SPE-181557-MS

Pushing the Completion Design Envelope in Ultra-Deepwater - Design, Installation, and Performance of Deep High Pressure Completions - A Case History of the Gunflint Development, Offshore Gulf of Mexico

Jack Sanford, John Healy, Tim Hopper, Josh Fink, Ladd Grammer, James Koy, Jocelyn Perroux, Ian Magin, Kevin Williams, and Tom Seeley, Noble Energy

This paper was prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Dubai, UAE, 26-28 September 2016.

Abstract

A Gulf of Mexico case history is presented that describes the successful delivery of two (2) deep (27,000-ft) high pressure (>17,500-psi) high rate design (25,000 BOPD) oil wells in an ultra-deep water (+6000-ft) environment. Well conditions, coupled with challenging production requirements (depletion of 10,000-psi), provided a very arduous design challenge. One well was completed as a single frac pack at 27,000-ft MD. The second well required a stacked frac pack at 25,000 ft-MD and intelligent flow controls.

Twenty-seven (27) firsts, to the industry and / or Noble, were required to deliver the final completion designs. These firsts ranged, to name a few, from a new tieback casing material, a paradigm change in the Temporary Abandonment (TA) procedure (which yielded a cost savings of $15 million per well), a new perforating charge, qualification of a new material for the Gravel Pack (GP) packer, weighted frac fluids, changes in the upper completion designs, Vacuum Insulated Tubing (VIT) welding qualification and re-design of a control line Y-block. Any one item or any single technology gap, is seldom insurmountable. However, it is the layers and the multitude of challenges in these type of environments, where every component and their interdependencies are stretched to the edge of the design envelope that pushes the completion team and suppliers to their limit. All of these together make the goal of flawless execution very challenging. This paper will provide an overview from design thru operations, and highlight some of the engineering challenges and lessons learned.

A field proven completion delivery process combined with a team of experienced people and rigorous procedures successfully designed and delivered two (2) complex completions that were on the edge of deep-water completion technology. Based on the Rushmore Review database, both wells (1 single GP and 1 single selective GP) were the fastest completions (when analyzed on a well depth basis) since Macondo. Both wells were completed in 2015, and are currently waiting on final hook-up and commissioning. First oil is forecast for July 2016.

Industry will continue to explore ultra-deep water and discover deeper and higher pressure reservoirs that push the completion technology envelope. It is imperative that engineers be able to confidently design and deliver completions for this extreme environment that will achieve the productivity and reliability required by the project economics. The aim of this case history is to provide the engineer, faced with similar

challenges, with information that may prove beneficial in the approach, method, design and delivery of these type of complex, critical completions.

Introduction

The Gunflint field is located in Mississippi Canyon (MC) blocks MC948, MC949, MC992, MC993 and MC904 in approximately 6100 feet of water (Figure 1). The discovery well (MC948 #2) was drilled in 2008 and was operated by BP Exploration and Production, Inc. Noble Energy took over as operator after the discovery.

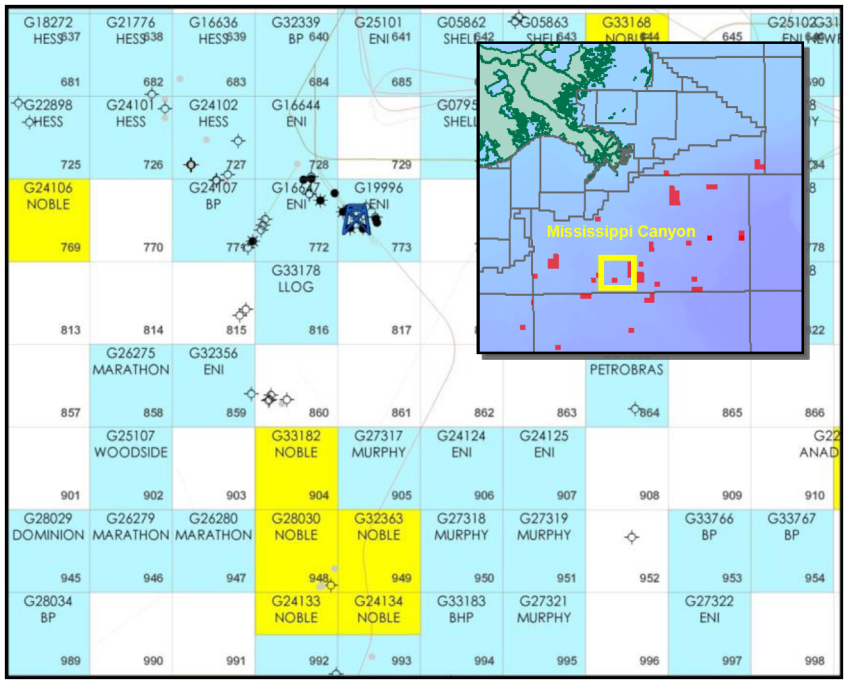


Figure 1—Vicinity Map

The field contains stacked Middle Miocene age reservoirs between depths of 23,800 and 27,000 ft tvdss. A mixture of black oil, rich gas condensate, and dry gas have been penetrated in seven reservoirs. Only three (3) oil reservoirs, the Green B, Green C and Blue E, are considered commercially viable for development. Reservoir pressures and temperatures range from 17,000 to 19,000 psi and 210 to 240°F respectively.

The development plan consists of two (2) subsea wells tied-back to the Tubular Bells, Gulf Star I platform. The first well (G4 aka the "Blue" well) is a twin to the original discovery well in the top of the structure and targets the Blue E horizon as a single completion. The second well (G2 aka the "Green" well) is a sidetrack of the original discovery well targeting the Green B and C reservoirs in a dual commingled, smart completion.

Initial well productivity was designed for 15,000 BOPD for the Blue well, and 20,000 BOPD from the commingled Green well. Instantaneous initial total oil potential is expected to be between 30,000 and 35,000 BOPD, and each well will have a dedicated 6 inch pipeline for flow back to the host facility. However, the expected total field plateau rate is 25,000 BOPD due to capacity limits at the remote host.

The general geologic setting of the Gunflint development is a four-way closure identified by the original discovery well at the top of the structure. The oil water contacts were penetrated by the delineation wells, MC 948 Well 3 to the north for the Green horizons, and MC 992 Well 1 to the south in the Blue horizon.

The Gunflint reservoir is a middle Miocene formation. The three (3) main reservoirs are the Blue E and Green B/C Sands. A conventional core was taken in the original discovery well in the Blue E horizon and

in the Green B&C horizons in MC 948 Well 3. Petrophyiscal analysis determined that the primary reservoir sands are high quality sandstones with good permeability (see Figure 2).

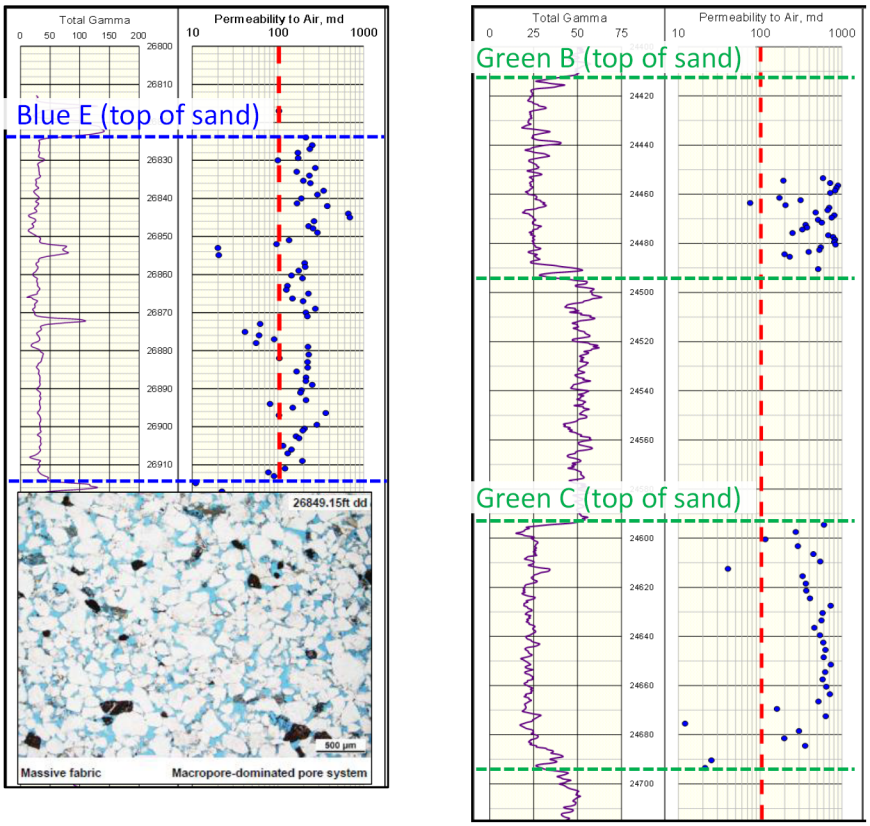


Figure 2—Log Sections with Measured Permeability

The key completion design parameters for the Gunflint project are summarized in Table 1.

Table 1—Completion Design Parameters

Property	Units	G4	G2	
		Blue E	Green B	Green C
Perforated Interval	ft, MD	26,920-27,027	24,288-24,342	24,458-24,490
Hole Angle @ Perforations	degrees	<1	17	
Reservoir Pressure, Initial	psi (ppge)	18,729 (13.5)	17,484 (13.9)	
Reservoir Temperature	°F	233	212	
SITP @ mudline	psi	12,555	12,053	
API Gravity	-	28 – 30	27 - 30	
Gas Gravity	Water = 1	0.878	0.878	
GOR	scf/stb	1400 – 1600	1350 - 2000	

Project Statement of Requirements

Blue Well (G4) – to deliver production capacity of 15,000 BOPD at a Skin (production efficiency) less than 3.

Green Well (G2) – to deliver production capacity of 20,000 BOPD (combined) at a Skin (production efficiency) less than 3.

Completion Delivery Process

This project utilized a field-proven completion delivery process (Figure 3) which was originally published in 2012 and is comprised of four (4) sequential phases.[1] Each phase identifies key elements (processes and procedures) considered imperative to the successful design and delivery of a completion for a "critical" well.

