Chair of Drilling and Completion Engineering

Master's Thesis

Investigating Possibilities to Automatically Capture Drilling Lessons Learnt

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MONTANUNIVERSITÄT LEOBEN
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AFFIDAVIT

I declare on oath that I wrote this thesis independently, did not use other than the specified sources and aids, and did not otherwise use any unauthorized aids.

I declare that I have read, understood, and complied with the guidelines of the senate of the Montanuniversität Leoben for "Good Scientific Practice".

Furthermore, I declare that the electronic and printed version of the submitted thesis are identical, both, formally and with regard to content.

Date 16.08.2021

Signature Author
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I want to dedicate this Thesis to my family, who always supports me.

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.

Eidesstattliche Erklärung

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

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Abstract

This study is devoted to improving Lessons Learnt reporting quality and procedures at OMV Well Engineering.

The first stage of the work was the analysis of informational support along the well engineering process. Types, capture, and transfer of drilling data were described for all well construction lifecycle phases. Reports were systematically categorized by introducing a four-digit coding, reflecting periodicity, data type, operation, and operation details. The analysis of current well construction reports identified shortcomings in the existing structure of the Lessons Learnt report.

The second step was to propose changes to the Lessons Learnt report structure to increase the effectiveness of the information collected. The distribution of non-productive time for OMV wells was analyzed, which identified drilling problem types. As an example, recommendations of improved Lessons Learnt reports were made for a particular type of problem.

The methodology of generating such a report was developed, which consisted of gathering meta-information and – depending on the type of drilling problem – various analyses of technical specifications and sensor data. The result of the procedure is a Lessons Learnt report, which is stored in a database that the drilling engineer uses in the well planning process during the offset well analysis phase.

In order to automate part of the process and reduce the human effort, a web-based application was created to extract non-productive time information from daily drilling reports or activities data.

In the final part of the work, the proposed methodology for creating the Lessons Learnt report was applied on a real well, and the results were successfully verified with historical data.

Zusammenfassung

Diese Studie widmet sich Verbesserungen der Qualität und des Verfahrens der Lessons Learnt-Berichterstattung bei OMV Well Engineering.

Die erste Stufe der Arbeit war die Analyse der Informationsunterstützung während der Bohrplanung und -ausführung. Datentypen, Erfassung und Transfer von Bohrdaten wurden beschrieben für alle Phasen im Bohrlochbergbau-Lebenszyklus. Berichte wurden durch die Einführung einer vierstelligen Kodierung systematisch kategorisiert, die die Periodizität, den Datentyp, Art und Details der durchgeführten Tätigkeiten widerspiegelte. Die Analyse der existierenden Bohrlochbergbau-Berichte identifizierte Defizite in der derzeitigen Struktur des Lessons Learnt-Berichts.

Der zweite Schritt bestand darin, Änderungen an der Struktur des Lessons Learnt-Berichts vorzuschlagen, um die Effektivität der gesammelten Informationen zu erhöhen. Die Verteilung der unproduktiven Zeit für OMV-Bohrungen wurde analysiert, was zur Identifizierung der Arten von Bohrproblemen führte. Empfehlungen für einen besseren Lessons Learnt-Report wurden beispielsweise für eine Art von Problem erstellt.

Es wurde eine Methodik zur Erstellung eines solchen Berichts entwickelt. Diese bestand aus der Sammlung von Metainformationen sowie, abhängig von der Art von Bohrproblem, unterschiedlichen Analysen von technischen Spezifikationen und Sensordaten. Das Ergebnis des Verfahrens ist ein Lessons Learnt-Bericht, der in einer Datenbank gespeichert wird, die der Bohringenieur bei der Bohrlochplanung während der Offset-Bohrloch-Analysephase verwendet.

Um einen Teil des Prozesses zu automatisieren und den administrativen Aufwand zu reduzieren, wurde eine webbasierte Anwendung erstellt, die Informationen über unproduktive Zeiten aus täglichen Bohrberichten oder Aktivitätsdaten extrahiert.

Im letzten Teil der Arbeit wurde die vorgeschlagene Methodik zur Erstellung des Lessons Learnt-Berichts an einem realen Bohrprojekt angewendet und die Ergebnisse wurden erfolgreich mit historischen Daten verifiziert.

Acknowledgements

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Besides that, I would like to express my gratitude to my family and friends for their support.

Contents

Chapter 1 Introduction

When designing new wells, an analysis of offset wells is a mandatory part of the work, the primary purpose of which is to apply the recommendations and experience gained during drilling and take into account the risks that may be encountered during the construction of this new well.

The study aims to improve the reporting of lessons learned from the drilling experience at OMV.

The objectives of the work are:

1. Analysis of existing reporting on drilling;
2. Analysis of OMV's current non-productive time (NPT) investigation procedure;
3. Analysis of OMV's Lessons Learned (LL) reporting;
4. Developing general recommendations to improve Lessons Learned reporting;
5. Developing specific recommendations to improve Lessons Learned reporting for the specific cause of NPT;
6. Development of a system for automatically generating Lessons Learned reports;
7. Application of the proposed system on the example of one of OMV's wells and comparison with historical reporting.

The most significant value of improving Lessons Learned reporting is creating a database of lessons learned and best practices obtained during the drilling process. Also, automated reporting will provide better data quality.

In the future, if such improvement is implemented, it may enable improving well design efficiency by incorporating the recommendations gathered into the design, trajectory, and drilling mode for the well being designed. This, in turn, may reduce NPT and associated costs.

For OMV, the issue of improving drilling efficiency is particularly acute in connection with the ongoing 'Well Planning in a Day' project, which aims to automate well design, requiring maximum use of information from wells that have already been drilled.

Chapter 2 Analysis of well construction reporting

The purpose of the chapter is to set the research problem.

Figure 1 shows the well construction cycle, consisting of three phases: well design or pre-study, well construction execution (real-time drilling), and post-drill analysis.

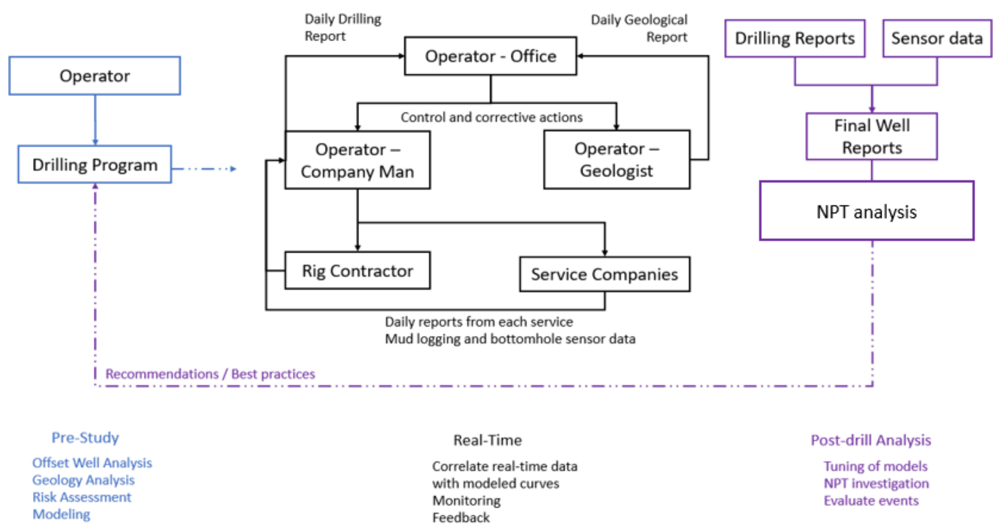

Figure 1: Well construction cycle

In the first phase, offset wells are chosen and analyzed to assess possible risks, to add, geological data is analyzed, and drilling process is modelled. In this phase, the participant is the operator.

The result of the process is a drilling program which is an engineering plan for constructing the wellbore which includes well specific data, equipment details, special procedures that may be needed during the course of the well.

The drilling program gives a characteristic of the well; it includes a justification of the technology and organization of well construction (Elmgerbi WS 2020/2021).

Such a description is generic. At OMV, the planning stage includes several gates (approvals). There are different documents compiled at every stage, such as Basis of Well Design, Conceptual Design, Drilling Program, Detailed Drilling Program, and others. Besides, costs estimation is performed at every stage, becoming more and more accurate at each step.

2.1 Information support for well construction

During well construction execution, the drilling organization chart is shown in Figure 2 (Hossain and Al-Majed 2015). The operator has overall responsibility for the drilling operations. The operator usually has a representative on the rig (supervisor). His job is to make sure that drilling operations are proceeding as planned, make decisions that affect the progress of the well, and arrange for equipment deliveries. The operator must provide all consumables (e.g., drill bits, drill pipes, cement). The drilling engineer and geologist hired by the operator may also work on the rig.

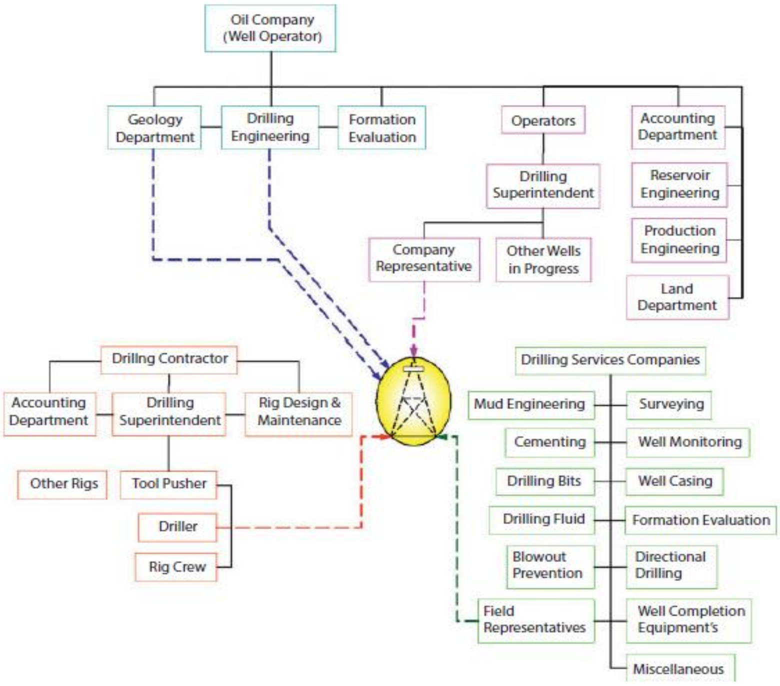

Figure 2: Organizational chart during drilling (Hossain and Al-Majed 2015)

The operator usually hires a drilling contractor who provides the rig and crew to operate it. The drilling contractor is responsible for maintaining the rig and associated equipment. Operating the rig and supervising rig personnel are the responsibilities of the drilling contractor. The drilling contractor has a toolpusher who is responsible for the overall management of the rig. He is responsible for all work on the rig and coordinates with company personnel to ensure the satisfactory progress of the work.

Since drilling lasts twenty-four hours a day, there are usually two drilling crews. Each crew works under the direction of a driller or a tool pusher. The crew usually consists of a derrickman, three roughnecks (working on the rig floor), plus a mechanic, an electrician, a crane operator, and roustabouts (general laborers). From the operator's point of view, data collection on the rig usually consists of morning reporting systems (daily drilling reports), survey data management, and well design software (Mitchell 2006).

The drilling contractor maintains a daily log of drilling operations. It contains hourly reports on drilling operations, drill string characteristics, mud properties, bit performance, and a time breakdown for all operations (Mitchell 2006).

Special work or equipment (e.g., logging) may be required during well operations, performed by designated service companies that provide all specialized logistical support and services on the rig. Service company personnel work on the rig as needed.

Service companies provide the most extensive data acquisition systems at the drilling site, such as mud logging, measurements while drilling (MWD), and logging while drilling (LWD) (Mitchell 2006).

After the construction of the well, the post-analysis phase takes place. In this phase, sensor data and reports of all kinds are used as a source of data. After drilling is complete, an End of Well Report (EoWR) is generated, and drilling experience is summarized in the form of Lessons Learned reports to be incorporated into the design of a new well in the offset well analysis phase.

Thus, the information collected from the drilled well affects the effectiveness of designing a new well.

2.2 Types of well construction reports

A large number of reports are transferred between all parties involved in the drilling operation. Well construction reports can include time series, video and photo, and unstructured text, which can be extremely difficult to parse and analyze. A coding system for the reports is proposed to organize this data set.

The proposed coding system consists of four parts:

1) Report frequency:

- D: Daily;
- E: After the well is drilled;
- J: After completing a specific job (e.g., after cementing);
- O: Optional reports that are generated under certain conditions (e.g., well control reports).

2) Job and information types (Industry 1987). The codes are shown in Table 1.

3) Data type. The codes are given in Table 2.

Job		**Information Type**	
COM	Completion	DST	Drill Stem Test
		CAS	Production casing/liner run and cement
HSE	Health, Safety and Environment		
GEO	Geology	COR	Coring
		FORM	Formation tops
		LOG	Logging
		LOT	FIT/LOT
		SEI	Seismic
DRL	Drilling	BHA	Bit/BHA
		BOP	BOP
		CAS	Casing run
		CEM	Cementing
		DD.	Directional Drilling
		KPI	KPI, drilling performance evaluation
		MAT	Materials and Logistics

Types of well construction reports

Job		Information Type	
		MISC	Miscellaneous
		MLOG	Mud logging
		MUD	Fluid
		PROB	Problem time

Table 1: Job and information type coding

Code	Description
ACT	Activities
CALC	Calculations
COST	Cost
LAB	Laboratory measurements
PLOT	Plot
SCH	Schematic
SEN	Sensor data
SPECS	Equipment details
SUM	Summary (tabular form)
TEXT	Text description

Table 2: Data type coding

Types of well construction reports are summarized in Appendix A.

Coding allows to determine which report contains the desired information and in what form.

The daily drilling report (DDR) occupies a special place in the reporting. The daily drilling report is a complete record of all daily operations and equipment activity during the reporting interval. It typically contains current work status, progress, formation tops, daily costs, surveys, drilling fluids, bits, bottomhole assembly (BHA), safety procedures, personnel, auxiliary equipment, and weather information.

Performance is measured through detailed tracking of planned (vs. actual) activities, NPT analysis, and equipment failure analysis for all types of operations.

Figure 3 shows a sample OMV well daily drilling report that includes the following sections:

– Header information;
– Daily key performance indicators (KPIs);
– Daily operations summary;
– Information about casing strings;
– Survey;
– Well control incidents;
– BHA;
– Bits;
– Hydraulics;
– Shakers;
– Time log;
– Geological data;
– Personnel;
– Bulk materials.

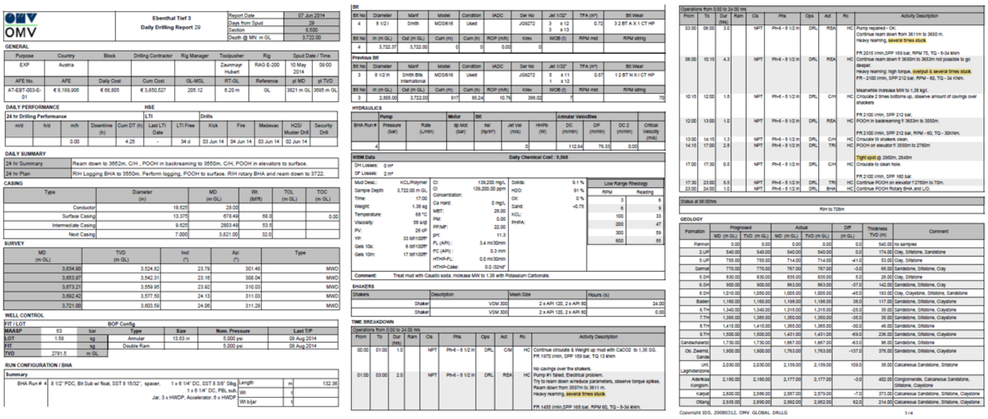

Figure 3: OMV Daily Drilling Report, courtesy of OMV

Gained experience, observations, and best practices during drilling are recorded and stored in Lessons Learned reports. This information can be shared throughout the organization and used for future well performance evaluations or operations planning.

2.3 Analysis of the current NPT investigation procedure at OMV

With daily drilling reports, it is easy to track and record instances of NPT. The proper investigation of NPT is another matter. The purpose of this section is to describe and analyze OMV NPT investigation procedure in order to highlight advantages and disadvantages for further improvement.

NPT includes the time that resulted in a violation of the planned well drilling process (Shamsi, et al. 2018). Determination of NPT is carried out by the supervisor and recorded. It is divided into categories (Kulchitskiy, et al. 2010):

1. Downtime - all situations where it is impossible to continue the drilling process, but it can be resumed without additional (emergency or repair) work. Downtime includes untimely delivery of spare parts, materials, and equipment, untimely arrival of equipment and contractor personnel, absence and, accordingly, waiting for necessary documentation, waiting for permission to continue well construction, work performance as a result of the violation of technological processes.
2. Accidents are all situations when it is impossible to continue the well drilling process without additional emergency works. This includes all time spent to

eliminate accidents (from the moment of the accident to the continuation of the normal course of the technological process).

3. Repairs are the time spent on unscheduled equipment repairs that resulted in the planned well drilling process stoppage. This includes any additional work that occurred for technical reasons and must be performed to maintain wellbore integrity. Time spent repairing equipment for more than 4% of the typical well construction period is considered downtime.
4. Elimination of defects is technical violations during work performance, resulting in non-fulfilment of design requirements and additional work. Includes time required to eliminate all technical violations (re-drilling the wellbore, additional pressure tests, drilling out excess cement plugs).

Understanding the causes of NPT is the starting point for reducing drilling time and saving money (Economides, Watters and Dunn-Norman 1997).

Invisible Lost Time (ILT), in its turn, are time losses arising from the performance of operations not with maximum efficiency, which is mainly due to low rate of penetration or low connection speed, etc. (Shamsi, et al. 2018) (Lakhanpal and Samuel 2017). In this Master's Thesis, ILT is not considered.

Objectives of the NPT investigation as a result of accidents and complications are (Hossan and Islam 2018):

– Determination of the causes and perpetrators of the accident;
– Development of a plan of action to eliminate the accident;
– Development of measures to prevent and reduce the risks of such accidents;
– Making changes to the action plan to respond to the accident;
– Changes in measures to prevent and reduce the risks of such accidents.

Currently, OMV does not have a defined procedure for investigating NPT. A summary of the reports and meetings related to NPT analysis is shown in Figure 4.

	Daily	**After a well is drilled**	**Long term**
Reports	• Daily Drilling Report (Time Log) • Sensor Data NPT recorded	• Lessons Learned Tickets NPT description / Actions taken / Recommendations for future – No requirements to the content – Compiled after a well/campaign is finished – a lot of details are missing	
Meetings	• Morning Meetings NPT announced – Stated as a fact without analyzing the reasons behind – Setup differs, not recorded for every well	• After Action Review NPT event analysis – Not stored in an organized manner	• Service Quality Meetings Discussion of service company performance – Includes only NPT with a SC as an Accountable Party

Figure 4: Actions accompanying the NPT analysis process at OMV

During drilling, NPT is recorded in a daily log in daily drilling reports. In addition, each day, there is a morning meeting between the drilling site and the office. Its purpose is to update the current work status and give a plan for the 24 hours ahead. During these meetings, discussions may be held in which NPT information is exchanged. The setup of the morning meeting depends on the well - it will be more extensive for exploration wells and 2-3 people for onshore production wells. Morning meetings for exploration wells are usually recorded as morning meeting minutes so that people who could not attend can be informed of the current status.

During these morning meetings, information such as health, safety and environmental statistics (incidents, observation cards), a 24-hour summary of operations, geological data (formations), status updates on various aspects - such as how real-time data transfer is going, logistics, and drilling fluid details are discussed. Also, along with the meeting minutes, the participant is sent a time vs. depth chart and formation tops in tabular form. A disadvantage or peculiarity of the morning meeting format is that cases of NPT, as well as actions to correct them are just announced; the analysis of root causes is not performed.

After a well is drilled, the drilling results can be analyzed at a special meeting called 'After Action Review'. The disadvantage is the decentralized storage of the meeting results, which makes it almost impossible to use them systematically in the design.

Service quality meetings discuss problems with service company jobs, but these meetings are often not related to a specific well and are held quarterly/semi-annually. They are related to cases of NPT due to the fault of the service company

Lessons Learned reports are particularly noteworthy; they are written after a well is drilled or a drilling campaign is completed. Lessons Learned reports do not include a detailed analysis of what happened; they serve to gather recommendations and observations for future well design.

As can be seen, the current NPT procedure lacks structure and prescribed actions. Reports lack specific content requirements; meeting results are not stored centrally. These problems make it impossible to use the data for their analysis fully.

