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Surface Safety System Enhances Gas Lift Safety and Optimizes Surface Line Architecture on Island Wells

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Abstract

The construction of drilling and production facilities for gas lift production and injection wells on artificial Islands provides a significant exposure to risk due to SIMOPS. Specifically, simultaneous drilling operations results in rig skidding operations over/near to live well cellars and production line trenches. This increases the risk of venting significant lift gas volumes to atmosphere in a manned area through dropped objects or other failures.

The authors describe a Lift Gas Safety System (LGSS) to be implemented that will prevent venting lift gas during both a dropped object and other unplanned incidents leading to loss of integrity (e.g. ESD). The system also provides benefits through improved annular pressure monitoring (APM) and confining barriers within the wellhead. Outlined is the implementation process by which the system was selected and which subsequently led to optimization of surface facilities from the well cellars through to the production manifold.

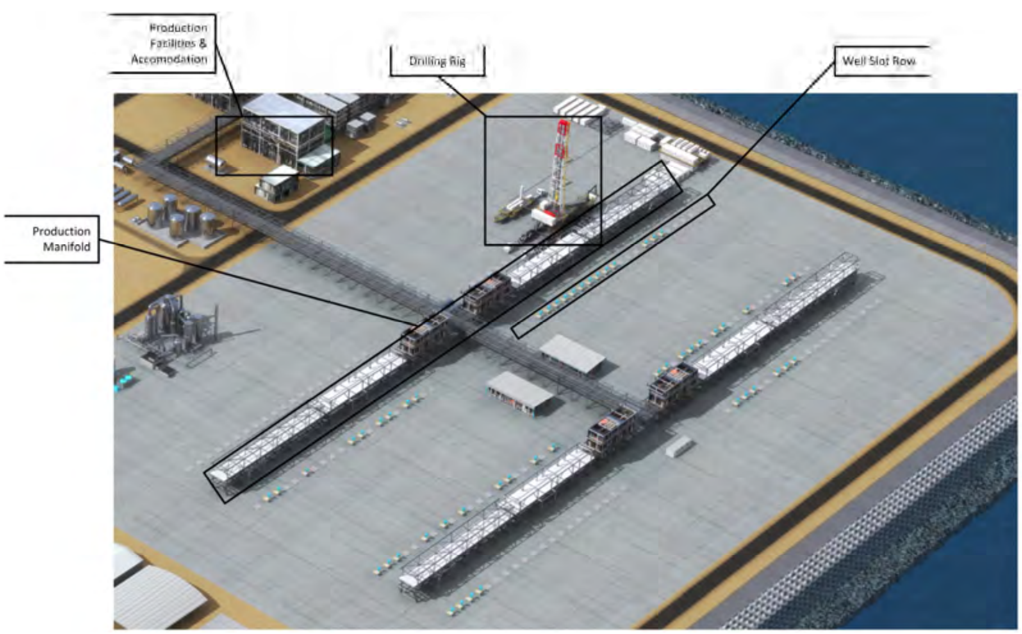

Figure 1 : Drilling and Production Operations Schematic in an Island Scenario

Introduction

Island developments present an environment whereby production wells are drilled using extended reach techniques out to targets with long offsets from the Island position. The Island wells are also located in close proximity (400 metres or less) to processing facilities, drilling operations, well intervention activities, well services and the associated infrastructure and personnel including base camps. Most new wells are able to naturally sustain flow of hydrocarbons to the surface, however, for those wells that are unable to naturally flow (due to low reservoir pressure support and high water cut) gas lift can be used to artificially lift and improve production rates. For naturally flowing wells, gas lift is utilized to achieve certain target production uplift to meet predefined reservoir/area target rates, and extend plateau.

The well annulus differs from a typical topside process plant in that its inventory of gas is not normally vented or blown down to flare in an emergency, instead the Wing Valve is closed and the gas contained within the annulus itself.

The ERD nature (sail angles of up to 82 degrees) of the Island wells places the measured depth within the upper completion to the deepest gas lift mandrel up to 14,000ft. The annular volume of pressurized lift gas in these wells exceeds 4,000 cubic feet per well. This volume of injection gas is planned to be injected at 1,500psi per well. A standard 1.4m height high pressure industrial gas cyclinder will hold ~1.7ft^3 of gas. Per production well this leads to an equivalent of ~2300 gas cylinders being present in the "A" Annulus in each production well. At current projected field development well counts this would result in each of the four artificial Islands having, on average, between 150,000ft3 and 230,000ft3 of pressurized injection gas within the annular volume per Island, at any given time (~130,000 gas cylinders).

Figure 2 : Representation of the volume of gas present in a single production well annulus

The location of processing, drilling operations, well intervention facilities and base camps on the Islands results in more than 400 people living and working on each of the Islands. Drilling activities will often be occurring within 6 metres of live wells (well centre to well centre distance). These activities include skidding operations whereby drilling rigs will move over the top of pressurised wells to move from well slot to well slot.