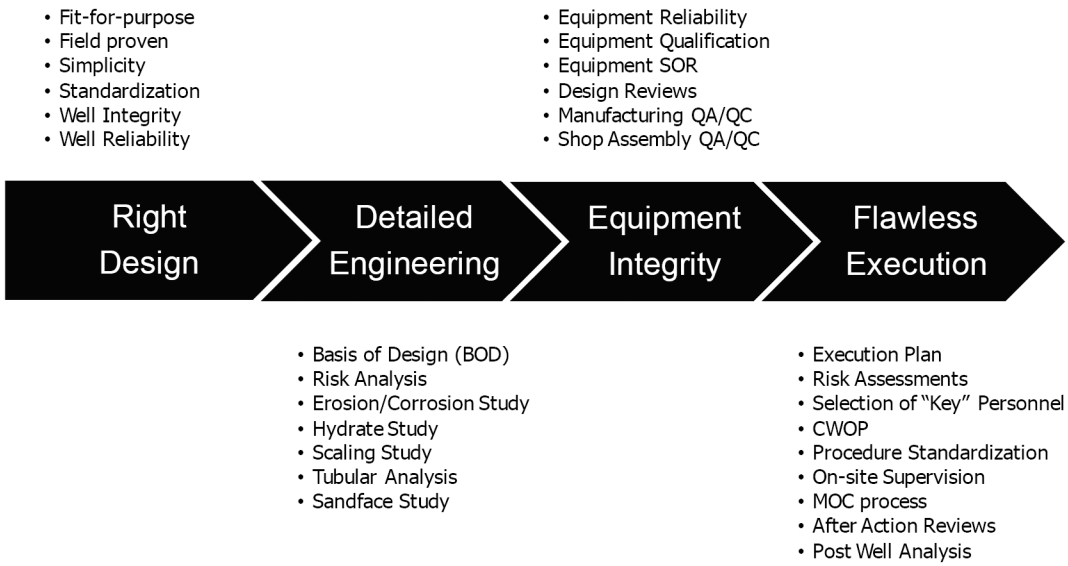


Figure 3—Completion Delivery Process for "Critical" Wells

Coupled to the Completion Delivery Process are guiding principles (Table 2) and key performance indicators (Table 3) which under-pin decision making for the completion design. These principles are largely based on learnings from other successful high-rate gas well developments.[1,2,3]

Table 2—Completion Guiding Principles

Priority	Description
1	Build on Successful Designs of past Deepwater Completions
2	Simplicity of Design
3	Field Proven Equipment
4	Qualified Equipment
5	Rigorous QA/QC Program (Critical Equipment)
6	Bona Fide Contingency Plans & Equipment

Table 3—Completion Key Performance Indicators (KPIs)

Priority	Category	Description
1	HSE	No harm to people, the environment or property
2	Productivity	Safe and highly reliable well design capable of 25,000-BOPD
3	Reliability	Field Proven
4	Schedule	Production start date: No later than 2nd Qtr 2106
5	Flawless Execution (Operational Efficiency)	Avoidance of train wrecks and major NPT events Actual Costs vs. AFE Estimate within +10%

This paper will highlight a few of the many technology challenges and how the process was utilized to engineer solutions. Future papers are envisioned that would provide more in-depth analysis on the various topics covered in this paper and present other design challenges, lessons learned and accomplishments that are beyond the scope of this paper.

Technology Challenges

The first step of the process is Right Design. In an effort to determine the right design, we needed to asses where the industry stood in comparison to the challenging completion design parameters. An in-depth, detailed technology assessment was performed by grouping the completion design into nine (9) areas. For each area, a technology assessment panel (Figure 5) was developed that featured a technology dashboard which utilized the color scheme as defined in Table 4. A project-level diagram (Figure 4) summarized the technology challenges.

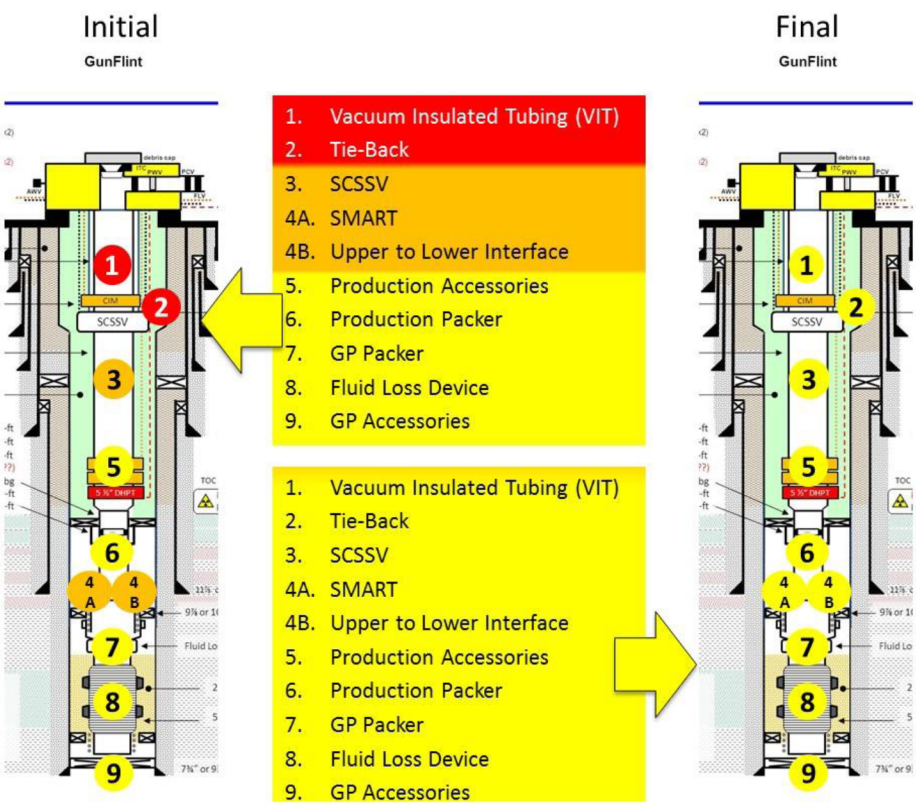


Figure 4—Completion Technical Assessment & Design Challenges – Initial & Final

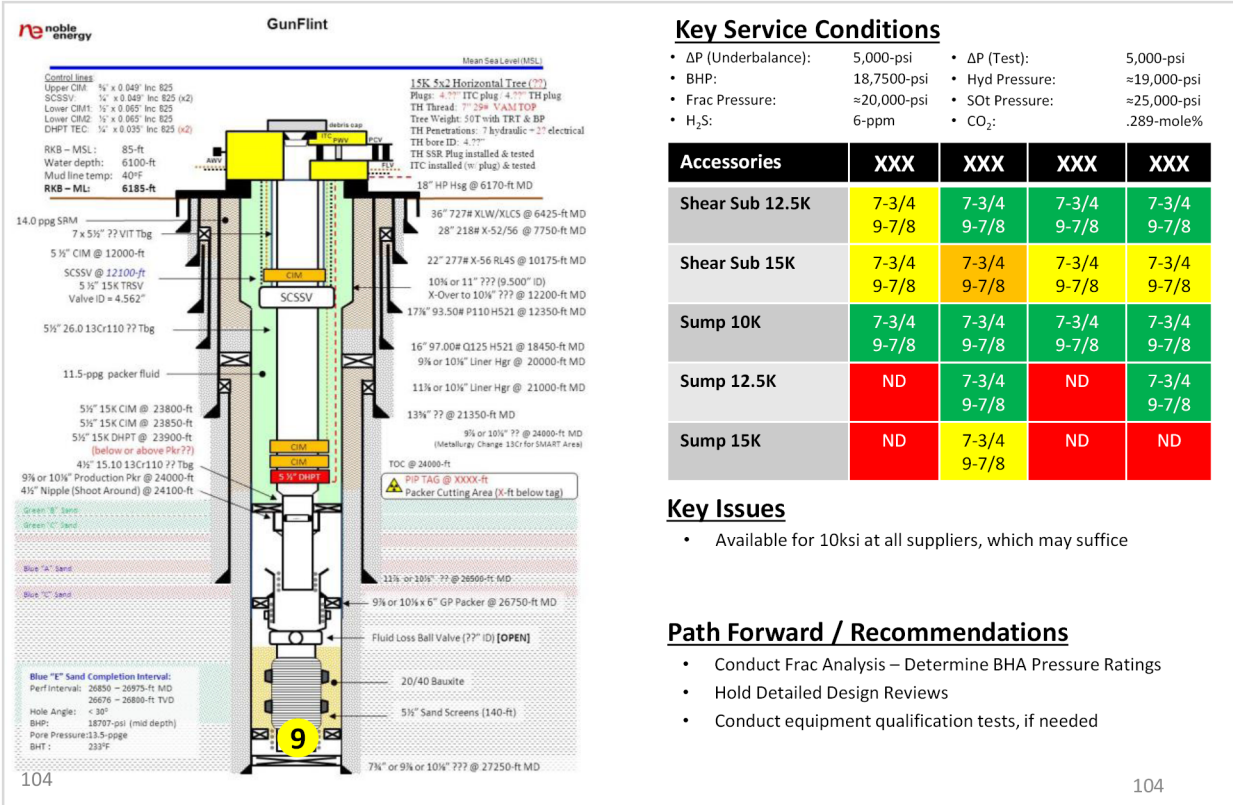


Figure 5—Example of Technology Assessment Panel (Gravel Pack Accessories)

Table 4—Gunflint Technology Assessment Color Scheme

Color	Definition
Red	Design Not Available (> 2-years away)
Orange	Orange – Design Available, Not Qualified (< 2-years away: Zero (0) Run History)
Yellow	Design Available, Qualified, Run History ≤ 3-wells
Green	Design Available, Qualified, Run History > 3-wells

New Color → Orange

The key areas assessed are defined in the center column of Figure 4, and are listed from most difficult to least difficult. None of the nine (9) areas had been performed more than three (3) times by the industry at the Gunflint design conditions.

Interestingly, at the conclusion of our initial analysis, it was found that a fourth color (orange) was required for the technology scheme.

The left side and top list of Figure 4 illustrates our original analysis - our starting point. The engineering objective was to eliminate the red and orange by in-depth analysis and qualification / verification of equipment design. The right side and the bottom list of Figure 4 illustrates our final analysis.

Detailed Engineering & Equipment Integrity

The second step of the process is Detailed Engineering. This step is the vehicle or mechanism whereby the risks are mitigated and the equipment becomes qualified (validated by testing). Following this step, the third step begins, which is Equipment Integrity (aka QAQC). A key principle of Equipment Integrity process is "Trust but Verify".

Detailed Design Review

The Detailed Design Review (DDR) is a bridge between these two (2) steps. It is captured under Equipment Integrity but often requires a significant amount time in Detailed Engineering. For this project, the DDR process is considered to be the single biggest contributor to the success of the project. A DDR can take many forms, but in general it is a comprehensive and in-depth process of evaluating equipment on a component by component basis to ensure each part is fit for purpose and meets the equipment Statement of Requirements (SOR) which includes well and service conditions. A key success factor for our work was the right team for the DDRs as depicted in Table 5.

