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LESSONS LEARNED IN HIGH-PRESSURE HIGH-TEMPERATURE WELL COMPLETION IN VIETNAM

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Summary

Well completion operation in high-pressure and high-temperature (HPHT) conditions is a big challenge for both operators and service companies. These encompass all aspects in well construction and production operation such as drilling, completion, workover, IOR/EOR application, specialized equipment, etc. Effective risk management, cost control, deployment of skilled human resources for HPHT wells require managers and operators to approach in a way different from that used in conventional environment. The lessons learned from well completion operations in HPHT conditions, summarized from construction practices at gas fields in Nam Con Son basin offshore Vietnam, provide valuable insights and serve as a noteworthy reference for the design and execution of HPHT well completions in the future.

Key words: High-pressure and high-temperature (HPHT), well completion, IOR/EOR, Nam Con Son basin.

1. Introduction

In recent years, the definition of "high-pressure high-temperature" (HPHT) wells has varied across companies and oil and gas associations. The American Petroleum Institute (API) classifies HPHT wells based on its guidelines for specialized HPHT equipment. According to API standards, a well is classified as high-temperature if the static temperature at the total depth exceeds 350°F (approximately 177°C), and as high-pressure if the shut-in surface pressure exceeds 15,000 psi (approximately 103 MPa). Wells exhibiting one or both criteria are categorized as HPHT wells. Meanwhile, the Society of Petroleum Engineers (SPE), the International Association of Drilling Contractors (IADC), and several multinational oil companies (such as Schlumberger) use a slightly different thresholds, setting high-temperature at 300°F (around 149°C) and high-pressure at 10,000 psi (around 69 MPa), as shown in Figure 1.

In Vietnam's oil and gas operations, although there are no official regulations for HPHT classification, Petrovietnam and oil and gas contractors have adopted HPHT standards based on the definitions provided by SPE and IADC, with certain adjustments to accommodate local conditions. A well with a bottom-hole temperature exceeding 149°C and bottom-hole pressure below 10,000 psi is still classified HPHT if it is drilled an abnormal pressure formation having a minimum average pressure gradient of 2.43 psi/ft and an expected maximum formation pressure equivalent to approximately 15.4 ppg EMW. In recent years, several HPHT fields/discoveries have been brought into production and development in Nam

