Innovative Sand Screen technology resolves Nigeria water injection issues

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Outline

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- Opportunity Description
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- Design of the Completion and Operations
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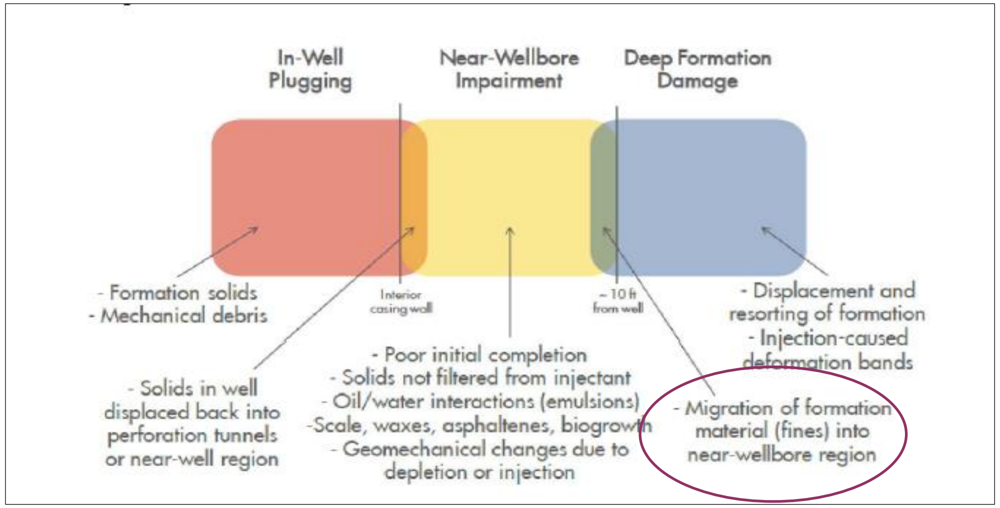
1.0

Introduction – Overview & Challenges

Introduction - Overview of Water Injection Challenges

- One major problems of water injectors is formation solids especially fines migration and accumulation in the wellbore during sudden or prolong well shut-in.
- These formation solids are normally resident in the reservoir during steady injection but can be mobilized into the wellbore during sudden shut-ins due to powerful transient flow effects such as:
  - Water Hammer
  - Cross-flow
  - Back flow
- Data analyses from X fields suggest that some wells suffer from the phenomena of water hammer, backflow and crossflow.

Impairment mechanism



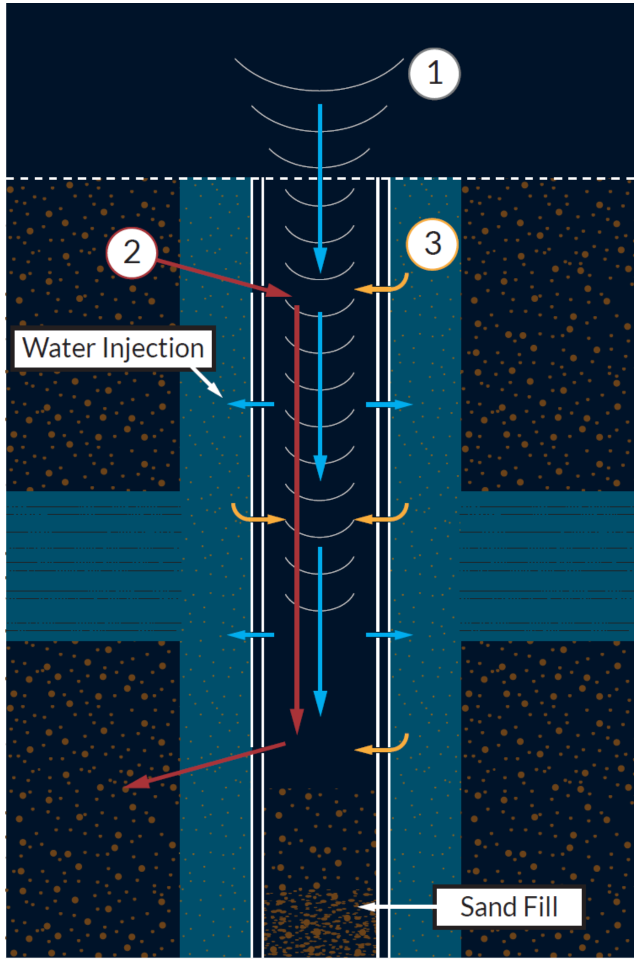
Type of impairment of water injectors base on location within the well and reservoir

Resultant effects:

- High injection bottomhole pressure, IBHP
- Diminished or loss of injectivity
- Loss of pressure support to pair producers.
- Screen plugging and erosion of downhole equipment
- Intervention, remediation or loss of well

