Montanuniversitaet Leoben

Chair of Drilling and Completion Engineering

Master Thesis

Feasibility Study of a Well Scale Laboratory at Erzberg, Austria

Author

Medardus Ramsauer, B.Sc.

Supervisor

Univ.-Prof. Dipl.-Ing. Dr. mont. Gerhard Thonhauser

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EIDESTATTLICHE ERKLÄRUNG

Ich erkläre an Eides statt, dass ich diese Arbeit selbstständig verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

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Acknowledgements

First of all I have to thank Professor, Dr. mont. Gerhard Thonhauser, for giving me the opportunity to work on this interesting and forward-looking topic for the purpose of my master thesis. I hope I can witness the realization of the well scale laboratory and the first spud of a well in the near future.

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Abstract

Nowadays, it is still a challenge to drill wells precisely, fast and cheap. Due to the high oil price in recent years and the generally conservative attitude towards changes in technologies in the petroleum industry, new developments in drilling and completion of a well were sluggish on the market. However, the current price development and rising environmental requirements call for reducing costs, increasing efficiency, highest safety levels and sustainability, during the drilling process and over the entire life cycle of a well.

This work deals with a feasibility study of a Well Scale Laboratory (WSL) on the location Palmer at the lowest part of the Erzberg in Eisenerz, Styria, Austria. For this purpose, a drilling rig should be used which is equipped with sensors at all relevant parts of the rig. Also the drillstring and even the borehole should be equipped with sensors for data gathering. At this for continental Europe unique research center, development and research should be done on drilling process and dynamics, well integrity and light weight drilling. Furthermore, the WSL offers the industry and the students the unique opportunity for training under real conditions in the oil field.

This master thesis covers both, local circumstances and the relevant infrastructure as well as the technical and economic part of the well scale laboratory at Erzberg.

Kurzfassung

Heute ist es nach wie vor eine technische Herausforderung, eine Tiefbohrung präzise, schnell und kostengünstig abzuteufen. Aufgrund des hohen Ölpreises in den letzten Jahren und der allgemein konservativen Denkweise in der Erdölindustrie, kamen neue Technologien nur schleppend auf den Markt. Die aktuelle Preisentwicklung und steigende Umweltanforderungen machen jedoch Kostenreduktion, Effizienzsteigerung, hohe Sicherheit und Nachhaltigkeit während des Bohrprozesses und über den gesamten Lebenszyklus einer Fördersonde notwendig.

Diese Arbeit beschäftigt sich mit einer Machbarkeitsstudie eines Well Scale Laboratory (WSL) an der Location Palmer im untersten Teil des Erzberges in Eisenerz, Steiermark. Dazu sollte ein speziell für Forschungszwecke mit Sensorik bestückter Bohrturm, Bohrstrang und Bohrloch verwendet werden. Die Forschungsschwerpunkte für dieses in Kontinentaleuropa einzigartige Projekt sind Bohrprozessdynamik-Optimierung, Zementierungsintegrität und Leichtgewichtbohren. Des Weiteren bietet das WSL Studenten und Mitarbeitern der Industrie Übungs-, Simulations- und Fortbildungsmöglichkeiten unter realen Bedingungen.

Diese Master-Thesis behandelt sowohl die örtlichen Gegebenheiten am Bohrplatz Palmer und die lokale Infrastruktur als auch den technischen und wirtschaftlichen Aspekt des WSL.

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1 Introduction

Exploration and production in the oil and geothermal industry are undergoing a change towards technically more challenging wells, to be drilled and produced, combined with increasing costs and higher levels of safety for their employees as well as increasing environmental standards.
For this propose intensive research and development activities have to be undertaken to keep up with the technical challenges the oil industry is facing now and in the future.

To be right at the forefront of research and education, the department of petroleum engineering (dpe) of the Montanuniversitaet Leoben (MUL) is going to establish three types of laboratories in the near future (see Figure 1).

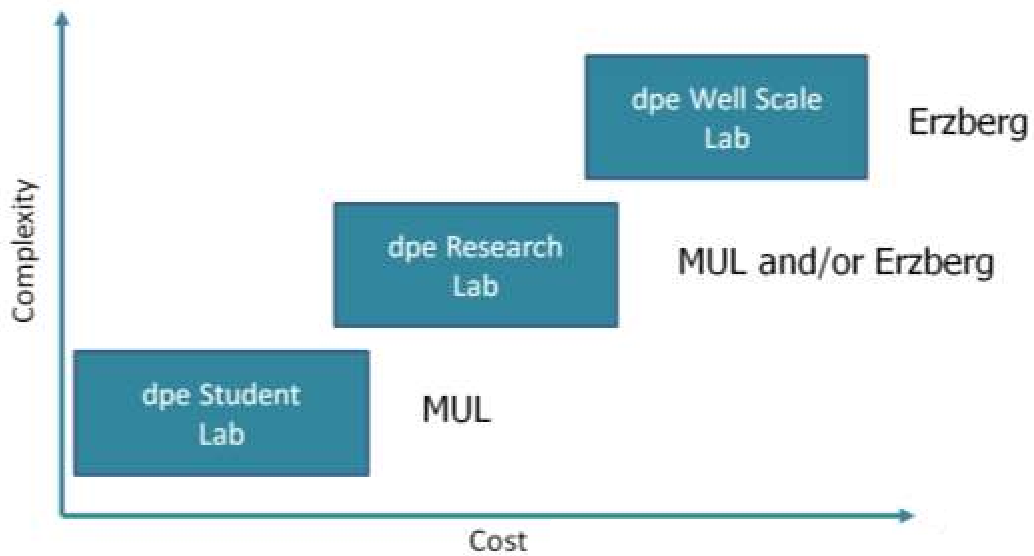

Figure 1: Future laboratory infrastructure at the department of petroleum engineering. At the student laboratory, theoretical classes are put into practice. The research laboratory is intended for extensive research within the university. Finally, the outcomes of research done in the research laboratory can be field-tested at the well scale laboratory. Furthermore, the well scale laboratory will be used for extensive data gathering, during field testing of newly developed tools and for training.

While the student laboratory and parts of the research laboratory are housed at the University in Leoben, the Well Scale Laboratory (WSL) and parts of the research laboratory will be established at the Erzberg, approximately 30 km north of Leoben (see Figure 2).

Figure 2: Overview of the Erzberg from the north. Eisenerz is in front of the Erzberg.

As the most advantageous place at the Erzberg, Palmer was chosen as site for the well scale laboratory (Figure 3). This place offers:

- Short access ways within the active ore mine.
- A large, flat surface area, appropiate for installing numerous long term testing wells, long term artificial lift testing and flow loops.
- The presence of mining tunnels next to Palmer and daily explosions at the ore mine offering the opportunity to establish a downhole seismic laboratory.
- Already existing electricity and water supply.

Figure 3: Drilling rig and auxiliary equipment placed at Palmer.

In the light of the above, this Master Thesis investigates and evaluates the feasibility of a well scale laboratory at Erzberg, and covers the following topics:

- Overview of local conditions
- Listing of present weaknesses of the current practices in drilling engineering and other petroleum engineering related areas and suggestions for relevant research work.
- Requirements for the drilling rig and auxiliary equipment
- Economic investigation prior to putting the rig into operation.
- Conclusion and further steps to complete the project.

This work does not cover legal requirements, detailed market studies and discussions with possible vendors and stakeholders.

The main motivations for establishing the WSL at Palmer are:

- Well integrity
    - Key issue for safe well construction
    - Nonexistence of a large scale laboratory.
    - Globally highly relevant topic
- Down-hole data gathering and sensor evaluation
    - Better understanding of down-hole physics
    - Combination of drilling and formation evaluation while drilling
    - Development of better and more reliable sensors
- Drilling safety and well control training
    - Increasing safety in drilling and well service operation
    - Well control training at the WSL

Value added

- MUL
  - Research & Development for improvement of oil field technology.
  - Enhanced of reputation in the industrial and academic world.
  - Education and training. Students leave the University with better practical background.
- Industry
  - “One Stop Shop”. MUL as a partner in R&D can cover most of technical and economic disciplines.
  - Unique opportunity for testing equipment and training of the rig crews.
  - Perfect infrastructure, accessibility, safety and reliability according to western standards.
- Business and research location Austria
  - Austria as an R&D partner of an industry of internationally nature.
  - Strengthening of Austria's reputation as a leading high tech country.
  - Economic impetus for local business

Realizing the WSL at Palmer would be a valuable asset for the Montanuniversitaet Leoben. Its realization would be technically possible and there is modern infrastructure. It is very likely that the formation drilled will be hard and competent from the surface to final depth, which would offer a desirable rough tool testing environment. However, the realization of the well scale laboratory depends on a great deal on financing and on the partners / clients who support this project. Recruiting the best employees and organizing employment when the laboratory is out of operation will also be challenging but manageable.

2 Geography and Geology

2.1 Geography

The Erzberg is located in the municipality of Eisenerz, which is in the northern part of the district of Leoben, in the federal state of Styria, Austria. Eisenerz is surrounded by the mountain ranges of Hochschwab in the north and east, Eisenerzer Alps in the south, the national park Gesaeuse in the west and Kaiserschild in the northwest.
Traveling time by car is about 30 minutes to Leoben, 65 minutes to Graz (airport) and 180 minutes to Vienna international airport.

2.2 Geology

This chapter gives a short overview of the tectonic classification of the Erzberg area and its geology. However, only the relevant geology for the WSL located at Palmer is described. The information regarding Palmer and its underlying formations is very limited and is more or less based on theories. Most of the information in this chapter is from H.P.Schoenlaub (1982) [1].

The Erzberg is part of the greywacke zone of the Eisenerzer Alps (see Figure 4) and is tectonically within the

- Nordzone,
- Schuppenzone
- Postvariszische Kalkalpen (Praebichlschichten).

The greywacke zone is part of the eastern Alpine nappe and the orogenetic[1] material consists of phyllite, shale, metamorphic vulcanite, low metamorphic limestone (marble), quartzite and greywacke[2].

[1] Orogenetic (orogeneses) is the process of mountain formation by tectonic processes

[2] Greywacke are grey to green grey sandstones with a high content of feldspar in the matrix

Nordzone

The Nordzone is the highest tectonic unit in the early Paleozoic[3] which is connected transgressively[4] with the base of the carbonate Alps. The sequence strata go from Upper Ordovician (495 mya) to Carbon (290 mya). Guiding rock is the Blasseneckporphyroid with a thickness of up to 1000 m, which is always above clastic shale with isolated lenses of lime (Gerichtsgraben-Gruppe).

Above the Porphyroid are local Polsterquarzit and Cystoideen-lime from the younger Ordovician (443 mya). Where these sequences are missing, Silurian lime is directly above the Porphyoid, followed by Devonian lime (Sauberger Kalk and Polster Kalk).

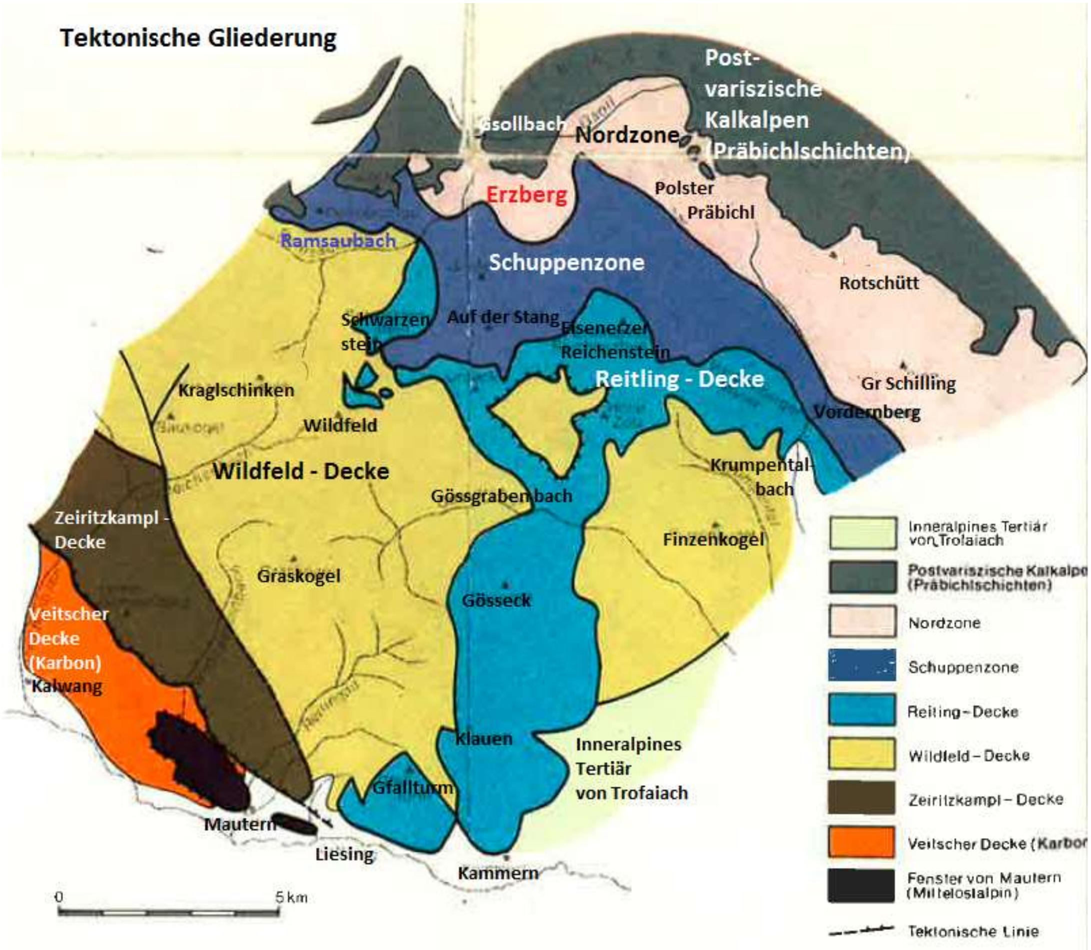

Figure 4: Tectonic structuring of the greywacke zone of the Eisenerzer Alps [2], modified from Schoenlaub (1981)

The Nordzone in the area of the asymmetric Erzberg depression is divided in a west wing (Tullgraben and Hoenegg at the mountain Kaiserschild) and an eastern wing. The west wing strikes from NW-SE with a dip from middle to steep towards the NE.

[3] Early Paleozoic spans from Cambrian (545 mya) to Devon (354 mya) [110]

[4] Transgressive is when the sea level is rising. The saddled sediments are usually not aligned with the origin formation [110]

At the Erzberg, the early Paleozoic together with the Praebichlschichten (Werfner Schichten), has a dip from 15° to 30° and a strike from north to northeast, whereas the eastern wing at the Erzberg is steep to overturned to the west.

Conclusion for the Nordzone with regarding to drilling

It has to be investigated if the location Palmer is in the west wing, east wing or has its own dynamic at the Erzberg, because this is not sufficient described in the literature.

Formations in the Nordzone encountered during drilling are (from top to bottom):

- local Polsterquarzit and Cystoideen-limestone **or**
- Devonian limestone (Sauberger- and Polster Kalk) followed by Silurian lime
- Blasseneckporphyroid with a thickness from up to 1000 m
- Clastic shale with isolated lenses of limestone

Schuppenzone

The Schuppenzone is a rock band which joins the Wildfeld-Decke and the Reitling-Decke on the north side. The Schuppenzone spans the area from Donnersalpe – upper Weißenbachtal (both Kaiserschild) and Groeßenberg (south of Palmer) – Hintererzberg – Plattenalm (south and southeast side of Erzberg) – south side of Gerichtsgraben (northeast side of Erzberg) to the Vordernberger valley.

The strike is usually east to west, the dipping predominantly steep to the north, more seldom to the south (Praebichl).

The stratification is (from top to bottom)

- Devonian (354 mya – 417 mya)
  - Tentakuliten containing nodule lime (Knollenkalk) and local Flaserkalk as well as Eisenerzer Schichten with inclusions of light-grey and black chert (Kieselschiefer) and lydite
- Silurian (417 mya – 443 mya)
  - Black cherts with inclusions of limestone and different colored limestones from the Upper Silurian
- Ordovician (443 mya – 495 mya)
  - Cystoideen limestone
  - Polsterquarzit
  - Blasseneckporphyroid
  - Shale with inclusions of lenses of limestone

The Schuppenzone is a small scaled, tight pressed scall (Schuppen), whereas individual layers are thin rolled to lamellas. The Schuppenzone is intensively folded, faulted and imbricated with the upper lime stones.

Outcrops in the area between Galleiten and Gerichtsgraben are a sign of the presence of a syncline with a strike to the north, where the axis is inclined with an angle of 15° to 30° to the north and NNE respectively.

Conclusion for the Schuppenzone with regard to drilling

The formations encountered during drilling are as shown above.

Cherts, quartzite and porphyroid can be very hard and under high tectonic stress.

Postvariszische Kalkalpen (Präbichlschichten)

Unfortunately the Paebichlschichten are not described by Schoenlaub (1982).

In the following, the Polsterquarzit, Blasseneckporphyroid and the Greichtsgraben-Gruppe is described, as at Palmer, these formations will be of interest.

Polsterquarzit

The Polsterquarzit is directly above the Blasseneckporphyroid and can be seen in Figure 5 in brown color at Groeßenberg (directly opposite of Palmer in the south) and Polster.

The thickness of the layer is 60 – 80 m and consists of 85 – 95 % of mono-crystalline quartzite. The lower part of the layer has a grain size of 2 mm and the upper part of 0.5 mm, where the cementation has a high content of carbonate.

Blasseneckporphyroid (Upper Ordovician)

There are two bands of Blaseneckporphyroid (marked red in Figure 5):

The first band starts from the Tullriegel, goes towards the north of Palmer, to the foot of Glanzberg and further to the south flank of Polster and in the Gsollgraben and has a thickness of around 400 m at Polster.

The second band, which has a thickness of around 100 m, starts at the Groeßenberg (the mountain south of Palmer), to Hintererzberg via Plattenalm to Gerichtsgraben). The facial interpretation indicates to a transgression sequence above the Blasseneckporphyroid.

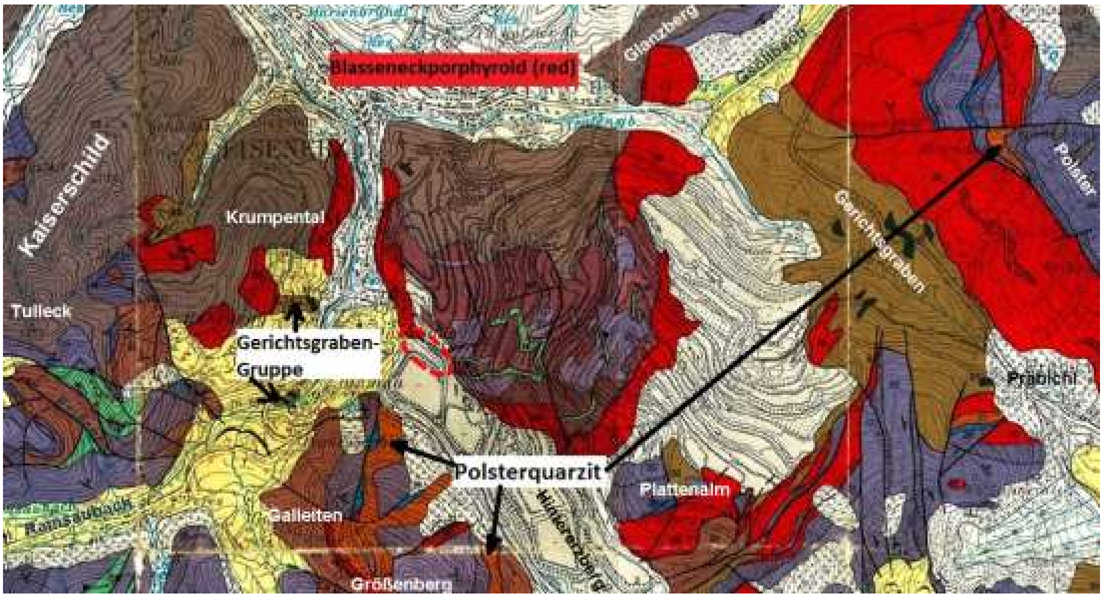

Figure 5: Cutout of Geologische Karte der Eisnerzer Alpen [2]. Modified from Schoenlaub (1981)

There are two types of Blasseneckporphyroide:

- The first and predominant predominately type can be found from Radmer to the south side of Polster. This type is a recrystallized, more or less split into thin sheets of porphyroids with granoplastic quartzite / albite tissue with a quartzite and feldspar grain size of 0.8 to 1.2 mm. The pre-volcanic initial rock must have been crystal rich ignimbrite[5] with alkali rhyolite chemistry.
- The second type is a Lapilli containing porphyroid which is usually found in this area at an altitude of 1200 m.a.s.l. and is of minor interest to the WSL.

A special type is the porphyroid directly at the Erzberg and its neighboring area. In this area the iron, potassium and calcite content is very high which leads to the conclusion that in this area a mass transfer (hydrothermal [3]) between the porphyroid and the overlaying limestone occurred.

Layers below the Blasseneckporphyroid

These layers are considered as a group, the Gerichtsgraben-Gruppe. The largest occurrence is in the Zeiritzkampl-Decke (near Liesingtal; thickness of 400 to 500 m) but also in the Gerichtsgraben, at the end of the Hintererzberg, near the Plattenalm and near Muenzboden and Blumau next to Palmer.

[5] Ignimbrite is a pyroclastic, sour to intermediary, magmatic rock, which was created by fine, hot magma fragments in very hot gases [111].

The Gerichtsgraben-Gruppe formation consists of:

- Serizit shale[6]
- Serizit quartzite
- Arkose[7]-shale
- Chlorite quartzite
- Sandstone scattered mica
- Greywacke
- Carbon rich shale (Schiefer)

On the base and on the top of this clastic layer various types of rocks can occur. In the Gerichtsgraben, inclusions of green shale (Gruenschiefer) with a thickness of 50 m can be found. In the Gerichtsgraben-Gruppe near Muenzgraben and Blumau there are inclusions of limestone and chert shale (Kieselschiefer).

It is not known by now, what kind of formation lies underneath the Gerichtsgraben-Gruppe.

Conclusion for these three types of formation regarding to drilling

The **Polsterquarzit** with a content of mono-crystalline quartzite of 85 to 95 % may become critical to drill [4].

Also the Balsseneckporphyroid with its **high quartzite content** and volcanic origin may become a problem during drilling when using an inappropriate bit [4].

In the Gerichtsgraben-Gruppe, the **chlorite quartzite and serizit quartzite** is the most critical mineral to drill.

Furthermore, in the Schuppenzone, if encountered, the **cherts** are hard to drill [4].

The formations are highly folded and faulted. High stresses in different directions have to be expected. The dipping and striking of the formation can vary and influence drilling.

According to Schoenlaub (1982), the Erzberg is the most tectonic element within the Grauwackenzone of the Eisenerzer Alps.

[6] Serizit is a very fine scaly muscovite

[7] Arkose is a sandstone with a feldspar content of more than 25 %

Formation	Location	Time (min-sec)	Rate of Penetration (ft/hr) $\times 10^{+1}$	Drillability Classification number
Sandstone, Wilcox	Natchez, Miss.	0- 1.9	998	1.9
Lime, Canyon Reef	Snyder, Tex.	0- 2.0	938	2.0
Anhydrite	Gulf Coast Tex.	0- 3.4	552	3.4
Lime, Mississippi	Dover, Okla.	0- 3.9	482	3.9
Hard Marine Shale, Hosston	Haynesville, La.	0- 4.3	437	4.3
Crystalline lime	Rotan, Tex.	0-11.6	162	11.6
Carboniferous Shale	West Tex.	0-15.0	125	15.0
Hard Sandstone, First Bromide	Lindsey, Okla.	0-19.6	95.7	19.6
Sandy Limestone, Smackover	Haynesville, La.	0-26.0	72.2	26.0
Impure Limestone	Unknown	0-30.1	62.3	30.1
Sandstone	Unknown	0-37.3	50.3	37.3
Syenite	Central Tex.	0-37.7	49.7	37.7
Chert	West Tex.	0-45.8	40.8	45.8
Pink Granite	Central Tex.	1-14.1	25.3	74.1
Quartzitic Sandstone, Hosston	Bethany, Tex.	9-15.7	3.4	555.7.*

Figure 6: Drill ability chart for different rock types [4]. In the last lines, granite and quartzite, which represent difficulties for drilling, are listed. However, it has to be noted, that this chart is from the year 1951, when the cutter material different from the cutter material used nowadays.

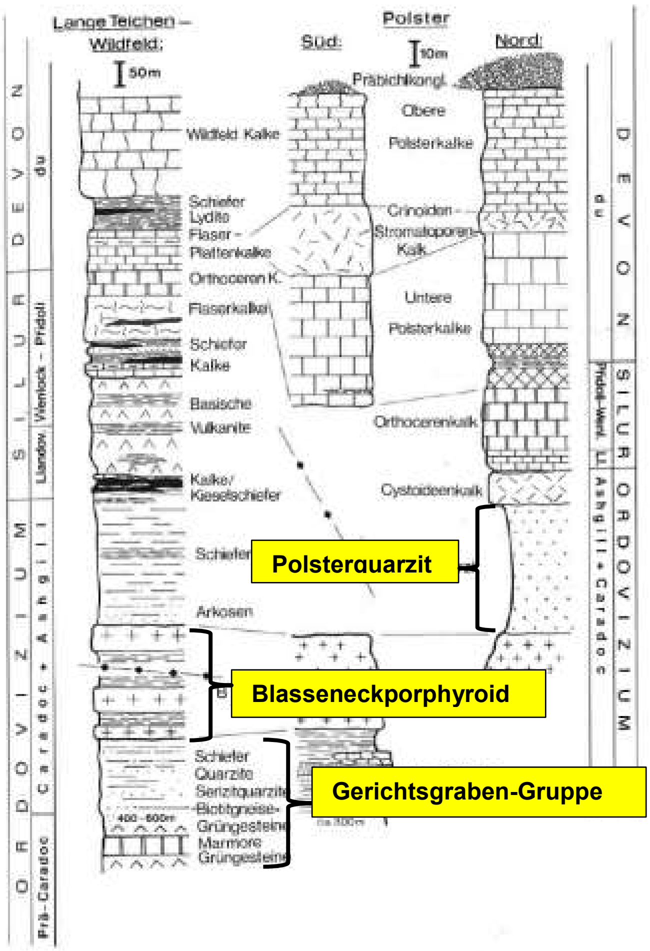

Figure 7: Stratigraphic column of greywacke zone [2]. The layers from interest concerning Palmer are highlighted. The left column represents the Wildfeld, the middle and the right columns show the Polster area. The layer below the Blasseneckporphyroid is considered as a group named Gerichtsgraben – Gruppe.

3 Local Weather Conditions

The following information in the chapter weather conditions and climate is taken from the digital atlas of the geo information system of the state of Styria: Digital atlas [5]; Podesser and Wakonigg, Synthetic Maps [6]; Wakonigg, Temperature, [7]; Podesser and Woelfelmaier, Humidity, Cloudiness and Fog [8]; Wakonigg, Precipitation [9]; Wakonigg and Podesser, Snow Fall and Snow Cover, [10]; Wakonigg, Thunderstorm and Hail, [11]; Podesser, Wind Conditions [12]; Wakonigg, Combined Values [13] and Harlfinger, Bio Climate [14].
Climate related data are taken from 665 meteorological stations in Styria and the neighboring areas of Styria between the year 1971 and 2000.
All values are valid for WSL site at Palmer, Erzberg.

3.1 Weather conditions / climate

Palmer is situated in the climatic region named "Raum Eisenerz mit Eisenerzer Ramsau und Radmer Seitental", number G.8. G stands for the valleys and basins of the main ridges of the Alps. 8 stands for the regional climatic region of Eisenerz. In this region the main precipitations are coming from the westerly to northerly directions. In summer it is warm, in winter it is cold with the possibility of cold air lakes near the surface.

3.1.1 Precipitation

Within the climate region G.8 the precipitation is strongly decreasing from Hieflau to Eisenerz due to the shielding effect of the mountain range Kaiserschild in the northwest. The main wind direction is from northwest to south east.
Amount of precipitation per year: 1567.7 mm/m²
[8] Duration of dry periods: 3.2 days
[9] Longest period of dry days: 30.1 days

[8] The dry period is defined as the average number of days, with a precipitation of less than 0.1 mm / m².
[9] The longest period of dry days is defined as the longest, sequence of dry days.

3.1.1.1 Rain

[10] Number of rain days from May to October: 36.2 days

[11] Average number of rainy days from May to October: 35.3

The maximum expected rain precipitation within 24 hours is 51.2 mm/m²

The 50 years maximum of rain precipitation in 24 hours is 87 mm/m²

Average rate of thundery precipitations of total precipitations: 27 %

3.1.1.2 Snow fall, snow cover and snow loads

[12] Date of the first snow cover: 7th of November

[13] Start of the winter snow cover: 12th of December

End of the winter snow cover: 31st of March

[14] End of the snow cover: 25th of April

[15] Number of days with a minimum snow cover thickness of 10 cm: 98

[16] Number of days with a minimum snow cover thickness of 20 cm: 75

[17] Number of days with a minimum snow cover thickness of 30 cm: 56

[18] Maximum snow cover thickness within 10 years: 136 cm

Average snow cover height on 15th of October: 1.5 cm

Average snow cover height on 1st of November: 3 cm

Average snow cover height on 1st of December: 18 cm

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[10] Rain days (Regentage) are defined as days with more than 1 mm/m² precipitation / 24 h.

[11] Rainy days (verregnete Tage) are defined as days with more than 1 mm/m² precipitation and an average cloudiness of 9/10

[12] The date of the first snow cover is defined as the average date at which the snow cover reaches a minimum height of 1 cm, regardless how long the snow cover has existed.

[13] The starting date of the winter snow cover is defined as the average date from which the snow cover remains throughout winter time without interruptions.

[14]The end date of the snow cover is defined as the average date when the snow cover has vanished from the ground by a minimum of 50 %.

[15] The number of days with a minimum snow cover thickness of 10 cm is defined as the limit of snow cover thickness that gives at least the visual impression of winter still exists.

[16] The number of days with a minimum snow cover thickness of 20 cm is defined as the limit of snow cover that gives the impression of “real” wintry conditions.

[17] The number of days with a minimum snow cover thickness of 30 cm is defined as the limit of snow cover which for most purpose would be considered as deep wintry conditions.

[18] The maximum snow cover thickness within 10 years is the expected maximum snow cover thickness with a probability of 10 %.

Average snow cover height on 21st of December: 28 cm

Average snow cover height on 1st of February: 43 cm

Average snow cover height on 20th of March: 40 cm

Average snow cover height on 20th of April: 24 cm

[19] Probability of a snow cover on the 21st of December: 77 %

Probability of a snow cover on the 1st of February: 87 %

Probability of a snow cover on the 20th of March: 53 %

[20] Number of days with blowing snow: 11

[21] Number of days with snow storm: 12

[22] Number of days with fresh snow: 40.8

[23] Total of fresh snow accumulation per winter season: 342.1 cm

Expected snow loads according to EN-1991-1-3:2003.

The expectid snow load on the ground can be calculated with equation (1) for the Alpine region.

$$s_k = (0.642 * Z + 0.009) * \left[1 + \left(\frac{A}{728}\right)^2\right] \qquad (1)$$

s_k....characteristic snow load on the ground [kN / m²]

Z.....Number according to the associated snow load zone

A.....Elevation of the area of investigation above mean sea level

According to OeNorm B 1991-1-3 Palmer is in snow load zone 3 [15] and is located on 880 m above sea level (see Appendix Figure 53).

This results in a snow load on the ground of 4.762 kN/m². This value can vary with the influence of the wind. Very much care has to be taken on the lee side of roofs, when the weather becomes warm or it starts to rain while snow remains on the roofs. In the design phase of buildings or wind shields the snow load must be taken into considerations.

[19] The probability of a snow cover is defined as a minimum snow cover of 1 cm at 7 o'clock in the morning.

