



TELLUS RENKUM PROJECT

WELL ENGINEERING PROGRESS REPORT

**TELLUS
RENKUM B.V.**

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
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Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Contents

CONTENTS	3
TABLE OF FIGURES	5
ABBREVIATIONS	6
1 INTRODUCTION	8
1.1 PURPOSE OF THIS DOCUMENT.....	8
2 SOURCES AND REFERENCES	9
2.1 AVAILABLE DATA.....	10
2.1.1 Location.....	10
2.1.2 Subsurface data	11
2.1.3 Reservoir type	12
2.1.4 Drilling Target	13
2.1.5 Well Depth(s)	13
2.1.6 Desired production rate:	13
2.1.7 Downhole temperature.....	14
3 OFFSET REVIEW	15
3.1 OFFSET WELLS.....	16
4 DESIGN ASSUMPTIONS	17
4.1 WELL TRAJECTORY - TD AT 5500 MTVD.....	17
4.2 WELL TRAJECTORY - TD AT 7000 MTVD.....	18
4.3 CASING POINTS – TD AT 5500 M TVD	20
4.4 CASING POINTS – TD AT 7000 MTVD	22
4.5 CASING AND LINER SIZES	22
4.6 CAPACITY PRODUCTION WELL	24
4.7 ESP SELECTION.....	25
4.7.1 Deilir	25
4.7.2 Deilir update 11 December 2020.....	27
4.7.3 Baker Hughes	29
4.7.4 Iceland Drilling	31
4.7.5 ST1.....	31
4.7.6 Ross Drilling.....	31
4.7.7 Germany.....	31
4.8 WELLHEAD	33
4.9 INCLUDED IN COST ESTIMATE	35
4.10 EXCLUDED FROM COST ESTIMATE	35
4.11 MORE DETAIL REQUIRED.....	35
5 ESTIMATED DURATION	37

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

5.1	DRILLING COMPLEXITY INDEX	37
5.2	PLANNING FOR PRODUCER.....	38
5.3	RIG PERFORMANCE METRICS	38
5.4	TD GRAPH – TD T 5500 MTVD.....	40
5.5	TD GRAPH – TD AT 7000 MTVD.....	41
6	COST	42
6.1	COST ESTIMATE TER-GT WELLS - 5500 MTVD	42
6.2	COST ESTIMATE TER-GT WELLS - 7000 MTVD	42
6.3	INCLUDED.....	45
6.4	EXCLUDED	45
6.5	MORE DETAIL IS REQUIRED ON.....	45
7	RISKS & OPPORTUNITIES	46
7.1	OPPORTUNITIES.....	47
8	CONCLUSIONS & RECOMMENDATIONS	48
	APPENDIX 1: GEOLOGY IN OFFSET WELLS.....	49
	APPENDIX 2 –DETAILED PLANNING (PRODUCER) – 5500 M	51

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Table of Figures

Figure 2-1 Proposed drilling location.....	10
Figure 2-2 Data provided – Geology / Lithostratigraphy (Quickscan).....	11
Figure 2-3 Target depth determination.....	12
Figure 2-4 Quickscan with reservoir highlighted	13
Figure 3-1 Offset well area with red circles indicating distance from Parenco site	15
Figure 4-1 Directional plots for one well (initial trajectory)	17
Figure 4-2 Initial well trajectories for doublet	18
Figure 4-3 J-shape trajectories for 6000 mTV reservoir top	19
Figure 4-4 Optimised S-shaped trajectory options (15° and 20° sail angle)	20
Figure 4-5 Casing setting depths	21
Figure 4-6 Casing and Hole size selector	24
Figure 4-7 High Temperature ESP system	25
Figure 4-8 High Temperature ESP system details.....	26
Figure 4-9 Deilir information	26
Figure 4-10 High Temperature ESP system	27
Figure 4-11 The email message form Deilir	27
Figure 4-12 The ESP that was recommended by Deiler.....	28
Figure 4-13 Overview of the data on HT ESP systems on a Baker Hughes website	30
Figure 4-14 Example of line shaft pump (Goulds)	32
Figure 4-15 Surface drive motor for line shaft pump.....	33
Figure 4-16 Compensator op top of wellhead.....	34
Figure 5-1 Drilling Complexity Index	37
Figure 5-2 TD graph for producer (5500 mTVD).....	40
Figure 5-3 TD graph for producer (7000 mTVD).....	41
Figure 6-1 Overview of detailed cost sheet TER-GT-01 Producer (5500 mTVD)	43
Figure 6-2 Overview of detailed cost sheet TER-GT-01 Producer (7000 mTVD)	44

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Abbreviations

AHD	Along Hole Depth
ARBO wet	Arbeidsomstandigheden wet (Labour Law)
BARMM	Besluit Algemene Regels Milieu Mijnbouw
BOP	Blow Out Preventer
CBL	Cement Bond Log
DAGO	Dutch Association of Geothermal Operators
DLS	Dogleg severity (a measure of how fast directional changes are made)
Drilling Contractor	Contractor that owns and operates the rig
ERT	Emergency Response Team
ESP	Electric Submersible Pump
EZ	Ministry of Economic Affairs (Economische Zaken)
FIT	Formation Integrity Test
GL	Ground Level
HAZID	Hazard Identification
HPHT	High Pressure High Temperature
HSE	Health Safety & Environment
HSE-MS	HSE Management System
HSEQ	Health Safety Environment & Quality
HWDP	Heavyweight drill pipe
IWE	Independent Well Examiner
JRA	Job Risk Assessment
LCM	Lost Circulation Material
LSA	Low Specific Activity (presence of radioactivity)
MD	Measured Depth
MOC	Management of Change
MWD	Measurement While Drilling
NOGEPA	Nederlandse Olie en Gas Exploratie en Productie Associatie
NORM	Natural Occurring Radioactive Material
NAP	Normaal Amsterdams Peil (standard water table in the Netherlands)
NPT	Non-Productive Time (trouble time)
PJSM	Pre-Job Safety Meeting
PM	Project Manager
POA	Plan of action
QHSE	Quality, Health, Safety and Environment

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

QRA	Quantitative Risk Assessment
RA	Risk Assessment
RVO	Rijksdienst Voor Ondernemend Nederland
SCE	Safety Critical Element
SDE+	Subsidy programme for renewable energy projects (Stimulering Duurzame Energieproductie)
SDS (MSDS)	Chemical Safety Data Sheets
SIMOPS	Simultaneous Operations
SMS	Safety Management System
SodM	Staatstoezicht op de Mijnen
SS-HSEC	Site Specific HSE Case
TRA	Task Risk Assessment
TVD	True Vertical Depth
UDG	Ultra Diepe Geothermie
VG	Safety & Health (Veiligheid & Gezondheid)
VG Document	HSE document (bridging document)
WWS	Wire wrapped screens
AHD	Along Hole Depth

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

1 Introduction

1.1 Purpose of this document

In 2017 the so-called 'Green Deal Ultradiepe Geothermie' was signed by the Dutch Ministry of Economic Affairs and Climate (EZK), the Ministry of Infrastructure and Environment (I en W), EBN (Energie Beheer Nederland), TNO (Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek) and a group of seven consortia with reputable Dutch (industrial) companies.

Tellus Renkum BV is one of the seven consortia developing its plans to drill deep geothermal doublets at suitable locations in the Netherlands. At the moment, from the original seven consortia, five remain. The GD UDG from 1 January 2020 continues under the name of Programma UDG (<https://www.ebn.nl/energietransitie/new-energy/programma-udg/>). While this UDG programme is hosted by EZK and EBN, additional support is provided for this project, e.g. for mapping the deep underground by doing seismic surveys (SCAN).

Tellus Renkum BV has requested WDC International BV to provide drilling related advice and support during the early planning phase of the geothermal wells for Tellus Renkum. The planned doublet is one of the candidates in the Netherlands that will be drilled under the Programma UDG umbrella.

The purpose of this document is to provide an overview of the work done by WDCI so far, including an initial cost estimate for the planned doublet.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

2 Sources and References

The data used to create this report was obtained from:

- Tellus Renkum Presentation on UDG project: **"Tellus Renkum BV Toelichting Aanvraag Opsporingsvergunning Aardwarmte – Renkum"**
- Tellus Renkum Excel sheet **"20191015_Financial Model Renkum v17_Vanguard Drilling"**
- NLOG website (e.g., offset well review data)
- **Google Earth Pro**
- **Experience** (cost elements for geothermal wells)
- **Assumptions** (see report)

The main data available at the time of writing this report (September 2020) is listed and clarified below. This data was used as the basis for all well engineering work.

All other data required for the preparation of a cost estimate for a geothermal doublet has been estimated or assumed, based on previous experience and on other recent drilling projects. This is further explained in chapter 4.

To be complete, and also for future reference, both known and unknown data at the time of preparing the report are listed in this report. Any subsequent versions of the report will be used to indicate also further cost developments, based on additional information becoming available.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

2.1 Available data

In this section (Figure 2-1) a listing is made of the available data that was used as the basis for this report and which was used to prepare a well design and a time- and cost estimate for the wells.

2.1.1 Location

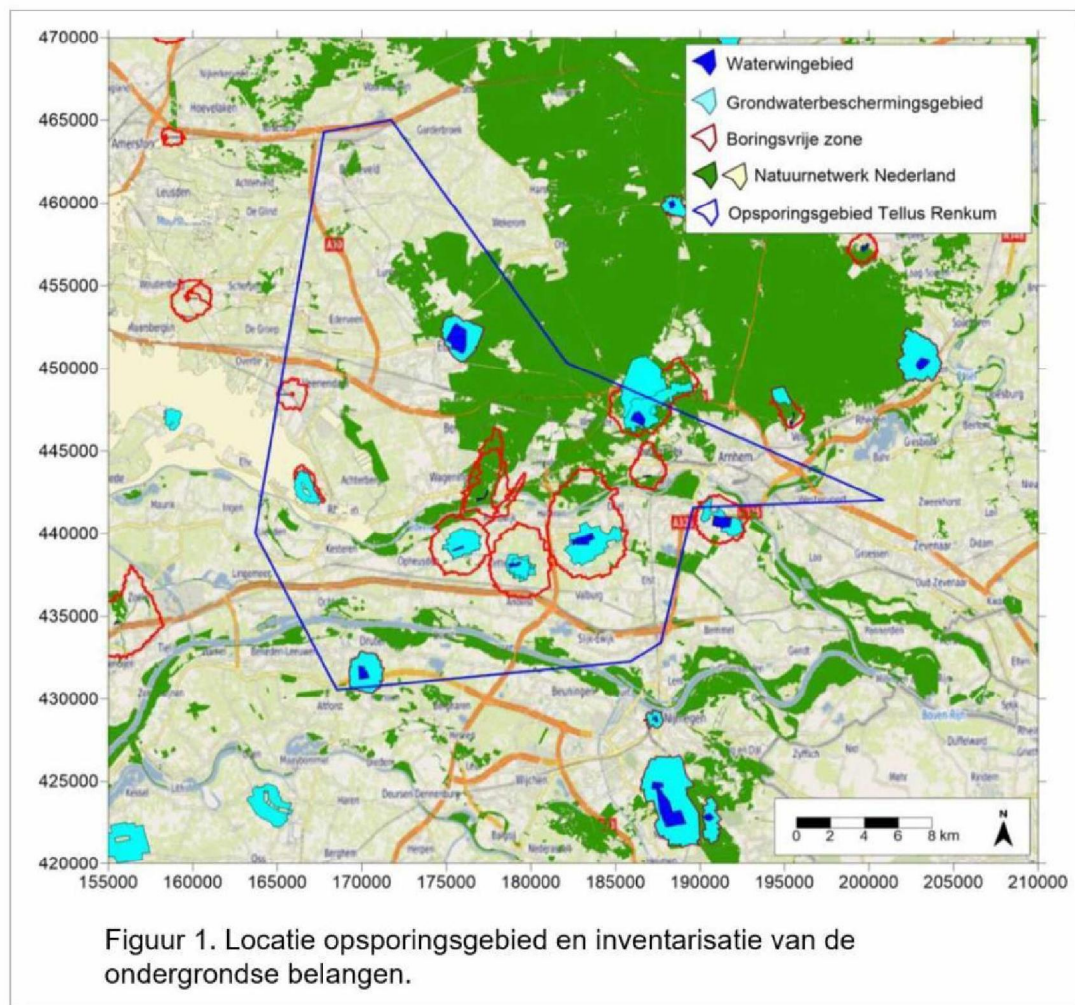


Figure 2-1 Proposed drilling location

The centre of gravity for this well engineering work is the location of the Smurfit Kappa Parencio paper mill in Renkum; this location is also used as for offset well selection.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

2.1.2 Subsurface data

The graph below was used as an indication of the lithostratigraphy at the drilling location Renkum. The purple line depicts the approximate drilling location, in relation to the main formation tops.

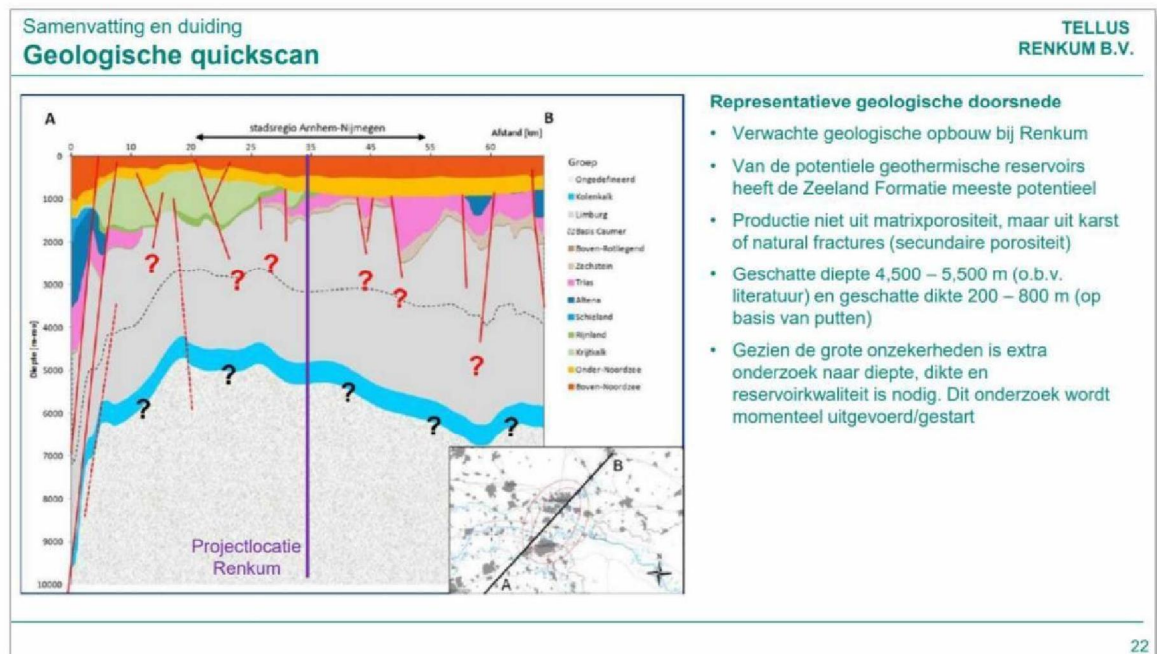


Figure 2-2 Data provided – Geology / Lithostratigraphy (Quickscan)

As stated in the text above and based on information to date (not including the newly acquired 2D seismic from Q1 2020), the main drilling target is the Zeeland formation, and in the picture the Kolenkalk is indicated as the reservoir. Depth and thickness ranges are indicated in the text next to the quickscan picture in Figure 2-2.

This data was investigated further to ensure that the correct formation was assumed to be the reservoir and also to confirm the anticipated drilling depths.

In Figure 2-3, the red ovals indicate the Carboniferous and the Zeeland formation respectively. It can be seen that the Zeeland formation can be found at the bottom of the Carboniferous. In the Netherlands, the Kolenkalk is composed of the Zeeland formation, which in turn comprises the Goeree, Schouwen and Beveland members.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

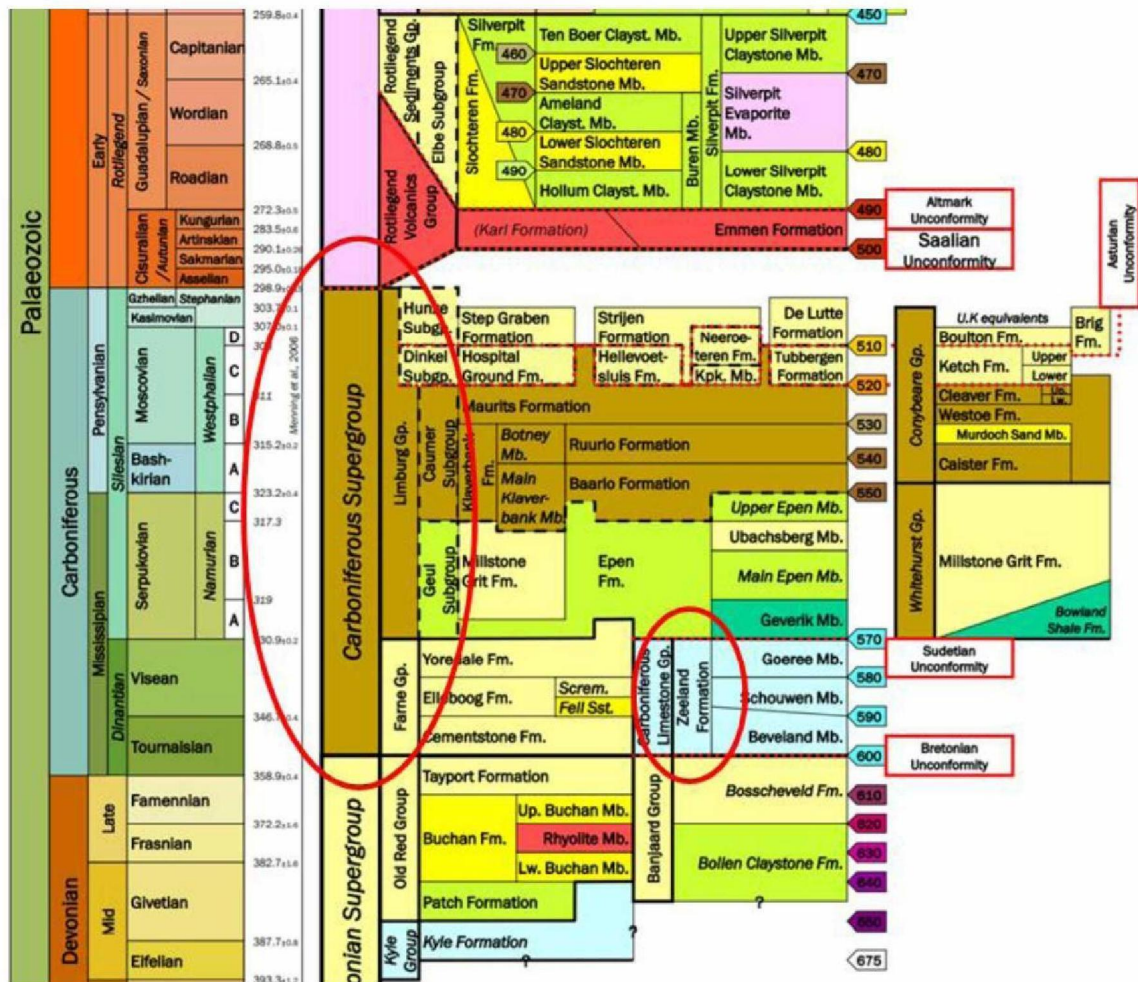


Figure 2-3 Target depth determination

2.1.3 Reservoir type

The producer well will produce the water from karsts and fracture (e.g. secondary porosity), rather than from a matrix porosity system. This has an impact on the drilling risks, as fractures and karsts are not easily closed off by the drilling solids, which can lead to major/total losses.

