ENERGIZATION OF SUBSEA POWER TRANSFORMERS

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Abstract –Energizing large transformers often cannot be done direct-on-line due to the negative effects of the inrush current. The typical schemes used in the past are energization via a high impedance, or via a tertiary winding connected to an auxiliary AC power source. These schemes require additional equipment resulting in increased foot print and complexity. For offshore and subsea installations, the increase in foot print often greatly exceeds the cost of the additional equipment.

This paper presents an alternative solution allowing direct-on-line energization of large transformers, both topsides and subsea. Different solutions for subsea auxiliary AC power supplies not requiring high-voltage circuit-breakers are presented.

For offshore and subsea power systems, the circuit-breakers supplying power to the transformers are standard 3.3 kV to 36 kV class devices having a 3-pole operating mechanism. The solution presented allows circuit-breakers to be switched such that the closing of the poles occurs at the point on the voltage waveform where the resulting inrush current is the least. For subsea power distribution systems, the auxiliary power required for the subsea control equipment is provided by a high-voltage DC auxiliary power link from the shore station and the control and communication link is via optical fiber.

The solutions presented use standard proven technology and can be integrated within the subsea modules required for supplying power to the loads. This keeps the number of penetrators and subsea connector systems to a minimum. The importance of redundancy and maintenance in obtaining and keeping the required system availability are discussed.

Index Terms — Transformers, Inrush Current, Subsea and Offshore Installations, Adjustable Speed Drives

I. INTRODUCTION

Fig. 1 shows a generic one-line diagram for supplying power to subsea processing loads. The link to the topsides facility is by means of a power umbilical shown connected to both the topsides umbilical termination assembly (UTA) and its subsea counterpart, the subsea umbilical termination assembly (SUTA). The umbilical consists of the main AC power cable supplying energy to the subsea loads, the optical fiber cable for communication, and DC auxiliary cables to power the subsea control equipment.

The one-line diagram shows the use of subsea switchgear and subsea adjustable speed drives (ASD). The common alternative to this system in which the switchgear and ASDs are located topsides will be discussed later.

There are several technical issues that must be solved when designing a subsea power distribution system as shown in Fig. 1. These are:

- Determining the status of the subsea power equipment prior to energizing the power umbilical (black-start function)
- Providing low-voltage auxiliary power for subsea loads
- Avoiding system disturbances when energizing power transformers
- Avoiding damage to ASD capacitors due to sudden energization

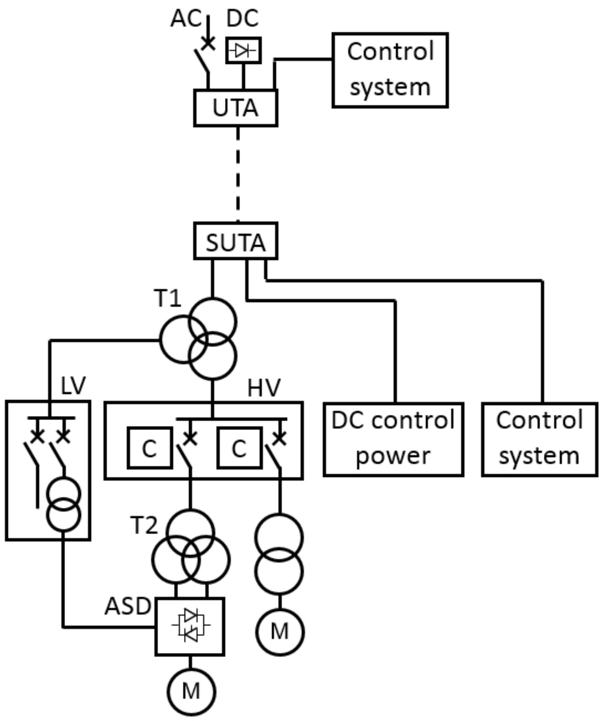

Fig. 1 Subsea Processing Power System

In the diagram shown in Fig. 1, the main loads would be subsea compressors, or subsea booster/multiphase pumps having rated power in the 1 MW to 15 MW range. The voltage used in the power umbilical will depend on the step-out distance and the subsea loads, and could be up to 110 kV. The subsea switchgear is typically operated at 20 or 30 kV. The compressor and/or pumps are powered via ASDs which are supplied by step-down convertor transformers. The other high-voltage HV motor (HV > 1000 V) in Fig. 1 is a water injection pump that is operated in an on/off manner. Some small subsea low-voltage loads (LV ≤ 1000 V) also require power. These LV loads may or may not require power prior to the energization of the main HV power circuit. One auxiliary load for subsea compression that requires special care is the magnetic bearings. This load must also be powered during emergency shut-down conditions when all power is lost.

Fig. 1 shows the use of a tertiary winding on the main step-down transformer to provide LV auxiliary power subsea. This auxiliary power is present only after energization of the main power circuit to the subsea installation and thus cannot be used for the black-start function. After energization of the main power circuit, LV auxiliary power is available for all LV loads not required for the black-start function. The use of a tertiary winding avoids installing a separate HV-LV subsea transformer and additional HV circuit-breaker (CB). Alternative methods for providing LV auxiliary power are presented later in the paper.

The HV CB control devices are indicated by the letter C in Fig. 1. The purpose of these control devices is to close the HV CBs at a time that minimizes the transformer inrush current. They are integrated into the overall control and protection scheme of the complete power system.

II. LIMITING INRUSH CURRENT

Power transformer inrush current has many negative effects in power systems including:

- Rapid voltage changes (voltage dips) that may oppose the grid code requirements defined for the interconnection with the landline power grid. In many countries, the voltage dip cannot be higher than 3%, imposing the necessity to integrate inrush current mitigation [1].
- Voltage transients and surges on cables that may exceed their operational limits as well as those of the interconnected electrical equipment
- Mechanical and electrical stress in the transformer and the CB can reduce the service life of the equipment and thus could require additional maintenance.
- It may be necessary to desensitize the protection relay in order to allow transformer energization without tripping. This reduces the reliability of the protection scheme.

Power transformer inrush current is mainly due to the presence of residual flux in the transformer core resulting from its previous de-energization. The magnitude and the polarity of the residual flux depend mainly on the transformer load and the de-energization moment relative to the voltage waveform.

A. Inrush Current Mitigation

Transformer inrush current can be mitigated using conventional techniques with series impedance (pre-insertion resistor, smoothing reactance) or by powering the transformer at reduced voltage. While it is possible to implement these solutions in onshore facilities, the cost due to the increase in footprint for offshore installations is prohibitive. Such solutions are not practical in subsea installations due to the additional requirements of minimizing the component count and connections.

The best option to mitigate the transformer energization inrush current is to use a controlled switching device (CSD). This technology has been used successfully for years with HV power transformers and offers the best possible mitigation of inrush current. This solution can be integrated into the subsea processing power system shown in Fig. 1.

In power transmission applications, the CSD mitigation technique has been initially used with CBs having independent pole operation or staggered pole mechanism. However, these devices are not common in HV applications with rated voltages ≤ 36 kV used in subsea systems. For such systems the use of 3-phase CBs with simultaneous pole operation is a requirement.

For any residual flux pattern in the transformer core, there is always an optimum energization moment that results in minimum inrush current. This principle is illustrated in Fig. 2, where the inrush current is shown for each phase relative to the CB closing angle deviation from the ideal energization instant. For this given flux pattern, the inrush current will stay at around 1 p.u. (per unit) when the closing angle varies ± 20° from the optimum switching moment. A similar curve exists for each possible flux pattern in the transformer, and the role of the CSD is to energize the power transformer at the optimum instant.

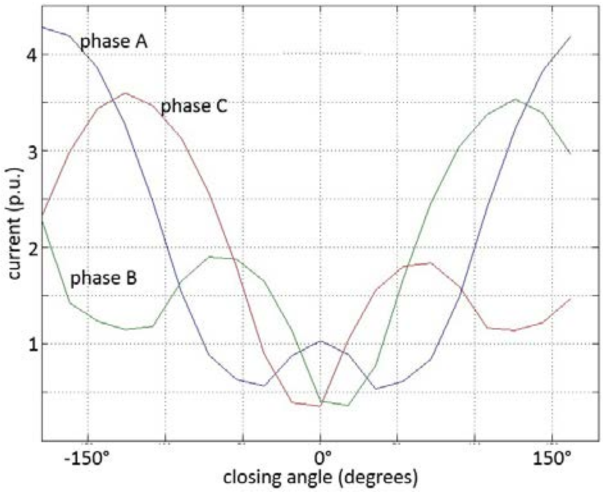

Fig. 2 Inrush Current vs Closing Angle Deviation

When a power transformer is not loaded, it is possible to control its flux pattern to a known value by opening the CB at a fixed instant and then close the CB at the optimum instant that minimizes the inrush current for that flux pattern. However, this technique cannot be used in subsea applications because the uncontrolled de-energization of the transformer may be due to a loss of power in the umbilical from the topside, resulting in an unknown residual flux pattern. Therefore, the successful mitigation of the inrush current at all times using a CB with simultaneous pole operation is only possible if the residual flux resulting from the previous transformer de-energization is measured by the CSD.

B. Basic device operation

Fig. 3 illustrates a typical CSD installation in a power transformer application. The unit can be seen as a synchronization relay inserted between the commands (CB On Off) and the CB control coils. The CSD is powered from the same DC supply as the CB. Protection relays are connected directly to the CB trip coils because the CSD is slightly delaying the CB commands in order to synchronize the CB operation to the power system waveforms. In power transformer applications, both the closing and opening commands are synchronized to the umbilical voltage measured using a resistive or capacitive voltage divider (Vs). The load current (I) is also measured using a Rogowski coil or a toroidal CT to determine if the CB operates properly as planned, which is equivalent to a 50BF (breaker failure) protection function.

The transformer residual flux is computed from the transformer voltage measured using a 3-phase resistive or capacitive voltage divider connected at its primary winding (V_L). The use of magnetic flux sensors inside the transformer core is to be avoided because that solution is intrusive. Each time the transformer is de-energized, the residual flux is calculated from the transformer voltage. The resulting residual flux pattern determines the optimum closing instant of the CB to mitigate the transformer inrush current.

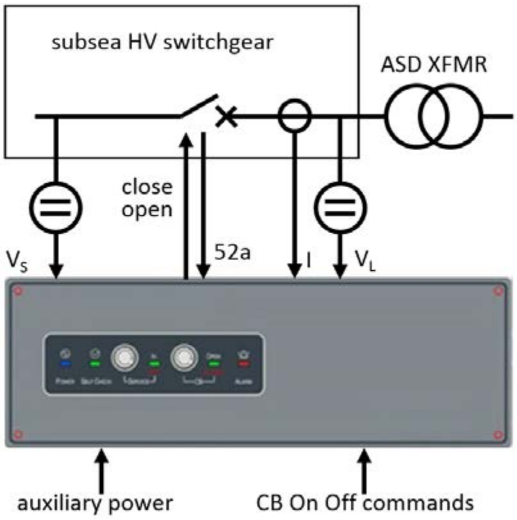

Fig. 3 Typical CSD Installation

Since the CB characteristics are closely linked to the accuracy of the switching operations, one CSD is required at each CB to be controlled. For high availability applications such as subsea installations, redundant units can be connected in parallel to the CB. Should a CSD need to be replaced, the residual flux pattern information can be retrieved and uploaded to the replacement device.

III. SUBSEA ASD CONSIDERATIONS

The ASD of Fig. 4 uses current source technology (CSI) which does not have a capacitive component either in the rectifier or the DC link. When the ASD is energized by closing the ASD transformer incoming CB, the inrush current is limited to that seen by the transformer and the snubber components of the ASD which are insignificant. This avoids the need for a pre-charge circuit typically required by voltage-source drives (VSI) which have a capacitive DC link.

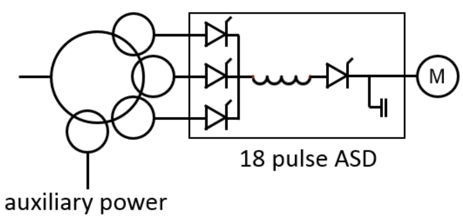

Fig. 4 Current Source ASD

There is a machine-side capacitor which is connected at the output side of the ASD. This capacitor is energized only after the ASD commences gating and the current is inherently limited by the ASD so that the rate of charge is controlled by the active front end (AFE) rectifier and DC link inductor which are inherent to this topology.

VSI drives, as mentioned earlier, typically have a large DC link capacitor. In order to limit or control inrush to the DC link capacitor when first energized, some form of pre-charge circuit is required. For drives with passive rectifiers (DFE), this pre-charge circuit is typically an impedance which is in series with the drive power circuit. This impedance is bypassed after charging of the link capacitors has been completed. This solution was used in the Ormen Lange pilot project by inserting an impedance in the HV circuit to the subsea ASD.

Recently, a number of HV VSI drives have come out with rectifiers utilizing AFE technology. These topologies typically make use of an LCL (inductor, capacitor, and inductor) configuration ahead of the active rectifier which will result in an inrush on energization with the magnitude dependent on the sizing of the capacitive and inductive elements of the circuit. Depending on the particular topology, an external pre-charge circuit may or may not be required.

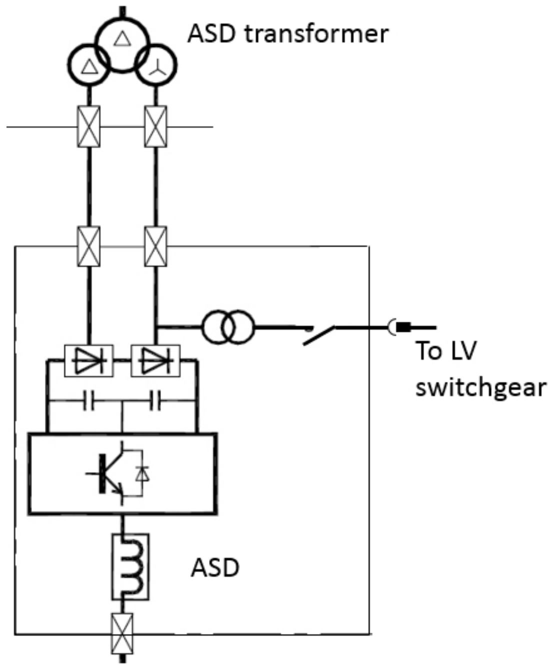

Fig. 5 LV ASD Capacitor Charging Circuit

Another solution is charging the capacitors via a LV connection as shown in Fig. 5. Since the capacitor charging must be done prior to energization of the ASD, an auxiliary AC power source is required. The tertiary winding of transformer T1 will provide AC auxiliary power subsea as soon as it is energized. This power via the LV switchgear is used to charge the VSI drive capacitors.

One disadvantage of this solution is that a failure in the LV circuit between transformer T1 and the LV switchgear could result in a total shutdown. Redundancy can be achieved by installing two tertiary windings and having redundant LV switchgear with interconnections between them as shown in Fig. 6.

Another possibility that avoids tertiary windings on T1 is to use a VSI drive that uses the DC link capacitor inrush current limiting LCL described above. This solution would need to be studied to see if feasible for use subsea. The advantage of this circuit is that the tertiary winding shown on T1 could now be changed to be on the ASD transformer T2. Since the precharging is internal to the ASD, it can be switched on directly without use of any external precharging circuit or power supply. Typically more than one subsea ASD would be used and this would provide more than one source of subsea AC auxiliary power for other loads as well (equivalent to having dual tertiary windings on T1). A single failure in the subsea LV distribution system would not result in a loss of production.

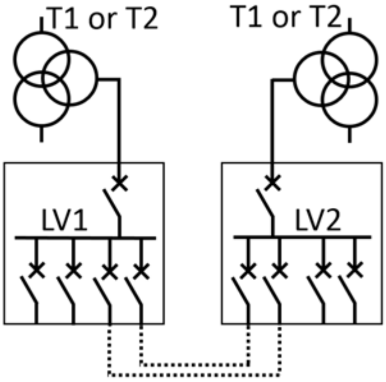

Fig. 6 Subsea LV Switchgear

Fig. 6 shows a subsea LV auxiliary power distribution. The power comes from tertiary windings, either from T1 or T2 depending on the solution adopted for ASD capacitor charging. A separate LV switchgear module is provided for each power source to enhance availability. Also the LV switchgear are interconnected via redundant circuits to provide additional operational flexibility.

A failure upstream of the incoming LV CB need not result in a loss of the LV switchgear, nor the transformer. It is possible to disconnect the LV cable from the tertiary winding and place a voltage-withstand cap to isolate the tertiary winding LV connection from seawater. The transformer can be energized and supply power to the process loads in this configuration. The LV incoming CB must be tripped and power to the LV bus can be obtained using an interconnection circuit with another LV switchgear module.

In both of these solutions, DC control power is provided to the ASD and LV switchgear via the low-power DC link from shore as shown in Fig. 1. This power is used to supply the part of the ASD control system needed to be able to communicate the status of the ASD prior to energizing it. It also provides the status of the LV switchgear and allows reconfiguration of the main LV CBs prior to energizing any transformers. This is part of the black-start function and can be implemented whether tertiary windings are on T1 or T2.

Installing an HV ASD subsea is a very good option should there be little space available topsides for the equipment. Where space is available however, it is cost effective if the ASD can be installed topsides. For longer step-out distances, the ASD output voltage is stepped up and a subsea transformer installed at the load to lower the voltage. The main challenge in such systems is designing the ASD to be able to correctly control the motor with long cables between them. Progress has been made over the last several years, and the step-out distances for which this system can be used have increased. Use of lower frequency systems (16 2/3 Hz) can also help extend this distance.

IV. AUXILIARY POWER SYSTEMS

Auxiliary power is required for all process systems. Part of this is for the black-start function mentioned earlier. Prior to switching on the main power of a subsea system by energizing the power umbilical, it is first necessary to know the status of the subsea equipment, and be able to change the configuration of the HV and LV switchgear prior to energization. The power requirement for the black start function is very small but must be independent of the main power supply. Most of the other auxiliary power supplies are required prior to energizing process equipment, but this occurs after the main power has been turned on.

For the black-start function, auxiliary power is transmitted directly from the shore station by means of a low-power HV DC system. The DC cables will be installed in the power umbilical together with the main AC power cables and the optical fibers required for the communication and control systems. This HV DC system can be energized and communications established without energizing the main power. This enables the status of subsea switchgear to be determined and modified if necessary by tripping or closing HV and/or LV CBs prior to energizing the main AC power umbilical. Thus black-start auxiliary power is available without the need for added complexity in the form of a subsea UPS. The use of low-power HV DC for subsea process control has been in use for several years.

A. General DC System Description

The subsea auxiliary power system will receive power via small DC cables operating between 1.8-10kV depending on the required power and step-out distance. At the subsea location, DC/DC converters and power supplies will reduce the voltage to a general low voltage system bus level which can then be distributed to various loads via local power supplies and DC breakers as shown in Fig. 7.

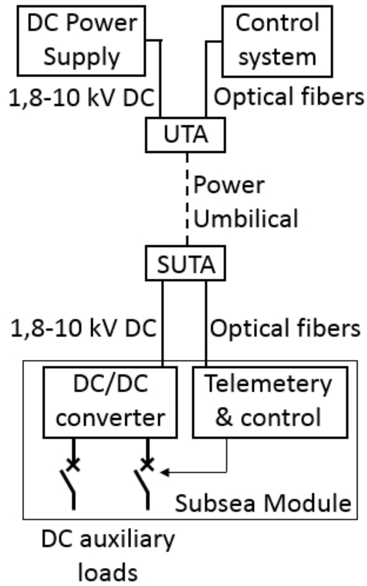

Fig. 7 Subsea DC Distribution

This DC power supply is completely independent of the main AC power supply and thus can provide power to the subsea telemetry & control and auxiliary equipment prior to energization of the main power system. The DC and fiber optic cables are integrated into the power umbilical as shown in Fig. 7.

Fig. 7 does not show any redundancy. Typically dual DC and optical fiber cables are provided, each connected to separate subsea modules. Any subsea module can be disconnected and replaced without loss of the other module, thus avoiding any loss of production.

B. Power System Auxiliary Loads

The DC system bus is routed to allow for power delivery to two main types of loads. The first of these is power system auxiliary loads, the principle ones being the HV and main LV CBs, protection relays, CB control equipment and the communications system.

As shown in Fig. 8, separate DC power circuits are provided for each subsea HV CB. Circuits A and C provide power to the CSD and protection relay, circuit B provides power to the CB trip and close coils, and circuit D supplies the CB spring charging motor. It is thus possible to monitor and control each HV CB without having energized the main AC power cable to the subsea location. This provides operators with the black-start capability.

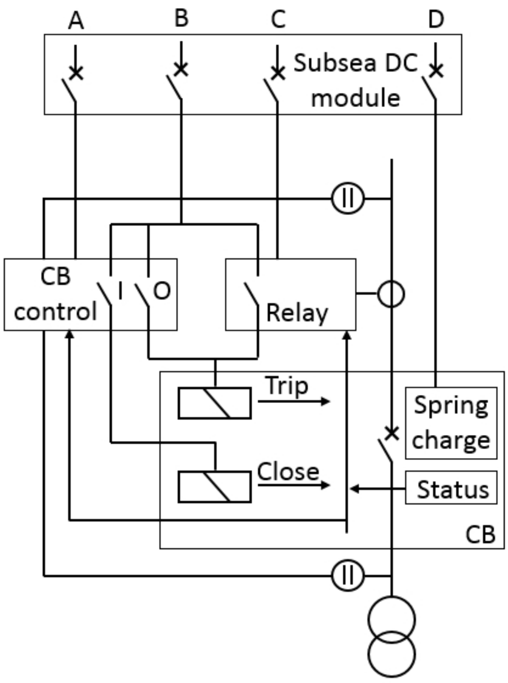

Fig. 8 Auxiliary DC Power for HV CBs

C. Process System Auxiliary Loads

The second type of DC loads are small process loads that may need to be operated prior to energizing any of the main subsea loads. Such loads could be motor operated valves (MOV) or lube pumps. The DC power system can be designed to provide the power for such small loads prior to energizing the main power circuit to the subsea facility. A separate DC circuit can be provided for each of these loads.

For small loads that require an AC power supply, a DC/AC converter is provided. For small intermittent loads, the DC auxiliary power system can supply the power without the need for a battery. Should the power requirements be larger, then either the DC auxiliary power system capacity must be increased, or for intermittent loads, a subsea battery is required. The battery is trickle charged by the DC supply and after charging, the energy necessary to power the process load is provided by the battery.

D. Magnetic Bearings

Magnetic bearings are often used subsea since there is no wear because the bearings float in a magnetic field. The power supply to magnetic bearings must be very reliable since loss of power results in bearing contact. The bearing supply must be available prior to starting the motor, and must remain energized until the motor has come to a complete stop after switching off. Since one cause of switching off a motor is a complete loss of power, some stored energy is required to allow the motor to coast to a stop in such conditions.

Two different solutions have been implemented to date. One uses redundant subsea UPS to provide the power, and the other redundant UPS at the shore station, each having an individual cable to the subsea template. Another possible solution is using normal AC auxiliary power as described above for operation, and a subsea battery trickle charged by the DC control power link for emergency stop conditions. When there is loss of power, the battery is discharged into the magnetic bearing control system providing the energy necessary during coasting down. Since magnetic bearings normally required DC power, such a solution could be cost effective.

V. TELEMETRY & CONTROL

All telemetry and remote control is provided via optical fiber connections. The subsea facility is connected to the topsides control system via fiber optic cables integrated in the power umbilical (Fig. 7). The auxiliary power required for the subsea communication and control system is provided by the DC from shore auxiliary power system as described above. Although not shown in the Figs. each device that must respond to control signals or provide information will be connected via an optical fiber.

The general practice for subsea process systems is to execute all control orders topsides. The subsea equipment will respond to these orders but, with the exception of protection relays will not act on its own.

All equipment deployed subsea must be able to communicate via a non-proprietary communication system that provides reliable and high-speed communication with the topsides control system. Although it is very common in topsides installations for the power system control and process control to be done by two independent systems, it makes sense for subsea applications to attempt to do both with the same system. Less hardware should result in a reduction of the number of possible failure modes.

VI. SYSTEM REDUNDANCY

Redundancy is often seen as a means of increasing the availability of the complete system. Failure of a single device should not cause a loss of production. Redundancy is however a double edged sword. Increasing the number of components and the additional interconnections can actually reduce the overall availability of the system. Sometimes it is also found during commercial operation that a process shut down is required to retrieve a faulty module that is being replaced, even though the redundant module is operating satisfactorily. Great care and diligence is required when designing redundant systems to avoid such unpleasant surprises.

Avoiding common modes of failure is a good starting point in the design of the systems. Some common modes of failure will continue to exist however, and their influence on availability must be carefully considered. The HV CB itself can have a mechanical fault causing it to stick in the open or closed position. A leak in a subsea module can allow sea water to enter and result in the loss of a substantial part of the subsea facility. Mechanical damage from equipment accidentally dropped into the sea above the facility can cause extensive damage.

A. DC Auxiliary Power Supply Redundancy

It is possible to design the DC auxiliary power system, the telemetry & control system, and the protection system such that there are no common modes of failure. The redundant DC/DC converters, DC breakers, power supplies and protection relays are housed in separately recoverable modules [2]. This decreases the Mean Time To Repair (MTTR) thus enhancing the overall availability. The modules can be disconnected and retrieved without requiring a process shutdown. If dual DC auxiliary power cables are provided for redundancy, consideration should be given to installing one cable in the power umbilical and the other one in the control umbilical or separate cable. The same applies to the fiber optic cables.

All connections between auxiliary power supplies and switchgear are made via wet mate connectors. In some cases it may occur that the removal of a control module may result in a subsea connection remaining energized and being exposed to sea water. In such cases the system is designed such that this cable end will terminate in the female connector. Since the conductor of the female connector is normally covered by oil or some other insulating fluid, it will not be in contact with sea water and can remain energized when in the disconnected position. An example of this is the signal on the terminals of a low power current transformer (LPCT). If a redundant protection relay is retrieved, the terminals of the LPCT remain energized since current is flowing through the primary winding. The voltage levels are small (< 1 V) and thus connection to the female wet mate connector allows continued operation even with the main power circuit energized and drawing current.

Where redundant control equipment is implemented, it is necessary to be able to independently shut of the auxiliary power to control outputs. Thus if a device fails in such a manner as to emit unwanted control signals, these can be neutralized by switching off the auxiliary power to the output circuits.

B. CB Control Redundancy

Fig. 8 shows the basic scheme for controlling a CB. The protection relay's main function is tripping the CB under fault conditions and the CSD (CB control device in Fig. 8) does the normal closing and opening. Protection relays can be selected and configured such that each relay can fully control two CBs, thus providing redundancy without adding additional devices. Failure of one relay does not result in any loss of production.

To achieve redundancy for the CSD, it is necessary to install two devices per CB. By controlling the power supply to the CSD output contacts, it is possible to isolate a faulty CSD and prevent it from closing or opening a CB due to misoperation. Normal operation would be with one CSD, the other one having the power supply to its output contacts isolated. Each CSD would be installed in a separately retrievable subsea control module to allow replacement while the other module continues to operate. The use of LPCTs and low power VTs provide measurement outputs that could be exposed to sea water by connection to female wet mate connectors thus allowing the main power circuit to remain energized.

C. Process Redundancy

Redundancy considerations for critical loads will often involve redundant power supplies. Some equipment will have two auxiliary power connections, each one being supplied by completely independent power supplies. The load must be designed such that no failure of one power supply will result in the incorrect operation of the other. Magnetic bearings is one example of such equipment.

D. LV Switchgear Redundancy

A possible solution to achieve redundancy in the LV distribution is shown in Fig. 6. Some applications have dedicated HV cables and step-down transformers to provide a redundant LV subsea power distribution. Such a system was provided for the Åsgard subsea compression station. This is feasible in shallow water and when the step-out distances are not too long. For deep-water applications the cost of such a solution could be prohibitive.

E. Telemetry & Control Redundancy

A dual-redundant control system architecture is normally used for subsea applications. Completely independent systems having no common mode failure points are to be used. Single device failure should never result in loss of production. This includes the auxiliary power supplies for the dual-redundant control equipment.

VII. INSTALLATION AND COMMISSIONING

One of the key factors in designing subsea electrical systems is modularization. Having several modules makes it easier to retrieve equipment that needs to be repaired or replaced, and in many cases this can be done without having to stop production. The main disadvantage or modularization is that it increases the number of wet-mate connectors required as well as the total number of penetrators. Additional equipment means additional possibilities for failure. Failure of a penetrator could let salt water into a subsea enclosure causing a major disruption in production.

After the modular design has been finalized, it is necessary to consider installation of the equipment. ROV access is required for connecting and disconnecting modules, but ROV access is also a potential cause of failures since ROVs can damage equipment. The layout of the subsea modules should be designed to provide the best protection against falling objects and poor ROV maneuvering.

The design of the flying leads connecting subsea modules is also a challenge. Often the male connector is simpler in design than the female connector and thus less prone to failure. It is thus probably best to install the female connectors on flying leads which could be retrieved for maintenance. Avoiding retrieval of subsea modules should be one of the main design criteria.

Submodules should also be considered. A submodule is integrated into a larger module allowing access to parts that may have a shorter design life, thus permitting their retrieval and leaving the main module in place. This technique can be used for electronic devices such a protection relays and communication equipment.

The installation design must also take into account how the system will be tested and commissioned. ROV access is key to successful commissioning; however designing safe ROV access to the equipment is a difficult task. Also consideration must be given to possible damage to installed equipment when handling the modules yet to be installed. Dropped items can destroy installed equipment.

Testing prior to commissioning is important but is not easy for subsea systems. A comprehensive test plan is required at the start of the design phase in order to be sure that the required tests can be conducted during installation and after installation is complete. This may influence the design of the equipment. All test equipment is to be defined during the design phase.

VIII. MAINTENANCE, ASSET MANAGEMENT

A. Availability study

The design of the system is based on an availability study. The starting point of the study is defining the functional requirements of the system that must be fulfilled at all times. For subsea power distribution this is the aptitude to supply sufficient power within acceptable limits of voltage and frequency to the subsea loads.

The availability is defined as

$$Availability = \frac{MTTF}{MTTF + MTTR}$$

where MTTF is the Mean Time to Fail, and MTTR is the Mean Time to Repair. Availability studies will provide the probability of meeting the functional requirements for different possible system configurations. Comparing different solutions is possible by evaluating the failure probabilities for each. Since improbable events happen, an availability study cannot be considered to guarantee a particular result.

