DEVEX 2020 VIRTUAL

21ST – 25TH SEPTEMBER

Design and Execution of Nitrogen Bull Heading Strategy and Well Start Up Sequence Using Computational Fluid Dynamics

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AXIS

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Outline

- Background and Objectives
- Field Overview, Identify the Problem, Well Intervention Process
- CFD Well Inflow Modelling
- Formation Damage Impact
- Simulation Results & Recommendations
- Executing the Well Start Up Sequence
  - Challenges
  - Outcome
- Summary - Project Economics

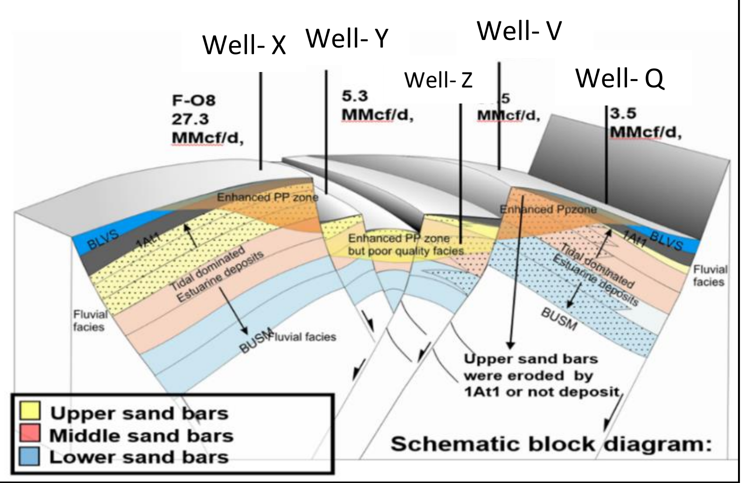
Background and Objectives

- Background:
  - A gas well fails to start up despite several attempts to start it up
  - The well is suspected to be liquid loaded
  - Questions to answer:
    - Can we deliquefy the well by injecting Nitrogen?
    - Assume we can, how fast and how much Nitrogen do we need to inject?
    - What happens to the liquid?
    - Should we displace the bulk of the liquid? Or should we over displace the liquid?
    - What is the impact of near wellbore formation damage (if any)?
    - How fast should we start up the well
- Objectives:
  - Use CFD to simulate the Nitrogen bull-heading to deliquefy the well
  - Incorporate Formation Damage Effect
  - Simulate the possibility to unload the well to start production again

Field & Well overview

Reservoir description

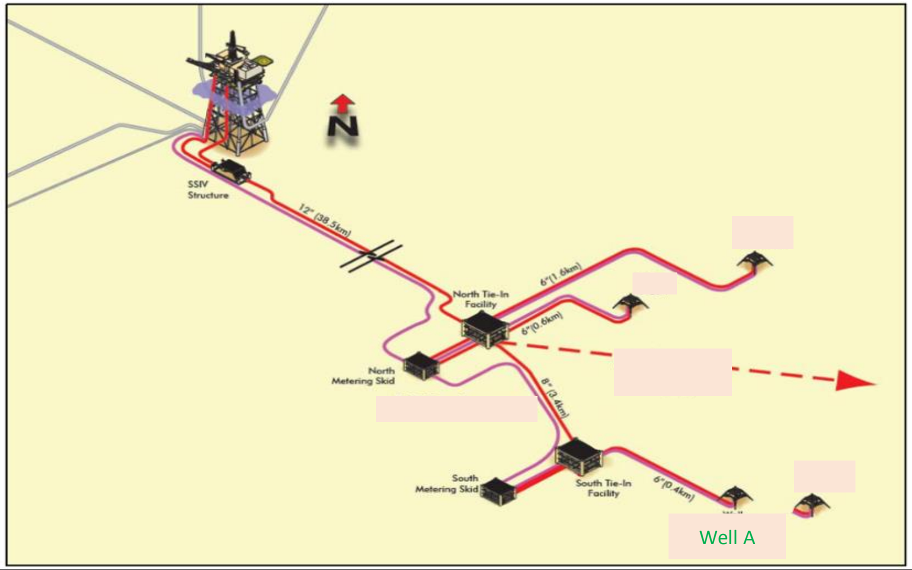
- ➢Field located~40 km to SE of F-A platform
- ➢East part of Block 9
- ➢High pressure high temperature reservoir (HPHT)
  - 7700 psi & 160 degC
- ➢ Heterogeneous (tight sand)
  - High perm streaks
- ➢ Structural trap: Anticlinal (highly faulted) trap
- ➢ Dry Gas (low water production)



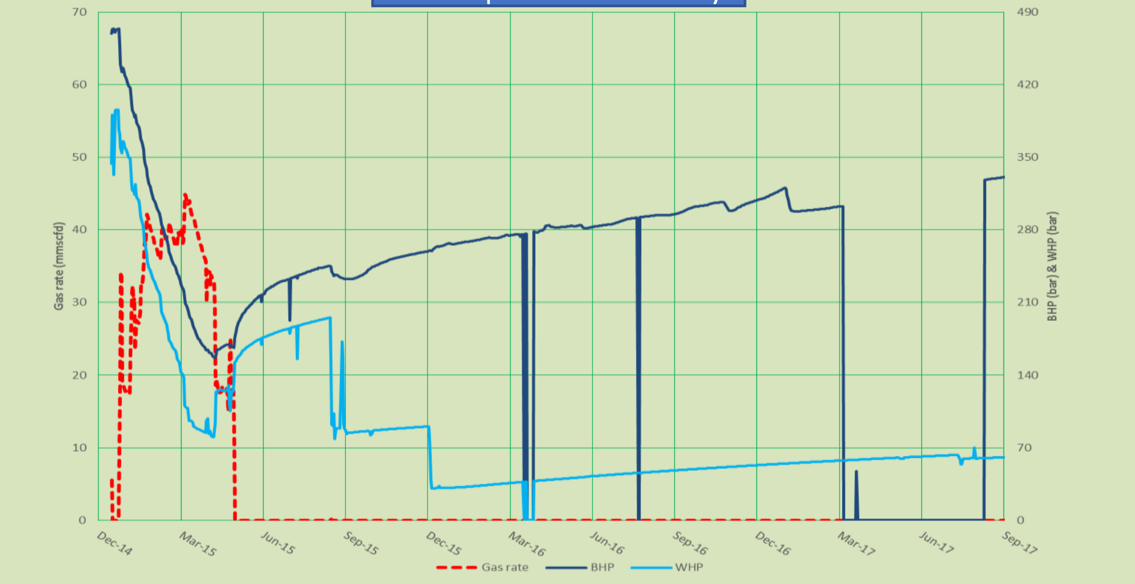
Well A description

- ➢ Horizontal well - intersects 6 fault blocks
- ➢ Well Test Analysis: Estimated 650 m of well length is contributing to flow
- ➢ TD 5328 m MD- openhole with 1600 m pre-perforated liner
- ➢ Last 500 m is barefoot
- ➢ Date Completed : 14 May 2014;Commissioned: 31 Dec 2015
- ➢ Sweet spot “hunting”- porpoising well trajectory