Introduction - overview of water injection challenges cont'd

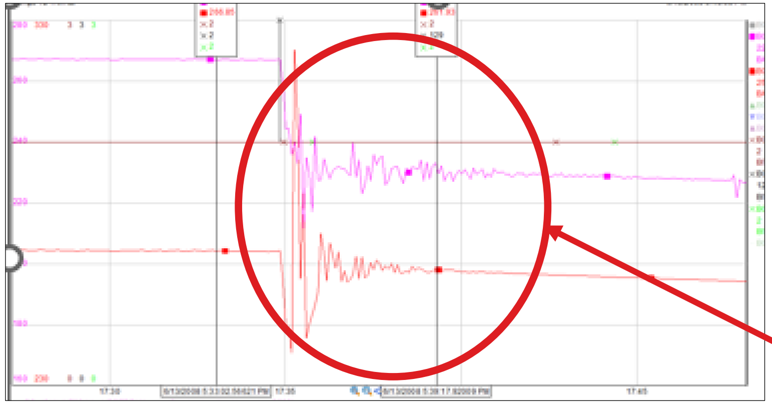
Three Major Drivers of Fine & Matrix Sand



1. Water Hammer – shock waves caused by sudden shut-ins (trips) travelling at the speed of sound impact the reservoir. This causes formation liquefaction and mobilises fine. The amplitude of the effect can be as much as 1500psi and increases with injection rate and well depth.
2. Cross-flow – can occur between wells or between zones within a wellbore due to pressure differential in the zones and permeability differences. In wells with shale barriers this can also lead to erosion of clay particles resulting in screen plugging. Modelling has shown that cross-flow rates can be in the '000's BPD
3. Back-flow – caused via water hammer or fluid level drop in the well below certain threshold, hence pressure in reservoir create backflow and mobilize fine particles back into the wellbore. As there is no flow to surface the problem is not detected until sand fill impacts injectivity.

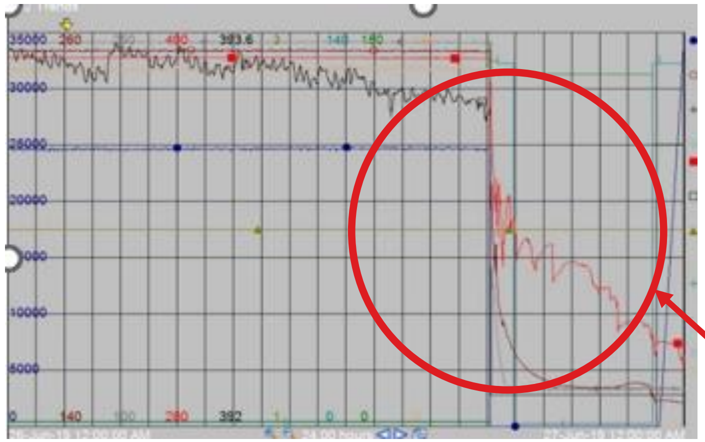
Challenges associated with injection wells in field x

The effect of water hammer and backflow in some field X wells due to pressure fluctuation intensity



Fluctuation signatures

Well A



Well B

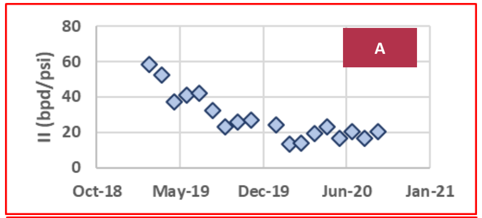
Fluctuation signatures

Well C

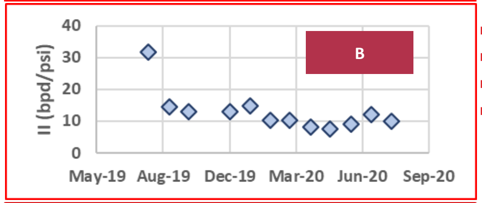
Fluctuation signatures

Well	Current Status	Potential impact on paired producer
A	Injecting at low rate (~8kbwpd) due to high IBHP	Deferred Production of paired producer, loss in revenue
B	Shut-in due to high IBHP	Deferred Production of paired producer, loss in revenue
C	Currently shut-in and open intermittently.	Deferred Production of paired producer, loss in revenue