As can be seen by the definition, there are two ways of having high availability. The first is to have a high value of MTTF. The second is to have a very low value of MTTR. [3]

Achieving a high MTTF requires the use of reliable components having a proven track record. Their failure rate, expressed as λ (lambda) is generally known. In addition to using components having a very low λ, it is also possible to increase the MTTF by adding some redundancy as discussed above. Hot swapping should be strived for any time redundancy is provided. Adding redundancy requires an extensive system analysis since redundancy generally means more components and thus more failure modes. Common mode failures are often introduced unknowingly when designing redundant systems. The complexity of redundant systems is higher than non-redundant systems making operations more difficult. Many failures are the result of operator errors so complexity can even offset the advantages redundancy can bring. Complex systems are also more difficult to maintain and are more costly. Thus it is necessary to take many considerations into account when defining the redundancy that is to be used in a particular system. The availability study should be able to determine which amount of modularity, with and without redundancy will bring the most benefit.

The physical location of the modules is also important in reducing down time. When modules are retrieved and deployed, it may be necessary to shut down the process if the modules are located close to other equipment. Damage occurring during retrieval or deployment could result in major environmental damage should the process not be shut down. Process modules that are designed to be retrieved periodically should be located remote from the rest of the process. If this is achieved, it will not be necessary to shut down the process when retrieving such modules.

B. Maintenance strategy

The maintenance strategy must ensure that the minimum requirements that were used in the availability study are met during the design life of the installation. Due to the modular nature of subsea installation, the strategy should include the following concepts:

- Modules: One spare module of each type is required. It shall be kept in working order so that it can replace a faulty module without delay. It is necessary to determine the best storage conditions as well as any requirements for periodic testing, permanent energization or condition monitoring.
- Components: Spares of all components used in the application are required. Since it may not be possible to replace obsolete components with newly purchased spares due to the constraints of installation within compact subsea modules, it is necessary to have an obsolescence strategy to avoid having to purchase different components. In addition to the hardware, this strategy should include all software, firmware and configuration files for the components as well as ensuring that the machines and software necessary to use the component software are available. The versions of all software, firmware, configuration files and user software that are necessary for refurbishment of any module and repair of any component at any time during the design life are required.
- Repair shop: A repair shop capable of refurbishing each of the modules is necessary. This includes all tools, handling equipment, storage space and skilled workmen.
- Warehouse: A warehouse in which all components required for refurbishment can be stored is required. The warehouse could also be used to store the spare modules. If it is decided that any spares need to be energized during their storage, then the warehouse shall be equipped with all necessary power supplies. It is recommended that the warehouse serve as the repair shop as well to simplify the maintenance procedures.

One of the main problems will be ensuring the availability of skilled personnel. A program must be defined to ensure that there is a minimum staff of qualified technicians and engineers in order to refurbish any equipment. It is necessary to define the training program required to ensure that the necessary competence is available at all times. Training equipment and simulators should be considered in this program.

IX. SIMULATIONS

For grass-root projects, simulations and calculations are the only tools available to engineers. Subsea installations with long step-outs have very particular characteristics which makes it difficult to base a new design on existing systems [4]. Simulations are required to validate new designs.

X. CONCLUSIONS

It is possible to provide auxiliary power for subsea processing prior to the energization of the main power system. This black-start function allows operators to ensure that the subsea system is in the right configuration before energization.

It is not necessary to implement complex and costly systems to pre-energize subsea power transformers or precharge the capacitors of subsea ASDs. Controlling the closing time of standard CBs eliminates transformer inrush current issues. The drive topology utilized is another major factor which will impact the inrush which will be seen by the system. The current source topology given in the paper minimizes inrush by the inherent design while voltage source drives typically require a pre-charge circuit. Tertiary windings on the subsea transformers and the possible use of a voltage source drive with DC link capacitor inrush reduction modules are means that can be implemented to avoid capacitor damage.

The modularity of the design is a key factor that influences almost all aspects of the application. A detailed availability study can help determine the optimal modular design. The maintenance strategy is a key factor when estimating the availability of the different possible solutions.

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XII. VITA

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PCIC EUROPE
How do we know? A journey of self-verification and assurance.

Paper No. PCIC Europe BER-38

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Abstract - Mature companies have good standards, specifications and maybe even an electrical safety program, but do they know how well these actually work? Verifying how sites perform against the company internal, external standards and processes, usually will involve an element of self-assessment, self-verification and then an external assurance view.

The paper will take the reader along the journey the company took of identifying key electrical risks, developing mitigating barriers and bowties, creating a self-verification program and assurance program to determine if these barriers are in place and strong.

The key concepts, some details of how these activities were initiated and examples of typical barriers across a downstream petrochemical organisation will be shared to offer the reader a tool for implementation at their sites.

The benefit to the reader would be to adopt a similar process to better assure themselves of the integrity of their key electrical risk barriers.

Disclaimer: The views within this paper are those of the authors and not the company they represent. Examples are fictitious and to aide explanation. The processes described are in the public domain.

Index Terms - Assessment, Assurance, Barriers, Bowtie, Risk management, Self-verification.

I. INTRODUCTION

A. Electrical risk

On a relative scale, electrical risk identification, prevention and mitigation within manufacturing and industrial companies seldom receive the same profile as that of other disciplines. This is often due to a number of factors;

- The Engineering manager or Senior leadership team are unfamiliar with the electrical discipline, therefore the detailed appreciation of risk is unknown or underestimated;
- Electrical design and manufacture of equipment has often been to such a high standard, even when considering 60 year old equipment, that serviceability may appear good, when in fact there may be unknown underlying risks.
- Many risks in the electrical field are covert. For example, partial discharge and arc flash risks cannot be seen and are often difficult to detect.
- Risk ranking usually focusses on catastrophic events and while an electrical incident might result in, possibly at most, 3 fatalities or the loss of power to a whole site, managing electrical risk is usually seen of lower importance as many risks that exist on such sites would be considerably higher.
- Power interruptions are usually infrequent, so the low likelihood of this high consequence scenario is seldom appreciated by decision makers.

However, these risks may encompass process and personal risks, reliability of supply, legal health and safety requirements and environmental consequences. Thus, electrical risks are a reality and worthy of being clearly defined.

Therefore, unless the electrical discipline has strong leadership, these risks may be overlooked in the company risk review processes leading to negative consequences.

B. Benefits of managing Electrical risks

Clear risk definition starts with accurate risk identification. Once known, management of these risks can follow. Managing risks includes quantifying, mitigation and verification of the various layers of protection.

This process used by the company includes identifying the current risk landscape and associated self-assessed risks; developing an applicable barrier and bowtie model with preventative and mitigation barriers; constructing assurance protocols along with supporting self-verification recommendations and finally implementing the program and managing the outcome. This approach is similar to that of a continuous improvement program. A further benefit has been to increase appreciation and knowledge of electrical risks by senior leadership.

II. THE ASSURANCE PROCESS

A. Basic concepts

Self-assessment – a process of determining the site's own compliance against a pre-determined set of criteria and scored in terms of an agreed ranking process.

Self-verification – the process of determining what key activities are required to ensure that risks are managed, and then carrying out activities to check that controls are still strong and in place. It is answering the question "Do I do what I say I do?"

Assurance - a systematic process to check, ensure, verify that the site "does what they say they do". It involves an independent review of the activities employed to ensure that risks are identified and managed suitably.

Barrier - a risk reduction measure that prevents a cause developing into a risk event or mitigates the consequences of a risk event once it has occurred. Barriers are fully functional and independent of each other.

Bowtie model - a graphical representation to communicate a risk event, its causes, consequences and barriers.

B. Determining and managing your risks

In order to determine and manage key risks, five fundamental questions can be asked:

1. What are the risks?
2. What are the barriers that control the risk?
3. Who owns them?
4. Are the barriers in place, strong and effective?
5. How do we know?

There are a variety of approaches available to answer these questions. The program chose to address each in order and this forms a core of this paper.

For successful implementation of any management system, it is good practice for it to be systematic and in control. Part of this processes included a need to:

- identify site accountable representatives,
- ensure they are competent,
- document the processes and
- verify the above with a wider team.

In most cases the accountable person for electrical risks was identified as the Electrical manager, however for smaller sites, management representatives may have filled this position. The topics of the other elements became the focus of the ensuing activity.
This is a useful tool and is represented by Figure 1.

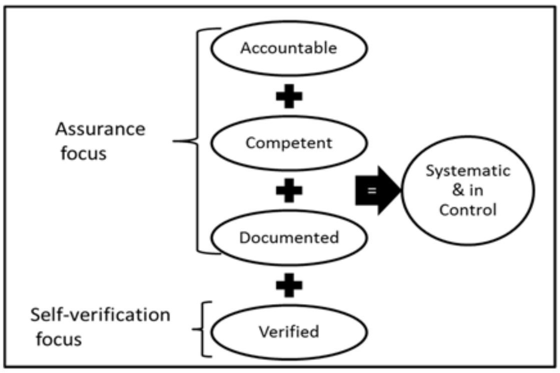

Fig. 1. Components towards being systematic and in control.

C. What are the risks? Identifying the risk landscape

In order to quantify the status of the electrical risk situation across 60+ sites, a risk survey was developed.

When using a self-assessment survey, the respondents should be aware of the purpose. This may require upfront awareness, preparation and clear definition of the intended outcome. In the case of this survey, the product was to determine a risk landscape across the company so as to know where to focus our risk mitigation efforts. This resulted in sites being ranked against each other and common themes being identified. Notwithstanding the comparative benchmark, conducting such a self-assessment allows the team to review their individual approach to criteria deemed relevant by the survey tool.

When the design of the survey was developed it was critical that the questions were specific, unambiguous and objective. Covering a global application, the intent had to be clear, concise and simple for non-first language English speaking respondents. The survey had to consider the design and processes covering complex refineries to less sophisticated industrial sites. Relevant international industry standards were used as a basis for the questions. A few key standards are listed in the References section below.

The survey tool consisted of questions covering:

- Site detail:
  - Responsible person;
  - Organisation;
  - Resources.
- Site incidents:
  - Personal injuries;
  - Loss of power or other electrical incidents
- Identification and management of risk:
  - HSSE policies compliant with local regulations;
  - Personnel risk responsibility and the escalation process of high risk tasks;
  - Competency management;
  - Authorization;
  - Control of work;
  - Isolation and lock out, tag out procedures;
  - High voltage switching operations;
  - Management of contractors;
  - Arc flash hazard management;
- Managing electrical equipment and processes:
  - Preventative maintenance strategy;
  - Explosion protected (Ex) equipment maintenance strategy;
  - Electrical equipment integrity and reliability;
  - Back-up systems;
  - Islanding, load shedding systems;
  - Earthing (grounding) integrity;
  - Anti-static electricity management;
  - Failure analysis and outcome management;
  - Aged, obsolete, common failure equipment management;
  - Documentation management;
  - Performance management;
- Electrical interfaces:
  - Portable equipment management;
  - Hazardous area management systems;
  - Loss of power response plans;
  - Projects, management of change; standards and specifications use;
  - Quality assurance and quality control;
  - Operations personnel knowledge on ignition prevention measures;

Cyber security was not addressed, but on reflection could have been, given its increasing prominence as an electrical risk.

The survey was completed by the electrical responsible person and their teams. It was noteworthy that for smaller sites, this person or team was hard to identify. This supports the case cited above about understanding and ownership of electrical risk.

Most teams saw the survey as a source of knowledge, as a baseline against which to identify areas of improvement and as an opportunity to compare themselves against other similar sites. This feedback indicated an immediate benefit of the survey.

Other feedback from the respondents worthy of note when developing a similar survey included:

- The completion of the survey was often not done by a single individual but in a team where a debate could take place over the answer to each topic. The benefit of this was that areas of improvement could be drawn out more effectively.
- A good approach was to have individuals of different experience and different previous employment history to offer a comparative view.
- When a question was looking for specific controls around a topic, for example "does a site have a robust process for the issue and control of electrical authorisations?" it was necessary to consider the details within the process of authorisation and not simply consider if there is a process and it "feels" like it works.
- The sites considered if there were internal and external checks and balances in place and if the processes were recorded and auditable.

The use of an on-line survey tool was made to coordinate responses. This assisted with managing over 3000 data points. A scoring system was used with weighting to prioritize some higher risk questions. This weighted scoring system allowed for easier management of data to report the site outcomes relative to the company internal management system metrics, business units and geographical regions. The benefit of this allowed the reader to relate to the gaps and reflect on what the data was telling them. It also removed the need for detailed technical knowledge of the topic. In, for example the question on "Control of Explosive Protected equipment" – the non-electrical reader does not need to understand the details of a hazardous area management system. They can rather reflect on the outcome relative to the familiar companywide scoring system.

A few examples of data analysis are shown in Figures. 2 and 3.

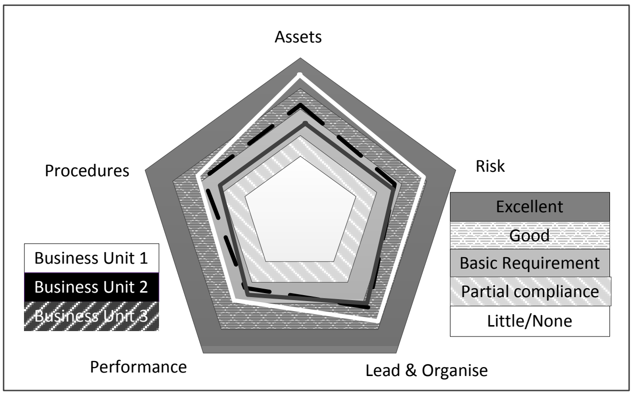

Fig. 2: Business unit performance in terms of Company key management areas

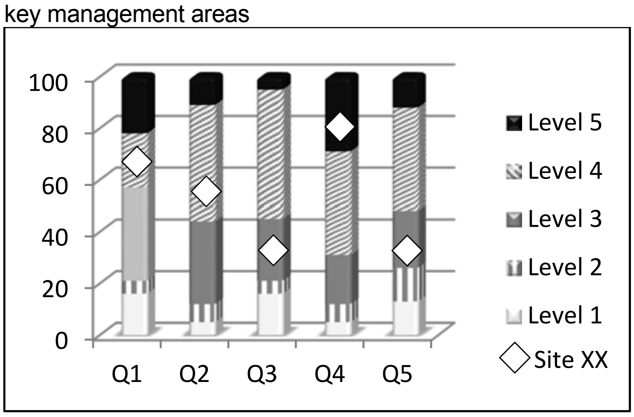

Fig. 3: Site position relative to others

The data was also analysed for any common themes in site specific, business type and regional risks. This was represented on a companywide risk matrix. Non-electrical readers could conceptualize the risk position against a familiar format. Fig. 4 offers a typical risk matrix with themed outcomes plotted.

	Likelihood of Risk Event				
	1	2	3	4	5
Severity	Remote	In Industry	In Company	1-2 times in Site	Several in site's lifetime
A					
B					
C					
D					
E			Ex Equip't	Incidents	
F			Arc Flash		
G				CoW	LOTO
H					Competency

Fig. 4: Risk analysis plotted on matrix

Each site then received feedback on their scores benchmarked for reference against the other sites. Where a site was found to be good or best in class this was highlighted. This demonstrated to the sites that the study was not only there to show areas of improvement, but to identify strong barriers. Best in class sites could potentially use those processes to implement actions for closure of other improvement areas.

Sites used this information to populate department and company risk registers and to develop action plans to address opportunities. Company standard action tracking systems were used to assist with definition, clarity, accountability, prioritisation and closure. This closure process was not part of the survey but rather the responsibility of each site and within their chosen time frame.

Some learning regarding the survey tool included:

- Adopting a weighted scoring system at the outset;
- Keeping the survey short without any possible repetition of questions;

- Preparing the survey respondents well ahead of time;
- Pre-empting and addressing regional and cultural self-assessment tendencies;
- Considering the ease of use and the cost of the survey tool.
- Managing the significant amount of data points and what the outcomes represent.

Feedback from sites on the use of the benchmarked data included:

- “When our site took an honest viewpoint of our position, we were able to compare our own belief of where the gaps were against that of the study. In most cases it simply reinforced our own knowledge in where the known gaps were, but when the weighting was applied, it provided a priority and starting point for an action plan.”
- “As with most businesses, there are many different pools of information to draw from for showing where gaps are. Together they can be considered as supporting information when developing an action plan. The benefit of this is to close off a number of gaps and build a stronger system in the long term. In one example, the survey highlighted an opportunity around the process around control of isolation. The site also had actions from other site surveys that indicated deficiencies in this area. By reviewing the two reports the site was able to revamp the complete authorisation process and update the site lock out tag out policy. “
- “Having multiple sites feedback analysed and compared in one report enabled those with opportunities to call upon other high scoring sites for assistance. Amongst other shared learning opportunities outside of the study, the process helped build and maintain technical support lines. Through these relationships, we have been able to share knowledge, resources, lessons learnt from safety incidents, improvements and problem solving skills.”

The final product was a holistic electrical risk landscape of all company sites risk positions communicated in an easily understood format for all stake holders - not just the electrical teams as is usually the case.

Significant progress has been made across the discipline to address and improve risk management following this survey.

Figure 5 shows a dashboard or landscape of the risk positions for various sites. A quick review allows one to identify common focus areas and address these accordingly.

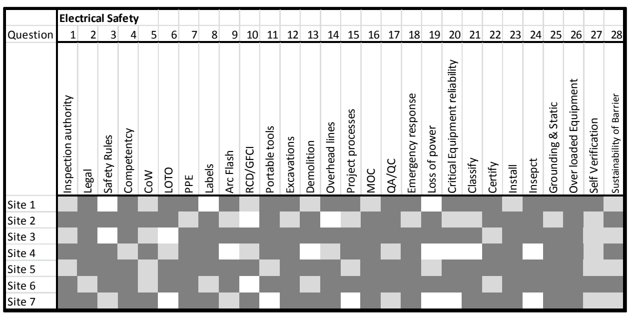

Fig 5 Risk profile across the business

D. What are the barriers? Developing an Electrical Bowtie Model.

Following the survey analysis, common themes emerged. In order to manage mitigation of these across the discipline in a focussed manner, a Bowtie model was developed. Using the standard conventions, a distinction between personal and process risks was made, resulting in two bowties. These can be used to represent the barriers required to prevent an incident and are useful for non-electrical personnel to understand risks and the reason why certain activities are necessary to manage these risks. Bowties help with communicating and understanding.

Testing the strength of each barrier within the bowtie led to the development of an assurance program. Appendix 1 provides an example of the bowties used. Note that per bowtie model definition, maintenance, training, competency, etc. are not barriers in themselves, but sustaining or controlling factors. Within each barrier in the model one may find supporting information detailing the degradation factors and degradation controls of that barrier. The Barrier team tried to keep the text similar to that of other non-electrical bowties for consistency.

While Bowties are traditionally represented in two triangles facing each other with the risk event in the centre - this makes for a poor presentation within slide shows and documents. The diagrams A1 and A2 offer a similar, if not unconventional view.

With these bowties now representing the cause, barriers and consequence for a risk, the next step was to determine the strength of each barrier to prevent the risk.

E. Are the barriers in place and effective? Developing an Assurance program

In order to test the strength of the barriers, it was decided to start with the end in mind and so an assurance assessment tool was developed. The company differentiates between self-verification, assurance and audit. The site is responsible for self-verification (see details below). As assurance and audit are performed by independent reviewers, it was decided to develop protocols applicable to that level. At this stage, audit activities within the electrical discipline focus mainly on Control of Work and Hazardous area management within the ATEX countries.

The assurance protocols were seen as the minimum standards a site should meet. This was to prioritize efforts and minimize the volume of any preparation. Protocols key function is to test the strength of the barrier. As such, the context of the site, organisation and installation may affect the line of questioning and intent.

The electrical safety assurance protocols covered:

1) Personal Safety

- Delegation of authority;
- Compliance to national standards and codes;
- Use of electrical safety rules;
- Personnel competency;
- Risk management;
- Control of work and safe isolation;
- Protective Personal Equipment;

- Documentation, labelling and identification;
- Arc flash hazard management;
- Personal shock hazard management.

2) Process Safety

- Project interfaces as pertains to electrical risk;
- Use of standards, regulations and codes;
- Application of project tools to electrical risks;
- Management of change;
- Quality control;
- Emergency preparedness for electrical related incidents;
- Business continuity in the event of loss of power;
- Equipment reliability management;
- Over-loaded or over-dutied equipment.

3) Ignition Prevention

- Hazardous area management including inspection authority, classification, certification, installation inspection and recording;
- Earthing/grounding and anti-static management;
- Operator and Electrical /Instrumentation personnel competency;
- Management of ignition prevention during Control of Work activities.

These protocols were then used to conduct barrier strength checks at various sites. The duration of site visits was 2-3 days led by one experienced electrical engineer as the assurance lead with a small team from the site.

Preparation involved developing and agreeing on the boundaries and scope in a Terms of Reference. Pre-read was provided and the review focussed on the barrier strength on the day.

Site activity included interviews with personnel from the HSE, Operations, Mechanical engineering, Process engineering, Projects, Maintenance, Emergency services, Training and Electrical departments. A site visit helped to identify and support opinions on barrier strength. Finally a draft report and feedback was presented to the site leadership followed by a formal report.

As with the survey results, the benefit of this assurance activity was seen by the site management as a further means to improve their understanding of electrical risks. Many highlighted the fresh viewpoint regarding the electrical infrastructure. Action plans were developed and now form part of the site prioritised action tracking system. A further benefit has been cross-pollination between sites. Best practices from one site are shared to address weaker barriers at others. Thus these summated best practices help to develop a continuously improving companywide standard. This realised the intended benefits from the assurance program.

F. How do we know? Self-verification

Self-verification is a systematic process owned, developed and managed by the site to evaluate whether a specific barrier is fully functional. It includes taking corrective action when work is not being carried out in conformance with the applicable requirements or if a barrier is found to be weak.

A Self-verification program evaluates the outcomes of the effectiveness of the various self-verification activities at a site level and determines if these are in support of the company requirements. It may include dedicated personnel to develop, coordinate and manage the program. Reviewers with the necessary expertise are required to conduct field inspections to form an opinion of the barrier strength.

“What you measure, you manage”. Using this as a driver, a robust self-verification program focusses on various levels of details as follows:

Level 1 activity: These are typically daily, weekly or monthly field inspections or conversations. The reviewer uses prepared protocols or checklists to verify whether the component of a barrier (operation/task) is robust. Level 1 activities provide primary information about the levels of system conformance and risk management (e.g. a monthly check to verify that shift handover procedures are being followed; a weekly check on permits written; a regular review on maintenance checks, inspection sheets and punch lists…)

Level 2 activities: These are typically monthly reviews which use checklists, audit findings, trends and discussions to evaluate whether Level 1 activities support a barrier. Examples include hazardous area inspection outcomes and trends; learning from incidents and improvements to the Level 1 activities; training and competence of field inspectors; monitoring preventative maintenance activities and the effectiveness thereof; reviewing failure statistics; monitoring critical spares holding, etc.

Level 3 activities: These are typically where the leadership team takes an annual, macro view to evaluate the results and effectiveness of the self-verification program in order to identify trends, emerging risks and opportunities to improve risk reduction measures and ultimately implement improvements. Examples include a review of the changes made due to the self-verification program; action tracking, closure and effectiveness review; confirming that resources are appropriately allocated; analysing findings and identifying trends, themes or repeat findings, verifying results with other sites, etc.

Details of a good self-verification program can be found elsewhere, and various self-verification activities were developed for each barrier. Sharing some general electrical related examples includes:

- Identifying a program owner.
- Verifying the process of delegation of authority, responsibility, competency, and work delegation.
- Field checks on a worker’s understanding of the risks involved; use of any electrical safety rules or procedures; appropriate use of PPE; awareness of arc flash risks; understanding of electric shock preventative measures; portable equipment condition and management; field equipment integrity; etc.
- Self-audits on control of work practices including the issuing of permits, understanding of risks involved by all concerned; proper lock out, tag out processes; inspection results and remediation; Operation’s emergency response to electrical incidents, etc.
- Quarterly or half-annual reviews of the effectiveness of field inspections trends and preventative maintenance activities; management of change

practices and documentation updates; contractor management matters; etc.

- Annual reviews of hazardous area (Ex) management; preventative maintenance effectiveness; aged or obsolete equipment management; project effectiveness; actions identified and closed, an overview of the effectiveness and benefits from the self-verification program, etc.

It was found that most sites are at the start of the self-verification journey and that while many carry out various self-verification activities, most do not record or manage the outcomes systematically. It may be seen by some as additional work, but if structured correctly, a self-verification program can actually reduce effort and increase alignment and effectiveness. All efforts go towards answering the question: "How do you know?"

III. CONCLUSION

In order to address electrical risks at a company level, a self-assessment electrical risk survey was conducted across a petrochemical company. These results provided an overall view of self-assessed risk in the electrical discipline.

A Bowtie model was then used to collate the common causes, assign these to personnel and process risks, determine common consequences and define common preventative and mitigation barriers.

Thereafter, an assurance process was developed to test the strength of various barriers. The assurance program was implemented across the business. The bowties are now used as a communication tool to represent the individual barrier performance.

Finally, a self-verification program has been started to consistently check the programs, processes and procedures established to support these barriers. This process is aimed at managing electrical risks while increasing the effectiveness of assurance programs at the various sites.

This paper summarises a process to identify risk, quantify its significance, develop mitigation criteria, assure these are in place and self-verify the strength of those processes implemented to manage the risks.

IV. ACKNOWLEDGEMENTS

The authors would like to acknowledge:

Stuart Brown, Electrical Advisor, BP, for his review of the various tools whilst in development phases and comments on this paper; Huw Morgan, Engineering Authority, BP Hull, for review and comment and the various site personnel who participated in the assurance reviews.

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VI. APPENDIX

Appendix A: Electrical Bowties

APPENDIX A

Electrical Bowties

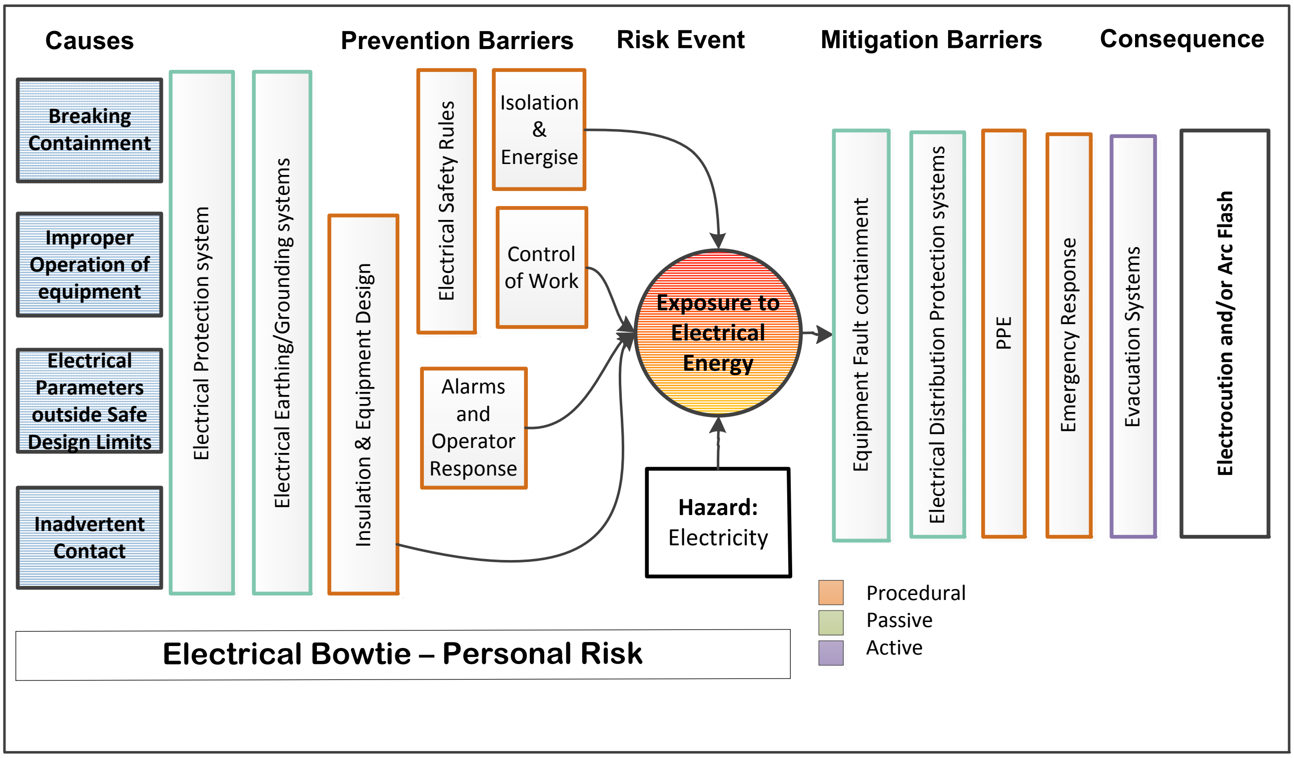

Figure A-1: Personal Risk Bowtie

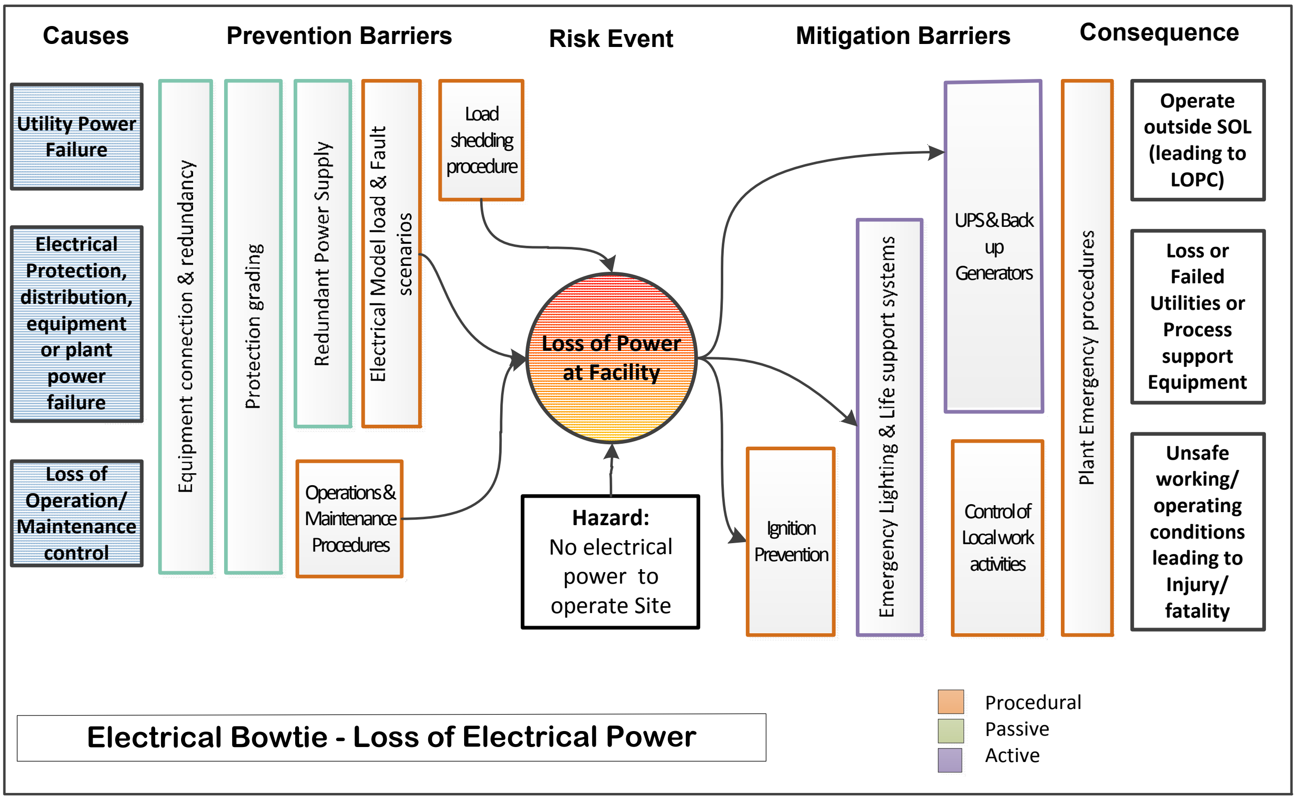

Figure A-2: Process Risk Bowtie

VII. VITA

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ARE THE IEC REQUIREMENTS FOR OVERPRESSURE TESTING OF FLAMEPROOF EQUIPMENT APPROPRIATE?

