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9-Zone All-Electric Multizone Intelligent Completion in Mozambique– Stretching the Boundaries of Technology

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Abstract

A 9-zone all-electric multi-zone intelligent completion was planned to be installed in an onshore well in Mozambique, in order to target multiple isolated stacked under-appraised oil and gas sands while maintaining the functionality of independently managing production and data acquisition from each of the sands. The paper discusses the design, planning and execution of a 9-zone all-electric multizone intelligent completion in an onshore oil and gas well.

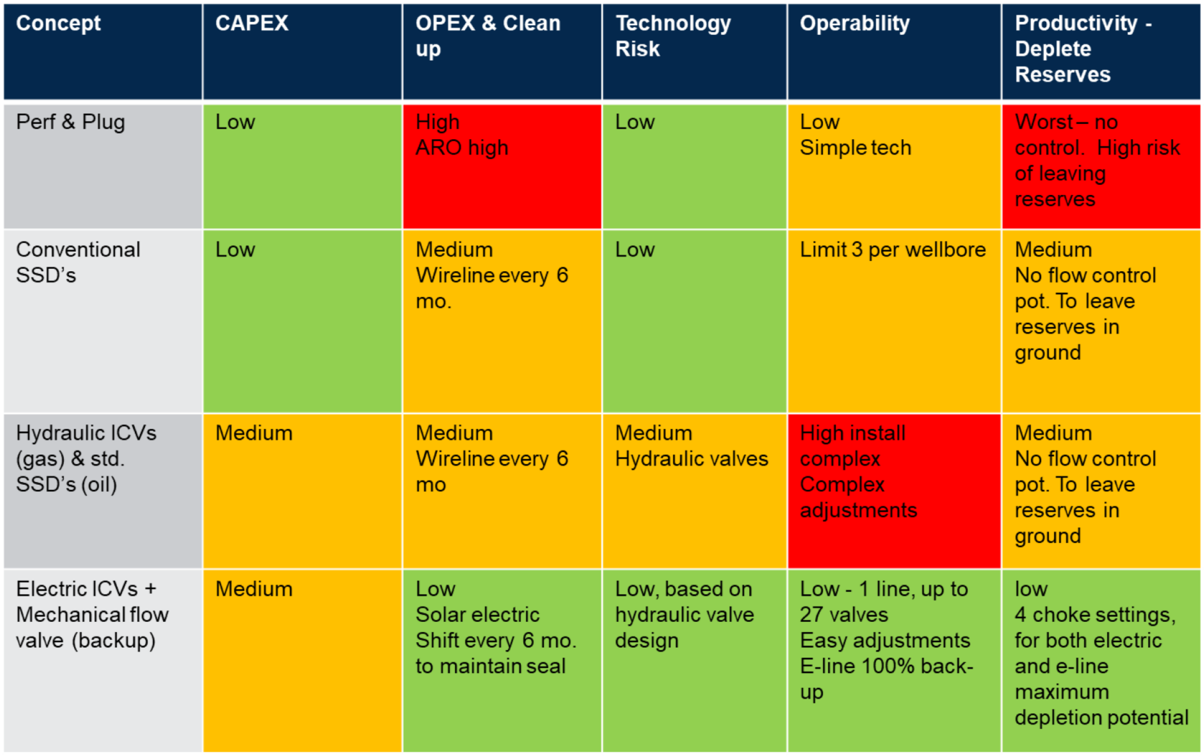
The completion required careful consideration during the design, planning and execution stages to ensure success. Rigorous quality assurance, regular reviews and careful advance planning ensured that the various formal and informal milestones were achieved successfully. The completion was executed within time and cost, with minimal Non-Productive Time (NPT). The well was subsequently successfully flow tested through temporary well test facilities. Expected production performance was exceeded in 7 out of 9 zones tested.

Introduction

Hydraulic Interval Control Valves (ICVs) are commonly used for multi-zone surface controlled intelligent completions globally. The greatest limitation with this system is the number of control lines required to operate ICVs. In hydraulic systems, the number of control lines required is typically the same as the number of ICVs deployed in the completion, each required to open a single ICV, plus a common close-function line. This is commonly referred to as the ‘n + 1’ system. This poses a limit to the number of isolated zones that can be controlled in a single well. This limitation is circumvented with all-electric ICVs which can be operated fully via a single cable connecting the ICVs in series. This was the key factor in the selection and deployment of electric ICVs in the 9-zone intelligent completion.

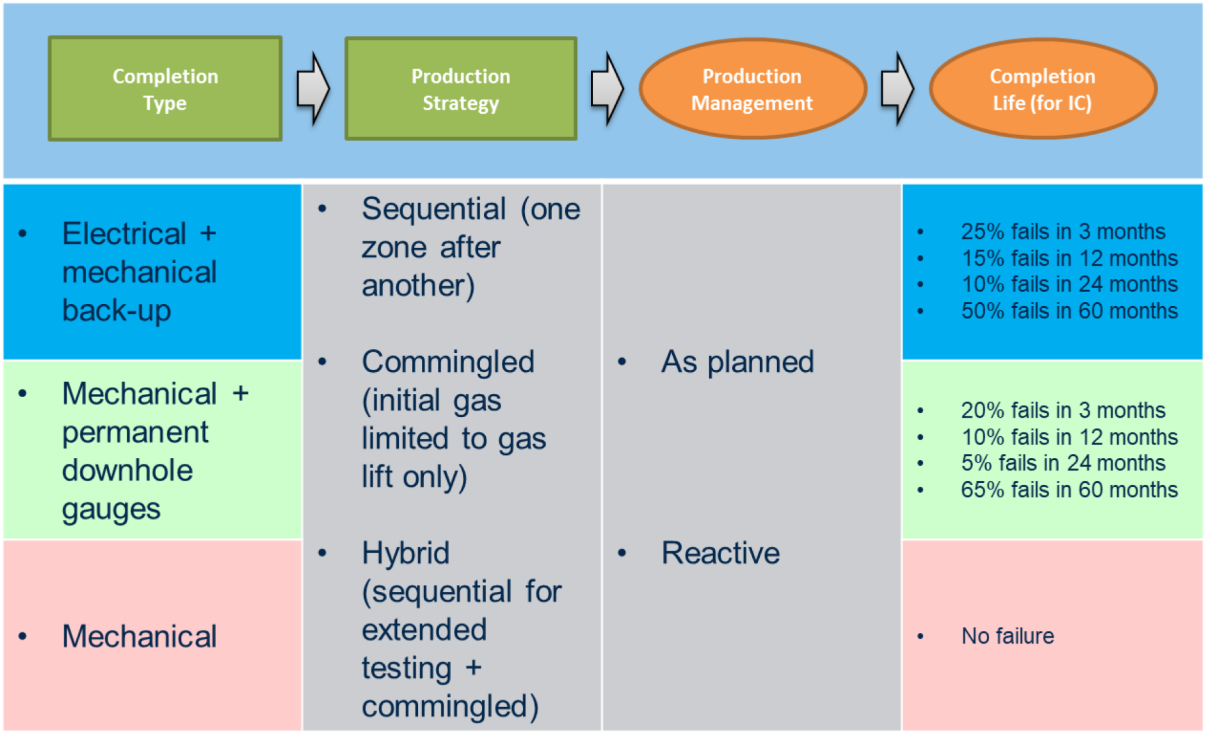
The objectives of the well were to target well delineated shallow gas zones to meet gas production targets, and under-appraised deeper oil zones encountered in an offset well in a mature onshore field, with significant uncertainties with reservoir quality and associated volumes. These uncertainties made it difficult to justify multiple wells for the deeper oil zones. Some of the key drivers for the completion were data acquisition to appraise the deeper oil zones and reduction of uncertainty with associated volumes.