Field layout schematic



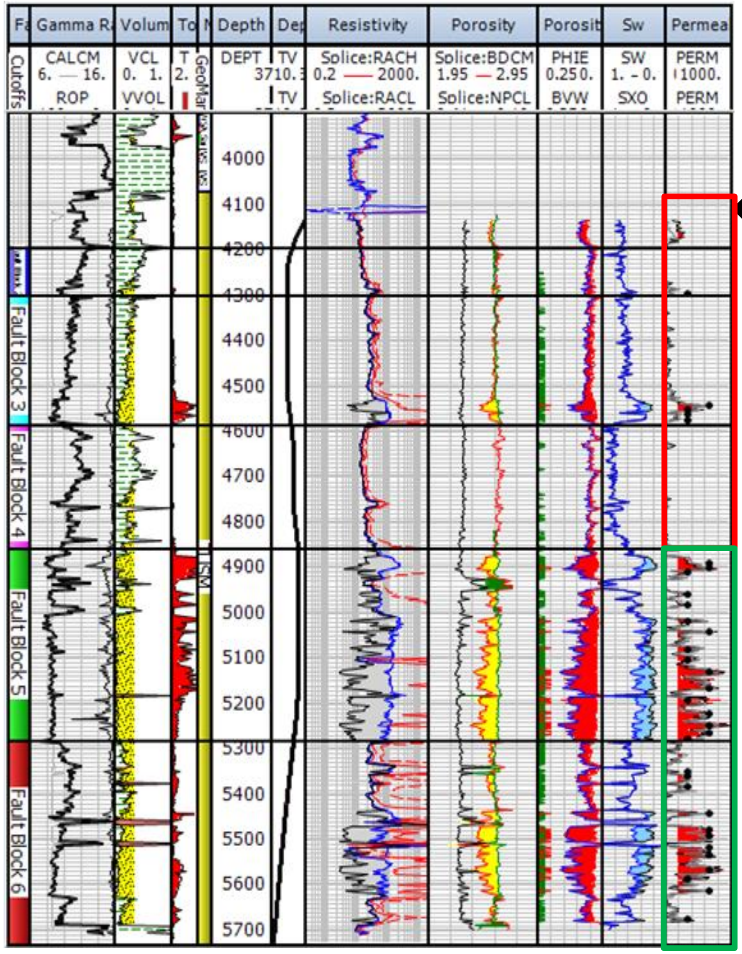
Well A production history



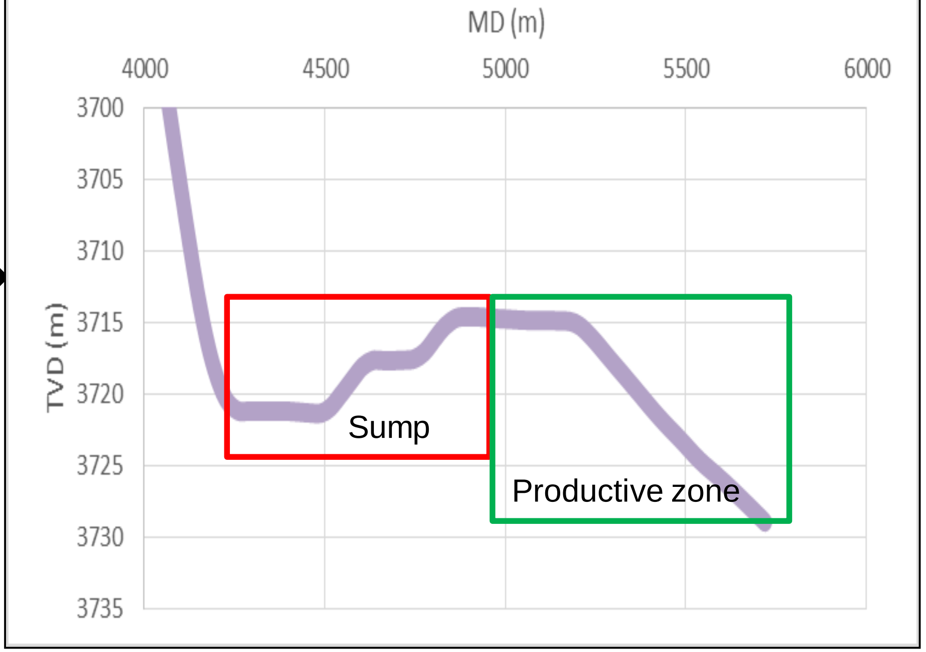
Identify the problem-Data analysis

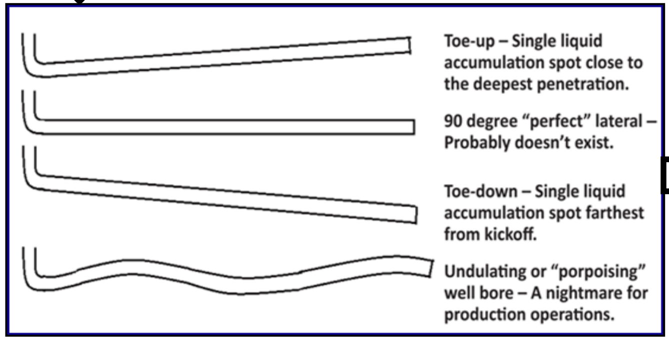
Well A Petrophysics overview

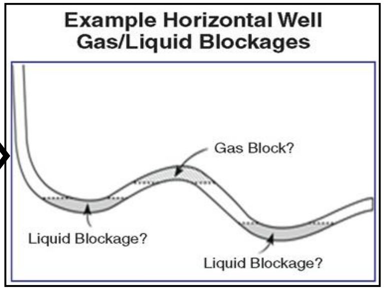
Heel of well (block 1 & 2) low permeability



Well A trajectory



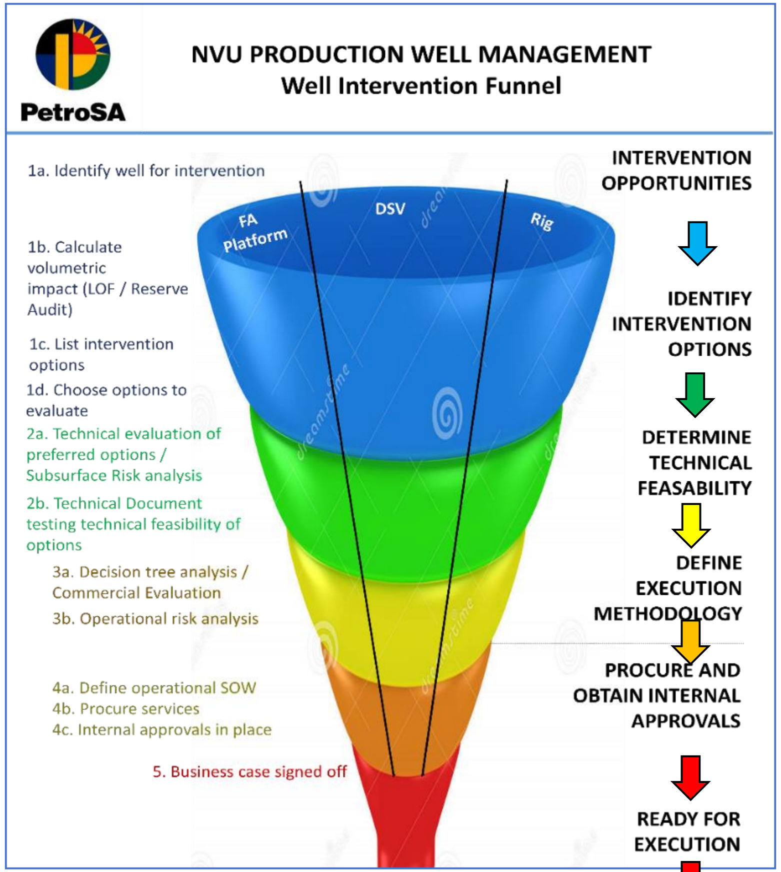




Well Intervention Process:

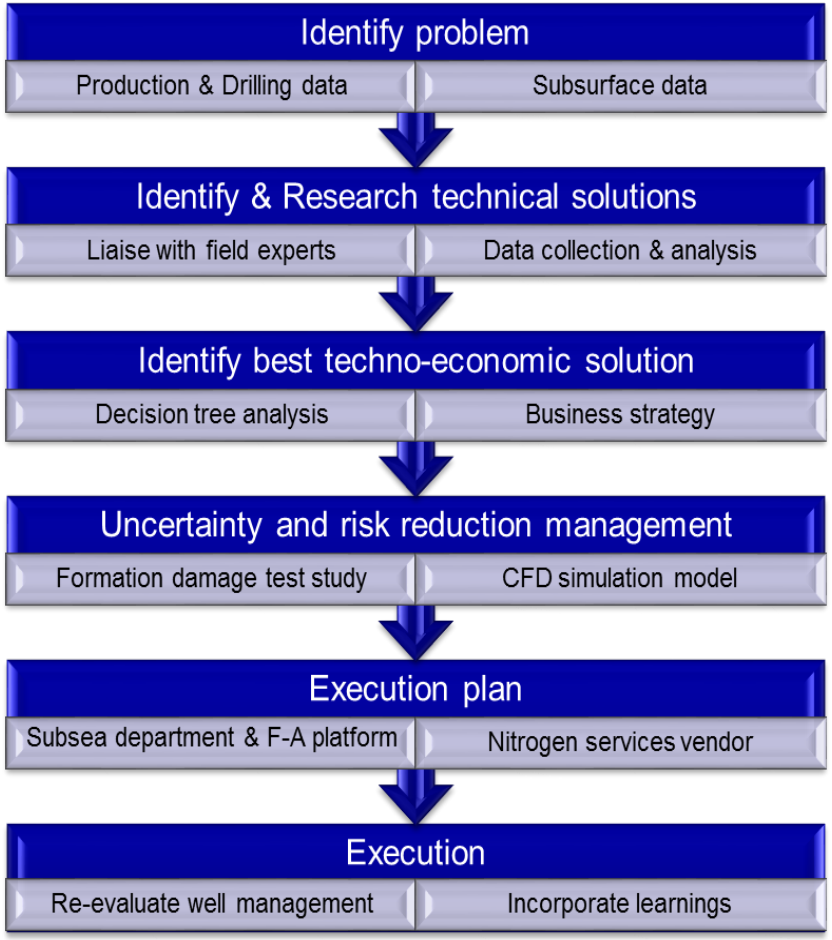
Objective: To optimize project (cost and timeline) and mitigate uncertainty & risk

PetroSA Well Intervention Process



Evaluate Lessons Learnt and incorporate in following interventions

Well A Well intervention process



Technical Intervention Options Identified (2017)

Intervention:	Estimated cost of intervention:	Risk to formation:	Probability of success:
Gas lift- drilling rig*	USD 15.6 million	Low	High
Gas lift – LWI vessel	USD 15.6 million	Low	High
Chemical treatment	USD 145,000	Medium	Low
Nitrogen bullheading*	USD 567,000	Medium- High	Medium-High
Depressurize flowline***	Production downtime	Low	Very Low

*Sharing mob/demob cost 5 well drilling campaign Using 75% contract rates
**Nitrogen bull heading operation R 8 million (Include diving cost and nitrogen services)
***Depressurizing of flowline was attempted already and failed

F-O10PZ1 reserve estimation and value

	Recoverable reserves (bscf)	Price per volume ($ per mscf)	Asset value (USD) 2017
2P Case Reserve Audit report	3.60	2.50	$ 9 MM
2P Case E-100 model	4.60	2.50	$ 11.5 MM
Blowdown case	5.00	2.50	$ 12.5 MM

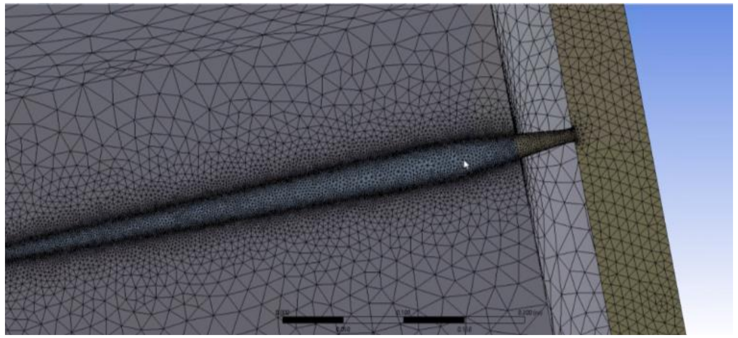
Decision Tree Analysis

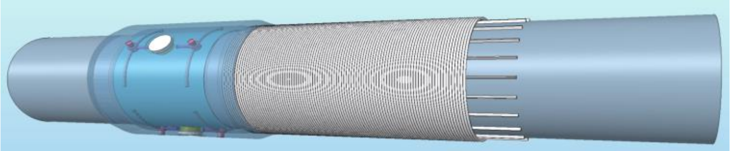
- Evaluated 3 options: Gas lift; Nitrogen bullheading & Chemical treatment
- Expected monetary value of options:
  - Gas lift: -$ 5.6 MM (90% chance of success)
  - Nitrogen bullheading: +$11.8 MM (50% chance of success)
  - Chemical treatment: +$ 2 MM (10% chance of success)
- Does not take into account:
  - time value of money
  - Production and company strategy

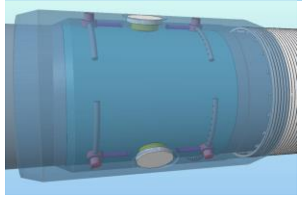
CFD Well Inflow Modelling – What are the differences?

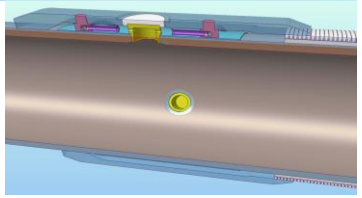
The differences: Model wells and near wellbore, considering fluids and well geometry to estimate well inflow and well component performance, providing more accurate prediction of productivity benefit from differing drilling and completion strategies.

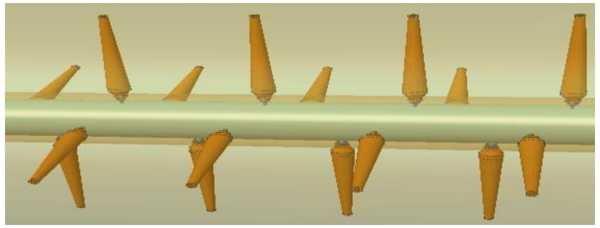
Typical scopes	• 1 – 3 phase simulations • steady state and transient • Well clean-up simulation • Sand and fines transport • Flow into and through sand control and ICDs • Component erosion modelling and prediction
Model Size	Model size: ~ 50 – 200+ million cells
Hardware	HPC (High Performance Computing) is utilised for massive parallel run





