Feasibility study

WarmingUP Doublet

Thema T4A

Potential location: Zwijndrecht

PREPARED FOR

WarmingUP 4A

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ABSTRACT / SUMMARY

WarmingUP consortium is investigating the potential to exploit shallow formations for geothermal heat extraction and particularly aiming at the Brussels Sands formation. Zwijndrecht is used as a case study location within the WarmingUP project Theme 4A.

In this document, several concepts are analysed to achieve the objective of economical, yet optimal and safe development of shallow geothermal prospects within Brussel sands formation, taking into account the associated risks and costs.

Several different well concepts for both production and injection wells were considered. Differentiating from each other by:

- (a) well trajectory: vertical (incl 2nd surface location), inclined, horizontal
- (b) well arrangement in the reservoir[1]: parallel, @ 90° and 180°
- (c) completion

Based on the analysis of all concepts, the concept with the perpendicular horizontal well arrangement appears to have an advantage over other designs in terms of produced heat and associated expenditures. Therefore, it is recommended to select it for a possible subsequent design phase. Inclined well and parallel well designs could also be included in the potential design phase candidate as Brussel sand gets shallower.

Wells are expected to produce within 50-200 m3/hr, therefore a 2-string well design with tie-back was chosen as a design for the various well trajectories. It can be easily scaled to accommodate a larger flowrate without major changes in the well design which allows better comparisons. Moreover, it is flexible for different sand control designs and corrosion control.

Shallow (near) and perpendicular horizontal wells give the highest production rates and seem the best economical option. Two vertical wells connected with a surface connection is economical the least attractive.

This report should be seen as a feasibility study on the economically best possible method to exploit shallow sands. As soon as the location data becomes available it's recommended to review whether the context of this document is valid (e.g. by means of a revision of this document), prior to starting working out the detailed well designs.

[1] *Only for the horizontal set-up*

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REFERENCE DOCUMENTS

Below is a list of documents that were consulted, used as a data source and/or used for reference information reported in this document.

WEP and Client Documents

- Lithostratigraphic Column WarmingUp_08-11-2021_v1

Client Documents

- Final Report Formation Evaluation Brussels Sand 2021-12-01
- Geel, de Haan and Peters, 2022. Characterisation and production of the Brussels Sand Member near Zwijndrecht Zuid. WarmingUp report

External Documents

- Protocol_injectiedrukken_bij_aardwarmte.pdf

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1 INTRODUCTION

WarmingUP consortium is investigating the potential to exploit shallow formations for geothermal heat extraction and particularly aiming at the Brussels Sands formation. Zwijndrecht is used as a case (or feasibility) study location within the WarmingUP project Theme 4A.

In this document, various concepts are analysed to achieve the objective of economical, yet optimal and safe development of shallow geothermal prospects within Brussel sands formation, taking into account the associated risks and costs.

The result is a recommendation of concepts with accompanying design notes on which the location-specific design could be based.

For this feasibility study, the WEP policies and procedures have been used, including the casing design manual. In addition, the best practices and lessons learned database has been reviewed and relevant items have been included in the design considerations. Legal requirements as set out by laws and regulations are implemented to create a realistic report with achievable recommendations.

1.1 Project definition and scope of work

1.1.1 Project definition

Perform a feasibility study for geothermal heat extraction from a shallow formation, and especially Brussels sand formation.

1.1.2 Scope of work

It is the scope of WEP to identify different concepts for WarmingUP/TNO requirements in order to establish a concept design for the shallow geothermal wells. The Concept Design will gather and consolidate data concerning:

1. Well objectives
2. Well trajectory
3. Well design and completion types
4. Well schematics
5. Drillability
6. Well maintenance and monitoring
7. Time and cost estimate

1.2 Well Data

Table 1: Well data

Item	Description
Operator	N/A
License	N/A
Drilling Location	Potentially Zwijndrecht; a range of depths is looked at
Well classifications	Vertical / Inclined / Horizontal
Well type	Geothermal (Producer / Injector)
Well name & ID	N/A
Target Formation(s)	Brussel Sands
Depth reference	570 – 1094 m

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2 WELL OBJECTIVES

The objective of the (pilot) geothermal doublet wells is to expand industry knowledge about shallow (unknown) and marginal reservoirs and develop economically viable well concepts for these less known geothermal prospects. Production will be achieved using an ESP in the production wells, after heat extraction (likely with help of a heat pump), a surface injection pump will be used to re-inject formation water back into the reservoir.

2.1 Well Lifetime

>20 years of well life is chosen and will mainly determine minimum separation between injector and producer wells.

2.2 Logging and coring

These objectives will depend on the amount of available knowledge on the exact location

Typical objectives:

1. Confirm lithological positioning of wellbore by means of MWD & LWD measurements and/or open hole logging.
   a. This will provide the basis for future depth referencing. In addition, the information gathered can be used for future wells in the same concession.
   b. For high inclination and horizontal wells, LWD is preferred over wireline to ensure the correct landing and placement of the well and to minimise openhole time
2. Coring operations need to be considered, as they are beneficial for better understanding of property distribution across Brussel sand formation. Which is critical for accurate well placements, which is ideally aligned with the best reservoir property direction. Coring is very beneficial in the design of sand control measures. Well placement is especially critical for horizontal wells where coring is not possible
3. Cased hole logging will be carried out to determine cement and casing integrity. In addition, cased hole logs will be used as baseline for any future wireline work and final abandonment.

Concept:

1. For depth referencing GR/MWD will be included in all drilling assemblies
2. Cutting descriptions will be made over the entire well.
3. Cement and casing integrity logs

2.3 Production

Objective:

1. Primary objective is to develop the less known shallow geothermal reservoirs i.e. Brussel Sands.

Concept:

1. Drill the well
2. Well clean-up and build natural gravel pack around screens
3. Well test
4. Produce warm water with temperature ranging from 28 to 45 degrees Celsius, extract heat and reinjection cold water back into a reservoir. Expected mean production rate is 50-200 m3/hr.

The low temperature range (~8°C injection temperature) imply that a heat pump will be required to increase the produced heat.

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3 WELL TRAJECTORY

3.1 Surface location

The (preliminary) surface coordinates are not known at this stage as this is a generic study. However:

- distance to the end-user has to be smaller compared to deep geothermal projects because of the low temperatures.
- 2 locations are required for the case of drilling 2 vertical wells both located above the geological correct position may be a challenge especially in or near an urban environment. Additionally, a surface pipeline is needed to transport the brine from the producer to the injector well what will add about 1M to 1.5M euro per kilometre.
- Locations will need to adhere to mining legislation requirements.

3.2 Lithostratigraphic column

A typical lithostratigraphic column has been generated to base the concepts upon. The real depths and presence of the various formations will depend on the exact location across the Netherlands.

The study considers 2 possible depths for the Brussels sands to create a complete overview that covers multiple locations. The column below is used for the shallow and technically most challenging case with a top Brussel Sands at only 570m TVD NAP.

Lithostratigraphic Column WarmingUp								WUP-GT-XX
Era	Group	Period	Formation	Epoch / Age	Member	Lithology	TV-NAP Depth (m)	AH-NAP Depth (m)
Cenozoicum	Upper North Sea NU	Quaternary	"Diverse"	Holocene-Pleistocene		Diverse continental deposits, mostly fluvial sands and silts intercalated by some thin layers of grey or greenish-grey, silty clays or peat, wood...	0	0
			Maassluis NUMS	Early Pleistocene		CU. Grey very fine to medium sand, micaceous and calcareous, shelly, slightly glauconitic. Intercalated light to dark grey clay, micaceous & calcareous with marine shells. Locally, basal gravel.	89	
		Tertiary	Oosterhout NUOO	Late Miocene to Pliocene		Light grey to greyish green very fine to medium sand, locally clayey, glauconitic, with shells. At the top, dark grey to greyish brown clay, silty or sandy. Shell banks (crags).	215	
			Breda NUBR	Late Oligocene - early Pliocene		Greyish to blackish green very fine to medium sand, silty, (very) glauconitic, calcareous, and locally micaceous or organic. Clay, very sandy to moderately silty. Intercalated sand and clay with goethite and phosphorite concretions.	354	
	Middle North Sea NM		Rupel NMRU	Early Oligocene Rupelian to Chattian	Boom NMRUBO (Rupel Clay)	Clay that becomes more silty towards base and top. Rich in pyrite, poor in glauconite and calcium carbonate tends to be concentrated in the septaria layers.	416	
				Rupelian	Berg NMRUBE (Vessem)	Silty to clayey sands with a low glauconite content, flint pebbles or phosphorite nodules commonly occur at the base.	510	
	Lower North Sea NL		Dongen NLDO	Middle to Late Eocene Lutetian to Bartonian	Asse NLDOAS	Marine dark greenish-grey and blue-grey, plastic clays. The unit locally shows indications of bioturbation, and may be glauconitic and micaceous.	535	
				Early to Middle Eocene Ypresian to Lutetian	Brussels Sand NLDOBR	Green-grey, glauconitic, very fine-grained sand with, mainly in the upper part, a number of hard, calcareous sandstone layers of some dm's thickness (high-resistivity).	570	
				Early Eocene Ypresian	Ieper NLDOIE	Soft, tough and sticky to hardened and friable clay. The lower part has a brown-grey colour, tending to beige or red-brown locally w/ pyrite and coalified plant remains. The upper two-thirds have a characteristic green-grey colour.	740	

Figure 1. Typical lithostratigraphic column for the shallow case.

3.3 Hydrocarbon Risk

Hydrocarbon Risk Assessment (HRA) & Quantitative Risk Assessment (QRA) were not performed as the exact location of the wells are not known. For potential projects these studies will be needed because shallow gas bearing layers are present in the Netherlands. The QRA study is used to assess whether the surface location is not in conflict with neighbouring structures (e.g. housing within 10^{-6} contour).

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3.4 Well target

The well targets are shown in the Table 2 and Table 3. This paragraph does not include coordinates, because the well targets have not been specified yet. For the purpose of this concept well design document the following assumptions are made:

- Top Brussel Sands:
  - similar to BRT-01 (top @ 570m TVD) for a shallow reservoir
  - and to OFL-01 (top @ 1094m TVD) for a deep reservoir

- Vertical and inclined wells are targeted to penetrate the whole reservoir section length.

- Although the best producing part of the Brussels Sand Mb is in the top ~80 to 100 m, the horizontal wells are targeted to the middle of the reservoir at depths of 655 meters and 1117 meters, respectively. Well placement of horizontal wells is critical and therefore the exact trajectories will have to be chosen based on project specific information and whether to stay in the best producing part of to cross the complete Brussel sands. The impact of such changes have only small impact on the feasibility.

