RESULT
Enhancing REServoirs in Urban deveLopmenT: smart wells and reservoir development, Geothermica Project Number 200317

RESULT-D2.01:
Lessons learned from hydrocarbon well technologies

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1 Introduction

Tanak Engineering B.V. was approached by EBN to deliver a study on the best technique to economically exploit geothermal reservoirs with limited transmissivity. The following techniques were evaluated: horizontal wells, short radius horizontal open hole sidetrackes (radial jetting) and ECI (Enhanced Casing Installation) deviated sidetracks that form the core of RESULT. The techniques compete not only on injectivity improvement, but also on costs and lowest operational risk. This work is part of the Geothermica RESULT program and the specific task is (from (1))

Task 2.1: Lessons learned (EBN, TNO, Huisman, , ISOR, OR)

a) Inventory of state of the art of most relevant design and construct elements affecting performance of wells in the RESULT reservoir settings based on literature assessment. This includes well design elements such as well placement, well trajectory (e.g. deeper drilling or stepping out into less productive zones) completions and artificial lift technology, and associated cost engineering parametrization.
b) Inventory of optimization challenges and technical parameters for the well design and drill and learn approach in view of different reservoir conditions.
c) Definition of performance criteria for geothermal wells in a formalized and quantitative decision framework.

2 Setup of this report

RESULT targets low enthalpy (non-steam) geothermal systems in both matrix settings (Rotliegendes; e.g. Zwolle and Haarlem, NL) and karstified / fractured carbonates (Dinantien; e.g. Nijmegen NL). Productivity and Injectivity enhancement in these are similar: whereas in the matrix setting the productivity will increase with exposed contact to the matrix, in the karstified reservoirs the extra well length will contact more fractures/fissures. This study focuses on matrix enhancements only.

The geothermal system forms a closed loop, where the produced water is cooled by a heat exchanger and re-injected. With the higher viscosity of the injection water, generally the injectivity index is more constraining than the productivity index. This will be quantified for a typical low transmissivity example, see section 4.2.

This report quantifies the merits of the following techniques to improve the productivity and injectivity: (a) horizontal wells, (b) short radius horizontal open hole sidetracks and (c) ECI (Enhanced Casing Installation) deviated sidetracks. The techniques compete not only on injectivity improvement, but also on costs and lowest operational risk.

The report is set up as follows: after describing a typical reservoir and location where injectivity improvement may be needed (section 3), a literature study will be presented where various injectivity

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and productivity improvement techniques are discussed. Focus here is on improvement factors, costs and operational aspects (section 4).

Section 5 discusses the Injectivity Improvement Factors (IIF) and Productivity Improvement Factors (PIF) of the various completions, based on literature and dynamic simulation using `OPM flow`. A simple excel tool will be presented in section 6 where the impact of improvements can be translated into doublet flow rates and thermal power. This is first done for a generic case with an improvement factor 2, either in Productivity, Injectivity, both or by using a dual injector. This example explains the impact of productivity and injectivity on the system performance, honouring the many constraints.

In section 7 the method to determine the impact of improvement on the flow rates and geothermal power is applied for the improvement factors derived in section 5, and then in section 8 translated into a Cost of Energy by taking into account both the cost and the flow rates of the completion techniques. For a range of reservoir transmissivities (permeability x height) it will then be calculated which well configuration is preferred, and how robust this choice is to uncertainty.

To improve the readability of this report, the calculations, technical descriptions of tools and simulations were moved to the appendices in sections 14 through 19.

3 Type location

It was decided (2) to use the Zwolle location as the type location to estimate the merit of the RESULT project. Type location data were obtained from EBN and are shown in Table 1.

For the trajectory, a J-shaped configuration was chosen similar to what was done in Honselersdijk, see Figure 1. Kick off point is 1300 m tvdss, below the ESP depth of 500 – 1100 m tvdss. A 7” monobore completion was assumed in the base case, see Table 2 for details.

4 Literature study

4.1 PI and II improvement techniques

The flow rate of a well at given reservoir height and pressure drawdown can be increased by either changing the fluid viscosity (e.g. steam injection), the reservoir properties (e.g. acid injection) or by changing the well exposure to the reservoir. The latter can be done by fracturing, side-tracking, and deviated or horizontal drilling. In many of the cases the flow direction will also change, i.e. in the case of the horizontal well the flow direction in the reservoir close to the well is changed from horizontal to vertical.

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The productivity index (PI) of a well is defined by dividing the flow rate (in m^3/h) to the reservoir drawdown (in bar) and has units $m^3/(h\ bar)$. The injectivity index (II) is defined in the same way, where the direction of the flow and the drawdown are both reversed. Unit is again $m^3/(h\ bar)$.

In this report the Productivity (Injectivity) Improvement Factor (PIF and IIF) are defined as the Productivity (injectivity) index of the studied well configuration divided by the PI (II) of a vertical unfracced well, and is thus dimensionless.

Various techniques to increase the well PI and II exist. The most commonly applied are (sand or acid) fraccing a well and drilling a ***horizontal well***. The PIF and IIF of both techniques are extensively described in the classical textbook by Joshi (3). Whilst fracturing will not be discussed in this report, the merit of horizontal wells will be estimated amongst other by using the correlations from (3) and by using the software PROSPER (4).

Short radius open hole sidetracks (Radial Jet Drilling or ***RJD***) is a relatively novel technique that is employed in the oil industry both for overcoming near wellbore damage and to increase reservoir exposure. For an introduction and some field examples see (5). The PIF is calculated in (6) and in the current report will be compared to a calculation for the geological setting in Zwolle.

Completed deviated ***multilaterals*** such as employed in the RESULT are calculated to yield a PIF of between 1.3 and 2 (1). In absence of literature values, this report uses dynamic reservoir simulation to calculate the PIF for various configurations of the RESULT multilaterals.

4.2 Operational aspects and field examples

4.2.1 Horizontal wells

Horizontal drilling is a very mature technology with thousands of proven field cases. For an overview see (3). Horizontal sections are either placed after drilling a pilot hole, or continuous steering takes place based on e.g. bio-stratigraphical data. The first is common in relatively immature areas with limited seismic and bio-stratigraphical control. In this report for the horizontals it is assumed that no pilot hole is drilled. ROP is based on recent horizontal wells drilled in Schoonebeek.

An alternative to above horizontal completion is e.g. Baker Hughes' HOOK hanger (7). Here several stacked sidetracks can be drilled after a pilot hole, and the sidetracks can be fully logged, cemented, perforated, coiled-tubing (CTU) accessed and re-stimulated. Typical sidetrack length is then 300 m; timing and cost assumptions for a single sidetrack are shown in Table 3.

Completion can be done in various ways: cemented and perforated liner, openhole completions (slotted liner, wire wrapped screens, standalone screens, etc), or if the rock is competent a pre-drilled (un-)cemented liner can be hung in the well to keep the hole intact. For very competent shallower reservoirs open hole completion is possible too; this was e.g. done in Al Shaheen offshore Qatar and in the low porosity Rotliegendes in the southern North Sea UK sector (Sole Pit area).

Well re-entry is typically done with a CTU, where extra perforations, (local) acidizations etc can be done at relatively low cost. In the producer this would necessitate temporary removal of the ESP. Note that when the well would be completed with a composite material like GRE (glass reinforced epoxy), this would make re-entry with a CTU challenging because of possible damage to the composite material (8), although this is dependent on the type material and application.

In 1995 a review (9) was done on 1306 horizontal wells in 230 fields, where for the conventional unfractured reservoirs a 4-fold increase in productivity was reported, compared with standard vertical wells.

In 2004, BP has published a paper (10) reviewing their experience with horizontal wells. A database of 93 "quality data" wells was used. An average PIF of 2.5 was found, but a large spread was observed. This spread could be largely removed when putting the horizontal wells in various classes of well length *L* over reservoir height *h*, see Figure 2. The study highlights an important risk for horizontal wells: the vertical permeability: *"[…] a horizontal well will be less productive than a vertical one in the same location unless L/h is larger than 20 on average. The most likely reason for this is the fact that horizontal-well productivity is significantly affected by the kv/kh ratio, which is usually less than 1. For a horizontal well to be more productive than a vertical one, the negative impact of a small kv/kh ratio has to be compensated for by well length.".* This is the reason that in the current study a 1 km well length (*L/h* ~ 20) is used.

4.2.2 RJD

Radial Jet Drilling (RJD) is a novel technique that is sometimes used to remediate wells with near wellbore damage. Working in a casing of 9 5/8" or 7", an "inverted question mark" inflector shoe is used where first a hole in the casing is drilled with a cutting tool, and then a coil with a nozzle can be inserted to drill short radius sidetracks, see Figure 3. Abrasive material is sometimes added to the working fluid to increase drilling efficiency. Sidetracks of up to 100 m can be made, but in practice the sidetracks are shorter (up to 40 m in (11) and typically 50 m in (12)). Quarry trials in Germany (13) showed that the radials were not necessarily going in a straight direction.

With this technology there seems to be a discrepancy in the literature between theoretical and practical gains. In theoretical optimization studies (14) the gains can be significant with PIF/IIF in excess of 2. The sidetracks cannot be completed and therefore geo-mechanical properties are important, see section 4.3. In practice, the gains are less than predicted. In (12) sidetracks were successfully drilled and initial productivity gains were measured of up to 47%, but there was no long term PIF. This gave doubt about the life-time of the drilled holes. The field had a history of sand production problems, which makes RJD hole collapse quite likely. Furthermore, as seen in testing RJD sedimentary and magmatic sites in the recent EU funded R&D project SURE (13), RJD did not result in the anticipated gains. In a geothermal project in Lithuania (15), theoretical IIF was 1.57 but in practice only 1.14 was attained after drilling 12 laterals. Note this injection well suffered from heavy near wellbore damage (skin of 120 pre-RJD), which was either not overcome by RJD or was re-appearing in the new RJD holes. In China, a successful RJD interventions claimed a PIF = 3, but with very limited details reported (16). In a geothermal project in Iceland RJD was not successful (a). Furthermore, in a geothermal project in the Netherlands RJD has been tried in Paleozoic rocks but has not proven to be successful. As witnessed in Iceland and the quarry results (a,11), the RJD technology appears not to be sufficiently mature to produce the laterals as anticipated in geothermal wells, as the radials appeared to be strongly deviating from the intended penetration length and orientation.

In West Siberia, RJD technology was trialed in five Cherkashin oil producers (17). The permeability of the Cherkashin reservoir in these wells was 15 – 100 mD. In total 24 holes with 25 mm diameter and 100 m length were jetted in various reservoir layers. The total RJD operation of a well took typically 10 days, of which the ESP removal, well killing, casing milling and ESP re-installation took the most time. Holes were jetted with a surface pressure of approximately 10000 psi. It took typically 1.5 hours to jet a 100 m length hole, so the rate of penetration is high: around 1 m / minute. For 4 jetted holes per well, a PIF = 1.6 was estimated before the field trial. The actual observed PIF was 1.3. In some cases the production is commingled between RJD and non-RJD layers. Taking account of this, in one well the PIF of the RJD layer was as high as 1.9.

4.2.3 RESULT ECI multilaterals

The ECI multilaterals sidetracks differ from RJD in two important aspects, see Figure 4:

- The ECI multilaterals sidetracks can be completed, e.g. with a sand screen
- The sidetracks are planned to penetrate all sand layers sub vertically, which means the inflow will stay horizontal and the productivity and injectivity will be less (or even in-)dependent of vertical permeability.
- Hole size for ECI multilaterals is 1 size larger.

Similar to RJD it is again difficult to re-access the side-wellbores and oriented coiled tubing is required.

In contrast to RJD the RESULT drilling will take place with a rig on site, which makes the technique more expensive than RJD.

The description of RESULT technology in the Geothermica project proposal provided in (1) suggests that uncemented liners or screens can be deployed in each of the laterals. Where the laterals join the original wellbore (the junction), the base pipe of such liners/screens will be constructed of a drillable material such as aluminium to facilitate drilling the next lateral. Only the last lateral will have a steel liner installed, which will be perforated to allow flow to enter from laterals. Swellable elastomer elements will serve to isolate individual laterals close to the junction – see also Figure 4.

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The position of the junction in the RESULT design is likely situated some distance above the top of the producing/injecting target formation. This distance is required to allow legs to penetrate the target formation some distance apart and thereby avoid excessive pressure interference between laterals. This distance will be quantified in subsequent RESULT workpackages, taken various geological/ technological restrictions and parameters into account. For a more realistic deviation together with measured geology of the Langenholte-1 well, see Figure 5.

The following subjects are listed as potential concerns with the above approach, and will need to be addressed or solved as part of the RESULT technology development.

- During drilling of a subsequent lateral, legs that have already been drilled remain open (no mechanical barrier mentioned) and this may result in ingress of debris from milling/drilling activity on the subsequent lateral. Such material should be removed prior to well commissioning but is this possible for laterals that will subsequently be inaccessible with CTU?
- Geothermal fluids are corrosive due to high salinity and low pH value[1]. The aluminium base pipe in the laterals is likely going to be attacked quickly and this may lead to integrity issues around the junction(s) of the system. Composite alternatives are currently being evaluated.
- In injection wells in particular, scale removal with acid is likely to be required at some point, as is common in geothermal wells. Again, the use of aluminium is concerning in this respect due to ease of Al corrosion in acid environments.
- Scale removal is often best achieved with a CTU entry into the reservoir section to ensure placement of acid along the length of the producing or injecting zone. Based on the description in the Geothermica project proposal (1), it is here assumed that CTU re-entry is not possible, unless a directional CT unit used, and the screens in the junction are milled.
- If the junction is situated in a cap rock material that is either plastic, could collapse or produce solid materials (e.g. Zechstein Z1 anhydrite, Z1 Claystone, Copper shale in LNH-01, see Figure 5) then this could either plug one or more laterals or lead to pump failures, plugging problems, etc. In the final leg screens will prevent material from a collapsed junction to enter the well, so in the worst case scenario only one leg will remain.
- Abandonment phase: restoration of cap rock integrity will be challenging if the junction is located into the cap rock (see also section 4.4).

[1] "the pH of the flashed brine may usually be around 6, but clearly the pH at reservoir level is much lower (3-5) due to the solution of CO_2" (32).

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4.2.4 Fishbone wells

Fishbone wells are employed mainly in the Shuaiba in the Middle East, a low (0.5 – 2 mD) permeability oil reservoir, often to prevent coning and cusping of water and gas. This reservoir was originally successfully produced with long horizontal "MRC" (maximum reservoir contact) wells in e.g. the Al Shaheen field in Qatar. Whilst some fishbone trials report a double production rate compared with horizontal wells (18), reservoir simulation studies by ADNOC indicate (19) that beyond 2 years the well performance is not much different from long horizontals and that *"fishbone well designs have serious limitations during well life cycle activities compared to extra-long MRC single lateral design in terms of stimulation, well accessibility and well intervention options making the extra-long MRC single laterals the preferred field development concept within tight reservoirs".* It is not known whether the MRC cases were modelled as fractured horizontals, if so there will be merit with respect to standard horizontal wells. The difficulty to access the wells will however be a serious operational issue for geothermal use, see section 4.3.Moreover, the installation of sand exclustion techniques is not possible in fishbone wells, making them only suited for consolidated reservoir.

4.2.5 Deviated wells

The merit of a highly deviated well (i.e. > ~ 80 degrees) comes from the increased reservoir exposure (well length) and will be shown to have similar benefits as a horizontal well of the same length, see section 5.2 and 5.6. The presence of horizontal geological barriers within the formation poses however a risk for perfectly horizontal wells since parts of the formation above or below the wellbore might not contribute to the performance of the well. Drilling (sub)horizontal or highly deviated wells might therefore be preferred above horizontals wells. However, since the drilling techniques, the costs and the performance of horizontal wells and highly deviated wells are equal, no further distinction between the two is made in the remaining part of this study and they are jointly called "horizontal wells"

Moderately deviated wells (~ 60 degrees or less) still exhibit the advantage of increased reservoir exposure, while still allowing for easy and relatively cheap future access to the reservoir section. The added technical value of these wells is commonly quantified in terms of a deviation skin, having typical values between -0.5 and -1.5 (20). Following from Darcy's law, this translates to a PIF of 1.06 and 1.2 respectively, which is, compared to the other concepts described in this document, not very significant. For this reason the impact of deviated wells is not described in further detail in the remaining part of this study.

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4.3 Sand stability and sidetrack life

As mentioned, RJD uses open hole completions and at least for one of the applications found in literature, this led to hole collapse and absence of incremental productivity (12). For RJD application it is hence advised to perform a sand stability study, preferably with the techniques such as applied in (21). For this, geo-mechanical parameters (Young's modulus and Poisson ratio) are needed, but these can be derived from modern sonic logs where both the shear (V_s) and the compressional velocities (V_p) are measured. Since the wells close to the type location IJD-01 and LNH-01 only have compressional sonic velocity measurements, a simpler "PETRONAS - TOTAL" approach (22) is taken.

This sanding criterion is based on $\Delta t = 1/V_p$. Δt is defined as the time for a compressional wave to travel a distance of 1 ft.

GREEN $\Delta t < 90$ µs/ft : no sand prevention needed.

ORANGE $90 < \Delta t < 110$ µs/ft: sand production possible during depletion and well start-up.

RED $\Delta t > 110$ µs/ft : sand prevention needed.

Plotting Δt of the nearby wells is done in Figure 7 and Figure 8. Both wells indicate consolidated sands.

For the expectation well life it needs to be taken into account that injection is planned to take place under matrix conditions with relatively warm (max 40 C cooling) water at relatively low pressure (THP_i < 50 bar), when compared to North Sea conditions (23) where sea water is injected that is up to 130 C colder than the reservoir water and the tubing head pressure can be above 200 bar. Under these conditions, thermally induced fracturing will take place which makes the wells quite insensitive to matrix impairment. During early North Sea development this came as a surprise, and the original large injection water cleanup facilities were not necessary. With assumed matrix injection, regular cleaning or acidizations are likely to be necessary. With the open hole completions of RJD this will mean bullheading the acid, where a "winner takes all" effect takes place where the undamaged branches will take the acid, and the impaired branches will not.This will make these cleanups very ineffective and restoring the injectivity of the branches probably means re-drilling them. Analysing the additional costs versus the expected gains must reveal the necessity and therefore feasibility of re-drilling braches.

RESULT re-access of the branches is not planned to be possible and hence suffers from the same issues, unless the decision is taken to mill through through the sandscreens with CT. It must be noted however that the last leg is fully accessible for intervention operations.

For the horizontal wells, access is possible and repeated well cleanups are more likely to be effective.

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4.4 Abandonment considerations

4.4.1 Legislation

Abandonment requires the restoration of natural barriers isolating formations that are, or could become, capable of flowing gases or liquids either into other subsurface formations or to surface. The Dutch mining regulations ('Mijnbouwregeling') specifies in section 8.5 what is required (24). An abandonment barrier has to be positioned at the cap rock location and fully close the wellbore including all annular spaces. The barrier is normally constructed of a 100 m column of cement (section 8.5.3.1 Mining Regulations) or a 50 m column of cement on top of a mechanical barrier, but may also be of a different material (after prior approval by SodM) provided it has at least the same strength.

For non-hydrocarbon wells, the Minister of EZK can make exemptions to the abandonment rules of Mijnbouwregeling section 8.5.

4.4.2 RESULT abandonment

Given the above, for RESULT the situation at the top of the reservoir therefore becomes quite relevant. If no confirmed cemented annulus/annuli are provided over the caprock, current regulations require the removal of uncemented steel or aluminium pipe and subsequent placement of a cement plug over the caprock. The absence of cemented casing over the reservoir legs in some situations, and planned use of swellable elastomers complicates matters in this regard. Discussions about potential exemptions and dispensations should be held with SodM prior to construction to avoid what could become a cumbersome abandonment operation.

4.4.3 Horizontal well abandonment

For the horizontal well, when the casing is under a considerable deviation (>70 degrees), special care needs to be taken when cementing this casing to make sure it is properly cemented in the cap rock. This needs to be confirmed by running a CBL.

5 IIF and PIF of various completions

5.1 Dual injector

With the injection water viscosity being twice as high as the produced water viscosity, most of the pressure drop across the reservoir will be around the injector. Defining $P_{½}$ as the pressure halfway the injection bottom hole pressure BHP_i and production pressure BHP_p , it can be derived from Darcy's equation that in this case $P_{½}$ is attained approximately 10 m from the injector, see Appendix A. The other half of the pressure drop is then taking place in the 990 m towards the producer.

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This indicates that the interference of two injectors can be limited even with short distances. For the Zwolle type location this was calculated with `OPM flow` in thermal mode, and the II of a dual injector was compared with the base case single injector, see Figure 9. It can be observed that for injector – injector distances of >150 m, the dual injector reaches to within 10% of the theoretical IIF of 2.0. Based on this analysis, for the dual injector cases in the remaining part of this study an i-i distance of 250 m and an IIF of 2.0 is assumed.

5.2 Horizontal wells

The IIF and PIF of horizontal wells are studied extensively in literature. In the current report use was made of three sources:

- a TNO publication (25) and spreadsheet, using analytical calculations based on an elliptically cylindrical symmetry.
- Eq. 3.26 of the book “Horizontal Well Technology” (3)
- Horizontal well correlations in PROSPER, using the Kuchuk and Goode method (26).

The analytical predictions for various vertical permeability (k_v/k_h = 0.1, 0.3 and 0.01) yield similar trends, see Figure 10 -- Figure 12, with `PROSPER` showing the highest IIF. In this report then the average is taken of the three methods. Base case uses k_v/k_h = 0.1, low case k_v/k_h = 0.01 and high case k_v/k_h = 0.3, see Table 4.

For a more elaborate description of the differences of the various analytical techniques, see (27).

As a first approximation the PIF for horizontal wells is independent of absolute permeability, in contrast to sand fracs. For very high permeability this assumption breaks down, since there the friction pressure in the well starts to approach the pressure drop in the reservoir. For the transmissivity range of interest of this report (~ 10 D.m) the friction in the horizontal section is of the order of 1 bar, whereas the pressure drop in the reservoir is typically 35 bar. This justifies this report’s assumption to ignore frictional pressure drop in the horizontal and branch sections. This was confirmed in `PROSPER`, see Appendix F, where it is shown that for the reservoir (134 mD) under study the well toe contributes similarly as the well heel.

For completeness, the IIF of the high deviation cases are calculated in `PROSPER` using the Wong correlation, see Figure 10.

5.3 RJD

For the PIF of Radial Jet Drilling, TNO have done extensive calculations (28) which are summarized in Figure 13. Since the calculations were isothermal, these calculations were reproduced with `OPM flow` in thermal mode for the Zwolle type location (called EBN_base for the vertical well), see Table 5.

For comparison, the `OPM flow` case for 4 branches of 20 m shows an IIF of 1.39, whereas the TNO correlation showed 1.34 for the 4 x 25 m case[2]. Here the correlation Eq. 2 and Table 2 of (28) were used. For the 4 x 37 m case in OPM flow the comparison is 1.59 and 1.48 for `OPM flow` and TNO respectively[3].

5.4 RESULT multilaterals

The multilaterals that are planned in the RESULT project typically look as depicted in Figure 4. No PIF and IIF were found for these completions in literature, only the 1.3 – 2.0 range quoted in (1). Having gained confidence from the reasonable match between simple `OPM flow` IIF calculations for RJD and the more extensive work done by TNO (28) for this technique, OPM flow was used to estimate IIF for the RESULT sidetracks, see the Appendix in section 18 for more details. Resulting IIF is shown in Table 5 for varying number of branches and deviation angle from the main wellbore. Kick-off is assumed at top sandstone.

5.5 Fishbone wells

The difficulty to re-access fishbone wells will be a serious operational issue for geothermal use, see section 4.3, and the applicability for the Dutch geothermal sector is currently unknown. For the current study fishbone wells are therefore not further explored..

5.6 Discussion and proposed PIF and IIF ranges

PI and II improvements will be used in the next sections to estimate the flow rate and economical merits of the various completions. PIF and IIF were estimated making use of the following techniques:

- For Horizontal wells: equations by Joshi (3) and TNO (25), compared with `PROSPER` correlations.
- For RJD: calculated correlation by TNO, compared with `OPM flow` thermal dynamic simulations.
- For RESULT sidetracks: `OPM flow` thermal dynamic simulations compared with mentioned PIF of (1).

`PROSPER` has refined modelling capabilities for multilayer wells, where careful bookkeeping is done for different transmissivity, PVT, pipe roughness, perforation type etc. However, the problem of predicting the IIF of multilateral sidetracks is about (a) pressure interference between well segments, in (b) a cold, growing injection bank, and neither is modelled in `PROSPER`. This is the reason why in the current study `OPM flow` was employed, since it captures both effects.

