University of Canterbury

Master of Engineering Management

Completion Design and Execution Strategy for Increasing Maui Reserve

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Abstract

This report provides Shell Todd Oil Service's Completion and Well Intervention Engineering Department with feasible options for the completion design and execution strategy for proposed sidetrack wells for Maui B. The project provides results and recommendations that can be carried forward into the next project phase, including:

- Completion design for the three proposed sidetrack well types for Maui B: crestal, down-dip and the extended reach Maui B North
- Stress analysis for each proposed design
- Execution program outline for the crestal wells
- Cost analysis
- Benchmarking against industry standard
- Analysis of Completion and Well Intervention Engineering departmental communication and synergies

The successes and failures of previous completion campaigns were analysed and heavily influenced the completion design for proposed sidetrack wells on Maui B. Shell standards, guidelines and open literature were called upon for the design.

Findings in this report provide evidence of issues that should be addressed for the continuous improvement of both primary completion design and it's synergy with the entire project group. Conclusions and recommendations have been provided for the consideration of Shell Todd Oil Service's Completion and Well Intervention Team, Well Delivery Lead and Maui B Increased Recovery Project Team.

This project has been prepared in partial fulfilment of the Master of Engineering Management (MEM) degree at the University of Canterbury for ENMG 606.

Acknowledgements

I acknowledge my supervisor Professor Piet Beukman for his honest advice, prompt responses and providing essential support as required. To my friends and family, who have supported my tertiary education and entry into the oil and gas industry.

Acknowledgement to Seamus Breeze and William Kyle for finding a position for me at Shell Todd Oil Services. To my sponsor, Nicole Hughes for her consistent advice and always making time for me in her busy schedule. Her ongoing support has been essential to the success of this project. Finally, to my colleagues Pete Marshall, Jian Chew, Ryan Ashworth and Aaron Wong for their ongoing technical support.

Executive Summary

Project Outline

Maui gas reserves are depleting, with deliverability shortfalls expected from 2015. The Maui B IRF Phase 3 project team has been put together to plan and deliver sidetrack wells on Maui B, to extend field life. The opportunity here for the MEM student was to complete high-level completion design, execution strategy and to identify department limitations. The project was broken down into four phases as shown in *Table 1*.

Table 1 - Summary of Project Stages

Phase	Objective	Outcome
1	Induction and project familiarisation	High level understanding of completion design
2	Stakeholder investigation Literature review	Understanding of communication pathways Summary of relevant literature
3	Cost and execution strategy Benchmarking	High level cost and time estimations Benchmarked results against industry standard
4	Combining and presenting of results	Oral presentation and report hand in

Key deliverables from this project include:

- Provide high-level completion design for proposed side-track wells
- Draft execution strategy for well completion
- Outline any assumptions and limitations
- Highlight issues that may impact future project execution and options for mitigation of these issues

A literature review was completed and information was gathered through internal Shell literature, online industry literature and interviews with industry experts. Main outcomes of this review that were considered in the investigation include:

- Ensure open and constant communication with stakeholders
- Identify sources of past successes/failures
- Benchmark against industry standards and pursue Top Quartile performance

Design

Basic completion engineering design stress analysis was completed for the three well concepts proposed for Maui B IRF Phase 3: crestal, down-dip and extended reach. The lower completion will be a 4 ½" OD cemented and perforated liner of 13CrL80. The upper completion tubing will be 4 ½" 13CrL80 with tubing, anchor, seal assembly, wellhead, tree, sub-surface safety valve side pocket mandrel and landing nipple profiles. Stress analysis was completed in Landmark's WellCat program, which must be kept updated as more information becomes available throughout the project.

The base cost of well completions is NZ$8million, including contingencies. Top quartile project delivery could be achieved by cutting NZ$3million off completion costs through:

- Emphasis on contract procurement
- Opening up to various contractor options

The implementation of proposed completions will take 22 days and will be completed in three main steps:

- Drilling to run lower completion, handover to Completion and Well Intervention Team
- Running upper completions
- Install tree, bring to producing state and handover to Operations

Investigation Recommendations

Observations were made on department proceedings. Through recognising day-to-day business challenges and synthesising the skills and principles learnt in the MEM program, several recommendations have been provided to add value for both the Wells department and STOS as an organization. These are provided in *Table 9*.

Table 2 - Project Conclusions and Recommendations

Priority	Conclusions	Recommendations
1	Front end planning is not completed adequately within STOS	Increase emphasis and awareness on front end work – include all relevant staff (that may not be critical up front) in front end planning. Focus on • Improved project definition • Make timely key decisions, don't leave options too open • Ensure historical findings are analysed and acted upon
2	CWI has developed a clear direction and open communication of strategy throughout the department	Keep staff engaged and challenged through providing overseas opportunities to broaden their knowledge and experience base
3	Inter-department communication is weak	In the planned interior redecorating of the STOS building, explore options improving flow between different departments
4	The main project risks include: • Scope creep • Lack of front end planning • HSE disaster	These situations can be mitigated through: • Admittance of a Project Manager early in the process • Increased project scope definition and assurance plan
5	Benchmarking is not a priority for completion design	Improve emphasis on benchmarking against industry standard. This gives international perspective on STOS cost and time requirements

Through the implementation of recommendations made in this report, CWI and the greater STOS could improve their business processes. This will ensure both Maui B IRF Phase 3 completions and all future projects are executed to their maximum potential.

Contents

Abbreviations

AAR	After Action Review
AD	Asset Development
BOM	Business Opportunity Manager
CSV	Completion Supervisor
CWI	Completion and Well Intervention
DCAF	Discipline Controls and Assurance Framework
DSF	Design Safety Factor
EPA	Asia-Pacific Region
GWDP	Global Well Delivery Process
HSE	Health, Safety and Environment
IG	Integrated Gas
IRF	Increased Recover Factor
JV	Joint Venture
KPI	Key Performance Indicator
MA	Maui A
MB	Maui B
MEM	Master of Engineering Management
MPS	Maui Production Station
NPT	Non Productive Time
PCAP	Project Controls and Assurance Plan
Ph2	Phase 2
Ph3	Phase 3
PM	Project Manager
POC	Point of contact
PT	Production Technologist
RE	Reservoir Engineer
Shell	Royal Dutch Shell
SITS	Subsurface Integrity Tests
SNZ	Shell New Zealand
SPM	Side Pocket Mandrel
STOS	Shell Todd Oil Services Limited
TA	Technical Authority
TRSCSSSV	Tubing Retrievable Surface Control Subsurface Safety Valve
VP	Vice President
WITS	Wellhead Integrity Tests

1.0 Introduction

The project has been completed as part of the University of Canterbury's Master of Engineering Management program (MEM). The contract was for employment at Shell Todd Oil Services (STOS) Limited during the period 15 October 2013 to 14 February 2014 in the Completion and Well Intervention (CWI) Engineering Department, based in the New Plymouth Office.

Henceforth, Shell Todd Oil Services will be referred to as STOS, and Completion and Well Intervention Engineering as CWI.

The due diligence addressed in this report includes data collected, results of analysis, development of a course of action, benchmark and analysis explanation, recommendations and an implementation proposal. Design of completions for the Maui B IRF Phase 3 wells, a high level cost analysis and program will be completed. This will provide a basis for credible conclusions and recommendations for STOS to take forward into the next stage of the Global Well Delivery Process (GWDP).

1.1 Background

Shell Todd Oil Services is a New Zealand pioneer in the oil and gas industry. Based in Taranaki, STOS is a joint venture of Shell New Zealand Ltd. and Todd Petroleum Mining. STOS is responsible for producing the majority of New Zealand's energy through the operation of three main gas fields:

- Maui
- Kapuni
- Pohokura

This project will focus on work around the Maui field that STOS operates for Shell, Todd Energy and OMV. Maui is located offshore and the hydrocarbon reservoirs cover 157 square km, 3km below sea-level. Maui B platform was installed in 1992; 15 years after Maui A, to enhance drainage of hydrocarbons from the field and allow oil production from deeper reservoirs.

The production forecast for the Maui field is declining, with deliverability shortfalls from 2015. The opportunity for STOS is to appraise and develop remaining gas opportunities in Maui B that have previously been bypassed. The goal of the project is to access bypassed reserves and extend the remaining field life.

1.2 Project Focus

Through recognising day-to-day business challenges and synthesising the skills and principles learned in the Master of Engineering Management (MEM) program, all recommendations provided in this report aim to benefit both the Wells department and STOS as an organisation.

1.2.1 Maui B IRF Phase 3 Project

Maui B IRF Phase 3 project summary points:

- Objective is to target bypassed gas in the multiple layers of the Maui reservoir layers from the Maui B fixed leg platform, offshore Taranaki
- Currently in the Concept Select phase of the Global Well Delivery Process (GWDP)
- Down-hole abandonment of up to seven depleted wells on the platform and drilling sidetracks from the donor wells to target the remaining producible reserves

1.2.2 MEM Project Deliverables

The MEM contribution to the Maui B IRF Phase 3 project is defined through deliverables:

- Provide high-level completion design for STOS Maui B IRF Phase 3 side-track wells
- Draft an execution strategy for well completion
- Outline any assumptions and limitations.
- Highlight issues that may impact future project execution and options for mitigation of these issues

1.3 Scope of Works

The project was divided into four main phases. A summary of the project progression plan is illustrated in *Figure 1*, with an explanation of proceedings explained further in sections 1.3.1 through 1.3.4. *Appendix I – Figure 3* gives this in further detail. The bulk of work remained within scope throughout the project, preventing cost overruns.

1.3.1 Phase One

A project proposal, charter and plan were completed to detail the scope, approach and structure of the investigation whilst providing a foundation document that defined boundaries and objectives. Scheduled deliverables and milestones defined here were fundamental in monitoring progress toward the project deadline.

Phase one allowed for time to become familiar with the oil and gas industry. Time was allocated for inductions, a BOSIET (Basic Offshore Safety Induction and Emergency Training), a forty hour WellCat course and the opportunity to interact with colleagues both in CWI and other departments.

1.3.2 Phase Two

Focus here was on interaction with project stakeholders and understanding the information different departments could provide for the project. Collection of information was completed by verbal and written stakeholder engagement and focused investigation to determine:

- Previous (related) project results
- Inter-department relationships
- Standards and regulations
- Documentation storage

Information was collated and recorded in Section 2, Industry and Literature Review. Observations from this investigation are described in Section 3. The second stage of Phase Two involved using completion design for the Maui B IRF Phase 3 crestal, down dip and Maui B North wells. WellCat was used for stress analysis on proposed completion design. The results from this analysis were compiled in reports; *Appendices V, VI & VII*.

1.3.3 Phase Three

A high level capital cost analysis was completed at this stage, drawing on previous information and contractor quotes. The proposed costing was analysed and benchmarked against similar cases. This cost analysis involved:

- Identifying industry best practice
- Recognising similar industry challenges, lessons learned and courses of action
- Identifying Lean and Total Quality Management leaders, guidelines and methodologies

It is important to acknowledge that the program will not be executed until 2016 at the earliest, and will be re-assessed and updated at later phases in the GWDP as more information becomes available.

1.3.4 Phase Four

Information gathered and work completed throughout the project was compiled to form a final report. Project recommendations were crafted and evaluated against previous jobs to ensure a realistic implementation plan was achieved, that would meet the needs of the department. The priority and practicality of improvement initiatives were considered at all stages of the recommendation process.

The implementation plan covers a high level proposal for the completion program. An in-depth implementation plan should be formulated with the input of the team if recommendations are taken forward.

Phase four involved verbal presentations of the project results to the Maui B IRF Phase 3 project team and the CWI group.

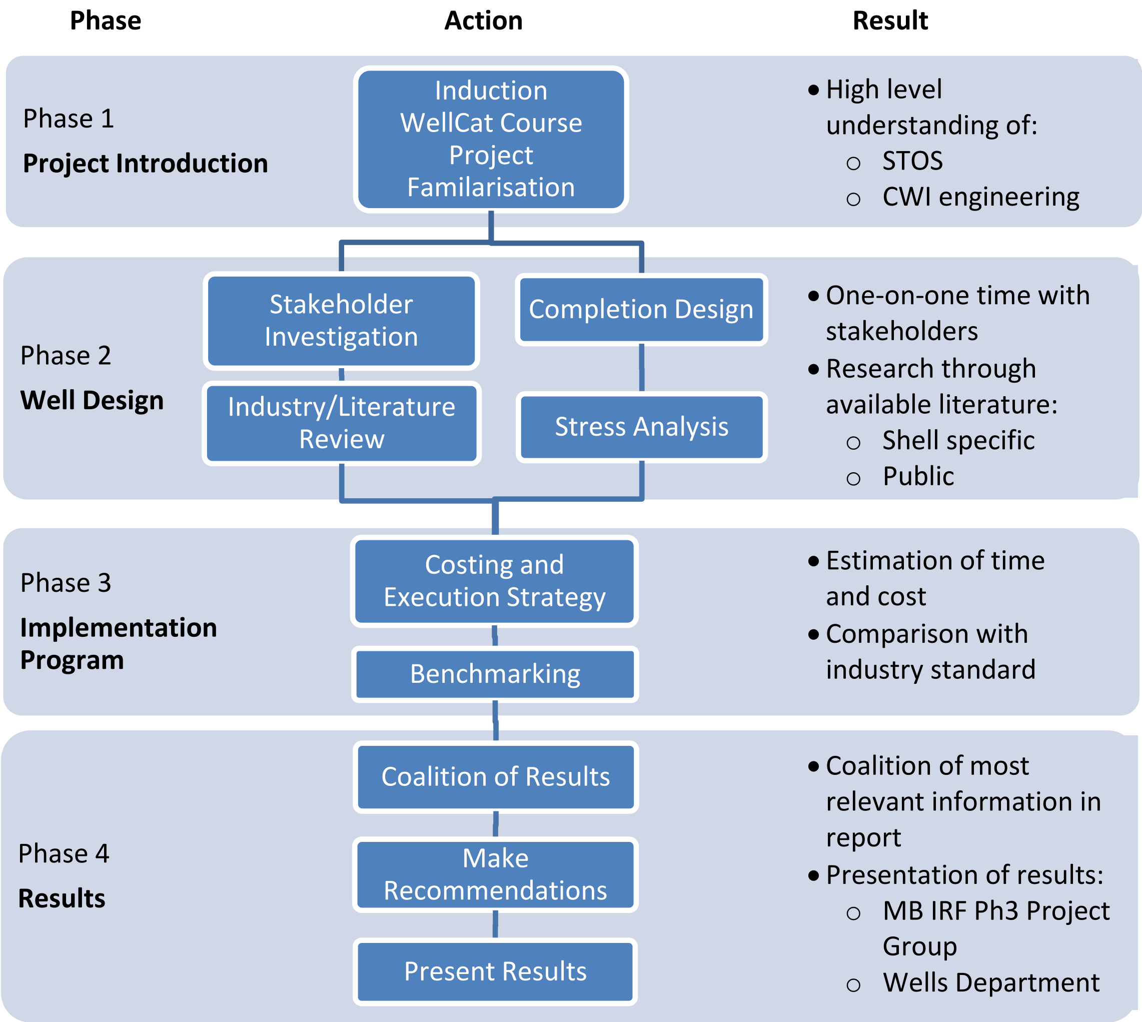

Figure 1 – Summary of Project Progression

2 Industry and Literature Review

A literature review and inquiry of industry knowledge has helped identify relevant standards and highlight current techniques and modern technologies.

2.1 Industry

This review was to put together as a guide to help understand typical industry proceedings. It highlights the importance of:

- Current Shell standards and protocols
- Implementing historical lessons learnt

Interviews were conducted with industry professionals and internal Shell literature was consulted to compile relevant information. The intention was to ensure the completion design meets minimum required safety factors and required inflow performance, and give apt recommendations for future completion design work done within CWI.

Due to the international nature of the oil and gas industry, social and cultural differences may contribute to the communication issues faced. It must be acknowledged that political, socio-cultural, technological, legal and economic factors influence each organisation and department differently.

2.1.1 Shell Practice

There are a series of Shell standards and manuals that STOS follows for well design and execution, some of which are outlined in *Section 2.1.1.2 - Standards.*

Once the concept has been selected and detailed design work done and assessed by the relevant technical authorities (TA's), as Well and CWI Engineers draft engineering programs. These programs form instructions for well construction and completion installation, to be executed by the drilling rig contract company and third party services, under supervision of STOS Drilling and CWI Supervisors.

2.1.1.2 Standards

The Global Well Delivery Process (GWDP) *Appendix I, Figure 1* is the founding procedure for the implementation of Well projects in STOS. This process provides a structure that sets all projects up for success, with certain deliverables and set decision gates. Within this, Project Controls and Assurance Plan (PCAP) is a framework that assigns people to particular tasks and project deliverables.

As previously mentioned, the Maui B IRF Phase 3 project is in the select phase of the global well delivery process. This in the second stage of the five stage GWDP in which the feasibility of proposed options is investigated.

Shell Casing and Tubing Design Manual (CTDM) guides Engineers through the design process, outlines design features such as minimum required safety factors, material selection, pipe strengths, design load scenarios, etc (Klever, 2013). Shell Well Cost Estimating Code of Practice provide a guideline for cost estimation (Halal, Jablonowski, & Adeleye, 2008)

2.1.2 Previous Experience

To improve, companies should implore focus on learning-by-doing (experience) from proficient projects (Okstad, 2006). This section investigates Maui B IRF Phase 2, executed in 2012 and draws on the project's completion experience.

Two important incidents in Phase 2 lead to 33 days of Non Productive Time (NPT) at a cost of NZ$7.3million (Segwick, 2012). An After Action Review (AAR) highlighted several recommendations to take forward into Maui B IRF Phase 3. Issues and recommendations are detailed in *Table 3*.

Table 3 - Major Issues faced in Maui B IRF Phase 2 (Altintas, 2013) (Marshall, 2013) (Sedgwick, Maui B IRF Phase 2 After Action Review, 2012)

Well	Problem	Result	Financial Impact	Recommendations
MB-08A	Unstable formation after drilling	• Difficulty in running the slotted liner to total depth • Poor fluid flow due to lack of zonal isolation	NZ$1.3million NPT	• Use cemented and perforated liner instead of slotted liner • Include CWI team in early stages of well planning
MB-04A	Pressure differential sticking	• As above	NZ$6million NPT	• Act on signs of probable differential sticking during GeoTap tests before liner is run • Avoid using swellable packers

2.2 Literature

A register of relevant sources for further reading is provided in *Appendix I, Table 1.* Included are references to leaders and theories of current practice for the consideration of recommendations within this report.

2.2.1 Success Factors

Value generation through investing in front end work is fundamental to the success of a Well campaign (Okstad, 2006). The oil and gas industry hasn't taken to business improvement initiatives like Lean and Six Sigma with comparable gusto to other industries. However, Lean can assist oil and gas companies through:

- The utility of Lean for integrating supply boats and helicopters to minimize costs/inventories
- Including Lean processes for prediction, prioritizing and sequencing to minimize well downtime (Traylor, 2011)

The industry has earned a reputation for not meeting their cost estimates, schedules and desired quality requirements. 30-40% of projects suffer budget or schedule overrun greater than 10% (Passalacua, Black, Barri, & Sapuelli, 2013). Front end loading offers the greatest opportunity to reduce life cycle costs, through the high impact of decisions made in early project stages (Batavia, 2001).

2.2.2 Ethical Considerations

Cultural diversity is significant in the oil and gas industry due to reliance on international training and experience. The acceptance and understanding of the way different cultures approach issues is vital to project success (Patrick & Kumar, 2012). A department wide personality assessment using the Myers Briggs Test could improve individuals understanding of colleagues and improve their interactions and communication. See *Appendix I, Table 1* for notes on personality workshop options.

Major ethical considerations in this industry are the importance of safety, in regards to both personal safety and the environment. This has been identified in *Section 6.3 – Risk Assessment* and options for mitigation have been explored.

2.2.2 Benchmarking

Rushmore Reviews is an online database through which oil and gas operators can "gain value through sharing high quality well data as efficiently as possible (Rushmore Reviews, 2014)." Operators upload well data for the completion type, including time taken and total costs. The collaboration of this data allows Top Quartile (TQ) and Best in Class (BIC) standards to be established, providing international benchmarks for the industry to strive towards.

2.3 Summary

Adherence to guidelines provided in Shell standards and manuals is encouraged to ensure work achieves above and beyond government requirements. Success of well completions is not solely based on cost efficiency which, whilst important, is just one factor amongst others such as successful implementation, safety, environmental awareness and timeliness. To ensure these factors are met:

- Ensure open and constant communication with stakeholders
- Identify sources of past successes/failures
- Benchmark against industry standards and pursue 'Best In Class' performance

3.0 Observations

The oil and gas industry is not covered by New Zealand education systems. Therefore, onsite training was an important ongoing factor throughout the project. The work breakdown structure was created in the Project Charter, alongside Nicole Hughes, Sponsor. This helped ensure the project was broken down systematically, allowing time for each area presumed relevant to the project.

3.1 Organisation Structure

STOS represents the best interests of all joint venture stakeholders and is working towards a more consistent following of Shell's processes and procedures. The STOS structure in the Wells Department is evolving to become more aligned with the Global Shell Wells organisation.

STOS's Information Technology (I.T.) framework is tied back to the Global Shell network. Locally developed applications are also utilised in some instances, but the base systems (modelling programs, email, etc) are all tied into the global network.

Historically completion design has not been prepared by STOS CWI employees as the department had been set up to support well intervention activities (maintaining well integrity and optimising production) only. The goal is to build completion capabilities in house and resources are now being allocated by bringing in experienced global Shell personnel and investing in training new graduates.

3.2 Department Structure

STOS has a relatively rigid hierarchical structure and reasonably high staff turnover. The CWI departmental hierarchy is led by Nicole Hughes, the Wells Engineering Team Lead (CWI). Her superior is the New Zealand Well Delivery Lead, Owen Hey, and then VP Wells in Kuala Lumpa, Davie Stewart. Details of the departmental structure can be found in *Figure 2*.

3.2.1 Department Communications

Internal communication between Wells and other STOS departments is a recognised area for improvement. This is widely acknowledged within the team but less accepted externally. To mitigate these issues, this project has focused on working closely with those in asset development and the drilling engineers to understand their views and contribution to the project.

Intra-communication (within the CWI team) is strong as the engineers work in an open plan office space. This environment facilitates impromptu face-to-face interaction on projects and allows engineers to readily obtain professional opinions and advice from their peers.

