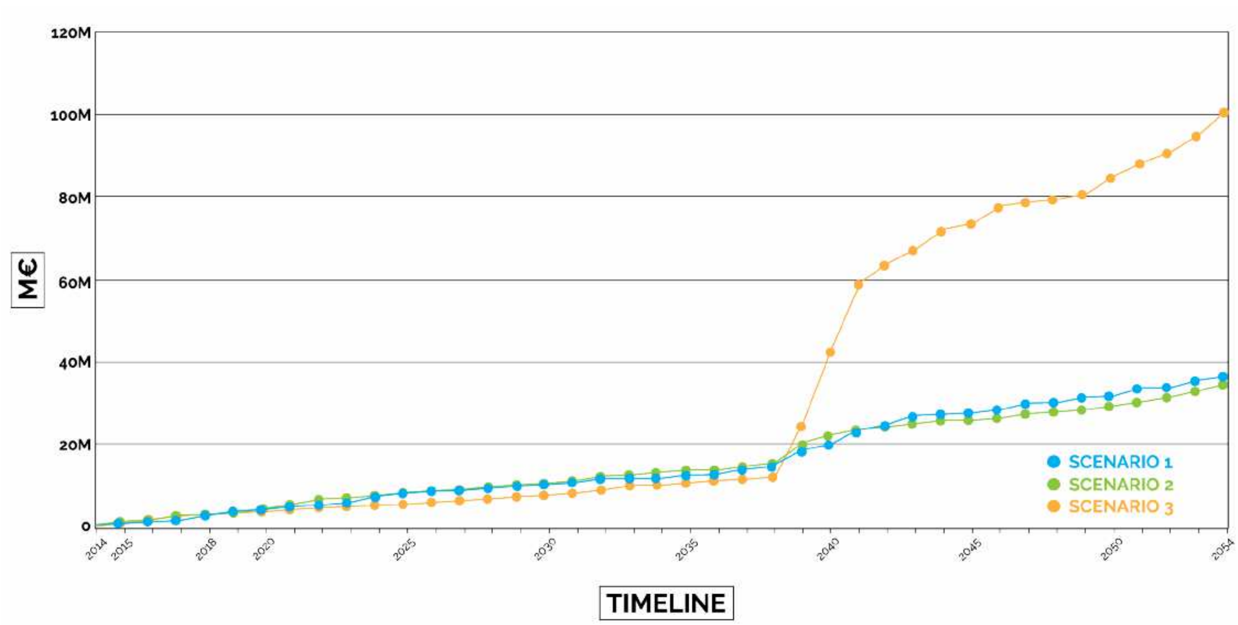


Figure 1. Comparison of cumulated NDE over time

A brief comparison of the scenario results shows the value and relevance of a systemic approach to AIP to optimize the maintenance and renewal strategies of an electric transmission grid.

Indeed, Scenario 2 clearly yields better results in terms of overall cost than Scenarios 1 and 3. Moreover, it appears that Scenario 3 carries a high level of risk, with NDE costs significantly increasing over time. Finally, Scenario 2 also reduces stress on the system, with -20% in delayed operations due to resource access conflicts compared to Scenario 1. This is due to alleviation of resource constraints (budget, lock out, teams, stocks, etc.) thanks to better planning.

A major benefit of using a systemic approach in this particular case is the capture of emergent phenomena that are undetectable for traditional *in silos* approaches. For instance, *non-systemic* approaches could be blind to tipping points such as cascading effects, occurring when one event triggers a sequence of uncontrolled consequences. This can lead to the following vicious circle:

- Recurring failures of overaged equipment cause an acceleration in the pace of operations.
- Lock out constraints required to maintain high service quality and to repair the assets affected by the failures as a priority create new deferrals in renewals.
- Deferrals cause other assets to become over-aged, increasing the size of the wall of investments.

A *systemic* approach to AIP enables to predict these cascading effects and therefore predict their devastating impacts. Moreover, the emergence of a tipping point proves to be very sensitive to small variations in the initial conditions of the system (e.g. budget constraints), and to the way different parts of the system interact with one another. Capturing these transitions requires a simulation of the entire system.

CONCLUSION

This paper has shown that with increasing challenges putting T&D utilities under pressure to better plan their asset investments for maintenance and renewal, these utilities cannot merely continue using their traditional decision making methods. Analytical methods are needed to enable strategic planners to make more optimal decisions optimizing expenditures, performance and risk, and to justify their plans to regulators.

AIP solutions enable their long term strategic plan by simulating multiple scenarios and comparing them according to relevant key performance indicators. However, optimized AIP goes through a systemic view of the utilities' network and their operational and organizational constraints. This innovative approach called *systemic* AIP takes a more accurate view of the impact of scenarios not only on operational and capital expenditure, but also on the risk and reliability of utilities' systems, which ultimately leads to better scenario optimization and planning decisions.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#87

Virtual World Asset Management for Transmission System Operators
What can precise position tell you about your assets?

R. HODDENBACH, P. MENTING, M. COLEMAN, J. BANGAY, and J. BARONIAN*
Fugro Geospatial B.V.
Netherlands

SUMMARY

What if a world existed where an asset manager had a complete picture of network risk and compliance across the entire network, where they could complete inspections, assess asset condition, perform monitoring and explore the impacts of policy changes through simulations virtually before committing in the real world? How could this change the way in which assets are managed?

'Virtual World Asset Management' is the concept of creating and annually refreshing a precise, 3D representation of the real world of such fidelity that these models can be used as a source of asset inspection and condition monitoring without the need to send inspection workers to the field. This allows asset managers to consider many paradigms, enabling them to optimize capital and maintenance programs as well as incident response. The result is reduced operational risk and cost with the added benefit of improved customer service.

Traditionally, network operators gather information about their assets during design and construction phases with updates based on periodical human inspection programs over the asset's lifecycle. Meanwhile the environment surrounding the asset is undergoing constant change and even the asset itself is continually evolving. The information typically collected through infield programs and contained in corporate systems is also limited in its application as it mostly consists of very basic asset attributes and 2D spatial data of variable reliability, therefore impeding the adoption of modern technologies including GPS and augmented reality.

Given the evolution of remote sensing technology, high performance computing, big data analytics, and machine learning, the application of this intelligence and knowledge into meaningful asset management services is now a reality.

KEYWORDS

Power management – network connectivity – vegetation analytics – clearance analytics – thermal calculations – asset condition assessment – 3D power models.

INTRODUCTION

Virtual World Asset Management represents a paradigm shift in the way infrastructure owners engage inspection services relating to their assets. The origin of this idea has emerged in Queensland, Australia where a complete utility's network and 600 towns and cities are now modelled in a virtual world. The corresponding impact to utility infrastructure asset management is rapidly being recognised as international best practice.

A virtual world is modeled using data gathered from sensors deployed in a range of capture platforms. The modelled virtual world needs to be of the quality that it can be reliably used as an

* r.hoddenbach@fugro.com, j.baronian@fugro.com and p.menting@fugro.com

alternative to in-field infrastructure inspection and condition monitoring programs. As a minimum standard current regulatory requirements need to be incorporated.

Providing solutions as hosted services allow asset managers to focus on their core roles without the need to become experts in a new breed of foundational technologies, sensors, high performance computing, and the latest 3D data streaming technologies.

The following utilities have been involved in testing Virtual World Asset Management and the results from these proof-of-concept projects have been included in this paper:

- National Grid - TSO England and Wales - 2015/2016 - 2000 kilometers of their transmission network has been automatically modelled and can be made available in the Virtual World Asset Management environment.
- RTE - TSO France - 150 kilometers of their transmission network was made available in the Virtual World environment and assessed for vegetation clearance violations in an automated manner.
- SSE - TSO Scotland - 2015 - 250 kilometers of their transmission network has been condition assessed and made available in the Virtual World environment.

KEY FOUNDATION ELEMENTS OF A VIRTUAL WORLD ASSET MANAGEMENT ENVIRONMENT:

2.1 3D network model

The first step in building a Virtual World Asset Management environment is the creation of an accurate 3D model of all towers, poles and wires. Next the network connectivity needs to be modeled identifying the existence of network of all voltages currently missing or incomplete in corporate asset systems. Finally, existing schematic and connectivity within these systems needs to be validated. Creating the 3D network model will involve the following:

- A validation of the circuit connectivity for verification and audit of the actual network circuit configuration and line transpositions, including attribute details for each circuit and conductor such as circuit type and voltage, span length, interstructure span and conductor length.
- Inclusion of asset attachments for identifying asset equipment attachments (e.g. transformers, separators, stays etc.) to the electrical networks for validation and updating of these assets in corporate asset systems
- Asset matching for linking data from corporate systems to real-world assets and 3D objects. Additionally it allows shifting of assets in corporate asset systems to their precise in-field location reflecting as-build operating network model location and information. Precise comparison of all poles/towers in the field against corporate asset systems ensuring all poles/towers have actually been historically inspected and maintained (compliance) and verify infrastructure owners and responsibility.

2.2 Vegetation analytics

Local regulatory policies and rules have been implemented and integrated in the Virtual World asset management environment. Additional data has been combined to prioritise on base of load at risk, criticality of load, life-support customers on circuit, previous treatment date, etc.

Utility engineers assess the business rules and associated risk profile via a web-based portal through 3D visual inspection layers and associated analytics.

- Proximity zones for client-defined clearance profiles modeled around the network and power line conductors and pole/tower objects to assess and model the distance and volume of any vegetation encroachments.
- Encroachment assessment for modeling of vegetation identified within proximity zones including encroachment attributes such as distances and volumes.

- Risk analysis for reporting and mapping of areas requiring treatment per span or management region; set by client-defined standards for encroachment and risk category.

2.3 Clearance analytics

As a ground rule for further temperature calculations, clearance in the as-is or as-acquired situation have to calculated to ground, structures, other utility and street level objects.

- Other conductors - Conductor phase-to-phase and circuit-to-circuit assessment and identification of potential breaches and at-risk conductors
- Ground - Conductor to ground proximity and identification of potential ground clearance breaches and at-risk conductors
- Structure - Conductor to structure proximity and identification of potential structural conductor clearance breaches and at risk conductors.
- Rail - Identifies conductors crossing rail corridors and provides conductor clearance assessment of potential clearance breaches and at-risk conductors.

KEY COMPONENTS OF VIRTUAL WORLD ASSET MANAGEMENT TESTED FOR UTILITIES

3.1 Automated tower matching

Within Virtual World Asset Management automated tower matching algorithms uses a mathematical approach to positions the tower in 3D space. This method is independent from client provided information and is therefore more reliable than the manual selection of tower models based on the route schedules.

If differences are detected between the tower model and models from previous baseline, for example differences in insulator length, alerts are provided there has been an as-constructed change affecting the previously understood network operating status, for example clearances impacts under the change in insulator length.

Virtual world asset management gives the asset manager the tools to flag, visualise and analyse anomalies between the as-built information and the actual highly accurate surveyed data. An example can be found in figure 1 below.

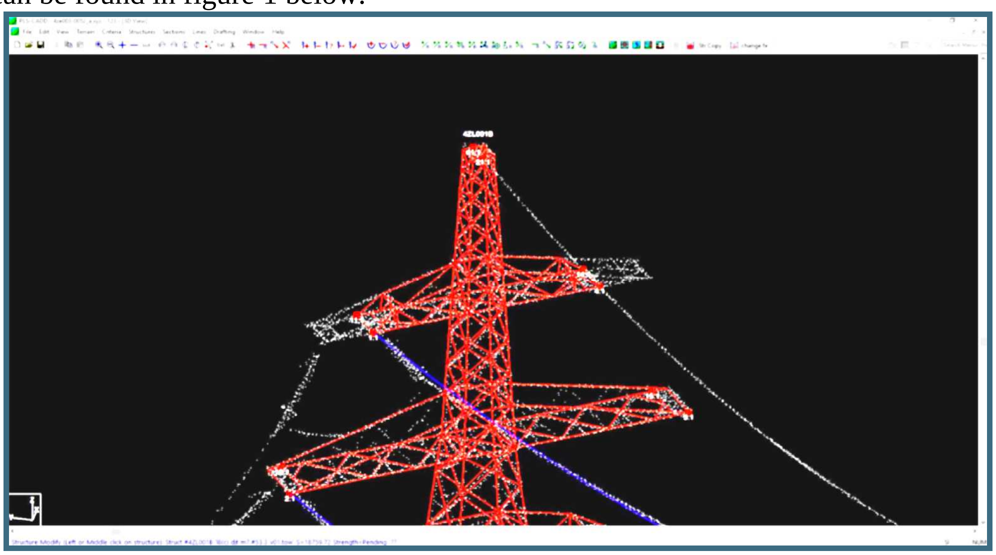


Figure 1: Automated tower models within Roames Virtual World Asset Management System

3.2 Automated design

The conductors and insulators are modeled from the 3D LiDAR point clouds as objects with physical characteristics. The objects are modeled in the state they are in during acquisition. Validation of the methodology is established by mathematical confidence factors which are reported to flag potential modeling errors. Independent validation by traditional modeling has been executed by the utility company.

International standard PLS-CADD models have been bought into Roames Transmission Models for use within the Virtual World Asset Management environment to complete change detection with new baseline modeled from Roames.

Once the structure has been accurately modeled, identifying structural strength and monitoring movement, such as weakened foundations, can be completed.

3.3 Thermal calculations

An IEEE, CIGRE and hybrid technique has been developed and academically published by Roames "Comparison of IEEE and CIGRE methods for predicting Thermal Behaviour of Powerlines and their relevance to Distribution Networks"[1].

For the calculation, collected weather data and utility provided electrical load and conductor type information are used as input together with the thermal characteristics of the conductors.

3.4 Simulations

Different scenarios have been implemented depending on the regulatory rules in regards to vegetation clearance reporting including: ambient position; "normal" position (calculated as the 3D band wherein the conductor would sit >95% of the time); maximum operating temperature; and blown position. Vegetation clearance is calculated relative to a 3D shape rather than a single point, taking into account the sag and swing of the conductors.

Pilot studies have been conducted to evaluate the benefits for a network-wide scenario of virtual world asset management and for those participating utilities, efficiencies were proven in various asset management practices and reporting/auditing and reduction in risk exposure.

Further research is recommended to test the ability to stream in real-time circuit loads for live operating status.

3.5 Asset Condition Assessment

A further element that has been tested is the asset condition assessment and inclusion in the virtual world environment. To be able to supplement the traditional practices of dedicated in-field and aerial patrol inspections millimeter resolution imagery of each structure, precisely positioned to its corresponding 3D object in the virtual world model needed to be achieved.

For SSE, between 4 and 8 images have been provided for each utility structure with over, 1000 structures captured in a single day using airborne sensors. The resulting imagery provides millimeter resolution of the current state of structures, sub-components (including cross-arms and insulators), and attached equipment.

Machine learning algorithms, guided by expert linesmen, analyse the images for defect detection such as corrosion, rot, salt accumulation, insulator, cross-arm, pole attached equipment, and conductor damage.

The conclusion by Scottish and Southern Electricity was that by using virtual world technology they were able to gain an in-depth view of the asset condition and will continue to pursue use of the technology to assist them in developing their refurbishment programme.

CONCLUSIONS AND RECOMMENDATIONS

Through the series of demonstrators with selected transmission system operators in Europe the preliminary conclusion is that Virtual World Asset Management promotes and enables a collaborative approach to asset management through:

- Providing utilities a strong evidence chain in compliance demonstration (data permanently accessible for litigation defense)
- Consistent application of business rules (removal of human subjectivity) in field inspection processes through highly automated and advanced interpretive algorithms which are tuned to detect network condition.

- Availability of enterprise wide consistent data quality supporting strategy development and whole of business risk assessment. The models produced by Roames can be used for a wide range of internal business processes.
- Reduction in the cost of each inspection cycle allowing more affordable shorter cycle inspections, thus providing improved condition sampling, trending and ultimately more highly tuned preventative maintenance programs.
- Reduction in total cost of ownership of Information technology relating to storing, accessing and processing data.
- Improved turnaround time and fault finding by using machine learning capabilities.
- Virtual World Asset Management enables infrastructure providers in the same geography to elect to share and exchange elements of their secure asset details to other authorised critical infrastructure providers without the ambiguity of spatial inaccuracies.

BIBLIOGRAPHY

[1] Comparison of IEEE and CIGRE methods for predicting Thermal Behaviour of Powerlines and their relevance to Distribution Networks. Published in PowerTech, 2015 IEEE Eindhoven, June 29 2015-July 2 2015, DOI 10.1109/PTC.2015.7232531, publisher IEEE.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#88

Modeling of hybrid off-grid energy system for electrical energy production from renewable sources

Constantin UNGUREANU[*1], Cezar Dumitru POPA[1], Stelica BIDU[2]**
Universitatea Ștefan cel Mare din Suceava
[1]Facultatea de Inginerie Electrică și Știința Calculatoarelor
[2]E-ON Romania
Romania

SUMMARY

The growth of electricity demand has led to the development of sustainable energy sources cheap with carbon dioxide emissions as low as possible. The photovoltaic energy offers promising results to this issue. New generations of photovoltaic systems are characterized by more stable parameters which led to increase their efficiency.

The paper presents the structure and modeling of hybrid off-grid electric energy system (HEES) for electrical energy production using two types of renewable sources (photovoltaic and wind turbine energy). It is considered as a backup system a diesel generator. To use the energy excess it was introduced in the HEES block diagram, in addition to electrical load, a thermal load. The location for the proposed HEES is in the north-east region of the country.

The paper presents the results concerning the HEES operation into different seasons of the year. Also, some suggestions to optimize the system operation are presented.

KEYWORDS

Photovoltaic system, wind turbine, electrical load, thermal load, storage battery, modeling.

1. INTRODUCTION

A photovoltaic system can be connected to the national power grid or not. To ensure a certain degree of autonomy, independent photovoltaic (PV) systems (off-grid systems) can be easily designed. Connecting a PV system to the electricity distribution network must meet certain conditions. The correctness connection to the national power grid is an important aspect in the operation of the PV systems or hybrid power systems. In this respect, it must be considered parameters of electricity injected into the grid.

The off-grid PV systems provide a solution for the electricity supply in remote areas. The degree to which the photovoltaic system or hybrid system can meet the needs of the consumer is an important parameter in these applications. The power which is supplied by a renewable hybrid system varies continuously being influenced by solar irradiance, ambient temperature, in fact, by the meteorological conditions.

Any hybrid system, regardless of its type, must submit a control strategy that reflects the operation and interaction of its components. In the case of a hybrid storage system must used a solar charge controller. The charge controller is used to manage the flow of energy from photovoltaic

[*] costel@eed.usv.ro,
[**] cezarp@eed.usv.ro

system, wind turbine, batteries and consumers by collecting information about the voltage across the battery. Also, a solar charge controller must ensure the battery charging control and to display the charge status of the battery, ensuring the discharge control up to a default state of charge and protect against overvoltage and short-circuit.

2. GRID-CONNECTED AND STAND-ALONE PV SYSTEMS

Two types of grid-connected photovoltaic systems are known: without battery storage and with battery storage.

Grid-connected PV systems (Fig. 1.1) are designed to operate in parallel with the electric utility grid. The main element in the system is the inverter. The inverter transform DC power into AC power with the power quality requirements of the utility grid and stops supplying power to the grid when the utility grid is not energized. A bi-directional interface is necessary between the PV system output circuits and the electric utility network. At night, when the electrical loads are greater than the PV system output, the balance of power required by the loads is received from the utility grid.

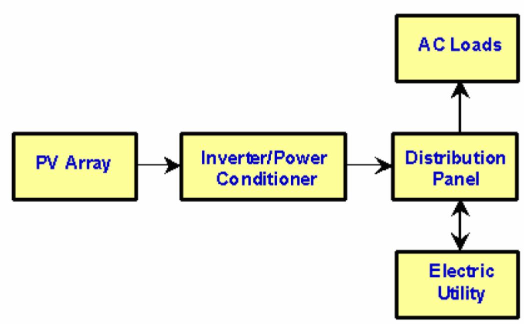


Fig. 1.1 Grid-connected PV system without battery storage [1]

Grid-connected PV system with battery storage (Fig. 1.2) is a very popular system for homeowners where the backup power is required for different applications: water pumps, refrigeration etc. Under normal circumstances, this type of system operates in normal grid-connected mode powering the loads or sending excess power back onto the grid while keeping the battery fully charged. In the situation when the grid becomes de-energized, control circuit from the inverter opens the connection with the utility through a bus transfer mechanism and operates the inverter from the battery to supply power to the loads circuits only.

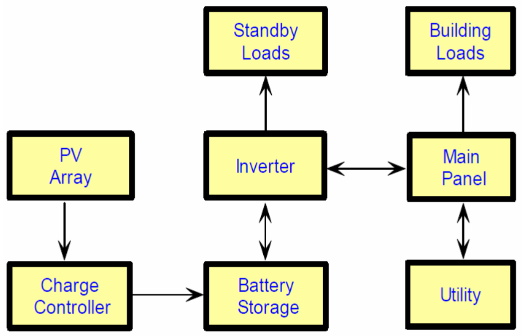


Fig. 1.2 Grid-connected PV system with battery storage [1]

Stand-alone systems can provide power to DC loads. With the inverter can also provide power to the AC loads. Water pumping is a major application for PV systems (Fig. 1.3). These systems include a PV array with or without a tracking device, a pump controller and an inverter. Batteries may be incorporated in these systems as well.

Also, photovoltaic systems can power remote residences and other small facilities where the utility grid is not available. The main components are presented in Fig. 1.4. This systems may also be supplied with an auxiliary power source such as wind generators and engine generators to meet electrical loads during a bad weather.

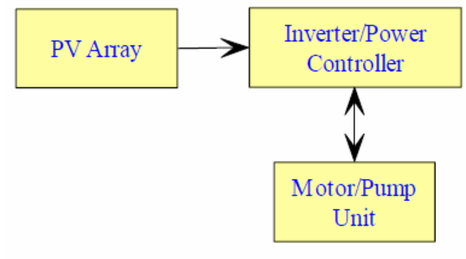


Fig. 1.3 Water pumping system diagram [1]

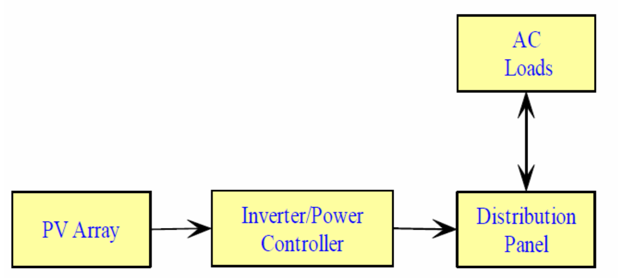


Fig. 1.4 Stand-alone photovoltaic system [1]

3. WIND ENERGY

The wind energy it is one of the most rapidly developing renewable energy sources. Wind power is a reliable technology which is able to produce electricity at costs competitive with coal and nuclear power. The available power in the wind with air density ρ, passing through an area A, perpendicular to the wind, at a velocity v, is given by the relation [2]:

$$P = 0{,}5 \rho A v^3$$

Air density decreases with increasing temperature and increasing altitude above sea level. The effect of temperature on density is relatively weak and is normally ignored because these variations tend to average out over the period of a year.

With a wind speed distribution and a turbine power curve properly adjusted for the local air density, the wind energy potential, or gross annual wind energy production, for a specific site can be estimated with the relation [Dale]:

$$E = 0{,}85 \left[8760 \sum_{i=1}^{n} f(U_i) \Delta U_i P(U_i) \right],$$

where, n is the number of wind speeds $f(U_i)\Delta U_i$ is the probability of a wind speed occurring in the wind speed range ΔU_i, $P(U_i)$ is the electrical power produced by the wind turbine at wind speed U_i

The 0,85 factor assumes 15% in losses (10% due to power transfer to the grid, control system losses, and decreased performance due to dirty blades; 5% due to operation within an array of wind turbines). If the turbine is not inside an array, the number 0,85 must be replaced with 0,90. Wind energy potential is typically 20%–35% of the wind energy resource.

4. HYBRID OFF-GRID ENERGY SYSTEM MODELATION

Continuity in the power supply is a priority if is desired an independent system for producing electricity from renewable sources. A hybrid system for electrical energy production may incorporate several types of sources, conventional or non-conventional. If we adopted as the main source of energy production a photovoltaic system, it is advisable to use a diesel generator as backup power. In addition, it is recommended that the system to be completed with a wind turbine and a hydroelectric system.

The hybrid off-grid system analyzed in this paper consists of the following equipments:

1. Photovoltaic system 8,28 kW_p
2. Wind turbine 1 kW
3. Engine generator 4,4 kW
4. Storage battery 833Ah (48V bus)
5. Inverter 10 kW
6. Storage tank with thermal controller
7. Electrical load 18,4 kWh/day
8. Thermal load 11,26 kWh/day

The hybrid off-grid system design has been initiated with the electricity consumption determining. Also, the design must be done for the situation in which all consumers are supplied at the same time. Estimating the electricity demand start from the establishment of the rating power for each consumer and period of time of its operation within 24 hours. The total daily energy consumption will be calculated by adding the individual consumptions. In the absence of annual load curve it was established the same consumption per month. The daily total energy consumption is about of 18,4 kWh/day.

Starting from the available surface area (~ 62 m^2) for installing the photovoltaic panels, was conducted the PV system sizing. The main parameters of the photovoltaic panel are: P_{MPP} = 230W, V_{MPP} = 46,75 V, I_{MPP} = 4,92 A, V_0 = 58,08 V, Isc = 5,40 A, T_{min} = - 25 ^{0}C and T_{max} = +50 ^{0}C.

The photovoltaic panel voltage variation with temperature:

V_{0max} = 58,08 + 0,197(25+25) = 67,93 V

$V_{min\ MPP}$ = 46,75 + 0,197(25-50) = 41,82 V

$V_{max\ MPP}$ = 46,75 V + 0,197(25+25) = 56,6 V

The number of photovoltaic panels that can be included in the available area of the building (60,62 m^2) is 36. The photovoltaic panels were divided into four parallel strings that means 9 photovoltaic panels per string.

Electrical characteristics of the photovoltaic panels array are presented:

$V_{MPP\ string}$ = 9*46,75 V = 420,75 V

$I_{MPP\ string}$ = 4,92 A

$I_{max\ scc.\ string}$ = 1,25*5,40= 6,75 A

$V_{0\ max\ string}$ = 9*120%*69,69 V = 752,65 V

$V_{min\ MPP\ string}$ = 9*41,82 V = 376,38 V

$V_{max\ MPP\ string}$ = 9*56,6 V = 509,4 V

The main characteristics of the used inverter are: P_{DC} = 12,8 kW; $V_{MPPT\ DC}$ = 360 – 750 V; $V_{max\ DC}$ = 900 V; $I_{max\ DC}$ = 18A/MPPT; P_{AC} = 13,8 kVA; V_{AC} = 400 V, 50 Hz; $I_{max\ AC}$ = 20 A.

Were necessary the following checks necessary for the operation of the photovoltaic system:

1. First condition: **Fulfilled**

$V_{0\ max\ string} < V_{max\ DC\ INVERTER}$: 752,65 V < 900 V

2. Second condition: **Fulfilled**

$V_{min\ MPP\ string} > V_{min\ MPPT\ DC\ INVERTER}$: 376,38 V > 360 V

3. Third condition: **Fulfilled**

$V_{max\ MPP\ string} < V_{max\ MPPT\ DC}$: 509,4 V < 750 V

4. Fourth condition: **Fulfilled**
$I_{max\ scc.\ string/\ 2\ in\ parallel} < I_{max\ DC\ INVERTER}$
2*6,75 = 13,5 A < 18 A / MPPT 1
2*6,75 = 13,5 A < 18 A/ MPPT 2
5. Fifth condition: **Fulfilled**
$P_{max\ PV\ system} \leq P_{DC\ INVERTER}$
$9*230W_p + 9*230W_p + 9*230W_p + 9*230W_p = 8280W_p$
$8{,}280\ kW_p \leq 12{,}8\ kW_p$

The modeling was performed with the Homer®Pro program which represents a specific work environment that performing various predictions regarding to the energy production systems operation using renewable sources.

The first stage involves the selection of the HEES location (Suceava city area). In the second stage were selected and configured the equipments from the HEES structure.

The operating block diagram of the proposed HEES achieved from Homer®Pro program is presented in Fig. 1.5.

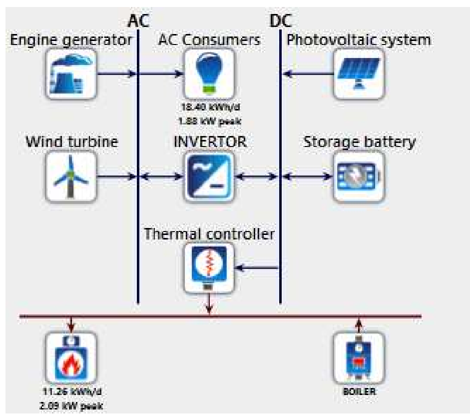


Fig. 1.5 Block diagram of the proposed HEES

For performance evaluation of the HEES must be imported three online resources as follows: monthly average solar global horizontal irradiance values, temperature values (monthly average) and wind speed values (monthly average). The solar irradiance values and temperature for selected location are presented in Fig. 1.6.

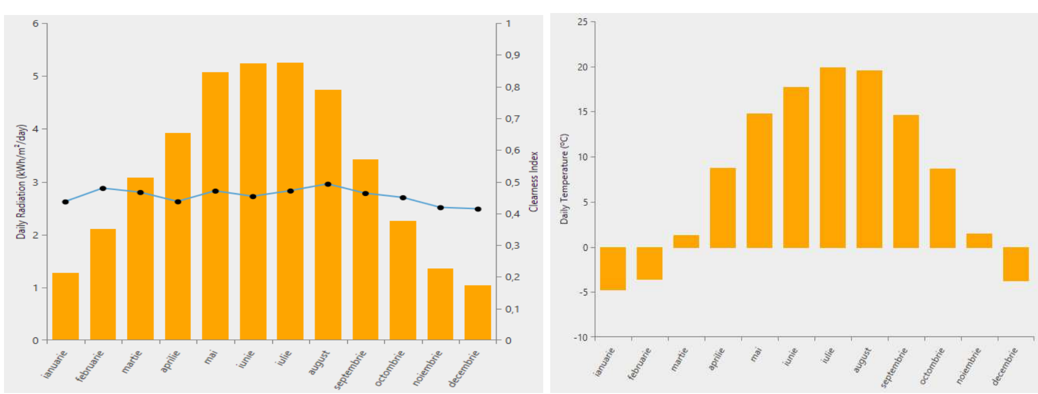


Fig. 1.6 Solar irradiance, clearness index and temperature variation for Suceava city.

Thus, the average solar irradiation value is 3,23 kWh/m^2/day, the daily temperature is 7,94 ^{0}C and wind speed average value is about 4,88 m/s (value measured at 50 m high).

In order to obtain the modeling results, were established several assumptions:

1. It has considered the effect of temperature on the photovoltaic system;

2. It was considered the photovoltaic system without tracking system;
3. Initial state of charge of the storage battery is 100%;
4. Minimum state of charge of the storage battery is 40%.

The wind turbine has a nominal power of 1 kW. The power curve of the wind turbine is presented in Fig. 1.7. The nominal power of the engine generator is 4,4 kW. This value is the optimized one and established by the Homer®Pro program. The engine generator (diesel generator) it is considered as the main energy reserve and may compensate a potential energy shortage. Can be set two operating mode for diesel generator.

The first variant (previously mentioned) relates to the case in which the diesel generator can be autosized by the program so as to cover the entire existing power consumption at a given time, if there is no stored energy produced by the photovoltaic system or wind turbine.

A second option refers to the establishment of hourly intervals for the generator operation.

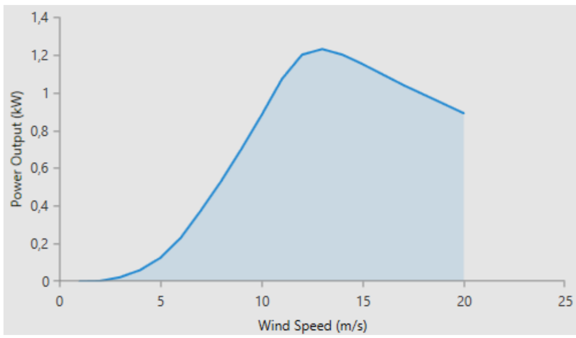


Fig. 1.7 Wind turbine power curve

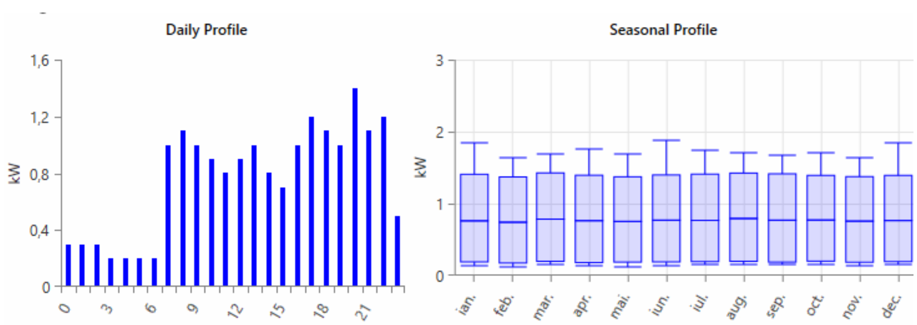


Fig. 1.8 Daily and seasonal profile for the electrical load

In Fig. 1.8 are presented the daily and seasonal profile of the AC consumers.

The modeling results have highlighted an electrical energy excess that is produced and there is no possibility of being stored. In this respect, it was introduced a heat load that be conceived as a source of heat for heating a space or water heating. For the management of energy excess was used a thermal controller.

In Fig. 1.9 are presented, as in the case of the electrical load, the daily and seasonal profile for the thermal load. These profiles were generated by Homer®Pro program.

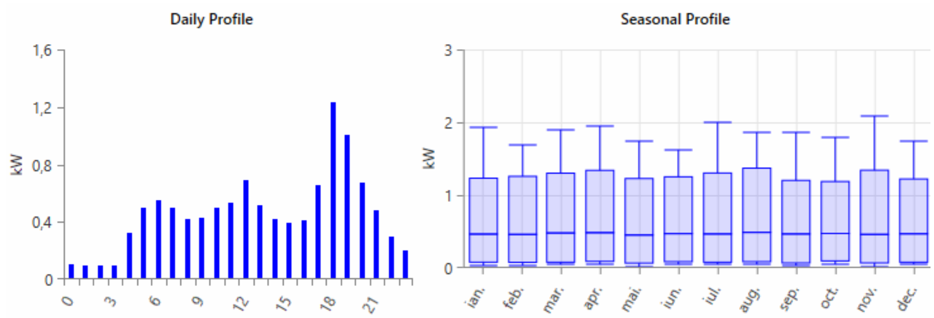


Fig. 1.9 Daily and seasonal profile for the thermal load

After calculations, the program offers several operating variants for HEES, differentiated after the investment and after the minimum number of equipment which can ensure optimum operation of the HEES. Thus, are provided detailed information about the operation of each subsystem as well as how it manage the produced energy.

4. RESULTS

The obtained results from modeling are multiple, in the sense that the program offers eight variants of operation of HEES. Out of these, the user can choose a variant that would ensure an energetic stability. The operation variants of the HEES is listed in Table 1.

Hereinafter, will be analyzed the results for the first variant of operation (No. 1), in which are used all the proposed equipments.

Table 1

Variant No.	Photovoltaic system	Wind turbine	Diesel generator	Storage battery	Invertor	Boiler	Thermal load
1							
2							
3							
4							
5							
6							
7							
8							

The results on the electricity production are summarized in Table 2. A representation of the amount of electricity produced by the three sources is illustrated in Fig. 1.10. Table 3 presents the data obtained from diesel generator operation within HEES.

Table 2

Power source	**The amount of energy produced kWh/year**	**Percentage %**
Photovoltaic system	8966	75,37
Engine generator	1508	12,68
Wind turbine	1422	11,95
TOTAL	**11897**	**100**
Energy consumption	6716	100
Electrical energy excess	2676	22,5
Thermal load	4110	100
Boiler	3641	100
Thermal energy excess	2208	100

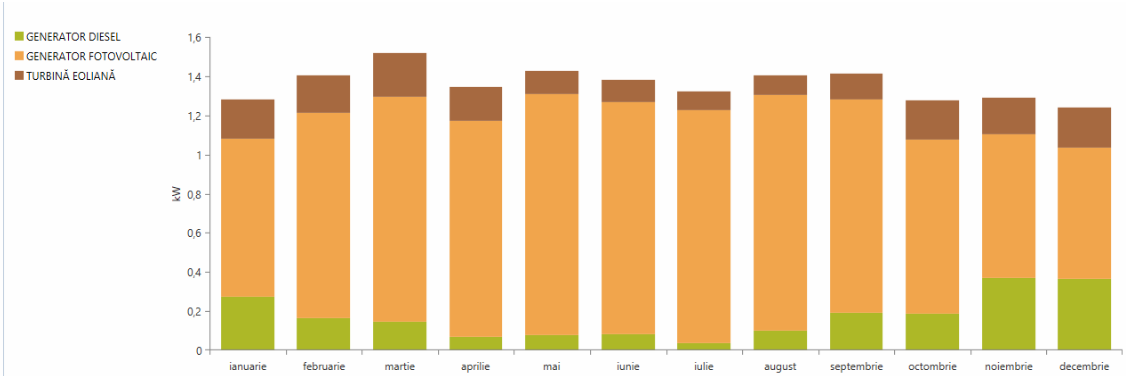


Fig. 1.10 The amount of electricity produced by the photovoltaic system, wind turbine and diesel generator

Table 3

Variable description	Value	UM
Operating hours	354	Hours/year
Starting number	55	Starts/year
Produced energy	1508	kWh/year
Maximum power	**4,4**	**kW**
Consumption	467	Liters/year

In Table 4 the characteristics of the storage battery are presented. In Table 5, some technical parameters regarding wind turbine operation are presented.

Table 4

Variable description	Value	UM
Number of strings	1	-
Number of string in paralel	1	-
Number of storage battery	1	-
Rated voltage	**48**	**V**
Rated capacity	39,98	kWh
Used capacity	23,99	kWh
Autonomy	31,29	Hours
The amount of stored energy	4838	kWh/an
The amount of consumed energy	3114	kWh/an

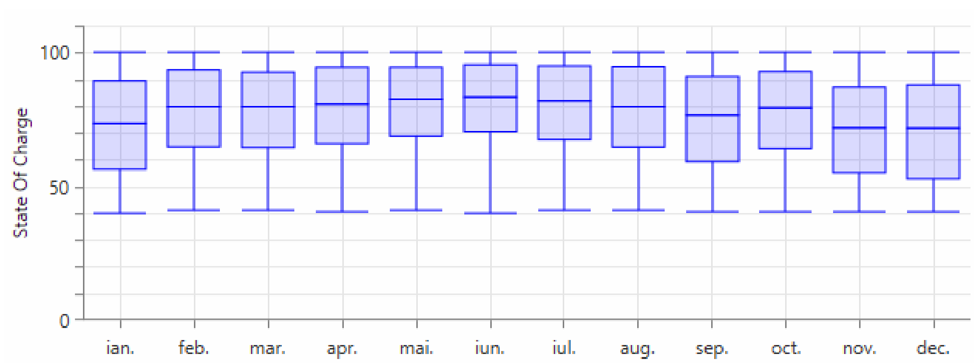


Fig. 1.11 Seasonal profile of the storage battery state of charge

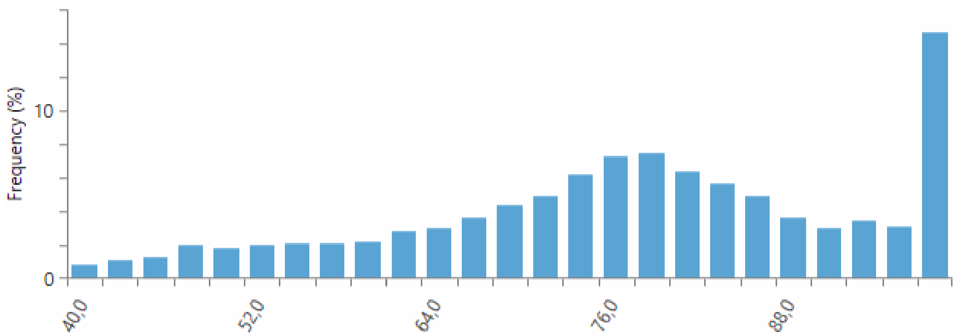


Fig. 1.12 The histogram regarding to the variation of the storage battery percentage

Table 5

Variable description	Value	UM
Rated power of wind turbine	1	kW
The amount of produced energy	1422	kWh/year
Average produced power	0,17	kW
Maximum produced power	1,23	kW
Number of operation hours	8464	Hours/year

It was chosen for analysis month of July. The electric power produced by the wind turbine and tine variation of the wind velocity is presented in Fig. 1.13. In Fig. 1.14 is observed the time variation of the electrical power produced by each source. The engine generator operation is evidenced when the stored energy falls below a certain level.

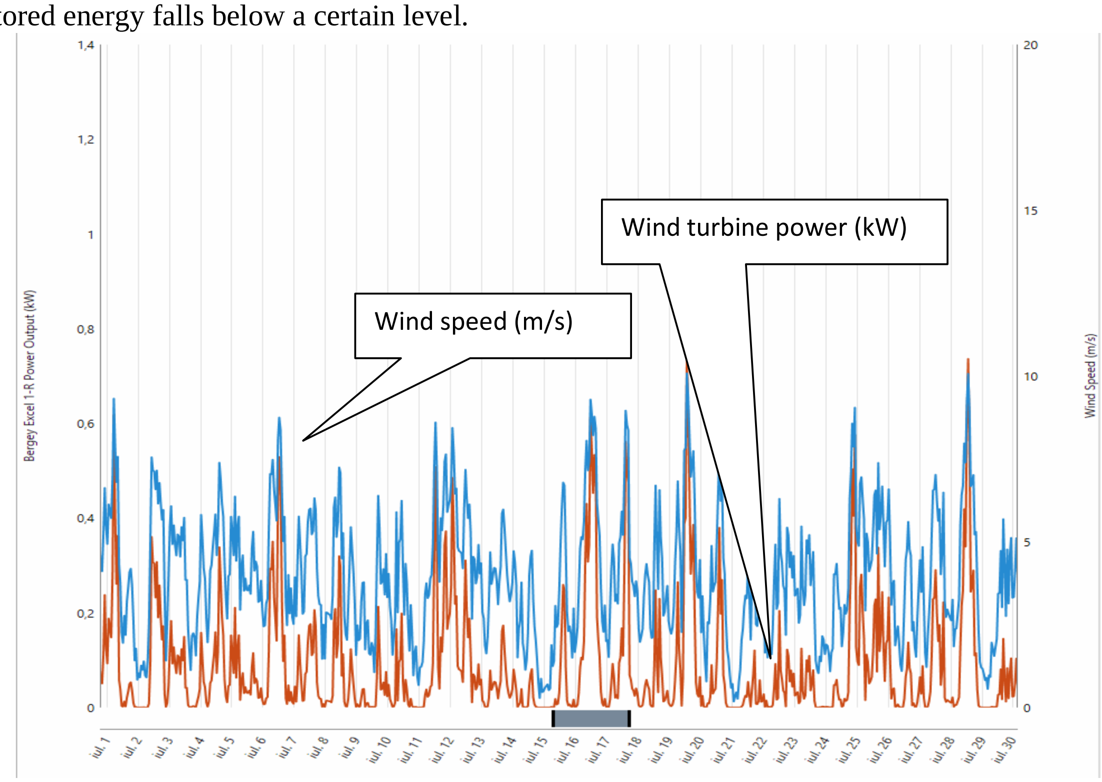


Fig. 1.13 Wind speed and wind turbine produced power

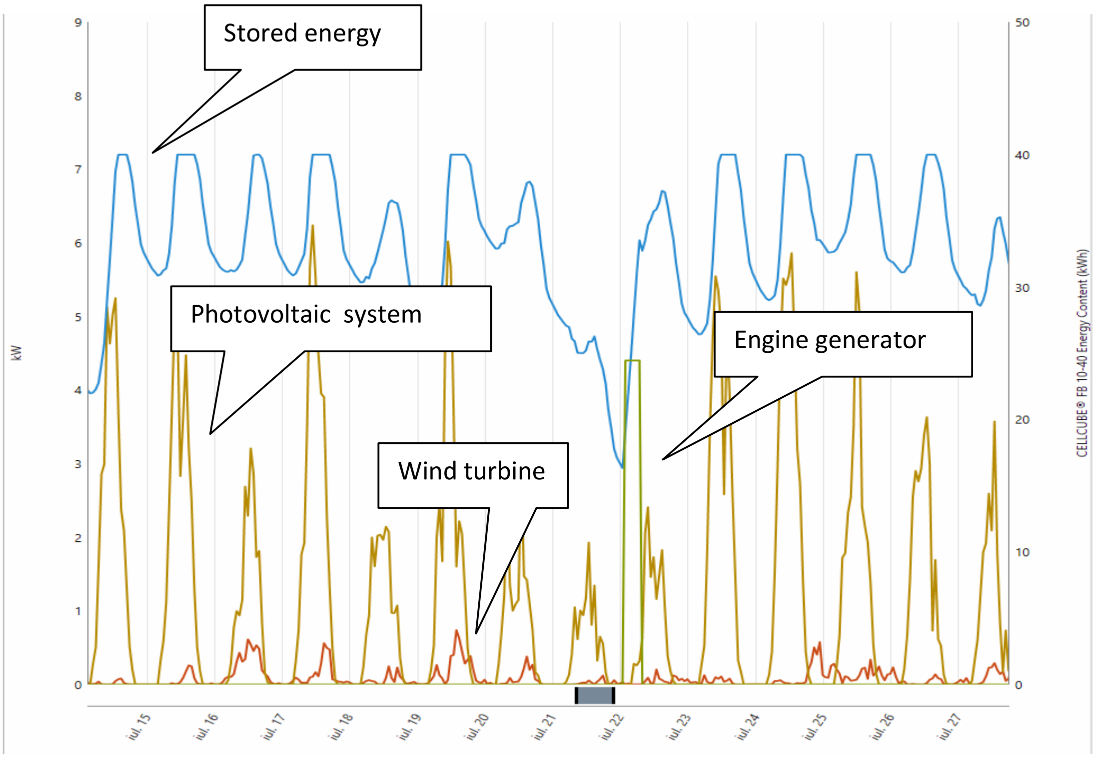


Fig. 1.14 The HEES produced power with distribution on the three sources. The state of charge variation.

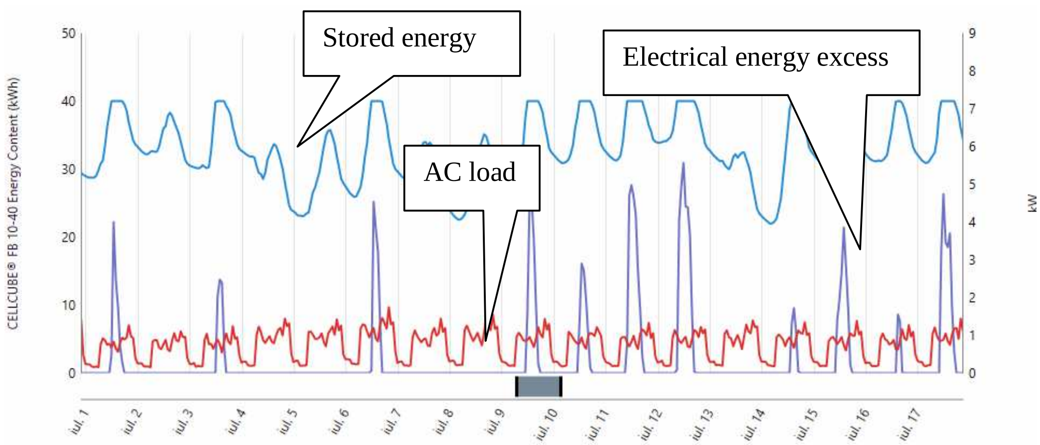


Fig. 1.15 The state of charge, AC load and excess of electricity for month of july.

The excess energy is the amount of energy that can not be used for storage or for use by a particular consumer. The excess energy occurs when there is a surplus of electrical power and storage battery can not absorb this amount of energy. The use of an electric water heater can turn the excess electricity into heat through the thermal regulator. Fig. 1.15 illustrates the amount of heat produced during July.

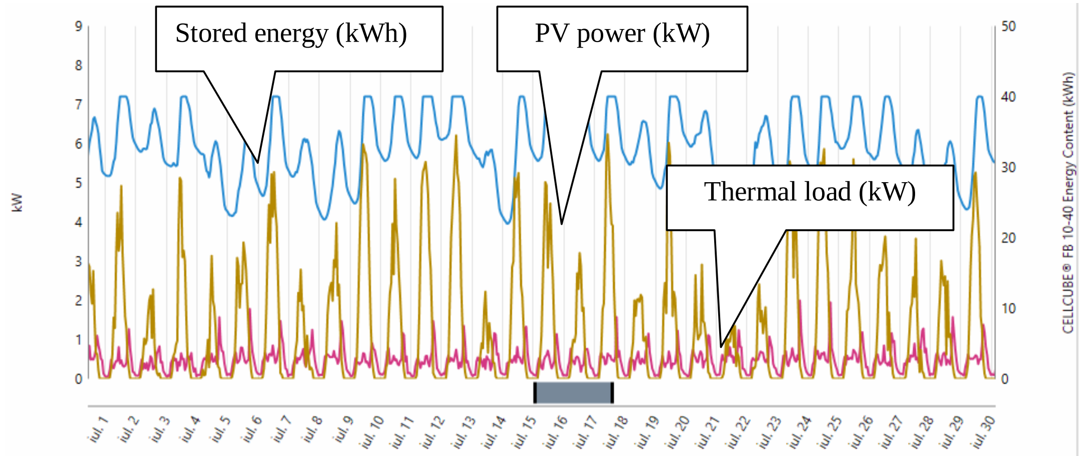


Fig. 1.16 The amount of the produced heat relative to the amount of energy generated by the photovoltaic system and the total amount of stored energy respectively.

The time variation for a day of July of the PV power and electrical and thermal loads are presented in Fig. 1.17. It can be observed that, for July 12, starting with 05.00 AM, the PV system begins to produce, reaching a peak of 6,21 kW at 12.01 PM. For this time of day the storage battery is charged 100%, thermal load has a value of 0,74 kW and wind turbine produces 0,31 kW. Towards to the end of the solar day (18.00 PM) is found a significant decrease in power production of the photovoltaic system and thermal load growth leads to the decreasing of the amount of stored energy, while the wind turbine produces an insignificant amount of energy (0,07kW).

In Fig. 1.18 is shown an explanatory to electric load variation in a solar day relative to the amount of energy produced by each power source. It is noted that, for this solar day, diesel generator does not start because of sufficient electricity to provide power to consumers.

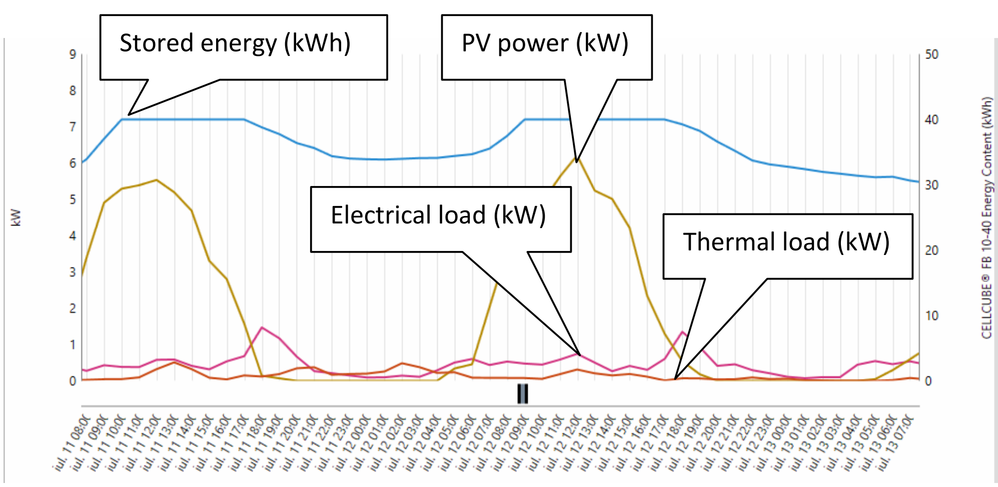


Fig. 1.17 Detail on the HEES operation - thermal load variation.

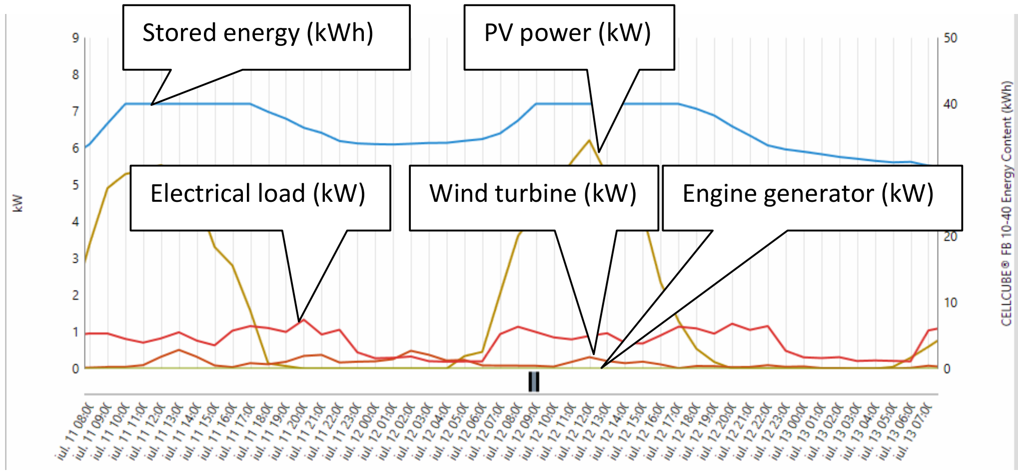


Fig. 1.18 Detail on the HEES operation - electrical load variation.

5. RESULTS

In this paper it was conducted a modeling of a hybrid off-grid electric energy system (HEES) using renewable sources. Thus, they were considered the following sources: photovoltaic system, wind turbine and diesel generator. The experimental results were analyzed and presented only for month of July. The amount of electricity produced by the system cover the existing need of heat and electricity. Is predicted an excess of electricity of 2676 kWh/year used mostly by the thermal load. The number of operating hours of the diesel generator is relatively low (354 hours) and covers 12,68% of the total produced electric energy. The wind turbine also produce 1422 kWh/year, representing 11,95% of the total produced electric energy. The main producer of energy remains the photovoltaic system with an output of 8966 kWh/year (75,37%). Storage battery has a annual average charging of over 60% which justifies the autonomy of HESS over 24 hours. The wind turbine produces approximately 50% of rated output actually justified by the low values of speed in the considered location. Hence and the amount of electricity produced in one year (1422 kWh/year).

Overall, the HEES system was correctly sized and can provide sufficient electricity and heat according to considered load curves.

BIBLIOGRAPHY

[1] *FSEC Standard, Procedures for photovoltaic system design review and approval*, Florida Solar Energy Center, 2005.

[2] Dale E. Berg, *Wind energy resources.* Sandia National Laboratories.

[3] *** Homer Energy software. www.homerenergy.com

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#89

Holonic control-based solution for service restoration and switch allocation in power distribution networks

V. VLAD*, C. D. POPA, R. D. PENTIUC
“Stefan cel Mare” University of Suceava
Romania

SUMMARY

This paper presents a distributed control solution based on holonic concepts for restoration of power distribution systems in case of failures generating blackouts. The control entities of the system (called holons) interact with each other for finding dynamic solutions for power restoration by isolating the faulted area and activating backup connections, so as the loses at the consumers level to be minimal. The proposed solution integrates the specifications of the IEC 61850 standard, thus providing connection to the control applications used currently within substations.

KEYWORDS

Holon, Power-System, IEC 61850

1. INTRODUCTION

In recent years, a worldwide growing interest was noted for the development of distributed control architectures in order to enable efficient management of the power distribution system in a dynamic context. Green energies, such as those produced by photovoltaic panels or wind turbines, raise important issues for traditional distribution systems due to the production’s unpredictability. Another novelty element is the introduction of the so-called "prosumers", which are both consumers and producers of energy, their effective integration in the distribution system leading to the need for distributed control mechanisms. Moreover, the possibility of a network segment to operate as a *microgrid*, in which are harmonized the loads profiles and local energy production, favors the development of distributed control solutions.

