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Subsea to Floating: A Unified Field Development Approach

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Subsea to Floating: A Unified Field Development Approach



When Repair Is Not Feasible: Engineering Trade-Offs in Locking Open a Subsea Production Master Valve

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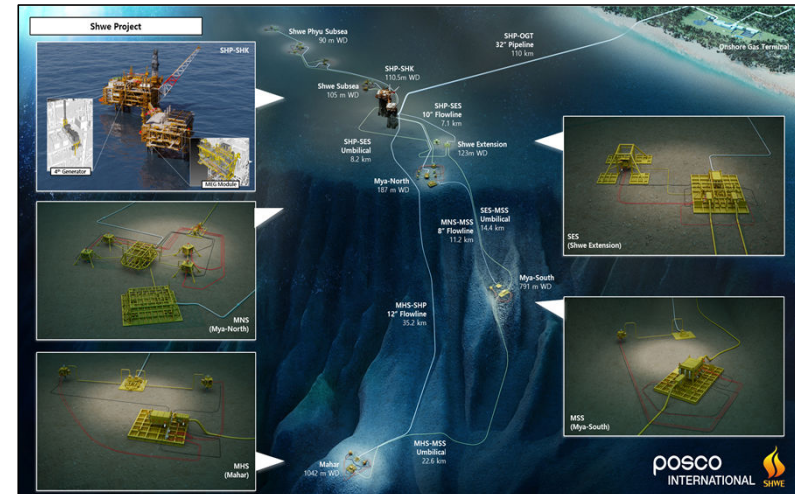
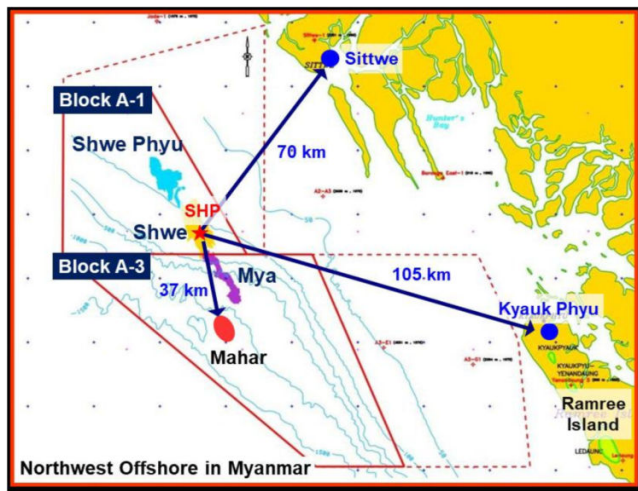


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Asset Background

- Phase 1: Shwe Platform (SHP), subsea production system (4 wells), 14" flowline & 32" export pipeline
- Phase 2: subsea production system (7 wells), 12" & 14" flowlines
- Phase 3: LP compression Platform
- Phase 4 (ongoing): subsea production system (4 wells), 8" & 10" & 12" flowlines



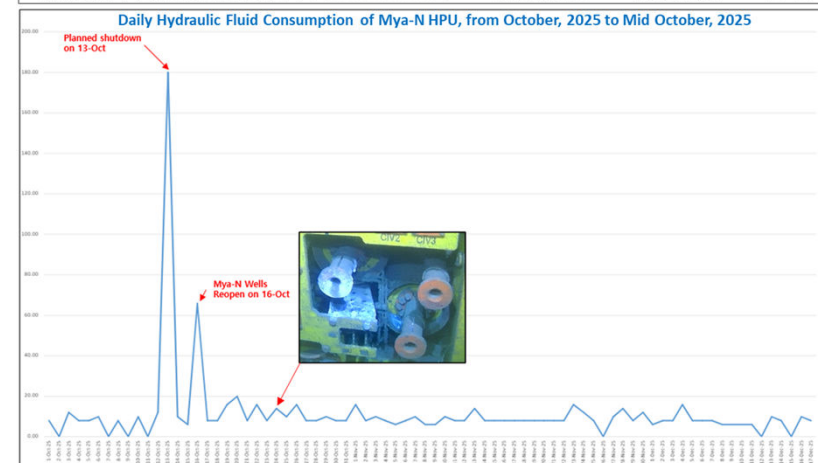
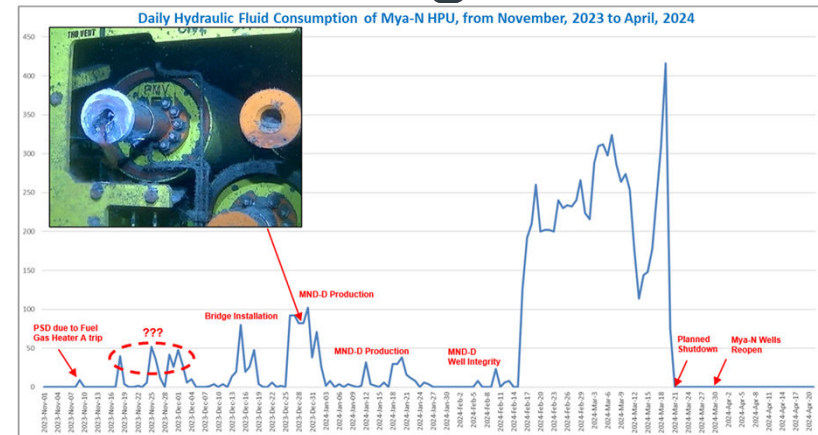