Paper No. PCIC Europe BER-40

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Abstract - For the IEC flameproof standard IEC 60079-1 there is an apparent lack of research data to clearly support all the factors that are applied to the pressure determination figures in order to do the overpressure test. Even in cases where data does exist, the tests may not reflect the best approach based on the data. The standard does not address impact of temperature on pressure figures in the standard temperature range. An investigation is shown into existing information and data, both published and unpublished. In addition, the minutes of the first meetings of TC 31 commencing in 1948 are examined to look at the decisions leading to the requirements in the first standard which was issued in 1957. The evolution of the testing requirements are then examined for subsequent revisions. A critical analysis is subsequently made on that evolution and the supporting data, with particular emphasis on the effect of temperature. Gaps are identified in the supporting data. The paper recommends potential changes to the existing standard based on existing data and recommends additional investigative testing that is needed to clarify the situation, and which could lead to changes in the next edition of the standard.

Index Terms — flameproof, pressure determination, extremely low temperature, pressure piling, motors

I. INTRODUCTION

The first international standard relevant to flameproof equipment was published in 1957 by the International Electrotechnical Commission (IEC) 79 [1]. The standard was developed by IEC Technical Committee TC 31, which was first established in 1948. Since then there have been six further editions of the standard (now called IEC 60079-1), with the latest edition being published in 2014. IEC 60079-1 is now adopted by most countries throughout the world, with the most notable exception being the USA. It has adopted the standard for situations where IEC zoning is used, but most US area classifications use divisions. For this, the US uses a comparable technique which it calls explosionproof (sometimes referred to as explosion-proof). The requirements for this technique are addressed in local standards, or in legal instruments, such as laws or regulations.

There was much research resulting in the development of individual country standards and regulations well before the international standard was first published. Most of the early research was done in coal mines research institutes with the explosion-protection techniques later being adapted for above-ground industries where explosive atmospheres of gas, vapours or dust might exist. In some instances research institutes for above ground industries also evolved.

What drove the formation of these research institutes? Coal mining was always recognised as a hazardous industry, but in the early days it was mostly a 'pick and shovel' exercise in mining the coal. Hence sources of ignition for methane (fire-damp) or coal dust atmospheres were low. The advent of technology and the push for greater production seems to have had led to a significant increase in explosions or other events, such as roof falls, that pushed the death rate higher. It appears two of the major new sources of explosions was the use of explosives and the use of electricity [2, 3]. There were three research institutes that seem to have played a key role in the early days. In each case the main driver appears to have been a dramatic increase in the number of deaths. I will briefly address the establishment of each of these institutes.

For Germany, Dill [3] reports that in Germany when "the annual number of fire-damp explosions reached three figures, it became necessary to act quickly". Hence in 1894 The Westphalian Mining Company Fund Mine established an explosion gallery in Gelsenkirchen-Schalke to investigate the influence of explosives on firedamp and coal dust. This subsequently became the Institute for Explosion Protection and Blasting Technology (BVS). Its first Director was Beyling.

In the USA, Breslin [2] states that in the single month of December 1907 there were a number of coal mine explosions that killed more than 600 miners. In one explosion alone, 362 miners died, making it the worst mine disaster in US history. This no doubt was a driving factor in the establishment of the Bureau of Mines in 1910 [2], although research had previously commenced within government departments, particularly looking at permissible explosives to be used underground.

In the UK, Luxmore [4] provides a summary of the early days. When electricity was first introduced in coal mines in the 1880s, almost a million people were employed in the industry in the UK. In 1880 there were 4,231 collieries. By 1900 safety legislation was in place, but there were still over 1,000 miners killed every year and legislation put no restrictions on the use of electricity.

The 'flameproof' type of protection for equipment is accepted as the earliest and probably still the most widely used type of protection to ensure electrical equipment does not cause an explosion in an explosive atmosphere of gas or vapour. The basic concept involves not excluding a gas or vapour from an enclosure, but ensuring that, if there is an explosion within the enclosure, the explosion does not spread to the surrounding explosive atmosphere. This means the enclosure needs to be strong enough to withstand the explosion and there must be a means of ensuring the transmission of the explosion via joints of the enclosure does not cause an external ignition. This type of protection goes by a few names. In the USA it is mostly called explosionproof. It is also commonly called Ex d or flameproof enclosure "d" with the 'd' coming from the German words 'druckfeste kapselung' which translates as 'flameproof enclosure'. For the purpose of the this document, unless otherwise indicated, the terms flameproof, explosionproof, explosion-proof, Ex d and flameproof enclosure "d" may be considered to be synonymous. However, it should be noted that the standards requirements can be different.

Published literature suggests that this approach was first developed in the late 1800s and early 1900s. In the UK, the first term used was "flame-tight". Luxmore [4] states that this was referenced in UK by a committee formed in 1902 "to enquire into the use of electricity in coal and metalliferous mines and the dangers attending to it" which (amongst other things) recommended that "all terminal (sic) should be enclosed in a flame-tight casing". He also indicated that experiments had begun in Germany by Beyling in 1884. But he further provides evidence that there was work going on in the UK at that time, for example Henry Davis of Davis Ltd submitted a report to the 1902 committee describing a flame-tight dc motor that he had designed. Perhaps the first major publication on this subject was a work published in 1906 by Dr Ing Carl Beyling [5] describing the results of the extensive research done at BVS. National standards or related instruments began to occur in various countries , initially focussed on coal mining but with some expanding to embrace above ground industry. The publication of British Standard BS 229 [6] in 1926 is an example.

II. THE FIRST INTERNATIONAL STANDARD

A. First Four Meetings of IEC TC 31

The first meeting of the newly formed IEC "Advisory Committee TC 31: Flameproof Enclosures" took place in London from 7 to 9 July 1948. With the kind permission of the IEC some information can be provided from those meetings. Of interest is an opening statement from the Chairman of the British National Committee on Flameproof Enclosures as recorded in the minutes:

> during the war, much electrical equipment imported into the United Kingdom from the U.S.A had been made to U.S.A. standards, which differed in some respects from British standards. This created problems for technical people and government officials concerned, resulting in suggestions being made to the B.S.I. that, if possible, international agreement should be obtained on the requirements of flameproof enclosures.

TC 31 held three further meetings prior to the publication of the first flameproof standard. These took place in Paris in November 1949, London in April 1953 and Philadelphia, USA in September 1954. During the meetings the decision was also taken to include in the publication the words: "The term 'flameproof' is synonymous with the term 'explosion-proof'." That has been dropped from more recent editions of the flameproof standard. At the third meeting the name of the committee was changed to "Technical Committee No. 31: Flameproof Enclosures". It is clear from the minutes that the question of what pressure an equipment enclosure should withstand occupied a significant part of those meetings. A decision was taken to include a test of one and a half times the "equivalent of the maximum dynamic pressure". But it was further agreed to defer questions for "factor of safety" to the second edition.

B. Publishing First IEC Flameproof "Standard"

As noted earlier, in 1957 IEC published Publication 79 "Recommendations for construction of flameproof enclosures of apparatus". According to the TC 31 minutes this was originally intended to be a specification, but it was changed to a recommendation to resolve a negative vote. The preface of the standard indicates that after the meeting in Paris and "examination by the Editing Committee in Brussels" the document was circulated in September 1953 for approval under the Six Months' Rule. After the meeting in Philadelphia, the revised draft was circulated under the Two Months' Procedure in 1955. 16 countries voted in favour of the document and none voted negative.

The requirements in the first edition relevant to the mechanical strength of the apparatus and enclosure, and hence overpressure testing, are quoted below:

> 7. **Mechanical strength of apparatus**
>
> The mechanical strength of the apparatus as a whole, shall be such as to withstand the normal conditions of use in industry and for the purpose for which it is intended.
>
> 7.1 The flameproof enclosure, in all its parts, shall be capable of withstanding the maximum dynamic pressure resulting from an internal inflammation of the most explosive mixture with air of the gas or vapour for which it is designed, or of a representative gas or vapour for the group for which it is designed, without suffering damage, or such deformation as would weaken any part of the structure, or would enlarge permanently any joints in the structure so as to exceed the permissible dimension. Normally the maximum pressure will be ascertained with the enclosure having all its mechanical and electrical parts assembled as in use. It is recommended that motors shall be tested while not running and also while running without load. Where necessary, control gear shall be tested under electrical overload conditions.
>
> 7.2 In addition to the foregoing requirement, the enclosure shall be capable of withstanding without damage a testing pressure of not less than one and a half times the maximum explosion pressure obtained when undergoing the flameproof tests, with a minimum of 3.5 kg/cm^2 (50 lb/in^2).
>
> This overpressure may be applied either statically or dynamically at the discretion of the competent national authority concerned.

This standard included four groups, namely Group I, Group II, Group III, Group IV based on the Maximum Experimental Safe Gap (MESG). These corresponded roughly to the current equipment groups of Group I, Group IIA, Group IIB and Group IIC.

The following is an analysis of the above based on discussions at the meetings:

1. The increase of one and half times is not referred to as a factor of safety in the standard and that term is still not used. However, that term was sometimes referred to in the minutes. At the first meeting the British delegation said that the "50% additional pressure was relied on to cover variables between prototypes tested and subsequently produced apparatus of the same type." An

obsolescent British Standard issued in the same year BS 229:1957 [7] does refer to it as a factor of safety.
2. This standard recognised the possibility of testing either statically (commonly this is done with water) or dynamically. For this latter approach the UK delegation indicated they normally used "an explosive, such as gun-cotton, under controlled conditions."
3. There is no indication that routine overpressure testing was expected. However, the standard does indicate that testing would be done at the manufacturers.

III. SUBSEQUENT EDITIONS

Table I provides a summary of the various editions that have been published since the first edition, including amendments. The titles can be found in the references for this paper.

TABLE I
EDITIONS OF THE IEC FLAMEPROOF STANDARD

Number	Edition	Date
Publication 79	Edition 1	1957
Publication 79-1	Edition 2	1971
International Standard 79-1A	First Supplement to Edition 2	1975
Publication 79-1	Amendment 1 to Edition 2	1979-09
International Standard 79-1	Edition 3	1990-12
IEC 79-1	Amendment 1 to Edition 3	1990-08
IEC 60079-1	Amendment 2 to Edition 3	1998-05
IEC 60079-1	Edition 3.2	1998-05
IEC 60079-1	Edition 4.0	2001-02
IEC 60079-1	Edition 5.0	2003-11
IEC 60079-1	Edition 6.0	2007-04
IEC 60079-1	Corrigendum 1 to Edition 6.0	2008-09
IEC 60079-1	Edition 7.0	2014-06

A. *Second Edition 79-1*

It took 14 years until the next edition of IEC 79-1 [8] was published (in 1975). The title also changed to "Electrical Apparatus for Explosive Atmospheres Part 1: Construction and test of flameproof enclosures of electrical apparatus". The preface shows that this standard had now become part of a series of standards with other types of protection covered, such as pressurized enclosures, intrinsically safe apparatus, sand-filled apparatus, oil-immersed apparatus and type of protection "e". 26 countries voted in favour of Section One (General) of the standard. Slightly smaller numbers voted in favour of Sections Two (Checks and tests) and Three (Special requirements for Group IIC). This edition was prepared by TC 31 Subcommittee SC 31A *Flameproof enclosures.*

There were some significant changes from the first standard. The standard introduced the now commonplace approach to the use of groups. Enclosures were classified into two groups as follows:

- Group I : for application in coal mining
- Group II: for application in other industries

Enclosures in Group II were further sub-divided according to the MESG into the same sub-groups currently in the latest standard, ie Groups IIA, IIB and IIC. But Group IIC only covered hydrogen. The test approach established is still used. Tests are broken down into the following;

1. Determination of explosion pressure;
2. Pressure test;
3. Test to determine whether the enclosure is flameproof (not addressed in this paper); and
4. Routine checks and tests.

For determination of explosion pressure the following mixtures were now specified ("volumetric ratio with air")

- Group I: 9.8% methane
- Group IIA: either 3.6% butane or 3.1% pentane or 4.6% propane
- Group IIB: either 8% ethylene, or 24% of 85/15 hydrogen-methane or between 3% and 4.2% ethyl ether
- Group III - no gas mixture defined

It stated that when doing the test, the mixture should be "suitably agitated" and that the test must be done at least three times. For the pressure test it still used the factor of 1.5 but applied this to the "highest of the maximum smoothed pressures obtained". A minimum of 3.5 bars was still applied (with the units changed). For the static test the factor was increased to three times the reference pressure if the rise time was less than 5 ms. It also provided for a pressure test of four times for enclosures that would not be subject to routine test (specified in 16.2). It required motors to be tested at rest and running. It also required pressures to be measured at the ignition end and opposite end, plus in the terminal box where not a separate enclosure.

In the static pressure test it required the pressure to be maintained for at least one minute. There was now a clear responsibility for the manufacturer to carry out a routine test pressure test unless specifically exempted.

B. *Amendment 1 to Second Edition 79-1*

Amendment 1 to the second edition [9], issued in 1979 contained some significant changes. For determination of explosion pressure the following mixtures were now specified ("volumetric ratio with air")

- Group I: (9.8±0.5)% methane - tolerance added
- Group IIA: (4.6±0.3)% propane - options of butane and pentane dropped and tolerance added for propane
- Group IIB: Normally the test mixture is (8±0.5)% ethylene. In cases where pressure piling may occur the test shall be made at least five times with a mixture of (8±0.5)% ethylene and it is repeated afterwards at least five times with a mixture of (24±1)% hydrogen-methane (85/15). Ethylene now was mandated as only test gas with tolerance added (ethyl ether dropped completely) and for pressure piling additional

number of tests and additional use of hydrogen-methane with tolerance was mandated.

- Group IIC: Still no test gas defined

Missing from the test approach was the need to agitate the test mixture. This appears to have been replaced by note that stated that "Alternative explosive mixtures to be used when turbulence is present are under consideration". Turbulence of course occurs with motors. Some changes were made to the details with the principle of testing at rest and rotating was retained, but only as an option "at the discretion of the testing authority". Perhaps the most significant issue was the dropping of the three times pressure test option for enclosures with pressure piling. The rationale for this was not given and published literature seems to provide no clues. However, Note 1 in Clause 15.2.2.4 of Edition 7.0 states:

> The need to conduct this repeat testing is based on the principles that (1) when pressure piling is not involved, ethylene will result in worst case representative pressures, and (2) when pressure piling is involved, it will not. Therefore, under this premise, when pressure piling is an issue, the additional testing with the mixture of (24 ± 1) % hydrogen/methane (85/15) is included.

For Group IIB perhaps the hydrogen-methane mixture was expected to provide a higher pressure comparable to when the factor of three was used. However, nothing similar occurs for Groups I and IIA. Further, for this testing the mixture given is the stoichiometric mixture. This can be expected to give the highest pressure for a simple enclosure, but for a complex enclosure this may not be the case. There may be situations where internal flame transmissions in an enclosure only occur at mixtures other than the stoichiometric mix; thus producing pressure piling that would not occur when using the mixture in the standard. It is worth noting that in the USA local standards, eg for UL [10] and FM Approvals [11] require pressure determination testing to be done over a range of mixtures.

A reason for the above change can be postulated. Applying a higher factor to an already higher determination pressure may be seen as a doubling the overall factor of safety. However, pressure piling, and the more significant scenario of detonation, are complex phenomena and it is hard to be confident that the small number of tests and restricted gas mixtures will in fact provide the highest pressure figure. Some clear factual support for this approach seems to be needed. A further significant change for the pressure test, which had its name changed to "overpressure test", was the dropping of the time to apply the pressure from "at least one minute" to "not less than 10 s and not more than 1 min". Some changes occurred to the dynamic pressure test.

C. Third Edition of 79-1

The third edition of 79-1 [12] was published in December 1990. This was the first time a general requirements document had been produced, IEC 79-0. Thus some of the requirements in IEC 79-1 were presumably transferred to that document. Also for the first time the standard clarifies the applicable ambient range of temperatures which it repeats from IEC 79-0 as being from "-20 °C to +60 °C for explosive gas atmosphere characteristics and from "-20 °C to +40 °C for the operation of electrical apparatus". It notes that for "ambient temperatures below -20 °C, stronger enclosures may be required due the higher pressures generated at low temperatures and the possibility of brittle fracture of the enclosure materials". It also referred to temperatures above 60 °C and the possible need to use smaller gaps.

For the first time reference was made on how to achieve a "smoothed pressure". A note suggested that one way to do this is to use a "5 kHz ± 10% filter in the signal circuit". There were no changes to the mixtures to be used for pressure determination for Groups I, IIA and IIB. The following mixtures were included for Group IIC (which now included acetylene):

- 5 tests at (31±1)% hydrogen (H_2); with
- 5 tests at (14±1)% acetylene (C_2H_2) added from the previous edition

The static pressure test was still done at 1.5 times the reference pressure with a minimum of 3.5 bar. The period of application of pressure was more precisely defined as 10 +2 -0 s. The provision for a four times test to avoid routine testing was retained. For small enclosures where the reference pressure could not be measured and the dynamic method was not practicable the following static test pressures were given: 10 bar for Groups I, IIA, IIB and 15 bar for Group IIC.

D. Amendments 1 and 2 to Third Edition of 79-1

Amendments 1 [13] and 2 [14] were subsequently made to the standard addressing breathing and draining devices. A version of the standard IEC 60079-1 Edition 3.2 [15] was issued in May 1998 incorporating the two amendments and adopting the new IEC numbering system.

E. Fourth Edition of 60079-1

Edition 4.0 of IEC 60079-1 [16] was issued in February 2001. Based on the memories of the author of this paper, as the then relatively new Chair of TC 31, this edition had a short and chequered history. Using an agreement between the European Committee for Electrotechnical Standardization (CENELEC) and IEC, called the Dresden Agreement, the European version of the standard was submitted for vote to the national committee members of Subcommittee SC 31A. Since the number of affirmative votes met the rules for acceptance, this edition of the standard was published in IEC with only editorial changes from the CENELEC version, for example referring to IEC standards. Thus it did not directly evolve from the previous edition of IEC 60079-1 and there was no opportunity to make technical changes. Hence some technical requirements from the previous edition were lost. When the ramifications of this approach were realised, a short revision cycle was instigated to allow incorporation of appropriate technical changes.

A significant omission from this edition was reference to the applicability of this standard for low and high temperatures that was in the previous edition. The speed to be used when doing pressure determination on rotating electrical machines was "between 90 % and 100 % of the rated speed of the machine". Where reference pressure determination was impracticable a range of pressures to be used between 10 and 20 bar, depending on Group and enclosure size, were specified. The period for pressure testing as "at least 10 s but shall not exceed 60 s". The use of a frequency limit for smoothing of 5 kHz ± 10%

was mandated for the first time.

In the context of pressure determination testing, the standard introduced the following about pressure piling:

NOTE There is presumption of pressure-piling when
- either the pressure values obtained during a series of tests involving the same configuration, deviate from one to another by a factor of ≥1,5, or
- the pressure rise time is less than 5 ms

The gas mixtures to be used for pressure determination did not change but the number of tests for Group IIC dropped from five to three for both acetylene and hydrogen. However, where pressure piling (see above) could occur, tests had to be done "at least five times". This applied to all Groups.

F. Fifth Edition of 60079-1

Edition 5.0 of 60079-1 [17] was issued in November 2013. The most significant pressure testing requirements introduced into this edition of the standard were those for temperatures below -20 °C. The following requirements were included for pressure determination:

For electrical apparatus intended for use at an ambient temperature below –20 °C, the reference pressure shall be determined at a temperature not higher than the minimum ambient temperature.

As an alternative, for electrical apparatus
– of Groups I, IIA, or IIB; or
– of Group IIC with internal free volume < 2 l,
other than rotating electrical machines (such as electric motors, generators and tachometers) that involve simple internal geometry such that pressure piling is not considered likely, the reference pressure may be determined at normal ambient temperature using the defined test mixture(s), but at increased pressure.

The absolute pressure of the test mixture (P), in bar, shall be calculated by the following formula, using Ta, min in °C:

$$P = [293 / (T_{a,min} + 273)] \text{ bar}$$

While this is based on a common law of physics, Amontons' Law of Pressure-Temperature, there is a lack of published literature to demonstrate that the use of increased pressure produces a result consistent with tests at very low temperatures, especially in the case of pressure piling, which is particularly relevant for motors. On a more general matter the approach to smoothing pressure now required the use of a low-pass filter with a 3 dB point of 5 kHz ± 10 %. Presumably this made no real difference to actual application. The test gases to be used and the number of tests to be done for pressure determination remained the same as the previous edition. This included the need to do five tests for all groups for pressure determination when there was a presumption of pressure piling. The requirements for rotating electrical machines were changed to bring some discretion into whether test running, with the provision:

Rotating electrical machines shall be tested at rest and, when the testing station considers it necessary, when running. When they are tested running, they may be driven either by their own source of power or by an auxiliary motor. The speed shall be between 90 % and 100 % of the rated speed of the machine.

G. Sixth Edition of 60079-1

Edition 6.0 of 60079-1 [18] was issued in April 2007. It removed reference to "electrical apparatus" and instead used the term "equipment". That was consistent with changes in terminology across the TC 31 standards at that time. The standard introduced more detailed requirements for extremely low temperatures as shown below.

For electrical equipment intended for use at an ambient temperature below –20 °C, the reference pressure shall be determined by one of the following methods:

- For all electrical equipment, the reference pressure shall be determined at a temperature not higher than the minimum ambient temperature.
- For all electrical equipment, the reference pressure shall be determined at normal ambient temperature using the defined test mixture(s), but at increased pressure. The absolute pressure of the test mixture (P), in kPa, shall be calculated by the following formula, using Ta, min in °C:
  $P = 100[293 / (T_{a,\ min} + 273)]$ kPa
  (After correction by corrigendum [19])
- For electrical equipment other than rotating electrical machines (such as electric motors, generators and tachometers) that involve simple internal geometry (see Annex D) with an enclosure volume not exceeding 3 l, when empty, such that pressure-piling is not considered likely, the reference pressure shall be determined at normal ambient temperature using the defined test mixture(s), but is to be assumed to have a reference pressure increased by the factors given in the table below.
- For electrical equipment other than rotating electrical machines (such as electric motors, generators and tachometers) that involve simple internal geometry (see Annex D) with an enclosure volume not exceeding 10 l, when empty, such that pressure piling is not considered likely, the reference pressure shall be determined at normal ambient temperature using the defined test mixture(s), but is to be assumed to have a reference pressure increased by the factors given in the table below. Under this alternative, the test pressure for the overpressure type test in 15.1.3.1 shall be 4 times the increased reference pressure. The 1,5 times routine test is not permitted.

The reference to Annex D appears puzzling as that Annex only deals with certification of empty component enclosures. However, it is likely the reference is meant to make use of the clarification of "simple internal geometry" shown in D.3.2. as follows:

Ex component enclosures shall consist of a basically simple geometry of only square, rectangular, or cylindrical cross-section with taper not exceeding 10 %.

NOTE When major dimensions exceed any other dimension by 4:1 for group I, IIA and IIB, or exceed any other dimension by 2:1 for group IIC, additional considerations may be necessary.

The table containing the test factors (the origin of which will be discussed later in this paper) is as follows:

TABLE II
TEST FACTORS

Minimum ambient temperature °C	Test factor
–20 (see Note)	1,0
≥ –30	1,37
≥ –40	1,45
≥ –50	1,53
≥ –60	1,62
NOTE This covers equipment designed for the standard ambient temperature range specified in IEC 60079-0.	

The edition of the standard had the following requirement regarding the overpressure test for low temperatures:

> For electrical equipment intended for use at an ambient temperature below –20 °C, the overpressure test shall be conducted at a temperature not higher than the minimum ambient temperature. Where the tensile and yield strength properties of the material used are shown by material specifications to not decrease significantly at low temperature, the overpressure test may be conducted at normal room ambient.

The test gases to be used and the number of tests to be done for pressure determination remained the same as the previous edition. This included the need to do five tests for all groups when there is a presumption of pressure piling.

The requirements for rotating electrical machines reinstated the mandated requirement to test while running and states the maximum speed shall be "at least 90% of the maximum rated speed ". This last seems only to be a change in wording. The standard also provides more precise requirements on the location of pressure transducers, including the need for three transducers if the termination compartment is interconnected to the motor. This reinstated information that had appeared in earlier editions.

H. Seventh Edition of 60079-1

Edition 7.0 of 60079-1 was issued in June 2014. In this edition requirements for very low temperatures remain the same except that the table with the factors (now called Table 7) includes the following statement under the note "Consideration should be given to applications in which the temperature inside the flameproof enclosure may be substantially lower than the rated ambient temperature". For testing small enclosures, reference to ambient temperatures below –20 °C has been introduced; see information from Table 8 of the standard below:

TABLE III
PRESSURES FOR SMALL ENCLOSURES BELOW -20 °C

Volume cm^3	Group	Pressure [a] kPa
≤10	I, IIA, IB, IIC	1 000
>10	I	1 000
>10	IIA, IIB	1 500
>10	IIC	2 000
[a] For equipment intended for use at an ambient temperature below –20 °C, the above pressures shall be increased by the appropriate test factors noted in Table 7.		

The mixtures for pressure determination remain the same, but five tests for Group IIC for acetylene and hydrogen are again required even if there is no pressure piling. This is the same as the requirement that was originally in the third edition. For pressure piling, the requirement for testing five times with ethylene and hydrogen/methane remains for Group IIB but is dropped for Groups I and IIA. This does not seem logical and may be an error. There was another change to specifying the filter with the statement: "a low-pass filter with a 3 dB point of 5 kHz ± 0.5 kHz shall be used". There is a new option for overpressure testing introduced of three times the reference pressure if the routine overpressure test is replaced by a batch test. Again there is change in specifying the period of application of the pressure, which is now "at least 10 s". The issue of turbulence (for other than rotating electric machines) gets a mention as follows:

> The continuous effects of devices inside enclosures, such as rotating devices, which can create significant turbulence that may result in an increase in reference pressure shall be considered.

This is significant, as turbulence can lead to higher pressures. One of the earlier references to turbulence was by Grice and Wheeler in 1929 in a UK Safety in Mines Research Board paper [20]. This was clearly recognised in the second edition with the requirement to agitate the mixture for all testing. However, it seemed to get lost or be more narrowly required in intervening editions for situations where agitation may occur in the equipment in normal use, for example in motors, as shown above. The latest wording represents a reasonable approach to this issue.

IV. FURTHER ANALYSIS OF OVERPRESSURE TESTING

A. Static Overpressure Testing

As noted earlier, the IEC standard permits both a static and dynamic approach to overpressure testing. The most common approach is to use static testing. Dynamic pressure testing normally involves the use of an autoclave style of chamber. These are not universally available in test laboratories around the world and the use of dynamic pressure to achieve a four times test is likely to be restricted due to pressure considerations for the autoclave. The author has inspected the majority of testing bodies around the world in this field in his role as an IECEx lead assessor and has not seen it done. He has also not seen anyone in recent times using explosives, such as gun-cotton. So the analysis in this paper is focussed on pressure determination and the static overpressure testing that is applied as a result of the pressures from the pressure determination.

B. Pressure determination

Of significance is that for equipment intended for the standard range of temperatures contained in IEC 60079-0 [21] of - 20 °C to +40 °C, no allowance is made for the variation in pressure that may result from the ambient pressure at the time of testing. It is likely that the impact of temperature on pressure was not appreciated at the time the first standard was developed. There have been very few published papers providing data from experiments looking at the impact of temperature on pressure in flameproof enclosures. But there are two relevant investigations that address the issue. One by George

Lobay [22-24] is 38 years old and the other by PTB in Germany is about 20 years old. Only the former study addresses pressure piling. It has been published in one report [22] and two papers [23, 24]. The data from the PTB study was purportedly used to develop factors to be applied in IEC 60079-1 for testing equipment designed for very low temperatures but a report on the testing was never published (internally or externally). PTB have provided the raw data from that testing to the author. The work of Lobay above looked at the effect of ambient temperature upon maximum explosion pressure in a single chamber test apparatus and in a pressure piling test apparatus. The experiment covered hazardous atmospheres in (USA) Groups A, B, C, D and coal mining applications. These are equivalent to IEC Groups I, IIA, IIB and IIC. The results for the test temperature range of approximately -50 °C to +40 °C indicated a linear increase in explosion pressures as temperature is reduced. This is not unexpected. If there is predictable geometry which provides confidence that pressure piling or detonation cannot occur, then the pressure is very closely linked to the gas density which increases as temperature decreases. The following concentrations of gas were used: propane 4.6%, methane 9.8%, ethylene 8.0%, hydrogen 32% and acetylene 14.5%. The series of explosions started at -50 °C and was increased at increments of not more than 3 °C to +40 °C. The concentrations used fall within the tolerance of those in the IEC 60079-1, although the concentrations for hydrogen and acetylene are different to the median figure specified in the latest edition of the standard. No tests are reported for the mixture of (24 ± 1) % hydrogen/methane (85/15) which is now included in the standard for Group IIB for cases where pressure piling may occur. The results published in IEEE in 2001 [24] and are shown redrawn in Fig 1. below.