The Island wells initially planned to utilize industry standard surface gas lift setup with a non-return check valve (NRV) on the injection line at some distance from the wellhead. However, failure of the "A" annulus valves or surface lines between this NRV and the wellhead will result in an uncontrolled release of pressurised lift gas inventory from the "A" annulus to atmosphere. Such a large volume of pressurized gas poses significant risk to the Island's personnel and facilities if it is not contained in the event of an emergency. Simultaneous production and well operations lead to a higher risk of such an event occurring. Initially this would rank the risk level for these gas lift operations on artificial Islands at high, with simultaneous drilling and production. As per Figure 2 a risk ranking of C5 would be assigned due to the history of similar incidents occurring globally in the Oil & Gas sector (e.g. Piper Alpha, ONGC Mumbai High North and PTTEP Montara) being well documented and the severity of such an incident on an island may be catastrophic, including the possibility for fatalities. This highlights a gap between the current base well design and the requirements to minimize risks and mitigate hazards for SIMOPS on the Islands.

HSE Risk Matrix									
CONSEQUENCE CONSIDERATIONS				PROBABILITY					
					A	B	C	D	E
People	Environment	Assets	Reputation	Severity of Consequence	Rare 1 in 100,000 years *Multiple barriers in place with remote possibility of simultaneous failure.*	Unlikely 1 in 10,000 years *Similar event has happened before, but effective barriers are in place.*	Possible 1 in 1000 Years *Similar events have happened before, and could happen again.*	Likely 1 in 100 Years *History of incident. This event is likely to happen, but not every year.*	Frequent 1 in 10 Years *History of incident. Anticipate event at least once per year.*
Multiple fatalities or permanent disabilities	Tier 3 Oil Spill Response or equivalent	Substantial or a total loss of operations (>$10,000,000)	Extensive adverse coverage in international media.	5 Catastrophic	MEDIUM	HIGH	HIGH	HIGH	HIGH
Single fatality or permanent disability	Tier 2 Oil Spill Response or equivalent	Partial operation loss and/or prolonged shutdown (<$10,000,000)	National public concern. Extensive adverse coverage in the national media.	4 Major	MEDIUM	MEDIUM	HIGH	HIGH	HIGH
Serious injuries (lost time cases)	Tier 2 Oil Spill Response or equivalent	Extended plant damage and/or partial shutdown (<$500,000)	Regional public concern. Extensive adverse coverage in local media.	3 Moderate	MEDIUM	MEDIUM	MEDIUM	MEDIUM	HIGH
Minor injuries (medical treatment cases)	Tier 1 Oil Spill Response or equivalent	Moderate plant damage and/or brief operations disruption (<$100,000)	Some local public concern. Some local media coverage.	2 Minor	LOW	MEDIUM	MEDIUM	MEDIUM	MEDIUM
Slight injuries (first aid cases)	Minor release Little or no response required	Minor plant damage and no disruption to operations (<$10,000)	Public awareness may exist, but there is no public concern.	1 Insignificant	LOW	LOW	LOW	MEDIUM	MEDIUM

	Probability should be based in order of preference upon data/experience of Company, Group, Country Industry, and Global Industry.
HIGH	This level of risk exposes the Company to intolerable losses to People, Environment, Assets or Reputation. The risk should be eliminated or reduced to a lower level immediately. Senior Management dispensation is required to continue to operate at a HIGH level of risk.
MEDIUM	This level of risk requires that hazards be managed to reduce the frequency and/or the severity of the hazardous events to As Low As Reasonable Practicable.
LOW	This level of risk is acceptable and is managed through continuous implementation of HSEMS. These risks may be further analyzed dependant upon the facilities/sites specific loss management philosophies and systems.

Figure 3 : HSE Risk Matrix

A review was performed of the base well design and surface line architecture based on the initial identification of a high risk level operation. The review team was tasked to identify a solution that would lower the risk level through:

- Actively containing the gas within the well on triggering of an associated well Emergency Shut Down (ESD) system.
- Providing a facility to monitor annular pressures with instrumentation while the annulus is shut in.
- Maintaining well integrity with a two barrier philosophy that meets company well integrity standards.

Base Well Design

The Island well completion design was originally planned to be a standard single completion with the following components:

- Downhole Safety Valve (DHSV)
- Master Gate Valves (LMGV & UMGV)
- Wing Valves (LIWV, LOWV, RIWV & ROWV)
- Gas Lift Mandrels & Valves (GLM & GLV)
- Cased Hole Packer