The requirement to test each completed zone individually through temporary test facilities post-completion, and to manage well test spread costs, drove the need for surface control of the ICVs in the completion. Flexibility to manage the number of zones in the well, water management and the need to cater to a wide range of test and production scenarios, drove the requirement for multi-position, adjustable ICV systems, which were deemed to provide the highest practicable well and reservoir management flexibility along with effective data acquisition. The requirements for real-time reservoir surveillance, transient analyses, coupled with concerted efforts to reduce uncertainties around flow contribution, manage water production, and acquire well and reservoir data without the need for wireline intervention, prompted the need for permanent downhole gauges against each zone. Figure 1 below shows the comparison of various completion alternatives for the well. Figure 2 below shows the decision matrix with well life cycle failure risk vs well & reservoir management and surveillance benefits.



Concept	CAPEX	OPEX & Clean up	Technology Risk	Operability	Productivity - Deplete Reserves
Perf & Plug	Low	High ARO high	Low	Low Simple tech	Worst – no control. High risk of leaving reserves
Conventional SSD's	Low	Medium Wireline every 6 mo.	Low	Limit 3 per wellbore	Medium No flow control pot. To leave reserves in ground
Hydraulic ICVs (gas) & std. SSD's (oil)	Medium	Medium Wireline every 6 mo	Medium Hydraulic valves	High install complex Complex adjustments	Medium No flow control pot. To leave reserves in ground
Electric ICVs + Mechanical flow valve (backup)	Medium	Low Solar electric Shift every 6 mo. to maintain seal	Low, based on hydraulic valve design	Low - 1 line, up to 27 valves Easy adjustments E-line 100% back-up	low 4 choke settings, for both electric and e-line maximum depletion potential

Figure 1—Comparison of Various Completion Alternatives



Completion Type	Production Strategy	Production Management	Completion Life (for IC)
Electrical + mechanical back-up	Sequential (one zone after another)		25% fails in 3 months 15% fails in 12 months 10% fails in 24 months 50% fails in 60 months
Mechanical + permanent downhole gauges	Commingled (initial gas limited to gas lift only)	As planned	20% fails in 3 months 10% fails in 12 months 5% fails in 24 months 65% fails in 60 months
Mechanical	Hybrid (sequential for extended testing + commingled)	Reactive	No failure

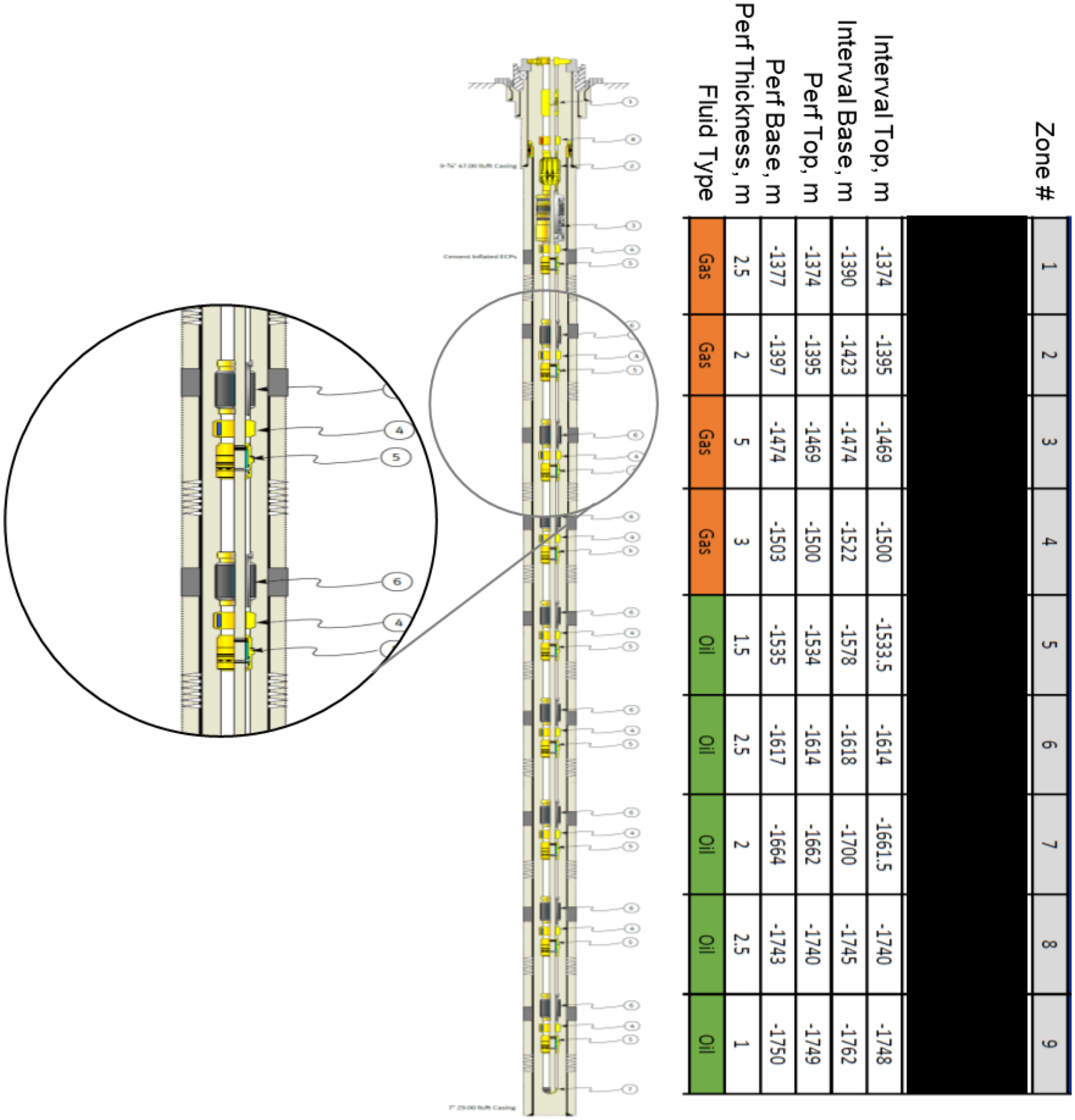
Figure 2—Completion Decision Matrix

Completion Design Maturation – Risks & Mitigation

The initial completion concept of a 9-zone intelligent completion with multi-position electric ICVs and mechanical back up ICVs based on the Pre-Drill Data Package (PDDP) provided by the Subsurface team, matured through various phases to a final design. Figure 3 below shows the completion concept against the PDDP information.

Several risks were identified early on due to the complexities of the completion concept:

- Risk of design and execution of an 'outside of the envelope' completion design. This arises from the fact that a completion with 9-zones in a single well with an all-electric ICV system, had never been installed prior to this, based on data sourced from the technology provider.
- Risk of equipment failure with a single electric cable connecting all the ICVs in the completion (a total of 55 potential termination failure points).
    - 2 × tubing hanger termination failure points (top and bottom).
    - 18 × feedthrough packer failure points (9 × packers top and bottom).
    - 18 × downhole gauge termination failure points (9 × gauges top and bottom).
    - 18 × ICV termination failure points (9 × ICVs top and bottom).
- Risk of equipment failure due to the system being insufficiently field proven at this early stage. Electric ICVs are an emerging technology in intelligent completions. Risk includes installation failure as well as premature in-service failure.
- Risk of damage to Tubing Encased Conductor (TEC) line during installation. As the ICVs are connected in series via a single TEC line, any TEC line failure would render all the ICVs below the failure point non-functional.



