Proceedings of the 33rd European Safety and Reliability Conference (ESREL 2023)
Edited by Mário P. Brito, Terje Aven, Piero Baraldi, Marko Čepin and Enrico Zio

doi: 10.3850/978-981-18-8071-1_P047-cd

Automated Well Control Improves Reliability and Reduces Risk in Well Construction

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The operation of drilling is a process which has traditionally been manually controlled. In all well operations the major accident hazard of losing well control resulting in an un-controlled flow of reservoir fluids to surface and subsequent fuel fed fire, or blowout, can occur. The process of controlling this hazard has also been manually controlled and is therefore subject to significant human factors' issues. Well control is a safety critical function in upstream operations. Automating the function of well control is perceived as a significant improvement in reliability and reduces risk for drilling operations. Traditionally, well control was reliant on a human reliably and accurately detecting an influx and shutting-in the well. However, the human condition means the Driller can be distracted, or unexpectedly influenced by extraneous factors. An Automated Well Control system has been designed to fully automate influx detection and shut-in sequences enabling a fail-safe condition to be automatically achieved. A comparative study has been performed which determines the reduction in exposure to human factors by automating the process of well control. The results indicate a reduction of 94%. The system has received a Technology Qualification Certificate for cyber and traditional rigs and awarded a patent by the UK Patent Office. Other systems in use on rigs, such as Managed Pressure Drilling and Early Kick Detection Systems, can also benefit from linking directly with the Automated Well Control system to facilitate a fast and effective shut-in. The paper describes system design, functionality, rig trial results and qualification.

Keywords: Automated well control, Well control, Human factors, Well Construction, Drilling, Automation.

1. Introduction

The drilling of challenging wells forces the petroleum industry to come up with innovative solutions in order to explore the remaining reserves in a safe and efficient manner. The industry works in High Pressure High Temperature (HPHT) regions, deep water, and narrow pressure margins where the probability of major accident hazards is high. Well control is one of the most important factors during the planning and execution of drilling operations. An uncontrolled kick can result in a loss of well control (LOWC) event resulting in the loss of human lives, environment impact, assets, and reputational damage (Abimbola et al. 2010).

The LOWC is a combination of processes that include technical and human factors. These factors are noticeable in an emergency and high stress situation (Thorogood et al. 2015). Despite the modern control systems, the driller is still required to identify an influx and manually function well control equipment appropriately.

During all phases of well control, human errors can occur, increasing the risk and cost of the operations. The cyclic nature of the oil and gas industry continues to deplete the industry of many of the experienced resources previously available. The combination of human factors issues stretched skills, and loss of resources places severe stress on the driller to perform flawlessly in a high stress situation (Health and Safety Executive 2013).

This fact is emphasised by the events of April 20th, 2010, in the Gulf of Mexico. A LOWC on the Deepwater Horizon resulted in eleven fatalities and an estimated 4.9 million barrels of spilt crude. The massive environmental and economic impact in the affected area, including the subsequent litigation and compensation, cost of the order of $65bn brought into sharp focus the huge negative impact of well control mistakes. A series of in-depth investigations indicated that there were several contributing factors, including the operating team on the rig who were the "last barrier", and literally "in the firing line". This team were under stress, were making quick decisions and were influenced by several extraneous and often competing factors. Poor or misguided decision making was judged to be the controlling factor in the escalation of the incident (St John 2016). The response to this incident results in the revision of the US regulatory framework, revised standards for BOP equipment, the development of the Bureau of Safety and Environmental Enforcement (BSEE) and the Bureau of Ocean Energy Management (BOEM) and more focus on the research, technological solutions, and mitigations (National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling 2011). According to study performed by the International Association of Oil and Gas Producers (IOGP 2021) on 172 well control incidents, 71% of the incidents were attributable to human factors.

Automated Well Control technology was developed to bypass traditional well control process and dramatically reduces the Human Factors risk elements. This is supported by a detailed analysis carried out in 2020, comparing the influence of Human Factors of traditional well control versus Automated Well Control, showing a reduction in probability of human error by 94% for blowout and serious well control events (Atchison and Sarpangal 2022). An independent analysis was performed by Safe Influx of nearly 3,700 incident descriptions involving the loss of primary well control which occurred between 1940 and 2021, derived from eight publicly available incident sharing databases. The analysis indicates that 46% of the incidents were attributable to Human Factors, 33% were attributable to Organisational Issues and the remaining 21% involved a failure related to Technology issues (Gillard and Bhatti 2022).