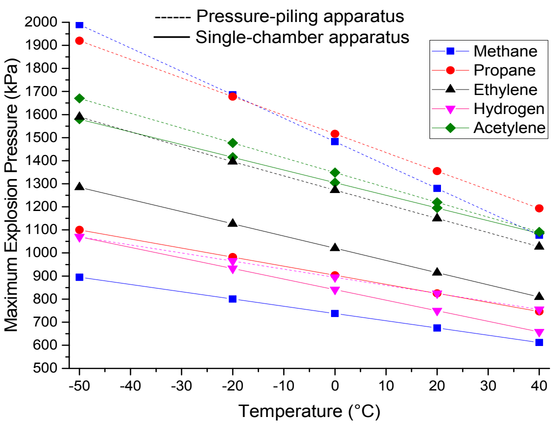

Fig. 1 Maximum explosion pressure versus ambient temperature

It can be seen that the temperature range tested only goes down to -50 °C. IEC 60721-2-1 [25] shows temperatures can be as low as -60 °C in areas designated as 'polar'. Personal communication has suggested that temperatures can occasionally get down to -70 °C. The data supplied by PTB shows testing in the range of -50 °C to -20 °C with hydrogen and acetylene only. The concentrations shown for hydrogen and acetylene fall within the tolerance of those in IEC 60079-1. The PTB work has the same temperature restriction as Lobay's work regarding the lowest temperature. The range of gases used is more restricted as only hydrogen and acetylene were used.

No editions of the standard take account of the effect of temperature on pressure in the standard range of -20 °C to +40 °C. Based on the data from Lobay, the potential change in pressure over that range can be as high as 2.75. TABLE IV below shows an analysis done by the author on the Lobay results for three scenarios; (1) no pressure piling (PP), (2) pressure piling based on low pressure piling figure, and (3) pressure piling based on low no pressure piling figure.

TABLE IV
ANALYSIS OF LOBAY'S PRESSURE FIGURES - LOW TEMPERATURE RANGE

Gas	Increased pressure (as a factor) for temperature change from +40 °C down to -20 °C		
	No PP	PP based on low PP figure	PP based on low no PP figure
Methane	1.31	1.56	2.75
Propane	1.32	1.41	2.25
Ethylene	1.39	1.36	1.72
Hydrogen	1.42	1.28	1.47
Acetylene	1.30	1.35	1.36

The most likely scenario for pressure piling is that shown in the third column. However, the fourth column is included to address situations where the test sequence has not produced pressure piling even though it may in fact be feasible (for example at a slightly different gas mixture). It can be seen that the most dramatic increases for the pressure piling scenario come with methane and propane (Groups I and IIA), with highest factor approaching three. Hydrogen and acetylene (Group IIC or Group IIB plus H_2) show the least increase. Ethylene (Group IIB) is somewhere between. But since the experiments did not include the hydrogen 85/methane 25 mixture shown in the later editions of the flameproof standard, the factor for that gas combination is not known. The above scenarios indicate that the factor that the pressure varies by could be larger than the factor of 1.5 currently often applied for overpressure testing. Thus it would seem appropriate to address this in the testing specification in the standard.

A similar analysis can be done for the figures in the Lobay tests for very low temperatures. Assuming testing is generally done around +20 °C the analysis is done for that temperature down to -60 °C by extrapolating the Lobay figure from -50 °C. TABLE V below shows the results and compares them with the factors in the standard. The approach involving factors for very low temperature testing can only be used where pressure piling is not present.

TABLE V
ANALYSIS OF LOBAY'S PRESSURE FIGURES - STANDARD RANGE - NO PRESSURE PILING

Gas	Increased pressure (as a factor) for temperature change from +20 °C down to -60 °C	
	Lobay results	Factor in standard
Methane	1.33	1.53
Propane	1.33	1.53
Ethylene	1.40	1.53
Hydrogen	1.43	1.53
Acetylene	1.32	1.53

The table only shows the analysis for one point (-60 °C) but since results are linear, it is reasonable to postulate from the table that the factors in the standard are appropriate. However, it might be wise to consider making some allowance for experimental error.

There are other factors that can introduce variation into the test result. While not dealt with in detail in this paper, the following are some factors that are known to affect pressure figures: (1) the temperature of the gas mixture in the enclosure which may be different to ambient, (2) ambient pressures (generally due to the height of the test facility above see level); (3) position of ignition source; (4) power of ignition source; (5) position of pressure sensors; (6) the testing equipment; and (7) the procedures used. Another factor that could impact on the pressures, particularly when pressure piling is present, is that the mixtures used for pressure testing are at the stoichiometric mix. This does not take account possible complexities in pressure piling; for example the scenario when the explosion may only propagate through a restriction between compartments at a mixture other the stoichiometric mix. In contrast in the US, UL [10] and FM [11] test over a range of mixtures

The IECEx proficiency testing program run by PTB on pressure determination using hydrogen and ethylene showed a significant spread of results. This displays the variation that can occur when testing identical equipment with many of the test factors above removed, for example location of the ignition source and location of pressure transducers.

C. Overpressure testing

The use of a factor of 1.5 (often shown as 1,5) as the factor to be used for the overpressure testing has been consistently applied since the first standard, despite uncertainty by the committee during development of the first standard as to whether it was correct. However, other options for certain circumstances have appeared, including factors of 3 and 4 . Factors that may be applied to the maximum pressure for very low temperatures also now appear in Table 7 of the standard as shown in TABLE II earlier in this standard. Hence two factors may be multiplied together for the overpressure test.

The factor when pressure piling occurred increased at one stage to three times the reference pressure. As noted earlier, it was introduced in the second edition in 1975 and then dropped in amendment 1 of that edition in 1979. The analysis earlier in this standard suggests that factor is appropriate and consideration should be given to reintroducing this factor into the standard.

The factors applied in the IEC standard do appear low when compared with UL [10] and FM [11] standards where the factors can range for 2 up to 5. However, the requirements do vary between the two standards. But it should be recognised that these enclosures may be used in equivalent to Zone 0 area and so this may lead to a more conservative approach. Nevertheless, based on the variety of reasons articulated in this paper, there appears to be good cause to critically review some of the factors currently in the IEC flameproof standard. However, it does appear that in any circumstance where the four times overpressure is applied, this can be expected to exceed any pressure that may be developed during an explosion and so may be considered to be appropriate.

V. CONCLUSIONS

This study indicates that further research is desirable in a number of areas to provide confidence in the requirements in the existing IEC standard, or to provide recommendations for change if the need is indicated in the outcomes of the research; these include:

1. Investigating the applicability of the formula for applying initial higher pressures when determining pressures for temperatures below -20 °C, particularly for cases involving pressure piling.
2. Investigating the impact of varying gas concentrations from those specified in the standard when pressure piling is present to see if higher pressures can be obtained in certain circumstances.
3. Examining the applicability of the hydrogen 85/methane 15 mixture for pressure determination in the case of pressure piling for Group IIB, including correlation with ethylene.
4. Given the improvement of instrumentation in the past 20 years and more, there may be value in re-validation of experiments done by Lobay and PTB with hydrogen 85/methane 15 included and with testing down to temperatures of -60 °C.

It is recommended that the specification for testing in the standard ambient range of -20 °C to +40 °C be more closely specified. There are a number of potential options that could be adopted, including restricting the allowable range. However, the best approach might be: (1) to allow testing in the current range; (2) define a narrower band where no factors apply; and (3) define factors to be applied for temperatures outside the narrow band but inside the current range. It is likely the narrow band could embrace most of ambient temperature conditions present in laboratories around the world.

It is also recommended that the current factors applied for overpressure testing be reviewed, possibly along the following lines:

1. Consider increasing factor of 1.5 when pressure piling is not present, at least for Group II where ambient temperature ranges are likely to be larger.
2. Dependent on how the above is applied, consider increasing factors used for very low temperatures to include provision for experimental error.
3. Consider restoring the factor of three when pressure piling is present that was in the second edition of the standard prior to the first amendment.

Finally it is recommended that the requirement from earlier editions that five tests should be done in the case of pressure piling should be restored for Groups I and IIA.

TC 31 has not yet achieved the aim that was proposed in its first meeting of TC 31 in 1948 of alignment between US and IEC standards and it does seem IEC TC 31 may have something to learn from those US standards when it comes to pressure determination and overpressure testing. But the reverse may also be true for other aspects of the standards, noting also that the US standards vary between bodies.

VI. ACKNOWLEDGEMENTS

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VIII. VITA

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PARTIAL TORQUE RIDE THROUGH WITH MODEL PREDICTIVE CONTROL

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Abstract - Symmetric and asymmetric dips of the grid voltage pose serious problems to gas compression stations powered by drives such as load commutated inverters (LCI). Drive control systems used in industrial practice are not capable to handle reduced grid voltage situations appropriately, and execute a ride-through procedure instead during which no drive torque is provided by the drive. Without drive torque compressors may quickly enter surge conditions, under which the gas flows rapidly back and forth, causing wear and risking damage to the equipment. In this paper we describe a novel control approach developed for load commutated inverters based on model predictive control (MPC). Model predictive control is an optimization-based control method, where a mathematical model of the system is used to determine control inputs which are optimal with respect to some objective function. With the revised control system, the drive is capable to provide partial drive torque during grid disturbances; thus resulting in robustness improvements for electrically-driven gas compression stations. In the case of a voltage dip, the compressor is still supplied with partial drive torque, decreasing the probability of the compressor diverging into surge. The paper includes experimental results executed on two real 41.2 MW LCI-fed synchronous machines each powering a gas compressor.

Index Terms — Gas compressors, variable speed drive, load commutated inverter, model predictive control.

I. INTRODUCTION

Electrically-driven gas compressors have a number of advantages compared to compressors driven by gas turbines: (a) the drive torque can be varied much quicker, (b) the variable-speed drive system can be operated with high efficiency in a much broader operation range and (c) there are no local greenhouse gas emissions. In situations such as subsea installations a variable speed drive (VSD) system may be the only option to power gas compressors [1], [2]. Due to the aforementioned reasons, a number of large gas processing plants in Norway employ electrically-driven gas compressors.

Gas compression is energy-intensive, such that high power solutions for the variable speed drive are sought. A typical solution consists of a synchronous machine fed by a load commutated inverter (LCI). Reasons for this choice are the proven reliability of the LCI combined with its competitive price in high power applications [3].

One of the gas compression sites is the basis for the technical innovation described in the paper. This gas treatment plant is located at a remote location and is affected by disturbances in the Norwegian electricity grid. Weather phenomena such as storms occasionally cause brief impairments of the power lines, resulting in a sudden reduction of the grid voltage in one or more phases. Typically the grid voltage is affected over a time span of 50 to 150 ms.

While of short duration, the consequences of these voltage dips can be severe. They can cause the LCI to trip, e.g. due to inrush currents at the return of the grid voltage. Or, due to the sudden loss of drive torque, the compressor may enter unstable operating conditions such as surge or rotating stall, and is tripped as a precaution to avoid mechanical damage and wear. In either case the operation of the gas compressor, and after a short time the upstream plant, is stopped and a time-consuming restarting procedure needs to be carried out. Since the amount of exported gas is considerable, the financial cost of such an incident can be immense.

The paper describes a novel torque control scheme and its commissioning on load commutated inverters powering two 41.2 MW gas compressors. The goal of this new control scheme is to increase the robustness of the torque controller in the case of grid disturbances. In particular partial torque shall be provided during partial loss of grid voltage. The proposed control scheme is based on model predictive control (MPC), an optimization-based control method [4], and requires the solution of a mathematical optimization problem at each millisecond on an embedded system [5].

The paper is structured as follows: After this introduction, preliminaries are summarized in Section II. Section III states technical information about the gas processing plant of interest. The proposed MPC solution is outlined in Section IV. The verification of the control solution during grid disturbances is shown on a Hardware-in-the-Loop (HIL) simulator, Section V. Subsequently measurements from the commissioning of the novel control algorithm on site and from a real voltage dip event are reported in Sections VI and VII, respectively. A list of abbreviations can be found in Table 1.

TABLE 1
LIST OF ABBREVIATIONS

Abbreviation	Meaning
AC	alternating current
DC	direct current
FPGA	field programmable gate array
HIL	hardware in the loop
I/O	input / output
LCI	load commutated inverter
MPC	model predictive control
MV	medium voltage
QP	quadratic program
SQP	sequential quadratic program
VSD	variable speed drive

II. PRELIMINARIES

In this section we take a closer look on grid disturbances. Depending on the reaction of the frequency converter, different types of ride through behaviour are distinguished. More information is provided in [6].

A. *Symmetric Vs. Asymmetric Voltage Dips*

In an ideal three-phase system, the voltages in the three phases are sinusoidal with the same amplitude, succeeding each other with a phase shift of 120 degree. By means of the alpha-beta transformation (also known as Clarke transformation), the three phase voltages can be mapped into the two-dimensional plane, where the ideal voltages correspond to a voltage vector rotating on a circle, [7].

In the case of *symmetric* grid disturbances the amplitude of all three phases is reduced by the same amount, whereas the phase difference is unaffected. In the alpha-beta plane this corresponds to circles with varying radii. Figure 1 shows a practical example of a symmetric voltage dip, as measured on the primary side of the transformer at a large gas processing plant in Norway.

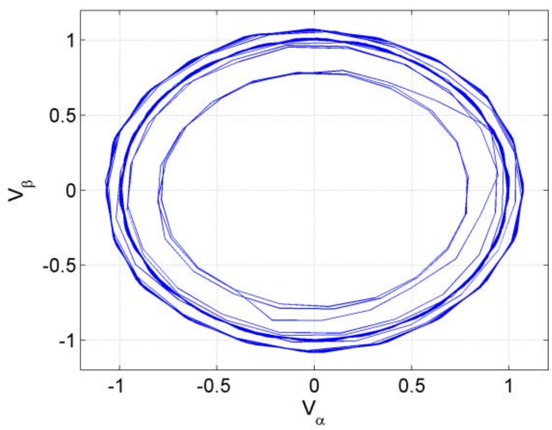

Fig. 1: Example for symmetric grid disturbance.

In the case of an *asymmetric* grid disturbance, the amplitudes of the three phase voltages are different, and also the phase separation of 120 degrees is not guaranteed. In the alpha-beta plane asymmetric grid conditions are typically identified by the voltage vector rotating on an ellipse. Figure 2 illustrates such an asymmetric grid condition, which was also measured on the primary side of the transformer at a large gas processing plant in Norway.

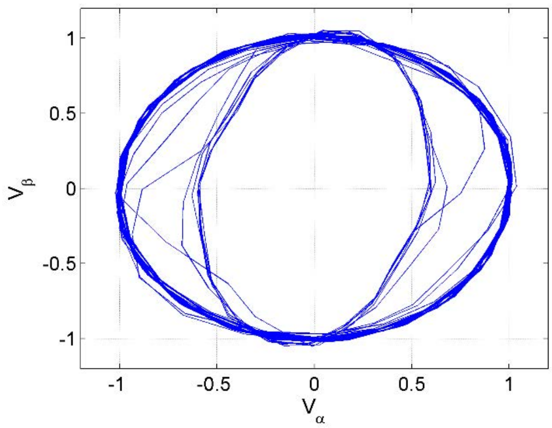

Fig. 2: Example for asymmetric grid disturbance.

B. *Ride-Through Characteristics*

The reaction of the frequency converter to grid disturbances depends on the physical properties of the frequency converter as well as on the implemented ride-through procedure. As was emphasized in [6], the amount of energy stored in a frequency converter is negligible compared to the transmitted power. The provided power and thus the drive torque is thus dependent on the type and depth of the voltage dip.

We distinguish three classes of ride-through procedures:

1) *Zero-Torque Ride Through:* The operation of the frequency converter is interrupted such that no drive torque is provided by the converter. Operation is resumed when normal grid voltage is available again.

2) *Full-Torque Ride Through:* The frequency converter continues its operation without reduction of the drive torque.

3) *Partial-Torque Ride Through:* The frequency converter continues operation, however only partial torque is provided.

C. *Requirements for power loss ride through*

The amount of torque necessary to prevent the compressor from going into surge depends on the operating point of the compressor. However, even if the available drive torque is not sufficient to prevent surge, increasing the available drive torque delays the point in time when the compressor enters surge conditions. There is a longer grace period for the grid voltage to recover, and for the initiation of protective measures for the equipment.

The requirements for the ride-through procedure can be summarized as follows:

1. Ensure the frequency converter does not trip e.g. due to overcurrent.
2. Supply either the requested drive torque, or, if that is not possible, as much torque as possible to prevent the compressor from entering surge.
3. Compromise on agreed-upon secondary performance targets in order to increase the drive torque during a ride-through. Examples would be increased torque ripple or a small short-term DC voltage on the VSD transformer.

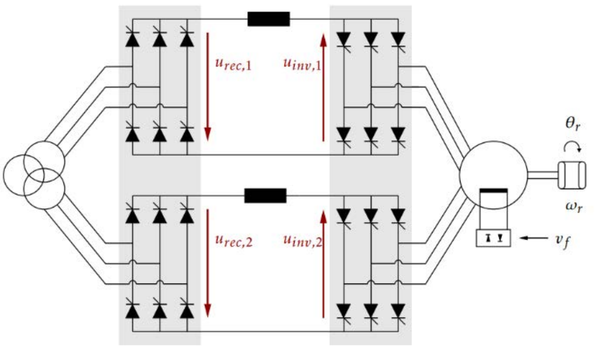

Fig. 3: Variable speed drive system comprised of transformer, load commutated inverter and synchronous machine.

III. SYSTEM DESCRIPTION

The plant processes natural gas from different oil fields in the Northern Sea. It has a capacity of 143,000,000 standard cubic metres (3.8×10^{10} US gal) of natural gas per day. Dry gas is compressed and pumped through four pipe systems to Belgium, France, Germany and the United Kingdom. Six 41.2 MW export compressors are powered by variable speed drive systems comprising dual winding synchronous machines and load commutated inverters.

Fig. 3 depicts a schematic of the employed variable speed drive system comprising a transformer, the load commutated inverter and a synchronous machine. The LCI is in a 2x6/6 pulse configuration with two parallel branches to reduce torque-pulsations. Each branch possesses a six pulse thyristor bridge as line commutated rectifier, a direct current (DC) link and a six pulse thyristor bridge as load commutated inverter. Not shown on this figure are the connection of the drive shaft to the compressor and the connection of the transformer to the medium voltage grid. The transformer employed on site is actually a four-winding three-phase transformer, which is also connected to electric filter banks used for power factor correction and input current harmonic compensation.

The control variables of the variable speed drive system are the firing angles (also called control angles) of the line commutated rectifier and the load commutated inverter, as well as the excitation voltage for the rotor windings. By means of the firing angle of the thyristor bridges, the rectified DC voltages u_{rec} and u_{inv} as well as the direction of power flow can be determined. The machine excitation can be adapted by the excitation voltage v_f.

TABLE 2
DESIGN DATA OF VSD SYSTEM

Parameter	Value	Unit
Line voltage, prim. side	132	kV
Line voltage, sec. side	6200	V
Line frequency	50	Hz
Rated line current, sec. side	2529	A
DC link inductance	7.5	mH
Rated DC current	3342	A
Rated stator voltage	5900	V
Rated stator current	2415	A
Rated stator frequency	60	Hz
Rated shaft power	39.2	MW
Rated rotational speed	3600	rpm

Conventional LCI control schemes assign separate tasks to the control variables: The firing angle β on the machine side are predetermined in order to minimize the reactive power in the machine. The excitation voltage v_f is used to control the stator voltage of the machine. The firing angle α on the line side is actuated to control the current flowing in the DC link, and thus the drive torque. The technical specifications of the variable speed drive system are summarized in Table 2.

IV. PROPOSED CONTROL SOLUTION

In this section the novel model predictive control solution for the LCI is outlined. We start with a generic description of the chosen MPC algorithm, before discussing the application at hand.

A. Generic Description of the MPC Algorithm

Firstly we provide a generic description of the employed model predictive control algorithm [4]. At the heart lies a mathematical model describing the system, and which is used for finite-horizon predictions. This model can be stated as

$$d\mathbf{x}/dt = f(\ \mathbf{x}(t), \mathbf{u}(t)\ ) \qquad (1a)$$
$$\mathbf{y} = g(\ \mathbf{x}(t), \mathbf{u}(t)\ ) \qquad (1b)$$

where:

$\mathbf{u}(t)$	control inputs
$\mathbf{x}(t)$	system states
$\mathbf{y}(t)$	system outputs
f	system equation
g	output equation

Apart from the dynamic model, a cost function is defined which describes the control objectives,

$$J = \int_{kTs}^{kTs+Tp} (\mathbf{x}-\mathbf{x}_{ref})^T\mathbf{Q}\ (\mathbf{x}-\mathbf{x}_{ref})+(\mathbf{u}-\mathbf{u}_{ref})^T\mathbf{R}\ (\mathbf{u}-\mathbf{u}_{ref})\ dt\,, \qquad (2)$$

where reference values are indicated by the subscript ref, k is the sampling instance, Ts the sampling time and Tp the prediction horizon. **Q** and **R** are weight matrices to prioritize the objectives for the MPC controller. Moreover, constraints on the control inputs, states and outputs can be defined:

$$\mathbf{x}\_min \le \mathbf{x} \le \mathbf{x}\_max$$
$$\mathbf{u}\_min \le \mathbf{u} \le \mathbf{u}\_max \qquad (3)$$
$$\mathbf{y}\_min \le \mathbf{y} \le \mathbf{y}\_max$$

The continuous-time optimal control problem can thus be stated as

$$\underset{\mathbf{u}}{\text{minimize}}\ (2)\quad \text{subject to}\ (1), (3). \qquad (4)$$

The chosen approach to solve the nonlinear problem (4) is a sequential quadratic programming (SQP)-type approach known as real-time iteration scheme with Gauss-Newton approximation of the second-order derivatives. At each time instance a discrete-time linearization of problem (4) is obtained, which corresponds to a quadratic programming (QP) problem. A more detailed description of this solution approach is

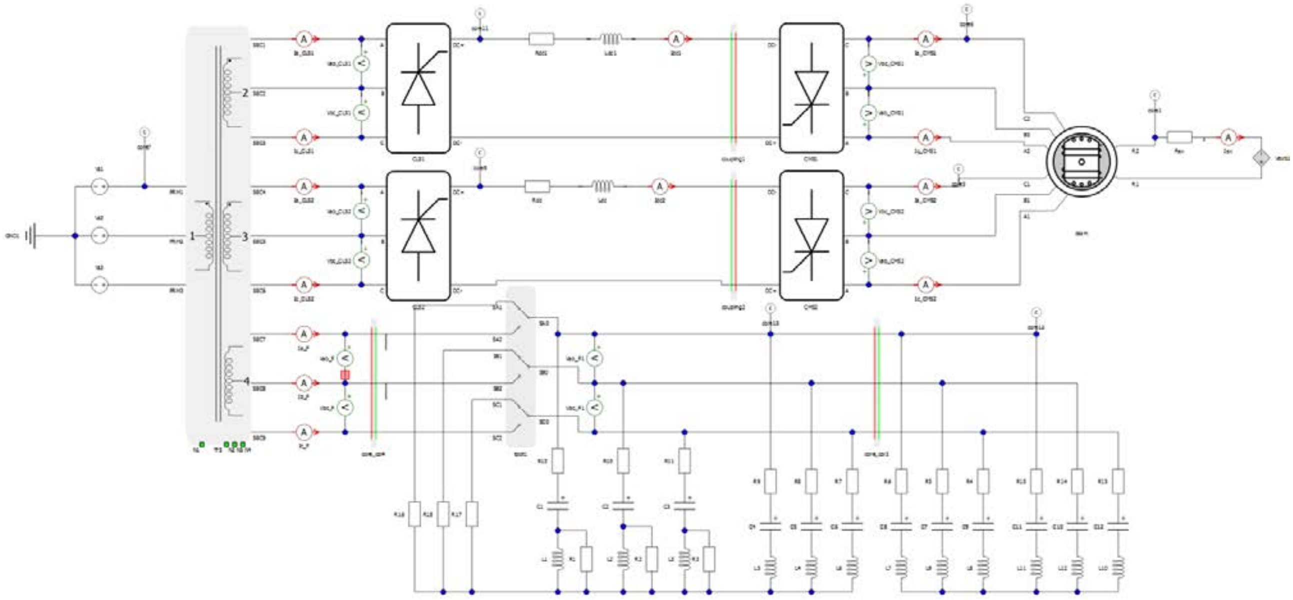

Fig. 4: Schematic of the simulation model on the Hardware-in-the-loop system.

beyond the scope of this paper, and can instead be found in [8]. A highly efficient implementation of this approach is provided by making use of the code generation functionality of the ACADO Toolkit [9]. The resulting QP problem is solved by the on-line QP solver qpOASES [10].

B. Application to Load Commutated Inverters

Some information on the application of the aforementioned MPC algorithm is given in this section. For a more elaborate discussion, see [11], [13], [13].

The model predictive controller is based on a nonlinear dynamic model of the LCI, i.e. of the DC link and the thyristor bridges, which can be stated as

$$\frac{d\, i_{DC}}{dt} = A\, i_{DC} + B_1 \cos\alpha + B_2 \cos\beta, \qquad (5a)$$

$$\tau_e = -\, i_{DC} \cos\beta\,, \qquad (5b)$$

where:

i_{DC}	DC link current
α	Control angle line side (rectifier)
β	Control angle machine side (inverter)
τ_e	Electric torque
A, B	Constants

The control inputs u are the firing angles on the rectifier and on the inverter. The states are the currents in the DC link, and the output is the drive torque of the VSD system. Apart from constraints on the firing angles, an upper bound on the DC link current is defined. Both the control angles of the rectifier and the inverter are selected by the model predictive controller, whereas the excitation voltage control remains independently controlled.

The MPC algorithm was implemented on a control board, which is based on a 32-bit dual-core Power PC processor with a clock cycle of 1.2 GHz. The board also includes a field programmable gate array (FPGA) and a 64-bit floating point unit. The sampling time was chosen to be 1 ms, i.e. at each millisecond a nonlinear mathematical optimization problem is discretized, linearized and solved. Thereby the MPC solution consumes only a minor fraction of the computational resources, such that the whole control system can be executed on time.

Compared to the classical control method, the MPC has the following advantages: (a) Instead of selecting the firing angle on the machine side by means of a predetermined lookup table (i.e. feedforward control), the angle is actively controlled, and can be changed in the case of grid disturbances; (b) instead of executing independent control actions of the firing angles on the line side and the machine side, the MPC coordinates both firing angles to reach the defined objectives; (c) both alternating current (AC) voltage magnitudes are taken into account by the controller; and (d) a constraint on the DC current can be defined to change the control behaviour when the DC current is close to its boundary, thus helping to avoid overcurrent trips.

V. VERIFICATION ON A HIL SYSTEM

Before applying the proposed control solution to a medium voltage drive, its effectiveness was verified on a Hardware-in-the-loop (HIL) system. In this section the findings during this verification are presented.

A. Description of the HIL System

For the verification of the model predictive controller on a HIL system, the control system, consisting of the control hardware and the control software, is exactly as on site. The HIL system is connected via analogue and digital I/Os to the control boards running the control software for the load commutated inverter. The HIL system comprises an FPGA on which a model of the variable speed drive system is simulated in real-time. The dynamics of the drive shaft and the compressor are not included in these simulations, however the compressor behaviour is approximated by a quadratic load torque curve. Another simplification is taken on the grid side. The grid voltages are imposed on the transformer, however the impact of the load commutated inverter on the grid voltage is neglected.

A schematic of the simulation model is depicted in Fig. 4. The upper part contains both branches of the LCI, whereas the lower part shows the electric harmonic filters connected to the transformer.

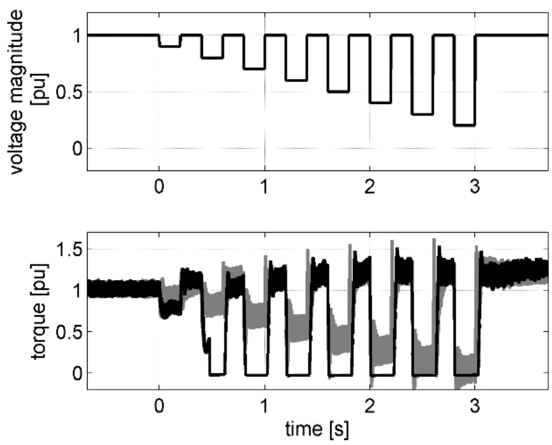

Fig. 5: Simulation results: Grid voltage magnitude and drive torque during symmetric dip series with conventional control (black) and MPC (grey).

B. Simulations Results

In this section the simulation results on the HIL system are reported. The behaviour of both the conventional control system and the novel MPC solution are compared during series of symmetric and asymmetric dips.

1) Symmetric Dips: In the first scenario the grid voltage magnitude is decreased in a series of voltage dips with increasing dip depth. Each voltage dip lasts for 200 ms, and the voltage magnitude changes without transition within a microsecond.

Figure 5 depicts the grid voltage magnitude and the electric torque, once with conventional control and once with the novel model predictive controller. No trip occurred regardless of the used controller. However the drive torque provided during the scenario differs significantly. While the conventional control executes a zero-torque ride through procedure for a grid voltage magnitude of 80 % and below, the model predictive controller continues operations and is able to provide partial torque. After the instantaneous reduction of the grid voltage magnitude, the MPC requires about 25 ms to stabilize the drive torque to the steady-state. The amount of residual drive torque decreases with the magnitude of the grid voltage. Full drive torque is guaranteed for a grid voltage magnitude higher than 0.93 pu, i.e. already the step to 0.9 pu voltage magnitude coincides with a reduction of drive torque.

2) *Single-Phase Dips*: The second scenario equals the first one, the difference being that instead of varying the grid voltage magnitude of all phase voltages, only a single phase voltage is changed. That way the controllers are tested under asymmetric grid conditions.

As can be seen in Figure 6, both controllers are able to provide more drive torque if only a single phase is affected. The MPC however outperforms the conventional controller in terms of residual torque.

Based on the conducted simulations, an estimate of the available drive power as a function of the remaining grid voltage can be derived. This estimate is visualized in Fig. 7. As is shown in the Figure, the amount of residual power depends not only on the remaining voltage magnitude, but also on the number of phases which are affected by the grid disturbance. For very low grid voltages operation of the drive is not possible due to problems with estimating the orientation of the grid voltage vector.