Zone #	1	2	3	4	5	6	7	8	9
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Interval Top, m	-1374	-1395	-1469	-1500	-1533.5	-1614	-1661.5	-1740	-1748
Interval Base, m	-1390	-1423	-1474	-1522	-1578	-1618	-1700	-1745	-1762
Perf Top, m	-1374	-1395	-1469	-1500	-1534	-1614	-1662	-1740	-1749
Perf Base, m	-1377	-1397	-1474	-1503	-1535	-1617	-1664	-1743	-1750
Perf Thickness, m	2.5	2	5	3	1.5	2.5	2	2.5	1
Fluid Type	Gas	Gas	Gas	Gas	Oil	Oil	Oil	Oil	Oil

Figure 3—Completion Concept

The risks were managed and mitigated by conducting several milestone reviews with the various stakeholders, at various stages of the completion design:

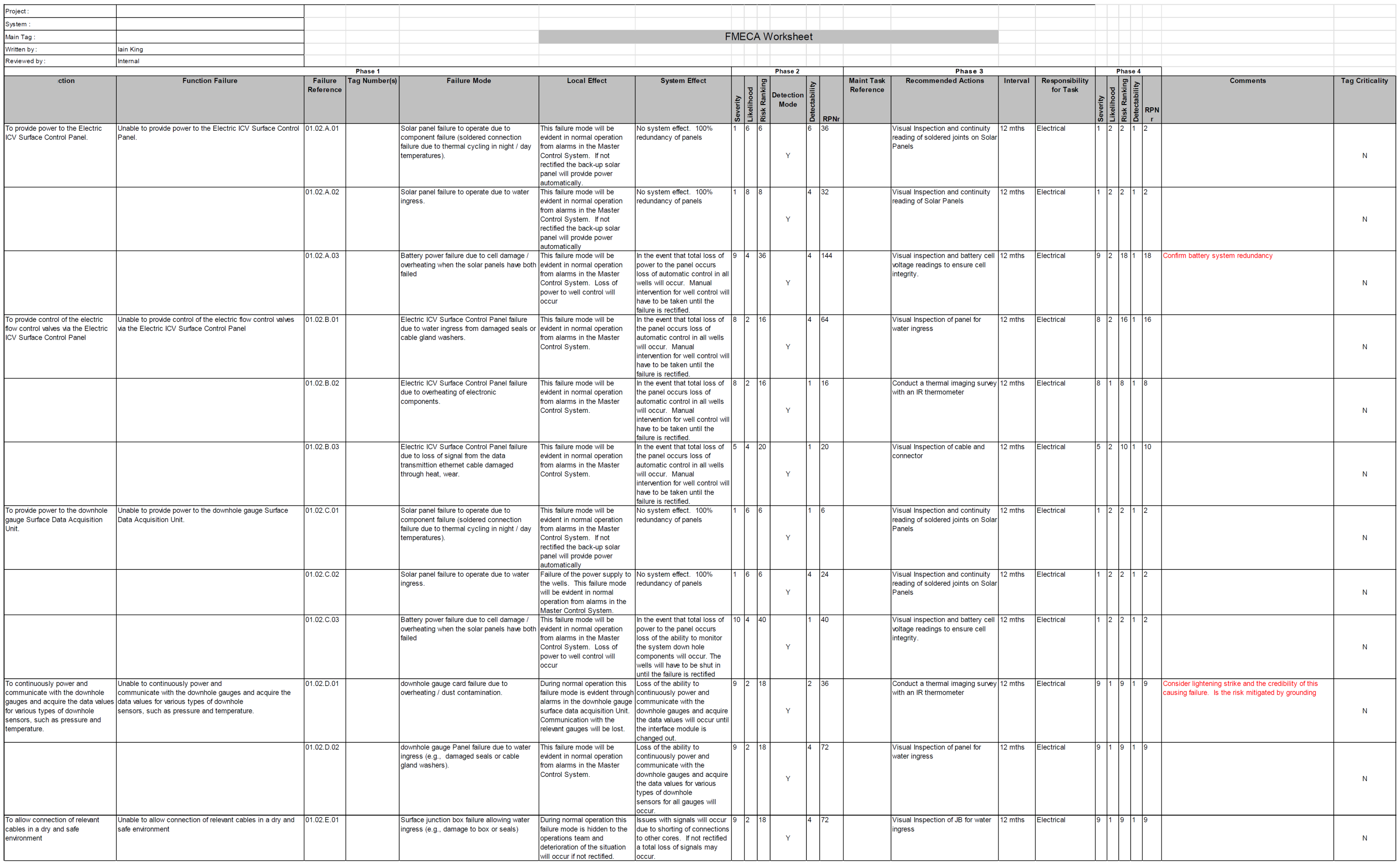
1. Preliminary Design Review: A multi-disciplined review of the completion concept, prioritizing the key objectives of the completion, and a review of the various design and operational pitfalls.
2. Final Design Review: Review of the final completion design, intended to finalize the completion components and interfaces, prior to placing orders.
3. Failure Mode Effects and Criticality Analyses (FMECA): Component by component review of the entire completion system, including the surface facilities and operational interfaces to identify and address failure modes and their impacts. Figure 4 below shows the output of the FMECA.
4. Pre-Production Review: Review of the equipment supplier's QA/QC measures at the manufacturing plant, prior to equipment manufacturing.

5. Complete Well On Paper/Test Well On Paper (CWOP/TWOP): A multi-disciplined review of the draft completion and well testing operational programs.
6. Operate Well On Paper (OWOP): A multi-disciplined review of the plan to hook up the well to permanent production facilities and bring the well on stream on routine production post completion and testing.
7. Completion Program Review: A line-by-line review of the final completion operational program, prior to sign-off and issue, involving all the stakeholders, including equipment and service providers and drilling rig contractor.
8. System Integrity Test (SIT): All ICVs and downhole gauges connected in series and tested for functionality at the wellsite, prior to running in hole.