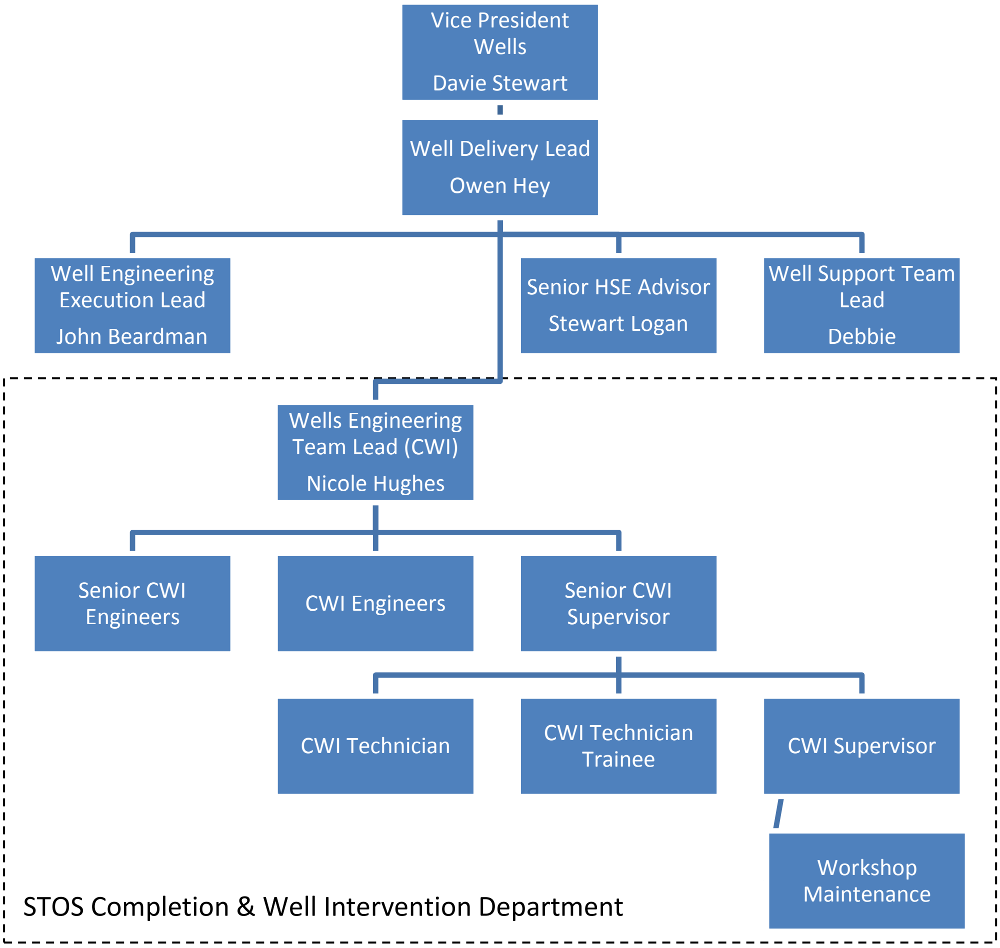

Figure 2 - CWI team hierarchy

Relationships between the CWI department and contractors appear to be strong. This has been observed as:

- Weekly contractor meetings discussing planning and operations
- First name basis on which contractors and STOS CWI Engineers regard each other
- Frequency of phone communicate between staff

These relationships provide an avenue for the CWI Engineers to keep contractors up to date with project proceedings and unexpected issues, allowing external parties to respond rapidly.

3.2.2 Stakeholders

There are several major stakeholders in the Completion Design and Execution Strategy for Increasing Maui Reserves project. These have been outlined in *Sections 3.2.2.1 & 3.2.2.2*.

3.2.2.1 Internal Stakeholders

Amy Hardy	MEM Student, University of Canterbury Responsible for ensuring that milestones and deliverables are met, whilst keeping both the project Sponsor and Supervisor up to date with project progress.
Nicole Hughes	Project Sponsor, STOS Role is to assist the student with background and provide information needed for project completion. Also, meet regularly with the student to review progress and provide feedback.
Piet Beukman	Project Supervisor, University of Canterbury Providing advice to ensure standards and criteria of the MEM program are being adhered to.

3.2.2.2 External Stakeholders

David Hadley	Maui B IRF Phase 3 Project Business Opportunity Manager
Keith Seddon	Maui B IRF Phase 3 Front End Development Manager
Ewan Robertson	Lead Subsurface Engineer involved with the Maui B IRF Phase 3 Project
Paul Sedgwick	Well Engineering Lead for the Maui B IRF Phase 3 Project (w/ Bernard Poon)
Joanna Breare	Exploration and Development Manager
Megan Alexander	STOS Contracting and Procurement
Shabbir Syed	STOS Production Technologist
Contractors	Halliburton - Completions equipment Cameron – Well head equipment

3.2.3 Strategy

The department strategy is developed by the VP of Wells Integrated Gas (IG), Davie Stewart. He communicates this to each country's Well Delivery Lead and distributes it to all Shell Well employees throughout IG. The top 5 strategic actions for 2014 have been highlighted as:

- Better-to-best – Improve application of the GWDP
- Well, Reservoir and Facilities Management (WRFM) – Increase production from well intervention activity
- Wells resourcing strategy and people plan – Emphasis on recruitment and training
- DROPS – Continue implementation of safety initiative to avoid drops
- Contractor management and quality control of installed equipment

n.b. Integrated Gas (IG) is the term used to group the countries in this region, headed by Malaysia. Countries included under the IG title include; Malaysia, Australia, New Zealand, Brunei and Qatar.

3.2.4 Critical Success Factors

Stakeholders expect quality completion design, delivery of which is vital to the projects success. Quality can be defined as compliant, accurate and safe design with a strong execution strategy. Additionally results must be within the scope of stakeholder requirements, meet budgets, schedules and be highly reliable. Critical factors for completion design are:

- Design safety factors
- Relationships with stakeholders
- Budgeting compliance
- Strong community relations (Iwi, farmers)
- Compliance with HSE standards
- Available resources

3.3 Summary

Historically in STOS, CWI was a Well Intervention group only and had no resourcing for front end planning. Over the past two years, resources have been building to provide STOS CWI Engineering department with the capability of taking on front end work. Their strengths lie in the areas of relationships within the department, and with contractors. Gaps that have been observed in the CWI department include:

- Lack of front end planning
- Lack of in house knowledge
- Lack of human resources
- Lack of department strategy
- Lack of inter-department communication

Completion design has a high impact on many stakeholders and the cost of each completion campaign is in the order of many millions. It is therefore vital that the design work is completed accurately at the front end so that later remedial work can be avoided.

Recommendation

Continued investment in the departments training of new engineers, alongside maintaining consistent staff with varied industry experience will assist in their ability to design support front end design on well projects. This is important to help optimise project execution plan and define the optimal solution.

Inter-department communication and alignment of senior management should be an area of focus for STOS. CWI projects require collaborative efforts from all STOS departments, and only through communication can members of each area learn from and build upon the experiences of their colleagues.

4.0 Design

The completion design for Maui B IRF Phase 3 was based on models created in Maui B IRF Phase 2 and sidetrack wells currently being completed at Maui A. An individual design was completed for each of the different well types anticipated for the project: crestal (targeting the top of the reservoir crest), down-dip (the direction going down the tilt angle of the formation) (PetroWiki, 2013) and Maui B North (an extended reach well). Information required for design is correlated from all disciplines including:

- Drilling Engineers - Well trajectory and casing schematic
- Production Technologists (PT) - Expected flow rates, suggested tubing sizes, water build up
- Reservoir Engineers (RE) - Fluid flow in reservoirs and aquifers

4.1 Completion Design

Decisions made for completions were based on recommendations outlined in Section 3.1.2. A ranking sheet for proposed completion options can be found in *Appendices I – Table 2*. Key decisions made for the high level completion design required include:

- Cemented liner with liner hanger – to avoid issues faced with slotted liner (Dyke, 2009)
- 4-1/2" tubing and liner – to achieve flow rates predicted (Klever, 2013)
- 13Cr L80 Material – due to non-sour, corrosive environment (Bellarby, 2012)
- Side Pocket Mandrel (SPM) – to underbalance well prior to perforation
- Tubing Retrievable Surface Control Subsurface Safety Valve (TRSCSSSV) – fail-safe shut in device
- Tubing anchor – keeps the tubing from moving (PetroWiki, 2013)
- Seal assembly – isolate production tubing from annulus (Halliburton, 2013)

Data sheets for the equipment outlined can be found in *Appendix III – Tables 1, 2 3 and 4*. Other completion options were not investigated during stress analysis and this level of detail can be considered at later project stages.

4.2 Stress Analysis

Stress Analysis was completed to ensure the proposed completion design could withstand subsurface conditions, thermal operations and loads that may be imposed on the completion throughout its expected life.

Table 4 - Minimum allowable design safety factors

Description	Label	Pipe Body		Connection		
Running, tension						
	RT1	$^{P}DSF_{1t}$	1.40	$^{c}DSF_{1t}$	1.40	1.55
	RT2	$^{P}DSF_{1t}$	1.20	$^{c}DSF_{1t}$	1.20	1.35
Running, compression	RC	$^{P}DSF_{1c}$	1.10	$^{c}DSF_{1c}$	1.10	1.25
Collapse	C	$^{P}DSF_{2}$	1.00	$^{c}DSF_{2}$	1.00	1.15
Burst - Triaxial						
	B1	$^{P}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B2	$^{P}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B3	$^{P}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B4	$^{P}DSF_{3}$	1.20	$^{c}DSF_{3}$	1.20	1.35
	B5	$^{P}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B6	$^{P}DSF_{3}$	1.10	$^{c}DSF_{3}$	1.10	1.25

Halliburton's Landmark program WellCat was used for stress analysis, allowing the simulation of fluid flow, analysis of tubing loads, movements, and design integrity under mechanical and thermal loading conditions (Halliburton Landmark, 2013). Thermal operations load cases considered during stress analysis can be found in *Appendix II, Tables 1 and 2*. Stresses were calculated to the design safety factors shown in *Table 4.*

4.2.1 Crestal Sidetrack Well

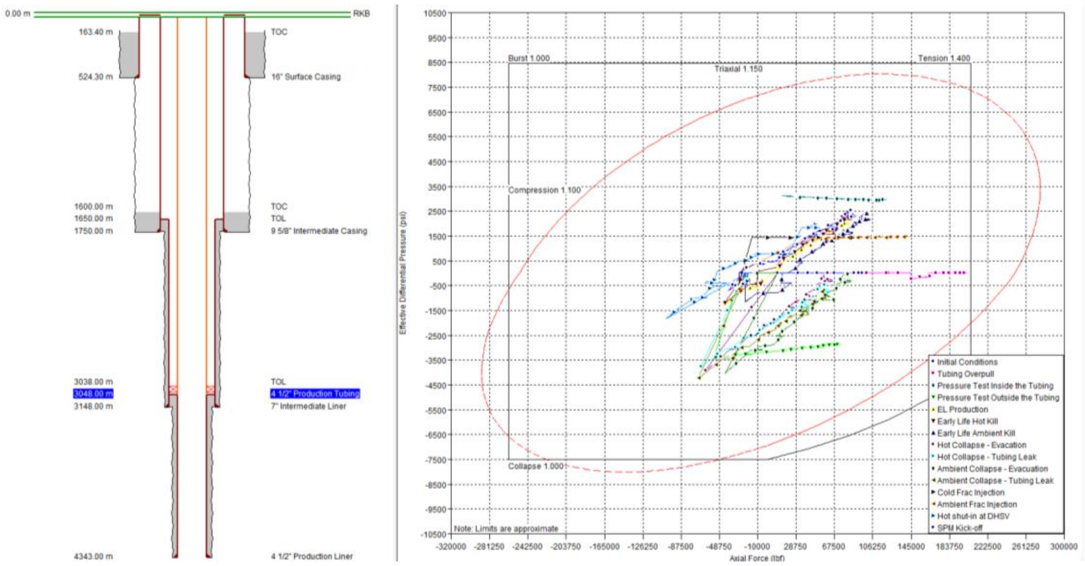

Figure 3 - Well schematic and design limits plot for MB-04C

The crestal well used for completion design was MB-04C. *Figure 3* shows the well schematic and associated design limits plot for MB-04C completions. *Figure 3* and details found in *Appendix V*, it can be stated the completion design is strong enough to withstand all load cases outlined in *Section 4.3*.

4.2.2 Down-Dip Sidetrack Well

The down-dip well used for completion design was MB-09A. This should stand similar for the other down-dip wells proposed for Maui B IRF Phase 3: MB-02B, MB-10A and MB-12A.

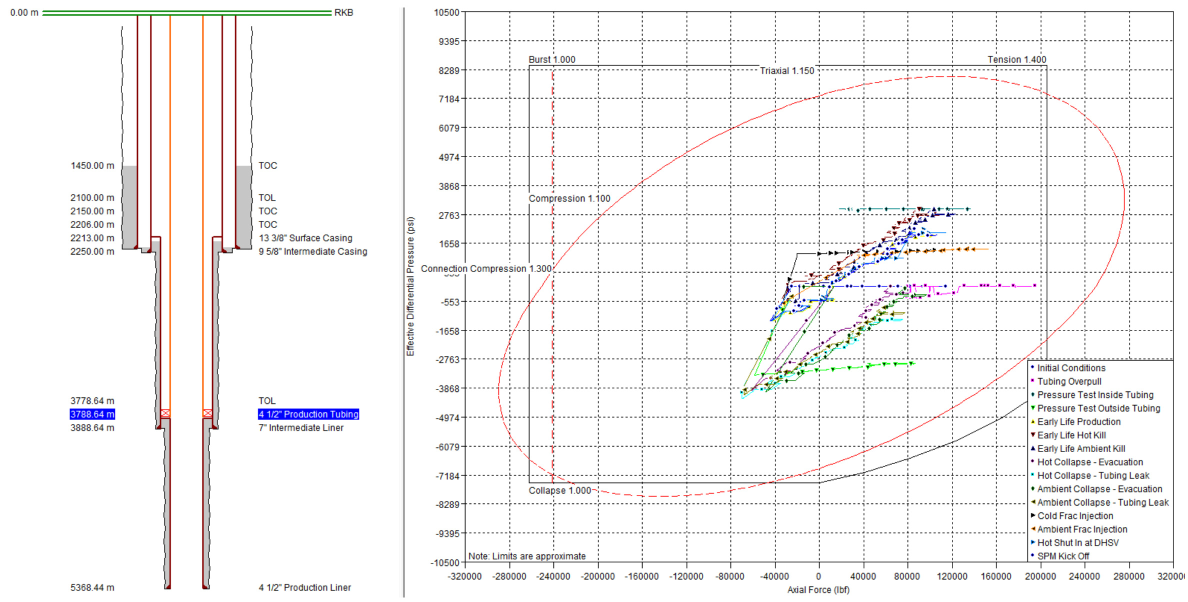

Figure 4 - Well schematic and design limits plot for MB-09A

The proposed cemented liner and hanger design for the down-dip sidetrack well's on Maui B appear to meet the design requirements outlined in the Casing and Tubing Design Manual. Details for this can be found in *Appendix VI*. Note: MB-09A can only withstand a tubing overpull of 80kips.

4.2.3 NB-North Sidetrack Well

The base well used for the Maui B North sidetrack well completion design was MB-08B. This is a one off extended reach well, which implies a particularly long, highly deviated wellpath. MB-North is expected to flow from a highly permeable reservoir and is carrying the project, with high production flowrates expected.

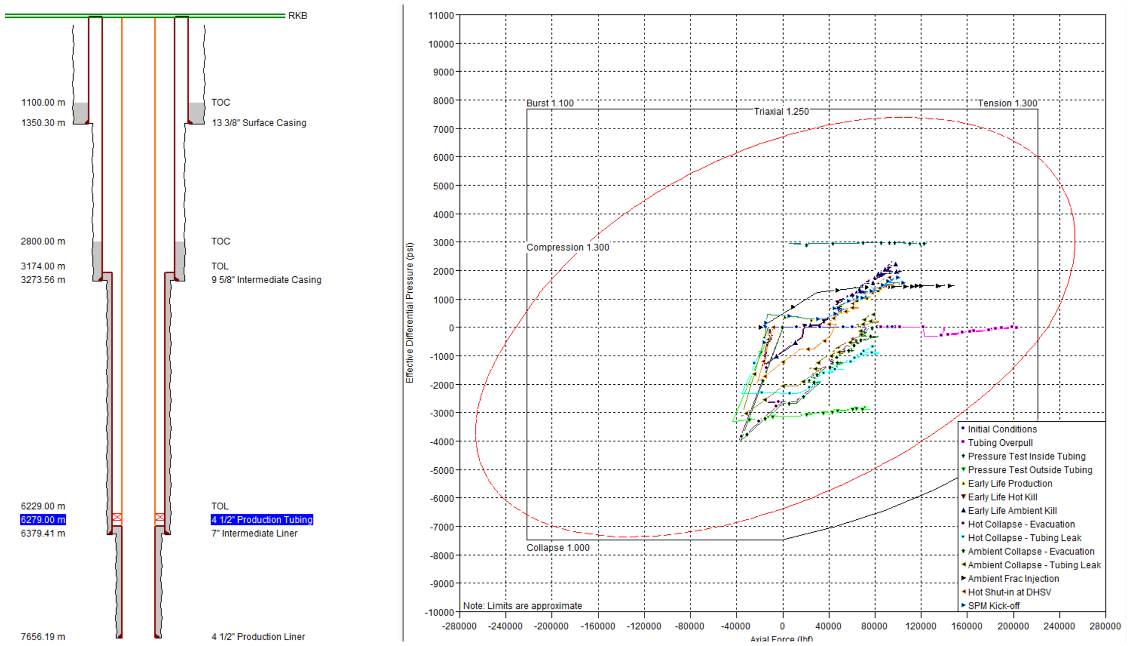

Figure 5 - Well schematic and design limits plot for the proposed Maui B North sidetrack well

The proposed liner hanger and cemented liner design for Maui B North well appear to meet the design requirements outlined in the Casing and Tubing Design Manual. Details for this can be found in *Appendix VII*.

4.3 Summary

Proposed completion design is acceptable and can be taken forward to the next project stage. The high level completion design for the three Maui B IRF Phase 3 sidetrack wells pass required stress analysis, as shown in sections *4.2.1* through *4.2.3*. Other aspects of the design are investigated in later sections to allow understanding of the economic, environmental and political feasibility of the project.

Recommendation

WellCat models have been set up and saved in the Shell database. These models are complete to the current information supplied from asset development and drilling. As options for trajectory, flow rates and tubing sizes etc. become more defined in later stages of the project, these models ought to be updated to reflect changes.

5.0 Cost Analysis

The crestal well MB-04C was used as a basis for cost analysis of the completion for Maui B IRF Phase 3. Values used were taken from historical information, including historical costs, quotes and budget blow-outs.

Total costs were broken down into two major project events. These events and their corresponding costs are given in *Table 2*. Contingencies have been taken into account for known technical risks that cannot be estimated with certainty. Contingencies were calculated for each incremental cost at each project stage based on a cost factor that puts a value on the uncertainty of that cost (Halal, Jablonowski, & Adeleye, 2008). At this high level of costing, uncertainties expected are in the range of +25%/-15%. This is expected to reduce to +10%/-5% as the project enters the execution phase.

Table 2 - Summary of Completion Costs for MB-04C

	Days/ Section	Cum. Days	Base time costs	Contingency time costs
Well Completion & Rig Down	20.0	20.0	5,870,256	6,249,433
Post Works & Rig Down/De Mob	1.9	21.9	1,436,668	1,836,093
		22 Days	NZ$7,306,924	**NZ$ 8,085,526**

The largest cost contributors to the project are indicated in *Table 3*, stating both their cost and contribution to the total project cost. It was found that six main costs contributed to 70% of the total project costs. It is recommended that these costs be further reviewed and an investigation taken place to understand where reductions can be made. Tangibles have been separated from service costs.

Rig operating rates are subject to change, as a final decision on rig selection has not been made. This model has been based off the Archer Emerald rig, currently operating on Maui A. Well kick-off costs could be reduced through increasing emphasis on contract procurement and negotiating lower rates with contractors. Costs on tangibles such as the tree could be reduced by considering alternative suppliers.

Table 3 - Main Cost Contributors to Project

	Activity	Cost (NZ$)	Totals	Contribution to Total Completion Cost (%)
Services	Rig Operating Rate	$ 1,884,850	**$4,333,397**	23%
	Well Kick-Off Costs	$ 1,125,000		14%
	Support Vessel	$ 765,774		9%
	Offshore Diesel	$ 557,773		7%
Tangibles	Tubing, Accessories	$ 713,042	**$1,331,716**	9%
	Tree/Wellhead	$ 618,675		8%

Results from this investigation were benchmarked against the industry standard for horizontal, platform wells between 3000 and 6000m completion. MA-04C plans were found to be Q2 (second quartile) for both cost and time constraints. To achieve TQ (top quartile) performance for completion, the costs would need to be reduced by NZ$3.3million. An extension of these results can be found in *Appendix IV – Figures 1 and 2*.

These cost estimates are a high level indicator of possible project costs and will be defined at later project stages.

6.0 Execution Strategy

The Maui B IRF Phase 3 project is a campaign where a series of wells will be planned, drilled and complete, following the structure of GWDP. The Discipline Controls and Assurance Framework (DCAF) was used to QA/QC business critical elements of the project.

Through working on a campaign, momentum is built in a way that is not possible in the execution of single wells. The synergy achieved through this momentum improves the flow of the project. The campaign supports reduced inventories through collaboration of resources. The inclusion of future Maui A work in the campaign is an option to be explored, to capitalise on synergies and possible cost savings.

The recommendations from MB IRF Phase 2 are being adhered in these early stages of planning. As the project proceeds, it is important to have CWI input at the early stages and throughout. The Maui B IRF Phase 3 project has implemented this through providing a CWI presence at weekly project meetings, project reframing, risk management planning and the Well Feasibility Report.

6.1 Key Performance Indicators

- Operation completed with ZERO environmental and personal safety incidents
- Completion operation run to timeline provided
- Adherence to budget
- Delivery of high quality with all acceptance criteria met
- Achieve a Non Productive Time (NPT) of ≤11%

6.2 Key Programme Steps

Ensure primary well barriers are in place, as outlined in *Appendix II – Tables 4, 5 and 6*. Key programme steps (for post detailed define phase) have been summarized in *Table 5*.

Table 5 - Key Technical steps in Program Implementation

Programme Step	Technical Activity to Perform	Non-Technical Considerations
Handover from drilling to completions	• Check completion fluid and pressure test well • Pull the wear bushing and clean the BOP (Blow out preventer) • Pressure test the BOP	• Check CSV documents all criteria have been met (store in OpenWells) • Ensure open communication between the departments
Run completions	• Run upper completion • Land tubing hanger • Drift Completion String • Pressure test upper completion string & inflow test TRSCSSSV • Set anchor	• Hold meeting at rig site with ALL crews required to attend to ensure awareness of planned completion operations • Ensure all process safety checks are completed at each step
Bring to producing state and handover to MPS	• Secure well and remove BOP • Install Christmas tree and remove down hole isolations • Perforate target zone • Complete well handover form	• Ensure installation & testing is carried out by qualified personnel • Check Weather forecasts • QA/QC toolstring components • Cross-check correlation with petrophysicist before perforating • Ensure documents are scanned, recorded and saved correctly • Perform well integrity tests

6.3 Risk Assessment

High level operational and commercial risks for execution of this project have been outlined and suggestions for mitigation included in *Table 6*. The ISO 31000 has been used to identify these areas of risk within the project. The impact these risks could have on the project have also been included. *Appendix II – Table 7* defines how the risks are classified: Risk Management Guidelines AS/NZS 4360.

