Unlocking low temperature geothermal reservoirs: Key insights for exploitation of geothermal energy from medium depths (500-1500 m)

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Unlocking low temperature geothermal reservoirs: Key insights for exploitation of geothermal energy from medium depths (500-1500 m)

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Contents

Summary

In the medium-depth (500-1500m) domain smaller, low temperature geothermal (LTG) systems can be developed at reduced costs, which would create an additional option for providing heat to urban heat networks or greenhouses. However, to unlock the potential of this depth domain, some challenges need to be solved to reduce operational risks and improve the business case. The main technical challenges specific to this depth domain are identified as supporting sufficiently high production rates without sand and fines production problems and creating the required outstep between the wells. Highly deviated and/or horizontal wells are a well-known solution to these challenges, however in this shallow domain often poorly or unconsolidated formations are present with poorly known rock strength properties which makes horizontal drilling much more challenging.

In this report, information on well drilling, completions and operations is presented from Dutch developments in the relevant depth domain, in particular from the Zevenbergen LTG doublet, the Schoonebeek heavy oil field, De Wijk gas fields and the shallow gas fields in the A and B-blocks offshore. The results show that drilling deviated and horizontal wells in this depth domain is quite mature. In the A/B blocks and Schoonebeek many of such wells have been drilled successfully in the past 10 to 15 years. Critical success factors are related more to organisational factors than recent technological developments. Key factors are careful upfront planning, good knowledge of the subsurface and a continuous learning curve with knowledge sharing, if possible, via campaign drilling. Typical drilling issues encountered are losses and differential sticking in high permeability formations, mobile/active clays and hard stringers (in particular for high-inclination wells). For well completions, different solutions have been used for the different locations, and these will need to be evaluated for LTG. On operational aspects such as maximum allowable production and injection rates and pressures, design standards and operational strategies from oil and gas fields have only limited applicability.

Based on this information, the most urgent knowledge gaps are related to the operational questions: safe constraints for rate and pressure. For drilling no clear technological knowledge gaps were identified, but research is recommended on cost reduction. Cost reductions in oil and gas drilling have been achieved to a large extent by campaign drilling and drilling with slim well concept, but neither is likely to be a good solution for LTG. For LTG compact well control in combination with slimmer rigs might be a way forward to reduce costs.

It should be noted that in the medium depth domain, uncertainty about the subsurface characteristics is relatively large, not only on the reservoir properties but also the fluid properties. Thus, characterization is crucial for reducing development risks.

1 Introduction

To support the heat transition, more sustainable heat sources are being investigated. One of these is geothermal heat. In the Netherlands, geothermal heat is mostly developed in the depth domain of 1500 to 3000 m and used for heating green houses or, more recently, as a heat source for other purposes such as urban heat networks. However, in some areas no suitable deep aquifers are available or the heat demand at surface does not match the source. In some of these cases, shallower geothermal sources could provide a solution and provide the required heat.

Medium depth geothermal (defined here as 500 to 1500 m) is not regularly exploited in the Netherlands. In the Netherlands, this depth range is usually related to a production temperature of 25 - 55°C and is therefore also referred to as Low Temperature Geothermal (LTG). Developments in this depth range present several opportunities (IF, 2012; Buik and Bakema, 2019; Schepers et al., 2019). The lower capacity of the systems aligns very well with urban heat developments at the level of villages or neighbourhoods. Typical Dutch geothermal systems of medium temperature (55 - 90°C) have a capacity in the range of 7 to 20 MWth. LTG systems typically could provide in the order of 3 to 7 MW. In addition, due to potentially lower development costs due to shallower target formations, these systems may have a lower investment threshold. As the fluids produced are expected to be less corrosive and the temperature is lower, materials used in a project might be less expensive. Another benefit is that the seismogenic potential is likely to be smaller (Aben et al, 2024). Finally, by enabling geothermal heat production in locations that do not have geothermal potential at greater depth, provision of geothermal heat can be expanded.

However, LTG poses a number of challenges. In the relevant depth range many reservoirs in the Netherlands are poorly consolidated, which complicates achieving sufficiently high production rates without sand and fines production. The shallow depth makes achieving sufficient step-out between the injector and producer more difficult. Horizontal or sub-horizontal well designs are currently considered to solve both challenges, but these are much more challenging to drill due to the poorly consolidated formations and shallow depth. In case these well designs are developed with traditional 'deep' drilling methods, they are generally more expensive than traditional deep geothermal projects compared to the delivered heat (Schepers et al., 2019). In the depth range considered here, far fewer exploration and production (E&P) and geothermal activities have been developed leading to a relative paucity of subsurface data (Houben et al., 2024) and less experience in drilling and operations. Other challenges for LTG relate to the use of the heat pumps to increase the temperature (given the low production temperature), but that is not further discussed here.

Although few, there are a number of petroleum developments in the depth range of interest, most notably the De Wijk and Schoonebeek fields onshore and a few gas fields in the A and B blocks offshore. Also, at Zevenbergen, the first LTG project was developed. Experience and information from these fields can benefit LTG but is currently not available in a readily available format to potential operators. Therefore, in this report we aim to provide information from existing medium depth developments that is useful for LTG developments. Based on the available information, we will map the most relevant knowledge/technology gaps.

The following approach has been followed:
- identify relevant developments in the medium depth range and present information and experience on drilling, completions and operations. The focus is on shallow, poorly consolidated, relatively young sandy formations.
- compare LTG developments to the existing developments and check which challenges mentioned above can be addressed satisfactorily with the presented information,
- identify the knowledge gaps,
- make recommendations to address the knowledge gaps

To support the approach, a following group of experts was involved in collection of the information and discussion of the results and recommendations for research:
- TNO: Elisabeth Peters, Andreas Reinicke, Pejman Shoeibi Omrani
- EBN: Henk van Lochem, Edward Schrijver, Sjoukje de Vries, Laurens de Waal
- Shell geothermal: Laurens van der Sluijs
- IF Technologie: Nick Buik
- HP Wellscreen: Dennis Breg

With support from:
- HVC: Bert Jan Koers, Sanne Braat, Charlotte de Wijkerslooth
- TUDelft: Phil Vardon
- Geothermie Nederland: Hannes Groot

In this report, first some background information is presented, namely an overview of the potential targets for LTG in the Netherlands, an introduction into the relevant medium depth developments and information on the business case of LTG developments that is currently available from literature. The technical information is summarized in three categories: drilling, completions and operations. The supporting data is presented in an easily accessible Excel database, which can be downloaded together with this report from the Geo4all website: https://innovatie.geothermie.nl/en/werkpakketten/work-package-1/. All data and information in the database is public information and has been taken from the Dutch Oil and Gas portal (NLOG.nl).

2 Background

The following topics are presented in this chapter:
- A description of the medium depth target reservoirs in the Netherlands
- An introduction into the current medium depth geothermal and oil and gas developments (on and offshore)
- State-of-the-art on the business calculation for LTG

2.1 Potential target reservoirs in the medium depth range

In the Dutch onshore area, the following potential target reservoirs are present in the relevant depth range:
- Upper North Sea Group (Neogene, mostly Miocene): Mostly Breda Subgroup (Sg), in some locations Oosterhout Formation (Fm).
- Middle and Lower North Sea Groups (Paleogene): Berg Member (Mb) and Brussels Sand Mb; Voort Mb, Oosteind Mb and Orp Mb, locally: Someren Mb, Steensel Mb and Reusel Mb.
- Rijnland Group (Early Cretaceous): Holland Greensand and Spijkenisse Greensand Members in the Holland Fm and several members of the Vlieland Sandstone Fm.
- Nieuwerkerk Fm (Early Cretaceous, late Jurassic): Delft Sandstone and Alblasserdam Mbs

The Chalk Group is present in the relevant depth range but is not included as a potential target because of the expected low permeability and, if it has permeability, it is of a very different character from the medium depth formations discussed in this report, namely via fractured limestone. It is also not included as a possible geothermal target in ThermoGIS[1]. There are however a number of gas and oil fields present in the Ommelanden Formation of the Chalk Group such as the unproduced oil fields F17 Vermeer and Rembrandt and the gas field Harlingen Upper Cretaceous, which is at a depth of around 1000 m.

In some locations, older formations with geothermal potential can be present in the relevant depth range. These are not included in this report, because the focus is on young, poorly consolidated, sandy formations.

2.1.1 Upper North Sea Group

The Breda Subgroup of the Upper North Sea Group is present throughout most of the Netherlands and is mostly of Miocene age (Figure 2.1). Below 500 m, the Breda Subgroup is mostly present in the Roer Valley Graben (RVG) and the Zuiderzee Low (ZZL). Two formations are currently identified in the Breda Sg: Diessen Fm and Groote Heide Fm (Munsterman et al, 2025; Houben, 2025). The deposits are mostly fine grained (very fine sand to silt),

[1] Thermogis.nl: ThermoGIS is a public, web-based geographic information system that displays the regional potential of geothermal energy and high temperature aquifer thermal energy storage (HT-ATES) in the Netherlands.

unconsolidated, glauconitic and of shallow marine origin. The greatest thickness is reached in the RVG and is more than 700 m. In the ZZL, the thickness reaches up to 500 m. Recently, the research well Stad van Gerwen-01 (SVG-01) has been drilled in the Roer Valley Graben near Eindhoven in the framework of the SCAN[2] program on data acquisition in the Dutch subsurface for geothermal. Data from that well was not used in this report.

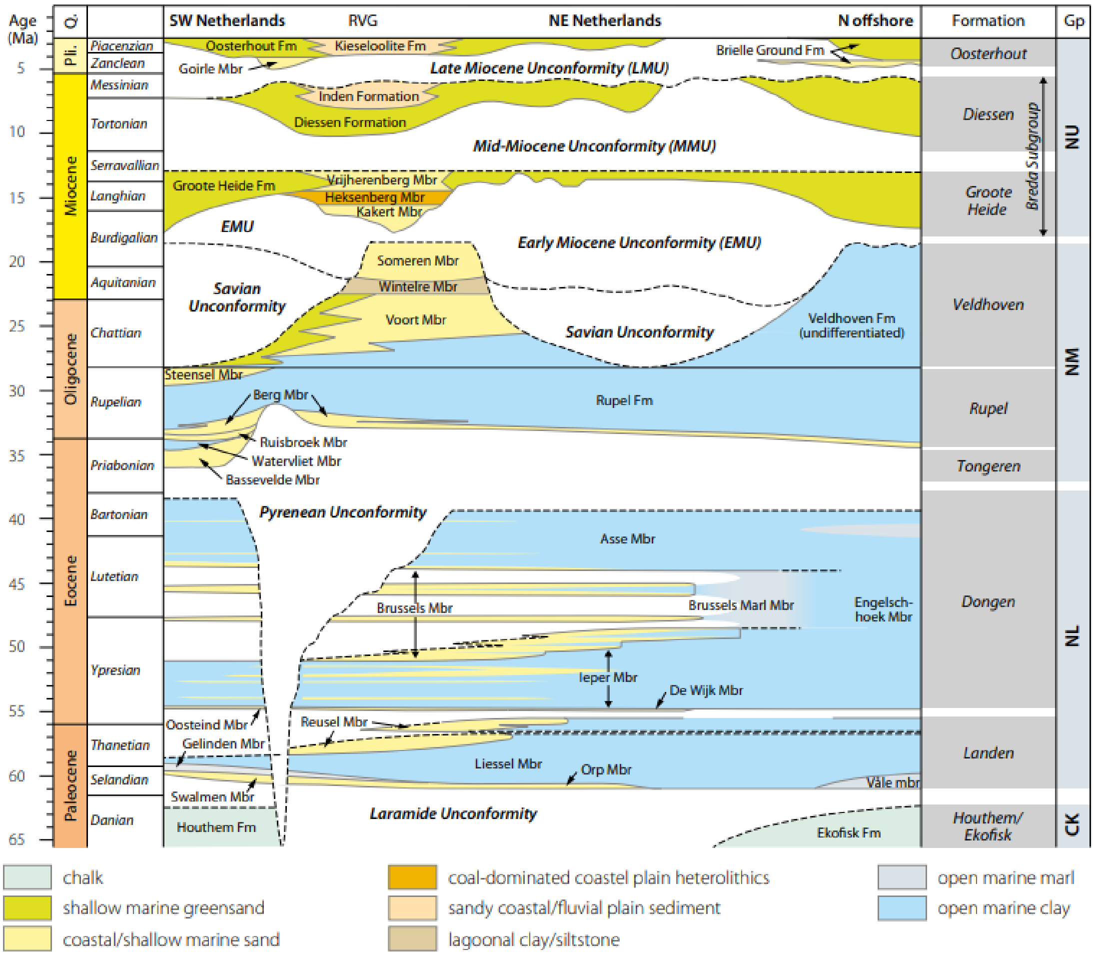

Figure 2.1: Stratigraphic scheme (Wheeler diagram) of the Lower (NL), Middle (NM) and Upper (NU) North Sea Groups in the Netherlands (with the exception of the Quaternary interval) (from Munsterman et al., 2025). The Breda Subgroup marks the base of the Upper North Sea Group.

Recently, the petrophysical properties of the Breda Sg were studied (Pascarella, in prep.) and a dedicated poro-perm relation was derived based on cores from (mostly) shallow wells (Figure 2.2). The wide-spread presence of glauconite[3] complicates the petrophysical analysis (Keijzer, 2025) as does the presence of high GR (gamma ray) peaks associated with the Miocene unconformities, in particular the MMU. The glauconite appears to be most abundant in the shallower, thinner parts of the Breda Sg. It could be that in the deeper and thicker parts, the high sedimentation rate prevented glauconite formation.

[2] https://scanaardwarmte.nl/het-programma/onderzoeksboringen/
[3] Glauconite is a mineral that is chemically similar to clay minerals, but is often present as sand-sized grains (Diaz et al., 2003)

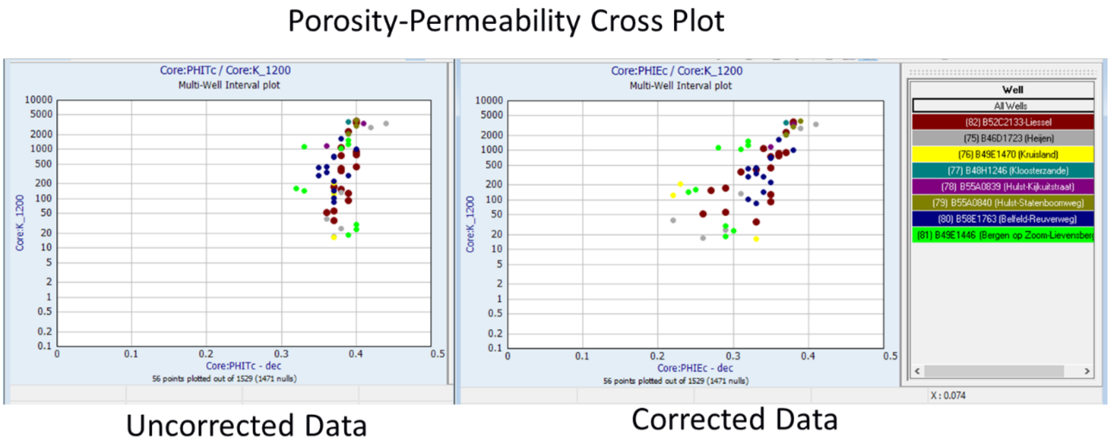

Figure 2.2: Cross plots of core porosity vs permeability before and after shale correction for the Breda Subgroup onshore. The presented porosity is corrected for shale content and is therefore an effective porosity (Pascarella, in prep).

Earlier estimates of the geothermal potential of the Breda Sg were presented by IF (2012) and Schepers et al. (2019), but these were based on more limited information such as available in REGIS and from shallow wells. More recent estimates based on new well log interpretations of deep wells are available via ThermoGIS.nl[4] based on Smit (2022) and Peters et al. (2022a). These estimates still have considerable uncertainty and don't cover the entire presence of the Breda Sg (please note that on ThermoGIS still the older nomenclature is used: Breda Fm instead of Breda Sg). However, it is known that in many areas were the Breda Sg is thin and shallow (< 500 m depth), it is quite clayey and has poor reservoir quality except in the south-east. The poor reservoir quality is seen in South-Holland (IF, 2012) and near Nijmegen from a recent well in Lingewaard[5] (B40D2828 and B40D2834). The estimates of the geothermal potential shown on ThermoGIS.nl for the RVG and ZZL show maximum values of about 9 MW_{th} in the ZZL using traditional deviated wells and a return temperature of 20°C. To calculate this potential it is assumed that production/injection occurs over the entire depth of the Breda Sg which is several hundreds of meters. If the composition of the fluids in Breda Sg is similar over its entire depth range, this is probably not a problem. However, variations in fluid composition (pH, redox potential, etc) could complicate the production from such a large depth range due to for example scaling or microbiological growth resulting from mixing of water with different properties.

Estimates of the particle size of the Breda Sg are available in (Peters et al., 2022a) and in (Smit, 2022) for the ZZL. Shallow wells, which were available in Zeeland near the border with Belgium, show low fines content and median grain size of around 200 µm. The available deeper samples are mostly located near the ZZL and show 10 to 20% particles < 2 µm and median particle size of 80 to 100 µm.

The Oosterhout Formation is a shallower formation: only in the north-west of the country does it dip below 500 m depth. It is mostly coarser grained than the Breda Sg and therefore has better reservoir quality. As the Breda Sg, it is glauconitic. Shell layers are common in the

[4] https://www.thermogis.nl/breda-formatie (access date 7/7/2025)
[5] Data available on Dinoloket.nl

Oosterhout Fm, in particular in the south of the country where the Sprundel Mb can be found.

2.1.2 Middle and Lower North Sea Group

From the potentially interesting formations from the Middle and Lower North Sea Groups (Figure 2.1), the Brussels Sand Member (Mb) is the best known (Geel et al., 2022; Veldkamp et al., 2022) and it was the main target in the recent Oranjeoord-01 (ORO-01) well, which is part of the SCAN program. The only LTG doublet in The Netherlands, which is located in Zevenbergen was developed in the Brussels Sand Mb. The Brussels Sand Mb is present over large parts of the Netherlands but appears to have best potential in the south-west part of the country. In the north of the country, it becomes increasingly fine grained and grades into the Brussels Marl near the Wadden Sea. The Brussels Sand is a shallow marine deposit and consists of relatively clean fine sand with some glauconite. It consists of a 150-200 m thick cleaning-up/coarsening up sequence which is interpreted as a marine shelf sand that gradually becomes shallower and cleaner toward the top. Although it is mostly unconsolidated, cemented streaks or stringers occur throughout the formation, although they are most frequent at the top of the formation. These cemented streaks are around 20 cm to 1 m thick and occur at distances of 5 to 10 m and are of much lower permeability. Although probably not laterally continuous, they do decrease the vertical connectivity significantly (Buik and Bakema, 2019; Geel and Foeken, 2021).

The particle size distribution of the Brussels Sand Mb has been analysed by Veldkamp et al. (2022). The information was mostly derived from cuttings, but some core material was available. De median particle size (d50) for the aquifer part was estimated to range from 70 µm in the north to 100 to 120 µm in the south. Larger values of d50 for the wells in Zevenbergen and Koekoekspolder were attributed to partly loss of the finer fraction due to the sample collection.

Estimates of the geothermal potential are available on ThermoGIS.nl. Without heat pump, the maximum power of a doublet is expected to be around 3 MW (P50 value using deviated wells). The low calculated power is mainly due to the return temperature, which is set at a default value of 30°C, which is high for LTG. Planned injection temperature for LTG doublet Zevenbergen was 7 to 12°C (injection protocol Zevenbergen, Visser & Smit Hanab, 2022). With the ThermoGIS heat pump scenario which reduces the injection temperature to a temperature difference of 40°C with a minimum of temperature of 5°C, power is estimated to reach around 5 MW (P50).

From the well test in ORO-01, the Brussels Sand was estimated to have a transmissivity of approximately 22 Dm (EBN B.V., in prep). ORO-01 is on the boundary of the map by Geel et al. (2022) shown in Figure 2.3 and is estimated to have a value of ~30 to 35 Dm according to this map. ThermoGIS shows a range of values from 9 Dm (P90) to 38 Dm (P50) to 160 Dm (P10) at the location of ORO-01. The observed value of 22 Dm is in the lower half of the ThermoGIS uncertainty range.

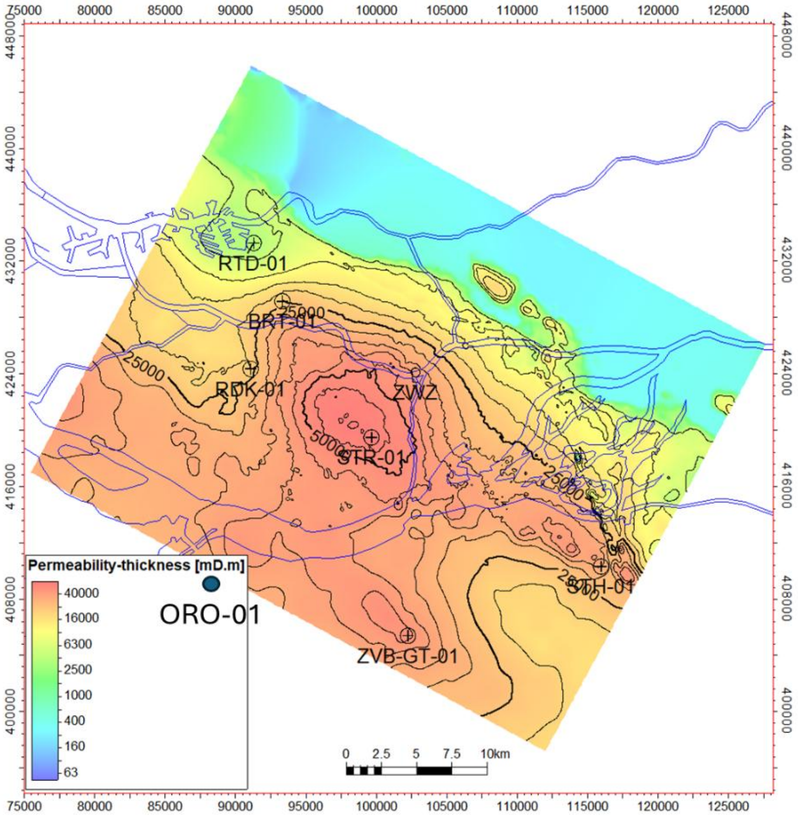

Figure 2.3: Net transmissivity (permeability x net thickness) (KH in mDm) of the regional model including the wells with permeability logs (fig 3.18 from Geel et al., 2022) with the location of well ORO-01 added. Blue lines indicate water ways. ZWZ indicates the location of the potential well location studied in the report.

Other potentially interesting reservoirs which are present in large parts of the country are the Berg Mb (NMRUBE), Voort Mb (NMVEVO), Oosteind Mb (NLDOOO) and Orp Mb (NLLAOR). Of these, the Orp Mb is predicted to be the most productive, and reaches an estimated geothermal power of 4 MW near Weert (P50 with a heat pump). It is a very fine-grained, shallow to open-marine sandy deposit. The Berg Member is very thin, except in the south-west of the country. In well ORO-01 it was found to be 122 m thick, but this is not included in the current ThermoGIS maps yet. The estimated power with the current maps does not reach more than 0.5 MW (P50) even with heat pump. The Voort Mb has only potential in the Roer Valley Graben (maximum P50 value is 1 MW with heat pump) and the Oosteind Mb has less than 0.3 MW (P50, with heat pump) estimated geothermal potential. In the RVG also the Someren Mb (NMVESO), Steensel Mb (NMRUST) and Reusel Mb (NLLARE) occur. Of these the Reusel Mb is the most prospective with up to 3.5 MW geothermal power (P50 with heatpump) near Eindhoven. None of these formations is well studied and the geothermal potential estimates on ThermoGIS carry very large uncertainty. In many cases, permeability estimates are only available in a few locations.

2.1.3 Rijnland Group

In the Rijnland Group (from the Lower Cretaceous), the Holland and Spijkenisse Greensand Members (KNGLG & KNGLS) and several members of the Vlieland Sandstone Fm (KNNS) are potential targets (Gildehaus Sandstone Mb (KNNSG), Friesland and Bentheim Sandstone Mb (KNNSP), De Lier Mb (KNNSL), IJsselmonde Sandstone Mb, Berkel Sandstone Mb (KNNSB) and

Rijswijk Mb (KNNSR)). These are only locally present, mostly in Zuid-Holland and near Enschede. At deeper locations, some of these formations are in production for geothermal energy, such as the Rijswijk Mb at Bleiswijk (wells VDB-GT-01 to 04). There are also several gas and oilfields in these formations. A few examples in Zuid-Holland are:

- De Lier and Berkel fields have targets in the Holland Greensand Mb
- De Lier, Rijswijk, Berkel and Pijnacker fields have targets in the de Lier and Rijswijk Mb.
- The Rotterdam field has targets in the Holland Greensand Mb, de Lier Mb and the IJsselmonde Sandstone Mb

In the east of country, the Schoonebeek oilfield produces from the Bentheim Sandstone Member (KNNSP). As a result, the amount of information is quite high. In some areas, the geothermal potential can be quite good, but in Zuid-Holland most geothermal systems target the better Nieuwerkerk Fm below.

The potential of the stacked Rijnland Group is shown in Figure 2.4 and is only very local. The highest potential is near Rotterdam and this is in the IJsselmonde Sandstone Mb. The IJsselmonde Sandstone Mb is deposited in a shallow marine environment: clayey lagoonal in the lower part and biosturbated shallow-marine sandstone in the upper part. The sandstones are massive and very fine- to medium-grained (TNO-GDN, 2025a). However, oil accumulations occur at certain locations in the IJsselmonde Sandstone Mb: the Rotterdam and IJsselmonde fields. In the area of the IJsselmonde field, the reservoir is at the relatively shallow depth of ~1000 m (Remmelts et al., 2025).

