PEOPLE’S DEMOCRATIC AND REPUBLIC OF ALGERIA
MINISTRY OF HIGH EDUCATION AND SCIENTIFIC RESEARCH

N° Série : ………/2024

Kasdi Merbah Ouargla University

Faculty of hydrocarbons, renewable energies and sciences of earth and universe

Department of production of hydrocarbons

DISSERTATION

To obtain master's degree

Option: Academic Production of hydrocarbons

Presented by:

BOUAICHA Mohamed Abdelkaioum

-TITLE-

Well integrity issues during hydraulic fracturing treatment

Publicly defended on: 08/06/2024

Jury:

President:	Mohamed OUAZAZI	Dr	Univ. Ouargla
Examiner:	Nabil BRAHMIA	Dr	Univ. Ouargla
Supervisor:	Miloudi MUSTAPHA	MAA	Univ. Ouargla
Co-supervisor:	Zakaria ADJOU	Dr	Univ. Ouargla

College year: 2023/2

Acknowledgement

Above all, I thank ALLAH, the Almighty, for providing me with the bravery and patience to finish my dissertation.

First and foremost, I am incredibly grateful to Mr. Youcef RIGHI, and all the staff of the “New technics Department” of SONATRACH DP IRARA whose advice, patience, and support were instrumental in completing this thesis.

Second, I'd like to thank my supervisors, Mr. Zakaria ADJOU and Mr. Mustapha MILOUDI, for their invaluable patience and feedback during this project. for their insightful comments.

I would be remiss in not mentioning the faithful and truthful teachers, for their full dedication for the sake of students, and their guidance in my journey in the Kasdi Merbah Ouargla University's Department of Hydrocarbons Production.

I would like to extend my genuine gratitude to Mr. Abdelmadjid AISSANI for his invaluable advice and mentorship over the past few years.

I would like to thank all my mentors during my internships in these years.

Last but not least, I express my heartfelt gratitude to the jury members Dr. Mohamed OUAZAZI and Dr. Nabil BRAHMIA for their tolerance and taking the time to assess my work.

Dedication

It’s an honor to be able to express my gratitude for the people I love the most.

I wholeheartedly dedicate this work to my beloved mother HAOUED MOUISSA Nadira Madjda, she has made me who I am today and did nothing less than everything to make sure that I am loved, save, supported, guided and most of all successful, my inspiration who never fail to encourage me morally, spiritually, and emotionally…

To my dear father BOUAICHA Slimane for his absolute support and tremendous effort in raising me all this time.

To my lovely grandmother KORICHI Naima.

To my cornerstone and brother BOUAICHA Mohamed Abdelhai.

To little brothers, MOUNIB, ABDALLAH, KHOBAIB and NADJI may ALLAH grant him heaven.

To my beloved family and friends, all by his name.

Special gratitude to RIGHI Youcef and KORICHI Youcef who never thought twice about providing ultimate help, support and guidance during these years.

Finally, to all who helped me during my journey and made it special and full of memories.

BOUAICHA Mohamed Abdelkaioum

Abstract

Maintaining well-integrity during hydraulic fracturing operations is a pivotal concern within contemporary petroleum engineering. This study goes beyond conventional pressure-centric methodologies, delving into the nuanced effects of temperature variations on the structural loads borne by tubular and production packers. Thus, it advances a comprehensive understanding of failure prevention and production optimization. This thesis will investigate the case of a well-integrity loss on a newly drilled well with a standardized completion to align with the prevailing practice in the investigated area, then use the acquired knowledge to prove the hypotheses on two wells that are candidates for hydraulic fracturing. This study requires complete knowledge of wells' completion, fluid properties, production history, and hydraulic fracturing treatment design. All of this is essential to the analysis in WELLCAT™; WELLCAT™ software plays a crucial role in ensuring well integrity during hydraulic fracturing by enabling engineers to design casings and tubing that can withstand the high pressures and stresses encountered during the process. The results of this investigation proved that the current pressure-centric approach, which lacks precision since it does not consider temperature effects, is insufficient. Therefore, using WELLCAT™ for thermal modeling and performing triaxial burst analysis and packers' performance envelope evaluation is crucial to ensure well-integrity. This thesis presents a multidisciplinary approach to designing and executing safe and cost-efficient hydraulic fracturing treatments while decreasing the chance of costly downtime and mitigating severe environmental concerns associated with wellbore failures.

Keywords Well integrity, hydraulic fracturing, loads, triaxial burst analysis, packer performance envelope, thermal modeling, WELLCAT™, downtime.

Résumé

Le maintien de l’intégrité des puits pendant les opérations de fracturation hydraulique est une préoccupation essentielle du génie pétrolier contemporain. Cette étude va au-delà des méthodologies conventionnelles centrées sur la pression, en approfondissant les effets nuancés des variations de température sur les charges structurelles supportées par les tubulaires et les packers de production. Ainsi, il fait progresser une compréhension globale de la prévention des défaillances et de l’optimisation de la production. Cette thèse étudiera le cas d’une perte d’intégrité de puits sur un puits nouvellement foré avec un complétion standardisé pour s’aligner sur la pratique courante dans la zone étudiée, utiliser ensuite les connaissances acquises pour prouver les hypothèses sur deux puits qui sont candidats pour la fracturation hydraulique. Cette étude exige une connaissance complète de la complétion des puits, des propriétés des fluides, de l’historique de production et de la conception du traitement par fracturation hydraulique. Tout cela est essentiel pour l’analyse dans WELLCAT™ ; le logiciel WELLCAT™ joue un rôle crucial pour assurer l’intégrité du puits pendant la fracturation hydraulique en permettant aux ingénieurs de concevoir des tubages et des tubes qui peuvent résister aux pressions et aux contraintes élevées rencontrées pendant le processus. Les résultats de cette étude ont prouvé que l’approche actuelle centrée sur la pression, qui manque de précision puisqu’elle ne tient pas compte des effets de température, est insuffisante. Par conséquent, l’utilisation de WELLCAT™ pour la modélisation thermique et l'analyse d'éclatement triaxial et l’évaluation de l’enveloppe de performance des packers est cruciale pour assurer l’intégrité du puits. Cette thèse présente une approche multidisciplinaire pour concevoir et exécuter des traitements de fracturation hydraulique sûrs et rentables tout en diminuant le risque de temps d’arrêt coûteux et en atténuant les graves préoccupations environnementales associées aux défaillances de puits.

Mot clés Intégrité du puits, fracturation hydraulique, charges, analyse d’éclatement triaxiale, enveloppe de performance de packer, modélisation thermique, WELLCAT™, temps d’arrêt.

ملخص

يعد الحفاظ على سلامة الأبار أثناء عمليات التكسير الهيدروليكي مصدر قلق محوري في هندسة البترول المعاصرة. تتجاوز هذه الدراسة المنهجيات التقليدية المتمحورة حول الضغط، وتتعمق في التأثيرات الدقيقة لتغيرات درجات الحرارة على الأحمال الهيكلية التي تتحملها أنابيب التغليف و سدادات الإنتاج. وبالتالي، فإنه يعزز الفهم الشامل لمنع الفشل وتحسين الإنتاج. ستبحث هذه الأطروحة في حالة فقدان سلامة الآبار على بئر تم حفره حديثًا مع تصميم تكميل موحد للتوافق مع الممارسة السائدة في المنطقة التي تم التحقيق فيها، ثم استخدام المعرفة المكتسبة لإثبات الفرضيات على بئرين مرشحين للتكسير الهيدروليكي. تتطلب هذه الدراسة معرفة كاملة بتصميم تكميل الآبار، وخصائص السوائل، وتاريخ الإنتاج، وتصميم التكسير الهيدروليكي. وكل هذا ضروري للتحليل في WELLCAT™ ؛ يلعب برنامج WELLCAT™ دوراً حاسماً في ضمان سلامة البئر أثناء التكسير الهيدروليكي من خلال تمكين المهندسين من تصميم أغلفة وأنابيب إنتاج يمكنها تحمل الضغوط والضغوط العالية التي تصادف أثناء العملية. أثبتت نتائج هذا التحقيق أن النهج الحالي المتمركز حول الضغط، والذي يفتقر إلى الدقة لأنه لا يأخذ في الاعتبار تأثيرات درجة الحرارة، غير كاف. لذلك، فإن استخدام WELLCAT™ للنمذجة الحرارية وإجراء تحليل الانفجارات ثلاثية المحاور وتقييم أداء السدادات أمر بالغ الأهمية لضمان سلامة الأبار. تقدم هذه الأطروحة نهجًا متعدد التخصصات لتصميم وتنفيذ علاجات تكسير هيدروليكي آمنة وفعالة من حيث التكلفة مع تقليل فرصة التعطل المكلف والتخفيف من المخاوف البيئية الشديدة المرتبطة بفشل الآبار.

الكلمات المفتاحية سلامة الأبار، التكسير الهيدروليكي، أحمال، تحليل الإنفجار ثلاثي المحاور، أداء السدادات، النمذجة الحرارية، ™WELLCAT، وقت التوقف.

Table of contents

Table of figures

List of tables

Symbols and abbreviations

Q: Production rate, STB/day.

A: Area, ft^2.

K: Formation permeability, md.

H: Pay thickness, ft.

μ : Reservoir fluid viscosity, cp.

ΔP: Pressure drop, psi.

Δx: The fluid displacement, ft.

PI: Well productivity, STB/psi.day.

Pr: Reservoir pressure, psi.

PLT: Production logging tools.

S: Skin.

Ks: Damaged formation permeability, md.

Rs: Damage radius, ft.

Rw: Well's radius, ft.

S_D: Skin due to deviation from Darcy's Law.

Sc: Skin due to clogging.

Sp : Skin due to partial penetration.

Sps : Skin due to perforations.

ΔP_{skin}: Pressure loss due to skin, psi.

$P_{wf\ undamaged}$: Undamaged bottom hole pressure, psi.

$P_{wf\ damaged}$: Damaged bottom hole pressure, psi.

E: Young's modulus, psi.

σ: Stress, psi.

F: Force, N.

ε: Strain.

ε_y: Radial strain.

ε_x: Axial strain.

δx: Change in direction, ft.

ν : Poisson's ratio.

G: The shear modulus, psi.

σ_v: Vertical stress, psi.

ρ_n: The density of the rock layer, g/cm^3.

g: The acceleration due to gravity, m/s^2.

h_n: The vertical height of the zone n, ft.

g_{ob}: Overload gradient, psi/ft.

α: Leak of factor.

p_{ob}: The covering pressure, psi.

α: The poro-elastic constant of Biot.

hf: Fracture height, ft.

rf: Fracture radius, ft.

σ_t: Tangential stress, psi.

Pif,upper: The rupture pressure, psi.

Pif,lower: The lower limit of the rupture pressure, psi.

η: A parameter defined by the Poisson coefficient and the Biot constant.

FEP: The Fracture Extension Pressure, psi.

η: The efficiency of the treatment fluid, %.

Gc: The G-function time at fracture closure.

CL: Fluid filtration, ft/min$^{1/2}$.

RFP: The fracture reopening pressure, psi.

ISIP: Instantaneous shut-in pressure, psi.

ΔP_{net}: Net Fracture Pressure, psi.

FCP: Fracture closure pressure, psi.

x_f: fracture half-length, ft.

w: Fracture width, ft.

F_{CD}: dimensionless fracture conductivity.

k_f: fracture permeability, md.

σLoad: Stress due to applied loads, psi.

σYield: Stress that will cause yield in the pipe, psi.

DF: Design Factor.

ΔF_{bal}: Incremental force due to ballooning, lbs.

ΔP_i: Change in surface internal pressure, psi.

ΔP_o: Change in surface external pressure, psi.

A_i: Cross-sectional area associated with casing ID, in^2.

Ao: Cross-sectional area associated with casing OD, in^2.

L: Free length of casing, ft.

$\Delta \rho_i$: Change in internal fluid density, psi/ft.

$\Delta \rho_o$: Change in external fluid density, psi/ft.

F_b: Axial force due to bending, lbs.

α / L: Dogleg severity, °/unit length.

A_s: Cross sectional area, ft^2.

ΔF_b: Buckling force, lbs.

ΔF_a: Actual axial force (tension positive), lbs.

p_i: Internal pressure, psi.

p_o: External pressure, psi.

ΔF_p: Paslay buckling force, lbs.

w: Distributed buoyed weight of casing, lbs.

θ: Hole angle, °.

EI: Pipe bending stiffness, lbs/in.

r: Radial annular clearance, in.

ΔFtemp: Incremental force due to temperature change, lbs

α: Thermal expansion coefficient (6.9 x 10^{-6} °F-1 for steel).

E: Young's modulus (3.0 x 10 7 psi for steel).

As: Cross-sectional area of pipe, in^2.

ΔT: Average change in temperature over free length, °F.

P_{eff}: Effective collapse pressure on pipe, psi.

t: Nominal wall thickness, in.

D: Nominal outside diameter, in.

S_{yr}: Reduced yield strength of axial stress equivalent grade, psi.

S_A: Axial stress- tension is positive, psi.

Y_P: Nominal yield strength of pipe, psi.

F_a: Dry weight of pipe below the point of interest, lbs.

F_p: Pressure forces acting on the pipe below the point of interest, lbs.

σ_B: Bending stress in pipe at a given point in the pipe wall, psi.

τ: Tossional stress, psi.

T : Torque, ft.lbs.

OD: Onside diameter, in.

ID: Inside diameter, in.

HP(A): Annulus hydrostatic pressure, psi.

ΔP Burst: Burst differential pressure, psi.

HP(tbg): Tubing hydrostatic pressure, psi.

ΔP Packer: Packer's differential pressure, psi.

MATP: Maximum allowable treating pressure, psi.

BPM: Barrel per minute.

ppg: Pound per gallon.

n': Flow behavior index.

K': Consistency index, $lb.s^{n'}/ft^2$.

sg: Specific gravity.

ppf: Pound per foot.

lbf: Pound.

AP_{P1}: Annulus pressure at Point 1, psi.

AP_{P2}: Annulus pressure at Point 2, psi.

WHP: Wellhead pressure, psi.

DBHP: Dynamic bottom hole pressure, psi.

Pg: Reservoir Pressure, psi.

Kh: Well test permeability, mD.m.

GOR: Gas oil ratio, sm^3/m^3.

TOC: Top of cement, m.

BHT: Botton hole temperature, °C.

T: Temperature, °C.

ACT: Acceptance criteria table.

API: American Petroleum Institute.

BOP: Blow out preventer.

BSW: Basic sediment and water.

CMHEC: Carboxymethyl Hydroxyethyl Cellulose.

CMHPG: Carboxymethyl Hydroxypropyl Guar.

CSE: Connection strength envelope.

DFIT: Diagnostic fracture injection test.

DHSV: Downhole Safety Valve.

DP: Drill pipe.

GKD: Kritianovitch and Zheltov, Geertsma and DeKlerk, further refined by Daneshy.

HEC: Hydroxyethyl Cellulose.

HPG: Hydroxypropyl Guar.

HSE: Health, Safety and the Environment.

ISO: International Organization for Standardization.

NORSOK: Norwegian Petroleum Standardization Organization.

PKN: Perkins and Kern, Nordgren.

PSA: Petroleum Safety Authority.

SCSSV: Surface Controlled Subsurface Safety Valve.

TAP: Trapped annular pressure.

VIT: Vacuum insulated tubing.

WBE: Well barrier elements.

WIM: Well Integrity Management.

WIT: The Wellhead Isolation Tool.

HPHT: High pressure/High Temperature.

Introduction

Hydraulic fracturing, a vital technology in oil and gas production, presents a complex engineering challenge. The quest for ever-increasing production rates pushes the boundaries of wellbore integrity. High-pressure fracturing fluids can induce a series of stresses within the wellbore, jeopardizing its structural stability and potentially leading to catastrophic failures. These failures not only result in severe environmental risk in addition to costly downtime.

This thesis ventures beyond the traditional pressure-centric approach to wellbore integrity during hydraulic fracturing. It proposes a multi-disciplinary approach that leverages advanced software like WELLCAT™ to unveil a hidden dimension - the critical role of thermal effects.