A viable solution for the development of distributed control architectures that enables the effective management of the power grid, in a dynamic context, is the implementation of multi-agent systems to control power distribution, this solution being dealt with in a substantial number of research papers. The adoption of multi-agent technology in the control of energy distribution usually associates intelligent agents to energy sources and consumers, which interact mediated by control agents for efficient energy production and consumption. An example in this respect is research paper [1], in which the authors propose a multi-agent architecture for controlling an IDAPS (Intelligent Distributed Autonomous Power System) microgrid. The developed control strategy covers both the “normal operation” mode (when the microgrid is connected to the grid) and the “outage mode operation”, when disconnected, due to upstream outage. The architecture defines four types of agents: control agents, DER (Distributed Energy Resource) agents, user agents and database agents. Each agent has unique objectives and responsibilities and cooperates with the other agents for achieving the

* vladv@eed.usv.ro

overall objective of the microgrid, which is to secure the critical consumers (priority level zero) in the outage mode from local energy sources.

Another example of using multi-agent systems for the control of a microgrid is considered in paper [2], in which the control objectives include, in addition to maintaining the supply of local consumers in case of grid failure, the optimal utilization of the distributed energy sources within the microgrid. The authors adopt a fully decentralized control solution, in which the primary responsibility is given to the controllers of the energy resources, which compete with each other for the production of energy, in order to satisfy the demand in the microgrid, as well as to and to export it to the main grid.

A similar paradigm to multi-agent systems is that of *holonic systems*, inspired by the organizational way of living systems. In addition to distributing the intelligence between autonomous entities (called holons), which cooperate to fulfill the overall objectives of the system, this paradigm adds the aggregation concept, meaning that a holon can be composed of several sub-holons and at the same time can be part of a bigger holon of a higher level. The holons on the lowest level are called *simple holons* or *elementary holons*. Initially applied in manufacturing systems, the holonic concepts were adopted also in the energy field for modeling the entities within the distribution system and their relationships. Examples of holonic architectures for energy distribution systems are presented in [3-5].

This paper presents a solution for the application of holonic concepts in the control of an electricity distribution system, consisting of several substations and feeders with backup connections. The overall objective of the control system is to perform the protection and reconfiguration of the distribution system in case of failures, so that the losses in the affected consumers to be minimum.

2. THE ANALYZED POWER DISTRIBUTION SYSTEM

Figure 1 shows the power distribution system considered for testing the control solution proposed. It includes two substations (110 / 20kV) supplying two feeders, which cross various areas of consumption. Along the feeders are placed remotely controlled sectionalizing switches, allowing the isolation of certain areas of a feeder (SW3 and SW4) and switches that allow the connecting/disconnecting of each consumption area (ex. SW5, SW6). The two feeders are connected at their ends by means of a recloser (SW11), which allows the connection/disconnection of feeders without interrupting their power.

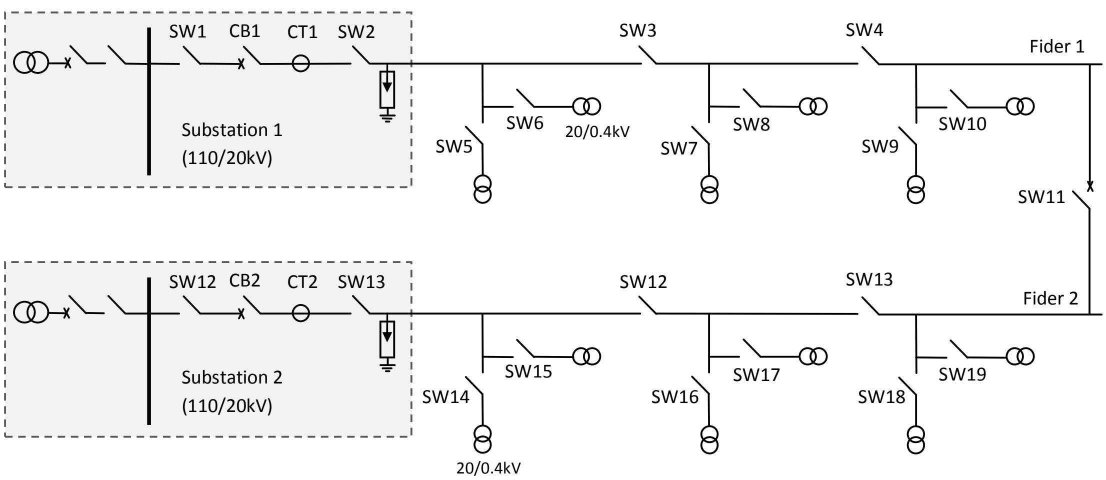


Figure 1. The schematic of the distribution system

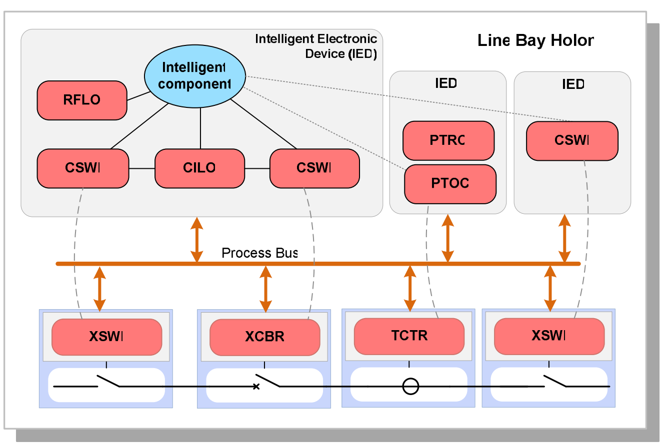
In normal operation, the SW11 recloser is open and each feeder is supplied from its substation. In case of a fault along a feeder (supposing a short-circuit), it is desirable the faulted area be isolated by opening sectionalizing switches, so as the consumers before the fault can be can be supplied further from the feeder’s substation and the downstream consumers be supplied from the other feeder, through the backup connection. In the best case, the two substations should be designed so as to be able to supply enough power for all consumers on both feeders. Otherwise, the occurrence of a fault on a feeder or in a station raises the problem of determining the power reserve of substations and the consumers that will be kept supplied. If the stations reserve power is not enough, it will be necessary to disconnect some consumers, based on a priority list.

3. THE DEVELOPED CONTROL SOLUTION

In the development of the control system, we aimed to combine the specifications of the IEC 61850 standard with the IEC 61499 standard and the holonic control concepts. The IEC 61850 standard [6], focused on communication between the intelligent electronic devices (IEDs) within substations, defines not only the protocol elements, but also how data should be organized in IEDs, facilitating their interoperability. According to the standard, each IED includes one or more *logical devices* which, in turn, include one or more *logical nodes*. A logical node (LN) is a grouping of data and services, logically related to some power system function, identified through predefined names. For example, a logical node of XCBR type will include data and services for the control of a circuit breaker.

The IEC 61499 standard [7, 8] is focused on the application of functional blocks in industrial processes monitoring and control systems. The programming unit is *the function block (FB)*, which can be of three types: basic, composed or for service interfacing. The functionality of a composed functional block is defined by a network of functional blocks (basic, composed or for service interfacing), allowing the encapsulation of complex functionalities and code reuse. The service interface FBs are usually developed for abstracting the details of a specific hardware platform (like how a sensor can be accessed), allowing the developers to focus on the control application. In this paper we chose to implement the IEC 61850 logical nodes through IEC 61499 functional blocks.

The implementation of the holonic concepts in the development of the proposed control system involved the definition of holons, their responsibilities and the exchanged messages between them. For the considered power system, *the elementary holons* were defined at the level of substation bays and at the level of consumers. As presented in paper [5], *a bay holon* includes (a) the equipment on the process level and the bay level, which encapsulates the elementary functions for acquisition and transmission of data (process level) and functions for protection and control (bay level) grouped in IEC 61850 logical nodes, and (b) an intelligent component for local decisions and interaction with other holons. In Figure 2 is presented an example of an elementary holon for a line bay. The meanings of the acronyms for the IEC 61850 logical nodes are given bellow.



XSWI	Circuit switch
XCBR	Circuit breaker
TCTR	Current transformer
CSWI	Switch controller
CILO	Interlocking
RFLO	Remote Fault Locator
PTOC	Protection Time Overcurrent
PTRC	Protection Trip Conditioning

Figure 2. Example of a holon for a line bay

The consumer holon also include an intelligent component in the form of a software agent, which interfaces the consumer with the power system, providing information such as the consuming profile, priority level, etc.

The elementary (line, transformer, measure) bay holons can be grouped along with an intelligent component so as to form a composed *substation holon* representing the whole substation.

Similarly, the consumers holons along a feeder can be grouped to form a composed *feeder holon*, which will interact with the line bay holon and with other feeder holons, with which electrical connections are possible.

As already mentioned, the objective of this work is to develop a holonic control system which allows the protection and reconfiguration of the power system in case of a fault occurrence along a feeder. The protection part can be considered covered by the IEC 61850 standard, which defines logical nodes for overcurrent detection (like PTOC), control of primary equipment (ex. XCBR) and reclosing (RREC), together with mechanisms for communication between nodes, as event messages (e.g. of type GOOSE - Generic Object Oriented Substation Events) or complex connections of CLIENT/SERVER type. A short-circuit protection scenario usually involves the detection of the fault by a PTOC logical node, the validation of the circuit breaker tripping command by a PTRC node and the transmission of an (opening) GOOSE message to the XCBR-type logical node controlling the circuit breaker. The opening of the circuit breaker (CB) is published within the system by the XCBR logical node through a GOOSE message, allowing the RREC logical node to reclose the CB. If the fault does not disappear after reclosing, the circuit breaker will remain open until the defect removal and its manual closing by an operator.

A permanent fault removal usually involves the traveling of a specialized crew onsite and the fixing process may take a long time, of hours or days. In order to reduce the blackout time of the consumers along the feeder it is desirable to isolate the fault area and restore the power as soon as possible. Fault isolation is realized by opening the upstream and downstream sectionalizing switches, their remote control requiring a rather precise knowledge of the fault location. Fault location is determined through different methods such as on line based impedance computation (by measuring voltage and current at one end or multiple ends), or traveling wave based approaches (using the transient signals generated by the fault) [9], or the synchronized phasor method, based on monitoring of voltage phasors in certain nodes, correlated with measurements of current phasors.

After isolating the fault, the feeder can be resupplied, but the downstream consumers continue to remain without energy. The supply of these consumers could be done from other feeders, through backup connections. Determining the new configuration of the distribution network, by activating the backup connections and considering the capacity of the neighbouring feeders to supply the necessary energy, was addressed in this paper by developing a *holonic control solution.* Practically, the feeder holons, bay holons and consumer holons interact with each other for choosing a system configuration that allows the supply of the affected consumers, taking into account their priority and the capacity of the substations powering the feeders. Figure 3 shows the messages transmitted by the IEC 61850 logical nodes and holons in a short-circuit protection and system reconfiguration scenario, considering the power system presented in Figure 1 and the fault occurred between the sectionalizing switches SW3 and SW4 of feeder 1.

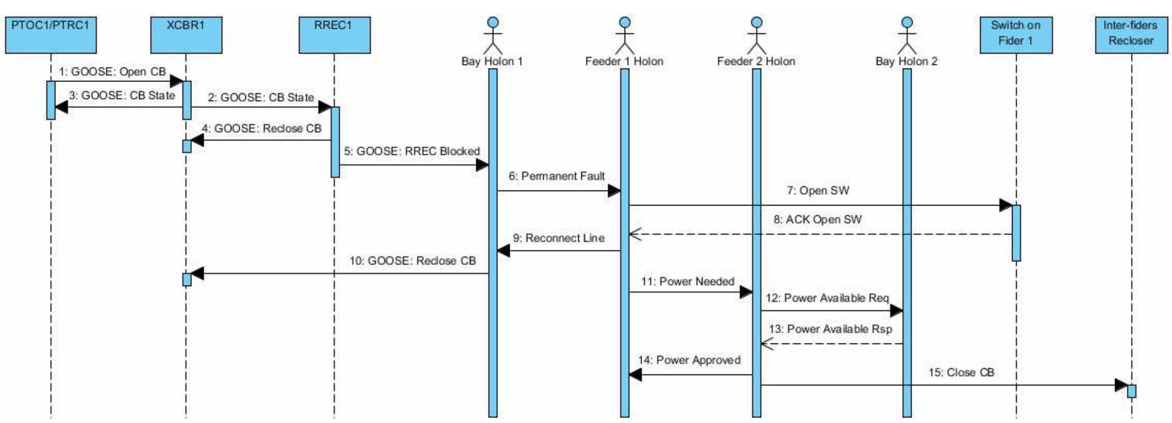


Figure 3. The messages transmitted in case of a permanent fault

An overcurrent detection determines initially the transmission of GOOSE messages between the PTOC1/PTRC1, XCBR1 and RREC1 logical nodes for opening and then reclosing the circuit breaker. If the fault persists, after two reclosing the RREC1 node goes into the *blocked* state and informs about this the agent of the bay holon, which notifies the feeder holon about the occurrence of a permanent fault. In this paper, we considered known and available the distance to the fault, according to the IEC 61850 standard, in a logical node of RFLO (Remote Fault Locator) type. Consequently, Feeder 1 Holon can read the distance through a CLIENT/SERVER connection and determine, based on a map with the locations of the sectionalizing switches, which are the switches positioned upstream and downstream of the fault. Considering remote controlled switches, they will be open through "Open SW" messages transmitted by Feeder 1 Holon. After receiving the opening confirmation, the feeder holon may require the bay holon to reclose the circuit breaker. In the same time, the Feeder 1 Holon will compute the power needed for the consumers positioned downstream of the fault and will transmit a message of type "Power Needed" to the Feeder 2 Holon. This holon computes the value of "the approved power" based on the maximum power of its substation and the priorities of the consumers along its feeder and the affected one. If the computed value is greater or equal to the requested one, it will send a closing message to the SW11 recloser, positioned on the connection between feeders. Otherwise, the value of the available power will be transmitted to Feeder 1 Holon, to disconnect one or more consumers.

4. THE IMPLEMENTATION OF THE PROPOSED CONTROL SOLUTION

As already mentioned, we chose in this paper to implement the IEC 61850 logical nodes through IEC 61499 models. Thus, each logical node was implemented as a network of functional blocks encapsulated in an IEC 61499 resource, named according to the IEC 61850 naming rules for logical nodes. The network of functional blocks includes a special FB containing the data of the LN and functional blocks for communications with other LNs or for interfacing with the power transmission equipment. Further details on mapping the IEC 61850 models onto the IEC 61499 specifications are given in paper [11].

The intelligent component of holons was implemented as a network of functional blocks encapsulated in a composed FB. In Figure 4 is presented the interface and the inside network of the FB implementing the agent of a bay holon. The CellAgentFB block type contains the software defining the agent's functionality, while the SUBSCRIBE_1 and Transmitter blocks type enable the receiving/transmission of messages from/to other holons.

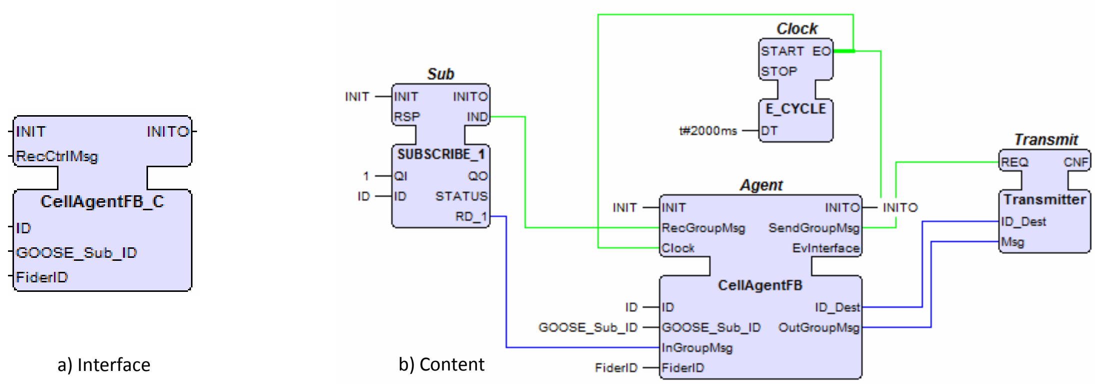


Figure 4. The interface and content of the FB implementing the agent of a bay holon

To test the developed holonic control solution, we modeled a power system similar to the one presented in Figure 1, using virtual equipment. The virtual equipment includes bus bars, switches, circuit breakers, current transformers, power lines and consumers, implemented through IEC 61499 functional blocks. Each virtual device has a graphical component allowing the real-time visualization of the device state. In Figure 5 is presented a part of the FBs modeling the primary equipment of the system and Figure 6 presents its graphical interface.

Regarding the consumers priorities, two levels were considered: priority level 0 (the highest), represented graphically by industrial consumers, and priority level 1, represented by domestic consumers. As illustrated in Figure 6, along feeder 1 six consumers were considered, of which five of priority 1, and one of priority 0. Along feeder 2 there are also six consumers, four of priority 1 and two of priority 0.

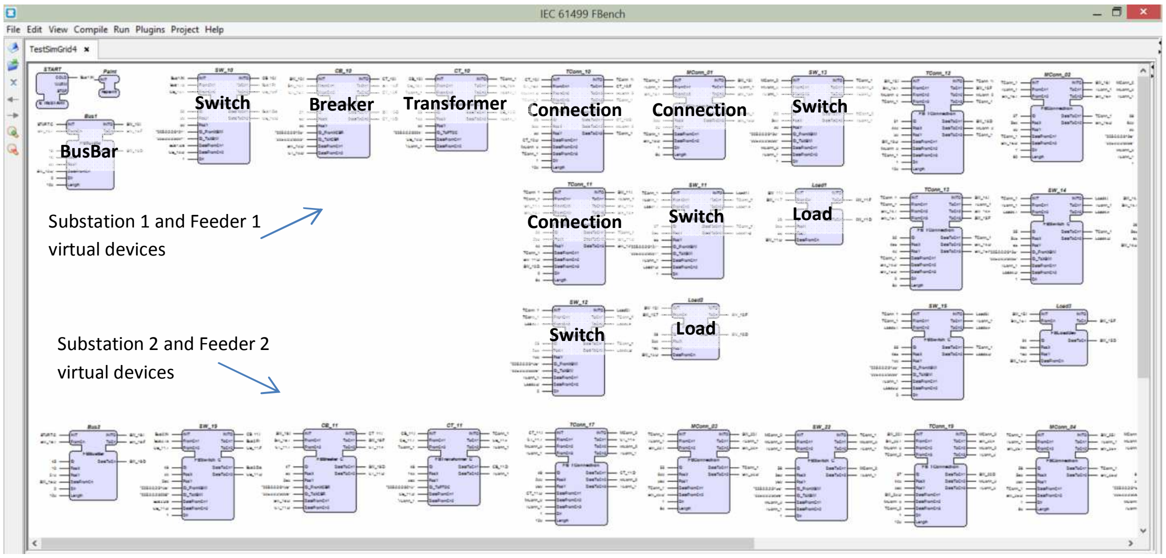


Figure 5. The network of function blocks modeling the power distribution system

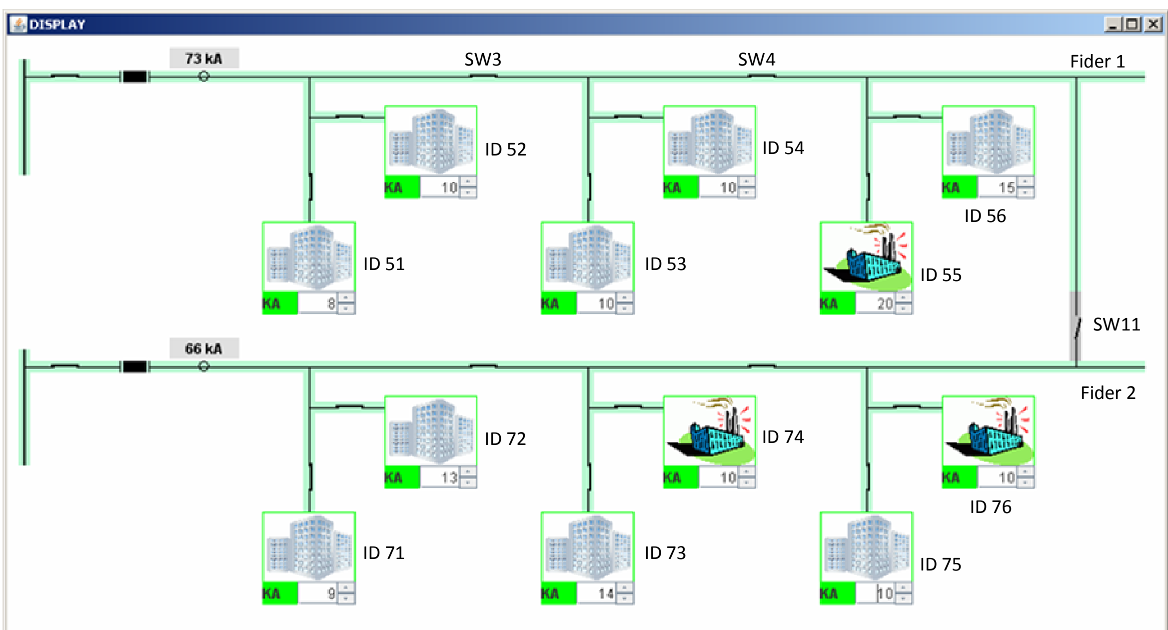


Figure 6. The graphical interface of the power system

For testing the control application, three cases of fault were considered, differentiated by the currents absorbed by consumers (according with Tabel 1). The maximum current supplied by each substation is supposed to be 100 kA, and the fault is considered occurring between the sectionalizing switches SW3 and SW4 of feeder 1.

In the first case, after opening the sectionalizing switches, Feeder 1 Holon will ask Feeder 2 Holon power for a 25 kA current, for supplying the two consumers positioned after the isolated area. The total current absorbed by the consumers along feeder 2 is 70 kA and, as a result, the request will be approved without negotiations, leading to the closing of the recloser SW11 between feeders.

Table 1

Cons. ID	Priority	Case 1 Consumer current [kA]	Case 3 Consumer current [kA]	Case 3 Consumer current [kA]
Feeder 1				
51	1	10	10	10
52	1	15	15	15
53	1	10	10	10
54	1	5	5	5
55	0	10	25	30
56	1	15	20	10
Feeder 2				
71	1	10	10	10
72	1	10	10	10
73	1	10	10	10
74	0	10	10	20
75	1	15	15	10
76	0	15	15	30

In the second case, the power necessary for the two consumers corresponds to a current of 45 kA, exceeding the capacity of substation 2. Analyzing the request of feeder 1, Feeder 2 Holon will conclude that the power necessary to supply the consumers of priority 0 corresponds to a current of only 25 kA, which remains within the capacity of substation. Consequently, it will send to feeder 1 a message of "Power Approved" type, indicating the power it can offer. The power value, corresponding to a current of 30 kA, will determine Feeder 1 Holon to disconnect the consumer of priority 1 and then requesting again a power for 25 kA.

In the third case, the current value requested by feeder 1 is 40 kA, while the total current consumed on feeder 2 is 90 kA. To cover at least the need of the consumer of priority 0, Feeder 2 Holon will disconnect two of the consumers of priority 1, and will transmit to Feeder 1 Holon the current value of 30 kA approved. Obviously, the approved value will determine Feeder 1 Holon to disconnect the consumer of priority 1. In Figure 7 is presented the final configuration of the power distribution system for this case.

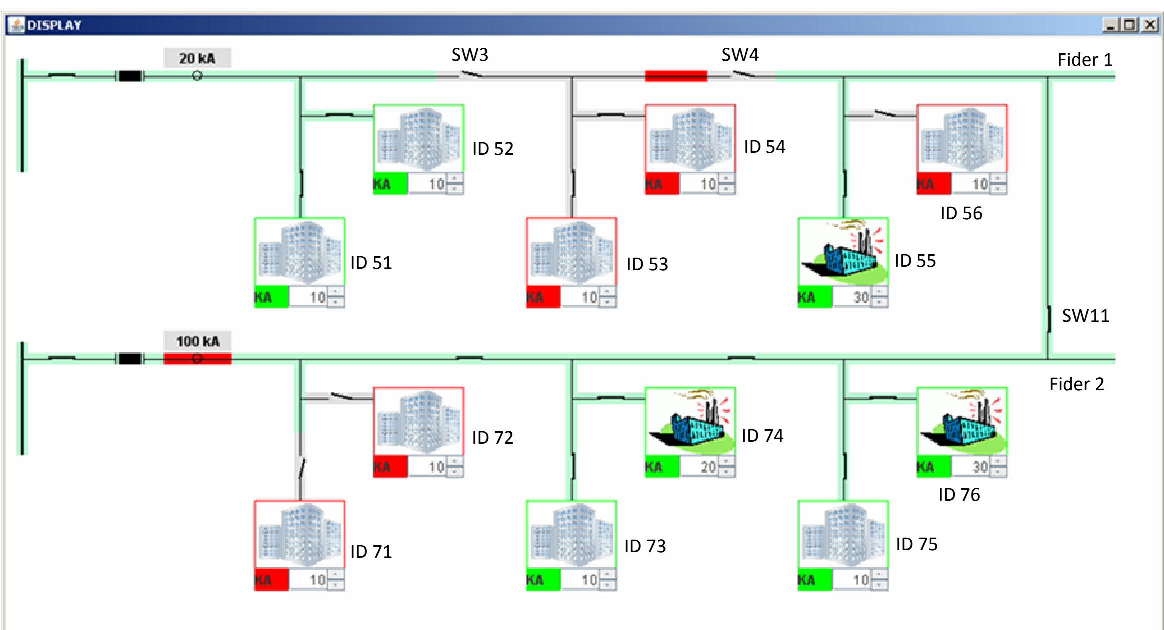


Figure 7. The final configuration of the power distribution system in the third case

5. CONCLUSION

This paper presented a holonic control solution for the restoration of a power distribution system in case of a permanent fault. The restoration refers to the reconfiguration of the distribution network by closing /opening the sectionalizing switches in order to isolate the fault area and restore the supply of the affected consumers through backup connections. Using a distributed control solution, like the holonic one, eliminates the necessity of a central computing equipment with high and costly performances and complex software, processing a big quantity of data acquisitioned from the system entities, and provides a better response time.

Compared to other control solutions based on multi-agent systems, the proposed solution provides connection to the control technologies used currently within substations, by integrating the IEC 61850 specifications for communications between IEDs. Beside this, the implementation of the IEC 61850 LNs and holons' intelligent component through IEC 61499 FBs allows a better structuring of the control application.

BIBLIOGRAPHY

[1] Pipattanasomporn, M., Feroze, H., Rahman, S. "Multi-Agent Systems in a Distributed Smart Grid: Design and Implementation", IEEE PES 2009 Power Systems Conference and Exposition (PSCE'09), March 2009, Seattle, USA, pp. 1-8.

[2] Dimeas, A.L., Hatziargyriou N.D. "Operation of a Multiagent System for Microgrid Control", IEEE Transactions on Power Systems, Vol. 20 (3), 2005, pp. 1447-1455.

[3] Pahwa, A. et al. "Goal-Based Holonic Multiagent System for Operation of Power Distribution Systems", IEEE Transactions on Smart Grid, 2015.

[4] Frey, S., Diaconescu, A., Menga, D., Demeure, I. "A Holonic Control Architecture for a Heterogeneous Multi-Objective Smart Micro-Grid", *Self-Adaptive and Self-Organizing Systems (SASO), 2013 IEEE 7th International Conference on*, Philadelphia, USA, 9-13 Sept. 2013, pp. 21-30.

[5] Vlad, V., Buzduga, C., Ciufudean, C. "An Approach to Developing Power Grid Control Systems with IEC 61850, IEC 61499 and Holonic Control", WSEAS Transactions on Systems, Vol. 13, 2014, pp. 503-509.

[6] IEC 61850 Communication Networks and Systems in Substations, IEC 61850, 2004.

[7] IEC 61499 Standard, International Electro-technical Comission, Geneva, 2005.

[8] V. Vyatkin, IEC 61499 Function Blocks for Embedded and Distributed Control Systems Design, Instrumentation Society of America, 2007, USA.

[9] Kezunovic, M. Smart Fault Location for Smart Grids, IEEE Transactions on Smart Grid, Vol. 2 (1), 2011, pp. 11-22.

[10] Miron A. et al., Real-Time Monitoring, Control and Protection by Implementation of the PMUs in North- East of Romanian Power Grid, Cigre Session, Paris, 2014.

[11] Vlad, V., Popa, C.D., Turcu, C.O., Buzduga, C.A Solution for Applying IEC 61499 Function Blocks in the Development of Substation Automation Systems, International Journal of Computers and Communications, Vol. 9, 2015, pp. 30-35.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#90

Wide-Area Protection based on PMU Measurement

C. HEYDE, E. LERCH, U. KERIN, R. KREBS*, C. NGUYEN MAU
Siemens AG
Germany

SUMMARY

In the last ten years PMUs (Phasor Measurement Units) play a more and more important role for the on-line monitoring and analysis of the state of the electrical systems. In the US and in Europe several systems are equipped with PMUs. For example the Italian grid is equipped with about 20 PMUs at the 400 kV level to avoid blackouts. In the US more than 1000 PMUs are expected in the next 10 years. Hundreds of PMUs are planned in India. The reasons for this development are high and changing loadings of the transmission systems, demand on flexibility of generation, high penetration by renewable generation and divergent load and generation centres. PMUs today allow monitoring frequency, voltage, power swing recognition, phase angle monitoring and island detection.

Further indices can be created by local basic measurements like line/transformer power flow indices, nodal loading indices, or voltage stability indices which can be used for alarming, protection and control.

The suitable combination of these measurements and indices allow for creating an overall PMU index which describes the online state of the system and consequently the change of state (tendency) of the system. These information are created in a phasor data processor (PDP) which can exchange data with a dynamic security assessment (DSA) system or/and a SCADA system in order to monitor local and global system states for stability monitoring, continuous stead state analysis, short term / forecast stability analysis and remedial actions. Finally, combining PDP, DSA and SCADA enables to enact a wide area protection and control (WAPC) arming and disarming pre-calculated system integrity schemes. In this WAPC a load flow and system state depending decision matrix is installed, which is pre-calculated by the DSA-system (or by precalculated simulations). This matrix allows deciding which is the best system integrity scheme for the current system situation and in case a major disturbance takes place the most suitable countermeasure can be activated.

In a large longitudinal 500 kV system the concept will be described and applied. The system is not (n-1)-safe and the outage of one 500 kV transmission line (double line system) results in blackout of a large part of the system. Using the PMU/DSA based WAPC system the necessary load shedding (system integrity scheme) can be selected to adapt the power balance depending on the actual power flow and location of the fault.

KEYWORDS

Phase Measurement Unit, Wide Area Protection and Control, Dynamic Security Assessment, Black Out Prevention, System Integrity Scheme.

* rainer.krebs@siemens.com

1. INTRODUCTION

The demand on electrical energy is growing in almost all countries in the world. More and more renewable sources with fluctuating infeed characteristic are installed. The role of conventional plants is changing. New targets like sustainable and environmental friendly sources are introduced in the system planning process. Transportation systems have to be more flexible to follow the demand. Classical system margins are reduced and new system margins are introduced to monitor the system behavior. New transmission systems based on AC and DC systems are necessary to interconnect new sources like off-shore wind farms with the grid. New control mechanisms have to be installed to guarantee a stable operation of these hybrid systems.

Distribution systems and transportation systems are operated under changed conditions. More and more small generation is installed in the distribution subsystems. Classical plants are operated with changing operational philosophies. Part load operation and flexible change of operation at low operation points become more important than base load operation over the whole year. New grid codes are necessary to describe how all sources have to support the controllability of the grid. These new conditions and the fast changing operation of the grid makes it necessary to collect more information of the grid to guarantee the smaller stability margins. Better and more accurate system monitoring, control and protection is necessary when systems are operated closer to the transmission systems transportation capability and generally with system loading close to the operational limits.

Especially in very fast growing systems a lack between transportation capacity and generation installation can lead to critical situations.

2. THE ROLE OF DSA

DSA (dynamic security assessment) becomes more and more important in grid control centers. The tasks of a modern DSA system are to: monitor the actual system state; evaluate how critical the state is; score the state trend of the system; assign possible contingencies starting with the actual system situation; recommend which countermeasures should be started after what time

In [1], a modern dynamic security system is described, which filters a huge number of information to a traffic light for the operator by using normed indices, which are combined in a classification process without losing important information. The same indices can be used for the PMU processing unit, but only indices which do not need information of system structure or system parameters can be realized for a fast acting control system. In the next chapter, the main parameters for a DSA- and a PMU-based-system are collected.

The role of the DSA system is not to act as a fast control or protection system. The PMU-based wide area control system is able to take over this role when operators cannot react on events which need decisions in milliseconds. The role of the DSA for such tasks is to pre-calculate the contingencies and to prepare the countermeasures which are activated using PMU measurements. The DSA delivers the loading and load-flow-depending amount of load-shedding, depending on the location of the fault and the resulting consequences for the system. A phasor data processor (PDP) activates the load shedding to keep the power system together to avoid splitting into subsystems without suitable power infeed. The DSA system is able to take into account all necessary switching measures which are helpful in case of outage of system equipment like outage of a large transformer between transportation levels. The calculated actual indices support the operators in case of a sudden change or outage in the system which the DSA system can monitor not as fast as a PMU.

Reference /2/ depicts the framework and architecture of the PMU-based wide area control system together with a modern DSA system using all necessary communication protocols.

3. PMU-BASED WIDE AREA PROTECTION AND CONTROL SYSTEM (WAPC)

Fast growing electrical systems demand more intelligent computer-based systems to support the operators. DSA allows the operators to find out how the system will react after severe contingencies and to define longer lasting countermeasures. Target of the PMU-based WAPC is not to substitute the control management in the dispatching center but to improve the system reaction.

Wide-area-effecting faults endanger systems to cascading effects and black outs. Wide-area faults are results of severe contingency situations. To prevent such contingency situations the severity of the outage situation has to be identified and depending on the expected consequences early countermeasures have to be defined to reduce the risk of spreading the effect of disturbances and outages.

Main benefits of the PMU-based wide are monitors and control systems are: improved system operation; better use of equipment; increased power system capacity; improved power flow; better use of system reserves.

The utility of a PMU-based system allows using on-line information about the system state. By collecting these data the operator can track the trend of the system over the time and initialize reactions like re-dispatch. High loading of the transmission systems increases the economical benefit of the system, but reduces transmission capacity and needs faster countermeasures in case of outage of equipment (lines, compensator, generators). PMU's allow monitoring the actual system state and therefore to activate suitable counteractions in case of critical situations. New algorithms allow to calculate the system oscillation and damping after system events which can drive the system into instability. Analyzing frequency stability, voltage stability and generator stability nowadays can be combined with on-line analyzing small signal stability to get a fast view on the risk of the actual state of the system. In addition, by observing the voltages and reactive power flows the operator can decide about additional reactive power control. The analysis of known pattern like critical/ uncritical voltage recovery or frequency behavior helps the operators to understand the dynamic phenomena. Electronic storage equipment with its fast reaction can be triggered by the PMU-based system to incorporate active and reactive power in ms after identification of a critical situation.

Activation of spinning reserve can be accelerated by change of controller reference values without delay through waiting on the system frequency response.

Figure 1 shows a PMU-based wide area monitoring and control system based on a SIGUARD PDP (Phasor Data Processor) which deploys direct measured information like voltage, current, frequency and phase angles, but in addition calculates new indices for a deeper view into the system state. These indices are normed between 0 and 1 and therefore can be easily understood, compared and combined, which helps the operators to understand the actual situation [3]. Monitoring can be build like a 'traffic light'. Reaching critical index levels allows the operator to make fast decisions to bring the system out of a dangerous situation [4]. If necessary, because the human reaction is not suitable, the system can start automatic control, for example automatic reactive power control or automatic power flow depending load shedding (LS). The example will show the benefits of such a dynamic load shedding. Here the LPFI index is udes to activate the LS. The LPFI index is introduced in the next section.

3.1 Transmission System

GRIDCo is the national interconnected transmission system operator of Ghana. Its mission is to provide reliable, secure, and efficient electricity transmission services and wholesale market operations to meet stakeholder expectations within Ghana and the West African Sub-region, in an environmentally sustainable and commercially viable manner. The work described in this paper was performed for the 161/225/330-kV transmission system comprising more than 100 overhead lines and more than 400 distance, differential and overcurrent protection relays.

Fast load growth is a major challenge and driver for large-scale system expansion. The transmission system has increased its transformer capacity by over 50% in the last five years. Even though the transmission system is often forced to operate close to its limits due to a lack of generation capacity. In the past, mal-operation of the protection system and cascading events were observed. Considering low critical fault clearing times, the situation poses a high risk of total system blackout in case of failure of the primary protection system.

In order to reduce the risk of system collapse, GRIDCo initiated a system-wide protection system review. The objective was to ensure system security and to maximize the utilization of the system through improvement of the performance of the protection system.

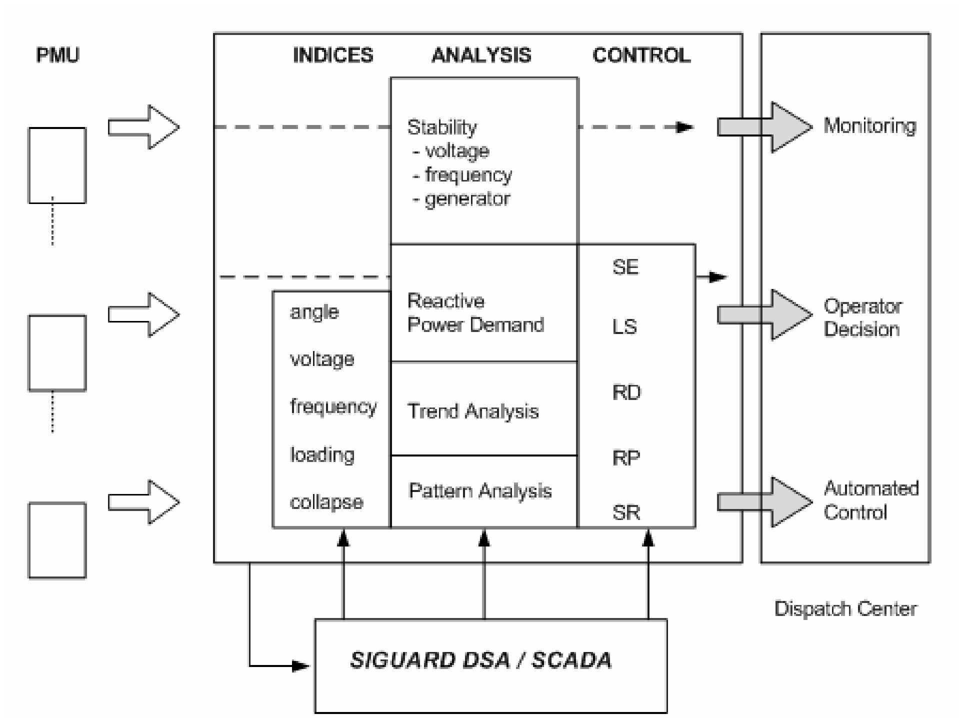


Figure 1: PMU-based wide area monitoring and control system using SIGUARD PDP SE stored energy sources, LS load shedding, RD re-dispatch, RP reactive power control, SR spinning reserve

SCADA and DSA can support the PMU-based system by actual information and pre-calculated countermeasures. For the automatic LS the critical contingencies are pre-calculated and the necessary amount of LS in combination with the actual spinning reserve is stored in a decision matrix.

Fig. 2 depicts the WAPS part which is used as fast wide-area load-shedding (WALS) to activate suitable load shedding depending on the system situation (loading, load flow, fault location).

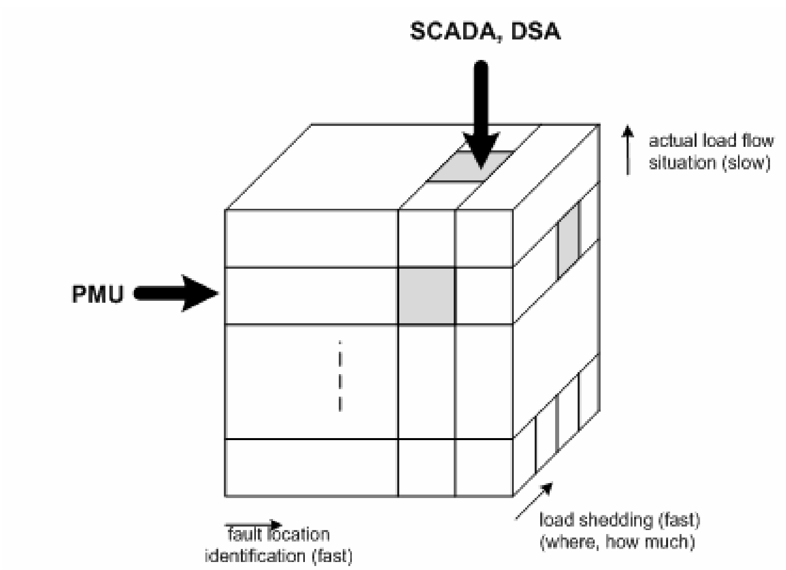


Figure 2: SIGUARD PDP based WALS (wide area load shedding) PMU: fault location, SCADA/DSA: system state, actual LF situation

4. PMU INDICES

PMU-indices are used for the analysis and control of a system based on local information in addition to the basic voltage, current and phasor measurement. The following normed indices (range 0-1) are used for the performance calculation. They can be individually used or combined as shown for a DSA system [5], [6].

4.1. Small Signal Stability Index (SSSI)

To monitor to which extent the damping capabilities of the system are affected by contingencies, the SSSI is proposed. Let ζi be the classical damping measure of i-th oscillation mode that suits the condition $\zeta > \zeta_{abs\,lim}$, where $\zeta_{abs\,lim}$ designates the absolute stability limit and sufficient damping is positively signed. The damping can be extracted by any of the modal identification techniques. For example, the matrix pencil method can be used. The SSSI is calculated by taking into account the ζi and the minimum acceptable damping limit $\zeta_{min\,adm}$. typically in the range of 3–5%. The SSSI is defined by (1), where n is the index norm; it ranges from near 0 for the case in which oscillations are fully damped (ζi = 100%) to 1 for the case in which the damping ratio reaches its minimum admissible value ($\zeta i = \zeta_{min\,adm}$).

$$SSSI = \min\left(1,\ \max\left(\frac{\zeta_i}{\zeta_{\text{min adm}}}\right)^{-n}\right),\ \text{if } \zeta_i > \zeta_{\text{abs lim}} \tag{1}$$

$$SSSI = 1,\quad \text{if } \zeta_i \le \zeta_{\text{abs lim}}$$

To cater to variety of power system responses, the sensitivity of the index may need to be adjusted. This is achieved by setting the norm n.

4.2 Angle Index (AI)

To establish a contingency severity level as a measure of change in the generator load angle, the AI is proposed. It is defined by (2) and ranges from 0 to 1; it is 1 for the case in which the maximum admissible angle ($\delta_{c\,max\,adm}$) is exceeded. In the equation, $\delta_{ci\,max}$ is the maximum angle of the i-th generator during system transition and NG is the number of the system generators.

$$AI = \min\left[1,\ \max_{i=1\ldots NG}\left(\frac{\delta_{ci\ \max}}{\delta_{\text{c max adm}}}\right)\right] \tag{2}$$

4.3 Frequency Gradient Index (FGI)

By being a good indicator of the power unbalance in the system, the frequency gradient can be used as a contingency severity measure. The FGI is defined by (3), where Gi is the gradient of the i-th generation unit following the contingency and Gmax adm is the maximum admissible Hz per second change that may be related to an outage of the largest unit in the system; for example, in the European UCTE, the frequency gradient caused by outage of the largest unit is 6 mHz/s. The index ranges from 0 in the case of no frequency deviation to 1 if the degree of frequency drop is larger than specified.

$$FGI = \min\left[1,\ \max_{i=1\ldots NG}\left(\frac{G_i}{\text{G}_{\text{max adm}}}\right)\right] \tag{3}$$

4.4 Maximum Frequency Deviation Index (MFDI)

The MFDI is derived on the assumption the higher the maximum frequency deviation, the bigger the disturbing effect produced by the contingency. The index is defined by (4) and considers maximum frequency deviation ($\Delta f_{i\,max}$) of the i-th generator relative to the maximum admissible frequency deviation ($\Delta f_{max\,adm}$). The index ranges from 0 for the case in which no frequency deviation is produced to 1 for the case in which the frequency reaches its maximum admissible value.

$$MFDI = \min\left[1,\ \max_{i=1\ldots NG}\left(\frac{\left|\Delta f_{i\max}\right|}{\left|\Delta f_{\text{max adm}}\right|}\right)\right] \tag{4}$$

4.5 Quasi-Stationary Voltage Index (QSVI)

The QSVI quantifies recovery of voltage at i-th node at the end of the transient period following the contingency. The index is calculated as a quotient between voltage deviation at the end of the transient period (ΔVpi) and the maximum admissible steady-state voltage deviation (ΔVi max adm). It is defined by (5), where maximum admissible voltage deviation is a percentage of the rated voltage. The index ranges from 0 for the case in which no voltage deviation is produced to 1 for the case in which the voltage goes below the minimum acceptable value; NN is the number of system nodes.

$$QSVI = \min\left[1, \max_{i=1\ldots NN}\left(\frac{|\Delta V_{pi}|}{|\Delta V_{i\ \mathrm{max\ adm}}|}\right)\right] \tag{5}$$

4.6 Voltage Drop Index (VDI)

To quantify voltage dips due to disturbances and load current transients, the VDI is proposed. The index is calculated by simple geometry, similar to solving the equal area criterion problem in power system stability. It is a ratio between the area ADVi, enclosed by the transient voltage curve Vi and the line of the lower limit of the normal operating voltage band Vi min adm, and area ADVi adm, enclosed by the Vi min adm and transient voltage limit line. The areas are illustrated in Figure 3. The index is defined by (6), where ΔVDVi denotes temporal voltage deviation at the i-th node with respect to (7); NN is the number of the load nodes with the assigned VDI. The VDI can be related to voltage-dip immunity requirements of industrial sites.

$$VDI = \min\left[1, \max_{i=1\ldots NN}\left(\frac{\int_0^{t_S}\Delta V_{\mathrm{DV}i}.dt}{A_{\mathrm{DV}i\ \mathrm{adm}}}\right)\right] \quad (6) \qquad \Delta V_{\mathrm{DV}i} = \begin{cases} V_{i\ \mathrm{min\ adm}} - V_i & if\ \ V_{i\ \mathrm{min\ adm}} \geq V_i \\ 0 & if\ \ V_{i\ \mathrm{min\ adm}} \leq V_i \end{cases} \quad (7)$$

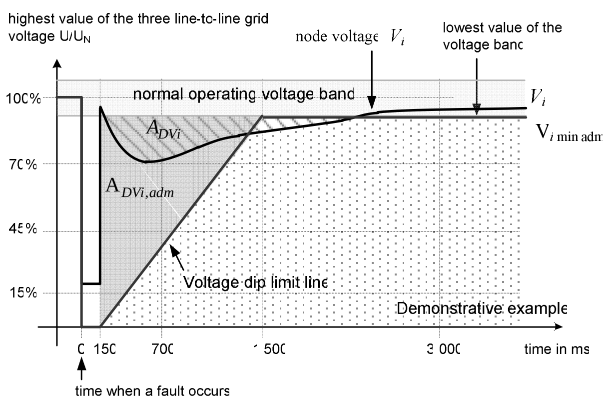


Figure 3: Voltage-dip immunity criteria

4.7 Voltage Ride Through Index (VRTI)

The VRTI is given by (8)–(10) and considers a transient voltage dip both in percentage deviation and in time duration; the fault-on and post-fault voltage deviation is quantified by comparing two areas. Similar as by the VDI, the first area is enclosed by the transient voltage curve (Vi) and the line of the lower limit of the normal operating voltage band (Vi min adm), while the second area is the reference one and enclosed by Vi min adm and the FRT limit line. Each stage of the voltage transient can be treated individually; satisfactory results are obtained if two subareas are defined: one for the fault-on and the other for the post-fault period.

In the equations, j denotes a subarea under evaluation and NN gives the number of the generator nodes with the VRTI.

$$\mathrm{A}_{\mathrm{max\ adm}}^{\mathrm{area}\ j} = \left(V_{\mathrm{min}\,adm}^{band} - V_{\mathrm{min\ adm}}^{\mathrm{area}\ j}\right)\cdot \mathrm{t}_{\mathrm{max\ adm}}^{\mathrm{area}\ j} \tag{8}$$

$$\Delta V_i^{\text{area } j} = \begin{cases} \infty \ , \text{ if } V_i < V_{\text{min adm}}^{\text{area } j} \\ V_{\text{min adm}}^{\text{band}} - V_i \, , \text{ if } V_{\text{min adm}}^{\text{area } j} < V_i < V_{\text{min adm}}^{\text{band}} \\ 0 \ , \text{ if } V_i \ge V_{\text{min adm}}^{\text{band}} \end{cases} \tag{9}$$

$$VRTI = \min\left[1, \max_{i=1,\ldots NN}\left(\frac{\int\limits_{t_{\text{area } j}} \Delta V_i^{\text{area } j} \cdot dt}{A_{\text{max adm}}^{\text{area } j}}\right)\right] \tag{10}$$

4.8 Line Power Flow Index (LPFI)

The LPFI is related to the requirement that the post-contingency power flow on transmission lines should not exceed a power flow limit (designated as Pi lim) since such excess may activate line protection and so degrade the system security. The LPFI is defined by (11)

$$LPFI = \min\left[1, \max_{i=1\ldots NL}\left(\left[\frac{P_{\text{p}i}}{P_{i\,\text{lim}}}\right]^n\right)\right] \tag{11}$$

where Ppi is the power flow through the i-th line at the end of the transient period following the contingency; n is index norm (real non-negative number), which stands for the relative importance of a line in the system; the more important the line, the lower the norm; NL refers to the number of the lines in the system. If a line is loaded to the limit, the LPFI is 1.

4.9 Transformer Power Flow Index (TPFI)

Overloading of power transformers may result in premature aging of insulation and irreversible damage. The TPFI is defined by (12); parameter Pi trf denotes the actual loading of the i-th transformer, whereas Pi trf rat relates to a transformer's rated loading; NT is the number of the transformers in the system.

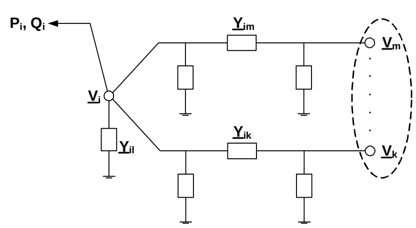
$$TPFI = \min\left[1, \max_{i=1\ldots NT}\left(\frac{P_{i\,\text{trf}}}{P_{i\,\text{trf rat}}}\right)\right] \tag{12}$$

4.10 Nodal Loading Index (NLI)

Starting with a formulation of the load flow equation as a two node model system representing the neighboring nodes by the voltage Ei (see Figure 4)

$$\underline{E}_i = E_i \angle \varphi_i = \sum_{\substack{k=1 \\ k \neq 1}}^{N} \left(\underline{Y}_{ik} / \underline{Y}ii\right) \underline{V}_k \tag{13}$$

$$\underline{Y}_{ik} = Y_{ik} \angle \phi_{ik}$$



$\underline{V}_i$ can be calculated related to E_i as e_i, where

$$e_i = \sqrt{\frac{1+2P_{ii}}{2}\left(1 \pm \sqrt{1-4\Delta_{ii}}\right)}, \qquad \Delta_{ii} = \left(P_{ii}^2 + Q_{ii}^2\right)/\left(1+2P_{ii}\right)^2 \ \text{ with } \begin{bmatrix} P_{ii} \\ Q_{ii} \end{bmatrix} = \frac{1}{Y_{ii}E_i^2}\begin{bmatrix} \cos\phi_{ii} & -\sin\phi_{ii} \\ \sin\phi_{ii} & -\cos\phi_{ii} \end{bmatrix}\begin{bmatrix} P_i \\ Q_i \end{bmatrix} \tag{14}$$

$$\sin \varphi_i = -Q_{ii} / e_i \tag{15}$$

This formulation of the nodal voltage allows defining critical absolute ranking margins of the system as follows:

$$4\Delta_{ii} \le 1 \; and \; |Q_{ii} / e_i| \le 1 \tag{16}$$

The margins are non-linear and reflect loading and voltage situation. This main margin allows to select critical loading cases (trend analysis) and shows the distance to system stability /7/.

NLI can be formulated to be

$$NLI = \min\left\{1, \max_{i=1,\dots N}\left(4\Delta_{ii}\right)\right\} \tag{17}$$

5. EXAMPLE OF A WAPC SYSTEM USED AS WALS

Figure 5 shows the topology of a 500 kV longitudinal system. This system spreads in about 2000 km and includes three subsystem named Nord, Central and South. At Central subsystem, there is a double line connected between two load center at North and South. The peak load of whole system is 49 GW. The system is equipped with hydro-, gas and CCPP's.

To investigate the effect of WALS, two simulation cases are shown (see Figure 4). In the first case, some disturbances are implemented at the double line mentioned above. This line is transferring about 2 GW from North to South. A three phase fault occurs on one circuit near one bus bar and then this fault is cleared by tripping this circuit. The total fault duration is 140 ms. In the second case, the same scenario is implemented for one single transmission line located at the biggest load center of system located at South. This line loading is 1 GW.