Table 5—DDR Team (Operator) Composition

Position Title	Expertise and Point-of-View
Sr. Completion Engineer	– domain expertise – well & service conditions – well site operations – installation procedures
Engineered Equipment Expert	– equipment design – states of stress, stack-up, tolerances – equipment validation and verification – knowledge of Industry standards – metallurgy
Completion Specialist	– well site operations – installation procedures – product knowledge
QAQC Engineer	– metallurgy – manufacturing process – inspection requirements

Most often, as shown above, the DDR included the participation of a multi-discipline team with each expert bringing his own point of view, expertise and experience to the process. The DDR process was critical for the right specification and selection of the equipment.

A DDR was performed on every part of the permanent downhole equipment. Approximately 14 DDRs were performed and a total of 59 changes were made. Every single piece of equipment had at least one change when compared to what was originally proposed. For example, it was not uncommon to find equipment proposed that had either one or several issues such as the improper material, incorrect connections, incorrect features and dimensions, subpar ratings, did not meet industry testing specified, or was not qualified at all per the conditions conveyed in the tender. On at least on one occasion, a modification was required that forced parallel qualification and manufacturing of a key component (gravel pack packer).

A holistic view of the completion must always be kept in mind as components are evaluated and changes made. Every change has an affect within the completion, some are intended and some are unintended. An example of an unintended affect is described in the Upper Completion section.

Ironically, the only downhole equipment failures and the two (2) highest NPT events occurred on service (rental) tools where DDRs were not performed. It is highly recommend that DDRs be performed on all critical equipment, including critical rental equipment (crossover tools, packer plug retrieval tools, subsea test tree, etc.).

Standardization

One of the key outcomes from the DDR process was the standardization of equipment between wells. This was not only a standardization of tangibles but also the standardization of operational procedures which lead to learnings and ultimately time savings. To achieve standardization of equipment between the two different well types (Smart Dual Zone Producer vs. a Single Zone Producer) some unorthodox methods and

applications of existing equipment were used. This effort lowered the overall cost of tangible equipment and yielded a savings of over $9-MM.

A summary of the standardized equipment between the two (2) wells was as follows:

- 20K x 15K Chemical Injection Valve: Valve design sufficient for 15K internal pressure but would not withstand APB and hydrostatic pressure. 20K design was required.
- Production Packers: feed thru production packers were utilized on both wells.
- Pressure and temperature Gauge Mandrels and Gauges: run below the packer on both wells.
- Sealing Long Space-out Telescoping Joint (LSOTJ): allowed for setting the production packer against the fluid loss device, eliminating the need for a slickline run to set the packer.
- Rupture Disc: to protect the 10K gravel packer against depletion loads.
- Lower Completion Equipment - ball valve fluid loss device for lowest completion.

Standardization also included many operational steps. Some of these included the following which resulted in operational savings of over $3-MM.

- LSOTJ: sealing to allow for setting the production packer against the fluid loss device, eliminating the need for a slickline run to set the packer
- Identical Upper Completion Designs: tubing running optimization
- Y-Block Installation

Temporary Abandonment & Displacement

The Macondo incident in 2010 involved a well control incident that occurred soon after a long-string production casing was installed. Due to this, Operators in the GOM moved away from long-strings and adopted a liner-tieback strategy with multiple cement barriers for an abundance of caution. As a consequence, Temporary Abandonment (TA) operations took much longer and became more costly with added time required to install and re-enter. Often cement retainers and cast iron bridge plugs were utilized which can compromise casing integrity during re-entry operations. The harden inserts and components (of drilled-out bridge plugs) have damaged casing and created spiralized pieces of casing (which are found in returns during the drill-out / re-entry phase).

Drilling AFEs and operations typically end after the first log is run at Total Depth (TD), and completion AFEs begin with the liner-tieback (TB) & TA operations. The phases between the end of a drilling campaign and the beginning of a completion campaign were often "forgotten" or were not scrutinized and analyzed to determine the best way to temporarily abandon, displace, and re-enter a well for completion.

The Right Design and Detailed Engineering stages of the completion process were utilized to holistically evaluate all of the "forgotten" phases as one operation, optimizing each step and providing the best recommendation at the lowest cost.

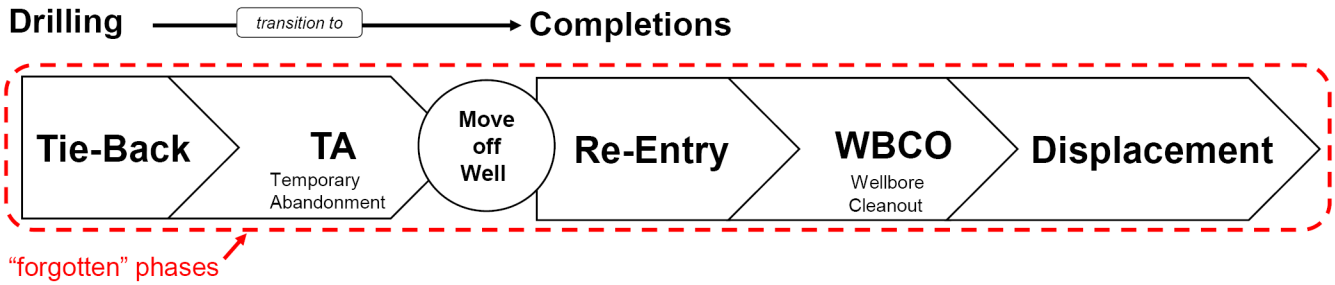


Figure 6—The "Forgotten" Phases

A detailed review of the last six (6) GOM completions were performed to determine the best method to tieback, TA and displace a well prior to completion operations. The recommended changes and optimizations were implemented on the Gunflint campaign in a staged program. Four (4) optimizations are discussed in detail in Table 6. The synergy of all the optimizations and recommendations yielded the savings detailed in Table 7.

Table 6—Optimization of Initial Completion Phases

Phase	Key Statistics
Displacement Optimization	• Displacements take the most time operationally (~35%) than any other phase in a completion (SPE 166368). • Dirty Displacements (no pit cleaning), lancing, and 2-phase displacement trials were completed and lesson's learned captured. • This eliminated ALL online pit cleaning time during the completion campaign.
Retrievable Bridge Plugs	• Retrievable bridge plugs were recommended over cement +fas-drill by quantifying times to set/retrieve and comparing the actual re-entry times to drill out the tie-back times. • Previous wells used cement and drillable bridge plugs which required 331 hours or rig time at a cost of $20.8 million. • Using retrievable bridge plugs, Gunflint operations estimated 70 hours of rig time at a cost of $4.5 million. • Actual Gunflint operations was 32.5 hours at a cost of $2.2 million.
Batch Completions	• In conjunction with displacement operations, batch operations eliminated the need for mud upon the re-entry. Thereby eliminating pit cleaning time and a secondary displacement operation. • Though difficult to quantify in total, batch operations as compared to Drill/Complete wells yield learned operational savings between wells because similar operations happen closely back-to-back.
Stack Hop	• An industry & Tamar lesson learned. Operationally, BOPs tend to work better at depth than when pulled out of water and tested. Given the short distance between wells, an already tested BOP stack at depth could be used for up to 180 days.

Table 7—Gunflint Estimated Savings from "Forgotten" Phases

Phase	($MM)	Comments
TA Optimization	7.9	Avg. Savings over all prior wells
Displacement Optimization	3.8	Avg. Savings over all prior wells
Batch vs D&C	2.9	Avg. Savings over all prior wells (pit cleaning)
TOTAL	**14.6**	Savings from Optimization of "Forgotten Phases"
Stack Hop	6.0	Savings: 4 days (Not included in total)
GRAND TOTAL	**20.06**	

The results (i.e., savings) achieved for the "Forgotten" phases were as follows:
A graphical representation illustrating the TA and Displacement optimizations are presented in Figure 7.

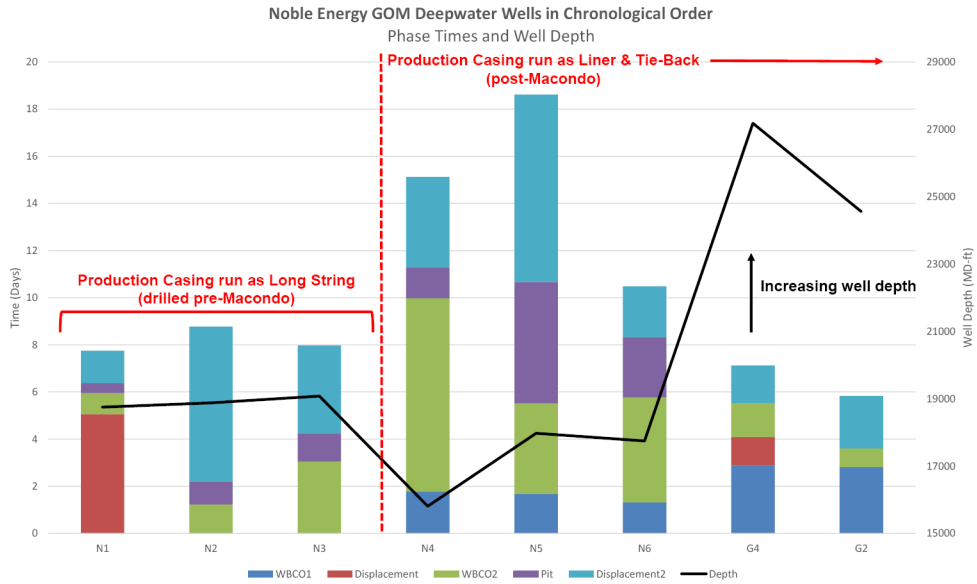


Figure 7—Displacement Comparison – All GOM Deepwater Wells

The utilization of a detailed completion process combined with a strong continuous improvement culture made these results possible. Given this validation, these procedures will be documented as a best practice and implemented throughout the company's deep-water operations. This cost savings represented the largest savings of any single process change during the Gunflint completion campaign. G2 (far right bar in Figure 7) was the fastest operation for theses phases even though it is more than 1.5 times deeper than the first three (3) completions (N1, N2 and N3).

Lower Completion

Fluids

Aside from the rudimentary fluid type and density selection, a stage gate process (Figure 8) was developed and utilized to ensure the fluids were qualified. This process was integrated, as applicable, with the downhole equipment selection and sandface (i.e, frac fluid) design. The main objectives were to ensure: equipment compatibility with proposed fluids, operational efficiency, and minimization of formation damage (low skin was a key driver of the project). Often Equipment Integrity is not thought to extend to operations or intangible services. This is another good example of the Detailed Engineering required and the continuation of the "Trust but Verify" process steps.