Traditionally, wellbore integrity analysis has focused primarily on pressure loads exerted by fracturing fluids. However, this approach overlooks a crucial aspect of the downhole environment: temperature. During fracturing operations, significant temperature fluctuations can occur due to the interaction between the injected fracturing fluids and the formation itself. These fluctuations induce thermal stresses within the wellbore casing and tubing, further adding to the complex stress regime.

This thesis utilizes WELLCAT™, a sophisticated wellbore integrity software, to perform a comprehensive downhole analysis that incorporates both pressure and thermal loads. WELLCAT™'s capabilities will be harnessed to:

- **Perform Triaxial Burst Analysis** Identify potential weaknesses in the casing susceptible to triaxial bursts under the combined influence of pressure and thermal stresses. This analysis will provide valuable insights for selecting appropriate casing materials and thicknesses to ensure structural integrity throughout the fracturing process.
- **Evaluate Packer Performance Envelopes** Guarantee effective zonal isolation during fracturing by analyzing the performance of packers under the combined effects of pressure and thermal expansion. This ensures that fracturing fluids are directed to the target formation, preventing unintended fluid migration and mitigating well integrity risks.
- **Model Thermal Effects** Move beyond the limitations of pressure-centric analysis by incorporating thermal considerations into WELLCAT™ simulations. This will enable a deeper understanding of how temperature variations impact casing and tubing stresses, allowing for the development of more robust wellbore design strategies.

Through this comprehensive approach, this thesis aims to:

- Enhance our understanding of the intricate interplay between pressure, stress, and thermal effects on wellbore integrity during hydraulic fracturing.
- Develop optimized wellbore design strategies that account for the complete downhole environment, not just pressure. This will lead to the selection of stronger casing materials, improved packer placement strategies, and potentially the implementation of techniques to mitigate thermal stresses.
- Provide valuable insights for engineers and operators seeking to ensure safe and efficient fracturing operations, ultimately contributing to a more sustainable approach to unconventional resource development.

By bridging the gap between pressure analysis and thermal modeling, this thesis sheds light on the previously neglected dimension of thermal effects. This enhanced understanding will pave the way for the design of more resilient wellbores, leading to safer and more efficient fracturing operations in the pursuit of unconventional resources.

CHAPTER I: HYDRAULIC FRACTURING

I.1 Hydraulic fracturing

Hydraulic fracturing is the process of pumping fluids at a pressure higher than the formation fracturing pressure to create a very high permeability pathway either to increase flow capacity from reservoir which means increasing productivity in low permeability reservoirs, damaged zones (by-pass damage) or connecting natural, increasing draining area and draining height (vertical & horizontal wells), or to decrease wellbore pressure drop by minimizing sand production and asphaltene and paraffin deposition. All leading to improving the economic return of the well. [1]

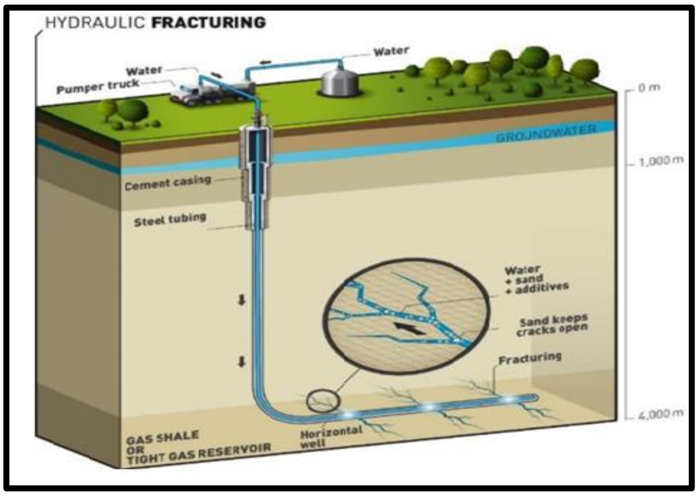


Figure I- 1 Hydraulic fracturing animation [4]

I.1.1 By-pass damage

Near-wellbore damage reduces well productivity. This damage can occur from several sources, including drilling-induced damage resulting from fines invasion into the formation while drilling and chemical incompatibility between drilling fluids and the formation. The damage can also be due to natural reservoir processes such as saturation changes resulting from low reservoir pressure near a well, formation fines movement, or scale deposition. Whatever the cause, the result is undesirable.

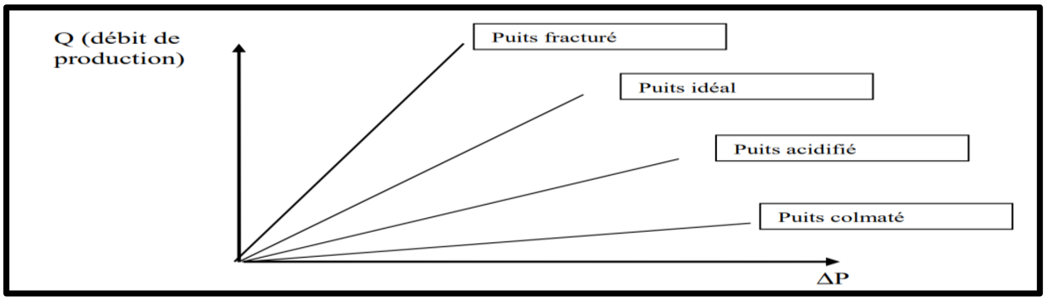


Figure I- 2 The flow rate difference between different treated wells [3]

Matrix treatments are usually used to remove the damage chemically, restoring a well to its natural productivity. In some instances, chemical procedures may not be effective or appropriate, and hydraulic fracture operations are used to bypass the damage. This is achieved by producing a high-conductivity path through the damaged region to restore wellbore contact with undamaged rock. [1]

I.1.2 Improved productivity

Unlike matrix stimulation procedures, hydraulic fracturing operations can extend a conductive channel deep into the reservoir and actually stimulate productivity beyond the natural level. All reservoir exploitation practices are subject to Darcy's law:

$$\boldsymbol{Q = \frac{kA}{\mu}\frac{\Delta_p}{\Delta_x}} \qquad \textbf{(I.1)}$$

Here the all-important production rate Q is related to; formation permeability k, pay thickness h, reservoir fluid viscosity μ, pressure drop Δp and formation flow area A.

Reservoir exploitation revolves around manipulating this equation. [1]

I.2 Formation damage and skin factor [11]

I.2.1 Formation damage

Formation damage is a common issue caused by wellbore fluids during drilling, completion, and workover operations. It is an obstacle that decreases the permeability of the reservoir formation, resulting in decreased productivity or injectivity. This damage can be found in various parts of the effluent flow, from the reservoir to the surface. The rapid decline in production is a result of reduced permeability, causing additional load loss on the production system.

I.2.2 Cause of formation damage

Table I- 1 Cause of formation damage [5]

Damage due to formation	Organic deposits (asphaltenes)
	Paraffine deposits
	Barium sulfate deposition
	Fines migration
	Swelling of clays
Damage due to well operations (Drill, Work Over and Snubbing)	Perforation Clogging
	Damage due to acidification

I.2.3 Skin factor

The "S" skin represents the degree of total damage of a well without differentiating the matrix damage (that acidification may solve) from the secondary damage caused by the configuration of the well: the Pseudo-Skin.

It is a dimensionless factor - determined by well tests- which reflects the connection between the reservoir and the well. The skin S is defined by the Hawkins equation as:

$$\boldsymbol{S = \left(\frac{K}{K_S} - 1\right) \ln\left(\frac{R_S}{R_W}\right)} \qquad \textbf{(I.2)}$$

The skin represents an additional load loss (ΔPskin) located in the vicinity of the well. This load loss can be caused by multiple parameters, such as:

- Skin due to perforations.
- Skin due to reservoir partial perforation.
- Skin due to partial penetration.
- Skin due to inclinations.
- Skin due to hydraulic fracturing.
- Skin due to the analysis of a horizontal well as a vertical well.
- Skin due to deviation from Darcy’s Law.

$$\boldsymbol{S = S_D + S_{C+0} + S_P + \sum S_{PS}} \qquad \textbf{(I.3)}$$

S > **0** if the layer near the well is plugged (additional pressure loss)

S < **0** if the layer near the well is improved.

S = 0 if there is no damage. [5]

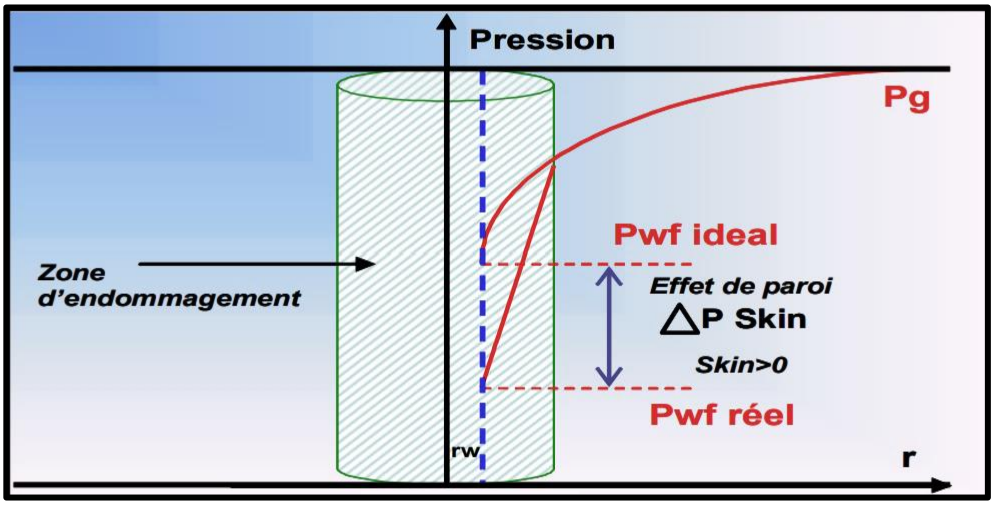


Figure I- 3 Presentation of pressure drop due to formation damage [11]

$$\Delta_{p\ skin} = P_{\text{wf undamaged}} - P_{\text{wf damaged}} \tag{I.4}$$

I.3. Hydraulic fracturing fluids and additives [4]

I.3.1 Fracturing fluid types

Fracturing fluids must be stable at high temperatures same as reservoir conditions pumping rates, and shear rates. For fracturing treatments several types of fracturing fluids and fluid additives can be used. The types of fluids include:

- Water-based fluids.
- Oil-based fluids.
- Foam and emulsions.
- Acid based.

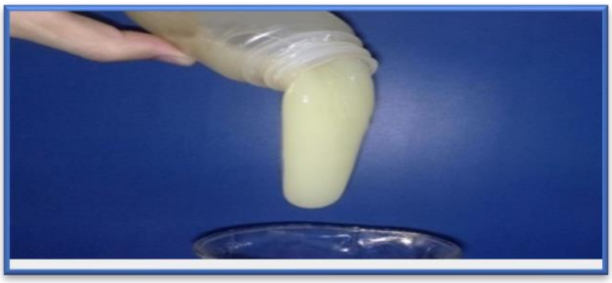


Figure I- 4 A sample of water-based fracturing fluid [2]

I.3.1.1 Water-based fracturing fluids

Rheological properties (viscosity, for example) can be manipulated easily by adjusting polymer loading and additive loading even during the job if required either in stages or continuously.

There are two types of water-based fracturing fluids:

- water-based **linear** fracturing fluids.
- water-based **crosslinked** fracturing fluids.

Figure I- 5 A sample of water-based crosslinked gel with proppant [7]

Before the dry polymer is added to the water, the individual molecules are tightly curled up on themselves. As the polymer molecule hydrates in water, it straightens out, which is why these fluids are referred to as linear gels.

The most used polymers for fracturing are Guar, HPG, and CMHPG, mostly as the basis for crosslinked systems. HEC is probably the most widely used polymer for linear gel fracturing, due to its popularity for fracturing low-temperature, high-permeability formations.

Most hydraulic fracturing treatments are carried out using water based crosslinked gels. These systems offer the best combination of low cost, ease of use, high viscosity, and ease of fluid recovery. Generally, water based crosslinked gels will be used unless there is a reason to avoid using them.

I.3.1.2 Oil-based fracturing fluids

Oil-based fracturing systems are compatible with most reservoirs but are rarely used due to higher costs and environmental restrictions. These fluids are less damaging to hydrocarbon-bearing formations than water-based fluids, making them suitable only for formations known to be extremely water-sensitive. Gelled oil systems can be prepared with various hydrocarbon-based fluids, such as diesel, kerosene, "frac oil," condensate, and lease crudes. The fluid used to fracture the well is hydrocarbon-based, allowing the well to be put in to production after treatment is over, making the fluid recovery phase of operations easier. Despite their compatibility, oil-based fluids are currently the most expensive and operationally difficult to handle.

I.3.1.3 Foam and emulsions fracturing fluids

Foams are made by mixing a gas phase such as N_2 or CO_2 (internal phase) with a liquid phase such as water, CO_2 (external phase), and a suitable foaming surfactant is used to maintain the stability of the foam produced, such as iodine or hydrogen peroxide. The quality of the foam depends on its composition, and high-quality foams have higher percentages of gas.

I.3.1.4 Acid-based Fluids

Acid fluids are used for low-permeability and acid-soluble rocks. The application of acid fracturing is confined to carbonate reservoirs and is never used to stimulate sandstone, shale, or coal-seam reservoirs. The best choise for acid treatments is reservoirs with temperature less than 200°F and the maximum effective stress on the fracture less than 5000 psi.

I.3.2 Fracturing fluid additives [7]

The following provides descriptions of typical fracturing fluid additives:

Gelling Agents Used to increase fluids viscosity.

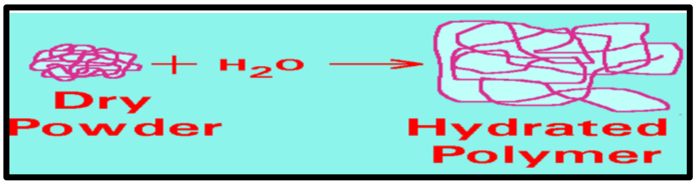


Figure I- 6 Schematization of polymer hydration [7]

Buffers Used to control the pH of the fracture fluid for polymer hydration as well as crosslinking and gel stability.

Breakers are designed to reduce the viscosity of the fracturing fluid so that the fluid can be easily recovered after the treatment, and to minimize polymer residues, so that damage to the proppant pack is minimized.

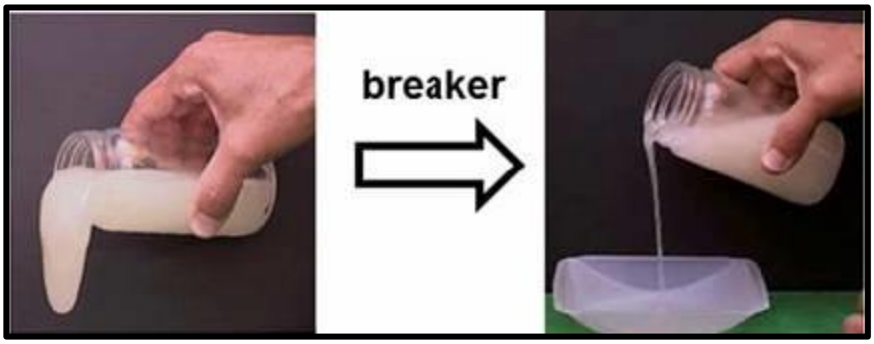


Figure I- 7 Breaking process [7]

Crosslinkers Used to exponentially increase the viscosity of gels -fluid.

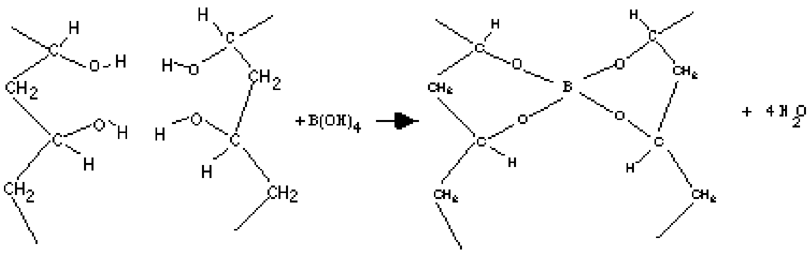


Figure I- 8 Crosslinking process [1]

Biocides Used to kill bacteria in the mix water, biocides are designed to prevent a colony of bacteria from developing in the first place, rather than for killing an existing colony.