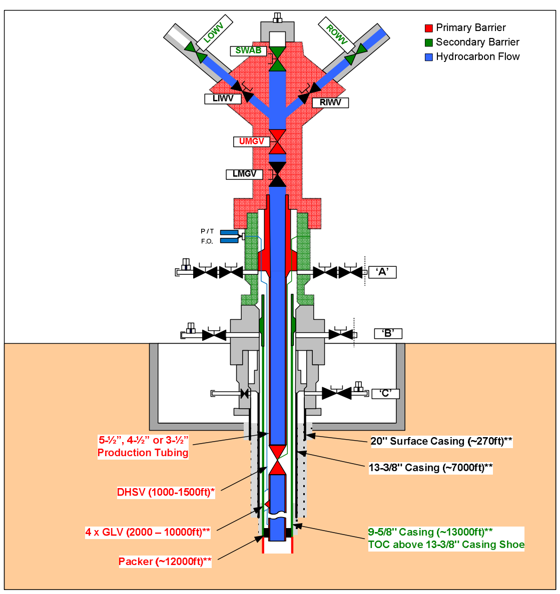

Figure 4 : Base Completion and Wellhead Design

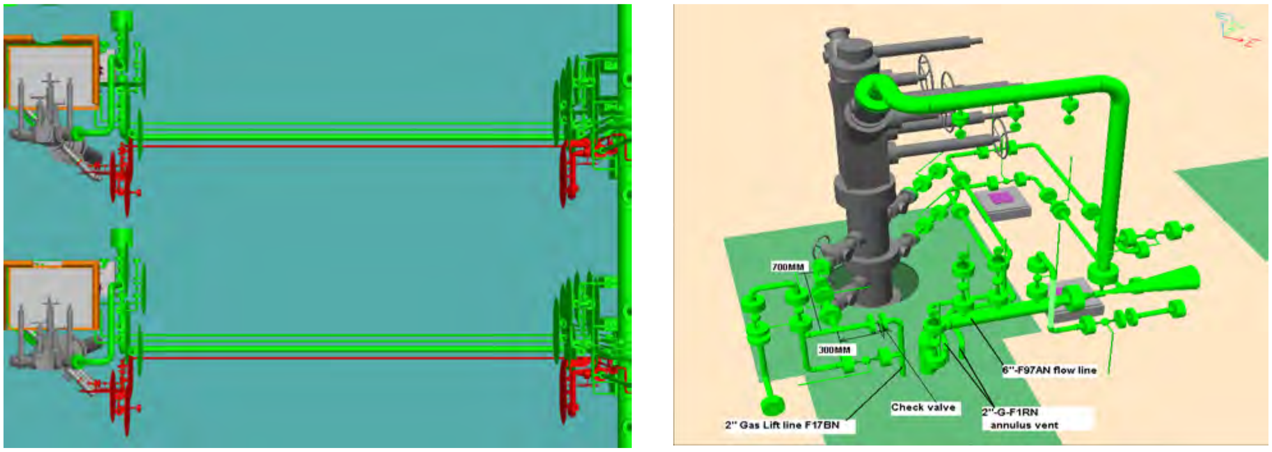

Figure 5 : Base Surface Line Design

Surface line architecture for the “A” annulus included separate bleed and injection lines on each annular outlet. These lines in turn were installed into a trench from the wellhead back to the main production line rack. Annulus pressure monitoring was planned to be via the bleed line at rack location.

The review identified key aspects of the base design that were considered deficient in minimizing the risk of venting lift gas and also identified aspects of the well design which did not meet the required two barrier philosophy, namely:

- During ESD, gas lift and gas injection check valve closure is reliant on depressurisation of the line upstream of the check valve. The check valve includes a bypass line (for equalization purposes) that includes a manual gate valve. The next failsafe valve upstream of the check valve was located at the pipe rack.
- During both gas-lift and non-gas lift production (and associated ESD’s), a 2” bleed line remains pressured within the trench area extending away from the wellhead to the normally closed gate valve in the rack area 42 ft. away.
- Bleed off of injection gas following ESD required manual bypass of the check valve at the cellar or the NC gate valve on the bleed line in the pipe rack - both operations requiring human intervention at the well site.
- Only limited dropped object protection would be provided by an Elevated Work Platform (EWP) above the bleed line close to the wellhead. The EWP only covers a portion of the bleed line in the cellar area. The injection line was not planned to be covered
- If the annulus was shut in at both manual outlet gate valves there was no means to monitor the pressure in the “A” Annulus.
- Two barrier philosophy was reliant on valves outside of wellbore / wellhead. To maintain a two barrier philosophy within the well, the gas lift valves (or dummy valves) must perform as a barrier and the “A” annulus gate valves on each outlet must be closed. Closure of the annular gate valves prevents lift gas injection and does not allow for fluid bleed off during thermal expansion of annular fluids.