- For the shallow and deep cases different reservoir thickness are used

Table 2: Target coordinates for a shallow reservoir

Description	Coordinates	X (RD) / N (ETRS89)	Y (RD)/ E (ETRS89)	Depth (mTVD)	Expected Thickness (mTVD)
Shallow	RD	unknown	unknown	570	170
	ETRS89	unknown	unknown		

Table 3: Target coordinates for a deep reservoir

Description	Coordinates	X (RD) / N (ETRS89)	Y (RD)/ E (ETRS89)	Depth (mTVD)	Expected Thickness (mTVD)
Deep	RD	unknown	unknown	1094	46
	ETRS89	unknown	unknown		

3.5 Lessons Learned & references

Observations, learnings and references to wells and papers especially about shallow directional work:

1. WEP lessons Learnt database shows few wells that targeted reservoirs shallower than 800m. Some wells show challenging shallow directional work e.g. the Frisia HVM-02 with an 28” section kicking off around 100m TVD. Section was drilled with a steerable mud motor (PDM) with an average BUR of 2°/30m and a maximum of 6°/30m. Special attention was given to the mud system used and very low flowrates to prevent washing out of the shallow sand layers.
2. The shallow and vertical Minewater wells in the south of Netherlands where drilled in harder formations prone to sever losses and had small targets that required active steering hence are not directly comparable with vertical well drilling the North Sea formations.
3. SPE-172897-MS - Successful Drilling and Completion of Shallow-depth horizontal well in unconsolidated formation with upto 18°/30m buildrates. Various interesting learnings

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& remarks such as preference of RSS over PDM's, mud & borehole stability importance and rig requirements (non-slant rig)

4. Zevenbergen GT wells with a TD at ~730m TVD. Drilled with 45° slanted rig. Required several sidetracks and months to complete. KOP of well with vertical section at 70m TVD with ~2-6°/30m DLS. The horizontal calcite streaks were difficult to cross at high angle with the used BHA designs.
5. Horizontal Drilling Pilot In a Shallow Heavy Oil Reservoir in Northwestern Romania – OMV-Petrom. Depth 198m TVD, 12-14°/30m with 9-5/8" casing. Used PDM with 2.12° bend. 300m OH and took 12 days. Similar wells took 20 and 26 days due to total losses. KOP at 10m in sand/gravel, low flows.
6. Schoonebeek horizontal steam injection wells at 700m ~900m TVD depth with KOP's at ~300m to 400m and BUR of ~2° to 6°/30m. Wells of ~1500m MD incl skidding and installation of completion are realised in less than 15 days. WWS screens are installed as lower completion
7. Recently drilled Nobian s-shaped wells have shallow KOP ~40m, 12-1/4" hole and do 6-8°/30m. Silicate mud and PDM's are used. Wells take about 2 weeks to drill.
8. Schlumberger Steerable Motor Handbook on Dog Leg Severity limitation per motorsize showing theoretical achievable limits which need to be respected :

Motor Type	Max DLS with 3° Bend (deg/100 ft)	Max Bit Offset with 3° Bend (in.)
A213XP	50	1.51
A238M	62	1.65
A287M	51	2.03
A313S	43	2.05
A350M	36	2.32
A475M	20	3.03
A500M	18	3.25
A625S	21	4.67
A675M	19	4.42
A700M	16	4.42
A825M	17	5.07
A962M	15	5.83
A1125M	13	6.15

From the various references mentioned above. The following learnings are taken:

1. A slant drilling rig is not considered because
   a) To prevent problem with future work-overs
   b) Rig availability
   c) Avoid special well heads
   d) Challenges with respect to maintaining hole angle in very shallow formations and subsequent high torque and drag values
   e) A vertical (or low angle) top hole creates a better torque & drag profile
2. Mud choice and specifications especially to prevent wash outs and high angle hole stability is very important
3. Steering equipment:
   a. Both mud motors and rotary steerable systems can be considered. Mud motors are in general less affected by hole condition as long as hole cleaning, operational restrictions (only low string RPM allowed with large bend settings) and drag are taken care off.
   b. High DLS RSS systems seem mainly available in smaller sizes (e.g. SLB Powerdrive Archer & WFD Revolution are capable of 15°/30m but come in

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maximum 6-3/4” size). The 9” SLB Powerdrive Orbit G2 can do 10°/30m also in larger hole sizes.
c. Taken a margin on the Orbit tool’s capabilities and to enable the use of both RSS as PDM tools, a maximum DLS of 8-9°/30m should be kept.

3.6 Well trajectory

3.6.1 Directional considerations

The required separation between wells at the reservoir mid was considered to be within the 850-1250m range. This will limit the early thermal breakthrough to 1-2° Celsius in 20 years according to Geel et al., 2022. To increase productivity and injectivity high inclination and horizontal wells must be considered. This will generate challenging directional trajectories.

The various well trajectories and well designs have been provided to TNO who used the Zwijndrecht reservoir model to calculate geothermal output (temperature and flowrate) and break through time. This has been an iterative process with rough optimisations in order to compare the feasibility of the various concepts opposed to optimise for 1 specific design/location.

There is no strict limit to a maximum inclination and build rate; Nevertheless, the minimum possible build rate will be used to ensure minimum pipe wear and a less problematic/expensive drilling procedure.

3.6.2 Vertical section

It was decided to have at least 270 meters of vertical section prior to the Kick-Off-Point:

- to ensure that we have sufficient weight to drill and compete for the well in most efficient manner
- an ESP pump should be installed either in a vertical or tangent section to prevent bending stresses on the pump and resulting shortened life of 270m seems sufficient for all relevant drawdowns.

3.6.3 Maximum inclination (wirelineability)

Wireline may be required during in the construction and/or production phase. The typical wireline limit is considered to be 65° by wireline contractors. Above this inclination, more expensive tractors or alternative logging tool conveyance would need to be used. For the inclined well option is therefore a maximum inclination of 65° chosen.

3.6.4 Torque, drag and wear

A J-shape and horizontal well with a large build rate generally creates high wellbore friction due to the bends present in the well. This high friction results from high side-loading on the pipes and can result in casing/tubing wear. To minimize these effects, it is important to create a smooth wellbore i.e. constant DLS.

3.6.5 Horizontal calcite streaks

For the cost, drillability and pressure drop estimates it does not make a big impact, but horizontal compartments are present in the Brussel Sand what will require further investigation and choses to be made on exact well placement such as horizontal wells to stay within 1 block or semi-horizontal to drill-through the streaks. BHA design will need to be adapted for the case that the streaks need to be crossed at high angle.

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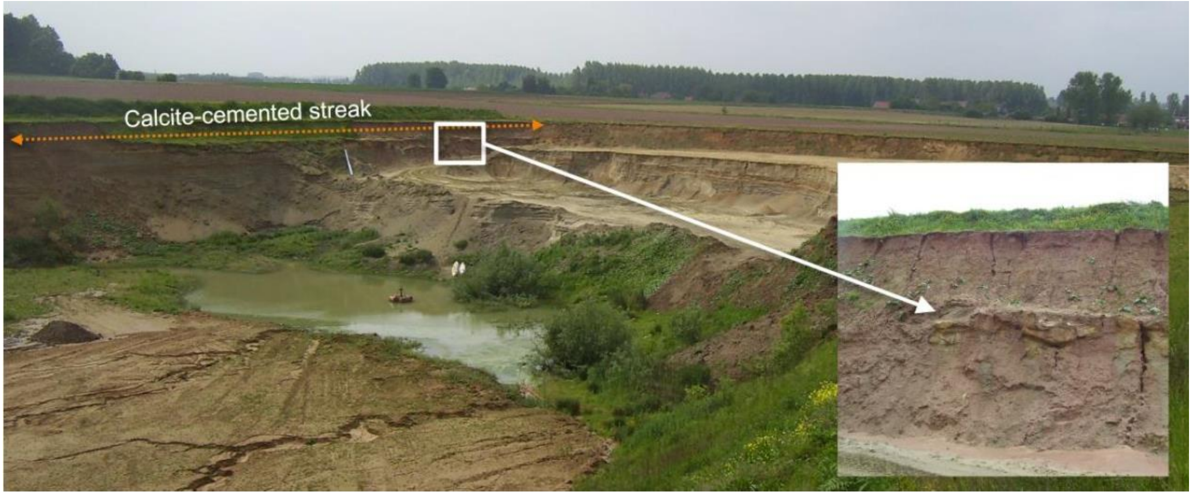

Figure 2. Horizontal streaks are present in the Brussel sands. Photo by Timo Nijland.

3.7 Well options

This report is considered a feasibility study hence many simplifications are made to allow a generic result focussing on the techno-economic part. Many optimisations especially with respect to well trajectories are possible and needed in a subsequent project.

3.7.1.1 Vertical

The first option is a simple vertical well that penetrates though the whole reservoir section length. Well trajectory details for a shallow and deep reservoir can be seen in the Table 4 and Table 5.

Table 4: Vertical well trajectory for a shallow reservoir

Design 1: Vertical well					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
End of Horizontal section	740	740	0	0	0

Table 5: Vertical well trajectory for a deep reservoir

Design 1: Vertical well					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
End of Horizontal section	1140	1140	0	0	0

3.7.1.2 Inclined

The second option is an inclined well with a 65° tangent section, where wells are drilled 180 degrees opposed to each other. Well, trajectory starts with a 270-meter vertical section, which provides the necessary weight on the bit for a stable directional drilling procedure. This is followed by a kick-off point (KOP) at 270 m TVD and 404m MD build section. With a build rate of (6.6°/30m), it was possible to reach desired maximum inclination of 65° at the depth of 570m (end of the build, EOB), just at the top of the Brussel Sands while satisfying the required well separation of 850m at the mid of the reservoir. The total length of the well is 1098m MD and penetrates the complete Brussel Sands member (S1, S2 and the most productive S3) through a 400-meter-long production section.

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Table 6: Inclined well trajectory for a shallow reservoir

Design 2: Inclined well					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
Kick-off point (KOP)	270	270	0	0	0
End of build (EOB)	570	694	65	90/270	6.59
End of Horizontal section	740	1098	65	90/270	0

To ease comparing the various concepts, it was decided to use similar trajectory for the deep reservoir, with an extension in the vertical section. A deeper kick-off will enable longer horizontal sections if needed but requires higher build (and turn) rates and prolongs the total well length. Therefore and depending on actual targets, geology, ESP placement, required break through times etc. the trajectories can be optimised.

Table 7: Inclined well Trajectory for a deep reservoir

Design 2: Inclined well					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
Kick-off point (KOP)	680	680	0	0	0
End of build (EOB)	1084	960	65	90/270	6.59
End of Horizontal section	1510	1140	65	90/270	0

The 2D and 3D images of well trajectories can be seen in the Figure 3 and Figure 4, respectively. Note, that trajectory in Figure 4 incorporate the ISCWSA MWD Rev.5 error model, which indicate possible deviation of the well within an elliptical uncertainty envelope. Red surfaces indicate top and bottom of the reservoir.

