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    - *replacement* of steam turbine drivers with electric motors
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    - *integration* of renewables and storage into electrical systems. Electrons are the new molecules!
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    - use cases (*case studies*)
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FIRST OIL & GAS APPLICATION OF A HYBRID POWER PLANT INTEGRATING: SOLAR PV - ENERGY STORAGE – CONVENTIONAL POWER GENERATION (GTG)

Paper No. PCIC Europe EUR21_01

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Abstract - A hybrid Power Plant solution integrating Solar PV, Energy Storage and conventional Power generation (i.e. Gas Turbine Generators) is applied for the first time to an Oil&Gas facility.
An existing Oil&Gas Plant fed solely by conventional power generation is being upgraded with the installation of Solar Power Generation and Battery Energy Storage. The integration of these new systems has allowed the Operator to obtain gas savings and reduction in CO_2 emissions.
This paper provides insights into the project presenting the technical challenges and selection process that have been followed during project development and a technical overview of the configuration selected.

Index Terms — Renewables, Energy Storage, Hybrid Power Plant.

I. INTRODUCTION

The project described in this article falls under the Eni green investments initiatives to develop innovative energy solutions with a low environmental impact. The aim is to promote the development of renewable energies, stimulating technological research and supporting their spread in the countries in which Eni operates. Eni has explored the possibility to integrate renewable resources to existing Oil&Gas facilities in order to both reduce CO_2 emissions and increase gas valorization while maintaining the overall Plant availability unaltered. Eni has decided to conduct a “Pilot” project on a mature field of medium size in order to evaluate its feasibility, time, cost, adverse events, and improve upon the study design prior to investing in a full-scale project. Various scenarios have been evaluated (i.e. Full, Minimum, Hybrid) from both technical (e.g. battery technology and configuration selection) and economical point of view (e.g. battery cost, gas savings). This paper presents in detail the selected option with particular focus on the BESS (Battery Energy Storage System) configuration.

II. INTEGRATION CONVENTIONAL – RENEWABLES GENERATION

A. Conventional Generation: Vendor Engagement

The Plant is located in North Africa in a desert area. The existing main power generation system consists of two Gas Turbine Generators (GTGs) with an available output of about 10 MW @ 15°C (6.6 MW @ 50°C) each. The current maximum power demand is approximately 6.1MW. The current operating configuration is based on one out of two GTGs running (i.e. 1+1: one running and one cold stand-by unit). The loss of one GTG will cause shutdown of the facilities and the loss of production. This is considered acceptable based on the current oil and gas production levels. The first phase of the project has required an in depth investigation on the existing GTGs. After engaging with the GTG supplier, the project team has established two main characteristics of the GTG:

- the minimum generator loading that can be applied continuously without compromising the machines design life. Minimum GTG loading equals approx. to 30% of rating at ISO Condition (i.e. 50% of rating at worst site conditions) that equals to 3.3MW.

- GTG capability to handle sudden load variations. The maximum step load that can be accepted by one GTG is approximately 15-20% of the total power output that equals to approx.1 MW.

The system design has been based on the above values.
The selected standard operating mode of the GTG requires a reduced loading during daylight (i.e. 3.3MW). The gap in the power demand is then covered by the Photovoltaic (PV) system. Stability studies have confirmed that the GTG cannot recover on its own the loss of the entire PV plant (due for instance to sand storms or cloud cover), but with the contribution of a BESS it has been calculated that a full recovery of the system can be achieved within a delta *t* of 10 sec. It is to be noted that the GTG takes the plant full load at night with the exceptions described in the following sections.

B. Renewables System Sizing

The solar system has been selected based on plant location and power requirements.
Global Irradiation of selected site is 5.1-7.3 kWh/m^2 per day, with around 2,300 sunshine hours/year. Maximum irradiation is approximately 100 W/m^2 during Summer season.
Particular attention has also been paid during equipment selection to identify a system could operate in a desert saliferous environment with wide temperature variations between night and day.

Based on the above meteorological conditions and ageing factor, the PV system selected was:

Rating:	**5MWp d.c.**
No. Modules:	**16,200**
Area:	**10.6 ha**
Module Peak Power:	**325 Wp**
Annual Energy:	**8.6 GWh/y**
Cell type:	**Polycrystalline**

The selected configuration guarantees an average power production of 2.8MW.
Based on a technical and economical assessment, the “Night option” has been discarded at an early stage of the design due to the high Capital Expenditure (CAPEX). The “Night Option” is defined as the scenario when the full contribution of the solar plant (i.e. 2.8MW) is replaced entirely by the BESS.

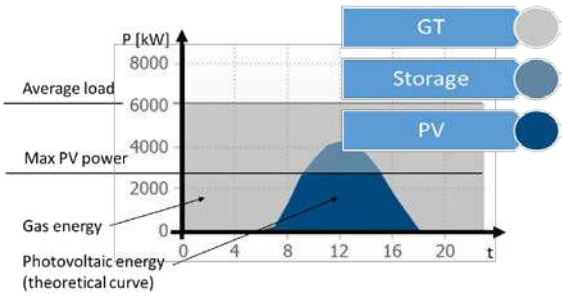

Fig. 1 Power contribution (MW) during the day

The peak a.c. power production of the PV system is approximately 5MW at site solar radiation. However, power production is capped automatically by the new PMS (Power Management System) to limit the power to the Plant to 2.8MW. This value is based on the minimum technical load factor of the GTGs. PMS will control the power generated from the PV system based on load configuration and hence generation load factor. The excess power generated from PV plant is therefore dedicated to the charging of the batteries.
Both PV System and BESS are connected to the main 20 kV Switchgear (refer to Annex A) via DC/AC inverters.
Because the PV plant is not designed to maximize its power output, it is to be noted that a tracking configuration has not been considered.

Configuration of PV power stations and design is based on Eni internal standardization.
The PV plant consists of 3 Power Stations (two Power stations rated 2 MW and one Power Station rated 1 MW).
All Power Stations are connected to a main 20kV Medium Voltage Switchgear located in the Main technical Room. The PV system is then interconnected to the existing Oil&Gas Plant via step-down transformer 20/11kV and cable connection.
PV Modules are collected in string of 20 Modules each; Strings are collected in Arrays and connected to String Boxes.
The Photovoltaic plant, and all relevant components, have been designed to communicate with a SCADA (Supervisory Control and Data Acquisition) System that receives from the nearby plant the relevant operation parameters. The plant is conceived to be operated completely unmanned in a non hazardous area at approximately 2km from the existing facilities.

C. Transient Analysis

The PV Plant power production is weather-dependent because solar irradiation can be affected by clouds and sand storms. In the ideal scenario the PV plant power production gently increases and decreases following solar radiation. PV power production during the day is generally represented with a curve which shows PV power production raising until noon and then decreasing. This is shown in Figure 2.

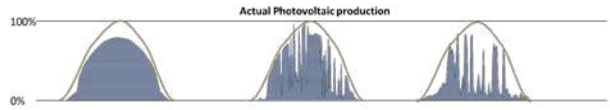

Fig. 2 PV power output vs clouds cover

In the real world, the PV production may be:
- Lower, during winter seasons (i.e. the grey area in the left chart);
- Following the theoretical curve, but intermittent, due to partial cloudy days – i.e. the central chart;
- Severely intermittent, during cloudy days (i.e. chart on the right).

In a «theoretical» day, no battery would be required.
However, the real scenario is when clouds or sand storms limit solar radiations causing PV plant power production suddenly to drop; without BESS, if the reduction in PV output is greater than the maximum step load acceptable by the gas turbine generator, the electrical system would shut-down, causing a loss of production.
A battery system is needed to smooth the transient in the PV power output. The removal of large load steps avoids situations of power generation black-out. The BESS selected allows transient load variations to be within system stability envelope.
The graph below describes the worst case scenario where a full loss of PV power input during daylight occurs.

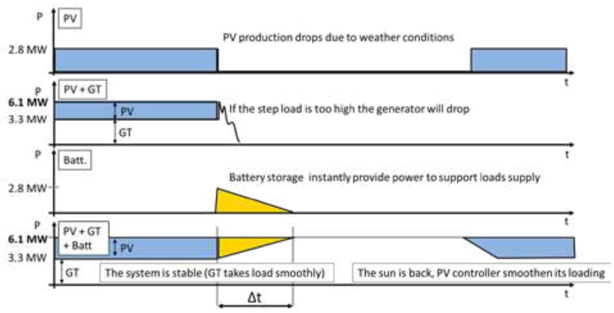

Fig. 3 BESS intervention during PV power output drop.

During the Front End Engineering Design (FEED), a comprehensive dynamic stability study has been carried out in order to select the optimal solution. Various scenarios have been evaluated covering the most significant perturbances the system could be subject to. Figures 4, 5 and 6 show the model output of the stability study for the worst case scenario.

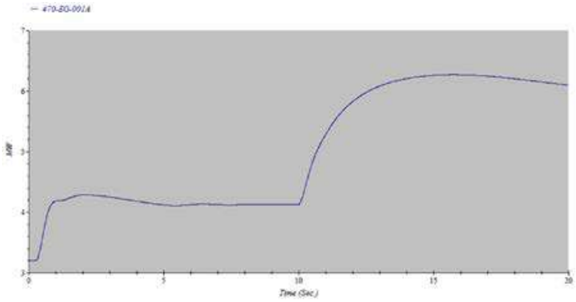

Fig. 4 GTG Power output

The governor system of the GTG is able to provide the required mechanical power to ensure stability. First step is limited to 1.2 MW by the presence of the BESS. Second step shows when the Battery Storage is disconnected.

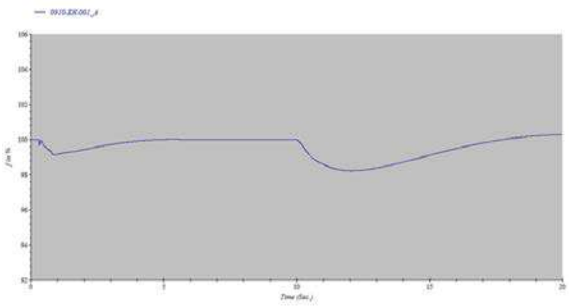

Fig. 5 GTG Frequency

The system frequency during the transient is within the admissible ±2% variation, preventing the frequency protections to trip, as per figure 5.

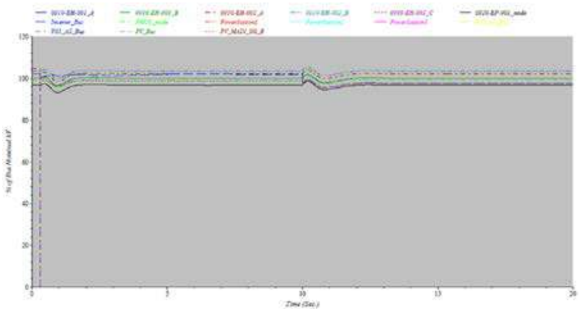

Fig. 6 Bus voltages

All main bus voltages are maintained within ±10% of their rated voltage.

D. Battery Technology Selection and Sizing

The Storage System has the objective to cover the power variations of the PV plant in order to reduce the step load of the gas turbine generator and ensure Plant electrical network stability.

During daylight, the irradiation cannot be considered constant due to clouds cover, sand storm etc. These phenomena can cause load steps larger than those acceptable by the GTG.

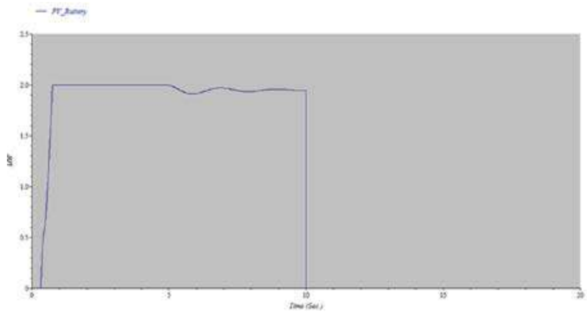

Fig. 7 BESS Power output during transient.

In order to maintain network stability, the gap in PV power generations are to be compensated by the contribution of a BESS system.

Figure 7 shows a typical BESS power output during a loss of PV system output. Peak generation is about 2 MW within 0.5 s, then power supply is disconnected after 10 s since stability is already achieved, saving battery charge.

The selected battery technology for the battery system is Power Intensive type. This is due to the fact that a very short response time (0-100% in 200 ms) and high energy release is required. Figure 8 shows the selection diagram for the battery type. Li-Ion Batteries have been selected.

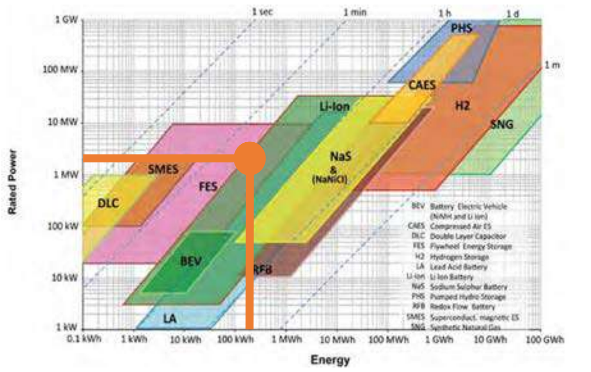

Fig. 8 Battery Selection Chart

The BESS selected rating is: 1 MW/1.7 MWh (2.8 MW for 30 minutes); Number of Cycle: 5000 at Depth of Discharge = 90%.
Further details are given in Section III.

III. SELECTED HYBRID SCHEME

E. System Functional Description

The functional scheme of the Hybrid system is shown in Figure 9.

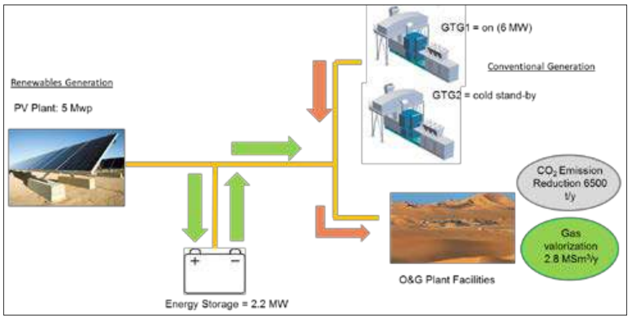

Fig. 9 Hybrid Concept

The system has been designed for a design life of 20 years. The main new sub-systems are now presented here below:

1) *PV Plant:*

The PV plant has been designed in order to:

- Facilitate a defined amount of active power flow (from PV source) to Plant electric users while the remaining of the power is generated by the GTG with a load factor higher than 50%
- Avoid any destabilization/trip of existing plant facilities
- Avoid harmonic resonances with existing electrical distribution

Based on the above objectives, the PV Plant has been sized to have an installed peak capacity of 5 MWp and an estimated average annual energy output of 8.6 GWh/y.

It includes about 16,200 PV panels (polycrystalline silicon type) facing southward with a fixed tilt angle of 30°. PV panels configuration is fixed-mount.

PV plant is directly connected to the existing Oil&Gas plant, which is electrically isolated (not connected to any external electrical grid).
Electrical power is generated by the PV plant at 20 kV. Voltage level is then reduced via a Step-down Transformer to 11 kV and delivered through an underground cable (length 1,500 m) to an existing 11 kV Switchgear. The existing 11 kV Switchgear includes a spare incomer which has been dedicated to the PV Power Plant connection.

The selected layout of the PV plant is shown in Figure 10.

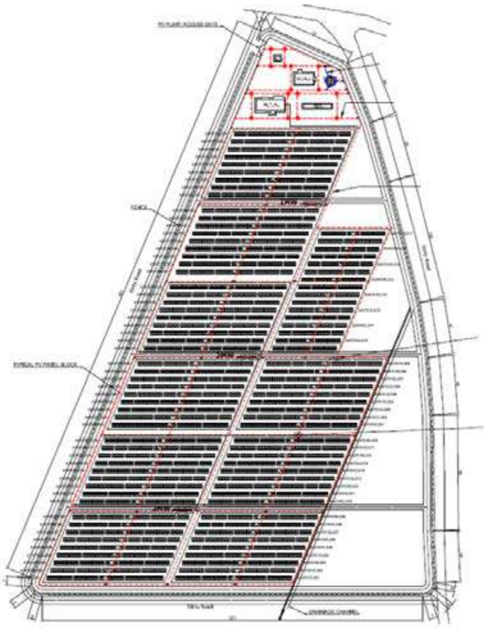

Fig. 10 PV Plant Layout

PV system main components are:

- PV Modules
- Arrays
- String Boxes
- Subarray
- Field Power Stations
- Main Technical Room
- Transformers.

The PV Plant has been split in three main sections called Power Stations. The first two are rated 2 MW each, while the third one is rated 1 MW. The typical electrical diagram of a PV power station is presented in Figure 11.

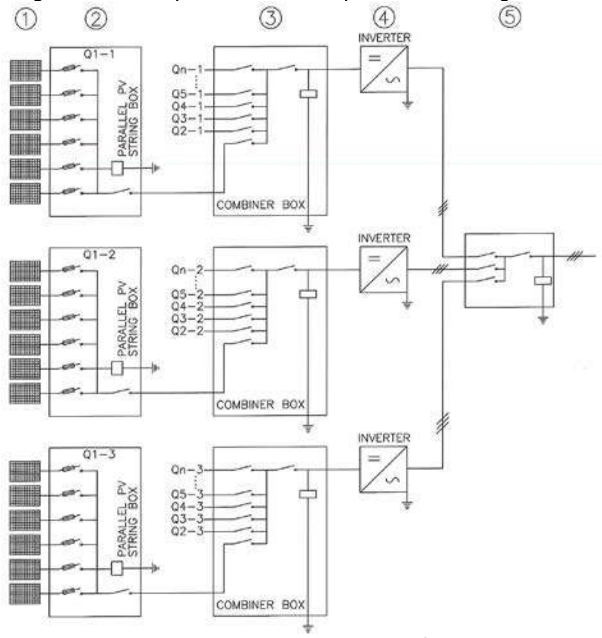

Fig. 11 Typical PV Power Plant Power Station diagram.

Where:

(1)	PV Module
(2)	String Box
(3)	Combiner Box
(4)	Inverter
(5)	Power Station

2) *BESS:*

The existing Plant electrical infrastructure is not connected to an external national grid. For this very reason, it has been necessary to consider an energy storage system (i.e. batteries) to assist the gas turbine ramp-up in case of sudden drop in PV plant power production. Gas turbines ramp rate are limited and therefore not able to manage big step loads as explained in Section II.

Considering, as worst-case scenario, 20 cycles per day and a number of expected cycles of 14,600 for 10 years, and taking in account battery aging factor, inverter efficiency, etc., the resulting minimum acceptable battery capacity calculated according to IEEE 1115-2014 [3] is 175 kWh, theoretical value that can be obtained with batteries with high rate discharge. The actual battery size is being selected after a cost optimization exercise, where

the best compromise between cost and performance has been investigated.
The optimal Storage System capacity has resulted being 1 MW/1.7 MWh (2.8 MW for 30 minutes).
The duration of 30 minutes has been selected based on the fact that batteries can only be recharged by the PV system and recharge cannot be possible for a long period of time. For these very reasons, a conservative approach has been considered to increase system availability.

The Energy Storage System is installed in two packaged buildings. Main equipment components include a vibrated reinforced concrete cabinet, battery system, Power Conversion System (PCS), output step/up transformer and local and remote control and monitoring equipment.
The BESS system is connected to a Main 20kV MV Switchgear located in the Main Technical Room by means of a step-up transformer 0.4/20 kV.

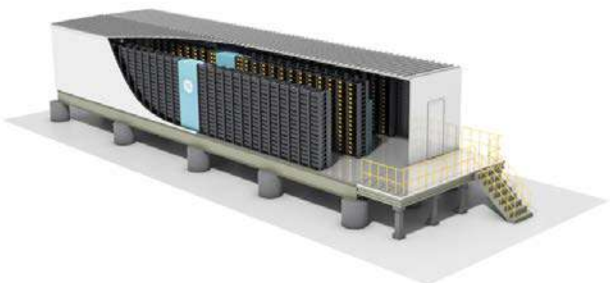

Fig. 12 BESS Module

3) Control System:
The Control System is a PLC (Programmable Logic Controller) based system that is installed to ensure efficient and stable integrated operation of new PV/ BESS systems and existing power generators.

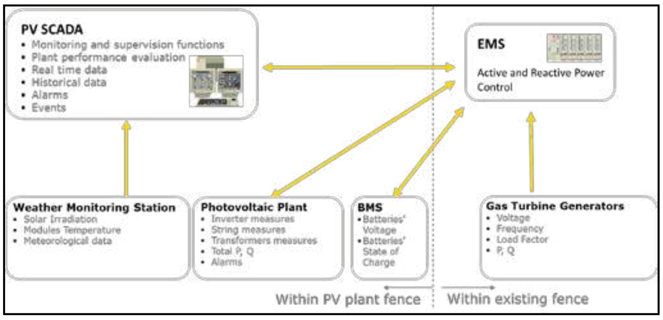

Fig. 13 Control System Architecture.

The Control System ensures the demand-oriented control of the photovoltaic system, dependent on the plant load and generator set characteristics.
Based on the GTG load factor, the PV plant will produce the power necessary to fill the gap in the plant power demand (both active and reactive).
The Power Management System (PMS) will collect data from PV inverters, energy storage system and gas turbine generators Unit Control Panel (UCP), 11 kV main switchgear and existing plant control system (e.g. Distributed Control System (DCS)).
A new HMI (Human Machine Interface) panel is installed for the monitoring and control of the overall plant.

The Power Management System (PMS) will be also connected to the plant SCADA system in order to have all data available globally.

Main system characteristics are summarized in Table I.

TABLE I
MAIN SYSTEM CHARACTERISTICS

PV Plant Power Output	5 MWp peak
PV Panel Type	Polycrystalline 72 Cell > 320 Wp
Inverter Type	1000V d.c. (max. 1500V)
No.of Power Stations	3
Fixed tilt Angle	30°
Number of PV Panels	16,200
Number of PV Modules per String	20
Battery size	1.7 MWh
PV Average Yearly Energy production	8.6 GWh/y
Required Area for PV plant	106.000 m^2
Weight of steel structures	Approx. 1200 t
Site preparation required	Minimal, no grading activities required
Foundations Type	Ballasted
Main Technical Room	Modular, 10 m x 24 m
Power Station	Modular, 3 m x 6 m
PV Power Plant perimeter	1,342 m

IV. CONCLUSIONS

This paper outlines a unique solution adopted to integrate an existing power generation system with a PV/ BESS system. After a long and challenging phase of concept selection, the selected Hybrid concept is regarded as a good optimized balance between cost and performance of both PV/ BESS systems and conventional generation systems. The adopted small scale Hybrid solution provides CO_2 emissions reduction (6,500t/y), fuel gas valorization (saving of approx. 2.8MSm^3/y) and electrical system stability with a reasonable CAPEX investment. It is estimated that the initial investment will be recovered within 10 years. Furthermore, the chosen configuration guarantees the optimal utilization of the existing Gas Turbine Generation system without compromising on its reliability and performance. The project is currently in the process of moving to the Execution phase, where the concept described in this paper will be validated.

V. NOMENCLATURE

BESS	Battery Energy Storage System
CAPEX	CAPital EXpenditure
DCS	Distributed Control System
FEED	Front End Engineering Design
GTG	Gas Turbine Generator
HMI	Human Machine Interface
ISO	International Standards Organization
MV	Medium Voltage
PCS	Power Conversion System
PLC	Programmable Logic Controller
PMS	Power Management System
PV	PhotoVoltaic
SCADA	Supervisory Control and Data Acquisition.
UCP	Unit Control Panel

VI. APPENDIX

The Appendix A shows the Key Single Line Diagram of the Plant.

VII. REFERENCES

[1] IEC 62548 Photovoltaic (PV) arrays - Design requirements

[2] CEI 82-25 Guide for design and installation of photovoltaic (PV) systems connected to MV and LV networks

[3] IEEE 1115-2014 IEEE Recommended Practice for Sizing Nickel-Cadmium Batteries for Stationary Applications

VIII. VITA

Stefano Fasoli of Eni S.p.A. He graduated from the "Politecnico di Milano" with an Electrotechnical Engineering degree in 1990. He worked as Electrical Lead Engineer in several Offshore and Onshore Oil&Gas projects and subsequently held the position of Head of the electrical Department both in Eni and EniProgetti until the end of 2019. He is currently working in the Technical Authority Department of ENI s.p.a..
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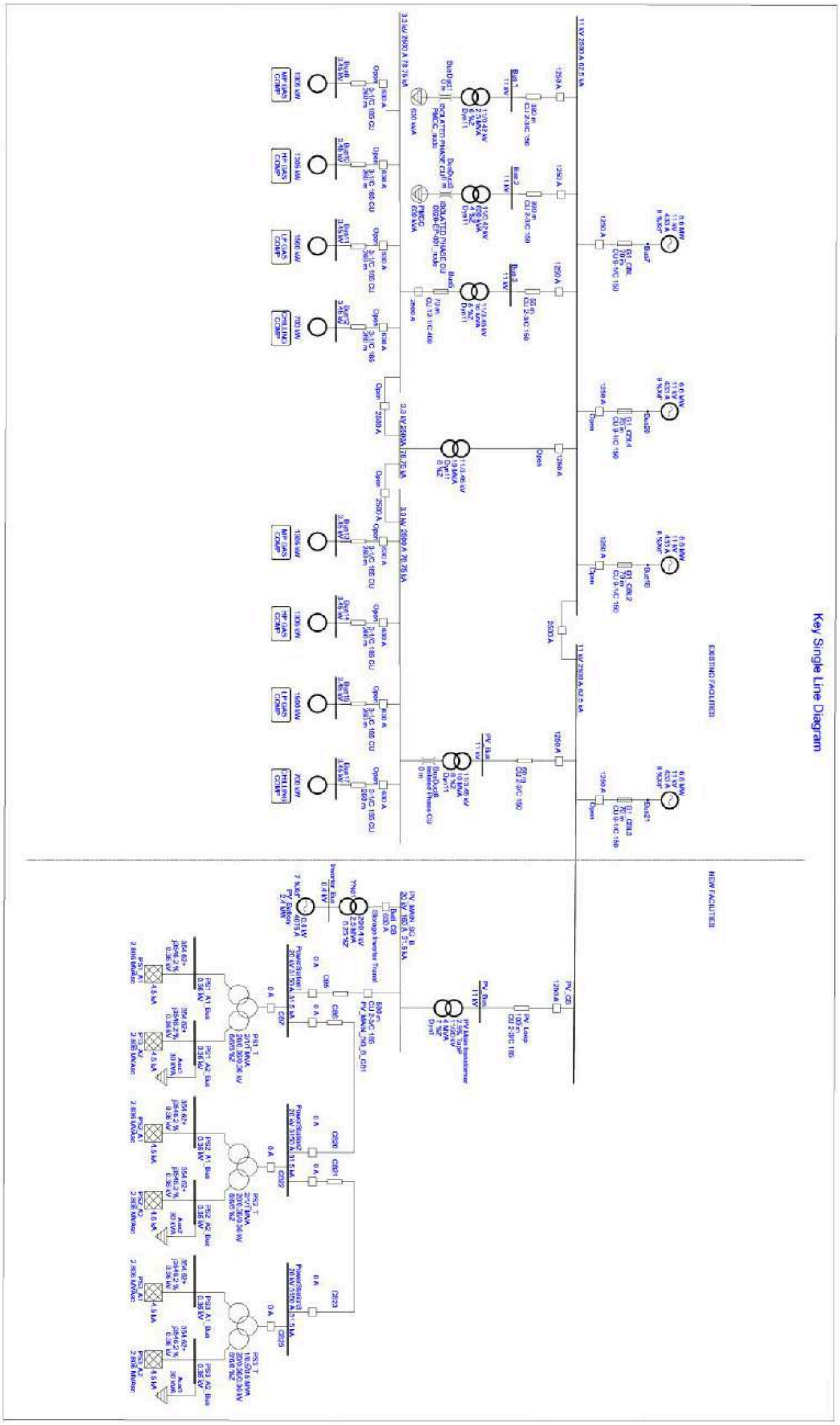
Appendix A

Key Single Line Diagram



INNOVATIVE STRATEGIES FOR INTERNAL ARC-FLASH RISK MITIGATION IN LV SWITCHGEARS

Paper No. PCIC Europe EUR21_02

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Abstract - Internal Arc Classification (IAC) of Low Voltage switchgear according to IEC and IEEE standards is one of the most important requirements to guarantee personal safety in case of internal arc faults. One of the challenges is to find innovative strategies to reduce damages of arc triggering utilizing more specific solutions inside the switchgear. As known, there are three mains philosophies of Arc Fault Management: *Active protection*, based on monitoring of electrical devices; *Passive protection*, obtained using structural reinforcements and insulations, *Avoidance philosophy*, where the assembly guarantees a reduced risk of arc fault (e.g. the arc ignition protected zone).

What this research is going to explore is the *Passive protection* and the *Avoidance philosophy* with the introduction of new approach for internal arc-flash risk mitigation. The paper presents an innovative validation procedure in order to improve the IAC.

Index Terms — Passive protection, Avoidance philosophy, Internal Arc, Arc Fault Management, Arc Fault protection.

I. INTRODUCTION

NFPA (National Fire Protection Association) Standard 70E [1] defines arc-flash as “a hazardous condition associated with the emission of energy by an electric arc”.

By definition, an arc-flash is an electric arc that occurs unintentionally. In particular, an arc-flash occurs when there is a loss in the insulation between two conductors of sufficient difference in voltage. The presence of an electric arc can therefore be a source of damage or fire, especially in the vicinity of high-power electrical equipment. The short-circuit capacity available is generally very high, as is the energy associated with the resulting arc-flash.

Identifying potential arc-flash conditions has become a very important part of the safety procedures adopted in industrial and domestic electrical systems, especially in integrated systems such as switchgear. Standards and regulations that protect operators from risks of direct contact while working on or near such systems are being drafted. Despite the arc faults and the risks of arc-flash incidents are widely known; the following documents are available only in the USA:

- NFPA 70E [1] (Standard for Electrical Safety in the Workplace) covers all risks of electrical nature, including those associated with arc faults, and specifies the PPE (Personal Protective Equipment) to be adopted according to the risk category;
- IEEE 1584-2002 [2] (Guide for Performing Arc-flash Hazard Calculations) provides methods to be used in calculating arc-flash incident energy and allows for the determination of safe work zones for protection against arc-flash events.

The principal effects of an electric arc considered by the standards are intense heat and light, loud noise and explosive overpressure. The consequent problems are:

- the heat and sprays of molten metal can produce lethal burns;
- the noise produced can cause temporary or permanent hearing loss;
- the arc-flash can cause damage to the eye vision;
- the explosive overpressure can open and unhinge the doors of switchgear assemblies and cause people working at heights to fall.

In addition to human injuries, the electric arc can cause serious damage to electrical equipment and trigger power outages in electrical systems in industrial plants and in the building sector at considerable service costs, sustained by huge system downtime.

Therefore, risk management and prevention is becoming an essential part of the safety program in the electric power sector, because the correct evaluation of arc-flash risk levels can help to reduce system downtimes and ensure safer work conditions. It must also be noted that present standards do not provide an evaluation method of arc fault risk, so *Active protections* (detection systems and switches capable of breaking fault currents) are mainly adopted.

In order to use *Passive protections* and *Avoidance philosophies* it is necessary to design the arc fault zone, and the knowledge of electric arc behavior is essential. Literature provides various models for use, see [3], [4], [5], [6], [7], [8]. These models are macroscopic representations of the arc phenomena that provide information that may prove useful in applying the best strategies to both reduce the probability of arc fault occurrence and to limit its effects.

A description of the electric arc behavior for a better understanding of arc-flash phenomena will be provided below.

II. VARIOUS ARC FAULT PROTECTION PHILOSOPHIES

Protection against the effects of an arc fault in low-voltage switchgear can be provided in various ways.

It has become consolidated practice to group these approaches to protection by the philosophies below: literature refers to *Active protection*, *Passive protection*, and *Avoidance protection*.

All the solutions in which the switchgear is monitored by a system comprising electric and electronic components capable of detecting the fault and triggering the intervention of protective equipment are grouped under *Active protection*.

Therefore, *Active protection* technical solutions include control, protection, and intervention systems.

Alongside traditional systems composed of protective equipment such as circuit breakers or disconnect switches and controlgear including transformers and relays, monitoring systems, consisting of infrared sensors for temperature measurement and optical sensors capable of detecting the light generated by an electric arc, are currently required. The optical sensors can be either point detectors or made in continuous optical fiber: as it will be illustrated below, both systems have their strengths and weaknesses.

Because limiting the damage caused by the development of an arc fault may be considered *a question of time*, the use of light-sensitive sensors is preferable in the realization of an efficient protection system.

These sensors must naturally be provided with an equally rapid data transmission for the shortest response times possible.

In contrast to than Active protection, the objective of *Passive* switchgear *protection* is the containment of the electric arc and its effects.

Because safety is such an essential part of the standards, particularly those of Europe, should an electric arc ever form, the switchgear's structure and enclosures must be capable of containing the explosive overpressure, incandescent gases, and violent ejection of material.

This measure guarantees the safety of the personnel, while practical interventions on the switchgear, such as structural reinforcement, the use of door/hinge blocks, the creation of ducts or vents for the discharge of the gases and the insertion of insulation barriers are the solutions adopted for *Passive protection* for switchgears.

Together with the measures taken for the switchgear structure, PPE (Personal Protective Equipment) provides personnel with *Passive protection* against arc fault events.

The third, the *Avoidance* approach or *philosophy*, is based on designing switchgear in such way to ensure that an arc-flash cannot occur.

In other words, the presence of insulation or segregation barriers with a high degree of protection inside the switchgear allows the manufacturer to define all or only certain compartments of the switchgear cubicle "arc ignition protected zones" with consequent protection guaranteed by the impossibility of arc fault occurrence.

The following additional observations are worth making before proceeding to an analysis of each solution's strengths and weaknesses.

Both *Active protection* and *Passive protection* are subjected to validation by laboratory tests that guarantee their correct functioning.

To this end, the European standard [2] and the United States standard [9] provide useful information for *Active protection* and *Passive protection* (design, construction, and testing of switchgear protected against faults that trigger arc-flashes), while when an *Avoidance protection* design solution is adopted, current standards offer no design validation instruments, and this makes the "arc ignition protected zone" a "weak" solution because it is not supported by experimental evidence.

Therefore, the identification of instruments capable of permitting the validation of this protection approach, assumes fundamental importance.

III. STRENGTHS AND WEAKNESSES OF THE VARIOUS SOLUTIONS

After providing an overview of the context in which switchgear equipped with internal arc protection is designed and constructed, a brief analysis of the advantages and disadvantages offered by each system of protection should be made.

Active protection systems, especially when the monitoring systems employ optical sensors, offer the advantage of providing very rapid arc fault detection times with an accuracy of a millisecond.

After this, almost instantaneous, detection the protection relay sends command to the protective devices to disconnect the power supply and eliminate the fault.

As described above, optical sensors can be either point detectors or made in continuous optical fiber.

Although point detectors are easier to install, they can only monitor a limited volume, meaning that higher numbers of sensors must be installed in each switchgear compartment.

Continuous optical fiber sensors permit wider monitoring on the other hand, but they are much more difficult to install. Furthermore, the length of the continuous fiber to be installed is limited by the loss of the signal, and this could prohibit its use in switchgears with many compartments.

It must also be remembered that despite their nearly instantaneous reaction times, damage caused by the formation of an arc is not precluded instantly, due to the fact that the optical signal must always be processed by the monitoring system before that the protective device is commanded by this system to make a circuit breaking manoeuvre (UK).

The signal processing time is usually around 10/30 ms, whereas owing to their electro-mechanical mechanisms, the protective devices that nearly always consist of switchgear of a large size and capacity have manoeuvre (UK) times in the order of 50/100 ms.

As short as it may be, the total intervention time is long enough for electric arcs to cause often quite serious damage to the compartment.

The economic aspect must also be borne in mind: monitoring and control system equipment can be expensive, and its installation and maintenance particularly so. Damaged sensors can be very costly to replace, and a malfunctioning continuous optical fiber sensor can break the circuit, leaving a large part of the switchgear unmonitored.

Passive protections, or rather structural reinforcements, door blocks, and all the other solutions described above offer the advantage of requiring no maintenance or monitoring.

Adopting higher and higher arc current protection values (typical rated values are 50kA, 70kA, 100kA, up to 150kA) cannot, however, be obtained by increasing *Passive protections* indefinitely.

Enhancing structural reinforcement, the thickness of the plating, and the insulation and segregation barriers results in excessive increases in both switchgear dimensions and production and assembly costs.

Continuing along these lines ultimately raises the risk of producing a product that is no longer economically competitive.

In accordance with above, the *Avoidance protection* appears the most interesting. Indeed, the design of switchgear with "arc ignition protected zones" offers the advantage, in theory, of reducing arc fault risks to zero. In practical terms, this means eliminating the costs required for intervention and replacement following a fault and, in any case, reducing equipment maintenance costs.

On the other hand the absence of a regulatory procedure that certifies that a compartment or a part of it is an "arc ignition protected zone" amounts to a serious drawback due to the fact that such protection remains based on an assumption that cannot be demonstrated and it is for such reason debatable.

In conclusion, when designing switchgear, the use of the various solutions must be assessed carefully, and a correct balance of strengths and weaknesses, benefits and costs must be reached without lowering the level of safety for personnel (an objective that must not be compromised for any reason whatsoever).

IV. EXAMPLE OF PROTECTION MODE: EXPLOSIVE ATMOSPHERE

It is useful to point out that some of the protection solutions previously described are also used in other industrial environments so it could be possible to adopt the same protection strategy and protection validation.

One of the main interesting and dangerous industrial environmental is Ex environment, such as Oil&Gas field where an explosive atmosphere could be often present.

An explosive atmosphere is a mixture of flammable substances in a gaseous, foggy, vaporous state, or powder mixed with air, under certain atmospheric conditions in which, after ignition, the combustion propagates itself to the flammable mixture. A potentially explosive atmosphere is only obtainable if the concentration of the flammable substance is not too low (lean mixture) or too high (rich mixture): in these cases, a combustion reaction may occur, or even no reaction at all, but no explosion.

In order to avoid an explosion, it is mandatory to limit one of this three elements: fuel, combustive agent (oxygen) and an ignition source. Therefore, an explosion cannot occur if even just one of these three elements is not present, as shown by the explosion triangle of Fig. 1.

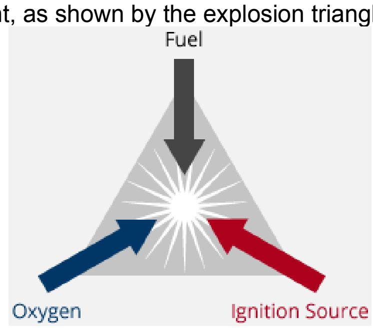

Fig. 1 – The explosion triangle.

Therefore, three different principles, which act differently on these three elements of the triangle can be implemented to be safe the electrical equipment. These three different principles are:

- *containment method*, the parts that can cause ignition are included in a box made to withstand the pressure of the explosion, preventing the spread of flame;
- *prevention method*, in this method necessary measures are taken to avoid excessive temperatures and creation of sparks, thus eliminating the ignition source;
- *segregation method*, in which active components are separated from explosive mixture using resins, sand, oil, preventing any contact with oxygen and fuel.

All the protection modes for Ex environment, as described in [10] for luminaries, born from these three different principles and it is possible to compare these protection solutions used for explosion atmosphere to the protection solutions adopted against the effects of a fault with the formation of an electric arc.

The *Passive protection*, used for Low Voltage Switchgear, has the aim of containing the electric arc and its effect, as for the *containment method* used in Explosive Atmosphere. The related mode of protection is called "Ex d" and the parts which can ignite a potentially explosive atmosphere are surrounded by an enclosure which withstands the pressure of an explosive mixture exploding inside the enclosure itself, and prevents the transmission of the explosion to the external atmosphere surrounding the enclosure [11]. Obviously, a correct design of the flameproof joint and the enclosure (thickness) is mandatory as well as the positive result of the type tests according to IEC 60079-1 [12]. It is very important to design the length, the gap and rugosity of the joint between cover and body of enclosure according to the Standard.

The philosophy of *Avoidance protection*, used for Low Voltage Switchgear in order to avoid the arc-flash effect, is based on the design of the switchboard to ensure that a failure cannot occur, as per the *prevention method* used in explosive atmosphere. The related mode of protection is called "Ex e", where additional measures are applied to the electrical equipment to increase the safety level, thus preventing excessive temperature development and the occurrence of sparks or electric arcs within the enclosure or on exposed parts of electrical apparatus, where such ignition sources should not occur in normal service [11]. Obviously, a correct design of the insulation distance (creepage and clearance) according to the material used and the electrical parameters is mandatory as well as the positive result of the type tests according to IEC 60079-7 [13].

Differently, there is no an equivalent mode of protection, used in explosive atmosphere, like the *Active protection*, used for Low Voltage Switchgear in order to avoid the arc-flash effect because the arc-flash has an high temperature and an high ignition energy that can be the ignition source itself.

In Ex design the minimization of the probability of arc ignition is a very important strategy that at the moment is not a IEC Standard yet. This minimization can be done by calculations or by practical tests.

By calculations, to minimize the probability of the arc ignition, it is possible to evaluate the causes of failure and the failure rates of each component suitable for protection (SIL - Safety Integrity Level). Comparing it with the hours of possible presence of the explosive atmosphere (depending on the danger zones), it is possible to check whether the installation is suitable or not [14].

By practical tests, it is necessary to define the right approach to follow and to spend money both for prototypes and to execute destructive laboratory tests.

V. THE ELECTRIC ARC

Many electric arc models have been developed: microscopic (particle physics) and macroscopic (thermal, dynamic and electric). The macroscopic electric models that describe the arc's behavior in a circuit are enough for the study of the arc-flash. These models include the well-known Ayrton Model [15] , the Mayr Model [16] and the

Cassie Model [17]. Using the Ayrton Model on which the others are based, it may be observed that in strictly electrical terms, an electric arc can be represented as a useful resistance R_U (having the nonlinear characteristic) shown in Fig. 2.

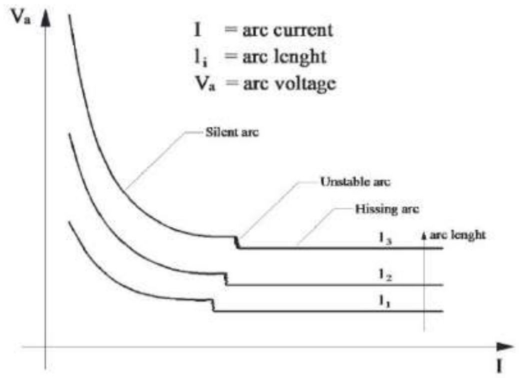

Fig. 2 - Volt-amperometric characteristic of the electric arc

Fig. 2 shows how the arc characteristic is anomalous: with modest current values: the apparent resistance $r = \frac{V_a}{i}$ decreases as the current *i* increases, whereas with very high current values, not represented in Fig. 2, it begins to rise in the same way as "normal" resistance. Between these two zones and for high current values in any case, the arc voltage V_a instead remains practically constant. This can be explained by imagining that as the current *i* increases, the section of the ionized region through which the current passes increases and at the same time, the state of ionization increases (or rather, the resistivity of the conductor decreases).

On the Cartesian plane in Fig. 2 with the current absorbed plotted on the x-axis and the arc voltage on the y-axis, for a determined arc length value, an electric arc can be divided into three zones:

- *silent arc*: where V_a decreases notably as *i* increases. For this zone of the characteristic, Ayrton's formula can be applied:

  $$V_a = A + B \cdot l + \frac{C + D \cdot l}{i} \quad (1)$$

  where *A*, *B*, *C* and *D* are positive constants that depend on the diameter and physical nature of the electrode and the gaseous interposed, and *l* is the arc length;
- *unstable arc*: in which the arc is intermittent and unstable;
- *hissing arc*: in which V_a remains practically constant with the variation of *i* notwithstanding its variation with the variation of the arc length. In this zone, the first binomial of the equation (1) is valid with the expression as follows:

  $$V_a = A + B \cdot l \quad (2)$$

An examination of the arc characteristics in Fig. 2 shows how in the first section, a decrease in arc voltage is followed by an increase in the current value: this zone section possesses a negative differential resistance, demonstrating the unstable nature of this phenomenon.

Even if formulas (1) and (2) are valid only for a limited range of current, and such limit is usually reached quickly when an arc-flash occurs, learning the principal parameters that govern the electric arc's behavior allows for the implementation of all the counter-measures that can reduce the probability of ignition.

Analyzing the electric arc's current and voltage waveforms is also helpful in acquiring a better understanding of the phenomenon. As will become clearer below, in reality, the anomaly of the arc characteristic is such that the electrical quantities in question are not sinusoidal in development.

Hypothesizing a sinusoidal arc current waveform *i*, V_a would take the waveform shown in Fig. 3.

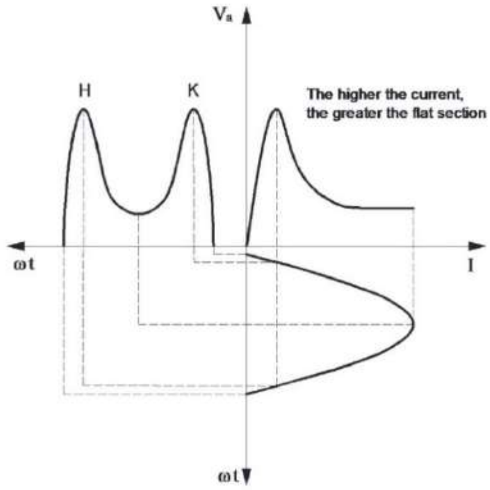

Fig. 3 – Characteristic of an electric arc with a sinusoidal current flowing through it.

In reality, arc hysteresis phenomena are such that V_a is not symmetrical. This can be seen in Fig. 4, where point H is lower than point K.

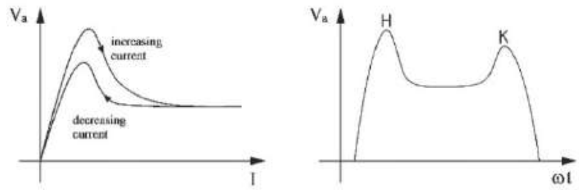

Fig. 4 - Characteristic of a real electric arc.

Based on the above, or rather, that the arc voltage V_a may be considered constant to a fairly good degree of approximation, an electric arc can be represented as a square wave voltage generator of constant amplitude V_a with the variation of the arc current, as shown in Fig. 5, and as a function of only arc length *l*.

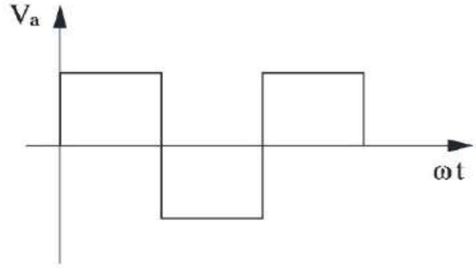

Fig. 5 – Representation of an electric arc by square wave.

Starting from an equivalent electrical circuit model for the electric arc shown in Fig. 6 in which the power supply network is hypothesized as having infinite power, the input voltage is sinusoidal and the source impedance is purely inductive because in general the X/R ratio is higher than 5.

In the circuit shown in Fig. 6, the arc was represented by a square wave generator of amplitude V_a. Even if not stated appropriately, the arc voltage may be said to be in phase with the arc current i, in the sense that it inverts its sign when it crosses the current's zeros.

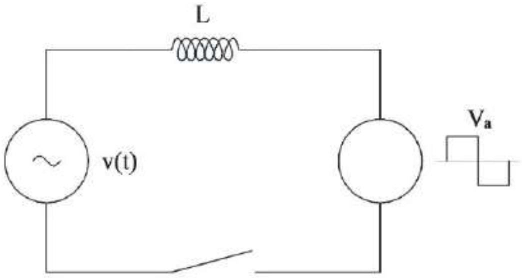

Fig. 6 – Equivalent electric circuit of an electric arc represented by a square wave generator.

When the circuit shown in Fig. 6 is connected to the supply in the moment t=0, the arc cannot ignite before $\omega \cdot t=\varphi_1$ because as shown in Fig. 7 the input voltage $v(t)$ equals V_a only in this moment.

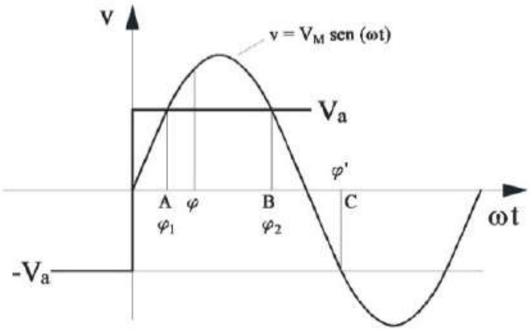

Fig. 7 - Electric arc arcing conditions.

In the circuit in question (prevalently inductive in nature), the first current rise in the electric arc current can take place only with an angle $\varphi \geq \varphi_1$. This means that Ohm's Law can be applied to the circuit, assuming the moment in which the current crosses zero as the starting time. In this way, the starting time for the sinusoidal supply voltage is expressed by:

$v(t) = V_M \cdot \sin(\omega \cdot t + \varphi)$

Assuming that the initiation of the electric arc takes place in any moment $\varphi > \varphi_1$, the voltage V_a shifts by φ in regard to $v(t)$, as shown in Fig. 8.

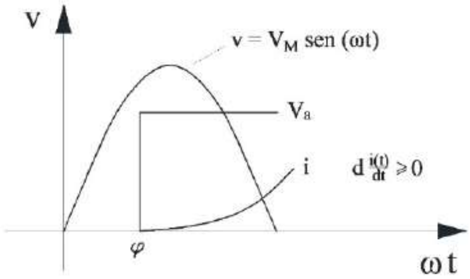

Fig. 8 – Initial behavior of the arc current.

The mathematical relationship obtained by applying Ohm's Law to the circuit in question is:

$v(t) - V_a = L \cdot \frac{d}{dt} i(t)$

Expanding this expression and inserting as initial working condition i(0)=0 allows the arc current to be represented as follows:

$i(t) = -\frac{V_M}{X} \cdot \cos(\omega \cdot t + \varphi) - \frac{V_a}{X} \cdot \omega \cdot t - \frac{V_M}{X} \cdot \cos\varphi$

where $X=\omega \cdot L$. The expression obtained above, at constant φ and V_a, which inverts its sign at every current zero crossing $i(t)$, expresses the non-sinusoidal periodic variation law of the current, which does not have a sinusoidal wave form and can be broken down into a fundamental component and into odd-order harmonics. In particular, the first term is sinusoidal; the second is a straight line passing through the x- and y-axis origin, and the third is a constant term.

From the above, it is clear that if the arc voltage V_a is higher than the peak value of the mains voltage V_M, the arc ignition is impossible.

Moreover, it is worth noting that even if the arc current may not necessarily ignite also with lower arc voltage values, most certainly with arc voltage V_a values of less than or equal to 0.537 of the mains voltage V_M, the arc current would be continuous and re-ignite at each cycle.

Largely similar conclusions would be reached by removing the hypothesis R=0 in the circuit shown in Fig. 6.

VI. A NEW APPROACH

There are clearly substantial differences between the *Active*, *Passive*, and *Avoidance approaches* to arc fault protection in designing equipment.

The concept forming the basis of *Active* and *Passive protection* is that because the arc-flash has already developed following a fault, the objective set for *Active* or *Passive protection* is to limit the damage.

We have seen that *Active protection* is costly and requires reliable control systems. *Passive protection* systems propose solutions that concern the structural sturdiness of the compartment where the arc-flash occurs.

It might be more interesting to succeed in adopting structural measures required not merely to provide passive resistance to arc-flash effects but influence the potential initiation and duration of the arc-flash itself instead.

Currently, only Standard IEC TR 61641 [9] specifies the methods of execution of a test suited to the validation of a *Passive protection* and a procedure for the validation of an "arc ignition protected zone".

The two processes are separate. For *Passive protection* validation, a practical test under arc-flash conditions is run. *Avoidance protection* is validated by means of experimental measurement of dielectric strength (the test voltage value is specified in IEC 61439-1 [18] on the basis of the device's rated voltage) and checking the degree of protection (IP) in accordance with Standard IEC 60529 [19].

In this paper, the authors intend to explore the *Avoidance protection* approach in an attempt to find a new viewpoint from which it may be validated because the test voltage value adopted for the validation of the *Avoidance protection* mode above is the same for a wide range of rated voltages for devices (from 300V to 690V, the test voltage is 2835V).

As presented in Section V and through acquired experience, it has been found that the device's rated voltage is a fundamental factor that affects the potential initiation and duration of the electric arc.

It is useful to specify that in this protection mode, *Passive protection* and *Avoidance protection* can be combined in a new approach.

In line with the new strategy that can be proposed also for a designed area such as an "arc ignition protected zone", the validation process must include a test under arcing conditions that is usually conducted for the validation of at least *Passive protection*.

Conducting experimental tests at the end of the design process of an “arc ignition protected zone” allows for the validation of its utility in establishing whether or not the arc ignited during the test phase proves stable and capable of re-ignition.

This requires the assessment of the factors that influence the life of the electric arc and the way in which it is possible to induce the arc generated during the device test phase to extinguish itself before the end of the test.

As reported in Section V, the parameters that influence the phenomena are input voltage (V_M), arc voltage (V_a), arc resistance (r) and the length of the arc (l) itself.

Obviously because no intervention can be made on the maximum mains voltage value V_M, which is a design value of the switchgear and the arc resistance r value cannot be directly adjusted, attention must be focused on the value of the arc voltage V_a and the arc length value l must be modified.

The choice of materials, their form and position, must therefore be assessed during the design phase, and the protections for the conductors must be designed on the basis of these parameters in order to achieve the two fundamental objectives of this new approach:

1. make the arc length as long as possible i.e. maximize the value of V_a;
2. resist, even if for a limited period of time, during the overtemperature near the arc, in order to prevent it from finding a direct path of re-ignition between the two conductors.

At the end of the design phase, an experimental validation procedure like the one described below must be introduced.

The first step in the validation procedure is to execute the tests indicated in Standard IEC TR 61641 [9] in order to verify the “arc ignition protected zone”.

As indicated above, the Standard specifies only a high voltage test at a voltage value of 2835V for switchgears with rated operational voltages in the range of 300V and 690V.

Given that the operational voltage value influences the duration of the electric arc, the previous test can only be considered necessary, but not sufficient to guarantee that the zone designed is really an “arc ignition protected zone”.

Whenever a fault with the ignition of an arc-flash occurs inside a switchgear, there are three possible scenarios:

1. the electric arc does not propagate inside the “arc ignition protected zone”;
2. the electric arc propagates inside the “arc ignition protected zone” and this prevents re-ignition by extinguishing it before the end of the test;
3. the electric arc propagates inside the “arc ignition protected zone” but this cannot prevent re-ignition and the electric arc is interrupted only at the end of the test.

The occurrence of any one of these scenarios depends directly on the maximum operational voltage value V_M. For this reason, it may occur that after the switchgear has been validated by following the procedure specified in Standard IEC TR 61641 [9], an arc fault test conducted at 300V voltage causes the effect described in point 1, and a fault test at 690V causes the effect described in point 3.

In regard to the above, an “arc ignition protected zone” may be considered as such only after experimental validation, that includes a test under arcing conditions at a precise operational voltage value.

A zone inside the switchgear may be defined an “arc ignition protected zone” only after this practical test has been conducted and provides the outcome described in point 1 (the electric arc does not propagate inside the zone) or in point 2 (the electric arc propagates inside the zone and extinguishes itself before the end of the test). Therefore, the zone can be defined an “arc ignition protected zone” only for values that are lower than or equal to the test voltage adopted during the test.

VII. A PRACTICAL EXAMPLE

For the sake of completeness, a real example of when this procedure was adopted is provided below.

A laboratory test was conducted in Motor Control Center configuration under arcing conditions with the characteristics below:

- rated operational voltage (U_e) 415V
- permissible current under arcing conditions 65kA
- permissible arc duration 0.5s

As shown in Fig. 9, one of the most critical zones, the busbar system, was designed and indicated by the laboratory observer as an “arc ignition protected zone”.

The tests envisioned by the standards for dielectric integrity were then performed at the voltage value 2835V (the value specified for switchgear assemblies with rated operational voltage in the range of 300V to 690V) were conducted and the assembly passed the test with positive result.

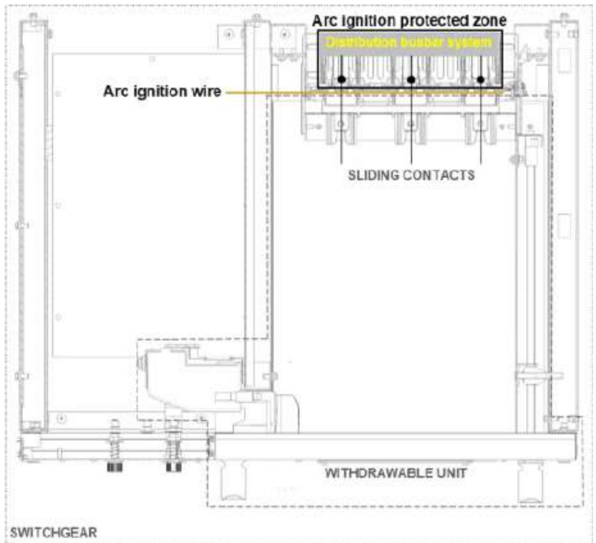

Fig. 9 – Arc ignition protected zone into tested switchgear and arc ignition wire

Fig. 9 shows the busbar zone inside the switchgear indicated to be the “arc ignition protected zone”.

Validation continues by subjecting the switchgear assembly to a practical arc resistance test by inserting a test wire directly between the switchgear’s active elements. Although the internal arcing test cannot not be conducted in the “arc ignition protected zone” by inserting the test wire directly in between the busbar system’s conductors, it is possible to insert such wire in points at the edges of the “arc ignition protected zone”. In this case, the test wire was inserted on the connection clamps of the busbars of a removable unit as shown in Fig. 9 (which shows the position of the test wire insertion in the switchgear ready for the internal arcing test).

From this position, the electric arc can propagate to the busbars and therefore there is no guarantee that an arc sparked in a point in the switchgear outside the “arc ignition protected zone” will not enter.

For this reason, attention should be turned to the influence that this protected zone may have on the behavior of the electric arc.

An initial test was conducted at switchgear with a rated operational voltage of 415V. As expected, once the arc sparked, it moved to the “arc ignition protected zone”. The waveform recorded during the test provided in Fig. 10 shows that the arc currents of all three phases (I_1, I_2 and I_3) cancel each other out after around 180ms. This means that the busbar zone (defined “arc ignition protected zone”) exhibited preventive behavior in inducing the extinction of the arc and preventing its re-ignition. The outcome is the one detailed in point 2 of Section VI above (the electric arc propagates inside the zone and extinguishes itself before the end of the test).

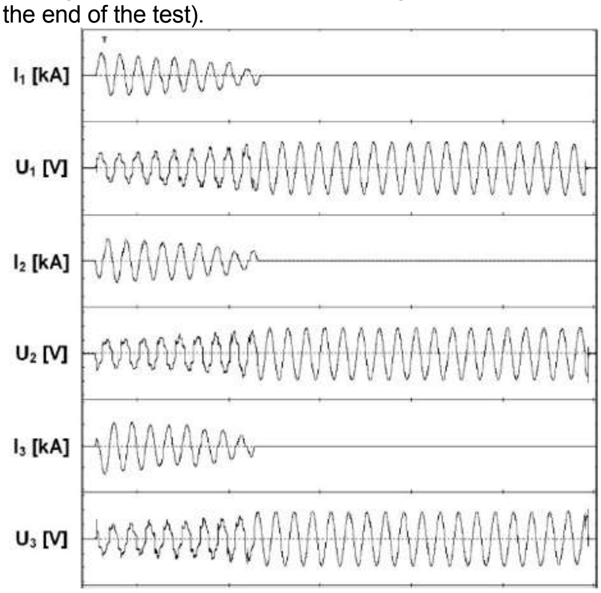

Fig. 10 – result of oscilloscope test at 415V

The same test was conducted also at the different switchgear rated operational voltage of 690V with a short-circuit capacity similar to the case above.

In this case as well, the arc propagated to the busbars, but this time, the spontaneous extinction of the electric arc between all the phases did not occur. This can be seen in Fig. 11, which shows the arc voltage and current values in the three phases. The outcome obtained is therefore the one described in point 3 of Section VI (the electric arc propagates inside the zone and does not extinguish itself before the end of the test).

The two different behaviors obtained depended on the different operational voltage value used during testing. According to the findings, the “arc ignition protected zone” influenced the electric arc’s probability of initiation and duration in the first test but not in the second one.

For this reason, the proposed new strategy is to design protections in such way that ignition is impossible - as indicated by the *Avoidance protection* method philosophy - and then to proceed to a functionality validation by laboratory testing in the same way as for *Passive protections*.

Analysis of the tests’ results may lead to the definition of rules to be shared when designing arc ignition protected zones that ensure correct behavior even when an arc ignites despite the protective measures adopted.

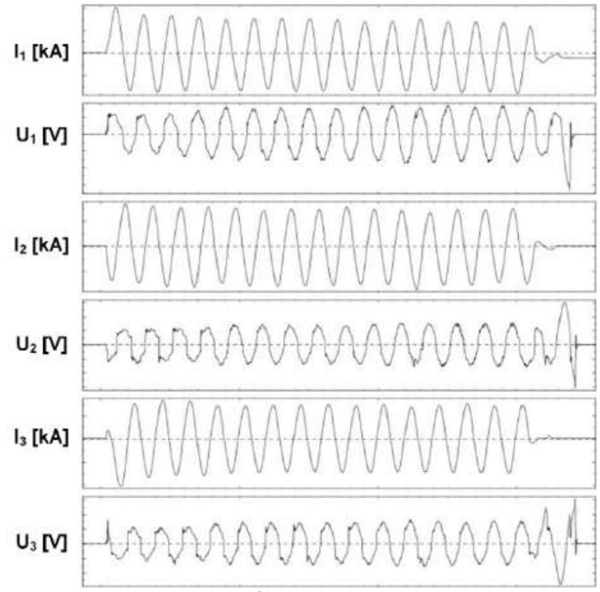

Fig. 11 – result of oscilloscope test at 690V

VIII. CONCLUSION

The final design of switchgear assemblies usually incorporates *Active*, *Passive*, and *Avoidance protection* solutions. While being able to understand the effectiveness of *Active* monitoring and control systems and the *Passive protections* associated with the structures capable of providing protection and containing arc-flash effects is within our possibility, demonstrating that any given zone of a switchgear can be defined “zero risk” is more complex.

Due to the fact that priority in design is generally given to safety, with which degree of certainty can we define a device as “zero risk” and assume all responsibility in that regard?

This paper attempts to clarify the differences between the *Active*, *Passive*, and *Avoidance* approaches to *protection*.

The authors have explored the *Avoidance protection* approach and establish a new viewpoint from which it may be validated.

Succeeding in adopting structural measures (hence those associated with *Passive protection*) required not merely to provide passive resistance to arc-flash effects but which influence the probability of the initiation and duration of the arc itself instead appears very interesting.

The *Avoidance protection* approach to design is therefore entirely different because it requires the assessment of the factors that influence the initiation and duration of the electric arc and the way in which it is possible to induce arc self-extinction or even prevent its ignition.

The choices of the materials, their form and position, therefore become very important for obtaining good results that can be supported by adequate experimentation.

The paper presents a practical method of analysis that may permit switchgear zones to be qualified as “arc ignition protected zones”, and describes the result obtained on the basis of the outcomes of a real practical test conducted on a switchgear.

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X. BIOGRAPHY

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PILOT PROJECT: EVALUATION OF IIOT- BASED METHODS AND PROCESS FOR CONDITION MONITORING OF OFFSHORE ELECTRICAL DISTRIBUTION INFRASTRUCTURES

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Abstract - As Industrial Internet of Things (IIoT) connected technologies prove their effectiveness along the industry value chain, new solutions are now driving both digital transformation and new business models across enterprises. In Oil & Gas industry exploration and extraction processes, management of electrical distribution infrastructure assets is a key business area that stands to benefit. Monitoring of electrical systems has been implemented for many years using Intelligent Electronic Devices (IEDs) and Electrical Network Monitoring and Control Systems (ENMCS) allowing smarter operation.

Today, IIoT and predictive analytics are taking smart operations a step further and are leveraging data to enable better decisions that result in the reduction of unscheduled downtime, increased safety and optimized maintenance. Many details must be considered when implementing a smart electrical distribution system including IIoT sensors, data collection, communication infrastructure, cybersecurity and both on-premise and cloud-based monitoring services. This paper describes a current oil company pilot project taking place aboard one of their remote Floating Production Storage and Offloading (FPSO) vessels and examines the design considerations, issues faced, implementation strategies and new perspectives realized for next steps to be taken by the industry.

Index Terms — Asset management, electrical distribution, Internet of Things (IoT).

I. INTRODUCTION

A French-based global oil and gas energy provider was looking for new methods to enhance the availability of electrical infrastructure of their offshore floating production storage and offloading (FPSO) facilities and to contribute to Health Safety & Environment (HSE) targets.

The company strategy was to focus on the reduction of unscheduled downtime to reduce costs and production losses.

A. Fire Incident Risk Accelerates Search For Alternative Electrical Systems Monitoring Solution

All most all Petroleum Facilities experienced a significant outage, consequences can be more dramatic for offshore installations. Let’s take an example of a bad connection inside a Low Voltage (LV) emergency switchboard, this bad connection could lead to a fire inside the room, detected by the Fire & Gas system that would trigger an Emergency Shutdown (ESD) of the platform and all satellite platforms fed from it. The fire would have probably damaged part of the switchboard including some mechanical interlocks preventing return to normal operation. In such crisis situation, a lack of experience surrounding full manual black start procedures would lead to an extended period of time to restart the electrical network, leading to a subsequent production loss and environmental consequences like flaring.

According to the International Electrical Testing Association (NETA), an organization that serves the electrical testing industry, more than 25% of fires in electrical distribution/switchgear systems are due to insufficient tightening of bolted connections [1]. Over time these connections deteriorate or loosen (especially in harsh environments exposed to corrosive elements or vibrations as is common on an FPSO). A loose connection can lead to the generation of heat, thermal runaway and/or arcing, that can cause system downtime or, in some cases, fire. In the case of fire, downtime is often accompanied by equipment destruction.

On spot Infrared Thermography has been an answer for several years, but new HSE regulations, Electrical Standards are making thermography more and more impossible. The NFPA 70E [2] standard also recommends not to expose personnel to such electrocution risk.

Testing and validation of thermal monitoring emerged as a key requirement for the company’s planned pilot project.

B. Background

The pilot project (12 to 24-month duration) is being conducted onboard a 10-year old FPSO (deep offshore).

The FPSO itself is the size of an oil tanker but is furnished with a topside processing facility that is dense with both mechanical and electrical equipment. The vessel measures around 330 meters (1,083 feet) in length by 60 meters (197 feet) in width. The vessel is manned by over 250 crew members, and is connected to subsea wells. This FPSO was chosen due to the planned Full Field Shutdown (FFSD) which occurred end of 2018 (see Fig. 1).

Fig. 1: FPSO vessel in operation

II. IDENTIFIED PAIN POINTS

For oil companies, any unplanned downtime aboard the installation can lead to loss of production in the thousands of barrels per day (which equates to millions of dollars per day). The company was looking for a solution to mitigate electrical distribution downtime. Such risks included electrical equipment failures due to wear and tear and aging. Personnel onboard the FPSO are focused on oil extraction and processing operations. There is also a dedicated on-site team that performs required maintenance activities. One of the company's objectives was to utilize a new monitoring solution in order to better optimize maintenance manhours.

In order to assure the reliability and safety of their electrical systems, the company invited electrical infrastructure vendors to participate in a pilot project based on a data-driven approach.

The pilot project was originally initiated to address three areas of concern:

1) The monitoring of electrical bolted connections to prevent fire.
2) A costly and inefficient preventive maintenance process for switchgear and switchboards. This traditional approach to time-based maintenance proved outdated and was not capable of identifying problems before they occurred.
3) They required a system that would assure improved electrical system availability in order to ensure reliable operation and increased safety.

In order to better define the pilot project, the company embarked on a review of the current electrical systems on board the vessel. Two principal areas needed to be addressed:

a) Thermal monitoring of bolted connections.
b) Circuit breaker and contactor health monitoring.

III. RECOGNITION OF TECHNOLOGY ADVANCEMENTS

Traditional practices for monitoring and maintaining electrical systems are quickly evolving. Typical approaches for temperature sensing, for example, involve sporadic utilization of IR for the scanning of components. In the case of IR, an on-site technician has to open the switchboard and use an infrared camera in order to detect the abnormal temperature rise inside of the switchboard. This approach is complex and labor intensive. IR thermography is not possible to perform on MV cubicles without IR windows. Also, in the case of LV, proper safety procedures discourage the use of IR thermography on energized switchboards [4].

The company had decided to discontinue this practice because of technician availability issues, an increased potential for human error, and safety concerns.

New approaches for accomplishing these tasks now involve smart sensors, 24/7 online monitoring by a team of remote analytics experts, and the analysis of data trends to determine if equipment is experiencing temperature anomalies. The same principles are also applied for the monitoring of circuit breakers which provide much more insight regarding their health.

The oil company recognized that new technologies were enabling more flexibility and fresh perspectives for addressing their current pain points. They decided to explore a data-driven solution that would be capable of automatically collecting data on site and forwarding that data to the cloud where analytical models perform the work of reviewing the data. Once the data is collected, the analytical engine then flags the data and generates dashboard charts and graphs for easy interpretation (see Fig. 2). Experts then review the results. If an anomaly is detected, experts are in a position to validate the anomaly and provide proactive maintenance recommendations, thereby ensuring normal operation of the systems.

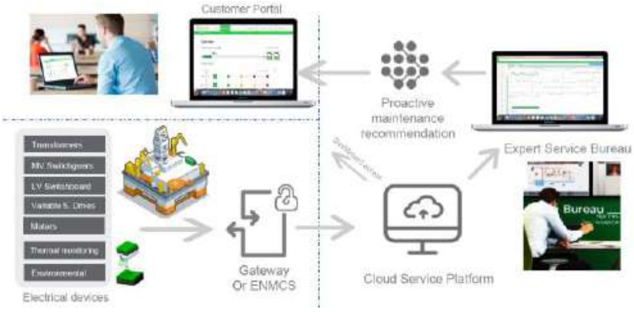

Fig. 2: Data flow between FPSO and Service Bureau

IV. PILOT PROJECT

The oil company's pilot project serves several purposes. The first is to test the vendor solution for taking accurate temperature measurements inside of electrical switchgear/switchboards. The second is to have onshore experts analyze the data gathered including data being generated from Intelligent Electronic Devices (IED). The experts use sophisticated analysis models, in order to deliver value in the form of higher FPSO electrical network uptime.

The pilot project is also being used as a mechanism for determining whether remote monitoring can serve as a suitable replacement for traditional monitoring methods and whether this new technology actually works in a real-world environment. Observations surrounding implementation conditions of this type of technology on a 10-year FPSO was also part of the research scope.

The company decided to launch the pilot project in November of 2017. Then an engineering phase was launched in October 2018, in tandem with the scheduling of the second full field shutdown for this particular FPSO. The new application then went live in May of 2019.

A. Success criteria

The operational pilot project is scheduled to end in May of 2020, with the option to extend for one additional year. Over the testing period, the company is determining whether or not the solution is successful based on electrical system uptime efficiency gains.

Additional success factors will include improved safety of people onsite (fewer accidents), reduced need for preventive maintenance due to better equipment health status insight, the ability to perform condition-based maintenance through continuous remote monitoring, and the ability to perform predictive maintenance (acting before the failure).

In addition, should the pilot project prove successful, it will redefine the company's approach to asset management strategies towards a more data-driven and analysis-based model.

V. IMPLEMENTATION OF A SERVICE

The oil company's decision to digitize its electrical system condition monitoring approach involved several unique business perspectives. The first was to place an emphasis on what is called lean implementation. Many oil and gas industry projects are capital-intensive and often involve costly and disruptive technology replacements. In this case, focus was placed on digitizing only what was needed to achieve the goals of the pilot project (in this case, placing thermal sensors into existing switchgear cubicles and collecting relevant data inside the existing IEDs). The data gathered from the equipment was then sent to a cloud, where Service Bureau experts then analyzed the data. Reports are then shared with stakeholders via dashboards. The processing of this information is offered *as a service*. No new software was added on premise.

Another unique trait of the pilot project involved the sending of data from the FPSO vessel to an off-premise third-party cloud without compromising the cybersecurity. Across the oil and gas industry, companies are traditionally hesitant and reluctant to send data off site to a non-company owned cloud or public cloud. Many organizations are worried about potential cybersecurity risks, but the cloud can provide advanced benefits in comparison to on premise solutions.

Having the pilot project delivered as a service meant that analytics were performed within a cloud-based platform with no analytics-related work being executed on-premise. New analytics updates are also applied at the cloud level without any modification needed on site.

VI. INNOVATIVE SENSORS

One objective of the pilot project is to validate the thermal monitoring solution offered by the vendor. This innovative technology uses wireless and battery-less thermal monitoring sensors installed at each connection point to be monitored. This type of sensor does not require any wiring (see Fig. 3).

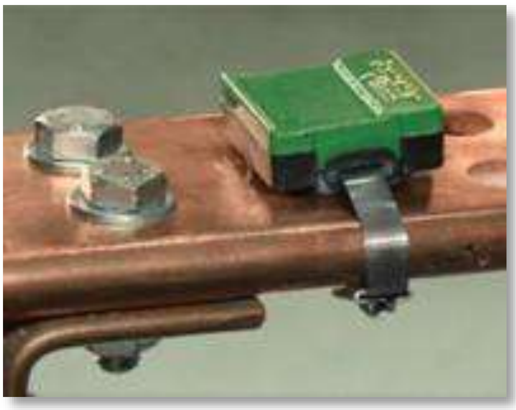

Fig. 3: Sensor shown without the tightening to demonstrate the ferromagnetic strip

A Negative Temperature Coefficient (NTC) probe (see Fig. 4) is included at the bottom of the sensor which is installed on the busbar in the vicinity of the connection.

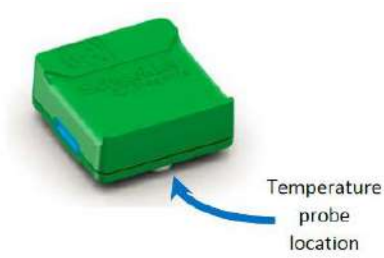

Fig. 4: NTC probe location

The sensor is powered by an AC electromagnetic field generated by the current through the busbar. A ferromagnetic strip is used to harvest the energy. When powered, the sensor will send the temperature measurement to a gateway using Zigbee Green Power (2.4 GHz radio frequency) every minute. Sensors need to be installed on each phase to detect any discrepancy that might occur. Encryption is used at the radio frequency (RF) level and a pairing process between sensor and gateway is required.

Due to the technology used, the dielectric impact of the sensor needs to be assessed for all MV connections or for each type of switchgear.

Different gateways are available, including one able to concentrate up to 60 sensors and provide the measurement over Modbus. Simple RF engineering rules need to be applied in order to ensure the performance of the system. In operation, the RF performance (RSSI Received Signal Strength indication) is available on the receiver.

Another sensor measuring temperature and relative humidity was also considered to capture ambient conditions to evaluate the risk of condensation inside a switchgear. Both sensors use the same wireless technology but this second sensor is powered by a battery with up to 20 years autonomy. Data are pushed to the gateway every 2 minutes. Initially proposed to monitor the ambient conditions inside the rooms, the sensor was finally rejected for safety reasons due to a local requirement preventing the powering of equipment by battery (a requirement to shut down the sensor in case of gas detection).

VII. ENGINEERING PHASE

A. On-board system overview

Multiple operational systems are used onboard the FPSO. In terms of electrical network, the following systems play a core role:

- Power Distribution Control System (PDCS, the company name for the electrical Network Monitoring and Control System-ENMCS). This system is responsible for controlling the electrical network in order to feed the process. The PDCS allows functions like fast load shedding and is used at the electrical equipment level PLC (Programmable Logic Controllers) to monitor and control the equipment (using hardwired interface or through communication). The system is redundant. This system is used to operate the electrical network and only data available from the system is required for operation. Equipment maintenance considerations were not part of the specification at the time of the construction of the FPSO. In most cases, these systems only monitor a single-phase configuration (for example, current inside one phase and not on the 3 phases).

- Instrumentation Control & Safety System (ICSS, the company name for the combined process control system – PCS, and safety shutdown system – SSS). This system is responsible for controlling and operating the process and requires a close interaction with the PDCS to feed the process.
- Data Historian - The Data Historian is mainly used to collect and store all the process data including some of the key electrical parameters. Information from the historian is called a Tag. Historians are designed to be able to collect a large amount of data with millisecond accuracy and to store them efficiently over a large period of time.

All those systems are layered with cybersecurity measures at each system boundary (see Fig. 5).

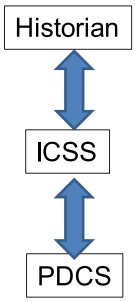

Fig. 5: Layered system overview (security measures not shown)

The company runs multiple historians, one on board the FPSO, one in their local headquarters and one in the company headquarters. These historians are updated permanently using historian to historian replications.

As a protection relay exerts a direct control on the circuit breaker, for example, direct connection to the protection relay or the PDCS are not possible for cybersecurity reasons. The company policy dictates that all electrical data from protection relays to be provided by the historian.

B. Condition monitoring data to be collected

The objective of the pilot project is to assess the health of the electrical equipment such as circuit breakers. Various data is provided by an IED that is fitted onto the equipment. For a circuit breaker, known circuit breaker monitoring data need to be collected. The parameters for data to be collected include, for example, the number of operations of that breaker, the cumulative breaking current from the circuit breaker, the opening time, and the charging time. During the engineering phase it was confirmed that those data were NOT collected by the PDCS.

C. Electrical network architecture

Most of the systems on board the FPSO are redundant on the A and B side switchboards (see Fig. 6). Main electrical rooms are spread over 3 locations, MV and LV equipment are also segregated. For ease of explanation, we will consider the MV and LV components as being housed in one electrical room.

One electrical room is located inside the hull. Two are located on the topside (inside of electrical/instrumentation buildings), one on portside, one on the starboard side, composing the A & B side configurations. The main electrical room inside the hull is not redundant but can be fed from both electrical/instrumentation rooms and includes an A & B bus arrangement.

The electrical network includes the following voltage levels:

-13.8 kV with the gas turbines
-6.6 kV
-400 VAC

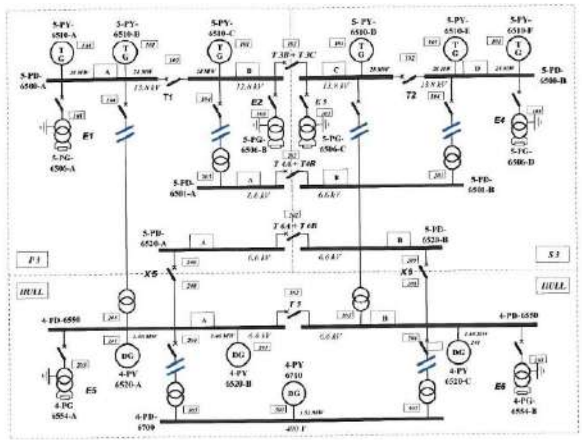

Fig. 6: Single-line diagram overview of the on-board electrical system

The 13.8kV and 6.6kV switchgear have been supplied by two different equipment manufacturers.

D. Site equipment selection

The 6.6kV switchgears are mainly composed of metal clad components fitted with circuit breaker and vacuum contactors that have been selected for the pilot project because sensor applications on those type of switchgear were previously validated. A total of 20 MV circuit breaker cubicles and 20 MV contactors were selected in the three electrical rooms.

In order to prove the viability of sensor technology on LV, three LV Motor Control Center (MCC) switchboards were also included, mainly on the main incomings. One switchboard inside each main electrical room was selected.

E. Initial proposal

The initial plan was to follow the same principles as the current configuration. This meant:

- Adding the thermal sensor measurements to the PDCS and updating the PDCS configuration to collect the missing data from the IED.
- Updating the ICSS to collect the above data from the PDCS.
- Updating the historian to collect the above data from the ICSS.

For the company, executing such a plan would have meant implementing multiple changes in an existing operational system by multiple contractors as each system was provided by a different vendor. The company reached the conclusion that a pilot project implemented in such a manner was not feasible for budgetary reasons.

F. Proposed implementation

The company and vendor worked on an alternative design compliant with company policy which consisted of:

- No modification to the PDCS nor the ICSS. Instead, a dedicated collection system leveraging the PDCS PLC would be implemented. Data was to be collected by an existing OPC server on site that would feed the historian. The company would then push the data from the IED.
- As no remote action was possible on the sensor itself, the company decided to implement a dedicated IIoT network without any connection to the process network, leveraging the company telecom network to send data directly to the cloud [5]. This represented the first pilot project testing of a truly integrated IIoT solution on board an FPSO.

G. Thermal monitoring

The on-premise infrastructure is quite simple. Depending upon the number of sensors and the size of the switchgear/switchboard, a number of Zigbee receivers are used. The receivers used provide a serial interface to a Modbus TCP gateway for each switchboard/switchgear to ease interconnection (see Fig. 7).

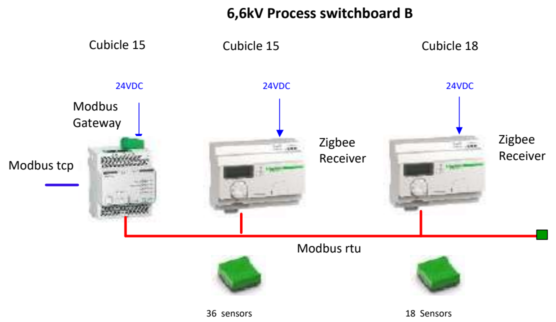

Fig. 7: Local hardware to collect sensor information (6kV B switchboard)

These types of equipment configurations have been added in some of the LV compartments of the MV cubicles and on some of the auxiliary compartments of LV switchboards.

Spare bare fibers were used to connect each TCP gateway to a central cloud gateway located in the telecom room of the FPSO, as were fiber optic switches. The company telecom network has been configured by several company IT teams to allow the data to be pushed to the vendor cloud platform in a secure way (see Fig. 8). Vendor Machine to Machine (M2M) infrastructure is used to collect data from the onboard gateway/datalogger. Cybersecurity measures are implemented at various stages.

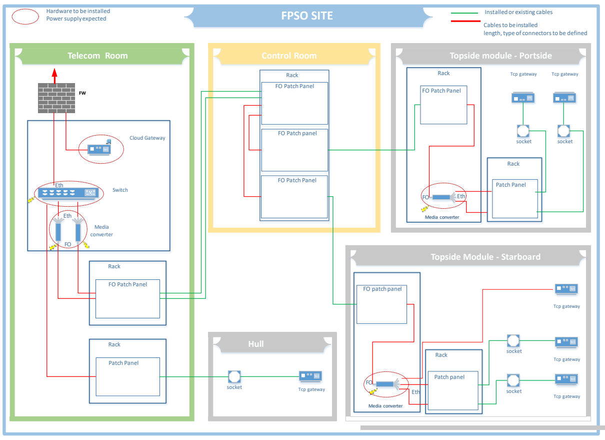

Fig. 8: LAN network implemented on board

Data are polled by the central gateway every 15 minutes, stored inside the gateway, and then pushed to the cloud platform every hour (see Fig. 9).

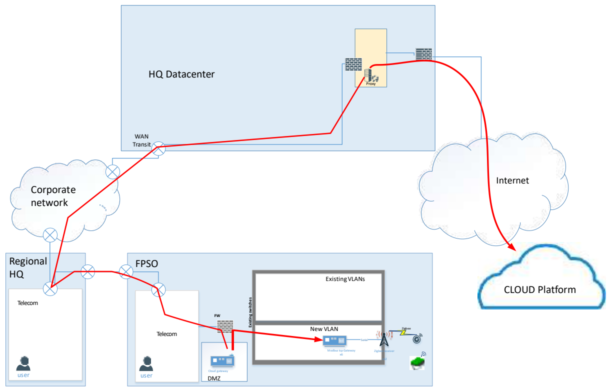

Fig. 9: Overview of the Thermal monitoring data flow

H. Protection relay data

Required data are polled by the PDCS PLC, and are collected by an OPC server before being available on the onboard historian. After two hops, the data are available on the historian at the company's headquarters in France. An extract transform load task is scheduled every 15 minutes on one server to extract relevant data from the historian and generate a CSV file with the measurements. This file is uploaded by the company to a vendor SFTP (Secure FTP) server from where it is ingested by the vendor cloud-based asset monitoring platform (see Fig. 10).