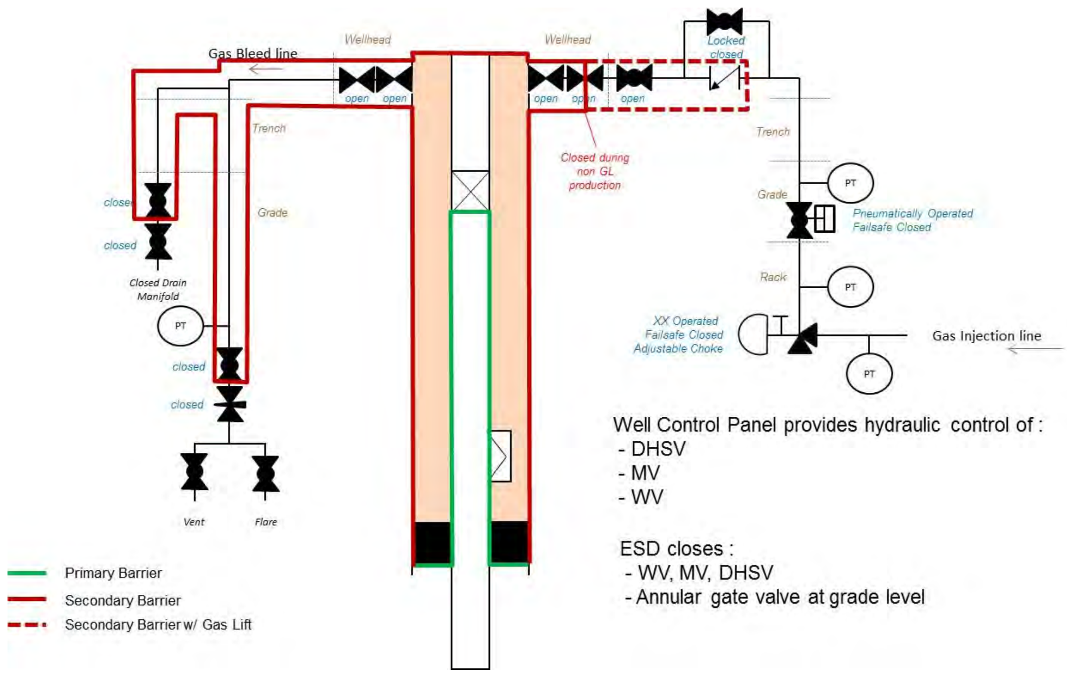

Figure 6 : Base Surface Line Design showing barrier envelopes

The review identified the need to incorporate additional barriers into the well design to safe guard against the release of annular lift gas. A review of available gas lift safety system solutions was performed.

Traditional Lift Gas Safety Systems

Traditional gas lift safety systems are either on surface, outside the wellhead area, within the production piping (Type A) or downhole, deployed as part of the well completion (Type B). Currently available systems for both type A and type B were reviewed for their applicability to Island production and drilling operations with the focus on:

- Maintaining two barrier policy for well integrity (given the wells can sustain natural flow to surface)
- Minimizing the volume of lift gas that has the potential to be vented
- Minimizing additional complexity and maintaining reliability of the well design

Lift Gas Safety System (LGSS)	Advantages	Limitations
Reinforced Gate Valves	Greater impact resistance than status quo	Weak point is the Flange or studded connection - requires wellhead modifications and modified gate valve / shield design. Surface valve or line failure can still provide leak path to A annulus. No automatic annular shut-in due to ESD. **Annulus gas inventory remains a risk.**
Deepset DHSV	Isolates GLM/GLV's during ESD	Surface valve or line failure can still provide leak path to A annulus. **Annulus gas inventory remains a risk.**
Surface Line Check Valve		Surface valve or line failure can still provide leak path to A annulus. **Annulus gas inventory remains a risk.**
Gas cap gas lift	No surface gas lines. Remotely actuated orifice sizing. **No gas inventory in upper A annulus.**	**No gas cap available in field.** Adds complexity. Full workover to replace
Downhole Hydraulic Annular Safety Valve	**Barrier to annulus gas inventory being lost** Remote actuation for ESD	Adds downhole complexity. Full workover to replace in the event of failure **Annulus gas inventory remains a risk though smaller volume**
Dual String System with DHSV	**Barrier to annulus gas inventory being lost** Remote actuation for ESD	Limits production tubing size. Adds downhole complexity. Full workover to replace in the event of failure **Annulus gas inventory remains a risk though smaller volume**
VR Annular Check Valve	**Barrier to annulus gas inventory being lost** Installed and retrieved without workover	No direct control. Spring/flow actuated check valve only (chatter). Requires manual bleed of annulus gas via manual gate valve. Requires loss of injection gas line pressure to close valve **Bleed line causes Annulus gas inventory to remain a risk**
VR Hydraulic Annular Safety Valve	**Barrier to annulus gas inventory being lost** Installed and retrieved without workover Remote actuation for bleed off and ESD	*VR Hyd. Ann. SV in combination with barrier rated GLV's is only solution that meets barrier policy & reduces risk associated with annulus gas inventory*
Barrier Gas Lift Valves	**Enables downhole GLM/GLV system to act with production tubing as primary barrier**	

Figure 7 : LGSS Summary Table

The review of available Lift Gas Safety Systems resulted in the selection of a combination of downhole barrier gas lift valves in addition to hydraulically actuated annular safety valves installed within the VR profile of the casing spool. This system provided the greatest risk mitigation, met barrier policy requirements while also minimizing future workover costs and without introducing additional downhole completion complexity.