An additional risk could be that after such losses and the associated loss of hydrostatic head, potential gas can come into the wellbore and cause kicks. Also, such gas could consist of various types of gas, some of them toxic, such as H_2S ; this would influence the material selection of the well and the blow out prevention systems.

Further work on the contents of the reservoir is required to ensure that all options are covered in the well design and the drilling operations.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

2.1.4 Drilling Target

In order to have sufficient definition of the reservoir depth and the targets that are to be drilled, the provided depth map was used, which has a rough depth scale. It was assumed that the target reservoir is the whole of the Kolenkalk, as indicated in the map, and the applicable depths were taken from the accompanying text in Figure 2-2.

The depth data in the text (4500-5500 m) in Figure 2-2 more or less correlated with the depths in the picture and to clarify this, an annotated version was made of this picture, see Figure 2-4 below.

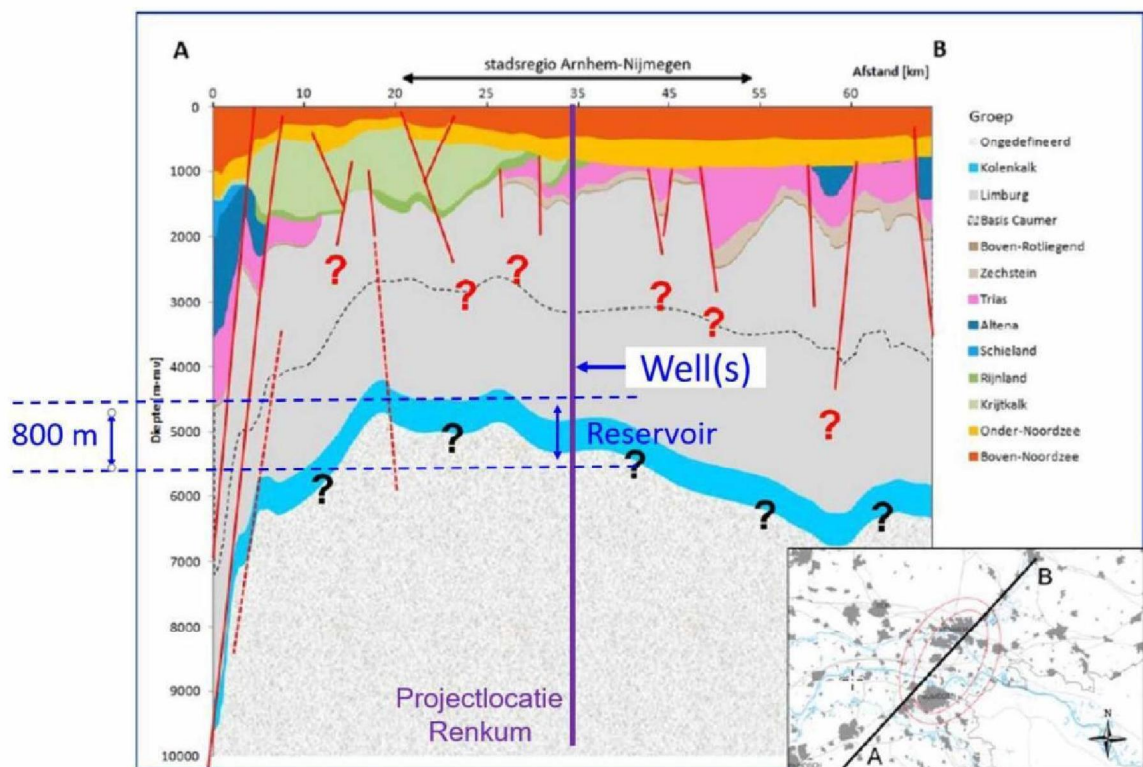


Figure 2-4 Quickscan with reservoir highlighted

2.1.5 Well Depth(s)

For the wells to be drilled, it was assumed that the final depth TVD for the wells was 5500 m plus a few meters for debris or logging pocket.

With the well trajectories that were used (see also chapter 4), the along hole depths were calculated, so that these could be used to determine drilling time and cost.

2.1.6 Desired production rate:

A production flow rate of 300 m³/hr was taken from the Tellus Renkum spreadsheet (20191015_Financial Model Renkum v17_Vanguard Drilling).

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

2.1.7 Downhole temperature

A key factor playing a role in the well design is the temperature of the water in the reservoir. This will have an effect on:

- Mud selection
- Drilling and logging tools
- Casing design
- Casing design verification software
- Wellhead design
- Pump design
- Pump driving mechanism design
- Materials
- Cement
- Drilling practices
- Preventive measures regarding safety of personnel

The temperature of the reservoir water was assumed at 170 deg C, which was also taken from the Tellus Renkum spreadsheet (20191015_Financial Model Renkum v17_Vanguard Drilling).

For the purpose of this report, all materials are assumed to be available for the planned operations.

The result of the high temperature is that the casing design will require highly competent software, such as Wellcat, to ensure that the effect of temperature on the casing strenghts is incorporated in the design.

Wellcat, or equivalent software, is very pricey and it takes considerable time to load all the welldata into the model (three full days or more is not exceptional).

Wellcat is considered to be the best programme in the market to verify casing design for HT wells and it is used by renowned oil companies like Shell.

The outcome of the Wellcat work may point to heavier casings, as the higher temperatures will cause greater strains on the casing, which means they may fail under production conditions.

The Wellcat work will have to be done by an engineer with access to Wellcat, or with a Wellcat license; license cost is appr 60-100 k per year.

So a cost reservation was also made for the use of the software (and the engineer).

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

3 Offset review

The NLOG database was used to provide information regarding the wells that have been drilled in the Renkum area. An offset well review was done on the wells closest to Renkum, whereby a number of circles was drawn on the map, see Figure 3-1. The most relevant wells are mostly the closest wells and the wells within the 15 and the 25 km radius from the Parenco site were examined.



Figure 3-1 Offset well area with red circles indicating distance from Parenco site

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

3.1 Offset wells

Offset wells that are found in the Renkum area are:

Abbreviation	Name	Year	Depth
<u>15 km radius:</u>			
AHM-01	(Arnhem-01)	1944	662m
NVG-01	(Nijmegen-Valburg-1)	1968	1277m
<u>25 km radius):</u>			
BNV-01	(Barneveld-01)	1971	1310m
SNM-GT-01	(Geoth well – Sanadome-GT-01)	1994	759m
ALT-01	(Altforst-01)	1944	654m
MSB-01	(Maasbommel-01)	1950	1713m
MSB-02	(Maasbommel-02)	1953	1278m

The available data for the offset wells in NLOG (<https://www.nlog.nl/keuzelijst-boringen>) was studied to determine if any learnings could be used for the preparation of the well engineering items for the Tellus Renkum doublet.

General findings were that these offset wells are old and not very deep, although Maasbommel-02 has drilled into Ruurlo & Baarlo formations. As such they are not very useful for the purpose of this project; technology used is outdated (especially mud and directional drilling tools) and also the depths drilled are not representative for the planned High Temperature wells.

Further offset wells (literally) that could be used in case deemed useful are:

35 km radius (additional wells/backup)

BUM-01, VRK-01, ZST-01, ODK-01, VHZ-01, APN-01, APN-02, BKH-01, ZED-01, GND-01

> 35 km

ERM-01, EPE-01, JPE-01, LOM-02

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

4 Design Assumptions

To prepare a sufficiently robust well design and cost estimate for the two wells at this early stage, further definition, and validation of some of the data was required and hence a number of assumptions was made to enable this. These assumptions are listed below.

4.1 Well trajectory - TD at 5500 mTVD

Given the early stage of the project and to allow the generation of provisional well (depth) data, a very simple well trajectory was prepared for both the producer and the injector well.

This allows for the determination of the along hole depths for the well sections and the associated casing lengths.

Base assumption was to use trajectories that are as simple as possible, and to have a horizontal separation of 1500 m between the targets (top reservoir) of both wells. The simplest and shortest trajectories that can achieve this are trajectories that go down vertically to approximately 1000 m and then build angle up to 12.5-degree inclination. This angle is then kept constant down to and in the reservoir.

The design for either of the wells then is as per pictures in Figure 4-1 below, indicating the simplest manner to drill to the target location; the 'vertical section' depicts the side view and the 'plot plan' represents the view from the top.

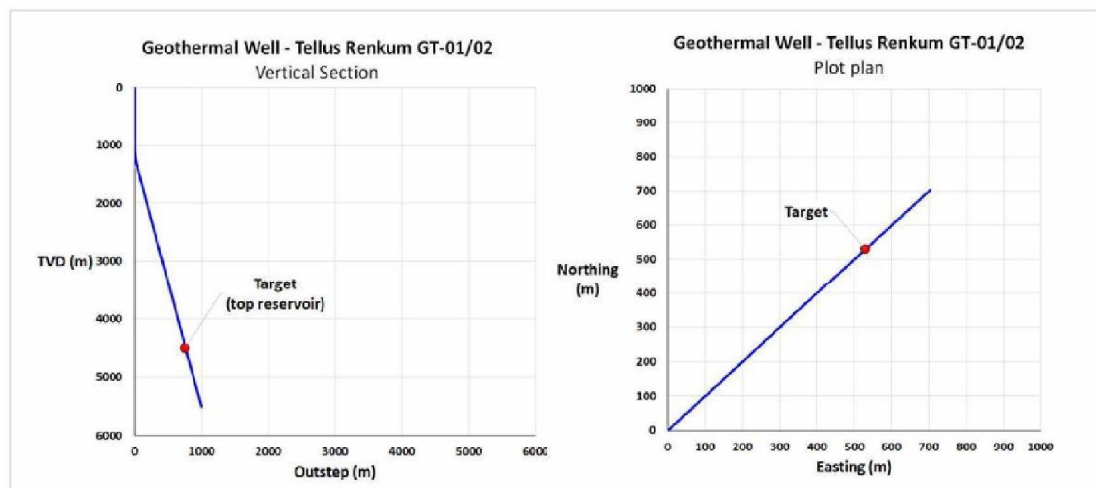


Figure 4-1 Directional plots for one well (initial trajectory)

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

To indicate the separation between the wells, the two trajectories have been plotted in one graph, which is shown in Figure 4-2.

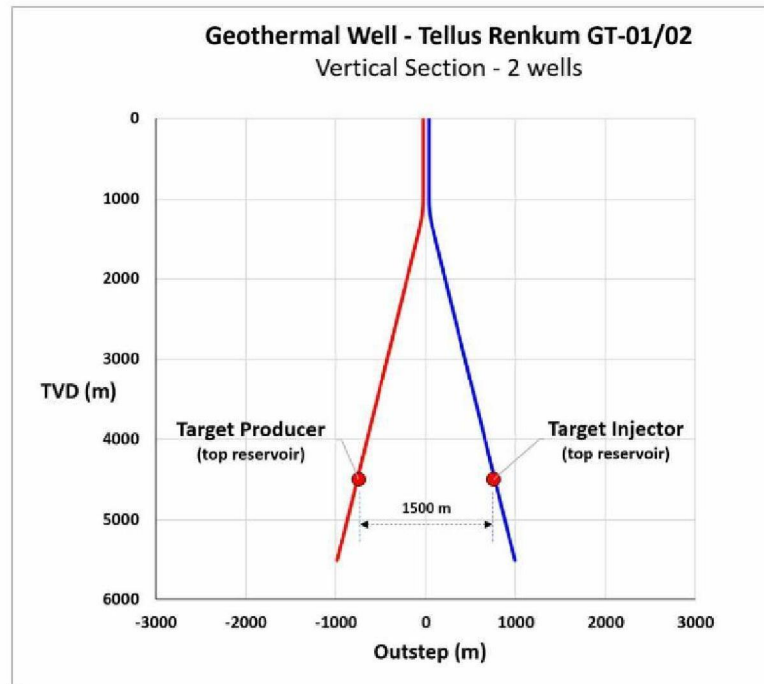


Figure 4-2 Initial well trajectories for doublet

A future update may be to adopt an S-shape trajectory, as this may be required to enable drilling at greater depths. At (very) high temperatures it may be impossible to use directional drilling tools, as the temperature rating may be a limiting factor for this application. Also, when drilling into 'the unknown', the risk of issues due to unforeseen circumstances is higher, hence the risk of losing tools in the well is greater than normal. In those circumstances it is wiser to use the simplest and cheapest tools available, i.e. rotary drilling equipment.

However, if only rotary drilling equipment can be used, it is wise to ensure that no directional drilling is required at the deeper sections of the well. This can be accomplished by drilling an S-shaped well, although this will mean that the along hole trajectory for both wells will be slightly longer. An S-shaped well will be the new base case in the next version of the report.

4.2 Well trajectory - TD at 7000 mTVD

Following the issue of the draft report on 6th October 2020, there was a request from Tellus Renkum to increase the well depth, as a result of an update in estimated reservoir depths. The result was that the anticipated top of the reservoir is now 6000 mTV, which value is now used for the further calculations for the doublet. Similar to the previous assumptions, the AH length of the drilled reservoir section is 1000 mAH.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

A number of scenarios were assessed, ranging from the simplest trajectories, as used before, to various iterations for an S-shaped well design. The latter is thought to be the wisest option for these complex wells, as it requires no steering (tools) in the deeper and hotter sections of the wells, which is also explained above in chapter 4.1.

The effect of the deeper reservoir top for simple J-shaped wells is as can be seen in Figure 4-3. The reason for the lower sail angle (8.8° rather than 12°) is the fact that a longer section is available to reach the 1500 m horizontal distance between the targets. The total well depth would increase considerably, from the previous 5620 to 7058 mAH.

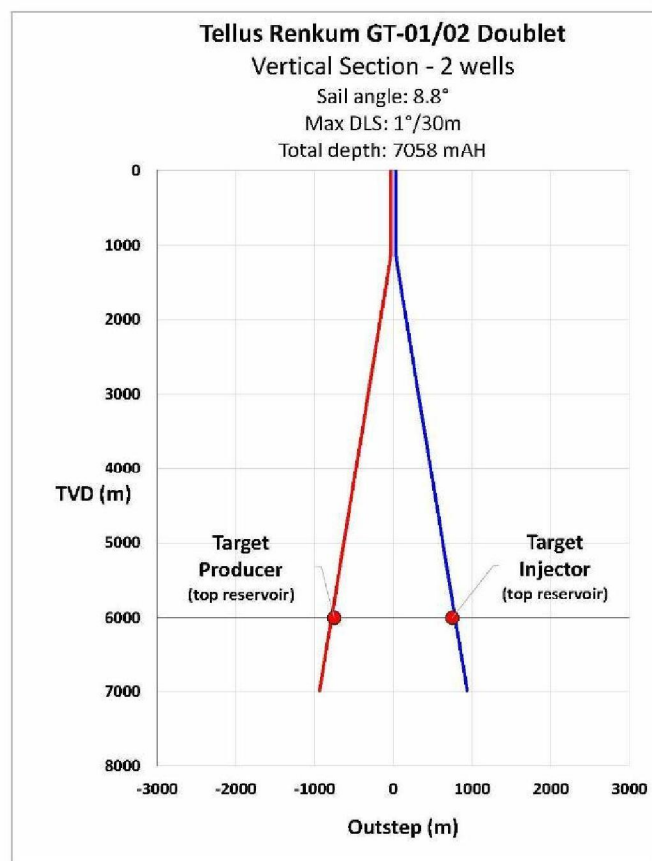


Figure 4-3 J-shape trajectories for 6000 mTV reservoir top

Taking into consideration that it is wise to drill the wells such that the lower part is vertical, the best strategy to be successful is to drill the wells S-shaped, with a low as possible (Dogleg Severity) DLS and Sail angle. The DLS is a measure of how fast directional changes are made in a well and is expressed in degrees per 30 m and the sail angle is the inclination in degrees for the inclined section of the wells. A number of iterations have been made, and the optimal solution for the trajectories is as shown in Figure 4-4.