Nevertheless, Lessons Learned reports have good potential for improving well planning efficiency in the Company because they:

1) Are stored centrally in the database used by the Company;
2) Have fields with meta information that can be used to search reports;
3) Have one defined template (Figure 5).

OMV

LESSON LEARNED REPORT

«CreatedDate»

Well Data			
Well Name	«WellName»	Well Country	«Country»
Well Region	«Region»	Onshore/Offshore	«OnOff»

Lesson Learned			
Lesson #		Lesson Date	«Date»
Phase	«Phase»	Company	«Company»
Activity	«Activity»	Service	
Category	«Category»	Reported By	«ReportedBy»
Root Cause	«RC»	Responsible Pary	«ResponsibleParty»
		Reviewed By	
Applicability	*Globally / Country specific / Project specific*	NCR Number	
Status		Potential Cost	«Cost»
Lesson Title	«Title»		
Lesson Description	«Description»		
Post Lesson Action			
Attachments			

Figure 5: OMV Lessons Learned Report Template

At the same time, there are some drawbacks. Because of the long interval between drilling the well and writing the report, the drilling engineer may miss some details or forget about minor problems while drilling, resulting in incomplete reports. In addition, there are no requirements for the content of the report. As a result, planning a new well is less effective because important historical experience data are missing.

Moreover, the culture of such reports is relatively low, which can be explained by the Company's policy of not blaming employees for NPT and a lack of awareness of the importance of Lessons Learned reports. To remedy the situation, OMV is conducting a "Knowledge in Action" project.

2.4 Conclusions for Chapter 2

This chapter analyzed the three phases of the well construction cycle and the information that accompanies them. The well construction reports were coded with a 4-digit coding system.

The activities and reports accompanying the NPT analysis at OMV have been also analyzed. A powerful part of it is the Lessons Learned report, which contains metadata on the well and the NPT event and recommendations for the future and lessons learned. This report is critical when designing new wells. However, it is flawed by the lack of content requirements and the low culture of such reporting.

The task of the next chapter is to improve the report itself and its creation procedure in order to reduce the time and improve the quality of the data in the report.

Chapter 3 Improving Lessons Learned reporting process at OMV

The goal of this chapter is to improve the current Lessons Learned reporting procedure at OMV and create a web application to automate this process.

3.1 Improving procedure for writing Lessons Learned reports

To improve the quality of Lessons Learned reports, it is important to analyze its structure and current state of the procedure to write them.

3.1.1 Structure of the Lessons Learned report

In order to ensure efficient search and unification of Lessons Learned reports, it is suggested to enter key information for each type of problem encountered (problem-specific meta data). This key information will be different depending on the influencing factors. For example, the formation in which it occurred is an essential parameter for mud losses but not relevant for surface equipment failure.

It is also proposed to introduce an additional section for describing sensor data, which will allow summarizing sensor signals missed during drilling. Next time, they may receive more attention, preventing a case of NPT. Figure 6 shows the proposed structure of the Lessons Learned report.

OMV

LESSON LEARNED REPORT
«CreatedDate»

Well Data			
Well Name	«WellName»	Well Country	«Country»
Well Region	«Region»	Onshore/Offshore	«OnOff»

Lesson Learned			
Lesson #		Lesson Date	«Date»
Phase	«Phase»	Company	«Company»
Activity	«Activity»	Service	
Category	«Category»	Reported By	«ReportedBy»
Root Cause	«RC»	Responsible Pary	«ResponsibleParty»
		Reviewed By	
Applicability	*Globally / Country specific / Project specific*	NCR Number	
Status		Potential Cost	«Cost»
Lesson Title	«Title»		
Lesson Description	Key info 1	« Key info 1»	
	Key info 2	« Key info 2»	
	Key info 3	« Key info 3»	
	Key info 4	« Key info 4»	
	Key info 5	« Key info 5»	
	Key info ...	« Key info 6»	
Sensor Data Patterns			
Extracted Learning/Best Practice/Comments			

Figure 6: Modified structure of Lessons Learned reports

Besides, now Lessons Learned reports are compiled after a well is drilled or a drilling campaign is over. Maybe in the future it would make sense to initiate a Lessons Learned ticket once an NPT event occurs and finalize it after drilling when a lot of information is available. In this case, it is possible to gather many important details.

3.1.2 General guidelines for writing Lessons Learned reports

To create a procedure for creating Lessons Learned reports, it is necessary to divide the report into information blocks (Figure 7).

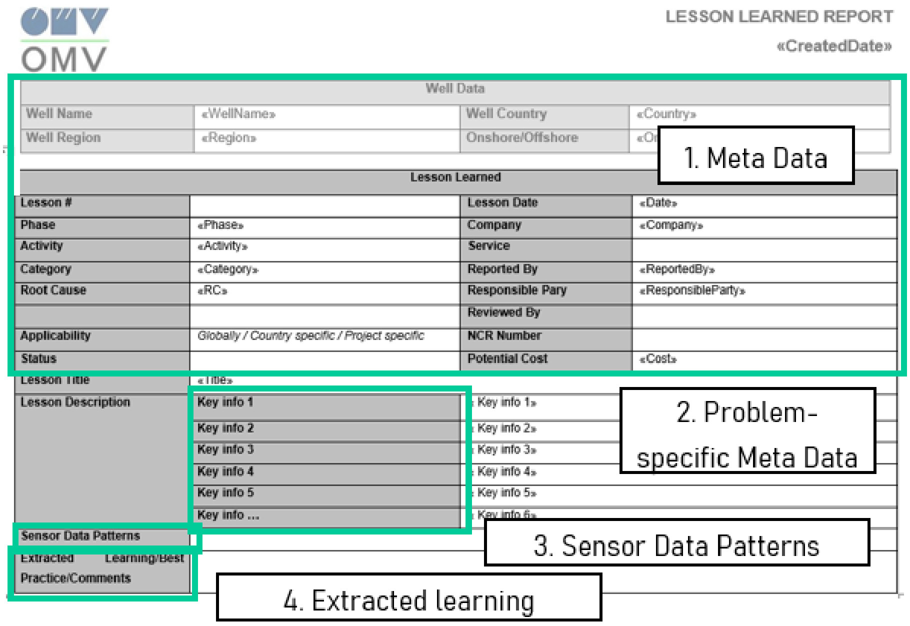

Figure 7: Information blocks of a Lessons Learned report (suggested)

A suggested procedure for creating Lessons Learned reports, taking into account the completion of each information block, is shown in Figure 8.

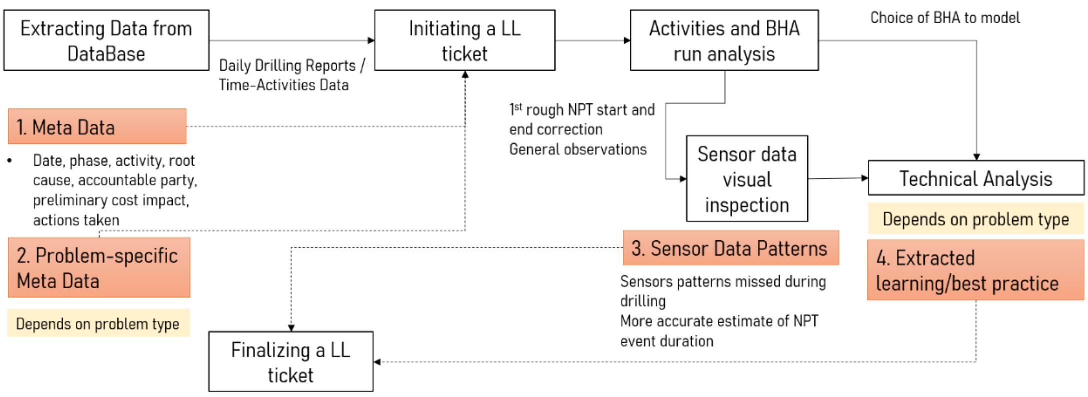

Figure 8: Proposed procedure for Lessons Learned report creation (in orange – information blocks from Figure 7, dotted lines show information blocks populated in the report, solid lines show process)

The first step is to select an event to investigate where something was potentially learned. The engineer can decide which events are a higher priority for investigation based on various factors, such as cost and duration impacts.

Basic information about NPT can be found in the time log in the daily drilling reports. Another source of data used in the Company is a summary of operations in CSV-file format from the IDS database repository.

When a complication or accident is selected for analysis, an initial version of the Lessons Learned report is generated and populated with general and problem-specific metadata. General metadata block includes well name, region, country, phase, activity, category, root cause, date, responsible party, impact on cost. The cost estimate from the daily report will be approximate - the daily cost multiplied by the duration of the complication/accident. Data on the actions taken to eliminate the complication/accident can be used as an initial iteration to describe the event in the Lessons Learned report.

Then, the BHA runs for the section where the NPT event occurred should be analyzed to get an overview and a basic understanding of the event. It will also correct when the complication/accident occurred since it usually starts earlier than the one reported in DDRs. Even at this stage, some anomalies can be noticed, described in the next chapter. The specified time of the complication/accident onset will help select sensor data fragments for analysis.

The next step is to inspect the sensor data visually. The curves should be presented so that interdependent factors such as RPM and torque, hook load and weight on bit, pump rate and standpipe pressure together can be tracked. It may also be helpful to connect the graphs to the activity description from the daily drilling reports to get an idea of what operations were being performed at a particular point in time, which is not always apparent from the sensor data separately.

Visual inspection of sensor data will help clarify the start and endpoints of the complication/accident; it will also help notice some patterns - signs that were missed during drilling and may have caused the complication/accident to occur. The findings from this control will go into the appropriate section of the report.

An optional but important part of the procedure would be parallel technical analysis of the BHA selected in previous steps. The type of analysis depends on the problem type. The technical analysis will identify the underlying causes of the event and highlight areas of control for improvement. The results of the technical analysis will go to the dedicated Lessons Learned section.

After the analysis, the Lessons Learned report must be completed. These reports will be stored in a common Lessons Learned database. The report will then be used to analyze offset wells when planning a new well and assessing possible risks during construction.

It is vital to improve the analysis of complications and accidents after the well is completed when the maximum set of collected data is available. Evaluating lessons learned and making recommendations for the future is the most critical aspect of well design preparation when identifying problems that may arise while drilling. A well cannot be adequately planned if these conditions are unknown. Therefore, the drilling engineer must first obtain various types of data to gain insight used to develop predicted drilling conditions (Mitchell 2006).

3.2 Recommendations for creating Lessons Learned reports for a specific problem type

3.2.1 NPT analysis at OMV

In order to narrow the scope of the study to a specific type of problem, an NPT analysis was conducted for several OMV wells.

Using daily drilling reports, NPT was analyzed for 52 Austrian wells, 4 of which had sidetracks. The wells were drilled on four rigs. The total drilling time is 1552.9 days or 37269.1 hours. The total NPT is 5917.8 hours; its share is 15.9%. Assuming a rig cost ranging from 18000 to 25000 euros/day, a rough estimate of the NPT cost is 4438350 to 6164375 euros.

The analysis was conducted on the time and cost factor; for the most common causes of NPT, a more detailed analysis was conducted on the influencing parameters.

The topic of reducing NPT is relevant to OMV can be confirmed by the fact that most of the wells in question were drilled behind their planned drilling duration (Figure 9).

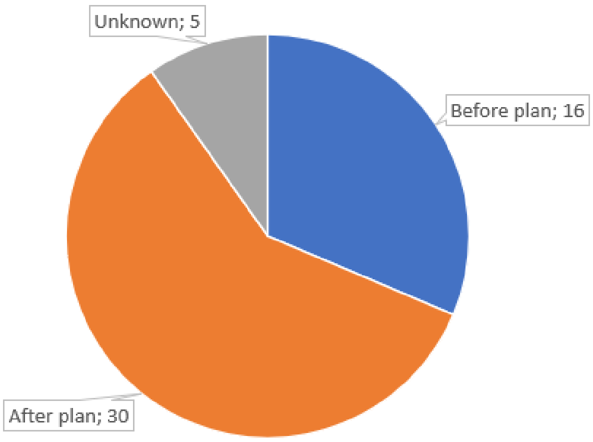

Figure 9: Wells drilled before/after the target date

3.2.1.1 NPT distribution by cause

Figure 10 shows the distribution of NPT by primary cause.

Causes that triggered most of the NPT duration more often than others were equipment problems, "other" category, stuck drill pipe/casing, loss of circulation, hole condition problems. The "other" category includes causes not covered by other groups, such as work stoppage due to COVID-19.

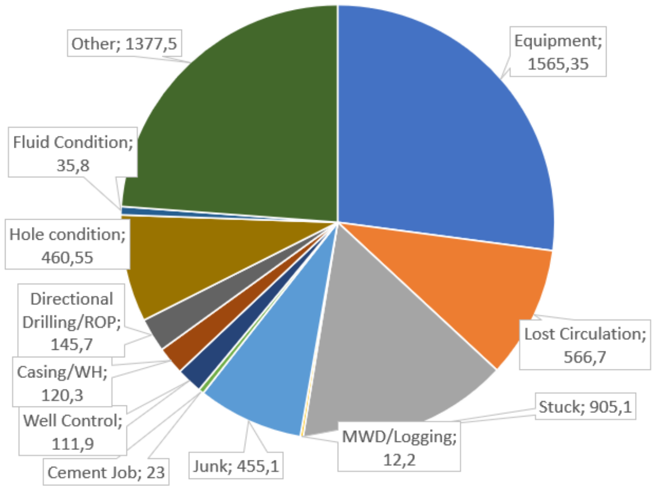

Figure 10: Distribution of NPT by cause [hours]

a) Equipment problems

The serviceability of drilling equipment and its maintenance are significant factors in minimizing drilling problems (Hossan and Islam 2018). It is interesting to analyze which category of equipment had the most problems. The distribution is shown in Figure 11.

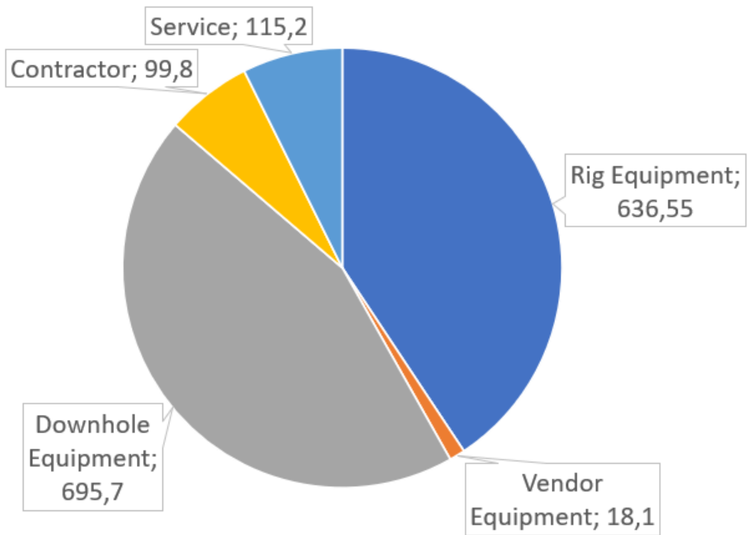

Figure 11: Distribution of NPT by equipment category [hours]

Downhole equipment caused the most NPT; for surface equipment, the numbers are almost the same. Considering the number of incidents, it is 231 for surface equipment; 16 for downhole equipment. This fact indicates that each of them was significant in terms of time and, therefore, cost.

The analysis can be continued by distributing NPT by downhole equipment subcategory, as shown in Figure 12.

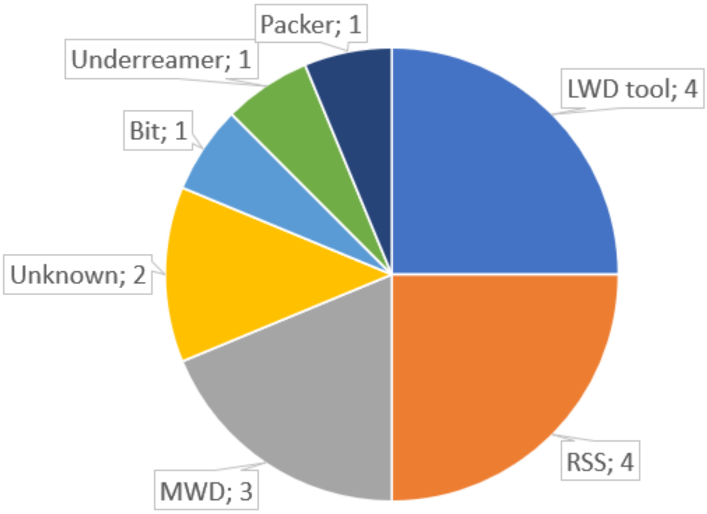

Figure 12: Problems with downhole equipment by subcategory [by number of cases]

The graph shows that the BHA elements for directional drilling, such as rotary steerable systems (RSS) and MWD/LWD, caused the most significant number of equipment failures, which can be explained by their technical complexity.

The integrity of the drilling equipment and its maintenance are significant factors in minimizing drilling problems. To reduce drilling problems, the following are necessary (Hossan and Islam 2018):

- Proper rig hydraulics (pump power) for the effective bottom hole and annulus cleaning;
- Proper hoisting power for efficient tripping out;
- Properly design derrick loads and drilling line tension loads to ensure safe overpull in the event of a sticking problem;
- Well control systems that allow kick control under any kick situation (i.e., proper maintenance of ram preventers, annular preventers, and internal preventers);
- Proper monitoring systems that track changes in drilling parameters;
- Pipes specially selected for all expected drilling conditions;
- Efficient equipment for drilling mud cleaning and treatment.

b) Stuck pipe

Several types of stuck pipe can occur during the drilling process (Mitchell and Miska, Fundamentals of Drilling Engineering 2011), such as differential sticking, key seating, mechanical sticking, etc. Using proper procedures to prevent stuck pipes in intervals where problems are expected to occur can significantly reduce the number of stuck-pipe incidents. Low-water-loss drilling fluids reduce the initial contact area because they form a thin, impermeable filter cake. The pipe cannot be immersed deeply into the mud cake, and therefore the sticking force is reduced.

Drill string design modifications can reduce the tendency for sticking by minimizing the pipe area in contact with the borehole wall. This can be accomplished by using stabilizers as part of the bottomhole assembly. To properly position stabilizers, the formation of interest must be relatively close to the stabilizer.

Another drill string modification involves spirally grooved drill collars or heavyweight pipe instead of conventional or smooth pipe.

A field-developed procedure was successfully used to minimize the (temporary) friction coefficient of drilling fluid along the borehole wall. The addition of walnut shells or similar specialty products has been found to reduce friction by embedding the shell in the filter cake. Although the friction reduction is temporary, it usually alleviates the immediate situation at the drill site. Adding bentonite to the drilling fluid is another temporary measure to reduce friction on the wellbore wall.

The NPT analysis revealed only four stuck pipe/casing occurrences, but they nevertheless caused a long period of NPT.

It is reasonable to divide instances of sticking by formation, trajectory, and type of operation, as shown in Figure 13.

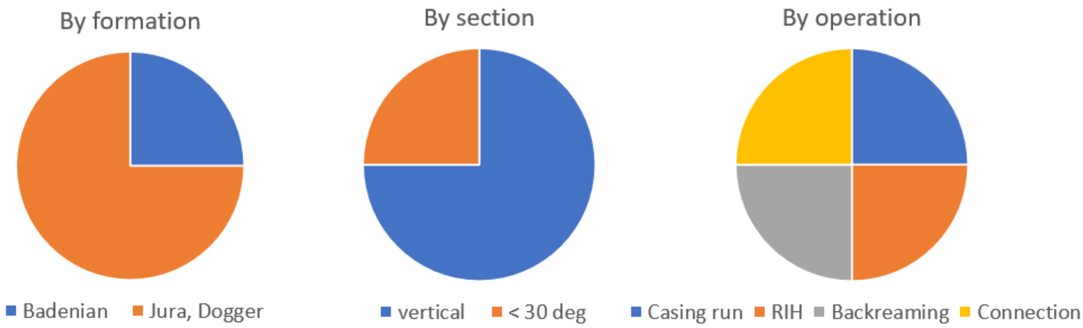

Figure 13: Distribution of events related to stuck pipe

The observed trends are somewhat difficult to generalize due to the small number of cases, but most of them are stuck pipe events that occurred in the same formation and trajectory type.

c) Lost circulation

Lost circulation is one of the most common problems when drilling a well. Signs of lost circulation can range from a gradual drop in the pit level to a partial or complete loss of returns. In extreme cases, the fluid level in the annulus can drop rapidly, sometimes by hundreds of meters (Mitchell and Miska, Fundamentals of Drilling Engineering 2011).