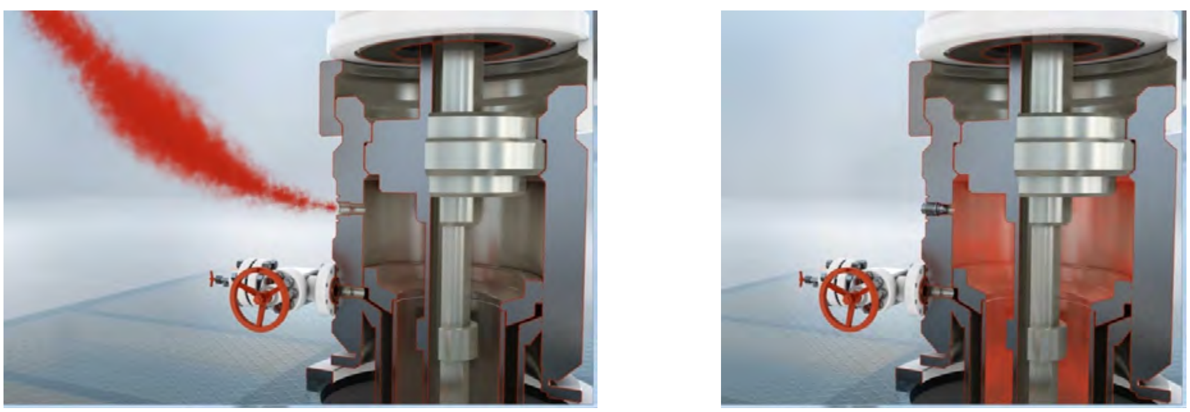

Figure 8 : Damaged annulus outlet showing with and without VR safety valve

Lift Gas Safety System

The LGSS consists of the following:

- A dart type (fail safe closed) check valve. The check valve is installed (threaded) into the annulus line valve replacement (VR) profile.
- A flow tube hydraulic actuator used to hydraulically open the check valve. It also facilitates pressure bleed off from the "A" annulus for integrity testing of the gas lift valves installed in the completion string. The hydraulic actuator is normally connected to the ESD system such that the valve is open whenever the actuated Xmas tree valves are open and closed when they are closed.
- The actuator and valve are separate items such that if the actuator and spool piece were to be separated from the wellhead during an incident, the valve will remain within the VR profile in the wellhead and act as a barrier.
- A spool piece, installed between the annulus outlet and the first gate valve. The spool piece has a penetration to allow hydraulic fluid from the ESD panel to supply pressure to the hydraulic actuator as well as appropriate seal bores to seal the hydraulic actuator within the spool.

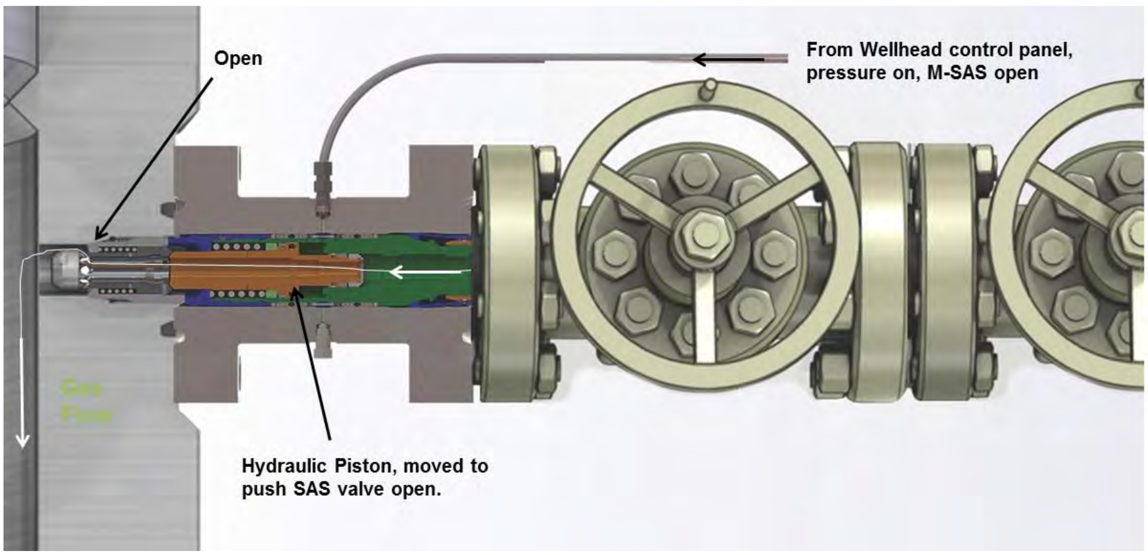

Figure 9 : LGSS Assembly

Tests/reviews performed on the Lift Gas Safety System during the evaluation period:

- Validation test of the actuated valve according to API 6A F.1.15
- Validation testing of the hydraulic actuator according to API 6A F.1.15.1
- Fire Test of water pressurized valve according to API 6FB (part I) and 6FD
- Fire Test of gas pressurized valve according to API 6FB (part I) and 6FD
- Flow test of valve, 4bpm @ 500 bbl. with and without spring return in valve
- CFD analysis of valve to model the flow test at 4bpm
- FMECA report for the valve and actuator
- Evaluation of the valve and actuator system regarding ignition hazard according to ATEX 94/9/EC zone 0
- Independent Review Certificate for the selected LGSS according to API 6A: 20th Edition: 2010 NACE MR0175 ISO15156:2009

"A" & "B" Annulus Monitoring Instrumentation

The monitoring system consists of the following:

- Annulus Pressure and Temperature Sensor installed within a VR plug providing a primary barrier
- Sensor ceramic bulkhead tested to gas tight criteria which provides a secondary barrier
- System is available in either wired or wireless HART data transmission protocols (Pressure and Temperature)
- System is available with wired power or battery power.
- System is designed such that if the electronic section is removed during an incident the plug section will remain in the VR profile acting as a barrier.

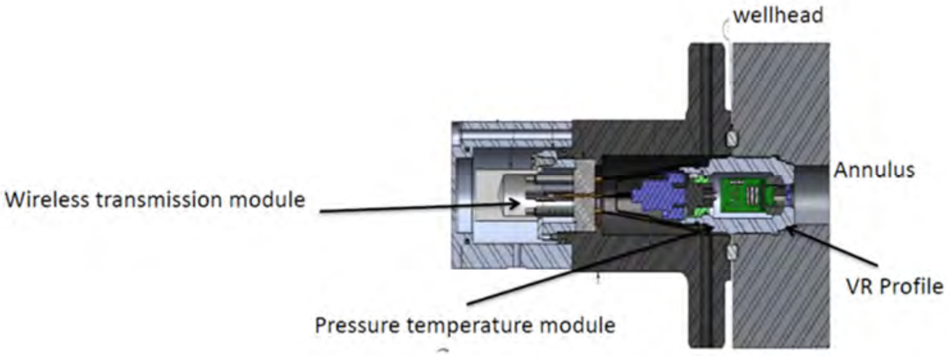

Figure 10 : Annulus Monitoring System (AMS)

Tests/reviews performed on the Annulus Monitoring System (AMS) during the evaluation period:

- Fire Test of AMS according to API 6FB (part 1, sect 3.2.1) and 6FD
- EC-Type Examination Certificate. (ATEX certification) according to ATEX 94/9/EC zone 0 for wired version of sensor
- Independent Review Certificate for AMS according to API 6A: 20th Edition: 2010 NACE MR0175 ISO15156:2009
- HART conformance test according to HART Communication Protocol Requirements
- Hart Communication verified according to HCF method
- Long Term test of the AMS over 18 months, 2 Sensors running continuous cycles (1 cycle per week) of pressure built up (100Barg) and bleed off, measured against a calibrated pressure transmitter.
- Shock & Vibration testing. HALT - according to IEC 62506. Shock and Vibration - according to IEC 60068

Well design optimized for lift gas safety

The selected system provided the ability to:

- Actively containing the gas within the well on triggering of Emergency Shut Down (ESD) System.
- Monitor annular pressures with instrumentation while the annulus is shut in.
- Maintain well integrity with a two barrier philosophy that met company well integrity standards.