In the east, the main potential is from the Bentheim Sandstone which is located at a depth of 1000 to 1500 m. The Bentheim Sandstone is quite well know from the Schoonebeek field and is a fairly thick sequence of massive sandstone from coastal to marine setting (TNO-GDN, 2025b). A more extensive description of the Bentheim Sandstone Mb is provided in Section 2.2.2.

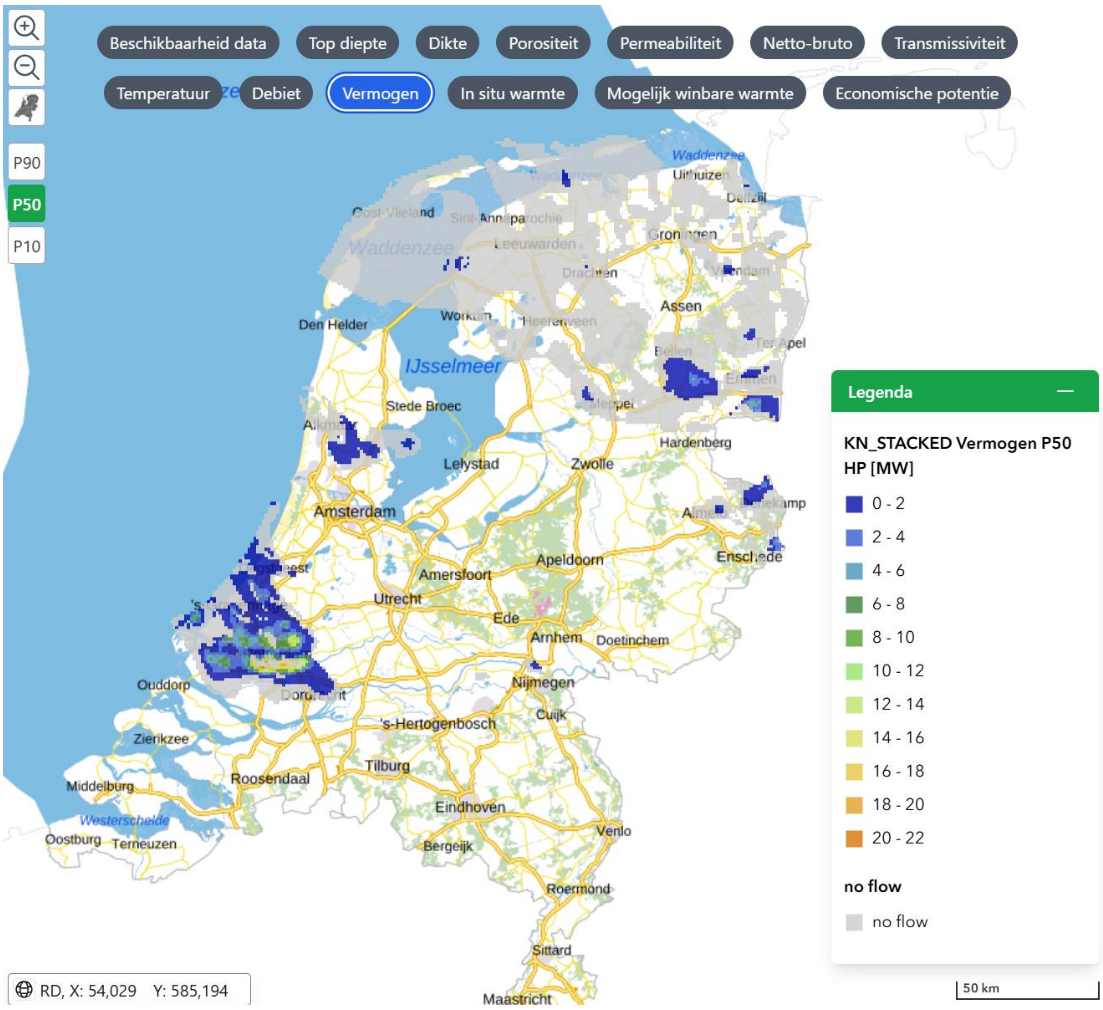

Figure 2.4: Estimated geothermal power (P50 value) including a heat pump for the Rijnland Group as shown on ThermoGIS.nl.

2.1.4 Nieuwerkerk Formation

The potential targets in the Nieuwerkerk Formation (from late Jurassic/early Cretaceous age) are the Delft Sandstone Member (SLDND) and Alblasserdam Member (SLDNA) and they are the oldest of the potential LTG target considered in this report. Where they are located at greater depth, they are well known from conventional geothermal and petroleum production (e.g. Pijnacker and Berkel). In particular the Delft Sandstone Mb has excellent reservoir quality and host almost 20 geothermal doublets to date. It is a light-grey massive sandstone sequence, fine to coarse-gravelly, characterised by a fining upward sequence (TNO-GDN, 2025c). It is poorly consolidated and can show sand production, but has few fines. The depositional setting is characterised by distributary-channels in a lower-coastal-plain setting. The Delft Sandstone Mb lies conformably on the Alblasserdam Mb, which consist of clay- and siltstones with sandstones beds deposited in a fluvial floodplain. The channel sandstone beds can be fine to medium grained beds of a few meters thickness or coarse grained, thick-bedded sandstones (TNO-GDN, 2025d). The difference between the

Delft Sandstone Mb and Alblasserdam Mb can be difficult to identify, which means the relative thickness of the two members can be uncertain (Bouroullec et al., 2024).

The formation is shallowest on the east side of its distribution (Figure 2.5). Due to the good reservoir quality and thickness, the geothermal power is still estimated to be up to 20 MW (including heat pump) in particular in the south-east (Figure 2.6). The data density however is lower in this area (Figure 2.7). In the south-east only the Alblasserdam Mb is present (Figure 2.8, Bouroullec et al., 2024), which has less favourable properties than the Delft Sandstone Mb in particular a much lower net sand content than the Delft Sandstone Mb. This may require production from multiple, stacked sand layers as shown by Szklarz et al. (2024).

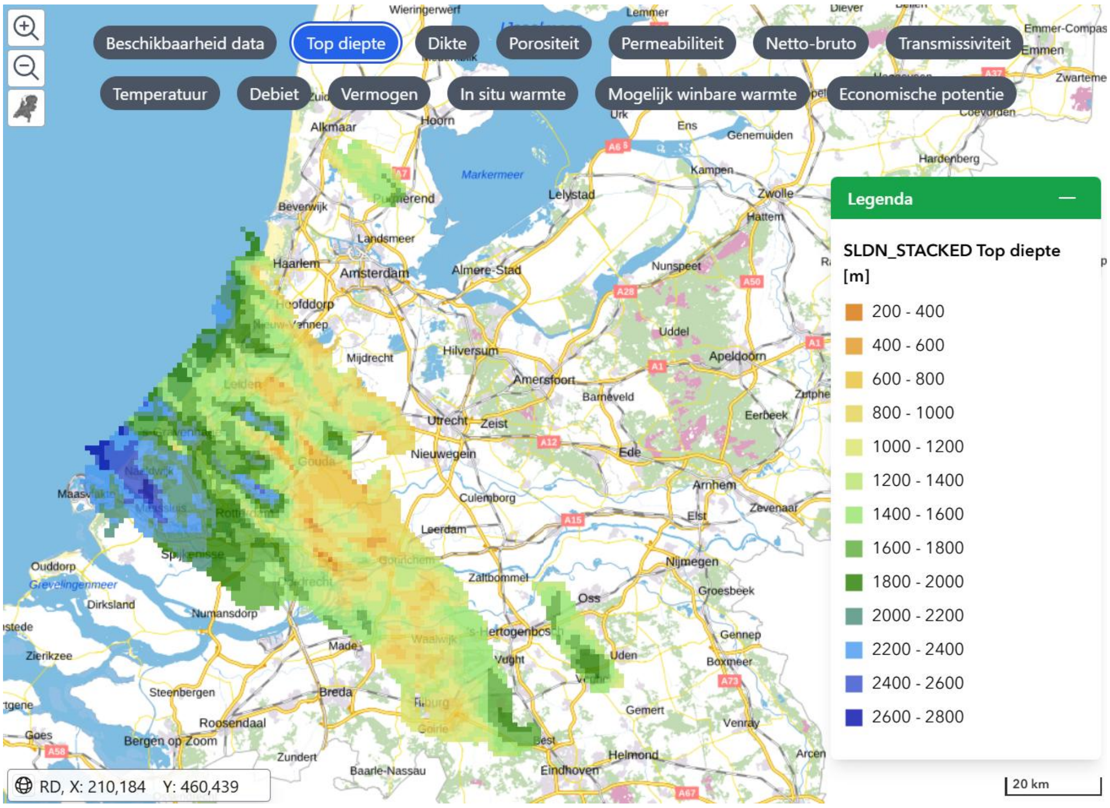

Figure 2.5: Top depth of the Nieuwerkerk Fm as shown on ThermoGIS.nl

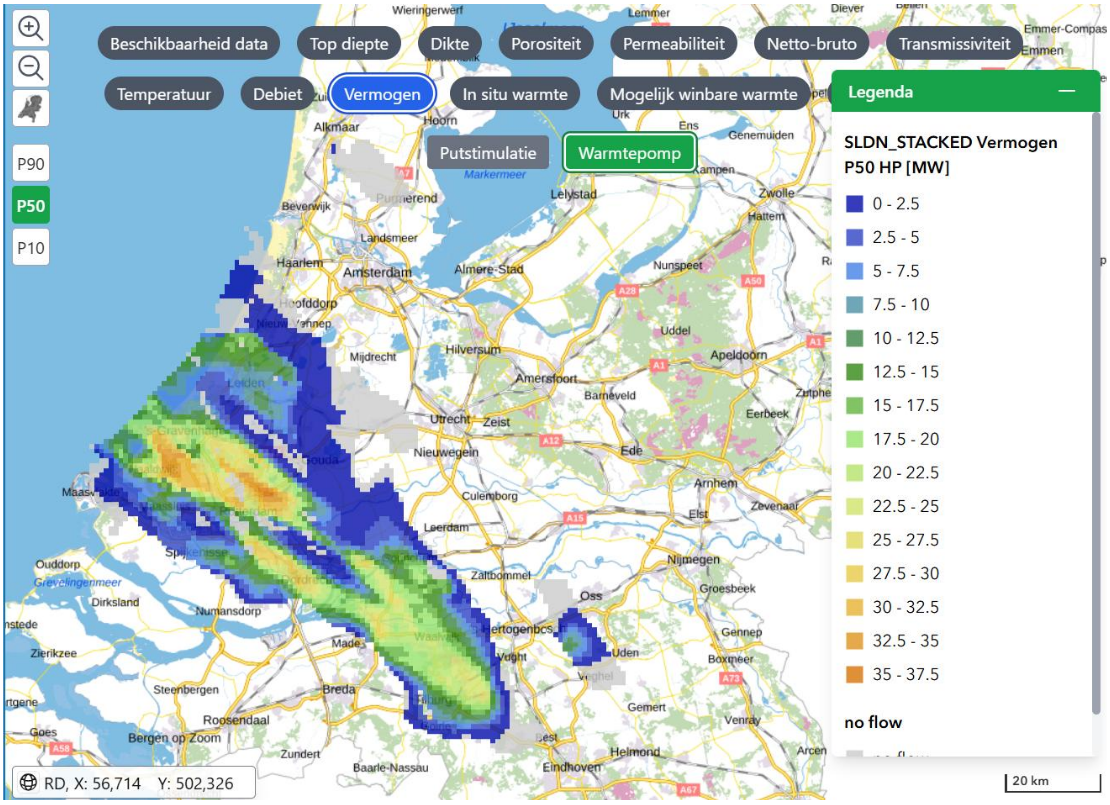

Figure 2.6: Estimated geothermal power (P50 value) including a heat pump for the Nieuwerkerk Fm as shown on ThermoGIS.nl.

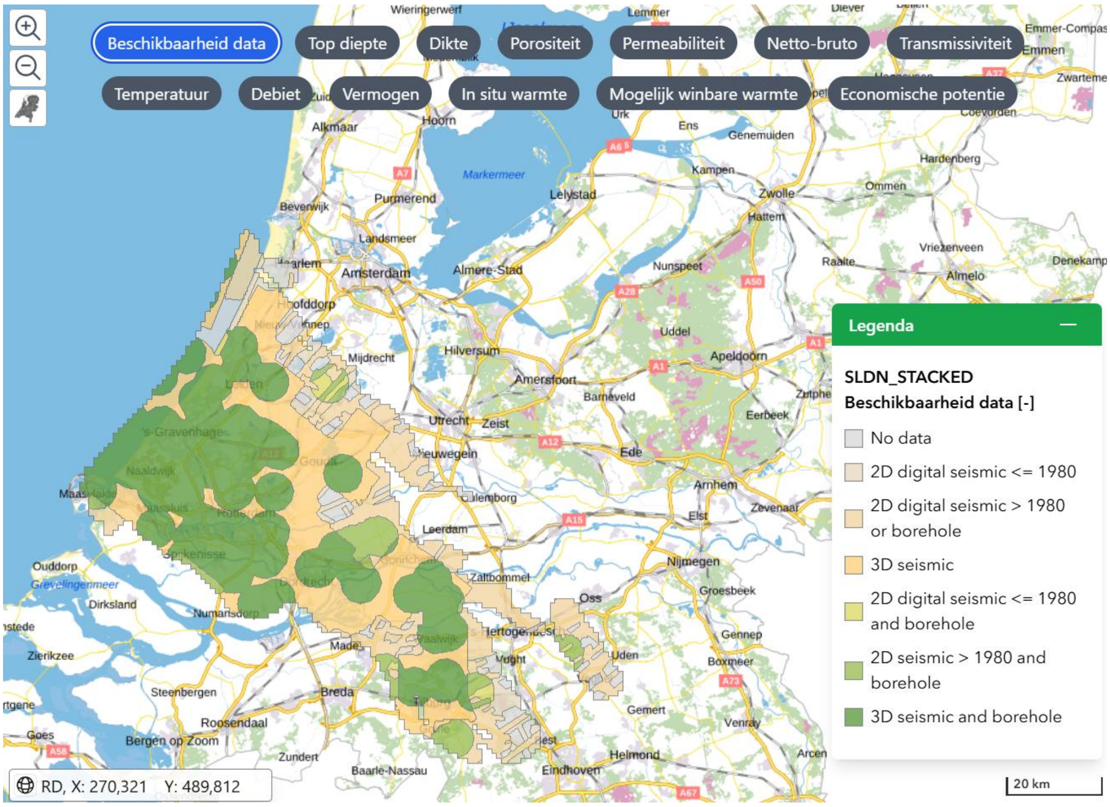

Figure 2.7: Data availability for the Nieuwerkerk Fm as shown on ThermoGIS.nl.

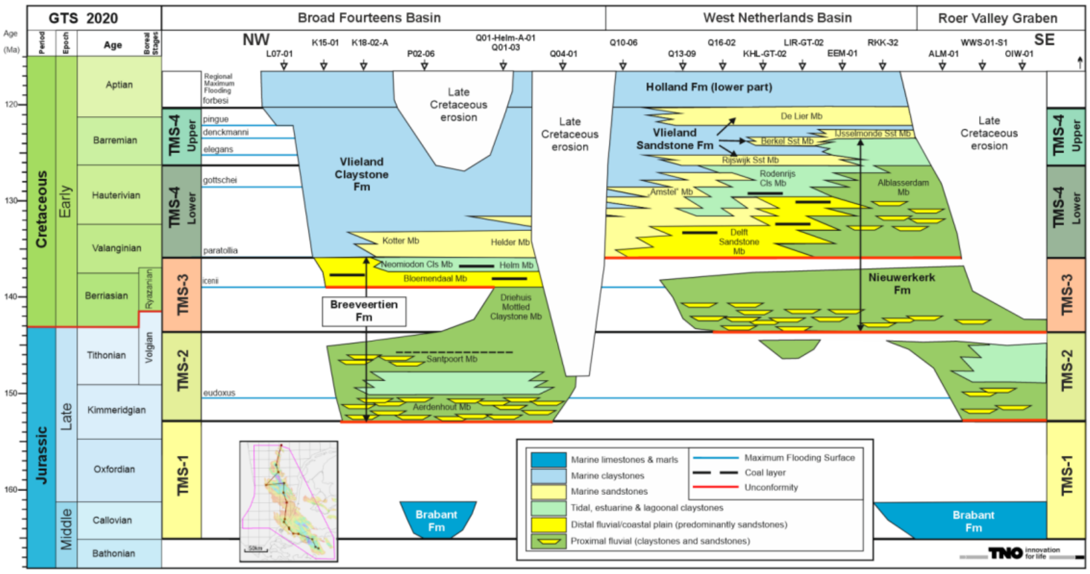

Figure 2.8: Wheeler diagram showing the Delft Sandstone Mb and Alblasserdam Mb of the Nieuwerkerk Fm (Bouroullec et al., 2024)

2.2 Introduction of existing shallow developments in The Netherlands

In this section a general introduction of the relevant shallow developments in the Netherlands will be presented. Details on drilling and completions will be given in the next chapters.

2.2.1 Geothermal

The doublet at Zevenbergen (Figure 2.9) is the only LTG development in the Netherlands and targets the Brussels Sand Mb at a depth of around 700 m. It is developed in an area where very few traditional, deep geothermal targets are present. The Brussels Sand Mb has already been described in section 2.1.2, which is not repeated here. The doublet was drilled in 2017 and the beginning of 2018. First an 8.5 inch pilot hole was drilled, followed by two highly inclined wells. The goals for the pilot hole were to collect more information on lithology and depth of the formation and to prove that there is no gas. Producer ZVB-GT-01-S2 has a kickoff point at 187 m TVD (True Vertical Depth) and a build rate of 3.6°/30 m. The injector ZVB-GT-02-S1 was drilled with an innovative inclined drilling rig and started at an inclination of 22°. At 345 m TVD was the kick-off point with a build-up rate of 3.2°/30 m. For both wells the inclination at reservoir level is ~84° (Figure 2.10).

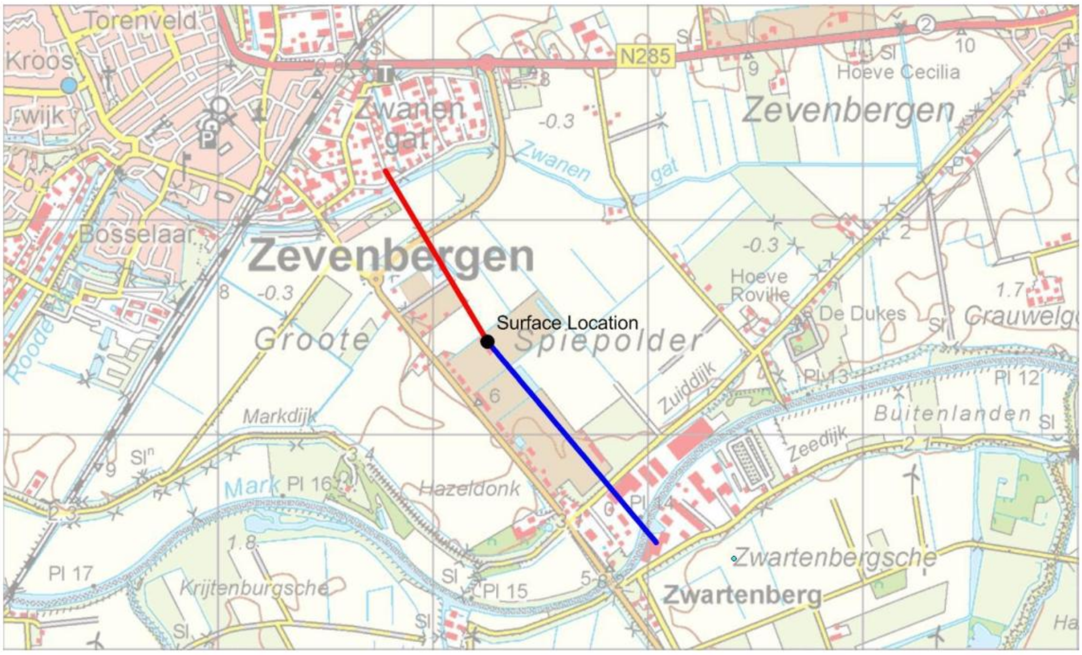

Figure 2.9: Site location map of the Zevenbergen doublet. In red the producer ZVB-GT-01-S2 and in blue the injector ZVB-GT-02-S1.

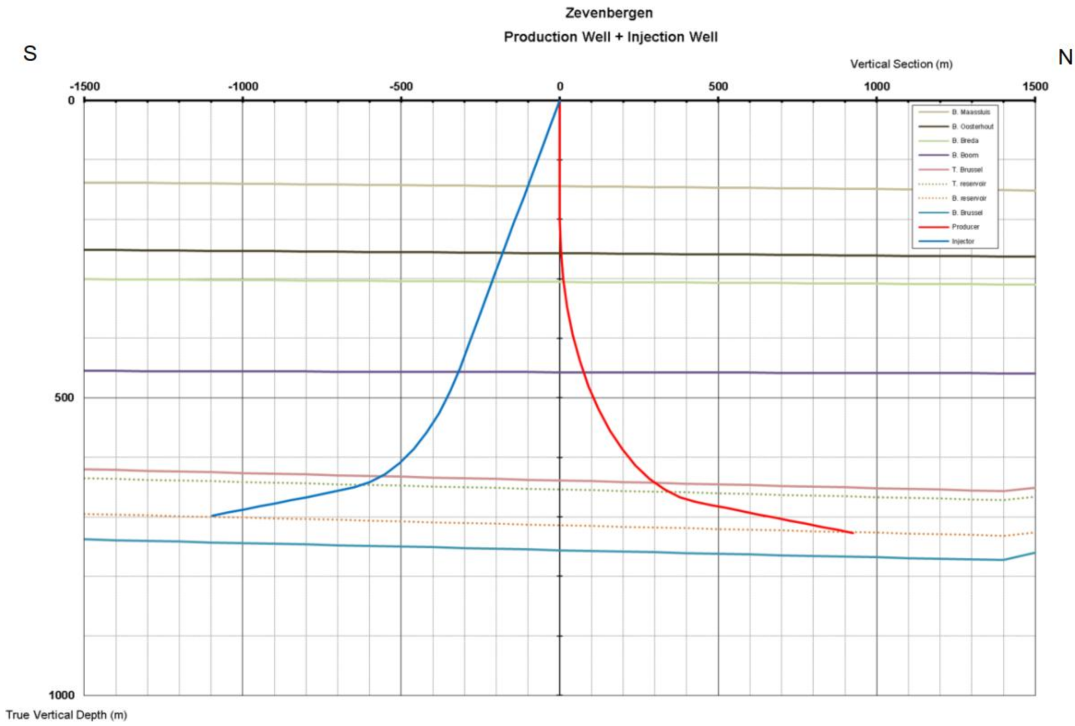

Figure 2.10: Deviation of the two wells drilled at Zevenbergen. In red the producer ZVB-GT-01-S2 and in blue the injector ZVB-GT-02-S1. Vertical layers show the formation boundaries. The dotted lines show the reservoir top and bottom.

In Figure 2.11 the monthly produced volumes of the Zevenbergen doublet are presented. This shows that the doublet was produced in the winter of 2019/2020 and during 2021. Production volumes decreased during 2021 due to issues with the decrease of productivity and injectivity. This will be discussed in Chapter 5.

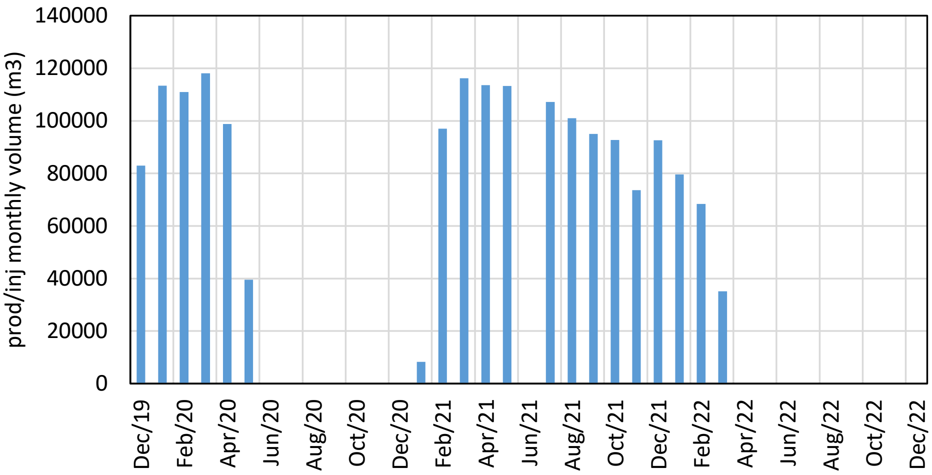

Figure 2.11: Monthly production volumes for the Zevenbergen doublet

2.2.2 Oil & gas

De Wijk

The De Wijk gas field is a conventional but shallow gas field, discovered in 1949 and operated by NAM. Production started in 1959. De Wijk gas field recovered 97% of its total recoverable reserves with peak production in 2005.

The field includes the following subsurface reservoirs:

- De Wijk Member (NLDOWY; previously named Basal Dongen Tuffite Member) and Ommelanden Formation (CKGR; also referred to as Ommelanden Chalk)
- Muschelkalk Formation (RNMU)
- Rogenstein Formation (RBSR)
- Z3 Carbonate Member (ZEZ3C) / Carboniferous

The shallow reservoir of interest in this report is the De Wijk Mb/Ommelanden Fm, which is located at a depth of around 500 m. The other reservoirs are deeper at 1100 m to 1400 m and are not further discussed here. The De Wijk Mb and Ommelanden Fm are separated by the lower permeable Liessel Member (NLLALI; previously named Landen Clay Member). The De Wijk member is a layer of around 20 m thick and mainly consists of unconsolidated clay with siltstone intercalations (description based on the field development plan, update from 2016). The porosity is variable and permeability is moderate to good for the production of gas. The Liessel Mb lies directly below the De Wijk Mb and it mainly consists of somewhat unconsolidated clay with a high marl content and some very fine sandy intercalations. Porosity and permeability in this rock are very moderate. The top of the underlying Ommelanden Formation is eroded, and the formation mainly consists of very fine-grained limestone. It has very high porosity but generally low permeability, except where "secondary permeability" has been created due to leaching by meteoric water.