Loss of circulation invariably results in increased costs for materials, services and additional rig time. Depending on the timing and severity of its occurrence, it can lead to a loss of formation evaluation data because information generally obtained from the drilling fluid output and cuttings drilled out is no longer available. Lost circulation can also reduce well performance if the loss zone is also a potential productive interval. If the wellbore-fluid level drops far enough and fast enough, the drop can allow fluid to enter the wellbore from a higher-pressure formation.

NPT lost circulation events from the well analysis were separated by formation type, as shown in Figure 14.

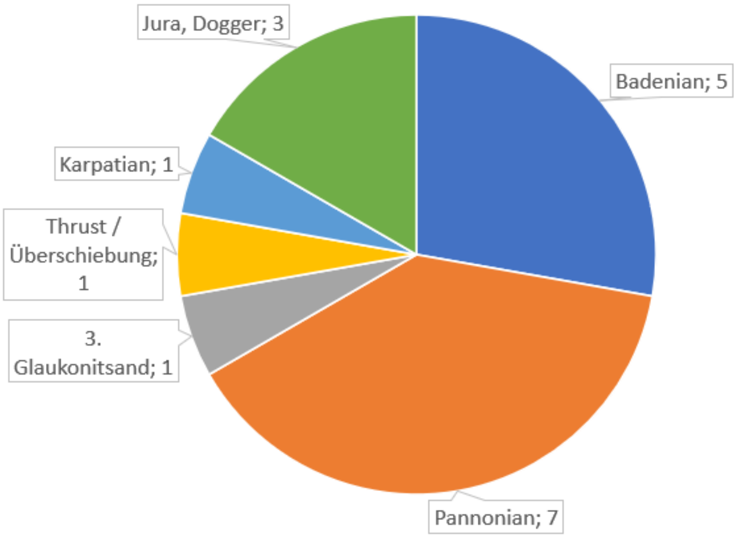

Figure 14: Mud losses by formation type [cases]

It can be seen that the most problematic strata are of geological age Pannonia and Badenian, and these same strata caused problems with stuck pipe in the last point.

d) Hole condition problems

According to definitions, hole condition problems include hole pack-off/ bridge, which can be caused by settled cuttings, unconsolidated formations, fractured rocks, and accumulated metal debris on the bottomhole (Hossan and Islam 2018). Settled cuttings are caused by unsatisfactory hole cleaning.

Wellbore cleaning, in turn, depends on the following factors (Hossan and Islam 2018):

- Rate of penetration, which determines the amount of cuttings in the returning mud;
- Hole stability determines the caving load that is added to the returning mud from the collapsed rock;
- The velocity of the mud in the annulus, which should transport the mud to the surface;
- The rheology of the drilling fluid, which is responsible for the mud being in suspension;
- Circulation time during which drill cuttings are transported to the surface;
- The inclination angle, which reduces the efficiency of hole cleaning.

However, it is not apparent what is coded as a hole condition problem in the daily drilling reports; therefore, it was analyzed which problems are coded this way. The results are shown in Table 3.

Cause	Actions
String held up, overpull, stuck, pressure and torque spikes, an indication of pack-off, large amount of cavings over shakers	Pooh, change BHA (change bit nozzles to increase total flow area), wash down and reaming, increase MW, pump HV pill, wiper trip
Stuck pipe, large amount of cavings over shakers, overpull, drag, pack off, tight hole	Backreaming, washing down, increase MW.
Bit balling, sticky clay over shakers, low ROP, conglomerate stuck between bit cones	POOH to check bit condition (bit balling), clean bit
High DLS	Reaming
Increased pressure and torque spikes, DHM stalling	POOH, conditioning run, reaming, HV pill
String held up, not possible to RIH (logging)	Wash, ream, increase MW.
Overpull, tight spots, large amount of cavings, increase of SPP, bit nozzles plugged	Wiper trip, reaming, increase MW.
Losses	LCM Pill
Low building rate	POOH BHA
Not mentioned	Change BHA, wash down last stand
Large amount of clay over shakers, mud contamination with cement	Circulate, change shaker screens
Losses, string held up, tight spots	Reaming, LCM pill
Held up while RIH	Wash down
Losses	LCM, flow check
High DLS	Reaming
Increased torque, stuck, fired jar without success	Pill, reaming

Table 3: Hole condition problems

According to Table 3, in most cases under hole condition problems, such complications as large amounts of clay over shakers, torque and pressure spikes, overpull, drag, and pack-off are meant.

Hole condition problems can be distributed by trajectory type, formation, mud, total bit flow area, as shown in Figures 15-18.

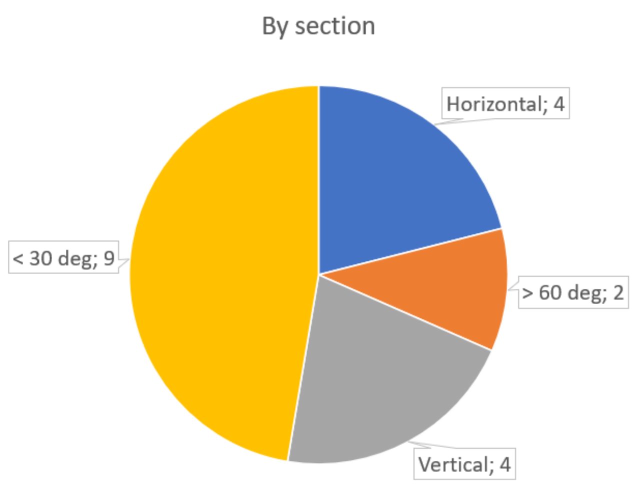

Figure 15: Hole condition problems by trajectory type

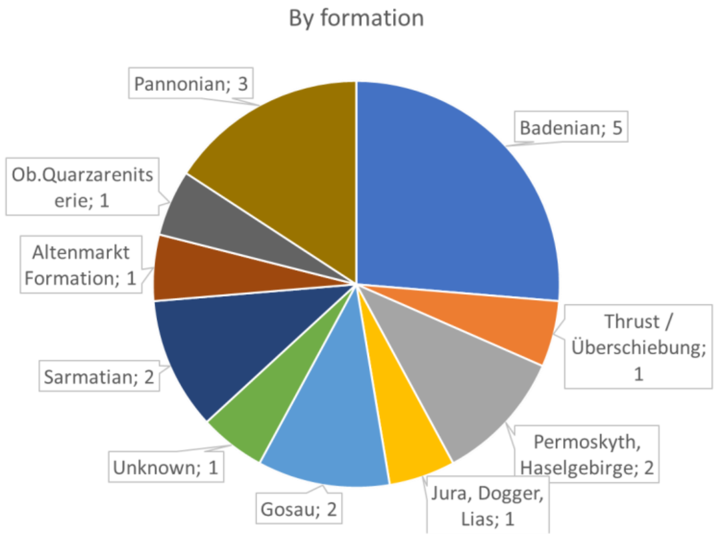

Figure 16: Hole condition problems depending on formation type

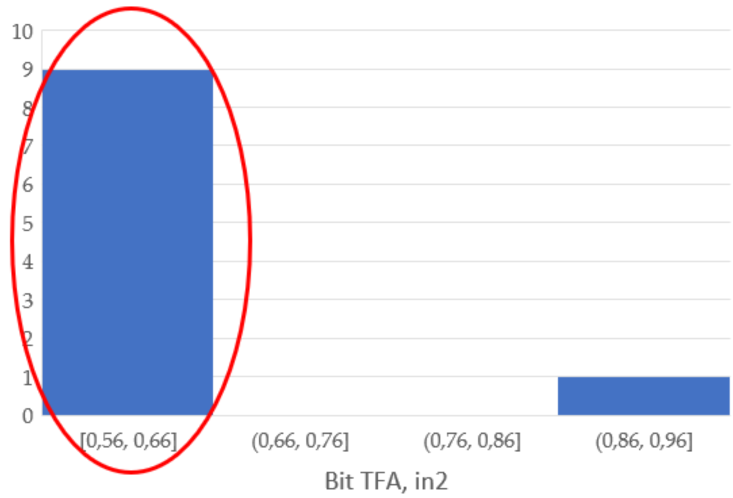

Figure 17: Hole condition problems as a function of bit total flow area (TFA)

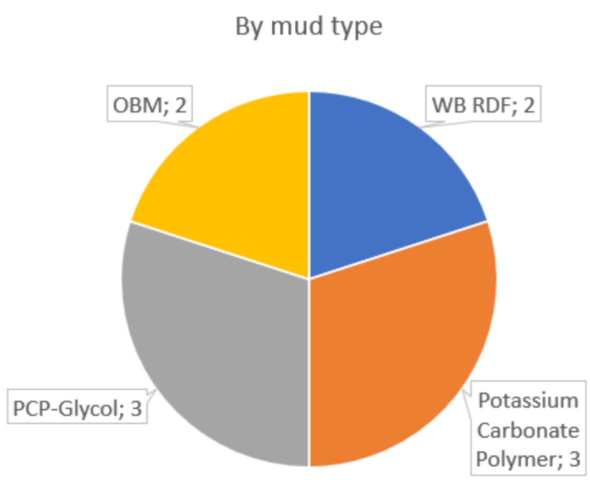

Figure 18: Hole condition problems depending on the type of drilling fluid

There is a clear correlation between bit total flow area and the occurrence of hole condition problems. Most NPTs occurred at bit total flow area between 0.56 and 0.66 inches², which may seem odd since the smaller this value, the higher the velocity in the nozzle and hole cleaning should be better. This fact means that the bit TFA does not play a key role in hole condition problems in this specific case.

3.2.1.2 Analysis of NPT precursors

The next step in the NPT analysis work was to investigate whether NPT had some sort of 'signals' or 'precursors' - problems mentioned in the reports before NPT but marked as productive time.

a) Downhole equipment

For downhole equipment, expect signs such as decreased standpipe pressure and hook load (in case of drill string problems), a drop in rate of penetration (ROP), and a sharp change in torque if there are problems with the bit (Borozdin, et al. 2020).

Two vibration incidents were mentioned in the daily reports, one 5.5 hours before and one 6.85 hours after the accident.

b) Stuck pipe

The following signs are expected for sticking (one or a combination of them), as (depending on the root cause and type of accident): difference in weight of the drill string and hook load (decrement while POOH, increment while RIH), increase in torque, increase in standpipe pressure, amount of cutting in shale shakers decrease (in case of sticking with cuttings), unexpected and fickle vibrations in torque and hookload (Borozdin, et al. 2020).

One sign of DHM stalling 14,75 hours before the NPT event makes it not reasonable to include it in the analysis.

c) Lost circulation

In theory, for lost circulation problems, the possible precursors are drilling fluid flow out less than flow in and mud level decrease in active tanks (Borozdin, et al. 2020). The signals of lost circulation problems detected in the analysis are shown in Figure 19: Signals before mud losses: distribution by type and time.

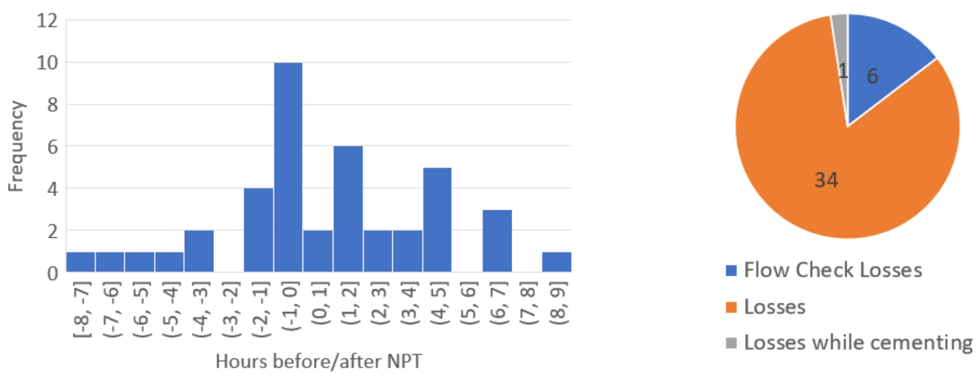

Figure 19: Signals before mud losses: distribution by type and time

It can be seen that most of the "signs" occur in the time domain (-1,0], which means during an hour before the NPT.

d) Hole condition problems

Hole condition signs can include a sudden increase in pump pressure, increased shape and size, amount of cuttings, impossible to tag bottom, drag (Borozdin, et al. 2020). Signs of hole condition problems are shown in Figure 20.

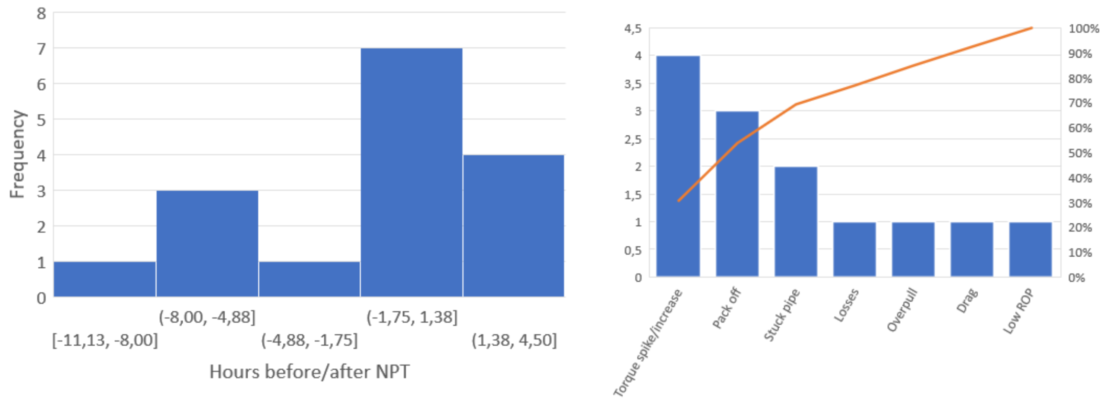

Figure 20: Hole condition problem signals: distribution by type and time

The figure above shows that the hole condition problem signs include torque spikes, pack off, stuck pipe, losses, overpull, drag, and low ROP.

When most of the signals occurred, the time window ranged from 1.75 hours before to 1.38 hours after the NPT event.

Narrowing the time window to three hours before NPT would help filter out signals that might be accurate signals on the rig. The results for lost circulation and hole condition problems are shown in Figure 21. It can be seen that, first, most of the signals come one hour before the NPT event for lost circulation and hole condition problems.

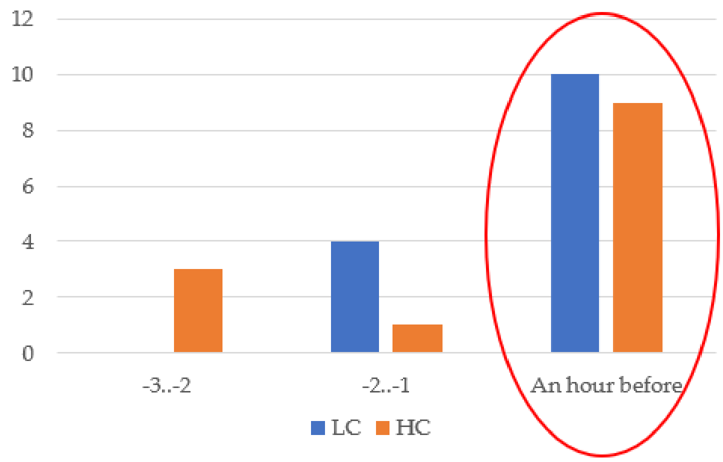

Figure 21: Narrowing the time window for signals (LC – lost circulation, HC – hole condition problems)

Another graph (Figure 22) shows how many NPT events were 'covered' with such precursors.

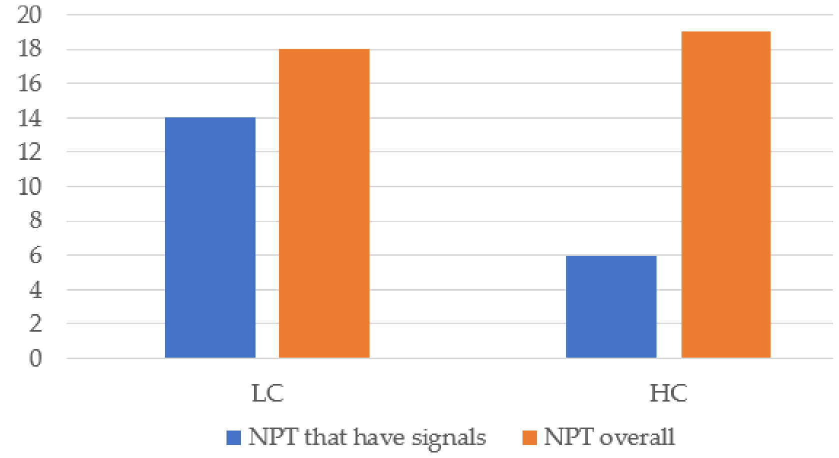

Figure 22: NPT cases covered by signals for lost circulation (LC) and hole condition (HC) problems

The chart shows that mud losses have signals in more cases than hole condition problems.

Figure 23 shows that not all of the signals detected in the daily drilling reports caused NPT. The difference between the ratios for signals of similar problems, such as overpulls and stuck pipes, may be due to different degrees of severity. It is also worth noting the good trend that more than 50% of the signals in each case did not result in NPT. However, it is not clear if any actions were taken to prevent NPT or if the signals were simply ignored.

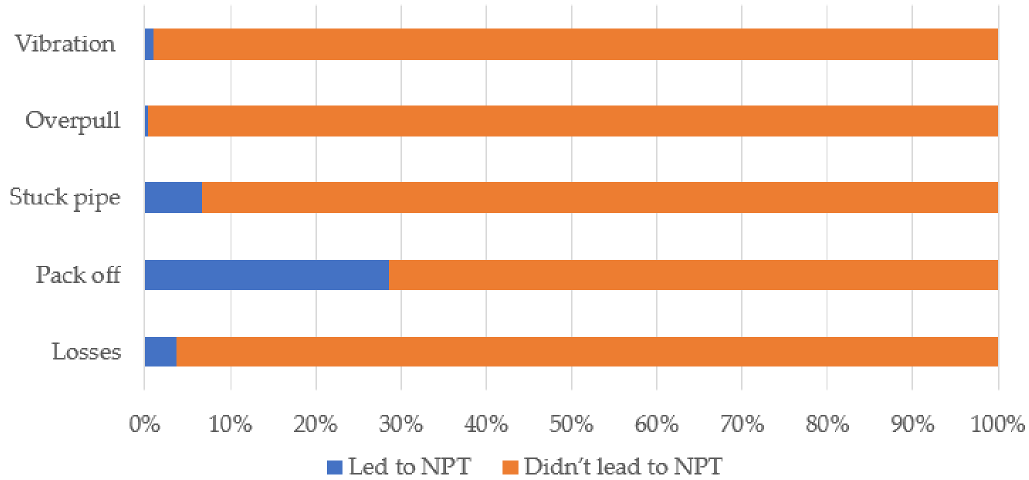

Figure 23: Total number of signals

That is why the two categories in which most of the signals did not result in NPT were chosen to analyze whether any action was taken to mitigate their effects (vibrations and losses).

In addition, mud losses occurrences were filtered by loss values greater than 1 m^3/min.

Figure 24 shows that actions were taken nearly 20 percent of the time for both categories. Actions for losses mitigation included pumping high-viscous pills, treating mud, decreasing flow rate, adjusting drilling parameters, flow check. In the case of vibrations, the actions were adjusting drilling parameters or logging speed, pumping high-viscous pill, treating mud for lubrication, modify/change BHA.

However, most of the signals that were not followed by corrective action did not result in NPT. In the case of losses, this can be explained by their property of passing by themselves, when in passing through the problem layers, mud cake is formed on them, reducing the mud losses.

As for vibrations, they are difficult to control by changing regime parameters; therefore, the formation change should be the main factor contributing to their attenuation.