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Problem Statement: Recurring Hydraulic Leakage

- 1st hydraulic leak suspected Nov 2023
- Confirmed leak from PMV of Mya-N A well
- Leak escalated after Mya-N D Well Integrity Test
- Fluid loss up to 400 L/day at peak
- No leakage detected following April 2024
- Recurrence of hydraulic leak suspected after wells restart in October, 2025
- Minor leakage confirmed from same location
- Further deterioration risks PMV functionality and production disruption





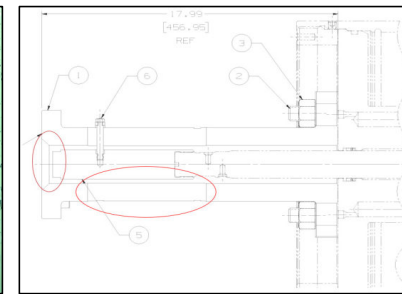
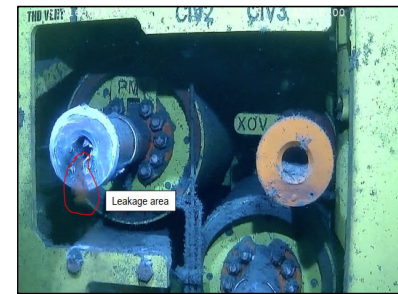
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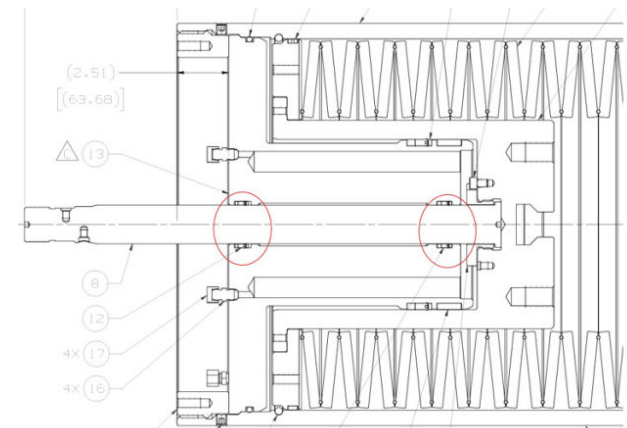
Understanding the Failure Mechanism

- Actual root cause cannot be confirmed without removing actuator assembly from XT
- Possible root cause analysis studied with OEM

No.	Possible Root Cause	Possible Reasons	Possibility
1	Actuator Upper Stem Damage	Defective Material, Faulty Design, Upper Stem damaged, Wrong assembly and test, faulty part	Low
2	Piston Housing Damage	Wrong Assembly and Test, Faulty Design, and Piston Housing Damage	Low
3	Pip Seal Defect	Defective Material	Low
4	Pip Seal Damage	Faulty Part, Wrong Assembly and Test, Faulty Design, Degraded seals	Low
5	Marine growth on Upper Stem	Damage to Coating isolating Stem from CP	Medium
6	Calicious deposits on Upper Stem	Extended water circulation in Upper Stem area, Damaged Coating on the Stem	Medium
7	Spring damage	Spring corrosion and damage	Low
8	Piston Housing damage	Faulty Design, Wrong Assembly and Test	Low



Leakage Area from MND-A PMV



Barriers that fail for Leak to Happen



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Why Conventional Repair was Impractical

- Replacement or refurbishment of PMV actuator requires XT retrieval
- Requires major offshore intervention campaign with huge budget
- High operational risk exposure
- Long production shutdown required
- Disproportionate cost impact