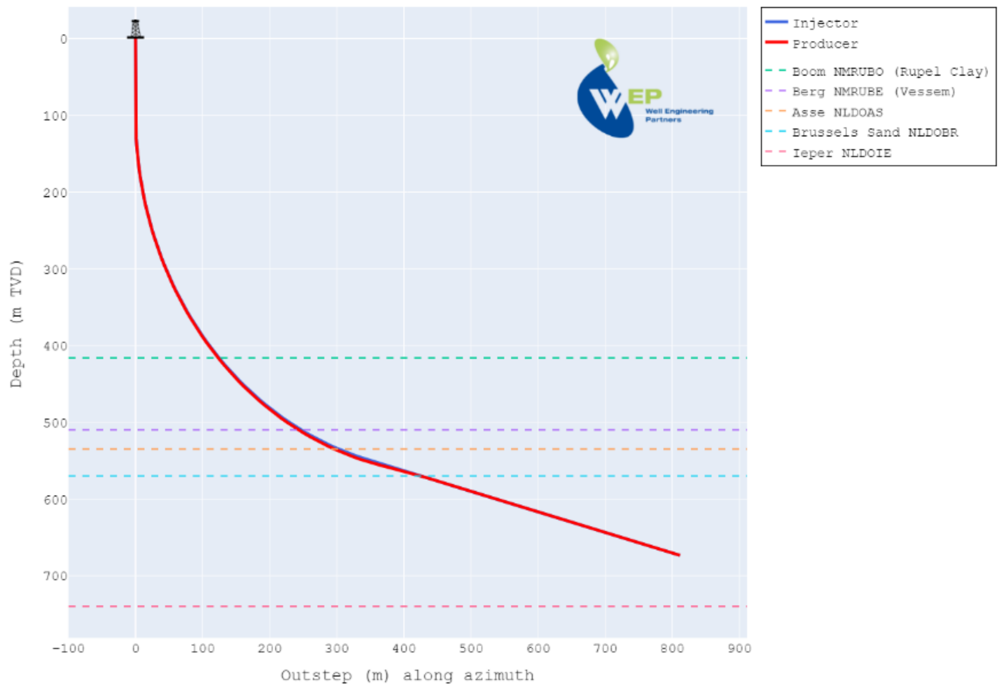

Figure 3: Outstep view of the well trajectory in a shallow reservoir

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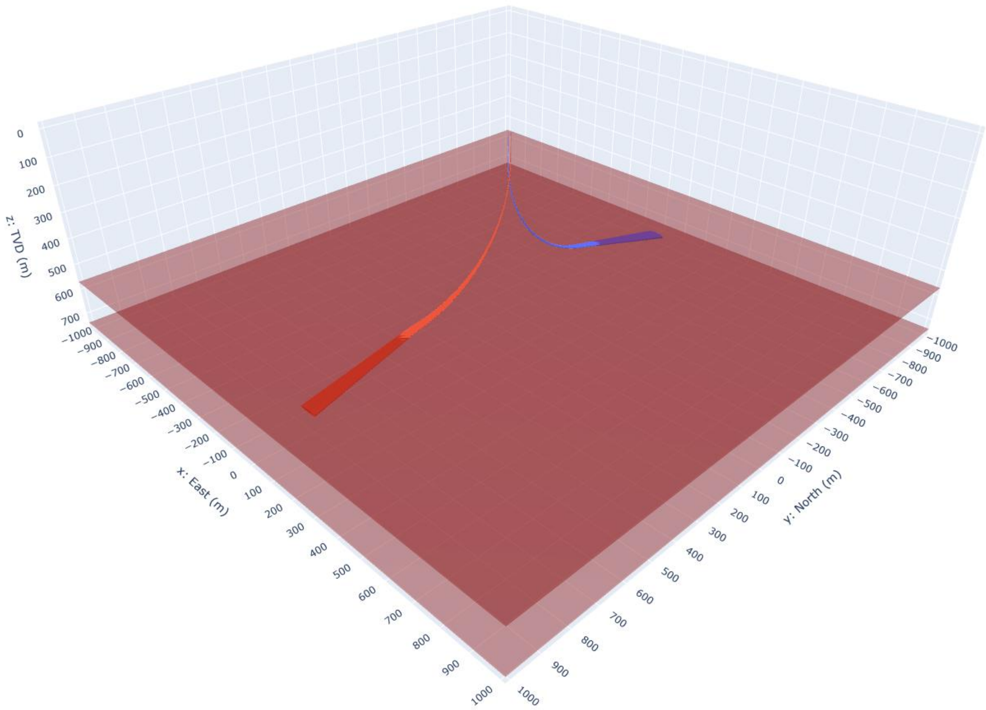

Figure 4: 3D view of the inclined wells in a shallow reservoir. Note the large differences between separation at the top and bottom of the reservoir.

3.7.1.3 Horizontal

3.7.1.3.1 Horizontal – opposed from each other (180° angle)

The third option is to drill 2D horizontal wells opposed to each other and a conservative build rate. The overview of this well trajectory can be seen in the Table 8 and Figure 5. The maximum inclination of 90° was reached at depth of 655m, which is followed by a 500m horizontal section. Well separation at the horizontal section start is equal to 1114 m. The required KOP was at 83m TVD. This depth was chosen to be an optimal depth for well to reach horizontal orientation right in the middle of the reservoir with the often-used build rate of 3°/30m. Unfortunately, this profile doesn't allow the ESP to be placed in a tangent section. Therefore, the often used 3°/30m is too low for such shallow wells. For injector wells this statement may be ignored to get more flexibility in trajectory and to allow lower build rates. Short term ESP use for clean-outs or well tests may still be considered or replaced with alternative lift methods e.g. nitrogen lifting.

Table 8: Horizontal well trajectory for a shallow reservoir

Horizontal (perpendicular)					
Section	**TVD [m]**	**MD [m]**	**Inc (°)**	**Azimuth (°)**	**DLS (°/30m)**
Surface	0	0	0	0	0
Kick-off point (KOP)	83	83	0	0	0
End of build (EOB)	655	983	90	90	3
End of Horizontal section	655	1483	90	180	0

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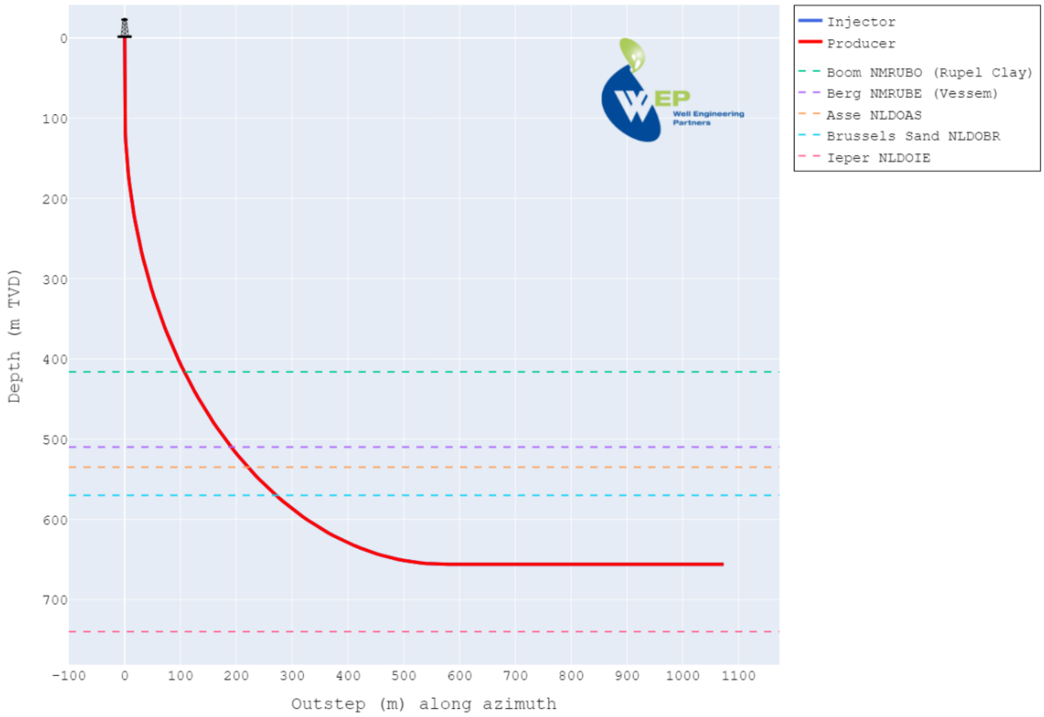

Figure 5: Outstep view of the horizontal well trajectory in a shallow reservoir

3.7.1.3.2 Horizontal - Parallel with an 850 meters separation

An alternative option is to drill 3D wells with a parallel arrangement and a fixed separation of 850m in the horizontal section. This design has a higher requirement for the weight on the bit, hence a longer vertical section is necessary. Therefore, well trajectory starts with a 270m vertical section, which is followed by a kick-off point (KOP). The maximum inclination of 87° was reached at the depth of 635m end of the build (EOB) with a maximum DLS of 5.4° / 30m. Finally, a 750 m horizontal section is drilled right in the middle of the formation making the total depth of the well equal to 1853 meters. The overview of this option well trajectory can be seen in Table 9 and Figure 6.
The wells are sub-horizontal to ensure that they are not stuck between low permeable layers. This will require attention to the BHA design to ensure that sufficient steering force is generated. Also right ‘landing of the well’ depth will require further investigation.

Table 9: Horizontal well trajectory for a shallow reservoir

Design 3: Horizontal well - 850m					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
Kick-off point (KOP)	270	270	0	0	0
End of build (EOB)	635	1103	87	205	5.43
End of Horizontal section	668	1853	87	205	0

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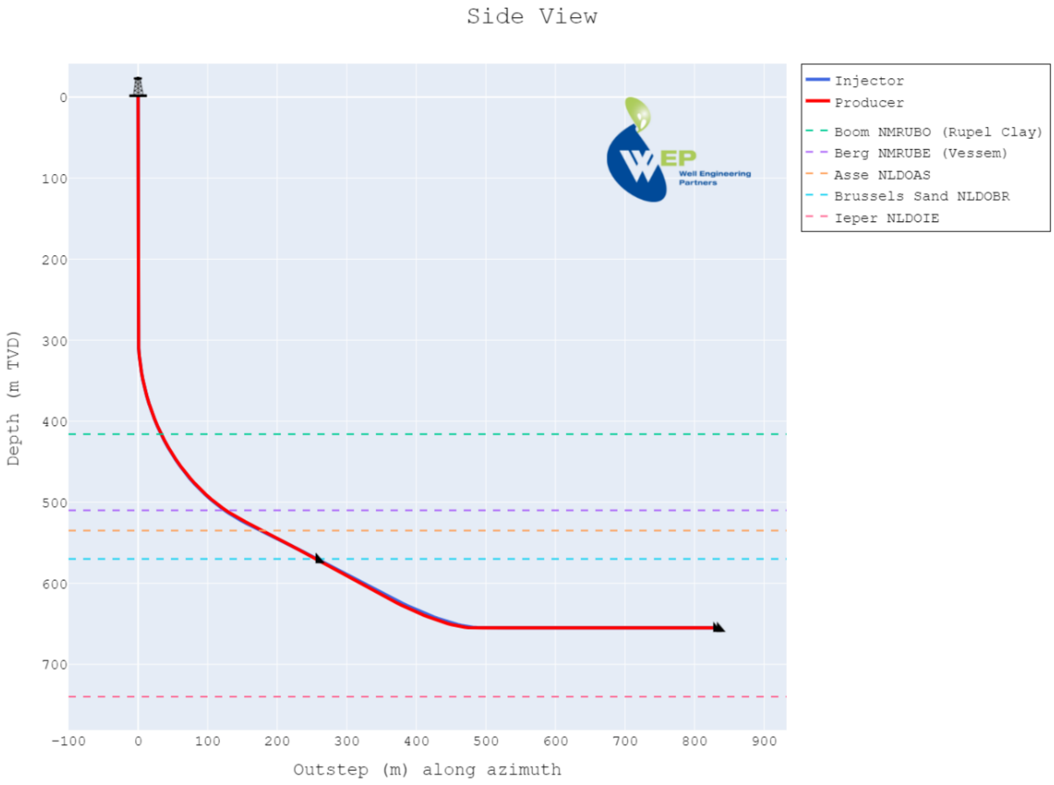

Figure 6: Side view of the well trajectory in a shallow reservoir

Trajectory design also incorporates an ISCWSA MWD error model with a cylindrical uncertainty edge as seen in Figure 7. Based on model results the maximum horizontal deviation from the target is equal to 39.3 m, whereas the maximum TVD error could be up to 13 meters.

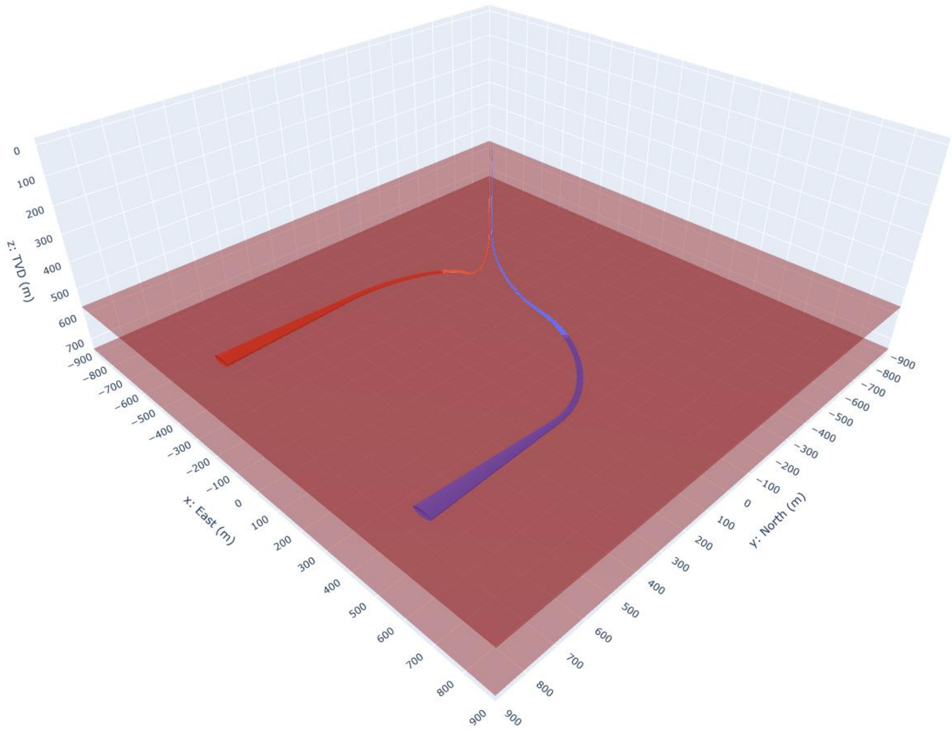

Figure 7: 3D view of the well trajectory in a shallow reservoir

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Similar well trajectory was proposed for the deep reservoir. All well designs can be scaled to reach deeper targets using an increased vertical section length.