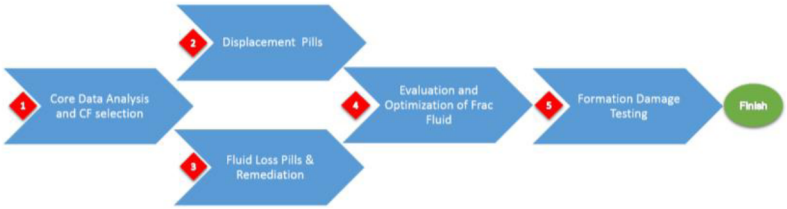
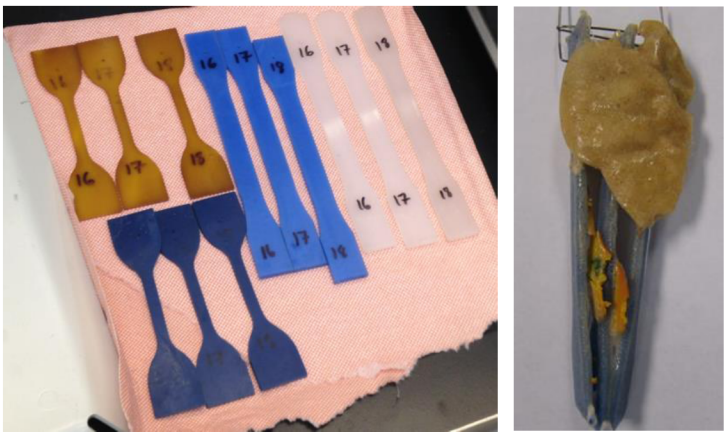


Figure 8—Fluid Design & Qualification Design Process

In the early stages of design, the completion fluid was proposed with a Zinc Bromide constituent, thus the downhole equipment was selected with this in mind. The fluid density requirements for the Gunflint wells exceeded temperature limits (TCT) for a CaCl2/CaBr2 blend. To eliminate the risk of brine crystallization, the safest option would have been to use a CaBr2/ZnBr2 blend. Due to the risk of zero discharge and

the excessive cost associated with disposal, a further review of the fluid formulation and constituents was undertaken. TCT/PCT testing was performed to validate the use of a Zinc-free pure CaBr2 fluid. This became the base fluid selected for both Gunflint wells. However, a CaBr2/ZnBr2 blend was carried as a contingency thru the design stage gate process. After the design and selection of the working completion fluids, the frac fluid was optimized for fluid/fluid and fluid/formation compatibility. Lab results were sporadic and finding the exact cause was difficult as the completion fluid provider was different from the frac fluid vendor. The resulting recommendation was to perform final regained permeability with a third party lab. In addition to the traditional stage gate testing shown in Figure 8, the fluids were tested with various downhole equipment components (e.g., VIT insulator material, packer element, perforating charge debris, and production tubing) that were deemed susceptible to deleterious effects from fluid interaction. All material selections made in the detailed engineering process were verified by testing. As an example, the fluids testing of the VIT insulator material disqualified all but one material as seen in Figure 9.



(Left) VIT insulator samples post 14 day exposure to completion brine at 240°F showed little sign of deterioration.
(Right) VIT insulator samples post 30 day exposure at 240°F failed testing

Figure 9—VIT Insulator Testing

Perforating

Perforating is the means of establishing communicating with the reservoir. This operation is of paramount importance. The critical components analyzed for perforating included charge size and charge type (Zinc versus Steel), perforating method (overbalance versus underbalance versus surge vesus flow), and operational efficieny / risk. The ultimate objective was to find the right balance between operational efficiency / risk while still holding true to the guiding principles and KPIs.

Obtaining the lowest possible skin (productivity) was the key driver on the Gunflint wells. As seen in the theorhetical IPR curves (Figure 10), a change in skin from 0 to 9 could result in sacrificing thousands of barrels of oil per day. The basis of design required skin of 3, not only on initial flow back, but throughout the life of the well.

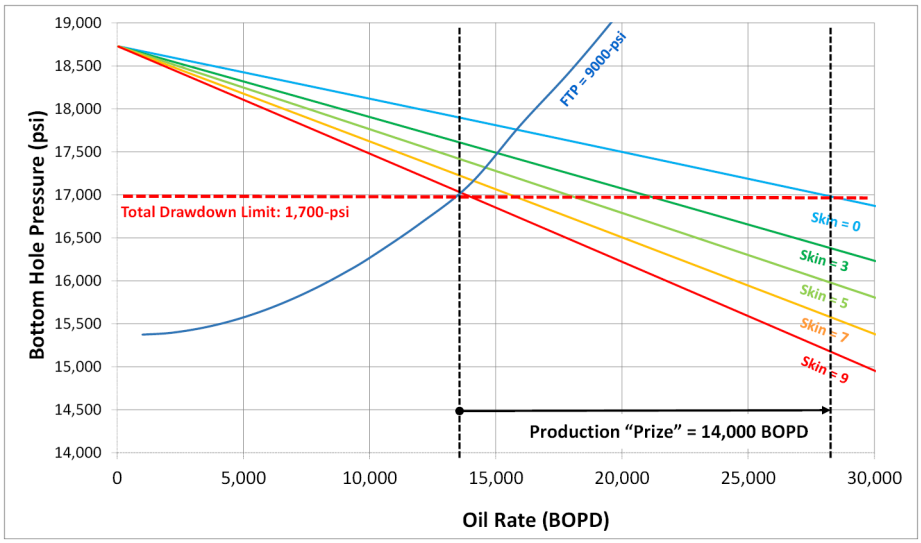


Figure 10—Gunflint NODAL Analysis

The perforating tendering process revealed that most vendors did not offer equipment rated to Gunflint's high pressure requirements. The selected perforating vendor supplied the information presented in Table 8. After significant technical analysis, the perforator with the largest AOF was selected.

Table 8—Perforating Charge Matrix (Blue Font indicates Charge Selected)

Material	Weight (grams)	Area Open to Flow (in^2/ft)	Comments
Steel	39	10.46	Established run history.
Zinc	**55**	**12.50**	**New Charge. Existing Design. No run history. Industry 1st**

With low skin as a significant driver, considerable technical analysis was exerted to determine methods to mitigate formation damage and debris plugging of the perforations. Four different perforating methods (see Table 9) were evaluated for their ability to clean-up perforation debris.

Table 9—TCP Perforating Methods

Option	Description
1	Underbalanced with flow
2	Overbalance with Surge
3	Underbalanced no flow
4	Overbalanced

Simplifying these methods further, each was put into a category "debris out" or "debris in". This ruled out overbalanced perforating, as well as underbalanced perforating with no flow. It is often assumed that underbalanced perforating leads to stuck guns, however a detailed run history review reveals that this was not true. Additionally, other mitigations could be implemented to even reduce this risk further. These mitigations included the following:

- "Fit for purpose" Equipment: Selected equipment allowed for an annular space of 0.94-inch on each side of the gun. This was large enough for any debris to fall past the gun into the rat hole.

- Confirming Formation Consolidation: The unconfined compressive strength (UCS) was validated by core analysis to be in a very high range (Green Sands UCS range 800 – 3,500 psi; Blue Sand UCS range 3,000 – 7,800 psi). These strengths are much less than the proposed underbalance pressure of 1,000-psi.

With these mitigations in place, underbalanced perforating (1,000-psi) on an open choke and flow (surge = 25 bbls) was recommended. The next focus was on the operational sequences to maximize rig efficiency. This ultimately proved to be a continuous improvement process.

Three (3) different spotting and circulating methods were performed. The method were as follows:

1. Conventional: The first method utilized the following steps. Drill Stem Test (DST) tools spotted underbalance, the erll was perforated underbalanced and flowed. The ball valve was closed and the hydrocarbons were reverse circulated out of the well above the packer and then ball valve was opened and wellbore was reverse circulated below the packer. This was performed on the Blue well.
2. Below Only: The second method was performed out of necessity due to the failure of the DST tool prior to perforating. All spotting and circulating was performed below the packer. The ball valve was never closed. The well was perforated underbalanced and flowed a minimal volume to reduce risk. The ther wellbore and all hydrocarbon were reversed circulted out from through the packer. This was performed on the lower zone of the Green well.
3. Above and Below: The third method, the best combination of Methods 1 and 2, was performed on the third perforating job. The spotting was performed through the DST tools (Method 1), the well was perforated underbalanced and flowed. The ball valve was closed for a short PBU, then it wsa re-opened. Then all reverse circulating was performed below the packer (Method 2). The overall operational time savings between Methods 1 and 3 was approximately 8.5-hrs.

The table below is a depiction of the procedure used on each well, as well as the corresponding steps eliminated.

Table 10—TCP Perforating Operational Sequence (Actual)

METHOD	1: Spot Above Circ Above & Circ Below	2: Spot Below Circ Below	3: Spot Above Circ Below
PROCEDURE	**BLUE E**	**GREEN C**	**GREEN B**
SNAP IN/OUT OF SUMP PACKER	✓	✓	✓
SET TCP PACKER	✓	✓	✓
CLOSE TV/ OPEN CV	✓	X	✓
CIRCULATE UB	✓	✓	✓
CLOSE CV/ OPEN TV	✓	X	✓
PRESSURE UP TO E-FIRE	✓	✓	✓
FLOW BACK	25 bbls	10 bbls	20 bbls
REVERSE OUT ABOVE PACKER	✓	X	X
REVERSE OUT BELOW PACKER	✓	✓	✓
RELEASE PACKER	✓	✓	✓
SNAP IN/OUT OF SUMP PACKER	NO FILL	NO FILL	PACKER PLUG
PRODUCTIVE RIG TIME (HOURS)	22.5	16.5	14.0
NPT RIG TIME (HOURS)	0	60*	0

* CIRCULATING VALVE FAILURE (13 HOURS) + CONTINGENCY CLEAN-OUT RUN (47 HOURS)

One interesting fact was around the expected fluid loss. High fluid loss was expected with the subject kH, however none of the perforated intervals exhibited any significant fluid lost to the formation. The Productivity Index (PI) was measured for each zone based on downhole pressures and build-up. Permeability-thickness (kH) and Skin (S) determinations were not attempted.