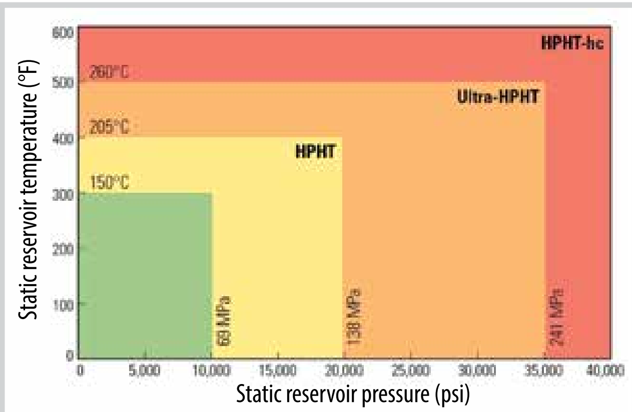

Figure 1. *HPHT thresholds [1].*

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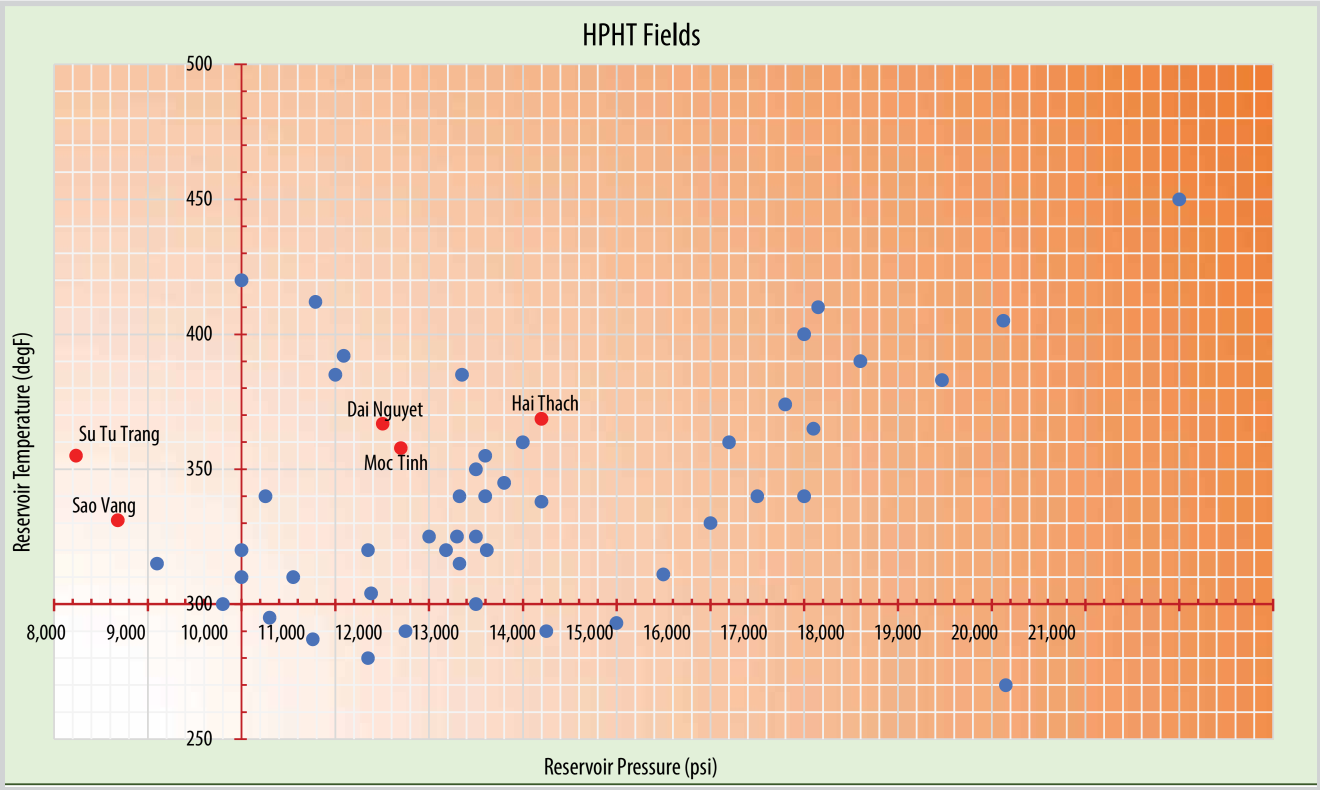


***Figure 2.** HPHT field examples worldwide and Vietnam [2].*

Con Son basin (Figure 2). Effective and safe well completion operations have played a significant role in ensuring the stable and secure production at the A and B fields, as well as in maintaining the on-schedule other field developments in the Nam Con Son.

During the production process, several wells in the A and B fields have encountered issues such as condensate buildup near the wellbore and liquid accumulation at the bottom of the well. To address these issues, various remedial solutions have been studied and proposed, which include circulating production combined with periodic gas injection into the well and installing velocity strings to regulate the upward flow rate of the well's production stream. Nonetheless, the implementation of these solutions has faced challenges due to the HPHT characteristics of the reservoir and the complexities of the well completion structures. The lessons learned from well completion operations at the A and B fields will serve as valuable references applicable to other HPHT formations in the future.

2. Issues during completion operation in the A field wells

- There are seven wells drilled on the A platform, including four wells (A-1P/3P/4P/7P) targeting the Upper Miocene B (UMB) 15-20, two wells targeting the Upper Miocene A (UMA) 10-20 and well A-2X for appraising deep reservoirs. The drilling campaign in the A field was divided into two phases: Phase 1 conducted in the early stage of the project with four wells A-1P/3P/6P and A-2X; and Phase 2, carried outin the late stage of the project, began after the completion of drilling nine wells in the B field then the rig was moved back to the A field to drill the remaining three wells A-4P/5P/7P before the project closure. During the interval between Phase 1 and Phase 2, some off-line interventions were taken place in the A platform, including perforation, zonal isolation, and addressing equipment failure.