Table 6 – Operational and Commercial Risk Register

Impact	Risk Description	Likely	Conc	Risk	Mitigation	Owner
Delay in project execution	WOW – Wait on Weather	3	2		Thorough planning and scheduling of workload. Use a boat with a large weather window	Logistical Coordinator
	Scope creep	3	3		Ensure full team investment in front end planning and stop-work points are defined	AD team
	Drilling runs overtime	2	3		Communication between drilling and completions. Use performance improvement coaching	Project Manager (PM)
	Operations not ready to take over completed well	3	2		Communicate and define a schedule for flow line installation	PM
	Unexpected issues with contractor/resource availability	2	3		Ensure regular communication with contractors on availability of resources	CWI Engineer
	Staff turnover	2	2		Mitigate via communication with staff on their expectations of their job and the project	Human Resource Coordinator
	Lack of front end planning	2	4		Ensure high emphasis remains on inclusion of all departments in planning. Correct sign-offs must be achieved at each project stage	Business Operation Manager (BOM)
Creep in proposed cost/ timelines	Delay in key decisions	3	2		Communication between key project decision makers	BOM
	Public reaction to outsourced work	2	3		Mitigate through compromise of using both local and international resources and expertise	Comms. Advisor
Project Failure	HSE disaster	1	5		Ensure all HSE rules are followed and staff trained. Programme and design have relevant TA sign off	STOS HSE Coordinator

The high level risks associated with project implementation are scope creep, lack of front end planning and HSE disaster, as calculated via the operational and commercial risk analysis summarized in *Table 6*. These situations can be mitigated through ensuring cross-departmental investment in front end planning of the project. This can be achieved through:

- Admittance of a Project Manager earlier in the process
- Increased project definition and assurance plan (Baker, 2014)
- Project input across all disciplines

7.0 Review

Throughout the project a number of procedures were observed that, if addressed, could significantly improve the success of future endeavours. Issues have been summarized in Table 7 and ranked on a scale from 1 through to 5 (most to least significant).

Table 7 - Summary of department findings and recommendations

Rank	Findings	Notes	Proposed Actions	Responsibility	Associated Costs
2	High department staff turnover	○ 7 CWI engineers in the team • Team lead leaving Jan 2014 • 3 senior engineers leaving Q1 2014 • New team lead Jan 2014 • 2 new senior engineers Mar 2014 ○ Well projects can take years from concept to execution and it is favourable to have the same engineer working on a project throughout ○ High turnover results in disruption of work ○ Negative impacts on team cohesion	○ Employ on longer term contracts ○ Increase staff to avoid overworking	○ Well Delivery Lead (Owen Hey) ○ Human Resources Team, Recruitment Consultant (Kate Wadsworth)	○ NZ$100,000 per experience hire hired (Peters, 2014)
3	Lack of Shell training	○ Shell expects their operating units (including JV's) to follow Shell standards and procedures ○ STOS employees are not all Shell employees, and have not completed the Shell discipline foundation training	○ Create a point of contact (POC) for queries around Shell expectations and procedures ○ Send STOS employees on Introduction to Shell courses to ensure everyone is on the same page ○ Ensure the Shell structure has been followed before sign-off	○ Well Delivery Lead (Owen Hey) ○ Well Support Team Leader (Debbie Dawson)	○ Cost of training courses for Asia: • Grad - NZ$5000 • Engr – NZ$8000 ○ For Europe: • Grad - NZ$8000 • Engr – NZ$15000
3	Inconsistency in completion design	○ WellCat is the standard program recommended by Shell for stress analysis on completion design ○ Historically, contractors have been used to design completions, namely Halliburton ○ There are no STOS wells with complete	○ CWI engineers need to be trained in completion design ○ WellCat training course in October 2013 may have aided this, but further training/updates are required	○ Wells Engineering Team Lead (CWI) (Nicole Hughes)	○ Base cost for external engineer to do design work is NZ$12,000 (Irena, 2014)

		data in WellCat	○ Support must be provided to CWI engineers as they endeavour to design completion in-house ○ Stop using contractors for completion design and turn focus into our own department		
2	Lack of inter-department communication	○ This leads to NPT time, project overrun and non adherence to budgets ○ CWI department has regular (twice-weekly) meetings with high attendance, allowing easy flow of communication ○ Wells department (Drilling and CWI) have regular (fortnightly) meetings with high attendance allowing flow of information on proceedings ○ The MB IRF Ph3 project group has regular (weekly) meetings, however these are often met with poor attendance from key parties in the asset development group, causing: • Lack of clear communication • Overstretching of deadlines as absence of required personnel • Project delays	○ Insist on attendance from all key project member ○ Enforce set deadlines	○ Project Leader (in this case, David Hadley) ○ Wells Engineering Team Lead (CWI) (Nicole Hughes)	○ Difficult to quantify, see **Project overrun** and **Acceptance of exceeding budgets**
1	Project overrun	○ Project overrun can cost up to NZ$220,000/day in NPT ○ During the last MB IRF Ph2 completions, NPT cost the project NZ$7.5million	○ Increase front end planning ○ Carry out more thorough AAR's to increase understanding of why these mistakes are occurring ○ Run sensitivity analysis on budgets in areas that have been known to blow out	○ Well Delivery Lead (Owen Hey) ○ Wells Engineering Team Lead (CWI) (Nicole Hughes) ○ CWI Engineer	○ Project overrun can cost up to NZ$220,000/day in NPT

			○ Develop a thorough contingency plan: • Assess all business critical operations • Conduct risk and scenario analysis • Determine risk impacts and prioritise • Communicate and maintain plan • Train staff • Locate opportunities to reduce/eliminate risk		
1	Acceptance of exceeding budgets	○ Projects within the Wells department have an overriding tendency go significantly over budget	○ Put more time into planning at the front end ○ Improve communication with contractors over quotes etc ○ Develop a thorough contingency plan (as above)	○ CWI Engineer ○ Contracts and Procurement Manager (Robert Kadlec)	○ A well with allocated budget of NZ$60million can be known to blow out by up to 50% ($30million)
4	Lack of document control	○ Different systems are used for the storage of final documents, including: • Livelink database • Shared 'N' drive • Personal desktops	○ This is currently being addressed by the appointment of Keith Chamberlain as Record Administrator	○ Record Administrator (Keith Chamberlain)	○ CWI Department spends: • NZ$374,600/yr searching for info • NZ$749,300/yr re-creating info (Chamberlain, 2014)

Conclusions drawn from analysis of department proceedings highlight key areas where STOS could reduce Well costs. Main areas include:

- Increase emphasis on front end planning - close in on concept earlier in project, allowing more accurate estimations
  - avoid time and cost overruns
- Improve personnel conditions - enhance inter-department communication through raising awareness and breaking down boundaries
  - reduce staff turnover

7.0 After Action Review

This section documents project strengths to be replicated in future projects and opportunities for improvement. It also includes a summary of personal development throughout the course of the project.

7.1 Project Strengths

- Communication with project Sponsor was a strong contributor to project success, as regular weekly meetings proceeded throughout the course of the project
- Assistance from respective team members (both CWI and MB IRF Ph3) was excellent throughout the project, and final successes would not have been achievable without the support received
- Schedule adherence was strong towards the end of the project. Sponsor Nicole Hughes, resigned from STOS on the 31st January 2014 so final project draft was completed and checked earlier that anticipated

7.2 Future Project Improvements

- Technical aspects of the project were challenging this caused a slight timeline overrun in the early stages of the project. This time was re-made in Phase 2 of the project
- Human resources are an important aspect of project success, but consultation with different staff can be difficult and it is recommended that meetings be organised well in advance of requirement

7.3 Reflection of Personal Value

Entry into the oil and gas industry proved difficult on a number of levels; technically, administratively and socially. I had an intensive four weeks coming up to speed on wells and in particular, completion design. This was only achieved through the help of my direct CWI team, and those contributing to my project from the Asset Development group and the Maui B IRF Phase 3 team.

Administratively it was challenging moving to a new town and entering an environment that greatly contrasted the five years spent as a student of the University of Canterbury. I encountered difficulty explaining my position at STOS; I was working here in both a short term (MEM project) and long term (Shell Graduate) capacity. I found the response from staff encouraging and this helped me succeed in my contractor role.

Oil and gas is a male dominated industry, with only 10% of Wells Engineers being female. The average age in the industry is relatively high, with many current STOS Well Engineers looking at retirement within the next 10 years. Whilst I certainly found it challenging moving into this environment, I found I was greeted warmly and have had ongoing support from a range of people throughout STOS. Nicole Hughes has become a valued role model to me, as a young woman achieving so highly in the career path I hope to follow.

The acceptance, encouragement and inclusiveness I received from members of the Maui B IRF Phase 3 was vital in improving my professional confidence. These experiences allowed me to build business relationships and understand STOS in a broader context than would otherwise have been achievable.

8.0 Conclusions and Recommendations

Feasible options for completion design and execution strategy for proposed sidetrack wells on Maui B were investigated. Through recognising day-to-day business challenges and synthesising the skills and principles learnt in the MEM program, several recommendations have been provided to add value for both the CWI department and STOS as an organization – *Table 9*.

Table 8 - Technical Conclusions and Recommendations

Priority	Conclusions	Recommendations
1	The base cost of well completions is NZ$8million, including contingencies	Reduce costs by NZ$3million to achieve top quartile performance, focus on: • Emphasis on contract procurement • Opening up to various contractor options
2	Proposed completion design is structurally feasible for the trajectories investigated for the three wells	Ensure WellCat models are updated as information becomes more defined at later stages of the project
3	Well completion will be completed in three stages and take a total of 22 days: • Handover from drilling to completions • Running completions • Bring to producing state and handover	Engage with involved staff to ensure everyone is aware of the work to be done, safety requirements and deadlines that must be met

Table 9 - Project Conclusions and Recommendations

Priority	Conclusions	Recommendations
1	Front end planning is not completed adequately within STOS	Increase emphasis and awareness on front end work – include all relevant staff (that may not be critical up front) in front end planning. Focus on • Improved project definition • Make timely key decisions, don't leave options too open • Ensure historical findings are analysed
2	CWI has developed a clear direction and open communication of strategy throughout the department	Keep staff engaged and challenged through providing overseas opportunities to broaden their knowledge and experience base
3	Inter-department communication is weak	In the planned interior redecorating of the STOS building, explore options improving flow between different departments
4	The main project risks include: • Scope creep • Lack of front end planning • HSE disaster	These situations can be mitigated through: • Admittance of a Project Manager early in the process • Increased project definition and assurance plan
5	Benchmarking is not a priority for completion design	Improve emphasis on benchmarking against industry standard. This gives international perspective on STOS cost and time requirements

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Appendix I - Research

1.0 Literature Review

A literature review was carried out to develop understanding and critically analyse topics within the scope of the project. Four main topics were covered in this literature review and these are discussed in Sections 1.1 through 1.4.

1.1 Completion Design

Completion and Well Intervention Engineering is a growing industry. New Zealand currently lacks competencies in this area and an educational system to build the relevant skills. Shell New Zealand (through STOS) recruits engineering graduates and trains them in an international Completion and Well Intervention Engineering course. Despite the lack of local knowledge, there is a lot of information available in the form of textbooks, research papers, previous completion designs and reviews on historical work.

There are several different completion types that can be implemented in a well. A liner is a completion type that hangs from the bottom of the intermediate casing, instead of reaching all the way to the surface. A cemented and perforated liner is cemented in place as the casing would be. Perforations are then created through the liner and cement into the formation (Halliburton, 2013). Cement is applied around the liner to prevent the escaping of hydrocarbons. Perforating is the process of breaking through the liner and cement, into the formation using charge. A perforating gun is used for this action. The gun creates perforations through the liner that allow fluid to flow from the formation into the well (Dyke, 2009).

In contrast to a perforated liner, a slotted liner is one that has pre-made holes. Because of this, the slotted liner needs to be aligned in the correct position (in the reservoir targeted) when it is being run in hole. It is important to consider these factors, and the implications of not reaching Total Depth (TD) of the well with the slotted liner. A perforated liner is the more reliable option as the position of perforations can be adjusted if there are issues with the liner reaching TD.

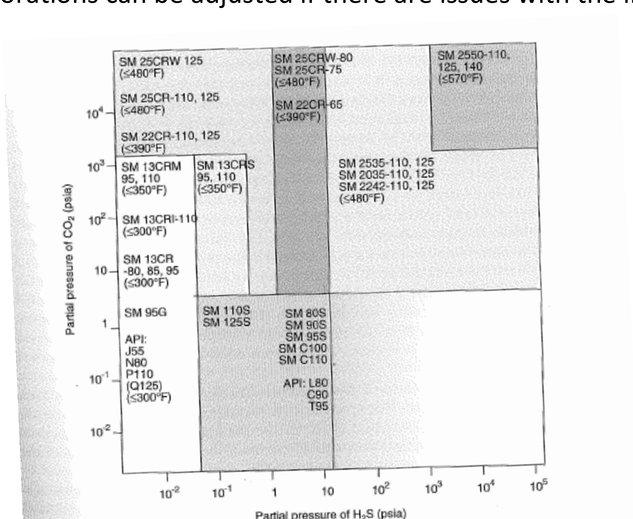

Figure 8.15 First-pass material selection (courtesy of Sumitomo Metals).

Figure 6 - Metallurgy Selection (Bellarby, 2012)

The material selected for the tubing and liner was 13Cr L80. This material is designed to withstand corrosive (above average CO_2) and non sour (very low N_2S) environments. The cost of the material is approximately three times the cost of carbon steel so should be deemed necessary before implementation (Bellarby, 2012).

The program used for stress analysis on completions was Halliburton's Landmark program, WellCat. This allows the simulation of fluid flow and heat transfer during completion, production, stimulation, testing and well-servicing operations. It is used to analyse tubing loads and movements, buckling behaviour, and design integrity under complex mechanical, fluid-pressure, and thermal-loading conditions (Halliburton Landmark, 2013).

In summary, WellCat is used to understand the likelihood of negative effects on the completion, such as annular trap pressure and unstable load stresses. It ensures the design is safe and can withstand all stresses that may be applied to the completion throughout its life.

Being a niche industry, there are no competing products that carry out the same function as WellCat. Schlumberger are developing a similar programme but as of now, there is nothing at a comparable level.

1.2 Shell Standards

The Global Well Delivery Process (GWDP) is the framework through which Shell selects, plans and executes all Well projects (Royal Dutch Shell, 2011). There are four main requirements including:

- Each project must have clear performance targets based on KPI's
- Projects must have a plan for how they will be executed, and a decision review board to approve plans
- Projects must have a PCAP (Projects Controls and Assurance Plan) aligned with other processes/disciplines
- Projects must report results regularly based on the agreed KPI's

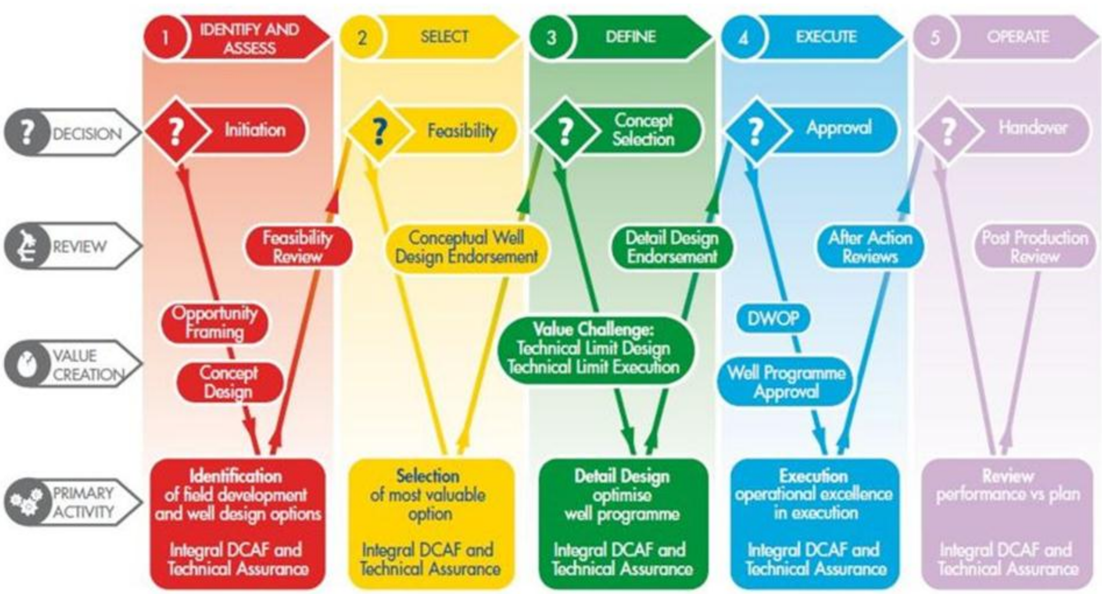

Figure 7 - Shell Global Well Delivery Process

Decision Gates (DGs) must be met at the end of each project phase, as defined in the GWDP. It must be ensured that Discipline Controls and Assurance Framework (DCAF) and Technical Assurance (TA) are employed throughout the project to ensure it remains on track to meeting predefined requirements.

As a part of the GWDP, the DCAF is implemented to standardise technical assurance across all disciplines. The DCAF enhances transparency by clarifying which deliverables are business-critical (Okstad, 2006). In summary, the DCAF is a Quality Assurance/Quality Control (QA/QC) framework vital in all opportunity realisation process phases. Through standardisation of these processes, Shell is ensuring each process is being checked to an appropriate standard.

The Well Cost Estimating Cost of Practice states that the required accuracy for costing in the Select Phase of GWDP is 15%. This can be found in the Shell International Global Networks system. Major risks, expected downtime, spread in contracts and durations should be quantified in Select Phase of GWDP. The practice ensures that relevant historical performance is considered in appropriate detail for putting together cost estimates (Adeleye, 2013).

The major strength of using the Well Cost Estimating Cost of Practice is the consistency with which costs are calculated throughout all projects. It provides structure and uniformity throughout the entire business. Limitations of the system arise where completion design is out of the ordinary scope, or new work is being done in a different area and historical costs are not applicable.

1.3 Improvements in Completion Engineering

1.3.1 Benchmarking

Benchmarking is a global technique used to compare business processes and performance against industry standards and best practice. The use of this technique in well engineering ensures employees understand how the company is performing relative to industry competitors. Rushmore Performance Reviews is an online database that serves as a specific tool for well engineers to benchmark their work.

It can be difficult to benchmark completion and well intervention activities due to the nature of their incremental production increases. However, by looking at planned versus actual ratios for Operational Time (OT) for specific activities, the work completed can be benchmarked (Rushmore Reviews, 2014).

Rushmore Reviews is an industry standard for life-cycle well data sharing with the participation of the majority of oil and gas operators globally. The website provides a quick and easy forum for accessing essential data that can be used for benchmarking. Conversely, the site has no direct competition which could lead to a manipulation of the market and information. To date however, the review website has had excellent feedback and is considered a useful tool that should be utilised further throughout the industry.

The Drilling Performance Curve (DPC) is another tool that can be used to rank Well Engineering performance. The DPC is used to assess the drilling performance in an area over a consecutive series of similar wells. The method can dictate the strategy for a drilling programme. Figure 8 shows a typical learning curve for a sequence of drilling events in a similar area. A DCP can indicate an organisations technological and operational capability and rate of learning (Brett & Millheim, 1986). This method could be implemented by the organisation to ensure their campaigns as they progress from well to well.

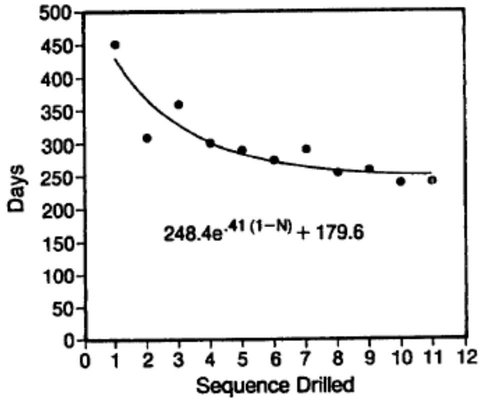

Figure 8 - Drilling Performance Curve

1.3.2 Stress Analysis

Completion engineering has become a more accurate design process through the introduction of computationally based stress analysis programmes. As described in Section 1.1, Landmark's WellCat programme has been designed to investigate loads on casing and tubing during design. Well design engineers can utilise WellCat to understand the likelihood of potential negative effects such as trap annular pressure and unstable load stresses (Halliburton Landmark, 2013).

WellCat allows stress analysis to be carried out in a faster, more accurate manner. The opportunity this programme provides is still being introduced and capabilities are being built globally. It is expected that programmes such as this will become the industry standard for oil and gas operators worldwide.

1.3.3 Front End Work

Front End Loading (FEL) is a process that emphasises the importance of allocating appropriate resources during front end work. The FEL methodology measures and increases the level of project definition whereby increasing the probability of success throughout the project life (Passalacua, Black, Barri, & Sapuelli, 2013).

In the oil & gas industry mega projects, cost estimates, schedules and desired quality requirements are frequently not met. 30 to 40% of projects in the industry suffer from budget or schedule overruns greater than 10% (Passalacua, Black, Barri, & Sapuelli, 2013). These incidents could typically be avoided by increasing emphasis on front end planning.

Front end planning offers the greatest opportunity to lower life cycle costs with the application of value improvement work processes. The FEL phase covers basic and preliminary engineering that should be done prior to commencing detailed engineering, procurement etc. The impact of decisions made early in the project have the greatest influence on final project costs (Batavia, 2001).

Disadvantages of the FEL process include the increased time investment required at the front end of the project. These costs may not have been budgeted for historically. Benefits of FEL include; informed investment decisions, increased benefits and improved take up of new ways of working, saving time and money, and de-risk change programmes (Popham, 2013).

1.4 Ethical Considerations

In the oil and gas industry, cultural diversity is prevalent in the workplace. There is no education system for training oil and gas engineers locally and therefore, companies up-skill local staff or hire experienced international personnel. Typically, oil and gas operators have both local and expatriate staff, creating an environment containing varied cultural beliefs. Therefore it is crucial that this workplace diversity is managed in a way that promotes a positive working environment.

The predominant barriers to accepting diversity are discrimination, prejudice, and ethnocentrism. Strategies that can be used in increasing inclusiveness in organisations include education about cultural differences, encouraging employees to take overseas assignments, and encouraging awareness of biases and prejudices that may be prevalent (Patrick & Kumar, 2012). Organisations should implement a combination of these techniques, allowing the company to maximise on the benefits of diversity whilst reducing prejudices.

There are numerous personality tests that can be utilised to improve the understanding of individuals' behaviours and actions. The purpose of these tests in a corporate environment is to enhance employees understanding of their colleagues behaviours and improve interactions. The Myers Briggs Type Indicator (MBTI) test is designed to make the theory of different psychological types understandable and useful in everyday life. The idea is that seemingly random behaviour is actually quite orderly, due to differences in individuals perceptions and/or judgments.

There are critics to the Myers Briggs test that bring to light the possibility of people being incorrectly categorised. Critics state that similar scores may be given to people with vastly different personalities, i.e. introverts and extraverts (Moffa, 2011). However MBTI has many positives, as shown by its popularity (utilised globally) and resilience in the market despite numerous competitors. Myers Briggs is understood to be one of the best methods for promoting understanding and appreciation of differences between personality types (The Myers & Briggs Foundation).