3.7.1.3.3 Horizontal - Parallel with a 1250 meters separation

Similar well trajectory was proposed for the this well design as for 850m separation case, but with an increased horizontal separation to reduce early thermal breakthrough.
The overview of well trajectory can be seen in Table 10.

Table 10: Horizontal well trajectory for a shallow reservoir

Design 4: Horizontal well - 1250m					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
Kick-off point (KOP)	270	270	0	0	0
End of build (EOB)	639	1309	88	205	6.3
End of Horizontal section	671	2059	88	205	0

3.7.1.3.4 Horizontal – wells perpendicular to each other

This option encounters a horizontal well doublet, where wells form 90° between them with a 500m separation at the start of horizontal section. The overview of well trajectory can be seen in Table 11 Table 10 Figure 8.

Table 11: Horizontal well trajectory for a shallow reservoir

Design 5: Horizontal well - perpendicular					
Section	TVD [m]	MD [m]	Inc (°)	Azimuth (°)	DLS (°/30m)
Surface	0	0	0	0	0
Kick-off point (KOP)	270	270	0	0	0
End of build (EOB)	655	858	88	250/160	4.8
End of Horizontal section	655	1608	88	250/160	0

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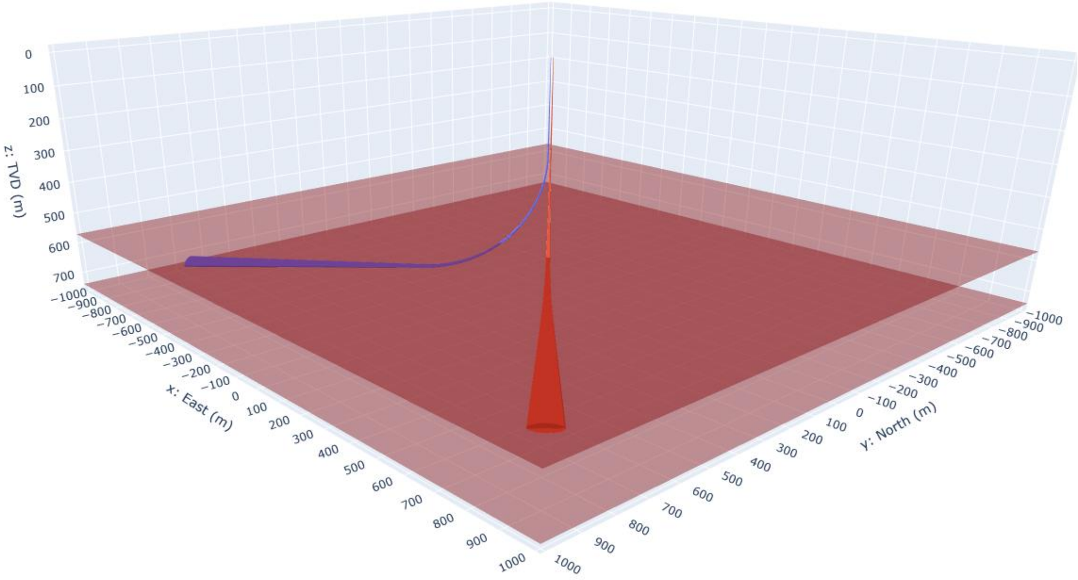

Figure 8: 3D view of the 90° (perpendicular) well trajectory in a shallow reservoir

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4 WELL DESIGN

The concept casing design is a bottom-up design starting with the completion and concluding with the casing strings required while considering technical limitations to well construction. The Dutch mining regulations, design requirements requested by WarmingUp and WEP's Casing Design Manual and design best practices are considered for the well design.

4.1 Concept overview

Following the objective to develop a shallow geothermal prospect in an economic, safe and regulation friendly manner it was decided to use a well schematic seen in Figure 9 as a basis for all well designs. The mentioned 2-string well design is applicable for both injection and production wells and all well trajectories. Differentiating only by the presence of the ESP and length, which is scaled according to the well trajectory. In all well concepts the cemented 9-5/8" casing is set at the bottom of the Asse clay formation (just above reservoir). In the North of the Netherlands the shoe will be placed in the bottom of the Rupel formation. The reservoir section is completed with a Metal Mesh Sand Screen (MMSS), which is placed over the whole reservoir section. Swellabe packers will be used in the horizontal wells to prevent cross-flow.

Concept A (base scheme) is based on the conventional geothermal casing scheme with a dedicated downhole sand control functionality. The concept is fitted with a (partial) internal tie-back to protect the cemented casing from corrosion and erosion and to provide a monitoring annulus. The overview of casing setting depth and pipe/hole sizes for all designs can be seen in Table 12 and Table 13, respectively. A 30-meter liner lap is considered in all five designs.

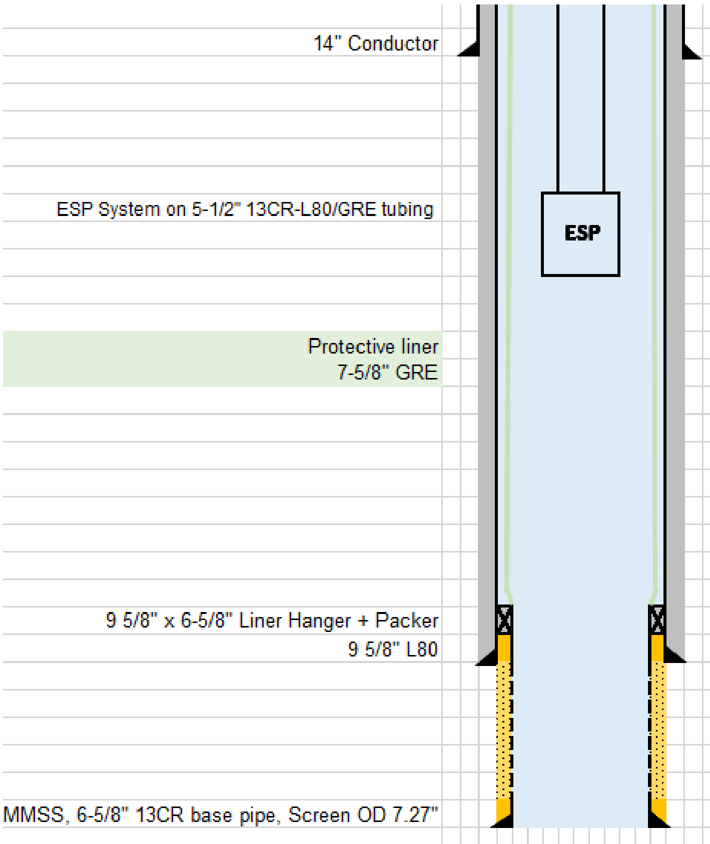

Figure 9: Overview of the well schematic Option A

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Table 12: Casing seat depth for different designs

Section	Design: 1 TVD [m]	Design: 1 MD [m]	Design: 2 TVD [m]	Design: 2 MD [m]	Design: 3 TVD [m]	Design: 3 MD [m]	Design: 4 TVD [m]	Design: 4 MD [m]	Design: 5 TVD [m]	Design: 5 MD [m]
14" Conductor	30	30	30	30	30	30	30	30	30	30
ESP & 5-1/2" tubing	260	260	260	260	260	260	260	260	260	260
KOP	270	270	270	270	270	270	270	270	270	270
9 5/8" Casing/EOB	570	570	570	694	655	1103	639	1309	655	858
MMSS	740	740	740	1098	668	1853	671	2059	655	1608

Table 13: Pipe and hole sizes for different well sections

Section	Pipe OD [in]	Pipe ID [in]	Hole ID [in]
14" Conductor	14.000	12.876	-
5-1/2" tubing	5.500	5.012	-
7-5/8" GRE	7.625	6.969	-
9 5/8" Casing	9.625	8.921	12.250
MMSS	6.625	5.920	8.500

4.1.1 Pressure loss calculations

Pressure loss calculation for the vertical/inclined section of the well is typically a straightforward process. Whereas the horizontal section is more complicated and requires assumptions regarding fluid influx. It was decided to use four different fluid influx profiles for the horizontal section as can be seen in Figure 10. Case 1 is the uniform influx entry, in case 2 flow distribution linearly increases with distance, whereas in case 3 flow distribution linearly decreases with distance. Finally, the ultimate case 4, where all influx is at the tip of the horizontal section (at 0 meters). For this study an average pressure loss of all four cases was used as an approximation of a pressure drop across horizontal section. A K-factor of 1.3 and pipe roughness of 0.2mm was used to estimate a minor and major pressure loss throughout the sand screen.

To get a more even drain in oil wells and to prevent early water break through, inflow control devices (ICD's) are used. However, in geothermal wells these are probably not beneficial and even counterproductive as they choke the flow.

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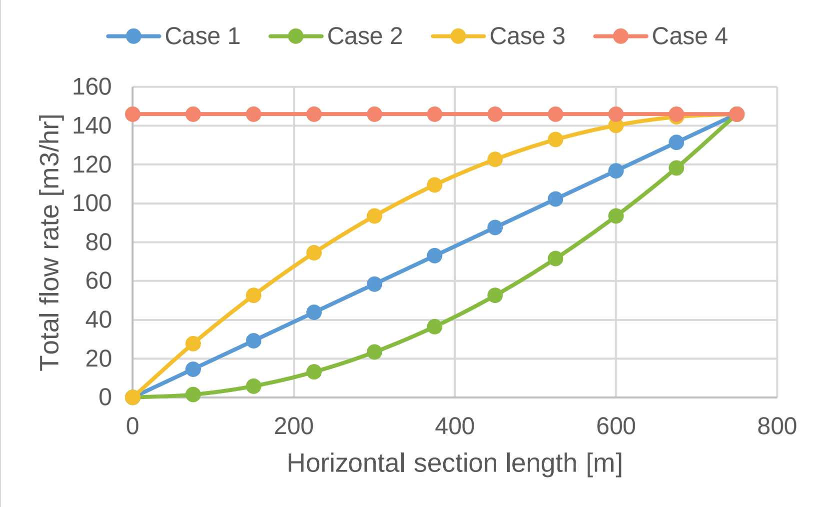

Figure 10: Total flow rate profile across the horizontal section of the well

The overview of frictional pressure losses for different concept design is present in Table 14. Contribution of different well components towards total pressure drop are following:

- 42% production tubing
- 15% ESP annulus
- 17% 9 5/8" Casing
- 26% MMSS

Table 14: Dynamic pressure loss for producer and injector

	Flow rate [m3/hr]	Dynamic pressure loss Producer [bar]	Dynamic pressure loss Injector [bar]
Design 1: Vertical well	95	1.89	0.70
Design 2: Inclined well	120	3.75	1.86
Design 3: Horizontal well - 850m	146	6.42	3.68
Design 4: Horizontal well - 1250m	139	6.16	3.65
Design 5: Horizontal well - perpendicular	148	6.18	3.36

Pressure loses through surface equipment and pipeline (Design:1) were not considered.

4.2 Reservoir Modelling

In the table below we can see an overview of the input parameters that were prepared by TNO and used throughout this study. The Productivity Index (PI), Injectivity Index (II) and production temperature is given after 20 years production. Initial injectivity and temperature is larger. Injection temperature is 8 °C for all well designs. The PI, II and temperature are the average of an ensemble of 14 members. For details see Geel et al., 2022.