Clay control Used to avoid swelling of clays.

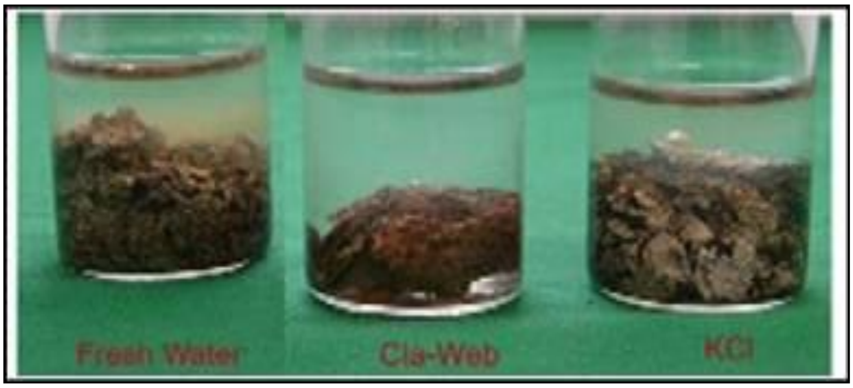


Figure I- 9 Clay controllers [7]

Surfactant Used to reduce the surface tension, interfacial tension between water and formation fluids, and also to change the contact angle of the leak off fluid for easier recovery.

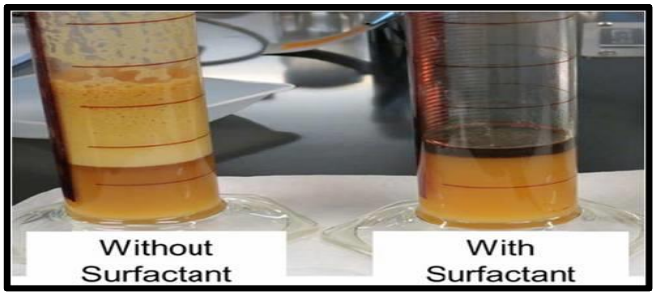


Figure I- 10 Surfactant's role [7]

Friction reducer Used to reduce the friction pressure and hence associated horsepower requirement for the pumping operation, friction reducers also protect equipment from wear and tear due to the high pumping rates of slick water jobs.

Figure I- 11 Water Based Friction Reducer vs. Oil Based [7]

Gel Stabilizers Used to increase the fluid stability of crosslinked gels at high temperatures.

I.4 Hydraulic fracturing equipment

Mixing and blending equipment

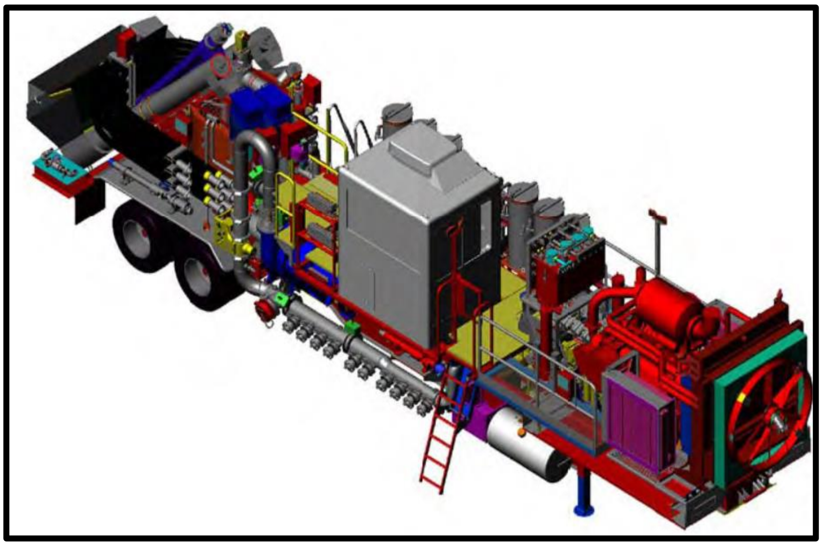


Figure I- 12 Blender schematization [7]

Pumping units

Figure I- 13 Pumping unit [2]

Hydration unit

Figure I- 14 LFC Hydration Unit [2]

Well isolation tool

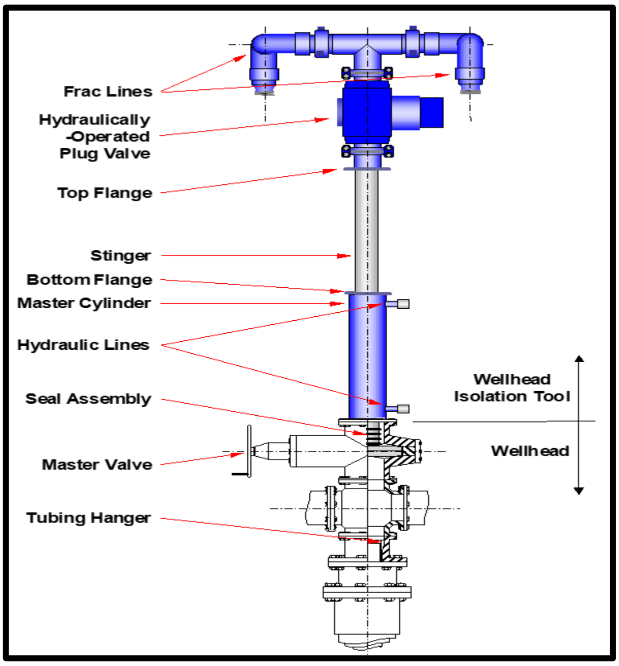


Figure I- 15 Generic wellhead isolation tool rigged up to wellhead diagram [2]

Treatment monitoring van

Figure I- 16 Treatment Monitoring Van [2]

Proppant storage and handling

Figure I- 17 Frac sand being delivered from a Sand King to the hopper of a blender [2]

The frac tank

Treating equipment

- Swivel joints.
- Valves.
- Treating adapters.
- Pipes and loops.
- Hose and fittings.
- Ball injectors.
- Fracturing heads.
- Fluid end.

The frac spread

The following figure shows the hydraulic fracturing equipment spread:

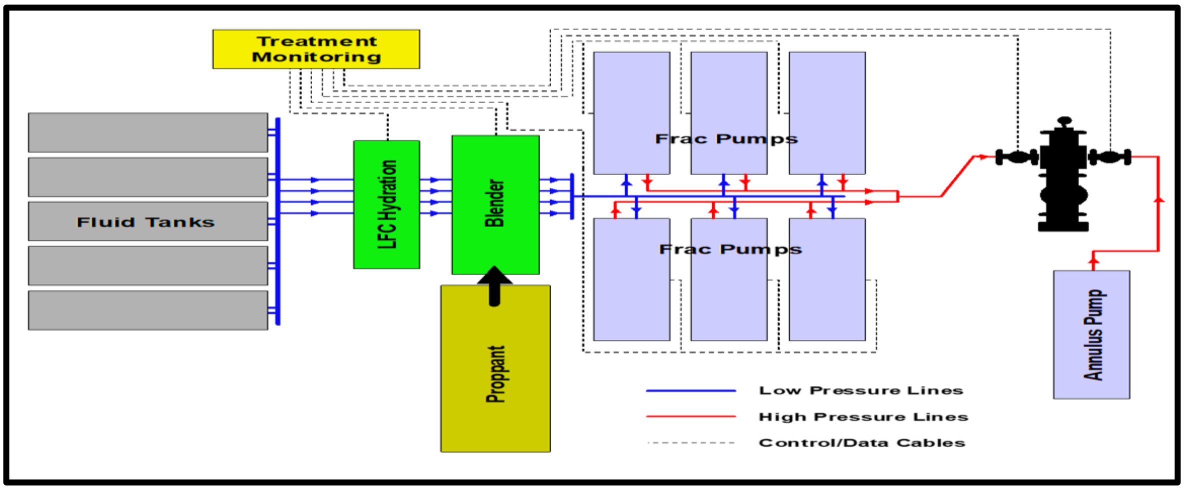


Figure I- 18 Schematic diagram of a frac spread [4]

I.5 Rock mechanics proprieties

I.5.1 Stress and strain

If a force F acts on a body whose cross-section A is perpendicular to the direction of action of the force, whereas the stress σ induced in this body is equal to:

$$\boldsymbol{\sigma = \frac{F}{A}} \tag{1.4}$$

Deformation is the measure of the magnitude of the deformation of the material when a stress is applied to it. When force F is applied in the X direction, the initial height of the X material block changes from δ_x. The deformation in the X direction, ε_x, is given by:

$$\boldsymbol{\varepsilon_x = \frac{\delta_x}{x}} \tag{1.5}$$

Note that the deformation is defined in the same direction as the applied force F, and perpendicular to the plane in which the stress acts. [6]

I.5.2 Young's modulus

Young's modulus, *E*, (also known as modulus of elasticity or elastic modulus) is defined as:

$$\boldsymbol{E = \frac{\sigma}{\varepsilon}} \tag{1.6}$$

Young's modulus is a measurement of stress over strain. Simply put, when hydraulic fracturing occurs, Young's modulus can be called the amount of pressure needed to deform the rock. Young's modulus measures how much a material will elastically deform when a load is applied to it. This is another term for hardness, and the higher the Young's modulus, the stiffer the rock. A higher Young's modulus will help to keep the fractures open.

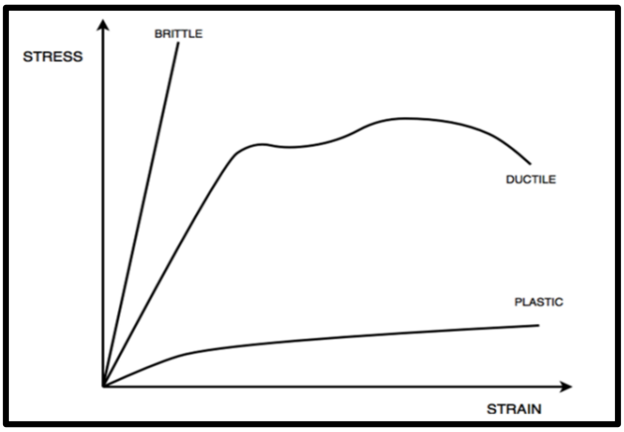


Figure I- 19 Young's modulus diagram [6]

On a more fundamental level, if stress and pressure are closely related, then in fracturing, we can think of Young's modulus as a measure of how much a material (i.e. rock) will elastically deform when a pressure is applied to it. As pressure is stored energy, *E* is also a measure of how much energy it takes to make the rock deform. [6]

I.5.3 Poisson's ratio

Poisson's ratio, ν, is a measure of how much a material will deform in a direction perpendicular to the direction of the applied force, parallel to the plane on which the stress induced by the strain is acting. This is illustrated by figure bellow:

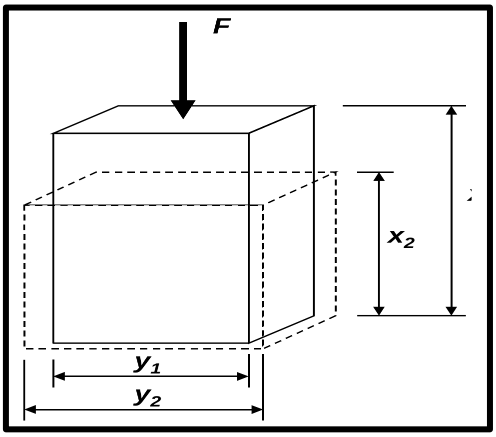


Figure I- 20 Poisson's ratio principle [6]

Application of force *F* also produces a deformation in the y direction.
The strain in the x direction, is given by equation:

$$\varepsilon_x = \frac{x_1 - x_2}{x_1} \quad \textbf{(1.7)}$$

The strain in the y direction is given by the following:

$$\varepsilon_y = \frac{y_1 - y_2}{y_1} \quad \textit{(1.8)}$$

Note that this value is negative – this is a result of the way the forces and the direction the forces act in are defined.
Poisson's ratio is defined by equation:

$$v = \frac{\varepsilon_y}{\varepsilon_x} \quad \textit{(1.9)}$$

Poisson's ratio is dimensionless.

Poisson's ratio is an important factor in determining the stress gradient of the formation, but is less important in defining fracture dimensions, although it does have some effect. Typical values for ε for rocks are between 0.2 and 0.35. [6]

I.5.4 Shear modulus

The shear modulus is similar to Young's modulus, except that it refers to the material being in shear rather than in compression or tension. It defines how much energy is required to elastically deform a material in shear. [15]

$$G = \frac{E}{2(1+\nu)} \tag{1.10}$$

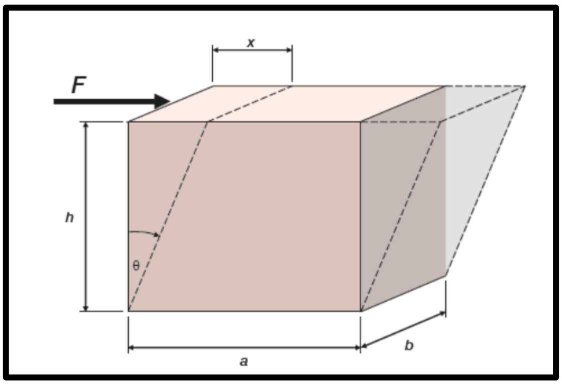


Figure I- 21 Force f applied to produce shear modulus [6]

I.5.5 Vertical stress

Vertical stress, also referred to as overburden stress, is the sum of all the pressures applied by all of the different rock layers. Every formation contains fluid and rock, and each one must be accounted for separately.

$$\sigma_V = \sum_0^H \rho_n g h_n \tag{1.11}$$

Where the density of the rock layer is n, g is the acceleration due to gravity and h_n is the vertical height of the zone n.

This is often expressed more simply in terms of overload gradient, g_{ob} : [15]

$$\sigma_V = g_{ob} H \tag{1.12}$$

I.5.6 Minimum horizontal stress

Minimum horizontal stress is approximated as fracture closure pressure. It is a direct result of overburden stress; Poisson’s ratio determines the amount of stress that can be transmitted horizontally [15]. Minimum horizontal stress or fracture closure pressure can be obtained from either a diagnostic fracture injection test (DFIT) or by using the following equation: [4]

$$\sigma_{h,min} = \frac{v}{1-v} x(\sigma_v - \alpha P_b) + \alpha P_b + P_{Tectonic} \tag{1.13}$$

I.5.7 Maximum horizontal stress

Maximum horizontal stress is more challenging to calculate. The minimum horizontal stress is calibrated from fracture closure analysis from surface low-rate injection tests (mini-fracture), downhole wireline straddle packer injection tests (microfracture). Then the magnitude of maximum horizontal stress can be estimated from the occurrence of borehole breakouts, induced fractures, or fracture initiation pressure (formation breakdown) recorded during open hole micro-fracturing tests. [4]

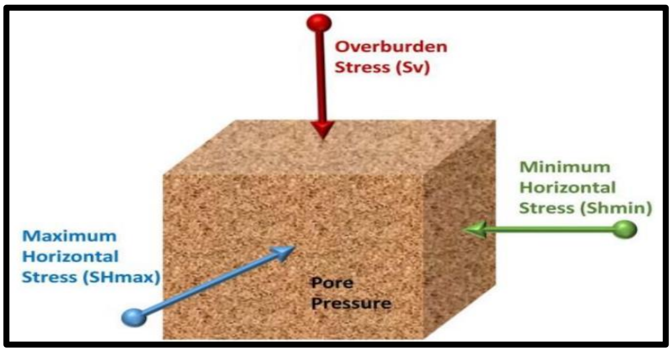


Figure I- 22 Minimum, maximum and vertical stresses on a rock [4]

I.5.8 Breakdown Pressure

Fracture pressure is the pressure required to initiate a fracture from the well. Due to the stress effects induced by the presence of the well, the fracture pressure is greater than the fracture gradient, which is a measure of the pressure required to propagate the fracture through the formation, far from the effects of the well.