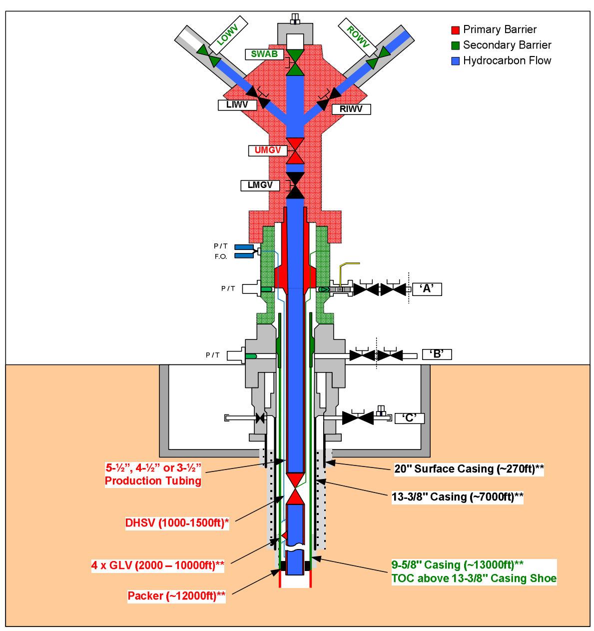

Figure 11 : Well Design optimized with LGSS and Annulus Monitoring

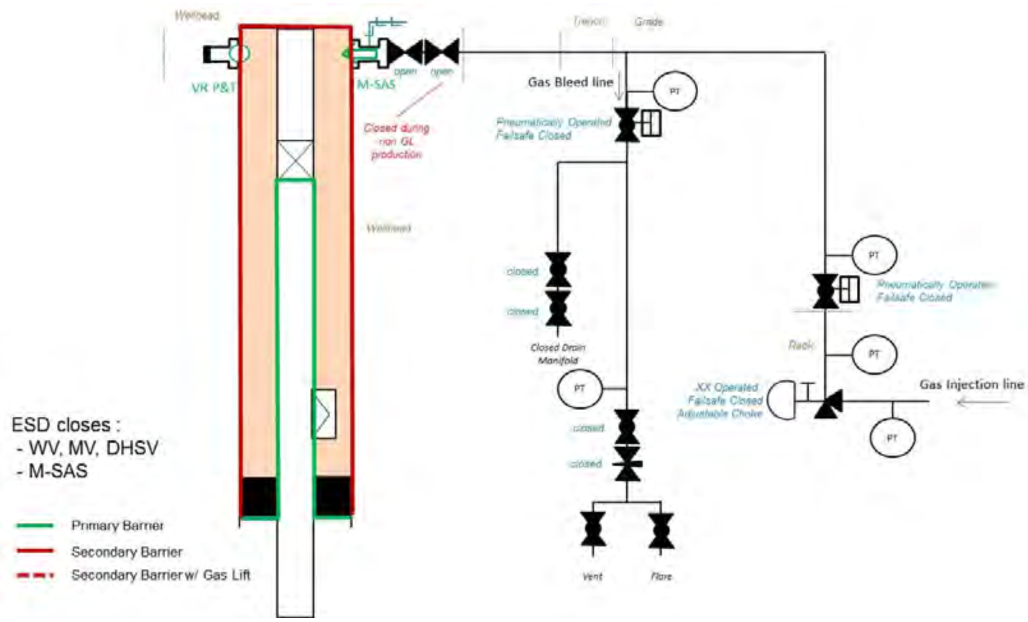

Figure 12 : Optimized well design with barrier envelope

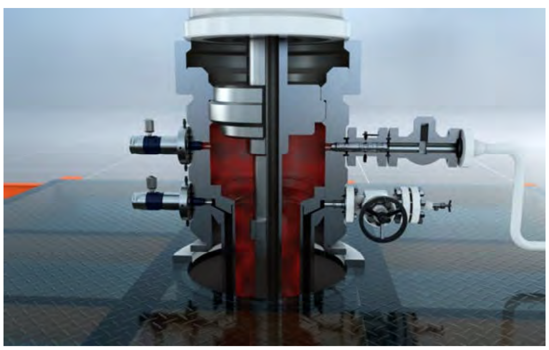
Figure 13 : Wellhead showing LGSS on "A" Annulus and VR Sensors installed on "A" + "B" Annulus

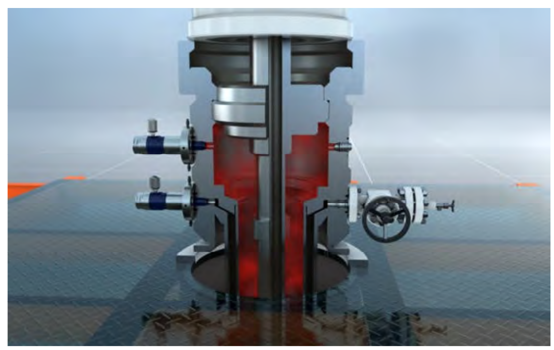
Figure 14 : Wellhead with LGSS flange removed through incident and VR Safety Valve remaining as barrier

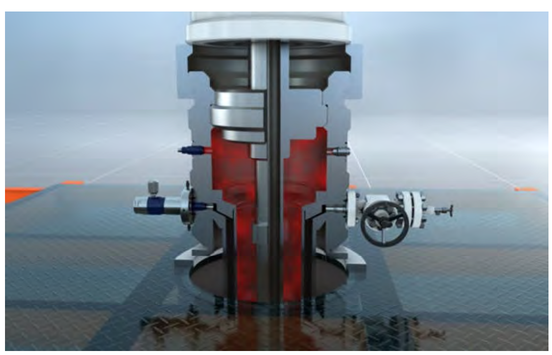
Figure 15 : Wellhead with VR Sensor flange removed through incident and VR Sensor Plug remaining as barrier

Optimized Surface Facilities

The outcomes from the risk review led to significant reduction in high alloy piping, valves and instrumentation between the wellheads and the manifold pipe racks. Figure 16 is a simplified before and after illustration of the facilities on a typical production wellhead. The orange facilities highlighted on the left of Figure 16 depict some of the piping and valves that were able to be deleted from the design. Additionally significant downstream piping, valves and instrumentation on the manifold pipe rack (not shown in Figure 16) were able to be deleted from the design.