2. Automated Well Control Description

Automated Well Control is an emerging technology in the upstream well construction industry. It is a driller assistive tool and is designed to be installed on a drilling unit with a minimum footprint. The footprint on the rig is the controller, which is the size of a filing cabinet and installed in a safe area on the drilling rig, and a Human Machine Interface (HMI) screen which sits in front of the driller at the Rig Floor. The controller and HMI screen are connected via a fibre optic cable.

The Automated Well Control system continuously monitors well flow out together with selected drilling and well control equipment I/O data through its Programmable Logic Controller (PLC) server. The topology of the system is illustrated in Fig. *1* (Atchison 2021; Atchison and Wuest 2021).

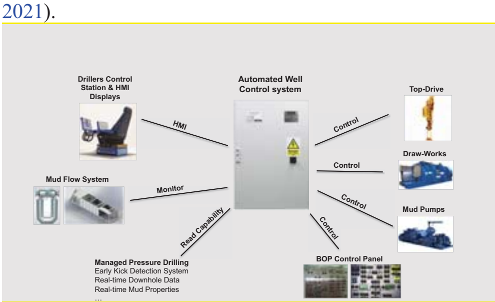

Fig. 1.Automated Well Control Topology (after Atchison 2021)

Automated well control uses the outputs from the existing rig equipment and uses an automated process to perform critical analysis of the appropriate signals. If a well control event is detected, within the pre-determined parameters input by the driller, the system takes control of the rig equipment and makes the well safe efficiently.

Human factors cannot be totally eliminated. It is not convenient to eliminate the impact of human factors even with the high degree of automation. As according to Reason (1990), human being design as well as operate the things i.e., the system we are involves are man-made and man-run, therefore human factor always lies in the workplace. Human factor causes can be reduced but are stubbornly resistant to new technology solutions.

When the Automated Well Control system identifies and confirms a self-sustained influx, a message appears on the driller's HMI screen indicating that an automated shut-in procedure is initiated. This prompts the driller to adopt a verification role based on the operation being conducted whilst the system automatically performs the necessary sequence of operations with the rig equipment to safely shut in the well (Atchison 2021 ; Atchison and Wuest 2021; Atchison and Sarpangal 2022).

A primary indication of an influx is, while pumping at a constant rate, there is an increase in flow rate leaving the well. The increase in the return flow is one of the most reliable indicators of a kick. Another primary indication of an influx is an increase in volume in the circulating system tanks. An evaluation of the primary indicators of an influx selecting the most sensitive, immediate information source and least error prone indicator is the increase in flow rate in the flow line. The flow rate down the flow line is a familiar indicator for the driller and was selected as the most important primary actionable indicator to base a decision-making capability. The rig flow rate sensors are continuously monitored to detect the increase in flow rate coming from the well.

In the event of a kick the system warns the driller, automatically decides, spaces out the drill string, stops the drilling equipment (top drive and mud pumps) and closes the pre-selected blow out preventer (BOP).

The driller has the power of veto throughout the automated sequence, reducing the frequency of errors caused by false positive indicators. An automated system reduces the opportunity for human error. This ensures that the volume of the influx is kept to a minimum (one of the key principles of well control) and reduces stress on equipment and personnel. This technology can be applied to all rigs including cyber rigs and, with additional minor modifications, to conventional rigs.

3. Design and Manufacture Principles

Automated Well Control System operates under a Quality Management System which has been assessed and registered by the National Qualifications Authority (NQA) against the requirements of ISO 9001:2008. This Quality System includes procedures which cover all design, software, purchasing, manufacturing, installation, and testing activities. As an innovative product intended to be deployed to ensure enhanced safety and performance in well control operations, the Automated Well Control system has been designed and manufactured with product assurance as the key qualifier. Documented assurance measures have been executed during the development of the product as shown in Fig. *2*:

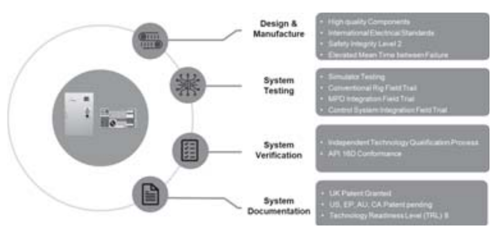

Fig. 2.Technology Assurance

3.1. Equipment and Manufacturing Quality

The Automated Well Control System is built and programmed using high specification Siemens PLC hardware and software. All equipment used in the system is designed such that the quality and reliability equals (or often exceeds) the quality and reliability of the connected equipment.