To produce a fracture in the formation, two forces must be overcome. The first force is in-situ stress, which is defined in the Hook and Handin equations when there are no external influences such as tectonics, etc. The second force is rock tensile strength, which is in the range of 100 to 500 psi. Roegiers (1987) defined the rupture pressure as a follow-up:

$$p_{if,upper} = 3\sigma_{h,min} - \sigma_{h,max} - p_r + \sigma_t \quad \textbf{(1.16)}$$

$$p_{if,lower} = \frac{3\sigma_{h,min} - \sigma_{h,max} - 2\eta p_r + \sigma_t}{2(1-\eta)} \quad \textbf{(1.17)}$$

where $p_{if,upper}$ is the rupture pressure assuming there is no fluid invasion in the formation (that is, the maximum theoretical rupture pressure possible), $p_{if,\ lower}$ is the lower limit of the rupture pressure, assuming significant alteration of pore pressure near the well due to fluid, and η is a parameter defined by the Poisson coefficient and the Biot constant, as follows: [3]

$$\eta = \frac{\alpha(1-2v)}{2(1-v)} \quad \textbf{(1.18)}$$

I.6 Fracture orientation

Fractures will always propagate along the line of least resistance. In a three-dimensional stress regime, a fracture will propagate so as to avoid the greatest stress. This means that a fracture will propagate parallel to the greatest principal stress, and perpendicular to the plane of the greatest principal stress. This is a fundamental principle – therefore the key to understanding fracture orientation is to understand the stress regime itself. [16]

Fracture orientation is influenced by various factors such as overburden pressure, pore pressure, tectonic forces, Poisson's ratio, Young's modulus, fracture toughness, and rock compressibility. [3]

I.6.1 Transverse fractures

To create transverse fractures, the well needs to be drilled (placed) parallel to the minimum horizontal stress or perpendicular to the maximum horizontal stress. [3]

I.6.2 Longitudinal fractures

To create a longitudinal fracture, the well needs to be drilled parallel to the maximum horizontal stress or perpendicular to the minimum horizontal stress. [3]

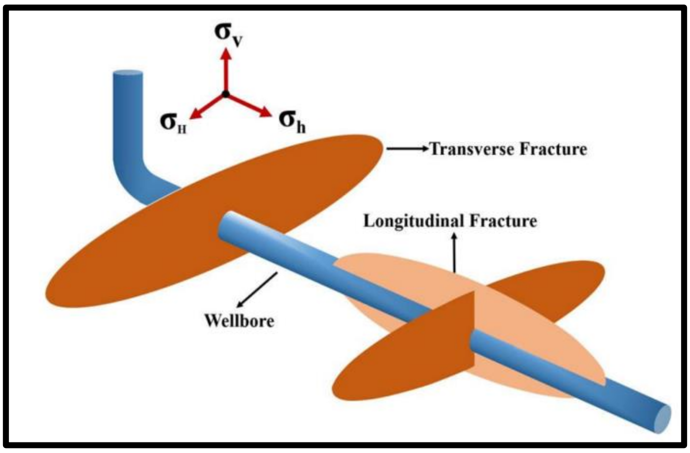


Figure I- 23 Transversal and longitudinal fractures [4]

I.7 Fractures geometry

Every fracture, regardless of how it was pumped or what it is designed to achieve, has certain basic characteristics. All fracture modelling is designed around determining these three characteristics, height H, half-length X and width W. Once these three characteristics have been determined, other quantities such as proppant volume, fracture conductivity and ultimately production increase can be determined. [3]

I.7.1 Two-dimensional (2-D) fracture geometry

Three main models existed; radial, KGD (Kritianovitch and Zheltov, Geertsma and DeKlerk, further refined by Daneshy) and PKN (Perkins and Kern, Nordgren). However, below is a brief, qualitative description of the models. [3]

I.7.1.1 GKD

In this model, fracture height is fixed, and width is proportional to fracture length. This model also assumes constant width against height and slippage at the formation boundaries. [3]

I.7.1.2 PKN

In this model, the fracture height is again assumed to be constant. However, this time there is no slippage between the formation boundaries, and the width is proportional to fracture height. [3]

I.7.1.3 Radial

Various radial models have been developed, but in each one the height is assumed to be directly related to the fracture length, such that $h_f = 2r_f$ (the radius of the fracture). In this model, fracture width is proportional to fracture radius. [3]

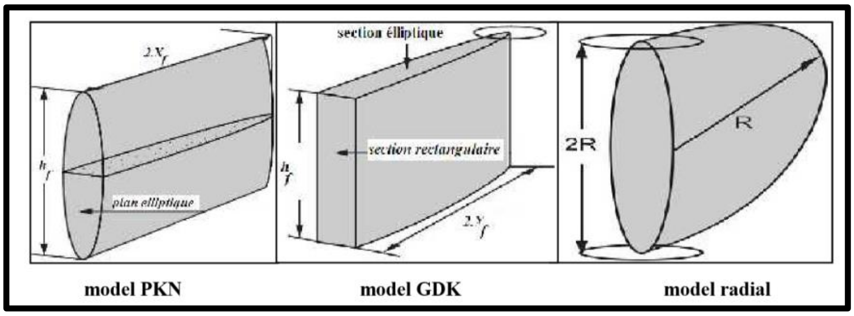


Figure I- 24 Fractures propagation models [3]

I.7.2 Three-dimensional (3-D) fracture geometry

Today, most fracture modeling is performed using lumped-parameter 3-D simulators. These models are considerably more sophisticated than the 2-D models but are not fully 3-D. The main fracture simulation 3D models used in the industry today are FracPro, frac cade, Gopher and MFrac. They are used on well over 90% of all treatments currently performed. [3]

I.8 Hydraulic fracturing treatment stages

I.8.1 Injection test

It requires injecting a fluid, such as treated water, brine, or crude, into a fracturing regime in order to:

- Evaluate whether the formation absorbs the fluid (hence, the name of the Injection test).
- Determine the gradient of fracturing.

This test is carried out in two stages: [1]

- **Step test (the propagation pressure's evolution)**

  It entails injecting fluid into the well at increasing flow rates in equal duration stages until the rock breaks, after which the flow rate is held constant to determine the evolution of the propagation pressure as well as the profile injection. [1]
- **Constant flow test (determine areas of fluid absorption)**

  The test includes pumping fluid (water containing 2% KCl) at a constant rate until the fracture occurs; the flow is then maintained for a set period to allow the fracture to propagate. The pump is turned off to record the pressure drop (Fall off). PLT passes are made during pumping to determine the areas of fluid absorption; this test is repeated at various flow rates to ensure accurate estimation of the fracture height. [1]

I.8.2 Mini frac tests (Data Frac, Shadow Frac)

The mini frac is designed to be as close to genuine treatment as possible without pumping massive volumes of proppant. The mini frac should be pumped at the anticipated rate with the anticipated treatment fluid. It should also have enough volume to access all of the formations that the planned main treatment design is expected to reach. A well-executed mini frac can provide information on:

- fracture geometry,
- rock mechanical properties, and fluid leak-off.
- information that is vital to the success of the main treatment

The mini frac includes two tests: [1]

Step rate test

The Fracture Extension Pressure (FEP) is determined by this test. It involves injecting the base fluid (treated water) at low rate at first, then gradually raising the rate in increments and sustaining it for a long enough period until the pressure stabilizes (5 to 10 min). All of this must be backed by continuous pressure recording.

This allows us to draw two curves P as functions of Q, and the intersection of the two gives us the pressure of fracture extension after projection on the pressure scale. [1]

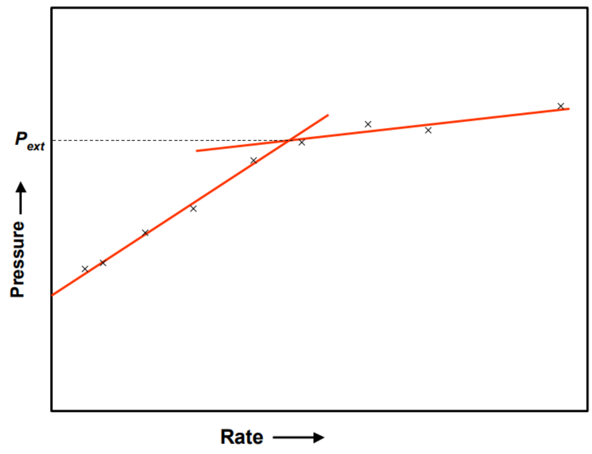


Figure I- 25 Step rate test [1]

- **Pressure decline test**

The purpose of this test is always to create a mini fracture in the formation using the same fluid as the main treatment. It is divided into two stages:

- Mini frac step, which makes it possible to determine the propagation model.
- Fall-off step or pressure drop after mini frac, which determines:
  - The efficiency of the treatment fluid (η).
  - Fluid filtration (CL).
  - The geometry of the fracture (width, length, and thickness).

This test entails injecting the fluid into the formation at the proposed rate of the main treatment and maintaining it until 10 to 15% of the total volume of proposed for the the treatment is pumped. Then, to initiate the second phase, stop the injection and shut the well, which is the fall-off, allowing the pressure at the bottom to drop. [1]

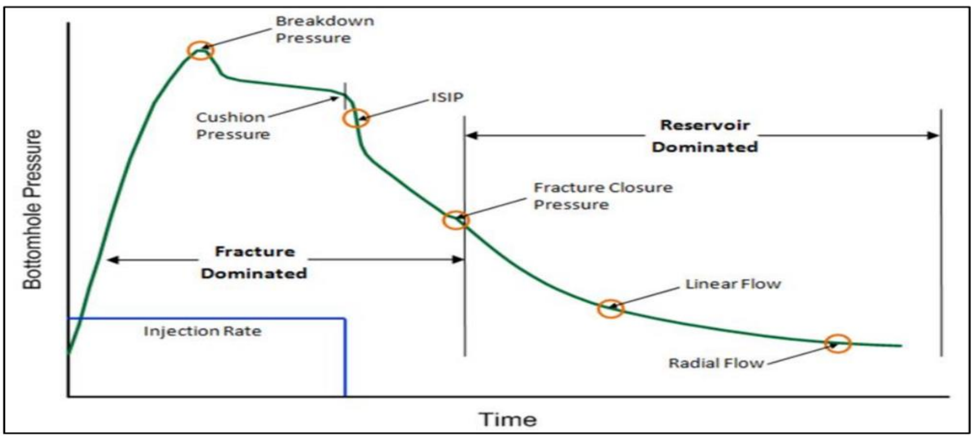


Figure I- 26 Idealized pressure curve for a minifrac test [6]

I.8.3 The main treatment

There are three stages to it:

- **Injecting a Pad** A fracturing fluid, typically a very viscous crosslinked gel that isn't carried with propping agent, is injected at the head to initiate, and develop a fracture by widening it enough to allow the balls to pass through. The pressure required to reopen the fracture is called fracture reopening pressure (RFP) and is generally lower than the fracturing pressure established during the test calibration tests.
- **Slurry injection** This phase consists of conveying the support agent from the surface to the fracture, using a cross-linked gel, with progressive Proppant concentrations (ramps or stages). Its role is to fill and maintain the open fracture once the fracturing pressure is released.

The Proppant is generally injected only when it is safe that the width of the fracture is wide enough to accept the intrusion of the supports, and the obtained length approaches the expected length. The concentration of Proppant is increased as we approach the end of the stage.

In this phase, two to three sizes of supports are often used, successively and separately. From the finest to the largest. Generally, 40% of the planned supports are injected with a constant concentration (plateau) at the end of the stage. This ensures maximum concentration around the well and maximum conductivity in this area. The sudden drop in the concentration of proppant on the surface announces the end of the current stage and the beginning of the hunt.

- **Flush displacement** This step involves pumping a Proppant-free linear gel that will flush out the excess of the previous mixture (Slurry) remaining in the tubing or in the perforations. Linear gel is used because it is easy to disgorge. The hunting volume varies depending on the size of the completion. When hunting, Care must be taken not to over-move the fluid loaded in Proppant, the volume of hunting must always be underestimated otherwise the area next to the well, is no longer supported. [1]

I.8.4 Pumping shutdown and well closure

At the end of the hunt, we stop the pumps. The opening of the well is done by observing the head pressure (While waiting for its stabilization, approximately 3000 psi for safety reasons). The closure of the well allows the excess pressure to be released by filtration. It is essential to block the Proppant in place before the well is disgorged. Some recommend disgorging the well after 24 hours of closure, others limit this wait to 8 hours. The duration of closure varies from well to well depending on the permeability of the reservoir and the nature of the fluid injected. The use of a temporary blocker can significantly delay the lowering of head pressure. [1]

I.8.5 Well disgorgement and production initiation

In this phase, it is necessary to try to evacuate not only the treatment fluid contained in the well and in the fracture, but also the fluid that filtered in the formation. It is recommended that the well be disgorged by gradually increasing the flow rate in order to avoid sudden variations in the effective stresses in the formation and to maintain the proppant in the fracture. The BSW measurements make it possible to specify the duration of the disgorgement (we will stop for example when BSW ≤ 5%). [1]

I.9 Analysis of hydraulic fracturing

After performing the treatment, the results should always be evaluated and analyzed to define the optimal design for performing the main treatment. The most applied method is:

I.9.1 Pressure decline analysis

After analyzing the curve recorded during the MiniFrac test data which consists of identifying closure and analyzing the early pressure falloff period while the induced fracture is closing, we can obtain the following parameters: [1]

- **Break down Pressure** this is the pressure required to initiate the fracture, so it must exceed the minimum stress of the hole.

- **Instantaneous shut-in pressure (ISIP)**

$$\mathbf{ISIP = Final\ injection\ pressure - Pressure\ drop\ due\ to\ friction} \quad \textit{(I.19)}$$

- **Fracture gradient**

$$\mathbf{Fracture\ Gradient} = \frac{\boldsymbol{ISIP}}{\boldsymbol{Formation\ depth\ (ft)}} \quad \textit{(I.20)}$$

- **Net Fracture Pressure (ΔP_{net})** Net fracture pressure is the additional pressure within the frac above the pressure required to keep the fracture open. It is an indication of the energy available to propagate the fracture.

$$\Delta \mathbf{P_{net}} = \mathbf{ISIP - Closure\ Pressure} \quad \textit{(I.21)}$$

- **Fluid efficiency** The fracture volume is divided by the total volume pumped. It can be determined by Nolte's Function G method.

$$\textbf{Fluid Efficiency} = \frac{G_c}{G_c+2} \qquad \textbf{\textit{(I.21)}}$$

Gc is the G-function time at fracture closure.

• **Formation leak-off** characteristics and fluid loss coefficients or Filtration coefficients: we can calculate it by a simple relation:

$$\textbf{\textit{Total pumped volume}}\ (\%) = \textbf{\textit{Filtration coefficient}}\ (\%) + \textbf{\textit{Fluid efficiency}}\ (\%) \qquad \textbf{\textit{(I.23)}}$$

• **Propagation pressure** This is the pressure necessary for the fracture to propagate.

• **Fracture closure pressure (FCP)** this is the pressure necessary to keep the fracture open. It is almost equal to the minimum horizontal stress.

In order to determine the closing pressures on the pressure decline curve, various methods have been developed in this direction, the most used methods are:

- G-Function method
- Square Root Time method
- Nolte and Smith analysis

I.10 Productivity of fractured wells

Hydraulically produced fractures collect fluid from the reservoir matrix and provide channels for it to flow into wellbores. The productivity of fractured wells appears to be determined by two steps: receiving fluids from the formation and transporting the fluid to the wellbore. One of the steps is usually a limiting step that controls the well production rate.

The first step's efficiency depends on fracture size (length and height), whereas the second step's efficiency is determined by fracture permeability. The concept of fracture conductivity can be used to evaluate the relative relevance of each phase. [6]

$$F_{CD} = \frac{k_f w}{k x_f} \qquad \textbf{(I.24)}$$

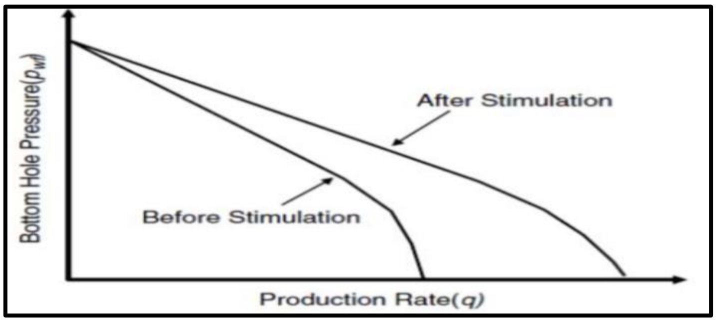


Figure I- 27 Stimulation effect on inflow profile [1]

CHAPTER II:
Well integrity: Tubular design, and packer performance envelope

II.1 Well integrity

Well integrity is in general terms related to the functionality of a well to prevent loss of containment or its capacity to execute its intended activities. However, there are numerous definitions that differ in both scope and focus area, which are briefly explained in this section.