[20] Blowing snow is defined by a level of fresh snow thickness of minimum 5 cm and a wind speed of minimum 12.5 m/s (45 km/h, wind force 6)

[21] A snow storm is defined, by a level of fresh snow thickness of minimum 1 cm and a wind speed of minimum 16,67 m/s² (60 km/h, wind force 8 = storm).

[22] The number of days with fresh snow is defined as the existence of a fresh snow layer with a thickness of minimum 1 cm within one day.

[23] The total of fresh snow accumulation is the total of all fresh snow heights during the winter season. It is a theoretical value and a benchmark for snow removal.

3.1.2 Temperatures

Date of the first frost day: 6th of October (279th day in the year)

Date of the first frost day: (-2°C): 20th of October (293rd day in the year)

Date of last frost day: (-2°C): 24th of April (114th day in the year)

Date of last frost day: 9th of May (130th day in the year)

[24] Average minimum temperature in January: -6.4°C

[25] Average maximum temperature in July: 21.4°C

[26] Number of frost days / year: 142

[27] Number of frost free days / year: 154

Number of frost-free (-2°C) days / year: 176

Number of extremely freezing days / year (≤ -10°C): 20

[28] Number of icy days / year: 36

[29] Number of heating days / year: 249

Last heating day of the year: 17th of June (168th day of the year)

First heating day of the year: 3rd of September (246th day of the year)

[30] Number of summer days / year: 22

[31] Number of tropic days / year: 2.1

[32] Number of muggy days / year: 3

[33] Average heat stress on summer days at 2 p.m.: 38.75°C

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[24] The average min. temperature in January is based on the min. temperatures in January.

[25] The average max. temperature in July is based on the max. temperatures in July.

[26] The number of frost days means days with a temperature below 0°C, at least one time per day regardless of how far, long and often the temperature is below 0°C.

[27] The number of frost-free days / year means the number of days between the last and the first frost day.

[28] Icy days are days with a temperature below 0°C all day.

[29] Heating days: Are days when heating becomes necessary to have an indoor temperature of 20°C. Therefore, a medium outdoor temperature of 12°C being taken into account.

[30] A summer day is defined as a day with temperature above 25°C at least once a day.

[31] A tropic day is defined in the same way as a summer day, but with a temp. above 30°C.

[32] There is no clear definition of muggy (Schwuele) days in H. Wakonigg's work. According to wikipedia.org [106] muggy days are defined as days, with water vapor-saturated air, which is temperature-dependent. Under these conditions the human thermoregulation system (sweating) is disabled, which means a higher burden for the human body.

[33] Average heat stress is a calculated value (temperature equivalent), combining ambient temperature and humidity. This value gives information about the heat tolerability of the human body.. For example, an equivalent temperature of 56°C is felt as muggy.

3.1.3 Lightning and thunderstorms

The number of lightning and thunderstorms is based on the ALDIS (Austrian Lightning Detection and Information System) records from 1995 to 2004.

[34] Average lightning per km² per year: 2.2
[35] Number of thunderstorms per year: 21.2

3.1.4 Wind

Unfortunately for wind at Palmer no or only very limited data are available.

Average wind speed (in Eisenerz) 0.5 to 1.4 m/s
Valley wind system class 2; Side valley 2nd and 3rd order
Wind thickness: 750 / 80
Main wind direction: From Eisenerzer Ramsau to Eisenerz along the valley (SE-NW)

$T_{equivalent} = T_{ambient} + k * e_{vapor\ pressure}$. T in [°C], k = 1.5 [°C / hPa], e in [hPa].

[34] Lightening is defined as lightning that hits ground (no lightning between clouds is counted).

[35] A thunderstorm is defined by lightning as described above, striking within a radius of 5 km.

4 Infrastructure

In the following chapter the infrastructure of the Erzberg area and the town of Eisenerz is described.

4.1 Eisenerz

The Erzberg with location Palmer is situated in the Eisenerz area. Eisenerz is an old town with a long tradition in mining. In the following, the most important data of Eisenerz are given:

Geographic location: 47° 33’N, 14° 53’E
Elevation: 736 m.a.s.l.
First documentary records: 1230
Ore mining since: The Middle Age and up to now
Population (31st of Oct. 2015): 4.367 [16])
Area of Eisenerz (town plus surroundings) 120 km²
Community code: 61101; Municipal code: 611

4.2 Erzberg

The Erzberg is the largest ore surface mining location in central Europe and the world largest [36]Siderite and Siderite - [37]Ankerite deposite [3].
VA Erzberg GmbH is the operator and owner of the Erzberg, including location Palmer
Yearly ore production: 2.15 million tonnes
Yearly total amount of degradation: 7.2 million tonnes
Daily rail transportation of ore to the steel mills: 6000 t

[36] Siderite is part of the carbonate family. Pure siderite has the chemical formula $FeCO_3$. At the Erzberg, the amount of Fe is between 38 and 41 %.
[37] Ankerite is also part of the carbonate family but there is also calcite in the mineral. Pure ankerite has the chemical formula $CaFe(CO_3)_2$. At Erzberg the amount of Fe varies between 10 and 17 % and also Mg is included. The ore mined nowadays consists of around 25% of siderite in the siderite-ankerite ore with a total amount of 22 % of Fe. This low amount of Fe, compared with hematite and magnetite is compensated by the presence of calcite which anyway is a necessary additive for removing undesired substances like phosphor, sulfide etc. during the steel production.

4.3 Location Palmer

Location Palmer (Figure 8) is located at 47° 52' N, 14° 89' E at an altitude of 880 m.a.s.l.. Palmer is a flat area next to the sludge pond Etage IV with a usable surface area of around 20.000 m². Care has to be taken for the pressurized line buried at Palmer. A safety clearance of 3 m on each side of the line must be kept.

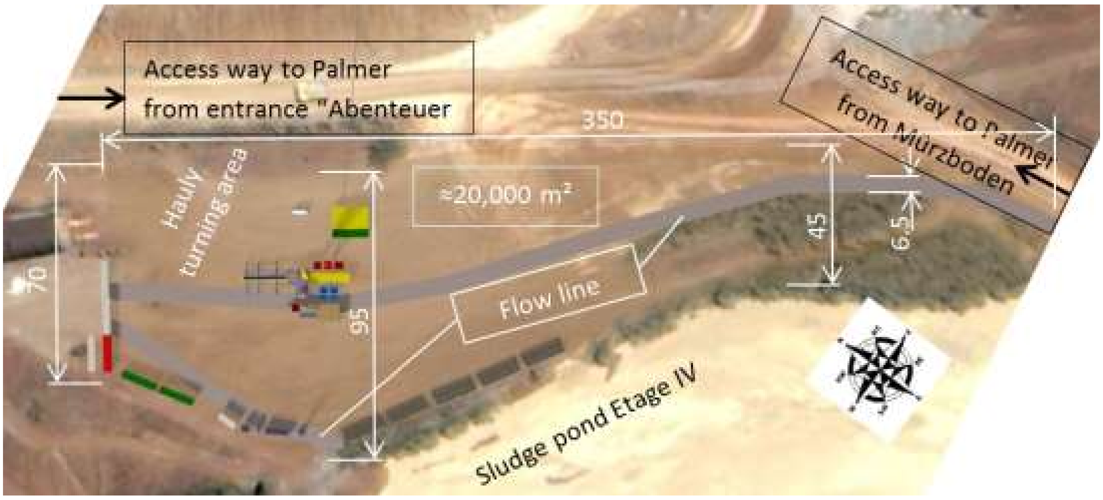

Figure 8: Location Palmer at Erzberg – dimensions next to the sludge pond Etage IV. The light brown area is the useable drilling area and the grey lines are buried, pressurized, flow lines, including a safety margin of 3 m to each side. On the very left side the building Bohrerschmiede can be seen. The measurements are given in [m].

Roughly below the "Access way to Palmer from the entrance Abenteuer Erzberg" (see in the figure above) is a mining tunnel system at an elevation of 808 m.a.s.l (around 70 m below the surface (for more detail see Figure 54 in the appendix). This tunnel system is more or less horizontal and provided with rail tracks. The mining tunnel with the entrance "Mundloch" was closed in the late 80ies last century and since then has not been maintained anymore, but an entrance still exists. These tunnels could possibly be used for seismic geophone installation (see chapter 5.4). Palmer is accessible with trucks either from the south or from the north.

4.4 Transportation

This chapter covers the most important information about transportation to and from Palmer via road, railway and air.

4.4.1 Roads

4.4.1.1 Truck traffic restrictions and toll

General restrictions in transportation with trucks in Austria [17]:

- Ban of night time driving for trucks with a permissible total weight of more than 7.5 t, between 10 p.m. and 5 a.m. on all public roads in Austria.
  - Excepted from this limitation are noise reduced vehicles with the L-label, mounted beside the number plate. For these trucks the speed limit is 60 km/h between 10 p.m. and 5 a.m.

- Ban for driving trucks on the weekend between Saturday 3 p.m. and Sunday 10 p.m. and on public holidays between 0 a.m. and 10 p.m. on all public roads in Austria.
  - This is valid for a truck and trailer combination when the permissible total weight of the truck or the trailer is more than 3.5 t.
  - For trucks or articulated road trains with a permissible total weight of more than 7.5 t.
  - However according to the regulation for combined cargo transportation it is allowed to deliver a container by rail to the cargo station Eisenerz and then moving the container with a truck to location Palmer. Further information may be needed from the Austrian federal railways.

The maximum permissible total weight of a truck train depends on the construction type of the truck and can go up to 44 t, which is regulated in § 4(7) Kraftfahrgesetz 1967.

In the area of Vienna, Lower Austria, Burgenland and parts of Styria (also Leoben) it is not allowed to drive with trucks with the emission level Euro 0, 1 and 2 [18].

For abnormal loads special permits are necessary. An overview in this respect is given in Figure 56 in the appendix. For more detail see Kraftfahrgesetz 1967 [19].

On highways, vehicles above a permissible total weight of 3.5 t, have to pay a toll per km, depending on the number of axels and the emission level of the vehicle (see appendix Figure 55) [20].

4.4.1.2 Most important access roads

All highways in Austria:
Highways with restrictions according to chapter 4.4.1.1. Special care has to be taken concerning emission limits in the area of Leoben, Lower Austria and Vienna.

Leoben to Eisenerz:
The road B 115 from Leoben (Trofaiach) via Vordernberg to Eisenerz is a two line mountain road over the Praebichl with a maximum slope of 10 %, the highest point being at 1240 m.a.s.l. The road is regularly cleared from snow but the use of snow chains may be necassary.

Hieflau to Eisenerz:
Road B 115 and B 146 from the north is a winding two line street without special weight limit.

From Eisenerz to location Palmer:
Figure 9 A and B show two access ways to Palmer. From the south (Figure 9 A) the road Krumpendorfer Straße leads via Muenzboden to the Heeressanitaetslager and further to Palmer. Starting at the junction Muerzboden / Heeressanitaetslager the road is owned by the VA-Erzberg and is unpaved.

The preferred access way is the way via the main access to Erzberg from the north (Figure 9 B).

Regarding for both access ways, for any weight and length limitations the VA-Erzberg has to be conducted.

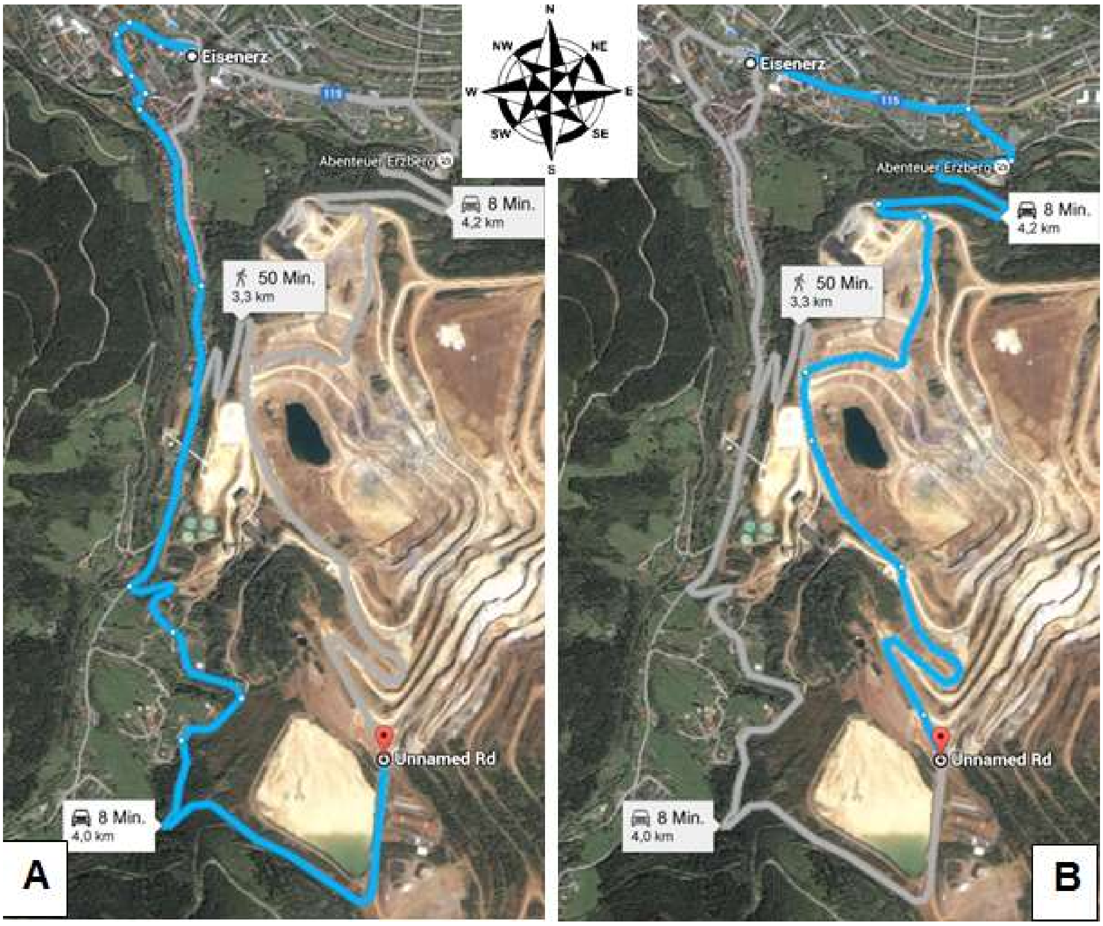

Figure 9: Access way to Palmer from the town of Erzberg. Picture A shows the way via the road Krumpendorferstraße, and Muenzboden (access from the south). Length is 4.0 km. Picture B shows the way via Erzberg (access from the north). Length is 4.2 km. Permissions for both accesses are necessary and have to be obtained from VA-Erzberg.

4.4.2 Railway

There is a good and dense rail road network in Austria. In major cities, cargo loading plants exist. Also on the way to Eisenerz, there is a rail road for cargo transportation with a loading and unloading plant. According to EN 15528 the railway sections from all major train stations in Austria to Eisenerz are class D4, which is standard for all new build tracks in Austria [21]. D4 allows an axel load of 22.5 t and a meter load of 8 t / m. An overview of the Austrian railroad network is given in Figure 58 in the appendix.

4.4.3 Airports and heliports

The closest passenger airports are: Graz-Thalerhof (94 km), Vienna International Airport (200 km), Blue Danube Airport Linz (150 km) and Salzburg Airport (220 km). The indications in brackets are the fastest ways to the airports by car.

The nearest emergency rescue helicopters and their teams are based in Ybbsitz (13 min), Niederoeblarn and Graz-Thalerhof (both 18 min), Wiener Neustadt (25 min) and Oberwart (30 min) [22].
The indications in brackets are extrapolated flying times from the helicopters bases to Eisenerz (see Figure 10).

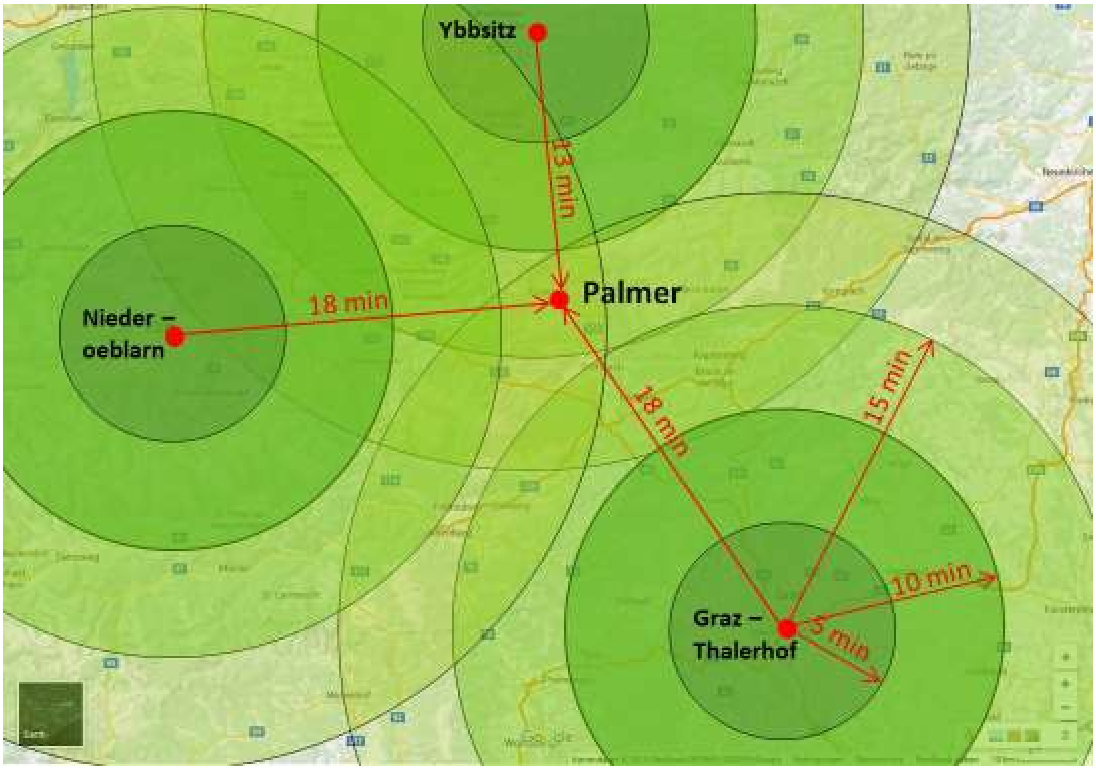

Figure 10: Rescue helicopters flying times to Palmer. The values are extrapolated from the webpage of OeAMTC – Flugrettung [22]. It has to be noted, that the time span between alarming an getting airborne is not included.

4.5 Rescue teams

4.5.1 Emergency medical doctor and emergency team

The Austrian Red Cross is based in Eisenerz and is in stand-by operation 24/7/365 [23]. In case all emergency vehicles are in operation, a back-up emergency team is available. The emergency vehicles are coordinated by the municipal control office of Leoben in Leoben. The control office has to ensure that an emergency vehicle or at least the back-up emergency team is always available for Eisenerz.

The emergency doctor is requested by the control office in Leoben, who is in charge of Eisenerz and Eisenerz area. If necessity, a medical doctor is alarmed additionally [23].

There are three medical doctors, three dentists and two drugstores in Eisenerz [24].

In Eisenerz a hospital specialized in pulmonary diseases exists. The hospital is not designed to treat serious injuries. For this reason, injured people are transferred by emergency vehicle or helicopter either to the hospital in Leoben or the one in Bruck an der Mur which have special departments for various types of injuries.
The emergency room of the hospital in Eisenerz is open from 7 a.m. to 3 p.m. From 3 p.m. to 7 a.m. only first-aid can be provided by the hospital [23].

For the locations of the emergency rescue helicopter teams see chapter 4.4.3 Airports and heliports.
The rescue helicopters are operated by OeAMTC and offer a place for one, in special cases for two injured people, one paramedical staff member, if necessary one dog handler, one emergency doctor and a pilot. The helicopters are also equipped with a winch and instruments for night flights [22].
Location Palmer offers enough sites for helicopter landing, but a windsock, a landing mark and a landing light for nighttime use should be provided by the operator of the WSL. The requirements have to be negotiated with OeAMTC.

The VA-Erzberg GmbH has no in-house medical emergency team but staff with first-aid education and training. Negotiations with VA-Erzberg have to be done to determine who helps in case of an incident.

4.5.2 Fire fighters

VA-Erzberg has an in-house voluntary firefighting team. The team has 41 members and their [38]FUB-Number is 51502 [25] [26].

For location outside VA-Erzberg and within the communal borders of Eisenerz the voluntary firefighters of Eisenerz are in charge of rescue and firefighting operations. The team has 79 members and is in charge of 124.46 km² and 310 households.

4.6 Internet coverage and data transfer rate at Palmer

As of December 2015, three internet and cell phone providers are covering the radio network for cell phones and mobile internet. The coverage of the three suppliers is shown in Figure 11. All three suppliers show a computer model with not proven data.

At Palmer [39]HSPA+DC, also known as 3G+, [40]3G, [41]2G and [42]EDGE technologies are available. The most important difference in these technologies is the data transfer rate, 3G+ being faster than 3G, 3G faster than 2G and 2G faster than EDGE, as long as the radio supply is high enough.

Unfortunately the providers don’t show possible data transfer rates. Only A1 gives a not proven and only theoretical benchmark.

The highest data transfer rate is promised by A1 with the HSPA+DC technology which is close to the [43]LTE technology [27]. A1 promises data transfer rates up to 42 Mbit / s. at Palmer [28]. DREI and T-Mobile promise the availability of the 3G technology [29] [30].

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[38] FuB stands for fire and recovery stand-by (Feuer und Bergebereitschaft)

[39] HSPA+DC High Speed Packet Access + Dual Carrier, also known as 3G+

[40] 3G Third generation of wireless telecommunication technology

[41] 2G Second generation of wireless telecommunication technology

[42] EDGE Enhanced Data Rates for GMS Evolution

[43] LTE Long Term Evolution, also known as 4G

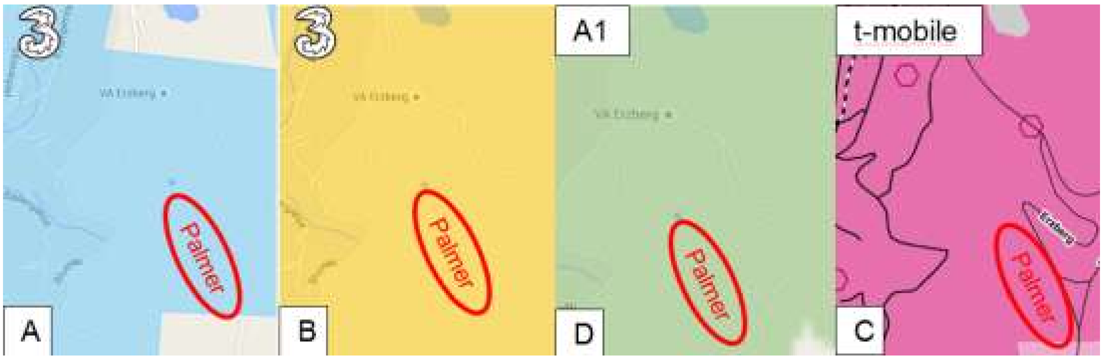


Figure 11: Internet and cell phone coverage at Palmer. From left to right: First two figures are from the internet and cellphone provider DREI. Most of Palmer is supplied with 3G (blue) and fully supplied with 2G (yellow). According to the provider A1 (third picture), Palmer is fully supplied with a data transfer rate up to 42 Mbit / s which is HSPA+DC technology (green). T-Mobile on the very right supplies Palmer fully with EDGE and most of Palmer with 3G (pink) [28] [29] [30].

It should be evaluated directly at Palma, if the phone and internet coverage is satisfactory. Possibly shaded areas should also be taken into consideration, like behind the rig or a in a container or near the Variable Speed Drive (VFD) and the transformer. If the coverage is too weak repeaters could be installed.

4.7 Electricity

In Austria the usual electricity supply is 240 V single phase and 400 V AC three phase.
Electrical current is available at Palmer, but it has to be figured out where and how much electrical load is permitted.

Additionally, near Palmer there is a 10.000 V power line and it would be possible to use it as power supply for the rig instead of three diesel driven generator sets.
It has to be checked with the power supplier and the owner of the power line, if this power line can be used for operating the WSL.

If it is possible, a transformer is used to transform 10.000 V to the operating voltage of the VFD. The big advantage of the electrical power supply compared to the diesel engines is:

- Zero organization and transport costs for energy once the negotiations with the power supplier and VA-Erzberg are done.
- Maintenance is reduced to changing the transformer oil every few years and to keep the transformer, the heat exchanger and the isolators clean and dry.
- Plug and play (no warming up or cooling down of the engines).
- Zero noise emissions.
- Zero CO_2 emissions.

4.8 Workshops

VA-Erzberg has an in-house workshop for the mining machineries they use [3].

According to The Austrian Federal Economic Chamber (WKO), all the most important handicraft businesses are established in Eisenerz [31]. As of December 2015, these were:

Building construction and civil engineering	2
Earth-moving	4
Forest work	6
Drilling and explosives	3
Automobile workshop	6
Electrician	2
Sanitary and heating engineering	3
Mechatronic in construction and agricultural machineries	1
Mechanical engineering	3
IT and software engineering	4
Plant manufacturing	1

…and so forth

The reason for this very excellent company infrastructure has a historic background, as Eisenerz has had a long and strong tradition in mining.

5 Areas of Research, Testing and Training

This chapter gives an overview of ideas about various R&D projects splitted in different disciplines. It has to be noted that further evaluation has to be done if each project is worth working on it and if there is a chance to make the project a technical and economic to success.

The WSL gives the unique opportunity for research and testing under real field conditions with a rig which is used in oil field drilling. For description of the drilling rig and the equipment see chapter 6 and 7.

The focus of the WSL is research and testing. Many drilling and artificial lift processes are not completely understood up to now, like drill string and sucker rod dynamics, detailed response of the surface equipment to processes downhole, stresses in the wellbore, etc.

The aim is to develop tools to react to or to control undesired processes downhole to make drilling and production more economic and safer.

For improved understanding of the processes downhole, and in order to control them from the surface in the right way, data gathering is the most important issue.

Figure 12 shows the way of developing models, which are necessary for designing control units, from data gathered of a dynamic process.

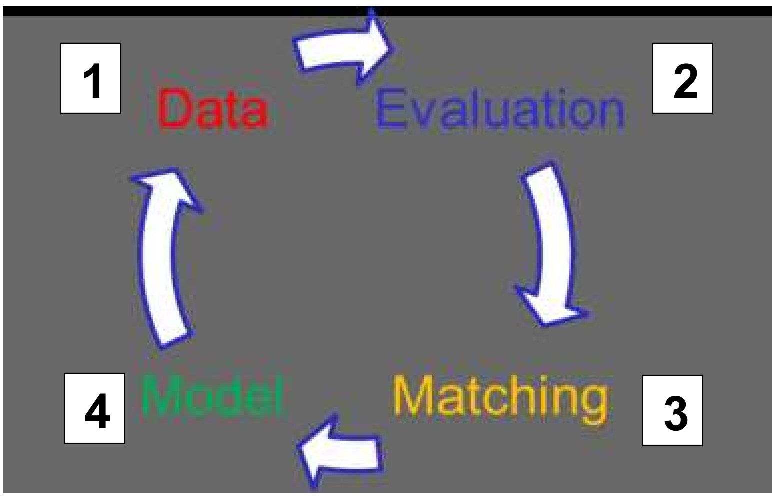


Figure 12: Iterative process of creating a model out of data

1 The rig, relevant tools and equipment are supplied with sensors to get **data** at any time drilling activities take place.
2 These data are **evaluated** for correctness and accuracy.
3 Then these data are **matched** with other data gathered from other points or tools from the drilling process.
4 In case relationships to each other or trends can clearly be seen, **models**, which are later used for controlling certain parameters on the rig, or for simulation issues, are created.

Beside an instrumented drill string, used for downhole data gathering, also an instrumented wellbore can be constructed for calibration and verification of data collected from the drill string as well as for the collection of data out of other processes. Furthermore, an injection line gives the opportunity to inject fluids for various simulation and trainings issues (see Figure 13).

Instrumented Wellbore with Injection Line (IWIL)

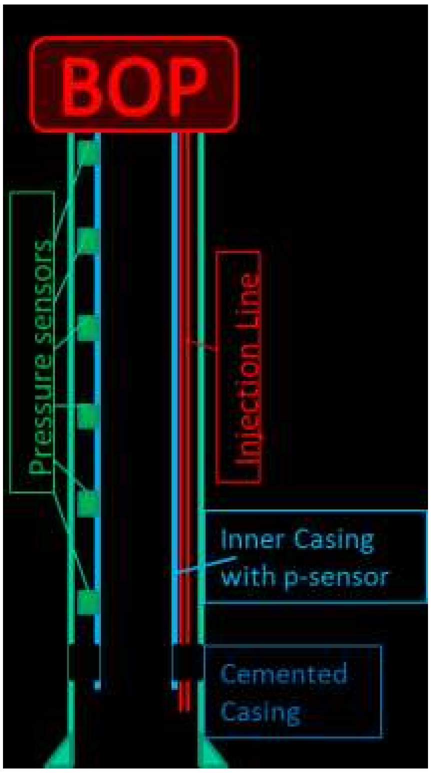


Figure 13: Instrumented wellbore with injection line.

5.1 Drilling Engineering

This chapter describes all drilling relevant research and testing issues and is subdivided in subchapters for each research and testing area.
First, the principal function of the equipment is described, then the shortcomings and finally the area of research and testing.

5.1.1 Top drive

To rotate the drill string, a driving mechanism is necessary to transmit the torque from the surface to the bit. The torque capacity during rotation is the limiting factor of a drilling rig when it comes to drilling of deviated or horizontal wells as the friction between the drill string to the formation is a major factor in these cases.

There are two different types of torque transmission on drilling rigs.

- In the first case, torque transmission occurs along the circumference of a specially shaped pipe – the “kelly” - and is called “kelly driven”.
- Alternatively, torque transmission can also be archived through a so called “Top Drive” (TD) at the upper end of the drillstring.

On a Kelly driven rig the torque is transmitted from the rotary table on the rig floor (stationary) over the kelly bushing (a special kind of clutch; stationary) to the kelly (a hexagonal or squared pipe connected to the drill string and moving up and down).

The top drive driven rig works the same way as a simple hand drilling machine, where the end of the drill bit is an electrical motor with a gear box and a jaw chuck which transmits the torque to the drill bit.
The first well spudded with a TD was offshore Abu Dhabi on April 6th, 1982 [32].

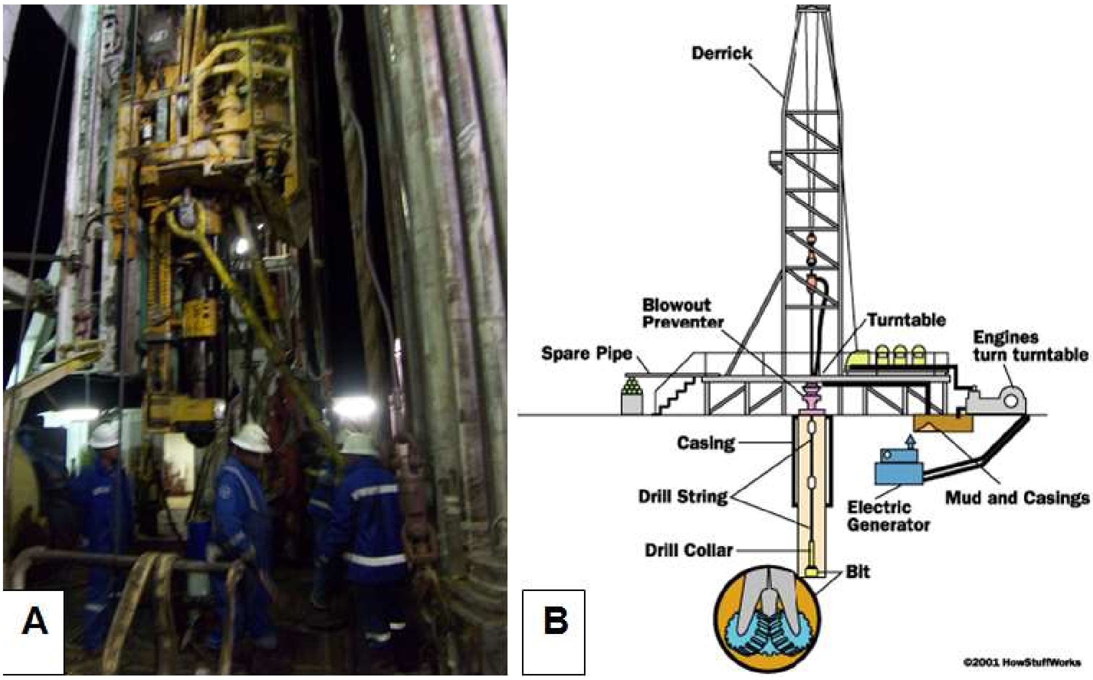


Figure 14 A,B: Top drive (A) and kelly driven (B) rig [33]. State of the art technology is top drive driven rigs, but kelly driven rigs are still widespread.