With WAPC, the optimized amount of automatic load shedding is defined to:

- Keep the system stable after fault
- Avoid overload of transmission lines

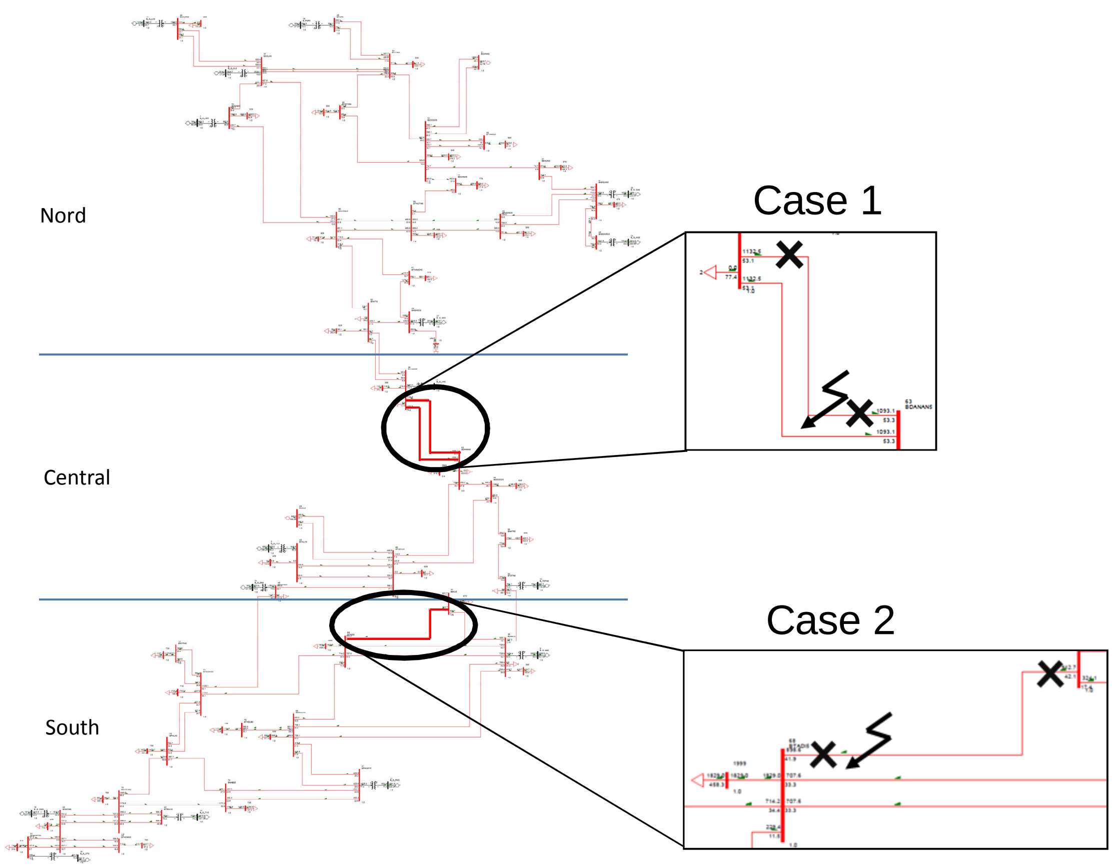


Figure 4: 500 kV studied system

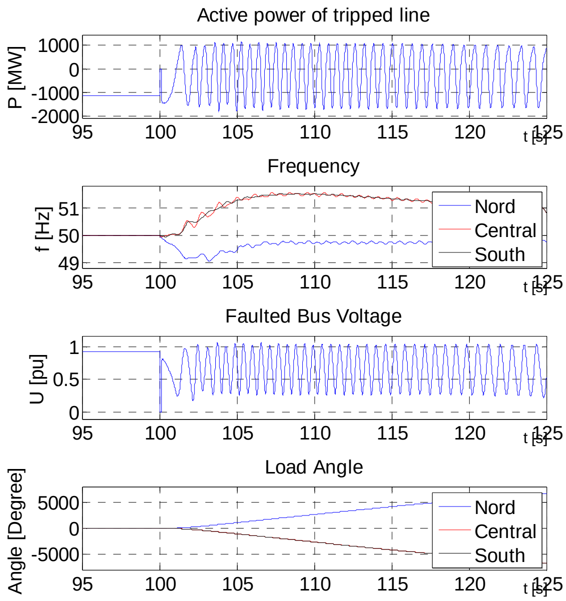


Figure 5: System behavior in case 1 without smart load shedding

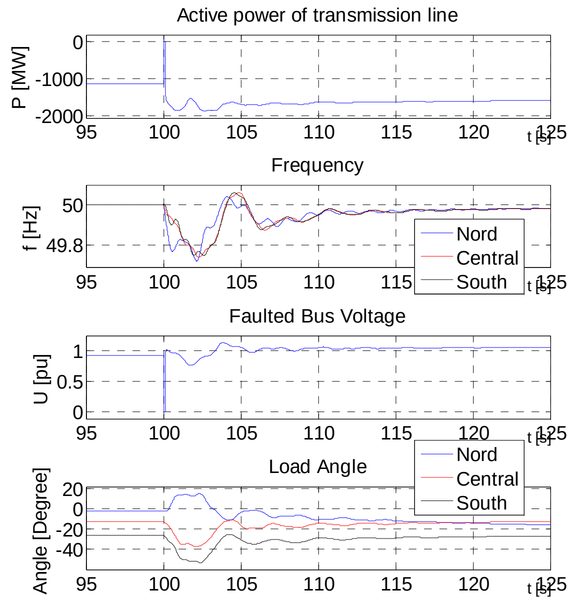


Figure 6: System behavior in case 1 with smart load shedding

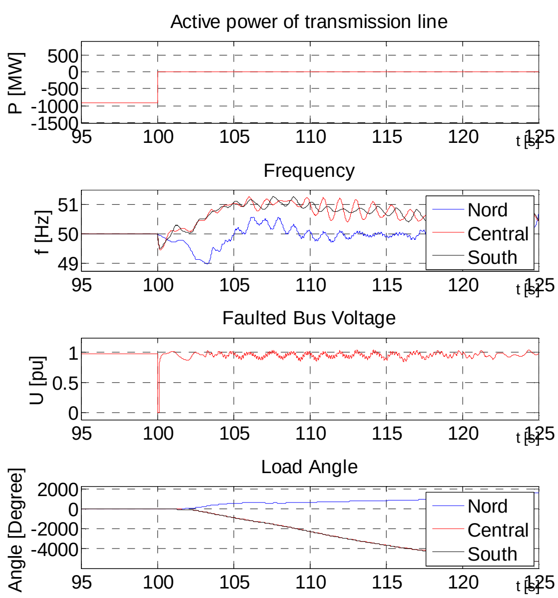


Figure 7: System behavior in case 2 without smart load shedding

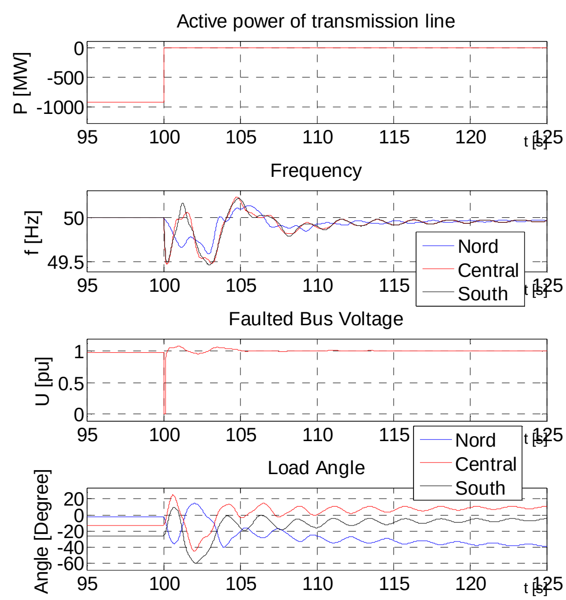


Figure 8: System behavior in case 2 with smart load shedding

The simulation results of case 2 are shown in Figure 7 and Figure 8. The same effect is gained when there is a minimum of 1330 MW load shedding activated. The frequency and voltage around the faulted bus and the load angle are stable after suitable transient time.

6. CONCLUSION

With an example of intelligent load shedding activation paper demonstrates the use of composed indices in a PMU-based wide area monitoring and control system. It results in lower risk of instability in the system. It minimizes outages and blackout situations by automatic counteractions. It allows the control of congestion situations. The example of an automatic load shedding system for the main transportation system of a large longitudinal structured electrical system shows how the reliability of a system, which is not (n-1)-safe, can be improved. By progressing the system reaction blackouts can be prevented safely. Cascading splitting into insolated part load system can be avoided and instability can be prevented.

BIBLIOGRAPHY

[1] Kerin, U., Trinh, N. Tuan, Lerch, E., Bizjak, Grega: Small Signal Security Index for Contingency Classification in Dynamic Security Assessment; IEEE Power Tech Trondheim, Norway 2011.

[2] Eichler, R., Krebs, R., Wache, M., Lerch, E., *Mitigating Risk of System Instability caused by Fluctuating Renewables with smart Transmission Grid Applications;* CEPSI-Conference Bali, Indonesia 2012.

[3] Kerin, U., Lerch, E., *Dynamic Security Assessment to Improve System Stability;* CRIS-Conference Hanoi, Vietnam 2011.

[4] Kerin, U., Heyde, C., Krebs, R., Lerch, E., *Power Application Tool for On-Line Security Investigations.*

[5] Kerin, U., Lerch, E., *Improved Fuzzy Approach to Contingency Classification in Dynamic Security Assessment;* to be published.

[6] Gimenez, J.M., Mercado, P.E. (2007), *Online inference of the dynamic security level of power system using fuzzy techniques,* IEEE Trans. Power Syst., vol. 22, no. 2, May 2007, pp. 717-726

[7] Lerch, E., Ruhle, O., *Ranking of System Contingencies in DSA systems.* APSCOM 2009, Hong Kong, China 2009.

.

CIGRE Regional South -East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#91

DSA of Power Grids in Real-Time

C. HEYDE, U. KERIN*, R. KREBS, E. LERCH
Siemens AG
Germany

SUMMARY

This paper presents a dynamic security assessment solution, which can be used in the power system control room to improve system stability. It is based on a set of security indices. The indices are able of establishing contingencies' severity levels as a measure of different aspects of power system security. A system based on fuzzy logic is used to combine the indices into a single composite index. The composite index is able to alert the control operator to the network conditions that represent a significant risk to system security based on over-all system performance.

KEYWORDS

dynamic security, stability, contingency ranking

1. INTRODUCTION

While it is true that electric power systems are designed to be stable, in actual practice, the systems may be prone to instability. This is largely due to uncertainties related to the assumptions used in the system planning and design phase. Most common are assumptions on electrical load, electrical generation, power network topology and inherent characteristics of the network components. A false assumption used in the system planning can introduce an error in actual system operations, resulting in equipment malfunction, local power interruptions or blackouts.

Electrical transmission systems are used for the transfer of bulk power from generation to loads. They are designed to withstand operational contingencies of a certain magnitude without significant impact on consumers and stability of the system.

The fact is, however, that modern transmission systems are not being used in the way they were intended to be used. Rather than being used for secure unidirectional power transmission, they are being used as a power exchange platform driven by national or international electricity markets and economic goals. In such environment local disturbances can easily develop into system-wide incidents.

The number of blackouts has been gradually increasing over the last two decades. The impact power outages can have on the economy and social welfare can be enormous. The consequences in terms of economic loss can easily be compared to ones of natural disasters [1]

The nature of these incidents may be related to the stability of an electrical system. Figure 1 shows different stability types a power system can undergo [2]. The main stability categories are generator stability, reflected in the rotor angle behavior against the grid, frequency stability, as a result of load and generation imbalance, and voltage stability, caused by a lack of reactive power. Various

* uros.kerin@siemens.com

disturbances showed that electrical systems are experiencing all types of stability problems. Two examples are given in this paper. In Figure 2, the blackout in Italy in 2003 is shown [3]. In about 2.5 minutes the frequency suddenly dropped and could not be stabilized by different methods; 7000 MW load shedding did not help to stabilize the system because of additional loss of 5500 MW after separation from the European grid. In 2007, a part of the South-Balkan-System separated from the European System due to loss of two lines, followed by an overload of the remaining lines and trip of these lines. The power system of Greece, Albania, Kosovo and Fyrom islanded and the frequency dropped to 48.7 Hz. Eventually, the lines between Greece and Albania, and Greek-Fyrom tripped too. The event ended with blackout in Albania, Fyrom and Kosovo. The blackout required approximately 30 seconds to develop (Figure 3).

Events like these imply that observing and analyzing system state during operations is of great importance. The main goal of online system analyzes is to alert an operator to conditions representing a significant risk to system stability and provide practical information for decision making [4], [5], [6]. In this paper, a system for dynamic security assessment is described, which allows online simulation of operational contingencies, identification of severe disturbances and monitoring of system reserve margins as the system operates. This indication allows the operator to predefine counter measures and to prepare actions to stabilize the system.

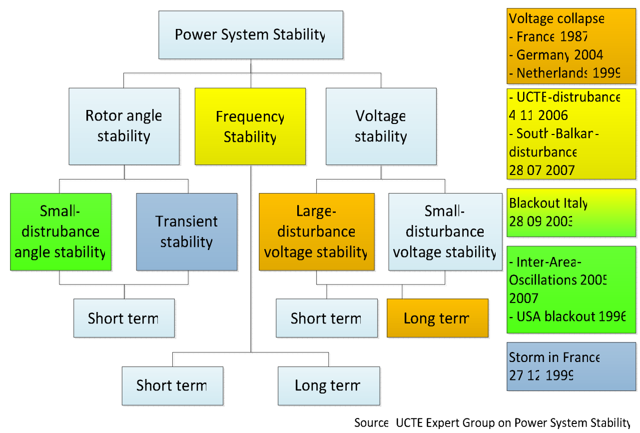


Figure 1: Classification of power system stability with examples

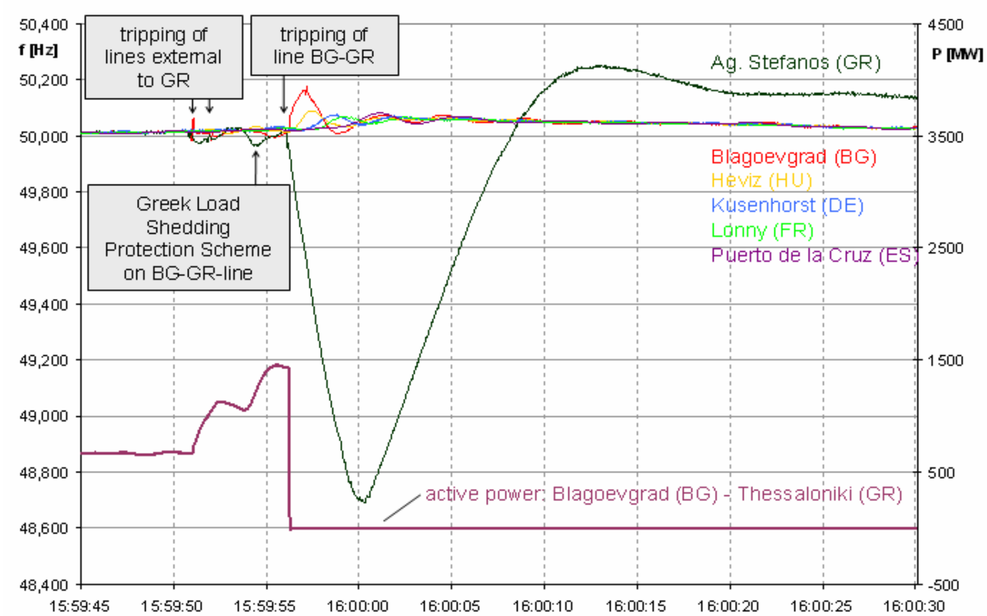


Figure 2: South-Balkan Disturbance in 2007 (source: UCTE Expert Group on Power System Stability, Rome, 17.06.2008 – V Hanneton, C. Jahnke).

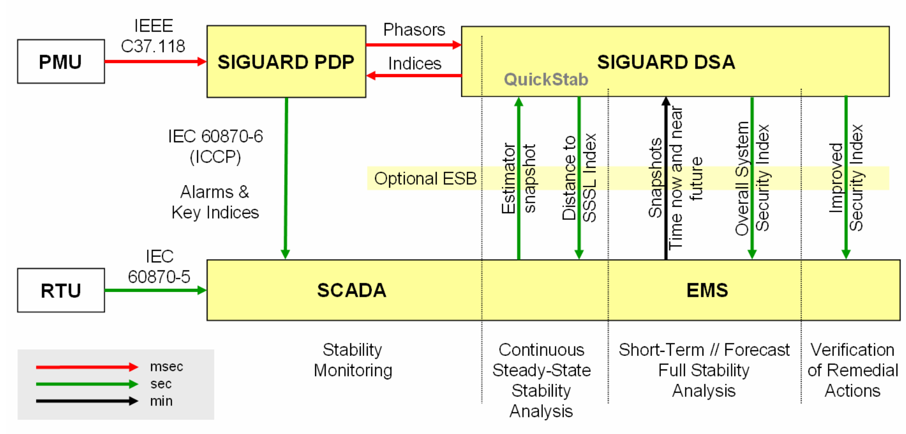


Figure 3: Typical control room setup with integrated dynamic security assessment.

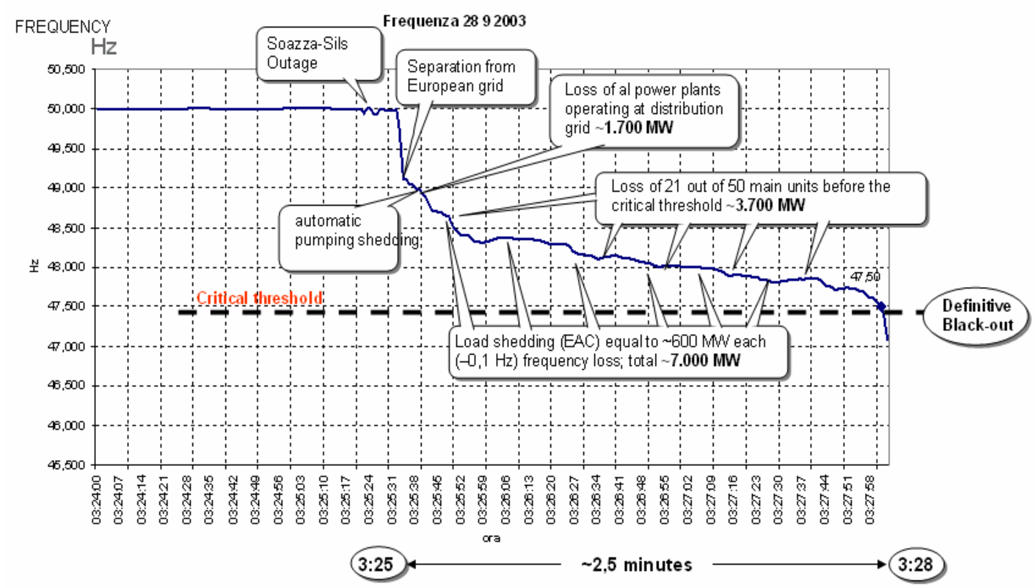


Figure 4: Blackout in Italy in 2003 (source: UCTE Expert Group on Power System Stability, Rome, 17.06.2008 – V Hanneton, C. Jahnke).

2. DYNAMIC SECURITY ASSESSMENT

To maintain security on required levels it is essential for the power system operator to establish an impression on the system condition. At any instant, he has to have a feel for the available "maneuvering space" to be able to respond fast in case of a power line or generator outage, or other similar contingencies. Crucial elements in achieving this are expert knowledge and experiences, but for predicting security under constantly changing load/ generation/ topology conditions it is necessary to also conduct online computer–aided investigations.

A tool capable of providing support in online decision making is Dynamic Security Assessment (DSA). DSA enables fast evaluation of single and multiple contingencies and delivers results that are indicative of operational irregularities. Typical criteria in DSA include:

- rotor angle stability, voltage stability and frequency stability;
- damping of power swings inside subsystems and between subsystems on an interconnected network;
- grid code compliance (for example frequency and voltage excursion during the dynamic state (dip or rise) beyond specified threshold levels).

The core of DSA is a computational technique [7]. A technique providing a high level of confidence is conventional time domain simulation. It is one of the main tools in system planning and analysis. It is accurate and has a superb modeling capability. High-order models can be considered. Time development of dynamic system parameters is calculated by integrating the system differential equations step by step. Typical integration time step would be about 10 ms. A sufficient simulation time would be in the range of 5 to 20 seconds. Note that simulation models and simulation need to be tailored to the phenomena under investigation.

The European Network of Transmission System Operators (ENTOS-E) is well aware of the importance of the control-room-conducted security investigations. In the development plan that guides the future development of the European transmission network, the ENTSO-E explicitly suggests that tools for DSA need to be adopted for the operators in order to increase situational awareness. These tools should primarily rely on well-established techniques and enable fast "what-if" investigations [8].

The backbone of every dispatch center is an energy management system (EMS). The EMS is a computer-aided tool used by the operators to monitor, control and optimize the performance of an electrical system. A monitoring and control part of the EMS is SCADA (supervisory control and data acquisition). SCADA is a control system deploying multiple technologies that allow the operator to monitor and process data as well as send commands to remote terminal units (RTUs); to line breakers to open or close, for example. Typical data refresh cycle of the EMS is several seconds.

In recent years, many dispatch centers have improved the monitoring capabilities with the implementation of the synchronphasor technology. Synchronphasors are field measurements of network quantities, synchronized in time and expressed as phasors (magnitude and phase). They allow monitoring power flow or frequency in real-time. The devices measuring the synchronphasors are Phasor Measurement Units (PMUs). A typical PMU sampling rate is 20 ms. The synchronphasors are processed and visualized by the phasor data processor (PDP). The components are shown in Figure 4.

In a standard configuration, the data from EMS and PDP are evaluated by the operator. The amount of data to be evaluated can be very large. In a small system with 50 nodes, for example, at least 100 parameters are to be considered to obtain clear picture on the current operating condition. The amount is significantly increased by "what-if" analysis and investigation of future system states. Each parameter needs to be examined with respect to specific limits and drawing conclusions on corrective actions may be necessary. In addition to effort, time is required for this, which might not be available in critical situations.

The effort and time required for examining the information on the voltage, frequency, and angular behavior in the current and future system states may be significantly reduced by running online DSA. Through interface to EMS and PDP, DSA is given access to real-time data and by making use of simulation, screening and ranking of current and future system states is performed without operator's involvement. An alarm can be configured to alert the operator only on potentially dangerous conditions and focus his attention on particular network components or problematic areas. Effectively, DSA is able to alleviate the operator of tasks associated with the system state assessment and provide him with insight not only into the current operating condition but also into its short-term development. With this information control errors are avoided and the stress on the operator is significantly reduced.

2.1 System state classification

In general, the state of a power system can be determined based on its ability to perform its intended function under different contingency levels. A reliable way of judging the impact of contingencies on the system operation is to perform the contingency analysis. Current practice to perform the analysis is in two phases: contingency screening and contingency ranking. The contingency screening phase is usually performed offline and with the objective to screen a number of possible contingencies down to the most credible ones; it gives a list of potentially severe cases that are most probable to occur and are expected to cause any kind of security violations. In the contingency ranking phase, full analysis of these credible contingencies is performed either offline or online.

In system operations, the analysis of the credible contingencies assists the operators to control the system at a secure operating point. Hence the contingencies are examined online on a periodic basis or after a change in the operation; nevertheless day-ahead offline runs are also common. The final list of contingencies to be checked is subject to the system condition in a state and operator's experience. Typically, the ones to be examined are defined as the loss of a single item or plant due to phase to earth faults or other adverse situations.

2.2 Contingency classification

A reliable contingency classification may be achieved through inference of important variables or indices related to system parameters which vary significantly with the prevailing conditions in the system.

Determining grid code compliance and system stability is possible in two ways: by using conventional the so-called deterministic approach or a methodology involving estimation of relative agreement between the actual and limiting values of important system quantities. The conventional approach delivers whether a system limit has been violated or not, which can be in terms of Boolean algebra represented by logical 0 or 1, whereas the other gives a relative distance to the limit by ranging from 0 to 1, where 0 stands for the full grid code compliance or excellent performance, 1 denotes a limit violation or poor system performance, while values in between give a relative performance level.

2.3 Performance and incorporation

Online DSA aims at determining the state of a power system as it operates. Credible contingencies are evaluated after system changes, periodically, or on demand. Typical time settings used in practice are: contingency and short circuit analysis are performed every 5 minutes, steady state transient stability calculation every 2 to 3 minutes, N-1 security is examined on a 5 minute cycle, and every time after a valid state estimation becomes available voltage security is calculated.

DSA can be integrated into the dispatch center in many ways. It may be added to the existing EMS architecture in the form of independent modules that are compatible with other subsystems. A loose solution, which has also been adopted by ONE Morocco, is illustrated in Figure 5. The solution requires minimum structure adjustments and allows for incorporation of any number of sub-processes. For instance, the EMS system installed at ONE control center did not contain a module for transient stability assessment (TSA). This missing functionality was added to the existing configuration later simply by installing a dedicated workstation running TSA on basis of a snapshot from the system state estimator.

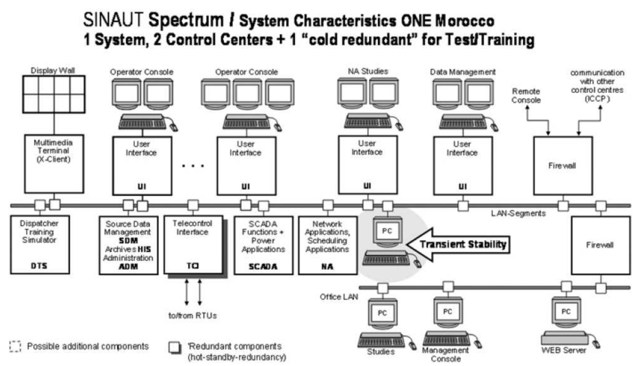


Figure 5: ONE National control center with integrated transient stability assessment [6]

3. DYNAMIC SECURITY INDICES

DSA can be sufficiently implemented by a number of security indices. These indices are designed so as to cater to various aspects of power system security by capturing transient response of dynamic parameters after system events. Table I gives some of the indices that can be used in DSA. They are able to detect voltage, transient and stability of low frequency oscillations, and evaluate quality of the system transition from pre- to post-disturbance condition. The intention of the indices is to replace visual analysis of the results, which is a task typically performed by the system analyst. The analytical definition of the indices is available in [9] to [12].

Experiences show that no single security index can reliably capture the entire system state. It is better to use a combination of the indices instead. Many techniques can be used for this purpose. The weighted sum technique is the most commonly used one since it is easy to understand and in most cases provides sufficient results. Also applying the simple maximum method is adequate, but finding the maximum index gives no information at all on the over-all security of the system. Dedicated functions are also an option however in most cases these are a custom derivative of the weighted sum technique.

An efficient alternative is a technique of soft computing. Assuming that the system analyst is capable of representing his knowledge about the system as a set of facts and rules, the uncertainties related to proper weight selection, as is the case when applying the weighted sum method, can be more efficiently handled by means of fuzzy logic [13]. Fuzzy logic provides algorithms for mapping an input space to an output space on the basis of if-then rules and allows high-flexibility when modeling multivariable-reasoning systems. Figure 6 shows the main steps of the process.

	Limit or regulation	Security index
1	Voltage stability	Voltage Stability Index
2	Small signal Stability	Small Signal Stability Index
3	Transient stability	Energy Margin Index
4	Out-of-step protection	Angle Index
5	Dynamic frequency deviation (dip or rise)	Frequency deviation index
6	Primary system control	Frequency recovery time index
7	Machine mechanical activity	Frequency gradient index
8	Dynamic voltage deviation (dip or rise)	Dynamic voltage index
9	Steady state voltage	Quasi-Stationary voltage index
10	Fault ride through requirements	Voltage ride through index
11	Power line rating	Line power flow index
12	Transformer rating	Transformer power flow index
13	Load shedding	Load shedding index
14	Nodal loading	Nodal loading index

Table 1: List of Some Power System Security Aspects and Security Indices for Their Evaluation

By fuzzification and defuzzification of the indices equally distributed along the interval 0 to 1, a multi-stage Fuzzy Inference System (FIS) sufficiently composes an over-all dynamic performance index. One possible way to combine the indices using a multi-stage FIS is illustrated in Figure 7. As the final output it delivers the Fuzzy Dynamic Security Index (FDSI). As shown by the case study, other input/output combinations are also possible and the system can be easily adjusted to meet the operator's requirements.

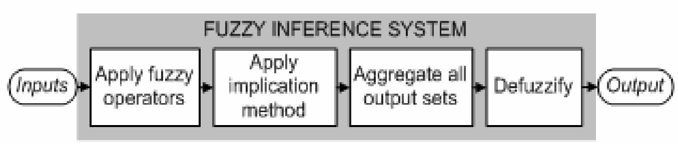


Figure 6: Main steps in fuzzy logic reasoning

Note that in this paper the indices are not explained in detail; nevertheless, to give the reader a feel for the concept, a basic reasoning behind the small signal stability index is presented in the following section.

3.1 Small Signal Stability Index[11]

Let ζ be the traditional damping measure of the most critical oscillation mode that suits the condition ζ > ζabs lim, where a positive sign denotes a sufficient damping. The Small Signal Security Index (SSSI) is calculated by taking into account the ζ and the minimum acceptable damping limit ζmin,admissible. The acceptable damping limit is system-dependent and typically in the 3-5% range [14]. The SSSI is defined by (1), where n is the index norm. The index ranges from near 0 for the case in which oscillations are fully damped (ζ=100%) to 1 for the case in which the damping ratio reaches its minimum admissible value (ζ = ζmin,admissible). The index can refer to a single mode or to a specific range of oscillation modes.

$$SSSI = \min\left(1, \left(\frac{\zeta}{\zeta_{\min,admissible}}\right)^{-n}\right), \text{ if } \zeta > \zeta_{\text{abs lim}}$$

$$SSSI = 1, \text{ if } \exists\ \zeta \le \zeta_{\text{abs lim}}$$

Power systems differ in the intensity of their dynamic response; in some, a disturbance severely affects the oscillation modes, while in others the effect is negligible. To cater to this variety of responses, the sensitivity of the index sometimes needs to be adjusted. This is achieved by setting the norm n. The norm regulates the dramatic progression of the index as the system approaches the security threshold and is crucial for visualizing the importance of the condition. It can depend on an investigation's particular requirements or one's intention to indicate specifics in the mode behaviour, and can be based on experience or system-sensitivity studies. The absolute relation to the security boundary is, however, given by n=1.

The typical index behaviour is obtained by setting the norm to 1.36. The setting is given, referring to the criterion of the SSSI that equals 0.5 at 5% damping and 1 at the security threshold of 3%. The norm is calculated by using equation (2), which is a derivative of (1). The criterion is based on the typical damping range (3-5%) and implies intense index progression as the damping decreases below the 5% boundary.

$$n = -\frac{\log\left(SSSI\big|_{\zeta}\right)}{\log\left(\dfrac{\zeta}{\zeta_{\min,admissible}}\right)} = -\frac{\log(0.5)}{\log\left(\dfrac{5\%}{3\%}\right)} = 1.36$$

4. STUDY CASE

A model of a large actual power system is used to test the performance of the algorithms for the DSA. The main characteristics of the model are: 500-, 230-, 115 kV and lower voltage levels, 259 transformers, 119 generators, and 515 transmission lines. The main 500- and 230 kV transmission network is shown in Figure 8. The generators are represented with high-order models and equipped with speed governors and exciters.

Two base scenarios are considered: normal operation (A) and normal operation with a uniformly distributed load increase of +2.5% on the load nodes (B). In each scenario two contingencies are applied: a three-phase fault followed by the outage of a 230 kV line connecting the western and southern parts of the network (LO), and spontaneous outage of a large generator in the central system area (GO).

The idea is to calculate the indices in the normal system state and compare them with the values calculated for abnormal operation. Calculations of the system's transient have been made using a full simulation whereas the system's low frequency characteristics have been extracted using the QR algorithm. Not all indices as per Figure 7 are considered in the study case.

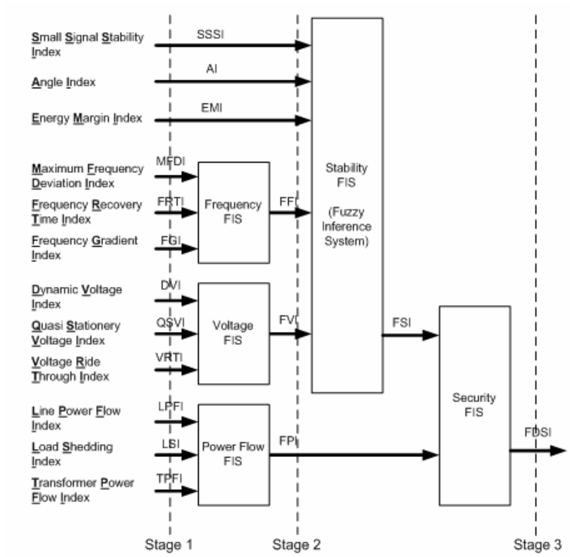


Figure 7: Proposed three-stage fuzzy inference system for power system dynamic security inference.

In normal operation the system excites 770 low frequency oscillation modes. As shown in Figure 9 most are sufficiently damped, while two are in close proximity to the damping threshold of 3%. These are the system's critical modes.

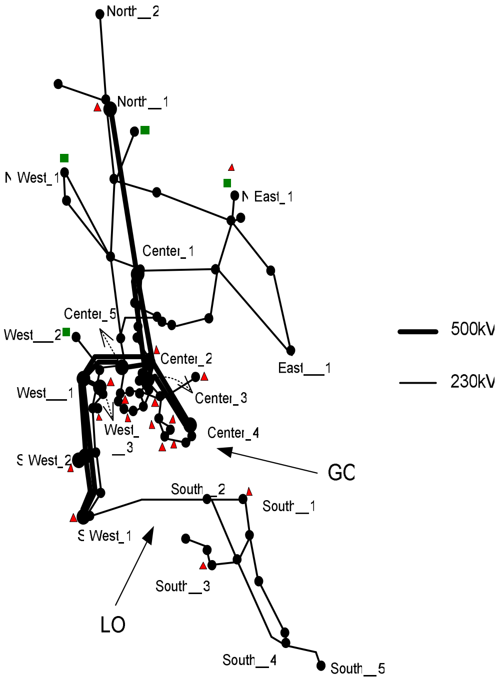


Figure 8: 500 kV and 230 kV networks of the test power system.

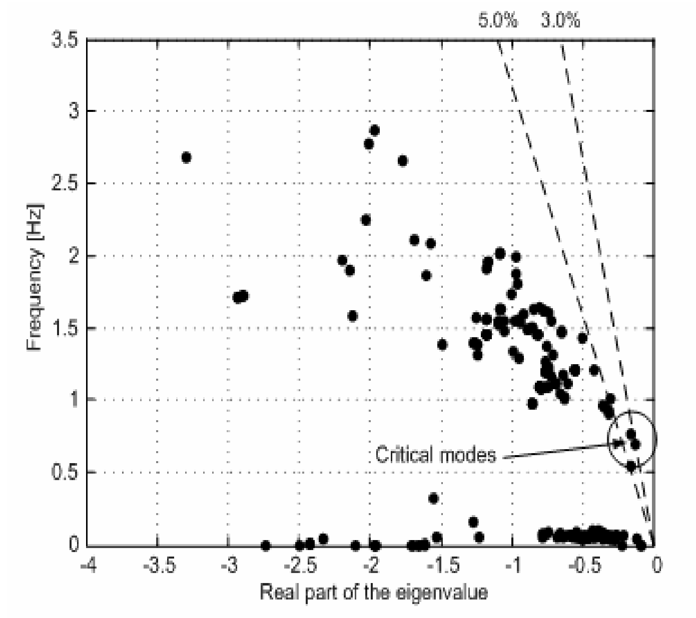


Figure 9: Critical inter-area oscillation modes of the test system

Applying the scenarios and consequently changing its condition alters the characteristics of the system and affects the modes. The change in position of the most critical mode is presented in Figure 10. The markings denote the mode position with respect to the scenario and contingency applied.

Calculation results are summarized in the following tables. Table II gives the most critical mode referring to a scenario. The small signal security of the system is assessed based on the mode's characteristics. If the system is subject to changes in the network the SSSI increases regarding its initial value in scenario A. The largest impact on the small signal security of the system is posed in scenario B-GO.

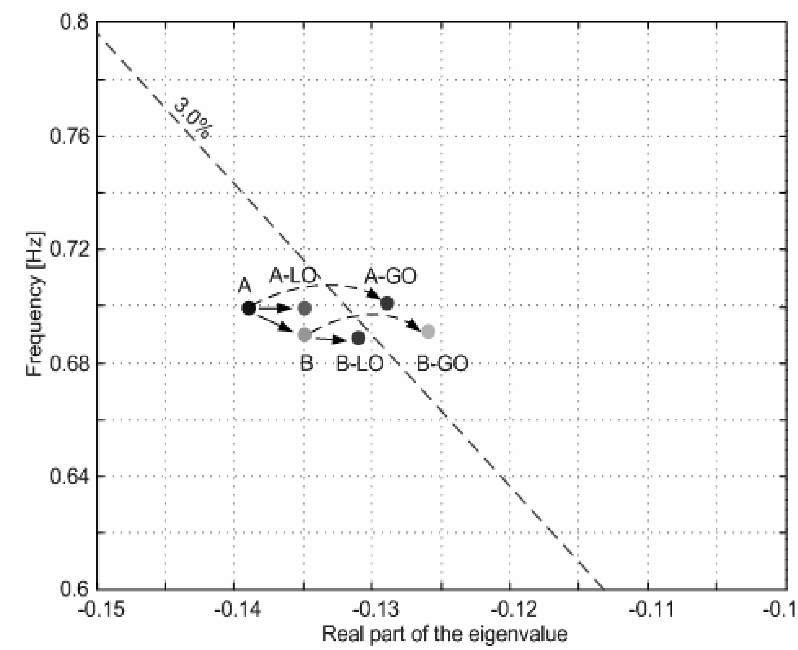


Figure 10: Critical mode variation of the test system when subjected to contingencies.

Table III gives the numerical values of the fuzzy over-all security index (FOSI). The FOSI combines the FDSI and SSSI and delivers an aggregated measure in which the overall security of a system is affected by the scenarios. To make FOSI calculation possible the three-stage FIS shown in Figure 7 has been reconfigured.

Scenario	*Critical mode*	*Damping %*	*SSSI*
A	-0.139 +*i* 4.398	3.16	0.93
A-LO	-0.135 +*i* 4.395	3.07	0.97
A-GO	-0.129 +*i* 4.408	2.93	1.00
B	-0.135 +*i* 4.337	3.11	0.95
B-LO	-0.131 +*i* 4.332	3.02	0.99
B-GO	-0.126 +*i* 4.346	2.9	1.00

Table 2: SSSI Calculation

Scenario	*Index*						
	AI	*FFI*	*FVI*	*FPI*	*FDSI*	*SSSI*	*FOSI*
A	0.26	0.00	0.82	0.7	0.67	0.93	0.82
A-LO	0.35	0.14	0.82	0.77	0.71	0.97	0.90
A-GO	0.28	0.18	0.81	0.67	0.65	1.00	1.00
B	0.27	0.00	0.95	0.82	0.87	0.95	0.93
B-LO	0.36	0.14	0.95	0.82	0.85	0.99	0.98
B-GO	0.28	0.18	0.95	0.82	0.86	1.00	1.00

Table 3: FOSI Calculation

From values of FVI and FPI a conclusion is possible that the system is experiencing unacceptable voltages and high loading of transmission lines; from values of SSSI it can be concluded that small signal stability is an issue in this system. Small signal stability, captured by SSSI, is usually associated with transmission of large amount of power through weak interconnecting power lines, captured by FPI. A suitable solution would therefore include system reinforcement, with additional lines at a specific location.

The transient response of the system to the scenarios is given in Figure 11 to Figure 12. In scenarios A-LO and B-LO a short circuit 100 ms in duration trips one of the two parallel lines connecting the nodes S.West_1 and South_2. The single line tripping causes the voltage to drop, the acceleration of nearby generators and a frequency deviation. The system remains secure.

The scenario including LO can be, however, easily escalated to an insecure case (SSSI and FDSI are 1). If following the outage the remaining line is tripped, the system breaks into two areas and loses its stability. The conditions are shown in Figure 13 and Figure 14, and visualized by colours in Figure 16.

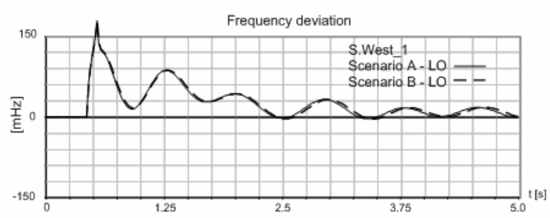


Figure 11: Frequency deviation following a three-phase fault with a line outage (S.West_1).

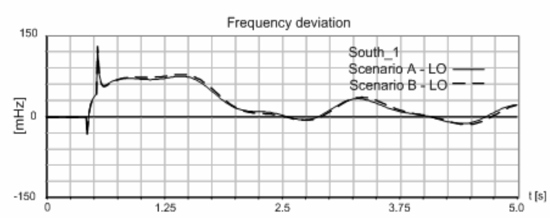


Figure 12: Frequency deviation following a three-phase fault with a line outage (South_1).

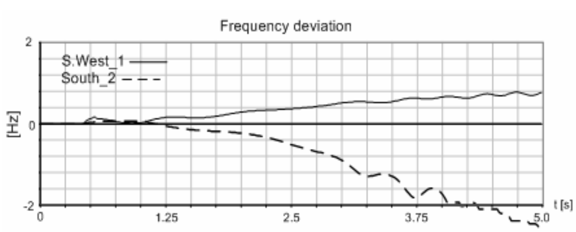


Figure 13: Frequency instability following a corridor outage.

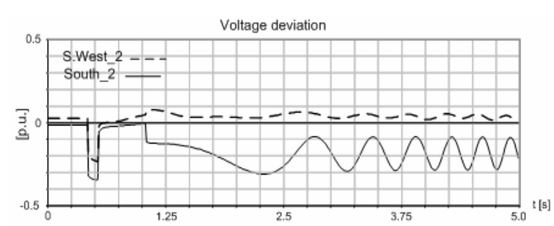


Figure 14: Frequency instability following a corridor outage.

Applying a visualization technique similar as in traffic control, the performance indices can communicate contingency severity and thus the power system security degree by means of indicative colors. These need to be carefully selected in order to deliver a suggestive message; if remedial actions are needed, for example. As illustrated in Figure 15, a smoothly changing color scale is suitable for that purpose.

The selected color scale refers to the index magnitude equally distributed along the interval [0 1]. The scale-ends denote the absolute security degree: secure-insecure. Although any color scale is adequate for the purpose, the most obvious is to use green and red for denoting the absolute secure and insecure system condition and a color-mix in between for security variation. In this way, the reporting is simple but indicative, suggesting the alert level and the expected magnitude of remedial actions for improvement of the condition.

In Figure 16, four indices are visualized. Angle Index and Fuzzy Frequency Index show participation of network generators in the angular and frequency oscillations. The generators with the most severe dynamic response are in the south. Depending on the protection settings they could be tripped. Since there are only few generators in the south, the reactive power support is limited; hence this region also experiences unacceptable dynamic and steady-state voltage deviations. The bottle-neck of the system is shown by the Fuzzy Performance Index, which considers the power flow through transmission lines and transformers. It indicates that dynamic contingencies can lead to local overloads which may results in a cascading event and system separation. The index clearly suggests system reinforcement is required.

The frequency response of the system following a spontaneous outage of the 700 MVA generator connected to the 500 kV network is presented in Figure 17. In both scenarios the frequency variation is alike (see FFI in Table III) and we thus only report on scenario B-GO. In the scenario the magnitude of the initial frequency sag is 0.502 Hz. After a time, the frequency improves and stabilizes at an offset of 0.228 Hz considering its nominal value. Although strong fluctuations in load flow and

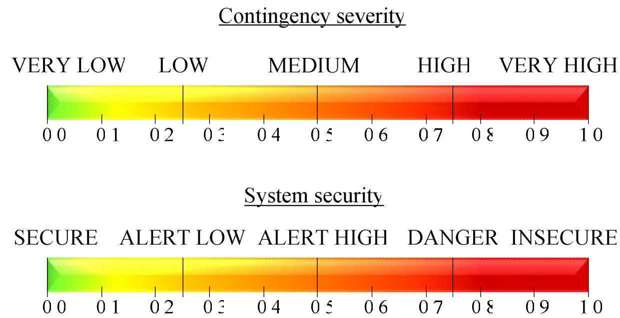


Figure 15: Visualization of power system security degree.

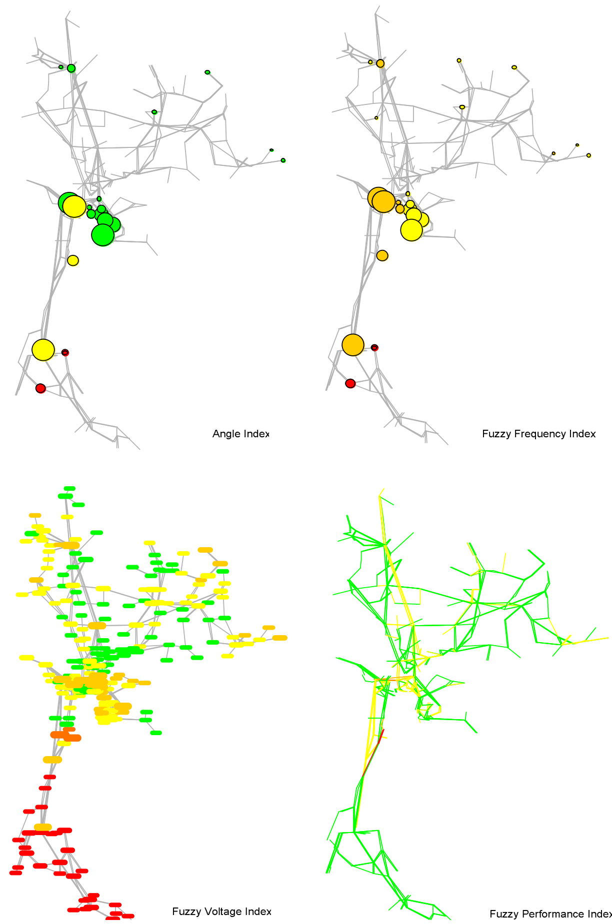


Figure 16: Visualization of power system dynamic security indices.

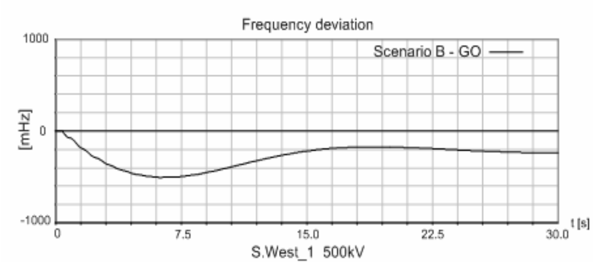


Figure 17: Frequency deviation following a generator outage

voltage the system survives the transient into the post-contingency steady state and remains stable. As indicated by the SSSI, however, the limit of minimum admissible damping (3%) has been surpassed and the system has drifted out of security bounds. This implies corrective actions including system reinforcement so as to avoid further damping decrease in case of additional network alternations.

5. CONCLUSION

Security management is not easy to execute in the unbundled system structure where the system operator has no direct control of generation. Any decisions affecting outputs or control settings of power plants have to be implemented using commercial agreements with power plants or enforced through the grid code. Under these changed operating conditions the assumptions made at the system planning stage are less and less valid and to cope with new circumstances DSA is required.

This paper shows how DSA can be implemented by using a set of security indices. The indices can help operators to investigate grid code compliance and system stability under contingencies. The intention of the indices is to replace visual analysis of the simulation results and measurements, which is a task typically performed by the system analyst. The indices are able to capture changes in dynamic system parameters and rank system conditions with respect to limits and constraints without operator's involvement. Ranking of the system states can be of great support to the operators when making decisions and trying to understand the complex structure of electrical systems.

BIBLIOGRAPHY

[1] M. Bruch et al, "Power Blackouts Risks, Risk Management Options Emerging Risk Initiative – Position Paper", Nov. 2011, available at www.allianz.com

[2] IEEE/CIGRE Joint Task Force on Stability Terms and Definitions Definition and Classification of Power System Stability, IEEE Trans. Power Syst.,, Vol. 19, No. 2, May 2004, p. 1390.

[3] Union for the Coordination of Electricity Transmission, "Final report of the investigation committee on the 28 September 2003 Blackout in Italy", UCTE Report, Apr. 2004.

[4] S. Boroczky, E. Gentle, "Real-Time Transient Security Assessment in Australia at NEMMCO", in Proce. of IEEE Power Systems Conference & Exposition, 15-18 March, Seattle, 2009.

[5] L.E. Arnold, J. Hajagos, "LIPA Implementation of Real-Time Stability Monitoring in a CIM Compliant Environment", in Proce. of Power Systems Conference & Exposition, 15-18 March, Seattle, 2009.

[6] E. Lerch, O. Ruhle, D. Vickovic, "Real-Time Stability Assessment in the Control Centers of the ISO of Bosnia and Herzegovina and a National Dispatching System in North Africa", in Proce of Power Systems Conference & Exposition, 15-18 March, Seattle, 2009.

[7] K. Morison, L. Wang, P. Kundur, "Power System Security Assessment", IEEE power & energy magazine, September/ October 2004.

[8] ENTSO-E, "Research and development plan EUROGRID 2020; European grid towards 2010 challenges and Beyond", first edition, Dec. 2009.

[9] J.M. Gimenez and P.E. Mercado, "Online inference of the dynamic security level of power systems using fuzzy techniques," IEEE Trans. Power Syst., vol. 22, no. 2, May 2007, pp. 717-726.

[10] C.K. Tang, C.E. Graham, M. El-Kady, R.T.H. Alden, "Transient stability index from conventional time domain simulation," IEEE Trans. Power Syst., vol. 9, no. 3, Aug. 1994, pp. 1524-1530.

[11] U. Kerin, E. Lerch, G. Bizjak, "Monitoring and reporting of security of power system low Frequency oscillations," Elec. Power Compon. Syst., vol. 38, no. 9, Jun. 2010, pp. 1047-1060.

[12] U. Kerin, T. N. Trinh, E. Lerch, G. Bizjak, "Small Signal Security Index for Contingency Classification in Dynamic Security Assessment", in Proce. of IEEE Powertech, 19 – 23 June, Trondheim, Norway, 2011.

[13] L. A. Zadeh, "Fuzzy sets," Information and Control, vol. 8, no. 3, 1965, pp.338–353.

[14] Kundur, P., Power System Stability and Control, New York: McGraw-Hill, Inc, 1994.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#92

Protection Security Assessment of Power Grids Improves Grid Reliability

T. BOPP[*1], R. GANJAVI[1], R. KREBS[1], B. NTSIN[1], M. DAUER[1], J. JAEGER[2]
[1]Siemens AG, [2]Friedrich-Alexander University Erlangen,
[1, 2]Germany

SUMMARY

Key findings derived by the application of an automated protection security assessment solution on a nationwide transmission system are presented.

Protection coordination and verification of settings through simulation is getting increasingly complex. Conventional protection coordination and simulation tools reach their limits of practical applicability for fast developing networks and changing operating conditions. New automated protection security assessment solutions can overcome existing limitations and allow the fast and systematic performance assessment of the protection system.

A new approach to assess the adequacy of protection settings and schemes is presented. It facilitates the verification of selectivity of protection settings for large numbers of different operation and fault scenarios. The presented solution is capable to handle large and complex network structures, and also to analyze the system behavior of the protection system and network as a whole. New concise result visualizations were developed to support protection engineers and operators to identify potential weak points and limitations of the protection schemes and settings.

The paper summarizes key findings and lessons learnt from an automated systematic protection performance assessment and enhancement project performed on a nationwide transmission system. It demonstrates how the applied solution can help to assure and improve the quality of protection settings through event-triggered or regular application.

The in-depth evaluation allows the pinpointing of false settings in individual relays and for various different operating and fault conditions. If false or improvable settings are detected then the solution supports the calculation of new improved protection settings. To enhance quality control, a new set of settings can be validated and verified through simulation before application in order to maximize network utilization and grid reliability by reducing the risk of unwanted protection actions and cascading events.

KEYWORDS

Automated Protection Performance Assessment

1. INTRODUCTION

Fast network development, load growth, increasing penetration of renewable generation and consequent changes in distribution and transmission networks pose new challenges for system operation and protection. Protection systems are crucial for system security because they limit the impact that faults have on power systems. Continuously evolving power systems and quickly changing operating conditions make it an increasingly complex task to calculate, verify, and to validate protection settings.

[*] thomas.bopp@siemens.com

The introduction of a competitive energy business and a de-carbonized power generation is enforcing the development towards new grid topologies. The infeeds of distributed and renewable generation are requiring an increased transmission capacity and stability requirements in power systems. An important factor for blackout prevention is a regular review of the protection tripping behavior itself and of the protection coordination concept [1, 2, 3].

In the field of transmission networks, protection coordination is developing more and more towards a task of handling nationwide power systems under continuous change and with numerous protection devices preferably graded by software tools. The aim of the presented method is to provide an automated protection security assessment system which analyzes the protection system of a whole network. It requires the systematic simulation of different fault events and the resulting response of the protection systems at each step of the fault clearing sequence to reveal limitations and weaknesses of in the protection system.

The described approach allows the detection of incorrect or improvable protections settings, and facilitates the identification of hidden faults that could cause the spreading of the fault events or cascading trippings. Based on the identification of limitations, adapted settings can be derived improving the protection system behavior for changing network conditions. This leads to an important enhancement of the protection and network security in today's and future grids. The presented Protection Security Assessment system is called SIGUARD® PSA [4, 5].

2. METHOD OF INVESTIGATION

2.1 Fault Simulation

The principle structure of the method of investigation is shown in Figure 1. The procedure starts with short-circuit (SC) fault simulation comprising different fault locations and types of faults with varying additional fault resistances.

An in-built scenario builder (Figure 2) makes it possible to simulate different combinations of network configuration, operating states and fault scenarios without making any time-consuming manual changes.

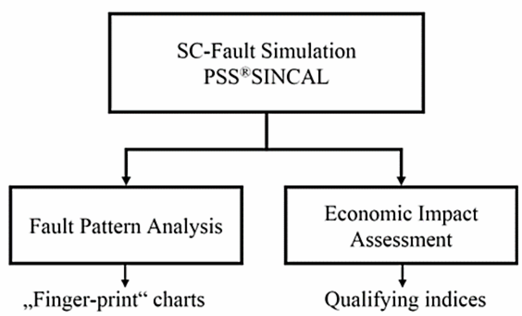


Figure 1: Principle structure of investigation method

In this way the tripping behavior of the protection devices in case of SC-faults is checked. The fault location is moving through the whole network in steps of e.g. 5% of the line length. The simulation tool calculates the reaction of all considered protection devices during all simulated SC-faults.

The whole data will be recorded by a data bank system which includes the network and protection input data as well as the whole result data. Line outages, line overloading, system separations or other customized contingencies can be simulated revealing hidden weak points or errors.

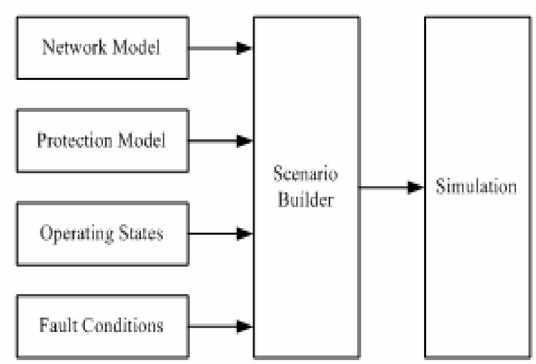


Figure 2: Scenario builder [4]

2.2 Fault Pattern Analysis

A general evaluation method of protection system behavior is given by the terms of Figure 3. Following definitions are stated:

- *Dependability* – The probability that a protection system will trip circuit breakers when it is required.
- *Security* – The probability that a protection system will not trip circuits breaker when it is not required to do so.
- *Reliability* – The probability a protection system will operate with the required performance. This parameter includes the aspects dependability and security.

The fault pattern analysis is based on this structure. The evaluation algorithms are focused to discriminate a violation of dependability and security. Dependability can also be described by the condition of "underfunction" and the security by the condition of "overfunction" of protection systems. This information will be completed by the trip delay times of all SC-faults.

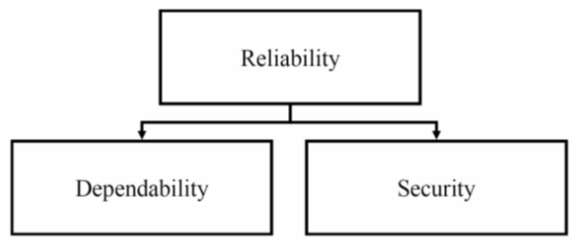


Figure 3: General structure of protection behavior evaluation

This approach enables the typification of fault patterns regarding their relation between relay malfunction and network configuration. For instance, in many networks a typical network characteristic frequently causing violation of the security criterion are parallel line configurations with mutual coupling. Such a typical fault pattern could be identified and trigger the adaption and improvement of protection settings in a generic way.

2.3 Economic Impact Assessment

The economic impact assessment is the second path of the method of investigation in Figure 1. It should estimate the potential damage of equipment caused by extended fault durations and monetary losses caused by unintentional supply interruption due to relay mal-operations. The estimated costs can be used for economic assessments of necessary investments in further protection setting studies, needed upgrades of protection equipment or maintenance schedules. As a first macroscopic approach the Gross National Product (GNP) estimation is proposed. The outage costs per kWh can be calculated as follows:

$$\text{outage cost (\$/kWh)} = \frac{\text{GNP (\$)}}{\text{TotalEnergConsumption(kWh)}}$$

The calculated outage cost represents the ratio of the served energy and the economic value that is derived from the supplied energy. Estimated values of interruption costs for individual customers are different, depending on the types of customer sector, such as residential, agricultural, industrial or commercial. The amount of unintentional non-served loads can be quantified as a qualifying index e.g. by the degree of selectivity. It will be calculated for each fault location as the ratio of the load which is served after the determined protection trippings to the load which should be supplied in the case of 100% selectivity. The degree of selectivity is 1, if the fault could be cleared fully selectively. Unselective cleared faults lead to a qualifying index less than 1.

3. PRACTICAL APPLICATION EXAMPLE

3.1 Transmission System

GRIDCo is the national interconnected transmission system operator of Ghana. Its mission is to provide reliable, secure, and efficient electricity transmission services and wholesale market operations to meet stakeholder expectations within Ghana and the West African Sub-region, in an environmentally sustainable and commercially viable manner. The work described in this paper was performed for the 161/225/330-kV transmission system comprising more than 100 overhead lines and more than 400 distance, differential and overcurrent protection relays.