- PLC Control System - Siemens PLC offers high availability (seamless switchover between master and slave), dual redundancy and has a proven record in several applications including rig controls.
- Power Supply(s) - The power supply is filtered to protect electronic componentry and incorporates an Uninterruptible Power Supply (UPS) battery power supply to ensure power availability for a minimum of 2 hours in accordance with API 16D.
- International Standard (IS) barriers - To protect HMI and other digital interfaces.
- HMI Screen – Atmosphere Explosible (ATEX) certified with a 19” Zone 1 touchscreen.
- Software - Commonly used open-source Supervisory Control and Data Acquisition (SCADA) software.

3.2. International Electrical Standards

The design and implementation of the Automated Well Control Equipment, where applicable, conform to the following Standards. The system is Conformité Européenne (CE) marked as self-declared by the manufacturer (Finesse Control Systems) to be compliant to these standards.

- BS 7671 – 2018 - IEE Wiring Regulations BS EN 60204 – 1 - Safety of Machines – Electrical Equipment
- IEC 62061 - Safety of Machines – Functional Safety
- BS EN 13849-1 - Safety of Machines – Safety Related Parts of Control System
- IEC 60079-11 - ATEX – Intrinsically Safe Equipment
- IEC 61508-3 - Functional Safety – Software

3.3. 3rd Party Systems Interfacing

It must be noted that this system has no capability on its own to either monitor instrumentation or control actuators. All monitoring and control is via existing rig sensors and 3rd party equipment control systems. A detailed Rig Site Survey document covers this issue.

Similarly, to achieve any Safety Integrity Level (SIL) rating on the shut-in functionality the systems supplying the data and the systems activating the shut-in, and the communication link between will also need to be similarly SIL rated if applicable. Protocol for interfacing will be determined for each individual system following a Rig Site Survey as it will depend on the existing equipment with which the system has to interface.

3.4. Safety Integrity Levels

“A measure of the rate of unsafe failures is the safety integrity of the system, which is defined in Part 4 of International Electrotechnical Commission's (IEC) standard 61508 as 'the likelihood of a safety-related system satisfactorily performing the required safety functions under all the stated conditions, within a stated period of time'. The standard defines a SIL as “a discrete level (one of 4) for specifying the safety integrity requirements of safety functions”

The IEC 61508 defines SIL using requirements grouped into two main components: functional component (hardware safety integrity) and systematic safety integrity. A device or system must meet the requirements for *both* categories to achieve a given SIL. The functional component is to “reduce the risk” and safety integrity component consist of SIL levels (between 1 and 4) (IEC 61508). The SIL requirements for hardware safety integrity are based on a probabilistic analysis of the device. To achieve a given SIL, the device must meet targets for the maximum probability of dangerous failure and a minimum risk reduction factor, both in continuous and ‘on demand’ use. The Automated Well Control system has been manufactured using high quality components in compliance with the Safety Integrity Level 2 classification as detailed in *Table 1* and *Table 2*.

Table 1. SIL 2 Compliance for demand use (after IEC 61508).

Probability of Dangerous Failure	Risk Reduction Factor
0.01 – 0.001	100-1000

Table 2. SIL 2 Compliance for continuous operation (after IEC 61508)

Probability of Dangerous Failure per hour	Risk Reduction Factor
0.000001 – 0.0000001	1,000,000 – 10,000,000

In most cases the SIL classification of the Automated Well Control equipment exceeds the SIL classification of both the input and output phases of the rig’s control system(s), meaning that the Automated Well Control System cannot be considered as the weakest link in the chain.

3.5. System Components - Mean Time between Failure

All components used in the manufacture of the Automated Well Control System have been selected with quality and reliability in mind. A measure of reliability is Mean Time Between Failure (MTBF), as quoted by the manufacturer, and a full system detail is summarised as:

- The minimum MTBF for the Control Panel is 90.3 years
- The minimum MTBF for the HMI display is 7.99 years at 25$^{\circ}C$

4. Technology Qualification

The Automated Well Control system has been qualified by Lloyds Register and comes with a Lloyds Qualification Certificate for both cyber and traditional rig application. A Technology Qualification workshop for the Automated Well Control technology was held at LR, Aberdeen between 18th -20th February 2019 in the presence of a range of relevant Oil and Gas Industry experts. The outcome of the TQ workshop was an agreed set of technology goals, a system decomposition, technology maturity assessment and a risk assessment.