In total, 48 wells were drilled in the field since 1949. Nine new wells were drilled in 2016 and one in 2020 (WYK-102), which were all deviated and were all drilled successfully (technically speaking). The deviations were modest with a step out of ~200 m at 550 m depth. Inclination at this depth was 35 to 37°.

Schoonebeek

The Schoonebeek heavy oil field (25° API (Visser and Sung, 1958)) was discovered in 1942. It was produced in two main phases: from 1947 until 1996 using mainly water injection and vertical to slightly deviated wells (Jelgersma, 2007). The first injector SCH-088 was drilled in 1949. In 2010 the field was redeveloped using steam injection and horizontal wells. New wells were drilled from 2010 onwards and production resumed in 2011. Production was stopped again in 2021 due to issues with permits for water injection wells (which occurs in a different reservoir).

The reservoir is the 20 to 30 m thick Bentheim Sandstone Member (KNNSP) from the Lower Cretaceous. The thickness is less on the west side of the field due to thinning and erosion (Vis et al., 2018). The depth of the reservoir is between 700-950 m and dips to the east. The sandstone is described as a sequence of massive sandstones, calcareous, with abundant shell fragments, lignite particles and glauconite grains (TNO-GDN, 2025b). Grain sizes predominantly range from fine to medium sand (125-350 µm; Rutten et al., 2020), but up to granule sizes occur. It is a clean and well-sorted strand plain deposit (Jelgersma, 2007). Bioturbation is common and the consolidation is poor to unconsolidated. Similar to the Brussels Sand Mb, harder calcite stringers can occur which complicate build-up during drilling. The low consolidation of the Bentheim Sandstone Mb can lead to sand failure during production. Current understanding is that this happens when wax is deposited on the screens if the oil is not heated up enough, which causes convergent flow, erosion and screen failure.

Nearly 600 wells were drilled in the field in the period 1947-1996. The initial wells were all vertical, but from 1971 also deviated wells were drilled. The first of these were water injector SCH-450 and oil producer SCH-451. These wells had a kickoff at around 250 to 300 m depth, and a maximum deviation of ~30° at reservoir depth resulting in a step-out of 150 to 200 m.

In the period 2009 until 2011, the field was redeveloped with horizontal wells in a drilling campaign. Of the 73 wells (49 producers and 24 injectors) that were drilled, only 3 needed to be sidetracked because of technical problems. In 2014, two additional wells were drilled of which one needed to be sidetracked (SCH-2952). Drilling duration was consistently less than 20 days (Figure 2.12). Although the range in AHD is from 1000 m to almost 2000 m, there is hardly any trend with drilling duration (R^2 is 0.14 on Figure 2.12).

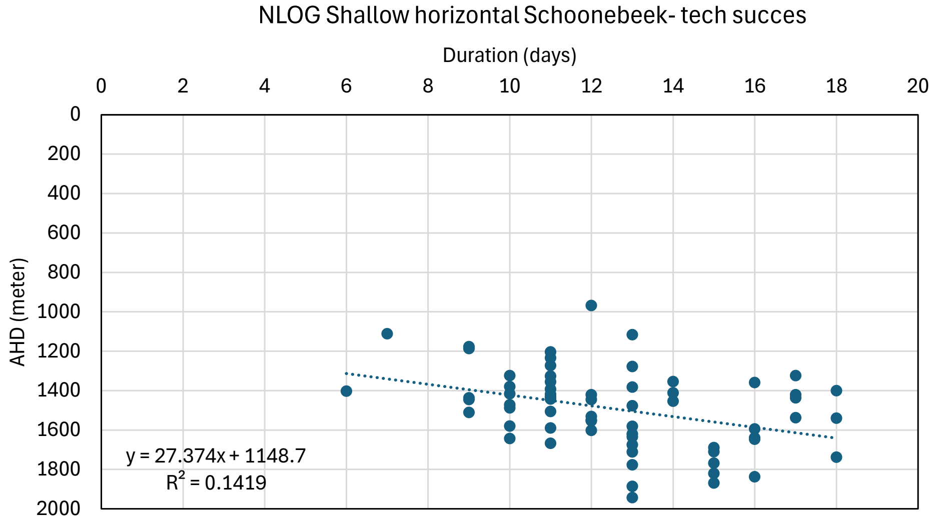

Figure 2.12: Drilling duration for shallow horizontal wells in the Schoonebeek field in the period 2009 - 2011

<u>A, B and F blocks</u>
In the A and B blocks in the Dutch offshore, a number of shallow gas fields are located:
- A12-FA, A15-FA, A18-FA, B10-FA, B13-FA, which are solely producing from shallow intervals;
- B16-FA and B17-FA which are not produced.

In the F-blocks, some multi-target fields are located. In the F02A-Hanze-Pliocene field, gas is produced from the Oosterhout Fm at a depth of around 700 m.

The gas fields in the A/B-blocks are stacked 4-way dip closures over the crest of Zechstein salt structures and have low relief (Figure 2.13 and Figure 2.14). The F02A-Hanze-Pliocene field is closed by a fault on one side and dip closures on the other three sides and show more relief. In all fields, production occurs from unconsolidated formations from the Upper North Sea Group at a depth of 350 to 750 m TVDss. The age ranges from late Pliocene to early Pleistocene, with the younger sediments in the A-blocks (Maassluis Formation) compared to the F-blocks (Maassluis and Oosterhout Formations). The fields are characterized by relatively thin sandy layers, interbedded with shales/clay layers. The thickness of individual reservoir layers ranges from a few meters to about 20 m. Locally, thin intercalations (10 to 30 cm) of clean, laminated, very fine to fine grained sands occur. The Pleistocene sediments in the A/B blocks were deposited in arctic, shallow marine conditions. In the F-block deposits are characterised by a variation in glacial period with fine grained deposits and interglacial periods which where coarser grained.

In general, higher gas column height is seen in downward direction (Figure 2.13 and Figure 2.14), but sometimes the gas column is also thin at greater depth. The height of the gas column depends on the sealing capacity of the interbedded clay layers, the thickness of the reservoirs and the depth of spill points.

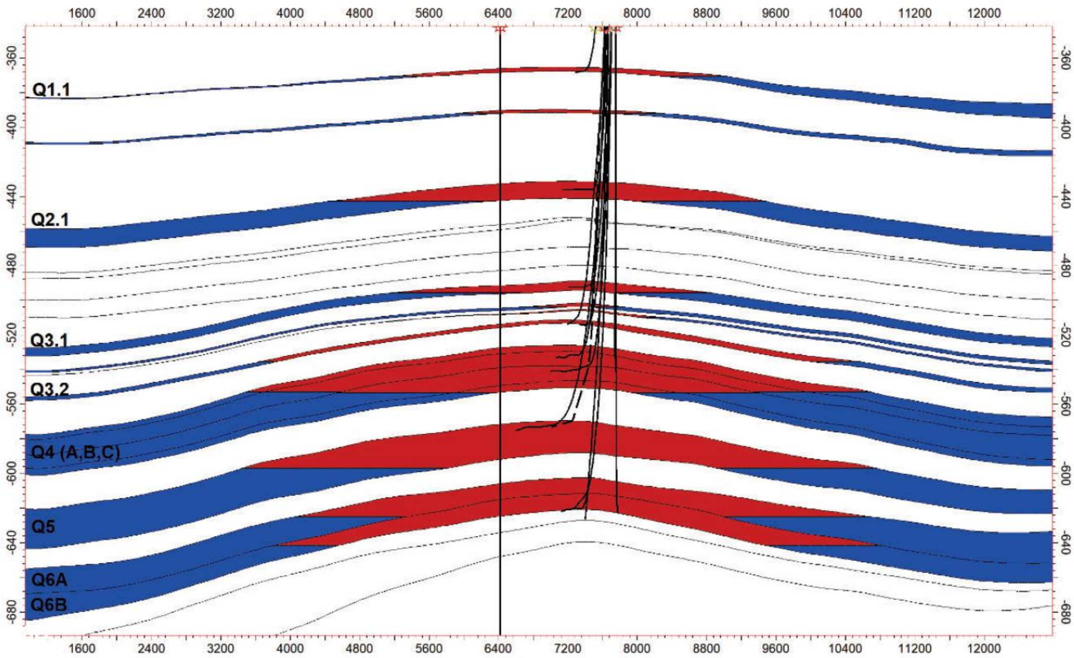

Figure 2.13: Cross section through the A12 field from the A12 production plan (Petrogas, 2024) (vertical scale increased by a factor of 20; gas indicated in red).

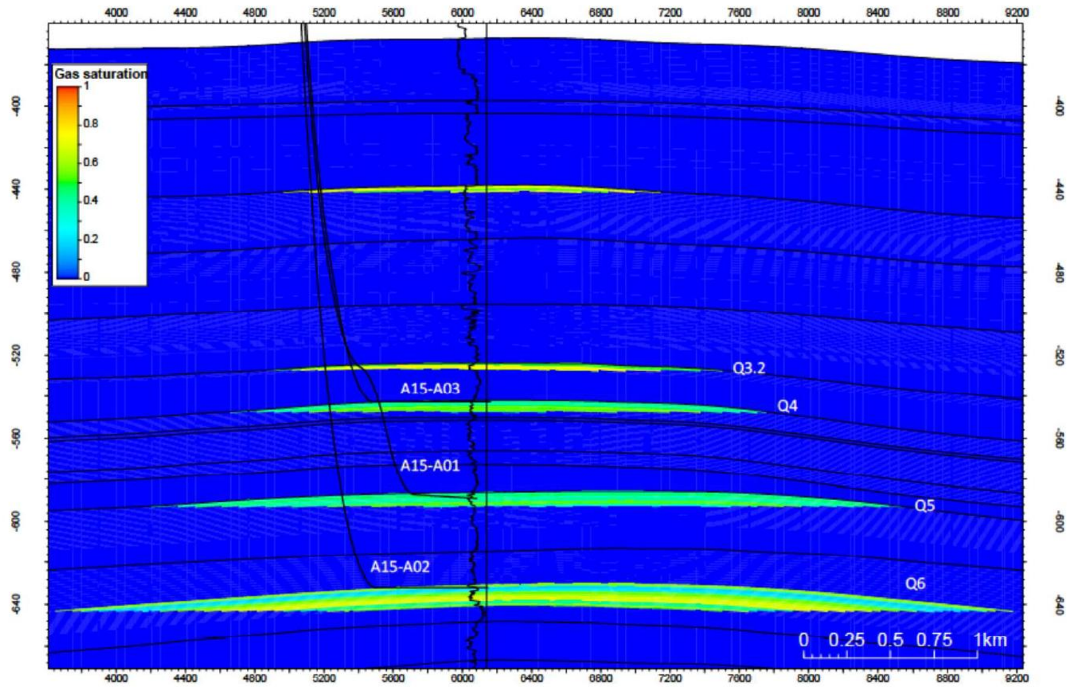

Figure 2.14: cross section through the A15 gas field showing the gas saturation (vertical scale increased by a factor of 15) (Petrogas, 2023).

Grain size analysis of the sand fraction is available for A12-03 on NLOG.nl, which show a median (d50) (weight-%) of the sand fraction for the coarsest sample of 122 µm. Many samples showed d50 below 100 µm. Cores with porosity and permeability estimates are available from 6 wells (Figure 2.15).

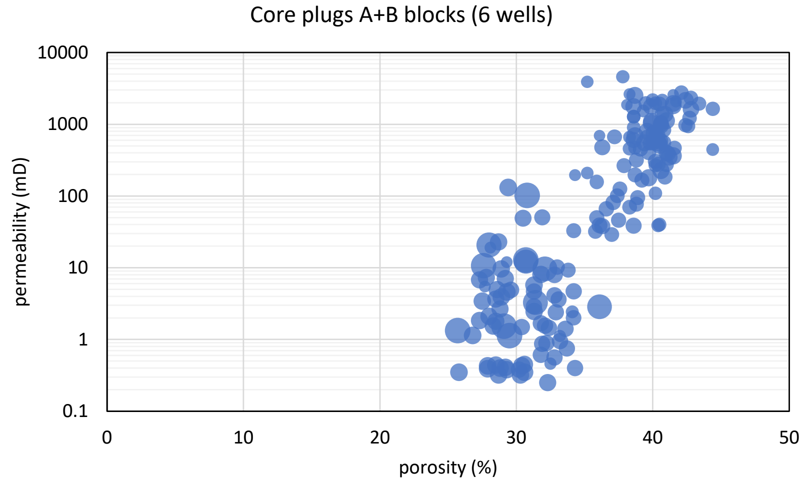

Figure 2.15: Uncorrected porosity and permeability from core plugs from A and B blocks (Peize and Maassluis Formation). Bubble size indicates depth (total depth range 400 to 1000 m TVDss).

The shallow reservoirs in the A, B and F blocks are primarily developed using horizontal wells with expandable screens. This allows for controlling sand production and limits the drawdown over the screens while maintaining sufficient production and limiting influx of water. Despite the low drawdown fines production may occur that clog facilities This can be understood from the unconsolidated nature of the reservoirs with high silt and clay content.

A15-FA and B10-FA have been developed less than five years ago and no detailed data of the realised wells are currently available, only the information in the field development plans on nlog.nl. The deviated and horizonal wells in A12-FA, A18-FA and B13 are listed below in Table 2.1, Table 2.2 and Table 2.3. From these wells, previous operator Chevron drilled 13 boreholes of which one was a technical failure (reason unknown). Petrogas drilled 14 boreholes without failure. In the F02A-Hanze-Pliocene field, only one horizontal production well is present: F02-B-01.

Table 2.1: Overview of the production wells drilled in A12-FA

Well name	Year	Operator	
A12-A-01	2007	Chevron	
A12-A-02	2007	Chevron	
A12-A-03	2007	Chevron	
A12-A-04	2007	Chevron	
A12-A-05	2007	Chevron	
A12-A-06	2007	Chevron	
A12-A-07-S1	2007	Chevron	Side tracked because of a technical failure @ 678 m TVD // 1186 mMD
A12-A-08	2017	Petrogas	
A12-A-09	2017	Petrogas	
A12-A-04-S1	2018	Petrogas	
A12-A-10	2021	Petrogas	Still confidential
A12-A-07-S2	2021	Petrogas	Still confidential
A12-A-01-S1 and S2	2025	Petrogas	Still confidential

Table 2.2: Overview of the production wells drilled in A18-FA

Well name	Year	Operator	
A18-A-01	2015	Petrogas	
A18-A-02	2015	Petrogas	
A18-A-03	2015	Petrogas	
A18-A-04	2017	Petrogas	
A18-A-05	2018	Petrogas	

Table 2.3: Overview of the production wells drilled in B13-FA

Well name	Year	Operator	
B13-A-01-S2	2011	Chevron	First hole technically failed @ 275 m TVD, first side track plugged back
B13-A-02	2011	Chevron	
B13-A-03	2011	Chevron	
B13-A-04-S1	2011	Chevron	First hole plugged back
B13-A-05	2011	Chevron	
B13-A-02-S1	2020	Petrogas	Still confidential

To interpret information from the A, B and F-blocks for potential geothermal targets for LTG in the Upper North Sea Group (mainly Breda Sg), it is good to realise that although there are similarities, there are also differences. The main similarities between the fields are as follows:
- Unconsolidated, shallow sands
- very fine sand to silt
- shallow marine deposits
- deltaic facies – foreset development
- with relatively high lateral continuity.

However, there are also some clear differences between the two areas:
- Different source areas resulting in different material deposited.
- Offshore the delta builds out into the basin from N-NE direction as a consequence of the uplift of Scandinavia and the subsidence of the North Sea Basin. In the Roer Valley Graben onshore the delta builds out into the basin from S-SE direction.
- Clear differences in accommodation space during the time of deposition.
- Different age of deposits –sequences produced from in the offshore blocks are younger than the sequences of interest for onshore geothermal development
- Onshore, the presence of glauconite and shell layers is more common.
- Offshore, more organic matter is present, which serves as food for bacteria and archaea generating biogenic gas as a waste product.

2.2.3 Other

There are other examples of wells in the Netherlands which have been designed to reach large step-out at (shallow) depth, for example BAS-03, PBR-01 and HVM-02 (all three in Friesland). PBR-01 and HVM-02 are drilled from the shoreline to reach targets offshore. BAS-03 is a salt production well drilled from a single surface location for multiple wells to create a cavern at some distance.

The HVM-02 well has a 28” section kicking off around 100 m TVD. The section was drilled with a steerable mud motor (PDM) with an average build rate of 2°/30 m and a maximum of 6°/30 m (WEP, 2022). To prevent washing out of the unconsolidated, shallow sand formations, very low flowrates were used and special attention was given to the mud system.

2.3 Aspects of the business case for LTG

Over the past years, a number of studies have investigated the financial feasibility of LTG from different angles. These are:

- Schepers et al. (2019) studied the use of LTG as a source of heat for district heating.
- Rhodes (2021) investigated the techno-economic feasibility of a LTG source in the Brussels Sand as a heat source for a heat network for a residential area in Zwijndrecht.
- WEP (2022) made a comparison of the business case for different well designs with the Brussels Sand as target.
- Boon et al (2022) investigated the business case of a residential heat network (example in Eindhoven) for different hypothetical LTG sources in combination with Aquifer Thermal Energy Storage (ATES).

Below, the main aspects of the studies and conclusions will be presented.

LTG as discussed in Schepers et al. (2019) was defined as having a temperature of 15 to 40°C. They considered cases without heat pumps (direct delivery) and with heat pumps (both distributed and central). They concluded that cost-effective exploitation is feasible in existing homes with a connection fee of 2000 to 4000 € per house (Bijdrage Aansluitkosten (BAK) in Dutch) assuming a range in capacity of the LTG systems of 3.8 MW to 14.3 MW for a depth of 400 to 1250 m. The cost of heat decreases with depth from 2000 €/kW at 400 m depth to ~1200 €/kW for 700 m and lower. The investment cost increase with depth that they assume is more than linear, which is unlikely at this depth range, which would imply that the cost of heat goes down further with depth. The relatively high capacity was achieved by assuming a high production rate of 300 m^3/hr (achieved by using horizontal wells) and a low return temperature of 8°C.

Rhodes (2021) presents a detailed case study for a neighbourhood in Zwijndrecht. The heat source was a LTG doublet in the Brussels Sand Mb. Instead of an ATES system, a 2000 m^3 storage tank was assumed to be incorporated in the system to help supply peak demand. A central heat pump was assumed to increase the produced temperature (31°C) to 80°C. The author considered several scenarios for revenue based on different heat prices and levels of subsidy. For drilling cost, 2350 €/m for high-inclination wells is assumed, which includes casing but no further completions and ESP. Without connection fee, only optimistic revenue scenarios lead to a positive business case. For a connection fee of 2500 €, the payback period ranges from 10 to 26 years for the high to low revenue case for the P50 flow rate (assuming deviated wells a flow rate of 128 m^3/h and geothermal power of 2.4 MW).

The study from WEP (2022) focused on evaluating the business case for different possible well designs including both vertical, inclined and horizontal wells. The target was the Brussels Sand with a top depth of 570 mTVD and 170 m thick. For the horizontal wells, a horizontal section was planned at a depth of ~650 m TVD. The required separation between the wells at the reservoir mid was considered to be at least 850-1250 m. With the assumptions used, the vertical wells delivered 2.5 MW and the horizontal wells 3.5 to 3.7 MW. The vertical wells showed the longest pay-back time of 18 years, due to the low rates that could be achieved (95 m^3/h) and the high cost for the required surface facilities (2 locations and surface pipeline to connect the locations). The best design was a doublet of horizontal wells which where perpendicular to each other which achieved a rate of 148 m^3/h and a payback time of 7.4 years. To calculate the income a heat price of 15 €/MWh was assumed and 15 years of SDE subsidy. The total construction costs of the doublets were estimated at 5 million € for the vertical doublet, 3.8 for the inclined doublet and 4.5 to 5.5 million € for the horizontal doublet. The construction cost estimates per m drilled for the production wells ranges from 3665 €/m for the vertical wells due to the high cost of the surface facilities and ~1500 €/m for the horizontal wells (not including RNES insurance and well testing and logging cost).

Boon et al (2022) looked at four different LTG source scenarios with different temperatures (28°C to 55°C) and rates (200 to 250 m^3/h) for a residential heat network. It was assumed in all scenarios that the temperature was increased to 70°C using a central heat pump. For 3 out of 4 scenarios a central ATES system was assumed to be used. Peak demand was met via a gas-powered system. To close the business case with a rate of return of 3.8%, a connection fee was required. The required connection fee ranged from € 5600 for the scenario with the highest production temperature to € 7600 for the scenario with the lowest production temperature. SDE++ subsidy (based on 2022 levels) was included in the calculations. They concluded that although a shallow well has lower investment costs, the electricity costs for the heat pump increase the operational costs more. The assumed cost for the wells was not explicitly listed, but only visible in the overview figures. The bulk of the investment costs were related to the development of the heat network.

Concluding, we can see that the business case can be positive when the conditions are favourable. However, in urban heat network applications quite substantial connection fees may be required, which potentially makes it challenging to implement in practice. The benefit of the lower drilling cost for LTG compared to deeper wells was not sufficient to compensate for the higher operating cost which result from the low temperature in the studies listed here. However, most cases examined assumed upgrading the heat to be compatible with current heat networks (which use relatively high temperatures). Using a LTG source in a heat network with lower temperature might be more cost effective but was not part of the available studies. In that case LTG would compete with different types of systems, e.g. ground source (closed) loop or air source heat pump systems, or standard ATES systems. Also, the large subsurface uncertainty gives rise to a poorer business case, due to the high uncertainty in the achievable production rates.

3 Drilling

3.1 Introduction

In this chapter, issues relating to drilling at medium depth are discussed. From the point of view of drilling at a depth of less than ~1000 m, the traditional kick-off depth of over 500 m depth and build rate of geothermal development does not provide sufficient step-out and distance between the wells at reservoir level to realize a doublet system. Three options are possible to solve this:

- Shallow kick-off to start building at shallow depth, potentially with aggressive build rates
- Horizontal sections to create distance between the injector and producer (WEP, 2022). Horizontal wells have the added benefit that higher production rates can be achieved or that drawdown can be reduced while maintaining production rates.
- Two vertical wells at different locations connected via a surface pipeline (assuming that reservoir productivity from the vertical wells is sufficient)

The first option is illustrated in Figure 3.1 in which the step-out is illustrated for three different well trajectories with different kick-off depth and build rate using a maximum inclination of 65°. In each of these cases, a step-out of around 600 m is reached at 700 m depth. Following WEP (2022), a maximum dog leg severity (DLS) of 9°/30 m is used resulting in a kick-off depth of 300 m. For the cases with DLS is 3.3°/30 m and 5.7°/30 m in Figure 3.1, the kick-off depths are 100 m and 230 m, respectively.

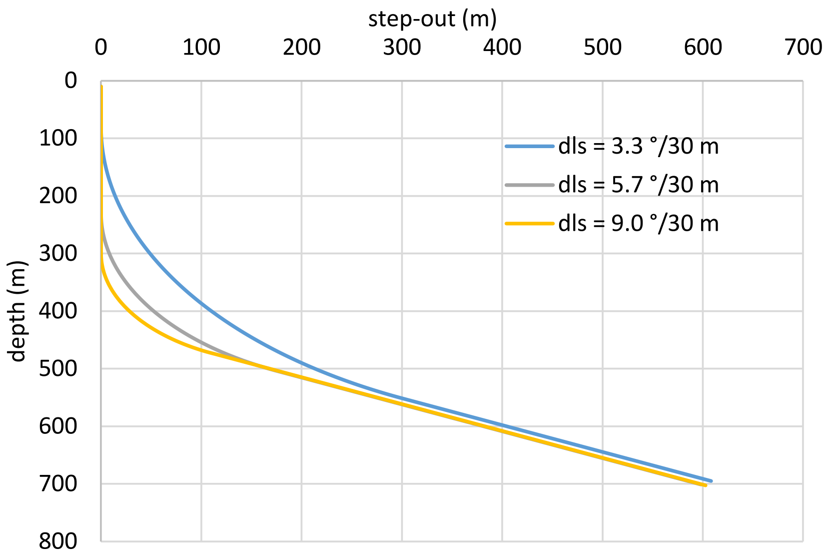

Figure 3.1: Examples of the step-out that can be reached for different drilling choices with 65° max. inclination.

Except for the option with vertical wells connected with surface pipeline network, drilling of deviated and/or horizontal wells at relatively shallow depths is required to reach sufficient distance between the producer and injector at the target reservoir depth. In the Netherlands, these targets are usually located in unconsolidated formations imposing challenges for wellbore stability. In the Netherlands there is a considerable amount of experience available on drilling deviated and horizontal wells in these formations, both onshore and offshore (Figure 3.2). Information from these wells will be summarised below.

The following topics are discussed in this chapter:
- Kick-off depths and build rates
- Geohazards and safety
- Logging / data acquisition
- Lessons learned

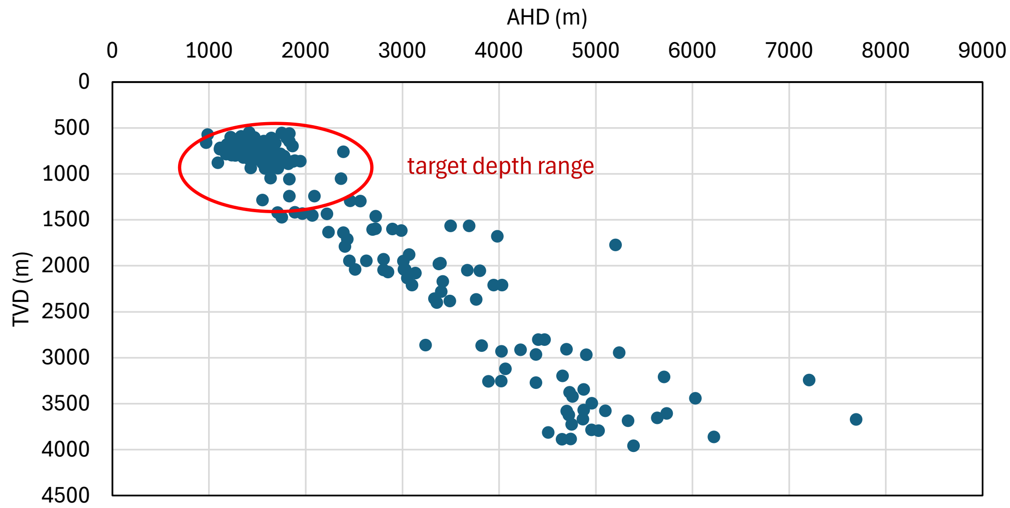

Figure 3.2: Overview of horizontal wellbores (excl. side tracks) drilled in the Netherlands showing Along Hole Depth (AHD) versus True Vertical Depth (TVD) at Total Depth (TD).