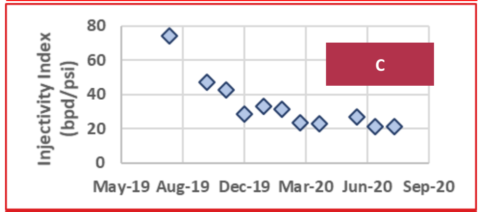
2018/2019 Injector Well performance



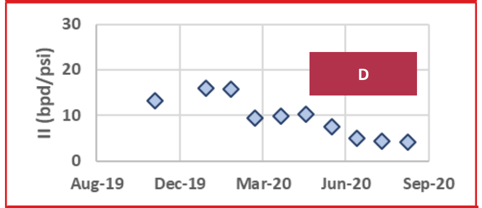
- Initial II ~60 bpd/si
- Declined to current II of 20 bpd/psi – still a relatively good II
- But limited by max 'DD' of ~450 psi to ~9kbpwd injection
- Successful stim with full II recovery can increase rate to ~25kbwpd. How quickly will it decline?



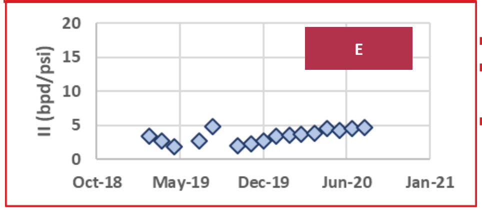
- Initial II ~32 bpd/psi
- Declined to current II of 10 bpd/psi
- Max 'DD' of ~1100 psi to limit injection to ~11 kbwpd
- Successful stim with inj recovery can increase inj rate > 25kbwpd. Decline rate post stim likely to be same or faster



- Initial II ~75 bpd/psi
- Declined to current II of 20 bpd/psi
- Max 'DD' of ~550 psi to limit injection to ~11 kbwpd



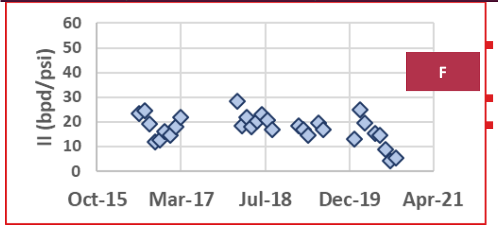
- Initial II ~15 bpd/si
- Declined to current II of 4 bpd/psi
- Max 'DD' of ~1160 psi & ~5 kbwpd injection
- Press BU might affect II estimate
- Connectivity challenge more pressing than II decline
- Planned operation envelope review can increase II as well help with the connectivity challenge



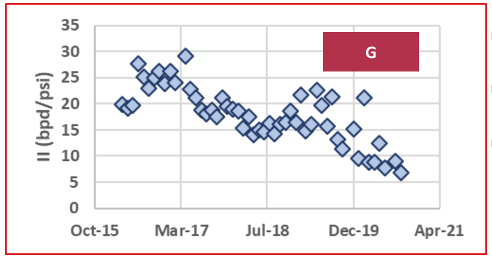
- Initial II ~3.5 bpd/psi
- Some increase from acid stim but still has the lowest II of ~4 bpd/psi
- Massive 'DD' limit of ~2175 psi, limit injection to ~8.5 kbwpd

Analogue Solutions

The injectivity decline in 2018/2019 injectors have been observed in other injectors with short completion intervals in the past

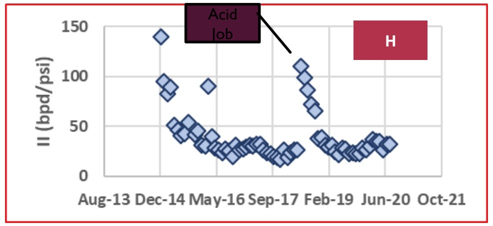


- Cannot sustain required rate in matrix injection at start-up in 2016
- Started in fractured injection with II ~ 20bpd/psi
- Maintained good injectivity in fracture mode for ~3 years with cum injection > 15 MMSTB MMSTB

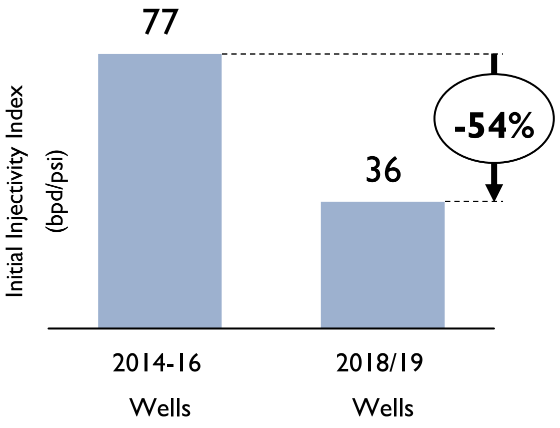


- Switched to fracture after 1 or 2 months of injection in 2015
- Gradual decline in fracture injectivity which became severe in 2019
- Cum injection of > 25 MMSTB over 5 years in fractured before severe impairment