The driving system can either be hydraulic or with electrical asynchronous motors (one or two motors, older systems with direct current motors, since the 90ies of the last century with Alternating Current (AC)).

A gearbox is installed between the electrical motor and the output shaft. The most sensitive parts of a TD are the bearings of the drive shaft, which have to withstand extremely high axial loads (depending on the size of the rig up to 1000 t and more). The loads can be static during tripping and drilling in sliding mode and dynamic during drilling in rotational mode, in both cases with or without vibrations. An improper operation of the top drive, for example jarring without disconnecting the drill string from the TD and hanging off the string in the elevator, can reduce the life time of the bearings dramatically. Also bad maintenance can result in high costs. The lubricant of the gearbox has to be checked and changed regularly. Also the right lubricating oil has to be chosen for the right operating temperatures. Very much care also has to be taken of the lubrication of the wash pipe and sealing elements. The wash pipe is the transition element from the static and highly pressurized gooseneck to the rotating drive shaft of the TD.

5.1.1.1 Electrical TD

In an electrical system, the output torque of a TD or Kelly is usually calculated from the energy consumption of the electrical motor (measured), the revolutions per minute of the motor or drill string (measured) and the gear box transmission ratio.
The torque of the motor shaft of an electrical driven motor can be calculated by measuring the current of the motor. For a three phase asynchronous motor the torque at the motor shaft can be calculated as follows:

$$M_{t.mech} = \frac{P_{in} * \eta_{Motor}}{\omega} = \frac{3 * U_{ph} * I * \eta_{Motor}}{2 * \pi * \frac{f}{p}} \qquad (2)$$

U_{ph}...electrical Potential of the phase, Voltage [V]
I...current, amperage measured [A]
f...frequency of the alternating current (varying depending on the desired RPM of the TDS) [s^{-1}]
p...number of poles of the asynchronous motor [-]

The output torque of the TD can be calculated with the gear transmission ratio.

$$r = \frac{n_1}{n_2} = \frac{M_{t,2}}{M_{t,1}} \qquad (3)$$

n_1...revolutions per minute input
n_2...revolutions per minute output
M_1...torque input [Nm]
M_2...torque output [Nm]

The gear transmission ratio of the gearbox is calculated by calculating each gear stage within the gearbox.

$$r = \frac{n_1}{n_2} = \frac{Z_2}{Z_1} \qquad (4)$$

n_1...revolutions per minute input [-]
n_2...revolutions per minute output [-]
Z_1...number of teeth of the input wheel [-]
Z_2...number of teeth of the output wheel [-]

The efficiency of a spur or helical gear is usually very high. Values are shown in Table 1.

Spur gear wheel (pair)	η_{th}	0.99
Helical gear wheel (pair, parallel)	η_{th}	0.97 to 0.98
Supporting a shaft with two roller bearings	η_{b}	0.99
Lubricating and sealing a shaft	$\eta_{s,l}$	0.98

Table 1: Efficiency factors for gear box elements [34].

For example, if a gear box has a transmission ratio of 1:4 and needs three shafts with two pairs of helical gear wheels, the efficiency of the gear box is calculated as shown below:

$$\eta_{tot,gear\ box} = \eta_{th}^2 * \eta_b^3 * \eta_{s.l}^3 \qquad (5)$$

The RPM can either be calculated from the frequency of the input current, the number of coils and the transmission ratio, or by a proximity switch and a magnet mounted at the main shaft

5.1.1.2 Hydraulic TD

A hydraulically driven TD usually has a gear box with a low transmission ratio because hydraulic motors run more efficiently at low rotational speeds.
For hydraulically driven TD it is much more difficult to calculate the torque at the output shaft because of the complex shape and vector forces from the pistons to the rotor, depending on the type of motor (see Figure 15).

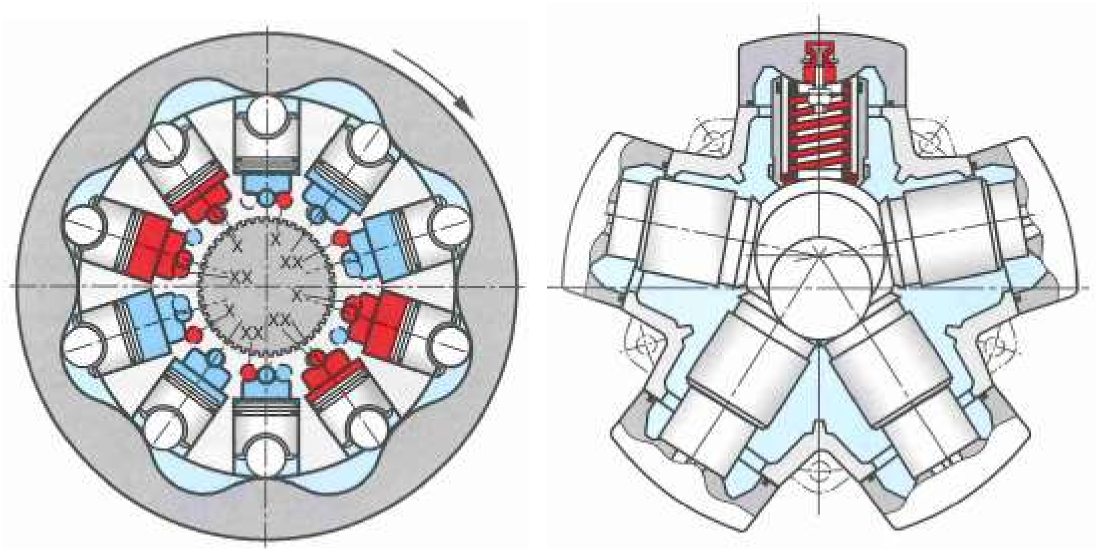


Figure 15: Types of radial piston motors. The left type works according to the multi stage principle and has more pistons than the right one. This makes it possible to change the speed by supplying a different number of pistons with oil by holding the pumped oil volume constant. Reducing the supply of the pistons by half doubles the rotational speed but reduces the output torque by the half. Due to the design, higher torque can be achieved with the multi stage principle in comparison with the radial piston motor like shown in the right picture [35].

Once the torque profile of the motor is developed by the manufacturer, it is relatively simple to display torque, depending on the accuracy needed, as torque is a function of the pressure of the hydraulic fluid applied.

Rotational speed can either be calculated by measuring the volume of hydraulic fluid pumped per unit of time divided by the fluid capacity of the motor for one revolution or by installing a proximity sensor and a magnet or a magnet band at the main shaft.

Problems of torque and rotational speed measurement

The calculation of torque and rotational speed at the drive shaft of the TD like described above, has the disadvantage that there are several undesired dampening elements in the TD which do not show the actual torque at the main shaft. Fast but small changes of the drive shaft in torque or rotational speed cannot be “seen” by just measuring the energy supply parameters of the TD.

Dampening elements:

- Twisting of all shafts, from the main shaft to the motor shaft, according to hook’s law
- Bending of the teeth root according to hook’s law
- Bending of the gear shafts because of a bending moment exerted by the gear wheel
- In electrical motors, magnetic elasticity between exciting coil in the stator – air gap – and short circuited conducting bars at the rotor
- In hydraulic motors, the compressibility of the hydraulic oil

5.1.1.3 Areas of research

An aim is to develop simple and cheap detection systems at the surface of the drill string, for example between the drill string and the drive shaft of the TD, which display the behavior or trends of the well and the drill string downhole, which can be used for:

- Controlling the TD-torque and rotational speed for preventing or reducing the stick slip and vibration behavior of the drill string.
- Observing the torque trend for early drilling problem detection (e.g. cuttings transport, key seating, well bore stability...)
- Early kick detection (sudden change of axial load).
- Reducing wear of the entire drill string, from the bit, M/LWD-tools to the TD.
- Improving well quality

This detection system could be a sub, equipped with strain gauges and / or acceleration measurement tools in radial and axial direction and permanent collection of data. These data have to be evaluated and matched with other data obtained from the research drilling process, for example from sensors along the drill string, the hoisting system, the mud pumps and others. With all these data obtained, models are developed to display abnormalities like described above.

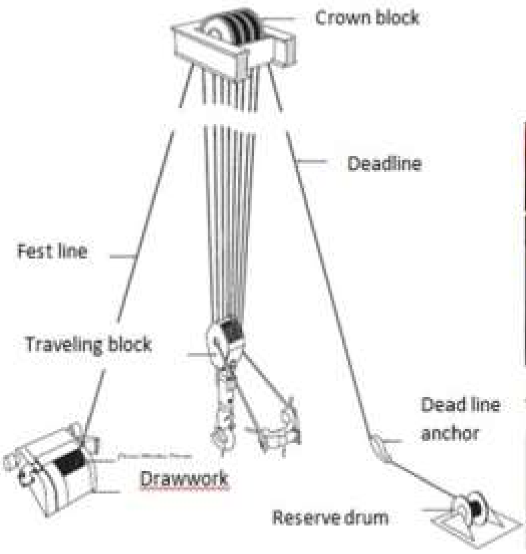
5.1.2 Hoisting system

A hoisting system is necessary to lower and raise the drill string in a fast way (tripping) and in a precise and slow way for the drilling process. The hoisting capacity of the hoisting system is the limiting factor for drilling vertical wells as there are the highest loads expected. Measurements of the hoisting system are taken to know the Hook Load (HL), the velocity of the traveling block and the block position which can be measured or calculated.
The most common hoisting systems are described below

5.1.2.1 Draw works: Description, measurement and problems

The most common system consist of a winch, called draw works, a rope, a number of sheaves on the crown block and on the traveling block, dead line anchor and reserve drum with additional rope. The number of sheaves determines the number of ropes which are carrying the traveling block including the load which is hanging on the hook (TD and drill string or casing). On the winch side, the rope is called fast line as it has the highest speed. On the dead line anchor, the rope is called dead line as the line has no movement and is fixed in the deadline anchor.

Measurement of hook load
The most common measurement taking for the hook load is done by a pressure cell, filled with hydraulic oil, mounted between the arms of the deadline anchor (see Figure 16).



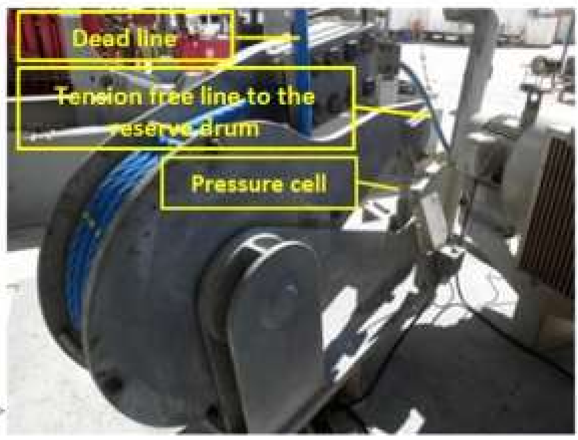


Figure 16: Draw works hoisting system and deadline anchor. The right picture shows the deadline anchor with the pressure cell.

The fluid energy within the pressure cell gets converted to electrical energy which displays the hook load for the driller in an electrical instrument.

Problems of the HL measurement

The disadvantage of this system is that the hook load is measured indirectly and far away from the load of interest (at the hook or even better right below the TD main shaft).

Not considered in this measurements are e.g. friction in the system shaft – bearing – sheave – rope, lost energy in the rope because of changing tension, the swinging mud hose from the stand pipe to the gooseneck, the difference of moving the block upwards or downwards and so forth which influences the measurement [36].

5.1.2.2 Hydraulic cylinder: Description, measurement and Problems

There are different cylinder hoisting systems on the market. Two of them are described below.

The first system shown in Figure 17 on left, uses a telescopic mast.

The movement of the block is activated with a hydraulic cylinder. To reduce the stroke length of the cylinder, a rope – sheave system can be added where the rope is fixed to the mast at the dead line side and fixed to the TD at the fast line side. In this system, the hoisting stroke length and velocity is twice the cylinder stroke length and velocity, but the pull force is half the cylinder pull force. For pull down operations the TD is locked to the telescopic mast.

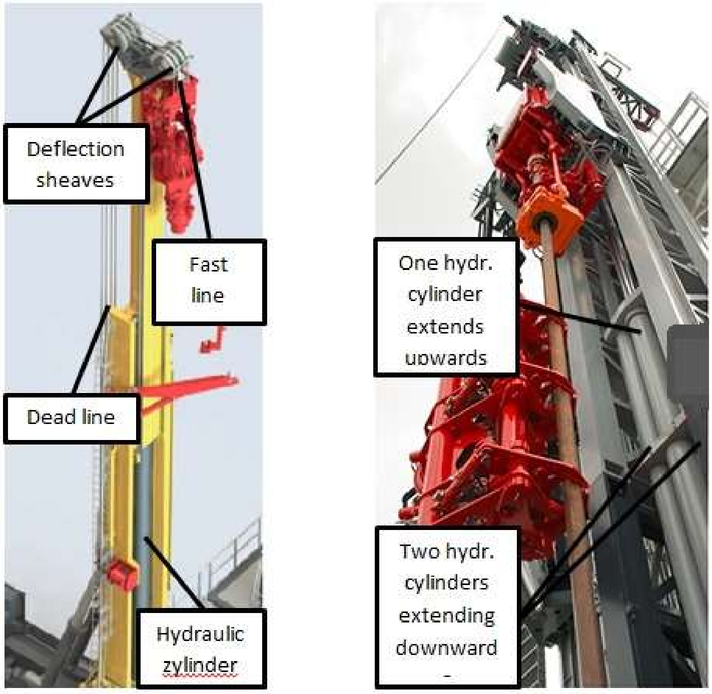


Figure 17: Hydraulic cylinder hoisting systems. The left picture shows a single cylinder and a rope-sheave system is used [37]. The right picture shows a double extending cylinder were the middle cylinder extends upwards and both outside cylinders extend downwards [38].

In the second system show in Figure 17 on the right, only a hydraulic cylinder is used without rope-sheave support like in the system described above. Therefore, to reduce the stroke length, a double extending cylinder is used, where the middle cylinder extends upwards and the two outside cylinders extend downwards. To achieve the same extension force of the inner and outer cylinders, the outer cylinders have to have the same piston area as the middle cylinder.

Measurement of the hook load

Usually the hook load is calculated by measuring the pressure of the hydraulic oil which activates the cylinder multiplied by the known area of the piston.
The calculation of the cylinder force:

$$p = \frac{F}{A_{piston} * \eta} => F = p * A_{piston} * \eta \qquad (6)$$

p...pressure of the hydraulic fluid [Pa]
F...Force [N]
A...Area of the piston [m^2]
η...efficiency factor [-]

The efficiency factor of a hydraulic cylinder strongly depends on the pressure applied and varies from 0.85 at 20 bar to 0.97 at 250 bar [39].

To get the hook load, all loads acting on the movement of the piston have to be reduced, excluding the drill string. This can be the TD, hook, ropes, moving part of the telescopic mast, filled mud hose, friction etc..

A challenge in designing a hydraulic cylinder is to avoid stick slip behavior of the sealing between both the cylinder wall and the piston, and the piston rod and the cylinder. The reason for the stick slip is the difference in static and dynamic friction and the varying sealing force of the sealing as a function of the fluid pressure. The slower the movement and the lower the applied pressure the higher is the chance of stick slip behavior which causes imprecise movement of the TD, additional loads due to sudden acceleration on the mast structure and loads to the axial TD bearings. This is even worse in case of the system shown in Figure 17 on the left. Depending on the selected sealing material and the roughness of the slip surface, continuous and smooth movement of the piston starts at velocities above 0.1 m/s [40].

Stick slip can be reduced by applying a counter force to the cylinder force (either the weight of the system which has to be moved or by regulating the choke of the drain side of the double acting cylinder).

Problems of the HL measurements

The easiest way to determine hook load is to measure the applied pressure on the hydraulic cylinder and then calculate the hook load.

As mentioned above, the efficiency factor of the hydraulic cylinder depends on the pressure applied and on the wear of the sealing. This has to be considered when the hook load is calculated from the pressure applied on the hydraulic cylinder.

During slow movement of the piston rod, stick slip can occur which can influence the displayed values in the driller cabin.

The accuracy of the measurement also depends on the place where the pressure sensor is installed. To avoid the storage capacity of the hoses and steel tubes, which can be significant, the pressure gauges should be installed as near as possible to the place of interest.

5.1.2.3 Rack and pinion: Description, measurement and problems

In this system, a toothed rack is mounted along the mast where a toothed wheel is engaged which is driven by a hydraulic motor. The hoisting capacity of the rig depends on the torque of the hydraulic motor and the number of hydraulic motors used.

Measurement of the hook load

Usually the hook load is calculated by measuring the fluid pressure in the hydraulic motor. It is also necessary to know the torque profile of the motor and the effective diameter of toothed wheel, the efficiency of the system, the moving direction and the weight of the moving parts which are not the drill string.

The hoisting force of the system can be calculated from the output torque of the hydraulic motor, which is a function of the pressure of the hydraulic fluid (7)(8).

$$M_{t,Motor(p)} = F * \frac{d_{eff}}{2} => F_{hoist} = \frac{M_{t(p)} * 2}{d_{eff}} => F_{hoist,eff} = F_{hoist} * n \quad (7)$$

$$d_{eff} = z * m \quad (8)$$

M_t... Torque of the motor as a function of the applied pressure[Nm]

d_{eff}...effective diameter [m]

z...number of teeth [-]

m...modulus [-]

n...number of motors [-]

Problems of the measurements

In all three systems, the hook load is measured indirectly and not at the point of interest. The measurements have to be calculated with different parameters shown above. Variable factors like friction factors which are a function of temperature, grade of wear and lubrication are just roughly included. Finally the elasticity of the mast and all the dampening effects mentioned before should not be forgotten.

All these parameters lead more or less to a measurement of a trend of hook load than to a real measurement of the actual HL.

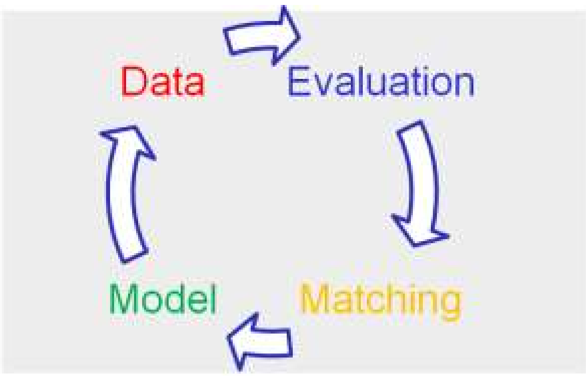
5.1.2.4 Areas of research

First a “precise measurement” has to be defined, since it is unclear what exactly should be measured. Is it enough to roughly know the weight that is hanging on the TD and is it enough to display more or less a trend of the hook load, or is it of interest to know the precise load, including load peaks, beneath the TD main shaft every fraction of a second?

It is clear that precise measurement at the load source with a frequency high enough to display short maximum and minimum values is necessary to make it possible to react (automated) in a fast way for any abnormalities (drill string dynamics, sudden influx, washouts and key seats and so forth).

Therefore, a kind of “Intelligent Saver Sub ISS”, or an “Instrumented Internal Blowout Preventer IIBOP” to reduce the additional length needed, should be installed right below the TD main shaft [41] [42] [43]. This sub should be equipped with strain gauges in axial and radial direction for measuring axial, torsional and bending loads. Also a pressure sensor for measurement of the mud pressure in the sub, accelerometers in axial and radial direction, a gyroscope to know the exact RPM of the main shaft as well as power supply and signal transmission to the rig floor must be included.

This surface measurement tool allows real time measurements and faster (automated) reaction to any abnormalities.
To develop control units which react to these abnormalities, the process of Figure 12 described in chapter 5 has to be followed.



The useable data gathered should be matched with other measurements from the BHA, drill string and material balance of the drilling fluid. If clear relationships can be seen, models can be created to program control units.

5.1.3 Drill string dynamics

Drill string dynamics (DSD) is one of the most difficult issues in oil field drilling, both in understanding and mitigating unwanted dynamics of the drill string. Unwanted DSD are all movements which are not the intended radial (rotation) and axial (moving in and out) movements of the entire drill string, from the bit to the saver sub of the TD, controlled by the driller.

All unwanted movements of the drill string have in common, that they "steal" energy introduced by the TD or hoisting system, which therefore does not fully reach the bit where it was intended to cut the rock (Mechanical Specific Energy, MSE), leading to reduced ROP. The "lost" energy causes additional wear of the equipment and unwanted hole enlargement which is again the reason for further instabilities in DSD.

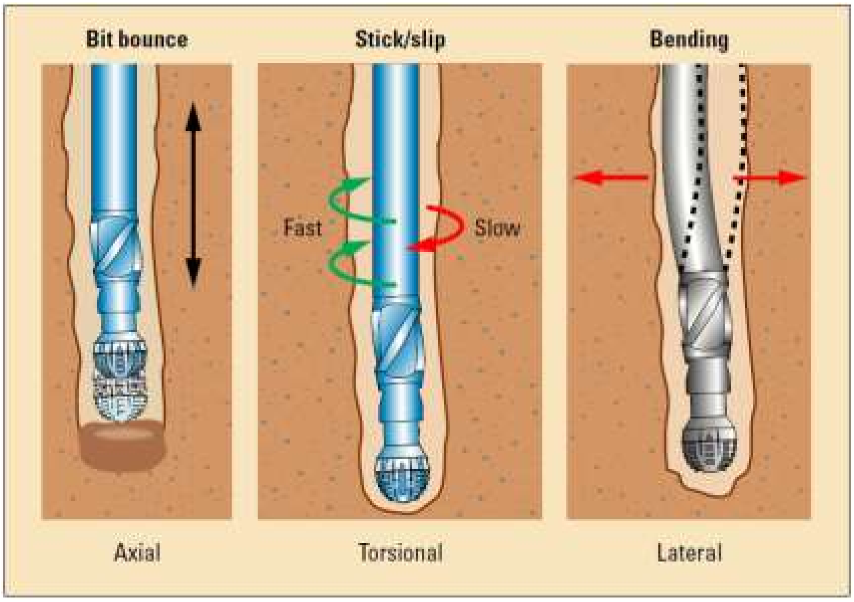


Figure 18: Types of unwanted string movement[44].

In Figure 18 three different types of unwanted movement of the drill string are shown. Usually a mixture of all three types of unwanted DSD occurs at the same time as for example bit bounce can be the initial point for stick slip which subsequently results in whirl.

5.1.3.1 Bit bounce

The left picture in Figure 18 shows axial movement of the drill string which is a result of bit bounce. In such a situation, the cutters of the bit, and in case of a roller cone bit also the bearings, experience very high changing loads which can destroy the sharpness of the cutters or exaggerate the allowable dynamic load rating of the bearing, thus redusing the life time of the bit rapidly.

Compression and elongation of the drill string is possible due to the elasticity of the steel string which behaves like a spring (Note: The term $\frac{EA}{l}$ is the spring constant k!). The force acting on the bit due to the elasticity of the string is:

$$F = \frac{EA}{l}\Delta l \tag{9}$$

F…Force stored in the drill string [F]

E…Young's modulus [Pa}

A…Cross section area of the drill pipe [m²]

l…length of the drill string [m]

Δl…change in length of the drill string [m]

The influence of the force created by the spring effect of the drill string is low compared to the impact of the changing weight on bit (WOB) which causes very high forces in the bearings of the roller cone bit or in case of a drag bit, very high load per area on the cutter.

Bit bounce can be the result of:

- too aggressive Polycrystalline Diamond Cutter (PDC) bit for a certain type of formation,
- roller cone bit with a large distance between the teeth,
- changing rotational speed which influences the depth of cut
- changing WOB or
- inhomogeneous formation like conglomerate or breccia or fractured hard formation like dolomite

The reasons for other unwanted jerky axial movement can be:

- key seating,
- caving of the borehole wall or
- high side forces of the drill string to the bore hole wall (because of dog legs or high friction forces).

According to Besalsow and Payne (1988), the excitation frequency of a three cone roller bit in axial direction is about 3 * ω of the bit, were ω is the pipe rotational frequency [rev/min] [45].

5.1.3.2 Stick slip

The middle picture of Figure 18 shows undesired change of rotational speed and is called stick slip behavior. The variation of rotational speed can be between slow and fast rotation, zero to fast or even between backward movement and fast rotation. In case of backward rotation a drag bit gets damaged within a short time.
In stick slip mode, the torsional energy introduced at the end of the drill string by the top drive gets stored in the string by twist of the string. The twist can comprise several revolutions and can be calculated using equation (10).

$$\varphi = \frac{M_t l}{G I_p} \qquad (10)$$

Φ…twist [rad]
M_t…torque [Nm]
l…length of the string [m]
G…Shear Modulus [Pa]
I_p…Polar momentum of inertia [m^4]

In equation (10) the spring constant k is equal to $\frac{G*I_p}{l}$.
Stick slip occurs as soon as friction forces are both high enough to twist the drill string and when the difference in static friction and sliding friction is high enough at constant normal force or the normal force is changing which results in changing torque needed to rotate the string. The reason for stick slip can either be friction forces acting on the circumference on the drill string or on the face side of the bit.
The cutting process itself can also create a “small scale” stick slip behavior. Before the rock fails under the pressure of the cutter, the torque is increasing. This torque energy can be stored in the slight compressibility of the drilling fluid, the twist of the rotor and the elastomer elements of the stator of the Positive Displacement Motor (PDM) [46].

Stick slip can occur as soon as:

- Friction forces are both high enough to twist the drill string and when the difference in static friction and sliding friction is high enough at constant normal force

- Normal force is changing which results in changing torque needed to rotate the string (bit bounce).
- “Soft” PDM design

5.1.3.3 Drill string whirl

The right picture in Figure 18 shows lateral movement of the drill string.
This can happen along the drill string at the bit (bit whirl), at the BHA or at the drill pipes. Lateral movement of the drill string components combined with rotational speed is called whirl. Whirl is a high frequency phenomenon with frequencies in the range of 20 to 60 Hz depending on the angular speed of the drill string [47]. There are three types of whirl:

- Figure 19 A shows forward whirl. The deflected drill string section rotates along the borehole wall in the same direction as the rotation of the drill string in its axis.
- Figure 19 B shows backward whirl. The rolling motion of the drill string section along the borehole wall in opposite direction as the rotation of the drill string axis.
- Figure 19 C shows chaotic whirl: The drill string section moves randomly between the borehole walls and rotates in the drill string axis [48].

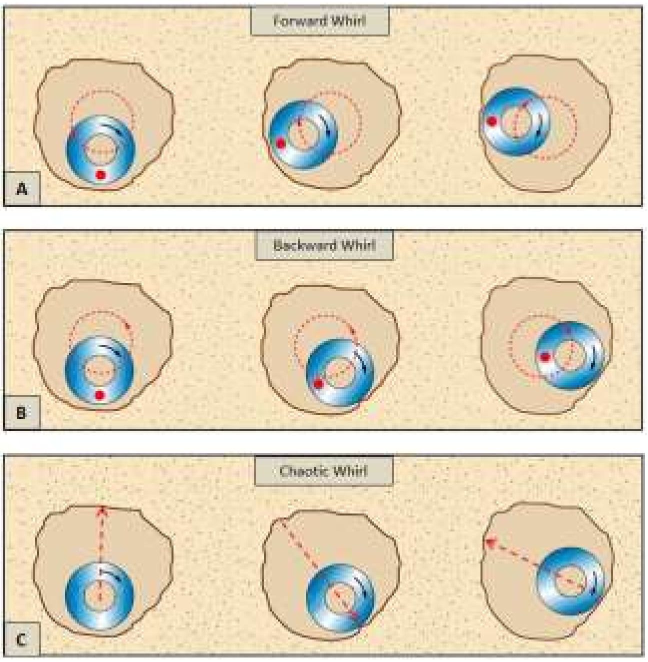


Figure 19 A, B, C: Types of drill string whirl. Source modified from Schlumberger, 2010 [44].

Bit whirl is described as the lateral movement of the bit in the hole while the bit rotates. In this case, the center of the rotation of the bit is not aligned with the center of the hole. This leads to an unbalanced load on the blades of the PDC bit and pushes the bit to the wall of the wellbore [49]. If in this case the friction force between wellbore and the bit is higher than the momentum of inertia of the bit, the bit starts to whirl backwards, the process starts again and the bit starts to walk around the geometric center of the wellbore. Once the bit whirls, it is hardly possible to bring it back to a non-whirling situation [50]

Because of the sudden change of the velocity pole (from the center of rotation to the rim of the bit when touching the wellbore wall) the cutters experience high cutting velocities, which increase the thermal wear of the cutter, and high impact forces to the wellbore wall when the bit gets pushed towards it. That is why bit whirl is one of the most harmful operating conditions a bit can experience [49]

A roller cone bit is not as prone as a PDC bit, but whirling is bad for the bearings since the axial loads for the bearings can become too high.

A bit is prone to bit whirl when following operating conditions take place [50]:

- High rotational speed causes bit whirl more easily than low rotational speed, once the bit is slightly out of the center of the hole, because $F_{radial} = m * \omega^2 * r_{excentricity}$; where m is the mass of the bit, v the velocity of the center of gravity and r the radius of the center of gravity.
- When the center of gravity of the rotating component is not aligned with the center of rotation
- Low WOB, because the vector forces in radial direction (see above) can become more dominant than the vector force in axial direction (WOB).
- Stabilizer can limit whirl but not eliminate.
- Anything that helps the bit drilling laterally, e.g. cutter imbalance, aggressive cutters and gauge cutters.
- Rocks which are drilled slowly, because the bit has more time to generate a regenerative structure on the bottom of the hole
- Friable rocks (conglomerate, dolomite…) are worse than other rocks.

The parts of the drill string which are most prone to the whirling effect, besides the bit, are the drill collars, the stabilizers and the M/LWD tools, as those parts are (partly) in compression and are the heaviest parts (see equation for radial force above).

Whirling can create bending moments with both large magnitude and high frequency [44] where at a BHA the transition from the pin to the body of the tool joint is the most sensitive part. But also at M/LWD tools, the electronics and other parts are prone to failure because of the high g-forces when the collar impacts the borehole wall.

When drilling extended reach wells, the limiting factors are torque, drill string buckling, hole cleaning problems and ECD.
In this case, axial or radial vibration can help to reduce friction between the drill string and the borehole wall [51] and can help keep the cuttings suspended in the mud which helps to transport the cuttings from the bit to the bell nipple.

5.1.3.4 Areas of research

- Combat vibrations to decrease drilling time and costs
- Understanding vibrations and knowing how to design a BHA which is minimally prone to vibrations can reduce drilling costs dramatically [52].