Project :	
System :	
Main Tag :	
Written by :	Iain King
Reviewed by :	Internal

FMECA Worksheet

Phase 1							Phase 2						Phase 3				Phase 4						
Function	Function Failure	Failure Reference	Tag Number(s)	Failure Mode	Local Effect	System Effect	Severity	Likelihood	Risk Ranking	Detection Mode	Detectability	RPNr	Maint Task Reference	Recommended Actions	Interval	Responsibility for Task	Severity	Likelihood	Risk Ranking	Detectability	RPNr	Comments	Tag Criticality
To provide isolation and flow control of individual well zone.	Unable to provide isolation and flow control of individual well zone.	01.01.A.01	See Main Tags	Electric ICV unable to operate due to cable damage / splice failure (e.g., Vibration effect).	During normal operation this failure mode is evident through alarms in the Electric ICV Surface Control Panel data acquisition Unit (investigation required to pinponit actual cause).	In the event of valve failure loss of control of the well flow will occur until manual measures are taken using wireline techniques.	6	5	30	Y	7	210					6	5	30	7	210		L
		01.01.A.02	See Main Tags	Electric ICV unable to operate due to internal erosion damage of valve.	During normal operation this failure mode is hidden. Over time the effects will worsen and the operator will notice a lack of control when the choke position is changed (investigation required to pinponit actual cause).	In the event of valve failure loss of control of the well flow will occur until manual measures are take using wireline techniques.	6	5	30	N	6	180		Monitor sand levels from surface monitoring via SCADA.	Daily	Operator	6	3	18	4	72		L
		01.01.A.03	See Main Tags	Electric ICV unable to operate due to motor failure (e.g., overheating)	During normal operation this failure mode is evident through alarms in the Electric ICV Surface Control Panel data acquisition Unit. When the operator request the valve to move position it will be unable to do so.	In the event of valve motor failure loss of control of the well flow will occur until manual measures are taken using wireline techniques.	6	8	48	Y	2	96		Move flow valve to ensure freedom of movement and check current draw readings from history	3 monthly	Operator	6	5	30	1	30		L
		01.01.A.04		Loss of valve operation due to plugging from well debris	During normal operation this failure mode is hidden. Over time the effects will worsen and the operator will notice a lack of control when the choke position is changed.	In the event of valve failure loss of control of the well flow will occur until manual measures are take using wireline techniques.	6	2	12	N	5	60		Move flow valve to ensure freedom of movement and check current draw readings from history	3 monthly	Operator	6	1	6	4	24		L
	Unable to provide isolation and flow control of multiple well zones.	01.01.A.05	See Main Tags	Electric ICV unable to operate due to cable damage / splice failure (e.g., Vibration effect) at a position in the cable that causes loss of all zone control.	During normal operation this failure mode is evident through alarms in the Electric ICV Surface Control Panel Data Acquisition Unit	In the event of valve failure loss of control of the well flow will occur on all zones until manual measures are taken using wireline techniques.	10	2	20	Y	1	20					10	2	20	1	20		L
To monitor the downhole temperature and pressure.	Unable to monitor the downhole temperature and pressure.	01.01.B.01	See Main Tags	Downhole gauge failure due to exposure to excessive temperature conditions over a prolonged period.	During normal operation this failure mode is evident through alarms in the Downhole Gauge Unit.	Loss of the ability to measure the temperature and pressure in the related zone.	5	2	10	Y	1	10					5	2	10	1	10		L
		01.01.B.02	See Main Tags	Downhole gauge failure due to cable damage / splice failure (e.g. vibration effect).	During normal operation this failure mode is evident through alarms in the Downhole Gauge Unit.	Loss of the ability to measure the temperature and pressure in the related zone.	5	5	25	Y	1	25					5	5	25	1	25		L
		01.01.B.03	See Main Tags	Downhole gauge failure due to blockage in the pressure port	During normal operation this failure mode is hidden during normal operations	Loss of the ability to measure the temperature and pressure in the related zone.	5	1	5	N	5	25					5	1	5	5	25		L
		01.01.B.04	See Main Tags	Loss of readings due to degradation of a component	During normal operation this failure mode is evident from failure codes in the Downhole Gauge Unit.	Loss of the ability to measure the temperature and pressure in the related zone.	5	2	10	Y	1	10					5	2	10	1	10		L
	Unable to monitor the downhole temperature and pressure on all zones.	01.01.B.05	See Main Tags	Downhole gauge failure due to cable damage / splice failure (e.g. vibration effect)at a position in the cable that causes loss of all zone gauges.	During normal operation this failure mode is evident from failure codes in the Downhole Gauge Unit.	Loss of the ability to measure the temperature and pressure in all zones.	10	2	20	Y	1	20					10	2	20	1	20		L
To provide back-up for the Electric ICV system.	Unable to provide back-up for the Electric ICV system.	01.01.C.01	See Main Tags	Mechanical ICV failure seized (e.g. sand build up)	In the event that the Mechanical ICV is required to take over from the Electric ICV it will not be able to operate. During normal operation this failure mode is hidden.	Loss of the ability to control the zone.	8	2	16	N	10	160		Can the Mechanical ICV be operated in normal well mode or lubricated to ensure it's avaliability if required?	0		8	2	16	10	160	Not in normal operation use. Contingency item.	K



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FMECA Worksheet

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To provide power to the Electric ICV Surface Control Panel.	Unable to provide power to the Electric ICV Surface Control Panel.	01.02.A.01		Solar panel failure to operate due to component failure (soldered connection failure due to thermal cycling in night / day temperatures).	This failure mode will be evident in normal operation from alarms in the Master Control System. If not rectified the back-up solar panel will provide power automatically.	No system effect. 100% redundancy of panels	1	6	6	Y	6	36		Visual Inspection and continuity reading of soldered joints on Solar Panels	12 mths	Electrical	1	2	2	1	2		N
		01.02.A.02		Solar panel failure to operate due to water ingress.	This failure mode will be evident in normal operation from alarms in the Master Control System. If not rectified the back-up solar panel will provide power automatically	No system effect. 100% redundancy of panels	1	8	8	Y	4	32		Visual Inspection and continuity reading of Solar Panels	12 mths	Electrical	1	2	2	1	2		N
		01.02.A.03		Battery power failure due to cell damage / overheating when the solar panels have both failed	This failure mode will be evident in normal operation from alarms in the Master Control System. Loss of power to well control will occur	In the event that total loss of power to the panel occurs loss of automatic control in all wells will occur. Manual intervention for well control will have to be taken until the failure is rectified.	9	4	36	Y	4	144		Visual inspection and battery cell voltage readings to ensure cell integrity.	12 mths	Electrical	9	2	18	1	18	Confirm battery system redundancy	N
To provide control of the electric flow control valves via the Electric ICV Surface Control Panel	Unable to provide control of the electric flow control valves via the Electric ICV Surface Control Panel	01.02.B.01		Electric ICV Surface Control Panel failure due to water ingress from damaged seals or cable gland washers.	This failure mode will be evident in normal operation from alarms in the Master Control System.	In the event that total loss of the panel occurs loss of automatic control in all wells will occur. Manual intervention for well control will have to be taken until the failure is rectified.	8	2	16	Y	4	64		Visual Inspection of panel for water ingress	12 mths	Electrical	8	2	16	1	16		N
		01.02.B.02		Electric ICV Surface Control Panel failure due to overheating of electronic components.	This failure mode will be evident in normal operation from alarms in the Master Control System.	In the event that total loss of the panel occurs loss of automatic control in all wells will occur. Manual intervention for well control will have to be taken until the failure is rectified.	8	2	16	Y	1	16		Conduct a thermal imaging survey with an IR thermometer	12 mths	Electrical	8	1	8	1	8		N
		01.02.B.03		Electric ICV Surface Control Panel failure due to loss of signal from the data transmittion ethernet cable damaged through heat, wear.	This failure mode will be evident in normal operation from alarms in the Master Control System.	In the event that total loss of the panel occurs loss of automatic control in all wells will occur. Manual intervention for well control will have to be taken until the failure is rectified.	5	4	20	Y	1	20		Visual Inspection of cable and connector	12 mths	Electrical	5	2	10	1	10		N
To provide power to the downhole gauge Surface Data Acquisition Unit.	Unable to provide power to the downhole gauge Surface Data Acquisition Unit.	01.02.C.01		Solar panel failure to operate due to component failure (soldered connection failure due to thermal cycling in night / day temperatures).	This failure mode will be evident in normal operation from alarms in the Master Control System. If not rectified the back-up solar panel will provide power automatically	No system effect. 100% redundancy of panels	1	6	6	Y	1	6		Visual Inspection and continuity reading of soldered joints on Solar Panels	12 mths	Electrical	1	2	2	1	2		N
		01.02.C.02		Solar panel failure to operate due to water ingress.	Failure of the power supply to the wells. This failure mode will be evident in normal operation from alarms in the Master Control System.	No system effect. 100% redundancy of panels	1	6	6	Y	4	24		Visual Inspection and continuity reading of soldered joints on Solar Panels	12 mths	Electrical	1	2	2	1	2		N
		01.02.C.03		Battery power failure due to cell damage / overheating when the solar panels have both failed	This failure mode will be evident in normal operation from alarms in the Master Control System. Loss of power to well control will occur	In the event that total loss of power to the panel occurs loss of the ability to monitor the system down hole components will occur. The wells will have to be shut in until the failure is rectified	10	4	40	Y	1	40		Visual inspection and battery cell voltage readings to ensure cell integrity.	12 mths	Electrical	1	2	2	1	2		N
To continuously power and communicate with the downhole gauges and acquire the data values for various types of downhole sensors, such as pressure and temperature.	Unable to continuously power and communicate with the downhole gauges and acquire the data values for various types of downhole sensors, such as pressure and temperature.	01.02.D.01		downhole gauge card failure due to overheating / dust contamination.	During normal operation this failure mode is evident through alarms in the downhole gauge surface data acquisition Unit. Communication with the relevant gauges will be lost.	Loss of the ability to continuously power and communicate with the downhole gauges and acquire the data values will occur until the interface module is changed out.	9	2	18	Y	2	36		Conduct a thermal imaging survey with an IR thermometer	12 mths	Electrical	9	1	9	1	9	Consider lightening strike and the credibility of this causing failure. Is the risk mitigated by grounding	N
		01.02.D.02		downhole gauge Panel failure due to water ingress (e.g., damaged seals or cable gland washers).	This failure mode will be evident in normal operation from alarms in the Master Control System.	Loss of the ability to continuously power and communicate with the downhole gauges and acquire the data values for various types of downhole sensors for all gauges will occur.	9	2	18	Y	4	72		Visual Inspection of panel for water ingress	12 mths	Electrical	9	1	9	1	9		N
To allow connection of relevant cables in a dry and safe environment	Unable to allow connection of relevant cables in a dry and safe environment	01.02.E.01		Surface junction box failure allowing water ingress (e.g., damage to box or seals)	During normal operation this failure mode is hidden to the operations team and deterioration of the situation will occur if not rectified.	Issues with signals will occur due to shorting of connections to other cores. If not rectified a total loss of signals may occur.	9	2	18	Y	4	72		Visual Inspection of JB for water ingress	12 mths	Electrical	9	1	9	1	9		N