Table 15: Input parameters used in this study

	Design 1: Vertical well		Design 2: Inclined well		Design 3: Horizontal well - 850m		Design 4: Horizontal well - 1250m		Design 5: Horizontal well - perpendicular	
	Prod.	Inj.	Prod.	Inj.	Prod.	Inj.	Prod.	Inj.	Prod.	Inj.
PI / II [m3/hr/bar]	9.6	6.3	11.6	7.5	13.6	10	14	9.4	16.3	9.6
Temperature [°C]	30.7	8	29.3	8	29.1	8	31	8	29.1	8
Brine viscosity [cp]	0.89	1.39	0.91	1.39	0.91	1.39	0.88	1.39	0.91	1.39

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Brine Density [kg/m3]	1024	1029	1024	1029	1024	1029	1024	1029	1024	1029

4.3 Casing design

4.3.1 Number of strings

A conventional 2-string design was used to be able to cement the 1st section and install an open hole sand screen in the 2nd section. A 3-string design is not required as most modern wells set first casing at the bottom of the North Sea group – if no shallow gas suspected. Therefore, a Hydrocarbon Risk Assessment will always be required. Such a study (and with good and nearby offset data) may be used to request to drill the reservoir section also without BOP to save time and money.

If no hydrocarbons are present a 1-string design may be used for the deviated wells which is in general cheaper and will reduce flat time and may therefore reduce overall time and cost. However, pressure testing of casing will be more complicated due to the open screens. Single-string designs are not an option for horizontal wells.

The following options could be considered with respect to a 1-string design:
1. 1-string (with casing & filters) will require a top-fill to ensure that filter remain open so similar to water well drilling:
    a. Is only possible in vertical wells
    b. Due to the top-fill requires a relatively large hole size to fit a chute (typically 10cm) and/or spaghetti string. This will increase drilling time; rig power requirements and mud & cutting quantities hence will increase cost significantly.
    c. The drilling fluid will be the same while drilling overburden and reservoir what introduces additional risk either in borehole stability or reservoir impairment.
2. 12-1/4” hole and 9-5/8” casing & screens are installed and cemented in place using a 2nd stage cement job. An open-hole packer is placed above the reservoir and a stage/DV-collar is used to cement the top section. A tubing on a packer will be installed to create a monitorable annulus.
    a. Reservoir will be cemented if the open-hole packer fails, so placement (in a not washed out) section is crucial. This is a high risk that needs to be evaluated.
    b. Due to the ‘*leidraad putontwerp’* requirement of monitorable annulus the horizontal ID will be larger than in the top hole. What does balance the pressure over the reservoir nicely.
    c. Space for the ESP and tubing/flatpack will be relative small so this approach seems primarily an option for the injector well

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4.4 Completion Design

4.4.1 Aquifer/lower completion

The Particle Size Distribution within the Brussel Sands has been investigated by Veldkamp, J.G., C.Geel and E. Peters, 2022., Characterisation of the Brussels Sand Member from cuttings - particle size distribution and permeability, WarmingUp report, by analysing cuttings from 17 wells across the Netherlands. In addition, data were available from wells sampled in the 1980s and the recent well ZVB-GT-01. The unconsolidated sands seem rather broadly distributed therefore to prevent clogging Metal Mesh Sand Screens (MMSS) are suggested instead of Wire Wrapped Sand Screens. The natural gravel pack will need to be built with care (slow start-up) and swell packers will be placed to prevent cross-flow via the annulus. The use of MMSS implies that during early production fines should be expected.

Property	Value
D10	146 µm
D40	87 µm
D90	40 µm
D95	32 µm
Sub 44 µm	11%
D10/D95	4.6
D40/D90	2.17

Figure 11. Properties of the approximate particle size distribution for the Zwijndrecht location.

For slot size determination (typically 200mu till 300mu) testing should be done using real cuttings or, better, core samples. However, this will require an 'exploration well'.

The use of screens in high angle wells will limit the operational options (no rotation) to get the screens to TD. Therefore, proper mud system and operational care is required to minimise ledges / washouts due to sands. An option to eliminate the use of wash pipe to keep the screens weight as low as possible but to enable circulation is wash pip free screen (see appendix 8.1 for more information). Further investigation or alignment to the required screens breaker fluid and potentially drilling fluid breaker may bring added value.

4.4.2 Upper completion

The upper completion comprises:

- Protective liner / tieback
- ESP + production tubing

The completion design focuses on the required tubular sizes to provide a flow path capable of handling up to 200 m³/hr production rates, while also taking into account additional measures to reduce corrosion and erosion effects. Note that production of fines will occur at the beginning of production.

Production will be maintained by use of an ESP due to its high efficiency. The ESP will have a maximum diameter of 5 1/2" and a 5-1/2" tubing inside a 7-5/8" tie-back.

4.4.3 Velocities & size considerations

A broad range of flowrates are expected, from 50 m3/hr to 200m3/hr. The 200m3/hr cap is used to limit the horizontal well length and the amount of well designs. For the low flowrate (vertical) wells no smaller well design is considered, although possible, but cost benefits may not be

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sufficient to offset the low heat production. Therefore, for all designs the same 8-1/2" hole size and pipe dimensions are used. The critical erosional velocity (API RP14E) is approximated as 5.72 m/s, which was calculated for an expected fluid density of 1024 m3/kg and empirical constant (C) of 150. The maximum velocity is expected in the ESP annulus, therefore applying critical erosional velocity as a threshold, Table 16 was generated and used for selection of an appropriate pipe size.

Table 16: Fluid velocity for different pipe size and flow rate. ESP system OD is equal to 5-1/2". Source WEP Casing Design Manual.

OD	Wht	ID	ID (drift)	Annulus area	Debiet / Flow rate (m3/hr)										
(inch)	(lbs/ft)	(inch)	(inch)	m^2	20	40	60	80	100	120	140	160	180	200	220
6 5/8	24.00	5.921	5.796	0.002436	2.3 m/s	4.6 m/s	6.8 m/s	9.1 m/s	11.4 m/s	13.7 m/s	16.0 m/s	18.2 m/s	20.5 m/s	22.8 m/s	25.1 m/s
6 5/8	20.00	6.049	5.924	0.003213	1.7 m/s	3.5 m/s	5.2 m/s	6.9 m/s	8.6 m/s	10.4 m/s	12.1 m/s	13.8 m/s	15.6 m/s	17.3 m/s	19.0 m/s
7	26.00	6.276	6.151	0.004630	1.2 m/s	2.4 m/s	3.6 m/s	4.8 m/s	6.0 m/s	7.2 m/s	8.4 m/s	9.6 m/s	10.8 m/s	12.0 m/s	13.2 m/s
7	23.00	6.366	6.241	0.005207	1.1 m/s	2.1 m/s	3.2 m/s	4.3 m/s	5.3 m/s	6.4 m/s	7.5 m/s	8.5 m/s	9.6 m/s	10.7 m/s	11.7 m/s
7	20.00	6.456	6.331	0.005792	1.0 m/s	1.9 m/s	2.9 m/s	3.8 m/s	4.8 m/s	5.8 m/s	6.7 m/s	7.7 m/s	8.6 m/s	9.6 m/s	10.6 m/s
7 5/8	29.00	6.875	6.750	0.008622	0.6 m/s	1.3 m/s	1.9 m/s	2.6 m/s	3.2 m/s	3.9 m/s	4.5 m/s	5.2 m/s	5.8 m/s	6.4 m/s	7.1 m/s
7 5/8	24.00	7.025	6.900	0.009678	0.6 m/s	1.1 m/s	1.7 m/s	2.3 m/s	2.9 m/s	3.4 m/s	4.0 m/s	4.6 m/s	5.2 m/s	5.7 m/s	6.3 m/s
8	58.50	6.500	6.375	0.006080	0.9 m/s	1.8 m/s	2.7 m/s	3.7 m/s	4.6 m/s	5.5 m/s	6.4 m/s	7.3 m/s	8.2 m/s	9.1 m/s	10.1 m/s
8	31.00	7.250	7.125	0.011306	0.5 m/s	1.0 m/s	1.5 m/s	2.0 m/s	2.5 m/s	2.9 m/s	3.4 m/s	3.9 m/s	4.4 m/s	4.9 m/s	5.4 m/s
8 5/8	36.00	7.825	7.700	0.015698	0.4 m/s	0.7 m/s	1.1 m/s	1.4 m/s	1.8 m/s	2.1 m/s	2.5 m/s	2.8 m/s	3.2 m/s	3.5 m/s	3.9 m/s
8 5/8	24.00	8.097	7.972	0.017893	0.3 m/s	0.6 m/s	0.9 m/s	1.2 m/s	1.6 m/s	1.9 m/s	2.2 m/s	2.5 m/s	2.8 m/s	3.1 m/s	3.4 m/s
9 5/8	47.00	8.681	8.525	0.022857	0.2 m/s	0.5 m/s	0.7 m/s	1.0 m/s	1.2 m/s	1.5 m/s	1.7 m/s	1.9 m/s	2.2 m/s	2.4 m/s	2.7 m/s
9 5/8	43.50	8.755	8.599	0.023511	0.2 m/s	0.5 m/s	0.7 m/s	0.9 m/s	1.2 m/s	1.4 m/s	1.7 m/s	1.9 m/s	2.1 m/s	2.4 m/s	2.6 m/s
10 3/4	51.00	9.850	9.694	0.033834	0.2 m/s	0.3 m/s	0.5 m/s	0.7 m/s	0.8 m/s	1.0 m/s	1.1 m/s	1.3 m/s	1.5 m/s	1.6 m/s	1.8 m/s
10 3/4	45.50	9.950	9.794	0.034837	0.2 m/s	0.3 m/s	0.5 m/s	0.6 m/s	0.8 m/s	1.0 m/s	1.1 m/s	1.3 m/s	1.4 m/s	1.6 m/s	1.8 m/s
13 3/8	72.00	12.347	12.250	0.061919	0.1 m/s	0.2 m/s	0.3 m/s	0.4 m/s	0.4 m/s	0.5 m/s	0.6 m/s	0.7 m/s	0.8 m/s	0.9 m/s	1.0 m/s
13 3/8	68.00	12.415	12.259	0.062772	0.1 m/s	0.2 m/s	0.3 m/s	0.4 m/s	0.4 m/s	0.5 m/s	0.6 m/s	0.7 m/s	0.8 m/s	0.9 m/s	1.0 m/s

4.4.4 Corrosion Prevention & material selection

Production water salinity is of sea-water level. No data was provided H_2S or CO_2 content but the temperature implies a non- or low-corrosive environment. Bacterial corrosion is potentially a challenge which may also affect injectivity.

The installation of the protective tie-back will provide protection to the 9-5/8" section, enables monitoring as per Code of Practice of GeothermieNL and allows future side-tracking if needed. Two approaches can be taken with respect to material choice of the tie-back:

1) An as cheap as possible tieback e.g. as low weight, low grade carbon steel tubing, with the scheduled replacement after a number of years. This will eventually require a work-over to replace the tubing plus a new tubing. However, after several years of production the optimal material choose can be made. Permanent components as the screens and hanger will need to be made out of 13 chrome steel.
2) Aim to reach the full 20+ years lifetime with 1 string. For steel pipe, further analysis is needed to determine the minimum percentage of chrome. A more more predictable alternative with respect to corrosion is a (full-) GRE tubing as shown below. Cost level is similar or lower than 13-Chrome. GRE lined pipe could be an option but will have a thicker wall hence smaller ID. Full-GRE (composite) will have the advantage that its lighter and easier to handle than steel.

A single skin full GRE or 13-Chrome (or higher) will give sufficient corrosion resistance and will reduce both CAPEX as OPEX. It will require a proper (wireline) monitoring program and it has to be seen if this fits in the '*leidraad put ontwerp'* (Code of Practice of GeothermieNL).

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Figure 12. Example of GRE connection suitable for downhole applications. Source Huisman Geo.

4.4.5 Artificial lift

For high-capacity systems, as geothermal doublets are, Electric Submersible Pumps (ESP ‘s) are chosen because of their high overall system efficiency (35-60%) which in general offset the ESP disadvantages such as high CAPEX and work-over cost, poor solids handling and space requirements in the well. The latest designs use permanent magnet motor what further increases the efficiency or decreases the size for a given efficiency. Therefore, a permanent magnet ESP would be best choice.