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

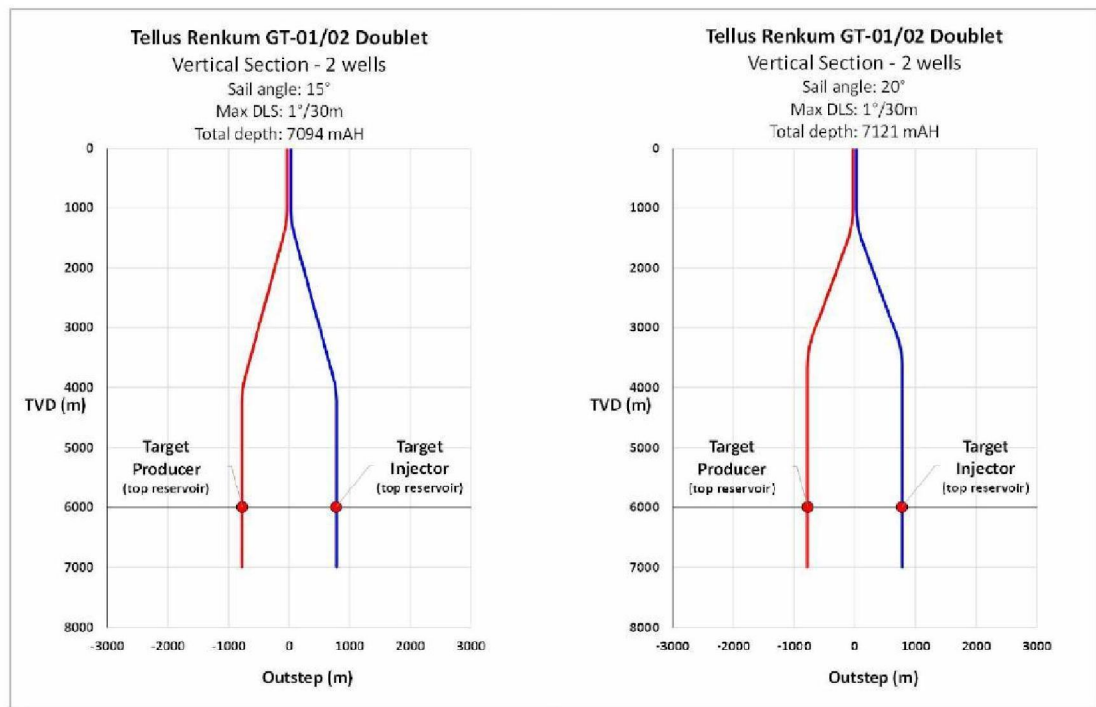


Figure 4-4 Optimised S-shaped trajectory options (15° and 20° sail angle)

As can be seen above, the horizontal separation between the wells is achieved at a much shallower depth (approx 4150 and 3640 mTVD respectively for the two options), after which the wells are vertical to final TD. Although the 15° sail angle option looks more benign, it may be more difficult to accomplish, as it means that the inclination needs to be reduced from 15° to 0° fairly deep in the well. This is likely to be more difficult than at a shallower depths, due to increased hardness of the formation and a potentially lower responsiveness of steering equipment as a result of higher temperatures and a longer drillstring (spring effect).

For the purpose of this report however, the well trajectory with the 15° inclination is selected, as it reduces friction in the buildup and dropdown sections of the well, and also the effect of the 20° inclination alternative is not major, with only 27 m extra to be drilled.

4.3 Casing points – TD at 5500 m TVD

Looking at the total depth of the well, and the anticipated geological formations, a likely scenario regarding casing / liner setting depths will be as depicted on Fig 4.3.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

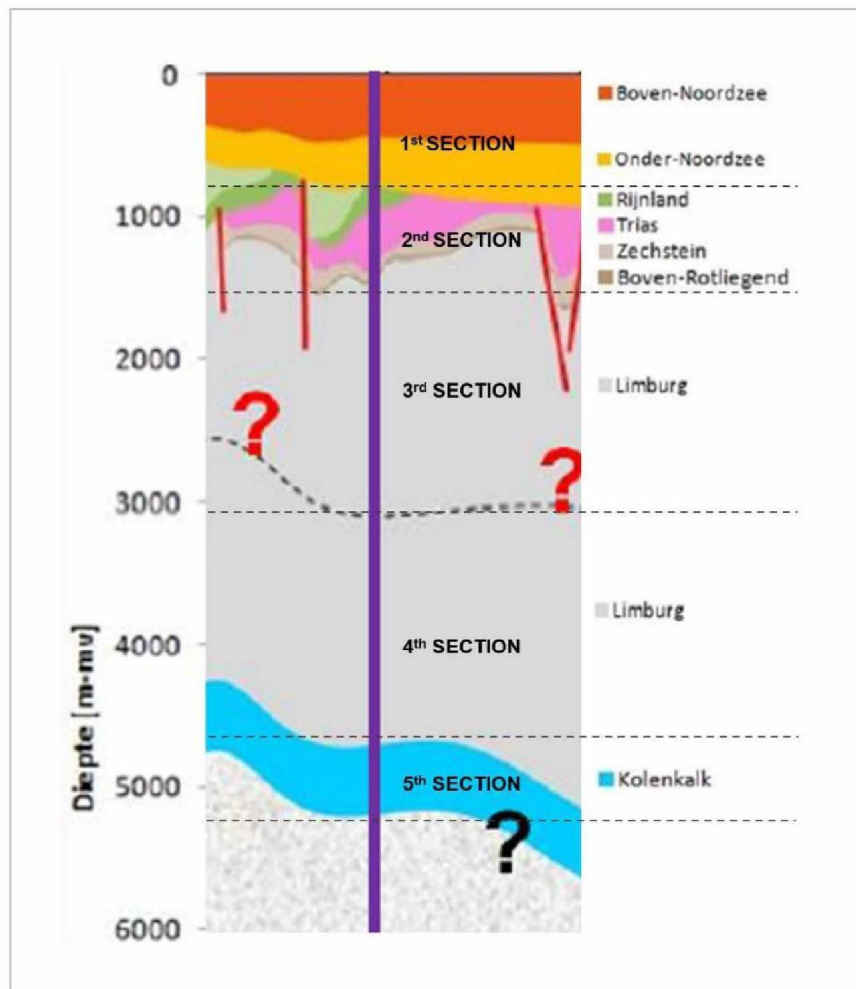


Figure 4-5 Casing setting depths

In the 1st section, the North Sea formation is drilled to a depth of approximately 1000 m. This will case off the relatively soft North Sea clays and sands, so that the well is kept open and also it will provide a good basis for the installation of the BOPs.

The 2nd section will be drilled through the Rijnland (KN) (Holland-KNGL/Vlieland-KNN), Trias and Upper Rotliegend (RO: ROCL-Silverpit & ROSL- Slochteren) into the Limburg (DC). Purpose is to case off the drilled formations and create a strong shoe to drill a long section through the Limburg formation.

The 3rd section will be drilled through the upper section of the Limburg formation. Purpose is to case off this competent formation, but also to create a very strong shoe, which may be required to deal with possible issues when drilling into the reservoir prematurely while drilling the 4th section. Issues could be circulating out a high pressure gas kick, bullheading a gas kick, etc.

Without this casing shoe, drilling into the reservoir prematurely would most likely be a scenario that cannot be handled by the shallower shoe and formations. Further detailed design work will

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

test this scenario and as a result this shoe may have to be set deeper than assumed in this report. This should not have a major impact on the planned timings and cost.

The 4th section drills the remainder of the Limburg and places the shoe just above the reservoir. Drilling into the reservoir prematurely can be handled by the shoe of the 3rd section. Once the 4th section has been cased off and cemented, this should create a very competent 'pressure vessel', which is required to deal with any high pressure kicks, containing a range of possible fluids (gases / liquids), but also losses situations can occur.

The 5th section is the reservoir section and it drills through the reservoir until a potentially good reservoir has been established.

In order to validate some of the casing points, offset wells were checked (NLOG), as this is the best confirmation of using the best assumptions.

Taking all of the above into consideration, the assumed casing points are:

- Chalk: 1000 m TV 1000 mAH
- Zechstein: 2000 m TV 2020 mAH
- Intermediate: 3000 mTV 3040 mAH
- Above reservoir: 4500 mTV 4600 mAH
- TD (max): 5500 mTV 5620 mAH

4.4 Casing points – TD at 7000 mTVD

With the new trajectories, as described in 4.2 above (15° sail angle and 1° DLS) , and assuming the well can still be drilled in five sections, the casing points have been recalculated.

The result is shown below.

- Chalk: 1000 m TV 1000 mAH (AH/TV depths unchanged)
- Zechstein: 2000 m TV 2025 mAH (AH depth increase)
- Intermediate: 3724 mTV 3810 mAH (AH depth increase)
- Above reservoir: 5500 mTV 5595 mAH (AH and TV depth increase)
- TD (max): 7000 mTV 7094 mAH (AH and TV depth increase)

Note: It has to be stressed that drilling to these depths is a tremendous challenge due to formation hardness, high temperatures and unknown composition of reservoir content. This will be reflected in the drilling time estimations.

4.5 Casing and Liner sizes

At this moment (September 2020), there are still several options open regarding casing sizes that can be used for the producer and injector. Decision drivers are:

- Reservoir size
- Completion type/size

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

- ESP size (if ESP an be used)
- Anticipated flowrates
- Flow restrictions
- Availability of OCTG (casing/liner sizes)
- Corrosion/erosion measures
- Strength of casing/liner
- HPHT load cases

For the purpose of this report (5 sections) it has been assumed that a reservoir section of 8 ½" is assumed.

Depending on the anticipated flow characteristics of the well, a reservoir hole size can be selected. This can be done at a later stage, however this may have an effect on the required hole size through through the reservoir.

There are many other items that need to be addressed in order to carry out a casing design that is suitable for these wells. Items such as reservoir fluid characteristics, cement quality requirements, testing requirements, protection of shallower layers, corrosion inhibition, design life, etc, etc, all need to be incorporated in a design.

Hence for now, a fairly simple design has been selected, whereby the reservoir section is 8 ½" and shallower casings/liners are selected with a view to ensure that a logical sequence of hole sizes and casings is used for the preparation of a time and cost estimate for this doublet.

A proper casing design will require considerable engineering input and the use of appropriate software, particularly Wellcat. This software is designed to incorporate the effect of temperature in the casing design, which is a must when designing HPHT wells.

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

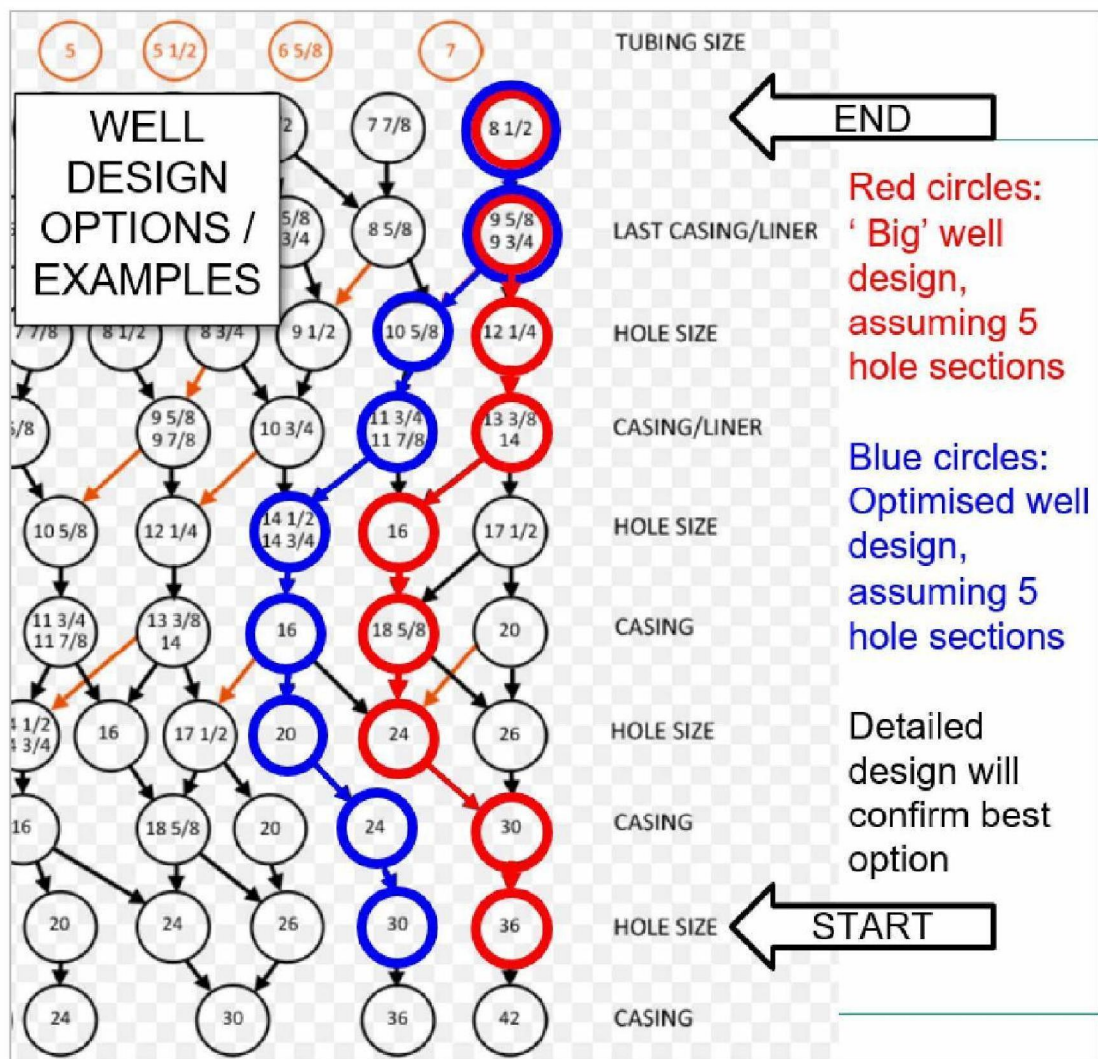


Figure 4-6 Casing and Hole size selector

As can be seen in Figure 4-6 Casing and Hole size selector, there is a number of options for the well design, if the reservoir section is assumed at 8 1/2". Two of those options are depicted in the graph, however more options are possible.

For the purpose of this early planning phase, the blue line in the picture was followed, i.e. the slimmer well design. Whether or not this is feasible, needs to be established later.

4.6 Capacity production well

The production well is expected to produce approximately 300 m3/hr. The effect on the well design may be that the pump system that is required may dictate certain decisions:

- The pump and motor (if used) needs to fit in the well (size)
- Other equipment required (cable) need to be accommodated as well

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

- Driving mechanism may impact surface equipment

4.7 ESP selection

The 'standard' geothermal well normally produces water by means of an ESP, which is hung off on a production string and powered by a motor. The maximum temperature for ESPs used in the Netherlands is in the region of 150 deg C and a standard ESP can therefore not be used for this project.

A number of alternatives were pursued: a high temperature ESP (if available) or an alternative system. Below an overview of the options considered.

4.7.1 Deilir

Contact was made with Iceland company Deilir who produce water from HT reservoir. Deilir is and Icelandic company, who are authorized agent for Novomet ESP pumps.

Novomet have produced many pumps for oil and gas, but also for geothermal wells. Some of them have a high temp rating (see Figure 4-7, Figure 4-8, Figure 4-9, Figure 4-10).

Novomet was contacted a number of times and a meeting was held with their main design engineer, to ascertain the capabilities of their pumps. The outcome was that the required flowrates could not be achieved with the pumps that were available.

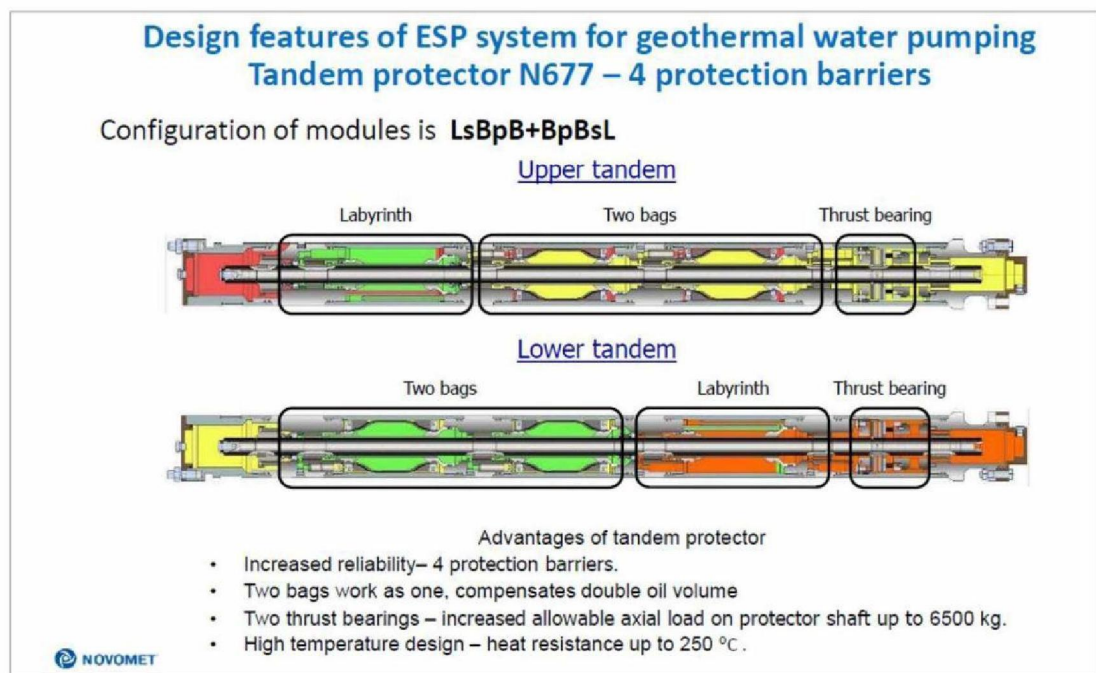


Figure 4-7 High Temperature ESP system

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Design features of ESP system for geothermal projects HT Motor solutions: epoxy stator, heat-resistant components, heat-resistant motor oil

Epoxy encapsulation vs. varnished type provides the following benefits:

- Complete sealing of stator winding provide no mechanical wear
- Decrease of motor winding overheating
- Increase of insulation resistance to 10 times
- Motor operation in wells with ambient temperature up to 392°F, max motor winding temperature – 428°F

Heat-resistant elements:

- AFLAS Rubber elements (O-rings, washers) up to 480°F
- RYTON Motor terminals up to 480°F
- Stator filling – high temperature compound up to 480°F
- Synthetic heat-resistant motor oil up to 480°F



Figure 4-8 High Temperature ESP system details

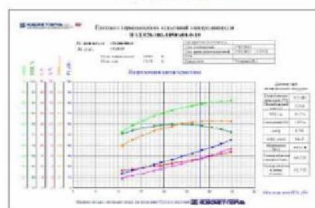
Motor bench tests

Every unit passes through acceptance tests of the motor assembly with a compensator and downhole sensor

The purpose of the test is to check compliance of the test sample with the technical specifications, in the conditions similar to the actual operating conditions.

Tests are performed on a specially designed bench with a load unit and cooling fluid supply system.

Determining operating parameters with different shaft loads.