The Technology Qualification (TQ) Process developed by Lloyds Register is a methodology to assess and help risks introduced by novel technology (Lloyds Register 2022).

- TQ is a robust and systematic risk management process that demonstrates to interested parties that the uncertainties introduced by a novel technology, or new application of an existing technology, have been considered and that any associated technology risks have been mitigated.
- TQ is a risk-based process that uses the readiness level framework, a total system perspective and lifecycle approach to qualify innovative technologies, unconventional designs, and new ways of applying existing technology.
- TQ is a methodology that provides assurance to Owners, Operators, suppliers, and investors at the distinct stages of novel technology development.

There are 3 main stages of the TQ process. The product of Stage 1 of the TQ process is the deliverable of a Technology and Risk Assessment report. Following the delivery of the report, Automated Well Control commence to Stage 2 of the TQ process by reviewing the recommendations made in the report and develop a TQ Plan. Upon acceptance of the TQ Plan linked to the recommendations, LR issues the technology with a Statement of Endorsement. This document suggests that the technology under review is viable, if the recommendations made in the report and described in the TQ Plan were implemented in full. The final stage (Stage 3) of the process involves the implementation of the tests identified in the TQ Plan and a collection of all test results in the form of a dossier to support the assumption that the technology work in the intended environment under the conditions identified in the workshop.

A Failure Modes, effects, and critical analysis (FMECA) was performed as a part of TQ examination process with Llyod's Register. A comparative human factors study for the use of automated well control against traditional well control methods was also performed. The human factors analysis, completed by means of Human Reliability Assessment methodology, provides a qualitative and quantitative assessment of the human failure modes associated with the operation of the automated well control compared with the equivalent associated with traditional methods.

The qualification process included a detailed Failure Mode Effect Analysis (FMEA), Factory Acceptance Test (FAT) and Site Acceptance Test (SAT). The SAT was performed as part of the test that was performed on a land drilling rig in Aberdeen, Scotland. The TQ plan covers the actual witnessed FAT of the control software and witnessed SAT of the technology on the RGU well-rig simulator and a traditional physical land rig.

The objective of the FAT and SAT for the Simulator testing was to demonstrate prior to delivery of equipment to the Manufacturer that the integration of hardware and software has been correctly performed as per the approved MVP functional design specification.

5. Risks Associated with Introduction of New Technology

There are several risks associated with the introduction of automation which several other industries have overcome. This section will discuss the prominent problems and how to deal with them.

5.1. Cybersecurity

The manufacturer recognises the concern of operators and drilling contractors that essential well control equipment could be vulnerable to external hacking. At present, Automated Well Control technology does not have, nor does it rely upon, any connection to the internet or use of wireless technology thus significantly reducing the exposure to cyber-hacking.

5.2. Loss of skills

Automated Well Control has redefined the drillers' role from manually and directly controlling all aspects of the well control operations to that of a system monitor and verifier. Other industries use extensive simulator training to ensure the necessary skill sets are still available if required.

5.3. Mistrust

Well Control is a Safety Critical process that requires confidence in the system by the user. A structured training program has been developed that addresses the system theory, includes simulator training and rig floor training provided by coaches with an emphasis on repetition, will develop confidence in the system. Easy to read process flow diagrams, using the swim lane format to portray parallel processes, have also been developed to enable comprehensive understanding of the system interactions.

5.4. Lack of independence

Automated Well Control is a tool to assist the driller. The driller retains the responsibility for Well Control. The driller has the power of veto and can intervene at any moment. This principle is emphasised in training.

5.5 Lack of familiarization with systems

Lack of familiarity with automation technology can lead to serious consequences. A comprehensive training program covering theory, simulator operations, practical training and weekly drills will ensure familiarity with the technology. Additional functionality of the system would require further training.

5.6 Performance Monitoring

The implementation of automation enables monitoring algorithms to be developed providing the opportunity for data capture and analysis of each driller. Further training requirements could be identified, if required.