Another popular personality test is the 16 Personality Factor (16PF) questionnaire that describes five main personality factors as being extraversion, tough-mindedness, self-control, anxiety and independence. The questionnaire is designed as a tool to aid professionals in recruitment of appropriate individuals for the organisation's needs, particularly in terms of problem solving styles and interpersonal skills (IPAT People Insights, 2013). Downsides to 16PF include the non-replication of the theory and the factors and their descriptions do not correlate. These issues need to be acknowledged if the test is to be implemented (Psychology of Personality).

Belbin team roles are a measure of behaviour rather than personality. It highlights individuals tendencies to "behave, contribute and interrelate with others in a particular way," states Dr Meredith Belbin. The aim of this method is to understand behaviour and ensure workplaces are employing a range of these types (Leadership Solutions Belbin NZ, 2007). Limitations of Belbin include its focus on a work and team setting. However, Belbin has a cultural bias as the theory is mainly focused around upper-management level executives in Britain (Belbin Improving Teams).

Myers Briggs Type Indicator is the most relevant method for the oil and gas industry, as determined through comparing and contrasting different methods for enhancing cohesion within diverse groups. This is due to its applicability over a range of demographics. Whilst the implementation of this programme may not be infallible, it promotes discussion around the topic and brings to light issues of diversity that may otherwise be swept under the table.

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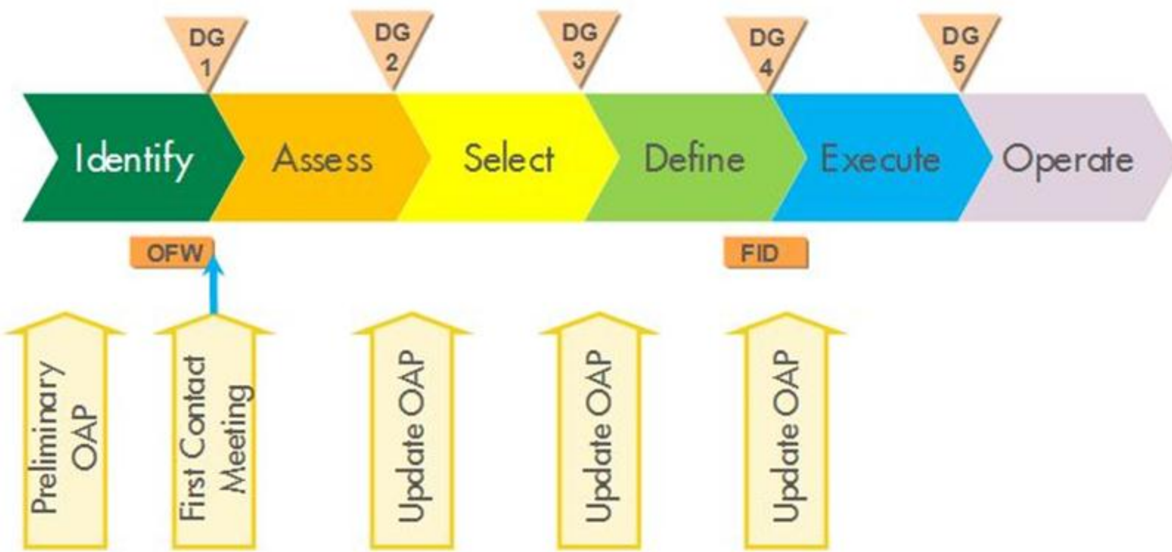


Figure 4 - Graphical explanation of the Opportunity Assurance Plan (OAP) (Royal Dutch Shell, 2013)

Table 1 - Completion Options Ranking (Sedgwick & Hughes, Maui-B IRF Phase 3 - Wells Feasibility Report , 2013)

Completion Component	Options	Cemented liner w/ liner hanger and anchor	Cemented liner w/ drop off liner and packer	Drilled-in cemented liner, perforate	Cemented liner with swell packers	Slotted liner, swell packers w/ liner hanger and anchor	Sliding sleeves and swell packers, uncemented	Cemented Monobore	Blank liner, uncemented, with swell packers, perforate	Cemented liner w/ drop off liner and on/off connector	Sliding sleeves, cemented	Smart (surface operated sleeves, valves, gauges, etc)
Relative ranking	High, Medum, Low	High	High	High	Med	Med	Med	Med-Low	Med-Low	Low	Low	Low
Production tree	Tbg size dependent	Same	Same	Same	Same	Same	Same	Same	Same	Same	Same	Extra control line outlets and surface facilities required
Tubing hanger	Tbg size dependent	Same	Same	Same	Same	Same	Same	Same	Same	Same	Same	Extra control line ports required
Tubing	4.5", 5", 5-1/2", 7"?	As required	As required	As required	As required	As required	As required	No crossovers	As required	As required	As required	As required
SCSSSV	WR, TR	Same	Same	Same	Same	Same	Same	Same	Same	Same	Same	Same
Tubing	4.5", 5", 5-1/2", 7"?	As required	As required	As required	As required	As required	As required	No crossovers	As required	As required	As required	As required
Accessory	Nipple, permanent gauges, SSD - must be set at low deviation to be accessed via slickline	Same	Same	Same	Same	Same	Same	Same	Same	Same	Same	Same
Bottom of upper completion	Packer, anchor, seal stack, centralizers, on/off connector...	Anchor, seal assy	Packer, overshot		Anchor, seal assy	Anchor, seal assy	Anchor, seal assy	N/A	Anchor, seal assy	On/Off	Anchor, seal assy	
Top of lower completion	Packer liner hanger, drop-off liner, centralizers, ID considerations, PBR, On/Off connector	Liner hanger, PBR	Drop off liner, external PBR (depending on MA08, 06 experience)		Liner hanger, PBR	Liner hanger, PBR	Liner hanger, PBR	N/A	Liner hanger, PBR	On/Off - rely on seals on connector for isolation. Cement through entire string, disconnect and circulate, latch and land	Liner hanger, PBR	Control line ports
Accessory	Nipple - possible need to isolate reservoir while running and testing upper completion; use in setting gauges	Not recommended (unable to access via slickline if at high deviation)	Not recommended (unable to access via slickline if at high deviation)									Control line ports?
Reservoir completion	Reservoir isolation - cement, swell packers, external casing packers, nothing... How will the reservoir be accessed?	Cemented liner; perforate	Cemented liner; perforate	Cemented liner, perforate	Cemented liner, swell packers, perforate	Slotted liner w/ external swell packers	Sliding sleeves, swell packers	Cemented liner; perforate	Uncemented liner w/ external swell packers, perforate	Cemented liner; perforate	Cemented sliding sleeves; require pressure application to break down cement	ECPs, control lines to sleeves
Shoe	See Lower Completion sheet for shoe details											
Experience, Reliability	Have we done it before? Have we been successful? Why should we/should we not? Is this really the best choice for the life of the well?				Swell packers may impede success running lower completion	Swell packers may impede success running lower completion	Swell packers may impede success running lower completion		Swell packers may impede success running lower completion	Best in low deviation. Cannot rotate during cementing.		Would be a first for the field
Production implications	Inflow area, produced fluids					Drilling fluid handling during kickoff and production - wash string will never clean all drilling fluid	Drilling fluid handling during kickoff and production		Drilling fluid handling during kickoff and production			Control production with no intervention
Reservoir management	Gauges, ability to shut off/open up flow paths					Difficult to isolate lower zones	Difficult to isolate lower zones		Difficult to isolate lower zones			Control production, monitor reservoir conditions with no intervention
Abandonment implications	Cement top in liner, production casing, relative to cap rock; condition of annuli, Moki etc					No cement in lower completion - more expensive and difficult abandonment	No cement in lower completion - more expensive and difficult abandonment		No cement in lower completion - more expensive and difficult abandonment			Accessories left in hole. Need to address non-cemented intervals.

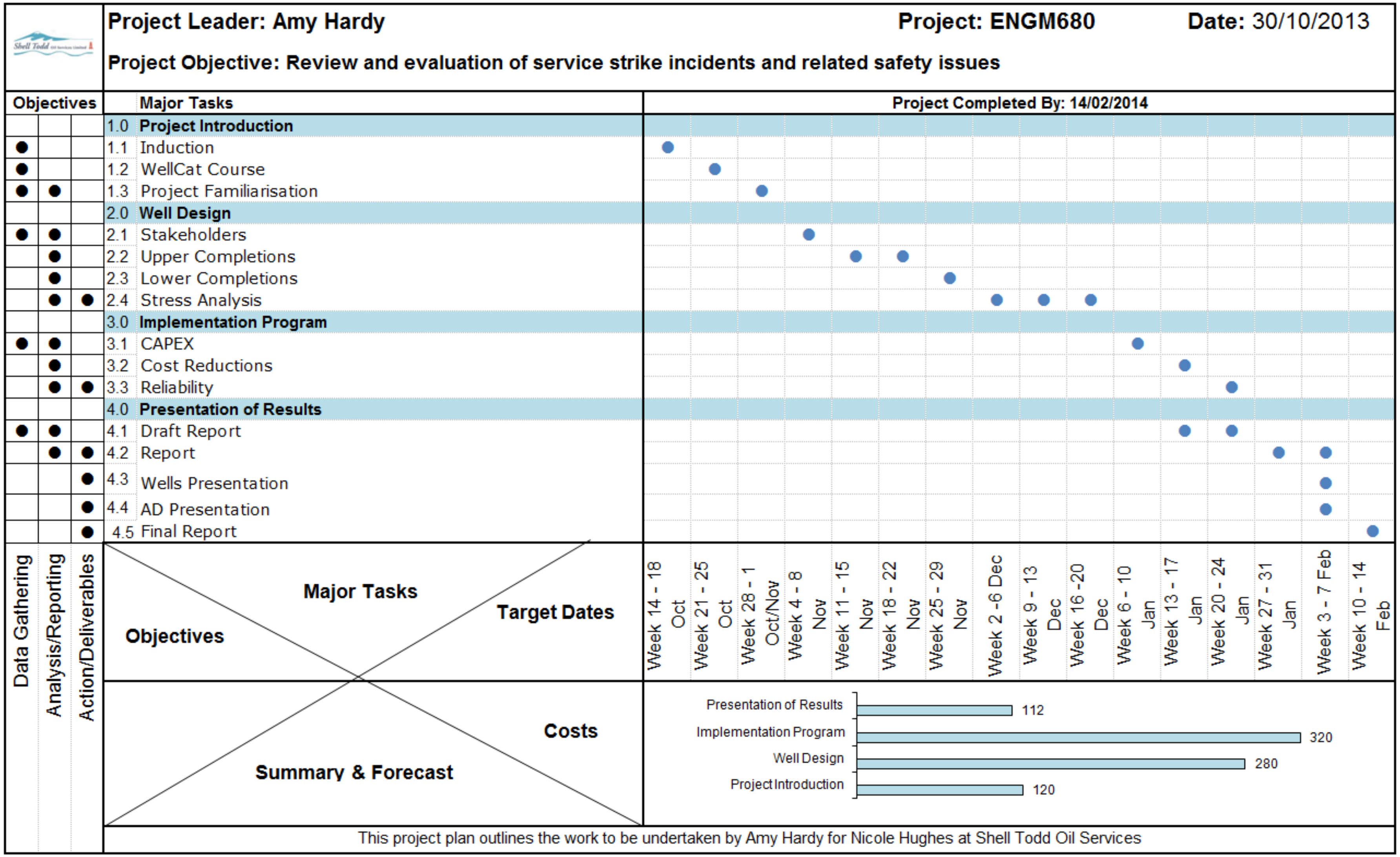


Figure 5 - Project plan (Hardy, 2013)

Appendix II – Design

Table 10 - Thermal Operations considered during Stress Analysis (Klever 2013)

CTDM Section	Thermal Operation
11.3.1	Initial Conditions
11.3.2	Early-Life Production
11.3.3	Late-Life Production
11.3.4	Immediate Shut-in from Early-Life
11.3.5	Cold Injection

Table 11 - Load Cases on the Tubing considered during Stress Analysis (Klever, 2013)

CTDM Section	Load Cases for Tubing
11.4.1	Running the tubing
11.4.2	Initial conditions
11.4.3	Tubing overpull
11.4.4	Pressure test inside the tubing
11.4.5	Pressure test outside the tubing
11.4.6	Production
11.4.7	Early-life hot kill
11.4.8	Early-life ambient kill
11.4.9	Hot collapse-evacuation
11.4.10	Hot collapse tubing leak
11.4.11	Ambient collapse evacuation
11.4.12	Ambient collapse tubing leak
11.4.13	Cold frac injection
11.4.14	Ambient frac injection

Table 12 - Key Technical steps in Program Implementation

Programme Step	Technical Activity to Perform	Non-Technical Considerations
Handover from drilling to completions	• Check completion fluid and pressure test well • Pull the wear bushing and clean the BOP (Blow out preventer) • Pressure test the BOP	• Check CSV documents all criteria have been met (store in OpenWells) • Ensure open communication between the departments
Run completions	• Run upper completion • Land tubing hanger • Drift Completion String • Pressure test upper completion string & inflow test TRSCSSSV • Set anchor and pressure test A-annulus	• Hold meeting at rig site with ALL crews required to attend to ensure awareness of planned completion operations • Ensure all process safety checks are completed prior to beginning

Bring to producing state and handover to MPS	• Secure well and remove BOP
	• Install Christmas tree and pull tubing hanger plug
	• Perforate target zone
	• Complete well handover form
		• Ensure christmas tree installation and testing is carried out by Cameron personnel only
		• Check:
		  ○ Weather forecasts
		  ○ Quality of e-line
		• Give confirmation for Shlumberger Engineer to fire perforating guns
		• Ensure documents are scanned, recorded and saved in correct places in the system

Table 13 - Primary Well Barriers for MB-04C for handover from drilling to completions

Element	Qualification	Monitoring
4 ½" Liner Hanger	Pressure test to 3900psi prior to handover	Trip tank and pressure monitoring
4 ½" Liner	Pressure test to 3900psi prior to handover	Trip tank and pressure monitoring
4 ½" Liner Cement	Job Performance	Not available
Overbalanced fluid column	Fluid specific gravity (SG) control based on expected pore pressure	Trip tank level and fluid specific gravity monitoring

Table 14 - Primary Well Barriers for MB-04C running completions

Element	Qualification	Monitoring
Landing String	Tubing pressure test to 3900psi	A-annulus pressure
Tubing hanger	Hanger seal pressure test to 5000psi. A-annulus pressure test to 3900psi	A-annulus pressure
4 ½" tubing	Tubing pressure test to 3900psi	A-annulus pressure
4 ½" Liner Hanger	Pressure test to 3900psi prior to handover	Trip tank and pressure monitoring
4 ½" Liner	Pressure test to 3900psi prior to handover	Trip tank and pressure monitoring
4 ½" Liner Cement	Job Performance	Not available
Overbalanced fluid column	Fluid SG control based on expected pore pressure	Trip tank level and fluid specific gravity monitoring

Table 15 - Primary Well Barriers for MB-04C – Bringing well to producing state and handover to MPS

Element	Qualification	Monitoring
Surface Christmas Tree	Pressure test to 5000psi	Pressure monitoring WIT
Tubing hanger	Hanger seal pressure test to 5000psi. A-annulus pressure test to 3900psi	A-annulus pressure
4 ½" tubing	Tubing pressure test to 3900psi	A-annulus pressure
4 ½" Liner Hanger	Pressure test to 3900psi prior to handover	A-annulus pressure
4 ½" Liner (above perforations)	Pressure test to 3900psi prior to handover	Not available
4 ½" Liner Cement (above perforations)	Job Performance	Not available

Note: Light Blue colour indicates barriers present once handover has taken place

Table 16 - AS/NZS 4360 Risk Impact Table

Likelihood	**Consequences**				
	1. Insignificant	2. Minor (some disruption)	3. Moderate (significant time and resources)	4. Major (operations severely damaged)	5. Catastrophic (business survival risk)
5. Almost certain >90%	Medium	High	High	Very High	Very High
4. Likely 50%-90%	Medium	Medium	High	High	Very High
3. Moderate 5%-50%	Low	Medium	High	High	High
2. Unlikely 1%-5%lowlow	low	Low	Medium	Medium	High
1. Very unlikely <1%	low	Low	Medium	Medium	High

Appendix III – Technical

Table 17 - Connection Data Sheet for the 4 ½ tubing

Issued on: 18 Dec. 2013

VAM TOP

Connection Data Sheet

OD	Weight	Wall Th.	Grade	API Drift	Connection
4 1/2 in.	12.60 lb/ft	0.271 in.	L80 13Cr	3.833 in.	VAM® TOP Tubing

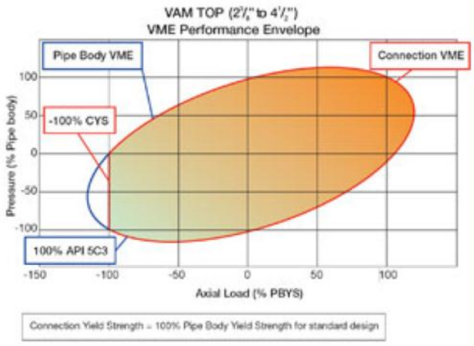
PIPE PROPERTIES	
Nominal OD	4.500 in.
Nominal ID	3.958 in.
Nominal Cross Section Area	3.600 sqin.
Grade Type	API 5CT
Min. Yield Strength	80 ksi
Max. Yield Strength	95 ksi
Min. Ultimate Tensile Strength	95 ksi

CONNECTION PROPERTIES	
Connection Type	Premium T&C
Connection OD (nom)	4.937 in.
Connection ID (nom)	3.913 in.
Make-up Loss	3.222 in.
Coupling Length	7.44 in.
Critical Cross Section	3.600 sqin.
Tension Efficiency	100 % of pipe
Compression Efficiency	100 % of pipe
Internal Pressure Efficiency	100 % of pipe
External Pressure Efficiency	100 % of pipe

CONNECTION PERFORMANCES	
Tensile Yield Strength	288 klb
Compression Resistance	288 klb
Internal Yield Pressure	8430 psi
External pressure resistance	7500 psi
Max. bending with sealability	30 °/100 ft
Max. Load on Coupling Face	162 klb

TORQUE VALUES	
Min. Make-up torque	4000 ft.lb
Opti. Make-up torque	4440 ft.lb
Max. Make-up torque	4880 ft.lb

VAM® TOP tubing (2 3/8"-4 ½") is the most used premium tubing connection throughout the world
The product line has been extensively tested as per ISO13679 CAL IV, with more than 60 qualification tests, on the full pipe body envelope.



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Vallourec Group

vallourec

Table 18 - Engineering Data Sheet for the Halliburton Liner Hanger

HALLIBURTON

April 16, 2012

Engineering Data Sheet

EQUIPMENT MATERIAL NO.: 102085335

BDY ASSY,LNR HGR,5 1/2,7 5/8,26.4

PART NUMBER: 59VF55762907

DESIGN SPECIFICATIONS

	English	Metric Conversion (For Reference)
LINER HANGER TYPE	STANDARD	
CASING SIZE	7 5/8	
CASING WEIGHT	26.4	
MATERIAL- EXPANDABLE BODY	SUPER 13% CHROME	
MINIMUM YIELD STRENGTH-EXPANDABLE BODY, CALC/1000	95	
MATERIAL- NON-EXPANDABLE COMPONENTS	SUPER 13% CHROME	
MINIMUM YIELD STRENGTH-NON-EXPANDABLE BODY, CALC/1000	110	
ELEMENT MATERIAL	FLUOROCARBON RUBBER	
TEMPERATURE RANGE POST EXPANSION REMARKS	40 TO 275	
TEMPERATURE RANGE DURING EXPANSION	40 TO 275	
SERVICE	STD	
BOTTOM THREAD	5 1/2-20.00 VAMTOP-HT	
CONNECTION TYPE	PIN	
BOTTOM THREAD MAKE-UP TORQUE (FT-LBS)	9850 (MINIMUM), 10850 (OPTIMUM), 11850 (MAXIMUM) FOR 5 1/2-20.00 VAMTOP-HT	
MAXIMUM OD	6.620 inch	168.148 MM
MAXIMUM OD REMARKS	TBR/BODY	
MAXIMUM OD (TIE-BACK RECEPTACLE)	6.620 inch	168.148 MM
SEAL BORE ID - MIN	5.750 inch	146.05 MM
SEAL BORE ID LENGTH - MAX	252.05 inch	640.207 CM
MAXIMUM OD (SETTING SLEEVE)	6.375 inch	161.925 MM
NOMINAL ANNULAR BYPASS AROUND LINER HANGER (SQ. INCHES)	3.83 (7 5/8 26.4)	
MINIMUM ID EXPANDED	4.715 inch	119.761 MM
NOMINAL LENGTH	401.52 inch	1019.861 CM
TIE-BACK BURST PRESSURE (CALC)	10800 PSI	74463 KPA
TIE-BACK BURST PRESSURE REMARKS	6.147 HST-DS THREAD	
TIE-BACK COLLAPSE PRESSURE (CALC)	6294 PSI	43396 KPA
TIE-BACK COLLAPSE PRESSURE REMARKS	BODY - 6.147 HST-DS THREAD	

Table 19 - Engineering Data Sheet for the Side Pocket Mandrel

ENGINEERING DETAILS

PART NUMBER 100329574
4-1/2 STANDARD KBG-2-1R SIDE POCKET MANDREL (13CR), (12.6 PPF VAM TOP), (1 THREAD RECUT)

TAB DATA	
Attribute	Value
ACTIVE FLOW WETTED MATERIAL - YIELD STRENGTH (KSI)	13CR [80]
APPROXIMATE WEIGHT (LBS)	480
CERTIFICATION STATUS	SLB STD
EXTERNAL WORKING PRESSURE (PSI) - EOEC AT SPECIFIED TEMP (F)	4361[70]
I.D. (IN)	3.865
I.D. - MIN. (IN)	3.860
INTERNAL WORKING PRESSURE (PSI) - EOEC AT SPECIFIED TEMP (F)	5158[70]
LOWER THREAD CONNECTING - SIZE (IN), WT (PPF), TYPE, CONFIG	4.500, 12.60, VAM TOP, PIN
MAKE-UP LENGTH (IN)	92
MATERIAL CLASS OF SERVICE	CO2 & COMPLIES TO NACE MR0175
MATERIAL/ELASTOMERS	N/A
MAX. WORKING TEMPERATURE (DEG.F)	300
MIN. WORKING TEMPERATURE (DEG.F)	40
O.D. (IN)	5.984
O.D. - MAX. (IN)	5.999
OVERALL LENGTH (IN)	95
QUALITY CONTROL PLAN - QCP	STD SLB
SERVICE NACE (YES/NO)	YES
SWAGE, LOWER - MAX. I.D. (IN)	3.870
SWAGE, LOWER - MIN. O.D. (IN)	4.965
SWAGE, UPPER - MAX. I.D. (IN)	3.870
SWAGE, UPPER - MIN. O.D. (IN)	4.965
TENSILE STRENGTH (EOEC AT AMBIENT)(LBS)	291000
TENSILE STRENGTH (LB)	288000
TENSILE STRENGTH (LBS) - EOEC AT SPECIFIED TEMP (F)	253170[300]
TEST PRESSURE (EXTERNAL) (PSI)	4,579
TEST PRESSURE (INTERNAL) (PSI)	5,444
THREAD NUMBER	YS
THREAD RECUTS	ONE
UPPER THREAD CONNECTING - SIZE (IN), WT (PPF), TYPE, CONFIG	4.500, 12.60, VAM TOP, BOX