During Phase 1, the completion operations mainly focused on deployment of the upper completion string. In this early stage of the project, several incidents occurred, and most of lessons learned and recommendations were documented in this stage.

+ The completion of A-1P encountered a failure of the wellbore clean-up tools during the inflow test with base oil, conducted in preparation for displacing underbalanced completion brine. The completion tool cleaner (CTC) was prematurely sheared due to excessive compression during the inflow test which resulted in pulling out the damaged equipment and subsequently deploying a retrievable test tool system (RTTS) packer. The well was then successfully inflow-tested and displaced to potassium formate. During the displacement from drilling mud to completion brine, the circulation system revealed its limitation. Specifically, the return system utilized a shared flow path for both drilling mud and completion brine, leading to increased operational time consumption. To fix this issue, the circulation was modified. The completion process also encountered equipment failures due to both human error (packer backing out due to inattention, lubricator valve (LV) fittings stuck inside operating ports) and design limitation (the SB pulling tool being unable to release from the fishing neck, the RPT running tool failing to hold off the shear screws). Eventually, the completion string was successfully deployed, and well was secured before handed over to production. Then the rig was skidded to the next well.

+ The completion of A-3P got an issue with the positive test of the 5½" liner lap, which failed at 7,200 psi during a 7,500 psi test. An easy shut-off valve (EZSV) bridge plug was set on the liner shoe and a tieback packer was installed on the 5½" liner lap but the test was still unsuccessful at 7,200 psi. Despite this, the well still proved good inflow test over 5 hours, and the completion brine was displaced while maintaining well integrity throughout the completion phase. The completion string was successfully deployed and set without any other major issues.

+ The completion of A-6P was taken place after a 20-day suspension for drilling and casing the 22" section of well A-2X. The prolonged suspension with drilling mud left in the well caused barite sag, leading to difficulties in deploying the wellbore clean-up string. It took about 2 days to clean the barite sag and condition the mud in the hole. Following these operations, the completion was successfully deployed, and the well was securely handed over to production.

- The completion of A-2X experienced a failure during the positive test of the 5½" liner lap at 6,400 psi then it was unable to hold 3,200 psi. After several attempts to address the issue, the gas circulation increased to 11% before reducing to zero after several bottom-ups. The well was then successfully inflow-tested for five hours and displaced to brine. However, during the inflow test, the completion tool cleaner circulation sub was sheared out due to high compression stress. As a result, the wellbore clean-up string had to be stripped out to replace the failure equipment with backup tools.

In Phase 2, after the drilling rig moved from B field to A field, the operation included completion and perforation for the last three wells of the project (A-4P/5P/7P). These wells were drilled into UMB 15-20 (A-4P/7P) and UMA 10-20 (A-5P).

+ The completion of A-5P encountered multiple issues involving the segment bond tool (SBT), logging tool and PBL (Multi Activation Bypass) sub during the wellbore clean-ups. Excessive cement at the 5½" liner shoe required activation of the PBL sub to increase the pump rate while milling the cement by a 4⅛" mill tooth bit. The PBL sub was deactivated and maintained integrity during the subsequent positive and negative tests. However, during the displacement of the well into brine, the pill train returned to the surface at early stroke, indicating a leak in the PBL sub. An onshore investigation showed a washout at one (1) port side of PBL and the absence of two O-rings.

+ The A-7P well was the last well drilled in the A field and of the project. It had the issue with the 5½" liner shoe as the plug was over-displaced, leading to the failure of the positive test at 3,170 psi. To fix it, an EZSV bridge plug was set right above the landing collar, and a subsequent positive test was successfully conducted at 3,200 psi. The well was then inflow-tested with base oil as normal, and the completion string was deployed successfully in completion brine. The well was secured and handed over to production.