6. Gap Analysis Vs. Existing and Emerging Industry Guidance

As with any new evolving and emerging technologies, there is minimal instruction and guidance given to innovators on design and operational principles. Acknowledging that automation of well control processes could encroach on statements in commonly used Standards and Procedures. A comprehensive GAP analysis of the overarching document - API Specification 16D, Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment (Third Edition, November 2018) and API Bulletin 16H, Automated Safety Instrumented Systems for Onshore Blowout Actuation (First Edition, February 2022) (API 16D and API 16H). It is important to mention here that the design and the TQ work of the Automated Well Control occurred back in 2019 prior to the API bulletin 16H (published in 2022). Despite this, the GAP analysis did not identify any deficiencies in the work done to date. The GAP analysis is focussed on documentation, procedures, and processes to ensure that the product has been designed, built, deployed, and operated within the criteria established by industry.

5.1. API 16D Standard:

It is recognised that most of the API 16D documentation refer to the hydraulic and electrohydraulic systems of a BOP control system and governs the standards and guidance for these controls (API 16D). It is therefore adopted as the minimum specifications for most BOP control systems. However, API 16D does recognise that sound business, scientific, engineering and safety judgement should be used when employing the information in the specification.

In line with the latter statement and because the Automated Well Control System forms a part of the control logic, a review of this specification was considered necessary to ensure that no specific conflicts with API 16D specification are noted A total of 789 sections of API16D were reviewed.

In simple terms, the operating criteria for the Automated Well Control system is to take over the activities of the driller (human) after detecting a pre- agreed volume of influx from a well and carry out the space out, machinery shut down and shut-in duties without human intervention (unless chosen).

The vast majority (652) were not relevant to the automated well control system. In the remaining 137-line items, no specific cases of non-compliance were identified. Of these 137 sections, 3 of them are relevant for purchaser, 111 sections are relevant for Manufacturer and remaining 23 of them are applicable to the vendor.

The automated well control system cannot be classified as 'compliant' as these systems are not specifically mentioned in the specification. However, given that any API specifications are intended to 'facilitate the broad availability of proven sound engineering and operating practices' a measure of conformance to API16D can be applied.

5.2. API Bulletin 16H

A comprehensive GAP analysis of the document API Bulletin 16H, Automated Safety Instrumented Systems for Onshore Blowout Actuation (First Edition, February 2022) was performed to achieve a measure of compliance to the recommendations in the Bulletin.

The API bulletin 16H provides information on existing and emerging technologies that could be integrated to bring a well to a safe state in the event other operational barriers fail. The bulletin discusses strategies to create an automated blowout preventer actuation system, the challenges and obstacles associated with these types of system, current existing technology, and the methods of achieving widespread implementation of such a system (API 16H).

An automated safety instrumented system is intended to bring the well to a safe state if the site personnel do not recognize a well influx or are unable to respond to one. The implementation of an automated safety instrumented system should consist of input from the lease operator, drilling contractor, and original equipment manufacturer.

The conclusion of this analysis is that the current Well Control System MVP and programmed additional modules are fully compliant with the requirements of API bulletin 16H.

7. Simulator Testing and Rig Trials

Safe Influx have also established that there is very strong potential to collaborate with several other technologies to enhance the automated solution. The system can acquire data from different technologies to monitor for potentially dangerous situations and then initiate a shut-in process. These technologies include Managed Pressure Drilling, Early Kick Detection, Automated Mud Property Measurements, and down hole data.

6.1. Simulator Testing at the Robert Gordon University (RGU) Facility

To ensure that the operation of the Automated Well Control system could be thoroughly evaluated in a benign environment, Safe Influx commissioned the compilation of an interface 'patch' to ensure effective and reliable data communications between the Automated Well Control system and a Drilling Systems DS6000 Simulator at the RGU facility.

This integration allowed several test scenarios to be run as follows:

a. To ensure that improved influx detection and reaction time was achieved by automation.

b. To ensure a number of faults finding and user error scenarios could be recognised, documented and if applicable incorporated into future upgrades to the system.

6.2. Rig Trial 1- Test Land Rig – Bridge of Don, Aberdeen, UK

Following the various simulator tests in the DS6000 Drilling Simulator, the next stage in development was to demonstrate that the technology work reliably on a real working rig. In 2019, a field trial of Automated Well Control system was performed at the Weatherford test rig at Bridge of Don, Aberdeen. The objective of the field trial was to demonstrate and document that Automated Well Control technology reliably worked as designed on a 50-year-old traditional manually controlled drilling rig. This would also enable an extension of the existing technology qualification certificate, currently valid for cyber rigs, to include a manually drilling rig. The secondary objective, supporting the primary objective, was to test the system in multiple "additional", "normal", and "stress" scenarios to verify the system works across a range of downhole scenarios.