Torque curve construction



Figure 4-9 Deilir information

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

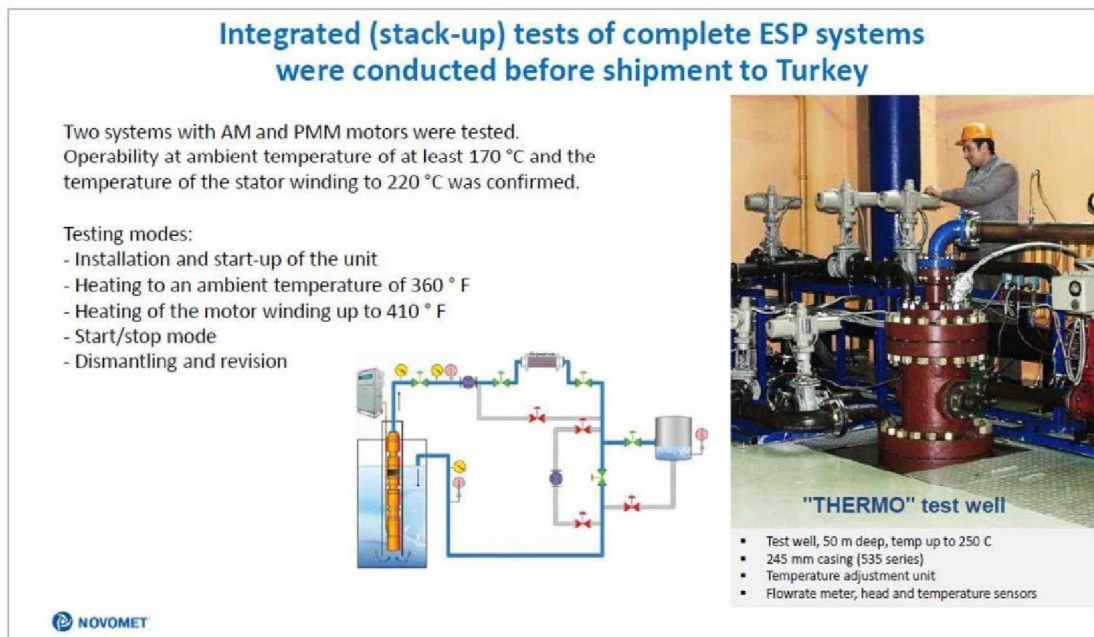


Figure 4-10 High Temperature ESP system

4.7.2 Deilir update 11 December 2020

Deilir has indicated that they have a downhole pump that is suitable for higher temperatures, in the range of 180-200°C and that can produce at 400 m3/hr (111 lt/sec).

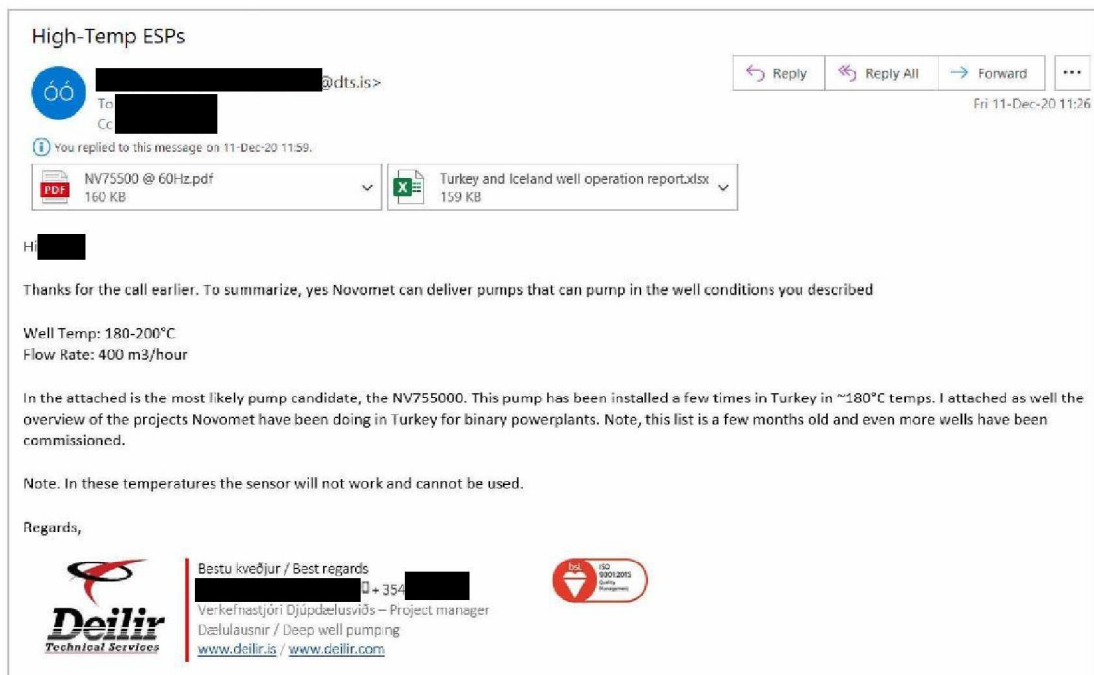


Figure 4-11 The email message form Deilir

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

In the message, they recommend the use of the 'NV755000' pump, a performance curve of which is displayed below in Figure 4-12. Further detailed investigation is required to assess the suitability and the quality of these pumps.

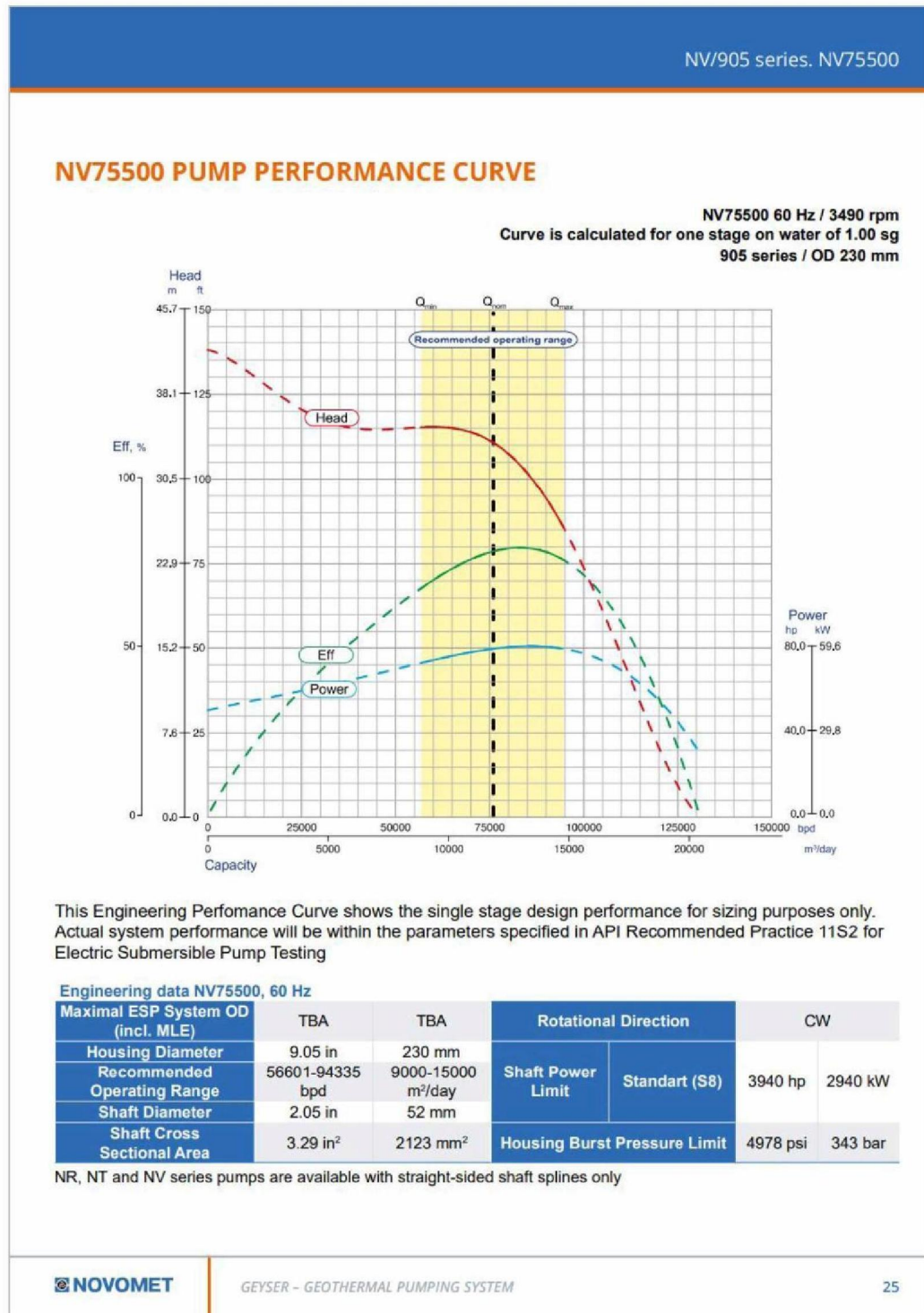


Figure 4-12 The ESP that was recommended by Deiler

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

4.7.3 Baker Hughes

In the Netherlands, Baker Hughes (BH) is the main provider for ESPs. As a result, they know the local geothermal market very well and have learned more lessons than any other service provider in the Netherlands.

At the moment, BH have no system readily available in the Netherlands, however they are working on an ESP that can work in temperatures up to 220 deg C.

On a Baker website mention is made of a system that is capable of handling water temperatures of up to 220°C. The link to the website is (see also Figure 4-13):

<https://www.bakerhughes.com/integrated-well-services/integrated-well-construction/production/artificial-lift/electrical-submersible-pumping-systems/pumps/centigrade-elevated-temperature-production-systems>

As BH is a reliable party for the provision of ESPs, they should be seriously considered for this project. Smaller companies could also design a suitable system, however there is a risk that the quality of such design is below par, due to the fact that they have smaller budgets available for research and QAQC.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Case study: Canada

CENTigrade ESP system designed for SAGD infill wells delivered record run time, saved \$750,000 USD

A major steam-assisted gravity drainage (SAGD) customer in Canada wanted to use electrical submersible pump (ESP) systems in infill wells with 7-in. casing and bottomhole temperatures up to 428°F (220°C).

Infill wells are drilled in SAGD fields between existing well pairs in order to maximize recovery from the reservoir.

Even though their temperatures are not as high as SAGD wells, infill wells are still hot enough to challenge ESP systems with conventional temperature ratings.

In the past, conventional ESP systems had operated for only a few months before failing. The operator had targeted run times over one year for these applications to justify these type wells.

The standard 500 series **CENTigrade™ elevated temperature production system** is too large to fit into 7-in. wells and the conventional 400 series ESP systems were not robust enough to handle the high-temperature environments.

Baker Hughes artificial lift experts developed an ESP system to handle temperatures up to 446°F (230°C). Its features include:

- The **CENTigrade 450XPV high-temperature motor** powering Baker Hughes compression pumps with high-temperature carbides
- High-temperature 400XPV seals with three metal bellows
- XPV motor lead extensions

High temperatures, along with steam, gas, abrasives, and low sub cool push the ESP systems to the limit. Separating gas using gas separators is not very effective in highly deviated wells and another solution was needed. Baker Hughes used the keyhole gas avoider to avoid the gas at the top of the casing and allow access to the wellbore fluid at the bottom into the pump.

The 400 series CENTigrade ESP systems proved to be a success with a total of 44 installs. The longest run achieved to date is 1,189 days and 56% of the systems exceed the one-year run time target.

Challenges

- Increase ESP system run lives in wells with bottomhole temperatures reaching 428°F (220°C)
- Determine different solution because the 7-in. casing with instrumentation in wellbore would not accommodate the typical 500 series CENTigrade ESP system

Results

- Developed a 400 series motor and ESP system rated to bottomhole temperatures up to 446°F (230°C)
- Successfully installed 44 units, exceeding the customer's run time target
- Reduced costs due to less frequent pulls and installs, and increased production uptime, saving the customer approximately \$750,000 USD to date

Figure 4-13 Overview of the data on HT ESP systems on a Baker Hughes website

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

4.7.4 *Iceland Drilling*

Iceland Drilling was also contacted for experiences, however the wells in Iceland are special, in that they are normally over-pressured (high pressure in reservoir) and do not require a pump to produce the water to surface.

4.7.5 *ST1*

ST1 in Sweden and Finland were contacted. They are reluctant in sharing info regarding their operations. Apparently, everyone that goes on location needs to sign an NDA, so this would require a considerable effort.

4.7.6 *Ross Drilling*

One Ross Drilling supervisor (who worked on the ST1 site) as well as the drilling manager were contacted. Both could not provide any detailed information on the pumps.

4.7.7 *Germany*

Several contacts in Germany were approached and it was observed that for wells with higher temperatures, in some cases line shaft pumps are used. These pumps are installed in the well and are driven by surface-installed motors.

This option can be investigated further, again focusing on temperature rating and also QAQC.

In fig 4.9 an example is shown of a line shaft pumping system; Figure 4-14 shows an example of a drive motor for a line shaft pump.

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

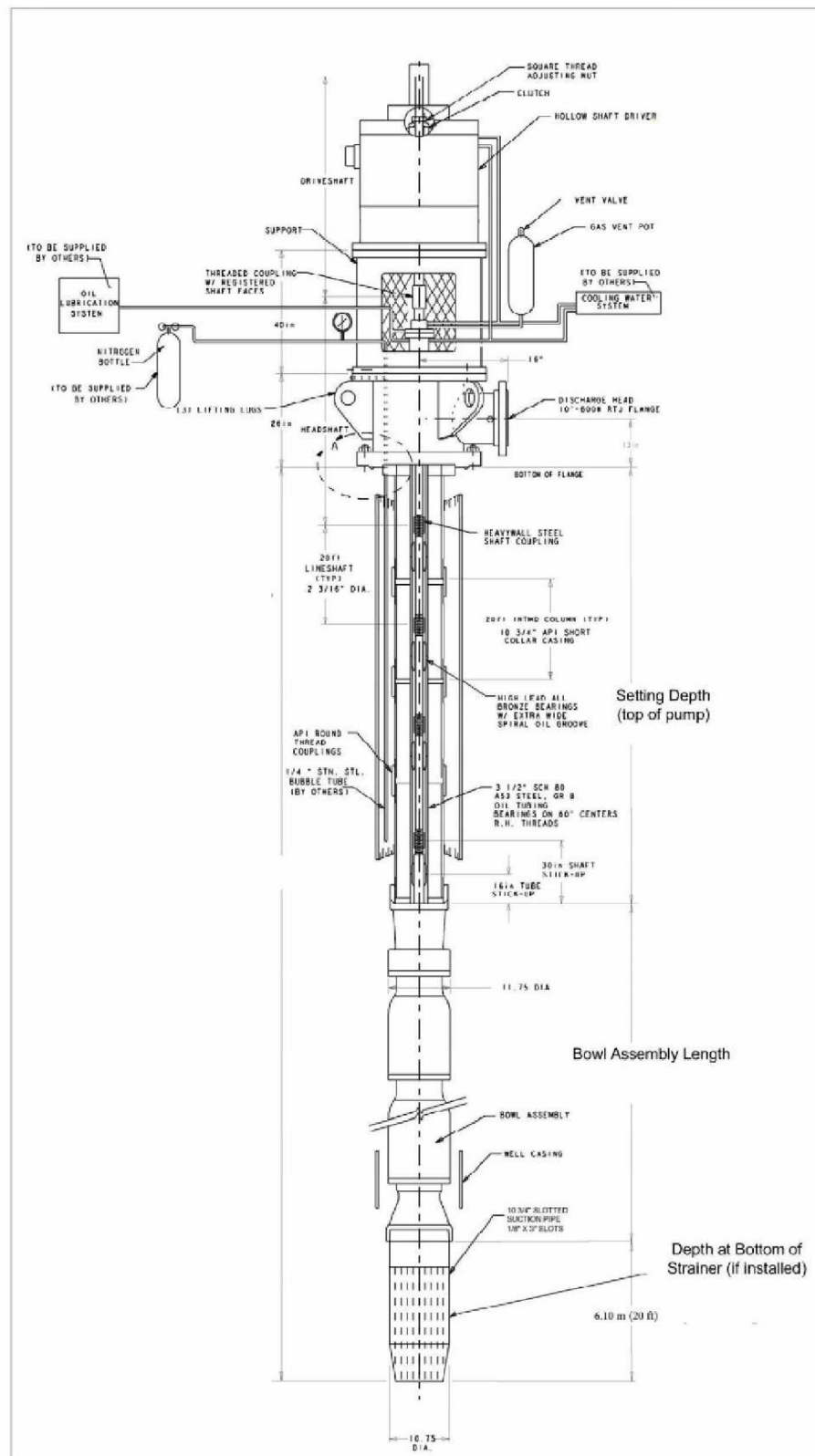


Figure 4-14 Example of line shaft pump (Goulds)

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

4.8 Wellhead



This setup for a line shaft pump will require a different setup for the surface equipment.

More detailed information and more accurate technical drawings regarding the line shaft pump and the surface drive system will be required to assess the full technical and financial impact of such a system.

Another additional item for the setup at surface may be the requirement for an extension or compensator sub, see also Figure 4-16

The idea of this compensator sub is to allow for expansion of the surface string, as a result of temperature fluctuations.

Also for this piece of equipment, the exact details of this setup and the cost will have to be investigated further in the future.