According to Norsok D-010, well integrity refers to the implementation of technical, operational, and organizational measures to minimize the risk of uncontrolled release of formation fluids throughout the life cycle of a well.

When choosing technical solutions, it is crucial to establish the appropriate equipment specifications and clearly describe the requirements for the well barrier in order to ensure the well's integrity is maintained throughout its lifespan. It is important to include particular details such as the BOP rating and size, the type of casings to be used, the pressure rating of both downhole and topside equipment, and the material specifications of the equipment. The specifications will be determined during the initial phase of the project, and the subsequent equipment selection will be based on these specifications.

Another common industry standard in the oil and gas industry is the API RP 17N. Integrity, in this context, refers to the capacity of a system or its components to carry out their intended purpose while effectively preventing or reducing incidents that could potentially endanger human life, well-being, and the environment over its operational lifecycle. This concept covers a wider range of risks, as it includes any incident that could potentially cause harm, not just the loss of containment. Additionally, the integrity aspect does not have any specified dimensions, such as technological or organizational requirements. Integrity management refers to the methodical execution of operations required to guarantee that crucial systems are correctly developed and installed according to specifications and remain suitable for their intended function until they are decommissioned.

NOGEPA Industry Standard no. 90 is a Dutch oil and gas standard that specifies asset integrity. The concept of well integrity is described as “the ability of the well(s) to perform its required function effectively and efficiently whilst protecting Health, Safety and the Environment (HSE)”.Well Integrity Management (WIM) is the methods to ensuring that the people, systems, processes and resources which deliver integrity are in place, in use and will perform when necessary during the lifecycle of the well(s). The definition is comparable in scope and focus to API 17 RP 17 N.

ISO/TS 16530-2:2014 is a standard explicitly addressing well integrity, covering the operational phase of oil & gas wells. Here, well integrity is defined as "containment and the prevention of the escape of fluids (i.e. liquids or gases) to subterranean formations and surface", while well integrity management is "a combination of technical, operational and organizational processes to ensure a well's integrity during the operating life cycle". Similarly to NORSOK D-010, the risk element is limited to the escape of formation fluids, while the integrity aspect covers processes aimed to prevent loss of containment. [15]

II.2 Well life cycle

All wells follow a similar life cycle, regardless of their purpose, with some variations in their design and operational aspects. The well life cycle, as outlined in ISO 16530-1 Petroleum and natural gas industries has the following phases:

- Basis of design phase,
- Design phase,
- Construction phase,
- Operational phase,
- Intervention phase,
- Abandonment phase. [10]

II.3 Well barriers

II.3.1 Definitions

Well barriers are any device or element (such as fluid column, casing, BOPs) that alone or in combination with other elements is capable of containing well pressure and preventing uncontrolled flow of fluids or gases from the formation, into another formation, or to the surface or environment. To control the well, two qualified independent well barrier envelopes should be present at each stage of a well's life. [9]

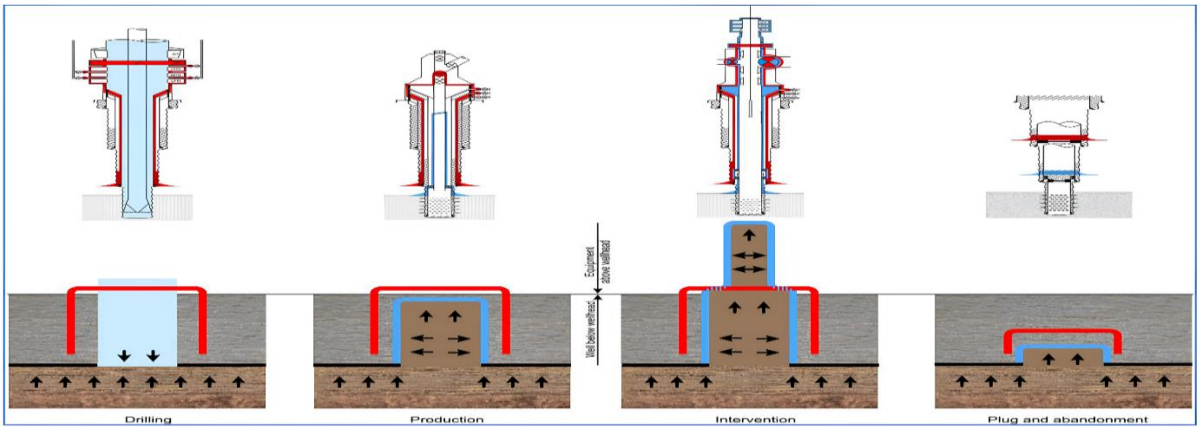
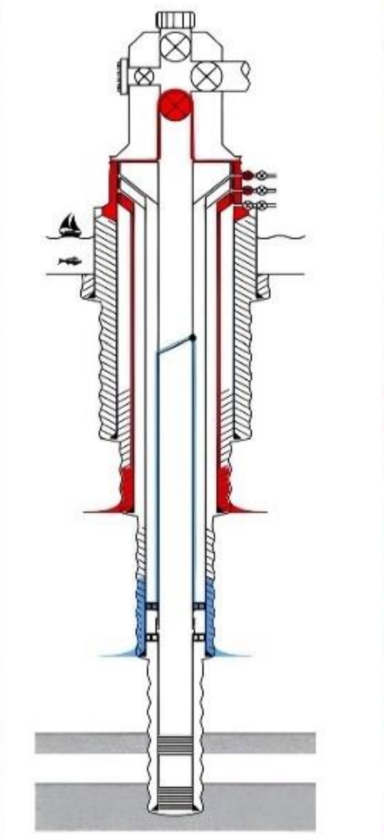


Figure II- 1 Illustration of the two-barrier principle throughout a well's life cycle [8]

Table II- 1 Examples of barrier systems through the lifecycle of the well [6]

Example	Primary Barrier	Secondary Barrier
Drilling	Overbalanced mud with filter cake	Casing cement, casing, wellhead, and BOP
Production	Casing cement, casing, packer, tubing, and DHSV (Downhole Safety Valve)	Casing cement, casing, wellhead, tubing hanger, and Christmas tree
Intervention	Casing cement, casing, deep-set plug, and overbalanced mud	Casing cement, casing, wellhead, and BOP
Plug & Abandonment	Casing cement, casing, and cement plug	Casing cement, casing, and cement plug



Production
Conventional oil or gas producer

Well handed over to owner

Primary well barrier

Element	As built	Monitoring
Downhole safety valve	Inflow tested to xxx bar	Frequent inflow test to xx bar
Tubing	Pressure tested to xxx bar with x.xx sg fluid	A-annulus pressure
Production packer	Pressure tested to xxx bar with x.xx sg fluid	A-annulus pressure
Production casing	Pressure tested to xxx bar with x.xx sg fluid	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote tested or prognosis strength	Not accessible

Secondary well barrier

Element	As built	Monitoring
Surface x-mas tree	Pressure tested to xxx bar	Periodic pressure testing
Wellhead annulus access valve	Pressure tested to xxx bar	Periodic pressure testing
Wellhead	Pressure tested to xxx bar	External observation
Intermediate casing hanger	Pressure tested to xxx bar	C-annulus pressure
Intermediate casing	Pressure tested to xxx bar with x.xx sg fluid	C-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	C-annulus pressure
Formation (in-situ)	Quote tested or prognosis strength	Not accessible

Healthy well, no or minor issue

Figure II- 2 Typical well barrier schematic [8]

II.4 Well barrier envelope

A barrier is an impenetrable object that prevents the uncontrolled release of fluid. Two-barrier philosophy considers two independent well barrier envelopes, primary well barrier, and secondary well barrier. Primary well barrier is the first enclosure that prevents flow from a potential source of flow. Secondary well barrier is the second enclosure that also prevents flow from the potential source of inflow. The secondary well barrier is a back-up to the primary well barrier, and it is not normally in use unless the primary well barrier fails. The principle of the two-barrier philosophy has already been shown in Fig. 1.1; primary well barrier shown as blue line and secondary well barrier as red. For situations where a formation with normal pressure is present, a one-barrier methodology could be acceptable for the abandonment design. [10]

Primary barriers

Element or combination of barrier elements in direct (primary) contact with the potential outflow source, there are two types:

- For conventional drilling

The primary well barrier is the fluid column which is in direct contact with the outflow source. It controls or overcomes the formation pressure.

- For logging in cased hole

Primary well barrier is formed by those elements which are in direct contact with pressure in the well: cemented casing, well head assembly, pressured lubricator and wire line valves.

Primary barrier consists of all elements that are in direct contact with formation pressure and prevent flow during well operations. They can be:

- Drilling or completion fluid column.
- Production casing or tubing.
- Well head assembly & valves.
- Casing or tubing hangers.
- Lubricator and pressure head, etc.

Secondary Barriers

An element or combination of elements defined as the ultimate defense should any of the primary barrier elements fail, and as such preventing uncontrolled flow from the well to surface or to the environment. It is the last and ultimate barrier envelope providing well Integrity to be activated. It is not necessarily barrier number two in a sequence. When primary barrier fails the well start flowing up to the surface or to the external environment formation pressure is contained and uncontrolled flow prevented by activating the defined secondary barrier envelope (cemented casing, casing hanger, well head assembly, lateral valves, BOP activation) and by closing the well in (stabbing safety valve on DP).

Secondary barrier: redundant barrier, outside the primary barrier, to be closed as last resort.

Examples of secondary well barrier envelopes for drilling, production and well intervention, for all well operations having potential uncontrolled flow of formation fluids to the surface, a second (external) barrier shall be defined and installed to be activated as the last resort for containment of formation pressure and flow. [10]

Table II- 2 Possible primary WBEs, and corresponding ACTs and qualifications [8]

Primary well barrier elements				
item	**WBE name**	**WBE type**	**WBE-ACT**	**Qualification**
1	SCSSV: Surface Controlled Subsurface Safety Valve	SCSSV	40	Current leak rate test
2	Tubing	Completion string	14	Pressure test during completion and current annulus pressure monitoring
3	Production packer	Production packer	27	Pressure test during completion and current annulus pressure monitoring
4	Gravel pack packer	Production packer	27	Pressure test during completion and current pressure monitoring
5	Casing	Casing	5	Pressure test during well construction and current pressure monitoring
6	Casing cement	Annulus cement	1	Pressure test during well construction and need to verify cement height
7	Cement plug	Cement plug	7	Pressure test during well construction and current pressure monitoring

II.5 Well barriers failure

Many different types of failures can lead to loss of well integrity. The degree of severity also varies. For each of the blowouts that happened, a long chain of events led to the incidents. The simplest approach would be to consider the failure of individual well components.

Ensuring well integrity involves verifying various elements that comprise a well barrier. The concept remains consistent, but the specific barriers and elements employed vary based on the risks and operational needs of each phase. The design of well barriers is influenced by factors such as well design, characteristics of the targeted resource, and identified risks.

Two well barriers between the reservoirs and the environment are required in the production of hydrocarbons to prevent loss of containment. If one of the elements fails, the well has reduced integrity and operations have to take place to replace or restore the failed barrier element.

A failure in well integrity occurs when all barriers have been compromised, creating a pathway for fluid to enter or exit the well. In a two-barrier design, both barriers must fail for a well integrity failure to happen. However, if the second barrier remains intact, a failure in one barrier will not result in fluid loss to or from the environment.

Some results from a PSA study conducted in 2006. Clearly the production tubing is the dominating component with failure. This is not unexpected as the tubing is exposed to corrosive elements from the produced fluids and, the production tubing consists of many threaded connections where the high number of connections gives a high risk of leak.

Well integrity issues can be caused by any of the following:

- A well breach, including failure of cement sheaths, plugs, bonds, casing, and downhole and surface sealing components,
- A hydrological breach, fluid movement between geological formations, including formations not targeted for exploitation,
- An environmental breach. contamination of or water balance impact on water resources,
- Fluid leaks at surface and causes contamination of water sources. Various potential impacts on environments can result from poor oil and gas well integrity, such as:
    - **Impact on groundwater** contamination of shallow and deep aquifers could be a risk associated with oil and gas well drilling and production activities due to poor well construction,

- Localized hydraulic connectivity between isolated aquifers along a well trajectory, this can occur because of failed casing, poor cementing or generally poor well construction, decommissioning or abandonment practices,
- Fugitive gas emissions, localized gas leakage to both the atmosphere and into aquifers from oil and gas wells can occur because of equipment failure or poor well construction and abandonment practices. [14]

II.6 Well completion

Well completion incorporates the steps taken to transform a drilled well into a producing one. These steps include casing, cementing, perforating, gravel packing and installing a production tree. The quality of completion will also increase the life of the well.

Completion is the operation to complete a well for production or injection after it has been successfully drilled. The completion string transports hydrocarbons to the surface in a safe, controlled, and cost-effective manner. Can also be used to transport injected fluids into the reservoir. The completion is designed according to information provided by logs run after the hole is drilled. For a well completion to be done, some parameters are required

- Production rate.
- Well pressure and depth.
- Rock and fluid properties,
- Surface location.
- Functional requirements.
- Service-workover.
- Drilling considerations.
- Company policies and government regulations. [13]

II.6.1 Well completion components

Completion main components are: [13]

- X-tree.
- Tubing.
- Tubing Hanger.
- Packers.
- Sliding Sleeves.
- Control line.
- Wireline entry guide.
- Sub-surface safety valves.
- Intelligent control valves.
- Isolation valves.

II.7 Tubular design philosophy

II.7.1 Functions of casing

Casing serves a multitude of purposes in wellbore stability and functionality, including: [12]

- Keeping the hole open from sloughing and swelling shales.
- Keeping the hole open from moving salt formations.
- Preventing contamination of fresh-water horizons.
- Providing a means of controlling fluid influxes.
- Providing a container for drilling and completion fluids.
- Confining produced fluid to the well bore.
- Providing a smooth conduit for drilling, logging, and completion tools.
- Providing a smooth conduit for future casing and tubing strings.
- Supporting wellhead equipment and subsequent casing strings.
- Providing a means of anchoring the BOPs and Christmas tree.

II.7.2 Casing string nomenclature

Wellbore construction utilizes various casing strings, each designed for a specific purpose downhole. These strings include: [12]

- Conductor string (1st string with BOPs installed)
  - Installed to cover shallow unconsolidated formations.
  - To seal off shallow water sands
  - To provide protection against shallow gas
- Surface string (Cemented to surface or inside conductor)
  - Installed to provide BOP protection.
  - To seal off water sands and/or to prevent loss of circulation intermediate string
  - To isolate weak formations
  - To case of loss zones, sloughing, caving & reservoir formations
  - Also set in transition zones to abnormal formation pressures
  - To provide BOP protection by upgrading the strength of the well
- Production String
  - Installed to separate productive zones (Hydrocarbons barrier)
  - Design for damage/wear when drilling.

- Liner (other than slotted liners)
    - A string of casing which does not extend all the way to surface.
    - Installed to permit deeper drilling.
    - To separate productive zones
    - Cemented to the top to avoid TAP effect.

II.7.3 Casing design process

Casing design is a critical process requiring a deep understanding of the wellbore as a dynamic system. It involves developing mathematical models to calculate the various loads the casing will experience throughout its lifecycle, including drilling, cementing, production, various shut-in scenarios, injection, and abandonment.

Equally important is understanding the mechanical properties of the casing material, including its deformation under load and ultimate strength. The goal is to define clear operational limits for the entire system, considering the interaction of the casing with surface and downhole equipment. Since casing integrity is vital for well safety, continuous monitoring of its condition is essential to assess how changes might affect its ability to withstand future loads.