Drill string and wellbore set up:
The drill string should be instrumented with strain gauges, pressure cells and accelerometers. For high data transfer rates (up to 500 Hz [41]) Wired Drill Pipe (WDP) is necessary. The sensors should be meaningfully positioned along the drill string. On the bases of the values obtained, tension, torque, bending moments, pressure and acceleration along the drill string can be calculated.
Again, according to chapter 5, Figure 12, DSD models are developed, which can be used for decision making (from a decision tree for the driller, to selecting of the right BHA and drilling parameter for planning the well), early detection of abnormalities, automation of the drilling process and further studies.

- Making a benefit out of vibrations

A. Esmaeili et al [53] performed laboratory tests on a small size rig in laboratory scale at the Montanuniversitaet Leoben, by using drill string vibrations measurements for real time mechanical formation evaluation. Further research and field tests should be done to develop a trustful tool for formation evaluation while drilling.

Another interesting research area would be to investigate how a (sudden) change in mud properties influences the DSD. Findings of this relationship could be used for early kick detection or vibration mitigation.
Improved knowledge in this field could also help in the development of methods where controlled vibrations are introduced into the drill string for torque and drag reduction and hole cleaning issues.
In conjunction with the right bit design this might also be used to introduce axial vibrations to increase ROP (e.g. percussion drilling) [46].

5.1.4 Hydraulics

Besides controlled rotation and the lowering and raising of the drill string, the hydraulics is one of the most influential parameters for successful drilling of a well bore.
Many problems during drilling a well, like well control issues, fluid losses, low ROP, stuck pipe, differential sticking and others are caused by incorrect control and maintenance of the mud pumps and the solid control system, insufficient fluid maintenance and fluid design.
The term “hydraulics” in oilfield drilling covers the properties and changing parameters of drilling fluid under rest and motion as well as the influence of the drilling fluid to the confining borders.

The drilling fluid is needed to:

- carry out the cuttings from the bit to the surface
- prevent the wellbore from an undesired influx, collapsing or deforming.
- rising the ROP and life time of the bit due to the jet impact force of the mud through the nozzles and cooling the bit during the cutting process
- cool and lubricate the drill string
- protect the drill string from corrosion
- supply down-hole motors and down-hole equipment with energy

The circulation system consists of the mud pumps, surface lines, drill string, annulus, solid control system and the mud tanks.

Mud pumps

Figure 20 shows mud pumps, needed to circulate the drilling fluid from the surface, through the inside of the drill pipes to the bit and through the annulus up to the surface, together with the cuttings. Therefore, the necessary pump pressure equals the sum of all friction pressure losses. The pump rate is determined by the minimum cuttings transport velocity in the annulus of drill pipe and formation, to clean the borehole reliably.

Usually mud pumps deliver a pressure of 345 bar (5000 PSI) and up to 2.3 m^3/min (600 gal/min). But due to the application of down-hole motors in conjunction with wells with a high measured depth, mud pumps with 520 bar (7500 PSI) become more and more common.

Figure 20: Mud pumps and mud tanks. Three mud pumps with 1600 HP each are used for a 500 t drilling rig.

Hydraulic parameters which are usually measured on the rig

Strokes per minute (SPM): The SPM is measured either with a simple switch device or a proximity switch, which is mounted by the mud logger on the mud pump (see Figure 21).

Figure 21: Stroke counter for mud pumps [54]. The blue cable stands for Ex i, where at a possible spark, the spark energy is below the ignition energy of the surrounding explosive area.

Also the volume pumped per unit time is of interest for drilling operations or volume pumped per stroke for well control issues. The volume pumped per unit time for a single acting pump is calculated by equation (11).

$$Q = SPM * V_{displ.} * N * \eta \qquad (11)$$

Q…Flow rate [l/min] or [gpm]
SPM…Strokes per minute [-]
V_{displ}*…Displacement volume of one piston*
N…Number of pistons
η…Efficiency factor for the displaced volume (volumetric efficiency) [-]

The displacement volume is the stroke length (fixed) times the diameter of the piston (piston and liner are exchangeable; The smaller the diameter of the piston, the higher the pump pressure and the lower the volume pumped).
η is the efficiency factor for the displaced volume and depends on the leak tightness of the system valve-seat and piston-liner wall, the compressibility of the drilling fluid, the SPM and the performance of the charging pump.
It can be seen that η is not a constant and often more or less an assumption. The valve and piston sealing, for example, can fast be destroyed when the solid content in the mud is too high. This often happens when drilling the surface or intermediate section, when highest pump rates are necessary. If ROP is too high, the solid control equipment is not able anymore to clean the loads of cuttings from the drilling mud properly.

Problems with the measurement of the pump rate

Q is a variable of η and the charging pressure and rate, and not a constant value. If the flow rate is lower than calculated, it has an impact on the performance of the down-hole tools (reduction of ROP and so invisible lost time) and on the cutting transport to the surface.

In case of managed pressure drilling with a narrow margin between pore and fracture pressure, a lower pump rate than calculated results in a lower ECD than expected which subsequently can result in an influx.

The pump pressure is usually measured at the stand pipe on the rig floor with a pressure gauge. In conventional drilling, this pressure is the sum of all friction pressure losses from the point of the pressure gauge to the bell nipple at atmospheric pressure. When down-hole motors are used, the fluid pressure drop along the drive section of the motor determines the torque of the down-hole motor, whereas the pump rate, beside the lobe ratio, is responsible for the rotational speed of the motor.

Fluid properties which are usually measured at the rig

API RP 13B-1 / ISO 10414-1provides standard procedures for field testing of water based drilling fluid, API RP 13B-2 / ISO 10414-2 for oil based drilling fluids.

The density must be permanently measured during the circulation of the drilling fluid. Early detection of a change in density can be an indication of an influx of formation water or hydrocarbons or a change in mud properties for example due to the exchange of ions (depending on the formation drilled, Na^+ replaced by Ca^{++} coming from the formation results in a change of the mud properties. The mud has to be treated quickly).

The mud density is measured with a mud balance (Figure 22) in conjunction with the temperature of the drilling fluid.

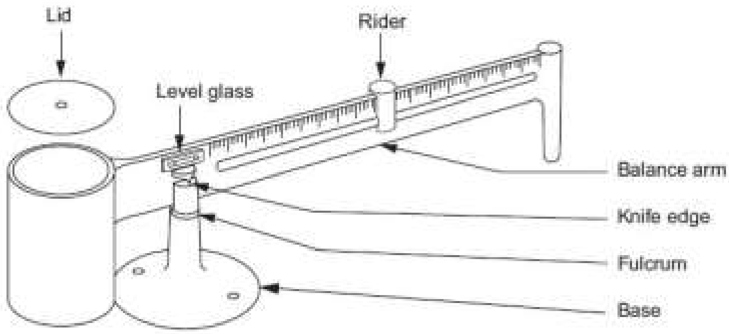


Figure 22: Mud balance[55]

According to API RP 13B-1 the accuracy of the mud balance has to be +/- 10 kg/m³. Therefore the mud balance has to be calibrated frequently with clear water at the a temperature of 21°C (70°F). The mud balance must show a density of 1000 kg/m³, otherwise the tool has to be adjusted.

This method is inaccuracy as there can be air or gas bubbles enclosed in the cup. To overcome this problem, there is also a pressurized mud balance available on the market.

The viscosity of the mud also has to be checked continuously, as any change in viscosity can be an indication of an influx or other reactions of the drilling mud with the formation. The viscosity is measured with a marsh funnel viscometer at the rig site according to API RP 13B-1 (see Figure 23).

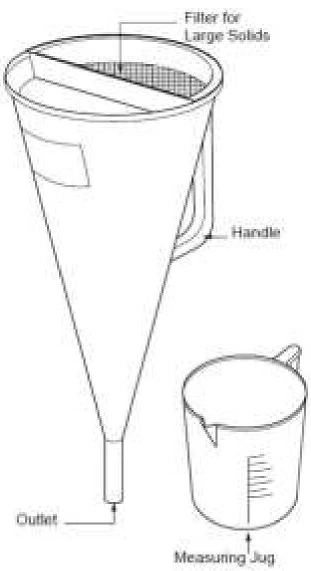


Figure 23: Marsh funnel viscometer

The marsh funnel viscometer has an exactly defined geometry. The time needed to drain one quart (946 ml) of drilling fluid through the funnel is measured in conjunction with the temperature of the fluid. The more viscous the fluid, the longer it needs to drain.
The calibration of the tool is carried out with water. One quart (946 ml) of water with a temperature of 21°C +/- 3°C must take 26 (+/- 0.5) seconds to drain.

Apart from the on-the-rig-measurements, there are more accurate measurements done by the mud engineer in a rig site laboratory.
The mud engineer is responsible for all drilling fluid related topics like preparation and maintenance of the drilling fluid to given fluid parameters according to the mud program and to parameters which have to be changed during the drilling process.

Problems of the rig site measurement with the mud balance and marsh funnel viscometer.

The measurement is a random sampling method within a certain time span and the accuracy and consistency of the measurement depends strongly on the operator of the tool. A precise working procedure has to be kept and regularly reported to the driller and the mud engineer. The results of the measurements can rather be considered as a trend (when this is done by the same person) than a real measurement.
Another problem is the economic part, as working with these two tools is time-consuming and costly.

Solid control equipment.

The solid control system has the task to prepare the mud, coming out of the wellbore together with the cuttings, for reuse. For this reason, the mud has to be cleaned from solids in a way that no damage due to erosion corrosion is done to the mud pumps, surface lines, drill pipes and down-hole tools.
The efficiency of the solid control system is rated on:

- how many solids can be removed from the drilling fluid and
- how much drilling fluid can be reused

The mud and the cuttings come out of the wellbore via the bell nipple, flow line, distribution line to each shale shaker, desander, desilter, if necessary centrifuge and flocculation (see Figure 24).

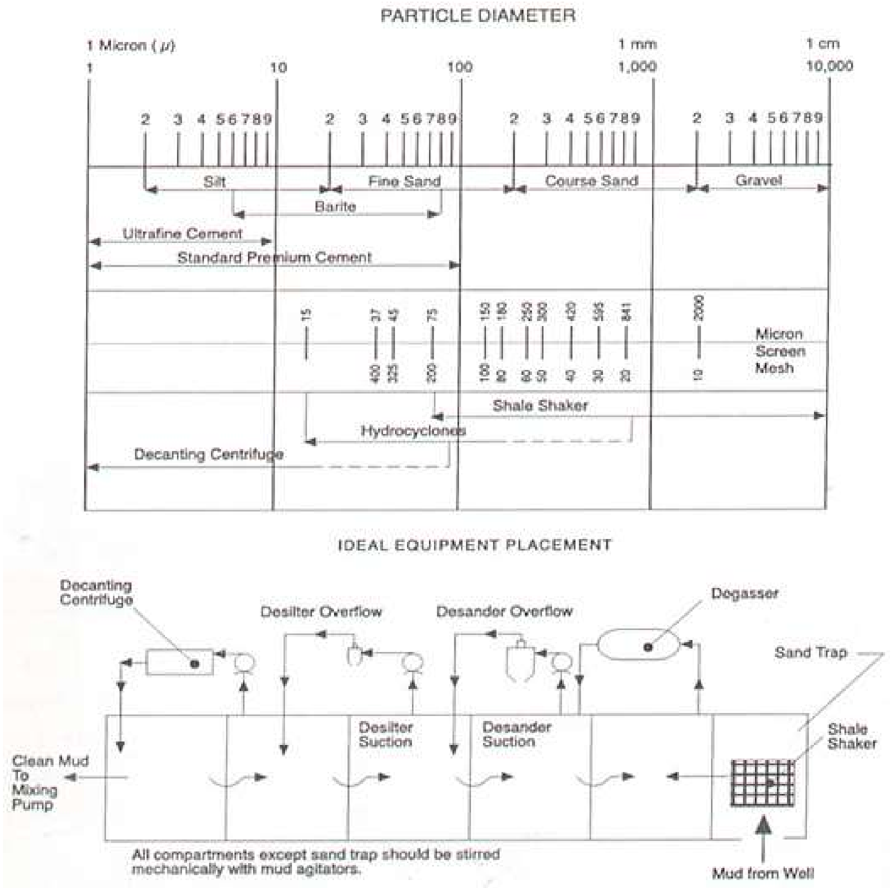


Figure 24: Solid control equipment placement and particle diameter[56].

The first step of cleaning the mud from solids is the use of the shale shaker where the mud and the cuttings are flowing over a shaking sieve. The sieve has a well-defined mesh size [#meshes / in²], depending on the cuttings size.

The quality of separation of mud and solids depends on the motion velocity, the inclination and on the condition of the sieve. The first two factors mentioned being a function of the amount of mud and cuttings coming from the distribution line.

The solids are moved to the sand trap and the mud to the desander. The solid size after passing the shale shaker depends on the mesh size of the used sieve. For example, a mesh size of 200 meshes / in² corresponds to a particle size of 75 µm.

The hydrocyclone - in the oilfield also referred to as desander (remaining particle size in the fluid < 30 µm), or desilter (remaining particle size in the fluid < 20 µm) - is a simple device with no moving parts. The separation of the solids from the fluid is based on the density difference [57].

The hydrocyclone consists of a tangential inlet section with a cylindrical part, a narrowing conic part, and a lower and upper outlet (see Figure 25).

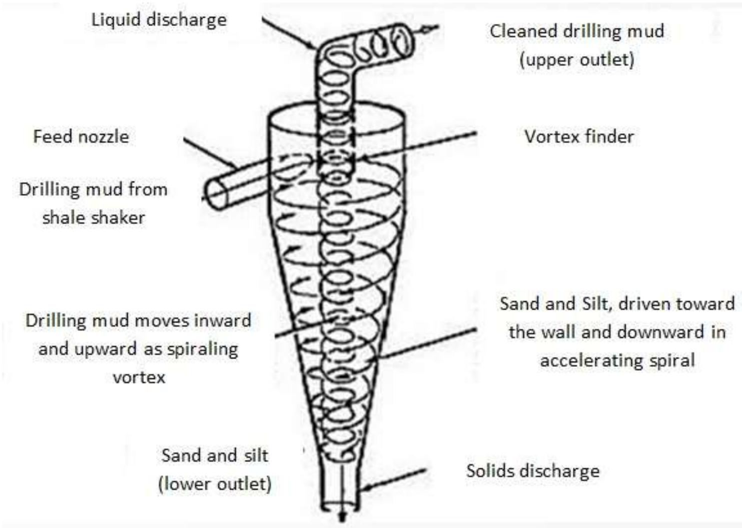


Figure 25: Functionality of a hydrocyclone

The slightly pressurized fluid enters through the tangential inlet section into the cylinder. The linear movement is transformed into a rotational movement. Due to the narrowing conic part, the fluid-solid mixture is accelerated and the heavier solid parts are pressed to the surface and hence slowed down while the fluid still rotates in full speed. As soon as the centrifugal force is lower than the gravitational force, the solid particles are sliding down the cone, exiting through the lower outlet of the desander. The fluid with smaller solids exits through the upper outlet.

Usually, hydrocyclones with a size between 4” and 12” diameter are used. The larger the diameter of the hydrocyclone, the higher the fluid mixture capacity and the larger the particle size which is segregated from the fluid.

Approximate values for fluid capacity, feed pressure und cut point for different sizes of hydrocyclones can be seen in Table 2.

Cone Size (I.D.)	4”	5”	6”	8”	10”	12”
Capacity (GPM)	50-75	70-80	100-150	150-250	400-500	400-500
Feed Pressure (PSI)	30-40	30-40	30-40	25-35	20-30	20-30
Cut Point (Micron [µm])	15-20	20-25	25-30	30-40	30-40	40-60

Table 2: Feed pressure, capacity and cut point of hydrocyclones[57].

The efficiency of a hydrocyclone is rated on:

- how many solids of the desired size can be removed from the drilling fluid and
- how many drilling fluid can be reused

If a hydrocyclone works in a proper way, it can be seen how the solids leave the lower outlet (see Figure 26) which should be frequently checked visually. If the outflow looks like spraying, the feed pressure is adjusted correctly. If the outflow looks like a rope, the hydrocyclone starts to get clogged or is clogged already and a part of the solids gets carried away with the discharge fluid.

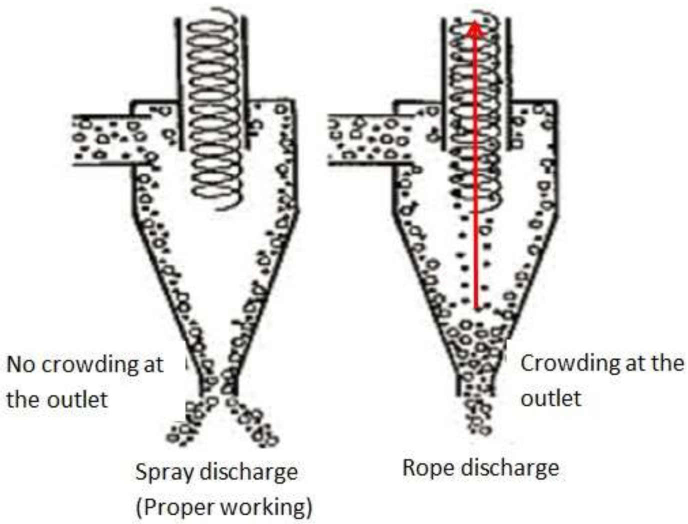


Figure 26: Properly and improperly working hydrocyclone[57].

If a maximum solid size of less than 20 µm is required, the mud is treated with a centrifuge right after it passed the desilter. This equipment uses also centrifugal forces to separate the heavier solids from the lighter drilling fluid. In a centrifuge the mud-solid mixture from the desilter is fed into a fast rotating (up to 3500 rpm) horizontal conical drum, where the fluid-solid mixture experiences centrifugal forces up to 3000 times gravity (depending on the diameter and on the rotational speed). The solid size which is still in the drilling mud is about 10 µm. Figure 27 shows the working principle of a centrifuge.

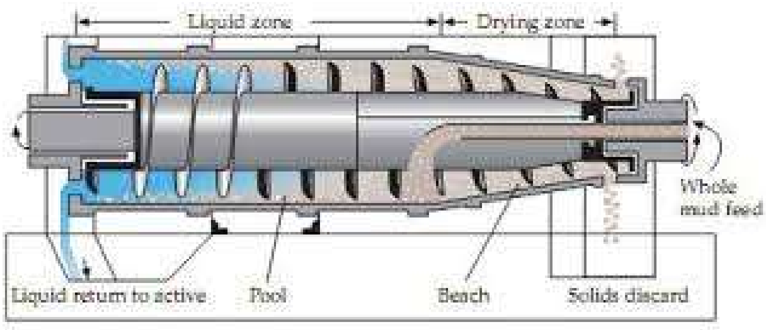


Figure 27: Centrifuge [58]

Problems with shale shaker and hydrocyclones

The efficiency of the shale shaker and the hydrocyclones is strongly dependent on the knowledge and conscientiousness of the equipment operator. If, for any reason, the equipment does not work properly and the mud is still solid-loaded when it reaches the mud pumps, the result is heavy wear and malfunction of the equipment. This becomes crucial when there are strong flow restrictions like for example at a core barrel [59], or a downhole PDM.

5.1.4.1 Areas of research

Permanent mud pump monitoring

Incorrect pump rate because of an unknown efficiency factor is a source of invisible lost time and lost time.

In the oil field it is common practice to evaluate the performance of the mud pump by “listening” to the mud pump pistons and valves. An experienced assistant driller can hear when the mud pump does not work in a proper way. However, for inexperienced staff it is hardly possible to recognize an improper function of the mud pump.

A system for monitoring the volumetric pumping efficiency of the mud pump should be introduced. This could be for example by measuring the current consumption of the mud pump motor.

$$P = U * I = \Delta p * Q \qquad (12)$$

P…Power [W]

U…Voltage [V]

I…Current [A]

Δp…delta pressure between suction and discharge side[Pa]

Q…Flow rate [m³/s]

Comparing the actual current consumption with the optimum current consumption at a given Δp, which also has to be measured precisely, gives an indication of the actual mud pump performance so that adjustments can be done.
Additionally a vibration monitoring system should be installed near or at the piston-valve-cylinder head system for early detection of abnormalities. During the suction process for example, the pressure in the fluid is lowered. If the pressure falls below the vapor pressure of the fluid, gas or air is released from the fluid and cavitation starts. As soon as the fluid pressure is higher than the vapor pressure of the fluid, the gas immediately is dissolved in the fluid again. The result is that the pump starts to hammer, which can clearly be seen in the vibration sensors. As a result, wear accelerates and the volumetric efficiency drops.
With a sensitive vibration monitoring system it should also be possible to visualize the wear on the sealing, when comparing an optimally running pump with the actual pump.
H.F.Spoerker and C.H.Lietzelbauer (2002) investigated this problem already by using high frequency pressure sensors and vibration sensors. The outcome of this investigation was partly satisfying; but more investigations have to be done [60]. The research work of P.Zoellner et al (2011) should also be implemented in control and automation processes of mud pumps [61] or back pressure devices at MPD respectively.
E. Cayeux, B. Daireaux and E. Wolden (2010) from the International Research Institute of Stavanger (IRIS) are working on an automation software for mud pumps for pump start up management (like P. Zoellner as mentioned above, but additionally including the consideration of the air in the drill string when making connection), maximum pump rate limits (as a function of time and mud temperature, depth, pipe rotation and others) and automatic pump shut down procedures in case of abnormal situations [62].

As the charging pump influences the efficiency of the mud pump - this type of pump (centrifugal pump) is prone to erosion corrosion due to the redirection of the fluid from a horizontal to a vertical direction by the impeller, associated with high acceleration and fine solid content in the mud-charging pumps should be continuously monitored to reduce invisible lost time.

Figure 28: Erosion corrosion of a centrifugal pump housing. This picture was taken of a mud pump charging pump. The depth of the erosion corrosion is up to 15 mm. Almost the entire impeller was gone. The pump was changed after having changed the valves and pistons at the mud pump several times during drilling of the intermediate section. This led to slower drilling and subsequently to invisible lost time [33]. Permanent monitoring of the energy consumption of the charging pump would avoid this problem.

Permanent drilling fluid monitoring

As permanent drilling fluid monitoring is essential for well control issues and prevention of drilling problems, drilling fluid should be monitored and data should be transferred to interested people permanently during the circulation process.

For permanent measuring of viscosity and density (mass flow) measuring instruments for explosive areas are available from different companies [63] [64]. The advantage of this measurement is permanent control of the fluid in constant quality without any human factor and easy real time data transfer to interested people.

Solids Control Systems

To improve the solid separation quality a permanent monitoring and remote control of the equipment should be introduced.

For example, the driller should be able to adjust the shale shaker (shaking speed and inclination of the screens) and hydrocyclones (charging pressure) from his work place. Therefore, cameras should be installed in a way that malfunctions of the shale shakers and hydrocyclones become clearly visible. If a camera is not sufficient, other solutions should be found, for example, sonic waves or x-ray or XRF [65].

Additionally the cleaned fluid should be monitored permanently and automatically, if the fluid corresponds to the expected solid contend before it reaches the mud pump.

A bottleneck during drilling with high flow rates and ROP is quite often the distribution line between the flow line from the bell nipple and the number of shale shakers. Due to the settlement of the cuttings the distribution line can get clogged, which leads to an uneven distribution of the mudflow. Some shakers are overloaded and are not able to clean the mud in a proper way anymore; some are underutilized [33].

Better solutions should be found in order to reduce manpower, which is needed to keep the distribution line free from clogging.

The aim should also be to get more information (automated) out of the returned mud. For example, permanent and automated investigation of the returning mud for hydrocarbons, influx formation water, cation exchange, pH-value but also cuttings amount and size (hint of cavings and wellbore instability) and so on.

5.1.5 Closed Loop Drilling

The biggest difference between an open loop circulation and a closed loop circulation system is that the annular backflow of the mud from the wellbore is not open to the atmospheric pressure at the bell nipple, like in the case of conventional over balanced drilling. Instead, the return flow is sealed against the atmospheric pressure with a Rotating Control Device (RCD) which allows controlled outflow of the mud from the annulus to the atmospheric flow line.

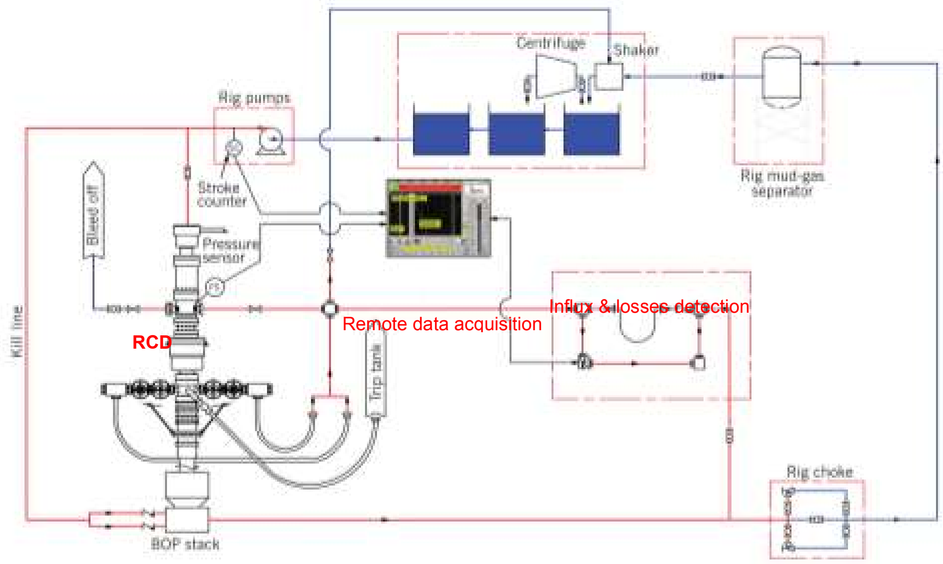


Figure 29: Overview closed-loop circulation system [66]. The major difference in the setup, compared to conventional overbalanced drilling, is the RCD, which is used to control the BHP and offers the opportunity of more accurate influx and loss detection.

The critical part of the circulation system is situated between the outlet of the mud pumps and the outlet of the wellbore.

With the closed system, it is possible to measure on the one hand the pressure[44] and the flow rate[45] on the inlet side and on the other hand, the pressure and the return rate on the outlet side.

The return rate can be measured with a coriolis flow meter and the pressure on the RCD in the same way as on the inlet side.

This gives the best opportunity to measure the mass balance of inflow and outflow of the well bore, which can facilitates early influx and early loss detection.

Depending on the bottom hole pressure the closed loop circulation is split into the categories of underbalance drilling and managed pressure drilling.

[44] The pump pressure is usually measured at the stand pipe

[45] The volume pumped is calculated from the SPM*V_{stroke}*η

5.1.5.1 Underbalanced Drilling

In underbalanced drilling (UBD) the bottom hole circulation pressure is below the pore pressure of the formation.

The following drilling fluids are used:

Medium	Specific density [s.g.]
Air-mist:	0.0 – 0.2 s.g.
Stable foam:	0.2 – 0.6 s.g.
Aerated fluid:	0.6 – 1.0 s.g.
Water:	1.0 – 1.2 s.g.

Table 3: Media used for UBD and their specific densities

Advantages of UBD [67] [68]**:**	
Higher ROP	Reverse chip hold down effect. High benefit when drilling horizontal wells with low WOB
Reduced / no formation damage	As the fluid pressure is lower than the pore pressure, no fluid enters the formation and therefore there is no positive skin effect. However, once the borehole is overbalanced, the damages are higher than in OBD as the fluid enters without any filter cake
No costs / NPT for lost circulation	Good in fractured, highly permeable and cavernous formations
No differential sticking	Especially when drilling through depleted zones.
Detection of bypassed reservoirs at OBD	Small reservoirs can be detected with UBD which cannot be "seen" at OBD
Reservoir investigation during drilling	Pressure increase and draw down can be seen on the RCD
Production during drilling	Closed loop circulation allows production during drilling.
Marginal reservoirs	Due to zero skin, a reservoir can become visible, whereas this is not possible with OBD.

Table 4: Advantages of UBD

Disadvantages of UBD [67] [68]:	
Risk of fire, or blowout	The only barrier is the RCD. Good maintenance is crucial
High drill string wear and higher friction (torque and drag)	No or low cooling and lubrication of the string leads to thermal cracking [69]. The cutters have a certain temperature limit which can easily be exceeded.
Erosion corrosion / corrosion	When drilling with air, the erosion corrosion can be significant. The oxygen in the air in conjunction with water can cause corrosion problems.
Higher drill string vibrations	Lack of dampening and lubrication due to the drilling fluid
Data transfer	Common M / LWD Tools and PDM cannot be utilized
High positive skin once the well gets overbalanced	There is no protecting filter cake in place
Can cause wellbore stability issues	No counter force inside the well
Fluid influx can change the properties of the drilling fluid	Foam reacts sensitive to an influx
Technique is still complex and expensive	An extensive economic feasibility study should be done before starting a drilling campaign

Table 5: Disadvantages of UBD

5.1.5.2 Managed Pressure Drilling

Managed Pressure Drilling (MPD) is also known as
More **P**roductive **D**rilling or **M**aking **P**roblems **D**isappear.
The International Association of Drilling Contractors (IADC) defines MPD as follows: "*Managed Pressure Drilling (MPD) is an adaptive drilling process used to precisely control the annular pressure profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular hydraulic pressure profile accordingly*" [70] .

The most important differences between OBD and MPD can be seen in Table 6.

Conventional OBD	**MPD**
$BHP_{(Static)} = HP$	$BHP_{(Static)} = HP + BP$
$BHP_{(Dyna.)} = HP + AFP$	$BHP_{(Dyna.)} = HP + AFP + BP$
Controlling an influx	
Weighting up the mud	Closing of the back pressure valve
Consequences	
Need of material and space	Continuous operation with no change
Need of time	
Increased costs	
Change of rheology	
Reduction of ROP	
Required casing strings (depending on type of MPD)	
Normally more than in MPD	Normally less than in OBD
Higher costs due to: A few more Casing runs, material, logistics, place, chance of HSE issues	The less pipe handling the better and cheaper

Table 6: Comparison OBD vs MPD.

BHP…Bottom hole pressure

HP…Hydrostatic pressure

AFP…Annular friction pressure loss

BP…Back pressure

OBD…Over balanced drilling

Methods of MPD

- Constant Bottom Hole Pressure drilling (CBHP) is used when drilling through narrow mud windows. Narrow mud window means a small operating range between pore pressure and fracture pressure (see Figure 30).

- Point of Constant Pressure drilling (PoCP) works in the same way as CBHP but focuses on a constant pressure at any desired point in the wellbore, e.g. casing shoe, critical formation.

- Dual Gradient Drilling (DGD) is used offshore in deep water and ultra-deep water to minimize the number of casing strings.

- Mud cap drilling (MCD), with its variations, is used to drill through highly fractured and cavernous formations where total losses of drilling fluid are expected.

- HSE-MPD has the objective to divert the returns from the rig floor in case of an incident, instead of having the return flow close to the working area on the rig floor permanently unprotected. Here, the RCD acts as a diverter with a higher pressure rating.

- Reverse Circulating (RC). The closed loop circulation system gives the possibility of circulating the mud down the annulus and up the drill pipe.

- An expanded method of MPD is MPD and the continuous circulation system CCS.

Constant Bottom Hole Pressure drilling CBHP

Figure 30 illustrates the difference in conventional OBD and the CBHP-MPD concerning the pressures exerted to the formation. In OBD, the formation experiences either the hydrostatic pressure (HP) of the mud column when there is no circulation (e.g. during making a connection) or the dynamic pressure, which is the sum of the hydrostatic pressure + annular friction pressure loss (AFP) from the point of interest (e.g. the bit) to the surface.

In CBHP-MPD, the aim is to hold the bottom hole pressure constant at any time, also when making connection. Therefore, when the circulation is stopped, the AFP has to be added on top of the wellbore at the back pressure valve. The challenge is to control the shutdown procedure of the mud pump and the closing of the back pressure valve in a way that the BHP stays constant. When circulation is started, the procedure is vice versa.

This method allows unlocking reservoirs which would have been hardly drillable by conventional methods.