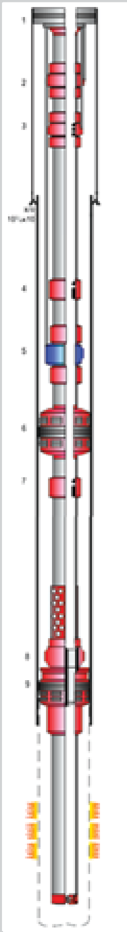
3. Issues during completion operation in the B field wells

There are nine wells drilled on B platforms including five wells (B-1P/4P/5P/6P/9PST) targeting the LMH reservoirs which are classified as HPHT and four wells (B-2P/3P/7P/8P) targeting the UMA and Middle Miocene flank (MMF) reservoirs, exhibiting pressures and temperatures similar to those in the A field. These wells were spudded after the drilling rig moved from the A platform to the B. Some wells were perforated under simultaneous operations (SIMOPS) conditions, allowing intervention equipment access below the rig floor while drilling adjacent wells. Upon completing the last well (B-9PST), the drilling rig was moved back to the A platform to drill the remaining three wells in the A field before the project concluded.

- The B-3P well was the first well drilled on the B platform, targeting MMF30 reservoir. Its completion phase smoothly proceeded as normal operation conducted in the A field when the well was tested and displaced into brine. However, during the dummy run, the tubing hanger (TBHG) was unable to land correctly. The blowout preventer (BOP) was nipped down and the multi-bowl was split to investigate the upper section inside. It was found that the landing shoulder of the isolation test tool (used to test BOP) rolled up, preventing the spacer of TBHG from landing properly. The edges were fined and all obstructions were cleared to allow TBHG landing correctly. The operation was resumed to deploy upper completion without any further incident.

- The B-1P well was drilled into the LMH reservoirs to appraise the deep targets in LMH 45A-45B-46. In the completion, the TBHG was again unable to land properly during dummy run, this time due to high elevation of the 10" bridging hanger. This was the first well in the project (followed by B-4P) to use the bridging hanger, necessitated by the damage of wicker on the 10" casing hanger (CSHG). The bridging hanger does not have a locking ring to secure it in-place during pressure test, causing it to move upward approximately 1". The multi-bowl again was split to confirm the high elevation of bridging hanger, and shims were adjusted on the TBHG spacer. The operation was resumed, and completion string was deployed in the hole. Upon landing the X-mas tree, the TBHG was found too deep for the VG-52 seal ring. Anyhow, the Xmas tree was successfully tested with its secondary seal on the TBHG neck, ensuring the well was safe for perforation.

- The rig was then skidded from B-2P to B-1P after finish drilling the 13⅝" section to perform the second perforation in the LMH 20-25-30 reservoirs of well B-1P. The LMH 45A-45B were abandoned by setting an EZSV bridge plug and topping it with a 50 m cement plug. EZSV bridge plug was stuck in the 5½" liner at 3,904 m (desired setting depth of 4,078 m). After several unsuccessful attempts to move the bridge plug, it was decided to set at stuck point. The e-line tool string was successfully retrieved to the surface without damage. The bridge plug passed an 8,000-psi pressure test and an inflow-test with a surface pressure of 436 psi. A 40 m cement plug was spotted on top of the bridge plug. Then, the well was perforated in the LMH 20-25-30 reservoirs and handed over to production. The rig was then skidded back to B-2P to drill the 10" section.