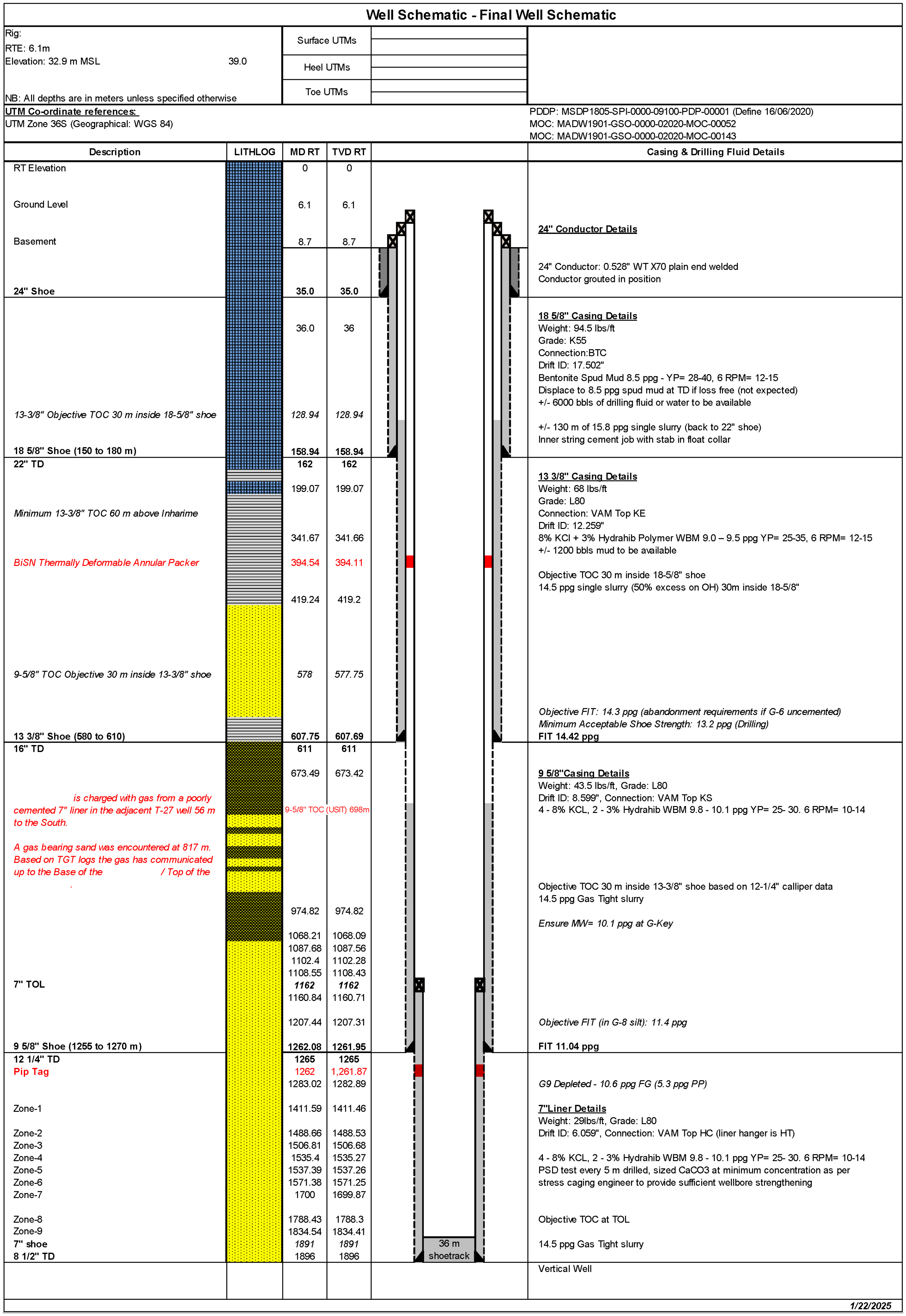
Figure 4—FMECA Output

In addition to the above, additional rigor was applied to the Quality Assurance and Quality Control (QA/QC) of the manufacturing of the electric ICVs and also the preparation of the completion sub-assemblies, prior to being shipped to the wellsite for completion operation execution:

1. An enhanced level of QA/QC was included in the purchase order for the electric ICVs and accessories, wherein the equipment manufacturer was required to provide a full end-to-end documentation pack for equipment manufactured and supplied.
2. A third-party independent QA/QC inspection (TPI) agency was appointed to review the documentation pack
3. TPI inspected every single component associated with the well completion, against the QA/QC documentation provided by the supplier(s).
4. The TPI also witnessed the completion sub-assembly make up operation, signing off on the torque-turn chart of every single connection made between completion components.