Figure 4-15 Surface drive motor for line shaft pump

Given the status of the information, a choice for the pumping system, and thus the wellhead setup cannot yet be made.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

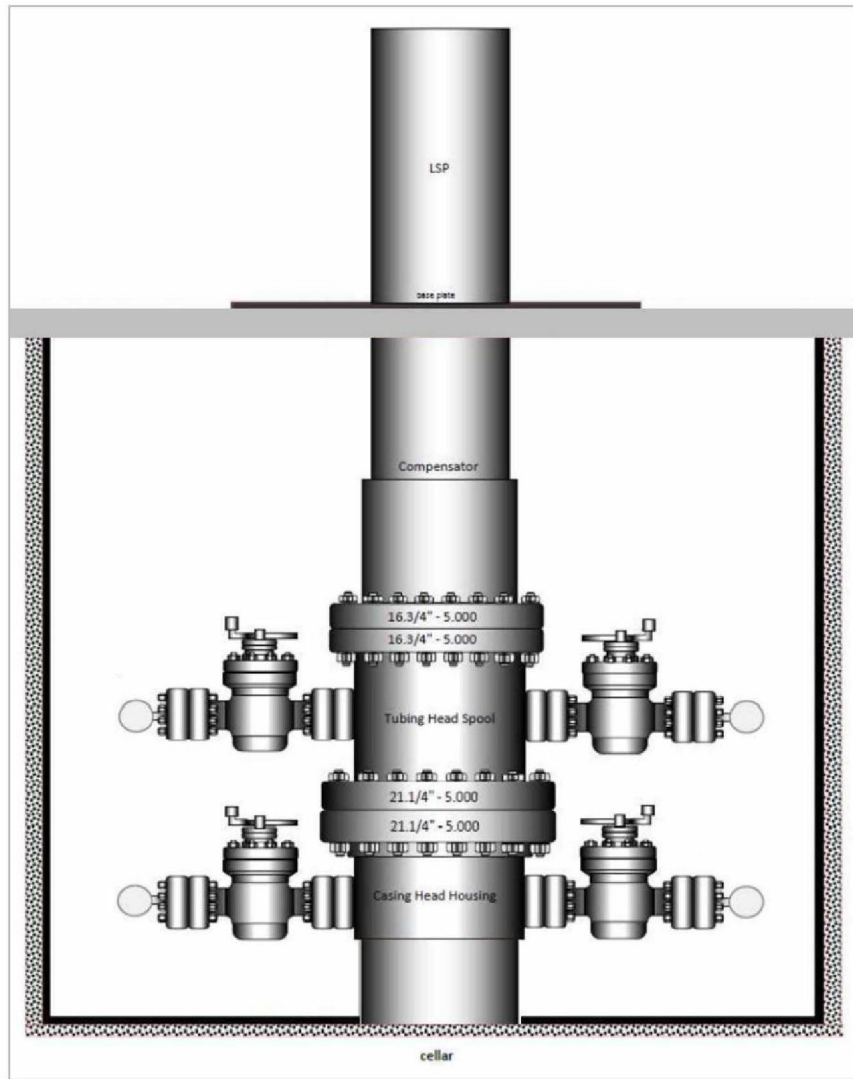


Figure 4-16 Compensator op top of wellhead

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

4.9 Included in cost estimate

- Appropriate time for rig commissioning has been included/considered, however this can be done during the rig mobilization to the location, so this time is not included as a rig day rate item. Only a cost provision for the actual commissioning cost (independent company) has been included. Reason is that the rig that is used for this project should only be accepted (for paying dayrate) after commissioning.
- Time for crew training has been added, however at this stage, this has also been planned at the beginning of the well, and as such it could be done during the rig mobilization, e.g. during the commissioning period, hence this will not have an effect on (rig) cost. It can be foreseen that the drilling contractor will request payment for the crews for attending the training, even if this is done during the mobilization period, so a cost element will be included for this item.

4.10 Excluded from cost estimate

- Surface Equipment
All of the surface equipment connected to the X-mas tree is excluded from the cost estimate (so surface equipment starts at the flow line).
- Conductor + installation
The conductor is best installed offline (without the rig on site). There are specialised companies that can be used to install the conductor.
- Upfront well design work
Not included in the cost of the well is the work required to design the well.

4.11 More detail required

- Special equipment
Deep wells may require special equipment; this depends on what the reservoir contains and how this needs to be managed. An example would be H₂S in the reservoir, which requires additional equipment and services, such as a Cascade system (breathing system for drill crew) or early kick detection (very sensitive Coriolis flowsensors).
- Testing duration
The exact duration of the test will probably be defined when drilling and approaching the reservoir, when more data is known on the geology and also the contents of the reservoir. This will have an effect on the well test programme, as permeability/skin and other metrics will define what is possible and required.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

For the purpose of this cost estimate, a test period of 14 days was included in the programme, excluding preparations.

- Logging requirements

Given the high temperatures of the subsurface, logging may be possible to a certain extend, however this requires considerable research into tool availability, logging requirements and logging options (can-cannot do).

It may be possible to test the logging tools that are planned to be used in an oven for a period of four weeks. This requires considerable planning and possibly an additional investment upfront.

For the purpose of this cost calculation, it has been assumed that all materials that are required to successfully drill the wells are available on the market.

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

5 Estimated duration

For the producer well, a detailed plan has been prepared, taking into consideration the knowns and the unknowns (assumptions) for the design of the wells and the execution of the drilling programmes.

5.1 Drilling Complexity Index

The complexity of the well normally has an impact on the risk profile, hence on well cost. To estimate the effect of this complexity on cost, a Well Complexity Index sheet was used, which points to 35% contingency that should be applied.

DRILLING COMPLEXITY INDEX						
Complexity Index: 88%			Complexity Rating: MEDIUM			Recommended Contingency: 35%
Complexity	Discipline	Subject	Selected value	Remarks	Score	Contingency
COMPLEXITY	Well Programme	New well / Re-entry ?	New Well			
		Surface or Subsea wellhead	Surface Wellhead			
		Field Experience and Logistics	Limited offset data			
		Logistics situation	Good Logistics			
	Rig Specifications	Rig Type	Land			
		Water Depth	Water Depth / 0 for Land			
		Rig Capability	At capacity (> 50% of rig's capacity is used)			
		Derrick Capacity	Derrick has sufficient capacity (LRD)			
		Month working since stacked	Oper. but new to fleet / Warm stacked			
		True Vertical Depth (m)	6500			
	Well Trajectory	Outstep (Horizontal Displacement)(m)	1000			
		Target - Measured Depth (m)	6620			
		Min Target Width (m)	100			
		Total planned dogleg	<30 degrees			
		3D trajectory?	No			
		Multiple Targets?	No			
		Max Hole Angle in well (degrees)	0 - 40			
	Pressures & Temperatures	Maximum Mud weight (sg - ppg)	1.92 - 2.1 (16 - 17.5)			
		Pressure Ramp ?	No pressure ramp			
		Maximum Mud Overbalance (bar - psi)	35 - 105 (500 - 1500)			
		Minimum Drilling Margin (sg - ppg)	1.6 - 2.0 (0.192 - 0.240)			
		Pore Pressure & Frac Gradient	Uncertain Pore pressure & Frac Gradient			
		Maximum Temperature	>204°C (>400°F)			
		Temperatures	Temperatures known			
	Casing Programme	Casing Program / number of strings	5 Strings / Liners			
		Casing configuration	4 Items(s)/point(s) selected. Press to change			
		Criticality of casing shoe depth	2 casing shoes			
	Formation Issues	Hole Stability	Certain problems			
		Formation Issues, please press blue arrow	> Single zone/section, moderate problems expected			
		Special considerations, pls press blue arrow	> Some special considerations apply			
	HSE Issues	Location and Discharges	Onshore Open pit			
		H2S	[Expected H2S] 10-15K BOP			
	TOTAL SCORE				84	
	Multiplication Factors	Water Depth Factor	Automatically calculated by program	1.00	84	
		Well type	Appraisal drilling	1.05	88	
	FINAL SCORE:				88	
	Project:	UDG Well	Status sheet:	COMPLETE		
	Customer:	Tellus Renkum	Date:	22th Sept 2020		

Figure 5-1 Drilling Complexity Index

Especially in the early stages, it is important to assume a reasonable contingency, as many unforeseen items will pop up in the planning phase while moving toward start of execution. A good example is the recent NOx disposition issues that have already stopped a number of drilling rigs.

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

This will be added to the risks register. A good solution in my opinion would be to use a rig that can run on grid power. This does mean that the location needs to be (made) suitable for such an application (power supply).

As stated before, the recommended contingency that should be applied to the cost is 35%. In reality this could be lower, but it could also be higher. The contingency can be lowered by working on the issues that have been identified. E.g.: if a better definition can be given regarding geology, better plans can be made regarding drilling strategy, mud type, drilling tools, drilling practices, crew training, etc, etc. This will then lower the chances of occurrence, but also the effect of the consequences, due to a better response.

Main items to cause additional cost are: the lack of detailed offset data, depth of the well, high temperatures and unknown formation behaviour (pore pressures, frac pressures and the fact that we will most likely be drilling into carsts and/or fractures).

5.2 Planning for Producer

The time planning model has assumed a fairly basic sequence of operations, based on what is seen as quite a normal performance of a standard land rig. The planning includes three phenomena that negatively affect rig performance:

1. In the recent years, most rigs have been upgraded with automated and more complex equipment, to improve safety, by means of a more hands-off approach. With increased automation, operational performance suffers somewhat, due to the fact that machines just cannot act as fast as humans. This is caused by the fact that all movements of machines are monitored by sensors, which have been programmed to only let machinery move when nothing is in the way. That means that equipment sometimes waits on other equipment to move out of the way, before it can perform its task. These interlocked systems are safer for humans, but slow down the rig, which has been incorporated in the time model.
2. Also, regular safety meetings are now pretty much standard in the operations, and companies take their time to do them during a range of operations. Also this has an impact on performance. A recent study on an offshore rig indicated that where a rig can pull pipe at 650 m/hr uninterrupted, the total time for tripping (pulling pipe out of the hole or installing pipe into the well) is more in the 200 m/hr range. Reason for the slower performance is: automation, safety meetings, additional circulating (pumping) and flow checks (monitor for gas influxes in the well).
3. The final issue with performance is the fact that many experienced engineers have left the industry during the recent downturn in the oil and gas business. Inexperienced people were hired to fill the gaps and as a result operations are a bit less smooth than before. This is also a reason for the more 'pronounced' safety meetings.

5.3 Rig performance metrics

- Tripping speed (in and out of the hole) has been assumed at 200 m/hr

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

- BOP test durations have 24 hrs (testing a HPHT BOP stack can be a bit more cumbersome)
- Time contingency 35 %
- Drilling the 10 5/8" section will be slower just above the reservoir due to the fact that the rock is hard and also, most likely, the last section has to be drilled carefully, to avoid drilling into the reservoir early. So ROP has been reduced from 7 & 7 to 4 resp 3 m/hr during the last 2 bit runs.
- An extra full roundtrip has been added in this section, to cater for an extra bit change, or for a motor/MWD failure (due to vibration).
- In the reservoir section, ROPs have been reduced from 5, 3 and 2 to resp 3, 2 and 1 m/hr. This is not an unrealistic assumption, as drilling can be really slow at these depths. This has meant that another bit trip had to be made to reach section TD.
- Consequence of the slower drilling and the extra roundtrip(s) is that more BOP tests need to be carried out, each adding a day to the schedule.
- Also 2 days have been added for rigging up additional equipment, related to drilling into the HPHT section. This may have to be done earlier if there is a risk of drilling into the reservoir while drilling that section.
- Time for rig commissioning has been included, but this may also be done in the rig move period, so this time is not included as extra cost
- Time for crew training has been added, however at this stage, this has been planned at the beginning of the well, and as such it could be done during the rig move, not having an effect on (rig) cost.
- Drilling the 10 5/8" section will be slower just above the reservoir due to the fact that the rock is hard and also, most likely, the last section has to be drilled carefully, to avoid drilling into the reservoir early. So ROP has been reduced from 7 & 7 to 4 resp 3 m/hr during the last 2 bit runs.
- An extra full roundtrip has been added in this section, to cater for an extra bit change, or for a motor/MWD failure (due to vibration).
- In the reservoir section, ROPs have been reduced from 5, 3 and 2 to resp 3, 2 and 1 m/hr. This is not an unrealistic assumption, as drilling can be really slow at these depths. This has meant that another bit trip had to be made to reach section TD.
- Time for rig commissioning has been included, but this may also be done in the rig move period, so this time is not included as extra cost

Project	TELL-GT-01/02	Document title	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

- Time for crew training has been added, however at this stage, this has been planned at the beginning of the well, and as such it could be done during the rig move, not having an effect on (rig) cost.
- Consequence of the slower drilling and the extra roundtrip(s) is that more BOP tests need to be carried out, each adding a day to the schedule.
- Also 2 days have been added for rigging up additional equipment, related to drilling into the HPHT section. This may have to be done earlier if there is a risk of drilling into the reservoir while drilling that section.

5.4 TD Graph – TD t 5500 mTVD

The estimated time to drill the producer is 191 days (see also Figure 5-2), including 35% contingency on time.

The time without contingency is 141 days.

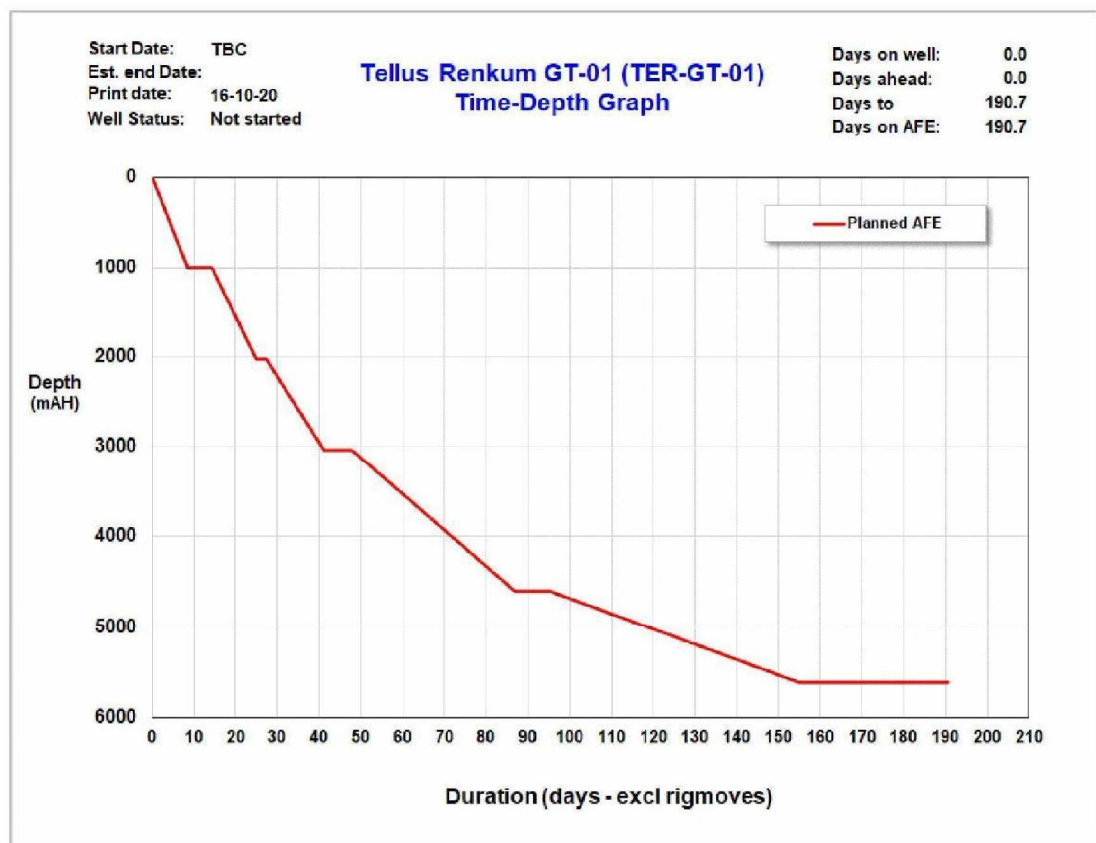


Figure 5-2 TD graph for producer (5500 mTVD)

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Also, for the time planning, this excludes:

- Surface Equipment
- Conductor + installation
- Upfront well design work

5.5 TD Graph – TD at 7000 mTVD

As can be seen in the TD graph in Figure 5-3, the impact of deepening the well so much is drastic. This is a known phenomena when drilling deep wells; the time it takes to drill such a well increases exponentially and so does the cost.

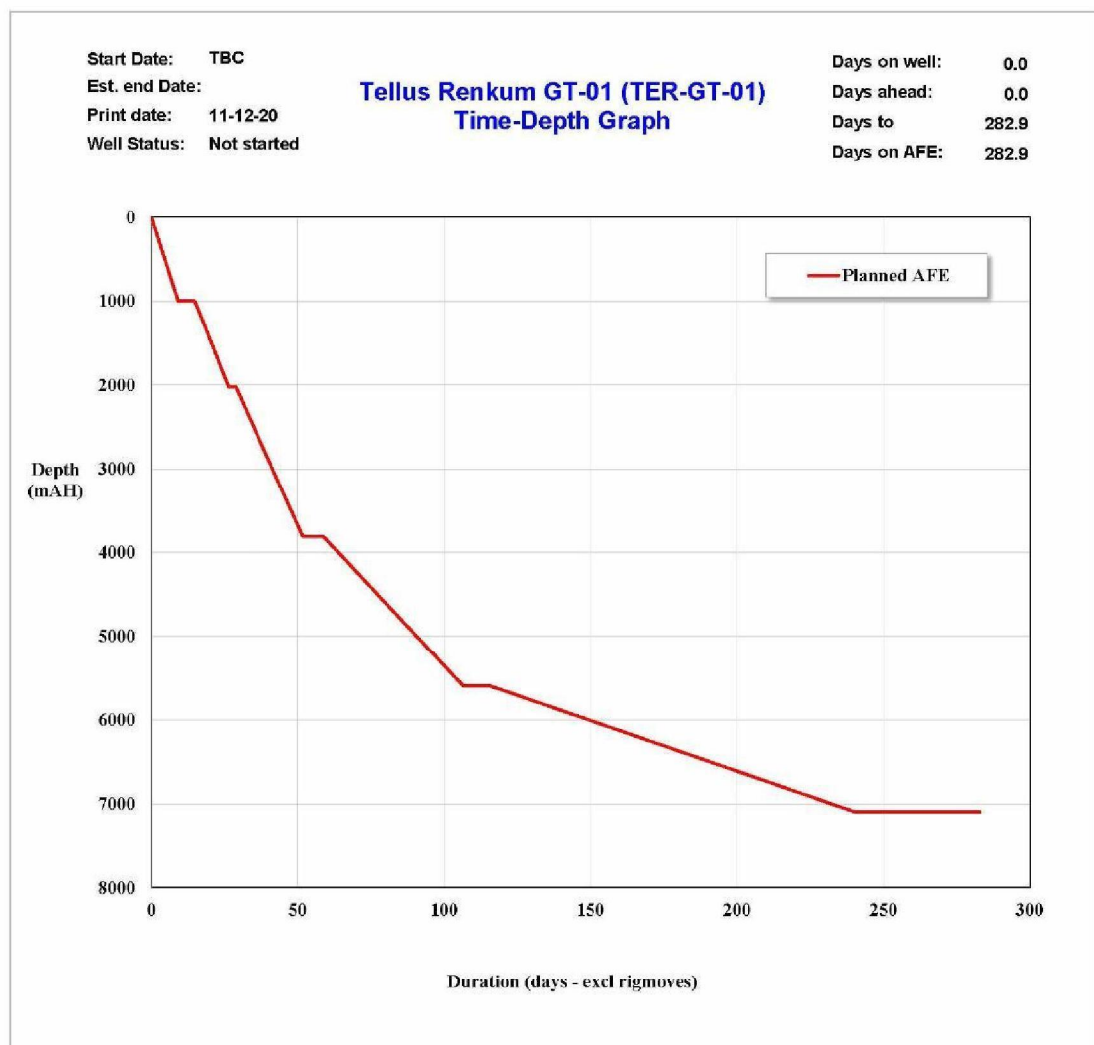


Figure 5-3 TD graph for producer (7000 mTVD)

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

6 Cost

6.1 Cost estimate TER-GT wells - 5500 mTVD

The cost estimate for the Tellus Renkum wells is

TER-GT-01 (Producer) :	22.1 m euro
TER-GT-02 (Injector):	<u>20.0 m euro</u>
TOTAL:	42.1 m euro

The detailed cost engineering work was only carried out for the producer well, and the cost for the injector well was assumed somewhat lower than the producer.