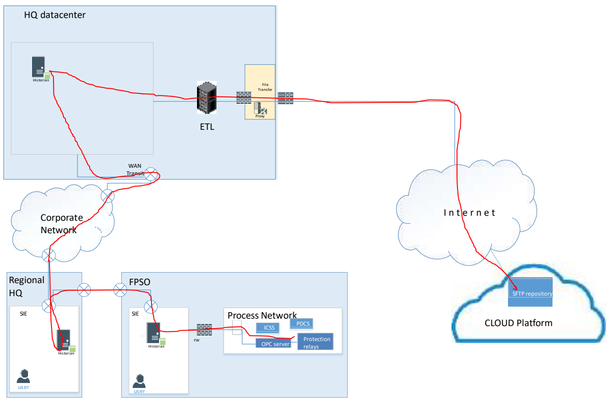

Fig. 10: Overview of the protection relays data flow

In reviewing the full scope of work from the engineering system design phase, the following high-level summary requirements was developed and communicated to the vendor.

- A system of multiple wireless temperature sensors that could be reliably installed
- A collection of sensors that could reliably measure temperature differences within the switchgear cubicles
- The ability to perform predictive maintenance recommendations to assure high availability of electrical equipment
- Improved safety through advanced notice of potential equipment failure
- Assured connectivity and linkages between sensor and data concentrator/aggregator and control system in the harsh industrial environment of an FPSO vessel
- Reliable and secure communication between the offshore site and the vendor's data analysis server
- Absolute compliance with the company's cybersecurity rules and requirements

VIII. IMPLEMENTATION SEQUENCE OF EVENTS

Since the environment on board meant working around the constraints of an existing brownfield installation, a number of preliminary steps needed to be taken prior to launching the pilot project:

- Testing of sensor and technology on a company site in France.
- Preliminary engineering studies that were required to examine the as-built documentation.
- Site survey performed by the company team onboard the FPSO using pictures to identify installation requirements and suitable location to finalize engineering.
- Ordering of equipment.
- Off-site equipment configuration including sensors pairing.
- Shipment of hardware to site.
- Modification of the PLC configuration off site
- Full field shutdown with three main activities, PLC configuration, OPC server configuration and sensor / hardware installation. Installation of sensors on the switchboard/switchgear requires a shutdown and a close coordination with the operation.
- Two data paths to be implemented end-to-end.

A. Installation of sensors during full field shutdown

In November of 2018, a window of opportunity presented itself for the installation of sensors. In order to perform general maintenance, operations on the FPSO are shut down once every five years. The platform stops production for an entire month. A critical milestone for the pilot project pilot was to install new state-of-the-art temperature sensors during this full field shutdown.

The sensors were installed on three types of equipment based on the risk analysis performed by the vendor:

- Within the MV cubicle containing circuit breakers, nine sensors were installed in each cubicle: three on the cable connections, three on the upper arms of the circuit breakers and three on the lower arms of the circuit breakers. Sensors were not installed at the busbar connection as busbar shutdown was highly improbable even during the full field shutdown.
- Within the MV contactor cubicle, three sensors were installed on the field shaper of the upper fuse holder and three sensors on the cable connections (see Fig. 11).
- Within the LV air circuit breaker main incomers, three sensors were installed at each rear connection of the circuit breaker chassis in order to monitor the circuit breaker connection and the circuit breaker cluster.

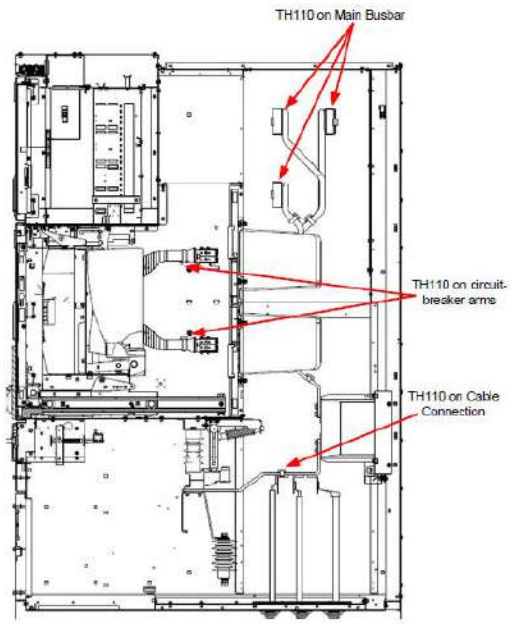

Fig. 11: Location of sensors within the MV circuit breaker cubicle

Two vendor field service representatives were sent on site, for two weeks, to install a total of 383 sensors during the intervention (see Figs 12 and 13).

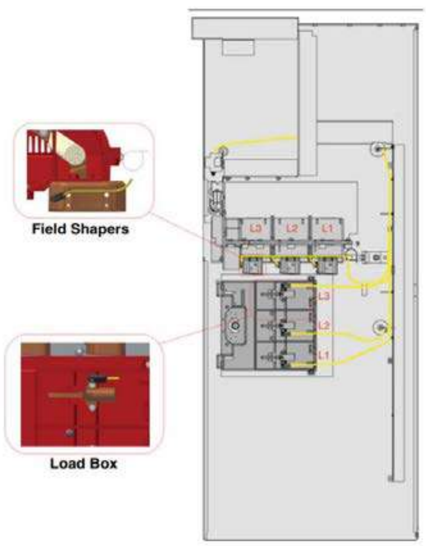

Fig. 12: Location of sensors within the MV contactor cubicle

The emergency switchboard which was identified as an LV switchboard inside the hull electrical room could not be made available for sensor installations, therefore, sensors were relocated to another switchboard.

Fig. 13: Sensors installed on a cable connection of an MV cubicle with circuit breaker

IX. OPERATION

Although some data began to flow to the platform early in February, the pilot project officially went live in May 2019. At that time, the two data streams were up and running after fine tuning actions between vendor and company were performed.

A. Data analysis methodology

Once the data became available on the vendor cloud platform, it was processed by analytics in background mode. A variety of analytics, ranging from basic to advanced analytics, were run. The analytical models that recognize anomalies are sometimes created using machine learning (ML) techniques. Benefits of ML include more accurate diagnosis and predictions and improved operational precision. Results are made available for the vendor Service Bureau experts. The parameters being monitored by the Service Bureau are used to provide the following key performance indicators:

- Usage (load factors, profiles calculated to obtain references and assess the use of the equipment).
- Wear and tear (electrical and mechanical wear of equipment). Circuit breaker mechanical wear, for example, is linked to the number of operations whereas electrical wear is associated to the contact wear.
- Aging (events causing accelerated aging of equipment). Thermal aging is a good example.
- Operating condition (environment and equipment condition).
- Thermal monitoring of bolted connections status (tracking temperatures of components inside of the switchgear). Analytics are tracking any anomalies or inconsistencies not only on a phase basis, but across the three phases. Correlation with current is also performed to verify that heating of the connection is in line with the current.

Gaps between the operating conditions and the design conditions are one of the main reasons for equipment failure.

The reason for analyzing the data is to identify any anomalies that could lead to an issue. Service Bureau experts are tasked with validating the asset health data being gathered from the FPSO.

When an issue is validated, the Service Bureau not only informs the company that an issue exists, but there is also an explanation of the probable cause of the issue. Recommendations are then made for how to best resolve that issue and the next steps to take.

All Service Bureau recommendations are shared with the company contact in the country and the team responsible for managing the on-board pilot project. There is a first-response team available on board the vessel should an issue need to be immediately addressed.

B. Report generation

Once the data is analyzed, insights and reports regarding the status of the on-board electrical equipment are provided to the company through web-based dashboards, where stakeholders within both regional and headquarters locations can view the asset health data. The dashboard reflects the overall health of all of the critical electrical distribution assets through an asset health matrix. This matrix is automatically generated and illustrates, on a continuous basis, the high-level health status of all assets being monitored, using yellow, green and red color-coded indicators (see Fig. 14). In this way, potential risks within their electrical distribution processes are identified.

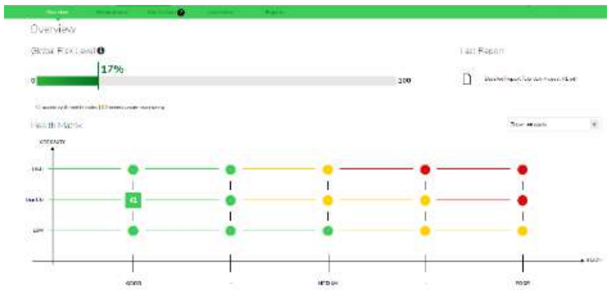

Fig. 14: Graphical interface demonstrating color-coded indicators

The web-based dashboard provides interested parties with the following types of information:

- Secure login screen
- A multi-site view
- A criticality matrix
- A one-line diagram of the installation
- Notifications
- Reports
- Asset view

X. PRELIMINARY FINDINGS AND CURRENT STATUS

Part of the purpose of the pilot project was to determine whether the system could identify and catch potential issues before they manifested themselves into electrical system downtime.

In June of 2019, only one month after having turned on the system, an abnormal temperature issue was identified in one of the MV contactor cubicles responsible for powering one of the sea water pumps. The rise in temperature of the cable connection might be the indicator of a possible current increase but this was not the case at that time. The higher temperature rise was observed on phase C only (see Fig. 15). The temperature discrepancy between the three phases was limited to 5°C which was deemed acceptable but not normal.

However, five hours later, as the current was stabilized, a second temperature increase appeared on phase C only, leading to a temperature discrepancy of up to 10°C. This second increase was not correlated with any current increase. However, the maximum temperature reached (50°C) was far from the absolute temperature limits of the connections (85°C). Thus, the situation was not deemed urgent. Investigations were communicated using an on-event report.

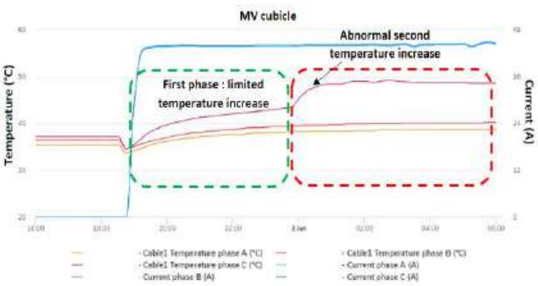

Fig. 15: Abnormal heating of one connection on a MV contactor cable connection

An action plan has been defined which consists mainly of an inspection of the connection. However, the intervention had not been performed yet as of the writing of this paper.

As the asset condition-based monitoring pilot project has progressed, new information has helped to raise awareness regarding the steps required for deploying a successful implementation.

XI. LESSONS LEARNED

Implementation of such technologies onboard an existing installation was a significant challenge for multiple reasons.

The FPSO was engineered more than 10 years ago. Changes are quite difficult to implement while an existing facility is under operation. Due to the “siloed” nature of the layered systems available on the FPSO, the pilot project might have been abandoned for budgetary reasons. However, a new, disruptive approach, which was fully aligned with company standards, has enabled the pilot project to move forward.

Adding even a single box to a low voltage compartment is sometimes not feasible. All assumptions regarding hardware implementation had to be confirmed through pictures.

The objective of the pilot project is to leverage the data to identify the condition of the equipment. For MV circuit breakers, the parameters of interest should be provided by the IED, but the availability depends on how it was configured and wired at construction stage. For example, one key parameter for a circuit breaker is the charging time (i.e., the time it takes for the spring to arm), in order to evaluate the condition of the mechanism. It was observed when the process was completed that all charging times were reported as null because the end of charging position was not wired to the logic input of the IED as not part of the specification.

The same situation occurred for the LV incomer circuit breaker fitted with an MV IED. It is not common on such installations for condition monitoring data—like contact wear or health state built into the vendor Electronic Trip Unit (ETU)—to be available. Implementing condition solutions which are leveraging the data available requires dedicated engineering practices and the implementation of smart equipment. This requirement has to be included in the project specification as EPC (Engineering Procurement and Construction) contracts are mainly cost driven and will only provide the minimum compliant equipment.

Implementing such a pilot project requires multiple teams to be involved: electricians, instrumentation, cybersecurity, IoT, telecom, with teams belonging to different companies and departments (i.e., on site, affiliate, headquarter, subcontractor). The role of the project manager is also key. It took less than 3 months to make the data available inside of the cloud platform.

The only true success factor in such a pilot project is the business benefit accrued. Sending data outside the facility / company is accepted only if there is a business value, and cybersecurity should not be considered a roadblock. However, cybersecurity has to be carefully negotiated and implemented.

Regarding thermal monitoring of bolted connections, it was confirmed that the absolute temperature of the connection, even taking the current into account, does not allow for the proper checking of connection quality [6]. Phase discrepancy enables a more precise and smarter insight.

XII. LOOKING FORWARD

The pilot project was still underway as this paper was written, but preliminary findings confirm that the wireless and battery-less technology is working. In parallel to the pilot project, several initiatives between the company and vendor were agreed upon to identify how the pilot project can be extended to increase the value provided.

Common pain points reported to vendor by the offshore industries are :

- Cable termination / Cable head monitoring - Issues are occurring with more frequency mainly due to quality issues when the connections are made at the construction yard.
- Subsea cable monitoring - This allows detection of impending failure on a subsea cable in order for it to be repaired before an extended period of unanticipated downtime occurs.
- Big Variable Speed Drive failures
- An issue of partial electrical discharge surrounding motors needed to be analyzed and addressed.
- A faulty single cell within a string of UPS batteries can jeopardize the capacity of the whole battery.

Within the context of the pilot project the following topics are currently under discussion:

- Increase the analytic coverage (for example by using big data techniques vis-à-vis the installed base to allow further correlation and a more intense statistical approach).
- Extend the equipment range hosting thermal sensors (for example 13.6kV switchgear or on the gas turbine generator connection.
- Involve other vendor equipment like 13.6 kV switchgear.

- Include additional equipment like electrical motors using Motor Electrical Signature Analysis for monitoring rotating equipment or batteries used inside of AC or DC UPS (Uninterruptible Power Supply).
- Incorporate soon-to-be-available new sensors from the vendor like ozone sensors to detect corona effect or heat detection sensors leveraging the volatile organic components that are emitted when an insulation material like PVC sheath is heating.
- Modify the data exchange mechanism between the company and the cloud platform for live streaming.

XIII. CONCLUSIONS

The oil company had experienced issues regarding electrical infrastructure and regular testing is challenging due to lack of suitable technologies. Any loss of production due to failure within their electrical systems network represents a huge loss of production and can have safety and environmental potential implication. That's why the decision was made to explore a data-driven solution that would enable the company to remotely monitor the health of their electrical infrastructure.

As believers in the overall vision that the old ways of monitoring and maintaining electrical can be optimized, the pilot project was streamlined to encompass a very narrow focus that introduced minimal disruption while radically altering the way electrical equipment data was captured, analyzed and acted upon.

Cybersecurity emerged as the most important issue to address. Rather than adopting a cookie-cutter, one-size-fits-all approach, the team decided to analyze the importance of the data being gathered, and the possible exposure of electrical assets and related data to outside control or view. As a result, two different systems of data gathering and consolidation were implemented in order to comply with the company requirement

The company also was willing to overcome the traditional practice of keeping all facility-generated data on site. Instead, the project team pursued the idea of testing the potential for IoT, data driven techniques, and cloud-based solutions to identify and address electrical system availability issues.

The oil & gas industry is undergoing a transformation that relies heavily on the ability to implement data-driven solutions. Industry observers have estimated that digitalization and related initiatives will create up to $1.6 trillion of value for the oil & gas industry, its customers and wider society [7].

Deployment of digitization technologies such as smart sensors and advanced analytics will modernize operations, drive efficiencies and improve breakeven cost of production. These newer technologies lower overall capital expenditures while increasing process efficiency and reducing maintenance costs.

But this is an evolution and not a revolution. Much is to be learned from pilot project exercises such as the work being conducted on Floating Production Storage and Offloading (FPSO) vessels.

XIV. NOMENCLATURE

AC Alternative Current.
CB Circuit Breaker.
DC Direct Current.
ENMCS Electrical Network Monitoring & Control System.
EPC Engineering Procurement & Construction.
ESD Emergency Shutdown.
ETU Electronic Trip Unit.
FFSD Full d Shutdown.
FPSO Floating Production Storage Offloading.
HSE Health Safety & Environment
ICSS Instrumentation Control and Safety System.
IIoT Industrial Internet of Things.
IR Infra Red.
IED Intelligent Electronic Device.
LV Voltages less than 1kV.
M2M Machine to Machine.
MV Voltages between 1kV and 40kV.
OPC OLE for Process Control.
PDCS: Power Distribution Control System.
PLC Programmable Logic Controller.
RF Radio Frequency
SFTP Secure File Transfer Protocol.
UPS Uninterruptible Power Supply.

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XVI. VITA

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HYBRID TECHNIQUE LOAD FORECAST AND ESTIMATION FOR UPSTREAM OIL & GAS INDUSTRY

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Abstract - Investment in the infrastructure of the power generation is one of the key portions of Oil & gas production projects. This infrastructure shall cover all power demand of production facilities as sales agreement and long-term field development plan. The load forecast and estimation shall be developed at the early phase to identify the power demand which significantly impacts project CAPEX.

As the normal practice, the total load demand is calculated based on equipment rating. This works well for midstream and downstream. However, this method might not result as well as others for upstream due to uncertainty from process variation and production profile.

The "Hybrid Technique" was thus implemented in two (2) Oil fields in 2014 and 2017 which results in $30 million saving and six (6) months early production gain.

This paper is to describe the new methodology to estimate better load forecast by using precess operation data into account. This method has been proved with good results in those two projects.

Index Terms — Hybrid technique, Load forecast, Load estimation.

I. INTRODUCTION

At the early stage of the oil and gas upstream project, it is necessary to estimate the power consumption correctly to ensure that the operation can operate smoothly without a power shortage, resulting in a financial return as planned. However, the power consumption can change over time due to the change in production volume and requirement over the production asset lifetime. The new load forecast will be used to determine the change in infrastructure development.

The accuracy of the load forecast is key to determine the CAPEX of the project. The over-estimation will result in oversized electrical infrastructure. On the other hand, the under-estimation might lead to production deferment, additional investment costs for infrastructure upgrade and expansion.

This issue occurred at Thailand's Oil field in 2013. This Oil field comprises one (1) Central Production Facility station, four (4) Local dehydration stations, and more than 300 operating wells. In order to achieve the company production target, this field was planned to increase crude oil production by increasing the number of artificial lift equipment (i.e. beam pump, progressive cavity pump or PCP and electrical submersible pump or ESP) and unlocking all de-bottlenecking points in the production facility. This new equipment required a large electrical power supply at various well site locations; hence, several electrical projects were thus initiated e.g. power generation system upgrade, 22 kV transmission network system extension, and new additional electrical distribution system.

At the early stage, the electrical load forecast was developed as per the field development plan and normal engineering practice. The result showed that electrical load would rapidly grow and reach 34.91 MW by 2021 which is greater than the in-plant power generation capacity by 11.21 MW. Therefore, additional power generation is needed.

The feasibility study of this 11.21MW additional power was conducted for finding the most economical solution. This study showed that 'co-generation between electricity and steam' is the best option for both technical and economic viewpoints. The estimated investment is about $30 million.

During 2012-2013, before the financial investment decision of the new power plant, the argument on the precision of the electrical load forecast (version 2013) was raised within the engineering team because from the calculation, the estimated load was about 27 MW but the actual load was only 12-14 MW. Therefore, the revisit on load forecast calculation was deeply investigated.

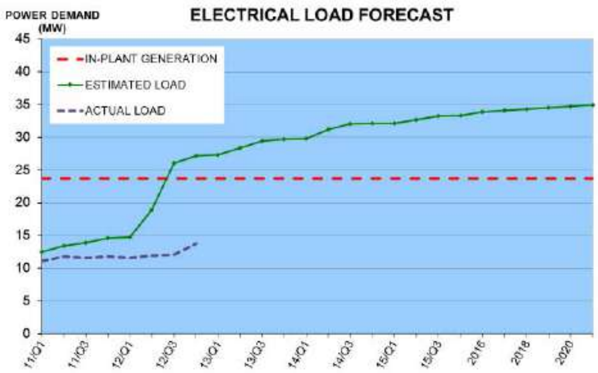

Fig. 1 The existing electrical load forecast

II. GENERAL ENGINEERING PRACTICE OF LOAD CALCULATION (NORMAL METHOD)

The general engineering practice of load calculation (normal method) has been widely used to calculate total load demand in all industrial plants. One of the best references is "Handbook of Electrical Engineering: For Practitioners in the Oil, Gas and Petrochemical Industry" by Alan L. Sheldrake [2]. Prior to calculating total load demand, each load (vital, essential, and non-essential loads) shall be reviewed and divided into typically three duty categories:

- Continuous duty;
- Intermittent duty;
- Standby duty (those that are not out of service).

Hence the total load consumption of each switchboard will usually be determined from an amount of these three categories. Call "*C*" for continuous duty, "*I*" for intermittent duty, and "*S*" for the standby duty. Let the total amount of each at a particular switchboard *j* be C_{jsum}, I_{jsum}, and S_{jsum}. Each of these totals will consist of the active power and the corresponding reactive power.

In order to estimate the total consumption for the particular switchboard, it is necessary to assign a diversity factor (*D*) to each total amount as per their operating nature. Let these factors be D_{cj} for C_{sumj}, D_{ij} for I_{sumj} and D_{sj} for S_{sumj}. Different types of plants may apply different diversity factors.

Table I shows the range of suitable diversity factors. The factors should be chosen in such a manner that the selection of main generators, transformers and main feeders are not excessively rated, thereby leading to a poor choice of equipment in terms of economy and operating efficiency.

TABLE I
DIVERSITY FACTORS FOR LOAD ESTIMATION

Type of project	D_c for C_{sum}	D_i for I_{sum}	D_s for S_{sum}
Conceptual design of a new plant	1.0 to 1.1	0.5 to 0.6	0.0 to 0.1
Front-end design of a new plant (FEED)	1.0 to 1.1	0.5 to 0.6	0.0 to 0.1
Detail design in the first half of the design period	1.0 to 1.1	0.5 to 0.6	0.0 to 0.1
Detail design in the second half of the design period	0.9 to 1.0	0.3 to 0.5	0.0 to 0.2
Extensions to existing plants	0.9 to 1.0	0.3 to 0.5	0.0 to 0.2

The total load can be considered in two forms as follow:

$$TPRL = \sum(D_c C_{sumj} + D_i I_{sumj}) \quad (1)$$

$$TPPL = \sum(D_c C_{sumj} + D_i I_{sumj} + D_s S_{sumj}) \quad (2)$$

Where

TPRL	Total plant running load (kW)
TPPL	Total plant peak load (kW)
D_c	Diversity factor for continuous load
C_{sumj}	Total continuous load for switchboard *j*
D_i	Diversity factor for intermittent load
I_{sumj}	Total intermittent load for switchboard *j*
D_s	Diversity factor for standby load
S_{sumj}	Total standby load for switchboard *j*

The above method can be used very effectively for estimating power requirements at the beginning of a new project, when the details of equipment are not known until manufacturers provide adequate information i.e. installed rating, load factor, efficiency and power factor; hence a more accurate version of load schedule can then be rectified.

Total plant running load (TPRL) is normally taken into account to select power sources e.g. gas turbine, diesel engine, gas engine, solar PV, wind turbine, receiving power from grid, etc. In parallel, the total plant peak load (TPPL) will be brought to the selection of power source and distribution equipment rating e.g. generator, transformer, and feeders.

Oil companies are used to apply this approach with different diversity factors based upon experience gained over many years of plant design and their operating paradigm.

Nevertheless, this practice still has some flaws which led to inaccurate plant load estimation. Therefore, further investigation on the practice was conducted and discussed in other relevant sections in this paper.

III. INVESTIGATION OF THE EXISTING LOAD FORECAST

A. *Data gathering*

It is necessary to gather data that directly and indirectly relates to load forecast preparation in order to identify the gap between the existing load forecast study and actual plant operating conditions. The gathered information is as below:

1) The existing load forecast study and calculation: to understand the calculation method and assumption;

2) Equipment manufacturing data i.e. pump performance curve, pump data sheet, etc.: to understand equipment behavior that impacts power consumption;

3) Field development plan: the production profile, water injection profile, and future development projects, artificial lift plan, etc.

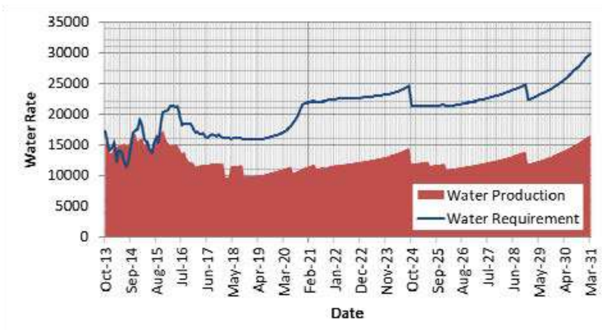

Fig. 2 Example of local dehydration water profile

TABLE II
ARTIFICIAL LIFT PLAN (ACCUMULATED UNIT)

Description	2013	2014	2015	2016	2017	2018
Beam Pump (BP)	171	210	250	271	307	336
Electric Submersible Pump (ESP)	37	57	59	61	62	63
Progressing Cavity Pump (PCP)	7	7	7	7	7	7

4) PI ProcessBook data (real-time process data system): all available online digital data from the PI system were extracted to study actual equipment operating conditions e.g. pump status (start/stop), pump flowrate, etc.

5) Field daily report: production rate (crude and water) and plant power consumption.

6) Additional field data e.g. actual load power usage and actual load operating time were recorded.

B. Finding

1) Error from Typical load factor

In order to avoid delay of long lead electrical equipment (generator, transformer, etc.), the equipment sizing, and equipment selection shall be completed at the early stage of the project. Normally, the actual load factor is not available at this period, therefore, the typical load factor from API 610 [1], Table III, is adopted in the total load consumption calculation. However, after the project is completed, each load factor was never been updated to the final document. To eliminate the error, the actual load factor as gathered from the manufacturing document was updated in the new calculation.

TABLE III
LOAD FACTOR OF MOTOR DRIVEN PUMP

Motor Nameplate Rating		Percentage of Rated Pump Power	Load Factor
kW	HP		
<22	<30	125	0.80
22-55	30-75	115	0.87
>55	>75	110	0.91

2) Incorrect diversity factor

The diversity factor of the beam pump was found that it was incorrect. Beam pumps are the biggest load at well sites (more than 300 units were planned to be installed within 2017, with 45kW each), thus, the incorrect diversity factor significantly affected calculation accuracy. According to the existing load forecast calculation, the diversity factor of 1.0 was used but in fact, the diversity factor of the beam pumps is difficult to specify due to their unpredictable character subject to well's conditions. From observation, some units operated all the time while some operated only 10% or less, depending on their subsurface conditions and operation adjustment. Thus, the status of beam pumps (on/off), was extracted from the PI system and used in the calculation. As a result, the average diversity factor (percentage of operating time) of the beam pumps is only 0.49, 51% saver compared to the original design figure, and was updated in load forecast calculation.

3) Uncertainty of sub-surface characteristics

Uncertainty is the nature of the upstream business. It is hard to determine subsurface formation and behavior; therefore, during the early development phase, all possible scenarios are considered for the equipment selection. Most of the equipment ratings are selected to serve a wide operating range and flexible for various scenarios. The actual operating point is changed as per the dynamic of subsurface information and profile.

However, the load forecast study was calculated using the aforesaid equipment's design rating with a typical load duty factor. Therefore, the outcome of the study did not correlate with the actual operating conditions (flow rate, pressure, etc.). This is found as the key root cause for the discrepancy between the load forecast and the actual power usage.

According to this finding, it can be concluded that the normal engineering practice, which commonly uses in the oil and gas industry. may not fit for all cases especially in the oil field which has sub-surface uncertainty. To optimize the design and selection, a new specific methodology was developed in 2014.

IV. HYBRID TECHNIQUE METHOD

A. Model

The new methodology is initiated so called "Hybrid technique load forecast and calculation". The approach needed a tight collaboration between the electrical engineer, process engineers, operation team, and asset planning team in order to understand actual plant facility behavior. All field data e.g. actual load power usage and actual load operating time was used and analyzed in a multi-view of operating paradigm. It was found that load calculation should not base on only electrical and mechanical design parameters but also hidden parameters that impact the plant demand significantly i.e. equipment behavior and availability.

With the electrical load forecast including operational data analysis, the "Hybrid technique load forecast" was successfully developed. This method had never been applied to any oil and gas industries. The key concept of the idea is to establish and implement several calculation models to include operational behavior parameters as shown below:

The normal load forecast method:

$$\text{Total loads} = \sum L_i \times D_i \qquad (3)$$

Where

L_i Equipment design's load
D_i Equipment diversity factor

The hybrid technique load forecast method:

$$\text{Total loads} = \sum L_i \times D_i \times B_i \qquad (4)$$

Where

L_i Equipment design's load
D_i Equipment diversity factor
B_i Equipment behavior factor

The equipment behavior factor is the correlation factor between power consumption at the operating conditions and design conditions. Each equipment category (pump, compressor, etc.) will have its characteristic between power consumption and operating conditions (flow rate, pressure, etc.). Moreover, the investigation also shows that most of the equipment with dynamic operating conditions is the pump. Therefore, the motor-driven pump's behavior factor was focused on in this study.

Behavior factor for pump

The relation between power consumption and operating conditions are as follow:

$$L \propto F \times \Delta P \qquad (5)$$

Where

L Pump load or output power
F Pump flow rate
ΔP Pump difference pressure between suction and discharge

Since the difference pressure of the pump is quite stable, the relation between power consumption and operating conditions can be simplified as follow:

$$L \; \alpha \; F \quad (6)$$

Thus, the pump's behavior factor can be calculated as below:

$$B_i = F_{io} / F_{id} \quad (7)$$

Where

B_i	Pump behavior factor
F_{io}	Pump operating flow rate
F_{id}	Pump designed flow rate

In addition, from historical data analysis, it was found the special operating condition of the artificial lift pump is pump availability. Since several artificial lift pumps have been installed without ramping up the maintenance team, resulting in less than 100% availability. This analysis also helps the maintenance team to identify their lack of manpower and a new target to improve the availability of artificial lift equipment.

TABLE IV

ARTIFICIAL LIFT EQUIPMENT AVAILABILITY

Description	2014	2015	2016	2017
Beam Pump (BP)	70%	71-82%	83-90%	90%
Electric Submersible Pump (ESP)	70%	71-82%	83-90%	90%
Progressing Cavity Pump (PCP)	100%	100%	100%	100%

Therefore, the artificial lift pump's behavior factor can be modified as below:

$$Bi = (F_{io} / F_{id}) \times A_i \quad (8)$$

Where

B_i	Pump behavior factor
F_{io}	Pump operating flow rate
F_{id}	Pump designed flow rate
A_i	Pump availability factor

After the estimation of the new load consumption method was completed, the total running and peak loads from such kind of load categories (continuous, intermittent, and standby) were achieved. Finally, the hybrid model verification was performed to fine tune the parameters of each load type against the actual load at operating conditions.

B. Model validation

For proof of the concept of using a new model methodology, the validation process had been examined with the historical actual three years plant load as per Table V.

TABLE V

Model Validation assessment result

Date	Actual Peak load (MW)	Model Peak Output (MW)	Difference (MW)
20-Jan-11	14.27	14.91	0.64
19-Mar-11	12.06	11.55	-0.51
19-Apr-11	13.47	12.73	-0.74
19-Jun-11	12.64	12.70	0.06
19-Jul-11	13.18	12.58	-0.60
18-Oct-11	10.20	11.83	1.63
19-Jan-12	13.07	13.53	0.46
19-Mar-12	12.50	12.25	-0.25
18-Apr-12	12.00	11.91	-0.09
19-Jun-12	13.01	11.91	-1.10
19-Jul-12	12.54	12.32	-0.22
19-Oct-12	14.47	13.57	-0.90
18-Jan-13	15.25	14.66	-0.59
20-Mar-13	15.93	14.74	-1.19
18-Apr-13	16.83	16.89	0.06
19-Jun-13	16.89	15.57	-1.32
18-Jul-13	17.00	15.53	-1.47
18-Oct-13	14.31	15.53	1.22
18-Jan-14	15.70	15.85	0.15
19-Feb-14	15.11	15.83	0.72
20-Mar-14	13.99	15.29	1.30
17-Apr-14	14.17	15.20	1.03
Average of difference (MW)			-0.08

The results of the sampling show that the output from the model is close to the actual load. The average difference between model output load and actual load is about -0.08 MW which is technically acceptable.

V. RESULTS

Load forecast is plotted and shown as below:

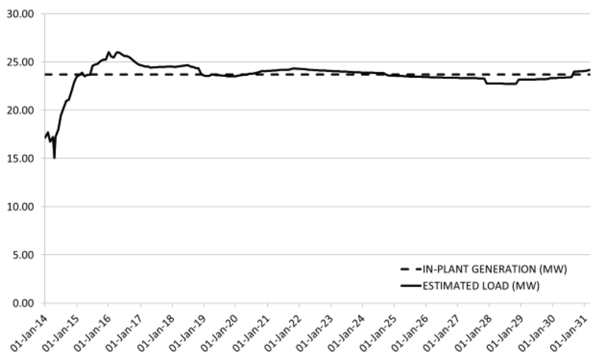

Fig. 3 New load forecast with Hybrid technique

The result from the new load forecast is summarized as below:

- In-plant generation remained at 23.7MW;
- The estimated load forecast would reach the highest demand of 26.05MW in January 2016 and decline down to 22.76 - 24.30MW as per Fig.3 between 2017 and 2031 before landed at 24.19 MW in the year 2031;
- During 2014, the estimated load forecast rapidly increased from 17.14MW to 22.92MW (5.78 MW) from the following activities:
    - o Water profiles are rapidly increased from 29,347 Barrel Per Day (BPD) in January 2014 to 80,155 BPD in December 2014;

- o 59 units of artificial lift (39 beam pump units and 20 oil ESP units) will be installed in the year 2014.

From the validation, no significant difference between the hybrid load forecast and the actual plant load is found; therefore, it is proved that the new hybrid technique load forecast model is more accurate and can be used for future estimation.

VI. ANOTHER USED CASE IN ONE OF THE OIL FIELDS

One of the oil fields planned to increase its production from 20,000 BPD to 40,000 BPD by plant expansion project. The project comprises production facility upgrades and a new facility to enhance oil production. The electrical power consumption was expected to increase from 15.13 MW to 30.48 MW while in-plant power generation was only 18 MW. Thus, electrical facilities in several areas need to be upgraded i.e. new gas turbine generator (GTG) and switchgear extension. Refer to the electrical load schedule calculation, the total load during the first oil milestone is 27.58 MW which requires the new GTG. Since GTG has a long lead time from ordering to delivery and becomes the longest bottleneck in the process, the project schedule of additional oil production was originally set according to this delivery time.

During tendering preparation, there was an issue raised on the precision of electrical load calculation because the actual load was only 10 – 12 MW compared to the calculation of 15.15MW. The re-visit of load calculation is initiated.

The same root cause is found in this field. Thus, the “Hybrid Technique” was used to improve the electrical load calculation. The investigation also shows that most of the equipment which operate with the dynamic operating conditions are pump and compressor. Therefore, the study is focused on the behaviors of pumps and compressors in field operation. The pump’s behavior factor is shown in section IV “Hybrid Technique Method” while the compressor’s behavior factor is as below

Behavior factor for compressor

Per the thermodynamic calculations of the polytropic process, the relation between power consumption and operating conditions are as follow:

$$L \propto F \times [(P_2/P_1)^{\{(K-1)/(K \times E_p)\}} - 1] \quad (9)$$

Where

L	Compressor load or output power
F	Compressor flow rate
P_1	Compressor suction pressure
P_2	Compressor discharge pressure
K	Adiabatic exponent (constant parameter)
E_p	Polytropic efficiency (constant parameter)

Since the suction and discharge pressures of the compressor are quite stable, the relationship between power consumption and operating condition can be simplified as follow:

$$L \propto F \quad (10)$$

Thus, the compressor’s behavior factor can be calculated as below:

$$B_i = F_{io} / F_{id} \quad (11)$$

Where

B_i	Compressor behavior factor
F_{io}	Compressor operating flow rate
F_{id}	Compressor designed flow rate

After the above information is considered to the new model, the validation process was carried out by comparing the model outcome with the historical data. The hybrid method was proven for its accuracy.

The estimation result with “Hybrid Technique” is as shown in the figure below:

Fig. 4 Electrical load estimation vs asset production

By study results from the hybrid calculation model, the existing in-plant power generation can support production up to around 33,100 BPD. Therefore, the plant can start to gain more production from 20,000 to 33,100 BPD immediately after the installation of other facilities without the new GTG installation, resulting in 6-month of early production gain

VII. RECOMMENDATION

Although the model for the operating field was already developed based on actual operating conditions as mentioned in the hybrid technique, there are uncertainty factors from major activities and changes of the production development plan. If these factors deviate from the original assumption, the accuracy of the load forecast will drop dramatically and lead to a wrong financial decision. It is recommended to regularly review and keep updating load forecast and estimation to ensure the high accuracy of the calculation.

Moreover, it is to be noted that there are many assumptions in the calculation. In case high accuracy is required, the individual pump characteristic shall be determined in the model one by one. Operating data of the major equipment should be recorded for deep analysis. By this technique, load behavior and availability shall be precisely specified for high quality modeling development.

VIII. CONCLUSIONS

From the result of the “Hybrid Technique” method, it is proven that this new method is suitable for the upstream oil and gas business which has an uncertainty from process variation and production profile. This technique requires both normal engineering practice, multi-discipline knowledge, and historical operating data to support the modeling.

The "Hybrid Technique" was successfully implemented in two (2) Oil fields in the year 2014 and 2017, saving $30 million in CAPEX and an early production gain of six (6) months.

The innovation of the "Hybrid Technique" load forecast methodology becomes one of the key decision tools for future investment and development of power generation for the upstream.

IX. ACKNOWLEDGEMENTS

The authors would like to thank Nucha Sawawiboon and Nuttapong Taranut for raising questions and their friendly support. Also thanks to Surakit Kanokngam and Anusorn Siriyut who provided support for process system and equipment sizing.

X. REFERENCES

[1] API STD 610 Centrifugal Pumps for Petroleum, Petrochemical and Natural Gas Industries

[2] Alan L. Sheldrake, *Handbook of Electrical Engineering: For Practitioners in the Oil, Gas and Petrochemical Industry*.

XI. NOMENCLATURE

TPRL	Total plant running load (kW)
TPPL	Total plant peak load (kW)
BP	Beam pump
ESP	Electrical submersible pump
PCP	Progressing cavity pump
BPD	Barrel Per Day
GTG	Gas Turbine Generator
D_c	Diversity factor for continuous load
C_{sumj}	Total continuous load for switchboard j
D_i	Diversity factor for intermittent load
I_{sumj}	Total intermittent load for switchboard j
D_s	Diversity factor for standby load
S_{sumj}	Total standby load for switchboard j
L_i	Equipment design's load
D_i	Equipment diversity factor
L	Equipment load/output power
F	Equipment flow rate
ΔP	Pump difference Pressure between suction and discharge
B_i	Equipment behavior factor
F_{io}	Equipment operating flow rate
F_{id}	Equipment designed flow rate
A_i	Equipment availability factor
L	Equipment load/output power
P_1	Compressor suction pressure
P_2	Compressor discharge pressure
K	Adiabatic exponent (constant parameter)
E_p	Polytropic efficiency (constant parameter)

XII. VITA

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ARC FLASH HAZARD MITIGATION TECHNIQUES IN PRACTICE

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Abstract – This paper presents practical mitigation techniques to reduce incident energy, by graphically visualization of theoretical and empirical studies in order to understand the dynamics of parameters that influence the energy released during an arc flash fault event. The practical use of mitigation techniques is based on the hierarchy of control measures from NFPA 70E [1]. The subjects in focus are; *Substitution* of existing equipment and recommendations for good design practices, *Engineering controls* to reduce the arcing current or the arc duration, increase the working distance and introduce work procedures. All is to make electrical work safer and to ensure high reliability of electrical system performance. For further considerations a method to handle cases of generator near nature in relation to arc flash calculations is proposed.

Index Terms – *Arc Flash, Mitigation Techniques, Regulations & New Standards, Good Design Practice, End User, Awareness, Personal Safety, Hierarchy of Control Measures, Substitution, Engineering Control, Operation & Maintenance, Life Cycle Management*

I. INTRODUCTION

Are you aware of the incident energy in your electrical systems? Have you considered what can bring the incident energy down? Are you aware of the danger an arc flash event can cause in an electrical installation? These are some of the questions that will be answered in this paper.

During the last decade, there has been high focus on arc flash hazards in the electrical industry. It is mainly due to a higher focus on the risks and because EN 50110-1 [2] has had an update on the topic in *Annex B.6 Arc Hazard* that focuses on the consequences associated with an arc flash fault event in electrical installations. Today, it is mandatory for all new electrical installations in the United States (US) to include an arc flash analysis according to NFPA 70E [1] to the project documentation in order to follow US federal law of regulation. This indicates that arc flash is a topic that we will see more and more all over the world in order to increase personal safety.

Statistically, arc flash fault events occur due to:

- Human errors, when someone is working on or near live current carrying parts creating an unintended contact between two or more conductive elements.
- Mechanical wear of equipment, corrosion on electrical parts and contactors.
- Faulty connections, wiring failure.
- Pollution, dust, leakage or other substance that may create an accidental electrically conductive connection.

One of the primary reasons for high incident energies are inadequate settings of protective devices, which earlier have been based on short-circuit studies dismissing considering the influence of an arcing current. This paper focusses on high incident energy and describes the mitigation techniques to be used in practice in order to reduce the risk and maybe even eliminate it through hierarchy of control measures from NFPA 70E [1], starting from most to least effective methods as shown in Fig. (1). This paper reviews practical mitigation techniques within *Substitution* and *Engineering Controls* as highlighted with red in Fig (1).

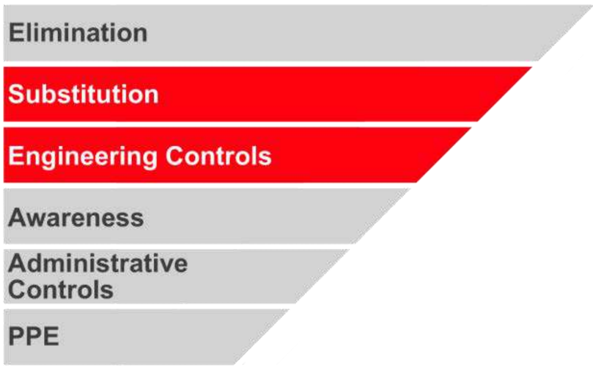

Fig. 1 – NFPA 70E [1] Hierarchy of Control Measures

The intention is to share knowledge, create more awareness and define mitigation solutions to the arc flash hazards by combining the experiences from an engineering perspective as well as a practical approach. Simple techniques such as awareness training and work procedures can reduce or even eliminate the risks by removing the personnel from potentially dangerous situations. It is not complicated to make an analysis and present the risks, but the end users need to know how to use the outputs in relation to incident energy and how to mitigate Arc Flash Hazards via handling, reducing or removing the risk. The important part is to take the action needed to implement control measures by obtaining safety of personnel and to ensure a reliable electrical system at the same time.

A discrepancy has been observed between fault calculations based on remotely located generators and a situation with power generation close by, with higher DC component but faster decay. This paper proposes a method for further considerations of arc flash hazard calculations including current transients and direct current (DC) contribution from a theoretical perspective.

The article ends with a memorandum of advice to the end user of electrical systems who either own or operate systems that could potentially be at risk of carrying high levels of incident energy.

II. ARC FLASH CALCULATIONS IN PRACTICE

Many can do arc flash hazard calculations, even a computer can do it with the right inputs. But to understand the dynamics of the parameters and the equations in a practical relation can be quite abstract. From a practical point of view this is where the engineering work begins.

An arc flash occurs when one or more electrical conductors are located close to each other and with an unexpected fault current passing through, typically in case of a short-circuit. In this situation, an ionization process of the air can take place as a result of various factors, such as high potential differences on electrically conductive devices and the gap between conductors which lead to a low-impedance connection that allows a current named arcing current, to flow through the air gap between the conductors in a plasma channel.

Before starting to use any mitigating techniques to reduce high incident energies, a general understanding of the influencing parameters must be set into relation. Different analysis models have been presented previously to calculate incident energy caused by an arc flash fault event. This section walks through a theoretical derivation known as the Ralph Lee method [3], to understand the dynamics of the parameters and present the empirical determined method known as IEEE std. 1584-2002 method [3] for further demonstration. From an electrical engineering perspective this can be investigated with a simple circuit in order to derive a method of maximum power exposure in case of an arc flash incident. Considered is an arc flash fault event as an electrical circuit containing a power supply with a fixed system voltage U_{sys}, a system impedance Z_{sys} and a variable arc impedance Z_{arc} representing the impedance of the ionized air of an arc flash, as shown in Fig. (2).

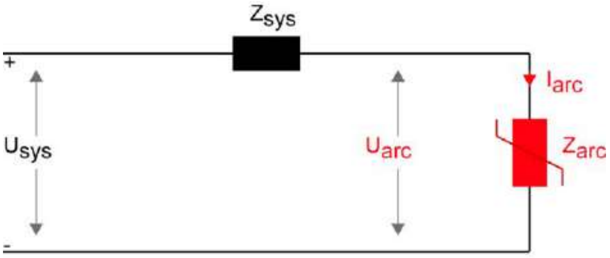

Fig. 2 – Engineering approach to arc flash fault event

The hardest variable to determine in this circuit is the arc impedance Z_{arc} as it depends on the distance between conductors and the surrounding humidity. Using basic circuit theory, it can be derived that the arcing current I_{arc} flowing through the air between the conductors as function of the arc impedance Z_{arc} can be expressed as shown in Eq. (1).

$$I_{arc}(Z_{arc}) = \frac{U_{sys}}{Z_{sys} + Z_{arc}} \; [A] \tag{1}$$

where

I_{arc}	Arcing current [A];
Z_{arc}	Arc impedance [Ω];
U_{sys}	System voltage [V];
Z_{sys}	System impedance [Ω];

Having the arcing current expressed as function of the arc impedance, it can be substituted into a general equation calculating the arc power exposure as shown in Eq. (2).

$$P_{arc}(Z_{arc}) = \left(\frac{U_{sys}}{Z_{sys} + Z_{arc}}\right)^2 \cdot Z_{arc} \; [W] \tag{2}$$

where

P_{arc}	Arc power exposure [W];

From Eq. (2), a plot of the maximum possible power exposure in the arc flash can be visualized by increasing the arc impedance Z_{arc} from $0 \rightarrow \infty$ as visualized on the x-axis in Fig. (3). Plotting this function in a given time interval with an example of a 400 V. system voltage and a system impedance equals 10 Ω, it is possible from Fig. (3), to realize that the maximum power exposure in the arc flash happens exactly when the relation between the system impedance Z_{sys} and the arc impedance Z_{arc} is equal as shown with a dotted grey line.

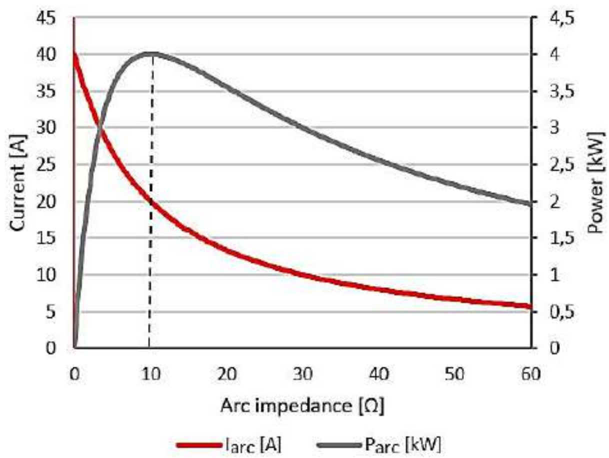

Fig. 3 – Maximum power method derivation

This allows the previous expression from Eq. (2) to be simplified to express the maximum arc power exposure P_{max} in the arc flash as per Eq. (3).

$$P_{max} = \left(\frac{U_{sys}}{2 \cdot Z_{sys}}\right)^2 \cdot Z_{sys} = \frac{U_{sys}^2}{4 \cdot Z_{sys}} \; [W] \tag{3}$$

where

P_{max}	Maximum arc power exposure [W];

Transferring the electrical representation of an arc flash fault event into energy, the maximum power exposure of an arc flash in a given period assuming worst case arc duration conditions to account for current limiting devices, is equal to the total arc energy as per Eq. (4).

$$E_{arc} = P_{max} \cdot T_{arc} \; [J] \tag{4}$$

where

E_{arc}	Arc energy [J];
T_{arc}	Arc duration [s];

Using the total amount of arc energy to assess personal safety would be a very conservative approach, as all vital parts of a human body is at least in a working distance equal to the length of an arm, from live electrical equipment, defined in the IEEE std. 1584-2002 [3] to be 455 mm (typical value). Considering the arc flash as a source of light in an open air environment, the light will radiate radially from the source as shown in Fig. (4). Just as light, the energy intensity from an arc flash will decrease with the distance to the arc flash fault location. By dividing the total amount of arc energy from the arc flash with the surface area of a sphere from Eq. (5), it is clear that the energy intensity from the arc flash, called incident energy E_i will decrease with the working distance squared D^2, as shown in Eq. (6).

$$A_{sph} = 4 \cdot \pi \cdot D^2 \; [cm^2] \tag{5}$$

where

A_{sph}	Surface area of a sphere [cm^2];
D	Working distance [cm];

$$E_i = \frac{E_{arc}}{A_{sph}} = \frac{P_{max} \cdot T_{arc}}{4 \cdot \pi \cdot D^2} \left[\frac{J}{cm^2}\right] \tag{6}$$

where

E_i	Incident energy [J/cm^2];

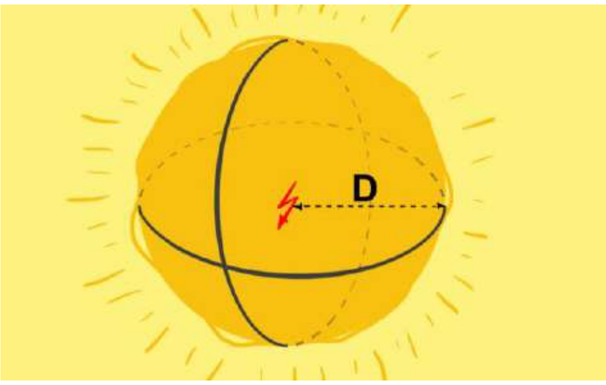

Fig. 4 – Arc flash light consideration

Incident energy is measured in calories per square centimeter (cal/cm^2). The primary choice of energy unit was introduced by the clothing industry. The level of protection is measured in cal/cm^2 and is defined as the maximum incident energy which can be absorbed by a layer of clothing in order to reduce the potential injury to a maximum of a 2nd degree burn, defined as 1.2 cal/cm^2. The conversion between the International system of Units (SI) unit joule and calorie is shown in Eq (7).

$$\frac{1\, Calorie}{1\, Joule} = 4.184 \tag{7}$$

Converting to calories and subtracting all constants to one single constant C in front of the fraction, this leaves only 3 influencing parameters left, as shown in Eq. (8).

$$E_i = C \cdot \frac{P_{max} \cdot T_{arc}}{D^2} \left[\frac{cal}{cm^2}\right] \tag{8}$$

where

C	Constant;

Since the theoretically derived equations for calculation of the incident energy have been proven very conservative, IEEE has developed a Guide for Performing Arc-Flash Hazard Calculations, IEEE std. 1584-2002 [3], which is based on an empirically derived model. This method has limitations as it has only been validated within the test ranges. From the IEEE std. 1584-2002 [3] the empirically derived model (Clause 7.5 and 9), based on statistical analyzes and curve fitting programs, is applicable for systems with:

- Voltages in the range of 208 V–15.000 V, three-phase.
- Frequencies of 50 Hz or 60 Hz.
- Bolted fault current in the range of 700 A–106.000 A.
- Grounding of all types and ungrounded.
- Equipment enclosures of commonly available sizes.
- Gaps between conductors of 13 mm to152 mm.
- Faults involving three phases.

Note; The IEEE defined bolted fault current corresponds to IEC defined symmetrical root-mean-square (RMS) short-circuit current.

The model is derived to predict the 3-phase arcing current in order to find the protective tripping time and determine the total arc duration. For system voltages below 1000 V. Eq. (9) is to be used and for system voltages above 1000 V. Eq. (10) is to be used.

$$\begin{aligned}\lg(I_{arc}) = K + 0.662 \cdot \lg(I_{bf}) + 0.0966 \cdot V \\ + 0.000526 \cdot G + 0.5588 \\ \cdot V \cdot \lg(I_{bf}) - 0.00304 \cdot G \\ \cdot \lg(I_{bf})\end{aligned} \tag{9}$$

where

lg	$\log_{10}(x)$;
K	-0.153 for open configuration
	-0.097 for box configuration;
V	System voltage [kV];
I_{bf}	Bolted fault current [kA];
G	Gap between conductors [mm];

$$\lg(I_{arc}) = 0.00402 + 0.983 \cdot \lg\,(I_{bf}) \tag{10}$$

As the arcing current calculation so far has been calculated on a logarithmic basis, this is converted into a numeric current value using Eq. (11).

$$I_{arc} = 10^{\lg\,(\mathrm{I_{arc}})} \; [A] \tag{11}$$

A second arc is to be calculated too for low-voltage (LV) systems, corresponding to 85% of the arcing current to account for current variations.

Calculating the incident energy, a normalized calculation is made as per Eq. (12). It is based on an arc duration T_{arc} of 0.2 s. and a working distance D equals 610 mm, with influence from the surrounding configuration and grounding system.

$$\lg(E_n) = K_1 + K_2 + 1.081 \cdot \lg(I_{arc}) + 0.011 \cdot G \tag{12}$$

where

E_n	Normalized energy (J/cm^2);
K_1	-0.792 for open configuration
	-0.555 for box configuration;
K_2	0.000 for ungrounded and high-resistance grounded systems
	-0.113 for grounded systems

Although grounding systems previously have been used as a mitigation technique, the new empirically derived IEEE 1584-2018 states: *Contrary to how the IEEE 1584-2002 model interpreted the effect of system grounding, the new IEEE 1584 arc-flash model will not utilize the system grounding configuration as an input parameter. The IEEE/NFPA Collaboration test results did not show any significant impact of the system grounding or bonding on the incident energy released by the arc*. Due to this statement system grounding has not been considered further.

Like the arcing current, the normalized incident energy is converted from a logarithmic basis to a numeric value using Eq. (13).

$$E_n = 10^{\lg(E_n)} \left[\frac{J}{cm^2}\right] \tag{13}$$

Finally, the calculation of incident energy E_i is adapted to the correct conditions for the given fault configuration using Eq. (14).

$$E_i = 4.184 \cdot C_f \cdot E_n \cdot \left(\frac{t}{0.2}\right) \cdot \left(\frac{610^x}{D^x}\right) \left[\frac{J}{cm^2}\right] \tag{14}$$

where

E_i	Incident energy [cal/cm^2];
C_f	1.0 for voltages above 1 kV.
	1.5 for voltages at or below 1kV.;
t	Arcing time (equals T_{arc}) [s];
x	Distance exponent, from [3] Table 4;

Although there is a difference between the theoretically and the empirically derived method, there are two core relationships that remain unchanged. Comparing Eq. (8) with Eq. (14) it can be concluded that the arc duration T_{arc} is directly proportional to the amount of incident energy E_i and that the amount of incident energy is inversely proportional to the working distance to the power of respectively 2 for the theoretical method and the distance exponent x from IEEE std. 1584-2002 [3] Table 4. for the empirical model.

The IEEE std. 1584-2002 [3] has already considered a practical solution to ensure personal safety by calculating an arc flash boundary. Solving for the working distance D from Eq. (14) and substitute the incident energy E_i with an incident energy boundary E_B as shown in Eq. (15), a safety distance can be determined, related to the maximum allowable incident energy boundary E_B. This arc flash boundary D_B is the distance of which an incident energy is exactly equal to the incident energy boundary E_B, as illustrated in Fig. (5).

$$D_B = \left[4.184 \cdot C_f \cdot E_n \cdot \left(\frac{t}{0.2}\right) \cdot \left(\frac{610^x}{E_B}\right)\right]^{\frac{1}{x}} [mm] \tag{15}$$

where

D_B	Arc flash boundary [mm];
E_B	Incident energy boundary [J/cm^2];

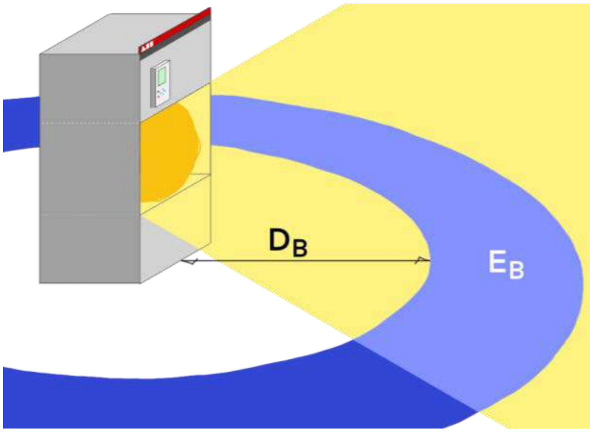

Fig. 5 – Arc flash boundary distance

Recently, IEEE have presented the IEEE std. 1584-2018 [4] with even more and complex input parameters than the version from 2002 including e.g. enclosure dimensions and electrode configurations. The guide is difficult to discuss in a practical perspective as the input parameters are highly dependent on each other, it can be difficult to decode the dynamics of computational relationships. The 2018 version is due to this only discussed further in relation to future recommendation of good design practice in this paper.

III. MITIGATION TECHNIQUES IN PRACTICE

Mitigation techniques are available in many formats ranging from simple to complex solutions. As stated in the introduction, mitigation techniques demonstrated in this paper are based on the NFPA 70E [1] with a primary focus on the control measures: *Substitution* and *Engineering controls*.

A. Substitution

Generally, substitution/replacement is often only applicable at the design stage, and therefore it is perhaps more essential to investigate ways to reduce the amount of incident energy in the event of a fault by making some arc flash recommended design criteria/practices which can reduce/eliminate the likelihood of occurrence of an arc flash fault event. However, this does not mean that replacement cannot be used at a later stage. Instead, you may have to distinguish between damage on personnel and damage on electrical equipment.

Examples of reducing the damage to personnel using replacements; If the installation can be operated from an external operative system or if this can be introduced subsequently, the remote switching system can be used to remove the risk of personal injury by moving all personnel outside the arc flash boundary as calculated per. Eq. (15). Equipment replacement can also be activation of protective devices faster acting overcurrent functions or selecting components that limit the available fault current such as; I_{th} limiter, fast earthing switches, arc guard protection, protection and control relays with dual settings introduced e.g. during maintenance mode. In addition, arc flash rated LV switchgear and controlgear assemblies can be used to reduce the risk of injury such as switchboards tested and certified in accordance with IEC 61641 [5] to withstand an arc flash fault event based on 690 V system voltage, 100 kA short circuit current for 300 ms arc duration.

All types of control measures for substitution require supervision of the state of the equipment in order to avoid improper or inadequate maintenance. Therefore, it is always recommended to perform electrical system services which include life cycle assessments, system health checks and system studies. If an installation has a system study it should be validated every time a change in the system occurs, as there might have been changes to the installation such as new equipment, replacements or new operational philosophies that might affect the energy levels and hereby create higher levels of incident energy. Equipment or functionality might change over time, and it might compromise the overall design criteria which then might affect personal safety. It is also important to validate the state of the equipment. The older the equipment is, the more worn out it will become. Therefore, it is important to test functionality and protection of the installation on a regular basis. There are incidents where breakers have failed to trip due to lack of maintenance, and the settings used from previous studies does not fit the purpose anymore or have been changed without validation. A protection relay has a response time to detect a fault and inform the breaker to trip. The breaker also takes time to trip, and if then the springs in the breaker are worn out, the functionality has not been tested or vital parts need lubrication, it will affect the time to clear a fault. As described in this paper, the time is of highest concern, due to the proportionality to the amount of incident energy. In the worst case, poorly maintained equipment can be described as unpredictable and a calculation of this must therefore consider the outer limit value for the absolute worst-case fault event.

Both the arcing current calculations in Eq. (9) and the normalized incident energy in Eq. (12) from IEEE std. 1584-2002 [3], depends on the distance between conductors G shown in Fig. (6). For LV systems, differences in the gap between conductors may result in deviations of approximately 15% within the standard distances defined in the IEEE std. 1584-2002 [3]. For systems with a voltage level exceeding 1000 V, the influence according to the IEEE std. 1584-2002 [3] is less than half, compared to LV systems. For future designs, it is recommended, in particular for LV systems, to increase the distance between conductors G to reduce the amount of incident energy, and in order to eliminate the likelihood of an arc flash initially occurring. From an experience-based point of view, the culprit in the industry is not the companies building electrical distribution boards, but more the component manufacturers who constantly push the terminal sizes of the components and decrease the distance between the conductors. In recent years, it is more frequently seen that LV busbars are insulated which provide flashover protection up to 1 kV.

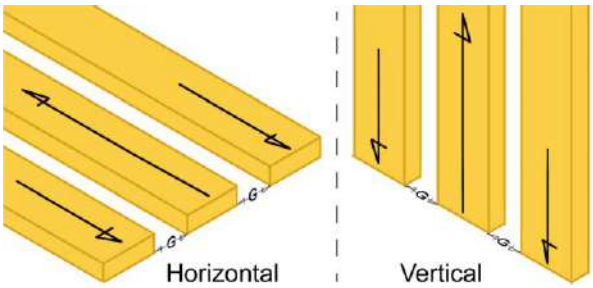

Fig. 6 – Gap between conductors and electrode configuration

In addition to the gap between conductors G, the new IEEE std. 1584-2018 [4] classifies electrode configurations, as it has been discovered that arc flashes typically occur at the end of a 3-phase busbar system. From IEEE std. 1584-2018 [4], Table 9 provides some examples of how equipment conductor arrangements could be classified based on their similarity to the electrode configurations. Fig. (6) illustrates a horizontal- (left) and vertical (right) oriented busbar system. In general, it has been found that incident energy at a given working distance D is increased in cases where horizontally designed busbar systems are used. For future good design practice, a general recommendation is to use vertically oriented busbar systems, both to reduce incident energies but also because experience has shown that horizontal busbars are more dangerous in cases of dropped tools or other foreign objects during work or maintenance.

Electrical cabinets across all voltage levels are required to be designed to withstand a short-circuit, but there is currently no detailed description of protection against arc flash faults. During an arc flash fault event, temperatures of up to 19.500 °C are achieved, causing copper to be gaseous and expand approximatly 65.000 times the unit of space. The rapid increase in pressure inside a cabinet can result in an explosion like event.

From previous presented PCIC Europe paper EUR19_14 [6], the effect of an arc limiting switchgear based on energy discharge defined as the integral of the arc power per unit of time, converted to pressure discharge, depending on the energy per volume as shown in Eq. (16) has been demonstrated. The pressure discharge is directly related to the intensity of incident energy theoretically decreasing to the power of 2 to the working distance D^2. The message from this is, that it is important to design cabinets which can withstand an arc flash fault event by equalizing the pressure inside the cabinet, as the pressure in many cases will be the most dangerous factor for the human being working in or near the cabinet. Typically systems such as; *pressure relief flaps, gas ducts and pressure blast canals* can be used to solve the problem. Otherwise, there is no point in the first place to make incident energy calculations.

$$p_f = \frac{Energy}{Volume}\left[\frac{J}{m^3}\right] \qquad (16)$$

where

p_f Pressure discharge fault event [J/m³];

Comparing an arc flash fault event in an open air environment with a square cabinet as illustarted in Fig. (7), this will increase the radial pointing intensity of the incident energy with a factor of π in front of the faulted cabinet as shown in Eq. (17), due to the relation between the surface area of a sphere A_{sph} with the radius of D and the surface area of a square A_{squ} with side length 2·D.

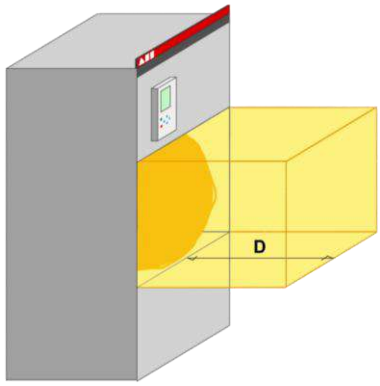

Fig. 7 – Arc flash intensity from a box (el. cabinet)

$$A_{dif} = \frac{A_{Sph}}{A_{Squ}} = \frac{4 \cdot \pi \cdot D^2}{4 \cdot D^2} = \pi \qquad (17)$$

where

A_{dif} Difference in surface area;

A_{squ} Surface area of a square [cm²];

B. Engineering Controls

Engineering control measures can be different things, but common to all according to NFPA 70E [1], engineering controls may have a substantial impact on risk. They should, where practicable, be considered and analyzed. Typically, engineering controls can be barriers and other safeguarding devices.

Through years of experience, best practice [7] engineering controls with theoretical and practical demonstrated effect is to:

- Reduce the arcing current
- Reduce the arc duration
- Increase the work distance

Or introduce work procedures, which might affect all the engineering controls listed above.

In order to reduce the level of incident energy, parameters presented in the IEEE std. 1584-2002 [3] will set the basis for further demonstration. For low-voltage systems there are 5 variable parameters:

- System voltage (V)
- Arc duration (t)
- Gap between conductors (G)
- Bolted fault current (I_{bf})
- Working distance (D)
- Distance exponent (x)

For high voltage systems, only the system voltage is considered not to have any influence whether it is a 1kV or 15kV system voltage.

The arcing current and the arc duration often have a connection in relation to the protective equipment and they are inversely proportional. The protection coordination philosophies have traditionally been based on short-circuit studies characterized by a minimum and maximum current according to standards such as IEC 60909-0 [8]. For future studies, due to personal safety, the impact of an arc flash occurring should be considered during the construction of protection coordination. Considering the calculation of a 3-phase short-circuit current I_{3p} according to IEC 60909-0 [8], using Eq. (18), only the system voltage U_{sys} and the fault impedance Z_f has to be determined.

$$I_{3p} = \frac{U_{sys}}{\sqrt{3} \cdot \sum Z_f} \tag{18}$$

where

I_{3p}	3-phase short-circuit current [A];
U_{sys}	Nominal voltage [V];
Z_f	Fault impedance [Ω];

Representing the calculation graphically as shown in Fig. (8), the system impedance Z_{sys} can be assumed constant, which makes it easy to determine the 3-phase bolted fault current I_{bf}, while the arc impedance Z_{arc} is variable and makes it difficult to define I_{arc}. The total fault impedance Z_f can be defined according to Eq. (19) as the sum of all impedances from the power source to the faulted location.

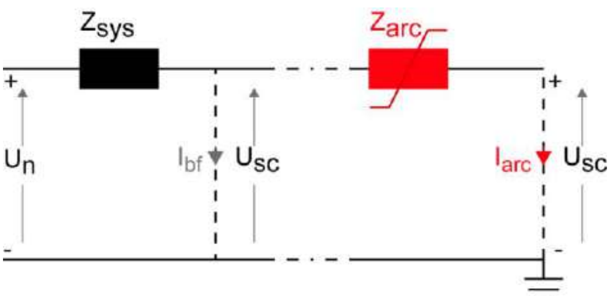

Fig. 8 – 3-phase short-circuit current calculation graphically according to IEC 60909-0 [8]

$$\sum Z_f = Z_{sys} + Z_{arc} \tag{19}$$

For boundary values calculating the arcing current according to IEEE std. 1584-2002 [3], this representation of 3-phase short-circuits calculations in accordance with IEC 60909-0 [8] cannot be asserted. Calculating on a circuit with a system voltage of 999 V in an open air configuration, the arcing current exceeds the 3-phase short-circuit current, when the 3-phase short-circuit current reaches 1.9 kA. This is physically not possible and may be caused due to an approximation in the derivation of Eq. (9), which is based on logarithmic curve fittings.

Representing the short-circuit current with and without the arc impedance in a typical protection time/current curve with a thermal overcurrent curve and a definite setting, as shown in Fig. (9), the difference in between can be considered as the arc impedance Z_{arc}. As per Eq. (14) the arc duration is proportional to the amount of incident energy. This means typically for a given example, the incident energy is increasing with a factor of 10-100 times just by introducing the arc impedance Z_{arc}. From best practices this should be a general protection recommendation in protection coordination- and selectivity studies to include the impact of the arcing current. As it is so difficult to determine, one must make some general assumptions from a conservative point of view. In cases where it is not possible to change the protection settings due to selectivty or limitations of the protective device, an arc time-limitng device can be installed in both existing- and new cabinets. Arc time-limitng device use an optical detection system which together with a current measurement is connected to an external breaker that trips the fault current typically within 10 ms. in the event of a short-circuit. Using an arc time-limitng device, the incident energy will decrease in all cases, without compromising personal safety and system selectivity, as visulized in the protection time/current curve in Fig. (9).

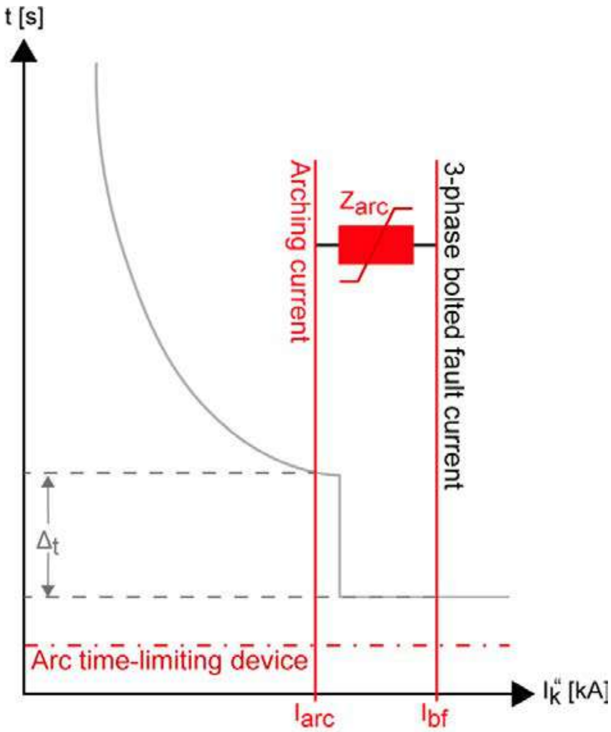

Fig. 9 – Protection characteristic with an Arc time-liming device

An example of various modes of operation is presented to show the relationship between security of supply and personal safety, as well as the importance of proper protection relay settings that account for the arcing current. One important thing to distinguish when considering electrical systems with multiple inputs in the event of a failure is that there is a difference between bus fault current and arcing current that flows through the protective device to limit the arc duration.

By considering a simple busbar system consisting of a generator connected to a distribution panel (3.3 kV.) feeding four MCC panels (400 V.) through each individual transformer with internal bus couplers (BC1, BC2, BC3) as shown from an ETAP [9] model in Fig. (10), for various constellations of bus couplers status (open/closed) one can illustrate the effect. The low-voltage protection relays (LV1, LV2, LV3, LV4) shown in Fig. (11), are assumed being identically set, with a; long time, short time and instantaneous protective settings as shown in Fig. (11).

Traditionally, there has previously been focus on security of supply by parallel mode of operation, but in a perspective of personal safety this may be reconsidered due to the risk of an arc flash fault event. A general recommendation from best practices is to divide busbars into as many sections as possible in order to reduce the bus fault current, increase the tripping current through each LV protection relay and hereby lower the arc duration. In some cases, this is not possible due to requirements of security of supply. In this case, an introduction of a work procedure can be useful.

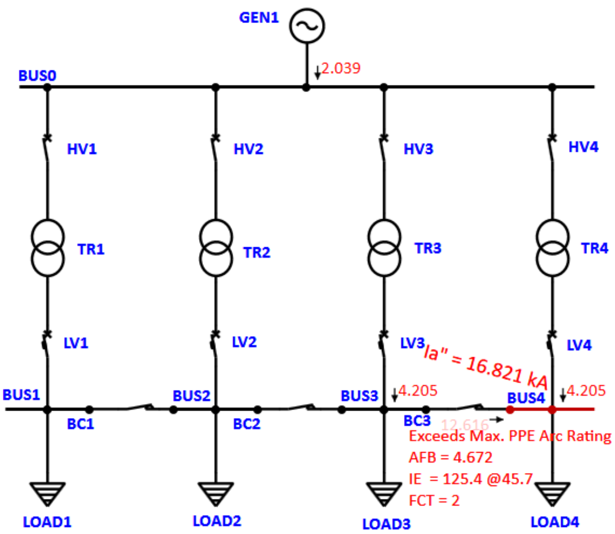

Fig. 10 – ETAP [9] busbar system, parallel mode of operation, fault at BUS4 (arc flash calculation)

From Tab. (1), calculation of 3 different modes of operation is performed, with a comparison to the level of security of supply. In case of a fault at BUS4 shown in Fig. (10), the incident energy can simply be reduced by opening the bus coupler BC2, as the total fault current on the busbar will be reduced and the arcing current flowing through each protection relay will increase, resulting in reduced arc duration as shown represented with read lines for each mode of operation in Fig. (11). This change in mode of operation will practically reduce security of supply but will result in a significant increase in personal safety as the amount of incident energy decrease from 125.4 cal/cm^2 to 17.5 cal/cm^2 which enable the possibility to put on proper personal protective equipment (PPE).

In case of maintenance on one of the MCC panels, BC1 or BC3 can be opened, which compromises the security of supply, but reduces the amount of incident energy to 2.1 cal/cm^2 where it is possible to protect all personnel with basic PPE.

Mode of Operation	**Security of Supply**	**Bus Coupler (BC) status**	**Incident Energy**
Parallel	High	BC1: Closed BC2: Closed BC3: Closed	125.4 cal/cm^2
Normal	Medium	BC1: Closed BC2: Open BC3: Closed	17.5 cal/cm^2
Maintenance	Low	BC1: Open BC2: Open BC3: Open	2.1 cal/cm^2

Tab. 1 – ETAP work procedure / reduce arcing current

Another parameter to adjust to reduce the incident energy is the working distance D, which according to Eq. (14) has the greatest impact hence it raises to the power of the distance exponent x. According to IEEE 1584-2002 [3] for low-voltage systems the distance exponent can range from 1,473 to 2, dependent of the type of equipment.

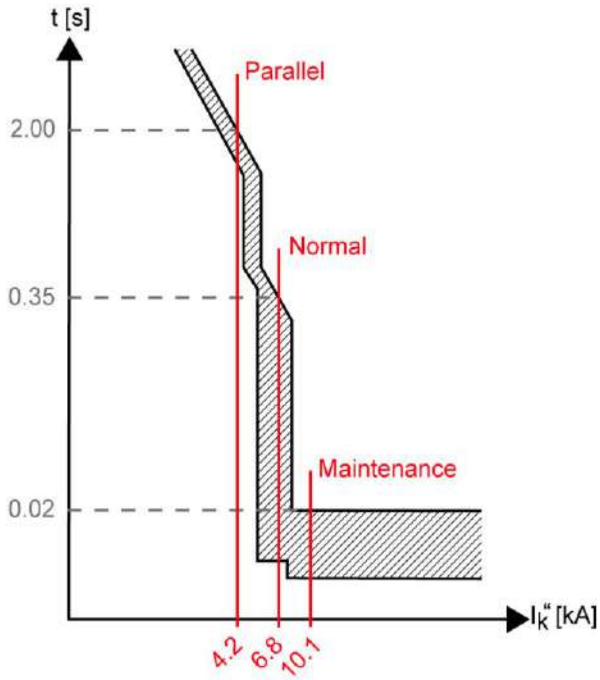

Fig. 11 – Low-voltage protection characteristics for LV1, LV2, LV3 and LV4

There are various approaches to increase working distance from live electrical equipment. Several switchgear manufacturers have developed remote switching devices and others have exchanged electrical equipment with built-in communication modules to operate the electrical system from a power management system. Using Eq. (15) to determine a minimum approach distance for a given level of PPE, energy zones can be introduced. Considering BUS4 from previous calculation example during normal operation, using Eq. (14), as shown in Fig. (12), the arc flash boundary D_B for NFPA 70E [1] defined energy categories can be graphically illustrated and listed in Tab (2). These zones can be used to define, depending on PPE, the observer distance, typically used in the offshore industry.

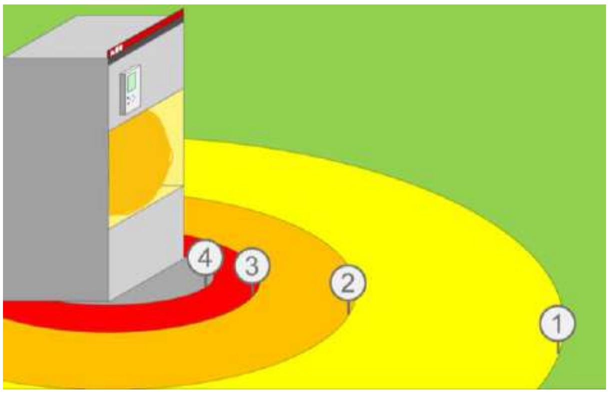

Fig. 12 – Arc flash boundary energy zones

II. Energy zones	Energy boundary E_B [cal/cm^2]	Arc flash boundary D_B [cm]
0	<1.2	-
1	>1.2	174.8
2	>8.0	67.7
3	>25.0	38.3
4	>40.0	30.3

Tab. 2 – Arc flash boundary energy zones

III. FURTHER CONSIDERATIONS

There are inconsistencies between the current guide for performing arc flash calculations [3] [4] and the petroleum industry as the generator near nature of the offshore electrical system studies and designs are considered for normal mode of operation as generator near nature. The IEEE std. 1584-2002 [3] is based on symmetrical RMS 3-phase short-circuit current in static conditions reached after approximately 30 cycles, which implies that current transient and DC components are not considered. This is a fair consideration far from generator, where steady-state conditions can be assumed. This cannot be assumed in cases with a generator near nature, as current peaks of up to 5 times nominal current occur.

From years of experience in the industry, a general model have been developed to handle the issue. Representing the incident energy as energy blocks in a 2-dimensional plot where the arcing current is plotted as function of the arc duration $I_{arc}(t_n)$ as shown in Fig (13), a method can be derived as per Eq. (20).

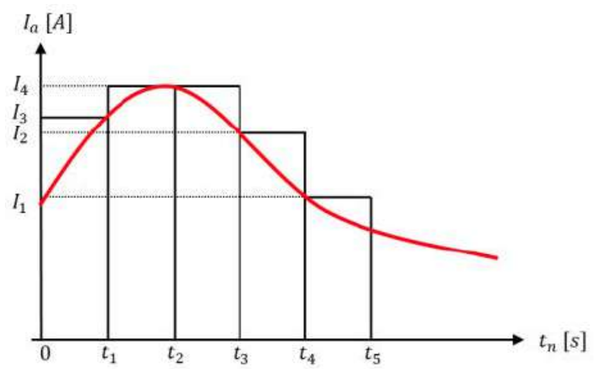

Fig. 13 – Transient arc flash calculation method

This can only be done due to the linear correlation between the incident energy and the arc duration as shown in Eq. (14), whereas the superposition principle can be used. This allows to calculate the incident energy by dividing the calculations into an appropriate number of rectangular energy blocks with time interval $t_{\Delta n}$ as shown in Fig. (13).

From Fig. (13) a theoretical derivation is applicable, in accordance to IEEE std. 1584-2002 [3]. The expression is made to calculate the transient amount of incident energy E_{i^*} taking into account current transients and the DC component, as shown in Eq. (20), by taking the integral of each individual energy block for a varying arcing current.

$$E_{i*} = \sum_{n=1}^{N} \int_{t_{n-1}}^{t_n} E_i\big(I_{arc}(t_n), t_{\Delta n}\big) \tag{20}$$

$$\rightarrow \quad t_{\Delta n} = t_{n-1} - t_n$$

where

E_{i^*}	Transient incident energy [cal/cm^2];
N	Number of energy blocks;
n	Counter number;
$t_{\Delta n}$	Arc duration time interval at the nth time [s];
t_n	Arc duration time [s];
I_n	Arcing current at the nth time [kA];

In direct relation to Fig. (13) this can be calculated as shown in Eq. (21).

$$E_{i*} = \int_{0}^{t_1} E_i(I_3, t_1) + \int_{t_1}^{t_2} E_i(I_4, t_2 - t_1) + \int_{t_2}^{t_3} E_i(I_4, t_3 - t_2) + \int_{t_3}^{t_4} E_i(I_2, t_4 - t_3) + \int_{t_4}^{t_5} E_i(I_1, t_5 - t_4) \tag{21}$$

The conservatism in the IEEE std. 1584-2002 [3] is still unchanged using this method. But considering current transients has shown significant reductions in incident energy when comparing the calculation with a worst-case estimate assuming peak currents (0,5 cycle) and long-time arc duration conditions.

IV. MEMORANDUM

Arc flash has been a well-known phenomenon for many years, but in the recent years arc flash has become a hot topic in the industry. This is due to greater focus on electrical safety from standards, regulations and company internal requirements. At this time many calculation softwares in the market can perform arc flash studies and print a sign to hang on the switchboards. But if the author of the study lacks understanding of the data input, analysis output, operation of the electrical system, as well as methods of dealing with high energy levels, it will not increase the level of personal safety. This paper provides guidance to the end user for simple electrical safety solutions so that both internal and external requirements can be met. It is important to understand the full picture of an electrical system to interact with it and protect personnel.

V. CONCLUSIONS

This paper presents graphical visualization of the influencing parameters used for arc flash hazard calculations. From an experienced practical perspective combined with a theoretical approach, mitigation techniques have been proven very effective in the reduction of incident energy to ensure high personal safety and ensure reliable operation of electrical systems in case of a fault event. In addition, recommendations for future good design practices have been presented to keep the amount of incident energy at a manageable level by conventional PPE. Based on the content of this article, the general recommendations to the end user is:

1) *Analyze*. Get to know the level of incident energy of the electrical system through a system analysis
2) *Mitigation*. Perform mitigations as presented in this paper where incident energy exceeds an inappropriate level
3) *Education*. Pay attention to the consequences of an arc flash fault event and do awareness training of all personal working with or near the electrical system.

VI. ACKNOWLEDGEMENTS

We would like to thank PCIC and ABB A/S for being able to contribute to the conference with this paper demonstrating some practical knowledge from the past decade in the oil and gas industry and contribute with new and innovative approaches in arc flash hazard visualization and handling of practical related issues.