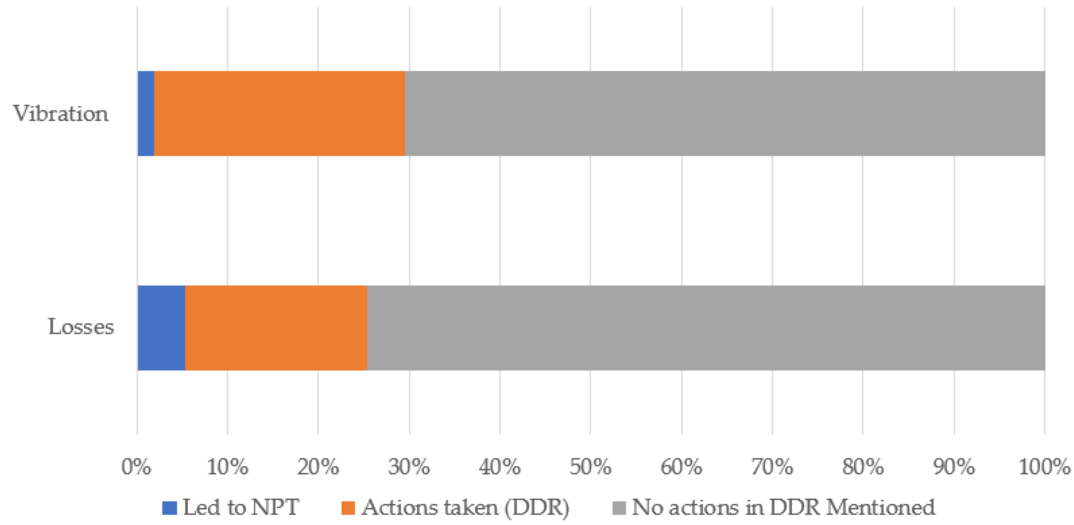

Figure 24: Actions taken at signs of vibrations and mud losses

To conclude, in this section, NPT analysis distribution was performed for the offset wells to identify the interesting problems to focus on. As agreed with OMV, the main focus of the Thesis would be hole condition problems.

3.2.2 Modification of the Lessons Learned report procedure for hole condition problems

As mentioned earlier, the proposed procedure will differ for each problem by the type of problem-specific meta information collected and the technical analysis performed.

In the case of hole condition problems, useful key information would be hole size, mud type and density, BHA description, and inclination angle. The report structure for hole condition problems is shown in Figure 25.

OMV

LESSON LEARNED REPORT

«CreatedDate»

Well Data			
Well Name	«WellName»	Well Country	«Country»
Well Region	«Region»	Onshore/Offshore	«OnOff»

Lesson Learned			
Lesson #		Lesson Date	«Date»
Phase	«Phase»	Company	«Company»
Activity	«Activity»	Service	
Category	«Category»	Reported By	«ReportedBy»
Root Cause	«RC»	Responsible Pary	«ResponsibleParty»
		Reviewed By	
Applicability	*Globally / Country specific / Project specific*	NCR Number	
Status		Potential Cost	«Cost»
Lesson Title	«Title»		
Lesson Description	Hole Size	«Hole»	
	Mud Type	«Mud»	
	BHA	«BHA»	
	Inclination Angle	«Inclination»	
	Formation	«Formation»	
	Description	«Description»	
Sensor Data Patterns			
Extracted Learning/Best Practice/Comments			

Figure 25: Lessons Learned report template for hole condition problems

Technical analysis for hole condition problems may include torque and drag analysis, along with hydraulic analysis. The reasons for this choice are that changes in torque and hook load indicate hole condition problems. As for hydraulics, its effectiveness must be evaluated because inadequate hole cleaning is one of the main causes of hole condition problems.

Since the subject of the study is limited to the part of the drilling engineer, geologic analysis, as well as geomechanical analysis of wellbore stability will not be included in the study.

3.2.2.1 Torque and drag analysis

Torque and drag can be critical factors in determining whether a well can be drilled along the desired trajectory (Mitchell 2006). Torque and drag models consider the well trajectory, drill string configuration, friction coefficients and casing depth.

Torque and drag models play a significant role in diagnosing hole cleaning problems, impending differential sticking, and determining whether casing and drill string can be reciprocated during operations. Models help identify the root cause of problems in the wellbore that were previously unexplained or attributed to other factors, such as mud density or chemistry.

The most commonly used torque and drag models are based on the "soft string" model (Mitchell 2006). The drill string is modelled as a string or cable capable of absorbing axial loads without bending moments. This model is widely used in the field and industrial applications due to its simplicity (Hossain and Al-Majed 2015).

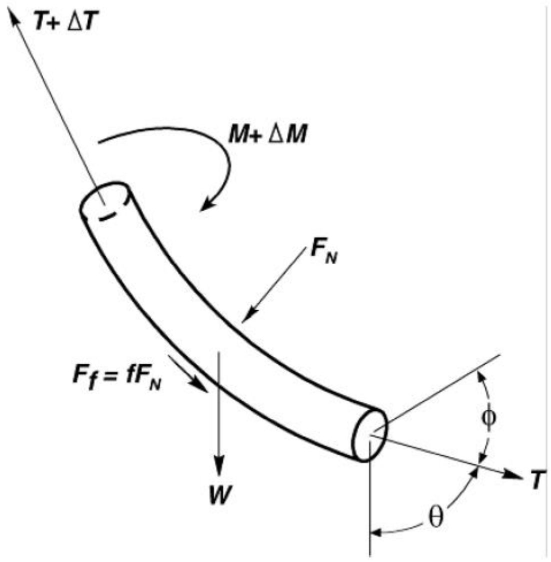

Figure 26: Drill string element for the "soft string" model (Mitchell 2006)

The friction force is the product of the normal force and the friction coefficient. The normal force at each calculation node consists of two components: (1) the weight of the pipe in the drilling fluid and (2) the lateral reaction force resulting from the tension of the drill string on the curved sections of the wellbore. The simplified drill string element shown in Figure 26 has net axial and normal forces.

If friction coefficients are obtained from available field data, the 'soft string' model gives reasonably accurate results for most drill pipe sizes and well curvature. However, because the 'soft string' model does not account for drill string stiffness, its accuracy will decrease as the diameter of the drill pipe and the curvature of the well increase. Both of these increases result in large normal force values and increased torque and drag values. 'Stiff string' model takes into account stiffness of drill string.

The hole condition has a major impact on the actual friction coefficient, which can be completely different from that assumed by experience. Influencing factors are the occurrence of key seats, ledges, wash-outs, and cavings. Other contributors to the true mechanical friction between the borehole wall and drill string are stiffness of the tubular components, the viscous drag of the drilling fluids, presence of stabilizers and centralizers, formation types, differential pipe sticking due to pore pressure, loss of circulation, micro-tortuosity.

Friction coefficients for different types of drilling fluids are shown in Table 4.

Drilling Fluid	Friction Factor in Cased Hole	Friction Factor in Open Hole
Oil-based mud (OBM)	0.16 – 0.2	0.17 – 0.25
Water-based mud (WBM)	0.25 – 0.35	0.25 – 0.4
Brine	0.3 – 0.4	0.3 – 0.4

Table 4: Range of friction coefficients (Economides, Watters and Dunn-Norman 1997)

Well design should include simulation of torque and drag with friction coefficients for the worst case. The torque and drag analysis results are usually expressed graphically with the torque and/or hookload and the measured depth on the other, so-called torque and drag roadmaps. They are calculated and calibrated for RIH/POOH and rotation-off-bottom (ROB) operations by superimposing simulated values on sensor data. Once the roadmaps are calibrated, the depths at which the anomalies/deviations occurred can be determined. A similar analysis is shown in Figure 27.

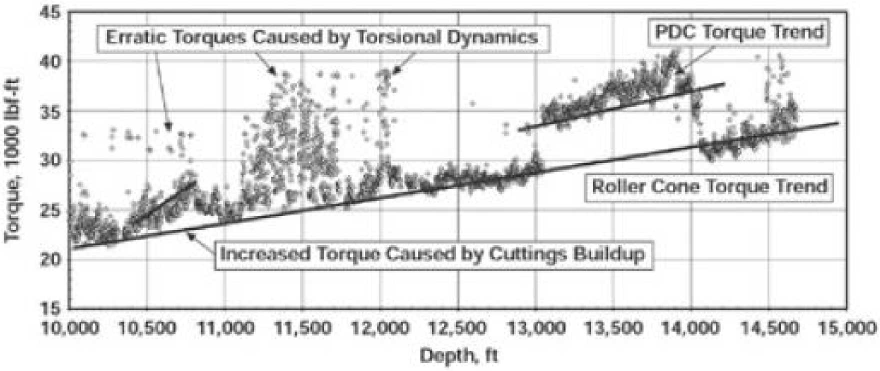

Figure 27: Actual and predicted torque (Economides, Watters and Dunn-Norman 1997)

To calibrate torque and drag models, the sensor values are used during tripping operations, during which the drill string is moved in the axial direction without any rotation. Rotating off bottom operation implies when the bit is not on the bottom hole during a rotating operation, the drill string rotates without any movement in the axial direction.

During the complication/accident investigation procedure, torque and drag analysis is performed after the well is drilled. However, it is possible and recommended to perform such analysis in real-time while drilling, recalculating roadmaps as new data become available and comparing them with actual sensor data. OMV has a project called "Drilling Cockpit" that does this real-time recalculation of roadmaps. It allows friction coefficients to be updated and checked; if actual friction coefficients are significantly different than planned, problems can be predicted and prevented rather than dealt with ex post facto. Such a comparison will also show the effect of changing bit types or changing operating parameters.

3.2.2.2 Hydraulics analysis

Since poor hole cleaning is one of the key factors causing hole condition problems (Hossan and Islam 2018), conducting a hydraulic analysis as part of the technical analysis is important.

It includes the following:

– Bit hydraulics analysis - how much pressure loss goes to the bit;
– Modeling the standpipe pressure and overlaying the modeled values on the sensor data to identify anomalies.

a) Bit hydraulics

When analyzing the hydraulics of a bit for hole cleaning, two main criteria are used (Mitchell and Miska, Fundamentals of Drilling Engineering 2011): either the drill bit hydraulics horsepower or the hydraulic jet impact force.

– The bit hydraulics horsepower criterion is based on the fact that cuttings are best removed from under the bit when the highest power is applied to the bottomhole. Pressure loss across the bit is important in determining hydraulic power. According to this criterion, optimal hole cleaning is achieved if the hydraulic power on the bit is maximum in relation to the pump flow rate.

– The jet impact force criterion is based on the fact that drill cuttings are best removed from under the bit when the force of the fluid exiting the jet nozzles and hitting the bottomhole is very high. The maximum jet impact force criterion states that bottomhole cleaning is achieved by maximizing jet impact force relative to flow velocity. At the bottomhole the jet impact force can be obtained from the Newton's second law of motion (Hossan and Islam 2018).

The force of the jet impact is maximal when (Mitchell and Miska, Fundamentals of Drilling Engineering 2011):

$$\Delta p_d = \frac{2\Delta p_p}{m+2}, \tag{1}$$

$$\Delta p_b = \Delta p_p - \Delta p_d = \left(1 - \frac{2}{m+2}\right)\Delta p_p = 0{,}47\Delta p_p, \tag{2}$$

where Δp_d – parasitic pressure loss, Δp_p – pump pressure, Δp_b – pressure loss on a bit. The flow exponent (m) between two points is deducted from the relationship between frictional pressure loss and flow rate. The flow exponent has a theoretical value of 1.75. Thus, the bit pressure loss should be equal to 47% for the jet impact force to be maximal.

b) Standpipe pressure analysis

The standpipe pressure when circulating the drilling fluid is the sum of pressure losses to overcome restrictions in all nodes of the circulation systems and losses on the bit (Sereda and Solovyev 1974):

$$SPP = \Delta P_{DS} + \Delta P_{BHA} + \Delta P_{Bit} + \Delta P_{annulus}, \tag{3}$$

where ΔP_{DS} – pressure loss along the drill string, ΔP_{BHA} - pressure loss in BHA, ΔP_{Bit} – pressure loss across the bit, $\Delta P_{Annulus}$ – pressure loss in the annulus.

Thus, the procedure for creating a Lessons Learned report for a hole condition problem includes specific key information and technical analysis of hydraulics and torque and drag, as shown in Figure 28.

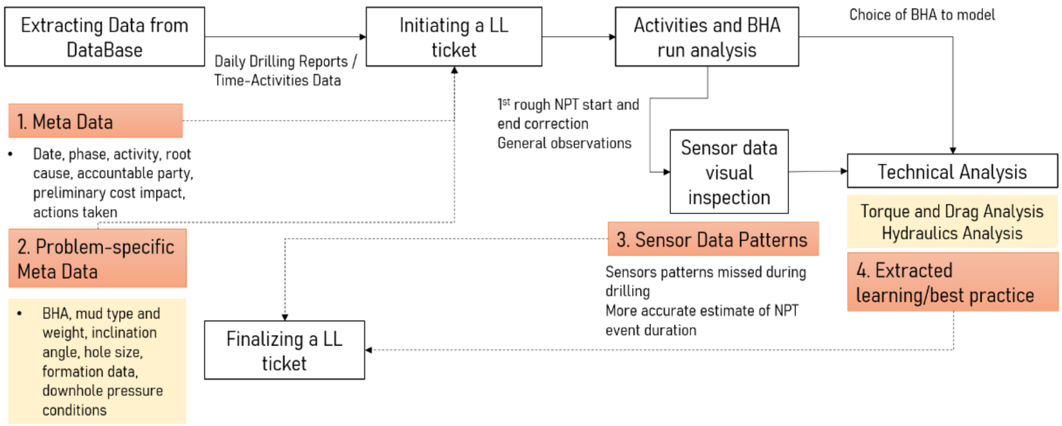

Figure 28: Procedure for creating a Lessons Learned report for a hole condition problem

3.3 Developing a system for automated generation of the Lessons Learned report

To reduce the barrier in creating Lessons Learned reports by company engineers, as described earlier, it is proposed to develop a system to automate some parts of its creation procedure.

Automation can be done with a special tool in the form of a web application. The application is written entirely in the Python FLASK language, including HTML templates.

The tool's main function would be to export metadata and visualize sensor data for easy future use. Figure 29 shows what subtasks of the procedure the application could help with.

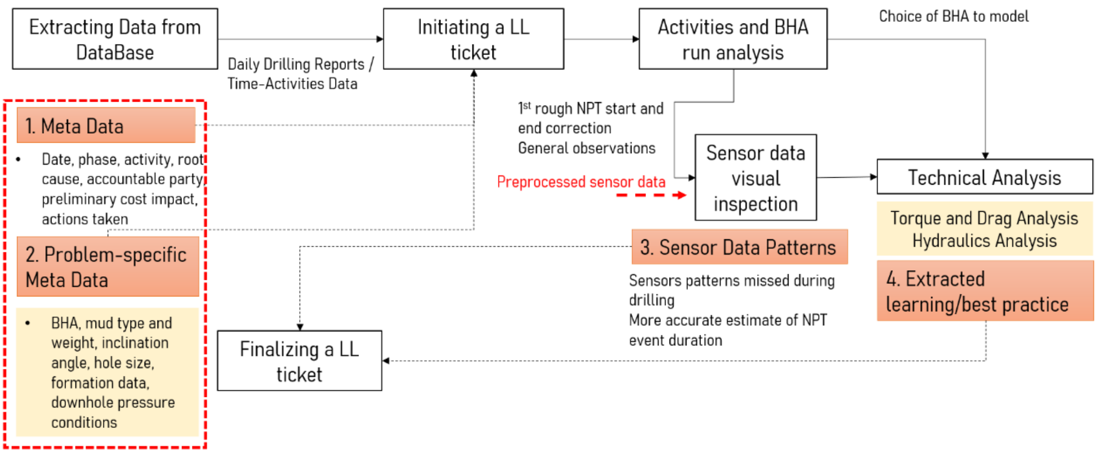

Figure 29: Role of the application to automate Lessons Learned reporting process

This tool allows:

1. Collect metadata and a block of key information (problem-specific meta data) from daily drilling reports/operational activity data;

2. Generate a report and fill in the information collected in the template used by OMV for Lessons Learned reports;
3. Prepare a workbook with preprocessed sensor data to improve the quality of the visual inspection.

Full functionality, including additional functions:

1. Keep statistics and records of NPT;
2. Generate Lessons Learned reports for all causes of NPT, including basic information, with the current OMV Lessons Learned report template;
3. A detailed "Lessons Learned" report based on the structure proposed in the previous section for hole condition problems.

The initial page prompts the user to select the type of file to download: multiple daily drilling reports in PDF format or CSV activities data from the IDS database. This is shown in Figure 30.

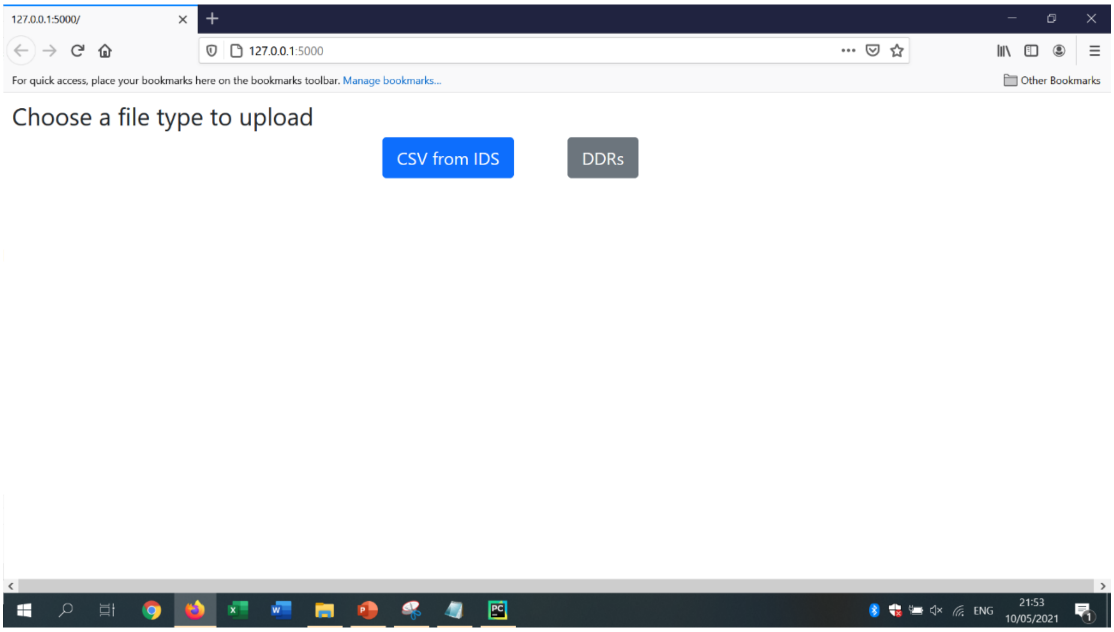

Figure 30: Home page of the application

Using daily drilling reports, approach may be more convenient because this data is usually available. However, it should be noted that processing multiple PDF files in Python is quite time-consuming. The second approach, with activity data in CSV format, is used directly at OMV. Such activity sheets are regularly retrieved from the database.

In the case of daily drilling reports, the data are analyzed from PDF files using the appropriate Python libraries for NPT tables. In the case of CSV, such tables are created directly using the Pandas library.

Regardless of the source file selected, an upload page appears after the initial page, where a user must enter the file name, select the country and the well designation - onshore or offshore.

The drop-down list includes countries where OMV operates. They are Austria, Romania, Kazakhstan, Bulgaria, UAE, Kurdistan Iraq, Libya, Tunisia, Yemen, Iran, Norway, Russia, Australia, New Zealand, and Malaysia (OMV Group Website 2021). The upload page is shown in Figure 31.

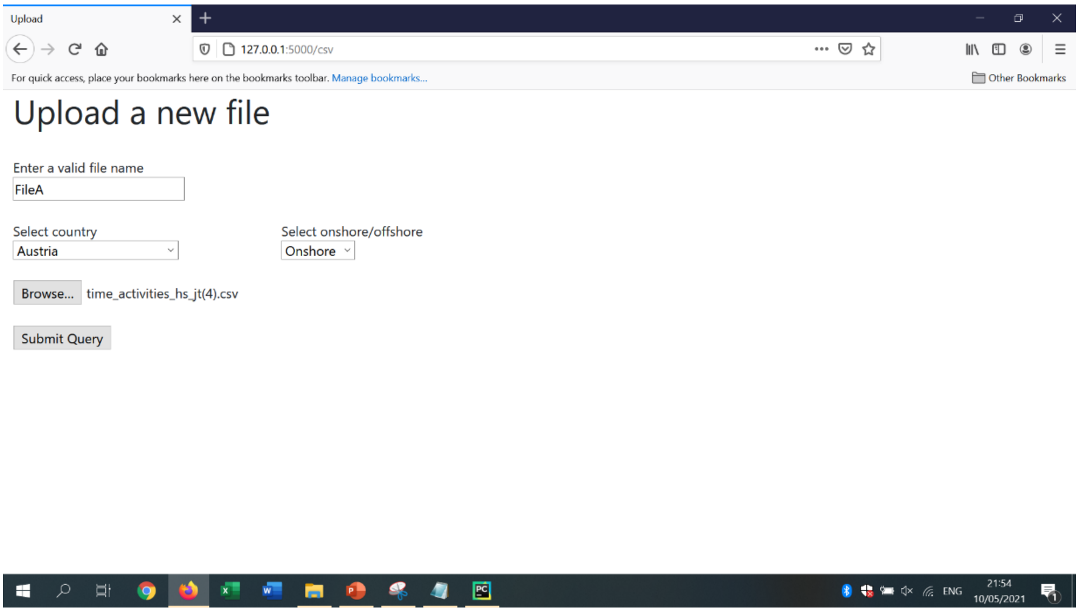

Figure 31: Download page

3.3.1 App functionality: NPT information

After loading the file, the NPT dashboard appears, which includes three key components (Figure 32):

- Duration of productive and non-productive time;
- A pie chart of NPT by cause;
- A table with a list of NPT events, grouping events by root cause, including their total duration and number of occurrences.