Reason for this approach is that the injector well requires a similar effort to drill and there should not be a great difference between the two wells.

The injector well could be somewhat smaller, due to the fact that no pump will be installed in the well. Also, the cost of the pump and the surface equipment required to drive the pump is not required. The total of this cost benefit is now estimated at appr 2 mln euro, which brings the cost of the injector well to 20 mln euro.

Further cost updates will be done, which may include changes to the trajectories and updates on the materials used.

6.2 Cost estimate TER-GT wells - 7000 mTVD

The cost estimate for the deeper version of the Tellus Renkum wells is:

TER-GT-01 (Producer) :	30.4 m euro
TER-GT-02 (Injector):	<u>28.2 m euro</u>
TOTAL:	58.6 m euro

As can be seen, the effect of the deepening of the well is considerable. This is caused by the fact that deeper formations are much harder and that round trips will take longer, which in turn also causes the need for more BOP tests.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

COST ESTIMATE - LEVEL 1 - Tellus Renkum GT-01 (TER-GT-01)								
No	Rig operations	Details	Days	Rig dayrate	Rig cost	Other	TOTAL	REMARKS
1	Reknow To TER-GT-01	And rig up on location				€ 300,000	€ 300,000	Lump Sum, low contingency
2	Drill 30" - 1000m		8.5	€ 30,000	€ 254,813		€ 254,813	
3	Run casing 24" - 995m		5.7	€ 30,000	€ 171,011		€ 171,011	
4	Drill 20" 2000m		10.9	€ 30,000	€ 325,845		€ 325,845	
5	Run casing 16" 2015m		2.5	€ 30,000	€ 74,503		€ 74,503	
6	Drill 14 1/2" - 3040m		13.6	€ 30,000	€ 408,670		€ 408,670	
7	Run liner 11 3/4" - 3039m		6.6	€ 30,000	€ 198,096		€ 198,096	
8	Drill 10 5/8" 4600m		39.2	€ 30,000	€ 1,175,541		€ 1,175,541	
9	Run liner 9 5/8" 4599m		8.5	€ 30,000	€ 254,796		€ 254,796	
10	Drill 8 1/2" 5620m		59.3	€ 30,000	€ 1,780,088		€ 1,780,088	
11	Logging Extended logs		5.4	€ 30,000	€ 162,000		€ 162,000	
12	Run WWS 7 5/8"		4.7	€ 30,000	€ 142,087		€ 142,087	
13	Testing Test well		23.5	€ 30,000	€ 705,375		€ 705,375	
14	Install DHP Complete well		2.3	€ 30,000	€ 67,500		€ 67,500	
Totals			190.7		€ 6,729,124	€ 300,000	€ 6,929,124	Total rig cost
				Contingency	35%	19%		
				Contingency cost	€ 2,002,044	€ 30,000	€ 2,032,044	Total Contingency - rig cost
No	Third party services, rentals & equipment (consumables)	Unit	Price/unit	Cost	Other	TOTAL	REMARKS	
1	Directional drilling - rentals	1	€ 965,000	€ 965,000		€ 965,000		
2	Directional drilling - services	1	€ 707,567	€ 707,567		€ 707,567		
3	Bits & Coring - materials (consumables)	1	€ 285,000	€ 285,000		€ 285,000		
4	Bits & Coring - services							
5	Hole openers, undersreamers							
6	Drilling & Compl fluids - materials/chemicals	1	€ 393,442	€ 393,442		€ 393,442		
7	Drilling & Compl fluids - services/engineering	1	€ 265,043	€ 265,043		€ 265,043		
8	Drilling & Compl fluids - solids control equipment	1	€ 180,000	€ 180,000		€ 180,000		
9	Waste Management Services/ waste cost - drilling	1	€ 345,000	€ 345,000		€ 345,000		
10	Waste Management Services/ waste cost - location							
11	Cementing services	1	€ 130,000	€ 130,000		€ 130,000		
12	Conductor/casing/liner running services (MIU)							
13	Electric Logging Services (formation evaluation)	1	€ 500,000	€ 500,000		€ 500,000		
14	Electric Logging Services (e.g. perforating)							
15	Slickline / wireline services							
16	Mud logging and geological services	1	€ 272,714	€ 272,714		€ 272,714		
17	Fishing, Milling, Cutting & Underreaming services							
18	Test Equipment Rentals	1	€ 400,000	€ 400,000		€ 400,000		
19	Testing supervision							
20	HP equipment rental (HP pump, HP test separator)	1	€ 529,307	€ 529,307		€ 529,307		
21	Wellhead Equipment & X-mas tree services	1	€ 40,000	€ 40,000		€ 40,000		
22	Downhole pump & accessories - RENTAL	1	€ 400,000	€ 400,000		€ 400,000		
23	Cranes and transport							
24	Mud cooler	1	€ 190,859	€ 190,859		€ 190,859		
25	Transformers, switchgear	190.7	€ 1,000	€ 190,671		€ 190,671		
Totals				€ 6,794,604		€ 6,794,604	Total 3rd party cost	
				Contingency	25.0%			
				Contingency cost	€ 1,448,651		€ 1,448,651	Total Contingency - 3rd party
No	Well materials	Unit	Price/unit	Cost	Other	TOTAL	REMARKS	
1	Conductor & accessories (materials)							
2	Casing 24"	1100	€ 350	€ 385,000		€ 385,000		
3	Liner 11 3/4"	2220	€ 200	€ 444,000		€ 444,000		
4	Liner 9 5/8"	1600	€ 150	€ 240,000		€ 240,000		
5	Liner 7"							
6	Blank pipe 7 5/8" for WWS	700	€ 110	€ 77,000		€ 77,000		
7	Liner hanger 11 3/4" - incl services	1	€ 250,000	€ 250,000		€ 250,000		
8	Liner hanger 9 5/8" - incl services	1	€ 230,000	€ 230,000		€ 230,000		
9	Liner hanger 8 5/8" - incl services	1	€ 80,000	€ 80,000		€ 80,000		
10	Float equipment & centralisers	1	€ 22,000	€ 22,000		€ 22,000		
11	Cement & Additives	1	€ 300,000	€ 300,000		€ 300,000		
12								
13								
14								
15	Wire wrapped screens	700	€ 624	€ 436,800		€ 436,800		
16	Wellhead Equipment and Xmas tree							
17								
18	Downhole pump & rods	1	€ 1,000,000	€ 1,000,000		€ 1,000,000		
19	Wellhead Equipment and Xmas tree	1	€ 300,000	€ 300,000		€ 300,000		
20								
21	Crossovers	1	€ 20,000	€ 20,000		€ 20,000		
				€ 3,784,800		€ 3,784,800	Total Well Materials	
				Contingency	25%			
				Contingency cost	€ 946,200		€ 946,200	Total Contingency - well materials
No	Well Engineering and Supervision	Unit	Price/unit	Cost	Other	TOTAL	REMARKS	
1	Well Engineering - preparation phase						Not included	
2	Daily supervision on site (DSV + NDSV)	190.7	€ 1,500	€ 286,006		€ 286,006		
3	Night supervision	190.7	€ 1,300	€ 247,872		€ 247,872		
4	Office support during execution (SWE/Drilling Manager/GHSE)	190.7	€ 3,000	€ 572,012		€ 572,012		
5	After action review	1	€ 10,000	€ 10,000		€ 10,000		
6	End of well report	1	€ 10,000	€ 10,000		€ 10,000		
7	HPHT training for crews	1	€ 100,000	€ 100,000		€ 100,000		
8	Rig & equipment audits	1	€ 100,000	€ 100,000		€ 100,000		
9	Rig site support while drilling HPHT	50	€ 3,000	€ 150,000		€ 150,000		
10	Wellcat Engineering & support	1	€ 40,000	€ 40,000		€ 40,000		
Totals				€ 1,515,891		€ 1,515,891	Total Engineering & Supervision	
				Contingency	25%	10%		
				Contingency cost	€ 539,982		€ 539,982	Total Contingency - 3rd party
TOTALS								
TOTAL COST GEOTHERMAL WELL						€ 17,115,419		
TOTAL CONTINGENCY						€ 4,957,456		
GRAND TOTAL						€ 22,072,875		

Figure 6-1 Overview of detailed cost sheet TER-GT-01 Producer (5500 mTVD)

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

COST ESTIMATE - LEVEL 1 - Tellus Renkum GT-01 (TER-GT-01)							
No	Rig operations	Details	Days	Rig dayrate	Rig cost	Other	TOTAL
1	Rigmove To TER-GT-01	And rig up on location				€ 300,000	€ 300,000
2	Drill 30" - 1000m		9.2	€ 30,000	€ 274,500		€ 274,500
3	Run casing 24" - 995m		5.7	€ 30,000	€ 171,011		€ 171,011
4	Drill 20" - 2025m		11.5	€ 30,000	€ 346,430		€ 346,430
5	Run casing 16" 2020m		2.5	€ 30,000	€ 74,503		€ 74,503
6	Drill 14 1/2" - 3810m		22.9	€ 30,000	€ 687,558		€ 687,558
7	Run liner 11 3/4" - 3808 m		7.0	€ 30,000	€ 211,106		€ 211,106
8	Drill 10 5/8" 5595m		47.6	€ 30,000	€ 1,427,187		€ 1,427,187
9	Run liner 9 5/8" - 5593m		9.1	€ 30,000	€ 271,603		€ 271,603
10	Drill 8 1/2" 7064m		125.0	€ 30,000	€ 3,749,954		€ 3,749,954
11	Logging Extended logs		5.4	€ 30,000	€ 162,000		€ 162,000
12	Run WWS 7 5/8"		6.0	€ 30,000	€ 178,774		€ 178,774
13	Testing Test well		28.8	€ 30,000	€ 865,131		€ 865,131
14	Install DHP Complete well		2.2	€ 30,000	€ 67,500		€ 67,500
Totals			282.9		€ 8,487,256	€ 300,000	€ 8,787,256
					Contingency	35%	
					Contingency cost	€ 2,979,540	€ 3,000,540
						10%	
						€ 30,000	€ 3,030,540
							Total Contingency - rig cost
No	Third party services, rentals & equipment (consumables)	Unit	Price/unit	Cost	Other	TOTAL	REMARKS
1	Directional drilling - rentals	1	€ 985,000	€ 985,000		€ 985,000	
2	Directional drilling - services	1	€ 1,131,046	€ 1,131,046		€ 1,131,046	
3	Bits & Coring - materials (consumables)	1	€ 345,000	€ 345,000		€ 345,000	
4	Bits & Coring - services						
5	Hole operators, underreamers						
6	Drilling & Compl fluids - materials/chemicals	1	€ 463,442	€ 463,442		€ 463,442	
7	Drilling & Compl fluids - services/engineering	1	€ 265,043	€ 265,043		€ 265,043	
8	Drilling & Compl fluids - solids control equipment	1	€ 180,000	€ 180,000		€ 180,000	
9	Waste Management Services/ waste cost - drilling	1	€ 500,000	€ 500,000		€ 500,000	
10	Waste Management Services/ waste cost - location						
11	Cementing services	1	€ 150,000	€ 150,000		€ 150,000	
12	Conductor/casing/liner running services (MIU)						
13	Electric Logging Services (formation evaluation)	1	€ 500,000	€ 500,000		€ 500,000	
14	Electric Logging Services (e.g. perforating)						
15	Slickline / wireline services						
16	Mud logging and geological services	1	€ 1,155,123	€ 1,155,123		€ 1,155,123	
17	Fishing, Milling, Cutting & Underreaming services						
18	Test Equipment Rentals	1	€ 400,000	€ 400,000		€ 400,000	
19	Testing supervision						
20	HP equipment rental (HP pump, HP test separator)	1	€ 529,307	€ 529,307		€ 529,307	
21	Wellhead Equipment & X-mas tree services	1	€ 40,000	€ 40,000		€ 40,000	
22	Downhole pump & accessories - RENTAL	1	€ 400,000	€ 400,000		€ 400,000	
23	Cranes and transport						
24	Mud cooler	1	€ 317,370	€ 317,370		€ 317,370	
25	Transformers, switchgear	282.9	€ 1,000	€ 282,909		€ 282,909	
Totals					€ 7,624,240		€ 7,624,240
					Contingency	25.0%	
					Contingency cost	€ 1,906,060	€ 1,906,060
							Total Contingency - 3rd party
No	Well materials	Unit	Price/unit	Cost	Other	TOTAL	REMARKS
1	Conductor & accessories (materials)						
2	Casing 24"	1100	€ 350	€ 385,000		€ 385,000	
3	Liner 11 3/4"	2220	€ 200	€ 444,000		€ 444,000	
4	Liner 9 5/8"	2200	€ 150	€ 330,000		€ 330,000	
5	Liner 7"						
6	Blank pipe 7 5/8" for WWS	900	€ 110	€ 99,000		€ 99,000	
7	Liner hanger 11 3/4" - incl services	1	€ 250,000	€ 250,000		€ 250,000	
8	Liner hanger 9 5/8" - incl services	1	€ 230,000	€ 230,000		€ 230,000	
9	Liner hanger 8 5/8" - incl services	1	€ 80,000	€ 80,000		€ 80,000	
10	Float equipment & centralisers	1	€ 22,000	€ 22,000		€ 22,000	
11	Cement & Additives	1	€ 300,000	€ 300,000		€ 300,000	
12							
13							
14							
15	Wire wrapped screens	800	€ 624	€ 499,200		€ 499,200	
16	Wellhead Equipment and Xmas tree						
17							
18	Downhole pump & rods	1	€ 1,000,000	€ 1,000,000		€ 1,000,000	
19	Wellhead Equipment and Xmas tree	1	€ 500,000	€ 500,000		€ 500,000	
20							
21	Crossovers	1	€ 100,000	€ 100,000		€ 100,000	
					€ 4,239,200		€ 4,239,200
					Contingency	60%	
					Contingency cost	€ 2,119,600	€ 2,119,600
							Total Contingency - well materials
No	Well Engineering and Supervision	Unit	Price/unit	Cost	Other	TOTAL	REMARKS
1	Well Engineering - preparation phase						Not included
2	Daily supervision on site (JGSV + MGSV)	282.9	€ 1,500	€ 424,363		€ 424,363	
3	Night supervision	282.9	€ 1,300	€ 367,761		€ 367,761	
4	Office support during execution (SWL/Drilling Manager/QHSE)	282.9	€ 3,000	€ 848,726		€ 848,726	
5	After action review	1	€ 10,000	€ 10,000		€ 10,000	
6	End of well report	1	€ 10,000	€ 10,000		€ 10,000	
7	HPHT training for crews	1	€ 100,000	€ 100,000		€ 100,000	
8	Rig & equipment audits	1	€ 100,000	€ 100,000		€ 100,000	
9	Rig site support while drilling HPHT	50	€ 3,000	€ 150,000		€ 150,000	
10	Wellhead Engineering & support	1	€ 40,000	€ 40,000		€ 40,000	
Totals					€ 2,050,870		€ 2,050,870
					Contingency	35%	
					Contingency cost	€ 717,804	€ 717,804
						10%	
						€ 30,000	€ 747,804
							Total Contingency - 3rd party
TOTALS							
TOTAL COST GEOTHERMAL WELL						€ 22,701,566	
TOTAL CONTINGENCY						€ 7,744,004	
GRAND TOTAL						€ 30,445,570	

Figure 6-2 Overview of detailed cost sheet TER-GT-01 Producer (7000 mTVD)

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

For all the services, recent prices are used and if no recent prices were available, an estimate was made, based on earlier experiences.

When the plans are detailed further, more detailed cost estimates can be produced based on the individual costs for the subcontractors (listed below). The service contractor cost are based on recent estimates and experiences with tenders for geothermal operators. The numbers assumed are visible in the cost estimate.

6.3 Included

The cost calculation includes:

1. The cost for one producer and one injector well
2. Rig mobilisation and demobilisation
3. One rig skid on the location
4. Use of a 2000 HP triples rig
5. Time for the installation of some sort of completion for the producer, which will be used for testing only and thus it will also be used on the injector well
6. Use of a unitised wellhead
7. Depths as per provided information

6.4 Excluded

Excluded are the following items:

1. Conductor pipe and installation
2. Drilling location build cost, (asphalt, cellars, conductors)aar aan te denken?)
3. Well design work (approximately 1.5 yrs) , except the use of Wellcat
4. Days required to rig up the rig (mobilisation), this is at a fixed cost
5. Sound insulation equipment such as sound walls
6. Surface Equipment
7. Special Equipment (e.g. BOP modifications)

6.5 More detail is required on

Drillpipe	The special conditions (HPHT) may require exotic materials
Casing design	Optimisation is always possible and several iterations are normally required
Geology	More detail is required on the geology, so that casing points can be optimised
Reservoir content	Reservoir content determines the materials selected

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

7 Risks & Opportunities

A number of risks and opportunities were identified. Risks can have a negative impact on cost, where opportunities could reduce cost.