Ultimately, any errors in calculations or exceeding operational limitations can have catastrophic consequences, highlighting the importance of robust risk management practices and incorporating appropriate design factors. [12]

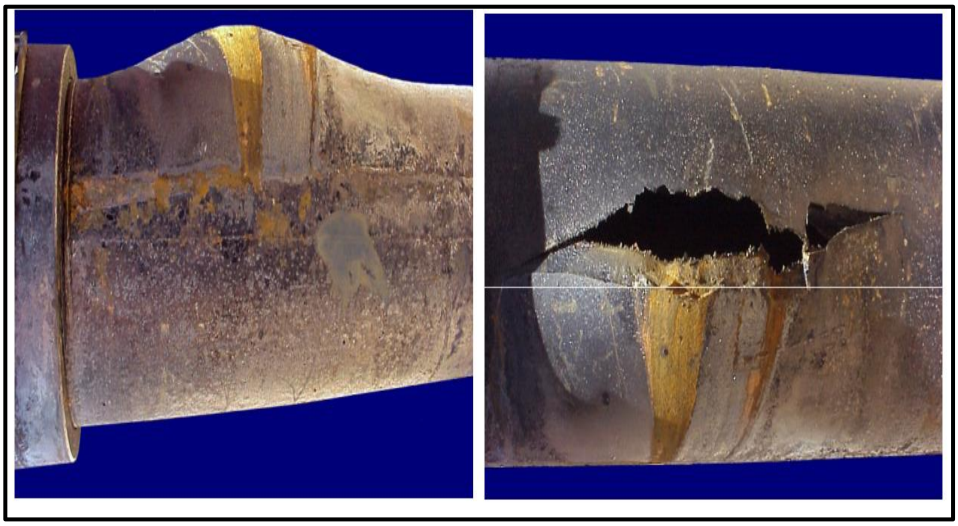


Figure II- 3 Pipe rupture failure [12]

II.7.4 Tubular design philosophy

At its core, tubular design revolves around ensuring the pipe's resistance (capacity) can overcome the various loads (forces and pressures) encountered throughout the well's life cycle. This philosophy necessitates considering three key elements: [12]

1. **Pipe capacity** This refers to the inherent strength or resistance of the tubular itself.
2. **Applied load** These encompass the weight of the pipe string, fluid pressures (both internal and external), temperature variations, and in some cases, additional loads from reservoir compaction or salt movement.
3. **Well operations** Different well operations (drilling, cementing, production, etc.) will subject the pipe to unique combinations of these loads.

The combined effect of these loads translates to stresses within the pipe. A fundamental concept in casing design is the concept of equivalent stress. This value must be maintained below a specific threshold, typically a certain design factor (DF) multiplied by the yield stress (σ_{Yield}) of the pipe material. In simpler terms, the equivalent stress (σ_{Load}) caused by the applied loads must stay comfortably below the stress level that would cause the pipe to yield. This ensures the pipe operates within safe limits and avoids catastrophic failure. [12]

$$\boldsymbol{\sigma_{Load} \times DF < \sigma_{Yield}} \tag{II.1}$$

II.7.5 Loads on tubulars

Tubulars in a wellbore encounter various types of loads throughout their service life, including: [12]

- Burst loads.
- Collapse loads.
- Tensile loads.
- Service loads.

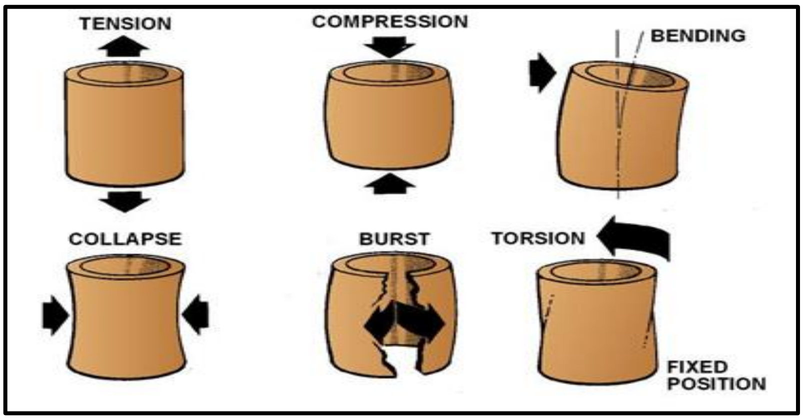


Figure II- 4 Illustration of different loads on tubulars [12]

The critical aspect of design is identification, documentation and modelling of all operations that are likely to take place on a well through to its eventual abandonment:

Table II- 3 The critical aspect of tubular design [12]

Likely operations to take place on a well	Predictable events that the pipe must tolerate
Normal production /injection.	Changes in operating temperature
Pressure testing.	Changes in reservoir pressure
Stimulation.	Well intervention operations such as stimulation, workover etc.
Workover and sidetrack.	Tubing Leaks
Gas lifting.	Annulus blowdown during gas lifting
Conversion from production to injection or vice versa.	Corrosion of tubulars
	Well-kill operations

II.7.6 Deliverables and process

The casing string selection process aims to define the specific components required for a wellbore's structural integrity. This critical step delivers several key outputs:

- **Material specifications** This includes the strength or grade of steel for each casing string, along with its wall thickness or weight. In some cases, the selection might specify a particular steel type like 13Cr for enhanced properties.
- **Coupling selection** The type of couplings used to connect casing sections is determined based on design requirements.
- **Running strategy** Whether a casing string will be landed at the wellhead or function as a drilling or production liner becomes part of the selection process.

Crucially, this selection ensures each string can withstand the most severe loads it might encounter during the well's entire lifespan. Furthermore, the chosen materials must be compatible with the anticipated construction and production fluids the well will encounter throughout its design life. [12]

II.7.7 Service loads

Accurate service load calculations are fundamental for ensuring wellbore integrity. These calculations rely on two key aspects being precisely modeled [12]

1. **Initial conditions (as cemented)** This assumes a fixed wellhead and zero strain within cemented sections.
2. **Applied load conditions** This primarily focuses on how changes in temperature and pressure impact the wellbore, as these variations can induce significant service loads.

II.7.8 Axial force components [12]

- Thermal
- Piston
- Ballooning
- Friction
- Bending

II.7.9 Axial load changes due to pressure change

Axial load changes due to pressure change can be defined in this formula: [12]

$$\Delta F_{bal} = 2\upsilon(\Delta P_i A_i - \Delta P_0 A_o) + \nu L(\Delta \rho_i A_0 - \Delta \rho_o A_0) \qquad (II.2)$$

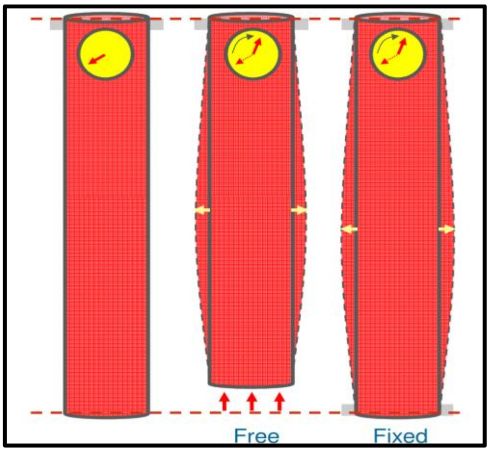


Figure II- 5 Axial load changes due to pressure change on a fixed and free tubular [12]

II.7.10 Axial force component caused by bending

$$F_b = \frac{E\pi}{360} D(\alpha/L) A_s \qquad (II.3)$$

The bending load is superimposed on the axial load distribution as a local effect. [12]

II.7.11 Buckling

Buckling occurs if the buckling force, F_b, is greater than a threshold force, F_p, (Paslay buckling force) [12]

$$F_b = -F_a + p_i A_i - p_o A_o \qquad (II.4)$$

$$F_p = \sqrt{4w(\sin\theta)El/r} \quad \textbf{(II.5)}$$

Table II- 4 Buckling force magnitude results [12]

Buckling force magnitude	Result
$F_b < F_p$	No buckling
$F_p < F_b < 1.4\ F_p$	Lateral (s - shaped) buckling
$1.4\ F_p < F_b < 2.8\ F_p$	Lateral or helical buckling
$2.8\ F_p < F_b$	Helical buckling

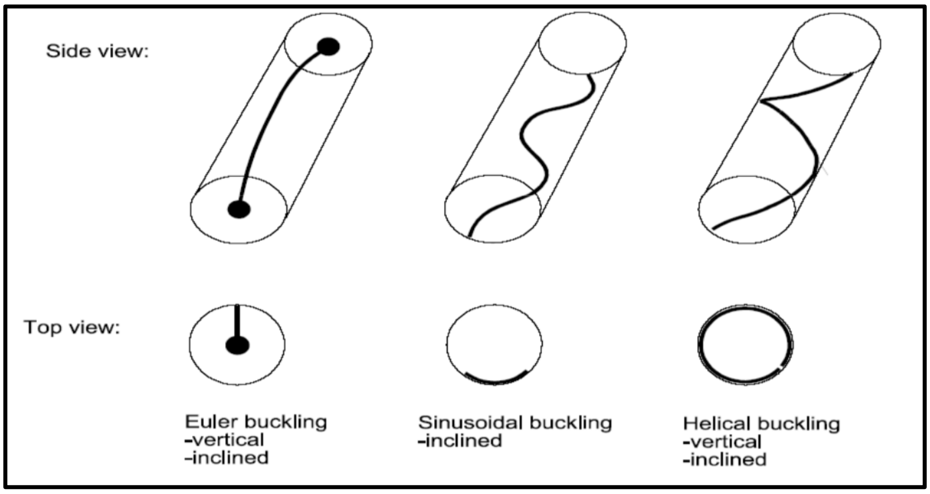


Figure II- 6 Illustration of buckling force magnitude results [12]

II.7.12 Service loads – temperature effects

Temperature changes from the as cemented state because of the changes in the casing stress state: [12]

- Thermal expansion / contraction of steel
- Thermal expansion / contraction of annular fluids

II.7.13 Temperature effects on axial load changes

$$\Delta F_{temp} = -\alpha E A_s \Delta T \quad \textbf{(II.6)}$$

II.7.14 Temperature effects – fluid pressure – TAP

$$\Delta P = \frac{E \times \Delta T}{C} \quad \textbf{(II.7)}$$

Note that:

It’s not a precise formulation because:

•C and E assumed constant

•Volume (casings) assumed constant (casing in reality will balloon) [12]

II.7.15 Trapped annular pressures

Trapped annular pressure (TAP) presents a unique challenge in subsea wells. Unlike onshore or platform wells where pressure can be bled off at the surface, subsea environments make this process difficult. TAP arises when fluids trapped within the wellbore annulus (space between casing strings) expand due to temperature increases during production. This trapped pressure can exert significant force on the casing, potentially leading to damage or failure.

Here are some methods to address trapped annular pressure: [12]

- **Leaving the shoe open** The "shoe" refers to the bottom most section of the casing. Leaving it purposely un-cemented creates a bleed path for any trapped pressure to be released.
- **Thermal insulation** Applying thermal insulation along the wellbore can help reduce heat transfer into the annulus, mitigating pressure buildup.
- **Advanced tubular solutions**
    - **Vacuum insulated tubing (VIT)** This specialized tubing minimizes heat transfer due to its unique construction.
    - **Uncemented bottom annulus** Similar to leaving the shoe open, strategically leaving a section of the bottom annulus uncemented provides a controlled pressure bleed-off point.
- **Nitrogen injection** Injecting inert nitrogen gas into the annulus can help manage pressure by providing a compressible cushion.

II.7.16 Influence of temperature

It can be summarized in the following effects: [12]

- Tubular movement and stresses = $f(\Delta T)$
- Buckling
- Annular pressure buildup
- Deration of tubular strength
    - yield strength = f(temperature)
- Corrosive environments
- Wellhead loads and movement.
- Packer loads
- Equipment limits: BOP and pack seal elements
- Cement design
- Fluid density and viscosity = f(temperature)

II.7.17 Biaxial collapse analysis

This analysis aims to identify the worst-case scenarios for pipe collapse by considering biaxial loading. We will achieve this by: [12]

1. **Determining internal and external pressure profiles** We will identify combinations of internal and external pressures that create the greatest difference between them (differential collapse pressure). This may involve multiple pressure profiles, especially when considering different axial loads on the pipe.
2. **Axial force vs. depth** For each identified pressure scenario (load case), we will calculate the axial force acting on the pipe along its entire depth.
3. **Temperature profile determination** A temperature profile will be established for each load case.
4. **Effective collapse pressure calculation** At critical depths within the pipe, we will calculate the effective collapse pressure using a designated formula (to be provided).

$$\mathbf{P_{eff} = P_o - (1 - \frac{2t}{D})P_i} \quad \textbf{(II.8)}$$

This equation also demonstrates the internal pressure effect on collapse resistance.

II.7.18 Axial load effects on collapse resistance

$$\mathbf{S_{yr}} = \left[\sqrt{\mathbf{1 - 0.75\left({}^{S_A}\!/\!_{Y_p}\right)^2}} - \mathbf{0.5\,{}^{S_A}\!/\!_{Y_p}}\right] \times \mathbf{Y_P} \quad \textbf{(II.9)}$$

This is then applied in the relevant formula for collapse resistance and compared with the collapse loading. [12]

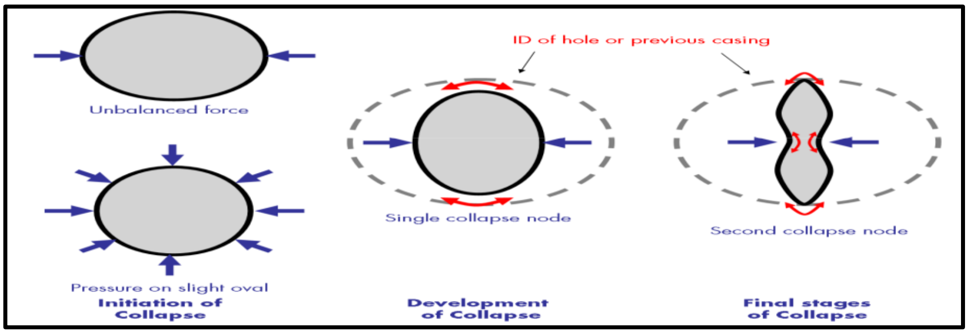


Figure II- 7 Illustration of collapse resistance stages [12]

II.7.19 Von Mises effective stress

For assessing yield strength under combined loading conditions in tubular design, a key concept emerges: [12]

- Integrates all principal stresses and torsion into a single yield stress.
- Must be calculated at 4 points across pipe wall.
- Results should be compared to API Yield Stress value (downrated by design factor)

$$\sigma_{VME} = \sqrt{\frac{\{(\sigma_t-\sigma_r)^2+(\sigma_t-\sigma_a)^2+(\sigma_a-\sigma_r)^2\}+6\tau^2}{2}}\ (kPa\ or\ psi) \qquad \text{(II.10)}$$

II.7.20 Triaxial burst analysis check

Triaxial stress analysis takes all three principal stress directions into account. This includes the two considered in biaxial analysis (axial and radial) but adds the tangential stress which acts circumferentially around the tube. [12]

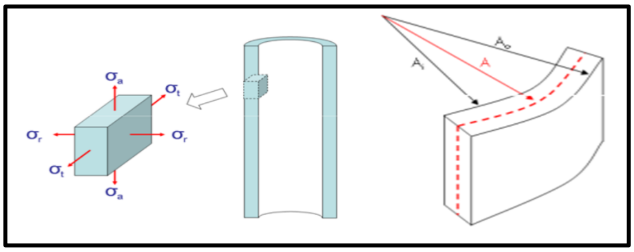


Figure II- 8 Illustration of the different stresses [12]

Axial stress $$\sigma_a = \frac{F_a-F_p}{A_o-A_i} \pm \sigma_B \qquad \text{(II.11)}$$

Tangential stress $$\sigma_t = \frac{P_iA_i-P_oA_o}{(A_o-A_i)} + \frac{(P_i-P_o)A_iA_o}{(A_o-A_i)A} \qquad \text{(II.12)}$$

Radial stress $$\sigma_r = \frac{P_iA_i-P_oA_o}{(A_o-A_i)} - \frac{(P_i-P_o)A_iA_o}{(A_o-A_i)A} \qquad \text{(II.13)}$$

Torsional stress $$\tau = \left(\frac{2T\sqrt{\pi A}}{A_o^2-A_i^2}\right) \qquad \text{(II.14)}$$

It can be performed manually by the following steps:

- Select locations of peak loads (burst and/or tension / compression)
- Consider tensile changes due to bending at 4 locations across pipe wall.
- Determine axial, radial and tangential stresses.
- Determine Von Mises equivalent.
- Compare with derated yield stress.