Frac Pack

The lower completion had a series of industry and Noble firsts. Three (3) first were required for the lower completion. They included the following:

- Metallurgy Change (945X) and Requalification of the GP Packer
- PIP Tag Ring on Bottom Screen Joint
- Use of Weighted Frac Fluids (Noble First)

Based on a review of fields analogous to Gunflint, the expected surface treating pressure would exceed 11,000-psi for G4. This determination was based on offset frac gradients (> 0.8-psi/ft) and high pump rate (35-bpm = high friction pressures) requirements for the Gunflint Completion Design Parameters (depth, long intervals with high kH). An effective mitigation for high surface pressures is to utilize a weighted frac fluid. By selecting an 11.5-ppg NaBr base fluid, versus the conventional 8.7-ppg NaCl, the surface pressure were reduced by approximately 4,000-psi. As detailed in the fluid section and as part of Detailed Engineering and Equipment Integrity processes, extensive testing was performed to confirm / verify formation and fluid compatibilities to avoid damage.

The following pumping steps were performed on all three (3) zones:

1. Pickle
2. Acid Stimulation
3. Fluid Efficiency Test (FET)
4. Step Rate Test
5. Frac Stimulation
6. Reverse out
7. Gravel Pack Log
8. Test and Close Fluid Loss Device

A summary of the results for the G4 well is as follows:

The results of the acid job were very encouraging. Several pressure break backs were realized and the pump rate was increased for diversion. The final rate at the end of the acid job was 15-bpm at 6,500-psi. It was late determined that fluid was being distributed over the entire interval based on the interpretation of the downhole washpipe gauge data. The results of the FET determined that the frac gradient was 0.770-psi/ft (less than expected). Based on this, a conventional base fluid was used on the next two (2) intervals in the G2 well. Figure 11 is an illustration of frac stimulation for G4.

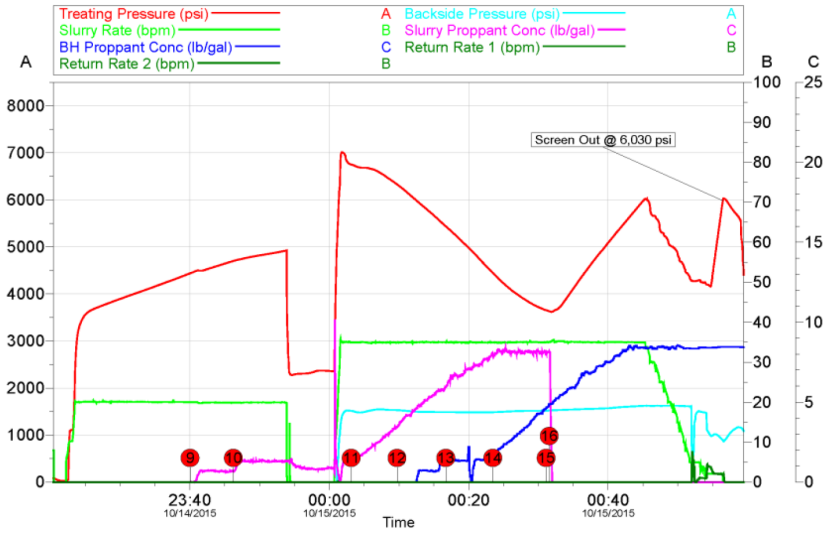


Figure 11—G4: Blue Well Frac Plot

A second illustration of the frac match and the corresponding geometry can be seen in Figure 12. An interesting observation is the approximate 10-ft void identified between Lobes 3 and 4 by the GP log (Figure 12). Noble's experience with these types of situations (detailed in SPE 181658) is that the effect of time and gravity will act to fill-in the void with proppant from the annular reserve above the screen.

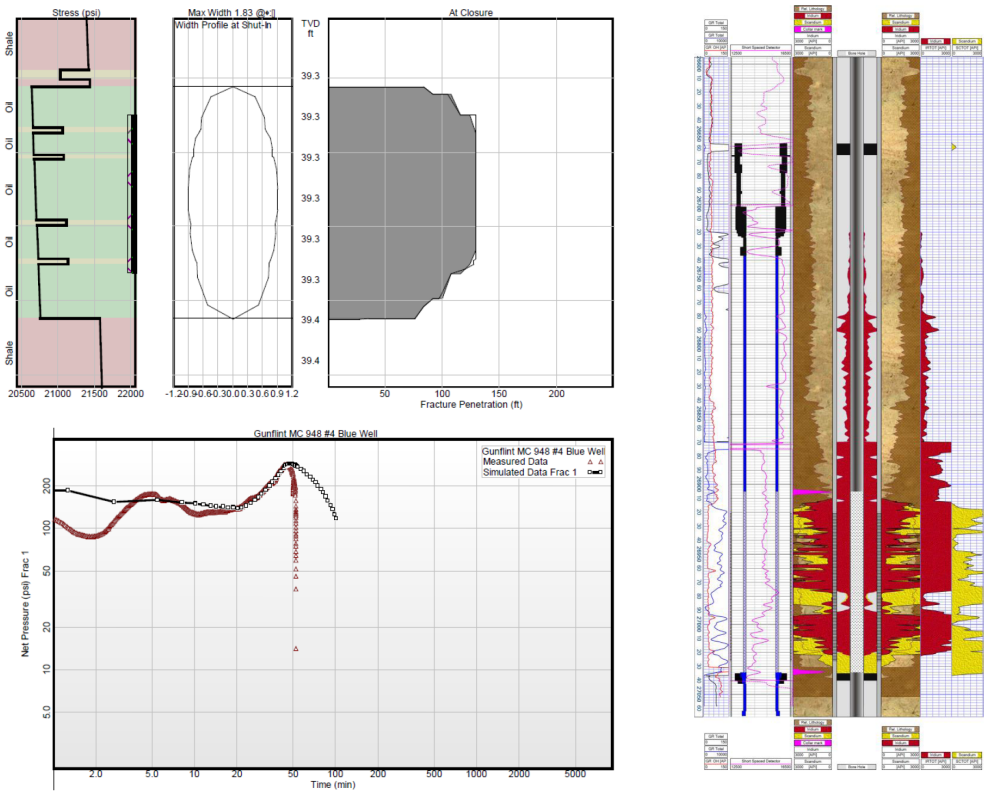


Figure 12—G4: Blue Well Frac Match & Tracer / Density Logs

A summary of the G4 frac metrics is detailed in Table 11.

Table 11—Gunflint #4 (Blue Sand) Frac and GP Log Metrics

Parameter	Value
Tip Screen-out	Yes
Rate & Pressure @ Screen-out	2-bpm @ 6,030-psi with Returns
PPA	8.4-ppa on perfs
Proppant Pumped	211,700-lbs
Proppant Reversed Out	2,000-lbs
Net Pressure	142-psi
Proppant Placement	1,830-lbs/ft-MD
Second Tracer Stage (Iridium)	At bottom perf
Good Annular Proppant Reserves	Yes – Good
Top of Sand (TOS) identified by both logs	Consistent
Blank Coverage	35-ft
Logging Tool Conveyance	Washpipe
Annular Pack	Complete. 10-ft Void between Lobes 3 & 4. No Remedial Work
Fracture	Contained in Reservoir
Completion Hardware	Identified Correctly

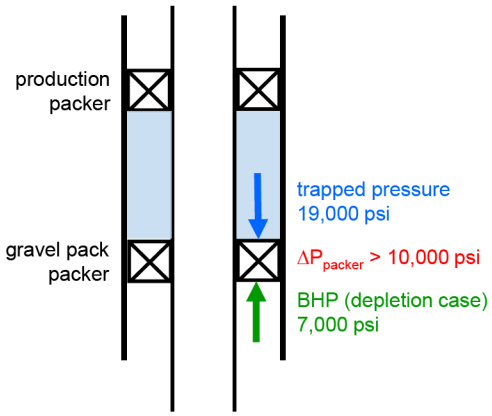
Interesting notes for the G2 well include the following:

- Very High Treatment Volume (>140-klbs of proppant for 32-ft of perforations: > 4,000-lbs/ft)
- Very High Injection Rate (> 1-bpm / ft of perforation: 35-bpm for 32-ft of perforations)
- Very Short Blank Interval (~15-ft for Green C: Required for the Perforated Interval for Green B)
- Tool Issues: Both zones: Jobs pumped in squeeze position (i.e, No "live" annulus)
- Unable to locate circulating position. (Cause unknown)

The details of the G2 FPs are also included in SPE 181658.

Interface

The extreme completion depth and pressure posed numerous engineering challenges. One example presented here was the risk of failure of the GP packer as the Blue Sand depleted. The purpose of the GP packer is to ensure the annular pack stays in place during production. The GP packer for this application was rated for a maximum differential rating of 10,000 psi. To ensure well integrity, a bona fide production packer (API 11D1 Validation Grade V3) was positioned above the GP packer (see Figure 13). Our detailed engineering identified that this would trap a hydrostatic pressure of ≈19,000 psi above the GP packer thus creating a significant differential load across the GP packer as the reservoir depleted. This could lead to a mechanical failure and loss of reserves.



Option	Discussion of Options
1	Non-sealing telescoping joint This leads to the necessity of an extra slickline trip to set a plug and allow setting of the production packer. Also eliminating the possibility of standardization of the Long Space out Telescoping Joint (LSOTJ) between the two wells. Because of the lack of standardization and extreme depth (26,700 ft) and tight tolerance, these trips add considerable risk and cost.
2	hydrostatic set packer with a non-sealing LSOTJ This would eliminate the need for the slick trip in order to set the production packer. However, the design for a 15K rated hydrostatic set production did not exist and could not be completed and qualified by the completion installation date. This option also removed the possibility of standardization between the wells and lead to higher risk due to parallel manufacturing and testing as well as increased cost.
3	Tubing Tester Valve (TTV) with a non-sealing LSOTJ Which enabled the use of the same production packer for both wells and the setting of the packer hydraulically, thus eliminating the need for slickline. But, increased risk by the addition a flapper in the completion design and higher cost due to the inability to standardize equipment.
4 Selected Option	Burst or Rupture Disc The final solution investigated was the addition of a burst or rupture disc to protect the critical equipment as the differential loads increase. This disc would need forward pressure containment (when setting the production packer) and reverse burst pressure relief late in the wells life to protect the gravel pack packer, in other words a Bi-directional rupture disc.

Figure 13—Trapped Annulus Option Analysis

Selection of the Burst Disc

This option was risk assessed, and the team decided it was worth the cost of testing to determine if the rupture disc and drain sub are fit for purpose application. The team designed a series of test to determine if the rupture disc would fail in the correct fashion and at what pressure this would occur. The testing was performed at Fike Industries in Blue Springs, Missouri.

A quantity of 10 disc were purchased from the same batch/lot. Five (5) discs were selected for testing (with the remaining discs reserved for use in the completion). Testing was conducted at the Blue sand reservoir temperature of 220°F. The setting of the production packer was simulated by a 5 minute, 6,000 psi differential forward cycle pressure test. Once the production packer had been set, the disc could rupture at any time without negative consequences. The last and most critical part of the test was verifying the reverse burst pressure and tolerance to ensure the 10,000 psi differential rating of the packer was not exceeded.