[2] A drainage radius L = 200 m was used here to be consistent with the relatively small `OPM flow` model.
[3] Interpolating the correlation parameters for 25 m and 50 m in Table 2 of (18)

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The `OPM flow` simulations for the RJD and RESULT assume vertical main wellbores. In reality the wellbore is most likely deviated because of the J-shaped trajectory. Radials leave the wellbore always perpendicularly. This implies that whena “horizontal” RJD is drilled it most likely cuts through various reservoir layers. Similarly, the RESULT sidetrack travelling under and angle of say 20 degrees from the main wellbore may then effectively be a vertical branch having an inclination typically between 20 to 60 degrees. This is ignored in the current study.

For the horizontal and RJD wells where the improvement is largely due to changing the inflow from horizontal to vertical flow, it can be imagined (and this is confirmed by the equations and correlations) that the vertical permeability has a large influence on PIF.

With k_v/k_h = 0.1 for the type curve location, a Mid case PIF and IIF of 2.5 and 4.0 will be assumed for the 500 m and 1000 m ***horizontal*** wells respectively, from Figure 10. For the Baker HOOK sidetrack of 300 m, IIF=1.7 can be used. See Table 4 for ranges.

For the ***RJD*** completion, a Mid case PIF and IIF of 1.5 can be calculated based on the TNO and `OPM flow` results of 1.48 and 1.59 respectively. However, given the disappointing field results (12) (17), here a value of 1.3 is used.

For ***RESULT***, a Mid case PIF and IIF of 1.9 were calculated. This Mid case is based on assumed 2x40 degree branches, and both mainbore and branches having a holesize of 6”. This PIF and IIF of 1.9 falls in the 1.3-2.0 range of (1), though in this reference it is not described how this range was derived.

Well model schematics of the various completion types used throughout the remainder of this study are shown in Figure 14.

6 Impact of PIF=2, IIF=2 or N_i=2

6.1 Introduction

This section discusses the generic case of factor 2 improvement in injectivity and or productivity, and its impact on system (doublet) performance. PIF = 2 will not automatically increase the doublet rate and thermal power with a factor 2, since the doublet has to obey the following constraints:

1. A maximum ESP head (ΔP_{ESP}) and pumping rate Q_p. These are connected since the product of (Q_p ΔP_{ESP}) has the unit [J/s] = [W], and indeed the typical ESP operating envelope can be approximated by a maximum power curve, see Figure 15. In this study, a 0.6 MW load line will be assumed for the pump constraint, with the following notes:
    a. 0.6 MW is not the actual pump electricity consumption,since both the pump and the Variable Speed Drive (VSD) have non-unity efficiency. For both 85% will be used,

bringing the efficiency of the system to 72%. This assumes an ESP that is close to design capacity. Detailed pump/VSD efficiency tables are supplied by the vendors but will not be used in this study.

b. SLB/Reda pumps have ~25% higher operating envelope, but the high voltages and currents come with associated risks. Hence the 0.6 MW gross load line is used here in the base case, with the larger ESPs as sensitivity.

c. To place the 0.6 MW in perspective, the doublet with the highest flow rate in the Netherlands is currently NLW-GT. In November 2020, the production rate averaged 356 m^3/h. But with a reported (29) *kh* of 60 D.m this is estimated to need a ΔP_{ESP} of some 40 bar, or a $Q \times \Delta P_{ESP}$ = 0.4 MW load line. So the base case load line of this report is 1.5x the load line of the highest producing well in the Netherlands.

2. A minimum Tubing Head pressure THP_p of the producer. Koekoekspolder (near Zwolle, NL) brine has a measured bubble point of 6 bar (30) and to stay above bubble point, in this study a minimum THP_p of 10 bar is taken. ESP placement will be such that an entry pressure of 10 bar minimum is attained, see the Appendix in section 16 for a description of how this is calculated.
3. A maximum THP_i of the injector. In the Netherlands, SodM has published a protocol (31) allowing a maximum THP_i that is dependent on well top depth *d* and gradient $\rho_I g$ (bar/m) of the injection water:

$$THP_{i,max}\ (bar) = (0.135\ - \rho_I g)\ d$$

In this study, this maximum injector THP will be obeyed. For the type location this means a $THP_{i,max}$ of 44 bar.

Tubing friction will further lower the merit of increased PI and II since higher rates will lead to quadratically higher friction.

The SodM maximum THP for the injector is pending a maximum temperature reduction of 40 C over the heat exchanger. In this study this limit will be honored. It may be economically attractive to apply heat pumps to further reduce the temperature of the injection water (and increase injectivity), but this is out of scope for the current study.

6.2 Calculation spreadsheet

For a description of the calculation spreadsheet `EBN_REPTool` see the Appendix in section 14. Figure 16 compares the `DoubletCalc` results with the `EBN_REPTool` thermal power P_{th}. For the vertical wells this is trivial, for the horizontal wells a representative negative skin will be used, see section 7.1 and footnote 4. The main reason that a separate spreadsheet was built parallel to `DoubletCalc` is that:

- It is easier to iterate the spreadsheet to honour the various constraints.
- the spreadsheet allows dual injectors.
- the spreadsheet allows a separate ESP and injector pump. In `DoubletCalc` these are combined and it is then more difficult to separately honour the ESP operating envelope
- for PIF=1 and high IIF, it may be that the drawdown needed to inject the water is less than the (gravity head injection brine) - (reservoir pressure). In this case the water "falls into" the injector and generates a vacuum. In oilfield operations, such injectors are (downhole) choked to prevent vacuum in the upstream facilities. This choke is not modelled in `DoubletCalc` but implemented in `EBN_REPTool` as a negative pressure increase in the injection system calculations.
- the spreadsheet automatically calculates cost of energy, IRR etc. using a macro.

Choosing a certain permeability, IIF, PIF etc. it takes the user approximately 15 minutes of iteration to generate a P_{th} (IRR, CoE etc) curve versus transmissivity.

6.3 Geothermal power calculations

In this section the impact of a doubling of the injectivity and/or productivity will be presented. This will be useful during the later discussion of the merit of the various completion techniques since it shows the main physical mechanisms of the geothermal system under constraints.

6.3.1 Base case N_i=N_p=PIF=IIF=1

The base case is a simple doublet without injectivity or productivity improvement. This case is the same as the earlier comparison to `DoubletCalc` and is shown in Figure 17 with the constraints of each calculated point. At low transmissivity the injection tubing head pressure is the limiting factor and for higher transmissivity the ESP becomes the constraint. At this point the P_{th} versus transmissivity shows a marked bend.

When the system is ESP constrained (at high *kh*), it may help to install a booster (injector) pump to alleviate this constraint. In Figure 18 the impact of this is presented. Further calculations in this report assume the possibility of a booster pump.

6.3.2 Injectivity improvement N_i=N_p=1; IIF=2

Doubling the injectivity index leads to a higher P_{th} for low *kh*. This can be understood because at these transmissivities the doublet was *THPi* constrained, and doubling the injectivity hence helps. For higher *kh* the system is ESP constrained and IIF=2 does not help, see Figure 19.

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6.3.3 Productivity improvement N_i=N_p=1; PIF=2

This situation is reversed when doubling the PI. At low *kh* the system is THP_i constrained and doubling the PI is of no influence. For higher *kh* the system is ESP constrained and PIF=2 *does* help, see Figure 20.

6.3.4 Combination improvement N_i=N_p=1; IIF=PIF=2

Combining the PIF=2 and IIF=2 effects is also shown in Figure 20.

6.3.5 ESP placement and power consumption

Focus of this report is on improving lower *kh* systems and hence improvement of the injectivity index is the most important, see section 6.3.2. Whilst IIF = 2 leads to much higher flow rates and thermal power at low *kh*, this improvement comes at the price of the ESP pumping at high rates at low *kh* and here the PI was not improved. This is shown in Figure 21 where the ESP gross power consumption is shown with the minimum ESP depth as calculated using the equations of Appendix E. Whereas for the earlier cases the low *kh* led to the system being THP_i constrained, when (PIF=1; IIF=2) the system is ESP constrained above 8 D.m and the high drawdown in the producer leads to high power consumption *and* deep placement, and the option to install the ESP deeper must be evalutated This adds to complexity and possibly costs when planning the drilling target in combination with the KOP, the distance between the producer and injector, etc.,

6.3.6 Triplet N_p=1; N_i=2; IIF=PIF=1

At low *kh* the thermal power can be improved beyond the IIF=2 case by drilling an extra injector. This N_i=2, IIF=PIF=1 case is shown in Figure 22. This case shows higher flow rates at low *kh* than the IIF=2 case, which means that the drawdown on the producer is higher and the pump needs to be placed even deeper than the IIF=2 case, see Figure 23.

N_i = 2 also shows the first cases of choking of the injector well. At higher *kh* when the ESP is constraining the system, the producer THP is kept at 10 bar but with the high injectivity and low friction of the dual injector, injection can take place under vacuum conditions: the injector drawdown is less than the gravity head – friction. For the booster and choke pressures, see Table 6.

6.3.7 Coefficient of Performance

The Coefficient of Performance (COP) is a measure of the efficiency of the geothermal doublet: it is defined here as the geothermal heat delivered to grid divided by the electricity consumption of the ESP and the booster pump. COP versus *kh* is shown in Figure 24 and shows a nontrivial behavior that needs explanation.

Looking at the base case *kh* = 6.3 D.m for PIF = 2 and IIF = 2, these have a very different COP of 12 and 8 respectively. The PIF=2 case has a P_{th} of just 3.3 MW, and is limited by the maximum THP_i. This needs a combined pump ΔP of 80 bars, here 47 bar for the ESP and 33 bar for the booster

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pump. Combined power consumption is then 0.26 MW. The IIF=2 case is also THP_i constraint but now can inject 165 m^3/h at this maximum THP_i. A total of 133 bar ΔP is applied, using 0.84 MW electricity for geothermal power of 6.5 MW.

In summary, the geothermal heat of the IIF=2 case is around 2x the PIF=2 case, but at 3x the electricity consumption: with IIF=2 at the same permeability, the system is allowed to run at 2x higher flow rates. But since friction in the tubing and hence dissipation is proportional to the square of the flow rate, the system efficiency is lower. It may still be that the IIF=2 case is economically more attractive: whilst variable (€/MW$_{th}$) OPEX will be higher in this case the return on capital will also be higher. This will be further discussed in section 8.

6.3.8 Electricity consumption and generation

In Appendix B it is argued that to first approximation, the type location doublet can generate its own electricity from the associated gas. Figure 25 shows that for high *kh* this assumption can be reasonably made, but for the higher dissipation low *kh* cases it breaks down, since here the pumps consume up to 2.8x the generated electricity. In this report it is assumed that the variable OPEX (€/MW$_{th}$) will cover for this effect. When an investment decision will take place this needs to be re-calculated with a more rigorous economic analysis.

7 Impact of various completions PIF and IIF on heat delivery

This section presents the impact on heat delivery, COP and ESP placement of the PIF and IIF of various completions, as derived in section 5.6.

7.1 Horizontal wells

A long horizontal well leads to a marked increase in geothermal power, especially at low *kh*. Figure 16 compares the vertical PIF=IIF=1 case with a PIF=IIF=3.7 horizontal well case. The dots in the figure are the numbers calculated with `DoubletCalc`, proving that EBN_`REPTool` can also be used with high PIF and IIF numbers[4].

Using PIF=IIF=4 as derived in section 5.6, Figure 26 shows the thermal power for the vertical well case, a single horizontal injection well and single horizontal producer. Since with the single horizontal injector the IIF is so high, this case is ESP constraint throughout the full *kh* range. In this single horizontal case, the ESP needs to be placed deeper than 800 m for the cases *kh* < 10 D.m.

Figure 27 adds the case for a dual horizontal well. It can be observed that again a marked increase in geothermal power is obtained, especially at lower *kh*. At low transmissivity the system is tubing

[4] In `DoubletCalc`, a skin was used of (1/PIF -1) ln(r_e/r_w) = -6.9. Because in `DoubletCalc` it was not possible to check whether both THP and ESP operating envelope constraints were honored, a ESP ΔP was used equal to the total pressure drop (ESP and booster pump) in `EBN_REPTool` at the various *kh*.

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and ESP constraint, so cases with bigger well bores (9 5/8" OD, 8.7" ID) and bigger ESP (1050 kW gross) are added in Figure 28. It can be observed that considerable extra thermal power can be obtained using horizontal wells, especially at low *kh*. The "bend" in the thermal power for the dual horizontal case is again due to the THP_i limit kicking in at low *kh*, even at this high IIF.

The large tubing large ESP case shows the highest rates and fluid velocities of the current study: 567 m^3/h and 8 m/s for the 56 D.m case. Note that at these rates and velocities other system constraints might become prominent which are not further worked out in this study (e.g. fluid velocity, sandface and sandscreen integrity, surface facilities, etc. Also note that at these high rates the assumption that the well heel and toe produce at similar rates per completed length needed verification, see Appendix F.

The reduced dissipation of the horizontal wells leads to a marked increase in COP, especially at higher *kh* and flow rates, see Figure 29.

In the dual horizontal well case, the increase in PI allows for relatively shallow placement of the ESP, see Figure 30.

7.2 RJD completion

The slightly increased PIF and IIF of the Radial Jet Drilling completion leads to increased thermal power, see Figure 31.

7.3 RESULT multilaterals

The increased PIF and IIF of the RESULT completion leads to increased thermal power, see Figure 31. The COP of the various completions is shown in Figure 29.

8 Impact of PIF and IIF on cost of energy

8.1 Economics spreadsheet

To make economic comparisons between the various completion techniques, a simple economics spreadsheet was made allowing the calculation of Cost of Energy (CoE). Here a distinction is made between:

- A ***corporate*** investor: a company wanting a return on investment. It is here assumed that this entity is striving to attain an incremental rate of return of 6%.
- A ***public entity*** e.g. a council or other government agency. With current low interest rates this entity can borrow money at very low (or even negative) interest rates and it is here calculated what the CoE would be by simply dividing expenditures by delivered heat over a 30 year period.

For more details see the Appendix in section 17.

8.2 Cost assumptions

The costs of the horizontal wells and RESULT sidetracks are calculated using the typical spread rate of geothermal wells in the Netherlands. For this, the average number presented in Table 1 of (1) was used: 0.16 M€/d. For the horizontal wells, an ROP was taken from the SCH-3101 and SCH-3102 wells: 138 m / d.

For the CTU a spread rate was taken of 25 k€/d, including the RJD kit.

For completion times assumptions and the resulting incremental cost of the completions, see Table 3.

It is assumed that the project will generate its own electricity from associated gas. For a justification of this assumption see the Appendix in section 15. For cost assumptions see Table 3 and Appendix D. A sensitivity for purchase of electricity is done in section 9.2.

8.3 Energy cost calculations

8.3.1 Energy cost calculations; investor view

In this section the economics is calculated as seen by a potential commercial investor in geothermal production, following the simplified approach of Appendix D. A COE will be calculated such that a 6% IRR can be made.

The cost-axis has three horizontal lines (see Figure 32):

- SDE subsidy (67€/MWh for the highest and last auction phase 4)
- SDE subsidy + the maximum regulated sales price (21 €/GJ ex VAT or 76€/MWh), so 143 €/MWh
- the “split the difference” price halfway of 105 €/MWh.

The price is then built up as follows:

- The utility company running the heat grid can and will charge the end customer 76 €/MWh ex VAT.
- Utility pays the geothermal company 143-105 = 38 €/MWh, utility then has 38 €/MWh to build and run the grid
- Geothermal company gets 67 €/MWh subsidy so effectively obtains 67+38=105 €/MWh

The latter is therefore an important line, since when the COE is higher than this 105 €/MWh the IRR of 6% will not be made, unless costs are reduced, subsidies are increased etc.

Figure 32 shows the base case vertical well COE calculation. It can be seen that below *kh* = 25 D.m, the IRR will get eroded. Above this, the line levels off because the system will be ESP constraint. Here larger ESPs and tubing may help, see section 8.3.3.

8.3.1.1 Adding an injector (Ni=2)

It was shown in 6.3.6 that adding an injection well can increase the thermal power considerably. However, the extra cost of this will hurt project economics, and the break-even *kh* is actually increased compared with the base case, see Figure 32. This is because at these transmissivities the system will be ESP constraint, and adding an injector only harms the IRR. At low *kh* the system was THP_i constraint and here the extra injectivity helps; the COE is lower than the base case. However, as can be seen in Figure 32 for the example of 10 D.m the COE drops from 220 to 145 €/MWh, but this would still make the project difficult since this the COE is considerable above the "split the difference" price of 105 €/MWh.

8.3.1.2 RJD, RESULT and Horizontal wells

The same calculations were done for the Radial Jet Drilling, RESULT and horizontal wells and are presented in Figure 33.

8.3.2 Energy cost calculations; public entity view

For the public entity view, the COE is simply calculated as the full non-inflated capex + opex divided by the heat delivery of 3500 h/y over 30 years. No subsidies are taken into account, and the COE can only reasonably be compared to the maximum regulated price that the company can charge for the heat. This line cannot be seen as the "breakeven" price since also the heat grid needs to be built and exploited for this price.

The results of this calculation can be seen in Figure 34.

8.3.3 Sensitivities

8.3.3.1 Tubing and ESP size

At higher transmissivity, considerable friction losses start to limit the flow rates and hence thermal power of the doublet. Increasing the tubing size to 9 5"8 OD (8.7"ID) reduces the friction and makes it also possible and interesting to install larger ESPs. This was already shown for the horizontal wells in Figure 28, and is now also done for the vertical wells (Figure 35). In Figure 36 the impact of larger tubing and ESP is shown on investor COE.

For the RESULT and horizontal wells the Cost of Energy is compared for the various tubing and ESP sizes, see Figure 37 and Figure 38.

Whilst the 9 5/8" / large ESP shows the highest flow rates, from a COP point of view the smaller ESPs are more efficient (see Figure 39). Here a balance will need to be found between economical (highest IRR) and operational (highest COP) parameters.

For the above calculations it was assumed that the bigger hole, tubing and ESP do not come with additional costs. This was done because the impact was checked to be small: as an example for the

28.2 D.m RESULT case, the investor COE is 62 €/MWh. Increasing the CAPEX by 10% (+2.3 M€) to cover for the extra hole size and steel only increases the COE to 66 €/MWh.
In Figure 40 a comparison is made assuming large tubing and large ESP for the base case, RESULT and horizontal completions.

8.3.3.2 Cost overruns

Calculations were repeated for CAPEX and OPEX overruns of 40%. The impact of this on COE is shown in Figure 41 and Figure 42 respectively.

8.3.3.3 Horizontal well low PIF and IIF case

The BP review (10) of horizontal well performance showed that for *L/h* ratios below 20 the merit of horizontal wells was much reduced. A case is run here where the horizontal well of 1 km would not yield a PIF and IIF of 4, but of 1.9, so the same as the RESULT case. This is shown in Figure 43.

8.3.3.4 6000 h/y scenario

A COE calculation for the public entity was run where the installation is operating 6000 h / y, see Figure 44. This is not shown for the investor case since the SDE is limited at 3500 h/y and "split the difference" price cannot be calculated. A summary of the sensitivities for semi-vertical, RESULT and horizontal doublets (including a 2% inflation case) is shown for the public entity COE in Figure 45, Figure 46 and Figure 47 respectively

9 Discussion

The main question of this report is: what is the best technique to economically exploit geothermal reservoirs with limited transmissivity (< 20 D.m). With "best" is meant here: what technique makes it possible for an investor to exploit these marginal reservoirs and still obtain a reasonable Incremental Rate of Return. In summary: ***what injectivity and productivity improvement techniques open up economical geothermal exploitation for hitherto marginal reservoirs, specifically what can be the role for RESULT completions***. Figure 33 presents the answer to the abovementioned question and is the core figure of this report.

9.1 Merit of various techniques

In section 4 the industry experience with various techniques to improve productivity and injectivity was discussed. It was argued that the Radial Jet Drilling has limited use since the practical gains are lower than expected, especially in the long term. In the calculations of section 7.2 and 8.3 it was shown that the PI and II increase of this technique are not "game changing" i.e. not drastically reducing the break-even *kh*. A likely reason for the limited reported merit of RJD is a combination of unconsolidated sand leading to hole collapse, and the impossibility to re-enter the holes. Also, the vertical inflow in this technique may suffer from low vertical permeability.

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The RESULT technique has less drawbacks. Inflow is horizontal and branches are completed, but re-access is again not planned to be possible. One drawback compared with the (Coiled Tubing based) RJD technique is the incremental cost, since expensive rig days will be used to drill the holes. The main competitor of RESULT will be the option to drill a horizontal well. Especially without a pilot hole a horizontal alternative can be rather cheap, and the technique is very mature, moreover re-access and hence targeted re-stimulation is possible. A potential drawback is the vertical permeability, but the Slochteren sand of the type location does not show significant shale breaks in the gamma ray logs of the nearby Langenholte-1 well, which is encouraging. Another drawback is the complexity associated with logging and installation of sand control techniques.

9.2 Preferred technique for permeability classes

It can be observed in Figure 33 that with current uptime, SDE and cost assumptions, it will become difficult for an investor to attain a 6% IRR on a vertical well development when the transmissivity of the reservoir falls below 25 D.m. This study then divides the reservoirs and completions in four classes:

1. ***kh > 25 D.m***. These high quality reservoirs can be economically exploited by vertical or low deviation well bores, and RESULT and horizontal wells do not make these reservoirs significantly more economical. Larger tubing and ESPs may be attractive here.
2. ***14 < kh < 25 D.m***. RJD can somewhat lower this break-even transmissivity, but it is the higher PIF and IIF of RESULT that open up economical exploitation of these reservoirs. For this *kh* class an alternative completion is a dual injector (Figure 32) or horizontal wells.
3. ***8 < kh < 14 D.m.*** With even lower transmissivity, more drastic measures are needed, here studied as horizontal wells of 1 km length having a L/h of 20. These appear to be the sole technique to economically exploit these reservoirs.
4. ***kh < 8 D.m*** here horizontal wells combined with larger tubings and ESPs are potentially the economical solution, but high dissipation leads to rather low COP of around 10.

When running sensitivities such as cost overruns, higher uptime and inflation, the above categorization still holds, albeit with slightly changed ranges. An example of this is shown in Figure 40, where for the base case, RESULT and horizontal completions a comparison is made assuming large tubing and large ESP. The "long term, zero cost of capital" view of a public entity has similar completion preferences as the commercial investor.

The other way to look at this is that of Figure 45, Figure 46 and Figure 47. Here the Cost of Energy (COE) is plotted versus *kh* fo r the vertical wells, RESULT and horizontal wells. All three techniques show a marked upward bend in COE when reducing *kh*. This generally happens when the injector well hits the maximum injection pressure constraint. For wells with high IIF, this happens at lower *kh*.

The actual behaviour is more complex since more constraints are active, but the main picture is determined by this switch from being ESP constraint to THP_i constraint.

What all low *kh* completions have in common is that at some point considerable dissipation is taking place, in the reservoir and/or the tubing. This brings down the Coefficient of Performance to around 10 and will have an impact on operational efficiency. It was assumed here that doublets can generate their own electricity, but when pushing the systems to the maximum, this does not longer hold. As an example, the 4.7 D.m double horizontal well with large ESP and tubing will use 0.94 MW electricity and only generates 0.47 MW. Adding the OPEX for the electricity that will need to be bought to cover this gap (here assumed at 75 €/MWh) was calculated to only add 3% to the COE, justifying the current approach.

Care must be taken that early cold-water breakthrough might happen in case of large flowrates; numerical simulation can help to determine this.

9.3 Implementation of "*kh* class" completion strategy

As discussed in the previous paragraph, the choice of completion will be largely determined by the transmissivity of the reservoir. In practice, for new geothermal plays this will mean that a production and/or injection test needs to be done in the vertical pilot hole, and from this the *kh* class is determined and completion type can be decided quickly using `EBN_REPTool`, `DoubletCalc` or the techno-economic model developed in workpackage 2. The pilot hole can then serve as the conduit to complete the well with RESULT or HOOK sidetracks or for planning the horizontal section. When the geothermal play gets more mature, *kh* determination and subsequent completion decisions can take place by porosity logs, without a well test. ESP choice in all producers of reference (17) was done successfully by only using porosity logs and k-Φ correlations. When even more confidence is obtained in a low *kh* development, it can be decided to drill big bore large ESP horizontal wells by default. Especially for the public entity this can be an attractive option, since it is less sensitive to capital costs.