Final Completion Design

The well was pre-drilled and suspended with the well completion installed later in the rig schedule. This provided the crucial detailed planning time required to fine tune the completion and the space out of the various zones. The well was drilled to TD in the 8-1/2″ hole with a 7″ liner across the target reservoir sections, and a 9-5/8″ casing to surface. Cement evaluation post-7″ liner job confirmed adequate isolation behind pipe, between zones to be completed in the well Figure 5 below shows the final as-drilled well schematic.



Well Schematic - Final Well Schematic

Rig:
RTE: 6.1m
Elevation: 32.9 m MSL 39.0

NB: All depths are in meters unless specified otherwise

Surface UTMs	
Heel UTMs	
Toe UTMs	

UTM Co-ordinate references:
UTM Zone 36S (Geographical: WGS 84)

PDDP: MSDP1805-SPI-0000-09100-PDP-00001 (Define 16/06/2020)
MOC: MADW1901-GSO-0000-02020-MOC-00052
MOC: MADW1901-GSO-0000-02020-MOC-00143

Description	MD RT	TVD RT
RT Elevation	0	0
Ground Level	6.1	6.1
Basement	8.7	8.7
24" Shoe	**35.0**	**35.0**
	36.0	36
13-3/8" Objective TOC 30 m inside 18-5/8" shoe	*128.94*	*128.94*
18 5/8" Shoe (150 to 180 m)	**158.94**	**158.94**
22" TD	**162**	**162**
	199.07	199.07
Minimum 13-3/8" TOC 60 m above Inharime		
	341.67	341.66
BiSN Thermally Deformable Annular Packer	394.54	394.11
	419.24	419.2
9-5/8" TOC Objective 30 m inside 13-3/8" shoe	*578*	*577.75*
13 3/8" Shoe (580 to 610)	**607.75**	**607.69**
16" TD	**611**	**611**
	673.49	673.42
is charged with gas from a poorly cemented 7" liner in the adjacent T-27 well 56 m to the South.	9-5/8" TOC (USIT) 698m	
A gas bearing sand was encountered at 817 m. Based on TGT logs the gas has communicated up to the Base of the / Top of the .		
	974.82	974.82
	1068.21	1068.09
	1087.68	1087.56
	1102.4	1102.28
	1108.55	1108.43
7" TOL	***1162***	***1162***
	1160.84	1160.71
	1207.44	1207.31
9 5/8" Shoe (1255 to 1270 m)	**1262.08**	**1261.95**
12 1/4" TD	**1265**	**1265**
Pip Tag	1262	1,261.87
	1283.02	1282.89
Zone-1	1411.59	1411.46
Zone-2	1488.66	1488.53
Zone-3	1506.81	1506.68
Zone-4	1535.4	1535.27
Zone-5	1537.39	1537.26
Zone-6	1571.38	1571.25
Zone-7	1700	1699.87
Zone-8	1788.43	1788.3
Zone-9	1834.54	1834.41
7" shoe	*1891*	*1891*
8 1/2" TD	1896	1896

Casing & Drilling Fluid Details

24" Conductor Details

24" Conductor: 0.528" WT X70 plain end welded
Conductor grouted in position

18 5/8" Casing Details
Weight: 94.5 lbs/ft
Grade: K55
Connection:BTC
Drift ID: 17.502"
Bentonite Spud Mud 8.5 ppg - YP= 28-40, 6 RPM= 12-15
Displace to 8.5 ppg spud mud at TD if loss free (not expected)
+/- 6000 bbls of drilling fluid or water to be available

+/- 130 m of 15.8 ppg single slurry (back to 22" shoe)
Inner string cement job with stab in float collar

13 3/8" Casing Details
Weight: 68 lbs/ft
Grade: L80
Connection: VAM Top KE
Drift ID: 12.259"
8% KCl + 3% Hydrahib Polymer WBM 9.0 – 9.5 ppg YP= 25-35, 6 RPM= 12-15
+/- 1200 bbls mud to be available

Objective TOC 30 m inside 18-5/8" shoe
14.5 ppg single slurry (50% excess on OH) 30m inside 18-5/8"

Objective FIT: 14.3 ppg (abandonment requirements if G-6 uncemented)
Minimum Acceptable Shoe Strength: 13.2 ppg (Drilling)
FIT 14.42 ppg

9 5/8"Casing Details
Weight: 43.5 lbs/ft, Grade: L80
Drift ID: 8.599", Connection: VAM Top KS
4 - 8% KCL, 2 - 3% Hydrahib WBM 9.8 - 10.1 ppg YP= 25- 30. 6 RPM= 10-14

Objective TOC 30 m inside 13-3/8" shoe based on 12-1/4" calliper data
14.5 ppg Gas Tight slurry

Ensure MW= 10.1 ppg at G-Key

Objective FIT (in G-8 silt): 11.4 ppg
FIT 11.04 ppg

G9 Depleted - 10.6 ppg FG (5.3 ppg PP)

7"Liner Details
Weight: 29lbs/ft, Grade: L80
Drift ID: 6.059", Connection: VAM Top HC (liner hanger is HT)

4 - 8% KCL, 2 - 3% Hydrahib WBM 9.8 - 10.1 ppg YP= 25- 30. 6 RPM= 10-14
PSD test every 5 m drilled, sized CaCO3 at minimum concentration as per stress caging engineer to provide sufficient wellbore strengthening

Objective TOC at TOL

14.5 ppg Gas Tight slurry

Vertical Well

1/22/2025

Figure 5—As-Drilled Well Schematic

The final well completion consisted of the following key components. Figure 6 below shows the as-run completion schematic with the main components:

- Sump Packer with Sealbore: This was installed in the well on wireline below the bottom most interval, prior to perforating. This was intended to serve as an additional depth reference for perforating and for landing the completion. The main completion was intended to tag the sump packer and then pick up to space out and land.
- Seal Assembly: This was deployed as the bottommost component in the lower completion, intended to stab into the sump packer bore and run without seal units.
- Landing Nipple: This was to allow setting of a plug so that flow from the lowermost zone could be diverted through the ICV by isolating the tubing end, given that the seal assembly at the bottom of the main completion was intended to be run without seals when stinging into the sump packer bore.
- Mechanical ICV: Adjustable 5-position ICV custom designed for gas zone and oil zone applications. Operable on electric wireline by a bespoke retractable shifting tool. One mechanical ICV deployed against each of the 9 zones in the well. The mechanical ICV body was concentric, while the packer, gauge mandrel and the electric ICV were all eccentric. Accordingly, the mechanical ICV had to be placed at a minimum distance away from the nearest eccentric component, to prevent the effective outer running diameter of the completion from exceeding the casing drift inner diameter.
- Electric ICV: 6-position ICV (including full open and full closed) with different off-the-shelf designs for gas zone and oil zone application. Finer control on the smaller choke sizes for the gas zone were incorporated to enable auto gas lift in future, and to artificially lift the oil zones in case of high water cuts. One electric ICV deployed against each of the 9 zones in the well. All the 9 electric ICVs were connected in series by a single 3-core cable (TEC line) to surface. Splitting the ICVs into 2 separate TEC lines in order to reduce the risk of all 9 ICVs failing in case of a failure of the TEC line, was contemplated during the design phase. This was deemed to be over-complicating the completion and a logical split for the ICVs could not be arrived at. Hence this option was ruled out early on.
- Gauge Carrier with gauges: One gauge carrier deployed against each of the 9 zones in the well. Each carrier equipped with 2 × pressure and temperature gauges – one ported to read tubing pressure and the other ported to read annulus pressure. An additional gauge carrier with 2 × pressure and temperature gauges was deployed above the production packer to measure pressure and temperature of the commingled flow from the well (tubing gauge), and for well integrity measurements (annulus gauge). All the gauges were connected via a single 1-core cable (TEC line) to surface.
- Blast Protectors: Special blast protector clamps were deployed against the perforation intervals in order to cover and protect the TEC lines on the outside of the tubing, from erosion caused by the impingement from the flow of hydrocarbons on the completion.
- 7″ Isolation Packers: 9 × Hydraulic set straight pull release feed-through packers with 2 × feedthrough ports (one for the TEC line connecting the electric ICVs and another for the TEC line connecting the downhole gauges) run between each zone completed in the well, for zonal isolation. All 9 packers were shear pinned to set simultaneously, in a single pressure-up sequence.
- Circulating Sliding Side Door (SSD): Deployed above the topmost 7″ isolation packer in order to be able to circulate in inhibited packer fluid into the tubing-casing annulus, after landing the completion, and setting the 7″ isolation packers.
- Ported Sub: Deployed below the production packer – similar to a chemical injection mandrel, equipped with dual redundant rupture discs, with rupture pressure set higher than the setting pressure of the 7″ isolation packers. The ported sub was connected to the production packer via