The test set-up consisted of a hydraulic press fitted with hot plates to enable heating the test fixture to 220°F, a temperature probe, and a pneumatic test pump with a pressure transducer. The testing confirmed that the discs did not burst during the forward pressure cycle. The testing confirmed that the discs ruptured during the reserve pressure cycle at an average pressure of 6,122 psi (well below the packer rating) and within a tolerance of only 1.32%.

Because of the positive results, the discs were incorporated into the completion design. The cost savings were estimated at $2.1-MM ($1.1-MM in tangible completion equipment + $1-MM in rig time savings) due to the use of a $172 rupture disc.

Upper Completion

The upper completion design contained the highest number of firsts (as previously defined). A description of all firsts are beyond the scope of this paper, but several examples are illustrated below. Two (2) of the examples will illustrate changes that were made after the first execution (lesson learned from the first well) or from a problem that was identified during assembly make-up.

Table 12—Examples of Upper Completion Design Improvements

Design Element	Delivery Process Elements
Control Line Routing Drawing	Identified and Prepared during "Detailed Engineering".
ICV Control Line Bypass Slot Change	Missed at DDR but caught at the "Flawless Execution" stage during equipment make-up.
Y-Block Modification	Problem identified during operations of first well. Utilized After Action Review (AAR) to modify design.

Control Line Routing Drawing

The objective of a control line routing drawing is to align all the control lines to ensure correct clamp designs, and to ensure the Tubing Hanger (TH) make-up is as simple as possible, which minimizes the required termination time. Even though this is simple, it is often not performed or it is performed incorrectly. Common mistakes include looking at bottom-up versus top-down orientations of control line clamps as compared to the tubing hanger (TH) design. Any crossing of lines (a spaghetti effect, see left photo of Figure 14) greatly increases the termination time, which could be as much as 12-hrs or $0.75 MM of rig time. The detailed engineering done ahead of time helped to create a control line routing drawing (Figure 14). The control line routing drawing details the orientation of clamps, control lines, and pass through ports on all components of the upper completion.

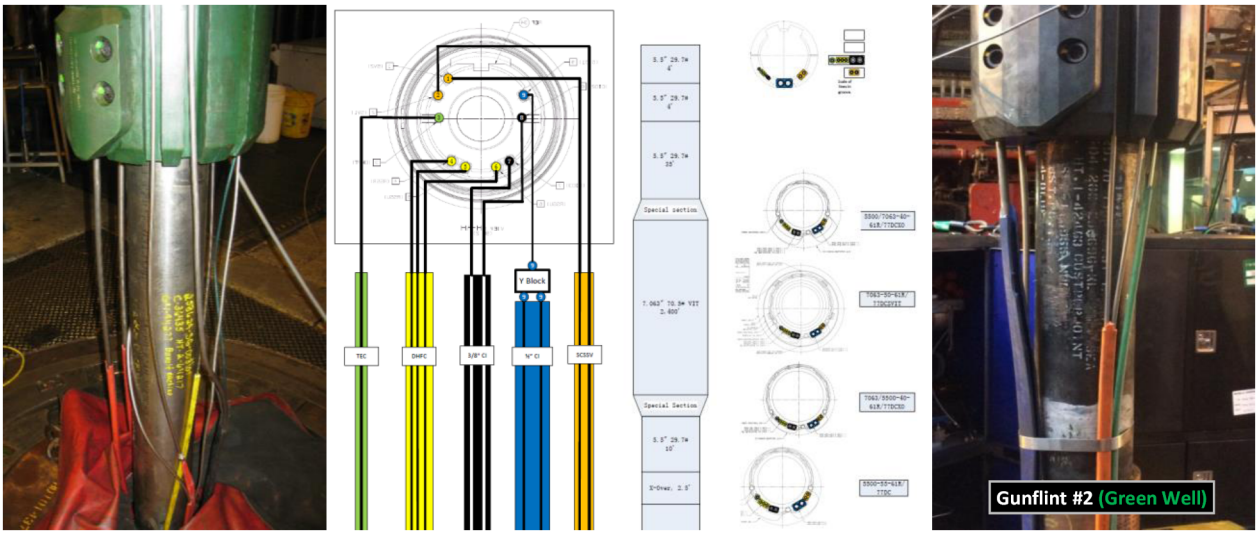


Figure 14—Control Routing Drawing & Gunflint #2 Green Well (photo at right)

All of the detailed engineering performed ahead of time ensured that the running of the upper completion was a smooth and efficient process. During the planning stages it was determined that timed pups would need to be made up below the SCSSV/CIM assembly and the tubing hanger in order to correctly orient the control lines during operations. All other orienting was done ahead of time while making up assemblies in order to streamline the process. The process of terminating lines at the hanger was very simple and did not require any control lines to be crossed which helped to ensure that we did not have any problems while landing the hanger.

Control Line By-Pass Slots

A DDR was performed on the control line slots (which align the control lines with the lower Intelligent Control Valves, ICVs) of the packer. An outcome of the DDR was a change of the slot orientation. The consequence of this orientation change was not revealed until shop assembly make-up at which point it was found that a control line passed directly over a flow port (see Figure 15). Four (4) options were considered for correcting the issue; ultimately, a "dog-ear" clip was selected to re-position the line to the far-side of the slot thereby re-routing the control line away from the flow port. The modification was made to all equipment prior to deployment. This finding highlights how DDRs must be holistic.

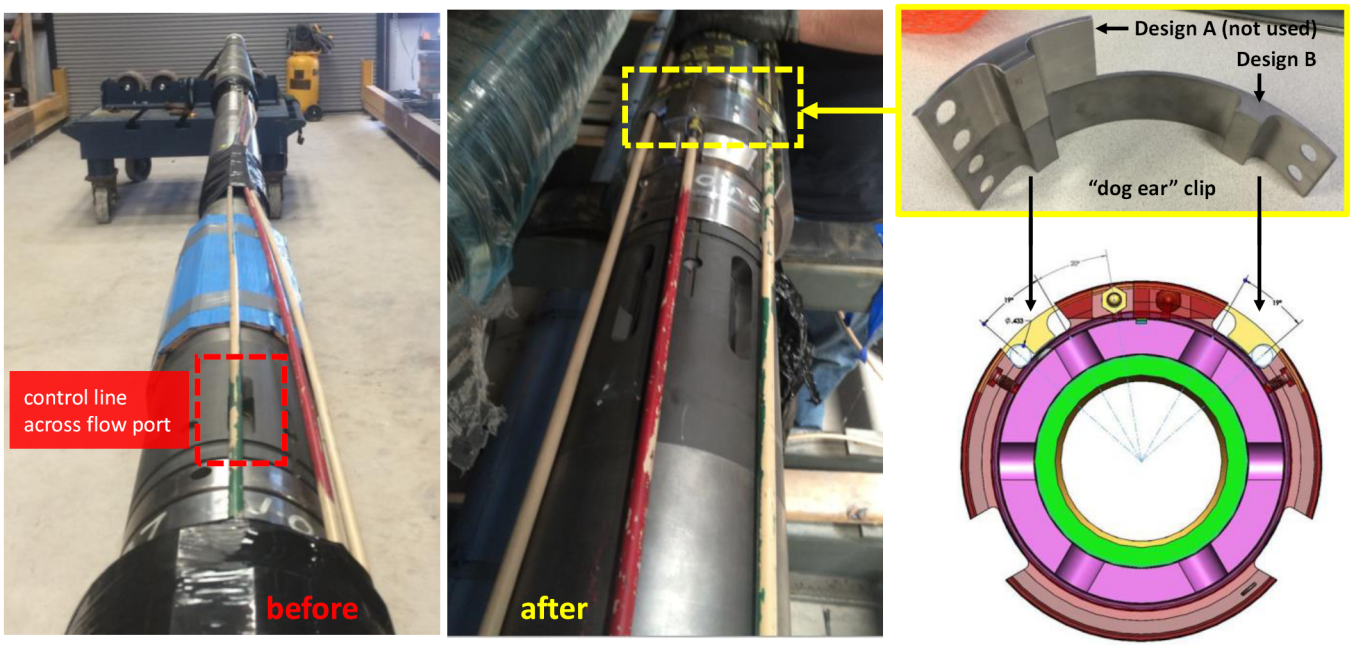


Figure 15—Before & After of ICV Control Line Paths

Y-Block

Unfortunately, all of the detailed engineering done for the control line routing drawing did not address the Y-block. Both wells required dual ½-inch control lines for the upper chemical injection mandrels. Due to the limited penetrations of a 15,000 psi rated tubing hanger (and the use of other penetrations for the SCSSV and downhole flow control systems), a junction (Y-block) was required. The Y-block design selected had never been used or installed before. Assurances were given by the supplier that an SIT would not be necessary as the ½-inch line design would not be any different than their field-proven (⅜-inch) design.

Unfortunately, on the first well, a significant delay was experienced on the critical path. The installation time was approximately 5-hours and numerous issues (opportunities for improvement) were identified as listed below:

- ½-inch lines difficult to bend and stab into Y-block simultaneously. Must stab them simultaneously because they're not easily bent and have to be the same length.
- Not enough room to tighten fittings where the control lines were made up
- The Y-block was built into a centralizer sub which had threads on both halves of the sub which made make-up next to impossible due to alignment tolerances. Tightening one side meant loosening another so it was an iterative process.
- Weight of Y-block made it difficult to hold while securing to the tubing

Following the After Action Review (AAR) process, multiple changes to the Y-block were recommended and three (3) different assembly options were identified. A Systems Integration Test (SIT) was performed to determine the best option. An illustration of the changes made to the Y-block can be seen in Figure 16.

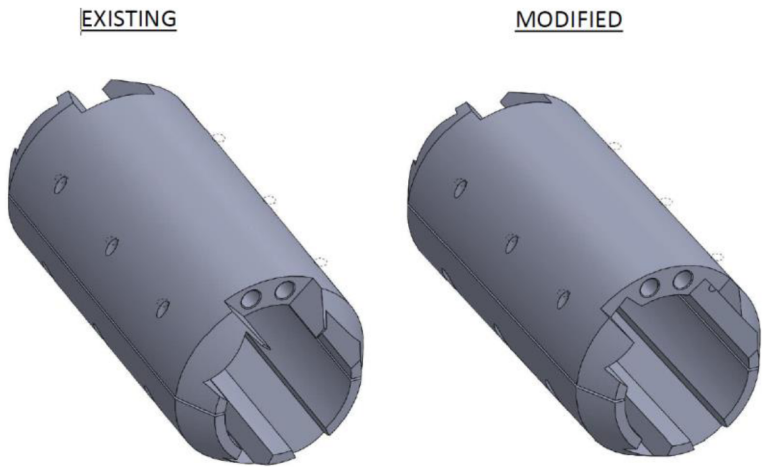


Figure 16—Y-Block Modifications

The modified design was successfully used on the second well and resulted in a savings of 2.5-hours. This example demonstrates the benefit of the AAR process even for relatively minor issues. More importantly, it demonstrates that a SIT should be performed for all new or modified designs.