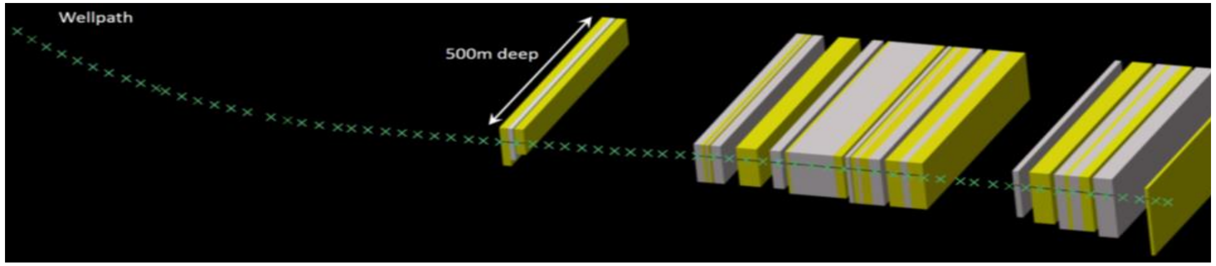


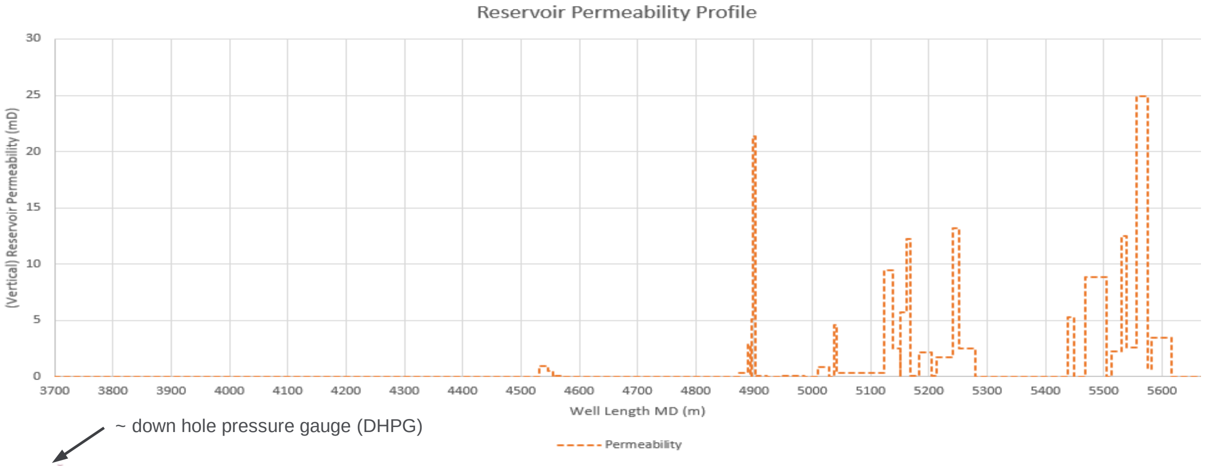


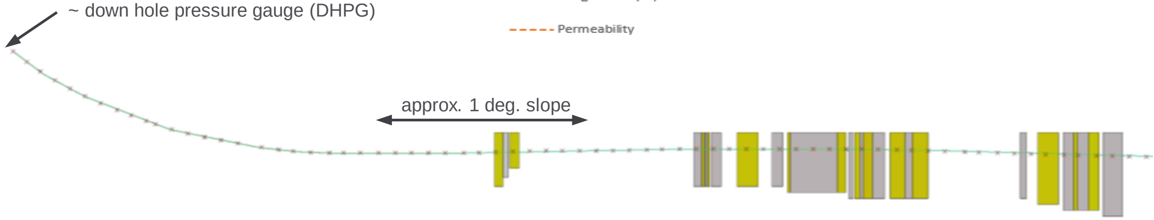


Well A Reservoir-Well Geometry and Permeability Profile

- All reservoir intervals along the well modelled
- Permeability contrast included
- Enabled bullheading of liquid with gas, gravity drainage, formation damage impact and well unloading to be modelled
- Modelling assisted with planning of well operations

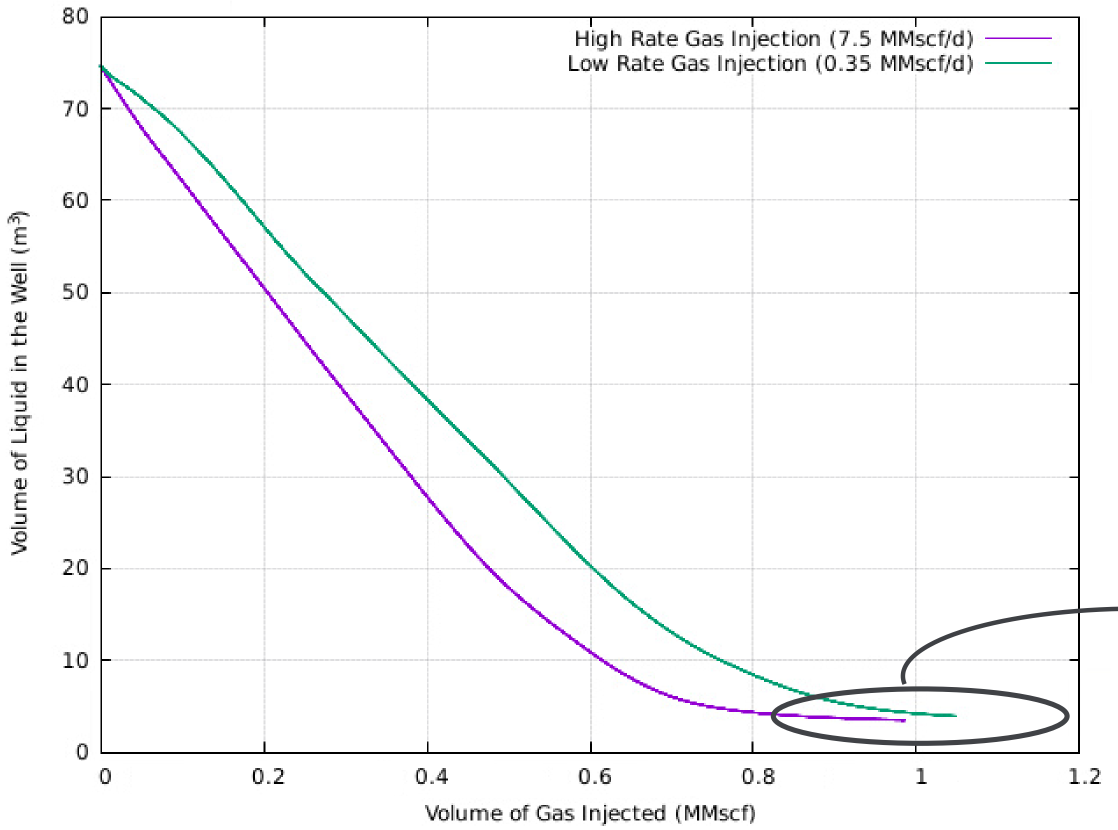






How Fast & How Much Should We Inject?

- High Rate v Low Rate Gas Injection
  Volume of Liquid in Well & Volume of Gas Injected