10 Conclusions and Recommendations

This report presents a study on the best operational and economical method to exploit marginal geothermal reservoirs, where low transmissivity naturally leads to high dissipation combined with low flow rates and heat delivery. What well completion techniques (with focus on RESULT ECI multilaterals) can be used to reduce the "break-even" transmissivity *kh*? With the latter a minimum reservoir transmissivity is meant where an investor can get a reasonable rate of return on the investment (IRR), when asking the client (the utility operating the heat grid) half the maximum heat price as determined by the regulator, and also taking SDE subsidies.

Calculations are done for a type curve location in the Netherlands, using a spreadsheet (“`EBN_REPTool`“) that mimics the physical results of `DoubletCalc`. This approach was chosen since it allows to honor all doublet constraints and calculate the IRR of the project. From the study the following is ***concluded***:

- The spreadsheet shows results that are consistent with `PROSPER` and `DoubletCalc` calibration. The latter has an element of triviality since many of the physical parameters (viscosity, density, tubing friction) are based on `DoubletCalc`.
- The spreadsheet offers a user-friendly, simple and verifiable way to determine the constraints of the system and the Cost of Energy (COE). Sensitivities are easy to run and a full COE versus transmissivity calculation takes approximately 15 minutes.
- The models of the doublets and triplets in this document are either constraint on ESP operating envelope (for high *kh*) or maximum Tubing Head Pressure (THP_i) of the injector. The first can be remediated by increasing the Productivity Index, since then the ESP needs to lift at lower ΔP. The latter is remediated by increasing the Injector's Injectivity Index. Both constraints are somewhat removed by reducing tubing friction, though when the system is already THP_i constraint at low rates and hence low friction, this does not help a lot. This complex interplay of constraints is all captured in the spreadsheet.
- Productivity and Injectivity improvement factors (PIF and IIF) for the horizontal wells were derived using `PROSPER` and literature correlations. `PROSPER` does not properly model the pressure and temperature interference of sidetracks (RJD and RESULT) and for this, `OPM flow` was used in thermal mode.
- Investor-view COE calculations show a break even *kh* of around 25 D.m for vertical wells. Below this transmissivity, it becomes more difficult to reach an IRR of 6%. This of course depends on uptime, costs and SDE subsidy levels.
- For lower transmissivities, the well PI and/or II need to be further increased to allow economic exploitation. The following categories and completions are proposed (see Figure 33):
    - ***kh* > 25 D.m**. These high quality reservoirs can be economically exploited by vertical or low deviation well bores.
    - ***14 < kh < 25 D.m***. Radial Jet Drilling can somewhat lower the break-even transmissivity, but it is the higher PIF and IIF of RESULT that open up economical exploitation of these reservoirs. For this *kh* class an alternative completion is a dual injector or horizontal wells.
    - ***8 < kh < 14 D.m.*** With even lower transmissivity, more drastic measures are needed, here studied as horizontal wells of 1 km length and a L/h of 20.

  - ***kh* < 8 D.m** here horizontal wells as described above, combined with bigger tubings and ESPs can be an economical solution, at the cost of lower Coefficient of Performance.
- In the sensitivities it was shown that the above categorization is relatively robust: with larger tubing, costs overruns and higher uptime the same categories can be identified with the same completion preferences.
- Of special interest to a public entity is the rather flat COE curve for the RESULT and horizontal completions down to *kh* of 15 D.m and 10 D.m respectively, see Figure 46 and Figure 47. These techniques can hence be considered as “insurance policies” against disappointing transmissivities.
- Note that whilst RESULT may open up the second reservoir category it will always be in competition with a horizontal development: in Figure 33 it can be seen at e.g. 20 D.m that the vertical completion will not be attractive, but RESULT and the horizontal wells are equally attractive: the higher well cost, PIF and IIF of the horizontals roughly cancel out.
- The non-standard completions of RESULT lead to some concerns for operations and abandonment, notably:
  - Cleaning the previous wellbores after drilling of a new wellbore
  - clean-up and later access / re-stimulation of wellbores during field life
  - use of aluminium in a corrosive environment.
  - potential un-cemented cap rock potentially leading to debris falling into the well bores.
  - Impact of the above points on abandonment

  In the RESULT calculations of this report a PIF and IIF of 1.9 are taken, from reservoir simulation, and it is hence assumed that the above completion problems can be resolved. This assumption needs to be reviewed after the RESULT pilot.

The following is ***recommended***:

- The (a) presence of an aluminium completion, (b) potential absence of cemented casing over the reservoir legs including cap rock, and (c) planned use of swellable elastomers makes abandonment a non-trivial affair. Discussions about potential abandonment dispensations should be held with SodM prior to construction to avoid what could become a cumbersome abandonment operation.
- The potential operational and abandonment concerns are advised to be addressed as part of the RESULT technology development and should then be translated into a risked PIF and IIF. These concerns will be addressed in the concept design phase.

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- The PIF and IIF of RESULT needs to be further verified by reservoir simulation, beyond the quick look approach of Appendix E. This is already part of the RESULT project. Once new values have become available, these should be used in the `EBN_REPTool` spreadsheet for verification of the conclusions of this report.
- For RESULT, geo-mechanical work is advised to verify the uncemented production and injection of the clastic reservoir and cap rock.
- Both theoretical analysis and field experience show that the vertical permeability is an important parameter for the merit of horizontal wells. Further work is recommended to quantify this for the target location. This should be based on available Slochteren core data and best estimates for the areal extent of shale layers.
- The sensitivities described in this report are based type location assumptions (see chapter 3); and it is recommended to run sensitivies on the range of geological uncertainties too (e.g. absolute permeability, thickness, etc). It must also be highlighted that the conclusions in this report are only a correct reflection of the assumptions made in this report; it is recommended to run further sensitivities on geological parameters in case the methodology or results of this study are applied to other geographical regions.
- Many further sensitivities can be done with `EBN_REPTool`, e.g.:
    - Low, Mid and High scenarios for the various well completions
    - Dependence of results on cost assumptions and subsidy levels
    - Merit of HOOK completions and shorter horizontal wells
    - Calculation of correct high electricity consumption at low *kh*.

To guarantee "ownership" of the calculation spreadsheet, it is preferred that EBN at least partially runs the above sensitivities, with help from Tanak Engineering.

11 References

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12 Tables

Table 1: Zwolle type location assumptions

			Comment
Tsurf	(C)	10	IF Technology, Herberekening vermogen Zwolle-Noord, 18 december 2019
Tgrad	(K/km)	34	
Salinity	(kppm)	254	IF Technology, Herberekening vermogen Zwolle-Noord, 18 december 2019
Top sand	(mtvdss)	2308	
Bot sand	(mtvdss)	2358	
Mid Depth	(m tvdss)	2333	IF Technology, Herberekening vermogen Zwolle-Noord, 18 december 2019
Tres	(C)	89	
Ti	(C)	49	
Thickness	(m)	50	IF Technology, Herberekening vermogen Zwolle-Noord, 18 december 2019
Net to gross		0.94	
Permeability	(mD)	134	
μ_p	(cP)	0.61	From DoubletCalc using above inputs
μ_i	(cP)	1.1	From DoubletCalc using above inputs
ρ_p	(kg/m3)	1159	From DoubletCalc using above inputs
ρ_i	(kg/m3)	1185	From DoubletCalc using above inputs
Average aqf density	(kg/m3)	1085	From DoubletCalc using above inputs
Heat cap.	(J / (kg K))	3201	From DoubletCalc using above inputs
GWR	(m3/m3)	0.54	Average value for NL geothermal doublets
Heating value gas	(MJ/(m3))	30.6	From KKP
Efficiency el. power plant		0.4	
Pres at top res	(bar)	246	From DoubletCalc using above inputs
Density at Tres	(kg/m3)	1163	From DoubletCalc using above inputs
Wellbore radius	(m)	0.076	6 inch screen
Well distance	(m)	1000	

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Table 2: DoubletCalc well inputs for base case calculation.

Producer				
outer diameter producer (inch)			6	
skin producer (-)			0	
penetration angle producer (deg)			26	
skin due to penetration angle p (-)			-0.16	
Segment	pipe segment sections p (m AH)	pipe segment depth p (m TVD)	pipe inner diameter p (inch)	pipe roughness p (milli-inch)
1	1300	1300	6.3	1
2	2425	2308	6.3	1
3				
4				

Injector				
outer diameter injector (inch)			6	
skin injector (-)			0	
penetration angle injector (deg)			26	
skin due to penetration angle i (-)			-0.16	
Segment	pipe segment sections i (m AH)	pipe segment depth i (m TVD)	pipe inner diameter i (inch)	pipe roughness i (milli-inch)
1	1300	1300	6.3	1
2	2425	2308	6.3	1
3				
4				

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Table 3: incremental cost of completions. Drilling time of RESULT and Radial based on assumptions. Speadrate CTU is assumed to be 25.000 euro per day. See main body text for other references.

	Drilling Time (d)	Completion time (d)	Cost (M€)
Baker HOOK 300 m	4	4	1.25
Horizontal well 500 m	3.6	4	1.20
Horizontal well 1000 m	7.3	4	1.76
RESULT 2 branch	3	1	0.63
RESULT 4 branch	5	2	1.10
Radial jet 4 branch	6	--	0.15

Table 4: IIF for horizontal wells of varying length. The average value is used from Joshi, PROSPER and TNO correlations.

L	IIF		
(m)	Low	Mid	High
300	0.8	1.7	2.2
500	1.2	2.5	3.0
1000	2.2	4.0	4.8

Table 5: Injectivity Improvement Factor of RJD (“Horizontal”) and RESULT (“Deviated”) techniques, from `OPM flow` thermal simulations.

					After 5y injection	
Run	# extra branches	Type	Length (mah)	Angle (deg)	II (m3/(h bar))	II/II_{base}
EBN_BASE	0	Base	n/a		1.6	n/a
1_66FT	1	Horizontal	20	90	1.8	1.13
2A_66FT	2	Horizontal	20	90	2.0	1.24
4_66FT	4	Horizontal	20	90	2.2	1.4
8_66FT	8	Horizontal	20	90	2.7	1.7
2_120FT	2	Horizontal	37	90	2.1	1.4
4_120FT	4	Horizontal	37	90	2.5	1.6
2_WS1	2	Deviated	51	23	2.7	1.7
4_WS1	4	Deviated	51	23	3.2	2.0
2_WS2	2	Deviated	62	40	3.1	1.9
4_WS2	4	Deviated	62	40	3.9	2.4
2_WS3	2	Deviated	76	52	3.5	2.1
4_WS3	4	Deviated	76	52	4.8	2.9

Table 6: example of choke pressures for triplet case.

Ni=2; 7"; Booster					
kh (D.m)	Max Pth (MW)	Qp (m3/h)	ESP Δp (bar)	Booster Δp or choke (bar)	Constrained by
4.7	6.6	168.5	125	9	ESP
6.3	7.5	189.2	112	3	ESP
7.1	7.9	198.4	108	1	ESP
9.4	8.8	219.9	98	-4	ESP
14.1	9.9	247.0	86	-10	ESP
18.8	10.8	267.3	80	-14	ESP
28.2	11.7	290.4	73	-17.5	ESP
37.6	12.5	307.8	70	-20	ESP
56.4	13.1	323.3	66	-22	ESP

13 Figures

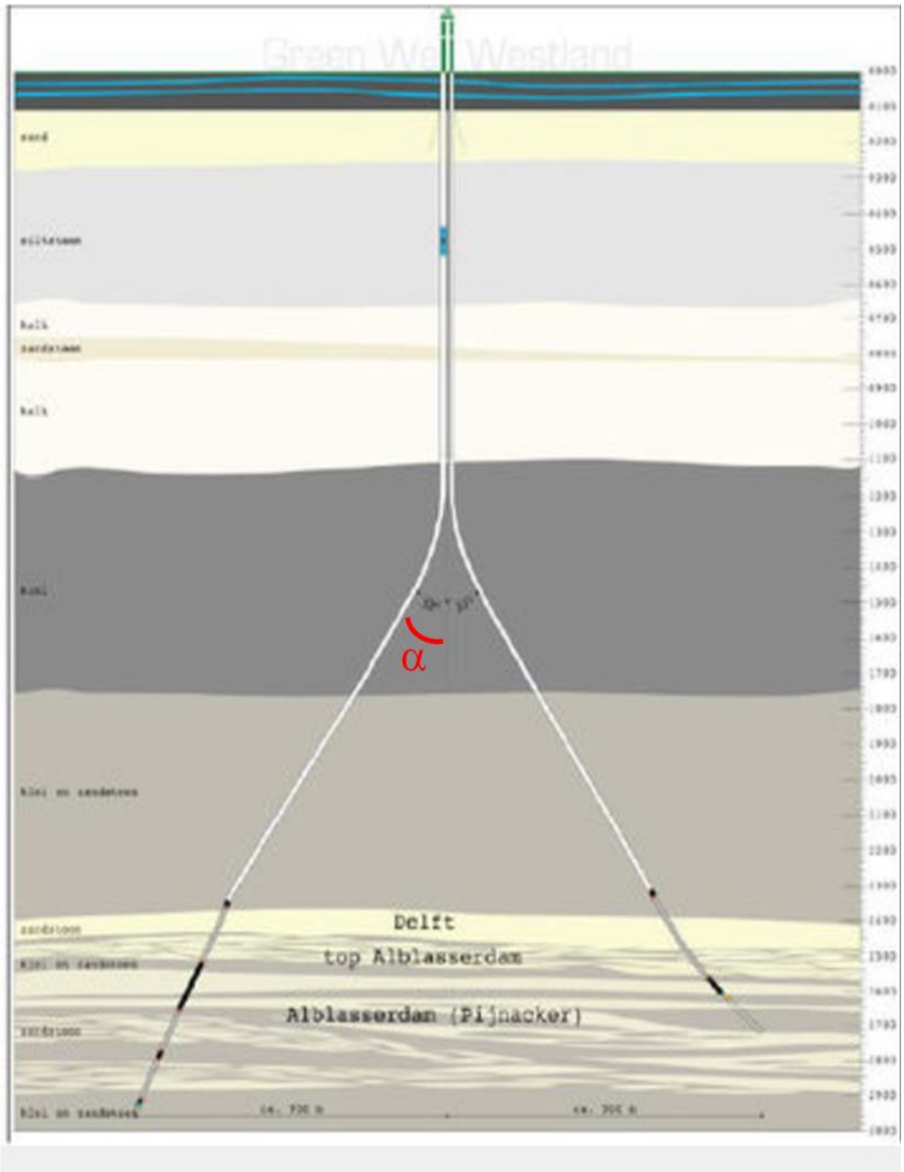

Figure 1: typical doublet well trajectories. Honselersdijk example.

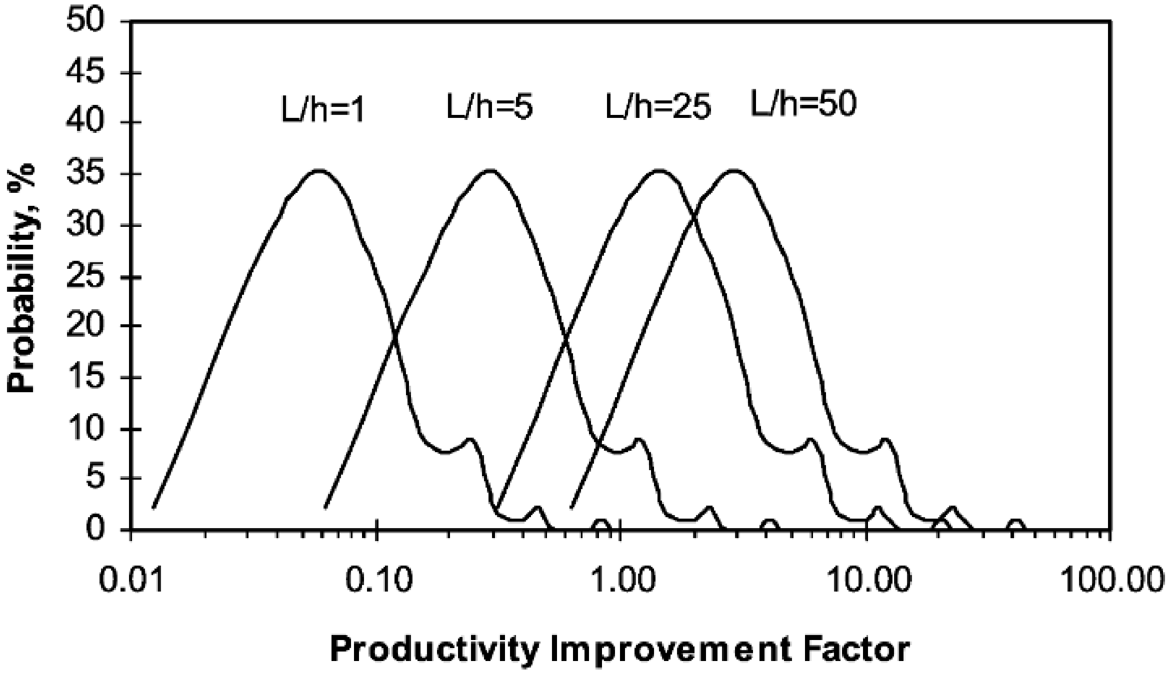

Figure 2: distribution of horizontal well PIF for various horizontal well length / reservoir height classes. Based on 93 BP wells (8).

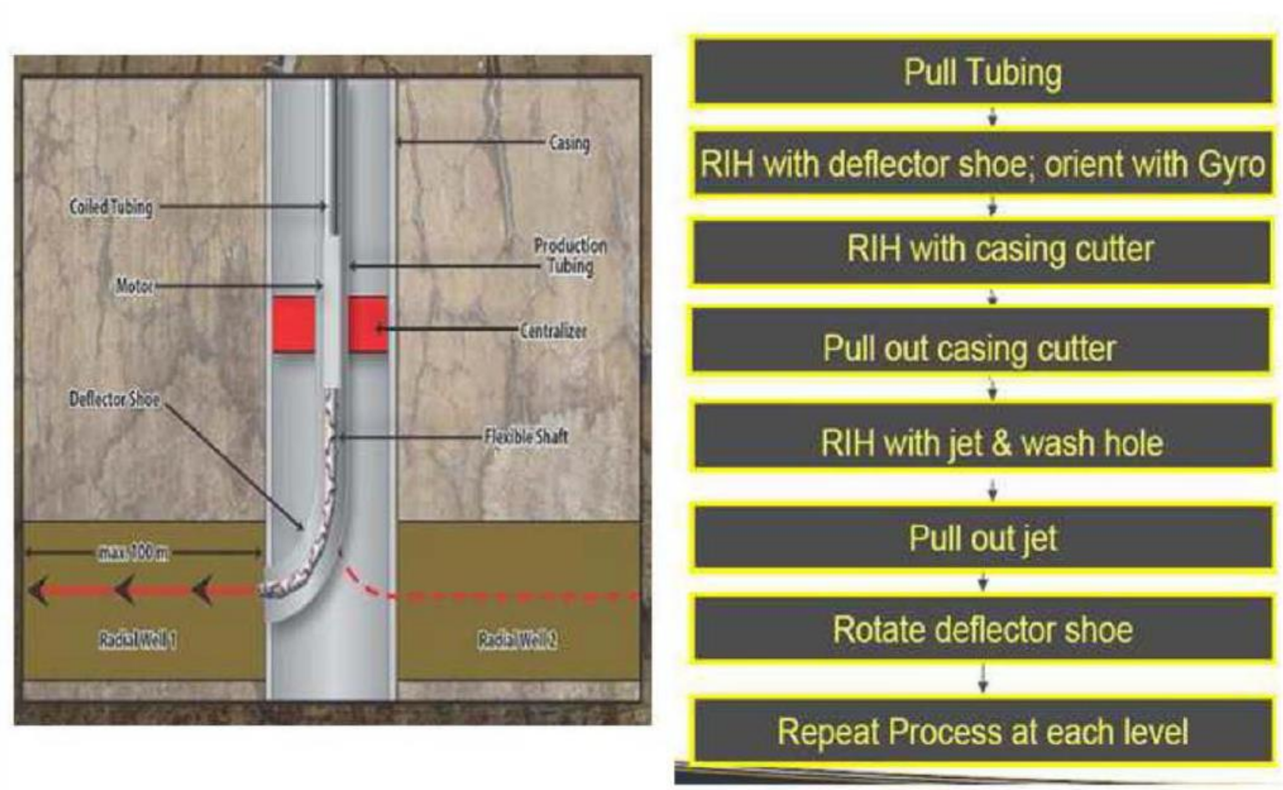

Figure 3: overview of RJD technology (from radjet.com).

Figure 4: Schematic multilateral well completion as proposed in the RESULT project

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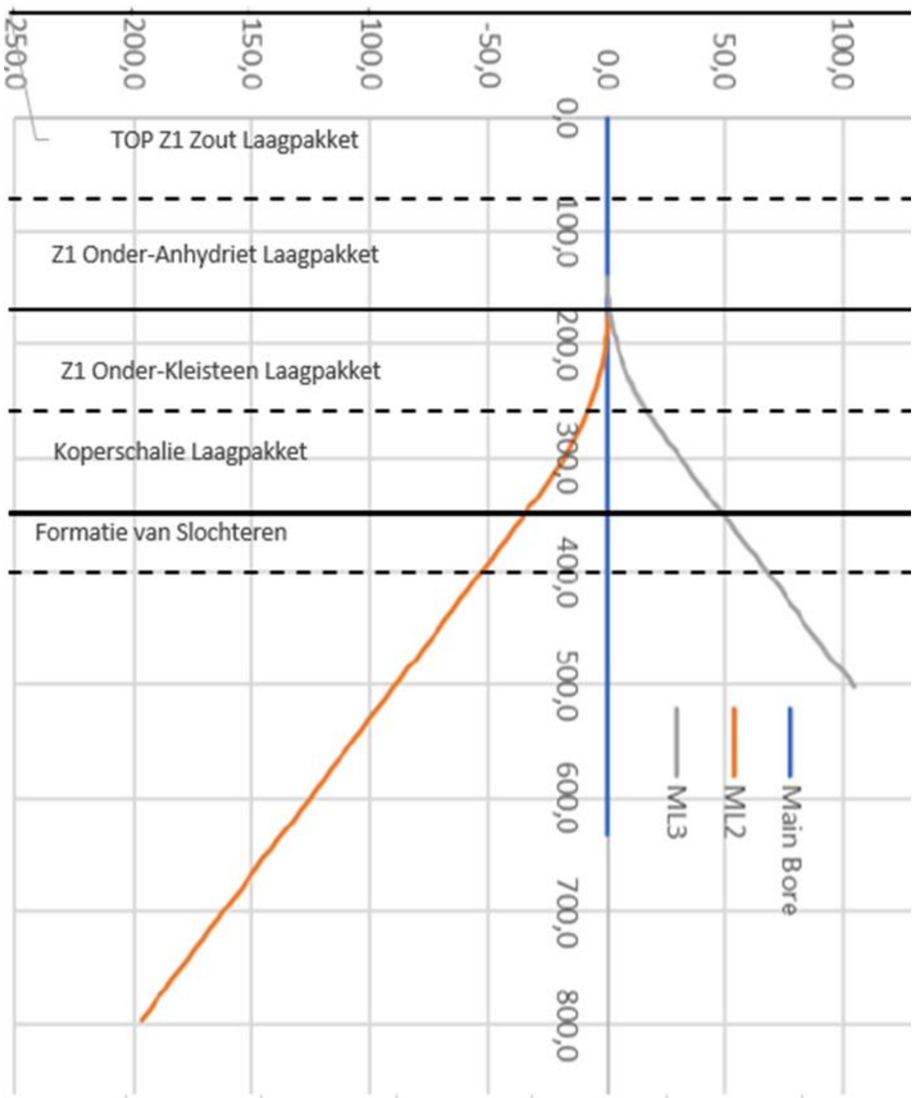

Figure 5: realistic RESULT trajectories, placed such that the RESULT branch distances in the Slochteren formation are around 50m; with Langenholte-1 geology. Note: vertical scale is relative to arbitrary point; not along hole depth

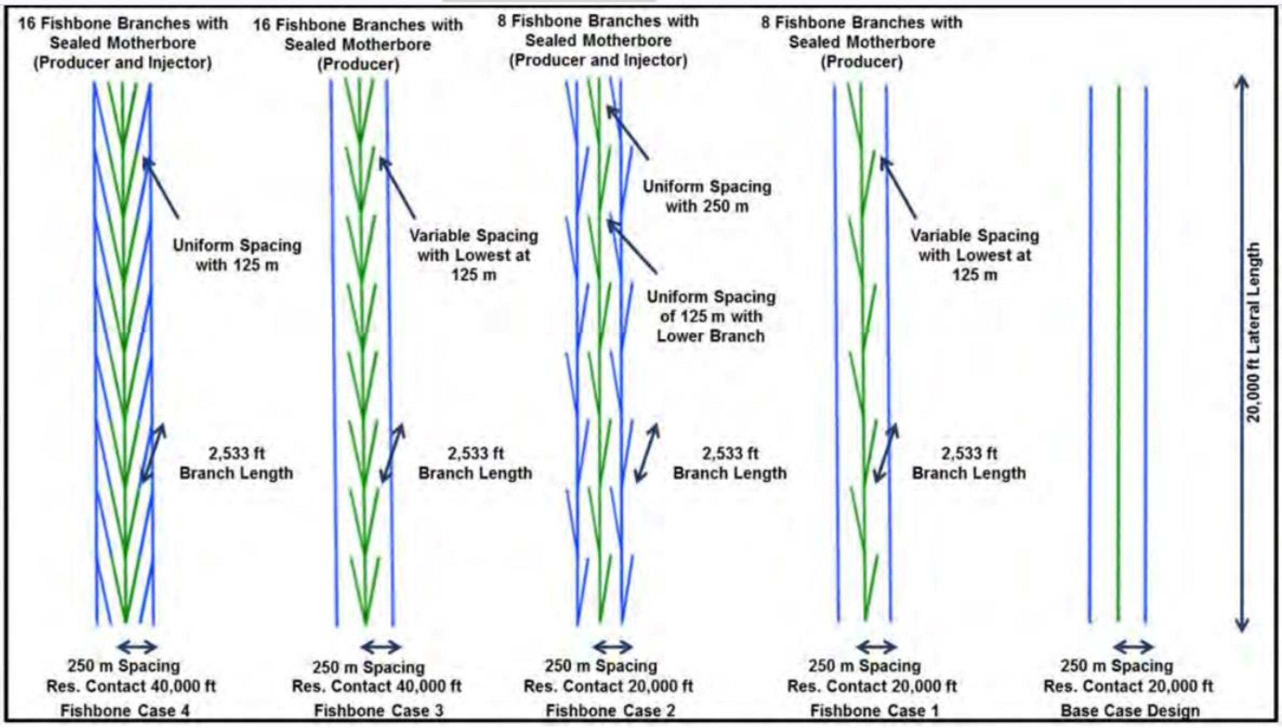

Figure 6: examples of fishbone wells. From (19).