Analogue for acid stim –HI



- H started with very high II - ~140 bpd/psi
- II declined to ~20bpd/psi in ~2 years
- Acid stimulation recovered ~80% of initial II but decline rate was similar to that observed after start-up



Summary

- The scenarios above show correlative decline in injectivity in well complete within the 2018/2019 campaign few months after completions. Using the only successful acid stim as analogue (H), the rate of injectivity decline after the F, G acid stim in 2021 might be similar to the decline seen between 2019 and 2020. Implies we might need another acid stim in 2022

Opportunity Description - attempt to mitigate fine migration

- Well D was drilled as horizontal water injection well with NtG sand of 61% in April 2015 to support Well E paired producer.

- Attempt to install SAS completion across a net sand of 565ft was unsuccessful as LC was stuck 42ft off-bottom~ shale exposure to screen with potential for fine migration.

- Subsequently an Tubing Installed Valve (TIV) was installed in the upper completion.
  - to mitigate possible fines migration due to hydraulic hammer effects and crossflow from the exposed shales during the life of the well.
- However, attempt to open Fluid Loss Control Device, FLCD was unsuccessful resulting to fish in hole. Well scheduled for sidetrack.

- Well D therefore, became the first field trial of in-string TIV deployment in X field.

2.0

Review of Technology Options

Technology value drivers – critical success factors

FINE MITIGATION: Isolate Reservoir during well shut-in to prevent or minimize water hammer and fines into wellbore; hence improve subsequent injectivity during start-up

WELLBORE ACCESS: Provide full access into the Lower completion sandface during injection and intervention without restriction or pressure drop.

RELIABILITY: Ability to withstand well conditions for the entire well Life-Cycle.

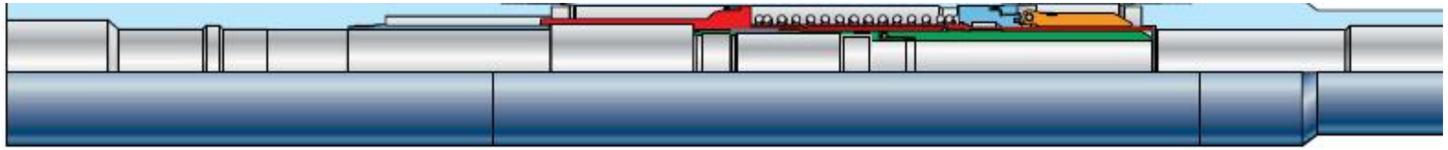
COST: Low-CAPEX when compared to similar product in the market.

PROVEN TRACK RECORD: Successful history of fine migration mitigations

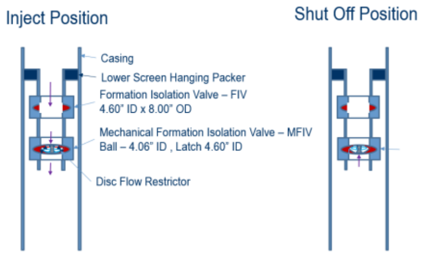
Review of available technologies

- X field formation is highly unconsolidated and significant pressure fluctuation in some wells induce drag forces mobilizing fines into the wellbore. These mobilized fines results in high skins leading to high injection bottom hole pressure.
- As a result of this, the following Options were considered to mitigate impact of Water hammer or hydraulic shock on Bonga Injector wells:

  - Tubing Installed Valve (TIV)



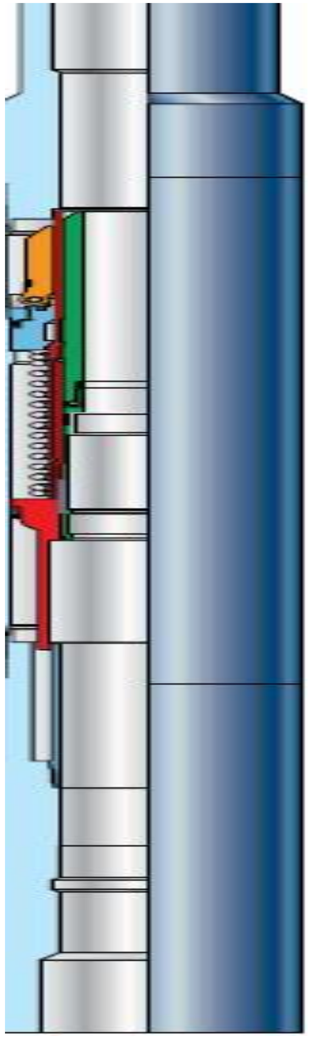
  - Backflow restrictor Technology



  - NRV screen Technology

Option 1 – tubing installed valve (tiv)