ITEM	P/N	DESCRIPTION	ID	OD	LENGTH	DEPTH	Deviation
					20.700	0.000	
		RKB - Landing Point				20.700	
1	Vetco Grey	Vetco Grey Tubing Hanger c/w pup joint	5.500	18.600	3.019	20.700	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 11`0 MY B - P	4.670	5.500	2.200	23.719	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 11`0 MY B - P	4.670	5.500	5.940	25.919	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	579.389	31.859	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 11`0 MY B - P	4.670	5.500	1.933	611.248	
	11BN509	Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.561	6.211	1.711	613.181	
2	P.560LV4552301	Lubricator Valve, 5 1/2" 23# Vam Top HC Alloy 718 125 MY B-P	4.587	9.200	3.259	614.892	
	11BN509	Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.561	6.211	1.718	618.151	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.918	619.869	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	25.273	621.787	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.933	647.061	
	11BN509	Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.561	6.211	1.719	648.994	
3	6780024	TRSV SP 13Cr, 5 1/2" 23# Vam Top HC, Alloy 718 125 MY, B-P	4.500	8.090	3.001	650.713	
	11BN509	Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.561	6.211	1.729	653.714	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.932	655.443	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1993.401	657.375	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	3.949	2650.775	
4	Baker hughes	Baker hughes Down hole Pressure Gauge 5 1/2" 23# Vam Top HC, B - P	4.675	7.000	1.712	2654.724	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	3.947	2656.436	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	861.725	2660.383	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.912	3522.108	
		Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.670	5.500	1.725	3524.020	
5	711RPT43118	4.313" RPT Landing Nipple, 5 1/2" 23# Vam Top HC, Alloy 945 125 MY B - P	4.313	6.211	0.750	3525.745	
		Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.670	5.500	1.727	3526.495	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.921	3528.222	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	12.802	3530.143	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	3.935	3542.945	
6	Baker hughes	Baker hughes Down hole Pressure Gauge 5 1/2" 23# Vam Top HC, B - P	4.675	7.000	1.715	3546.880	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	3.932	3548.595	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	12.802	3552.527	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.932	3565.328	
		Top of Packer - COE	4.465	8.310	0.895	3567.260	
	212HNT9547-E	HNT Packer 9 5/8" 47-53.5 # 5 1/2" 23# Vam Top HC, Icl 718 125 MY B-P	4.465	8.310	0.000	3568.155	
7		COE - Bottom of Packer	4.465	8.310	2.423	3568.155	
	212N100502	Millout Extension, 5 1/2" 23# Vam Top HC, Alloy 945 x 140 MY B - P	4.588	6.211	1.675	3570.578	
	892BPC55127-E	X-Over 5 1/2" 23# Vam Top HC, S13Cr 125 MY B - P	4.588	6.211	0.220	3572.253	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.937	3572.473	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	12.193	3574.410	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.915	3586.603	
		Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.670	5.500	1.720	3588.518	
8	711RPT41807	4.188" RPT Landing Nipple, 5 1/2" 23# Vam Top HC, Alloy 945 125 MY B - P	4.188	5.520	0.754	3590.238	
		Blast Nipple, 5 1/2" 23# Vam Top HC, Alloy 718 110 MY B-P	4.670	5.500	1.726	3590.992	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.934	3592.718	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.67	5.5	1.913	3594.6519	
		Tubing, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	415.057	3596.565	
		PUP Joint, 5 1/2" 23# Vam Top HC, S13Cr 110 MY B - P	4.670	5.500	1.931	4011.622	
		Perf Pup, 5 1/2" 23# Vam Top HC, B - P S13Cr 110 MY	4.670	5.500	3.944	4013.553	
9	H297500082	X-Over 7" 35# Vam Top HC Pin X 5 1/2" 23# Vam Top HC Box, S13Cr	4.625	7.063	0.438	4017.497	
		NO GO LOCATOR	6.000	8.118	0.475	4017.935	
	H299892832	MULESHOE GUIDE & NO-GO LOCATOR S13Cr, 7" 35# Vam Top HC Box Up	6.000		5.938	4018.410	
		End of Tubing				4024.348	

Clamp Protector used : 301 eacross coupling and 2 ea special clamp protector as per Baker hughes

Figure 3. B-8P well completion schematic.

- The B-2P well was drilled, completed, and perforated into UMA 40, MMF5-10 reservoirs. The operation went as planned with the perforation using 1.75" coiled tubing to deploy 170 m of 2⅞" high nitrogen steel (HNS) guns. After finishing the 22" casing in the B-5P well, the memory production logging tool (MPLT) string was deployed into the B-2P well. The MPLT operation was executed successfully without any tool failure, and well was then handed over to production. During production phase, the down hole gauge (DHG) lost signal; troubleshooting confirmed a complete failure of the electronics.