Fast load growth is a major challenge and driver for large-scale system expansion. The transmission system has increased its transformer capacity by over 50% in the last five years. Even though the transmission system is often forced to operate close to its limits due to a lack of generation capacity. In the past, mal-operation of the protection system and cascading events were observed. Considering low critical fault clearing times, the situation poses a high risk of total system blackout in case of failure of the primary protection system.

In order to reduce the risk of system collapse, GRIDCo initiated a system-wide protection system review. The objective was to ensure system security and to maximize the utilization of the system through improvement of the performance of the protection system.

3.2 Initial situation and challenge

In general, protection settings were calculated by different substation vendors or consultants. The protection system model and settings were not available in a central database or power system simulation software. No system-wide coordination and check of protection settings was possible.

To ameliorate the situation the following tasks were investigated to improve the existing systems' performance:

- Review of existing protection system and generation system stability to achieve performance improvements,
- Development of enhanced protection schemes and relay settings calculation guidelines,
- Calculation of new improved settings and verification of their performance through simulation,
- Definition of short-term actions, and a medium- and long-term strategic protection system development plan.

3.3 Power and Protection System Modelling

3.3.1 Data Collection & Validation

The initial challenge was the power and protection system data gathering and validation. The power system contains long and short line configurations and many parallel lines with multiple zero-sequence couplings. A high number of protection relays from different manufacturers are installed.

Only a good quality of collected data could have allowed plausible results for relay schemes and their settings.

The detection of non-sufficiently set protection devices was realized due to multi-level data plausibility checks. The first two levels of plausibility test series were performed in advance to study the protection functions independent of each other. The third level of plausibility tests included the complete range of protection functions according to the collected data from the network. The check procedure followed test routines that were developed and used to process large amounts of data. In this way, a great number of statistical diagrams and tables were produced which allow a comprehensive overview over the installed protection systems.

3.3.2 Modelling

A detailed power and protection system model was built and benchmarked with GRIDCo's existing PSS E

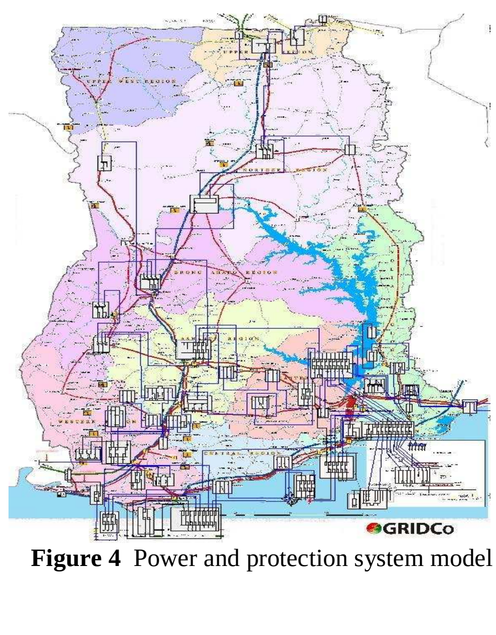


Figure 4 Power and protection system model

model. The created geographic system model (Figure 4) includes a detailed internal substation model with all CBs, CTs, VTs and protection relays.

All protection setting parameters were collected in the field and imported into the system model. The zero-sequence and mutual coupling model was amended to simulate single-phase faults with the highest possible accuracy. The model building process was complemented with multi-level data plausibility checks for highest data quality.

3.3.3 Scenario Building

To systematically assess protection system performance a multitude of fault scenarios with varying location, fault type and arc resistance were defined.

3.3.4 Simulation and Performance Assessment

Siemens' SIGUARD PSA (Protection Security Assessment) solution was used to simulate selectivity, sensitivity and speed of the protection system. In each scenario, all stages of the entire fault clearance sequence were simulated in detail. This provides deep insight into the protection system response for a given fault condition. All currents, voltages and impedances measured by protection devices are available.

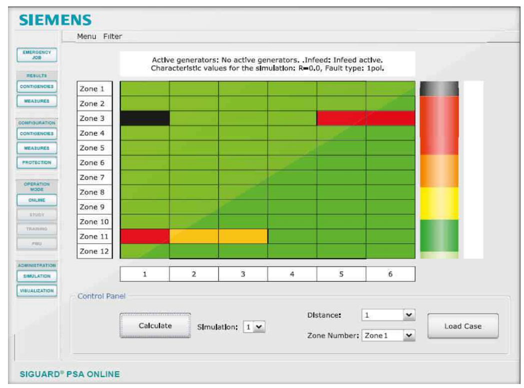


Figure 5 SIGUARD PSA protection performance visualization

Generation system stability was assessed for the existing and newly proposed improved under-frequency load shedding schemes taking into account different system configurations. In total, hundred thousands of fault scenarios were simulated. The results were automatically assessed and visualized in a concise way with SIGUARD PSA. Figure 5 depicts the protection performance using color-coding, i.e. red - fault not cleared, orange/yellow - over-/underfunction, black – high risk of blackout.

In this state-of-the-art approach the protection system performance is assessed by simulation, and not only using the classical approach of sole depiction of setting values. The new methodology sets itself apart from the conventional separate evaluation of distance, differential and overcurrent time relay characteristics because it assesses the combined 'system' response comprising the power system with all its main and back-up protection relays.

The quality of the protection system performance is depicted by color-coding that is meaningful for both technical and non-technical staff. Results can be represented aggregated for complete network regions or detailed for individual power system components or protection relays. This allows the identification of incorrect settings, weaknesses and limitations of protection system.

The high degree of automation enables the efficient assessment of a very large number of fault scenarios and complex system conditions, and minimizes the individual treatment of special cases.

Figure 6 and Figure 7 depict the performance of the protection system on a system-wide level for 3-phase and 1-phase faults with varying fault location on all lines for a given power system state and set of protection settings. On the x-axis all lines and on the y-axis the performance of all relays are depicted. The violation of the protection dependability and security is illustrated by different colors. Green color means fully selective fault clearing. With this analysis it was possible to identify incorrect settings, weaknesses in the protection schemes and limitations of the protection system.

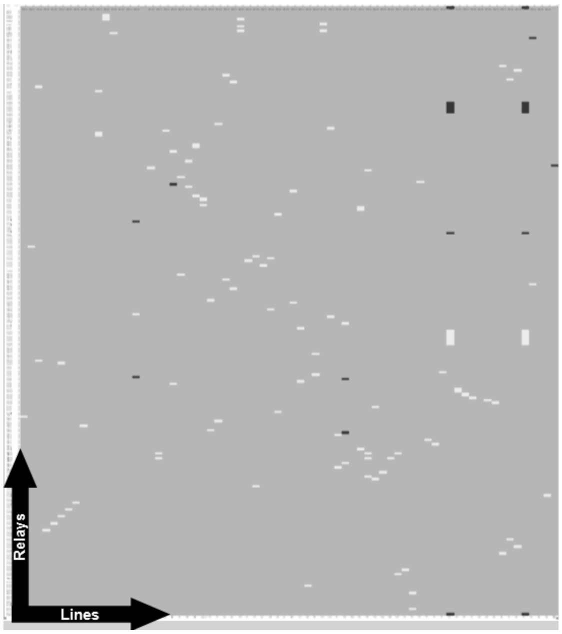


Figure 7 Protection relay performance for 3-phase faults

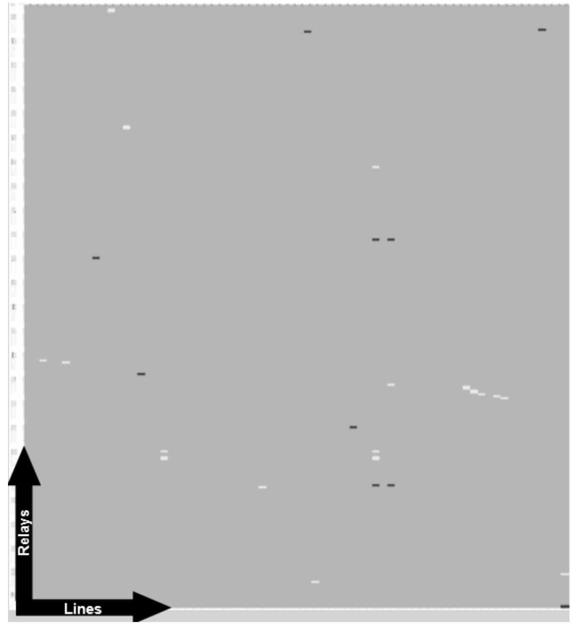


Figure 6 Protection relay performance for 1 -phase faults

3.3.5 Protection System Improvement

In summary, about 500.000 faults were automatically simulated with the simulation system and the reaction of the protection relays was monitored and stored. Based on these protection security assessment results and findings, the protection settings and scheme were improved in a systematic manner.

Identified false or improvable protection settings were corrected using a rule-based algorithm. The underlying protection grading rules were improved by iterating simulation, assessment and setting improvement. The system was re-coordinated and the quality of newly calculated setting was verified before approval by using the same method and tool. In this way the protection system can be optimized interactively until the targeted quality and reliability levels are achieved.

Decisive improvements have been achieved in the selective clearance of faults. Figure 8 shows the protection performance of transmission lines. The x-axis shows the lines and the y-axis the protection error rate, i.e. the lower the values the better is the protection system's performance. From Figure 8 can be read that the overall protection system performance could be significantly improved through re-coordination of the protection systems. The improvement is depicted as the difference of the original settings (upper line) to the improved settings (lower line). In this case only the improvement achieved through automated relay coordination is shown which achieved good results in the majority of the cases. The remaining small number of special cases indicating constraints due to physical or technical reasons was solved individually for each concerned line. In few cases the outcome was the identified need to improve the protection scheme, e.g. by using tele-protection or differential protection.

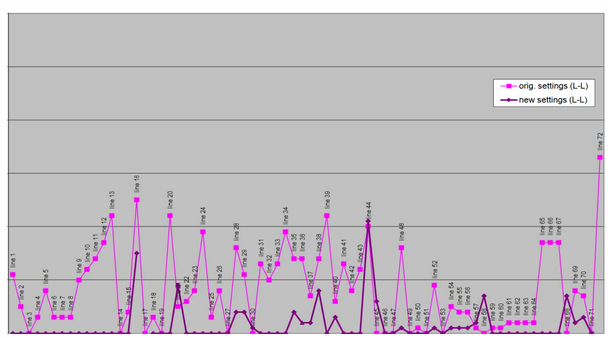


Figure 8 Protection performance improvement achieved through new settings

3.3.6 Key achievements

The achieved benefits by the application of an automated simulation-based protection security assessment solution on a nationwide transmission system were:

- Complete data survey, documentation and modeling of the power and protection system with validated high quality
- Assessment of the performance of the existing protection system showing its specific characteristics, behavior, weak points and limitations
- Development of new improved protection settings, grading rules, scheme recommendations and an under-frequency load shedding scheme based on the review findings. Validation of new settings by simulation before approval
- Recommendations for the efficient future strategic development of the protection system

It was demonstrated that the adaptation of protection settings can help increase system security and maximize the utilization of the existing system which in turn avoids CAPEX investment.

4. CONCLUSION

A new method for the analysis and assessment of protection system performance was applied on a nationwide transmission system. It was shown that the protection system performance and settings could be improved by a software automated method. The proposed protection security assessment method is applicable for transmission and distribution. It can be customized for different simulation and assessment tasks using the same simulation setup. For instance, it can be used for the validation and improvement of protection systems and settings, or the verification of new system states in operational planning, and as training simulator.

The assessment solution and the evaluation results have shown a good performance in real-world applications. The newly proposed result visualization and filtering method has been proven practical for the illustration of the enormous amount of output data. Based on the clearly arranged visualization diagrams, practical constraints of applied protection schemes and coordination concepts can be easily detected and systematic improvements are enabled. Based on the findings from the presented and other projects, it can be concluded that automated protection security assessment software solutions have reached a degree of maturity that allows their regular application. They can support protection engineers to carry out protection system performance assessments and enhance the protection system coordination process. Herewith, they have the potential to contribute to an increased protection and grid reliability.

BIBLIOGRAPHY

[1] R. Krebs, E. Lerch, O. Ruhle, S. Gal, F. Lazar, D. Paunesco, *Vision 2020: Blackout Prevention by Combined Protection and Network Security Assessment*, IEEE PES Conf. Conversion and Delivery of Electrical Energy in the 21st Century, 2008.

[2] M. Ordacgi; R.B. Solero, *Minimizing Risks of Cascade Tripping, A Systematic Analysis of Component Protection*, Cigre Conference, Paris, 2006, Report B5-202.

[3] K. Yamashita, S.-K. Joo, J. Li, P. Zhang, Ch.-Ch. Liu, *Analysis, Control, and Economic Impact Assessment of Major Blackout Events.* ETPEP Euro. Trans. on Electr. Power, 18:854-871, 2008.

[4] SIGUARD® PSA, *Protection Security Assessment*, www.siemens.com/siguard

[5] T. Bopp, C. Blug, R, Krebs, *Schutzsysteme systematisch überprüfen und verbessern*, EW Magazin für Energiewirtschaft, pp. 66-70, EW 10, 2013.

[6] J. Jaeger, R. Krebs, *Automated Protection Security Assessment of Today's and Future Power Grids.* IEEE PES General Meeting, 2010.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#93

The new revision of internal technical standard for power line and bus coupler protection in correlation with SCADA internal standard

Andrei ROMANESCU*
Senior Engineer
Technical & Grid Development Division
Romania

SUMMARY

The paper present the new approach that Romanian Power Grid CNTEE TRANSELECTRICA SA have applied for protection of power line and bus coupler of 400kV, 220kV, 110kV and medium voltage. Basically through the new revision of our internal procedures we managed to apply redundancy for all the high voltage cells, fact that increase our strength in energy transmission. Nevertheless the new revisions establish principles and details for the required technology to achieve the best control, protection and automation in our power grid.

KEYWORDS

SCADA, redundancy, protection, control system, substation.

1. INTRODUCTION

Power Grid Transelectrica is the only one transmission and system operator in Romania which administrates the transmission network (400kV, 220kV and part of the 110kV). Transelectrica has always applied the newest and best rules to assure a high quality transmission grid. Nowadays Transelectrica is facing with many refurbishment projects of different substations throughout his entire network. The whole process of grid automation is based on clear technical procedures which establish the main rules for SCADA, including the control and protection system.

The first step to assure a: high quality of the power network, an increasing safety of the personnel and a high life cycle of earlier investment, was made by the procedure NTI-TEL-S-009-2010-01 which established the main rule for SCADA architecture.

* andrei.romanescu@transelectrica.ro

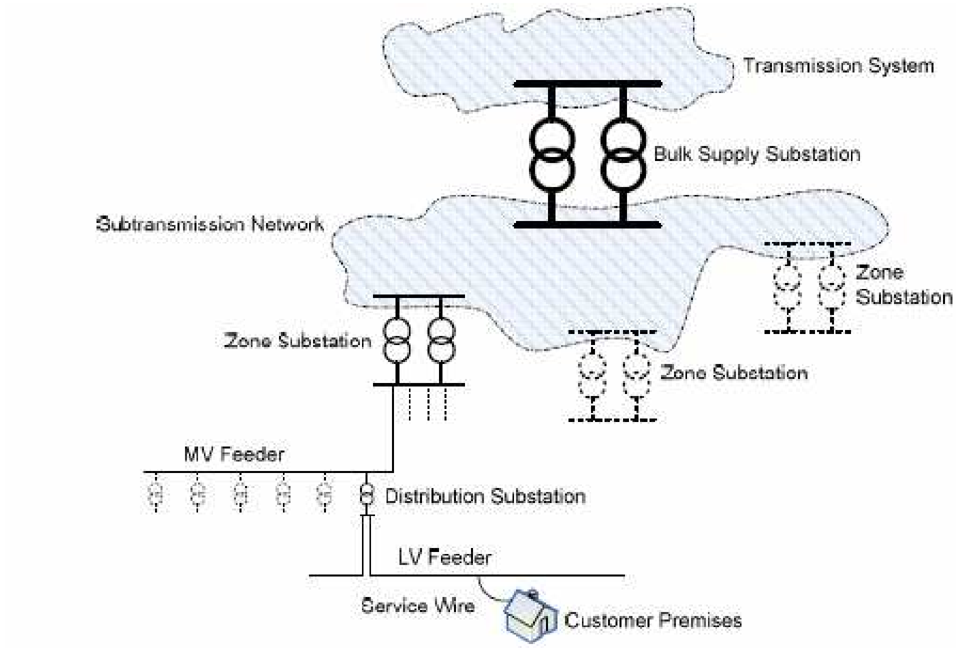


Figure 1 Typical Romanian transmission and supply structure

Having a clear goal, based on NTI-TEL-S-009-2010-01 and a lot of previous experience due to 10 years of substation refurbishment routine, Transelectrica has successfully started to increase the automation system based on a redundant distributed intelligence which leaves aside the traditional centralised control systems which were made much more earlier, back in the 70's.

NTI-TEL-S-009-2010-01 overcome the barriers of traditional electrical integration solutions and offer full plant integration, started form low voltages up to high voltage. Full substation integration is accomplished by taking advantage of open standards from the process control and protection, see Figure 2. Only one SCADA system is requested for the entire substation voltage levels.

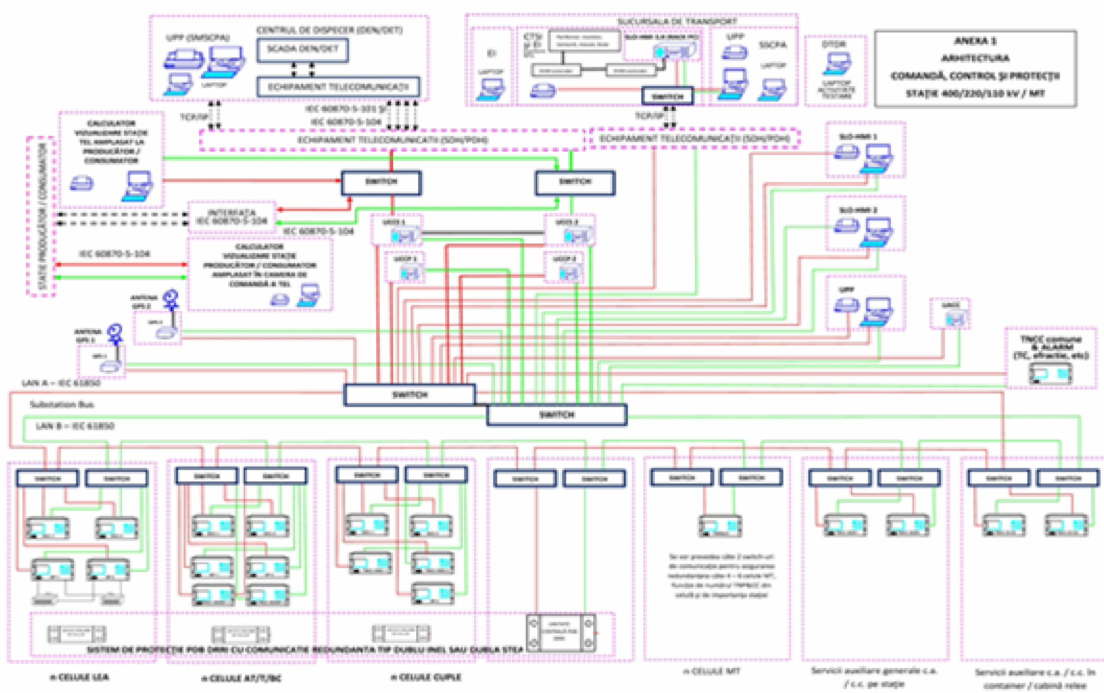


Figure 2 Physical and logical structure of the substation automation system according to NTI-TEL-S-009-2009-01

2. THE NEW REVISION OF NTI-TEL-S-003-2009-01

The new revision of NTI-TEL-S-003-2009-01 is made on the structure of NTI-TEL-S-009-2010-01 and updated with a number of technical conditions designed to increase reliability for our protection and automation systems. NTI-TEL-S-003-2009-01 establishes the rules that have to be applied for the control, protection and automation substation system on 400kV, 220kV and 110kV.

Protection and automation systems are so critical that they have always been designed very conservatively. Wherever possible they are designed with overlapping zones of protection to ensure that any fault will be seen by at least two independent protective relays. Our transmission system protection was designed with a high degree of redundancy.

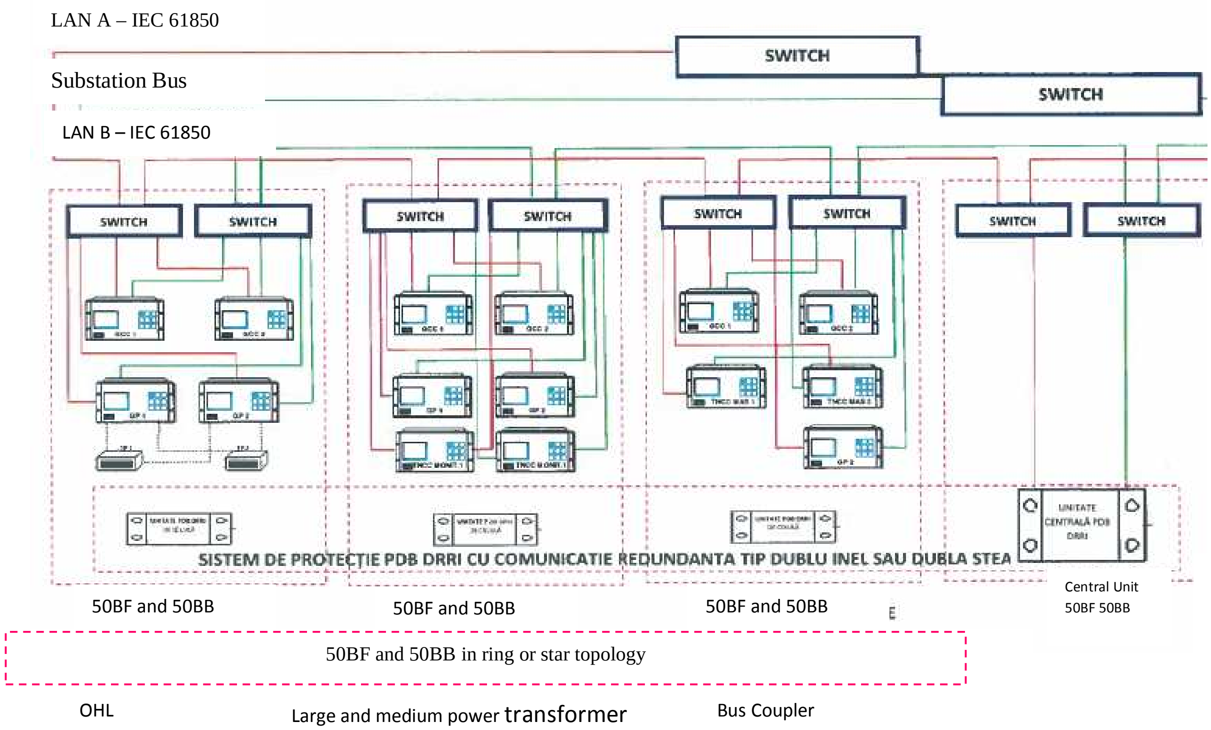


Figure 3 Redundant SCADA architecture for protection and automation system

By the new revision of NTI-TEL-S-003-2009-01 & NTI-TEL-S-009-2009-01, Transelectrica managed to apply new rules which impose the SAS (substation automation system) to be redundancy and interconnected all the time in all our substation, this means that for a single power line cell we have:

- two BCU (bay control unit);
- two protection relay;
- two teleprotection equipment;
- two switches;
- one bas bar unit.

This new network topology for SAS is tremendous redundant, it offers a highly reliable operation, for example: if one appliance failed (BCU, relay, teleprotection, switch) the substation equipment is based on the redundant appliance fact that allow to maintain in exploitation the primary equipment without taking any risk.

Regarding the bus bar protection and the redundant criteria that Transelectrica is requesting, 78BB units has to have a redundant communication between local unit and central unit, fact which increase the automation function.

The main SAS components (BCU and protection relay) is redundant interconnected on two switches in two LAN protection rings using the leading international standard IEC 61850. So all our SAS equipment use IEC 61850 communication protocol fact that confer a wide range of control assuring a reliable interlocking, communication, signalling and command through the entire substation.

Another advantage of using IEC 61850 is made due to the amount of information that that can be used (e.g. GOOSE messages, accurate clock synchronization, fast and secured peer-to-per automation, raw data exchanges, etc.) in comparison with traditional hard-wired signals, this represent a high level of performance with a high level of interoperability.

More information enables better protection which leads to protection devices with faster and more secure elements. NTI-TEL-S-003-2009-01 requires command and protection relays with a reliable microprocessor that can perform very fast operation, fault recording, real-time calculations, easier settings, digital communication, to name only a few.

What is more is that for all the protection functions, the procedure established rules regarding how the protection function has to operate, basically we requested an impose algorithm who has to be made by the vendors. Through this, we had managed to put down the hammer, and assure us that in each part of our system a fault has the same way of evaluation.

Imposing a higher sampling rate with a greater number of analogue inputs allows for some very innovative protection schemes not only great flexibility but also provide system security while breakers are taken out of service and tested, requirements that we had imposed for a breaker-and-a-half scheme and for polygonal scheme, were is very important to provide feeder availability when a breaker is removed to service.

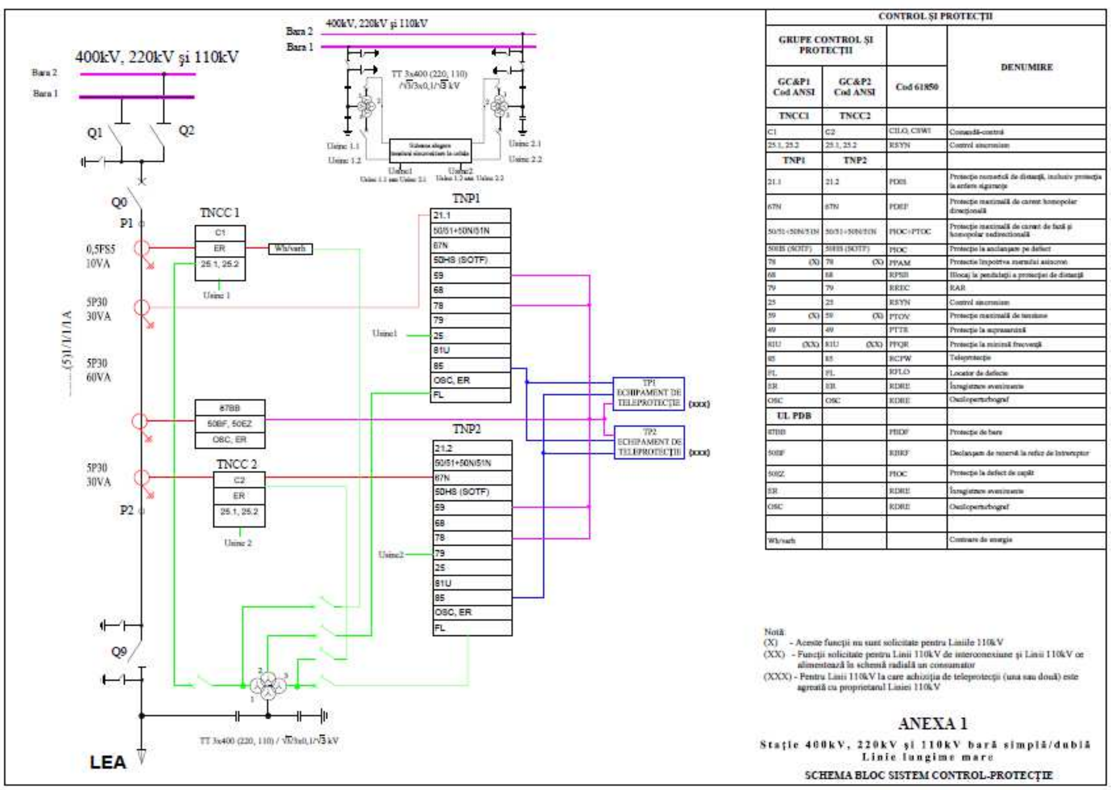


Figure 4 Susbtation and automation design for power lines

3. THE NEW REVISION OF NTI-TEL-S-006-2009-01

The new revision of NTI-TEL-S-006-2009-01 is also made on the structure of NTI-TEL-S-009-2010-01 and updated with a number of technical conditions designed to increase reliability for our protection and automation systems. NTI-TEL-S-006-2009-01 established the rules that have to be applied for the control, protection and automation substation system on medium voltage (33kV, 20kV and 6kV).

Distribution networks remain the last link between the power grid and the consumers, which is why the reliability impacts for the overall level of satisfaction with the power supply is higher. The reliability solutions known and widely deployed in the high voltage transmission system are not used in the distribution network because of the cost implications, which is why the command and protections are operated in one single relay. Building redundant power flow paths by adding feeders and transformers remains impractical; however, making extra investments in the secondary protection and control systems can be considered given the available technology, this is where the NTI-TEL-S-006-2009-01 has intervened and imposed reliable command and protection requests.

In addition NTI-TEL-S-006-2009-01 doesn't impose two protection relay for a single cell, but maintain the redundant request for two communication port. Through this request, every single relay is compulsory connected on the substation LANs (LAN-A and LAN-B).

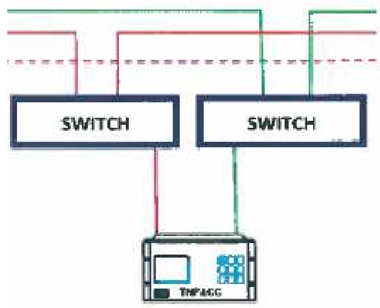


Figure 5 SCADA architecture for medium voltages SAS

Concerning the line-drop compensation, different shunt scheme, including the earth-fault compensation NTI-TEL-S-006-2009-01 provides the entire automation scheme that allows the network to operate even when a temporary earth-fault appears among the line.

4. CONCLUSIONS

The procedure of control, protection and automation systems has brought an important advantage because nowadays Transelectrica has an impose SAS architecture in all the substations.

Correlating NTI-TEL-S-009-2010-01 with other specialized procedures like NTI-TEL-S-003-2009-01 and NTI-TEL-S-006-2009-01 has allowed us to strongly increase the reliable of our National Grid. In addition, the new revisions came to help substation's SAS systems designers by providing them all the necessary schemes that they need.

In the near future we plan to revise all the other technical procedures to further strengthen the system reliability. This is way during this year Transelectrica is preparing with priority to revise our technical standard regarding the protection of transformer and large power transformer including also autotransformers and reactors.

BIBLIOGRAPHY

[1] IEC 61850_1÷9, *Communication networks and systems in substations.*

[2] Nicorescu H., *Technical standard regarding protection and automation system, supervisory control and data acquisition applied in Romanian Power Grid Company – Transelectrica,* CIGRE Sesion RSEEC, Timisoara, 2014.

[3] Higgins N., Vyatkin V., Nair C. and Schwarz K., - "Distributed Power System Automation with IEC 61850, IEC 61499 and Intelligent Control", The IEEE International Conference on Systems, Man, and Cybernetics, UK, 2008.

[4] Wahlström B., Aoshima Y., Mino Y., Lajoie-Mazenc C., Torderson D.R., Zomers A.N., – *The future substation a reflective approach,* 23-207, Sesion CIGRE, Paris, 1996.

[5] Waterman D.A., - *A guide to expert system – Addison Wesley Publishing Co.,* Inc. Reading, MA

[6] ANRE, Romania 2007, "The Electricity Transmission Grid – Standard of performance".

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition) October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#94

"Implementation of special mathematics in energy transmission– Romanian Power Grid Company Transelectrica"

[1]**Valentin ZAHARESCU**[*], [2]**Andrei ROMANESCU**[**]
[1]**Transmission Subsidary of SIBIU,** [2]**Technical Departament and Grid Development**
Romania

SUMMARY

The main purpose of this paper is based on the possibility of generating forecast to various parameters, that characterize the power equipments. This forecasts was made by using mathematical models, in special linear regression from grade I to V designed in software MathCAD. Getting the result of such forecasts allows us to take important decisions regarding maintain in operation of various power equipment. Another scope is to see how the technical state of an equipment is evolving during the time, after a complex rehabilitation programme.

KEYWORDS: linear regression, MathCAD, mathematical, power equipment, life time.

1. INTRODUCTION

Large power transformes are the most significant portion of our transmission system assets, and a major concern to every electric utility. Their replacement will involve a considerable amount of time and expensive. Based on matemathical linear regression ST Sibiu developed a life time management for major power unit transformers. By implementing a monitoring operation of power transformers, we can avoid the appearance of damage to electricity transmission network, also we can extend the lifetime of transformes.

The calculation for life time of transformers is based on generating a mathematical predictions for the evolution of the main parameters that characterizing a power transformer unit in operation, for example the lifetime calculation can be made for: insulation resistance, dielectric dissipation factor measurement.

Admittedly, the corelation between calendar age and insulation deterioration is subject to some uncertainty, not all tranformers were created equal, so we can afford to make prediction mainly for vintage transformer. We must say that there is no single scientific method available to calculate exact the and life of power transformer, but based on the history data of transformer: common short circuit forces that are inherent in a transmission or distribution system, mechanical strength of the transformers, failure history, oil testing history, operating history, calendar age, measurement date we can calculate the life cycle for aiging transformers.

[*] valentin.zaharescu@transelectrica.ro
[**]andrei.romanescu @transelectrica.ro

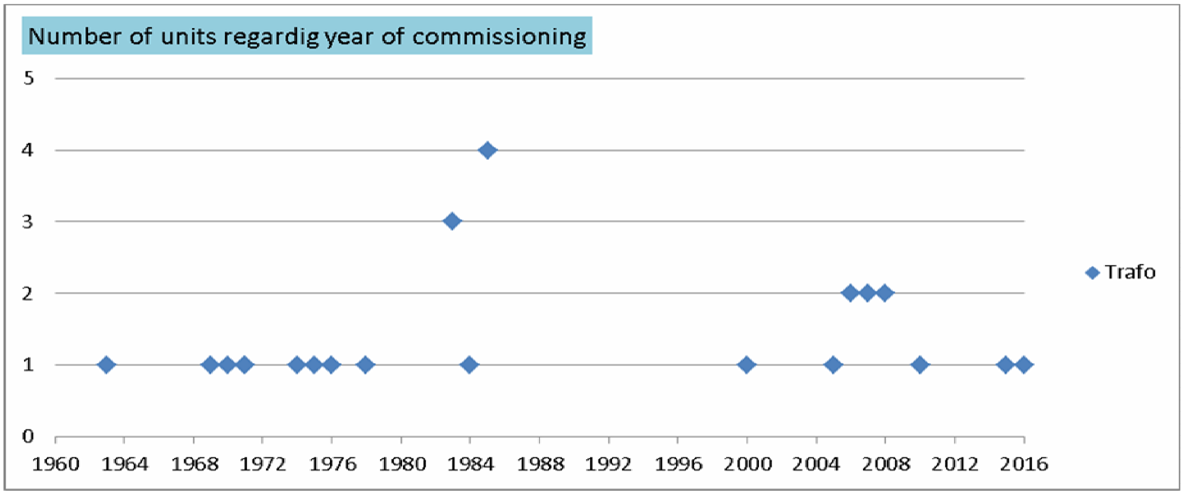


Figure 1 Transformer commissioning in Transmission Subsidiary of Sibiu

2. CALCULATION OF LIFETIME BASED ON LINEAR REGRESION

2.1 Introduction to calculate mode

In the statistical analysis of correlation and regression there we identify two major problems:

- to determine the equation that gives the functional relationship between the parameters of that process;
- to characterize the statistical relationship intensity with correlation coefficients;

For a data set $\{y_i, x_{i1}, \ldots, x_{ip}\}_{i=1}^{n}$ of *n* statistical units, a linear regression model assumes that the relationship between the dependent variable y_i and the p - vector of regressors x_i is linear. This relationship is modelled through a disturbance term or error variable εi — an unobserved random variable that adds noise to the linear relationship between the dependent variable and regressors. Thus the model takes the form:

$$\sum_{i=1}^{n}(y_i - y_{i\,tr})^2 = \text{minim} \tag{1}$$

where: - y_i represent the experimental data;

- $y_{i\,tr} = a \cdot x_i + b$ represent the theoretical data;

Standard linear regression models with standard estimation techniques make a number of assumptions about the predictor variables, the response variables and their relationship. Numerous extensions have been developed that allow each of these assumptions to be relaxed (i.e. reduced to a weaker form), and in some cases eliminated entirely. Some methods are general enough that they can relax multiple assumptions at once, and in other cases this can be achieved by combining different extensions. Generally these extensions make the estimation procedure more complex and time-consuming, and may also require more data in order to get an accurate model.

For the ralationship numeber 1 a minimum is required then you can form stationary point system (2), which it calculated by Cramer's rule (3).

$$\begin{cases} \sum_{i=1}^{n}(a \cdot x_i + b - y_i)x_i = 0 \\ \sum_{i=1}^{n}(a \cdot x_i + b - y_i) = 0 \end{cases} \tag{2}$$

$$\Delta_b = \begin{vmatrix} \sum_{i=1}^{n} x_i^2 & \sum_{i=1}^{n} x_i y_i \\ \sum_{i=1}^{n} x_i & \sum_{i=1}^{n} y_i \end{vmatrix} = \sum_{i=1}^{n} x_i^2 \sum_{i=1}^{n} y_i - \sum_{i=1}^{n} x_i y_i \cdot \sum_{i=1}^{n} x_i \quad (3)$$

where: a and b are regression coefficients.

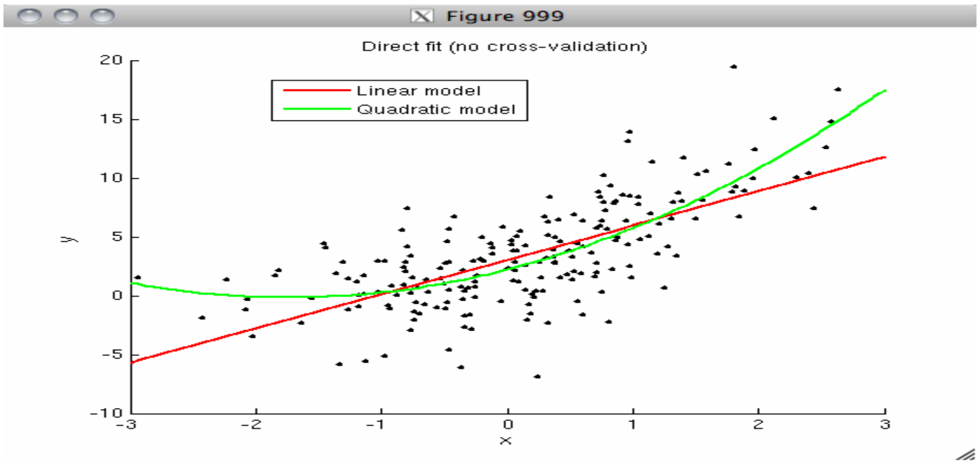


Figure 2 Example of simple linear regression comparising a quadratic model power by Matlab

The most important coefficient in mathematics regression is the correlation coefficient (4) that expresses the intensity dependence of the two parameters (years and measurement) and varies between -1 and +1.

$$r_{xy} = \frac{\frac{1}{n}\sum_{i=1}^{n}(x_i - \bar{x})(y_i - \bar{y})}{S_x S_y} \quad (4)$$

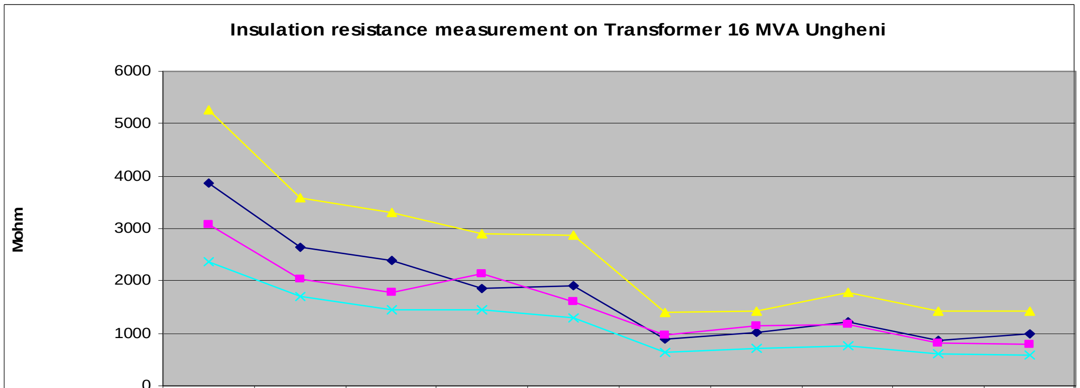
Addition to these data we will be able to calculate S_x and S_y that represent averages and standard deviation of selection:

$$S_x = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(x_i - \bar{x})^2} \quad (5)$$

$$S_y = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(y_i - \bar{y})^2} \quad (6)$$

3. CALCULATION OF LIFETIME TRANSFORMER – A THEORETHICAL MODEL AND PRACTICAL ACTIVITIES

Based on MathCAD program ST Sibiu developed a special program for mathematical regression grade I, II, III, IV, and V through we are able to calculate diferent predictions. For example, during 2012 measurements for a unit transformer form Substation 220/110/20 kV Ungheni, Transformer 16MVA 110/20 kV, was discovered that had an insulation resistance which reached a minimum HV values according to energetycal prescribed PE 116/94.



	7-May-03 20	28-Apr-04 20	29-Apr-05 20	8-Sep-06 20	22-May-07 20	6-Jun-08 20	29-May-09 20	29-Jun-10 20	3-Aug-11 20	14-Mar-12 20
(HV)-(LV+E)	3856	2653	2378	1864	1903	887	1021	1230	867	981
(LV)-(HV+E)	3071	2022	1791	2133	1607	975	1143	1182	826	780
(HV)-(LV)	5275	3597	3317	2897	2882	1402	1414	1783	1425	1412
(HV+LV)-(E)	2356	1694	1452	1459	1294	623	712	772	605	597

Figure 3 Historical measurements for Transformer 16 MVA Ungheni

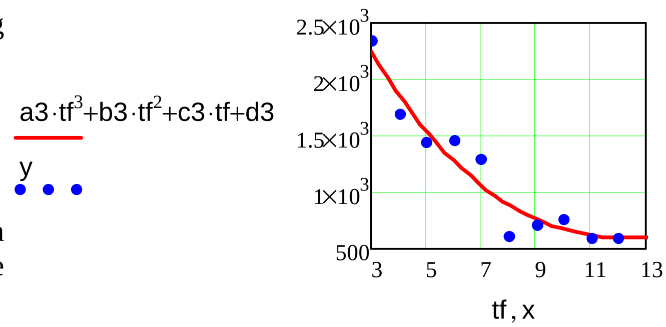
In the figure above, the following abbreviatons have been used:

- HV – means High Voltage;
- LV – means Low Voltage;
- E – means Earth.

After running regression program in MatHCAD for the connection mentioned have been obtained:

a) Regression grade I

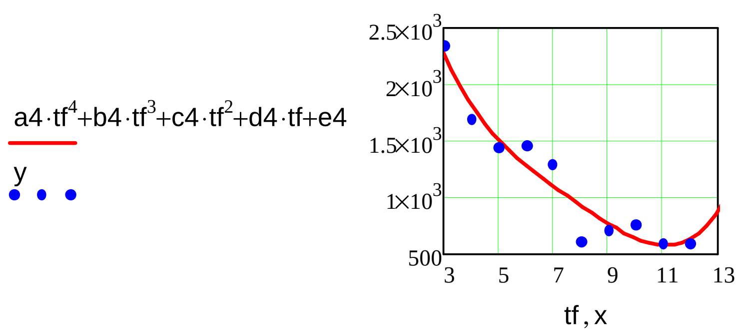
Correlation coefficient – indicate a strong correlation



$$r_{1xy} = \sqrt{1 - \frac{\sum_i (y_i - a_1 \cdot x_i - b_1)^2}{\sum_i (y_i - y_m)^2}}$$

$r_{1xy} = 0.9199$

Prediction for 2013: 344 Mohm

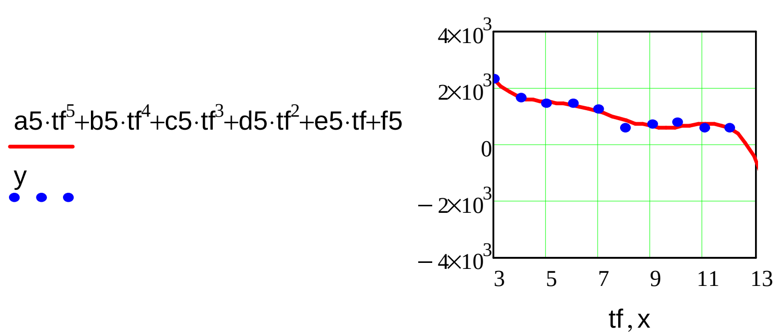


b) Regression grade II

Correlation coefficient – indicate a strong correlation

$r_{1xy} = 0.9642$

Preditcion for 2013: 656 Mohm



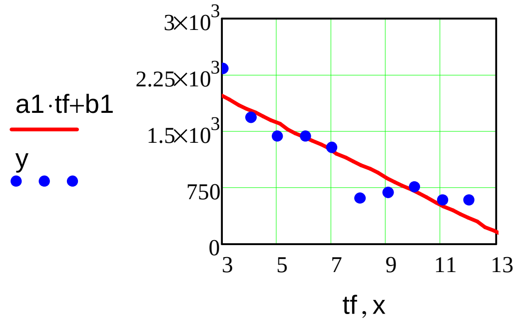
c) Regression grade III
Correlation coefficient –
indicate a strong correlation
$r_{1xy} = 0.9644$

Prediction for 2013: 885 Mohm

d) Regression grade IV
Correlation coefficient –
indicate a strong correlation

$r_{1xy} = 0.9663$

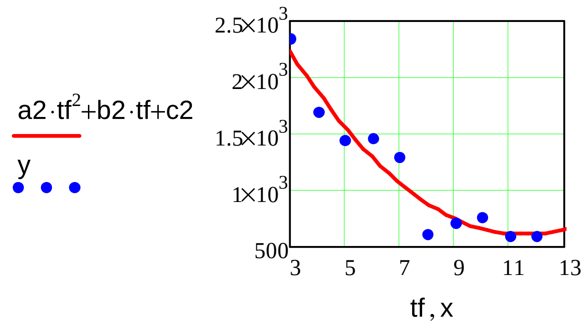
Prediction for 2013: 656 Mohm



e) Regression grade V
Correlation coefficient –
indicate a powerful correlation

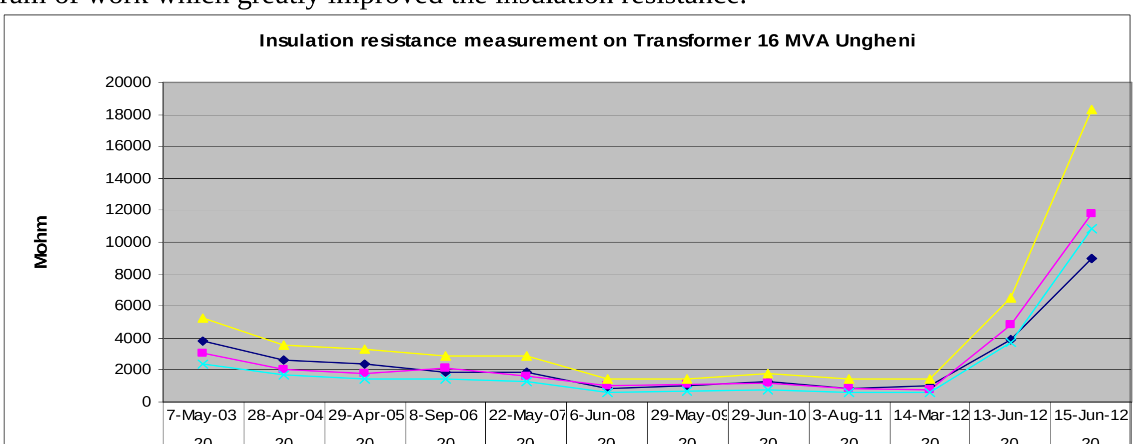
$r_{1xy} = 0.9804$

Prediction for 2013: 568 Mohm



As previously stated the eligible prediction, is the prediction which was the highest correlation coefficient therefore we choose the corresponding prediction for interpolation function for grade V with the correlation coefficient at 0.9804.

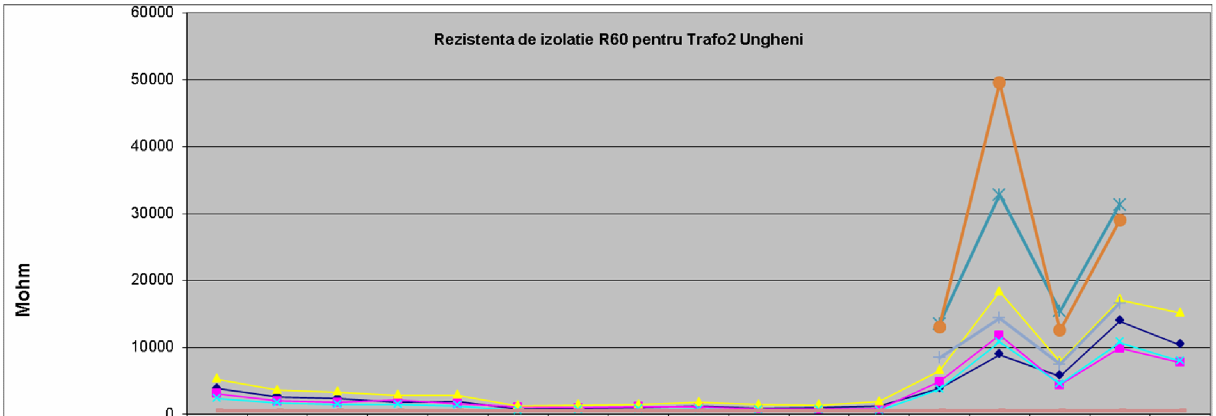
Due to practical measurement made in Substation 220/110/20 kV Ungheni and predictions resulting from running the regression program in MathCAD, ST Sibiu has successfully implemented a program of work which greatly improved the insulation resistance.



	7-May-03 20	28-Apr-04 20	29-Apr-05 20	8-Sep-06 20	22-May-07 20	6-Jun-08 20	29-May-09 20	29-Jun-10 20	3-Aug-11 20	14-Mar-12 20	13-Jun-12 20	15-Jun-12 20
(HV)-(LV+E)	3856	2653	2378	1864	1903	887	1021	1230	867	981	3859	8946
(LV)-(HV+E)	3071	2022	1791	2133	1607	975	1143	1182	826	780	4857	11819
(HV)-(LV)	5275	3597	3317	2897	2882	1402	1414	1783	1425	1412	6515	18325
(HV+LV)-(E)	2356	1694	1452	1459	1294	623	712	772	605	597	3706	10832

Figure 4 Insulation resistance chart at the end of the works

After the end of the programme which was in the last part of 2012, ST Sibiu implemented a strictly monitoring for T2 16MVA Ungheni, as it can be seen in picture 5.



	7-May-03 20	28-Apr-04 20	29-Apr-05 20	8-Sep-06 20	22-May-07 20	8-Jun-07 20	6-Jun-08 20	29-May-09 20	29-Jun-10 20	3-Aug-11 20	14-Mar-12 20	4-May-12 20	13-Jun-12 20	15-Jun-12 20	5-Nov-12 20	27-Mar-13 20	8-Jul-14 20
(IT)->(JT+m)	3856	2653	2378	1864	1903	809	887	1021	1230	867	981	1268	3859	8946	5702	13922	10432
(JT)->(IT+m)	3071	2022	1791	2133	1607	1078	975	1143	1182	826	780	763	4857	11819	4397	9901	7804
(IT)->(JT)	5275	3597	3317	2897	2882	1291	1402	1414	1783	1425	1412	1927	6515	18325	7866	17138	15162
(IT+JT)->(m)	2356	1694	1452	1459	1294	518	623	712	772	574	597	518	3706	10832	4538	10755	7947
IT->JT (m+garda)													13471	32854	15402	31361	
IT->m (JT+garda)													13082	49553	12580	28999	
JT->m (IT+garda)													8462	14421	7466	16636	
Limita min.PE116	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600

Figure 5 Insulation resistance chart after three years from rehabilitation

4. CONCLUSIONS AND FUTURE TRENDS

Although the prediction based on the regression is undoubtedly useful and important technique. Also a great deal of subtlety is involved in finding the best solution to a given prediction problem, and it is important to be aware of all the things that can go wrong.

Another advantage is that the program generated in MathCAD can be applied without any problems to calculate different prediction for the primary equipment substation, so we can calculate different prediction for the main parameters of the circuit breakers, current transformers, voltage transformers, separators, etc. Also on the future we take into account to create an algoritm in the main program through which can be disposed or can be identified an erroneous measurement.

Looking back after a couple of years it can be seen that the program is worth to try because the result obtained for T2 16MVA Ungheni has improved the safety in delivering reliable energy to distribution network.

BIBLIOGRAPHY

[1] William H. Bartley, *Hartford Steam Boiler*, Inspector & Insurance Co, “Breakthrough Asset Management for for the Restructured Power Industry”, Salt Lake City, Utah, 2002.

[2] P. N. Larman, J. A. Lapworth, A. Wilson “Evaluation de la duree de vie de transformateurs de puissance pour reseaux 275 et 400 kV” CIGRE 1998 raport 12-210.

[3] VP. Jarman, R. Hooton, “Transformer life prediction using date from units removed from service and thermal modeling”, Cigre 2010.

[4] Maksay Stefan, “Mathematical Analysis Volume I and II”, Sigma Plus, Deva, Romania, 1999.

[5] Internet Wikipedia, General principles for mathematical regression.

[6] MathCAD, Help and Support Guide.

[7] V. Zaharescu, B.D. Guzun “Operational mode analysis in service of high power transformers and transformers”, PhD. thesis, Bucharest 2012.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#95

The road to interoperability - using the Common Information Model and the Common Grid Model Exchange Standard

A. TALPOS*[1], C. BULAC[2]
[1]**C.N.T.E.E. „TRANSELECTRICA" S.A.,** [2]**University "Politehnica" of Bucharest**
[1, 2]**Romania**

SUMMARY

The paper outlines the background and the necessity for the implementation of the Common Information Model (CIM) in the member countries of the European Network of Transmission and System Operators for energy (ENTSO-E), while also concentrating on the modeling technologies of the CIM and its building blocks. The last chapter gives insight into the steps necessary to create a standard, namely the Common Grid Model Exchange Standard (CGMES) and offers information on the status of implementing different versions of this standard.

In Europe, ENTSO-E requests affiliated transmission and system operators (TSOs) to provide grid models for regional and pan-European studies, while also helping in running these studies. Merging grid models created with different tools for power system analysis is impossible: each tool uses its own logic and the files containing the (valid, converged) grid models have different extensions. Program developers created certain import functions for files obtained with other tools or export functions to ensure that the files the program outputs could be used in other tools. However, reaching the desired interoperability by means of these methods is also impossible: information is lost by converting data from tool to tool, certain tools tend to be used more than others and, therefore, some TSOs may feel obligated to acquire those tools, although having experience in calculating load-flows on other programs.

As follows, since 2009, ENTSO-E decided to start the implementation of the International Electrotechnical Commission (IEC) CIM standard for network model management. In December 2013, ENTSO-E published the first version of the CGMES, a superset of the CIM, which was developed to meet necessary requirements for TSO data exchanges in the areas of system development and system operation (e.g. The Ten Year Network Development Plan - TYNDP and network codes).

Modeling of the CIM is based on three technologies: the Unified Modeling Language (UML), the Extensible Markup Language (XML) and the Resource Description Format (RDF).

The UML is a modeling language that helps specifying, visualizing, building and documenting models of software systems, including their structure and design. It is designed based on classes, entities that have one or more attributes and multiple types of relationship between each other: inheritance, association and aggregation. Each of these essential relationships is exemplified in the paper.

The XML, is a markup language (a language that makes use of tags in order to separate elements) designed to store, transport and share data. It stores data in plain text format, therefore being both human and machine-readable. XML is the language for expressing a large part of the UML: the classes, their attributes and values, and the inheritance relationship between classes. The paper discusses XML Syntax and Schema.