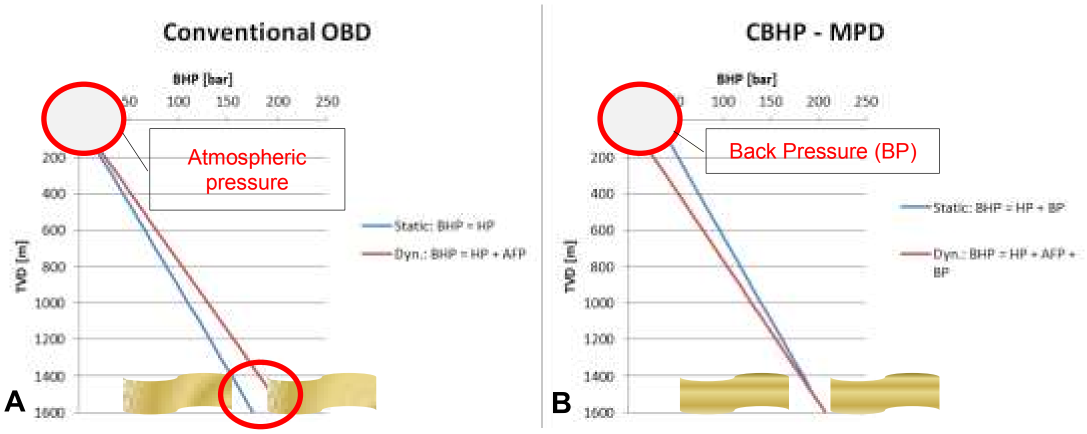


Figure 30 A, B: Conventional OBD (A) versus CBHP-MPD (B): Figure A shows pressures exerted on the formation during circulation (BHP=HP+AFP) and non-circulation (BHP=HP) at conventional OBD. Figure B shows a CBHP bridging the gap between static and dynamic pressure at the top of the fluid column with the back pressure valve.

Point of Constant Pressure PoCP

PoCP Drilling works in the same way as CBHP Drilling but the point of interest is somewhere along the wellbore where it is necessary to apply this method.

Dual Gradient Drilling

The definition of DGD according to the IADC is the use of "*two or more pressure gradients within selected well section to manage the well pressure profile*" [71].

DGD is used in deep and ultra-deep waters combined with narrow mud windows. In DGD seawater is used between the rig vessel and the BOP and from the subsea rotating control device (SRD) down to the bit weighted drilling fluid according to the required mud window. DGD can also be executed riserless or with a riser.
Additional equipment is necessary like a drillstring valve (DSV), SRD, solid processing unit (SPU), a mud lift pump (MLP), a return line etc.

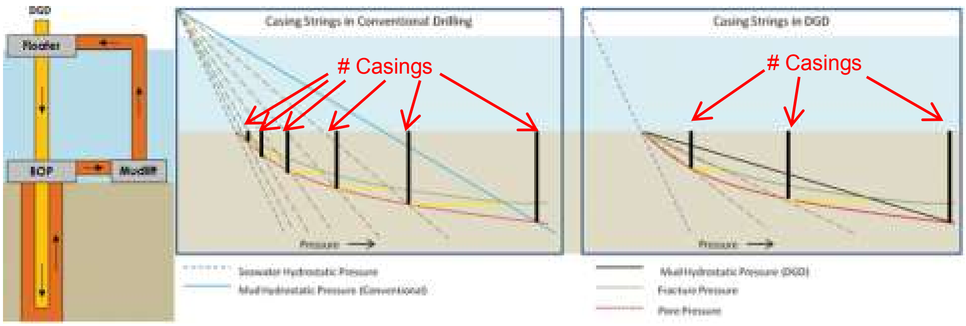


Figure 31: Dual Gradient Drilling - Function principle [72]. The left picture shows the circulation way of the mud at DGD. Drilling can be done riserless or with a riser filled with sea water. The pictures in the middle and on the right show the difference of the operating window, hence the number of casings needed in conventional OBD compared to DGD.

Advantages of DGD [73]	
Well Control	In case of an emergency during which the riser is disconnected, seawater simply disappears into the surrounding water and the well stays still overbalanced because of the properly weighted mud (not the case in conventional drilling). This mimics a position of the rig on the seabed floor.
	In DGD, the margin of safety between pore and fracture is larger than in other drilling methods.
Well integrity	Drilling in regions with narrow pore and fracture pressure windows, can lead to low clearance between the casing strings. With DGD, the number of casings can be reduced significantly and the cement sheath can become thicker (see Figure 31). Also the number of cement-steel, cement-formation interface is reduced and so the risk of gas migration and leaks.
HSE Costs	Less casings needed and therefore less tripping runs needed, longer bit on bottom time, less HSE issues, less logistics and space needed.

Table 7: Advantages of DGD

Disadvantages of DGD [73]	
Complexity	DGD is technically challenging as a lot of equipment has to work properly and without failure on the seabed floor.
Rig crew	A better educated and well trained rig crew is necessary
Planning	The more complex the system, the more pre-planning and risk assessment is necessary.
Development	Still in development. First well drilled in 2001.

Table 8: Disadvantages of DGD

Mud Cup Drilling MCD

MCD is a key drilling technology, when zones with total losses of drilling fluid have to be drilled. In MCD, with its variations, two different drilling fluids are used with no returns to the surface (see Figure 32). The mud cap fluid is used to create a barrier between the drilling fluid (including cuttings and sometimes formation fluid), and the surface and the mud cap fluid forces the drilling fluid, into the formation. The hydrostatic head of the mud cup fluid provides the barrier to the drilling fluid and is typically of high viscosity to prevent migration of formation fluids to the surface [74].
The formation has to be capable and large enough to absorb the drilling fluid, cuttings and sometimes formation fluid, without significant changes in pressure, permeability or fluid properties during the drilling process. This formation can be cavernous, vugular, highly fractured etc.
The drilling fluid is sacrificed to the formation.

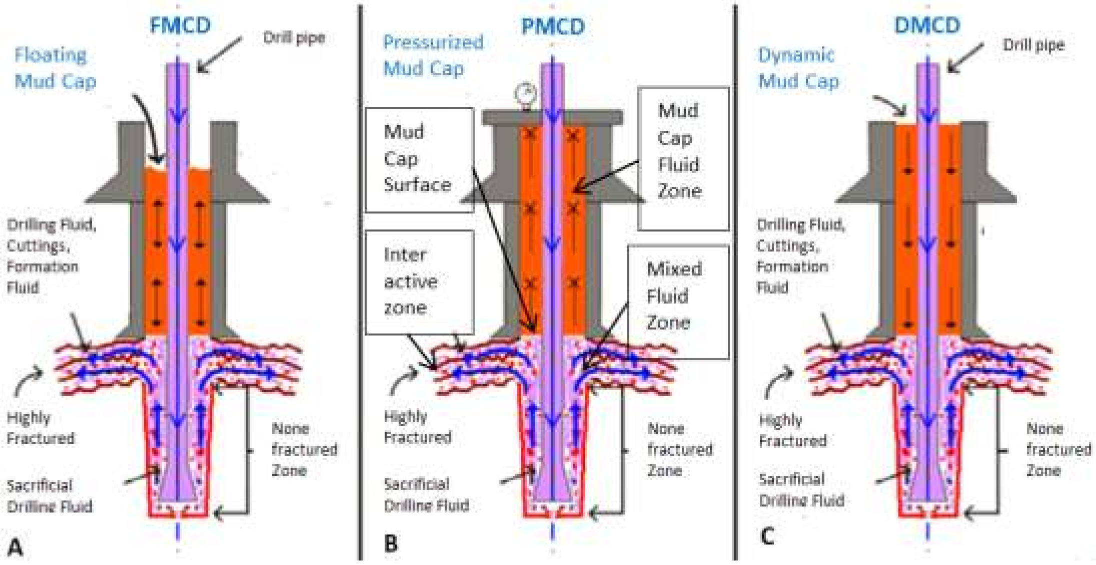


Figure 32 A, B, C: Variations of mud cap drilling. Picture modified from B. Goodwin et al (2014).

Variations of MCD [74]

In Floating Mud Cap Drilling (FMCD), the hydrostatic head of the mud cap fluid is high enough to force the drilling fluid into the formation. The mud cup fluid is exposed to atmospheric pressure without the need of a RCD. FMCD is the easiest and cheapest way of MCD but also risky in terms of controlling the MCD operations and HSE.

Pressurized Mud Cap Drilling (PMCD) is defined by the IADC as *"A variation of MPD, that involves drilling with no returns to the surface and where an annulus fluid column, assisted by surface pressure (made possible by the use of an RCD) is maintained above a formation that is capable of accepting fluid and cuttings"*.
The top of the mud cup fluid is held under some pressure with the RCD. This gives a better control of the MCD operation and is also better in terms of HSE.

At Dynamic Mud Cap Drilling (DMCD), the mud cup fluid is injected continuously. This method is applied, besides other reasons, when hazardous fluids, for example H_2S or CO_2, appear in a quantity which cannot be handled safely enough by conventional methods, and when it must be ensured that this fluid does not come to the surface.

5.1.5.3 Reverse circulation drilling (RC)

Usually the drilling mud is pumped down through the drillstring, PDM, bit, then added with the cuttings through the annulus to the bell nipple.
In Reverse Circulation (RC), the circulation circuit is vice versa (see Figure 33). Clean mud goes down the annulus and up inside the drill pipe.

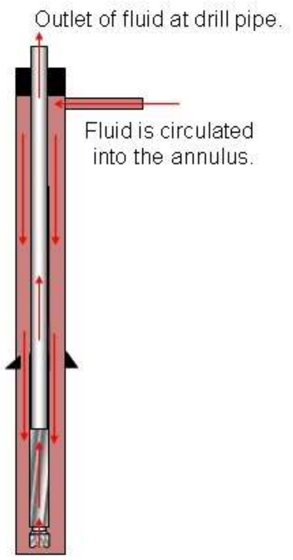


Figure 33: Flow path of the drilling fluid in reverse circulation operation.

In conventional drilling, one of the challenges is to clean the wellbore from the cuttings during the drilling operations. This becomes even more challenging when drilling deviated and horizontal wells especially during the phase of shutting down and starting up the pumps.

Advantages of RC compared to normal circulation

- Annulus is free from cuttings. → The problem with the cuttings bed is solved!
- Much lower pump rates needed because the fluid velocity for cuttings transport is governed by the cross section of the inner diameter of the drill pipe.
- Less potential of washouts in sensitive formations because of the lower annular velocity.
- Reduction of stuck pipe events because there is no settlement of cuttings in the annulus.
- Cuttings flow on the inner steel surface easier than on the borehole wall.
- The wash pipe, a weak point on top drives and swivels, experiences atmospheric pressure instead of pressures up to 500 bar.
- Smaller mud pumps as the pump rate and the friction pressure losses are lower.
- Smaller solid control equipment necessary because of lower feed rates for the equipment.
- Installing a choke valve, or adapting the valve of the IBOP to a valve which can be used as a control valve, gives the opportunity for MPD.

Disadvantages and Problems of RC

- Conventional PDM, turbines for power generation of M/LWD tools, pulser are not designed for abrasive material.
- Less or no jet impact force at the bit. Different bit design is necessary. Bits are available on the market for RC.
- The question if the small inner diameter areas (DC, “Nozzles”) on the drillstring can handle the cuttings volume when drilling with high ROP?
- ECD = Hydrostatic mud + back pressure at rotating control device – annular friction pressure loss from the top to the point of interest (lower than at conventional circulation). The ECD has to be calculated. If the ECD in RC is higher than in conventional circulation drilling, the chance of fluid losses is higher → evaluations have to be done.
- Low experience and development level in RC.

5.1.5.4 Areas of research:

RC: If the problem of abrasive solids in the PDM, turbines and pulsers can be solved, RC would become a problem solver when drilling long horizontal wells.
Excluding the downhole motor, the turbine and the pulser part, an investigation should be made, if RC can be done and if RC would have a chance on the market. If there is a realistic chance, a solution for driving the downhole motor should be found, whereas the pulser and turbine problem could be solved by using wired drill pipe.

At Palmer, Erzberg, the likelihood that the formation is tight and stable is high. This gives the opportunity to simulate high downhole pressures for testing equipment or research activities (e.g. pressure up the well as high as possible) with the aid of a high pressure rating RCD and heavy weighted mud.
The drilling fluid can also be heated up to display High Pressure High Temperature (HPHT) conditions in the wellbore.

Also of interest is the influence of the increasing annular pressure on the drillstring dynamics caused by the back pressure at surface. This includes possible dampening effects but also the question if it is possible to bring unwanted DSD effects under control with increasing annular pressure.

The measurement readings of downhole tool sensors under HPHT conditions could also be investigated.
Are the results correct or are there any deviations? What are the results of the measurements taken along the drill string compared to the instrumented and calibrated wellbore?

By matching the results with other measurements (drill string sensors, T&D measurements, measurements taken of the instrumented wellbore), models and software should be developed in order to increase safety (early kick detection), reduce wear and improve drilling performance.

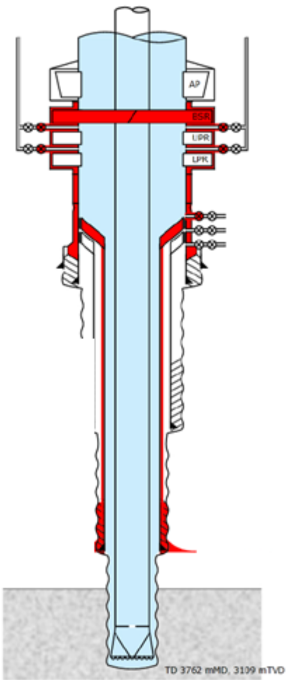
5.1.6 Well Control System

A well control system prevents the uncontrolled flow of formation fluid.
Therefore, two types of barriers are designated to prevent uncontrolled flow of formation fluid to the surface.

The first barrier – the primary well barrier – is directly exposed to the formation pressure.
During drilling operation and as long as the completion and the wellhead and Christmas tree installation are not installed, the primary well barrier is the drilling fluid. The pressure of the drilling fluid - in work over operation the completion fluid - must be higher than the formation pressure at any time.

The second barrier – the secondary well barrier – is a back-up barrier in case the primary barrier fails.
A secondary well barrier can be a BOP, a wireline BOP and a lubricator, a wellhead, a Christmas tree, a casing with casing hanger, a cement sheath and etc.

Figure 34 shows an example of a schematic of well barriers during drilling.



Primary well barrier		
Element	**Qualification**	**Monitoring**
Fluid column	$p_{mud} > p_{pore}$	Trip tank, outflow
Secondary well barrier		
Element	**Qualification**	**Monitoring**
BOP-RAMs	p-test (API)	Frequent p-test (API)
Riser / spool	p-test (API)	Frequent p-test (API)
Wellhead annulus and valve	p-test (API)	Frequent p-test (API)
Wellhead	p-test (API)	Frequent p-test (API)
Production casing hanger & lock ring	p-test (API)	External annulus monitoring
Production casing	p-test (API)	External annulus monitoring
Production casing cement	LOT	External annulus monitoring

Figure 34: Schematic of well barriers during drilling operations. Drawing modified from www.wellbarriers.com [75].

During drilling and workover operations, the crew has to be in a state of continuous readiness for a well control event.

Uncontrolled influx of formation fluid causes in best case lost time and delay in the drilling progress and in the worst case loss of human life, equipment and money.

Current practice in oilfield drilling

If an influx happens during drilling, more fluid flows out of the hole than into the hole. This becomes visible on the surface, after a certain time delay, by a raising fluid level in the trip tank and by the flow paddle in the flowline which is coming from the bell nipple to the shale shakers. Furthermore, depending on the viscosity and density of the influx fluid, the pump pressure is decreasing and the pump rate (SPM) is increasing.

The observation is carried out visually by the staff and automatically by setting an alarm. Additionally, the density and viscosity of the drilling fluid is frequently controlled by the assistant driller as mentioned in chapter 5.1.4.

If a crew member recognizes a rising fluid level at the trip tank or in the flowline to the shale shaker or any change in the rheology of the drilling fluid, the driller is informed and takes the first action in well control.

Problems of current well control activities

Apart from the proper setting of the outflow alarms on the paddle and on the trip tank, the recognition of an influx strongly depends on the attention of the people who are involved in well control. This usually concerns several people on the rig with different tasks, education levels and responsibilities.

5.1.6.1 Areas of research

Since saving time between an influx, recognition and taking action is very important, the aim is to develop models for early kick detections to keep the lost time event as short as possible. Therefore a kick should be simulated by injecting a liquid via an injection line into the wellbore and data should be collected from the various sensors installed in the drill string, the casing string, the saver sub, the pumps and the outflow. A schematic of a kick simulation wellbore is shown in Figure 35.

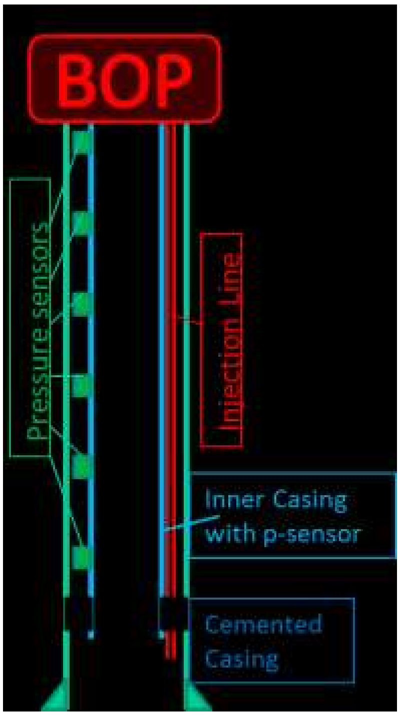


Figure 35: Schematic of an influx simulation wellbore

If it is possible to “see” a link between the simulated kick and the sensors of the saver sub, pumps and outflow sensors, models for early kick detection should be developed which can be used for early kick detection alarms for the driller.

Thanks to the possibility to measure the pressure along the instrumented casing string, the influence of the pressure wave during hard and soft shut in of the BOP can be analyzed in detail which is in the industry still rather based on philosophy than on technical factors.
During a hard shut in procedure, the choke valve is closed while drilling, while in a soft shut-in procedure the choke valve is open which results in different pressure waves along the wellbore while closing the BOP and in a different influx duration.

Finding more sensitive but cheap and reliable flow-out measurement methods can also facilitate a fester reaction when an influx occurs. One possibility could be to measure the height of the fluid level in the bell nipple without the influence of drill pipe rotation and / or cuttings settlement in the flowline to the shakers.

Training

With the presence of the kick simulation wellbore and well control equipment according to API Std 53, full scale well control training under various situations could be done at the WSL.

The advantage of this training would be that people work with full size equipment in operation mode. Moreover equipment training and maintenance could be trained on the WSL. The difference between real scale and laboratory scale well control training is illustrated in Figure 36 and Figure 37.

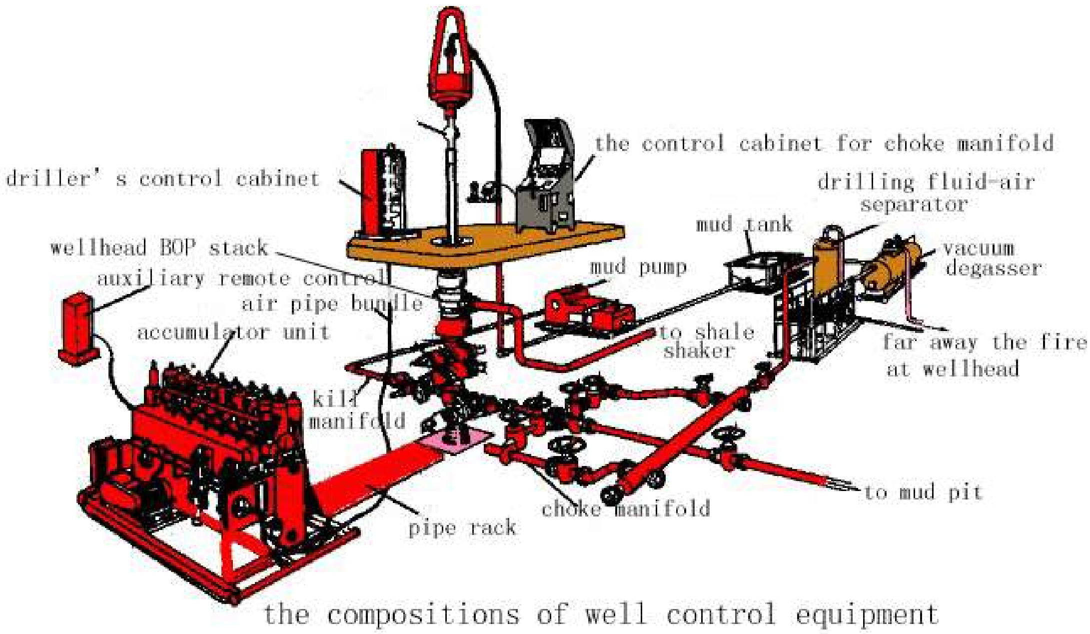


Figure 36: Real scale well control equipment arrangement [76]

Figure 37: Usual well control training in laboratory mode [77]

5.1.7 Well integrity

The most widely accepted definition of well integrity is given by NORSOK D-010: “Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well” [78].

In other words, well integrity can also be expressed as maintenance of full control of fluids within the well over the lifetime of the well in order to prevent unintended fluid flow or loss of containment to the environment.

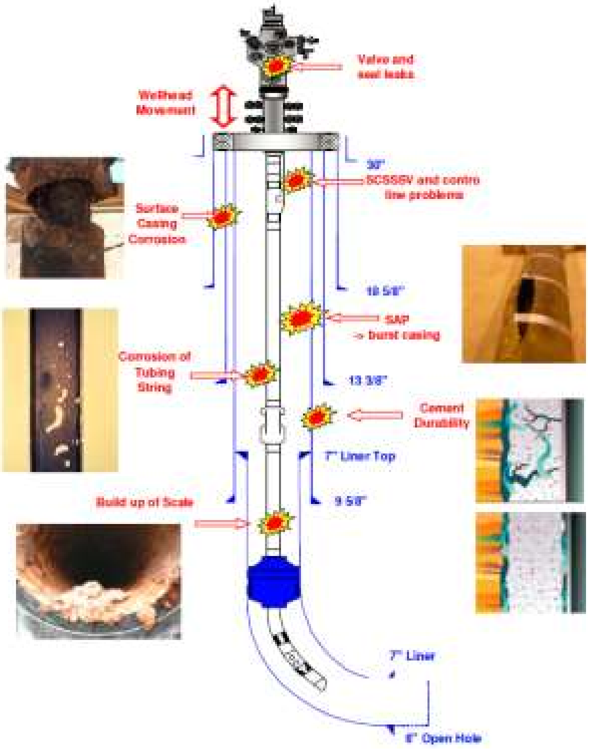


Figure 38: Overview possible well integrity failure[79]

Figure 38 shows an overview of possible well integrity failure along the entire well. Whereas leakages at the wellhead and at the tubing string can be fixed quite easily and fast by exchanging the leaking equipment by a new one, a leaking casing or cement sheath can become technically challenging and cost intensive.

The main purposes of cementing the casing to the formation are

- to provide zonal isolation of formation fluid and so to restrict communication of the fluid to other fluid bearing zones or to the surface
- to prevent the casing from buckling
- to control external corrosion of the casing by protecting the casing with cement with a higher pH-value than the corrosive formation fluid.

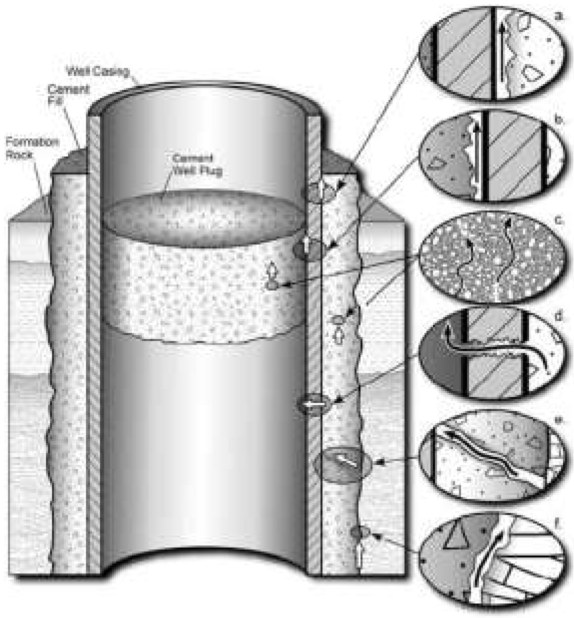


Figure 39: Weak points in the system formation-cement-casing

A leaking casing or cement sheath can be observed by the Sustainable Annular Pressure (SAP, often also mentioned as Sustained Casing Pressure SCP) or even worse, by pollution of ground water due to gas or oil migration through micro fractures in the cement or bad cement bonding.

According to Smith (2005) approximately 30 % of the onshore wells in Middle East show SAP and in some wells the SAP exceed the design values of the well [80]. Bourgoyne (1999) claims in a paper for the offshore technology conference, that in Gulf of Mexico more than 8000 wells show SCP and many of these wells show SCP in more than one annulus [81]. Between 2012 and 2013 researchers from several Universities investigated the groundwater for methane pollution in the Marcellus and the Barnett shale. The outcome of the study was that for all pollutions either a faulty production casing or a bad cement job was the reason [82]. Also at the Macondo incident on the 20th of April 2010 one major reason besides others was a bad cementing job.

5.1.7.1 Areas of research

Currently, one of the most important topics is to improve cement and casing integrity. Case studies show that the current state of the art in cementing practice is not sufficient to isolate the zones in a reliable way. The bonding between formation and cement, and the bonding between cement and the steel surface of the casing has to be investigated and improved under static and dynamic conditions (see Figure 39).

Suggestions for research

- After drilling with oil or synthetic based mud the following questions arise:
  - What influence does the oil wet surface of the formation and the steel of the casing have on the bonding of the cement?
  - If the bonding is reduced, is there any solution to improve it?
  - Can the chemical composition of the cement be changed in order to improve the bonding in an oil wet environment?
  - Can the spacer be designed in a way that the oil is removed from the surface of the formation / casing to give a perfect bonding of the cement?
- What kind of roughness of the steel surface of the casing provides the best bond?
- What influence does a special coating (e.g. epoxy) on the casing have to the bonding of the cement and to the corrosion protection of the casing?
- If the cement becomes fractured after the introduction of dynamic loads, is there a self-curing solution for of the cement?
- How can a high pH-value of the cement be maintained as long as possible, as a high pH-value is essential for corrosion protection of the casing? (the aging process of concrete results in decrease of the pH-value and thus in corrosion of the steel. The corrosion of steel leads to an increase of volume and a fracturing of the concrete)
- Usually the cement is pumped down the casing and up the annulus to the surface, while the casing is in static condition.
  - What influence does the rotation of the entire casing string have during pumping the cement?
  - What influence does it have to introduce targeted vibrations into the casing while or shortly after pumping the cement?
  - How and where should the vibrations be introduced?
- How does the cement behave after the application of several dynamic loads to the casing? For example dynamic loads can be pressurizing and depressurizing the well or pumping steam after cooling down the well several times [83].
- What influence does hammering of the tool joints of the vibrating drillstring have to the system casing-cement-formation? In which inclinations does this hammering become critical?

- Improvement of the accuracy and reliability of CBL and USIT measurements. Development of tools which “look” better into the cement and the bond between cement and formation.
- How can the cement integrity be monitored over the life time of the well and beyond in a simple, cheap and reliable way?

Answers to many of the unresolved questions above could be found in a research laboratory but the final tests should be done in real scale under real conditions on several shallow and deeper wells.

5.1.8 Improving exploration drilling.

The goal of an exploration well, also referred to as wildcat well, is on the one hand to examine the presence of hydrocarbons as expected by the geologists and on the other hand to get information on the geology, both in a cheap and fast way.
Usually, conventional drilling rigs with conventional drilling methods are used. For example, when using a conventional drilling method, the final bit diameter is 8.5” and four casing runs are necessary. The intermediate-2 section is drilled with a 12.25” bit, the intermediate-1 section with a 17.5” bit and the surface section with a 26” bit. This results in large amounts of rock which have to be excavated, in the need of huge mud pumps which provide enough pump rate to carry out the cuttings from the large annulus between borehole wall and drill pipe and a rig which is able to carry for example 4000 m of 5” drill pipe plus BHA. Quite often, the aim of an exploration well is not to put the well on production but just to “look what’s down there”.
If this “looking what’s down there” can be carried out with slimhole drilling or even microhole drilling huge savings of time and money could be made. In Table 9, the difference in the required pump rate and hook load of the rig is listed, when using conventional drilling and slimhole drilling respectively.
There is no clear definition, when slimhole drilling starts and ends, but it can be said that conventional drilling has a drill pipe to hole ratio of around 0.3, slimhole around 0.75 and microhole around 0.9

	Conventional Drilling	Slimhole Drilling			Conventional Drilling	Slimhole Drilling	
Production Section				**Intermediate-2 Section**			
MD/TVD	2900	2900	[m]	MD/TVD	2000	2000	[m]
Bit-diameter	8.5	4	[in]	Bit-diameter	12.25	6.125	[in]
DP-diameter	3.5	2 7/8	[in]	DP-diameter	5	3.5	[in]
min.flow-rate	130	130	[ft/min]	min.flow-rate	130	130	[ft/min]
min Q	343	44	[gal/min]	min Q	714	144	[gal/min]
min Q	**1297**	**167**	[l/min]	min Q	**2703**	**546**	[l/min]
Drillstring Load	**74**	**41**	[t]	Drillstring Load	**57**	**42**	[t]
Csg Load	**108**	**24**	[t]	Csg Load	**120**	**39**	[t]
Intermediate-1 Section				**Surface Section**			
MD/TVD	1000	1000	[m]	MD/TVD	70	70	[m]
Bit-diameter	17.5	8.5	[in]	Bit-diameter	26	12.25	[in]
DP-diameter	5	3.5	[in]	DP-diameter	9.675	9.675	[in]
min.flow-rate	130	130	[ft/min]	min.flow-rate	130	130	[ft/min]
min Q	1606	343	[gal/min]	min Q	3325	322	[gal/min]
min Q	**6078**	**1297**	[l/min]	min Q	**12586**	**1220**	[l/min]

Table 9: Comparison of conventional vs. slimhole drilling. In slimhole drilling the required hookload of the rig is reduced by the factor of 2.5. The required pump rate for cuttings transport is reduced by a factor of 5 to 10.

Advantages	Disadvantages
Less footprint on location	The acceptance in the oil industry is low
Less impact on roads as less truck loads needed	Step changes are difficult to introduce in the oil industry
Faster mobilization and rig move	ECD increases faster and can be a limiting factor
Less material in stock, less spare parts	Mud maintenance becomes more important with increasing pipe/hole ratio
Less drilling fluid and hence easier spending of better drilling fluid	Drilling non-competent sediments can become difficult
Lower buckling and vibration tendency	Limited petrophysical access
Less waste and cuttings	Kick detection and well control becomes more difficult but can be controlled by the use of automatic kick detection systems
Fewer employees and therefore better HSE performance	
Smaller and cheaper BOP and wellhead	

Table 10: Slimhole drilling vs conventional drilling. Pros & Cons.

5.1.8.1 Areas of research

Most research issues, as mentioned earlier, can also be applied to slimhole drilling. Moreover, improving coring technology for conventional and slimhole drilling is of great interest. Continuous coring without having to stop drilling would enhance ROP dramatically because on the one hand less volume would have to be cut and brought to surface and on the other hand WOB would be transferred to cutters which operate at a more efficient cutting velocity.

5.1.9 Bit and downhole motor design

The problem of all drilling operations with a rotating, shearing tool (also related to as fixed cutter or rotary drag bit) is that only the cutters which are placed at the outer diameter of the bit are operating at the optimum cutting velocity designed for a given cutter, cutting material and cooling fluid. The further the cutters are placed to the center of the bit, the lower is the cutting velocity and hence the cutting efficiency (see Figure 41).