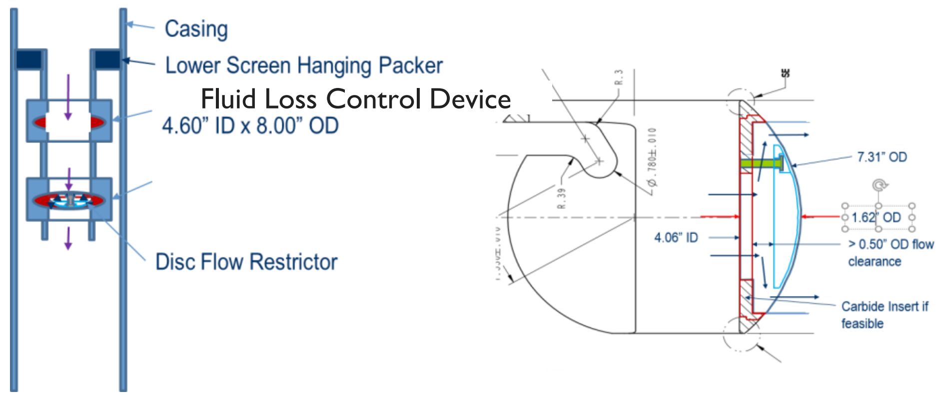
- Injection flow generates a pressure drop across the orifice in the retrievable choke mechanism which acts on piston area of flow tube and spring, causing it to move downward and open the valve. When fluid injection stops, differential pressure across orifice decreases and the force of the power spring lifts the flowtube and the flapper moves up to close against the valve seat preventing backflow from well.
  - Compact modular, tubing retrievable, subsurface-controlled valve designed to open at predetermined injection flow rates and prevent injection wells from flowing back.
  - Can be set deeper in the well proper material choices makes it suitable for corrosive environments.
  - Large-bore design optimizes the flow path. Retrievable choke mechanism for adjusting orifice sizes.
  - Metal-to-metal seals with proprietary locking and sealing threads.



Option 2 – backflow restrictor technology

- The Backflow Restrictor is a Mechanical Formation Fluid Loss Control Device Valve (MFLCD) with flow restrictor. Check valves installed in the Mechanical Formation Isolation Valve profile to prevent back flow from the reservoir during shut down. During injection, the ports on the flow restrictor is open to allow injected fluid passage. Some features of the valve are:
  - Automatic back flow prevention during unplanned injection shut off
  - Back Flow Restrictor for preventing Water Hammer effect
    - Perfect Seal not required
  - Handle injection rate of 10KBPD to 40KBPD
    - 15 Micron filtered water
  - Full Open to allow access in the screen when lock open but with 2.62" ID during injection.
  - Allow running Fluid Loss Device Shifting tool in and out

Fluid Loss Control device



Option 3 – nrv screen technology

- Check valves with on orifice per joint installed on the screen base pipe under a shroud that allows injection of fluid into the reservoir and prevent any back flow from the reservoir during shut-ins
  - Ball-check valves installed under a screen shroud.
- Allows water injection but prevents back-flow during pump shutdowns.
- Flow control check valves mounted within conventional sand screens do not alter completion geometry
- Metal to metal seal isolating fluid in the completion annulus and locking injection water into the formation.
- Compatible with SAS, GP completions and direct wrap or metal mesh screens.

3.0

Technology Screening and results

Technologies screening/Evaluation

Options	Tubing Installed Valve (TIV)	MFLCD Flow Restrictor	NRV Screen Technology
Fines Mitigation	- Valve installed in upper completion(far from sand face). - Does not prevent fines into the lower completion	- Valve incorporated in the FLCD - Limited fines prevention about the MFLCD. - Valve seat not a perfect seal system.	- Check valve installed on Sand screen closest to the sandface. - Stop crossflow, water hammer and fines into the wellbore. - Stop reservoir fluid into the wellbore during shut-ins
Wellbore Access	- Removed prior to entry into the LC - Cause 50-70psi pressure drop and restrict fluid flow - May impact remote hydraulic opening of FLCD	- Valve has 2.62" ID in open position during injection. - Cause higher pressure drop of 100psi and flow restriction. - Will require intervention to lock open to allow access to lower completion	- Gives full access into the lower completion wellbore. - Minimal pressure of 4psi across the wellbore at high injection rate of 40kbwpd - Does not impact intervention into the LC
Reliability	- High corrosion resistance alloy, incoloy 718 materials. - Temperature from 40 -300F. - Tensile strength of 612klbs & WP of 6,500psi.	- Valve disc made of tungsten carbide. - High corrosion resistant material - Working pressure of 5kpsi and service life of 15yrs at 25kbwpd injection.	- Check valves made of tungsten carbide material with 316L screen material - Suitable for 15yrs + service life with up to 40kbwpd. - Tensile strength of 442klb and WP of 10,000psi.
Cost	**$xxx k** per unit (Rate for unit installed on well D)	**$xxx K per unit (Post development)**	$xxx K per joint of Range 3 (For average of 1000 ft reservoir sand = **$xxx K)**
Proven track Record in Injectors	- Installed in well D - Installed a Competitor wells.	- No track record-undergoing development.	- Deployed in 3 injectors by a company with injection interval of 200ftah - Currently injecting at 5-25kbwpd with 25psi pressure drop.