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VIII. NOMENCLATURE

A_{sph} Surface area of a sphere [cm^2];
A_{squ} Surface area of a square [cm^2];
A_{dif} Difference in surface area;
C Constant;
C_f 1.0 for voltages above 1 kV.
1.5 for voltages at or below 1kV;
D Working distance [cm];
D_B Arc flash boundary [mm];
E_{arc} Arc energy [J];
E_B Incident energy boundary [cal/cm^2];
E_i Incident energy [cal/cm^2];
E_{i*} Transient incident energy [cal/cm^2];
E_n Normalized energy [J/cm^2];
G Gap between conductors [mm];
I_{arc} Arcing current [A];
I_{bf} Bolted fault current [kA];
I_n Arcing current at the n^{th} current [kA];
I_{3p} Three-phase short-circuit current [A]
K -0.153 for open configuration
-0.097 for box configuration;
K_1 -0.792 for open configuration
-0.555 for box configuration;
K_2 0.000 for ungrounded and high-resistance grounded systems
-0.113 for grounded systems;
lg $\log_{10}(x)$;
n Counter number;
N Number of energy blocks;
p_f Pressure discharge during fault event [J/m^3];
P_{arc} Arc power exposure [W];
P_{max} Maximum arc power exposure [W];
t Arcing time (equals T_{arc}) [s]
t_n Arc duration at the n^{th} time [s];
T_{arc} Arc duration [s];
U_{sys} System voltage [V];
U_n Nominal system voltage [V];
V System voltage [kV];
x Distance exponent, from [3] Table 4.
Z_f Fault impedance [Ω];
Z_{arc} Arc impedance [Ω];
Z_{sys} System impedance [Ω];

IX. VITA

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A SUCCESS STORY OF STEAM TURBINE REPLACEMENT BY HIGH SPEED ELECTRIC SYSTEM DRIVEN COMPRESSOR

Paper No. PCIC Europe EUR21_08

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Abstract – Thanks to the development of high-speed induction motors and voltage source inverters, standalone electric drivers are today an alternative to the traditional train driven by steam and gas turbines when regulating the operating speed of compressor, improving the system efficiency and reducing significantly the emission of greenhouse gases as requested by the new European regulations. This will be developed in the first introductory part of this paper. The second part of this paper describes the main expectations and challenges of the end-user in term of project time line, reliability, inter-changeability and site electrification based on an actual business case in Nederland operating at 5.7MW @ 6,400rpm. The third part overviews the selected architectures of electric systems delivered to the end-user, including the induction motors and Voltage Source Inverters technologies. The last part is dedicated to the key technical milestones, during the design phase, Factory Acceptance Tests, and commissioning with a focus on the mechanical integration when using oil lubricated bearings. The conclusion highlights the learnings and the win-win cooperation of this project.

I. INTRODUCTION

In the past, gas and steam turbines have been natural drivers for compressors in most the Oil & Gas processes, from offshore applications to refineries. For some years now, electrical drives (Fig.1) have been selected for new plants and/or new compressor trains as they provide a more efficient, environment friendly and flexible solution [1]. For existing equipment, the decision on how to replace an ageing steam turbine is primarily dependent on the plant steam balance. If the plant has an excess of produced steam by the other processes, the replacement by a new steam turbine could be relevant even if we start to see replacement by electric motors in regions where environmental incentives are in place despite that steam production is not necessary. However, if no steam is available and steam production from boilers would be require investment for continued operation then the replacement by an electric motor must be seriously considered. This could be quite challenging in the way that the footprint of the electric motor must fit the existing environment. Classical arrangements, based on industrial speed motors (1500/3000 rpm-50Hz or 1800/3600 rpm-60Hz) driving the compressor through a gearbox to match the compressor speed, are usually too large to be accommodated in lieu of the turbine to replace. The development of high-speed electric motors driving directly the compressors enables a drastic reduction of their size and their weight, opening doors to the electric solution. We will illustrate, through real cases, the benefits of the electrical solution.

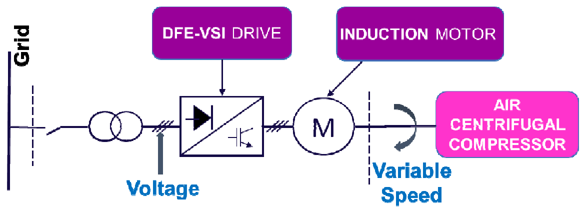

Fig. 1. Electric System

A. Global efficiency

Most of the time, the operation costs are a key point in the selection of the replacement solution. If we consider for instance an islanded station, it does not seem obvious that replacing a turbine driving a compressor by a complete electrical system is more efficient. In such a system, the electric power is produced by gas turbines as prime movers driving generators. Part of this electric power is used to supply the compressor driving motor through a Variable Speed Drive (VSD) and a transformer [2]. Nevertheless, the electrical solution is more efficient with an average improvement of 15% compared to the conventional one. Even though there are losses in the different components of the electrical chain, i.e. generators, transformers, VSD and motors, the efficiency of condensing steam turbines taking in account an optimistic assumption of 80% for the efficiency of the condensing steam turbine and adding it's boiler to generate the steam we obtain an overall efficiency of the steam turbine system below or equal to 45% (Fig.2). Taking equivalent and pessimistic values for the electric motor system chain, the overall efficiency is 6% better (Fig.3).

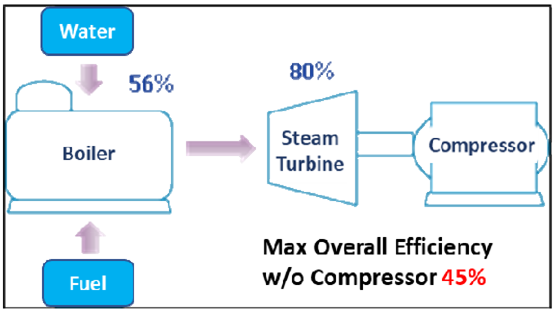

Fig. 2. Optimistic efficiency of a steam turbine system driving a compressor

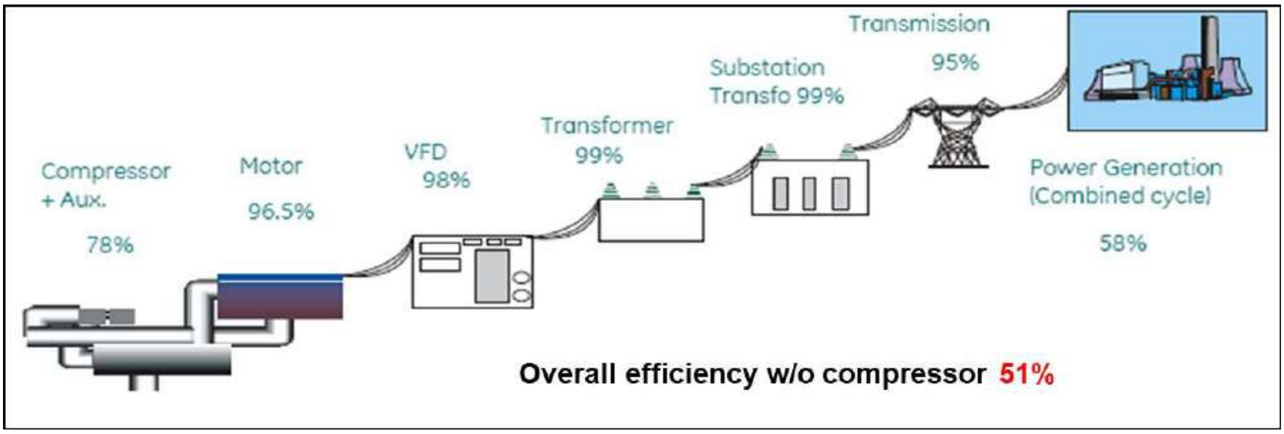

Fig. 3. Overall Electric System and Distribution Efficiency

B. Environment, Health and Security

Environmental regulations are becoming more and more stringent in larger parts of the world. For instance, the NL Klimaatakkoord law reduces Industrial GHG emissions by 60% by 2010. CO2 emissions produced by variable speed turbines directly coupled to compressors are much higher than the produced by fixed speed turbines used in the electricity generation plant. The electrical solution enables plant operators to reduce by around 30% the amount of their plant CO2 emissions.

Noise emissions produced by an electric motor are also lower than those produced by a turbine, typically -12 dB(A). In a world that pay increased attention to the wellness of workers, this advantage can represent a high value.

C. High Flexibility

High speed motors driven by Electrical Variable Speed Drive offer high flexibility compared to most other solutions. In a few seconds, the motor can be operating at full speed and with full torque, without having to wait for any thermal cycle. The starting current is always limited by the VSD to the motor rated current, thus increasing its lifetime. The number of starts and stop sequences is therefore nearly unlimited.

D. Operation cost

Thanks to the higher efficiency of the electrical solution, the operation costs related to fuel consumption are drastically reduced. An electric motor does not require much maintenance, which is even more the case if the motor is fitted with active magnetic bearings. For an electric motor, the time between major overhauls is usually 15 years, compared with 10 years for a steam turbine. Lube oil consumption is reduced and can even be eliminated with a magnetic bearing solution. In cases where an oil lubricating unit is totally removed, site potential risks are reduced, thus leading to a safer environment for the operators - and usually the site insurance premiums are also reduced.

Finally, a condensing steam turbine consumes a tremendous amount of treated water which has a very high cost for the plant. While motors and VFD are also cooled by water, the cooling water flow required is much lower driving lower operating costs.

E. Key enablers of the electrical solution

One of the major difficulties faced in the past was that any new equipment that pretended to replace the steam turbine had to be of a compatible size with the existing environment. With the classical solution, i.e., an electric motor running at a conventional speed and driving a compressor through a gearbox, this condition was difficult to reach especially on elevated locations. Fundamental physics dictates that the power delivered by an electric motor is the product of its torque multiplied by its rotational speed. Given that the size of an electric motor is proportional to the torque it delivers, it therefore follows that, for a given output power, the higher a motor's speed, the generally smaller its size. For many years now, a new technology of high-speed electric motors has been developed. A full range of power is available from 1 to 80 MW, running between 3,600 and 18,000 rpm. More than 150 units are known to be operating around the world in various Oil & Gas applications, most of them in Midstream for transportation and gas storage and Downstream in refineries. The return of experience from millions of hours of operation has proven how reliable and how efficient this solution is. Another difficulty has been to develop a new type of Variable Speed Drive (VSD) to supply the electric power to such motors, whose rated frequency is up to 300 Hz due to their high speed. A new converter topology, using new high-performance power electronic devices, has been selected to build a full range of Medium Voltage Variable Speed Drives. A modular concept is used to provide a power range from 1 MW to 100 MW with rated voltages from 3 kV to 11 kV.

II. THE END USER OPPORTUNITY

In May 2017, the end-user organization identified the opportunity to reduce their site's energy footprint and variable cost by replacing a high-pressure steam driven turbine of an air compressor by a 6 MW high-speed electric drive (Fig.4). At that time there were two main options being considered. The first option was the construction of a full new train consisting of an electric motor and a compressor, replacing the existing turbine-compressor train. The second option was the replacement of the steam turbine with a new electric motor and keeping the existing compressor and associated utilities.

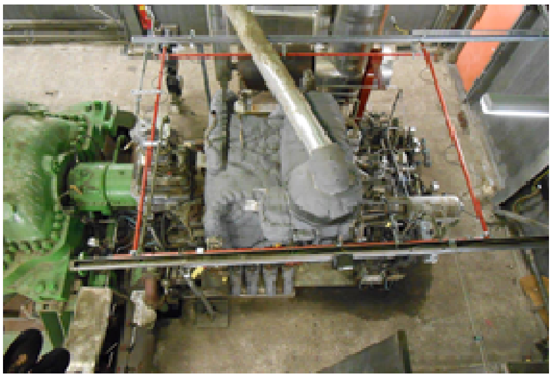

Fig. 4. Compressor (Left) - Steam Turbine (Right)

By replacing the steam turbine with an electric motor, the high-pressure steam consumption of the site is minimized. Steam is typically generated by fossil fuels, whereas electricity is produced by a mix of sources, including renewable energy. It is the first step in the site's journey from 'molecules to electrons' and important demonstration of how electrification technology can change our industry.

An economic and technical evaluation between the two options showed that building a new train was not viable in this case. While replacing only the steam turbine made sense from an economical perspective, it also introduced many risks such as schedule pressure, potential reduced plant availability and deep brownfield interfaces. The project team had a challenging task to balance expenditure, speed in project delivery and quality.

TABLE I

Summarized evaluation of replacement options

	Option 1: Replace with motor-compressor train	Option 2: Replace turbine with electric motor	
Civil structure	-	+	Plot space needed for option 1 while option 2 will re-use existing turbine location
Tie-in duration	+	-	Minimal downtime needed to tie-in new train
re-use existing auxiliaries	-	+	Option 2 to reuse lube-oil system
Cost	-	+	

A project management strategy was introduced to realize the site's aspirations. This included combining of project phases, incorporating the equipment manufacturer into the integrated project team very early-on during front-end design, use of critical path analysis and pre-funding of long leads to fast-track schedule. In addition, a decision was made to build a modular substation (instead of stick build), which allowed parallel construction activities.

This made it possible to engineer and construct most of the project scope within a timeframe of 16 months, except for the actual steam turbine replacement which was executed during a scheduled maintenance stop (6 days/week and 10 hours/day).

III. 1st CHALLENGE - RAMS AND SYSTEM SELECTION

A. The End-user Requirement

The key challenge during engineering (and construction) was to find a design that could integrate into the existing brownfield site without compromising on plant reliability and availability. The air compressor delivers air to one of the production units and is not redundant, meaning that the complete production facility will need to shut down in case of compressor trip. It is therefore of utmost importance to have a very reliable machine, including the electric drive of the compressor. Three key aspects were worked out further to ensure brownfield integration. Firstly, a stringent MTBF (mean time between failure) of 6 years was given as a requirement for the combined system (Motor + VSDS + Transformer + connections), to match with plant shutdown intervals.

B. The Manufacturer Solution

After a first project of steam turbine replacement by an electric system operating at 2.4MW @ 10700rpm, in Singapore, with the end user, the equipment manufacturer carried out a detailed RAM study in which we identified the "weak links" of the system. A RAM (Reliability Availability Maintainability) analysis is performed, and the details are given below. The reference documents used to perform this reliability study are:

- IEEE 493–2007 standards: IEEE recommended practices for design of reliable industrial and commercial power systems,
- FIDES guide 2009: Methodology of calculation for reliability of electronic systems,
- MIL-HDBK-217F standards: Reliability prediction for electrical and electronics equipment,
- GRIF Tree: Interactive graphical software tool for reliability calculation using fault tree method,
- IEEE Calculation tool: New Model 280 Propst plus Dong Elec Reliability Model.

Each of the items of the system is analyzed as a single device in term of failure rate expressed in FITS which is the number of failures per billion hours. Once performed, it can be extended to the entire system by summing all the single devices failure rates to obtain the global failure rate. Finally, the MTBF is obtained from the failure rate on standard system. The MTBF calculation is more complex for the other type of systems such as reparable systems or systems with device redundancies. Final goal is to determine which configuration was able to meet customer expectations in term of reliability and availability. The different equipment studied are:

- The 2x 3 winding 24-pulse transformer connected to the 30kV supplying grid,
- The drive including Diode Front End Rectifier
- The induction motor driving the compressor.

The study focuses on failures that causes a motor stop as it was the main criteria for this customer. For redundant devices or blocks that are reparable or replaceable while the system is running, we consider that the MTTR is short compared to the MTBF of the system. This hypothesis is realistic since the MTBF of the system will be at least several years.

Most of the electrical single devices failure rates considered in this study are those given by the IEEE Std 493™-2007 but when they are known, the single devices failure rates given by the manufacturers are considered (e.g. for Injection-Enhanced Gate Transistors - IEGT). Measuring the number of failures over time provides a failure rate (λ). The failure rate that occurs during one billion device hours is called the Failure In Time (FIT). The Mean Time Between Failure (MTBF) is the distribution for a population of components. MBTF can be determined by taking the reciprocal of FIT (λ).

TABLE II
System Reliability Optimization

24-pulse Transformer	**Failure rate (FIT)**	**Comment**
Standard	4,415	
Reinforced Reliability	< 4,334	Could avoid spare transformer, description of the reinforced reliability options is not described in this document

VFD - Cooling	**Failure rate (FIT)**	**Comment**
Standard	17,360	
Oil & Gas application	7,350	
Reinforced Reliability	2,091	Recommended option, description of the reinforced reliability options is not described in this document

VFD - Control	**Failure rate (FIT)**	**Comment**
1^{st} generation	12,352	
2^{nd} generation	6,480	
Current generation	4,349	
Fully redundant control	438	Highly expensive solution
Redundant CPU	1,755	Recommended option

VFD - Power	**Failure rate (FIT)**	**Comment**
1^{st} generation	7,399	
2^{nd} generation	6,432	
2^{nd} generation w/o pre-magnetization	5,652	
N+1 IEGT cell redundancy	2,006	Recommended option

Motor	**Failure rate (FIT)**	**Comment**
IEEE 493	4,554	
High speed motor with Reinforced Reliability	< 3,791	Recommended option

Failure rate (FIT) with standard options	**Failure rate (FIT) with recommended options**
28,451	13,977

A new computation is done with two configurations: the one that was provided at the initial stage (Version 1) and a new one that includes the redundancy of the CPU (Version 2). The redundancy of the CPU increases the MTBF by more than 1 year. As the MTTR of the control is low, the Availability and the Forced downtime are not significantly changed, but the Probability of failure is reduced from 15% to less than 13%. The Medium Voltage components are not subject to wear and therefore they do not require any specific maintenance during the 6 years of continuous operation. One can then consider that their Probability of failure is constant during the 6 years (in other words, the probability to fail in the 6th year is not higher than the one to fail in the 1st one). It is not the case for the auxiliary circuits such as the cooling system, UPS, etc. for which it is necessary to perform a regular preventive maintenance (usually every year) to avoid that their Probability of failure increases with the time (in other words, a preventive maintenance activity "resets" the Probability of failure at its initial value). In conclusion, this study clearly shows that, with a MTBF of the complete system at almost 8 years and an associated availability of 99.92%. The goal of a continuous operation for 6 years is achieved, selecting the recommended options associated to the preventive maintenance program.

C. Electric System Selection

Only Voltage Source Inverter (VSI) drive can control an induction motor at a requested power factor, maximizing the torque generation by an optimum vector control. The requested power below 7MW allows the use of a simple DFE 3-level IEGT Neutral-Point Piloted (NPP) converter without an additional heavy current harmonic filter on the rectifier side (Fig.5). The IEGT VSI technology has been applied to many applications in a wider power capacity range. VSI drives can now deliver tens of MW with a small number of such components, which gives them a high reliability. In the system speed range, the 7-pulse synchronous control of the inverter reduces significantly up to the 15^{th} and 17^{th} time harmonics of the currents fed into the motor, limiting the stator joule losses and the torque pulsations. The NPP topology for the valves of the inverter downsizes the cooling unit of the drive. The clamping diode valves are replaced by IEGT ones giving additional controllability. Each valve is commutating with only half the DC bus voltage, reducing the devices commutation losses by three. The output voltage is increased proportionally to the number of power switches per valve, each device being operated with the same current and sharing the same voltage. As shown on Figure 5, the 5kV 3-Level NPP inverter has 3 IEGT in serial arrangement per half phase plus 1 IEGT for redundancy thus #ph =3(+1), and 2 IEGT in back to back arrangement at neutral point location plus one IEGT for redundancy thus #np = 2(+1) + 2(+1). A sinus filter is necessary to avoid any risk of electrical resonance between the inverter and the stator via the cables and to reduce the IEGT transient switching voltages below 3 kV/μs to protect the inter-turn insulation of the stator coils as requested by the IEC60034-18-42.

The grid design does not require power regeneration from the motors to the grid to brake the driven load of the compressors. For this reason, it makes sense to use a Diodes Front End rectifier which requires some capacitive reactive power from the grid to commutate the diodes with a lagging power factor greater than 0.95 at full load conditions. A multiple bridge 24-pulse arrangement generating harmonic currents above the 23^{rd} rank of the grid frequency is compatible to the Current THD requirement of the end-user and the limited power needs for designing the cables and the step-transformers with limited weights and layouts.

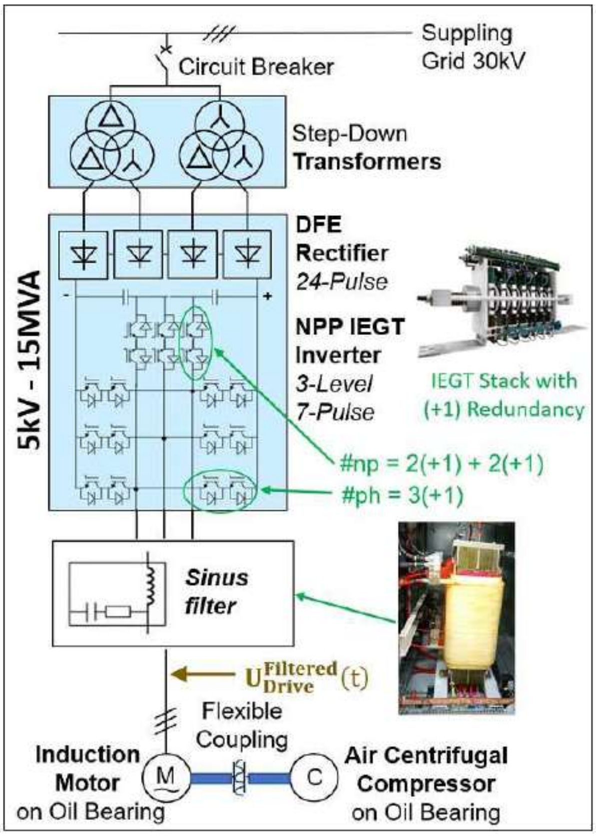

Fig. 5. System Architecture for Moto-Compression DFE NPP 3-Level VSI

IV. 2nd CHALLENGE - DRIVER INTERCHANGEABILITY

A. The End-user Requirement

It was critical for the customer to not touch the existing compressor and foundations. The power to deliver is 5.7MW@6400rpm. The plot space dimensions, and allowable weight were clearly established, giving the project team the task to design a machine that would fit over the bolt locations of the existing machine. As the machine is standing on a concrete tabletop, the full scope of steel base frame and electric motor was given as one scope to the equipment manufacturer. This allowed detailed stiffness calculations to be carried out and keeping the scope definition with one party only, limiting organizational interfaces. The static and dynamic behavior of the new train (electric motor and compressor) was an important design parameter as there was a concern that the new electric motor would be too heavy, would not fit the existing footprint or would vibrate too much. Several studies were carried out to assess the static and dynamic behavior of the new configuration. Lastly, a very detailed inspection and test plan was worked out with the integrated team (owner, engineering contractor, equipment supplier, installation contractor). This ITP identified several attention areas and key hold points throughout the construction, commissioning, and start-up.

B. The Manufacturer Solution

Special attention has been given by the manufacturer to be able to integrate the electric motor with the 4 main existing interfaces:

- *Interface #1:* Maximum available volume,
- *Interface #2:* Axis height & Rotor of the compressor,
- *Interface #3:* Re-use of the oil system for the bearings,
- *Interface #4:* Existing 10-point of fixation by tie-rods in the foundation.

According to the volume constraint of the Interface #1, the compressor is directly driven by the high-speed air-cooled induction motor (Fig.6). The advantages of the induction motor compared to the synchronous motor include no excitation system and simplified rotor construction, leading to longer run-time with fewer maintenance issues. The cooling with motor-fans is chosen for a better operability especially at low speed using the electric motor for the compressor barring. The stator insulation is customized for high speed VSD: Class H (180°C) Insulation, Class F (155°C) Temperature Rise, Vacuum Pressure Impregnated (VPI).

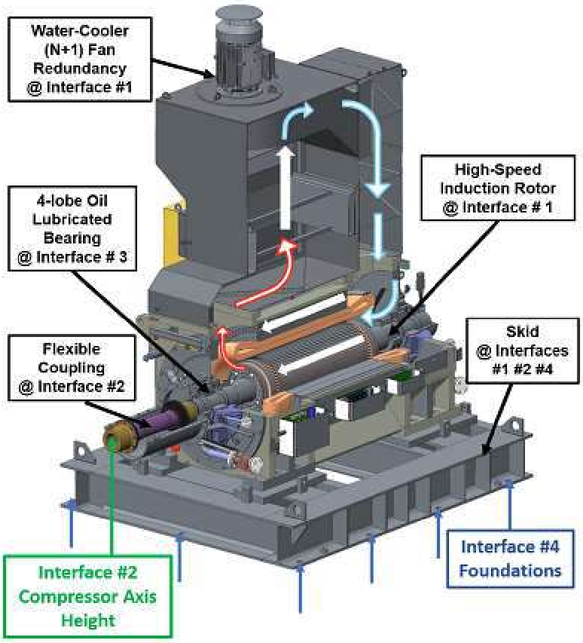

Fig. 6. Electric driver general view

The rotor construction is customized for conditions of high centrifugal stresses up to peripheral speed of 180 m/s, especially the squirrel cage and the laminated ferromagnetic part hooped (Fig.7). The cage bars can expand axially through the end ring avoiding any risk of deterioration by thermal fatigue mechanism at the interface of the copper bars and the steel shaft, respectively having coefficients of thermal expansion of 17.10^{-6} K^{-1} and 12.10^{-6} K^{-1}.

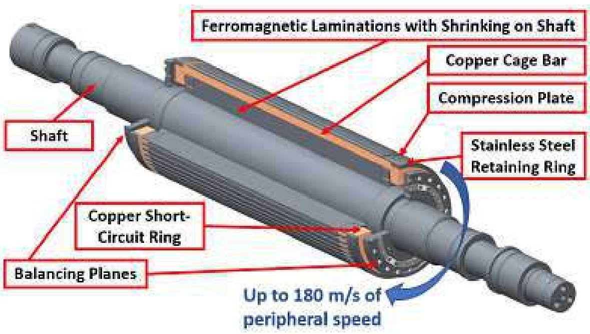

Fig. 7. Induction Rotor Technology up to 180 m/s

V. 3rd CHALLENGE – MOTOR INTEGRATION

A. Full Compression Train Torsional Analysis

Conventional trains present complex torsional behavior. Their equivalent models contain multiple inertias and stiffnesses (motor, low speed coupling, gear wheel, gear pinion, high speed coupling, compressor). The combination with the high motor shaft inertia results in high modal density at low frequency that must be checked carefully. On the contrary, the high-speed moto-compressor presents a very simple torsional model, consisting of the motor shaft and compressor shaft inertias, coupled by the coupling stiffness. As the interface #2, the compressor manufacturer provides the torsional model of the air compressor. The motor manufacturer performs the torsional study of the full shaft line. The first global torsional mode around 22 Hz, while next modes are rejected above 295 Hz without any risk of excitation by the torque harmonics (Fig.8).

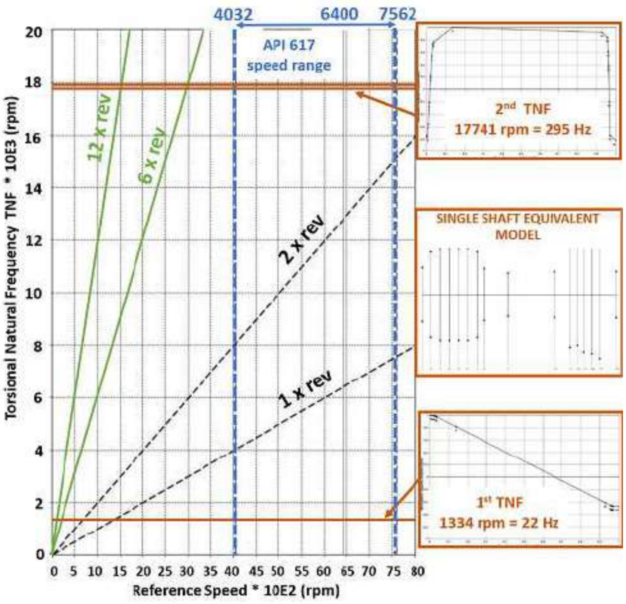

Fig. 8. Torsional Shaft Line Campbell Diagram

Because of the DC energy stored in the VSI DC capacitors, the VSI induces overall very low torque ripples to the motor (Fig.9) and does not produce significant inter-harmonic interactions in between the grid and the motor as for torsional sub-synchronous excitation improving a lot the system reliability. Significant torsional shaft excitations are unlikely to occur.

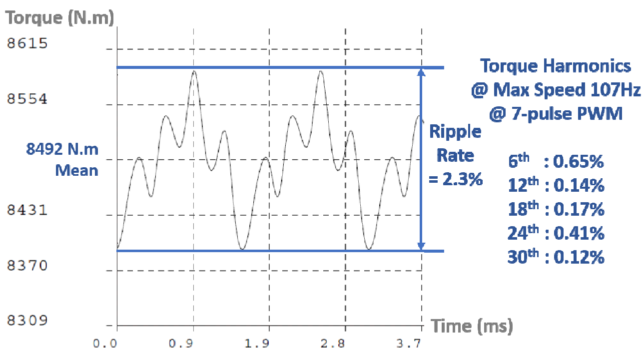

Fig. 9. Torque vs Time @ 6,400 rpm

As the VSI inverter generates voltage harmonics V_h to the motor, the higher the motor impedance Z_h is, the lower the harmonic currents are ($I_h = V_h / Z_h$). The design of the motor can thus be freely done so that the short-circuit torque is reduced. Because of the 7-pulse PWM control of the inverter coupled to the sinus filter, the harmonics of the torque remain low, mainly driven the 24th rank around 0.41% of the mean torque.

B. The Skid

The skid is the keystone and the adjustment variable of the mechanical system. Indeed, the constraints of integration related to the axis height of the compressor (interface # 2) and the re-use of the 10 fixing points of the foundation define the input interfaces for the design of the skid. The skid must be also perfectly designed and modeled in terms of dynamic interfaces for the lateral analysis of the electric rotor. The use of lubricated oil bearings (Fig.10), answering to the need of the Interface #3, strongly couples the dynamic of the rotor, operating above its first bending modes, with the static structural part of the motor through the stiffness and the damping of the oil film and the skid.

Fig. 10. Assembly of the Induction Rotor with Oil Bearings

The contractual speed range of the motor is 4,480rpm to 6,880rpm with a rated speed at 6,400rpm. The acceptance criteria of vibrations are 2.3mm/s rms on bearing housings and 4.5mm/s rms in all directions on the motor frame including main terminal boxes. Based on the bibliography, the structural design will be under control if the following design rules are satisfied:

- No natural frequency of rotor bending in the 1X variable speed range.
- No natural frequency of the end-shields of the frame in the 1X and 2X variable speed range.
- No global “reed” mode of structure bending (horizontal or axial) in the ½X, 1X and 2X variable speed range, or close to the rotor bending natural frequencies avoiding any risk of modal chaotic couplings and rotor instability.
- Skid vibration near the motor feet to be less than 30% of the vibration measured at the bearings [3].

The methodology of the manufacturer is to find the minimum stiffnesses of foundation by conducting a sensitivity study on the stiffness of the anchoring points. This allows to know very early in the design phase the necessary stiffnesses of foundation that can be discussed and validated with the end-user and the EPC partner in charge of the civil works.

The full motor, including the skid and the rotor with the bearing's symmetric stiffness and damping matrixes, is modelled with a mix 3D/shell FE model predicting the vibrations when the structure is excited by the rotor unbalances and the stator by the pole passing frequency at 2 times the inverter fundamental frequency.

The sensitivity study of foundations shows the needs of stiffness of foundations above $10^9 \mathrm{N/m}$ for the anchoring points to avoid significant resonances in the 1X and 2X range of speed (fig. 11).

In addition, the overall structural modes named A, B and C are not in the most probable ½X frequency range of use (i.e. 52Hz-54Hz) corresponding to a speed variation between 6,250rpm and 6,450 rpm.

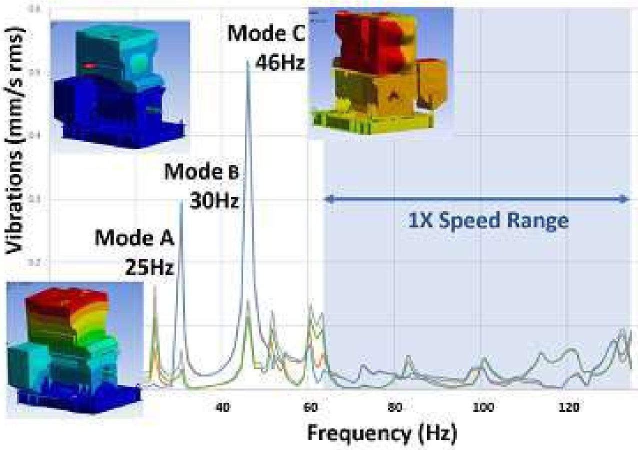

Fig 11. Dynamic response at the bearing housings location

The 3D-FEA model also allows the computation of the dynamic stiffness necessary for the rotor lateral analysis at the interface of the bearing housing (Fig.12) [4]:

$$K_{ij}^{dyn}(\omega) = K_{ij} - \omega^2 M_{ij} = F_i(\omega) * \frac{\bar{U}_{Re,j}(\omega)}{\bar{U}_{Re,j}^2(\omega) + \bar{U}_{Im,j}^2(\omega)} \quad (1)$$

$$C_{ij}^{dyn}(\omega) = -\frac{F_i(\omega)}{\omega} * \frac{\bar{U}_{Im,j}(\omega)}{\bar{U}_{Re,j}^2(\omega) + \bar{U}_{Im,j}^2(\omega)} \quad (2)$$

Where $\bar{U}_{Re}$ and $\bar{U}_{Im}$ are real and the imaginary complex averaged displacements at the nodes of the interface of fixation and i,j={x,y,z}.

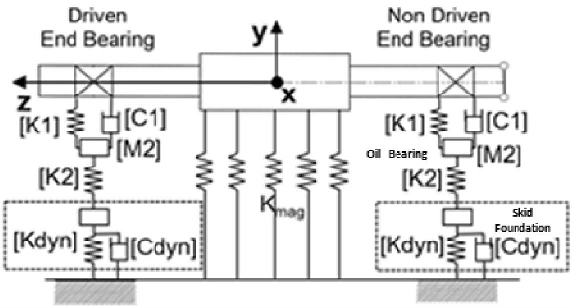

Fig. 12. Rotor Dynamic Model for FEA Lateral Analysis

The motor is compliant to the End User Specification and also the API 541 for the shaft displacements, and the bearing and frame vibrations, considering the stiffness and damping matrixes of the 4-lobe bearings at minimum, rated and maximum temperature of oil and the minimum, rated and maximum clearances of the sleeves (Fig.13).

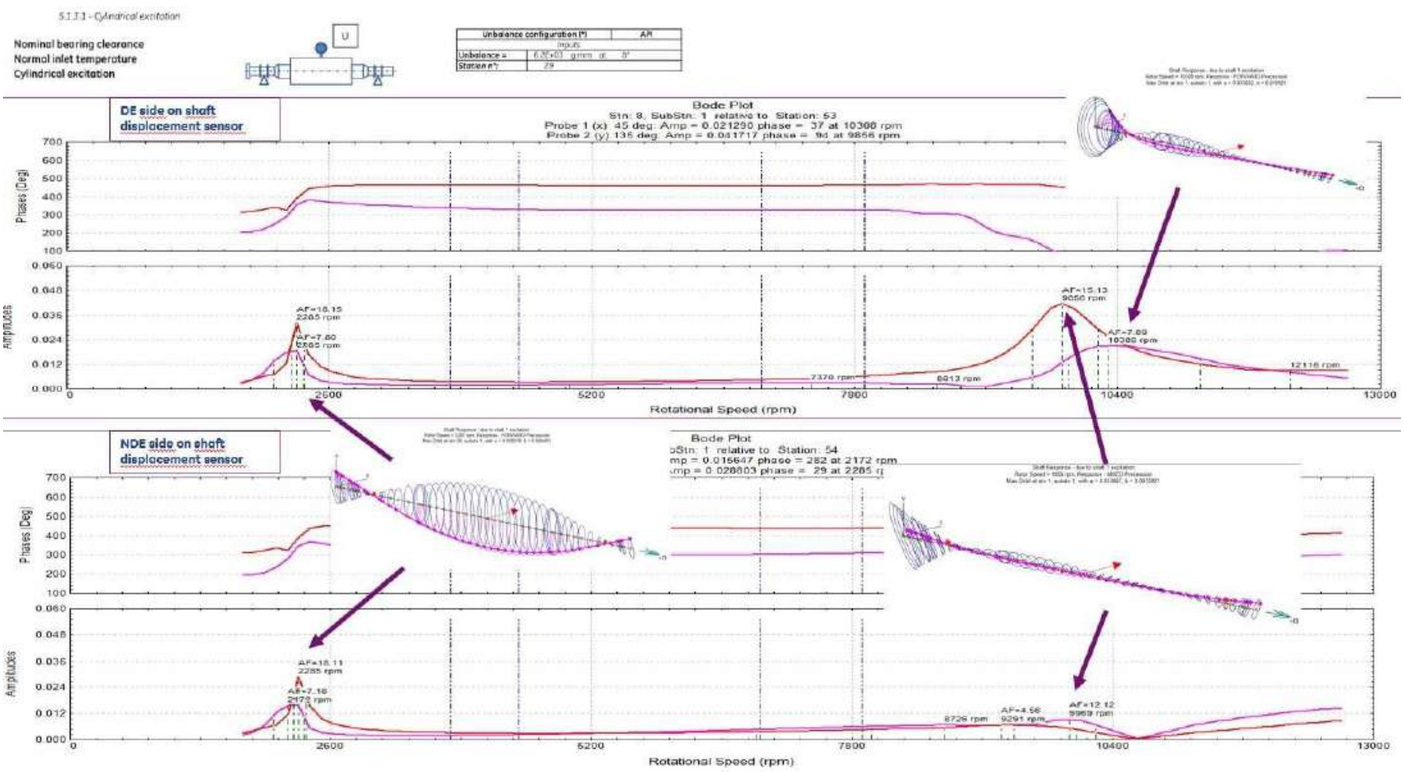

Fig. 13. Dynamic response of the Driven End (DE) & Non-Driven End (NDE) shaft displacements

C. Specific Motor Tests

After an overspeed test useful for relieving the stresses inside the rotor, a rotor heating test [5] is carried out for this type of a high-speed motor:

- Helping the rotor in relieving all residual stresses, reaching stable vibrations over the time in cold and hot conditions,
- Checking centrifugal and thermal expansion of the different components especially at the interface of the copper bars and the ferromagnetic laminated shaft, respectively having coefficients of thermal expansion of $17.10^{-6}\ K^{-1}$ and $12.10^{-6}\ K^{-1}$,
- Checking residual unbalance.

During a partial load test (Motor + Skid + Test Bench VSI), an Operational Deflection Shape (ODS) combined to a Bump Tests campaign is carried out to identify all the principal natural frequencies (Fig. 16 & 17) and to quantify of the dynamic stiffnesses at the different interfaces of fixation of the system. The motor outputs including vibrations are summarized below (Fig.14 & 15):

TABLE III
Main Outputs of the 2-pole Motor Performance

Parameters	Measurement
Power	5.7MW
Rated Speed	6,400 rpm
Speed Range	4,480-6,880 rpm
Rated frequency	107.1 Hz
Fundamental Voltage	4.7 kV rms
Current	866 A rms
Motor Efficiency fed by VSI	97.3%
Motor Weight	12 tons
Stator RTD Temperature	< 120°C
Bearing Vibrations @ full load	< 2.3 mm/s rms
Structure Vibrations @ full load	< 4.5 mm/s rms
Run Out	< 12.5 um pp
Thermal Unbalance	< 5 um pp
Shaft Displacements @ Full Load	< 20 um pp

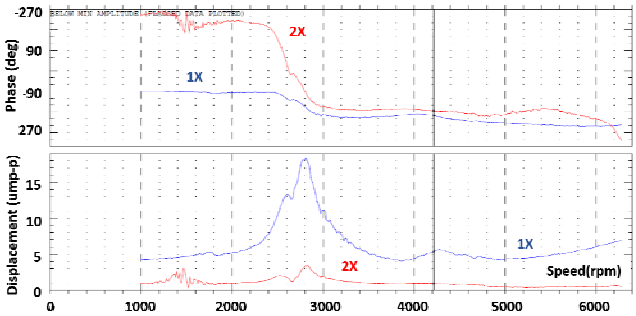

Fig. 14. 45° Left NDE Shaft Displacement vs Speed

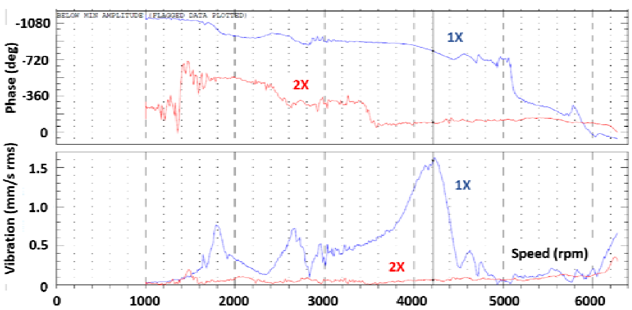

Fig. 15. Horizontal DE Seismic bearing Housing Vibration vs Speed

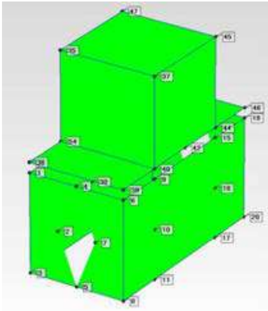

Fig. 16. ODS Mesh

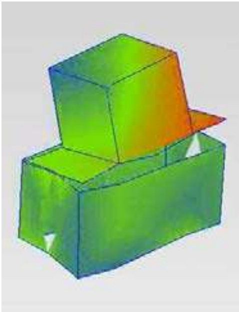

Fig. 17. Mode A @ 25Hz

VI. 4th CHALLENGE – CONSTRUCTION AND START-UP

The final investment decision of the project was taken in February 2018 after which construction started in April 2018 with excavation of the trenches for the main high voltage routing. This consisted of 1.3 kilometers of high voltage cable. In parallel with the cable installation, the underground infrastructure for the new modular substation was prepared, which consisted of tubex piles, concrete, and steel on which the new substation could be placed. The substation itself was completely built off-site, which allowed to integrate the electrical equipment into the substation prior to on-site installation. The key electrical equipment inside the substation consisted of 30kV switchgear, a water-cooled variable frequency drive, low voltage motor control centers (MCC), a HVAC system and fire and gas protection. In September 2018, the substation, transformer and cooler for the VSDS arrived on site and were hoisted onto the foundation. After this the E&I connections were made and the project scope prior to the maintenance stop was completed (Fig.18).

Fig. 18. Substation Module Lift

The only item left to install was the actual steam turbine replacement with the electric motor which took place during a maintenance period between April 29th and June 18th, 2019. The demolition scope at the start of the turn-around was extensive. It required expertise to remove the piping as well as the old steam turbine. The key challenge was to separate it from its foundation without damaging the concrete so that the tabletop could be re-used without too much civil works (Fig.19). Once the concrete surface was cleaned and prepared, the new steel base frame was hoisted into position, aligned with laser, and grouted (Fig.20). It is vital to get the grouting right. Thus, several flow tests were done to determine the right mixture and viscosity of the grouting before actual under-grouting the steel base frame (skid). Afterwards, the new electric motor was installed and aligned with the compressor and the mechanical and E&I connects were made after which commissioning began (Fig.21).

Fig. 19. Replacement of the anchoring tie-rods

Fig. 20. New Grouting

Fig. 21. Motor (L) - Compressor (R) after replacement

VII. LEARNINGS & CONCLUSION

There were two key lessons learned during the commissioning phase of the project. Firstly, the existing oil lubrication system delivered an oil flow that was too large for the bearings of the new electric motor. It was assumed that the flow would be regulated through installation of new restriction orifices. Unfortunately, the required orifice size would have been unacceptably small to reach the desired oil flow. This caused a late scope change during commissioning to achieve the required oil flows for both the electric motor and existing compressor. It is highly advised to thoroughly study the lube oil system during the engineering phase, up to the last detail of orifice restriction size and assess whether the existing lube oil system is fit-for-purpose. In the case of this motor-compressor, the existing system was too big and should have been partly re-sized as part of the project. This is a difficult trade-off between scoping, schedule, expenditure, and operational flexibility.

Secondly, as part of the commissioning process, there was an extensive test-run of the coupled configuration, blowing air to atmosphere for a period of 4 days, prior to lining-up the air to the reactors. During this test run, the diodes in one of the Diode Front End stacks of the variable frequency drive failed. The project team decided to replace all diode stacks preventively, this was resolved within 2 days. A root cause analysis concluded that the failure was caused by a fabrication defect. Looking back, the end-user had high expectations for this electrification project with many stringent requirements on minimum scope, minimum cost, schedule, logistics, plot space dimension, reliability, and availability. After the post implementation assessment, it was concluded that this project as a success, having delivered the project without any safety incidents, on time, below budget and started-up the unit “first-time-right” with no trips to date. The motor-compressor train has delivered more value than originally anticipated in the business case and reduces the site’s CO_2 footprint with 13 ktpa.

A win-win contribution from an environmental and economical perspective. A win-win collaborative success story for the end-user, the Engineering Procurement Company (EPC) and the Electric System manufacturer.

VIII. ACKNOWLEDGEMENTS

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X. VITA

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EMS FOR INTERCONNECTED O&G OFFSHORE FACILITIES A SUCCESS STORY

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Abstract

As for any complex facilities electrically driven, and running islanded from a reliable Grid utility, Electrical availability is a key factor for processes' profitability and safety.

It is particularly true for an O&G Offshore structure of which Electrical power is ensured by Gas Turbine Generators fueled by local produced gas,

Ensuring this availability with reliability, sustainability and coherence for two interconnected entities having capability to run independently or coupled, managed by 2 different Yards and accordant EPCs, involving more than 450 apparatus and devices from several manufacturers was a challenge that have been achieved.

The intend of this paper is not to present technological insights linked to disruptive technologies' implementation, but the methodology and lessons learned gained during the realization of a large scale and complex O&G project.

Beyond implemented solutions, it reveals how and why, involvement, rigor, organization, pugnacity, consistency and confidence between teams from different organizations, often in competition, kept all along the project's phases from FEED to Commissioning and Start-up have governed the success.

Ichthys EMS is the first milestone of a complete change of the EMS framework which adequately fits with the recent move of O&G's Companies, from O&G Producers toward Energy Providers.

Index Terms

CPF : Central Processing Facility
Floating platform for Gas processes and compression for export to onshore treatment
ECS : Electrical Control System, focusing on electrical distribution and Load Shedding management
EDG : Emergency Diesel Engine Generator,
EMS : Energy Management System, encompassing PMS & ECS functions within the same structure
FPSO: Floating Production Storage & Offloading Facility
Floating vessels for oil processes and storage
GTG : Gas Turbine Generators, main electrical power generation
IED : Intelligent Electronic Devices
ICSS : Integrated Control & Safety System (Centralized Process Control & Safety)
ISMS: Integrated Security Management System
PMS : Power Management System, focusing of Power Generators sets' coordination and power sharing
SCADA: Supervisory Control And Data Acquisition.

I. INTRODUCTION

For any Oil & Gas Offshore facility, the selection of the electrical control system is usually not straight forward. Besides the level of complexity, the size of the power generation and the associated electrical distribution systems, other key factors such as the contractual strategy, the cost, the schedule and the interfaces of the whole project are contributing to the selection of the electrical control system.

Consequently, it is crucial to define accurately the applications within its project environment, at early stage i.e. during Front End Engineering Design and before drafting the contractual documents for the Call For Tender.

The needs and the functionalities of the Electrical Control System shall be assessed through technical and contractual reviews.

Those reviews shall involve discipline leads (Safety, Process, Mechanic, Electrical, Instrument & Control, Telecom & Security), main equipment package leads (power generation, ICSS/SCADA, ISMS) and Field Ops (operating philosophy) to address the matters related to power management and power distribution control system. Typically:

- ✓ The load acceptance and rejection capability of the main power generation, (Electrical and Mechanic);
- ✓ Active and reactive Load sharing control (Electrical and Mechanic)
- ✓ Busbar synchronization, (Electrical)
- ✓ HV neutral earthing management, (Electrical)
- ✓ Source automatic transfer, (Electrical and Field Ops)
- ✓ Load shedding table (Electrical, Safety, Process and Field ops)
- ✓ Parallel operation with the essential and emergency power generation, (Electrical, Mechanic and Field Ops)
- ✓ Waste heat recovery management to minimize fire heater, (Electrical, Process and Field ops)
- ✓ Remote control start/synch/stop of power generation, (Electrical, instrument & control and Field ops)
- ✓ Automatic black-start recovery sequence, (safety, process, mechanic, electrical, instrument & control and Field Ops)
- ✓ Rationalization of event, alarm and fault list, (Electrical, instrument & control and Field Ops)
- ✓ Power quality monitoring and energy performance measurement (Electrical, instrument & control and Field ops)

- ✓ Cybersecurity, (Electrical, instrument & control and Telecom)
- ✓ Interface with other systems, (safety, process, mechanic, electrical, instrument & control and Telecom)
- ✓ Remote access for maintenance, configuration, update, upgrade, (Electrical, instrument & control and Field ops)
- ✓ Future known and unknown development, extension or tie-in.
  In particular power from shore, wind or solar farm connection or energy storage system (safety, process, mechanic, electrical, instrument & control and Telecom)

The outcome will set the scope of supply and allocate the battery limits (if any) with other packages and systems (power generation, ICSS/SCADA, future tie-in power generations).

Once the boundaries of the scope of supply have been clearly identified, the scope of work shall be developed emphasizing the type of interfaces with other systems and/or packages such as communication protocol, preliminary Input/Output list, IP(Internet Protocol) / MAC(Media Access Control) address, functions, pursued by associated testing sequence such as Hardware Interface Validation Test, Factory Acceptance Test (FAT), Integrated Factory Acceptance Test (iFAT).

Contractual documents shall detail and include sufficient technical interface meetings at the different phases of the project execution. Simulator or "dummy" EMS shall be specified allowing communication, configuration and function tests at other equipment package premises.

Project schedule shall implement the appropriate work break down structure in order to achieve each interface milestone prior triggering the shipment of any related package or system to site.

Whatever is its acronym, an automation control structure, here after named EMS standing for Energy Management System, is in charge to coordinate all electrical apparatus, in order to ensure at any time and under any circumstances, the electrical network's stability of the facility, especially when running in full islanded configuration.

Long considered as secondary, his role of "electrical control" has evolved along the recent past, to an "energy management" function. It is now a key element to guarantee the permanent electrical power balance and stability of islanded plants, considering that a single black out (or total power failure) leads to a production loss of minimum 18 to 24 hours before full process recovery as well as potential environmental and safety implications.

Indeed, the continuous improvement of the Power Plant's heat rate of the facility, leads to more accurate control functions to mitigate additional risks linked as example to:

- Reduction of available spinning reserve, driven by a constant quest of the best efficiency set point of the on-line power generators,
- Additional processes improving the Power Plant's efficiency (Steam production for Combined Cycle electrical generation or for treatment processes),
- Addition of a percentage of Renewable Energy to reduce fuel gas consumption while keeping produced power availability – Hybrid Power Plant,
- Reduction of greenhouse gas and other emissions

Therefore, the EMS concept is born, to provide electrical availability in line with the overall optimization of energy costs and efficiencies. It is based on maximizing integration of former segregated Electrical Control System (dealing with power distribution & load shedding) AND Power Management System (dealing with power generation sets synchronization & load sharing).

However, even if this integrated concept answers to new technical constraints, it is a change in projects' management approach & realization rules as EMS comprises Power Generation and Power Distribution. Therefore, having a common system compared to usual segregated packages from different worldwide vendors is a new paradigm to be taken into account by End User and EPCs in charge of the project execution, especially when some packages are managed as LLI (Long Lead Item) while the others are not.

In order to illustrate how this new paradigm has been addressed on a large-scale project and associated issues solved, we will take as example, the full hot redundant EMS done for ICHTHYS FPSO and CPF, for INPEX, located in Offshore Australia.

The base case was 2 Offshore facilities fitted with independent power generation and distribution, modeled on a typical marine/Offshore arrangement:

Respectively:

- ✓ 4 Gas Turbine Generators (n+1 configuration, rated at 25MW ISO / 11kV) feeding the normal load;
- ✓ 2 diesel engine generators (rated at 4MW/11kV) feeding the essential load;
- ✓ 1 diesel engine generator (rated at 1MW/690V) feeding the emergency load.

During the course of the FEED phase, an exercise of optimization has been conducted to find a means of uniting both power generations.

Increasing the power generation efficiency and reducing the overall emission of carbon and nitrogen oxide as well as providing a higher reliability and availability rates of the electrical power supply

The selected scheme was to interconnect both facilities via an umbilical composed of fibre optic cables (to facilitate an united EMS control) and power cables (rated at 25MW/33kV equivalent to the power rating of one gas turbine generator).

Leading to a twofold benefit, the power umbilical acting as a virtual Gas Turbine Generator as well as an essential source for either facility.

The arrangement of the power generation for each facility turned into:

Respectively:

- ✓ 3 Gas Turbine Generators (rated at 25MW ISO / 11kV, the n+1 configuration provided by the power umbilical) feeding the normal load;
- ✓ The power umbilical feeding the essential load;
- ✓ 2 diesel engine generators (rated at 2MW/690V) feeding the emergency load.

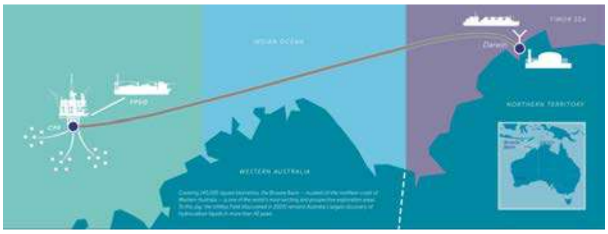
II. PROJECT'S OVERALL CRITERIONS

This section will cover the 3 main aspects of the project, as Operational Offshore facilities presentation, EMS key requirements and Realization structure organization.

A. ICHTHYS Operational presentation

Ichthys LNG is four mega-development projects rolled into one, from subsea wells, through two of the world's largest offshore facilities located approximatively 220 km off the western coast of Australia, linked by a 890 km long subsea gas export pipeline, to onshore LNG processing facilities near Darwin (Northern Territory).

It is expected to produce 8.9 million tons of liquefied natural gas (LNG) and 1.6 million tons of liquefied petroleum gas (LPG) per annum, along with more than 100,000 barrels of condensate per day at peak.



1) Central processing facility - CPF

The CPF is the world's largest column-stabilized offshore semi-submersible production unit. Docked in 250 m of water, it consists of a hull (110 x 110 m) carrying topsides (130 x 120m) as well as living quarters for 200 people. On the CPF, gas is treated, compressed then exported via a gas export pipeline to the onshore liquefaction plant. Two condensate rich MEG (CRM) umbilicals transfer a mixture of liquids from the CPF to the FPSO. This mixture consists of most of the condensates mixed with MEG (Monoethylene Glycol) and water. The remaining condensate is sent to shore through the gas export pipeline.

2) Floating production, storage and offloading facility

Permanently moored on a non-disconnectable turret about 3.5 km from the CPF, the FPSO is 336 m long and 59 m wide and accommodate a workforce of up to 200 people. It is linked to the CPF by subsea umbilicals. It is designed to produced up to 85,000 barrels of condensate per day, to store more than a million barrels and to load the condensate onto tankers at sea. The FPSO also regenerates the MEG, which is injected back into the wellheads to prevent the formation of hydrates and to treat the production water before it is discharged into sea in accordance with Australian Environmental Protection Authority regulations.

3) Electrical Power characteristics
   - FPSO: 3 x GTG 25 MW @ 33°C / 11 kV
   - CFP: 3 x GTG 25 MW @ 33°C / 11 kV
   - Interconnecting link rated 25 MW
   - 19 Electrical rooms (11 x FPSO / 8 x CPF)

B. EMS key requirements

Synthetically, the key requirements were:

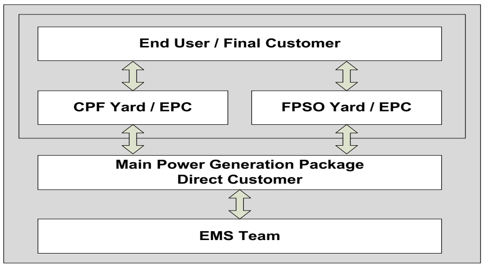
- Electrical network stability & Power sharing,
- Overall energy supervision & Data logging,
- Capability of CPF and FPSO facilities to run independently or as 1 coherent entity.
- When running as 1 entity:
  - Power exchange between CPF & FPSO via subsea interconnector,
  - Maximizing the power produced by FPSO's GTGs to optimize the FPSO's WHRU efficiency,
- Full hot redundant EMS architecture & communication network, keeping process' performance whatever the configuration,
- Marine Class Certifying Authority certification for hardware & software,
- Reinforced Cyber security.

C. EMS Realization structure organization

As for any complex and large-scale projects, numerous companies were simultaneously involved during its realization.

EMS being part of the two facilities, the EMS team was involved with the execution teams:

- The End Users,
- CPF Engineering Procurement Construction & Commissioning Contractors,
- FPSO Engineering Procurement Construction & Commissioning Contractors,
- Power Generation sets' manufacturer,
- Subcontractors / Vendors in charge of the 450 electrical apparatus managed by / linked to the EMS, and mainly composed of:
  - Gas Turbines & Generators,
  - HV and LV switchgears,
  - On Load Tap Changer,
  - Uninterruptible Power Supply,
  - ICSS,
  - Emergency Diesel Generators,
  - Waste Heat Recovery Unit,



EMS Project Organization chart

III. EMS CHARACTERISTICS & FUNCTIONS

A. EMS key objectives

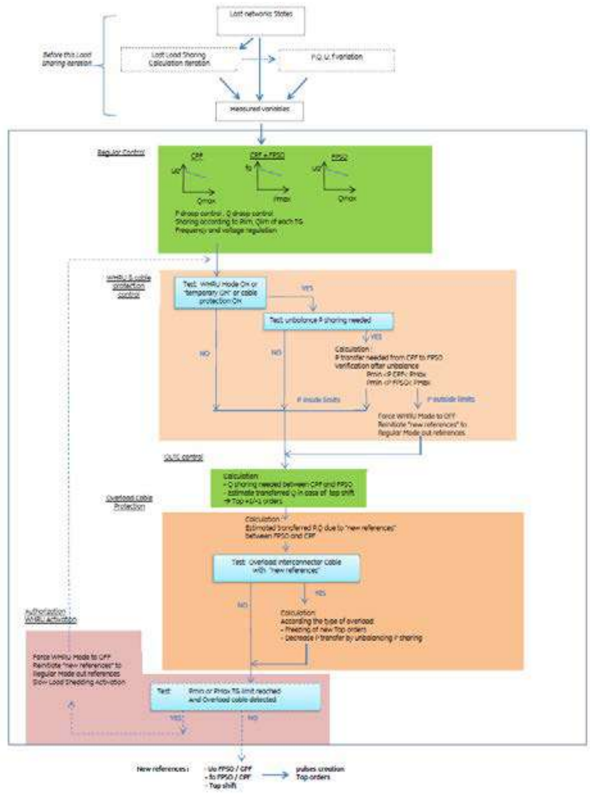
The main objectives of the EMS are:

1) Availability of the FPSO & CPF power supply and distribution network, by means of automatic Frequency & Voltage regulation (Load Shedding, Load Sharing...)
2) Centralizing, displaying and recording the alarms and events of the whole electrical network, for analysis by electrical maintenance operators after the occurrence of a fault,
3) Supervising and remotely controlling the equipment of the power supply network, from EMS Operator workstations,
4) Communicating with the Integrated Control & Safety System (ICSS), feeding it with general information on the electrical network and generators status; as well as specific control (Process loads starting authorization),
5) Configuring online and remotely, the load shedding steps
6) Live bus bar Synchronizing, local 11kV and 33kV/11kV Power Interconnector,
7) Either in “Islanded mode” (CPF & FPSO independently) or in “Interconnected mode” (overall CPF & FPSO considered as one entity among which the electrical energy is shared)

B. EMS Main Functions

To reach above objectives, the EMS ensures:

1) Main Generators individual Management,
   - Start / Stop / Coupling requests orders,
   - Load Sharing, by Speed & Voltage adjustment setpoints,
   - Unload / Disconnect / Stop requests orders,
   - WHRU (Waste Heat Recovery Unit) control,
   - OLTC (On Load Tap Changer) control,
2) Emergency Diesel Generators supervision and individual Start / Coupling / Return to normal & Stop request orders,
3) Dynamic Load Shedding,
4) Manual Source Transfer initiating; Functions of Automatic & Manual source transfer being directly managed by dedicated switchgears’ devices
5) Neutral earthing resistor management
6) CPF & FPSO GTGs’ synchronizing, to allow local 11.5 kV & interconnection Busties closing (Manual / Automatic)
7) CPF-FPSO Power interconnection control,
8) Monitoring and Control of the Electrical Equipment (fault discrimination with 5ms accuracy)
9) Large load start authorization.
   Even if loads start / stop decisions are ensured by the ICSS as per Process’ needs, the EMS authorizes / inhibits the starting of large loads, depending on the GTGs’ Active & Reactive power reserve vs the loads’ Active & Reactive power demand.

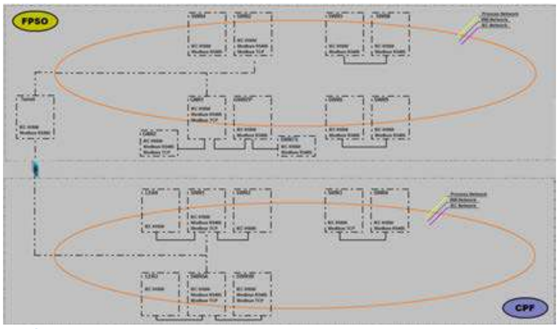

EMS Typical Logic Diagram for Power Management and Load Control

C. EMS Main Characteristics

1) Data base: 12000 I/Os,
   - 4 500 wired I/Os
   - 7 500 Serials
2) From 900 electrical equipment, including 400 devices by smart communication (Modbus TCP/RS, IEC61850 [1], Open Platform Communications)
3) 20 supervisor workstations including 2 servers in redundant configuration
4) 22 EMS cabinets located in electrical substations embedding PMS and PDCS management system including local supervision,
5) 26 hot redundant EMS active devices (Controllers, gateways Remote Gateways and Remote IO concentrators)
6) GPS time acquisition and distribution system for time synchronizing of EMS equipment and Ethernet connected smart devices (Protection relays) through Network Time Protocol,
7) Marine Class Certifying Authority certification for hardware and Software.

D. EMS Structure

1) Three-level automation architecture
   - L2: Supervision, Alarm recording & Archiving,
   - L1: Automation functions & Data server for supervision,
   - L0: Data acquisition & event data server for supervision.
2) All active devices in full hot redundancy, under Real Time Operating System,
3) Interconnected by Optical Fiber ring Networks to link all CPF & FPSO's electrical & control rooms.



EMS Network ring structure

IV. MAIN REALIZATION CHALLENGES AND SUCCESS APPROACH

Even if an EMS is not an "off the shelf" product but a System, it is based on a structured & field proven architecture embedding experienced functions, to be customized to act as an "Anti-Black-Out" system of a dedicated facility.

Therefore, the present section will not cover all above expressed architecture & functions' details but will focus on the ones for which collaborative approach & deep involvement from each party were key to turn out successfully each phase of the project, leading to an overall success.

A. EMS Data Base / Operational Functions Equipment List – Equipment Type – Functional entities Document

To allow the EMS to match with its automation control and supervision objectives, a clear definition and count of exchanged data including the associated functions with the "electrical world" of the facility are fundamental.

The first action was to issue a credible and representative list of devices / equipment to be connected to the EMS, considering that too many data affects speed and reaction time whereas not enough data affects accuracy:

1) Undersized list: Risks of unreachable functionalities by a lack of data,
2) Oversized list: Risks of Operators' disturbance (over complexity), un-affordable costs and increase of cabinets' footprint impacting electrical room layouts,

It was crucial, considering that both interconnected facilities were manufactured by:

1) Two different yards & EPCs, each with their own realization rules & experience,
2) Switchgear manufacturer also sub-segregated by 4 teams [(HV & LV) x (CPF & FPSO)],
3) EMS team was interfaced to above electrical teams through our BHGE mechanical colleagues of the power generation package, also segregated by 2 teams CPF & FPSO.
4) Numerous sub-sub providers, as for Thrusters, UPS, Emergency Diesel Engine Generator…

This was solved by:

a) A close collaboration and regular face to face meetings with Client and Vendor representatives, held all along the project, from FEED phase to Startup, allowing:
   - Mutual pooling of expertise & experience,
   - Clear definition of End User's expectations,
   - Never questioning of past decisions,

b) Co-location of teams during the FEED phase allowing CPF – FPSO coherence,

c) Co-location of EMS core teams, for both CPF and FPSO, kept all along the project, from FEED phase to Startup,

d) Accurate and mutually agreed definition during the FEED phase, of all key EMS principles, functions, Data base, interfacing, based on:
   - Deep analysis of INPEX FEED's document, as mainly, CPF and FPSO:
     - EMS specifications,
     - Main Power System Generation & distribution philosophy,
     - Load Shedding philosophy,
     - Electrical Loads Schedules,
     - Single Line Diagrams,
     - …
   - Ranking of each data as per their processes' importance,
   - To reach an agreed "90%" EMS data base and accordant functions, composed by:
     - CPF and FPSO <u>Equipment List</u>, focusing on the 900 main devices to be considered,
     - Accordant approved <u>Equipment type,</u> describing the matter to characterize each similar equipment, by a standardized:
       - IO type and number,
       - Acquisition and Control principle (Hard / Serial)
       - HMI representation,
     - IO List, consolidation of IO list with equipment's details provided by the Equipment type.

e) Relocation since the beginning of commissioning phase, of the Head of the EMS engineering team, close to the CPF & FPSO yards in Korea.
   This has been key to ensure and check the coherence between initial decisions and results & adequacy with facilities' real needs.

f) Continuous data cross-checking between EMS team and all the electrical systems involved, through meetings and document's centralization, ensuring that any modification to the Data Base and/or associated functions were captured and updated in due time:
   - EMS cabinets advancement status, with CPF / FPSO manufacturing constraints, to allow cabinets installation within electrical rooms,
   - CPF & FPSO EMS Homogeneity for similar devices, "BD, HMI, Functions" despite "one side" philosophical evolutions,

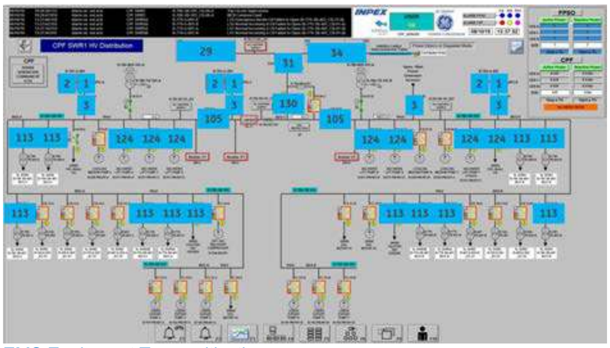
At the beginning of the execution phase, it was known that "agreed 90%" was not realistic to be kept all along the realization, but has been used as common guide line to guarantee consistency beyond EPCs, Yards, Switchgears and Packages suppliers (GTG, EDG, UPS…)

As result, the project successfully kept this homogeneity for the main devices by limiting the number of different Equipment Types from CPF vs FPSO, and limiting the differences when not kept:

Switchboard / System	Item number	Item Description		Items quantity CPF
	1	11kV Generator Control Panel		3
	2	11kV Gas Turbine Control Panel		3
	10	11kV Fault current limiter		1
	14	Bus Riser for Is-Limiter		1
	29	11kV/33kV Interconnector Transformer NER Feeder (CPF)		1
	31	11kV/33kV Transformer AVR OLTC		1
	34	11kV/33kV Transformer Power Circuit Breaker (33kV)		1
	40	690V Incomer		10
	43	LV bus coupler		4
	45	690V Switchboard Interconnector Feeder		11
	47	690V UPS Main Supply Feeder		28
	48	690V UPS Bypass Feeder		10
	50	400V Incomer		6
	51	LV Transformer Outgoing Feeder (ACB Feeder Type)		6
	55	690V Incomer 1 to GSP Aux SWB		3
CPF & FPSO	56	690V Incomer 2 to GSP Aux SWB		3
	60	690V EDG Unit Control Panel (CPF)		2
	67	690V Main Emergency Incomer		4
	70	400V/230V Small Power & Lighting Distribution Board Feeder		132
	71	230V Small Power & Lighting Distribution Board		57
	72	400V Emergency Power Distribution Board		33
	76	110VDC/24VDC Battery Charger (HV/LV SWBD)		14
	77	AC UPS		8
	79	Navigational Aids AC UPS		2
	80	UPS Sub-Distribution Board		25
	83	DC UPS Switchboard Control Supply		34
	86	690V Main emergency switchboard bus-tie		2
	89	690V Bus-tie		3
	90	400V Bus-tie		2
	100	690V incomers to heater/thyristor panels		7
	103	11kV Gas Turbine Generator Incomer		4
CPF	105	11kV Bus Tie		2
	106	11kV Bus VTs and ES		1
	112	11kV Bus VTs		2
	113	11kV/720V Transformer Feeder		12
	115	11kV Earthing Transformer Feeder		2
	118	11kV/720V Captive Transformer Feeder for process heater		7
	120	11kV Package P2 type / HV Motor ≤ 1000kW		6
	121	11kV Package P2 type / HV Motor > 1000kW		4
	122	11kV Package P3 type / HV Motor ≤ 1000kW		4
	124	11kV Sea water lift pump		7
	130	11kV/33kV Transformer Incomer/Feeder		1
	133	11kV Pre-Insertion Resistor Feeder		1
	162	690V EDG Incomer		3
	163	690V Bustie A/B (between both EDG)		1
	177	AC UPS (Helideck Lighting)		2
	187	LV Emergency Bus-tie/Interconnector		2
	188	LV Bus-tie/Interconnector		1

EMS Equipment Types' Definition & List

Operators' satisfaction and Maintenance team feedback are the key homogeneity and coherence KPIs as the EMS is a central point for the 2 facilities even if engineered by segregated teams.



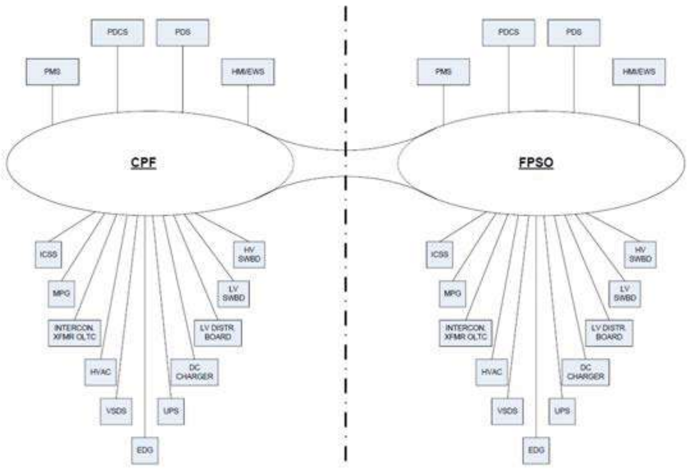
EMS Equipment Type unitization

B. *EMS IO Interfacing - Coordination*

Considering that an average of 60 % of the Data base is issued from 400 external devices, a high integrity of the communication networks is the backbone of the EMS, and key for efficiency and sustainability.

Coordination with equipment suppliers was done by issuing, consolidating and centralizing interfacing document, to be discussed with all involved parties, until reaching agreement by:

a) Interconnecting Lists definition: List of the external wiring and network connection with EMS cabinets,
b) Acquisition / Control principle, hardwired versus Serial link depending on data's criticalities,
c) Establishing communication protocols between EMS and interfaced devices respecting devices' capabilities (HV relays by IEC 61850 [1], GTG UCP by Modbus TCP, UPS UCP by Modbus RS…)
d) IP Address document: List of IP addresses of EMS system and interfaced Ethernet devices' Class addresses,
e) Updating above document until startup phase – As built document version.,



EMS Interfacing structure

C. EMS IO Interfacing – Communication Network Structure

The EMS efficiency, meaning its capability to ensure key functions to avoid blackout risks & Gen sets power sharing, is directly linked to the guarantee of its reaction time.

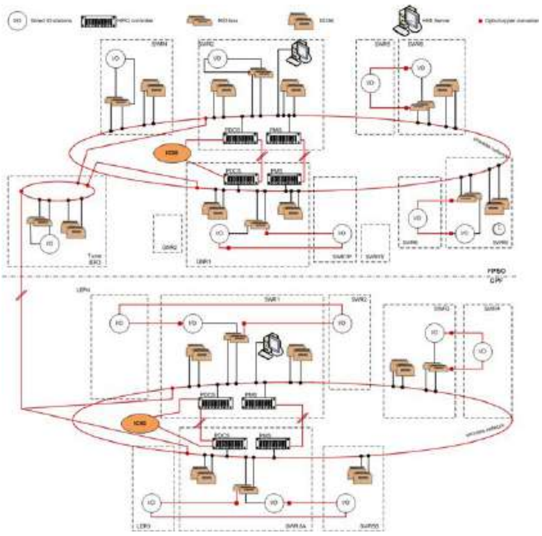
Considering the number of devices simultaneously in communications, not all mastered by EMS, and not all dedicated to EMS functions (as the IEC 61850 GOOSE messages [1] between some Protection Relays), Independence of Data Flux is key success factor to avoid networks' saturation risks.

This segregation is ensured by using six dedicated Ethernet mono-mode optical ring Networks to link all CPF & FPSO's electrical & control rooms (FPSO x3, CPF x 3) while limiting maintenance complexity.

a) EMS Process Networks

Dedicated to level 1 (Processes), these rings are used for Ethernet communications between Process' main real time controllers, RIO concentrators and Gateways.

MRP (Main Ring Protocol) is used for the rings.

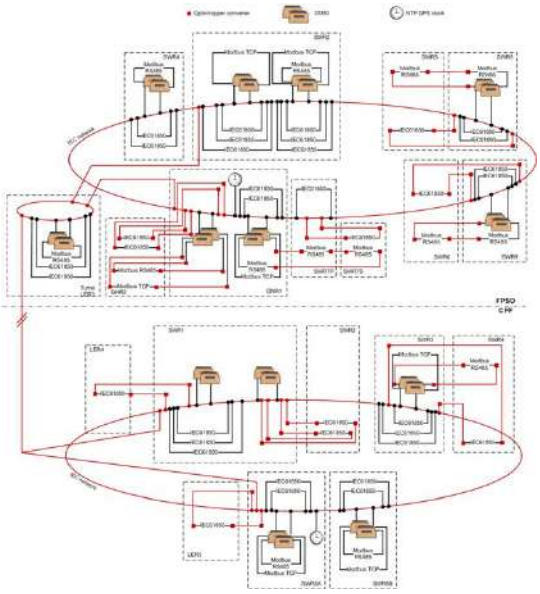


EMS Process network structure

b) IED communication Networks

Dedicated to level 0, these rings are used for Ethernet communications between IEC 61850 devices [1] (protection relays…) & EMS gateway and between IEC 61850 devices [1] & accordant configuration tools.

MRP is used for the main ring, completed by RSTP (Rapid Spanning Tree Protocol) within the sub chains between relays organized as "Daisy Chain".

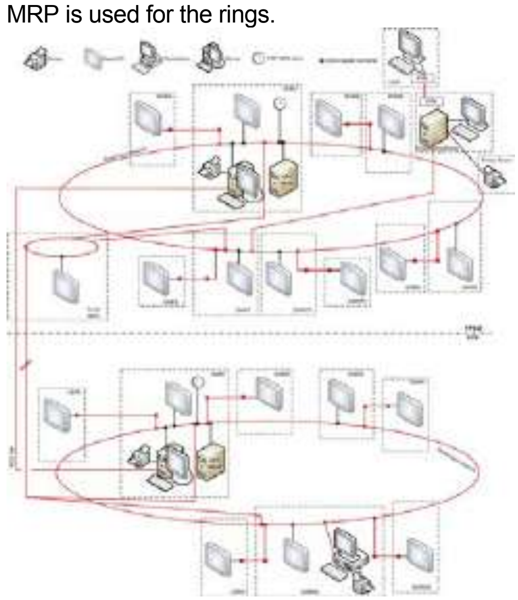


EMS Data acquisition network structure

c) EMS Supervision Networks

Dedicated to level 2, these rings are used for Ethernet communications between HMI servers PCs, client workstation PCs and panel PCs.

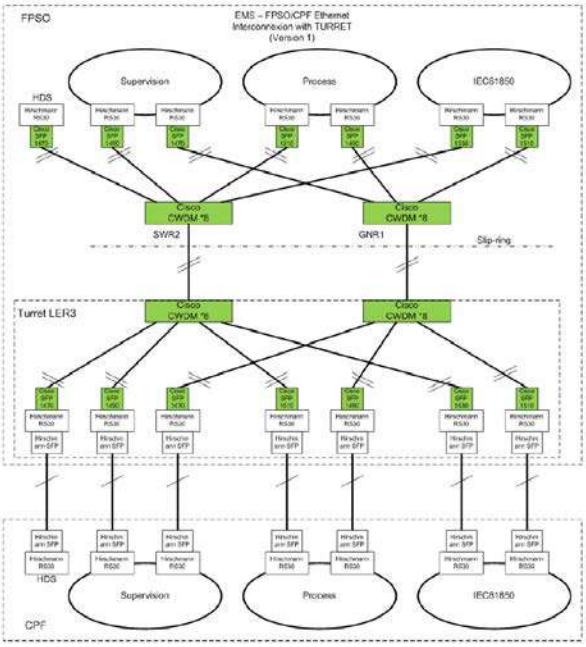
MRP is used for the rings.



EMS Supervision network structure

d) Rings Coupling

Rings' coupling between CPF and FPSO are done through the turret slipring of which the number of available optical fiber cores are limited. A Multiplexer / Demultiplexer device is used to enable the transmission of up to 8 Ethernet link over one single-Mode fiber strand.



EMS Ring coupling FPSO - CPF network structure

Demonstration of above structure efficiency has been assessed during commissioning phase when the interconnection between CPF & FPSO, has been established. 2 HV protection relays (1 on CPF and 1 on FPSO) with the same MAC @ have communicated through GOOSE messages triggering protection and unexpected trip on the opposite facility.

D. EMS IO Interfacing – IEC 61850 Interfacing [1]

Using IEC 61850 protocol [1] provides key communications' improvements between Intelligent Electronic Devices (IED) operating in electrical substations, in terms of interoperability & sustainability & capex reduction.

However, huge attention must be paid to avoid jeopardizing of IED's network functioning by saturation.

It is true for configuration risks (as above example and particularly with spare parts), but also during exploitation when IOs' state change occurs.

Indeed, thanks to digitalization progress, IEDs have huge capabilities to also provide additional contextual data (time stamping, status of associated IOs, measurements, etc.), which can unexpectedly multiply network's load at each process' data state change if not correctly managed. All capabilities and IED's available data are described within IED's ICD (IED Capability Description)

Therefore, to consolidate and ensuring the coherence of IEC 61850 communications [1] while keeping IEC 61850 [1] network's availability despite the numerous devices, ranges, manufacturers…, we established a dedicated document describing the basic configuration capabilities that each IED must have, and the philosophy that have been applied during project execution :

a) Daisy chain connection capability as preferred, with star connection as fallback, for media redundancy purpose,

b) Availability in Device's "Public Area" of Logical nodes & Datasets configuration in accordance with EMS database, for accordance with operating philosophy & service life purposes,

c) Multi "consumers" capability, to communicate with two EMS Gateways for Control redundancy purpose.
It means capability to integrate each Dataset into 2 separated Report Control Block (RCB), each controlling the exchanges with the 2 EMS devices of the redundant Gateway.

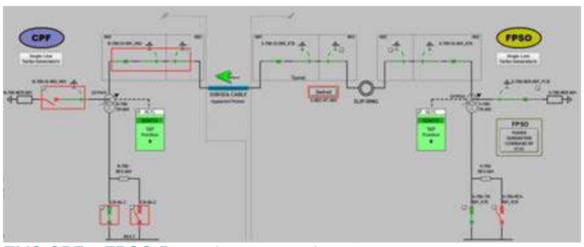
d) Capability of IEDs to be time synchronized by EMS time servers (GPS clock) through SNTP (Simple Network Time Protocol), for time stamping accuracy purpose,

e) Assignment by EMS team of main network parameters, as IED name, Ethernet IP address & subnet mask,

f) Assignment by EMS team of CID (Configured IED Description) configuration rules, including the customization of DataSet in order to limit the exchanged data to those declared in the EMS I/O schedule.

E. CPF-FPSO 11kV/33kV Power interconnection

Each facility's 11kV switchboard are interconnected by the 11/33kV Power Interconnector subsea cable, through a dedicated 11kV/33kV transformer including an OLTC device (On Load Tape Changer) on the 33kV side.



EMS CPF – FPSO Power interconnection structure

For Interconnection purpose, EMS ensures following functions:

a) Open/close control and supervision of the CPF-FPSO 11/33kV Power Interconnector distribution devices (Manual / Automatic), including synchronization of live bus bar.

b) The 4x 11kV CB (2 in CPF + 2 in FPSO) and the 3x 33kV CB (1 in CPF + 2 in FPSO)

c) NER (Neutral Earthing Resistor) CB Control, Automatic by EMS / Manual, on CPF or FPSO side

d) OLTC (On Load Tap Changer) control, to ensure the best Reactive Power sharing between facilities regarding WHRU set-point and 33kV cable maximum power.

e) “Black start” function to allow re-energizing of one facility since local black-out (CPF or FPSO) by the other remaining safe. This function has been required by Marine Class Certifying Authority to mitigate a potential failure of the local Emergency Diesel Generator and associated emergency switchboard.

Not particularly technically complex, the main difficulties to be solved during their realization, were linked to :

a) The impossibility of real testing during the commissioning & Site Acceptance Tests on the fabrication yards, as the 2 facilities were erected on separate locations.
b) The segregation by dedicated teams (1 for CPF and 1 for FPSO), with the EMS as only common node (for electrical energy purpose)
c) Late Black start function’s requests during Offshore commissioning execution, meaning far from EMS development facility and to be done by tight schedule while keeping EMS sustainability.

Once again, factors leading to “Plug and Play” interconnecting success for EMS purposes, were due to:

a) Close collaboration between involved teams (Power Generation package, Yards teams, main Switchgear providers and EMS teams, on behalf of Client representatives,
b) High degree of testing, including on simulation tools, from FAT done in EMS facility in France, until the 2 Yards’ SAT.
c) Collaborative approach and confidence between involved teams for Black start definition & realization & testing.

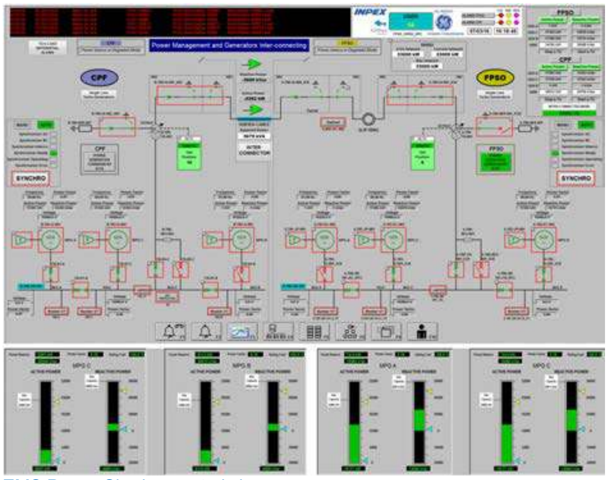
F. *Waste Heat Recovery Unit (WHRU) control*

The purpose is to minimize the use of the fire heaters by recovering maximum waste heat generated by the FPSO MPG’s (combined cycle). To achieve the best efficiency WHRU/Fire heaters, the FPSO GTG shall be loaded as much as possible without impairing the integrity of the FPSO/CPF power generation

WHRU control, is part of Load Sharing functions. It modifies the regular Active Power sharing to drive the FPSO Power Generation to a dedicated active power set-point sent by ICSS.

Hence, WHRU control will unbalance the active power sharing, to increase the active power supply by the FPSO and to decrease proportionally the active power supplied by the CPF.

WHRU control is then in charge to maintain the level of FPSO active power equal or above the ICSS set-point (depends on global power consumption) while checking to not reach the minimum load off CPF Gas Turbine Generators and to not reach the overload limits of the 11kV/33kV subsea interconnection cable.



EMS Power Sharing control view

G. *Cyber Security*

Cyber Security is probably one of the main challenges to be addressed in the coming years, to guarantee the availability, safety, integrity and productivity of industrial facilities.

Even though Cyber-attacks are long story against IT infrastructure (Information Technology), they are fairly new and few against OT infrastructure (Operation Technology), with first SCADA attack in 2010 (Stuxnet), 2015 (Black Energy) …

However, they quickly evolved from basic interference with the HMI via the Graphical OS, to serious disturbance via the process and /or the safety PLC like in 2017 (Triton).

Therefore, huge attention must be paid to secure our OT architecture facing our uncertain world, especially for safety purpose.