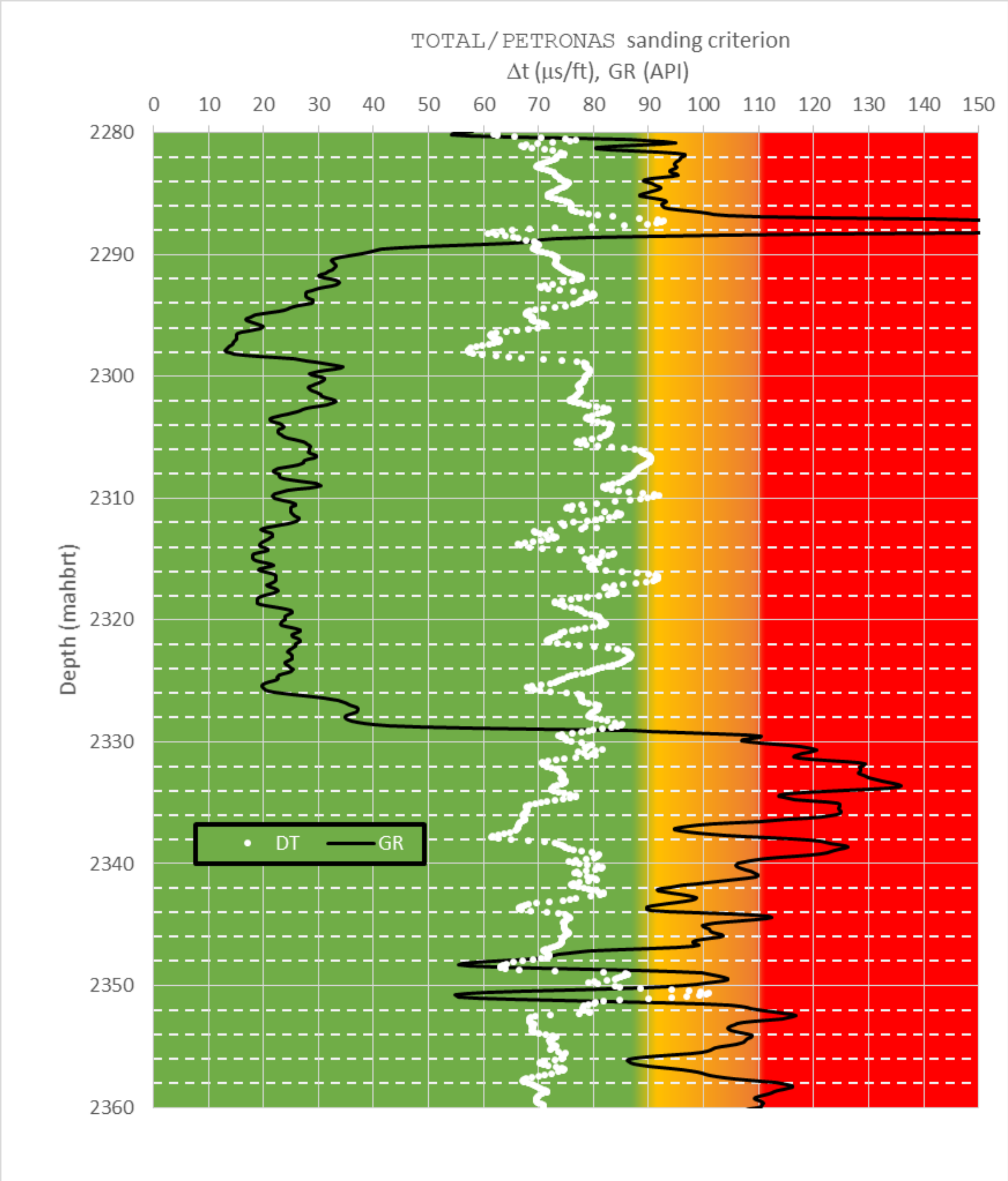

Figure 7: gamma ray (black) and Sonic Δt (white) for the LNH-1 well. In the reservoir sand (2290 – 2329 mah) the low sonic Δt indicates consolidated sand.

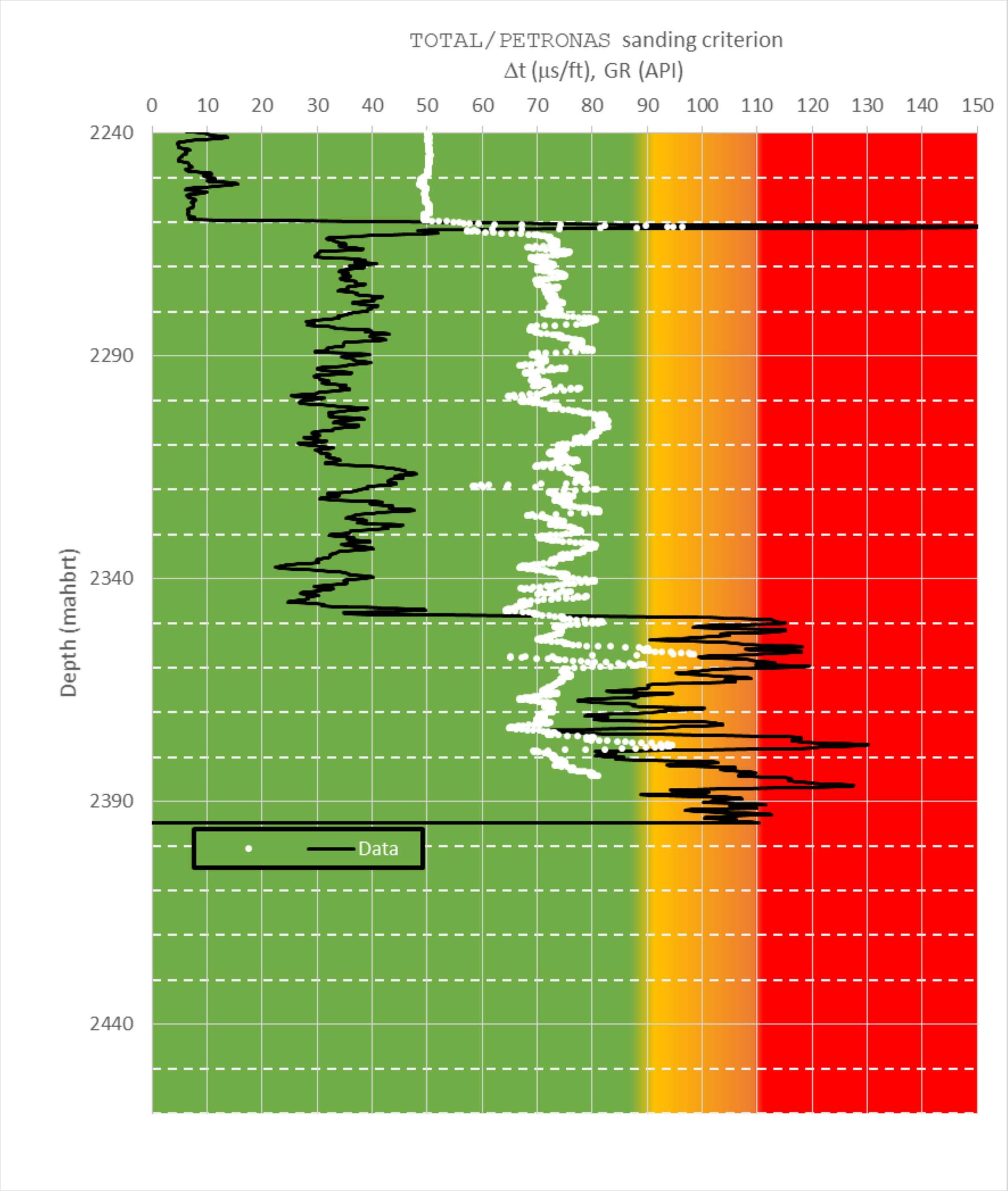

Figure 8: gamma ray (black) and Sonic Δt (white) for the IJD-01 well. In the reservoir sand (2260 – 2348 mah) the low sonic Δt indicates consolidated sand.

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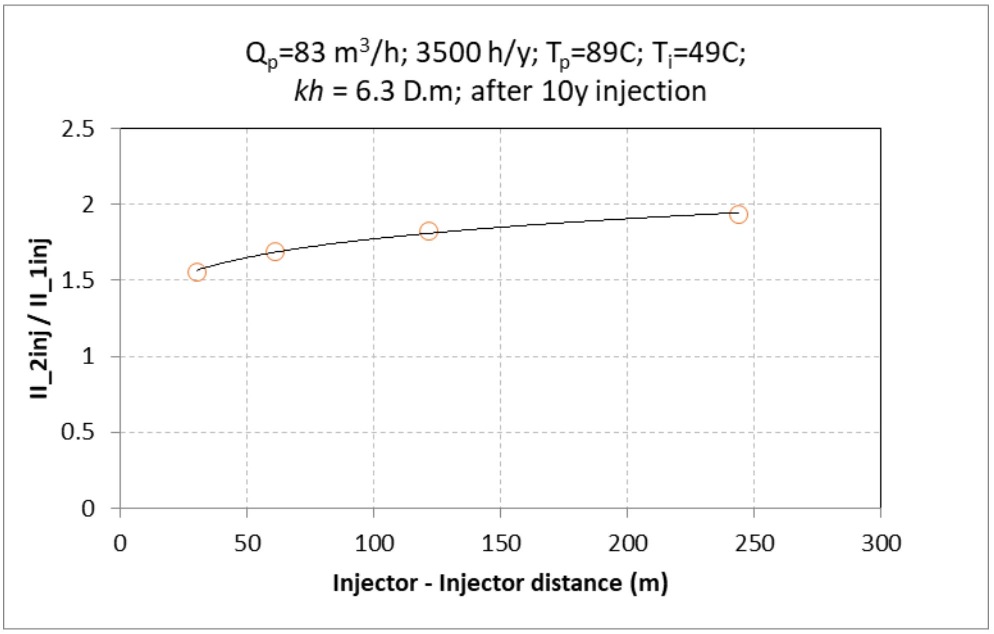

Figure 9: calculation of interference between injectors. `OPM flow` thermal simulation for Zwolle geology.

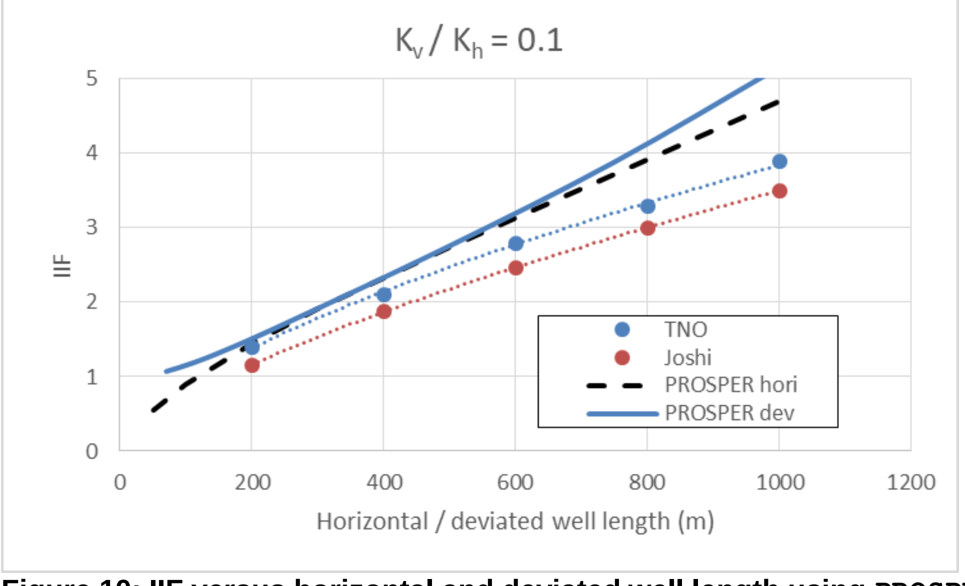

Figure 10: IIF versus horizontal and deviated well length using `PROSPER`, TNO (25) and Joshi (3) correlations.

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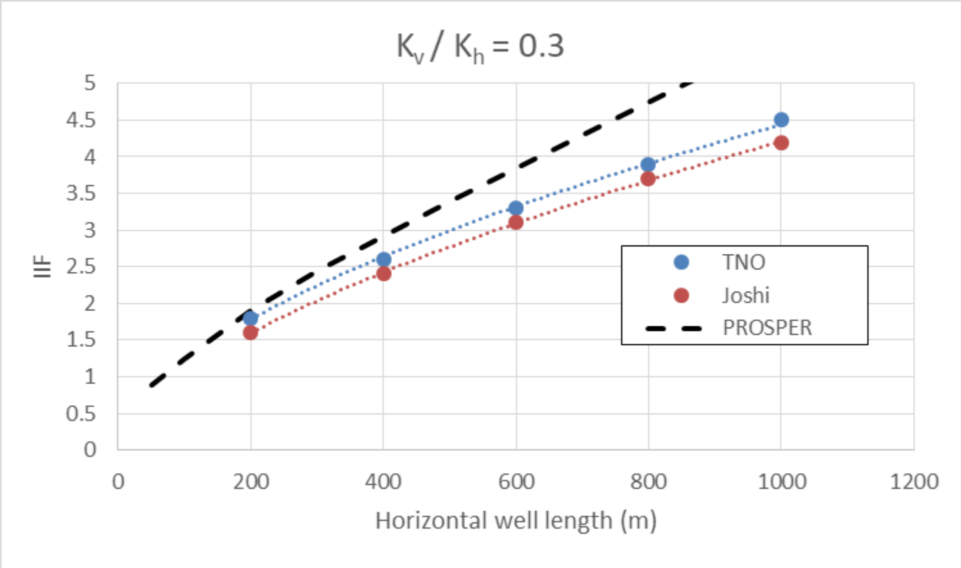

Figure 11: IIF versus horizontal well length using PROSPER, TNO (6) and Joshi (3) correlations.

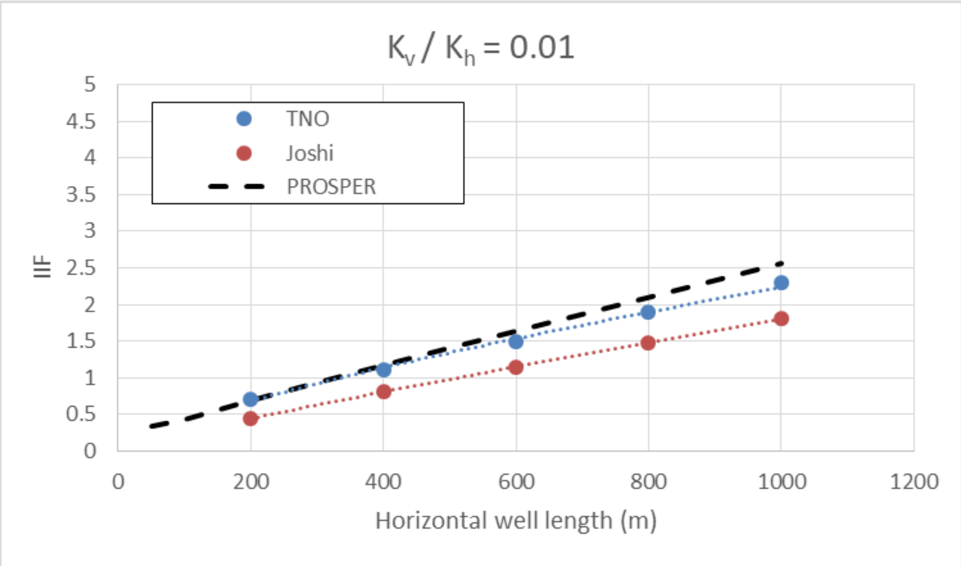

Figure 12: IIF versus horizontal well length using PROSPER, TNO (6) and Joshi (3) correlations.

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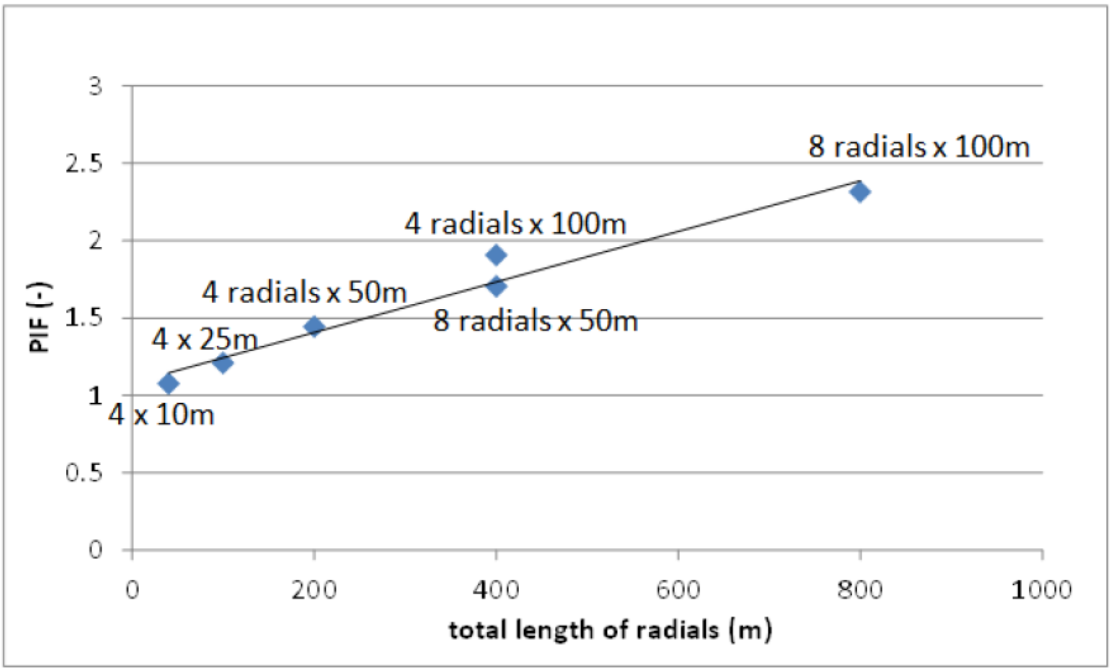

Figure 13: TNO calculation for PIF merit of RJD sidetracks. Reproduced from (28).

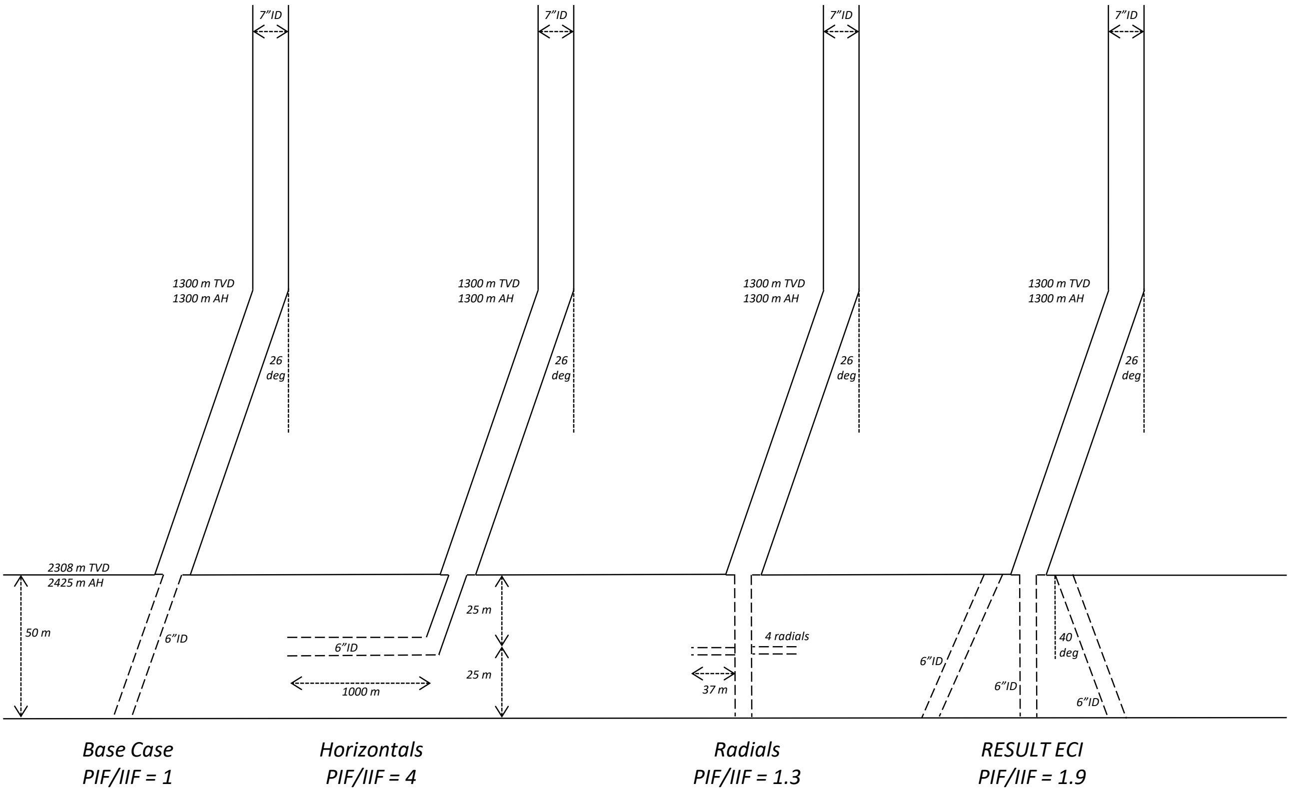

Figure 14. Well diagrams showing the modelling approach of the various completions.