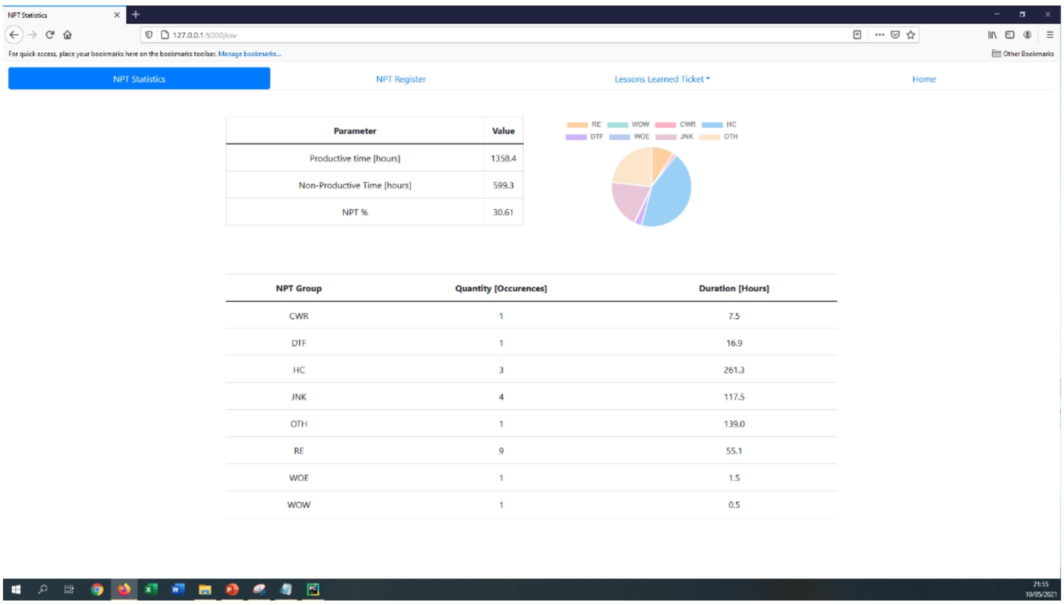

Figure 32: NPT dashboard

In the NPT Register tab, the events that caused the NPT are summarized in one table. It contains information about the root cause, start day and time, end day and time of the event, its duration, actions taken, and impact on cost. The register is shown in Figure 33.

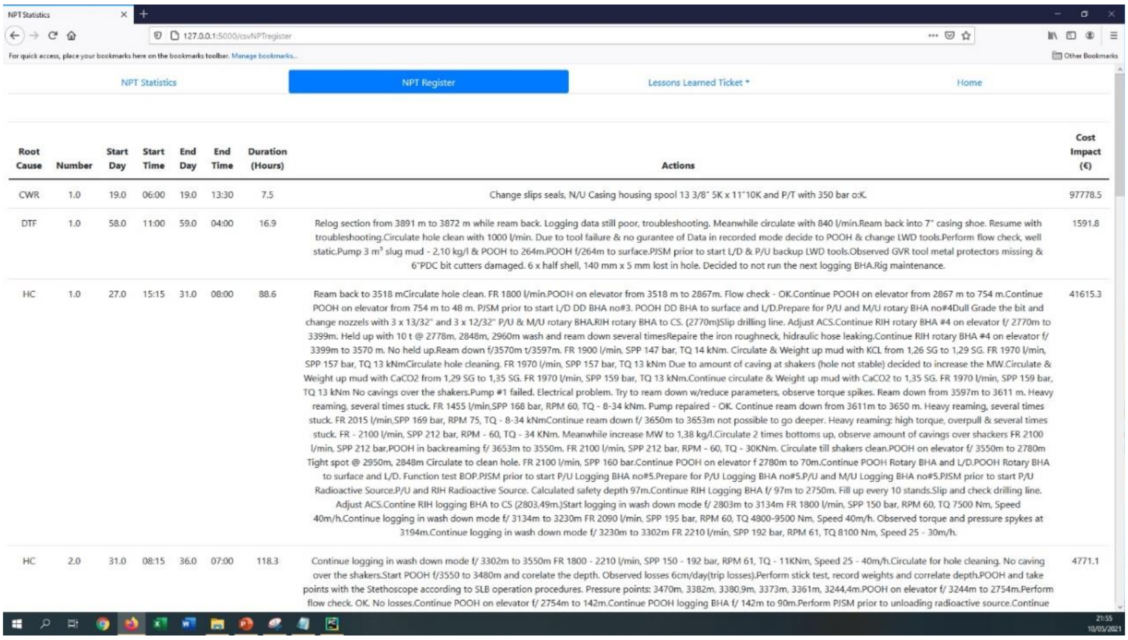

Figure 33: Register of NPT cases

The most technically challenging part is extracting the actions from the daily PDF drilling reports.

This dashboard and register table are good for getting an overview of events during drilling and determining which ones to focus on. It also provides some anchor points, such as start and end dates, allowing you to find the appropriate daily report quickly, so this part can be used independently for various purposes.

3.3.2 App functionality: Automated creation of Lessons Learned reports

The user has two options for generating a Lessons Learned ticket: generate tickets from the NPT register described above with the current OMV Lessons Learned report template, or generate a more detailed Lessons Learned report specifically for hole condition problems based on the proposed template discussed in the previous chapter. Hole condition problems have been chosen as some of the most time-consuming ones; it is possible to create similar modules for other types of problems outside the scope of this Master's Thesis.

3.3.2.1 Lessons Learned reports with the current OMV template from the NPT register

To generate reports from the NPT register data, one needs to specify the name of the reporting person, select for which root causes Lessons Learned tickets should be generated (one can do it for all root causes), specify the hours threshold and cost impact threshold for events. For example, if the time threshold is set to 10 hours and the cost impact threshold is set to 100,000 euros, then Lessons Learned tickets will be generated for such NPT events that either lasted more than 10 hours or had a cost impact greater than 100000 euros. An example is shown in Figure 34.

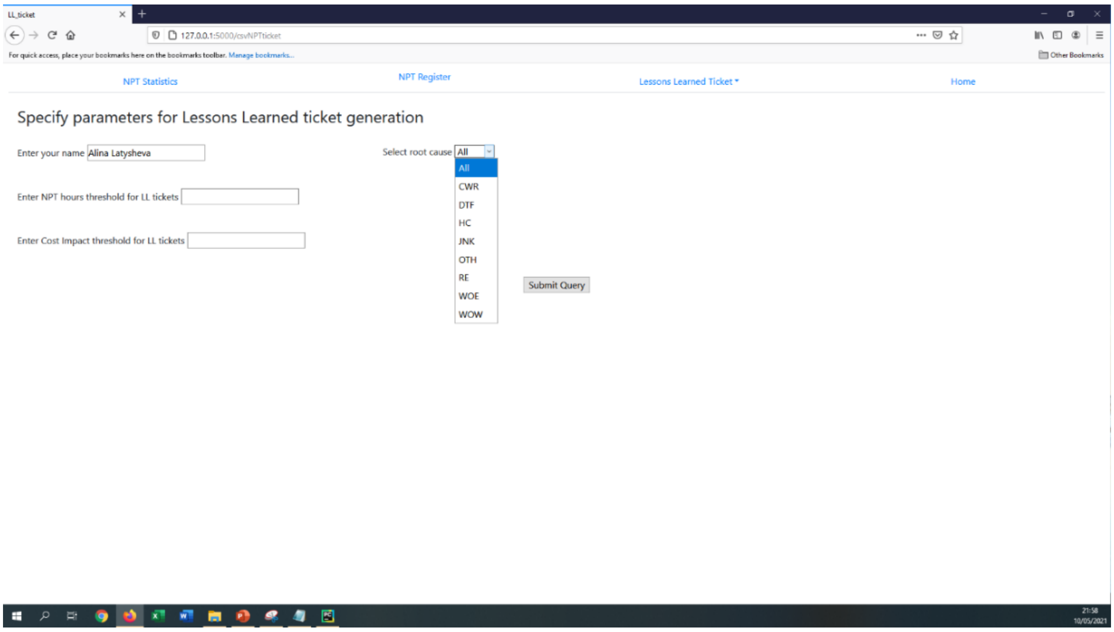

Figure 34: Setting up the Lessons Learned report

Reports are created and populated using the MailMerge Python library and OMV Lessons Learned report templates. Data fields such as creation date, well name, country, region (a dictionary was created for this purpose), operation, category, root cause, event date, name of person reporting the event, responsible party, impact on value, report name and event description are filled in automatically.

An example of the generated report is shown in Figure 35.

LESSON LEARNED REPORT

10/05/2021

Well Data			
Well Name	EBENTHAL TIEF 003 - Ebenthal Tief 3	Well Country	Austria
Well Region	Central Eastern Europe	Onshore/Offshore	Onshore

Lesson Learned			
Lesson #		**Lesson Date**	12-Jul-2014
Phase	Ph-6	**Company**	
Activity	RRE TDS	**Service**	
Category	Equipment	**Reported By**	Alina Latysheva
Root Cause	Rig Equipment	**Responsible Party**	RAG.Energy.Drilling
		Reviewed By	
Applicability	*Globally / Country specific / Project specific*	**NCR Number**	
Status		**Potential Cost**	11313.6
Lesson Title	Rig Equipment		
Lesson Description	Repair Top Drive (change electro-fan motor)		
Post Lesson Action	Top Drive main motor fail. Attempt to repair - no result.PJSM about Rig Down the Top Drive.Start Rig Down Top Drive.Continue Rig Down Top Drive. Meanwhile: Circulate several times B/U FR 750 l/min, SPP 75 bar. Replace pumps equipment.PJSM about R/U Top Drive.Start Rig Up and install new Top Drive. Meanwhile: Circulate several times B/U FR 750 l/min, SPP 75 bar. Wait on equipment. (Hydraulic oil)Wait on equipment. (Hydraulic oil)Continue install Top Drive and function test & P/T (30/350bar) Meanwhile Perform PJSM about P/T Stand pipe & TD.		
Attachments			

Figure 35: Example of a Lessons Learned report generated automatically

3.3.2.2 Lessons Learned reports with the proposed template for hole condition problems

A more detailed Lessons Learned report can be created for hole condition problems if the user uploaded the operations data in a CSV format.

To retrieve the problem-specific meta information, it is needed to upload the daily drilling report for the event's start date (the application itself suggests the date). It is also possible to download a snippet of sensor data, which will be an attachment to the report.

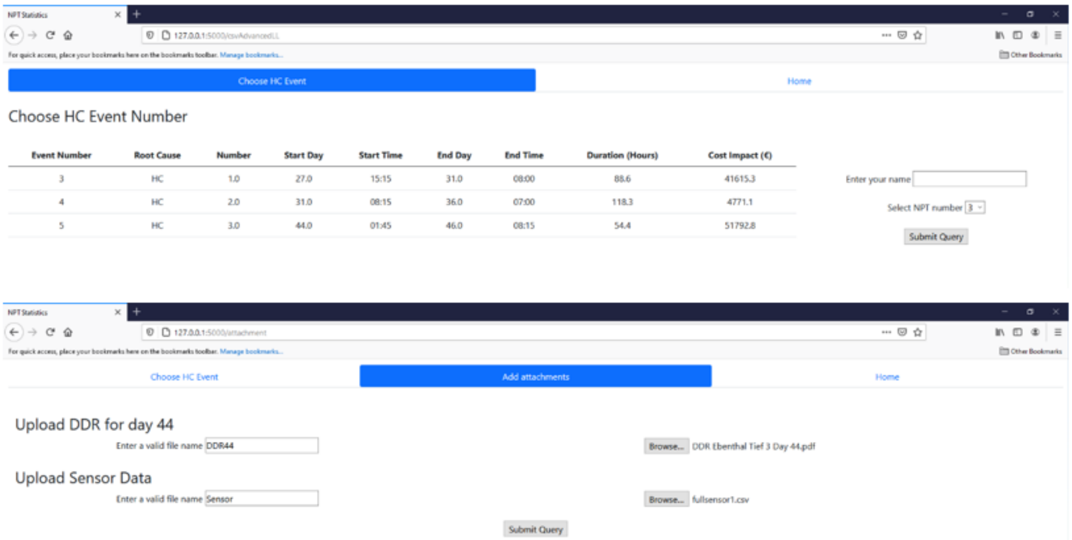

Figure 36: Selecting a hole condition event and uploading additional information to fill in the Lessons Learned report fields

The sensor data attachment module is designed for easy visualization: fixing axis ranges and curve groups in the most representative way, e.g. RPM and torque on one tab, pump flow and standpipe pressure on another; it also clears NaN values (-999.25).

The output gives the user a Lessons Learned report, a 1-page sensor data file that can be used as an attachment to the report, and a preprocessed sensor data workbook. The sensor data workbook is a PDF file with a 30-minute slice of sensor data on each page. At the top of each page is an activity description taken from the corresponding daily drilling report. The user does not need to download the exact sensor data slice for the time interval; it is extracted automatically. The application output is shown in Figure 37; the sensor data workbook page is in Figure 38.

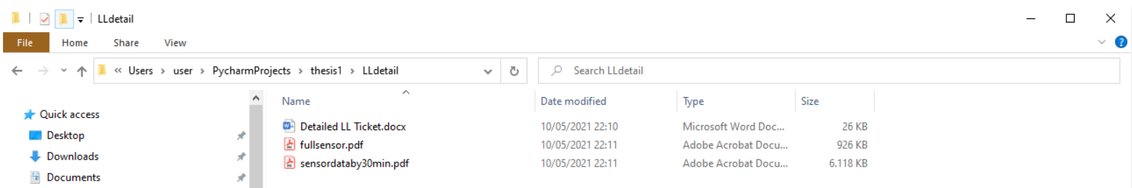

Figure 37: Application output

Figure 38: Workbook of sensor data created automatically

A Lessons Learned report with more information on hole condition problems is shown in Figure 39.

LESSON LEARNED REPORT

10/05/2021

Well Data			
Well Name	EBENTHAL TIEF 003 - Ebenthal Tief 3	Well Country	Austria
Well Region	Central Eastern Europe	Onshore/Offshore	Onshore

Lesson Learned			
Lesson #		Lesson Date	22-Jun-2014
Phase	Ph-6	Company	
Activity	DRL REA	Service	
Category	Subsurface/Geology	Reported By	Alina Latysheva
Root Cause	Hole Condition	Responsible Pary	Unassigned
		Reviewed By	
Applicability	*Globally / Country specific / Project specific*	NCR Number	
Status		Potential Cost	51792.8
Lesson Title	Hole Condition		
Lesson Description	Hole Size	6.0	
	Mud Type	KCL/Polymer 1.11 sg	
	BHA	6" PDC, Bit sub, 5 3/4" SST, 4 3/4" DC, 5 3/4" SST, 4 3/4" DC, 14 x 4" HWDP, Jar, 5 x 4" HWDP, Intensifier, 3 x 4" HWDP.	
	Inclination Angle	19.422	
	Formation		
	Description	POOH in backreaming from 3775 m to 3709 m. FR - 800 l/min, SPP - 114 bar, RPM - 50.POOH in elevator from 3709m to 3650 m. Observe swabbing efect. Overpull 40 To.Circulate hole clean. FR- 850 l/min, SPP - 115 bar Observe large amonut of cuttings.POOH in elevator from 3650 m to top HWDP (263m).Continue POOH BHA 8 and L/D same.TD service and Check drilling line.P/U & M/U rotary BHA #9 and RIH to 247m.Continue RIH on elevator rotary BHA #9 f/ 247m to 2586 m. Fill up string.Wash down from 2586m to 2738 m.	

Figure 39: Lessons Learned report for hole condition problems

In addition, the sensor data is displayed on the application page, where the user can manipulate it, move the axis, select the time frame, etc. (Figure 40).

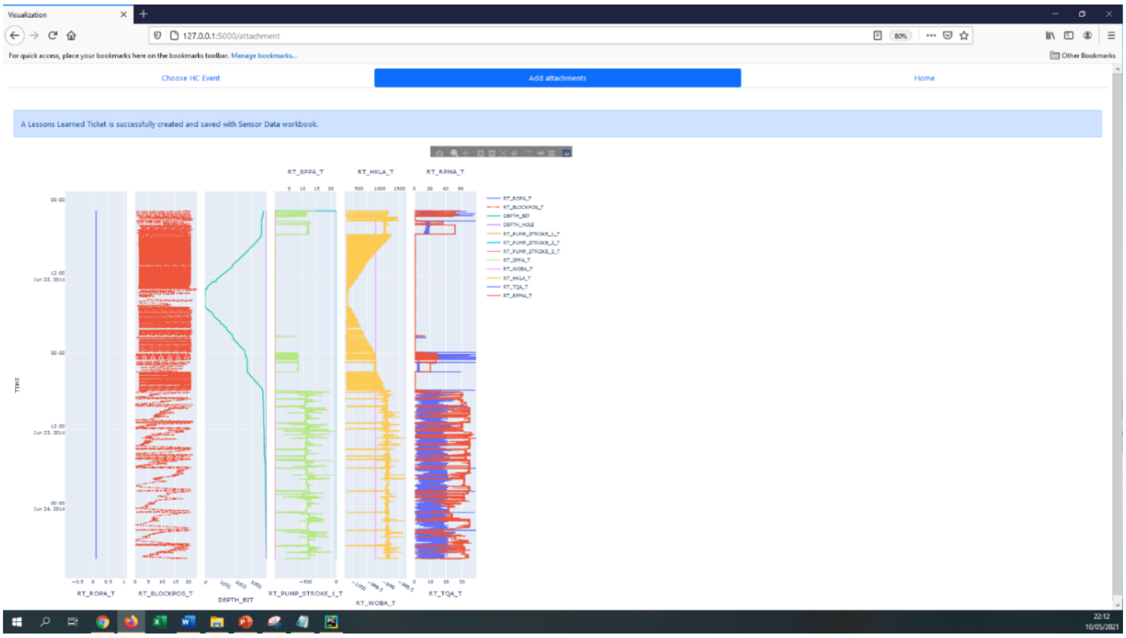

Figure 40: Demonstration of sensor data in the application

3.4 Conclusions for Chapter 3

In this chapter, suggestions for changing the structure of the Lessons Learned report were formed, and the procedure for creating this report was defined.

As support for report generation, a web application was created to extract metadata and key information (problem-specific meta data) for the report, as well as provide information on NPT incidents and generate a workbook with preprocessed sensor data combined with operations from the daily drilling reports.

Chapter 4 Applying the proposed recommendations to a specific well

Well A was selected based on the duration of the hole condition problem: for this well, the duration of the hole condition problem was 261.3 hours, the impact on cost can be roughly calculated as 1000254.2 euros.

This chapter will show how the proposed Lessons Learned reporting procedure would work in real life.

4.1 General information about Well A

Table 5, Table 6, Table 7 present Well A general information. The first section 12.25 in. was drilled with MWD and Motor BHA. After section total depth and setting a 9 5/8 in. casing, the 8.5 in. section was drilled with an RSS and MWD BHA. A coring run was also planned for this section. The well plot changed, and the decision was made to drill further with RSS and MWD tools to provide real-time data for geological purposes. In the 6 in. section, the logging run was performed to the final depth of the well - 4378m MD (OMV 2015).

Parameter	Value
Purpose of the well	Exploration well
Planned MD, m	3821
Actual MD, m	4378
TVD, m	4148,93
Kick off point, m	2248
Azimuth	308.77° at the final depth of the well
Maximum value of the inclination angle	53.4° at the final depth of the well

Table 5: Well A summary information

Diameter	Depth (MD)
23"	28 m
17-1/2"	680 m
12-1/4"	2805 m
8-1/2"	3722 m
6"	4378 m

Table 6: Hole sections

String	String Nominal OD	Depth (MD)
Conductor	18-5/8 "	28 m
Intermediate	13-3/8"	678,49 m
Intermediate	9-5/8"	2803,49 m
Liner	7"	TOL (2707m), 3720,0 m

Table 7: Casing strings summary

4.2 Extracting data from the database and collecting meta-information for the Lessons Learned report

The first step of the procedure is performed through a web-based application. The user uploads the daily drilling reports or activities data and enters the requested information. The user must then select the NPT event for which the Lessons Learned report should be created.