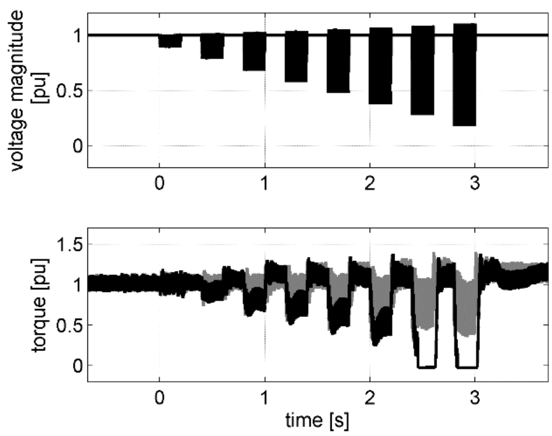

Fig. 6: Simulation results: Grid voltage magnitude and drive torque during single-phase dip series with conventional control (black) and MPC (grey).

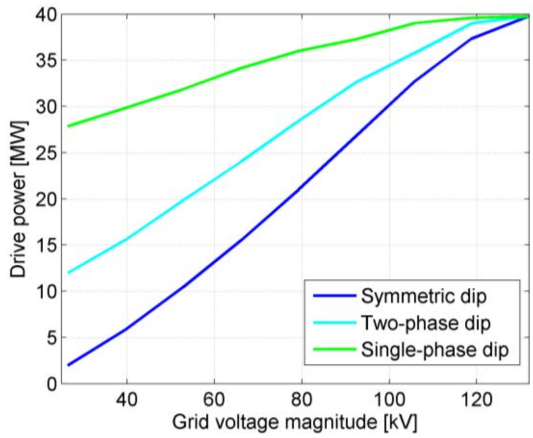

Fig. 7: Estimate of the residual power during voltage dips.

VI. COMMISSIONING ON MV DRIVE

After verifying the effectiveness of the novel control approach on the HIL system, the control system was commissioned on site. Two out of six export compressors on the gas treatment plant were chosen as pilots for the proposed MPC solution. In this section it is shown that under normal grid conditions, the novel control solution works as expected. Fig. 8 shows the speed, the DC current, the control angles and the voltage magnitudes during the first 16 hours of operation. The control behaviour during the commissioning is as expected. The DC link current follows it reference, as provided by the speed controller. A number of speed changes are requested by the process controller, which are delivered swiftly.

A closer look on the start-up of the machine is provided in Fig. 9. Again the behaviour is as expected. First the pulse mode is traversed, then we observe a normal start-up, with switch in of the electric harmonic filters, and reduction of the current reference after the requested speed is reached. The startup procedure is virtually unaffected by the new control system.

Fig. 10 provides an even closer zoom to show the waveforms of the signals under steady-state conditions.

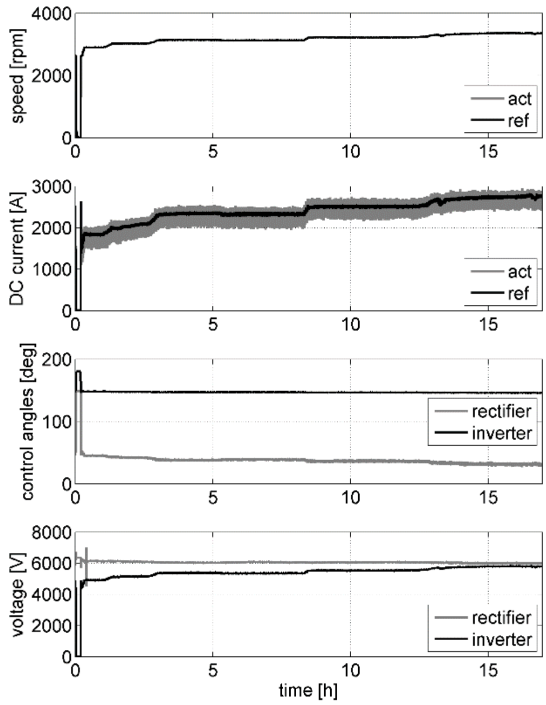

Fig 8: Experimental results: Speed, DC current, control angles and AC voltage magnitudes during the commissioning of the novel control solution.

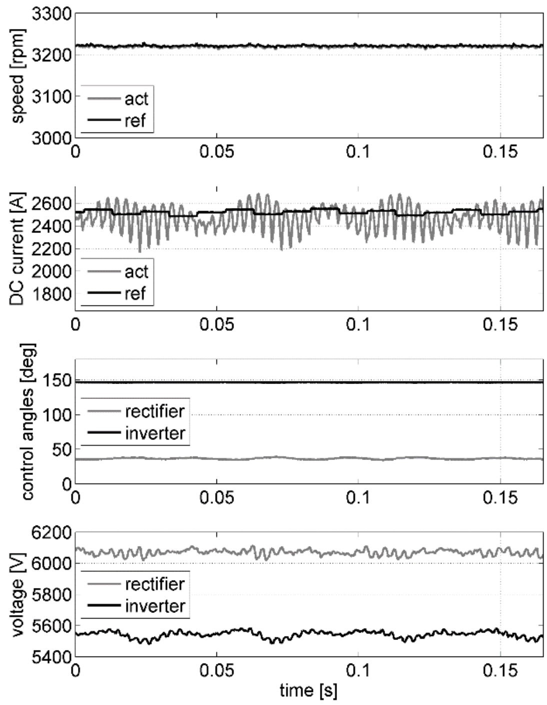

Fig 10: Experimental results: Zoom to waveforms under steady-state conditions.

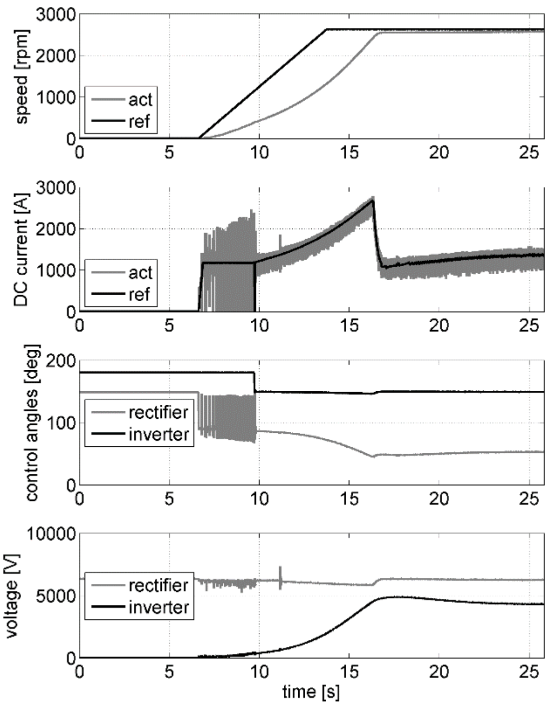

Fig. 9: Experimental results: Zoom to recorded signals at start-up procedure during commissioning.

I. VOLTAGE DIP EVENT

During the course of the winter, a number of grid voltage disturbances occurred. In this section the results of one such case are reported.

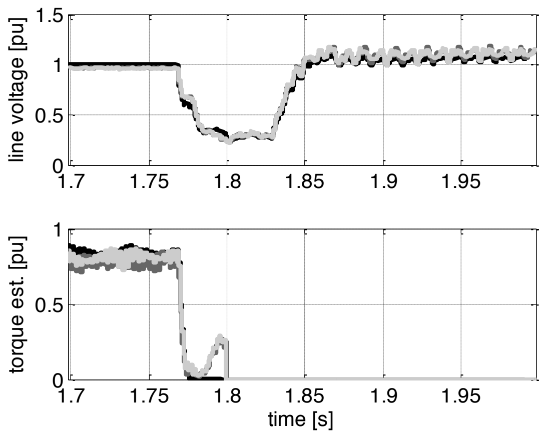

Fig 11: Experimental results: Estimated torque during an undervoltage event. Conventional control (black) vs. MPC solution (dark and light grey).

In Fig. 11 the course of the grid voltage magnitude and an estimate of the drive torque is shown. Since no direct measurement of the drive torque was available, an estimate was calculated from the electric signals of the drive. The black line belongs to an LCI with conventional control, whereas the dark and the light grey lines refer to two LCIs controlled with the new MPC solution.

As can be seen from the plot, the grid voltage is affected by a deep symmetric voltage dip down to about 0.3 pu of the rated grid voltage for a duration of approx. 80 ms. The effect is a significant reduction of the available drive torque. While the conventionally-controlled LCI executes a zero-torque ride through, both MPC-controlled LCIs are subject to an undershoot, from which they recover to provide 0.23 pu of rated drive torque. This result matches the expectations raised by the HIL simulations quite well (0.23 pu torque is a bit more than anticipated). However, the protection system of the gas compressor, which is a timer-based solution not taking into account the available drive torque, trips the operation of the gas compressor approx. 30 ms after the start of the voltage event.

II. CONCLUSION

In this paper the application of a novel model predictive control scheme to load commutated inverters was presented. Simulations on a HIL system have shown its ability to provide partial torque during grid disturbances, and thereby to increase the robustness of electrically-driven gas compression stations.

The control scheme was implemented on two LCIs each powering a 41.2 MW gas compressor on a large gas processing plant in Norway. During voltage dip events in the winter, the ability of the model predictive controlled LCIs to provide partial torque was verified in practice. What remains to be done in order to reap the economic benefits of the solution is a systematic relaxation of the compressor protection system, taking into account the amount of partial torque which is available.

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ALL-ELECTRIC FPSO: ONSHORE AND OFFSHORE COMMISSIONING EXPERIENCE

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Abstract – The increasing scope of electrical equipment in an offshore facility without turbo-driven End-Users has a known impact on the design of such facilities that has been discussed in the recent years [1]. The intent of this paper is to recall the historical events and present the specificities of such project execution from Vendor delivery (equipment FAT) until start-up of the facility (first oil and ramp-up).
As such project is executed in many locations changing throughout time, from Vendor to yard, then towing to offshore, we will review splitting and sequencing of testing activities at the various locations and phases of project execution.
A selection of the different issues encountered and solutions implemented eventually, will be covered with highlights on the priorities leading to the decisions which were taken.
Feedbacks and lessons learned from designing, commissioning, operation and maintenance team perspective will be discussed in order to propose future roadmaps' items for the industry.

Index Terms — All-Electric, FPSO, Commissioning and Start-up.

I. INTRODUCTION

The successful start-up of a project heavily rests on the successful execution of the commissioning which is the last active technical step of the 'project life'. Commissioning will consolidate all the achievements done during design and construction as well as inherit of all the issues left.

Therefore, it becomes the last adjustment stage before the project ends and the production facility is handed over to Operation team for plant start-up and eventual operation. Commissioning is very largely consisting of tests and verification of equipment installed in their final configuration. Thus, mastering the complete testing activity throughout the project life is an important contributing factor to a successful start-up of the plant.

II. ACRONYMS

CB: Circuit Breaker
CCR: Central Control Room
DC: Direct Current
ECS: Electrical Control System
ICSS: Integrated Control and Safety System
FAT: Factory Acceptance Tests
FPSO: Floating Production Storage and Offloading
GTG: Gas Turbine Generator
HV: High Voltage
HVAC: Heating Ventilation Air Conditioning
LQ: Living Quarters
N.O.: Normally Open
O&G: Oil and Gas
OEM: Original Equipment Manufacturer
OTP: Operational Test Procedure
PMS: Power Management System
POB: People On Board
RMS: Root Mean Square
SAT: Site Acceptance Test
SOLAS: Safety Of Life At Sea
UCP: Unit Control Panel
UPS: Uninterruptible Power Supply
VSDS: Variable Speed Drive System
WHRU: Waste Heat Recovery Unit

III. TESTING REQUIREMENT

A. Testing need

Testing (FAT, SAT, commissioning) has become such a standard feature in our industry, that sometimes one may lose sight of the ultimate purpose of this activity. In projects, the main objective of testing is to demonstrate that the item (single equipment, complete package, whole process unit…) is fit for purpose for both operational and safety requirements during the life of the production facility. Secondary objectives are to verify the contractual performance requirements, to enable operation team to begin the "learning curve" before the actual start-up. The ideal methodology to review the testing requirement is to consider the full project lifecycle and to define the optimum stage for which one test is to be performed.

Obviously, the later tests are carried out in the project life, the more meaningful the results are. But we shouldn't be blinded by this consideration as the capability to test everything and exhaustively just before start-up is simply impossible to achieve.

Indeed the offshore man-power capabilities are strongly reduced, the working hours are costly and the testing activities limited by the amount of material resources.

Therefore, the aim of any offshore project will be to minimize offshore works as much as practical.

Moreover, in the unfortunate event of test failure, the corrective actions may take a significant amount of time to be defined and also to be implemented. Hence the late discovery of damaged equipment or improper design or construction may lead to catastrophic delay of the project start-up.

B. Design stage

The testing requirement definition will start no later than the BASIC Design stage. This testing requirement will be influenced by a large variety of considerations such as:

- Equipment criticality
- Amount of equipment considered
- Material technology maturity
- End-User internal policy
- Contractor and Vendor experience and know-how
- Commissioning execution strategy
- Project schedule and cost constraints
- Legislative requirements
- License constraints
- And many more…

For standard electrical components (switchgears, transformers, UPS,…) the testing requirements will be less sensitive to the above mentioned considerations and a more detailed definition can take place during detailed design stage. But for more specific equipment (ECS, Power generation, large drives with variable speed drive systems…) the objective should be to finalize the testing scope of such equipment at the end of the BASIC Design stage.

Once the specific equipment list has been identified and agreed within the Project team, the methodology to define the testing requirement is to review (ideally backwards) the testing steps that the package will undergo.

At this stage the Project team shall ensure that all checks are performed and functions tested at least once before plant start-up. In many cases, one testing item will be repeated at different times and different locations as the equipment may be partly dismounted for transportation or preservation purposes.

C. Commissioning stage

For electrical discipline, in the vast majority of cases, the commissioning start is matching the energization of the equipment.

As per our Company practice, electrical components are assigned to system and subsystems which are autonomous entities meant for one specific purpose.

Example: “Gas” is a system within which gas compression train “A” is a subsystem, gas compression train “B” is another, gas dehydration is another, and gas lift another subsystem. In that case, all the electrical loads that are directly involved in the gas compression train 1 and their relevant feeders and cable will also be grouped under this subsystem. This rule applies to all disciplines (mechanical, piping, instrumentation…). When all items of all disciplines have reached sufficient completeness: the ready for commissioning certificate is signed by all involved parties and commissioning activities may start.

A good all electrical example is lighting. Plant lighting is one system in which multiple subsystems will be declared. Most often, the lighting subsystems will be split by area and type of duty (normal / emergency).

The commissioning execution of one subsystem is meant to be done as independently as possible from the other subsystems, which is believed to optimize time wise this set of activity. However, there is a relationship between systems and subsystems to be defined in order to sequence properly the activity. For instance: the commissioning of telecom cannot start if the UPS and relevant distribution boards have not been completed. The commissioning of low voltage motors cannot start if the commissioning of their feeding switchgear is not complete.

Assuming all conditions are met to start the commissioning, the activity is structured in two main parts:

- Individual test / Basic function sheets
- Operational test procedure

The individual test sheets are applied systematically for each type of component (a motor, a protection relay, a transformer, a lighting circuit). They list in a systematic way the checks to be performed for that individual component. Example, each motor will undergo insulation resistance test, starting current recording, verification of rotation direction, vibration checks etc… without consideration for the motor surroundings (i.e. it does not matter whether this motor is driving a pump, a fan or a compressor). Once the individual tests and checks have been carried out successfully, the operational test procedure is being run. It can be a single discipline document (e.g. key interlocking checks for a complete switchgear), but most cases it is mutli-discipline, it will verify the proper operation of the functional entity in the various operating conditions that have been defined:

- Start-up
- Duty-standby features
- Guaranteed operation points
- Regulation system
- Normal and safety shutdowns
- Etc.

The assignment of functional sheets to the items can be partly or fully automated depending on the use of database tools since the engineering phase. But each OTP is a custom document with inputs from Vendor documentation, Contractor functional specification, and Commissioning and Operation teams’ requirements.

Clearly, the commissioning role is not to redo the engineering, but it still needs to understand the engineering intent. This will serve as input with the same level as the successful and unsuccessful testing outcomes as well as the cancelled tests. The subsequent outcome may be an increase of the testing scope during commissioning phase.

Hence, this means that commissioning team needs to be informed of all adjustments done in earlier testing activities and be capable of readjusting its own scope of work.

This is not the wishful thinking of what an ideal project should be. It is rather the acknowledgement that when a project is drifting from the initial plan, adjustments may be required. It is being done for cost and schedule, likewise, it needs to be ensured to testing activities.

IV. TESTING BY LOCATION

A. Factories

Factory Acceptance Tests (FAT) are the most conventional tests. Supposedly, the factory is the ideal location to clear any issue as it is where the equipment was manufactured or at least assembled. The typical test plan will be defined by:

- Standards - national and/or international
- Vendor internal procedures and quality plans
- Client requirements

This test plan will be mostly "equipment" oriented and not customized for the equipment final application. But the results it will provide are very important. They allow validating many basic features of the supplied items. In addition, FAT results provide a first reference of the equipment performance, which may be used as a reference both for further tests in a different environment and, for the longer term maintenance, to compare the evolution of various parameters (insulation resistance, partial discharges…) in time. In addition, in most of the cases, it is the first contact of commissioning team with the equipment and it is a useful input for developing the future operational test procedures (OTP). The main limitation of the FAT is that the individual component being tested is "the center of the world" and little (if any) consideration is given for the outer world in which this component will be inserted.

As it is the first testing step, FAT are always an important milestone, however its meaning and outcome will be different from one package to another, for relatively standard equipment such as switchgear and UPS, it will more likely be a 'foundation stone' on which the project will build further and potentially proceed with adjustments to the surroundings of the equipment. For more customized items (typically control systems) it will often lead to further design developments.

B. iFAT

An iFAT: is an integrated FAT of two packages, one being a control system, most of the time seen from the control system point of view. The schedule of the iFAT depends on the execution schedule of the main system (usually the ICSS).

Typical execution of the iFAT for electrical items is to bring one package UCP to be tested with another control system. But it may also be the other way around e.g.: ECS representative attending switchgear FAT to perform communication and time response tests

iFAT requires both entities, interfacing each other, to be at a sufficient development stage. Common and sufficient development stage is not very often the case as the packages have different award and delivery dates. Because of these different schedules, one entity is using this test just as "communication protocol" validation test. This is not enough nor satisfactory: we have observed that simply validating the communication mode along with the address does not clear further instances on site. In particular the complete communication configuration should be reproduced to verify and validate the correct operation of redundancy, and switching of lines.

For specific packages that are similar to a stand-alone process unit (e.g. containerized technical room for a subsea pump). The iFat may also refer to the complete package testing. This case is not addressed in the frame of this article.

C. Back to back tests & String tests

Back to back and string tests apply to mechanical drives.

The back to back test does not include the driven equipment (e.g. compressor), it consists in bringing the full driving train (e.g. transformer, converter, and electric motor) and make it perform mechanically 'as if' there was a real mechanical load. The load may be a twin package, in which case two strings may be tested in one shot, or a permanent factory test bench. There are several advantages for back to back tests:

- Complete electrical line is being tested
- Strong electrical skills of the testing team
- Energy efficiency of the test: as only the losses are consumed it makes it a more environmentally friendly test and the test costs are also reduced.

The string test is the closest "real life" testing experience the package may undergo before its final installation location. It requires almost complete package assembly and it is dedicated only for the most critical applications. In our case, all power generators and one type of each large compressor and pump driven by VSDS underwent a string test.

Fig.1: Moto-compressor string test arrangement

The drawback of the string test is that electrical equipment sometimes comes as a last priority and it is not completely part of the test plan. It is not monitored and controlled with the same level of attention and as continuously as the 'process' equipment (compressor, pump or turbine). In addition, testing means and qualified personnel for the electrical scope, may not be available as this test is not occurring at an electrical factory.

It is then important that electrical End-Users attend such tests and have their say during the introduction meeting and during the tests in order not to miss any important part of the electrical validation steps.

In addition, the complete extent of protection is not always available and even if it is physically in place, it does not automatically imply that it has been properly set-up. There are multiple records of damages that could have been avoided if the proper protection had been put in place.

D. Onshore Commissioning

Onshore commissioning will cover all the commissioning activities done at the construction or integration yards. In the case of an FPSO the Onshore commissioning shall at least cover a very large part of the Hull and LQ, because these will need to be very close to completeness during towing (SOLAS and classification requirements applicable to a ship with people onboard).

This set of activity will likely be mostly managed by the Contractor, as there will be concurrent commissioning and construction works. It is done with a large amount of available workforce, in particular many Vendors may be working in parallel.

During this stage, the main focuses of the commissioning team are:

- Collect all necessary inputs
- Populate database and write OTPs
- Make sure that safety standards are applied satisfactorily on site
- Attend/witness the most significant activities as their amount may be higher than the available people

The commissioning preparation activities start during the detailed design. The engineering team will sometime need to adjust their documentation to suit the commissioning team needs.

E. Offshore Commissioning

As soon as the production facility leaves the yard, we may consider that the offshore commissioning has begun. For complex projects in terms of sourcing and local content, it is theoretically possible to have several alternated phases of onshore and offshore commissioning. But such case is still considered as rare.

Offshore commissioning is associated to a sudden and drastic reduction in terms of manpower. This workforce reduction will be amplified by higher logistics constraint (capability to load and unload material).

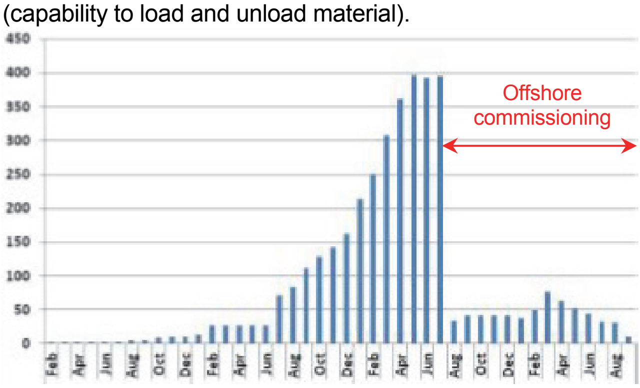

Fig.2: Commissioning manpower curve example

This will also be the time when the maintenance and commissioning teams will start working in close coordination. In particular: shutdowns and restarting of the electrical network of the facilities (both in case of planned exercises and unplanned upsetting events).

Finally, it is a good opportunity for maintenance team to get familiar with the operational and safety feature of the electrical network and its components:

- Basic automation functions (e.g. source transfer)
- Black start of UPS
- Periodic tests of generators
- Mechanical key interlocking

V. TESTING PRIOR TO OPERATION

A. ECS

Electrical Control System usually benefits from a relatively extensive FAT. Depending on the interface tests performed with other components (switchgears, UPS, generator UCPs,…) and the availability of real equipment for FAT, the scope of testing may be quite different from one case to another.

Despite our preference to have several real equipment of each type (in particular switchgear protection relays) the trend is that more and more FAT are being done with simulator interfaced to the ECS. The use of such simulator introduces several limitations. The simulator is done by the ECS Vendor, it reproduces what the ECS Vendor expects as an interface, and some cases may be missed or eluded. The simulator may create some completely inconsistent configurations in which the ECS behavior and display will be satisfactory to the End-User. It is not always an easy task to identify that such wrongly simulated configurations do not require any type of correction. Hence the simulator is a double edge sword in terms of testing. It does allow carrying out a large volume of testing, but this does not mean that all significant cases are properly reviewed and it can make all parties lose time on non applicable cases.

FAT are a good opportunity to test each item type in a very detailed manner, to review mimics and to test the sequence with simulator. Some sequences (typically the ones which deal with the network topology) can be tested to a very large extent and give a good degree of confidence. But the ones which have more interaction with the process (e.g. load shedding) cannot be considered as fully functional at FAT stage.

It is also an opportunity for the commissioning team (if involved during FAT as we recommend to do) to discuss directly with Vendor on the future site mobilization, expected phasing of activities and testing means.

In the various issues we have experienced, one in particular was quite puzzling: we identified in multiple instances inconsistencies between the ECS Vendor functional specifications and the actual coding of the system. This kind of issue was found among other instances in the particular case of load shedding.

To briefly explain the purpose of a load shedding: it is a mitigation mean that prevents a complete shutdown of the power generation when the generation capacity becomes significantly lower than the power demand. Typical triggering conditions for load shedding are:

- Tripping of one GTG
- Opening of one coupler CB
- Frequency drop

The load shedding sequence will then disconnect some load according to a predefined priority table to enable steady state condition for the power generation.

As we tested the load shedding, we expected that when a GTG would trip and sufficient spinning reserve was available on the remaining ones, no load shedding would be launched. This was confirmed by the reviewed and approved Vendor documentation. However, the way the system acted was to trigger a load shedding sequence without any load disconnection. This may look as inoffensive from the ECS point of view. But in fact, it had quite a few collateral consequences on the overall plant: an alarm message would be sent to the operators creating confusion and would freeze automatic duty/standby feature on the process side. In addition, other ECS sequences would be frozen for a few seconds in order not to interfere with a potentially unstable transient period during the load shedding.

As a lesson learned, we have organized workshops upfront with our main ECS suppliers to communicate on this kind of issues. We have discussed document format and content in order to minimize the gap between what the ECS specialist are programming and what the End-Users read and understand.

Moreover, as the early availability of ECS is more critical for offshore projects, as part of the electrical network and some equipment are energized during towing, the way forward that we have decided to take is to have more upfront detailed description of ECS functionalities at head quarter level. During the BASIC stage, our specialist will have to pick predefined features and adjust them to their project specificities.

B. Power Generation

The power generation is one of the most expensive and complex items considered in this paper. The testing was in line with this level of complexity. Thus, each main sub-component has had its own individual FAT (the gas turbine, the alternator, the UCP,…).

Then, each Gas Turbine Generator (GTG) package was string tested but to different extent. Some were tested at full load while others were tested at no load full speed only. Many other tests, which were not directly related to the electrical performance were also performed (noise, fuel change over…).

The full load testing of a large electrical generator (20MW and over) is difficult to achieve. Obviously, there is a need for large amount of fuel, but the main issue is to be able to export the amount of energy produced. In most cases, the energy will be simply lost into load banks.

Then the load banks introduce another type of limitation: they are quite often purely resistive while the real load of the GTG will have an inductive content. Moreover, the voltage level of the loads is not always matching with the rated alternator output which will then have its excitation system regulating at a set point which is not the correct one. In addition, as the GTG will run in islanded mode the regulation mode generally selected will be isochronous. Thus all the GTG settings could not be applied to the future stages of the Project.

In our case, the extensive scope of string testing was largely motivated by the use of a new GTG configuration, combined with the unusual arrangement of direct coupling on a two pole generator (i.e. no gearbox). Such arrangement had led us to some concerns regarding the dynamic response of the power generation package, and many simulations were run to assess the potential issues.

However, the string test could not reproduce as much as we expected the site conditions: each GTG being tested one by one their regulation mode was set to isochronous rather than droop, due to load bank availability a different voltage than the one of the project was set. It relied on the sole GTG UCP regulation and did not test the regulation performance with the PMS. We later had to spend a significant amount of time offshore to compensate for the lack of regulation testing between PMS and GTG UCP.

At yard, the GTG (dual fuel type) were commissioned with diesel fuel. For this reason, there was little effort by Vendor to try to verify and optimize the GTG dynamic performance; again this decision impacted the further commissioning work offshore.

Practically the regulation set onshore was so inefficient, that it would take over 5 minutes for the GTG to recover speed from a 30% load impact (from 33% loading to 66% loading).


Fig.3: Frequency response on load impact

Considering such result and the issues faced during the commissioning phase, it is legitimate to question the added value of the extended FAT and string tests of the GTG. However, we remain confident that the benefit of testing cannot only be measured by the end result of the dynamic behavior of the GTG. Starting sequence (including WHRU), noise and vibration verification, capability to synchronize and share load (even with a slow response time), etc. remain important milestones and should be cleared as early as possible. Both because they will enable to proceed further and because the later you discover issues, the more difficult it is to solve them.

It is also part of our lessons learned to test the GTG in droop mode during FAT in addition to the OEM standard procedure.

C. Large Drives

As there were few references of VSDS being used in offshore O&G projects, our aim was to have a very ambitious testing plan. Indeed, any component was required to be tested at full voltage and full current (but not always simultaneously). As a base case, we had defined that each component would at least undergo either a type test or a back to back test or a string test. In practice some components made two of the above tests.

Type tests did not reveal any significant issue according to our experience.

Our detrimental experiences during back to back or string tests have been to damage some auxiliary equipment such as:

- Bearing damages as well as minor scratches on shafts for motors, due to lube oil system failure,
- VSDS semi-conductor failure due to cooling issue and absence of temperature monitoring activation

Fortunately, we did not record any main equipment damage during such tests. But it enabled us to discover mechanical resonance issues [2].

As a consequence, it is recommended that a technical workshop is held prior to such complex test. It should determine all gaps (protection, auxiliaries,…) between string test and design case. When no gap is identified: validation of the protection setting and effectiveness of the configuration arrangement needs to be ensured. Then for each gap identified, additional precautions have to be defined, put in place and, last but not least: tested prior to the main test.

D. UPS

UPS are typically tested twice: during FAT and during onshore commissioning. As it is one of the most vital items, their readiness is usually needed before departure from yard.

The FAT limitation will typically be:

- Absence of batteries
- Limitation of load (often purely resistive and sometimes power limitation)
- Downstream distribution not present
- Twin item (when applicable) not available on the same bench for redundancy verification

This equipment will be one of the first to be commissioned. The challenges faced will be to:

- Perform the first battery charging while final HVAC system is not available
- Properly preserve this operating equipment in unclean environment (typically UPS have forced air cooling)
- Manage all safety by-passes
- Keep a daily vigilance on the insulation levels as the distribution is progressively put into service (valid for IT neutral management)

This last point remains actually valid throughout the complete commissioning phase (onshore and offshore). Keeping track of all activities is time consuming and tedious, but the very nature of UPS loads are to stay energized. Once a problem needs to be solved on the distribution side, the testing means are limited because shutdowns are difficult to achieve.

One of the unexpected issues we had to face during commissioning were internal design mistakes by our DC UPS supplier. As our internal practice is to be able to charge battery B with charger A (and vice versa) a N.O. coupler is installed between the two chargers. An electric interlock prevents the closing of this N.O. coupler in normal conditions. Our issue was that the polarization voltage used for the interlock was taken from both chargers without galvanic segregation. In normal configuration (two chargers in parallel and sharing the load), only one insulation monitoring system was on line, and no issue observed. However, every time we split the distribution network into two parts: the two insulation monitoring systems would be on line and disturb each other.