But the preference is to utilize StressCheck or WELLCAT™ because:

- Multiple load cases can be analyzed.
- Consistent calculation methods

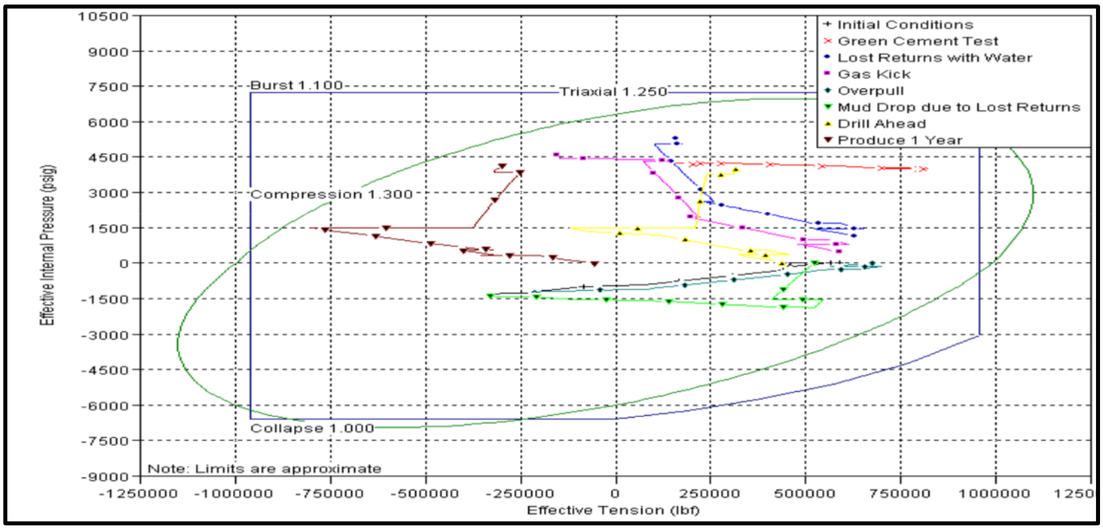


Figure II- 9 Example of triaxial design check in WELLCAT™ [12]

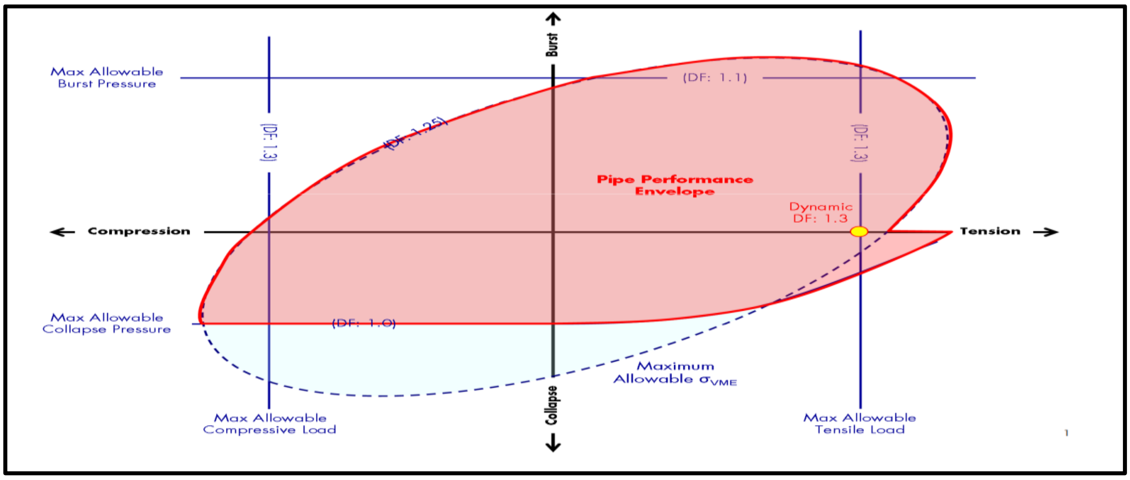


Figure II- 10 Detailed casing design - Pipe performance envelope [12]

II.7.21 Connections

The casing design manual specifies that all connections must be qualified for the service that they will see. This includes:

- The axial loading (tension and compression).
- The burst and collapse loads.
- The triaxial effect of all combinations of burst, collapse, and axial loading.

Connections – in particular premium connections – are weaker in compression than in tension.

In addition to mechanical failure (reaching or exceeding yield stress), connection must not leak.

Key parameter is the type of fluid casing exposed to during the lifetime of well. [12]

II.7.22 Connection strength

Approved connections shall be used for barrier elements connections shall have a connection strength envelope (CSE). [12]

- Defines the design strength of a connection.
- Loads within CSE will not cause leaks or structural failure.

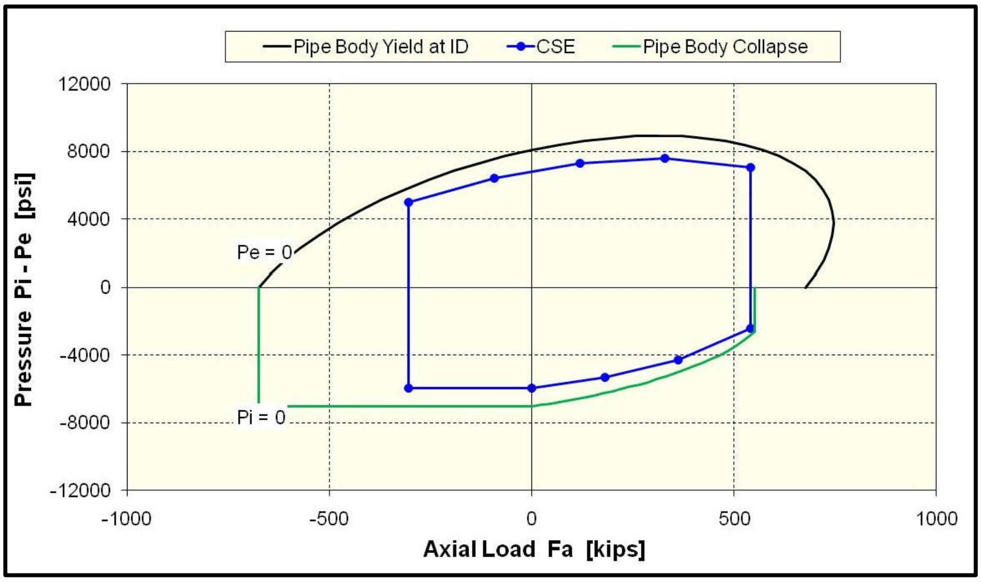


Figure II- 11 Connection strength envelope [12]

II.8 Production packers

A packer is a downhole device used to provide a seal between the outside of the tubing and the inside of the production casing or liner.

The packer seal is created by resilient elements that expand from the tubing to the casing wall under an applied force. When set, this seal prevents annular pressure and fluid communication across the packer. [13]

II.8.1 Functions

Production packers are used to: [13]

1. Isolate well fluids and pressures.
2. Keep gas mixed with liquids, by using gas energy for natural flow.
3. Separate producing zones, preventing fluid and pressure contamination.

4. Aid in forming the annular volume (casing/tubing/packer) required for gas lift or subsurface hydraulic pumping systems.

5. Limit well control to the tubing at the surface, for safety purposes.

6. Hold well servicing fluids (kill fluids, packer fluids) in casing annulus.

7. Protect the casing from pressure and produced fluids.

8. Isolate casing leaks or squeezed perforations,

9. Isolate multiple producing horizons,

10. Eliminate or reduce pressure surging or heading,

11. Hold kill fluids in the annulus, and

12. Permit the use of certain artificial-lift methods.

II.8.2 How packers work and how packers fail

Before a packer's rating can have value, it is necessary to understand its function and how various loading conditions and environmental factors influence its ability to perform. By simplest definition, the packer's function is to grip and seal. It must remain anchored stationary within the casing, and it must maintain pressure sealing integrity with differential pressures, either below or above the tool.

Initial setting forces apply loads, wedging the slips into the casing wall through movement of the cones. These same forces supply energy for the packing element system, generating rubber pressure sufficient to produce the sealing effect. Conditions after setting can act to enhance the initial sealing and anchoring effect, but when increased sufficiently, will ultimately produce failure. The area(s) of failure can be predicted by the combination of the applied loads.

Variations in design will influence load carrying characteristics, but all have failure modes associated with extremes of the same conditions. The basic load matrix (Table II-5) provides the basis for evaluating the simultaneous effects of both differential pressures and applied axial loads. Temperatures and other environmental conditions, as well as the packer's component materials, will influence the packer's ability to carry combined loads. [5]

Table II- 5 Rating envelope quadrants [5]

Tension applied with pressure above the packer	Tension applied with pressure below the packer
Compression applied with pressure above the packer	Compression applied with pressure below the packer

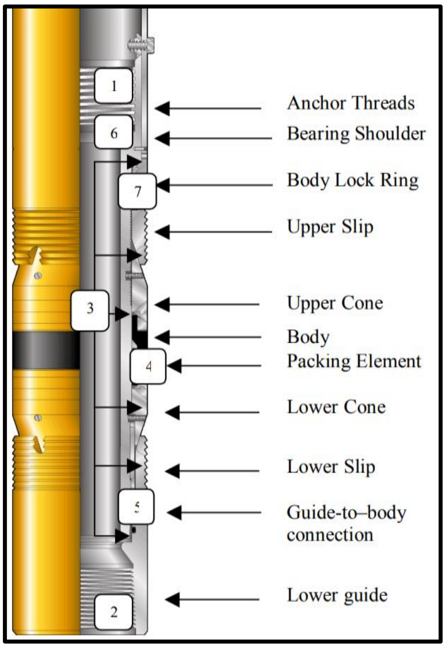


Figure II- 12 Basic permanent production packer configuration [5]

The seven most common areas of failure on a permanent production packer are enumerated, including body collapse (3), packing element system failure (4), pin collapse at the body/lower guide connection (5), body-to-guide connection failure (2), anchor attachment failure (1), body lock ring failure (7), and bearing failure (6).

II.8.3 Packer performance envelopes

The successful performance of any packer includes recognizing that the combined effects of varying differential pressure or applied forces cannot be considered independently. Rating a production packer in terms of the differential pressure alone does not sufficiently describe the packer's performance limits. To accurately measure and compare the performance of various packers, an understanding of the simultaneous effects of differential pressure and axial loading is required.

Development of the performance envelope represents a major step forward in bringing practical meaning to packer ratings. With an understanding of the interaction of combined loading conditions, it is possible to produce a representation of a predictable safe operating zone (performance envelope) for a packer. The performance envelope concept has made it possible to evaluate the packer's design, calculating the envelope parameters, based on dimensional and material specifications. Worst case conditions of the application can then be overlaid to the envelope.

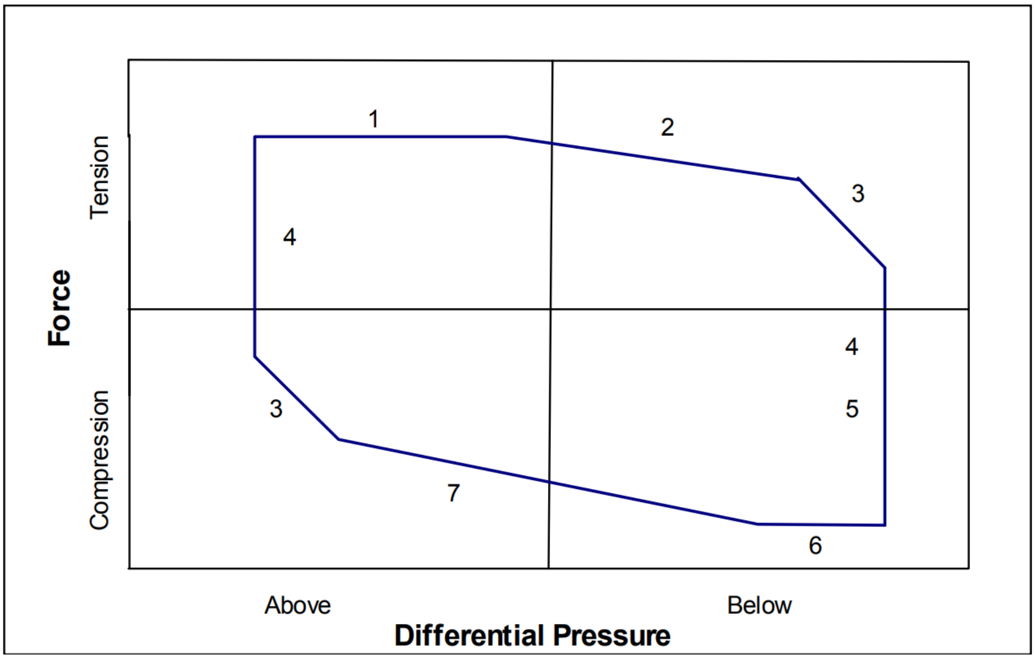


Figure II- 13 Packer performance envelope [5]

Areas outside the envelope are beyond the calculated safe operating zone. The numbers represent a failure mode, called out in figure II-13, resulting from axial loading and differential pressure.

It is important to realize this envelope does not define points of failure. Rather, it only illustrates limits that can be calculated to provide predictably reliable performance. Where conditions of actual application define a condition outside the envelope, risks are introduced. The level of risk might or might not be deemed acceptable, following careful evaluation. When using performance envelopes as a comparative tool between competing manufacturers, it also important to recognize the influence of variations in acceptable safety factors, and how they might be calculated.