Table 20 - Engineering Data Sheet for the Tubing Retrievable Surface Control Subsurface Safety Valve

HALLIBURTON

October 29, 2009

Engineering Data Sheet

EQUIPMENT MATERIAL NO.: 101839825

TRSV,NE,6.62 3.813,STD,5K

PART NUMBER: 781SXE38724-U

DESIGN SPECIFICATIONS

	English	Metric Conversion (For Reference)
VALVE MODEL	NE	
CLOSURE TYPE	FLAPPER	
SIZE	4 1/2	
LOCK PROFILE	X	
MINIMUM INSIDE DIAMETER WITHOUT PACKING BORE	3.845 inch	97.663 MM
TOP SEAL BORE ID-MINIMUM	3.813 inch	96.85 MM
BOTTOM SEAL BORE ID-MINIMUM	3.813 inch	96.85 MM
MAXIMUM OD	6.62 inch	168.148 MM
LENGTH	65.43 inch	166.192 CM
MATERIAL	13% CHROME/410 STAINLESS STEEL/17-4 PH STAINLESS STEEL	
SERVICE	STD	
TOP THREAD	4 1/2-12.60 VAMTOP	
BOTTOM THREAD	4 1/2-12.60 VAMTOP	
CONNECTION TYPE	BOX-PIN	
TUBING THREAD TORQUE	4440 foot pound	6019.83 N*M
PRESSURE RATING	5000 pounds/sq. inch	34474 KPA
BURST PRESSURE	11005 pounds/sq. inch	75877 KPA
API COLLAPSE PRESSURE AT AMBIENT	4861 pounds/sq. inch	33515 KPA
API COLLAPSE PRESSURE AT MAX TEMPERATURE RATING	4660 pounds/sq. inch	32130 KPA
EXTERNAL PRESSURE RATING	5000 pounds/sq. inch	34474 KPA
TENSILE WITH WORK PRESS, WITHOUT TBG THD, AT AMBIENT, CALC/1000	486 pound	220.45 KG
TENSILE WITHOUT WORK PRESS, WITHOUT TBG THD, AT AMBIENT, CALC/1000	620 pound	281.23 KG
TENSILE WITH WORK PRESS, WITHOUT TBG THD, AT MAX TEMPERATURE RATING, CALC/1000	418 pound	189.6 KG
TENSILE WITHOUT WORK PRESS, WITHOUT TBG THD, AT MAX TEMPERATURE RATING, CALC/1000	552 pound	250.38 KG
TEMPERATURE RATING	20 TO 300 Deg. F	-7 TO 149 Deg. C
MAXIMUM FULL OPEN PRESSURE	1650 pounds/sq. inch	11376 KPA
MINIMUM CLOSING PRESSURE	600 pounds/sq. inch	4137 KPA

Table 21 Engineering Data Sheet for the Anchor

HALLIBURTON

May 21, 2012

Engineering Data Sheet

EQUIPMENT MATERIAL NO.: 102072213

TBG AHR,7 5/8,26.4,5 1/2-17.00 VAMTOP

PART NUMBER: 812OO7289-F

DESIGN SPECIFICATIONS

	English	Metric Conversion (For Reference)
CASING SIZE	7 5/8	
WEIGHT RANGE	26.4 pound/foot	385 N/M
MAXIMUM OD	6.784 inch	172.314 MM
MINIMUM ID	4.105 inch	104.267 MM
LENGTH	119.76 inch	304.19 CM
MATERIAL	13% CHROME	
MATERIAL YIELD STRENGTH-MIN	80000 pounds/sq. inch	551581 KPA
O-RING MATERIAL	FLUOROCARBON RUBBER	
TOP THREAD	5 1/2-17.00 VAMTOP	
BOTTOM THREAD	5-15.00 VAMTOP	
CONNECTION TYPE	BOX-PIN	
TEMPERATURE RATING	40 TO 325 Deg. F	4 TO 163 Deg. C
SERVICE	STD/CO2	
SERVICE REMARKS	H2S AND/OR CO2 SERVICE BASED ON CUSTOMER DEFINED, WELL SPECIFIC CONDITIONS. APPLICATIONS MUST BE REVIEWED FOR SPECIFIC ENVIRONMENTAL COMPATIBILITY.	
BURST PRESSURE (CALC)	7740 pounds/sq. inch	53365 KPA
BURST PRESSURE (CALC) REMARKS	5 1/2-17.00 VAMTOP	
COLLAPSE PRESSURE (CALC)	6290 pounds/sq. inch	43368 KPA
COLLAPSE PRESSURE (CALC) REMARKS	5 1/2-17.00 VAMTOP	
TENSILE STRENGTH, CALC/1000	318.1 pound	144.29 KG
TYPE RELEASE	CUT TO RELEASE	
PISTON AREA	6.495 sq. inch	41.9 SQ CM
START SETTING PRESSURE	1340 pounds/sq. inch	9239 KPA
SETTING PRESSURE-MIN	2500 pounds/sq. inch	17237 KPA
SETTING PRESSURE-MAX	3000 pounds/sq. inch	20684 KPA
THREAD TORQUE (FT-LBS)	4560 (MINIMUM), 5060 (OPTIMUM), 5560 (MAXIMUM), FOR 5-15.00 VAMTOP 4880 (MINIMUM), 5420 (OPTIMUM), 5960(MAXIMUM), FOR 5 1/2-17.00 VAMTOP 1800 (MINIMUM), 2000 (OPTIMUM), 2200 (MAXIMUM), FOR 4 7/8-6	

Appendix IV – Results

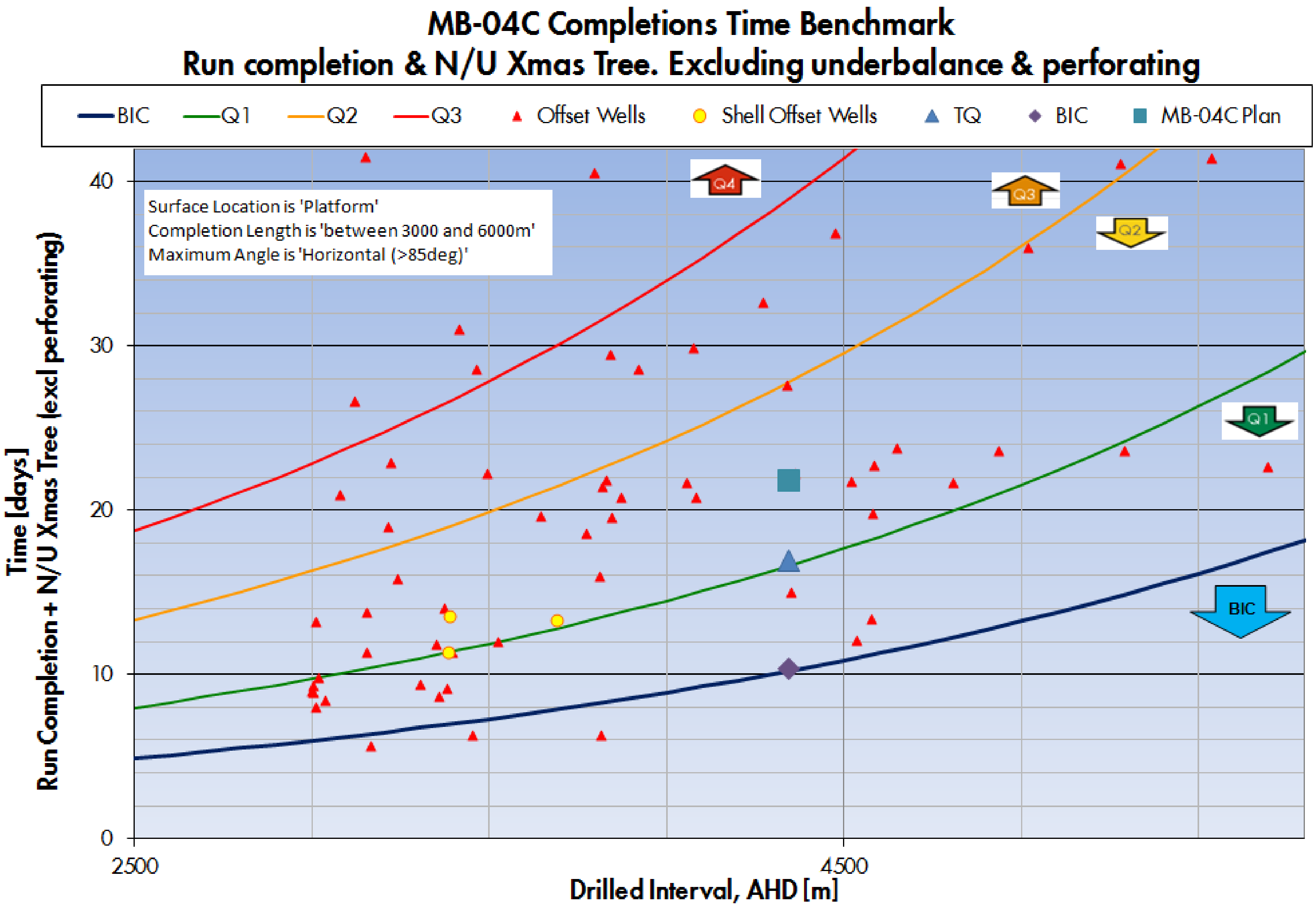

Figure 9 - Timeframe benchmarking

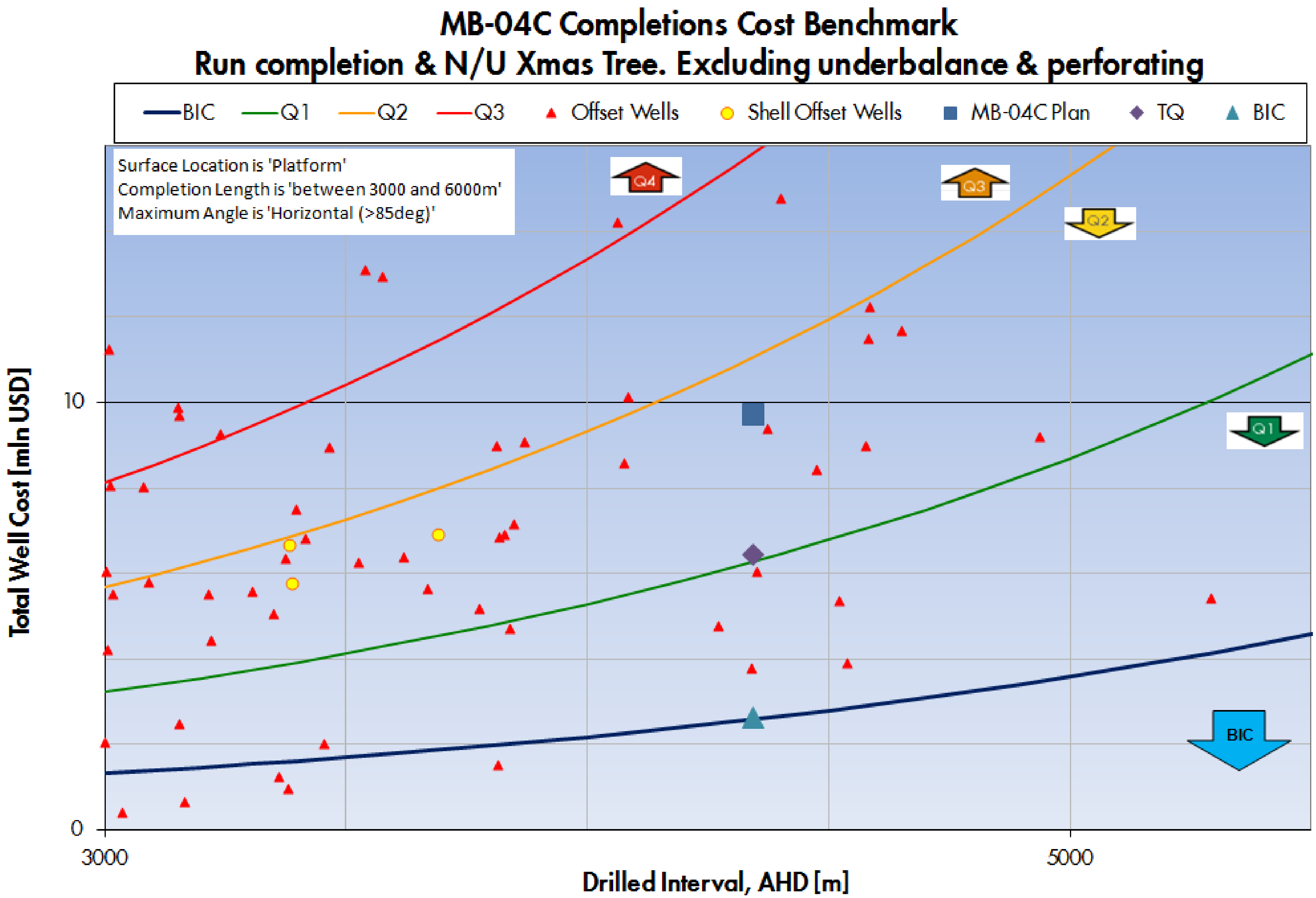

Figure 10 - Cost Benchmarking

Appendix V - Crestal Well

MB04 Sidetrack
Offshore Tubing Design

Author:
Amy Hardy
Completion and Well Intervention Engineering Graduate
With supervision from Nicole Hughes
December 2013

Contents

1.0 Introduction

1.1 Design Factors

Note that the Minimum Allowable Design Safety Factors (Table 22) used in this document are taken directly from the Shell Casing and Tubing Design Manual.

Table 22 - Minimum Design Safety Factors (DSFmin) for Use in the Design Check Equations

Minimum Allowable Design Safety Factors						
Description	**Label**	**Pipe Body**		**Connection**		
					Tested	**Legacy**
Running, tension						
	RT1	$^{p}DSF_{1t}$	1.40	$^{c}DSF_{1t}$	1.40	1.55
	RT2	$^{p}DSF_{1t}$	1.20	$^{c}DSF_{1t}$	1.20	1.35
Running, compression	RC	$^{p}DSF_{1c}$	1.10	$^{c}DSF_{1c}$	1.10	1.25
Collapse	C	$^{p}DSF_{2}$	1.00	$^{c}DSF_{2}$	1.00	1.15
Burst - Triaxial						
	B1	$^{p}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B2	$^{p}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B3	$^{p}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B4	$^{p}DSF_{3}$	1.20	$^{c}DSF_{3}$	1.20	1.35
	B5	$^{p}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B6	$^{p}DSF_{3}$	1.10	$^{c}DSF_{3}$	1.10	1.25

1.2 Trajectory

The well trajectory version that has been used for the tubing design for MB-04 C (sidetrack) well. This is subject to change, but this should not have significant impact on the resulting load cases. Figure 11 gives a graphical representation of the current well trajectory. This was taken from Compass file MB-04 Sidetrack (IRF Ph3).

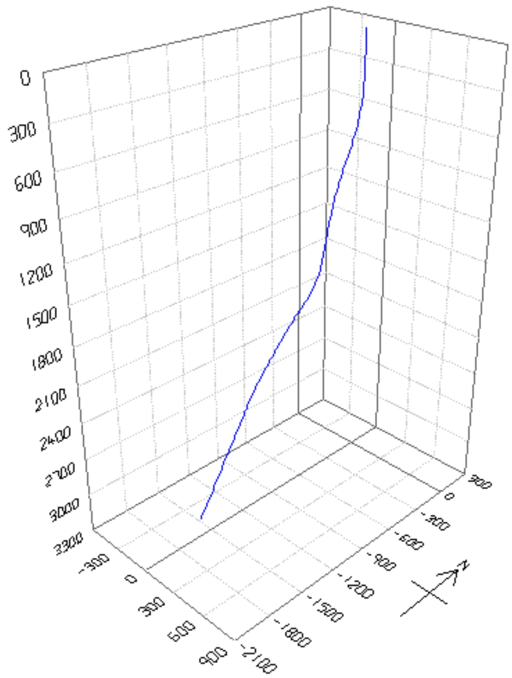

Figure 11 - Proposed Well Trajectory

1.3 Sand Composition

The rock composition for the proposed MB-04 Sidetrack well was modeled from the more generic Maui B Upper C-Sands compositions.

Table 23 - Composition of Maui B Upper C Sands

Component	Mol %	Mol wt	Liquid Density
	%		g/cm³
N2	2.024	28.014	
CO2	2.042	44.01	
C1	78.445	16.043	
C2	6.649	30.07	
C3	3.199	44.097	
iC4	0.804	58.124	
nC4	1.090	58.124	
iC5	0.518	72.151	
nC5	0.438	72.151	
C6	0.659	86.178	0.664
C7	0.921	92	0.7466
C8	1.022	102	0.7688
C9	0.612	114	0.7887
C10	0.408	129	0.7915
C11	0.249	144	0.7953
C12	0.189	156	0.808
C13	0.231	175	0.8217

C14	0.157	190	0.8345
C15	0.107	206	0.8463
C16	0.074	222	0.8574
C17-C18	0.086	242.693	0.8719
C19-C42	0.076	292.704	0.9063

2.0 Basis for Design

2.1 Reference Documents

For the Tubing design, the following documents were utilized for guidance and design specifications.

- Shell Casing and Tubing Design Manual Issued 1st June 2013
- WellCat Training Workbook Issued 2013 by Altus Well Experts

2.2 Design Software

Modeling has been completed using the Halliburton's WellCat Software (version 5000.1.10.0).

2.3 Well Trajectory

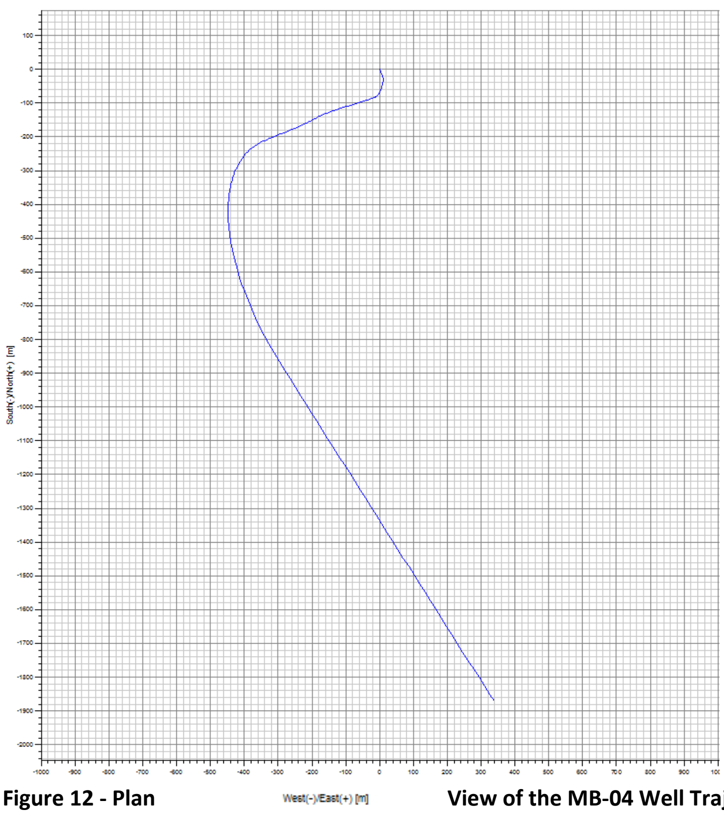

Figure 12 - Plan View of the MB-04 Well Trajectory

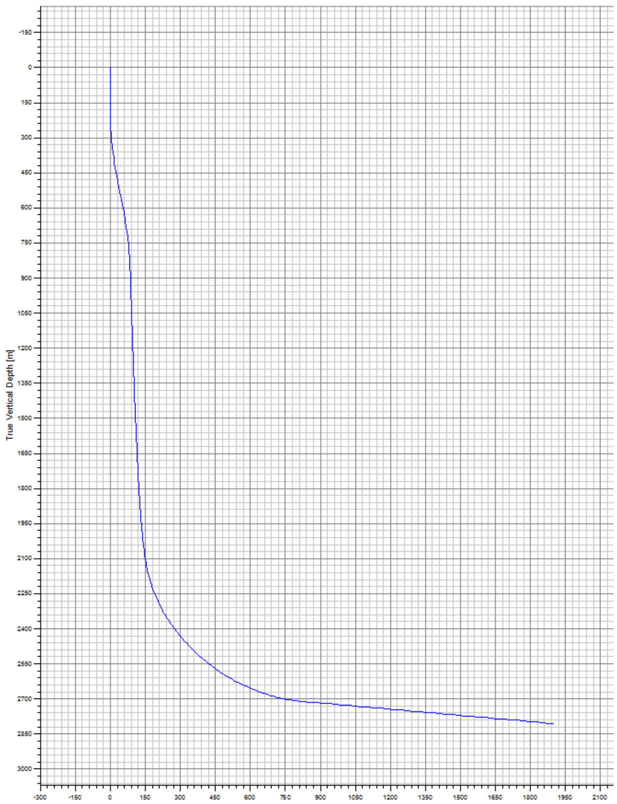

Figure 13 - Section View of the MB-04 Well Trajectory

2.4 Design Pressures

Table 24 - MB-04C Well Life Parameters

Condition	Units	Start of Life	Normal Op.	End of Life
CITHP	bar	170	160	140
CITHT	ºC	15 to 17	15 to 17	15 to 17
FTHP	bar	150	110	90
FTHT	ºC	60 to 65	60 to 65	60 to 65
WGR	m^3 water/ mln m^3 gas	8	8	2500
IRF Well Gas Flow	STDm3/s	7	5	2

3.0 Casing & Tubing Design Load Cases

The Shell Casing and Tubing Design Manual – released June 1st 2013 – was followed throughout the design as the design as the minimum standard. A summary of these values can be seen in

.

3.1 4-1/2" Production Liner

The 4 ½" cemented production liner will be set in the Maui B C sands. The casing and tubing design it has been verified whether the casing can withstand all the load cases as per the latest revision of the casing and tubing design manual, based on the normal pipe body properties of the 4 ½" slotted liner.

This production liner has a Shell qualified connection.

3.2 4-1/2" Production Tubing

3.2.1 Design Objective

The 4 ½" production tubing, together with the 4 ½" production liner and including the completion components for the completion conduit through which the hydrocarbons are brought to the surface.

The tubing design (Completed using WellCat) has verified that this tubing can withstand all the load cases in compliance with the Shell Wells Standards.

The tubing used has a Shell qualified connection.

3.2.2 Operations and Loads

Table 25 shows the thermal operations modeled in WellCat for the MB-04C Well. Table 26 shows the load cases applied on the tubing in WellCat, and what parameters were used.