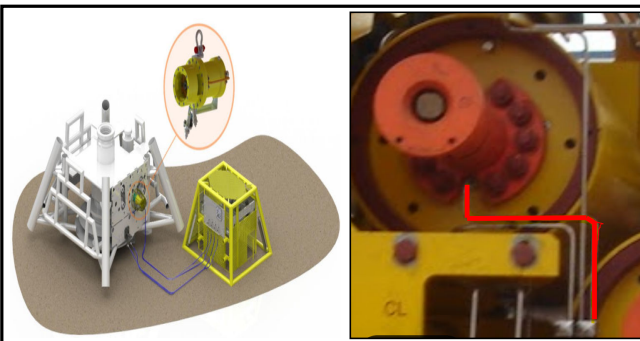


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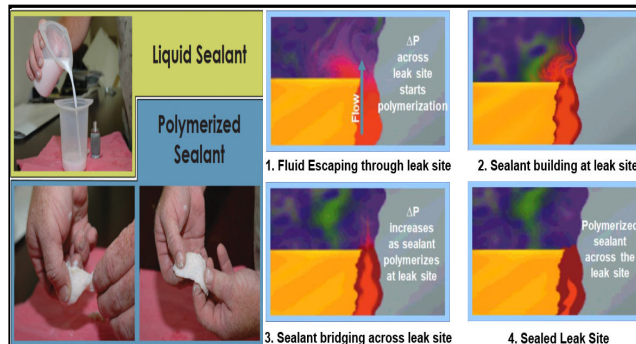
Screening of Alternative Remediation Options

- Preliminary evaluations with third parties assessed alternative remediation options.



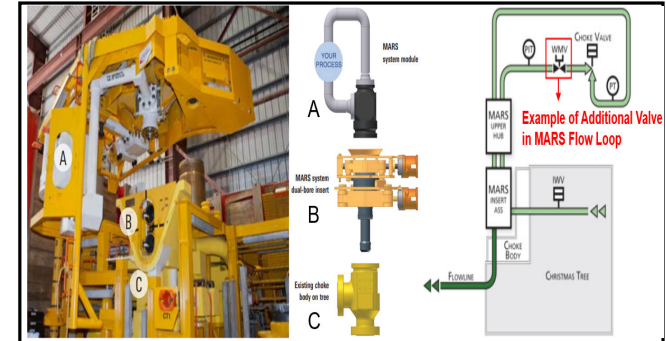
PCOL to Reinstatate Actuator Function

- Platform Controlled Override Linear (PCOL) system enables remote actuator override
- API Type A/B/C Interface Compatible
- Requires SCM hydraulic connection
- No available hydraulic connection from SCMMB to supply control fluid to PCOL tool**
- Only accessible part of tubing circuit from SCMMB to actuator is the highlighted line**
- Hot tap into that line would be a possible method of diverting fluid to PCOL**



Injecting Pressure Activated Sealant to Leak Location

- Field proved technology since 1995
- Solidified into polymer at the leak site in the presence of differential pressure
- Excess sealant remains liquid
- Requires pumping down hydraulic control line via SCM hydraulic circuit
- Requires Dummy SCM which is configured to route flow from ROV to leaking actuator only**
- No dummy SCM available**



Installing MARS to Add Well Barrier(s)

- Multiple Application Re-injection System (MARS)
- Enables additional subsea process installation in place of existing choke insert
- Idea was to install Lock Out Tool to PMV and install MARS to reestablish loss of well barrier by adding new control valve in MARS
- Needs hydraulic control for additional valve
- No available hydraulic supply path**
- High development and installation cost**
- Not economically viable**

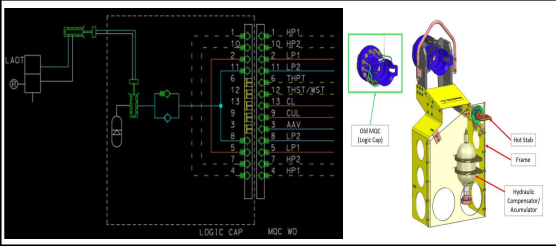
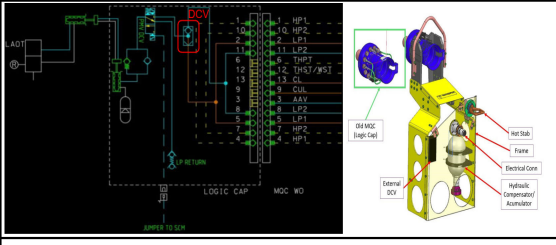
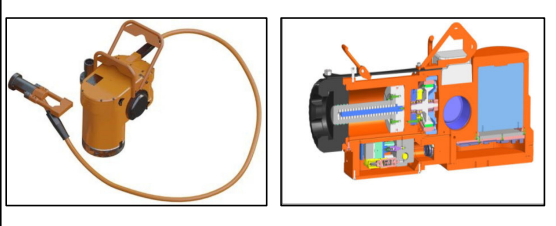


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Engineering Studies to Retain PMV Function

- Evaluated potential solutions with OEM to control LAOT and alternative solution for LAOT.