* ana.talpos@transelectrica.ro

The Resource Description Framework (RDF) is a framework for expressing information and resources that need to be processed by applications. It allows for exchanges between applications without loss of meaning. Applied in XML, RDF allows for the other relationships between UML classes to be represented: association and aggregation.

The paper also regards the building blocks of the CIM model: the Equipment, Topology, Steady State Hypothesis and State Variables profiles.

KEYWORDS

System, power system, load-flow, interoperability, data management, model exchange, Common Information Model, Common Grid Model Exchange Standard, UML, XML, RDF

1. BACKGROUND

A system is a collection of interconnected parts that work together to achieve a task, should it be performing a duty or solving a problem. The various parts of a system have, beyond the implied structural relationships between each other, functional relationships. These functional relationships that exist between the parts suggest the flow and transfer of energy and/ or matter. Systems usually transfer energy and/or matter beyond their boundary with the outside environment and other systems by means of inputs and outputs.

In power engineering, these flows between systems (national/ regional electric power systems) are energy flows. The amount of energy supposed to be transferred is set on energy markets: day-ahead, intra-day, balancing for system operators or it is based on market studies for system developers. In order to ensure this scheduled exchange, the system operator/ developer establishes the inputs of the system (power generation) to be equal to the outputs (loads, network losses, external flows), while also checking that the system's components function according to set values (keeping bus voltage within limits and avoiding overcharge of lines/ transformers). Due to the size and complexity of a country's power system, maintaining its stability (input equals output) depends on automated power system network analysis. Power-flow (load-flow) studies stand at the core of this analysis – fault, small-signal stability and dynamic analyses are built on its base. The system operator/ developer uses a power system analysis program by creating a grid model and inputting the expected load, generation and exchanges and then running a power-flow analysis method. The desired result is a convergent power-flow with no violations of voltage limits for buses and no overcharges on branches while keeping close to the scheduled generation (both active and reactive power).

In Europe, the European Network of Transmission and System Operators for energy (ENTSO-E) requests affiliated transmission and system operators (TSOs) to provide grid models for regional and pan-European studies, while also helping in running these studies. Merging grid models created with different tools for power system analysis is impossible: each tool uses its own logic and the files containing the (valid, converged) grid models have different extensions. Program developers created certain import functions for files obtained with other tools or export functions to ensure that the files the program outputs could be used in other tools. However, reaching the desired interoperability by means of these methods is also impossible: information is lost by converting data from tool to tool to tool, certain tools tend to be used more than others and, therefore, some TSOs may feel obligated to acquire those tools, although having experience in calculating load-flows (and other power system analyses) on other programs.

As follows, since 2009, ENTSO-E decided to start the implementation of the International Electrotechnical Commission (IEC) Common Information Model (CIM) standard for network model management. All developers of power analysis programs that are used by ENTSO-E members were obligated to pass conformity with this standard: having a conversion tool between their formats and the CIM format and being able to solve a load-flow using a CIM model. It is important to note that CIM does not include algorithms for network analysis, except in the sense that CIM must satisfy the algorithm's need for data. Algorithms generally are internal to vendor products and their design is left to vendor competition.

In December 2013, ENTSO-E published the first version of the Common Grid Model Exchange Standard (CGMES), a superset of the CIM. It was developed to meet necessary requirements for TSO data exchanges in the areas of system development and system operation (e.g. The Ten Year Network Development Plan - TYNDP and network codes).

2. THE COMMON INFORMATION MODEL. MODELING CONCEPTS AND BASIC COMPONENTS

The CIM as defined by Working Group 13 (WG13) of the IEC, the organism that manages the basic CIM model, covers the modeling of electrical networks from the perspective of a transmission system operator. Therefore, it focuses on defining the electrical network and applications linked to online operations and offline analysis of the network.

As CIM has to be a database management system (DBMS), its design concept is based on an architecture proposed by the American National Standards Institute/Standards Planning and Requirements Committee (ANSI/SPARC): the three-level DBMS architecture.

The three levels are:

1. The Internal level: Also known as the physical level, it describes how the data is physically stored and organized on the storage medium to achieve optimal runtime performance and storage space utilization, by using storage space allocation techniques for data and indexes, access paths such as indexes, data compression and encryption techniques, and record placement.
2. The Conceptual level: Also known as the logical level, it offers an overall view of the database and it includes all the information that is going to be represented in the database: the type of data stored in the database, the relationships among the data and the user’s requirements.
3. The External level: Also known as the view level, it allows users to access data according to their needs, while also providing a security mechanism by hiding parts of the database from certain users.

Each of these levels has a schema, a structure that defines the building blocks of each level and the constraints that govern each relationship between them. Thus, the three-level architecture is also called the three-schema architecture. The main advantage of this architecture is providing data independence - changing the schema at one level of the database system doesn’t imply changing it at the other levels. There are two types of data independence:

1. Logical data independence: changing the conceptual schema doesn’t affect the external schemas or programs.
2. Physical data independence: changing the internal schema doesn’t affect the conceptual or external schema.

Logical data independence is more difficult to achieve than the physical data independence because the application programs are always dependent on the logical structure of the database. Therefore, the change in the logical structure of the database may require change in the application programs.

At the conceptual level, CIM is developed based on three modeling technologies:

A. The Unified Modeling Language (UML)
B. The Extensible Markup Language (XML)
C. The Resource Description Format (RDF)

A. The Unified Modeling Language (UML)

The Object Management Group's (OMG) Unified Modeling Language (UML) is a modeling language that helps specifying, visualizing, building and documenting models of software systems, including their structure and design. The modeling is not tied to one particular implementation technology and can be realized on multiple platforms.

In the CIM, the UML is used for designing the power system as a class diagram (a structure diagram), whose components are identified as classes that have certain parameters and relationships between each other: inheritance, association and aggregation.

Classes

A class may have internal attributes and relationships with other classes and it may appear several times in the model as separate objects with different internal values, but with the same set of attributes and relationships.

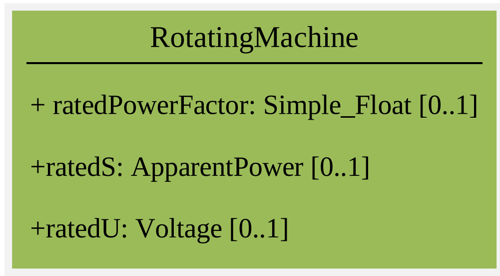


Figure 1. The Rotating Machine Class

In Figure 1 the Rotating Machine class is described. This machine may be used either as a generator or a motor. It has three attributes, all nameplate data: the rated power factor, which must be a float number, the rated S, which is an apparent power and the rated U, which is a voltage. The [0..1] multiplicity factor for each attribute means they may either appear once or not at all for a certain rotating machine.

Relationships between classes

1. Inheritance

Inheritance (also known as Generalization) defines a class as being a subclass of another class. As a subclass, it inherits all the attributes of its parent, but it can also contain its own attributes.

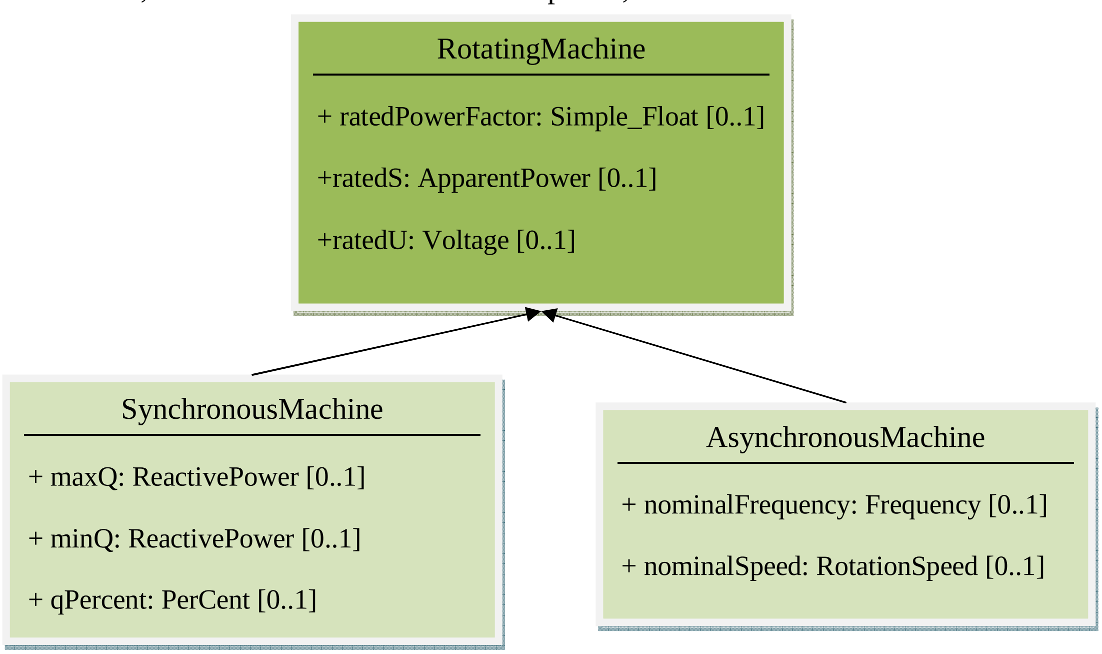


Figure 2. Subclasses inheriting attributes

In Figure 2 the Rotating Machine class is a parent class, and the added Synchronous Machine and Asynchronous Machine classes are its subclasses. Both children classes have automatically inherited the rated power factor, the rated S, and the rated U attributes, while also having attributes of their own:

reactive power limits maxQ and minQ, participation factor of the machine in the coordinated reactive control q Percent and the type of machine (generator or motor) for the Synchronous Machine class, nominal frequency and rotational speed for the Asynchronous Machine class.

2. Association

Besides the parent-child relationship, there may be other connections between classes. Such a link is the association relationship, illustrated in Figure 3.

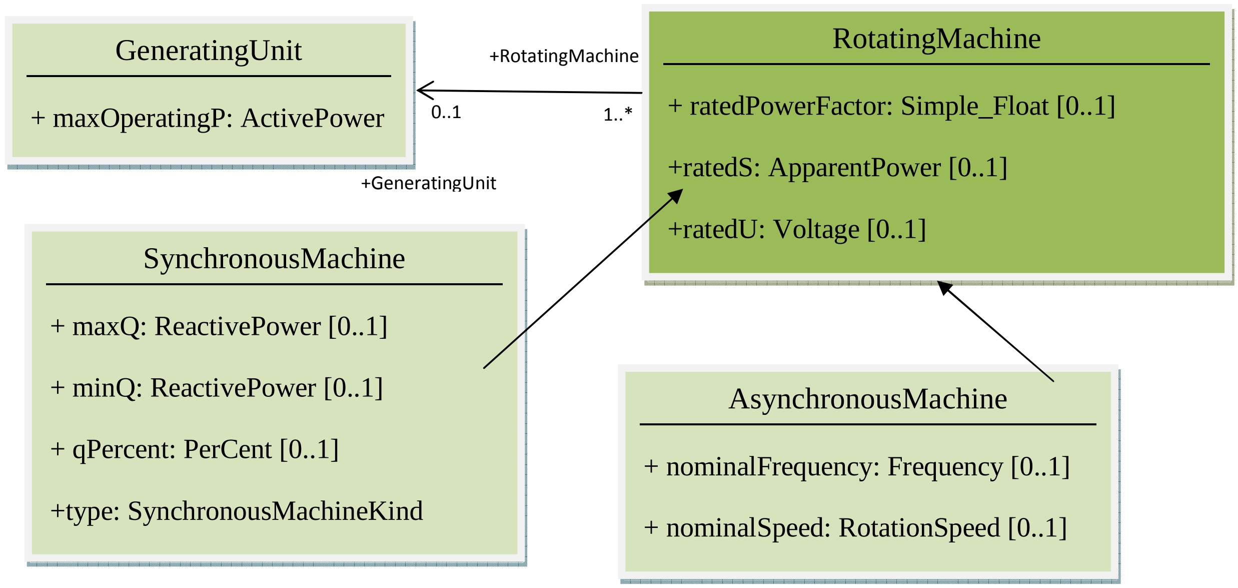


Figure 3. Association between Generating Unit and Rotating Machine

The association is shown as a line between Generating Unit and Rotating Machine. The numbers and symbols on each end of the line express cardinality. The Rotating Machine class has an association with the Generating Unit class with a cardinality of 0.1. This shows that a Rotating Machine may either be a Generating Unit (1) or not (0). Reading the relationship backwards, the Generating Unit class has an association with the Rotating Machine class with a cardinality 1..*. That means that a Generating Unit must associate with at least one Rotating Machine (1..* means one or more). This means that the Generating Unit class will have the attributes and values of the Rotating Machine(s) that it is associated with.

3. Aggregation

The Aggregation relationship between two classes indicates than one of them is contained in the other.

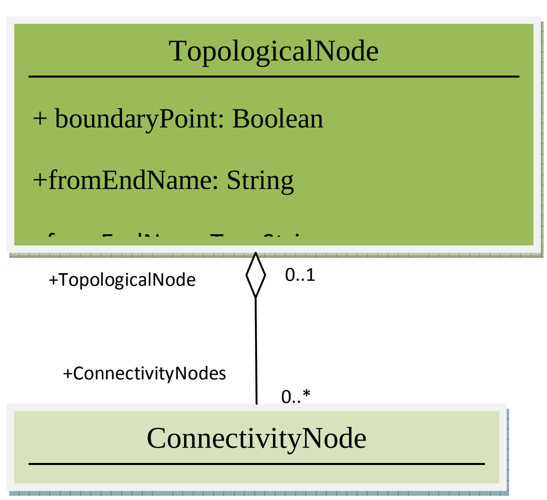


Figure 4. Aggregation of the Connectivity Node class in the Topological Node class

For a detailed substation model, a topological node is a set of connectivity nodes that are connected together through any type of closed switches. Topological nodes change with the change of the network state (for example, if disconnectors change state). This detailed model is also referred to as the “Node-Breaker” or Operational model.

For a planning model, switch statuses are not used to form topological nodes. Instead they are manually created or deleted in a model builder tool. Topological nodes maintained this way are also called “busses”. This simplified model is called the “Bus-Branch” or Planning model.

Connectivity nodes are points where terminals of AC conducting equipment are connected together with zero impedance.

This diagram indicates that a Topological Node may contain zero (Planning Model) or more instances of Connectivity Nodes while a Connectivity Node will be contained in zero or one Topological Node. This relationship, described by the clear diamond, does not stand for complete interdependence. Should the Topological Node be removed, the Connectivity Nodes would still exist.

B. The Extensible Markup Language (XML)

XML, the Extensible Markup Language, is a markup language (a language that makes use of tags in order to separate elements) designed to store, transport and share data. It stores data in plain text format, therefore being both human and machine-readable.

XML Syntax

1. *The XML Prologue* - although optional, if it exists, it must be the first line of the file

```
<?xml version="1.0" encoding="UTF-8"?>
```

Figure 5. The XML Prologue

2. *Root element* - the parent of all other elements, the entire document is contained within its tags.

```
<rdf:RDF
xmlns:cims=http://iec.ch/TC57/1999/rdf-schema-extensions-
19990926#xmlns:rdf="http://www.w3.org/1999/02/22-rdf-syntax-ns#"
xmlns:xsd="http://www.w3.org/2001/XMLSchema#"xmlns:cim="http://iec.ch/TC57/2013/CIM-
schema-cim16#" xmlns:rdfs="http://www.w3.org/2000/01/rdf-schema#"
xmlns:entsoe="http://entsoe.eu/CIM/SchemaExtension/3/1#"xmlns:md="http://iec.ch/TC57/61970-
552/ModelDescription/1#">
</rdf:RDF>
```

Figure 6. The root element for CIM

Any element can contain attributes. The attributes of the CIM root element, “xmlns”, define the namespaces for the entire file. Namespaces are a method of avoiding name conflicts (when combining separate XML documents from different developers).

3. *Otherelements*

```
<cim:ACLineSegmentrdf:ID="_0a1a2a3a4a5a6a7a8a9a0b1b2b3b4b5b">
<cim:IdentifiedObject.name>Node 1 - Node 2</cim:IdentifiedObject.name>
<cim:ACLineSegment.r>1.230000</cim:ACLineSegment.r>
<cim:ACLineSegment.x>12.300000</cim:ACLineSegment.x>
<cim:ACLineSegment.bch>1.23000E-004</cim:ACLineSegment.bch>
<cim:ConductingEquipment.BaseVoltagerdf:resource="#_56D28BB6-A2CC-4988-B80E-
3CF3EA2F3791"/>
<cim:ACLineSegment.r0>3.69000</cim:ACLineSegment.r0>
<cim:ACLineSegment.x0>36.990000</cim:ACLineSegment.x0>
<cim:ACLineSegment.b0ch>9.9900E-005</cim:ACLineSegment.b0ch>
</cim:ACLineSegment>
```

Figure 7. Example of CIM element: Line

In Figure 7 an AC line segment element (class in UML) is described. It has an inherited attribute: “name” from (great-grand) parent class “Identified Object”. Its own attributes (positive and zero sequence resistance “r”/ “r0”, reactance “x”/ “x0”, susceptance “bch”/ “b0ch”) have their values written between tags.

4. *Comments* - useful inserts to help identify the elements better in a large CIM file

<!--Line--><!--GeographicalRegion-->

Figure 8. Example of CIM comments

XML Schema

An XML Schema is a standard for exchanging data that describes the structure of an XML file. It provides support for defining data constraints, validating data correctness and converting between different data types.

An example of XML schemas is provided in Figure 6, where the Uniform Resource Identifiers (URIs, links) for namespaces are Schemas: the CIM namespace complies to the CIM Schema CIM 16, the RDFs namespace complies to the RDF Schema, the ENTSO-E Schema complies to CIM Schema Extensions designed especially for CGMES and the XSD (XML Schema Definition) complies to the XML Schema.

C. The Resource Description Framework (RDF)

The Resource Description Framework (RDF) is a framework for expressing information and resources that need to be processed by applications. It allows for exchanges between applications without loss of meaning.

RDF Syntax

A basic XML document does not allow for connections to exist between two elements that are not a parent or a child. However, the RDF provides a solution by allowing each element of a document to be assigned a unique “ID” (or “about”) attribute under the RDF namespace and also allowing for a “resource” attribute to a certain element to have its value equal to another element’s ID. Thus, a relationship between the two elements is defined.

In Figure 7, for the “AC Line Segment” class, the “Base voltage” class is an associated class of the parent class “Conducting Equipment”. The rdf:resource="#_56D28BB6-A2CC-4988-B80E-3CF3EA2F3791" coincides with the rdf:ID of a “Base Voltage” class with the “nominal Voltage” attribute equal to 220 (kV).

RDF Schema

The RDF Schema is a semantic extension of RDF, which provides a data-modeling vocabulary for RDF data. It introduces tools for describing groups of related resources and the relationships between them.

The RDF and the RDF Schema allow for relationships between classes and properties to be as expressed in XML format. Therefore, the two technologies, RDF and XML, are a means of expressing UML in a syntax that may be used for developing a power system application.

The basic building blocks of a CIM Model are the following model parts (profiles):

1. The Equipment (EQ) profile
2. The Topology (TP) profile
3. The Steady State Hypothesis (SSH) profile
4. The State Variables (SV) profile

These first four profiles are the essential parts of a CIM Model (upon conversion from a power analysis tool): the equipment profile contains all physical elements in the grid model (lines, transformers, generators, loads), the topology profile contains data about the connections in the grid (between the physical elements), the steady state hypothesis profile contains the value of the parameters needed for load-flow calculation and the state variables profiles contains the value of the parameters after solving the load-flow.

5. The Dynamics (DY) profile
6. The Short-circuit (SC) profile
7. The Diagram Layout (DL) profile
8. The Geographic Location (GL) profile
9. The Operation (OP) profile

All classes are a part of one of these profiles.

3. THE COMMON GRID MODEL EXCHANGE STANDARD. DEVELOPING A STANDARD AND TESTING FOR CONFORMITY

The CGMES is a standard tailored to ENTSO-E's requirements for achieving full interoperability in data exchanges between its member TSOs. Full interoperability translates into a TSO being able to import in its power analysis program another TSO's grid model and obtaining the same results after solving the load-flow, regardless of the programs used by the two TSOs.

CGMES includes the CIM standards while also using CIM Extensions. These may be traced in UML or XML by the "entsoe" prefix (namespace).

The steps for a (CGMES) standard approval process are as follows:

1. Vendors, members of the IEC WG 13 and the ENTSO-E Secretariat attend the interoperability meeting at the ENTSO-E headquarters to establish the final UML and XML models. Its goal was to verify the UML profiling and extensions, while also verifying/ specifying test configuration and test data.
2. The period following the interoperability meeting is dedicated to fixing bugs in the CGMES – compliant programs.
3. The next step in the compliance process is updating the documentation in accordance with the latest modifications in software.
4. Preparation of the System Operating Committee (SOC) / System Development Committee decision.
5. Deciding the faith of the standard version at the SOC / SDC meeting.
6. After receiving positive feedback from the two organisms, the next step is submitting the draft standard to the IEC.
7. Upon approval by IEC, the last step of the process in TSO implementation.

The current CGMES standard version, 2.4.15, based on the 16^{th} version of the IEC CIM standard, available since August 2014, may be considered a stable one and is, at the date of this paper, at step 7 of the standard approval process.

Step 7 is the last step in reaching full interoperability: The TSOs test their CGMES grid models exported from a CGMES-compliant tool in other CGMES-compliant tools (programs that have received ENTSO-E's Attestation of Conformity with the standard). The purpose of this tests is obtaining the same load-flow results for the same model in all tools.

Different load-flow results are obtained due to each program's treatment of reactive control equipment during iteration. Treatment of shunts, tap control for tap-change transformers and respecting a generator's reactive limits may all change the results of a power-flow reactive power-wise.

At the same time as the TSO implementation part, CGMES standard version 2.5 is being discussed in the first step of the approval process. It may be considered that this standard version is one tailored for operations, as it brings out vast improvements in terms of dynamic stability assessment, capacity calculations, coordinated security analysis, steady state power- flow and efficient data exchange, while also covering outage coordination for the first time.

4. CONCLUSION

As long as a system does not work in an isolated mode, exchanges with the other systems it is connected to will be monitored and continuously modified. However, in order to achieve full communication between systems, as is the case with diplomatic relations between countries, a common language must be spoken. The Common Information Model (and based on it, the Common Grid Model Exchange Standard) provide an extensive dictionary for power systems (or their models, at least) to co-operate in creating a stronger interconnected network.

BIBLIOGRAPHY

[1] ITL Education Solutions Limited, "Introduction to Database Systems" (Pearson Education India, 2010)
[2] EPRI, "Using the Common Information Model for Network Analysis Data Management: A CIM Primer Series Guide" (Technical Report 3002002587, November 2014)
[3] EPRI, "Common Information Model Primer: Third Edition" (Technical Report 3002006001, June 2015)
[4] W3Schools, "XML Tutorial" (http://www.w3schools.com/xml/)
[5] W3C WG Note, "RDF 1.1 Primer" (https://www.w3.org/TR/rdf11-primer/, June 2014)
[6] W3C Recommendation, "RDF Schema 1.1" (https://www.w3.org/TR/rdf-schema/, February 2014)
[7] ENTSO-E, "Common Grid Model Exchange Standard (CGMES) Version 2.4" (August 2014)
[8] ENTSO-E, "Detail description of the CGMES profiles Version 2.4.15" (August 2014)
[9] ENTSO-E, CGMES 2.5 draft UML (July 2016)

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#96

The process of identifying new projects under ENTSO-E rules; Study case – new tie-line HU-RO

A. TOLEA[*1], C. BULAC[2]
[1]**C.N.T.E.E. „Transelectrica" S.A.,** [2]**University "Politehnica" of Bucharest**
[1, 2]**Romania**

SUMMARY

The TYNDP (Ten Years Network Development Plan) for Electricity is the most comprehensive and up-to-date planning reference for the pan-European transmission electricity network. The TYNDP is a biennial report published every even year by ENTSO-E and acts as an essential basis to derive the next Projects of Common Interest (PCI) list, in line with the Regulation (EU) No. 347/2013 ("the Energy Infrastructure Regulation"). ENTSO-E is structured into six regional groups for grid planning and other system development tasks. Romania CNTEE Transelectrica SA is a part of two regional's groups Continental South East and Continental Central East.

The development of the TYNDP consists of a multitude of studies which identify the grid bottlenecks and potential investment solutions of pan-European significance for a large long time horizon (2030 and beyond), the potential investments being evaluated and promoted.

For a potential investment to be identified Market and Network Simulations are performed. During these simulations performed for TYNDP 2016 a new project between Hungary and Romania was identified. This project was labeled as future project candidate (it will be commissioned not earlier than 2030).

To identify the projects that have a significant contribution to European energy policies implementation and are valuable in several possible future energy scenarios and in the same time are efficient in order to minimize costs for consumers, Cost Benefit Analysis (CBA) and multi-criteria assessment are carried out.

This paper presents the process of new projects identification, the CBA indicators and a study case: a new 400kV OH interconnection line between Romania and Hungary.

KEYWORDS

Ten year network development plan, Regional Investments Plans, Cost benefit analysis.

INTRODUCTION

Considering the high dynamics of the energy sector, the grid development has to reflect these fast changes and has to ensure a secure and reliable transmission grid. The main drivers for the grid development are: generation evacuation under high RES installed capacity, market integration in order to achieve a common European market, security of supply improvement and climate change mitigation under increase energy efficiency measures and electricity peak demand increase. Grid development is an important step towards fulfilling the European Goals such as reduction of the greenhouse gas emissions, increase the share of renewable energy and energy efficiency.

[*] alexandra.tolea@transelectrica.ro

Each release of a new TYNDP has the role to reconfirm existing projects, to analyze new strategies, goals and issues in order to cover the possible energy situation in Europe in the considered time horizon and also provides the reference point for European grid development. In order to develop an accurate TYNDP a strong collaboration between Transport System Operators(TSO’s), EU community and stakeholders is needed. In the current TYNDP 200 projects in transmission and storage are analyzed.

The process of making the TYNDP 2016 was divided in two phases:

- In the first phase, Common Planning Studies were performed and the results were then published in the Regional Investment Plan, one for each region. Based on them a list of TYNDP project candidates was identified;
- The second phase consisted of the project assessment. In this phase the identified projects in the first phase were evaluated using the CBA Methodology under certain scenarios.

COMMON PLANNING STUDIES

The Common Planning Studies are built using the past TYNDP input data and projects considering national and regional input and following a consolidated European network planning approach.

The Common Planning Studies aim to identify the optimal grid investments that will reinforce the existing European network in order to accommodate the future generation mix/demand in a reliable and cost–efficient way. In order to cover the evolution of the generation mix/demand, a number of visions are built. The visions can be assimilated as a bridge between the European energy targets for the near future and 2050, they differ enough from each other and are built in a manner so that the future will fall with a high level of certainty in the range described by the visions.

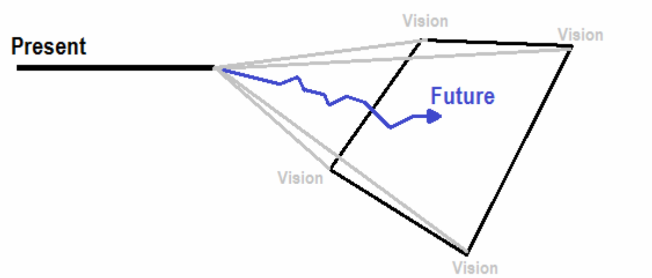


Fig.1 Promoted visions against future reality

The visions are divided in two classes: top down visions and bottom up. The bottom-up visions are based on the member countries input regarding load and generation evolution. The top-down visions assume a pan-European approach and they are developed starting from the bottom-up visions and considering a greater harmonization of the data’s provided by the member states. In the top-down scenarios the same macro-economic and political view of the future was considered for all countries.

Considering the data input, for each scenario/vision the investments needs are identified in order to eliminate grid bottlenecks or to support market integration opportunities, RES integration, interconnection targets and security of supply issues. In order to identify the investment needs Market and Network Simulations are performed.

Market Simulations (MS) provide results regarding the socio-economic welfare brought by a new interconnection project which increase the border capacity. Performing iterative Market Simulations increasing a specific border capacity with 500MW or 1000MW at each iteration, and calculating the socio economic welfare we can conclude it does worth to build a new project on that border if the socio economic welfare is significantly increased taking into account also the project cost.

The Market Simulations are run for each border and each direction aiming to identify the beneficial borders suitable to a boundary transport capacity (BTC) increase and the target capacities.

The Network Simulations (NS) use the output of the Market Simulations (MS) and identify and asses new feasible projects that can achieve the BTC target provided by the MS. In order to perform network analysis, network datasets are needed. A number of Points in Time are defined and are implemented in the datasets in order to perform network simulations under general rules. The network simulation allows testing the projects proposed, suitable for capacity increase or as grid reinforcements to eliminate bottlenecks.

After the identification of the investments needs is made, different grid investments projects/solutions are proposed in order to meet the needs. As a general idea the investments needs are considered new projects candidates and reconfirm in most cases the past TYNDP projects. A project is defined as the small set of assets that effectively add capacity to the transmission infrastructure that can be used to transmit electric power.

The Regional Investment Plan is built on the conclusions of the Common Planning Study and analyses the development of the power system at a regional level, based on common guidelines and identify investments needs linked with a set of proposed projects. The Regional Investment Plan contains all the projects of regional significance and based on them a list of TYNDP projects candidates is proposed.

The TYNDP is a continuously evolving process that takes into account the feedback from TSO's, institutions and stakeholders also takes into account EU regulations. The report provides a wider view on the European grid development in the conditions of achieving European energy objectives, such as security of supply across Europe, sustainable development of the energy system with renewable energy sources integration and affordable energy for European consumers through market integration. Also the TYNDP is the instrument for the selection of Projects of Common Interest. Starting from the project list proposed by the Regional Investment Plan, the projects of pan-European significance are chosen. The TYNDP project list is submitted to a Cost Benefit Analysis in order to identify the projects that contribute significantly to European energy policies and that are robust enough, are possible in different energy projections and in the same time are efficient in order to minimize costs for consumers.

COST BENEFIT ANALYSES

The CBA describes the common principles and procedures, including network and modeling methodologies in order to identify transmission projects and measuring the cost and benefit indicators. Some of these indicators are monetized while others are measured through physical units. The CBA Methodology was developed by ENTSO-E and adopted by the EC and allows the assessment of infrastructure projects in an objective, transparent and economically manner against indicators which can range from market integration, security of supply, RES integration or environmental impact.

The indicators are divided in three categories: benefit indicators, cost indicators impact on society and grid transfer capability.

The Benefit indicators are:

B1. Improved security of supply (SoS) is the ability of a power system to provide an adequate and secure supply of electricity under ordinary conditions. The criteria on measuring the improve of the security of supply is made by calculating the difference between the cases with and without the project, with the defined indicator being either Expected Energy Not Supplied (EENS) or the Loss of Load Expectancy (LOLE).

B2. Socio-economic welfare (SEW) or market integration is characterized by the ability of a power system to reduce congestion and thus provide an adequate GTC so that electricity markets can trade power in an economically efficient manner. To calculate the increased benefit from socio-economic welfare it can be compared the generation costs with or without the projects for different bidding areas or it can be compared the generation and consumption surpluses for both biding areas, as well as the congestion between them, with or without the project.

B3. RES integration: Support to RES integration is defined as the ability of the system to allow the connection of new RES plants and unlock existing and future “green” generation, while minimizing curtailments. The calculation of these indicator is done by calculating the connection of RES to the main system without regard to the actual avoided spillage or it can be calculating as the avoided curtailment due to congestion in the main system.

B4. Variation in losses in the transmission grid is the characterization of the evolution of thermal losses in the power system. It is an indicator of energy efficiency and is correlated with SEW. Network development usually decreases losses by performing a better load flow also leads to a better voltage profile and thus increases energy efficiency. The variation in loses can be determined by using market and modeling tools. The losses in the power system are quantified considering the system with and without project while taking in to account the change of dispatch that may occur in the market studies.

B5. Variation in CO2 emissions is the characterization of the evolution of CO2 emissions in the power system. It is a consequence of B3 indicator (unlock of generation with lower carbon content). The impact of CO2 is calculated using the generation dispatch and unit commitment used for calculating of B2 indicator.

B6. Technical resilience/system safety is the ability of the system to withstand increasingly extreme system conditions (exceptional contingencies). The technical resilience and system safety is evaluated by considering a number of key performance indicators (KPI).

B7. Flexibility/Robustness is the ability of the proposed reinforcement to be adequate in different possible future development paths or scenarios. The robustness and the flexibility of a project will ensure that the project can be utilized in the long term perspective considering the uncertainties related to the network development and evolution. This indicator is evaluated also considering a number of key performance indicators as: ability to comply with all cases analyzed using a probabilistic, multiscenario approach, ability to comply with all cases analyzed taking out some of the foreseen reinforcements, ability to facilitate sharing of balancing services on wider geographical areas.

The indicators that reflect the project costs are defined as follows:

C1.Total project expenditures are based on prices used within each TSO and rough estimates on project consistency (e.g. km of lines). Environmental costs can vary significantly between TSOs. To determine the total project expenditures it should be taken into account the following items: the cost for materials, costs for temporary solutions which are necessary to realize a project, environmental costs and maintenance cost.

The indicators that reflects the impact on society of the project is defined as follows:

S.1. Environmental impact characterizes the project impact as assessed through preliminary studies, and aims at giving a measure of the environmental sensitivity associated with the project.

S.2. Social impact characterizes the project impact on the (local) population that is affected by the project as assessed through preliminary studies, and aims at giving a measure of the social sensitivity associated with the project.

The **Grid Transfer capability (GTC)** reflects the ability of the grid to transport electricity across a boundary. The GTC depends on the considered state of consumption, generation and exchange, as well as the topology and availability of the grid, and accounts for safety rules. The GTC is calculated starting from a stress system in order to highlight the contribution of the possible project. The GTC takes into account the congestions in the both areas.

The purpose of the project assessment is to evaluate the impact of the project from the perspective of the added value to the European system and from cost perspective. During the Common Planning Studies if transmission weaknesses are identified reinforcements are proposed. The reinforcements can consist of duplication of lines to increase rating, reinforcement of overhead lines, network equipment’s or substation, additional transformer, new overhead lines and cables, AC or DC. In the situation where multiple projects depend on each other to provide the same benefit for the network they can be clustered in order to be assessed as a group. During the assessment phase it is used a combined cost-benefit and multi-criteria assessment and at the end will be supplied information regarding the project benefits in terms of EU network objectives, measurement of project costs and feasibility.

Considering the fact that for the calculation of the benefit indicators the both situations with and without project are considered, two possible ways for project assessment can be used:

- Take Out One at the Time (TOOT)method in which it is considered the reinforced network and are excluded one by one each investment item or whole project in order to evaluate the load flows over the grid elements with and without the corresponding project.
- Put IN one at the Time (PINT)method that starts from the reference grid and considers each new investment item or whole project and evaluates the network flows over the grid elements.

For a project to be considered of pan-European significance is has to fulfill a number of criteria's: the voltage level has to be at least 220 kV for a AC line or at least 150 kV for DC lines, it has to be located at least partially in one of the countries represented in ENTSO-E and the project contributes to a grid transfer capability increase.

Study case: A new 400 kV OH interconnection line between Romania and Hungary

During the Common Planning Studies all the internal borders of a regional group are analyzed and are identified the borders with beneficial cross-border capacity increase. The borders proposed for cross-border capacity increase are obtained during a series of iterations. For the next consecutive iteration are considered the borders with the greatest SEW/cost-ratio and Net Present Value (NPV). During the last Common Planning Studies in the RG CCE two borders were identified with beneficial cross-border capacity increase: the Polish border with a profile of importing and the Hungarian – Romanian border. For the Hungarian-Romanian border during the Common Planning Studies the benefits and the economic viability were demonstrated in a high RES scenario. The both TSOs considered that this project will not be commissioned earlier than 2030 and is characterized as a future project candidate. The new project will consist of a 400 kV line between Debrecen-Jozsa (HU) and Oradea (RO), with double-circuit towers and single circuit conductors. The new line will not only contribute to the market integration but also will improve the security of supply in both countries. The additional reinforcements that will be necessary in both countries will be determined by detailed network analyses in extended time frame coordinated with national development plans.

For the Hungarian-Romanian border the reference capacity (capacity without the new proposed project) was considered 1300 MW. The Common Planning Studies were made considering the vision with high RES (2030 Vision 4) and were chosen as basis for promoting the TYNDP project candidates. The network base case was defined on the data used in the previous TYNDP and considering the vision with high RES conditions but also information regarding installed capacities, generation profile for photovoltaics and wind, reference capacities and additional details provided by the regional members (TSOs) were allowed. For the market simulation process the member states had to provide a list of costs for each possible capacity increase on a border. These costs included necessary internal reinforcements to make the additional cross-border capacity possible. Starting from the base case, market simulations were performed with an increase capacity of 500 or 1000 MW. After each market simulation step, the socioeconomic welfare (SEW) and NET Present Value (NPV) was calculated for all borders with increased capacity. The NPV is determined using the standard costs for the project, the SEW aver a 25 year period of amortization and an interest rate of 4% per year. The capacity increases which gave the highest SEW/cost ratio in the region, were considered in the new base case. The borders that showed unsatisfactory results were removed from the new base case. The process continued until no more beneficial increases were identified. After the process ends, a list of borders susceptible to a capacity increase and the amount of those increases is presented. After this step the regional members analysis the new "target capacity" and propose possible project candidates. In the RG CCE after three iterations there were no borders left with a positive NPV and the process stopped.

The Network Simulations investigate the impact of the increased border capacity obtained during the market simulations in order to detect new problems regarding the grid development. The Network studies starts with selecting a number of representative snap-shots from all the 8760 simulations performed during the market simulations (8760 hours for 2030 year). The points in time are selected by each regional group considering different inputs regarding the RES production, load, market exchanges and take in to account a preliminary simplified load flow. For the chosen points in time detail analysis were performed. The analysis provided information regarding voltage profile, network elements loads and elements to be heavy loaded or overloaded under contingency under contingency conditions. The NS showed that for the Hungary-Romanian projects for all the PITs selected considering all network elements connected were not observed overloaded elements for the complete scheme but considering the N-1 criteria some network elements were overloaded. This situation appeared due to the fact that the majority of the installed capacity is located in the south part of Romania. Further analyses are required in order to investigate the necessary grid reinforcements for the identified capacity increase.

Considering the fact that the Hungarian-Romania project is a future project only a few CBA indicators were computed and only for some of the visions. For this type of projects the following CBA indicators were evaluated: B2 Security of supply, B3 RES integration, B5 CO2 emissions and GTC. The GTC values obtained for the both directions showed that it is possible a contribution of 200 MW for HU-RO and of 800 MW for the RO-HU direction.

CONCLUSIONS

The rapid development of renewable energy sources and the liberalization of the European market had led to a more complex and interdependent power flow. Therefore, in order to cope with the new energy policies the network development has to be done in a coherent and coordinated way and with a strong cooperation at a regional and European level. The main objective of the TYNDP is to plan and develop a secure, efficient and economic electricity transmission system while taking into account different requirements and regulation toward the liberalization of the European electricity market, EU policies and targets, national legislation and regulatory framework, economic efficiency and using transparent rules. The TYNDP is based on the best methodology to identify and assess projects of European interest while ensuring transparency regarding electricity transmission network and providing information to the decision makers.

BIBLIOGRAPHY

[1] ENTSO-E, “ENTSO-E Guidelines for Cost Benefit Analysis of Grid Development Projects” (February 2015)

[2] ENTSO-E, “Regional Investment Plan 2015 Continental Central East region” (October 2015)

[3] ENTSO-E, “10-YEAR NEWORK DEVELOPMENT PLAN 2014” (December 2014)

[4] ENTSO-E, “TYNDP2016 combined project sheets 2016” (June 2016)

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#97

Improving the fault location for transmission lines using the actual measurements

*

M. DRAGOMIR[1], Gh. MORARU[2], A. MIRON[3]
[1]CNTEE Transelectrica SA, [2]SMART SA, [3]University of Suceava
[1, 2, 3]Romania

SUMMARY

Transmission line fault location represents the process of calculating the location of the permanent and intermittent faults with high precision. Taking into account the fact that the transmission lines cover important areas of the power system, the location of the faults with high precision can minimize the restoration time of these lines with benefits in the stability of the system. In the paper is presented a method to improve the fault location precision using the actual measurements of the line ends. In order to implement this method first there are downloaded the measurements of voltage and current from each end of the faulted line independently, then a manual synchronization of these measurements is applied and in the end the two-end data fault location is applied. The method was tested with real data as well as with simulated data. The simulated data was obtained from a simulation equivalent model of the faulted grid. The results obtained demonstrate the precision of the proposed method when compared with the results of the actual one-end data fault location method.

KEYWORDS

Fault location algorithms; unsynchronized measurements, numerical relay.

1. INTRODUCTION

Transmission line is one of the most important components of a power system. Due to the fact that these transmission lines cover important areas, they are often exposed to faults. Furthermore, the power systems are expanding and along with this expansion stability issues arise in their operation. The use of precise fault location solutions can lead to faster finding of the fault location and to the minimization of the restoration time of the faulted line. In this way the stability of the power system and the quality of the energy are fairly improved.

The majority of the fault location algorithms use the fundamental frequency phasors of the voltage and current. Another category of the fault location algorithms use the traveling wave components generated by the fault [1, 2]. Generally, the traveling wave algorithms obtain the fault location more precisely when compared to the fundamental frequency phasor algorithms. The implementation of the traveling wave algorithms is complex and expensive because they require high sampling rate equipments and in some cases special sensors and external GPS synchronization sources are needed [3]. In the other hand, the fundamental frequency algorithms are cheaper and less complex to implement because they do not need special sensors or high sampling rate equipments. In this case there can be used the actual sensors and sampling rate equipments (e.g. those used for protection or monitoring) [4]. In some cases, however, there are needed external GPS synchronization sources which increase the implementation cost [5].

* marian.dragomir@transelectrica.ro

The fault location algorithms that use the fundamental frequency phasors of the voltage and current are divided in two main categories: the one-end data and the two-end data algorithms.

The one-end data algorithms rely on the estimation of the apparent impedance from the measurement point (e.g. one end of the line) using the voltage and current phasors from the fault regime [6]. In order to obtain the fault location, this apparent impedance is compared with the total impedance of the line. To improve the fault location, some one-end data fault location algorithms use in addition the pre-fault voltage and current phasors [7, 8]. The one-end data algorithms are cheap and very simple to implement, that's why the fault location using one-ended voltage and current phasors became a standard feature in the majority of the numerical relays [5]. In the other hand, the precision of these algorithms is affected by many source of errors such as: value of the fault resistance, the remote in-fed current, value of the zero-sequence line impedance, errors in current phasor estimation due to the decaying DC component from the fault current [4-8]. With all these, the one-end data algorithms introduce acceptable errors and are widely used around the world.

The two-end data algorithms estimate de fault location using the measurements from both ends of the line. In the standard approach, these measurements contain the voltage and current phasors from both ends of the line [9], but over the past years there were developed two-end data algorithms which use only the current phasors [10] or only the voltage phasors [11]. The two-end data algorithms can use synchronized or unsynchronized measurements. The two-ended synchronized measurements need an external GPS source which increases the cost of implementation but in the other hand it increases the fault location precision [1, 9]. The two-ended unsynchronized algorithms can be used where synchronized timing is too expensive. In order to obtain as precise results as possible, the goal of the unsynchronized algorithms is to synchronize the measurements off-line. The off-line synchronization can be done manually or using dedicated software [12]. The implementation of the two-end data unsynchronized measurements is less expensive, but the precision in estimating the fault location can be altered [1].

For lines equipped with numerical relays it is possible to remotely download the registered signals. If on these lines are implemented one-end data fault location algorithms at each end, unacceptable fault location errors can arise in some cases. It is possible to improve the fault location for those lines by manually downloading the measurements from both ends and then apply a two-end data fault location algorithm. The result can be obtained within minutes with good precision. In the paper, this solution for improving the fault location is considered and it will be described in the next section.

2. ONE-END DATA FAULT LOCATION ALGORITHMS

The majority of the transmission lines are equipped with numerical relays, where the one-ended fault location function is implemented. To illustrate how the fault location is calculated, first it is considered a three-phase line connected to sources which experience a fault in point F on phase a, like in Fig. 1, where the variables are as follow: $\underline{E}_{Sa}$, $\underline{E}_{Sb}$ and $\underline{E}_{Sc}$ are the source **S** voltage phasors, $\underline{E}_{Ra}$, $\underline{E}_{Rb}$ and $\underline{E}_{Rc}$ are the source **R** voltage phasors, $\underline{I}_{Sa}$, $\underline{I}_{Sb}$ and $\underline{I}_{Sc}$ are the current phasors measured at end **S**, $\underline{V}_{Sa}$ is the voltage phasor measured at end **S**, $\underline{Z}_{La}$, $\underline{Z}_{Lb}$ and $\underline{Z}_{Lc}$ are the line self-impedances corresponding to phase *a*, phase *b* and phase *c*, R_F is the fault resistance, $\underline{Z}_m$ is the mutual impedance, $\underline{I}_{Ra}$ is the remote current phasor on phase *a*, $\underline{I}_F$ is the fault current and *d* is the per-unit distance to the fault measured from end **S** of the line.

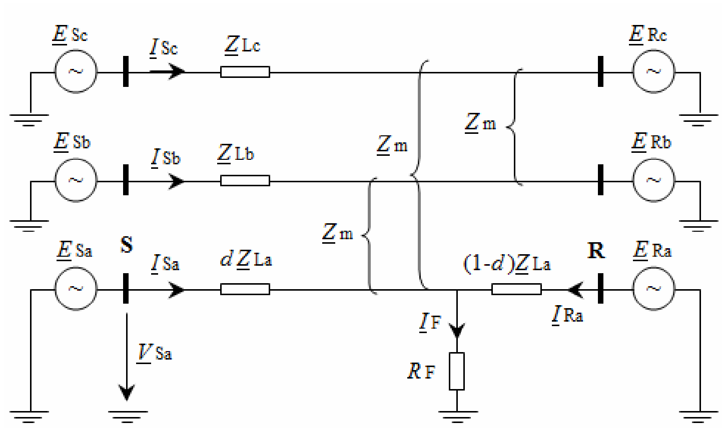


Fig. 1. Simple two-sources grid with fault on phase *a*

The phase *a* voltage measured at end **S** of the line is:

$$\underline{V}_{Sa} = d\cdot(\underline{Z}_{La}\cdot\underline{I}_{Sa} + \underline{Z}_m\cdot\underline{I}_{Sb} + \underline{Z}_m\cdot\underline{I}_{Sc}) + R_F\cdot\underline{I}_F \qquad (1)$$

where $\underline{I}_F = \underline{I}_{Sa} + \underline{I}_{Ra}$. Using the measured phase currents at end **S** it can be calculated the zero sequence current $\underline{I}_{S0}$ as follow:

$$\underline{I}_{S0} = \underline{I}_{Sa} + \underline{I}_{Sb} + \underline{I}_{Sc} \qquad (2)$$

If (2) is introduced in (1), it can be obtained:

$$\underline{V}_{Sa} = d\cdot[\underline{Z}_{La}\cdot\underline{I}_{Sa} + \underline{Z}_m\cdot(\underline{I}_{S0} - \underline{I}_{Sa})] + R_F\cdot(\underline{I}_{Sa} + \underline{I}_{Ra}) \qquad (3)$$

The phase *a* line self-impedance $\underline{Z}_{La}$ and the mutual impedance $\underline{Z}_m$ can be calculated using the line's positive sequence impedance $\underline{Z}_{L1}$ and the zero sequence impedance $\underline{Z}_{L0}$, as following:

$$\underline{Z}_{La} = (\underline{Z}_{L0} + 2\cdot\underline{Z}_{L1}) / 3, \text{ and } \underline{Z}_m = (\underline{Z}_{L0} - \underline{Z}_{L1}) / 3 \qquad (4)$$

Replacing $\underline{Z}_{La}$ and $\underline{Z}_m$ calculated with (4) in (3) and making simple mathematical operations it results in:

$$\underline{V}_{Sa} = d\cdot\underline{Z}_{L1}\cdot(\underline{I}_{Sa} + \underline{k}_0\cdot\underline{I}_{S0}) + R_F\cdot(\underline{I}_{Sa} + \underline{I}_{Ra}) \qquad (5)$$

with $\underline{k}_0 = (\underline{Z}_{L0} - \underline{Z}_{L1}) / (3\cdot\underline{Z}_{L1})$ being the compensation factor. The current phasors of the faulted phase can be divided in pre-fault and pure fault components as in (6):

$$\underline{I}_{Sa} = \underline{I}_{Sa\_PRE} + \underline{I}_{Sa\_F}, \text{ and } \underline{I}_{Ra} = \underline{I}_{Ra\_PRE} + \underline{I}_{Ra\_F} \qquad (6)$$

where the subscript "PRE" denotes the pre-fault component and the subscript "F" denotes the pure fault component. Supposing that $\underline{I} = \underline{I}_{Sa} + \underline{k}_0\cdot\underline{I}_{S0}$, (5) results in:

$$\underline{V}_{Sa} = d\cdot\underline{Z}_{L1}\cdot\underline{I} + R_F\cdot(\underline{I}_{Sa} + \underline{I}_{Ra}) \qquad (7)$$

Replacing (6) in (7) and extracting the fault resistance R_F, results in:

$$R_F = (\underline{V}_{Sa} - d\cdot\underline{Z}_{L1}\cdot\underline{I})/[\underline{I}_{Sa\_F}\cdot(1+ \underline{I}_{Ra\_F} / \underline{I}_{Sa\_F})] \qquad (8)$$

Supposing that $\underline{I}_{Sa\text{-}F}$ is in phase with $\underline{I}_{Ra\text{-}F}$ and extracting the imaginary part of equation (8) will result in:

$$\mathrm{Im}\{(\underline{V}_{Sa} - d\cdot\underline{Z}_{L1}\cdot\underline{I})/\underline{I}_{Sa\_F}\} = 0 \qquad (9)$$

and extracting the per-unit distance to the fault location measured from end **S** of the line, *d*, will result in:

$$d = \mathrm{Im}\{\underline{V}_{Sa}\cdot\underline{I}^*_{Sa\_F}\}/\mathrm{Im}\{\underline{Z}_{L1}\cdot\underline{I}\cdot\underline{I}^*_{Sa\_F}\} \qquad (10)$$

where the superscript "*" denotes the complex conjugate and $\underline{I}_{Sa\text{-}F}$ is obtained with (6). Equation (10) represents the fundamental fault location equation using one-ended voltage and current phasor measurements [7].

3. TWO-END DATA FAULT LOCATION ALGORITHMS

For power transmission lines where the synchronized voltage and current phasors can be obtained from both ends of the line, a two-end data fault location algorithm can be applied [9]. The principle of this algorithm is that the voltage along the line can be represented as a function of the distance to the fault point, *d*. Considering the same faulted grid as in Fig.1, in Fig. 2 there is presented the connection of the sequence schemes for a phase-to-ground fault in point **F**. The variables from Fig. 2 are as follow: $\underline{V}_{S1}$ and $\underline{V}_{R1}$ are the positive sequence voltage phasors at end **S** and **R**, $\underline{I}_{S1}$ and $\underline{I}_{R1}$ are the positive sequence current phasors at end **S** and **R**, $\underline{V}_{F1}$ is the positive sequence voltage at the fault point, $\underline{I}_{F1}$ $\underline{I}_{F2}$ and $\underline{I}_{F0}$ are the positive, negative and zero sequence currents at the fault point. The positive sequence voltage at the fault point $\underline{V}_{F1}$ seen from end **S** and from end **R** is calculated with (11) and (12).

$$\underline{V}_{F1} = \underline{V}_{S1} - d\underline{Z}_{L1}\underline{I}_{S1} \quad (11)$$

$$\underline{V}_{F1} = \underline{V}_{R1} - (1 - d)\underline{Z}_{L1}\underline{I}_{R1} \quad (12)$$

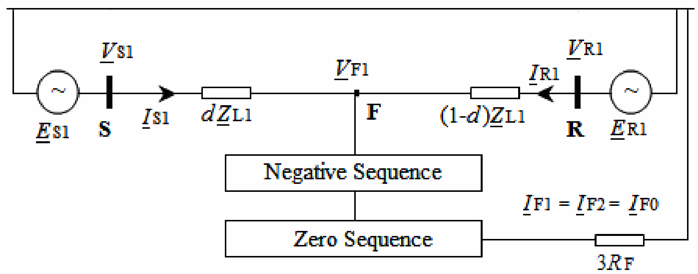


Fig. 2. The connection of the sequence schemes for phase *a*-to-gound-fault

Equating (11) and (12) and solving for *d* results in:

$$d = (\underline{V}_{S1} - \underline{V}_{R1} + \underline{Z}_{L1}\underline{I}_{R1})/(\underline{Z}_{L1}\underline{I}_{R1} + \underline{Z}_{L1}\underline{I}_{S1}) \quad (13)$$

The algorithm depicted above use synchronized phasors of voltage and current. For off-line synchronization there can be used several methods, including the manual synchronization.

To compute the fault location using only the independent measurements from the two ends of the line and supposing that there is one fault, the following steps need to be accomplished:

- remotely download the faulty voltage and current measurements from the line ends;
- manual synchronization of the measurements;
- apply equation (13) to obtain the fault location.

As mentioned above, all the steps depicted are off-line and the time for obtaining the fault location is around 10 minutes. The relays from the line ends must be numerical ones and must allow the remote downloading of the measurements. The fault location solution using the two-end measurements is achieved with no additional costs over the actual communication infrastructure.

4. RESULTS AND COMMENTS

In a first stage, it is presented a real event where the steps depicted above were applied with success. A 400 kV line with the length of 124,7 km experienced a phase *c*-to-ground permanent fault at 34,5 km from the first end (let's say end **S**) and at 90,2 km from the second end (let's say end **R**). The exact location of the fault was established after the line inspection crew reported the line span where the fault was in. The line in discussion is protected and monitored with numerical relays at both ends and each relay has implemented the fault location function using measurements from that end only. After the exact location was found, it was concluded that the relay from end **S** calculated the fault location with an error of 4,6 % and the relay from end **R** calculated the fault location with an error of 7,9 %. In the case of the two-end data fault location algorithm with manual synchronization of the measurements, the fault location error was 0,78%.

Starting from the event mentioned above, in Matlab environment there was imagined an equivalent grid which contain two sources and a 400 kV transmission line. The goal was to obtain a simulation tool in order to mimic as close as possible the real behavior of the grid in which the event occurred. After the grid model was validated, there were simulated other faults in different points of the equivalent grid and the fault locations obtained with the actual one-end data algorithm and the proposed solution were compared.

The transmission line model is obtained by transposing the parameters of the real line mentioned above into the simulation model. The model of the line consists of two blocks, each one modeling the line portion between end **S** and the fault point, and between end **R** and the fault point, respectively (see Fig 3). Also, in a third-party application (EDSA Paladin) there were modeled all of the real grid generators in operation at the time of the event. In this way there were obtained the short circuit powers of the adjacent buses (**S** and **R**) with the faulted line. All the parameters mentioned above are indicated in Table I.

Table I. The grid parameters values

Line	Positive Sequence			Negative Sequence			Length [km]
	R_1 [Ω/km]	L_1 [mH/km]	C_1 [F/km]	R_0 [Ω/km]	L_0 [mH/km]	C_0 [F/km]	
	0,034	1,047	1,1E-08	0,125	1,932	8,6E-09	124,7
Source	**End S**			**End R**			
	Shortcircuit power [MVA]	Rated voltage [kV]	Source angle [degrees]	Shortcircuit power [MVA]	Rated voltage [kV]	Source angle [degrees]	
	3770	400	0	4400	400	-6	

In the model depicted in Fig. 3 there is a fault block where the user can model the fault resistance and the fault type.