- The B-5PST well was side-tracked from the original well plan due to the issue encountered while drilling through the targets. During the completion phase, the well was successfully tested and displaced to completion brine. Then, the 10" SBT was logged as normal, however, the tools were found broken at the bow springs at surface. The well was subsequently cleaned with two clean-up trips: the first using an 8⅜" flat bottom junk mill, and the second using a 4⅛" mill tooth bit, without any obstruction encountered in both runs. An investigation indicated a complacency during rig-up and rig-down of wire-line tools by air tugger. The lesson learned was to use wireline with load cell for rig-up/down the tools to avoid similar incidents. The SBT run on the 5½" liner was omitted due to the concern of remaining junk in the hole. The completion string was then deployed with any further incident.

- The B-6P well was completed with a deviation from the plan which omitted the cement bond log in production liner. The well was then perforated in the LMH 20-30 with 1.75" coiled tubing and 2⅞" high nitrogen explosive gun, using the surface well test package to connect the Xmas tree to production system. There was a minor issue with e-line unit while perforating due to its electronic device. In the dummy run, the guns found difficult to pass the liner with gun hanger releasing tool that was subsequently decided to replace with a bullnose and keep the gun hanger at the setting depth after perforation. The operation was conducted safely, and the well was then handed over to production with LMH 20-30 perforated as per plan.

- The B-7P well was completed without any issue, and then perforated in the UMA10 while the rig was drilling B-8P. The perforation gun was 3⅜" high melting explosive (HMX), deployed with a braided line and gun hanger system ensuring sufficient rat-hole for dropping the guns.

- The B-8P well was completed as shown in Figure 3. Since the clean-up tool experienced the overpull at the 10" Tieback, the cement bond log was then omitted in the 5½" section. While deploying completion string, the DHG lost signal after 1,357 m string in-hole. A back-up DHG was then installed on completion, causing the DHG being positioned higher than planned.

- The B-4P well was completed without any problem and then perforated in the LMH 20-30-40 reservoirs while the rig was drilling the B-9P well. The perforation gun is 2⅞" HNS with coiled tubing perforation system. The B-9P well was completed. The operation was executed as per plan until the completion string found obstruction at 2,771 m. The attempts to run the completion string through obstruction had caused the production packer prematurely set. To address this, the upper tubing section was cut using an e-line remote control torch cutter and retrieved on surface. The production packer was then

Table 1. *Completion time and NPT distribution*

No.	Well	Completion duration (hours)	NPT (%)	NPT code
1	A-1P	281	4	Completion services
			9	Fluids services
2	A-3P	427.5	2	Wellhead services
3	A-6P	863.5	6	Fluids services
4	A-2X	476.0	4	Wireline logging services
5	B-3P	223.5	16	Wellhead services
6	B-1P	268.5	17	Wellhead services
7	B-8P	199.5	5	Clean up
8	B-4P	371.0	48	Wait on weather
9	B-9P	596.5	72	Well problems
10	B-9PST	223.0	1	Wireline logging services
11	A-5P	197.5	4	Wireline logging services
12	A-4P	185.5	18	Wireline logging services

***Table 2.** The process of evaluating NPT caused by wireline logging services*

Category	Assessment
Pre-job planning/equipment Preparation	✓ All equipment was delivered for load-out on time; ✓ Contingent equipment was ready for load out on time; ✓ Procedures and simulations were provided in advance of jobs; × Lack of coordination and preparation for mobilizing zone 2 logging unit.
Job execution (equipment)	✓ Successful open-hole logging performance in HPHT environment (PCL and WL); ✓ Successful cased-hole logging performance (cement bond integrity measurements); ✓ Successfully completed 15 interventions with WHP > 5,000 psi; × Some major issues and equipment failures were identified for certain jobs.
Job execution (personnel)	✓ Effective communication between the field crew and operator's supervisors; × Intermittent levels of crew competency observed throughout the campaign.
Onshore support	✓ Effective communication between support staff and operator engineering team via various meetings held before operation and weekly updates during job preparation progress; × Technical support and assistance between coordinator and project team need to be further enhanced.
Lessons learned/Follow up	✓ Being proactive in failure investigation and root cause analysis; ✓ Corrective actions were effectively applied, yielding good results for cased-hole logging; × The timeliness of failure investigation reporting requires improvement, including frequent status updates.