Table 25 - Thermal Operations for Producing Wells

Operation	Pressure (bar)	Position	Comment
Early-life Production	150	Wellhead	
Late-life Production	90	Wellhead	
Early-life Hot Shut In	170	Wellhead	

Table 26 - Load Cases for Tubing

Operation	Summary
Tubing Overpull	Run with seawater with force of 100,000 lbf
Pressure Test Inside	Pump pressure in tubing of 20,000kPa, anchor at 3048mMD
Pressure Test Outside	Pump pressure in tubing 0kPa, in annulus 20,000kPa
Early Life Production	Steady state 150barTHP, 65°C, 5 STDm^3/s, 0bbl/min water
Late Life Production	Steady state 90barTHP, 65°C, 2 STDm^3/s gas, 2bbl/min water
Early Life Shut In	Shut in at 170bar, 1min
Early Life Hot Kill	2387psiTHP, 1 min
Early Life Ambient Kill	2387psiTHP, 20 yr
Hot Collapse-Evacuation	Tubing evacuation at "Early Life Production" conditions
Hot Collapse Tubing Leak	"Early Life Production" tubing conditions, annulus pressure 2387psi

	(SIWHP + 500psi)
Ambient Collapse Evacuation	Tubing evacuation at "Early Life Ambient Shut In," pressure in tubing 2387psi, 20yrs
Ambient Collapse Tubing Leak	"Early Life Shut In" tubing condition, annulus pressure 2387psi
Cold Frac Injection	Undisturbed prior, 100bar, 17°C, 1200m^3/day, 1 min
Ambient Frac Injection	Undisturbed prior, 100bar, 17°C, 1200m^3/day, 6 mths
Side Pocket Mandrill Kick-off	SPMD set at 1680m, "Early Life Production" tubing conditions
Hot Shut in at DHSV	DHSV set at 350m, "Early Life Production" tubing conditions

*Assume annulus pressure is 0psi unless otherwise stated
**Initial Conditions set to default

3.2.2 Properties

Production tubing properties can be found in Table 27. The corresponding Connection Data Sheet can be found in Appendices A, page 10.

Table 27 - Properties of the 4 1/2" Production Tubing

Size	Interval	Weight	Grade	Connection	Collapse Strength	Burst Strength	Tension Strength	Compr. Strength
Inches	mAHRD	Lbs/ft			Bar	Bar	MT	MT
4 1/2		20.6	L80 13Cr	VAM TOP Tubing	217	581	130	-130

3.2.3 Minimum Safety Factors

Table 28 shows the minimum Safety Factors (SF) per failure mechanism. These have been listed for the CTDM load cases. At this stage **only the pipe** is considered, not the connections. Table 29 shows the minimum SF's for additional load cases where the SF is lower than the CTDM load cases.

Table 28 - Minimum Safety Factors for 4 1/2" Tubing

Minimum Safety Factor	Load Case	Safety Factor	Depth (mTVD)
Triaxial	Tubing Overpull	D1.419	797.40
Axial	Tubing Overpull	1.442	702.20
Collapse	Ambient Collapse – Tubing leak	1.769	9967.12
Burst	Pressure Test Inside Tubing	2.711	9500
Compression	See Axial (Axial governed by compr.)		

Table 29 - Minimum Safety Factors where the Safety Factor is lower than the CTDM load cases

Minimum Safety Factor	Load Case	Safety Factor	Depth (mTVD)
Triaxial	n/a		
Axial	n/a		
Collapse	n/a		
Burst	n/a		

3.2.4 Non-Compliance with Standards

For the 4 ½" Tubing, there are no CTDM or UIA/UIZ/BSP wells standard non-compliant load cases. I.e. Cases where the Safety Factor is below the Shell Design Factor. Therefore, there are no deviations in this instance.

3.2.5 Graphical Representation

3.2.5.1 Design Limits Plot

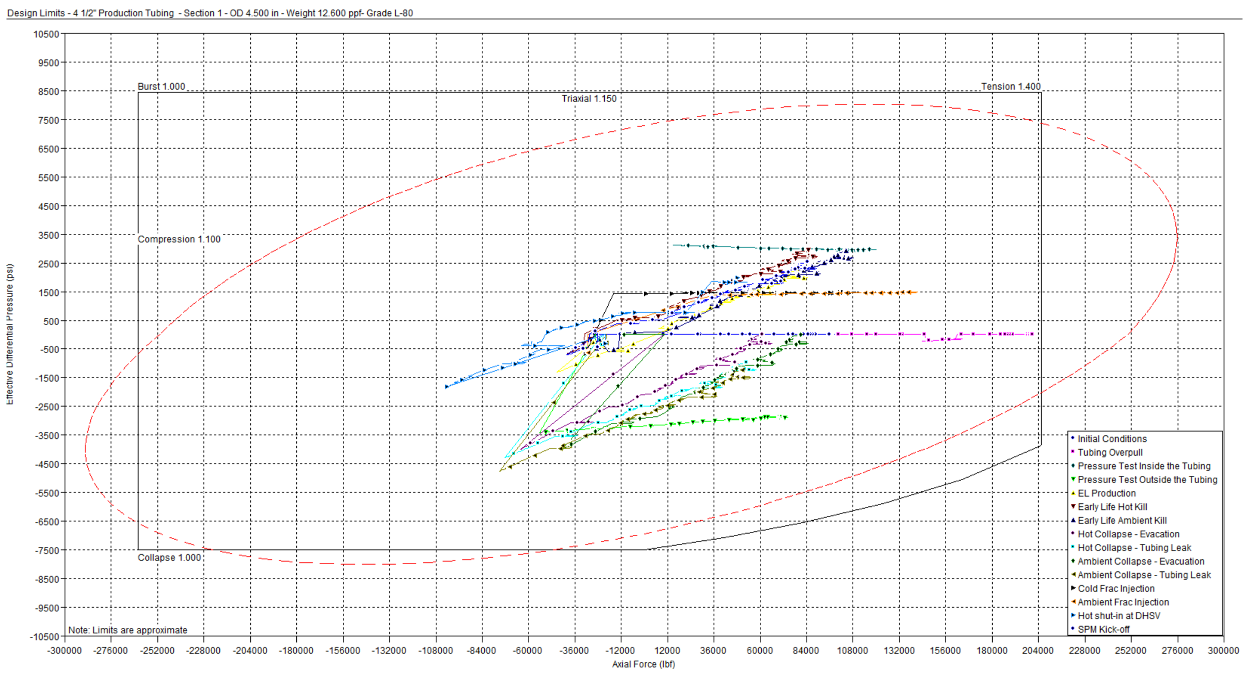

Figure 14 - Design Limits Plot for CTDM load cases

3.2.5.2 CTDM Safety Factor Plots

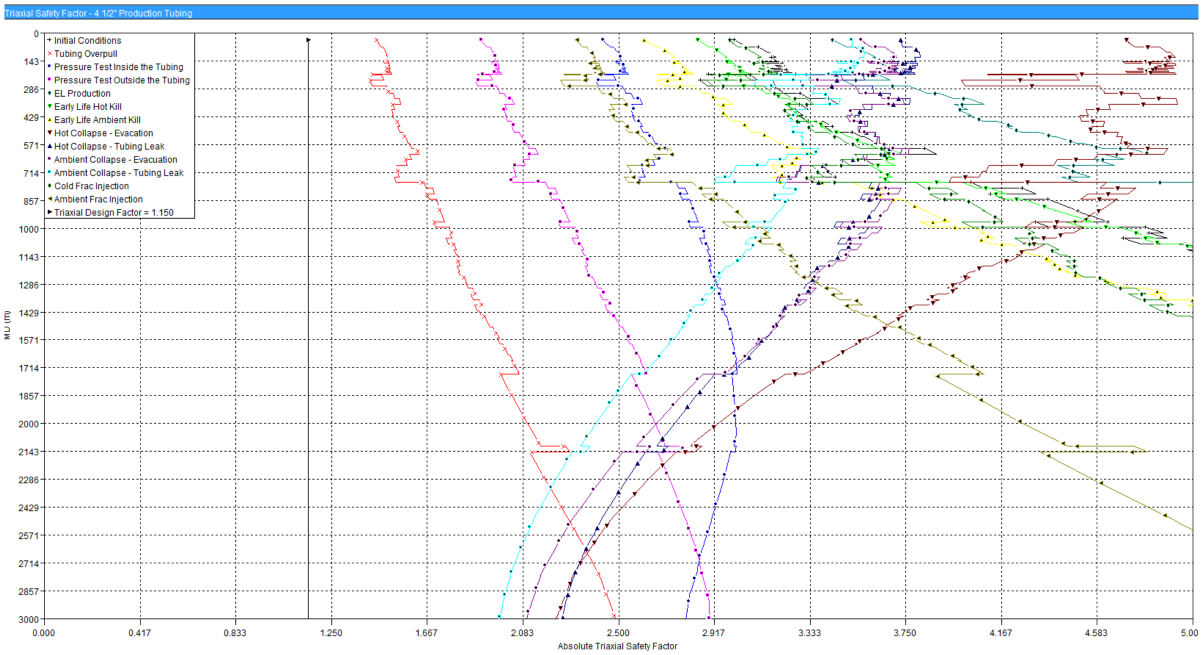

Figure 15 - Triaxial Safety Factor Plot for CTDM load cases

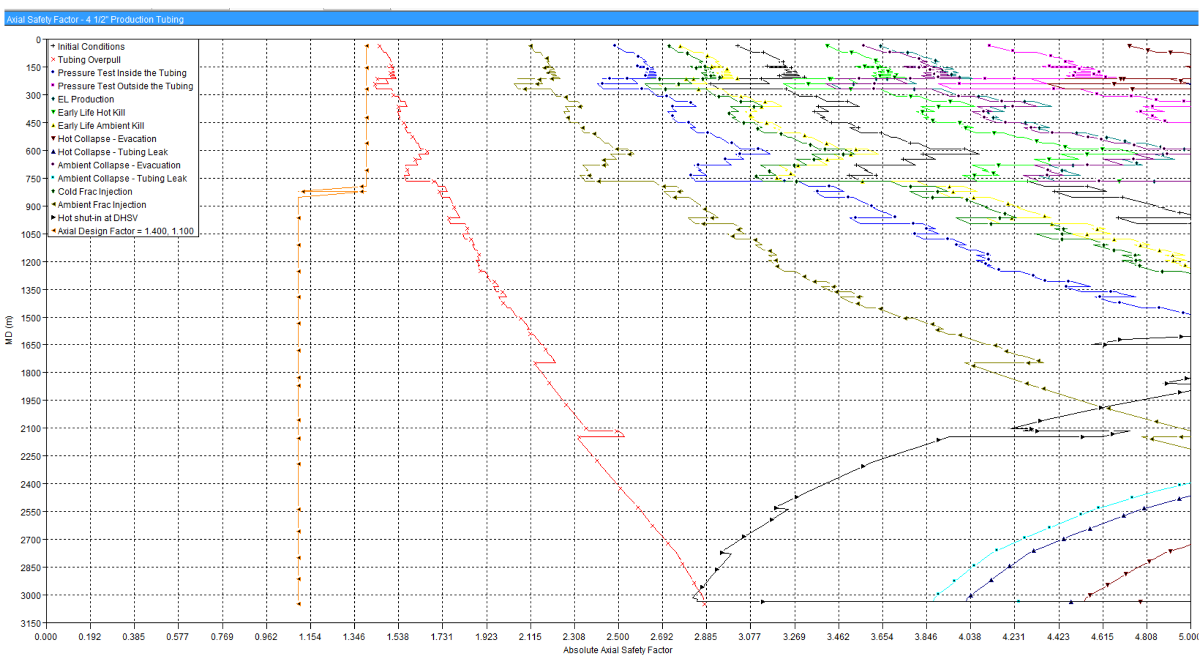

Figure 16 - Axial Safety Factor Plot for CTDM load cases

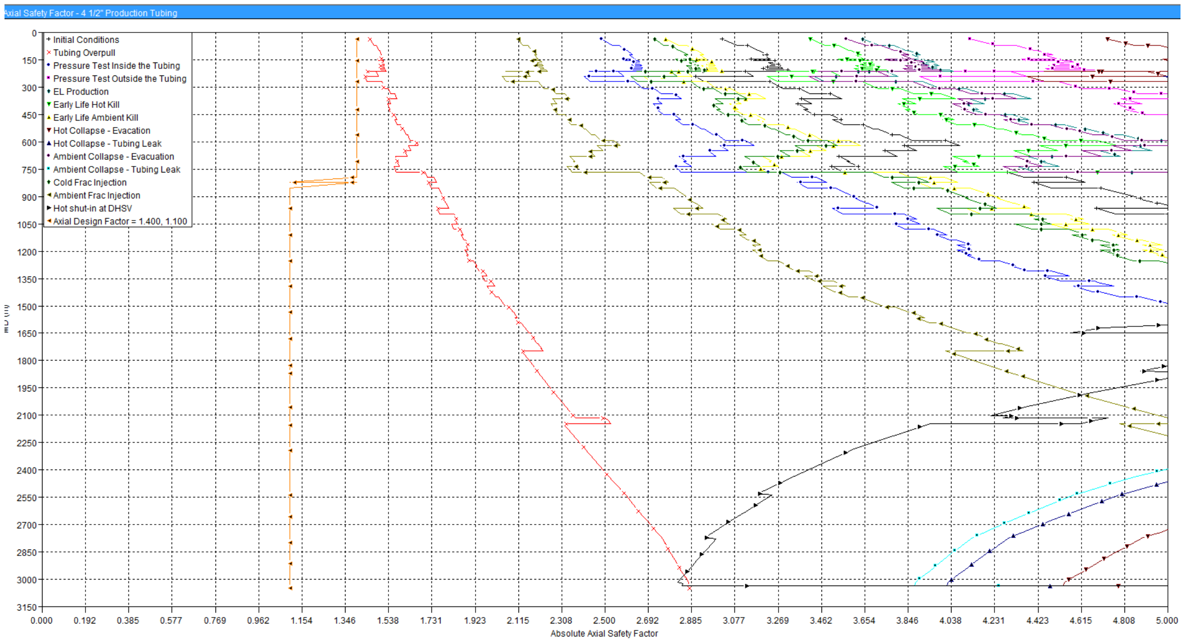

Figure 17 - Collapse Safety Factor for CTDM load cases

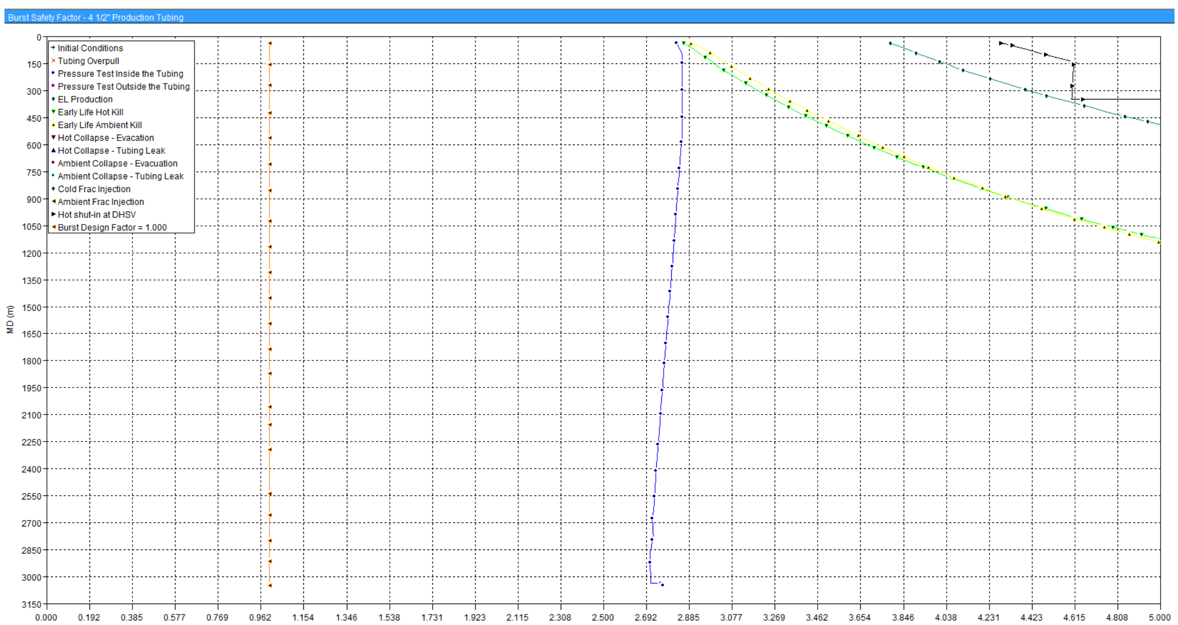

Figure 18 - Burst Safety Factor for CTDM load cases

Appendix VI - Down Dip Well

MB09 Sidetrack
Offshore Tubing Design

Author:
Amy Hardy
Completion and Well Intervention Engineering Graduate
With supervision from Nicole Hughes
December 2013

Contents

1.0 Introduction

1.1 Design Factors

Note that the Minimum Allowable Design Safety Factors (Table 22) used in this document are taken directly from the Shell Casing and Tubing Design Manual.

Table 30 - Minimum Design Safety Factors (DSFmin) for Use in the Design Check Equations

Minimum Allowable Design Safety Factors						
Description	**Label**	**Pipe Body**		**Connection**		
					Tested	**Legacy**
Running, tension						
	RT1	$^{p}DSF_{1\,t}$	1.40	$^{c}DSF_{1\,t}$	1.40	1.55
	RT2	$^{p}DSF_{1\,t}$	1.20	$^{c}DSF_{1\,t}$	1.20	1.35
Running, compression	RC	$^{p}DSF_{1\,c}$	1.10	$^{c}DSF_{1\,c}$	1.10	1.25
Collapse	C	$^{p}DSF_{2}$	1.00	$^{c}DSF_{2}$	1.00	1.15
Burst - Triaxial						
	B1	$^{p}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B2	$^{p}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B3	$^{p}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B4	$^{p}DSF_{3}$	1.20	$^{c}DSF_{3}$	1.20	1.35
	B5	$^{p}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B6	$^{p}DSF_{3}$	1.10	$^{c}DSF_{3}$	1.10	1.25

1.2 Trajectory

The well trajectory version that has been used for the tubing design for MB-09 A (sidetrack) well. This is subject to change, but this should not have significant impact on the resulting load cases. Figure 11 gives a graphical representation of the current well trajectory. This was taken from Compass file MB-09 Sidetrack (IRF Ph3).

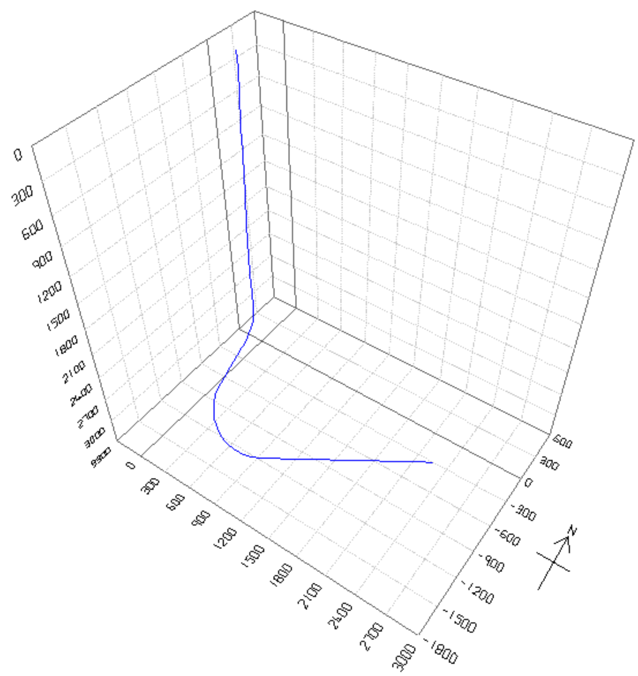

Figure 19 - Proposed Well Trajectory for MB-09A

1.3 Sand Composition

The rock composition for the proposed MB-09 Sidetrack well was modeled from the more generic Maui B Upper C-Sands compositions.

Table 31 - Maui B Upper C-Sands compositions.

Component	Mol	Mol wt	Liquid Density
	%		g/cm^3
N2	2.024	28.014	
CO2	2.042	44.01	
C1	78.445	16.043	
C2	6.649	30.07	
C3	3.199	44.097	
iC4	0.804	58.124	
nC4	1.090	58.124	
iC5	0.518	72.151	
nC5	0.438	72.151	
C6	0.659	86.178	0.664
C7	0.921	92	0.7466
C8	1.022	102	0.7688
C9	0.612	114	0.7887
C10	0.408	129	0.7915
C11	0.249	144	0.7953
C12	0.189	156	0.808
C13	0.231	175	0.8217
C14	0.157	190	0.8345
C15	0.107	206	0.8463

C16	0.074	222	0.8574
C17-C18	0.086	242.693	0.8719
C19-C42	0.076	292.704	0.9063

2.0 Basis for Design

2.1 Reference Documents

For the Tubing design, the following documents were utilized for guidance and design specifications.

- Shell Casing and Tubing Design Manual Issued 1st June 2013
- WellCat Training Workbook Issued 2013 by Altus Well Experts

2.2 Design Software

Modeling has been completed using the Halliburton's WellCat Software (version 5000.1.10.0).

2.3 Well Trajectory

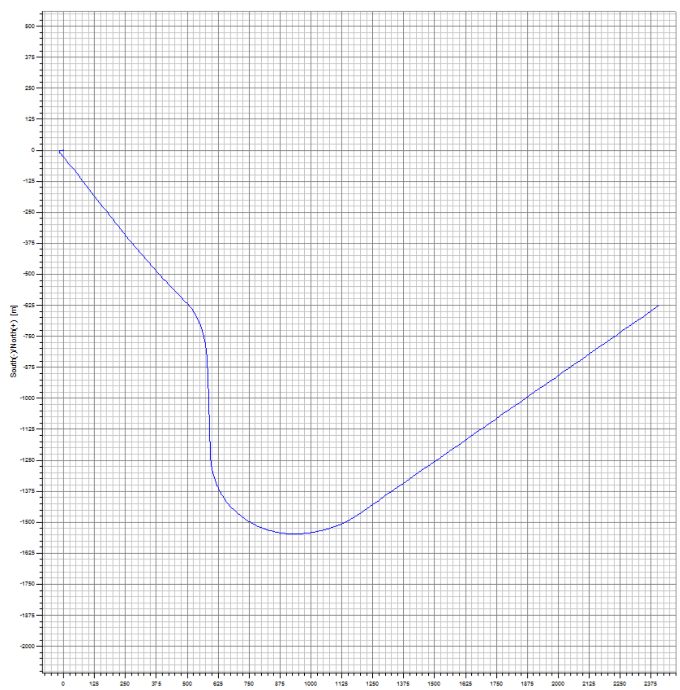

Figure 20 - Plan View of the MB-09A Well Trajectory

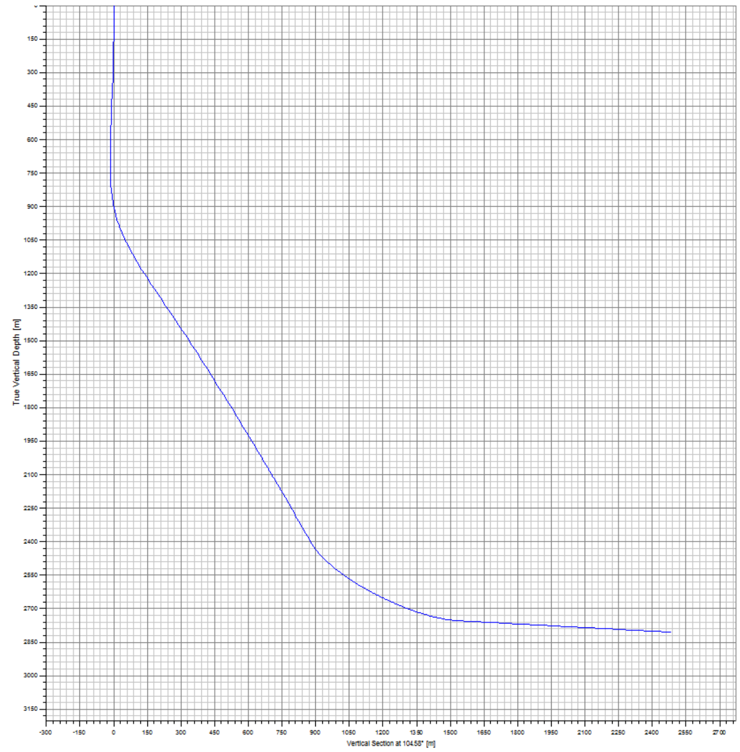

Figure 21 - Section View of the MB-04 Well Trajectory

2.4 Design Pressures

The maximum anticipated wellhead pressure is based on an expected reservoir pressure of

Table 32 - MB-09A Well Life Parameters

Condition	Units	Start of Life	Normal Op.	End of Life
CITHP	bar	170	160	140
CITHT	ºC	15 to 17	15 to 17	15 to 17
FTHP	bar	150	110	90
FTHT	ºC	60 to 65	60 to 65	60 to 65
WGR	m^3 water/ mln m^3 gas	8	8	2500
IRF Well Gas Flow	STDm3/s	7	5	2

3.0 Casing & Tubing Design Load Cases

The Shell Casing and Tubing Design Manual – released June 1st 2013 – was followed throughout the design as the design as the minimum standard. A summary of these values can be seen in

.