Indeed, even though the EMS is not a safety critical element of the facility, being the focal interface point with electrical protection devices and power generation systems, it is a key contributor to the reliability of the electrical power generation and distribution.

Consequently, securing data exchanges concurs to the safety and availability of the components constituting the OT infrastructure.

As mentioned, it is fairly new, and well-known tools and rules focusing on IT security cannot directly apply to OT, because objectives and priorities are not the same, exploitation and maintenance teams are different. Even though main HMI are using the same Graphical OS for both OT & IT, the difference resides in the version, IT operates with the latest version while OT operates with the “FAT” version (except for security patch).

IEC 62443 [2] defines Risk as combination of Threats x Vulnerability x Consequences. Feared events and potential impacts for IT and OT are different whatever the cause (intentional or not), therefore risk analysis shall be used to define appropriate cyber protection (Security Level Target / Tolerable risk / Mitigation Plan).

Even if the 3 basis objectives are common,

a) Their precedence is in opposite order:

- IT: Confidentiality / Integrity / Availability,
- OT: Availability / Integrity / Confidentiality,

b) A fourth key objective, which doesn't exist for IT, has to be added to the first priority for OT, as a complement to Availability: Safety.

Together, they guarantee that crucial EMS functions of Load Balancing:
- Will be **Ensured** = Availability
- In **Due Time** (Deterministic) = Safety.

Even though the Ichthys EMS realization started before the latest cyber-attacks, the Information Security have been addressed by permanently keeping in mind these 4 key aspects, including the Maintainability as part of the Availability.

Indeed, it would have no sense to "over-secure" the architecture, if the EMS became non-operational at the first device or interfacing failure, especially with 400 devices in communication.

In other words, high availability is a paramount attribute and secured design is a permanent balance between performance and security, including fallback mechanism like degraded mode.

In close collaboration with Client inspectors in charge of Cyber security until validation, added to our Power Conversion's rules for the purpose, Cyber aspects were addressed by:

a) EMS devices location
To ensure physical security, thus to mitigate unauthorized access, all operators' HMI & Servers and all EMS devices are installed:
- In secure, accessible only by authorized users locations. i.e. Electrical Rooms and Central Control Room,
- Housed within EMS key lockable cabinets, including the electrical rooms local HMI which are panel door mounted.

b) EMS main active devices (Process Controllers, Gateway, Remote IO Concentrators):
- All running under Real time Operating System,
- Managed as per rules for cyber security,

c) Segregated communication networks

As explained in section 4-C – The communication structure is composed of 3 main segregated networks, completed by sub-networks generating physical network segmentation, which provides high availability as well as safety.

d) Graphical Operating System for HMI (Human Machine Interface)

- All provided PC are featuring Antivirus software,
- During EMS HMI PCs boot and HMI application loading sequences, the Graphical Operating System are not accessible to any operator
- After the PC boot sequence and during HMI application normal operation, only duly "high access level" authorized operator can access to the Graphical Operating System,
- All the EMS HMI PC external mass storage devices including CD/DVD reader/writer and USB ports are disabled (Auto-play mode disable).
- All EMS PCs are equipped with an automatic log-off session in a time delay of 15 minutes when no operator action is detected (mouse nor keyboard)
- …

V. OPEN-ENDING TO THE FUTURE

As introduced, the paradigm of O&G companies is changing from O&G producers to Energy providers. It essentially means for EMS to actively participate to the transformation of End Users' operating model by allowing seamless:

a) Fossil fuel Power Generation's heat rate optimization by loading power generators to their best efficiency point and in parallel providing a substitute such as renewable energy and/or energy storage capacity offering sufficient spinning reserve in event of fossil fuel power generator failure. Resulting to lower the emission of carbon and nitrogen oxides without jeopardizing operating availability and reliability of the power plant

b) Interfacing with Digital Assets Performance tools, to provide risk identification before failure and remote diagnosis, to achieve significant gain in operational efficiency, (Periodic maintenance - inspection program and local maintenance team optimization…)

c) Power import/export from/to local Utility Grid when cost effective, allowing a win-win benefit, Companies' additional revenues by selling electrical energy in excess, as well as Utilities' capex reduction (Energy Peak period management…)

d) All above complementary functions and interfaces will have to be implemented taking into account the Cyber-Security constraints and challenges ensuring devices' interoperability in a safe and efficient operational context.

Obviously, Ichthys EMS doesn't fit all new above purposes yet, but its realization approach & philosophy pave the way for, reason why its completion can be considered as the first milestone of the future Energy Management.

VI. CONCLUSIONS

The Electrical automation management system, whatever is its acronym (ECS, PMS, EMS, ENMCS…), is no longer to be considered simply as an Operator's help, but as an active, influential and key system, for smooth and economical electrical availability and reliability, especially in the new O&G paradigm.

Therefore, this evolution implies a change in automation approach, to realize the benefits of new system capabilities, in terms of performance, redundancy, cyber security, sustainability, interfacing, etc.

This requires:

a) Teams' close collaboration beyond the Companies, merging and sharing knowledges and solutions for mutual business benefits and End Users' satisfaction, thus overall growth,

b) Independence from proprietary platforms for sustainability, including the total cost of ownership,

c) Independence from "One-sided" package solutions:
    - Neither Power Generation, of which electrical power supply is the core business,
    - Nor Power Distribution, of which electrical power distribution, control and protection is the core business,

d) Independence from the Process Control system, of which process instrumentation, control and safety is the main purpose,

Regardless the efforts of Engineering teams, money spent and the intrinsic qualities & performance of above-mentioned systems:

A formula 1 car will never win a rally race in the desert and a rally car will never win the Formula 1 cup;

It is not a question of devices' performance, but a question of accordance between the needs and solutions.
The project EMS realization pro-actively embeds this paradigm changes, reason why it is a success story of Peoples and Companies doing the right things to deliver a purpose driven solution.

VII. REFERENCES

[1] IEC 61850 International Electrotechnical Commission – Communication networks and systems for power utility automation Standard.

[2] IEC 62443 International Electrotechnical Commission – Industrial communication networks - IT security for networks and systems

VIII. VITA

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ELECTRICAL EQUIPMENT DESIGN CONSIDERATIONS FOR NOW AND THE FUTURE

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II. STAKEHOLDERS

There are many stakeholders involved in a project. A number of these are well known and have always been the key participants, however, with the broader scope associated with projects such as greater integration than ever before, new parties should now be considered as members of the project team; members that have taken a more passive or disconnected role previously.

More stakeholders means additional input and opinions. One of the concerns which has been expressed is that this can also mean unrealistic expectations and limitations which can be detrimental to innovation. The limitations often come from the mindset that they have always done things a particular way and are not willing to change or there is a financial aspect where an organization has not funded something in the past even if the analysis indicates that it is the best direction.

Future consideration should be part of overall project management strategy. This requires buy in from facility owner, facility operator, project management, engineering company, system integrator and equipment manufacturer. This collaboration may need to be agreed upon by all stakeholders and shall be evaluated against their ethics policy.

Fig. 1 All Groups and Experts Need to be Engaged

End users and EPCs have skilled designers and subject matter experts (SMEs) with the required experience and knowledge to put together and implement projects. These skilled persons have historically been divided into distinct teams based on their function and area of expertise working independent from each other for the most part on given a project. EPC and end users are running leaner than ever particularly with the current economic situation in Oil & Gas. Staff reductions, the emphasis on utilization and tighter budgets dramatically limits training due to the cost and non-productive time. The rate of change is also prohibitive since training must be ongoing to keep pace. By the time technology implementation is completed, the idea / technology is out of date. Taking into consideration just the basic power related aspects of a project alone, there are at least three groups who may be assigned to a project for a typical scope possibly more when you consider all engineering disciplines such as civil and mechanical. From the electrical perspective, there are usually 3 groups.

A. The Power Distribution group focused on the incoming supply to the installation who will coordinate with the utility, local generation, select the necessary switchgear along with the network aspects of power supply, ~~and~~ distribution and control
B. The Process Control group which will address specifying the motor control
C. The Control and automation group which oversees the design and programming of the network and the required network aspects associated with the process.

These 3 groups have specific design responsibilities ranging from engineering studies which must be performed to control and deliver related objectives that they must achieve with the network which is deployed. Historically these groups have worked independently such as meeting with their prospective providers in isolation from the other groups. Where these groups have interacted usually is in defining the information which must be shared across their unique systems which often communicate using different protocols. The reason that these protocols are different is because these groups have worked as independent entities. This is how it has been and in discussions with each group, they value their segregation to a certain degree and the fact that this allows them to exercise control over their area. As a result, SCADA systems are necessary and commonplace as they are necessary to marry these independent systems together at least to the point that the necessary information can be transferred.
Things are changing.
It is now possible to use a common protocol to connect the power distribution control system directly to the process control system which brings numerous benefits. Recognizing this, companies are beginning to change their outlook and are now bringing these groups together earlier than ever before. At a few progressive companies, representatives from each of these groups participate in the evaluation of technology options and set corporate standards for the network and for the components which will be connected to the network so that base requirements will be met.
Other stakeholders that should be taking a more active role earlier in project design are IT, Operations and

Maintenance. Looking out even further, a Connected Enterprise will cross the barrier that has existed between IT and OT such that the front end of the facility can obtain key data directly from their OT system. For these later items, we will discuss this in more detail later in the paper. Another group which is playing an increasingly greater role due to the current economic circumstances are the equipment suppliers or vendors. In a conventional project execution, equipment vendors are not recognized as part of the project team until the PO is placed. The equipment vendor /suppliers bring with them the latest technology; what is available today and what will be compatible for tomorrow. By engaging equipment vendor / supplier early for technology selection and future technology inclusion, project management can benefit from latest technology.

A further aspect is the delegation of work to lower cost centers - workshare. Companies like to delegate certain aspect of design and support to other office – workshare getting is getting more and more popular to reduce the cost. In todays' market, how the right information is shared with workshare offices, maintaining schedules and remaining within or under budget is the first aspect that companies consider. Whether component level detail such as patented confidential technology or other IP must be shared or not with a remote office is a valid question if they do not require it. Sharing only items that need to be communicated should be the approach. More communication some time doesn't mean more understanding. During the workshare with offices across the globe, the project management team should make sure that the plant under design is considering the aspect of future design of upgrade or expansion getting done.

III. SYSTEM DESIGN & REQUIREMENTS

One of the first challenges will be to select an overall approach that meets the expectations of all stakeholders and will stand the test of time for all aspects of the project scope. Coordination of industrial automation and control systems including Process Automation systems and SCADA systems requires robust networks that connect thousands of IEDs reliably. In addition, today's industrial requirements are increasing the demands on network infrastructure. Networks are expected to handle increased network traffic and security services while delivering a full spectrum of real-time control and monitoring capabilities within a site-wide operating environment.

A robust system which has capability and capacity to not only expand but to accommodate new additions which will undoubtedly arise over the life of the installation is a fundamental and key starting point. The system needs to be sustainable. While forward compatibility is certainly an important factor, it is not the only consideration or answer to the problem. Items such as component life cycles enter into the picture. Is the equipment that is being chosen today going to be supported over the life of the installation?

A. The System

- *Network - Field Network Infrastructure*
  - *Scalability*
  - *Expandability*
  - *Reliability & Redundancy*
  - *Remote Accessibility*

B. Elements of System Design

- Asset Management
- Management of Change
- Accessibility

Most modern IED do not support individual user account and have a single set of passwords. For future considerations IED may be selected that support individual user account. IED with individual user account poses another level of challenge where password management system need to be implemented looking at any typical complex network of components and devices on any petrochemical or Oil & Gas facility.

IV. NETWORKS

Communication protocol is very important consideration. For green field project this may be simple solution on apparent basis. As many organizations have a preferred way of communication at their existing facilities, this may prevent the selection of a more suitable network protocol for the entire facility under design. For brown field projects, this may be even more challenging due to variation between legacy systems at an existing facility.

Network scope, security & communication protocol are the most important aspect of this discussion[1][2]. Information Technology or the IT network is part of the solution and have equal stake in the process.

Other considerations when looking at the network are robustness and redundancy.

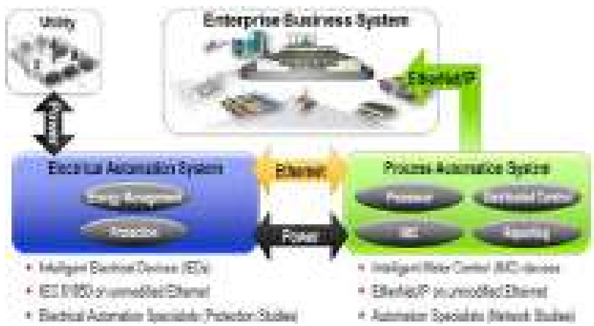

Fig. 2 Network Incorporating Electrical and Process Automation Systems

A. Process Control

Process control is the most important aspect of safe plant operation and production of any industrial commodity. With more and more IIoT devices and equipment connected over network through various communication protocol are major stake in the cyber security of industrial plant.

While it is comparably easy to reboot computers on an IT network, computers & servers on OT are not so easy to reboot on frequent basis as it has more consequences in terms of financial, environmental and plant safety perspective. While selecting OT systems designer may consider following points:

- Adequate design and strong system architecture
- Adequate and expandable hardware software capabilities
- Network configuration for future protocol compatible
- Secure connectivity with Ethernet
- Secure enforcement
- Plan for crisis situation
- Strong password policy
- Redundancy
- Adequate backup power supply (EDG, UPS)

Additionally change management should be a part of system architecture.
The OT computers / server may be equipped with on board logic and parameter for safe operating conditions and compare the real time command received for execution. In case of any unsafe received operating command it can send an alarm to operator / supervisor using different channel.

Other considerations may include, Industrial component and equipment working on power over Ethernet. More industrial component, devices and equipment are now available running on PoE (Power over Ethernet) than ever before. Industry analysts forecast the global industrial power over Ethernet (PoE) market to grow at a CAGR (compound annual growth rate) 15% during the period of 2019-2025. Selection of these devices will reduce the capital cost investment and make industrial plant more future compatible.

B. Power Distribution Control

The power distribution control through network and IIoT devices will determine the future of network. With more and smaller renewal power sources connecting to the main grid of the power distribution network, this aspect is more important than ever before.
PMS system should be capable of providing intrinsic and extrinsic capabilities with ability to logically separate from more than one firewall [9].

C. Substation Automation

The conventional substation RTU is now replaced by IEDs, PLCs and integration network using digital communications. Intelligent electronic devices (IEDs) being implemented in substations today contain valuable information, both operational and non-operational (for the purpose of enterprise management). Substation automation is getting more sophisticated and smart relays and other logical devices will control and operate the substation equipment using automation. AI need to consider the network security aspect to avoid any mal operation of substation equipment.
One of the challenge is to apply software update patches on server. A system needs to be developed for software maintenance and compliance. Testing should be completed before updating software. Substation automation development and testing plan need to be developed along with SAS designing.

The PLC which were not typically connected to network are now connected to network a comprehensive approach including cyber security needs to be developed for new facility. A multilayer substation security approach may be developed to deter hackers and provide more time for security software to counteract cyberattacks.

On top of that we have a Control System group who takes care of DCS and PLC which will also be communicating over network.

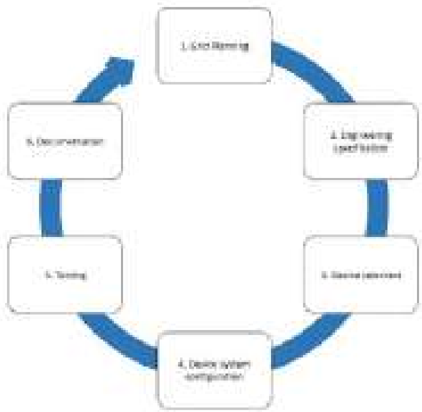

Fig. 3 Digital Substation Design Process

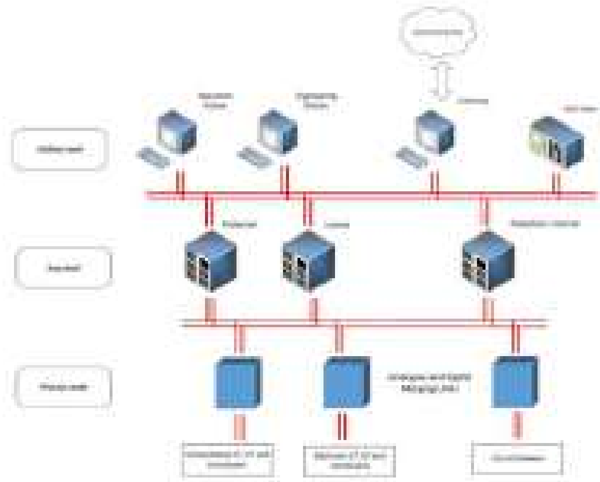

Fig. 4 Digital Substation Layout

Today's substation automation can provide important information for Equipment Condition Monitoring (ECM). With ECM equipment operating parameters are automatically tracked to detect any abnormal operating conditions. Data from protection, control and monitoring IEDs can be used to understand health and performance of substation equipment. Full blown substation monitoring system can be developed from existing IED and SAS.
Developing trends in Optical electrical technology and non-conventional instrument transformer shall be consider for future plant design to accommodate future technology that might show up later in plant life cycle. This non-conventional instrument transformer uses fibre optic cable for communication which will result in massive reduction of copper control cable requirement and so the installation cost. This will reduce the CAPEX of the plant.

V. SECURITY

Unfortunately, the need for security goes hand in hand with increased accessibility. There is a very real threat as can be seen by the most significant reported cyberattacks of the decade listed below, however, there are numerous smaller incidents which may not be reported as well[3][4].

Stuxnet - US & Israeli governments
Shamoon - Iranian state backed hackers - Saudi Aramco
Sony Hack - North Korean attack on Sony pictures
Office of Personnel Breach - Chinese government
Ukranian blackouts - target control systems
Shadow Brokers - North Korean hackers - utilities, etc.
2016 US presidential hack - Russian hack of Democrats
NotPetya - Russian hacking group - devastate networks
Equifax Data breach - Target, Home Depot, etc.
Aadhaar - Indian government breach

Design engineers are challenged to bring, as a business case, network security related solutions which mitigate risk to project decision makers in order to help make an informed decision. To do so the design engineers need to quantify the risk based on network vulnerability and process plant operation hazard scenarios on the other hand decision makers need to stay away from media hype for IT related security breach.

Fig. 5 IT Best Practice of Passwords Allows Security Team to Define Who Can Access and Where Accessed

For any system, there is a tradeoff between accessibility of information and system security. One of the factors which is key and will help determine what is required relates to how much access is really required to meet the needs of the project.

IT will also be part of this design aspect and are equal stake holder. IT should be able to provide the supportive network for the requirement of the plant design. This goes in to Firewall and physical barrier that IT might have consider for their design. The project electrical design team needs to be aware of this aspect of IT design and make any plant communication approach compatible with current and future IT requirements[5].

The current practice of protecting equipment and devices using firewall technology is similar to the medieval technique of protecting the asset with wall. The thicker the wall that is built around the asset, the more it is isolated and a reduced resource in case of need. A heavily fortified structure is perhaps not the best strategy. Cyber security should be inherent to system with proactive monitoring embedded in the solution rather than protecting from outside. Defense in Depth is a technique which does not simply count on a solid firewall alone. It goes further by monitoring what is happening, raising alarms and can take action when it is recognized that the system is under attack. Continuing the analogy, this is similar to putting cameras at the castle wall which will alert the owner to the attack preventing a sustained attack from being effective.

Process control equipment, power distribution control equipment and substation control equipment connected over network communication under various protocol must all be considered[6][7][8]. EPC companies and vendors using the distributed resources across the globe for plant design or product development puts the process at risk and compromise network protocol that can only be visualize once the attack is visible. Plant design or product development is a long vigorous process and sometime more communication does not necessarily turn to more understanding. To develop more understanding most of the time intellectual property is compromised.

In a typical plant design project management team used BRMS (Business Risk Management System) plan to identify and mitigate risk. In the same line we are proposing here to develop BiRMS (Business intelligent Risk Management System) plan to identify, handle and mitigate intelligent.

Advent of IIoT capabilities provides a natural method of attaining the needed information. Using this information effectively without causing any additional risk requires innovation. Design engineer can use these IIoT capabilities and may take the innovation challenge for plant design.

Here are some areas of Cyber security that needs to be consider for plant design. Cyber security strategy focus areas are grouped by: [NIST 800-82]

- Planning
- Incident prevention
- Detection
- Containment
- Remediation
- Recovery & Restoration
- Post incident analysis / Forensics

Incidents are inevitable and an incident response plan is essential. A major characteristic of a good security program is how quickly the system can be recovered after an incident has occurred.

Following special considerations are required when considering security for ICS:

- Timeliness and Performance Requirements
- Availability Requirements
- Physical Effects
- System Operation
- Resource Constraints
- Communications
- Change Management
- Managed Support
- Component Lifetime
- Component Location
- Risk Management Requirements

For risk management requirements it is important to note that any security measure that impairs safety is unacceptable.

Conventional management is well versed with the layered approach for HSSE implementation. Layered approach of HSSE can help us in defining Cyber security. The layered approach is:

- Elimination – Network Isolation
- Substitution – Block unused port via software or physically
- Engineering Control – Automatic password management, Firewall, Patch management, N+1 server
- Administrative Control – Training, Password policy, Access Control, Risk ranking

- PPE – Crisis plan

The best way to address any uncertainty and fear around cyber security is to incorporate security in the overall business plan and strategic objectives for the organization [1].

VI. DATA MANAGEMENT

During the design phase, EPC Companies produce massive amounts of data for building the plant. How we can make sure that the same data is transferred and used for the plant operation? Engineering plans or strategy documents shall be developed that define object level attribution and other necessary information for plant operation. The component and devices selected for the purpose should be able to communicate the actionable data package.

With more and more facility Owners seeking dataset developed during detail design phase to transfer for plant operation. It is essential to distinguish the data requirement for plant design, plant construction & commissioning, and plant operation.

- Data set required to complete engineering design
- Data set required for plant mechanical completion and pre-commissioning
- Data set required for plant commissioning and start up
- Data set required for plant operation and maintenance

Not all the data set developed during detail design phase is actionable for plant operation and analytics. The EPC contractors, Owners and Vendors shall identify the required data set for each purpose to avoid duplication of data and accumulation of non-relevant data in the communication network.

Data gathering and analytics – The system should have capacity and capabilities to collect relevant data or actionable data that help in data analytics to make decision based on the AI.

With convergence of OT and IT, industrial communication networks are connected to internet web more than ever. Advances in IED, IIoT and AI pushes the boundary further to communicate non-technical information to enterprise management for commercial decision making, technical decision making and plant operation. What are the business risk involved in merging OT and IT? What strategy business planners need to develop to mitigate the information exchange risk from one platform to another? How business planners can make informed decision about industrial cyber security for OT? The intention of this paper is to look at the changing landscape for the business planners, decision makers for selecting level of OT and IT merger. Developing business information risk mitigation strategy without compromising safety of personnel, equipment, environment & community without driven by media hype for cyber security breach.

Design engineer may consider that component selected for plant are compatible with IT and IT security requirements. Plant operators lean more towards the data collection and analytics that provides information for predictive maintenance and condition based maintenance. This data help minimizing the impact of component failure on plant operation. Design engineer may consider to select the component or equipment under consideration will be able to communicate to current network and future network or other complex network that it will be connected over the plant life cycle to fulfill the maintenance requirement.

Plant owners and executive management team are more interested in consumption and production data for the purpose of data analytics. The relevant data set needs to be available and communicated over network. One aspect of these communication can be linked to metering point. This metering point can be for any commodity including utilities.

VII. SPECIFICATIONS

A. Equipment Specification

Equipment specifications are the usual starting point of defining the equipment design once the overall concept has been agreed upon. The engineer responsible for preparation of equipment specification, need to consider following aspects other than all normal technical consideration made while doing a conventional design:

1) *Connectivity with other operating device*
2) *Cyber security of all connecting devices in chain*
3) *Failure mode protection of network activated device*
4) *Safe communication over the spectrum*
5) *Separate network identification for safety critical device*

B. Facility Specifications

Engineers and designers responsible for preparing facility specifications need to consider following aspects other than all conventional considerations made

1) *Secured IT network and suitable IT infrastructure for providing protection to devices, equipment and network*
2) *Network safety for devices and equipment for manned facility*
3) *Network safety for devices and equipment for unmanned facility*
4) *Define resting position or safe position for equipment / device for unmanned facility*

C. Operational Specifications

Engineers and designers responsible for preparing operational specifications for wired or remotely operated device and/or equipment need to consider the following aspects other than all conventional considerations made

1) *Safe operation in absence of network*
2) *Operational sequence check over network*
3) *Device / Equipment network safety for human interface machines*
4) *Device / Equipment network safety for machines with no human interface*

VIII. EFFICIENCY & COST OF OWNERSHIP

Efficiency has always been a consideration in system design, however, even more emphasis is being placed on this today. There are several reasons for this with the most important depending on your perspective[9].

The current economic situation with respect to oil requires major cost reductions to remain profitable. One of the leading costs to produce is the energy required in the phase of the extraction to market process. Further to this are the environmental aspects with penalties such as carbon tax either in effect or imminent making this both an environmental and cost saving factor. Both of the aforementioned points are very important from the end users point of view. For the EPC Company, the importance of efficiency depends upon the type of contract that it is dealing with. For a cost reimbursable project, it is not so important. In the case of a lump sum project, the capital cost of the project is the driving motivation. If the EPC company can reduce the CAPEX significantly, the higher operating cost (OPEX) will be passed on to the owner operator. The vendor will look at efficiency as selling point with a justifiably higher price tag, however, the efficiency savings get lost during the conversation between vendor, EPC and the end user. There are contracts which can incorporate an efficiency / energy savings component but this is the exceptional case.

The manner in which the procurement process is done needs to be changed if energy reduction is truly a key objective[10]. Conventional procurement methods evaluate on the basis of technical compliance and then cost. New methods should allow evaluation of energy efficiency as a primary consideration. On the basis of current methods, a less efficient machine, which has a lower cost to produce, will win out in the selection process due to a lower CAPEX over a more expensive premium design which can easily overcome the cost difference in the short term, realize better environmental compliance and cost of ownership in the long term OPEX.

IX. CERTIFICATIONS, SPECIFICATIONS & STANDARDS

With more companies, countries, regions and even joint partners (such as IOGP - JIP) developing their own standards, this is leading to a more complex web of codes and regulations that are being imposed not only on the equipment manufacturer but on the EPCs, system integrators, plant operators and owners as well. With more regulations and regulatory bodies asking for their own certifications and compliance, this puts more economic burden on the whole design cycle as well as obviously on product vendor related to the development and testing of product to each of the arbitrary requirements of each regulatory body in addition to their usual development costs. This also makes vendor to develop and get certifications for selective market based on financial return on product. This selective development and certification can lead either to no availability of certain technology in certain regions or non-compliance of components such as IIoT devices over the network. This particular aspect needs to be addressed when creating specifications. Engineers need to realize that requiring unnecessary local code certifications or asking for a product certification that is either not available or will add a cost to the project should be identified and avoided where possible.

The global demand for codes standard and certification is increasing and diversifying to group of companies. Everyone needs to find a better path to make a marketable product that meets the need of industry at an affordable rate.

X. TIMELINE / LIFECYCLE

The authors believe that there are 4 distinct phases in the timeline of a project.

- Design
- Commissioning
- Operation
- Decommissioning

Factors discussed in this paper impact each of these phases in different ways and to varying degrees.

A. Design

The majority of the discussion in the paper has been with respect to initial design. This is the area in which the authors have experience and expertise.

B. Commissioning

EPC companies develop design documentation for plant construction and commissioning. The EPC companies program the process control automation software and the substation automation control automation software. Very important data set can be carved out of the design data set for pre-commissioning and commissioning purpose. The design data set can be helpful in developing mechanical completion plan and commissioning activities plan.

C. Operation

Some may argue that operation is not to be considered as a part of a project. In fact, once operation starts, the project is considered to be over for some stakeholders. The reality is that, while this philosophy may be a good approach for some team members to limit the scope to what they wish to focus on, this is not reality. A facility is dynamic and evolves over time along with the personnel that occupies it.

For predictive and condition based plant maintenance, increasingly more devices and sensors are used in industrial plants worldwide. These devices will be designed for and part of a connected network which will continue to expand over the life of the facility as the demands for input information expand.

D. Decommissioning

Decommissioning is a planned activity for Oil & Gas, Life Sciences and Nuclear plants. Various levels of government agencies and regulators are getting stricter with respect to the decommissioning of plants. For control decommissioning design data, historical data archived during plant operation and changes made during plant life cycle is very important. In addition, for future and trend considerations, owners, operators and regulating bodies would like to keep data set after decommissioning of the plant.

XI. RECOMMENDATIONS

In the paper to this point, we have primarily discussed the challenges which are associated with designing the ideal plant. Items that the authors see which we believe are important questions to ask and items to address throughout the process are as follows

- Include all stakeholders and affected areas in the organization in all key milestones of the project as a minimum including system design, reviews and implementation. Earlier in the paper we suggested IT and Operations & Maintenance should participate throughout the duration of the project and evaluate things as they become available.

- Existing work flows need to be re-evaluated to ensure that the aspects being discussed in the paper are addressed. Examples of items that the new work flow must take into account are the additional stakeholders, the earlier involvement by these parties in the process and scheduled / defined test checkpoints to name a few.
- In a typical plant design, the project management team uses a BRMS (Business Risk Management System) plan to identify and mitigate risk. In a similar vein, the authors propose the development of a BiRMS (Business intelligent Risk Management System) plan to identify, handle and mitigate intelligent issues.
- Spend more time at the initial design stages insuring that all foreseeable factors have been addressed and considered up front.
- As a team, keep an open mind and evaluate all possible directions. Encourage the imagination and solicit feedback from the project team with the potential of smart, scalable, connected technology.
- There should be a clear definition of the responsibility of each supplier of equipment and/or services. This should include the functional requirements in both normal and abnormal (fault) conditions. Precise means should be defined for demonstrating that the required performances are met both during the design phase, during FATs, during commissioning and during plant operation. For systems involving several users, diagnostic equipment should probably be supplied that can be used during system operation to detect any malfunctions.
- Digital 3D models can be used to test designs for functionality as well as to do trials during development. Further along in the project, these same capabilities can be used to give advance training pre-commissioning and for new machine operators post commissioning. They can also be useful in real operation and maintenance.
- Extensive testing should be required from the design phase through to final commissioning in order to ensure that the systems at site will operate correctly. System testing is very expense and time consuming and often not enough time is allowed in the project schedule. The test requirements are based on the performance requirements mentioned above.
- Maintenance is a very sensitive subject since failures in communication systems could result in larger outages than failures in individual pieces of other types of equipment. Also communication system maintenance would require a high level of expertise which most likely would not be available at site. Ideas such how to identify faulty equipment, use of hot swapping, configuration of replacement devices etc. should be included, with recommendations on what to do. What about testing after a replacement device has been installed? How can this be done with a plant in commercial operation?
- Modifications, extensions etc. can happen during plant operation. How are the systems to be designed to allow this to take place without minimal loss of production? How can communication systems be adapted at site without risk of incorrect operation of existing devices?
- How are the different versions of firmware, software etc. to be handled? Even during manufacturing, the same types of devices may have different versions of firmware and/or software. Who determines when firmware/software should be modified and how it is to be done without risking loss of production.
- Realize that what is implemented in the project must survive the life of the asset. Typical plant design life is considered to be 25 to 35 years. Typical project implementation is several years prior to that. Do you want to begin with old and dated concepts considering this facility is to operate to 2060?
- With increasing technology and the pace of change, it is difficult if not impossible for one provider to be the best in all technical areas and technologies required in a project. Farm out areas which require absolute state of the art capabilities.
- Design with a view to upcoming requirements and capabilities - Analytics, Augmented Reality, etc.
- Longevity of key companies, technology and support. Are the providers going to be there in 40 years to support the asset?
- Is the lowest capital cost the best option for the project considering the total cost of ownership? Have OPEX costs, licensing, maintenance costs been considered in the overall picture?
- Can the end user be involved earlier in the design and hand off process? While this does open things up to the potential problem of pushback by those who “have always done it this way”, it is better to address this up front with information sessions and trial runs, etc.
- Determine whether there is there an actual need for remote access and to what degree when considering the approach. Do we want to just include remote access or unmanned operation of the facility as an option because of a definite need or is it because most facilities are moving in the direction of unmanned remote operation.
- Investigate whether the selected equipment, components and devices have a lifecycle and migration path to support the equipment for the timeline of the project.

- Evaluate the technological capabilities, present equipment, components and devices along with the future 5 year development plans for any primary suppliers.

XII. CONCLUSION

With the rapid pace of change and the complex scope of most new projects today, it is increasingly important to establish the correct functional approach and team members to address a project. This team should not only include all of the key stakeholders as discussed in the paper, this group needs to review the project on a regular basis to insure that the key objectives continue to be met as things progress and evolve such as things often do particularly for those initiatives with extended timelines. With the rapid pace of change and innovation, the challenge will be to have a concept which remains state of the art over the course of several years prior to commissioning let alone after.

Furthermore, objectives and requirements can change from initial concept of the project to those that will be required once in operation. Examples are items such as environmental compliance requirements (carbon capture) and other regulatory requirements which can change dramatically during the period of the project.

The archaic law / code system is not able to keep up with the latest trends in technological development, it will be a challenge for design engineer to design a plant / equipment / component that will be compatible for future technology and at the same time make it suitable for today's code compliance.

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Electrical Control Systems – Process control interface design

Paper No. EUR21_13

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Abstract - Adoption of integrated Electrical Supervisory Control and Data Acquisition systems for the operation, control and monitoring of electrical distribution equipment has presented challenges across a global portfolio of projects and operating assets.
The former transition from discrete hardwired to serial interfaces mainly suffered due to interface latency attributed to the hardware and software limitations. The subsequent natural progression to serial interfaces over Internet Protocol network communications has to some degree mitigated the early latency issues. However, this paper outlines the investigations findings as a result of multiple major projects and operating assets, in a global portfolio, suffering process control interface issues, where the majority of those issues impacted the project start-up and early operation. The investigation team established several lines of enquiry encompassing the system interface designs, technology limitations, contractual framework with equipment suppliers and personnel competence.
The work concluded in the development of a technical specification and associated proof of concept testing recommendations of less utilised protocols for process control interfaces.

Index Terms — Electrical equipment instrumentation, On-line Monitoring & Condition, Substation automation and Control. Process Control interfaces. Integrated Control Safety System ICSS, Intelligent Electronic Device IED. Power Management System PMS, Electrical Control System ECS, Electrical Maintenance Network EMN, Electrical Data Monitoring and Control System EDMCS, Modbus, Profibus, IEC 61850, PRP, HSR.

I. Introduction

Contemporary Electrical Control Systems (ECS) have evolved since the advent of microprocessor based electrical protection relays, known as Intelligent Electronic Devices (IEDs), resulting in the ECSs replacing the conventional hardwired control interfaces with electrical equipment such as Switchboards (SWBD) and Motor Control Centres (MCC).

Many features and value adding concepts have been built upon the ECS foundation, enabling remote operation, diagnostics and device parametrisation etc.

Despite the value adding features, ECS's have been tarnished over several system generations due to the performance and reliability of the interface(s) to the Integrated Control and Safety System (ICSS) / Supervisory Control and Data Acquisition (SCADA). The first generation of interfaces mainly utilised two wire serial interfaces directly to local serial to discrete Input/Output (I/O) modules. These interfaces were plagued by latency and bandwidth constraints.

The advent of IED technology installed within each SWBD and MCC outgoing circuit, initially provided a number of benefits, and with the subsequent generations of the technology, communications enabled remote operation, diagnostics and device setting parametrisation. As a result of the network capabilities, process control of electrical equipment evolved to utilise Internet Protocol (IP) networks, which resolved several of the two wire serial interface constraints, however introduced numerous reliability and availability issues which plagued the systems during commissioning, start-up and operations. The situations were greatly exacerbated due to gaps in operations personnel's ability, experience and competence to fault find such systems.

This paper (1) summarises the generic conventional approach to ECS system interfaces for process control for major energy industry assets; (2) summarises subsequent overarching investigation findings as a result of multiple major projects and operating assets suffering process control interface reliability issues, where the majority of the issues impacted the project start-up critical path.

Finally, the paper focuses on a key learning identified during the investigation of the lack of system technology experience and fundamental knowledge, resulting in the development of a bespoke training course for engineer and technicians.

II. Conventional Approach

A. Recent Challenges

Multiple major projects in regions shown in **Erreur ! Source du renvoi introuvable.** have experienced certain availability and performance issues during commissioning and early operation of the process control and monitoring interfaces between the ICSS and electrical systems via the ECS.

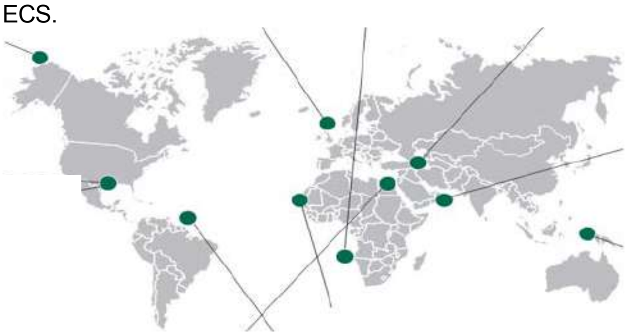

Figure 1 outline of asset locations experienced availability and performance issues

The results of a global survey found that almost all the projects surveyed had faced interface issues in one form or other independent of the system Original Equipment Manufacturer (OEM) / system integrator ICSS / ECS combination. All system designs were bespoke for each project, moreover even when the same combination of electrical and ICSS supplier were used on two projects, the engineering design of the interface were very different.
Despite each bespoke project implementation, the overall concept of the interfaces were based on some common principles:

- Communication interface between ICSS and electrical systems;
- Communication bus linking IEDs on the electrical network;
- Data concentrator / protocol convertor used in the interface between ICSS and IED data.

In spite of this, each project developed a different technical solution in terms of the communication protocols used, the detailed physical and logical architecture, along with the hardware specification. These differences attributed to the uncertainty and irregularities observed through the systems sub-optimal performance and unreliability. Specific events include multiple communication losses during the switchover process of the dual redundant interface leading to equipment trips. A reason identified for this is the limited capability of the interface to handle multiple communication sessions concurrently. The second was associated with inadequate firmware Management of Change (MOC) for the key elements of the interface such as firewalls, network switches, interface cards, etc. leading to incompatibility issues post Factory Acceptance Testing (FAT). A further observed behavior was due to the interface becoming unresponsive as a result of unexpected and unassociated high network traffic.

Interface	**Purpose includes (not limited to)**	**Default Protocol / Interface**	**Optional Protocol / Interface**
ECS to ICSS^{M}	Process control and monitoring	Modbus TCP/IP	Hardwired [2, 6] EtherNet IP[1] IEC 61850[1]
ECS^{M} to SWBD (HV/LV distribution)	Control and monitoring	Suppliers standard	Modbus TCP/IP [3] ProfiNet IEC 61850 Hardwired [2, 6]
ECS^{M} to LV MCC/feeders	Control and monitoring	Suppliers standard	Modbus RTU (LV MCC) [3] Profibus Modbus TCP/IP [1] IEC 61850 Hardwired [6]
PMS^{M} (non 3rd party) to SWBD	Sync CB control, FLS, monitoring	Suppliers standard	IEC 61850 Hardwired [2] Modbus TCP/IP [4] ProfiNet [4]
PMS^{M} (3rd party) to SWBD	Sync CB control, FLS, monitoring	Hardwired	IEC 61850 Modbus TCP/IP [4] ProfiNet [4]
PMS^{M} to gen UCP	Control and monitoring	Hardwired	N/A
PMS to ECS^{M}	Monitoring	Suppliers standard	Modbus TCP/IP ProfiNet EtherNet IP [1] IEC 61850 [1]
SWBD to SWBD [7]	Inter-locking, inter-tripping, auto transfer schemes	IEC 61850	Hardwired [2]
ECS^{M} to non-SWBD IEDs. e.g. UPS/DB/Transformer	Control and monitoring	Suppliers standard	Modbus TCP/IP [3] ProfiNet Hardwired [2]
ECS^{M} to SWBD integrated VSD	Control and monitoring	Suppliers standard	IEC 61850 Modbus TCP/IP [3, 5] ProfiNet

B. Investigation

The subsequent in-depth investigation identified a number of root and system causes, these are summarised below:

- Lack of SPA (single point accountability) for the interface management;
- Products / engineering standards have not necessarily kept pace e.g. IEC 61850 is not standard for LV switchgear;
- Engineering capability has not kept pace e.g. electrical engineers / technicians do not traditionally have detailed network / data comms skills;
- Project specification of the interface has tended to lack enough detail;
- Vendors do not yet have mature, standard designs as seen in the variations from project and regions;
- Highly variable levels of off-critical path testing across different projects – often severely compromised due to multiple companies involved, remote locations from design centres, travel constraints and construction schedule pressure etc.;
- Vendor device compatibility even when using the same protocol.

Following the identification of the causes above, the team developed mitigation in response which is outlined within the following section.

C. Intervention

Each of the projects that experienced undesired behavior during commissioning, start-up and early operations, along with those with minimal issues were investigated in an effort to deeply understand the root causes and learnings.
The process depicted in Figure 2 was utilised to develop mitigation for each of the identified root causes.

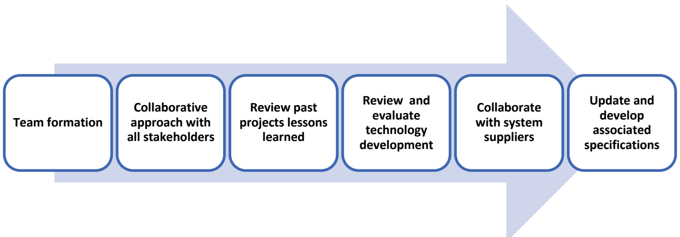

Figure 2 *Process for root cause development*

Ultimately the work concluded in the development of a procurement specification and application requirements, incorporating the mitigation including associated proof of concept testing of less utilised protocols for process control interfaces (see
). The following section summarises the key

enhancements to the approach resulting from the mitigations developed.

III. ENHANCED APPROACH

A. Data Concentrator (DC)

Due to multiple methods of serial communication and protocols in use within an ECS, protocol conversion is often required when interfacing to another system (such as an ICSS for process control). Furthermore, a level of intelligence / signal manipulation is required to manage response to such events as a communication failure.

DCs can provide the required protocol translation, and I/O mapping, along with the required intelligence to manage communications failures and signal consolidation. Other advantages include, the level of abstraction between the controlled device (IED) and the controller (ICSS) so that modifications e.g. an address change, within the electrical equipment does not commonly extend out over the interface, minimising the impact of change.

DCs are generally available in two forms, the first is an industrial Programmable logic controller (PLC) / process controller, with the required optional communications cards. The second is an industrial Personal Computer (PC) / server form, often with a non-Real time operating system (RTOS) such as Unix® or Microsoft® Windows®. As the availability and data integrity of a DC is critical for process control reliability, the selection of both hardware and operating systems is an important factor.

B. OPERATING SYSTEMS

The reliability of devices located in the critical path of process control signals and data are crucial to the reliability of the interface and ultimately the overall system performance. As a result, the performance of any Operating System(s) of a device located in the critical path is fundamental to system reliability.

Most operating systems appear to allow multiple programs to execute at the same time, commonly referred to as multi-tasking. In reality, each processor core can only service a single thread of a program at any given point in time. An operating system will include a scheduler, which is responsible for deciding which program to service when, this provides the illusion of simultaneous execution by rapidly switching between each program.

The type of operating system is defined by how the scheduler decides which program to run when. For example, a multiuser operating system (such as Unix®) uses a scheduler that will ensure each user gets a fair amount of the processing time.

The scheduler in an RTOS is designed to provide a predictable execution pattern, normally described as deterministic. This is particularly of interest in embedded systems as such systems often have real time requirements. A real time requirement is one that specifies that the system must respond to a certain event or events within a defined time. Real time requirement execution can only be guaranteed if the behaviour of the operating system's scheduler can be predicted and is therefore deterministic.

An RTOS uses maximum time and resources to output exact and on time results, there is no difference (beyond jitter) between the results (both outcome and time to execute) when the same program is executed, on different occasions, on same machine/hardware.

Advantages

- Maximum Utilisation: RTOS provide maximum utilisation of the system, giving a greater performance using all the resources of a system;
- RTOS in embedded system: Due to small size of programs, RTOS can also be used in embedded/application specific environments;
- Task Shifting: There is very little time required by these systems to shift between tasks;
- Priority-based scheduling: The separation of non-critical and critical processing;
- Focus on Application: An RTOS focuses on the current application, which is running, rather than other applications waiting for execution. Typically, an RTOS will only be required to run a single application at any one time;
- Easier testing: An RTOS allows for testing of modular tasks, therefore making testing easier.

C. PROTOCOLS

The choice of protocol to be used to facilitate the separate functions of the system at first glance would suggest the same protocol to be used in all instances, but this does not take into account the requirements for functionality, performance, support and cost. Each protocol lends itself to an area of the system giving the best balance of the requirements:

- IEC 61850 GOOSE is used for data/control with a high performance demand;
- IEC 61850 MMS is used for data/control generally related to device data and is recorded as timestamped at source;
- Modbus TCP/IP is commonly used for ICSS interfaces as data is generally high volume with a medium demand on performance. Standard use of protocol does not carry source timestamp;
- Modbus RTU is utilised by the Process RTU for data/control such as IED. It is low cost but maintains the data volume and performance requirements of the system. Standard use of protocol does not carry source timestamp.

Figure 3 below shows the interfaces and protocols utilised by a generic ECS / ICSS interface.

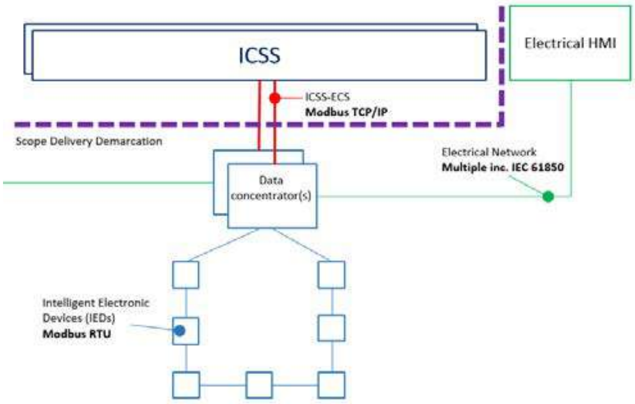

Figure 3 Representation of a generic ECS to ICSS interface including the Electrical network and HMI

D. INTERFACE SPECIFICATION

The importance of the hardware components and associated operating system's along with a deep understanding of the interface and protocol implementation is critical for success, whether it is for simple Power Management System's (PMS) status monitoring or an operational critical process control interface with the ICSS. Historically, ECS procurement specifications regularly failed to fully address the interfaces and specifically failed to appreciate that many and multiple protocols required, along with their limitations. This has resulted in poorly designed systems due to misunderstanding and "blind compliance" by the suppliers.

Following both internal and industry supplier's / OEM consultation, was developed to detail the specific interfaces, their

Interface	Purpose includes (not limited to)	Default Protocol / Interface	Optional Protocol / Interface
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PMS[M] (3rd party) to SWBD	Sync CB control, FLS, monitoring	Hardwired	IEC 61850 Modbus TCP/IP [4] ProfiNet [4]
PMS[M] to gen UCP	Control and monitoring	Hardwired	N/A
PMS to ECS[M]	Monitoring	Suppliers standard	Modbus TCP/IP ProfiNet EtherNet IP [1] IEC 61850 [1]
SWBD to SWBD [7]	Inter-locking, inter-tripping, auto transfer schemes	IEC 61850	Hardwired [2]
ECS[M] to non-SWBD IEDs. e.g. UPS/DB/Transformer	Control and monitoring	Suppliers standard	Modbus TCP/IP [3] ProfiNet Hardwired [2]
ECS[M] to SWBD integrated VSD	Control and monitoring	Suppliers standard	IEC 61850 Modbus TCP/IP [3, 5] ProfiNet

purpose and preferred protocol for the application. The table also includes options for smaller scale projects, prevision for technology development and the recommended communication 'master' device (see table notes below).

Table 1 ECS interface purpose and recommended protocols at interface level.

Table 1 Notes:
[1] Dependant on technology readiness.
[2] Hardwired to be considered for a small-scale process control interface (circa 10 loads or if the I/O is considered critical, such as Fire & Gas related control).
[3] Use of this protocol limits visibility Sequence of Events (SOE) time stamping at source (IED) and therefore require a further protocol in parallel to extract the source SOE to the ECS.
[4] For monitoring only.
[5] Critical hardwired signals directly to ICSS as defined. e.g., tripped on fault, analogue setpoint.
[6] Emergency/Process Shutdown (ESD/PSD) executive action signals are hardwired directly from the ICSS to the electrical equipment.
[7] For information only, to be defined on the SWBD data sheet.
[M] Communications Master device.

E. NETWORKS

The choice of network architecture to be used in an ECS and interfaces is largely dictated by the requirement for reliable and low-latency communications between system components. Parallel Redundancy Protocol (PRP) and High-availability Seamless Redundancy (HSR) Protocol are suited for applications that require high availability and short switchover time, the recovery time of commonly used protocols such as the Rapid Spanning Tree Protocol (RSTP) is too long, which would result in a negative impact on the operation of the system.

Most Industrial Ethernet protocols in the IEC 61784 suite can be used with PRP and HSR, as they are independent of the application-protocol. They are network protocols for Ethernet that provides seamless failover against failure of any network component. Both utilise nodes with two network ports, but differ in that HSR utilises the ports as a network bridge which allows arranging them into a ring or meshed structure without dedicated switches, PRP utilises the ports independently and are attached to two separated networks of similar topology. HSR requires specific hardware, PRP can be implemented entirely in software, i.e. integrated in the network driver. Nodes with single attachment (network port) can be used in a HSR topology but only when connected to a dedicated switch, whereas in a PRP network, Redbox devices may be used to maintain the topology.

With either choice it is desirable that all equipment to be connected to the network has the appropriate protocol support to ensure predictable and correct system behaviour. Ideally there should be no single attached nodes to avoid single points of failure, reduce topology complexity, remove the need for extra 'steps' (protocol converters (e.g. Redbox devices)) which will result in increased latency in a network path.

F. INTERFACE PERFORMANCE

As with the protocol specification inadequacies outlined in the previous section, a deep understanding of the overall interface performance (i.e. latency of the communication), is required. The specification requirements should clearly articulate the overall path of communication, including the components located in the critical path and highlight any specific items such as control commands that should be given priority by the ECS and interrupt lower priority status communications. Along with any non-deterministic components / processes such as a Human Machine Interface (HMI) refresh rate.

An example of the interface performance requirement in its simplest form may be:

- The time from receipt of an ICSS command to verification feedback to the ICSS that the IED has actioned the command shall be no longer than 6 seconds overall ‘loop time’.

However, as depicted in Figure 4, further detail is required to clearly define the overall performance requirements for each side of the interface boundary, including;

- The performance requirement shall not be affected by a fully configured ECS system with the specified maximum number of IEDs or high ECS loading e.g. network traffic;
- The performance requirement is exclusive of motor start-up time and “running” status feedback signal being established within the IED.

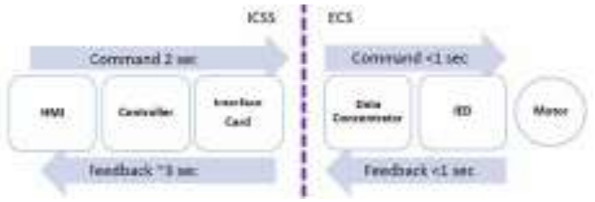

Figure 4 Generic interface performance for key components (excluding IED status update duration)

G. SYSTEM TESTING

There are two main strategies for software testing: ‘Positive’ and ‘Negative’ testing. With consideration these strategies can be expanded to validate the operation of multiple 'components' which when combined form the overall ECS.

1) Positive Testing: determines that an ECS works as expected, performing all the prescribed functions, generating the desired outcomes as defined in the project documentation.
2) Negative Testing: ensures that an ECS can gracefully handle invalid input or unexpected behaviour of system components or users. The purpose of negative testing is to detect situations that are outside the specified operation of the ECS and prevent an ECS from crashing or performing/functioning in an undesirable manner. Negative testing also helps to improve the integrity of an ECS and find any weak points.
3) The core difference between positive and negative testing is that generating an exception is not an unexpected event in the latter. When performing negative testing, exceptions are expected – they indicate that the ECS handles improper system component/user behaviour correctly.
4) Negative testing is aimed at detecting possible incorrect operation in the ECS in different situations. These can include:
    - Equipment failure;
    - Incorrect user operation;
    - Network overload;
    - Data bounds and limits.
5) The complexity of negative testing of a ECS is in the scale of the interactions of each of the systems sub-components and the potential cascade effect of seemingly unrelated functions of the system. A positive testing procedure is relatively simple to generate as it will largely be dictated by the functional requirements of a system. In contrast negative testing is very much a product of the design and implementation of a system, it requires a deep understanding of the infrastructure, component relationships and often complex interactions to ensure complete coverage of the operations boundaries.

The balance of minimising test scope on the project critical path with validating system performance is key to successful delivery. As a result of consultation with project discipline engineers, suppliers and system OEM’s,
the interface testing is recommended to be broken down into three stages. The testing should encompass a representative sample of the hardware, architecture, and interfaces of the overall project scope at key milestones during the schedule.

H. SYSTEM SUPPLIERS

System suppliers generally fall into two main categories, System Integrators and OEM single source providers. Each supplier brings its own potential risks which need to be carefully assessed against the goals of the project to ensure they are met. A major advantage of an OEM supplier is their tried and tested solution and known interoperability/compatibility of the components within their catalogue. They are also the owners of the components, as such will have ready access to internal support should it be required to assist in issue analysis and resolution; a Systems Integrator can be reliant on third parties for product support, which will require them to have a good relationship with, and strong Management of suppliers to ensure support is provided if required.

A key advantage of a Systems Integrator is their flexibility to meet a projects multi-aspect specification and produce bespoke solutions, utilising the best tools and components available, while an OEM will be largely restricted to their own products which may require compromises to be made in the final solution. The System Integrator will also have the advantage of experience and knowledge gained through the execution of previous projects, using alternative tools and components from multiple manufactures. The key comparisons are outlined within Table 2 and Table 3 below.

System Integrator	OEM System
The ability to produce an unbiased solution using "best of breed" components to satisfy the key client objectives, culminating in the most efficient and reliable solution architecture without compromise.	All components used can be from within the company’s catalogue with known interoperability / compatibility.
Able to provide a cost-effective solution to the requirements by selecting components.	OEM Project team should be intimately familiar with each of the components utilised.

Projects generally executed from a single location with all parties familiar will all system components.	If issues are identified during the execution of the project (or when in service) an OEM supplier should not have to rely on a third party for a resolution.
Expertise within the project execution team to perform design and analysis of the complete system.	OEM may have the facilities, the roadmap and the control to develop, test and sell new technologies.
Independent lab component comparison of performance in simulated applications.	Knowledge of issues earlier due to exposure in other industries / markets of their own devices, early workarounds / firmware update.

Table 2 Supplier advantages

System Integrator	OEM System
Reliant on third parties for component issue resolution.	The system design may be compromised to allow the accommodation of OEM components.
System architecture may be unique or contain components that have not been used together previously.	Because of the relative size of OEM system suppliers and the segregation of business units within, a system may be engineered by multiple disparate groups with little knowledge of each other's components.
The system integrator is reliant on what the market has to offer and has little influence on product evolution and upgrade planning.	OEM suppliers may not have subject matter experts within the execution team.

Table 3 Supplier disadvantages

I. PMS

As identified by Mun and Combs [1] in their paper "Distributed Logic Load Shed System Via IEC 61850" distributing the load management decision making operations within a PMS throughout the system, and demanding a higher function of the IEDs in the process, allows for the utilisation of the performance advantages of IEC61850 GOOSE communication over hardwired alternatives. The utilisation of the IEDs in the load management, allows for direct and pre-emptive operations without reliance on the 'main' PMS processors further improving the system performance and availability.

J. CYBER SECURITY

Implementation of cyber security controls is critical in the effort to assure the security and reliability of automation and control systems that enable operations. The cyber security landscape is constantly changing, with new vulnerabilities, threats, and attack vectors identified daily. Therefore, cyber security barriers require maintenance and management throughout the operations life cycle, and barrier strength and risks require regular review to maintain a 'defence in depth' approach.

K. TRAINING

The electrical industry has naturally evolved in the direction of utilising IEDs and data networked solutions. However, practitioners and engineer's technical knowledge has not kept sufficient pace. Electrical engineers / technicians do not traditionally have Information Technology (IT) network / data communication skills, this is considered analogous to the advent of the electronic based control systems in 1970 / 80's, where a generation of instrument mechanics would have had to upskill or become left behind in knowledge to support the technology as it was introduced. The OEM / supplier specific system training offering commonly assumes a basic / fundamental understanding and without this a candidate would not see the full benefit of the training.

In response to this finding identified across numerous major projects and operations assists, the associated competences were identified and established into a training program for technicians and engineers. The program includes existing training / certification offering, such as 3rd party provider online video content, cyber security fundamentals. This is then followed by a suite of bespoke video content covering industry specific protocol implementations such as Network redundancy protocols, two wire serial communications, IEC 61850, Network Time Protocol.

On completion of the training above, the candidates then attend a virtual instructor led training offering learning objectives including, a detailed look at the specific application and lessons learned when implementing or operating an ECS and PMS.

Finally, the training outline above provides the candidate with the fundamental knowledge to attend the OEM / Supplier training offering for their specific system.

NOMENCLATURE

EtherNet IP	Industrial network protocol that adapts the Common Industrial Protocol (CIP) to standard Ethernet
GOOSE:	IEC 61850 - Generic Object-Oriented Substation Event
MMS:	IEC 61850 - Manufacturing Message Specification
Modbus RTU:	Serial data communications protocol
Profibus:	Serial data communications protocol
Redbox:	Provides an PRP interface to a non PRP enabled device
TCP/IP:	Internet protocol suite - Transmission Control Protocol (TCP) and the Internet Protocol (IP).

IV. CONCLUSIONS

The ECS has evolved with the advent of IEDs enabling a shift from traditional hardwired control to communication network type of systems. The ECS foundation has been gradually strengthened with the advent of new technologies enabling several value adding features. However, numerous previous projects have identified gaps in terms of reliability and performance of the ECS / ICSS interface. These gaps had resulted in negative impacts on projects start-up delays and production losses during operation. This paper progresses through the lines of enquiry encompassing the system interface designs, technology limitations, contractual framework with equipment suppliers and personnel competence. The work concluded in the summary of a system specification, including protocol recommendations, and detailing the associated proof of concept testing of the recommended architecture and protocols for process control interfaces summarised.

This paper may be considered as the first step towards standardisation of the interface engineering between ECS and ICSS. Work will need to continue with the aim of improving the reliability and performance of this critical interface for the energy industry, as the technology further evolves, with respect to technology readiness level and further lessons are learnt from the projects.

V. ACKNOWLEDGEMENTS

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VII. VITA

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DIFFERENCES BETWEEN THE ATEX DIRECTIVE, THE IECEX SCHEME AND NORTH AMERICA REGULATIONS

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Abstract – In this globalized world, projects are awarded to international engineering firms and vendors located outside of the end user country. This scenario brings additional challenges to all parties involved and requires a full understanding of the differences between standards and regulations of many different countries. Depending on the end user country, exporters and manufacturers of Ex equipment will be regulated by different standards, codes and regulations that will govern the product approval process and the necessary factory inspections.

This paper addresses some of the most damaging misconceptions about the electric motors certification for North America and the main differences to ATEX Directive and IECEx scheme. It is really important to have a full and clear understanding of these myths and differences in order to make informed decisions, assuring this way compliance with the standards, codes and regulations whilst guaranteeing the safety of people and installations.

Index Terms — ATEX, IECEx, hazardous area, North America regulations

I. INTRODUCTION

The use of electrical equipment in areas that are subjected to presence of flammable substances is regulated through three major schemes: ATEX, IECEx, NEC and CEC.

Even so, there are still major accidents occurring today around the globe taking lives and causing damage and costs. To avoid such incidents, the focus should be in controlling, regulating and leveling the knowledge between the different parties involved in the assurance of protection levels of electrical equipment.

The misunderstandings between the different codes and regulations will not only increase the costs in the certification of products and facilities, but may also jeopardize the security of these facilities associated with the use of erroneous protection levels for hazardous areas.

This paper begins with a brief history of the three major schemes. After which the concept of area classification is detailed for Zones and Divisions. Furthermore, the differences in the protection types for each scheme are analyzed, with special emphasis on the most common protection types.

Finally, the projected future for the different schemes is presented and discussed.

II. THE HISTORY OF HAZARDOUS PROTECTION

The need for protection of electrical equipment in areas with potentially explosive atmospheres was originated by the occurrence of several related accidents around the world. As stated in the work of Munro [1] several authors identify the life cost of accidents in the beginning of 20th century, in the US (1907 – 600 deceased), UK (over 1000 deceased early).

A. European ATEX

The European Economic Community (EEC) was created with the aim to allow the economic communication and integration between the member countries.

In relation to the equipment protection in hazardous areas, the work was initiated to bring the economic operators in the member states under the same guidelines.

The directive 94/9/EC was effectively applied in 2003 in the European Economic Area. In 2016, it was replaced by the new directive 2014/34/EU.

B. North America Regulations

The article 500 of the National Electrical Code represents the foundation for the Division system in the United States.

It supports also the Articles 501 to 504 for this system which addresses both Class I, Class II and Class III hazardous substances.

The Zone system is also associated with NEC and based in Article 505, in an approximation effort to IEC standards.

For Canada the equivalent regulations are the Canadian Electrical Code (CEC).

C. IECEx Scheme

The appearance of the *IECEx* scheme aimed to create an international regulation scheme to provide manufacturers with a single mechanism for certification and safety assessment.

The establishment of IECEx was in 1996 as an initiative of the industry and with support from certification bodies of the United Kingdom, France, Germany and Canada.

The first equipment certificate was issued in 2003 and 33 countries participate in the IECEx to this date. [2]

III. AREA CLASSIFICATION

The risk of explosion is associated with the occurrence of specific conditions that provide what is called the Triangle of Fire for gases or the Pentagon of Fire for dusts.

Focusing in the triangle of fire (Fig. 1) it is possible to identify the three components intervening in the reaction:

- Ignition source;
- Fuel;
- Oxygen.

The simultaneous presence of these three elements in the correct proportions will cause an explosion of the atmosphere.

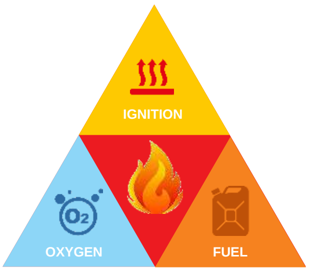

Fig. 1 Triangle of fire

The classification regarding the level of danger in a hazardous area is then dependent on the fuel type and the frequency of occurrence.

A. Zones and Divisions

The ATEX directives, the IECEx scheme and NEC 505 classify the hazardous areas in Zones according to the probability of occurrence:

- Zone 0 and Zone 20: continuous presence;
- Zone 1 and Zone 21: in normal operation;
- Zone 2 and Zone 22: in abnormal operation.

Zones associated with gas atmospheres are 0/1/2 and with dust 20/21/21, in the Fig. 2 an example is shown to illustrate a potential zone distribution.

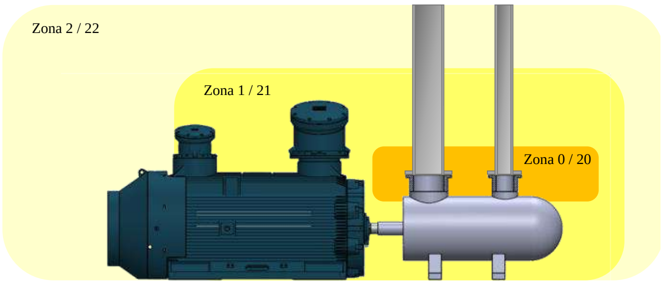

Fig. 2 Typical zone identification

In case of NEC 500 the classification is done using Classes:

- Class I – associated with gas atmospheres;
- Class II – associated with dust atmospheres;
- Class III – associated with ignitable fibers.

And divisions:

- Division I – continuous presence of a hazard;
- Division II – in abnormal operation.

The combination of classes and divisions defines the level and type of hazardous area.

In Fig. 3 the comparison between Zones and Divisions is represented, to be noted that Division 1 encompasses both Zone 0 and Zone 1. This difference implies that the equipment designed for Zone 1 and Division 1 will therefore have different levels of protection to comply with the higher risk level of the Division I.

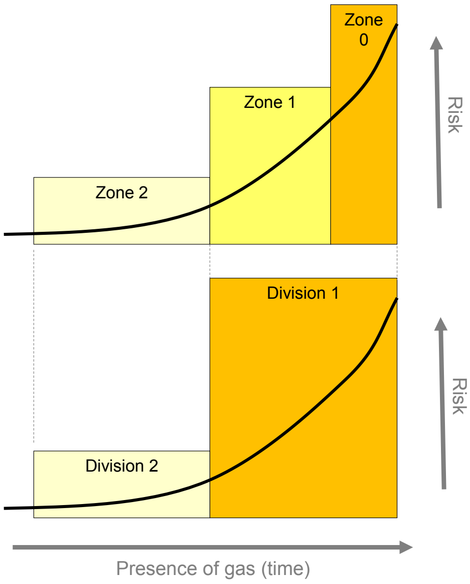

Fig. 3 Equivalence between zones and divisions according to risk level

B. Types of gases and dusts

The classification of gases and dusts in distinct groups is connected to the level of hazard they represent. This concept is associated with two major parameters:

- Minimum ignition energy;
- Maximum Experimental Safe Gap (MESG).

Both of these parameters are connected and as the minimum ignition energy decreases, the MESG also decreases. The most explosive, therefore dangerous gases are associated with the lower levels of both parameters.

In ATEX and IECEx, the gases and dusts are both grouped in three groups [3, 4]. In case of North America division approach gases are divided in four groups [3] and dusts in three groups [4].

A point of attention must be taken related to fiber atmospheres, as they are included in ATEX/IECEx dust group, but in a separate Class for North America [3].

The comparison chart may be seen in Fig. 4.

Explosive atmosphere			ATEX IECEx	NEC 500 CEC		Examples
				Class	Group	
Mines			I	-	-	Methane
Surface	Gases or vapors		IIA	I	Group D	Propane
			IIB		Group C	Ethylene
			IIC		Group B	Hydrogen
					Group A	Acetylene
	Dust	Fibers	IIIA	III	-	Paper fibers
		Non conductive dust	IIIB	II	Group G	Cereal dust
					Group F	Coal dust
		Conductive dust	IIIC		Group E	Aluminum dust

Fig. 4 Different groups of hazardous substances for ATEX/IECEx and NEC/CEC

With reference to Fig. 4 it is important to note that the differences between Zones and Divisions do not allow a clear equivalence between groups.

In the particular case of electric motors, they cannot be certified or installed in Class I, Division I, Group A. (not included in the scope of the standards [8])

This subject will be addressed with detail in chapter IV and V.

C. Surface temperature

In addition to the classification of the hazardous atmospheres in groups associated with the energy of the explosion, both regulatory schemes also define the classification of hazardous substances according to their auto-ignition temperature and group them in Temperature Classes.

Fig. 5 shows the temperature classes of both regulations, their correspondence and the maximum surface temperature of the equipment allowed to be installed in the associated explosive area.

ATEX IECEx	NEC 500 CEC	Maximum Surface Temperature
T1	T1	450 ºC
T2	T2	300 ºC
	T2A	280 ºC
	T2B	260 ºC
	T2C	230 ºC
	T2D	215 ºC
T3	T3	200 ºC
	T3A	180 ºC
	T3B	165 ºC
	T3C	160 ºC
T4	T4	135 ºC
	T4A	120 ºC
T5	T5	100 ºC
T6	T6	85 ºC

Fig. 5 Temperature classes for the different regulations

The intermediate temperature classes of the North American Division scheme do not exist in ATEX and IECEx and are not applicable.

IV. TYPES OF PROTECTION OF MOTORS

Electric motors are the main drive in most industry processes, driving a huge variety of machines such as compressors, fans, pumps, which take part in both critical and costly industries where an accident may have a huge impact not only on facility damage costs but also on lives lost.

The protection of motors that are installed in hazardous areas may be done through different approaches. Considering the triangle of fire (Fig. 1), if one of the corners is removed the risk of explosion is excluded, consisting in protection types like: “Increased Safety”, “Non-sparking” or “Pressurized”.

The other concept, considered the oldest type of explosion protection [1], and also one of the safest, is the containment of the explosion of the atmosphere inside the motor enclosure. This protection is referred as flameproof or explosion-proof.

It is very important to understand that the concept of type of protection is not applicable to the Division Scheme. Nevertheless it is possible to correspond some requirements between this scheme and the type of protection of Zone Scheme.

In the next sections the different protection types for Zone Scheme are detailed and analyzed. The particular cases are addressed in chapter V, including the manufacturer point of view.

A. Flameproof (Ex d)

The flameproof concept in consists of containing the explosion inside an enclosure (Fig. 6). This protection method incorporates two distinct concepts:

- Enclosure integrity;
- Flame transmission.

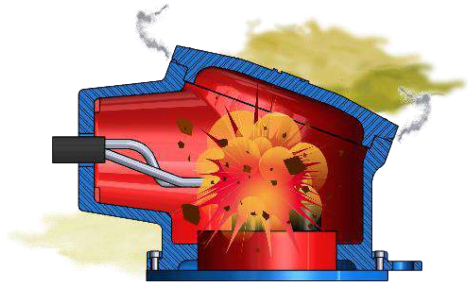

Fig. 6 Explosion-proof or flameproof concept example

The first is achieved by ensuring that the enclosure has enough strength to withstand the explosion of the volume of hazardous substance inside. [8] The intensity of the explosion is highly dependent on the temperature and manufacturers need to select the appropriate materials and calculation procedures, so motors are able to operate and start in these extreme conditions. [1, 8]

The flame transmission to the exterior atmosphere needs to be avoided at all cost. Explosion-proof or flame–proof motor enclosures need to be precisely machined and controlled to achieve critical gaps between parts that quench the explosion flame before it reaches the exterior atmosphere.

Fig. 7 shows a failed test for flame transmission, which caused ignition of the surrounding atmosphere.

Fig. 7 Flame transmission in terminal box test

In the specific case of electric motors there are multiple components where the impact of explosion is sustained and where flame needs to be quenched on its way to the exterior environment. (Fig. 8). All these components need to pass a strict quality control and testing to achieve this kind of protection, as a result, these motors are heavy structures.

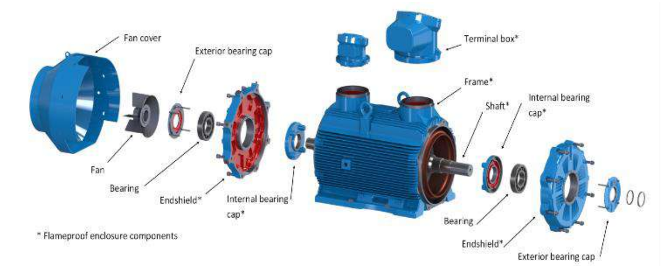

Fig. 8 Exploded view of a motor assembly with identification of flameproof components

Similarly, handling and maintenance of motors with this type of protection needs to be performed by high qualified personnel and following strict rules to avoid damaging the enclosure components that may not only impair the operation of the motor but more importantly invalidate its proper flameproof concept. [9]

B. Increased safety and non-sparking (Ex e, Ex n and NI)

This concept is associated with preventing the occurrence of ignition sources in the electric motor which eliminates one of the corners of the fire triangle. [11]

These motors are similar to safe area motors in their mechanical construction, with the major changes linked with electrical design and limiting the temperature.

However, there is a major difference in this concept between the Zone scheme and Division scheme.

In the Zone scheme, this type of protection may be used in both Zone 1 (Increased Safety) and Zone 2 (Non-Sparking), but in the Division scheme it can only be applied in Division 2 under this type of protection (Non-Incendive).

The protection of this type of motors is then based on reinforcing the insulation of stator which needs to be surrounded by hazardous gases and tested for occurrence of sparks that may ignite the external environment atmosphere.

In addition, the rotor temperature shall also be maintained below the associated temperature rating of the motor, resulting in a control on the locked rotor time and number of starts.

Furthermore, this protection concept is also sensitive to the use of inverters, where the inverter parameters need to be carefully adjusted to avoid both the occurrence of sparks and heating up of the components.

C. Pressurized (Ex p)

Pressurization concept removes the hazardous atmosphere from the vicinity of electrical components inside the enclosure of the motor.

This method can be used in both Zone 1 and Zone 2 or in Division 1 and Division 2.

The disadvantage of this type of protection is requiring several support equipment to pressurize the interior of the motor, and also maintain and control this pressure. (Fig. 9)

Fig. 9 Example of pressurization system installed in electric motor

This protection method is mainly used for higher power motors where the weight of a flameproof or explosion-proof motor would be extremely high in comparison to a pressurized motor.

D. Dust protection

The protection of dust is mainly associated with the ingress protection of the enclosure and its surface temperature. Dust environments may sometimes be wrongly perceived as less dangerous compared to gas environments, however, accumulation of dust when dispersed by air may create a highly dangerous atmosphere that may cause extremely damaging accidents.

In Fig. 10, a motor withstanding an ingress protection test is shown.

Fig. 10 Electric motor covered in dust during ingress protection test

V. MAIN DIFFERENCES BETWEEN REGULATION SCHEMES

Both regulation schemes are intended to improve the safety of people and installations. They both aim to prevent accidents and to regulate the protection degree between manufacturers and end-users across markets.

The two biggest world markets for hazardous areas are also associated with two different schemes. The difference in hazardous areas classification induces major differences that need to be clearly pointed out:

- Divisions scheme allows to place motors in permanent hazardous areas where Zones scheme excludes motors from these areas by limiting them to Zone 1;
- No electric motor can be certified to operate in Class I, Division 1, Group A, thus excluding the application of motors in atmospheres with acetylene in this division;
- Zones scheme permits a more gradual increase in protection, allowing cost reductions for equipment installed in Zone 1.

The difference in cost is more evident with the possibility of using increased safety apparatus in Zone 1.This allows the use of flameproof motors with increased safety terminal boxes, which are usually lightweight and allow easier maintenance and cable installation.

Thus, both schemes have their own specific relaxation compared to the other, where one allows to optimized cost construction and the other allows to have motors operating in any condition using tighter rules and tests.

As an example, an IECEx certified flameproof motor for Zone 1 group IIC may only be certified without additional explosion tests to a motor for Class I, Division I, Groups B, C and D, but it is not allowed to be installed in an Acetylene environment (Group A in Division scheme).

A. Comparison between Class1, Division 1 and Zone 1 requirements for electric motors.

The following standards/parts were analyzed for this comparison:

- C22.2 No. 145-11 [8];
- IEC 60079-0 ;
- IEC 60079-1 [9];
- IEC 60079-7 [12];

As the type of protection concept is not used in the Division scheme, it is necessary to include the three different parts of IEC 60079 standard

In the rest of this section several requirements from the standards above are compared and analyzed. The tables in this section summarize the differences in the relevant standards.

Requirements to contain the explosion

Firstly, the requirements associated with the containment of explosion are compared, both in terms of structural strength and flame transmission.

In Table 1, the safety factors for overpressure test in both schemes can be found.

It is interesting to note that where IEC includes both routine and type test possibilities, in the Division Scheme there is no reference to routine overpressure tests. Based on safety factor values it is safe to assume that the intent of Division Scheme is overpressure type tests.

Another major difference is the acceptance of mechanical strength calculation for the enclosure in Division Scheme, with a consequent increase in the safety factors.

In Division Scheme, the safety factor for overpressure tests is determined based on types of materials used in part which can bring flexibility to the manufacturers as far as manufacturing methods. On the other hand, not having the routine test option will require an enclosure with more mechanical integrity.

Table 1 – Comparison of safety factors

	CSA C22.2 No. 145-11				**IEC 60079-1**			
	Type Test		**Calculation**		**Type Test**		**Routine test**	
Cast Metal	*Table 35*	4	*Table 2*	5	*15.2.3.2*	4	*15.2.3.2*	1,5
Fabricated steel		3 (2)		4				
Bolt		3		3				

The surface roughness requirements for the flameproof joints are similar and the major difference is the inclusion of clear criteria for validation methods in the standard for Division Scheme. (Table 2)

Table 2 – Comparison of roughness of flameproof joints

	CSA C22.2 No. 145-11		**IEC 60079-1**	
Roughness	*11.1*	Ra 6.3	*5.2.2*	Ra 6.3
Verification		Defined feeler gauge dimensions and approval criteria	-	-

To determine the reference pressure of the explosion, both schemes rely on tests with the same explosive gases. (Table 3)

It is important to note that Division Scheme only allows motors to be installed in gas group's equivalent to IEC Group IIB+H.

Also, the gas mixtures are very similar between Schemes but for IEC scheme fewer tests are required to be performed in Groups IIA and IIB.

Table 3 – Comparison of reference pressure tests

		CSA C22.2 No. 145-11		**IEC 60079-1**	
Reference pressure tests	**Group D / Group IIA**	*Table 31*	20 x Propane at 3 - 7%	*15.2.2.2*	12 x Propane at 4,3 - 4,9%
	Group C / Group IIB		20 x Ethylene at 4 - 9%		12 x Ethylene at 7,5 - 8,5%
	Group B / Group IIB+H		20 x Hydrogen at 15 - 35%		20 x Hydrogen at 30 - 32%
	Group A / Group IIC	-	Not Allowed		20 x Acetylene at 13 - 15%

As far as flame transmission tests which is summarized in Table 4, both schemes are very similar. However, the following differences should be mentioned:

- Division scheme allows the enlarged gaps method even for Group D and C (IEC Group IIA and IIB);
- Without enlarged gaps method, the oxygen enrichment is higher in IEC;
- The enlarged gap for IEC can vary between 1,35 and 1,5 times the construction gap, when in Division Scheme it is only permitted 1,5 times;

- Group A (IEC Group IIC) is not allowed in Division scheme.

Table 4 - Comparison of flame transmission tests

		CSA C22.2 No. 145-11		IEC 60079-1	
Flame transmission without enlarged gaps	**Group D / Group IIA**	*Table 33*	10 x Hydrogen at 54 - 56%	*15.3.2*	10 x Hydrogen at 54,5 - 55,5%
	Group C / Group IIB		10 x Hydrogen at 36 - 37%		10 x Hydrogen at 36,5 - 37,5%
	Group B / Group IIB+H		10 x Hydrogen at 39 - 40% and Oxygen 8,5 - 10,5%	*15.3.3.4*	10 x Hydrogen at 39 - 40% and Oxygen 19 - 21%
Flame transmission with enlarged gaps	**Enlarged gap**	*Table 32*	1,5	*15.3.3.2*	From 1,35 up to 1,5
	Group D / Group IIA		10 x Propane at 4,1 - 4,3%		-
	Group C / Group IIB		10 x Ethylene at 6 - 7%		-
	Group B / Group IIB+H		10 x Hydrogen at 26 - 28%		10 x Hydrogen at 26 - 29%
Condition to larger gaps than standard	**Without enlarged gaps**	*36.4*	Use 1,2 times construction gap	-	-
	With enlarged gaps		Use 1,8 times construction gap instead of 1,5 times		

According to Table 4, additional conditions for larger gaps identified in CSA C22.2 No. 145-11 need to be met.

With the comparison above, and if an electric motor is certified using the "First Method" of IEC 60079-1, the following particular situation can be considered:

A motor prototype, tested with enlarged gaps for IIC and the same prototype tested for IIB:

- Tested with 27,5% hydrogen;
- Tested in the same prototype with 37% hydrogen;

Can comply with the following condition for Division if constructed with the gaps for IEC Group IIC:

- $CSA: i_E = 1{,}2 \times i_C$, tested with 37% hydrogen.

Thus, an IEC certified motor for gas group IIC would only be able to be recertified for Class I, Division 1, Groups C and D, and only in this particular situation.

Requirements to limit surface temperatures

One of the main differences between schemes is the concept of "type of protection".

As the Division Scheme does not recognize the type of protection for motors, the requirements extend to other IEC types of protection, demanding compliance and additional tests.

As shown in Table 5, the Division Scheme requires several operational tests with overload conditions which are not required for flameproof motors in IEC, where thermal tests are limited to normal operation.

Due to the requirement of motors to withstand overload conditions without reaching the temperature class, it is normally mandatory to fit and install a device for limiting the motor temperature.

Table 5 – Comparison of thermal tests

	CSA C22.2 No. 145-11		IEC 60079-1	
Thermal tests	*31 to 33*	- Normal temperature test (until stabilization) - Running overload test (until trip) - Single-phasing test (until trip) - Locked-rotor test (until trip)	*Table 6*	- Normal temperature test (until stabilization) - No overload

For VFD operation the requirements of both Schemes are similar, as IEC allows to use a temperature limiting device to guarantee the surface temperature.

Table 6 – Comparison of VFD operation

	CSA C22.2 No. 145-11		IEC 60079-1	
VFD Motors	*30*	Marked frequency range, tested with representative type of inverter	*Annex H*	Test with specific inverter or use of temperature limiting device in windings

Requirements for external fan

Regarding fans and fan covers, the Schemes differ and Division Scheme requires a fan made from aluminum or brass with limited hardness.

On the contrary, IEC Scheme only imposes requirements regarding non-metallic materials.

Table 7 – Comparison of fan and fan cover

		CSA C22.2 No. 145-11		IEC 60079-0	
Fan and fan cover	**External fan material**	*22.1*	Brass or aluminium with hardness not over Rockwell B66	*17.2.2*	Any material, restrictions if non-metallic
	Non-metallic fan	*22.1.2*	Pass in conductivity test and accumulation of static electricity test	*7.4.2*	Multiple methods including testing
	Ventilation openings	*22.2.3*	Block entry of rod of 19,1mm Do not allow touching moving parts of rod of 12,7mm and 101,6mm	*17.2.1*	IP20 in inlet (≤ 12mm) IP10 in outlet (≤ 50mm)

Requirements for air distances

As mentioned in the previous sections, due to the non-existence of the type of protection concept in the Division Scheme, some requirements extend the scope of IEC 60079-1 part of the standard.

One of the other relevant points is the air distances between conductive parts. In IEC 60079-1, there is no requirement since the flameproof concept guarantees the containment of a potential explosion.

In Table 8, the air distances between the CSA C22.2 No. 145-11 standard and the IEC 60079-7 are compared and it is verified that the distances in the Division Scheme are even greater than those for Zone Scheme Increased Safety protection method.

Table 8 - Comparison of air distances

		CSA C22.2 No. 145-11		IEC 60079-0		IEC 60079-7	
Air insulation	Creepage	*Table 26*	For 7200 V - 125mm	*14.3*	According to Type of Protection requirements	*Table 2*	For 6300V and IIIa - 100mm For 8000V and IIIa - 125mm
	Clearance		For 7200 V - 100mm				For 6300V and IIIa - 63mm For 8000V and IIIa - 80mm

B. Motor manufacturer point of view

Having the two different regulation schemes has both benefits and disadvantages for motor manufacturers

The standards associated with the Division scheme for motors have a high degree of details which clearly define not only the minimum requirements for structure and dimensions but also the acceptance criteria for a multitude of industrial cases such as porosities, etc. Measurement methods for flameproof gaps are also clearly identified.

On the other hand, IEC and EN standards and their equivalent for North American markets only represents major guidelines of compliance, allowing the manufacturer a broader range of options but at the same time leave some specific design points out.

The inherent differences between products are indicated in this chapter, conducing to products that may be radically different, both in performance and in its application.

The correct understanding of both Schemes is mandatory for all those involved in the development and certification of these machines, nevertheless it is an enormous challenge to design a product that may comply with both Schemes as the concepts are clearly distinct.

C. End user and maintenance team

If the end users have the same type of classification throughout their facilities, the maintenance challenges are reduced compared to when multiple classification and schemes are used, which is common when a single maintenance party is responsible for multiple plants.

End users and maintenance team need to be clearly trained that using “zone marked” equipment in a division area is not allowed and vice versa. Even though some maintenance aspects can be equivalent between the regulation schemes, they should never be assumed as interchangeable.