3.2 Kick-off depths and build rate

To reach well targets below 1000 m depths, an evolution of kick-off depths and the utilisation of aggressive built-up rates can be observed in drilling data from the three fields considered here: De Wijk, Schoonebeek, and A/B blocks. For characterisation, several performance indicators are used. These are: kick-off depth (m), DogLeg Severity (degree/30m), step-out factor from AHD/TVD (m/m), and well construction speed (mAH/day).

The evolution of the step out factor is demonstrated in Figure 3.3. Between 1970 and 2020, all three fields considered illustrate the evolution from step-out factors between 1 – 2 towards step-out factors close to 4 in the Schoonebeek field and the A/B Blocks.

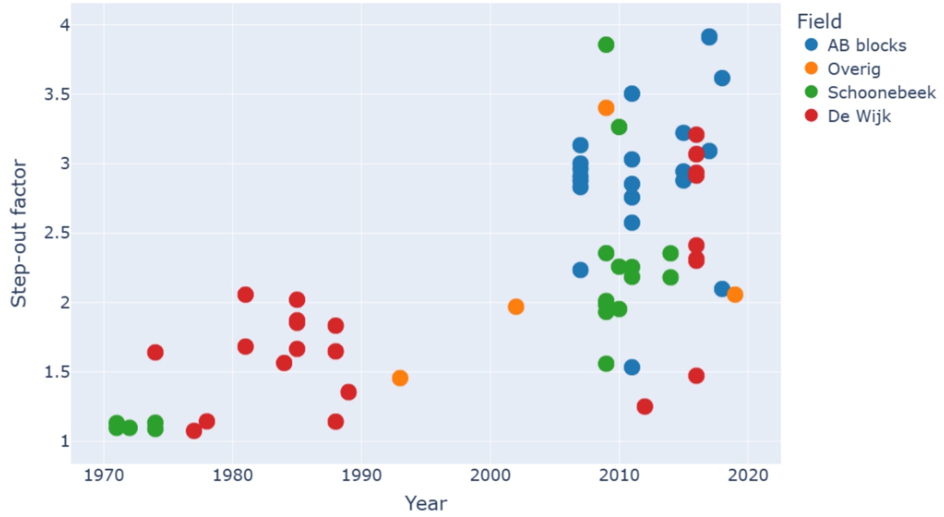

Figure 3.3: Step-out factor (total AHD/max. TVD) as function of spud year

<u>De Wijk</u>

In Figure 3.4 an overview is presented of inclination as a function of depth for wells with shallow kick-off in the De Wijk field. As can be seen in the figure, many wells have a kick-off depth shallower than 200 m. The average DLS in the initial part of the well is around 3 to 3.5°/30 m (Table 3.1) including a strategy to increase the DLS gradually between 100m and 400m depth. During the 1970's, three wells were drilled with step-wise reduction in kick-off depth (Figure 3.5a) from ~300 m in WYK-14, towards 200 m in WYK-15, and ~125 m in WYK-17.

In the second drilling campaign during the 1980's, several wells were successfully drilled with a kick-off depth around 100 to 200 m with a well construction speed of ~60 mAH/day (Figure 3.5b). The slowest well to be drilled was an appraisal well WYK-21 from 1981. In the final drilling campaign in 2016, the kick-off depth was brought down to ~50 m depth and the well construction speed increased to ~100 m AH/d. The slowest wells were WYK-43 in which a fibre optic cable was installed to monitor compaction and WYK-102, which was drilled stand-alone rather than in a campaign.

Key enablers for the successful construction of these shallow producers have been:

- For the shallow kick-off, bentonite mud has been used for good hole cleaning and environmental protection. Building rates and well inclination have been gradually increased with depth to ensure directional control and wellbore stability. Maximum DLS and inclinations were assigned to depth intervals between 100 m and 450 m (Table 3.1).
- To reduce construction costs, a slim well concept was introduced reducing the 7 inch liners used in the 1980s to a 3.5 inch cemented completions with perforations (see also chapter 4). With this concept, a casing string was saved and the first casing (7 inch) was set at ~420 m depth. The directional control of these 9.5 inch well sections has been improved compared to the 12.25 inch sections drilled at these depths in earlier campaigns.

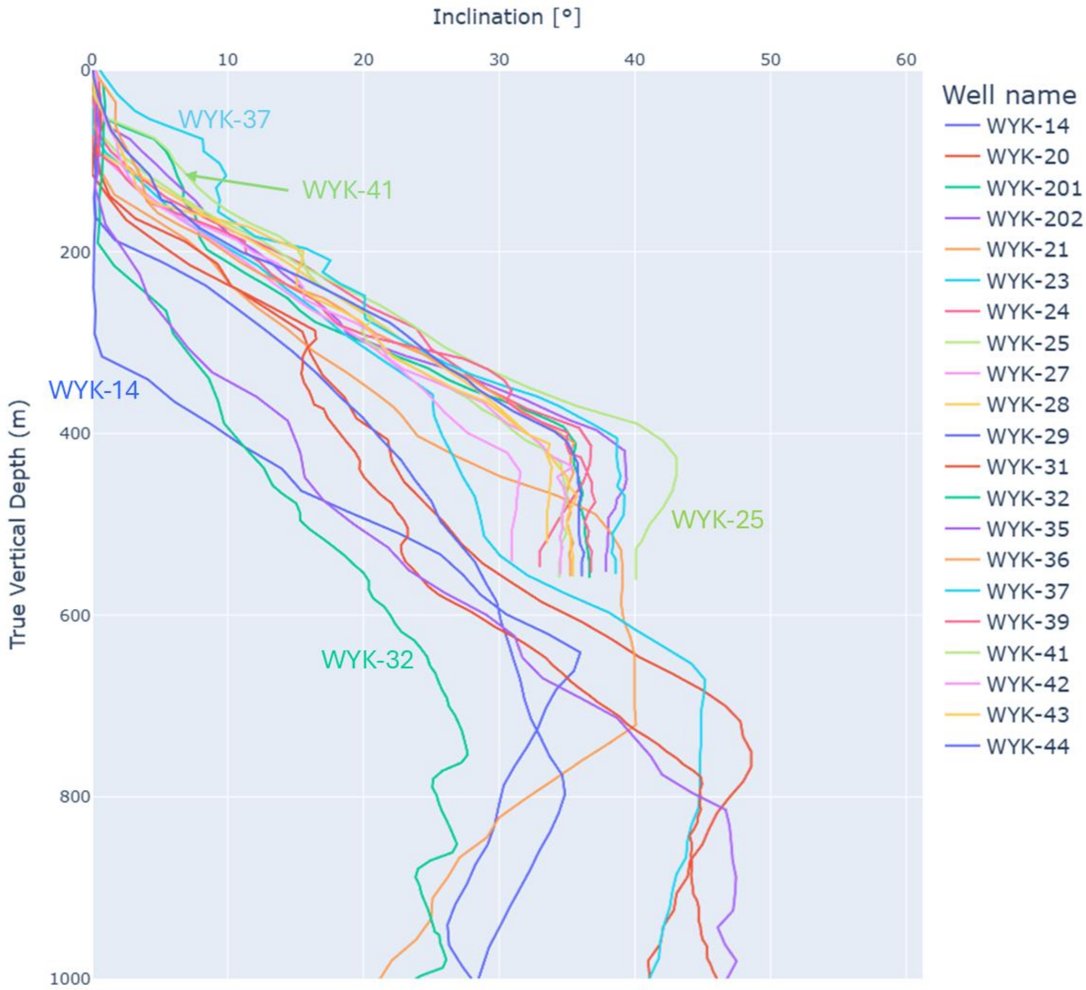

Figure 3.4: Realised inclination as a function of depth for wells with shallow kick-off in the De Wijk field. A tendency towards shallower kick-off depth and larger inclinations (at same depth) is demonstrated from the 1970s (e.g. WYK-14) towards the 2010s (e.g. WYK-41).

Table 3.1: Summary of the build rate and inclination used in the De Wijk field.

Depth range from (mTVD)	Depth range to (mTVD	Max DLS (°/30 m)	Max inclination (°)
0	100	0	0
100	150	3	5
150	200	3.3	10
200	350	3.6-3.9	25-30
350	450	4.2	35-40

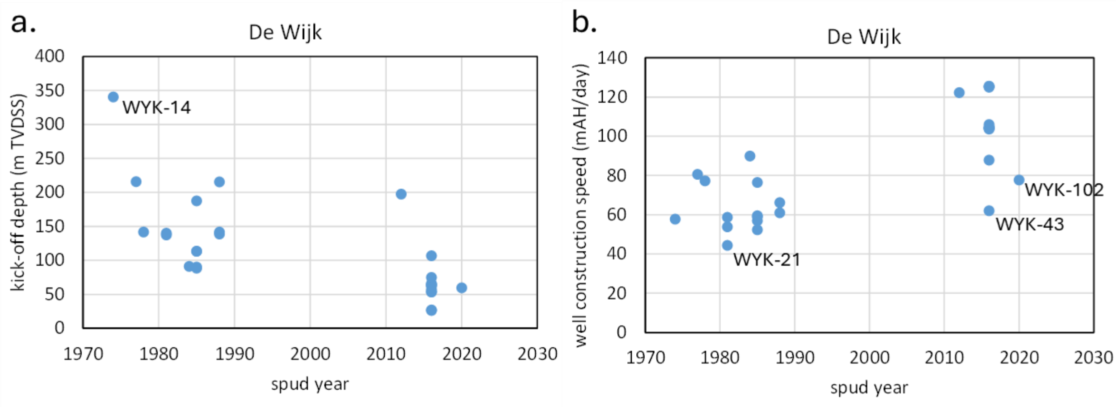

Figure 3.5: a. Kick-off depth and b. well construction speed as a function spud year.

<u>Schoonebeek</u>
For the Schoonebeek field, typical well paths of horizontal wells from the re-development of 2009-2011 are shown in Figure 3.6 For comparison, a small number of wells from the 1970s is added, which are deviated (SCH-450 - SCH-465). Unlike in De Wijk, the kick-off depth is generally deeper than 200 m depth. The field was discovered in 1942 and the earlier wells drilled until the 1990s were vertical or slanted. The redevelopment program in the 2010s featured a Steam Assisted Gravity Drainage (SAGD) approach for enhanced oil recovery developing the reservoir with horizontal steam injectors and horizontal producers. In total, about 700 wells have been drilled into the unconsolidated Bentheim sandstone target formation. The information reviewed in this paragraph focus the redevelopment program due to availability of data.

In addition to the SAGD approach, the redevelopment was enabled by slime hole drilling concept reducing the hole size at reservoir section to 5 inch and a standardisation of the wells design for injector and producers. A new, customized rig type was employed from a local drilling equipment supplier. The well design features a gradually increase of dog leg severity (DLS) from 2 °/30 m up to 6 °/30 m, with KOP > 200 m depth, archiving 90 ° inclination at reservoir level. The drilling duration on average remained steady throughout the campaign (Figure 3.7a) while the total number of meters drilled increased (Figure 3.7b).

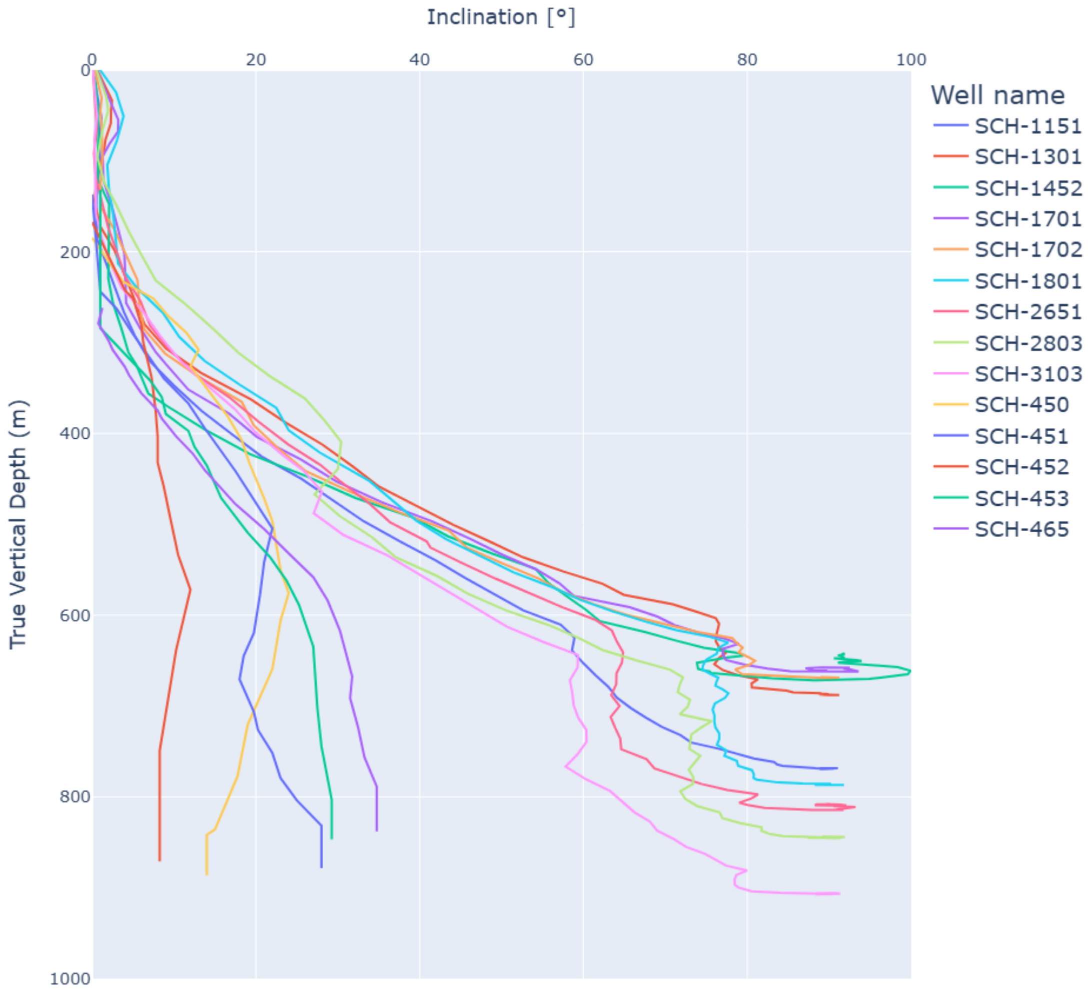

Figure 3.6: Inclination as a function of depth (TVDSS) for some wells with shallow kick-off in the Schoonebeek field.

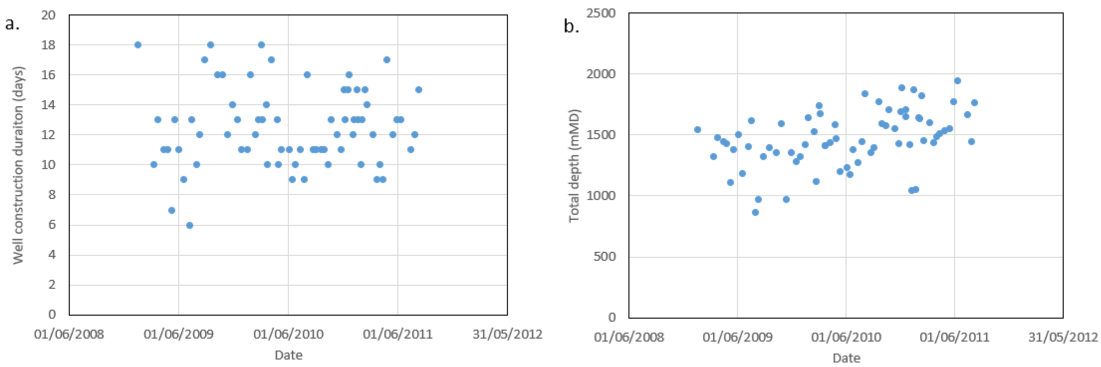

Figure 3.7: Well construction duration (a) and total depth (b) over time for the drilling campaign from 2009-2011 in Schoonebeek.

A/B blocks

Figure 3.8 shows the inclinations for the mainly horizontal wells in the A/B blocks. Kick-off depths are below 100 m, partly as low as ~30 m. Unlike the other fields, the wells are quite similar and no historical changes or performance developments can be observed, which can largely be explained by the fact that the oldest wells shown are from 2007. Many of the most recent wells are still confidential, so the amount of information is limited.

The A/B block produces from a stacked gas reservoir with relatively small gas columns with 3 m to 15 m height. The gas caps are located at TVD levels between 350 m and 750 m resulting in step-out factors larger than 3 (Figure 3.9). For the development, an innovative concept was utilised by sidetracking existing producers to reach a different reservoir level. From the 14 wells drilled by Petrogas more recently, no technical failures were reported. The number of reported technical failures in earlier wells is also low.

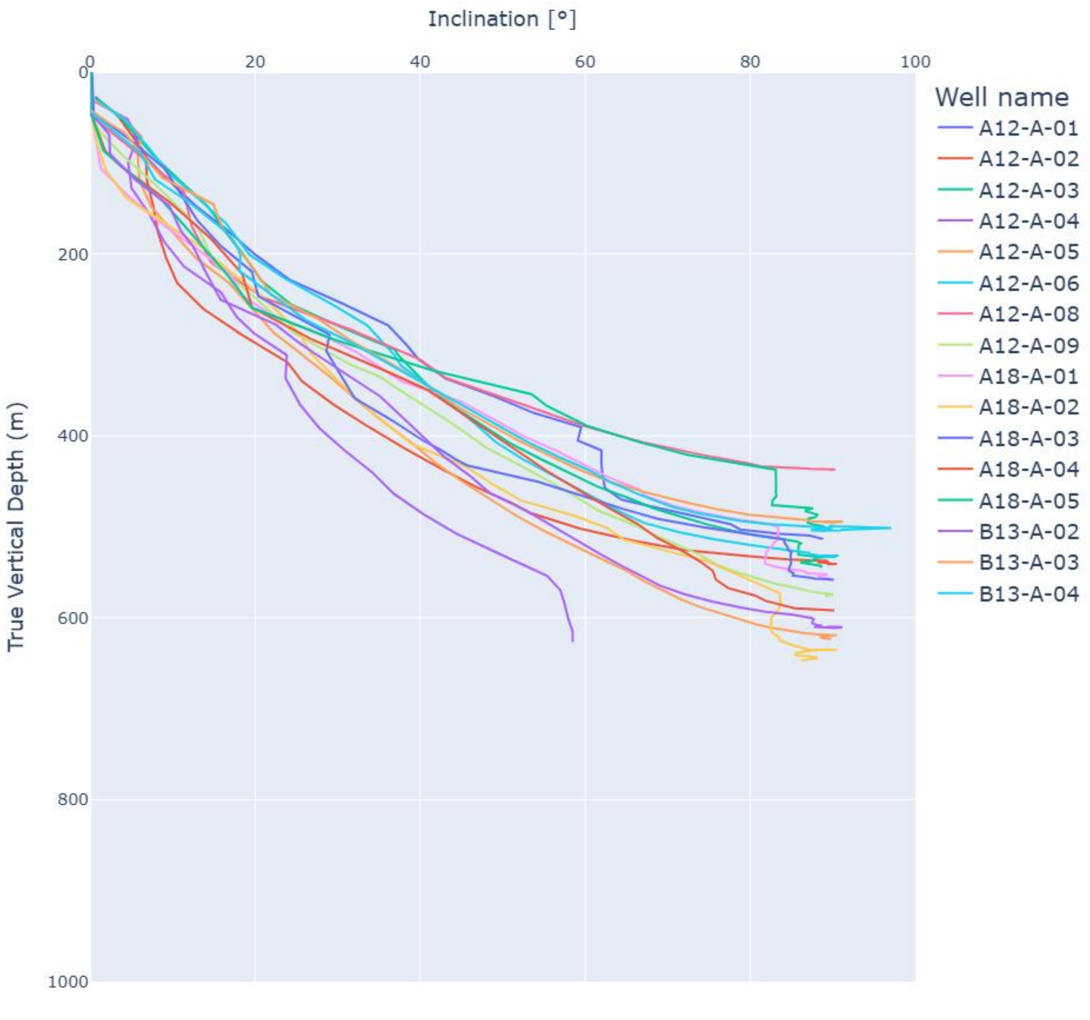

Figure 3.8: Inclination as a function of depth (TVDSS) for wells in the A/B blocks.

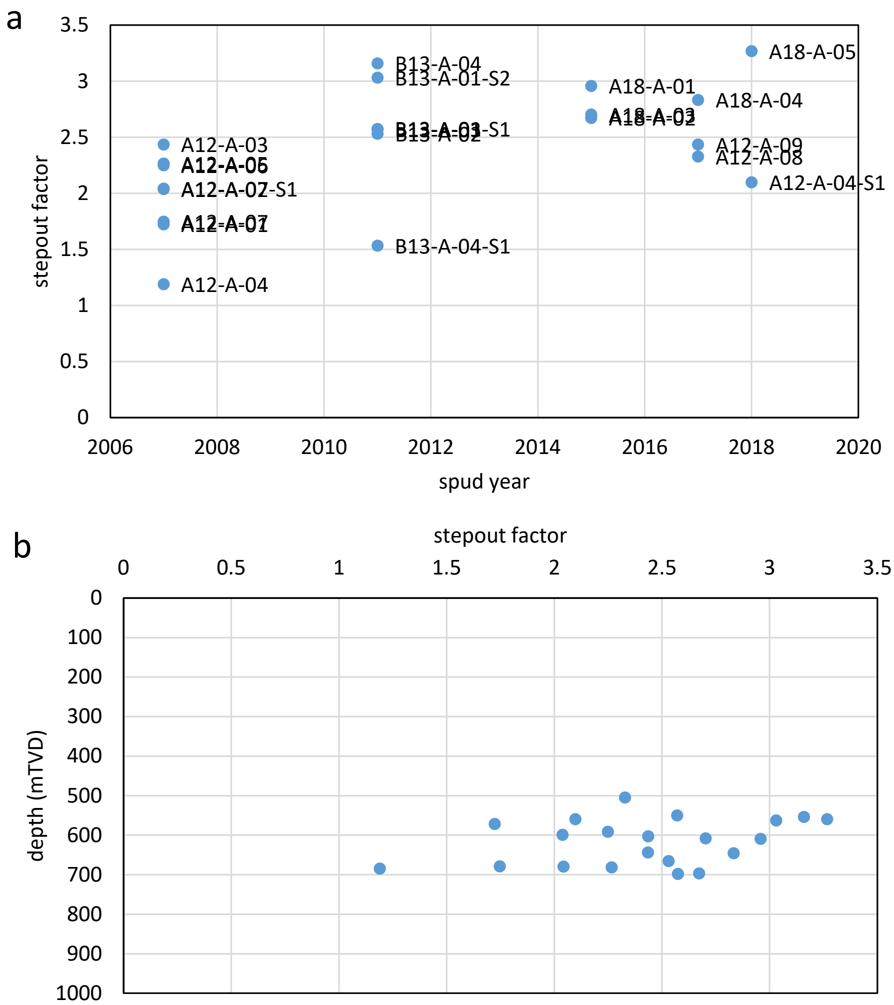

Figure 3.9: Stepout factor (AHD/TVD) for wells in the A/B blocks: a) as a function of time and b) with depth (mTVD).

Well construction duration A/B blocks

In Table 3.2, the duration of drilling and completion of different sections in the A/B blocks (fields A12-FA, A18-FA and B13-Fa) are summarized from a total of 16 wells (details in the database). For all sections, there were some wells in which the section took much longer than in the other wells and much longer than expected. For the 8 ½ inch section of well B13-A-03, the maximum duration of 3.9 days is almost three times more than the average. In well B13-A-02, the section took 3.5 days. There are no root causes documented for these delays. Potentially, the variation results from different ways of reporting the operational periods. Some companies cover more aspects than others in an operation sequence.

Another sequence that took much longer than planned was the setting of the 9 5/8" casing in well A18-A-02. It took 8.1 days rather than the planned 2.8 days (partly due to bad weather). Running the lower completion in B13-A-03 took relatively long 9.5 days but no information on the planned operational time is documented. No explanation on the causes for the reported delays is provided.

Table 3.2: Well construction duration of the different sections in A/B blocks (A12, A18 and B13) (total of 16 wells; excluding sidetracks)

Well name	Mean	St dev.	Min	Max
Drilling 16" hole section	0.96	0.48	0.36	2.30
13 3/8" casing	2.62	1.17	1.32	5.93
Drilling 12 1/4" hole section	1.97	1.13	0.63	4.90
9 5/8" casing	3.50	1.75	1.35	8.10
Drilling 8 1/8" or 8 3/8" hole section	1.33	0.96	0.46	3.90
Lower completions (ESS screens mostly)	4.17	1.66	2.64	9.50

<u>Other</u>
In Figure 3.10, the inclination of the wells in Zevenbergen are plotted. Well ZVB-GT-01-S1 was created as a sidetrack from the vertical pilot hole. Well ZVB-GT-02 was drilled with an inclined well head. Both wells needed to be side-tracked at reservoir level. At reservoir level the inclination is between 80 and 90° and changes rapidly due to difficulty in drilling the hard streaks/stringers that are present.