After that, the application requests additional data - a daily drilling report on a specific date (if the original file was activities data) and a sensor data file. These steps are shown in Figure 41.

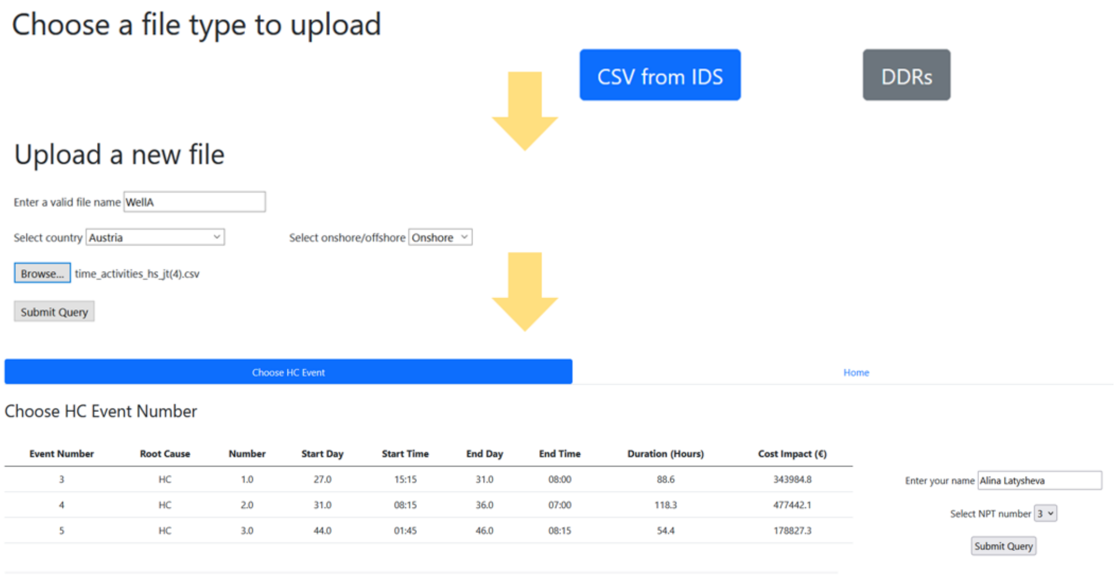

Figure 41: Loading Files

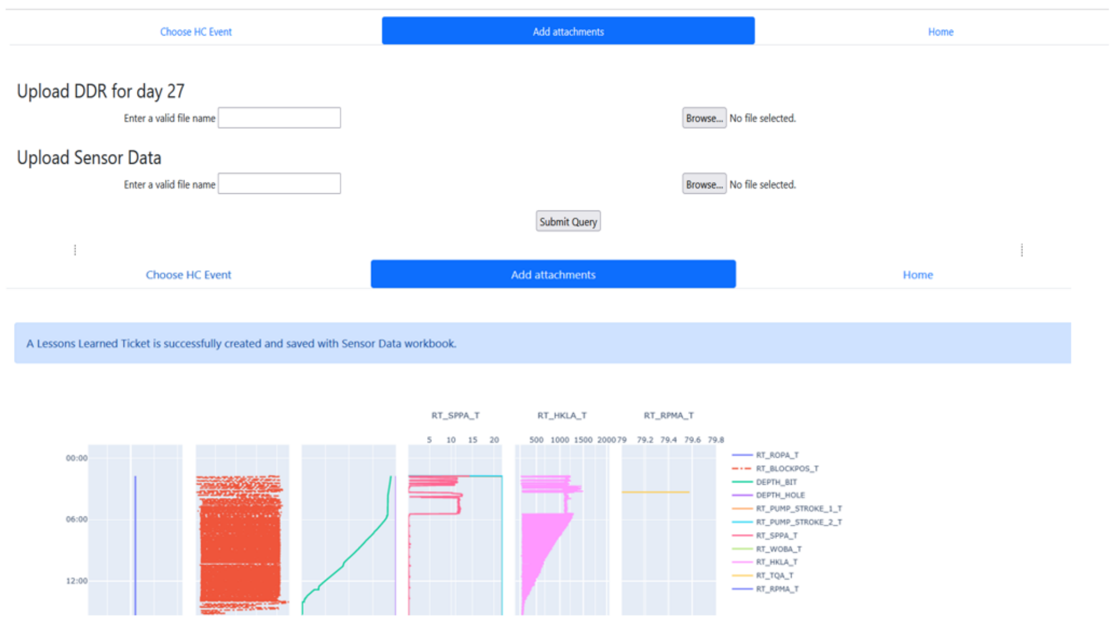

Figure 42: Created Lessons Learned report

A Lessons Learned report is then created and pre-filled with some information, such as well name, region, country, phase, operation, category, root cause, lessons and report date, responsible party, potential cost, section, mud type and density, type of bottomhole assembly, inclination angle, description (shown in Figure 43).

LESSON LEARNED REPORT

19/07/2021

Well Data			
Well Name	EBENTHAL TIEF 003 - Ebenthal Tief 3	Well Country	Austria
Well Region	Central Eastern Europe	Onshore/Offshore	Onshore

Lesson Learned			
Lesson #		Lesson Date	05-Jun-2014
Phase	Ph-6	Company	
Activity	DRL REA	Service	
Category	Subsurface/Geology	Reported By	Alina Latysheva
Root Cause	Hole Condition	Responsible Pary	Unassigned
		Reviewed By	
Applicability	*Globally / Country specific / Project specific*	NCR Number	
Status		Potential Cost	343984.8
Lesson Title	Hole Condition		
Lesson Description	Hole Size	8.5	
	Mud Type	KCL/Polymer 1.26 sg	
	BHA	8 1/2" PDC, PD, Receiver stab. w/slick sleave, Telescope 675 NF, XO, 8 3/8" NMSST, 2 x 6 1/2" NMDC, PBL sub, Jar, 3 x 5" HWDP, Accelerator, 6 x 5" HWDP.	
	Inclination Angle	24.78	
	Formation		
	Description	Ream back to 3518 mCirculate hole clean. FR 1800 l/min.POOH on elevator from 3518 m to 2867m. Flow check - OK.Continue POOH on elevator from 2867 m to 754 m.Continue POOH on elevator from 754 m to 48 m.	

Figure 43: The Lessons Learned report, created and filled out automatically

4.3 Analysis of BHA runs

The next step is to analyze the bottomhole assembly runs for the 8.5" section where the selected NPT event occurred. Drilling regime parameters by BHA are shown in Table 8.

BHA	Operation	Depths, m	WOB, t	RPM	TQ, kN	FR, l/min	SPP, bar
RSS BHA	Drilling	2808 - 2817	6			1800 - 2100	
		2817 - 2848	6	60	11	2000	
		2848 - 2893	6	70	6 – 11	2000	
		2893 – 3035	6	70	15	2100	130
		3035 - 3188	6	75	16	2100	135
		3188 - 3235					
		3235 - 3275	3-5	80	12	2100	141
		3275 – 3288	6	80	12	2100	141
		3288 – 3418					
		3418 - 3575		70-80	13	2000	147
		3575 – 3722 (section TD)	4-6	70-80	13	1900	149
	Pump out	3703 - 3695					
	POOH in backreaming	3695 - 3410		30		1500	
		3410 - 3050					

BHA	Operation	Depths, m	WOB, t	RPM	TQ, kN	FR, l/min	SPP, bar
	Pump out	3050 - 2780				1500	
	RIH	2780 - 3570					
	Ream down	3570 - 3585			40	1500	
	POOH to change BHA in backreaming	3585 - 3515				1800	
	POOH	3515 - surface					
Rotary BHA	RIH	Surface to 2803 m (previous casing shoe)					
		2803 - 3399					
		3399 - 3570					
	Ream down	3570 - 3597			14	1900	147
		3597 - 3611					
		3611 - 3653		60	34	2100	212
	POOH in back reaming	3653 - 3500					
	POOH	3500 – surface					
Logging BHA	RIH	Surface to 2803 m (previous casing shoe)					
	Logging in wash down mode	2803 – 3550					
	POOH	3550 – surface					
Rotary BHA	RIH	Surface - 3554					
	Ream down	3554 – 3572		61	13	2220	211
		3572 – 3660		61	8 - 30	2300	211
		3660 to 3707					
	Circulate 2x bottoms up	3707		40		2000	180
	Reaming	3707 – 3573		50	8	1800	
		3573 – 3707		50	37	1800	160
		3707 – 3716		70	Up to 38	2000	182
	Reaming	3716 – 3698					
	Reaming	3716 – 3722		70	Up to 38	1500-2000	110-182
	Circulate 2 x B/U	3722		60		2000	185

BHA	Operation	Depths, m	WOB, t	RPM	TQ, kN	FR, l/min	SPP, bar
	Wiper trip: ream out	3722 – 3485		50	8 - 32	1500-1700	
	Wiper trip in back reaming	3722 – 3550					
	RIH dry	3550 - 3680					
	Ream down	3680 – 3722		20		1800	149
		3722 – 3480		60		1800	
	POOH	3480 - surface					
Liner		RIH					

Table 8: Drilling parameters by BHA for 8.5" section

Complications encountered by BHA for 8.5" section are shown in Appendix B.

Already at this stage, it can be seen that hole condition problem was encountered in a way that after drilling 8.5" section till its total depth, reaming back to the previous casing shoe was performed, then reaming down commenced. And during this reaming operation, at some point, it was not possible to go deeper. The same issue happened in the 6" section. It indirectly indicates that probably the hole was not stable, and cuttings were falling into the wellbore.

According to the analysis made above, RSS BHA 8.5" was chosen for further modeling.

4.4 Sensor data visual inspection

During Sensor data visual inspection, such anomalies already during drilling were noticed:

- Increase in hookload (overpull);
- SPP peaks;
- Torque hour-glass shapes (indication of stick-slip);
- Torque does not correspond to RPM change (or high torque at low RPM);
- High torque variance.

Examples of such sensor patterns are shown in the Figures below.

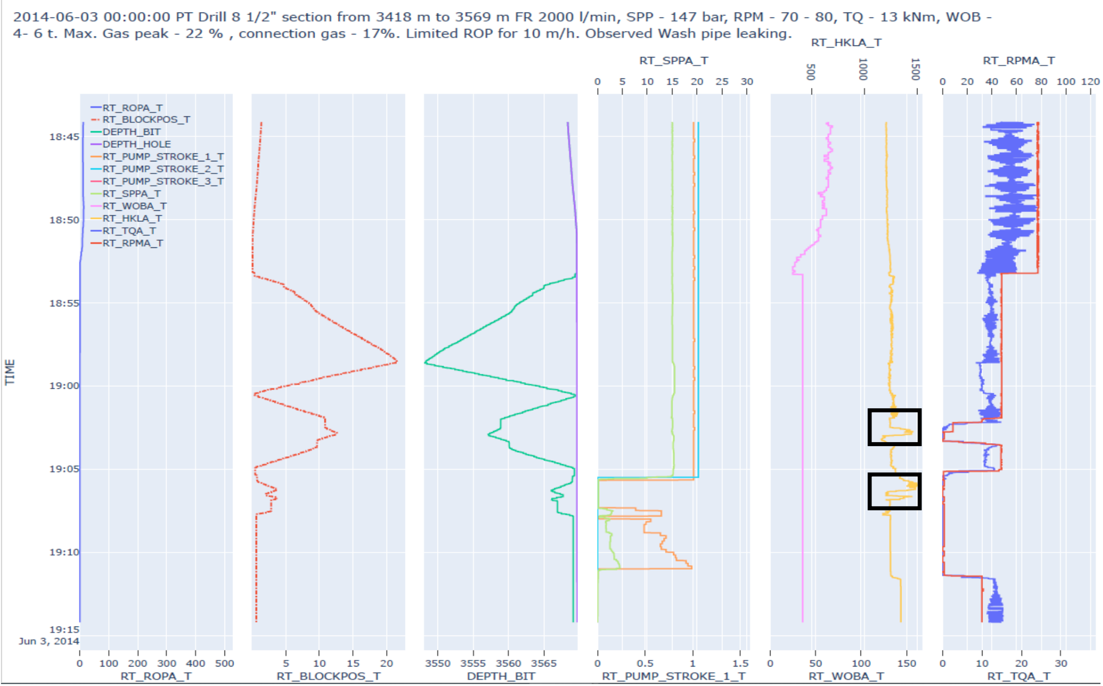

Figure 44: Overpull at 3569 m, Hour Glass shapes are showing indication of Stick-Slip issues

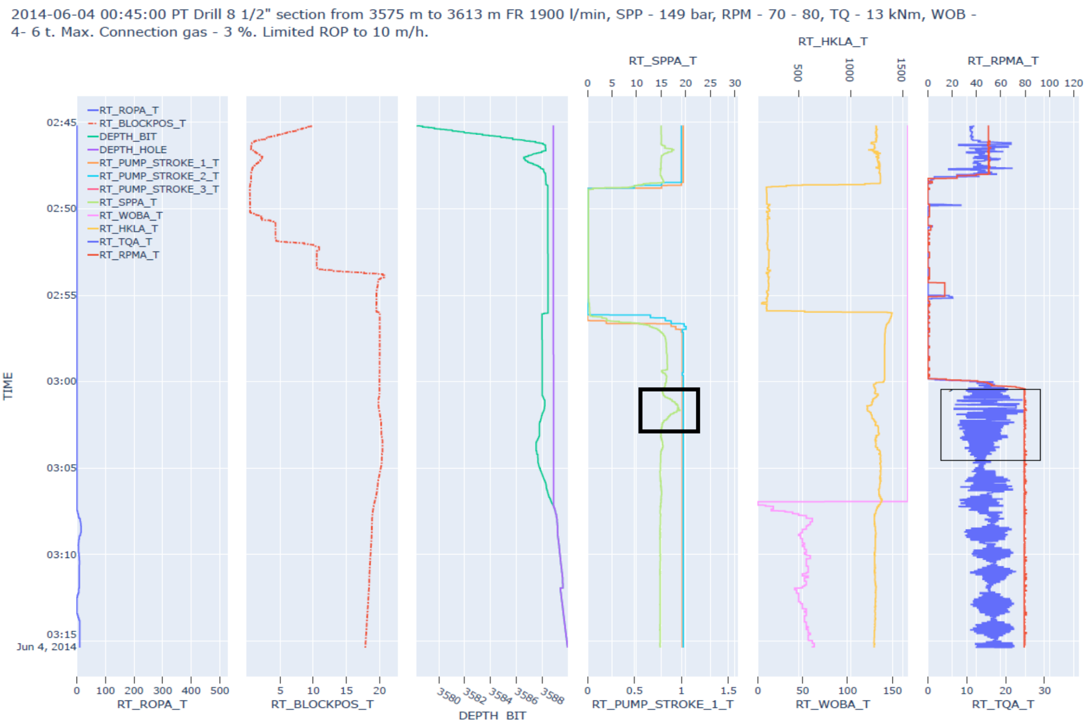

Figure 45: Torque range became wider, SPP peak (3588 m), Hour Glass shapes are showing indication of Stick-Slip issues

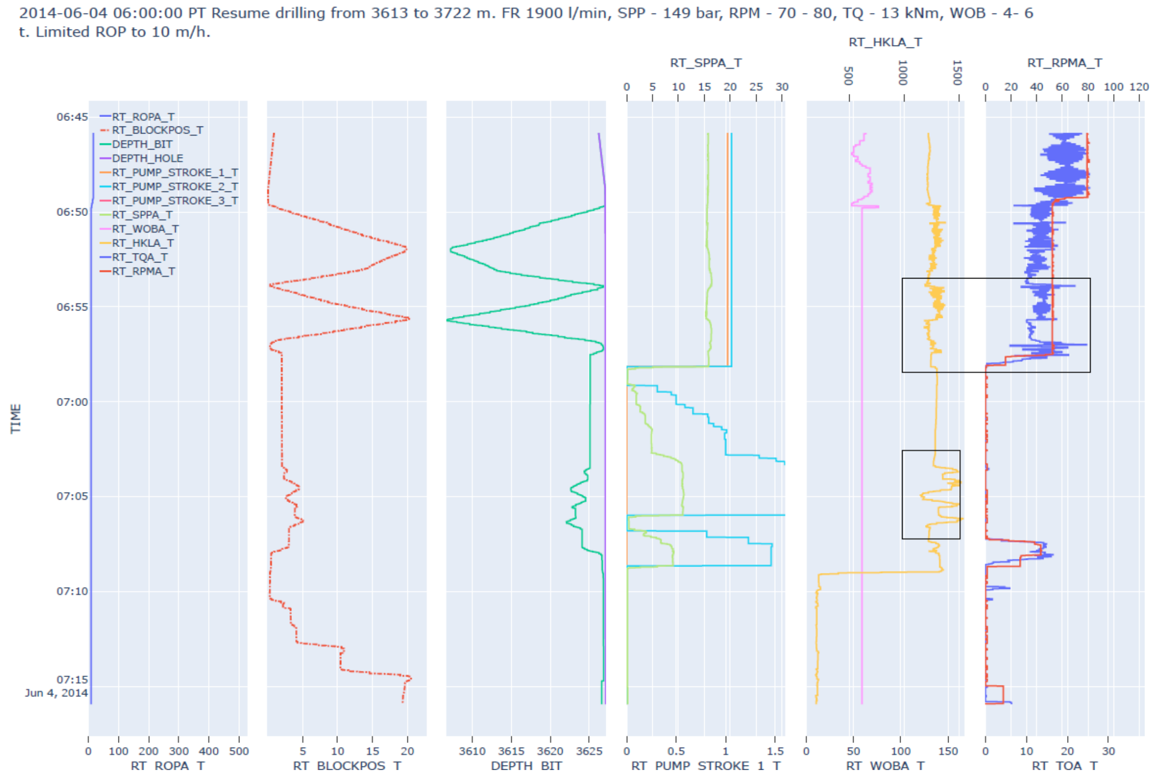

Figure 46: Overpulls at 3610 - 3625 m

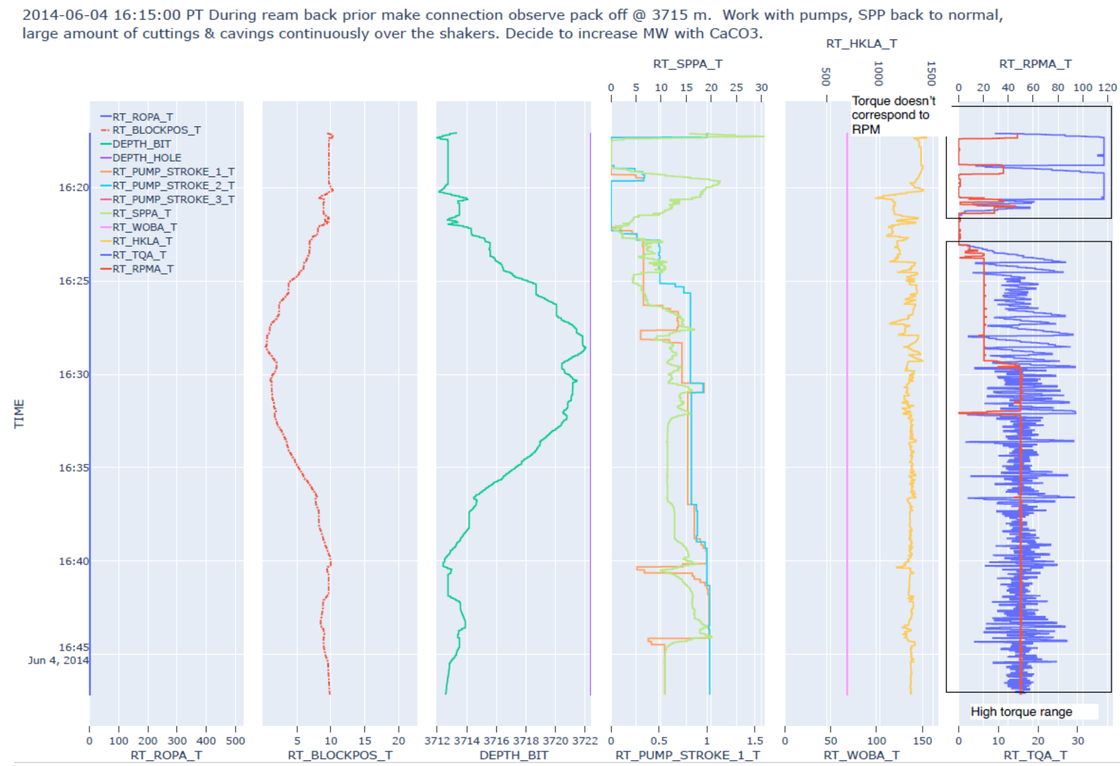

Figure 47: Torque does not correspond to RPM behavior (torque at zero RPM) and wide torque variance

4.5 Torque and drag analysis in Landmark

The 8.5" section contained both normal and troublesome operating conditions; it was chosen to simulate WellPlan (Landmark package). Initial data for calculating torque and drag roadmaps are shown in Table 9. Bit details are represented in Table 10.