The maximum allowable cutting velocity is governed by the thermal stress capability of the cutter material. Usually, the harder the formation and the higher the cutting velocity, the more heat is generated by the shearing process. Figure 40 shows the uneven damaging distribution of the cutters from the outside of the bit with the highest cutting velocity to the center of the bit where the cutting velocity is decreased and becomes zero in the center.

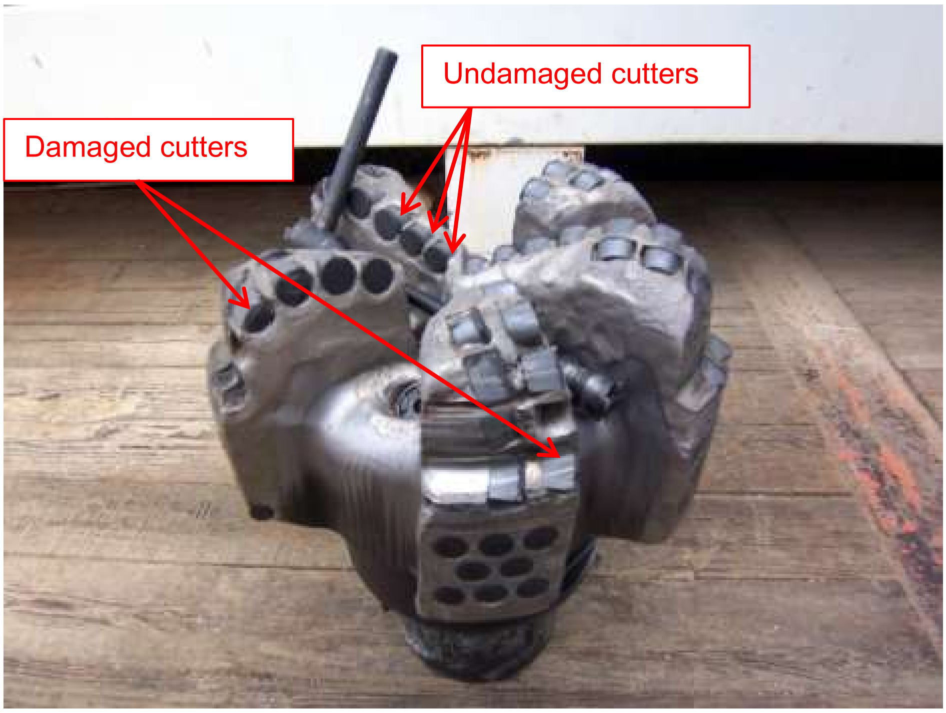


Figure 40: 12 ¼ " PDC bit after 140 hours of operation. The difference in wear of the outer cutters to the inner cutters can clearly be seen. Drilling distance was from 1500 to 3200 m depth in the Sarmatian formation, Romania.

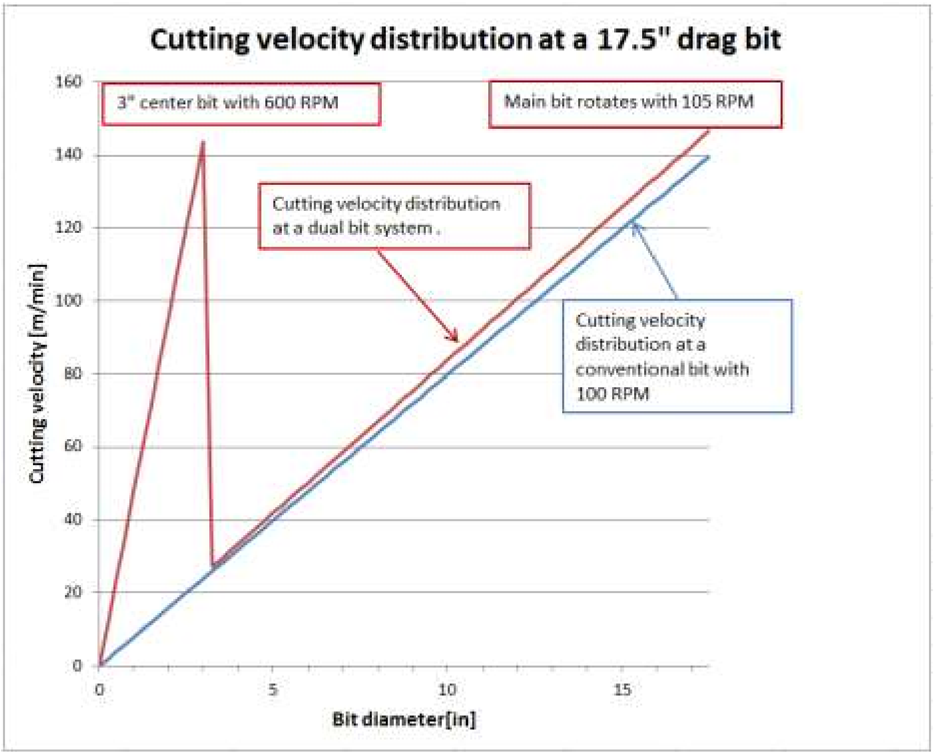


Figure 41: Cutting velocity (v_c) distribution on a 17.5" drag bit. The blue line shows a conventional 17.5" bit and the red line shows a split bit configuration, the main bit is rotating with 105 RPM and the center bit with a diameter of 3" with 600 RPM. At a conventional bit, the v_c at a diameter of 3" is only 25 m/min which is 1/6 of the optimum.

Due to the bad cutting performance of the inner cutters, which do not operate at their best cutting velocity compared to the outer ones, also the WOB distribution is not equal along the face side of the bit.
The optimum rotary speed can be calculated by equation (13)

$$RPM = \frac{v_c}{d * \pi} \qquad (13)$$

v_c...cutting velocity [m / min]
d..diameter of the bit [m]

A practical example:
When drilling a hole in a piece of steel or in a wall of concrete and when the “WOB” is high but the depth of cut low, the spiral bit starts to vibrate and to whirl, the bit becomes hot and the cutting edge becomes worn. But as soon as the bit gets a “grip”, the spiral bit moves smoothly into the hole and does not become that hot anymore. When drilling with a larger spiral bit (above 10-12 mm) it becomes hard to supply the bit with enough axial force, as the center of the bit consumes the most axial force and the cutting edges are grinding over the surface and get worn fast. A solution to this problem is to drill a small hole with high RPM first and to drill with the final spiral bit in a second run excluding the center of the bit from cutting.

The same problem occurs in oil field drilling, except that the bit is much larger in this case and the cutting geometry of drag bits is unfavorable (negative rake angle) for satisfactory ROP at low WOB.

5.1.9.1 Areas of research

Finding the right solution for better drilling performance in the center area of the bit. Possible approaches:

- Finding a solution for a dual RPM bit where the center bit operates at a better performance. For example, the outer bit is rotated by the drill string and the inner bit by a PDM with the right lobe ratio, lobe inclination and pressure drop along the lobe length to provide the right RPM and torque at a given flow rate.
- Finding a solution to the problem that most top drives cannot operate at more than 180 RPM. For bits of [46]12 ¼ "and less a dual downhole PDM-RPM motor would be of high value. This could be accomplished by a serial connection of two PDM, the rotor becoming the stator and one PDM operating at a lower RPM but a higher torque and the other PDM vice versa.
- Investigating of the influence of opposite rotation of the center bit in relation to the main bit on the hole quality in terms of bit walk
- Supporting the inner drag cutters by a crushing element (functioning in the same way as a roller cone).
- Investigating the use of jet impact force to support the excavating action of the cutter [84].
- Supporting the cutting action by targeted vibrations to the bit or only to the center bit [84] [85]
- Tying in with the work of C. Simon et. al. (2007) to find a way for a bit design needing less WOB without over-aggressiveness of the bit [86].

Finding a solution in this topic would enhance ROP especially in horizontal wells where it becomes difficult to apply WOB. Bit whirl and vibrations should also decrease as the bit has a higher and more homogeneous counter torque when the bit is "in grip".

[46] When a 12¼" bit rotates with 180 RPM, the outer cutters of the bit have a v_c of 175 m/min, a 8.5" bit has a v_c of 175 m/min at 180 RPM respectively, which is much too low in soft formations

5.2 Production Engineering

Once the well is drilled for research and testing issues and is not needed anymore, it can be used for several other testing and long term testing purposes of the industry or production engineering department.

Long-run artificial lift tests can be performed with various types of pumps and different fluids. The pump can be supplied with fluid either be running an injection line together with the casing or tubing from top to a level below the pump or, if the formation is permeable enough, by injecting via an injecting well. The following paragraph shows new challenges in artificial lift systems.

So far this has not been a European problem but for 2014 it was estimated that 14 % of hydrocarbons worldwide come from shale plays but 24 % of all artificial lift spending worldwide being focused on shale plays [87].
According to an article in the Journal of Petroleum Technology in October 2015, 95% of all shale wells drilled in North America are somehow depending on artificial lift to keep the well flowing, but many artificial lift equipment is designed for conventional wells and not for shale wells with a true vertical depth of more than 3000 m and a departure of several km. Furthermore, the directional drilling section is quite often a series of valleys and hills and in order to save costs there is a trend in completion towards 4” to 5 ½ “ casing which makes artificial lift a challenge and requires new developments. More improvements in the early abnormality detection of artificial lift systems should be made to keep the Mean Time Between Failure (MTBF) as long as possible and the downtime as short as possible. Artificial lift in shale wells is one of the key issues in the planning of shale wells, technically and economically.
But also the operators’ drilling departments have to change their attitude from bringing the wells as fast as possible to TD in order to drilling as cheap as possible to considering the entire life cycle of the well, which means straighter and more precise wellbores [88].

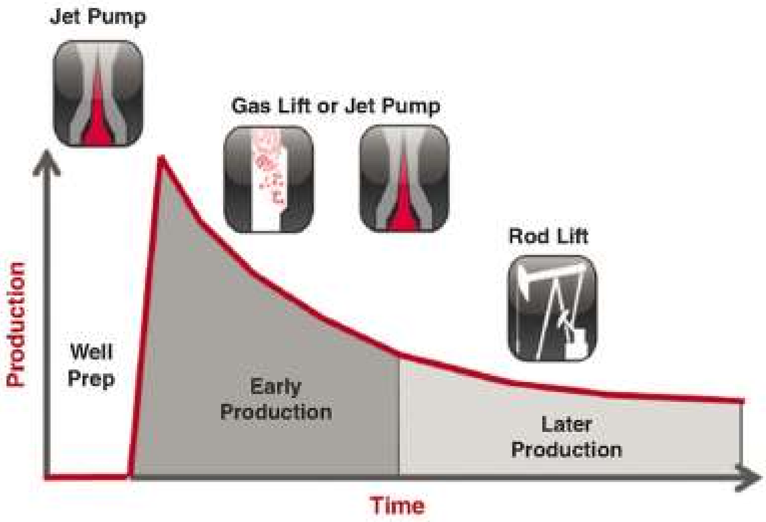


Figure 42: Types of artificial lifts needed in shale well production [87]. In the first step frequently jet pumps are used for Fracturing Fluid Recovery (FFR) to lower BHP and to initiate flow in the well. This usually lasts between 3 days to 3 weeks. Then, when production declines, different types of pumps are used, depending on the rate. Producers are increasingly planning for the life cycle and preinstall equipment which can quickly be put in operation and couses less downtime.

5.2.1.1 Areas of research

The areas of research at the WSL are widespread for production engineering and not the main objective in this Thesis. As soon as the research wells are drilled for the drilling related topics and the well is not needed anymore, the wells can be handed over to the production engineers, or the wells can be ordered from the WSL operator.

Suggestions for research in artificial lift

- Long run artificial lift tests (if requested up to several years)
- Several artificial lift test can be performed at the same time
- The composition of the Injection fluid can be precisely selected according to the requirements and changed any time it is necessary
- To be on the forefront of artificial lift for shale plays production, intensive long run tests of new developed components for shale play application can be performed.

5.3 Reservoir Engineering

At this planning stage, the geology of Palmer is not yet investigated and proven. But if permeable sections (fractures, permeable faults, porosity) are encountered, theses sections can also be used for field testing of research topics, like Enhanced Oil Recovery (EOR) and testing and verification of various models.

5.4 Geophysics

In this chapter, several possibilities for geophysics and the related industry are listed. Palmer at Erzberg would be a perfect seismic laboratory for R&D of new tools and for improving existing tools and methods. Furthermore, the developments in conjunction with slimhole or microhole drilling can also be used for other industries or in earthquake science.

5.4.1 Improving logging tools for cement bounding

The wells drilled offer a unique research and testing possibility for R&D of new or better formation evaluation tools, both, cased hole and open hole, cement evaluation and measuring methods during drilling operation.

5.4.1.1 Cement integrity logs

Currently the main topic is cement and cement bond evaluation as already mentioned in chapter 5.1.7. Christoph Thonhofer from the Montanuniversitaet Leoben made in his Master Thesis an extensive investigation of well bore cement integrity and the tools used for cement evaluation [89]. This chapter gives just a short overview of possible research areas.

Good tools already exist but the most widely used cement bond log (CBL) does not shows satisfactory and reliable results [90]. For example, the CBL cannot detect channels which are smaller than 12.7 mm (½ “) and the CBL cannot identify the azimuth of a bad cement bond to the casing [91]. Furthermore, the CBL can only detect type I and II channels but no other types (see Figure 43).

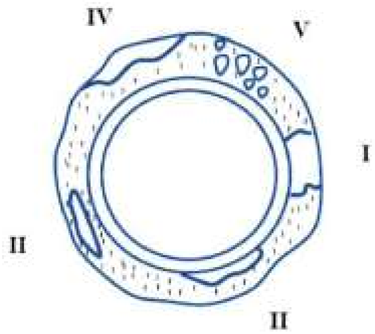


Figure 43: Channel types in a cement sheath [90]. Only type I and II can be detected by the CBL tool.

Most evaluation tools focus on the bonding of the cement sheath to the casing but a high quality evaluation of the entire cement and bonding between cement sheath and the formation is also from interest.

As wells always experience somehow dynamic conditions due to changing pressures in and outside the well, changing chemistry of the interacting fluid (formation fluid and treatment fluids), thermal changes, corrosion and so forth, the well integrity should better be permanently controlled during the entire lifetime of the well and after its abandonment.

Therefore, cheap and simple ways should be found to permanently monitor the cement sheath and other well barriers by installing sensors in the well and / or cement sheath.

5.4.1.2 Other areas of research

- According to Johannes Pluch from VA-Erzberg, five to six explosions per week for mining activities take place always at 9.52 o'clock [92]. This seismic source can be used for testing new models for seismic formation evaluation or for new tool developments, downhole or on the surface.
- Other wells drilled at Palmer can be used for improving cross well tomography[47] during drilling operations. For this purpose a geophone which receives the induced seismic waves created by the drill bit is installed in a neighboring well. If useful, instead of lowering the geophones in an existing well, the mining tunnel with the entrance Mundloch (see Figure 54 in the Appendix) can also be used. This tunnel is roughly 70 m below the surface.

[47] Tomography is using any kind of penetrating waves for sectional imaging.

- Seismic While Drilling (SWD): The shearing and crushing action of the drill bit can be used as source of seismic waves for formation evaluation in front and to the side of the bit in conjunction with the use of wired drill pipes. Together with the investigation of changing vibrations of the drill bit at changing properties of the formation (see chapter 5.1.3, idea of Ali Esmaeili et. al. (2012) [53]), SWD could become a powerful tool for formation evaluation while drilling.
- Chapter 5.4.2.

5.4.2 Development of small size downhole geophones

it is from great interest for reservoir and production engineers how the water-oil, oil-gas or water-gas contact (WOC, OGC, and WGC) changes over time during production of the reservoir. Usually this can be investigated by cased hole logging technic or by shooting a 4D seismic. For logging a well a wireline service must be ordered and the well must be shut-in which results in considerable costs. For shooting a 4D seismic the costs are many times higher.

In order to reduce costs and to make the data accessible at any time, a seismic receiver (geophone) or a seismic source should be lowered and installed in a monitoring well next or beneath the reservoir. On the surface above the reservoir a geophone or a seismic source is placed (see Figure 44). By sending a seismic signal, the contact levels can be observed over time. Permanent level observation helps for decision making for the reservoir and production engineers. The geophone or the source should be designed as slim as possible so that slimhole drilling or even microhole drilling can be applied which would save a lot of drilling costs.
The challenge for the geophysics engineers is to develop a tool which should on the one hand be small enough to fit in the hole and on the other hand be sensitive enough to recognize a contact level change of one meter or less. Furthermore the receiver / source and data transmission device should withstand bottom hole pressure, temperature and exposure to aggressive fluids over a long period of time without losing the accuracy of the received / transmitted signal.

If the method mentioned above is unsatisfactory, other physical principles which are able to “look” deeper into the formation could be investigated.

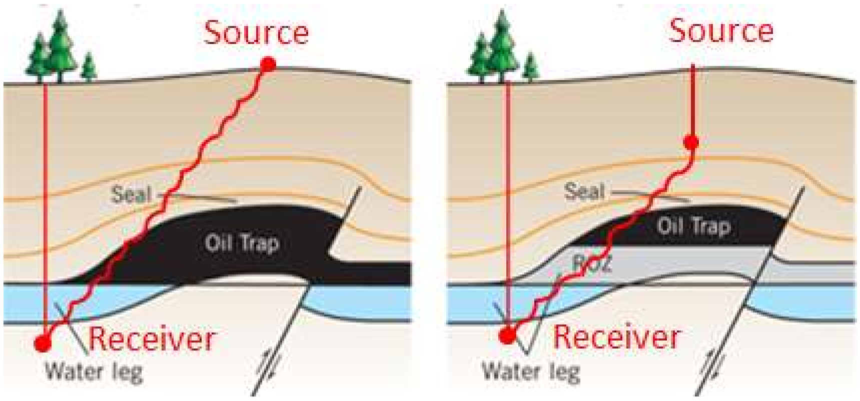


Figure 44: Illustration of WOC / OGC monitoring. Picture modified from oil and gas journal [93]. The right picture shows an installation where the source is lowered just above the cap rock of the reservoir, in case the left, cheaper version does not give a satisfactory resolution. The question is also if the residual oil zone (ROZ) blurs the impedance difference of the two fluids.

If this method works reliably and well enough, it can also be used for permanent monitoring of tectonic activities in tectonic sensitive areas, like the Mur – Mürz Furche, the Periadriatic fault or other endangered areas. This would be a step forward in early warning of tectonic activities and of great public interest.

5.4.3 Dampening of the rig, mud pumps and generator set.

If required by geophysicists, the rig and other vibration emitting equipment can be put on dampeners to receive undisturbed signals during drilling and the development phase of the tools. Operating devices have always a certain amount of unbalanced mass. Depending on the dampening effect of the structure, more or less vibrations are transferred to the surroundings. Equation (14) and Figure 45 show the relationship of the forces acting on an externally excited system.

$$F_0 cos\omega t = m\ddot{x} + c\dot{x} + kx \qquad (14)$$

$F_0 cos\omega t$...externally excited force (e.g. unbalanced motor)

m...mass of the swinging structure

c...dampening constant (material constant or adjustable)

k...spring constant (material constant or adjustable)

x...distance of oscillation

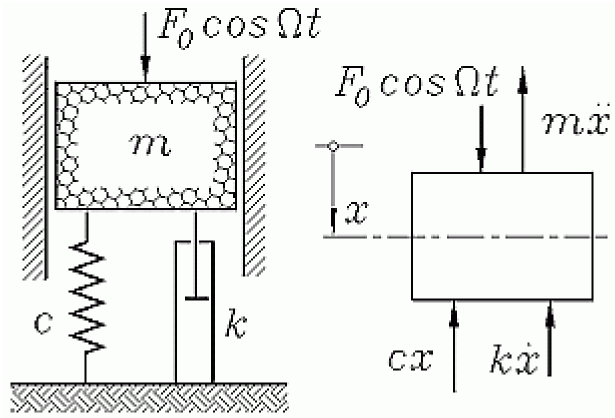


Figure 45: Externally excited dampened oscillation system [94].

As a mud pump, drilling rig or generator set do not swing at a constant frequency, the spring and the dampener have to be adjustable. With a vibration sensor and a control unit adjusting c and k according to the external excitation, vibrations can be minimized automatically.

5.5 Geology

The main interest of geologists, geophysicists, but also for reservoir engineers when coring reservoir rocks, is to gather information about the formations drilled. A lot of areas, also Eisenerz (see chapter2.2), are not investigated so far and much information is still based on theoretical assumptions without verifiable proofs. Getting more information about the geological structure in Austria would facilitate understanding of

- tectonics
- basement
- groundwater flow and
- groundwater protection
- geothermal resources and
- geothermal flow of fluid
- land slides
- mineral deposits.

The first choices of information source for geologists are cores.

Advantages of coring:

- direct measurements of physical properties
- direct analysis of grain size, grain distribution, sorting, dipping

- Small cores (plugs) can be drilled out of the core and analyzed in detail in a laboratory
- Stress regimes can either be seen, measured (stress release has to be considered) or assessed
- Cores are the one and only reliable information from downhole without uncertainties (only the depth measurement could be a source of inaccuracy)
- Logging tools and logs can be calibrated with the cores.

Disadvantages of coring:

- Still expensive (coring service and rig time)
- When analyzing the core for reservoir properties, change of pore space and formation fluid composition due to decreasing pressure and temperature during pulling out of hole has to be considered
- If the core is moved too fast to the surface, the core can break because fluids with in-situ pressure do not have enough time to reach a level below the fracturing pressure of the core sample.
- The core can break because of drill bit vibrations (which are usually lower than in conventional drilling, as the WOB acts on cutters operating at or near the optimum cutting velocity).

If coring would be cheaper and at least or nearly as fast as conventional drilling, all the advantages mentioned above and even more could be exploited, thanks to better knowledge of the formation and the stress regimes encountered from the top, to the final depth of the well.

The advantage of the coring bit compared to the conventional bit is that less rock volume has to be excavated and there is a better WOB distribution to cutters which act at or near optimal velocity. This results in higher ROP than in conventional drilling.

The disadvantage is that lifting the core to the surface while the bit is not rotating at the bottom is time consuming.

If any way could be found to lift (pieces of) the core without stopping drilling, this method would be a step forward in drilling and formation evaluation.

At Palmer, continuous coring equipment for conventional and slimhole drilling should be developed, and tested to make core drilling more affordable and accessible for companies or government institutions.

6 Drilling Rig and Equipment

In this chapter, the drilling rig and the equipment needed for drilling operations are described. It has to be noted that this is a fist selection of the equipment which has to be evaluated in detail before sending out a tender to relevant companies, for renting or buying the equipment.

6.1 Rig

A drilling rig, designed according to state of the art and national standards is recommended. The highest level of safety at work is self-evident and working conditions must fulfill the standards. A certification according to API is desirable for international clients.

6.1.1 Requirements

The following requirements apply to the drilling rig:

- Mast
  - Suitable for super single drill pipes, (range III; 38 ft - 45 ft ≙ 11.6 m - 13.7 m), Range III casing and casing running tool for top drive
  - Hoisting capacity up to 100 t
  - Possibility of pushing
  - Self-erecting mast
- Catwalk or automatic pipe handling system remote controllable and prepared for automation
- Top drive driven
  - Either a skid for easy top drive change or a top drive with a broad operating range in torque and rotational speed.
  - Hollow shaft for wireline operation and core retrieval
  - Torque up to 45 kNm at 160 RPM
  - Rotary speed 800 RPM
  - Rated to 5000 PSI
  - Capable for casing running tool
  - Power wrench
  - IBOP (IIBOP) manual and remote control activated
  - Designed for pushing loads
  - Optional automation

- Substructure
    - Clearance high enough to install a BOP (for trainings issues)
    - Large rig floor area to install testing equipment
    - Easy to welding or cutting off testing equipment (it's a place for working and testing)
    - Easily mountable and removable wind shields for drilling in wintertime
    - Anti-slip surface for HSE issues
    - Minimum two access ways
- Driller's cabin
    - Large cabin which is divided by a door into a driller's area (two men) and researcher's area (four men). Alternatively a small cabin at the rig floor and the researcher are in the office area (see chapter 6.1.3.1).
    - Both areas fully equipped with drilling data screens
    - Air condition and good insulation.
- Power tongue (iron roughneck)
    - Spin and make-up device
    - Make-up torque up to 70 kNm
    - Break-out torque up to 90 kNm
    - Tool joint OD 2 ½ " to 10 " (microhole drilling – DC)
    - Optional automation
- Besides manual slips as a back-up, hydraulic slips with the option of automation
- Catheads and tongues as a back-up and for making up BHA
- Easily moveable from spud to spud

6.1.2 Make, rent or buy a rig

The first considerations about this well scale laboratory were to work out a concept to design and build the "perfect", highly automated testing rig. The questions were:

- What is the best hoisting system for a testing rig with a 100 t hook load and a 20 t pushing load?
- What is the best pipe handling system for range III drill pipes?
- Hydraulically driven vs electrically driven rig
- Highly modular system for fast and easy change from testing to training mode and easy transportation

- Evaluation of the possibility to build a rig in modular design light enough for helicopter transportation. This would be a step change in drilling in remote and permafrost regions.
- Possibility of remote control of the rig.

The advantage of a self-designed and self-constructed rig is that it would meet the outlined requirements best. It would become a unique and more competitive tool with higher chances on the market. The rig could be adapted to changing requirements faster and more easily because the designer team and the workshop are near or at the site of the rig.

The disadvantages of a self-built rig are:

- Large amount of time needed from planning to operation and finally eliminating all the teething problems of the systems to make it a perfect and solid rig with long Mean Time Between Failure (MTBF) and low maintenance costs.
- Designing, building and maintaining the rig according to standards can become a challenge and can be costly and time-consuming. To name some standards which have to be met:
    - EN-1090 1-3. CE-certification of steel and aluminum structures (EN-1090-1; compulsory) Execution for Steel (EB-1090-2) and for aluminum (EN-1090-3) structures
    - Machinery Directive 206/42/EC
    - Low Voltage Directive 2014/35/EU
    - Pressure Equipment Directive 97/23/EC
    - ATEX Directive 2014/34/EU
    - etc…
- International clients may ask for API certification of the equipment. If so, the rig and equipment have to be certified according to:
    - Spec 4F; Specification for drilling and well service structures
    - Spec 7F; Oilfield chain and sprockets
    - Spec 7K; Drilling and well service equipment
    - Spec 8C; Drilling and production hoisting equipment
    - Spec 9A; Specification for wire rope
    - Spec 20A; Load and pressure bearing castings made of steel (alloys)
    - Spec 20C; Load and pressure bearing closed-die forgings
    - etc…

- Lack of experienced design engineers in the area of oilfield equipment and rigs (but this is also an enrichment, when designing new devices because of a new and different approaches to solutions, as long as the framework and requirements are clearly defined).
- Need of workshops and craftsmen who can manufacture the equipment.
- Financing of the project which involves a number of engineers over a long period of time and a lot of material and equipment.
- Higher risk but also higher chances to introduce innovations and to make profit.

Renting the rig, equipment and personnel	
Advantages	**Disadvantages**
The contract can be negotiated according to the client's requirements.	A very accurate and precise contract with a clear framework is essential.
The responsibility for the rig is limited to the contract	Any incident or change not provided for in the contract and happening after its signing can become expensive
Financial risk is lower, costs are predictable.	Costs can become extensive
No worries about training of the crew	Bad performance or HSE issues harm the reputation of the operator
No administrative work and logistics	Good quality control is necessary
No spare parts	Dependence on the contractor's performance

Table 11: Renting rig, equipment and personnel - Pros & Cons

Renting of the rig but own personal	
Advantages	**Disadvantages**
The contract can be negotiated according to the client's requirements.	A very accurate and precise contract is essential.
The responsibility for the rig is limited to the contract	Any incident or change not provided for in the contract and happening after its signing can become expensive
Lower financial risk	After a certain time, a rented rig can become more expensive than a bought one.

Continuation	
Advantages	Disadvantages
High flexibility as to the size of the rig, duration of the contract, auxiliary equipment etc.	If quick decisions have to be made the responsible person at the lessor's office is not always available.
The design loads of the rig can be outbid without thinking of later costs	Depending on the contract and rig, overloading can become expensive.
In the event of damage, responsibility and administrative work are assumed by the lessor.	Precise documentation of any activity on the rig (for argumentation if complaint arises).

Table 12: Renting the rig but own personnel - Pros & Cons

Buying	
Advantage	Disadvantage
The rig can be adapted to changing requirements as needed (as long as the standard are met)	High CAPEX
At the right time, during a downtime, rig and equipment can be bought cheaply.	Financing and interests can become a challenge
With a good crew and maintenance the rig can easily exceed the usual lifetime and save a lot of money	The condition and running costs of the rig strongly depend on the quality of the rig crew
Usually a good business as long as there are enough orders and paying clients.	Without a client for a certain time the project can quickly become loss making
Repair and maintenance work can be done quickly and according to the demands of the owner	Spare parts have to be in stock and financed
	Drilling range depends on the capacity of the rig.
	Storage yard and workshop necessary

Table 13: Buying a rig - Pros & Cons

6.1.3 PRAKLA RB-T-100

Well suited for purpose is the rig Prakla RB-T-100 (a member of Bauer Group; see Figure 46).

Figure 46: Prakla RB-T 100 [37]

RB-T 100 is a self-erecting, fully hydraulically driven rig. The power unit for hydraulic energy is in the trailer. The hoisting system consists of a hydraulic cylinder and a rope and sheave which doubles the hoisting speed and stroke length of the cylinder. This rig is field proven and also used as a stand-by rescue drilling rig for trapped mining workers in case of an accident.

Some technical data [37]:

Max. hook load	100 t
Pull down capacity	20 t
Stroke length of the mast	16.4 m
Max. torque	46 kNm
RPM	0 - 450
Max. break-out	70 kNm
Rated power top drive	327 kW
Wash-pipe ID, rated to 350 bar	75 mm
Wash-pipe ID, rated to 40 bar	200 mm

6.1.3.1 Modifications for RB-T 100

For the use as a testing rig the rig should be slightly modified.

There are two possibilities where to place the researcher's work place. The Pros & Cons from the researcher's point of view are listed in Table 14 and Table 15. It has to be noted that in the first case the rig floor has to be large and a new substructure has to be built.

Large driller's cabin with researchers' area on the rig floor	
Advantages	**Disadvantages**
Best way of communication with the driller	HSE issue. The rig floor is prone to accidents and fatalities
Researcher are psychologically more involved in the drilling operation	Crowded work place and limited access. The driller can be disturbed.
Direct "feeling, listening and seeing" how the rig, top drive, and string responds to the data gathered downhole	Limited place for equipment.
For researchers with passion to for drilling, it is more exciting to be fully involved in the process than just sitting in front of a screen (higher motivation)	Guests have to receive safety instructions and must be equipped with PPE[48] before they go to the researchers' cabin

Table 14: Researcher on the rig floor, Pros & Cons

[48] PPE…personal protective equipment consist of helmet, coverall, safety shoes class S3 (steel toe, sole penetration resistant, fully enclosed heel, antistatic, water penetration and absorption resistant, oil and fuel resistant, energy absorption of seat region [109]), safety classes and safety gloves.

Driller's cabin at the rig floor, researchers' cabin in the office area	
Advantage	**Disadvantage**
HSE. The people are out of danger	Loss of "soft" information (feeling, listening, seeing)
Visitors and guests can observe the operation without special safety restrictions. No PPE necessary	Limited communication with the driller
No spatial constraints for equipment and people. Possibility for expansion	
The driller and rig crew are not disturbed	

Table 15: Researchers at the office area, Pros & Cons

The trailer shown in Figure 46 is not necessary for Palmer, but gives the advantage of easier transportation and is later, when exploration drilling and geophones for permanent seismic monitoring are field proven, a valuable criterion for scientific drilling operations outside of Erzberg.

Also a way should be found to move the whole rig without laying down any devices from the rig.
The cheapest and fastest way is installing simple steel plates on the bottom of the rig and pulling the rig by a vehicle which can move very slowly, or by pushing with hydraulic cylinders.
Another, even safer opportunity, is to install a walking mechanism (Figure 47) driven by hydraulic cylinders which move the entire rig.