Concepts Screening/Evaluation

OPTION RANKING				
OPTION	**WEIGHTING**	**TUBING INSTALLED VALVE(TIV)**	**MFLCD FLOW RESTRICTOR**	**NRV SCREEN TECHNOLOGY**
FINE MITIGATION	25	0.5	0.5	1
FULL WELLBORE ACCESS	20	0.5	0.2	1
RELIABILITY	25	1	1	1
LOW CAPEX	15	0.5	1	0.2
PROVEN TRACK RECORD	15	1	0.2	0.5
	100%	70	59.5	80.5

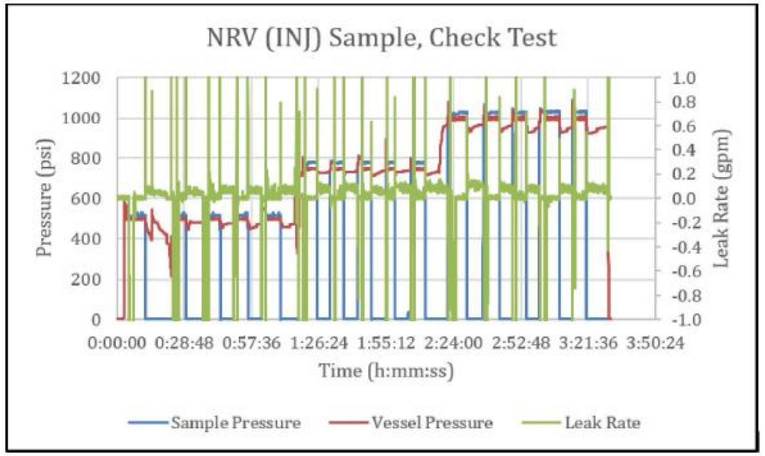
After careful consideration, the *NRV Screen Technology* option was selected based on weighted average score on the value drivers.

4.0

Design, Qualification & Deployment

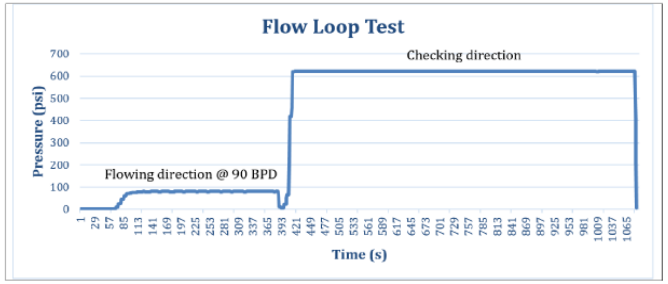
NRV Screen technology Qualification

- Design and major qualification test were carried out on the valve over 18months period by the integrated team. Tests proved successful



Back/crossflow prevention analysis

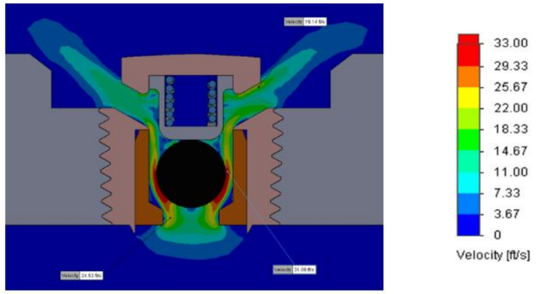
- High pressures cycles of 500psi, 750psi and 1000psi were applied.
- Max leak rate recorded was 0.1gpm.



Erosional test analysis

- Flow of 40 & 90bpd/valve and solid conc of 2ppm was passed through valve
- Total of 379lbs of sand ranging from 20 to 150um over 5hrs periodically
- Reverse flow of 600psi was conducted for 10mins , repeated for 10hrs
- Valve removed and inspected with no wears observed on the ball.

ZK Field trial: Following the successful qualification tests, a field trial was conducted by the team & OEM. Results conformed to the lab tests and proved NRV screen concept.