Methodology	Required Modifications	Advantages	Disadvantages
	<p>LAOT Hydraulic Control (via LP2 line pressure change)</p> <ul style="list-style-type: none"> Utilizes a LAOT connected to the existing LP2 line at XT MQC plate 	<ol style="list-style-type: none"> Reworking of MQC logic cap to use LP2 for LAOT Topside HPU tubing modification to have separate pressure regulators for LP1 & LP2 	<ul style="list-style-type: none"> No SCM modification No EFL jumper required More economical option
	<p>LAOT Hydraulic Control (via External DCV)</p> <ul style="list-style-type: none"> Similar to previous option but involves an external DCV which will control fluid flow to LAOT 	<ol style="list-style-type: none"> Reworking of MQC logic cap to use LP2 for LAOT including external DCV, Electrical connector & EFL SCM modification to use spare EC3 to reroute cables from PMV DCV to EC3. 	<ul style="list-style-type: none"> Provides CRO precise control over PMV. PMV will close during the L3 shutdown.
	<p>Utilizing E-Actuator for PMV</p> <ul style="list-style-type: none"> Employs an electric actuator to operate the PMV, replacing hydraulic actuation with pure electrical motor control via SCM electrical control 	<ol style="list-style-type: none"> SCM hardware modification to use EC3 and internal wiring changes to control E-actuator. SCM software modification to operate E-actuator instead of DCV. 	<ul style="list-style-type: none"> Reduces upfront cost compared to MQC modification. Provides CRO precise control over PMV. PMV will close during the L3 shutdown.

*LAOT – Linear Actuator Override Tool

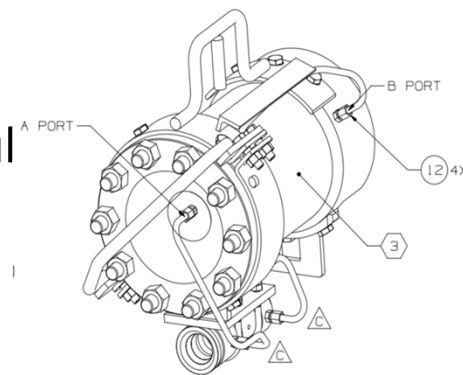


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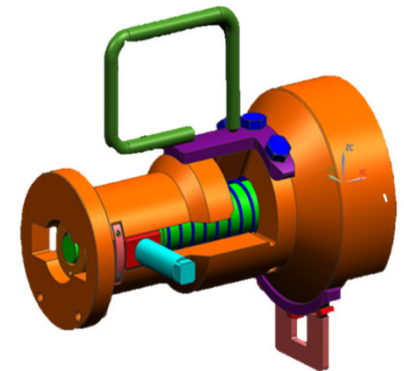


Simpler Path: Mechanical Lock-Open Strategy

- Previous options technically constrained or uneconomic
- Mechanical override to actuator and hydraulic supply isolation to actuator eliminates hydraulic leakage
- Significantly lower cost than alternatives
- Simple ROV-based installation method
- Prior proven tool with long-term field use

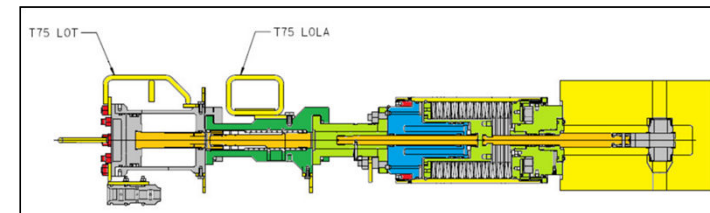
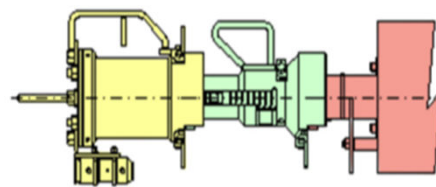


Linear Override Tool (LOT)