a hydraulic control line. This was required to ensure that the production packer was not set along with the 7″ isolation packers, and was set separately later, in order to allow circulation of the packer fluid in the annulus via the Circulating SSD prior to setting the production packer.

- 9-5/8″ Production Packer: Hydraulic straight pull release feed-through packer run in the 9-5/8″ casing. The setting mechanism of this packer was via the rupture discs in the Ported Sub run directly below this production packer in order to delay the setting of the packer until after circulation of packer fluid. The production packer was installed in the 9-5/8″ casing in order to provide a barrier above the liner lap, effectively isolating the liner lap and the circulating SSD.
- Rotating Splice Sub: This was deployed above the 9-5/8″ production packer in order to allow splicing of the electric ICV TEC line when feeding through the packer
- Self-Equalizing Tubing Retrievable Subsurface Safety Valve (TR-SSSV): Deployed as a well safety critical element in line with the general completion design for all the wells in the campaign. This is controlled by a hydraulic line to surface
- Timed Connection Couplings: These were deployed at various points in the completion (total 39 couplings), in order to ensure that the electric ICV and gauge TEC lines, and the TR-SSSV hydraulic control line are all aligned on one side of the completion, for ease of termination, to avoid damage to the lines during completion installation, and to ensure that all the eccentric components in the completion are aligned in a single direction to ensure that the effective running outer diameter of the completion does not exceed the drift inner diameter of the casing.
- Tubing hanger: Tubing hanger and adapter with 4 feed-through ports was deployed in the completion. One feedthrough port was spare and was blanked off, whereas the other three were utilized for the pressure and temperature gauge TEC and electric ICV TEC lines, and for the TR-SSSV hydraulic control line.

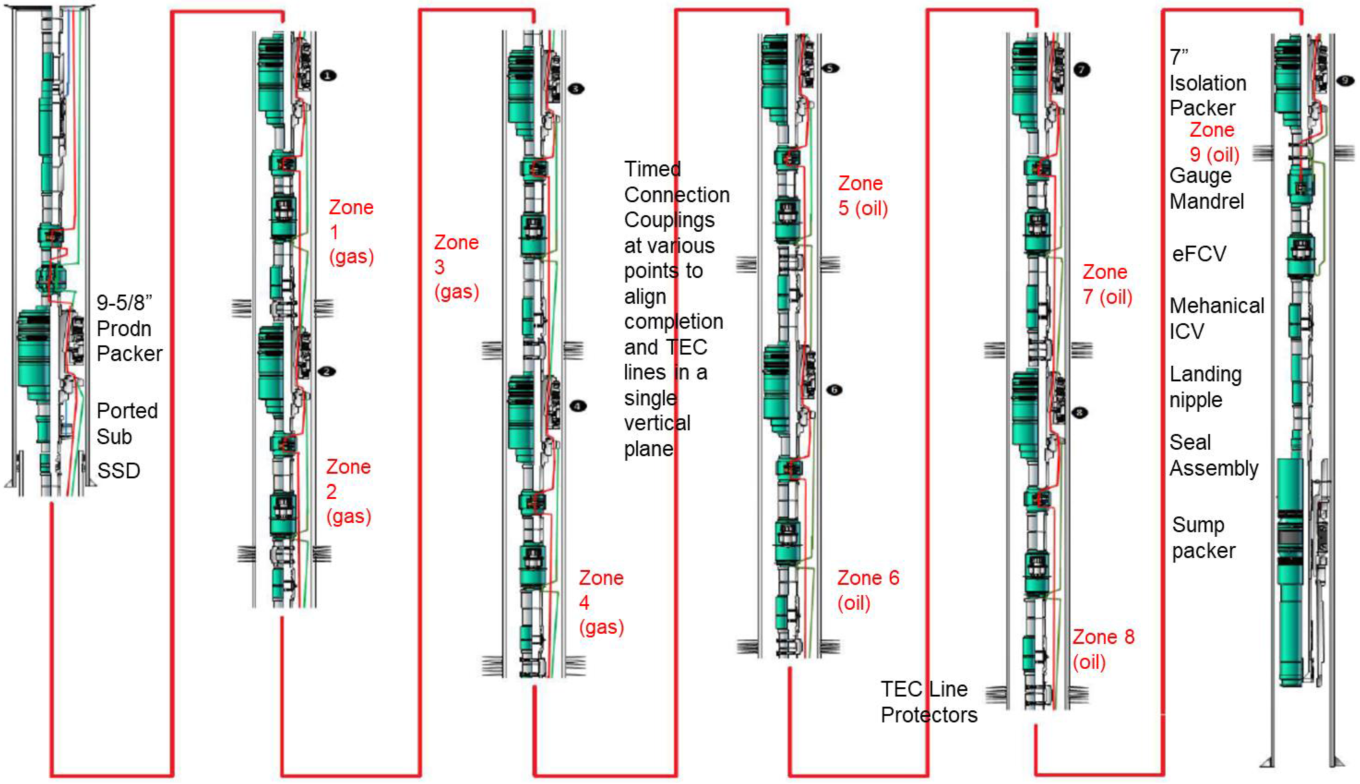


Figure 6—As-Run Completion Schematic

Overall, the completion was designed with minimal intervention, with full surface control of the downhole components and surface data acquisition. Due to the complexity of the completion, an additional packer was included in the 9-5/8″ casing to serve as a production packer and a downhole annular barrier, while isolating the 7″ liner lap and the circulating SSD.

Completion Operations Stages

Completion operations commenced with re-entry into the suspended wellbore. The temporary suspension cap was removed, and the BOPs nippled up, followed by retrieval of the Two-Way Check Valve (TWCV) and dummy hanger. A wear bushing was installed in the wellhead.

A Wellbore Clean Up (WBCU) string incorporating a bit without nozzles and casing scrapers was then run in the well, and the well displaced to clean, filtered 6% KCl brine. Proposed packer setting depths were scraped.

The sump packer assembly was then deployed on electric wireline and set below the lowermost perforation depth.