- Flow analysis done using maximum flow rate of 60 bpd.

CFD analysis

First a computational Flow Dynamics were conducted during the initial design phase to optimize velocities through the valve and to determine pressure differential that could be maintained. The most robust prototype was build for the lab test.

Valve plugging test

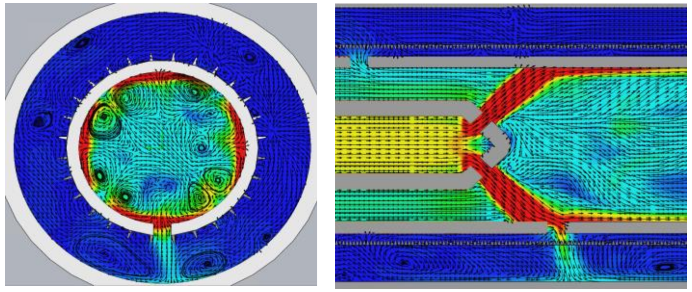
- Test conducted with ISO 17824 $CaCl_2$ pills range of 40 to 500microns sizes
- No failure after 1.5hr steady interval injection. This was due to large exit port of 1.6mm and 2.0mm.
- Additional testing with particles size of 1700micron, with plugging observed for 1.65mm port

Nrv screen technology risks & mitigation

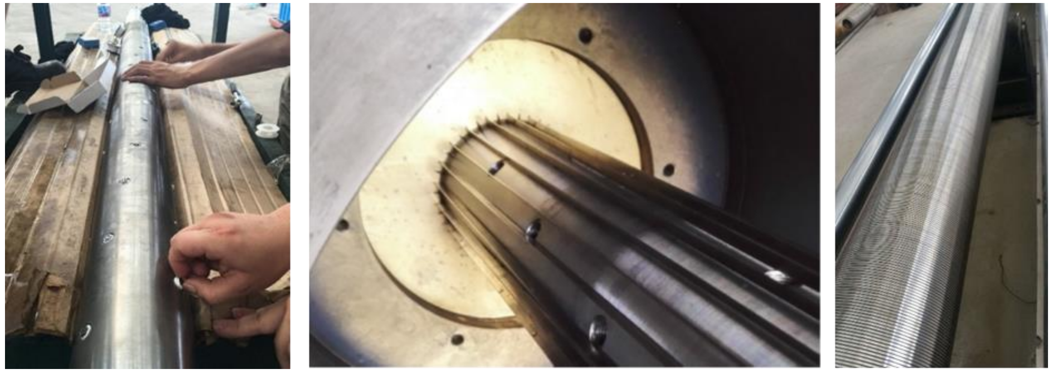
S/N	RISKS	CAUSES	MITIGATIONS
1.	Valve failure due to vibration	High injection rate causing severe vibration of downhole equipment especially screen	The check valves comes with hex head and usually torques to API specification for ¼ NPT port which is 25ft-lbs beyond finger tight with applied thread sealant. The check valves are then overplayed with filtering component of the screen. This make it suitable for detrimental vibration due to high rate injection.
2.	Plugging and erosion of Screen.	Erosion of screen filter media and plugging check valve due to abrasive fluid particle.	Screen qualified for erosion and plugging effect. Valve seats made of high grade tungsten carbide material to withstand erosion due to abrasive fluid particles.
3.	Failure from collapse and tensile loads.	Inability to withstand collapse and tensile load by the reservoir	Screen meet minimum burst, collapse and tensile limit for 5-1/2" 20ppf screen making it suitable for all required load.
4.	Corrosion	Impacted of downhole corrosion due from injected fluid	Screen manufactured to ISO 17824 quality level 1 and base pipe material of 20ppf, 1Cr-80 with H_2S/CO_2 service life. Filtered media is 316L and tungsten carbide check valve.
5.	Damage during handling	Damage to screen due to difficulty of Handling at the rigsite.	Ensure Screen comes in protective military jacket and 6ft pup at the end for a range 3 joint for handling during make up.
6.	Sand production.	Wrong specification of screen gauge size leading to sand production	Ensure that appropriate screen gauge size is specified during front end design and confirm filtering media size with a gauge filler.

Design of completion and operations

- CFD modelling was performed to evaluate different short per foot, SPF and injectivity
- Base pipe material selection critical to the technology design.
- Quality processes, sizes and positioning of valves during manufacturing critical to the durability of the screen



CFD modelling – Velocity profile



Valve insertion, screen wrapping and CFD final product

Design of the completion and operation - Operational procedure

- High level installation operational procedure during lower completion deployment:
- Pick up and make up the lower completion BHA, NRV screen, and run in hole to the packer setting depth.
- Carry out a wellbore cleanout and displace the well to brine.
- Set the lower completion packer and carry out packer anchorage and annulus test.
- Spot breaker fluid across the open hole.
- Activate the jetting tool and carry out acid stimulation of the well.
- Pull out of the hole service tool and close the open hole isolation barrier valve.
- Test the barrier valve and lower completion packer envelope.
- Carry out casing clean out and displace the well to packer fluid.
- Pull out of the hole Lower completion service tool and lay down the same.