However, as production of solids are for the first period expected it may be useful to consider a jet pump which is cheaper and can handle solids better. It can also be placed in curved sections. The low efficiency of maximum ~30% is a significant disadvantage. A sensitivity study taking also into account changes in production over the year, formation uncertainties, production of fines may be useful.

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5 DRILLABILITY

5.1 Torque, Drag and hydraulics

The following tables summarize the torque and drag (T&D) analysis using *Landmark Wellplan* software.
The highest modelled hook load and off-bottom torque are used to define the minimum rig requirements (see Table 17); therefore the largest hole/casing and deepest casing point combination has been considered: Horizontal well
The completion strings have been modelled with 1,20 sg drilling fluid in the well.

Table 17: Torque and Drag analysis for a Horizontal well

#	Section, phase	Max. Hook load (metric ton)	Max. Torque (ft-lbf)	Min. Flow rate (l/min)
1	Drilling 12 1/4" hole	75	6919	3550
2	Running 9 5/8" csg	62	8699	n/a
3	Drilling 8 1/2" hole	91	12542	1740
4	Running 7" liner	45	3710	n/a

5.2 Minimum drilling rig requirements

Based on the above-mentioned torque, drag and hydraulics analysis the minimum requirement for the rig is summarized in the Table 18.

Table 18: Minimum drilling rig requirements

Max. expected drag	91.3	ton +
Overpull margin	50	ton +
round off (incl. 10%)	160	
Top Drive / Min. continuous torque requirement:	-	-
Max. expected torque	12542	ft-lbf
Pump power		
Flowrate and SPP:	3550	l/min
Number of mud pumps:		
Shaker capacity		
Able to handle min.:	3550	l/min

5.3 Alternative Options

5.3.1 Casing drilling 12-1/4” hole

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Casing drilling is a good option to reduce formation related risks, to simplify mud systems and to safe time, hence reduce CAPEX. Casing drilling is typically used for drilling soft shallow sections and it will increase flexibility with concern to mud systems and allows drilling at lower flowrates. Also weight transfer is less of a problem compared to conventionally drilled very shallow high angle wells. In Figure 13, Figure 14 and Figure 15 torque and drag analysis are shown for casing drilling a 12-1/4" hole of Design: 4 (it has the longest 12-1/4" section). The feasibility of CwD will require further investigation as casing fatigue will limit the allowable dogleg. In general as maximum 6°/30m dog leg is considered for 9-5/8" CwD.

Minimum pump requirements:

- Power > 550 KW
- Conservative pump rate > 3000 l/min

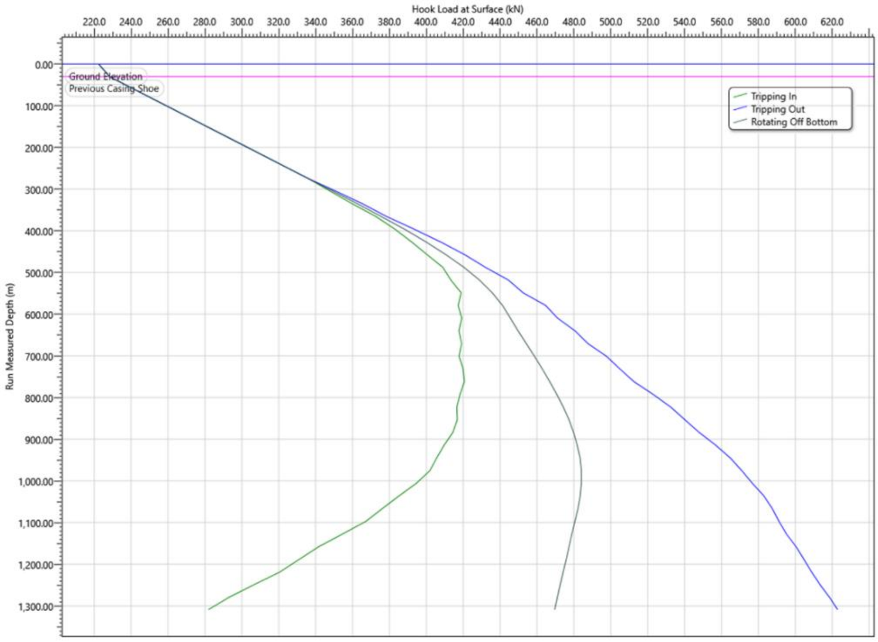

Figure 13: Hook load. Source: Landmark suite

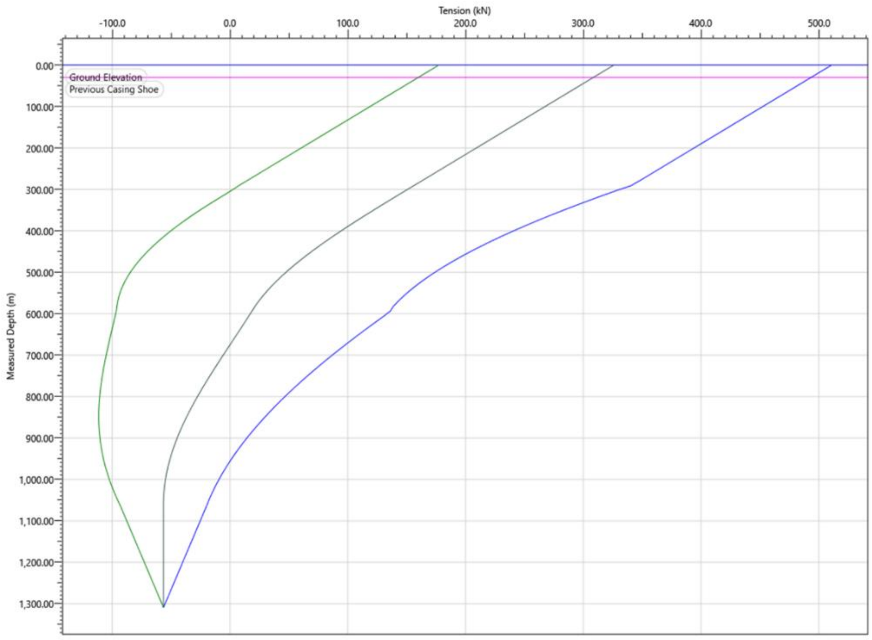

Figure 14: True Tension. Source: Landmark suite

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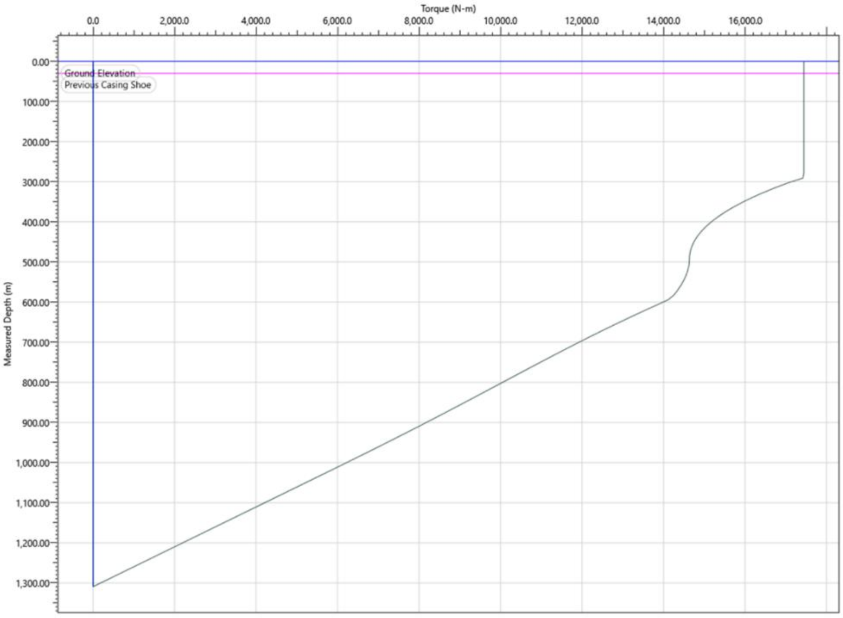

Figure 15: Torque. Source: Landmark suite

5.3.2 Water well rigs

During meetings the question was raised if water well rigs e.g., Haitjema or DeRuiter type of rigs using reversed circulation drilling method, can be used or adapted to drill to the Brussel Sands with the idea of reducing costs. The following items will need to be addressed:

- Water drillers follow the BRL protocols for designs, rigs, crew requirements, operations etc. and fall under the ILT. Wells deeper than 500m fall under the Mining Law and SodM hence exemptions will be needed.
- Mining law and SodM have different requirement that partly result in added costs such as better trained staff, more safety systems, and inspections, well control.
- Maximum depth is insufficient (max ~750m, info the DeRuiter) hence rigs may have to upgraded in specifications what may not be feasible
- Only vertical wells can be drilled
- 1 Section only:
  - 2nd section requires BOP by law or exemption if absence of hydrocarbons can be proven
- Typically use topfile method with sand/mikolit
  - Large hole required more mud, cuttings disposal hence more cost
  - Cement is possible but requires HP cement pump
- Crews don’t work 24/7 but according to labour law introducing risks associated to openhole, more rental costs and longer realization times. With an exemption (as mining works already have) crews will be paid compensation what will take away the cost saving.

An alternative could be the use of small oil&gas rigs (e.g. 160t rigs or less) as already active in the Netherlands (hence with safety case). Such truck-based rigs have lower mobilization costs and footprints. Daldrup & Sohne is an example of a water well driller using small oil&gas rigs.

Experience shows that rig performance strongly depends on the rig crew and that continuous work with fixed and skilled teams is a efficient way to reduce cost.

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6 TIME AND COST ESTIMATE

6.1 Time vs Depth

Time breakdown for different drilling operations related to production well drilling and completion can be seen in Table 19 and Figure 16. Injection well has the same time distribution as for production well, only excluding ESP installation.

In shallow drilling often high ROP's can be obtained with cutting separation often as limiting factor. This will need to be taken into consideration when selecting the rig. The total times can be considered conservative compared to the Schoonebeek wells.

Table 19: Production well time breakdown

WarmingUP	Design 1: Vertical well	Design 2: Inclined well	Design 3: Horizontal well - 850m	Design 4: Horizontal well - 1250m	Design 5: Horizontal well - perpendicular
Mobilize & R/U	0.00	0.00	0.00	0.00	0.00
Spud, clean out conductor and RIH 12 1/4" BHA	0.50	0.50	0.50	0.50	0.50
Drill 12 1/4" top hole	1.20	1.43	2.19	2.57	1.73
Circulate hole clean & POOH, L/D BHA	0.48	0.56	0.83	0.97	0.67
Install / cement 9 5/8" surface casing	1.43	1.52	1.79	1.93	1.63
Install Wellhead / CHH	0.50	0.50	0.50	0.50	0.50
N/U & P-test BOP	1.00	1.00	1.00	1.00	1.00
Drill 8 1/2" hole	1.34	2.27	3.69	3.73	3.64
Circulate hole clean & POOH, L/D BHA	0.79	1.12	1.82	2.01	1.59
RIH metal mesh sand screen	1.00	1.17	1.52	1.60	1.42
Displace well to GT brine	1.00	1.00	1.00	1.00	1.00
Install Tie-Back	0.73	0.85	1.26	1.47	1.02
Install ESP	0.56	0.56	0.56	0.56	0.56
Dismantle BOP & Install Xmas Tree	1.00	1.00	1.00	1.00	1.00
Skid Rig	0.00	0.00	0.00	0.00	0.00
Total	**11.52**	**13.47**	**17.66**	**18.84**	**16.25**