For instance, manufacturer A sets standards defining any calculated bearing damage to components as beyond acceptable. Manufacturer B considers that same calculation's degree of bearing failure not significant enough to interfere with the performance of the system. Taking this latitude wherever possible affords manufacturer B the opportunity to enhance the perception of performance, despite having no real performance advantage. For this reason, performance envelope representations are most appropriately used as tool in evaluating each manufacturer's tool to a given application. Incorporating the performance envelope in the completion planning process provides the opportunity to make necessary modifications in the completion design, material changes, and/or procedural changes to ensure reliable performance. If the performance envelope is to be used in a manufacturer-to- manufacturer comparison for performance value to price, close scrutiny as to calculated values is necessary for a fair comparison. [5]

II.8.4 Using the performance envelope

Familiarization with the four quadrants of loading conditions and the associated failure modes provides understanding of the failure implications. With this knowledge, the completion engineer can reasonably evaluate the implied risks when all best efforts still point to some conditions beyond the envelope boundaries. Each of the failure modes are examined here. Distinction is made concerning what conditions constitute potential damage to the tool, and what conditions can result in catastrophic failure. This discussion is limited to permanent production packers, but the same considerations apply to retrievable production packers or service packers. Although the differences in configuration of retrievable packers will apply loads to components different from those in the permanent packers, loading implications can be similar. [5]

II.8.4.1 Body collapse

This failure mode is defined by the collapse of the packer body onto the outside diameter (OD) of the seal assembly. This condition results from excessive stress generated in the body. The excessive stress can be produced by differential pressures from above or below the packer, packer to tubing forces, or the combined effects of these forces. These forces act on both the cross-sectional area of the body and that of the packing element system. Any compressive or tensile forces applied to the body are permanently trapped between the slips. [5]

II.8.4.2 Packing element system failure

This system is comprised of the packing element and supporting back-up rings. Failure of the system can occur with the packing element extruding through the back-up system, or by degradation of the packing element due to temperature or chemical effect, or failure of the back-up system. Extrusion of packing element through small gaps in the back-up system or anomalies in the casing ID can result when the temperature rating of the packing element material is exceeded, particularly in combination with differential pressures and packer-to-tubing forces that exceed the tool's rating. Degradation of the packing element resulting from excessive temperature or chemical effect is an application design issue that must be considered in the completion system plan. It is not expressed as part of the pressure and axial load limits represented in the rating envelope. The failure of the packing element back-up system is the bending or shearing of the back-up rings. The back-up system is designed to expand to the casing ID, filling the extrusion gap between the packer's OD and casing ID. Excessive pressure can produce this failure, so it follows for a given size packer, support for the back-up system is reduced, relative to increased casing ID. **Consequences**: Failure of the packing element system is catastrophic. Once the sealing integrity is compromised, well pressure can no longer be controlled, failing the completion system. This limitation is illustrated in region 4 of the rating envelope. [5]

II.8.4.3 Pin collapse at the body/guide connection

This failure mode is possible in applications with a plug set in a nipple below the packer, or where a seal-bore extension is fitted to the bottom of the packer. Similar to body collapse, exposure of thread connection to pressure can cause deflection of the pin connection of the packer. This has the same implications as body collapse, resulting in sticking the sealing assembly. **Consequences**: As with body collapse, stuck seals can cause high tubing stresses, but is considered non-catastrophic. Unlike body collapse, deflection of the pin connection to point of interference with seal assembly is not a locked in force, and equalization of the pressure will normally allow the pin connection to return to its original dimension. Region 5 of the rating envelope illustrates this limitation. [5]

II.8.4.4 Body-to-guide connection failure

Failure of the body-to-guide connection is defined as one of two variations. It can occur as a failure of the material at the thread relief when tensile forces exceed the body material's yield strength. A failure of the thread itself can occur when tensile loads exceed the bearing strength of the threads. This connection is affected by both differential pressure from below the packer and packer-to-tubing tensile forces. This condition will normally occur as a result of the additive forces of both differential pressure and tensile load and is typically at issue during stimulation procedures. [5]

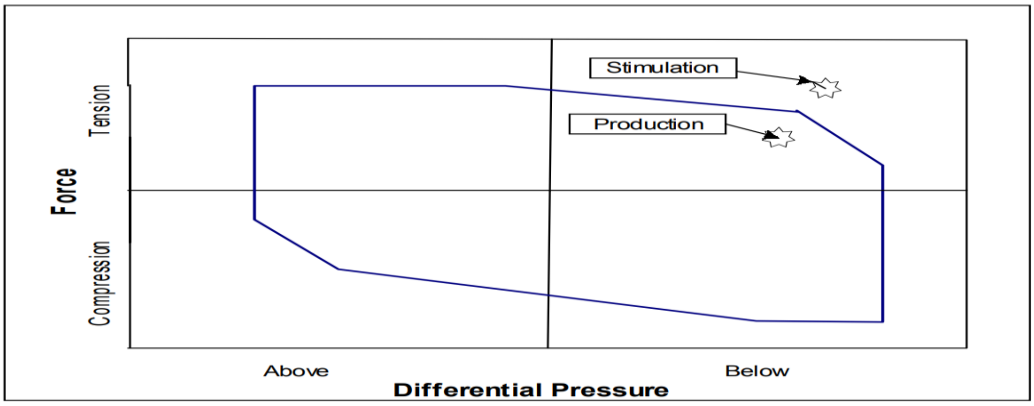


Figure II- 14 Packer performance envelope in production and stimulation scenarios [5]

The point within the envelope referencing the production condition is safely within the performance range of the packer. However, the combination of forces associated with ballooning and contraction of the tubing during stimulation indicate tensile forces at the packer, possibly causing failure.

The importance of considering the impact of anticipated stimulation procedures is illustrated in Figure II-14. The plotting of both producing and stimulating conditions would imply other options should be considered. Although it is acceptable for the producing condition, it would likely be necessary to consider changing to a higher yield strength material in the packer or allowing the seal assembly to float in order to manage the stresses of stimulation. **Consequences**: Failure of the body-to-guide connection is a catastrophic failure. The connection's failure would free the body to move up through the packer. The guide, with its attachments, would fall downhole. The rating limit of the connection is represented in region 2 in the rating envelope. [5]

II.8.4.5 Anchor attachment failure

This failure can occur only when the tubing is anchored to the packer, which is normally accomplished with a left-hand square thread or jay lug / jay slot type anchor. Both configurations are similar in load considerations of material strength versus contact area. Failure can occur in the thread relief if tensile loads exceed the body's material yield strength. Failure of the thread itself can occur when the thread's shear or bearing strength is exceeded. The same would apply to the jay lug / jay slot. Swelling of the body can also be seen as a failure, or as a contributing factor in the failure of the thread or jay lug. This would occur when the elastic burst limit of the wall is exceeded. **Consequences**: Failure of the anchor connection is catastrophic. The seal assembly is freed from the packer seal bore, resulting in loss of the completion system's pressure integrity. Limits of the anchoring device are represented in region 1 of the rating envelope. [5]

II.8.4.6 Body lock ring system failure

Failure of the body lock ring system can result with stresses exceeding the material's shear or bearing strength. This applies to the ring itself or its supporting components.

Consequences: With failure of the body lock ring system, the body is allowed to float as pressure reversals are experienced. Although the slips have locked in packing element force, movement of the body will cause wear on the ID of the packing element. This can eventually cause a leak, but in the absence of pressure reversals, there are no serious consequences associated with the body lock ring failure. The limits of the body lock ring system are represented in region 7 of the rating envelope. [5]

II.8.4.7 Bearing failure

This failure mode is associated with both anchor and locator type seal assemblies. Bearing failure can occur when compressive packer-to-tubing force exceeds the bearing strength of the material at the contact point between the anchor or locator and the packer. Another criterion of failure is the stress generated by the radial component of the contact force. **Consequences**: There is potential, with extremely high compressive loads, to swage the seal assembly into the body when the seal assembly's top shoulder angle is shallow. Minor bearing failure that only causes slight deformation of the mating surfaces will not compromise the completion system. The bearing load limitation is represented in region 6 of the rating envelope. [5]

II.9 Maximum allowable pressure calculations

Hydraulic fracturing requires a delicate balance between maximum allowable annulus surface pressure (MAASP) and maximum allowable treating pressure (MATP). MAASP sets the surface pressure limit for fracturing fluid injection, while MATP defines the downhole wellbore's safe pressure limit. Understanding both is essential for safe and efficient fracking.

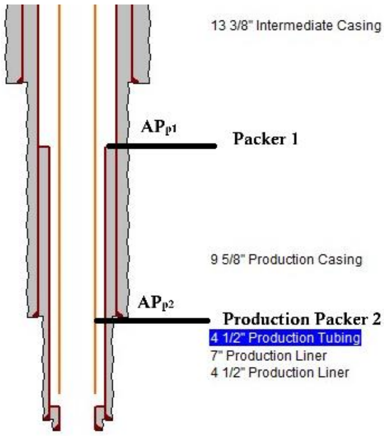


Figure II- 15 Hypothetical completion diagram

II.9.1 Maximum allowable anulus pressure calculation

$$\begin{cases} AP_{P1} + HP(A)_{P1} < 80\% \ \Delta P \ Burst \ 9^{"5}/_{8} \ casing & \text{(II.15)} \\ AP_{P2} + HP(A)_{P} < 80\% \ \Delta P \ Burst \ 7^{"} \ casing & \text{(II.16)} \end{cases}$$

$$\begin{cases} AP_{P1} \\ AP_{P2} \end{cases} \rightarrow Minumum \ Value$$

MAASP is the minimum value between AP_{P1} AP_{P2}.

II.9.2 Maximum allowable treating pressure calculation

$$(TP + HP(tbg) - Friction \ loss) - \left(AP_{min} + HP(A)\right) < 80\% \ \Delta P \ Packer \qquad \text{(II.17)}$$

$$MATP < MAASP + HP(A) + 80\% \ \Delta P \ Packer - HP(tbg) + Friction \ loss \qquad \text{(II.18)}$$

II.10 WELLCAT™

WELLCAT™ is a software program used to design and analyze oil and gas wells, particularly their casings and tubing (steel lining). It helps engineers by providing accurate downhole conditions, analyzing stresses on casings and tubing, and modeling thermal effects. This ensures safe and efficient well design, especially for complex environments. [16]

II.10.1 WELLCAT™ Applications

- Temperature-critical applications
  - ❖ HPHT wells.
  - ❖ Arctic or deepwater wells.
  - ❖ Cement slurry design.
  - ❖ Annulus fluid expansion (subsea wells).
  - ❖ Calculation of undisturbed temperatures from log data.

- Advanced analysis
  - ❖ Advanced buckling and friction.
  - ❖ Complex completions.
  - ❖ Critical wells. [16]

II.10.2 Wellbore thermal simulation's purpose

- Predict temperatures in wellbore casing.
- Predict fluid pressures and temperatures in wellbore annuli and tubing.
- Predict temperatures in the formation. [16]

II.10.3 Wellbore thermal simulation's use

Well completion design

- ❖ Thermal simulation generates temperature and pressure loads used to:
  - Design casing and tubing.
  - Influence material selection.
  - Influence packer selection and seal assembly design.
  - Generate fluid thermal expansion annulus pressures.
- ❖ Thermal simulation of steam injection wells predicts:
  - Insulation effects on heat loss and steam injection well efficiency.
  - Choke sizes for limited-entry steam injection.

Cementing operations

- ❖ Thermal simulation aids cement retarder formulation by:
  - Predicting slurry placement temperatures.
  - Predicting temperature build-up after placement.
- ❖ Thermal simulation predicts slurry hydraulics.
- ❖ Logging.
- ❖ Thermal simulation helps estimate undisturbed temperatures.

- ❖ Thermal simulation predicts thermal disturbance of formation.

Production operations

- ❖ Thermal simulation generates temperatures and pressures that may be used to:
    - Size production tubing for expected production.
    - Design surface facilities.
    - Predict start up conditions.
    - Predict permafrost thaw.
    - Design resin and gel injection treatments.
    - Design stimulation treatments.

Coil tubing operations

- ❖ Well intervention.

Fluid flow correlations

- ❖ Non-Newtonian laminar and turbulent flow for muds.
- ❖ Large selection of multiphase flow correlations for oil and gas production.

Mathematical formulation

- ❖ Heat balance in wellbore.
- ❖ Finite difference in formation.

Equation solution techniques:

- ❖ Implicit formulation for stability.
- ❖ Alternating direction implicit method for efficient solution. [16]

Chapter III: Well integrity assurance approach

Conclusion

WELLCAT™ plays a critical role in ensuring well integrity during hydraulic fracturing treatments by providing a comprehensive analysis of downhole conditions. Triaxial burst analysis and packer performance envelope evaluation within WELLCAT™ are crucial for understanding the well's ability to withstand the high pressures and complex stresses induced by fracturing fluids.

However, WELLCAT™'s value extends far beyond pressure analysis. By accurately modeling thermal effects alongside mechanical loads, WELLCAT™ offers a unique advantage. During fracturing, temperature fluctuations can significantly impact casing and tubing stresses. WELLCAT™'s ability to predict these thermal effects allows engineers to design wells that can handle the complete downhole environment, not just the pressure spikes. This approach minimizes the risk of tubulars and packer failures and ensures the well's structural integrity throughout the fracturing process.

In essence, WELLCAT™ empowers engineers to optimize wellbore design and avoid catastrophic failures by:

- **Analyzing triaxial burst stresses** Identifying weaknesses in the casing that could lead to bursts under the combined pressure and stress conditions.
- **Evaluating packer performance envelopes** Guaranteeing that packers can effectively isolate zones and prevent fluid migration during fracturing.
- **Modeling thermal effects** Predicting how temperature variations will impact casing and tubing stresses, ensuring the well can withstand the complete downhole environment.

By considering both pressure and thermal loads, WELLCAT™ provides a robust platform for designing and executing safe and efficient hydraulic fracturing treatments.

Recommendations

Based on the comprehensive analysis and findings presented in this thesis, the following recommendations are proposed to address the identified challenges, enhance well integrity during hydraulic fracturing treatments, while improving cost-effectiveness in the studied cases:

- If the load conditions for the hydraulic fracturing operation design fall outside the safe operating zone of the packers' performance envelope, there would be two possible recommendations:
  - Using a packer with a greater performance envelope.
  - Manipulating the injection parameters such as rate and pressure by lowering them if possible.
- If the triaxial design check reveals that any of the data points for the tubing design in the well fall outside the safe operating zone, a tubular with a greater pipe performance envelope shall be used.
- If the triaxial design check reveals that any of the data points for the tubing design in the well fall within the safe operating zone with ease, a tubular with a smaller pipe performance envelope can be used to reduce the cost.
- If the triaxial design check reveals that any of the data points for the tubing design in the well fall outside the connection strength envelope, a stronger connection is a must.

While WELLCAT™ provides a robust foundation for ensuring well integrity during hydraulic fracturing, further advancements can unlock even greater safety and treatment optimization. By incorporating the following recommendations, we can leverage WELLCAT™'s thermal modeling capabilities to achieve a deeper understanding of the downhole environment and conduct a more comprehensive well integrity analysis by studying the effect of these probable factors on well integrity:

- **Well design** Considering wells with different designs, such as casing and cementing configurations, well depths, and diameters, allows for evaluating the influence of design parameters on well integrity performance. A more complex wellbore configuration (multiple casings, packers etc.) might be more interesting to model from a WELLCAT™ perspective.
- **Type of fracturing fluid** The chemical composition, viscosity, proppant type and concentration, fluid volume, additives, and temperature of the fracturing fluid can all impact well integrity. Different fluids may cause varying degrees of chemical

interaction, mechanical stress, and thermal stress on the well components, making this an important factor to consider.

- **Hydraulic fracturing history** Choosing wells with different hydraulic fracturing histories, including varying numbers of fracturing stages for multistage hydraulic fracturing, volumes of injected fluids, and types of proppants, helps assess the impact of fracturing operations on well integrity.
- **Well age** Including both older and newer wells in the study provides insights into how well integrity might evolve over time, considering factors like material degradation, technological advancements, and regulatory changes.
- **Production history** Examining wells with diverse production histories, including production rates and decline trends, can uncover correlations between production activities and well integrity issues.

Bibliography

[1]: BJ. (n.d.). Asia-pacific region Frac Manual.

[2]: BJ. (n.d.). ENG103 Fundamentals of Fracturing Engineering.

[3]: BJSP. (n.d.). Fracture Design (Wellbore and Fracture Orientation).

[4]: CHERFAOUI Safa, C. S. (2021). Multistage Hydraulic Fracturing With Horizontal Wells In Unconventional Reservoirs. Ouargla.

[5]: Fothergill, J. (2003). Ratings Standardization for Production Packers. Oklahoma City, Oklahoma: SPE, Baker Oil Tools.

[6]: GUENAOUI, A. S. (2022). Etude expérimentale des facteurs affectant la perméabilité des agents de soutènement en fracturation hydraulique dans un réservoir pétrolier. Ouargla.

[7]: Haliburton. (n.d.). Lab Preparation for Delta and Hybor system .

[8]: Joe Anders, B. M., & Tore Fjågesund, W. A. (2015). Implementation of Well Barrier Schematic Workflows. Texas, USA: SPE.

[9]: Laaouar Zine Labidine, K. Y. (2022). Well Integrity Management: Annulus Pressure, Causes and Solutions. Ouargla.

[10]: Mehdi, K. O.-Z. (2023). Applications of advanced well integrity evaluation technologies for critical. Ouargla.

[11]: REZZAG BEDIDA Abdessalam, H. A. (2021). Etude de la Fracturation Hydraulique à HASSI MESSAOUD (Design et Evaluation). Ouargla.

[12]: Shell International E & P. (2011). W200 – Core & Well Engineering Knowledge.

[13]: Wan, R. (2011). Advanced Well Completion Engineering.

[14]: CRUMPTON, H. (n.d.). WELL CONTROL FOR COMPLETIONS AND INTERVENTIONS.

[15]: Norwegian University of Science and Technology. (2012). An Introduction to Well Integrity.

[16]: Halliburton. (n.d.). WELLCAT™ Software: Advanced Casing Design and. Complex Completion Analysis

[17]: BENOUIS Ahmed Chaker, D. M. (2023). PETROPHYSICAL ANALYSIS IN CAMBRIAN RESERVOIR RA OF HASSI MESSAOUD (SOUTH EASTERN SECTOR). 2023: University of Kasdi Merbah Ouargla.