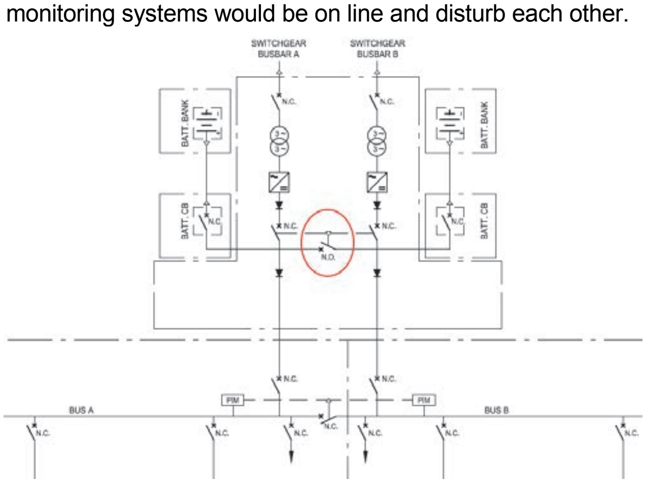

Fig.4: DC UPS configuration (circled interlocked CB)

Such kind of internal issue is actually quite hard to solve during commissioning as:

- First, UPS Vendor representative will come at very specific stages onboard and for a very limited time
- Second, the focus during commissioning stage will be the outer part of the package (i.e. the distribution)

This example, once explained, is actually quite obvious and banal, but the time between first identification of the issue and the complete resolution lasted over 6 months.

Our lesson learned regarding this particular item is that the FAT of UPS which work in a redundant mode with parallel operation and load sharing need exhaustive testing. FAT should not be the testing of two single units.

The reliability and availability of UPS is by definition paramount. With every project trying to capitalize on the lessons learned, we have observed that increase in the variety of architecture and other more subtle items. Even after start-up, operation and maintenance team are keen to make the design evolve to their priorities. Such evolutions do not always qualify as real improvement. Whatever the technology breakthroughs, we shall bear in mind that no single technical solution is the best answer to all priorities and choices need to be made. Once the priorities are clearly presented, it is possible to provide an optimal solution that may be updated later on when inputs are changed. In this regard, our Company objective is now to develop into more details a selection of architecture and to provide both design and operational guidance and selection criteria.

E. HV Switchgear

At switchgear FAT, it is common practice not to test the protection settings as they will be exhaustively tested during commissioning. In addition, the relay coordination and selectivity study has not always been finalized by the time equipment is ready to undergo FAT and shipped due to the yard construction schedule requirement. However, experience has shown us that there may be some protection inconsistencies such as the management of earth/tank protection of large transformers or earthing transformer unit protection (64 REF, 87G,…). Then, even if set points have not been finalized, it is recommended to test the operational logic of the protection (is the neutral current calculated by phase summation, is it directly measured,…).

With respect to this consistency requirement, End-User should promote that both design and commissioning team members attend the switchgear FAT.

VI. TESTING DURING OPERATION

A. General

Before the actual start-up of the plant, also known as “first-oil” the overall plant management is being transferred to Operation team. This is done to ensure the best safety level as the operation team will start enforcing their work permit system which is more complete than the one of the contractor commissioning team.

The work permit request becomes more formalized and stringent. One will need to apply for a work permit with a very complete and detailed work description and job safety analysis 48h before start of the job. It will systematically be reviewed and validated by the operation team. The start of the activity will be conditioned by the verification by Operation team representative that all people involved in the activity took part to the safety tool box meeting, that all required safety precautions have been implemented and that the CCR operators do not observe unplanned event or upset condition which would cancel or postpone the activity.

Hence there is a major change in the operational mode, the timing and the way of thinking and acting of the various teams. The work needs to be more explicitly described and one cannot modify its further actions in case the testing outcome is not as per plan without referring to the operation authority to indicate a change in scope. This change is absolutely not intuitive for the commissioning members who have proceeded otherwise for months. A significant effort in terms of awareness and training is required for Company, Contractor and Vendor’s team.

B. Production and Operation Constraints

Offloading is a major event for the production: it is the very reason for the plant to exist. Delivering the cargo in a marine environment can be critical at the early stage of the production lifecycle. The first offloading may be done while not all systems are in place. For instance.: the absence of offloading terminal / buoy will impose a tandem offloading with more exposure to risks and therefore more stringent safety monitoring, which will imply less work permit authorization due to manpower limitation and intent to limit disturbing events. Moreover the mobilization time of a tanker cannot be extended free of charge.

This will have a severe impact on all non routine activities: usually they are simply prohibited one day before the offloading is started and during the complete offloading sequence which can last from 18h to 36h.

Hence, considering the work permit request to be issued 2 days prior to job execution and that offloading will occur every five days, it is quite possible that 4 days in a week are days where the forecasted testing activities will remain on hold.

There is a dedicated process to manage simultaneous operation per area which will limit the amount of work and associated manpower that can be organized in a given time. As an example: hot work permits (such as outdoor welding activities) are limited in amount for the complete plant they require enhanced safety supervision that may prevent the electrical testing activities to be performed.

Another potential issue is the limitation of POB and its indirect consequences. The amount of people present on an offshore installation will be limited by two main criteria: the capacity of the LQ (number of available beds and meals that will be served) but even if this limitation is overcome with the use of a flotel, the means of evacuation (freefall boats, and availability of other boats in the close vicinity) will be another limitation factor. Again, this will limit the amount of activities that could be held in parallel and independently. But there is another side effect for such POB limitation: one individual will combine multiple roles: the crane operator may be also the helideck officer and he will not be available for crane operations during crew changes. The electrical maintenance supervisor may be part of the firemen team and will be requested for some special exercise and not be readily available to lock or un-lock the electrical feeder to the equipment you had planned for work.

Each of these internal constraints seen individually may not be so impacting, but the cumulated effect of all the above is actually extremely penalizing and is a significant reason for activities to be executed more slowly.

C. HV Switchgear

The power demand increase combined with the limitation of voltage levels due to weight and space optimization in the offshore environment, it becomes more and more common to find short circuit limiting devices using pyrotechnic technology [3]. These devices enable connecting more short-circuit capacity (i.e. more generators) to a switchboard than the short circuit withstand of that switchboard (either RMS and/or peak). The firing logic needs to be extremely fast in order to blow the cartridge, i.e. clear the fault, in a time which is typically less than a quarter of cycle (5ms at 50Hz). We have observed that the collateral effect of such speed is an extreme sensitivity of the firing logic that is sometimes triggered for no valid reason. Indeed we have experienced several times, in some particular cases of dead bus being energized, the short-circuit limiting device has blown one of its phases. While the physical explanation of this spurious was never really agreed between End-User and the OEM, the behavior (from commissioning team standpoint) is as described as follows: during energization with a very low connected load and a low short circuit capacity, upon the energization of the half busbar with the short-circuit limiting device was activated instantaneously, while the bus was fault free, and did not have any load being connected to it.

Our solution to this issue was to add an inhibition switch (standard feature for this kind of devices) that enabled us to energize the switchgear (and its short circuit limiting device) with a light load and a reduced power generation.

However our final lesson learned was to consider the automatic activation from the ECS in addition to the capability to manually activate the firing logic (i.e. automatic and manual activation operating in parallel). As we want to avoid relying on the sole human application of the procedure, but on the other hand we need to make sure that a safety feature does not only rely on the ECS whose primarily role is not to maintain safety and which is not designed according to our internal Company rules of a safety related system. And finally the ECS will also be recording the status of the firing logic at all times for post event analysis.

D. Power Generation Testing

It has to be made absolutely clear that in the case of “all-electrical” plant, the statement “full load testing will be done offshore” is incorrect. When the full load is reached, the production is ongoing and there is very little chance that the Offshore Installation Manager will let the commissioning team perform tests with high risks of tripping the GTG.

This initial statement may be applicable where the large machines (typically gas compressors and water injection pumps) are turbo driven and it is possible to reach significant loading before the production is ongoing, but for all electrical projects, this does not apply.

Practically, the onshore testing of the power generation will be split in two types:

1. What the operation team will allow
2. What the commissioning engineers can interpret and improve from real life event

As a general rule, it must be understood by all electrical engineers that from the production standpoint, electrical power supply is a utility: it has to be available at all times and testing with risks of partial or complete power outage are almost a taboo.

Significant pressure will be applied on commissioning team for the scope of testing, and to make things even worse, the less successful the tests, the less testing will be allowed.

Practically it takes all resources from technical authority at headquarters, down to maintenance team who wants to have the best possible knowledge of the GTG capabilities to convince Operation team to test the power generation.

Additionally, for such complex item, the Vendor mobilization is permanent, but unlike the onshore stage the main priority of the Vendor is now to demonstrate that its package is reliable, not to fine tune it.

As an example, it took over 6 months and two third parties audit to have the GTG Vendor representative improve the regulation so that frequency value would be completely recovered in less than 20s instead of more than 2 minutes after a 15% load impact:

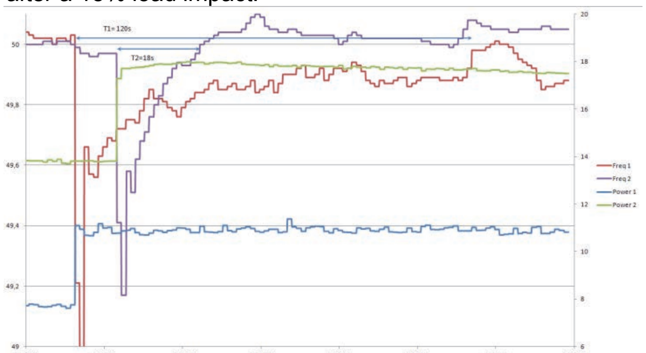

Fig.5: 4MW Impact - “Before & After” speed recovery

As a lesson learned, it is confirmed to be of prime importance in the Contract that the dynamic performance of the GTG is an acceptance criterion at the same level as its guaranteed output power and its reliability figure.

E. Large Drives

The large drives testing, was by far, the most traumatic we endured during commissioning. Some minor issues with relatively easy resolution were faced: as the internal cooling loop being inactive for a long time contaminated to a large extent the deionized water and we rapidly run out of all spares for the filtering cartridges of our converter.

But the main issue we faced was a motor generic design issue which impacted all our main drives (7 units) and was not identified during FAT. Our motor supplier had modified its rotor design: changing the rotor slots number which modified the natural frequency of the rotor lamination teeth.

This natural frequency would be found in the operational speed range of our drives, but it did not correspond to any guaranteed point and therefore went unnoticed despite our extensive upfront testing plan (FAT, back to back and string tests) described here above. However, on site, as we had to adapt to different conditions (changing gas flow due to increase of production level), we operated the drives on more set points and unfortunately it lead to motor damage within a few hundred hours of operation.

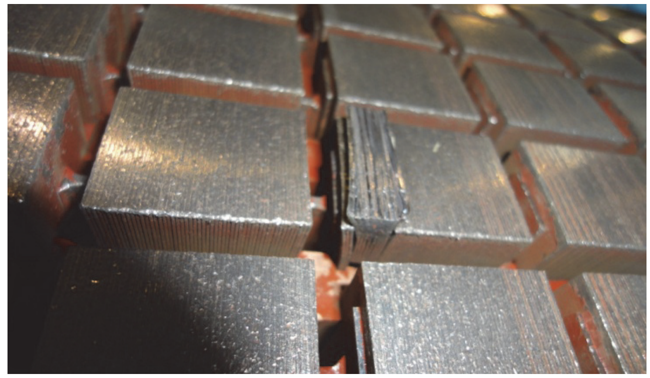

Fig.6: Broken rotor teeth exiting through the air gap

This issue had of course many impacts on the operation of our plant but it also slowed down drastically the electrical commissioning of other items (mainly GTGs and ECS) as more that 50% of the load became unavailable for testing. It shall be stated that despite the initial wrong design of the motor, our supplier did a lot of efforts to support us in overcoming this crisis.

The magnitude of the issues encountered and their associated impact have been so high that our internal lessons learned are still not finalized. The general trend is that we are considering major modification on our specification for design and testing requirement.

However some rules and practices already in place were strongly confirmed: our motor standardization policy enabled us to benefit from common analysis and solutions. Moreover, the common spare for identical motors was made available in a short time to perform tests and allow Vendor and End-User to validate and finalize the root cause analysis that would eventually lead to finding the corrective actions. Finally the spare motors as well as identical motors from another project on a less critical path were used for replacement campaign and helped reducing the impact on production.

F. ECS Testing & Operation

For various reasons the ECS item which was most tested during operation was the load shedding. As good as previous studies and simulations can be: it will not be possible to reproduce real life experience of a GTG tripping, followed by a load shedding sequence with further collateral trips due to process condition that are fully ignored by electrical specialist and sometimes not identified by the process and operation specialists. To summarize: the load shedding table will likely be modified after a few shutdowns along with the triggering set points.

The first real life load shedding experiences will be in a configuration which is not the full rated one. For items such as seawater lift pumps or air compressors which are usually in relatively large amount (sparing strategy of: 3x50%, 4x33%, 5x25%...) the fact that there is less machines in service combined with a static priority table may lead to total black out of the plant, because unfortunately the few machines that are running are on top of your list while the ones which were in the bottom of that list are actually stopped. This issue generated a strong internal feedback with direct consequences on the way we will specify our load shedding.

As a lesson learned, we decided to communicate with our most common ECS Suppliers in order to prepare a new feature in the load shedding sequence: the automatic reallocation of priorities to loads based on their running status.

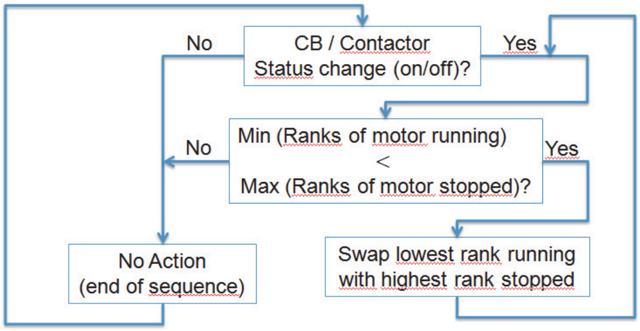

Fig.7: Load shedding table automatic configuration

Another item to be considered is the load shedding and its interaction with power generation dynamic response. According to our experience, the spinning reserve provided by the GTG UCP is not corrected by the load impact capacity. Hence it is possible that the theoretical capacity of the power generation would make believe that it can withstand the trip of one GTG, but in fact, the remaining ones will drop so much in speed (i.e. frequency) that the electrical protection will actuate before the GTG are able to recover.

Hence, it is required to have multiple events, either planned or coming from operational upsets to perform an analysis. The results are then used to properly fine tune the maximum impact capability of the GTG in conjunction with the under-frequency settings (both in time and amplitude) to ensure:

1. Activation of the load shedding sequence
2. Trip of less critical loads by protection relay
3. Trip of GTG by protection relay

in this order.

Initially, we had set all high voltage motors under-frequency protection with the same setting. After multiple unfortunate outcomes, we re-thought this scheme to stagger the disconnection of these loads for two main reasons:

1. If all HV loads are stopped at once, the GTG will rapidly trip because its utilities have been shutdown (no more air, no more cooling water…)
2. Even if the utilities were kept, they would represent a relatively low power demand. In case of a very large power tripped in one single event (e.g. all gas compression), the GTG would still undergo an over-speed that would again lead to a black out

Therefore, our lesson learned is that we may have a typical setting for motors under-frequency set point, provided that: depending on the amount of power and the service of the motors, different time setting shall be set. The basic rules for defining this time setting should be: longer than the load shedding triggering condition, but shorter than the GTG trip value.

Another lesson learned from the same experience is to implement correction factors inside the ECS to be able to adjust the real dynamic spinning reserve capability based on real life events. One should remember that unfortunately, this dynamic performance is not frozen once and for all and will evolve with the GTG ageing, the climatic conditions, and fuel type.

VII. CONCLUSION

The follow-up by one specialist of a project from the early design to the early production stage is one of the best ways to gain proper feedback on project and start-up execution. It also allows keeping continuity and trying to achieve the initial design intent whilst taking into account the external constraints that occur throughout the execution of a project.

This continuity should be extended by smooth coordination with commissioning team and eventually operation and maintenance team.

Despite the numerous issues presented, we remained able to achieve a smooth start-up and rapid ramp-up to plateau. This is one more positive argument to the credit of all-electrical concept robustness and it validates our strategy to keep a strong technical follow-up from throughout our projects' course.

These are key elements to the sound technical execution and the successful production of the plant.

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IX. VITA

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RESPONSIBLE PERSONS – ARE THE RESPONSIBILITIES FULLY UNDERSTOOD?

Paper No. PCIC Europe – BER - 45

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Abstract

In relation to explosive atmospheres, the IEC 60079 Standard Part 14 covers the Electrical installations design, selection and erection, with Part 17 covering the Electrical installations - inspection and maintenance in addition to the European legal requirements in the ATEX Directive 1999/92/EC (ATEX 137) that provide the minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres. Competency schemes are well established to assist employers meet their legal obligations under the ATEX Directive or appropriate in-country Regulation for Electrical and Mechanical Operatives/Technicians and Application Design Engineers, but what about the Responsible Person's competency - are these duties well understood across industry and do these Responsible Persons have access to the appropriate 'tools' to enable them to adequately carry out their responsibilities?

This paper will examine the scenarios where these responsibilities have been carried out inappropriately and in some cases contracted-out to third parties, leaving both the Responsible Person and the Employer exposed to enforcement action when there is an incident in the workplace. The difficult part is getting it right in a cost effective manner and being able to demonstrate a professional attitude to embracing the spirit of both the applicable IEC Standards and the ATEX Directives to maintain both a safe workplace and protect the expensive capital assets of the major user. The paper will provide direction to assist the Responsible Person conduct their duties in this manner.

I. INTRODUCTION

When it comes to incidents involving explosive atmospheres it can be in no doubt that the cost of “getting it wrong” can be devastating to victims, their families and communities. The wider issue of the environmental impact as well as the commercial cost and effects to companies and industry can be far reaching. The negative impact to capital assets, financial balance sheets and company and industry reputations can be felt long after the actual incident. One of the most significant and tragic events occurred on the night of July 6th 1988, when 167 men lost their lives during an explosion and resulting meltdown of the offshore Piper Alpha Oil & Gas platform in the UK sector of the North Sea. More recently the explosion at the Texas City Oil Refinery on 23rd March 2005 where 15 workers were killed and the Deepwater Horizon explosion and Oil Spill on 20th April 2010 which killed 11 workers illustrates the human cost of getting it wrong. The financial impact and damage to a company’s reputation can be no better illustrated than that of the Deepwater Horizon incident. Costs that run into the 10’s of billions of dollars have had a huge and long term impact that is still felt today and will be felt for many years to come.

Given that the impact highlighted above is so well known and understood it is somewhat surprising that the role of the responsible person is not well understood. Companies not only face the prospect of dealing with the human and financial effects but the impact of various regulatory bodies can be severe especially after a major incident. Whilst legislation should be adhered to, standards and industry codes of practice help companies and individuals meet their obligations in terms of protecting life, property, the environment as well as the financial balance sheet.

In Europe, two ATEX Directives [1] have been implemented that cover equipment and protective systems, intended to be used in hazardous locations as well as the safety of workers in these areas. The US has a comprehensive National Electrical Code (NEC) developed by the National Fire Prevention Association Committee (NFPA). The NEC is approved as an American National Standard by the American National Standards Institute (ANSI). It is formally identified as ANSI/NFPA 70, Section 5 lists the Special Occupancies and Articles 500 – 505 consider hazardous location electrical activities. The American Petroleum Industry (API) provides recommended practice for Design, Installation and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities; 14F for Unclassified, Class 1, Division 1 and Division 2 Locations as well as 14FZ for Unclassified and Class 1, Zone 0, Zone 1 and Zone 2 Locations.

Internationally, the International Electrotechnical Commission (IEC) is a leading global organization that prepares and publishes International Electrical Standards for all electrical, electronic and related technologies. The IEC 60079 Standard Parts 14 & 17 applies to classification of hazardous areas and installation & inspection requirements. It is imperative that the responsible person who helps protect the interests of the oil, gas, chemical and fuel industries understands these directives, standards, and recommended practices that are applicable, as well as is being able to correctly apply them to further enhance safety and protect the large capital investment assets of the major users.

When dealing with explosive atmospheres Annex A of the international standard IEC 60079-14:2013 [2] and Annex B of IEC 60079-17: 2013 [3] state in some detail the knowledge, skills and competencies of responsible persons but what of their duties under these standards? The general duties of the operative/technicians and designers appear to be well understood by most parties, indeed this is at least inferred in the actual title of the above standards in so far as part 14 covers electrical installations design, selection and erection and part 17 covers electrical installations inspection and maintenance. Clearly the designer will participate in or take a lead role in ensuring the design (including equipment selection) of any installation meet the relevant clauses of part 14. The operative/ technician on the other hand will subject to the design involve themselves in the equipment selection, and erection (installation) of the equipment. Referring to part 17 the operative/ technician may actively participate in the initial and subsequent inspection as well as maintenance post installation.

So what of the actual role of the responsible person? Annex A and B of parts 14 and 17 respectively state they should engage with the management of operatives covering selection, installation, inspection and maintenance duties. So what is management? Management of these persons will involve ensuring that individuals are competent and that they carry out their respective duties by following the requirements laid down in the standards.

The role can also be expanded to include the management of processes, procedures and documentation thus ensuring that the correct technical and organisational measures are in place to control the risks associated with explosive atmospheres effectively.

II. TECHNICAL PERSONS WITH EXECUTIVE FUNCTION

Given its reference in Annex B of IEC 60079-17 it is first worth clearing up a common misunderstanding as to the use of the term "technical persons with executive function". This term is often used to describe a person who has overall responsibility for inspection and maintenance activities. In fact this term only applies to persons who have responsibilities under the type of inspection "Continuous supervision by skilled personnel", i.e. where an installation is visited (and inspected) by skilled personnel on a regular basis in the normal course of their work. The role of "technical persons with executive function" is covered in some detail under section 4.5 of part 17 and not discussed further in this paper.

III. LEGAL ASPECTS OF THE RESPONSIBLE PERSON

The position of the responsible person is likely defined in legal terms as the responsibilities under the term employer as someone within a company's hierarchy must take ownership (responsibility) for a company's strategy and actions for the prevention of explosions. The term employer appears in numerous pieces of legislation. Examining the two ATEX directives we can see that the term employer is used to describe some of the general duties as well as some more specific requirements.

In Europe the ATEX "product" directive 94/9/EC[1] covers equipment and protective systems intended for use in potentially explosive atmospheres whereas the ATEX "user" directive 99/92/EC covers minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres. Taken from section II "Obligations of the Employer", Article 3 of ATEX directive 99/92/EC "Prevention of and protection against explosions" states:

With a view to preventing, within the meaning of Article 6(2) of Directive 89/391/EEC [4], and providing protection against explosions, the employer shall take technical and/or organisational measures appropriate to the nature of the operation, in order of priority and in accordance with the following basic principles:

- *the prevention of the formation of explosive atmospheres, or where the nature of the activity does not allow that,*
- *the avoidance of the ignition of explosive atmospheres, and*
- *the mitigation of the detrimental effects of an explosion so as to ensure the health and safety of workers.*

These measures shall where necessary be combined and/or supplemented with measures against the propagation of explosions and shall be reviewed regularly and, in any event, whenever significant changes occur.

More specifically and in terms of documentation Article 8 of directive 99/92/EC "Explosion protection document" states:

In carrying out the obligations laid down in Article 4, the employer shall ensure that a document, hereinafter referred to as the 'explosion protection document', is drawn up and kept up to date.

The explosion protection document shall demonstrate in particular:

- *that the explosion risks have been determined and assessed,*
- *that adequate measures will be taken to attain the aims of this Directive,*
- *those places which have been classified into zones in accordance with Annex I,*
- *those places where the minimum requirements set out in Annex II will apply,*
- *that the workplace and work equipment, including warning devices, are designed, operated and maintained with due regard for safety,*
- *that in accordance with Council Directive 89/655/EEC [5], arrangements have been made for the safe use of work equipment.*

The explosion protection document shall be drawn up prior to the commencement of work and be revised

[1] ATEX directive 94/9/EC is to be replaced in April 2016 by the new ATEX directive 2014/34/EU

when the workplace, work equipment or organisation of the work undergoes significant changes, extensions or conversions.

The employer may combine existing explosion risk assessments, documents or other equivalent reports produced under other Community acts.

IV. THE REQUIREMENTS OF THE RESPONSIBLE PERSON

Given that the requirements of IEC60079 parts 14 and 17 require the responsible person to possess a general understanding of relevant electrical engineering as well having the ability to understand, read and assess engineering drawings it stands to reason that the person must have an electrical bias, i.e. have come from an electrical background.

Not only must the responsible person ensure the competence of operatives/ technicians carrying out their duties under IEC 60079 parts 14 and 17 they must also ensure the effective management of the requirements laid down in these standards. These measures include technical measures that relate to specific protection concepts assigned to equipment, systems as well as the organisation measures required to control and administer them. The role can be further expanded to include hazardous area classification where the release (leak) of flammable material such as a gas, vapour, mist or dust is categorised into zones based on its frequency and duration.

A. Hazardous area classification

Hazardous area classification is used to identify places where, because of the potential for an explosive atmosphere, special precautions over sources of ignition are needed to prevent fires and explosions. Hazardous area classification should be carried out as an integral part of the risk assessment to identify areas (places) where controls over ignition sources are needed (hazardous areas) and also those places where they are not (non-hazardous areas).

Hazardous area classification is covered under Article 4 “Assessment of explosion risks” of ATEX Directive 99/92/EC as well as specifically required under Article 7 “Places where explosive atmospheres may occur” and Annex I “Classification of places where explosive atmospheres may occur”. Hazardous area classification is outlined in standards IEC 60079 parts 10-1 [6] and 10-2 [7] covering explosive gas and dust atmospheres respectively. It is also covered under a number of publications (codes of practice) such as EI15 [8] and IGEM/SR/25 [9].

Area classification is an activity that should not be carried out in isolation from others; it should be carried out as a team exercise where it is highly likely that the lead for such a team is a process safety engineer or other such specialist individual. The role of the responsible person here is to play an active part in the group discussions be it an initial/ periodic study or a review prompted by a plant modification. The results of this study displayed as an area classification drawing showing the type and extent of the zones, relevant equipment protection level, gas/ dust group and temperature classification as well as any supplementary information such as reports or schedules are of infinite importance as, forming part of a plants ‘basis of safety’ this will drive future equipment design and selection as well as subsequent installation, inspection and maintenance techniques and activities.

B. Electrical installation design, selection and erection

The duties of the responsible person as discussed previously will involve the management of competent persons carrying out design, selection and erection (installation) activities. The knowledge, skills and competencies of these individuals should be aligned with the requirements of Annex A of IEC60079-14:2013. Adequate training should take place alongside competency validation which has been internationally accredited to a recognised standard covering the certification of persons, i.e. ISO/IEC 17024:2012 [8]. Training and competency validation should also be refreshed on a regular basis and therefore the responsible person should be responsible for the management of any personnel records as well as the mechanisms adopted to prompt such refresher training.

In terms of the activities associated with installation design, selection and erection then the responsible person should ensure that the relevant standards are being followed and that the documentation required ensuring compliance is recorded and retained for future reference. IEC 60079 parts 14 makes specific reference to the verification dossier that records information on the site, equipment installed as well as the actual installation. Here, specific reference is made to information such as hazardous area classification details, external influences and ambient temperatures, manufacturer’s information, certification, intrinsically safe system documentation, wiring diagrams, drawings and schedules, etc. The responsible person should also ensure that the initial inspection is completed post installation and prior to first use and that this information is also contained within the verification dossier.

How initial inspections are handled is also of prime importance as key decisions can be made at the on-set of any project through effective management. Inspecting and recording the information should be an integral part of a projects installation, commissioning and handover activities. Missing documentation can hinder the efficient progress of inspection activities therefore clear instructions and requirements for the type and format of any documentation should be agreed at an early stage between groups such as design, construction, commissioning and operations.

Effective planning and auditing can help with the transfer of information between all parties involved. The timing of initial inspections should also receive careful consideration so that equipment covers go undisturbed post initial inspection.

Creating an asset or “Ex” equipment register is also a vital part of the initial inspection process. Sufficient information should be recorded against every item of equipment installed whether it is in the hazardous area or outside the hazardous area but performs a safety function on equipment and systems inside the hazardous area. Without the equipment register sites may not know what equipment they have installed making future inspections and on-going maintenance impossible to manage accurately. This could lead to equipment going undetected and therefore increasing the risk of introducing hazards into the workplace through poorly maintained and potentially dangerous equipment.

C. Electrical installations inspection and maintenance

The duties of the responsible person will be similar to those duties imposed under design, selection and erection in so far as the knowledge skills and competencies of the operative/ technician. The specific requirements associated with inspection and maintenance is described in Annex B of IEC 60079-17:2013.

In addition to these requirements the duties of the responsible person also covers the type, grade and information recorded as part of the inspection. Initial inspections should already have been completed prior to first use therefore the main focus here will be on the grade of inspection be it visual, close or detailed as well as time between periodic inspections including any sample inspections required. Inspections are not set for the life of the installation and the responsible person should review the results of the inspections in order to inform themselves whether the frequency and grade of inspection including that of sample inspection needs to be amended. Annex A of IEC 60079-17 provides a sample flowchart that provides guidance on how periodic inspections including sample inspections can be managed.

Remedial repairs that result from the inspection also need special consideration. Regulatory authorities are increasingly examining the way inspections are assigned and how subsequent remedial repairs are handled. It is not acceptable simply to stack up the repairs and adopt the "top of the pile" approach where the next repair on the list is tackled with little regard to the type of fault and how serious a risk it poses. Regulatory authorities are looking for a "smart" approach where inspection results are reviewed and frequencies and grades of inspection amended dependent upon the results. Remedial repairs are also ranked and therefore tackled in order of risk. Factors such as the type of plant or facility, i.e. the consequence of a hazardous event, the hazardous area zone, protection concept and whether a piece of equipment is ignition capable all need careful consideration. Other factors such as the type of fault as well as environmental effects will also play a part in the decision making process of how to risk rank repairs.

Resources assigned is also a major factor as to few can often mean that inspections are not completed in a timely manner resulting in potentially serious faults going undetected. Assigning insufficient resources to remedial repairs can also have a similar effect in so much as repairs are not completed in a timely manner and that repairs including those of a serious nature are not closed out between inspections.