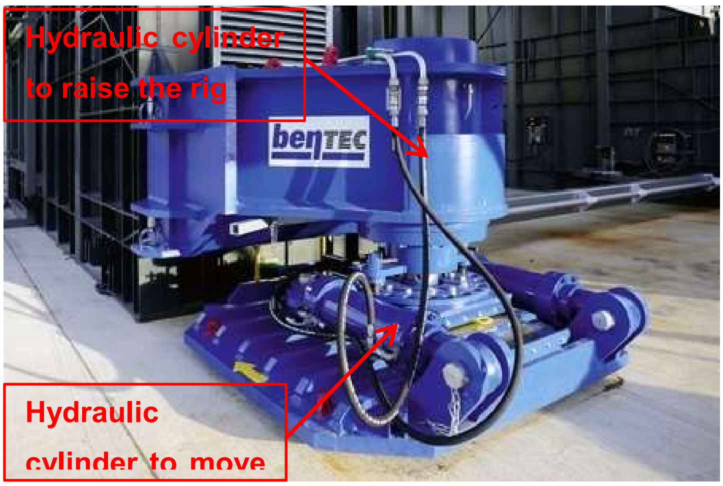


Figure 47: Rig walking system [95].

To improve the operating range of the top drive, a top drive skid should be designed and built, where a top drive with low RPM and high torque can be exchanged for one with high RPM (up to 800) and low torque and vs., for slimhole and microhole drilling.

6.1.4 Possible drilling range

Table 16 to Table 19 list maximum measured drilling depths. For details see Appendix.

6” vertical, WOB 3 t	
3 ½ “ DP (13.3 lb/ft)	3684 m
3 ½ “ HWDP	54 m
4 ¾ “ DC	162 m
6 “ drill bit	
MD = TVD	**3900 m**
HL string 3900 m	**80 t**
HL string 3900 m – lost circulation	**93 t**
5 “ Csg (18 lb/ft) at TD	**91 t**

Table 16: Approximation of max depth with 6” bit and 5”–18 Csg.

8 ½ ” vertical, WOB 8 t	
5 “ DP (19.5 lb/ft)	2460 m
5 “ HWDP	36 m
6 ¾ “ DC	54 m
8 ½ “ drill bit	
MD = TDV	**2550 m**
HL string 2550 m	**80 t**
HL string 2550 m – lost circulation	**93 t**
7 “ Csg (29 lb/ft) at TD	**95 t**

Table 17: Approximation of max. depth with 8.5“ bit and 7“ – 29 Csg.

17.5” vertical, WOB 15 t	
5 “ DP (13.3 lb/ft)	1092 m
6.625 “ HWDP	18 m
10 “ DC	90 m
17.5 “ drill bit	
Depth	**1200 m**
13.375 “ Csg (61 lb/ft) at TD	**95 t**

Table 18: Approximation of max. depth with 13.375” - 61 Csg.

8 ½ “ horizontal	
KOP	100 m
Build rate	3° / 100 ft
TVD	660 m
Departure	**2130 m**
MD	2500 m
5 “ HWDP (55 lb/ft)	2550 m
8 ½ “ drill bit	
Friction factor OH	0.3
Torque	30 kNm
HL – POOH String	78 t
7 “ Csg (29 lb/ft) POOH	50 t
7 “ Csg Torque	22 kNm

Table 19: Approximation of horizontal drilling range, 8 ½ “ bit. For the entire string HWDP are used to reduce buckling. M/LWD, RSS and PDM and Stabilizers are not considered.

6.2 Mud system

The entire solid control and pumping system as used in conventional oilfield drilling is employed. It consists of:

- Shale shaker
- Degasser
- Desander
- Desilter
- (Centrifuge)
- Trip tank
- Tanks and agitators
- Mud pumps and manifold

A degasser is needed when gas, also in small amounts is encountered, to reduce the partial pressure of gas in the fluid and to avoid damage of the mud pump during the suction stroke.

At Palmer usually no gas is expected but for drilling the first deeper wells a degasser is preferred for safety reasons.

A centrifuge is only needed in case of high requirements as to solids removal.

The selection of the mud pump depends on the highest expected pump pressure and pump rate. Table 20 displays pump pressures, pump rates and borehole volume for the 17.5”, 1100 m well mentioned in chapter 6.1.4. For more detail see Appendix.

17.5” vertical		
Bit diameter	[in]	17.5
MD = TVD	[m]	1100
$v_{annular}$	[ft/min]	105
Q	[gal/min]	1200
Tot.p-loss	[PSI]	3644
Inkl. 20% safety	[PSI]	4373
Mud volume of hole	[m³]	171
Mud volume incl 10 % OH safety	[m³]	188

Table 20: Pump pressure, pump rate and borehole volume

The requirements of a 1100 m 17.5” wellbore according to Table 20 demands:

- Three 20’ containers to store one sort of mud of the well.
- Two 1600 HP, 5000 PSI mud pumps
- Shale shakers, desander and desilter which are capable of 1200 gal/min (4.5 m³/min) of mud and cuttings according to ROP
- Flow lines valves and equipment which is designed for 5000 PSI and / or minimum 1200 gal/ min.

6.3 Auxiliary equipment

The minimum necessary auxiliary equipment can be split in:

- Drilling rig auxiliary equipment
    - Catwalk
    - Iron roughneck
    - Tongs
    - Slips
    - Elevators
    - Diverter, diverter line and ignition mechanism
- Power pack for energy supply (everything except the rig itself)
    - Generator set
    - Double walled diesel tank
    - In case the 10,000 V power line can be used
        - Transformer instead of the gen. set and diesel tank.
    - Variable Speed Drive (VFD)
    - Rig air supply (screw compressor, pressure vessel, pneumatic maintenance unit, pipes and hoses)
- Mud system according to chapter 6.2
- Drill string
    - Drill pipes (5” and 3 ½ “)
    - Heavy weight drill pipes (5” and 3 ½ “)
    - Drill collars (9” and 6”)
    - Stabilizers
    - Drill bits
- Housing
    - Six 40’ container
        - Office room; meeting room, directional driller and MWD
        - Shower and bathroom
        - Mechanic and electrician container
        - Storage container
- Mobilization
    - One fork lift (wheel loader)
    - Two crew cars (one for crew change, one for the active crew)

Additional auxiliary equipment

- Managed pressure drilling equipment for increasing the bottom hole pressure
  - Rotating control device
  - Backpressure device and control unit
  - Auxiliary device for MPD operations (hoses, lubrication…)
- Wireline logging unit
  - Winch
  - Wireline
  - Lubricator / wireline BOP
  - Logging tools and connection or activation tools for downhole devices
- Well control equipment for trainings issues
  - Annular BOP
  - Double shear ram BOP
  - Accumulator unit
  - Control panel
  - Choke manifold
  - Poor boy degasser, flow line and flare stack
  - BOP installation mechanism
- Cementing equipment
  - Cement pump
  - Mixing tank
  - Batch mixing tank
  - Cement silo
  - (rotating) Cementing heads (13 3/8”, 9 5/8”, 7”, 5”)
  - Chicksans, valves, hoses….

A sufficient number of wear and spare parts has to be in stock (shaker screens; mud pump valves, liners piston; RCD-rubber sealing, valve seats…

7 Economics

This chapter shows the WSL's acquisition and operation costs.

7.1 Rig and equipment

It is intended to buy a new rig but most of the other equipment can be bought second-hand, as long as the equipment is in (very) good condition which has to be carefully checked before buying.
During the downtime of the E&P industry, drilling equipment can be bought at a cheaper price than during an uptime.

Equipment baggage according to chapter 6.3	**Costs [€]**
Prakla Rig RB-T 100	2,000,000
Drilling rig auxiliary equipment	250,000
Power pack (diesel generators)	1,600,000
Drill string	500,000
Housing 40' container	50,000
Mobilization	100,000
Mud system	1,200,000
Shipping and preparation	200,000
Uncertainties (decision new instead used equipment.)	1,100,000
Total costs	**7,000,000**

Table 21: Costs rig and equipment

7.2 Maintenance

The costs for maintenance are estimated in a way that after 20 years of operation the value of the rig and equipment is spent. The expenditures being low during the first years of operation and then riding to a constant maximum (see Figure 48).

Figure 48: Rig and equipment maintenance costs distribution

7.3 Crew and payroll expenses

To run a company successfully, the following aspects should be fulfilled

- Good (best) equipment and tools
- Best employees
- A good idea and business plan
- Capital
- Some luck

Having the best employees is one of the major assets of a successful company. Best employees are characterized by:

- Motivation
- Love for their job
- Deep understanding of what they do
- A sense of responsibility for, what they are doing
- Careful use of the tools and the equipment as if they were their own
- Loyalty to the company

Therefore, for operating the rig, qualified personnel should be employed.
However, also the employer has to contribute considerably to keeping his employees highly motivated.

For every shift of the rig operation, the following personnel are needed:
:

- Business and technical administration
    - One technician with experience in petroleum engineering acting as head of the WSL
    - One secretary (20 h/week)
- Rig crew, for every shift
    - Driller
    - Toolpusher who can also work as driller
    - Two technicians
    - Two students as roustabouts
    - It has to be considered if an additional mechanic during dayshifts is necessary.

The rig and the equipment have to be treated with great care. The technicians and the toolpusher should have completed a training (apprenticeship) in metal work. This can be a training as a(n):

- Truck mechanic
- Agriculture mechanic
- Automotive mechanic
- Metal worker
- Tool maker

A truck mechanic or an agriculture mechanic should be preferred, as they are well-trained in machine hydraulic.

The rig should run 24/7 around 180 days per year. Therefore the shifts have to be carefully planned to fulfill the requirements.

There are two possibilities to manage the 24/7 operations:

- The rig crew is employed the entire year, but the full workforce is deployed from the early April to late September and in between they are off work
- The rig crew works a forty-hour week, but between late September and early April they are unemployed (in the same way as seasonal workers), or they work in a workshop to construct and develop tools which can be used in the next drilling season.

As in oilfield industry usual and in other areas common (police, medical doctors and so forth), the duration of one shift is 12 hours. It has to be checked if this complies with legislation, or what has to be done to comply with legislation.

Figure 49 shows a shift rotation example for full employment the entire year.

2018 April		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30			
Crew		So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo		days	hours
1	day		1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1		23	287.5
	night																																	
2	day																																21	262.5
	night				1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1			
3	day								1	1							1	1							1	1							14	175
	night		1	1							1	1							1	1							1	1						
occupied?	day	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
	night	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			

2018 May		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31		
Crew		Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	days	hours
1	day																																23	287.5
	night			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1		
2	day							1	1							1	1							1	1							1	15	187.5
	night	1	1							1	1							1	1							1	1							
3	day	1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1		24	300
	night																																	
occupied?	day	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		
	night	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		

2018 June		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30			
		Fr	Sa	Su	Mo	Tu	We	Th	Fr	Sa	Su	Mo	Tu	We	Th	Fr	Sa	Su	Mo	Tu	We	Th	Fr	Sa	Su	Mo	Tu	We	Th	Fr	Sa		days	hours
1	day							1	1							1	1							1	1								14	175
	night	1	1							1	1							1	1							1	1							
2	day	1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1		24	300
	night																																	
3	day																																22	275
	night			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1	1	1			1	1	1	1			
occupied?	day	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
	night	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			

Figure 49: Example of shift with full employment

In this case, three crews with a 6 – 2 shift are needed which means that they work 6 consecutive days in 12.5 hours shifts (12 hours on the rig and 15 min before and after the shift for safety meeting (briefing) and debriefing), followed by two full days off work.
The first crew starts with dayshifts, changes to nigh shifts the next month and the third month to “light” shifts. After three months the rotation starts again.

180 days of rig operation and 5 days before and 5 days after the start of the drilling operation for rigging up and down, result in the following working hours per year:

Annual working time [96]	2017.6	[h]
Minus vacation (5 weeks) [97]	195.0	[h]
Minus public holidays (11 d) [96]	85.8	[h]
Effective working time	**1736.8**	**[h]**
Crew 1	1637.5	[h]
Crew 2	1650.0	[h]
Crew 3	1637.5	[h]

Table 22: Working time 6-2 rig crew

In addition to the three core crews, a stand-by crew is organized. This crew is employed at a cooperation company as normal workers, but in case somebody of the core crew gets sick or injured, one of these workers stands for this person. The worker and the company where the worker is employed get compensation for this (see Table 25: Stand-by costs).

Figure 50 shows a shift rotation example for seasonal shifts.

2018 April		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30			
Crew		So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo	Di	Mi	Do	Fr	Sa	So	Mo		days	hours
1	day	0			1					1			1				1	1			1					1			1				14	175
	night		1			1					1			1					0			1					0			1				
2	day		0			1					1			1					1			1					1			1			14	175
	night			0			1					1			1					1			1					1			1			
3	day			1			0					0			1					1			0					1			1		14	175
	night				1			1	1				1			1					1			1	1				1					
4	day						1	1	1			1				1							1	1	1								14	175
	night									1							1	1	1							1	1							
5	day	1	1																														3	37.5
	night			1																														
	day	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
	Night	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			

Figure 50: Example seasonal shift rotation

In this case each crew works 175 hours per month, but is unemployed when there is no work at the rig (October to March), or, as the workers are metal workers, they can be employed during the off-time to manufacture special tools for the next test in summer in a metal workshop.

Payroll expenses

Assumed salaries are shown in Table 23. The values for nonwage labor costs originate from the Ministry of Finances, Austria [98]. The payroll costs for the company and the stand-by costs for the stand-by crew are shown in Table 24 and Table 25. The costs for the stand-by crew are estimated and have to be verified or negotiated.

Payroll (proximity)	Head of WSL	Secretary 20hrs	Driller	Toolp/Tech	Technician1	Technician2	Student
Gross salary / year	50,000.00	15,000.00	40,000.00	40,000.00	33,000.00	33,000.00	28,000.00
Gross salary / month	3,571.43	1,071.43	2,857.14	2,857.14	2,357.14	2,357.14	2,000.00
Nonwage labor cost	15,500.00	4,650.00	12,400.00	12,400.00	10,230.00	10,230.00	8,680.00
Nonwage labor cost [%]	31.00	31.00	31.00	31.00	31.00	31.00	31.00
Cost for company	**65,500.00**	**19,650.00**	**52,400.00**	**52,400.00**	**43,230.00**	**43,230.00**	**36,680.00**
Assumptions extra pay (nightshift...)	5,000.00	1,000.00	10,000.00	10,000.00	7,500.00	7,500.00	7,500.00
Extra pay costs for company	6,550.00	1,310.00	13,100.00	13,100.00	9,825.00	9,825.00	9,825.00
Tot. Payroll for company/year/man	**72,050.00**	**20,960.00**	**65,500.00**	**65,500.00**	**53,055.00**	**53,055.00**	**46,505.00**
Tot. Payroll for company/quarter/man	**18,012.50**	**5,240.00**	**16,375.00**	**16,375.00**	**13,263.75**	**13,263.75**	**11,626.25**
Number of craftsmen	1.00	1.00	3.00	3.00	3.00	3.00	6.00
Tot. Payroll for company/year/craftsmen	**72,050.00**	**20,960.00**	**196,500.00**	**196,500.00**	**159,165.00**	**159,165.00**	**279,030.00**
Tot. Payroll for company/quarter/craftsmen	**18,012.50**	**5,240.00**	**49,125.00**	**49,125.00**	**39,791.25**	**39,791.25**	**69,757.50**

Table 23: Payroll expenses business administration and rig crew

Payroll	costs/year [€]	costs/quarter(3M) [€]
Sum business administration	**93,010.00**	23,252.50
Sum operation of the rig	**990,360.00**	247,590.00
Total payroll expenses	**1,083,370.00**	270,842.50

Table 24: Total payroll expenses per year and quarter

Stand-by	To company	To employees	Students
/Tag	40	20	10
#	4	4	2
Sum Tag	160	80	20
Sum Saison	28,800	14,400	3,600
Sum quarter	**14,600**	**7,300**	**1,825**
Tot Sum/quarter	**23,725**		

Table 25: Stand-by costs

7.4 Office lease and housing

In case the full employment model for the rig crew is utilized, the rig crew needs housing near Palmer and a car to drive from the hotel to Palmer (car is included in chapter 7.1)

The price used for a one night stay in a single room, corresponds to local price levels in Eisenerz [99].

Housing crew	price / night	# nights	# rooms	total	quartar	pro quartar
1. Year hotel costs incl breakfast	35	60	8	16800	1	16800
2. Year hotel costs incl breakfast	35	90	8	25200	1	25200
3. Year hotel costs incl breakfast	35	120	8	33600	2	16800
4. Year hotel costs incl breakfast	35	150	8	42000	2	21000
5. Year hotel costs incl breakfast	35	180	8	50400	2	25200

Table 26: Costs housing rig crew

In the table below the expected costs for office lease and extras are listed

Business administration	[m²]	[€/m²/month]	costs/month [€]	costs/quarter [€]
Office lease	30	12	360	1080
Extras (traveling, phone,......)			1000	3000
Sum				**4080**

Table 27: Costs for office lease and extras

7.5 Day rate Calc.

Table 28 shows the calculation for the day rate, rate per hour, rate for operation and rate during rigging up or rigging down, respectively.

Steps of calculation:

- Total costs per year including CAPEX (with depreciation) and OPEX are summed up.
- Risk and profit are added
  - ➢ This results in the basis for further calculations
- This value is divided by the expected number of days drilled,
  - ➢ and results in the day rate offered to the client

As there is a difference in costs during drilling and rigging up, rigging down or waiting time, the result is split into operations day rate (rate per hour) and non-operation day rate (rate per hour).

	Total Costs: SP, Rig, PP, MS, Housing, Mob, DS
Rig & Equipment	7,000,000.00
Depreciation duration [year]	**8.00**
Depreciation/year	875,000.00
payroll per year	1,083,370.00
Crew Standby costs	23,725.00
Lease Office+extras	4,080.00
Crew housing [180d/y]	50,400.00
Lease Palmer+building	28,900.00
Mean intersts rig&equipment	57,381.87
Mean interests salaries,...	8,014.82
Sum/year	2,130,871.69
risk [%]	**30.00**
	2,770,133.19
profit [%]	**55.00**
	4,293,706.45
# drill.operation days/year	**180.00**
operating hours / day	**24.00**
Average rate / hour [€/h]	**993.91**
R/u R/d time percentage [dez-%]	0.20
R/u R/d time share [h]	4.80
R/u R/d rate of average [dez-%]	0.60
R/u R/d rate [€/h]	**596.35**
Operating percentage [dez-%]	0.80
Operating share [h]	19.20
Operating rate of average [dez-%]	1.10
Operating rate [€/h]	**1,093.30**
Check(must be same as [€/d]	23,853.92
dayrate [€/d]	**23,853.92**
Quartal in days	45.00
rate per quarters(distributed)	1,073,426.61

Table 28: Day rate calculation

The amount of risk added depends on the development status of the project. As most values are roughly estimated and it is not known yet tools will be bought exactly, the risk assumed is relatively high. The more accurate the planning, the less risk can be assumed.

The day rate is driven by the competitors and by the price the client is willing to pay (target costing).

7.6 Break-even analysis

A break-even analysis shows graphically if the project is currently making the loss or profit or if it is at the break-even point, where the project makes neither loss nor profit.

For the WSL, 180 days of operation are assumed after the startup phase. As operation usually starts slowly, Table 29 shows the assumed days of operation during the startup phase. After five years, the full operation with 180 days per year should be reached and this level should be continued in the future.

Income curve start-up phase	1st year	2nd year	3rd year	4th year	5th year
dayrate	23,853.92	23,853.92	23,853.92	23,853.92	23,853.92
operation/y	60	90	120	150	180
distributed to quarters	1	1	2	2	2
income/y	1,431,235.48	2,146,853.22	2,862,470.97	3,578,088.71	4,293,706.45
income/quarters	1,431,235.48	2,146,853.22	1,431,235.48	1,789,044.35	2,146,853.22
income/q.-distributed	357,808.87	536,713.31	715,617.74	894,522.18	1,073,426.61

Table 29: Operating days during startup phase

Figure 51 shows the break-even for the WSL. In addition to the expenditures explained above, interest for purchasing the rig and equipment and interest for paying the payroll expenses, housing and office lease for the rig crew and business administration are included. Table 30 shows the assumed values for the duration, the interest rate for the loan, and the quarterly repayment rate.

Loan for rig and equipment		
Duration	10	years
loan interst/year	5.00%	
loan interst/quarter	1.25%	[%]
repayment rate	-245,292.79	RMZ

Loan for employees, housing, office		
Duration	5.00	years
loan interst/year	5.00%	[%]
loan interst/quarter	1.25%	[%]
repayment rate	-80,186.34	RMZ

Table 30: Loan and repayment rate for rig, equipment and payrolls expenses, housing and office lease

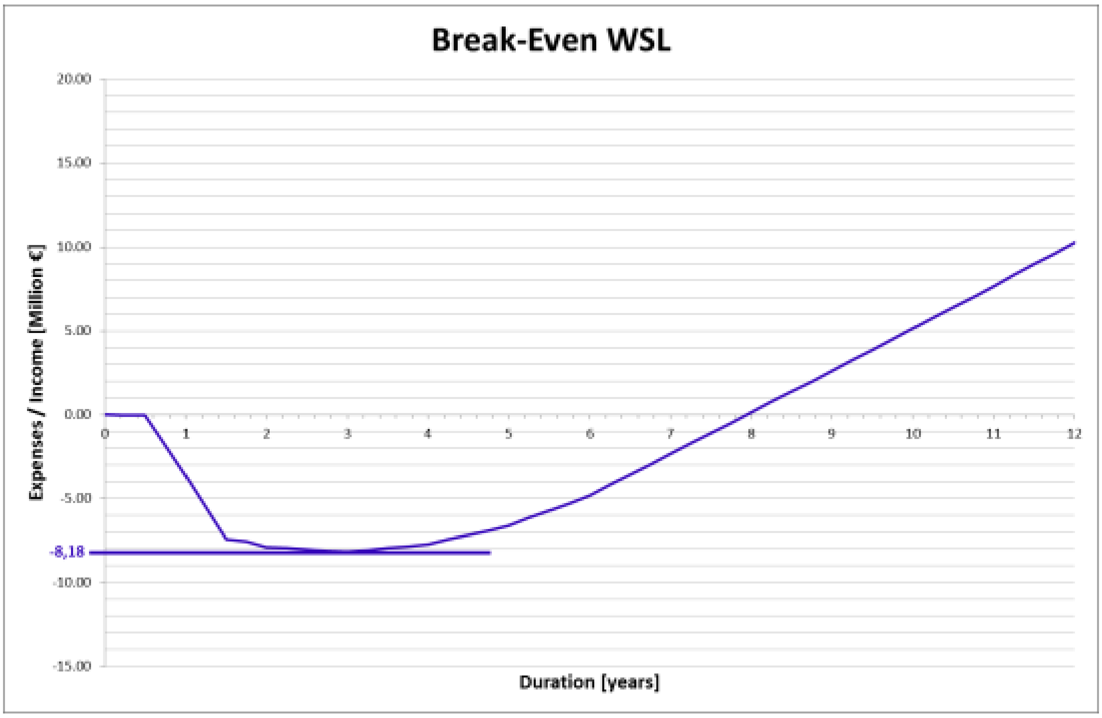


Figure 51: Break-even WSL The maximum expenditures value is 8.18 Mio €.

Explanation of the break even curve:

- In year zero the expenditures start with the payroll for business administration and office lease
- Acquisition of rig and equipment starts with year 0.5 and ends with year 1.5
- The expenditures for payroll, office lease and housing start in year 0.25 and end in year 7.75
- The expenditures for the interest for the rig and the equipment start in year 0.5 and end in year 12.5
- The payroll expenditures for the rig crew starts with the year 1.75
- The costs for the lease of Palmer, water and sewage, road charges at Palmer, start with year 0.75
- Stand-by and housing for the crew start in year 2 and occur only in the summer quarters
- Maintenance starts in year 2
- The first income starts in year 2.5 and rises to its maximum in year 7.5.
- The break-even point is reached eight years after the start of the project, and 5.5 years after the first income.
- The maximum expected expenditures are 8.18 Mio. €

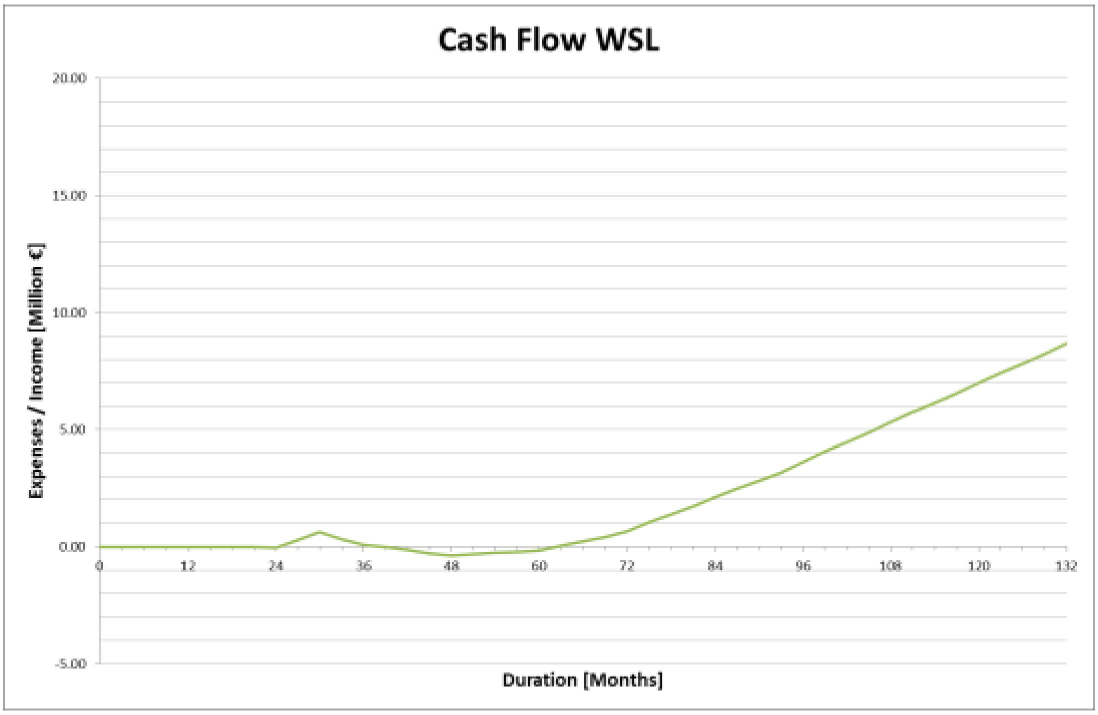


Figure 52: Cash flow WSL

In the figure above the cash flow can be seen, when a pre-financing loan is taken as long as the WSL does not generate income. For the loan parameters see Table 30. There are two different loans:

- One for payroll expenses, the stand-by crew, housing and office lease
- One for rig and equipment.

Explanation of the cash flow:

- The WSL project starts in year zero
- In year 2.25 (month 27) the first income generated (60 days of operation)
- In year 2.5 (month 30)the first payment has to be done (all operating costs and costs for both loans)
- At the start of year 3.25 (month 39) the income is based on 90 days of operation
- At the start of year 4.25 (month 51) the income is based on 120 days of operation
- At the start of year 5.25 (month 63) the income is based on 180 days of operation
- In year 7.5 (month: 90) the loan for payroll expenses, housing and lease is paid off
- In year 12.5 (month 150) the loan for rig and equipment is paid off

7.7 Market analysis

In operation?	Operator	Location	Wells	Max.depth [ft]	Completion	Geology	Primary Attributes
RMTOC Rocky Mountains Oilfield Testing Center [100]							
No	Us-Government; **Sold in Jan. 2015**	Tea Pot Dome Field ,WY 35 mi north of Casper	600, producing oil and gas from 6 zones	6000	Various	Cretaceous and Pennsylvanian sandstones and shale	Gov. partnerships Producing field 40 km² On site tech staff
CATOOSA (former AMOCO test facility) [100]							
Yes	GTI Gas Technology Institute	Catoosa, Ok 18 mi east of Tulsa	26 wells non-producing	3000	OH, CH, v, h,	Pennsylvanian sediments over Arbuckl group limestone	Low risk testing environment Easily accessible location Dedicated reference wells On-site technical staff
Baker Hughes Experimental Test Area BETA [100]							
Yes	Baker Hughes (**noncommercial**)	Beggs, Ok, 24 mi south of Tulsa	62, more than 166,000 ft drilled	3000	Not compl.	Similar to Catoosa but thicker sections incl Sandstone	State of the art data collection & analysis Well known geology, variety of rock types Easily accessible location
Baker Hughes Technology Laboratory [101]							
Yes	Baker Hughes	Woodlands, Tx	No wells but Lab.	-	-	-	*"the industry's most advanced drilling technology Lab"* Drill bit tests up to, 12 ¼", 14 kNm, 50 t WOB, 10,000 PSI…etc.
Baker Hughes western hemisphere education center [102]							
Yes	Baker Hughes	Tomball, Tx	10	2000			One rig for training
Baker Hughes eastern hemisphere [102]							
Yes	Baker Hughes	Dubai VAE	7				Two rigs for training & testing
Schlumberger Cameron Texas Facility [103]							
?	Schlum-berger	Texas	?	?	?	?	Triple stand rig, high volume mud pumps on reels

In operation?	Operator	Location	Wells	Max.depth [m]	Completion	Geology	Primary Attributes
Schlumberger Genesis Test Facility [103]							
?	Schlum-berger	Sugar Land, Tx since 1988	?	?	?	?	Cantilever rig 550 t, skid able
International Research Institut of Stavanger IRIS							
yes	IRIS-Ullrig	Ullandhaug, Stavanger, Norway	7	6600	Partly	Phyllite (Tonglimmerschiefer) to 800m , from 800 Augergneis	**Commercial** test facility Can be rented. Triple stand rig. *“World’s most advanced full-scale testing rig”* Hl: 450 t; Tq: 74 kNm; 2*1000 HP – 5000PSI mud pumps; autom. Pipe handling ISI 9001 & ISO 14001 certified 25 employees at Ullrig (200 at IRIS, additional 550 at Uni Stavanger
CAPRO, Texas Tech University [100]							
Yes	Texas Tech University	Lubbock, Tx	1	4000	9 5/8”Csg	Northern West Texas sandstone carbonates	West Texas Location New production equipment Ideal for artificial lift testing
University of Ufa, Russia [104]							
yes	University of Ufa	Ufa campus	?	?	?	?	For training issues?
National Iranian Oil Company, NIOC [105]							
?	NIOC	Ahvaz, Iran	?	?	?	?	Training rig?

Table 31: Market analysis of testing and training rigs (incomplete)

Table 31 displays a market analysis of active and non-active, commercial and non-commercial testing and training rigs. It has to be noted, that this analysis is not complete and further research has to be done.

Before starting a project, a market analysis is essential. It is also necessary to find out, where the WSL would be unique and would offer competitive advantage. Analyses of the customer needs and the research areas, which are the most important, also have to be carried out.

8 Conclusion

"Necessity is the mother of invention"

Location Palmer offers the most advantageous place to install a well scale laboratory for extensive long term testing and training. The geology is with a high chance hard and competent which offers an advantage for simulating high downhole pressures and finding the weak points of the equipment fast while testing.
The weather conditions are moderate which makes testing and research work possible most of the year. Only during winter time, snow loads and frost may become a constraint.
The transportation by trucks is only limited by the ban on nighttime driving and partly on weekend driving. Railroad transportation is possible, which is an advantage for transporting large amounts of heavy loads, and Eisenerz offers a cargo loading and unloading station at a short distance to Palmer.
The access ways within the active ore mine are short. Power, water supply and a workshop already exists.
Different kinds of local workshops and craftsmen companies are already located in Eisenerz. First aid and firefighter teams are based in Eisenerz and at VA-Erzberg. In case of emergency, a rescue helicopter has sufficient place for landing directly at Palmer.
The area of R&D in the oil industry is wide and there is demand for new or better control mechanisms, tools and training. It needs to be analyzed which research project is worth being investigated, and which one has a chance of technical and economic success.
Further investigation has to be done, to define the industry's needs and to determine how the WSL will be financed and operated.
The rig and the equipment have to be selected carefully. Modifications must be possible to adapt the rig to the requirements of each application.
The model of financing shows on the one hand that despite the high CAPEX and OPEX the break-even point can be reached relatively fast and further investments can be done soon, but on the other hand the success of operating the WSL depends strongly on the availability of clients.