Sourcing equipment, principally for replacement needs to be done with due diligence to avoid any mistakes as these may trigger additional certification testing and even in some cases create a new product, therefore new certification

The next chapter demonstrates an example where a motor already dispatched was converted from Zone to Division Classification.

VI. CONVERSION OF FLAMEPROOF MOTOR FROM ZONE TO DIVISION

In some cases, the type of equipment purchased may be of a classification not suitable for the installation. In this example, a flameproof electric motor was dispatched for United States, which was certified and marked as:

- Class I, Zone 1, AEx db IIC T4

The motor was certified for Class I, Zone 1 using the type tests and documentation for obtaining the ATEX and IECEx certificate.

After the motor was dispatched, it was identified that an error has occurred in the order, and it was asked if the motor could be installed in a Division classified Area as followed:

- Class 1, Division 1, Groups C and D, T4.

In a joint analysis with the certification body, it was confirmed that the tests for reference pressure, overpressure and non-transmission performed for type certification for Group IIC motors also comply with the requirements of Division 1, Groups C and D.

It is also worth mentioning that manufacturers need to prove the equipment performance and its characteristics as an electric motor, in addition to meeting the Division classified area compliance requirements.

To comply with the major differences enunciated in Chapter V there is the need to perform product modifications and witnessed tests are mandatory for the approval for U.S. (UL-674) or Canada (CSA 22.2 No. 145).

To comply with the referred standards above, it was identified that the motor needed to be modified in the areas below:

- Internal volume of terminal boxes;
- Certified equipment installed in the motor;
- Temperature control devices;

In addition to these changes, tests below were mandatory to be performed at the manufacturer facilities which were witnessed by a certification body representative:

- Normal temperature test
- Running overload test;
- Dielectric Voltage-Withstand Test.

Fig. 11 – Motor subjected to modifications to comply with UL-674 and CSA 22.2 No. 145

Following the indicated changes and tests, the motor was set to return to the manufacturer facility where the terminal box was changed for an increased size, a thermostat was installed in the windings and some equipment were needed to be replaced such as space heaters and thermal sensors.

The motor was then tested at full load condition up to thermal stabilization, shut down and checked for maximum surface temperature. After this test the motor was subjected to overload test until the thermostat actuated to confirm the effectiveness of thermal protection.

The motor was finally approved to be shipped to final destination marked for Division I, Groups C and D.

VII. THE FUTURE OF HAZARDOUS AREA PROTECTION

The important question for the future of hazardous area protection is if the two regulation schemes will be converged into a single scheme and if the new single scheme can use the benefits of these two separate schemes. Can a single classification scheme for hazardous areas that would allow the flexibility of protections of Zones but at the same time the availability of Explosion-Proof motors in Divisions with a permanent hazardous atmosphere exist?

This convergence appears to be difficult in the near future, as obstacles to globalization still exist and are growing in some cases. These tendencies might push industries and political representatives to drive away from uniform market policies and increase the internal market protection by means of economic policies.

VIII. CONCLUSIONS

The arising of electricity drove the world to developments never before thought possible. It also created the dangers associated with these new equipment to a level that caused the death of many people over the years.

The need for protection and regulation of electrical equipment installed in these hazardous areas drove several countries to find means of prevention and control over these industries.

The pursuit of new means of protection and new concepts brought to light technologies, testing and calculation methods that evolved and to this day are still used to validate the compliance of electrical products.

The industrial growth and globalization has moved the world markets closer and harmonized their own rules to decrease costs and increase safety and efficiency. This gave birth to the major guidelines that, today, rule and control the manufacturers and end-users of hazardous area electrical equipment.

Nevertheless, even today the world clings in two major blocks of area classification – Zones and Divisions – that, despite aiming for the same goals, still maintain their distance due to conceptual and technical differences. There are markets faithful to one of the concepts and other that allow both, but the misconception and doubts persist in which is safer . On the other hand, there are many existing facilities that are designed and stablished based on a particular regulation scheme which needs to be considered as well and developing a harmonized scheme is gradual and will take time. For instance, U.S. and Canada debated the reasons of classifying hazardous areas as zones instead of divisions for over 20 years. As a result of these discussions, NEC allowed zone scheme to be used in 1996 and CEC quickly followed in 1998.

This paper summarizes a broad vision of the concepts behind both Zones and Division regulation schemes and the advantages and disadvantages of each. If used correctly and within their scope of application they are safe and valid.

Finally, the big question is: will these two schemes be able to converge and allow a global market for hazardous areas in the future or will they maintain their individuality?

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X. VITAE

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SUBSEA ELECTRIFICATION APPLICATIONS AND TECHNOLOGY QUALIFICATION RESULTS

Paper No. PCIC Europe EUR21_16

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Abstract - The use of subsea processing equipment, which maintains, increases and accelerates oil and gas production, is now more and more widespread on offshore subsea oil and gas field developments. To meet the technical challenges of these developments, subsea transmission, distribution and conversion electrical equipment are developed through the Subsea Power JIP where ABB, Equinor, Chevron and Total are partners. In the first part of the paper, Equinor and Total will present the foreseen subsea processing applications to use electrical subsea transmission, distribution and conversion equipment. In the second part of the paper, ABB will present the subsea Medium Voltage Variable Speed Drive and Medium Voltage Circuit Breaker modules developed to enable subsea factory vision, then give the technology Subsea Power JIP qualification results and technology readiness level.

Index Terms — Subsea VSD, Subsea Circuit Breaker, Subsea processing, Voltage Source Inverter, Subsea transformer.

I. INTRODUCTION

Many of the existing offshore oil and gas installations are currently on declining production, requiring IOR measures to maintain production. These installations typically have limited space and weight capacity. Subsea electrical distribution and conversion can enable supply of power to subsea pumps and compressors with limited modifications topside.

Tie-ins to existing installations will be increasingly important for the industry moving forward. Many of the existing discoveries are not large enough to bear a standalone development. Subsea electrical power technologies can be an important tool to enable new tie-in, due to the limited modification need on the host. Also, in cases where several pumps or compressors are needed, the technology enables supply of all consumers by one cable.

In parallel with the development of subsea processing equipment, some Oil and Gas operators promote the vision of full subsea factory or subsea to shore development as the preferred way to enable cost-effective field development of more dispersed, deeper and smaller oil and gas fields.

Therefore, to realize their vision, these oil and gas operators decided to join their efforts on a JIP Subsea Power project [2] aiming to develop technology for Transmission, Distribution and Power Conversion for implementation of their future subsea solutions at greater distances and deeper waters.

II. OIL AND GAS FIELD DEVELOPMENTS

A. Subsea equipment's, environment, requirements and challenges

Subsea is an environment with no eyes, ears or hands on the spot, where maintenance is both extremely costly and limited by the use of Remote Operated Vehicles (ROV). In this context subsea equipment must have high reliability and shall be designed to last a minimum of 25 years [1].

Subsea equipment should be as compact as possible and modularized to facilitate individual installation or retrieval at sea without requiring heavy ships and cranes. Control modules should be separately retrievable from main power modules.

To allow their use on different oil and gas field locations and secure their reliability, they must be designed for installation in water depths up to 3000 m, temperature ranging from -2°C up to 25°C and with standardized and simple interfaces to other subsea equipment.

Unlike onshore transmission and distribution systems which are often based on a ring system where faults are easy to isolate, subsea transmission and distribution systems are point-to-point connections with a single transmission link, especially for long step-outs; this sets requirements for high reliability and availability.

B. Subsea processing applications

Existing offshore fields are depleting fast and the new coming fields are not easy to develop due to their reduced size or dispersed locations. Fields may also yield more challenging fluids. Therefore, new ways for economical subsea processing are being developed for subsea separation, electrical heating, subsea compression and multiphase pumping on the sea floor, which accelerates production and as well increasing its recoverable volume (Figure 1). All these solutions require power at the seafloor to drive the respective pumps and compressors.

C. Energy efficiency

Improving energy efficiency and reducing CO_2 intensity associated with production of hydro carbons are amongst the top priorities as of today.

The subsea electrification technology can be an enabler for supplying subsea boosting with power from shore. Also, subsea compression as a standalone technology requires significantly less energy compared to platform compression. The closer the compression is located to the source, the higher the efficiency. The conversion and distribution technology may be an enabler for subsea compression and pumping.

By placing the VSDs subsea, the electrical transmission will operate at a fixed frequency of 50 or 60 Hz, compared to a variable, and higher, frequency in case of topside/onshore VSDs. A case study for a specific use candidate showed that the electrical transmission losses can be reduced up to 50% by using subsea VSDs.

Subsea power distribution and conversion can play an important role in realizing un-manned faculties, both for all subsea solutions and in combination with un-manned topside installations. Reduction in manning/personnel and utilities required for topside offshore installation reduces the associated emissions from the oil and gas production.

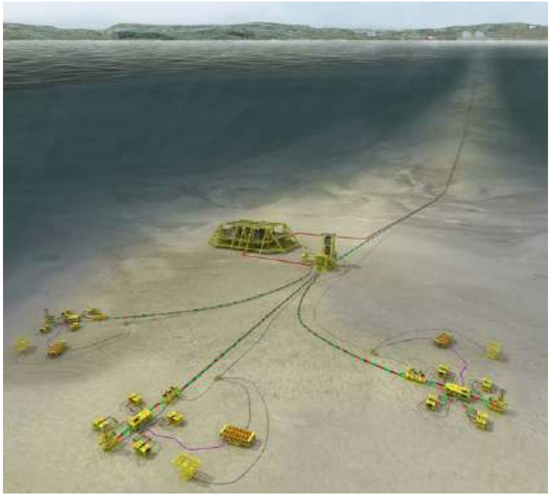

Fig. 1 Subsea processing facility

In these applications, subsea processing equipment can be linked to topside facility offshore or onshore either from new facility or brown fields.

D. Combined DEH and boosting

An interesting use case for the subsea electrification technology is combining power supply for Direct Electrical Heating (DEH) and pumping (Figure 2). This is particularly attractive for tie-ins to an existing host. In this concept, a single power cable is used to supply pipe heating and boosting. When the subsea pumps are running, there is no need for heating, hence the combined use does not lead to over dimensioning of the cable.

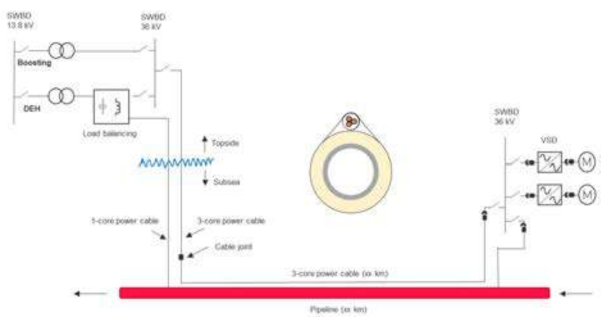

Fig. 2 Combined DEH and boosting

In pipe heating configuration, the three conductors in the cable are connected in parallel, operating as a single phase cable, while in pumping configuration it operates as a regular three phase cable. A subsea switchgear is used to switch between the configurations.

The solution gives minimal impact on the host combined with maximum utilization of the subsea power cable.

III. TECHNOLOGY DESCRIPTION AND QUALIFICATION STATUS

The base case for subsea power distribution covers the transmission of 100 MW power over distances up to 600 km to 3,000 m water depth. Power electronics and control systems would also be supported with 230/400 V.

Designing a power supply infrastructure that can operate at 3,000 m water depth for 30 years is a considerable challenge. Multiple significant technical challenges need to be overcome to achieve the exacting reliability required in the operational conditions specified above for such long periods of time. The inaccessibility of the equipment required fault tolerant approaches to assure the availability of the equipment. The pressure of the environment in these pressure-balanced subsea tanks is a new requirements on the electric components, and cooling needed to be of failsafe passive design. The found solutions are the result of a careful balance between novel and highly proven design approaches.

Started in 2013, the JIP project reached a major milestone in late 2017 when the first full-scale prototype of the variable speed drive (VSD) passed a 1000-hour shallow water test (SWT). Further, another major milestone was achieved in November 2019 when a full-scale shallow water test of the complete subsea power system with two VSDs in a parallel configuration combined with subsea switchgear and controls were successfully completed. Figure 3 shows the equipment being submerged into water for the 3000-hour test at the harbor test site in Vaasa Finland.

Fig. 3 Submerging of VSD (top photo) and switchgear (lower photo) for full-scale shallow water prototype testing at harbor facilities in Vaasa Finland in 2019

The JIP developed the following key products for subsea use:

- Subsea variable speed drive
- Subsea medium voltage switchgear
- Subsea control and low voltage distribution

The medium voltage subsea switchgear is required to distribute main power to subsea VSDs and other power consumers located on the seabed. The subsea switchgear can support up to six feeders including an incoming breaker, or a tie breaker to support cascading two switchgears. The incomer of the switchgear connects to the secondary of a subsea step-down transformer, or directly to a subsea power cable from topside/shore. The feeders connect to the subsea consumers, typically variable speed drives for seabed pumps and subsea compressors. The switchgear rated phase-to-phase voltage is 36 kV and main bus bar current is 1600 A. A modular and scalable concept accommodates a range of system cases and configurations, covering conventional 50/60 Hz but also LFAC 16 2/3 Hz power distribution for very long transmission distances.

The subsea VSD is the key equipment developed to control the speed and the torque of the subsea motors for seawater injection, boosting and compression applications. Here it is particularly important, that modular building blocks can be qualified and then used to configure VSD installations for a wide variety of subsea motors and loads (Figure 4). In the developed design, a single tank VSD can be scaled to run pump loads of 2 – 6 MW but also compressors requiring the 10MVA range using the appropriate number of internal cell modules and considering the maximum water temperature at the deployed location. Using a drive train with two parallel connected power conversion units, support of a load up to 18 MVA is possible. The overall solution is flexible and scalable and covers most identified needs for subsea power. The power source can be from any available topside installation or directly from shore. In case of multiple drives nearby, a switchgear will reduce the need of cables.

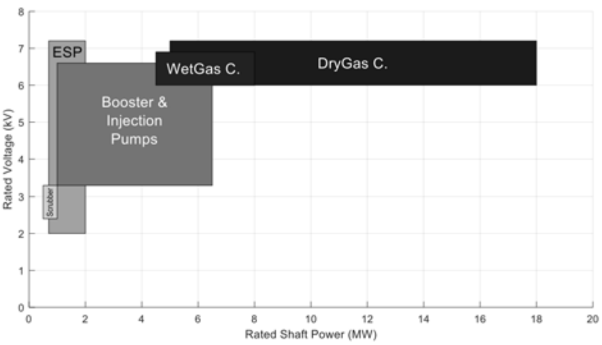

Fig. 4 Applications, power range and motor voltages typical for the subsea VSD.

Available subsea pump motors are dominantly robust induction type motors, but also permanent magnet motors exist. The subsea VSD has an integrated drive transformer which is powered via the subsea switchgear at the rated supply voltage (typically designed for a voltage in the range 11-33 kV), either at conventional 50/60 Hz or at LFAC 16 2/3 Hz supply frequency. The drive then converts the power to a variable output voltage ranging from 2.3 kV to 7.2 kV or above. The design-operating frequency range is up to 200 Hz for the full power range, up to 300 Hz for high-speed compressor loads below 5 MVA. An output filter is integrated into the VSD to ensure that the power quality and voltage transients are within motor and cable tolerances. To optimize for long service life without maintenance or repairs, the subsea VSD is based on a robust cell-based topology and long-established power semiconductors with overrating design margins. It has also built-in redundancies in both the control and power circuits. Any power cell failure is prevented from migrating to neighboring cells, whereas the faulty cell can be bypassed with the use of integrated disconnectors to continue operation. The VSD will provide full nominal power and voltage even with the loss of one cell per phase. The drive redundancy has a fault management system that is also in itself redundant at several levels. Also keeping high focus on quality, significant effort was been spent on establishing the necessary Environmental Stress Screening on a routine basis for the parts used in the drive.

Novel design solutions for packaging existing IGBT and rectifier chips were developed in order to obtain compatibility with pressure and oil environment for the subsea application. Test programs included extensive subsea-specific verifications to prove robustness of the materials adapted for the new environment. Power cycling and thermal cycling capabilities were used to demonstrate the robustness of the semiconductor modules to the load and temperature cycles in the application. Testing was generally done all the way from small components to higher assembly levels. The full power cell has separately been operated also over 3000 hours at the 345 bars qualification pressure. Part of the test were also all relevant sensors and electronic PCBAs, including the optical fibers and their connectors. The modules performed flawlessly in these pressure tests and were concluded already in 2018.

All project qualification activities followed the recommendations and technology readiness level (TRL) stages defined in DNV RP-A203, applicable for components, equipment and assemblies in hydrocarbon exploration and exploitation offshore. This recommended practice provides a systematic approach to ensure that the technology will function reliably within specified limits, and it provides a common understanding and terminology of technology status and risk management.

To ensure compact and reliable solutions, oil-filled pressure compensated tanks are used for enclosure of the VSD and switchgear. All components are tested extensively under the full pressure they will experience at the target water depth. It is a high-level objective to design the equipment to minimize production downtime and number of retrievals.

The JIP has focused on the development and qualification of a subsea switchgear, variable speed drive (VSD) and a control system. Base case is a subsea power system with a subsea switchgear feeding four VSD loads at a water depth of 3000 meter. In general, existing requirements applicable for topside systems and equipment apply, as well as API17F Standard for Subsea Production Control Systems. Equinor's technical and professional requirement TR3025 was developed in parallel with the project and specifies requirements applicable for subsea systems and equipment, e.g. system design margins and equipment immunity levels. While the JIP project over recent years developed packaging-technologies to enable robust and cost-efficient power distribution and conversion for subsea, the final goal of the project is to provide industry with the right confidence that the developed products are ready for use. This is indeed as far as ABB will take subsea technology without operational experience of the drive system in a subsea production field. Off course, before taking the steps into commercial Pilots, JIP Partners have conducted Failure mode and effects analysis at an unprecedented level of detail. This allowed identifying all relevant risks, which were subsequently mitigated by specific tests and acceptance conditions in technology qualification program. The subsea industry has adopted a TRL system (Technology Readiness Level) for a common understanding of the development stages in the qualification process, and the degree of testing required to reach each stage (see e.g. API Recommended Practice 17Q, 2nd edition). This entailed initially a breakdown of the overall subsea power system into separate manageable technology parts and classifying these in terms of novelty. The project is currently progressing from API TRL3 to TRL4 with full-scale prototypes. This includes a 4-feeder subsea switchgear, two medium-voltage subsea power drives with input transformers, and a subsea control module with the subsea protection relay. Each prototype has undergone tests at various assembly stages and have completed a final shallow waters test for 3000-hour high-power demonstration. The objective was to test and prove the thermal properties and the marinization of the equipment. Figure 5 shows the power level during the 3000 hours of operation. The power was circulated by the two VSDs through the subsea switchgear in a "power-in-the-Loop" circuit. The grid supplies thus only circuit losses. This test was structured to reflect the key aspects of field operation. One aspect of the test was a larger than 1000 h trip free phase to show the system stability. Another 6 weeks focused on severe thermal power cycling to demonstrate the highest thermal loading. In reality, this would correspond to far more than a decade of real operation, where in fact fewer full thermal cycles would be expected. These two main phases where interspersed with characterizing runs to assess the detailed thermal performance. Among other aspects, the test duration from mid-summer to early winter allowed testing over the full specified water temperature range. The final TRL assessment will be made by JIP Partner's subject experts after some remaining formal TRL 4 qualification tests on components are completed. Then the overall system will be TRL4+.

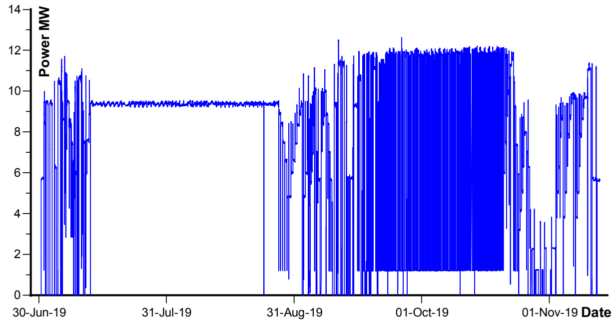

Fig. 5 Time trace of power level in VSD and switchgear during the 3000 h shallow water qualification in 2019.

Critical areas of focus for ABB, throughout the JIP, were designing the system to be modular, flexible and open and to meet reliability and availability targets that are even higher than for topside applications. The approach, from the start, has been to base the technology largely on ABB's existing technologies, where reliability is proven, where quality control and obsolescence strategies are well established and where integration with existing topside systems and software will therefore be straightforward. The design philosophy was that all failures should be mitigated by design improvement or change, rather than adding simple ruggedizing steps. Furthermore, all issues encountered during testing were shared and discussed with the project partners and sub-suppliers to draw on their field experience.

To ensure electronics and power components could tolerate operation in both a pressure tolerant environment and dielectric oil, there has been extensive focus on component screening and selection, as well as material compatibility, material interface aspects and thermal performance. The subsea electronics and control modules have been designed to be flexible and modular, allowing for variability in size, as well as positioning within the system, according to the template layout of system design philosophy. Communications and control are ethernet-based, for ease of interfacing with the rest of the subsea system, with high-speed fiber optic communications to enable responsive remote operations and an ABB Ability™-ready system.

IV. CONCLUSIONS

Having achieved qualification of all subsystems – the VSDs, switchgear and control systems – through tens of thousands of hours of exhaustive design, engineering and testing, we've now also achieved the final challenge: a full system test. All the pieces were assembled for the final 3,000-hour shallow-water test. The entire system, comprising the MV switchgear, control and low voltage distribution equipment, plus two parallel 9MVA VSDs were successfully put through its paces as a single operational unit.

The JIP results are extending the limits of what is possible subsea. The developed technology is enabling electrification of all subsea infrastructure, reducing emissions and minimizing the industry's environmental footprint; while increasing automation, process capability

V. ACKNOWLEDGEMENTS

Thanks to Chevron our JIP partner.

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VII. NOMENCLATURE

DEH	Direct Electrical Heating
IOR	
JIP	Joint Industry Project
ROV	Remote Operated Vehicles
VSD	Variable Speed Drive.
VSI	Voltage Source Inverter.
TRL	Technology Readiness Level

VIII. VITA

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Important Considerations for Testing and Commissioning Digital Relays

Paper No. PCIC Europe EUR21_17

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Abstract - The proven advantages of digital technology for power system protective relays are now commonplace in the power producing and delivery industry. Digital relays provide unsurpassed reliability and extended capabilities at an economical cost. Keeping pace with the testing and commissioning requirements of these devices has proven to be a challenge for both protective relay engineers and technicians. Although testing procedures have been well defined for single-function electromechanical (EM) protection devices, modern relay test procedures have been left to the utility to develop, creating possible shortcuts that may compromise the protection system operation.

Index Terms — Protective Relays, Protective Relay Testing, Protective Relay Commissioning, Automated Relay Testing

I. INTRODUCTION

Extended options and settings, complex trip logic equations, and advanced communication options can lead to overwhelming difficulties in ensuring that a multifunction intelligent electronic device (IED) is properly tested. Observations from within the industry indicate that a common reason for potential errors is the implementation of shortcuts, primarily for simplifying the process and meeting regulatory recordkeeping requirements. Some of these testing shortcut practices include setting and logic changes that accommodate easy testing, creating test values based on single-element settings rather than the actual applications, and failing to test the entire enabled capabilities of the protection system.

This article presents examples of common mistakes typically observed during testing and commissioning as well as ways to avoid them with simple-to-understand guidelines. The importance of testing protection systems, rather than single, protective elements that avoid protective relay mis operations once in service, is also discussed.

The process of testing multifunction digital protective relays brings new challenges for many reasons. First, we must understand the focus of testing these devices as compared with that of EM or single-function relays. The main purpose of testing EM relays was to ensure proper calibration. Calibration and testing procedures were widely available from the manufacturer and relatively easy to understand. Although modern digital technology provides many advantages, finding appropriate guidance for proper testing can be very difficult. This article offers suggestions for simplifying the testing process without compromising proper testing procedures.

II. ADEQUATE TEST EQUIPMENT

For the proper testing of multiphase IEDs, it is essential to provide a multiphase source of voltage and current. Testing a multiphase protective element with a single-phase source can lead to false assessment. Some calculations of fault values rely on measured values from a nonfaulted phase. Typically, all possible faults should be simulated for each protective element. All utilized CT and PT inputs must be taken into consideration during the testing process. Additionally, all binary inputs and outputs utilized by the IED must be accounted for in the test equipment because it is equally important to test all logic associated with the IED's operation.

III. UNDERSTANDING DIFFERENT TYPES OF TESTS

The different types of testing procedures are defined as follows:

1. *Evaluation testing* determines whether a protective relay is suitable for use on a particular protection application(s) within a power system; this is also recognized as a process to evaluate and validate published specifications by the relay manufacturer.
2. *Commission testing* ensures correct functionality of the relay when first installed and activated within the power system.
3. *Periodic or maintenance testing* routinely checks and validates the correct operation of an already installed and active protective relay.

For the purposes of this article, we refer mainly to the commissioning of digital protective relays, although the discussion can also be relevant to the other testing processes as well [1].

First Consideration: Why Do We Test?

For EM technology, the main purpose of testing was to ensure proper calibration of the device. Over long periods of time, contacts, springs, potentiometers, and coils tend to require recalibration, cleaning, or adjustments to ensure proper operation. The term *silent sentinel* was often used to describe this type of technology because there were no self-diagnostics present to determine whether or not the relay would function properly in the event of a fault. With no such calibration required for digital technology, as well as the ability to rely on certain self-diagnostics, why is the commission process still required?

In 2013, the North American Electric Reliability Corporation (NERC) released a report that claimed a dramatic rise in the annual number of mis operations due in large part to the complexity of programming and testing digital protection relays.

As shown in Figure 1, mis operations primarily occurred because of the following reasons:

- incorrect setting/logic/design errors
- communication failures
- relay failure or malfunctions.

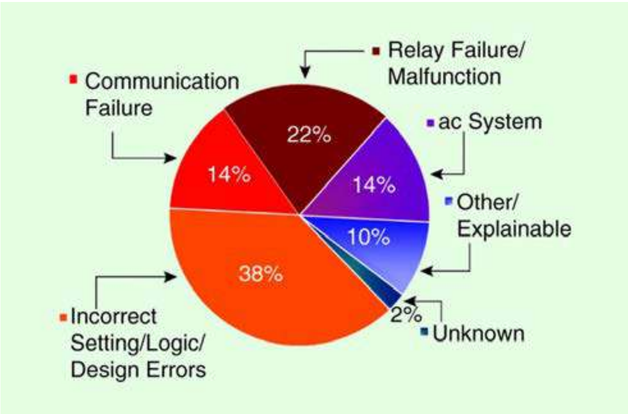

Figure 1.
The 2020 NERC mis operations graph.

These events include human error during testing and maintenance activities. This human error, resulting in protection system activation, has contributed to large disturbance events. Proper testing is just as important for multifunction digital IEDs as it is for older EM technology, but the focus has changed significantly. It is true that the IED self-diagnostics can alert operations of an internal failure and remove itself from service, but only through proper testing procedures can it be determined that the protection system is properly configured. Complex logic configurations, multiple setting groups, communication-based protection schemes, and a large number of protective elements in a single IED add significant challenges to proper commissioning. Much of this complexity has led to recognized shortcuts within the testing process, which can ultimately lead to mis operation [1].

IV. What Do We Test?

At first glance, this may appear to be a simple question, but when faced with the complexity of a modern protection IED, it is anything but. The components tested are as follows:

1. *Test each protection element*: Each protection element must be tested to ensure that it has been set properly. This may seem unnecessary because there is no calibration, but relay engineers and technicians are quite capable of human error in setting each device. A misplaced decimal point, forgotten time delay, or even forgetting to enable an element are all possible and can lead to mis operations.
2. *Associated logic*: This important factor is often overlooked. The complexity associated with some logic equations adds to a large majority of mis operations. For example, when protective element supervision from a breaker contact is required, breaker simulation during the testing process is essential. Many protection IEDs also have programmable human–machine interface controls, some of which invoke safety-related commands such as Hot Line Tag (Figure 2). If the controls are not programmed and tested properly, extreme hazards could be present [2].

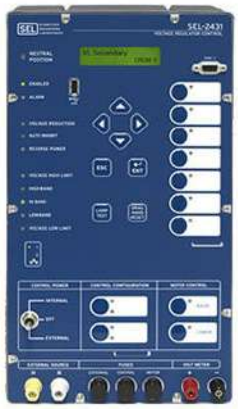

Figure 2.
A feeder relay with human–machine interface control.

3. *Communication-based protection schemes*: These are most often seen in transmission line protection and, in the majority of cases, are the basis for end-to-end testing. However, these types of tests are time-consuming and often difficult to achieve. Nonetheless, in this critical test for a transmission line, the protection engineer can verify the delay time of the teleprotection signals (i.e., the delay time between sending signal transmissions recorded on the first end and the received signal recorded on the other end) immediately after executing the shot, as shown in Figure 3 [3].

Figure 3.
The delay time of teleprotection signals

V. How Do We Test?

These test procedures should be avoided:

- testing a protection IED based on factory settings
- changing, altering, or disabling the associated logic with each protective element to validate settings
- changing, altering, or disabling the components of a protective element to validate settings
- testing the IED by relying only on the settings that lie within the relay
- closing the relay trip circuit without the metering validation of a non-trip state [1].

These procedures should be followed:

- ensure that the settings coincide with those pertaining to the application and not factory or predefined “test settings”
- test the device with associated logic enabled, considering both sides of a logic equation for proper validation
- test the element without changing settings such as pick up, dropout, or time delays and using proper fault values for fault simulations.
- use relay software to validate proper secondary CT and PT wiring prior to enabling the trip circuit, as shown in Figure 4 [2].

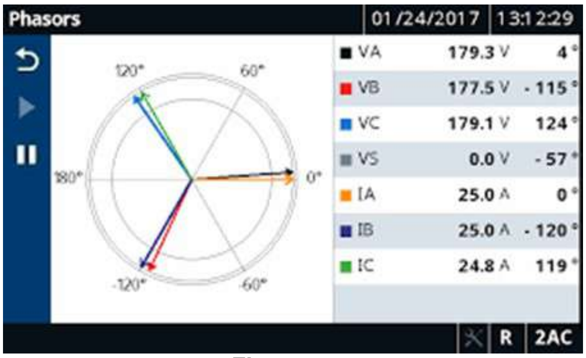

Figure 4.
An example of relay-metering software.

The proper test sequences that account for associated logic are as follows:

1. Begin each test with a proper pre-fault condition: “Be the relay.” This should include, but not be limited to, the proper simulation of breaker contacts and the application of pre-fault analog values (nominal) that are maintained long enough for lockouts to reset (feeder management relays). Doing so will mitigate logic interference such as “switch on to fault,” “cold load pickup,” and so on.
2. Maintain a proper calculated fault value until the element picks up, allowing for the validation of trip times and thresholds.
3. Follow up with a proper post-fault state, including breaker open logic, and faulted values that would be eliminated in a normal trip state condition. Doing so removes interference from associated breaker failure conditions.
4. Ensure that calculated test values coincide with published tolerances provided by the relay manufacturer. Most modern testing software allows for automated test sequences and assessment (Figure 5).

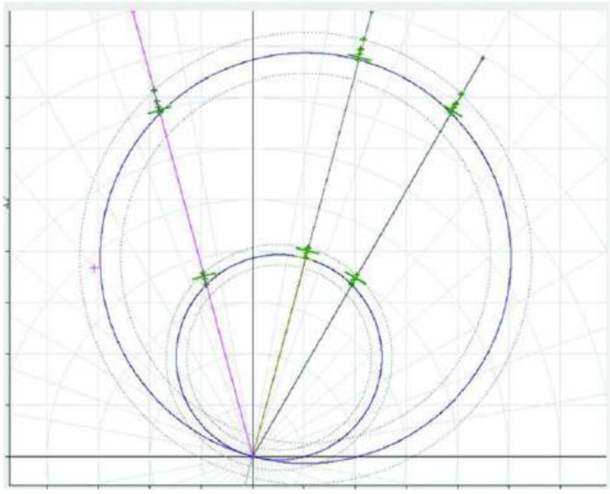

Figure 5.
The automated tests from a test set.

VI. When Do We Test?

NERC / NETA Testing Intervals:

As shown in Figure 6, the System Protection and Controls Task Force of the NERC Planning Committee publishes maximum testing intervals by equipment category [4]. Figure 7 illustrates published recommendations of relay testing intervals, according to International Electrical Testing Association (NETA) standards.

Maximum Allowable Testing Intervals by Equipment Category

Category	Component	Maximum Verification Interval				Verification Activities
Reference Figure 1		Un-monitored	Partial Monitoring Note 1	Thorough Monitoring Note 2	Full Monitoring Note 3	
1	Testing and calibration of protective relays, per Note 7	Five years	Seven years (Notes 1a, 1e, 1f)	10 years (Note 2a)	Continuous Monitoring and Verification	Test the functioning of relays with simulated inputs, including calibration per Note 7. Verify that settings are as specified. See Section 12 for a discussion of verifying settings.
2	Verification of instrument transformer outputs and correctness of connections to protection system	Seven years	Seven years (Notes 1a, 1f)	10 years (Note 2a)	Continuous Monitoring and Verification	Verify the current and voltage signals to the protection system and instrument transformer circuit grounding.
3	Verification of protection system tripping including circuit breaker tripping, auxiliary tripping relays and devices, lockout relays, telecommunications-assisted tripping schemes, and circuit breaker status indication required for correct operation of protection system	Five years	Seven years (Notes 1a, 1b,1d,1e, 1f)	10 years (Note 2b)	Continuous Monitoring and Verification	Perform trip tests for the whole system at once and/or component operating tests with overlapping of component verifications as explained in Section 10. Every operating circuit path must be fully verified, although one check of any path is sufficient. A breaker only needs be tripped once per trip coil within the specified time interval. Telecommunications-assisted line protection systems may be verified either by end-to-end tests or by simulating internal or external faults with forced channel signals.
4	Station battery supply (Note 12)	One month	Seven years (Notes 1b, 1d, 1f)	Continuous Verification (Notes 2b, 2d)	Continuous Monitoring and Verification	Verify voltage of the station battery once a month if not monitored.

Figure 6.
NERC testing intervals.

Section	Description	Visual	Visual and Mechanical	Visual and Mechanical and Electrical
7.9	Protective Relays			
7.9.1	EM and Solid State	1	12	12
7.9.2	Microprocessor Based	1	12	12
7.10	Instrument Transformers	12	12	36
7.11	Metering Devices			
7.11.1	EM and Solid State	12	12	36
7.11.2	Microprocessor Based	12	12	36

Figure 7.
Relay testing intervals in months per the NETA.

Additional considerations for testing intervals are

- environmental conditions
- criticality of the protected asset
- redundancy of protection
- historical performance.

The final considerations for when to test are

- setting changes after commissioning
- relaying firmware updates
- rewiring in the trip circuit or secondary CTs or PTs.

VII. Conclusion

When considering digital protection relays, it is important to understand the impact that self-diagnostics play in the testing process. Although self-diagnostics will detect the failures of certain components, such as power supplies, microprocessors, and circuit board parts, we must also understand what it will not detect, such as relay output contacts. Most importantly, self-diagnostics will not alarm when there is human error in setting the protective elements or logic correctly. While digital technology adds greater reliability within the protection system, this does not eliminate the need for proper testing; rather, this technology necessitates refocusing of the testing process.

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VITA

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Ex Management for Explosive Atmosphere, an EPC Contractor point of view

Paper No. PCIC Europe EUR21_18

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Abstract –

Managing explosion risk in our industry is a must have. It is not a question of choosing the right equipment for a given risk, but also to deeply understand the context in order to mitigate all possible risks.

This paper will present the organization put in place in an EPC contractor to cover both the competency management along the complete supply chain and the procedures attached in order to control the job down to the establishment of the verification dossier required by IEC 60079-14.

I. INTRODUCTION

Ensuring safety of an EX installation start from design and continue all along the life of the plant by ensuring proper operation and maintenance.
Cost impact of compliance correction at late phase of the project like the startup phase can cost millions of dollars, including change of equipment due to missing certificates or total reinspection of packages component by component due to impossibility to formally prove competency of the different person involved in the different phase of inspection.

The verification dossier is a set of documents showing the compliance of electrical equipment and installations; the guideline is given in section 4.2 of IEC60079-14. Depending on local regulations, it is the base of regulatory inspections all along the life of the plant.
So far, the verification dossier has been considered out of EPC scope of work, in particular the records of the initial inspection and records of installer's/qualified person's declaration. The initial inspections must be performed before plant or equipment is brought into service.

On one of our offshore projects, client Operation & Maintenance team was in charge. The team was mobilized on site just before the plant start-up; and EPC Contractor scope was completed before at mechanical acceptance.

In order to improve the project overall schedule, and also to consider the impact of modularized construction, the records of inspection for assemblies in vendor workshop or pre-installed items in construction yard can be accepted as part of initial inspection records instead of final inspection onboard once construction completed. Thus, Client has requested EPC Contractor to build the verification dossier all along the construction phases.

Unfortunately, and also on other recent projects, it has been identified:

- A lack of knowledge even in our teams with the requirements of IEC 60079 series.
- A lack of Competence in Ex equipment of vendors installers.
- A lack of Inspection requirements (competencies, ressources, ITPs, …)
- A lack of Vendor Surveillance.

Then, a lot of non-conformities to ATEX/IECEx schemes were identified at a late stage of the project, significantly impacting the production start-up date.

So, it has been decided to develop an assessment methodology of the competency of people involved on Ex matters on the projects.

An internal organization and typical procedures and tools have been set up to meet Client expectations and IEC requirements for both competency assessment and verification dossier establishment.

II. EX ORGANIZATION WITHIN EPC

First, a function of “Ex compliance Coordinator” has been created at project level as it is a transverse activity. Its role is to coordinate all actions related to Ex matters management. A split of responsibility within the organization defines the activities to be performed by Ex compliance coordinator, Discipline engineers and Inspection department.

Ex Compliance Coordinator
profile is decided project wise. He/She could be E&I expert, Compliance Manager or Project Engineer.
He/She is a key people in front of authorities, clients, partners and vendors.
He/She is responsible for the overall ATEX/IECEx compliance.

III. ENGINEERING DELIVERABLES

A number of documents need to be elaborated during design phase.

First of all, in order to apply rules of the IEC 60079 and especially comply with the IEC 60079-14 for installation, Engineering/Safety and Loss Prevention shall provide **hazardous area classification** documents (see IEC 60079-10-1) with plans showing the classification and the extent of the hazardous areas including the zoning.

“**Ignition Source Management Execution Plan**” is a guidance document issued by HSED (Health Safety and Environnemental Design) department that describes the procedures, standards and methods used to identify potential ignition sources (not only Equipment subject to Ex classification) appearing within the project. They identify all elements or phenomena that can lead to creation of the spark or hot spot that can ignite the potential Ex atmosphere.

“**Material Job Specification for Supply**” identify the selected protection method to be used according to each zone on the project.

“**E&I Installation specification**” provides the rules and method for safe installation of electrical and instrumentation equipment’s, including the cable gland selection guideline (not as simple as it could appear) and other interfaces between zone or devices.

Those last two documents must be communicated to vendors and construction contractor even during the bidding phase in order for them to integrate those constraints in their costs and schedule.

IV. EX PROJECT PROCEDURES

EX MANAGEMENT PLAN :

The purpose of this document is to describe Contractor organization to ensure the Project compliance with Ex requirements (with the IEC 60079 suite of standard, and the ATEX directive requirements, when applicable), for the Engineering, Procurement and Construction.
It also defines the strategy, associated actions and assigned personnel to ensure that the Project will be executed to reach the final compliance to Ex requirements applicable.

INSTRUCTION TO EQUIPMENT VENDORS FOR EXPLOSIVE ATMOSPHERES:

This document defines the requirements applicable to VENDORS in relation to equipment suitable for operation in explosive atmospheres.
This document covers VENDOR’s responsibility for compliance from design through procurement, manufacturing and factory inspection and tests.
These requirements shall be used throughout all the project by all parties with scope of work including Electrical and Non-Electrical Equipment for hazardous areas/explosive atmospheres

It must be issued at very early stage of the project, so it can be part of the vendor selection criteria to ensure final compliance of materials.

The typical contents is:

- Main project requirements for Ex material selection.

- Vendor Personnel competency and qualification requirements
- Vendor documentation including: verification dossier summary, Ex register template, list of test reports….
- Check sheet templates,
- Vendor clarification questionnaire

CONTRACTOR VERIFICATION DOSSIER

This is the compilation of the dossiers prepared by vendors for each Purchase Order which contains copies of all engineering documents referenced in the Ex register including but not limited to :

Relevant location drawings,
Certificates of Conformity,
Classification drawings,
Schedules,
Installation and maintenance instructions,
Calculations,
Wiring drawings.
…/…

The database is required to form a traceable set of documentation according to IEC 60079-14 section 4.2, IEC 60079-17 sections 4.1 and 4.2.

V. VENDOR'S MANAGEMENT

VENDORS PERSONNEL COMPETENCY AND QUALIFICATION

- VENDOR and their associated sub-vendors in charge of the design, selection and installation of equipment for explosive atmosphere shall fulfil the competencies and qualification requirements set out in IEC 60079-14 (section 4.5 and Annex A: Knowledge, skills and competencies of responsible persons, operatives/technicians and designers).

- VENDOR shall be able to demonstrate evidence of their personnel attaining the knowledge and skill requirements specified in IEC 60079-14, relevant to the type of protection and/or types of equipment involved.

- An Assessment and Declaration of knowledge, skills and competencies (IEC 60079-14) shall be provided for each employee involved in the project.

- VENDOR's personnel in charge of installation and cabling work shall be suitably trained. Certification of training by cable gland manufacturers is a must.

- VENDOR Quality Manager shall issue an Assessment and Declaration of knowledge, skills and competencies (IEC 60079-14) for the employee(s)/foremen in charge of assessing others.

- VENDOR may hire competent third party service supplier as per above requirements to validate - on their behalf – the design, selection and installation of equipment for explosive atmosphere if they cannot prove competencies of their own team.

- For Inspection, VENDOR shall be able to demonstrate evidence of their inspectors attaining the knowledge and skill requirements specified in IEC 60079-17, relevant to the type of protection and/or types of equipment involved.

VENDOR VERIFICATION DOSSIER SUMMARY

- 'Ex Register' i.e. a schedule of all Electrical and Non Electrical Equipment used in explosive atmosphere
- IEC Ex Certificates of Conformity (or other applicable as per local regulation, ie ATEX in Europe , Gost in Russia, UL in US…)
- 'Ex' Inspection Check-sheets for all tagged equipment for explosive atmosphere within the VENDOR's scope of work
- Records of Maintenance, Repair, and Modification of equipment for explosive atmosphere where applicable
- Personnel Competency Records of Inspectors who signed the check sheets
- Hazardous Areas Calculations :
  - Maximum Power Dissipation
  - Pressurization Calculation
  - Heat tracing Descriptive Documentation
  - IS Descriptive [System] Design Documentation
  - Simple Apparatus Assessment Document
- Engineering Assessments
- Cable Test Results
- Manufacturers (OEM) Manuals

EX REGISTER

A schedule of Electrical Equipment for explosive atmosphere or “Ex Register” shall be provided by each VENDOR to capture all data for identification of ALL electrical, telecommunication and instrument/automation items which will be suitable for use in explosive atmosphere even if they are not located/installed in hazardous area.
Non-Electrical Equipment shall be identified on a separate table, using the same format.

Each item shall be entered, as an individual row, identified according to the project numbering/tagging procedures.

The untagged bulk items (cable glands, reducers, etc.) shall be entered on a separate table with generic reference per model applied.

The Ex register shall provide the reference of the associated “Ex” certificate of Conformity for each item.

EX INSPECTION CHECK SHEET

Typical check sheet are established by type of equipment at the beginning of the contract to ensure that all required data can be collected during execution. Depending on criticality of equipment, different level of examination shall be indicated from Detailed to Verification.

FORM: V-ITR-E Ex1

EX INSPECTION CHECK SHEET

Item/Tag No:	
Equipment Description :	
Package No./Supply Vendor	
Location	
Status Codes:	OK : Item is complete and there is no further work associated with this item NA : Check is not applicable to the item references in checklist PL : Punch Item

RECORD NAMEPLATE DETAILS

Manufacturer		Equipment Type(Model)	
Ex Proof Certificate No.		Certificate Issue No.	
Ex Protection		Gas Group	
Equipment Group		Temperature Class	
Ingress Protection (IP)		Ambient Temp Range	

RECORD EX AREA DETAILS (HAZARDOUS AREA CLASSIFICATION)

Zone		Gas Group		Temperature Class	

INSPECTION GRADE

Detailed (D)		Close ©		Visual (V)	

Note: The inspection and maintenance of installations shall be carried out only by experienced personnel, whose training has included instruction on the various type of protection.

NO.	ITEMS TO BE CHECKED	Inspection Type			Status		
		D	C	V	OK	NA	PL
1	Equipment is clearly marked with identification that complies with specification	X	X	X			
2	Equipment Data is correct for the area classification	X	X	X			
3	Equipment Ex protection type appropriate for area classification	X	X	X			
4	IP rating correct for location	X	X	X			
5	Special conditions of use (if applicable) are in compliance	X					
6	Equipment circuit identification is available and correct	X	X	X			
7	Condition of enclosure gaskets/seals are satisfactory	X					
8	There is no equipment damage or unauthorized modifications	X					
9	Fixings (bolts, covers) are of the correct type, and are complete and tightened	X	X	X			
10	Unused entry plugs are correct type for Ex technique, completed correctly	X	X	X			
11	Lamp rating, type and position are correct	X					
12	Cable glands are correct type for Ex technique, completed correctly	X	X	X			
13	The cables/conduits are adequately supported and not obviously damaged	X	X	X			
14	Cable type is appropriate and installed in accordance with documentation	X					
15	All unused cores/cables are correctly terminated	X					
16	All unused cores/cables are correctly terminated	X					
17	Earthing continuity/equipotential bonding is satisfactory	X	X	X			
18	Insulation resistance is satisfactory (review test documents)	X					
19	Equipment protected against adverse conditions	X	X	X			
20	No undue accumulation of dust, dirt or moisture	X	X	X			
21	All equipment housings / cables are clean and dry	X					
22	Motor fans and couplings are not rubbing on cowls / guards	X					

VENDOR CLARIFICATION QUESTIONNAIRE

CONTRACTOR shall assess the competency of VENDOR’s team prior to issue of purchase order. Reviewing responses to the EEA (Equipment for Explosive Atmosphere) Vendor Clarification Questionnaire will help to ensure this.

	Score table for IECEx vendor assessment ranking
Score	Installation
4	IECEx CoPC Ex 003
3	Compex, ISM ATEX, EEHA or equivalent
1	Self declaration
0	no declaration
Score	Inspection
5	IECEx CoPC Ex 008
4	Recognized Third Party
3	IECEx CoPC Ex 007, Compex, ISM ATEX, EEHA or equivalent
1	Self declaration
0	no declaration
Score	Ex instruction to Vendor check list
3	Fully filled and compliant
1	not fully filled
0	no answer
Score	Previous vendor Experiences with IECEx
4	Major project vendor
2	Other similar project
0	no experience

The total score evaluation is part of the vendor selection process.
The level of vendor surveillance by CONTRACTOR will be adjusted based the vendor score.

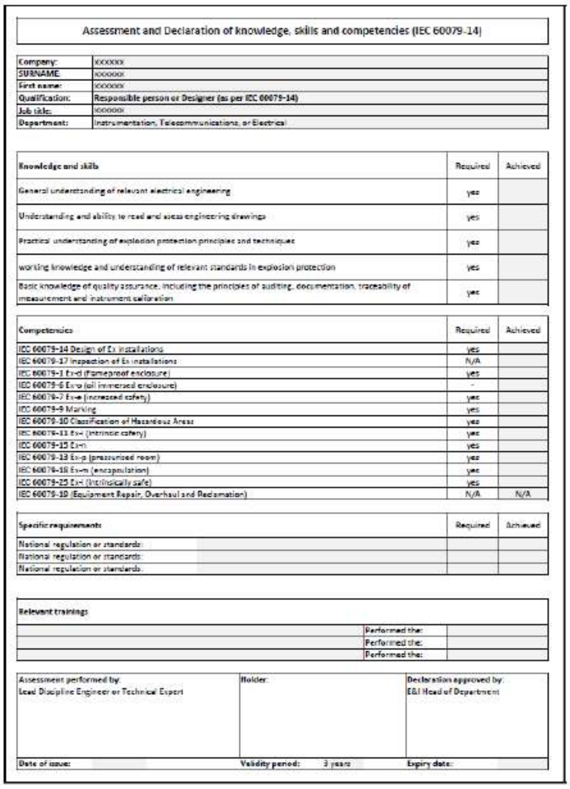
VI. EPC CONTRACTOR PERSONNEL COMPETENCY

Selected E&I and Telecommunications engineers (responsible persons) or designers (specifying, requisitioning, or reviewing technical vendor documentation) with apparatus located in a hazardous area shall be able to demonstrate their competencies and to provide evidence of attaining the knowledge and skill required to select and design installation of Ex equipment.

The competencies and qualifications of personnel involved in "Ex" equipment shall fulfill the requirements specified in the IEC 60079-14 (Annex A: Knowledge, skills and competencies of responsible persons, operatives and designers) relevant to the types of protection and/or types of equipment involved.

A competency Matrix allows the identification of potential gaps to be filled in for ensuring competence of the engineers (responsible persons), operatives, designers, dealing with "Ex" equipment on Project.

An example of competency matrix is given below:


Assessment and Declaration of knowledge, skills and competencies (IEC 60079-14)

Company:	xxxxxx
SURNAME:	xxxxxx
First name:	xxxxxx
Qualification:	Responsible person or Designer (as per IEC 60079-14)
Job title:	xxxxxx
Department:	Instrumentation, Telecommunications, or Electrical

Knowledge and skills	Required	Achieved
General understanding of relevant electrical engineering	yes	
Understanding and ability to read and asses engineering drawings	yes	
Practical understanding of explosion protection principles and techniques	yes	
working knowledge and understanding of relevant standards in explosion protection	yes	
Basic knowledge of quality assurance, including the principles of auditing, documentation, traceability of measurement and instrument calibration	yes	

Competencies	Required	Achieved
IEC 60079-14 Design of Ex installations	yes	
IEC 60079-17 Inspection of Ex installations	N/A	
IEC 60079-1 Ex-d (flameproof enclosure)	yes	
IEC 60079-6 Ex-o (oil immersed enclosure)	-	
IEC 60079-7 Ex-e (increased safety)	yes	
IEC 60079-9 Marking	yes	
IEC 60079-10 Classification of Hazardous Areas	yes	
IEC 60079-11 Ex-i (intrinsic safety)	yes	
IEC 60079-15 Ex-n	yes	
IEC 60079-13 Ex-p (pressurized room)	yes	
IEC 60079-18 Ex-m (encapsulation)	yes	
IEC 60079-25 Ex-i (intrinsically safe)	yes	
IEC 60079-19 (Equipment Repair, Overhaul and Reclamation)	N/A	N/A

Specific requirements	Required	Achieved
National regulation or standards:		
National regulation or standards:		
National regulation or standards:		

Relevant trainings		
	Performed the:	
	Performed the:	
	Performed the:	

Assessment performed by: Lead Discipline Engineer or Technical Expert	Holder:	Declaration approved by: E&I Head of Department
Date of issue:	Validity period: 3 years	Expiry date:

Competency will be assessed by the Lead Discipline Engineer and/or Technical Expert, and approved by the E&I Head of Department.

A pool of 4 Experts have been trained to be trainers based on a recognized Certified Body referential. Trainers hold the Certified Body certificates.

More than 100 engineers have been trained within three years, mainly E&I engineer but also non-technical personnel like project or quality managers, and each of them has received a nominated Certified Body certificate valid for two years.

For Inspection activities, it is recommended to select a recognized certified personnel IECEx CoPC Ex08, Compex Ex04, or equivalent. But this mainly driven by customer requirement according to its own procedures.

VII. EX EQUIPMENT INSPECTION

Prior to Inspection, Ex register and Verification Dossier shall be in place and approved, as per Inspection and Test Plan requirements.

Moreover, in order to detect and fix any “Ex” related issues, EPC CONTRACTOR should, at different stages of the project, check through surveys and inspections, that the construction, installation, and inspection of these Ex Equipment are in accordance with the “Ex” requirements. Inspection plan should reflect with adequate Hold points.

Ex Inspector shall get from Engineering all relevant documents to perform the Inspection.

Prior to the final inspection (before shipping), Vendor Inspectors shall use Initial Detailed Inspection (IDI) Ex check sheets identical to the ones provided in IEC 60079-17 - Tables 1,2,3 or using the project template to assess the compliance with regard to the IEC 60079 (series) requirements for each Ex item.

The inspections shall be based on the "D" detailed grade of inspection columns from Tables 1,2,3."

Level of sample inspection check by CONTRACTOR Inspectors will be set based on:

- previous experience with the selected vendor regarding Ex matters,
- level of competency of Vendor Inspectors,
- level of quality of Ex information on Engineering vendor documents.

Some of the items which need to be systematically addressed during the final inspections with EPC CONTRACTOR are listed below:

- During (or prior to) this inspection, the manufacturers shall also provide satisfactory evidence that they have put in place some specific action / carried out detailed inspections for ensuring that the Ex rated Electrical, Instrumentation, Telecommunications equipment, components and Instruments of the package have been installed / integrated in the package according to the “Ex” requirements and Project specifications.
- “Ex” register with regard to the Equipment actually installed in the package, including all relevant documentation and vendor redline markups.
- Temperature range of marking in accordance with project ambient temperature range
- For cables glands, sample inspection of the glands can be a first step. But if too much non-conformities are found, a more detailed inspection would provide a clear status of the manufacturer’s quality/performance for cable glanding.
- Cables insulation measures
- Cables wiring into Junction Boxes
- Earth bonding according to project standards

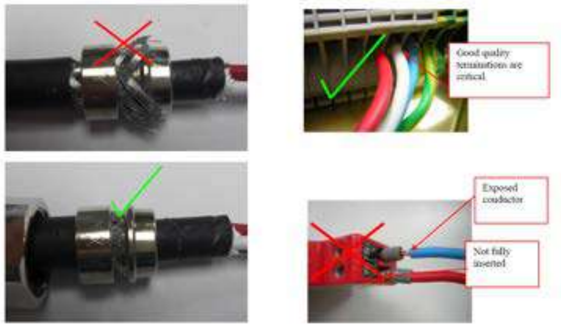
The following guide should be used when transferring a non-compliance to the Punch List during an Ex Inspection. If the non-compliance affects the integrity of the Ex protection technique and where the non-compliance increases the risk that the integrity of the Ex protection technique is affected, this shall be defined as a Punch List Category "A" and the inspection check sheet won't be signed off.

Such examples of a punch list Category "A" could be, but not limited to, the following:

- Damaged equipment affecting the IP rating / Ex protection technique
- Heat Dissipation Calculation and/or IS Calculation / Simple Apparatus Assessment not completed
- Cable glanding not completed correctly or internal seal damaged
- IECEx CoC not available or ATEX declaration not provided
- Broken terminals
- Thread Sealant used on Ex-d flame paths
- Incorrect crimping
- Damaged Flame paths on Ex d
- IP seals damaged or missing on Ex e
- Incorrect fasteners or covers' screws/bolts missing, damaged or of incorrect type
- Not compliant to special condition "x" of certificate
- Missing Ex certified plugs on free opening
- Missing or wrong Ex nameplate
- Where a temporary cable for the space heater is connected, Ex inspection will be accepted for subsystem construction completion but a final inspection will be carried out before the energization.

If a non-compliance does not affect the integrity of the Ex protection technique and there is no risk that the integrity of the Ex protection technique could be affected, then this shall be defined as a punch list "B" or "C" and the inspection check sheet can be signed off.

This should be carefully evaluated on a case by case basis and it is a major reason for using certified and experienced inspector to make this evaluation.



VII. COMPLETION DATABASE

During Construction and Commissioning activities, Ex documents are collected and maintained in the completion database.

Where initial detailed inspections have been completed and signed off during the project completion phases, no further inspections are required for at least three years after the Ex equipment is actually put in service i.e. energized and the areas of the facility have become hazardous; as defined in IEC60079-17.

Typical examples of number of Ex tags in completion databases:

- North Sea Platform: 28 000 tags
- FPSO: 65 000 tags
- FLNG: 88 000 tags

VIII. CONCLUSION

Management of Ex matters in project is a complex and transverse activity, impacting all stages of the project from specification and procurement to final inspection and start up.

The EPC Contractor scope of work and its limit for management of explosive atmosphere matters shall be clearly identified in the contract and dully agreed with customer from the very beginning.

Then, a number of competent people dully confirmed shall be assigned to the project to ensure full compliance to ATEX/IECEx schemes. However standard do not define the way this competency must be certified. So from the beginning of the project, method for this assessment shall be agreed between contractor, customer and also notified body or local authorities in charge of final plant acceptance for operation.

The cost and schedule impacts of Ex matters for EPC Contractor shall be carefully integrated in the overall costs of the project as it can be quite significant, but anyway less than complete reinspection of a fully complete plant as inspections on basic package or vendor competency has been incorrectly managed.

IX. REFERENCES

[1] IEC 60079-14 Explosive atmospheres - Part 14: Electrical installations design, selection and erection.

[2] IEC 60079-17 Explosive atmospheres - Part 17: Electrical installations inspection and maintenance

X. VITA

Lénaïc Fesnières has more than 20 years' experience in the field of instrument installation engineering & detailed studies, in particular in Chemicals, Petrochemicals, Oil Refining, Gas Treatment, LNG trains and onshore & offshore units LSTK projects.
Extensive experience of leading instrument installation studies, within the context of multi-national joint ventures, from the conceptual and basic design to the detailed engineering.
Focal point on Ex matters for various major EPC projects.
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Philippe Angays has a master in Electronics and Electrical Engineering and a specialization in Robotics at the University of Science of Lyon. He worked as engineer for industrial robotic applications. In 1991, he joined 2H Energy, a major gensets builder in Oil & Gas applications. He managed the design department for special applications, like black-start and emergency electrical systems for installations such as FPSO or offshore platforms. He joined the electrical department of Technip in 2005 as expert engineer for power plant applications. He his now a Technology Expert Fellow for electrical matters for Technip Energy worldwide.

Large Battery systems to help LNG plants cut their carbon footprint

Paper No. PCIC Europe EUR21_20

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Abstract - The Paris Climate Agreement has set the long-term vision for the management of Green House Gases (GHG). For the LNG industry, it means a significant reduction in carbon footprint. The electrical power generation for LNG plant typically has a spinning reserve philosophy of “N+1” Gas Turbine Generators (GTGs). An abatement opportunity is the replacement of part-load GTGs with a Battery Energy Storage System (BESS), allowing the plant to turn off the operating spare power generation unit and operate as (N+BESS). By doing this, the remaining units will operate at higher load and consequently at a higher efficiency.
This paper examines the technical aspects of deploying a large BESS, based on Li-ion batteries, into onshore LNG plants. For an example feed gas constrained plant, the benefits are:
1. GHG and NOx reduction
2. GTG running hours reduction
3. LNG production increase
4. Improved power quality and faster dynamic response

The aspects addressed in the paper are:
1. Will it work? The functionality of the BESS to stabilize the electrical system in case of a trip of the running GTG.
Is it safe? The safety aspects of a large-scale BESS installed on an operating LNG plant.

I. INTRODUCTION

Many LNG plants are in remote locations where the local electrical power grid has insufficient capacity to provide the required operating power, which can be up to hundreds of megawatts, with the necessary availability and reliability. LNG plants, therefore, often generate their own power.

To deal with the planned and unplanned downtime of the power generation unit, an LNG plant has a “spinning reserve” philosophy of at least N+1 operational gas turbine generators so that a trip of one power generation unit does not cause a total power failure. There is often an even higher margin between the operating power generation capacity and the electrical power load demand to enable the power system to recover from a trip of one unit, as the units have limited ramp-up rates and ability to deal with step changes in load. This results in lightly loaded and, hence, less efficient gas turbine generator operation (part-load efficiency can be less than half of full-load efficiency). This configuration provides a highly available power generation system at the expense of cost and greenhouse gas intensity.

An extreme case of the spinning reserve philosophy is shown in Figure 1(a). Two gas turbine generator units are each running (N = 1) at 40% load (the spare unit is offline) so that a trip in one unit will cause the other to ramp up to 80% load while still retaining some margin between its capacity and the plant load. Figure 1(b) shows two offline units and the running unit loaded to 80%. In this case, the spinning reserve is provided by a BESS sized to supply the power for the LNG plant for the period necessary to restart the tripped unit or to start one of the offline units.

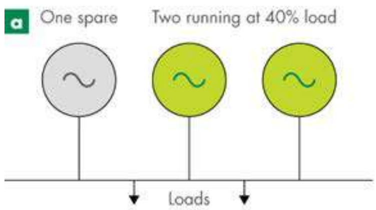

Figure: 1(a) N+1 gas turbine generators

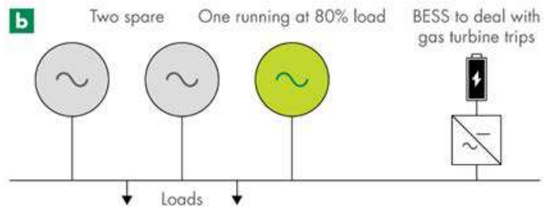

Figure: 1(b) N gas turbine generators + 1 BESS

II. BESS COMPONENTS

Current commercially available BESSs are mostly based on lithium-ion batteries (Figure 2) controlled using a battery management system.

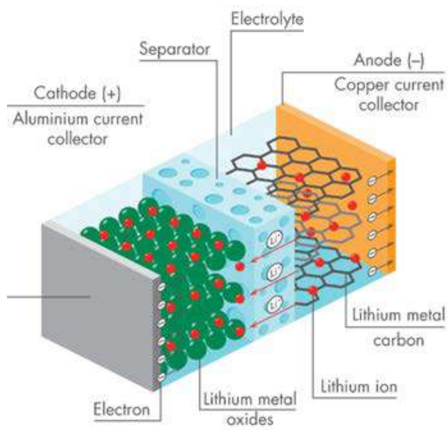

Figure 2: Typical lithium-ion cell construction

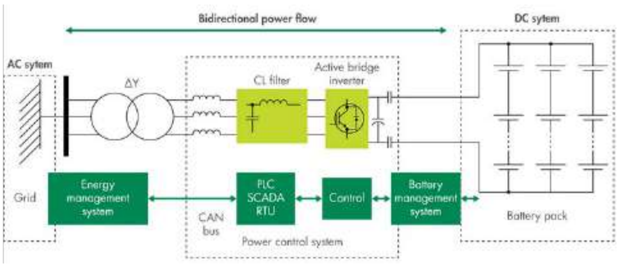

Figure 3: Components of a Battery Energy Storage System

A BESS (Figure 3) has a hierarchical control system. The power management system interfaces with the external power system of the LNG plant (typically 50 or 60 Hz alternating current (AC)) and reacts to commands (i.e., planned events to provide power from the BESS) and to signals (for example, changes in power system voltage and frequency) that indicate a response is necessary to restore control to the power system.

The power control system controls the operation of the inverter, which converts the direct current (DC) from the battery into the AC the LNG plant requires. The AC side of the inverter is connected to the external power system using a step-up transformer to match the voltage. A power system harmonic filter smooths the output voltage waveform for a better sinusoidal output. The power control system also controls the BESS auxiliaries, including other monitoring and cooling systems.

The battery management system controls the lithium-ion cells and modules that form the battery. This system has a high safety integrity level, depending on the type of lithium-ion cell chemistry, and contains a set of redundant measurements and actuators to protect the battery cells against out-of-range voltages, currents and temperatures that could lead to a cell or module thermal runaway. This is a self-sustaining, highly exothermic chemical reaction that can cause extremely high temperatures, produce flammable and toxic gases, and, eventually, result in a fire.

Commercially available BESSs may be highly modular, with each container providing 2–4 MWh of power and including the cells, inverters and auxiliaries for cooling.

III. BESS INTEGRATION INTO LNG PLANTS

When looking at BESS integration into LNG plants, the team considered two basic questions: does a BESS have the functionality to stabilise the electrical system if a power generation unit trips; and is it safe in an operating LNG plant?

A. BESS FUNCTIONALITY

Electrical system studies were carried out to confirm that a BESS could react sufficiently fast to stabilise the electrical system of an LNG plant in case of a trip of a running power generation unit.

When a power generation unit trips in a traditional island power system (see Figure 1a), there is an imbalance between the electrical load and the generated power that causes the frequency of the system to fall. The inertia of the remaining connected units and the rest of the rotating electrical machines (mainly motors) determines the rate at which the frequency falls before the governor control systems of the power generation units act to increase the generated power to restore the frequency. The more spinning reserve there is in the system, the higher the inertia and the smaller the proportional response of each power generation unit.

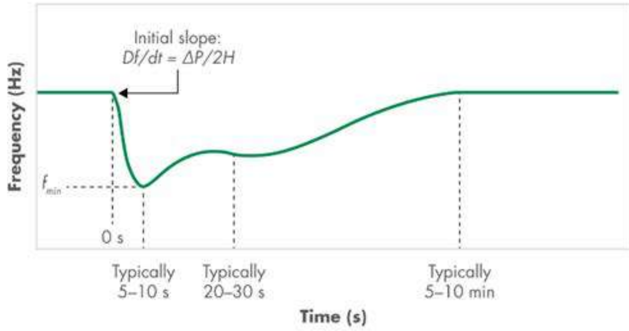

Figure 4: The response of a conventional power generation system after a power generation trip.

Replacing the spinning reserve in part or in whole with a BESS changes the way the electrical system reacts. There is less inertia, which means that the frequency falls faster, but the power electronics and control systems in the BESS can act much faster than those of conventional turbine or engine-driven generators. The BESS response is fast and stabilises the electrical system within a few milliseconds. Figure 4 shows a typical response for conventional power generation system.

Figures 5(a–d) show the system response from a standby BESS when the running gas power generation unit trips. Note that in this configuration, the BESS is operated in parallel with a single GTG, see Figure 1b. After the GTG trips, the BESS is the only active source in the system. The BESS can stabilize the electrical system by generating the voltage and frequency set points as long as the inverters are "grid forming" type. For "grid following" inverters, it is necessary that another power source stays connected to the grid to provide voltage and frequency set points.

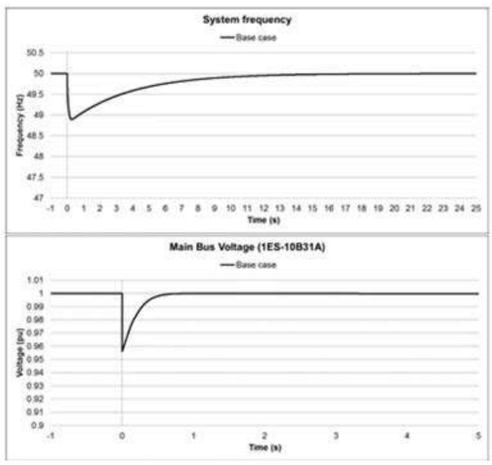

Figure 5: The response of a system with a BESS after a GTG trip: (a) system frequency, (b) main bus voltage

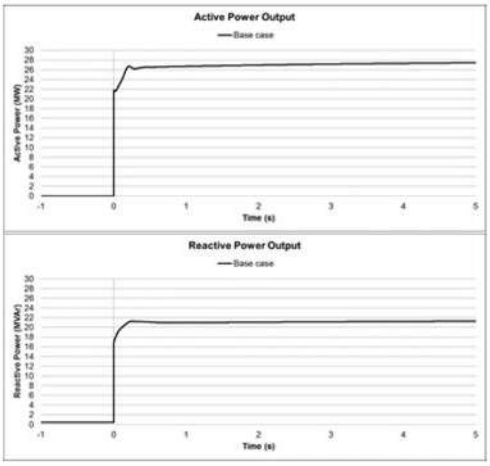

Figure 5: The response of a BESS after a GTG trip: (c) active power output, (d) reactive power output

The BESS delivers active power (megawatts) and reactive power (volts) support to the system more than five times faster than a conventional power generation unit could.

One of the drawbacks of this fast response time is that the BESS effectively acts as an isochronous control unit: it reacts to every load starting or stopping yet still maintains near perfect control of the power system frequency and can have a comparable effect on system voltage. To prevent this from happening, a control system is necessary to provide a suitable deadband so that the BESS only responds to significant events on the power system and does not operate continually. Adequate battery autonomy time is required, for example, 30–60 min, to allow long enough for starting up a second gas turbine generator or restarting the tripped unit.

As an example, at Alinta Energy's Newman gas-fired power station in Australia, a 30-MW BESS successfully took over the complete load after a trip in an external feeder within 10 ms. The power station supplies mining operations.

The main difference between such units and those used in large power grids in North America and elsewhere is the ability to do "grid forming" to control the system frequency and voltage, which is necessary when the BESS is to operate to supply the load on its own.

This capability is currently limited to vendor-supplied models only; a global power industry working group called MIGRATE (www.h2020-migrate.eu) is leading work to study and model what happens to power systems when supplied only by inverter-based power generation systems such as a BESS.

Traditional electrical protection systems based on the detection of the high current that flows during a fault (the principle of operation of a fuse or circuit breaker) are ineffective when considering inverter-based power generation, as the normal load current is not very different from that flowing during a fault. Consequently, different electrical protection philosophies and equipment are needed.

The harmonic content of the system (a measure of how pure the sinusoidal waveform is for the AC voltage) is difficult to estimate during the engineering phase and to control during operation; this requires detailed analysis when the specifics of the equipment are known.

Simple modelling of the inverter-based generation does not adequately address how BESS reacts to events such as the energisation of large transformers. Figure 6 shows typical voltage and current waveforms for the system when a large power transformer is energised. In this situation, the BESS might detect and interpret the current imbalance as an electrical system fault and thus shut down, which would lead to a total power failure; again, more detailed analysis and modelling are required for project deployment.

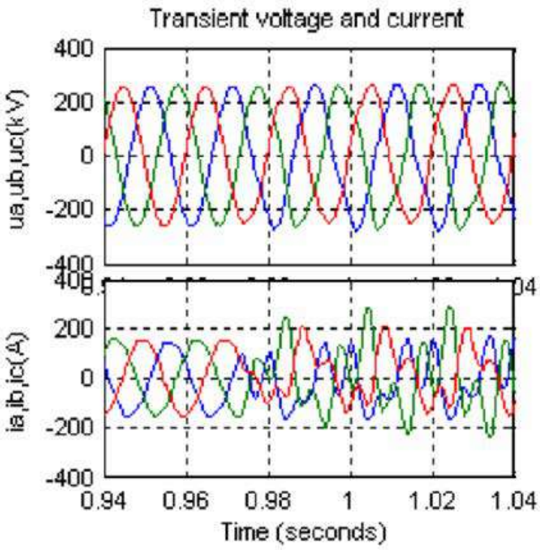

Figure 6: Typical voltage and current waveforms associated with power transformer energisation.

The connection of large numbers of inverters on the same system, for example, a BESS, some solar photovoltaic power generation and variable speed drive units for motor control, could lead to small signal instabilities.

B. BESS SAFETY

Lithium-ion battery technology is the current choice for deployment in utility and industrial systems. Figure 2 shows the structure of a typical lithium-ion cell; the direction of the flow of ions and electrons is shown with the battery discharging.

Lithium-ion battery chemistry offers several advantages over other types of energy storage and battery chemistry for grid and industrial system applications, the main ones being low losses, (relatively) low cost per megawatt-hour and the widespread availability in the sizes (1–50 MWh) being considered.

Lithium-ion batteries have an associated inherent risk of thermal runaway. To evaluate the risks, a coarse hazard identification (HAZID) was undertaken that was initially agnostic to battery chemistry. This identified the following safety risks associated with the use of a large BESS in an LNG plant: thermal runaway, toxicity, flammable gases, electrocution and arc flash. The electrocution and arc flash risks associated with large battery systems are familiar to electrical engineers, as most sites have uninterruptible power supply units connected to large batteries. The major difference is the number of battery cells involved and, therefore, the potential fault current that would flow. There are some industry standards to reflect the phenomena associated with DC arcs and to calculate the arc flash incident energy.

The risk of thermal runaway was analysed by reviewing available test results and literature and by evaluating vendors' protection systems. The conclusion was that the risk associated with a BESS can be mitigated to as low as reasonably practicable. Measures for avoiding thermal runaway and fire include the design of the battery cell, module and rack layout, and the battery management system.

Some scenarios, such as a battery internal short circuit, an external short caused by water or liquid or external heat input, cannot be mitigated by the battery management system. Although such scenarios have a low incident frequency, the battery module design needs to ensure that a thermal runaway in a single cell does not propagate to adjacent cells or modules and subsequently a whole rack or container. The UL 9540A test method and IEC 62619:2017 standard describe methods to test and validate this and should be included in the project specification.

In a thermal runaway situation, flammable and toxic gases are released that could lead to an explosion or fire and/or affect human health.

The risk can be partly mitigated by:

- installing a gas detection system, for example, hydrocarbon gas detection or very sensitive smoke detection system, appropriate to the battery chemistry in co-operation with the vendor or a cell off-gas detection system;
- installing adequate ventilation;
- installing pressure release hatches in the container or housing roof;
- using a firefighting agent to cool down an incipient cell or module fire;
- considering a deluge system to flood the BESS housing with water; however, this might lead to significant quantities of contaminated water and additional short circuits, so controlled burnout might be preferable;
- siting the BESS where fire propagation has limited impact; and
- training firefighters and operations and maintenance staff on recognising and responding to a BESS thermal runaway and fire.

IV. BUSINESS CASE FOR A BESS

Having a BESS will enable a plant to turn off, but not necessarily to eliminate, the operating spare power generation unit and to operate as an N + BESS configuration. With fewer machines operating, the remaining units will run at a higher load and, consequently, higher efficiency. This reduces the total fuel consumption, associated greenhouse gas and nitrogen oxide emissions, machine running hours and operating and maintenance costs. This will also increase LNG production at feed-gas constrained plants.

Screening studies have shown that having a BESS at an operating plant could mean:

- a carbon dioxide emissions reduction of about 20% from the power generation facilities and of 1–3% of the total LNG plant emissions;
- up to a 50% reduction in the gas turbine generator running hours (cumulative) with an associated maintenance cost reduction;
- an LNG production increase;
- a positive net present value or value–investment ratio; and
- improved power system voltage quality and fast dynamic responses to load changes in the electrical distribution system.

V. CONCLUSTION

Battery energy storage has multiple applications in the oil and gas industry, and greenhouse gas abatement by replacing the conventional spinning reserve in power generation is just one. With battery costs continuing to fall, it is hoped that more opportunities for deployment will be identified and progressed.

VI. VITA

Paul Donnellan

Paul Donnellan is a principal electrical engineer with Shell Projects & Technology in the Netherlands. He joined Shell in 2002, having previously worked for National Power and Esso Petroleum in the UK. Paul has a BEng in electrical engineering from Southampton University, UK

Arie Bal

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ELECTRIC MOTOR FAULT DIAGNOSIS BASED ON THE ADVANCED ANALYSIS OF THE STRAY FLUX

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Abstract - This paper presents the most novel research concerning the application of modern technologies for condition monitoring of electric motors based on the advanced analysis of the stray flux. The analysis of the magnetic field in the vicinity of the motor has proven to provide very useful information for the diagnosis of several failures. This technique has drawn recent attention due to the advance in the technology of the necessary sensors, simplicity, non-invasive nature and low cost. The paper presents the different variants within this technology, including the classical method based on the stationary analysis of the flux as well as recent techniques relying on the advanced analysis of transient flux signals. The paper includes experimental results in motors with different failures and proves the potential of this technology for becoming a reliable source of information for the determination of the motor health.

Index Terms — Induction motor, Fault diagnosis, Stray flux, Transient analysis, Reliability, Rotor, Eccentricity.

I. INTRODUCTION

Electric motor reliability is a matter of increasing concern in the industry due to the vast participation of these machines in processes and applications which are often critical in the plants where they take part [1]. Therefore, proper maintenance strategies must be adopted to maintain these machines in suitable conditions in order to prevent unexpected outages and subsequent production downtimes. According to some surveys [2], maintenance costs may account for 15-40% of total cost of production for petrochemical industries. This gives an idea of the relevance of this area in petrochemical facilities, where electric motors play an especially prominent role due to the critical nature as well as to the safety requirements of the processes taking place at these sites.

Different types of failures may occur in an electric motor. Rotor faults, eccentricities, bearing damages, degradation of the stator insulation or core faults are some of the failures that may take place in induction motors [1], the most widespread type of electric motor in industry. The consequences of the occurrence of these faults are very negative leading even to catastrophic effects on the machine itself that may have severe repercussions for the process where they operate. Fig. 1 shows some examples of catastrophic faults that led to forced motor outages [3]. Most of them are referred to H.V. motors.

Fig. 1 Catastrophic faults in induction motors [3]

Over recent decades, many researchers both in academia and in industry have worked in the development of reliable techniques able to diagnose the previous faults when they are still in their early stages of development, so that proper maintenance actions can be adopted before the machine collapses. These techniques rely on monitoring specific motor quantities and on their subsequent analysis to detect possible evidences of the presence of the failure. In this regard, electrical monitoring (currents, voltages), mechanical monitoring (vibrations), thermal monitoring (internal temperature, infrared data), partial discharge monitoring or even acoustic (noise, ultrasounds) and chemical monitoring have been proposed as a basis of the developed techniques [3]. In spite of this dynamic activity, one of the most important conclusions derived from this vast work is that none single technique or quantity has proven to be enough reliable to diagnose, alone, the condition of the whole motor. In other words, each specific quantity is valid for diagnosing certain faults but not for others. And, even for the faults that it can better diagnose, there may be cases in which false alarms or erroneous diagnostics can be derived from the use of a specific quantity [4]-[6]. Therefore, the best solution seems to be to combine the information coming from different diagnosis methods, so that a more reliable conclusion on the motor condition can be obtained. At the same time, investigation of new techniques that enable to overcome the diagnosis provided by the already existing ones is another way to reach a more reliable diagnostic of the motor health.

In this context, the analysis of the external magnetic field and, more specifically, of the stray flux at the vicinity of the electric motor is drawing the attention of many researchers and companies worldwide, due to the interesting advantages that this diagnosis technique provides [7]–[9]: on the one hand, it is a non-invasive approach, since the registration of the necessary data can be carried out without perturbing the normal operation of the motor. Moreover, the necessary equipment for the registration of this quantity is simple, it has low cost and it has had a spectacular development over recent years with regards to the features of the necessary flux sensors [8]. Furthermore, previous works have proven the potential of the stray-flux-based technique for obtaining relevant information for the diagnosis of certain faults such as stator short-circuits [10]-[11], rotor problems [12]-[13], eccentricities [14]-[15] of even coupling system problems [16]. Some well-known manufacturers have started building coil sensors for fault diagnosis which rely on this technique.

Note that, due to the recent dynamic research activity, the former approaches for stray-flux data analysis that were based on the Fourier analysis of stationary signals [10]-[15] are being complemented by more modern and robust technologies that rely on the advanced analysis of the stray-flux data under transient operation of the machine (e.g. the motor startup). Recent works have proven the potential of transient analysis of the stray flux which has provided excellent results for enhancing the diagnosis of some of the aforementioned failures in several types of electric motors, such as cage induction motors or wound rotor induction motors [17]-[19], avoiding some drawbacks of the conventional methods. The application of transient analysis requires the use of more advanced and sophisticated signal processing tools that are suitable for the analysis of non-stationary quantities (time-frequency transforms).

This paper reviews the different fault diagnosis approaches relying on stray flux analysis, including both the classical methods based on steady-state analysis as well as the recently introduced technologies that rely on the analysis of stray flux data under transient regimes. The paper includes several experimental cases that demonstrate the suitability of both approaches for the detection of certain faults in induction motors.

II. STRAY FLUX DATA ANALYSIS FOR FAULT DETECTION

In its more widespread modality, the diagnosis technique based on stray flux data analysis relies on installing a coil sensor on the external part of the motor frame [7], [12]. The dispersion flux created by the motor during its operation (stray flux) induces an electromotive force (emf) in the sensor; the waveform of this emf can be easily registered with the aid of an oscilloscope or waveform recorder. The proper analysis of that emf signal enables to detect evidences of the presence of faults in the motor. To this end, suitable signal processing tools must be applied, depending on the operation regime under which the emf has been captured (steady-state or transient).

One of the most important characteristics of this diagnosis technique is that its results are strongly influenced by the sensor position. This is due to the fact that, depending on the position of the sensor, a higher portion of axial or radial flux will be captured and, hence, the corresponding fault components (axial or radial) will be better observable when the emf signal is analyzed. Fig. 2 depicts three typical locations of the flux sensor on the motor frame [7],[20]: at position A, a higher portion of axial flux is captured and, therefore, fault components with axial nature will be better noticeable in the results of the analyses. On the contrary, at position C, the captured stray flux is primarily radial and, consequently, the radial components will be better observed. Finally, at position B, a mixture of axial and radial flux is captured by the sensor and all components can be observed in a certain level.

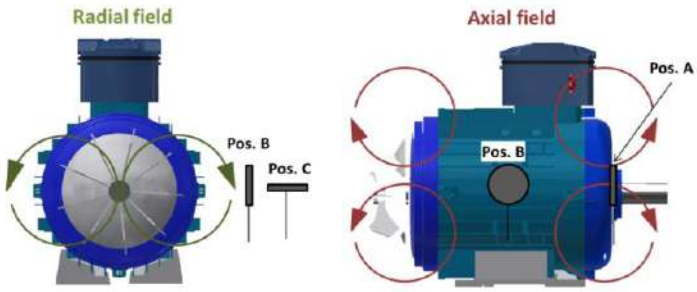


Fig. 2 Nature of the flux captured at each coil sensor position [20].

A. Classical method (steady-state)

In the early 2000's several authors proposed the analysis of the stray flux data under stationary conditions as a way to detect several faults in induction motors [11], [13], [21]. The idea of these methods was to analyze the data representative of the stray flux (e.g. the emf induced in an external sensor) at steady-state by applying the Fast Fourier Transform (FFT). It is well-known that this transform extracts the frequency components present in the analyzed signal as well as their corresponding amplitudes (in other words, the FFT is an amplitude vs. frequency representation of the analyzed signal). The idea of this conventional approach is that, when a certain fault is present in the motor, specific frequency components will be amplified in the FFT spectrum. Therefore, the evaluation of the amplitudes of these components enables to diagnose the presence of the failure in the machine.

More specifically, several authors proved that, in the case of rotor damages, the components given in Table I are amplified in the FFT spectrum of the emf [7], [21] (f=supply frequency and s=slip). Note that, according to that table, some of the rotor fault components have an axial nature, while others have a radial nature. Hence, depending on the location of the flux sensor that is employed, one or the other will be better observed in the resulting FFT spectrum of the registered emf signal.

TABLE I
FREQUENCY COMPONENTS AMPLIFIED BY ROTOR DAMAGES IN THE FFT SPECTRUM OF STRAY FLUX

Component	Nature	Comments
$f\cdot(1\pm2\cdot s)$	Radial	
$s\cdot f$	Axial	May be also amplified by eccentricities/misalignments
$3\cdot s\cdot f$	Axial	May be also amplified by eccentricities/misalignments

On the other hand, other authors stated that, in the event that eccentricities are present in the motor, the components given in Table II are amplified in the FFT spectrum of stray flux data [14]. In the expression written in that table, p stands for number of pole pairs and m=1,2,3…Hence giving values to m, different pairs of frequency components are obtained, the most relevant being those for m=1.

TABLE II
FREQUENCY COMPONENTS AMPLIFIED BY ECCENTRICITIES IN THE FFT SPECTRUM OF STRAY FLUX

Component	Nature	Comments
$f \cdot (1 \pm m \cdot (1-s)/p)$	Radial/axial	May be also amplified by rotor faults

Other authors provided similar expressions for the components amplified by other faults and anomalies such as bearing faults, gear problems or even stator short-circuits [10]-[15].