D. Management of competence

What does competency mean? The Regulatory body in the UK, the Health and Safety Executive state in their COMAH [9] operational delivery guide: "*Competence means the ability to undertake responsibilities and perform activities to a relevant standard, as necessary to ensure process safety and prevent major accidents. Competence is a combination of knowledge, skills and experience and requires a willingness and reliability that work activities will be undertaken in accordance with agreed standards, rules and procedures".*

The most important aspect is that any competency validation of Operatives/Technicians and Application Design Engineers is conducted by third party organisations, totally independent of the major users. The Certification Body must be accredited to an International Standard IEC/ISO 17024: 2012 - Conformity Assessment – 'General requirements for bodies operating Certification of persons', to ensure the validation process meets an agreed international standard and not just an interpretation of requirements which could introduce variability.

By meeting the requirements of this International Standard, a company who send employees or direct contracting staff to attend competency validation courses, do so safe in the knowledge that there will be a uniform, structured approach to the validation process worldwide and that variability from different course providers will not occur. The Certification Body must have access to Technical Experts who fully understand the scope of IEC 60079 Parts 14 & 17 and continue to develop the courses in line with the ongoing revision of the International Standards.

It is the advancement of standards, equipment, workplace area, systems design and management and the technical understanding of practitioners who install, maintain and inspect equipment that will change over time. Without recognising these changes, more variability can be introduced and weak links will start to appear again.

Whether it is design, installation or inspection and maintenance utilising external organisations to provide such services can be fraught with risk if this process is not managed carefully. Not only should the competency of on-site staff be examined but careful scrutiny should be exercised as to the level of support and supervision they receive. Enquiries as to methodologies employed for inspection and the quality systems in place to support it such as ISO 9001 [10] are obvious questions. What about technical support? Having access to the correct standards as well as supporting documentation is an absolute must. Having senior staff available for technical guidance and support is also required. Supervision can vary dependent upon the type of site, level of knowledge, skills and experience. Clearly someone with a high level of knowledge, skills and experience will require less on-site supervision than a new employee.

So how is the process managed? Training and competency records should be retained and a frequency of refresher training and validation decided upon. For "major" sites this documentation should form part of a quality system approach such as ISO 9001 and as such form part of a Competency Management System (CMS). Ultimately the CMS should be integrated into or form part of the Explosion Protection Document (EPD) which in turn may form part of a sites overall Safety Management System (SMS).

E. Outsourcing responsibilities

Outsourcing the role of responsible persons should be given very careful thought and consideration. It should be remembered that the employer has overall responsibility regardless of what has been outsourced. Competencies need to be checked and verified against an agreed benchmark. Holding basic awareness training even with some form of basic validation is hardly enough when addressing the requirements of the responsible person. Qualifications including competency records, verifiable experience and endorsement are all aspects that require consideration.

Ultimately whoever is employed should be subject to regular discussions and even auditing to ensure that the correct philosophies and practices are being followed. Remember outsourcing does not remove blame from the employer should things go wrong!

V. CONCLUSION

A company's legal obligations are set out under the ATEX directive 1999/92/EC supported by the requirements set out in standards such as IEC 60079-14 and 17 as well as other related standards such as IEC 60079-10-1 and 10-2. The employer should therefore be aware of the duties required under these regulations and standards and ensure that persons have been identified to take responsibility for its effective management as well as implementation.

Ensuring that all persons who play an active role in achieving a safe site and therefore business cannot be underestimated and here the Responsible person must be aware of their own competency requirements as well as those of any supporting persons such as engineers/ designers, technicians and operatives.

Documentation and the ability to manage this via a quality driven process is key to its effective management providing an auditable trail that can satisfy regulatory authorities as well as acting as a measure for continual improvement.

Outsourcing various roles is an option but one that should be given very careful consideration as the employer cannot remove their own legal responsibilities set out under the term Responsible Person. Being the 'intelligent' customer is key here where an organisation possesses a very clear understanding and knowledge of the service being supplied and is able to lead not follow the activities provided by the service provider.

Neglecting to identify a person or persons as the responsible person or worse simply ignoring the role all together is fraught with risk and can compromise a company's ability to operate a site safely and effectively. Further to this, failure to act puts a business at risk from being able to operate as the repercussions from an incident could affect a company's value as well as reputation. Legal proceedings by the regulatory authorities such as enforcement notices and even prosecutions could also prevent a business from operating.

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VII. VITA

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IEC 61850-based EMCS training simulation tools ensure operational efficiency and peace of mind.

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Abstract - Power system in Oil & Gas Installation requires complex and automated Energy Management and Control Systems (EMCS). Operators use different control systems (DCS, EMCS…) using different HMIs and Intelligent Electronic Devices (IEDs), controllers, sensors. Remote and actual site learning is usually not feasible, and certainly not during abnormal or crisis scenarios.

EMCS architecture is composed of a hierarchy of various communication network topologies. Software-based simulation tools offer a very effective way to better understand system behaviour. Simulation can be done in two ways- Emulation which is replacing the actual devices with on Communication Simulation and Excitation which is injection by hardware simulation. Simulation can emulate most electrical data and control by emulating IEC 61850 protection or LAN concentrators. A selection of IEDs can be activated by simulated embedded hardware that allows (while keeping coherency of electrical data) to learn real IED maintenance or setting operations. A limited set of IEC devices are often used, including an EMCS HMI, DCS gateway, central automation such as iFLS, iPMS, and black start, in order to exactly replicate site behavior, settings and maintenance procedures (such as patch management, upgrades, or site evolution).

This paper presents an Operator & Maintenance Training System (OTS & MTS) solution. Its inner basis is a site EMCS IEC 61850 System Configuration Description (SCD, according to IEC naming). In EMCS simulation set-up, IEDs can be physically replicated then can be excited physically if needed, or emulated (replaced) in communication network for the majority of time. Simulator reacts to direct control or automation settings reactions in case of contingency. A trainer can specify multiple sets of electrical data and initial status, schedule events, or re-inject captured IEC data exchange of current real project EMCS. This paper describes this top-down approach of simulation and solution modularity required by end user, from real to and emulated IED, and from simple electrical behaviors to real-time dynamic load flow injection.

1. Challenges with EMCS and other control systems

Industries worldwide are striving toward more connected, more efficient, and more distributed operations. Apart from these needs, energy optimization is also targeted. The ever-present challenges of this industry include safety and continuous operations with the use of technology and processes aimed at energy optimization. In addition to ease of maintenance and the flexibility necessary to upgrade solutions, end users seek to reduce ownership and maintenance costs.

To manage energy and meet expected outcomes, various control systems are used – electrical, process, safety, and security control systems. EMCS is one such control system that provides a complete electrical system overview and helps ensuring maximum energy availability to critical loads, thus an uninterrupted process.

Due to the criticality of electrical energy for processes to run bumpless; the efficiency of EMCS operation is extremely important. It integrates switchgears at different voltage levels (LV/MV/HV) with a generation system and has IT/OT convergence.It has power management functionalities (load shedding, load sharing, etc.) for demand and supply management of energy needs. Because technology is evolving and systems and equipments are becoming increasingly connected, operators want tools and systems to support the optimization of CAPEX and OPEX.

The motives and drivers behind meeting these challenges are to save time (commissioning, start-up) and expenditure (reduction of total cost of ownership) by expanding system and device knowledge and readiness and with the practice of various contingencies.

EMCS training via simulation provides one option to respond to these challenges.

2. What can simulation do for operators?

Operator Training System (OTS)

The domain expertise of an electrical system provider, and convergence of IT/OT with the use of relevant technology, can significantly help end users by adopting simulation.

The first and most important aspect is training and building operator confidence in EMCS, so that human error is minimized. This can be referred to as the Operator Training Simulation and can also be part of simulation for testing and maintenance personnel.

OTS is a key solution to deploy energy-saving control strategies and improve sites' energy performance by letting the personnel in charge of site operation acquire and retain a high level of experience and expertise.

It presents an easy-to-use software application that simulates real site situations in a safe, non-energized (offline) environment to learn, practice, and improve EMCS users' operational aptitudes.

OTS leads to safe and efficient operator performance that benefits users, workers, and the overall profitability and productivity of the company.

2.1. Actual project replication

Simulation of the same single line diagram as an electrical distribution system with the same power management settings (i.e., priority and contingency for load shedding, spinning reserve requirements) gives an experience of existing operation. It trains and builds confidence in the operator about full system awareness. By simulation, operators can also learn how to use graphical user interfaces (GUIs), navigation, alarm and event handling, and control procedures. The linkage of dynamic simulation enables end users to simulate real-time power system disturbance mismatches in demand and supply, and prepares operators to confidently address those eventualities. An end user can have not only a complete system replica but also IED replica.

2.2. Solution simulation

Simulation can be performed in different ways:

- By emulating devices or solutions-Replacing actual device by Communication Simulation.
- By excitation - Hardware stimulation or excitation by forcing some values.

Both options can give end users different experiences and more knowledge to tackle any eventualities. Emulation is simply replacing actual equipment and keeping the same replica by using IEC 61850. IEDs can be emulated by following IEC 61850 definitions of their functionalities.

Alternatively, a system's performance can be stimulated by injecting values through hardwired I/O and creating scenarios as close as possible to the real case.

2.3. Configurable scenarios

End users can leverage the flexibility and learning experience the simulation can provide. Therefore, the more customizable the simulation solution, the more realistic the experience and the better the operator can relate to the system during actual scenarios. The key element is to have the use case scenario configurable by the user.

3. What can simulation do for maintenance engineers?

Maintenance Training System (MTS)

MTS is a simulation solution for training field engineers on real devices to prepare them for safe and accurate operations in an actual electrical network. This simulation takes place by injecting electrical analog (CT/VT) values.

MTS software allows for hands-on training with real IEDs that are identical to plant devices. Engineers can therefore obtain experience and expertise prior to working with real installations.

MTS allows better scheduling of maintenance operations and a reduction of downtime, which results in greater efficiency and significant cost savings.

3.1. Real-time, dynamic, post-mortem analysis and study of IED settings/parameterization

IEDs or numerical protection relays form the center of electrical power system networks. Technology is driving toward one-box solutions capable of performing control, monitoring, protection, and analysis. Simulation capable of changing and emulating IEDs can train operators and maintenance engineers to use IEDs to their maximum potential (settings optimization). Unfamiliarity with devices limits their use to a basic minimum, and any electrical disturbance or inappropriate operation or circuit breaker tripping cannot be effectively diagnosed. Specific tools can help to capture network data to be replayed on emulated IEDs in a safe environment to facilitate post mortem analysis and diagnose the disruption root causes.

3.2. Real life contingency analysis and load flow solutions

The closer simulations can bring operators and maintenance engineers to real environments and operating conditions, the higher the impact. Simulations should include an exact replica of the installed electrical network, simulate it, create scenarios of fault and contingency, and demonstrate the impact on the demand and supply of electrical power. This can be extended to analysis of complete load shedding, load sharing, and restoration of the system in a simulated environment of changing priority, contingency, and islanding scenarios. The operator can gain expertise by becoming deeply familiar with the IED by utilizing IEC 61850 logic node definitions and attributes and identifying IED parameters for protection. Power system behavior (i.e., due to contingency generation vs. consumption) and complete flow analysis in a simulated system can be performed. Such elements can increase operator confidence.

3.3. Capture communication between devices and scenario reproduction

Ideally the simulation should provide the flexibility to recreate scenarios to investigate site data between devices and reproduce any contingency condition or abnormal situation. IEC 61850 functionality, e.g., GOOSE, can allow a high-speed communication Capture action between various devices, making diagnosis and analysis very easy.

IEC 61850-based simulation allows the spread of a massive flow of data coming from IEDs, PLCs, servers, etc. In the case of failure or post-mortem analysis, data must be presented to electrical and system engineers in a way that facilitate this complex cross analysis, mixing electrical, operator, and EMCS system data. To help, all components are synchronized and all data are time stamped at the source.

3.4. Scenarios with and without hardware injection

In some cases, simulation will be limited to software emulation for operator training. The real EMCS uses some components that can be easily plugged into the simulated environment. The goal is to validate the impacts of any modifications prior to deployment on site:

- Algorithm modifications
- Cyber security and patch management
- Firmware and software updates
- Server replacement
- IED setting modifications
- Fast load shedding priority changes
- Etc.

3.5. Ability to accept load flow analysis software from any vendor

The Simulator is not using its own predefined reflex value, but results of load flow computation. We feed the value of circuit breaker status, position, etc.

The Load Flow software is fed by EMCS simulator with the current breaker values using an OPC Link. Load Flow software computes dynamic value and return to EMCS simulator accurate analog values and possible threshold, e.g. trip. From the EMCS HMI, operator can control any circuit breakers, and the simulator transmits the new dynamic load balance situation.

The combination of these two bricks allows the implementation of:

- "What if" feature.
- State Load Estimator (SLE) feature.

"What if" helps operators control the plant. The sequence of operations can be reproduced in a simulated mode before being carried out on the plant. It prevents any misuse and/or electrical collateral disturbances.

A State Load Estimator feature can raise alarms when real measurements are too far from simulated values. It helps operators make decisions during abnormal circumstances and maintenance people replace critical sensors.

4. The solution

4.1. A simulation solution based on a set of exact replica/ copies of EMCS IEDs

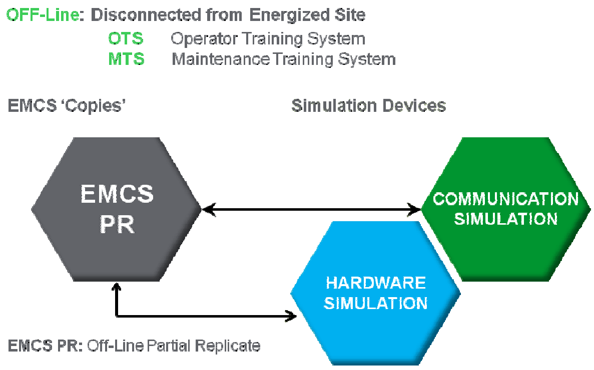
As previously pointed out, simulations can be of two types:

1. Emulation of missing IEDs over EMCS LAN, by communication means.
2. Excitation of existing IEDs by hardware or by communication means.

The second case requires an OTS to have some real IEDs as "copies" of those on site. Choices can be made during implementation of a simulation solution to compose it of:

- Exact "copies" of site EMCS IEDs, as EMCS partial replicate.
- Simulation devices as Communication Simulation and optional Hardware Simulation.

"Copies" (also called "replicated" and "duplicated") are exact "spares" of those on site, with the same hardware, software, configuration, and settings. The IED copy is powered and behaves exactly as the one on site because simulation can place the same site excitation value on its interface (and inject all kinds of signals, including CT/VT). In the case of maintenance, it is then possible to practice on IED site settings to learn and to reproduce reactions. In a second stage of maintenance actions, it is possible before site implementation to test any new patch: hardware, operating system (OS), software version (evolution or correction), configuration, or setting.



Global Simulation

Whatever the simulation type the "copy" of the EMCS project must be replicated in the simulation environment. This simulation environment uses the actual EMCS project database without any rework.

EMCS HMI replicate is mandatory in OTS to be comfortable with electrical operating sequences.

For MTS, HMI is useful to check all IED system interfaces (communication signals, remote setting, administration, synchronization, disturbance recording, and all mass archiving).

For advanced electrical control functions, the simulation environment contains an "exact replica" of IEDs managing automation logics (iFLS, Load Sharing, PMS, ATS, etc.). It allows reproducing the exact reactions in the simulated environment as it applies on the plant in real time.
Then, depending on budget, and especially for maintenance purpose, we recommend creating a "duplicate" of the IEDs of each range (protections, meters, etc…).

4.2. Simulation device interface to EMCS IED: Communication Simulation

The simulation devices can act via communication means or hardware signals that define two main devices: Communication Simulation and Hardware Simulation
Nowadays an EMCS is composed of several LANs to reduce inner communication traffic, possible congestion, cyber risk against intrusion, etc. The EMCS LANs commonly use Ethernet with IEC 61850 protocol. The Communication Simulation device can operate with several Ethernet boards to act on several EMCS physical

LANs (validated with up to 4 physical LANs). This feature can be degraded to operate using VLAN and a single Ethernet board. Ethernet switch boards can be embedded when required to handle various Ethernet redundancy cases, and to study specific aspects of this transmission layer.

The Communication Simulation device mainly uses the IEC 61850 protocol. Two IEC tasks are used depending on the selected simulation. When Communication Simulation emulates/replaces an IED, it uses an IEC server task to publish all data that the replaced IED could have exposed (with report and GOOSE). When Communication simulation captures/sends control to the IED "Copy"/"Duplicate", it uses a second IEC task called IEC Client to subscribe to the IED data set, and optionally sends control to the IED. Both IEC tasks are based on real EMCS IEC 61850 SCD (System Configuration Description). For example, in simple OTS, there is an exact replica of the EMCS HMI and a Communication Simulation that emulates via up to 400 IEC server tasks and all possible IEDs on various LANs (some of the emulated IEDs like gateways are a concentration of data normally provided by sub-LAN or legacy network). Separate tasks are selected for modularity and the possibility of generating degraded exploitation cases (killing or disconnecting specific IEDs).

The Communication Simulation configuration should be based not only on IEC specific but also on electrical labeling.

4.3. Simulation device interface to EMCS IED: Hardware Simulation

Hardware Simulation is the second main simulation device– the device interface part. It provides physical input and retrieves output from the related "Copy" of the EMCS IED. Based on a PLC, it can provide time-tagged hardware excitation to the created EMCS IED, and retrieve time-tagged responses.

We have two ways for simulation – Emulation is the most common, also the Communication Simulation should log everything that happens in hardware or communication simulation, and trigger all actions in both types of simulation.

Communication Simulation should have several independent LANs to be replica in real site implementation.

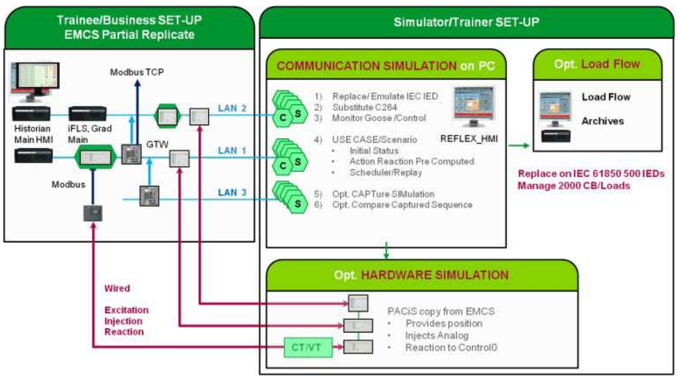


Figure 2 Offline Simulation Architecture

Simulation needs to log operator actions, and store IED reactions. This monitoring can be split in two: file archives and runtime operator log displays. All logs contain electrical naming and communication addresses (IEC 61850).

File archives contain standard logs (everything seen or done in Communication Simulation), specific GOOSE archives, and operator can export archives in csv, html and COMTRADE (only for goose data).

The main HMI contains two working areas. The central one is always displayed. The second allows data filtering (input on the left of the browser, output on the right) or manually generated output changes (status change of emulated IED, control on present IED).

The operator's HMI log display and the browser can be switched during runtime from electrical context to IEC 61850 modeling context (In OTS and MTS, electrical naming is normally used because it displays the same names as those used in the EMCS HMI "copy" used by trainee. Whatever kind of display (electrical or IEC), tooltips provide complementary information (IEC or electrical).

Three logs are used - Action/Reaction, goose_Spy and SOE. All cells of these logs can be exported or copied to an external editor (text or Excel) for reporting. The Action/Reaction viewer logs each computed event, inputs, and outputs. The goose Spy monitors all goose exchange between IEDs.

A double naming is used to cover operator skill (Electrical or automation based on IEC61850).

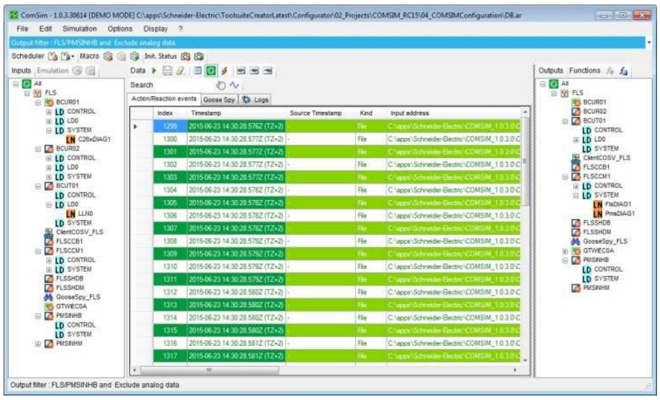


Figure 3 HMI General View

The principle of Communication Simulation is simple. Via appropriate configuration, when there is an action (input) there is a reaction (output). One input action can trigger several outputs. One output status can be triggered by several inputs.

An important part for running an OTS/MTS is the scenario part called Use Case. The Use Case is defined by:

- Action/Reaction.
- Initial Status.
- Scheduler.
- Or combination defined by macros.

To help the trainer, the dedicated HMI (especially in electrical mode) can be used to define new initial status or via “Activity” to define the sequence of events that the trainee should handle. Globally, this user friendly way to configure new scenarios allows direct use of the configured Communication Simulation without special training.

All scenario files, action/reaction (as configuration), initial status, scheduler (as Activity) should be defined in a readable format e.g., csv formats for easy flexibility of scenario generations.

For electrical engineers, the electrical data is mapped to several communication addresses (main, back-up computer, or protection device, in one LAN or above a LAN concentrator). In order to face this redundancy, the LAN/IED names appear below the electrical name in the browsers when such acquisition redundancy appears.

4.5. Enhanced Load Flow Computation: Process and Analog Simulation

Basically, the previous simulation devices are specialized in interfacing with EMCS. They use predefined action/reaction and pre-computed analogues, not accurate in complex simulation (but sufficient in common trainings).

Process and Analog Simulation is a complementary component in charge of electrical dynamic computation and all load flow variation. In an OTS, the trainee is active and sends controls to simulated primary devices and their controlling IEDs. It could also be exciting to introduce contingency to the test operator and system reactions. In both cases, the electrical topology is changed then, load flow is also changed.

- o Subscribe (report/GOOSE) to capture data.
- o IED communication reactions.
- o Optionally, send control/settings to replicated IED via communication.
- o Optionally, act on the simulation hardware device to change/react to actual IED hardware configuration.

Communication Simulation uses several LANs, EMCS labeling, and handles IEC tasks via EMCS SCD files. A configuration tool running in Excel is used to configure Communication Simulation first, but also links to hardware simulation and Process and Analog Simulation.

Several load flow software applications can be used as long as they use a communication interface. Such dynamic configuration is complex engineering as it is often hard job to select the correct model and then identify the exact parameters of the electrical data. Two families of load flow software can be considered with short circuit analysis software (used to define protective IED settings) or enhanced process simulators (including electrical and industrial process dynamic).

5. Conclusion:

The OTS, MTS, and the Dynamic Simulation Solution enable users to optimize both CAPEX and OPEX. Trained and up-skilled operators and maintenance engineers contribute to an enhanced operational efficiency.

***<u>OTS Benefits</u>*:**

<u>CAPEX Impact</u>:

- Increased operational efficiency ensuring increased asset efficiency.
- Increased safety and reduced risk.
- Optimized electrical distribution management.
- Confidence building for future projects.

<u>OPEX Impact</u>:

- Operator skills enhanced with full knowledge of the EMCS capabilities - efficient operation.
- Shorter turnaround time impacts on operation.
- Faster and on-time operator reaction.
- Shorter commissioning times.
- Minimized operator turnover impact.

<u>MTS Benefits:</u>

<u>CAPEX Impact</u>;

- MTS is the simulation solution designed to train field engineers and prepare them for safe and accurate operations in the actual Electrical Network.
- Initial start-up costs are reduced with awareness of IEDs, their parameterization and the system.
- Increased safety and reduced risk by familiarity with IEDs.

<u>OPEX Impact:</u>

- Engineers’ skills are enhanced with full knowledge of EMCS capabilities.
- With MTS, maintenance operations can be better scheduled as well as downtimes reduced, resulting in greater efficiency and significant cost-savings.
- Faster and more efficient testing and maintenance.
- Shorter or eliminated production downtimes.
- Minimized field engineer turnover impact.
- Problem analysis.
- Evolution testing and corrections.

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Glossary

ATS
Automatic Transfer Switch.

CB
Circuit Breaker
Specific dipole switches with the capability to power on and break on fault current. Some have not isolation capability (nominal-ground at each side).

CT/VT
Current Transformer / Voltage Transformer.

DCS
Distributed Control System.

EMCS
Energy Management and Control System.

HMI
Human Machine Interface.

HV
High Voltage.

IED
Intelligent Electronic Device.

iFLS
Intelligent Fast Load Shedding.

IT/OT
Information Technology/Operational Technology.

LAN
Local Area Network.

LV
Low Voltage.

MTS
Maintenance Training System.

MV
Measurement Value.
Medium Voltage.

OS
Operating System.

OTS
Operator Training System.

PLC
Programmable Logic Controller.

PMS
Power Management System.

SCD
System Configuration Description: An IEC 61850 term for a file containing descriptions of all IEDs including the configured data flow and needed DataTypeTemplates, a communication configuration section and a substation description section.

SLE
State Load Estimator.

VLAN
Virtual Local Area Network.

ADVANCES IN MOTOR PROTECTION RELAY FEATURES

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Abstract—The algorithms used by numerical relays in motor thermal protection accurately simulate the characteristics of the motor. These algorithms use the motor speed to calculate rotor heat. This results in proper starting for high-inertia loads connected to motors and minimizes the cooling time, providing quicker restarts. These algorithms are performed in a numerical relay that also performs logging and plotting of starting characteristics. An accurate record of motor performance can therefore be obtained, providing an indication of possible motor failure. Broken rotor bars cause reduced accelerating torque, increased motor heating, and increased vibrations, which can inflict severe damage on a motor. Modern numerical motor relays monitor the stator current spectrum for frequency components associated with this phenomenon and use motor current signature analysis to detect broken rotor bars. For added safety, these devices can also include arc-flash protection, allowing faults in the switchgear to be quickly detected and cleared.

Index Terms—Motor protection, thermal model, arc-flash protection, broken rotor bar.

I. INTRODUCTION

Electric motor systems account for about 60 percent of global industrial electricity consumption [1]. They are fundamental to industrial processes. An undesired operation of the system protecting the motor can lead to substantial economic losses and may even compromise the safe operation of the plant.

The main function of industrial electrical power systems is to provide energy for these electric motors. Motors are subject to faults and abnormal conditions that can cause extensive damage. Motor damage can cause delays in industrial processes, with corresponding economic losses. For this reason, a reliable motor protection system is fundamental for increasing the reliability of industrial processes. This paper discusses key elements of creating a reliable motor protection system, including thermal modeling, the detection of broken rotor bars, and arc-flash detection.

Thermal protection is required to detect and protect electric motors against abnormal conditions like overload, locked rotor, frequent starts, unbalance, low-voltage operation, and others.

Installations using electromechanical relays have limited or no capabilities to accurately track motor heating conditions. In the case of large industrial motors, only numerical relays or intelligent electronic devices (IEDs) with special algorithms are able to adequately simulate actual rotor and stator thermal conditions. Modern numerical relays are the natural choice for retrofit applications, and they offer many improvements over electromechanical or static relays. These enhancements include improved thermal modeling of motor heating, event reporting, sequential event reporting, motor start reports, motor operating statistics, additional protection features (such as the detection of broken rotor bars in induction motors), and additional control functions (such as synchronous motor starting). A comprehensive thermal model that precisely represents motor heating is discussed later in this paper.

According to surveys performed by the Electric Power Research Institute (EPRI) and IEEE, 5 percent of motor failures happen because of problems in the rotor cage [2]. Early detection of a broken rotor bar is very important to minimize motor damage and reduce the time out of operation, which consequently reduces repair and operation costs. The broken-bar condition can be initiated by a fracture at the junction between the rotor bar and the end ring as the result of thermal and mechanical stressors. Motors with high-inertia loads are more susceptible to a broken rotor bar condition when starting [2]. Motor current signature analysis (MCSA) is the most popular method to detect rotor cage faults and is discussed later in the paper.

There are ten Occupational Safety and Health Administration-reportable (OSHA-reportable) arc-flash incidents every day in the United States [3]. In addition, up to 80 percent of all electrical worker injuries are due to external burns created by the intense radiant heat energy of an electrical arc flash [3].

Arc-flash detection sensors provide a cost-effective method to reduce arc-flash energy by minimizing detection times. High-speed light detection combined with high-speed overcurrent element supervision and high-speed output contacts can provide a dependable, secure, and fast method for tripping. This, in turn, can contribute to reducing damage to equipment and significantly increasing personnel safety. Numerical motor relays can use multiple sensors for arc-flash detection. The most common sensors are lens-point sensors and bare fiber-optic sensors.

II. THERMAL MODELS

A. *Motor Thermal Limits*

The thermal limitations of induction motors are specified by thermal limit curves that are plots of the limiting temperatures of the rotor and stator in units of I^2t, where I is the positive-sequence, balanced stator current for a three-phase motor and t is time. The curves for a 7,000 hp, 6.6 kV, 900 rpm motor are shown in Fig. 1.

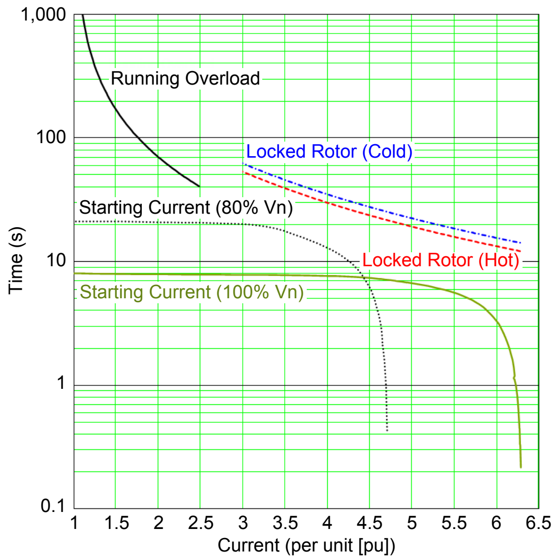

Fig. 1 Thermal limit curves for a 7,000 hp motor

The starting curves are an indication of the amount of time and associated current for the motor to accelerate from a stop condition to a full running condition. In Fig. 1 there are two starting curves: the solid curve represents the motor starting at rated voltage and the dashed curve represents the motor starting at 80 percent of the rated voltage.