Linear Override Locking Assembly (LOLA)

No.	Description	Estimated Cost (USD)
1	Procurement of LOT & LOLA	200,000
2	Installation Cost (2 days of ROV Intervention)	300,000
Total Estimated Cost		500,000



Using LOT to Install LOLA to Actuator for Mechanical Override



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Trade-Off: Loss of PMV Barrier

- Required formal well integrity risk study due to reduced well barrier after LOLA installation to PMV

Overall Well Integrity Status (as per study with 3rd Party)

Primary Barrier	Secondary Barrier	Overall
●	●	●

Integrity Status Color Code

●	High	●	Medium
●	Low	●	Very Low

“Medium” Risk WBEs and Recommendations by 3rd Party

WBE	Required Verification (in accordance with NORSOK D-10)	Mitigation
Secondary Well Barrier		
Subsea Tree (concerned only when PMV is locked open)	<ul style="list-style-type: none"> PMV is excluded as part of Subsea Tree secondary WBE. Periodic inspection and tests for sign of external leaks or deterioration of X-mas Tree Valves and LOLA on a yearly basis. 	<ul style="list-style-type: none"> PWV, XOY, SCSSV leak and function test (Freq – 3 or 6 months) ROV inspection campaign (Freq – 12 months) PWV, XOY control line pressure monitor (Freq – real time/daily)

WBE	EAC Table	Verification/Monitoring
Primary Well Barrier		
In-situ formation (AI casing shoe)	51	Formation integrity pressure was verified by a documented field model. The estimated Fracture pressure at the casing shoe depth is 5,166 psi. Monitoring: N/A after initial verification.
Production casing cement (Up to production Packer)	22	The cement sealing ability was verified by displacement efficiency based on records from the cementing job (volumes pumped, returns during cementing, etc.). The lead and tail slurries volume pumped were according to the design. No losses were reported during cementation. Differential pressure at the end of displacement was 815 psi. Maximum displacement pressure recorded was 1,050 psi. Monitoring: N/A after initial verification.
9 5/8" Production casing (Up to production Packer)	2	Casing was leak tested to maximum differential pressure to 5,000psi / 15 min (Good test). Monitoring: n/a after initial verification.
9 5/8" Production Packer	7	Production packer sealing ability was verified by pressure test to 500psi/5min, and 4,000psi/10min, good test. Monitoring: The A-annulus shall be continuously monitored for any pressure irregularities.
Completion string up to DHSV depth	25	Tubing along packer was pressure tested to 500psi/5min, and 4,000psi/10min, good test. Monitoring: The A-annulus shall be continuously monitored for any pressure irregularities.
DHSV	8	TRSCSSV was inflow tested with 4,000psi against the flapper and 500 psi maintained above TRSCSSV's flapper. Hold for 15 Minutes. Good test and no pressure bypassing. SCSSV control line was pressure tested to 1,000psi then after to 10,000psi. Good test. The DHSV was function tested and leak tested, and passed the tests (20-02-2023). Test evaluation period is volume and compressibility dependent and was held for a period that give measurable pressure change for the allowed leak rate (0.1bbl/30min), minimum 30 min.
Secondary Well Barrier		
In-situ formation-	51	Formation integrity pressure was verified by a documented field model. The estimated Fracture Pressure at Packer depth for shale formation is 8,820psi. Monitoring: N/A after initial verification.
9 5/8" Production casing Cement (Above Production Packer)	22	The cement sealing ability was verified by displacement efficiency based on records from the cement operation (volumes pumped, returns during cementing, etc.). The lead and tail slurries volume pumped were according to the design. No losses were reported during cementation. Differential pressure and of displacement was 815 psi. Maximum displacement pressure recorded was 1,050 psi. Monitoring: N/A after initial verification.
9 5/8" Production casing (Above Production Packer)	2	Sealing ability was verified by pressure test to 5,000psi / 15 min (Good test). Monitoring: The A-annulus shall be continuously monitored for any pressure irregularities.
Production casing hanger with seal assembly	5	Sealing ability was verified by pressure test to 5,000psi / 15 min (Good test). Monitoring: Continuous pressure monitoring of A-annulus
Tubing hanger with seals	10	Tubing hanger with seals was pressure tested to 5,000psi/ 15min. Good test. Monitoring: The A-annulus shall be continuously monitored.
Wellhead with Seals	5	Wellhead with seals was pressure tested to 5,000psi/ 15min. Good test. Monitoring: Periodic leak and function testing for annulus valves. Monitoring: The A-annulus shall be continuously monitored for any pressure irregularities.
Subsea Tree	31	The housing with bores that are filled with production and annulus master valves, crown plugs, flow valves and crossover valves were pressure tested to 5,000psi (Bidirectional), good test. Monitoring: PWV and XOY valves were leak tested recently. Good test (21-03-2024). PMV hydraulic control fluid was found leaking. The loss of the hydraulic pressure could result in unplanned PMV closure and lead to production losses. Failed PMV is dysfunctional. PMV is planned to be locked open with (LOI). PMV is excluded as a part of the Subsea tree secondary WBE.