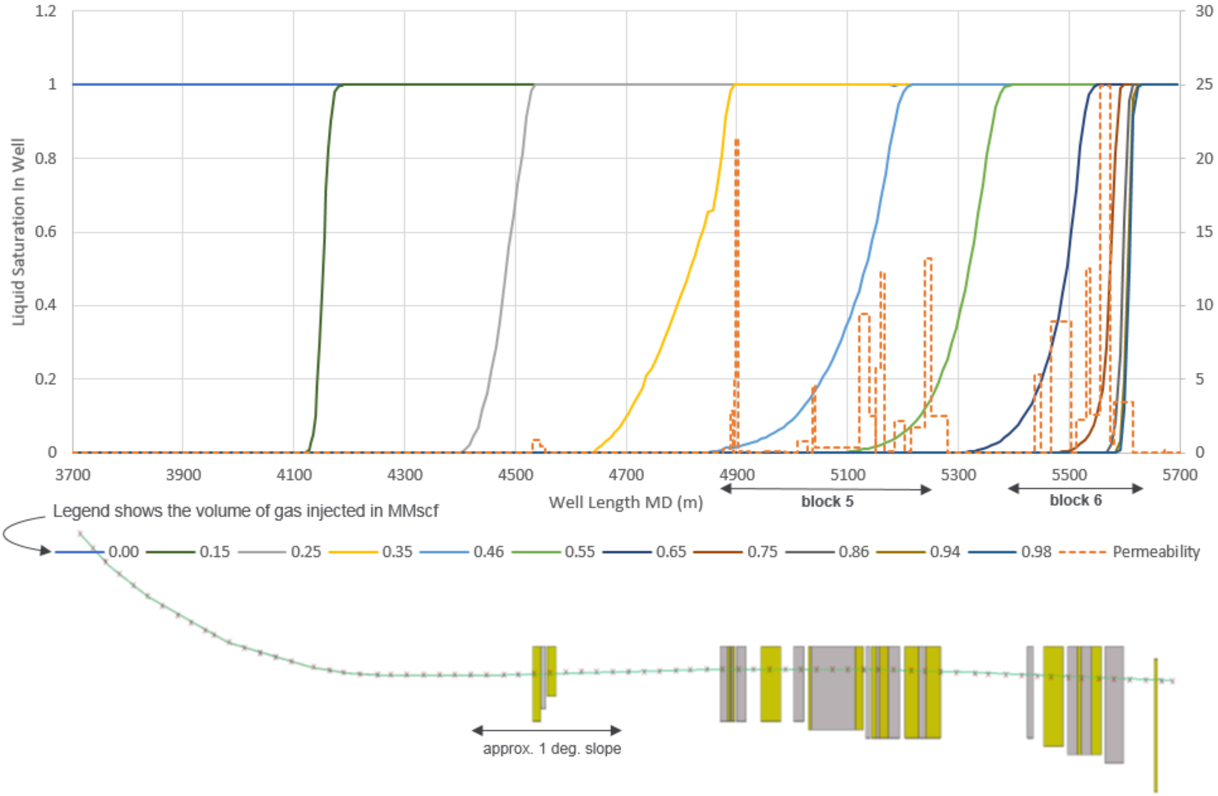


- The high rate gas injection displaces the liquid more efficiently than the low rate gas injection
- High rate requires approx. 0.8 MMscf of gas volume to reach the 'asymptote' condition, whereas the low rate requires approximately 1.05 MMscf to reach similar condition
- It is recommended to inject the gas at high rate, 7.5 MMscf/d, via 2" down line from a vessel.

@ 7.5 MMscf/d rate: ~0.85 MMscf of gas removes ~71 m^3 of liquids in ~ 3 hrs

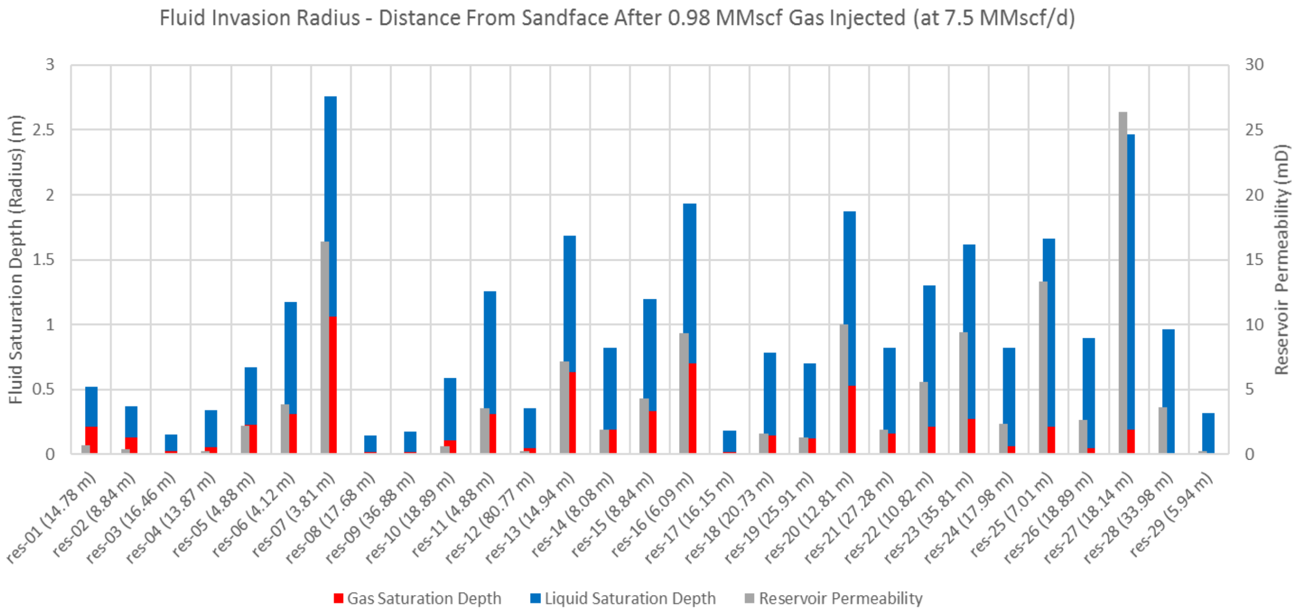
@ 0.35 MMscf/d rate: ~1.05 MMscf of gas removes ~71 m^3 of liquids in ~ 3 days

Well Deliquefication & Liquid Invasion Depth



Liquid Movement Inside the Well Due To 7.5 MMscf/d Gas Injection Rate

After around 0.86 MMscf well appears to have been deliquefied



Fluid Invasion Depth After 0.98 MMscf Gas Injected at 7.5 MMscf/d

This could have some substantial consequences in determining the extent of the invasion zone, hence the impact of formation damage on well performance

Formation Damage Effect

- Formation Damage (FD) Laboratory testing indicated that draw down through samples that contains liquid causes significant damage
  - Approximately 80% reduction in reservoir permeability is obtained from FD Lab. testing

Case	Draw Down (bar)	Gas Rate (MMscf/d)	Gas Rate Reduction
Undamaged	51	40.00	-
Damaged	51	31.20	22%

- Simulation shows that there is approx. 22% reduction in gas production rate, caused by liquid invading the reservoir – after approx. 0.98 MMscf of gas has been injected