ISSUE	RISK	Rationale/Explanation
	Medium	Will drive up cost, as all materials need to be suitable for HT operation. This is not so much a risk, more a given, however the risk is that something is missed.
Availability of an ESP for high temperature application	High	Max ESP working temperature (Oct 2019) is 155 deg C. Alternative option could be a line shaft pump Cost unknown yet
Low Productivity Index	Low	Determines installation depth ESP
Casing availability	Medium	Sizing of BOPs (availability of sizes beyond 21 ¼")
Seismicity	Medium	Re-injecting cold water into hot reservoir can cause thermal shock. Bringing temperature down too much adds value (domestic heating after use in paper factory), but may increase risk of seismicity (i.e. can affect business model)
Noise	Medium	Producing steam can be noisy, silencers may be required (permit / cost risk)
NOX deposition	Medium/High	This needs to be resolved before start, potential showstopper Has impact on rig selection Has impact on location (vicinity Nature 2000 area?, needs power grid for rig?)
Use 'new' ESP supplier	Medium	What is the quality of these pumps? How is the after-sales support ? (experiences from others) How to perform QAQC? There seems to be a test installation (which is good) Will ask my contact in Rumania if he has any experience with Novomet

Table 1 Project risks

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

7.1 Opportunities

OPPORTUNITY	VALUE	Rationale/Explanation
Do a Hazid on drilling and production	Very high	With the right people in the room, most (potential) issues will be raised in time
Learn from other high temperature operations	High	Visit to Iceland production facilities (I can set this up if you are interested) (experience up to 550 deg C) Steam is used to generate power, to heat houses, but also streets Other areas to visit could be France (Fonroche, 210 deg C) or Italy (350 deg C)
Presence of water in the area (Nederriijn)	High	Can we take water from the river? Could be used for cooling purposes
Talk to other operators about how to deal with NOX deposition	High	New legislation forces contractors to deposit almost no NOX to the environment and sometimes this requires a considerable upfront investment

Table 2 Project Opportunities

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

8 Conclusions & Recommendations

Drilling ultradeep wells requires considerably more front-end input than a conventional well and the range of outcomes is vast and depending on many variables.

With the limited data available, and using previous HPHT experience, a best estimate has been made regarding the expected timing and cost of such a project. Still, many details are unknown and thus there still is a considerable range of uncertainty within the presented data. The effect of the latest changes in anticipated depths is actually a great example of this; as can be seen, the consequence this has on timing and cost is major and uncertainties follow suit.

Having said that, this report represents a solid start for more detailed engineering work, which will be required, should the project go ahead at a later stage.

Looking ahead at the next phase of this project, it is advised to spend much more time and effort in the further definition of the drilling engineering aspects of the wells. This will determine technical feasibility and it will provide many more risks and opportunities, which will help define the project further. This is adamant for the success for the Tellus Renkum geothermal wells.

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Appendix 1: Geology in offset wells

Boorgatnaam	MAASBOMMEL-02		
Diepte in meter t.o.v.	Rotary Table		
Einddiepte (m)	1278		
Lithostratigrafie			
Datum interpretatie	2004-11-10		
Bron	KARTERING DIEP - ONSHORE 2004		
Conform Adrichem Boogaert & Kouwe (1993) en Munsterman et al (2012)			
Diepte stratigrafische eenheden (gemeten langs het boorgat)			
Stratigrafische eenheid	Bovenkant van interval	Onderkant van interval	Anomaliecode
QUATER. UNDIFF.	0	70	
Oosterhout Formation	70	180	
Breda Formation	180	356	
Veldhoven Formation	356	402	
Voort Member	402	414	
Rupel Clay Member	414	485	
Vessem Member	485	500	
Ommelanden Formation	500	852	
Texel Formation	852	932	
Upper Holland Marl Member	932	950	
Middle Holland Claystone Member	950	964	
Holland Greensand Member	964	973	
Lower Holland Marl Member	973	1041	
Ruurlo Formation	1041	1133	
Baarlo Formation	1133	1278	TD

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Boorgatnaam MAASBOMMEL-01
Diepte in meter t.o.v. Rotary Table
Einddiepte (m) 1713.5

Lithostratigrafie
Datum interpretatie 2004-11-10
Bron KARTERING DIEP - ONSHORE 2004
 Conform Adrichem Boogaert & Kouwe (1993) en Munsterman et al (2012)

Diepte stratigrafische eenheden (gemeten langs het boorgat)

Stratigrafische eenheid	Bovenkant van interval	Onderkant van interval	Anomaliecode
QUATER. UNDIFF.	0	97	
Oosterhout Formation	97	178	
Breda Formation	178	360	
Veldhoven Clay Member	360	415	
Voort Member	415	436	
Rupel Clay Member	436	494	
Vessem Member	494	510	
Ieper Member	510	530	
Basal Dongen Sand Member	530	543	
Landen Clay Member	543	566	
Gelinden Member	566	570	
Heers Member	570	580	
Ommelanden Formation	580	1006	
Texel Formation	1006	1089	
Upper Holland Marl Member	1089	1105	
Middle Holland Claystone Member	1105	1123	
Holland Greensand Member	1123	1132	
Lower Holland Marl Member	1132	1204	
Upper Röt Fringe Claystone Member	1204	1258	
Röt Fringe Sandstone Member	1258	1305	
Lower Röt Fringe Claystone Member	1305	1400	
Solling Claystone Member	1400	1410	
Detfurth Claystone Member	1410	1445	
Lower Detfurth Sandstone Member	1445	1470	
Upper Volpriehausen Sandstone Member	1470	1538	
Lower Volpriehausen Sandstone Member	1538	1556	
Rogenstein Member	1556	1691	
FAULT	1691	1691	
Z3 Carbonate Member	1691	1713	TD

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

Appendix 2 –Detailed Planning (Producer) – 5500 m

The tables below provide the detailed planning for the production well.

TIME PLANNER V.28

RIG: Land rig

WELL: Tellus Renkum GT-01 (TER-GT-01) (V1)

TELLUS
RENKUM B.V.

Main Activities & codes:

1. Rigmove To TER-GT-01, 2. Drill 30" x 1000m, 3. Run casing 24" x 955m, 4. Drill 20" x 2020m, 5. Run casing 16" x 2015m, 6. Drill 14 1/2" x 3040m, 7. Run liner 11 3/4" x 3020m, 8. Drill 10 5/8" x 4098m, 9. Run liner 9 5/8" x 4098m, 10. Drill 6 1/2" x 5020m, 11. Logging Extended logs, 12. Run WWS 7 5/8", 13. Testing Test well, 14. Install OHP Complete well

Sub-Activity codes:

1: Drill/Core (M) (influences hole depth), 2: RH / POOH (single trip), 3: Single in / out, 4: Unplanned event (not for planning purposes, only when drilling / executing well), 5: Run/Full casing, 6: Plug back hole or set hole depth, 7: Set building depth, 8: BOP test, For PUJ and Set back pipe use Single in + POOH.

Start Date:

Start Time:

RH / POOH: 200 m/hr

Single in/Out: 150 m/hr

Run/Full Casing: 100 m/hr

ROP Index: 24 fpm, Max Prog: 24 days

Casing/Day: 36 %

Cost Sheet uses Time Planner data

Main Activity Descr	Sub-Activity # Descr	Detailed steps # Description of activity	Drill/Fullcore Fm To Dist	To ROP Depth	Amt	Depth mtr	HOURS Bt Hole Auto Manual	Cum days	Days Incl Cont	Predicted Actual start	Actual times planned Cum Depth	LAST BOP	TLD hrs days
Rigmove To TER-GT-01		1 Rig move to TER-GT-01			0	0				16-10-20 14:26			
		2 Rig commissioning			0	0				16-10-20 14:26			
		3 Crew induction + HSE training			0	0				16-10-20 14:26			
Drill 30" x 1000m		4 MU 30" BHA			0	0	5.00	0.21	0.28	16-10-20 14:26			9.3
		5 Clean out conductor and test circulating system			0	0	2.00	0.35	0.35	16-10-20 21:14			0.4
	1 Drill/Case	6 Drill	1000 1000 8		1000 1000	125.0	5.50	7.43		16-10-20 23:36			7.4
		7 Circulate hole clean			1000 1000		4.00	5.67	7.65	24-10-20 00:41			7.7
		8 POOH			0 1000	5.0	8.55	7.93		24-10-20 08:05			7.9
		9 Extra time circulating and cleaning the hole			0 1000	5.0	8.13	8.27		24-10-20 12:50			8.3
		10 LID BHA			0 1000	4.00	6.25	6.49		24-10-20 20:36			8.5
Run casing 24" x 955m		11 RTU to run casing			0 1000	4.00	6.46	6.72		25-10-20 02:30			8.7
		12 Pick up 24" shoeback and test floats			0 1000	4.00	6.03	6.54		25-10-20 07:44			8.9
		13 RH casing		1134	0 1000	11.3	7.10	9.58		25-10-20 13:08			9.6
		14 Circulating time getting casing down			0 1000	4.00	7.26	9.81		26-10-20 04:27			9.8
		15 Hang off casing at cellar level			0 1000	2.00	7.35	9.83		26-10-20 09:51			9.9
	2 RH	16 RH stringer	1000	1000 1000	5.0	4.00	7.56	10.20		26-10-20 12:35			10.2
		17 Stop stringer and circulate BU until smooth			1000 1000	4.00	7.72	10.43		26-10-20 19:16			10.4
		18 Cement 24" casing			1000 1000	8.00	8.06	10.88		27-10-20 00:42			10.9
		19 Stop out and circulate clean			1000 1000	2.00	8.14	10.89		27-10-20 11:30			11.0
	2 POOH	20 POOH stringer			0 1000	5.0	8.35	11.27		27-10-20 14:12			11.2
		21 WOC			0 1000	5.00	8.66	11.72		27-10-20 20:57			11.7
		22 Rig up wellhead			0 1000	12.00	9.18	12.39		28-10-20 07:45			12.4
		23 Rig up 25 1/4" BOPN			0 1000	8.00	8.91	13.84		28-10-20 23:57			12.8
	8 BOP test	24 Test BOPN			0 1000	24	10.51	14.19		29-10-20 10:45			TEST
Drill 20" x 2020m		26 MU 20" BHA			0 1000	5.00	15.68	14.42		30-10-20 16:09			0.2
	2 RH	27 RH to shoe	1000	1000 1000	5.0	4.00	15.89	14.70		31-10-20 00:33			0.5
		28 Drill out 24" shoe with Rot BHA			1000 1000	5.00	11.14	15.64		31-10-20 07:18			0.6
	1 Drill/Case	29 Drill subsea	1000 1000 5 8		1000 1000	1.0	11.18	16.09		31-10-20 16:24			0.9
		30 Circulate hole clean			1000 1000	3.00	11.31	16.29		31-10-20 16:40			1.1
		31 FIT			1000 1000	1.00	11.35	16.32		31-10-20 20:46			1.1
		31 Dedicated drillout required for this shoe ?????			1000 1000		11.35	16.32		31-10-20 22:05			1.1
	1 Drill/Case	32 Drill 1st section of the 20" hole	1000 1000 695 8		1000 1000	61.9	13.93	19.80		31-10-20 22:08			6.6
		33 Circulate clean			1000 1000		14.02	19.87		01-11-20 09:40			6.8
	2 POOH	34 POOH for bit change			0 1000	7.5	14.26	19.59		01-11-20 13:52			6.9
		35 Extra time circulating and cleaning the hole			0 1000	3.00	14.49	19.55		01-11-20 23:51			5.4
		36 RH change & BHA handling			0 1000	4.00	14.65	19.75		01-11-20 03:54			5.6
	2 RH	37 RH stringer	1000 1000 7 5	1500	1500 1500	7.5	14.67	20.21		01-11-20 09:16			6.0
	1 Drill/Case	38 Drill to section TD	1000 2020 320 8		2020 2020	59.0	17.68	23.85		01-11-20 19:25			9.7
		39 Circulate clean			2020 2020		17.80	24.63		01-11-20 11:10			9.8
		40 POOH			0 2020	19.0	18.22	24.60		01-11-20 15:10			10.0
	2 POOH	41 Extra time circulating and cleaning the hole			0 2020	4.00	18.30	24.63		01-11-20 04:57			10.6
		42 LID BHA			0 2020	4.00	18.55	25.05		01-11-20 10:16			10.9
Run casing 16" x 2015m		43 Rig up to run casg 16"			0 2020	3.00	18.68	25.22		01-11-20 15:40			11.0
		44 Pick up cap and test floats			0 2020	3.00	18.80	25.39		01-11-20 19:43			11.2
	5 Casing	45 RH	2015	0 2020	20.2		18.64	25.82		01-11-20 23:46			12.4
		46 MU 16" stringer			0 2020	2.00	18.73	26.53		12-11-20 02:58			12.5

16-10-20 / 14:31

20200124-Coe/Estimate Tool-V2-TellusRenkum-Producer

1 / 5

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

WDC

TIME PLANNER V.28

RIG: Land rig

WELL: Tellus Renkum GT-01 (TER-GT-01) (V1)

TELLUS RENKUM B.V.

Main Activities & codes:

1: Rignove To TER-GT-01, 2: Drill 30" - 1000m, 3: Run casing 24" - 995m, 4: Drill 20" 2020m, 5: Run casing 18" 2015m, 6: Drill 14 1/2" - 3045m, 7: Run liner 11 3/4" - 3039m, 8: Drill 10 5/8" 4500m, 9: Run liner 9 5/8" 4599m, 10: Drill 8 1/2" 5620m, 11: Logging Extended logs, 12: Run WWS 7 5/8" - 13: Testing Test well, 14: Install DHP Complete well

Sub-Activity codes:

1: Drill/Case/MI (influences hole depth), 2: RH / POOH (single trip), 3: Single in / out, 4: Unplanned event (not for planning purposes, only when drilling / executing well), 5: Run/Pull casing, 6: Plug back hole or Set hole depth, 7: Set bitting depth, 8: BOP test, For PU and Set back pipe use Single in + POOH.

Start Date:

Start Time:

RH / POOH - 200 m/hr

Single In/Out - 150 m/hr

Run/Pull Casing - 100 m/hr

BOP tests: 24 hrs, Max Freq: 21 days

Contingency: 35 %

Cost Sheet uses Time Planner data

Main Activity	Sub-Activity	Detailed steps	Drill/MI/Case	To	Am	Depth	HOURS	Cum	Days	Predicted	Act times	Act	LAST	TLD
Descr	#	Description of activity	From	To	ROP	Depth	Manual	days	Incl Cont	Actual start	plact	Cum	Depth	hrs
		47 Circulate to get down				0	2020	4.00	19.59	25.36				12.7
		48 Circulate hole clean, condition mud				0	2020	4.00	20.06	27.06				12.9
		49 Cement csg				0	2020	8.00	20.39	27.53				13.3
Drill 14 1/2" - 3040m						0	2020	4.00	20.56	27.76				13.6
						2020	2020	10.1	20.98	28.33				14.1
						2020	2020		21.23	28.66				14.5
	2	RH												
		50 MU 12 1/4" BHA				0	2020	4.00	20.56	27.76				13.6
		51 RH to shoetrack				2020	2020	10.1	20.98	28.33				14.1
		52 Drill out shoetrack				2020	2020		21.23	28.66				14.5
	1	Drill/Case				2020	2025	5	21.27	28.72				14.5
		53 Drill rathole				2025	2025	1.0	21.40	28.89				14.7
		54 Circulate clean				2025	2025		21.44	28.94				14.8
		55 FIT				2025	2025							
		56 Displace well to new mud				2025	2025	4.00	21.61	29.17				15.0
Run liner 11 3/4" - 3039m	1	Drill/Case				2025	2500	475	24.08	32.51				18.3
		57 Drill 1st section of the 12 1/2" hole				2500	2500	59.4	24.21	32.68				18.5
		58 Circulate clean				0	2500	3.00	24.73	33.36				19.2
	2	POOH				0	2500	12.5	24.94	33.66				19.5
		59 POOH for bit change				0	2500	2.00	25.02	33.77				19.6
		60 Extra time circulating and cleaning the hole				0	2500							
		61 Bit change				0	2500							
	8	BOP test				0	2500	24	26.02	35.12				TEST
	2	RH				2500	2500	12.5	26.54	35.83				0.7
	1	Drill/Case				3040	3040	67.5	29.35	39.82				4.5
		62 Drill to section TD				3040	3040							
Run liner 11 3/4" - 3039m		65 Circulate clean				0	3040	4.00	29.52	39.85				4.7
		66 POOH				0	3040	15.2	30.15	40.70				5.0
		67 Extra time circulating and cleaning the hole				0	3040	4.00	30.32	40.93				5.6
		68 LD BHA				0	3040	4.00	30.49	41.15				6.0
		69 Rig up to run liner				0	3040	3.00	30.61	41.32				6.2
		70 Pick up Intern liner and test floats				0	3040	3.00	30.74	41.49				6.4
	5	Casing				0	3040	11.0	31.19	42.11				7.0
		71 RH liner				0	3040	2.00	31.28	42.22				7.1
	2	RH				1939	1939	9.7	31.68	42.77				7.6
		72 MU hanger etc:				0	3040	4.00	31.85	42.99				7.9
		73 RH on pipe				1939	1939	2.00	31.93	43.11				8.0
		74 Circulate to get down				1939	1939	4.00	32.10	43.33				8.2
Drill 10 5/8" 4500m		75 Rig up PDH				1939	1939	2.00	32.18	43.44				8.3
		76 Circulate hole clean, condition mud				1939	1939	4.00	32.40	43.78				8.7
		77 Set liner hanger				1939	1939	1.00	32.47	43.84				8.7
		78 Cement liner				1939	1939	2.00	32.56	43.95				8.8
		79 Rig down PDH				1939	1939	2.00	32.64	44.36				8.9
		80 Pull out and set LH packer				0	3040	9.7	33.04	44.61				9.5
		81 Circulate excess cement				0	3040	2.00	33.13	44.72				9.6
	2	POOH				0	3040	9.7						
		82 POOH liner running tool				0	3040							
		83 lay down equipment				0	3040							
		84 Remove 20 3/4" BOPs				0	3040	8.00	33.38	45.06				9.9
		85 Install 13 5/8" BOPs				0	3040	12.00	33.88	45.73				10.6
		86 Wellhead work as well				0	3040	12.00	34.38	46.41				11.3
Drill 10 5/8" 4500m	8	BOP test				0	3040	24	35.38	47.76				TEST
		87 BOP test				0	3040							
		88 MU BHA				0	3040	4.00	35.54	47.98				0.2
	2	RH				3040	3040	15.2	36.18	48.94				1.1
Drill 10 5/8" 4500m		89 RH to liner shoetrack				3040	3040	5.00	36.38	49.12				1.4
		90 Drill out liner shoetrack				3040	3040							
	1	Drill/Case				3040	3045	5	36.43	49.18				1.4
		92 Circulate clean				3045	3045	4.00	36.59	49.40				1.8