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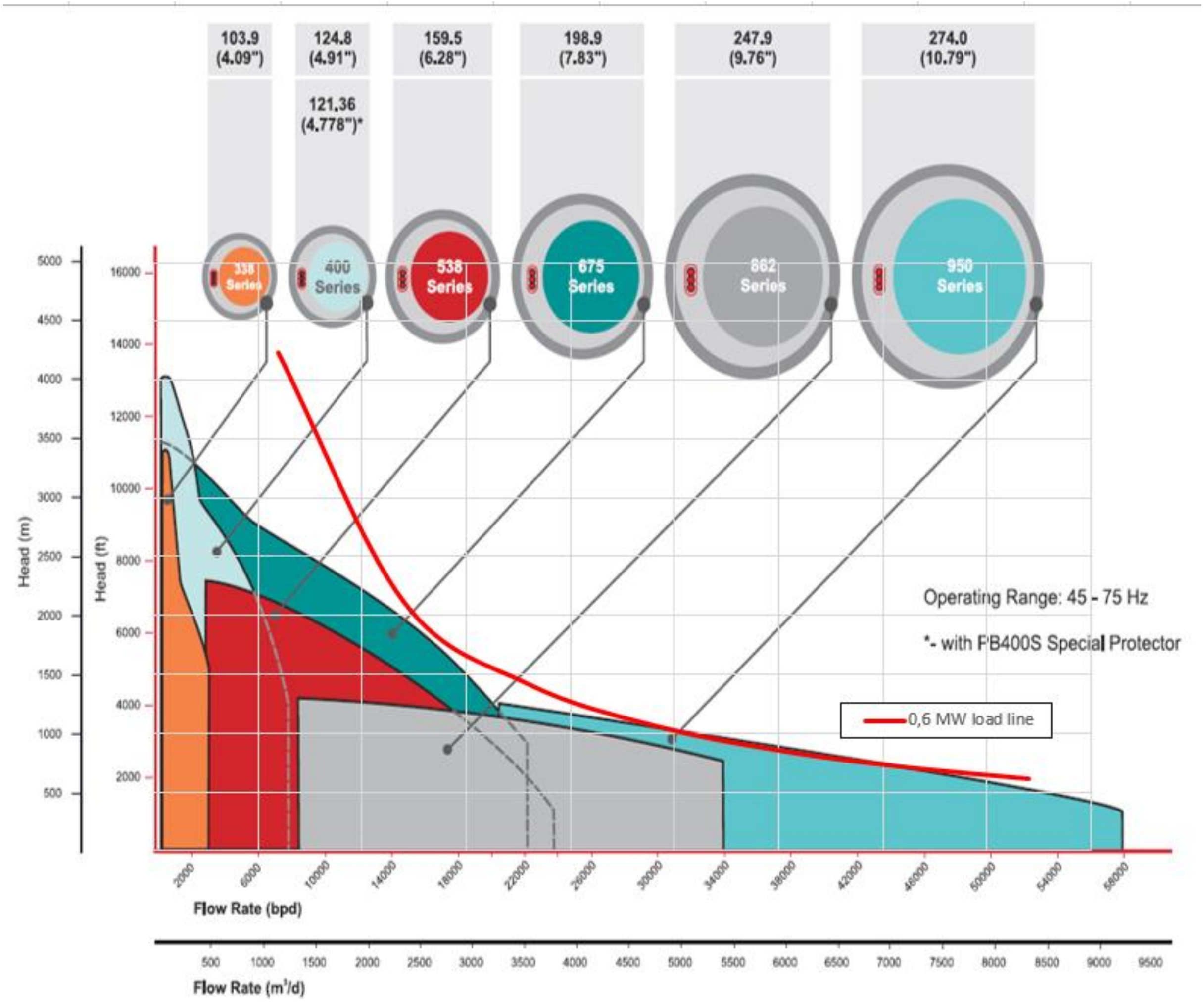

Figure 15: BORETS ESP Operating Envelope (head versus flow rate) and 0.6 MW gross power approximation (red line)

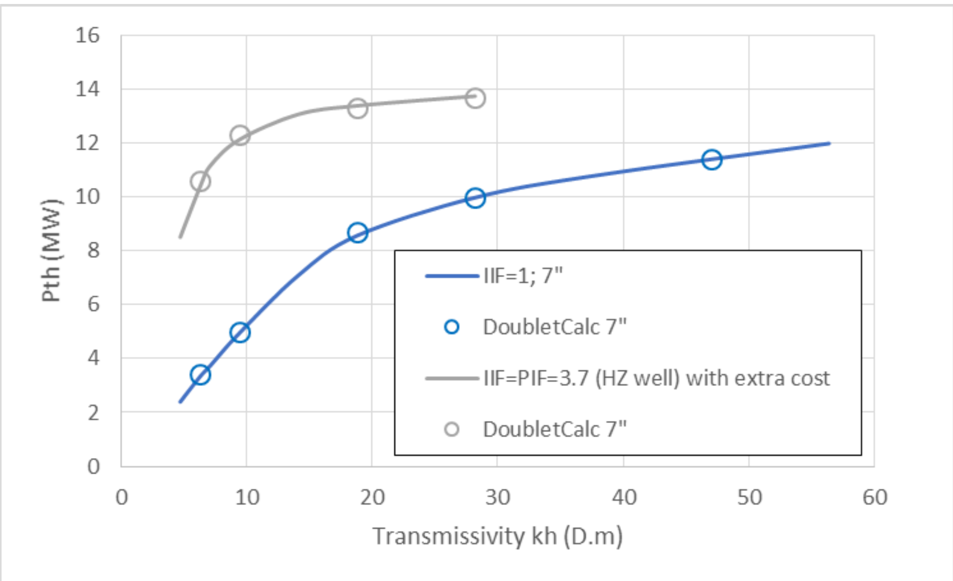

Figure 16: comparison of thermal power of `DoubletCalc` (dots) and `EBN_REPTool` (line). Blue: base case PIF=IIF=1. Grey: horizontal well PIF=IIF=3.7 (`DoubletCalc` skin -6.9)

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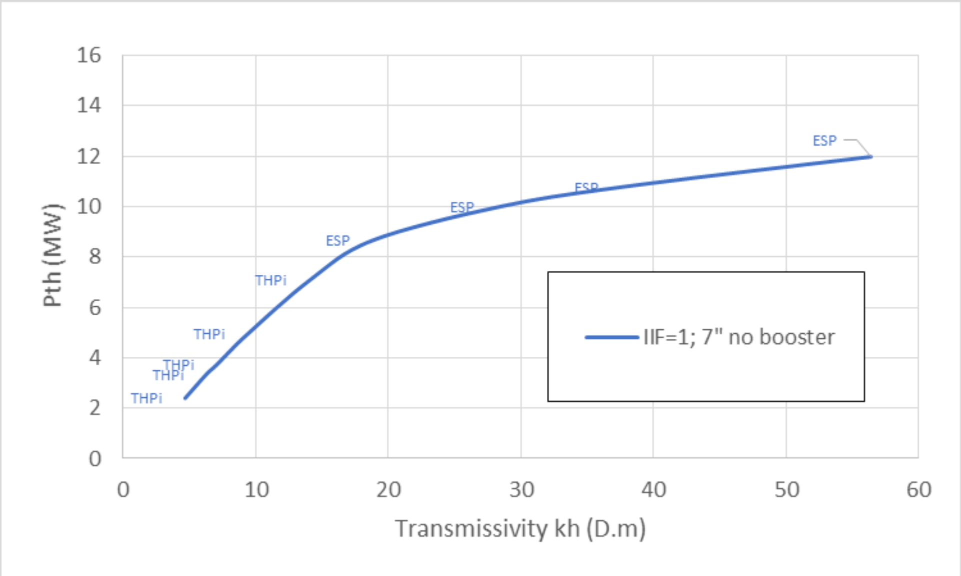

Figure 17: Thermal power versus transmissivity. Case without booster pump.

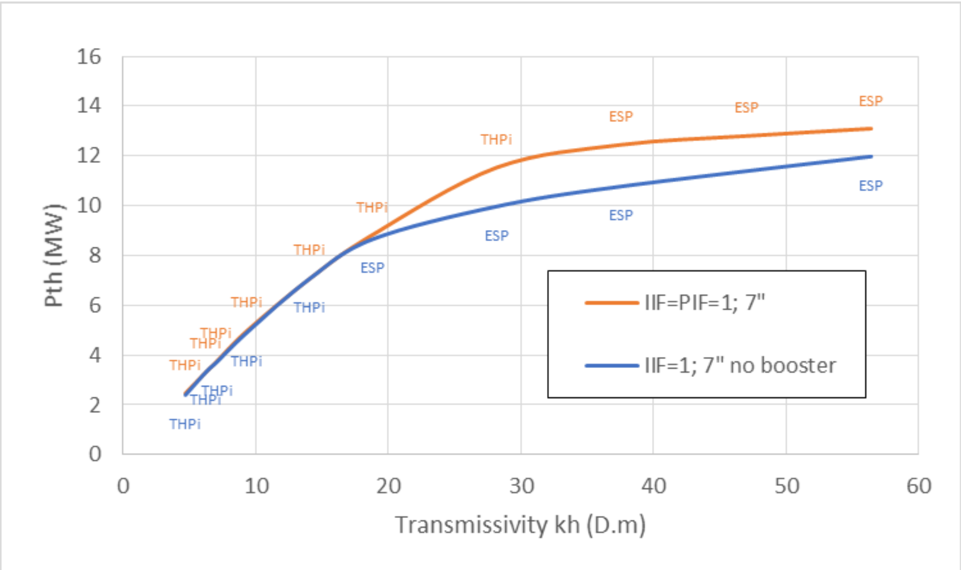

Figure 18: Thermal power P_{th} versus transmissivity. With and without booster pump.

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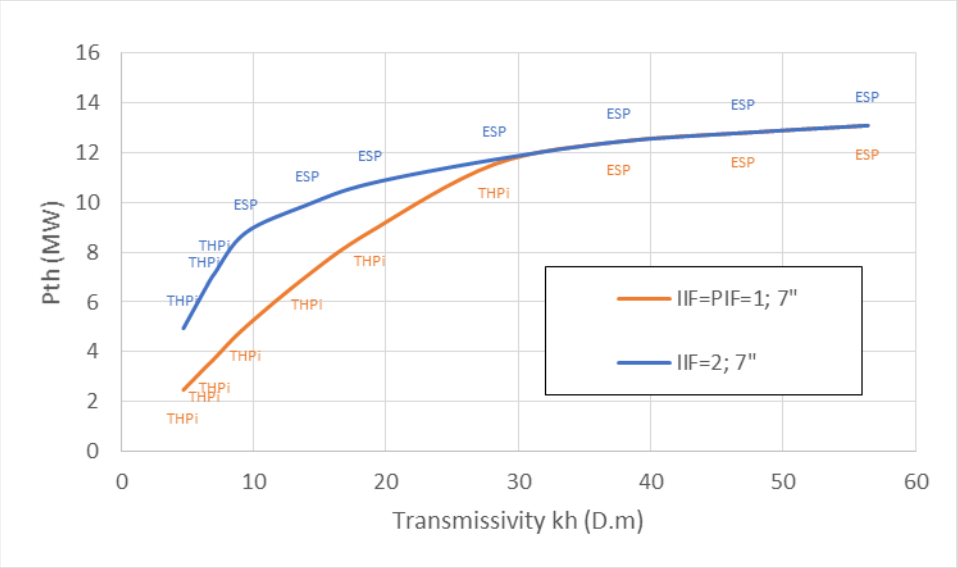

Figure 19: impact on doublet P_{th} of IIF=2

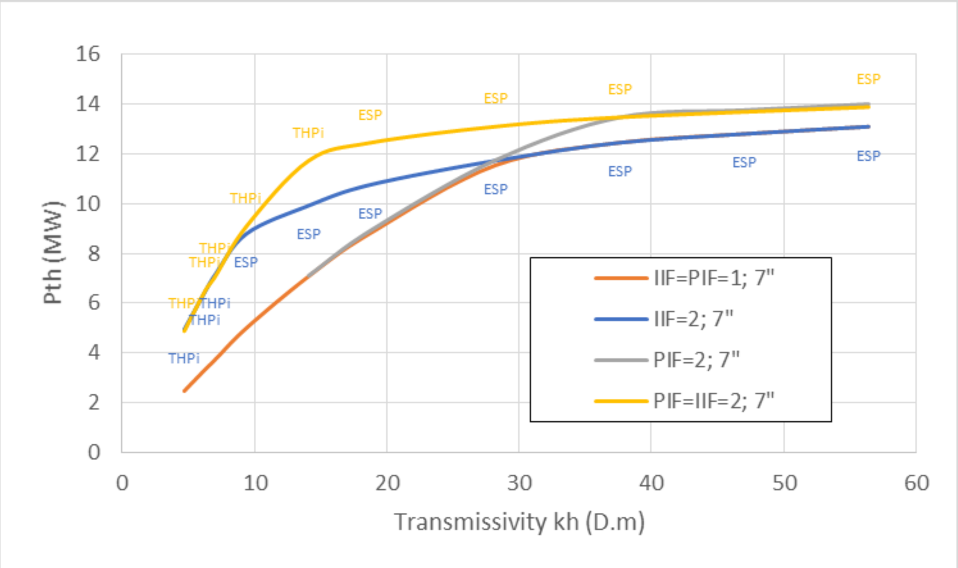

Figure 20: impact on doublet P_{th} of PIF=2, IIF=2

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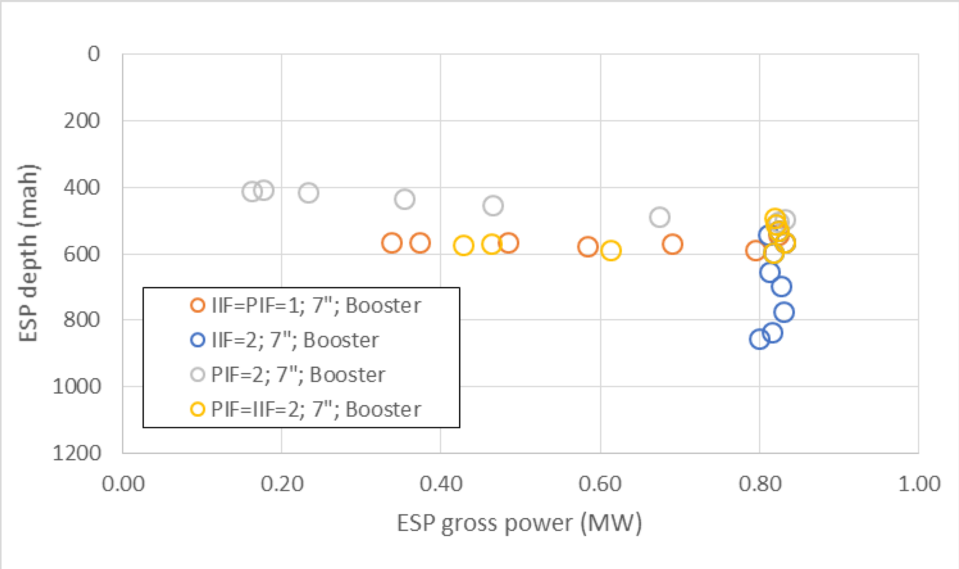

Figure 21: Impact of IIF=2 and PIF=2 on ESP gross power consumption and depth. Highest cases (ESP power ~0.83 MW) are ESP constraint.

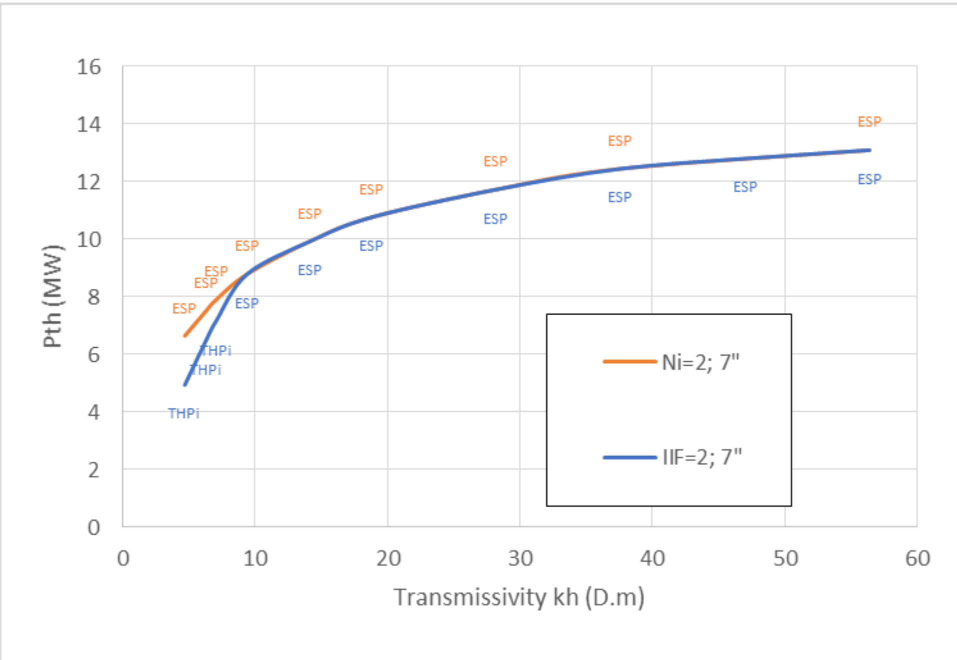

Figure 22: Comparison between IIF=2 and N_i=2.

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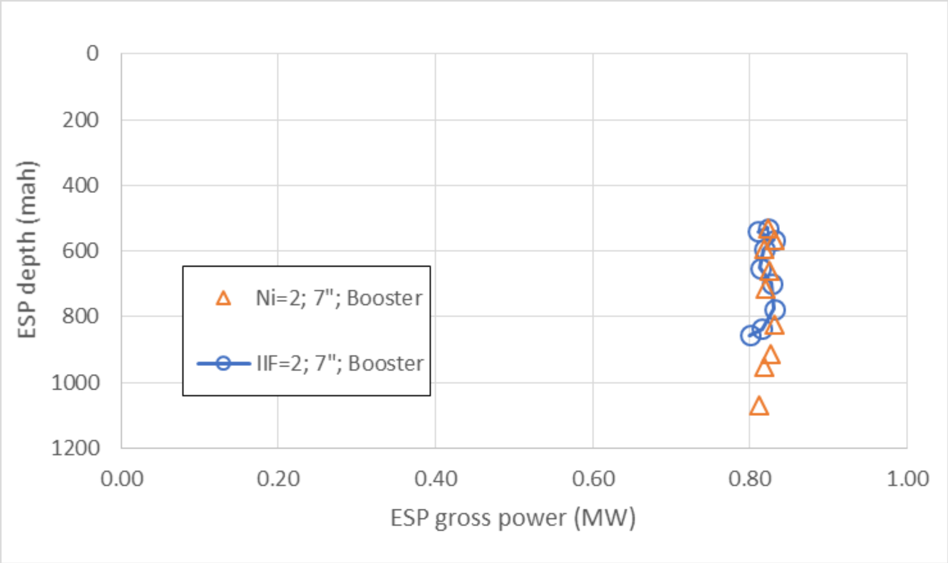

Figure 23: Impact of IIF=2 and N$_i$=2 on ESP gross power consumption and depth.

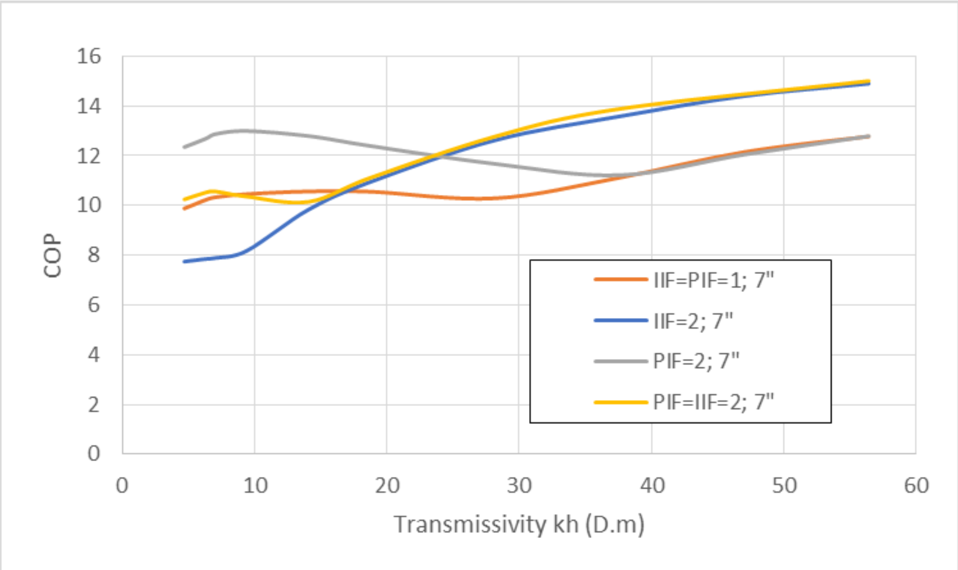

Figure 24: impact of IIF and PIF improvements on doublet COP.

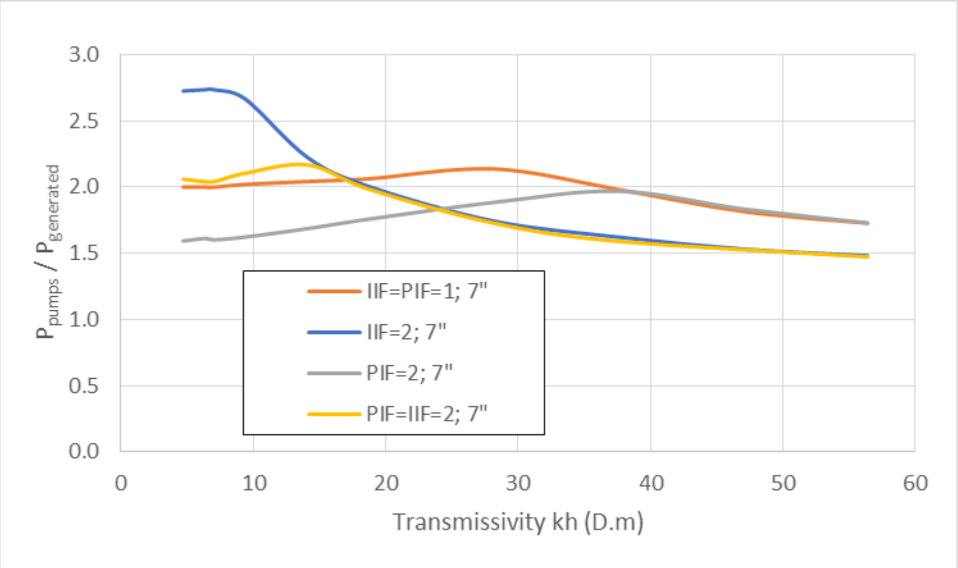

Figure 25: electricity consumption / generated electricity from the associated gas.

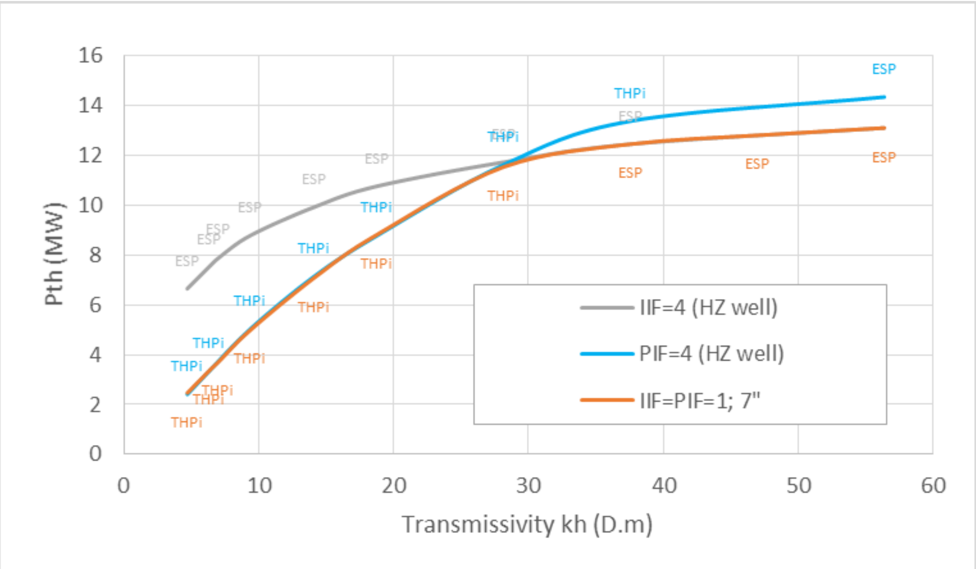

Figure 26: Doublet thermal power versus transmissivity for vertical and horizontal producer and horizontal injector.