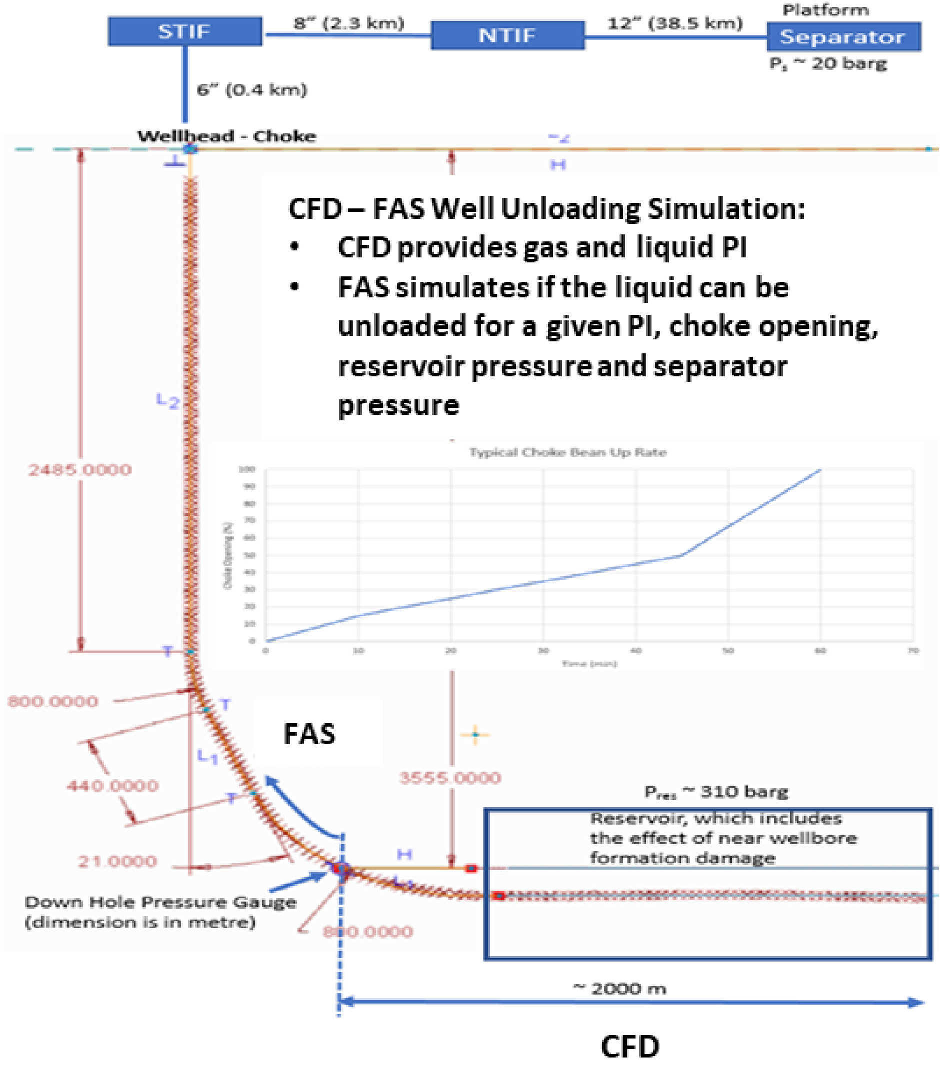
- Over flush and Extended shut-in for gravity drainage is not recommended, since this only enlarges the liquid invasion zone, resulting in larger damaged zone and further reduction in gas production rate
  - Following the gravity drainage:
    - the already damaged zone above the wellbore would remain damaged even when the liquid has fallen downwards
    - the damaged zone below the wellbore would increase due to liquid gravity segregation

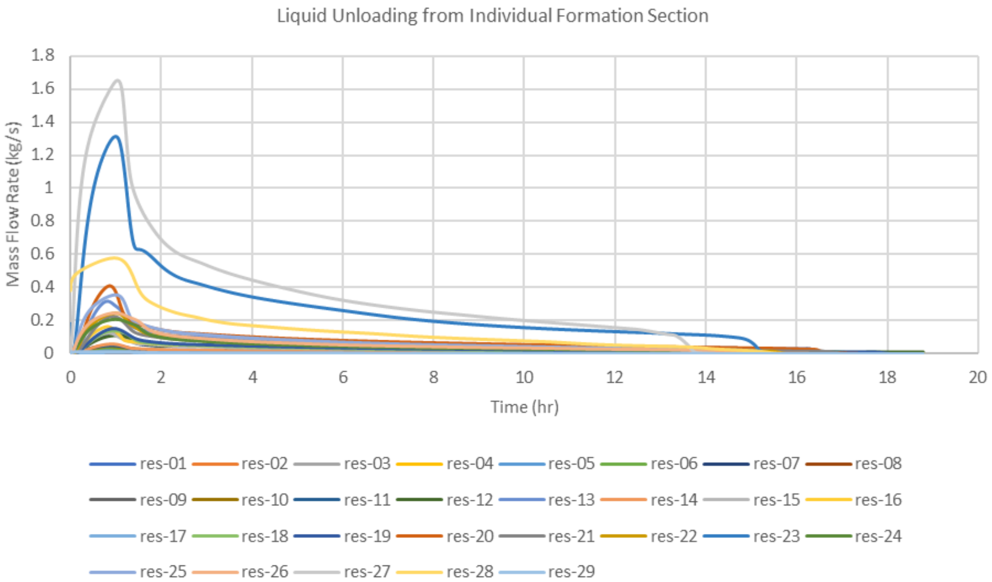
Well Unloading Simulation – CFD-FAS

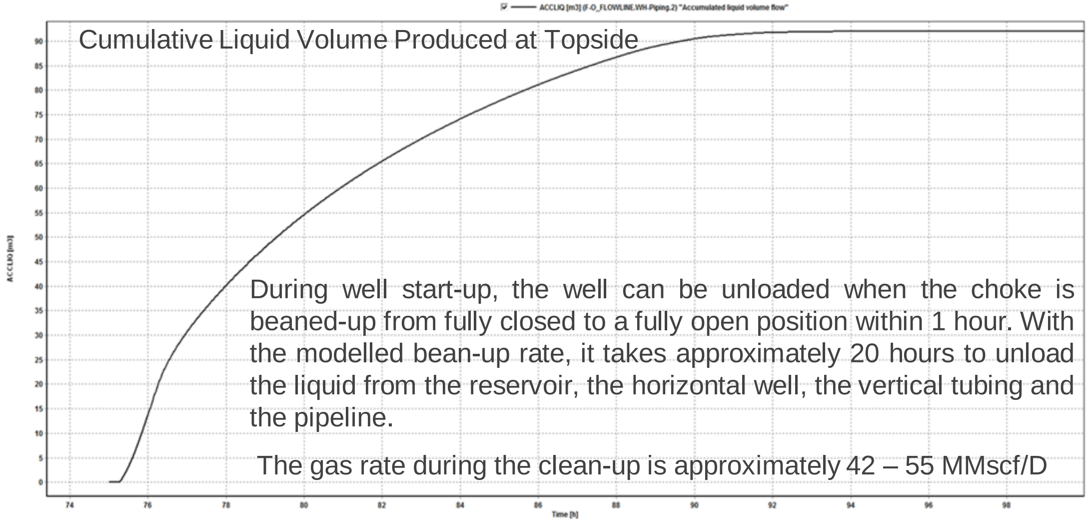
(FAS: Flow Assurance Simulator)

CFD – FAS Well Unloading Simulation:

- CFD provides gas and liquid PI
- FAS simulates if the liquid can be unloaded for a given PI, choke opening, reservoir pressure and separator pressure







During well start-up, the well can be unloaded when the choke is beaned-up from fully closed to a fully open position within 1 hour. With the modelled bean-up rate, it takes approximately 20 hours to unload the liquid from the reservoir, the horizontal well, the vertical tubing and the pipeline.

The gas rate during the clean-up is approximately 42 – 55 MMscf/D

Questions To Answer (Recommendations):