***Table 3.** NPT have been analyzed, evaluated, and lessons learned*

Category	Assessment
Pre-job planning/equipment Preparation	✓ Equipment was correctly prepared, serviced and maintained according to company's procedures and delivered on time. × Services contractor's equipment "just in time" delivery strategy reduced flexibility. × Poor QA/QC on some manufactured equipment.
Job execution (equipment)	✓ Equipment worked as designed. × High NPT at the start of project as this was the first time this system was run in the world. ✓ NPT was reduced once new procedures and right service hands was assigned.
Job execution (personnel)	✓ Dedicated service hands did a good job. × Services contractor's personnel crew competency was questionable at the start of the project. Service hands were changed out until the expected level of support was achieved.
Onshore support	✓ Good equipment preparation & support from Vung Tau workshop. ✓ The additional of Operator wellhead specialist to the team significantly reduced downtime attributed to Services contractor. × Poor levels of customer technical support from Services contractor's office.
Lessons learned/Follow up	× Having the right people using the right equipment and knowing how the equipment works is required for efficient operations. × This was specifically designed equipment and needed specifically trained personnel - "on the job training" was not appropriate for this work. × Low improvement, response to failure investigation, root cause analysis.

milled and recovered although the lower slip segments were missing. Consequent attempts to clean the slip segments resulted in the wellbore clean-up string stuck in the hole. This serious stuck pipe led to a series of fishing run and ended up with the fish of a 2⅞" drill pipe left inside the 5½" liner. The whipstock was then set above the 5½" liner hanger, and the well was side-tracked. And the completion of B-9PST was executed without any further problem.

4. Major completion lesson learned

During the well completion process in the A and B fields, the issues occurring at the wells, as mentioned above, resulted in non-productive time (NPT). Table 1 shows the total well completion time and the corresponding non-productive time for each well. For example, the total well completion time of the well A-4P was 185.5 hours, with 18% of the time attributed to NPT due to wireline logging services. The lesson learned was applied to subsequent wells for reducing NPT related to this specific issue.

Each type of NPT code will be evaluated step by step to draw lessons learned. Table 2 provides a specific example of the evaluation of NPT code related to wireline logging services. The three wells A-4P, 5P, and B-9PST were drilled during phase 2 of the project. Based on the statistics in Table 1, it is clear that well A-4P was drilled first and had an NPT related to Wireline logging services of 18%. A deeper analysis reveals that the primary causes of NPT in this well are issues encountered during equipment preparation and equipment failures during operation. The root causes are lack of coordination and preparation for mobilizing zone 2 logging unit, therefore, the installation time took longer than expected. The results of the analysis, evaluation, and lessons learned, summarized in Table 2, form the basis for a significant reduction in NPT for subsequent wells (4% for well A-5P and, notably, only 1% for well B-9PST).

Table 3 provides another example of the evaluation of NPT code related to wellhead services. As summarized in Table 1, the three wells with NPT related to wellhead services are B-1P, B-3P, and A-3P. The causes leading to NPT at these wells have also been analyzed, evaluated, and lessons learned are presented in Table 3.

Other NPT codes were also analyzed and evaluated using the same method to draw lessons learned for each type of well completion service as below.

4.1. Wellbore clean-up

- Do not place shear-activated tools on one string: In wells A-1P and A-2X, the CTC tool (circulating sub) was prematurely activated during the inflow test, causing operational delays. The lesson learned is to closely monitor pressure during the test and replace the CTC with a PBL sub activated by a ball-drop.

- Incorporate clean-up tools into one string: Instead of performing wellbore clean-up in two separate runs, it is recommended to combine the tools into a single string to reduce rig time and ensure efficient well cleaning.