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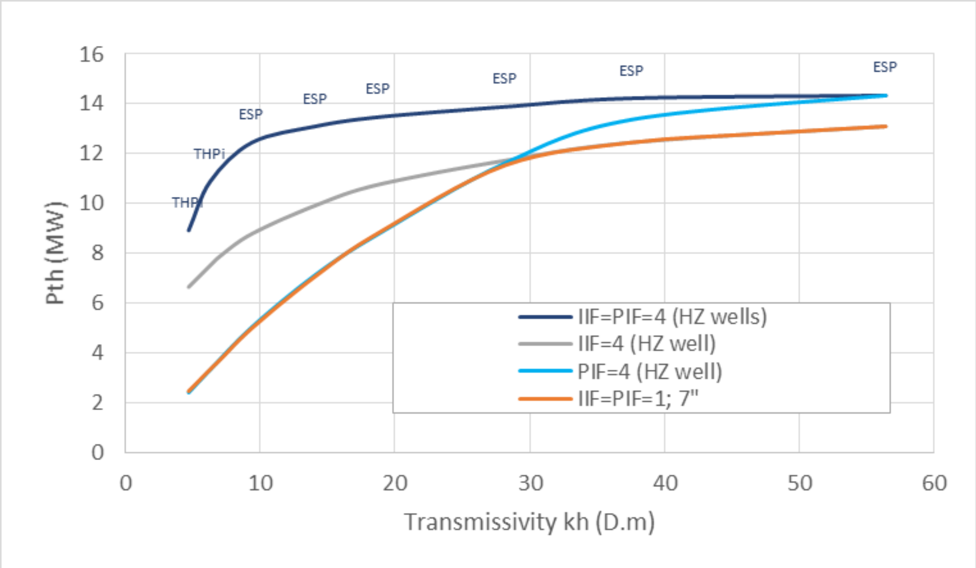

Figure 27: Doublet thermal power versus transmissivity for vertical, horizontal producer, horizontal injector and horizontal producer and injector

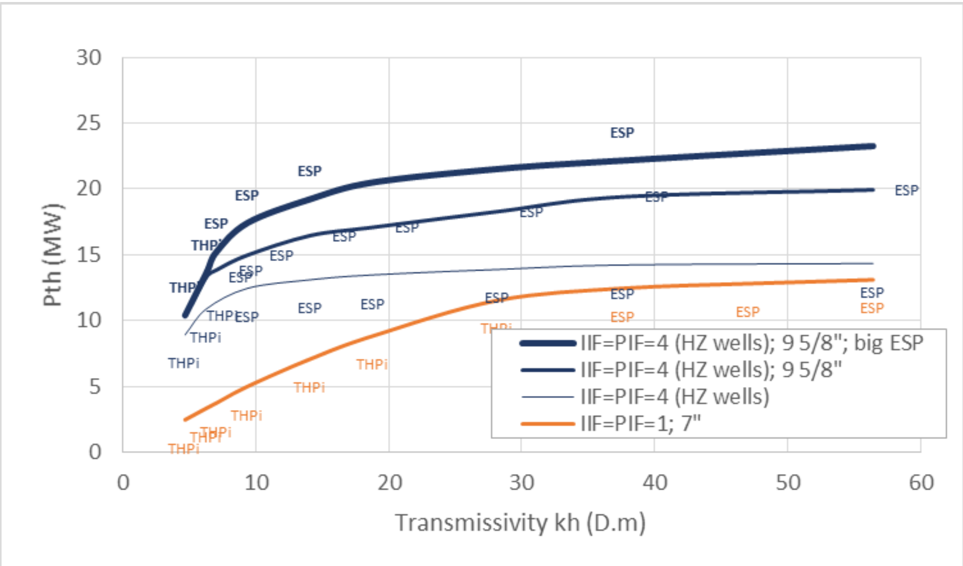

Figure 28: Doublet thermal power versus transmissivity for vertical and horizontal wells.

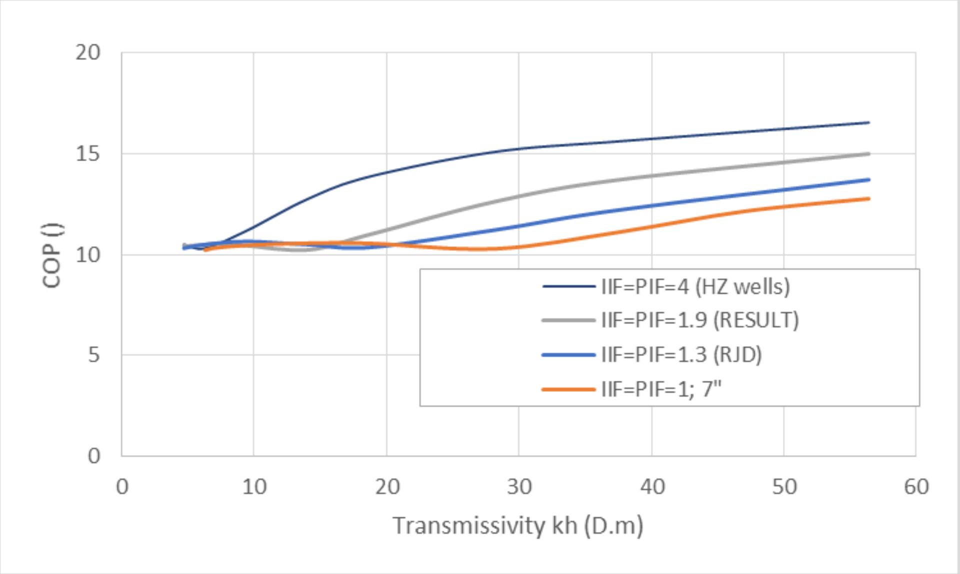

Figure 29: COP of various completions

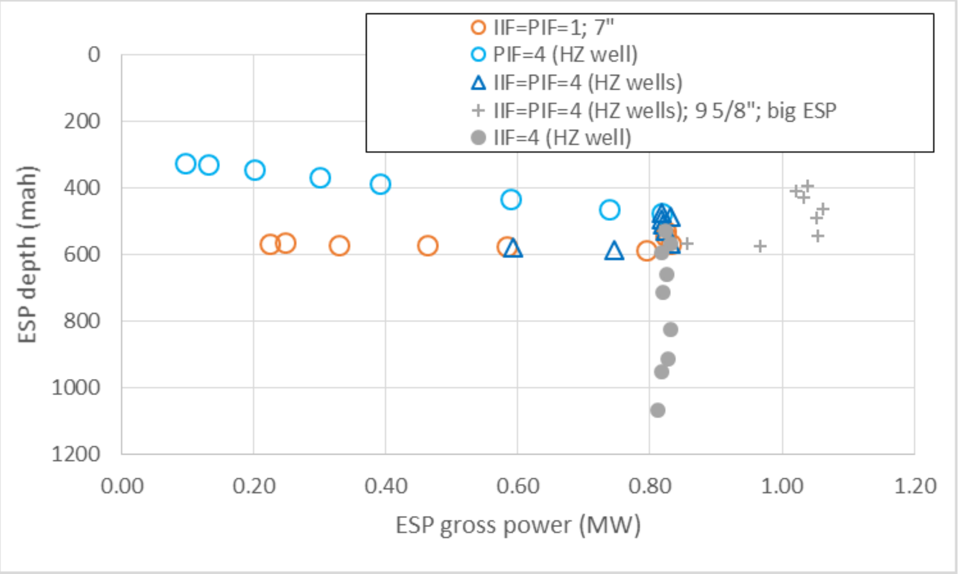

Figure 30: ESP gross power and depth for vertical and horizontal well cases

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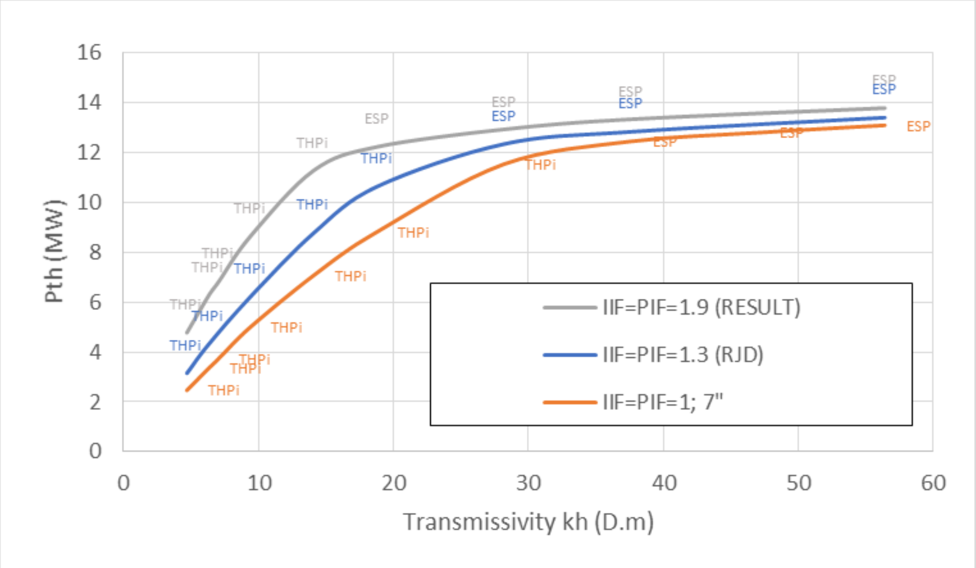

Figure 31: Thermal power increase of RJD and RESULT sidetracks.

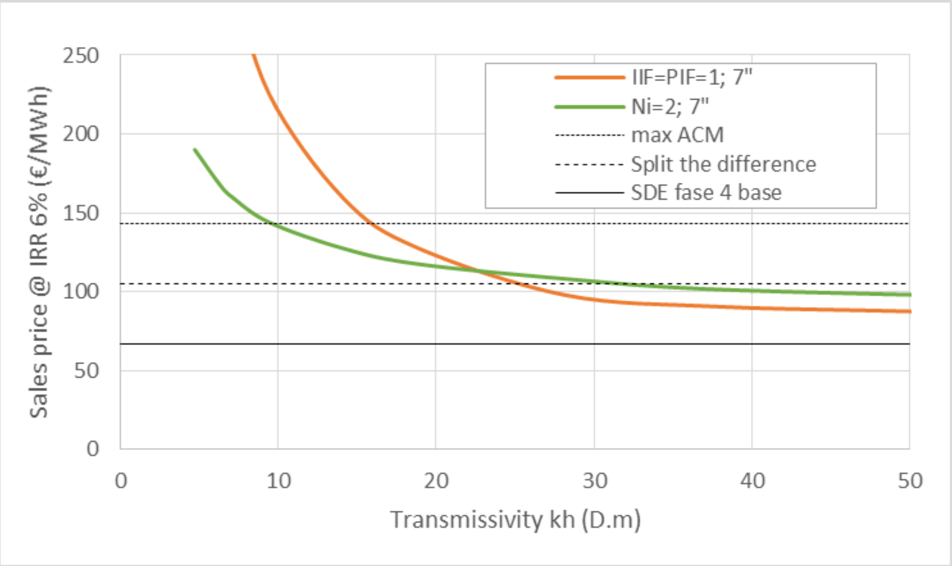

Figure 32: investor view COE of base case and extra injector.

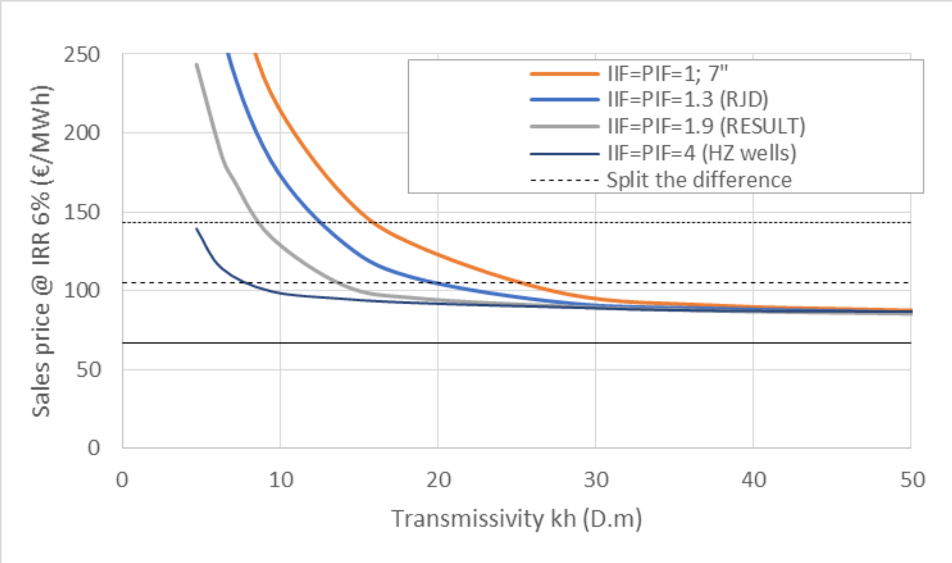

Figure 33: investor view COE of various completions

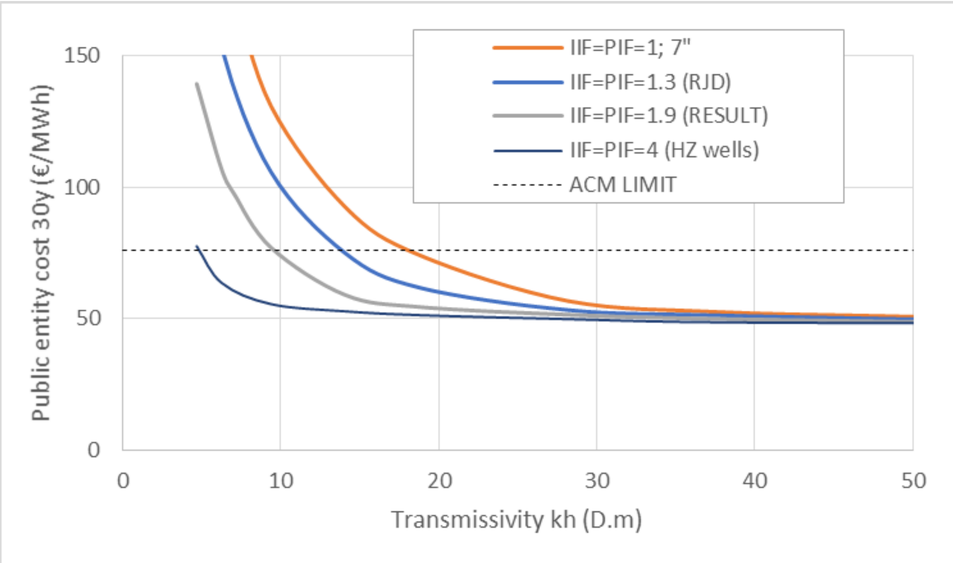

Figure 34: public entity view of various completions

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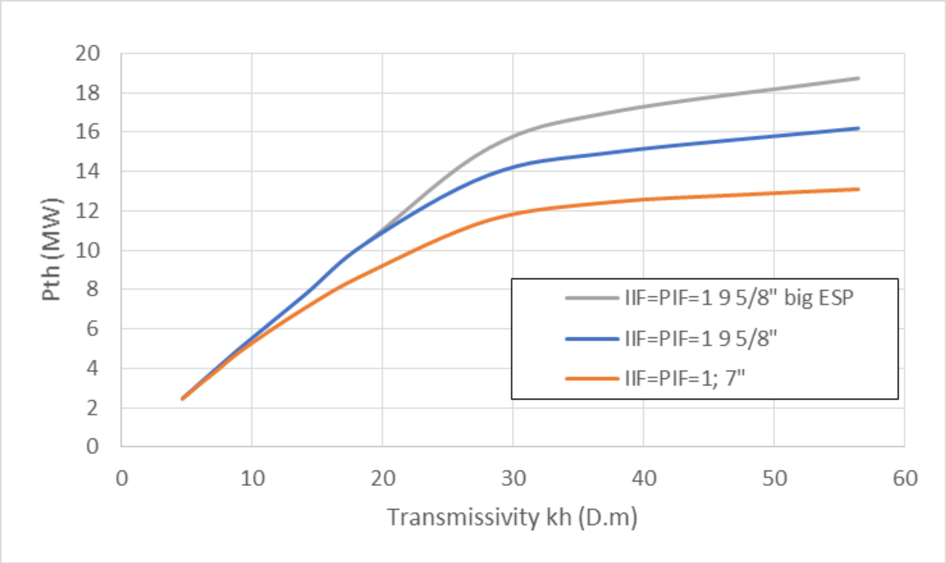

Figure 35: impact of larger tubing and ESP on base case thermal power

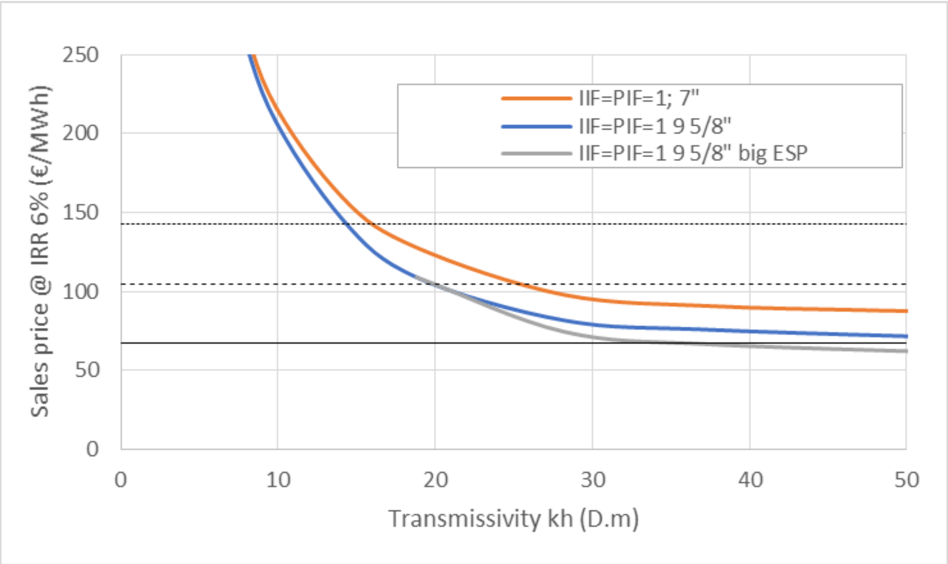

Figure 36: impact of larger tubing and ESP on base case COE

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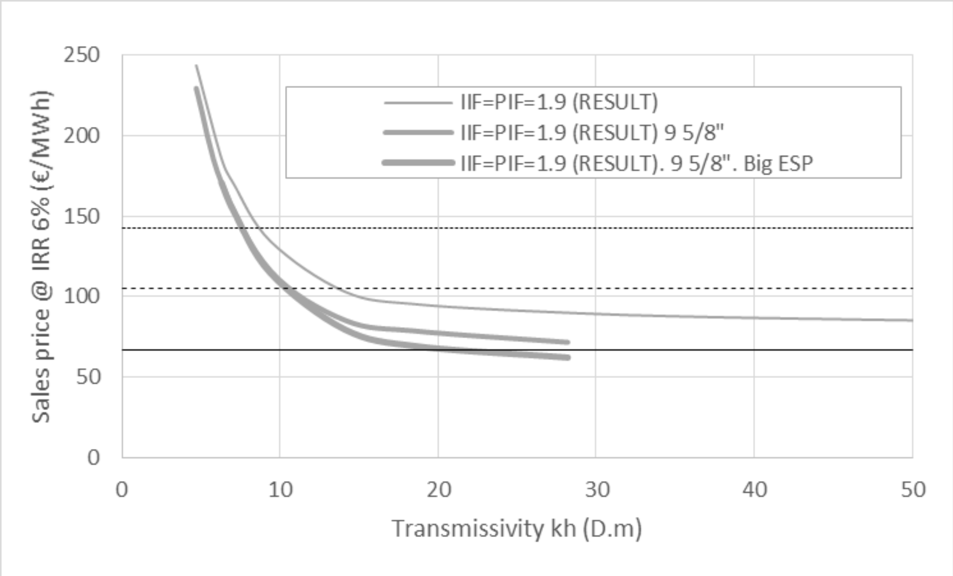

Figure 37: impact of larger tubing and ESP on RESULT COE.

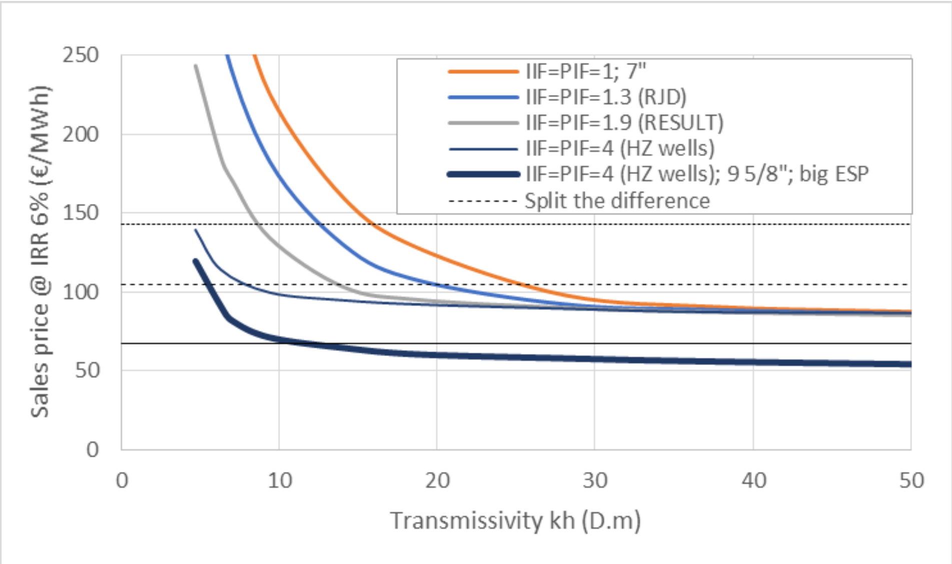

Figure 38: impact of larger tubing and ESP on horizontal wells COE

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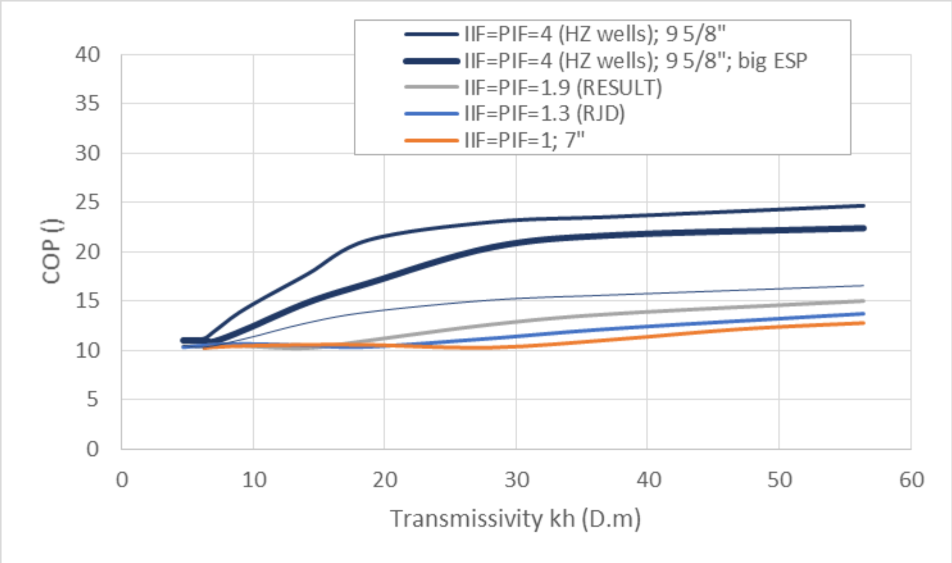

Figure 39: impact of larger tubing and ESP on COP

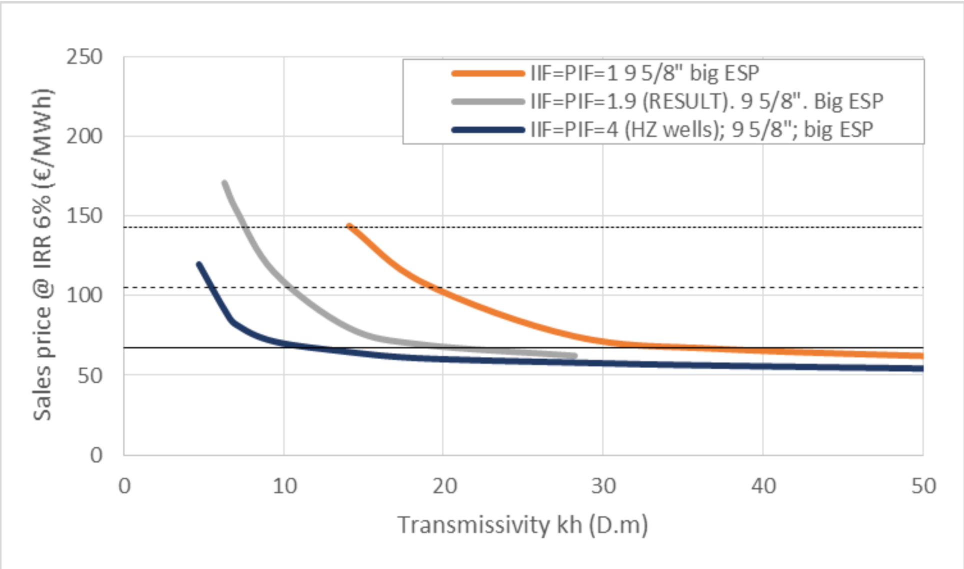

Figure 40: COE of various techniques assuming larger tubing and ESP for all cases.