The field trial objectives were fully met and exceeded the expectations of the team. The field trial was supported by the UK Oil & Gas Technology Centre (OGTC) and was witnessed by Lloyds Register as the independent verifier, and personnel from Independent and National oil companies.

A summary of the results is as follows:

1. All activities were incident free.
2. The Automated Well Control unit and interfaces were successfully and efficiently installed and commissioned at the rig.
3. A series of system tests and additional stress and normal tests, 15 in total were executed to demonstrate the systems functionality and capability in a range of downhole and surface situations.
4. The system was demonstrated successfully to Lloyds Register (LR) and has achieved a Llyod's Register Technology Qualification certificate for both cyber and traditional rigs.
5. The system was successfully demonstrated to 4 VIP groups and a total of 33 people. This included senior staff from UK and Overseas Well Operators; Drilling Contractors; IADC; OGTC; Service Companies; Financial Investors and the Press.

7.1. MPD Integrated Rig Trial 2- Test Rig – Houston, USA

In March 2021, a rig trial and integration test of the Service Providers Managed Pressure Drilling (MPD) & Automated Well Control system was performed on a test rig in Houston, USA. The objective of the integration test and rig trial was to witness and verify the integrity and functionality of the integrated MPD and Automated Well Control system (Atchison and Wuest 2021).

The Automated Well Control equipment was required to be installed remotely by the Service providers MPD and Research and Development (R&D) team in Houston.

The complete design of the MPD and Automated Well Control technology link, the installation of the equipment and the management of testing were operations that necessitated significant levels of videoconferencing between the teams over a period of many months.

Twenty-seven tests were performed. They were pre-agreed between MPD service provider, vendor, and manufacturer, which covered:

- Setting up of systems
- Independent system configuration and integrated commissioning.
- Integrated contingency, communications, and comparison testing.

For all tests the expected & actual outcomes were documented, and whether the test was deemed successful. All tests were completed successfully, and without major issues. All pre-agreed Test Criteria have been met.

7.2. OEM's Drilling and BOP Operating Control Systems Simulator Testing, Arbroath, UK.

As part of the agreement between Safe Influx and major Original Equipment Manufacturer (OEM), a programme of both simulator and rig interface testing was developed. The object of these tests was to prove that effective and reliable data communications could be achieved between Automated Well Control system and the OEM's Drilling and BOP Operating Control Systems.

A remote Simulator test was performed in a virtual environment using a cloud-based rig simulator based in Norway, and the Remote BOP control system and Automated Well Control system were based in Scotland.

A simulator test was performed by the collaboration between the UK, Norway, and USA teams. Two successful remote simulator tests were conducted to establish and test the interface arrangements to ensure that:

- The Automated Well Control system can be integrated with the OEM's Drilling and BOP Operating Control systems.
- The integrated system successfully functions and completes the automated shut-in sequence on detection of an influx.

The test was conducted during two separate instances:

- **03 Mar 2022** – a full test team and conducted 6 tests to prove connectivity and control of the OEM's systems. These were conducted successfully, but a PLC software error prevented verification of the control sequence.
- **08 Mar 2022** – the software issue was identified, and a further 9 tests were conducted with a small test team to prove the control sequence was valid across several scenarios. These tests were all successful.

For all tests, the expected and actual outcomes were documented. All Integration tests were performed, and all were completed successfully without significant issues. All pre-agreed Test Criteria were met.

7.3. OEM's Drilling and BOP Operating Control Systems Rig Trial 3, Houston, USA

In April 2022, a rig trial and integration test between Automated Well Control system and the OEM's Amphion Rig Drilling and BOP Operating Control Systems was executed at STC Test Rig in Navasota, TX, USA. This rig-based test was the second phase of the required Automated

Well Control/OEM's Integration after the successful evaluation of the Automated well Control in the benign simulator environment. The test was performed to establish and test the interface arrangements to ensure that:

- The Automated Well Control system can be integrated with the OEM's Operating Control systems.
- The integrated system successfully functions and completes the automated shut-in sequence on detection of an influx.

The test was conducted as detailed below:

- **01 Apr 2022** – the test team conducted 5 tests to prove connectivity and control of the NOV systems.