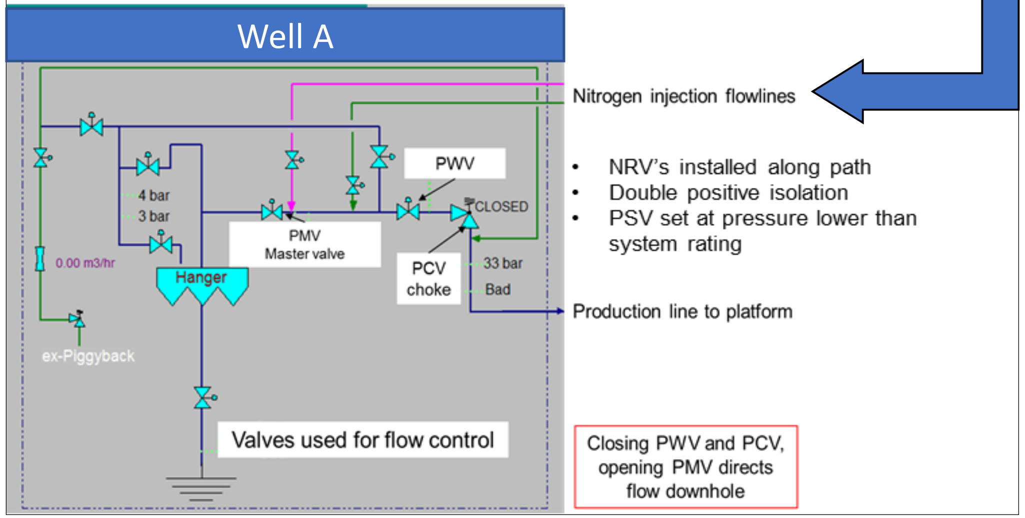
- Can we deliquefy the well by injecting Nitrogen?
  - Yes
- Assume we can, how fast and how much Nitrogen do we need to inject?
  - 7.5 MMscf/d, via 2” down line from a vessel
  - Inject approx. 0.85 MMscf gas
- What happens to the liquid?
  - Liquid invaded the formation, could potentially cause formation damage
- Should we displace the bulk of the liquid? Or should we over displace the liquid?
  - Yes, since this could also reduce the “size” of formation damage (FD)
  - Over-flush and extended shut-in for gravity drainage would only increase the impact of FD – should be avoided
- What is the impact of near wellbore formation damage (if any)?
  - Simulation shows that there is approx. 22% reduction in gas production rate, caused by the liquid invading the reservoir
  - after approx. 0.98 MMscf of gas has been injected
- How fast should we start up the well
  - Simulation results showed that beaning up the choke from fully closed to fully open choke within one hour could unload the well within approx. 20 hours

What happened at the field?

Execution plan – using the DSV

- Nitrogen pumping done from DSV & Well control done from platform
- Primary means of communications : SATNAV phone
- Secondary means of communication: Radio

Well & Flow control



- Shut-in other field wells to lower back pressure before start-up
- Troubleshoot Well A bottomhole gauge (back-up data logger)
- Intervention was risked assessed (TRA)

Well A intervention timeline (Planned vs Actual)

	Duration:	
	Planned	Actual
Activities before sailing out :		
Building of bund	1 day	1 day
Loading tanks, pumps and equipment	1 day	1 day
Function & Pressure testing	2 days	4 days
Activities at location:		
Connect downlines to wellhead & Test SSSV	8 hours	1 day
Pressure test system	3 hours	2 days
Flow test	4 hours	4 hours
Foamer injection + diffuse period	2 hours	1.5 hours
Nitrogen injection	12 hours	1 day
Well-start-up	1 day	2 days
Delays:		
Delivery of Nitrogen to Mosselbay		2 days
Waiting on weather (WOW)		1 day
*Unavailability of the DSV		50 days
Total:	6.5 days	65.5 days

*Statutory requirements Milk runs & repairs and installations

Execution plan (planning & Challenges)

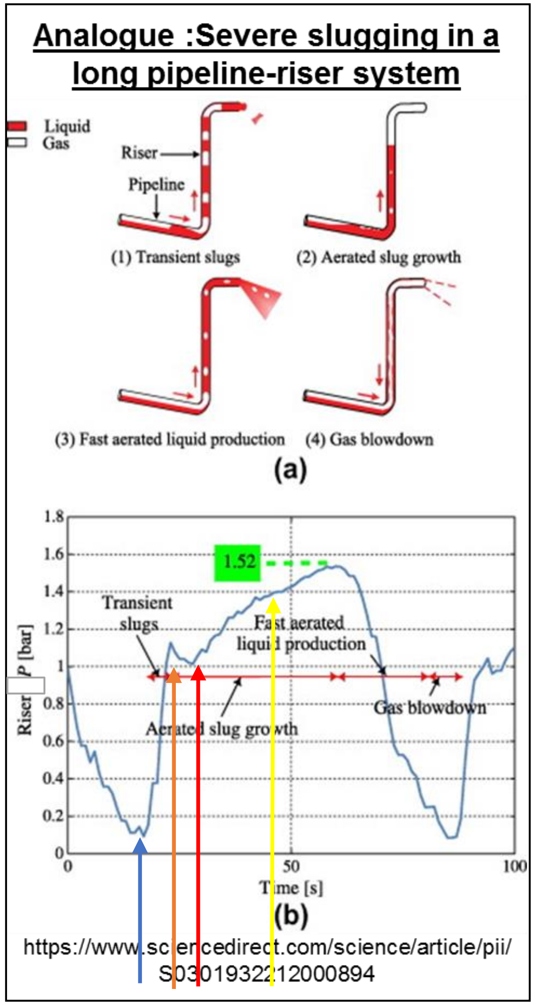
Rigorous planning

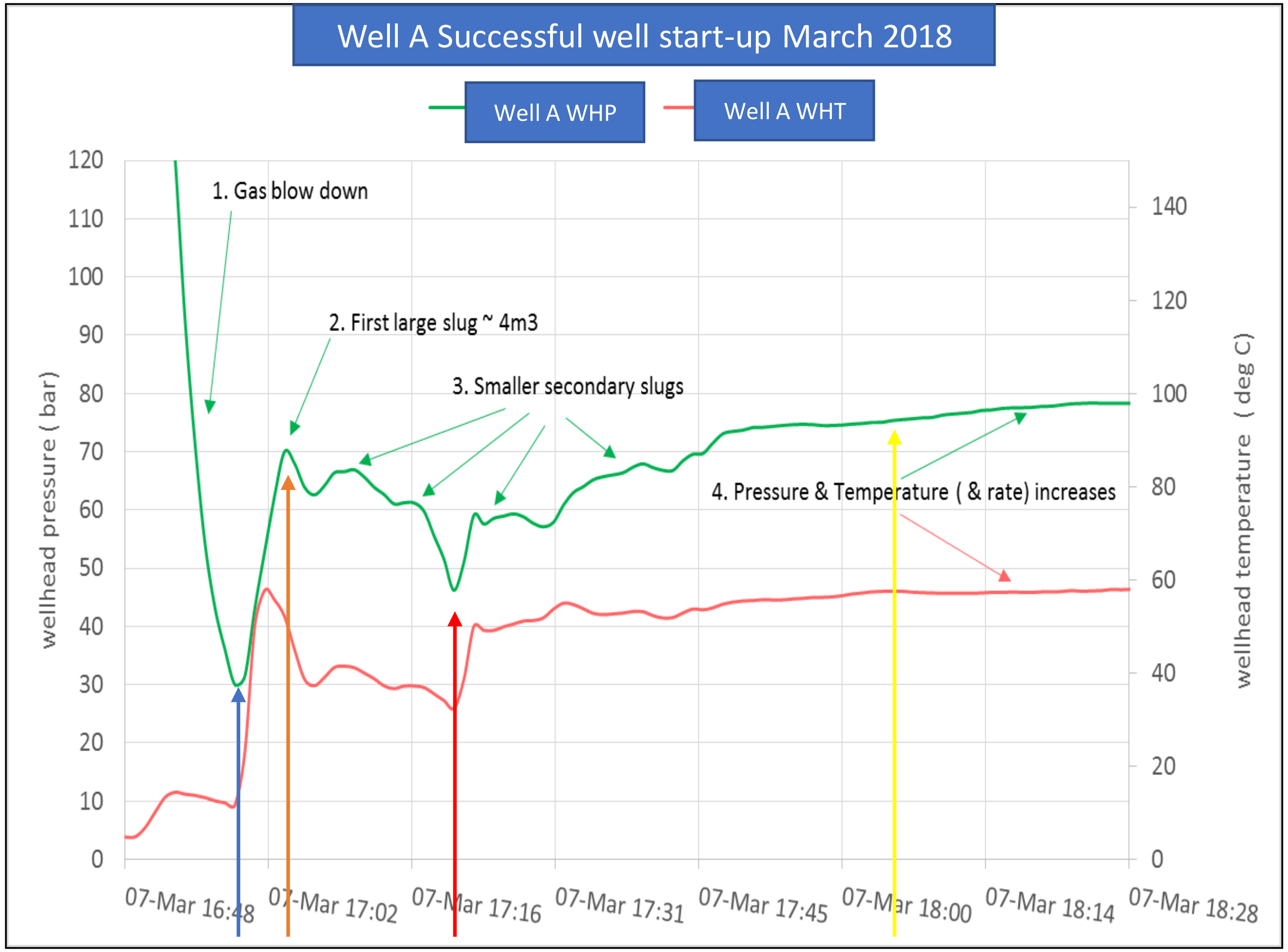
- Communication: no direct line
  - Communication protocol in place
- Crane for loading and off loading:
- Downhole pressure gauge failure
  - Emergency Expert call-out
- Account and plan for inherent nitrogen losses
  - Efficient contingent volume
- Account for hose (downline) failure
  - 50% spare hose length
- TRA action items implemented:
  - Building Bund area incase of spillages
  - Sea fastening (welding of containers)
  - Several pressure and function test completed on equipment
  - Spares & contingency
  - Alternative injection routes
- Ensure F-A platform is ready to receive flow
  - Various routing options investigated
  - Mitigate against N2 tripping plant
  - Ensure plant can handle expected volumes