3.1 4-1/2" Production Liner

The 4 ½" cemented production liner will be set in the Maui B C sands. The casing and tubing design it has been verified whether the casing can withstand all the load cases as per the latest revision of the casing and tubing design manual, based on the normal pipe body properties of the 4 ½" slotted liner.

This production liner has a Shell qualified connection.

3.2 4-1/2" Production Tubing

3.2.1 Design Objective

The 4 ½" production tubing, together with the 4 ½" production liner and including the completion components for the completion conduit through which the hydrocarbons are brought to the surface.

The tubing design (Completed using WellCat) has verified that this tubing can withstand all the load cases in compliance with the Shell Wells Standards.

The tubing used has a Shell qualified connection.

3.2.2 Operations and Loads

Table 25 shows the thermal operations modeled in WellCat for the MB-09A Well. Table 26 shows the load cases applied on the tubing in WellCat, and what parameters were used.

Table 33 - Thermal Operations for Producing Wells

Operation	Pressure (bar)	Position	Comment
Early-life Production	150	Wellhead	
Late-life Production	90	Wellhead	
Early-life Hot Shut In	170	Wellhead	

Table 34 - Load Cases for Tubing

Operation	Summary
Tubing Overpull	Run with seawater with force of 100,000 lbf
Pressure Test Inside	Pump pressure in tubing of 20,000kPa, anchor at 3048mMD
Pressure Test Outside	Pump pressure in tubing 0kPa, in annulus 20,000kPa
Early Life Production	Steady state 150barTHP, 65°C, 5 STDm^3/s, 0bbl/min water
Late Life Production	Steady state 90barTHP, 65°C, 2 STDm^3/s gas, 2bbl/min water
Early Life Shut In	Shut in at 170bar, 1min
Early Life Hot Kill	2883psiTHP, 1 min
Early Life Ambient Kill	2883psiTHP, 20 yr
Hot Collapse-Evacuation	Tubing evacuation at "Early Life Production" conditions
Hot Collapse Tubing Leak	"Early Life Production" tubing conditions, annulus pressure 2883psi

	(SIWHP + 500psi)
Ambient Collapse Evacuation	Tubing evacuation at "Early Life Ambient Shut In," pressure in tubing 170psi, 20yrs
Ambient Collapse Tubing Leak	"Early Life Shut In" tubing condition, annulus pressure 2883psi
Cold Frac Injection	Undisturbed prior, 100bar, 17°C, 1200m^3/day, 1 min
Ambient Frac Injection	Undisturbed prior, 100bar, 17°C, 1200m^3/day, 6 mths
Side Pocket Mandrill Kick-off	SPMD set at 2130m, "Early Life Production" tubing conditions
Hot Shut in at DHSV	DHSV set at 350m, "Early Life Production" tubing conditions

*Assume annulus pressure is 0psi unless otherwise stated

**Initial Conditions set to default

3.2.2 Properties

Production tubing properties can be found in Table 27. The corresponding Connection Data Sheet can be found in Appendices A, page 12.

Table 35 - Properties of the 4 1/2" Production Tubing

Size	Interval	Weight	Grade	Connection	Collapse Strength	Burst Strength	Tension Strength	Compr. Strength
Inches	mAHRD	Lbs/ft			Bar	Bar	MT	MT
4 1/2		20.6	L80 13Cr	VAM TOP Tubing	217	581	130	-130

3.2.3 Minimum Safety Factors

Table 28 shows the minimum Safety Factors (SF) per failure mechanism. These have been listed for the CTDM load cases. At this stage **only the pipe** is considered, not the connections. Table 29 shows the minimum SF's for additional load cases where the SF is lower than the CTDM load cases.

Table 36 - Minimum Safety Factors for 4 1/2" Tubing

Minimum Safety Factor	Load Case	Safety Factor	Depth (mTVD)
Triaxial	Tubing Overpull	1.322	704.60
Axial	Tubing Overpull	1.329	704.60
Collapse	Hot Collapse – Tubing leak	1.751	12303-12330
Burst	Early Life Ambient Kill	2.834	122.60
Compression	See Axial (Axial governed by Compression)		

Table 37 - Minimum Safety Factors where the Safety Factor is lower than the CTDM load cases

Minimum Safety Factor	Load Case	Safety Factor	Depth (mTVD)
Triaxial	n/a		
Axial	Tubing Overpull	1.329	704.60
Collapse	n/a		
Burst	n/a		

3.2.4 Non-Compliance with Standards

For the 4 ½" Tubing, there is one CTDM or UIA/UIZ/BSP wells standard non-compliant load cases. I.e. Case where the Safety Factor is below the Shell Design Factor.

This will need to be investigated in more detail.

3.2.5 Graphical Representation

3.2.5.1 Design Limits Plot

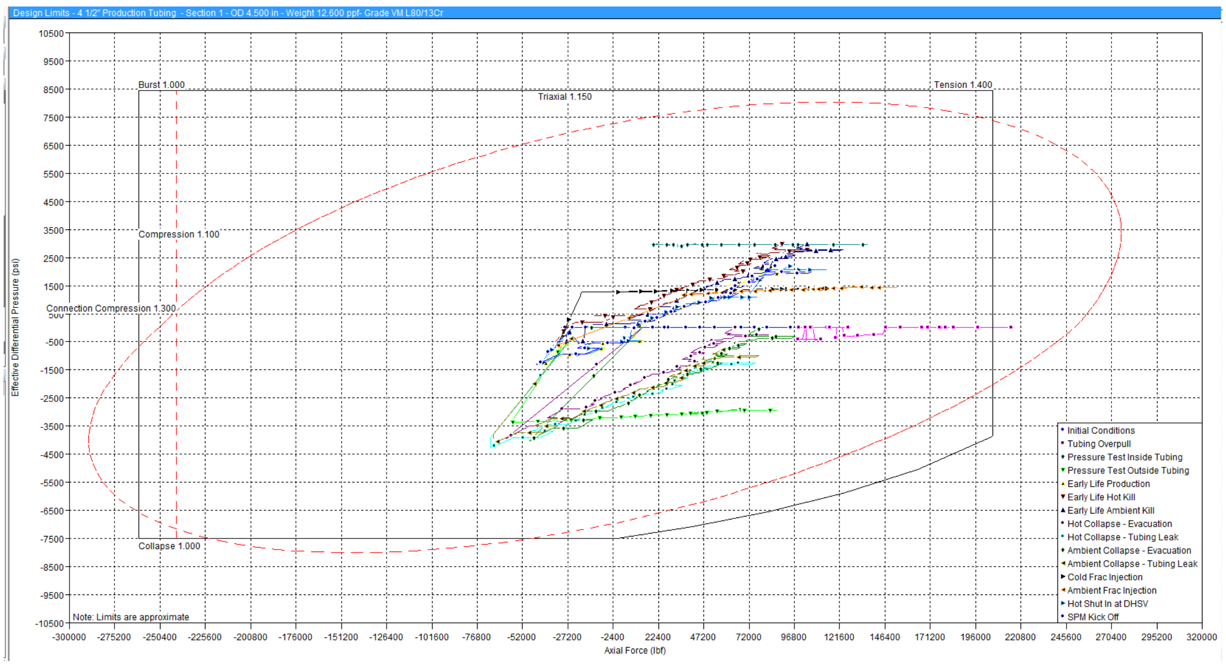

Figure 22 - Design Limits Plot for CTDM load cases

The tubing fails at an overpull of 100kips, as shown in

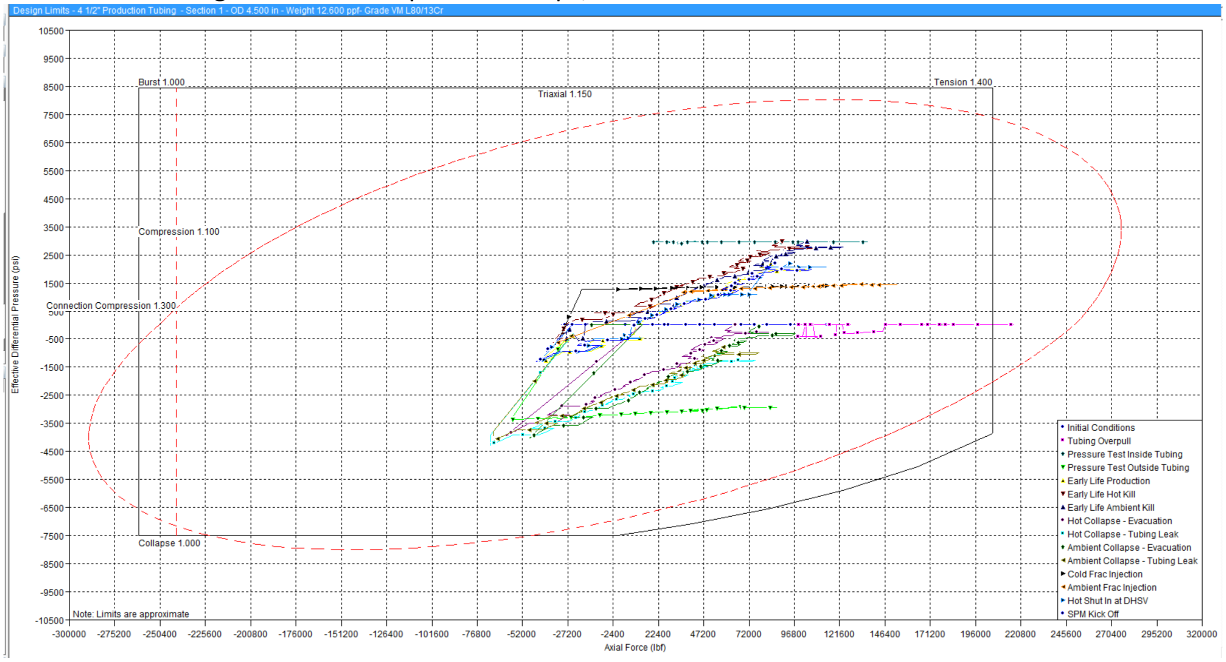

Figure 22.

3.2.5.2 CTDM Safety Factor Plots

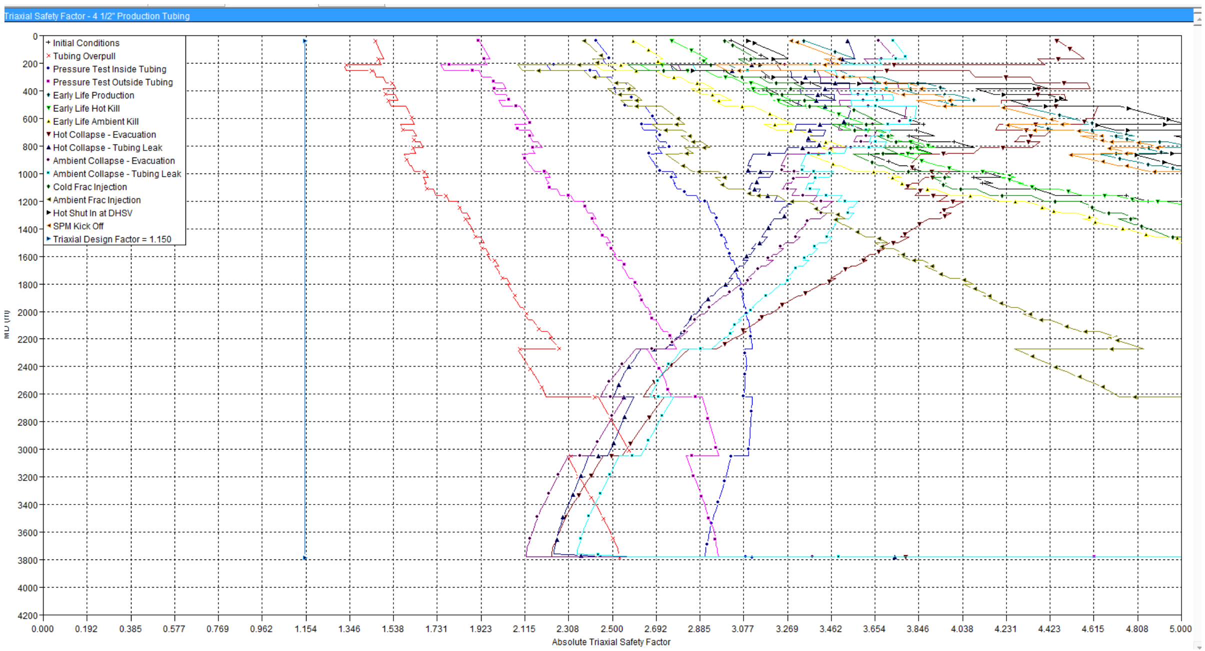

Figure 23 - Triaxial Safety Factor Plot for CTDM load cases

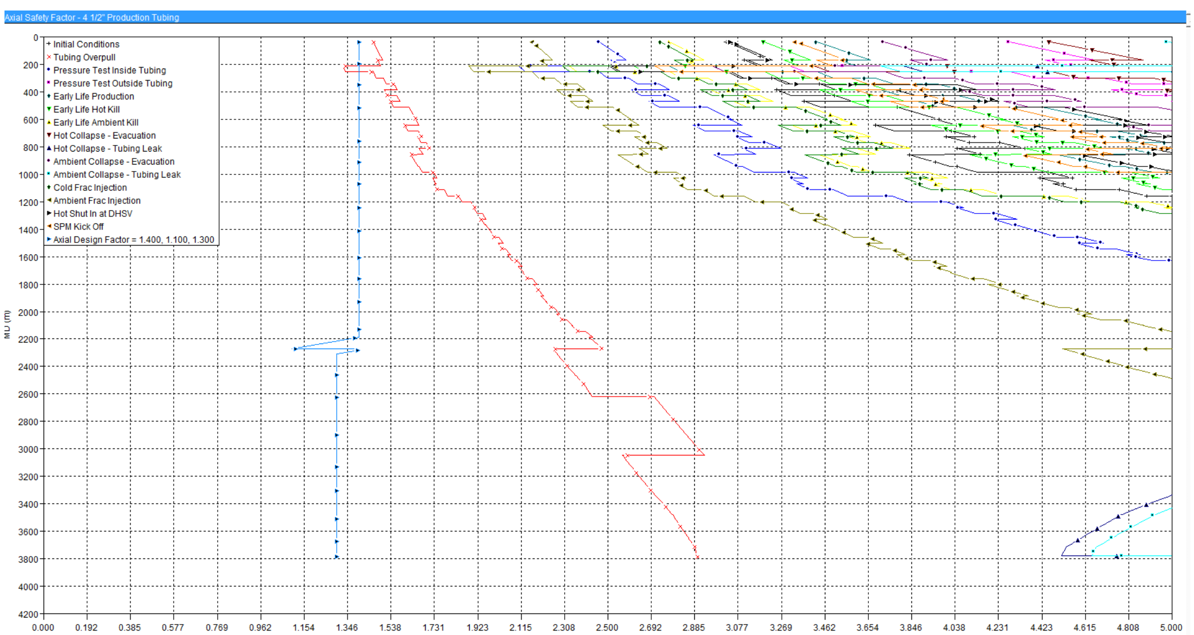

Figure 24 - Axial Safety Factor Plot for CTDM load cases

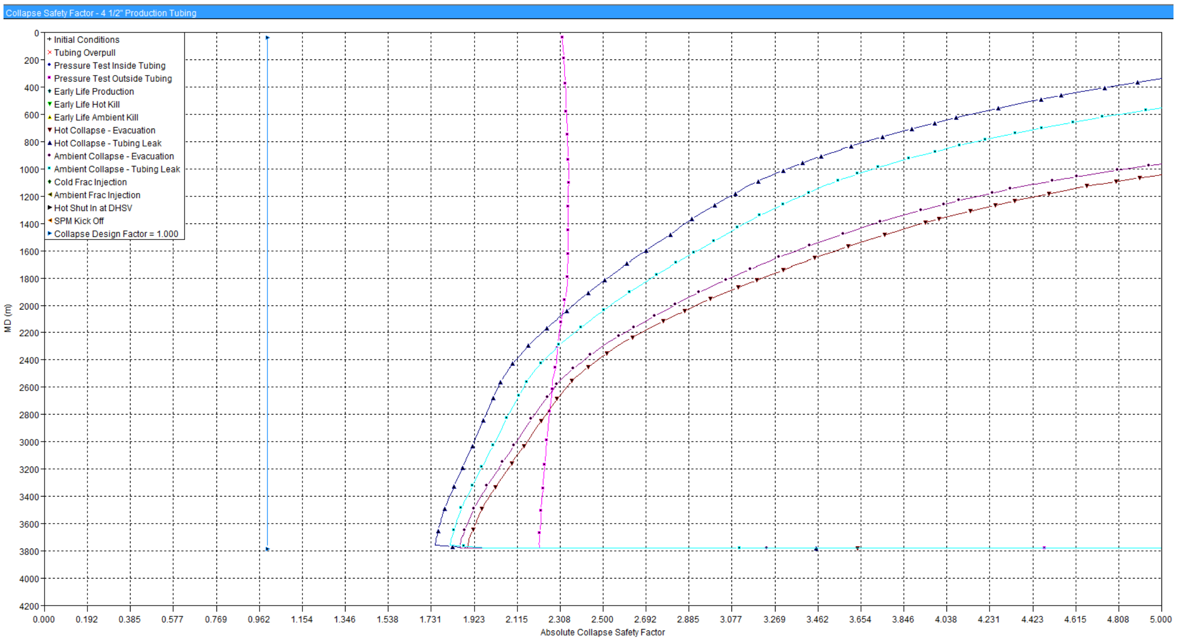

Figure 25 - Collapse Safety Factor for CTDM load cases

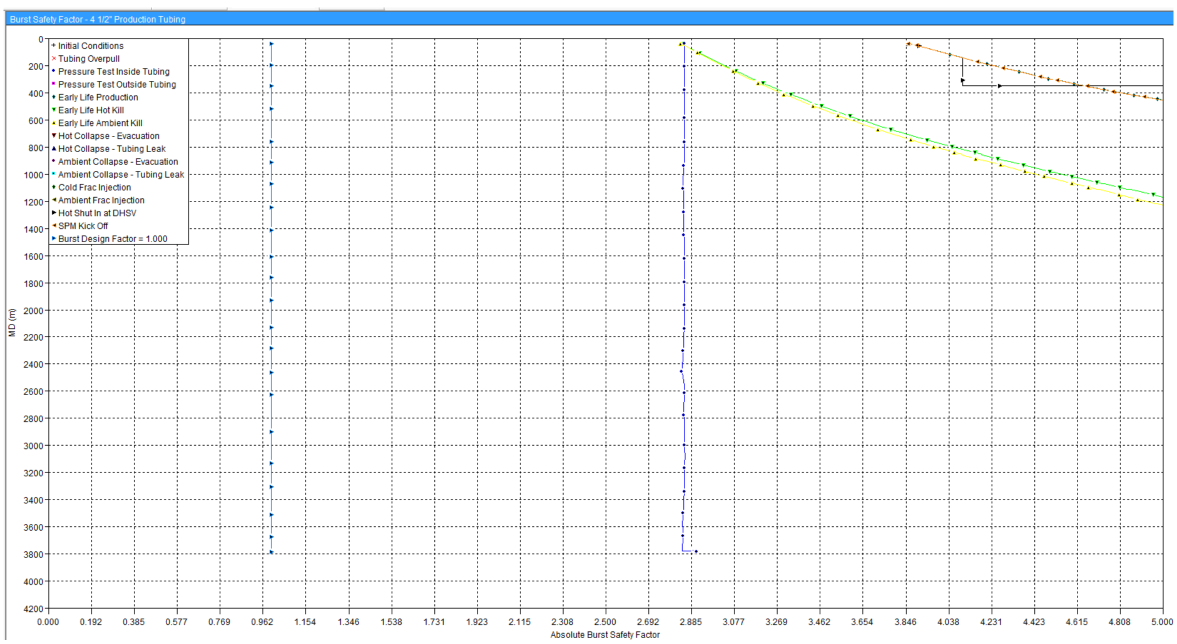

Figure 26 - Burst Safety Factor for CTDM load cases

Appendix VII- Extended Reach Well

MB North
(MB01 Sidetrack)
Offshore Tubing Design

Author:
Amy Hardy
Completion and Well Intervention Engineering Graduate

With supervision from:
Nicole Hughes
Completion and Well Intervention Team Lead

December 2013

Contents

1.0 Introduction

1.1 Design Factors

Note that the Minimum Allowable Design Safety Factors (Table 22) used in this document are taken directly from the Shell Casing and Tubing Design Manual.

Table 38 - Minimum Design Safety Factors (DSFmin) for Use in the Design Check Equations

Minimum Allowable Design Safety Factors						
Description	Label	Pipe Body		Connection		
					Tested	Legacy
Running, tension						
	RT1	$^{p}DSF_{1\,t}$	1.40	$^{c}DSF_{1\,t}$	1.40	1.55
	RT2	$^{p}DSF_{1\,t}$	1.20	$^{c}DSF_{1\,t}$	1.20	1.35
Running, compression	RC	$^{p}DSF_{1\,c}$	1.10	$^{c}DSF_{1\,c}$	1.10	1.25
Collapse	C	$^{p}DSF_{2}$	1.00	$^{c}DSF_{2}$	1.00	1.15
Burst - Triaxial						
	B1	$^{p}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B2	$^{p}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B3	$^{p}DSF_{3}$	1.25	$^{c}DSF_{3}$	1.25	1.40
	B4	$^{p}DSF_{3}$	1.20	$^{c}DSF_{3}$	1.20	1.35
	B5	$^{p}DSF_{3}$	1.15	$^{c}DSF_{3}$	1.15	1.30
	B6	$^{p}DSF_{3}$	1.10	$^{c}DSF_{3}$	1.10	1.25

1.2 Trajectory

The well trajectory version that has been used for the tubing design for the MB-North (sidetracked from MA-01A) well. This is subject to change, but this should not have significant impact on the resulting load cases. Figure 11 gives a graphical representation of the current well trajectory. This was taken from Compass file MB-North Sidetrack (IRF Ph3) – from the MB-01 IRF Well Plans.