16-10-20 / 14:31

2020/12/24-CostEstimateTool-V2-TellusRenkum-Producer

2 / 5

16-10-20 / 14:31

20200124-CostEstimateTool-V2-TellusRenkum-Produser

2 / 5

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

TIME PLANNER V.28 RIG: Land rig WELL: Tellus Renkum GT-01 (TER-GT-01) (V1)														
<div> <div>WDC</div> <div> Main Activities & codes: 1: Remove To TER-GT-01, 2: Drill 30" - 1000m, 3: Run casing 24" - 955m, 4: Drill 20" 2000m, 5: Run casing 19" 2015m, 6: Drill 14 1/2" - 3040m, 7: Run liner 11 3/4" - 3039m, 8: Drill 10 5/8" 4500m, 9: Run liner 9 5/8" 4500m, 10: Drill 8 1/2" 5520m, 11: Logging Extended logs, 12: Run WYS 7 5/8" , 13: Testing Test well, 14: Install DHP Complete well </div> </div> <div> <div>TELLUS RENKUM B.V.</div> <div> Sub-Activity codes: 1: Drill/Case/ML (influences hole depth), 2: RH/POOH (single trip), 3: Single in / out, 4: Unplanned event (not for planning purposes; only when drilling / executing well), 5: Run/Pull casing, 6: Plug back hole or Set hole depth, 7: Set bitting depth, 8: BOP test, For PU and Set back pipe use Single in + POOH. </div> </div>														
<div> <div>RH / POOH : 200 m/hr</div> <div>Single In/Out : 150 m/hr</div> <div>Run/Pull Casing : 100 m/hr</div> <div>BOP tests: 24 hrs, Max. Freq: 21 days</div> <div>Contingency: 35 %</div> <div>Cost Sheet uses Time Planner data</div> </div>														
Main Activity	Sub-Activity	Described steps	Drill/ML/core	To	Amt	Depth	HOURS	Cum	Days	Predicted	Actual start	Act times	Act	LAST
Descr	#	Description of activity	From	To	Dist	ROP	Depth	hrs	days	Actual start	Actual start	planned	Cum	Depth
	93	RT	3045	3045			1.00	36.63	49.46	05-12-20 00:06				1.7
	94	Displace well to new mud	3045	3045			5.00	36.84	49.74	05-12-20 01:27				2.0
1	Drill/Case	95 Drill 1st section of the 10 5/8" hole	3045	3800	755	4	3800	3800	188.8	44.71	06:28	05-12-20 08:12		12.8
	96	Circulate clean	3800	3800			4.00	44.87	60.58	15-12-20 23:00				12.8
2	POOH	97 POOH for bit change	0	3800	19.0		4.00	45.67	61.65	15-12-20 04:24				13.9
	98	Extra time circulating and cleaning the hole	0	3800			4.00	45.83	61.67	17-12-20 05:03				14.1
8	BOP test	99 BOP test	0	3800	24		4.00	46.83	63.22	17-12-20 11:27				TEST
	100	Bit change & BHA handling	0	3500			3.00	46.96	63.30	18-12-20 15:51				0.2
2	RH	101 RH again	3800	3800	19.0		4.00	47.76	64.46	18-12-20 23:04				1.2
1	Drill/Case	102 Drill to section TD	3800	4500	800	3	4500	4500	255.7	56.56	79.46	20-12-20 01:33		16.2
	103	Additional time to find section TD (slow, avoid drilling into reservoir)	4500	4500			24.00	56.56	60.61	04-01-21 01:33				17.5
	104	Additional rounding in line with HPHT procedures (see below)	4500	4500			0.00	56.56	60.61	05-01-21 09:57				17.6
8	BOP test	105 BOP test	4500	4500	24		4.00	60.86	62.16	05-01-21 09:57				TEST
	106	Circulate clean	4500	4500			4.00	61.03	62.33	05-01-21 18:21				0.2
2	POOH	107 POOH	0	4500	23.0		4.00	61.09	63.68	05-01-21 23:45				1.5
2	RH	108 RH to STD	4500	4500	23.0		4.00	62.94	64.97	05-01-21 05:48				2.6
	109	Circulate clean	4500	4500			4.00	63.11	65.20	09-01-21 13:51				3.0
2	POOH	110 POOH	0	4500	23.0		4.00	64.07	66.49	09-01-21 19:15				4.3
	111	Extra time circulating and cleaning the hole	0	4500			4.00	64.24	66.72	11-01-21 02:18				4.6
	112	LOG BHA	0	4500			4.00	64.40	66.94	11-01-21 07:42				4.8
Run liner 9 5/8" 4500m		113 Rig up to run liner	0	4500			3.00	64.53	67.11	11-01-21 13:06				5.0
	114	Pick up inner liner and test floats	0	4500			3.00	64.66	67.28	11-01-21 17:09				5.1
5	Casing	115 RH liner	0	4500	16.0		2.00	65.32	68.16	11-01-21 21:12				6.0
	116	MLU hanger etc	0	4500			2.00	65.40	68.29	12-01-21 18:48				6.1
2	RH	117 RH on pipe	2999	4500	15.0		2.00	66.03	69.14	12-01-21 21:30				7.0
	118	circulate to get down	2999	4500			4.00	66.19	69.38	13-01-21 17:45				7.2
	119	Rig up RPH	2999	4500			2.00	66.26	69.47	13-01-21 23:09				7.3
	120	Circulate hole clean, condition mud	2999	4500			4.00	66.44	69.70	14-01-21 01:51				7.5
	121	Set liner hanger	2999	4500			2.00	66.53	69.81	14-01-21 07:15				7.6
	122	Cement line	2999	4500			6.00	66.78	70.15	14-01-21 09:57				8.0
	123	Rig down POH	2999	4500			1.00	66.82	70.20	14-01-21 18:30				8.0
	124	Put out and set LH packer	2999	4500			2.00	66.90	70.52	14-01-21 19:24				8.2
	125	Circulate excess cement	2999	4500			2.00	66.99	70.43	14-01-21 22:06				8.3
2	POOH	126 POOH liner running tool	0	4500	15.0		2.00	67.61	71.27	15-01-21 02:48				9.1
	127	lay down equipment	0	4500			2.00	67.69	71.59	15-01-21 21:03				9.2
8	BOP test	128 BOP test	0	4500	24		4.00	68.69	72.74	15-01-21 23:45				TEST
	129	RU additional HPHT equipment, such as HP pump, HP separator (test?)	0	4500			48.00	70.09	95.44	17-01-21 05:09				2.7
Drill 8 1/2" 5520m		130 MLU BHA	0	4500			4.00	70.56	95.66	20-01-21 00:57				2.9
	131	RH to liner shootback	4500	4500	23.0		4.00	71.82	96.56	20-01-21 05:21				4.2
	132	Drill out liner shootback	4500	4500			5.00	72.03	97.24	21-01-21 13:24				4.5

16-10-20 / 14:31

20200124-CostEstimateTool-V2-TellusRenkum-Producer

3 / 5

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

WDC		TIME PLANNER V.28		RIG: Land rig		WELL: Tellus Renkum GT-01 (TER-GT-01) (V1)		TELLUS RENKUM B.V.																			
Main Activities & codes:						Sub-Activity codes:																					
1: Rignmove To TER-GT-01, 2: Drill 30" - 1000m, 3: Run casing 24" - 995m, 4: Drill 20" 2020m, 5: Run casing 16" 2015m, 6: Drill 14 1/2" - 3040m, 7: Run liner 11 3/4" - 3039m, 8: Drill 10 5/8" 4600m, 9: Run liner 9 5/8" 4509m, 10: Drill 8 1/2" 5620m, 11: Logging Extended logs, 12: Run WWS 7 5/8" , 13: Testing Test well, 14: Install DHP Complete well						1: Drill/Core/Mat (influences hole depth), 2: RH / POOH (single trip), 3: Single in / out, 4: Unplanned event (not for planning purposes; only when drilling / exceeding well), 5: Run/Pull casing, 6: Plug back hole or Set hole depth, 7: Set bitstring depth, 8: BOP test, For RH and Set back pipe use Single In + POOH.																					
Start Date:						Start Time:																					
RH / POOH : 200 m/hr						Contingency: 35 %																					
Single In/Out: 150 m/hr						Cost Sheet uses Time Planner data																					
Run/Pull Casing: 100 m/hr																											
BOP tests: 24 hrs, Max Pres: 21 days																											
Main Activity		Sub-Activity		Detailed steps		Drill/Mat/core		To		Amt		Depth		HOURS		Cum		Days		Predicted		Act times		Act LAST		TLD	
Descr		#		# Description of activity		Frm To Last HOP Depth		mtr		mtr		mtr		Manual		days		hrs		Actual start		pract		Cum Depth		BOP hrs day	
1 Drill/Core	132	Drill/Core	134	Circulate clean		4605	4605	5	3	4605	4605	4.00	72.28	97.33	21-01-21 20:09	4.8				21-01-21 22:24	4.8						
	135		135	FIT		4605	4605			4605	4605	1.00	72.30	97.61	22-01-21 03:48	4.9				22-01-21 03:48	4.9						
	136		136	Displace well to new mud		4605	4605			4605	4605	5.00	72.51	97.89	22-01-21 05:09	5.2											
	137		137	Drill 1st section of the 10 5/8" hole		4605	5100	495	2	5100	5100	247.5	82.83	111.81	22-01-21 11:54	19.1											
	138		138	Circulate clean		5100	5100			5100	5100	4.00	82.99	112.04	05-02-21 10:01	19.3											
	139		139	POOH for bit change		0	5100	25.5		0	5100	25.5	4.00	84.05	113.47	05-02-21 15:25	20.7										
	140		140	Extra time circulating and cleaning the hole		0	5100			0	5100		4.00	84.22	113.70	07-02-21 01:51	21.0										
	141		141	Bit change & BHA handling		0	5100			0	5100		3.00	84.35	113.87	07-02-21 07:15	21.1										
	142		142	RH again		5100	5100	25.5		5100	5100	25.5	4.00	85.41	115.30	07-02-21 11:18	22.6										
	8 BOP test	143	BOP test	143	BOP test		5100	5100	24		5100	5100	24	86.41	116.65	08-02-21 21:43	TEST										
1 Drill/Core	144	Drill/Core	144	Drill to 5360m		5100	5360	260	1	5360	5360	260.0	97.24	131.28	10-02-21 08:07	14.6											
	145		145	Circulate clean		5360	5360			5360	5360	4.00	97.41	131.90	24-02-21 21:07	14.9											
	146		146	POOH		0	5360	26.8		0	5360	26.8	4.00	98.53	133.01	25-02-21 02:31	16.4										
	147		147	Extra time circulating and cleaning the hole		0	5360			0	5360		4.00	98.69	133.23	26-02-21 14:42	16.6										
	148		148	L/D BHA		0	5360			0	5360		4.00	98.85	133.45	26-02-21 20:06	16.8										
	149		149	BOP test		0	5360	24		0	5360	24	99.88	134.81	27-02-21 01:30	TEST											
	150		150	Bit change & BHA handling		0	5360			0	5360		4.00	100.03	135.03	28-02-21 09:54	0.2										
	151		151	RH		5360	5360	26.8		5360	5360	26.8	4.00	101.14	136.54	28-02-21 15:18	1.7										
	152	Drill/Core	152	Drill to section TD		5360	5620	260	1	5620	5620	260.0	111.98	151.17	02-03-21 03:29	16.4											
	153		153	Circulate clean		5620	5620			5620	5620	4.00	112.14	151.39	16-03-21 18:29	16.6											
2 POOH	154		154	POOH		0	5620	28.1		0	5620	28.1	4.00	113.31	152.97	16-03-21 23:53	18.2										
	155		155	Extra time circulating and cleaning the hole		0	5620			0	5620		4.00	113.48	153.20	18-03-21 13:49	18.4										
	156		156	L/D BHA		0	5620			0	5620		4.00	113.65	153.42	18-03-21 19:13	18.6										
	157		157	BOP test		0	5620	24		0	5620	24	114.65	154.77	19-03-21 00:37	TEST											
	158		158	Logging campaign (possibly on dripline)		0	5620	96.00		0	5620	96.00	118.65	180.17	20-03-21 09:01	5.4											
	159		159	Rig up to run WWS		100	0	5620		0	5620		4.00	118.81	180.40	25-03-21 18:37	5.8										
	160	Casing	160	RH WWS		700	0	5620	7.0	0	5620	7.0	4.00	119.10	180.79	26-03-21 00:01	6.0										
	161	Casing	161	RH on base pipe		500	0	5620	5.0	0	5620	5.0	2.00	119.31	181.07	26-03-21 09:28	6.3										
	162		162	Hang off WWS		0	5620			0	5620		2.00	119.40	181.18	26-03-21 18:13	6.4										
	163		163	Install circulating string inside WWS		0	5620			0	5620		2.00	119.42	181.18	26-03-21 18:55	6.4										
2 RH	164		164	Connect together		0	5620			0	5620		2.00	119.48	181.30	26-03-21 18:55	6.5										
	165		165	Fit depth of WWS		0	5620			0	5620		2.00	119.48	181.30	26-03-21 21:37	6.5										
	166		166	RH string		4420	5620	22.1		4420	5620	22.1	120.40	182.54	26-03-21 21:37	7.8											
	167		167	String depth		5620	5620			5620	5620	4.00	120.40	182.54	28-03-21 03:27	7.8											
	168		168	Circulate hole clean to brine outside WWS		5620	5620			5620	5620	4.00	120.57	182.77	28-03-21 03:27	8.0											
	169		169	Hang off WWS on liner hanger		5620	5620			5620	5620	2.00	120.65	182.88	28-03-21 08:51	8.1											
	170		170	Circulate B.U. to brine on inside WWS		5620	5620			5620	5620	4.00	120.62	183.10	28-03-21 11:33	8.3											
	171		171	Pull out circulating string out of WWS		4420	5620	6.0		4420	5620	6.0	121.07	183.44	28-03-21 19:57	8.7											
	172		172	Circulate well clean to brine		4420	5620			4420	5620	4.00	121.23	183.67	29-03-21 01:03	8.9											
	173		173	Set string depth		4420	5620	22.1		4420	5620	22.1	122.15	184.91	29-03-21 06:27	10.1											
Testing Test well	175	MU HT downhole test pump	175	MU HT downhole test pump		0	5620			0	5620		36.00	123.65	186.93	30-03-21 12:17	12.2										
	176	RH DHTP + on 7 5/8" pipe	176	RH DHTP + on 7 5/8" pipe		0	5620			0	5620		8.00	123.96	187.38	01-04-21 12:53	12.6										
	177	Line up surface lines & Pressure test same	177	Line up surface lines & Pressure test same		0	5620			0	5620		12.00	124.48	188.06	01-04-21 23:41	13.3										
	178	TEST WELL (14 days) (includes well kill)	178	TEST WELL (14 days) (includes well kill)		0	5620			0	5620		336.00	138.48	186.96	02-04-21 15:53	32.2										
	179	R/D surface lines	179	R/D surface lines		0	5620			0	5620		8.00	138.82	187.41	21-04-21 13:29	32.6										
	180	POOH DHTP etc	180	POOH DHTP etc		0	5620			0	5620		8.00	139.15	187.86	22-04-21 00:17	33.1										

16-10-20 / 14:31

20200124-CostEstimateTool-V2-TellusRenkum-Producer

4 / 5

Project	TELL-GT-01/02	Document titel	TELLUS RENKUM PROJECT
Customer	Tellus Renkum	Document no	WDCI-TR-01
Revision	1	Date	11-12-2020

WDC

WORLDWIDE DRILLING COMPANY

TIME PLANNER V.28

RIG: Land rig

WELL: Tellus Renkum GT-01 (TER-GT-01) (V1)

TELLUS
RENKUM B.V.

Main Activities & codes:
1: Rigmove To TER-GT-01, 2: Drill 30" - 1000m, 3: Run casing 24" - 995m, 4: Drill 20" 2020m, 5: Run casing 16" 2015m, 6: Drill 14 1/2" - 3040m, 7: Run liner 11 3/4" - 3039m, 8: Drill 10 5/8" 4600m, 9: Run liner 6 5/8" 4599m, 10: Drill 8 1/2" 5620m, 11: Logging Extended logs, 12: Run WWS 7 5/8" , 13: Testing Test well, 14: Install DHP Complete well

Start Date:
Start Time:

Sub-Activity codes:
1: Drill/Core/Mill (influences hole depth), 2: RH / POOH (single trip), 3: Single in / out, 4: Unplanned event (not for planning purposes; only when drilling / executing well), 5: Run/Pull casing, 6: Plug back hole or Set hole depth, 7: Set blocking depth, 8: BOP test, For PU and Set back page use Single In + POOH.

RH / POOH : 200 m/hr		Single In/Out : 150 m/hr		Run/Pull Casing : 150 m/hr		BOP tests: 24 hrs. Max Freq: 21 days		Contingency: 35 %		Cost Sheet uses Time Planner data						
Main Activity	Sub-Activity	Detailed steps		Drill/Mill/core		To	Am	Depth	HOURS	Cum	Days	Predicted	Act times	Act	LAST	TLD
Uesor	#	Uesor Description of activity		Frm	To	Unit	HOH Depth	hrs	Auto Manual	days	End Cont	Actual start	pract	Cum	Depth	hrs days
Install DHP Complete well	181	Rig down DHTP & BVA		0	5620			8.00	139.49	188.31		22-04-21 11:05				33.5
	182	Install temporary Tree or suspension cap		0	5620			2.00	139.57	188.42		22-04-21 21:53				33.6
	183	Specify downhole pump and order		0	5620											33.6
	184	Remove temp cap		0	5620			4.00	139.74	188.65		23-04-21 00:35				33.9
	185	RH HTDHP		0	5620			24.00	143.74	196.00		23-04-21 08:59				35.2
	186	Install seals etc		0	5620			4.00	143.90	196.22		24-04-21 14:23				35.4
	187	Install tree & test name		0	5620			8.00	141.24	190.67		24-04-21 19:47				35.9

16-10-20 / 14:31

20200124-CostEstimateTool-V2-TellusRenkum-Producer

5 / 5

16-10-20 / 14:31

20200124-CostEstimateTool-V2-TellusRenkum-Producer

5 / 5