In Figure 3.11 the increase in inclination is shown for other relevant wells, including the well BAS-03 which has one of the most aggressive shallow build-ups in The Netherlands: 9.26° at 110 mMD, which is similar to WYK-37 (from 2016) which shows 9.38° at 116.37 mMD. The highest inclination at 100 m is ZVB-GT-02, which has 19° due to an inclined well head as discussed in Section 2.2.1.

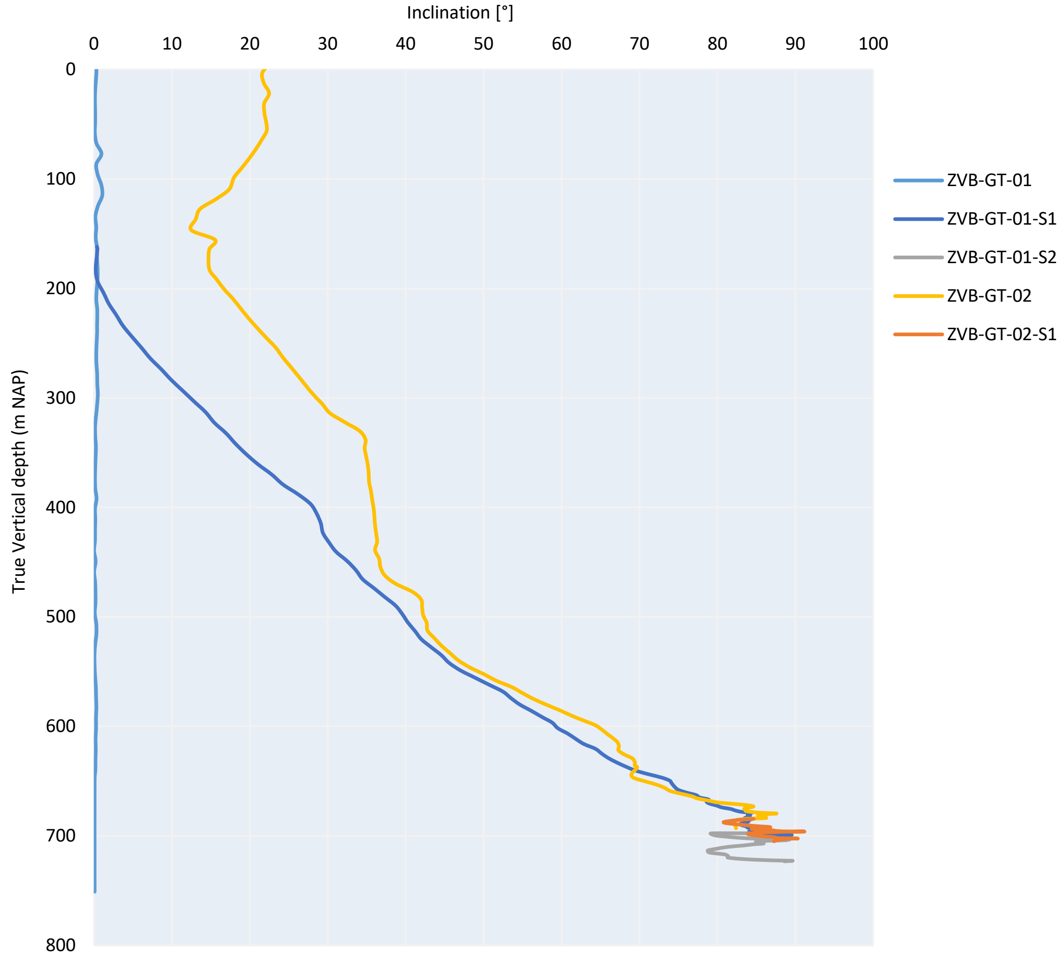

Figure 3.10: Inclination as a function of depth (TVDSS) for the wells drilled in Zevenbergen.

3.3 Geohazards and safety

The reported cases of drilling issues resulting in delays, emergency activities and ultimately lost pipe and sidetracking are discussed for the medium depth developments targeted in this report. Root causes and learnings are documented if this information is available in the well documentation on NLOG.nl. Please note that a general overview of drilling events can be found in the geo-drilling events database by EBN[6].

[6] https://www.ebn.nl/feiten-en-cijfers/data-centre-geologische-data/

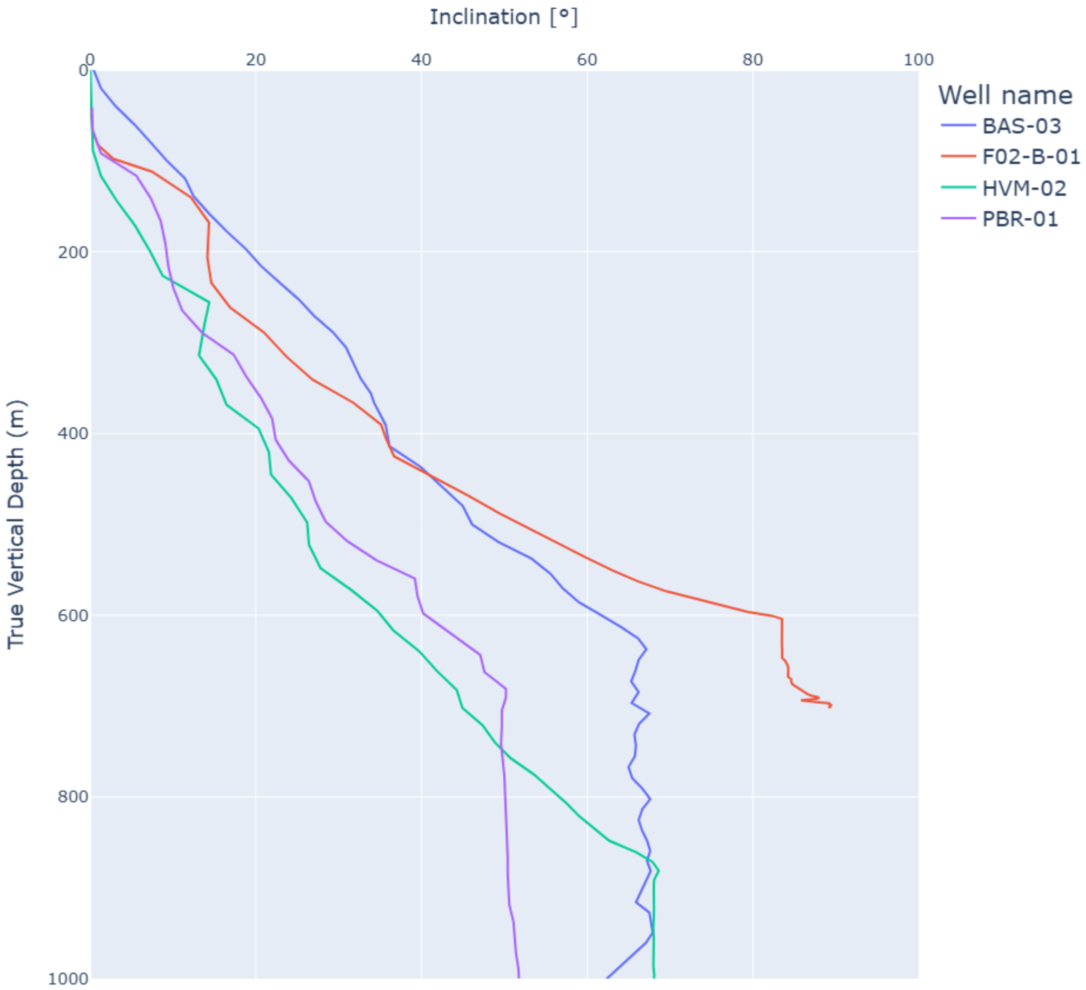

Figure 3.11: Inclination as a function of depth (TVDSS) for various wells with high inclination at shallow depth.

<u>De Wijk</u>

From 44 producers drilled as part of the De Wijk development, only 3 wells report a technical failure, namely WYK-15 (1977), WYK-17 (1978) and most recently WYK-33 (1989). WYK-15 needed to be side-tracked due to an issue with the directional control resulting in a too low deviation of the wellbore. WYK-17 faced stuck pipe issues. For WYK-33 differential sticking within the highly permeable Rogenstein Oolite formation with a 1.2 sg drilling mud is reported as root cause for the lost in hole string. An emergency pill was pumped and themud weight was reduced until the well started to flow but the pipe couldn't be released. Other reported issues in the De Wijk wells are the result of sticky / mobile clays present in various sections resulting in clay balling, overpulls and squeezed wellbores. An overview of potential geohazards per geological unit is presented in Table 3.3.

Table 3.3: Geohazards as identified in De Wijk gas field grouped per geological unit (for the relevant shallow units only).

Group	Formation/member	Code	Potential hazard
Upper North Sea	Various	NU***	Losses in unconsolidated sands
Middle North Sea	Boom Member (previously Rupel Clay Member NMRFC)	NMRUBO	Clayballing – sticky clay
	Berg Member (previously informal Berg Sand mb NMRFS)	NMRUBE	Clayballing; losses
Lower North Sea	Asse Member	NLDOAS	Clayballing
	Brussels Sand Member	NLDOBR	Losses, reduced ROPs
	Ieper Member	NLDOIE	Overpulls
	De Wijk Member (previously Basal Dongen Tuffite)	NLDOWY	
	Landen Formation		
Ommelanden chalk	Ommelanden Formation	CKGR	clay balling

<u>Schoonebeek</u>
In the Schoonebeek drilling campaign from 2009 – 2011, only 3 wells from 73 needed to be sidetracked, and from the 2 wells drilled in 2014, 1 well was sidetracked. Key issues have been severe losses in the porous and weak Bentheim sandstone layer. Mitigation measures like viscous / LCM pills were not successful in the wells that needed to be sidetracked. In two cases, the completion couldn't be run to TD. In the two other cases, the drill string got stuck without possibility to be released. Reasons for the side-tracking mentioned in the end-of-well reports on NLOG in the sidetracked wells mentioned above:

- SCH-1451: incurable losses in top Bentheim Sst
- SCH-2501: unable to run casing across an earlier severe loss zone in the upthrow Bentheim Sst block.
- SCH-1803: drilling bit and stabilizer lost in hole
- SCH-2592: stuck pipe

In addition to the losses in the permeable Bentheim Sandstone Mb (Table 3.4), pack-offs and swabbing is reported frequently indicating mobile formations. Differential sticking, a common issue in permeable formations, required good maintenance of the drilling mud properties with precise mud weight and filter cake thickness control. Minimization of static time were part of the operational practice and dynamic mud losses had to be accepted to some extend due to limited success of mitigation measures like LCM (Lost Circulation Materials) pills. Poor weight on bit (WOB) transfer in the horizontal section resulted in torque spikes and directional control was partly challenging with the motor bent-sub assembly deployed. A rotary steerable (RSS) assembly and/or sufficient heavy weight drill pipe (HWDP) could deliver a better WOB transfer and enhance directional control.

Table 3.4: Summary of geohazards in the Schoonebeek heavy oil field grouped per geological unit (details in Appendix B).

Stratigraphic unit				
North Sea groups	Swabbing			
Chalk				
Holland/Vlieland	Pack offs			
Bentheim	Dynamic losses due to high permeability	Calcite streaks leading to poor directional control	Low fracture gradient leading to losses	Differential sticking

A/B blocks

From the accessible drilling reports of the newer drilling campaigns, no technical issues leading to a lost hole and/or unplanned sidetracking activities are documented while the wells feature shallow kick-offs and built towards horizontal to target thin layers of unconsolidated sandstone. The operational strategy and drilling plan execution of Petrogas appears to be well developed. Operational details of this strategy are not publicly available. A general strategy for effective field development is presented in Section 3.5.

From the earlier drilling campaigns when the field has been operated by Chevron, some technical failures and sidetracks are covered on NLOG.nl. This includes the A12-A-07 (from 2007) and B13-A-01 and B13-A-04 (both from 2011). A root cause for the technical failure of these 3 wells and resulting side tracking is not reported.

Bit balling, a common drilling issue in younger sediments / clays is reported from B13-A-01-S1 and the mud strategy should incorporate this risk for these shallow developments by reducing the sticking tendency of the cuttings and enable a good suspension of the cuttings in the drilling mud.

Zevenbergen

In the Zevenbergen project, both wells needed to be sidetracked due to technical problems related to penetrating a hard layer at a depth of around 700 m (704 m and 699 m TVD RT for ZVB-GT-01-S1 and ZVB-GT-02 respectively based on the end of well reports of ZVB-GT01-S2 and ZVB-GT-02-S1 on nlog.nl). The unstabilised bottom hole assembly and selected bit were unable to penetrate the alternating layers of unconsolidated, soft rock and hard layers at high inclinations. The drilling tool started to follow the hard layers resulting in an unpredictable DLS (see the well path in Figure 3.10).

During drilling of the side track ZVB-GT-02-S1 the mud properties were changed to a higher chloride content, but less solids, compared to the mud properties that were used to drill the other reservoir sections. Significant time was spent cleaning this well. During cleaning with a polymer breaker pill and soaking, total losses were observed and circulation was impossible. A downhole pump was lowered in the screen liner to clean out the well. During cleaning of well ZVB-GT-01 significant amounts of fine sand were recovered (18 m^3 from the 13 3/8” casing).

Apart from the technical problems due to the challenging reservoir and the testing of innovations such as the inclined rig, part of the long drilling time (> 40 days per well) and complications may have been caused by the organisation of the project. Many different parties were involved and the project developer was generally active in shallow unconsolidated drilling (e.g., water wells).

Other shallow well developments
F02a_Hanze_Pliocene
Well F02-B-01 suffered severe losses and poor hole conditions. The well experienced total losses while drilling below the 20" conductor shoe. Despite attempts to cure losses with LCM pills, the losses persisted. This, combined with the misaligned trajectory, led to the decision to plug back and sidetrack

Well BAS-03
The shallower part of the BAS-03 well has been constructed with a casing while drilling concept incorporating a strong build with an DLS up to ~9 °/30 m. Water well equipment with a reamer like drill bit was deployed and the casing joint were welded in place with a 1° angle to realise the built section with 24 inch casing.
Tophole drilling (which was done by Haitjema) suffered from delay due to collapse of loose North Sea sands. Initially, it was attempted to drill the 22" hole with a fresh water-based mud, which unfortunately proved to affect the Asse clay. After a change to salt saturated brine the hole was drilled rather smoothly until TD was called in the Lower North Sea Group because of low ROP. The 18 5/8" stood up in the top section of the hole and created a ledge due to dogleg and inflexibility of this large diameter pipe. The ledge was passed with great difficulty. Pipe could not be run to bottom and was set and cemented at some 100 m above section TD.
In drilling of the 17 ½" section, instability of the Lower North Sea clay's together with improper hole cleaning, caused the well to be side-tracked twice. One BHA was lost-in-hole. Carrying capacity of the OBM used proved to be insufficient to bring drill cutting to surface at maximum pump-rate of some 4500 LPM. An intermediate 16" string was set in top Chalk and drilling was continued with 14 ¾" equipment to section TD, some 50 m below the squeezing Carnallite. Bit ran stuck when pulling out after a checktrip. Some drilling equipment had to be left downhole but could be pushed to bottom. Casing was run without problems and the well was successfully side-tracked around the fish.

3.4 Well logging

Data acquisition is a key part of the field development, since it enables understanding of the reservoir. Logging in shallow (horizontal) wells is widespread and doable but of course needs good planning. The advantages of modern Logging While Drilling (LWD) tools makes much of this data acquisition relatively cheaper if compared to a stand-alone wireline logging campaign executed after drilling of the well section. Reduced open hole times due to utilisation of LWD can be an advantage for completing these wells as run-in-hole issues can be mitigated.

In Appendix A, logging in the shallow gas fields in the A/B blocks is shown as illustration of the logging for shallow formations. A summary is presented in Table 3.5. A main difference between oil and gas and geothermal development is that drilling of exploration and appraisal wells, which is rarely done in geothermal development. The exploration/appraisal list is relevant for wells in new geothermal plays, and logging in the production wells for more well-known areas. Data acquisition in the production wells is performed using LWD. However, specific logging tools might require recalibration if the correlation functions derived for oil and gas formations aren't applicable for geothermal reservoirs.

Table 3.5: Summary of data acquisition in shallow wells in the A/B blocks (details in Appendix A).

Data type	Exploration/appraisal	Production wells (LWD)
GR (gamma ray)	Always	Always
SGR (spectral gamma ray)	Often	Rarely
RES (resistivity)	Always	Always
CAL (caliper)	Always	Always
NEU-DEN (neutron-density)	Always	Always
DT (sonic)	Always	Sometimes
FPRESS (formation pressure)	Often	Sometimes
BHI (borehole imaging)	Often	Never
NMR (nuclear magnetic resonance)	Often	Never
core	Sometimes	Never

Qualitative value of specific data:

- SGR helps with glauconitic/uranium-rich sands, which is especially valuable in glauconitic sands such as the Breda Sg, and other formations of the North Sea Groups. SGR is also valuable for the characterisation of shales.
- The resistivity log is sensitive to changes in fluid properties. In petroleum wells, RES is generally run for identifying hydrocarbons, which is less relevant in geothermal wells. However, RES is also sensitive to changes in salinity, which makes it useful to identify the transition from fresh to saline water. In shallow wells, it can be used to get a qualitative estimate of porosity.
- CAL provides information about wellbore deformation, break outs and wash outs.
- NEU-DEN and DT are used for quantitative porosity estimation. In general, porosity estimation is far less important for geothermal operations than for petroleum. Permeability and reservoir thickness are the key features that determines performance of a geothermal system. Porosity is required for estimating permeability from poro-perm relations and for proper accounting of the heat balance. These logs can also be used for the estimation of the geomechanical properties. In that case the shear sonic needs to be derived from the compressional sonic.
- Compressional sonic (DTC) and shear sonic (DTS) together are also referred to as dipole sonic and can be used to derive geomechanical properties and well tie (in absence of a VSP/Check-shot).
- FPRESS (via RFT or MDT) gives information on formation pressure, fluid densities and contacts with possible HC's. Formation pressure is usually estimated more economically by the fluid level in the well for geothermal wells, but it has a larger uncertainty. Fluid density caries a far lower uncertainty in geothermal and can in many cases be estimated with sufficient accuracy from fluid samples.

- BHI/Image logs provide insight into reservoir characterization such as bed thickness and bedding attitude, fractures, facies and heterogeneity. These types of logs can also give information on borehole geometry.
- NMR measures porosity and pore-size distribution, from which permeability and free-fluid volumes can be derived. Calibration using core data is required in particular for unconsolidated shallow formations as the standard interpretations are for deeper, consolidated formations. Calibration of NMR data with cores is currently investigated in the Warming^{UP}*GOO* project (https://www.warmingup.info/WarmingUPGOO/1/resultaat-1)
- Information from cores gives valuable insight in the formation properties (porosity and permeability) but is expensive in acquisition and analysis. The information from cores is especially important in new areas with little information, because it is needed to calibrate other logs and get information on the poro-perm transform.

3.5 Lessons Learned

Shallow Kick-off, increased step-out and well construction speed
Shallow kick-off points to realise the required outstep have been reported from various drilling projects. An effective strategy included the gradual increase of the DLS and the inclination limitations per depth within the first ~ 450m TVD of drilling. For very shallow kick-offs (partly as low as 30 m), bentonite drilling muds have been used instead of KCL polymer muds due to their good hole cleaning capacity, plastering effect in unconsolidated sands, and their environmental benefits. In one field development, the progress towards shallower kick-off points and increased step-out is well documented. This development towards optimized well designs has been realized by learning and optimisation of the drilling operations, not by a technical development. Step-out factors (AHD/TVD) of up to 4 have been realised. Likewise, the average well construction speed (mAH/day) could be almost doubled over a dedicated period of time in one field development.

Critical success factors
Achieving a high success rate is to a large extent achieved by careful upfront planning, drilling in campaign mode, building the learning curve and optimizing the drilling process. Upfront planning to arrive at an optimized well construction process and well completion would include i.a. well trajectory, mud program, hole cleaning considerations, wellbore stability, build rates, completion placement options.
Severe issues resulting in lost in hole strings and side-tracking activities are predominately reported early within a drilling campaign, or for single well / single doublet projects. Optimizing and maintaining the field experience and operational knowledge is key for an optimised well construction and overall cost reduction of a development. Learning curve development, learning curve acceleration concepts and dedicated experience in unconsolidated formation drilling is published in many papers in addition to the Dutch drilling campaigns reviewed in this report.

With regard to the well drilling operations, following learnings can be derived:
Mud Losses
The high permeability and low strength of the targeted unconsolidated sandstones require well defined and controlled drilling mud properties. The mud weight should target the correct, potentially narrow mud window to avoid inflow including inflow of sand slurry and destabilisation of the wellbore. Due to the risk of differential sticking, the mud weight should

be sufficiently low on the other hand to limit losses into the formation. To mitigate differential sticking issues, the static times in the well should be minimized and the mud system should deliver a thin filter cake with good filter properties. Overpressures in the wellbore should be limited and the BHA design adapted to limit flush area which is more prone to sticking.
LCM pills have been pumped in several instances with limited efficiency to stop, partially severe mud losses. To some extent, the mud losses were accepted during drilling operations and the mud program should take supply of sufficient drilling mud into account. However, losses of fines or polymers into the formation might results in a positive skin and hamper well productivity if a clean-up isn't effective.

Mobile / Active Clays
Issues can be caused by reactive clays (in particular smectite – illite). Such issues can be running to TD, the need to 'work down' the casing to depth as well as pack-offs and swabbing. All are documented with many drilling operations at relevant depth. In one instance, severe cavings have been encountered when drilling the top hole with fresh water. Commonly, these issues are caused by clay formation which are mobile and/or swell due to insufficient shale inhibition functionality of the drilling mud. The mud system should contain a clay inhibitor like KCl. Often the use of KCL-Polymer mud systems has been reported, partly OBM has been deployed for deeper well sections.

Interbedded formations, hard stringers
Penetration of interbedded hard layers oriented in a shallow angle to the well inclination is a common challenge in drilling operations. The drill bit could bounce off from the harder / consolidated layer resulting in unpredictable DLS, well tortuosity. Ultimately, the dedicated well trajectory cannot be drilled.

Cost reductions
The reduction in well construction time as well as the optimisation towards slimmer completions and reduced casing schemes has been demonstrated in oil & gas drilling campaigns. The application of slim well concepts as used for the redevelopment of the Schoonebeek field, have limited application to LTG projects. The typical flow rate requirements in LTG projects request a hole size > 8-inch at reservoir section (WEP, 2022). Cost reduction by standardisation and operational optimisation within multi-well drilling campaigns could be applied in future when larger geothermal fields are developed to deliver heat for a region. However, to date the LTG drilling campaigns do not have a sufficient size to realise the typical cost savings (drilling time savings) from campaigns.

Thin reservoir
Pilot hole strategy and geo-steering has proven successful in optimal positioning of the horizontal production wells within the relatively thin layers. An orientated conductor with bended shoe is often used to minimize Dogleg Severity and access the limited vertical landing window.

4 Completions

In unconsolidated formations, production and injection operations face significant challenges due to the migration of fines and the potential for clogging. Fines can migrate within the reservoir and enter the wellbore, leading to blockages in the completion system, including the casing and tubing. In addition, sand production can be an issue in case of production from unconsolidated formations. The sand production can compromise material integrity by causing erosion and, in some cases, erosion-corrosion, where the combination of abrasive wear and corrosive fluids accelerates the degradation of materials like steel casings and tubing. The presence of these sands and fines can lead to a decline in the efficiency of production and injection, increase the risk of well failure (sand production can eventually lead to wellbore instability), and necessitate costly interventions to clean the system and restore proper flow. Effective sand and fines control and careful material selection are essential to mitigate these risks, improve reliability, and ensure the long-term success of well operations in unconsolidated reservoirs.

An important part of completion design and fines and sand control are appropriate limits on flow velocity and pressure gradients around the well. However, very few details on that are available and therefore this information is largely missing in sections below.

In this report, we initially summarize the potential risks of production from unconsolidated formations on casing and tubing. Then, we further discuss the importance of screen selection and installations. Finally, there is a dedicated section that briefly describes the impact of sand on ESP operation and integrity, due to the criticality of ESP performance and reliability in the geothermal well.

4.1 Impact on casing and tubing

Based on the available data, an overview of completion diagrams for three shallow gas fields are provided in Figure 4.1 to Figure 4.3, for Schoonebeek, A/B blocks, and de Wijk, respectively. In Figure 4.1, the casing size and depth of some wells in the Schoonebeek field are provided with the wells' along hole depth ranging from ~ 850 to 1800 m and casing sizes ranging from 4-7 inch for the lowest sections and 20-28 inch for the top sections. In Schoonebeek field, in the 1950s, 5" slotted liners were commonly used. By the 1980s, they shifted to 7 5/8" cased and perforated completions with 5½" production tubing. In the 2010s, the SAGD approach was adopted, featuring 5" horizontal K55 316L tubing for steam injection and oil production, along with long-stroke beam pumps achieving rates up to 400 m^3/d using 5½" production tubing. Both the wells from the De Wijk and Schoonebeek show the move to smaller diameters.