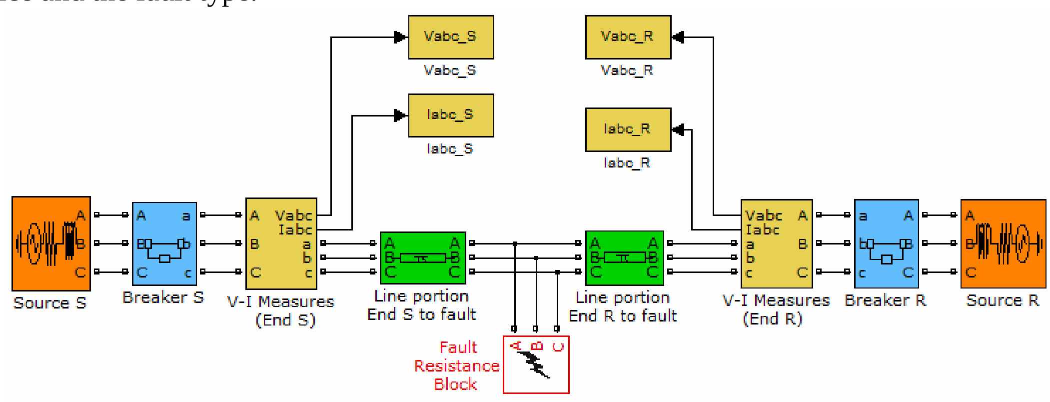


Fig. 3. The simulation model of the grid

After implementing the values from Table I in the grid model blocks, it was simulated a phase *c*-to-ground fault considering that the fault resistance is 7,8 Ω (same as in the real event). In Fig. 4 there are represented two current waveforms, where the dotted black line is the real current and the continuous grey line is the simulated current, from the source **R**. It can be seen that the waveforms are almost identical. Also, the simulated voltage waveforms of the faulty phase as well as the simulated voltage and current waveforms from the other phases resulted identical with the real waveforms. Thus, it can be said that the simulation model is validated.

After this validation, a fault location analysis is conducted to compare the fault location errors introduced by the two-end data algorithm (the proposed solution) in one hand and the actual end **S** and end **R** one-end data algorithms in the other hand. Using the simulation tool, and starting from end **S** of the line, there were simulated single-phase-to-ground faults and double-phase-to-ground faults considering the same 7,8 Ω value for the fault resistance. The errors are calculated with (14) and are indicated in Table II. In (14) e is the error in %, d_{ACTUAL} is the actual distance in km from end **S** to the fault point, $d_{CALCULATED}$ is the calculated distance in km from end **S** to the fault point using the two-end data fault location equation (13) and the actual end **S** and end **R** one-end data fault location equation (10); L is the line length in km.

Table II. Fault location errors

Actual location [% from end S]	Single-phase-to-ground faults			Double-phase-to-ground faults		
	Two-end locator	***End* S *locator***	***End* R *locator***	***Two-end locator***	***End* S *locator***	***End* R *locator***
0	1,01	2	9,1	1,2	0,5	2,9
10	0,9	3,2	8,4	0,9	1,3	2,86
20	0,85	4	7,9	0,89	2,1	2,5
30	0,79	5	7,2	0,79	2,2	2,45
40	0,73	5,7	7	0,71	2,5	2,6
50	0,63	6,5	6,3	0,63	2,4	2,1
60	0,71	7,4	5,5	0,65	2,6	1,9
70	0,73	8	4,9	0,72	2,8	1,7
80	0,83	8,3	4,2	0,79	3,1	1,65
90	0,85	8,8	2,9	0,82	3,3	1,4
100	0,9	9	1,9	0,88	3,3	0,9

$$e\ [\%] = 100*(d_{\mathrm{ACTUAL}} - d_{\mathrm{CALCULATED}})/L \qquad (14)$$

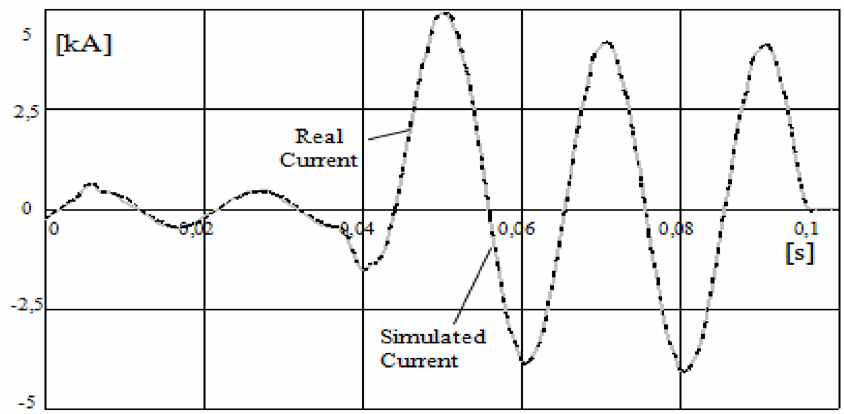


Fig. 4. Real and simulated current from Source **R**

As it can be observed from Table II, the general tendency of the errors introduced by the actual one-end data fault location algorithms is to increase when the actual distance from the line end to the fault point increases. For the two-end data algorithm the errors introduced are almost the same when the distance from end S to the fault point varies from 0% to 100%. The output results of the proposed solution are much better than the output results of the actual one-end data fault location algorithms. Two-end data fault location approach can be useful especially when the faulted line is a long transmission line or when the line crosses mountains or hard terrain because it can reduce the time for finding the fault along the line by the inspection crew.

BIBLIOGRAPHY

[1] M. M. Saha, J. J. Izykowski, and E. Rosolowski, Fault location on power networks, Springer, London 2010.

[2] IEEE Guide for determining fault location on AC transmission and distribution lines, IEEE C37.114 Standard

[3] P. F. Gale, Overhead line fault location based on travelling waves and GPS, Proceedings of the Precise Measurements in Power Systems Conference, Arlington, VA, October 1993.

[4] E. O. Schweitzer III, A review of impedance-based fault locating experience, in 14th Annual Iowa-Nebraska System Protection Seminar, October 1990.

[5] K. Zimmerman and D. Costello, Impedance-based fault location experience, in Proc. 58th Annual Conf for Protective Relay Engineers, April 2005, pp. 211 – 226.
[6] S. Das, S. Santoso, Impedance-based fault location in transmission networks: theory and application, IEEE Acces, Vol. 2, June 2014, pp. 537-557.
[7] T. Takagi and Y. Yamakoshi, Development of a new type fault locator using the one-terminal voltage and current data, IEEE Transactions on Power Apparatus and Systems, Vol. PAS-101, No. 8, August 1982, pp. 2892-2898.
[8] L. Eriksson, M.M. Saha, G.D. Rockefeller, An accurate fault locator with compensation for apparent reactance in the fault resistance resulting from remote-end infeed, IEEE Trans. on PAS, vol. PAS-104, pp. 424-436, No. 2, 1985.
[9] K. P. Lien, et al. A novel fault location algorithm for multi-terminal lines using phasor measurement units. Proceedings of the 37th Annual North American Power Symposium; October 2005; pp. 576–581.
[10] O. Avendano et al. "Tutorial on fault locating embedded in line current differential relays – methods, implementation, and application considerations", 17th Annual Georgia Tech Fault and Disturbance Analysis Conference, April 2014.
[11] M. Istrate et al. "Single-phased fault location on transmission lines using unsynchronized voltages", Advances in Electrical and Computer Engineering, Vol 9, Issue 3, 2009.
[12] D. Spoor, K. Hinley, "Unsynchronised fault location on asymmetrical lines" CIGRE, South East Asia Protection and Automation Conference, 17-18 March 2015.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#98

Electric Energy Storage Systems and regulatory framework

Dr.ing. Ciprian G. DIACONU, Ing. Mihai C. MARCOLT*
CNTEE Transelectrica SA
Romania

SUMMARY

The paper presents general information about electric energy storage systems that can be used in the electric grid and the benefits from introducing this technology.

Also, the regulatory framework needed for this is discussed in the final chapter of the paper.

Electric energy storage is close related with renewable energy sources and the growth of production that is estimated in different plans and strategies for the next decades.

KEYWORDS

Energy storage, regulatory framework, power systems, Romania, CIGRE

1. INTRODUCTION

Electricity storage is able to maintain excess energy produced by variable sources such as wind and solar at night, when consumption is low, for later use at peak time. Additionally, they represent an important flexibility solution in improving grid stability, reducing temporary mismatch between supply and demand and in controlling the fluctuations of renewable energy sources.

Storage serves several purposes in today's power system.

European and global energy policies based simultaneously on a CO_2 emissions reduction, shifts towards intermittent renewable power while maintaining secure energy supplies. This changes the ground rules for storage and calls for a new approach to storage as a key component of the future low-carbon electricity system. Decisions to invest into the development of storage and deployment of adequate storage capacity will depend on the evolution of the whole energy system. They are closely linked to developments such as: (a) electricity super-highways with large-scale RES in the North Sea and North Africa combined with distributed/regional RES solutions; (b) penetration of electric vehicles; (c) improvements in demand response/demand side management/smart grids.

The need to promote more energy storage is related to the increase in intermittent wind and solar and to the demand peak increase.

When the intermittent renewable share is lower than 15% to 20% of the overall electricity consumption, the grid operators are able to compensate the intermittency. This is not the case when the share exceeds 20-25%, as it is reached at times in Denmark, Spain and Germany. When these levels of 25% and above are reached, intermittent RES need to be curtailed during the low consumption periods in order to avoid grid perturbation (frequency, voltage, reactive power) and grid congestion, unless the RES excess can be stored.

Alternative resources – back-up and/or storage are needed when demand does not fall at the same time as the fall in RES generation.

* mihai.marcolt@transelectrica.ro

Energy storage needs to be integrated in network-based energy systems, in the electrical grid system, heat or cooling network and gas networks. It can also provide an important contribution to the development and emergence of the Smart Grid concept at all voltage levels.

The peak increase issue can also be solved where energy storage is available at different levels of the Electrical System: centralized energy storage as a reserve; decentralized storage in the form of demand management and demand response systems.

Different energy storage systems will have to be considered (centralized and decentralized) and specific business models will have to be identified.

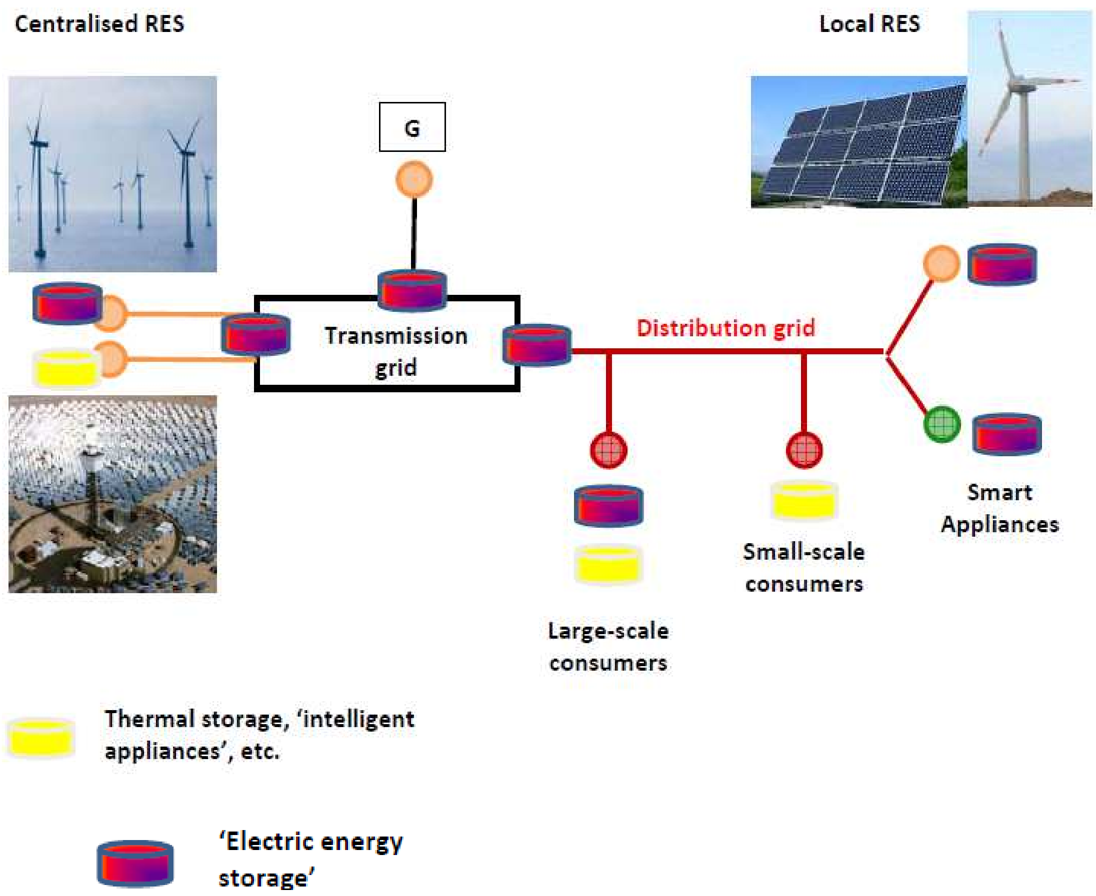


Figure 1. Efficiency of energy storage systems

It is important to ensure that electricity from RES keeps its RES label, even if it has been stored before the final consumption. Possible feed in tariffs should not be affected by intermediate storage. Only the share of renewables at the point of pumping should qualify as renewable electricity.

2. STORAGE TECHNOLOGIES AND COMPARISON

Some of the key technologies, not all of which are at the stage of commercial application, are:

- Large bulk energy (GW):
  - Thermal storage, pumped hydro;
  - Compressed Air Energy Storage (CAES);
  - Chemical storage (e.g. hydrogen - large scale >100MW, up to weeks and months).
- Grid storage systems (MW) able to provide:
  - Power: super-capacitors, Superconducting Magnetic Energy Storage (SMES), flywheels;
  - Energy: batteries such as Lead Acid, Li-Ion, NaS & Flow batteries;
  - Energy & Power: LA & Li-Ion batteries

- Hydrogen Energy Storage/CAES/Pumped Hydro Energy Storage (PHES) (small scale, 10MW< P > 100MW, hours to days).

- End-user storage systems (kW):
  - Power: super-capacitors, flywheels;
  - Energy: batteries such as Lead acid and Li-Ion;
  - Energy & Power: Li-Ion batteries.

Storage technology	PHS	CAES	Hydrogen	Flywheel	SMES	Supercap	Conventional Batteries		Advanced Batteries			Flow batteries	
							Pb-acid	NiCd	Li-ion	NaS	NaNiCl ZEBRA	VRB	ZnBr
Power rating, MW	100-5000	100-300	0.001-50	0.002-20	0.01-10	0.01-1	0.001-50	0.001-40	0.001-0.1	0.5-50	0.001-1	0.03-7	0.05-2
Energy rating	1-24h+	1-24h+	s-24h+	15s-15min	ms-5min	ms-1h	s-3h	s-h	min-h	s-hours	Min-h	s-10h	s-10h
Response time	s-min	5-15 min	min	s	Ms	ms						ms	ms
Energy density, Wh/kg	0.5-1.5	30-60	800-104	5-130	0.5-5	0.1-15	30-50	40-60	75-250	150-240	125	75	60-80
Power density, W/kg			500+	400-1600	500-2000	0.1-10	75-300	150-300	150-315	90-230	130-160		50-150
Operating temp (°C)				-20 - +40		-40- +85				300-350	300	0-40	
Self-discharge (%/day)	~0	~0	0.5-2	20-100	10-15	2-40	0.1-0.3	0.2-0.6	0.1-0.3	20	15	0-10	1
Round-trip efficiency	75-85	42-54	20-50	85-95	95	85-98	60-95	60-91	85-100	85-90	90	85	70-75
Lifetime (years)	50-100	25-40	5-15	20+	20	20+	3-15	15-20	5-15	10-15	10-14	5-20	5-10
Cycles	$2x10^4$-$5x10^4$	$5x10^3$-$2x10^4$	10^3 +	10^5-10^7	10^4	10^4-10^8	100-1000	1000-3000	10^3-10^4+	2000-4500	2500+	10^4+	2000+
Power cost €/kW	500-3600	400-1150	550-1600	100-300	100-400	100-400	200-650	350-1000	700-3000	700-2000	100-200	2500	500-1800
Energy cost €/kWh	60-150	10-120	1-15	1000-3500	700-7000	300-4000	50-300	200-1000	200-1800	200-900	70-150	100-1000	100-700

Note. The power price reported for hydrogen relates to gas turbine based generator. The power price for fuel cells is in range of 2 000-6 600 €/kW.
Sources: Schoenung and Hassenzahl, 2003; Chen et al., 2009; Beaudin et al., 2010; EERA, 2011; BNEF, 2011b; Nakhamkin, 2008.

Table 1. Different storage technologies and details about them

In the transmission grid, energy storage can be used to improve power quality by correcting voltage sags, flicker and surges. It can also provide line stability and Power Oscillation Damping (POD). During the last decade, coinciding with renewable energy growth, different energy storage technologies have reached maturity and have been installed to improve supply quality and to boost renewable energy integration. However, these efforts have been not enough. Most studies have shown that in order to reduce transmission bottlenecks and to decrease the generation costs, new transmissions, interconnection capacities and load management programs are needed.

The generation based on renewable energy sources will play a significant role in the energetic scenarios of the future. This role can become even more significant if the solutions to the problems due to energy congestion are adopted. New transmission lines and load management programs together with energy storage systems can definitely encourage the usage of renewable energy sources.

Electricity storage applications in transmission networks may pursue different objectives:

• Deferral of investment into new transmission lines
• Reduction of transmission losses
• Increasing the interconnection capacity among loosely coupled subsystems
• Improvement of power system stability
• Stable power system operation and compensation for intermittent power sources

Based on the high storage capacities required for these applications, it is assumed that transmission applications of storage will be a priority, with the notable exception of the continued use of the existing pumped storage plants.

The three major applications of energy storage are:

1. Power Quality: Here energy storage is applied for short periods of time in order to ensure a predictable power outline. Rapid cycling is generally required for better power quality.

2. Bridging Power: Used when switching from one power generator to another. Main purpose is to ensure continuity of power supply. Usage is in the order of minutes.

3. Energy Management: Used as a storage medium. This helps in applications that involve delivering the power generated to the loads independent of the timing of generation. A good example would be load levelling where energy is bought at low prices and stored for times when prices are high, or generation is low, compared to demand.

Shown below, in Figure 2, is a list of energy storage devices categorized into three types of energy applications (based on their discharge times). This figure illustrates how efficient each type of system is and where they can be efficiently utilized.

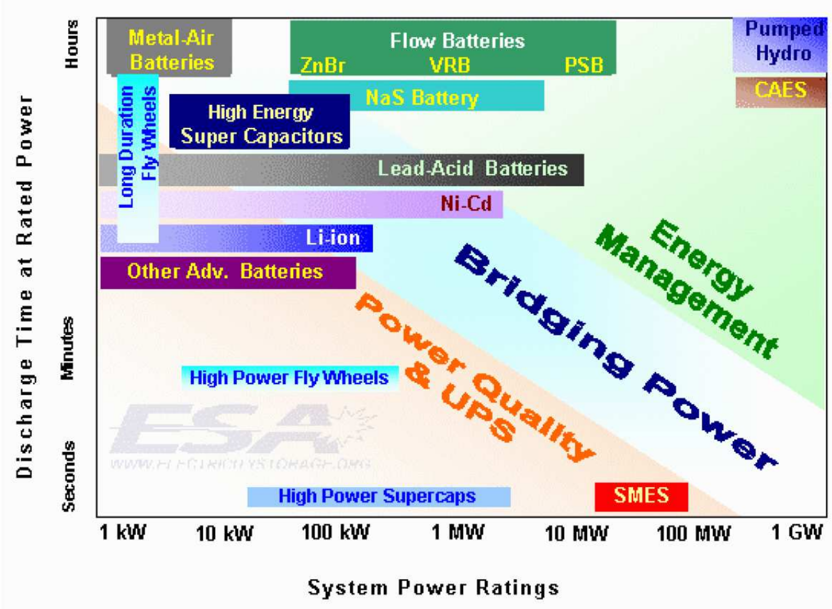


Figure 2. Efficiency of energy storage systems

Application in power system / Functionalities of storage	**Transmission grid-central storage** **(national and European level)**	**Distribution grid storage** **(city level)**	**End-user Storage** **(household level)**
Balancing demand and supply	Seasonal / weekly fluctuations Large geographical unbalances Strong variability of wind and solar (electricity and gas storage need to be integrated)	Daily / hourly variations Peak shaving (electricity and heat/cold storage need to be integrated)	Daily variations (electricity and heat/cold storage need to be integrated)
Grid management	Voltage and frequency regulation Complement to classic power plants for peak generation Participate in balancing markets Cross-border trading	Voltage and frequency regulation Substitute existing ancillary services (at lower CO2) Participate in balancing markets	Aggregation of small storage systems providing grid services
Energy Efficiency	Better efficiency of the global mix, with time-shift of off-peak into peak energy	Demand side management Interactions grid-end user	Local production and consumption Behaviour change Increase value of PV and local wind Efficient buildings Integration with district heating /cooling and CHP

Table 2. Several purposes served by storage in today's power system

Physical size and weight of storage devices are important factors and have the ability to determine their types of applications. For instance metal-air batteries have the 49 highest weight energy density, and largest volume energy density, this means that these batteries will be smaller and lighter than a similar powered lead-acid battery, as shown in Figure 3. The energy density, volume and weight, ranges reflect the differences among manufacturers, product models and the impact of packaging.

The graph in Figure 3 illustrates the Weight Energy Density vs. Volume Energy Density for different energy storage technologies. This information may be especially important for selecting battery types for certain applications of power storage.

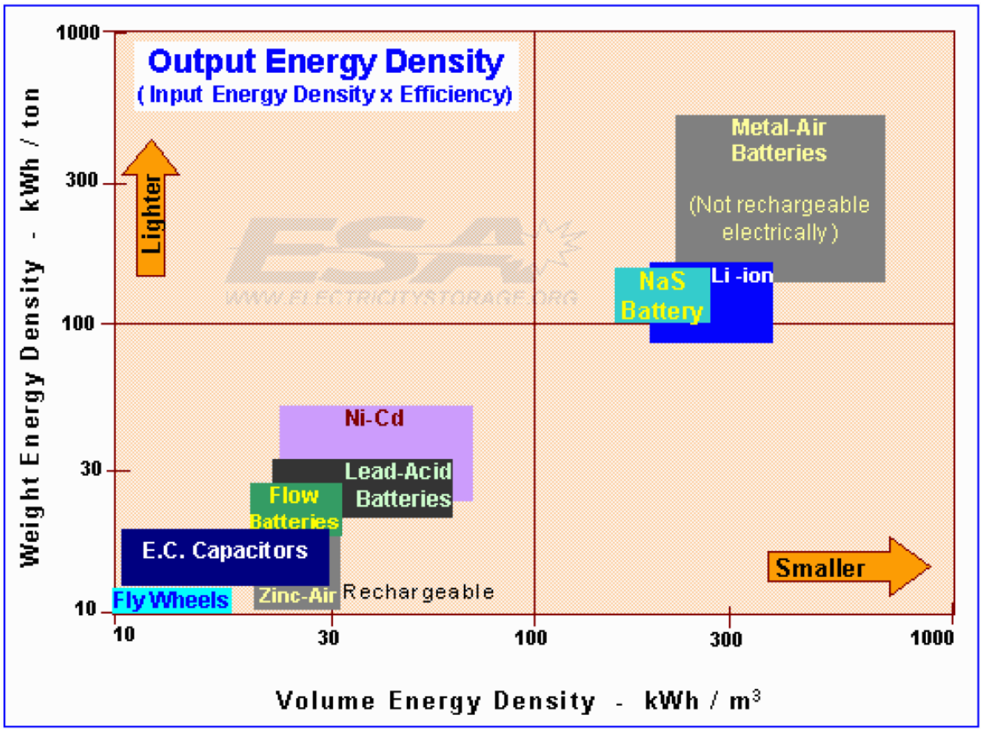


Figure 3. Weight Energy Density vs. Volume Energy Density

The overall cost of a project is always a major factor; therefore selecting the appropriate storage device will be affected by capital cost. The graph in Figure 4 displays the plot of various battery technologies costs per unit energy vs. cost per unit power. However, the chart excludes the cost of power conversion, electronics and installation costs. Also the chart does not take into consideration the life cycles of the batteries, hence it is not a sufficient tool to estimate the total ownership cost which would include all these factors.

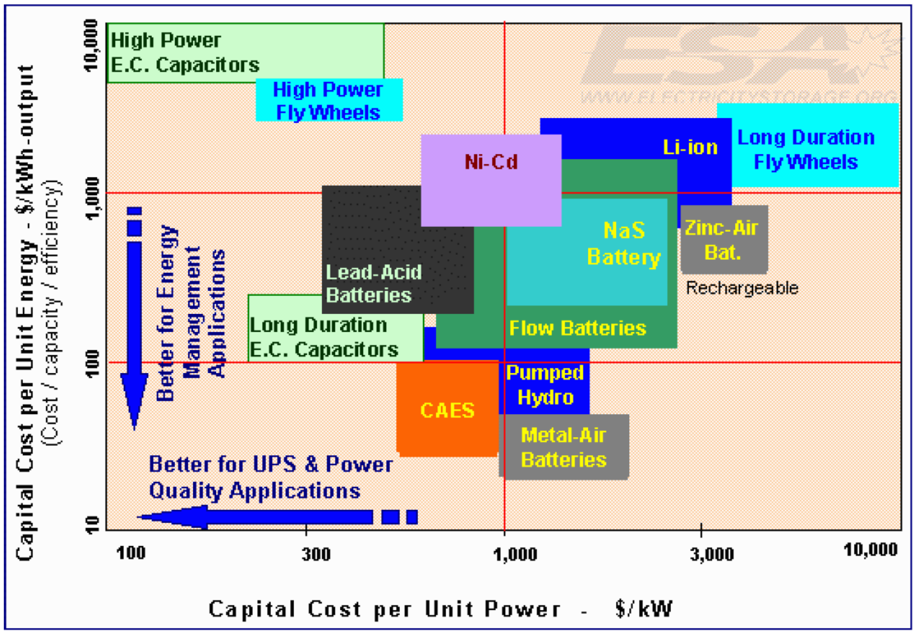


Figure 4. Cost per unit energy vs. Cost per unit power

In order to get a better picture of the real ownership cost of any energy storage system, it is necessary to factor in its life efficiency and cycle life. These parameters are important to consider before selecting a storage technology. Low efficiency, for example, contributes to a higher effective energy cost since now only a fraction of the input energy can be used. Also, short life spans of storage devices contribute to a higher cost, as devices will need to be replaced more often. Figure 5 below is a graphical representational of the efficiency of the energy storage device and how many cycles (at 80% depth of discharge (DoD)) the battery is capable of. This graph shows that for a storage device which has requirements of relatively high discharge and high efficiency an EC Capacitor (super capacitor) and Li-ion battery may be considered.

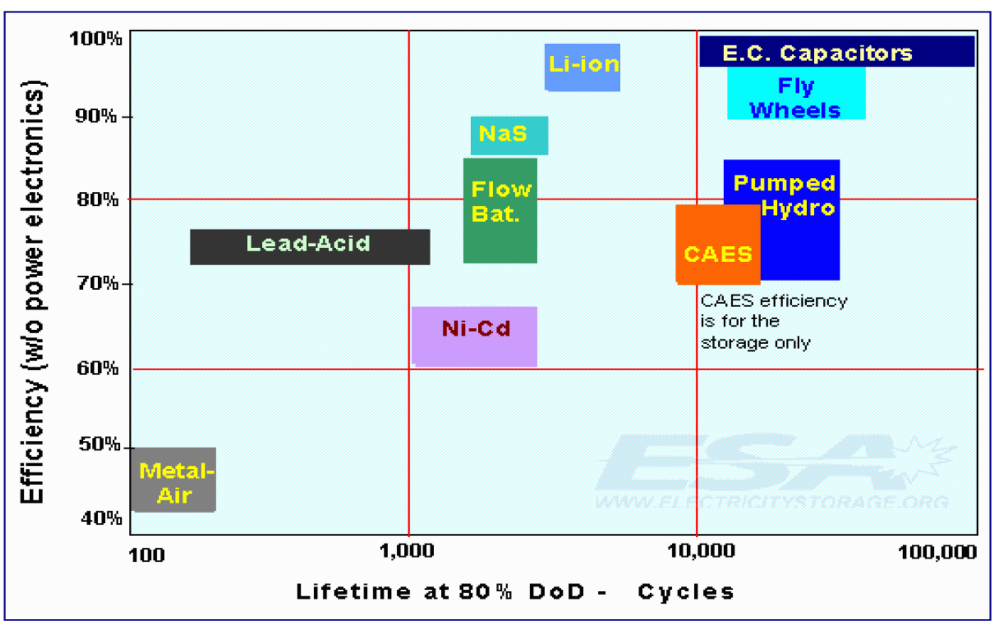


Figure 5. Efficiency vs. Lifetime

Storage Technologies	Main Advantages (relative)	Disadvantages (Relative)	Power Application	Energy Application
Pumped Storage	High Capacity, Low Cost	Special Site Requirement		●
CAES	High Capacity, Low Cost	Special Site Requirement, Need Gas Fuel		●
Flow Batteries: PSB VRB ZnBr	High Capacity, Independent Power and Energy Ratings	Low Energy Density	◑	●
Metal-Air	Very High Energy Density	Electric Charging is Difficult		●
NaS	High Power & Energy Densities, High Efficiency	Production Cost, Safety Concerns (addressed in design)	●	●
Li-ion	High Power & Energy Densities, High Efficiency	High Production Cost, Requires Special Charging Circuit	●	○
Ni-Cd	High Power & Energy Densities, Efficiency		●	◑
Other Advanced Batteries	High Power & Energy Densities, High Efficiency	High Production Cost	●	○
Lead-Acid	Low Capital Cost	Limited Cycle Life when Deeply Discharged	●	○
Flywheels	High Power	Low Energy density	●	○
SMES, DSMES	High Power	Low Energy Density, High Production Cost	●	
E.C. Capacitors	Long Cycle Life, High Efficiency	Low Energy Density	●	◑

●	Fully capable and reasonable
◑	Reasonable for this application
○	Feasable but not quite practical or economical
None	Not feasable or economical

Table 3. Comparison Chart of Various Energy Storage Technologies

3. REGULATORY FRAMEWORK

How could the regulatory framework be adjusted to integrate storage better in the supply chain?

The regulatory framework should aim to create an equal level playing field for cross-border trading of electricity storage.

- The regulatory framework needs to provide clear rules and responsibilities concerning the technical modalities and the financial conditions of energy storage.
- It must address barriers preventing the integration of storage into markets. It should guarantee a level playing field vis-à-vis other sources of generation, exploit its flexibility in supplying the grid, stabilize the quality and supplies for RES generation. This will require new services and business opportunities linked to the deployment of electricity storage solutions.
- The framework should be technology neutral, ensuring fair competition between different technological solutions (not picking a winner).
- It should ensure fair and equal access to electricity storage independent of the size and location of the storage in the supply chain.
- It should ensure medium-term predictability in the investment and financial conditions (taxes, fees, etc.), enabling favorable conditions for all kinds of storage, particularly micro-storage (home and district level).
- It could help improve the business/economic model for energy storage. The principal domains where intervention are needed relate to ancillary services and the grid tariff.

For example, the grid tariff should be based on the principle of cost causality: if an energy storage system is systematically using the grid during off-peak periods and not during peak periods, it should not generate grid investment. Thus, the introduction of a time component in grid tariffs could take account of the part of grid investment due to energy storage.

Today, energy markets are mainly connected to the day-ahead horizon. As a result, the balancing products (tertiary frequency reserve) are only to a limited extent exchangeable cross-border among Member States. Connecting and harmonization on EU-level of the actual very heterogeneous intra-day and balancing markets is a precondition for energy storage development and needs to be addressed urgently.

The regulators are currently drafting a framework guideline for a European balancing and reserve power market. This will be followed by a legally binding network code drafted by the European Network of Transmission System Operators (ENTSO-E).

As mentioned above, ownership of storage energy systems has a significant impact on the viability of the business model and on competition. The question is: which ownership model is likely to make the business case more attractive – one driven by regulation, or deregulation? More reflection is urgently needed regarding the issue of competition: regulated vs. deregulated; deregulated actors within one MS (Member State), or deregulated actors in different MS. This issue should be addressed as high priority.

What can the EU do to enable the short and medium term development and deployment of storage at all levels?

The issue of energy storage should be clearly positioned within EU energy and climate policy: the internal market, 2020 and 2050 targets and infrastructure priorities. EU policy needs to give clear and consistent signals to technology developers, the industry and consumers.

The optimization of the power system and the synergies between the existing system and storage technologies must be explored and promoted.

To enable the short term and large scale deployment of storage on an EU-wide level a number of urgent actions could be undertaken:

- Strategic: Developing and assessing visions for the role of storage in integrating variable renewable electricity generation, optimizing the use of generation and energy network capacities, providing services to the electricity system and promoting distributed generation to improve energy efficiency and reduce CO_2 emissions, as envisaged by the EU's 2020 binding targets and the indicative targets for 2050 (RES Directive, Roadmap 2050). Synergies could be made by a common approach to storage for electricity systems and storage for transport (upcoming Electric vehicles, Plug-in hybrid vehicles);
- Consumer level: Supporting the development of consumer-based energy storage services linked with local RES production, smart meters and smart local grids that ensure financial benefits for the consumers; distinctions have to be made between short-term needs (up to 2020) and long term visions (2020 to 2030) storage used in Smart Cities and in RES integration) ('roadmaps');
- Market issues: Developing a level playing field – removing barriers related to accessing neighboring markets and cross border trading;
- Regulatory: Support for storage within the EU internal electricity market and regulatory adjustments to enable storage to facilitate the progress towards a single internal electricity market in Europe;
- Technological development: Mapping storage potential, storage technology development and demonstration including the interoperability of different smart energy networks and deployment through Horizon 2020 (RTD, Demonstration) – especially regarding how to integrate storage into the SET plan activities (European Industrial Initiative);
- Investment support: All different forms of energy storage could be supported providing they contribute towards the European climate and energy targets (technology neutral; target oriented).

4. CONCLUSIONS

The present and future costs of energy storage are still high and they are unlikely to compete with base load generation. However the energy storage will be viable when the marginal cost of electricity exceeds the costs of charging and discharging the storage and losses. This can happen when the generating plant operates under low load factor and the storage offers multiple services including energy supply, load levelling, peak shaving, reserves, regulation, reactive power supply and power quality. Furthermore for some very special applications, such as extreme unreliability of a conventional supply, need to compensate for fluctuating generation or in application like EVs where a premium is attached to the portability, they may be a valid solution.

To conclude, energy storage systems, both electric and thermal, will be the key to integrating variable renewable sources in the power systems of the future, to reduce 86 the production of pollution and decrease the consumption of fossil resources. In the future of energy storage systems in combination with other Smart Grid measures such as Demand Side Management will be suitable to accommodate a truly “balanced” electricity generation system.

BIBLIOGRAPHY

[1] Global Market Outlook for Photovoltaics until 2013. European Photovoltaic Industry Association, March 2009.

[2] A European Strategic Energy Technology Plan (SET-PLAN) “Towards a low carbon future”. Commission of the European Communities, Brussels, November 2007.

[3] The vision scenario for the European Union. Matthes, C., Gores, S., Graichen, V., Repenning, J., Zimmer, W. Öko-Institut e.V., Berlin, 2006.

[4] European Energy and Transport – Trends to 2030 – Update 2007. Capros, P., Mantzos, L., Papandreou, V., Tasios, N., Office for Official Publications of the European Communities, 2008.

[5] T. Fujii, T. Hirose, and N. Kondou, “ Liquid circulating secondary battery equipment,” JP Patent 55096569, Jul 22, 1979

[6] Woodbank Communications Ltd..“Flow Batteries.” Internet:
http://www.mpoweruk.com/flow.htm, 2005 [Aug. 4, 2008]

[7] L.H. Thaller, “ Electrically rechargeable REDOX flow cell,” U.S. Patent 3 996064, Dec 7, 1976

[8] M. Skyllas-Kazacos, D. Kasherman, D.R. Hong, M. Kazacos. “Characteristics and performance of 1 kW UNSW vanadium redox battery”. J. Power Sources, Vol. 35, pp. 399-404, 1991.

[9] Ch. Fabjan, J. Garche, B. Harrer, L. J¨orissen, C. Kolbeck, F. Philippi, G. Tomazic, F. Wagner. “The vanadium redox-battery: an efficient storage unit for photovoltaic systems”. Electrochimica Acta, Vol. 47, pp. 825-831, June 2001.

[10] Woodbank Communications Ltd.. “Flow Batteries.” Internet:
http://www.mpoweruk.com/flow.htm, 2005 [Aug. 4 2008]

[11] Susan M. Schoenung, Clayton Burns. “Utility Energy Storage Applications Studies”. IEEE Transactions on Energy Conversion, Vol. 11, No. 3, pp.658-665, Sep. 1996

[12] Ali Nourai, Bradford P. Martin, and Doug R. Fitchett. “Testing the Limits”. IEEE Power and Energy Magazine,pp. 40-46 ,Mar. 2005

[13] Buchmann. "Battery University." Internet: http://batteryuniversity.com/, March 2006 [Aug. 4, 2008]

[14] J. Voelcker. “Lithium Batteries Take to the Road”. IEEE Spectrum , pp.27-31 , Sep. 2007

[15] U.S Department of Energy, “Energy Storage.” Internet: http://www.eere.energy.gov/ 2008 [Aug. 4, 2008] 91

[16] F. Meyer. “Compressed air Energy storage power plants. ”Internet:
http://www.bine.info/templ_meta.php/publikationen/projektinfo/494/link=clicked&search_year=2007/, 2007 [Aug. 4, 2008]

[17] NGK Ltd..“NaS Batteries.” Internet:

http://www.ngk.co.jp/english/products/power/nas/index.html, 2008 [Aug. 4, 2008]
[18] Buchholz, B.M. Povh, D. and Retzmann, D. : Stability Analysis for large Power System Interconnections in Europe. Power Tech 2005 Conference Proceedings, St. Petersburg, Russia, 2005
[19] Pritchard, R.: The contemporary rationale for interconnection of Power Systems, ResourcesLaw International, Vol. I, issue 1, 2003.Industry, Shangai, 2004.
[20] C. D. Parker, Lead-acid battery energy storage systems for electricity supply networks, J. of Power Sources, 100, 18-28, 2001
[21] H. A. Kiehne, "Battery Technology Handbook", Expert Verlag, 2003
[22] D. Berndt, "VRLA batteries, advances and limitations", Journal of Power Sources, 154, pp. 509-517, 2006
[23] RWE Power and GE to develop new power storage system, http://www.rwe.com/web/cms/en/113648/rwe/press-news/pressrelease/?pmid=4001954 (retrieved May 27, 2009).
[24] CIGRE Technical Brochure of WG C6.08 "Grid Integration of Wind Generation" to be published in 2009
[25] DENA, Energy Management Planning for the Integration of Wind Energy into the Grid in Germany, Onshore and Offshore by 2020, February 2005
[26] CIGRE Technical Brochure of WG C6.15 "Electric Energy Storage Systems", 2011
[27] IEC White Paper – Grid integration of large capacity RES and use of large capacity EES, 2012
[28] EC – DG ENER Working Paper – The future role and challanges of Energy Storage, 2012

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016 University "Politehnica" of Bucharest, Romania

#99

Using electrical parameters measurement results in protection settings

Gh. MORARU*[1], F. BALASIU[2]
[1]SMART SA, [2]CNTEE Transelectrica SA
[1, 2]Romania

SUMMARY

Distance protections are important elements for the reliability of electrical power transmission systems. The Positive Sequence Impedance and the Ground Impedance Matching Factor, or k-Factor, as it is often referred to, are some of the most important settings for these protection. Should one of these settings be done improperly, the whole investment in protection from instrument transformers over the relay up to the circuit breaker is not used as efficient as it could be.

This paper explains the difficulty of k-Factor settings and points out cost effective solutions for preventing incorrect behaviour of distance protection schemes.

The results of measurements performed to date, for 110 kV OHL double circuit and 400 kV OHL are presented in the paper.

KEYWORDS

K-Factor, Matching Factor, Distance protection.

1. INTRODUCTION

In case of single phase faults, such as RN, voltage drop until the fault is a direct sum of voltage drops direct, inverse and zero sequence between protection mounting location and location of the fault:

$$\begin{aligned}
&\underline{U}_{RO} = \underline{I}^d \cdot \underline{Z}_L^d + \underline{I}^i \cdot \underline{Z}_L^d + \underline{I}^h \cdot \underline{Z}_L^h \\
&\underline{I}_R = \underline{I}^d + \underline{I}^i + \underline{I}^h \\
&\underline{I}_N = \underline{I}_R + \underline{I}_S + \underline{I}_T = 3\underline{I}^h
\end{aligned} \tag{1}$$

where: $\underline{I}^d, \underline{I}^i, \underline{I}^h$ - sequence components direct, inverse and zero-sequence currents across the distance protection

$\underline{I}_R, \underline{I}_S, \underline{I}_T$ - line currents across the distance protection;

$\underline{Z}_L^d, \underline{Z}_L^h$ - line direct impedance, respectively line zero-sequence impedance to the fault.

In this case the voltage across protection will be [3]:

* gheorghe.moraru@smartsb.ro

$$\underline{U}_{RO} = \underline{Z}_L^d \left[\underline{I}_R + \left(\underline{I}_R + \underline{I}_S + \underline{I}_T \right) \cdot \frac{k-1}{3} \right] = \underline{Z}_L^d \left[\underline{I}_R + \underline{I}_N \cdot \frac{\frac{\underline{Z}_L^h}{\underline{Z}_L^d} - 1}{3} \right] \tag{2}$$

Noting these: $\underline{K}_0 = \frac{1}{3} \left(\frac{\underline{Z}_L^h}{\underline{Z}_L^d} - 1 \right)$ - K factor, generally, complex size.
Is obtained:

$$\underline{U}_{RO} = \underline{Z}_L^d \cdot \left(\underline{I}_R + \underline{K}_0 \cdot \underline{I}_N \right) \tag{3}$$

It is found that the impedance measured by the distance protection

$$\underline{Z}_M = \frac{\underline{U}_{RO}}{\underline{I}_R + \underline{K}_0 \cdot \underline{I}_N} = \underline{Z}_L^d \tag{4}$$

is equal with the line impedance to the fault, if single phase fault is considered phase voltage ($\underline{U}_{RO}$) and offset current ($\underline{I}_R + \underline{K}_0 \cdot \underline{I}_N$).

For phase to phase faults on the ground, it is preferring loop phase - phase instead phase - earth loops considering that in this way eliminates the influence of transition resistance at fault. Measured impedance is proportional with the distance to the fault.

The six impedances are calculated in parallel in the following format:

for phase – earth faults (valid formula for R0 phase, but similar to S0, T0):

$$Z_{R0} = \frac{U_{R0}}{I_R + K_0 * I_H} \tag{5}$$

where $K_0 = \left(\frac{Z_L^h}{Z_L^d} - 1 \right) * \frac{1}{3}$ (K factor);

for phase to phase faults (valid formula for RS fault, but similar for SR, TR):

$$Z_{RS} = \frac{U_{RS}}{I_R - I_S} \tag{6}$$

Unfortunately the K-factor does not exist. There are various formats out there. For all types it is to say that they are constants of the line, in general independent from the length. They express the relationship of the impedance of a phase to phase loop and a three phase to ground loop. The half of a phase to phase loop is referred to as Positive Sequence Impedance Z1, three times the impedance of a three phase to ground loop is referred to as Zero Sequence Impedance Z0 [1], [2].

One common format is the complex ratio of the Zero Sequence Impedance and the Positive Sequence Impedance.

$$\underline{K}_0 = \frac{\underline{Z}_0}{\underline{Z}_1} \tag{7}$$

Because Z1 is the impedance of one line it is also named ZL quite often.

The ground impedance ZE can be calculated from the Zero Sequence Impedance as follows:

$$\underline{Z}_E = \frac{\underline{Z}_0 - \underline{Z}_L}{3} \tag{8}$$

Defining the ground impedance this way, obviously leads to strange results with a negative inductive component in ZE, as soon as the three-phase to ground inductance is much smaller than the inductance between two phases. This is the case on some power cables when the shield is close to the conductors but the conductors are relatively far from each other. This fact is of no further concern, it is just good to know that it can happen.

Another possibility to express the relationship is the ratio of ground to line impedance.

$$\underline{K}_L = \frac{\underline{Z}_E}{\underline{Z}_L} \tag{9}$$

kE or unfortunately even also k0 are other common names for this definition. One has to be careful how a k-factor is defined before using it. Splitting the complex impedances ZE and ZL into their real and imaginary parts R and X lead and defining real ratios, leads to the third commonly used definition.

$$\frac{R_E}{R_L} \quad \text{and} \quad \frac{X_E}{X_L} \tag{10}$$

Conversions between the different k-factor formats are possible.

$$\underline{k}_0 = 1 + 3\underline{K}_L \tag{11}$$

For converting from the format (10) to the other formats the other line constants (or at least the line angle) have to be known.

$$\underline{K}_L = \frac{R_E / R_L}{1 + jX_L / R_L} + \frac{X_E / X_L}{1 - jR_L / X_L} \tag{12}$$

The line angle can be used to obtain the ratio XL / RL that is needed for the conversion in (12).

$$\tan \varphi_L = \frac{X_L}{R_L} \tag{13}$$

Distance protection relays use algorithms that make use of these different k-factors to transfer all phase to ground faults, so they can be assessed as if they were phase to phase faults. This allows using the same zone polygons independent from the line geometry. Because different relays use different algorithms identically measured voltages and currents lead to different impedances depending on the algorithm used.

Details of these algorithms [4] are not further discussed in this paper; it is only to mention that the entry format of the K factor does not allow deducting which algorithm is used by the relay.

2. OHL PARAMETERS MEASUREMENT

Up to now the effort to measure line impedances and k factors was so high, that it has hardly been done. To obtain the data needed they had been calculated manually, or by using appropriate software tools [4]. The parameters needed to calculate the line impedance are many.

The geometrical configuration is needed (see figure 1):

• height above ground and horizontal distance for each phase conductor and each ground wire
• average sag of the line and ground wires at mid-span

Several electrical parameters have to be known:

• ground/soil resistivity ρ
• DC resistance of all conductors
• spiralling construction of the conductors
• geometrical mean radius of the conductors
• overall diameter of the conductors

Similar parameters are needed for calculating line impedances of power cables, on a first glance they might seem even simpler, but when this is the case for new cables it might be the opposite for old installations where often a mixture of different cable types is used, but not documented too well quite often.

In general it can be said that the calculation of the Positive Sequence Impedance works quite well and sufficient for the Zero Sequence Impedance as long as the ground wire is a very good one. When the ground wire or shield is not a very good conductor and a large component of the fault current is flowing back through the soil, things tend to become complicated. The influence of the ground/soil resistivity ρ and the accurate distance of the wires above ground, are growing and both are very difficult to determine along the whole length of the line (especially in complicated landscape geometry).

Another cause for concern is that a huge number of parameters are involved in the calculation of line parameters. If one parameter is wrong this might cause a substantial error. In the Positive Sequence Impedance there are several, but even more prone to error is the Zero Sequence Impedance or k-factor, because they need parameters for their calculation. On several occasions when our team found wrong relay settings it was the Zero Sequence Impedance or the k-factor that was set wrong. But we also had the situation that two similar lines were just mixed up.

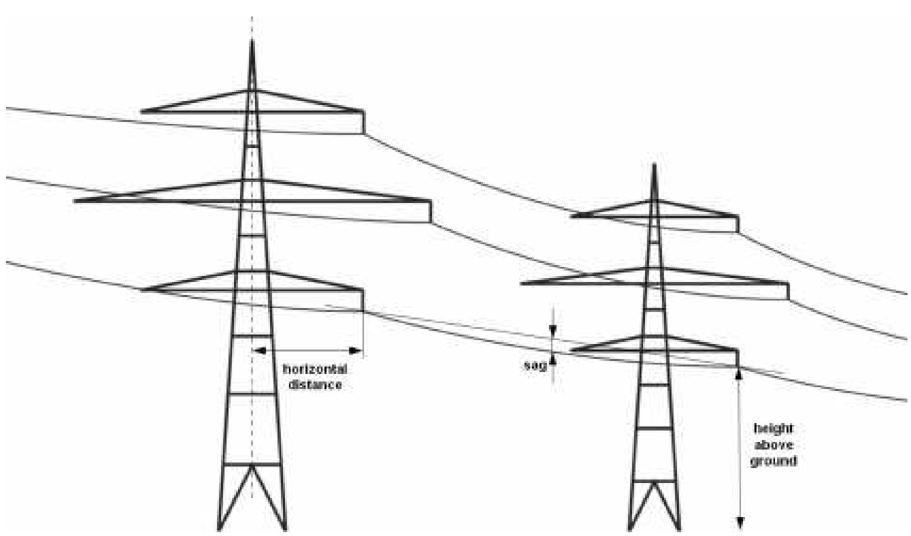


Fig. 1 – Overhead line geometrics

Compared to the calculation the measurement of line parameters including the k-factors is nowadays relatively simple.

The measurement is performed with currents between 1 and 100 A depending on the line length. Using frequency selective measurement allows using currents in the size of a fraction of the nominal currents. Anyway higher currents mean higher accuracy therefore the biggest current possible is chosen. Measurements on lines up to 270 km have been performed so far. Overall seven measurements per system are made, three for each combination of phase to phase loops, three for each phase against ground and one for all three phases against ground. There is some redundancy in these measurements, allowing reliability crosschecks and calculation of individual k-factors for each phase. The latter seems strange at a first glance, but especially for short lines often not too much care is taken having a symmetrical line, leading to quite different values for the phases. Knowing about the problem allows tending rather to smaller k-factors to avoid zone overreaches in all cases.

A measurement on a single 400 kV overhead line with a total length of 120 km and for double 110 kV overhead line with total length 60 km has been performed in last years.

Measurement scheme used is shown in the following figure.

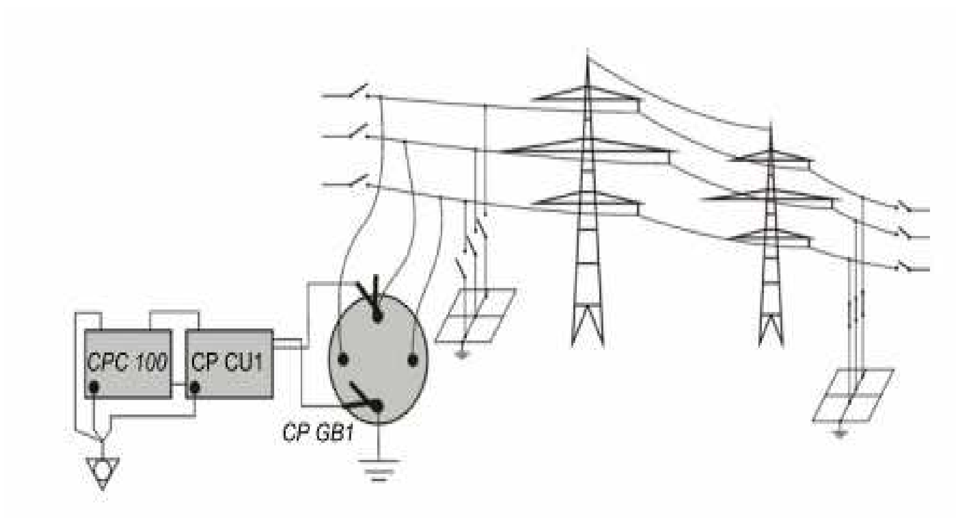


Fig. 2 – Measurement scheme

The results are presented below (Table 1 – 400 kV and Table 2 for 110 kV).

Table 1– Results parameters for 400 kV OHL sc

	R/X [ohms]	Err [%]
R1calc	4.24	
R1meas	4.47	-5.42
X1calc	41.52	
X1meas	42.69	-2.82
R0calc	32.82	
R0meas	28.21	14.05
X0calc	131.1	
X0meas	105.92	19.21

Table 2– Results parameters for 110 kV OHL dc

	R/X [ohms]	Err [%]
R1calc	6.3	
R1meas	6.81	-8.10
X1calc	16.37	
X1meas	16.85	-2.93
R0calc	16.7	
R0meas	10.77	35.51
X0calc	56.5	
X0meas	34.12	39.61

Analysis of impedance measurements on 110 kV OHL double circuits

From database:

$$\underline{Z}1 = 6.3 + 16.366\,j[\Omega p]$$
$$\underline{Z}0 = 16.7 + 56.92\,j[\Omega p] \tag{14}$$

With these data, K factor becomes:

$$\underline{k}0 = \frac{1}{3}\cdot\left(\frac{\underline{Z}0}{\underline{Z}1} - 1\right) = 0.7904 + 0.0924\,j$$
$$\frac{RE}{RL} = \frac{1}{3}\cdot\left(\frac{R0}{R1} - 1\right) = 0.5503$$
$$\frac{XE}{XL} = \frac{1}{3}\cdot\left(\frac{X0}{X1} - 1\right) = 0.826 \tag{15}$$

From measurements direct impedance measured is:

$$\underline{Z}1m = 6.807 + 16.853\,j[\Omega p] = 18.176\angle 68^0 \tag{16}$$

For zero sequence impedance are three values discussed:
1. The mean, calculated from measurements on single-phase loops:

$$\underline{Z}0ma = 10.72 + 34.17\,j[\Omega p]$$
$$\underline{k}0ma = 0.3213 + 0.0524\,j = 0.326\angle 9.3^0$$
$$\frac{RE}{RL} = 0.192; \frac{XE}{XL} = 0.342 \tag{17}$$

2. Value calculated from the measurement zero sequence loop (the three phases in parallel)

$$\underline{Z}0mb = 10.77 + 34.17j[\Omega p]$$
$$\underline{k}0mb = 0.321 + 0.0512j = 0.325\angle 9.0^0$$
$$\frac{RE}{RL} = 0.194; \frac{XE}{XL} = 0.341 \tag{18}$$

3. Value calculated from the measurement loop L2-E (SO):

$$\underline{Z}0mc = 10.808 + 39.052j[\Omega p]$$
$$\underline{k}0mc = 0.405 + 0.0844j = 0.414\angle 12^0$$
$$\frac{RE}{RL} = 0.196; \frac{XE}{XL} = 0.439 \tag{19}$$

Comparing direct impedance value obtained from relations (14) and (16) show that the measured value is close to that calculated and acceptable.

Comparing the measured zero sequence impedance values obtained from relations (17), (18) and (19) reveals a certain inconsistency, especially on zero sequence reactance. Furthermore, measured values obtained differ considerably from the calculated value, given by the relation (14). Accepting that the calculated value is correct (since direct impedance measurements is confirmed), the zero sequence impedance values measured are affected by errors introduced, most likely the circus. 2 in operation. On the other hand, we accept the hypothesis that the measured values are correct and the calculated value is incorrect. To validate one of the two hypotheses was analyzed oscillogram of 19.09.2009, 23:15 a real fault RO, most likely on the 110 kV remote end substation bars "seen" by the protection of local end 110 kV substation.

Calculation are presented below:

Table 3–Parameters calculated from disturbance recordings for real fault

Values from osc.	Formula used	Impedance calculator	R[%]	X[%]
$IL1 := 0.74 - 1.72$ $IL2 := -0.112 + 0.212$ $IL3 := -0.0771 + 0.289$ $IL0 := IL1 + IL2 + IL3$ $UL1 := 48.8$ $UL2 := -23.4 - 60.1$ $UL3 := -29.4 + 58.8$	15	$\underline{Z}L1E = 8.07 + 17.2[\Omega p]$	28	5.1
	17	$\underline{Z}L1E = 9.80 + 22.1[\Omega p]$	55.5	35
	18	$\underline{Z}L1E = 9.79 + 22.1[\Omega p]$	55.5	35
	19	$\underline{Z}L1E = 9.89 + 20.6[\Omega p]$	57	26

where:

$$R[\%] = \frac{\mathrm{Re}\{\underline{Z}L1E\} - \mathrm{Re}\{\underline{Z}L1Ecalc\}}{\mathrm{Re}\{\underline{Z}L1Ecalc\}} \cdot 100$$
$$X[\%] = \frac{\mathrm{Im}\{\underline{Z}L1E\} - \mathrm{Im}\{\underline{Z}L1Ecalc\}}{\mathrm{Im}\{\underline{Z}L1Ecalc\}} \cdot 100 \tag{20}$$

In conclusion, the measured zero sequence impedance of the circuit appears to be damaged in operation and zero sequence impedance calculated value seems quite realistic (R0 may be slightly higher than the calculated value).