Flawless Execution

Both wells were delivered as expected, under budget (AFE) with less than 8% NPT for the project. The final wellbore schematics for G4 and G2 can be seen in Figure 20 and Figure 21, respectively.

Operations

The Gunflint #4 (G4) was completed in 52.6-days. The overall efficiency of the operation was 52% productive time, with 25.4-days (48.3%) of Non-Productive Time (NPT). However, the bulk of the NPT time was due to waiting on loop currents. Evaluating the well without weather and loop current, the overall efficiency was, in fact, 97% productive time, with only 0.8-days (2.8%) of NPT.

The Rushmore Review database was used for benchmarking the execution of the Gunflint completions. The wells selected for benchmarking met the following criteria:

- Completion Type (Single GP or Single Selective GP)
- Post Macondo (Normalizing for the additional BOP maintenance times)
- Well Depths Greater than 22,000-ft MD.

For the purposes of benchmarking and performance analysis, the selected data considered only the completion phases (beginning with fluid displacement and ending with the pulling of the SSTT). Rig mobilization and demobilization and the running and pulling of the BOP stack were not included.

Based on the Rushmore Review database, G4 is the fastest single GP completion with the lowest NPT for all wells. An illustration of the planned and NPT for the single completion used in the analysis can be seen in (Figure 17). The blue bars are productive time; the red bars are NPT; and the black line is the Well Depth. G4 was the fastest completion and it was the second deepest well. This is significant because a majority of the time in a completion is trip time, which normalizes the plots for depth.

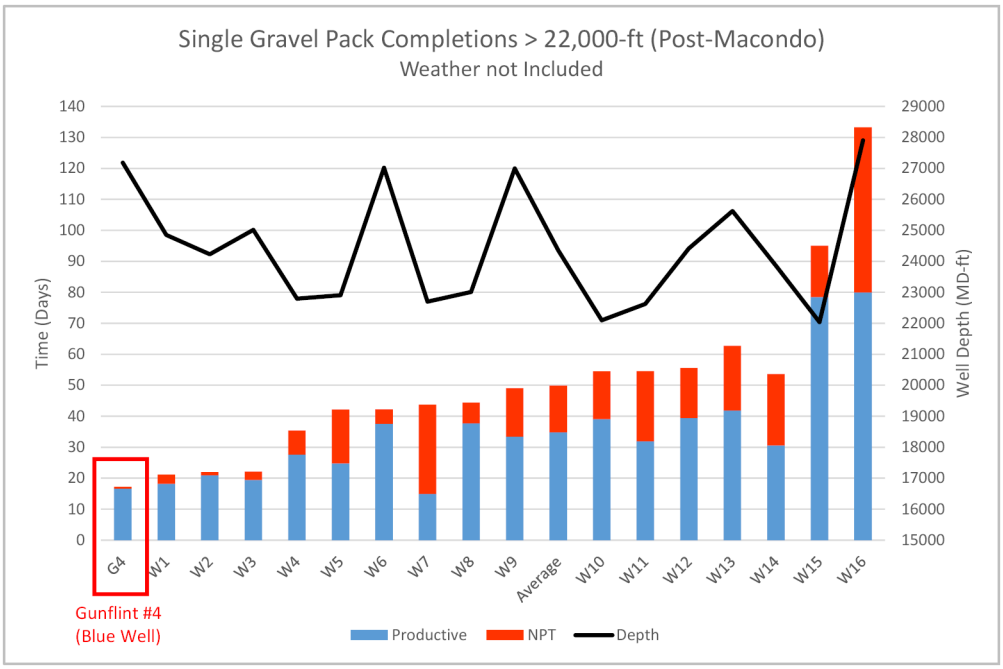


Figure 17—Benchmark Data for Gunflint #4 Peer Group

The Gunflint #2 (G2) was completed in 38.9-days. The overall efficiency of the operation was 79% productive time, with 8.3-days (21.4%) of NPT. Four (4) significant NPT events occurred: choke manifold testing (1.0-days); precautionary WBCO trip (2.0-days); second trip to recover packer plug (1.8-days) and WOW (2.1-days). When evaluated without weather related or rig equipment issues, the overall efficiency was 85% productive time, with only 5.2-days (14.5%) of NPT.

Based on the Rushmore Review database (using the same criteria as detailed above), G2 is the fastest single selective GP completion based on well depth. An illustration of the planned and NPT for the single selective completions used in the analysis can be seen in Figure 18. G2 was the second fastest completions, but normalizing for depth (±2500-ft deeper than W1) makes G2 the fastest completion based on days per 1000-ft MD.

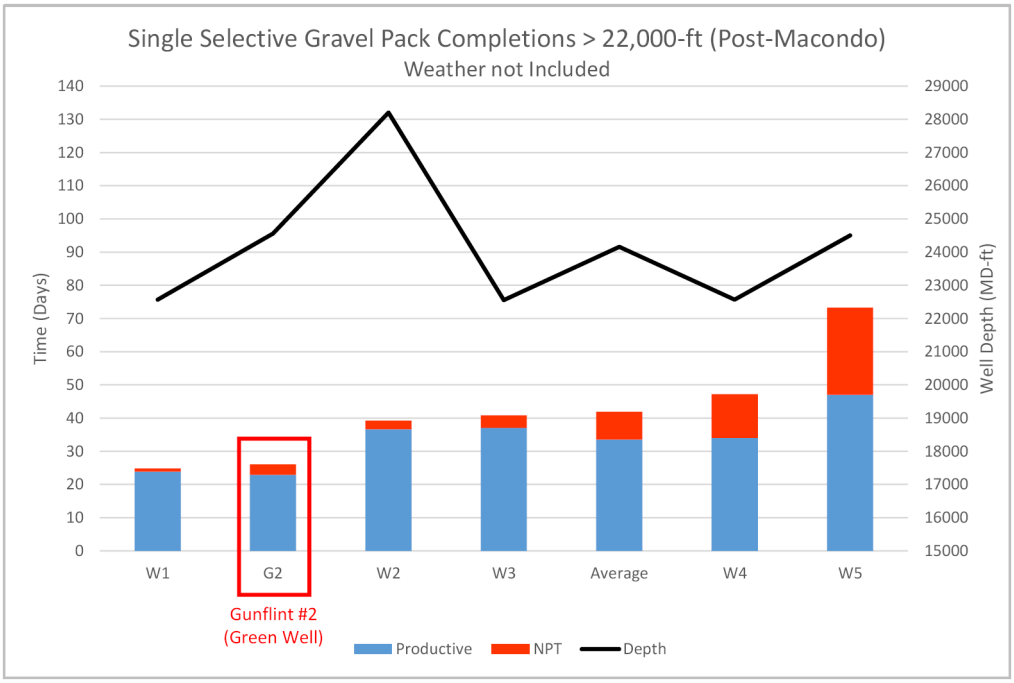


Figure 18—Benchmark Data for Gunflint #2 Peer Group

Completions Team

The team required to design, engineer and deliver the results of this project is depicted in Figure 19. It cannot go without saying, that the completion delivery is not effective without the right team and rigorous procedures to implement the process from Right Design to Flawless Execution. Without the correct team make-up, complete buy-in and strict adherence to the procedures, "Flawless Execution" is not possible. The "Trust but Verify", a key principle of our Equipment Integrity (QAQC) process was used in all phases.