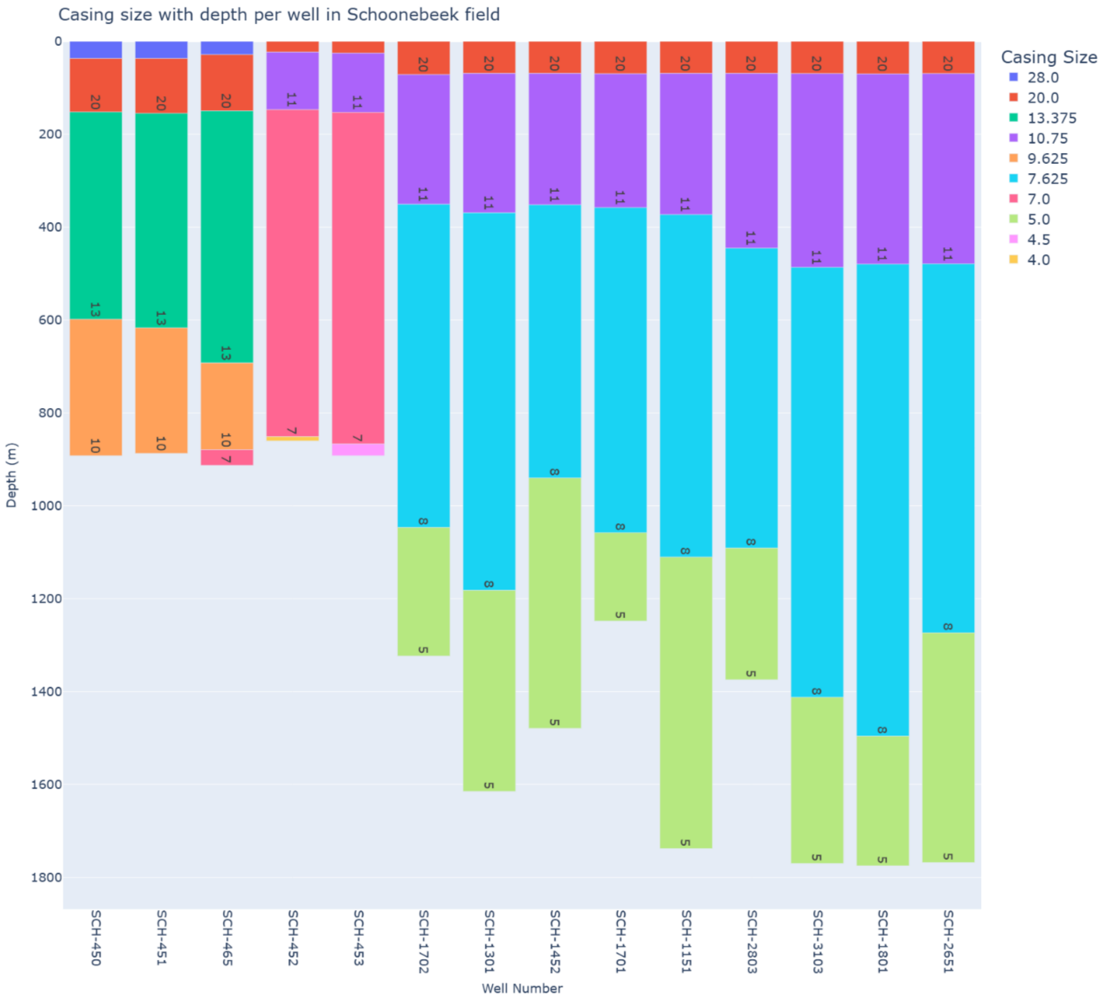

Figure 4.1: Casing size with along hole depth per well for some wells in the Schoonebeek field. Wells SCH-450 to SCH-453 and SCH-465 from the 1970s. And the other wells from the period 2009-2011.

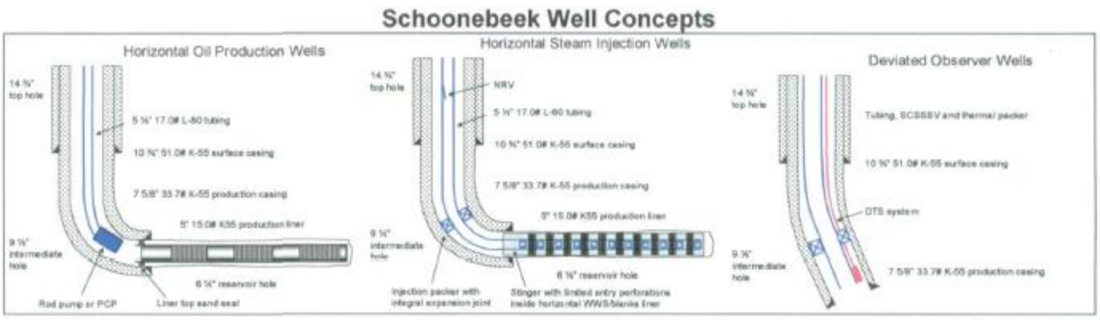

Figure 4.2: Completion overview of the horizontal wells used in the Schoonebeek field (from the production plan for Schoonebeek (NAM, 2008).

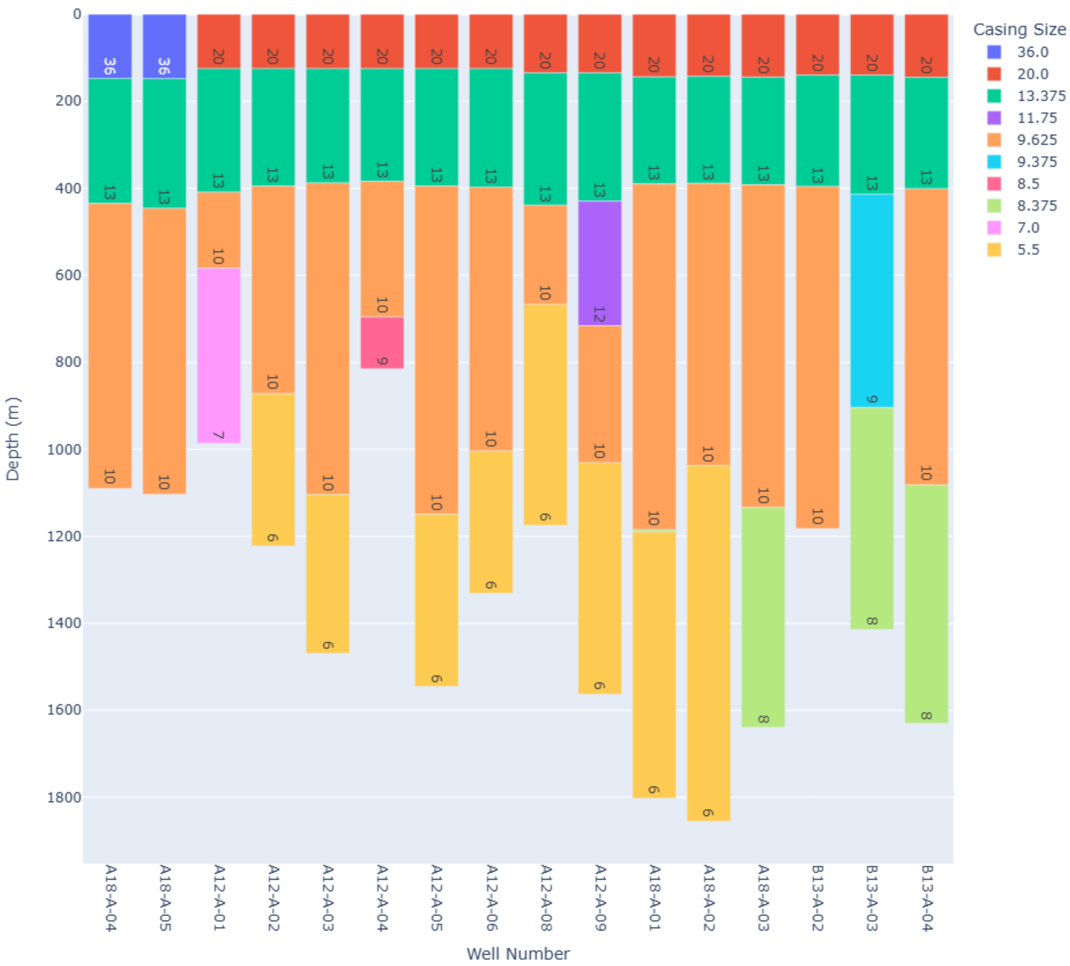

Figure 4.3: Casing size with along hole depth per well for wells in A/B blocks

The casing sizes in A/B blocks have slightly larger diameters, with the lower sections ranging between 5.5-10 inch and the upper sections in a range of 20-36 inch while the shallower wells have the largest casing diameter. In De Wijk field, the majority of the shallow wells have a small diameter of the lower completions with the size of 3 ½” which are cemented completion with perforations. The initial design in this field is with 5” slotted lower completion while later in 1960s the completions were cased and perforated with 5” liner. In the 1980s, larger casing sizes were utilized (cased and perforated 7” liners /7 5/8” casings) until in the 2000s the 3 ½” cemented completions with perforations were used. The reserves and costs are the main drives for the evolution of the completion sizes and practices over time.

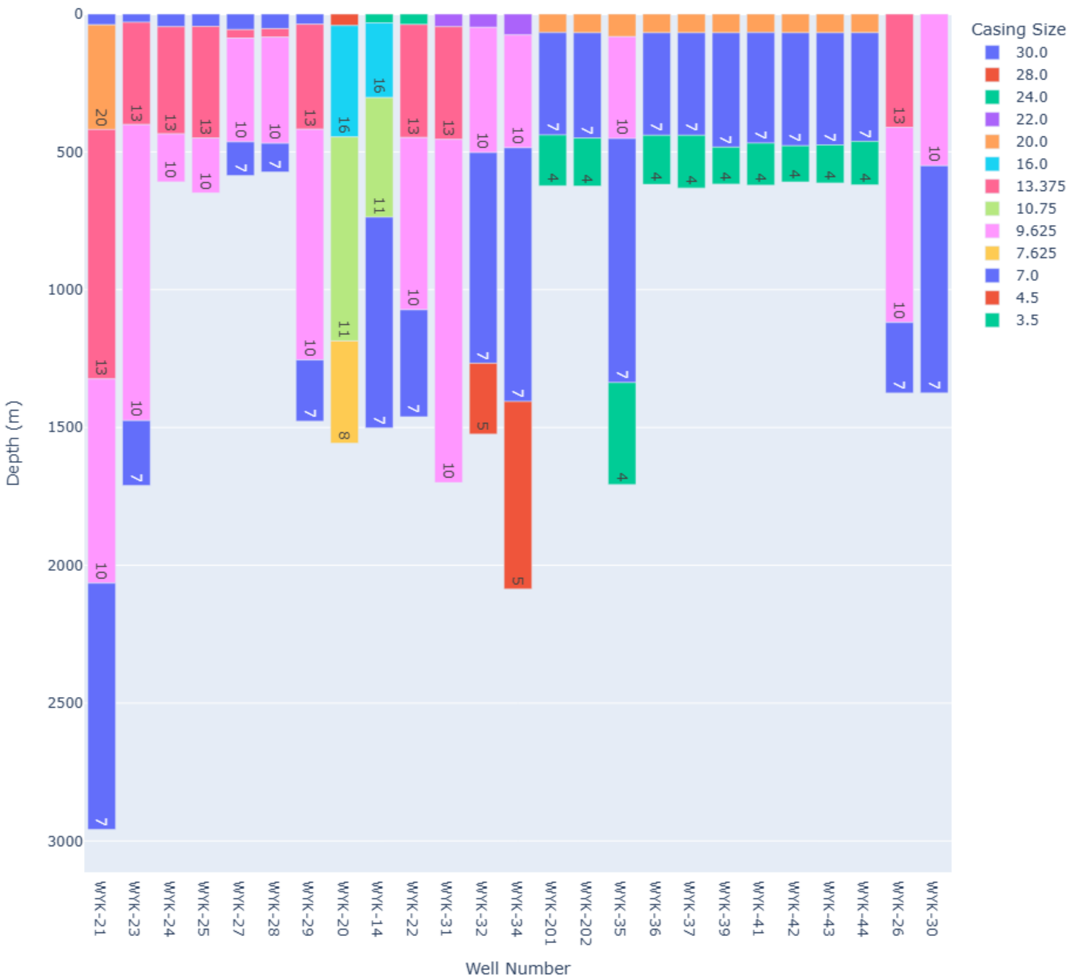

Figure 4.4: Casing size with depth per well for wells in De Wijk field

The data presented above pertains to well completions in the gas fields and heavy oil in Schoonebeek, where extensive operational experience and design standards have been developed over decades. An overview of the available wells in the Netherlands is shown in Figure 3.2 based on information on nlog.nl. It can be seen that an extensive set of information and data is available in the Netherlands for the shallow fields which are in line with the target depth range for shallow geothermal systems. Even though those formations are not directly related to geothermal reservoirs, the learnings on well completion and operational practices can be partially transferred. For instance, the trend toward reduced casing and tubing sizes in oil and gas is generally not applicable to geothermal wells, where larger diameters are necessary to ensure sufficient flow rates and project economics. However, lessons related to well trajectory design, completion strategies, and sand control techniques can be adapted to geothermal contexts. Several of these transferable aspects are explored in more detail in the following section. In addition, gas is much less viscous and has a higher energy density (meaning different pressure and flow rate regimes for the production) that can overall impact the particle transport mechanisms. Lessons learned from water and ATES wells can be of interest for shallow geothermal applications, given their similarities in scale, design, and depth. However, a detailed comparison was not within the scope of this report.

At this stage, there is limited publicly available information on completion practices for shallow geothermal systems. The only available data specific to shallow geothermal applications is summarized in the following section (Section 4.2).

More insights are needed into the production challenges specific to shallow geothermal systems in order to develop clear guidelines for completion design and screen selection. While the operational context differs from oil and gas applications, certain experiences and best practices from the O&G sector can still be adapted to inform and improve geothermal well design. Formations are not comparable between gas and geothermal fields, but operational experiences can be used and transferred for (hot) water production facilities. Based on shallow gas field operations, long horizontal trajectories (in combination with expandable sand screens) have been found to be successful to limit the sand production (more information in the Section 4.2). For optimal completion in shallow gas fields, the wells are generally placed in a crestal position with a large spread to access an optimal drainage area and avoid early water breakthrough while maintaining low drawdowns. Completion is generally limited to one single layer to avoid cross-flow. These practices can be further studied and validated for shallow geothermal wells.

4.1.1 A Note on Erosion

Erosion represents one of the factors limiting production capacity in geothermal wells; however, it should be emphasized that it is not the primary constraint (Wood, 2017). Erosion–corrosion, a form of mechanical degradation, commonly develops at bends, joints, and other flow obstructions. Surface irregularities such as pitting increase turbulence, accelerating material loss and the damage often follows the flow direction. Mitigation strategies include maintaining smooth surfaces and limiting flow velocity which would be a more critical challenge. Erosion is predominantly observed at the ESP, wellhead, and topside piping. In contrast, straight tubing generally exhibits lower sensitivity to erosion, although localized erosion can occur at discontinuities such as casing steps and poorly aligned couplings.
The erosion rate is primarily influenced by the particle concentration, system geometry, and flow velocity, with velocity being particularly significant (erosion rate $\propto u^{2.6}$) (Det Norske Veritas, 2007). Existing base case flow limitations only partially account for erosion rates and typically neglect particle mass fraction (i.e., the concentration of entrained solids that strongly affects erosion rates), since most of them only considering local velocities and mixture density. As a result, these conservative standards may underestimate the actual capacity of the system, leaving room for a potentially higher allowable flow velocity. Nonetheless, this approach requires a sound understanding of expected sand production rates and particle size distribution. When sand control measures, such as screens, are implemented, the standard limits may indeed prove excessively conservative.

Velocity limitations for production and injection wells and top-side piping tend to be based on general guidelines such as API 14E and Norsok guidelines. The application of the general process piping norms to production/injection tubing is not a given but the general practices tend to be used due to their ease of form and ease of application.

The widely used equation is from the API 14E and takes the form

$$V_c = \frac{c}{\sqrt{\rho_m}}$$

in which the critical velocity is calculated based on a coefficient (c) and the fluid density (ρ_m). Strictly speaking this API 14E equation only concerns itself with erosional velocity for particle-

free gas/liquid two-phase flow conditions and not for particle laden single phase liquid. For single phase liquid flow a limit of 15 ft/s (4.6 m/s) is stated. Despite this, the multiphase equation has been used quite generally.
The background of the equation is not certain and is discussed in a large body of open literature. Essentially the equation is based on a limit in the fluid momentum ($\rho_m u_m^2$=15000) but the source of the critical value of 15000 is unknown. This corresponds to the API 14E constant c, since inserting the velocity equation gives the constant c value ($c^2 = \rho_m V_c^2$) which will be around 100-150 in the field unit. The variation in c values is mainly based on empirical fit. Other potential causes are (Madani Sani et al., 2019):

- Pressure drop limit (Bernoulli equation with a pressure drop of 3000 – 5000 psi)
- Erosion due to liquid impingement
- Removal of corrosion inhibitor films

The downside of the models described above is that multiple limits are often combined, the background of the equations is not always clear and there is no indication of the relation between critical velocity and solid content. Therefore, in case of solids contents, in practice erosion models are applied in conjunction with solid management and monitoring techniques such as sand screens, and erosion probes are applied. Common models are the models as described in the DNV-RP-O501 (2018) and the models developed by Tulsa. The main structure of these models consists of:

$$E_m = K \cdot U_p^n \cdot F(\alpha) \cdot m_p \quad \text{[kg/s]}$$

in which E_m is the erosion rate, K a flow/geometry constant, U_p the particle velocity, n the coefficient, F an angle dependent material dependent coefficient and m_p the particle load. The DNV erosion model (DNV-RP-O501) is a semi-empirical standard for predicting material loss due to sand particles in multiphase flows. It relates erosion to particle velocity, size, impact angle, and material properties by scaling from a reference case with correction factors, making it widely applied to bends, chokes, and other critical components. Over the years, various research groups have developed increasingly sophisticated erosion models which a comprehensive overview of these models were reported by Madani Sani et al. (2019). Based on a comprehensive analysis performed in this paper, it was found that the DNV model exhibits substantial error under both single and multiphase conditions (Madani Sani et al., 2019).

The erosion rate is primarily influenced by the particle concentration, system geometry, and flow velocity, with velocity being a particularly critical factor. Existing base case flow limits are only partially derived from erosion considerations and typically do not account for particle mass fraction. As a result, there may be scope for increasing allowable flow velocity relative to these standards (> 6 m/s). However, this approach requires reliable knowledge of anticipated sand production rates and particle size distributions. When sand control measures such as screens are employed, the generalized flow limits may in fact be overly conservative.

To illustrate this effect, we have performed some calculations for erosion rate (in mm/year) for three different fields where completion information was available. The particle loading of 0.05 kg/m^3 and particle size of 100 μm was chosen. It is important to note that the calculations are only for illustration purpose and detailed information is needed to perform the full analysis. For the calculations DNV-RP-O501 models were employed for this analysis. The results are shown in Figure 4.5. DNV models give empirical formulas for erosion rates in components like straight pipes, bends, tees, reducers, and welded joints. The estimations are provided for the straight pipe, welded joints, and bend (with an assumed radius to diameter ratio of 1.5).

The results of the erosion calculations are shown in Figure 4.5. The results are plotted for erosion rate per each casing ID. In order to estimate the severity of the erosion, we have used 1 MPY (corresponding to 0.025 mm/year) as a threshold for an acceptable erosion process. The results show that for all the fields and casing ID sizes provided, the erosion in straight pipe is not likely to be a problem and higher velocities can be achieved in straight pipes. The erosion in smaller casing ID for welded joint and bends can be problematic and erosion can be further enhanced at higher flow rates. However, for the majority of the cases the erosion rate is below the acceptable level and this provides insight on a potential scope to consider higher allowable flow velocity during the design of the completion.

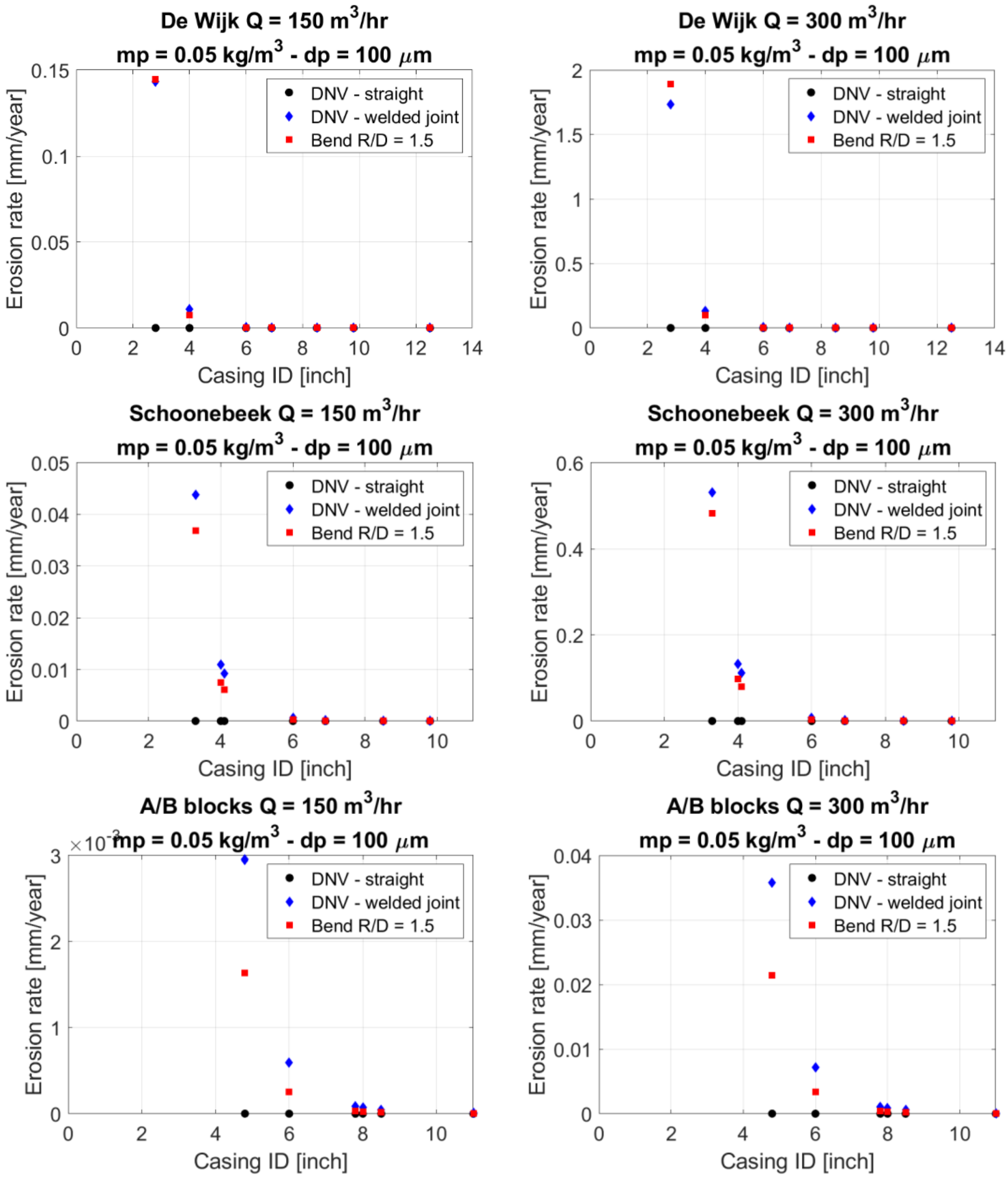

Figure 4.5: Estimated erosion rate based on DNV model for three fields (top: de Wijk, middle: Schoonebeek, bottom: A/B blocks). The calculations were performed for two different flow rates of 150 and 300 m^3/h with the solid fraction of 0.05 kg/m^3 and mean particle size of 100 µm

4.2 Impact on screen selection

Several methods are used for sand control in wells. The most common options are shown in Figure 4.6. In this Figure, different sand control techniques are categorized based on the open hole and cased hole completion. Different types of sand control screens offer distinct advantages depending on the formation characteristics, completion strategy, and operational constraints. Stand-alone screens (e.g. wire-wrapped screens) are commonly used in unconsolidated formations and are simple to deploy but rely heavily on accurate sand retention design. Expandable screens provide good wellbore contact and zonal isolation in open-hole completions, reducing the need for gravel packing and enabling larger inner diameters, though they require precise deployment. Gravel packs, whether in open or cased holes, involve placing gravel around the screen to filter formation sand; they offer high reliability in severe sanding environments but come with added complexity and cost. Cased-hole oriented perforating with screens is used to align perforations with productive zones, enabling targeted sand control behind casing, and is often paired with gravel packing for effectiveness. Each approach must balance sand retention efficiency, flow performance, ease of installation, and compatibility with the formation and well trajectory.

Gravel packing is one of the common techniques, where sized gravel is placed between a screen and the wellbore to form a barrier that filters out sand while allowing fluids to flow. It is especially effective in high-rate wells and weak formations but requires careful design to prevent gravel movement and plugging. Pre-packed screens, which incorporate gravel or ceramic materials directly into the screen assembly, offer an alternative in wells with lower sand production risks or where rig time is limited. These screens simplify installation but have lower tolerance for extreme flow rates compared to gravel packs.