This was followed by the Tubing Conveyed Perforating (TCP) string. The TCP guns consisted of 12 shots per foot (spf) deep penetrating charges with hydrostatic chambers to achieve a dynamic underbalanced perforation. A Radioactive (RA) marker sub was run above the topmost gun in order to allow correlation of the TCP strings. The high-level operational steps for the TCP run was as follows:

- The top of the sump packer was tagged by the TCP string to obtain depth reference and the guns picked up and placed approximately on depth.
- A gamma ray-casing collar locator (GR-CCL) tool was run on wireline and the signals from the radioactive pip tags in the 7″ liner and from the RA marker sub were picked up.
- The pip tag in the 7″ liner and the RA marker sub were correlated against the gamma-ray signals from the cement evaluation log, in order to accurately place the guns on depth.
- A lactic acid based fluid loss control pill (designed to break up with time and temperature) was circulated in and spotted above the topmost perforation depth, in the TCP string.
- The wellbore was pressured up to initiate firing of the TCP guns. All the 9 intervals were perforated simultaneously in a single TCP run.
- The well was subsequently killed and confirmed to be near static, followed by retrieval of the spent TCP string.

A deburring string was then deployed in the wellbore with scrapers in order to polish off any burs caused by the perforation. This was achieved by reciprocating the string across the perforation intervals. No circulation was carried out during this run, in order to ensure that the well did not go to losses.

The wear bushing was retrieved from the wellhead, and a dummy tubing hanger run was conducted. This was followed by the main completion consisting of the various completion components including mechanical ICVs, electric ICVs, downhole gauges, isolation packers, circulating SSD, production packer, splice sub, TR-SSSV, timed connection couplings and tubing hanger. The completion was run on 3-1/2″ tubing. The electric ICVs and gauges were tested for communication at every stage of the completion running. The completion was spaced out, the TEC and hydraulic lines fed through the tubing hanger and the tubing hanger landed in the wellhead. The following operations were then carried out to set the 7″ isolation packers and test the uppermost packer:

- A plug was set on slickline in the landing nipple in the completion tailpipe.
- The tubing was pressure tested against the plug and TR-SSSV was function and inflow tested.
- The 7″ isolation packers were all set simultaneously by pressuring up the completion against the plug in the landing nipple.

- The uppermost 7″ isolation packer was tested by pressuring up the annulus above.

After successfully setting the 7″ isolation packers, the following operational steps were carried out:

- The circulating SSD was opened on slickline, the packer fluid was reverse circulated into the annulus, and the circulating SSD was then closed.
- The completion was pressured up against the plug in the landing nipple to a higher pressure to rupture the disc in the ported sub and set the 9-5/8″ production packer.
- The circulating SSD was then opened again.
- The 9-5/8″ production packer was tested from above by pressuring up the annulus above and monitoring the tubing returns.
- The production packer was tested from below by pressuring up via the open circulating SSD, from the tubing side.
- A shallow set plug was then run on slickline in a nipple profile in the TR-SSSV and pressure tested, in order to provide a secondary barrier when nippling down the BOPs.
- A TWCV was installed as a debris barrier in the tubing hanger.

The main completion running sequence by itself took 9.6 days due to the complexities of the completion, the numerous TEC line connections involved, and the need to check for electrical connectivity/functionality of the electric ICVs and the downhole gauges at every step of the completion running.
The final operational steps in the completion sequence were as follows:

- The BOPs were then nippled down and the Xmas tree and the tubing head adapter landed on the wellhead.
- The TEC lines and TR-SSSV control lines were terminated at the wellhead and functionality of the electric ICVs, downhole gauges and the TR-SSSV was checked and confirmed.
- The Xmas tree was pressure tested and the TWCV retrieved from the tubing hanger.

The total time incurred for the entire completion operation was 26.3 days, with just 1 hour of NPT, as compared to a planned time of 30.33 days.

Challenges

Despite the advance planning and risk mitigation efforts early on in the design process, significant challenges were encountered during the preparation phase of the completion.

- Facilities for completion sub-assembly make up and preparation were inadequate, due to the remoteness of the location. lack of overhead crane facilities in the base, lack of enclosed areas for testing of sensitive electronic/electric components, quality of electrical earthing, local unavailability of hand tools, cables and connectors, etc. A portion of the facility was ring-fenced for this operation and dedicated resources in terms of crane, forklift, etc were provided to ensure focus on the planning for this well completion.
- Mobilizing the required skilled resources to the location during the preparation phase and during completion operation execution also proved challenging due to a shortage of qualified personnel globally for the relatively new technology deployed, and the difficulties/delays in obtaining required local immigration clearances. Contingency planning was put in place to carry out the well completion operation with remote support from vendor subject matter experts.
- The back up mechanical ICV option had to be changed out due to issues with compatibility of the intervention tools required to operate the mechanical ICV with other completion components.

- SIT conducted in the base post completion sub-assembly make up took significantly longer due to incorrect cables having been mobilized. Cables had to be modified on site to conduct the SIT, due to the anticipated difficulties and time required to mobilize the correct cables for the SIT

Conclusion

The completion operations were executed within time and cost, with less than 1% NPT. The time taken to execute the entire completion 4 days less than the time estimated in the well completion AFE, resulting in a cost saving of US$ 800,000. The successful execution of the completion operation was achieved despite facing several obstacles during the planning stage, including difficult equipment and personnel logistics in a remote location, several technical and operational setbacks, as listed in the paper.

The well was subsequently tested by flowing each zone independently via temporary test facilities. The functionality of the electric ICV, the zonal isolation provided by the cement behind the 7″ liner, and the 7″ isolation packers, were successfully confirmed. 7 out of the 9 zones tested yielded better than expected results with very low skins and higher deliverability than prognosed. The completion provided the opportunity to record pressure build-ups on each individual zone while simultaneously testing other zones above in the well. This provided significant time and cost savings for the well test operations. The estimated cost savings in the well test operation by deploying a surface-controlled smart completion is US$ 750,000.

The completion provided a great opportunity to appraise reservoirs with significant uncertainties about reservoir quality, extent and associated volume at a relatively low cost. The completion also served as a proof of concept for future wells which could be used to appraise similar under appraised reservoirs.

The following were the key success factors:

1. Thorough engineering and integrated approach for the design, execution and associated risks
2. Rigorous QA/QC at all stages
3. Mitigation of almost all potential failure modes during execution by exhaustive planning and using the right resources with prior experience with this specific system

The well is planned to be hooked up to permanent production facilities later this year. It is planned to produce the well sequentially by bringing single zones for production for further data acquisition, which is one of the key objectives of the well which will help realize the value of the well completion by acquiring data to appraise the individual reservoir sands targeted by the well.

Abbreviations

ARO : Asset Retirement Obligation
BOP : Blow-Out Preventor
CWOP : Complete Well On Paper
FMECA : Failure Mode Effects & Criticality Evaluation
GR-CCL : Gamma Ray – Casing Collar Locator
ICV : Interval Control Valve
NPT : Non-Productive Time
OWOP : Operate Well On Paper
PDDP : Pre-Drill Data Package
SIT : System Integrity Test
SSD : Sliding Side Door
TCP : Tubing Conveyed Perforation
TEC : Tubing Encased Conductor
TPI : Third-Party Inspection
TR-SSSV : Tubing Retrieved Sub-Surface Safety Valve

TWCV : Two-Way Check Valve
TWOP : Test Well On Paper
WBCU : Wellbore Clean Up

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