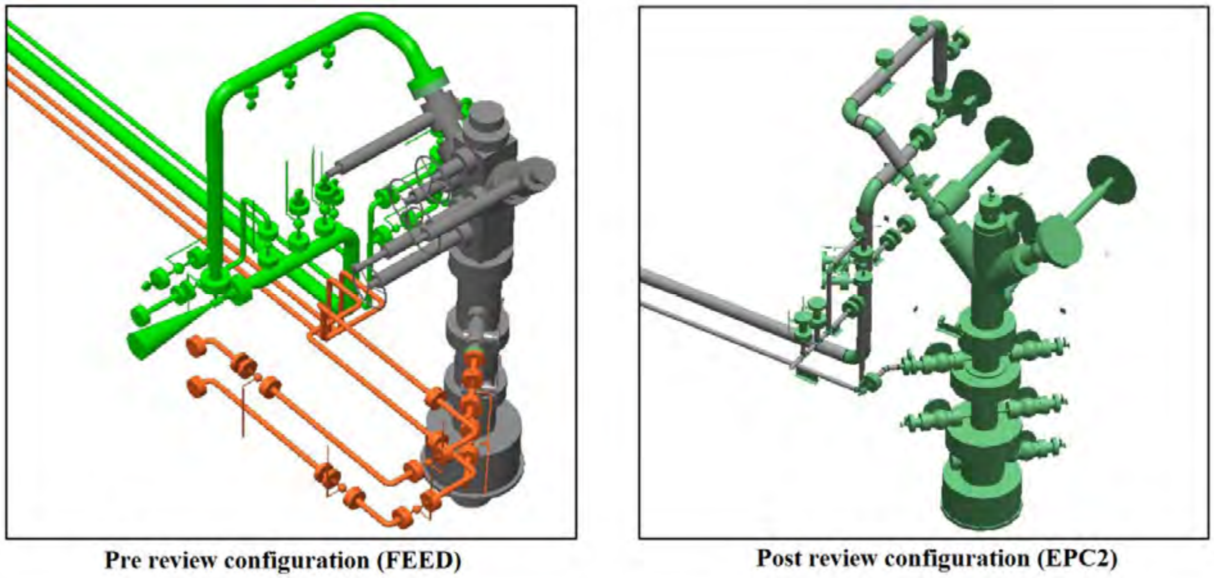

Figure 16 : Production wellhead surface piping comparison

In addition to the safety benefits of less facilities subjected to damage from drilling and maintenance operations, there is a direct cost savings achieved through the optimization of surface facilities. These savings are derived from the deletion of facilities (estimated quantities of piping, valves and instruments) and the associated costs to fabricate, install, and test those facilities. The large number of wells planned for full field development, coupled with the high cost of alloy materials (Inconel 625), combines to provide significant cost savings. The costs savings far exceeded the cost of implementing the new LGSS technology into the field development.

Other benefits

Analysis of SIMOPS in relation to barriers and well control while skidding drilling rigs over a live well identified the potential for other benefits of the system. The LGSS and AMS combination would permit skidding a rig with pressurized annular gas or live gas injection rather than the original plan of bleeding down annulus lift gas and shutting in production.

Project Execution

Equipment has been procured with first installations planned for Q4 2014 following successful system integration testing. The system design provides the flexibility for the equipment to be installed during wellhead manufacture, in a workshop to the casing spool’s annular outlets or in-situ to already installed casing spools. The first installations performed will be in-situ to casing spools currently installed on production wells.

The systems procured also have the added flexibility to adjust to differing data transmission and power supply types when moving the artificial Island project from the initial production (temporary) phase to full field (permanent) production phase. Initial production will be set up for wireless data transmission with power supplied by integral batteries whilst full field production will be setup for wired data transmission and power supply.

Conclusion and Results

The revised well design which includes the use of a surface deployed Lift Gas Safety System (LGSS) in conjunction with annulus monitoring systems (AMS) has addressed several well integrity issues surrounding the use of high pressure lift gas within ERD production wells on artificial Islands with simultaneous production and drilling operations.

The revised well design provides a solution that lowers the risk level associated with SIMOPS and gas lift operations through:

- Actively containing the gas within the well on triggering of Emergency Shut Down (ESD) System.
- Providing a facility to monitor annular pressures with instrumentation while the annulus is shut in.
- Maintaining well integrity with a two barrier philosophy that meets company well integrity standards.

This revised well design allowed for significant flow on improvements to surface line architecture resulting in significant cost savings to the project.

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Abbreviations Used

AMS: Annulus Monitoring System
DHSV: Downhole Safety Valve
ERD: Extended Reach Drilling
ESD: Emergency Shutdown
EWP: Elevated Work Platform
GLM: Gas Lift Mandrel
GLV: Gas Lift Valve
LGSS: Lift Gas Safety System
LIWV, LOWV, RIWV & ROWV: Left/Right Inner/Outer Wing Valves
LMGV & UMGV: Lower & Upper Master Gate Valves
VR: Valve Replacement

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