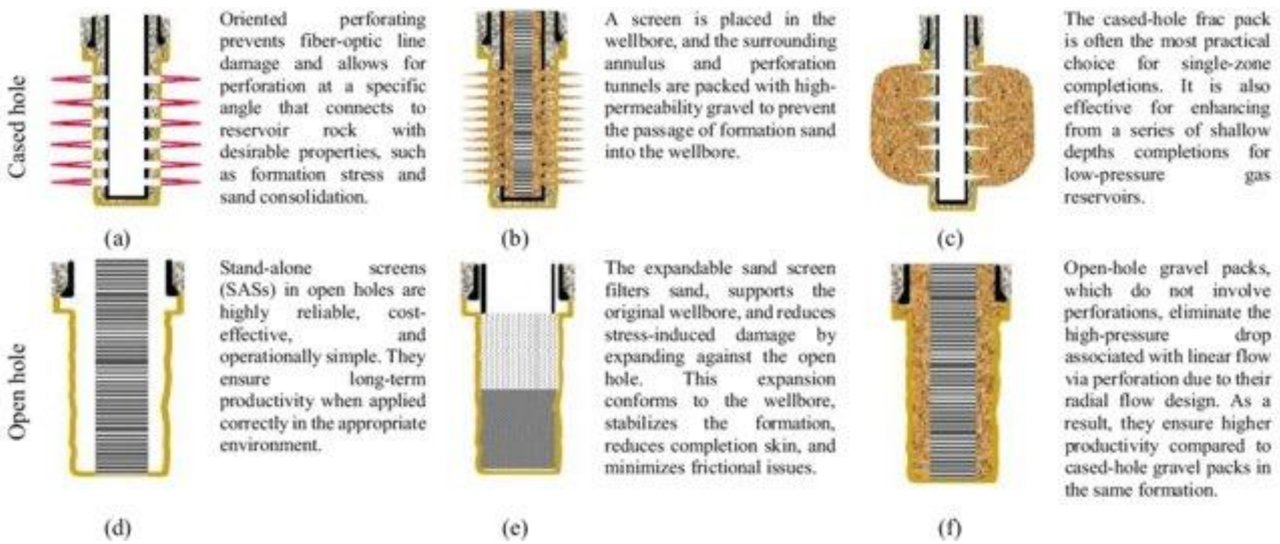

Figure 4.6: An overview of commonly used sand control completion techniques (Khan et al., 2024)

Other types include standalone screens (SAS) such as wire-wrapped screens and premium mesh screens. Such screens have been used in Schoonebeek and the LTG development in Zevenbergen. The well concepts for Schoonebeek were shown in Figure 4.2. The following screens were used in ZVB-GT-01/02:

Base pipe:

- Casing 7 5/8 inch

- Pipe ID 177.1 mm
- Perforation 150 holes/ft
  - Hole size 12.5 mm
  - Open area 9.9 %

Screen (production well):
- 7 5/8 inch PoroLock,
- Screen OD 219 mm (max OD 223 mm)
- Dutch Weave 80/100 micron
- Protective shroud

Wire-wrapped screens consist of a continuous wire wrapped around a perforated basepipe, offering high collapse resistance and sand retention but with limitations in very fine sand environments. Premium mesh screens, often made from sintered metal or multilayer woven wire, provide finer filtration and more uniform flow distribution, reducing erosion risk. Advances like expandable sand screens (ESS) allow the screen to conform to the wellbore, improving contact and reducing annular flow paths that can lead to erosion. Selection of the appropriate sand control method depends on factors such as formation strength, sand grain size, expected production rate, and well geometry. In the shallow gas fields in the A/B blocks the combination of ESS with drilling (long) horizontal trajectories have proven to be successful to limit sand production and limit draw down over screen while obtaining sufficient production rates.

The selection of screen types and completion design in wells is influenced by formation characteristics and operational requirements. The paper “Comparison of Inflow Performance and Reliability of Open Hole Gravelpacks and Open Hole Stand-Alone Screen Completions” (Burton and Hodge, 2010) focuses on oil and gas wells and compares open hole gravelpack (OHGP) and open hole stand-alone screen (OHSAS) completions in terms of inflow performance, screen selection, and sizing strategies. The study shows that both OHGP and OHSAS designs are governed by factors such as mud cake removal efficiency and hole/screen annular permeability, which directly impact total skin and productivity. OHSAS completions generally use larger diameter screens, resulting in narrower annuli, lower skin values, and often higher productivity compared to OHGP, particularly at lower annular permeabilities. The paper also emphasizes that screen sizing should be based on laboratory flow testing against formation cores to balance sand retention and flow capacity, with premium wire-mesh screens commonly applied. For gravelpacks, appropriate gravel size selection is equally critical to avoid plugging or formation solids flow. Overall, both completion types can achieve comparable productivity when properly designed and installed, but OHSAS may offer advantages in simplified screen sizing and operational efficiency under favorable conditions. While the findings are derived from oil and gas applications, it is important to note that geothermal wells typically operate at much higher flow rates, which may influence screen performance and sizing differently.

In formations with smaller grain sizes, the design of wire-wrapped screens becomes increasingly challenging, making premium screens the preferred option due to their superior performance under these conditions. For wells drilled in unconsolidated formations, different strategies are employed to prevent the migration of sand and fines into the annulus, which can lead to partial screen blockages and the development of localized hot spots. These hot spots cause uneven fluid entry and increase the risk of erosion. Some operators in oil and gas wells utilize expandable screens to mitigate this risk, while swellable packers can be applied as an alternative method to restrict sand movement in the annulus. For stand-alone screens, often swellable packers on each screen joint is used to limit annular flow and prevent mixing of different sands. Zonal insulation reduces annular flow paths. A safe limit for the design velocity of the screens to minimize erosion risks is 0.5 ft/sec based on literature (Procyk et al., 2015; Cameron and Jones, 2007) and experience in the project group.

In geothermal applications, swellable packers are effectively used to isolate clay layers, a practice that has proven to enhance well stability and integrity. Additionally, the overall completion design includes a combination of an open hole, screens, and a perforated base pipe. The number and arrangement of holes in the base pipe vary between suppliers, which can impact fluid distribution and inflow performance. Higher density of perforations can potentially offer a more uniform inflow profile.

Screens are suitable methods to control sand production into the wellbores and top-side equipment. However, erosion of sand screens can be a major operational challenge in oil and gas wells, particularly in high-rate production environments with sand-laden fluids. The paper by Procyk et al. (2015) explores the mechanisms behind screen erosion, identifying that particle impacts, fluid velocity, and particle concentration are the primary drivers. Using a combination of laboratory experiments and computational simulations, the study shows how erosion typically initiates at screen inflow points and progresses under turbulent flow conditions. Critical factors influencing erosion include screen geometry, flow distribution across the screen, and local flow accelerations caused by plugging or design inefficiencies. Once initiated, erosion can rapidly lead to severe damage, risking catastrophic sand production and subsequent equipment failure. The paper highlights the importance of design optimization, including proper screen selection, flow control devices, and operational best practices to minimize erosion risk. The findings emphasize that erosion is preventable when screen design is matched to expected production profiles.

In terms of completion designs we can refer to few studies and field trials developed in Gulf of Thailand as sand production in unconsolidated reservoirs is identified as a major challenge in these fields, particularly in water injection wells (Khunmek et al., 2021; Vimolsubsin et al., 2020). One of the primary issues is sand flow-back into the tubing, which leads to increased operational costs for workovers and sand clean-out. This sand production can significantly disrupt the injection process, necessitating additional interventions throughout the well's life. To mitigate this, they implemented an Autonomous Inflow Control Device (AICD) with bypass valves to prevent sand from flowing back into the wellbore during shut-in periods, effectively addressing sand control and enhancing the efficiency of water injection operations. AICD works by using a bypass valve that only allows fluid to flow out of the well. When there is no flow or the well is shut-in, the valve automatically closes to prevent any backflow of fluids or sand into the tubing. This ensures that sand does not enter the wellbore, maintaining well integrity and reducing the need for costly workovers. The AICD's ability to shut off flow in static conditions helps improve sand control and optimize water injection performance.

It is important to consider the cost implications of different screens and sand control techniques. Expandable sand screens (ESS) typically involve higher initial costs compared to wire-wrapped or premium screens. However, in unconsolidated formations, the investment can be offset by the reduction in operational risks, such as erosion and premature failure, and the associated reduction in maintenance and workover costs. In addition, when there are washouts the ESS has the same effect as a SAS

4.3 Impact on ESP

Electrical Submersible Pumps (ESPs) are commonly used in geothermal systems. Several studies have investigated the performance of ESPs in geothermal environments, focusing on challenges such as high-temperature operation, scaling, corrosion, and motor reliability (e.g., Shoeibi Omrani et al., 2021; van ’t Spijker and Ungemach, 2016). These issues are critical due to the demanding thermal and chemical conditions typical of geothermal fluids. However, most of these studies did not examine solid (sand, fine, etc.) production in detail, despite its potential to cause wear, pump failure, and reduced efficiency in shallow geothermal wells. As a result, much of the material presented in this section draws on operational experience and technical insights from sand control practices in oil and gas applications, where sand management for ESPs has been more extensively studied.

Sand production poses significant challenges for ESP systems, causing erosion, reduced efficiency, and frequent failures (Shakirov et al., 2018; Riyami et al., 2022). Experimental studies have demonstrated that sand-induced wear causes head loss, particularly at low flow rates, due to increased leakage through secondary flow paths inside the pump (such as clearance and side gaps) which reduces the pump’s ability to generate sufficient pressure head at a given power consumption (Zhu et al., 2019). Continuous sand ingress accelerates the degradation of pump components such as impellers, diffusers, and bearings, leading to increased vibration, unbalanced loads, and eventual mechanical failure. Additionally, sand accumulation within the pump and tubing string can obstruct flow paths, causing elevated power consumption and reduced lifting capacity. When the ESP trips or is shut down, the fluid in the tubing string flows back down through the pump. As the production fluid returns, suspended debris and particles tend to accumulate in the upper pump stages and at the discharge, making re-starts difficult. This can result in high current draw and an increased risk of shaft failure. Additionally, if the motor restarts without sufficient fluid flow past the motor and motor lead extension (MLE) for cooling, the elevated current significantly raises the temperature, leading to damage of the MLE insulation. An extensive study on different ESP failures, both mechanical and electrical, with sand production is reported by Boudi (2016). As a result, operators face higher maintenance costs, production downtime, and the need for frequent equipment replacements, which significantly impacts the economic viability of ESP-operated wells.

However, technological advancements have improved ESP resilience to sandy conditions. Ultra-high-speed ESPs with improved designs and metallurgy have shown increased tolerance to solids, with maximum solid content reaching up to 2 g/l (Shakirov et al., 2018). Novel technologies such as Sand Aid PM filter and Sand Guard Cyclone have been developed to mitigate sand production through pumps (Riyami et al., 2022). Riyami et al. (2022) presents the successful application of four innovative technologies to mitigate sand production and extend the run life of artificial lift systems. The Sand Aid system reduces solids accumulation around the pump intake, the PM filter prevents fine particles from entering the pump, Sand Guard acts as a mechanical barrier to protect pump internals from abrasion, and the Cyclone separator removes sand from the production stream through centrifugal separation. Field trials demonstrated that combining these technologies significantly reduced pump failures, improved equipment reliability, and optimized production efficiency in sand-producing wells. Additionally, dual-purpose designs addressing both gas slugging and sand handling have improved ESP performance and efficiency (Vazhappilly et al., 2023). These findings highlight the importance of proper fluid conditioning and pump design in managing sand production and improving ESP performance in challenging environments.

Dogleg severity has a significant negative impact on the lifetime and reliability of ESPs. Sharp or abrupt changes in wellbore trajectory introduce bending and mechanical stress along the ESP string, which can lead to fatigue and eventual failure of critical components such as the motor lead extension (MLE), pump shaft, and seals (Walters et al., 2023). Misalignment caused by doglegs increases radial loads and induces excessive vibration, accelerating wear on bearings and seals, ultimately resulting in fluid ingress into the motor and catastrophic motor failure. In addition, doglegs increase the risk of power cable insulation damage from continuous rubbing against the casing or tubing, leading to electrical failures and shutdowns. These factors not only reduce the run life of ESPs but also complicate installation and retrieval operations, increasing the likelihood of stuck equipment and raising intervention costs. Even moderate doglegs can significantly reduce ESP performance and longevity, particularly in highly deviated or horizontal wells.

5 Operations

Medium depth geothermal systems are proposed to exploit low-enthalpy aquifers in unconsolidated or weakly consolidated sediments for direct-use heat. These systems are likely to face operational challenges similar to those in shallow oil/gas or water wells targeting loose sand reservoirs. Key issues include mechanical problems like sand production and flow performance decline (injectivity and/or productivity loss) due to among others fines migration and clogging or flow-chemistry issues (typically scaling and corrosion). In the sections below, we summarize each potential operational challenge and their implications on the production and injection, and where relevant compare with analogy from shallow oil and gas operations.

5.1 Erosion

Erosion in geothermal wells (as explained in Chapter 4) and surface facilities is often caused by the production of formation sand that is carried along with the geothermal fluid. It is common to see some transient sand production when a new well is started up, which can be cleaned out, but sustained sand influx is a serious problem requiring sand control measures (Peters et al., 2022b).

High flow rates or steep pressure drawdown tend to enhance sand production. This phenomenon, well-documented in oil and gas wells producing from unconsolidated or weakly cemented sandstones, leads to erosion, equipment damage, and unstable production conditions (Rahmati et al., 2013). Sand typically refers to larger grains that can cause mechanical damage and erosion, whereas fines are smaller particles more prone to migration and clogging. Unconsolidated or poorly cemented sands lack strength and key triggers include high production rates, water breakthrough into a reservoir (in oil wells this often dislodges clays), reduction in pore pressure (depletion), or any stress change that breaks grain interlocking can lead to sand transport (Hao et al., 2024). The impact of fine production on productivity and injectivity decline is further described in the next section.

In shallow geothermal producers, similar issues can arise. If sand is not properly managed (e.g. with screens), these solids can erode downhole components, surface piping, valves, and compromise flow control equipment. Erosion will impact the operation of the geothermal plant. Since the details of erosion estimation and its impact on wells and facilities are explained in Chapter 4, we have just briefly mentioned erosion in this chapter as a process impacting the operation. However, those details are not repeated in this section.

5.2 Productivity and injectivity decline

Field experience shows that injection well performance can drop. Under high-risk conditions, injectivity in geothermal wells has been observed to decrease by as much as ~75% within the first month of operation (Pasikki and Yoshioka, 2010). This decline is caused by a combination of physical, chemical, and biological clogging processes that block flow pathways (Song et al., 2020; Luo et al., 2023), with the overview shown in Figure 5.1. Injectivity loss in geothermal wells can result from three types of processes (apart from the temperature and viscosity impacts):

- Physical processes (blue in Figure 5.1) like fines migration and clay swelling. Clogging occurs when particles (e.g., fines and clay) migrate and plug pores, especially near the wellbore. It can also result from gas bubbles blocking pore space.

- Chemical clogging involves mineral precipitation (e.g., carbonates, iron oxides), clay swelling due to salinity changes, or scale formation from incompatible water chemistries.

- Biological clogging is caused by microbial growth and biofilms in injection systems, especially in low-temperature or oxygen/nutrient-rich environments.

These mechanisms reduce permeability and flow, highlighting the importance of managing water chemistry, filtration, and system design in geothermal operations. Proper management is required to minimize the net injectivity loss (Song et al., 2020). Preventative strategies include filtering injection water and preventing oxygen ingress. However, periodic well stimulation is often needed, using methods such as back-flushing or acidizing to restore flow. Injectivity loss is common, especially in shallow systems, and requires a combined approach of treatment, operational care, and stimulation.

In the oil industry, many wells that initially produced sand-free began sanding after reservoir pressure fell, as depletion or water breakthrough destabilized the formation (Peters et al., 2022b). These conditions are less relevant in LTG wells. However, monitoring for evolving mechanisms that impact formation stability in LTG wells, such as start-up, shut-in, ramp-up and ramp-down, is required.

Similar to injectors, the production wells in a geothermal system can suffer performance declines over time. A drop in the productivity index may occur due to reservoir pressure depletion or due to damage around the well (fines plugging, etc.). Any scaling or precipitation that occurs in the production well's tubing or perforations will add a flow restriction (positive skin effect). If formation fines migrate toward the producer and clog the screen or pack, the well's capacity diminishes. In severe sand-producing wells, the accumulation of sand in the wellbore or completion can choke off the flow. These mechanisms mirror those seen in oil wells: formation damage (from fines, scales, etc.) increases flow resistance, lowering productivity. In some cases, equipment issues like pump wear or clogging can pose as a reservoir productivity problem – e.g. a downhole pump filling with sand will yield less fluid. Maintaining geothermal well performance involves regular monitoring and maintenance, including mechanical cleaning, chemical inhibition, and acid treatments. To manage sand ingress, sand screens and controlled offtake rates are used. Overall, a balanced approach to production and injection helps stabilize reservoir pressure and chemistry, reducing long-term productivity decline.

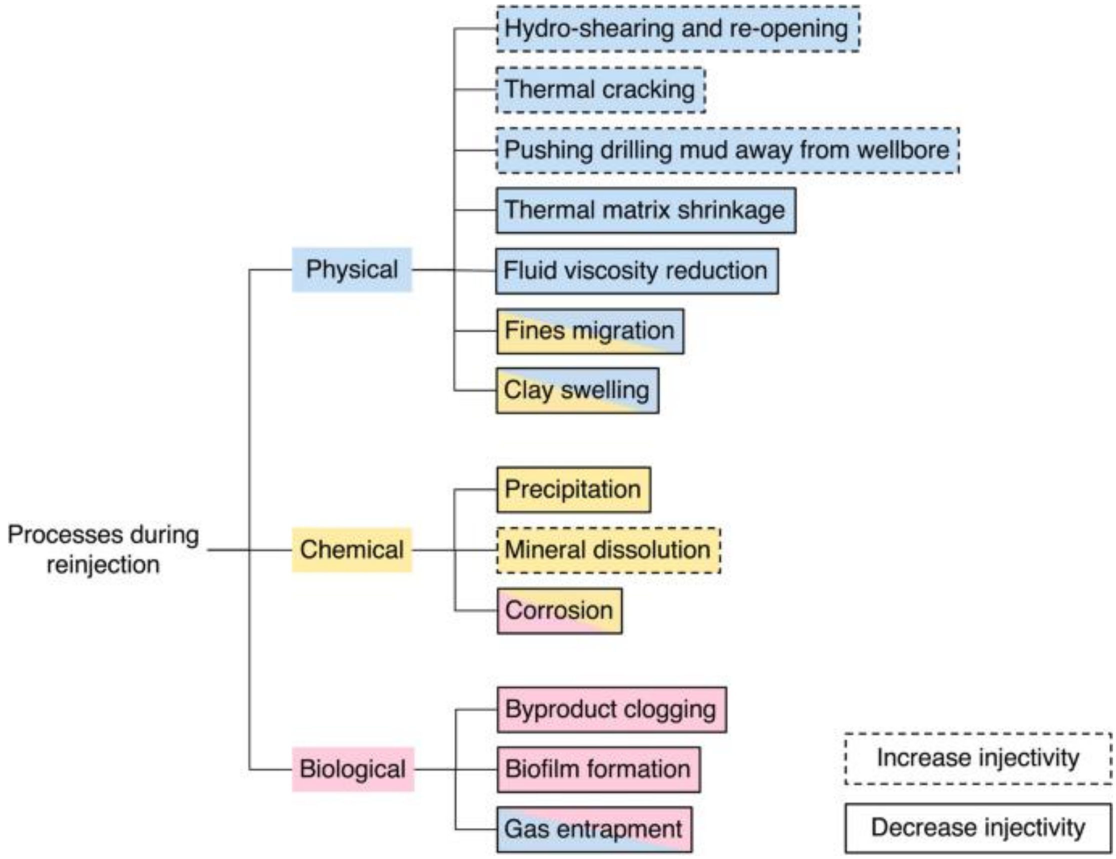

Figure 5.1:. Overview of mechanisms underlying injectivity decline or enhancement during reinjection. Mechanics are color-coded by type, i.e. whether they are physical, chemical or biological. Mechanisms in two colours include two processes (i.e. physico-chemical, physico-biological, chemo-biological processes) (Luo et al., 2023).

5.2.1 Zevenbergen productivity and injectivity

In the LTG doublet in the Brussels Sand Mb at Zevenbergen, injectivity and productivity issues do occur. Initial productivity of both wells was estimated at ~22 m^3/hr/bar. Longer tests however showed that the productivity declined. In the Winnigsplan (Geobrothers b.v. and Visser & Smit Hanab b.v., 2020; v1.2 April 2020), it was reported that the productivity had declined to 10.5 m^3/hr/bar for the producer ZVB-GT-01-S2 and 12.5 m^3/hr/bar for the injector ZVB-GT-02-S1 since the start in December 2019. Probably a part of the decline can be explained by the fact that the initial productivity had not stabilized yet.

Analysis and test in 2021 showed continuing decline of the injectivity to ~9 to 10 m^3/hr/bar in Nov 2021 (Figure 5.2; Visser & Smit Hanab, 2022 (Addendum winningsplan Zevenbergen LTA)). Investigations showed microbiological contamination. Different cleaning actions were attempted, but did not result in permanent improvement. Possible issues are identified and listed below.

<u>Microbiological and corrosion</u>

Microbiological contamination (with anaerobic bacteria) was found in all parts of the system (Visser & Smit Hanab, 2022) potentially causing a biofilm. In addition to microbiologically induced corrosion (MIC), it was concluded that FeS (iron sulphide) and $CaCO_3$ (calcite) could also be deposited. Experience from shallow wells is that microbiological problems are often introduced for example due to mixing of water with different composition and redox potential or contamination (Drijver and Ridder, 2021). In nearby SCAN drilling ORO-1 no microbiologically problematic organisms were encountered (Bents, 2024), indicating that the problem was possibly introduced. It is not clear how the microbiological contamination was caused: no re-injection occurred from water from the 'pond', which was disposed of in another way. As a mitigation measure, a continuous injection of corrosion inhibitors and batch injection of biocide was executed. Corrosion inhibitors are often composed of amines or organic film inhibitors, which have been found to act synergistically with biocides.

Monitoring of the injectivity is shown in Figure 5.2. In the figure, the safe region is shown in green colour in which no action is needed. If there is a deterioration of the injectivity, there will be a shift to the yellow signal regime. In this region, it is recommended to reduce the flow rate and thus inject at a lower pressure or injection of biocide to control microbiological contamination. The red area is where the operational limits will be exceeded.

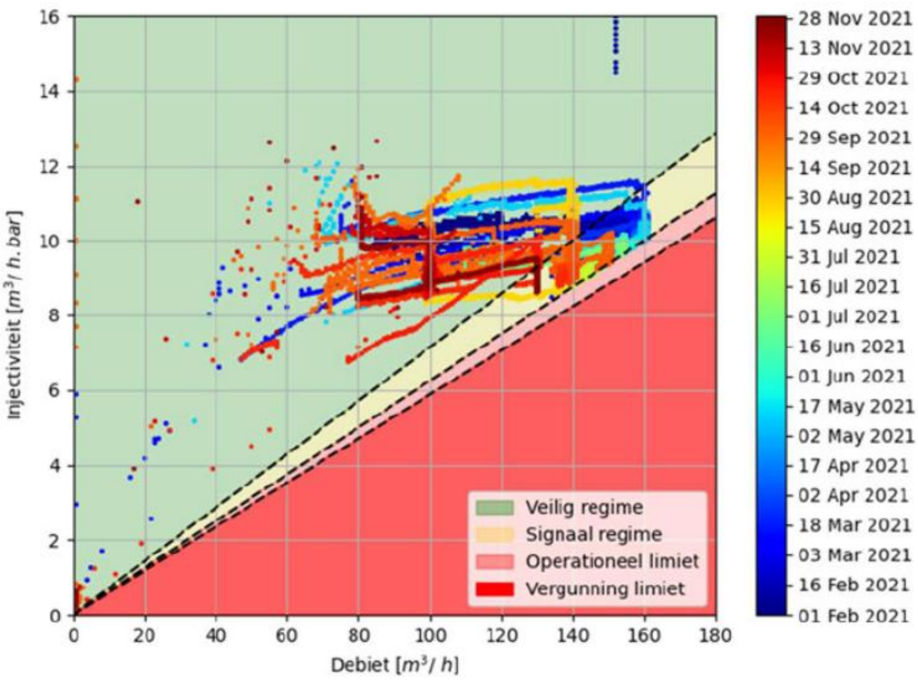

Figure 5.2:. Traffic light system for microbiological intervention around the four defined operational regimes (Visser & Smit Hanab, 2022)

Fines migration

Fines migration could also be a cause of performance reduction. The mesh size is relatively coarse compared to the grain size distribution, to allow cleaning of the screen (Buik and Bakema, 2019; Peters et al., 2022b). The realised flow velocity is however higher by a factor 5 than would be advised based in the design criteria of shallow wells (Buik and Bakema, 2019). Peters et al., 2022b showed that that the flow rates at the sand face are not expected to exceed the flow velocity, which is expected to mobilize sand particles, but only sufficient to mobilize fines. However, that assumes a uniform distribution of the flow. Incomplete cleaning of the well, could have impacted the velocity distribution and the possibility of sand or fines migration.

<u>Compartmentalization</u>
A lack of communication between the injector and producer can also lead to a decrease in productivity and injectivity. There is no indication of faults in the seismic data and the wells are in communication according to the Winningsplan (v1.2, April 2020). However the presence of the hard stringers/streaks could cause partial compartmentalization in the reservoir, which would reduce the productivity.

5.3 Impact on operational costs

LTG systems offer several advantages that can make them both cost-effective and easier to operate. Because of the lower temperatures involved, they can rely on temperature-resistant but less expensive materials and equipment. Higher permeabilities and shorter flow paths reduce friction losses, which in turn lowers pumping costs. In addition, these systems typically contain lower amounts of dissolved gases, minimizing or even eliminating the need for gas treatment. Finally, the generally lower salinity levels reduce the risk of corrosion, cutting down the need for corrosion inhibitors and costly well workovers to replace tubing.

However, the challenges described in the previous sections directly influence the operational and maintenance (O&M) costs of geothermal assets. The sand and fines production can not only lead to productivity and injectivity decrease but can also lead to clogging of surface installations such as heat exchangers, degassers, and filters. As found in the literature for some geothermal operations, such particulate-related fouling and clogging are common in unconsolidated or weakly cemented formations and require systematic mitigation strategies (Song et al., 2020; Luo et al., 2023). Accumulated particulates on heat transfer surfaces reduce thermal efficiency, requiring more frequent cleaning and resulting in increased energy consumption or even temporary system downtime. In parallel, the higher frequency of filter replacement and the need for sand separators or advanced filtration systems elevate recurring maintenance demands. In cases where these filters accumulate materials with elevated concentrations of Naturally Occurring Radioactive Materials (NORM), safe handling and disposal could further increase O&M costs—though such instances have not yet been documented in the literature for shallow geothermal or oil wells.

Beyond O&M costs, the total cost of ownership of shallow geothermal systems in unconsolidated formations can be adversely impacted. To mitigate fines migration and sand production, operators must often limit pressure drawdown and maintain flow rates below critical thresholds. Similarly, maximum allowable injection pressures must be carefully controlled to avoid formation damage or re-mobilizing formation particles, often necessitating the use of pressure management systems or reinjection redesign. These operational constraints can limit flexibility, reduce thermal output, and extend project payback periods. Research has shown that maintaining long-term injectivity in such settings often requires periodic stimulation or chemical treatment, further compounding lifecycle costs (Brehme et al., 2017).