< MND-A Well Barrier Elements Schematic (WBEs) >



Operational Risk Assessment and Mitigation Strategy

Operational Hazards	Risk Mitigation
Loss of MND-A PMV function and well safety barrier after LOLA is installed to lock PMV in Open Position	<ul style="list-style-type: none">• Proven functionality and integrity test results of remaining active subsea well barriers; SCSSV & PWV and topside HIPPS ESDVs.• Mya-N field has transitioned to LP mode, operating pressure (45 barg @ downstream choke, 20 barg @ SHP arrival) is much lower compared to system design pressure (pipeline @ 306 barg, SHP topside @ 95 barg)• Shut-in Tubing Head Pressure of MND-A is 85 barg in Oct, 2025 which is still below the pipeline and topside design pressure,• Change the MND-A well integrity test from yearly to 6-monthly after LOLA installation.
Discrepancy between the actual PMV position and status indication at MCS/DCS HMI	<ul style="list-style-type: none">• No impact to MND-A shutdown sequence due to MND-A PMV “CLOSED” status at MCS and DCS – all subsea valves except PMV will close as per existing logic during shutdown.• PMV “CLOSED” Status Impact to Chemical Injection Valves opening interlock can be overridden.
Mechanical failure of LOLA for long term deployment due to corrosion, marine growth and calcious deposits	<ul style="list-style-type: none">• The installed LOLA will be inspected with ROV every year to ensure that specific conditions are not accelerating the corrosion rate and marine growth beyond predicted.• Excessive marine deposits may risk the tool being stuck at PMV which can be considered permanent installation, before that happens, LOLA will be cleaned and replaced as required.



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Execution and Outcome

- LOLA installed on PMV actuator using LOT
- “CLOSE” command issued to isolate hydraulic supply
- Associated DCV was closed, stopping hydraulic flow to PMV actuator
- However, accidental “OPEN” command from HMI could reintroduce leakage
- PMV was set to “ROV” mode to prevent unintentional operation
- Leakage eliminated following LOLA installation and isolation



< LOLA Installation >



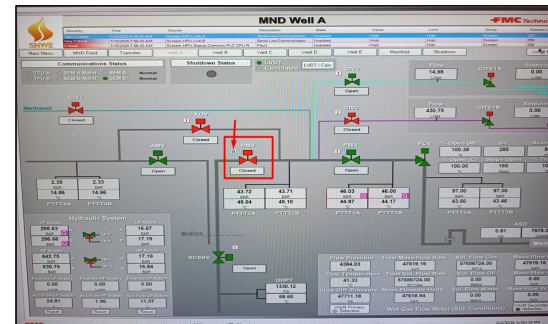
< LOT Installation on top of LOLA >



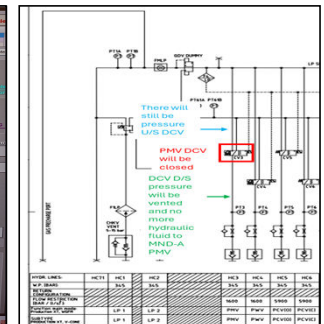
< Locking LOLA Lock Pin in J-Slot >



< LOLA As-left Inspection >



< MND-A PMV Status Showing “CLOSED” and “R” for ROV Mode >





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Conclusion: From Constraint to Practical Solution

- Structured risk assessments confirmed that LOLA installation is acceptable within ALARP limits.
- Through meticulous planning and close cross-functional collaboration, the intervention was executed safely and subsea intervention cost was optimized via integrated campaign.
- Post-installation verification confirmed that hydraulic leakage was effectively eliminated and production continuity was maintained without extended shutdown, while retaining sufficient well barriers.
- This case demonstrates that structured engineering evaluation and risk-based decision-making can enable practical, non-standard solutions when conventional repair is not feasible.
- The approach should provide a useful framework for operators managing actuator degradation in aging subsea systems, where safety, cost, and operability must be balanced.