These measurements must, it seems, to eliminate the influence of parallel circuits. In what condition should be made parallel circuits (earthed in both ends, non-earthed both ends). Remains to be seen as we gain experience.

3. CONCLUSIOS. LESSON LEARNT.

Measurements showed that for several reasons calculations often gave wrong results. Therefore, most likely measurement and calculation will be done in future. Save, selective and fast failure clearance is only possible, if all relay parameters are set properly. Conclusions: for simple circuits were confirmed calculate parameters (400 kV OHL sc), for double circuit parameters have not been confirmed – Z0 (110 kV OHL dc), long maneuvers (75% of work time), measurement (25% of work time), OHL parameters to be measured at commissioning, need for periodic measurements.

Future targets: HV cables measurements, confirmation double circuit overhead measurements.

Line impedance and k-Factor are of highest importance for a fully operational distance protection relay.

BIBLIOGRAPHY

[1] U. Klapper, M. Kruger, S. Kaiser “Reliability of transmission by means of line impedance and K-factor measurement”, Omicron Austria.

[2] S. Kaiser "Different Representation of the Earth Impedance Matching in Distance Protection Relays", Proceedings Omicron User Conference in Germany 2004, Omicron, 11.1-11.5

[3] A. Vasilievici, F. Balasiu, A. Gal “Fault locator for HV OHL”, International Conference for Power Systems, Timisoara, 1997.

[4] A. Dierks "Accurate Calculation and Physical Measurement of Transmission Line Parameters to Improve Impedance Relay Performance", Proceedings Southern African Power.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#100

Coordinating Generating Units and Power System Protections

F. BALASIU[*1], Gh. MORARU[2]
[1]CNTEE Transelectrica SA, [2]SMART SA
[1, 2]Romania

SUMMARY

New objectives to mitigate global climate change led to an increase of installed generator units based on renewable energy sources and new high efficiency cogeneration units. Based on their rated apparent power and network voltage level, these generation units are connected either to the transmission network or to the 110 kV sub-transmission network. Different connection solutions were developed, voltage level and size dependent. On the other hand, TSOs must maintain and increase the secure operation of the power system facing new challenges as high variability of wind generation or large scale dispersion of generation as for photo-voltaic generators. Obviously, new philosophies and procedures for monitoring, control and protection have to be developed to integrate these new generation units. The paper highlights on coordination aspects regarding both large scale generating units protection schemes and medium size renewable generating protection schemes. Essential aspects on protection systems organisation and operation, for both the power system protections and generating units' protections are also presented.

KEYWORDS

Line-protections, generator protection-coordination, communication schemes for protection.

1. INTRODUCTION

Large size generators (more than 100 MW), using synchronous units are connected to the transmission network at 220 kV or 400 kV. Usually, the generators are connected to the network through step-up transformers and also supply auxiliary transformers. The behaviour of the synchronous generators under steady state conditions as well as their dynamics are quite well known, analysing and simulation tools are available. The medium size (30-90 MW) renewable energy sources are typically connected to the sub transmission 110 kV network by two types of links the direct dedicated line to an existing substation or to a new substation, and the tapped connection to a non loaded line or, in many cases, to a loaded line.

The Romanian National Regulatory Agency (ANRE) stated that units larger than 5 MW are dispatchable and thus fully controllable, independent of the nature of the prime mover or energy source. It is the authority of the TSO to coordinate the protection philosophy and settings of the generating units and the protections of the network starting with the 110 kV voltage level.

The paper highlights the current aspects on protection system organisation, operation and coordination, for both the power system protections and for the protection of the generating units at their interface to the network.

[*] florin.balasiu@transelectrica.ro

2. LARGE SIZE GENERATOR AND TRANSFORMER UNITS PROTECTIONS

The large size synchronous generator unit protective system [1] includes protection functions against internal faults in the generator itself or step-up transformer and back-up protection functions against external network faults. Usually, only network back-up protection functions need carefully coordination to the protective system of the grid. Thus, the distance protection function, the line differential protection function, the out-of-step back-up protection, or the breaker failure protection are to be considered when coordinating the settings of the protection functions in the network. Coordination of settings is also needed for frequency based and voltage based protection functions. A single line diagram of the protection arrangement for a gas turbine (GT) driven generator of a power plant is shown in figure 1.

The generator protection trips are, as a rule, arranged into three types. The General Trip applies to the simultaneous trip of the generator breaker, removal of excitation, trip the auxiliary transformer and closing the prime mover valves. The Generator Trip applies for all internal faults that must be isolated through the trip of the generator breaker. The Breaker Trip applies for tripping only of the line breaker and allows the generator to isolate with the auxiliaries, thus ensuring a fast resynchronisation when the power system allows to.

Normally, the generator, the step-up transformer and the auxiliary transformer protection system include the underneath mentioned protection functions.

a) Stator overcurrent protection. Operation of the generator above the rated apparent power could harm the stator windings. Monitoring of stator current, without automatic tripping is provided, but some applications also use the stator overtemperature protection function for alarm and trip.
b) Stator phase fault protection. The generator differential protection function is used to detect such faults and to issue a General Trip. Although rare, a turn-to-turn fault could exceed the differential protection function detection possibility and some applications provide a current unbalance protection function.
c) Overvoltage protection. Applications involving turbine-generators typically do not require such a protection function as it is unlikely that voltage will be considerably different from the preset value. However, some applications do use this protection.
d) Overexcitation protection. The Volt/Hertz protection function is used for flux supervision in the generator itself and in the step-up transformer core. This protection function usually issues a Generator Trip.
e) Field earth protection. A single ground fault in the rotor winding is not dangerous by itself but could generate a second one that is more difficult to be detected. A sensitive rotor earth-fault protection function is used in certain applications that issues a General Trip.
f) Loss-of-field protection. Loss of excitation results in loss of synchronism and operation of the generator as an induction machine. Consequently, severe torque oscillations of the rotor shaft could occur. The reactive power deficit may cause a voltage collapse, mainly if the generator unit is connected to a weak power system and loses excitation [3]. The loss of excitation also results in a significant change of reactive power and thus an admittance protection function is suitable that issues a General Trip.
g) Unbalanced load protection. As a result of supplying an unbalanced load, negative sequence current flows through the windings that makes a flux in the air gap, rotating in opposition to the rotor at synchronous speed and which in turn induces currents in the rotor body. A negative sequence overcurrent protection function detects negative sequence currents that exceed the threshold of the generator I22t limit and issues a Generator Trip.
h) Out-of-step protection. A loss of synchronism can occur as a result of sudden large load changes, network faults or dynamic instability, loss of excitation or synchronising errors. Out-of-step operation can result in oscillating torques, winding stresses and high rotor iron currents that could damage the generator. The out-of-step protection function is based on the impedance measurement and evaluation of the apparent impedance trajectory and location of the electric centre of oscillations. The protection function issues a Breaker

Trip, usually during the first slip cycle if the electric centre of oscillations is located in the generator or step-up transformer, or after a preset number of cycles if the electric centre of oscillations is located somewhere in the network, far from generator place. The out-of-step protection function is integrated into the line multi-functional relays (F87L.1, F87L.2) dedicated to back-up network faults and settings must be coordinated to other similar protection functions in the grid.

i) Abnormal frequency protection. For a generator connected to the power system, abnormal frequency operation is a result of a severe disturbance. The generators must operate in a frequency range of 47.5 Hz to 51.5 Hz, independent of the prime mover energy source. The generator is able to tolerate underfrequency or overfrequency operation for relatively long periods, but the turbine can be sensitive to such operation regimes and issuing a General Trip is desired. A decrease or an increase in system frequency can occur as system large disturbance, tripping of significant loads, a malfunction of the regulator or even a failure of the centralised automatic generation control (AGC) system.

j) External faults back-up protection. The system back-up protection functions are used to protect the generator from supplying short circuit currents onto a fault in the network because of a primary protection failure or a line breaker failure. Such disturbances issue a Breaker Trip. The line multi-function protection relay includes the line differential protection, the distance protection, some phase or earth and the breaker failure protection with remote direct inter-trip. All the settings of these protection functions should be coordinated to the other protection functions in the grid.

k) Reverse power protection. Typically, there are three conditions that lead the generator to run as a motor. The first motoring regime can occur when turbine output is reduced, while the generator is still on-line. The second one can occur if field excitation is lost, along with turbine output and the generator runs as an induction motor driving the turbine. The third condition of motoring can occur if the generator is energised when still at low speed. Motoring following loss of turbine output can be detected by the reverse power protection function and a time delayed General Trip is issued.

l) Other technological protections. These protection functions include, if applicable, the stator overtemperature protection function, the loss of coolant gas/water or the reduced seal oil pressure protection functions and are beyond of the scope of this paper.

m) Main transformer protection. The generator step-up transformer protection functions are typically included into two separate multi-functional relays, the transformer differential relay (F87-T) and the unit differential relay (F87-U). Typically, they include the technological protections (e.g. Buchholtz, valve over-pressure, oil/winding/core overtemperature, etc), the transformer differential protection and, if applicable, the restricted earth fault protection function. In addition, phase or earth overcurrent protection functions are also included. The unit relay provides a back-up protection for the step-up transformer, generator and auxiliary transformer and includes, as main the differential protection function. The main transformer protection functions issue a General Trip along with the line breaker failure protection start.

n) Auxiliary transformer protection. The auxiliary transformer protection functions are typically included into a single multi-functional relay (UAT) and include the technological protections (e.g. Buchholtz, oil/winding/core overtemperature, etc) and the transformer differential protection. In addition, phase or earth overcurrent protection functions are also included. The auxiliary transformer protection functions issue a General Trip along with the line breaker failure protection start.

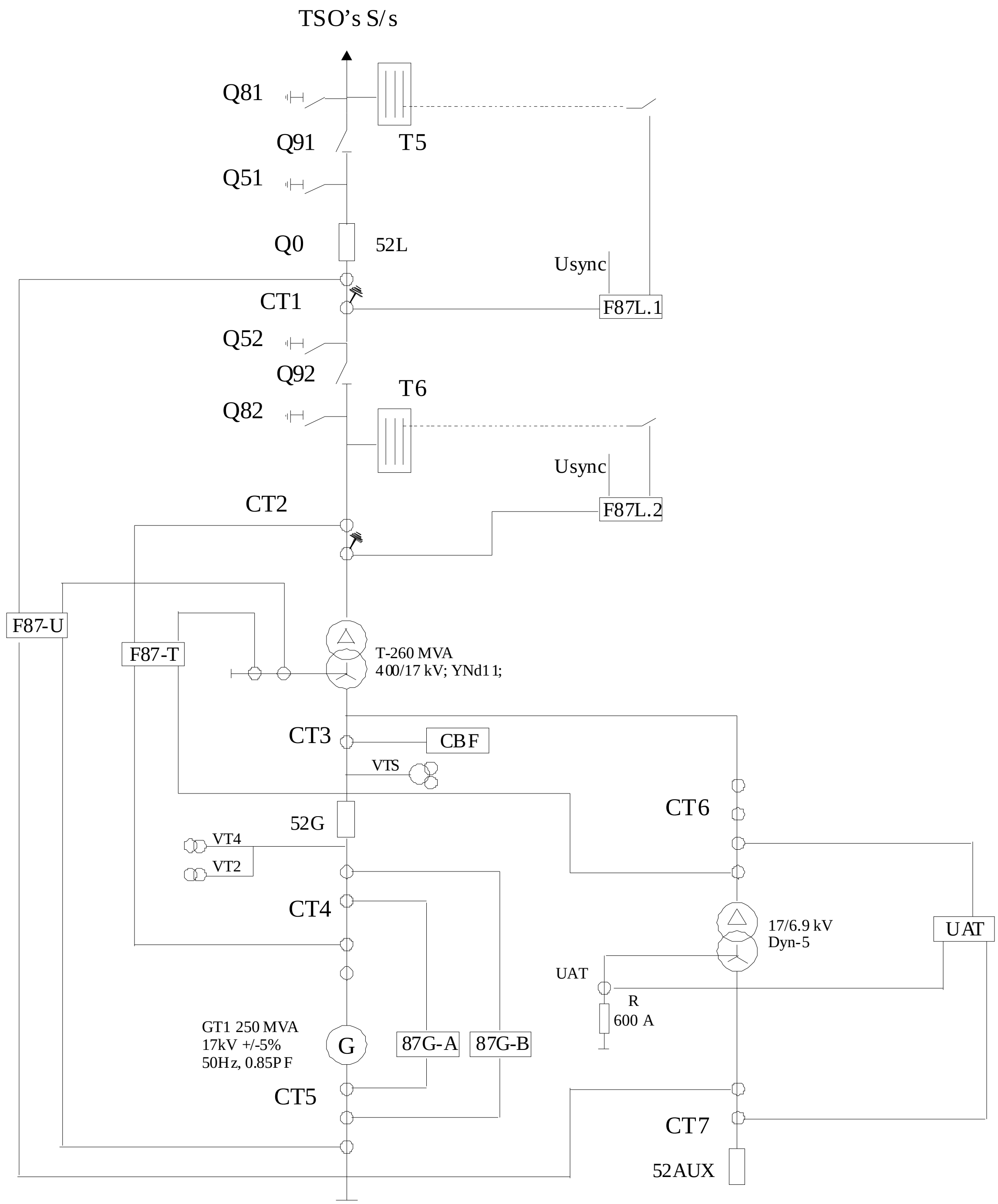


Figure 1. Protection organisation of a large size generator

At the interface of the large size synchronous generator units to the grid, the network protective system ensures both the line protection functions [2] and the back-up protection functions. Typically, the protection organisation (figure 2) includes two multi-function relays located into two separate cubicles. These relays include the line differential, the distance protection and phase and earth overcurrent protection functions [4].

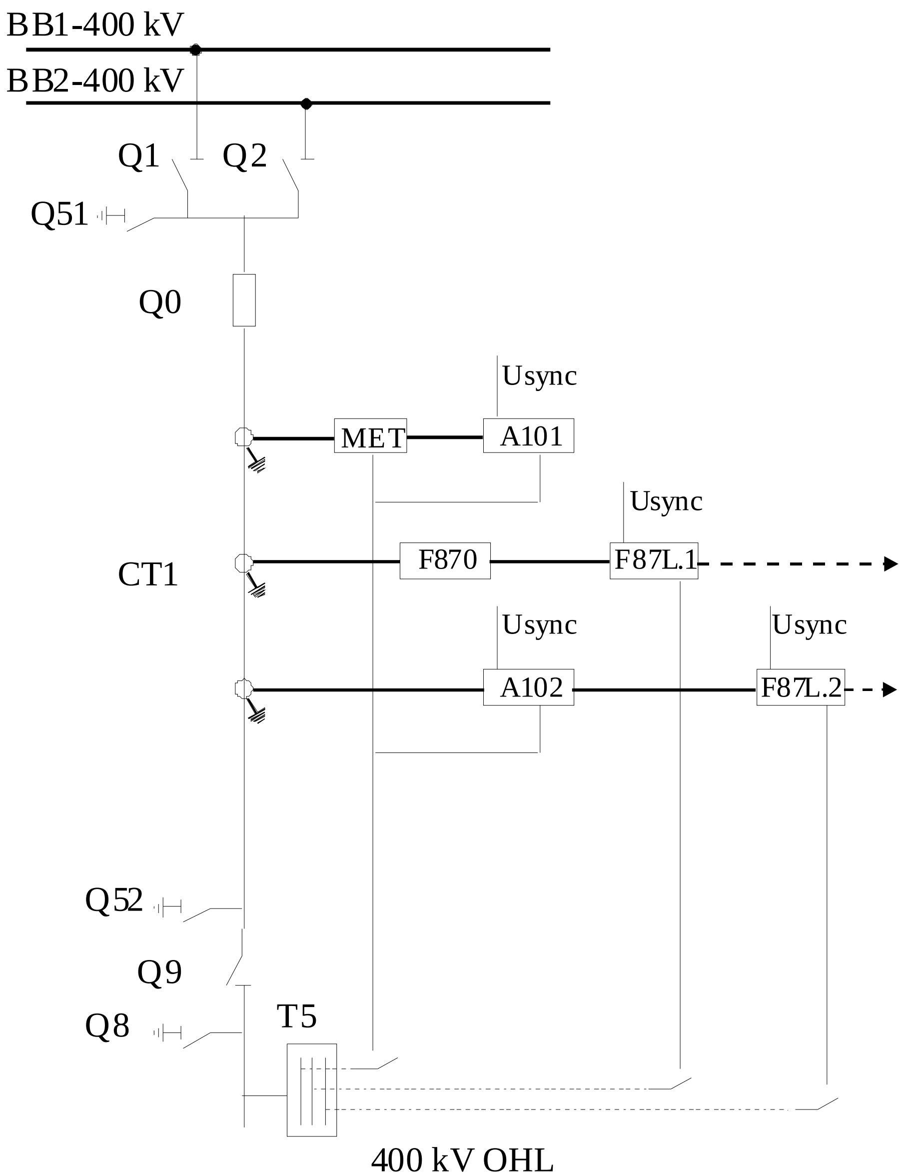


Figure 2. Protection organisation in the network s/s

The main protection function is the line differential protection included in both relays (F87L.1, F87L.2) that communicate to the remote line end relays via two separate fibre optic links. The distance protection function provides back-up for the line and time delayed back-up for the step-up transformer and generator unit itself. Taking advantage of the fibre optic connection, scheme communication for distance protection is used, in this case a permissive overreach transfer trip is chosen. Additional, phase overcurrent protection functions and earth fault protection functions are provided.

To control the bay, a redundant control sub-system is used, based of two bay control units (BCUs) that include SCADA functions, synchro-check functions and inter blocking functions. The two devices (A101, A102) are connected to separate CT cores and to separate mcbs to the same VT core, to receive the same data and each controls the circuit breaker. In case of one BCU failure the other one takes the control of the bay, without any loss of data.

2.1 Single-pole high-speed reclosing philosophy

High-speed aureclosing (AR) contributes to the improvement of the dynamic stability of the power system as for the single-pole AR the generator continues to supply the network through the two healthy phases. The single-pole dead time may be set a little bit longer than the arc de-ionizing time and normally it is set at 1 sec. As the synchronism is preserved during the dead time there is no need of synchro-check devices or functions, thus simplifying the overall protection scheme.

2.2 Power swing blocking and pole-slip tripping

Power system faces short circuits, unbalances or sudden load changes. Under such conditions it is possible to develop power flow swings. Power swings cause oscillations of the relative position of the generator rotor against the system and are a mechanical stress for the generator. Power swings make the voltage envelope to reduce and the magnitude of the currents to increase. The distance protection function, basically an under impedance function could trip unwanted in case of stable power swings. To prevent this, the power swing blocking scheme is used, to block all or only some of the distance protection zones. If the power swing is damping then the blocking condition resets and normal operation is established. However, if the power swing is unstable, the apparent impedance entering the second quadrant of the impedance characteristic, then a tripping signal is released. To back-up pole slip protection of the generator unit, the relays include the pole slip protection function. In case of a stable oscillation the apparent impedance (figure 3, trace 1) could enter the protection zones of the distance protection, mainly zone one and produce an unwanted trip. In case of an unstable oscillation (figure 3, trace 2) it is desired to back-up trip of the same function of the generator protection based on the locus of the electric centre of oscillation (ECO). If the ECO lies on the connection line then a fast trip should be issued. On the contrary, if the ECO lies in the step-up transformer, or generator, then it is recommended to wait for more than one slip and trip in case the counter of oscillations indicates it.

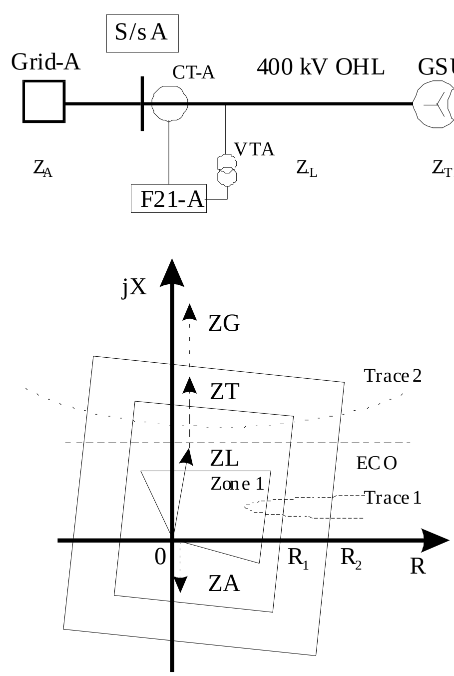


Figure 3. Power swing detection and pole slip trip

One method to sense power swings is based on the rate of change of the apparent impedance measured by the protection function [4], [5]. To estimate the rate of change of the apparent impedance, many relays use two concentric characteristics and measure the time delay between entering the outer and entering the inner characteristic. If the time delay is greater than the set one, power swing is declared and distance zones are blocked. If the time delay is shorter, then a fault is declared and normal operation of the distance protection is allowed.

In case of an unstable swing then a tripping signal is released. There are two possibilities to trip, on the way in or on the way out of the trajectory of the apparent measured impedance. The second is preferred as it does not stress too much the circuit breaker.

2.3 Breaker Failure Protection

The protection organisation already presented provides redundancy for the protection functions. The circuit breaker (CB) as it is only one, does not provide redundancy for a CB failure to trip. To overcome the CB failure an additional protection function is used the breaker failure protection (BFP). This protection function is intended to detect CB failure to trip and to initiate the trip of all adjacent CBs that supply the fault. BFP provides faster fault removal thus improving overall power system stability, reduce equipment stress and improve power quality.

Detection of CB failure is based on two simultaneous conditions: a trip signal from a protection function and current flowing through the breaker for more than the time delay setting.

In the network s/s, the BFP function is normally part of the bus bar differential protection. For the power plant the BFP of the line breaker (52L) is a function included in the line protection units (F87.1, F87.2). For the generator breaker (52G), the BFP is included in a separate device (CBF) that gathers all trip signals that should start the BFP and monitors the current flow through the CB, as it is connected to a protection the secondary core of CT3 (figure 1).

3. POWER SYSTEM PROTECTION SCHEMES FOR RENEWABLE ENERGY SOURCES

3.1 Protection arrangement

The sub-transmission network protective system includes protection functions against line faults and back-up protection functions against either network faults or internal generation plant faults. The network protection system arrangement is somewhat depending on the primary connection link of the generation station. The below considerations are mainly related to the single tie line connection architecture as presented in figure 4.

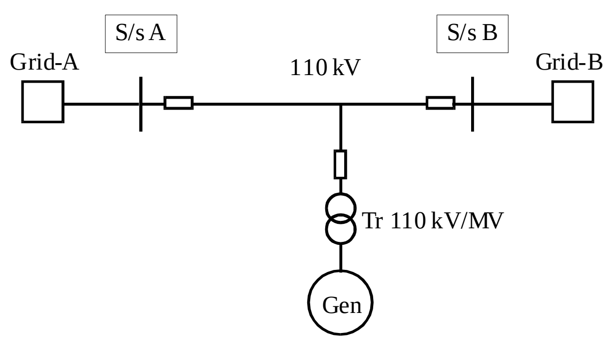


Figure 4. Single 110 kV tie line connections

In case of the single tie line connection of the generation unit at 110 kV, the line protection system is in some way typical, as shown in figure 5 for a synchronous biomass generator and consists of two multi-functional relays, noted F87L-A, F21-A for the left side of the drawing, respectively F87L-B, F21-B for the right side. The first multi-function relay (F87L) is assigned to the main protection and is primarily based on the current line differential protection function for three line ends. The data exchange between the line ends multi-functional relays (F87-A, F87-B and F87L-G) is based on optical fibre communication links. The distance protection function is either included in the same multi-functional relay or in a separate device. This protection function offers back-up protection for both network faults and generation units faults. Power swing detection is used to block distance protection zone one, in case of stable power swings.

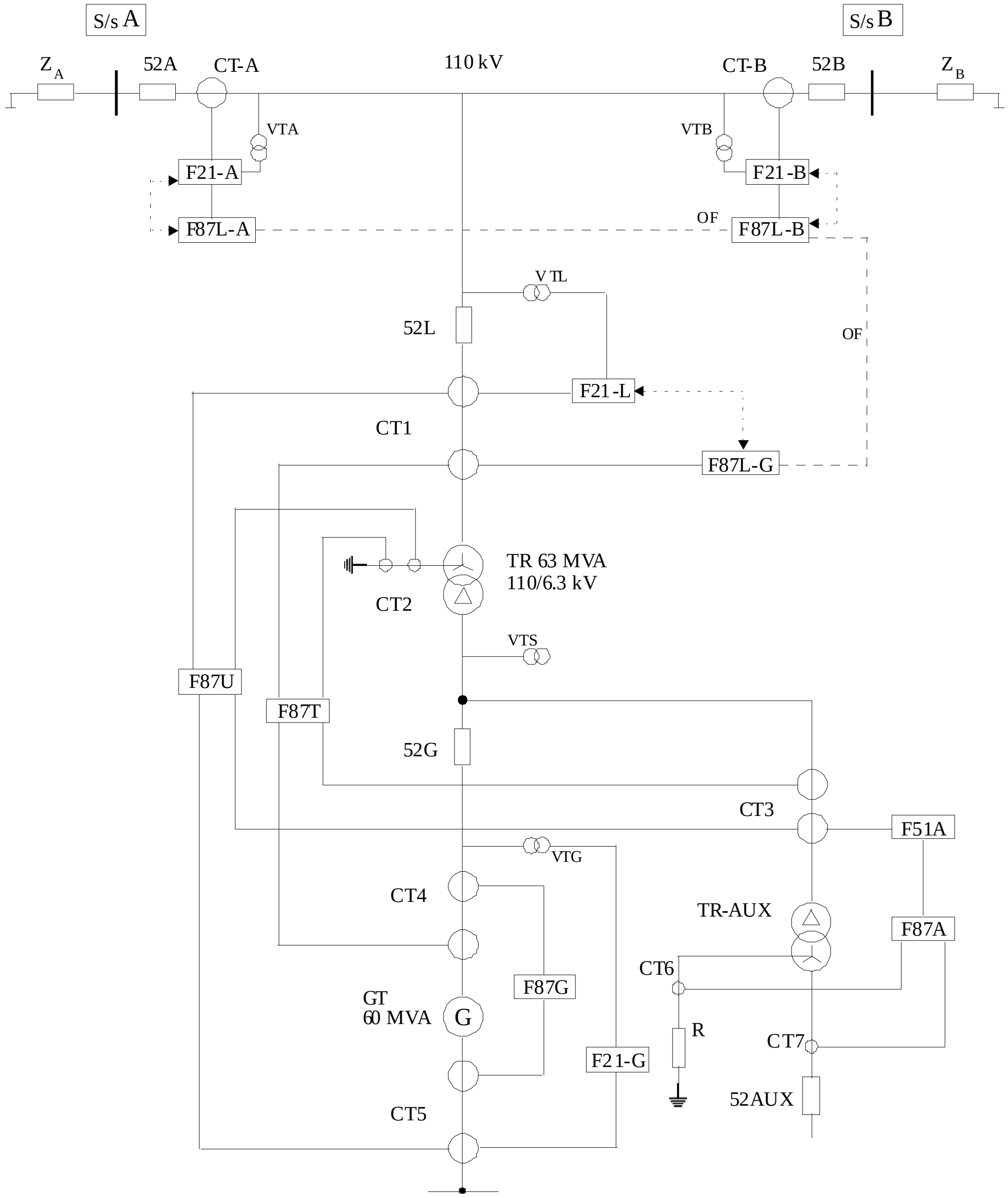


Figure 5. Single line diagram and protection system organisation

In case of unstable power swings a pole slip function is used to trip all line circuit breakers. In case of a pretty long overhead line it is common to use the single-shot, single-pole AR function, assuming proper circuit breakers and generation units' capabilities.

The second multi-function relay (F21) includes the back-up protection functions, the distance protection function as the main protection function and also some phase overcurrent or directional earth-fault protection functions. This arrangement preserves the generation unit connected to the network, even if the communication channel for the line differential protection function is broken. The distance protection function is also set as back-up for the step-up transformer protection functions. Some applications could include an additional multi-function relay as back-up to cope with high-resistive faults, mainly in case of the line differential protection failure.

3.2 Protection Coordination

The line differential protection function is based on the well proven principle of summing all currents that flow through the protected zone. During a fault in-zone, the total sum of currents is equal to the fault current, while during an external fault the total sum of currents is equal to zero. In order to calculate the differential and restrain currents at each line end, the measured quantities must be transmitted, in a suitable form over the communication link from each line end to the other two line ends. This is achieved by transmitting the measured quantities as digital telegrams. The communication topology can be a star one or a ring one. The differential currents are calculated for each phase apart, thus making possible to operate single pole AR, if the line circuit breakers are able to operate single pole. This can be an advantage for generator operation, if supported. On the other hand, attention should be paid to coordination issues regarding the pole discrepancy protection, earth fault protection and to the unbalance protection as these could operate during single pole dead time. To set the differential protection one has to keep in mind certain conditions that can influence its operation such as unequal line current transformer ratio, current transformer saturation or line charging currents.

4. TESTING THE PROTECTION SYSTEMS IN THE NETWORK SUBSTATION

It is a common rule to start the field tests with the preliminary checks based on visual check of the protection and control cubicles, visual check of all racks, mechanical fixing of the cases, relay protection degree check, visual check of external wiring and proper marking according to the applicable drawings, visual check of cubicle and relays grounding and check of DC supply voltage.

Next, hardware checks have to confirm the proper connections of all binary inputs and outputs to the protection and control scheme. Activation and deactivation of all binary inputs and outputs is done for this purpose. Checking of the proper alarms, events and messages sent to the substation SCADA system as well as to EMS SCADA system at the Network Control Centre (NCC) should be done during this stage.

For analogue inputs check, the injection of all voltages and currents rated values is mandatory. During this test it is possible to confirm the proper displayed values on the work stations of the control systems, on the EMS SCADA associated work stations and also to check for the secondary burden of the CTs and VTs as well as their proper connections related to the current direction flow.

Next step is checking of the correct operation of the different protection functions, trip relays, alarm relays, LEDs, event and disturbance recordings, alarms and messages to local/remote control centre. Basically, the tests have to confirm the proper operating of the different protection functions included in the multi-function protection relays, according to the settings and configuration logic. For doing these tests single phase-to-ground and phase-phase faults as well as forward and reverse are to be simulated for each protection function and multi-function relay. To test the line differential protection two (or more) testing devices with GPS time synchronization may be needed. Thus, from one line end is possible to start both the local and remote testing devices based on the accurate time synchronization and to simulate in-zone faults and outer-zone faults as well.

To check the teleprotection scheme two testing devices with GPS time synchronisation are needed. Thus it is possible to operate the two multi-function relays close to the real conditions by simulating faults close to each line end and recording the fast trip of both distance protection functions.

Numerical testing devices offer the facility of importing disturbance recordings previously saved in a Comtrade file. After importing the file it is possible to play back the event by generating voltages and currents corresponding to those recorded before. Starting from this facility the basic idea for simulation of a power swing or an out-of-step condition is to generate a Comtrade file containing the values of current and voltages closed to the real ones.

Functionality checks of circuit breaker trip and reclose, if applicable, all switching equipment close/open commands, teleprotection scheme and interlocking are to be done according to a detailed procedure taking into account the substation layout and the protection and control system philosophy.

The final confirmation of proper behaviour of the protection system according to the actual load flow is done by the on-load tests on energised equipment. Checking of the correct on-line direction of currents and voltages for all protection and control devices is the nearest test to real conditions. During this test reading out the values of currents, voltages, active and reactive power for both control and protection relays is the common way to confirm the proper connection of the relays. In addition triggering of disturbance recordings and analysing them offers valuable information of relay behaviour under load conditions.

5. CONCLUSIONS

Coordination of the large or medium size generator protection schemes and settings face the protection engineer to challenges regarding protection functions selection and proper setting of them.

The use of the line differential protection function together with a back-up distance protection function is a suitable solution for almost all topological arrangements, including the single tie line arrangement. However, some provision has to be taken into account in case of the differential protection failure.

Testing of the overall functionality of the protection scheme has to be done in order to proof the correct operation of the protection system. Beside, checking of the proper alarms, events and messages sent to the substation SCADA system as well as to the NCC EMS SCADA system contribute to the overall dependability and secure operation of the power system.

Some aspects of all these challenges were addressed by the paper indicating the possible solutions to achieve a robust and secure protection scheme.

BIBLIOGRAPHY

[1] IEEE Standard C37.102 “IEEE Guide for AC Generator Protection”.

[2] IEEE Standard C37.113 “IEEE Guide for Protective Relay Applications to Transmission Lines”.

[3] H.J.A. Ferrer, E.O. Schweitzer III “Modern solutions for protection, control and monitoring of Electric Power Systems”.

[4] G. Ziegler “Numerical Distance Protection”, Publicis Corporate Publishing, Erlangen, 2008.

[5] WG B5.15 “Modern Distance Protection Functions and Applications”, CIGRE 359, October 2008.

[6] WG B5.34 “The Impact of Renewable Energy Sources and Distributed Generation on Substation Protection and Automation”, CIGRE 421, August 2010.

.

CIGRE Regional South-East European Conference RSEEC 2016 (3rd edition)
October 10th - 12th 2016 University "Politehnica" of Bucharest, Romania

#101

Modeling of Differential Protection to AT 400 MVA for fault using the finite element method

Valentin VILCU*
Transelectrica, UNO - DEN
Romania

SUMMERY

Creating protection settings needed for the parametrization of an AT 400 MVA transformer longitudinal differential protection, requires the knowledge of the limits of the protection selectivity.

Modelling the defects using finite difference method may determine these limits of such protection. At the same time, by analysing a real event in EPTN, interpreting the activation of such protection at failure in the EPTN 400 kV in Romania, the completion of the operational logic of relay is proposed, so that to eliminate any possible future error in activation.

KEYWORDS

Autotransformer, Longitudinal Differential Protection (LDP), Operating Conditions, Electric Power Transmission Network (EPTN), over-fluxing protection, switch on to fault (SOTF)

1. INTRODUCTION

Nowadays, by TSO standards, according TEL regulations, a 400 MVA auto-transformer is protected with redundant protection systems, both for internal defects and for defects occurring in the transmission network. The autotransformer or a transformer longitudinal differential protection acts on the occurrence of short circuits in the protection area that is in the inner connection area delimited by the current metering transformers. The protection should be at the same time sensitive to „weak" defects in autotransformers which are short circuits between turns in the winding of the same phase or grounding in the network with such high currents and safe in the meaning of not acting even in the presence of the highest fault external currents.

Currently, for the autotransformers (400 MVA AT) of EPTN are used protection systems against internal malfunctions, longitudinal differential protection considered to be critical while for external malfunctions are used remote protections considered to be back-up protections. Modern numerical terminals have included both protection functions which, despite all technological achievements meant to render such faster, safer, selective, with malfunction elimination times of 40 ms, non-selective triggers are still possible and present in network operation.

2. GENERAL CONSIDERATION

Estimation of failure currents is made by direct calculation, using the reactance so as to schedule the network shown in Figure 1, yielded the following values that will power differential protection of the AT short-circuit single phase, two-phase, two-phase with earth and phase, taking place in different areas of EPTN:

* valentin.vilcu@transelectrica.ro

Table 1

Failure	Measured value of TDP at 400 kV side [kA]	Measured value of TDP at 220 kV side [kA]	Failure area
at bus-bar 400 kV B	idem to born to AT 400 kV: $12{,}28^{(3)}$; $10{,}2^{(1)}$; $10{,}64^{(2)}$;		
A-N	$3{,}38^{(1)} = 0{,}93^{(d)} + 0{,}93^{(i)} + 1{,}53^{(0)}$	$5{,}41^{(1)} = 1{,}53^{(d)} + 1{,}53^{(i)} + 2{,}34^{(0)}$	internal defects
A-B	$2{,}9^{(2)} = 1{,}68^{(d)} + 1{,}68^{(i)}$	$4{,}8^{(2)} = 2{,}77^{(d)} + 2{,}77^{(i)}$	internal defects
A-B-N	$3{,}37^{(2\text{-}0)} = 2{,}07^{(d)} + 1{,}28^{(i)} + 1{,}3^{(0)}$	$5{,}49^{(2\text{-}0)} = 3{,}43^{(d)} + 2{,}11^{(i)} + 2^{(0)}$	internal defects
A-B-C	$3{,}35^{(3)}$	$5{,}54^{(3)}$	internal defects
at bus-bar 220 kV B	idem to born to AT 220 kV: $21{,}72^{(3)}$; $20{,}42^{(1)}$; $18{,}81^{(2)}$;		
A-N	$2{,}93^{(1)} = 0{,}99^{(d)} + 0{,}99^{(i)} + 0{,}95^{(0)}$	$5{,}4^{(1)} = 1{,}64^{(d)} + 1{,}64^{(i)} + 2{,}12^{(0)}$	internal defects
A-B	$2{,}74^{(2)} = 1{,}58^{(d)} + 1{,}58^{(i)}$	$4{,}53^{(2)} = 2{,}62^{(d)} + 2{,}62^{(i)}$	internal defects
A-B-N	$3{,}06^{(2\text{-}0)} = 2{,}07^{(d)} + 1{,}11^{(i)} + 0{,}89^{(0)}$	$5{,}31^{(2\text{-}0)} = 3{,}39^{(d)} + 1{,}84^{(i)} + 0{,}89^{(0)}$	internal defects
A-B-C	$3{,}17^{(3)}$	$5{,}23^{(3)}$	internal defects
at bus-bar 400 kV A	$15{,}18^{(3)}$; $14{,}08^{(1)}$; $13{,}68^{(2)}$;		
A-N	$1{,}53^{(1)} = 0{,}49^{(d)} + 0{,}49^{(i)} + 0{,}55^{(0)}$	$2{,}46^{(1)} = 0{,}81^{(d)} + 0{,}81^{(i)} + 0{,}84^{(0)}$	external defects
A-B	$1{,}43^{(2)} = 0{,}83^{(d)} + 0{,}83^{(i)}$	$2{,}37^{(2)} = 1{,}37^{(d)} + 1{,}37^{(i)}$	external defects
A-B-N	$1{,}6^{(2\text{-}0)} = 1{,}05^{(d)} + 0{,}61^{(i)} + 0{,}49^{(0)}$	$2{,}62^{(2\text{-}0)} = 1{,}73^{(d)} + 1{,}01^{(i)} + 0{,}75^{(0)}$	external defects
A-B-C	$1{,}65^{(3)}$	$2{,}73^{(3)}$	external defects
at bus-bar 220 kV C	$6{,}61^{(3)}$; $6{,}3^{(1)}$; $5{,}72^{(2)}$;		
A-N	$0{,}48^{(1)} = 0{,}2^{(d)} + 0{,}2^{(i)} + 0{,}09^{(0)}$	$0{,}85^{(1)} = 0{,}33^{(d)} + 0{,}33^{(i)} + 0{,}2^{(0)}$	external defects
A-B	$0{,}54^{(2)} = 0{,}31^{(d)} + 0{,}31^{(i)}$	$0{,}89^{(2)} = 0{,}51^{(d)} + 0{,}51^{(i)}$	external defects
A-B-N	$0{,}57^{(2\text{-}0)} = 0{,}4^{(d)} + 0{,}22^{(i)} + 0{,}08^{(0)}$	$0{,}95^{(2\text{-}0)} = 0{,}67^{(d)} + 0{,}36^{(i)} + 0{,}19^{(0)}$	external defects
A-B-C	$0{,}62^{(3)}$	$1{,}02^{(3)}$	external defects

3. BRIEF PRINCIPLES of CREATING LDP SETTINGS RELATED to AT 400 MVA

The longitudinal differential protection is considered fully selective, responsible with eliminating malfunctions in the protected area, that is in the area physically delimitated by measurement, current transformers and current-conductor elements and also very quick because it does not require the correlation (query) to other protection systems, initiating instantaneous triggers to all the AT switches.

The differential protection works against multi-phase short-circuits in the protection area (area ranging between current transformers), against short-circuits between the windings of a phase, as well as against ground connection on the side of the transformer connected to a network of large grounding currents. The real protection against malfunctions inside the transformer case is the gas protection, the differential protection being an additional protection backing up the gas protection. The differential relay (current relay) is connected in parallel to the differential circuit. Because the differential protection is fully selective, it need not be coordinated with any other protection and so the trigger is very quick. Under normal operation and especially at external short-circuits, through the differential relay passes an unbalanced current due to several causes: current transformers are not identical, inequality of secondary currents, adjusting the voltage under load, etc. In order for the protection not to trigger due to the unbalanced current, which would be a wrong trigger, the protection deploy current is set to a higher value than the maximum unbalanced current (resulting in short-circuits), but lower than the rated current of the transformer. In order to reduce the unbalanced current through the differential relay, with classical protection schemes were used rapid saturation transformers which were connected to the differential circuit. The current relay is connected to their secondary. As a result of reducing the unbalanced current, the protection deploy current could be set to a lower value which provided better conditions for the sensitivity of the protection. Theory of operation of the longitudinal differential protection at the AT, the limitations of the fully selective or very quick operation are imposed by the operation with magnetizing shock currents, transient or passing currents, in which case such is rendered insensitive, braked or blocked to prevent faulty operation lacking a real malfunction, but the fault showing similar symptoms.

Modern numerical differential protections feature a data transfer facility through fiber optic and use open communication standards for the exchange of information between the protection terminals and the data transmission system.

All differential protections have as underlying principle the comparison of the values measured as amplitude and phase of instantaneous values, by direct comparison or phasorial comparison, in other words is applied Kirchhoff’s 1st Law whereby the vector sum of the current going in or out from a knot is zero.

Another limitation for the sensitivity of the protection taken in consideration in the practice of protection adjustment is the existence of a false differential current due to the CT transforming errors. In the linear part of CT's magnetizing current feature, this error is proportional to the secondary current but in the case of a malfunction with the saturation of the magnetic circuit of the CTs, it determines a rapid increase of the false differential current.

The current differential protection achieved with numerical technology compares the currents from the local protection terminal to the currents received through the communication channels at the protection terminal situated at the opposing end in order to determine to location of the malfunction, inside or outside of the protected area.

The function can be implemented having as base the segregation on phases or a combination of direct sequence currents, reverse sequence currents and zero currents. In the first case, the system compares currents phase by phase while in the second case is compared a mono-phase signal obtained locally and from the opposing end proportional to the direct sequence, reverse sequence and zero currents.

The operation of the relay is determined by the „difference” of the currents passing through the CTs from each side of the AT. Measuring the differential current is stabilized with an adjustable scalar current both for the exterior malfunction currents and for the minimum operating currents. Numerical relays detect the saturation index of the CTs in order to decrease the over-current number imposed for the CT windings. Another advantage of the numerical differential relays with fiber optics communication is the possibility to adjust / adapt transformation ratios of the CT. Primary, input and output current are not in phase, between them being the phase difference determined by the connections group of the AT, they are not equal, but proportional to the primary transforming ratio, they are not equal even in terms of reported values, the phasorial difference of such being equal to the magnetizing current of the AT; with regard to all these aspects, the numerical relays execute solutions by compensating the inequality of the currents, compensating the currents difference of phase, blocking the magnetizing shock, compensating current measurement errors from the sections with different voltage, ensuring the stability of the differential protection to malfunctions exterior to the area towards the weak source; the differential protection is rendered insensitive, braked or blocked so as not to operate faulty at the transient magnetizing current of the magnetic circuit, the solution used for the classic protections being to time to 100 ms the trigger protection, with the obvious drawback that correct triggers were also delayed. Processing the trigger algorithm is done in a very short time of about 5 ms as of the initiation of the short-circuit, time in which the CTs are not yet saturated, and so is avoided the faulty trigger of the protection function.

4. ANALYSIS OF A LDP IN CASE OF AN EVENT IN EPTN

When a single-phase defect occurs on 400 kV A-B overhead power lines, the electric stations protection systems in figure 1 have acted thus:

In the 400 kV A station: the distance triggered the defect phase C, initiates the reclosing command pulse for the circuit breaker, following to the unsuccessfuly autoreclose; in the same mode action system protection in the 400 kV B station;

To the energizes line A from station 400 kV B, simultaneously triggering to SOTF protection line is definitive trip to AT 400 MVA, 400/231 kV at LDP;

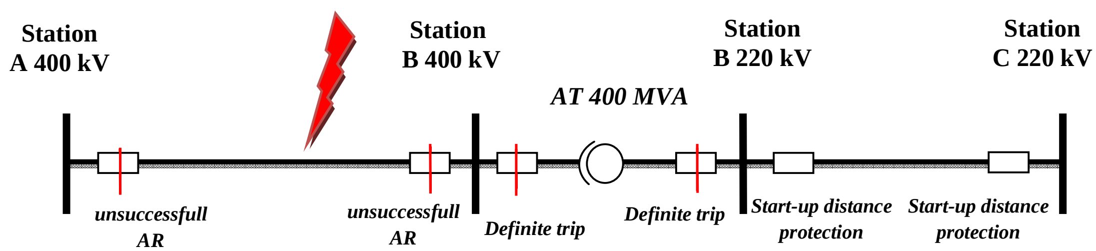


Fig. 1 – EPTN schemes

4.1 VERIFICATION OF THE CORECTNESS OF LDP ACTION RELATED to AT 400 MVA

For the AT 400 MVA in figure 1, the differential protection was used according to the default settings, respectively of compensating the lagging due to the connection group Y_0y_0, when balancing the currents of the following algorithm [1]:

$$\begin{pmatrix} \underline{I_A} \\ \underline{I_B} \\ \underline{I_C} \end{pmatrix} = \frac{1}{3}\begin{pmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{pmatrix}\begin{pmatrix} \underline{I_{L_1}} \\ \underline{I_{L_2}} \\ \underline{I_{L_3}} \end{pmatrix}$$

The relay showed on the oscillograph the following instant values of currents which initiate the trigger

at the 400 kV side:

I_{L1} = 241 A∟-90,1˚ ≡ (- 0,38 – j 241) A

I_{L2} = 525 A∟-158,8˚ ≡ (- 489 – j 190) A

I_{L3} = 1161 A ∟-134,4˚ ≡ (- 1170 – j 1110) A

and the 220 kV side:

I_{L1} = 387 A∟96,2˚ ≡ (- 41,8 + j 385) A

I_{L2} = 820 A ∟21,2° ≡ (760 + j 300) A
I_{L3} = 2910 A ∟27° ≡ (2590 + j 1320) A

The sign (-) is because the CT „star" is made towards the AT (towards the protected element), and with these read values, the terminal (LDP) processed the following values:

at side 400 kV

$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_B \\ \underline{I}_C \end{pmatrix} = \frac{1}{3}\begin{pmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{pmatrix}\begin{pmatrix} \underline{I}_{L_1} \\ \underline{I}_{L_2} \\ \underline{I}_{L_3} \end{pmatrix}$$

$$\underline{I}_A = \frac{1}{3}\left(2\underline{I}_{L1} - \underline{I}_{L2} - \underline{I}_{L3}\right) = -401{,}33A$$

$$\underline{I}_B = \frac{1}{3}\left(-\underline{I}_{L1} + 2\underline{I}_{L2} - \underline{I}_{L3}\right) = -117{,}33A$$

$$\underline{I}_A = \frac{1}{3}\left(-\underline{I}_{L1} - \underline{I}_{L2} + 2\underline{I}_{L3}\right) = 518{,}66A$$

- identical at side 220 kV:

$$\begin{pmatrix} \underline{I}_A \\ \underline{I}_B \\ \underline{I}_C \end{pmatrix} = \frac{1}{3}\begin{pmatrix} 2 & -1 & -1 \\ -1 & 2 & -1 \\ -1 & -1 & 2 \end{pmatrix}\begin{pmatrix} \underline{I}_{L_1} \\ \underline{I}_{L_2} \\ \underline{I}_{L_3} \end{pmatrix}$$

$$\underline{I}_A = \frac{1}{3}\left(2\underline{I}_{L1} - \underline{I}_{L2} - \underline{I}_{L3}\right) = -985{,}33A$$

$$\underline{I}_B = \frac{1}{3}\left(-\underline{I}_{L1} + 2\underline{I}_{L2} - \underline{I}_{L3}\right) = -552{,}33A$$

$$\underline{I}_A = \frac{1}{3}\left(-\underline{I}_{L1} - \underline{I}_{L2} + 2\underline{I}_{L3}\right) = 1537{,}66A$$

With these values the protection calculates the operating current and braking current:

$I_{\text{operate phase A}}$ = 584 A; $I_{\text{operate phase B}}$ = 435 A; $I_{\text{operate phase C}}$ = - 1019 A;
$I_{\text{bias phase A}}$ = 1386,66 A; $I_{\text{bias phase B}}$ = 669,66 A; $I_{\text{bias phase C}}$ = 2056,32 A

In the tripping characteristic of the differential protection will have:

$I_{\text{DIFF phase A}}$ / I_{operate} = 584/ 578 A = 1,01 p.u.
$I_{\text{DIFF phase B}}$ / I_{operate} = 435/ 578 A = 0,75 p.u.
$I_{\text{DIFF phase C}}$ / I_{operate} = 1019/ 578 A = 1,76 p.u.
$I_{\text{restrain phase A}}$/ I_{operate} = 1386,66 / 578 A = 2.39 p.u.
$I_{\text{restrain phase B}}$/ I_{operate} = 669,66 / 578 A = 1.15 p.u.
$I_{\text{restrain phase C}}$/ I_{operate} = 2056,32 / 578 A = 3.55 p.u.

Settings of characteristic of phase differential protection is:

- pick-up value of differential current: I-DIFF=0.2;
- base point for slope 1 of characteristic: BP1=0.2
- Slope 1 = 0.2;
- base point for slope 2 of characteristic: BP2= 2
- slope 2 = 0.5

With these values in the characteristic of the differential protection to obtain into a locus in the tripping area.

Idiff A=0.258 Irst_A=2.25
Idiff B=0.295 Irst_B=1.18

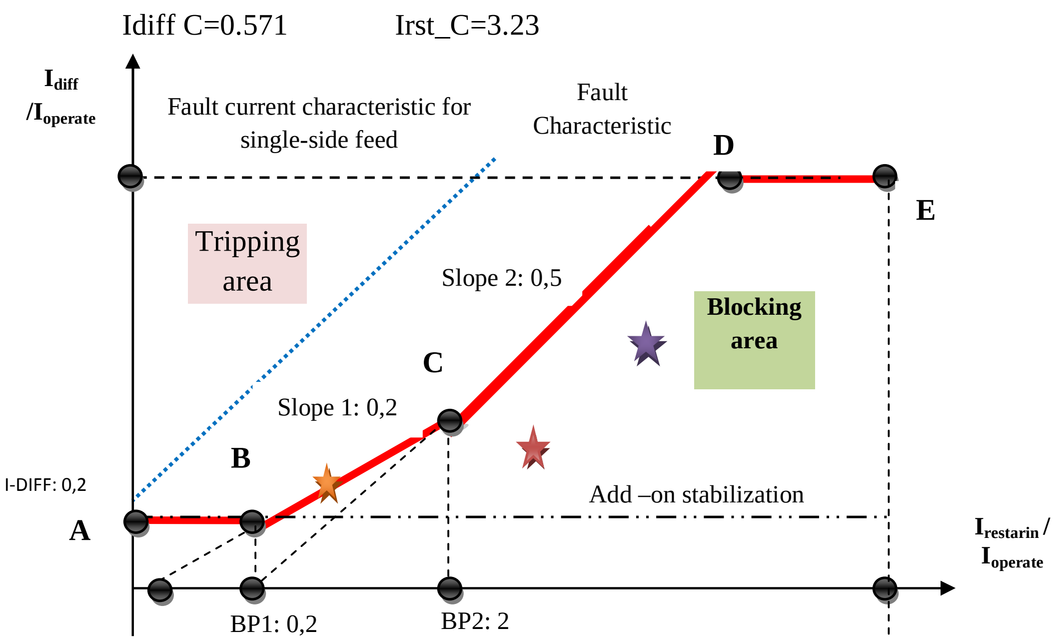


Fig. 2 – Tripping characteristic of differential protection

The calculation algorithm used by terminals is that which was presented here, the sensitivity of such to the deploy threshold of 0.2 In/Ioperate, implementation recommended by the producer, can be totally non-selective in the case of weak braking currents as shown in this paper. The yellow star on the line of the work axis for phase B determined the trigger of the protection. The events are absolutely real, the malfunction being an external one at the 400 MVA AT, at app. 40 km on a 400 kV OHL adjacent to the 400 kV bars where the AT is connected. The non-selective trigger, the way in which it occurred, determine the analyzing of these protections and the determination of those limits of selectiveness.

4.2. MODELING FAILURE USING THE FINITE ELEMENT METHOD

Modelling with FEMM program is really helpful because it is designed for solving low frequency electromagnetic fields on plane and axisymmetric two-dimensional plane.
Modelling an AT winding, assuming having 36 mm^2 1000 copper winding , necessary to estimate from quantity viewpoint the magnetic energy flow in the coil developed.

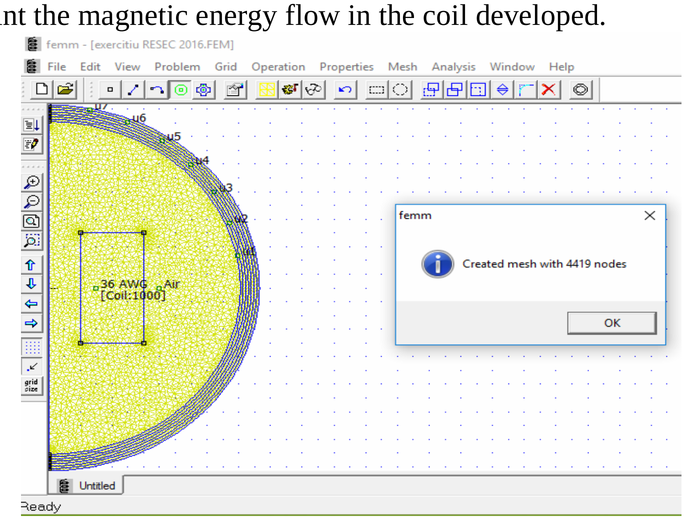


Fig. 3 – creating AT coil from FEMM

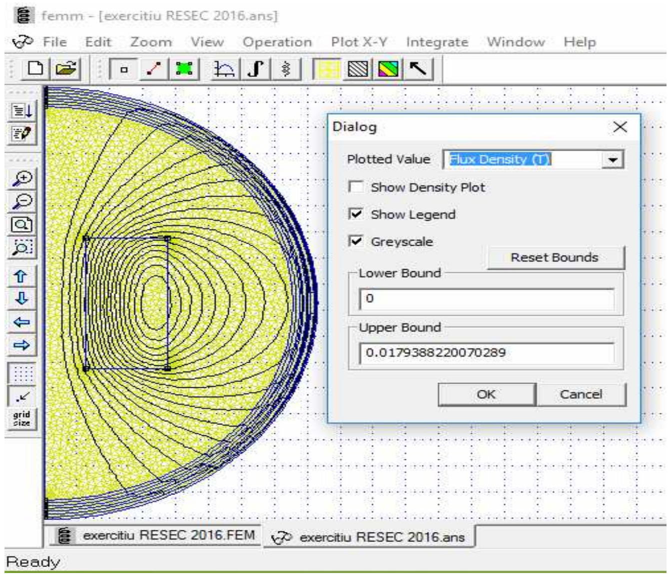


Fig. 4 – readings value from FEMM

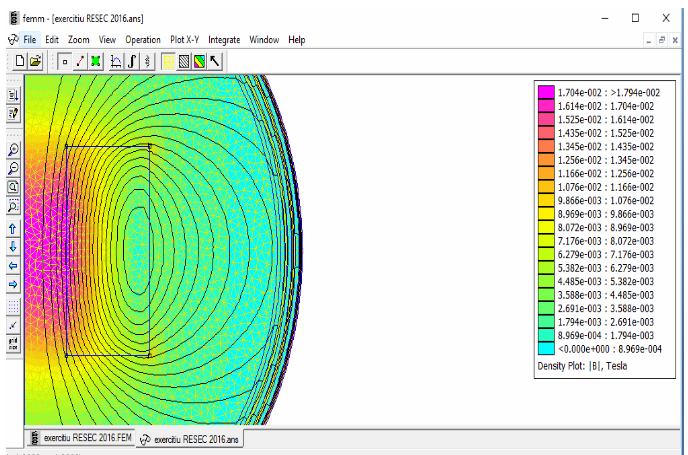


Fig. 5 – Magnetic field strength shown by FEMM

As per transformer design practice and the Factory Test, it is known that the peak rated value of the flux density of a 400 MVA autotransformer is kept about 1.7 to 1.8 Tesla, while the saturation flux density of CRGD steel sheet of core of transformer is of the order of 1.9 to 2 Tesla which corresponds to about 1.1 times the rated value. If during operation, an AT is subject to carry, rather swallow, more than the above mentioned flux density per its design limitation, the AT have to face over fluxing problem and consequently bad effects towards its operation and life. Depending on the designed flux density, the core saturation and the thermal time constants of the component parts submitted to heating, the autotransformer bears a certain over-excitation or over-fluxing capacity, which for a short period is considered admissible, but it must not exceed 110%. Magnetic flux estimation of core / windings with FEMM program V.4.2 for different fault currents, such as those obtained in Table 1 traversing the AT windings, may be sufficient to activate a new, more selective protection functions. These flux values are parameterized in relay because in case of an internal fault the AT, the flux will be much higher, the failure being supplied from two systems existing in parallel, the one of 400 kV EPTN, and 220 kV EPTN, respectively, while at external faults this will be powered either by 400 kV EPTN or 220 kV EPTN, never from both systems.