Altogether, the use of unconsolidated formations for geothermal heat production introduces a set of technical and maintenance requirements that operators must account for in feasibility studies and design phases. While such formations can offer high permeability and low drilling resistance, their operational challenges impose strict design and operational trade-offs. Without adequate mitigation, these issues can escalate O&M costs and increase the total cost of ownership significantly, highlighting the need for conservative completion design, and robust monitoring frameworks to ensure system longevity and cost-effectiveness.

As a concluding remark, while lessons from the oil and gas sector and particularly those involving unconsolidated formations can offer valuable insights into risks like sand production, fines migration, and injectivity decline, their direct applicability to shallow geothermal systems remains limited. This is primarily due to differences in fluid properties, system configurations, and, most notably, flow rates. For example, low-temperature geothermal systems typically operate at high volumetric flow rates, ranging from 150 to 300 m^3/h, to ensure sufficient thermal energy delivery. In contrast, oil and gas wells, such as those in the Schoonebeek field, inject steam at rates as low as 10–15 m^3/h, with production wells often delivering even less.
These operational discrepancies imply that geothermal systems are subjected to much higher hydraulic loads, leading to different mechanical stresses, filter fouling behavior, and pressure constraints. As a result, mitigation strategies and design standards from the oil and gas industry must be critically evaluated and adapted rather than directly transferred.

6 Conclusions and recommendations

6.1 Conclusions

LTG developments in the medium depth range (500 to 1500 m depth) could be a useful addition to the energy transition but face a number of challenges. In this report, information is presented from existing developments (geothermal and oil & gas) in this depth domain to address some of these challenges, in particular the following two:

- Realising the required step-out at the relevant depth range in the mostly unconsolidated formations, which is most challenging at depths shallower than 1000 m.
- Achieving sufficiently high rates while controlling sand and fines production.

The information presented in this report shows that drilling the wells with the required step-out is technically feasible. Both deviated and horizontal wells have been drilled to target depth in the Netherlands for more than 25 years to produce shallow oil and gas resources. The dedicated well geometries with extended step-out targeting unconsolidated formations have been realised with available technology. The diameter of many of these wells is however quite small and probably smaller than required for LTG. Achieving a high success rate in drilling these wells is attributed more to organisational structures than technological advancements. Key factors are careful upfront planning, good knowledge of the subsurface and a continuous learning curve with knowledge sharing, if possible via campaign drilling. Typical drilling issues encountered are losses and differential sticking in high permeability formations, mobile/active clays and hard stringers (the latter is in particular problematic for high-inclination wells).

Although drilling for LTG is technically feasible, the business case appears not to be very attractive when oil and gas drilling technology is utilised without further cost optimisation. The reduction in drilling cost compared to the deeper wells is not sufficient to compensate for the reduction in produced fluid temperature. Cost reductions in oil and gas drilling has been achieved to a large extent by campaign drilling along with equipment standardisation and deployment of slim well concepts to reduce rig requirements and casing schemes. For geothermal developments, campaign drilling is difficult to achieve, because only in rare cases more than a couple of wells are constructed in one site. To compensate for the lower energy content of hot water, high flow rates are very important and acceptable pressure losses are very important to reduce OPEX (electricity cost of the ESP). Both requesting relatively large production tubing / casing diameter. Consequently, slim hole concepts are not likely to be effective.

Advanced concepts of well construction, based on the vast experience of the oil & gas community are required in combination with the development of dedicated LTG operational strategies and operational experience for cost-effective LTG well construction.

For the second challenge of controlling sand and fines production in the predominantly unconsolidated formations, completion designs and operational procedures have been investigated. The issues resulting from fines and sand production are that cumulative production of sand and fines can potentially lead to clogging of completions and even loss of a well due to collapse, which is particularly relevant for horizontal or highly deviated wells. Another potential issue is that channelling in the annulus occurs, due to blocking of part of the completions. This leads to localized increase in the fluid velocity, potentially causing erosion. These issues can be mitigated by producing and injecting at conservative rates, but that will make the business case more challenging.

In gas fields in the A/B blocks, which are very young (of late Pliocene to early Pleistocene age), unconsolidated, fine-grained sediments, expandable sand screens (ESS) have been used successfully in the horizontal wells, (note that ESS can be expensive). For the Schoonebeek heavy oil field which is in the older, slightly more consolidated and coarser Bentheim Sst Mb, wire wrapped screens were successfully used.

Completion designs based on erosion limits needs to be validated and, if required, revised to ensure that conservative design limits (e.g. maximum 6 m/s for fluid velocity) is not a limiting factor in the casing/tubing diameter design.

Regarding the operational practices, while lessons from the oil and gas sector (such as managing sand production and injectivity decline) can offer useful guidance, their direct application to shallow geothermal systems is limited due to key differences in fluid properties, system design, and flow rates (150–300 m^3/h compared to 10–15 m^3/h), Therefore, oil and gas design standards and operational strategies must be carefully adapted to address the specific demands of geothermal applications. The lessons learned from the LTG project in Zevenbergen on the injection and production decline showed the significant impact of microbiological contamination and corrosion in shallow geothermal systems performance. A comprehensive analysis, mitigation measures, and monitoring is required to minimize these unwanted impacts during the operation to ensure high flow rates within the allowable injection pressure.

Finally, it should be mentioned that the uncertainty about many aspects of the subsurface conditions has a significant impact on all aspects of a potential LTG development. Since some of the target reservoirs such as the Breda Sg have not been produced previously, a steep learning curve can be expected. In addition, some of the target reservoirs have characteristics that complicate production. For example, the Breda Sg is very thick in for example the Roer Valley Graben and Zuiderzee Low and may need to be produced from very thick inflow zones (many 100s of m). Another example is the Alblasserdam Mb of the Nieuwerkerk Fm, which might need to be produced in a stacked manner to get sufficient production.

6.2 Recommendations

In this section possible research topics are discussed which address the identified knowledge gaps. In Appendix C, an overview of the knowledge gaps and potential research topics is presented including an indication of projects in which these topics are already (partly) addressed. There are two key directions for research: (i) reducing costs to improve the business case, and (ii) improving knowledge to reduce the risk for developers. Improved understanding of the business case specific for LTG and how different topics could benefit the business case, would help deciding on which topics to address first.

On the topic of drilling, no clear technological knowledge gaps have been identified in this analysis. It is recommended to explore options for reducing cost or increasing productivity without compromising safety and effectiveness. Below several options are discussed.

Reducing drilling cost
Rigorous pre-planning, drilling in campaign mode, and building of the learning curve for a specific field has been demonstrated as an effective way to reduce well construction costs over a period of time. Well construction speed could be increased, large out steps, and horizonal wells at relatively shallow depth in unconsolidated formations were realised. Awareness and availability of the lessons learned from shallow, unconsolidated formation drilling must be assured for future projects and future operators. Likewise, the building of the learning curve will remain a key factor for successful site developments.

Typical cost reduction options from the petroleum industry (slim well concepts and campaign drilling) cannot easily be transferred to LTG, because LTG requires sufficiently large completion diameters at reservoir level and campaign drilling is not common for LTG. Thus, new insights or technologies leading to higher heat production per euro invested would be very useful.

While outside the scope of the historic well development in the Netherlands, one promising way to reduce well cost has been discussed intensively and has been demonstrated partly in more recent drilling operations. This way includes drilling without BOPs for specific targets and might be enhanced by the implementation of compact, fit-for-purpose BOPs that can be utilised in combination with mobile, super-light rigs (<100 mT hook load). This compact well control concept could be realised for shallow to mid-depth drilling due to following facts:

- Shallow gas is uncommon in onshore Netherlands
- Shallow gas is well visible on seismic data ('bright spots')
- Gas column height is low at shallow depth and thus the amount of gas is limited. Veen et al. (2013) analysed the capillary seal capacity in this area to understand the distribution of shallow gas and tried to relate the gas column height to the properties of the mudstone seals and checked their method on the A and B block fields.
- Without a significant gas column, no gas overpressure is expected at shallow depth and hence, the ability to flow (gas kick) is very low. The drilling mud will provide sufficient overbalance as long as the mud system prevents any severe losses (i.e. a drop of liquid column in the wellbore).
- Drilling is done mostly outside of areas with 'closure' like synclines
- Already several wells have been drilled in The Netherlands to depth beyond 500 m without BOPs. While this operational procedure is not standard, it might be allowed when the risk of a well control incident is very low. A risk-based approach is required to make an exception from standard operations. The NOGEPA Industry Standard 43 requests the installation of a BOP after the cementation of the first pressure containing casings.

Options for supporting the safe use of compact well control with slimmer rigs:

- Case studies documenting drilling operations in The Netherlands beyond 500m depth without BOP: Pre-requirements, risk based approach, operations, learning curve

- Documentation of a risk based approach (workflow) towards safe drilling without BOP and development of risk maps identifying areas of high likelihood for no gas down to LTG target depth.
- Screening and mapping of expected gas pressures and volumes at LTG target depths (kick potential). Identification of well control options and safe well construction operations with annular preventer and flow diverter as surface Pressure Control Equipment (PCE) for low kick potential environments.
- Identification of compact PCE that can be placed below a super-light rig (water well rig / mining exploration rig) usually not prepared for drilling with a BOP. Identification of rig upgrade solutions to integrate minimum sensor sets for telemetry, directional control, geo-steering, hole cleaning conditions, kick detection.
- Demonstration of optimised well designs for LTG reaching the reservoir level with one casing string.
- Testing of the compact well control concept in a simulated environment.
- Pilot hole drilling at a dedicated site demonstrating the feasibility to reach LTG target depth safely with super-light rigs and minimized casing scheme.

The Dutch Mining Regulations request a BOP after installing and cementing the first pressure containing casing (surface casing). The BOP shall consist of:

- An annular preventer
- A pipe ram
- A blind ram

After installing and cementing the second pressure containing casing, the BOP shall include:

- A second pipe ram
- In this configuration, the blind ram shall also have a shearing capability.

Effectively, these regulations mean that all wells require a defined minimum BOP stack (Class 3) after installing and cementing the first pressure-containing casing, regardless of their Minimum Allowable Surface Pressure (MASP) rating. Exceptions from the regulation for a reduced BOP stack can be requested for non-self-flowing wells.

Other industry standards (i.e. API) specify different requirements concerning the BOP classes for MASP below 3000psi (~200 bar) and 5000psi (~340 bar), respectively. For wells with a MASP of 3,000 psi or less, a minimum Class 2 BOP stack arrangement, which includes only one ram, must be installed. For wells with a MASP of 3,000 to 5,000 psi, a minimum Class 3 BOP stack arrangement is required. This arrangement should include one blind ram or blind/shear ram and one pipe ram. Further, guidelines exist that solely an annular preventer is accepted when the MASP is below 1000 psi (~70 bar).

These differences in guidelines / regulations when it comes to lower pressure environments and hence, lower MASP ratings might be a starting point to explore the opportunities for PCE dedicated to LTG where no gas or limited gas accumulations at hydrostatic pressures are expected.

<u>Other options for reducing cost</u>
Alternative concepts for realising cost-effective LTG developments could be investigated. Examples could be:

- Can slim hole concepts be used, even though they do not provide large flow rates?
- Can low cost, vertical wells be used by integrating them cost-effectively in a heat network, without the need for additional (expensive) surface pipelines?

It should be noted that these sort of options would also require a compact form of well control to reduce the well costs.

All other aspects of the drilling technology can be investigated to identify possible options for cost savings. One of these is well logging. It could be investigated whether it is feasible to extend the applicability of shallow (< 500 m) logging tools. Typical measurements done at this depth range include GR, induction, electrical conductivity and calliper. Currently also NMR is investigated[7]. The costs of these measurements is much lower than measurements in 'deep' wells. For wells that are not deviated and not much more than 500 m in depth, it could be investigated whether this way of measuring can be done.

Due to the lower temperature, lower stresses and possibly less corrosive fluids (lower salinity and CO_2 content), the use of different materials could be investigated for casing and cementing. No evidence was seen that this is investigated for the shallow wells in the petroleum industry. For traditional 'deep' geothermal wells GRE liners are becoming common, but not for the complete casing. Water wells, which can be several 100s of meters deep are typically vertical and completed with PVC and gravel pack.

The second part of the recommendations focuses on the identified knowledge gaps in completions and operations.

<u>Erosional limits</u>
As discussed in the report, the assessment of the design criteria for shallow geothermal wells to avoid erosion and erosion-corrosion is a clear knowledge gap. In case the maximum design velocity can be extended beyond 6 m/s, higher production rates can be achieved with smaller tubing sizes. One approach to perform such an assessment is through experimental measurements or field validation by measuring the erosion locally at several location of the plant (with an extensive coupon or LPR measurements) and assess the true impact of higher velocities on the erosion and erosion-corrosion. It is important to note that higher the flow velocity, e.g. up to 8 m/s, can increase the SDE+ production and production subsidy by 33% but also lead to an increase in the electricity OPEX by up to 90%. Thus, such a higher velocity can be achieved in a part of the well to reduce the drilling and completion cost but does not increase the overall OPEX significantly. For reducing OPEX, innovative solutions such as drag reducing agents can be tested and demonstrated to reduce the frictional losses at those high velocities.

<u>Improved well constraints</u>
Improved estimates of appropriate well constraints in terms of allowable flow rate and pressures, is very important because it affects all LTG developments and is an important driver for the business case. To better understand limits on fluid flow, it is important to understand how fines migration and clogging is affected by changes in depth, and the associated changes in temperature, fluid properties (most importantly salinity) and in situ stress. To investigate this a combination of experiments and modelling effort is proposed. Experiments:

- Flow-through experiments to understand the fundamental processes and study impact of parameters one-at-a-time
- Large scale experiments which also include radial flow and relevant completions get overall behaviour and understanding and provide input to field applications. Such a setup is illustrated in Figure 6.1.
- Pilot projects to implement and test

[7] https://www.warmingup.info/WarmingUPGOO/1/resultaat-1

Modelling:
- Detailed modelling to understand the processes
- Simplified model approach to translate large scale experimental information and field data.

Impact of temperature only has been studied in WarmingUP (Esch, 2022).

Sand production and hole stability are also relevant topics, which could also be studied in the large experimental setup.

To derive safe, but avoid unnecessarily stringent pressure constraints it is important to have improved understanding of the geomechanical properties of sealing clay layers. This topic is currently addressed in the project Diameter.

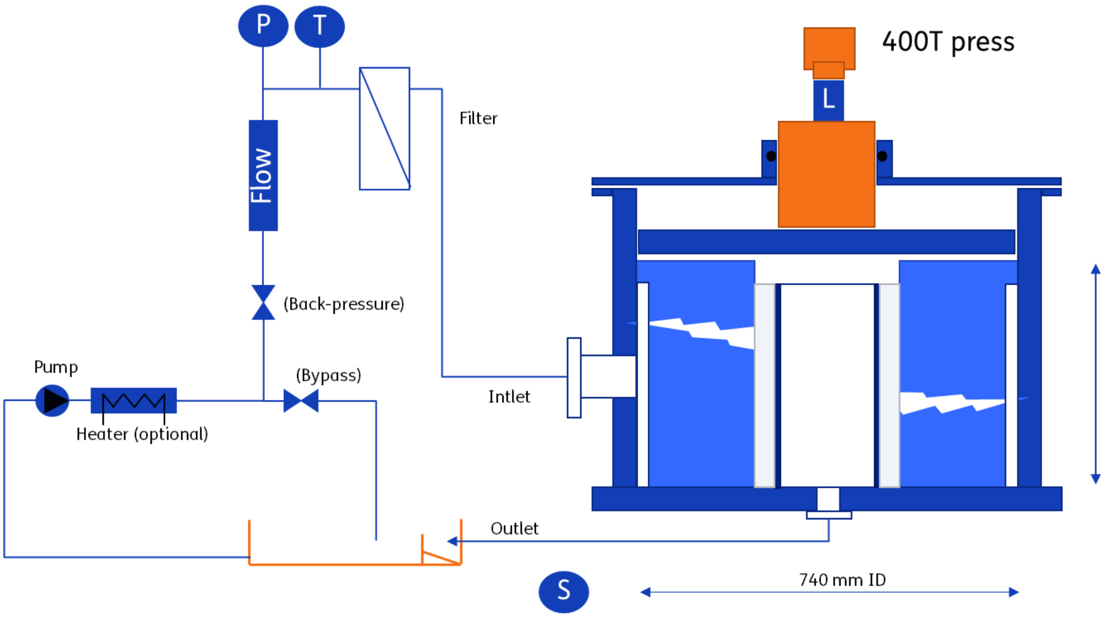

Figure 6.1: Possible setup for investigating fines migration and clogging and sand production.

Inflow from long completions

This topic is of lower urgency than improved well constraints, because it affects only a limited number of geothermal plays. The inflow from thick reservoirs is mainly important for the Breda Sg, because this formation is very thick (> 500 m locally) and fine grained. Questions that need to be answered to better address this issue are:
- Do changes in fluid composition occur with depth? If yes, can problems be expected when the fluids are mixed.
- Are there variations in grain size distribution and permeability with depth?
- Can cross-flow occur?

It is proposed to first understand these questions, before investigating solutions.

Data collection

Data collection on the subsurface plays a crucial role in the proposed research topics and the overall risk reduction due to lack of information. Although not the focus of this report, more information on the subsurface is necessary to further define the research topics and make sure they deliver the required information and development. Information that is required:

- Information on the particles: particle size distributions, shapes of particles, geochemistry (e.g. presence of glauconite, types of clays)
- Fluid composition including presence of dissolved gas
- Geomechanical properties both of the aquifers and seals
- In situ stress conditions
- Porosity, permeability

Further data and information on formation fluid in shallow reservoirs is especially important. Several production and operational problems in these systems are mainly driven by the fluid composition. Frequent sampling of the production fluid, analysis, and developing a fluid database for shallow geothermal systems can provide insights to the sector to minimize production and injection challenges in the current and future shallow geothermal plants. In addition, analysis of the co-produced gas production, naturally occurring radioactive materials (NORM) in the formation brine is a significant gap that needs to be studied.

Some of this information may be derived from existing wells, but in many areas little information is available. Drilling to provide additional information, could be combined with testing of different concepts in pilot projects.

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Appendix A
Monitoring in the A and B blocks

Put	Type	Deviatie type	Logging	Coring	Spud year
A12-03	Exploration	Sub-vertical	GR/RES/CAL/DEN/NEUT/SON/FPRESS	No	1988
A15-02	Exploration	Sub-vertical	SGR/CAL/DEN/NEUT/SON (X-DIPOLE)/FPRESS	No	1992
A15-03	Exploration	Sub-vertical	SGR/RES/DEN/NEUT/SON (X-DIPOLE)/FPRESS/BHI/NMR	Yes	1999
A15-04	Exploration	Sub-vertical	SGR/RES/DEN/NEUT/SON (X-DIPOLE)/FPRESS/BHI/NMR	Yes	2001
A15-05	Appraisal	Sub-vertical	SGR/RES/DEN/NEUT/SON (Full waveform)/FPRESS/BHI/NMR	No	2019
B10-03-S1	Exploration	Sub-vertical	SGR/RES/CAL/DEN/NEUT/SON	Yes	1991
B13-03	Exploration	Sub-vertical	SGR/RES/CAL/DEN/NEUT/SON/FPRESS	Yes (SWC)	1990
B17-06	Exploration	Sub-vertical	GR/RES/CAL/DEN/NEUT/SON (Full waveform)/FPRESS/BHI	Yes	1997
A12-A-03	Production	**Horizontal**	GR/RES/CAL/DEN/NEUT (**LWD**)	No	2007
A12-A-04-S1	Production	**Horizontal**	GR/RES/CAL/DEN/NEUT/FPRESS (**LWD**)	No	2018
A12-A-05	Production	**Horizontal**	GR/RES/DEN/NEUT (**LWD**)	No	2007
A18-A-01	Production	**Horizontal**	GR/RES/CAL/DEN/NEUT (**LWD**)	No	2016
A18-A-02	Production	**Horizontal**	GR/RES/CAL/DEN/NEUT (**LWD**)	No	2015
A18-A-04	Production	**Horizontal**	GR/RES/CAL/DEN/NEUT (**LWD**)	No	2017
A18-A-05	Production	**Horizontal**	GR/RES/DEN/NEUT/CAL (**LWD**)	No	2018
B13-A-01-S2	Production	**Horizontal**	GR/RES/DEN/NEUT/SON/FPRESS (**LWD**)	No	2011
B13-A-03	Production	**Horizontal**	GR/RES/DEN/NEUT/SON (**LWD**)	No	2011
B13-A-04-S1	Production	**Horizontal**	GR/RES/DEN/NEUT/SON (**LWD**)	No	2011

Acquired data	Exploration/ Appraisal	Production
GR/SGR	Always	X (LWD)
RES	Always	X (LWD)
CAL	Always	X (LWD)
NEUT – DEN	Always	X (LWD)
SON (X-Dipole/ Waveform)	Always	Sometimes (LWD)
FPRESS	Often	Sometimes (LWD)
BHI	Often	
NMR	Often	
Core	Sometimes	

Appendix B
Details geohazards Schoonebeek

Stratigraphic unit	SCH-1504 (2009)	SCH-1452 (2009)	SCH-1505 (2009)	SCH-2502 (2010)	SCH-2803 (2010)	SCH-2601 (2011)	SCH-1801 (2011)	SCH-1802 (2011)
NS	Swabbing during POOH Losses during casing RIH		Swabbing during POOH			Overpull during POOH		
Chalk	String hung up during sliding, added starglide							Erratic torque / stick-slip
Holland/Vlieland	Pack offs	Swabbing during POOH Overpull	String hung up during sliding, added starglide Swabbing		Pack offs during RIH		String hung up Pack offs	
Bentheim	losses	Minor lossses	Losses during RIH 7 5/8” csg	losses	losses	Impossible to build	losses	losses

Appendix C
Overview tables knowledge gaps

Overview tables summarizing per topic the identified knowledge gaps, research topics and in which projects this is already (partially) addressed that we are aware of.

Drilling

What knowledge is missing?	Possible research topic	Ongoing research/projects on this topic
How to safely reduce cost?	Compact well control development	MOOI DIAMETER investigates a well concept for LTG, but this is not specifically focused on well control.
	Lighter rig options (in combination with previous)	
	Collection of information relevant for compact well control (e.g. presence of shallow gas, sealing capacity of shallow seals)	SCAN wells, wells and geomechanical experiments in DIAMETER, COVRA is investigating Paleogene clays
	Overview and description of cases in which compact well control has been used and to which depth (e.g. SCAN wells)	
	Alternative development options, like slim hole well in combination with storage; vertical wells only	
	Choice of well materials (lower pressure rating, corrosion, well materials)	MOOI Collectieve Bodemlus investigates materials for gravel packs and cementing (bentonite). MOOI DIAMETER wp1.1 investigates well concept for LTG.
	Optimization of logging	DIAMETER wp1.2
Business case: What is the maximum LCOH to let LTG fly? What can then be achieved in cost reduction by technological developments?	Desktop study to analyse the business case for different reservoirs (extensions of available studies listed in section 2.3)	

Subsurface characteristics (porosity, permeability, net thickness, geomechanical properties)	Reservoir characterization in areas/depth with little information	SCAN wells, wells in Warming^{UP}*GOO* and DIAMETER

Completions

What knowledge is missing?	Possible research topic	Ongoing research/projects on this topic
What is the performance of the different completions options used in NL for LTG?	Investigate the completions via simulations, lab and field experiments	Partly to be investigated in DIAMETER WP1.1 on LTG well concept, but can test only one option in the field.
Are the current erosional limits appropriate for LTG conditions	Investigate the real velocities and sediment load that will/might occur. Modelling and experimental validation to understand the impact on erosion	DIAMETER WP1 will aim to perform some CFD calculations to better understand the erosion impact, but no experimental validation is planned.
Is the slim well concept applicable to shallow geothermal?	Identify methods to reduce frictional pressure drop in slim wells to enable higher flow rates at lower pumping cost. E.g. in DRAGLOW project the impact of drag reducing agents (DRA) for geothermal wells is investigated	Pilot of DRA injection in existing or smaller tubings and estimate the impact of DRA on OPEX reduction in shallow wells
What are the relevant reservoir characteristics (particle sizes and shapes, fluid composition, geomechanical properties)	Reservoir characterization in areas/depth with little information	SCAN wells, wells in Warming^{UP}*GOO* and DIAMETER

Operations

What knowledge is missing?	Possible research topic	Ongoing research/projects on this topic
What is the maximum safe velocity at sand face for fines migration / sand transport?	Fundamental understanding of the impact of temperature, in-situ stress and fluid properties via 1D flow experiments + modelling + 3D flow experiments with relevant completions. Finally field trials.	for vertical HTO wells: HTO experiments in Warming UP and Warming^{UP}*GOO* DIAMETER work focused on erosion Missing: knowledge development/experiments for deviated/horizontal wells, relevant completions, relevant reservoir characteristics (PSD etc)

What is max. drawdown / injection pressure?	Max. drawdown affects the well bore stability Max injection pressure: investigation of sealing clay layers (properties and modelling)	DIAMETER wp2 in investigates properties of sealing layers (experiments and modelling)
What are the scaling, corrosion, and microbiological contamination challenges in LTG wells?	A comprehensive sampling, field measurements, and modelling to analyze the geochemical and operation conditions within LTG wells and develop risk matrices for different scaling, corrosion and MIC challenges	Not covered in any project
What are guidelines for operational procedures (shut-in, start-up, cleaning etc)?	Optimized strategies for start-up and shut-in of LTG in shallow reservoirs as a function of heat demand, duration of shut-in, completion type, etc.	Not covered in any project
How to handle inflow from thick, fine-grained reservoirs like Breda Sg or stacked reservoirs?		DIAMETER partially

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