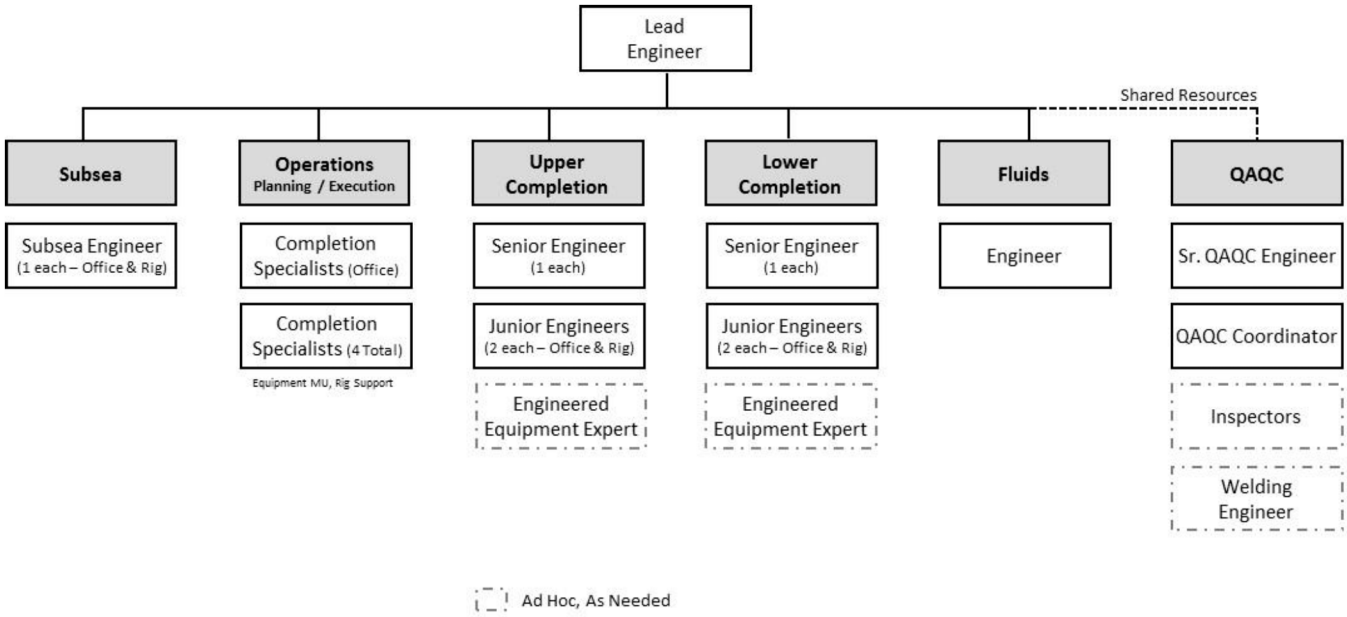


Figure 19—Completion Team Organizational Chart

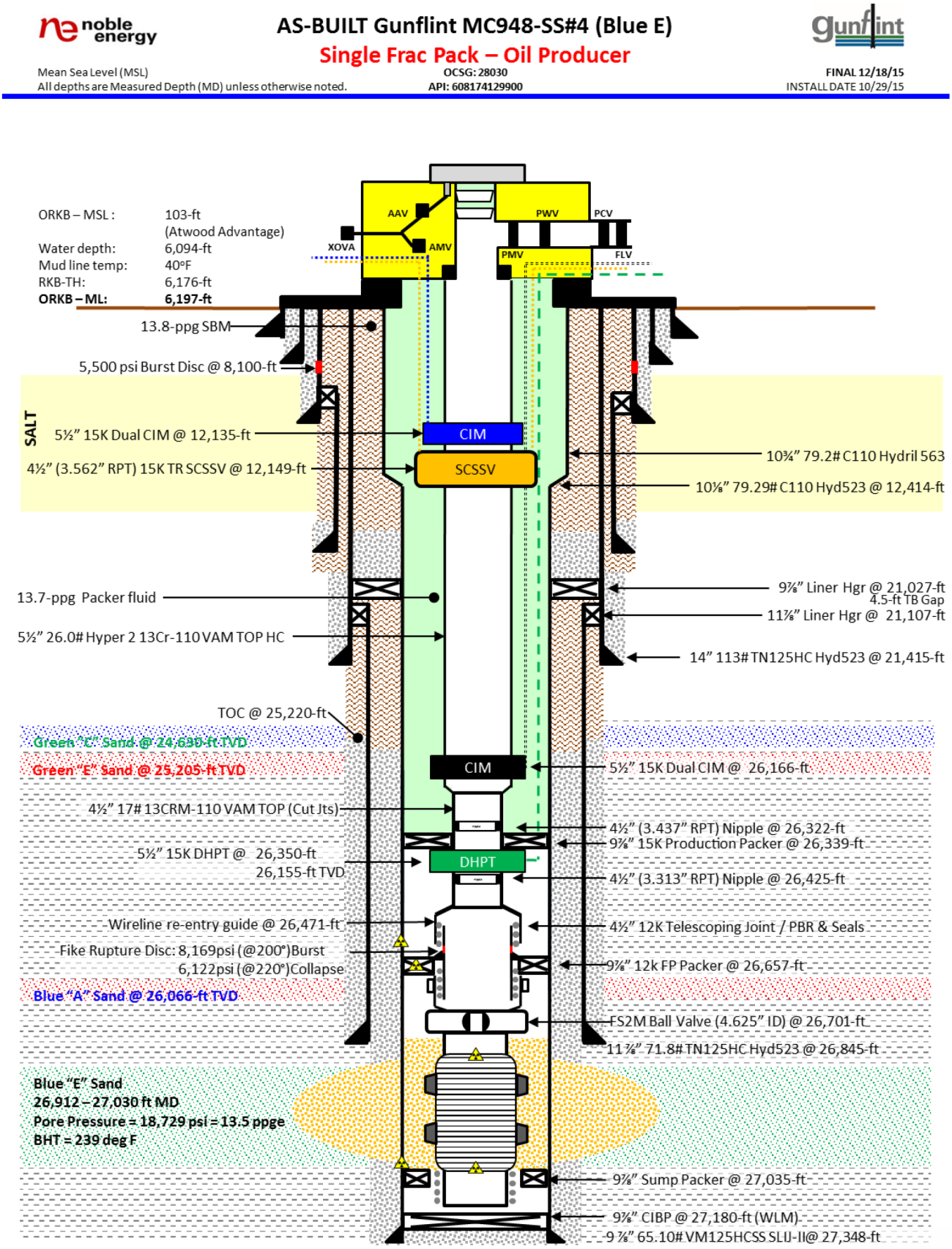


Figure 20—Actual Completion Schematic – Gunflint #4 (Blue E) Well

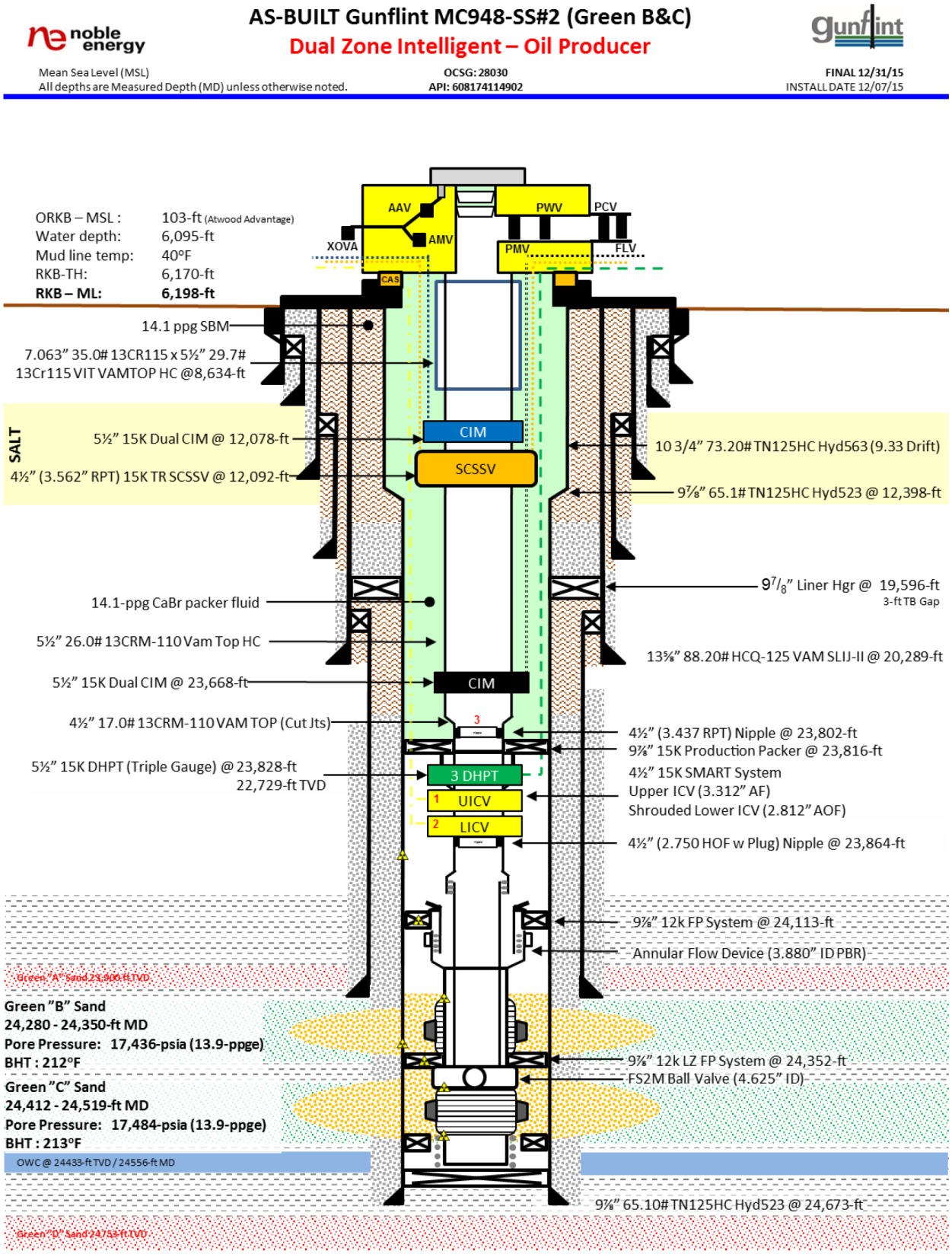


Figure 21—Actual Completion Schematic – Gunflint #2 (Green B/C) Well

Conclusions

Based on the work presented in this paper (and previous papers by the Authors) the following conclusions are made:

1. Technical rigor and due diligence in all phases of the completion delivery process is imperative to successful execution, rate delivery and well reliability.
2. A "Stage Gate" approach to engineering and qualification provided a deliberate and methodical approach to delivering fit-for-purpose completion designs required when pushing the Completion Design Envelope.
3. An "honest" technology assessment is the most critical step in the determination of the completion "readiness" which then determines the design challenges and the team required to solve them.
4. Rigorous DDRs proved to be the single biggest contributor to the successful completion of the Gunflint wells; ironically, the only downhole equipment failures and the two (2) highest NPT events occurred with service (rental) equipment for which DDRs were not performed.
5. A focused equipment standardization effort simplified the scope of work and yielded a savings of $12-MM.
6. Significant savings ($14.6 MM per well) were realized by re-thinking and rigorously engineering the old paradigm of the "forgotten" phases (Tie-back / TA / Re-Entry / WBCO / Displacement).
7. For any design firsts or modified designs, SITs are high recommended, even if it is simple (like making up a Y-block).
8. Flawless Execution is only consistently achievable, when this type of approach is completely implemented. Despite Pushing the Completion Design Envelope, Gunflint was implemented as the fastest completions (normalized for depth) performed since 2010. G4 had the lowest NPT% for all completions benchmarked.

Ultimately, two (2) ultra-high rate oil well wells were successfully delivered, as designed, at Best-in-Class operational performance.

Acknowledgements

The authors wish to thank the Management of Noble Energy and our partners Ecopetrol (31.5%), Samson (19.1274%), and Marathon (18.2308%) for their permission to publish this work. In addition the authors acknowledge the significant efforts and contributions of the Noble Energy Drilling Team and the Atwood Advantage drilling rig. In addition, we recognize the technical contributions of Kerby Dufrene, David Scott and Dr. Bruce Craig and the following key suppliers: Baker Hughes, Halliburton and Schlumberger.

References

1. Healy, J.C. et al: "Design, Installation, and Performance of Big Bore (9-⅝ in.) Completions: Mari-B Field, Offshore Israel," paper SPE 151770-PP prepared for presentation at the SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, Louisiana, U.S.A., 15-17 September 2012.
2. Healy, J.C. et al: "Completion Design, Installation, and Performance - Cannonball Field, Offshore Trinidad," paper SPE 110524-PP presented at the 2007 SPE Annual Technical Conference and Exhibition, Anaheim, California, U.S.A., 11-14 November 2007.
3. Healy, J.C. et al: "Design, Installation, and Initial Performance of Ultra-High-Rate Gas Deepwater Completions – Tamar Field, Offshore Israel," paper SPE 166368 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, U.S.A., 30 September – 2 October 2013.

4. Sanford, J.R. et al: "Mississippi Canyon Gulf of Mexico Frac Pack Case Histories and the Importance of Proppant Tracing and Gravel Pack Logging," paper SPE-181658-MS prepared for presentation at the SPE Annual Technical Conference and Exhibition held in Dubai, UAE, 26–28 September 2016