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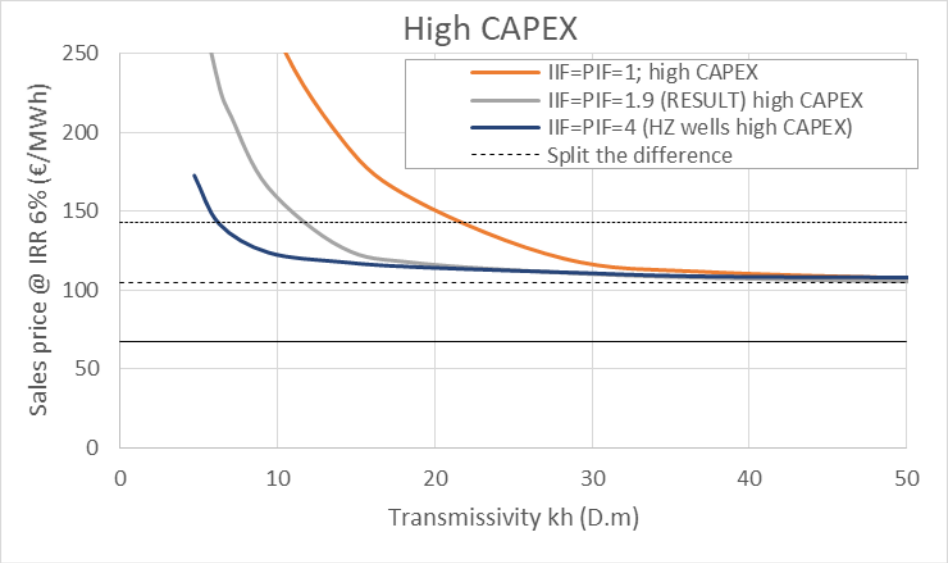

Figure 41: Investor COE; high CAPEX scenario.

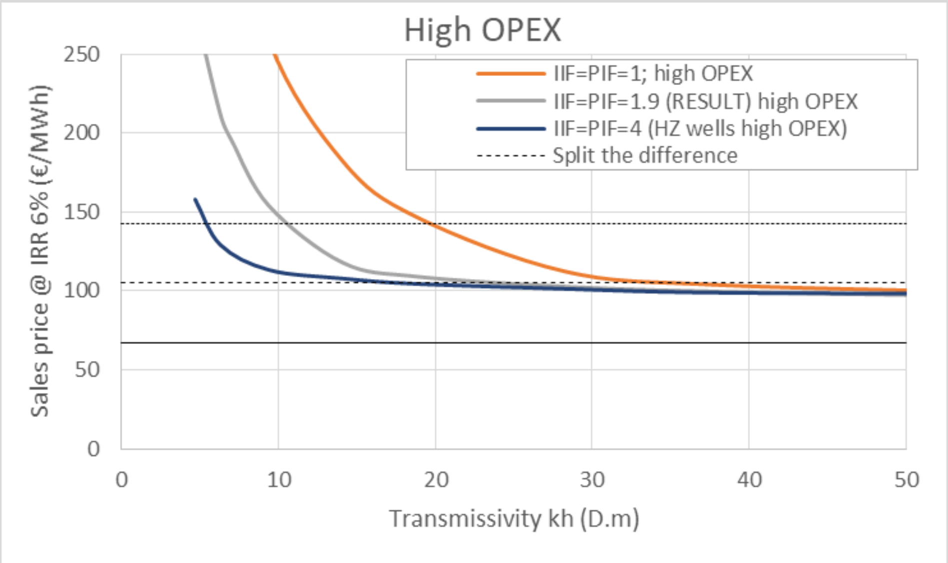

Figure 42: Investor COE; high OPEX scenario.

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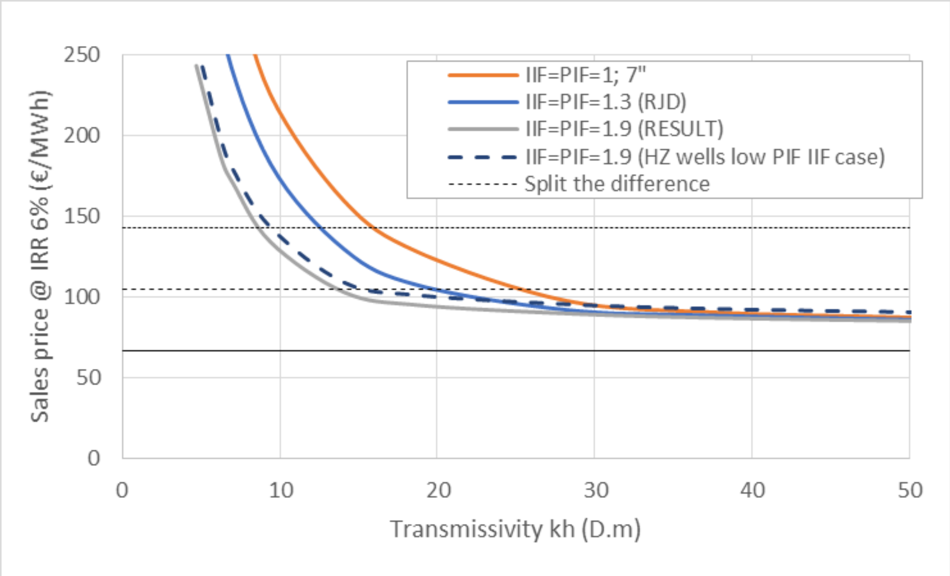

Figure 43: COE of various techniques, case with low PIF and IIF for horizontal well.

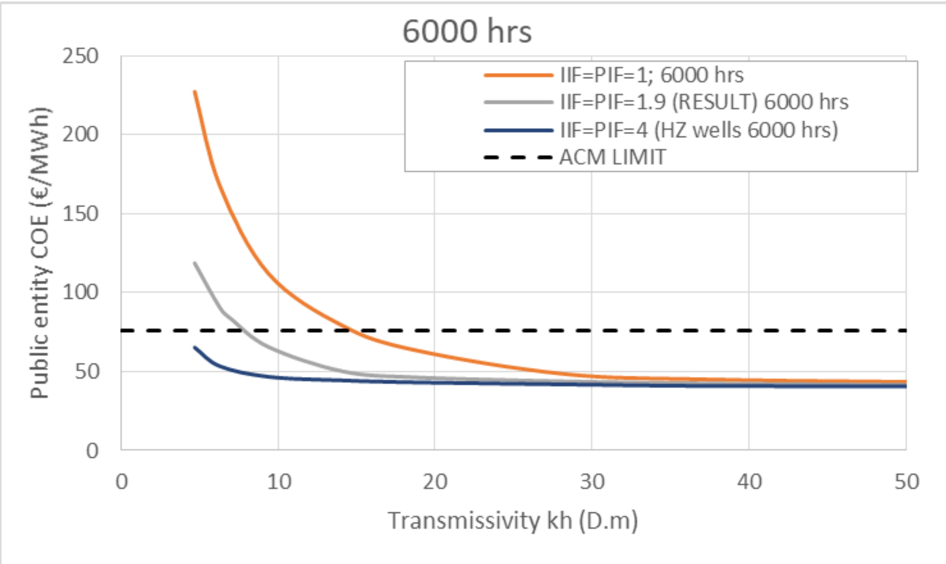

Figure 44: Public entity COE; 6000 hrs sales per year scenario.

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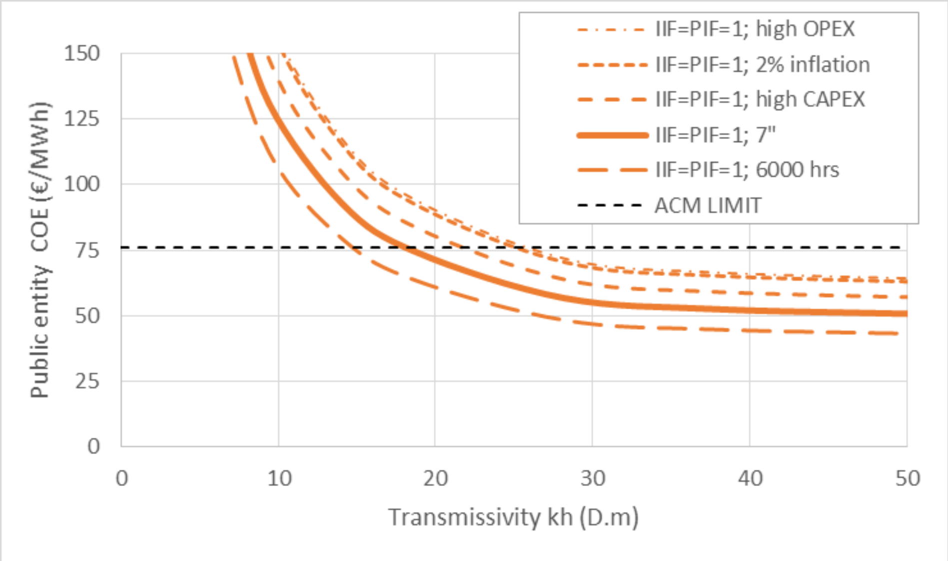

Figure 45: Public entity COE sensitivities. Base case semi-vertical wells.

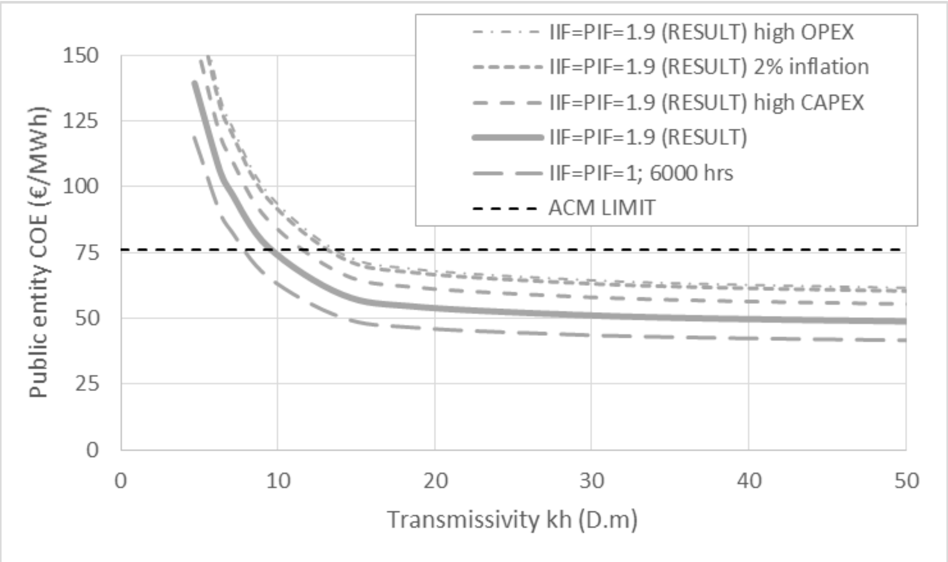

Figure 46: Public entity COE sensitivities. RESULT wells.

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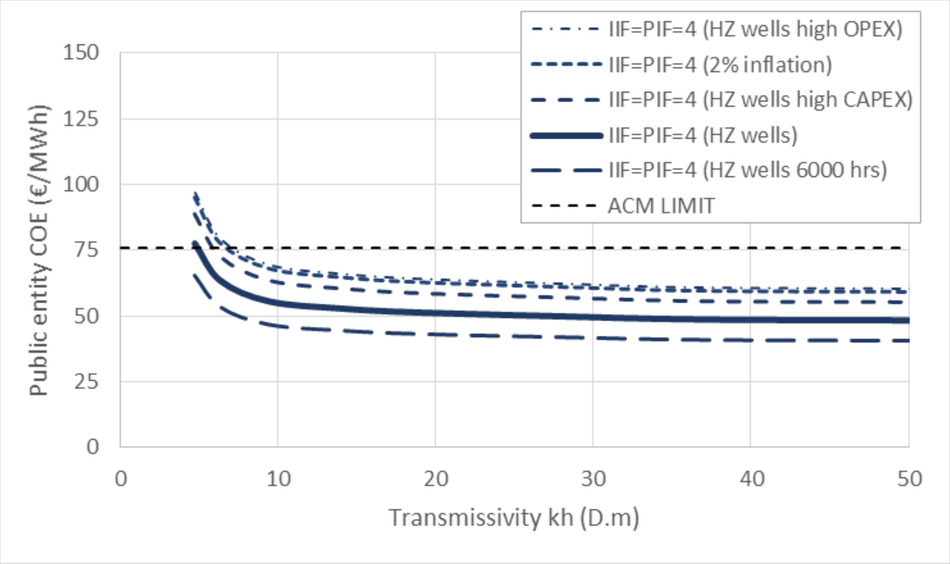

Figure 47: Public entity COE sensitivities. Horizontal wells.

14 Appendix A: `EBN_REPTool` calculation spreadsheet

For this report a simple mass balance tool was made to estimate the merit of improving the Productivity and Injectivity indices.

For the injector, the water injection rate Q_i is (following Dake (32)):

$$Q_i = IIF \frac{2\pi kh(BHP_i - P_{res})}{\mu_c \ln {}^{L}/_{r_w}} \qquad \text{..........................(A.1)}$$

with

P_{res} the initial reservoir pressure

BHP_i the injection bottom hole pressure

L The distance between the injector and producer[5]

kh the well transmissivity

μ_c the cold water viscosity

r_w the wellbore radius

IIF the injectivity index improvement factor, equal to 1 in the base case.

For the producer:

$$Q_p = PIF \frac{2\pi kh\left(P_{res} - BHP_p\right)}{\mu_h \ln {}^{L}/_{r_w}} \qquad \text{..........................(A.2)}$$

With μ_h the viscosity of the hot water and PIF a productivity improvement factor equal to 1 in the base case.

When an injector tubing head pressure THP_i is applied, the injector bottom hole pressure is:

$$P_i = THP_i + \Delta P_{gr} - \Delta P_f$$

Here ΔP_f is the pressure drop due to friction, and ΔP_{gr} is the gravity head, the depth times the density difference between the cold, salt injection water and the average aquifer brine from reservoir to surface.

The injection rate for N_i injectors is then:

$$Q_i = \alpha_i \left(THP_i + \Delta P_{gr} - \Delta P_f\right) \qquad \text{..........................(A.4)}$$

[5] Following (21), instead of L the reservoir drainage radius r_e needs to be used here. For the doublets under study L is not a trivial number, since in the direction between the injector and producer it is $L/2$, but in the other direction it can be many kilometers. A practical compromise – consistent with `DoubletCalc` – is therefore to assume $r_e = L$

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with

$$\alpha_i = IIF \frac{2\pi kh}{\mu_c \ln {}^{L}/_{r_w}}$$

The friction coefficient is calculated from the `DoubletCalc` deterministic case with a quadratic dependence on Q_i:

$$\Delta P_f = aQ_i^2 + bQ_i + c$$

…………………….(A.5)

Substituting (A.5) in (A.4) and solving for Q_i yields:

$$Q_i = \frac{-\alpha_i b - 1 + \sqrt{(\alpha_i b + 1)^2 + 4\alpha_i a(\alpha_i THP_i + \alpha_i \Delta P_{gr} - \alpha_i c)}}{2\alpha_i a}$$

…………………….(A.6)

A similar equation can be derived for the production rate with a producer THP_p.

$$Q_p = \alpha_p \left(\Delta P_{ESP} - \Delta P_f - THP_p - \Delta P_{gr}\right)$$

…………………….(A.7)

Note here both the gravity head and THP work the other way: an increase in these pressure leads to a reduction in producer drawdown.

Mass balance requires:

$$Q_i \rho_c = Q_p \rho_h$$

With ρ_c and ρ_h the injection and production water densities.

Now THP_i ΔP_{ESP} can be iterated until three constraints are met:

1. Mass balance of the injector and producer is between 98% and 102%
2. THP_i is below the maximum pressure allowed by SodM. This pressure is dependent on well top depth d and gradient $\rho_c g$ (bar/m) of the injection water:

   $THP_{i,max}$ *(bar) = (0.135 -* $\rho_c g$*) d*

3. The product Q_p ΔP_{ESP} is within the Operating Envelope of the ESP

When these conditions are met, the following three cells become green in the spreadsheet:

Mass balance?	1,01
SodM match	0,7
BORETS OpEnv	0,30

(A.6) becomes slightly more complex for the case where the number of injectors N_i >1. In this case, the friction in (A.5) is calculated per well, so the equations (A.4) and (A.5) are first solved for Q_i / N_i and the result is multiplied by N_i to get the total injection rate.

$$Q_i = N_i \, \alpha_i \left(THP_i + \Delta P_{gr} - \Delta P_f\right)$$

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……………………..(A.8)

$$Q_i = \frac{-1 - \frac{\alpha_i b}{N_i} + \sqrt{\left(\frac{\alpha_i b}{N_i} + 1\right)^2 + \frac{4\alpha_i a}{N_i^2}\left(N_i \alpha_i THP_i + N_i \alpha_i \Delta P_{gr} - \alpha_i c\right)}}{2\alpha_i a \Big/ N_i^2}$$

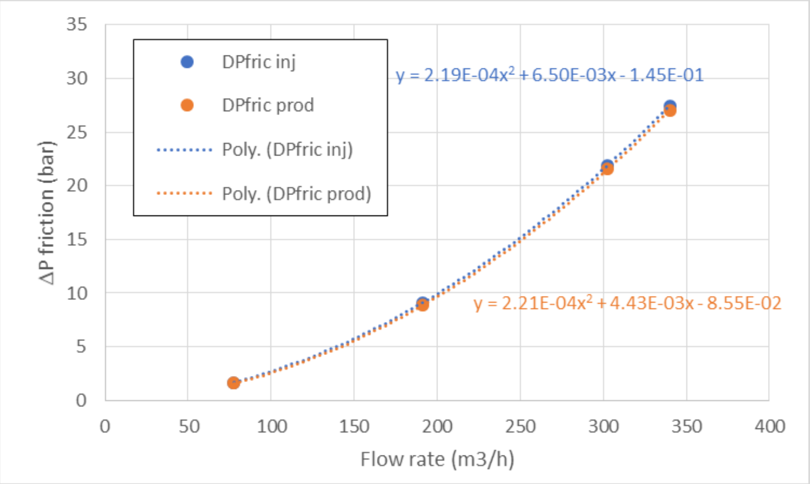
……………………..(A.9)

This is then the reason that the N_i =2; *IIF* = 1 case has a higher injection rate than the N_i =2; *IIF* = 1 case: the first has less injector tubing friction at equal Q_p.

The spreadsheet does not cater for N_p >2, but when needed can be adapted for this. Note that then the electricity consumption of the ESP needs to be multiplied by N_p .

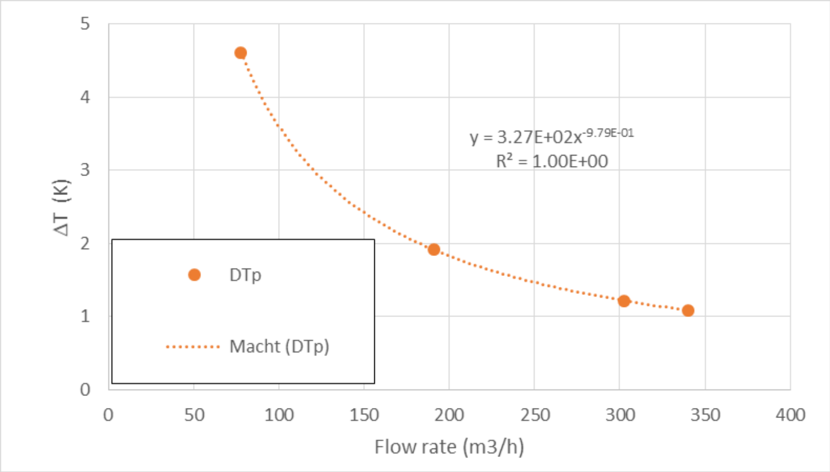
The *a, b* and *c* parameters of (A.5) were calculated with `DoubletCalc`. For the current situation, the relations are essentially quadratic and the *b* and *c* parameters can be ignored but are implemented in the spreadsheet for flexibility.

For the 7”monobore location with input data from Table 1 and Table 2 the fit is as follows:



Note the friction is independent of fluid viscosity. This is because at the rates studied in this report, the flow regime is fully turbulent (*Re* ~ 10^6).

The temperature loss from bottom reservoir to heat exchanger was also calculated with `DoubletCalc`. The correlation there is a power law ~ 1 / *Q*:



Now a first order estimate can be made for the distance from the injector r_1 where the pressure $P_{½}$ is halfway the injection bottom hole pressure BHP_i and production pressure BHP_p.

From the mass balance and Eq. (A.1) and (A.2) it follows:

$$\frac{\rho_c 2\pi kh(BHP_i - P_{½})}{\mu_c \ln {}^{r_1}/_{r_w}} = \frac{\rho_h 2\pi kh\left(P_{½} - BHP_p\right)}{\mu_h \ln {}^{r_2}/_{r_w}}$$

L - r_1 is the producer distance from the place where the pressure is $P_{½}$.

Following the definition of $P_{½} = (BHP_i+BHP_p)/2$ this means:

$$\frac{\rho_c}{\mu_c \ln {}^{r_1}/_{r_w}} = \frac{\rho_h}{\mu_h \ln {}^{r_2}/_{r_w}}$$

……………. (A.10)

Introducing

$$a = \frac{\mu_h \rho_c}{\mu_c \rho_h}$$

$$x_1 = {}^{r_1}/_{r_w}$$

$$x_2 = {}^{r_2}/_{r_w}$$

Eq. (A.10) is re-written as:

$$\ln x_1 = a \ \ln x_2$$

or

$$x_1 = {x_2}^a$$

……………………….. (A.11)

Taking L = 1000 m, r_w = 0.1 m, and injecting and producing at the same temperature and density, a = 1 and this leads to the trivial result $r_1 = r_2 = L/2$ = 500 m.

Assuming the cold water having the same density but double the viscosity of the hot water, a = 0.5. Eq. (A.11) then becomes a quadratic equation and can be solved to give r_2 = 990 m and r_1 = 10 m. This means that that just 10 m away from the injector, the pressure has dropped by half the total pressure drop between the injector and producer. The other half then takes place in the remaining 990 m. For other values, eq (A.11) can be solved iteratively using Excel goal-seek.

15 Appendix B: Electricity generation from associated gas

From the KKP-GT-02 well test it was measured (33) that associated gas was produced with a GWR of 0.54 m^3/m^3, and the gas had a calculated calorific value of C_v 30.6 MJ/m^3. Assuming an electricity generation efficiency of η_e of 40% this would yield an electrical power P_{el} of:

$$P_{el} = Q_p \;\; GOR \;\; C_v \, \eta_e \tag{B.1}$$

with a flow rate of 250 m^3/s or 0.07 m^3/s this yields around 0.5 MW of electrical power.

The electricity consumption of the combined pumps adding a pressure ΔP is

$$P_p = \frac{Q_p \times \Delta P}{\eta_p} \tag{B.2}$$

With η_p the efficiency of the combined[6] pump system, taken here as 0.75.

Equating (B.1) and (B.2) gives the ΔP that can be generated by the associated gas:

$$\Delta P = GOR \times C_v \times \eta_p \times \eta_e \tag{B.3}$$

Note this is independent of flow rate. With the numbers above this equates to 50 bar. Since this is similar to the ESP ΔP it can to first order be assumed that the doublet can generate its own electricity.

[6] In `EBN_REPTool` separate efficiencies of 72% and 80% were used for the ESP and booster pumps respectively.