B. New approaches (transient)

Recently, an alternative diagnosis approach relying on the analysis of stray-flux data has been introduced [17]-[18]. Unlike the previous FFT-based method, the new approach relies on the analysis of stray-flux data that are registered under transient operation of the motor. More specifically, the recent works that propose this new methodology have been focused on the analysis of the emf signals captured during the startup transient (i.e. the connection of the motor). It has been demonstrated that under a direct-on-line startup of an induction motor, due to the characteristic variation of the slip s (from s=1, when the motor is connected, to s≈0 at steady-state), the fault-related frequencies described in Section II.A (which are slip-dependent) will also change. Therefore, they will follow characteristic variations over time. The identification of these evolutions is a reliable evidence of the presence of the corresponding failure. As an example, Fig. 3 shows the characteristic time evolutions during a direct-on-line startup of the fault frequencies related to rotor damages and eccentricities (described in the previous section) [20]. If these evolutions are detected, the corresponding faults can be properly diagnosed in the motor.

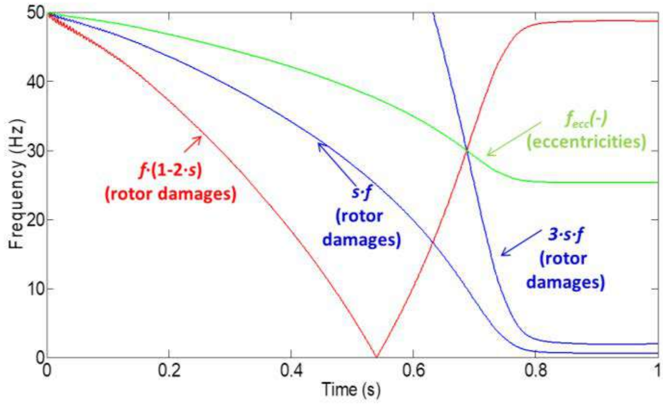


Fig. 3. Expected t-f evolutions of the emf fault harmonics during a direct-on-line startup of the motor.

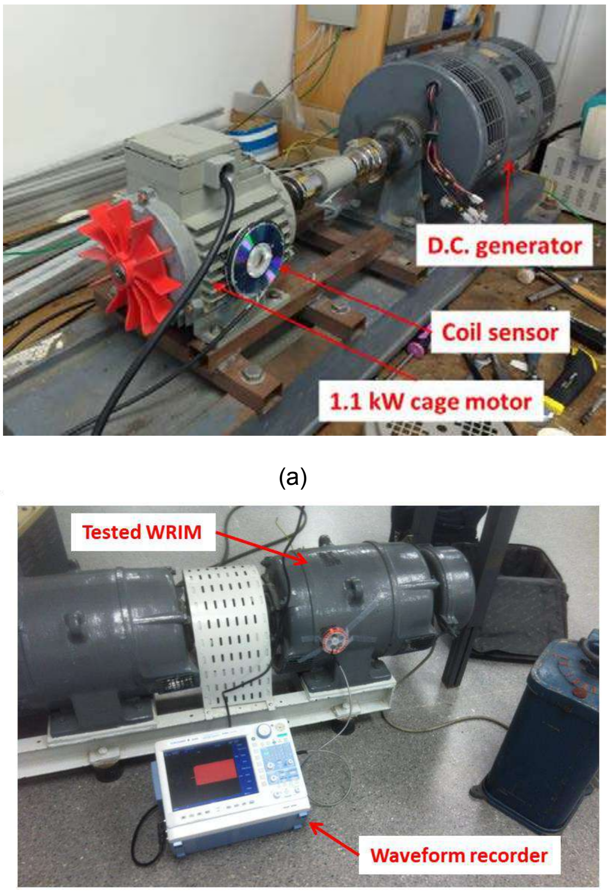
The detection of the evolutions of the aforementioned components under a startup requires the application of sophisticated signal processing tools that are capable to represent not only the frequency components present in the analyzed signal but also how they change over time. These tools are known as time-frequency transforms since they provide, as a result, a time-frequency map that depicts the time evolutions of all frequency components present in the signal. There are several time-frequency transforms that have been optimized and applied in the area of transient analysis (wavelet transforms, Hilbert-Huang-transform, Wigner-Ville Distributions…) [17]. In this paper, the Short Time Fourier Transform (STFT) will be applied since it gives a good tradeoff between computational burden and user availability, despite it requires the previous optimization of the parameters needed for its application. The STFT performs a time-frequency decomposition of the analyzed signal by multiplying this signal by a window function that is moved over time and by computing the FFT at each location of that function. The window function length must be selected by the user depending of the considered problem. In this particular work, a suitable window length has been selected so that the frequency harmonic's evolutions of interest can be properly tracked.

III. EXPERIMENTS

In order to illustrate the operation of the two approaches based on stray-flux analysis described above, different emf signals obtained from experimental tests will be analyzed. The tests were carried out on two different types of induction motors in order to show the validity of the method for a variety of constructive characteristics. More specifically, a cage induction motor (motor 1) and a wound rotor induction motor (motor 2) were tested. The characteristics of these machines are shown in Table III. The test benches used for testing both motors are depicted in Fig. 4(a) and (b). Three different positions of the coil sensor were considered (corresponding to those depicted in Fig.2). Moreover, different types of faults were forced in each of the machines: in motor 1, different levels of rotor damage were forced by drilling holes in the corresponding bars and, also, a certain level of eccentricity was created. In motor 2, different levels of rotor asymmetry were forced by inserting external rheostats in series with the rotor winding, simulating a high-resistance connection of the rotor circuit (this would correspond, for instance, to an uneven contact between brushes and slip rings or a high resistance connection between rotor coils).

TABLE III
CHARACTERISTICS OF TESTED MOTORS

	Motor 1	Motor 2
Type	Cage IM	Wound rotor IM
Rated power	1.1 kW	11 kW
Rated frequency	50 Hz	50 Hz
Rated voltage	400 V	400 V
Rated current	2.7 A	23 A
Rated speed	1410 rpm	1425rpm
Connection	Star	Star
Number of poles	4	4
Rotor slots	28	24
Stator slots	36	36



(a)

(b)

Fig. 4. Experimental test benches for the stray flux data acquisition: a) cage induction motor (motor 1), b) wound rotor induction motor (motor 2).

IV. RESULTS

In this section, the results obtained with the test benches described above are discussed. These results illustrate the usefulness of the approach to detect a diversity of failures both in cage and wound rotor induction motors.

A. Motor 1: cage induction motor

Fig. 5 shows the application of the conventional method based on stray-flux analysis to the cage induction motor [17]. This figure shows the FFT analyses of the emf signals (only the low frequency region is depicted) captured at steady-state, considering three different positions of the sensor (shown in Fig. 2) and three different fault cases: 1) healthy motor, 2) misalignment and 3) motor with 2 broken bars and misalignment. Note how the expected fault components are amplified in the analyses when the corresponding fault is present in the machine. However, these components have different amplitudes depending on the location of the sensor. This is due to the fact that, depending on the nature of the corresponding fault component (axial/radial), its increment when the fault is present will be more evident at the sensor position that enables capturing the flux portion in which it appears.

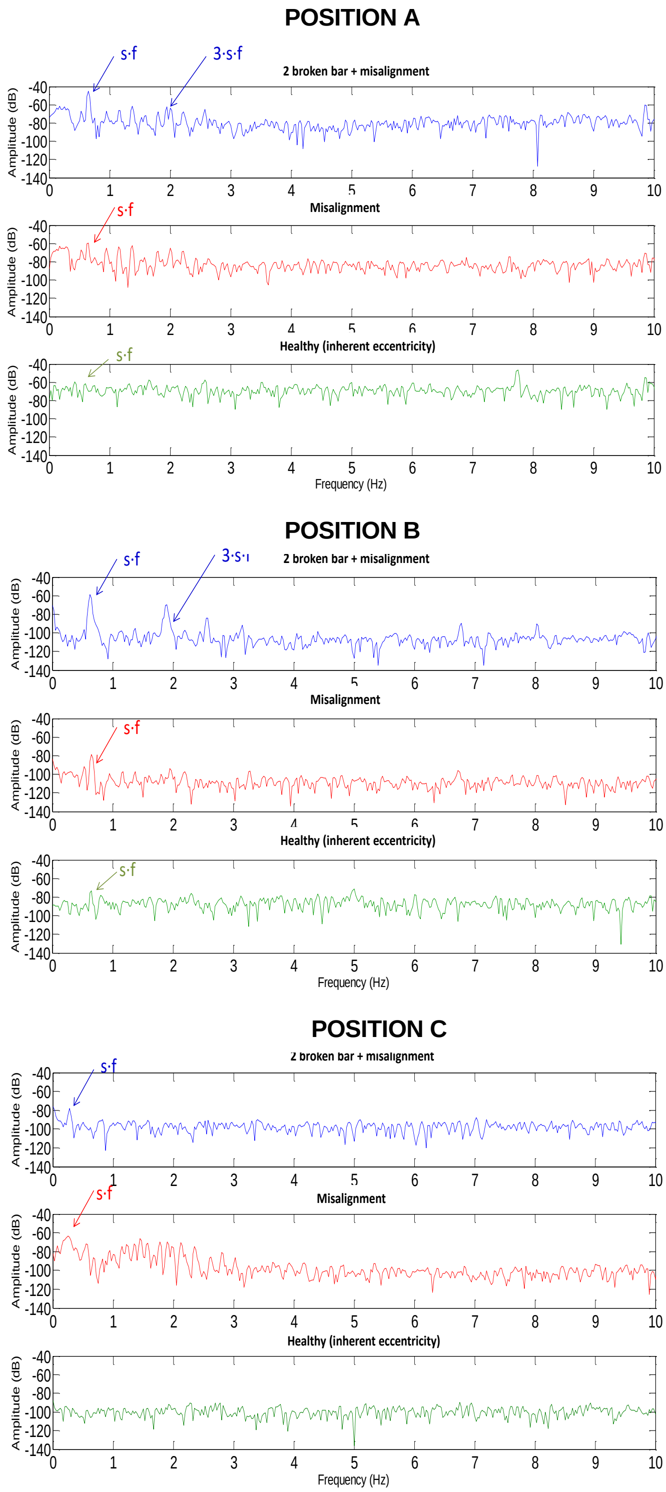


Fig. 5 FFT analyses of the coil sensor signal for the three fault cases and for the three considered positions of the sensor (motor 1).

For instance, in case of rotor damages (broken bars), the axial components $s{\cdot}f$ and $3{\cdot}s{\cdot}f$ will be amplified, among others. As observed in the graphs, these increments are more evident in position A and position B since, at these positions, a higher portion of axial flux is captured. At position C, the captured flux is primarily radial and, hence, these components show little increments when the fault is present. These analyses prove that the technique is able to detect the fault but the sensor location plays an important role on the components amplified by the failure.

On the other hand, Fig. 6 shows the STFT analyses of the emf signals (motor 1) captured during the startup for the three fault cases and sensor positions commented before [17]. Note that the transient evolutions of the fault components (depicted in Fig. 3) are clearly observable in the resulting time-frequency maps: on the one hand, we can clearly observe the evolution of the axial component s·f associated with rotor damages, which is significantly amplified as the fault gets worse (compare healthy motor and motor with misalignment + 2 broken bars). In addition, the evolution of the component f_{ecc} caused by eccentricities/misalignments is clearly observed and, finally, the radial component f_{sb}=f·(1-2·s) evolution is also identifiable at position C, in which a predominantly radial flux is captured. In conclusion, these fault signatures can be used as reliable evidences of the presence of these failures.

B. Motor 2: wound rotor induction motor

Fig. 7 shows the FFT analyses of the emf signals captured at steady-state for the wound motor induction motor, considering three different rotor asymmetry levels and two positions of the sensor (positions A and C). In this figure, the region around the fundamental frequency is depicted. Note the clear increment of the amplitude of the fault component f·(1-2·s) when the fault gets worse. This is visible for both positions of the sensor since this component is radial and at both positions of the sensor a certain amount of radial flux is captured.

Fig. 8 shows the STFT analyses of the emf signals (motor 2), captured during the startup, for the three different levels of rotor winding asymmetry. Note that the components associated to the different faults are clearly visible in the resulting time-frequency maps. Particularly evident is the evolution of the component f·(1-2·s) that increases its amplitude when the fault gets worse, at all positions of the sensor. The axial component s·f is also detectable, especially at position A, that captures the axial flux. Finally, the evolution of the eccentricity/misalignment component at f_{ecc} is also detectable and reveals the existence of a certain level of misalignment between the tested motor and the driven load.

V. CONCLUSIONS

This paper describes the currently existing approaches for condition monitoring of electric motors relying on stray flux data analysis: on the one hand, the classical methods based on the analysis of the steady-state flux data using the FFT and, on the other hand, the new technologies relying on the advanced analysis of stray flux data captured under transient operation of the motor by applying time-frequency tools.

The analysis of the experimental data obtained in the paper enables to illustrate the operation of each approach. Whereas the conventional methods enable the detection of the different faults through the assessment of the amplitudes of the fault harmonics present in the FFT spectrum, the new transient-based technologies rely on the detection of characteristic patterns that are caused by the evolution of the fault components. These latter methods increase the reliability of the diagnosis since these patterns cannot be caused by other phenomena different than the failure, thus avoiding false indications that may appear with the classical methods.

The paper intends to be a first approximation to show the state-of–art in the use of this diagnosis technology which is drawing the attention of certain manufacturers that have recently developed integrated sensors embedded on the motor frame with the aim of providing self-diagnostics capability to the motor. The inherent advantages of this technique, some of them proven in recent works (non-invasive nature, simplicity, higher sensibility for detecting certain faults…) makes it a very interesting option. However, as it is shown in the paper, some issues are still under study, such as the influence of the sensor position on the results or the necessity of further massive validation that enables to set objective fault severity thresholds valid for a wide number of cases.

The method is planned to be applied in the near future to detect damper bar damages in synchronous motors in the range of MW, which are largely used in the Petrochemical industry.

VI. ACKNOWLEDGEMENTS

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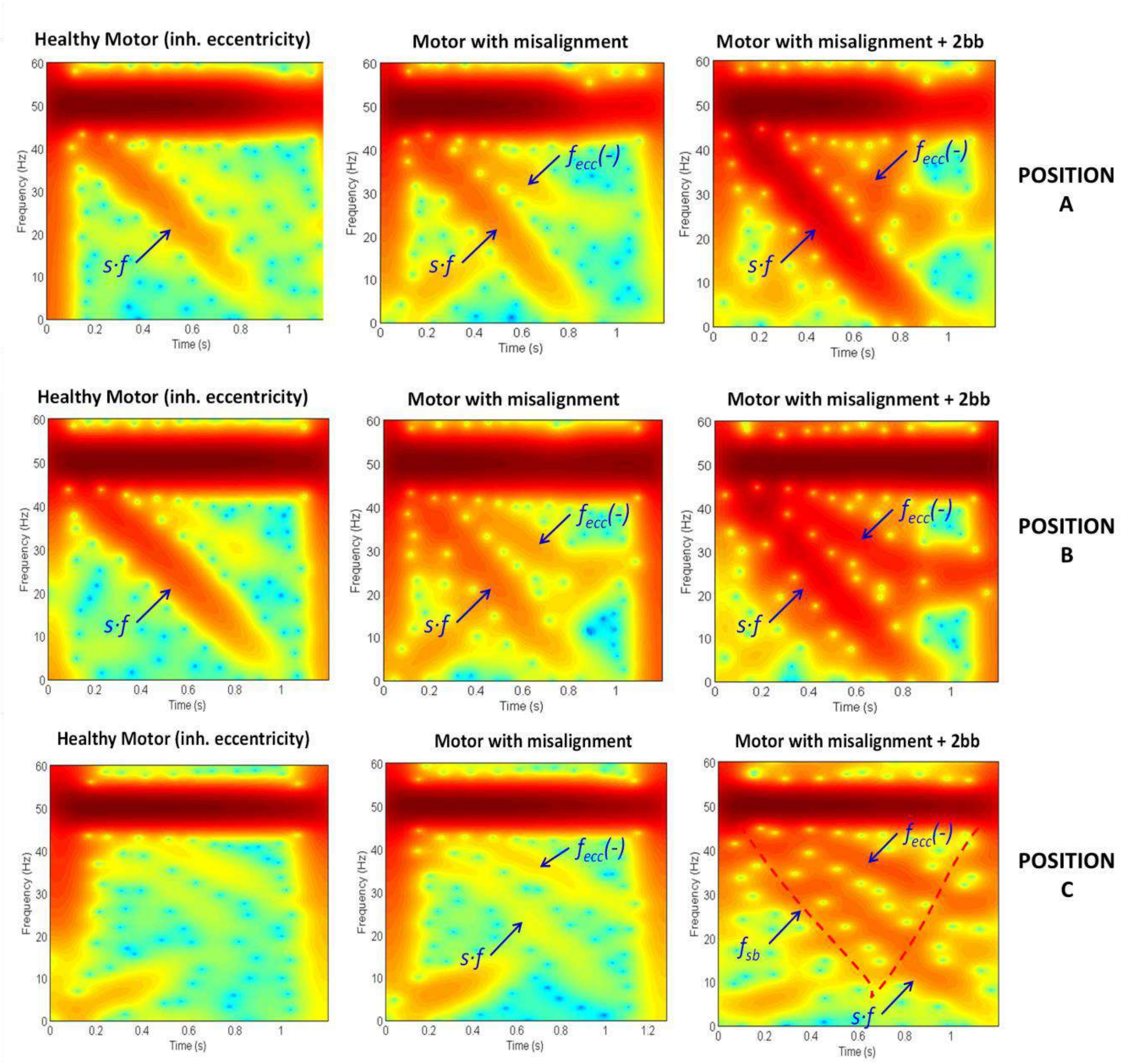
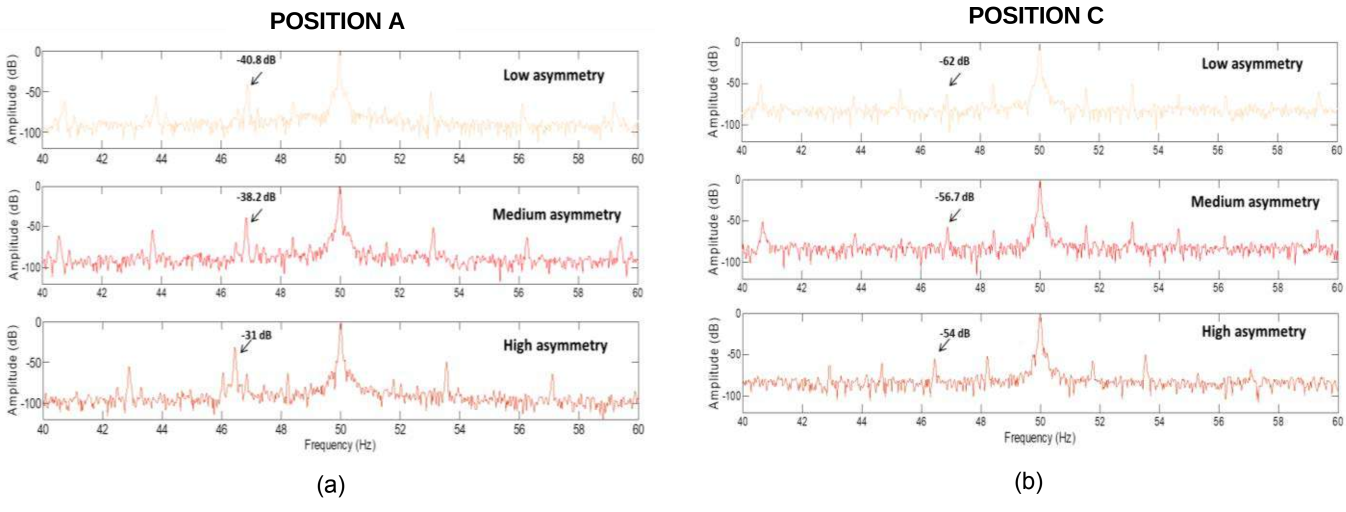


Fig. 6 STFT analyses of the coil sensor signals for the machine (Motor 1) with inherent eccentricity, motor with misalignment and motor with misalignment +two broken bars and for the three considered positions of the sensor (the color denotes the energy density in each point of the time-frequency map, with red=highest density while blue=lowest density).



(a) (b)

Fig. 7. FFT analyses of the steady-state EMF signals for the sensor at positions A and C for the cases of low, medium and high asymmetry (motor 2).

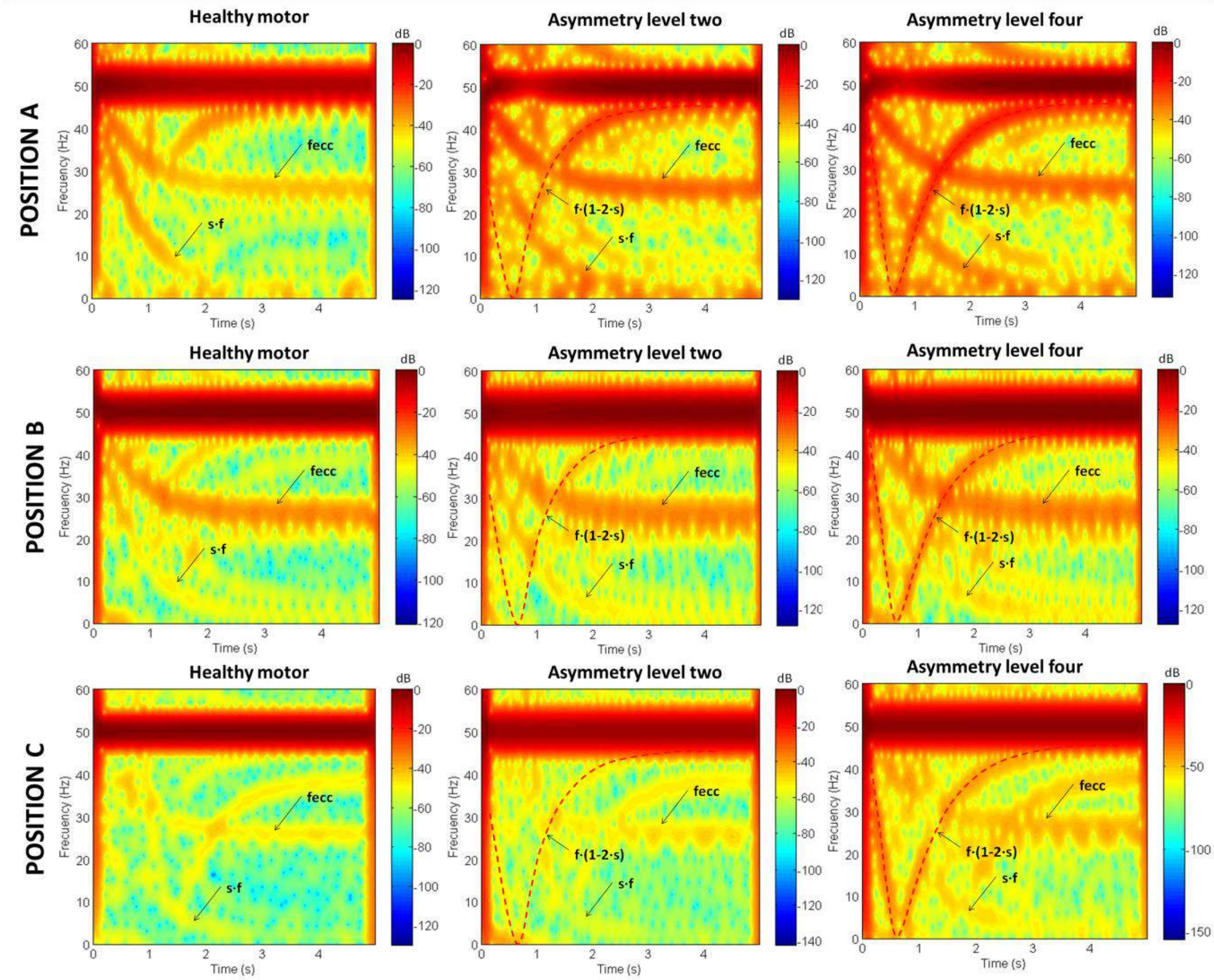


Fig. 8 STFT analyses of the coil sensor signals for the machine (Motor 2) in healthy state, motor with rotor asymmetry level two out of four and motor with rotor asymmetry level four out of four and for the three considered positions of the sensor (the color denotes the energy density in each point of the time-frequency map, with red=highest density while blue=lowest density).

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Digital Twin : What is this animal?

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Abstract - Digital twin (DTW) is today a buzzword in the industry and everyone has a different understanding, comprehensive definition of what it is and what it is for.
The purpose of this article is to explain/define what is a digital twin, to introduce the different types of DTW, with some illustration (aerospace & building).
In a second part, the prerequisites in an engineering organisation to reach the maturity of being able to do a DTW are described (integrated tools, data driven organisation…) and how to manage DTW during a project execution (from front end engineering to hand over to operation, with the added complexity of change orders).
In a third part, the document will focus on digital twin usage for industrial operation:

- What are the customers/operation expectations from engineering : easy single access to the complete project documentation (3D, 2D, process and technical specifications, operational manual, maintenance data and PM linked to MMS...), and to the process simulation part,
- What needs to be done for the real time process modeling part (with real time data acquisition and real time data reconciliation)

I. DEFINITION OF DIGITAL TWIN

The first part of this paper examines the different concepts hiding behind the DTW and delimit the boundaries of each of them, with examples from other industries.
The next section explores what are the impacts of the DTW when it comes to engineering and what are the pre-requires to extract all the value from this concept. The final part of the paper is intended to be practical by briefly listing a series of use cases tackled thanks to the DTW, and the detailed explanation of the real time processing example.

Since the beginning of the digital transition era, the DTW concept has attracted a lot of attention, becoming a catch-all idea without clear boundaries.

As operators' core activity is to run assets, the DTW comes as the natural common base to support digital initiatives. For operators willing to embrace new technologies, the DTW appears as a pivoting point of their digital transition.

As a broad definition, DTW is the virtual representation of a physical process, object or service. In practice, the DTW main benefit is to aggregate different data to build a consolidated visualization and help making decisions or offer new services. This visualization can be a 3D representation, a dynamic process model, or a data centric twin.

Moreover, the DTW is not a sedentary animal as it should follow the whole life-cycle of its real twin. From the design phase to the decommissioning, the DTW will grow by the aggregation of every data affiliated to the physical system it is entitled to represent.

Fig. 1 DTW maturity over the last decades

The DTW concept applies to all the existing layers of assets/processes in a plant. Mapping the data interactions between layers of physical assets, the DTW will gather data to numerically recreate the digital replica of a system. From these interrelations, we understand the challenge of DTW is to collect, aggregate and use data from different sources and various natures. Thus, to let people and objects from different entities talk to each other, the DTW requires standards to align its actors.

In practice, different series of standards have already been developed to frame digital practices. The first of it to be developed and implemented, has been the RAMI 4.0 (Reference Architecture Model Industrie 4.0) [1] by the ZVEI, based on ISO and IEC standards. In this example, the DTW relies on a three dimensional map to connect things together, as seen below.

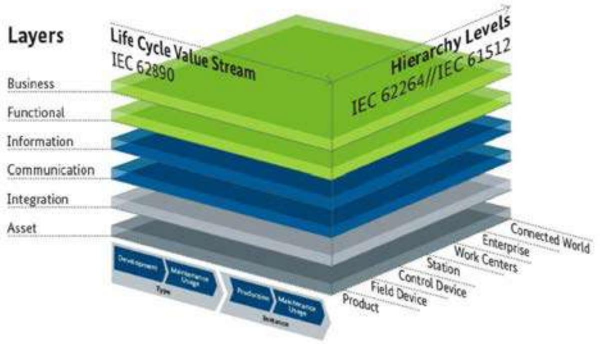
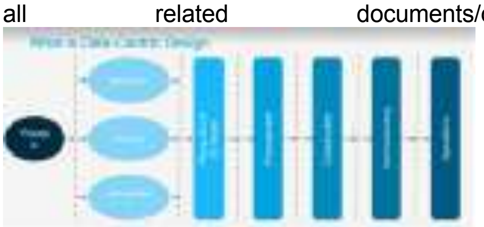


Fig. 2 RAMI 4.0 architecture model

The other main series of standards called CFIHOS (Capital Facilities Information HandOver Specification) [2] is driven directly by many actors of the process industry, under the governance of the IOGP (International association of Oil and Gas Producers). Still in development, CFIHOS standards' main goal is to facilitate the communication of information between partners of projects to reduce cost and save time.

II. TYPES OF DIGITAL TWIN

DTW is a general denomination for an umbrella of solutions. Depending on the final objective of the solution, different types of DTW can be built:

1. 3D Model
   In this case the DTW objective is to recreate the physical characteristics of an asset. Meaning, the model should integrate information about the structure of the asset, being the shape, color, material, weight, position, motion.
   Use cases relative to this DTW include: operator training, maintenance test, operability study.
2. Data centric Twin
   All data referring to the design, specification, proposal, detail, or maintenance manual. The current practice is a 2D model: PIDs with links to all related documents/data.
   
   Fig. 3 Organizational layers of a Data centric approach
3. Mathematical / Physical model
   In this case, the objective is to go beyond the physical aspect and consider its operating logic. Meaning, the model recreates the patterns of interaction between the variables of the digitized assets, either in steady state or in dynamic. This model can be drafted from the equations ruling the physical phenomena happening in the asset.
   Use cases relative to this DTW include: predictive maintenance, scenario anticipation, process simulation.

One often assumes that DTW is only the business of a new build plant, in fact it is also applicable to existing facilities. Considering the life-cycle of the plants in the petroleum industry, it would be a shame not to apply the technology to existing plants, even if it may have a different extent.
For new plants, the DTW is updated and used all along the complete life cycle of the asset/process it represents. In this case, the DTW will start to be specified from the design phase, then be continuously updated until handover to operators, to finally also be edited during operations and end of life.
For existing plants, the DTW may not have been built since the initial steps of the project development. Yet a DTW can still be implemented, at least partially, through the reconsolidation of the data available in the documentation, running data, and 3D scan.

III. ILLUSTRATIONS OF DIGITAL TWINS

DTW takes different shapes depending on the industry and the use case to tackle. Here are presented three DTW coming from other industries, with their underlying technologies.

A. *NASA Spaceship*

Today NASA is using the DTW under its Data centric twin version to develop the optimum equipment. NASA motivation is to design, build and test every piece of equipment digitally before manufacturing for efficiency and safety purposes. The designed system has to fully operate accordingly with required performances before being manufactured. After production, the physical asset is connected to the DTW once again to check and validate operational behaviour. This application combines different clusters of technology, such as:

1. Big Data
   Gathering and reconciling data from multiple sources working in collaborative mode on the development of equipment to guarantee the data update and unicity.
2. Digital Infrastructure
   A robust information system is required to manage the data and the accesses of the cloud system. The data architecture also calls for a high level of data standardization on the project.
3. 3D Printing
   Useful for prototyping pieces of equipment or for manufacturing complex geometries, the 3D printing technology enables new manufacturing possibilities.
4. Blockchain
   In the matter of certification and control, NASA started to use blockchain to trace its equipment all along the lifecycle.

B. *Autonomous Vehicle*

An autonomous vehicle is able to understand and perceive the surrounding space in order to actively interact with moving objects or people, and drive itself without human input and the need to change or modify the environment. According to our definition, this case corresponds to a 3D Model of DTW. It combines different technologies belonging to four main clusters:

1. Internet of Things
   Both long- and short-range are required for the system to localise itself in real-time, or to exchange information in connection with other vehicles/infrastructures.
2. Machine Learning
   The vehicle needs to develop an intelligent vision to detect interactions from its environment. This intelligence is learnt from Big Data analysis and algorithms training.
3. Digital Infrastructure
   Extensive data storage and data processing are required for the analysis, especially the Fog/Edge Computing to reduce latency and obtain real-time response.
4. Robotics
   The full automated vehicle can be viewed as a drone itself, meaning a robot, as the connexion can also be made to receive instructions from a remote pilot.

C. *Smart Building*

For a few decades, all buildings are designed, constructed, operated and maintained using BIM (Building Information Modeling). Online, the following definition of the US National Building Information Model Standard Project Committee [3] details :

> *"Building Information Modeling (BIM) is a digital representation of physical and functional characteristics of a facility. A BIM is a shared knowledge resource for information about a facility forming a reliable basis for decisions during its life-cycle; defined as existing from earliest conception to demolition."*

After its construction, the same 3D tools are used to deliver traditional services – such as illumination, thermal comfort, air quality, physical security, alarm, waste management, with the lowest cost and environmental impact over the building life cycle. Moreover, devices in the building can be mutually connected and be controlled on premise or in distance by operators and occupants. From our definition, this is a Mathematical/Physical model of DTW. This application combines different technologies belonging to four main clusters:

1. Internet of Things
   Short-Range IoT devices (e.g. smart meters or smart power grids) enable real-time automation, data collection and remote control.
2. Artificial Intelligence
   Including Machine Learning for efficiency related predictions and Intelligent Vision for advanced tracking, object/person recognition and high-level security systems
3. Digital Infrastructure
   Involving cloud technologies for internal and external data gathering, Big Data for real-time analysis.
4. Biometrics
   For occupants recognition to manage buildings accesses.

IV. PREREQUISITES OF THE DIGITAL TWIN IN AN ENGINEERING COMPANY

The DTW is intended to process data of various natures but interacting between each other.

The idea is to move from a Document centric organisation during the engineering phase to a Data centric one.

It intends to answer the following challenges met during any project execution and provide efficiency in lots of engineering data manipulation all along the project lifecycle: data inconsistency, workflow inefficiency, design errors, difficult management of change, non-conformity from design and/or procurement, site handover, commissioning and tool issues.

A strong engineering data management is essential to DTW. We can identify 2 types of Data: Design Data and Time stamped Data which are evolving during the Operation. There is a non-exhaustive list of information that can be contained:

1. Process Data
   Flow, temperature, pressure, composition...
2. PID
3. Mechanical
4. Electrical/Electronics
5. Automation
6. Documentation

The data must be located in only one location either during engineering and operation : **single source of truth.**

Central to the DTW concept is the creation of an asset data management platform.

The data location is something to think about from the start as well as the DMS (Document Management System) to be used. Further tools to be used by project members for data storage, access rights, collaborative platform and dedicated servers where licences pooling is managed must be agreed and well set-up upfront for:

1. Software
   Same software to be used by all teams
2. Safety
   Access rights management and data protection (co-working with partners and contractors to be evaluated)
3. Maintenance
   Critical asset information loaded in MMS,

4. Status
   AFD, AFC, As Built
5. Business
   Collect the data to allow all types of interventions (equipment replacement, maintenance, …) estimation and scheduling.

The DTW data are collected from day 1 of the engineering up to the handover to Operation. Then data will be managed by the Operation team.

Prior to any data collection, data governance must be clearly set-up and in line with customer expectations.

The pre-requisite is definitely having a data integration layer between all tools modules (Process, PIDs, 3D …) ensuring data consistency all along the project life cycle.

A. *Tools to integrate*

Standards: to all talk in the same language, data format to be agreed from the beginning and aligned with the final user.

Platform/database: to all share data and exchange information on the same location. Allow co-working and co-design using the same database and tools.

Integration layer: agnostic module to allow integration of all types of data.

Data capture: to gather all the valuable data from the asset. After collection, the dataset needs to be analysed and cleaned.

B. *Data Governance*

By nature, a DTW needs to operate the aggregation of multiple data obtained from different sources. Most likely, these data may belong to different players, raising an **Intellectual Property's issue.** How to share data between partners and how to respect each partner property?

In order to be shared and thus create value, data managed by the DTW needs to follow a strict **data governance**. This data governance objective is managing the access rights of the various services in order to respect the collective intellectual property (workflow to define by who and when the master data can be changed, who should be informed..).

One challenge during project execution is to ensure data consistency between each discipline which are sometimes used to work in silos.

V. EVOLUTION OF THE DIGITAL TWIN ALONG THE PROJECT

As the asset is evolving along the lifecycle of the project, the DTW needs to adapt and grow. The global data nomenclature may stay the same along the twin life, variable values are expecting to change. The stage of the DTW can be presented as:

1. Product development
   Basis of design, input data to be considered..
2. FEED (Front End Engineering and Design) (if any)
3. Basic and detailed engineering (including procurement)
4. As Built (for handover): Update after construction and commissioning completion.
5. Operation and Maintenance: When data are loaded in the MMS and in the Scada for "operation readiness" topics.
6. Decommissioning of the plant: This topic is more and more considered in the projects (already the case for building and on-going for industrial facilities).

VI. OPERATORS AND ENGINEERING EXPECTATIONS FROM THE DIGITAL TWIN

The maturation of digital technologies has created a path for the development of new solutions to answer problematics, yet stayed untouched or still unsolvable. The boiling environment surrounding the digital world, with the births of unenumerable start-ups and creation of new offers from usual actors, provides operators with loads of solutions for their business. Nevertheless, even having many solution providers, End-Users still rely heavily on the Engineering companies to integrate these technologies in their operations.

From Project development to Operational excellence, or Health & Safety, the scope of applications of digital technologies is broad for the Oil&Gas industry. Operators have realized the importance of the digital turn happening as it may be a fantastic opportunity for innovation or a massive trap, depending on how the turn is negotiated.

From all the fields of applications for operators of the DTW, an overview can be drawn from the following list. Those are concrete use cases using the DTW with technology available as of today's date:

1. Project design
   A process in which each digital twin types are utilized to design, engineer, plan and execute the construction of a complex project. The data centric twin allows a data centric project organization, guaranteeing the data uniqueness to all the partners, for more accuracy and efficiency in the design and engineering phases. In parallel the mathematical model enables to pre-simulate the process of the project, thus minimizing mistakes or defects in the project being built, providing confidence that quality requirements will be fulfilled. The 3D DTW with the time dimension (also known as 4D) is also a powerful visualization and communication tool that gives a project team much better understanding of project milestones, schedule, and construction plans. Moreover, this project design approach allows an operator step

by step validation. Taking advantage of information stored in the DTW to help validate progress as well as ensuring that the operator intent for the facility is being honored both conceptually and contractually.

2. Asset performance
A process in which the mathematical DTW is used to optimize the performance of an asset (e.g. a pump, a motor, a catalyst, etc). This optimization may have different objectives such as minimizing the running cost, maximizing the life expectancy, maximizing production, preventing downtime.
3. Process performance
A process in which the mathematical DTW is used to analyse and optimize the operations of a real-world process over time. The act of optimizing the process requires a model to represent the key characteristics or behaviors of the selected physical process, to find the best suitable configuration of production, given the environment conditions. Thus production configuration can be adapted in real time to reduce the cost, maximise production, or increase margin. The process performance use case can be considered at a train level, a plant level, but also at the size of a grid if multiple plants are connected on the same network.
4. Predictive maintenance
A process using the mathematical model of an asset to anticipate the failure of an equipment. To stave off asset downtime, real time operational data are constantly compared with historical data of the same asset to detect deviation from the normal cluster of working points. By combining all the data coming from the asset and its environment, the DTW is able to detect weak signals way before any usual threshold alarm warnings. This early detection gives time for the operator to react, as the asset can still operate for a while, and find the best maintenance solutions which will satisfy both the operator and the client at the lowest appropriate cost.
5. Operator Training Simulator
A process in which the 3D DTW is used for creating images, diagrams, or animations to introduce and train operators virtually. Visualization through virtual imagery has been an effective way to communicate perceptions of plants to operators and recreate concrete installations. Used to familiarize operators with sites and maintenance operations, the DTW enables a closer monitoring of training sessions in the comfortable environment of offices for a share of the cost. The development of augmented and virtual really also supports advanced visualization.
6. Equipment installation
A process using the 3D DTW to perform a spatial analysis on the plant. Considering the perceivable architectural elements with their boundary, the DTW is able to stress the feasibility of an installation.
7. Process simulation
Simulation requires a mathematical model of the DTW to represent the key characteristics of the process when the real system cannot be engaged itself. The model represents the system itself, whereas the simulation represents the operation of the system over time. Simulation can be used in many contexts, such as the research of new operational configurations for performance optimization, validate engineering solutions, new equipment integration in the process, and evaluate production costs. Simulation is also used with scientific modelling of engineering designs to gain insight into their functioning.
8. Scenario anticipation
Scenario anticipation is a use case linked to process simulation, as it is used to show the eventual real effects of alternative conditions and courses of action. Based on the process simulation, scenarios can be useful to prepare turnarounds, shutdowns, equipment failure, safety plan and choose the most efficient script.
9. Virtual visit
Virtual visit is based on the 3D DTW and has different values depending on the user. For people on site the value would be to learn how to evacuate from any location, or where the emergency system is located (Emergency System Device : button, phone, extinguisher). For project managers the virtual visit is useful to analyze the construction of complex system as a tool for design reviews at all along the project life.
10. Root cause analysis
A process in which the DTW can be used both front and backward to find the causes of an incident. Frontward, because the existence of deviations between the digital and real twins can enlighten the causes of an incident. Also frontward, the absence of deviations may suggest a design error or an external factor, as the system has been operating according to its command. And backward, because the model can be used as a reverse engineering tool to establish the inputs of the incident.
11. Existing plant modifications
A process in which the DTW is used during the design and construction process to identify and coordinate potential process/space conflicts by evaluating the model of the existing system with the integration of the new modification. During modification design the goal of clash avoidance is to ensure there is adequate space or process flexibility to fit all designed modifications in the existing plant.
12. Remote operating
The DTW model of the equipment/plant behaviour is requested to decentralize the decision making process. This decentralization can have two aspects: either the control room is outsource from the plant location to send high level requests (e.g. start/stop, production setpoint); or the equipment/plant becomes fully automated and decisions as well as commands are made from a different location (e.g. subsea operations).
13. Document management system
A platform based on the data centric DTW to gather, centralize and organize all the documentation and information from internal and external sources, regarding the project to guarantee the unicity of data and constant update of documentation. Such a system increases the accuracy and the efficiency of the project team for design, engineering and optimization of asset

installation. The document management system facilitates the access to manufacturers information, from a product library in a machine-readable format, promoting interoperability. The equipment library will mature to ultimately include not only graphic and spatial information but also information related to technical specifications, engineering capabilities and tolerances, first cost, Total Cost of Ownership, location in the plant, maintenance and repair, environmental, mean time to failure, as well as installation, warranty, and any other information pertinent to the equipment for suitability in a designed facility. It may also include performance information, or relationship with other pieces of equipment and other information which could bring value.

14. Operation readiness
A process gathering the different types of DTW to allow a smooth handover between commissioning and operation by ensuring all data to be transferred (e.g. As Built documentation, spare part list, MMS data population, etc) from the hands of the engineering company to the operator. Work follow-up, quality, welding, pointing, precom, Data management for decommissioning; every nature of data is concerned in this handover to verify all subsystems just prior to commissioning to ensure operator requirements as intended by the owner and as designed by the building architects and engineers are met.
15. Design replication
A process in which all the DTW types are exploited to satisfy the approach: design one, build many. Accumulating all the technology bricks of multiple already designed projects, the concept is to capitalize on the hard benefits for next upcoming projects by replicating previous solutions to new projects, saving time and mitigating risks.
16. Robot operations
The basic concept is to have routine maintenance operated by robots and not humans. Especially interesting from the safety and cost aspects, unmanned operations technology key is the 3D DTW for robots to be able to locate themselves and move on site. Robots' objective is double; first execute repetitive tasks to free more time for operators on complex tasks, second to intervene and replace humans in high-risks environments.
17. Electrical network supervision
A process by which the DTW is used to determine the most effective electrical engineering design based on the specifications. The performance simulations can significantly improve the electrical design of the facility and its energy consumption over its life-cycle. A close monitoring of the electrical network performances and its DTW also reduce downtimes.
18. Installation monitoring
A process using drones and DTW to measure the position of every piece of equipment in an installation and validate that construction is in accordance with the plan. This approach is used to rapidly capture the real shapes of objects, buildings, landscapes and detect a deviation from the digital 3D model. By comparing both, the system is able to avoid space clashes at a really early stage and reduce corrective costs.

VII. REAL TIME PROCESSING WITH DIGITAL TWIN

When the DTW needs real time data, three main steps describe how to convert data to value/information.

A. *Data Acquisition*

The first step consists in "**Collect**" the data (all field instrumentation, IoT, external data as meteorological data) into a historical record. The acquisition frequency, the accuracy, "compression" parameters have to be properly defined to balance the needed accuracy with the data storage and the transfer rate between local Distributed Control System and record. This record is more and more a cloud (private or not), to make the access easier.

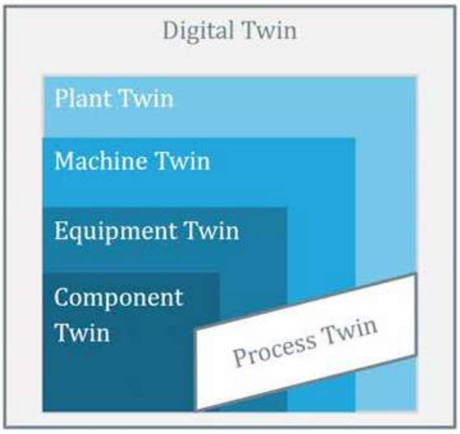


Fig. 4 DTW layers structure

B. *Data Manipulation*

As a second step, the raw data will be processed in order to make them directly valuable for people or the upper system. This step can be called "**Augment**": basic data validation, operating mode automatic detection (off, start-up, running, max), new KPI calculated to follow performance, data manipulation (such as clusterization /filtration /linearisation) to detect abnormal operation mode, and generate an alarm in case of deviation.

To help/speed the deployment and to guarantee the consistency of the analysis, some templates will be used to define the information needed (design data, time data), the calculation (KPI, alarm..). This also allows data reconciliation and generates aggregated KPI (global reliability/efficiency of a fleet).

C. *Share and Act*

When the information is available, some actions need to be taken to create some value. This can be done through the final part that can be called "**Share**". The operation needs to put in place an organisation in order to follow and track all the alarms. A remote center will manage the alarms generated in case of mechanical parameters moving outside of their normal clusters (to decide if it's a fake alarm, or if this is a true/serious alarm needing a stop and a maintenance to fix the detected issue). Similarly, an alarm detecting an under performance will be studied in order to understand and potentially give instructions to change the operating mode to improve the efficiency/profitability.

In front of the screen, the first level will manage the alarm generated, and if needed will escalate to a higher level with Subject Matter Expert (Maintenance expert, Rotating expert, Process Expert..).

Fig. 5 Collaborative team to handle DTW

VIII. CONCLUSION

In this article we have tried to present the best picture of DTW within the industry.
DTW is a buzz word but also a real diamond which can bring added values on each facet of the project life cycle; there is a huge number of "facets" . Usually a DTW is in fact only one or two of all those facets. The complete DTW is like a mythic diamond: nobody ever sees it, as it's today very complex and very expensive.
The term "Digital Twin" pops up more and more as companies look for ways to drive New Ways of Working and innovation, and for good reasons. Twins can help businesses monitor the state of equipment at remote sites, optimize product designs for specific needs, and even model the business itself.

IX. REFERENCES

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X. NOMENCLATURE

DTW Digital TWin
ZVEI Zentralverband Elektrotechnik- und Elektronikindustrie *(German: electrical and electronic manufacturers' association)*
CFIHOS Capital Facilities Information HandOver Specification
BIM Building Information Modeling
PID Process Instrumentation Drawing
OTS Operating Training System
MMS Maintenance Management System
AFD Approved For Design
AFC Approved For Construction

XI. VITA

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NOTES

OPPORTUNITIES FOR FURTHERING THE ELECTRIFICATION IN HEATING PROCESSES IN INDUSTRIAL FACILITIES

Europe Paper No. EUR21_30

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Abstract- Fifty years ago, the concept that "steam was not free" became a reality in the process industry. The process industry has realized and perfected the use of electric heating as a highly efficient and in many cases a less costly energy source.

Electric process heater manufacturers provide heating solutions for temperatures under 780°C. These solutions are utilized in trace heating, space heating, heating of process fluids (gases and liquids) and conductive heating of solids.

Centralized large-scale power generation can allow improved efficiency in converting fossil fuel to electrical energy. In addition, the growing production of renewable power gives excess power to the grid. Combining this with targets for the industry on the reduction of the use of natural gas for process heating, a substantial contribution in the reduction of greenhouse gases can be achieved.

This paper will present numerous process heating application solutions where conversion to electric heating source opportunities may exist. A feasibility case study will be presented that transforms a cogeneration based steam energy supplied production unit to one that uses an electric steam boiler.

Index Terms — Trace Heating, Space Heating, Conductive Heating, Energy, Process Heating

I. INTRODUCTION

Climate experts attribute the vast build-up in the atmosphere of carbon dioxide and other greenhouse gases as a part of the reason for global warming being experienced in our world today. The carbon dioxide in the atmosphere is due in part to the growth in use of fossil fuels to generate heat and electricity for the world. There are many known ways to reduce greenhouse gas emissions in the industrial sector. For the industrial process industry, these include **improving energy efficiency, fossil fuel type switching, use of combined heat and power generating units, adding renewable energy sources to supply the electrical power grid, and the more efficient use and recycling of materials.** In the few cases where existing industrial processes have no lower-emission alternative, carbon capture and storage to reduce carbon dioxide emissions over the long term may become a required alternative.

Many of the application solutions for heating processes that exist today are evolutionary. That is, they have been the best solution based on the technology, economics, and practicality in existence at the time. Once the application solution was initially proven successful, it became the default way. With today's emphasis on renewable energy, sources used in creating electrical power and reducing carbon dioxide emission levels through more efficient conversions of fossil fuel energy to electrical power; it also seems appropriate to consider reducing in-plant usage of lower efficiency fossil fuel process heating equipment and begin utilizing direct electric process heating where possible. A number of candidate direct electric process heating application opportunities will be reviewed based on the perspective of furthering the electrification within industrial facilities. In parallel with an increased focus on a more efficient heat generation equipment selection, there is a need to reassess the heat generation and power grid sources and capacity in each industrial facility. A case study of one such infrastructure assessment of a mid-size chemical plant is given to provide a glimpse of that process.

II. Trace Heating Application Solutions Where Electrification Potential Exists

In its simplest form, trace heating may be thought of as a line source of heat that is applied parallel to a process pipe, vessel, or piece of equipment to heat its external surface. The line source of heat may be an electric trace heater or a steam/fluid trace heater. The trace heaters most basic function is to replace the heat lost from the process line, vessel, or equipment. Trace heating applications in the earliest times were often considered an incidental part of the facility processes. Today, many industrial facilities and processes find that trace heating plays a major role in its operations. For example, it is not unheard of today to find 15000 and more trace heating circuits in a petrochemical facility. In terms of energy consumption, this could represent as high as 15 megawatts of power (energy consumption is dependent in part on the process maintenance temperature, heating surface geometry, the insulation system, and ambient conditions).The following sections describe a few of the trace heating applications that may be found in an industrial facility.

A. Trace Heating of Water and Water-Base Solutions

Perhaps the largest process applications of trace heating are those where water or water solutions are involved. Along with not being processible when frozen, water and water-based solutions cannot be allowed to freeze without risk of damage to containing piping or equipment because

[1] Reproduced from https://www.nrcan.gc.ca/energy/publications/efficiency/industrial/cipec/6699

of the expansion characteristics of water when thawing. These solutions are typically maintained between 5°C and 40°C with the higher maintenance temperatures (above the traditional water maintenance temperature of 5°C) typically being for acid or caustic based water solutions. Direct electric trace heating continues to be growing in popularity for these applications. Electric trace heating is relatively easy to control process piping and equipment at these lower maintenance temperature ranges. Electric trace heating systems are more commonly configured with ambient on-off, ambient proportional controlled, or surface sensing controlled trace heaters in these applications today. Typically, a self- regulating polyolefin based core trace heater is most often prescribed. The use of ambient sensing type controls is selected to limit heater operation to only those times when the ambient drops below the desired maintenance temperature. Today, a proportional control aspect has been added to ambient sensing systems that linearly increases the heat input as the ambient drops to the minimum ambient value. In this way, the energy required is significantly reduced. The use of ambient sensing in these applications reduces the initial capital cost of the temperature controls needed especially in complex piping areas where multiple process flow paths are likely. In some longer transfer line applications, use of constant wattage series or parallel metallic element trace heaters may be appropriate. When using these types of heaters, surface sensing temperature control is generally required. Where further reduced energy consumption requirements are dictated or where tight process temperature limitations exist, pipe or equipment temperature sensing control with electric trace heating becomes the preferred trace heating control solution for all types of trace heaters. Surface sensing controls require consideration of process flow patterns when establishing the electrical circuitry.

Where low pressure steam distribution is available within the plant, steam tracing utilizing isolated tubing (for reduced heat transfer and better matched heat delivery) can be utilized in these water and water based solution heating applications. While this is not the most energy efficient application, in some cases it does provide a use for excess low pressure steam and thus helps to balance out the plant energy requirement budget.

B. Trace Heating of Crude Oil, Asphalt, and Bitumen

Another extensive application for trace heating is viscosity control. Depending on the amount of wax content in the various hydrocarbons, viscosity reduction is often required in order to maintain stagnant process lines readily pumpable. Process heating requirements range from maintaining fuel oils such as No. 6 fuel oil at 60°C or higher up to 150°C or more for asphalts and bitumens. The electric trace heating selection for these processes in complex piping areas is usually a fluoropolymer based self-regulating electric trace heater at the lower end of the maintenance temperature range and mineral insulated Alloy 825 sheathed constant wattage trace heaters at the upper end of the maintenance temperature range. Control systems used for these trace heating applications are usually of the surface sensing type, which requires consideration of process flow patterns when establishing the electrical circuitry. For long hydrocarbon transfer lines between process units, skin effect trace heating is the most prevalent trace heating system used today. Skin effect trace heating can cover a large part of this maintenance temperature range (up to at least 150°C) and generate the heat outputs typically required.

Where steam distribution lines are available and its use is justified to balance out the plant energy requirement budget, convection steam tubing tracers can be used in the lower maintenance temperature range. Conduction type steam tracers are more suitable in the upper maintenance temperature range. Steam trace heating circuits are not generally configured with temperature control devices due to the difficulty of maintaining constant temperatures along the trace heater circuit path. Acceptable temperature range control is achieved by matching the heat delivery requirement by appropriate selection of the steam tracer heat transfer characteristics.

C. Trace Heating of Sulphur

When refining crude oil (especially sour crudes), a necessary byproduct is Sulphur. The extraction and handling of Sulphur presents another significant application for trace heating. Sulphur is a rather unique process fluid to handle as it has two distinct changes in structure as it melts or solidifies. The first structural change when heating up Sulphur occurs at an approximate temperature of 100°C. The second change results in a complete Sulphur change from solid to liquid and this occurs at an approximate temperature of 120°C. As a further complication, liquid Sulphur becomes much more viscous and difficult to process when it attains temperatures in the 150 to 160°C range. These temperatures are approximate as the previous process history and the Sulphur makeup can cause these numbers to vary some. Traditionally, Sulphur is usually maintained at a temperature of 135°C for optimal control and handling.

For complex piping areas within the process unit, either steam or electric trace heating is suitable. Direct electric heating is usually achieved with Alloy 825 sheathed mineral insulated trace heaters and surface sensing temperature controllers. When using steam in this application, it is functionally best to use 3.5 to 5-bar steam in order to avoid heating the Sulphur above 150°C. Conduction type tracers or jacketed piping is usually necessary to achieve the desired 135°C to 150°C temperature range maintenance temperature when using steam. When using conduction tracers or jacketed piping, temperature control is usually achieved by selecting the proper steam pressure for this heating. Where long Sulphur transfer lines exist between process units, skin effect trace heaters with surface sensing temperature controls are usually the best choice. Providing a supply and return steam distribution system to heat long transfer lines is generally viewed as being impractical from an economic viewpoint unless the distribution headers are already in existence for other purposes.

In most of the above applications (A, B, C), electric trace heating is the most energy efficient means of delivering process heat. This is primarily due to the cost effective implementation of the electronic temperature control technologies, which are available today. These controls allow only the minimum required heat/energy to be delivered to achieve the desired maintenance temperature range. The amount of heat/energy required is also a function of the thickness and type of thermal insulation specified. There are numerous types of very efficient (low in-situ thermal conductivity) thermal insulation in use in trace heating today. For the lower temperature ranges (pipe and equipment temperatures below 100°C) water resistant closed cell insulations are generally preferred. Above this temperature range, low thermal conductivity with water resistance (to avoid in-situ thermal conductivity increases) is still important but other factors such elevated temperature exposure and dimensional stability are also important. An extensive review of the insulation selection process for trace heating may be found in the references [1]. With proper design of the electrical distribution, the energy losses in the electric distribution wiring to electric trace heating circuits can be minimized. Steam or fluid heat transfer systems should be considered in those cases where the heat delivery by the steam or heat transfer fluid tracer is inherently well matched to the heat loss requirement in the trace heating application. In general, controls for steam and heat transfer media systems are not generally as effective in maintaining a relatively constant temperature along the trace heater length. In addition, the cost of providing any such control is high compared to that cost associated with electric trace heating system controls. As well, the steam distribution system supply and return headers have a high energy/heat loss associated with them. This is due to both the heat losses through header insulation systems as well as those energy losses associated with steam trapping /condensate return systems/fluid handling systems.

III. Space and Process Heater Application Solutions Where Electrification Potential Exists

Depending on the manufacturing processes in any given industrial facility, a variety of other substantial heat generators may be found in a process unit. In each case, there is an opportunity to consider the potential of considering direct electric heating rather than using a fossil fuel based energy source such as a local steam generating unit. A variety of heat generators that have electrification conversion potential are covered in the following sections.

A. Electric Radiant Comfort Heaters

Infrared radiant heaters provide the benefit of directly transferring heat to a target location without heating the surrounding air. Heat transfer occurs without the need for an intermediary transfer material. Radiant heating solutions are therefore ideal for such applications as large open buildings in an industrial facility, where heating the entire volume would prove overly burdensome and costly.

As an example, a person doing heavy work typically requires an air temperature of 19°C to 20°C to maintain the feeling of warmth. Utilizing radiant heater technology, the same feeling can be provided at lower ambient air temperatures in the range of 13°C to 16°C.

Type of Work	Normal Air Temperature (°C)	Equivalent Temperature With Infrared Heating (°C)
Heavy Work	19 to 20	13 to 16
Light Work	21 to 22	16 to 18
Seated	23 to 24	18 to 21

Fig. 1 Comfort Heating with Infrared Equipment

The amount of heat transferred is dependent on two important factors. The first is the temperature difference between the heater (emitter) and the person or object to be heated (source). For comfort heating, the source temperature stays relatively constant (usually close to a room temperature of 20°C). Therefore, it is only necessary to consider the operating temperature of the heater. The other factor in radiant heat transfer is the ability of both the heater and the source to give off and absorb radiant heat energy. This characteristic is expressed as an object's emissivity that ranges from 0 to 1 (where an emissivity of 0 absorbs and transmits no radiant heat and an emissivity of 1 absorbs and transmits all radiant heat).

Both electric and fossil fuel powered radiant heaters utilize high temperature emitters. The temperature of the emitter is the predominant factor in dictating the amount of heat transferred through radiation. Electric heaters convert electricity to heat through high watt density resistance elements. Elements are available in a variety of constructions including metal sheathed, quartz tube, and quartz lamp. Each type of element provides a different set of performance advantages depending on both the application and user preference.

All electric resistance heaters benefit from the principle that when electricity flows through a resistive element, heat is generated at close to 100% efficiency. Although some losses can be attributed to eddy currents, these losses are so small they are widely regarded as negligible.

For radiant heaters, the overall efficiency must take into account the mode of heat transfer. For radiant applications, any heat transferred by way of convection is considered waste heat. Radiant heaters are mounted high where radiant line of sights are unobstructed and where there is sufficient clearance to keep personnel away from their hot surfaces. For this reason, any heat transferred to the air by way of convection is lost. The heated air rising from the heater offers no benefit to the target at ground level. There are a number of different variables that govern radiant heat transfer. Some of these include temperature, surface area, electromagnetic wavelength, surface finish, etc. For comfort heating, heater temperature is the predominant factor in controlling the split between radiant and convection heat transfer.

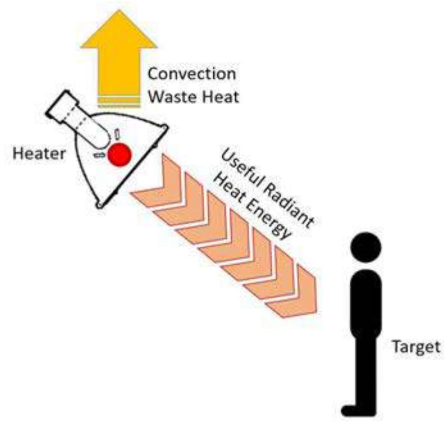

Fig. 2 Radiant Efficiency

Typical fossil fuel based combustion heaters have efficiencies that range from 80% for standard equipment to above 90% for high efficiency models. It is not as common to see efficiencies in the 90% range for radiant fossil fuel based heaters. Where possible, it is somewhat impractical for radiant heaters to achieve above 90% efficiencies as these efficiencies are usually achieved by recovering low temperature waste heat in the exhaust stream. While this is effective in maximizing overall efficiency, it has little value in transferring heat by radiation. The temperatures are simply too low to radiate heat.

The efficiency advantage of electric radiant heaters increases when varying load conditions are considered. Control of fossil fuel based radiant heaters are typically limited to one or two heat stages. The low heat stage reduces temperatures, lowering radiant heat transfer efficiency even further. At reduced load requirements (below that of any low heat setting), a fossil fuel based heater cycles on/off to regulate temperatures. Cycling of this nature is inefficient due to long heat up and cool down times outside of optimal radiant heat transfer temperatures. In addition to this, pre- and post-combustion chamber purging evacuates the heated gas to the outside and increases overall waste heat losses. For optimal efficiency and control, multiple electric radiant heaters are packaged together to heat the same target. In this configuration, heat output is varied by individually energizing and de-energizing different combinations of elements. Radiant heat transfer and overall efficiency is maximized by providing the necessary heat output at optimal heating element temperatures.

Electric radiant heaters are manufactured in a wide range of sizes and configurations. Single unit lengths can be as long as 2m or as short as 0.5m. This versatility allows for custom solutions, tailored to heat only the locations deemed necessary. Operational cost savings are realized by carefully designing a heating solution to only provide full heat where workers are commonly present. The simplicity and customizable nature of electric radiant heaters provides for precise control of temperatures. The low mass of the heating element is more conducive to on/off cycling for heat attenuation. Rapid startup and cool down times facilitate accurate temperature control while minimizing inefficient operation time at low temperatures below radiant heat transfer thresholds.

Electric radiant heaters are relatively easy to mount and install. They are simple lightweight designs. Mounting an electric radiant heater has many similarities to installing factory lighting. A qualified electrician can install both. Fossil fuel based equivalents require both a certified gas fitter and electrician to install. Typically, these heaters are larger and heavier and may necessitate moving shop floor equipment to provide proper access for installation. For interior installations, appropriate means for venting combustion exhaust must also be addressed.

B. Boilers

In the US and Europe, it is estimated that steam generation accounts for about one third of the overall industrial energy demand.[2] Fossil fuel fired boilers account for the vast majority of all boilers in industrialized countries. It is also estimated that the majority of the industrial boilers in use are more than 30 years old. [3]

Electrically powered boilers offer an interesting alternative to their fossil fueled counter parts. Efficiency numbers are higher. They provide quiet, clean, emission free operation, and their power output attenuation is more precise, providing improved temperature and steam generation control. Electric heat generation also reduces greenhouse gas emissions.

Traditionally, the practical use of low voltage electric boilers was limited to smaller applications with maximum heating requirements of 1 to 5 MW. This left industry with few options other than fossil fuel based boilers for large-scale demands. With the emergence of medium voltage heating technology in the range of 4 to 7.2kV, large electric boilers now offer a viable alternative to the fossil fuel dominated large scale boiler market. Additionally, electrode boilers are also now available which can operate at electrical supply voltages from 6 to 24 kV.

Fossil fuel burning boilers are available in a variety of different designs. Common operating fuels include natural gas, coal, oil and in some cases biomass. Thermal efficiencies for new boilers can reach 75% for natural gas, 85% for coal, 80% for oil and 70% for biomass [3]. These efficiencies can be marginally improved by adding complex and sometimes costly heat optimizing features such as exhaust heat recovery economizers, feedback loop combustion control, and variable speed combustion air drives. Poorly maintained boilers can lose up to 30% of their benchmark efficiency over 2 to 3 years [2].

Electric boilers benefit from virtually 100% efficiency in the transfer of electrical energy to heat energy. Operational waste heat is limited to pipe losses in steam/water transportation and losses at the process equipment utilizing the heat. Good insulating and sizing practices can maximize system efficiency without the need for costly and complicated waste heat recovery systems.

In larger boiler applications, electrical transmission losses become more significant as the heat load increases. Joulian (I^2R) heat losses in circuit wiring for electric loads in excess of 1MW become an obstacle for low voltage installations (480V-600V). Utilization of medium voltage heating technology can significantly improve efficiency by lowering current draw, thus lowering I^2R losses and maximizing efficiency. Through medium voltage heating technology, larger heating demands can be satisfied with high efficiency electric boilers. Medium voltage heating equipment negates the need for a medium to low voltage step down transformer. This lowers installation costs and improves overall system efficiency.

Fossil fuel boiler efficiencies are significantly impacted by varying load requirements, which are commonly experienced in industry. Turndown ratios are limited and efficiency typically drops off at lower power outputs. At heat load requirements below the minimum turndown output, fossil fuel based heaters blow off either excess steam or initiate inefficient on/off cycling.

Electric heaters naturally provide opportunity for excellent output control variation. Boiler output control is accomplished through a number of different methods depending on the size and design of the appliance. In most boiler applications, on/off switching is utilized to control heat output. Electric boilers are manufactured using many individual heating elements, bundled into multiple flange heaters dependent on the size and power output of the boiler. Through utilization of a step controller, the heat output is attenuated by switching distinct element bundles “on” and “off” to accurately match heat output to load requirements.

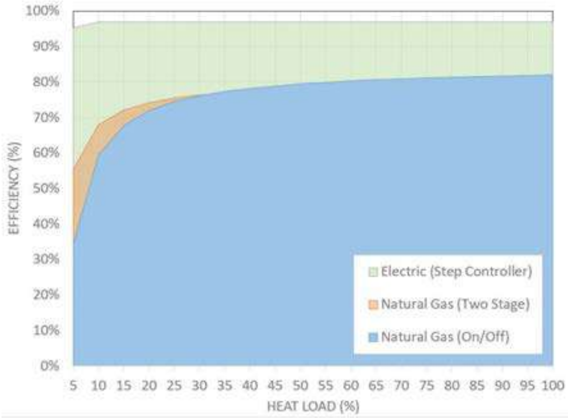

Fig. 3 Theoretical Boiler Efficiency vs. Percent Heating Load

The inherently simple design of electric boilers provide for reliable operation with low maintenance requirements. Electric boilers with vertical heating elements require less scheduled maintenance. The vertical orientation of the heating bundle creates a water to water vapour "stack" effect. This provides a cleansing action over the elements. This design has proven to minimize scale build-up on the heating element sheath that reduces the need for blowdown and increases the heater life. The vertical orientation allows for easy removal from the top when maintenance is required. Clearance to adjacent equipment is minimized enabling greater flexibility for plant layout optimization. Vertical element orientation, however, is only feasible in boilers up to a certain size. Larger boilers require elements to be installed horizontally.

C. Circulation Fluid Heating

Process fluid heating is utilized for many different applications in many different industries, including food processing, power generation, chemical manufacturing, and petroleum refining. Process heaters are used to increase the enthalpy of a fluid, sometimes to increase temperature, and other times for complete or partial vaporization. In other cases, process fluid heaters contribute to chemical processes such as cooking, fermentation, cracking, distillation, etc.

Fundamentally, heaters transfer heat to the process fluid through any combination of conduction, convection, and radiation heat transfer modes. This is accomplished directly by placing the heating device in direct contact with the fluid or indirectly by introducing an intermediary heat transfer fluid. Intermediary heat transfer fluids are more common in fossil fuel based heaters where the process temperature limitation is below that of the combustion heat temperatures. Process fluid heater designs provide great heat flux versatility. With a proper design, heating element temperatures can be reduced resulting in the elimination of the need for an intermediary fluid.

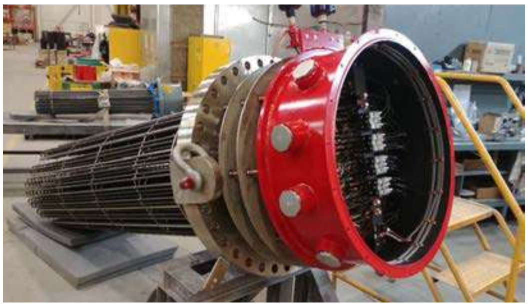

Fig. 4 Electric Process Heater

Electric process heaters are in many ways similar to tube and shell heat exchangers. The distinguishing feature is that the core heat exchanger bundle is manufactured with electric tubular heating elements. Their designs are simple and robust and provide the opportunity for high efficiency heating. The generation of heat from electricity is provided with virtually zero waste losses. Therefore, overall efficiency is governed by waste heat losses between the process and the environment. With the highest temperatures situated at the heating element core in the center of the equipment, waste heat losses are limited to the outside of the shell. These losses are easily controlled with the use of proper insulating techniques, since the temperatures are relatively low. The need for special refractory insulating material is not as common in this case.

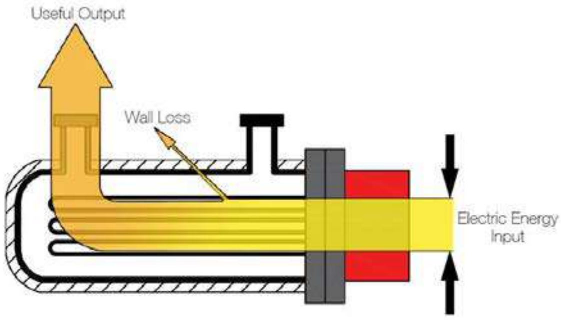

Fig. 5 Electric Process Fluid Heating Energy Losses

Fossil fuel based process fluid heaters have inherent vulnerabilities that affect their efficiency. Their fundamental designs are susceptible to varying levels of energy loss through a number of different paths. The result is overall reduced thermal efficiency. There are losses associated with incomplete or non-optimized fuel burn in the combustion process. Significant losses are linked to energy escaping as heated exhaust through the flue. Heat loss through furnace walls is also a factor.

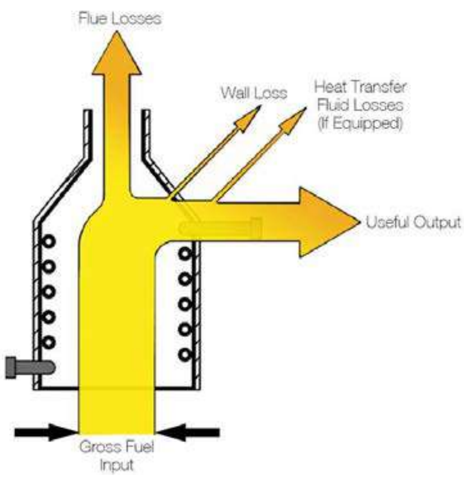

Fig. 6 Fossil Fuel Based Process Fluid Heater Losses

The total efficiency of implementing electric heaters starts to drop at load demands in excess of one to 2MW. This is a result of high current associated waste heat losses in the supply wiring and upstream electrical infrastructure. For higher heat load applications, utilization of medium voltage heating technology mitigates these losses by reducing the number of electrical circuits, lowering the overall current draw and eliminating the need for upstream transformers.

Superior turndown combined with virtually continuously variable power output control is arguably the largest functional benefit of electric powered heaters. For extremely high precision, SCRs (silicon-controlled rectifiers) are utilized for output power control. SCRs can cycle as fast as 0.008 seconds on a 50/60 Hz power line. Paired with appropriate sensors and PID control, SCR based systems provide unmatched response time and process control. The result is stable, widely adjustable process temperature control. Electric process fluid heaters also provide fast response time to changing conditions with minimal overshoot or temperature undulation.

Functionally smaller in nature, electric heaters benefit from their simple design. This characteristic not only helps with response time, but also makes for easier installation in tight plant layouts. Electric fluid heaters do not include some of the bulky components required by their fossil fuel fired counterparts. Heavy walled furnace enclosures, sophisticated controls, process fluid heat exchangers, flue gas components as well as many other add on items that are sometimes included to improve efficiency or potentially remove harmful emissions are not required with an electric heater.

Another added benefit for electric process heaters is their suitability for hazardous locations. With no open flame operating at extremely high temperatures, electric heaters can be easily constructed to comply with the various requirements for different types of explosive environments.

D. Vessel Heaters

Electric vessel heaters are used for small, medium, or large vessel heating applications. They can be either of the direct immersion type design where the heating elements are directly immersed in the fluid being heated or by indirect heating design where a heat transfer medium such as a liquid or air is used to transfer the heat to a pipe which then transfers the heat to the process fluid.

Direct immersion and indirect type vessel heaters are available for virtually any type of fluid heating application and are nearly 100% efficient since almost all of the heat generated is transferred into the process fluid. Most fossil fuel fired heating systems use steam either as a heat transfer medium, which is about 65-70% efficient, or as oils, which are about 90% efficient. Electric vessel heaters are more energy efficient, and are simpler to install, operate and maintain than fossil fuel burning equipment. Heating applications include heating or maintaining process fluid temperatures for use in their specific processes.

Other operational advantages of electric vessel heating as compared to fossil fuel burning equipment include reduced footprint (since the heater is typically contained completely inside the vessel), very precise control of process fluid temperatures, fast heat up, lower installation and maintenance service costs, easy monitoring and inspection, and fewer components.

Environmental advantages include no smoke, dust, fumes or combustion gases, no OSHA monitoring of CO emissions, compatibility where special environments such as areas with explosive dusts or gases are present, improved safety, and reduced environmental impact.

The adaptability of a closed-loop temperature control system provides additional energy efficiency, and the fast heat up time ensures that power usage is minimized. These heaters are suitable for both continuous or batch heating processes, and can accommodate multiple operating stages.

The indirect type vessel heater is suitable for use for heating viscous fluids such as heavy oils, asphalt, bitumen, lube oils and diesels. Heaters are often mounted inside of a pipe containing only air. This configuration offers the advantage of easy removal and replacement of the heater without having to stop the process or to drain the contents of the tank. Another advantage of these types of heaters is that they are designed with very low heater watt density, which is important to maintain low film temperatures as some process fluids can be damaged by over temperature exposure conditions.

Environmental advantages of the indirect type are the same as direct immersion type heaters, but also includes eliminating the possibility of costly contamination of the process fluid and reduced productivity. The indirect electric vessel heater type does not require use of oil as a heat transfer medium as used in fossil fuel burning vessel heaters.

E. Conductive Heating of Solids

Conductive heating of solids is an area where electric heating has a large presence. Many processes use exclusively electric heat since it is nearly 100% efficient, allows precise temperature control and adaptability to changing process requirements, is compact and simple to operate and maintain, and does not produce any harmful emissions.

Conductive heating applications include platen or die heating, injection-molding equipment, hopper heaters, heat transfer presses for use in plastic and laminate industries, railway track switch heaters for removal of ice and snow, and even new applications such as electric vehicle battery heating.

Conductive electric heaters are nearly 100% efficient, and are available in small and large formats for many specific applications. For many conductive heating applications of this type, fossil fuel burning equipment is typically only used where very large-scale heating is required or electricity availability is limited.

Conductive electric heaters are very easy to control, are simple to use and maintain and can be designed for very specific heating applications. They are also safe, since there is no open flame, and produce no combustion gases or harmful emissions.

IV. Increasing Electrification of The Heat Generation Infrastructure

The discussion to this point has been focused on improving the efficiency of heating processes and switching from fossil fuel based heat generators to direct electric heating within the various process units. In a new grass roots facility, these decisions will have an overall impact on the plant fossil fuel based steam and electrical power generation (including renewal energy component) requirements in the facility planning. Where enhancing electrification in an existing facility, it is important to realize that if significant changeovers to direct electric heating are achieved, the overall power and steam heat generation budget and power generation infrastructure may need changes as well. Thus, it is important when making significant changes to step back and look at the fossil fuel generated steam heat generation and electric power grid existing capability. Taking some fossil fuel based stream boiler capacity offline, converting fossil fuel based boilers to electric boilers, increasing the electrical power grid capacity, or adding renewal energy source power may be a companion requirement. Additional electrical power distribution to the various process units will also no doubt be required. Likewise, fossil fuel generated steam capacity may need to be down sized and some distributed steam generators within each process unit may need to be decommissioned. Obviously, each facility is unique in its manufacturing purpose and thus it is difficult to make general recommendations regarding this management decision-making process. However, a glimpse of this process is provided with the following case study.

Case Study of a Midsize Chemical Facility in the Netherlands

In order to reduce CO2 emissions, as required by the recent climate change agreements, a midsize chemical plant in the Netherlands needs to electrify the on-site heat generation. In the climate agreement, this is called “power to heat”. The scope for this existing plant is steam generation and oil heating. The total existing electrical plant load in this scenario is estimated to be >200 MW. In the current situation, the heat is produced with the use of two gas fired cogeneration units with islanding capacity and gas fired boilers. The plant power consumption is fed by the cogeneration units balanced by the utility grid. The current connection consists of two connections with a total capacity of approximately 90MVA and a limited back-up supply. The electrification of this site requires the modification of the grid to support the new power demand. This study identifies the necessary upgrade of the electrical grid connection, the on-site distribution system and the new electrical steam boilers, as follows:

- 10 kV steam boilers
- Redundant 150 kV grid connection
- 150kV voltage substation
- 6 pcs, 150/10 kV transformer
- 3 x 10 kV substation
- 150 kV on site cable connections

In order to identify necessary investments in the electrical grid connection and on-site distribution system, this study includes the identification of the total plant load, upgrading the power grid connection, and defining the plant distribution system.

A. Grid Configuration

Indication of plant load is as follows

Present plant load	70	MW
Other load	10	MW
Total	**80**	**MW**

The present grid configuration is based on two separate grid connections with a reduced backup power supply. Each grid has a cogeneration unit to provide steam and hot oil.

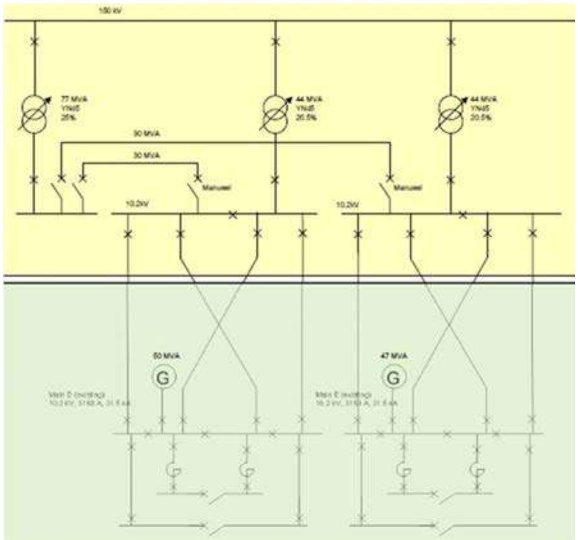

Fig. 7 Present Grid Configuration

B. Future Plant Load

The total anticipated future plant load has been defined as follows:

Present Plant load	70	MW
Other load	10	MW
Steam boilers	~70	MW
Oil heaters	~20	MW
Future expansion	XX	MW

Sub Total	>170	MW
Design Margin	>30	MW
Total	**>200**	**MW**

Taking into account a power factor of 0.8, this results in a new future apparent power of 200/0.8 = 250 MVA

C. New Grid Connection

A meeting has been held with the national grid operator. The projected plant load, as mentioned above, will result in a connection at a voltage level of 150 kV. Standard rating of one connection is 300 MVA. In order to have N-1 reliability, the grid connection shall consist of two cable connections, each with a rated continuous transport capacity of 300 MVA.

According the local grid codes, connection shall be done on the closest substation with the required voltage level. This is the 150 kV substation, which is located at about 1.5 km from the site. However, the national grid operator explained that this substation is congested. It is not to be expected that the required grid connection will be realized at this location. The national grid operator intends to build a new 380/150 kV substation. The new connection would be realized at this location.

D. Plant Distribution System

Design of the plant distribution system shall take into account following conditions:

- Plant load = approx. 250 MVA
- Grid connection = 2 x 300 MVA, 150 kV
- Voltage level for connection of medium voltage equipment = 10 kV
- N-1 reliability

Based on these conditions, one-line diagrams of four conceptual distribution systems have been developed. These conceptual distribution systems have been evaluated in coordination with the global asset technology centre, taking into account following criteria:

- Reliability
- Maintainability
- Operation ability
- Possibility to integrate/reuse existing equipment
- Possibility for future growth
- Rough cost estimate

This proposed plant distribution system consists of following main components.

- 1 x 150 kV substation
- 6 pcs, 150/10 kV transformer
- 3 x 10 kV substation
- 150 kV on site cable connection

Based on the results of this evaluation process, the selected grid configuration for the future electrification project is as shown in Fig.8

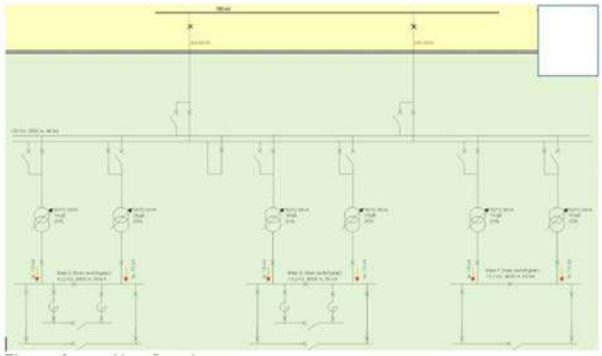

Fig.8 Future Grid Configuration

IV. CONCLUSIONS

Almost half of the world's energy use is dedicated to industrial activity [3].The drivers for optimizing process heating may be divided into **Policy**, (environmental, regulatory, and political often resulting in tax incentives which encourages lower carbon generated electricity), **Technology,** doing more with less and **Consumer Preferences** both internal and external. All the drivers influence how we use energy and each driver influences the other as they all influence **Demand.**

For the future, gaining the increased efficiencies associated with large scale centralized electrical power generation as well as adding renewable energy power to the electric grid should be a key management focus in any current or new industrial facility. In concert with that effort, every effort should be made to use direct electric process heating. As has been seen in this paper, there are multitudes of proven direct electric heating application solutions where the past practice of utilizing energy generated from smaller distributed fossil fuel based process heating units can be eliminated.

V. ACKNOWLEDGEMENTS

We acknowledge the essential contribution of SABIC in allowing information regarding the assessment process on the conversion of an existing facility in the Netherlands from a high fossil fuel energy based consumer to a more efficient electrification based facility to be used in this paper.

VI. REFERENCES

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VII. VITA

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Autonomous solutions reduce environmental impact

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Abstract – Remote locations, hazardous environments and cost of lost time incidents are some of the drivers for autonomous facilities.

We will describe levels of autonomy and key criteria and technologies to achieve safe, controlled and maintainable operation at each level. Even though manning has a significant cost, the real cost reduction comes from increased availability and reduced maintenance. In a typical process plant, 80% of lost production is preventable, and half of this is caused by human error. As much as 30-40% of net operating cost is maintenance related and this could be reduced by 30% or more though prescriptive maintenance.

The artificial intelligence machine learning technologies that support autonomy can also be used refine equipment models. This allows us to increase energy efficiency, prevent hidden losses and reduce both normal and accidental emissions. This paper will discuss these technologies and the results for a typical oil and gas facility.

Index Terms — Autonomy, Digitalization, Environmental Impact, Emissions

I. INTRODUCTION

The petrochemical industry has been working towards autonomous facilities for well over four decades. It is often desirable to limit the need for human physical presence and intervention in industrial process plants. This new way of working may offer significant benefits to operators in terms of safety and operational efficiency, and should also reduce the cost of new installations by removing the living space for workers and support staff. Typical benefits drivers for autonomy include: [1]

1. Hazardous conditions often exist with risk of toxic or flammable gas exposure or ignition. This makes it desirable to limit human presence both for regular operations and inspection and maintenance.

2. Legacy designs often specify local control rooms and/or field control panels that necessitates local operators to be present for startup, operational changes and other operations. Often this leads to excessive flaring during startup and mode changes, and lost opportunities in implementing efficient control strategies.