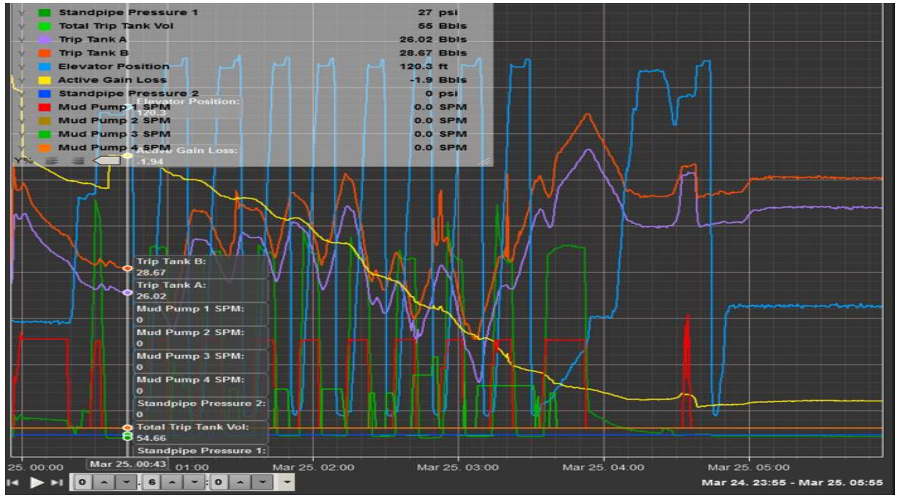
The wells were successfully completed with the new system installed across the sand face below a hydraulic-set packer.

5.0

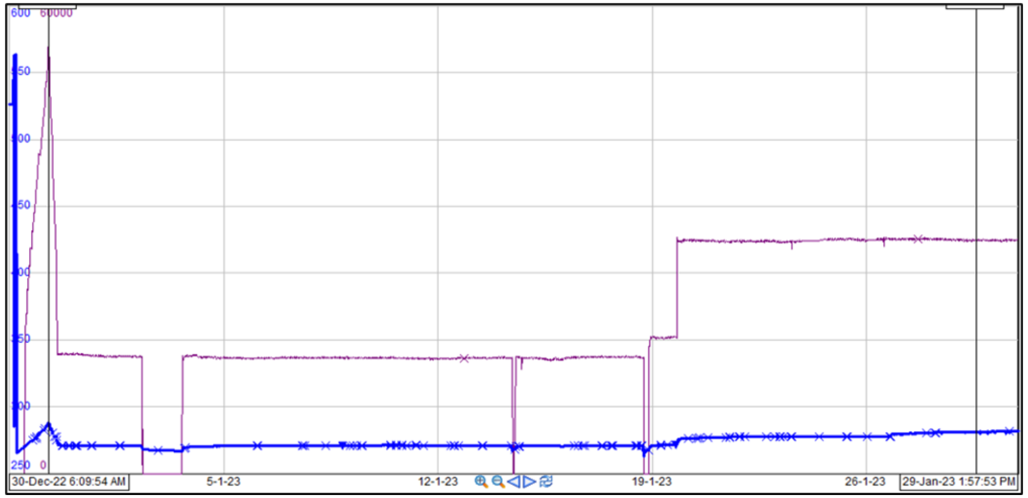
Results and Conclusions

Results

- The deployment operations were successful as the indication of losses that demonstrate the valves' capability to allow injection into the formation.
- The WRFM team reported a good injectivity index for well G, even after the initial short-in. The well was restarted and gradually ramped up to the current injection rate of 30Kbwpd at a BHIP of 4,233.6psi. This rate's sustainability indicates that the screens have effectively prevented fines mobilization from the reservoir into the wellbore
- Production increase of about 128% when compared to expected.



Loss rate during installation



Well injectivity performance data , well G

Conclusion

- The performance data from these wells indicates that the completion technology has successfully met the target rate and performance objectives, offering a robust solution for the operator to address common issues with injection wells.
- This technology has the potential to prevent premature injection well failures caused by water hammer, crossflow and backflow, which were previously unavoidable in unconsolidated formations in the Southern part of the Niger Delta.
- This innovative screen technology shows great promise to mitigate costly interventions and well losses.