Thermal protection is required to detect and protect electrical motors against abnormal conditions. Unbalances produce negative-sequence currents that can cause rotor overheating [4]. A low-voltage condition, if it occurs during normal motor operation, can cause the motor to jam. If a low-voltage condition occurs during starting, the motor may not start normally because the motor torque might be less than the load torque. In both cases, the resulting overcurrent can damage the motor. Motor stall occurs during the start operation when the motor torque cannot overpower the load torque and the motor cannot start moving.

The cause of a locked rotor may be a failure of the load bearings, a failure of the motor bearings, a low supply voltage, single phasing, or a load that exceeds the motor torque. When the rotor is locked, the stator mimics a transformer with a resistance-loaded secondary and experiences current that is typically 6 times the rated current. Because of the rotor resistance during a locked rotor being 3 times greater than during running conditions, the effective heating due to rotor ohmic losses is 108 times that of normal operation [5].

B. *First-Order Thermal Model*

Motor thermal protection is responsible for removing power before a motor's temperature reaches values above of the maximum level permitted by the thermal limit curves. The actual motor heating can be calculated with a thermal model that represents the motor thermal system, as shown in Fig. 2.

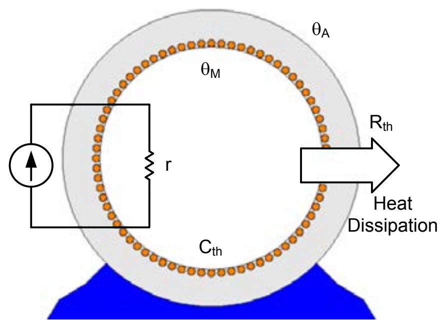

Fig. 2 Motor thermal system

The electric power applied to a motor is partially converted into heat that is stored in the motor, causing the temperature to rise. Thus, the temperature is a function of current and time. These variables are the basis of the thermal model that represents the motor temperature. A first-order thermal model is used to calculate the motor heating and is applied to the motor thermal protection [6].

Consider the motor heating caused by the current flowing through a resistor (r) that represents the resistance of the motor windings, as shown in Fig. 2. The environmental temperature is θ_A and the motor temperature is θ_M.

This simple first-order thermal system is modeled by a thermal resistance (R_{th}) to the environment and a thermal capacitance (C_{th}), with the motor considered a homogeneous body.

Fig. 3 illustrates the first-order thermal model used to represent the motor heating [5]. The major components of the model are as follows:

1. Heat source. Heat flow from the source is $I^2 \cdot r$ watts (J/s).
2. Thermal capacitance (C_{th}). This represents the capacity of the motor to absorb heat from the heat source. The unit of thermal capacitance is J/°C.
3. Thermal resistance (R_{th}). This represents the heat dissipated by a motor to its surroundings. The unit of thermal resistance is °C/W.
4. The comparator. This creates a trip condition when the calculated motor pu temperature exceeds a preset value that is based on the motor manufacturer's data, as explained in more detail later in the paper.

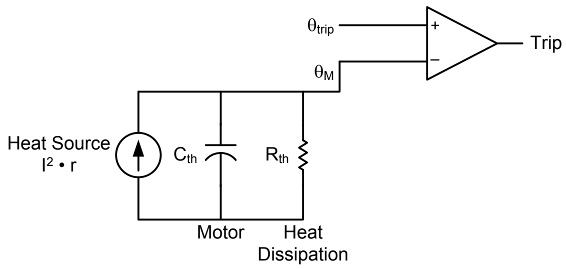

Fig. 3 First-order thermal model

Heat produced by the heat source is transferred to the motor, which in turn dissipates the heat to the surrounding environment. Motor thermal protection is implemented in modern numerical relays based on this thermal model. The relay input current is the phase motor current. The purpose of motor thermal protection is to allow the motor to start and run within the manufacturer's published guidelines and to trip if the motor heat energy exceeds those ratings due to overloads, negative-sequence current, or locked-rotor starting.

Because the positive- and negative-sequence rotor resistances (R_{r1} and R_{r2}) are functions of the motor's speed, the model becomes nonlinear. An approach used by some relay designers employs two linear models for two different stages of the motor, as shown in the Fig. 4. The limit current (I_{LIM}), which determines when each model applies, is defined by the designer. Certain relays use a limit of 2.5 times the full load current of the motor.

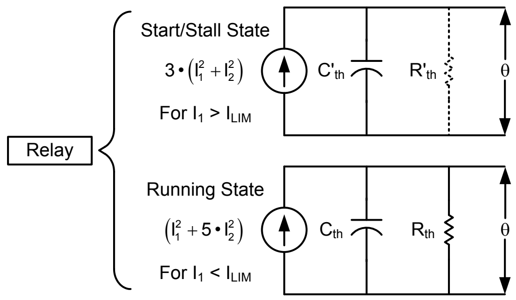

Fig. 4 Thermal models for start/stall and running states

Because locked-rotor heating occurs over just a few seconds, the start/stall state thermal model assumes that no heat is lost to the surroundings and the resistor is removed from the thermal circuit. The motor's rated locked-rotor current defines the thermal trip value.

When the motor is running, it returns heat energy to its surroundings through radiation, conduction, convection, and (in some cases) forced cooling. The running state thermal model provides a path for that energy return through the thermal resistance (R_{th}) resistor, as shown in Fig. 4.

The motor thermal characteristics (R_{th} and C_{th}) depend on many design factors. Among others, they depend on the motor size (mass). This explains why it is so difficult or impossible to emulate large motor thermal behavior with small bimetal devices. This is a clear advantage for numerical relays, in which it is possible to set different values for the motor parameters.

A slip-dependent thermal model of the rotor is discussed later in the paper.

When a motor is de-energized, it does not require thermal protection per se; however, it does need to be locked out and not allowed to re-energize until it cools down sufficiently to offer further service. When current ceases to flow in the thermal circuit shown in Fig. 3, the circuit reconfigures, as illustrated in Fig. 5, and the capacitor discharges according to the value of R_{th}.

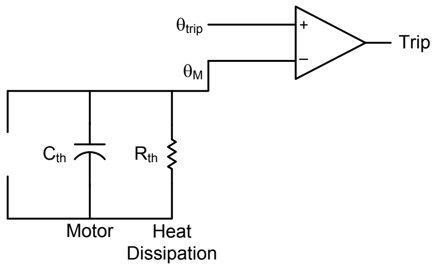

Fig. 5 Thermal model for motor stopped state

By applying the presented approach to thermal modeling, it is possible to emulate the dynamic thermal behavior of a motor, as shown in Fig. 6, to prevent damaging temperatures for any operating condition.

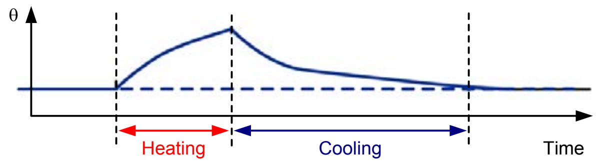

Fig. 6 Example of thermal model response for different motor states

C. *Stator and Rotor Thermal Models*

To accommodate the differences in stator and rotor thermal properties, the first-order thermal model can be divided into two separate thermal models, as follows:

1. The rotor model consists of the following elements:
   - A starting element that protects the rotor during the starting sequence.
   - A running element that protects the rotor when the motor is up to speed.
2. The stator model protects the stator during starting and when the motor is up to speed.

1) *Rotor Model*

In the rotor model, the transition from one element to the other is set at 2.5 times the rated full load current of the motor. The high-inertia starting solution using the slip-dependent thermal model described in the following subsection only affects the rotor element design.

It is valid during a starting or stalled-motor condition to neglect ambient heat losses. This results in a conservative estimate of the temperature to ensure good operation. This is equivalent to eliminating (making infinite) the thermal resistance from the model.

The rotor starting thermal limit is expressed in terms of the maximum time (motor safe stall time) that the corresponding locked-rotor current (I_{LRA}) can be applied to a motor, as calculated in (1).

$$\theta_{trip} = I_{LRA}^2 \bullet T_{STALL} \tag{1}$$

The rotor resistance at a speed of zero is typically 3 times that of the rotor resistance when the motor is at its rated speed. For this reason, the effect of the positive- and negative-sequence currents is multiplied by a heat source factor of 3 in the starting motor rotor thermal model.

Incorporating all of these changes results in the I^2t starting element of the first-order thermal model illustrated in Fig. 7.

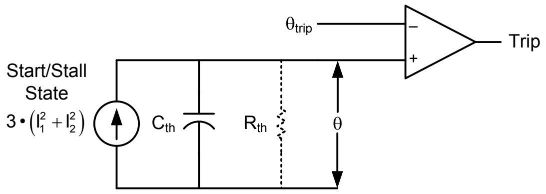

Fig. 7 I^2t starting element

To match the heat source factor of 3, the selected thermal capacitance is also 3. When the motor positive-sequence current is equal to the locked-rotor current, the estimated heat reaches the trip value within the locked-rotor time limit. Therefore, for starting protection, only the motor nameplate data are needed for the starting motor rotor thermal model.

If the temperature response of this model is plotted against the line current of the motor, the response curve is a straight line, as illustrated in Fig. 8.

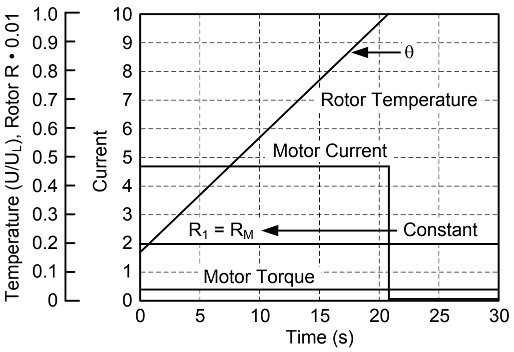

Fig. 8 I^2t starting element response curve

Note that this model keeps the rotor resistance constant at R_M, which occurs at a standstill, where the slip (S) is equal to 1.0 pu.

Fig. 9 depicts the electric analog of the first-order rotor thermal model for the motor running condition. When the motor is running, it returns heat energy to its surroundings. The running motor rotor thermal element provides a path for that energy return through the thermal resistance (R_{th}) resistor. In this state, the trip threshold "cools" exponentially from a locked-rotor threshold to the appropriate threshold for the running condition using the motor thermal time constant. This emulates a motor temperature that cools to the steady-state running condition. In the running condition, the model considers the rotor resistance to have the rated speed value ($R_r = R_N$).

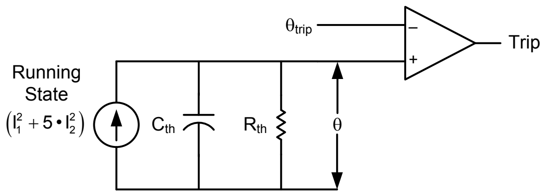

Fig. 9 Running motor rotor thermal element

2) Stator Model

The running motor overload curves show the stator thermal limit. These curves fit the time-current equation (2), where τ is the stator thermal time constant, *I* is the stator current in pu of rated current, I_0 is the initial current in pu of rated current, and SF is the motor service factor. This equation has the form of a first-order thermal model.

$$t = \tau \cdot \ln\left(\frac{I^2 - I_0^2}{I^2 - SF^2}\right) \tag{2}$$

The motor stator thermal time constant is a setting parameter for the running motor thermal model, and it can be calculated from the stator thermal limit curves by applying (2).

Fig. 10 depicts the equivalent circuit that corresponds to the stator first-order thermal model. In this case, the thermal capacitance (C_{th}) equals the stator thermal time constant (τ). Assigning a value of 1 to the thermal resistance (R_{th}) resistor provides a value equal to τ for the time constant ($R_{th} \cdot C_{th}$) of the equivalent circuit. Because the positive- and negative-sequence currents have the same heating effect on the stator, the heat source equals $I_1^2 + I_2^2$. When R_{th} = 1, the trip threshold should equal SF^2.

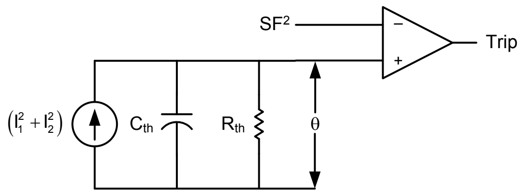

Fig. 10 Stator running thermal model

D. Slip-Dependent Thermal Model

Reference [7] derives an expression for slip-dependent rotor resistance [$R_r(S)$] in terms of the maximum rotor resistance (R_M), which occurs at a standstill (S = 1), and the normal rotor resistance (R_N), which occurs at the rated motor speed (S = rated slip). This expression is shown in (3):

$$R_r(S) = (R_M - R_N) \cdot S + R_N \tag{3}$$

Fig. 11 shows the rotor resistance during starting.

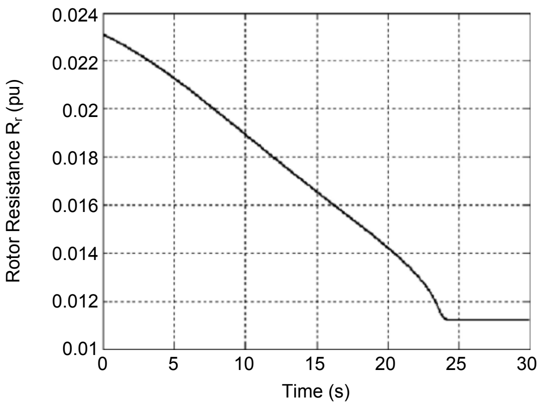

Fig. 11 Rotor resistance during starting

The values in pu of the maximum rotor resistance (R_M) and the normal rotor resistance (R_N) can be calculated by using (4) and (5) [8].

$$R_M = T_{LR} \bullet \frac{S_{LR}}{I_{LRA}^2} \tag{4}$$

where:

T_{LR} is the locked-rotor torque in pu.

S_{LR} is the slip when the locked-rotor condition = 1.

I_{LRA} is the locked-rotor current in pu.

$$R_N = T_N \bullet \frac{S_N}{I_{FLA}^2} \tag{5}$$

where:

T_N is the nominal torque in pu.

S_N is the slip at the rated speed.

I_{FLA} is the motor's rated current in pu.

To establish the slip-dependent thermal model, it is necessary to incorporate the slip-dependent rotor resistance into the heat source of the thermal model shown in Fig. 7.

Expressing the slip-dependent resistance value $R_r(S)$ in terms of its maximum value (R_M) and substituting it into the heat source equation provides (6):

$$W = I^2 \bullet r = I^2 \bullet \frac{R_r(S)}{R_M} \tag{6}$$

Breaking (6) down into positive-sequence (R_{r1}) and negative-sequence (R_{r2}) components accommodates motor heating caused by balanced current (positive sequence) and any current unbalance (negative sequence) that is present.

Replacing the heat source of Fig. 7 with (7) provides the slip-dependent thermal model shown in Fig. 12.

$$W_{TOTAL} = I_1^2 \bullet \frac{R_{r1}(S)}{R_M} + I_2^2 \bullet \frac{R_{r2}(S)}{R_M} \tag{7}$$

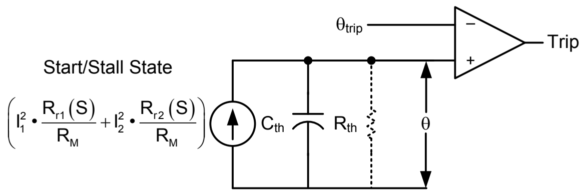

Fig. 12 Slip-dependent thermal model

E. High-Inertia Starting

In high-inertia starting, the time to accelerate a motor up to its rated speed is equal to or longer than its locked-rotor time limit. High-inertia loads, such as induced-draft fans, require long accelerating times and can exceed the allowable locked-rotor thermal limit. Prolonged starts are safely permitted in some situations because the rotor resistance $R_r(S)$ is a function of slip and decreases as the motor accelerates.

The starting current of an induction motor at the beginning of the start nearly equals the locked-rotor current magnitude but has a lesser heating effect during the start because rotor resistance decreases as the motor accelerates to rated speed.

A comparison of the conventional I^2t starting element response curve to the slip-dependent starting element response curve is shown in Fig. 13. The comparison clearly shows that, because of the decreasing rotor resistance as the motor accelerates, rotor temperature is not a linear relationship. This provides the ability to facilitate high-inertia starts without premature motor trips.

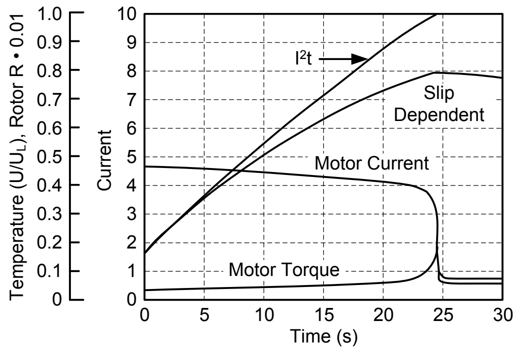

Fig. 13 Comparison of starting element response curves

III. DETECTING BROKEN ROTOR BARS

The detection of a broken rotor bar as soon as it occurs is essential to minimize damage and reduce the time and cost to repair the motor. According to [2], the broken-bar condition results from mechanical and thermal stresses that lead to a fracture at the junction between the rotor bar and the end ring.

In order to detect a broken-bar condition, MCSA can be applied [9] [10]. With this method, the frequency spectrum of the stator current is calculated and analyzed to check whether lower and upper sidebands (i.e., $[1 \pm 2S]f_0$, where f_0 is the nominal frequency) are present in the stator current, indicating that the rotor has broken bars. The magnitude of the sidebands is proportional to the number of bars that are broken.

A. Broken-Bar Detection Element

Reference [2] describes a broken-bar detection element (BBDE) with zero settings. The BBDE algorithm runs periodically to detect a broken-bar condition. It is composed of three steps: initialization, data collection, and data processing. During the initialization step, the algorithm calculates a new current from the phase currents that does not include the portion that flows to ground. It then records this current magnitude and the system frequency. A motor-running condition is detected during the data collection step using these values as a reference.

During the data collection step, the algorithm squares the current calculated in the initialization step to decouple the frequency of interest from the power system frequency and to move both sidebands into the same frequency. This squared current is also passed through a low-pass filter. Finally, the algorithm stores a collection of consecutive samples, referred to as a samples window, in digital memory.

During the data processing phase, the algorithm computes the fast Fourier transform of the samples window data and then calculates the magnitude associated with each frequency component. Finally, the average magnitudes of the frequency components are compared with a healthy motor threshold. Figure 14 in [2] shows the thresholds on the frequency spectrum of a motor running at 50 percent load with one broken bar.

B. Experimental Results

Reference [2] also presents some experimental results of the method described in this section using actual broken rotor bars. For the experimental tests, a healthy motor and motors with one, two, or three broken bars had their current frequency spectrums compared when running at 50 percent of the nominal load. The results are shown in Figure 27 in [2]. The values of the sideband peaks clearly increase as the number of broken bars increases.

Different load conditions were also experimentally tested, and the results are shown in Figure 28 in [2]. The frequency of the sideband peaks decreases as the load level decreases, and the peaks become undetectable when the motor is unloaded.

Reference [2] describes how broken bars can be erroneously detected during low-frequency source voltage oscillations. It also recommends some strategies to differentiate a broken-bar condition from a voltage oscillation (e.g., verify if all motors connected to the same feeder show the same current spectrum, and measure the voltage farther away from the motor and closer to the source to confirm the presence of low-frequency components on the power supply). In addition, these low-frequency voltage oscillations may not be present in the system all of the time. They typically appear when the system is heavily loaded or very lightly loaded.

Low-frequency load oscillations can cause current signatures similar to those of a motor with broken bars [2]. One method of differentiating the two is to apply an algorithm that detects the presence of a greater-than-normal frequency component, which may indicate a broken-bar condition.

To detect broken rotor bar conditions in different situations and monitor how they evolve, the event history and fast Fourier transform function can be applied in conjunction. This makes it possible to differentiate situations involving voltage sources with low-frequency components and oscillating loads from the broken-bar condition.

IV. ARC-FLASH DETECTION

Applying traditional time coordination for industrial systems, like motor control centers (MCCs), can lead to high fault-clearing times. Fault clearing times are typically between 0.5 and 1.0 second. However, high fault current in combination with long fault clearing times causes a very high arc-flash energy, which is a highly undesirable situation [11]. Therefore, the goal is to reduce the fault clearing time in order to reduce the arc-flash energy.

One option to reduce arc-flash energy in radial substations is to apply a simple and economical zone-interlocked blocking scheme, sometimes called a fast bus-tripping scheme. This scheme provides relatively high-speed fault clearing for buses that do not have differential protection. Instead of relying on a traditional coordination interval in the bus main relay, this scheme only requires a short delay to allow the feeder relays to block the bus main relay for a fault external to the bus. The scheme can operate for bus faults in approximately 2 to 3 cycles.

Fig. 14 shows an event report for a real fault on a 480 V bus with an arc flash. The fault started as a single-line-to-ground (SLG) fault on Phase B. After 1 cycle it evolved into a three-phase fault with a considerable increase in the fault current level. Even in impedance-grounded systems that have low current levels for SLG faults, such faults represent a high risk in terms of arc flash because of the fault evolving.

Another interesting observation about Fig. 14 is the fact that the fault current is not a pure sine wave at the fundamental frequency. This is because the arc resistance is not constant, and it plays an important role in low-voltage systems. Overcurrent relays that operate based on fundamental components calculate an incorrectly low value for the fault current, which can compromise the tripping of the instantaneous overcurrent element.

The most effective method to reduce fault clearing times is applying arc-flash protection with light sensors combined with fast overcurrent elements. Some modern numerical motor relays have incorporated arc-flash detection and support the connection of multiple sensors.

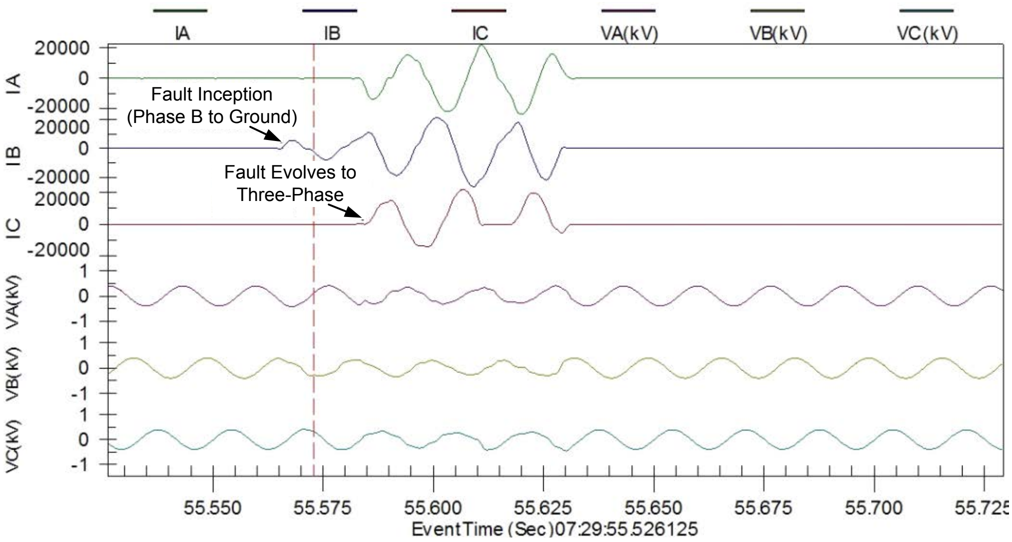

Fig. 14 An event report for a real fault on a 480 V bus with an arc flash

The purpose of detecting arc flashes is to accelerate accurate decisions to trip the circuit breaker and interrupt the fault. Arc-flash detection in a protective relay minimizes trip time, cost, and complexity. Enabling arc-flash detection in the relay makes use of the current monitoring and protection already in the circuit.

Arc-flash detection sensors provide a clear measurement of an arc flash because the light emitted during an arc-flash event is significantly brighter than the normal background substation light. It is also possible to supervise their operation with a fast overcurrent element, as discussed later in this section. The light surge is visible from the initiation of the flash and is easily detected using proven technology. The most common sensors are lens-point sensors and bare fiber-optic sensors.

The light is channeled from the sensor to the detector located in the protective relay. Monitoring the system integrity is accomplished using a fiber-optic loop. In the case of lens-point sensors (see Fig. 15), each lens has an input and an output connection. The input is connected to a transmitter in the relay, and the output is connected to a detector in the relay. This loop connection allows periodic testing of the system by injecting light from the transmitter through the loop and back to the detector. This loop connection system works with either a lens-point sensor or a bare fiber-optic sensor.

Fig. 15 Lens-point sensor

A bare fiber-optic sensor consists of a high-quality plastic fiber-optic cable without a jacket (see Fig. 16). The clear fiber-optic cable becomes a lens that captures light from the area. Using a bare fiber-optic sensor makes possible the detection of arc flashes in large areas with only one sensor.

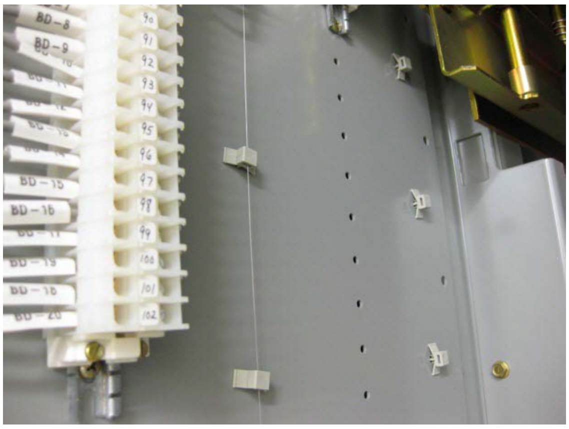

Fig. 16 Bare fiber-optic cable

Arc-flash detection systems typically use a combination of lens-point and bare fiber-optic sensors. Proper installation of the sensors and relays provides logical detection and trip points in any system.

Sensors should be located where arc-flash detection can trip the corresponding upstream circuit breaker. Using multiple sensors and having motor and feeder relays that support connections to light sensors, as shown in Fig. 17, provides 100 percent coverage for arc-flash protection that operates in the order of 2 to 3 ms.

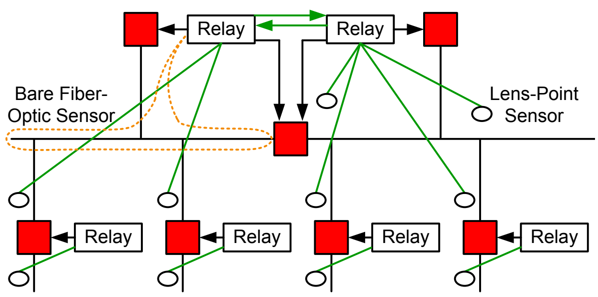

Fig. 17 Typical arc-flash detection system with sensors and relay-to-relay communication

The installation of sensors varies depending on the switchgear manufacturer, type of gear, and number of sections. Multiple sensor inputs provide coverage and sectioning options. One bare fiber-optic sensor can provide excellent coverage for an entire bus section. Lens-point sensors provide better detection in small, confined spaces.

One obstacle to using light sensors is the need to measure and adjust for changing ambient light levels. Relays store analog measurements of light and current values. Users can view these measurements and set the normal light levels for the application. Relay event reporting also provides a commissioning and troubleshooting tool with time-tagged events, including sensor light levels.

In order to add security to an arc-flash detection scheme, a high-speed overcurrent element can be applied in conjunction with the light sensors, as shown in Fig. 18, without sacrificing trip speeds. The high-speed overcurrent element is based on raw samples in order to avoid the long delays of filtering. The added advantage of processing the arc-flash detection in the protective relay is the ability to use a true overcurrent measurement as a supervising element to improve security. Setting the current level below the normally expected load enables the arc-flash detector as the trip mechanism and removes any time lag; however, it sacrifices security and makes the system dependent on light detection alone and must be avoided.

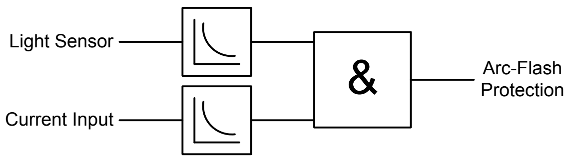

Fig. 18 Light detection in combination with high-speed overcurrent element

V. CONCLUSIONS

Motor protection is greatly enhanced by numerical relays. Induction motors require thermal protection to prevent overheating for cyclic as well as steady-state overloads.

The heat rise in a motor caused by $I^2 \cdot r$ watts is a first-order process that can be represented by a first-order thermal model, which a motor relay can use to continuously calculate the temperature in real time. The calculated temperature is monitored to prevent overheating.

The slip-dependent thermal model tracks the motor temperature more accurately than the I^2t model, thus facilitating high-inertia starts without the use of speed switches.

BBDE algorithms that apply MCSA in modern numerical motor relays, in conjunction with the event history and the fast Fourier transform function, permit the detection of broken rotor bars under a wide variety of motor conditions. The detection element identifies the most common broken-bar cases. The event history records and makes possible more accurate analysis of when problems start and how they evolve.

Arc flashes present a clear danger to personnel. Worker safety should always be at the forefront of designs, processes, and procedures. The addition of arc-flash detection improves the safety of installations. Arc-flash detection systems can be designed into new switchgear or retrofitted into existing gear. The security of arc-flash detection systems can be increased by parallel overcurrent and light-detection systems.

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VII. VITAE

Ricardo Abboud received his B.S.E.E. degree in electrical engineering from Universidade Federal de Uberlândia, Brazil, in 1992. In 1993, he joined CPFL Energia as a protection engineer. In 2000, he joined Schweitzer Engineering Laboratories, Inc. (SEL) as a field application engineer in Brazil, assisting customers in substation protection and automation. In 2005, he became the field engineering manager, and in 2014, he became the engineering services manager. In 2016, he transferred to Pullman, Washington, and is currently an international technical manager. He is a certified instructor at SEL University, and has authored and coauthored several technical papers.

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Dibyendu Bhattacharya graduated from Jadavpur University, India, in 1991 with a bachelor of electrical engineering first-class honours degree. He worked for 14 years with the Indian Oil Corporation Ltd. refineries division, testing, commissioning, troubleshooting, and maintaining electrical equipment and power systems. He worked for the Kuwait National Petroleum Company, as well as Fluor Limited and KBR, as a lead engineer for oil and gas projects before joining BP. He has presented papers at PCIC London and coauthored one paper. He is a Chartered Engineer and a Fellow of the Institution of Engineering and Technology (IET) in the United Kingdom.

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John Needs graduated from the University of Bath in 1981 with a degree in physics with physical electronics. He started work with GEC Measurements in 1982 as a development engineer, initially working in type testing and then programming distance relays. Next, he was a relay engineer for National Grid and later joined Alstom, first as an application engineer and then as an instructor in the training department. In 1998, Mr. Needs joined Schweitzer Engineering Laboratories, Inc., where he currently works as a regional technical manager.

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