3. Human operators have a high error rate for routine operations and is ideally suited to handle complex and unexpected events. Thus, a high degree of autonomy is a goal.

4. Inspection and maintenance operations should ideally be converted to condition based predictive to reduce the overall in operation failure rate, and use remote inspection and intervention solutions such as robotics and drones to handle as many tasks.

Over a long period, we have seen a gradual development from unmanned small facilities such as wellhead and satellite platforms 40-50 years ago through low and lean manning, remote operations assistance, remote operations with various levels of automatic actions such as automatic startup and mode changes. Still we have only reached what is described as “occasional autonomy” where a large number of procedures and tasks may be preprogrammed but is initiated by the operator, In facilities such as DOW/Aramco SADARA, Shell Ormen Lange and Equinor Aasta Hansteen. In the Ormen Lange Nyhamna facility this has reduced the required manning significantly, but cannot be described as autonomous plants. Even so, we have been able to reduce emissions significantly as plants may be started up without continuous flaring during the startup process.

Condition based and Predictive maintenance are now reaching the same maturity level and should result in 30-40 % reduced human time in the process, due to reduced inspection and corrective time- This is significant since most in operation failures result in unwanted release and burning of hydrocarbons, a reduced emissions rate should be achievable. These technologies have now been proven in field trials and as field machine learning is built into the systems, will be ready for use in upcoming projects. As digital twin models of the plants are developed as part of the current Digitalization focus of the industry, this execution model should significantly reduce the amount of effort necessary to implement these schemes.

A third area that should benefit from autonomy is control and optimization, and the opportunity to raise process performance to new levels. While existing systems are optimized and tuned at infrequent intervals, an on line digital twin model and description of the process, should support continuous improvement throughout the lifecycle. It is not uncommon to find improvement potential on the order of 3-8% and up to 20% have been found in certain cases such as fuel gas use for aeroderivative gas turbine driven compressors.

II. FROM LEAN TO REMOTE AND AUTONOMOUS

Autonomous systems’ is used by the industry without a common standard that defines what we mean by autonomous operations. The Merriam-Webster dictionary defines autonomous as ‘undertaken or carried on without outside control’. In the process industry we use a more accurate description of “a system that without manual intervention can change its behavior in response to unanticipated events”. This means the word unanticipated is the crucial differentiator. [2] The differentiator is that the system will be able to modify its behavior, without the need for preprogrammed responses.

Most control systems can make changes to the operation of a process in the occurrence of a pre-defined series of events. Even though the complex algorithms that make these decisions will have numerous inputs, the data is highly structured and the actions are pre-programmed. This type of response is automatic action, such as automatic startup, shutdown and mode changes. Such systems will pass control to an operator in emergency situations that cannot be handled automatically.

A. Levels of autonomy

There are several industry definitions of autonomy levels, but as yet no accepted international standard, For this paper we use our own company definition that our corporate research staff developed based on the automotive sector: [3]

TABLE I
Levels of Autonomy

Level	Definition of Autonomy level
5 Autonomous	Full autonomous operation occurs in all situations. No user interaction is required, and humans may be completely absent. Today, this is aspirational, and would for instance allow a shuttle tanker to mate with an unmanned FPSO to perform fully autonomous offloading
4 Adaptive	The system is in full control in certain situations and learns from its past actions to be able to better predict and resolve issues by itself. An example for such a situation could be unattended night shift operation, when no major changes to the process are expected, with remote supervisory role
3 Limited	The automated systems can take control in certain situations, referred to as limited autonomy. In this mode operators are required to confirm the proposed solutions or act as a fall back. Example would be “one button startup” procedures with remote operator alert in exceptions.
2 Occasional	System moves into occasional autonomy in certain situations. In such situations the automation system takes control when and as requested by a human operator, but only for a limited period of time. People are still heavily involved, monitoring the state of operations and specifying the targets for limited control situations.
1 Assisted	These systems provide operational assistance by decision support or remote assistance. Examples include software collaborative solutions that react to detection of instabilities and failures and may also inform a remote operations center for additional assistance
0 Manual	No autonomy, operator is in complete control, but extensive low-level automation may still be in place at this level

B. The road to unmanned and autonomous operation

We here want to explore how these mechanisms can affect system stability, and process performance and as a result reduce emissions, both those from normal operations, and from exceptional events. As part of autonomy, we must ensure that the underlying system is safe, controllable and can be inspected and maintained, factors which will also contribute to stable and efficient operations.

- As a basis, operation has to be safe: Safe by design and safe in operations. The basis for process safety lies in the IEC standards for safety systems IEC 16508 and IEC 16511. For the design, Failure mode, effects, and criticality analysis (FMECA) and Hazardous Operations study (HAZOP) must pay particular attention that all potential safety threats and failures can be detected and handled without physical presence. For operation, safety barrier management must ensure that the barriers built in are maintained. Process safety management uses predictive analytics and diagnostics to reveal latent and developing problems to track the safe operating state. This is also important to prevent accidental emissions e.g. due to blowdown events, as well as massive spills due to catastrophic events.

- Process operation and operational efficiency is the next step. We must ensure that the facility be operated without a physical presence? This means that all information necessary for automatic and autonomous control is available and that all necessary control actions can be performed by the system. When this information is available and represented in high fidelity model of the plant (digital twin), we also have a good foundation to check, tune and optimize the facility in a continuous improvement process. We now also have the tools to determine and implement best strategies for automatic control such as state-based controls for startup, change and shutdown, in a way that minimizes e.g. flaring emissions. Autonomous process operation would include such items as handling of consumables and reset of safety devices.

- Inspection and maintenance will have specific targets such as the frequency of major maintenance campaigns, e.g. once a year, and the frequency of minor service visits. This both has consequences for the design of the system, such as redundancy schemes and MTTF considerations, and for the way the system handles inspection and maintenance remotely. A major contribution to plant uptime comes from elimination of unplanned shutdown resulting from equipment malfunction or failure. We also need to track the many inefficiencies that can result from equipment wear and tear, such as scaling, abrasion and stiction that will affect process and equipment performance and reduce energy efficiency, generally resulting in increased specific emissions. This requires a good understanding of the wear and failure mechanisms and for autonomous facilities requires a change from periodic inspection to facility-wide condition monitoring and predictive analytics, as opposed to only tracking critical equipment as the latter is insufficient in processes with so many interdependencies.

- And, finally there are actions that cannot be handled with measurements and automatic actions but require some form of physical interaction with the plant. Remote and inaccessible facilities have demonstrated how these can be reduced to a minimum but will have to be identified and handled. Over the last 15 years many solutions have been verified in pilot projects and are now reaching TRL 6 level. This will eventually be part of the unmanned and autonomous operation, where the system can dispatch a drone for visual clarification or instruct a robot to perform some intervention such as mechanically testing a valve, scraper handling, gas detection or physical shift detection (such as ground load displacement)

- We also need a revised regulatory framework that can issue license to operate on the desired autonomy level. Today most petroleum industry legislation lack handling of levels beyond level 3.

These criteria are summarized in the following table

TABLE II
Criteria for unmanned and autonomous facilities

Criteria	Requirement
SAFETY	Can we maintain Safety: Standards, FMECA, HAZOP, IEC 61508, IEC 61511
OPERABILITY	Can the facility be operated and optimized without a physical presence?
MAINTAINABILITY	Can the facility be inspected and maintained with a limited number of service visits?
INTERVENTION	Solutions for actions that cannot be handled with measurements and automatic actions needing physical interacton.
REGULATORY	Regulatory framework for autonomy

C. *Enabling technologies*

1) Intelligent Projects and the Digital Twin As a basis, digital engineering and Digital Twin type technology should be used to model the overall system and implement the control schemes [4]. This ensures that we have good overview of the process and collect data that can later be used for Process Optimization, Condition Based Predictive maintenance and Artificial Intelligence decision making. The aim of this is not only to reduce manning in normal operations, but also to ensure that the process is running in an optimal way, and to reduce the overall number of incidents requiring (remote) human intervention.

2) Automated procedures, one button and state-based control. To reduce the load on the central process model, it is generally recommended to close have some level of edge processing where normal functions are handled by control logic in the local controller. This also gives the possibility to preprogram automatic controls with responses to common tasks and events that could be handled without complex model-based systems.

This would be in the form of sequences or state-based controls that allow startup sequences, mode changes, responses to hazardous events, workover procedures etc. to be built into the logic (based on e.g. ISA SP 95 specifications). Based on this, the central model can gradually develop autonomous capability to perform all regular operations.

One example where these technologies were employed was the Aasta Hansteen project by Equinor [5]. Part of the challenge was to make the first gas start-up process as quick and efficient as possible and eliminate flaring during startup. For this, the challenge was to reduce a sequence of over 1000 manual interventions to as few as possible. The outcome is a series of buttons that are as simple as starting a car, referred to as “one button startup”. One important experience we could draw on in this work was the recently completed Sadara complex where Dow / Aramco used state based control to achieve similar results.

During this process, the start-up steps were defined and we identified obstacles that needed to be improved. The digital twin simulator environment allowed us to do a virtual start-up of the plant, and identify numerous improvements for starting up and operating the plant in the process. In this way we managed to reduce a complex set of manual interventions to just 20 and also accomplish the “no flare” target.

The company recorded 57 specific improvements that were verified and implemented, resulting in about 40 saved days in the commissioning phase of the project, and a corresponding reduction in trouble shooting and corrections of circa 2,700 man-hours.

The next step is to establish a continuous improvement process though AI (Artificial Intelligence) Machine Learning technology to analyze and respond to abnormal events or detect hazardous process conditions and respond to them.

Some key facts [6] [7]:

- 80% of production losses can be avoided, half of which can be attributed to the wrong control decisions [5] by human operators.
- Human error has been the second most frequent cause for the 100 largest plant accidents globally over the last 30+ years.
- 14.5 billion dollars have been lost as a result of these accidents referenced above
- Roughly 3-5% of lost capacity in process equipment is caused by loss control in abnormal situations, which means a typical plant savings could be € 2.7 million annually
- Elimination of abnormal situations in petrochemical plants could increase profits by 5%

3) Predictive Maintenance For most oil and gas assets, the detailed maintenance planning for new assets is started after the design and instrumentation level have been set. This usually leads to a maintenance plan that does not take into account the technological development which is already field proven in other industries. We need to include the richness of information from smart devices and instrumentation in maintenance concepts and used during design of the asset and also change work processes to reduce the frequency of manned interventions to a minimum.

The most common practice in the industry is to apply condition monitoring to critical machinery. Each individual equipment has its own condition monitoring system which assesses the health of the equipment independently from any connected plant components. However, oil and gas facilities are complex and highly coupled systems. A problem occurring in one part of the plant can often propagate to other components, and a holistic approach to towards predictive and proactive maintenance is needed. Analytics to support improved maintenance planning can now be performed on component, system, plant or fleet levels using big data analytics and deep machine learning, where large amounts of data are processed to extract subtle, previously hidden, information. In combination with Digital Twin system modeling, the logic to support this can be extracted from the overall engineering model.

4) Artificial Intelligence and Machine Learning A fully autonomous system operating at Level 5 should be able to handle unforeseen situations and perform high-level problem solving without human intervention. Autonomous systems may require lower level automated functions in order to be effective: E.g., a robot manipulator system can learn how to pick up an object that it has not encountered before by making use of automated functions such as vision-based object detection and sensor-based collision avoidance. The robot can apply methods for robot learning [8] to learn how to safely grasp and pick up the previously unknown object.

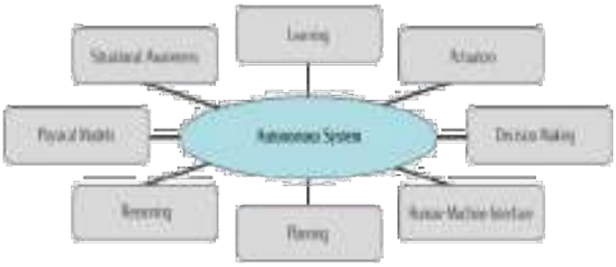

Fig. 1 Capabilities of a Level 5 Autonomous System

An autonomous system needs all or most of the following capabilities (Fig 1) [1]:

- Situation awareness: "Knowing and understanding what is going on" [9]
- Reasoning: Generate conclusions from available knowledge
- Planning: Construct a sequence of actions to achieve a goal
- Decision making: Select a course of action among several alternative scenarios
- Learning: Improvement through practice, experience, or by teaching
- Actuation: The ability to physically interact with its environment
- Human-machine interfaces: How the autonomous systems interact with humans [10]

III. IMPROVING ENERG EFFICIENCY AND REDUCED EMISSIONS

Many of the areas listed above, supporting reduced emissions using normal process operation and exceptional events could be performed during normal manual operation of the systems. We often see that optimal operation needs continuous follow up as they tend to fall out of tune or optimal control within days and weeks. This is particularly true for controls dealing with multi-phase flows, such as well control.

Even if a manual continuous improvement program can be established, an automatic and autonomous system would likely maintain an up to date dynamic model of the plant, which is ideally suited to automatically adjusted process optimization.

We van the summarize the emissions reduction potential of an autonomous facility as follows:

A. Emissions during safety action

One of the most important contributors to emissions from an operating facility is safety shutdown actions and the following restart procedure. Often this means that large quantities of pressurized hydrocarbons in the process must be vented to flaring systems, as systems are depressurized, purged and started up.

The remedy is of course to reduce the number of process upsets that are the cause of these events, and this is both a design issue (safe and reliable by design) and a safety management task.

This is managed by a process safety barrier management system as illustrated by the figure below.

Figure 2 Process safety management

Here the objective is to monitor that all safety related equipment is operating with the required barriers intact, early detection of potential shutdown situations and operator support functionality.

As shown earlier, 80% of process shutdowns are preventable, and half of them are caused by operator error, so autonomous systems with good safety analytics should be able to eliminate a majority of these.

It is not uncommon that such shutdowns can lose as much as 10 full production days per year, or about 3% for complex processing facilities, such as LNG plants, and about half that for average production facilities.

B. Emissions during catastrophic events

Catastrophic events that cause fires, oil and gas spills, or loss of toxic substances have caused some of the largest singular environmental impacts in the industry.

These events often result from loss of overview of the facility combined with fail to operate of critical equipment. Solutions such as the process safety management as discussed with fig. 2 above coupled with a barrier management system are invaluable in preventing these incidents. Humans excel at solving complex problems with limited data, but often fail to respond correctly to large rapidly changing data sets. Many events that are attributed to human failure, are in reality system problems that overload the operator with data that cannot be efficiently handled by humans.

C. Emissions from worn and failing equipment

Condition monitoring of industrial assets, such as motors or pumps, can ensure that critical issues are detected early, thus avoiding unplanned downtime or damage. Early intervention, which reduces the need for corrective maintenance, is more cost-effective than simply allowing a component to run to failure. [11]

Condition monitoring of such equipment combined with predictive analytics to determine the action to take in the various detected conditions. In the reference case, A neural-network-based, machine-learning model was trained to predict the future health status of the asset (an electrically driven pump).

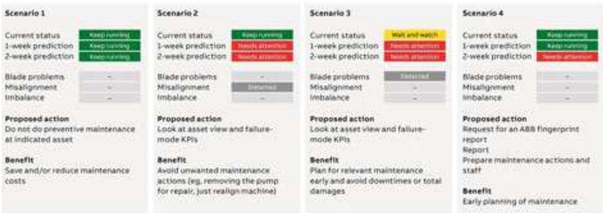

Figure 3 Scenarios for predictive maintenance

Here, we illustrate three scenarios:

Scenario 1 The asset is operating normally with no damage predicted, the current and predicted statuses are "Keep running." No unnecessary time-based maintenance need be undertaken.

Scenario 2 The asset is currently exhibiting evidence of damage but not imminent failure. The current-status field advises to keep operating the asset and the predicted-status fields for the weeks ahead would show "Needs attention" and recommend an action (review the asset sensor data in a detailed fashion and to take appropriate action)

Scenario 3 The asset is currently exhibiting evidence of significant damage, not severe enough that it needs to be stopped, but enough that its condition should be monitored closely. The diagnostic algorithms indicate any initiated damage.

Scenario 4 The asset is currently exhibiting symptoms of considerable damage and could reach a significant damage level in two weeks or later. Since there is no devastating damage in the current status, it advises the user to "Keep running" and the prediction based on past historical data and current data would suggest the status field for the two-week prediction as "Needs attention."

Such systems should allow us to monitor borh for equipment efficiency and falire.

Efficiency issues might for example be scaling in pumps or heat exchangers which would turn up as deviations from the known good equipment performance envelope.

D. Emissions from Process Inefficiency

Process performance capability is an important area for gaining value and reducing emissions. Examples from 20 years of improving upstream operations at more than 40 sites give us the following indicators of the potential:

- Increase normal production 3-10%
- Reduce unplanned shutdowns ~20%
- 50% faster well ramp-up
- Reduced start-up operator load by 3600 HMI interactions at Aasta Hansteen
- Removed flaring during start-up for Aasta Hansteen
- Reduce compression cost by 20%
- Days and weeks' worth of earlier start-up

The principle behind this is often relatively simple, although the solution itself may be complex: Reduce stability, use improved operating margin to shift setpoint, as illustrated in the following figure:

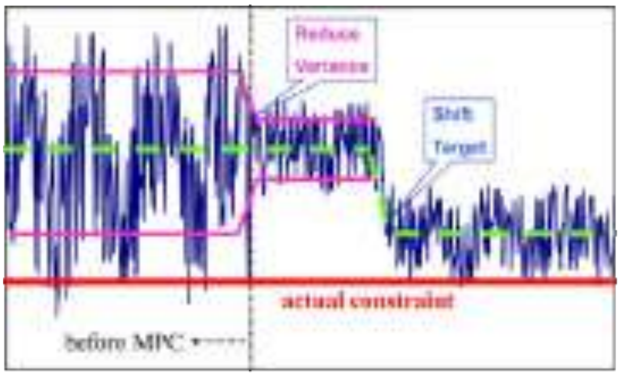

Fig. 4 Basic process optimization

As an example, the following figure illustrates how process optimization reduced the fuel gas use of a gas turbine driving a natural gas compressor by around 20%

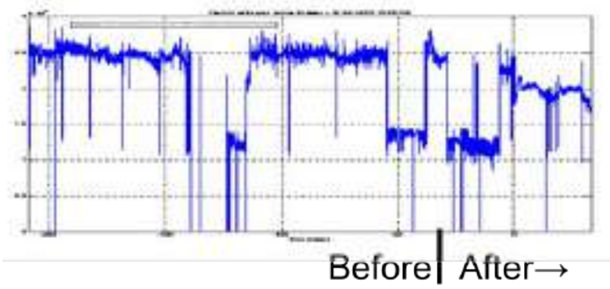

Figure 5 Fuel gas consumption reduction

However, as mentioned above such systems may fall out of optimal tuning within days to weeks, and on level 3 and above an autonomous system would provide Automatic Production Optimization analytics.

E. Emissions from Support Infrastructure

Supply Vessels, Helitransport etc.

While these emissions are not directly affected by our above technologies we would still expect a significant reduction due to reduced manning, reduced maintenance and reduced intervention needs. Therefore it still makes sense to include these in the overall emissions reductions resulting from increased Autonomy.

IV. CONCLUSIONS

The gained efficiency and loss prevention could range from 3-6% for typical well and process equipment, up to 20% in special cases. We know that the oil and gas industry on the average 12% of the well stream is consumed by the production transportation and processing facilities before the product can be sold, and based on observed figures, it is likely that more than a third of this can be eliminated with Automatic Production Optimization and Process Safety management analytics.

While part of this reduction could also be realized in a system operated by humans alone, we see that the continuous optimization that could be realized with in combination with a higher level autonomous solutions such as Digital Twin, Process Models, Machine Learning and Artificial Intelligence are likely to maintain and improve the reductions.

Higher levels of autonomy will require a detailed understanding of the tasks that will be automated when increasing autonomy from one level to the next. This includes economical impact (life of field), and the operational and safety challenges related to automating the task and removing the human from that loop. This will be based both on experience and competence .Often this can be realized by drawing on how similar challenges have been solved in other industries and applications, and who was involved (competency), how it was developed (POC Pilot – Test – Operation) and the technology deployed (algorithms, infrastructure and software).

NOMENCLATURE

FMECA	Failure mode, effects, and criticality analysis
HAZOP	Hazardous Operations study
MTTF	Mean Time To Fail

V. ACKNOWLEDGEMENTS

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VII. VITA

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FUTURE ARCHITECTURES OF ELECTRICAL SUBSTATIONS

Paper No.EUR21_32

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Abstract -
For 40 years, most of the HV/MV & LV electrical substations have been build using copper cables wiring together protection relays, automation and measurement units and primary equipments such Power Transformer, Circuit Breakers, Switches and Voltage/Current Transformers and protection relays to control of the electricity. Beginning of the 21th century, the used of Ethernet based substation communication coupled with the generalization of digital technologies have started the step to digital substations.

The present paper presents the future evolutions for the HV & LV electrical substations based on the new technology evolutions and communication technologies with in detail the new Centralized Protection, Control, Automation & Measurement Systems for substation supported by IEEE and the expected evolution to the virtualization of all equipments taking benefits of the Merging Units (MU) generalization.

In conclusion, the impacts over substation engineering tools and security concepts are identified coupled with these new HV & LV architectures.

Index Terms — Substation Automation, Electrical Grid, Virtualization, Digitization, IEC61850, Centralized architecture, Merging Unit, Process Bus.

I. INTRODUCTION

One of the key challenge Industrial sites face is the need to optimize what is not in their core business and reduce all additional costs. Electricity is considered as a resource to be optimize in term of availability, dependability and cost. This is mainly achieved by integrating technology evolutions, adapted products and engineering tools and services able to reduce investments and managements costs in respect of site security, international applicable standards and interoperability between suppliers.

Introduction of digitization and possibilities of virtualization change the way the HV & LV industrial grid design will be done. We will see in the following chapters how this can be evaluated and what is today possible at reasonable risks and with potential benefits.

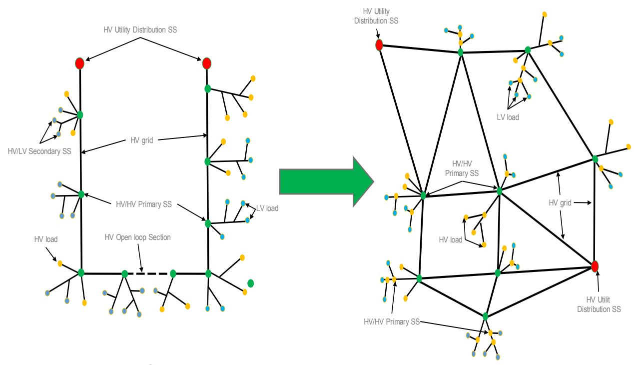
II. EXISTING ARCHITECTURES FOR HV & LV INDUSTRIAL GRIDS

Since the standardization of electricity use for industrial site process, the global structures of the site electrical grid have not changed but recent technological evolutions coupled with climate change regulations generate recent strong evolutions.

A. HV & LV industrial grid architecture

The HV & LV electrical grids of Industrial sites have been mostly designed since more than 50 years upon a traditional pyramidal architecture; The power is delivered by the Utility connection at the highest voltage level and then through various voltage transformers, substations and sub-grids distributed to the local applications connected on LV or HV. All elements are adapted to this top to down concern.

New availability of renewable and intermittent energy resources and storage capacities on site, industrial application consumption management with demand responses concepts create conditions for a complete redesign of the new grids from the historical pyramidal to a complete flexible mesh architecture.



Industrial Open-loop HV grid to HV architecture

B. Protection, Control & Measurement systems

Since the middle on the 80s, start to be applicable for HV & LV Electrical grid, Intelligent Electronic Devices (IED) based on the first hardened microprocessors and controllers taking advantage of analog grid measured quantities into digital signal. All these equipments were handling single function similar to what was possible with modular existing static devices. Technology evolutions make existing features smarter, faster and more integrated but without major changes in the architectures of the electrical substations and grids.

In the HV & LV substations, the various actuators (CB, SW,..) remains with their interposing relays and sensors (CT, VT, IOs); IEDs handle single function similar to what was possible with modular existing static devices, interconnection slowing move from the copper wirings to serial (IEC103, MODBUS, DNP3, ..) and Ethernet based protocols (OPC, IEC61850, IEC104, DNP3/IP, …), Local Display, SER (Sequence of Event Recorder) and RTU (Remote Terminal Unit) have been replaced by HMI (Human Machine Interface) and GTW (Gateway).

Traditional HV substation PCAS architecture

At Grid Level the technology migrations have push the replacement of the multiple cooper wiring cabinet by serial communications and by Ethernet or wireless support. Same evolutions for the Energy management System which features are now possibly embedded in the Process Management System (PMS) or the Building Management System (BMS).

II. Concepts of HV & LV Industrial grids virtualization

The publication of the IEC61850 fast and standardized Ethernet based standard have been the first formal step of the potential evolution of the HV and LV substation sand grid through mainly three directions:

- Communication structure for substation (61850-7.1)
- Time-critical and non-time-critical data exchange through local-area networks (61850-8.1)
- Publication of the sampled value Process bus (61850-9.2)

Other standards regarding Time synchronization (IEEE 1588), Ethernet redundancy (IEC 62439), Merging Units and Non-Conventional IT (IEC 61869) have been an enabler or the emergence of new substation PCAM solution architectures mainly based on the virtualization concept.

A. *Virtualization concepts*

Virtualization concept refers to the substitution of a virtual machine acting like the real one. Multiple physical machines may be virtualized in a single software with application running in parallel with different types of virtualization steps:

- Para-virtualization: Local applications are transferred in a dedicated hardware running in their own isolated domain with their own sensors. The different subparts are interconnected together in a real domain. It is usually a first step to virtualization allowing a smooth migration
- Full virtualization Complete simulation of the hardware to allow software environments, including a guest operating system and its apps, to run unmodified.

Virtualization help to reduce the physical infrastructure cost of electrical PCAM solution, ensure a shortest testing and restoration time and improve security and installation safety.

B. *Virtualized Industrial grid architectures*

Industrial electrical grid resource virtualization is the first concept to be considered and may be achieve using two ways:

- The Platform virtualization impacting mainly electric management applications.
- The Resource virtualization involves splitting or combining real IEDs into virtual groups.

Platform virtualization consider one physical equipment divided into multiple virtual environments. This approach provides positive elements:

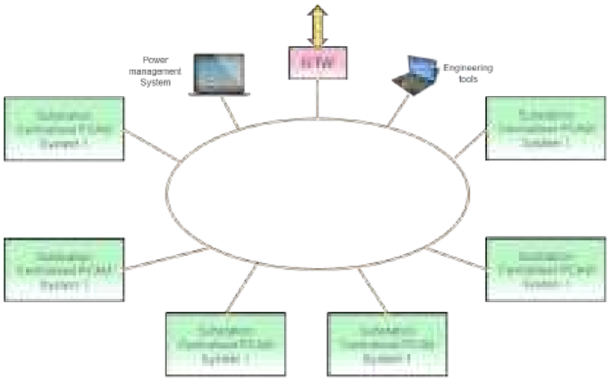
- Deployment/restoration time: Creating and installing a virtual machine is simple and request limited time (10 to 30 mn) compare to traditional methods (1 to 8 h)
- Cost reduction by the optimized used of equipments and energy resources
- Evolutions as most of tests are run using simulation machines similar to site elements

Resource virtualization mainly consider the communication network by the use of VPNs and VLANs making communication architecture simpler. A specific attention must be given by network administrator to performance and topology management to avoid complexity and security risk.

Storage and archiving virtualization are also very common and popular resource virtualization methods in Industrial applications by abstracting application data archiving from multiple physical storage unit to a virtual remote unit mostly known as “cloud storage”.

Electrical Management virtualization can be deployed as:

- The entire industrial grid HV & LV elements (substations, feeders, generator, etc..) with all functional elements in a single or redundant central machine,
- HV and LV Substations as elementary bricks combine to run the industrial electrical grid application.



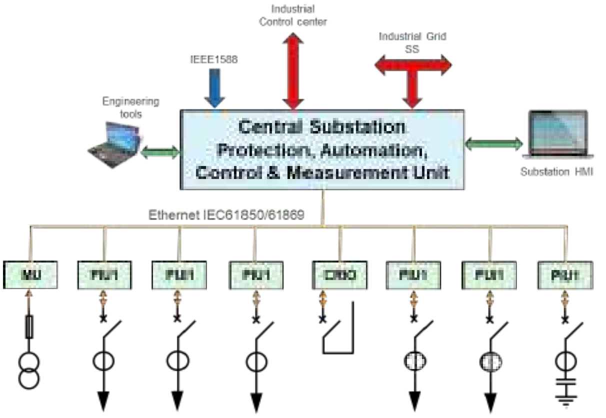
Industrial HV & LV grid architecture with virtualized PCAM System

Electric management virtualization simplifies the application installation and deployment as the application software are independent from the physical hardware and software environments. This makes possible running of simultaneous applications even they use the same data or used incompatible hardware or software.

Virtualization allows to mix over the same global application different virtualization concepts and architectures to full-fill application requirements and project delivery time constraints; Evolutions are also simplified and help to reduce maintenance costs.

III. ARCHITECTURE OF VIRTUALIZED ELECTRICAL INDUSTRIAL GRIDS

Considering all virtualization concepts and availability of various applicable standards, the most suitable architecture for Industrial HV & LV site is the partial virtualization with HV & LV centralized substation PCAM systems connected on a redundant HSR/PRP Ethernet fiber optic network with Power Management system and interface to the Site Process management System.



HV Substation Centralized PCAM System architecture

A. *Substation elements*

In electric substations, the functional scope of the virtualization will mainly be:

- HV & LV Protection functions (OC, Dir OC, Diff Line, Diff Transformer, Generator, Busbar, etc..)
- HC & LV Control capability (Switchgear Control, Generator Start & Stop, OLTC control, …)
- HV & LV Automation schemes (earth control, Inter-tripping, Logic selectivity, Volt/Var regulation, …)
- HV & LV Measurements & Monitoring (Quality, Measure, CB monitoring, Oil monitoring
- HV & LV substation HMI and archiving
- HV & LV gateway (from associated equipments, to surrounding HV & LV substation, to Site Energy management system)
- Inter-equipment wirings (analog and logic) and associated interposing relays

In complement, virtualization concept will also integrate:

- HV & LV substation engineering tools for design, wiring, and configuration of the various IEDs
- Test procedures and methods of the single IEDs and the global HV & LV substation

Additional HV & LV substation parts are also impacted by the Digitization concept

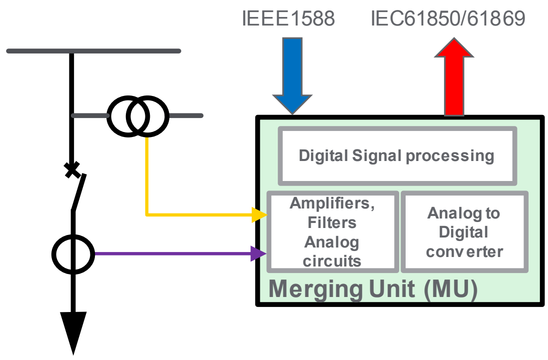
- Cabinets and cubicles hosting communication devices (switch, router, Gateway, ….)
- Auxiliary power supply including associated UPS
- Electric & communication cable trays
- Security & Cyber-security rules and procedures

B. *New Substation elements*

PCAM virtualized HV & LV substation architecture change strongly the hardware and software used.

Many IEDs are virtualized (protection relays, RTU, Measurement units, etc..) and some new elements mainly sensors interfacing electric process as defined by the IEEE/IEC WGs, Smart grid concepts and IEC61850 standards, are coming on field:

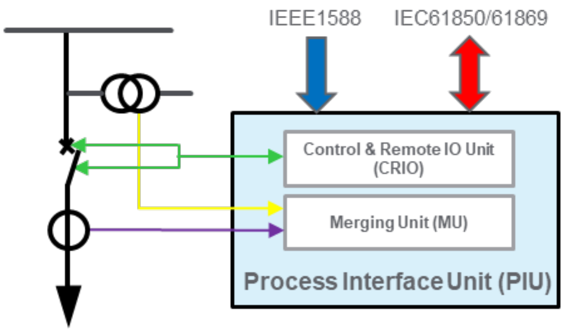
- Merging Unit (MU) IED converting analog signals (protection and measurement CT or VT mostly) into sampled values (IEC61869),
- Control & Remote IOs unit (CRIO) converts control and status information for primary equipment (SW, CB, Transformer, ...) to Process Bus GOOSE based mainly,
- Process Interface Unit (PIU) combines a MU and a CRIO unit into a single equipment. PIU can publish over IEC61850 analog values and equipment status and accept control commands for primary equipment operation.



Merging Unit typical architecture

Based on study done in IEEE PSRC WG, two physical model of PIU are considered:

- Class 1 PIU (PUI1) combines analog and logic bay equipment interface as per IEC 61850-9-2, IEC 61869-9/13
- Class 2 PIU (PIU 2) is a PUI with additional safety protection function able to run in a stand-alone mode



PIU typical architecture

All these new elements use Ethernet Fiber 1, 10 or 25 Gb/s with Standardized redundancy methods (Parallel Redundancy (PRP) and High-Availability Seamless Redundancy (HSR) and Time synchro IEEE 1588 based

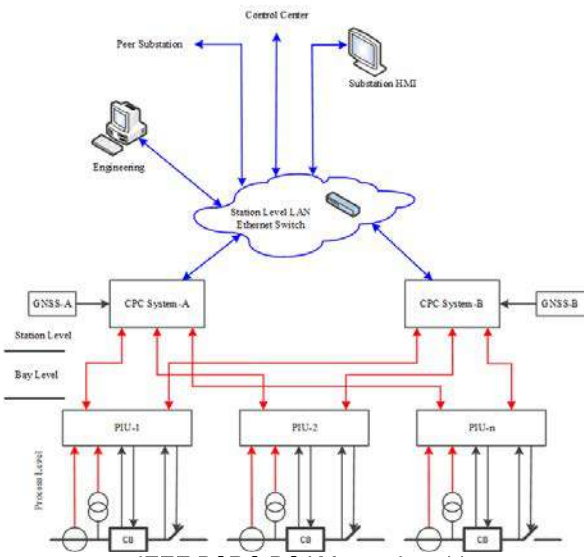
A central potentially redundant device embedded:

- Communication with the different PIUs, MU & CRIOs of the substation via IEC61850 Ethernet fiber interfaces
- Multiple functional bricks as define by IEC61850 and running all primary equipment, voltage level and substation functions (Protection, Automation, Control & Measurements) in a coherent and consistent manner based on data received from the PUIs, Mus and CRIOs
- Local Data storage and Archiving on a dedicated unit (optional)
- Display on a local Human Machine Interface (optional)
- Interfaces to the outside of the substation with two main directions:
  - the Site Energy management application,
  - Surrounding substations (HV & LV) for distributed protection and automation functions

C. *PCAM HV & LV substation solution architecture*

The PCAM HV & LV substation solution architecture is built around 3 main layers:

- The process/bay level interfacing the different primary equipments (logic and analog)
- The communication level based on Giga-Ethernet optical fiber (1, 10 or 25 Gb/s) with or without redundancy (IEC62439 HSR or PRP), Ethernet switch/router and IEEE 1588 time synchro clock
- The substation level with the central computer CPC (single or redundant), engineering tool, local HMI display, gateways to site Energy Management System and other site substations (HV & LV) and equipments (Generator, Storage units, ...)

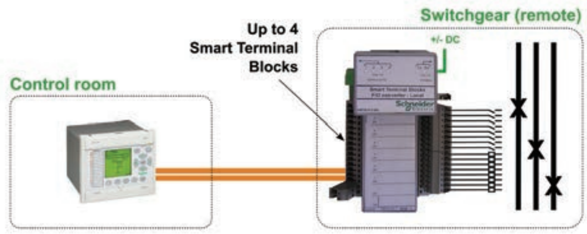


IEEE PSRC PCAM type 3 architecture

Note : for LV substation /equipment the attachment to a main HV substation allows to simplify the architecture by removing part of the CPC and associated equipments.

As define by IEEE PSRC WG, 6 typical PCAM architectures have been defined (type 1 to 6) with various integration level, redundancy and functional split. For Industrial site applications, type 3 and type 5 are the most usable. Both refer to similar organization while in type 3 PIUs are connected to CPC systems over Point-to-Point connection; In Type 5, PIUs are multicasting SV and GOOSE to CPC systems, and each PIU receives multicast GOOSE from CPC systems.

It is also key to note that these architectures allow the interoperability between the Virtualized environment and any legacy systems. This is a major challenge to support multiple suppliers and application domains in the same environment. Virtualization of legacy sub-systems is then easily and cheap.

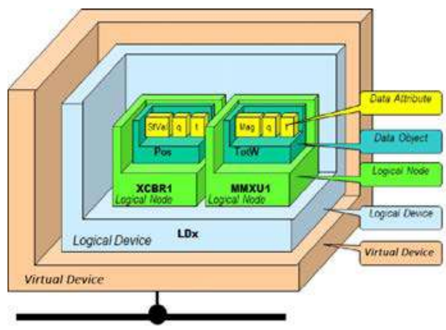


PUI (SE Smart Blocks) interfacing wired legacy equipment

D. *Engineering tools*

PCAM solution for industrial electrical HV & LV substation are configured based on IEC61850 concepts. The use of IEC61850 System Configuration Language (SCL) combine with the standardized data and function modeling (IEC61850-7) allows application engineering to be fully independent from the physical implementation and an easy migration from a traditional architecture to a full virtualized concept.

Applying IEC61850 concept, each standard bay (LV feeder, HV/LV transformer, HV busbar, ..) is associated a series of logical devices representing the bay functions housed in a virtual IED.

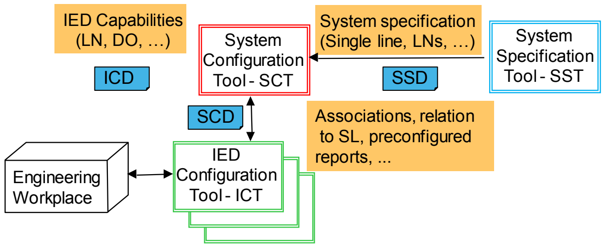


Virtual IED functional architecture

IEC61850 engineering are built mainly around three layers/tools:

- The System Specification Tool (SST) for the specifications of process signal, automation data exchange, communication and electric network topology. SST allows to associate IEC 61850 Logical Nodes to Industrial Power system resources

- The System Configuration Tool (SCT) integrate SST data and will generate application functions, communication network topology & characteristics.
- The IED Configuration Tool (ICT): in Digitization process, the ICT create the functional capabilities of a virtual IED including parameters.



IEC61850 configuration tools

Virtualization takes fully benefits of IEC61850 ed2 concepts and elements and provide all potentials to the designer and the user for a better and more efficient HV & LV electrical grid architecture and use.

E. *Tests of Virtualized CPAM*

The concept of CPAM testing is similar to what is done with traditional IEC61850 Substation Automation System (SAS) with a specific concern regarding Ethernet IEC61850 network and the various interfaces. Simulation testing tool help to cost reduction during Factory Acceptance Tests (FAT) and Site acceptance Tests (SAT) by minimizing all commissioning and outages time especially during the site installation phasing when part of the CPAMs have been validated and new ones are added to them (step by step installation);

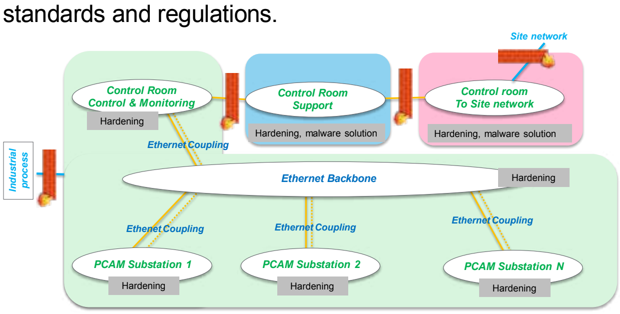
Simulation tools are also key for operator and maintenance team trainings. The simulation tools take benefits from the virtualization concepts by simulating at 100% the missing equipment, data or function

Same tools could be used to anticipated future evolutions of the site (new grid, increase of consumption, change in power delivery, etc.) These application software are also usable in the quasi-real-time simulation to provide options to the operator in their site management actions;

F. *Cyber-security for Virtualized CPAM architecture*

Cyber security management rules are applied to maintain application availability as a priority and then device integrity and data confidentially. Cybersecurity acts at 2 levels:

Network and Device. All are regulated by dedicated standards and regulations.



HV & LV secured Virtualized integrated architecture

The Cyber security design applied to Industrial Virtualized Electric grid must integrate the following items:

- In-depth Defense- concepts with firewall and DeMilitarized Zone (DMZ)
- Role-based Access Management
- Authentication, security and access management
- Remote communication Encryption
- Consistent patch management for all software and firmware components
- Intrusion detection systems

Use of NERC, NIST, IEC62351, ISO17065 rules and standards to analyze and prevent cyber threats is mandatory to protect industrial electrical grid from most of cyber threats of malicious intrusions.

IV. FUTURES OF HV & LV INDUSTRIAL VIRTUALIZED GRIDS

A. *New HV & LV grid industrial functions*

The capability to distributed over a common communication grid data (analog and logic) with a very precise time stamping allow to simplify existing installations and give new opportunities for protections and automation schemes with a clear objective to reduce Electrical costs and improve energy delivery.

The capability to have at the same moment LV and HV data will make motor management more efficient and reduce direct and indirect stress over involved electrical installation. Associated logic selectivity will be possible with a time refence of few milliseconds. Fast ATS becomes simple at HV and LV levels

Distribution of Voltage and frequency precise measurements make power generation more reactive and will reduce the associated costs and impact over the Industrial process

The imposed HV & LV electric grid mesh architecture change the rules of protection characteristics and impose the replacement of Overcurrent and Dir Overcurrent relay by more adapted Differential Current relay; The constraint of this type of protection relay is the need to have fact and precise measurement exchange between cable two ends; In the traditional approach this can only be achieve using dedicated communication path. Now with virtualization, this become possible easily and at near no cost with the capability to reduce fault elimination to less than 40 or 60 milliseconds.

B. *Globalization of the virtualized solutions*

The evident evolutions of the virtualization will be the transfer of all various PCAM central computers function to the Site Energy Management system central system physical hardware.

The second step will the virtualization of the Energy Management System it self on the site Process management System or on a local or remote cloud where all application dedicated to energy runs and exchange data with the rest of the site systems (Fluid, Process, Fire & safety, etc…).

C. *Primary equipment simplification and cost reduction*

The use of virtualized solution in HV & LV Electrical Industrial grid will directly impact the primary equipments in their actual design, manufacturing, testing and maintenance.

In a standard HV or LV Circuit breaker, there are mainly replicated information for the multiple display or use by various operators (position display on local and distance HMI, capability to open/close the CB, etc..). Virtualization will remove all these duplications at associated equipment with possible better availability and dependability, mostly by giving the capability to have real-time test (Ethernet communication vs cooper wiring) with efficient redundancy modes. Associated information are available at data level such as Time stamping, topological information, etc.…

Simplification in the primary equipment wirings and less interposing relays, will also reduce the execution time of any order or status change (typically an interposing relay introduces 3 to 5 ms time delay). With less devices at primary equipment level, global solution direct cost will be reduced and testing time either while possible space and weight reductions must be considered as direct benefits of Virtualization.

V. CONCLUSIONS

Virtualization of HV & LV Electrical grids for Industrial applications has created a significant interest as a new combination of technology and methodology that will potentially change the design, build, test and use of HV & LV electrical grids; This virtualization combines with the necessary changes in the use of energy and the need to comply with environmental requirements make new industrial installations acceptable from both a cost aspect and an ecological concern.

The use of standard and implication of international organizations and committees give a complete credibility to this approach and announces Digitization as a must have for the new HV & LV electrical grids in Industrial sites.

VI. ACKNOWLEDGEMENTS

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VIII. VITA

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Delivering a Periodic Functional Safety Assessment in the Industrial Process Operational Phase

Paper No. PCIC Europe EUR21_33

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Abstract -
Historically, the way in which safety instrumented systems have been operated and maintained can vary significantly. Essentially whatever methodologies are deployed within the operation, the use of a proper lifecycle management approach will be required to maintain the necessary levels of risk reduction.

When modifications are applied to the SIS over time, the requirements for change management, impact assessment and functional safety assessment will need to be implemented. The basis of safety will need to be re-evaluated and the safety requirements updated along with the current 'As Built' documentation.

IEC 61511 recognises that 'periodic functional safety assessment' within the SIS O&M lifecycle phase is mandatory to support the successful functional safety management and delivery of the necessary risk reduction. This paper will identify what is reasonable and practicable to include and assess while operating, maintaining, modifying and testing this important layer of protection.

Index Terms – Functional Safety Management, Functional Safety Assessment, Periodic, Safety Lifecycle, IEC 61508, IEC 61511, Safety Instrumented System.

I. INTRODUCTION

Today many process industry company standards ask for specific requirements to be met in order to manage the maintenance, testing, inspection, and performance analysis of the operating facilities. basis of functional safety.

As part of 'overall safety' for the operating facility, effective safety related systems operation, maintenance, inspection and associated proof testing should confirm the correct operation of the devices deployed and in doing so, detect dangerous hidden faults in such protective barriers.

Ultimately, the Asset Owner will need to know if they can 'demonstrate' the operation and maintenance of SIS is in compliance to recognised industry good practice standards such as those for safety instrumented systems i.e. IEC 61508, IEC 61511 or ISA84 and the associated requirements to meet any regulatory / business insurer expectations.

This important 'protection layer' clearly needs to be managed and delivered against current process industry challenges such as e.g.:

- Compliance to industry code or practice
- Changing market conditions
- Ever increasing production norms
- Lean operational resources
- Increasing regulatory and business insurer expectations on what is good safety
- Sustaining the basis of safety over time and change management
- Cost reduction mandates
- Maintaining focus on process safety leadership and culture

As a means to ensure the operating basis of safety is being maintained, the IEC 61511 safety lifecycle identifies the need for the duty holder to undertake a periodic review of the management process and the technical verification of current site safety requirements being implemented to meet operational risk reduction needs.

For the operation and maintenance (O&M) phase of the safety lifecycle, part of this assurance process will be afforded by the need to undertake a '*Stage 4 Functional Safety Assessment'* for the specific Asset.

There is also the relationship to the broader process safety picture where SIS form part of 'overall safety' regarding the operating facility complete risk reduction measures e.g. operating in conjunction with other technology systems such as machinery & power drives, mechanical relief and blowdown systems, containment systems, etc.

Typically, a review of the basis of safety for the operating facility will be undertaken on a periodic frequency of between 3-5 years, and therefore it would be appropriate that the requirements of Stage 4 FSA for SIS would practically be a sub-set of the more comprehensive process safety review.

It could also be observed that the topics required for SIS Stage 4 FSA could be extended to facilitate the auditability requirements for any protection layer (either instrumented / non-instrumented or control / prevention functions) of overall safety dependent on the composition and technical coverage / depth of the assessment team undertaking the more holistic review. This would be appropriate as Stage 4 FSA will require the same site-based input and responses from EHS, Process, Engineering, Operation & Maintenance and Management teams that are available at site.

II. SIGNIFICANCE OF STAGE 4 FSA

Within manufacturing facilities today, there are known to be a wide range of techniques and methods adopted by the end-user community in their approach to safety system operation, maintenance, inspection, proof testing and modification.

There is too, the previously mentioned desire to comply with industry good practice standards particularly for safety instrumented systems (SIS) such as IEC 61508 and IEC 61511. Here, broadly speaking, it is now accepted good practice to follow the requirements of these standards to show that the necessary protective systems are being operated, maintained and tested in accordance with details as identified within the original safety requirements specification (SRS), and its subsequent change management revision over time.

Experience also suggests, that during planned site visits regarding compliance auditing and assessments to relevant good practices, both internal company and external stakeholders are increasingly showing an interest in the duty holders' operation, maintenance, proof testing and change management regimes. In particular, for documented evidence of the organisation having undertaken an IEC 61511 stage 4 FSA.

The basis of safety delivered by SIS will need to be re-evaluated against the SRS along with the current 'As Built' documentation. Any supporting preventative and corrective maintenance measures will need to be scheduled and executed in accordance with device safety manuals.

When modifications are applied to installed protective systems, the requirements for change management, impact assessment and functional safety assessment will need to be implemented.

Such processes will need to consider as a minimum:

- Proper operation and maintenance planning for such safety related systems
- Procedures and instructions for O&M of the SIS
- Demonstration of compliance to the relevant functional safety standards
- Functional Safety management compliance demonstration including the key structural requirements for:
  - Management Process (Policies, Procedures & Records)
  - Competency Assurance
  - Audit and Assessment

III. REQUIREMENTS FOR FUNCTIONAL SAFETY ASSESSMENT

IEC 61511 specifically requires: at clause 5.2.6.1.4 that "*the stages in the SIS safety life-cycle at which the FSA activities are to be carried out shall be identified during the safety planning*, and in particular for Stage 4 FSA, *after gaining experience in operating and maintenance".*

Further, clause 5.2.6.1.10 identifies that an "*FSA shall also be carried out periodically during the operations and maintenance phase to ensure and operation are being carried out according to the assumptions made during design and that the requirements within IEC 61511 for safety management and verification are being met".*

Figure 1 below provides an overview of the IEC 61511 lifecycle and the identified 'stages' for functional safety assessment to be carried out and the focus for this paper regarding Stage 4 FSA.

Here we also need to recognise the difference between an 'Audit and an 'Assessment' in the context of the standard. We identify that an Audit is the determination as to whether the company operational procedures and practices are being followed consistently and whether the overall management program is working effectively, whereas, an Assessment is different in as much its emphasis is to undertake a detailed technical and management focused investigation to judge the functional safety achieved by the relevant protection layers under review.

So, given the role and importance of this specific activity, how are you meeting the requirements of periodic Stage 4 FSA in your organisation?

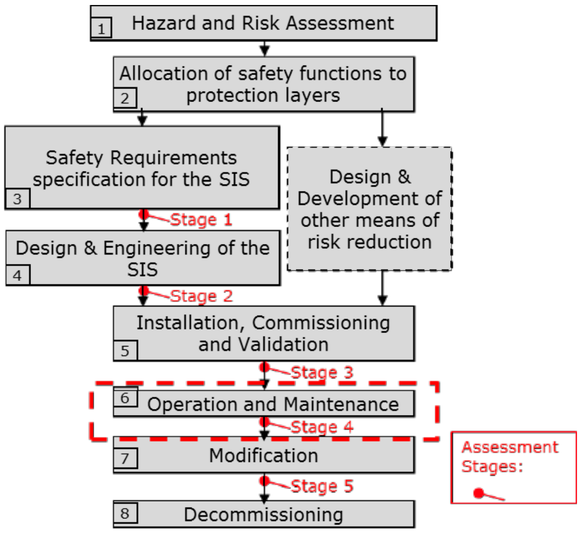

Figure 1 – IEC 61511 Safety Lifecycle and FSA Stages

IV. MANAGEMENT PROCESS AND FSAS

As the IEC 61511 standard focuses predominantly on SIS, it identifies that *a '"functional safety management system shall be in place so as to ensure that where safety instrumented systems are used, they have the ability to place and/or maintain the process in a 'safe state''* and by association this means that '*there shall be in place systems & procedures that cover the requirements for proper operations & maintenance to ensure:*

- *The designed SIS functionality is maintained*
- *The required SIL of each SIF is maintained during operation and maintenance"*

Further, many years of experience in the development and assessment of operational management procedures across a range of operating sectors within the process industries, identifies that in several cases, robust management processes can be found to be lacking or contain significant gaps in good practice expectations.

Observations regarding process and underpinning senior management commitment to achieve functional safety excellence in this area concludes that:

- Many QMS as per ISO 9001 lack sufficient depth and rigour even for baseline management requirements (greater reliance on individual competencies rather than any codification of requirements)
- Many management systems are disconnected between various departments that can cause issues on process delivery and effective communication requirements
- Some management systems cannot be shown to comply with expected industry good practice standards/guidance
- Many process industry statistics show that errors, omissions and incidents are directly attributable to a lack of robust management system/process and internal commitments to sustain them
- Many management processes are implemented and then receive little attention once in place
- Stakeholders expect robust management processes to be in place and will require the duty holder to demonstrate that this is the case
- There is some evidence that it is common practice for companies to ignore the requirements for undertaking Stage 3 FSA

It therefore follows that the IEC 61511 standard requires for periodic assessments to be conducted to address the issues identified above to ensure safety integrity and security measures are as implemented and that they continue to provide the necessary risk reduction for the operational facility.

V. What should be included in you periodic FSA?

A Functional Safety Assessment (including the management process requirements of system auditing) is identified as a systematic and independent examination of the particular SIS safety lifecycle phases activities under review and as in this case the operation and maintenance lifecycle phases of the safety lifecycle.

In accordance with IEC 61511 requirements, this periodic FSA approach will determine whether the management process and technical activities comply with the planned arrangements, are implemented effectively, and are suitable to achieve the specified objectives.

Performing FSAs requires personnel with a high level of competency and is more often than not based on subjectivity, particularly when applied to the earlier phases of the safety lifecycle. A further key consideration is the level of independence of the team performing the FSA and by implication, their assessors. The necessary level of independence shall comply with IEC 61508, Part 1, clauses 8.2.12 to 8.2.14 or IEC 61511 part 1, clause 5.2.6.1.2.

To set out to achieve this goal, those responsible for ensuring FSAs are conducted should establish and effectively manage the following key parameters:

- A Stage 1-3 / 4 FSA plan is developed and is being followed
- Competency and independence are addressed by those completing Periodic FSAs
- Requirements for developing a common approach to FSA topics requirements are met i.e. focus on what is most important.
- An approach is applied that is structured on compliance requirements to the basic safety standard IEC 61508-1, or the standard derived from IEC 61508 to which functional safety claims are made (e.g. IEC 61511)
- A methodology is agreed which would be useful to benchmark assessment findings in a speedy manner and provide a means for comparison between different process units/assets for company KPI’s
- A repeatable process is utilised so that it can be used to track and monitor improvements and provide the necessary forwards/backwards traceability between differing assessments
- Harness the use of FSA support tools to quickly establish the process when undertaking assessments with busy operational resources and in a cost-effective manner

VI. Assessment methods for improving functional safety – requirements?

The methodology to be applied should identify a means to optimise the assessment process for the current performance status of the operational safety related systems. This means the use of a methodology that can be easily traced to industry good practice expectations whilst digitizing the operational status assessment process and findings for sustainable and traceable records.

Here, the Lead Assessor needs to ensure that the assessment process and subsequent results are readable, intuitive, and easily presented for understanding and adoption by all stakeholders. Nowadays, Lead Assessors can utilise specific database Tools for this purpose regarding the digitization of the FSA process.

The organisation that provides the Lead Assessor will need to deploy an assessment structure (procedures / instructions / process / tools) that is robust, repeatable and allows for the comparison and analysis of findings to support senior management focus and underpinning safety culture.

In doing so, this should provide a means to identify Key Performance Indicators (KPIs) for areas of non-compliance. Ultimately the Asset Owner needs to satisfy themselves that the FSA process / methodology to be applied essentially assesses if appropriate technical methods, techniques and measures, results and processes have been used to achieve the necessary functional safety.

From the author’s experience, Stage 4 FSA methodology for SIS should consider the following ‘Key Principles’ topic areas:

- Functional Safety Management
- Competency Assurance
- Stage 1, 2 and 3 Assessments and Audits results and their implementations

- Management of Change
- Human Factors (systematic failures)
- SIS Cyber Security
- Pre-start-up / Ongoing Process Safety
- SIS Operation & Maintenance
- Planning / procedures to be applied on the system for detected faults
- SIS Inspections, maintenance & proof testing
- Operational performance and device mission time monitoring

So, what should be considered for assessment at the detail level under each Key Principle? As with this type of assessment, the Lead Assessor will open with a critical question and lead the assessment team down a structured narrative to explore the topic at the comprehensive level.

During the FSA team discussion, the assessment team will need to establish the associated 'sub-principle' criteria to be assessed and the findings recorded, compliance levels defined, and any recommendations made.

To fully describe and detail a complete FSA process would clearly be inappropriate for this paper. However, to further assist the reader in what may constitute a high-level overview of this recommended approach, the following section will provide a high-level introduction and a little more detail and thought processes to be applied for the Key Principles identified earlier.

This could be used as a means to demonstrate '*one example approach'* to achieve such a level of depth to be covered.

I) FUNCTIONAL SAFETY MANAGEMENT

Opening question:

Is the policy and strategy for achieving functional safety identified within the organisation?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Policy
- Roles and responsibilities
- Planning
- Procedures
- Competency
- Risk evaluation
- Verification
- Documentation

Here the assessor is seeking clarity on the management process and importantly management commitment to underpin its effectiveness.

A competency management system should be in place and there is a structure being used to periodically monitor and re-assess the performance of personnel in plant operations.

Risks associated with the operational hazards have been evaluated and documented.

II) COMPETENCY ASSURANCE

Opening question:

How does the site management team ensure that personnel have the correct level of knowledge, training and experience appropriate to their role, the plant process and technology deployed for the SIS?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Procedures
- Planning
- Understanding of Process and Technology
- SIS Functionality and Operation
- Operational Hazards
- SIS Devices Failure Modes
- SIS Bypassing

Here the assessor requires to know that competent persons are identified, assessed for their specific roles and responsibilities for safety related activities and that such competencies are recorded, reviewed and approved, including the need for any mentoring, training and supervision for the tasks assigned at the individual level.

III) AUDIT & ASSESSMENT

Opening question:

How are FS Audits and FS Assessments compliance requirements being met in the company?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Scope
- Procedures
- Planning
- Results and action tracking
- Assessors Competency & Independence

Here the assessor needs to establish that audits and assessments are planned, visible and communicated. It is important that competency and independence is established and that the results of such activities are actioned tracked with supporting management involvement to ensure their satisfactory conclusion.

IV) MANAGEMENT OF CHANGE

Opening question:

How are changes / modifications to any safety instrumented system planned, reviewed and approved?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Procedures
- Planning
- Impact assessment and analysis
- Competency of persons involved in modification
- Confirmation of effectiveness (reverification / revalidation and approval)

Here the assessor will be keen to establish that change management controls are robust and that impact assessments are being carried out for change approval by competent and independent approvers.

This will also include for version control and 'As Built' status updates across a range of documentation, technology, serialisation, etc. that are correct to reflect current operational status and that the basis of safety remains accurate and valid.

V) Human factors

Opening question:

How have the requirements for Human Performance and the impact of these requirements onto those persons responsible for operations and maintenance being implemented?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Policy
- Procedures
- Planning
- Safety critical tasks and risk assessment
- Task analysis and human reliability analysis
- Analysis reports on sub-task performance
- Requirements for highly managed alarms
- Control measures for human performance
- Investigation reporting

Here the assessor will be seeking to establish the requirements for the adoption of structured methodologies for undertaking human reliability analysis (HRA) on critical tasks for safety in line with relevant good practice and that the level of human involvement / interaction is understood with respect to the consequences of human failure.

VI) SIS Cybersecurity

Opening question:

How is the organisation's security policy defined, organized and executed?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Policy
- Risk Analysis
- Personnel security
- Physical security
- Network segmentation
- Account administration
- Authentication and authorization
- Information management
- Incident planning
- Monitoring and improvement

Here the assessor will identify the systems, processes and organisations involved in cyber security management (CSMS) for the SIS and confirm how the organisation understands the importance of security for its IT / OT operating environment.

A risk profile will have been established and applied across the technology in use which should have records and analysis of performance available. The organisation will also detail an incident response plan and that all employees have been trained to deal with cybersecurity breaches.

VII) Process Hazard and Risk Analysis

Opening question:

Is a comprehensive Hazard and Risk Analysis available for review, and if so, what does it contain?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Procedures
- Planning
- Safety function analysis / allocation
- Design assumptions
- Stage 3 FSA including implementation of findings
- Utilities
- Reliability assumptions
- Explosive atmospheres
- Control room suitability
- HMI

Here the assessor requires to establish that a description of each identified hazardous event exists and that the likelihood and consequences of each hazard is fully understood.

Where SIF protection layers exist, they are fit for purpose regarding the required risk reduction and that they are maintained and operated correctly (including supporting utilities) against safety requirements and design assumptions.

In addition, the threat of explosions and pressure bursts have been considered for control room operations and the HMI within this environment effectively informs the operating team of any deviations from normal safe operating levels.

VIII) Operation

Opening question:

How do the current operating procedures cover the comprehensive topics/key requirements for safe plant operation – what depth of operational detail/requirements do they cover?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Procedure range
- Procedure coverage
- How each plant mode of operation is addressed
- Procedure task analysis
- SIS Interface requirements
- SIF definitions
- Override management
- Behaviour on fault

Here the assessor will establish adequate consideration for the maintenance of the operating plant including such requirements during several modes of operation.

SIS operators have been effectively trained for such duties using approved method statement and routines. Root case analysis exists for failure consequences and demands on protective systems are recorded and analysed.

IX) MAINTENANCE

Opening question:

How are maintenance practices identified and managed for the operational facility?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Procedures
- Planning
- Practices
- Routine actions
- Repairs
- Sensors Calibration
- Records
- Spares
- Inspection

Here the assessor will establish the standard operating procedures and operating philosophy including the requirements for abnormal operating mode procedures.

The available operator information will need to provide the necessary status for effective protective barrier management and the basis of managing overrides and requirements for when faults occur.

X) PROOF TESTING

Opening question:

What constitutes a robust proof test procedure? Do they apply for every safety function across the facility?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Procedure
- Test coverage
- Test methods
- Failure modes to be addressed
- Diagnostics
- Security
- Records and analysis

Here the assessor will require to review that written proof test procedures are adequate for their intent and that the test coverage is commensurate to the safety functions available at site. Records need to exist for preventative and corrective maintenance including the requirements for management of change.

Testing is carried out against defined schedule and that any deferments are managed correctly. Failures and detected faults are recorded and analysed for improvement.

XI) OPERATIONAL PERFORMANCE AND DEVICE MISSION TIME MONITORING

Opening question:

How does the management team ensure that the performance of the safety critical assets is maintained and that they are fit for service at all times?

Sub-principle topics to be explored, evaluated and compliance levels agreed covering:

- Leadership
- Asset register
- Containment
- Critical equipment list
- Inspection and test
- monitoring of the demand rate on SIS
- monitoring of the rate of SIS failures
- the SIS spurious trip rate
- root cause analysis with subsequent changes to reduce systematic failures rates
- Obsolescence

Here the assessor will seek evidence of a comprehensive asset register which identifies safety critical equipment and that the register is current and up to date.

A mechanism should exist for identifying and highlighting equipment that due to operational factors may be subject to significant ageing. Such safety critical equipment needs to be monitored and managed effectively including relevant planning and resolution of system obsolescence.

XII) FSA REPORTING

Digitizing the results of the FSA process provides the opportunity to improve corporate memory and support information management needs. It also allows for the data to be displayed in various formats to suit several stakeholder requirements e.g. from high level summaries down to technical detailed reporting.

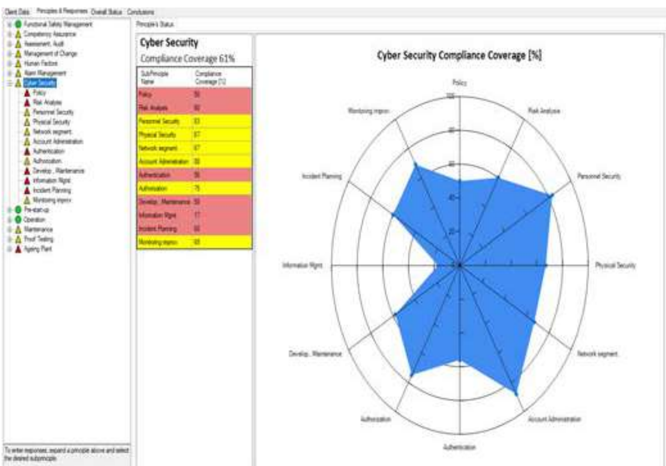

Figure 2 – Example Sub-principle FSA result for Cybersecurity

The opportunity to speedily set up trending and comparison of data for a single Asset or more than one Asset would be a desirable outcome for any reporting criteria. Such FSA Tool can provide scoring mechanism and compliance coverage graphics to aid comprehension of any key issues with budget holders regarding the improvement recommendations to be planned and implemented.

An example of how such information could be scored and weighted are as per figure 2:

VII. Conclusions

From experience, FSAs can reveal real errors and deficiencies in management processes, technical capabilities, and misalignment with the operating facility risk reduction requirements for installed operational safety related systems.

Such deficiencies can manifest themselves as issues such as:

- An insufficient independency between protection layers that are unrevealed and acknowledged during the process of safety function allocation to protection layers, thus leading to inappropriate safety requirements and required reliability measures
- Deviations in device safety manuals and by detailed review of supporting device certification reports, identification that installed devices do not meet safety standard requirements for use
- Management of change issues caused by a loss of system ‘Freeze’ for safety system modifications, leading to differing teams working on differing versions of system documentation and associated common safety function modification requirements
- Inadequate Hardware reliability calculation where too low failure rates used leads to too low PFDavg achieved and omission of compliance with Systematic Capability requirements, both leading to higher claimed SILs than in reality
- Lack of substance in change management ‘Impact Assessments’ leading to changes being approved that potentially compromise both safety functionality and safety integrity
- Safety system corrective maintenance that has evolved to a ‘modification’ without supporting impact assessment and document revision controls
- Real discrepancies and misunderstanding between Safety Instrumented Function (SIF) device response times and overall Process Safety Time (PST) leading to non-compliant PST claims
- Conflicting client requirements for both application program ‘destruct’ and ‘construct’ using the same field devices & I/O for differing SIF requirements
- Identification that safety devices are operating well outside the manufacturers ‘useful life’ requirements and continue in operation without justification or obsolesce planning
- Out of date safety case / dossier (including H&RA & SIL Determination reports and Safety Requirement Specifications) to that of the current plant process operating envelope
- *And many more….*

By contrast a robust FSA process can provide the operating company with the following benefits:

- Documented demonstration of senior management commitment and focus for continuous improvement
- A defined assessment and review process for supporting overall stage 4 periodic FSAs in accordance with IEC 61511 clause 5.2.6.1.10
- Demonstration that actions to ensure the process functional safety are being taken showing the pro-active attitude which is expected by the regulatory authorities, public and workforce, and supports company risk management arguments and traceability to industry good practices
- Knowing in advance from proactive assessment results, that prioritised improvement is required aids business planning and avoids ‘surprises’
- Provides essential information on how to maintain the level of safety designed into the facility safety related systems
- Supporting effective barrier management to reducing the plant spurious trip rate and cost of its consequences
- Provides evidence to authorities and business insurers that normative requirements and good practice on safety related systems management can be presented in structured and logical way
- Allows the Asset Owner to highlight the areas in most need of improvement, whilst in some cases relaxing the demands on sparse operational resources by using a risk-based FSA approach
- Provides the Asset Owner with a means to benchmark differing operational assets to identify trending for both good practices and those areas that are not performing to expectations, thereby providing a common understanding for risk management across several business locations

So, in your organisation, where is your planning for undertaking periodic FSA? Who will conduct them, and what will be the scope of assessment?

To ignore undertaking this important FSA activity is to do so at your peril. From the author’s experiences operating in various high hazard manufacturing operations over many years, any such ***‘complacency invites increasing operational risk’.***

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IX. VITA

John Walkington has some 39 years’ experience within the Process Industries working previously for operating companies such as ICI Agrochemicals, ICI Chemicals & Plastics, BASF Chemicals & Plastics and Huntsman Refining & Petrochemicals, before joining ABB in 2003. This is in addition to providing process and functional safety consultancy and training services directly to ABB’s customers.

He is currently Head of the Global Department for the management and governance of a TÜV Rheinland accredited functional safety management system for the design, engineering, operation and maintenance of safety related systems within ABB’s global network of certified Safety Project Execution & Service Centers.

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LARGE MOTOR STATOR WINDING FAILURE DUE TO LIGHTNING TRANSFERRED OVERVOLTAGES

Paper No. PCIC Europe
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Abstract - In polypropylene petrochemical plants high power motors are normally used to drive extruder or compressor machines required by this type of industrial process. Each motor of such a big size is usually fed by a dedicated supply captive transformer which often is directly connected to a high voltage overhead line.

In case of lightning stroke hitting the overhead line, a surge voltage impinging on high voltage transformer windings can be transferred to the motor side due to the electrostatic and electromagnetic coupling of transformer windings, with the risk of endangering the motor stator winding to frame insulation as well as the stator winding inter-turn insulation.

The effectiveness of installing surge arresters at motor terminals is evaluated by EMTP modeling and then comparing the resulted over-voltages to the impulse withstand limits given by IEEE standards for rotating machines.

Index Terms — Lightning overvoltage, metal oxide surge arrester, surge capacitor, transferred surge.

I. INTRODUCTION

The application of high power induction or synchronous motors (typical rated power between 9 MW and 30 MW), which drive machines like extruders or compressors, has become in the latest years a common practice for polypropylene chemical plants.

In order to be started direct-on-line, the large power motor usually requires the supply by a dedicated captive transformer where the primary winding is fed at high voltage (typically between 69 kV and 230 kV) by the transmission network system operator (TNSO). Sometimes, the primary winding of the captive transformer is directly fed by an overhead line which is then potentially exposed to the risk of direct lightning strokes due to line shielding failures or line back-flash failures. It is historically well known in the technical literature [1] that rotating machinery connected directly or electrically close to overhead lines is more vulnerable to surges than many other type of apparatus.

A fault incident event which happened in an industrial plant is discussed: an unexpected ground fault occurred inside the frame of a large synchronous motor with quite apparent damages to the insulation of the stator windings.

The novelty of this work consists in the way a root cause analysis is carried out in order to find the origin of the fault event: an explanation in terms of lightning overvoltage transmitted from the overhead line to the motor windings is derived by means of numerical simulations performed with EMTP-ATP software.

Finally, some remedial corrective actions are suggested in order to prevent in future the damage due to this type of fault event.

A. System Data

The electrical distribution scheme of a typical industrial plant, in which a large synchronous motor (27.5 MW rated power at 11 kV) is applied, is shown in Fig. 1. The motor is necessary to drive a gas compressor needed by the chemical plant based on the technology of LDPE – low density polyethylene. The motor is fed by a 220/11 kV captive transformer which receives the supply by a 220 kV overhead line.

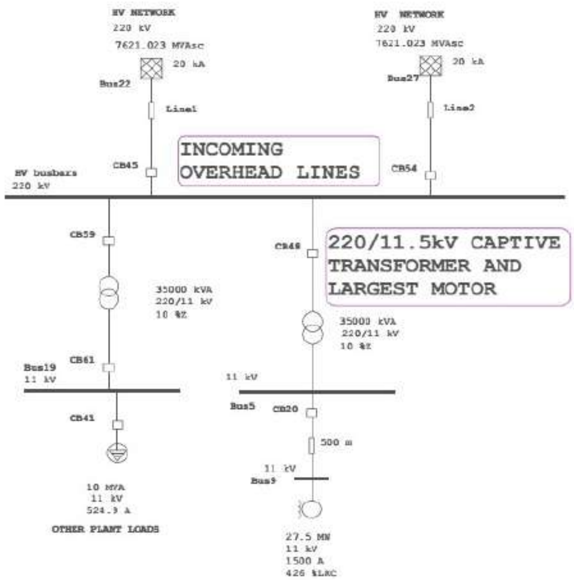

Fig. 1 Single-line diagram of the industrial electrical system

Main electrical parameters for the network components are reported in the Appendix.

B. Need for Electromagnetic (EMT) Modelling

In order to study lightning overvoltages, a simple RMS-type modelling, which is usually used for short circuit studies or for transient stability studies, is not sufficient in this case, because in general the lightning phenomena occur within few microseconds and not between tens of milliseconds and some seconds, and it is therefore necessary to model the surge impedance characteristic of the network components involved.

In particular here the phenomenon of transferred lightning overvoltage between the primary and secondary transformer windings is studied, hence it is necessary to model all the stray capacitances of transformer windings.

For the above reasons it was decided to use an EMT based software like EMTP-ATP. Other EMT software equivalent to EMTP-ATP can in general be used for such kind of studies, like PSCAD-EMTDC or EMTP-RV which are also well known worldwide nowadays.

C. *Modelling*

For the aim of numerical simulation by ATP (Alternative Transient Program) [2], the electrical network is simplified and modeled as shown in Fig. 2, following the general guidelines presented in [3].

All equivalent impedances of the network components are referred to the motor rated voltage.

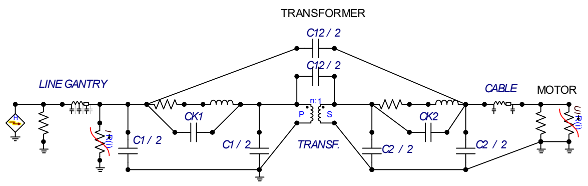

Fig. 2 EMTP-ATP model of the electrical system

The motor captive transformer is modeled by means of a capacitive network due to the electrostatic surge transfer from primary to secondary winding, and by its leakage inductance and turns ratio due to the electromagnetic surge transfer from primary to secondary winding [4], [5], [6]. Since the neutral point of the primary high voltage wye-connected winding is solidly grounded, it is assumed that the coupling between the three-phase windings does not influence significantly the calculation of the phase-to-ground voltage according to experience get from technical literature [7]. This simplifying assumption allows to consider only the single-phase equivalent circuit of one winding for studying the lightning surge wave process.

The lightning surge current on the high voltage system is modeled using an exponential surge function (Heidler current source generator), on the basis of data from the transmission network system operator (TNSO) of the 220 kV network who performed the study of insulation coordination considering the lightning striking location close to the industrial plant substation (few hundreds of meters): the type of simulated lightning strike is a shielding failure of the incoming 220 kV supply overhead line, without the presence of insulator string flashover. The probability of lightning back-flashover events was considered null by TNSO due the good tower foot resistance of the overhead line (approximately 10 ohm):

- back-flashover happens when the lightning hits the earth wire among transmission towers or one transmission tower, then the potential of the tower increases beyond the withstand voltage (critical flashover voltage) of insulators and a flashover across the line insulators finally occurs. Thanks to the good value of tower foot resistance (10 ohm) the critical flashover overvoltage of line insulators is not exceeded.
- shielding failure means that the lightning hits directly the line conductors and a consequent overvoltage wave then travels along the line conductors.

The surge arresters on both high voltage and medium voltage levels are modelled with non-linear resistors (graphical symbol by a red line through in Fig. 2) based on data sheet from relevant manufacturer: this means that the voltage vs. current characteristic of the resistor is not a straight line as is shown in Fig. A-IV and Fig. A-V into the Appendix.

The last span between two consecutive towers of the supply high voltage overhead line is modelled by a line element having a certain characteristic surge impedance, while the medium voltage cable from the captive transformer to the motor is modeled by a single pi-grec impedance element.

The surge impedance of the motor is estimated on the basis of inductance and capacitance parameters provided by motor vendor, by means of procedure from technical literature [4].

II. PRE-ANALYSIS AND ASSUMPTIONS

Before performing numerical simulations, a few theoretical assumptions are first discussed for the aim of getting a likely explanation of the fault event.

A. *Description of the events*

The synchronous motor driving the largest compressor motor in the industrial chemical plant as shown previously, experienced stator winding failure to ground while in operation, which was detected and cleared promptly by the earth fault motor protection relay, causing an inadvertent plant shutdown.

After the motor inspection by plant personnel with the assistance of motor manufacturer, it was clear that the coil failure to ground was due to a turn-to-turn insulation breakdown which then evolved rapidly to the breakdown of the ground-wall insulation, with the final result of a stator to ground fault event.

The single phase-to-earth fault damaged mainly the stator coil winding, without causing the melting of the stator iron core, thanks to the fact the earth fault was cleared quickly (less than 200 ms) and considering that the neutral point of the secondary winding of the captive transformer was high-resistance grounded to a quite low value (20 A) which can be withstood for twenty seconds by the stator iron core.

B. *Interpretation of the incidental event*

After deep investigation by plant personnel and motor manufacturer technicians about the root cause analysis of the incident event, it was highly suspected that the origin of the fault had to be searched externally to the management of the industrial plant, that is, in an external cause not depending on incorrect maintenance activities.

The transmission network system operator (TNSO), owner of both the 220 kV supply line and of the 220/11 kV motor captive transformer, was inquired about the lightning strike activity in the zone where the plant is installed, and a high lightning flash activity was actually confirmed (lightning flash density equal to almost 150 thunderstorm days/year). TNSO confirmed the occurrence of several events of lightning flashes hitting the line conductors (shielding failure) due to the triggering of surge arrester counters installed at the primary high voltage side of the 220/11 kV captive transformer.

A plausible explanation for the motor stator winding failure is that the lightning overvoltage originating on the 220 kV incoming line traveled towards the captive transformer: here, the magnitude of the surge was partially suppressed by the surge arresters installed to protect the high voltage winding of the transformer, but a residual overvoltage was still transferred through the transformer to the motor windings causing the breakdown of the stator ground-wall insulation.

C. Case Study

The most representative lightning stroke current, from the TNSO who was responsible for the insulation coordination for the 220 kV overhead line, is injected into the line, and the resulting over-voltages impinging on the captive transformer and on the motor are analyzed.

In fact, the impact of a lightning stroke directly on a phase conductor can be seen as a current injection on the phase conductor: the current divides itself into two equal parts at the point of impact, and the two generated voltages travel in both directions along the line away from the point of strike.

A flashover will generally occur if the critical flashover overvoltage $U_{50\%}$ (i.e. the overvoltage having 50% probability to cause line insulator flashover) of the line insulation is exceeded. For a stroke at the midspan between two consecutive towers, the critical stroke current magnitude I_c that will cause flashover is given by:

$$I_C = 2 * (U_{50\%} / Z_c) \qquad (1)$$

where:

I_C	critical lightning stroke current (peak vakue)
$U_{50\%}$	critical flashover voltage (CFO) of line insulation
Z_C	surge impedance of line phase conductor

Taking Z_C = 500 ohm, $U_{50\%}$ = 1250 kV (line-ground), it results I_C = 5 kA (peak value).

III. RESULTS

The results of numerical simulations are shown graphically in the following figures. Lightning over-voltages (instantaneous peak values), are chosen as the most significant magnitudes in order to evaluate the impact of the 220 kV system lightning stroke current on the 11 kV distribution system.

A. Overvoltage calculation

The lightning overvoltage at overhead line tower and the overvoltage at the primary bushings of the captive transformer are shown in the following Fig. 3.

The phase A is taken as reference for all the plots.

As can be seen, the overvoltage peak value at 220 kV tower is around 1050 kV (line-ground), and it is within the lightning impulse withstand level for which the line insulators are designed (1250 kV, line-ground), therefore no back-flashover takes place. The line overvoltage, travelling towards the captive transformer, is then chopped by surge arresters in order to protect the primary transformer windings: the actual overvoltage peak value of 415 kV (line-ground) is less than the transformer design withstand level (950 kV, line-ground).

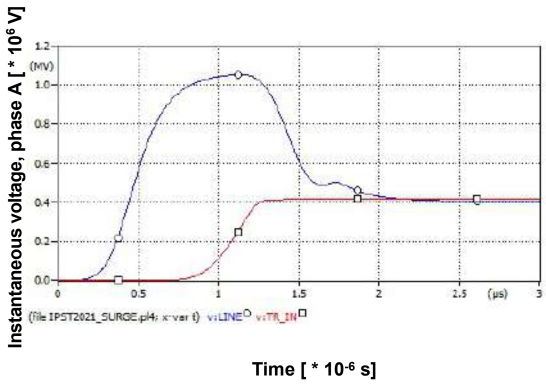

Fig. 3 Lightning overvoltages on 220 kV side (line and transformer)

In the next figure, the overvoltage being transferred from the primary winding to the secondary winding of the captive transformer is shown.

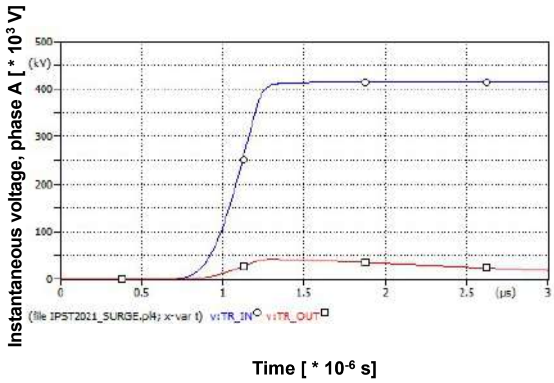

Fig. 4 Lightning overvoltages on 220 kV and 11 kV transformer windings

The overvoltage on transformer primary winding, whose peak value is 415 kV (line-ground), is quite attenuated on the secondary winding side, where it reached the peak value of 41.5 kV (line-ground) which is within the lightning impulse level of transformer secondary winding (75 kV, line-ground). However, the overvoltage transferred on the 11 kV distribution system, although it is not dangerous for transformer windings, could still impact the insulation of downstream motor equipment.

In the next figure, the overvoltage occurring at motor terminals is shown, taking into consideration the effect of the supply cable between captive transformer and motor. The cable helps lowering the rate of rise of the incoming surge, thanks to the cable capacitance.

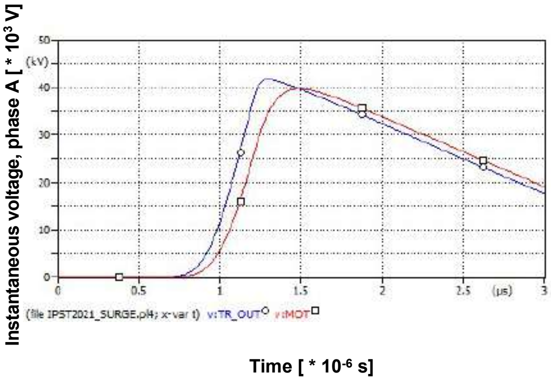

Fig. 5 Lightning overvoltages on transformer and motor 11 kV windings

As can be seen, the motor overvoltage reaches the peak value of 40 kV (line-ground).

B. Comparison with IEEE impulse withstand envelopes

The insulation of motor stator winding was manufactured and type-tested in factory according to the applicable IEC standard for impulse voltage withstand levels [9]. However, the same IEC standard does not consider the effect of ageing on the impulse voltage withstand levels.

For the above reasons, the overvoltage calculated at motor terminals is compared with the voltage withstand envelopes taken from IEEE standard [8], as shown in Fig. 6.

There are two types of withstand envelope in IEEE standard. The former (IEEE-1 in Fig. 6) having the greatest magnitude is the standard withstand envelope: the characteristic point at 0.1 $*10^{-6}$ s is 3.5 p.u. (per unit of $\sqrt{2}/\sqrt{3}$*line-line voltage), which means 32 kV (line-ground) for a system having 11 kV rated voltage and which corresponds to the withstand value foreseen by IEC standard for the rated steep-front-impulse voltage withstand [9]. The latter (IEEE-2 in Fig. 6) refers to the alternative withstand envelope, which is used for testing coils in machines that are not likely to see high-magnitude fast-fronted surges.

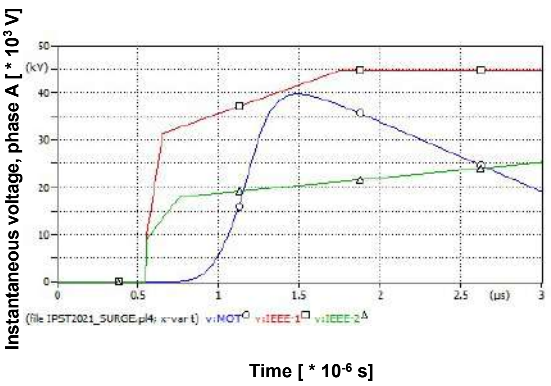

Fig. 6 Overvoltages on 11 kV motor windings vs. IEEE withstand envelopes

As can be seen, the overvoltage at motor terminals is within the standard (3.5 p.u.) envelope normally applied to test a newly manufactured stator coil, but it exceeds significantly the alternative withstand envelope.

Considering that the motor has been operating for more than ten years in an industrial environment and therefore is not new, the standard (3.5 p.u.) withstand envelope is deemed no longer a reliable reference to judge the impulse voltage withstand quality of the motor insulation.