Directional RSS BHA was made up and ran in a hole to drill the cement and 9 5/8" casing shoe and continue drilling to coring point. When drilling a new section started, stick and slip increased to a maximum acceptable level; there were attempts to mitigate it by changing drilling parameters. When 3722 m total section depth was reached, a high overpull was observed when picking up from the bottom. When it was tried to reach 3722 m again with reaming, pressure and torque increased. It was decided to make a wiper trip to a previous casing shoe. POOH could not be done on elevators. It was POOH with back reaming with 40 RPM to the shoe during the wiper trip. After circulation at the shoe and RIH, it was impossible to go back to 3705 m; 3580 m was the maximum reach. It was decided to POOH this BHA.

Mud details	Mud type	KCl/Polymer WBM
	Mud density	1,26 sg
Rig specifications	Rig block rating	2450 kN (Economides, Watters and Dunn-Norman 1997)
	Rig torque rating	35 kNm (Economides, Watters and Dunn-Norman 1997)
Drilling parameters	WOB	58,8 kN
	RPM	80
	TOB	2,145 kNm
	Pump rate	1,9 m^3/min
	SPP	154 bar
BHA run parameters	Depth in	2805
	Depth out, m	3722
	Inclination angle range	19,4 – 24,13

Table 9: Initial data for calculations

The torque on the bit was calculated using the following equation (Elmbergi 2012) (Pessier and Fear 1992):

$$TOB = \frac{\mu \cdot D_b \cdot WOB}{36} = \frac{0,5 \cdot 8,5 \cdot 13440}{36} = 1582\ [ft - lbf] = 2145\ [N \cdot m] \tag{4}$$

where μ is the friction coefficient equal to 0.5 for the PDC bit, D_b is the drill bit diameter [inch], WOB is the weight on bit [lb-ft].

Bit type	PDC
Nozzles	5x11, 1x12
Total nozzle area, inches2	0,574
IADC	M422

Table 10: Bit information

Figure 48 shows the components for a RSS BHA for 8.5" section.

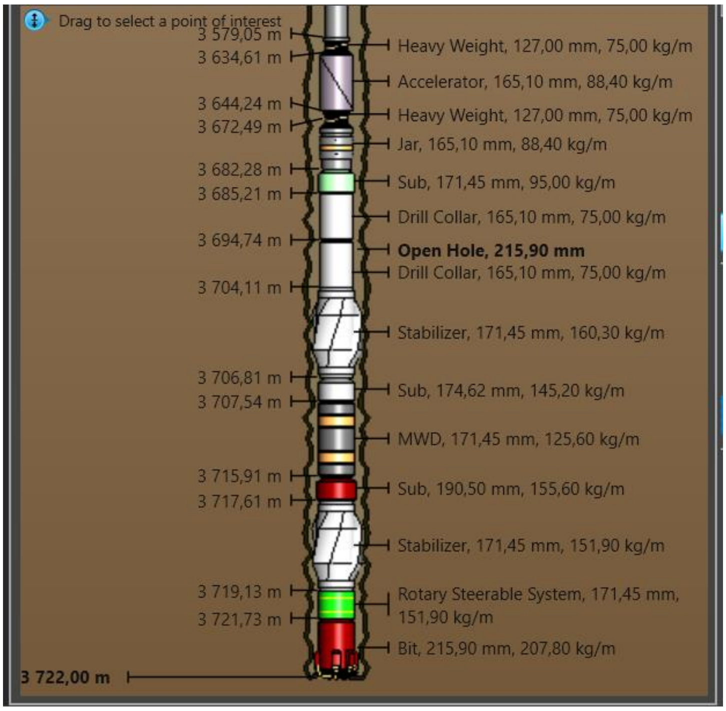

Figure 48: 8.5" RSS BHA components

The operating torque and drag roadmaps were calculated for this BHA using a 'stiff string' model in WellPlan. It is necessary to compare the actual values with the modelled values to calibrate the roadmaps and identify discrepancies between them. As for the actual values, either rig sensor data or directional drilling slide sheet data can be used. Data from both sources is shown in Figure 49.

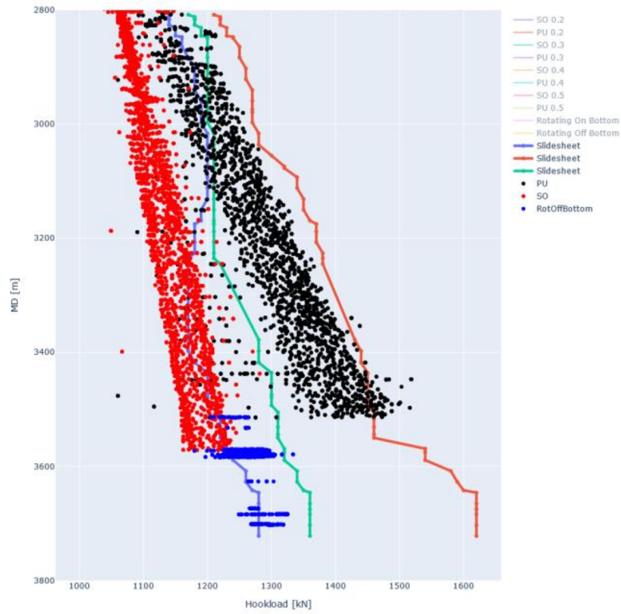

Figure 49: Hook load values from directional drilling slide sheets and rig sensor data

There is a big difference between the two data sources. There may be several reasons for this: perhaps a correction for block weight was taken into account in one case. In the second case, it was ignored. Another reason could be that the values of the directional drilling slide sheets are hand-picked and represent averages over some time. However, this picture emphasizes how unreliable it is to use human observations to analyze NPT.

Several anomalies appear if slide sheet values are chosen as actual data, and operational torque and drag patterns are calibrated against them (Figure 50). From a depth of 3000 m to 3200 m, there is an interval where the slack-off (S/O) weight does not change, although it should increase due to increased drill string weight. The second problem occurs at 3550 m, where the weight values during POOH move from a friction coefficient curve of 0.2 to a friction coefficient curve of 0.5, indicating increased friction in the wellbore. However, if this occurs, the S/O curve should also approach the 0.5 curve, but it does not. Since this data is unreliable, it is better to compare operational patterns with rig sensor data.

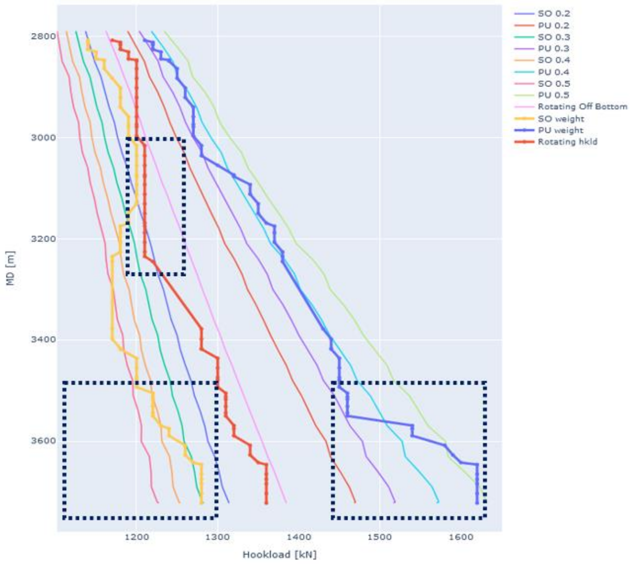

Figure 50: Hookload roadmap (planned and slide sheet values)

If the roadmaps are calibrated against rig sensor data, a large data cloud can be seen that lies on friction coefficient curves of 0.2 to 0.5 (Figure 51).

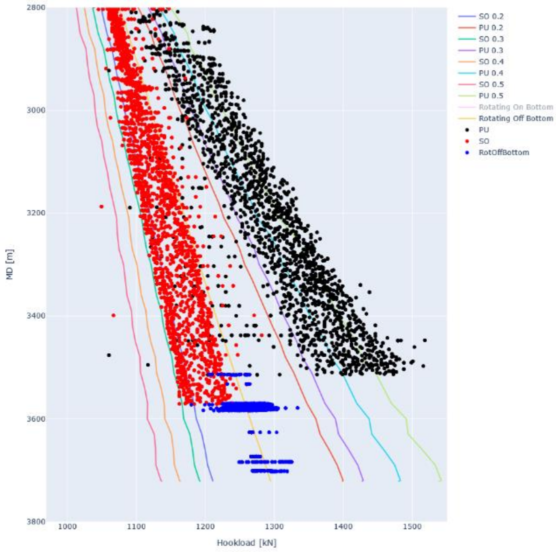

Figure 51: Hookload roadmap, superimposed on the surface sensor data

This data cloud appears because all the points from this interval are taken during connection (example for pick-up / POOH) (Figure 52). It can be preprocessed to determine the actual hookload trend taking median values (in blue).

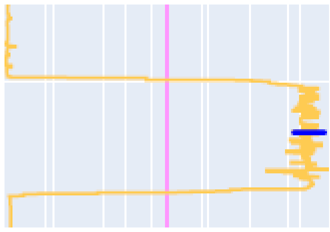

Figure 52: Hookload values during connection while POOH

Figure 53 shows the filtered sensor data. It can be seen that at a depth of 3200 m, the friction coefficient becomes more significant during P/U. This should correspond to a mirror deflection on the S/O curve, but in this case, it does not. This is due to a timing factor: something happened between S/O and P/U operations that drastically worsened the condition of the wellbore. Combining this with an analysis of BHA runs, it can be assumed (based on the available data) that gas influx could have caused the borehole walls to collapse and the friction coefficient to increase.

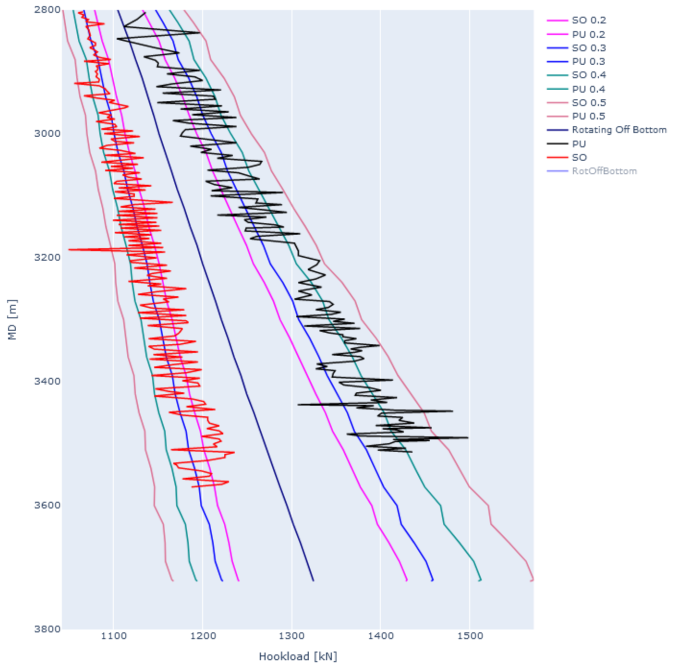

Figure 53: Filtered data

Usually, when calibrating roadmaps, rotation on bottom data is not used, because in this case, the weight and torque on the bit affect the results. Since they are not constant, they introduce some uncertainties into the data.

To overcome this uncertainty, Figure 54 shows a torque roadmap for rotating off bottom operation.

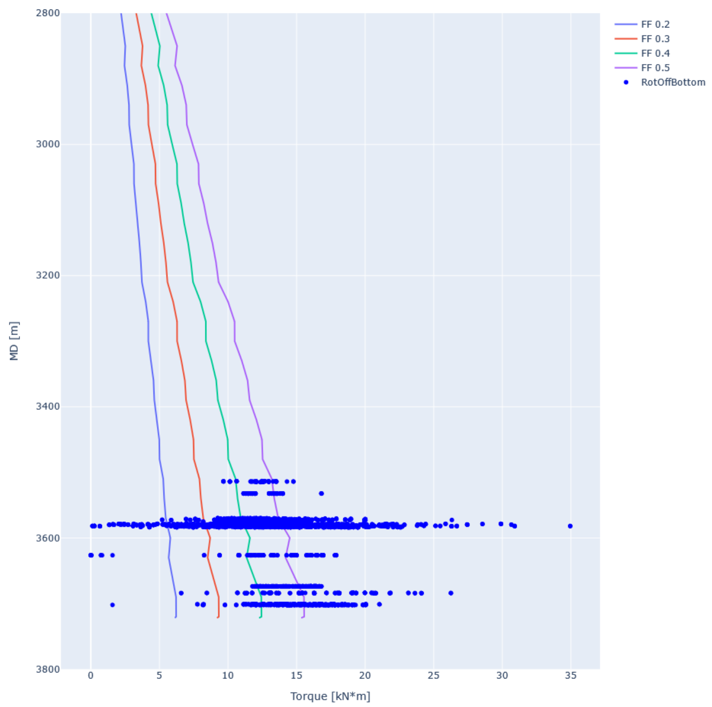

Figure 54: Torque roadmap for rotating-off-bottom operation

However, even without considering the torque on the bit, the torque pattern, unlike the hookload, does not show any noticeable trend. This can be explained by the fact that the drill string rotates irregularly, and surface torque values are not always representative. If we plot torque patterns while the bit was rotating on bottom, it is clear that the actual torque values were higher than predicted.

It can be concluded that there is some discrepancy between the sensor data and the roadmap, indicating that the friction force was higher than it should have been.

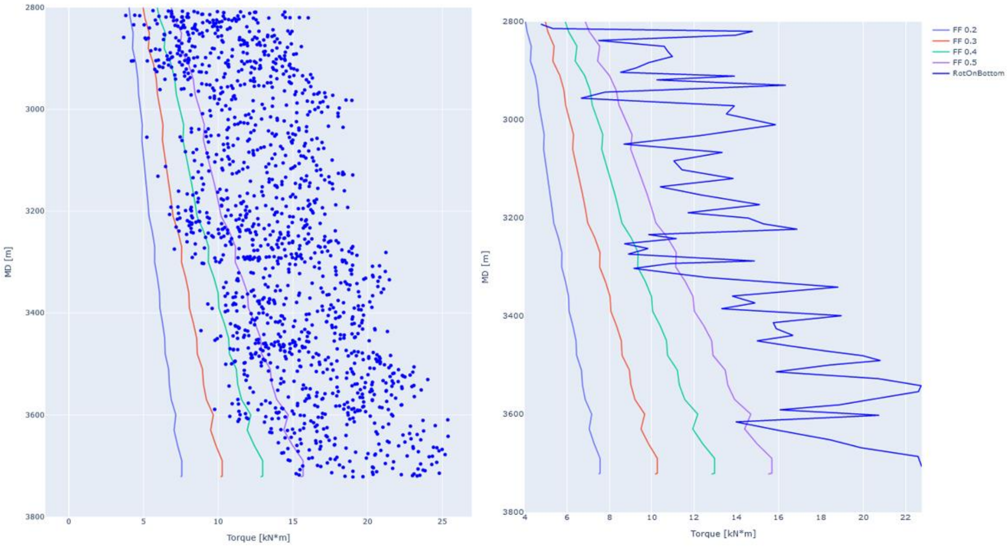

Figure 55: Torque roadmap for rotating on bottom operation (right - averaged values)

If conducted in real-time while drilling, such analysis can identify when something starts to go wrong in terms of torque and help prevent a complication/accident. At OMV, a project called "Drilling Cockpit" is looking at the possibility of recalculating such roadmaps in real-time and using them to prevent or reduce NPT.

4.6 Hydraulics analysis in Landmark

There are two ways to improve hole cleaning – jet impact force or horsepower (based on the criteria described in (Mitchell and Miska, Fundamentals of Drilling Engineering 2011)). Several investigators have concluded that the cleaning action is maximized by maximizing the total hydraulic impact force of the jetted fluid against the hole bottom (Hossain and Al-Majed 2015). In Landmark WellPlan, hydraulics analysis was performed. In Table 11, pressure loss by a BHA component is shown.

Component	Depth (m)	Pressure Loss (kPa)	Percentage (%)
Drill Pipe	3 579.05	6 133.69	51.0
Heavy Weight Drill Pipe	3 634.61	355.32	3.0
Accelerator	3 644.24	76.31	0.6
Heavy Weight Drill Pipe	3 672.49	180.26	1.5
Hydraulic Jar	3 682.28	77.58	0.6

Component	Depth (m)	Pressure Loss (kPa)	Percentage (%)
Float Sub	3 685.21	668.01	5.5
Non-Mag Drill Collar	3 694.74	67.27	0.6
Non-Mag Drill Collar	3 704.11	66.14	0.5
Integral Blade Stabilizer	3 706.81	21.73	0.2
Non-Mag Crossover Sub	3 707.54	2.89	0.0
MWD Tool	3 715.91	5.04	0.0
Steering Tool	3 717.61	20.42	0.2
Integral Blade Stabilizer	3 719.13	2.05	0.0
Hybrid	3 721.73	3.86	0.0
Polycrystalline Diamond Bit	3 722.00	4 355.80	36.2

Table 11: Pressure loss by component

The pressure loss in the bit should be 47% (described in the previous chapter) for the jet impact force to be maximum, while it is 36.2%, which means that the bit nozzles can be resized to increase this percentage.

Pressure loss on the bit (Mitchell and Miska, Fundamentals of Drilling Engineering 2011):

$$\Delta p_b = 8{,}074 \cdot 10^{-4} \rho v_n^2, \tag{5}$$

where ρ is density, v_n is the velocity of liquid from the nozzle. Thus, the pressure loss on the bit can be increased by increasing the velocity.
The fluid velocity from the nozzle is equal to the pump flow rate divided by the total flow area (Mitchell and Miska, Fundamentals of Drilling Engineering 2011), so the nozzle size must be reduced to increase the velocity.
The hydraulics can be improved in two ways:

- Bit modification. It is proposed to reduce the total bit nozzle area by changing the size or number of nozzles.
- Hydraulic mode optimization.

The minimum flow rate should be chosen according to the expected ROP (50 m/h assumed) (Figure 56), the maximum - based on the allowable pressure losses (Figure 72).

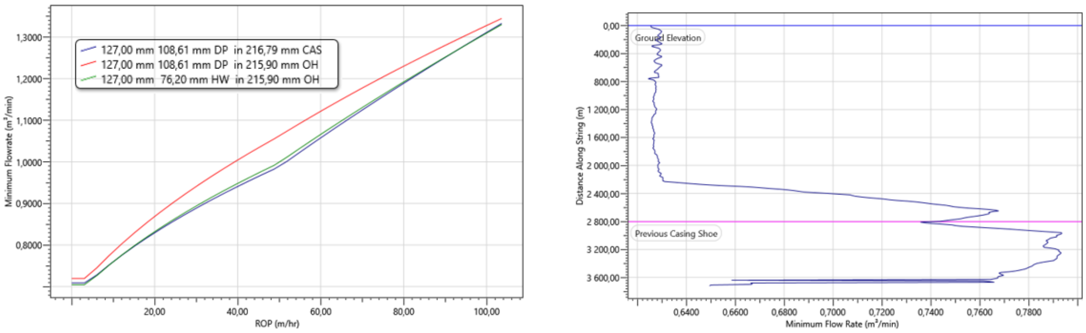

Figure 56: Flow rate as a function of ROP and distance along the drill string

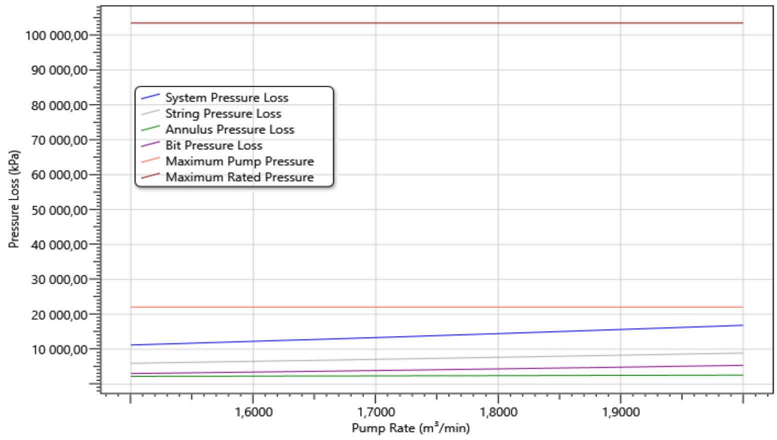

Figure 57: Pump rate as a function of pressure loss

It can be seen that the operating flow rate of the pump is within the permissible operating range.