Challenges at location

- Downhole gauge failure
  - Trouble shoot system with F-A and expert on phone
- False start-up due to restriction (6 March 2018)
- Nitrogen volumes planned to inject ~1 mmscf of vaporized nitrogen
  - Pumped into well ~0.8 mmscf
  - Due to higher than normal inherent losses
  - Multiple pressure test failures
    - Retrieving lines; fix leaks and redeploy and test
  - Pressure leak on tanks & pumping efficiency at low tank levels
- Multiple departments and vendors working together ☺
  - Procurement; Subsea, Capital projects, Logistic base, F-A, Greatship Manisha, Diving team, Enermech, Schlumberger, GE, Aubin, Lloyds Register

Well start-up – Successful startup

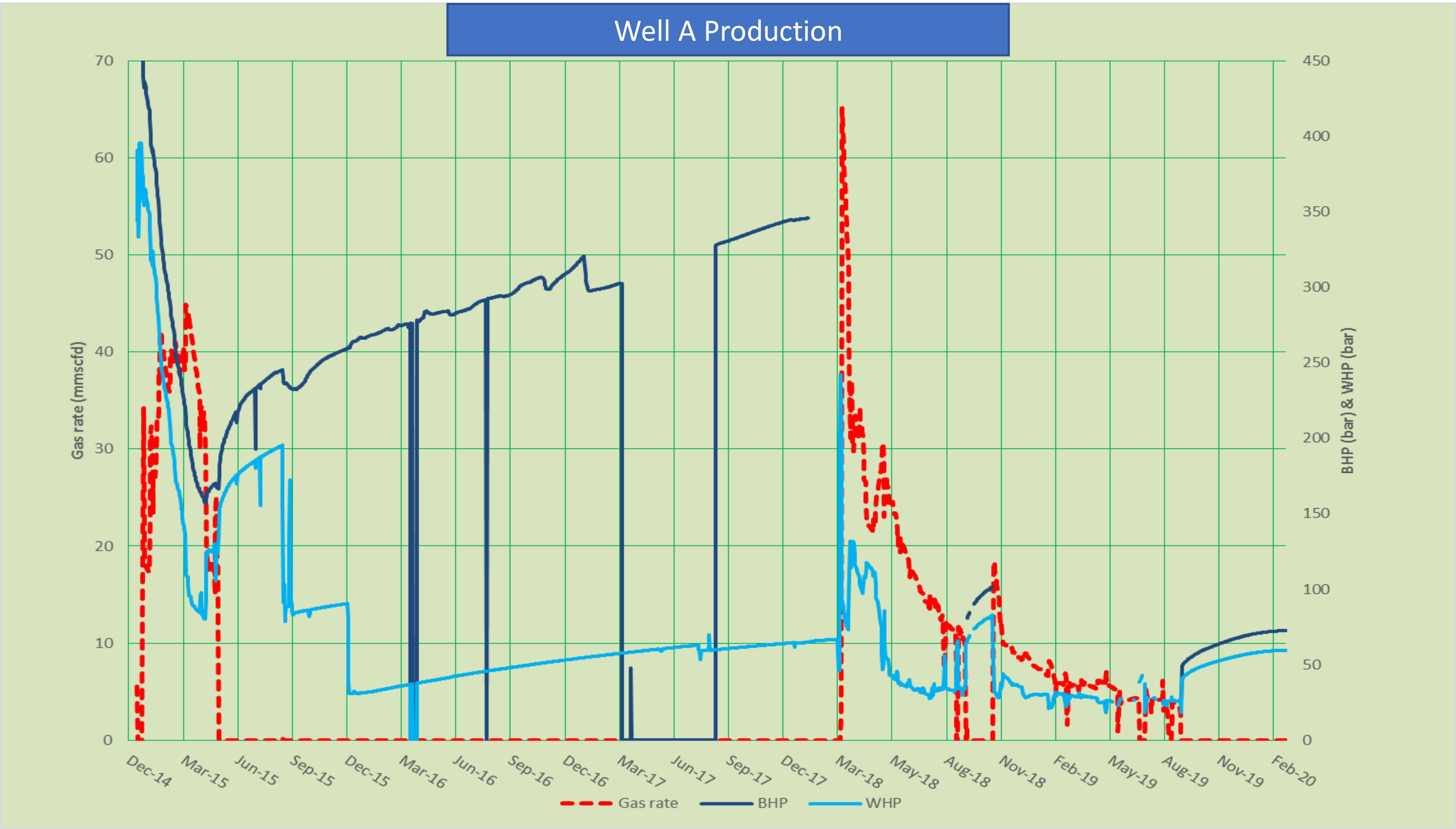




Well performance post intervention

Well A cumulative volumes before intervention:		
Gas	4.1 Bscf	
Condensate	940 bbl	CGR: 0.19 bbl/mmscf
Water	28,100 bbl	WGR: 5.6 bbl/mmscf

Well A cumulative volumes after intervention:		
Gas	11.4 Bscf (+7.3 bscf)	
Condensate	8,940 bbl + 8000 bbl)	CGR: 0.19 bbl/mmscf
Water	94,100 bbl (+66,000 bbl)	WGR: 6.9 bbl/mmscf



Project Economics

<u>Well A intervention budget vs actual</u>		
	Budget	**Actual**
Nitrogen services	$ 160,839	$ 335,664
Logistic services (crane rental etc.)	$ 45,455	$ 76,923
Consulting services (Downhole gauge repairs etc.)	$ -	$ 34,965
Risk management studies (Core flood tests & CFD modelling)	$ 349,650	$ 209,790
Diving cost	$ 349,650	$ 349,650
Total	$ 909,091	$ 1,013,986

<u>As of 18 May 2018:</u>	**Cumulative volumes produced**	**Price per volume**	**Revenue generated ($)**
Gas	2.6 bscf	$ 2,500/ mmscf	$ 4.5 MM
Condensate	400 bbl	$ 64/ bbl	$ 20 k
Total			$4.52 MM

- **Pay back period: Was ~9 days**
  - Start-up date : 07 March 2018
  - Payback date :16 March 2018 (cumulative gas production 0.48 bscf)
- **IRR: 955 %** (production until end of 2018)
  - Average gas rate ~ 15 mmscf/d
  - Estimated Cumulative gas volume ~ 5.1 bscf
- Try to maximize recovery from field
  - Realize the **2P reserves as per latest LOF**