The alternative withstand envelope is instead exceeded in the zone having front times greater than 1.2 * 10^{-6} s, just where it is likely that a stress to groundwall insulation can occur [8].

C. Installation of surge arresters at motor terminals

The application of surge arresters installed at motor terminals can be a valid remedy to prevent excessive voltage surges to stator winding insulation [10].

In the next figure, the overvoltage at motor terminals, after the installation of the surge arrester, is shown.

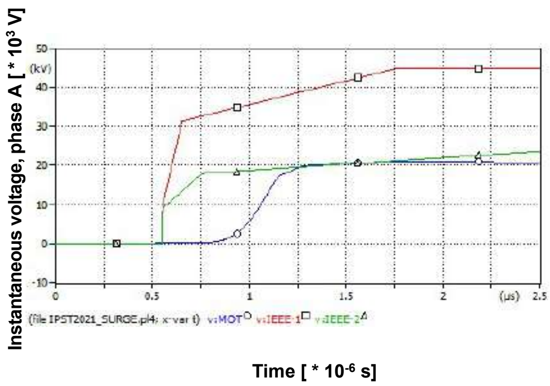

Fig. 7 Overvoltages on 11 kV motor windings vs. IEEE withstand envelopes

In this case, the overvoltage at motor terminals is safely within also the most conservative IEEE voltage withstand envelope (IEEE-2 in Fig. 7).

IV. CONCLUSIONS

The surge arresters installed at the primary bushings of a motor captive transformer are necessary in order to chop the incoming lightning overvoltage originating on the supply overhead line such as to protect the transformer windings insulation, but they are not sufficient to prevent that a residual overvoltage be still transferred to the motor windings.

The overvoltage impinging on motor stator winding is for sure not so harmful as the scenario of a motor being directly fed by an overhead line; anyway this surge, whose magnitude is a bit attenuated by the transformer impedance as well as by the surge arresters installed at high voltage primary windings of the transformer, can damage the groundwall insulation of the motor.

IEEE standards recommend that the insulation of a motor being already in service since a long time be tested at only 75% of the standard impulse test voltage applied to newly designed equipment [8]. In fact, for a motor being already running for many years, and especially used with a continuous service duty into an industrial polluted environment, it is more likely that the motor insulation may have lower strength with respect to the new design condition and could be impacted by transferred lightning over-voltages, as it actually happened in the case study where this problem was not faced at all neither during the commissioning of the industrial plant nor during the first ten years of motor operation.

In order to prevent similar surge events in the future, it was decided to install the following devices at motor terminals (detail data are shown in the Appendix):

- a metal oxide surge arrester, necessary in order to further reduce the surge amplitude at machine terminals within acceptable limits for both the turn-to-turn and groundwall insulation;
- a R-C surge suppressor device (also named sometimes R-C snubber or R-C filter) used to lower enough the rate of rise of the incoming surge voltage at motor terminals, due to its well known effect of flattening the surge wave slope; this was a conservative and additional safety choice [10], since simulations showed that the capacitance of motor feeding cable was already sufficient for this aim thanks to the quite long motor supply cable;
- both the above components were installed near to the motor terminal box and designed for the same area being classified as hazardous for the risk of explosion where the motor was installed.

V. REFERENCES

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VI. APPENDIX

A. *Electrical Network Component Data*

TABLE A-I
CAPTIVE TRANSFORMER

Equipment	Parameters
Transformer dedicated to the supply of the largest compressor 11 kV motor	35 MVA rated power
	50 Hz rated frequency
	220 / 11 rated voltage ratio
	Z_T = 10% short circuit impedance (referred to rated power)
	L_T = 1.101 mH inductance/phase (at 11 kV)
	R_T = 0.01153 ohm resistance/phase (at 11 kV)

The equivalent circuit for the overvoltage surge transfer is shown in Fig. A-I, with relevant manufacturer parameters shown in Tab. A-II:

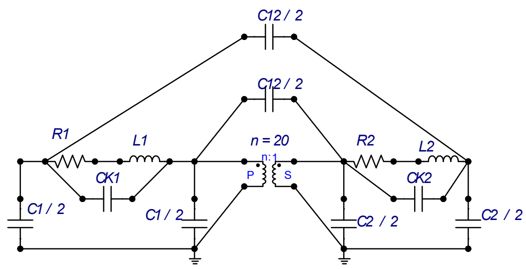

Fig. A-I Circuit model of the captive transformer for surge transfer study

TABLE A-II
SURGE TRANSFER PARAMETERS OF
CAPTIVE TRANSFORMER

Parameter	Numerical value
Primary turn-to-turn capacitance C_{K1}	1425 pF
Secondary turn-to-turn capacitance C_{K2}	7640 pF
Primary-to-Secondary capacitance C_{12}	1570 pF
Primary phase-to-ground capacitance C_1	2080 pF
Secondary turn-to-turn capacitance C_2	1040 pF
Turns Ratio n	20
Primary winding resistance R_1	2.306 ohm
Secondary winding resistance R_2	0.005765 ohm
Primary winding leakage inductance L_1	220.4 mH
Secondary winding leakage inductance L_2	0.551 mH

TABLE A-III
SYNCHRONOUS MOTOR DATA

Manufacturer's Data
27500 kW rated power
11000 V rated voltage (r.m.s. line to line)
1654 A full load stator current (FLC)
400% of FLC locked rotor current
0.90 rated power factor
0.97 rated efficiency
42.5 nF phase-to-ground capacitance
3.057 mH (locked rotor inductance)

From the above manufacturer data, the surge impedance Z_s of the motor is estimated from the following equation, as per technical literature [4], and it results equal to Z_s = 403 ohm:

$$Z_s = 3/2 * \sqrt{(L/C)} \qquad \text{(A-1)}$$

where:

Z_s	surge impedance of the motor
L	locked rotor motor inductance
C	motor phase-to-ground capacitance

TABLE A-IV
CABLE

Equipment	Parameters
cable feeder from captive transformer to synchronous motor	500 m length
	240 mm^2 cross section
	3-core aluminum conductors 4 parallel runs/phase
	X_c = 0.1 ohm /km reactance / phase / km
	C_c = 0.2 *10^{-6} F/km capacitance / phase / km

TABLE A-V
OVERHEAD LINE

Equipment	Parameters
220 kV last span of incoming overhead line supplying the motor captive transformer	Z_L = 500 ohm Line surge impedance
	v = 3*10^8 m/s Propagation velocity
	R_L = 0.06 ohm/km Line resistance

The equivalent circuit model for the lightning stroke current, hitting the last span of the overhead line, is shown in the below figure, with following corresponding equation for the Heidler current generator [2]:

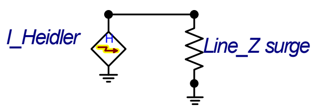

Fig. A-II ATP circuit model of the lightning stroke current on 220 kV system

$$I_{Heidler} = Amp \cdot \frac{(t/T_f)^n}{\left(1+(t/T_f)^n\right)} \cdot e^{(-t/tau)} \qquad \text{(A-2)}$$

where:

$I_{Heidler}$	Heidler current source
t	time variable
Amp	5000 A (current amplitude)
T_f	1.488 * 10^{-6} s (front duration)
tau	75 * 10^{-6} s (stroke duration)
n	5 (rate of rise factor)

The lightning stroke current waveform resulting from the previous equation is shown in the next figure:

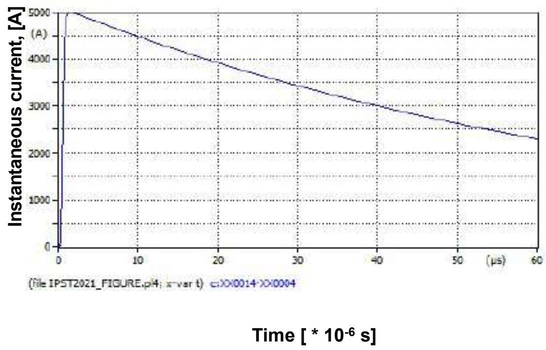

Fig. A-III Lightning stroke current waveform on 220 kV line phase conductor

TABLE A-VI
220 kV SURGE ARRESTER DATA

Equipment	Parameters
Metal Oxide Surge Arrester installed at the 220 kV bushings of Captive Transformer	U_R = 192 kV Rated Voltage (phase-to-ground)
	U_C = 154 kV Maximum Continuous Voltage (phase-to-ground)
	I_R = 20 kA Rated discharge current
	U_s = 488 kV discharge voltage (at rated discharge current I_R)
	IEC Class 4

TABLE A-VII
CIRCUIT MODEL OF 220 kV SURGE ARRESTER
(TYPE 92 RESISTOR IN ATP)

Current (A)	Voltage (V)
2500	400000
5000	424000
10000	455000
20000	488000

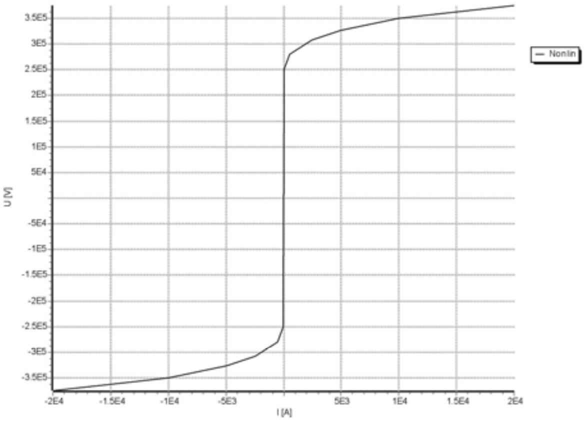

Fig. A-IV Voltage vs. current characteristic of 220 kV surge arrester modelled in EMTP-ATP

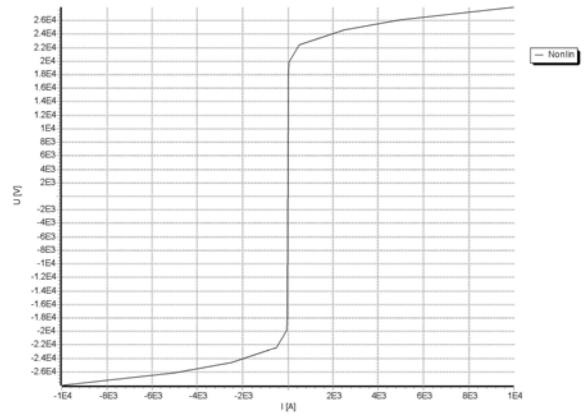

Fig. A-V Voltage vs. current characteristic of 11 kV surge arrester modelled in EMTP-ATP

TABLE A-VIII
11 kV SURGE ARRESTER DATA

Equipment	Parameters
Metal Oxide Surge Arrester installed at the 11 kV terminals of compressor motor	U_R = 11.3 kV Rated Voltage (phase-to-ground)
	U_C = 9 kV Maximum Continuous Voltage (phase-to-ground)
	I_R = 5 kA Rated discharge current
	U_s = 26.1 kV discharge voltage (at rated discharge current I_R)
	IEC Class 2

TABLE A-IX
CIRCUIT MODEL OF 11 kV SURGE ARRESTER
(TYPE 92 RESISTOR IN ATP)

Current (A)	Voltage (V)
500	22400
2500	24600
5000	26100
10000	27980

TABLE A-X
R-C SUPPRESSION DEVICE

Equipment	Parameters
R-C suppression device installed at the 11 kV terminals of compressor motor	$C = 0.25 * 10^{-6}$ F Capacitance (per phase)
	R = 50 ohm Resistance (per phase)
	U_R = 12 kV Rated Voltage (phase-to-phase)

VII. VITA

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Efficacy comparison of PV Panel for Ex environment

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Abstract - The production of electricity from renewable sources, avoiding the use of fossil fuels that are running out, is proposed as an important topic on which to conduct innovative studies in favour of the environment and safety in particularly sensitive areas. Among the production methods, the greatest potential as regards the possible contribution of energy is the photovoltaic one which, with cost of materials accessible and increasing efficiency, is proposed as a solution to the electricity generation needs. In particular, the presence of solar systems on islands, i.e. separated from the public grid, makes it possible to meet the needs of particularly remote areas, difficult to connect or areas with explosive atmospheres (offshore platforms) thanks to the storage systems and connected regulation devices.
A characteristic environment for a possible and essential application is the Explosion Atmosphere, for which energy generation systems, according to necessity, are always a particularly sensitive topic. In these areas, safety is not insignificant and, as can be easily understood, the use of static and combustion-free components can be much more suitable for the environment than traditional methods, i.e. combustion Diesel Engines or other technologies based on the use of fossil fuels or rotating mechanisms. Power generation systems based on solar technology are not, in fact, free from sources of danger for environments at risk of explosion, as it is possible that faults or operating conditions may occur that could trigger an explosion. Leaving each manufacturer the freedom to choose the protection mode he considers the best for this type of apparatus, it has been instead decided to deal with aspects considered "transversal" for the compliance of the photovoltaic panel. The results of a test campaign carried out on photovoltaic panels that can be installed in explosive atmospheres will then be shown in order to assess their efficiency under different conditions according to the impact test.

Index Terms — PV Panel, Efficacy, ATEX, Explosive Atmosphere, Modes of protection, risk assessment, hot spot.

I. INTRODUCTION

In areas at risk of explosion (ATEX), the need for energy supply to plants is a sensitive and delicate issue to be addressed. There are many ways in order to remedy this situation and they are often based on the local production of the energy needed to sustain the activity because many of the areas concerned are far from the main electricity grids. One example is an offshore platform where electricity is of paramount importance, from crane drives for loading and unloading goods to signalling or service lighting for workers. Usually power is supplied by diesel engines or other internal combustion equipment, leading to pollution and waste of the raw resources extracted and CO2 emissions.

The hazards inherent in the use of devices capable of producing energy using controlled explosions within an ATEX environment must also be considered. There are two main solutions to overcome this problem, namely ignition control of high power equipment (e.g. motors), with high equipment costs, or production through equipment with less risk of ignition and, if possible, eco-sustainable. Photovoltaic systems with suitable energy storage systems [1] are offered as a valid alternative because they are able, if properly sized, to provide the necessary energy supply both during the day and the night. The use of this equipment, however, like any electrical device, is not without risks, so it is essential to evaluate them with the relative EN 60079 standards, which define the protection methods that give the presumption of conformity to the ATEX Directive.

Leaving each manufacturer the freedom to choose the mode of protection for any installation area (Zone 1 or Zone 2), the aim of this work is to deal with aspects considered "transversal" for the conformity of a PV panel. The main aspects to be considered are:

- Risk assessment;
- Impact test (and the related efficiency test);
- Temperature class and thermal test.

II. PHOTOVOLTAIC PANEL

Traditional PV panels for non-architectonic applications are normally built as reported in Fig. 1.

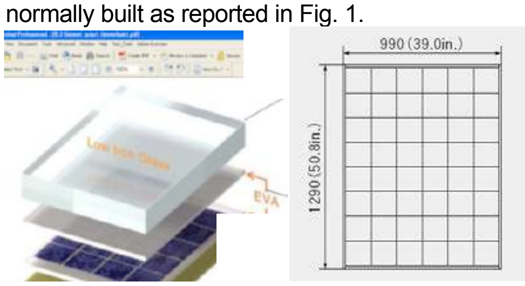


Fig. 1 – Typical PV panel for non-architectonic applications.

Panels are realized by 48-72 series cells, assembled by connecting and welding the cells among each other by means of terminals on front and rear contacts (in a N-P-N-P-N ... sequence) in order to form a string.

A sandwich is then realized by placing the PV cell in the middle layer that is surrounded by (going from the external layer to the internal one) a glass plate of 4mm, characterized by very good mechanical resistance, an EVA (Ethylene Vinyl Acetate) sealant sheet of 0.5mm, which allows the dielectric insulation of the cell layer, then another identical EVA sheet and then a Tedlar insulant layer of 0.5mm.

The sandwich is then heated in the oven at about 100°C, the temperature at which the components seal to each other. Once this temperature is reached, EVA becomes transparent and the residual internal air, which might cause corrosion because of the presence of water vapor, is then evacuated. Eventually, the sandwich is fixed in an extruded anodized aluminum frame - to be protected against corrosion - and the junction box is placed. Typically, the shape of these PV panels is rectangular.

III. DIFFERENT EX PROTECTION PRINCIPLES

One of the most challenging industrial environments is the Ex environment - such as an Oil & Gas field - where an explosive atmosphere could be often present.

An explosive atmosphere is a mixture of flammable substances in a gaseous, foggy, vaporous state, or powder mixed with air, under certain atmospheric conditions in which, after ignition, the combustion propagates itself to the flammable mixture. A potentially explosive atmosphere is only obtainable if the concentration of the flammable substance is not too low (lean mixture) or too high (rich mixture): in these cases, a combustion reaction may occur, or even no reaction at all, but no explosion [2].

In order to avoid a gas explosion, it is mandatory to exclude one of this three elements: fuel, combustive agent (oxygen) and ignition source. Therefore, an explosion cannot occur if even just one of these three elements is not present, as shown by the explosion triangle of Fig. 2.

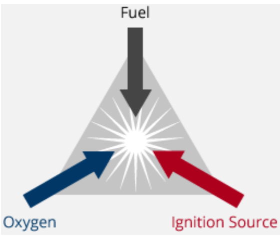


Fig. 2 – The explosion triangle.

Therefore, three different principles, which act differently on these three elements of the triangle can be implemented to be safe the electrical equipment.

These three different principles are:

- *containment method*, the parts that can cause ignition are included in a box made to withstand the pressure of the explosion, preventing the spread of flame;
- *prevention method*, in this method necessary measures are taken to avoid excessive temperatures and creation of sparks, thus eliminating the ignition source;
- *segregation method*, in which active components are separated from explosive mixture using resins, sand, oil, preventing any contact with oxygen and fuel.

All the protection modes for Ex environment, as described in [3] for luminaries, born from these three different principles and it is possible to use these protection solutions for Photovoltaic panel also.

The *containment method* is related to “Ex d” (Flameproof enclosure) mode of protection where the parts which can ignite a potentially explosive atmosphere are surrounded by an enclosure which withstands the pressure of an explosive mixture exploding inside the enclosure itself, and prevents the transmission of the explosion to the external atmosphere surrounding the enclosure [4]. It is very important to design the length, the gap and rugosity of the joint between cover and body of enclosure according to the Standard.

The *prevention method* is related to the “Ex e“ or “Ex i” mode of protection. The “Ex e” (Increased Safety) is where additional measures are applied to the electrical equipment to increase the safety level, thus preventing excessive temperature development and the occurrence of sparks or electric arcs within the enclosure or on exposed parts of electrical apparatus, where such ignition sources should not occur in normal service [4]. The “Ex i” (Intrinsic Safety) is where the value of current, voltage a power are considered intrinsically safe. This means that under any operational condition or unserviceable state, it cannot produce any spark or overheat such as to ignite an explosive atmosphere.

Another mode of protection according to the prevention method is “Ex t”. It is used for DUST atmosphere protection only, so it is not very appropriate for this application.

The *segregation method* is related to the following mode of protection: “Ex m”, “Ex p”, “Ex o”, “Ex q”, and “Ex t”. The “Ex m” (Encapsulation) protection consists of covering the components which might produce sparks or over temperatures, with a resin which is resistant to environmental conditions. The “Ex p” (Pressurized) exploits the segregation technique by impeding the access of explosive atmospheres through an internal pressure due to insufflation of an inert gas or air, maintaining an internal pressure greater than the external one. The “Ex o” (Oil Immersion) exploits the principle of segregation using Oil applied as a filler. Maintenance is evidently difficult as the container must be emptied of oil and, subsequent to any maintenance and/or repair work, refilled. Furthermore, the presence of systems guaranteeing a constant level of oil is required. The “Ex q” (Powder Filling) protection involves the filling of the component casing with a material, normally with quartz powder, which under normal conditions impedes any sparks being transmitted to dangerous atmospheres externally.

IV. RISK ASSESSMENT

The failures in PV systems can be classified in two categories: those related to the overall PV system and those concerning single PV modules. Some of these failures occur because of transportation, installation, clamping, connector failures (fuse boxes, extension cables, inverters or combiner boxes) and lightning [4].

The main reasons for PV plant failures are mainly due to installation errors and design/planning & documentation errors. Among design errors, a very important cause of failure in PV plants is related to lightning and overvoltage systems. According to the literature, 30% of PV plants are subjected to this kind of problems in the first three years of operation. Fig. 3 shows an example of damaging in PV module due to lightning.

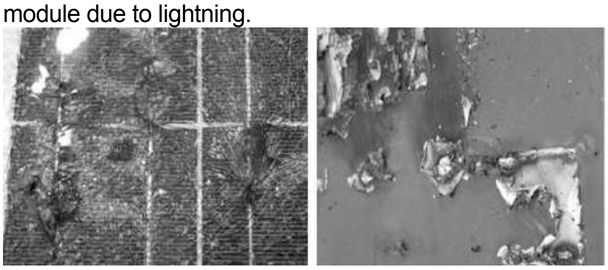


Fig. 3 – Fault due to lightning: (a) front of the module, (b) back of the module.

The serious faults occurring during the PV plants installation are due mainly to lack of heat dissipation in inverter and solar generator cabling not mechanically fastened. Some other faults can be due to the junction boxes or incorrect terminal connection in cables.

The solar module consists of PV cells, encapsulant, bypass diodes, connectors, frame, junction box, cable, glass on the front side of the module for protection, and glass or polymer film on the rear sheet of the module. These components can protect the cells against the climatic stress and various contacts.

During the PV power plant operation, PV modules may be subjected to many different failures and defects (e.g., snail trails, hot spot, micro cracks, cell breakage, delamination, bubbles, yellowing, discoloration, oxidation, corrosion, etc...) due to the weather condition like wind, sand, humidity, high UV radiation and other internal and external stresses. However, most of these stresses cause power losses in the PV systems, hence investigating about inspection methods of PV module is a significant issue to identify the failures in the solar energy field. Thus, the lifetime of PV modules hugely depends on monitoring and maintenance; early defect detection can reduce the degradation of PV modules as reported in [5] and [6].

Typically, any effect on a PV module which decreases the performance of the module, or even influences the module characteristics, is considered as a failure whereas, a defect can be defined as an unexpected or unusual thing which has not been observed before on the modules. However, defects often are not the cause of power losses in the PV fields.

The rated performance of PV modules is at a standard temperature (25ºC). Hence, any increase in PV module temperature will reduce the output vs. the standard performance. Temperature stress can accelerate the chemical degradation of the panels. Therefore, it can lead to creating defects in the PV modules, and the performance of PV systems may decline in a short time.

According to the investigations, most visible failures appear in the PV modules due to the polymers' defects such as delamination, bubbles, cracking, or yellowing. Other phenomena such as snail trails, shading, hot spots, micro-cracks, and cell breakage defects can have the highest influences on the performance of the PV modules. These kinds of failures can, in fact, be better detected also using thermal and infrared cameras.

Adherence loss among PV modules' layers usually causes delamination. Typically, it happens between cells and front glass or between polymeric encapsulant and cells. This defect can increase reflection, and the water can then penetrate into the module itself. Nevertheless, a delamination defect in the borders of the PV module causes both electrical and installation risks and likely transmittance losses. On the other hand, a bubble defect is more similar to delamination, while adherence losses occur only in some areas of PV modules due to chemical reactions. Bubble defects arise in the backside and not on the front side of the PV module. In fact, any object in the back cover or polymeric encapsulant prevents the dissipation of heat from the solar cells.

Yellowing and browning can appear in PV modules due to dry heat (e.g., due to desert climate), high UV radiations, and humidity. Moreover, it can occur because of insufficient adhesion between cells and glass material. However, this creates an obstacle between solar cells and sunlight, which leads to reduction in PV modules' voltage output.

The corrosion will occur in the PV modules' glass and metal because of the combination of gasses and humidity. Snow and wind can produce a higher static load; hence, they can break PV modules' glass due to the mechanical load for dynamic and static reasons. In the desert climate, for example, sand, wind, and dust significantly decrease the performance of PV modules. Furthermore, glass breakage can be caused by object impacts (see Fig. 4).

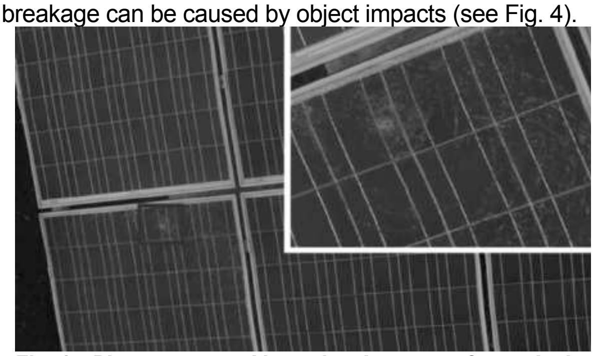


Fig. 4 – Picture captured by a visual camera of a particular shock-defect.

Micro-crack defects can appear as some different color lines on both sides of the PV module, and they can be detected only using special devices such as thermal and infrared cameras or by optical methods. Cracks and micro-cracks are formed in PV modules due to mechanical loads or during the process of lamination and soldering. Cracks in solar cells can influence the performance of PV modules, thus investigation about the formation of the cracks is required.

The PV modules can be subjected to a defect known as the snail trail phenomenon. The snail trail impact emerges on the PV modules' edge because of both environmental conditions and manufacturing process. They appear as dark and small lines or solar cell discoloration on the PV modules. Furthermore, snail trails can occur if the PV cell is produced as a thin thickness, and in this case, it cannot compromise efficiency too much [6].

One of most significant defects is the hot spot phenomenon, which is defined as an area on the PV module with a higher temperature. Typically, the reasons of the hot spot defect include mismatch of solar cells, partial shadowing, or any failure in the interconnection between the solar cells. Hot spots can easily be detected by thermal cameras. Fig. 5 shows some hot spots detected by IR inspection and also the corresponding visual images [8].

The hot spot defect is very critical because increasing temperature could ignite the explosive atmosphere. For this reason, it is very important to evaluate the maximum temperature during his failure also in order to determine the Temperature Class of the Ex panel.

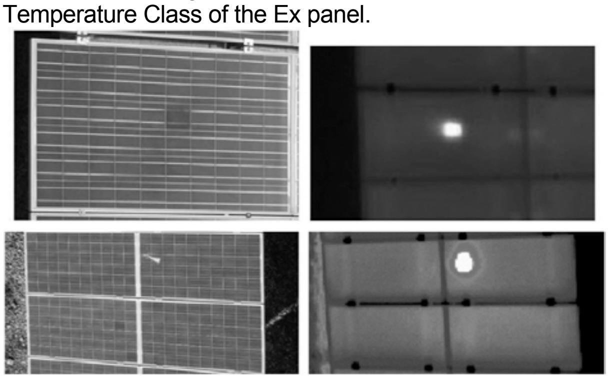


Fig. 5 – Hot spot due to corrosion or dirt

Some failures occur within the first two years of the PV modules installation which impacts the costs of PV modules installers and manufacturers (because they should be responsible for these failures and defects).

V. IMPACT TEST AND ENERGY PERFORMANCE

All the previous modes of protection summarised in section III above can be used for an Ex Photovoltaic panel both for Zone 1 and Zone 2. Each of them has advantages and/or disadvantages over the others. Whichever mode of protection is used to make the photovoltaic panel usable in explosive atmospheres, first of all it is mandatory to follow the General Rules and all the general tests must be taken into account.

In particular, for this kind of products, the impact test according to IEC/EN 60079-0 (General Rules) could be a problem, because it is a little bit different from the test performed according to the photovoltaic industrial panel Standard IEC/EN 61215-2 [9]. In fact, according to the Standard IEC/EN 60079-0 [10], the impact test shall be performed using a spherical mass of 1 kg that fall down in order to have an impact of 4J (high risk) on the transparent part (where the cells are) or 2J (low risk). In case of the test should not be positive, the manufacturer could install on the transparent part a metallic grid. The individual openings of the grid can be realized from $625mm^2$ to $2500mm^2$.

So, in order to pass positively the impact test, it is necessary to have a sufficient thickness of the glass. If this is not enough, it is necessary to apply an additional glass or an additional guard grid. These additional protections reduce the efficiency of the photovoltaic panel, so it is necessary to choose the best configuration in order to have the maximum result.

For this reason, we prepared and tested the following three configurations of photovoltaic panel (Fig. 6):

a) Standard photovoltaic panel (as Reference);
b) Reference panel in which an additional 5mm Glass has been added in the front of each module (as Double Glass);
c) Reference panel plus a Grid in the front of each module (as Grid). The dimension of the individual opening of the grid is $2500mm^2$.

Fig. 6 – Reference, Double Glass and Grid

The test has been performed by connecting two modules (module A and module B) of the same typology in series and then to the grid by using a single inverter. This means that every configuration is composed of module A and module B, so in the following table it is possible to check both the results of single module (A or B) and the result of A+B for Reference, Glass and Grid configuration.

Table 1 shows the results of the characterizations tests.

TABLE 1 – Maximum Power Determination measured in some days of 2019

Sample Type	T (°C)	G (W/m^2)	V_{MPP} (V)	I_{MPP} (A)	P_{MPP} (W)	Eff (%)	P_{dat} (W)
Reference A	49.9	978	16.45	7.12	117.4	96.5%	121.6
Reference B	54.0	968	15.90	7.05	112.2	95.2%	117.8
Reference A + B	50.1	1000	31.85	7.31	232.8	93.7%	248.5
Double Glass A	50.2	945	15.85	6.08	96.4	82.2%	117.3
Double Glass B	49.5	949	15.70	6.23	97.8	82.7%	118.2
Double Glass A + B	48.8	983	32.00	6.36	203.7	82.8%	245.9
Grid A	50.4	928	16.40	5.35	87.7	76.2%	115.1
Grid B	47.4	922	16.45	5.51	90.6	78.0%	116.1
Grid A + B	48.8	977	32.3	5.83	188.3	77.1%	244.1

The ambient temperature has been measured by using a meteo-station with calibrated sensors, while the panel temperature is measured by using an IR camera [11]. Table 1 shows the results of the tests in term of the Maximum Power Determination, considering Reference A+B, Double Glass A+B and Grid A+B configurations. The data sheet power (P_{dat}) at temperature (T) and irradiation (G) measured during the test is also reported. Finally, the efficiency (Eff) is evaluated comparing the power at maximum power point (P_{MMP}) and the data sheet power.

The measured I-V and P-V curves of these three different cases are reported as follows:

- Ref. A+B (Fig. 7);
- 2Glass A+B (Fig. 8);
- Grid A+B (Fig. 9).

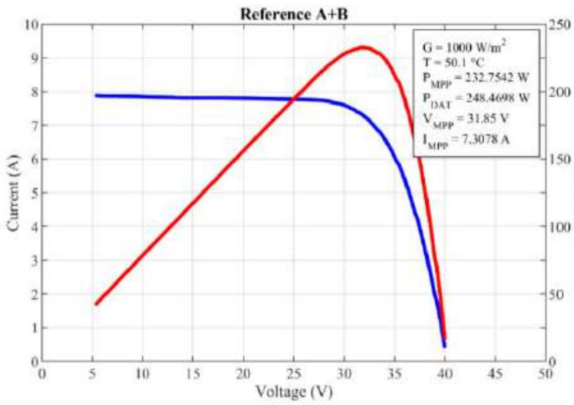


Fig. 7 – IV (blue) and PV (red) line curves for Reference A+B panel.

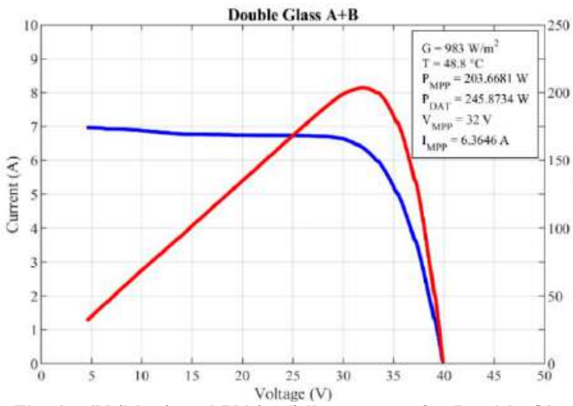


Fig. 8 – IV (blue) and PV (red) line curves for Double Glass A+B panel.

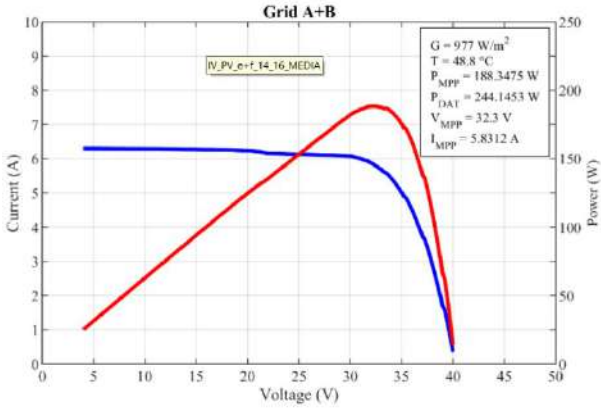


Fig. 9 – IV (blue) and PV (red) line curves for Grid A+B panel.

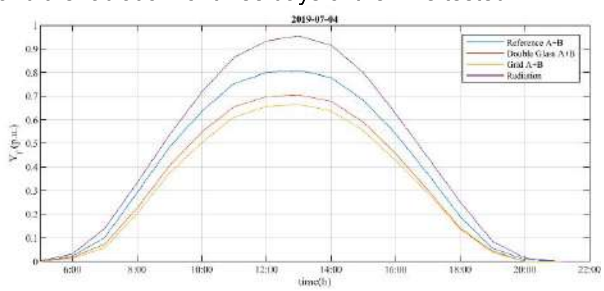
The box in each figure reports the temperature of the panel (T) and irradiation (G) measured during the test and also the values of current, voltage and power at MMP.

Table 2 shows the results of the test of Energy Performance for the three different configurations analyzed. The energy is calculated day per day for 9 different days in 2019; the total amount of radiation (I_{rr}) and the average ambient temperature (T_{av}) for each day is also reported. ∆% represents the difference in term of energy produced by Double Glass and Grid respect to Reference panels.

TABLE 2 – Energy performance for nine different days

Day	Ref. A+B (Wh)	Double Glass A+B (Wh)	∆%	Grid A+B (Wh)	∆%	I_{rr} (Wh/m^2)	T_{av} (°C)
04/07	1826	1550	-15.10	1446	-20.77	7644	25.7
05/07	1868	1583	-15.22	1482	-20.65	7865	27.6
06/07	1748	1486	-15.02	1383	-20.91	7370	27.1
10/07	1732	1495	-13.67	1393	-19.57	7141	24.4
11/07	913	764	-16.29	710	-22.26	3459	23.6
12/07	1849	1577	-14.72	1476	-20.20	7741	24.9
13/07	1818	1521	-16.32	1419	-21.95	7578	25.5
14/07	1859	1581	-14.97	1485	-20.13	7738	24
15/07	787	664	-15.57	608	-22.68	3019	19.4

As showed in Table 2, the energy performance of the Double glass panel is about 15% less than the Reference and the energy performance of the Grid panel is, more or less, 20% less than the Reference panel. Fig. 10 shows the measured final yield for the three different configurations and the radiation for three days of the nine tested.



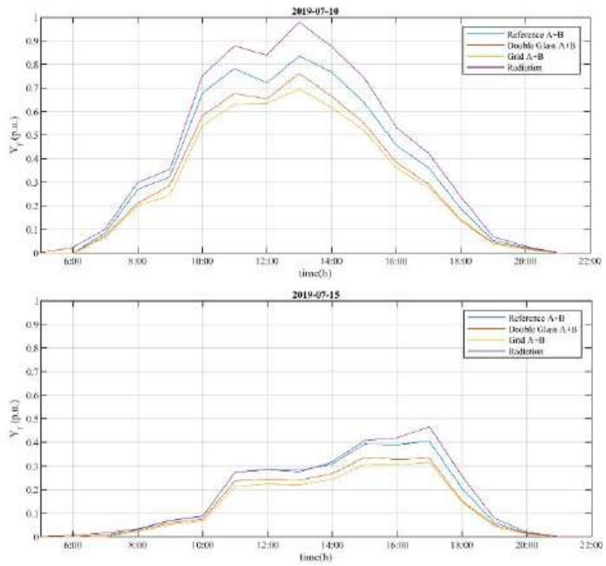


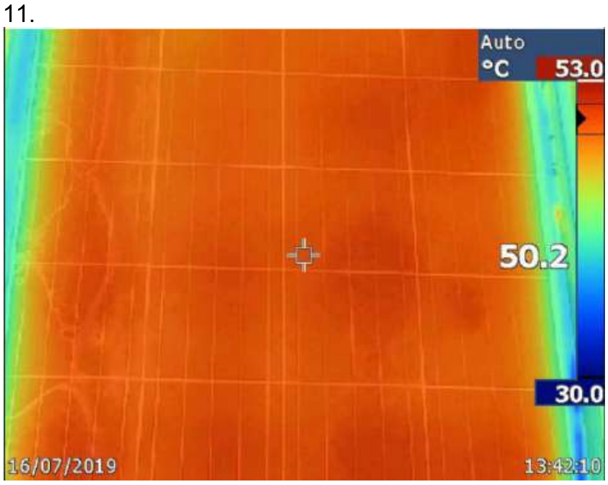
Fig. 10 – Final yield and irradiation measured in three different days.

Double Glass configuration always outperforms the Grid configuration. The addition of a second glass reduces the amount of radiation reaching the photovoltaic cell, consequently reducing the efficiency of the photovoltaic module. The addition of the grid, which makes the module more robust in term of Ex environment, causes local shading which reduces the performance of the module even more.

VI. THERMAL TEST

The maximum temperature reached by the panels during the normal running of the photovoltaic panel is a very important data, because that value determines the class of temperature of the panel. The Class of Temperature is a classification of an Ex apparatus and it is important because it gives an indication about where the apparatus can be installed according to the presence of gas type. In order to determine the Class of Temperature it is important to know the maximum temperature of the apparatus during its running.

All the configuration tested have showed, more or less, the same maximum temperature on the surface (see Table 1). The grid seems to show a temperature a bit less, but it may be due to the shading of the grid itself. Anyway, the maximum temperature is around 50°C, as showed in Fig. 11.



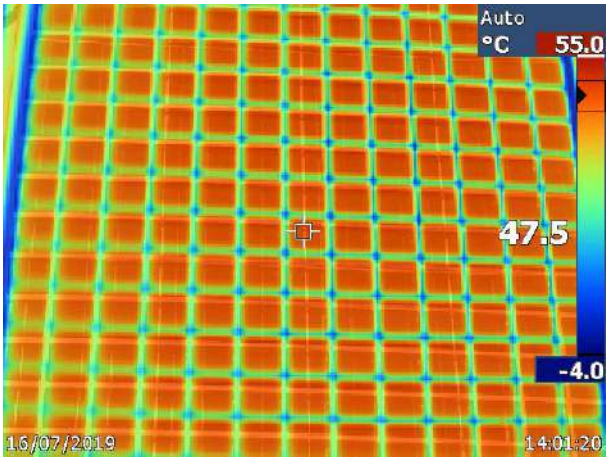


Fig. 11 – Thermal result in normal running for the Double Glass and Grid configuration respectively.

The same test shall be also performed in case of failure (if present), in order to evaluate if the temperature increase in that specific condition.

According to the risk assessment explained in the paragraph IV, the only critical cause of failure is when a hot spot happens. The IEC or EN Standards do not explain the test procedure in order to determine the max temperature on the photovoltaic panel. It works differently from other electrical equipment, so the result of the maximum temperature depends on the solar condition during the test.

VII. CONCLUSION

As for the test result: adding some “transparent” material on the reference panel, in order to pass positively the impact test per IEC 60079-0, causes a reduction of performance of the panel. This means that the manufacturer has to think regarding the mode of protection to use for this kind of apparatus. For example, it is absurd to use an Ex d enclosure with a big window (15-20 mm of glass) for this kind of application.

Moreover, another problem remains unsolved, that is the procedure for thermal test both in normal condition and in failure condition. As explained before, the IEC/EN Standard 60079-0 does not explain the test procedure in order to determine the max temperature on the photovoltaic panel. It works differently from other electrical equipment, so the result of the maximum temperature depends on the solar condition during the test. In conclusion the test is not repeatable.

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IX. VITA

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DECARBONIZATION OF COMPRESSOR TRAINS, ELECTRICAL DRIVER CONSIDERATIONS FOR HIGH POWER SYSTEMS.

Paper No. PCIC Europe EUR21_36

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Abstract - Driven by targets for CO2 reduction, Oil & Gas operators are increasingly investigating electrical solutions for their high-power compressor systems that have historically been powered by turbines and are also considering retrofitting electrical drives to existing compression trains.

Traditionally such very high power electrical variable frequency drive systems use current source, load commutated technology (LCI). However, recent developments in voltage source inverters (VSI) has made this technology available at increasingly higher powers. Current source LCI drives are well referenced but are viewed as complex by operators, whilst VSI is considered, overall, a simpler system but lacking in experience at very high ratings. This paper will compare both VSI and LCI drives above 25MW including availability, efficiency, footprint, weight, cooling, technology readiness, CAPEX and OPEX for a complete working system.

Index Terms — CSI, LCI, VSI, AFE, Availability, Adjustable Speed Drives, Variable Frequency Drives, Synchronous motor, Induction-Asynchronous motor, Network behaviour.

I. INTRODUCTION

Main components of an electric drive system.

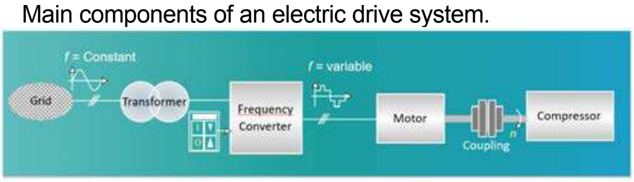

Fig. 1 Main elements of the drive system

Network

The network includes the electrical grid at the point of common coupling (PCC) where the harmonics and power factor are normally defined, together with the network fault level, where other large loads and generation are connected. Interaction between these components are evaluated during SSTI studies including load shedding and line disturbance immunity or support. The network is normally a national electrical grid but can be an island network.

Transformer

The VFD is most commonly connected to the network via a transformer as the network voltage for high power drives is normally significantly higher than the VFD operating voltage level. There will be switchgear connecting the network to the transformer, normally GIS type for protection and isolation. The transformer also provides galvanic isolation for the VFD restricting short circuit currents. The base solution is a single primary and single secondary winding in a 6-pulse configuration, however to reduce harmonics normally additional phase displaced secondary windings are used to connect to the rectifier bridges. This can be 12, 18, 24, 30, 36 pulse or more. If a harmonic filter is required, this is normally connected to an additional winding.

Variable Frequency Drive

This paper is predominantly considering the Variable Frequency (VFD) or Adjustable Speed Drive (ASD) characteristics for high power levels (30-100MW). So, the statements and considerations are for this high power range and not considering other requirements more applicable at lower power levels.

The VFD as its name suggests changes the frequency from the fixed line frequency to a variable frequency that in turn alters the speed and torque of the electrical motor driving the load. The drive is split into 3 main power parts rectifier-dc link-inverter. The rectifier rectifies the AC waveform into DC, the DC link smooths the DC and finally the inverter converts the DC back into AC at the desired frequency, this can be from 0 to 50Hz, or in the case of high speed be several hundred Hz. Other major parts of the drive include the controls and the cooling system. Current Source Inverter (CSI) drives as their name suggest control the current, whilst Voltage Source Inverter (VSI) drives control the voltage. The 2 families of drives are discussed in section II of this paper. CSI drives use thyristors in the switching sections of their rectifier and inverted sections which are uncontrolled switches. Whilst VSI drives have diodes in the rectifier section as standard. It is also possible to have Active Front End drives (AFE) with controlled switches in the rectifier which can provide some additional capability to the system that will be discussed later in the paper. The inverter section uses controlled switches such as IGBT's or IGCT's.

Motor

Considering the power level above 30MW the most common motor type is a synchronous motor, in the case of LCI this is mandatory as the motor provides the commutation to switch off the uncontrolled thyristor. The synchronous motor is most commonly used as it has higher efficiency and considerably more references, however, has some additional complexity in the excitation circuit, however this had almost on effect on the motor availability. Induction motors have a slightly lower cost. The motor the transition of electrical power into mechanical torque that is used to drive the load equipment.

Load

For loads in excess of 30MW the majority of cases are compressor applications although some fan and pump applications do exist. Normally these applications tend to be square law torque load profiles.

System Comparison

Whilst the main focus is on the VFD comparing LCI and VSI aspects such as availability, efficiency, opex, capex, TRL, safety, footprint, weight, cooling, AFE, harmonics, power factor and testing the impact on the network and load will also be considered.

II. OVERVIEW OF HIGH POWER DRIVE TOPLOOGIES

Fig. 2 shows the main medium voltage drive topologies for high power ratings in industrial applications.

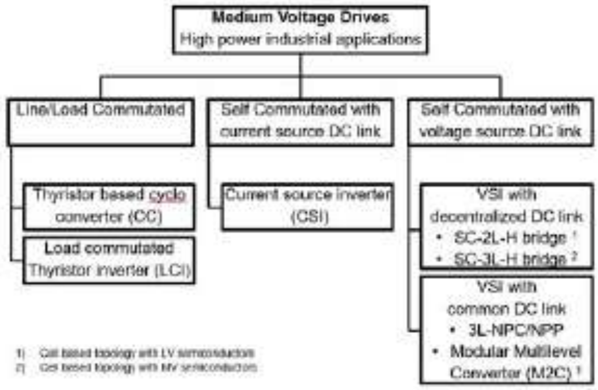

Fig. 2 Family tree of MV drive topologies.

CSI / LCI (Load Commutated Inverter) (figure 3) have been in operation since the 1970's, however today due to improvements in the VSI technology are rarely used below about 25MW. VSI came into the MV market in the 1990's most manufacturers use slightly different topologies, multi-level / multi-cell drives are the most common form of VSI VFD. Most manufacturers have a single thread VSI solution up to 25-35MW, these can be paralleled together to achieve higher power although paralleling more than 2 together increases complexity and impacts availability. Above 30MW there are only a handful of VSI references from any supplier.

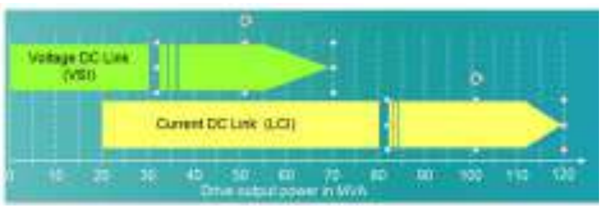

Fig. 3 Increasing power of VSI and LCI

Over the last few decades, the voltage source inverter (VSI) topologies have become the predominant converter technology. This paper will only focus on topologies capable of power above 20MW. Because of the various applications, the wide voltage and power range for medium voltage drives and the rapid development of the power semiconductor devices that are now available, numerous different voltage source inverter topologies have been developed for medium voltage applications in recent decades. Unlike the low voltage range, where the two level (2L) voltage source inverter has become the dominant concept, a large number of different converter topologies are available in the medium voltage drive market. The spectrum includes IGBT converters with low and high voltage IGBTs as well as IGCT-based converters including both 3-level, 5-level and multilevel drives with more than 9 levels.

The advantages of motor speed (frequency) control may be summarised as follows:

- Energy saving (compared to fixed speed operation and flow control via valves)
- Accuracy and speed of process control
- Reduced reactive power demand during motor starting – so called "soft start"
- Regeneration and energy recovery

A. **Current Source Load Commutated Converter**

CSI / LCI (Load Commutated Inverter) (figure 4) are very simple drives with high reliability and compact footprint. The main complication is they normally require a harmonic filter to comply with network standards such as IEEE 519. The technology is very well referenced and applied to power levels up to 100MW, in oil and gas the highest power level referenced is at about 80MW. All manufacturers use a similar topology of circuit

The base configuration is a 6-pulse rectifier and inverter, at high power the systems is normally a 12 pulse design at both the network and motor sides. The DC link reactor (inductor) is used to damp the DC ripple. The switching devices (Thyristors) naturally operate at a poor power factor and considering 12 pulse is normally not sufficient to comply with network harmonic requirements, a harmonic filter is required to absorb harmonics and correct the power factor to an acceptable level. Only synchronous motors can be powered by CLI drives as the thyristor is an uncontrolled switch it needs the back EMF of the motor to turn the thyristor off.

The LCI drive is naturally 4 quadrant as the rectifier thyristors can conduct in both directions, unlike a diode that can only conduct in 1 direction.

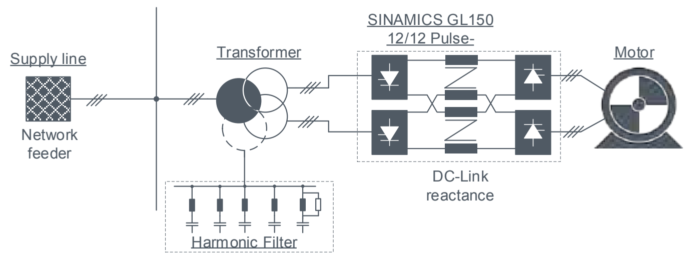

Fig. 4 Current Source Load Commutated Inverter.

B. **Modular Multilevel Converter (M2C)**

The modular multilevel converter (see Fig. 5) is the latest topology to enter the high-power medium voltage drive market. Depending on the motor voltage and the corresponding number of cells, the M2C is a 7-level up to 17-level drive. It uses simple, two terminal cells equipped with 1.7 kV IGBTs and state-of-the-art polypropylene film capacitors. These technologies are well established in the low voltage converter industry. Since the low voltage drives market is 80-90 % of the total drives market, these components are manufactured in very high quantities.

This ensures the highest possible quality at reasonable costs. Furthermore, all new technologies (e.g. new IGBT and diode generations, new module technologies with higher load cycling capabilities) are first introduced into the LV markets. All these developments are driven by

high volume applications, such as the wind power industry requiring very high-quality standards. Therefore, MV drives using LV technologies can benefit from these applications, leading to a long-term availability of spare parts, fast innovation cycles and high reliability.
On the line-side, the M2C can be connected to any conventional 12 to 36-pulse diode rectifier using press pack diodes and RC snubbers. This technology has been employed for many decades and has reached a very high quality standard.
Due to the modularity of the M2C topology, redundancy can easily be implemented in the motor-side inverter. By adding 6 (or 12) additional cells and bypass switches to all the cells an n+1 or n+2) redundancy can be realized.
This kind of redundancy covers a complete cell including semiconductors, capacitors, heat sinks, PCBs, and power supply. Having this type of redundancy, the drive voltage and current capability does not have to be reduced in case of a cell failure. One advantage of cell-based topologies that should be noted is that a cell bypass allows operation with reduced power that would allow the process to remain operational.

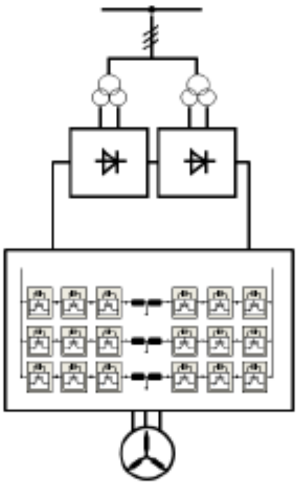

Fig. 5 Voltage Source Load M2C topology.

3L neutral point piloted converter (3L-NPP)
The 3L neutral point piloted converter (3L-NPP, Fig. 6) is derived from the conventional 3L neutral point clamped converter (3L-NPC, Fig. 6). Due to the high DC link voltages, this topology requires MV IGBTs connected in series [7]. Today 4.5 kV IGBTs offer the best compromise between the number of devices connected in series and semiconductor performance. Compared to the 3L-NPC topology, the IGBT switching losses can be reduced in the 3L-NPP concept as twice the number of IGBTs connected in series are employed for blocking half the DC link voltage during switching. This allows a higher power rating, which is the reason why the 3L-NPP topology was selected for the additional comparisons made in this paper.

MV IGBTs are available in either single-side cooled module packages or double-side cooled press pack packages. While IGBT modules are usually also used in other applications (e.g. traction drives), IGBT press pack devices are usually single-source devices and their usage is currently limited to fewer applications. The single source situation might result in problems regarding spare parts availability over the long term. Due to the low production quantities, innovation cycles take longer and the amount of feedback from problems in the field is limited as there is a lower number of devices in operation.

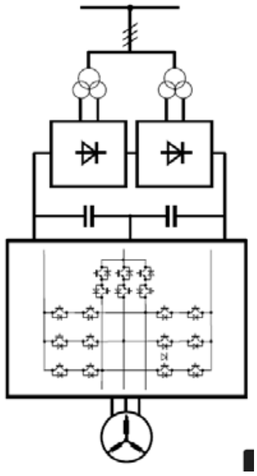

Fig. 6 3L-NPP (neutral point piloted) topology

Due to the centralized DC link capacitor, the amount of the total installed film capacitor energy of the 3L-NPP is lower than in the cell-based drives mentioned before. Even though the total capacitance is less, the value of the total capacitance, and therefore stored energy, in a single location, is many times greater than in topologies that are based on a distributed power architecture design. On the line-side, the 3L-NPP can also be connected to any conventional 12-pulse to 36-pulse diode rectifier using press-pack diodes and RC snubbers. The press-pack IGBTs and diodes in the 3L-NPP mean that devices can be simply connected in series without excessive stray inductances that would otherwise result in high switching losses. Furthermore, the conduct-on-fail capability of press pack devices is the deciding factor for this type of application.
By adding

- 12 (24) additional press pack IGBTs and
- 12 (24) additional press pack diodes

an n+1 or (n+2) redundancy can be realized with no decrease in voltage and current in case of a failure. The series-connected press pack IGBTs require isolated gate driver circuits connected to the emitter potential of the corresponding IGBT for controlling the gate-emitter voltage. In contrast to the LV cell-based topologies, gate driver failures cannot be covered by this kind of redundancy. This is because a failed driver does not necessarily result in a short-circuited IGBT, i.e. the IGBT gate drivers are still potential single points of failure and can cause a drive to be shut down.

The required off-state voltage of the power semiconductors directly depend on the DC link voltage. Therefore, continuous operation with reduced motor power without using additional hardware components (semiconductors, drivers) is not possible. This is different to the LV cell-based topologies where the cells that are still in operation are not affected by the bypassed cells in any way.

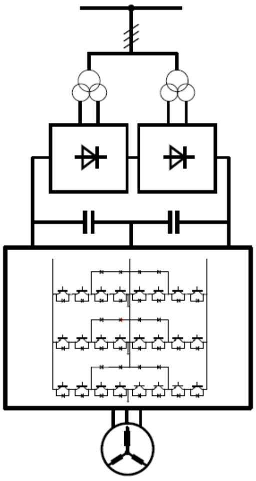

Fig. 7: 3L-NPC (neutral point clamped) topology

Series-connected (SC) 3L-H bridge converter
Regarding its cell-based design the series-connected 3L-H bridge converter is similar to the 2L-H bridge converter. The cells are individually fed by galvanically isolated transformer secondary windings. The required installed capacitor energy is higher than in concepts having a centralized DC link because of the single phase cell output.

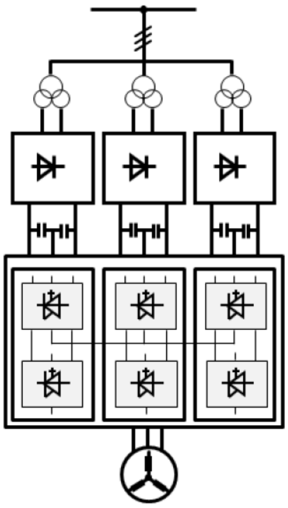

Fig. 8: 3L-H Bridge converter topology.

Commercially available converters use press pack semiconductors (4.5 kV IGBTs/IEGTs; 4.5 or 6 kV IGCTs/GCTs) with a maximum of two cells per phase, i.e. max. 6 cells in total. This results either in a 5-level (3 cells in total) or a 9-level drive (6 cells in total). Just the same as the press-pack IGBTs, the IGCTs are specifically designed to address certain applications. Due to the limited market, these kinds of devices are usually single-source components. On the line side, each cell can be equipped with a 12-pulse diode rectifier using press-pack diodes and RC snubbers, resulting in a 36-pulse line-side performance for 3-cell configuration. Due to the high number of additional devices a redundant operation of the SC-3L-H bridge topology is not reasonable, and therefore not available on the market.

III. LCI & VSI COMPARISON

The following criteria is used to evaluate both LCI and VSI systems.

1) Reliability MTBF

Transformer

The transformer is very similar to the topologies stated in section II, The LCI transformer will normally have 4 windings (primary, 2 secondaries and a 4th winding for the harmonic filter) whilst VSI will be configured most likely in a 24 or 36 pulse arrangement, this will comprise of two 50% rated transformers in one tank, each having a primary and 2 or 3 secondaries to create either 24 or 36 pulse. Either can be connected to very high input voltages in excess of 100kV and will normally be oil cooled. MTBF and MTTR are comparable for each solution.

Harmonic filter

The harmonic filter normally only relevant to LCI, it is a passive system including container and HVAC system. Redundancy should be used for the cooling system. This is generally a very reliable system.

Variable speed drive

Including controls and cooling systems. LCI is a much simpler circuit and high reliability, all VSI circuits > about 30MW require parallel systems to achieve the required output power. The power circuits are more complex with a higher component count that impact the reliability, hence N=1 redundancy should be implemented to improve availability to a comparable level with LCI. The figure below are for a single thread system. See reference [1] and [4] for further details.

Motor (synchronous/induction)

Although induction motors are simpler in comparison to synchronous motors (fewer moving parts) and thus might have higher reliability/availability, this advantage is more than lost due to the far higher complexity/components of high power multi-parallel VSI.

	MTBF	MTBF
Component	**LCI**	**VSI**
Transformer	540y	540y
Harmonic Filter	95y	N/A
Motor	65y	65y
Excitation	140y	140y
VFD (N)	6.5y	5.3y
VFD (N+1)	11.5y	11.8y
VFD system (N+1)	**6.5y**	**6.5y**

2) Efficiency

The figures below are typical values, higher efficiency for the transformer and motor are possible with higher cost components.

Component	**LCI VFD system**	**VSI VFD system**
Transformer	99.2	99.0
Harmonic Filter	99.9	-N/A-
Motor	98.0	98.0
VFD	99.0	98.5
System Total	96.15%	95.56

3) CAPEX

Component	**LCI VFD system**	**VSI VFD system**
Transformer	100%	95%
Harmonic Filter	100%	0
Motor	100%	95%

Excitation	100%	100%
VFD	100%	125%
System Total	100%	90-95%
For > 50MW+ systems.		

These figures are typical and develop year by year.

Operational cost (OPEX) and maintenance is mainly driven by the cost of electrical power, hence efficiency is the most important factor. Maintenance cost differences between the topologies are minor.

4) TRL

Technology readiness level for LCI drives is proven at power levels about 80MW for compressor applications operating motors at speeds above 3000rpm. However extending this to powers of 100MW+ is simple to scale from lower powers as it means adding additional thyristors to increase the motor voltage level from about 11kV to about 13.8kV. A TRL process should be considered to understand the development required.

For VSI there are references for continuous duty up to about 27.5MW, above this higher motor voltage levels and/or paralleling of systems are required to achieve the power level to about 70MW. A TRL process should be considered to understand the development required at these higher power levels.

5) Footprint and Weight

	50MW m^2		70MW m^2	
Component	**LCI**	**VSI**	**LCI**	**VSI**
Transformer	29.4	25	37.4	32.4
Harmonic Filter	45	N/A	60	N/A
Motor 3600rpm	27.7	26.4	33.6	31.7
Excitation	0.24	0.24	0.24	0.24
VFD	19.2	33.2	27.2	39.4
System Total	**121.5**	**84.8**	**158.4**	**103.7**

	50MW kg		70MW kg	
Component	**LCI**	**VSI**	**LCI**	**VSI**
Transformer	85	80	104	97
Harmonic Filter	24	N/A	29	N/A
Motor (2 pole)	108	102	137	130
Excitation control	0.4	0.4	0.4	0.4
VFD	22	30	27	36.4
System Total	**239.4**	**212.4**	**279.4**	**260.8**

As can be seen the values are strongly influenced by the harmonic filter. However in most cases both the filter and the VFD are in containerized housing which means the complete system dimensions for both solutions tend to be very similar (+/-<10%) after the containerization is included.

6) Containerization

Considering the above dimensions, the larger VSI drive is still a smaller system due to the harmonic filter. However as both drives are large systems it is often more practical to use containerized systems to minimize site installation work. Containers can be supplied with HVAC and be pressurized depending on site environmental conditions. Overall, with all equipment in containers the difference in footprint is relatively small.

7) Safety

Most suppliers have capability to offer arc flash drives for operator safety, safe torque off SIL ratings are becoming an increased request. Suitability for different SIL rating are still being developed by suppliers.

8) Cooling

Variable speed drives have 2 possibilities of cooling either direct air cooled or direct liquid cooled. Losses (see above) are in the range 1-1.5% which at 50MW = 500-750kW of heat load.

Direct air

Forced air is drawn across the switching device heat sink fins to cool the drive, stray heat losses are also picked up by the cooling air flow and removed from the VFD. Redundancy for the fans is recommended for increased reliability. Air cooling presents a simple and highly reliable cooling system as managing cooling liquids is not required and often useful in very cold arctic locations, instant startup can be done without checks on the cooling system. However, if the heat load cannot be absorbed by the switchroom or directly blown outside an air-to-air or air-to-water heat exchanger can be provided.

Direct Water cooling

Cooling water is directly pumped through pipes to all the main heat loads within the VFD (switching devices, DC link components etc..) additional heat sinks can be placed in control cabinets and other hot spots to remove stray heal losses. As the water is directly passed through heatsinks clamped against the power electronics the water needs to be non-conductive (de-ionized). Redundant pumps, main heat exchangers are recommended for increased reliability. Serviceability of the cooling circuit during operation is recommended to avoid shutdown for maintenance on de-ionizer cartridges and pumps. The de-ionized cooling circuit is an internal closed loop. This can be cooled via a water-to-water heat exchanger, where ambient conditions fall below +5degC glycol is required in any cooling loop that is exposed to this temperature. If cooling raw water is not available a water-to-air fin-fan heat exchanger is required.

9) Harmonics

The rectification process of the variable speed drive creates non sinusoidal elements within the voltage and current waveforms. A single rectifier bridge across the 3 phases draws current or voltage in 6 distinct pulses which creates a square profile waveform. With two 6-pulse connections it is possible to phase displace the 2 waveforms to create a 12-pulse more sinusoidal connect to the line. With more rectifier bridges in parallel connections in excess of 36 pulse are possible. National electrical grids will have standards such as IEEE519 which have to be met to allow VFD's to be connected.

A current source drive is normally configured in a 12-pulse arrangement, this is unlikely to conform to the electrical grid requirement for harmonic limits. A harmonic filter in the form of an LC circuit is added to meet the harmonic limits. Designing a harmonic filter requires network information such as fault level and existing harmonic profile. If the network characteristics change over time the harmonic filter may need to be re-designed.

MV Voltage source drives are normally supplied as a minimum in an 18-pulse connection with 3 rectifier circuits to allow for compliance with the harmonic standards. The more pulses the more sinusoidal the waveform. Due to the higher number of rectifier bridges in a VSI drive harmonic filters are almost never used. Care should be taken that the harmonic pulse number does not excite a network resonance.

10) Power factor

Current source drives with thyristors naturally operate at power factor of about 0.82. This is undesirable as it causes higher currents and impacts on efficiency and results in voltage drops, causing the operator higher running costs. To correct the power factor the capacitance in the harmonic filter is used to improve the power factor to an acceptable level of about 0.95.

This is not a problem for voltage source drives with diode bridges as the diode operate at about 0.96 power factor. If the VSI drive has an active front end (AFE) see below then the drive can be used to provide leading VArs into the grid to correct the grid power factor.

11) Testing

Both topologies of drive are standard tested at full current and full voltage, but not both at the same time. If a load test is required then the complete systems needs to be assembled either in the form of a back-to-back test or a string test with the driven equipment (compressor).

For a back-to-back test [3] if there are 2 identical systems then the LCI systems can be connected together at the motor shaft with one motor in motoring mode and the other motor in generating mode. The power can be circulated through the 2 systems and loaded close to full power. However as VSI is not naturally 4 quadrant either a test bay drive/load is required or an AFE implemented on the rectifier circuit.

12) Active Front End

Active Front End drives (AFE) means the switching device in the rectifier if controllable. For a voltage source drive the standard solution is to use a diode in the rectifier, this is an uncontrolled switch and is a 2-quadrant drive, meaning the VFD can drive the motor clockwise or anticlockwise. By replacing the diode with an IGBT for example means that the drive can regenerate power from the motor (acting as a generator) to the electrical grid. This is also known as a 4-quadrant drive. Any spare capacity in the drive and transformer can be used to provide VAr's back into the grid for power factor correction. The drive can support the grid against voltage and frequency disturbance, grid code functionality needs to be investigated for requirements at site.

Whilst LCI Current source drives are naturally 4 quadrant this is not an active front end drive, as VAr compensation is not possible due to the limitation on switching the thyristor off, as it is not fully controllable. However, optimization of firing angles of the thyristor can help support the drive system through voltage disturbance by allowing continued operation and avoiding losing control of the motor for larger dips and longer durations of dips.

Further examples of AFE and 4 quadrant drives are discussed in the next chapter.

13) Interharmonics

Interharmonics [2] is a well understood issue where there can be interaction between rotating equipment on the electrical grid and driven equipment rotating equipment. Mitigation techniques are used for LCI drives, whilst VSI has not experienced problems due to the DC link design.

14) Load torsional vibrations

Non sinusoidal elements in the current waveform to the motor result in air gap torques that can cause problems for the mechanical train. Torsional vibrations in the motor-load shafts need to be evaluated to ensure there are no interactions with natural resonances and issues across the operating speed range of the system.

15) SSTI

Sub Synchronous Torsional Interactions of the complete system need to be evaluated for vary large power drive systems, this is particularly important for islanded networks where the motor power can be a high proportion of the generator power. The interaction between the generator is discussed above in interharmonic issues, however SSTI also includes the complete start up and operating philosophy of the plant including the commissioning phase that is likely different to normal operation conditions and also black start up of the island system. Load shedding needs to be carefully considered, under normal circumstances when there is a voltage dip the variable speed drive will try to maintain power to the load to prevent interruptions in the process. However for island system if a turbine generator were to trip causing a voltage dip and the VFD responded by drawing more current to maintain the process this will further exacerbate the other turbine generators from recovering and could cause the complete system to trip. Pre-programmed load shedding scenarios will ensure the network has the best chance of recovery. A team of process and grid experts will need to consider the response to each failure event.

16) Soft starter for fixed speed motors

The electronic soft starter device is one of the motor starting options, among others, that is selected when voltage drop constraints are fixed by the energy provider, or not to exceed limits are set for the adjacent bus bars. The LCI as well as the VSI allow reducing inrush current and voltage drop when starting large motors, offering a smooth start-up. In some cases the electronic soft starter is convenient to save space or additional equipment (e.g. versus an autotransformer starting method). The LCI and VSI device makes it possible that the starting current would not be more than the rated current of the large motor. This is also good for the motor and other electrical equipment associated with the plant as it lessens the stresses placed on them by the other types of starting methods.

The main inconvenient for the operations is the complexity of the equipment that requires specific skills in the maintenance and operations teams.

The choice of this solution is made on a case by case basis, more especially when it is supposed to be shared between two motors. Then the most appropriate technology and product may be selected taking into consideration the:

- type and reference with regard to the existing fleet,
- return of experience with products and suppliers,
- OEM's technical support in the geography,

- simplicity of the system,
- line current total harmonic distortion,
- input power factor,
- reliability (MTBF),
- equipment size,
- cooling system.

More broadly:

- The electronic soft starter should provide the motor accelerating torque, such that a minimum net accelerating torque of 10% should be available for the entire speed range up to pull-in speed. The soft starter control and acceleration rate should be programmed and commissioned, to give optimum compressor acceleration,
- the LCI or VSI system could produce negligible sidebands of the characteristic current harmonics on the source side, due to the operation of the load side bridge,
- the LCI or VSI system may be designed to minimize the motor ripple torque, due to interaction between the source and load-side converters,
- the design and construction of the soft starter output transformer could allow forced commutation starting at low frequency to accelerate the motor and connected inertia to pull-in speed using the compressor starting load torque shown on the compressor load torque curve. The design parameters of the transformer should be submitted the operator and soft starter vendor for approval,
- the LCI or VSI drive could provide its own referencing voltage for the load,
- the design of the LCI / VSI should be as independent as possible of Motor(s) and Motor Control Panel(s). After startup, it should be possible to disconnect the drive without impact on motors. If required, a Master PLC is to be used to make the interface between the drive, the MCP, the MV circuit breakers and the control system (BPCS and SIS).

IV. USE OF DRIVES AND CONVERTER-BASED POWER GENERATION

The global drive to reduce CO2 footprint increases the potential for electric VFDs compared to turbine drivers. Traditionally, island networks use local diesel or gas turbines as prime drivers for high power mechanical loads. This also includes sites such as offshore platforms. New platforms may be designed with power from shore or power supply from offshore wind farms or other local generators such as hydro-electric and solar, where electrical cables connect the offshore facility to the local power grid or power generation facility. Depending on the distance from shore and power demand, high voltage AC or DC power transmission systems can be used.

Operators are also investigating power from shore for existing platforms, where offshore power generation is removed and turbine driven loads converted to electric systems. There is the added complication of a mismatch of frequency, where for example the offshore platform is using 60Hz but the power from shore is at 50Hz, this means where an HV cable is used to deliver power offshore a frequency converter is required to operate the existing 60Hz loads. Industrial VFDs can be used as cost effective SFC's. Using an AFE means the SFC can deliver power in both directions, also VAr compensation can be provided to the grid, as well as support against voltage and frequency disturbance.

There is increasing penetration of grid-following renewable and other converter-based sources of power, such as battery energy storage systems, which rely upon VSC technology for connection to the power system. As the amount of converter-based equipment increases, effects not previously considered become more relevant especially the interaction of the power electronics / control of the converter-based equipment with other system components notably drive converters.

CIGRE has highlighted the issues to be considered when deploying large amounts of converter-based resources into systems [5]. Other than the general issues regarding the quantification of non-integer harmonics produced by many AFE VSCs [6] there is also the risk to system operation as unstable oscillations are identified within the frequency range of the VSC outer controls, which include dc-link voltage control (DVC), ac voltage control (AVC), and the frequency tracking phase-locked loop (PLL). It is reported that the PLL can lose stability under weak ac system (high impedance) conditions.

In general, the stability of a system formed by the ac power system and the power converter can be studied using frequency domain methods, such as the impedance-based Nyquist stability criterion. This requires detailed modelling and knowledge of controller dynamics, and so is difficult to do in early project phases. More simply, a screening analysis can be done per the advice in CIGRE TB671 – this is based on the ratio of the power system short circuit level to the MVA rating of the connected converter-based equipment at the point of coupling (referred to as the Short Circuit Ratio, which can confusing for those familiar with synchronous machines). While there are discussions about the exact details the calculation method, when this ratio (System MVA SCL / connected MVA) < 3, problems may be anticipated with control of converter-based resource and further study is needed in the early project phases, potentially leading to testing of controller hardware once equipment and suppliers have been chosen. The literature does indicate stability at lower levels of SCR, but this should be modelled and then demonstrated during project development.

As grid-forming converters become more standard where measurement and feedback loops are less susceptible to signal amplification by the power system impedance, it may be that the SCR values at 1 or below may be acceptable.

V. CONCLUSIONS

As a general rule owners and operators nearly always use VSI technology below 25MW and nearly always use LCI above 50MW. In the range 25 to 40MW the market is cautiously considering VSI technology and references are increasing year by year. In the range 40-60MW whilst VSI is technically possible, the lack of references in a conservative market means there needs to be a compelling reason to consider VSI over LCI.

VSI has several advantages over LCI, namely better waveform to the network and motor, so harmonic filters are almost never required. This makes the system simpler and slightly lower cost, however as power increases more and more components (series or parallel switching devices) are required, which impacts complexity and availability of the VSI drive, hence N+1 redundancy can be implemented to improve availability. VSI **can** have the required availability by offsetting the high component count with higher redundancy.

At high penetrations of converter-based equipment (both generation and motor drives), EMT modelling studies and controller testing are required to demonstrate controller stability and overall impact on the electrical grid.

VI. ACKNOWLEDGEMENTS

Thanks to Lennart Baruschka for input on AFE.

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How does our industry in Europe keep up with the global economy?
The journey to Smart Industries and Digital Transformation

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Abstract - While the concept of applying digital technologies to improve operational excellence isn't new, in 2019 a staggering US$ 345 billion was earmarked for digital transformation initiatives in process and manufacturing industries. These investments are considered to be the largest of their kind by any industry worldwide, according to the International Data Corporation (IDC). The question thus arises: what's driving these large-scale investments in digital transformation in recent years? The answer lies in both the changing market and consumer preferences.

Fluctuating commodity prices have had a tremendous impact on process industry earnings of late, while pressure to decrease capital expenditures year-on-year is weighing on traditionally asset-heavy industries. Increased competition and consolidation mean that speed rather than size has become the deciding factor for success. Moreover, a new generation of tech-savvy but less experienced workers are replacing veterans, leading to an experience gap. Simultaneously, the expectations of industrial customers' have been rising due to exposure to technology and tailored consumer experiences, driving demand for more customized solutions.

I. DIGITAL TRANSFORMSTION

Digital Transformation (DX) offers certain compelling responses to these challenges in production and manufacturing.

1. **Agile response to market changes**
   A clear view to financial, asset, and production data across the value chain speeds up decision making and time to benefit.
2. **Remote and autonomous operations**
   Empower your facility to run, learn, adapt and thrive in tomorrow's environment.
3. **Increased customer loyalty**
   A 360-degree, seamless customer experience and journey contributes to increased customer conversions and loyalty.
4. **A culture of innovation**
   Digital transformation generates enthusiasm and inspires product and service development. Employees feel empowered through education.
5. **Increased internal collaboration**
   Collaboration improves between business functions to unlock greater business value and efficiency.
6. **Sustainable economic excellence**
   In a survival of the fittest, businesses that adapt and lead in digital transformation enjoy a lasting competitive advantage.

Many advanced digital technologies, such as artificial intelligence (AI), autonomous robots, cloud computing, intelligent sensor technology, and augmented reality (AR) have become cost-efficient, providing firms with a clear view of financial, asset, and production data across the value chain, and empowering them to respond more promptly to market changes. Remote and autonomous operations are bridging the experience gap in process industries, and big data is being used to develop deeper customer insights. Firm-wide adoption of DX also strengthens collaboration and innovation.

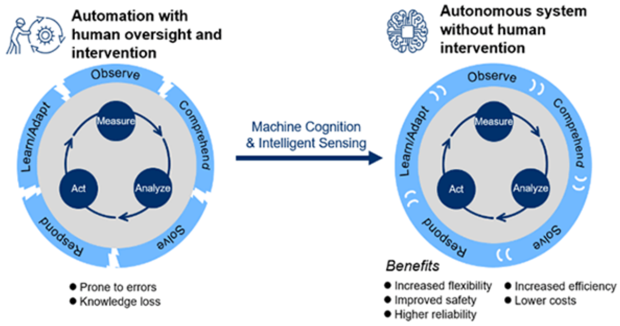
II. DIGITAL TRANSFORMATION AND THE INDUSTRIAL ENTERPRISE

Digital transformation as the novel use of digital technology to accelerate business strategy. It is about the application of digital technologies to empower people, optimize processes and automate systems of an organization to radically reorient its business performance. With DX, technology is evaluated based on its ability to strengthen business strategies, human capital, processes, data, and assets.

DX has applications throughout an enterprise. For instance, in sales and marketing, creating customer journeys with the aid of big data analysis can bolster customer acquisition, while in middle office, AI can enable HR departments to analyze thousands of candidates for best-fit.

Once DX is applied to manufacturing it can often be classified as 'Smart Manufacturing'. integrates the use of technology-assisted processes to create and deliver products and services in a way that is adaptable, data-driven, and integrated with other domains within enterprise value chains.

The key benefit of smart manufacturing is deriving real-time data from the manufacturing process for decision making and problem solving across the organization. This entails deriving and integrating data with the use of devices and solutions such as intelligent sensors, computerized control, and production management. This integration enables an enterprise to collect and utilize real-time data, such as raw material availability and work-in-progress inventory to improve operations.



Smart manufacturing is also uniquely positioned as a driver in the shift from automation to autonomy in process industries. Industrial autonomy transcends industrial automation by adding layers of intelligent sensing and AI to anticipate and adapt to circumstances, both known and unforeseen. In a fully autonomous operation, the industrial system is responsible for all aspects of operation, from start up to shut down (see above graphic).

While unattended remote operations are a first step in the autonomous journey - with a number of companies realizing benefits in productivity, flexibility, and safety - human interventions and decision-making remain important as plant personnel learn to work alongside autonomous systems. The integration of autonomous/human systems is a near-term goal across the industry, but organizations need to approach automation as an evolutionary challenge.

III. DIGITAL TRANSFORMATION AND THE SHIFT TOWARDS SMART FACTORIES

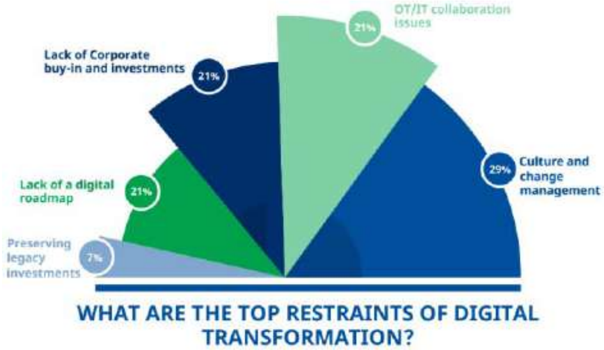
A key pillar of digital transformation lies in a firm's ability to integrate information technology (IT) throughout its operations - in concert with operational technology (OT) - and human resources. Given the breadth of OT in manufacturing, the machines, devices, and control mechanisms of modern factories often operate in relative isolation and communicate using a variety of niche protocols. This creates silos, communication difficulties, and procedural blind spots. A blended and hybrid architecture which can connect on-premise (Industrial Internet of Things) IIoT devices to cloud-based systems creates an ideal digital solution platform, enabling the linking of legacy systems and better management of data quality.

Enhanced IT/OT convergence is also leading to the rise of smart factories using digital twins. Digital twins are a key element for implementing smart manufacturing and industrial autonomy initiatives to realize operation optimization, asset failure prediction, and the reduction of process development lead time. A digital twin typically resides within an on-premise IT system or in the cloud, and it emulates all or part of a manufacturing operation (figure 15). AI and simulation technologies are used either individually or in tandem to analyze a digital twin and create added value by, for example, predicting equipment malfunctions. Based on these predictions and analysis of historical data utilizing AI technology, an AI system can propose multiple recommended countermeasures.

IT/OT convergence is changing the way manufacturers work, and the skills that workers need. More and more, engineers are being tasked with work that has traditionally been done by software developers and network specialists. Thus, smart manufacturing requires the organi linking of not only processes and technologies, but also the integration of people skills to achieve stable, sustainable, and profitable operations.

IV. CHALLENGES AND THE PATH FORWARD

A survey by Forbes shows that almost 70% of digital transformation efforts fail, and as per research among our end users in the Process Industry, the most common reasons for failure are culture and change management issues, followed by challenges posed by OT/IT collaboration. While each organization is different, there are some industry-wide best practices which have proven to work for many and can be easily incorporated by those undertaking their manufacturing DX journey.



A. Align the digital strategy to corporate strategy

Many organizations approach digital transformation as a one-time strategy-development exercise. This often leads to unclear vision of the digital element across the organization, followed by limited C-level support and IT involvement. In fact, a survey conducted by McKinsey pointed out that only 8 percent of their surveyed companies felt that their current business model could remain economically viable if their industry keeps digitizing at its current course and speed?

To keep up with the demands of industry, a more strategic approach is needed to link DX objectives to an organization's business goals and strategy. This helps incumbent companies to explore new digital business models as they align their investments in creating operational excellence. In other words, DX should be a driver of corporate strategy and senior management must support these with the same rigor as their core business initiatives.

B. Mapping current state capabilities

Whether you are at the start of the journey and would like support in planning your digitalization roadmap, or whether you are looking for an implementation partner who understands how to safely deploy new technologies in a plant environment, every DX journey is unique and supported by enabling technologies and services. Along with maturity and operational assessments, your focus areas and desired outcomes will be used to guide you in determining your ideal approach for creating value. Organizational strategy, operational challenges, risk appetite and automation ambitions should be the drivers to decide a digital target state roadmap.

C. Break organizational silos and collaborate

Kodak invented the digital camera, but its management was resistant to change and shelved the whole project. Why? It threatened the company's legacy film business. DX, by its very nature, requires people to change their ways of working and break out of organizational silos and into collaboration on key projects. While corporate restructuring can eliminate some of the existing organizational silos that exist, it's often a lengthy and complex process. A more practical approach is to empower employees to lead DX efforts. By identifying the most influential people at key points across the organization and inviting them to participate in a digital transformation task force, a company can create buy-in and trust among employees. This, in combination with communication mechanisms like townhalls, blogs and social media, results in wider employee collaboration and, ensure that your DX efforts will face far less resistance.

D. Organize processes around customers

DX requires a mindset and culture that places the market, customer value, and customer experience first. A report published by Deloitte Insight demonstrates how, over the course of a year, customer experience-driven businesses grew revenue 1.4 times faster than other companies. While evaluating risks and return on investment, companies must adopt a perspective that prioritizes the needs of the market over the needs of its departments, fiefdoms, or leaders. Aligning the IT/OT ecosystem to solve the unmet needs of your customers ensures the best results in executing your DX strategy.

E. Identify quick wins and estimate benefits

There are always opportunities for quick wins by shedding light on pressing issues that erode operational performance - such as unplanned downtime or problematic equipment. A report by Aberdeen Research provides an example: organizations are expected to be hit with unplanned maintenance costs upwards of US$260,000 per hour. Tackling these issues upfront, creates immediate and measurable benefits, freeing up valuable time for more strategic initiatives.

F. Build a stable technology foundation and organize your data

Leading companies ensure they have established a stable technology foundation before moving to cross functional integration and acceleration. In the early phases of DX, up to 80% of digitalization efforts were spent on janitorial and data housekeeping activities. An Experian report found 68% of their surveyed companies experience poor data quality issues, and while tedious, a clean and stable data foundation is essential to support effective analysis, decision making, and automation. In process industries, this often means securing the right data through devices, analyzing the data for new insights and using data to create business value. Only a data centered approach to technology can ensure a reliable foundation on which to apply analytics, application logic, and interoperability.

V. PARTNERING TO CREATE FUTURE-PROOF RESULTS

When done correctly, DX leads to future-proof results. DX is a daunting challenge with many interdependent factors, and there is not a one-size-fits-all solution. Process industry companies need a business partner who believes that innovation is not just a one-off event or project but a change in mindset, organizational culture, and business agility. The business partner should integrate business and domain knowledge with digital and automation technologies with customers to drive their digital transformation and operations and manufacturing.

Leveraging decades of experience in process manufacturing along with our digital fluency, we co-create value by connecting data, systems, and organizations to the value chain and business and domain knowledge.

There are numerous disruptive technologies and transformation paths; The business partner should guide, plan and implement the right one for your organization. Laying out your digitalization roadmap that thoughtfully considers people, processes, technology, assets, and data is the key direction to reorienting your business performance.

VI. CONCLUSIONS

As DX continues to disrupt, transform, and reshape global business, the imperative to change is clear and very present in process industries. To make this change, you will need to shift your focus from reactive operations to proactive, predictive, and profit-optimizing operations. Successful process industry companies see DX as a key strategy for deploying sustainable innovation across value chains through the judicious use of digital technologies, while structurally altering operational models, culture, and best practices that encompass new ways of working.

Companies cannot make the DX journey alone. They need to leapfrog innovation by partnering with experts fluent in both operational technology and IT. Your partner must understand your existing operations, technology, and data. As complexity differs for each company, the imperative is to co-create solutions that fit your needs, requirements, and budgets. Many solution providers have piece-meal offerings, including consulting, IT, and OT technologies. Increasingly, the best fit DX approach requires a partner who will support you throughout this journey, is open and oriented to all possibilities, and takes responsibility in all aspects of the process from planning to performance-based results.

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