The timeline of the Project is shown in *Fig. 3* below:

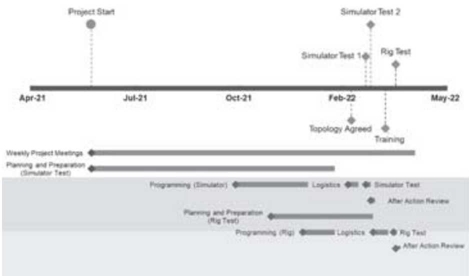

Fig. 3.Simulator and Rig Test Timeline

The following highlights were recorded during the trial:

- Successful integration of Automated Well Control system with an OEM's Rig and BOP operating control system.
- Rig test achieved all the objectives.
- The Automated Well Control equipment was installed physically by the Safe Influx and OEM's team.
- Proper planning, experience, and competent personnel were the key factors that contributed to the success.
- This integration combines the functionally of both systems to provide a comprehensive automated well control package to the upstream industry.
- All activities were incident free.

8. Automated Well Control Documentation Patent

Automated Well Control is patented technology capable of delivering the full well control protocol. To protect Intellectual Property (IP), manufacturer applied for the UK Patent in April 2019.

The manufacturer was awarded UK Patent No GB2581586 on 27th January 2021 by the UK Intellectual Property Office, for Automated Well Control, together with an additional 50 potential modules to provide well control protection for all aspects of well operations.

A patent was applied for in the United States of America and, using the Patent Cooperation Treaty (PCT), further patents have been applied for in Canada, Australia, and Europe.

9. Comparative Human Factor Analysis

Research and development is a vital part of the company work scope to retain our position as "Thought Leaders" in Automated Well Control. Given that a sizeable number of Well Control Incidents have been attributed to Human Factors (up to 71% have been reported by IOGP 2021), Safe Influx commissioned a comprehensive study to compare the human factors influence on traditional manual well control methods with the automated system (Atchison and Sarpangal 2022).

The analysis provided a clear demonstration of the reduction in exposure to human factors issues that Automated Well Control system brings compared to traditional well control methods. The dramatic reduction in exposure is achieved by a combination of factors which include:

- Reduction in the overall number of task steps.
- Elimination of 'situation evaluation' type activities from the well shut-in process.
- Reduction in the cognitive workload and time pressures for the driller.

The quantitative assessment demonstrated that:

- The human probabilities failures associated with the traditional well control method, which could lead to a potential loss of well control, would be reduced by 94% when the automated well control system is used.
- The automated well control could achieve 96% chance of reducing the shut-in influx volume (Marex 2020)

Table 3. Results Human Error Probabilities (after Marex 2020)

	Failure to shut in on an influx	Delay in shutting in on an influx
Traditional Well Control	0.4411	0.5528
Automated Well Control	0.0250	0.0246
Reduction in HEP for Automated Well Control vs Traditional Well Control	94%	96%

10. Technology Readiness Level

The concept of Technology Readiness levels was originally developed by NASA as a method of measuring the maturity of technology. Generic details of this process are included in *Fig. 4*. This concept has been employed by Safe Influx to ensure that the maturity of the Automated Well Control Technology is documented, and it is considered that the Automation system is categorised as NASA TRL-8 (System Completed and Qualified) and API RP 17 N TRL-6 (System installed, tested, and commissioned) and is ready for field deployment (NASA and API RP 17N).

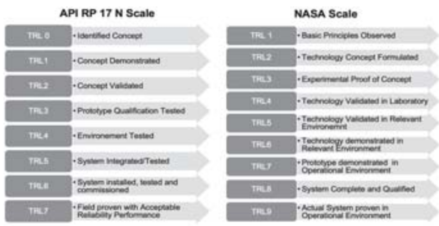

Fig. 4.Technology Readiness Level (NASA and API RP 17N Scale)

11. Concluding Remarks

Automated Well Control uses computer logic to identify the influx, take control of the rig equipment and place the well into a secure position without the intervention of a human. In addition to the obvious benefits of prevention of fatalities, pollution, and reputational risk, there are several other benefits that will reduce well construction costs: less time spent on recovery and remediation, and potentially an enhanced well design leading to reduced well costs. Overall, the probability of successfully delivering all wells, especially technically challenging wells, within time and cost estimates will be increased.

Acknowledgements

The authors would like to thank, John McGillivray, and Richard Rose of Safe Influx; Fraser Dunphy of Finesse Control Systems Ltd, and MAREX Marine and Risk Consultancy for assisting in preparation of this paper.

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