5. CONCLUSION

These false tripping revealed by different modeling assumptions calculating short-circuit currents, indicating possible erroneous LDP of an AT/Transformer. After making feature work from Figure 2 this acting has been highlighted in the case of a low current external failure at which the specific metering errors determines erroneous action of the protection device.

The paper analyzed the non-selective operation of an LPD related to an AT, an external defect. Although the release was incorrect, failure being on a line adjacent to the AT connection station, the protection worked "correctly" according to its calculation algorithm, highlighted in the analysis.

The actions of these protection functions (LPD) may be corrected/ correlated with the power overflux function (volt per hertz), also integrated in the numerical protection terminals. Values of thus obtained protection calculated operating current and bias current, which will compare with defaults shown in figure 5.

Thus, an additional criterion in safety action will be entered, because as seen in shaping FEMM flow, the magnetic flow of AT coils will be different at internal defects and respectively, at external faults to the differential area.

BIBLIOGRAPHY

[1] F. Bălașiu, St. Gal, Al. Vasilievici, T. Făgărașan, *Implementarea Echipamentelor Digitale de Protecție și Comandă pentru Rețele Electrice*, Editura Tehnică, București, 2000.

[2] D. Mihoc, S. St. Iliescu, *Protectii prin Relee Clasice si Numerice*, Editura Printech, Bucuresti, 2009.

[3] *** Siprotec – Distance Protection 7UT6 v4.3, Siemens AG 2003.

[4] *** *Network Protection & Automation Guide Protective Relays Mesurement & Control*, Altstom Grid, 2011.

[5] *** V. Vîlcu, *Modelarea, Simularea și Analiza Funcționării în Regim de Avarie a unor Principale Noi Funcţii de Protecţii dintr-o Staţie Electrică*, Teză de Doctorat nr. Decizie Senat 237/02.09.2015

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#102

Live working technologies and the limitation of the impact of maintenance on people and environment

M. OLTEAN[*], O. JURASCU, G. COTRIGASAN, M. STANCU
SMART S.A.
Romania

SUMMARY

The Live Workinging Technologies have an important contribution to reduce/limit the impact which electric networks bring to the environment (ecosystem, neighbourhood, electricity consumption). From this point of view and to ensure the legitimacy of worker safety, Live Workinging Technologies are very proper to be applied to all voltage levels, from overhead lines to electric substations. An objective for SC "Smart" SA is to increase the use of these new technologies which have a positive impact on environment and on worker safety. In this context, having already a Live Workinging team at Sibiu Subsidiary, we chase to train and form a large number of personnel able to perform Live Workinging. This will be made using the experience which our experts accumulated in the last 20 years. Other priority for Sibiu Subsidiary is to introduce the most recent Live Workinging technologies.

KEYWORDS

- environment survey; environment management system; Live Working

1. ELEMENTS OF ENVIRONMENTAL STRATEGY

In the last 20 years the business climate in Romania recorded substantial changes - on one hand due to the efforts dedicated to integration in the EU, and - on the other hand due to competition from foreign companies interested to sell their own products and to develop local production capacities.

Simultaneously, the transposition of the acquis communautaire has generated for Romanian businesses a significant impact on the conformity needs, imposed together with the development of quantitative and qualitative dimensions of legal requirements.

So there were issued laws, government decisions, ministerial orders, all aiming environmental protection, beginning with quality of water and air and ending with waste management, the most important legal documents issued being OUG 195/2005 on environmental protection, completed with OUG 164/2008 and HG 1076/2004 establishing the procedure of environmental assessment for plans and programs, Order no. 1026/2009 - approving conditions for the development of the environmental report, environmental impact report, site report, safety report, the appropriate evaluation study, and Order no. 184/1997 - approving the procedure for achieving environmental audit.

At the same time, our country has acceded to a number of international conventions on environmental protection, most of them having serious implications in the Romanian energy sector. Since autumn 1997 the family standards EN ISO 14000 appeared, with express reference to environmental management systems and environmental audits.

[*] marius.oltean@smartsb.ro

In the view of many analysts, the key step when an environmental management system is built of and subsequently the own development capacity, namely environmental performance, is the determining and identifying the risks and opportunities related to environmental issues and associated environmental impacts. It is necessary to continuously identify environmental issues / dangerous activities and products, to evaluate (classify) environmental impacts and to identify those who can kept under control, to implement the necessary controlling actions.

According to SR EN ISO 14001, section 3.2.1, the notion of *environment* finds a complex meaning, namely:

"*The environment is composed of the environment in which the organization operates, including air, water, soil, natural resources, flora, fauna, human beings and relations between them, meaning that the environment extends from the organization up to the global system*".

Principles and objectives of the National Strategy for Environmental Protection, which relate directly to the subject of the essay consists of:

-caution in decision making;

-preventing environmental risks and damage occurrence;

-biodiversity and natural ecosystems preservation, specific to biogeographic framework;

-principle "polluter pays";

-elimination with priority of the pollutants that endanger directly and severely human's health;

-creation of the national system for integrated environmental monitoring;

-sustainable use;

-maintaining and enhancing the environment quality and reconstruction of damaged areas;

-development of international collaboration to ensure environmental quality.

In the Policy Statement of the Company's Management, entitled "*Goals and Commitment in Quality, Environmental, Health and Safety at Work for 201*6", two of the strategic objectives are: "*Limiting the negative effects on the environment of the activities in the subsidiaries by acting over significant environmental aspects*" and "*Meeting the expectations of employees on the principles regarding prevention of occupational accidents and occupational diseases, to eliminate the risk factors of labor accidents and occupational diseases existing in the work process".*

Overhead lines and power substations, through their vast location in the environment, are in constant interrelation. Conversion processes of energy's forms are accompanied by secondary phenomena, non-energy, including the impact of high voltage installations on the environment, but also the environment's influences over them plays an important role. It is already recognized that the increasingly use of electricity, together with the added comfort brings negative aspects, known under the general term of environmental impact.

As main environmental impacts of the overhead lines can be listed:

-impact on living organisms caused by electric fields, magnetic fields, acoustic noise, toxic substances;

-impact on the affected land;

-impact on the industrial objectives, construction, roads, bridges, pipelines etc;

-impact on receptions of radio and television;

-impact due to electromagnetic incompatibility;

-visually, psychologically impact etc.

Regarding Live Working activity, the main direction to achieve the objective of reducing the environmental impact is to improve the training of maintenance personnel and awareness of the same personnel about the environmental protection and, in this context, widespread promotion of the ability of Live Workinging.

2. GENERAL CONSIDERATIONS REGARDING LIVE WORKING TECHNOLOGY ANALYSIS

Live Working method is applied of about 100 years and has permanently developed for the purposes of enriching it with new technology and equipment, as to meet more requirements related to:

-works on compact overhead lines;

-increase the workers safety;

-simplification of work, equipment and staff training;

-environmental protection and accomplish continuity of supply of electricity consumers;

-the possibility of generalisation of these technologies in all countries.

All three Live Working methods "*rubber glove*", "*hot stick*" and "*bare hand*" bring important improvement in the quality of overhead lines maintenance, proving many advantages and with direct influence on limiting the effects over the environment due to various interventions type „*switching voltage*" method.

2.1 Live Working Technology - positive impact on the psychic and on the safety of the working staff.

Live Working Technology eliminates the restrictions in movement and stimulates the quality of maintenance operations. At the same time, this technology provides the safety of personnel and equipment through the use of increasingly complex and handy equipments, leads to increasing interest towards work, to improvement of the workers and to disappearance of the routine, which is less productive.

Ergonomic sciences requirements are also fulfilled, the security rules being provided in all phases and operations:

-choosing, arranging, maintenance and installing of equipment and working tools;

-site organization at various stages of the same actions or activities for preventive or corrective maintenance;

-progress phases's succession of various operations during one intervention.

Studies accomplished in order to eliminate poor security led to the removal of some elements causing fatalities as:

-human errors, the risk increasing with the complexity of the installation (example: power sources remained non-switched);

-wrong interventions in neighboring installations (causing internal overvoltage);

-failure of equipment or appliances of the working circuit;

-induction phenomena (possible to double circuit overhead compact lines);

-shortened of the execution time by speeding up the interventions.

2.2 Live Working Technology - positive impact on economic and social conditions

From a technological standpoint, Live Working has some undeniable advantages, namely:

-Live Working operations are planned and organized in advance, provided weather conditions;

-Live Working can be performed during the normal work schedule;

-Live Working eliminates the set of maneuvers which affect the network, in order to bring the installation to the state "*unplugged*", maneuvers possibly causing errors and wear of equipment; to perform Live Working is sufficient to make only amendment protections (example: cancellation of AR);

-Live Working enables execution of operations, where works by interrupting the voltage could not be performed because of time limitations;

-Live Working enable supply continuity of electricity consumers.

Ensuring continuity of electricity supply to consumers has significant economic effects:

-reduce investments in reserve overhead lines or for looping the power supply;

-reduce own consumption by ensuring optimal power circulation into the network;

-reduces / eliminates possible damage affecting the consumers.

From the above, it appears that Live Working Technologies have significant benefits in terms of environmental protection. So:

-ensure greater protection of ecosystems and surrounding living organisms in neighboring areas of operation, due to reduced affected area, eliminating execution of pathways often expensive, removal of heavy equipment, eliminating the possibility of remaining, after the interventions, of waste more or less toxic for the environment as well as the speed and security of interventions which make that fauna isn't very affected;

-affected land is much lower than in the case of interventions type "*switch off*" because of both rules and work discipline, much stricter, and access restrictions around installations or below them, and by eliminating building overhead reserve lines or loops;

-increase protection of industrial objectives, buildings, human settlements, forests etc., from several points of view:

1. consumers are not harmed, being not interrupted with power supply. This involves reducing the amount of scrap / waste at the consumers;

2. decreases the coefficient of ecological risk, by allowing multiple works performed in a relatively short time, leading to increased equipment reliability, which implies a higher lifetime thereof;

3. crops are not affected, given the very limited work space;

-the protection of broadcasting radio and TV is improved due to the need to equip the overhead lines and power substations with electrical insulation elements, clamps and fittings, in order to eliminate the possibilities of reverse creepage, partial discharge or electromagnetic field increases, so as to make possible Live Working;

-in case of water course crossings, applying increased security measures, use of chains of insulators and of modern clamps and fittings allowing Live Working leads, also, to an increased environmental protection (waters and aquatic ecosystems) and to a substantial reduction of environmental risk factor.

2.3 Specific Live Working rules with positive effects on the environment.

Given the legislative interpretation of the term "*environment*", it should be considered a series of organizational and technical rules imposed by environmental legislation, which provides the general framework, and rules on technical, legislative laws of labor safety and health.

So:

-"*rubber glove*" Live Working method, applicable to Low and Medium Voltage facilities, the worker enters the forbidden zone, being equipped with electrical insulated boots and gloves and, maneuvering tools with insulating handles, he enter in contact with conductive parts on which he intervenes;

-regarding the "*hot stick*" Live Working method the worker remains outside the forbidden zone and carry out the work using tools mounted at the end of insulated rods; the method is applying to Medium and High Voltage installations, where the configuration and the geometry of the top part of the towers (pillars and frames) permits it;

Fig. 1 Bare Hand Method

-regarding the Live Working method "*bare hand*", the worker, isolated from the ground by means of an insulator (ladder, chair or beam) is moved progressively to the potential of the live part, on which he will intervene; until he reach the live line the worker is at a "*floating potential*"; workers must wear an electroconductive suit (constituting a Faraday cage) to protect himself from the effects of the electric field, helmet, gloves and electroconductive shoes, all parts of the protective clothing being attached to each other and thus ensuring continuity of the currents drainage circuits;

-the electrical installation must be at normal running, without unexpected switch off, otherwise Live Working is prohibited;

-the special exploitation regime, that requires mandatory provision of specific technical requirements, it means that any AR is made impossible and any re-energized is prohibited without the approval of the responsible of the Live Working;

-weather conditions: Live Working is prohibited if events such as rainfall (rain, hail, snow, frost), dense fog (with 80% humidity or who can dangerously reduce visibility), atmospheric discharges or strong wind (v = 9.5 m/s).

3. ACTIONS TO INCREASE SAFETY AND DECREASE ENVIRONMENTAL RISK FACTOR BY APPLYING LIVE WORKING TECHNOLOGY

Safety during Live Working, meaning minimizing the risk of an accident and, implicit, of a fault, it is an objective influenced by many factors of physical, mechanical, weather or human, such as:

-factors that can affect the mechanical behavior (example: tensile strength) of the components of the overhead lines or the Live Working equipment;

-factors that can affect the electrical behavior of the insulating intervals;

-factors that can determine overvoltage with the maximum value for which the overhead line was designed; AR being excluded, overvoltage value falls during the route up to the work area, but the phenomenon should be avoided. In this case it should be specified that the tools voltage withstand for Live Working is usually chosen at 10% higher than the insulation voltage withstand of the overhead line at commutation overvoltage;

-factors that can cause arcing between worker and pole, or in worker vicinity; seriousness of accidents in these cases imposed, worldwide, intensive laboratory research to exclude that occurence.

Fig. 2 and 3 Working Live with manual devices

The problem of assessing whitstand voltage modification of the overhead lines at different overvoltage due to the equipment used for Live Working is quite delicate. Additionally, consider that inside the structure of the insulator chains being subject of Live Working exists the possibility of some insulation defects that lead to a reduced level of insulation. That’s why the problems have been studied and are studied in laboratory, at natural scale. Because it was found that the cancellation of AR is insufficient, a number of solutions were adopted, such the use of two surge arrester mounted as close of the place of intervention, one side of the work area, or shorting an adequate number of insulators from the superior part of the chain of insulators and on the same phase at the pillars framing the pillar to which intervenes, or using two limiters type spherical spark gap, which is fixed between the tower crossarm and the wire's phase on which intervenes, at a distance of several meters from the chain.

Limitation to an imposed value, however large enough, which didn't provoke unwanted tripping in case of minor disturbances generated by overvoltage that may arise, creates also, in addition to increasing safety in conducting the Live Working, the possibility of Live Working approach on overhead compact lines.

Many activities performed in order to mitigate pollution effects and to guarantee system reliability, are based on live working methods. Live line working have contributed to fundamental solutions to solve the difficult problem of pollution on insulator. Using the live line working techniques we can replace, wash and monitor the insulators.

4. LIVE WORKING IMPACT ON WORKER

Around electrical lines or High Tension power substations, there is an electromagnetic field whose action on living organisms must be known by the operating or maintenance staff. It is necessary to distinguish between certain unpleasant effects, like stinging or small electric spark discharges and so-called "*bio-physiological*" effects whose existence is a matter of scientific controversy and speculation. Development of Live Working methods, imposing to stand in areas of intense electric fields, led to onset of medical tests, meaning analysis of overall health status of persons working in such conditions. These investigations have not led to spectacular results, so could not be revealed a clear effect of the electric field. However, as a precaution, and to keep out the technical staff from unpleasant sensations, there were introduced the conductive suits, which may screen the person who wears them, shielding it from electrostatic effects.

The value of the induced current in living organisms, near the overhead lines must not exceed 10 mA (STAS 2612), but the problem is far away for the workers wearing electroconductive outfits.

Fig.4. Electroconductive equipment

In 1990, International Radiation Protection Association – IRPA, indicated in "*Provisional directives on the limits of exposure to electric and magnetic fields of 50/60 Hz*", the limit values of electric and magnetic fields that staff must not exceed. So:

-If staff is working throughout the entire workday, they must:

$E \leq 10$ kVef/m,

$B \leq 0{,}5$ mTef

-If staff is working on short term, they must:

$E \leq 30$ kVef/m, and

the exposure duration will be:

$t\,[\text{hours/day work}] = \frac{80}{E[kV/m]}$, B = 5 mTef,

the daily maximum exposure duration must not exeed 2 hours.

Work periods in certain areas of electric influence must be limited to a few hours, in order to not enable the emergence of biological effects.

5. CONCLUSIONS

From the above, it appears that Live Working Technologies have an important contribution to reducing / limiting the effects that electrical installations produce on the environment (ecosystems, neighborhoods, electricity consumers).

Until 2013 our Sibiu branch designed and applied Live Working technological instructions for the electric installations of 110-750 kV, actually being certified by RLWA (Romania Live Workinging Association).

From these points of view and ensuring appropriate legal framework of requirements regarding work safety, Live Working Technologies are well suited to be applied at all voltage levels, for overhead lines and also for power substations.

Another objective of the Company "Smart" SA, extracted from "*Policy statement, objectives and management commitment - in the field of Quality, Environment, Health and Work Safety for 2010-2016*" is "*diversification with new activities and expansion of that ones provided in statutes, with introduction of advanced technologies having favorable impact on the environment and on personnel safety*." In this context, within the organization, which dispose of a Live Working team of extremely high experience, the Company has pursued education and training of a larger number of staff that can perform Live Working.

A priority is to apply more advanced technologies in the Live Working field and research on new tools and devices for Live Working.

BIBLIOGRAPHY

[1] ***- Live Working Technologies

[2] G.S.C.I. CSE – „Instrucţiuni privind natura şi rezolvarea problemelor de impact a reţelelor de inaltă şi medie tensiune asupra mediului ambiant, faza a II a”, Bucuresti 1996.

[3] I.S.P.E. – „Studiul de impact a reţelelor de transport a energiei electrice asupra mediului inconjurător”, Bucuresti 1997.

[4] G.T.D.E.E. – U.P.B. – “Instrucţiuni privind natura şi rezolvarea problemelor de impact a reţelelor de de înaltă tensiune (Linii si Statt) asupra mediului ambiant, faza I-Studiu de impact LEA 750kV asupra mediului”, Bucuresti 1996.

[5] ROENG – „Strategii pentru reducerea impactului instalaţiilor asupra mediului. Practici la nivel de sucursală de reţea de distribuţie si transport” 1998.

[6] Vladimir Sokol - Live Workinging Commission Member – “Labour safety and Live Workinging”

[7] G. De Donà, C. Valagussa- “Pollution and Live Line Working” (in proceedings ICOLIM 2011, Zagreb, Croatia)

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#103

Smart Grid and Cyber Security. Good Practices Guide for Implementing Cyber Security in TSO's SCADA Applications

PhD. M. COTEANU[*], BSc. I. PAVALOAIA, BSc. R. HUCH, BSc. L. SPATARU
Energy Design & Consulting S.R.L.
Romania

SUMMARY

The growing dependence of critical infrastructures and industrial automation on interconnected physical and cyber-based control systems has resulted in a growing and previously unforeseen cyber security threat to supervisory control and data acquisition (SCADA). This paper provides an overview of cyber security and risk assessment for SCADA Smart Grid, the main threat vector methods which entities or individuals may intent to use and the main issues that any supplier must meet to ensure the security of Smart Grid.

KEYWORDS

SCADA; Cyber security; Control systems; Smart Grid; Data Diode; UTM; WAF; IPS; IDS.

1. INTRODUCTION

Today's world is more interconnected than ever before. Increased connectivity brings increased risk of theft, fraud and abuse. At the moment, most electronic devices such as computers, laptops and smartphones come with built in firewall security software, but despite this, computers are not 100 percent accurate and secure to protect data. It was observed that the methods of hacking into computers are becoming more diverse and more difficult to predict. It can be done through a network system, clicking into unknown links, connecting to unfamiliar Wi-Fi, downloading software and files from unsafe sites, power consumption, electromagnetic radiation waves, and many more. However, computers can be protected through well - built software and hardware. Software complexity can prevent software crash and security failure if it will have strong internal interactions of properties.

Examples of critical infrastructures in our society are the power, the gas and the water supply networks. These infrastructures are operated by means of complex supervisory control and data acquisition (SCADA) systems, which collect measurement data from remote terminal units (RTUs) or intelligent electronic devices (IEDs) installed in the substations, and deliver the measurement data to the central master station located at the control center. The measurement data is usually transmitted through unencrypted communication channels, making these critical infrastructures vulnerable to cyberattacks. SCADA systems for power networks are complemented by a set of application specific software, usually called energy management systems (EMS).

The growing dependence of critical infrastructures and industrial automation on interconnected physical and cyber-based control systems has resulted in a growing and previously unforeseen cyber security threat to supervisory control and data acquisition (SCADA). It is critical that engineers and managers understand these issues and know how to locate the information they need.

[*] mihail.coteanu@ed-c.ro

Security is not just about preventing security attacks or system compromises; it is also about managing the inevitable successful (deliberate or inadvertent) attacks. Particularly for real-time operations, it is crucial to “live through” any attacks or compromises to the information infrastructure, and to recover with minimal disruption to the power system operations - including power system reliability, efficiency and cost.

2. CONTROL SYSTEM

A control system is a device, or set of devices, that monitors, commands, directs or regulates the behaviour of other devices or systems. In the electric power industry, they can manage and control the transmission and delivery of electric power, for example, by opening and closing circuit breakers and setting thresholds for preventive shutdowns.

Security concerns about control systems were historically related primarily to protecting against physical attacks or the misuse of refining and processing sites or distribution and holding facilities. However, in more recent years, there has been a growing recognition that control systems are now vulnerable to cyberattacks from numerous sources, including hostile governments, terrorist groups, disgruntled employees, and other malicious intruders.

Increasing the risk that these control systems to be accessed by unauthorized entities was due to the following concerns [1]:

- The adoption of standardized technologies with known vulnerabilities;
- The connectivity of many control systems via, through, within, or exposed to unsecured networks, networked portals, or mechanisms connected to unsecured networks (which includes the Internet);
- Implementation constraints of existing security technologies and practices within the existing control systems infrastructure (and its architectures);
- The connectivity of insecure remote devices in their connections to control systems;
- The widespread availability of technical information about control systems, most notably via publicly available and/or shared networked resources such as the Internet.

To succeed in their attack on control systems, entities or malicious individuals may use one of the following methods [1]:

- Disrupt the operations of control systems by delaying or blocking the flow of information through the networks supporting the control systems, thereby denying availability of the networks to control systems’ operators and production control managers;
- Attempt, or succeed, at making unauthorized changes to programmed instructions within PLC (programmable logic controller), RTU (remote terminal unit), or DCS (distributed control system) controllers, change alarm thresholds, or issue unauthorized commands to control station equipment, which could potentially result in damage to equipment, premature shutdown of processes (shutting down transmission lines or causing cascading termination of service to the electrical grid) or rendering disablement of control station equipment;
- Send falsified information to control system operators either to disguise unauthorized changes or to initiate inappropriate actions to be taken by systems operators;
- Modify or alter control system software or firmware such that the net effect produces unpredictable results (such as introducing a computer “time bomb” to go off at midnight every night, thus partially shutting down some of the control systems, causing a temporary brownout condition; a “time bomb” is a forcibly introduced piece of computer logic or source code that causes certain courses of action to be taken when either an event or triggered state has been activated);
- Interfere with the operation and processing of safety systems;
- Many remote locations containing control systems (as part of an enterprise DCS environment) are often unstaffed and may not be physically monitored through surveillance; the risk of threat remains and may be higher if the remote facility is physically penetrated at its perimeter and intrusion attempts are then made to the control systems’ networks from within.

3. CYBERSECURITY [3]

Computer security, also known as cybersecurity or IT security, is the protection of information systems from theft or damage to the hardware, the software, and to the information on them, as well as from disruption or misdirection of the services they provide.

Cybersecurity for the power industry covers all issues involving automation and communications that affect the operation of electric power systems and the functioning of the utilities that manage them.

In the power industry, the focus has been almost exclusively on implementing equipment that can improve power system reliability. Until recently, communications and information equipment have been considered of peripheral importance - they were often seen as just another isolated piece of equipment to help achieve power system reliability. However, increasingly the reliability of this information infrastructure has become critical to the reliability of the power system.

SCADA systems, essential utilities, and telecommunications rely on information technology for the management of their everyday operations with greater volumes of susceptible economic and commercial information being exchanged electronically over potentially insecure channels all the time. The massive increase in complexity and interconnectivity coupled with simple point and click attack tools has appreciably amplified the necessity to ensure the privacy, security, and availability of information systems.

The threat agents acting against SCADA systems exist in several general categories. Any of the following may be a source of threat that can lead to an incident:

- Accidental antagonists who causes you harm through ignorance or by negligence;
- Incidental antagonists who seek another target but attack because you are there and obtainable;
- Insiders. They may compromise or steal information assets because of motivations from dissatisfaction to economic gain;
- Competitors may attack to gain a benefit or to achieve market dominance.
- Cyber vandals;
- Hackers and crackers;
- Thieves that may attack to further their own financial well-being;
- Terrorists can attack in order to disrupt the connection linking the general public and critical infrastructure.
- The military involved in information warfare actions.

In the Smart Grid, there are two key purposes for cyber security:

- Power system reliability: Keep electricity flowing to customers, businesses, and industry. For decades, the power system industry has been developing extensive and sophisticated systems and equipment to avoid or shorten power system outages. In fact, power system operations have been termed the largest and most complex machine in the world. Although there are definitely new areas of cyber security concerns for power system reliability as technology opens new opportunities and challenges, nonetheless, the existing energy management systems and equipment, possibly enhanced and expanded, should remain as key cyber security solutions.
- Confidentiality and privacy of customers: as the Smart Grid reaches into homes and businesses, and as customers increasingly participate in managing their energy, confidentiality and privacy of their information has increasingly become a concern. Unlike power system reliability, customer privacy is a new issue.

Cyber security solutions must be implementation-specific, driven by the configurations, the actual applications, and the varying requirements for security of all of the functions in the system. Typically, security requirements address the integrity, confidentiality, and availability of data. However, in the Smart Grid, the complexity of stakeholders, systems, devices, networks, and environments precludes simple or one-size-fits-all security solutions.

3. HARDWARE AND SOFTWARE PROTECTION MECHANISMS

Implementation of SCADA Smart Grid information security involve that supplier will have to implement policies, concepts, solutions and equipment to ensure information security risk the lowest possible and a minimal vulnerability to cyberattacks. The provider must ensure that the key safety information proposed satisfy the security policies, concepts of information security adopted by TSOs and the use of equipment or software modules for information security implementation in SCADA Smart Grid system and integration with SCADA station, such as:

- Data Diode for physical isolation from other systems when unidirectional data transfer occurs;[4]
- UTM (Unified Treat Management) to secure access if bidirectional data is transferred;
- UTM and WAF (Web Application Firewall) to publish data on the Internet and / or safe access to web-based applications;
- VPN tunnel / Encryption;
- Login with user name and token.

The main issues that any supplier must meet to ensure the security of Smart Grid are:

a) Policy on cyber security for SCADA and Smart Grid SCADA station [3]

Identification and assessment of the following types of connections:

- Internet and local area networking areas including extensive networks of third parties;
- Wireless devices / GSM (Global system for Mobile Communications) / GPRS (General Packet Radio Service) / 3G Internet / LTE (Long Term Evolution);
- Dial-up modem
- Connections to business partners, suppliers and regulatory agencies

b) Switching off unnecessary connections from the SCADA and Smart Grid SCADA station

To ensure the highest degree of security of data networks network data is isolated as much as possible from other network connections. (Any other network connection introduces new security risks, particularly when the connection creates a route of transmission to or from the Internet). Strategies stringent are recommended as the use of " demilitarized zone " (DMZs) and " data storage 'that ensures secure transfer of data between data network SCADA Smart Grid and SCADA station, "Core LAN" (MZ – “militarized zone”) and networks to third parties.

c) Assessing and enhancing security of any remaining connections to the SCADA data network

Will be performed penetration tests and vulnerability analysis of data network connections to evaluate the protection of data network system. Data network system is as secure as the weakest point of connection, it is imperative implementation of security systems, intrusion detection and other ways appropriate to measure safety at any point Interface.

d) Smart Grid SCADA network data security is based on removing or disabling unneeded services.

Control of the server’s network system data built on commercial operating systems or open-source can be exposed to attacks via the default network services, removing or disabling unused network and bullets, until the risk of direct attack is reduced. In addition, close cooperation with suppliers of data system that identify secure configurations and coordinate all changes to operating systems, ensure the removal or disabling the services to not cause downtime, disruption of service, or loss of support.

e) The use of the security features offered by the system devices

Owner’s data systems should insist that the system provider implement security functions in the form of patches or upgrades. (Some systems come with basic security functions, but they are usually turned off to ensure ease of installation). Analyze each device system to determine whether security functions are present. In addition, factory default security settings (such as network firewalls computers) are often designed to provide maximum usability, but minimal security. Setting all security features to ensure maximum security.

f) Establishing control using remote access / RRAS / VPN network.

If there is remote access or connection provider's data system, then it should be implemented a strict authentication to ensure secure communications. Modems, wireless sites and network communications of any kind used for maintenance presents a significant vulnerability on data network system. To reduce the risk of such attacks, it is recommended to disable access and direct entry to use a callback philosophy.

g) Implementation of internal and external systems for monitoring intrusion detection and determination for incidents 24 hours a day

In order to respond effectively to cyberattacks, it will be necessary setting out a strategy for intrusion detection, which includes alerting network administrators in relation to malicious network activity coming from internal or external sources. Also, intrusion detection system monitoring is recommended 24 hours / day. To complete network monitoring, logging and daily control records are allowed on all systems to detect suspicious activity rapidly. Constantly monitored data, alarms and critical events will be signaled to TSOs administrators by both critical alarm files, SMS, information transmitted on dashboards operating.

h) Making physical security studies and remote network assessment data to evaluate the security system

Any location that has a connection to the data network system is a possible target, especially places without the personal or unsupervised. Make a security survey and inventory of physical access to each facility that has a connection to the data system. (Identify and assess any sources of information, including remote access via telephone / computer network / fiber optic cables, which could be accessed, radio links and microwaves are exploitable, computer terminals, which could be accessed and access points in wireless local network). Security location should be suitable for detection and intrusion prevention. It is not allowed to access the network in real time remotely from unsafe locations.

i) Defining cyber security roles, responsibilities and authorities for managers, system administrators and users

Staff organization must understand the specific demands associated with protecting information technology resources by defining clear roles and clear and logical responsibilities. In addition, key personnel must have sufficient authority to discharge their allocated responsibilities. (Often, cyber security is left to individual initiative, which typically leads to inconsistent and ineffective security implementations). Establish an organizational structure for cyber security, which defines roles and responsibilities and clearly identify how cybersecurity issues are considered and who is notified in an emergency.

j) Establishing a rigorous risk management

Understanding the sources of risk calculation network from attacks and denial-of-service vulnerability that could compromise sensitive information is essential for an effective global cyber-security protection and identification of points of failure. Due to rapidly changing technology and the emergence of new threats every day, a continuous process of risk assessment is necessary so that the routine of protection strategy ensure that security remains in effect).

4. CONCLUSIONS

Traditional power systems are moving towards digitally enabled Smart Grids which will enhance communications, improve efficiency, increase reliability, and reduce the costs of electricity services.

One of the increasingly visible issues of supervisory control and data acquisition (SCADA)/control systems security deals with the disclosure of vulnerabilities; whether the vulnerabilities are disclosed within a public venue, or closed confinement, continues to be a heated debate of those close to this effort. As this community continues to evolve, many are observing some progress being made regarding security-related vulnerabilities, research, and disclosure, along with the many interesting issues that have come and gone.

Over time, one of the largest challenges (realistically, *the* biggest challenge) is to educate all stakeholders within this community, such that they recognize the complexity of many of these issues discussed in this paper, while assuming responsible courses of action, and continuously improving the security posture of their systems, regardless of whether they are an owner/operator, an integration vendor, a SCADA/control systems manufacturer, or an independent researcher performing analysis against these systems. Ideally, the responsibility falls on all of us.

BIBLIOGRAPHY

[1] Radvanovsky, R., Brodsky J., *Handbook of SCADA / Control systems security*, the 2nd edition, CRC Press, 2016.

[2] Frances Cleveland Xanthus Consulting International, *White Paper: Cyber Security Issues for the Smart Gris*, NIST CSWG, Dec 28, 2009.

[3] U.S. Departament of Energy, *21 Steps to Improve Cyber Security of SCADA Networks.*

[4] Waterfall Security Solutions Ltd., *Unidirectional Security Gateways as Secure Alternatives to Firewalls and Network Intrusion Detection Systems*, 2014.

.

CIGRE Regional South-East European Conference - RSEEC 2016 (3rd edition)
October 10th - 12th 2016, University "Politehnica" of Bucharest, Romania

#104

Sensitivity based analysis of voltage and reactive power in HV power grids

L.-G. MĂNESCU*[1], D. RUŞINARU[1], M. CIONTU[1], M. ALBĂ[2], P.C.STROICĂ[3]
[1]UNIVERSITY OF CRAIOVA INCESA, [2]CEZ DISTRIBUŢIE, [3]Transelectrica S.A.
[1, 2, 3]Romania

SUMMARY

The reactive power flows affect voltages, losses and transmission capacities. Thus MVAR flows are a matter of increasing concern for the grid operators. The latest corresponding regulation for Romania allows the grid operator to exonerate of payment those injections of reactive which affect in a positive manner positively the voltages in the network. Such exemption is difficult to apply since the influence of MVARs on voltages is locational and time dependent. This paper proposes a sensitivity based analysis for a real 110 kV network. The survey is conducted for 6000 hours and outlines voltage to sink's MVARs.

KEYWORDS

Voltage sensitivity – reactive power compensation **-** optimal placement – voltage control.

1. INTRODUCTION

Reactive power is a topic of constant concern in modern electric network operation. Nowadays everyone agrees on the drawbacks of reactive power: affects voltage magnitude [1], increases losses [2], reduce available transmission capacity (ATC) of the network [3] etc. Transmission and distribution companies are interested in reducing reactive power flows [4], mainly by compensation or reciprocally cancelling [5].

The synchronous generator is the most common source of reactive power. It can deliver MVARs at opportunity costs. Another traditional reactive power, spinning too, is the synchronous compensator. This one can has no active load and produce more expensive MVARs. The new generation of reactive power sources, employed for compensation purposes as well as for system control, consists of flexible AC transmission devices (FACTS): thyristor controlled reactors (TCR), static VAR compensators (SVC), shunt static synchronous compensator (SSSC) and static compensators (STATCOM), [6], [7].

The features and capabilities of the reactive power sources become very important in a competitive market environment. The cost characteristics of the solutions able to supply the required reactive powers in secure steady state and dynamic operational conditions are of great importance. These elements are to be refereed in conjunction with the sensitivities of individual elements, depending mainly on their location in the network, [8].

The compensation of the reactive power is mainly directed towards voltage control. Optimal voltage control through V/Q ancillary service looks also for loss reduction and capacity relieve for hosting additional flows.

The reactive power problem is rather local: one inductive flow seeks to pair with the leading reactive power of the nearest capacitive element. In most cases the consumers are inductive and they

* leman78@hotmail.fr

shall be compensated either by neighboring under loaded lines or specific compensator.

However, transformers and transmission line exhibit own reactive powers, which depend on the system load. Nobody pays for these reactive powers, either beneficial or not for the network operation.

2. COMPENSATION OF REACTIVE POWER

Various methods are available for evaluating the effect on voltage control of reactive power injections on voltage control [references].

2.1. Marginal sink variation method

This outlines IQ contributions to voltage upholding for marginal sink variations. The sensitivity of IQ at bus i to the marginal variation of sink from bus j is:

$$SQ_{ij} = \frac{dQ_i}{dS_j} = \frac{dQ_i}{dU} \cdot \left(\frac{dS_j}{dU} \right)^{-1} \tag{1}$$

where dQ_i is IQ at bus i which maintains voltage if sink at bus j varies of dS_j.

The overall sensitivity of IQ at bus i is the sum of equations (1) for all sinks:

$$SQ_i = \sum_{j=1}^{c} SQ_{ij} \tag{2}$$

with c – no. of consumers.

The IQ sensitivity of all the g reactive "sources" to a marginal variation of the sink from node j is:

$$S\Sigma Q_j = \sum_{i=1}^{g} SQ_{ij} \tag{3}$$

Full IQ sensitivity to all sink marginal variations becomes:

$$S\Sigma Q = \sum_{i=1}^{g}\sum_{j=1}^{c} SQ_{ij} = \frac{\sum_{i=1}^{g} dQ_i}{dV} \cdot \left(\frac{\sum_{j=1}^{c} dS_j}{dV} \right)^{-1} \tag{4}$$

Sensitivities from (1) … (4) allow to compare technical efficacy of As-U/Q service provider bids. However, these sensitivities deliver no systematic way for ranking bids.

2.2. P/V curves method

In this method the loads are increased not by a marginal value, as in the previous section, but until the system reaches the stability limit. The scenario is chosen to fulfill the purpose of the analysis (e.g. we can increase only the consumption from a region, at various quotas, at constant/variable power factor).

The issues aren't wide-ranging. Moreover, the selection of the scenario can be critical.

By simulating a consumption ($\Delta S_j \big|_{j=1,\ldots,c}$) increase up to the stability limit, balanced by AGC units (all others remaining PU buses at constant specified voltages and powers) we get the IQ variations, ΔQ_j. Various specified voltages can be utilized.

The appraisal of different IQ, reveals the efficacy of each reactive power "sources". The conclusions are useful rather for security analysis than for assessing As-U/Q tariffs.

2.3. Fictitious compensators method

When the IQs change, voltages alter. Fictitious compensators at each PQ bus can restore system voltages.

We denote by $Q_j^{(x)}$ the IQ of the As-U/Q service provider from bus j in regime x and $Q_j^{(\min)}$ its

IQ minima (lower edge of secondary range for voltage regulation from Figure 1). For synchronous compensators and static „sources" we let $Q_j^{(\min)} = 0$.

By simulating a variation $\Delta Q_j^{(S)}$:

$$\Delta Q_j^{(S)} = Q_j^{(x)} - Q_j^{(\min)} \tag{5}$$

we determine the Iqs of the fictitious compensators which "replace" the missing injection. For a load at bus i, the resulting fictitious IQ, $\Delta Q_i^{(C)}$, defines its "duty" for the $\Delta Q_j^{(S)}$ service. Because $\Delta Q_j \neq \sum_i \Delta Q_i^{(C)}$, the "duties" aren't normalized and must be shared (e.g. pro-rata: load i pays to provider j matching to: $\left(\Delta Q_i^{(C)} \Big/ \sum_i \Delta Q_i^{(C)} \right) \cdot \Delta Q_j^{(s)}$).

2.4. Back-up generation method

An IQ, $\Delta Q_j^{(S)}$, can be "replaced" not only by a fictitious compensator, but also by the IQ of another As-U/Q provider. For the provider from bus k we note:

- $\Delta Q_k^{(x)}$ IQ in the regime x;
- $\Delta Q_k^{(\to \min_j)}$ IQ in the regime having the same voltages as in *x*, and $Q_j = Q_j^{(\min)}$.

We can consider that the IQs $\Delta Q_j^{(S)}$ (at bus j) and $\Delta Q_k^{(\to \min_j)}$ (at bus k) are equivalent. This statement is very useful for assessing tariffs for As-U/Q service in the operating regime x.

2.5. dV/dQ sensitivity method

The voltage sensitivities to IQ describe a widespread tool in voltage control. The reactive power injection at bus k meant to correct the voltage at bus i of about ΔU_i is:

$$\Delta Q_k = \frac{\Delta U_i}{S(U_i, Q_k)} \tag{6}$$

where: $S(U_i, Q_k) = \dfrac{\vartheta U_i}{\vartheta Q_k}$ (7)

is the reverse, $(= \vartheta Q_k / \vartheta U_i)$ of the corresponding element of the Jacobian.

Equation (6) exhibits that the voltage at bus i can be equally corrected by an IQ of:

$$\Delta Q_j = \Delta Q_k \cdot \frac{S(U_i, Q_j)}{S(U_i, Q_j)} \tag{8}$$

at bus j or by an injection of ΔQ_k at bus k.

For voltage regulation at bus i:

- (6) defines the required amount of challenging injections for voltage correction;
- (8) states the tariffs' ratio for two IQs at buses j and k, which are equivalent in voltage "correction": $S(U_i, Q_j) / S(U_i, Q_j)$.

3. ROMANIAN REGULATION FOR REACTIVE ENERGY

The Romanian Regulatory Authority for Energy - ANRE has settled new guidelines for coping with reactive power matter and specific tariff issues in [9]. All basic elements are explained in this order; definitions, conditions, formulas and computing methodology for the reactive energy payments.

This regulatory norm states that lagging reactive energy (inductive) and leading reactive energy (capacitive) have not to be compensated any more into the final invoice. Each of them entitles for separated payments. From this point on, if power factor falls below 0.65 than the tariff for reactive energy, inductive or capacitive, becomes three times higher than for power factors between 0.65 and

0.92. This rule intends to discourage the consumers to run al low power factors. In such cases, inductive loads draw from the network and capacitive ones inject into the network massive reactive power. Thus reactive flows related to the consumers' reactive powers become even more harmful for the network producing additional losses, excessive voltage drops and diminishing of the available transmission capacity.

In order to stimulate the positive behavior of the consumers and to reward those which have a positive impact on the voltage regulation the ANRE Order 33/2014 states the conditions required in order to exonerate network users of their payments for reactive. This addresses prosumers which:

- participate to the V/Q regulation, under the command of the network operator, for the energy exchanged injected in/drawn from the network during this service;
- contribute to the improvement of the voltage level by injecting or drawing reactive power.

The second case seems unsharp because it lacks of practicality in defining the benefit of reactive power injections on voltage regulation service. This opportunity could entitle a prosumer having sometimes fortunate V/Q sensitivity to wait to be exonerated for the reactive energy exchanges with the network. In order to characterize the true contribution to this service over a time period, an in depth analysis, as in section VI is required.

After applying this Order in the last 18 month, ANRE has published some global outcomes and has decided to continue applying it with minor changes and updates, [10]. The results are as follows:

- the inductive energy billed raised with 15% for power factors between 0.65 and 0.92 and with 25% for users operating at power factors bellow 0.65;
- the capacitive energy payments have increased by 12% for power factors between 0.65 and 0.92 and by 200% for users operating at power factors bellow 0.65.

The last case corresponds to situations where capacitive power is injected in under loaded network region and has to be hardly discouraged. All these results entitled the Regulatory Authority for Energy from Romania to maintain this rules and to correct some descriptions. Moreover, the network operators where asked to apply exonerations solely based on in depth analysis and measurements. Thus only beneficial reactive powers have to be rewarded. All the others have to be penalized according to their perturbing effect.

In the following section the opportunity of ANRE regulation regarding the reactive power tariff is analyzed by considering a set of operation regimes for a 110 kV distribution network. The presented study cases outline the influence of reactive power on the voltage level by using multiple analysis approaches.

4. EVALUATION OF REACTIVE POWER INFLUENCE ON GRID VOLTAGES

The considered study cases have considered a HV 110 kV distribution network configuration. The survey is conducted for 6000 hour. In order to evaluate the influence of the reactive power flows on the voltages in the test distribution network the authors propose basically three approaches: firstly, by direct comparison of two simulation cases (the real operation of the test network vs. the suggested compensated configuration); secondly by using an interpretation of sensitivity based analysis in the buses of the test network; finally, by analyzing the information given by Q-V curve.

4.1. Direct simulation

According to this approach, two cases are considered in order to perform a comparative analysis. There is considered the real normal operation of the test HV network. The power flow analysis is performed and the bus voltages are generated. The output data is consequently compared with the values resulting by analyzing the network operation after the reactive power was totally compensated in an interest consumer bus.

The method is rather inefficient for studying long time operation, since the number of the analyzed steady regimes is practically doubled.

By exemplification, the F2 bus is considered – see Fig.1. The bus voltage increase by comparison with the case of nil reactive power injection is 0.02 p.u. - see in Fig. 2.

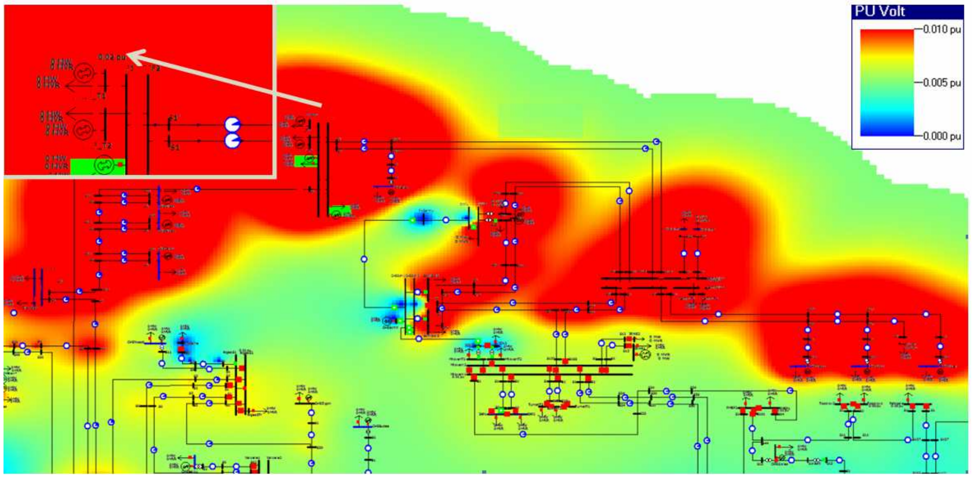
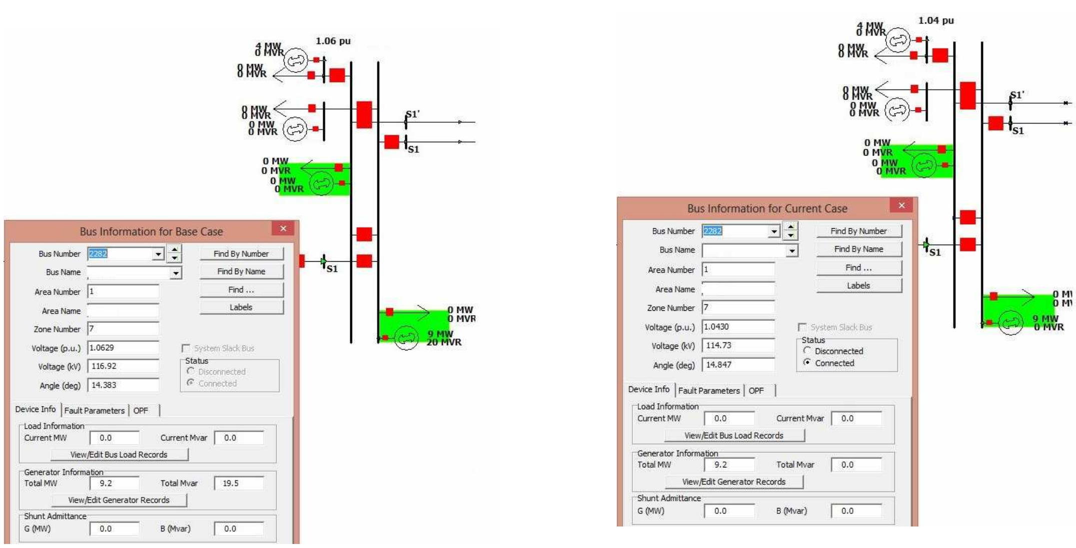


Figure 1: Illustration case - map of bus voltage variations in the test network determined by Q injection in the controlled bus #F2



a. b.

Figure 2: Voltage of the compensated bus F2: a. Q injection of 19.5 MVAr; b. zero reactive power injection

4.2. Sensitivity dV/dQ based analysis

This approach is facile to use. Nevertheless it does not give information about the effect on the voltage in far placed buses.

The dV/dQ sensitivities depend on the network's configuration and parameters, as well as the voltage control in the area. The differences of the two analyzed operation regimes refer only at the power injections MW/MVAr's in the HV network.

For the analyzed bus case a reduced dispersion can be observed for these parameters: i.e. around 10^{-3} on the analyzed time interval (6000 hours) – see Fig.3. Therefore a value equal to 10^{-3} can be considered as reference for the sensitivity.

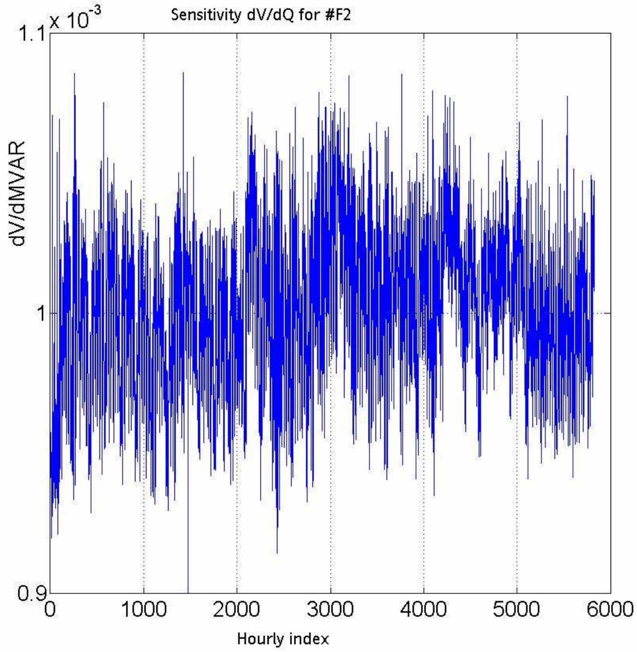


Figure 3: 12 month evolution of sensitivity dV/dQ for the analyzed bus #F2

For the analyzed case (bus #F2) by annulling an injected reactive power of 19.5 MVAr the voltage decreases with approximately 10^{-3} x 19.5 MVAr ≈ 2%, as it can be seen in Fig. 4.

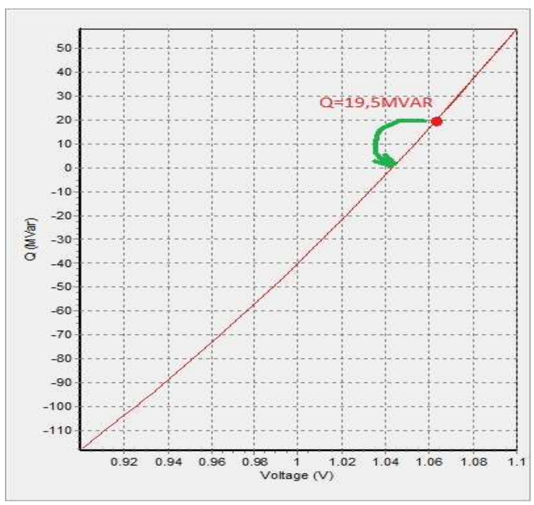


Figure 4: Sensitivity dV/dQ for the analyzed bus #F2

In the same manner it is also possible to analyze the influences of other buses' injections on the voltages in the network since the relationship cause-effect is analyzed separately – e.g. Fig. 5. The sensitivities are more volatile and more difficult to be reached. Therefore an estimation of these sensitivities based on the own injections (Q-V in the same bus) is preferred although there is a risk of a lower precision.

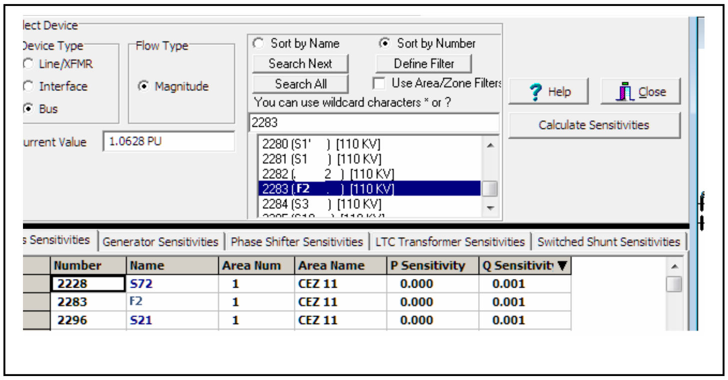


Figura 5: Influence of Q variation in the analyzed bus on the voltage of other buses of the network

3. Q-V curve based analysis

The Q-V curve indicates the value of reactive power injected in the bus so that its voltage to be brought to the target value – e.g. Fig. 6.

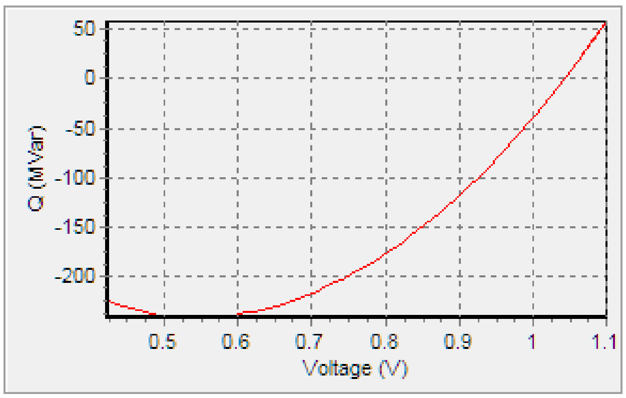


Figure 6: Q-V curve for the analyzed bus #F2

The operation point is far of the instability area and the slope of Q-V characteristic (sensitivity V/Q) is almost linear for the voltage's admissible band of 0.9…1.1. The slope of the Q-V characteristic is equal to 10^{-3} in this area.

5. CONCLUSIONS

The reactive power compensation is considered the most efficient method for voltage control in the power networks (V-Q dependency).

The control efficiency is evaluated based on the sensitivities of the voltages to the reactive power injections (dV/dMVAr).

This type of analysis allows identifying the critical areas by considering the voltage control. Consequently, the proper recommendation regarding using the existent structure or further investment in new compensation can be made.

BIBLIOGRAPHY

[1] C. W. Taylor "Power system voltage stability" (McGraw-Hill Inc., US 1994).

[2] P. Kundur, N.J. Balu, M.G.Lauby "Power System Stability and Control" Electric Power System" (McGraw-Hill, 1994).

[3] J. Angelov, R. Taleski "Total Transfer Capacity Calculation with Consideration of Reactive Power Constraints" (Periodica Polytechnica Electrical Engineering and Computer Science 59(3), pages 58-63, 2015).

[4] L. Haddadi, A.P.Neghab, S.N.Mozafari, M.G. Slamroodi "A Study of Reactive Power Requirements of Traditional and Restructured Power System", (Journal of Electrical and Electronic Engineering Volume 3, Issue 2-1, March 2015, pages: 101-106).
[5] W. Hofmann, J.Schlabbach, W.Just "Reactive Power Compensation: A Practical Guide" (Wiley 2012).
[6] A. Narain, S.K.Srivastava "An Overview of Facts Devices used for Reactive Power Compensation Techniques" (International Journal of Engineering Research & Technology (IJERT) Vol. 4 Issue 12, December-2015).
[7] D. Murali, M. Rajaram, "Active and Reactive Power Flow Control using FACTS Devices" (International Journal of Computer Applications 0975 – 8887 Volume 9– No.8, November 2010).
[8] H. Singh, A. Papalexopoulos, "Competitive Procurement of Ancillary Services by an Independent System Operator" (IEEE Trans. on Power. Systems, Vol. 14, No. 2, May 1999, pages 498–504).
[9] ANRE "Methodology regarding establishing of the payment obligations for reactive electrical energy and regulated price for reactive electrical energy" (ANRE Order 33/2014).
[10] ANRE "Annually report regarding the activity of National Authority for Energy Regulation" (April 2015).

.

AUTHORS' INDEX

Papers of RSEEC 2016