4.2. Fluid cleanliness

Use appropriate cleanliness criteria: In well B-1P, using total settling solids (TSS) instead of nephelometric turbidity unit (NTU) as a cleanliness criterion was proved to be more accurate and practical for assessing the return brine, which minimizes excessive circulation time.

4.3. Pilot test before mixing old and new brine

Conduct pilot testing: In wells A-6P and B-9P, mixing old and new brine without prior testing caused unwanted precipitation. The lesson learned is to always perform pilot testing before mixing to avoid unexpected chemical reactions.

4.4. Completion equipment and tools

- Special ball requirements for PBL sub in heavy mud: In wells A-6P and B-5P, standard balls failed to work in heavy mud, resulting in delays. The lesson is to use heavier dart-type balls that can perform in high-viscosity fluids.

- Mark completion equipment: In well A-1P, a production packer came loose due to insufficient marking. The lesson learned is to ensure that all completion equipment is clearly marked for monitoring during installation.

- Avoid excessive work on completion string: In well B-9P, excessive work on the completion string caused the production packer to set prematurely, leading to severe operational issues. The lesson learned is to pull out of hole (POOH) when encountering obstructions instead of forcing the string.

4.5. Perforation and intervention operations

- Use gun hanger for depth correlation: In well B-1P, using a gun hanger as a depth correlation tool for perforation with coiled tubing avoided off-depth perforation issues.

- Surface pressure test with water: Methanol was found to damage O-rings due to gas reactions. The lesson learned is to use water for pressure tests to maintain the integrity of seals.

- Design for snubbing wireline tools in high wellhead pressure: In well A-2X, tools couldn't be snubbed into a high-pressure well due to insufficient weight. The lesson learned is to calculate the proper tool weight with a safety margin for HPHT conditions.

4.6. Other operational issues and lessons

- Wireline tool issues: Several instances of tool malfunction were noted, such as tools failing to pass through heavy mud, being unable to snub due to high wellhead pressure, or centralizers breaking. The key lesson learned is to carefully design tool strings, considering the specific working conditions (HPHT) and ensuring adequate weight and flexibility.

- Increase safety margin for cable tension in PLT logging: During PLT logging in HPHT wells, excessive cable tension was encountered. The lesson learned is to design jobs with a higher safety margin for flowing conditions and ensure that proper friction factor is applied to calculate cable specifications.

In summary, the application of the lessons learned as mentioned above in well completion for future drilling projects will contribute to reducing NPT. Reducing construction time will, in turn, lower drilling costs and enhance the economic efficiency of the project.

5. Conclusion

The conclusion of the paper emphasizes the importance of applying real-world experiences to optimize operations and minimize NPT in drilling and well completion activities. The lessons gathered stem from challenges encountered across various phases of operations, including wellbore clean-up, fluid cleanliness checks, well completion, perforation and well intervention, and wireline tool use. Key lessons learned include:

- Integration of tools and processes: Combining tools into a single string and optimizing processes such as wellbore clean-up and fluid cleanliness checks significantly reduces time and resources. Instead of performing separate runs, tools should be integrated to minimize downtime and enhance operational efficiency.

- Accurate criteria application: Shifting from the nephelometric turbidity unit to total settling solids as the fluid cleanliness criterion greatly improves the ability to assess solid content in the filtered brine, preventing unnecessary circulation. This demonstrates the importance of applying the correct standards suitable to specific well conditions.

- Pre-testing critical steps: Conducting pilot tests before mixing old and new brine or performing other critical operations helps prevent unexpected chemical reactions and precipitations. These proactive measures protect equipment and ensure smoother operations in the wellbore.

- Attention to equipment design and supervision: Well completion equipment requires careful design and supervision, such as clear markings or precise weight calculations when deployed in specialized conditions like HPHT wells. Ineffective planning can lead to significant issues, including additional runs or equipment failure.

- Tool modifications and adaptations to actual conditions: The challenges with wireline tools, perforation guns, and other downhole equipment highlight the need for constant improvements and adjustments to suit real-world working conditions, especially in HPHT environments. Tools must be calibrated for weight, pressure, and other operational factors to ensure safety and efficiency.

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