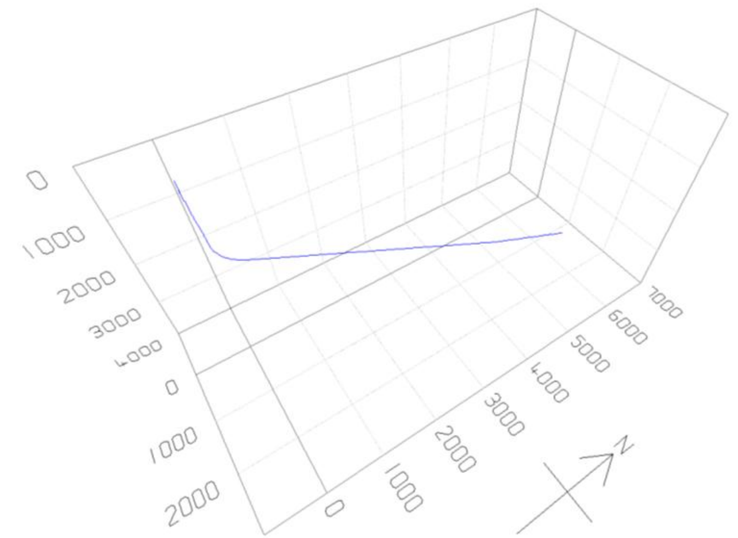

Figure 27 - Proposed Well Trajectory

1.3 Sand Composition

The rock composition for the proposed MB North well was modeled from the more generic Maui B Upper C-Sands compositions.

Table 39 - Composition of Maui B Upper C Sands

Component	Mol	Mol wt	Liquid Density
	%		g/cm³
N2	2.024	28.014	
CO2	2.042	44.01	
C1	78.445	16.043	
C2	6.649	30.07	
C3	3.199	44.097	
iC4	0.804	58.124	
nC4	1.090	58.124	
iC5	0.518	72.151	
nC5	0.438	72.151	
C6	0.659	86.178	0.664
C7	0.921	92	0.7466
C8	1.022	102	0.7688
C9	0.612	114	0.7887
C10	0.408	129	0.7915
C11	0.249	144	0.7953
C12	0.189	156	0.808
C13	0.231	175	0.8217
C14	0.157	190	0.8345
C15	0.107	206	0.8463
C16	0.074	222	0.8574
C17-C18	0.086	242.693	0.8719
C19-C42	0.076	292.704	0.9063

1.0 Basis for Design

2.1 Reference Documents

For the Tubing design, the following documents were utilized for guidance and design specifications.

- Shell Casing and Tubing Design Manual Issued 1st June 2013
- WellCat Training Workbook Issued 2013 by Altus Well Experts

2.2 Design Software

Modeling has been completed using the Halliburton's WellCat Software (version 5000.1.10.0).

2.3 Well Trajectory

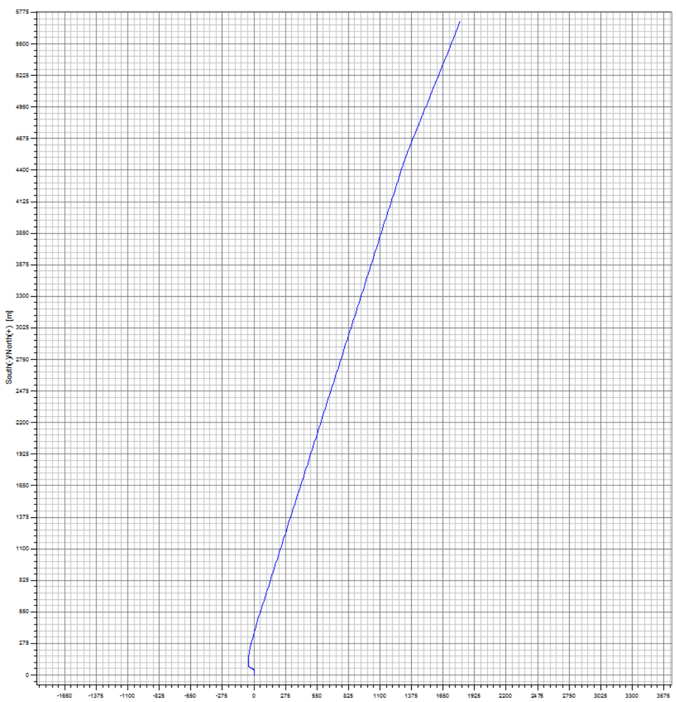

Figure 28 - Plan View of the MB-04 Well Trajectory

Figure 29 - Section View of the MB-04 Well Trajectory

2.4 Design Pressures

Table 40 - MB-04C Well Life Parameters

Condition	Units	Start of Life	Normal Op.	End of Life
CITHP	bar	185	185	185
CITHT	ºC	15 to 17	15 to 17	15 to 17
FTHP	bar	120	150	170
FTHT	ºC	60 to 65	60 to 65	60 to 65
WGR	m^3 water/ MMm^3 gas	8	8	2500
IRF Well Gas Flow	$STDm^3/s$	20	15	5

2.0 Casing & Tubing Design Load Cases

The Shell Casing and Tubing Design Manual – released June 1st 2013 – was followed throughout the design as the minimum standard.

3.1 4-1/2" Production Liner

The 4 ½" cemented production liner will be set in the Maui B C sands. The casing and tubing design it has been verified whether the casing can withstand all the load cases as per the latest revision of the casing and tubing design manual, based on the normal pipe body properties of the 4 ½" slotted liner.

This production liner has a Shell qualified connection.

3.2 4-1/2" Production Tubing

3.2.1 Design Objective

The 4 ½" production tubing, together with the 4 ½" production liner and including the completion components for the completion conduit through which the hydrocarbons are brought to the surface.

The tubing design (Completed using WellCat) has verified that this tubing can withstand all the load cases in compliance with the Shell Wells Standards.

The tubing used has a Shell qualified connection.

3.2.2 Operations and Loads

Table 41 shows the thermal operations modeled in WellCat for the Maui B North Well. Table 42 shows the load cases applied on the tubing in WellCat, and what parameters were used.

Table 41 - Thermal Operations for Producing Wells

Operation	Pressure (bar)	Position	Comment
Early-life Production	120	Wellhead	
Late-life Production	170	Wellhead	
Early-life Hot Shut In	185	Wellhead	

Table 42 - Load Cases for Tubing

Operation	Summary
Tubing Overpull	Run with seawater with force of 100,000 lbf
Pressure Test Inside	Pump pressure in tubing of 20,000kPa, anchor at 6279m
Pressure Test Outside	Pump pressure in tubing 0kPa, in annulus 20,000kPa
Early Life Production	Steady state 120barTHP, 65°C, 20 STDm^3/s, 0bbl/min water
Late Life Production	Steady state 170barTHP, 65°C, 5 STDm^3/s gas, 4bbl/min water
Early Life Shut In	185barTHP, 1 min
Early Life Hot Kill	2240psiTHP, 1 min
Early Life Ambient Kill	2240psiTHP, 20 yr
Hot Collapse-Evacuation	Tubing evacuation at "Early Life Production" conditions
Hot Collapse Tubing Leak	"Early Life Production" tubing conditions, annulus pressure 2240psi (SIWHP + 500psi)
Ambient Collapse Evacuation	Tubing evacuation at "Early Life Ambient Shut In" for 20 yrs

Ambient Collapse Tubing Leak	"Early Life Shut In" tubing condition, annulus pressure 2240psi
Ambient Frac Injection	Undisturbed prior, 100bar, 15°C, 1200m^3/day, 6 mths
Side Pocket Mandrill Kick-off	SPMD set at 3200m, "Early Life Production" tubing conditions
Hot Shut in at DHSV	DHSV set at 350m, "Early Life Production" tubing conditions

*Assume annulus pressure is 0psi unless otherwise stated
**Initial Conditions set to default

3.2.2 Properties

Production tubing properties can be found in Table 43. The corresponding Connection Data Sheet can be found in Appendices A, page 39.

Table 43 - Properties of the 4 1/2" Production Tubing

Size	Interval	Weight	Grade	Connection	Collapse Strength	Burst Strength	Tension Strength	Compr. Strength
Inches	mAHRD	Lbs/ft			Bar	Bar	MT	MT
4 1/2		20.6	L80 13Cr	VAM TOP Tubing	217	581	130	-130

3.2.3 Minimum Safety Factors

Table 28 shows the minimum Safety Factors (SF) per failure mechanism. These have been listed for the CTDM load cases. At this stage **only the pipe** is considered, not the connections. Table 29 shows the minimum SF's for additional load cases where the SF is lower than the CTDM load cases.

Table 44 - Minimum Safety Factors for 4 1/2" Tubing

Minimum Safety Factor	Load Case	Safety Factor	Depth (mTVD)
Triaxial	Tubing Overpull	1.398	820.30
Axial	Tubing Overpull	1.407	820.30
Collapse	Ambient Collapse – Tubing leak	1.894	20436.34
Burst	Pressure Test Inside Tubing	2.852	902.1-5000
Compression	See Axial (Axial governed by Compression)		

Table 45 - Minimum Safety Factors where the Safety Factor is lower than the CTDM load cases

Minimum Safety Factor	Load Case	Safety Factor	Depth (mTVD)
Triaxial	n/a		
Axial	n/a		
Collapse	n/a		
Burst	n/a		

3.2.4 Non-Compliance with Standards

For the 4 ½" Tubing, there are no CTDM or UIA/UIZ/BSP wells standard non-compliant load cases. I.e. Cases where the Safety Factor is below the Shell Design Factor. Therefore, there are no deviations in this instance.

3.2.5 Graphical Representation

3.2.5.1 Design Limits Plot

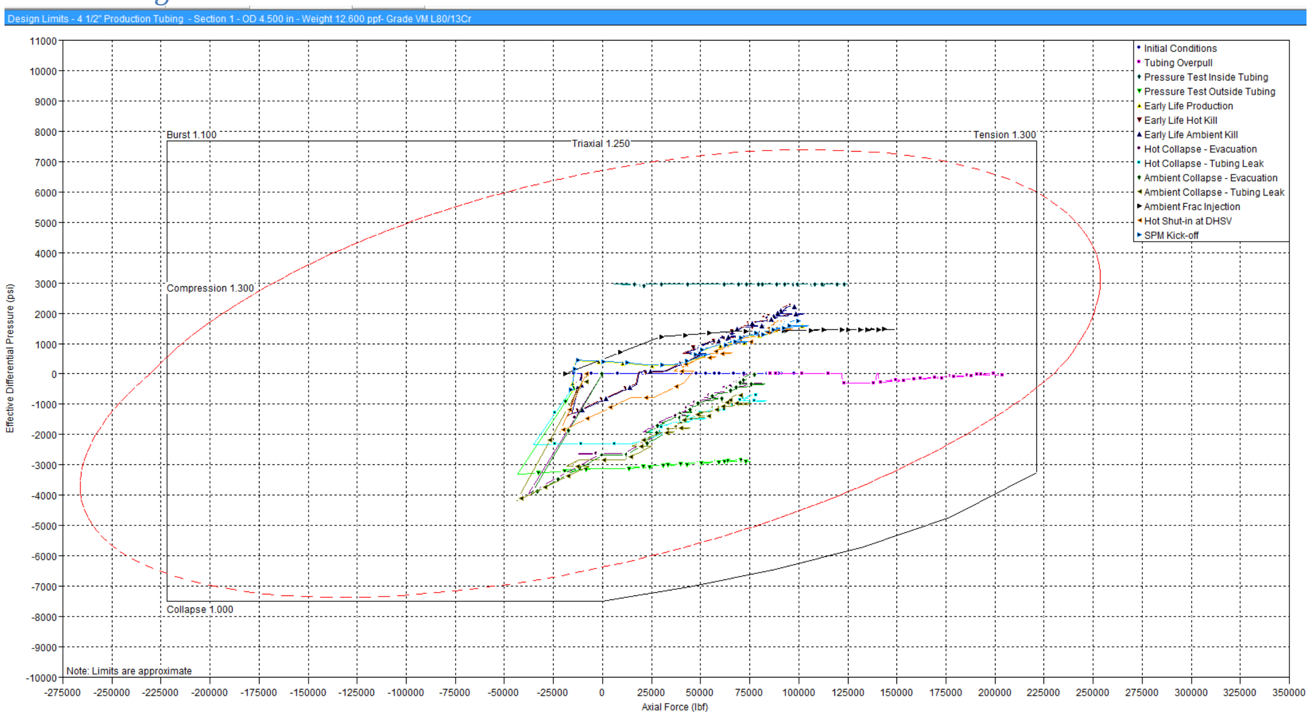

Figure 30 - Design Limits Plot for CTDM load cases

3.2.5.2 CTDM Safety Factor Plots

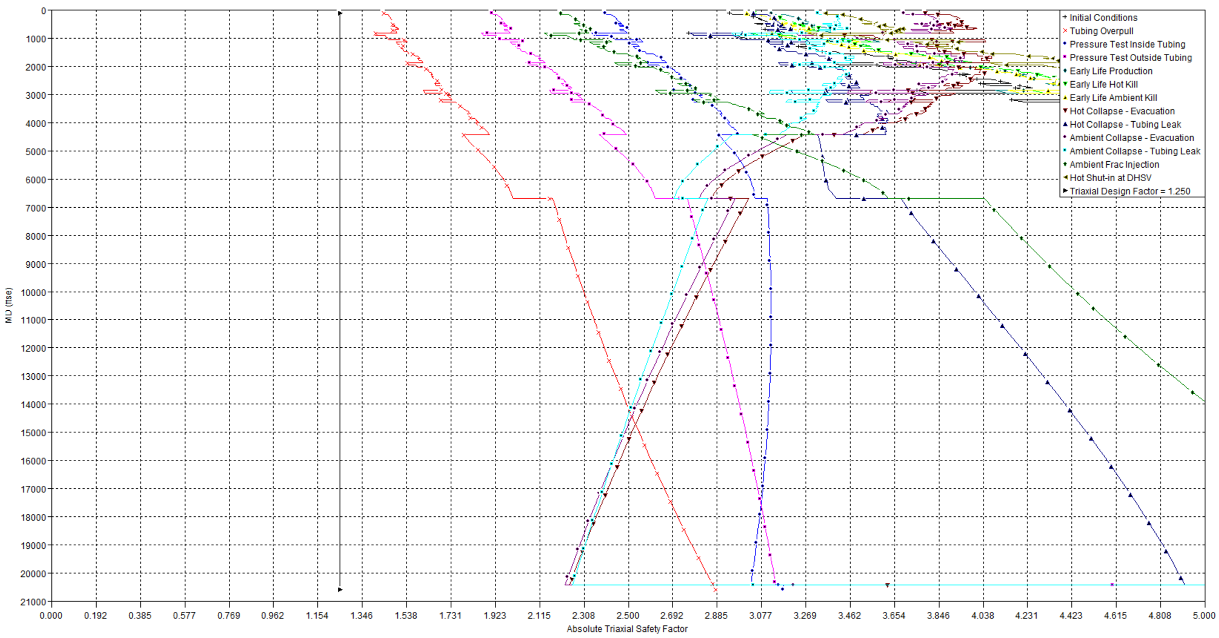

Figure 31 - Triaxial Safety Factor Plot for CTDM load cases

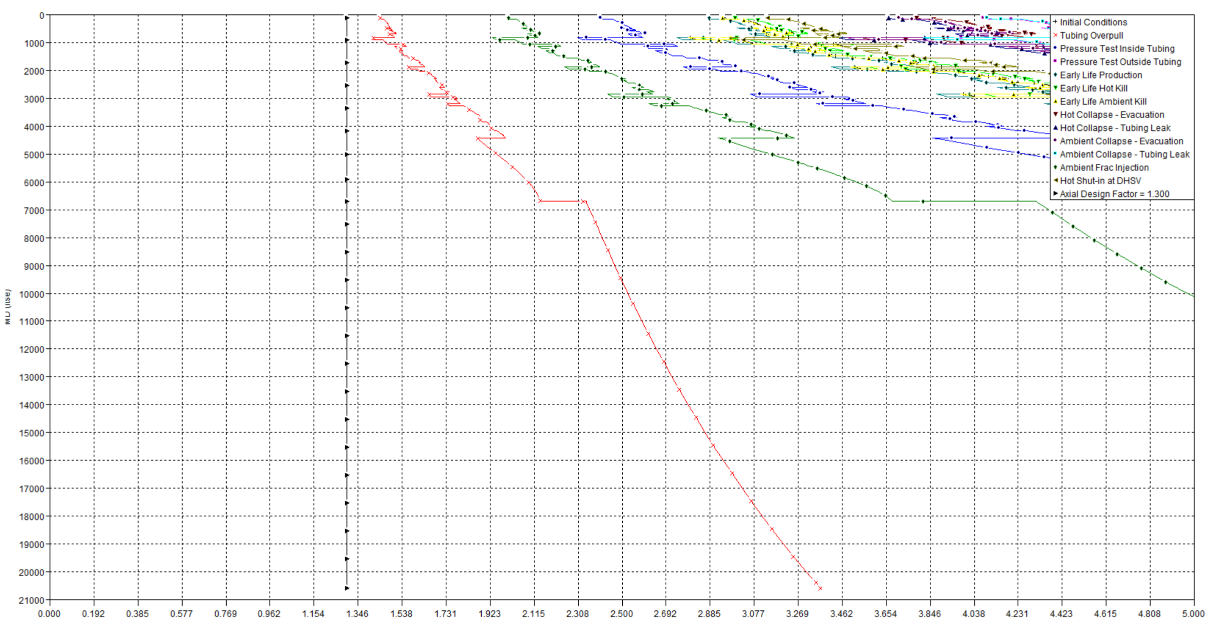

Figure 32 - Axial Safety Factor Plot for CTDM load cases

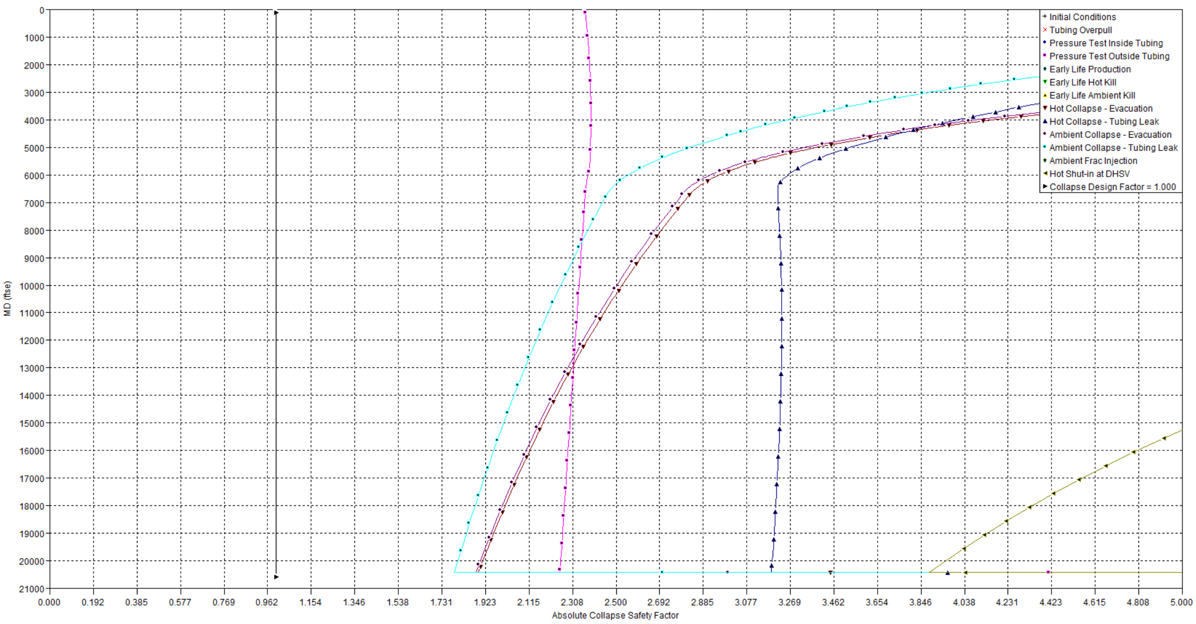

Figure 33 - Collapse Safety Factor for CTDM load cases

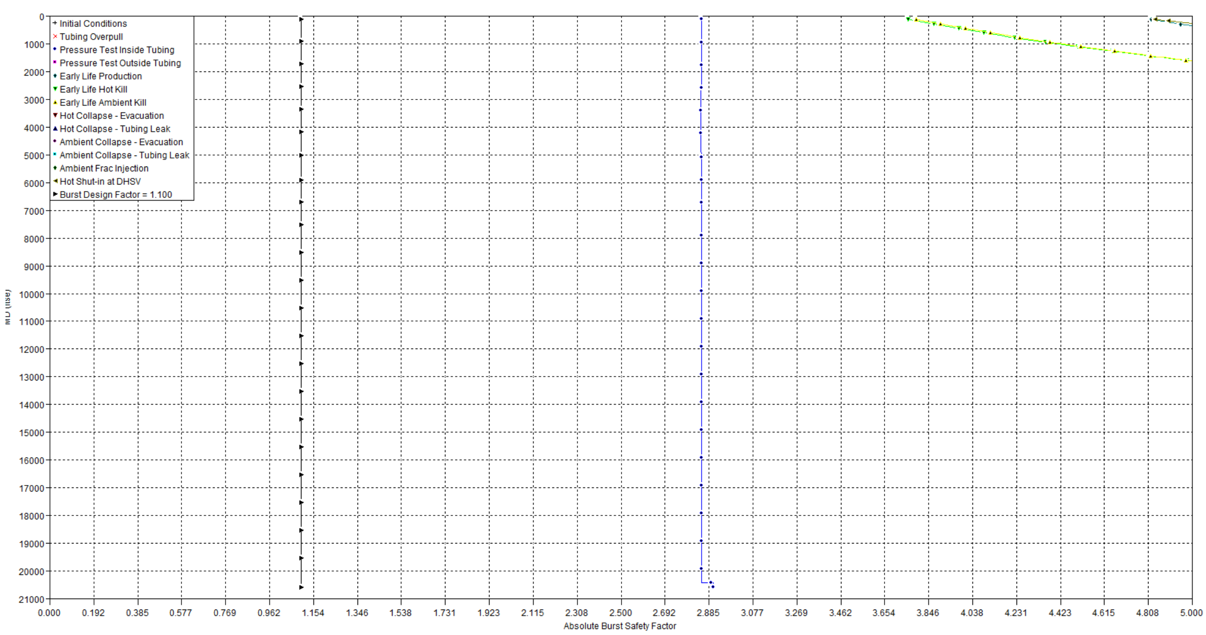

Figure 34 - Burst Safety Factor for CTDM load cases