Establishing the WSL would create a boost in reputation for all, the Montanuniversitaet, Eisenerz and Austria as a business and research location.

9 Further Steps

Market analysis:

- What is the most important research topic to work on (University)?
- What is the industry looking for?
- How high is the level of demand for the WSL?
- What are the industry's requirements concerning the well design?
    - Promote the WSL in the industrial sector
    - Figure out the demands of the industry (Questionnaire or other ways).
- Are there any competitors?
    - If so, what advantage can the WSL offer in comparison to others?

Discussion with VA-Erzberg about:

- Evaluation of the allowable area loading, buried depth and pressure of the pressurized line at Palmer as well as the conformation of safety distance to the line.
- Accessibility of mining tunnel Mundloch.
- Clarification if electricity (240 V, 400 V and 10,000 V) can be used and in the affirmative case, determination of maximum allowable load.
- Access ways, any limitations (time, weight, length, noise…)
- Any restrictions for drilling 24/7?
- Use of sludge pond IV for cuttings and drilling mud?
- Conformation of the mining tunnels, positions and the stability of the dam of sludge pond IV.
- Use of workshops of VA-Erzberg?
- Procedures to follow in case of accident? Determination of responsibilities and of emergency contacts to alarm (public safety organizations or those from VA-Erzberg)?

Mining agency (Bergbaubehörde) and legislation:

- What are the legal requirements for operating a WSL?
- Compliance with the labor protection law
- Compliance with the ground water protection law
- Compliance with any other laws and public authorities.

10 Nomenclature

AC	Alternating current
AFP	Annular friction pressure loss
API	American petroleum institute
BHA	Bottom hole assembly
BOP	Blow out preventer
CAPEX	Capital expenditures
CBHP	Constant bottom hole pressure
CBL	Cement bond log
Csg	Casing
DC	Drill collar
dpe	Department Petroleum Engineering at MUL
DGD	Dual gradient drilling
DP	Drill pipe
DSD	Drill string dynamics
E&P	Exploration and Production
ECD	Equivalent circulation density
HL	Hook load
HSE	Health safety and environment
HWDP	Heavy weight drill pipe
IADC	International association of drilling contractors
IIBOP	Instrumented inside blow out preventer
ISS	Instrumented saver sub
M/LWD	Measurement / logging while drilling
MCD	Mud cap drilling
MPD	Managed pressure drilling
MUL	Montanuniversitaet Leoben
OBD	Overbalanced drilling
OGC	Oil gas contact
OPEX	Operating expenditures
PDC	Polycrystalline diamond cutter
PDM	Positive displacement motor
PoCP	Point of constant pressure
PSI	Pounds per square inch
R&D	Research and development
RC	Revers circulating

RCD	Rotating control device
ROP	Rate of penetration
RPM	Revolutions per minute
SPE	Society of petroleum engineers
SPM	Strokes per minute
SWD	Seismic while drilling
T&D	Torque and drag
TD	Top drive
UBD	Underbalanced drilling
USIT	Ultrasonic imaging tool
VFD	Variable speed drive
WDP	Wired drill pipe
WGC	Water gas contact
WOB	Weight on bit
WOC	Water oil contact
WSL	Well scale laboratory

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12 Appendix

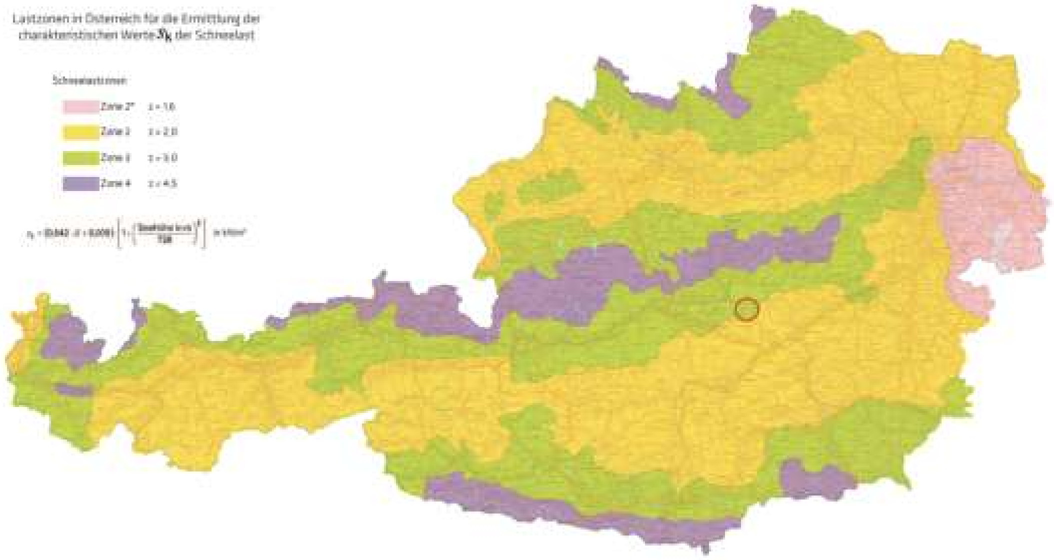

Figure 53: Snow load regions, Austria. The red circle indicates the area of Eisenerz.

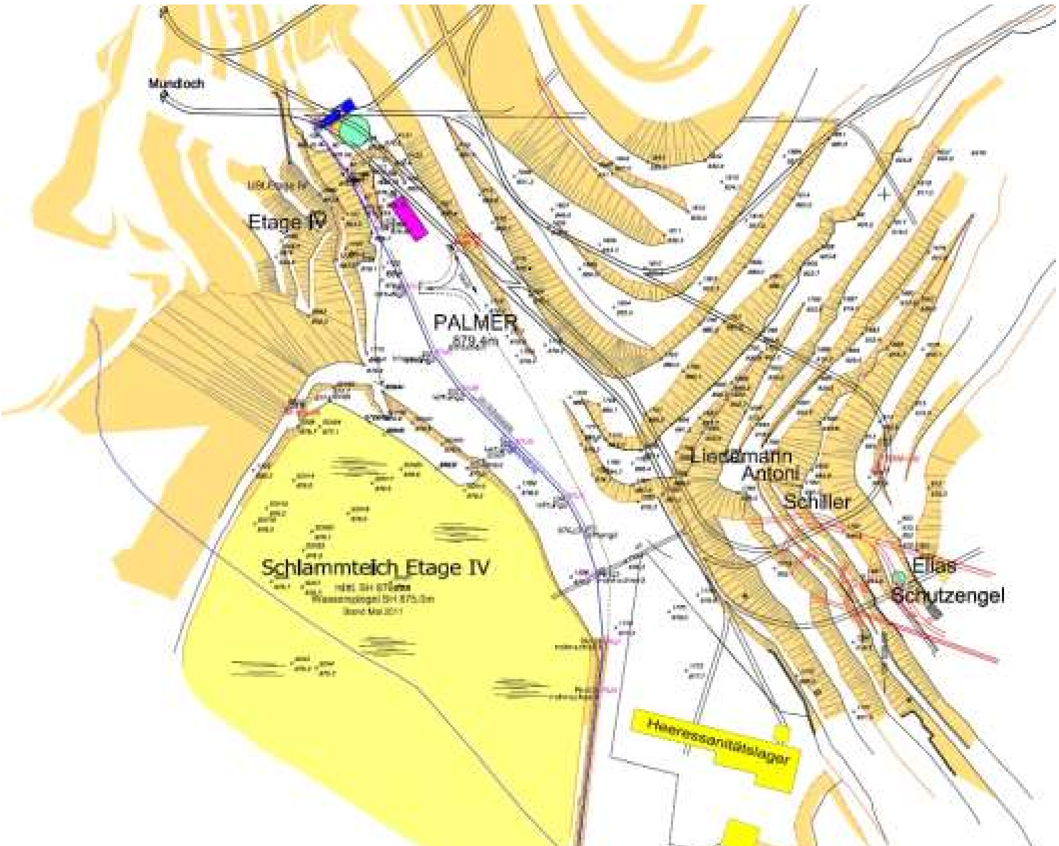

Figure 54: Palmer and mining tunnel system

Toll rates 2015

Tolling according to EURO emission classes Rates for vehicles with a max. permissible gross weight of more than 3.5 tonnes from 1-1-2015			
Rate group	Category 2 2 axle	Category 3 3 axle	Category 4+ 4 a. more axle
A EURO-emission class EURO VI	0,156	0,2184	0,3276
B EURO-emission class EURO EEV	0,170	0,2380	0,3570
C EURO-emission class EURO IV a. V	0,188	0,2632	0,3948
D EURO-emission class EURO 0 to III	0,211	0,2954	0,4431

Rates in EUR pro km, exkl. 20% USt.

Figure 55: Toll rates on highways in Austria 2015. The rate is depends on the number of axles and the emission class according to EURO [20].

Ab folgenden Grenzwerten ist eine Ausnahmebewilligung erforderlich:

Abmessungen:

Fahrzeugtyp	Länge (m)	Breite (m)	Höhe (m)
Kraftfahrzeug/Anhänger	12,00	2,55	4,00
Sattelkraftfahrzeug	16,50	2,55	4,00
Kraftwagenzug	18,75	2,55	4,00

Gesamtgewichte:

Fahrzeugtyp	Gesamtgewicht (kg)
Kraftfahrzeug / Anhänger (2-achsig)	18.000
Kraftfahrzeug / Anhänger (3-achsig)	26.000 / 24.000
Kraftwagen mit mehr als 3 Achsen	32.000
Kraftwagen mit Anhänger / Sattelkraftfahrzeug	40.000

Figure 56: Limiting factors for special transport on the road (Sotra). This figure is just a rough estimation [19]. For more details see Kraftfahrgesetz 1967

Figure 57: Overview, driving ban for trucks with EURO 0, 1 and 2 emission class in Styria [18].

Figure 58: Cut-out of rail road network load classes. The blue lines are D4 load classes which stand for 22.5 t axel load and 8 t / m meter load.

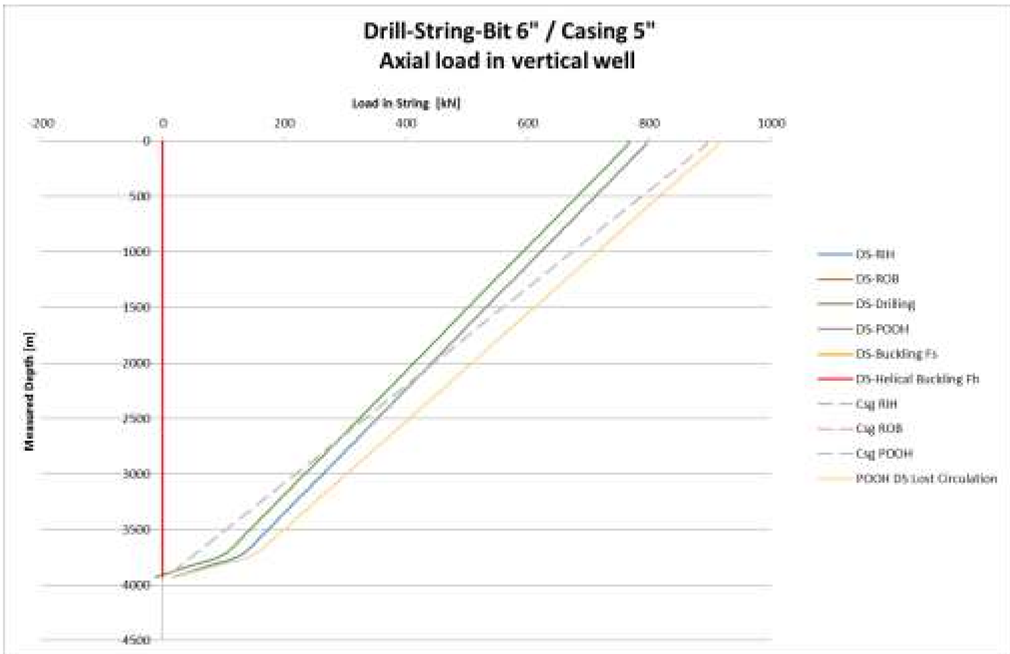

Figure 59: Axial loads 6" vertical well. The casing size is 5"-18. The maximum expected load takes place during a total loss of circulation.

	Production OH	Units
Pipe Pressure Loss Power Law Model	389	[PSI]
Bit Pressure Loss (psi)	411	[PSI]
Annular Pressure Loss Power Law Mode	75	[PSI]
Total Pressure Loss (psi)	876	[PSI]
Pump requirement incl. 20 % safety	1051	[PSI]
Hhp required	51	[hhp]
Hhp incl 20% safety	61	[hhp]
Nozzle Area	0.138	
Nozzle 1	6	
Nozzle 2	6	
Nozzle 3	6	
Nozzle 4	6	
Nozzle 5	6	
Nozzle 6	0	
Nozzle 7	0	
Nozzle 8	0	
flow area coring bit (assumed core OD)		[in²]
Calculation for a Bingham Fluid	**Production OH**	**Units**
Mud Density (ppg)	8.51	[ppg]
Mud Density [kg/m³]	1020.00	[kg/m³]
Bit Size (inch)	6.00	[in]
Bit Area (sq. Inch)	28.27	[in²]
Θ600	1.00	
Θ300	0.85	
Flow index n	0.23	
Consistency index K	100.54	
Yield Point (lb/100ft²)	4.00	[lb/100ft²]
Plastic viscosity (cp)	20.00	[cp]
Pump Rate q (gal/min)	100.00	[gal/min]
discharge coefficient	0.95	
ECD at bit (ppg) Power Law	8.62	[ppg]
ECD at bit (kg/m³) Power Law	1033.45	[kg/m³]
ECD at bit (ppg) Bingham	8.72	[ppg]
ECD at bit (kg/m³) Bingham	1044.47	[kg/m³]
Frac pressure incl. Safety@bit (kg/m³)	1483.18	[kg/m³]
ECD/ frac. Pressure	0.70	
Nozzle Area (sq.inch)	0.14	[in²]
Bit Pressure Loss (psi)	411.27	[PSI]
Hydraulic Horsepower (hp)	23.99	[hhp]
Bit Performance (2-5) hhp/ sq. Inch	0.85	[hhp/in²]
Min. Annular velocity Pipe Area (ft/min)	104.56	[ft/min]
Max. Annular velocity Pipe Area [ft/min)	182.40	[ft/min]
SPM-Calculation	**Production OH**	**Units**
Liner size	5.5	[in]
Liner length	11	[in]
Nummber of pistons	3	
Volume per stroke (single acting)	3.394	[gal]
Strokes per Minute SPM	29	[SPM]

Table 32: Hydraulic data for 6" vertical well

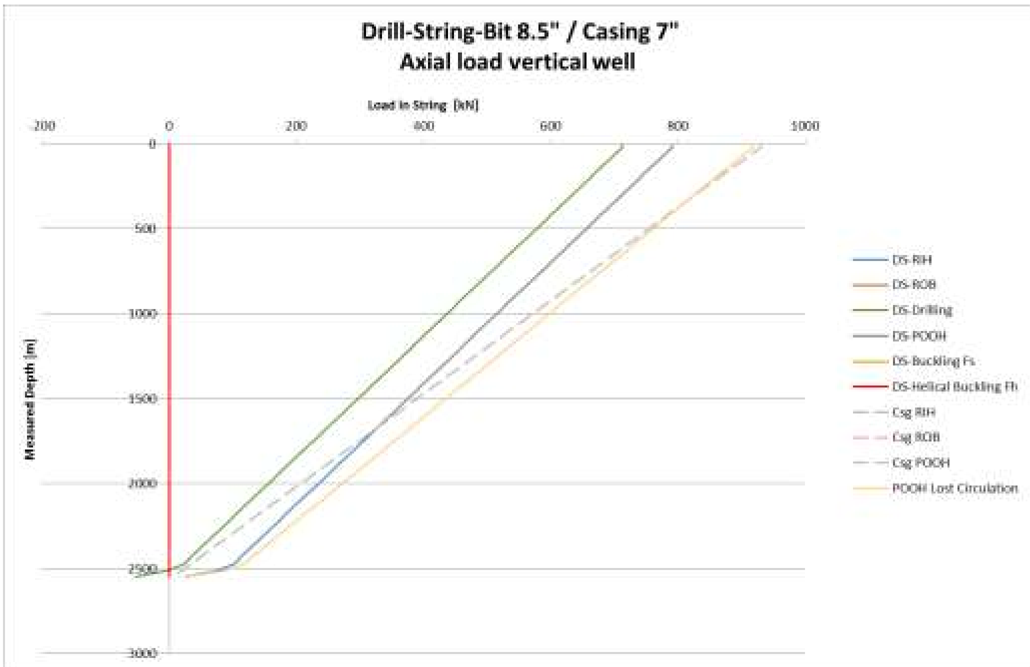

Figure 60: Axial loads 8.5" vertical well. The casing size is 7"- 29. The maximum expected load is while running casing.

	Production OH	Units
Pipe Pressure Loss Power Law Model	152	[PSI]
Bit Pressure Loss (psi)	551	[PSI]
Annular Pressure Loss Power Law Model	35	[PSI]
Total Pressure Loss (psi)	738	[PSI]
Pump requirement incl. 20 % safety	886	[PSI]
Hhp required	86	[hhp]
Hhp incl 20% safety	103	[hhp]
Nozzle Area	0.245	
Nozzle 1	8	
Nozzle 2	8	
Nozzle 3	8	
Nozzle 4	8	
Nozzle 5	8	
Nozzle 6		
Nozzle 7		
Nozzle 8		
flow area coring bit (assumed core OD)		[in²]

Calculation for a Bingham Fluid	Production OH	Units
Mud Density (ppg)	9.01	[ppg]
Mud Density [kg/m³]	1080.00	[kg/m³]
Bit Size (inch)	8.50	[in]
Bit Area (sq. Inch)	56.75	[in²]
Θ600	1.00	
Θ300	0.85	
Flow index n	0.23	
Consistency index K	100.54	
Yield Point (lb/100ft²)	4.00	[lb/100ft²]
Plastic viscosity (cp)	20.00	[cp]
Pump Rate q (gal/min)	200.00	[gal/min]
discharge coefficient	0.95	
ECD at bit (ppg) Power Law	9.09	[ppg]
ECD at bit (kg/m³) Power Law	1089.65	[kg/m³]
ECD at bit (ppg) Bingham	9.15	[ppg]
ECD at bit (kg/m³) Bingham	1096.91	[kg/m³]
Frac pressure incl. Safety@bit (kg/m³)	1483.18	[kg/m³]
ECD/ frac. Pressure	0.73	
Nozzle Area (sq.inch)	0.25	[in²]
Bit Pressure Loss (psi)	551.13	[PSI]
Hydraulic Horsepower (hp)	64.31	[hhp]
Bit Performance (2-5) hhp/ sq. Inch	1.13	[hhp/in²]
Min. Annular velocity Pipe Area (ft/min)	106.33	[ft/min]
Max. Annular velocity Pipe Area [ft/min)	183.68	[ft/min]

SPM-Calculation	Production OH	Units
Liner size	5.5	[in]
Liner length	11	[in]
Nummber of pistons	3	
Volume per stroke (single acting)	3.394	[gal]
Strokes per Minute SPM	59	[SPM]

Table 33: Hydraulic data for 8.5" vertical well

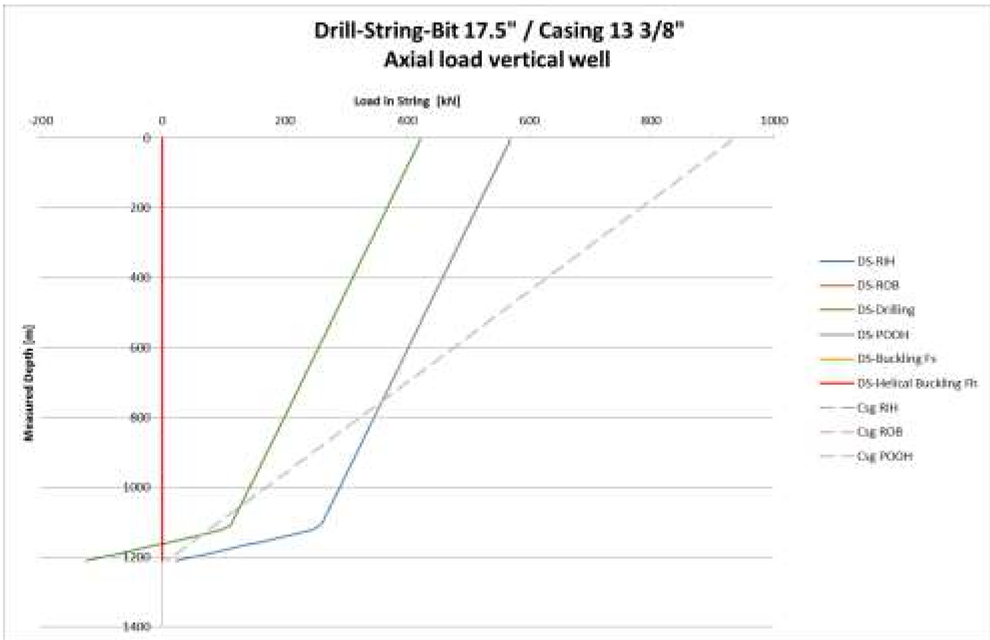

Figure 61: Axial loads 17.5” vertical well. Highest load is running 13 3/8 – 61 casing

	Production OH	Units
Pipe Pressure Loss Power Law Model	2109	[PSI]
Bit Pressure Loss (psi)	1531	[PSI]
Annular Pressure Loss Power Law Mode	4	[PSI]
Total Pressure Loss (psi)	3644	[PSI]
Pump requirement incl. 20 % safety	4373	[PSI]
Hhp required	2551	[hhp]
Hhp incl 20% safety	3062	[hhp]
Nozzle Area	0.884	
Nozzle 1	12	
Nozzle 2	12	
Nozzle 3	12	
Nozzle 4	12	
Nozzle 5	12	
Nozzle 6	12	
Nozzle 7	12	
Nozzle 8	12	
flow area coring bit (assumed core OD)		[in²]

Calculation for a Bingham Fluid	Production OH	Units
Mud Density (ppg)	9.01	[ppg]
Mud Density [kg/m³]	1080.00	[kg/m³]
Bit Size (inch)	17.50	[in]
Bit Area (sq. Inch)	240.53	[in²]
Θ600	1.00	
Θ300	0.85	
Flow index n	0.23	
Consistency index K	100.54	
Yield Point (lb/100ft²)	4.00	[lb/100ft²]
Plastic viscosity (cp)	20.00	[cp]
Pump Rate q (gal/min)	1200.00	[gal/min]
discharge coefficient	0.95	
ECD at bit (ppg) Power Law	9.03	[ppg]
ECD at bit (kg/m³) Power Law	1082.34	[kg/m³]
ECD at bit (ppg) Bingham	9.05	[ppg]
ECD at bit (kg/m³) Bingham	1084.16	[kg/m³]
Frac pressure incl. Safety@bit (kg/m³)	1483.18	[kg/m³]
ECD/ frac. Pressure	0.73	
Nozzle Area (sq.inch)	0.88	[in²]
Bit Pressure Loss (psi)	1530.93	[PSI]
Hydraulic Horsepower (hp)	1071.83	
Bit Performance (2-5) hhp/ sq. Inch	4.46	[hhp/in²]
Min. Annular velocity Pipe Area (ft/min)	105.00	[ft/min]
Max. Annular velocity Pipe Area [ft/min)	130.57	[ft/min]

SPM-Calculation	Production OH	Units
Liner size	5.5	[in]
Liner length	11	[in]
Nummber of pistons	3	
Volume per stroke (single acting)	3.394	[gal]
Number of pumps	2	
Strokes per Minute (SPM9 per pump	177	[SPM]
Q per pump	600	[gal/min]

Table 34: Hydraulic data 17.5" vertical well

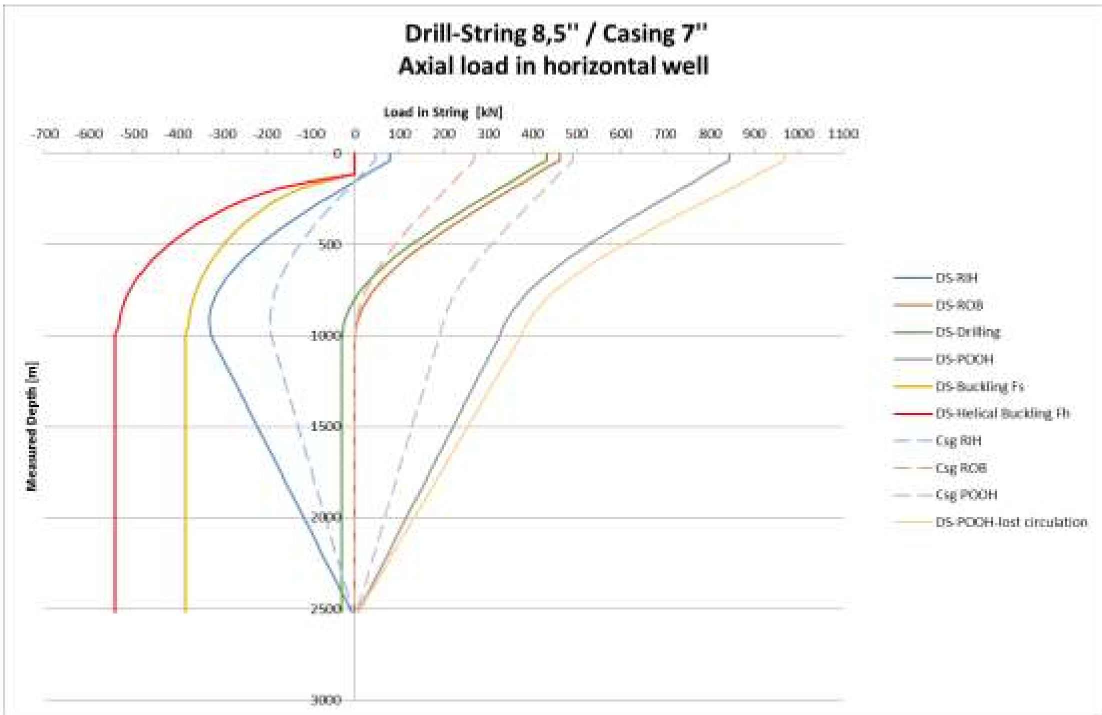

Figure 62: Axial load 8 1/2 " horizontal well. 5"-55 HWDP are used to avoid buckling. The casing size is 7"- 29. The maximum expected load is while POOH the drill string

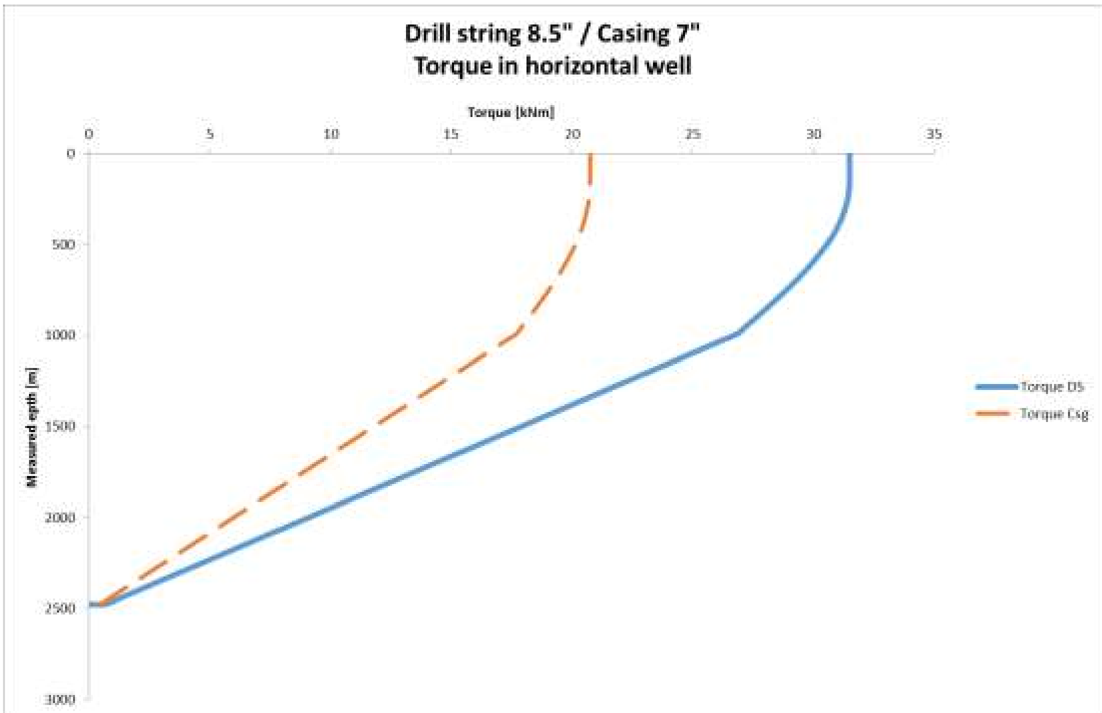

Figure 63: Torque profile in a horizontal 8.5" well. To avoid buckling 5" – 55 HWDP are used. The casing size is 7" – 29.

	Production OH	Units
Pipe Pressure Loss Power Law Model	1799	[PSI]
Bit Pressure Loss (psi)	1220	[PSI]
Annular Pressure Loss Power Law Mode	87	[PSI]
Total Pressure Loss (psi)	3106	[PSI]
Pump requirement incl. 20 % safety	3727	[PSI]
Hhp required	725	
Hhp incl 20% safety	870	
Nozzle Area	0.321	
Nozzle 1	9	
Nozzle 2	9	
Nozzle 3	8	
Nozzle 4	8	
Nozzle 5	8	
Nozzle 6	8	
Nozzle 7	0	
Nozzle 8	0	
flow area coring bit (assumed core OD)		[in²]

Calculation for a Bingham Fluid	Production OH	Units
Mud Density (ppg)	8.51	[ppg]
Mud Density [kg/m³]	1020.00	[kg/m³]
Bit Size (inch)	8.50	[in]
Bit Area (sq. Inch)	56.75	[in²]
Θ600	1.00	
Θ300	0.85	
Flow index n	0.23	
Consistency index K	100.54	
Yield Point (lb/100ft²)	4.00	[lb/100ft²]
Plastic viscosity (cp)	20.00	[cp]
Pump Rate q (gal/min)	400.00	[gal/min]
discharge coefficient	0.95	
ECD at bit (ppg) Power Law	9.28	[ppg]
ECD at bit (kg/m³) Power Law	1112.40	[kg/m³]
ECD at bit (ppg) Bingham	9.57	
ECD at bit (kg/m³) Bingham	1147.27	
Frac pressure incl. Safety@bit (kg/m³)	1483.18	[kg/m³]
ECD/ frac. Pressure	0.75	
Nozzle Area (sq.inch)	0.32	[in²]
Bit Pressure Loss (psi)	1220.23	[PSI]
Hydraulic Horsepower (hp)	284.77	
Bit Performance (2-5) hhp/ sq. Inch	5.02	[hhp/in²]
Min. Annular velocity Pipe Area (ft/min)	205.06	[ft/min]
Max. Annular velocity Pipe Area [ft/min)	212.67	[ft/min]

SPM-Calculation	Production OH	Units
Liner size	7	[in]
Liner length	11	[in]
Nummber of pistons	3	
Volume per stroke (single acting)	5.498	[gal]
Strokes per Minute SPM	73	[SPM]

Table 35: Hydraulic data 8.5" horizontal well