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16 Appendix C: ESP depth

The entry pressure P_{in} to the ESP should not be too low since this would lead to large free gas volumes and reduced ESP life. In order to achieve this, the ESP should be placed at a certain depth d_{ESP}. The pressure at this depth is:

- the initial reservoir pressure $P_{res} = \rho_{av}\, g\, d$, with d the reservoir depth, ρ_{av} the average density of the aquifer water from top well to reservoir (~ 1000 + (ρ_h – 1000)/2) *minus*
- The producer drawdown Q_p/α_p *minus*
- the friction between the reservoir and the inlet of the ESP. With the same ID below and above the pump this friction is the fraction 1 - d_{ESP} / d of the total friction ΔP_f of the producer, to be calculated with the producer equivalent of eq. (A.5) *minus*
- The water column (d - d_{ESP}) ρ_h g between the reservoir and the ESP inlet.

$$P_{in} = \rho_{av}\, g\, d - \frac{Q_p}{\alpha_p} - \Delta P_f \left(1 - \frac{d_{ESP}}{d}\right) - (d - d_{ESP})\rho_h\, g$$

……………………..(C.1)

From this d_{ESP} can be calculated:

$$d_{ESP} = \frac{P_{in} - \rho_{av}\, g\, d + \dfrac{Q_p}{\alpha_p} + \rho_h\, g\, d + \Delta P_f}{\rho_h\, g + {}^{\Delta P_f}\!/_{d}}$$

……………………..(C.2)

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17 Appendix D: Economics spreadsheet for COE calculation

17.1 Introduction

To make economic comparisons between the various completion techniques, a simple economics spreadsheet was made allowing the calculation of Cost of Energy (CoE). Here a distinction is made between:

- A ***corporate investor***: a company wanting a return on investment. It is here assumed that this entity is striving to attain an incremental rate of return of 6%. Since this entity is likely to apply for SDE++ subsidies that act for 15 years, a 15 year time horizon is taken for heat delivery. Capital costs are depreciated over 10 years. The COE is then the lowest heat sales price to the grid that attains this minimum IRR.
- A ***public entity*** e.g. a council or other government agency. With current low interest rates this entity can borrow money at very low (or even negative) interest rates and it is here calculated what the CoE would be by simply dividing expenditures by delivered heat over a 30 year period. No subsidies are taken into account.

17.2 Costs

For capital (CAPEX) and operational (OPEX) costs, numbers are taken from PBL (34).

		PBL
		EA19
Pth	(MW)	13
Uptime	(h/y)	3500
Investeringskosten	(€/kW)	1523
Fixed opex	(€/(kW y))	105
Variable opex	(€/(kWh y))	0,0019
Investeringskosten	(M€)	20
Fixed opex	(M€/y)	1,4
Variable opex	(M€/y)	0,09

The spreadsheet will calculate a range of thermal power depending on completion, transmissivity etc. In the current calculations this will ***not*** have an effect on above numbers, e.g. when a low transmissivity leads to a calculated thermal power of 6.5 MW, the capex and opex will not be halved, since drilling investment costs will have been realized at this time and lower transmissivity will lead to lower Coefficient of Performance so higher electricity costs per delivered MWh heat. The PBL numbers are hence seen as typical investment and operational costs, independent of thermal power. For the costs of the various completions (RJD, RESULT, horizontal wells), rig time and a “spread rate” is taken. The spread rate is the average from Table-1 of (1): 0.16 M€/d.

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For the rig time of horizontal wells, data is taken from the recent horizontal wells SCH-3101 and SCH-3102, where 138m was drilled per day, largely over horizontal sections. As a check the ROP was calculated for the extended reach well SGZ-4. Here it took 15 days to drill from 5 km to 7 km ahd, with a deviation angle of around 70 degrees. ROP here was hence 133 m/d, very similar to above number.

For RESULT and RJD the number of days depends on the number of branches, see Table 3.

17.3 CoE calculation

The CoE calculation goes as follows:

- A project is started in 2021, where 1.0 M€ opex is spent on studies, permits etc.
- In 2022 the wells are drilled and facilities are built. For a standard doublet this equates to a capital investment of 20 M€ conform (34). Adding a well costs (dual injector sensitivity) adds 4.2 M€, from Table 4-2 of (34).
- During 2022 again 1.0 M€ opex is spent for project overheads.
- If special drilling techniques are used, this is added to the capex following above table.
- From 2023 – 2052 the project delivers heat (as calculated by the spreadsheet) with uptime 3500 h/y, at an opex of 1.5 M€ conform (34).
- In 2053 the project is abandoned, ABEX is 10% of capex.

For the public entity case CoE is then calculated as Σ(opex+capex+abex) / heat sales.

The CoE calculation for the corporate case is slightly more complicated, with the following additional steps:

- Yearly sales are calculated by multiplying the assumed heat price by the uptime.
- Cash flow is calculated as heat sales – yearly opex – 10% of Capex, the latter for the first 10 years only.
- A corporate tax rate of 25% is applied to profits
- The resulting net cash flow is used for an IRR calculation. The heat price is then changed until the required IRR is achieved.

Again, no subsidies are taken into account at this point, however, the required heat sales price to grid will be compared to SDE++ subsidy levels and the allowed maximum heat sales price as determined by the ACM, here assumed at the 2021 level of 76 €/MWh ex VAT.

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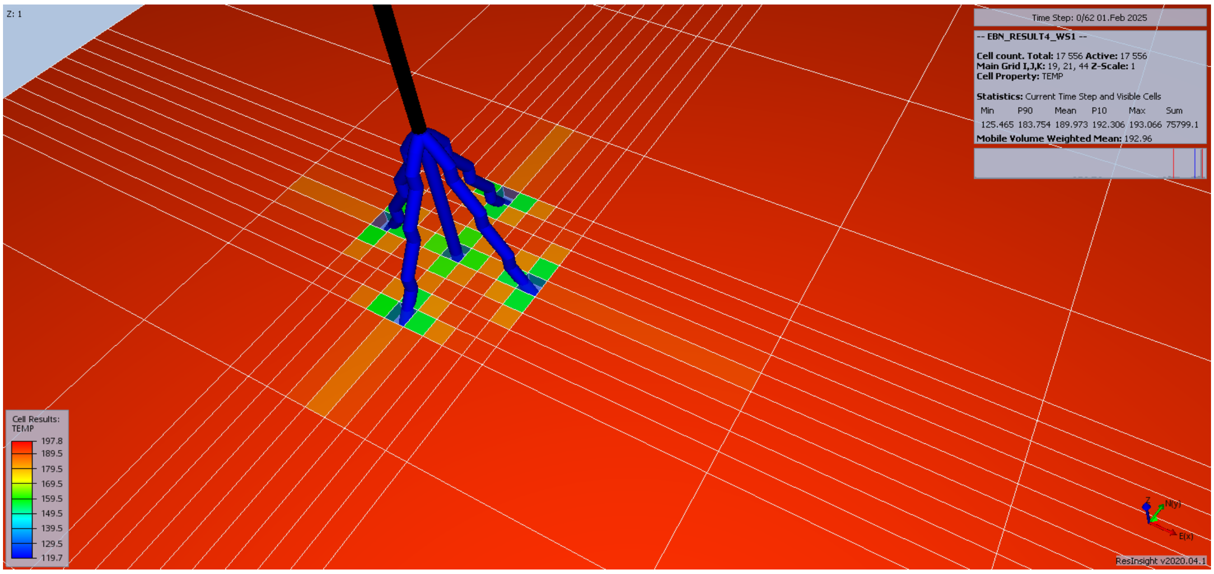
18 Appendix E: `OPM flow` IIF calculations

Whilst `PROSPER` could be used to derive the Injectivity Improvement Factor (IIF) for horizontal wells, it is not designed to calculate the merit of short radius horizontal (RJD) or deviated (RESULT) sidetracks. In this Appendix, the numerical simulator `OPM flow` is used in thermal mode to compare the II of vertical wells with RJD and RESULT sidetracks. Note this was out of scope for the current study so the below results should be seen as preliminary.

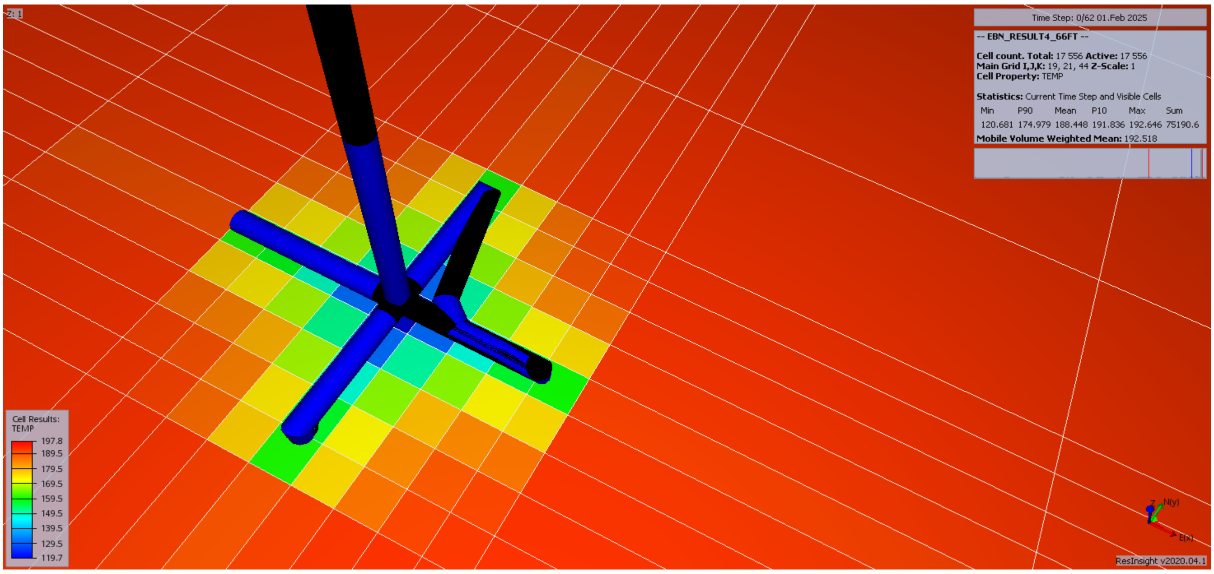
A simulation grid was built with a single injector and producer and 5000 stb/d of water was produced and injected year average. The calculated drawdown was then used to determine the Injectivity Index. Dividing this to the base case vertical well II leads to the IIF of the various techniques.

A reservoir sand of 47 m net and 134 mD was used for the simulation. Care was taken to include considerable over- and underburdens to enable heat sinks. A reservoir temperature gradient was used resulting in a sand temperature of 89 C for the sand of interest. Water is injected at 49 C; temperature dependence of the viscosity is imposed using the `WATVISCT` keyword.

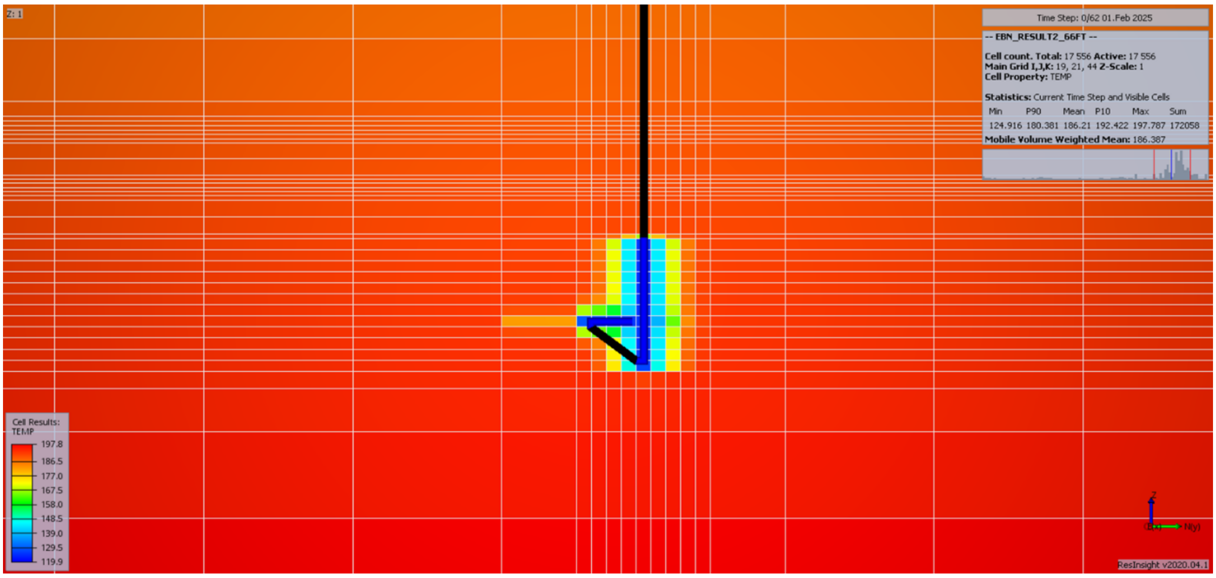
A top view of the simulation grid (layer 44, one of the bottom layers of the sand) shows the fine gridding around the injector. This is the four legged RESULT case with 23 degree angle after one month injection. Note the developing banks of cold water around the branches and the main injector.



A similar view of the four legged RJD case:



A side view of the one legged RJD case shows the vertical gridding with large over- and underburden:



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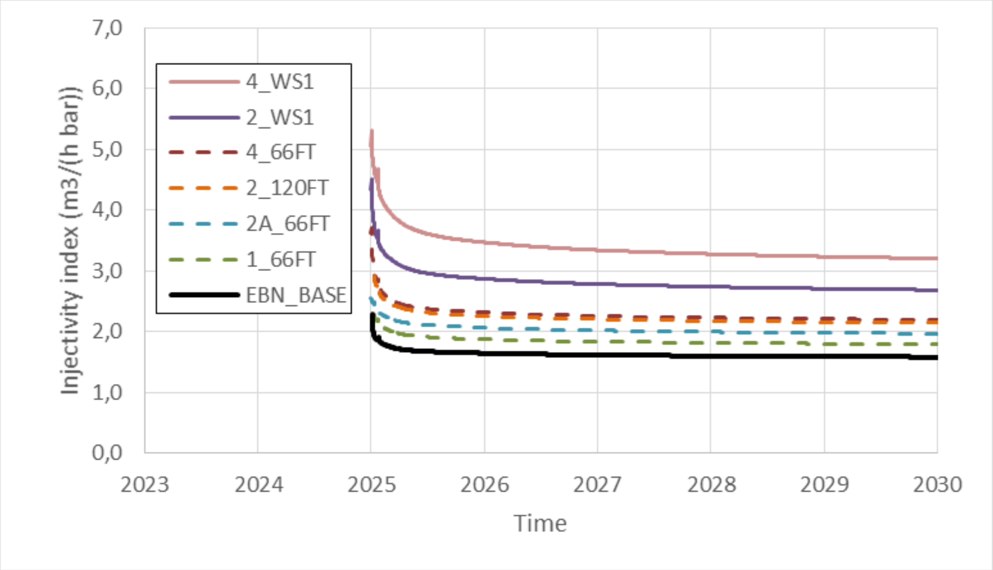
The injectivity Index of the RJD and 23 degree RESULT cases versus time, compared to the base case vertical well then looks like this:



These then lead to the IIF of Table 5.

Note the II of 1.6 m^3/(h bar) is higher than the 1.1 m^3/(h bar) that is derived using Darcy's equation and data from Table 1. The reason for this is two-fold: (a) the boundary pressure in this small model is not at 1000 m but around 200 m. (b) the Darcy equation assumes a full cold bank, whereas `OPM flow` calculates that most of the moving water has a higher temperature hence lower viscosity than the injection water.

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19 Appendix F: DoubletCalc and PROSPER vertical lift comparison

In this report, the newly developed EBN_REPTool was used to calculate flow rates. EBN_REPTool was compared with DoubletCalc, to make sure physical results were derived. In this Appendix, a quick comparison is made of above tools with PROSPER.

Reservoir model: PROSPER's "Darcy" model was used for this test. With a Dietz shape factor of 31, drainage area of π (1500 m)^2 , reservoir thickness of 50*0.94 m and permeability of 134 mD, a well PI of 3.0 (m^3/(h bar)) was obtained, more than the 2.5 (m^3/(h bar)) calculated in DoubletCalc. This is due to the viscosity of 0.51 cP in PROSPER and 0.61 cP in DoubletCalc. The PI is around 2x the calculated Injectivity Index of the previous Appendix, since the production water viscosity is half that of the injection water. Density in the producer well is 1154 kg/m^3 in PROSPER and 1159 kg/m^3 in DoubletCalc. Detailed investigation of the above differences was considered out of scope for the current study.

With the above differences it can be imagined that no perfect match could be obtained between the softwares. Below shows the 6.3 D.m base (no booster) case with IIF=1, where a 98 bar ΔP_{ESP} led to a 43 bar THP_i and 89 m^3/h rate in EBN_REPTool. Imposing this rate on PROSPER and using a 56 Hz 40 stage REDA 540 ESP at 1856 ft (the depth calculated in EBN_REPTool to get an intake pressure of 10 bar) yields below pressure and temperature traverse.

The THP and THT match well, but here the ESP frequency was changed to obtain this match and hence the THP match is trivial. PROSPER calculates only a 92 bar ΔP_{ESP} to be needed to obtain the rate and THP. The friction in PROSPER is around 1.5 bar lower, but the main reason is the FBHP difference of 5 bar due to the PI difference. This then explains the 6 bar difference in ΔP_{ESP}. and also the 6 bar higher intake pressure of the ESP in PROSPER.

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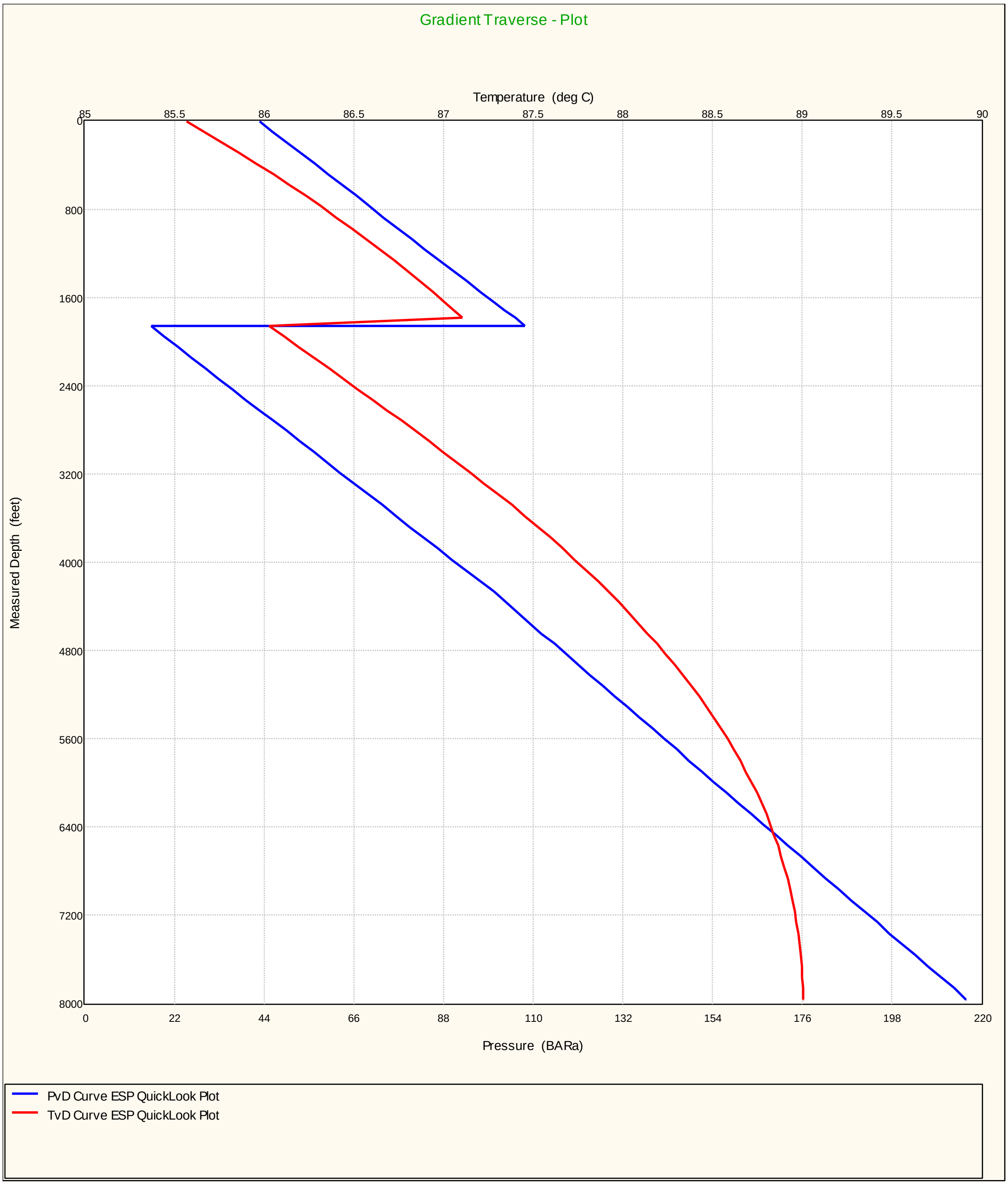

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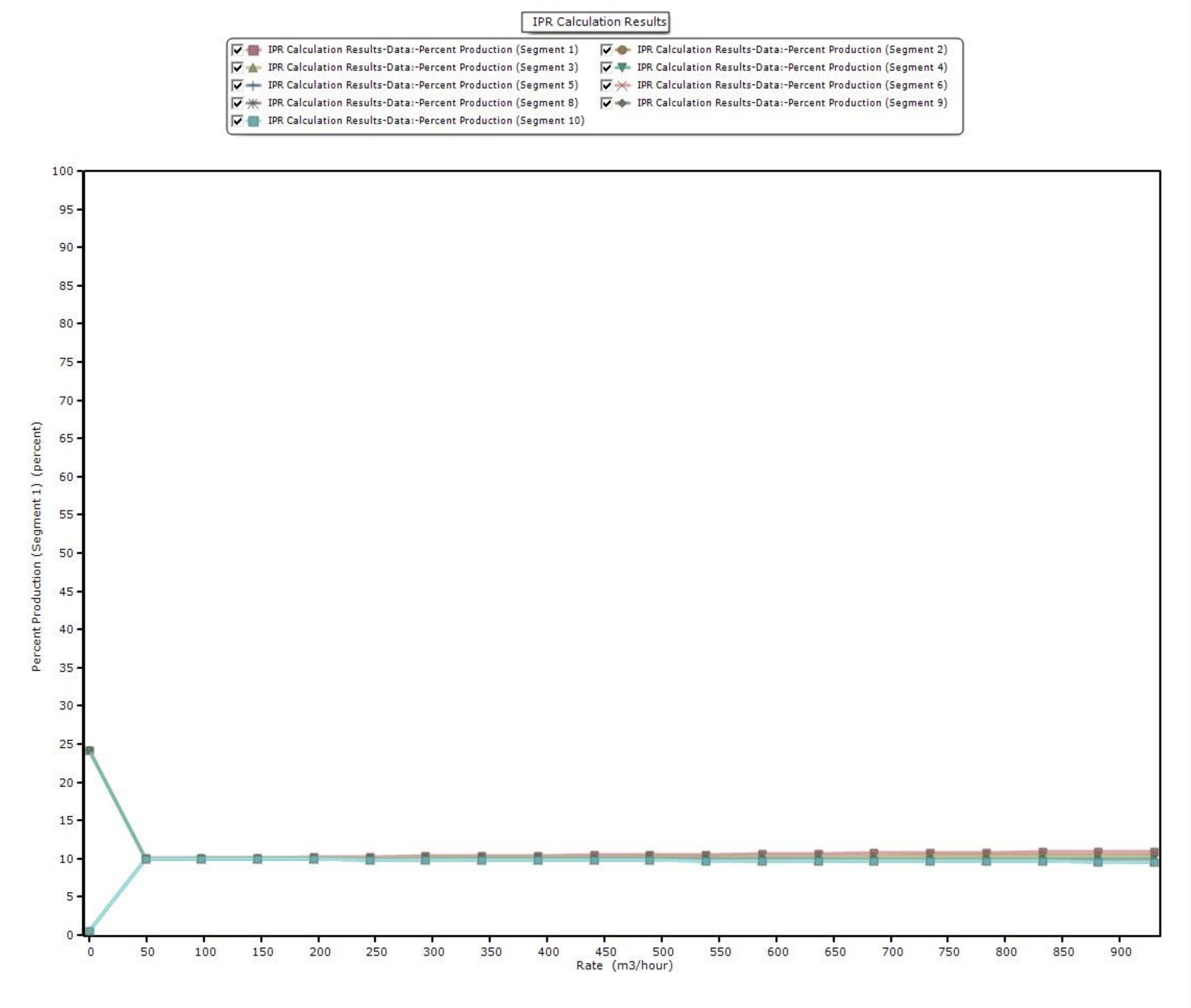
In section 5.2 it was argued that pressure drops in the horizontal tubing can be ignored since they are much lower than the pressure drop in the reservoir. This is confirmed by using the “Horizontal well with dP” option in `PROSPER`, where the horizontal well is divided in 10 sections and the contribution of each section is calculated, including pressure drop in the well itself.

It can be observed below that for the base case (134 mD; 6.3 D.m) all but the very highest flow rates, the contribution of each section is very close to 10%, indicating no influence of pressure drops in the tubing. If the latter would have been relevant, the heel section would have shown much higher production rates than the toe section.



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This case was re-run for the high permeability case (1200 mD). Here, at high flow rates the pressure drop in horizontal section starts to have some effect with the heel segment 1 showing slightly higher production than the toe section.