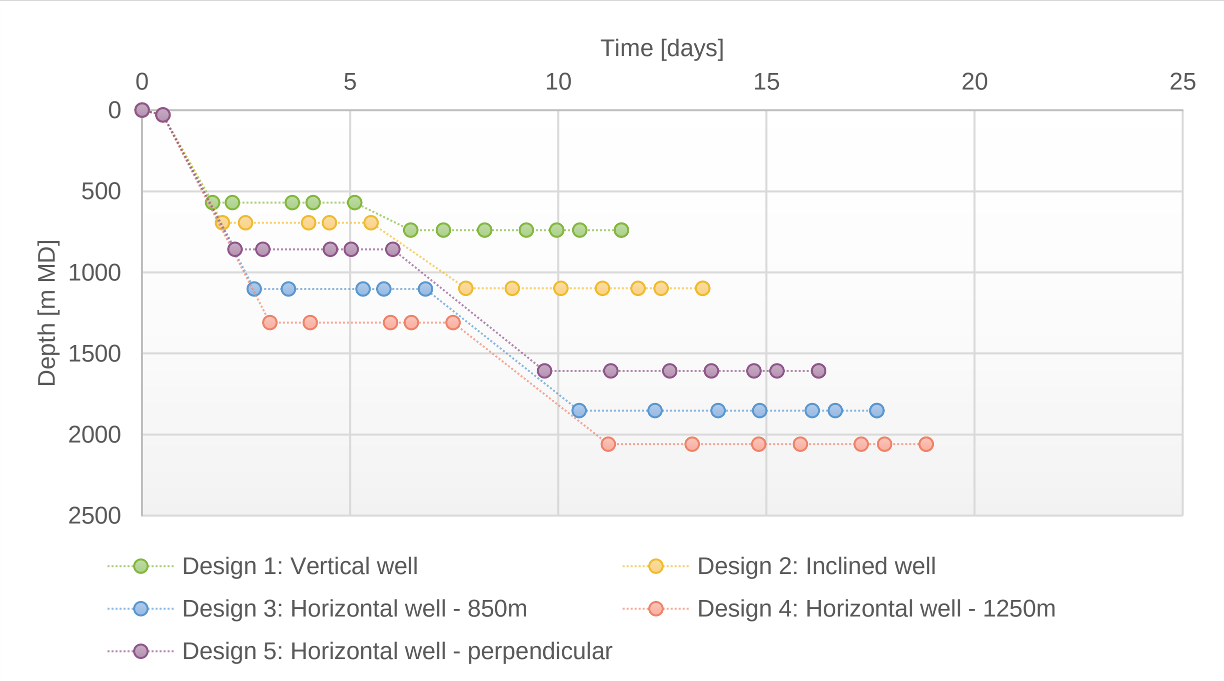

Figure 16: Time vs. Depth for a production well

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6.2 Concept cost estimate

The wells' CAPEX and OPEX has been estimated based on recent budget indications (either specifically for this well or from recent WEP projects, or WEP cost database), and on the planned operations for the wells construction and operation and maintenance.

6.2.1 CAPEX

The table below shows the Level 2 cost estimate for production and injection wells including contingency and probability of 25% from the total CAPEX. Injection wells don't include costs associated with ESP system installation.

Table 20: Cost estimate for a production well

Cost category	Design 1: Vertical well	Design 2: Inclined well	Design 3: Horizontal well - 850m	Design 4: Horizontal well - 1250m	Design 5: Horizontal well - perpendicular
Site preparations	€ 1,000,000	€ 130,000	€ 130,000	€ 130,000	€ 130,000
Rig / Operational cost	€ 322,000	€ 358,000	€ 439,000	€ 463,000	€ 413,000
Additional services	€ 148,700	€ 304,900	€ 472,300	€ 512,650	€ 424,950
Materials	€ 866,000	€ 949,000	€ 1,184,000	€ 1,359,000	€ 1,061,000
Engineering and Supervision	€ 83,000	€ 89,000	€ 103,000	€ 107,000	€ 98,000
Total	€ 2,169,700	€ 1,700,900	€ 2,198,300	€ 2,441,650	€ 1,996,950
Total with probability and contingency [25%]	€ 2,712,125	€ 2,126,125	€ 2,747,875	€ 3,052,063	€ 2,496,188
Price per meter	**€ 3,665**	**€ 1,936**	**€ 1,483**	**€ 1,482**	**€ 1,552**

Table 21: Cost estimate for an injection well

Cost category	Design 1: Vertical well	Design 2: Inclined well	Design 3: Horizontal well - 850m	Design 4: Horizontal well - 1250m	Design 5: Horizontal well - perpendicular
Site preparations	€ 1,000,000	€ 130,000	€ 130,000	€ 130,000	€ 130,000
Rig / Operational cost	€ 311,000	€ 347,000	€ 428,000	€ 452,000	€ 402,000
Additional services	€ 143,600	€ 298,550	€ 472,300	€ 512,650	€ 418,600
Materials	€ 527,000	€ 610,000	€ 884,000	€ 1,020,000	€ 722,000
Engineering and Supervision	€ 81,000	€ 87,000	€ 101,000	€ 105,000	€ 97,000
Total	€ 1,812,600	€ 1,342,550	€ 1,885,300	€ 2,089,650	€ 1,639,600
Total with probability and contingency [25%]	€ 2,265,750	€ 1,678,188	€ 2,356,625	€ 2,612,063	€ 2,049,500
Price per meter	**€ 3,062**	**€ 1,528**	**€ 1,272**	**€ 1,269**	**€ 1,275**

The estimated costs include:

- Budget and best estimations for services and materials, as received from various suppliers and recent (< ½ year) WEP projects
- Construction drilling location (240 k€ (can be split if drilled from one site) + 10 k€ each cellar). Note that a cellar may not be required.
- Surface pipeline when drilled in two locations (1500 k€ for a doublet (750 k€ per well))
- Rig mobilization (100 k€) based on MB T49 – 300 km
- Drilling rig is self-supporting in energy (Electricity)
- ESP system (300 k€)

The estimated costs don't include:

- Land rent/purchase
- Insurances as RNES, CAR
- Auxiliary surface equipment as filters, heat exchangers, pumps etc.
- Well testing and disposal of test water
- Logging

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6.2.2 Plug and abandonment costs

The well doublet abandonment cost was estimated as a 10 percent of the total construction cost and is presented in Table 22. Surface pipeline cost (Design 1) was not included in abandonment cost approximation.

Table 22: Total well doublet construction and abandonment cost

	Construction cost [k€]	Abandonment cost [k€]
Design 1: Vertical well	4977.9	347.8
Design 2: Inclined well	3804.3	380.4
Design 3: Horizontal well - 850m	5104.5	510.5
Design 4: Horizontal well - 1250m	5664.1	566.4
Design 5: Horizontal well - perpendicular	4545.7	454.6

6.3 Life-cycle-cost comparison

This overview is only used as a comparison for the different well designs, and not to justify a positive business case for a shallow geothermal project because for example CAPEX/OPEX of the heat pumps are not considered. In the end, each shallow geothermal project should be tested on its (complete) business case and the commercial viability.

The life-cost analysis of each doublet design was performed for a production period of 20 years. It assumes a systematic replacement of ESP system and single major well intervention, furthermore, a yearly maintenance and inspection cost was included for all designs. The overview of assumptions used in this analysis are depicted below and extended in Table 23:

- ESP replacement is approximated to take place every 3 years
- Tubing/tie-back will last >20 years i.e. GRE/composite or 13Chrome.
- Only half of the total heat amount is produced in the first year
- 200k-euro undefined major well intervention in year 10 e.g. clean-out, acid job,..
- Abandonment cost is included in the last year cost
- ESP replacement reduces heat production of that year by 2/12
- Major well intervention reduces heat production of that year by 6/12
- Heat Exchangers, filters, degassers etc. are not included
- Booster pump (also for surface pipe line) and heat pumps CAPEX and maintenance is not included

Table 23: Life-cycle-cost assumptions

Maintenance and inspection	50	k€/year
Pre-ops	125	k€
ESP pump replacement	300	k€
Major well intervention	200	k€
Tax	25%	
Depreciation rate	10%	
Loan percentage	50%	
Loan pay-off period	20	years
Interest rate	3%	
Discount rate	8%	
Years left SDE	15	years
Heat sales	15	€/MWhr

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Comparison of different designs in terms of energy production and its cost can be seen in Table 24. Inputs for those calculations are provided by TNO and are summarized in Chapter 4.2. Inclined well design has a 19 % increased energy production and has considerably lower construction cost as a result of a single drilling location. All three horizontal well designs have nearly the same produced energy amount, with an average of 45 % increase in production compared to vertical well design.

Table 24: Energy costs versus production.

	Flow rate	Total pressure loss	Energy produced			Combined energy costs	
	[m3/hr]	[bar]	[GWh]	[k-euro/y]	[%]	[k-euro/y]	[%]
Design 1: Vertical well	95	13.04	15	564	0%	39	0%
Design 2: Inclined well	120	15.37	17.59	668	19%	57	47%
Design 3: Horizontal well - 850m	146	18.44	21.20	806	43%	77	99%
Design 4: Horizontal well - 1250m	139	17.33	21.99	836	48%	71	84%
Design 5: Horizontal well - perpendicul	148	16.54	21.49	817	45%	75	93%

With a closer look on economic indicators which are depicted in Table 25, we can clearly see that vertical well design is not a favourable option compared to the other design and based on given financial assumptions. Design option two, three and four has similar economic performance and can potentially result in a viable geothermal project, especially with an increased gas price. Horizontal design with a perpendicular well arrangement outperforms all other design due to low capex and considerable energy production. The relative performance of the different horizontal designs of course depends on the detailed placement in the reservoir and the permeability distribution. For more information on the uncertainty in the simulated flow rates, see the report by Geel et al. (2022).

Table 25: NPV, IRR and payback time for different designs

	Net present value [€]	Internal rate of return [%]	Payback time [years]
Design 1: Vertical well	-2,104	-7%	18.0
Design 2: Inclined well	-159	7%	8.4
Design 3: Horizontal well - 850m	-552	5%	10.4
Design 4: Horizontal well - 1250m	-196	7%	8.7
Design 5: Horizontal well - perpendicular	834	12%	7.4

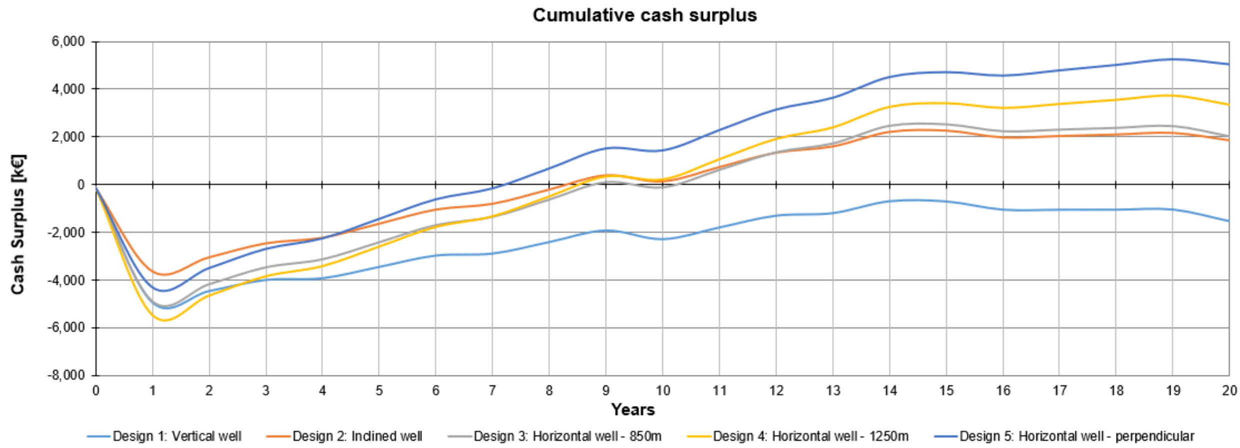

Figure 17: Cumulative cash surplus to compare well designs.

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7 CONCLUSION

In conclusion, shallow geothermal doublets could potentially be a feasible source of heat developed from the Brussels sands formation. Based on the analysis of all concepts, the concept with the perpendicular horizontal well arrangement appears to be financially the most advantageous. Two vertical wells connected with a surface connection to close the loop for the formation brine is economical the least attractive. The delivered work can function as base to continue the study to include also the surface equipment to get a complete overview.