A comparison of actual and planned standpipe pressures (Figure 58) showed a deviation at a depth of nearly 3400 m.

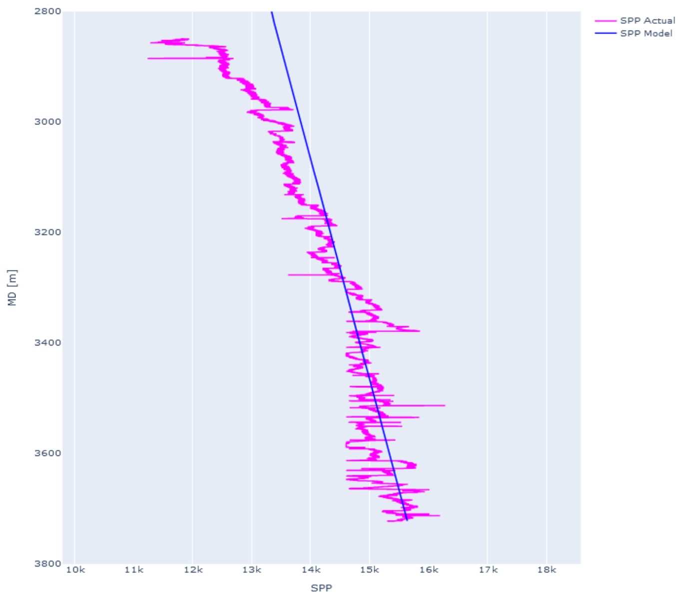

Figure 58: Predicted standpipe pressure vs. actual pressure (kPa)

The deviation at a depth of nearly 3400 m could have been caused by an increase in mud weight from 1.09 to 1.15 sg due to a well control event (influx into the wellbore).

4.7 Completing the report

After the technical analysis, one can complete the Lessons Learned report with information in the "Sensor Data Trends" and "Lessons Learned/Best Practices" sections. The result is shown in Figure 59.

Sensor Data Patterns	Overpull at 3569 m, Hour Glass shapes are showing indication of Stick-Slip issues Torque range became wider, SPP peak (3588 m), Overpulls at 3610 - 3625 m Overpull and torque peaks at 3665 – 3680 m High torque at small RPM Torque does not correspond to RPM behavior (torque at zero RPM) and wide torque variance Overpull and torque peaks, high torque range at 3700 – 3710 m
Extracted Learning/Best Practice/Comments	• Hole instability caused by well control incident at depth 3575 m. • It is noticed that bit pressure loss is equal to 36,2% which can be improved to enhance hole cleaning efficiency

Figure 59: Manually completed sections in the Lessons Learned report

4.8 Comparison with actual reporting

No actual "Lessons Learned" tickets were found in the database for this well. However, there is a special "Lessons Learned" section in the EoWR for this well:

On 8 ½" section was drilled with H2S contingency plan in place. 3 high gas readings on this section @3370m – 17%, @3370m – 3378m ~29% and @3418m – 26%. Due to gas influx the hole collapse and need to perform wiper trip but the string get stuck at 3580m. After several attempts string was free but hole was in bad conditions and unable to perform logging log. In this conditions perform soft drilling practice, wiper trip and circulate till shakers are clean. Take into consideration for the next wells in the area the gas influx. Such annotation is good for understanding the immediate root cause; however, finding this information later in this format seems impossible. A better way would be to include this text in the comments area of the Lessons Learned report being created, with all the details (OMV 2015).

Such an annotation is good for understanding the problem and its immediate cause; however, it seems impossible to find this information later in this format. A better way would be to include this text in the 'Description' area of the Lessons Learned report being created, with all the details.

4.9 Importance of the proposed Lessons Learned generation procedure

The proposed procedure could potentially help further reduce NPT by including relevant best practices and lessons into a new well design during the offset well analysis. It is difficult to predict the cost impact. However, it is possible to assume that one of the hole condition NPT events for Well A could have lasted less if the relevant lessons would have been incorporated in its design before. Three scenarios (e.g., P90, P50, P10) in which the event duration is reduced by 5, 10, 15% to get a rough estimate.

The approximate cost of the case of NPT due to the hole condition analyzed earlier is 1000254 euros. According to such figures, it can be reduced to 950241.49, 900228.78 or 850216.07 euros, depending on the scenario. Updated time versus depth charts in these scenarios is shown in Figure 60.

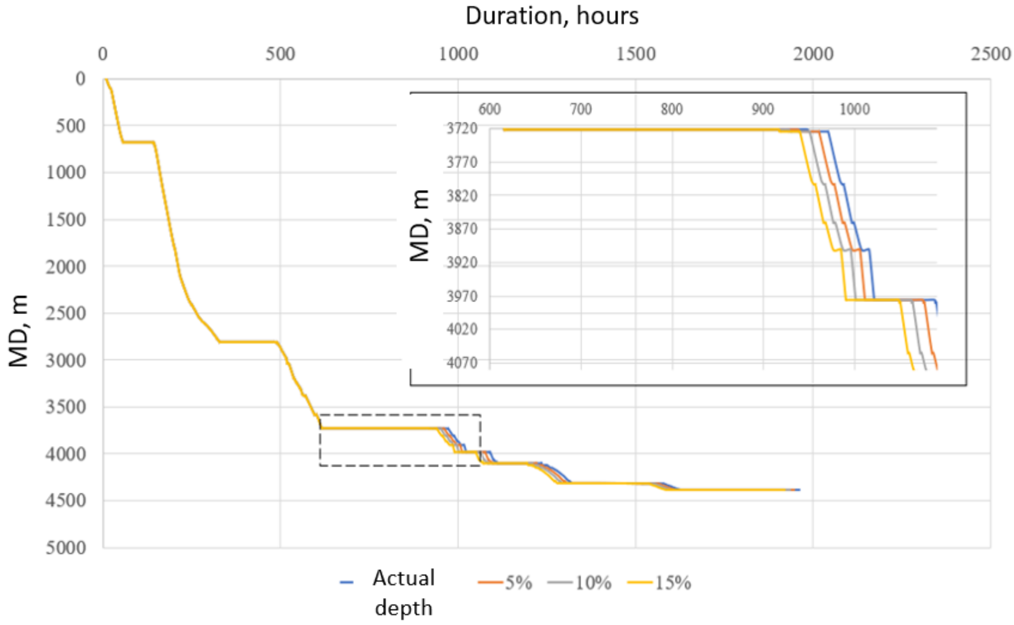

Figure 60: Time-depth curve, taking into account the reduction of a single Hole Condition NPT event duration by 5, 10, 15%

4.10 Conclusions for Chapter 4

In this chapter, the procedure for creating a Lessons Learned report using the application was described for a particular OMV well for a hole condition problem.

Compared to historical reports, the generated report has more data completeness and is easier to use when designing a new well because of the keywords and information it contains.

Improved Lessons Learned reporting leads to better new well design, which reduces NPT risks and monetary/time costs.

Chapter 5 Conclusion

During the work on this Master's Thesis, main goal was accomplished which included investigating a way to automatically extract Lessons Learned and generate relevant reports out of drilling reports, such as DDRs.

To achieve this, several tasks were solved:

1. Existing drilling reports were analyzed based on their content, party in charge and path to the operator’s office. 4-digit coding was introduced, reflecting periodicity, job and information type, data type of the report, allowing to search for the proper report for different purposes easily;
2. Analysis of the existing procedure for investigating NPT at OMV was made, during which areas for potential improvement were highlighted;
3. Current Lessons Learned reporting process at OMV was analyzed extracting advantages and disadvantages that can be fixed in the future;
4. General recommendations to improve the Lessons Learned reporting at OMV were propose;
5. The recommendations were specified for the case of hole condition problems. This problem was selected as a result of an NPT analysis of OMV 52 wells;
6. An automated report generation system was developed which supports parts of the proposed procedure;
7. The procedure together with the automated Lessons Learned report generation system was testes on a real well. The comparison with historical reporting data showed that the process, if implemented, may increase quality of the data.

An important result of the Master's Thesis is the creation of mentioned automated report generation system which is a web application. This web application is:

– A handy tool for NPT statistics in the form of a dashboard and a register table;
– Proof of concept that Lessons Learned reports can be created automatically;
– A tool for generation and partial population of Lessons Learned reports;
– A tool that assists in inspecting sensor data by creating a workbook with preprocessed sensor data combined with activity descriptions from daily drilling reports.

The value of the work is increased quality of Lessons Learned reports. Revised structure of the Lessons Learned report and proposed mandatory fields depending on the type of problem will ensure efficient searches, by keyword, in the IDS database. The report content requirements will improve the quality of the information that will be the basis for justifying the expected risks when designing a new well.

Also, as the process is supported in automated way, it will reduce the psychological barrier for company employees by facilitating the process of creating a quality Lessons

Learned report. The drilling engineering community of the company will benefit from transparency of data, thus, increased awareness about best practices and lessons learned at the company.

In the future, if such process for generating Lessons Learned tickets is implemented, it may reduce NPT and associated costs due to the optimized well design which incorporated lessons taken from the previously drilled wells.

Appendix A Well construction reports

Report	Content	Code
Daily Drilling Report	Header. General Information. Operations Summary. Bit Records. Casing and Tubing Details. Cement Summary. Lithology. Mud Information. Loss Information. BHA Components. Survey. BOP Test Information. Personal on Board.	D - DRL/GEO - BHA/BOP/CAS/CEM/DD/FORM/KPI/MAT/MUD - ACT/COST/LAB/SUM/TEXT
Daily Geological Report	Geological Summary. Lithology. Liberated Gas. Mud and Formation Pressures. Formation Tops.	D – GEO - - SUM/TEXT
Drilling Fluid Daily Report (includes Waste Material Report)	Mud Volume. Circulation Data. Mud Properties/Specifications. Mud Products/Inventory. Solids Control Equipment. Treatment Remarks. Activity Remarks. Mud Volume Accounting. Solids Analysis. Rheology/Hydraulics. Cost.	D – DRL -MUD- COST/LAB/SUM
Mud Logging Daily Report	Gas readings (mud gas, gas peaks). Chromatographic analysis of gas content. Drilling parameters.	D – DRL – MLOG - LAB/SEN

Well construction reports

Report	Content	Code
Directional Drilling Daily Report	BHA. QHSE. MWD Personnel. Operations.	D – DRL – BHA/DD/HSE – ACT/SUM/TEXT
Actual Survey Report	Header. Inclination. Azimuth. MD. TVD. NS. EW DLS.	D – DRL – DD. – CALC/PLOT/SUM
Daily Cost Report	Tangible and Intangible Costs: Code, Description, Comments, and Cost.	D – DRL – MISC – COST
Completion Daily Report (during the completion phase)	Completion Services. Companies that performed Completion Services. Associated Daily Cost. 24 Hrs Summary. Current Operation. 24 Hrs Forecast. Activities in chronological order.	D – COM – CAS/DST – ACT/COST/SPECS
Casing/Tubing Tally	Recording measurements of casing/liner/tubing and accessories as it is run in the hole. OD. Weight/ft. Grade. Connection Type.	J – DRL – CAS – SPECS
Logging report	Well Sketch. Equipment Summary. Run Summary. Borehole fluids. Log curves. Calibration Report. Survey Record.	J – GEO – LOG – PLOT/SPECS/SCH
Coring report		J – GEO – COR
FIT report	Pressure vs. Time Plot. Mud density for FIT. The volume pumped—equivalent mud weight.	J – GEO – LOT – CALC/PLOT
Cementing Report	Cementing Slurry Design. Additives and Accessories. Mud Properties. Current	J – DRL – CEM – SUM

Report	Content	Code
	and Previous Hole/Casing Data.	
Materials and Logistics Report	Received Consumable Items Record.	J – DRL – MAT - SUM
DST report	General information about formation. Interval of testing. Test comments. Pressure summary. Pressure vs. Time Plot.	J – COM – DST – PLOT/TEXT/SUM
Well Control Report	If after a Well Control Incident: Wellbore schematic. Well control incident category. Operation with the course of events. Reason for events. Lessons Learned. Recommended actions. Direct and underlying causes.	O – DRL – PROB – CALC/TEXT/SCH
Bit Performance Report	Bit Type & Model. Footage. Time on Bottom. ROP. Bit Cost. Cost per foot drilled.	J – DRL – BHA/KPI – COST/SPECS/SUM
Seismic Report		J – GEO
HSE Report	Accident Details. Treatment Received by the Victim.	J – HSE
Equipment Failure Report	Equipment Data. Equipment History. Event Data.	O – DRL/GEO/COM – PROB - TEXT
End of Well Report	Well Summary. Wellbore Diagram. Well Path. Operation Summary. Comparison of Planned and Actual Operation. Lessons	E – COM/DRL/HSE – COR/FORM /LOG/LOT/SEI/BHA/BOP/CAS/CEM/DD/MAT/MISC /MLOG/ MUD/PROB/KPI – ACT/CALC/COST/KPI/LAB/PLOT/SCH/SEN/SPECS TEXT

Report	Content	Code
	Learnt. Statistics. Time - Depth Chart. Cost – Depth Chart.	
Lessons Learned Report	Lessons Learned Tickets. Event Description.	E – DRL – KPI/PROB - TEXT
Contractor Performance Evaluation Report	Review of Contractor Performance (Equipment, Services, Personnel). Suggestions for improvement.	E – DRL – KPI – TEXT
BHA recordings	BHA length. Configuration. Connection. OD, ID.	E – DRL – BHA – SUM/SPECS
Bit recordings	Bit Runs Summary. Dull Grading. Running Environments.	E – DRL – BHA – SUM/SPECS
Final Drilling Fluids Report	Summary of Drilling Fluids.	E – DRL – MUD – SUM
Final Directional Drilling Report	QHSE. Well Overview. Performance Statistics. Surveys. Depth Control. Sensor Calibrations. BHA Performance Reports, Drilling Parameters Sheets, and Hydraulics.	E – DRL – BHA/DD – CALC/LAB/PLOT/SUM
Final Cementing Report	Sections Cementation Details.	E – DRL – CEM – CALC/PLOT/SUM
Final Geological Report	Geological Tops, Targets. Wellpath. Lithology. Samples and Cores. Hydrocarbon Shows. Logging. Temperature and Pressure Gradients.	E – GEO – COR/FORM/LOG – SUM

Appendix B Complications in 8.5′′ section

BHA	Operation	Depths, m	Complications	Mitigation
RSS BHA	Drilling	2808 - 2817	High torque and increased SPP	Ream back to casing shoe (2803 m) and down
		2817 - 2848	Stick slip	Adjust parameters
		3188 - 3235	Drilling break	SI, circulate
		3275 – 3288	Drilling break	SI, circulate
		3288 – 3418	Gas readings	Increase the mud weight with KCl from 1,09 SG – 1.12 SG
		3418 - 3575	Well slightly flowing	SI, bleed off pressure, weight up mud with KCL from 1, 15 SG to 1,18 SG
		3575 – 3722 (section TD)	Pack off at 3715 m	Increase MW with CaCO3, circulate to homogenize and adjust the mud weight to 1,25 SG.
	Pump out	3703 - 3695	Overpull to 20 tons	
	POOH in backreaming	3695 - 3410	Annulus overloading	
		3410 - 3050	Slightly overpull	
	Pump out	3050 - 2780		
	RIH	2780 - 3570	String held up	Circulation and try to ream down, observe pressure and torque spikes
	Ream down	3570 - 3585	Pressure and torque spikes were observed, again indication of pack off and not possible to go deeper	POOH to change BHA
	POOH to change BHA in backreaming	3585 - 3515		

Complications in 8.5’’ section

BHA	Operation	Depths, m	Complications	Mitigation
	POOH	3515 - surface		
Rotary BHA	RIH	Surface to 2803 m (previous casing shoe)	No problems	
		2803 - 3399	Held up with 10 t @ 2778m; 2848m, 2960m	Wash and ream down several times
		3399 - 3570		
	Ream down	3570 - 3597		Circulate and weight up mud with KCl from 1,26 SG to 1,29 SG
		3597 - 3611	Heavy reaming, several times stuck	
		3611 - 3653	Not possible to go deeper, high torque, overpull and several times stuck	Circulate 2 times bottoms up, observe large amount of cavings over shakers.
	POOH in back reaming	3653 - 3500		
	POOH	3500 – surface		
Logging BHA	RIH	Surface to 2803 m (previous casing shoe)		
	Logging in wash down mode	2803 – 3550	Torque and pressure spikes at 3194 m	
	POOH	3550 – surface		
Rotary BHA	RIH	Surface - 3554		
	Ream down	3554 – 3572		
		3572 – 3660	Overpull - 20t. Stuck several times. Tight points: 3643m,3646m, 3649m, 3652m 3654m, 3656m, 3659m Observed torque and pressure peaks and high amount of cavings and cavings over shakers.	Pump high viscous pill

BHA	Operation	Depths, m	Complications	Mitigation
		3660 to 3707	several tight spots: 3697m, TQ 38 KNm, overpull - 30 t, pressure peaks to 230bar, 3 times @ 3699m, TQ 38,4 KNm, overpull - 50 t, pressure peaks to 260 bar, @ 3699m, TQ 38,4 KNm, overpull - 50 t, pressure peaks to 260 bar,@ 3702m TQ 38,4 KNm, overpull - 45 t, pressure peaks to 250bar, @ 3700m TQ 38,3 KNm, overpull - 30 t, pressure peaks to 265bar, @ 3704m TQ 38,5 KNm, overpull - 43 t, pressure peaks to 260 bar, @ 3703m TQ 38,5 KNm, overpull - 34 t, pressure peaks to 261 bar.	
	Circulate 2x bottoms up	3707		
	Reaming	3707 – 3573		
		3573 – 3707	String stuck several times: @ 3686m TQ 36,4 KNm@ 3679m TQ 37,7 KNm; @ 3686m TQ 36,4 KNm; @ 3691m TQ 38,4 KNm.	
		3707 – 3716	String stuck during back reaming: @ 3706m TQ 38,7 KNm, overpull - 50 t.	
	Reaming	3716 – 3698	High torque and stuck tendency	
	Reaming	3716 – 3722		
	Circulate 2 x B/U	3722		

Complications in 8.5′′ section

BHA	Operation	Depths, m	Complications	Mitigation
	Wiper trip: ream out	3722 – 3485	Held up on several intervals: f/ 3485m to 3575m and 3590m to 3609m	Circulate B/U and pump 10m^3 HV pill.
	Wiper trip in back reaming	3722 – 3550		
	RIH dry	3550 - 3680	Several intervals of held up: f/3550m to 3603m; f/3629m to 3653m; f/3667m to 3680m	
	Ream down	3680 – 3722		Pump 10m^3 HV pill
		3722 – 3480		
	POOH	3480 - surface		
Liner		RIH	Held up	Establish circulation & wash/ream down from 3655 m to 3720m. Pump 8 m^3 of lubrication pill.

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Acronyms

B/U	Bottoms up
BHA	Bottomhole assembly
CSV	Comma separated values (format)
DDR	Daily drilling report
DLS	Dogleg severity
EoWR	End of well report
FR	Flow rate
HV.	High viscous
ILT	Invisible lost time
KPI	Key performance indicator
LCM	Lost circulation material
LL.	Lessons Learned
LWD	Logging while drilling
MW.	Mud weight
MWD	Measurements while drilling
NPT	Non-productive time
OBM	Oil-based mud
P/U	Pick up
PDC	Polycrystalline Diamond Bit
POOH	Pull out of hole
RDF	Reservoir drill-in fluid
RIH	Run in hole
ROB	Rotating off bottom
ROP	Rate of penetration
RPM	Rotation per minute
RSS	Rotary steerable system
S/O	Slack off
SC	Service company
SI.	Shut in
SPP	Standpipe pressure

TFA	Total flow area
TQ	Torque
WBM	Water-based mud

Symbols

D_b	drill bit diameter	[inch]
v_n	velocity	[m/s]
$\Delta P_{Annulus}$	pressure loss in the annulus	[Pa]
ΔP_{BHA}	pressure loss in BHA	[Pa]
ΔP_{DS}	pressure loss along drill string	[Pa]
$\Delta p_b \ or \ \Delta P_{Bit}$	pressure loss on a bit	[Pa]
Δp_d	parasitic pressure loss	[Pa]
Δp_p	pump pressure	[Pa]
WOB	weight on bit	[lb-ft or N]
m	flow exponent	[dimensionless]
μ	friction coefficient	[dimensionless]
ρ	density	[kg/m^3]

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