The investigated wells are expected to produce 50-200 m3/hr, therefore a 2-string well design with tie-back was chosen as an design for the various well trajectories. It can be easily scaled to accommodate larger flowrate without major changes in the well design what allows better comparisons. Moreover, it is flexible for different sand control designs and corrosion control.

In horizontal wells accurate landing and well placement is critical. Drilling sub-horizontal wells in the Brussel sands require special attention with respect to BHA design due to the hard cemented layers found in the formation.

To sum up, it was shown that the objective of economical, yet optimal and safe development of shallow geothermal prospects within Brussel sands formation is feasible and can be achieved. It provided an alternative geothermal prospect that under increased gas price become more attractive.

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8 ATTACHMENTS

8.1 Info on metal mesh screens


HP WELL SCREEN

WASH PIPE FREE SCREEN

The Wash Pipe FREE Screen is a sand screen used for sand control in production and injection wells, eliminating the need to deploy wash pipe for circulation, fluid displacement, well cleanup, gravel packs and setting packers.

Eliminating the need for wash pipe

Any sand screen completion in long laterals or gravel packed wells requires a significant amount of time for wash pipe deployment to displace drilling, completion and breaker fluids and to clean up the well.
The Wash Pipe FREE Screen eliminates the requirement of a dedicated inner string and allows for circulation and displacement to be performed with the liner running string. Enabling the operator to save several days rig time, reducing costs and increase operational efficiency, safety and logistics.

Dissolvable Plugged Perforation Assembly

Instead of using a standard perforated base pipe, the sand screen uses a Dissolvable Plugged Perforation Assembly (DPPA), preventing fluid loss through the holes in the base pipe during running in hole of the screen completion.
The perforations in the DPPA are temporarily plugged providing hydraulic integrity of the completion string and allowing for circulation through the shoe and setting of hydraulic set packers.

The plugs are composed of a specifically formulated polymer or metal alloy which will dissolve in a water-based fluid, brine or breaker system. The dissolving time is designed and customized based on temperatures, pressures and fluids. The dissolution of the plugs provides an interventionless opening of the perforations, where after the screen is ready for production or injection.

Customized Design

- Different hole diameters 24 / 12 / 6 / 5 / 4 / 3 / 2,5 mm
- Engineered dissolution times From 1 to 25 days
- Dissolves in (sea)water, acid, wbm, obm
- Material grades: A825/A718/Tungsten
- Differential pressure 3000 - 5000 psi
- Temperature range 50 - 150C
- Compatible with all screen types
- Over 12.000 plugs run successfully

Benefits

- Time and cost savings
- Ability to wash to TD
- Less fluids losses to formation
- Effective wellbore and screen cleaning
- Improved breaker coverage
- Improved gravel packing
- Reduced formation damage

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Figure 18. Wash pipe free metal mesh screen. Source HP WellScreen

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Metal-Mesh Screens

A woven single-layer or a woven—sometimes sintered—multilayer metal mesh is shaped and combined with a protective, perforated outer covering in a cartridge, or jacket, which is slipped over a perforated liner/base pipe. Metal-mesh screens reduce the risk of plugging at the screen face. The screen opening stops some of the produced sand until larger grains "bridge" on the screen surface. The sizing criteria recommended is that a weave will adequately retain sand with a D5 minimum to D10 maximum equivalent to the weave aperture. Weatherford's **Excelflo**® and **Maxflo**® screens provide reliable sand control ideal for short-radius, horizontal wells and stand-alone applications.

Base Pipe			*Maxflo* Metal-Mesh Screens				*Excelflo* Metal-Mesh Screens			
Size (in.)	Weight (lb/ft)	ID (in./*mm*)	Shroud OD (in./*mm*)	Weight (lb/ft)	Tensile Strength[1] (lbf/*kN*)	Maximum Bend Angle[2]	Shroud OD (in./*mm*)	Weight (lb/ft)	Tensile Strength[1] (lbf/*kN*)	Maximum Bend Angle[2]
2-3/8	4.6	1.995 *50.67*	N/A	N/A	N/A	N/A	3.08 *78.23*	7.9	88,690 *394.5*	120°
2-7/8	6.4	2.441 *62.00*	N/A	N/A	N/A	N/A	3.57 *90.68*	10.2	123,220 *548.1*	105°
3-1/2	9.2	2.992 *76.00*	4.22 *107.19*	13.5	176,130 *783.5*	86°	4.11 *104.40*	13.5	176,130 *783.5*	86°
4	9.5	3.548 *90.12*	4.72 *119.89*	14.4	182,210 *810.5*	75°	4.61 *117.09*	14.4	182,210 *810.5*	75°
4-1/2	11.6	4.000 *101.60*	5.23 *132.84*	16.9	226,980 *1,009.7*	67°	5.12 *130.05*	16.9	226,980 *1,009.7*	67°
5	15.0	4.408 *111.96*	5.74 *145.80*	20.8	297,450 *1,323.1*	60°	5.63 *143.00*	20.8	297,450 *1,323.1*	60°
5-1/2	17.0	4.892 *124.26*	6.24 *158.50*	23.2	337,440 *1,501.0*	54°	6.13 *155.70*	23.2	337,440 *1,501.0*	54°
6-5/8	24.0	5.920 *150.37*	7.38 *187.45*	31.1	472,340 *2,101.1*	45°	7.27 *184.66*	31.1	472,340 *2,101.1*	45°

All values are based on 316L screen jackets and L80 base pipe.
[1]Screen tensile strength is based on entire screen assembly.
[2]Maximum bend angle for screen (° per 100 ft, or 30.5 m) may exceed allowable bend angle for some threads. See thread manufacturer's specifications. Maximum DLS (dogleg severity) is 50% of maximum bend angle.

Figure 19. General information on Metal Mesh Screens. Source Weatherford.

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8.2 Horizontal influx

Equations 1: Horizontal section influx equations. Source: S.D. Joshi

Case 1: uniform flow distribution, (Fig. 10–10b)

$$q(x) = q_{\text{total}}/L$$

Case 2: flow distribution linearly increases with distance x (Fig. 10–10c)

$$q(x) = 2xq_{\text{total}}/L^2$$

Case 3: flow distribution linearly decreases with distance x (Fig. 10–10d)

$$q(x) = \frac{2(L - x)q_{\text{total}}}{L^2}$$

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8.3 Cost estimations

Table 26: Cost Estimate (Inclined producer)

Cost estimate WarmingUp					
Site preparations					
Duration days	**Activity**	**Rig price / day**	**Additional**	**Additional service costs**	**Total costs**
	constructing location			€ 130,000	€ 130,000
Rig / Operational cost					
Duration days	**Activity**	**Rig price / day**	**Additional**	**Additional service costs**	**Total costs**
0.0	Mobilize & R/U			€ 100,000	€ 100,000
0.5	Spud, clean out conductor and RIH 12 1/4" BHA	€ 19,200			€ 10,000
1.4	Drill 12 1/4" top hole	€ 19,200			€ 27,000
0.6	Circulate hole clean & POOH, L/D BHA	€ 19,200			€ 11,000
1.5	Install / cement 9 5/8" surface casing	€ 19,200			€ 29,000
0.5	Install Wellhead / CHH	€ 19,200			€ 10,000
1.0	N/U & P-test BOP	€ 19,200			€ 19,000
2.3	Drill 8 1/2" hole	€ 19,200			€ 44,000
1.1	Circulate hole clean & POOH, L/D BHA	€ 19,200			€ 21,000
1.2	RIH metal mesh sand screen	€ 19,200			€ 22,000
1.0	Displace well to GT brine	€ 19,200			€ 19,000
0.9	Install Tie-Back	€ 19,200			€ 16,000
0.6	Install ESP	€ 19,200			€ 11,000
1.0	Dismantle BOP & Install Xmas Tree	€ 19,200			€ 19,000
0.0	Skid Rig	€ 19,200			€ -
14.0	Operational days				**€ 358,000**
Additional services					
Description		**Unit**	**Unit price**	**Unit(s) estimated**	**Total cost**
Directional drilling services & equipment		m	€ 118	1098	€ 130,000
Drilling fluids services (incl. solids control)		day	€ 3,000	14	€ 42,000
Disposal of fluids & Cutting incl. transport (WBM)		pce	€ 64,000	1	€ 64,000
Mud logging & Well Site Geologist		day	€ 2,100	14	€ 29,400
Tubular running services		day	€ 2,500	7	€ 17,500
Wellhead services		day	€ 2,000	1	€ 2,000
Cementing services + 1 x LOT testing		section	€ 20,000	1	€ 20,000
					€ 304,900
				Sub total	**€ 662,900**
Materials					
Description		**Unit**	**Unit price**	**Unit(s) required**	**Total cost**
14" stovepipe/conducter		m	€ 170	30	€ 5,000
9-5/8" casing		m	€ 159	730	€ 116,000
6-5/8" metal mesh sand screen		m	€ 80	444	€ 58,000
7-5/8" GRE tie-back (protective string)		m	€ 316	730	€ 231,000
5-1/2" production tubing		m	€ 150	260	€ 39,000
Wellhead and X-mastree		pce	€ 40,000	1	€ 40,000
Casing & cementing accessories		section	€ 20,000	1	€ 20,000
Cement		ton	€ 300	33	€ 10,000
Drilling fluids		pce	€ 60,000	1	€ 60,000
12-1/4" bit		pce	€ 25,000	1	€ 25,000
8-1/2" bit		pce	€ 20,000	1	€ 20,000
Electicity		est.	€ 25,000	1	€ 25,000
ESP + Surface equipment		est.	€ 300,000	1	€ 300,000
					€ 949,000
				Sub total	**€ 1,611,900**
Engineering and Supervision					
Pre-engineering		est.	€ 40,000	1	€ 40,000
Supervision during execution		day	€ 3,250	13	€ 44,000
End of well reporting		est.	€ 5,000	1	€ 5,000
					€ 89,000
			Total		**€ 1,700,900**
Probability and contingency				25%	€ 425,225
			Grand total		**€ 2,126,125**

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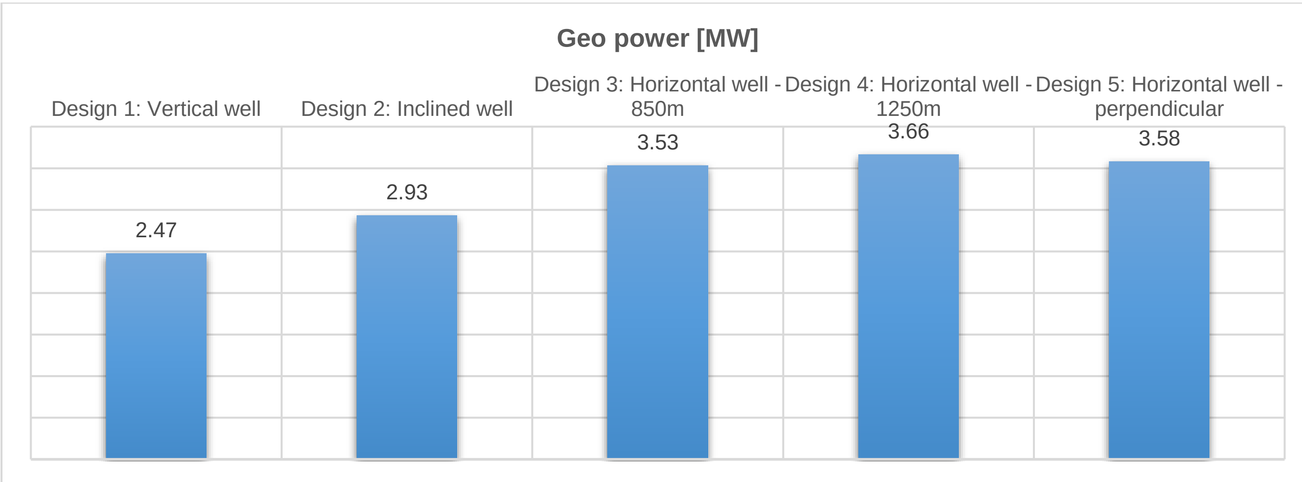
8.4 Heat production

Table 27: Heat production in MW per concept.



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